Indian Technology Catalogue

Generation and Storage of Electricity

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Danish Energy Agency

Green Strategic Partnership India-Denmark

सत्यमेव जयते

B.K. ARYA
Chairperson (I/C)
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FOREWORD

The world is focusing on environmental issues, especially climate change and therefore, the idea of growing sustainably has taken center stage globally. India being an active participant has already started taking several initiative towards sustainable development and green energy transition. Hon'ble Prime Minister of India has recently announced during COP26 held at Glasgow that India will take its non-fossil electricity installed capacity to 500 GW by the year 2030.

The demand for power is increasing with the increase in economic activity. Availability of affordable and reliable power is a key factor in sustainable growth of the country. Meeting the increasing demand along with the green energy transition is an opportunity as well as a challenge for the country. This can happen with appropriate policy initiatives and associated regulations which are conducive for transitioning towards clean sources along with sustainable growth of power sector. The huge growth in power sector and requisite policy directives necessitates detailed long term generation expansion plan studies for optimal use of all the resources.

Government of India has taken several initiatives in last few years for increasing share of renewable technologies in generation capacity mix. A MoU has been signed between Ministry of Power, Govt. of India and Ministry of Climate, Energy & Utilities, Kingdom of Denmark on 5th June, 2020 to develop and promote strategic and technical cooperation in energy sector for mutual benefits. Preparation of Technology Catalogue is one of the major activity under the India Denmark Energy Partnership (INDEP) program.

The primary purpose of the technology catalogue is to provide standardized data for analysis of electricity systems, including economic scenario models and high-level energy planning studies. The technology catalogue may aid in power sector planning, analysis and policy formulation by governments. The catalogue would make the relevant data of generation technologies publicly available for all the stakeholders. The technology catalogue may therefore be used as a standardized database comprising of inputs from across the Indian power sector.

The first technology catalogue focuses on the key technologies in the current Indian power system, hence primarily mature technologies, and has lesser focus on technologies with limited deployment or technologies that are in Research, Development & Demonstration stages. Battery and offshore wind power technologies are included as these technologies are expected to have a significant role in future of Indian power system and their global deployment justifies their inclusion in the catalogue.

The first technology catalogue has been reviewed by key stakeholders from the Indian power sector and Government institutions to ensure that the information is latest and according to Indian conditions.

I would like to thank all the stakeholders for their cooperation in timely giving their valuable inputs making the publication possible. I would also like to thank team of officers from IRP Division, CEA who along with Danish Experts for the excellent job. I wish that Technology Catalogue will fulfill the expectations and needs of all the stakeholders who are engaged in development of power sector.

(B.K. ARYA)

Kristoffer Böttzauw
Director General
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FOREWORD

To ensure a sustainable world for future generations, we stand before a substantial, global transformation of the energy sector. Renewable energy technologies have seen a rapid development with a subsequent cost reduction that support the global green energy transition. India is estimated to see the largest increase of energy demand of any country in the world. To respond to this challenge, the Government of India has set unprecedented and ambitious targets for variable renewable energy and a green and sustainable societal transition.

In the process to reach the target of 500 GW non fossil power capacity in 2030, long-term energy planning is a crucial tool to align long-term objectives with short-term plans. However, long-term energy planning relies on estimates of current and future power generating technologies' costs and performances to be a beneficial tool.

This is exactly the objective of the first Indian Technology Catalogue: The aim is to establish a uniform, public, commonly accepted and up-to-date platform for all Indian power planning activities. In this manner, the technology catalogue will support analysis and decision-making for governmental power planning, but also making these data publicly available for all interested parties. The technology catalogue should therefore be used as a standardized database comprising of inputs from across the Indian power sector.

The first Indian Technology Catalogue is jointly developed under the India-Denmark Energy Partnership as a collaboration between the Indian Central Electricity Authority (CEA) and the Danish Energy Agency (DEA). It applies an approach used for decades by the DEA to make Technology Catalogues for power and the energy sectors in Denmark and around the world. It applies a fundamental open public process of collaborating with Indian and local stakeholders to provide transparency behind the long-term planning studies through a publically available Indian Technology Catalogue.

In this first Indian Technology Catalogue, the focus is on developing a broad outset for the main components in the power system now and in the future. The later editions of the Technology Catalogue will update these estimates or focus on newer technologies determined in collaboration with stakeholder requests.

As the Director General of the Danish Energy Agency, together with our outstanding colleagues at CEA, it is a great pleasure to present you with this first Indian Technology Catalogue. We hope that this Technology Catalogue will support and contribute to developing relevant energy policies and long-term energy planning aimed at helping India reach their great targets for the power sector.

Acknowledgements

This technology catalogue is prepared by CEA, DEA and COWI under the India-Denmark Energy Partnership. We would like to acknowledge all the stakeholders in India and abroad who contributed to this technology catalogue by providing technical data, reviewing chapters and participating in workshops. Without these contributions, it would not be possible to produce this publication.

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Abbreviations

a-Si/μc-Si	Amorphous/microcrystalline layer of silicon
AC	Alternating current
AEP	American Electric Power
Ah	Ampere hours
BAU	Business As Usual
BESS	Battery Energy Storage System
BHEL	Bharat Heavy Electricals Limited
BOP	Balance of Plant
BOS	Balance of System
c-Si	Crystalline silicon
CAPEX	Capital Expenditure
CEA	Central Electricity Authority
CEMS	Continuous emission monitoring system
CdTe	Cadmium telluride
CH4-e	Methane emissions
CHP	Combined Heat and Power Plants
CIGS	Copper Indium Gallium Selenide
CO2-e	Carbon dioxide emissions
CPCB	Central Pollution Control Board
CPV	Concentrated Photovoltaic
CUF	Capacity Utilization Factor
DANIDA	Danish International Development Agency
DC	Direct current
DEA	Danish Energy Agency
DFIG	Doubly Fed Induction Generator
di	Copper Indium Gallium

DNES	Department of Non-Conventional Energy Sources
DO	Dissolved oxygen
DTU	Technical University of Denmark
EMF	Electromotive force
EMS	Energy Management System
EPC	Engineering, Procurement and Construction
EROI	Energy Return on Energy Invested
ESP	Electrostatic precipitator
FCR-D	Frequency Containment Reserve for Disturbances
FCR-N	Frequency Containment Reserve for Normal operations
FGD	Flue-gas desulfurization
FID	Final Investment Decision
FIMOI	Financial modelling of offshore wind in India
FOWPI	First Offshore Wind Project of India
GHI	Global Horizontal Irradiance
GW	Gigawatt
HVDC	High-voltage direct current
IEA	International Energy Agency
IFC	International Finance Corporation
IIT Bombay	Indian Institute of Technology Bombay
INR	India Rupee
IRENA	International Renewable Energy Agency
kV	Kilovolt
kWh	Kilowatt-hour
kWp	Kilowatts peak
LCA	Life Cycle Analysis
LCO	Lithium cobalt oxide

LCOE	Levelized Cost of Energy
LCoS	Levelized Cost of Storage
LFP	Lithium Iron Phosphate
LIB	Lithium-ion battery
LIDAR	Light Detection and Ranging
LMO	Lithium Manganese Oxide
LTO	Lithium Titanate Oxide
MCal	Megacalories
MNRE	Ministry of New and Renewable Energy
MOEF&CC	Ministry of Environment, Forest and Climate Change
MPUVNL	Madhya Pradesh Urja Vikash Nigam Limited
Mt	Metric ton
MW	Megawatt
MWh	Megawatt-Hour
NCA	Lithium Nickel Cobalt Aluminium Oxide
NCL	Northern Coalfield Limited
NHPC Limited	National Hydro Power Company Limited
NIWE	National Institute of Wind Energy
NMC	Nickel manganese cobalt oxide
NO_X e	Nitrogen oxide emissions
NREL	National Renewable Energy Laboratory
NTPC Limited	National Thermal Power Corporation
O&M	Operation and Maintenance
OPEX	Operational Expenditure
PLF	Plant Load Factor
PM	Particulate matter
PMSG	Permanent magnetic synchronous generator

PSP	Pumped storage plants
PSU	Public Sector Units
PSS	Power system stabilizers
PP	Power Plant
PV	Photovoltaics
R&DD	Research and Development Department
RCC	Roller compacted concrete
RE	Renewable Energy
Rewa UMSPP	Rewa Ultra Mega Solar Power Project
Rewa RUMSL	Rewa Ultra Mega Solar Limited
SCADA	Supervisory control and data acquisition
SCR	Selective Catalytic Reduction
SECI	Solar Energy Corporation of India Limited
SOC	State of charge
SO_X -e	Sulfur oxide emissions
STC	Standard Test Condition
THDC Limited	Tehri Hydropower Development Corporation Limited
TSO	Transmission System Operator
TWh	Terawatt-hour
USD	U.S. Dollar

1. Methodology

1.1. Objective of the technology catalogue

The main objective of the technology catalogue is to provide generalized information and technical and financial parameters for power generation technologies for analysis of power systems, including economic scenario models and energy planning. In this manner, the technology catalogue will support analysis and decision-making for governmental power planning, but also making these data publicly available for all interested parties. The technology catalogue should therefore be used as a standardized database comprising of inputs from across the Indian power sector. The ambition is that this technology catalogue can act as a common point of reference for the Indian power sector in terms of generation technologies.

Background of the technology catalogue

Technology catalogues have been developed for numerous years in various countries with great success. In Denmark, the first technology catalogue was published more than 15 years ago and today there are six versions publicly available covering different sectors. The technology catalogue experiences have been replicated in collaboration with the Vietnamese, Indonesian, Ethiopian and Mexican governments and now also in India. The applicability across the countries has been proven and is directly used for governmental energy planning. In Denmark, the technology catalogue is the default point of reference for all power system analyses in the government as well as in a large number of research institutions and universities, public organizations, private companies and NGOs.

The Indian technology catalogue will be continuously updated, when relevant, and might be expanded with more power generation technologies and for other sectors.

Data collection

A variety of data sources is used for the technology catalogue. The list below highlights the main sources:

- Indian power sector stakeholder consultation
- Local projects
- Literature studies
- Data from similar countries

The data is prioritized in the following manner:

- Data inputs from Indian stakeholders with key knowledge for a given technology is prioritized above other data sources, when available. Other data sources are used when no stakeholder data is available and for benchmarking the stakeholder data inputs. Data from stakeholders are anonymized and if more than one stakeholder provided data inputs for a technology, the data is aggregated. Data and inputs from more than 15 Indian stakeholders were received, including from private manufacturers, developers, research institutions, consultancies and government agencies.
- Operational data from existing, newer plants in India is prioritized above normative values from Indian regulation and norms. In situations where no operational data is

available, normative data is used. In cases where estimates exist for both operational and normative data, both values are provided in the datasheet notes. Consequently, there might be some discrepancies between the data provided based on operational data and the Indian norms.

The qualitative chapters have been reviewed by key stakeholders from the Indian power sector and government institutions to ensure that the information is up-to-update and according to Indian conditions. In connection with the technology catalogue development, two public workshops have been organized, each with more than 100 participants, and in addition the document was made available in the public domain for stakeholder comments and feedback.

The technology catalogue focuses on the key power generation technologies in the current Indian power system, hence primarily mature technologies, and has lesser focus on technologies with limited deployment or technologies that are in Research, Development & Demonstration stages. Battery and offshore wind power technologies are included as they are expected to have a significant role in the future Indian power system or because their global deployment justifies their inclusion.

Applications of the technology catalogue

It is imperative that the technology catalogue should only be used for certain applications. For example, the technology catalogue on its own cannot be used for prioritizing between technologies as this would require additional studies (e.g. power system modelling analyses, Levelized Cost of Energy analyses, etc.).

The technology catalogue presents data in a general, generic level for India as these data inputs are necessary for the governmental energy planning. Hence, the technology catalogue should not be used for the planning of concrete projects as the local conditions will change from project to project and rather individual feasibility studies are advisable for each project.

The technology catalogue collects best available data for current technologies and projects their performance and costs into the future (2030, 2040 and 2050). This naturally implies a great degree of uncertainty as technologies can develop differently than expected. However, it is necessary to have best available projections for the future for the purpose of long-term energy planning and policy making. Read more about the methodology and assumptions for technology projections in the Appendix.

In addition to power generation data, other inputs are also necessary for power planning, such as demand projections, fuel prices and projections, etc. This technology catalogue has a sole focus on power generation technologies along with few selected power storage technologies.

Three distinct categories of plants are included:

1. **Thermal electricity generation**: plants producing electricity with thermal processes (for example steam cycle or internal combustion engines), including nuclear.
2. **Non-thermal electricity generation**: technologies producing electricity without thermal processes, such as wind power, solar power or hydroelectric power plants.
3. **Electricity storage:** plants consuming and producing electricity without thermal processes such as lithium-ion batteries and pumped storage.

Each technology is subsequently described in a separate technology chapter, making up the main part of this catalogue. The technology chapters contain both a description of the technologies and a quantitative part including a table with the most important technology data. The following sections (1.2 and 1.3) explain the formats of the technology chapters, how data were obtained, and which assumptions they are based on.

1.2. Qualitative description

The qualitative description describes the key characteristics of the technology as concisely as possible. The following paragraphs are included where relevant for the technology.

Brief technology description

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

An illustration of the technology is included, showing the main components and working principles.

Input

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

Output

The forms of energy generated, i.e. electricity, and any relevant by-products.

Typical capacities

The stated capacities are for a single unit capable of producing energy (e.g. a single wind turbine or a single gas turbine), not a power plant consisting of a multitude of units. The only exception is for CCGT gas plants where one module (3GT+1 ST, 2 GT +1 ST or 1 GT+1 ST) is taken as generating capacity.

In the case of a modular technology such as PV, a typical size of a solar power plant based on the market standard is chosen as a unit. Different sizes may be specified in separate tables.

Space requirement

Space requirement is expressed in 1000 m^2 per MW. The value presented only refers to the area occupied by the facilities needed to produce energy.

In case the area refers to the overall land use necessary to install a certain capacity, or a certain minimum distance from dwellings is required, for instance in case of a wind farm, this is specified in the notes. The space requirements are for example used to calculate the rent of land, which although included in the financial cost of some technologies, depends largely on the specific location of the plant.

Regulation ability and other power system services

Regulation abilities are particularly relevant for electricity generating technologies. This includes the part-load characteristics, start-up time and how quickly it is able to change its production when already online.

If relevant, the qualitative description includes the technology's capability for delivering the following power system services:

- Inertia
- Short circuit power
- Black start
- Voltage control
- Damping of system oscillations (PSS)

Advantages/disadvantages

A description of specific advantages and disadvantages relative to equivalent technologies.

Environment

Environmental characteristics are mentioned, for example special emissions or the main ecological footprints.

The energy payback time or energy self-depreciation time may also be mentioned. This is the time required by the technology for the production of energy equal to the amount of energy that was consumed during the production and the installation of the equipment.

Research and development perspectives

This section lists the most important challenges to further development of the technology. Also, the potential for technological development in terms of costs and efficiency is mentioned and quantified if possible. Indian research and development perspectives are highlighted, where relevant.

Examples of market standard technology

Recent full-scale commercial projects, which can be considered market standard, are mentioned. For technologies where no market standard has yet been established, reference is made to best available technology in R&D projects.

Prediction of performance and costs

Cost reductions and improvements of performance can be expected for most technologies in the future. This section accounts for the assumptions underlying the cost and performance in 2020 as well as the improvements assumed for the years 2030, 2040 and 2050.

In formulating the section, the following background information is considered:

Data for 2020

In case of technologies where market standards have been established, performance and cost data of recent installed versions of the technology in India or the most similar countries in relation to the specific technology are used for the 2020 estimates.

Learning curves and technological maturity

Projecting the future costs of technologies is carried out by using learning curves. Learning curves express the idea that each time a unit of a particular technology is produced, learning accumulates, which leads to cheaper production of the next unit of that technology. The learning rates also take into account benefits from economy of scale and benefits related to using automated production processes at high production volumes. Further details about the cost projection methods applied in this catalogue is available in the Appendix.

Uncertainty

The catalogue covers both mature technologies and technologies under development. This implies that the price and performance of some technologies may be estimated with a relatively high level of certainty whereas in the case of others, both cost and performance today as well as in the future are associated with high levels of uncertainty. This includes technological or market related issues of the specific technology as well as the level of experience and knowledge in the sector and possible limitations on raw materials.

The level of uncertainty is illustrated by providing a lowest and highest value observed in the data. It should be noted, that projecting costs of technologies far into the future is a task associated with very large uncertainties. Thus, depending on the technological maturity and the period considered, the confidence interval may be very large. It is the case, for example, of less developed technologies and long-time horizons (2050).

References

References are numbered in the text in squared brackets and bibliographical details are listed in this section.

1.3. Quantitative description

To enable comparative analyses between different technologies it is imperative that data are actually comparable: All cost data are stated in fixed 2020 prices, excluding taxes and subsidies. The information given in the tables relate to the development status of the technology at the point of final investment decision (FID) in the given year (2020, 2030, 2040 and 2050). FID is assumed to be taken when financing of a project is secured and all permits are at hand. The year of commissioning will depend on the construction time of the individual technologies.

In the technology catalogue, operational data from existing plants are prioritized if available and subsequently normative values based on regulation are used. If both types of values are available, the operational value will be included in the table while a note will specify the normative value.

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

Each cell in the table contains only one number, which is the assumed value for the market standard technology, i.e. no range indications.

Uncertainties related to the figures are stated in the columns named uncertainty, if available. To keep the table 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. These are chosen to reflect the uncertainties of the best projections. For technologies in the early stages of technological development or technologies especially prone to variations of cost and performance data, the bounds expressing the confidence interval could result in large intervals. The uncertainty only applies 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).

The level of uncertainty is stated for the most critical figures such as investment cost and efficiencies. Other figures are considered if relevant.

All data in the tables are referenced by a number in the utmost right column (Ref), referring to source specifics below the table.

Notes include additional information on how the data are obtained, as well as assumptions and potential calculations behind the figures presented. Before using the data, please be aware that essential information may be found in the notes below the table.

The generic parts of the tables are presented below:

Technology		**Thermal (COAL, GAS, NUCLEAR, BIOMASS) electricity generation**								
	2020	**2030**	**2040**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)										
Electricity efficiency Gross (%), name plate										
Gross Heat Rate at 55% loading (MCal/MWh)										
Gross Heat Rate at 65% loading (MCal/MWh)										
Gross Heat Rate at 75% loading (MCal/MWh)										
Gross Heat Rate at 100% loading (MCal/MWh)										
Auxiliary Power Consumption (%)										
Forced outage (%)										
Planned outage (weeks per year)										
Technical lifetime (years)										
Construction time (years)										
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Minimum load without secondary fuel support (% of full load)										
Ramp Up Rate (% of Full Load/Minute)										
Ramp Down Rate (% of Full Load/Minute)										
Minimum Up time (hours)										
Minimum Down time (hours)										
Hot start-up time (hours)										
Warm start-up time (hours)										

Cold start-up time (hours)										
Hot Start-up fuel consumption (MCal/MW)										
Warm Start-up fuel consumption (MCal/MW)										
Cold Start-up fuel consumption (MCal/MW)										
Environmental data										
SOx (mg/Nm^3 fuel)										
NOx (mg/Nm^3 fuel)										
Standard Particulate Matter (mg/Nm^3 fuel)										
Financial data (in 2020₹)										
Capital Cost (crore ₹/MW)										
- of which equipment (%)										
- of which installation (%)										
Fixed O&M (crore ₹/MW/year)										
Variable O&M (₹/MWh)										
Hot Startup cost (₹/MW/startup)										
Warm Startup cost (₹/MW/startup)										
Cold Startup cost (₹/MW/startup)										

Technology		**Non-thermal (HYDRO, SOLAR, WIND) electricity generation**								
	2020	**2030**	**2040**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)										
Location-wise Capacity Utilization Factor (FOR WIND & SOLAR ONLY)										
Forced outage (%)										
Planned outage (weeks per year)										
Auxiliary Power Consumption (%)										
Technical lifetime (years)										
Construction time (years)										
Regulation ability										
Ramp Up Rate (% of Full Load/Minute) (FOR HYDRO ONLY)										
Ramp Down Rate (% of Full Load/Minute) (FOR HYDRO ONLY)										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Financial data (in 2020₹)										
Capital Cost (crore ₹/MW)										
- of which equipment (%)										
- of which installation (%)										
Fixed O&M (crore ₹/MW/year)										
Variable O&M (₹/MWh)										

Note: Addition/deletion may be carried as per requirements

Technology	Energy storage technologies (PUMPED STORAGE, BATTERY ENERGY STORAGE)									
	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)										
Charging efficiency (%)										
Forced outage (%)										
Planned outage (weeks per year)										
Auxiliary Power Consumption (%)										
Technical lifetime (years)										
Construction time (years)										
Storage capacity (MWh)										
Discharge time (h)										
Depth of Discharge (%) (ONLY FOR BATTERY)										
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Ramp Up Rate (% of Full Load/Minute)										
Ramp Down Rate (% of Full Load/Minute)										
Primary load support (% per 30 seconds)										
Secondary load support (% per minute)										
Minimum load (% of full load)										
Financial data (in 2020₹)										
Capital Cost (crore ₹/MW)										
Capital Cost per MWh basis (crore ₹/MWh) (FOR BATTERY ENERGY STORAGE SYSTEM ONLY)										
Fixed O&M (crore ₹/MW/year)										
Variable O&M (₹/MWh)										

Energy/technical data

Generating capacity for one unit

The capacity is stated for a single unit, capable of producing energy, e.g. a single wind turbine (not a wind farm), or a single gas turbine (not a power plant consisting of multiple gas turbines). The only exception is for CCGT gas plants where one module (3 GT+1 ST, 2 GT +1 ST or 1 GT+1 ST) is taken as generating capacity

In the case of a modular technology such as PV, a typical size of a solar power plant based on the historical installations or the market standard is chosen as a unit. Different sizes may be specified in separate tables.

The capacity is given as gross generation capacity.

The unit MW is used for electric generation capacity.

The relevant range of sizes of each type of technology is represented by a range of capacities stated in the uncertainty field in each technology table, for example 200-800 MW for a new coal-fired power plant.

It should be stressed that data in the table 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 inside the range of typical sizes (see the section about investment cost).

Energy efficiencies/Auxiliary Power Consumption

Efficiencies for all thermal plants are expressed in percent.

Two efficiencies are stated: the nameplate efficiency as stated by the supplier and the expected auxiliary power consumption.

The expected typical annual efficiency takes into account a typical number of start-ups and shut-downs and is based on the assumed plant load factor.

The energy efficiency for intermittent technologies (e.g. PV and wind) is expressed as Capacity Utilization Factor (CUF). The Capacity Utilization Factor is calculated as the annual production divided by the maximum potential annual production. The maximum potential annual production is calculated assuming the plant has been operating at full load for the entire year, i.e. 8760 hours/year. For certain technologies, the Capacity Utilization Factor will change according to the energy resources at the specific location, i.e. for technologies such as wind power, PV and hydropower. In such cases, the CUF data should be provided with information about the expected location. If available, data for various locations can be provided.

Energy storage type technologies (e.g. Battery storage and pumped storage) is expressed in two parts: Charging efficiency and auxiliary power consumption (discharging efficiency).

Gross Heat Rate at different load

Gross Heat rate at different loads is the heat energy input (MCal) per unit of electrical energy output (MWh) rate for specific levels of power plant output.

Forced and planned outage

Forced outage is defined as the number of weighted forced outage hours divided by the sum of forced outage hours and operation hours. The weighted forced outage hours are the sum of hours of reduced production 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 overhauling) is given in weeks per year.

Technical lifetime

The technical lifetime is the expected time for which a power plant can be operated within, or acceptably close to, its original performance specifications, provided that normal operation and maintenance takes place.

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

Time from final investment decision (FID) until commissioning is completed, expressed in years.

Regulation ability

Thirteen parameters describe the electricity regulation capability of the technologies:

A. Primary regulation (% per 30 seconds): frequency control
B. Secondary regulation (% per minute): balancing power
C. Minimum load without secondary fuel support (% of full load).
D. Hot start-up time (hours)
E. Warm start-up time (hours)
F. Cold start-up time (hours)
G. Hot Start-up fuel consumption (MCal/MW)
H. Warm Start-up fuel consumption (MCal/MW)
I. Cold Start-up fuel consumption (MCal/MW)
J. Ramp Up Rate (% of Full Load/Minute)
K. Ramp Down Rate (% of Full Load/Minute)
L. Minimum Up time (hours)
M. Minimum Down time (hours)

For several technologies, these parameters are not relevant, e.g. if the technology is regulated instantly in on/off-mode.

Parameters A and B are spinning reserves; i.e. the ability to regulate when the technology is already in operation.

Parameter C. The minimum load is the lowest possible gross load a generating unit can deliver under stable operating conditions. It is measured as a percentage of normal load or the rated capacity of the unit.

Parameters D, E, F. The start-up time is defined as the period from starting plant operation till reaching minimum load. The start-up time of different generation technologies varies greatly. The other factor influencing the start-up time are down time (period when the power plant is out of operation).

Parameters G, H, I. The start up fuel consumption is defined as the fuel consumption in MCal/MW during the period from starting plant operation till reaching minimum load.

Parameters J, K. The ramp rate is the rate at which a plant can change its gross power during operation defined as a (% of Full Load/Minute).

Parameters L, M. The minimum up or down time is defined as the minimum time that the plant must be kept running after start-up or remain closed after shutdown.

Environment

All plants are assumed to be designed to comply with the environmental norms.

CO_2 emission values are not stated, as these depend mainly on the fuel, not the technology. However, CO_2 emission values may differ based on the levels of unburnt carbon in the boiler.

SO_x emissions are calculated based on the sulphur contents of fuels measured as mg/Nm^3 fuel.

NO_x emissions equal NO_2 + NO emissions, where NO is converted to NO_2 in weight-equivalents.

Particulate matter is provided as mg/Nm^3 fuel.

Financial data

Financial data are all in Rupees (₹), fixed prices, at the 2020-level and exclude taxes, subsidies and inflation for future years for comparison purposes.

Some data inputs are based on global references. For those data a fixed exchange ratio is used.

This is done as generalizations of costs of energy technologies has been found to be impossible above the regional or local levels. For renewable energy technologies this effect is even stronger as the costs are widely determined by local conditions.

Capital costs

The capital cost is also called the engineering, procurement and construction (EPC) price or the overnight cost. Infrastructure and connection costs, i.e. electricity, fuel and water connections inside the premises of a plant, are also included.

The capital cost is reported on a normalized basis, i.e. cost per MW. The capital cost per MW is the total investment cost divided by the capacity stated in the table, i.e. the capacity as seen from the grid. For electricity generating technologies the denominator is the electric capacity.

Where possible, the capital cost is divided as a percentage fraction between equipment cost and installation cost. Equipment cost covers the components and machinery, including environmental facilities, whereas installation cost covers engineering, civil works, buildings, grid connection, installation and commissioning costs of the system.

In case of Battery Energy Storage Systems, the capital cost is divided into per MWh basis costs which cover the Battery cost including battery management system cost and per MW basis costs which cover the inverter cost and other installation related costs.

The land cost is not included unless defined and can be assessed per site based on the space requirements, if specified in the qualitative description.

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

Cost of grid expansion

The costs of grid expansion from adding a new electricity generator or a new large consumer (e.g. an electric boiler) to the grid <u>are not included in the presented data</u>.

The most important costs are related to strengthening or expansion of the local grid and/or substations (voltage transformation, pumping or compression/expansion). The costs vary significantly depending on the type and size of generator and local conditions.

Operation and maintenance (O&M) costs

The fixed share of O&M is calculated as cost per generating capacity per year (crore ₹/MW/year), where the generating capacity is 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, property tax, and insurance. Any necessary reinvestments to keep the plant operating within the technical lifetime are also included, whereas reinvestments to extend the life are excluded.

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.

Start-up costs

Start-up costs are stated in costs per MW of generating capacity per start up (₹/MW/startup), if relevant. They reflect the direct and indirect costs during a start-up and the subsequent shut down.

The direct start-up costs include fuel consumption, e.g. fuel which is required for heating up boilers and which does not yield usable energy, electricity consumption, and variable O&M costs corresponding to full load during the start-up period.

The indirect costs include the theoretical value loss corresponding to the lifetime reduction for one start up. For instance, during the heating-up, thermal and pressure variations will cause fatigue damage to components, and corrosion may increase in some areas due to e.g. condensation.

An assumption regarding the typical amount of start-ups is made for each technology in order to calculate the O&M costs.

Technology specific data

Additional data is specified in this section, depending on the technology.

2. Coal Power Plant

2.1. Brief technology description

The catalogue distinguishes between three types of coal fired power plants: subcritical, supercritical and ultra-supercritical. The names refer to the input temperature and pressure of the steam when entering the high-pressure turbine. The main differences are the efficiencies of the plants.

Subcritical is defined by CEA as below 225.4 kg/cm2 and 374 degree C. The gross electricity efficiency of sub-critical plants in India is typically 35%-37%. Both supercritical and ultra-supercritical plants operate above the water-steam critical point, which requires pressures of more than 225.4 kg/cm2 (by comparison, a subcritical plant will generally operate at a pressure of around 150-170 kg/cm2). Above the water-steam critical point, water will change from liquid to steam without boiling. Supercritical designs are employed to improve the overall efficiency of Turbine-Generator (TG) cycle to get better heat rate, reduced fuel consumption and less greenhouse gas emissions. Supercritical plants in India typically operate at 247-270 kg/cm2 and 537-593 degree C. This corresponds to a gross electricity efficiency of around 40%. Ultra-supercritical plants in India typically operate at around 270 kg/cm2 and 600 degree C, yielding a gross electricity efficiency of around 40-41%.

2.2. Input/output

Output is electricity. The gross electricity efficiency is typically between 35-37% for subcritical plants. The Auxiliary Power Consumption (APC) of coal-based unit generally varies from 6% to 8% (depending on unit size, type of BFP drive etc.) excluding APC of Pollution control equipment (PCEs). In general, the self-consumption of the coal-fired plants is about 6.5-7.5%.

The process is primarily based on coal but will be applicable to other fuels such as wood pellets and natural gas. Also, LDO/heavy fuel oil can be used as start-up or reserve fuel.

2.3. Typical capacities

Subcritical power plants can be from 30 MW and upwards. Globally, supercritical and ultra-supercritical power plants are larger and usually range from 400 MW to 1500 MW (Ref. 2). In India, the smallest subcritical power plant unit is of 30 MW and available up to 600 MW. The supercritical units generally have minimum nameplate capacity of 660MW and largest unit being of 800 MW in India.

2.4. Regulation ability and power system services

Regulation abilities are particularly relevant for electricity generating technologies. This includes the part-load characteristics, start-up time and how quickly it is able to change its production when already online.

International experience shows that pulverized fuel power plants can deliver both frequency control and load support. Advanced units are in general able to deliver 3% of their rated capacity per minute as frequency control at loads as low as 30% (Ref. 4, 5 and 7). In India, a pilot test of unit 6 at Dadri TPS demonstrated that 3%/min ramp rates at 40% minimum load were possible.

According to international experience, such fast load control is achieved by utilizing certain water/steam buffers within the unit. The load support control takes over after approximately 5 minutes, when the frequency control function has utilized its water/steam buffers. The load support control can sustain the 5% load rise achieved by the frequency load control and even further to increase the load (if not already at maximum load) by running up the boiler load.

Negative load changes can also be achieved by by-passing steam (past the turbine) or by closure of the turbine steam valves and subsequent reduction of boiler load.

The coal power plants in India have primarily been used for base load. However, with the increase in the share of renewable energy within the Indian energy mix, power plants are required to be more flexible. A CEA study from 2019 (Ref. 7) analyses the flexibility of Indian coal-based power plants, in current load situation. The study indicated that major retrofit is not required to operate coal based thermal units at 55% load. Further, NTPC has demonstrated 40% minimum load operations at one unit (490MW) in Dadri TPS, however, this has required approx. INR 20 Crores (in 2019) in capital expenditure.

Figure 2-1 provides an overview of the projected contribution from different sources in Business-As-Usual (BAU) scenario in 2021. Considering an effective contribution from other energy sources it is estimated that a 1% ramp rate across all power plants will be sufficient in meeting the required system ramp capability. However, this scenario may change significantly due to higher share of renewable energy in the Indian energy mix. The BAU scenario presented in the graph below considers the scenario without implementation of proposed measures in the study (Ref. 7) such as re-allocation of Hydro & Gas, pumped & battery storage and RE curtailment for grid balancing.

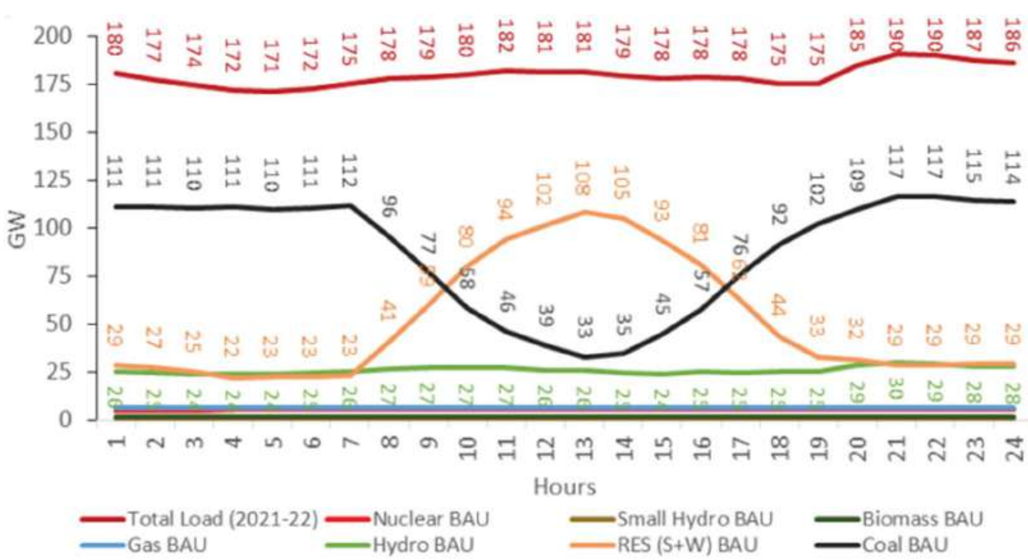

Figure 2-1: Projected contribution from different sources in meeting demand-2021 (Ref. 7)

2.5. Advantages/disadvantages

Advantages

- Mature and well-known technology.
- The efficiencies are not reduced as significantly at part load compared to full load as with combined cycle gas turbines.
- High reliability and low cost of electricity production (in terms of LCOE), especially in countries with local availability of coal.
- Provide ramping capabilities for grid security based on power demand.

Disadvantages

- Coal fired power plants with no pollution control emit high concentrations of NO_x, SO_2 and particulate matter (PM).
- Coal has a high CO_2 content.
- High water consumption of operations.
- Waste management – produces a large quantity of Fly Ash that needs to be reused / disposed.
- Coal fired power plants using the advanced steam cycle (supercritical) possess the same fuel flexibility as the more conventional subcritical boiler technology. Inexpensive heavy fuel oil cannot be burned due to materials like vanadium, unless the steam temperature (and hence efficiency) is reduced.
- Compared to other technologies such as gas turbines or hydro power plants, the coal thermal plants have lower ramp rates and are more complex to operate.

2.6. Environment

The burning and combustion of coal creates the products CO_2, CO, H_2O, SO_2, NO_2, NO and particulate matter (PM). CO, NO_x and SO_2 particles are unhealthy for the brain and lungs, causing headaches and shortness of breath, and in worst case death. CO_2 causes global warming and thereby climate changes (Ref. 2). Additionally, coal fired power plants consume significant amount of water and therefore must be located close to a surface water body (reservoir / river). In terms of waste management, fly ash constitutes the largest contributor due to significantly high ash content in Indian Coal. Ash content in Indian coal varies from 25-45%, whereas average ash content for imported coal varies from 10 to 20% (Ref. 14).

All coal-fired plants in India must ensure that the emissions are within the permitted level as specified in:

- Environment (Protection) Amendment Rules, 2015
- National Ambient Air quality standards (CPCB :2009)
- Environmental guidelines for Thermal Power Plants (MoEF&CC, 1987)
- Stack Height Limits for Thermal Power Plant (Environmental Protection Rules, 1986 and amendments from 2018)

Without applying technical solution to control the emission, the amount of pollutants such as dust, SO_2, NO_x, particulate matter and CO_2 will exceed the allowed limit.

Therefore, the coal-fired plants in India are applying pollution control equipment to maintain emission within permitted level, including:

- Electrostatic precipitator (ESP) / Bag filter: Remove ash from the exhaust
- Flue-gas desulfurization (FGD): Reduction of SO_2,
- Selective Catalytic Reduction (SCR): Reduction of NO_x (Thermal plants using Circulating Fluidized Bed boiler do not apply)
- In addition, the chimneys of the plants are required to install a continuous emission monitoring system (CEMS)

2.7. Research and development

Conventional supercritical coal technology is well established and therefore no major improvements of the technology are expected. There is very limited scope to improve the cycle thermodynamically. The ongoing research efforts towards development of Advanced ultra-supercritical power plants is focused on the application of new materials that could allow higher pressure and temperature in the boiler and turbine system. This will help in achieving higher efficiencies though the same is likely to come at a significantly higher cost (Ref. 3).

Increased flexibility is also an area for R&D and includes installation of a boiler water circulation system, adjustment of the firing system, allowing for a reduction in the number of mills in operation, combined with control system upgrades and potentially training of the plant staff (Ref. 5, 6 and 9).

2.8. Prediction of performance and cost

Projections about the future investment costs of coal power plants can be made by looking at past prices and global capacity developments. Due to the maturity of the technology and the low increase in capacity expected for future years, a low variation in the costs of coal-fired power plants is expected. Moreover, it is possible that the capital cost will increase as a result of the reduction in the technology deployment. It is expected that no or only very few subcritical coal power plants will be constructed in India in the coming years.

Using the learning rate methodology, which translates the variation in installed capacity into a cost variation, the future prices for coal-fired power plants were projected. In 2050, coal-fired power plant investment costs are around 1% lower than in 2020.

The resulting cost development trend can be observed in Figure 2-2.

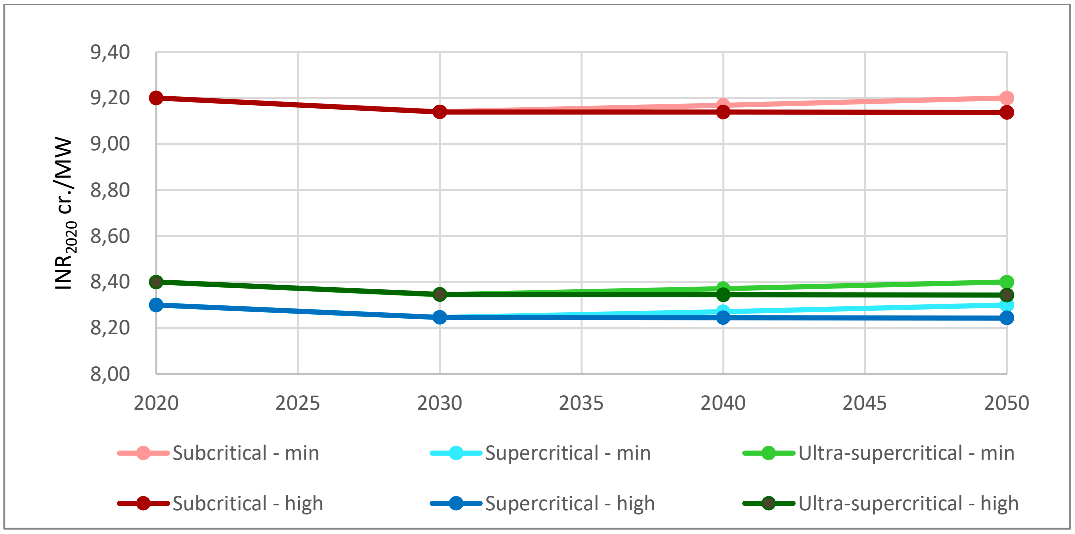

Figure 2-2: Projected coal power plant investment costs development from 2020 to 2050 considering a minimum and high development scenario.

2.9. Examples of market standard technology

Chinese, German and Danish coal fired plants have been analysed as examples of state-of-the-art technologies. Flexibility in Danish and Chinese coal-based power plants have been analysed in Ref. 5 and 6. For German and Danish cases see Ref. 9. In comparison to Indian coal plants, typical Danish coal-based power plants are significantly more flexible and have minimum generation of 15-30% as well as ramping speeds of roughly 4% of nominal load per minute on their primary fuel. These results have been achieved through retrofitting in relation to existing plants. The investments typically include installation of a boiler water circulation system, adjustment of the firing system, allowing for a reduction in the number of mills in operation, combined with control system upgrades and potentially training of the plant staff. Estimating the additional cost/capital costs savings of flexible technology is challenging as it varies greatly from plant to plant dependent on the scope of works (Ref. 5, 6).

2.10. Examples of existing projects

Sub-critical coal

1. LANCO Anapara C project

Figure 2-3: Anpara 'C' Thermal Power Station, Sonbhandra (Ref. 15)

Anpara C thermal power station is located in Sonbhandra District of Uttar Pradesh and is one of the series of power plants within Anapara Thermal Power Station (9 units of total 3830 MW installed capacity). This is a private project being operated by LANCO Infratech (privately held) and has two subcritical units of 600 MW each. Both of these units were commissioned in 2011 and employs imported machinery.

The total cost of project was estimated to be INR 4000 Crores (2007 prices). The plant sources its coal from adjoining northern coal fields (within 25 km), which is fed through Northern Coalfield Limited (NCL) owned freight trains. The input coal is estimated to have ash content of 37.4% and sulphur content of 0.6%. The plant had a recorded Plant Load Factor (PLF) of 75% in 2018-2019.

2. Vindhyachal thermal power station Madhya Pradesh

*Figure 2-4: Vindhanchal Thermal Power Station, Madhya Pradesh (*Ref. 16)

Currently the largest thermal power plant in the country, the Vindhyachal thermal power station has an installed capacity of 4760 MW. Located in Singhrauli district in Madhya Pradesh, it is a coal fired power plant owned and operated by state-run National Thermal Power Corporation (NTPC).

The plant commenced operations with the commissioning of its first unit in 1987 (210 MW), while the last unit was commissioned in 2015 (500 MW).

It comprises of thirteen (13) generating units (6x210 MW and 7x500 MW) and was developed in five (5) stages (Stage I- 1260 MW, Stage II- 1000 MW, Stage III-1000 MW, Stage IV-1000 MW, Stage V- 500 MW).

This thermal power plant supplies power to the states of Madhya Pradesh, Gujarat, Maharashtra, Chhattisgarh, Goa, Daman and Diu, as well as Dadra and Nagar Haveli.

The plant has a PLF 85% (2018-2019) against the national average 60.85% for coal-fired thermal power stations. Although having a large fleet of 13 units in operation, the plant has consistently been able to maintain a plant availability of around 90% for the past 10 years. Further, the plant has successfully operationalized the country's first 100 percent flue-gas desulfurization (FGD) in its Unit 13 of 500 MW, helping bring down sulphur oxide levels, while simultaneously started retrofitting FGD in 4X500 MW units.

Super-critical coal

1. Barh Super Thermal Power Plant

Figure 2-5: NTPC Barh Super Thermal Power Station (Ref. 17)

Barh super thermal power plant is owned by National Thermal Power Company (NTPC), a government owned public sector entity, and is located in Bihar. The plant is envisaged to have total installed capacity of 3,300 MW with five units of 660 MW rated capacity. At present, 3 units are operational (commissioned in year 2013, 2015, and 2020) and the construction of 2 units is under progress. The remaining two units are envisaged to be operational by end of 2022.

The coal for the power plant is obtained from the mines located in the neighbouring state of Jharkhand and operated by Central Coal Fields Ltd. as well as imported coal (1.5-2%) and around 16.9 million Mt of coal annually (calculated for 90% PLF). An inland waterway project is currently being commissioned to connect the plant with the Kolkata to allow transport of coal through surface water transport. The plant currently employs approx. 425 staff for operations and maintenance (0.32 person/MW). The plant supplies power to the eastern states of India, including West Bengal and Bihar.

During 2018-19, the plant load factor was 81% and produced 9.3 TWh of electricity.

2. Mundra Ultra Mega thermal power station Gujarat

Figure 2-6 : Mundra Ultra Mega Thermal Power Station Gujarat (Ref. 18)

The 4,000 MW Mundra Ultra Mega Thermal Power Station located in the Kutch district of Gujarat is currently the second biggest operating thermal power plant in India. It is a coal-fired power plant owned and operated by Tata Power.

The power plant consists of five generating units of 800 MW capacity each. The first unit was commissioned in May 2012 and the fifth (last) unit of the plant commissioned in March 2013. The plant utilises imported coal (primarily from its own mines in Indonesia). The capital cost invested in the project was approx. INR 16,560 Crores[1] (2007 prices), including a loan of INR 1,800 Crores (2007 prices) from IFC (World Bank Group).

During project operation, about 718 people are employed. About 1,600 people (employees and their families) live in the residential complex near the power plant. Power plant personnel would thereby create demand for food and services, thus benefiting the local people (Ref. 10). During 2018-19, the plant produced approx. 25 TWh at a PLF of 70%.

During the construction period, the project created demand for about 16,000 construction workers over the construction period of about five years. The project therefore created local

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[1] Considering exchange rate of 1 USD = INR 40 in 2007

employment opportunities and encouraged small enterprises, thereby augmenting existing household incomes.

Ultra-supercritical coal

1. Khargone Power Plant

Figure 2-7: Khargone Power Plant (Ref. 19)

Khargone super thermal power station is the first ultra-supercritical coal project in India. The project is located in Khargone district of Madhya Pradesh and consist of two units of 660 MW capacity each, and the units got operational in August 2019 and April 2020.

The Khargone plant operates at a gross efficiency of 41.5%, with steam parameters of 600 degree Celsius temperatures and 270.3 kg/cm^2 allowing them to consume less coal to produce as much power as supercritical units.

It is envisaged that the project will generate direct and indirect employment opportunities as well as opportunities for self-employment. Power projects have mechanized and automated plants, therefore the direct opportunities for employment during operation phase are limited (Ref. 11).

The estimated number of employees during operation phase of the project is around 900. However, during the construction phase, the total number of workers was estimated to be approximately 2,000.

In addition to the people directly involved in construction and operation of the project, employment opportunities in subsidiary industries and service sectors as well as self-employment opportunities are also anticipated.

Image	Location	Criticality	Commissioning year	Plant capacity	Owner / Operator	Ref.
	LANCO Anapara C project, Uttar Pradesh, India	Subcritical	2011	3,830 MW	Lanco Anpara Power Pvt. Ltd	15
	Vindhyachal thermal power plant, Madhya Pradesh, India	Subcritical	1987	4,760 MW	NTPC	16
	Barh Super Thermal Power Plant, Bihar, India	Supercritical	2014	3,330 MW	NTPC	17
	Mundra Ultra Mega thermal power station, Gujarat, India	Supercritical	2012	4,000 MW	Tata Power	10, 18
	Khargone Power Plant, Madhya Pradesh, India	Ultra-supercritical	2019	1,320 MW	NTPC	11, 19

Table 2-1: Examples of existing thermal power plants

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2.12. Datasheet

Technology	01a Pulverized coal fired, subcritical steam process, condensing plant									
	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)	210-600									
Electricity efficiency, condensation mode, gross (%), name plate	36	36	36	37	35	37			A, B, C, D	1, 2
Gross Heat rate at 55% loading (MCal/MWh)	5.6% increase								E, I	3
Gross Heat Rate at 65% loading (MCal/MWh)	2.5% increase								E, I	3
Gross Heat Rate at 75% loading (MCal/MWh)	0.5% increase								E, I	3
Gross Heat Rate at 100 % loading (MCal/MWh)	2396	2396	2389	2324	2457	2324			A, B	2
Auxiliary Power Consumption (%)	7.5				5.75	8.5			K	10
Forced outage (%)	10									5
Planned outage (weeks per year)	2.3									6
Technical lifetime (years)	25	25	30	30						2, 4, 11, 12, 13
Construction time (years)	3-4	3-4	3-4	3-4						4
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Minimum load without secondary fuel support (% of full load)	55				50	75			F	8, 9
Ramp Up Rate (% of Full Load/Minute)	1								J	3
Ramp Down Rate (% of Full Load/Minute)	1								J	3
Minimum Up time (hours)	6									7
Minimum Down time (hours)	4									7
Hot start-up time (hours)	2-3									3
Warm start-up time (hours)	3-5									3
Cold start-up time (hours)	5-10									3
Hot Start-up fuel consumption (Mcal/MW)	600									3
Warm Start-up fuel consumption (Mcal/MW)	1000									3
Cold Start-up fuel consumption (Mcal/MW)	1800									3
Environment										
SO_2 (mg/Nm^3 fuel)	100								G	14
NO_X (mg/Nm^3 fuel)	100								G	14
Standard Particulate Matter (mg/Nm^3 fuel)	30								G	14
Financial data (in 2020₹)										
Capital cost (cr. ₹/MW)	9.20	9.14	9.16	9.17			9.1	9.2	H	2
- of which equipment (%)										
- of which installation (%)										

Fixed O&M (cr. ₹/MW/year)	0.27	0.26	0.26	0.26	0.20	0.33				4
Variable O&M (₹/MWh)										
Hot Startup cost (cr. ₹/MW/startup)	25000									3
Warm Startup cost (cr. ₹/MW/startup)	30000									3
Cold Startup cost (cr. ₹/MW/startup)	52000									3

References

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2) Inputs based on internal information in CEA and stakeholder inputs

3) Flexible Operation of Thermal Power Plant for Integration of Renewable Generation, Central Electricity Authority, 2019

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5) National Electricity Plan Vol I - Generation, Central Electricity Authority, 2018

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8) Indian Electricity Grid Code Regulations (Fourth Amendment), CERC, 2016

9) Reserve regulation ancillary services: half year analysis and feedback, POSOCO, 2016

10) Values based on stakeholder inputs

11) Technology Data – Generation of Electricity and District Heating; Danish Energy Agency, Energinet; 2020

12) Viet Nam Technology Catalogue – Technology data input for power system modelling in Viet Nam; EREA, Institute of Energy, Ea Energy Analyses, Danish Energy Agency, Danish Embassy in Vietnam, 2019

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14) Environment (Protection) Amendment Rules (MoEF&CC : Dec 2015)

Notes

A) Considering the boiler efficiency as 86%

B) The gross design Heat rate and gross Efficiency is based on HHV basis

C) Considering the Generator efficiency as 99%

D) Based on operating values

E) Defined as increase in net heat rate for a 200/210 MW unit

F) This is based on the normative value for central plants according to Indian regulation rather than actual operational data

G) Environmental norms for thermal power stations

H) Input supported by a number of Indian and international sources

I) Heat rates according to Indian grid code norms are 6% increase at 55% loading, 4% loading at 65% loading and 2.25% at 75% loading

J) According to Indian regulation (ref 1), the ramp up/down norms are 3% of Full Load//minute

K) As per CERC tariff regulation, 2019 lower bound should be 5.75

Technology	01b Pulverized coal fired, supercritical steam process, condensing plant									
	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)	660-800				660	800				
Electricity efficiency, condensation mode, gross (%), name plate	38	39	40	41	38	40			A, B, C, D	1
Gross Heat rate at 55% loading (MCal/MWh)	5.2% increase								E, L	1
Gross Heat Rate at 65% loading (MCal/MWh)	3.4% increase								E, L	1
Gross Heat Rate at 75% loading (MCal/MWh)	2.0% increase								E, L	1
Gross Heat Rate at 100 % loading (MCal/MWh)	2257	2205	2150	2098	2263	2150			A, B	1
Auxiliary Power Consumption (%)	6.5				5.75	8			F, N	1
Forced outage (%)	10									5
Planned outage (weeks per year)	2.34									5
Technical lifetime (years)	25	25	30	30						1, 3, 10, 11, 12
Construction time (years)	4	4	4	4						3
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Minimum load without secondary fuel support (% of full load)	55				50	75			K	7, 8
Ramp Up Rate (% of Full Load/Minute)	1								M	2
Ramp Down Rate (% of Full Load/Minute)	1								M	2
Minimum Up time (hours)	6									6
Minimum Down time (hours)	4									6
Hot start-up time (hours)	2-3									2
Warm start-up time (hours)	3-5									2
Cold start-up time (hours)	5-10									2
Hot Start-up fuel consumption (Mcal/MW)	600								G	2
Warm Start-up fuel consumption (Mcal/MW)	1000								G	2
Cold Start-up fuel consumption (Mcal/MW)	1800								G	2
Environment										
SO_2 (mg/Nm^3 fuel)	100								I	4
NO_X (mg/Nm^3 fuel)	100								I	4
Standard Particulate Matter (mg/Nm^3 fuel)	30								I	13
Financial data (in 2020₹)										
Capital cost (cr. ₹/MW)	8.30	8.25	8.26	8.28	7.60	8.70	7.58	8.67	H	1
- of which equipment (%)										
- of which installation (%)										
Fixed O&M (cr. ₹/MW/year)	0.20	0.20	0.20	0.20						3
Variable O&M (₹/MWh)										

Hot Startup cost (₹/MW/startup)	25000								J	2
Warm Startup cost (₹/MW/startup)	30000								J	2
Cold Startup cost (₹/MW/startup)	52000								J	2

References

1) Inputs based on internal information in CEA and stakeholder inputs

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11) Viet Nam Technology Catalogue – Technology data input for power system modelling in Viet Nam; EREA, Institute of Energy, Ea Energy Analyses, Danish Energy Agency, Danish Embassy in Vietnam, 2019

12) Technology data for the Indonesian Power Sector – Catalogue for Generation and Storage of Electricity; National Energy Council, Danish Energy Agency, Ea Energy Agency, Danish Embassy in Indonesia; 2017

13) Environment (Protection) Amendment Rules (MoEF&CC: Dec 2015)

Notes

A) Considering the boiler efficiency as 86%

B) The gross design Heat rate and gross Efficiency is based on HHV basis

C) Considering the Generator efficiency as 99%

D) Based on operating values

E) Defined as increase in net heat rate for a 660 MW unit

F) Turbine driven BFP/ Motor driven BFP based auxiliary consumption

G) Defined as oil consumption for a 500 MW unit

H) Input supported by a number of Indian and international sources

I) Environmental norms for thermal power stations

J) Defined as increase in O&M costs for a 500 MW unit

K) This is based on the normative value for central plants according to Indian regulation rather than actual operational data

L) Heat rates according to Indian grid code norms are 6% increase at 55% loading, 4% loading at 65% loading and 2.25% at 75% loading

M) According to Indian regulation, the ramp up/down norms are 3% of Full Load//minute

N) As per CERC tariff regulation, 2019 lower bound should be 5.75

Technology	01c Pulverized coal fired, ultra-supercritical steam process, condensing plant									
	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	660-800				660	800				
Electricity efficiency, condensation mode, gross (%), name plate	41.3	41.8	42	43	39.6	43			A	1
Gross Heat rate at 55% loading (MCal/MWh)	6.0% increase									1
Gross Heat Rate at 65% loading (MCal/MWh)	3.9% increase									1
Gross Heat Rate at 75% loading (MCal/MWh)	2.3% increase									1
Gross Heat Rate at 100 % loading (MCal/MWh)	2082	2057	2048	2000	2172	2000				1, 2
Auxiliary Power Consumption (%)	6.5				5.75	8			F, G	1
Forced outage (%)	10									4
Planned outage (weeks per year)	2.34									3
Technical lifetime (years)	25	25	30	30						2, 5, 6, 7
Construction time (years)	4	4	4	4						11
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Minimum load without secondary fuel support (% of full load)	55								B	8
Ramp Up Rate (% of Full Load/Minute)	1								E	9
Ramp Down Rate (% of Full Load/Minute)	1								E	9
Minimum Up time (hours)	6									2
Minimum Down time (hours)	4									2
Hot start-up time (hours)	2-3									9
Warm start-up time (hours)	3-5									9
Cold start-up time (hours)	5-10									9
Hot Start-up fuel consumption (Mcal/MW)	600									9
Warm Start-up fuel consumption (Mcal/MW)	1000									9
Cold Start-up fuel consumption (Mcal/MW)	1800									9
Environment										
SO_2 (mg/Nm^3 fuel)	100								C	4
NO_X (mg/Nm^3 fuel)	100								C	4
Standard Particulate Matter (mg/Nm^3 fuel)	30								C	10
Financial data (in 2020₹)										
Capital cost (cr. ₹/MW)	8.40	8.35	8.36	8.38					D	1
- of which equipment (%)										
- of which installation (%)										
Fixed O&M (cr. ₹/MW/year)	0.20	0.20	0.20	0.20	0.18	0.33				11
Variable O&M (₹/MWh)										

Hot Startup cost (₹/MW/startup)										
Warm Startup cost (₹/MW/startup)										
Cold Startup cost (₹/MW/startup)										

References

1) Inputs based on internal information in CEA and stakeholder inputs

2) Report on Optimal Generation Capacity Mix for 2029-30; Central Electricity Authority, 2020

3) Review of performance of thermal power stations 2017-18, Central Electricity Authority, 2020

4) National Electricity Plan Vol I - Generation, Central Electricity Authority, 2018

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6) Viet Nam Technology Catalogue – Technology data input for power system modelling in Viet Nam; EREA, Institute of Energy, Ea Energy Analyses, Danish Energy Agency, Danish Embassy in Vietnam, 2019

7) Technology data for the Indonesian Power Sector – Catalogue for Generation and Storage of Electricity; National Energy Council, Danish Energy Agency, Ea Energy Agency, Danish Embassy in Indonesia; 2017

8) Indian Electricity Grid Code Regulations (Fourth Amendment), CERC, 2016

9) Flexible Operation of Thermal Power Plant for Integration of Renewable Generation, Central Electricity Authority, 2019

10) Environment (Protection) Amendment Rules (MoEF&CC: Dec 2015)

11) Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019

Notes

A) Based on operating values

B) This is based on the normative value for central plants according to Indian regulation rather than actual operational data

C) Environmental norms for thermal power stations

D) Data only based on few plants

E) According to Indian regulation, the ramp up/down norms are 3% of Full Load//minute

F) As per CERC tariff regulation, 2019 lower bound should be 5.75

G) Turbine driven BFP based auxiliary consumption

3. Gas Power Plant

3.1. Brief technology description

The principle of a gas power plant is to derive power from burning fuel in a combustion chamber and using the combustion gases, which have a high pressure and high temperature, to drive a turbine. The most common fuel type is natural gas. The thermal energy of the gas is transformed into rotating energy by the turbine and is later converted to electricity by the electric generator. The gas turbine operates on the principle of the Brayton cycle[2]. This process is similar to how steam drives a steam turbine in a Rankine cycle.

Gas power plants can be distinguished between open cycle and combined cycle. Both types are described in brief in the following sections.

Open cycle

The major components of open cycle (or simple-cycle) gas turbine (OCGT) power unit are: a compressor, a combustion chamber, a turbine and a generator.

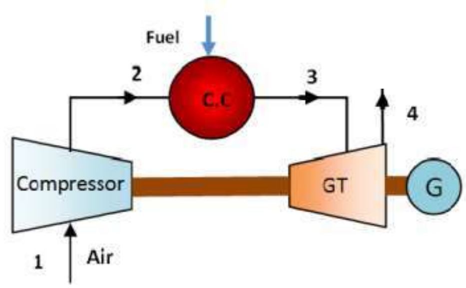

Figure 3-1: Process diagram of a OCGT (Ref.1)

Open cycle gas turbines are generally of two types: 1) Industrial turbines (also called heavy duty) and 2) Aero-derivative turbine. There are limited Aero-derivate installations in India.

Combined cycle

The combined cycle gas turbine (CCGT) includes the same components as the OCGT, and, in addition, a heat recovery steam generator (HRSG)/flue gas heat exchanger, as shown in the diagram below. In the HRSG, the exhaust gasses heat up a fluid which is used to generate electricity through a Rankine cycle. The utilization of the exhaust gasses thermal energy leads to a higher energy efficiency. In the OCGT, this energy is wasted.

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[2] Brayton cycle is the ideal cycle for gas-turbine engines in which the working fluid undergoes a closed loop (Ref. 1). That is the combustion and exhaust processes are modelled by constant-pressure heat addition and rejection, respectively.

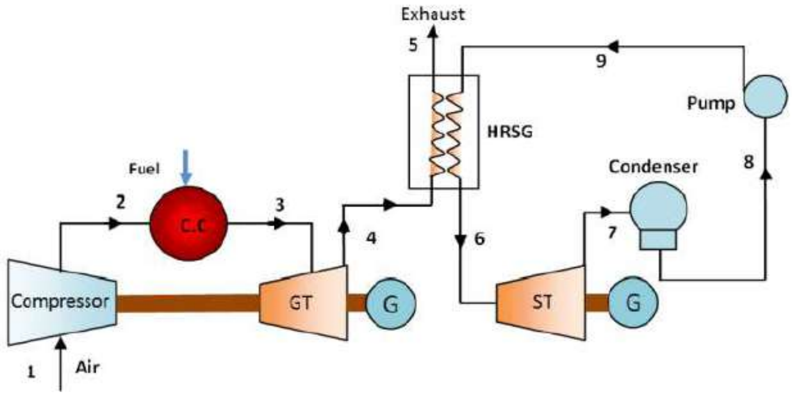

Figure 3-2: Process diagram of a CCGT (Ref. 1)

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 to cost effective installation operation, the multi-shaft (separate) has a slightly better overall performance and comparatively higher reliability. The condenser is cooled by sea water/surface water source (circulating water).

The electric efficiency depends, besides the technical characteristics and the ambient conditions, on the gas turbine inlet temperature, the flue gas temperature and the temperature of the cooling water.

3.2. Input/output

Input

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

Output

Output is power.

Electricity and heat (optional). All heat output is from the exhaust gas and is extracted by a flue gas heat exchanger (heat recovery boiler). The heat output is usually either as steam or hot water.

3.3. Typical capacities

OCGTs are globally available in the 30 kW – 450 MW range. Most CCGT units have an electric power rating of >40 MW. In India, OCGT turbines are in the range of 5-250 MW whereas the largest CCGT plant of 400 MW (Single module) are installed at Torrent Power Plant at Dahej (Gujarat).

3.4. Regulation ability and power system services

An OCGT 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 equivalent operating hours (Ref. 6).

Gas turbines can operate at part load. This reduces the electrical efficiency and increases the emissions of e.g. NO_x and CO while operating at lower loads. The increase in NO_x emissions with decreasing load places a regulatory limitation on the ramping ability. This can be improved by adding de-NO_x units; however, in India, de-NOx units have not been used.

The larger gas turbines for CCGT installations are usually equipped with variable inlet guide vanes, which will improve the part-load efficiencies.

In a CCGT, 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.

In future, simple cycle Gas Turbines may find use to balance the grid with every increasing Renewable (Solar/Wind) generation which remains inherently variable.

3.5. Advantages/disadvantages

Advantages:

- OCGT plants have short start-up/shut-down time, if needed. For normal operation, a hot start will take around 10-15 minutes and possibly even shorter time (Ref. 6, 7).
- Construction times for gas turbine based simple cycle plants are shorter than steam turbine plants (Ref. 7).
- 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.
- Low air emissions (NOx, SOx, SPM, CO_2) as compared to other fossil-based technologies.
- CCGT plants have higher efficiency than steam turbines (Rankine Cycle) based plants.

Disadvantages:

- Availability of natural gas is one of the major constraints for India, which is not a major producer of natural gas. The shortfall in domestically produced natural gas resulted in these plants running at low PLF of about 22% since 2011-2012 (Ref 12).

3.6. Environment

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

3.7. Research and development

Assumptions and perspectives for further development

Gas turbines are a very well-known and mature technology. Technological improvements are continuously being made; new materials, new surface treatments or improved production methods can lead to higher electrical efficiency, improved lifetime and less service needs.

Increased efficiency for OCGT 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. The trend is more towards dry low-NO_x combustion, which increases the specific cost of the gas turbine (Ref. 12). Water or steam injection in the burner section may reduce the NO_x emission, but have an adverse impact on total efficiency of the turbine and thereby possibly the financial viability.

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

3.8. Prediction of performance and cost

Projections about the future investment costs of gas power plants can be made by looking at past prices and global capacity developments. Furthermore, the cost reduction is driven by the technological improvements, so it is highly dependent on the maturity of the technology, hence on its margin of improvement.

The efficiency of the simple-cycle turbine can be increased if inlet temperatures to the turbine section can be increased. Therefore, development of ceramic materials that can withstand high temperatures used in the gas turbine is taking place. Improvements in the electricity efficiency are assumed for both types of gas turbine plants. For open-cycle gas turbine plants, the electrical efficiency goes from around 28% to around 34%, while for combined-cycle gas turbine plants, it increases beyond 48%.

Given the high cost of imported Liquified Natural Gas (LNG) and low availability of domestically produced gas a significant number of currently installed assets have become or are close to becoming non-performing assets (Ref 12). Few gas-fired power plants are expected to be installed in the future in India, in particular for simple-cycle plants. This means that limited reductions in costs are expected.

Using the learning rate methodology, which translates the growth in installed capacity into a cost reduction, the future prices for gas-fired power plants were projected. In 2050, the investment costs are at most around 2% lower than in 2020. These values exclude cost developments of fuels and other infrastructure and does not represent the generation costs.

The resulting cost development trend can be observed in Figure *3-3*.

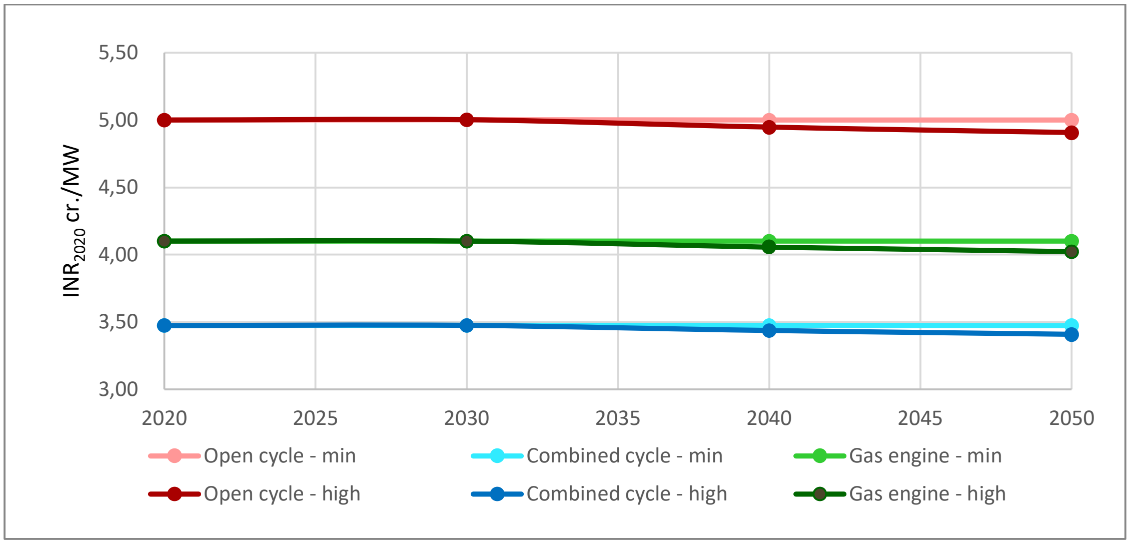

Figure 3-3: Projected gas power plant investment costs development from 2020 to 2050 considering a minimum and high development scenario.

3.9. Examples of market standard technology

Globally, the best technology commercially available today regarding simple cycle gas turbines is a medium size gas turbine with integrated recuperator that can reach approximately 38% electrical efficiency (5 MWe unit) (Ref 13). Typically, the efficiency ranges between 20% and 35%.

Large CCGT units have demonstrated an electrical efficiency around 60% (e.g. General Electric (ref 9), Siemens (ref 10)) and up to 64% (e.g. Mitsubishi Hitachi Power Systems (MHPS) ref 10).

In India, the gas power plant market follows the global trend. High efficiency F class Gas Turbines have been installed for power generation at several locations in India.

Larger CCGT modules in India can reach up 870 MW in capacity.

3.10. Examples of existing projects

1 Torrent Sugen Combined Cycle Power Plant, Gujarat

Sugen Combined Cycle Power Plant is situated in Akhakol District in Gujarat. The overall rated (nameplate) capacity of the plant is 1147 MW and consist of 3 CCGTs of 382.5 MW capacity each. Natural gas supplies to the plant are obtained via a dedicated pipeline operated by GSPL

(Gujrat State Petroleum Corporation). The Construction of the plant began in 2005 and was commissioned in August 2009. The cost of the plant was INR 30,960 Cr in 2009 (Ref 13). The plant uses Siemens F-Class (4000F) gas turbines coupled with Siemens steam turbine and Doosan HRSG (Heat Recovery Steam Generator). The plant has a reported PLF of 60.4% in 2018-2019.

Figure 3-4 : Sugen Combined Cycle Gas Power Plant (Ref 14)

2 Tripura (Palatana) CCGT Power Plant India, Tripura

The ONGC Tripura power plant is a 726.3MW combined-cycle gas turbine power plant located in the Palatana village of the Udaipur District in Tripura, India. It consists of two 363MW GE 9FA Heavy duty Gas Turbines. The plant construction started in October 2005. The first unit was commissioned in June 2013 and the last in November 2014. The electricity efficiency is around 56% (ref 19).

The plant was constructed by Bharat Heavy Electricals Limited (BHEL) and it is operated from ONGC Tripura Power Company Ltd. General Eletric (GE) provides support with the support operation and maintenance of the plant.

The power is evacuated from the plant with a 400 kV AC transmission line which was built for the purpose. It connects the plant to a 400 kV receiving substation of Power Grid Corporation of India Limited ("PGCIL") at Bongaigaon in upper Assam over a distance of around 650 km (ref 19).

The estimated investment in the project is approximately Rs34.3bn ($600m approximately) (ref 20).

Figure 3-5: Tripura Combined Cycle Gas Power Plant (ref 19)

3 Other installed gas power plants

The gas power plants operated by central government owned generating companies are reported in the table below (ref 21). It can be noticed that the difference in size of the gas turbine units between these older plants and the two presented above. Newer power plants have larger gas turbines units.

Table 3-1: Gas power plants operated by central government owned generating companies

Operator	Plant	Year of first unit	Plant type	Units (MW)	Capacity (MW) 2020
NTPC	Anta	1989	CCGT	3 x 88 GT 1 x 149 ST	419
	Auraiya	1989	OCGT	4X110 GT 2X106 ST	663
	Dadri	1992	CCGT	4 x 130 GT 2 x 154 ST	830
	Faridabad	1999	CCGT	2 x 143 GT 1 x 144 ST	432
	Gandhar	1994	CCGT	3 x 131 GT 1 x 255 ST	657
	Kawas	1992	OCGT	4 x 106 GT 2 x 110 ST	656
	Rgandhi	1998	CCGT	2 x 115 GT 1 x 129 ST	360
NEEPCO	Agartala (ref 22)	1998	CCGT	4 x 21 GT 2 x 25 ST	135
	Karhalguri	1995	CCGT	6 x 33 GT 3 x 30 ST	291
Total					4392

4 Example of market standard technology for gas power plants

In the following table are some examples of market standard technologies for gas power plants.

Image	Technology provider / Location	Type	Commissioning year	Efficiency and output	Ref.
	GE Gas Power	Simple cycle		38% efficiency, 210 MW	Ref 13
	Emerson, France	Combined cycle, 50 Hz	2018-2019	800 MW	Ref 16
	SUGEN (Torrent Power), India	Combined cycle, 50 Hz	2004	1100 MW	Ref 14
	MPHS, USA	Combined cycle, 60 Hz	2017	More than 64 % efficiency, 575 MW	Ref 11, 16
	GE and EDF, France	Combined cycle, 50 Hz	2016	62.22 % efficiency (64% net), 605 MW	Ref 16
	GE, Japan	Combined cycle, 60 Hz	2018	63.08 %, 1,188 MW	Ref 18
	Siemens Energy, Germany	Combined cycle, 50Hz	2016	61.5%, 600 MW_e, 300 MW_{th}	Ref 23

Table 3-2: Example of market standard technology for combined cycle gas turbine power plants.

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3.12. Datasheet

Technology	02a Gas turbine, open cycle (large), back pressure									
	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)	50-200+				10	200+			A	1
Electricity efficiency, condensation mode, gross (%), name plate	28	30	32	34	28	32			B, C	1, 5, 6, 7
Gross Heat rate at 55% loading (MCal/MWh)	3277									2
Gross Heat Rate at 65% loading (MCal/MWh)										
Gross Heat Rate at 75% loading (MCal/MWh)										
Gross Heat Rate at 100 % loading (MCal/MWh)	3071	2867	2688	2529	3071	2688				1
Auxiliary Power Consumption (%)	1									1
Forced outage (%)	2								D	5, 6, 7
Planned outage (weeks per year)	3									10
Technical lifetime (years)	25									1, 10
Construction time (years)	1.5									10
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)	22				22	50				10
Minimum load without secondary fuel support (% of full load)	55								E	8, 9
Ramp Up Rate (% of Full Load/Minute)	3									4
Ramp Down Rate (% of Full Load/Minute)	3									4
Minimum Up time (hours)	4									2
Minimum Down time (hours)	3									2
Hot start-up time (hours)										
Warm start-up time (hours)										
Cold start-up time (hours)										
Hot Start-up fuel consumption (Mcal/MW)	30									2
Warm Start-up fuel consumption (Mcal/MW)	50									2
Cold Start-up fuel consumption (Mcal/MW)	90									2
Environment										
SO_2 (mg/Nm^3 fuel)										
NO_X (mg/Nm^3 fuel)										
Standard Particulate Matter (mg/Nm^3 fuel)										
Financial data (in 2020₹)										
Capital cost (cr. ₹/MW)	5.00	5.00	4.97	4.95	2.79	5.2			F	10
- of which equipment (%)	80									10
- of which installation (%)	20									10
Fixed O&M (cr. ₹/MW/year)	0.18	0.18	0.17	0.17					E	3

Variable O&M (₹/MWh)										
Hot Startup cost (₹/MW/startup)	2473									10
Warm Startup cost (₹/MW/startup)										
Cold Startup cost (₹/MW/startup)										

References

1) Inputs based on internal information in CEA

2) Report on Optimal Generation Capacity Mix for 2029-30; Central Electricity Authority, 2020

3) CERC Regulations (Terms and Conditions of Tariff), 2019

4) CEA Regulations (Technical Standards for Construction of Electrical Plants and Electric Lines), 2010

5) Technology Data – Generation of Electricity and District Heating; Danish Energy Agency, Energinet; 2020

6) Viet Nam Technology Catalogue – Technology data input for power system modelling in Viet Nam; EREA, Institute of Energy, Ea Energy Analyses, Danish Energy Agency, Danish Embassy in Vietnam, 2019

7) Technology data for the Indonesian Power Sector – Catalogue for Generation and Storage of Electricity; National Energy Council, Danish Energy Agency, Ea Energy Agency, Danish Embassy in Indonesia; 2017

8) Indian Electricity Grid Code Regulations (Fourth Amendment), CERC, 2016

9) Reserve regulation ancillary services: half year analysis and feedback, POSOCO, 2016

10) Inputs based on stakeholder values

Notes

A) One unit configuration consists of 1 GTs

B) The gross design Heat rate and gross Efficiency is based on HHV basis

C) Considering the Generator efficiency as 99%

D) Based on international data

E) This is based on the normative value for central plants according to Indian regulation rather than actual operational data

F) Industrial gas turbines are more expensive than Utility size turbines. Utility Size turbines could be implemented at 40% lower price than Industrial turbines (10MW ~ 70MW size range)

Technology	02b Gas turbine, combined cycle, condensing plant									
	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one module (MW)	50-870	50-1000	up to 1000	up to 1000	50	870			A	
Electricity efficiency, condensation mode, gross (%), name plate	60	62	64	66	58	63			A, B, C, D	1
Gross Heat rate at 55% loading (MCal/MWh)	1614									1
Gross Heat Rate at 65% loading (MCal/MWh)	1592									1
Gross Heat Rate at 75% loading (MCal/MWh)	1527									1
Gross Heat Rate at 100% loading (MCal/MWh)	1423	1377	1334	1294	1365	1483			B	1
Auxiliary Power Consumption (%)	2%	2%	2%	2%					G	1
Forced outage (%)	0.75%									1
Planned outage (weeks per year)	2									1
Technical lifetime (years)	25	25	25	25						1
Construction time (years)	2.5									1
Regulation ability										
Primary regulation (% per 30 seconds)	1%/s .max limit 10% of GT load									1
Secondary regulation (% per minute)	10%									1
Minimum load without secondary fuel support (% of full load)	55%								E	3
Ramp Up Rate (% of Full Load/Minute)	11.5%									1
Ramp Down Rate (% of Full Load/Minute)	11.5%									1
Minimum Up time (hours)	4									2
Minimum Down time (hours)	3									2
Hot start-up time (hours)	0.75									1
Warm start-up time (hours)	1.5									1
Cold start-up time (hours)	2.3									1
Hot Start-up fuel consumption (Mcal/MW)	1700									1
Warm Start-up fuel consumption (Mcal/MW)	1750									1
Cold Start-up fuel consumption (Mcal/MW)	1900									1
Environment										
SO_2 (mg/Nm^3 fuel)										
NO_X (mg/Nm^3 fuel)										
Standard Particulate Matter (mg/Nm^3 fuel)										
Financial data (in 2020₹)										
Capital cost (cr. ₹/MW)	3.47	3.47	3.45	3.44						1
- of which equipment (%)	80	-	-	-						1
- of which installation (%)	20	-	-	-						1
Fixed O&M (cr. ₹/MW/year)	0.29	0.29	0.29	0.2					F	1

Variable O&M (₹/MWh)	0.21	0.21	0.21	0.21						1
Hot Startup cost (₹/MW/startup)	1556									1
Warm Startup cost (₹/MW/startup)	7782									1
Cold Startup cost (₹/MW/startup)	12451									1

References

1) Values based on stakeholder inputs

2) Report on Optimal Generation Capacity Mix for 2029-30; Central Electricity Authority, 2020

3) Indian Electricity Grid Code Regulations (Fourth Amendment), CERC, 2016

Notes

A) Single module includes 1GT+1 ST/ 2GT+1ST/3GT+1ST

B) Value changes according to size of unit

C) The gross design Heat rate and gross Efficiency is based on HHV basis

D) Considering the Generator efficiency as 99%

E) This is based on the normative value for central plants according to Indian regulation rather than actual operational data

F) According to CERC tariff regulation the O&M should be 0.18 cr. ₹/MW/year

G) As per CERC tariff Regulation norms, 2019-24 it is 2.75%

Technology	02c Gas Engine									
	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	10	12			1	10				
Electricity efficiency, condensation mode, gross (%), name plate	46	48	49	50					A	1
Gross Heat rate at 55% loading (MCal/MWh)									B	
Gross Heat Rate at 65% loading (MCal/MWh)									B	
Gross Heat Rate at 75% loading (MCal/MWh)									B	
Gross Heat Rate at 100% loading (MCal/MWh)	1868	1782	1755	1720					B	1
Auxiliary Power Consumption (%)	2									1
Forced outage (%)	1									1
Planned outage (weeks per year)	1									1
Technical lifetime (years)	25	25	25	25						1, 2
Construction time (years)	1	1	1	1						1, 2
Regulation ability										
Primary regulation (% per 30 seconds)	84								C	1
Secondary regulation (% per minute)	84								C	1
Minimum load without secondary fuel support (% of full load)	10								D	1
Ramp Up Rate (% of Full Load/Minute)	100								E	1
Ramp Down Rate (% of Full Load/Minute)	100								F	1
Minimum Up time (hours)	0									1
Minimum Down time (hours)	0.083								G	1
Hot start-up time (hours)	0.033									1
Warm start-up time (hours)	0.083									1
Cold start-up time (hours)	0.167									1
Hot Start-up fuel consumption (Mcal/MW)	287								H	1
Warm Start-up fuel consumption (Mcal/MW)	836								I	1
Cold Start-up fuel consumption (Mcal/MW)	1660								J	1
Environment										
SO_2 (mg/Nm^3 fuel)										
NO_X (mg/Nm^3 fuel)										
Standard Particulate Matter (mg/Nm^3 fuel)										
Financial data (in 2020₹)										
Capital cost (cr. ₹/MW)	4.10	4.10	4.08	4.06						1
- of which equipment (%)	97									1
- of which installation (%)	3									1
Fixed O&M (cr. ₹/MW/year)	0.07	0.07	0.07	0.07					K	1
Variable O&M (₹/MWh)	557	557	554	551						1, 2
Hot Startup cost (₹/MW/startup)									L	

Warm Startup cost (₹/MW/startup)									L	
Cold Startup cost (₹/MW/startup)									L	

References

1) Value based on inputs from Indian stakeholder

2) Technology Data – Generation of Electricity and District Heating; Danish Energy Agency, Energinet; 2020

Notes

A) Gross, Single Cycle, without Heat Recovery

B) Plant efficiency remains unchanged for all loading factors due to modularity.

C) Maximum genset specific loading rate for hot machine.

D) GEGs designed for continuous operation with primary fuel. No secondary fuel is needed

E) 2.8% per sec for engines which are operating for more than 15 min.

F) 4% per sec for engines which are operating for more than 15 min.

G) Required by exhaust gas ventilation before start-up

H) Corresponding to "2 minutes to full load" and meaning fuel consumption up to full load.

I) Corresponding to "5 minutes to full load" and meaning fuel consumption up to full load.

J) Corresponding to "10 minutes to full load" and meaning fuel consumption up to full load.

K) According to CERC tariff regulation the O&M should be 0.36 cr. ₹/MW/year

L) For reciprocating engines there is no additional start-up related costs. The technology is capable of achieving full load in under 5 min without any secondary fuel support and additional O&M cost.

4. Biomass Power Plant

4.1. Brief technology description

Biomass can be used to produce electricity or fuels for transport, heating and cooking. The figure below shows the various products from biomass.

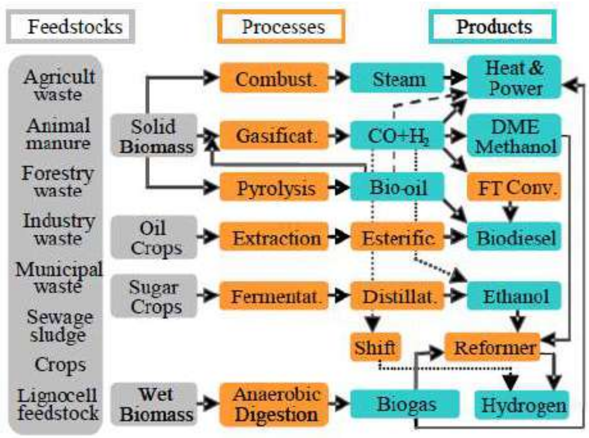

Figure 4-1: Biomass conversion paths (Ref. 1)

This chapter focuses on solid biomass consisting mostly of agriculture residues namely bagasse and rice straw (including husks) for combustion to power generation.

The technology used to produce electricity in biomass power plants depends on the biomass resource. Due to the lesser heating value of biomass compared to coal and the limitations in steam temperature and pressure due to the mineral contents of the ash, the electric efficiency is lower – 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, similarly to a coal fired power plant. A flue gas heat recovery boiler for recovering and pre-heating 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 in India today are direct-fired. In direct combustion, steam is generated in boilers that burn solid biomass, which has been suitably prepared (dried, baled, chipped, 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 (see figure below). Recently, the Ministry of Power has set-up a National Mission on use of biomass in coal based thermal plants and a committee has been set-up to further increase the level of co-firing using biomass (Ref 4).

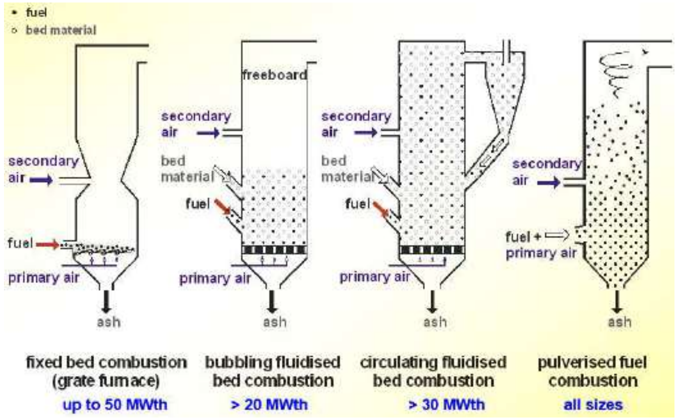

Figure 4-2: Technologies for industrial biomass combustion (Ref. 4)

India has considerable biomass resources and therefore has significant potential for generation of electricity. Ministry of New and Renewable Energy (MNRE) has estimated a potential of 18,000 MW of power from agriculture and agriproducts residue (ref 6) in India. The table below shows the calorific value of the biomass feedstocks ranging from 1,800-3,100 Kcal/Kg, with bagasse as the lowest. The calorific value is highly dependent on the moisture content of the fuel. Rice straw has higher ash content than other straw based biomasses.

Type	LHV (Kcal/Kg)	Moisture (%)	Ash (%)	Ash fusion (°C)
Bagasse	1,839-1,911	45 - 55	3 - 5	950
Wood chips	2,006-4,060	35 – 55	2	1050
Wheat straw	2,866	7 - 25	7 - 8	750
Rice straw (paddy)	3,105	15 -25	15 - 22	720

Table 4-1: Heating values of different biomass fuel types (Ref. 6)

The total current installed capacity of grid connected biomass (including Independent Power Producers (IPP) and Bagasse cogeneration) power plants in India is about 9,373 MW till December 2020 (Ref 6).

Co-firing with coal

There are three possible technology set-ups for co-firing coal and biomass: direct, indirect and parallel co-firing (see figure below). 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. 8).

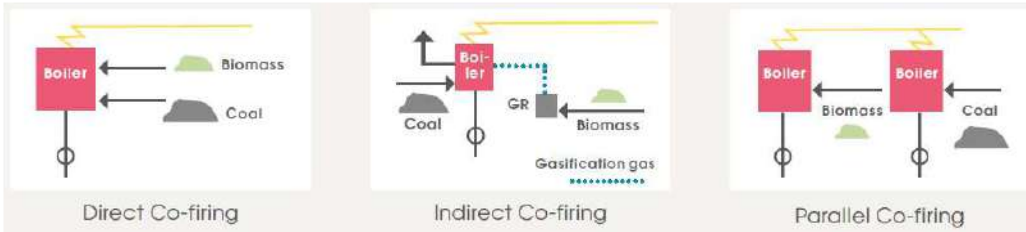

Figure 4-3: Different biomass co-firing configurations (Ref. 9). GR = Gasification Reactor.

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.

In the direct co-firing, bio pellets are blended through the grinding equipment in the same or separate feeder. Then, they are mixed with coal into the same boiler to be burned. Generally, there is no or limited investment cost for special equipment with this method. This co-firing method is mostly adopted by pulverized coal boilers.

The indirect co-firing method requires additional equipment such as a gasifier for pre-processing the biomass. The biomass is gasified into syngas in a gasifier before finally entering the coal boiler for combustion. This allows better fuel flexibility than direct co-firing and potentially higher co-firing rates. The requirements to the gas quality (heating value, tar and particles content) are lower compared to other types of applications, such as gas engines or gas turbines (Ref. 10).

The parallel co-firing requires an investment for separate bio-pellet or biomass fired boiler. The resulting steam from the biomass fired boiler is fed into the existing coal fired steam boiler system. This approach uses a separate biomass fired boiler which allows maximum biomass utilization. This method is usually used on paper mills by using bark or wood waste.

Bio pellets are an ideal fuel for co-firing coal fired power plants. As a densified, low-moisture, uniform biomass fuel, pellets avoid many challenges associated with raw biomass. Bio pellets have many parameters comparable to coal making them a compatible co-firing fuel. NTPC has successfully demonstrated the co-firing of 7% blend of biomass pellets in one of its power plants. Accordingly, the Ministry of Power under its policy "Biomass utilisation for power generation through co-firing in pulverised coal fired boilers, Nov 2017" (Ref 11,12) encourages use of 5-10% blend of biomass pellets. The surplus biomass availability from the agriculture sector is estimated to be 123 million tonnes in 2010, which could be sufficient to substitute 25% of the current coal consumption in the power sector (Ref 13).

4.2. Input/output

Input

Biomass; e.g. residues from agriculture and agriproducts industry (bagasse, rice straw and husks).

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.

Output

Electricity and Heat (e.g. Bagasse cogeneration).

Heat is in principal a by-product of electricity production, but can be used for heating purposes or as auxiliary steam for various purposes.

4.3. Typical capacities

Biomass power plants can be divided into three categories according to their size. Small plant is in the range 1- 10 MWe, while medium plants go up to 50 MWe and large plants from 50 MWe and above. In India most of the biomass plants are around 10 MWe and few between 20-30 MW.

4.4. Regulation ability and power system services

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.

4.5. Advantages/disadvantages

Advantages:

- Mature and well-known technology (more than 550 direct fired biomass power plants in operation throughout India today).
- Burning biomass is considered CO_2 neutral according to UN guidelines.
- Using biomass residue will usually be cheap.
- Can provide ramping capabilities for grid security based on power demand.

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 economics of scale is quite considerable.
- When burning biomass in a boiler, the chlorine and sulphur 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% in order to keep the boiler from being damaged (Ref. 11).
- Fuel supply / collection is a challenge, especially for biomass based Independent Power Plants (IPP) in India as feedstock is mostly collected from a catchment area around these

plants. This requires complex logistical arrangements and significant transportation costs.

4.6. Environment

The main ecological footprints from biomass combustion are persistent toxicity, climate change and acidification. However, the footprints are small, particularly when only biomass residues are used for combustion (Ref. 15).

Extensive use of biomass for energy purposes – even residues – can shift the economic incentives of land use. As the demand for residues grows, so does the value of the residues. This can incentivise farmers to shift focus to crops that provide high value residues which may shift the entire agricultural supply chain and lead to increased pressure on marginal land and deforestation to increase agricultural production. Sustainable use of biomass is a key point of attention for biomass fired power generators in Europe. If the use of biomass for power generation gains traction in India, the same sustainability issues could come into focus.

4.7. Research and development

Biomass power plants are a mature technology with limited development potential. In India, there are currently 550 biomass based power plants (Ref 6), which have a well-established local supply chain.

Consumption of biomass for traditional uses, for example cooking with low efficiency, is very common. Modern uses of biomass for power generation include mainly high-efficiency, direct biomass combustion, co-firing with coal and biomass gasification. These modern uses, especially direct combustion, are increasing in India now. The installed power capacity for biomass power has grown from 8.7 GW in 2016 to 10.1 GW in 2021 (ref 15). Rice and sugarcane residue seem to be the most favourable choices for biomass power plant's feedstock due to the easy access, handling and availability.

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, 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, shredding, pelletization and briquetting, torrefaction and pyrolysis, where the first two are by far the most commonly used in India.

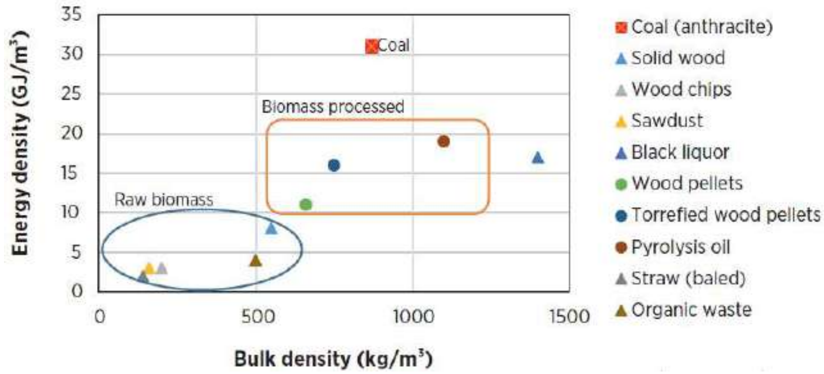

Figure 4-4: Energy density of biomass and coal (Ref. 17)

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 demonstration to promote their widespread commercial use.

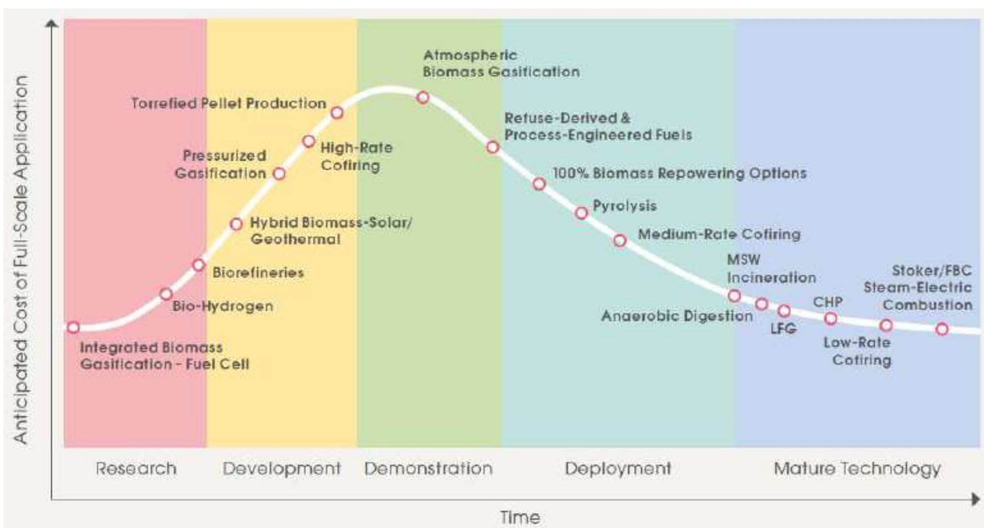

Figure 4-5: Global biomass power generation technology maturity status (Ref. 18)

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. Biomass plants in India are relatively small, operate in condensing mode and display a lower efficiency compared to biomass fired powerplants in e.g. Europe. However, compared to similar installations in other countries, the Indian biomass plants demonstrate comparable efficiencies.

4.8. Prediction of performance and cost

Projections about the future investment costs of biomass power plants can be made by looking at past prices and global capacity developments. Furthermore, the cost reduction is driven by the technological improvements, so it is highly dependent on the maturity of the technology, hence on its margin of improvement.

Biomass power plants are a mature technology with limited development potential. Moreover, it is assumed that a limited increase in installed capacity will take place in the coming years. As a result, the potential for cost reductions is expected to be marginal for biomass power plants.

Using the learning rate methodology, which translates the variation in installed capacity into a cost variation, the future prices for biomass power plants were projected. In 2050, the investment costs are at most around 5% lower than in 2020 in the high development scenario.

The resulting cost development trend can be observed in Figure 4-6.

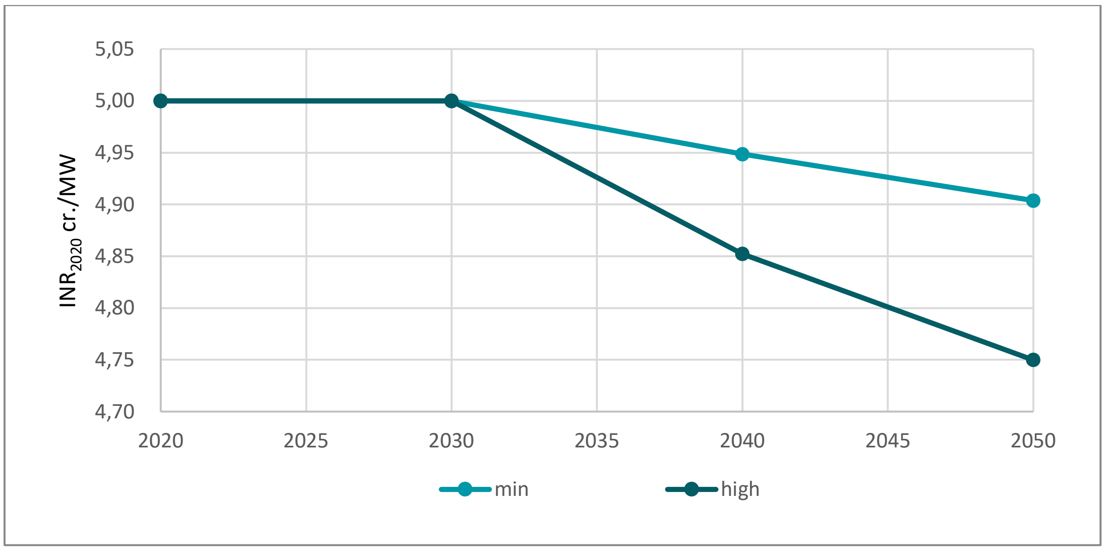

Figure 4-6: Projected biomass power plant investment costs development from 2020 to 2050 considering a minimum and high development scenario.

4.9. Examples of market standard technology

A number of examples of global and Indian biomass power plants are presented in the table below.

Image	Name / Owner / location	Biomass fuel	Year	Capacity	Ref.
	KCP Phu Yen Biomass Power Plant, Vietnam	Co-firing coal power plant, Bagasse, rice husk, coconut and cashew nut shell	2017	2x30 MW	20,22

	Clean Power Indonesia (CPI), Mentawai, Indonesia	Bamboo-based biomass power plant	2019	700 kWp	23
	PT Rezeki Perkasa Sejahtera Lestari, West Kalimantan, Indonesia,	Independent Power Plant (IPP). Solid waste – palm kernel shells, palm fibre and empty fruit bunches	2018	15 MW	24
	PT Buyung Poetra Sembada, South Sumatera Indonesia	Rice husk	2019	3 MW	25
	Ravi Kiran Power Project	Rice husk and agro waste (e.g coconut shells)	2005	7.5 MW	27
	UGSIL Bagasse Based cogeneration biomass plant	Bagasse	2007	25 MW	29

Table 4-2: Examples of market standard technology for biomass power plants

4.10. Examples of existing projects

1 Ravi Kiran Power Project (7.5 MW)

Greenko's 7.5 MW Ravi Kiran Power Project is located in Marlanhalli, Karnataka and was commissioned in 2005. This is a grid connected Independent Power Plant (IPP) that utilises low cost agro-waste (primarily rise husks) from local farming villages and supply electricity to the regional grid. The annual biomass requirement of the plant is estimated at 75,000 tonnes of agriculture residue (ref 27). The capital investment in the project was INR 42 Crores (2014) and has the operational expense of approximately INR 14 Crores (2014) / annum (ref 28). The plant reported a PLF of approximately 60% in 2011-2012 (ref 27).

2 UGSIL bagasse-based cogeneration biomass power plant (25 MW)

Upper Ganges Sugar Industries Limited (UGSIL) is a subsidiary of Birla Sugar, a large Indian company operating in sugar production. UGSIL has installed a 25 MW bagasse-based cogeneration power plant in 2007 as part of its sugar production complex located at Seohara, Uttar Pradesh. The congregation plant is designed to generate 25 MW power in addition to 120 Tonne Per Hour (TPH) of steam. The produced steam is entirely used within the sugar production unit, whereas the power produced is used in ancillary units and exported to the regional grid (Uttar Pradesh Power Corporation Limited). The plant has reported a PLF of 48% in 2008 (ref 29).

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4.1. Datasheet

Technology	03 Biomass plant									
	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	10									1
Electricity efficiency, condensation mode, gross (%), name plate	26.5				24	28				1
Gross Heat rate at 55% loading (MCal/MWh)	3440				3245	3660				1
Gross Heat Rate at 65% loading (MCal/MWh)	3373				3185	3583				1
Gross Heat Rate at 75% loading (MCal/MWh)	3308				3127	3510				1
Gross Heat Rate at 100% loading (MCal/MWh)	3245				3071	3440				1
Auxiliary Power Consumption (%)	10				8	13				1
Forced outage (%)	10				3	15				1
Planned outage (weeks per year)	3.5				2	5				1
Technical lifetime (years)	20				15	25				1
Construction time (years)	1.5				1.25	2				1
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Minimum load without secondary fuel support (% of full load)	40				30	60			A	
Ramp Up Rate (% of Full Load/Minute)	0.1									1
Ramp Down Rate (% of Full Load/Minute)	0.2									1
Minimum Up time (hours)	2				1.5	3				1
Minimum Down time (hours)	1				0.5	2				1
Hot start-up time (hours)	1				0.75	1.5			B	1
Warm start-up time (hours)	1.5				1.25	2			B	1
Cold start-up time (hours)	2				1.5	3			B	1
Hot Start-up fuel consumption (Mcal/MW)	3000				2250	4500			B	1
Warm Start-up fuel consumption (Mcal/MW)	4500				3750	6000			B	1
Cold Start-up fuel consumption (Mcal/MW)	6000				4500	9000			B	1
Environment										
SO_2 (mg/Nm^3 fuel)										
NO_X (mg/Nm^3 fuel)										
Standard Particulate Matter (mg/Nm^3 fuel)										
Financial data (in 2020₹)										
Capital cost (cr. ₹/MW)	5.00	5.00	4.90	4.83	4	5.5				1
- of which equipment (%)	80				70	85				1
- of which installation (%)	20				15	30				1
Fixed O&M (cr. ₹/MW/year)	0.10	0.10	0.10	0.10					C	2
Variable O&M (₹/MWh)										

Hot Startup cost (₹/MW/startup)	2217				1663	3325			B	1
Warm Startup cost (₹/MW/startup)	3325				2771	4433			B	1
Cold Startup cost (₹/MW/startup)	4433				3325	6650			B	1

References

1) Value based on inputs from Indian stakeholder

2) Report on Optimal Generation Capacity Mix for 2029-30; Central Electricity Authority, 2020

Notes

A) This is based on operational data. According to norms minimum load is 55% for central plants.

B) To reach 10 MW

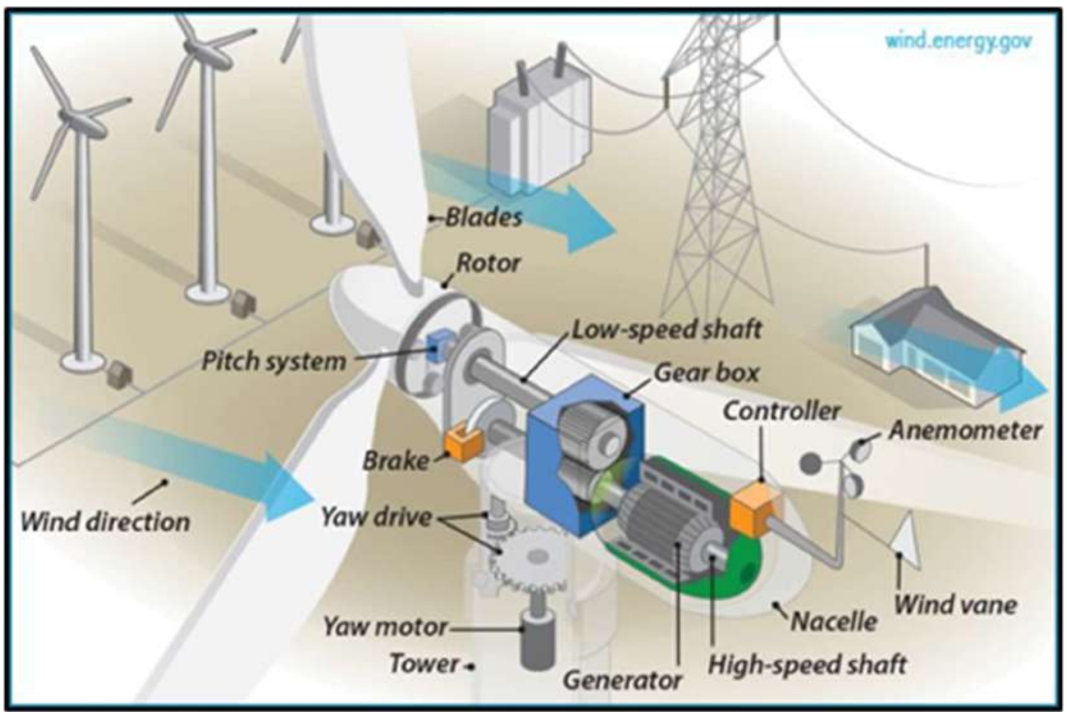
C) As per CERC tariff regulation for RE, in 2020 it is 0.46Cr/MW/year

5. Wind Turbines, onshore

5.1. Brief technology description

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 the figure below.

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.



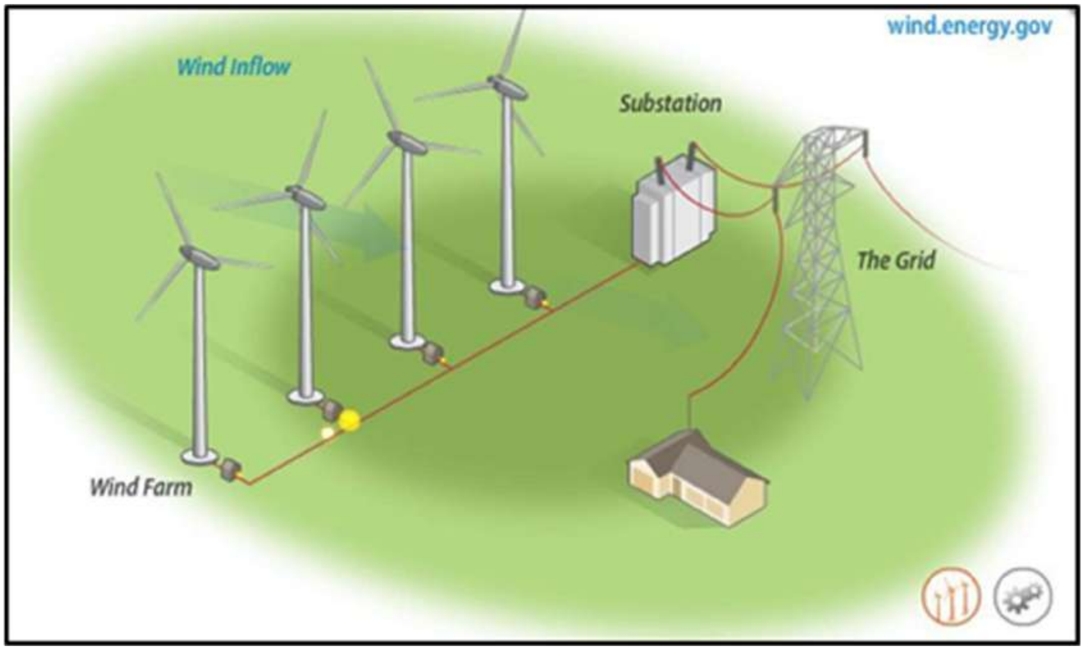


Figure 5-1: General turbine technology and electrical system (Ref. 1)

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 operate and produce electricity. 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.

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 2 and 3). 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 includes requirements to contribute to voltage control on the network;
- Control of active power;
- Protective devices; and
- Power quality.

5.2. Input/output

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 like wakes from neighbouring turbines. The increase in wind speed from 50 m to 100 m height is around 20% for typical inland locations.

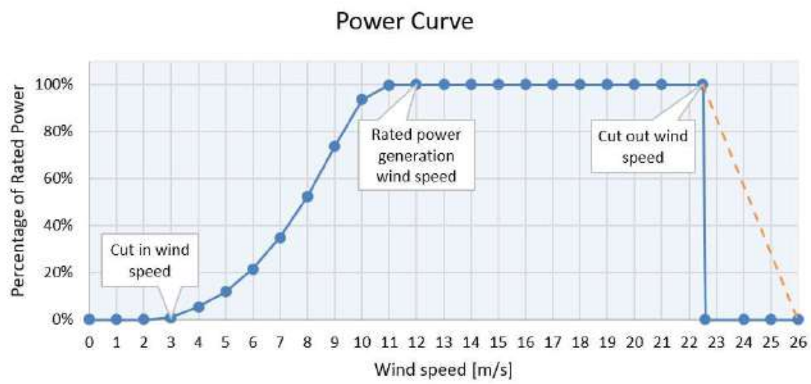


Figure 5-2: Power curve for a typical wind turbine. Instead of the traditional cut-out curve, some turbines have a gradual cut-out curve (dashed line) (Ref. 2).

Input is wind. Cut-in wind speed: 3-4 m/s. Rated power generation wind speed is in general 10-12 m/s. Considering low wind speeds in India, few of the recent wind turbines (e.g Suzlon 2.2 MW) have rated power generation wind speed on 11 m/s. Cut-out or transition to reduced power operation happens at wind speed around 22-25 m/s. Some manufacturers offer a soft cut-out for high wind speeds (indicated with dashed orange curve in the figure) resulting in a final cut-out wind speed of up to 26 m/s for onshore wind turbines (Ref. 2).

Wind measurements of at least 1-year duration must be made to predict the generation. Measurements should be at the same height as the hub height.

Generally speaking, the onshore wind resource in India is scarce, with a predominance of areas with low average wind speed (less than 3.0 m/s). However, a few sites, especially in the coastal areas of Gujarat, Tamil Nadu, Andhra Pradesh and Maharashtra experience moderate average wind speeds as indicated in the figure below.

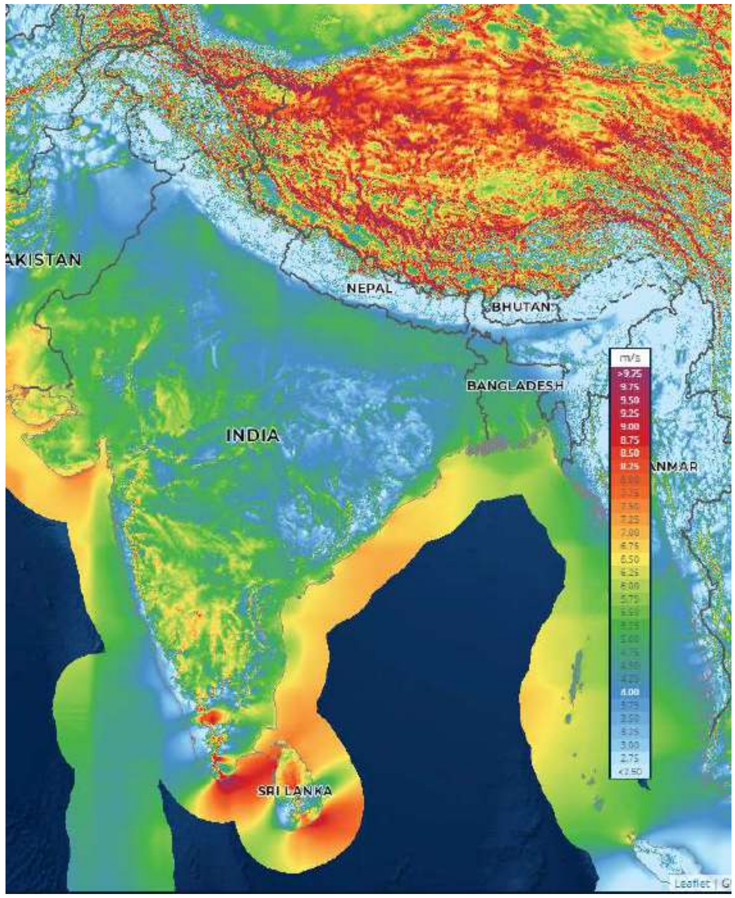


Figure 5-3: Wind resource in India, average wind speed at 100 m. (Ref. 4).

With cumulative wind power installation of 37 GW, India is the world's fourth largest onshore wind market by installation. Table 5-1 provides the installed capacities in various states in India. The Government of India has set an ambitious target for total installed capacity of 60 GW by 2022 and state-wise wind installation is provided in the table below.

State	Installed capacity (MW) as of 31st March 2020 (ref 5)
Tamil Nadu	9,304
Karnataka	4,791
Maharashtra	5,000
Rajasthan	4,300
Andhra Pradesh	4,093
Madhya Pradesh	2,520

Gujarat	7,542
Telangana	128
Kerala	63
Others	4.3
Cumulative capacity	37,744

Table 5-1: State-wise wind power installation (MW) in India (2020)

Suitable sites for installation of wind energy parks are identified by Ministry of New and Renewable Energy (MNRE) in association with National Institute of Wind Energy (NIWE), with Capacity Utilization Factor (CUF) >30% at 120 m hub height (Ref. 6).

5.3. Typical capacities

Wind turbines can be categorized according to nameplate capacity. At present time, new onshore installations are in the range of 2 to 6 MW. In India, the current trend is installing wind turbines between 2 to 3 MW.

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. Larger generators, larger hub heights and larger rotors have all contributed to increase the electricity generation from wind turbines. Lower specific capacity (increasing the size of the rotor area more than proportionally to the increase in generator rating) improves the capacity factor (energy production per generator capacity), since power output at wind speeds below rated power is directly proportional to the swept area of the rotor. Furthermore, the higher hub heights of larger turbines provide higher wind resources in general.

However, installing large onshore wind turbines requires well-developed infrastructure to be in place, in order to transport the big turbine structures to the site. If the infrastructure is not in place, the installation costs will be much higher, and it might be favourable to invest in smaller turbines than the current infrastructure can manage.

In India, the installation of power evacuation infrastructure (up to the nearest sub-station) invariably remains with the project developers for individual wind farms projects. For road infrastructure, the wind sites are selected based on feasibility of transporting blades and inaccessible site(s) are normally excluded.

5.1. Space 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.

5.2. Regulation ability and power system services

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, with the possible exception of voltage regulation.

With sufficient wind resources available (wind speed higher than rated wind speed and lower than 25-30 m/s) wind turbines can always provide down ramping, 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).

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. 7).

Wind turbine generation can be regulated down quickly, and this feature could potentially be used for grid balancing. The start-up time from no production to full operation depends on the wind resource available.

New types of wind turbines Doubly Fed Induction Generator (DFIG) and converter based can also provide supplementary ancillary services to the grid such as reactive power control, spinning reserve, inertial response (virtual inertia), etc.

5.3. 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.
- Wind power is a domestic source of energy, produced locally in India.
- Modular technology allows for capacity to be expanded according to demand, avoiding overbuilds and stranded costs.
- Short lead time compared to most alternative technologies.

Disadvantages

- Land use is a particular issue in India for the continued growth of RE.
- 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, forecasting generation can be a challenge.
- Not dispatchable capacity. Energy generation is dictated by the wind resource, not the energy demand.
- Visual impact and noise.
- Adverse impacts on birds and bats.

5.4. Environment

Wind energy is a clean energy source. A life cycle analysis (LCA) of electricity production from an onshore 100MW wind plant of V112-3.45 MW turbines suggests that the whole-life environmental impact associated amount to 5.3 CO_2 equivalent for each kWh unit of energy produced (Ref. 9). The mining and refinement of rare earth metals used in permanent magnets is an area of concern (Ref. 8, 9, and 10).

5.5. Research and development

The wind power technology is a commercial technology but is still constantly improved and decreased in cost (category 3[3] of R&D potential) (Ref. 8,11):

- 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 can improve value of wind power significantly, but is expensive at present.
- Lifetime extension of wind turbine. Wind turbines have a planned service life of approximately 25 years. Nevertheless, it has been demonstrated that many turbines are able to operate beyond their design life. In several instances, the lifetime of a wind farm may be extended through minor and low-cost repairs. In order to establish whether a wind turbine can continue to operate past its service life, a practical and analytical evaluation is required to be carried out.

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[3] The three categories of R&D: (1) Basic research, (2) Applied Research, and (3) Experimental Development. Experimental Development relates to – amongst others - incremental improvements in existing technologies, e.g. new materials, greater efficiency.

5.6. Prediction of performance and cost

Investment costs in India for onshore wind farms are among the lowest in the world and are approximately 6.7 INR_{2020} cr./MW (900 USD/kW).

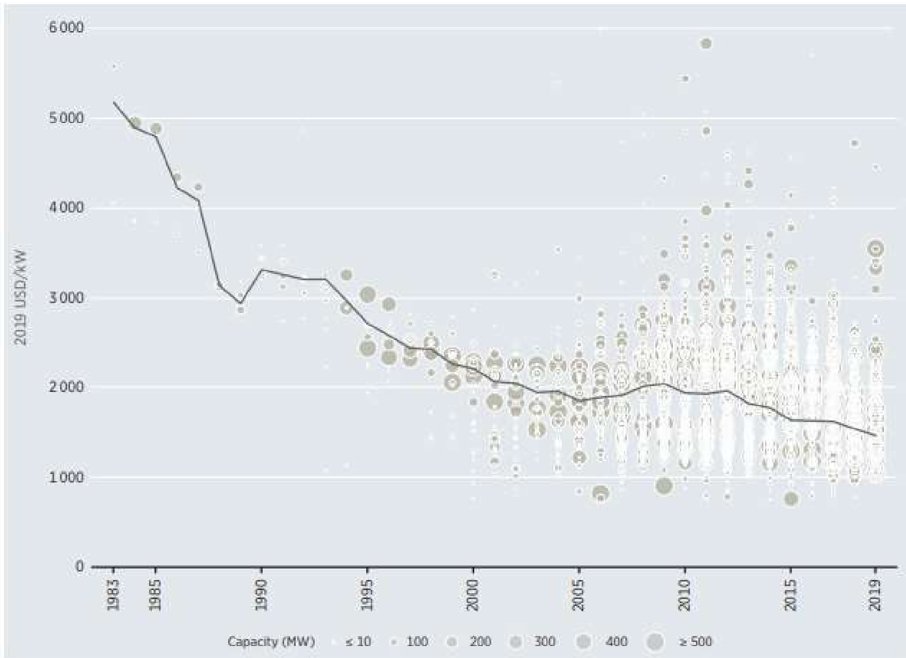

Figure 5-4: Total installed costs of onshore wind projects and global weighted average, 1983-2019 (Ref. 13)

Further technological development and cost reductions by global wind turbine manufacturers can be expected to reduce investment costs further. Recent tariffs of 2.77 INR_{2020}/kWh was obtained under a competitive bidding process by SECI in February 2021. This confirms the development towards a very low cost.

Onshore wind turbines can be seen as off-the-shelf products, but technology development continues at a considerable pace, and the cost of energy has continued to drop. While 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 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.

Using the learning rate methodology, which translates the variation in installed capacity into a cost variation, the future prices for onshore wind were projected. The capital cost in 2050 is between 5.7 and 6.2 INR_{2020} cr./MW, which correspond to a decrease between 14.3% and 5.3%.

The resulting cost development trend can be observed in Figure 5-5.

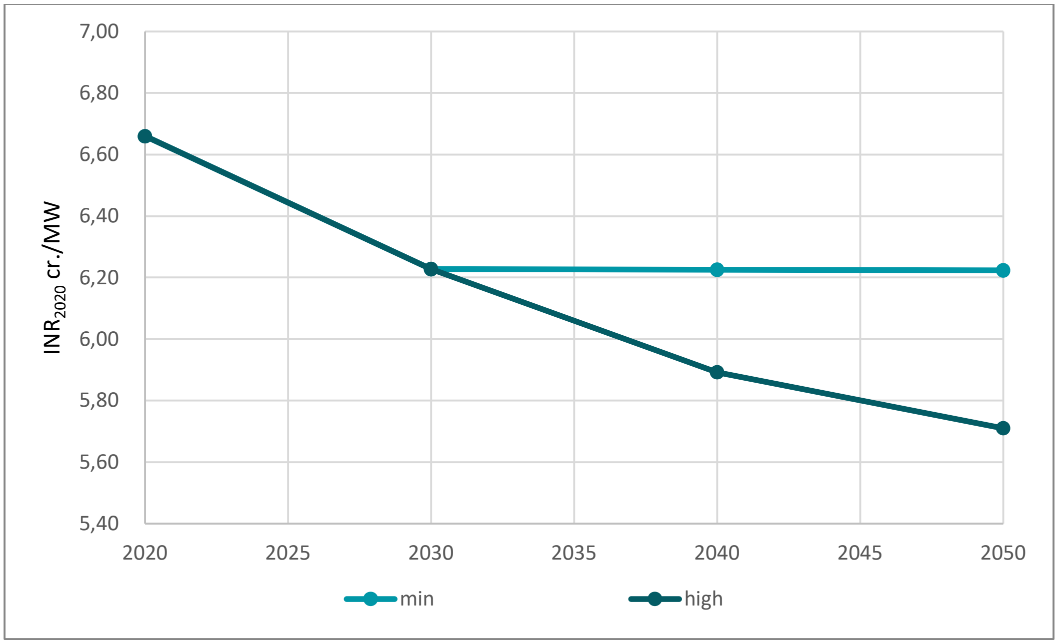

Figure 5-5: Projected onshore wind farm investment costs development from 2020 to 2050 considering a minimum and high development scenario.

5.7. Examples of existing projects

During the decade of 1980, Department of Non-Conventional Energy Sources (DNES) undertook many demonstration projects in the states of Gujarat and Tamil Nadu. As part of this initiative, the first grid connected and privately owned wind turbine was set up in Verawal, Gujarat.

Danish Aid Agency (DANIDA), in 1988 further supported the plans to develop two commercial projects of 10 MW each in the states of Gujarat and Tamil Nadu. These were the first demonstration projects of large-scale grid-connected wind farms.

Since then, onshore wind installations have steadily increased in India and the March 2020 installed capacity is approximately 37.7 GW, which is 10.1% of the total installed power capacity in India.

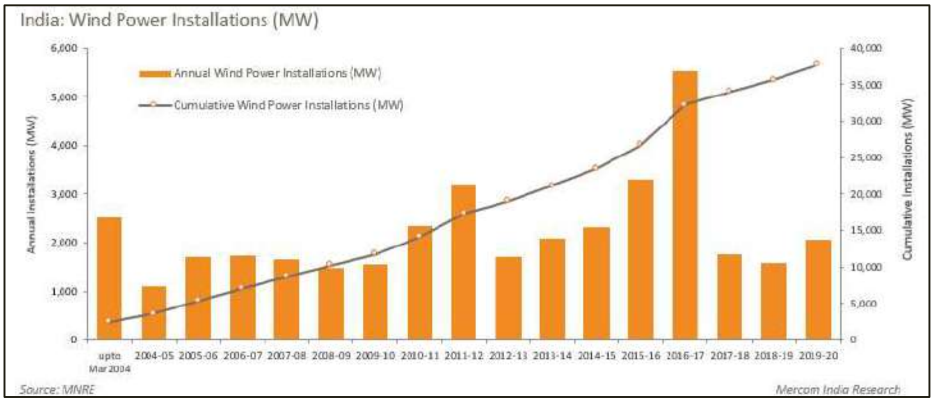

Figure 5-6: Annual and cumulative wind power installations in India (2004-2020) (Ref. 15)

1 Jath Wind Farm

Jath wind farm is a 60 MW project located in Maharashtra. It was commissioned in 2014 and the power from the project is sold to Maharashtra State Electricity Distribution company. The project utilizes Gamesa 2.0 MW (G97) wind turbines with a rotor diameter of 97 m. The farm is owned and operated by CLP Wind farms (India) pvt ltd. Specific investment details for the plant are not available, however similar onshore wind plants in Jath developed in 2017 -2019 has reported capital cost of INR 4.5 - 7.0 crores / MW (Ref. 16).

2 Jaisalmer Wind Park

Figure 5-7: Jaisalmer wind park (Ref. 17)

Developed by Suzlon Energy, the Jaisalmer wind park is the country's second-largest onshore wind project with a total capacity of 1,064 MW and is located in Jaisalmer district, Rajasthan.

The wind park development started in 2001 and its current capacity was achieved in April 2012. Suzlon's entire wind portfolio, ranging from the earliest 350kW model to the latest S9X – 2.1MW series, has been used in the project.

Renewable energy solutions provider Suzlon built the wind farms for a range of customers, including private and public sector firms, independent power producers and power utility providers.

Image	Location	Type	Year	Power capacity	Developer	Ref.
	Jath Wind Farm, Maharashtra, India	Onshore	2014	Gamesa 2.0 MW (G97) wind turbines	CLP Wind farms pvt ltd	16
	Jaisalmer Wind Park, Rajasthan, India	Onshore	2001	1,064 MW	Suzlon Energy	17

Table 5-2 Examples of existing onshore wind farms in India

5.8. References

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5.9. Datasheet

Technology	04 Large wind turbines on land									
Year of final investment decision	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data										
Generating capacity for one unit (MW)	2.5	4-5	6-8	8-10	2.2	2.5				1
Location-wise Capacity Utilization Factor (%)	38	40	42	44	35	38			A, B	1
Forced outage (%)	2.5	2	2	2	1	3				1
Planned outage (weeks per year)	0.5	0.3	0.3	0.3	0.3	0.5				1
Auxiliary Power Consumption (%)	0.5	0.5	0.5	0.5						1
Technical lifetime (years)	25	30	30	30						1
Construction time (years)	1.5	1	1	1						1
Space requirement (1000m^2/MW)	14	14	14	14						1
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Financial data (in 2020₹)										
Capital Cost (cr. ₹/MW)	6.66	6.24	6.04	5.91	6.00	7.70				1, 3
- of which equipment (%)	64	62	61	60					C	2
- of which installation/development (%)	8	8	8	8					C	2
- of which is related to grid connection (%)	5	5	5	5					C	2
- of which is related to rent of land (%)	8	8	9	9					C	2
- of which is related to other costs (i.e. compensation of neighbours, etc.) (%)	12	13	14	14					C	2
Fixed O&M (cr. ₹/MW/year)	0.068	0.064	0.062	0.061						1, 3
Variable O&M (₹/MWh)	240	225	218	213						1
Technology specific data										
Rotor diameter	132	155	170	180	120	132				1
Hub height	130	140	150	160	120	130				1
Specific power (W/m2)	183	239	309	354						1
Average capacity utilization factor (%)	38	40	42	44	35	38				1
Average availability (%)	96	97	97	97	95	96				1

References

1) Value based on inputs from Indian stakeholder

2) Technology Data – Generation of Electricity and District Heating; Danish Energy Agency, Energinet; 2020

3) Report on Optimal Generation Capacity Mix for 2029-30; Central Electricity Authority, 2020

Notes

A) This value is highly location specific and related to the size of the turbine

B) The data provided is for new, large turbines with hub heights around 130 m. Existing Indian onshore wind turbines with hub heights around 80 m would result in a lower CUF, possibly around 25% depending on location

C) This data is solely based on international experiences as no Indian data is available

6. Wind turbines, offshore

6.1. Brief technology description

The most common offshore 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 (Ref. 6).

Offshore wind farms must withstand the harsh marine environment. The installation and maintenance costs are significantly higher compared to onshore wind (e.g. specialized equipment, more expensive foundations and cabling, slower processes due to higher risks, dependency on weather). The electrical and mechanical components in the turbines need additional corrosion protection and the offshore foundations are costly. The high cost of installation, results in much higher investment costs than for onshore turbines of similar size (Ref. 6). However, offshore wind has a number of advantages compared to onshore wind, among others a higher wind resource, less limitations in relation to available sites and closer proximity to load centres (see paragraph about advantages/disadvantages for more information).

The total cost of the offshore wind installation will vary from site to site, depending on distance to shore, metocean/seabed conditions and water depths. Deeper waters and further distances from shore increases the total cost. Offshore wind farms have historically been installed on four different types of foundations: monopile, gravity base, jacket, and tripod structures. Today, monopiles and jackets are the most common foundation type (Figure 6-1, Figure 6-2). Choice of foundation type depends on local seabed conditions and water depth.

Figure 6-1: Jacket (left) and Tripod (right) foundation structures. (Ref. 7)

Figure 6-2: Monopile (left) and gravity base (right) structures (Ref. 7)

Technological innovations, such as suction buckets and floating foundations, are being investigated and may in the future have the potential to reduce the overall cost in areas where other foundations are harder to deploy. Bucket foundations are typically preferred when the seabed is sand. Their main advantage is they use less material and have low decommissioning costs. For deep waters (approx. 60m+), the floating foundation is likely the most suitable solution and can be designed for large serial production. Nevertheless, these technologies are still being researched, tested and demonstrated, and are not currently deployed on a commercial basis. However, floating wind is expected to play a significant role in the future offshore wind energy market. The current floating offshore wind capacity of only approximately 50 MW is likely to increase many fold in the next decade. DNV expects more than 4 GW in 2030 and over 30 GW in 2040 (Ref. 8).

The offshore wind project life cycle includes four phases: pre-construction, construction, project O&M and decommissioning. Every phase consists of different types of services and equipment requirements. Based on the services involved in offshore wind installation and decommissioning, at least 11 different types of vessels are needed during the offshore wind lifecycle. Vessel availability in the region where the site is located may be high, but might not be specialized for offshore wind installation. In regions where the offshore wind industry is well developed, specific vessels built for offshore wind requirements are now common. However, in newly developing offshore markets such as India, it is anticipated that utilisation and modification of vessels from adjacent sectors will be required until a sufficient supply chain is developed.

Figure 6-3: Types of specialized vessels such as: Installation (Jack up), multipurpose cargo, heavy lift. (Ref. 9)

6.2. Wind resource and capacity factors

Detailed wind resource assessments are needed to estimate the changing wind resource across different locations and for this reason wind atlases have been created by averaging estimates of wind speed and power density across multiple years (Ref. 10).

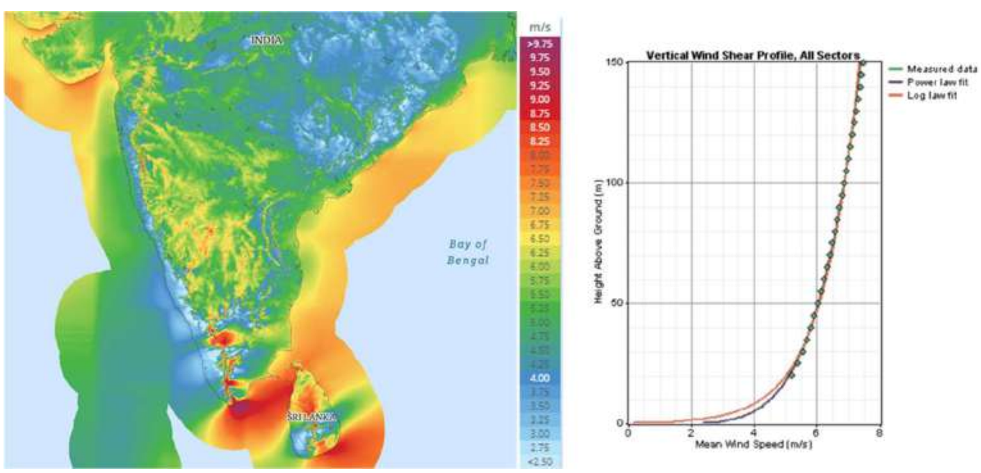

Figure 6-4: Locational variation of wind speed from the Global Wind Atlas (left) and wind variation with height (right). (Ref.10)

In relation to height, the wind speed increases with the elevation above the sea/ground level with a power or logarithmic law: the higher the hub height, the more wind resource can be harvested by the turbine (Figure 6-4).

One major driver for developing wind farms offshore rather than onshore is the improved wind resource, which can justify some of the additional investment and O&M costs. The combination of larger, purpose-built wind turbines, improved technology, higher hub heights and longer blades with larger swept areas leads to increased capacity factors for a given wind resource.

For offshore wind farms globally, significant improvements are possible as illustrated in Figure 6-5, with global averaged capacity factors in the range of 36% to 58% in 2030 and 43% to 60% in 2050, compared to an average of 43% in 2018 (Ref. 11).

There can however be a significant variation in capacity factors between different projects. This is caused by a combination of differences in turbine technologies, including different specific power ratings, and in the wind resource quality. A combination of improved wind turbine technologies such as larger wind turbines with longer blades and with larger swept areas has led to increased capacity factors for a given wind resource.

For India there is not a significant amount of measured offshore wind data available. The map in Figure 6-4 therefore is mainly based on extrapolated data and meso scale modelling, but the local variations in the wind resource are quite significant. In India wind speeds offshore will often limit the maximum capacity factor possible. However, a detailed geospatial analysis showed that capacity factors in the Palk Strait between India and Sri Lanka could be well above average for the region and comparable to those found in Europe (Ref. 3).

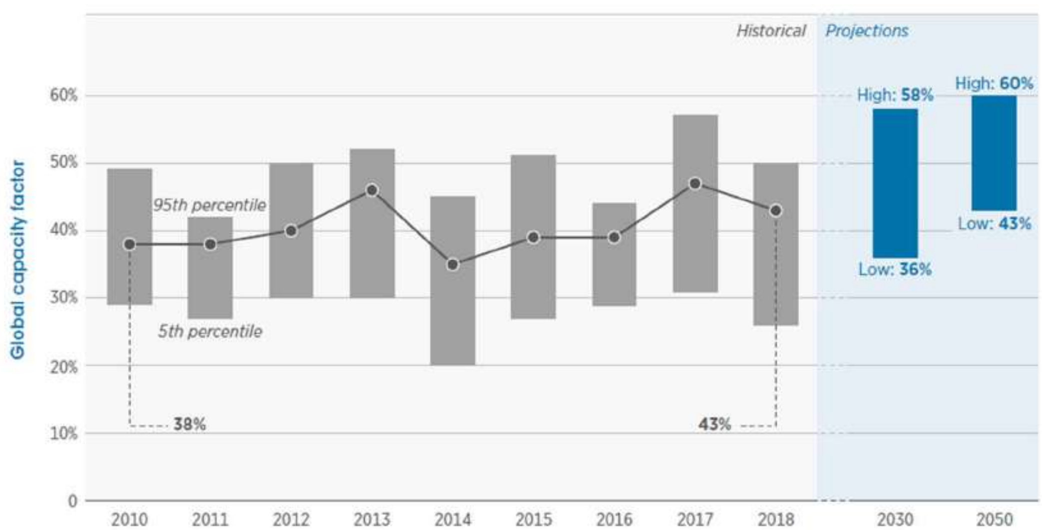

Figure 6-5: The global weighted average capacity factor for offshore wind has increased by 5 percentage points since 2010, to 43%, and upcoming projects would have capacity factors up to 58% in 2030 and 60% in 2050 (Ref. 11).

Table 6-1 summarizes technical characteristics and wind resource data for selected Danish offshore wind farms recently commissioned, under construction or in planning. Capacity factors are estimates calculated by COWI for the Danish Energy Agency.

For comparison estimates from the FIMOI (Financial modelling of offshore wind farms in India) project under the Centre of Excellence for Offshore Wind, which is a project co-developed under the Indian and Danish government collaboration show that Gujarat could achieve capacity factors of close to 40% and Tamil Nadu in the best zones could achieve close to 60%.

	Horn Rev 3	Kriegers Flak	Thor
Expected date of operation	2019	2021	2026
Total capacity	407 MW*	605 MW**	800 MW*****
Average wind speed (100m height)	10.0 m/s*** (Nordsøen 4)	9.5 m/s*** (Avg. Kriegers Flak)	10.2 m/s*** (Nordsøen 2)
Estimated capacity factor (Park production, excl. grid losses)	52%***	51%***	57%****
Turbine rating	8.3 MW*	8.4 MW**	10 MW****
Specific power	393 W/m²*	383 W/m²**	-

*Table 6-1: Key data for recent offshore wind farms in Denmark, compared to estimates for Gujarat. Estimated capacity factors depend on detailed park layout. Sources: * Ref. 12, ** Ref. 13, *** Ref. 14, **** Ref. 15, (these estimates were made in 2018 before the Thor project was tendered) , ***** Ref. 16.*

Another wind resource characteristic is seasonality. Seasonality of wind resource varies by location, depending on the specific atmospheric and climate conditions. In Europe, for example, wind speeds are generally stronger during October to March and lower during June to September. In India, simulations indicate that the monsoon season from June to September would see higher output from offshore wind projects compared with other parts of the year. The seasonal profile of offshore wind is complementary to that of solar PV, which tends to produce less during the season of monsoons. This is shown in the graphs in Figure 6-6, adapted from Ref. 3.

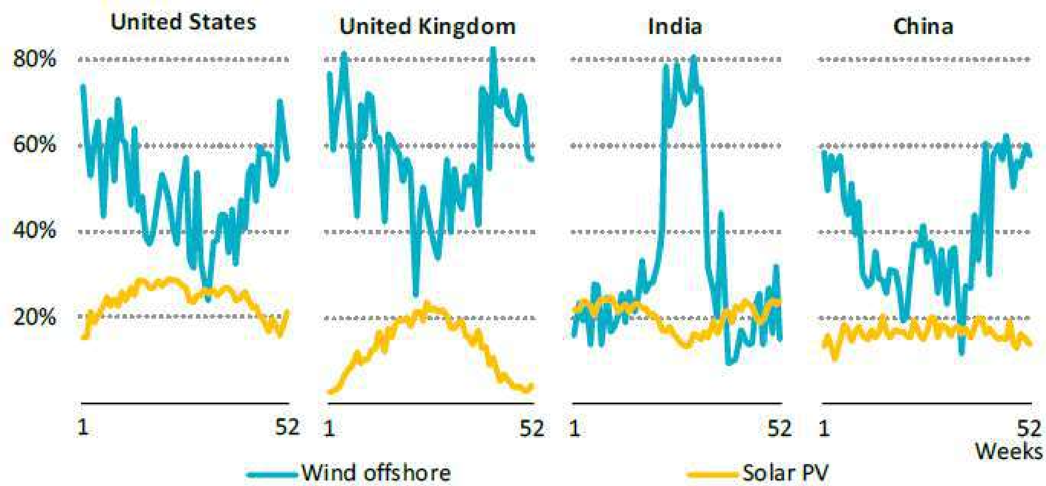

Figure 6-6*: Average weekly capacity factors (%) for offshore wind and PV in India and other wind locations. (Ref. 3)*

6.3. Typical offshore turbine capacities

Technology innovation has led to an increase in offshore turbine size in terms of tip height and swept area, and this has raised their maximum output. The rotor diameter of commercially available offshore turbines increased from just over 90 meters (m) in 2010 (3 MW turbine) to more than 164 m in 2016 (8 MW turbine) while the swept area increased by 230%. The larger swept area allows for more wind to be captured per turbine. A 12 MW turbine is currently being tested for full scale market launch and has a rotor diameter of about 220 m (Ref. 3). Also a 14 MW turbine with a 222 m rotor diameter is being tested for later commercial launch and 15 MW turbines with even larger rotors have already been announced to come to the market before 2025 (Ref. 31). The average size of offshore wind turbines grew by a factor of 3.4 in less than two decades and is expected to continue to grow, with 15-20 MW turbines expected by 2030.

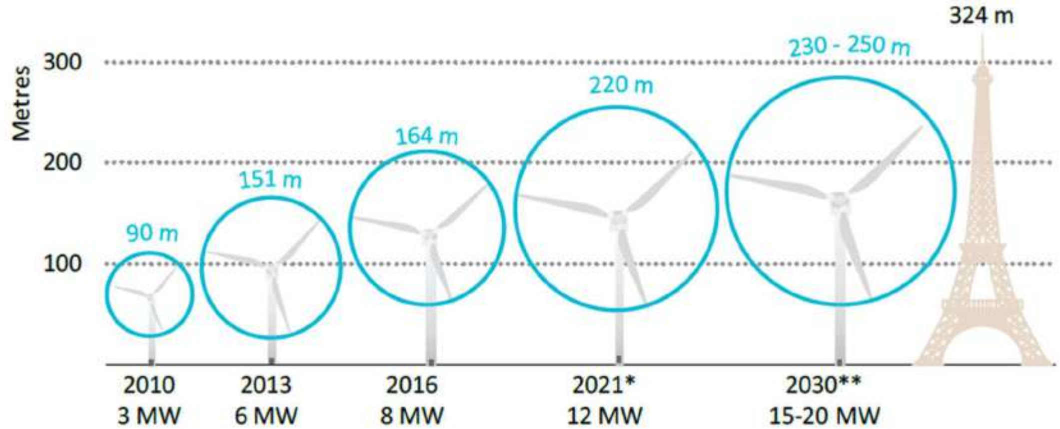

Figure 6-7: Evolution of the largest commercially available offshore wind turbines (Ref. 3)

Generally, this increase in turbine size and rated power has increased the capital cost of each individual turbine and foundation, as larger turbines require more material, pose construction and installation challenges and require larger foundations. At the same time moving to larger turbines reduces the number of turbines/foundations and reduces the operation and maintenance costs, most often leading to lower levelized costs of electricity. Nevertheless, real case feasibility studies (Ref. 18) illustrate that turbine model selection should be performed considering trade-offs between the pure minimization of costs and the maximization of capacity factors, especially in low wind conditions.

The power rating of an offshore wind turbine is not the only important parameter. The size and length of offshore wind blades have seen a dramatic increase in the last few years, with models today up to 200 m diameter. A key parameter in the definition of a wind turbine technology is Specific Power (expressed in W/m^2 or kW/m^2). It is defined as the ratio between the rated power of the turbine in W or kW and the swept area expressed in m^2. The specific power of a turbine has implications on capacity factors, production patterns and market value of wind, as indicated in literature (Ref. 6).

6.4. Regulation ability and variability/ramping

Electricity generation from wind turbines is variable because it depends on the wind resource available. In terms of regulation abilities, further details can be found under the chapter on onshore wind power. IEA expects that technological advances enabled by digitalization could increase the value of preventively curtailing generation to be able to provide upward regulation in the future (i.e. ancillary services to the balancing market), so as to make these services economically attractive (Ref. 3).

Most of the multi-MW wind turbine generators (DFIGs and PMSGs) also have the ability to provide supplementary ancillary services to the grid, such as reactive power control, spinning reserve, inertial response, etc. However, these supplementary ancillary services from wind turbines are seldom utilized, due to a lack of economic incentives.

Offshore wind turbines have a disadvantage for regulation of voltage and reactive power in the main power grid, because of the distances between the wind farm and the point of connection to the power grid. An offshore wind farm will be able to compensate for reactive power created by itself, however their contribution to further compensation of reactive power in the main grid is limited depending on the distance to point of connection (Ref. 6).

6.5. Advantages/disadvantages

Advantages of offshore wind technologies versus conventional power sources:

- No emissions of CO_2 during operation.
- No emissions of air pollutant emissions.
- Stable and predictable variable costs, due to the lack of uncertainties related to fuel cost.
- Close-to-zero marginal cost when operating.
- Shorter construction times compared to nuclear and thermal power plants.

Disadvantages of offshore wind:

- Variable generation that cannot be dispatched when needed and requires power system integration measures, as opposed to conventional power plants.
- More up-front capital-intensive technology than conventional fossil-fuelled power plant.

Advantages of offshore wind versus other variable renewable power sources (i.e. onshore wind and solar PV):

- Access to higher and more stable wind speeds compared to onshore wind and higher capacity factors than both onshore wind and solar PV.
- It can generate electricity during all hours of the day in comparison to solar PV plants.
- Higher capacity credit and larger contribution to power system adequacy.
- Exhibits generally higher market value[4] compared to onshore wind and solar and the market value is reduced less at high penetration rates (Ref. 24).
- The availability of large sites suitable for larger projects, thus exploiting economies of scale.
- For some potential wind parks in India, they could be located with closer proximity to load centres compared to onshore wind.
- Less need to deploy additional storage capacity compared to onshore wind and solar, due to the lower fluctuations of generation and more stable production.
- Reduction of the visual and noise impacts from turbines compared to onshore wind, which affects public acceptance, which has become a major barrier for onshore deployment in some markets.
- Shorter construction times compared to hydro and nuclear power plants.

Disadvantages of offshore wind versus other variable renewable power sources (i.e. onshore wind and solar PV):

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[4] Market value is defined as the average power price seen by the wind generators. It is calculated as total revenue in the market divided by total production and expressed in currency/MWh. It is a relevant metric to calculate in countries with an established day-ahead market.

- More complex logistic associated with constructing wind turbines offshore compared to onshore wind and PV solar. These challenges increase capital costs for developing offshore wind farms.
- Need for developing supply chain for offshore wind (ports, offshore turbines production, vessels, etc.), which is needed to drive down costs.
- Weather dependency for accessing wind turbines on site during O&M, which in the worst case may result in an additional penalty of reduced turbine availability and hence reduced output.
- Longer construction times compared to onshore wind and solar.

6.6. Environment and Social Impact

Environmental considerations for offshore wind typically revolve around the impact on wildlife, visual impact, noise, manufacturing process and the use of rare earths specifically for direct drive wind turbine generators.

Concerns have been raised in relation to impacts on fish, marine mammals and birds related to habitat change, displacement or injury during construction and operational noise (Ref. 19). However, several studies have pointed to potential benefits from offshore wind farms, including enhanced biological productivity and improved ecological connectivity. Based on a long-term environmental study on the Horns Rev project in Denmark, fish species may be attracted to foundations, providing a refuge and potentially increasing the number of species in a project area (Ref. 19).

Some of the challenges faced by other technologies, such as onshore wind and utility-scale solar PV, regarding public acceptance are not as applicable to offshore wind farms. Concerns about noise, visual impacts and use of arable or other valuable land are less critical compared to onshore wind and solar PV.

However, challenges regarding public acceptance have been experienced in locations closer to shore (below 10 km), thereby causing significant delays and even project cancellations. In general, there is a willingness to pay for locating wind farms at distances where the visual effects on the coastal landscape are reduced (Ref. 20).

The environmental impact from manufacturing offshore wind turbines is moderate and is comparable to the impact of other normal industrial production. The mining and refinement of rare earth metals used in permanent magnets is an area of concern. Life-cycle assessment (LCA) studies of wind farms have concluded that environmental impacts come from three main sources (Ref. 6):

- bulk waste from the tower and foundations, even though a high percentage of the steel is recycled
- hazardous waste from components in the nacelle
- greenhouse gases (e.g. CO_2 from steel manufacturing and solvents from surface coatings)

The Energy Return on Energy Invested (EROI) is a metric that defines how much energy is produced from the wind turbines compared to the energy needed to produce them. Today the value for Offshore wind is around 20-50, meaning an offshore wind farm produces 20-50 times the energy required to build it over its lifetime (Ref. 21), making it one of the best energy sources for this metric (better than coal and on par with hydro). Energy payback time ranges between 3 and 9 months.

6.7. R&D and new technology developments

Offshore wind technology is improving quickly and cost for projects with a FID (Final Investment Decision) in 2020 is considerably lower than sites already being commissioned in 2020. This cost reduction can be attributed to progress in several main areas of innovation and market maturity such as the high pace of product development and competition. Consequently, projects are often planned and developed on the basis of turbines that are not yet in serial production (Ref. 8).

Some of the main future anticipated innovations in offshore wind technology are (Ref. 11, 23):

- New, larger and more efficient wind turbines. Key cost reductions from using turbines larger than 12 MW are due to lower balance-of-plant and O&M costs. It is likely that higher capacity factors can also be achieved.
- Consolidation of 66 kV electrical wind farm systems as alternative to current 33 kV, relevant especially for longer array cables and higher power ratings of the individual turbines, since losses and cable size can be reduced.
- Technology development and cost reduction for transmission systems: Development of compact offshore substations (which will reduce platform, installation and transport cost). Wider application of high-voltage direct current (HVDC) converter stations and cables, which offer cost effective transmission options for offshore wind farms far of the coast. HVDC equipment is available today.
- Improvement of design methods in the planning and operation phase, e.g. reduction of wake losses, reduction of O&M costs by improved control strategies, more optimized tower/foundation structure by integrated design.
- Autonomous inspection and predictive maintenance. Drones and remotely operated vehicles will be used more to inspect wind farms. This reduces the turbine downtime, reduces the health and safety risks, and is cheaper to perform and allows for more frequent inspections. Operators will be able to use more sophisticated structural health monitoring.
- Logistical issues, e.g. more dedicated vessels in installation and maintenance phase.
- Improved methods for handling different seabed conditions, which will reduce foundation costs.
- Improved monitoring in the operational phase for lowering availability losses and securing optimal operation.
- Reduce the uncertainty of wind generation through advanced weather forecasting. New techniques and algorithm methods can increase the accuracy of the forecast by handling big data and hence advance the overall reliability of the system.

Figure 6-8 illustrates the expected period for commercialization for some of the innovations mentioned.

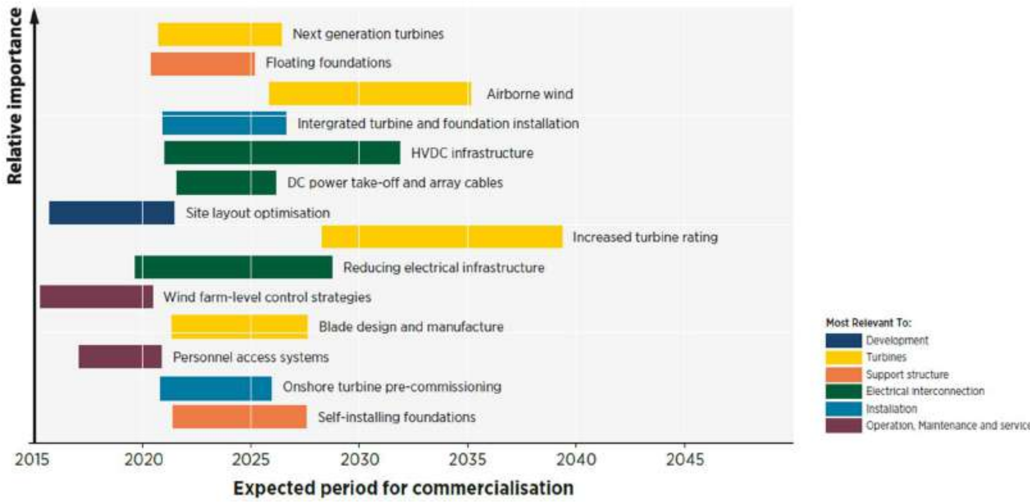

Figure 6-8: Improvements of offshore wind technology vs time horizon estimation for market accessibility (Ref. 11)

Existing barriers at different scales such as market evolution and power system integration could hinder the deployment of offshore wind in the coming decades. Mitigating these barriers, through a range of R&D, support policies and implementation is vital to boost future development (Ref. 11).

Floating offshore wind

The deployment of floating foundations would allow harnessing of untapped wind resources located in regions with water depths exceeding 50-60 m. Floating offshore wind, a technology currently under research and development with few pilot projects completed, is currently significantly more expensive than offshore wind in shallower waters, but has a vast potential. IEA estimates that the floating offshore wind potential worldwide is 330,000 TWh/year, almost four times bigger than offshore in shallow water (87,000 TWh/year) (Ref. 3). This extensive potential would be enough to supply the current global electricity demand 13 times.

There are many ideas under development that may ultimately realize lower costs than fixed structure solutions: catenary moored semi-submersible platforms, the tension leg platform (TLP) which has a smaller and lighter structure, but requires a design which increases stress on the tendon and anchor system; and the spar-buoy which is more suited to deeper waters (> ~80 m) (Ref. 23).

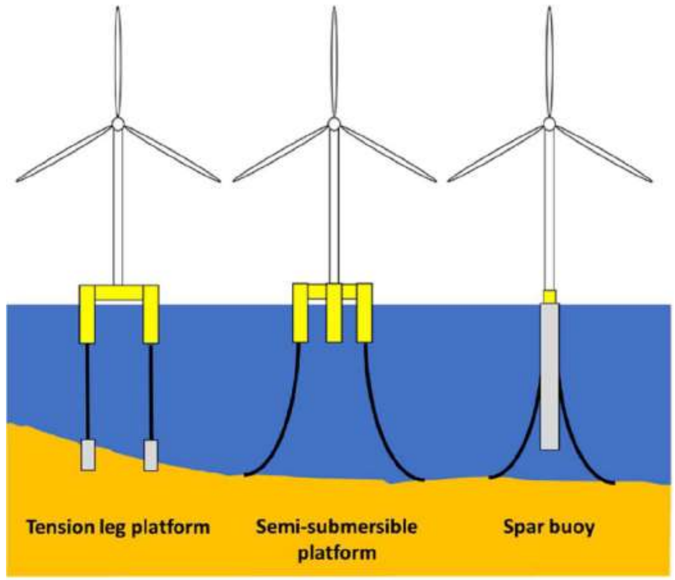

Figure 6-9. Floating concepts (Ref. 23)

Among the characteristics of floating offshore wind are:

- Potential to be deployed in countries with deep waters, where traditional fixed bottom foundations cannot be installed (Scotland, Japan, California, South Korea, Norway and France).
- Significant worldwide potential.
- Lower sensitivity to cost increase with water depth, but higher cabling and mooring costs compared to standard offshore wind.
- Potential for lower LCOE due to standardization of the foundation manufacturing, which is independent of the sea bottom and water depth.
- Potentially lower transport and installation costs (platforms can be dragged to position).

In recent years, there have been significant developments in floating offshore wind projects, including the commissioning of the world's first multi-unit installation in 2017 (30 MW Hywind in Scotland). Several demonstration projects were installed in 2018, including Floatgen in France (2 MW) and Hibiki in Japan (3 MW) (Ref. 3). Several pre-commercial projects are planned in Europe in the next three years, ranging between 24 and 88 MW, while France plans to have a combined 750 MW of floating offshore auctions by 2022 (Ref. 2). Equinor recently received approval to build a 200 MW floating offshore wind farm in the Canary Islands. In January 2022, Scotland awarded seabed rights for 25 GW offshore wind where 15 GW of that capacity would be floating foundation wind energy (Ref. 32).

6.8. Prediction of performance and cost

Globally, offshore wind has become a competitive energy source. Global offshore wind capacity is more than 35 GW, representing 4.8% of total global cumulative wind capacity (Ref. 30). Wind technologies are steadily improving, wind turbines are becoming larger and more efficient. Likewise, offshore technology is developing further to accommodate larger wind farms. Also, the growing global offshore wind market is boosting the offshore wind supply chain. As a result, significant cost reductions are expected in the future.

Costs for India are to a large extent based on stakeholder feedback supported by data from the FIMOI (Financial modelling of offshore wind farms in India) project, which is a project co-developed under the Indian and Danish government collaboration. Over the next 10 years, investment costs are expected to drop by 40% in India. This is contingent on building a substantial pipeline of offshore wind projects starting today. A predictable and substantial pipeline will allow developers, manufacturers, and service providers to establish a local supply chain, thus greatly reducing the costs.

Using the learning rate methodology, which translates the growth in installed capacity into a cost reduction, the future prices for offshore wind farms were projected. As a result, the investment costs in 2050 is expected to be between 13.5 and 11.2 INR_{2020} cr./MW. This equates to a reduction between 42% and 52% compared to 2020 prices.

The resulting cost development trend can be observed in Figure 6-10.

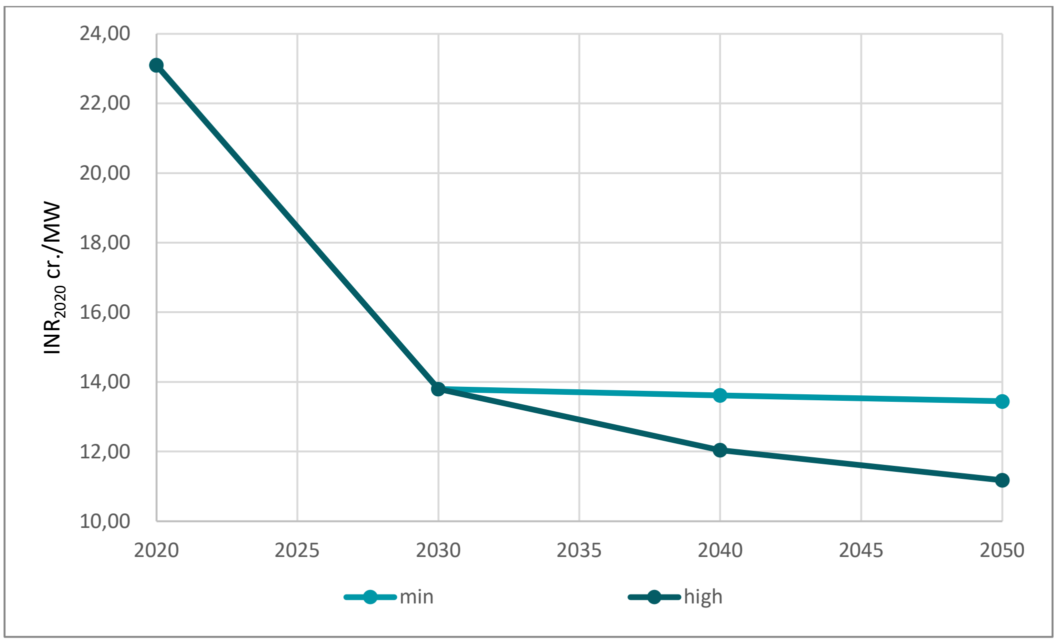

Figure 6-10: Projected offshore wind farm investment costs development from 2020 to 2050 considering a minimum and high development scenario.

6.9. Examples of standard technology

The largest operational offshore wind farm as of January 2020 is Hornsea 1, a UK wind farm of 1,218 MW composed of 174 Siemens SWT-7.0-154 turbines, commissioned in 2019 and developed by Ørsted. The record for the greatest number of turbines in a farm belongs to London Array (630 MW), composed of 175 turbines.

The largest wind turbine installed today is a *MHI Vestas 9.5 MW* with 164 m rotor diameter, while other wind turbine models from Siemens Gamesa and Vestas models up to 10 MW are and will be commercially available with expected delivery in 2021-2022. The largest turbine currently announced and under development is Vestas V236-15MW which features not only a very large power rating of 15 MW but also a rotor diameter of 236 m (Ref. 33).

Several projects in the UK and Germany surpassed 100 km distance to shore, exemplified by the offshore wind HVDC link SylWin1 of 160 km.

The cost of offshore wind farms from the latest auction rounds in 2019 (commercial operation date generally after 2023) in France, UK and Netherlands showed prices around 44-47 €/MWh (Ref. 1) (i.e. 3,600-3,800 INR/MWh). Another important landmark for the industry has been the award of subsidy-free offshore projects in both Germany (*He Dreiht, Borkum Riffgrund West 1 and 2, and OWP West*), the Netherlands (*Hollandse Kust Zuid*) during 2018 and 2019 and in Denmark (*Thor*) during 2021, thanks to the combination of high wind speeds, large competition in the tenders, socialized grid connection costs and the possibility to predict the expected electricity price.

Image	Location	Type	Year	Power capacity	Operator	Ref.
	Hornsea, UK	Offshore	2019	1,218 MW 174 turbines	Ørsted	25
	London array, UK	Offshore	2012	630 MW 175 turbines	London Array Ltd	26
	Hywind, Scotland	Floating offshore	2017	30 MW	Equinor and Masdar	27
	Floatgen, France	Floating offshore	2018	2 MW	Ecole Centrale de Nantes	28

	Hibiki, Japan	Floating offshore	2018	3 MW	Hibiki Wind Energy Co., Ltd	29

Table 6-2: Examples of existing market standard technology of offshore wind farms

6.10. Examples of existing projects

The National Institute of Wind Energy (NIWE) installed meteorological masts and a LIDAR along the coast to develop a preliminary assessment of the offshore wind potential. As indicated in the National Offshore Policy (Ref. 5), preliminary assessments along the Indian coastline have indicated prospects of development of offshore wind power, with wind resource data collected in Gujarat and Tamil Nadu.

Recently, MNRE announced that based on mesoscale mapping, it is estimated that, approximately 36 GW offshore wind power potential exists off the coast of Gujarat and 35 GW offshore wind power potential exists off the coast of Tamil Nadu, bringing the total expected potential in those areas close to 71 GW (Ref. 4). This assessment does not include estimates of the total gross potential for India and does not take into account oceanographic data, geophysical and geotechnical data at the actual sites. Estimations from the World Bank indicate a large technical potential for offshore wind power around 112 GW in India within 200 kilometres of the shoreline.

This offshore wind potential can with an enabling framework be harvested which in turn is a conditions for unleashing the cost reductions projected in the 1.8 Performance and Cost chapter.

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6.12. Datasheets

Technology	05 Large wind turbines offshore									
	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	8	15	18	20	4.2	8.0	15	30	A, B	1,2,3,4
Location-wise Capacity Utilization Factor (%)	43	44-60	44-60	44-60	38	47.5	44	65	D	1
Electrical losses (%)	5	5	5	5					E	1
Forced outage and planned outage (%)	4	4	4	4					C, E	1
Technical lifetime (years)	25	30	30	30			25	35	B	1,2,3,4
Development time (years)	1.5	1.5	1.5	1.5			1.5	2		1
Construction time (years)	2.5	2.5	2	2			1.5	2.5		1,3
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Financial data (in 2020₹)										
Capital Cost (cr. ₹/MW)	23.1	13.8	12.7	12.0					E	1
- of which equipment (%)	57								F	1
- of which installation (%)	19								F	1
- of which grid connection (%)	24								F	1
Fixed O&M (cr. ₹/MW/year)	0.674	0.364	0.323	0.298					E	1
Technology specific data										
Rotor diameter	164	240	260	280						1,3
Hub height	103	150	160	170						1,3
Specific power (W/m2)	379	332	339	325						1,3

References

1) Value based on inputs from offshore wind stakeholders and the FIMOI project, Centre of Excellence for Offshore Wind, India

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3) Technology Data – Generation of Electricity and District Heating; Danish Energy Agency, Energinet; 2020

4) Viet Nam Technology Catalogue – Technology data input for power system modelling in Viet Nam; EREA, Institute of Energy, Ea Energy Analyses, Danish Energy Agency, Danish Embassy in Vietnam, 2019

Notes

A) This value is highly location specific and related to the size of the turbine

B) Future projections based on international data

C) Potential curtailment not included

D) The span covers very diverse sea zones in both Tamil Nadu and Gujarat. The capacity factor is gross without electrical losses and forced or planned outages.

E) Technical and financial data are based on a 'full scope' offshore wind farm, including wind farm and full transmission asset (offshore substation, export cables and onshore substation and cabling)

F) The category 'equipment' covers wind turbine, foundation and array cables; 'installation' covers project development and execution, and installation; 'grid connection' covers offshore substation, offshore and onshore cables and onshore substation.

7. Photovoltaics

7.1. Brief technology description

A solar cell is a semiconductor component that generates electricity when exposed to light. For practical reasons, several solar cells are typically interconnected and laminated to (or deposited on) a glass pane in order to obtain a mechanical ridged and weathering protected solar panels. The photovoltaic (PV) panels are typically 1-2 m^2 in size and have a power density in the range 150-250 W_p/m^2. They have an expected lifetime of around 25 years.

PV panels 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 poly-crystalline silicon wafers. Currently more than 90% of all PV panels 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). Future improvements include development from mono-facial to bifacial panels, which convert light captured on both the front and the back of the cell into power (Ref. 2). Another trend is multilayer when area is a scarce resource.
- 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 panels are commercially available. In these panels several layers are deposited on top of each other in order 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).

In addition to PV panels, 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). Based on stakeholder inputs, the PV module itself accounts for approximately 40-50% of the total system costs, inverters around 15% for utility scale and 20% for rooftop systems.

The capacity of a photovoltaic plant can be expressed in two ways: MW_p is the rated DC capacity (installed panel capacity) of the solar power plants under solar Standard Test Condition (STC) and MW_{ac} is the output capacity delivered to the grid under STC.

PV units can be scaled from kW to MW installations. Economy of scale makes the specific investment costs lower for large plants.

Figure 7-1: Utility scale PV plant

7.2. Input/output

Input

Solar radiation. The irradiation, which the module receives, depends on the solar energy resource potential at the location, including shade and the orientation of the module (both tilting from horizontal plane and deviation from facing south).

In India, the average annual solar energy received on a horizontal surface measured in terms of power potential varies between approximately 1300 kWh/kWp and 1750 kWh/kWp per year. See figure below.

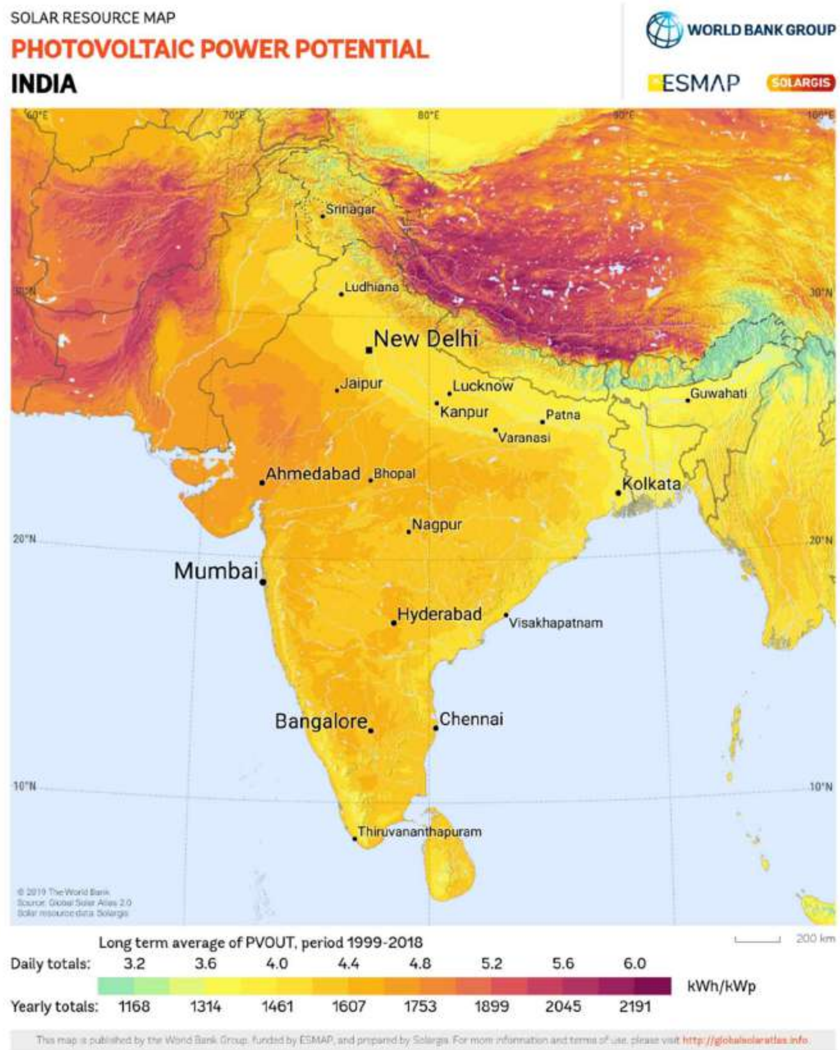

Figure 7-2: Power potential (kWh/kWp) for PV in India (Ref. 4)

At locations far from equator, generation may be increased somewhat by tilting the solar power PV panels towards equator. In India, solar power potential is concentrated in Western, central and southern regions of the Central Highland, Southern Central and the Southern with latitude from 9° (State of Kerala, Tamil Nadu) to 22° (Gujrat, Rajasthan), hence the tilt need to be around 15° in average.

The irradiation to the module can be increased even further by mounting it on a sun-tracking device. At the equator, a sun-tracking device could result in a 20% increase in total irradiation to the PV module[5].

Output

[5] Rough estimate by COWI PV expert.

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.
- Installed module generation capacity.
- Losses related to the installation site (soiling and shade).
- Losses related to the conversion from sunlight to electricity.
- 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/m^2 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 (kWp). 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/m^2.

In practice, irradiation levels of 1000 W/m^2 are rarely reached, even at locations very close to the equator. The graph below shows the global irradiance on a fixed plane (W/m^2) during the day for a location in New Delhi for an average daily profile for July - the month with the best solar conditions.

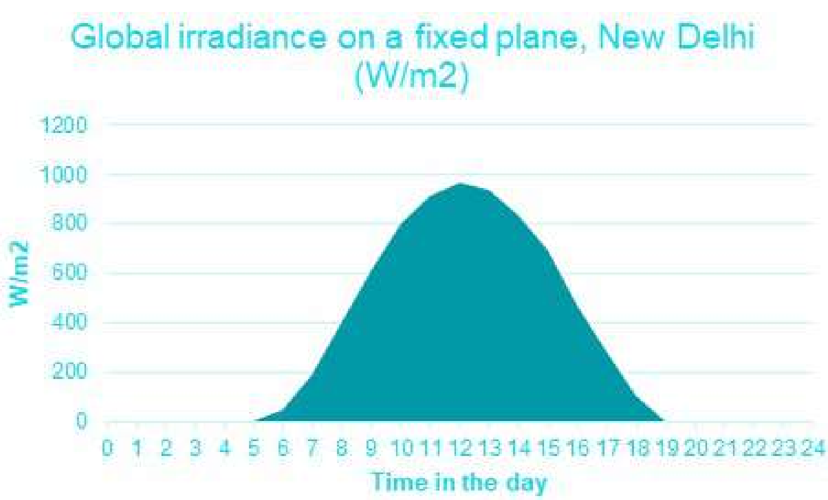

Figure 7-3: Global irradiance on a fixed plane (W/m^2) during the course of the day in New Delhi; average daily profile for July, the month with the best solar conditions (Ref. 13).

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 from a PV installation with a peak capacity P_p, can be calculated as:

P_p * Global Horizontal Irradiation * Transposition Factor * (1 - Incident Angle Modifier loss) * (1 - PV systems losses and non-STC corrections) * (1 – Inverter losses) * (1 – Transformer losses).

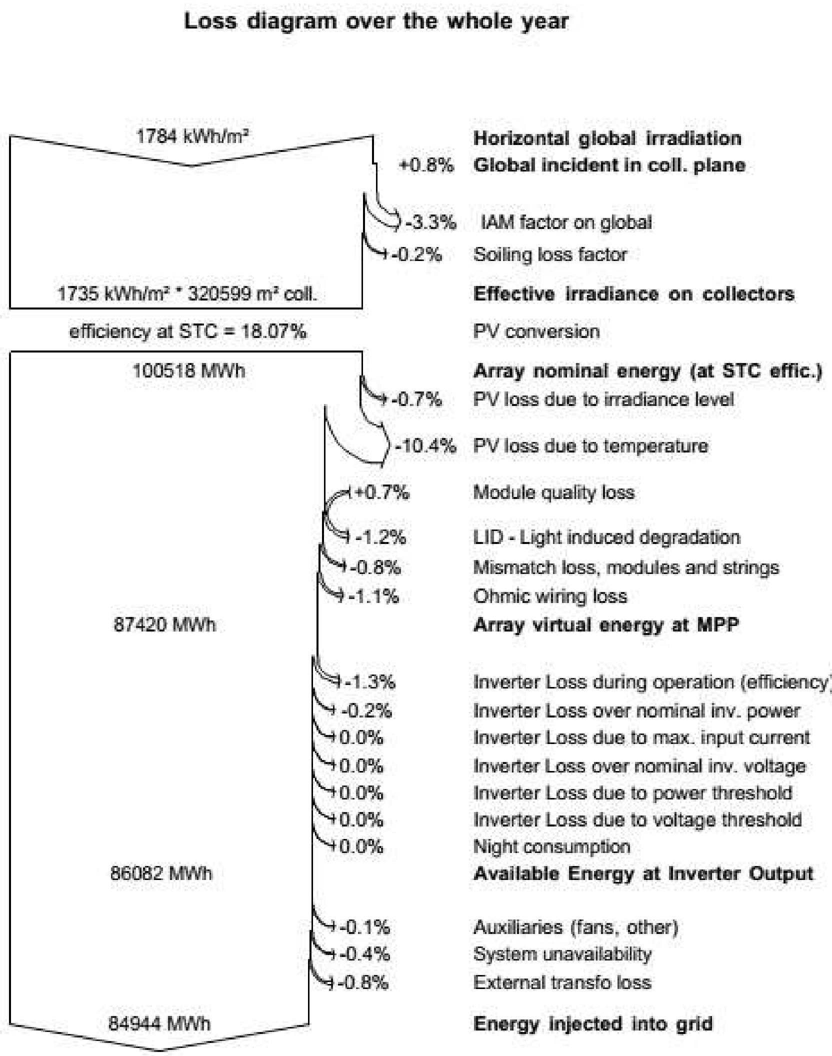

Figure 7-4: Source: Yearly output calculation result of a 46 MW system in Dak Lak province by PVsyst software version V6.67.

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 average annual degradation of capacity utilization factor of around 0.7% per year to the overall production output modelling of the installation.

However, a study carried out by IIT Bombay and MNRE to evaluate performance degradation of field mounted PV modules (Ref. 5) identified relatively higher (than commonly projected by manufacturers) degradation rate of 1.33%/year. However, they have observed significant variation in the rates based on modules supplied by different manufacturers, module capacity (kWp) and climatic conditions.

Efficiency and area requirements

The efficiency of a solar module, η_{mod}, expresses the fraction of the power in the received solar irradiation that can be converted to useful electricity. A typical value for commercially available PV panels today is 15-17%, with high-end products already above 20%, when measured at standard test conditions. The module area needed to deliver 1 kWp of peak generation capacity can be calculated as $1 / \eta_{mod}$ and equals 6.25 m^2 by today's standard PV panels.

7.3. 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 240-550 W_p.

Solar rooftop 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 mid-day. A smaller inverter leads to higher full-load hours.

7.4. Regulation ability and 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.

7.5. Advantages/disadvantages

Advantages

- PV does not use any fuel or other consumable. It is a domestic source of energy, produced locally in India.

- 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 in some parts of India while the demand peak in other parts of India are after PV peak production.
- 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.
- Low installation time as compared to other renewable energy sources.
- 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 trackers. 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.
- PV systems only produce power when there is sun, necessitating dispatchable power production or storage.
- 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) as production 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 and cannot support frequency control in the same way as thermal power plants.
- The water required for cleaning solar collection and reflection surfaces might be a disadvantage in water scarce regions, however new methods are researched to reduce the water consumption for this.

7.6. Environment

The environmental impacts from manufacturing, installing and operating PV systems are limited. Thin film panels may contain small amounts of cadmium and arsenic. MNRE has recently (2019) proposed to make it mandatory for solar power developers to follow glass recycling. Other components such as invertors are covered under e-waste (Management) Rules 2015 (MoEF&CC) and used lead acid batteries are covered under Batteries (Management and Handling) Rules 2001.

7.7. Research and development

The PV technology is commercial but is still constantly improving resulting in decreased costs. A trend in research and development (R&D) activities reflects a change of focus from manufacturing and scale-up issues (2005-2010) and cost reduction topics (2010-2013) to implementation of high efficiency solutions and documentation of lifetime/durability issues (2013-). R&D is primarily conducted in countries where the manufacturing also takes place, such as Germany, China, USA, Taiwan and Japan.

Indian companies like Sterling & Wilson Solar Ltd, L&T and Tata Power are large EPC contractors that specialize in construction of large solar farms and have executed projects globally.

In the coming years, floating solar is expected to gain traction, both in India and internationally. The space requirements for conventional PV can be a challenge in densely populated areas or areas used for agriculture or forests. Floating solar takes advantage of the area available on bodies of water not being used for other purposes thereby greatly increasing the available total area for PV. In 2021, a 60 MW floating solar farm was opened in Singapore (Ref. 12).

7.8. Prediction of performance and cost

Projections about the future investment costs of solar PV systems can be made by studying past prices and global capacity developments. The cost of solar PV projects globally has decreased significantly in the past years; a reduction in the order of 23% has been achieved each time the cumulative production has been doubled.

Furthermore, the expected increase in capacity over the next decades suggests an additional decrease in costs. The cost reduction is driven by the technological improvements and the increase in proficiency of the solar PV systems supply chain.

According to the data collected from various stakeholders, the Capacity Utilization factor for large scale utility PV systems goes from 19.5% in 2020 to 25.0% in 2050. Similarly, the Capacity Utilization factor for rooftop PV systems goes from 18.5% in 2020 to 23.0% in 2050.

Using the learning rate methodology, which translates the growth in installed capacity into a cost reduction, the future prices for PV systems were projected. As a result, the large-scale utility PV systems cost in 2050 is expected to be between 2.60 and 2.07 INR_{2020} cr./MW in 2050. This equates to a reduction between 52% and 62% compared to 2020 prices.

The resulting cost development trend can be observed in Figure 7-5.

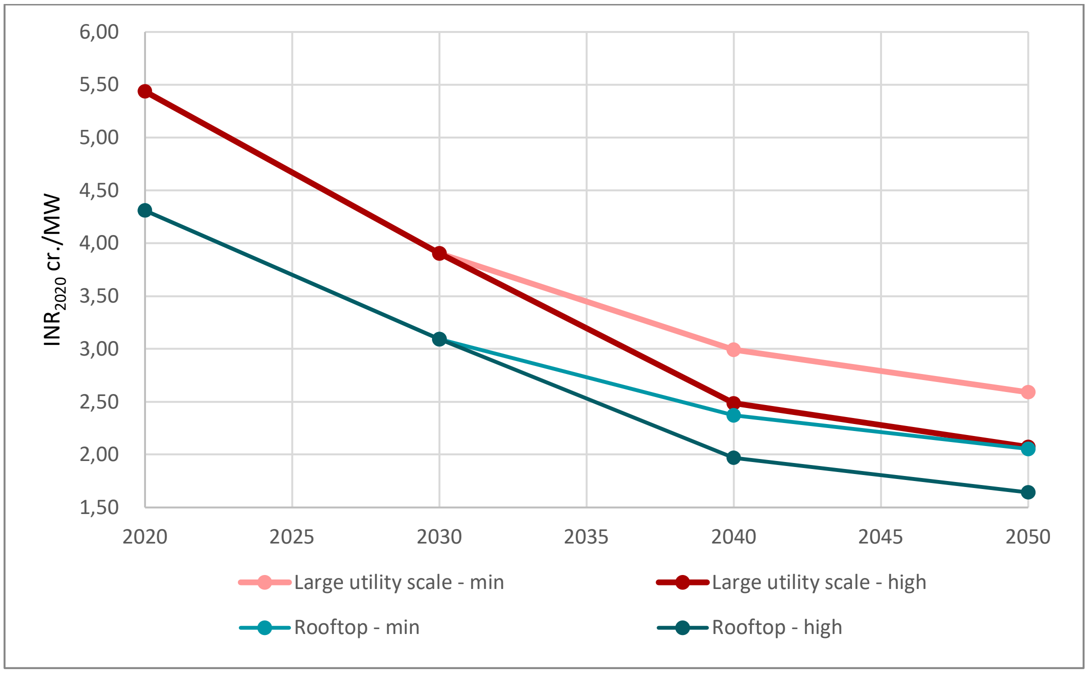

Figure 7-5: Projected solar PV system investment costs development from 2020 to 2050 considering a minimum and high development scenario.

7.9. Examples of market standard technology

High efficiency solar cells and modules have been available for a decade based on interdigitated back contact or hetero-junction cell technologies. PV modules with an efficiency of more than 20% are already commercially available. However, a typical global average value for commercially available PV modules today is 17-20 %. Figure 9 shows the efficiencies of a wide range of commercially available PV modules.

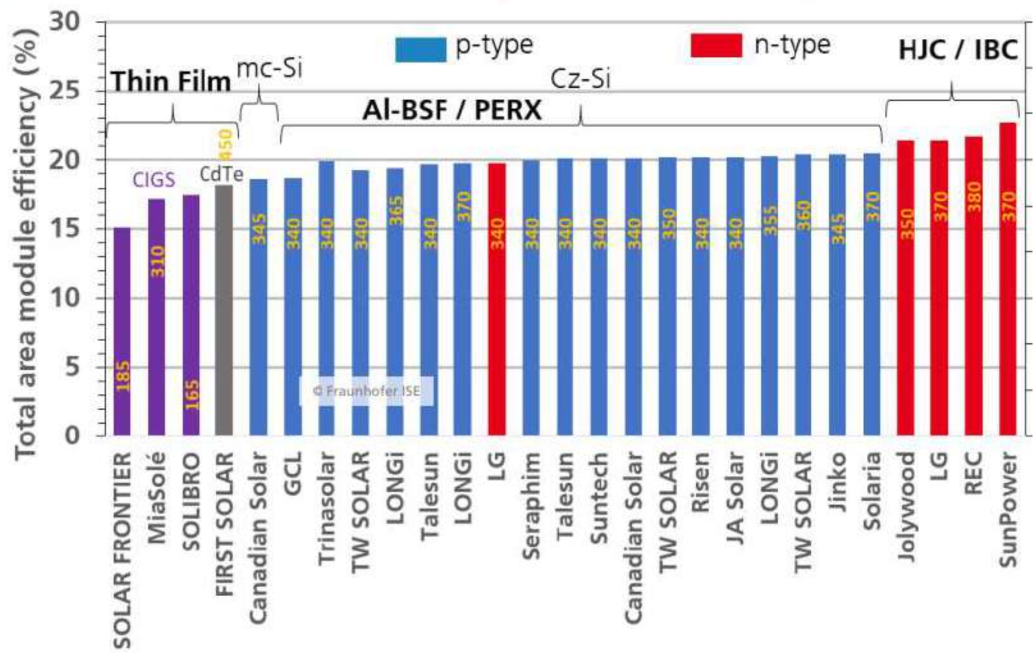

Figure 7-6: Efficiencies of different PV cell brands (Ref. 8)

Not only the efficiency but also the reliability of PV modules has improved significantly over the last years. Based on extensive research in materials science and accelerated/field tests of components and systems, manufacturers now offer product warranties for materials and workmanship up to 25 years and power warranties with a linear degrading warranty from initially 97% of the peak power value to a level of 87% after 25 years.

7.10. Examples of existing projects

1. Charanka Solar Park

Charanka Solar park was the first project undertaken to harness solar energy potential at large scale. The project is located in Patan District of Gujarat. Initially planned for a rated capacity of 250 MW, it was commissioned in April 2012 with a total of 214 MW capacity. Spread over an area of 2000 Hectare, the plant has continued to increase its capacity and has reached 600 MW in 2018.

Since then, solar power projects in India have been developed at various parts of the country and as of March 2021 the total installed capacity of solar power plants was 40.1 GW.

2. REWA Solar Power Project

Figure 7-7: Rewa Solar Power Plant (Ref. 10)

750 MW Rewa Ultra Mega Solar Power Project (Rewa UMSPP) is one of the largest single-site solar power plants in the world, which spreads over an area of 1590 hectares in Rewa district of Madhya Pradesh. The project was commissioned in December 2019. The project was developed by REWA Ultra Mega Solar Limited (RUMSL), a joint venture between Madhya Pradesh Urja Vikash Nigam Limited (MPUVNL) and the Solar Energy Corporation of India (SECI). The project was developed under 3 packages of 250 MW each, executed by Mahindra Susten, ACME Solar and Solengeri Power.

During the first year of operations the project achieved a tariff of INR 2.97/kWh. The plant has been reported to function at 17-18% CUF. The total cost of the project was around INR 4,500 crores (2018 prices).

3. Kamuthi Solar Power Project

Figure 7-8: Kamuthi Solar Power Project (Ref. 11)

Kamuthi Solar power project is developed by Adani Green Energy and is spread over an area of 2,500 Acres (10.11 Sq Km). It has a rated capacity of 648 MW and was commissioned in Sept 2016 and was set-up with an investment of INR 3,900 Crores[6]. The plant was constructed within 8 months and is connected to Tamil Nadu Transmission Corporations substation.

Image	Location	Type	Year	Power capacity	Developer	Ref.
	Charanka Solar park, Patan District of Gujarat, India	Utility scale	2012	600 MW	Gujarat Power Corporation Limited	9
	REWA Solar Power Plant, India	Utility scale	2019	750 MW (CUF: 17-18%)	RUMSL	10
	Kamuthi Solar Power Plant, India	Utility scale	2016	648 MW	Adani Green Energy	11

Table 7-1: Examples of existing solar power plant projects in India

[6] Considering exchange rate in 2016 i.e. 1 USD = INR 65

7.11. References

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7.12. Datasheet

Technology	06a Photovoltaics: Large scale utility systems									
Year of final investment decision	**2020**	**2030**	**2040**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data										
Generating capacity for one unit (MW)	50-150	150-400	150-1000	150-2000	50	150	150	2.000		1
Location-wise Capacity Utilization Factor (%)	20	22	23	25	15	24	20	30	A, B	1
Forced outage (%)	1.5	1.0	0.8	0.6	0.5	2	0.5	1		1
Planned outage (weeks per year)	0	0	0	0						1
Auxiliary Power Consumption (%)	1	1	0.75	0.70	0.5	2	0.4	1		1
Technical lifetime (years)	25	28	30	33	25	30	25	40		1
Construction time (years)	0.75	0.5	0.5	0.5	0.5	1.0	0.4	0.5		1
Space requirement (1000m2/MW)	14	12	10	8	7	21	5	10		1
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Financial data (in 2020₹)										
Capital Cost (cr. ₹/MW)	5.4	3.9	2.7	2.3	3.5	6.0	1.4	4.0		1
- of which PV module (%)	45	45	47	46	35	50				1
- of which inverter (%)	15	15	10	10	0	15				1
- of which transformer and grid connection (%)	10	10	5	5	5	10				1
- of which installation (%)	20	20	21	21	0	20				1
- of which is related to other costs (i.e. residual balance of plant, mark-up & contingency cost) (%)	10	10	17	18	5	0				1
Fixed O&M (cr. ₹/MW/year)	0.035	0.022	0.017	0.012	0.030	0.035	0.011	0.013		1
- of which is rent of land (₹/MW/year)	15.000	20.000	25.000	25.000						1
Financial data (in 2020₹) per installed peak capacity										
Capital Cost (cr. ₹/MW_p)	4.1	2.9	2.0	1.7	2.6	4.2	1.2	3.0		1
- of which PV module (%)	45	45	47	46	35	50				1
- of which inverter (%)	15	15	10	10	7	15				1
- of which transformer and grid connection (%)	10	10	5	5	5	10				1
- of which installation (%)	20	20	21	21	6	20				1
- of which is related to other costs (i.e. residual balance of plant, mark-up & contingency cost) (%)	10	10	17	18	5	30				1
Fixed O&M (cr. ₹/MW_p/year)	0.035	0.025	0.017	0.015	0.030	0.035	0.011	0.013		1

- of which is rent of land										1
Technology specific data										
Global horizontal irradiance ($kWh/m_2/year$)	1900 - 2100	1900 - 2100	1900 - 2100	1900 - 2100					C	1
Generating capacity for one unit (MW_p)										
Average annual peak power full-load hours (MWh/MW_p)	1.577	1.734	1.821	1.912						1
Average annual degradation of full-load hours (%)	0.7	0.7	0.7	0.6	0.7	0.7	0.5	0.7		1
DC/AC_{MAX} sizing factor (W_p/W_{ac})	1.2-1.5/1.0	1.2-1.5/1.0	1.2-1.5/1.0	1.2-1.5/1.0	1.2/1.0	1.5/1.0	1.2/1.0	1.5/1.0		1
Transposition Factor (fixed tilt system)	1.17									1
Performance ratio (measure of combined losses)	0.80	0.82	0.83	0.84	0.78	0.80	0.82	0.85		1
PV module conversion efficiency (%)	19	22	23	25	19	21	25	26		1
Inverter lifetime (years)	10	10	10	15	5	10	10	20		1
Space requirement ($1000m_2/MW_p$)	10	9	7	6	8	16				1

References

1) Value based on inputs from various Indian stakeholders

Notes

A) This value is highly location specific

B) Based on sizing factor 1:1

C) This value is according to satellite data as local factors such as cloud cover, pollution, etc. will impact the value

Technology	06b Photovoltaics: Rooftop System									
Year of final investment decision	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data										
Generating capacity for one unit (MW)	0.5-5				0.3	5				1
Location-wise Capacity Utilization Factor (%)	18.5	21	22	23	15	22	20	30	A	1
Forced outage (%)	5	3	2.5	2	0.5	9	2	2.5	B	1
Planned outage (weeks per year)	1.1	0.6	0.3	0.2	0.3	4.0	0.1	0.3		1
Auxiliary Power Consumption (%)	1.0	0.6	0.5	0.4	1.0	3.0	0.0	0.4		1
Technical lifetime (years)	25	28	30	33	25	25	25	40		1
Construction time (years)	0.5	0.4	0.3	0.3	0.5	2.0	0.3	0.4		1
Space requirement (1000m2/MW)	9.5	9.0	7.5	6.3	5.0	14.0	4.5	8.0	A	1
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Financial data (in 2020₹)										
Capital Cost (cr. ₹/MW)	4.3	3.1	2.1	1.8	4.0	5.0	0.1	4.0		1
- of which PV module (%)	51	47	44	44	45	58	40	47		1
- of which inverter (%)	22	20	23	23	20	22	20	25		1
- of which transformer and grid connection (%)	7	8	8	8	6	10	6	10		1
- of which installation (%)	10	15	15	15	1	20	10	20		1
- of which is related to other costs (i.e. residual balance of plant, mark-up & contingency cost) (%)	10	11	11	11	5	14	5	17		1
Fixed O&M (cr. ₹/MW/year)	0.046	0.033	0.023	0.014	0.019	0.079	0.014	0.035		1
Financial data (in 2020₹) per installed peak capacity										
Capital Cost (cr. ₹/MW_p)	3.9	2.8	1.9	1.6	3.6	4.0	1.1	3.0		1
- of which PV module (%)	51	47	44	44	45	58	40	47		1
- of which inverter (%)	22	20	23	23	20	22	20	25		1
- of which transformer and grid connection (%)	7	8	8	8	6	10	6	10		1
- of which installation (%)	10	15	15	15	1	20	10	20		1
- of which is related to other costs (i.e. residual balance of plant, mark-up & contingency cost) (%)	10	11	11	11	5	14	5	17		1
Fixed O&M (cr. ₹/MW_p/year)	0.051	0.037	0.025	0.022	0.030	0.079	0.014	0.035		1
Technology specific data										
Global horizontal irradiance (kWh/m_2/year)	1900 - 2100	1900 - 2100	1900 - 2100	1900 - 2100					C	1

Generating capacity for one unit (MW_p)	1									1
Average annual peak power full-load hours (MWh/MW_p)										
Average annual degradation of full-load hours (%)	0.7	0.7	0.6	0.5						1
DC/AC_{MAX} sizing factor (W_p/W_{ac})	1.0-1.5/1.0	1.1-1.5/1.0	1.1-1.5/1.0	1.1-1.5/1.0	1.0/1.0	1.0/1.5	1.1/1.0	1.5/1.0		1
Transposition Factor (fixed tilt system)										
Performance ratio (measure of combined losses) (%)	77	81	82	84	75	80	82	85		1
PV module conversion efficiency (%)	19	22	23	24	13	21	23	25		1
Inverter lifetime (years)	10	10	13	15	5	10	10	20		1
Space requirement ($1000m_2/MW_p$)	10	9	8	7	9	12	6	8		

References

1) Value based on inputs from various Indian stakeholders

Notes

A) This value is highly location specific and specified for Standard Test Condition (STC)

B) This value will differentiate between rural and urban systems

C) This value is according to satellite data as local factors such as cloud cover, pollution, etc. will impact the value

8. Hydro Power Plants

8.1. Brief technology description

There are three types of hydro power facilities:

- Run-of-river
  (RoR) schemes are the schemes with very little (i.e. daily storage enabling the station to operate for 3 to 4 hours peaking) or no storage (i.e. all the incoming water is passed through turbine at the same time). The RoR scheme with very little storage is called RoR (with pondage) and the one without any such storage is called RoR (without pondage).
- Storage/reservoir
  Schemes with reservoir to store excess water in monsoon months and to generate power in non-monsoon months.
- Pumped-storage
  Schemes with two reservoirs, upper & lower. Water flows from upper reservoir to lower reservoir during generation and vice-versa during pumping.

Figure 8-1 provides a graphical overview of typical reservoir and run of river setups. Pumped storage would typically be added to the reservoir hydropower to pump water back up to the reservoir. A typical application of pumped storage is to use excess power to drive the pumping during low demand periods.

Run-of-river and reservoir hydropower plants can be combined in cascading river systems and pumped storage plants can utilize the water storage of one or several reservoir hydropower plants, illustrated in Figure 8-2. In cascading systems, the energy output of a run-of-river hydropower plant could be regulated by an upstream reservoir hydropower plant, as in cascading hydropower schemes. 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.

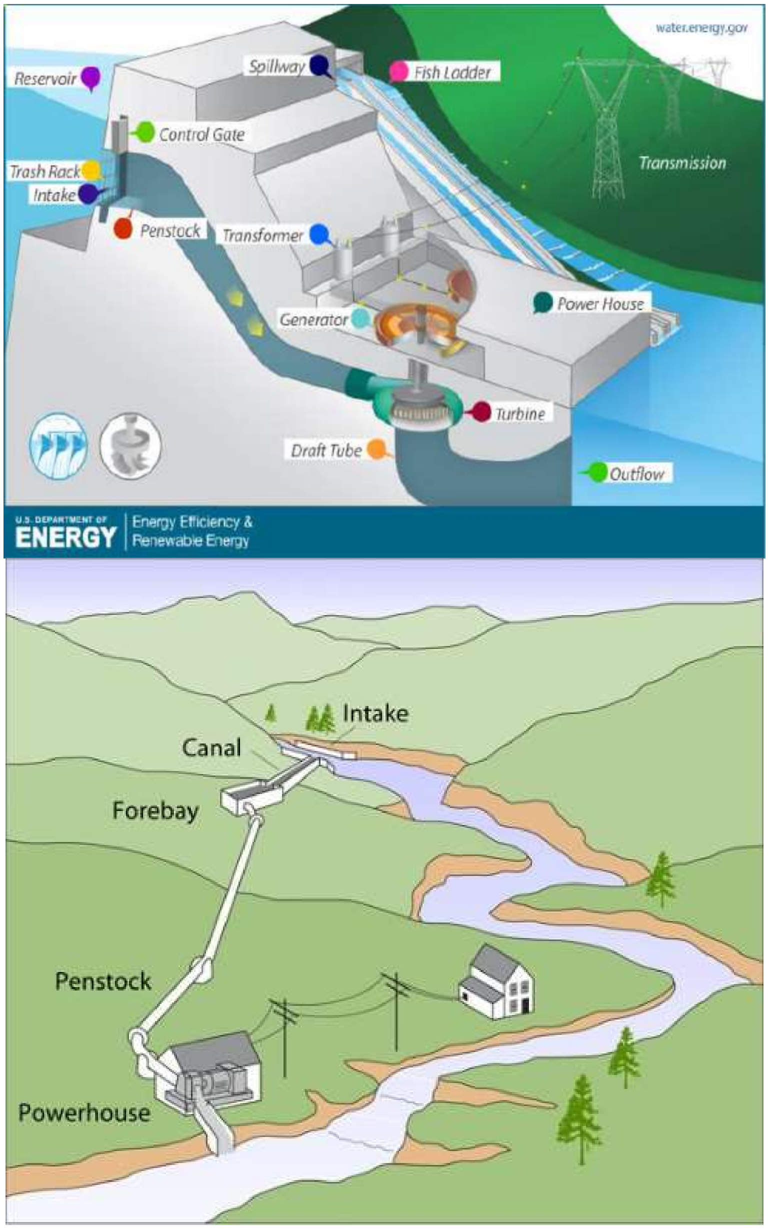


Figure 8-1: Reservoir and run-of-river hydropower plants (Ref. 1)

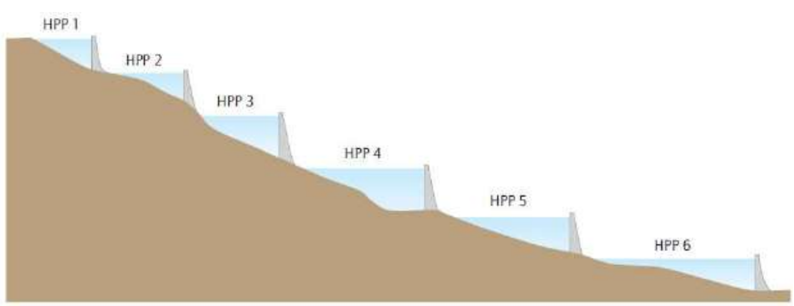


Figure 8-2: Cascading Systems (Ref. 2)

Hydropower systems come in a very wide range of capacities. A classification based on the size of hydropower plants is presented in table below.

Type	Capacity
Large hydropower	> 25 MW
Small hydropower	1 MW – 25 MW
Mini hydropower	< 1 MW

Table 8-1: Classification of hydropower size

Large hydropower plants often have outputs of hundreds or even thousands of Megawatts and use the energy in 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 and installation capacity. Small and mini hydropower plants are run-of-river schemes. These types of hydropower use Cross-flow, Pelton, Horizontal Francis, Bulb or Kaplan turbines. The selection of turbine type depends on the head and flow rate of the river.

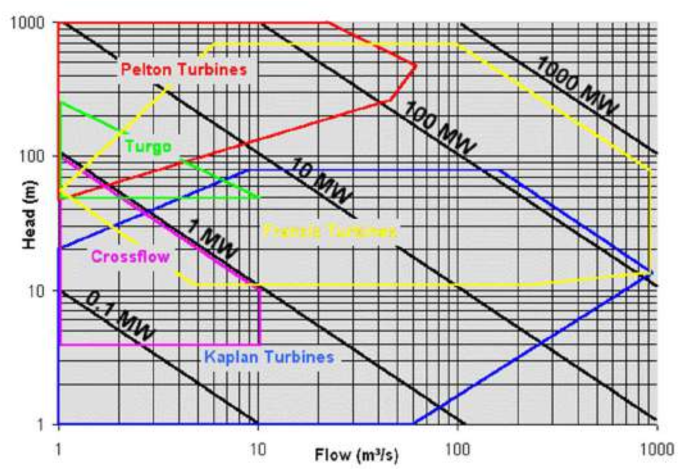


Figure 8-3: Hydropower turbine application chart (Ref. 2)

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. 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.

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.

The capacity factor achieved by hydropower projects depend on the availability of water. Data for 142 Clean Development Mechanism (CDM) projects around the world yield capacity factors of between 23% and 95%. The average capacity factor was 50% for these projects. In India, the average capacity factor of hydropower is approximately 35%.

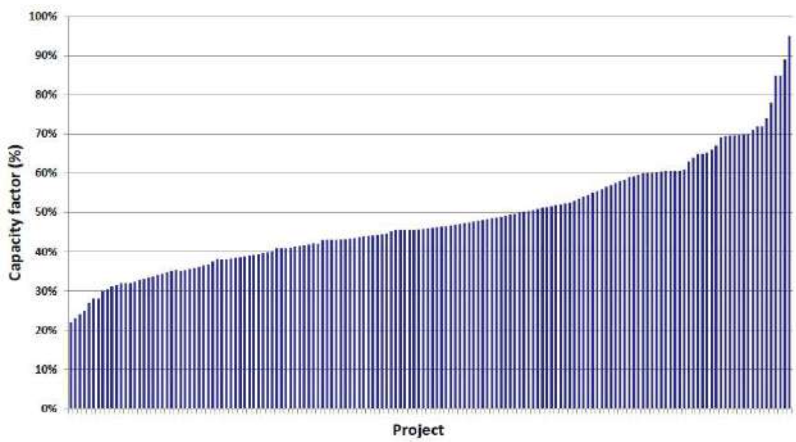


Figure 8-4: Capacity factors for 142 hydropower projects around the world (Ref. 3)

Pumped storage plants (PSPs) use water that is pumped from a lower reservoir into an upper reservoir to charge the storage. To discharge the storage, water is released to flow back from the upper reservoir through turbines to generate electricity. Pumped storage plants take energy from the grid to lift the water up, then return most of it later (round-trip efficiency being 70% to 85%). Hence, PSP is a net consumer of electricity but provides for effective electricity storage. Pumped storage currently represents 99% of the world's on-grid electricity storage (Ref. 4).

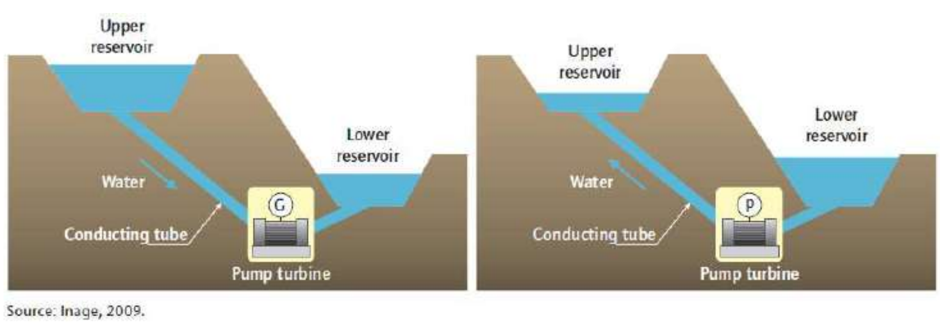


Figure 8-5: Pumped storage hydropower plants (Ref. 5)

The storage capacity of PSP schemes will vary greatly depending on the size of the lower and upper reservoirs. PSP is considered a bulk storage technology, which means it is possible to store large amounts of energy over longer periods of time. The scaling of generating capacity, pumping capacity and reservoir capacity is highly dependent on the intended operation of the facility. By increasing plant capacity in terms of size and number of units, hydroelectric pumped storage generation can be concentrated and shaped to match periods of highest demand, when it has the greatest value.

Both reservoir and pumped storage hydropower are flexible sources of electricity that can help system operators handle the variability of other renewable energy sources such as wind power and photovoltaic electricity and the variation in demands.

There are three types of pumped storage hydropower (Ref. 6):

1. Open loop: systems that are developed from an existing hydropower plant by addition of either an upper or a lower off-stream reservoir. Open loop is typically applied to run-of-river systems or hydropower plants with no downstream reservoirs.
2. Pump back: systems that are using two existing reservoirs in series. Pumping from the downstream reservoir during low-load periods making additional water available to use for generation at high demand periods. Pump back is typically applied to existing hydropower plants with reservoirs.
3. Closed loop: systems are completely independent from existing water streams – both reservoirs are off-stream.

Pumped storage and conventional hydropower with reservoir storage are the only large-scale, low-cost electricity storage options available today. Pumped storage power plants are often a cheap way of storing large amounts of electricity. However, pumped storage plants are generally more expensive than conventional large hydropower schemes with storage, and it is often very difficult to find good sites to develop pumped hydro storage schemes. As of late, both the project cost as well as tariff of hydro projects (especially the initial tariff) have become relatively higher, and the hydro projects have tended to be unviable. Cost of conventional PSPs involving construction of two new reservoirs is relatively higher. However, the cost of off-the river PSPs as well as PSPs on existing hydro projects where one or both the reservoirs are existing, the cost is much lesser.

Interest in pumped storage is increasing, particularly in regions and countries where solar PV and wind are reaching relatively high levels of penetration and/or are growing rapidly (Ref. 7). The vast majority of current pumped storage capacity is located in Europe, Japan and the United States (Ref. 7).

Currently, pumped storage capacity worldwide amounts to about 140 GW. In the European Union, there is 45 GWe of pumped storage capacity. In Asia, the leading pumped hydropower countries are Japan (30 GW) and China (24 GW). The United States also has a significant volume of pumped storage capacity (20 GW) (Ref. 8). India currently has a combined pumped storage capacity of 4.8 GW, and various plants of total 1.5 GW storage capacities are under construction (Ref 9).

8.2. Input/output

Input

The falling water from either reservoir or run-of-river having certain head and flow rate.

Output

Power capacity and energy.

8.3. Typical capacities

Hydropower systems can range from Kilowatts to thousands of Megawatt for commercially operational units. The largest unit capacity of hydropower plant which has ever been installed in India is Nathpa Jhakri in Kinnaur & Shimla district of Himachal Pradesh, which has the rated capacity of 1500 MW. The maximum turbine capacities installed is 250 MW at Nathpa Jhakri in Kinnaur & Shimla district (Himachal Pradesh), Koyna (Maharashtra) and Tehri (Uttarakhand). Recently, the unit size of Karcham Wangtoo HEP in Himachal Pradesh has been uprated to 261.25 MW.

8.4. Regulation ability and power system services

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 usually very large ramp ranges, making it very efficient to follow steep load variations or intermittent power supply of renewable energy such as wind and solar power plants.

8.5. Advantages/disadvantages

Advantages

- Hydropower is fuelled by water and is therefore a clean fuel source that does not pollute the air.
- Hydropower is a domestic source of energy, produced locally in India.
- Hydropower is generally available as needed; engineers can control the flow of water through the turbines to produce electricity on demand.
- Hydropower facilities have a very 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.
- Hydropower plants provide benefits in addition to clean electricity. Impoundment hydropower creates reservoirs that offer a variety of recreational opportunities, notably fishing, swimming, and boating. Other benefits may include water supply, irrigation and flood control.
- All large hydro projects (above 25 MW), including pumped storage projects provide great system benefits due to their inherent qualities of fast ramping up and down and flexibility imparted to the system. They play an important role in providing peaking and balancing power to the system and help in grid safety/stability. These projects have very long life as compared to other energy storage sources.

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, damages mechanical equipment and creates a wide range of environmental impacts.
- 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.

8.6. 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 100 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.
- Lifecycle greenhouse gas emissions;
  Life-cycle CO_2 emissions from hydropower originate from construction, operation and maintenance, and dismantling. Possible emissions for land-use related net changes in carbon stocks and land management impacts are very small.
- The environmental and ecological aspects involved in construction of hydro projects are looked after by MoEF&CC at the time of Environment Clearance of the hydro projects. The hydro projects are taken up for construction only after necessary clearances are given by MOEF&CC. As such, there may not be any significant adverse impact of hydro projects if proposed Environment Management Plans are effectively implemented.

8.7. Research and development

Hydropower is a very mature and well-known technology. While hydropower is a very 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.

- Improvements in turbines;
  The hydraulic efficiency of hydropower turbines has shown a gradual increase over the years: modern equipment reaches 90% to 95%. This is the case for both new turbines and the replacement of existing turbines (subject to physical limitations).
- Development of Silt and Acid resistant materials and Coatings for underwater components of turbines, wherever required as per site operating conditions, would enhance the operational performance of machines with minimal cost.

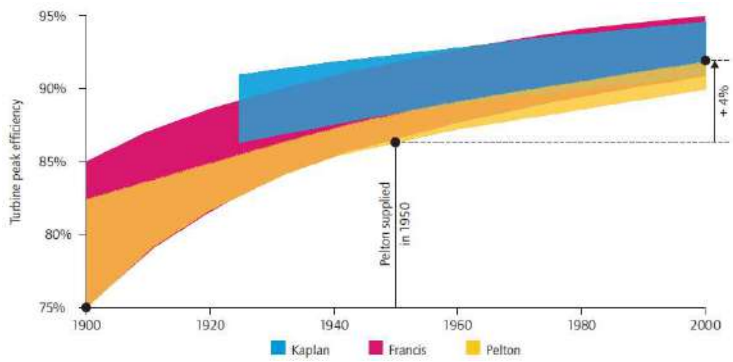


Figure 8-6: Improvement of hydraulic performance over time (Ref. 11)

- 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 80% of the total project cost, so improved methods, technologies and materials for planning, design and construction have considerable potential (Ref. 12). 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, capacity, availability, reliability, environmental performance and enhance useful operational life. Add hydropower plant units to existing dams or water flows.

8.8. Prediction of performance and cost

Costs for hydro power plants are by nature difficult to assess and project specific given the different conditions of each plant in terms of topography, climate, etc. Cost and performance variations are therefore large for this type of technology.

The cost estimates have been assumed according to currently under-construction plants in India (Ref. 23) while remaining data parameters are consistent with existing plants that are already under operation. As can be seen in Figure 8-7 below, economy-of-scale applies to these types of plants as the costs per MW decrease as the plants increase in size. A linear function is provided for each type of hydro power technology.

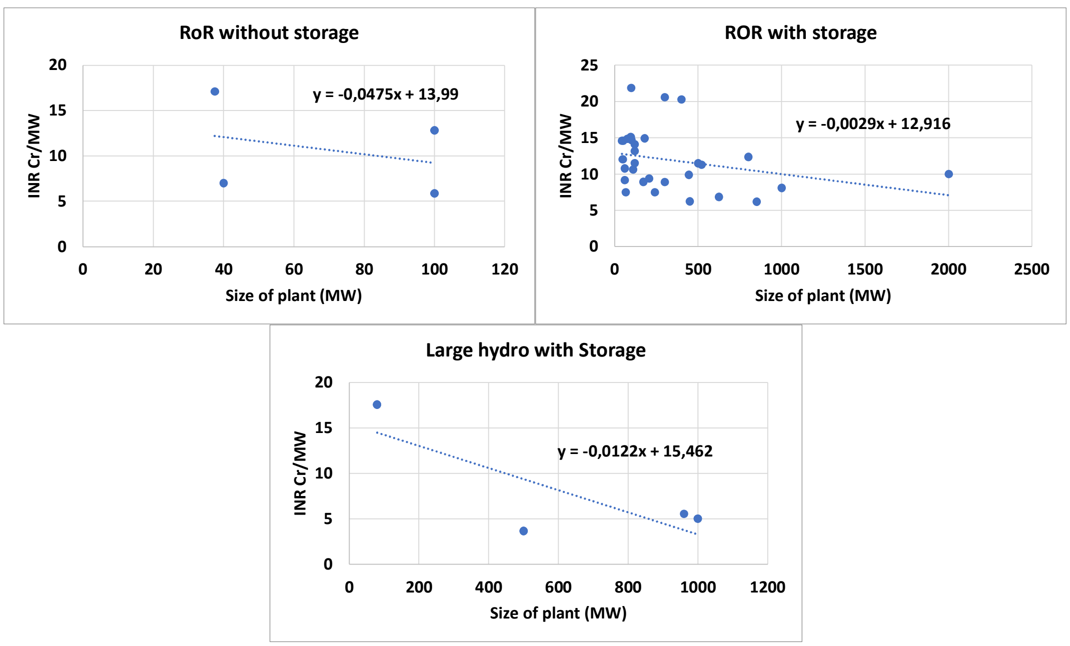


Figure 8-7: Hydropower investments costs for under-construction plants in India in relation to the size of plant (Ref. 23).

Projections about the future investment costs of hydro power plants can be made by looking at past prices and global capacity developments. Furthermore, the cost reduction is driven by the technological improvements, so it is highly dependent on the maturity of the technology, hence on its margin of improvement.

In the past years, there has been a slow, yet steady, increase in installed hydro power capacity. This growth is expected to continue in the future due the reliability of this technology and the highly flexible production, which is important for implementing the variable renewable energy sources. Limited technology improvements are expected for now and the future due to the high maturity of this technology. As a result, a low decrease in investments costs towards 2050 is expected.

Using the learning rate methodology, which translates the growth in installed capacity into a cost reduction, the future prices for hydro power plants were projected. In 2050, hydropower investment costs are around 1% lower than 2020.

The resulting cost development trend can be observed in Figure 8-8.

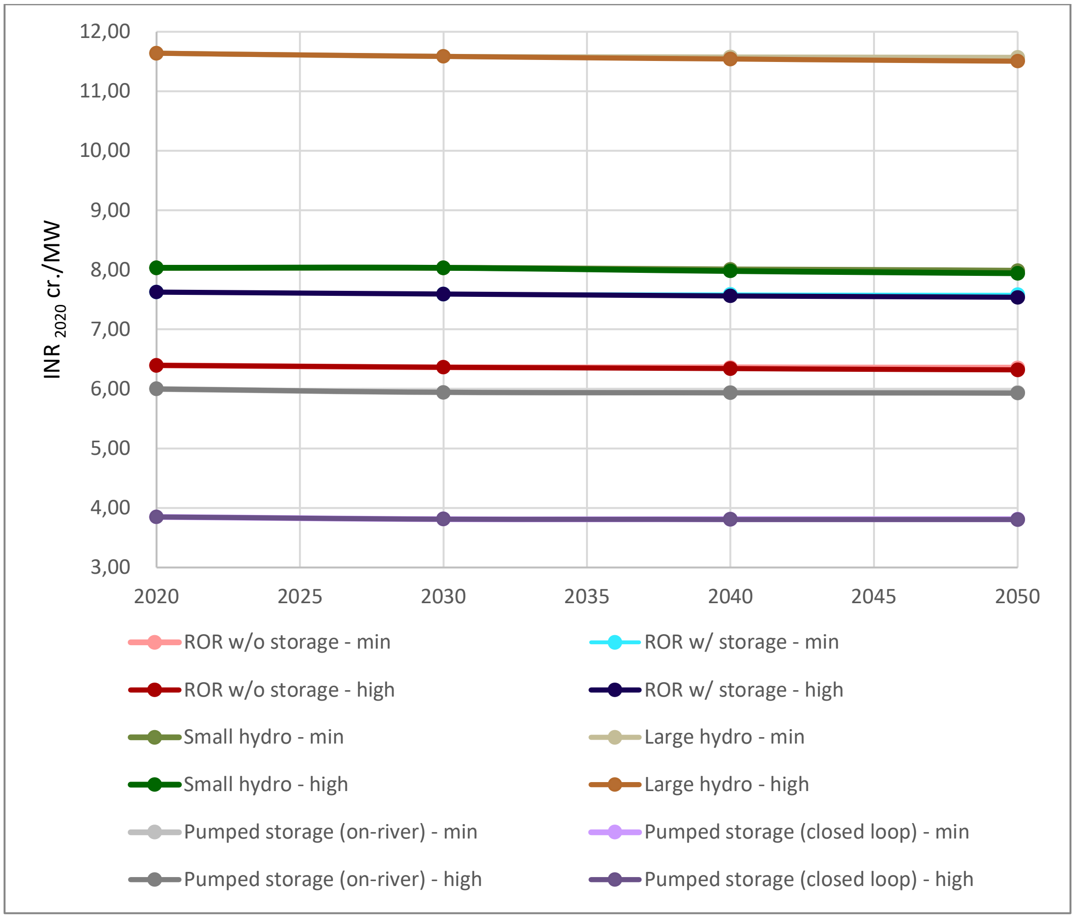


Figure 8-8: Projected hydropower plants investment costs development from 2020 to 2050 considering a minimum and high development scenario.

8.9. Examples of market standard technology

Hydropower is a mature technology. The world's largest operating hydropower plant is the Three Gorges plant in China with a capacity of 22.5 GW. The plant generated 98.8 TWh in 2014 (Ref. 14). The second largest hydropower plant is Itaipu in Brazil/Paraguay, with a 14 GW capacity and a generation of 103.09 TWh in 2014 (Ref. 14). Both hydropower plants use Francis type turbines with unit capacity reaching up to 767 MW. In the summer of 2021, the first two 1 GW unit capacity plant out of a total 16 units were commissioned in Baihetan, China. The remaining 14 units are expected to be commissioned by July 2022 (Ref.22).

Koyna Hydroelectric plant with a total installed capacity of 1960 MW is amongst the largest in India. The plant uses Francis type turbines of various sizes ranging from 80 MW to 250 MW.

Brazil operates the 3,150 MW Santo Antonio hydropower plant on the Madeira River in the Amazon rainforest near Bolivia. The plant design calls for use of 88 bulb type turbines. Some of them has unit capacity of 75 MW. This is the most powerful bulb in operation at present.

8.10. Examples of existing projects

India has a long history of hydropower projects. Sidrapong Hydroelectric Power Station commissioned on 10 November 1897 is the oldest hydropower station in India located at the foothills of Darjeeling town. Its original capacity was 2x65 kW, which was later expanded to 1000 KW in 1916. The station uses water from 3 streams, channelled through a network of flumes to reservoirs, then passed down 220-meter penstock to the generator. The station was operational until 1991 and was later converted to a heritage site.

Since then, India has steadily increased the capacity of hydroelectric power stations. As of March 2020, India's installed capacity is in excess of 50 GW or 13% of its total power generation capacity. This puts India in 5th place globally measured by installed hydroelectric power capacity. A few examples of hydropower plants are listed below.

1. Tehri Dam

Figure 8-9 Tehri Dam, Uttakhand (Ref. 17)

At 260.5 m, Tehri is the tallest dam of India. It is a rock and earth-fill embankment dam on the Bhagirathi River (one of the head streams of Ganges) in Tehri District of Uttarakhand. The

Tehri dam withholds a reservoir for irrigation, municipal water supply and generation of 1000 MW of electricity.

Under Phase-1, installation of four turbines of 250 MW each were commissioned in 2006. The cost of development of this stage is estimated to be INR 8,392 Crores (2013 prices). The project was developed and is operated by Tehri Hydro Development Corporation, which was taken over by NTPC in November 2019. Based on a report of Controller and Auditor general of India, average CUF for the year 2009-2014 at Tehri hydroelectric station was 37.40%.

2. Tehri Pumped Storage Plant (PSP)

Tehri PSP is an under-construction pumped storage plant, which would, upon completion, be an integrated part of Tehri Hydroelectric Complex. Tehri PSP will comprise of four reversible pump turbines of 250 MW each. The operations are based on the concept of recycling of water discharged between upper to lower reservoir. The Tehri Dam reservoir shall function as the upper reservoir and Koteshwar reservoir as the lower balancing reservoir. On completion, the plant will generate 1000 MW peaking power, with annual generation of 1321.82 million kWh. For pumping operations, the reversible unit's off-peak energy requirement is in the order of 1651 million kWh.

As of 2019 the capital cost of construction of Tehri PSP is estimated at INR 5024 Crores (2019 prices). The project is expected to be completed in 2022.

3 Parbati Hydroelectric Project

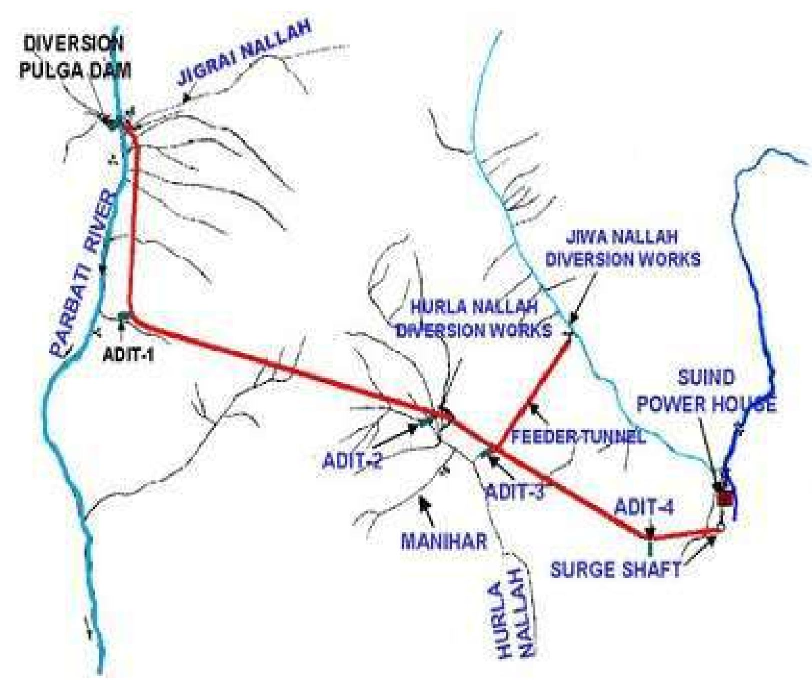


Figure 8-10: Layout Plan for Parbati Hydroelectric Project -Stage II (Ref. 21)

Parbati Hydroelectric Project (Stage-II) is a run-of-the-river scheme proposed to harness hydro potential of the lower reaches of the river Parbati. The river is proposed to be diverted with a

Concrete Gravity Dam at Village Pulga in Parbati valley in Himachal Pradesh, through a 31.52 km long Head Race Tunnel and the Powerhouse shall be located at village Suind in Sainj valley. Thus, gross head (altitude drop) of 863 m between Pulga and Suind will be utilized for generating 800 MW power. The powerhouse containing four Pelton Turbine Generating units of 200 MW each will be installed.

The project is designed to generate 3124.6 kWh in a 90% dependable year (P90). The capital cost of the project is estimated (in 2016) to be approx. INR 8399 Cr. The project is under construction and is expected to be completed by March 2022.

Image	Location	Type/Primary usage	Year	Power capacity	Operator	Ref.
	Three Gorges Dam, Yangtze River, China	Francis type turbines, Hydroelectric power dam	2006	22.6 GW 700 MW	China Three Gorges Corporation	14
	Itaipu, Brazil/Paraguay	Francis type turbines, Hydroelectric dam	1984	14 GW 700 MW	Itaipu Binacional	14, 16
	Koyna, India.	Francis type turbines Hydroelectric plant	1962	1,960 MW 80 MW to 250 MW	MANHAGENCO and Maharashtra State Power Generation	15, 19
	Santo Antonio, Brazil	88 bulb type turbines Hydroelectric dam, Bulb operation	2012	3,150 MW 75 MW	Santo Antônio Energia	18
	Tehri Dam, Uttakhand, India	Generation of hydroelectricity and irrigation and municipal water supply	2006	1,000 MW (CUF: 37.4%)	THDC	17, 19

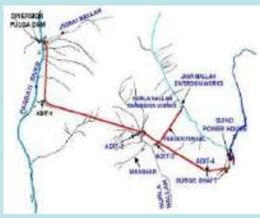
	Tehri Pumped Storage Plant, India	Pumped storage plant	2022	1000 MW 1321 million kWh	THDC India Ltd	20
	Parbati Hydroelectric Project, India	Hydroelectricity	2022	800 MW 3124.6 kWh	NHPC Ltd	21

Table 8-2: Examples of market standard technology for hydropower projects

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8.12. Datasheet

Technology	**07a Hydro power plants, Run-of-river without storage**									
Year of final investment decision	**2020**	**2030**	**2040**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data										
Generating capacity for one unit (MW)	35-120				35	120				1
Electricity efficiency, condensation mode, gross (%)	97.3				94	98			A	1
Forced outage (%)	1				0.1	6			B	1,2
Planned outage (weeks per year)	3.12				1.1	4.7			B	1,2
Auxiliary Power Consumption (%)	0.6				0.6	2.11				1,2
Technical lifetime (years)	40									1
Construction time (years)	7									1
Regulation ability										
Ramp Up Rate (% of Full Load/Minute)	58				20	90				1
Ramp Down Rate (% of Full Load/Minute)	64				30	100				1
Primary load support (% per 30 seconds)	38				10	60				1
Secondary load support (% per minute)	58				20	90				1
Minimum load (% of full load)	34				5	60				1
Financial data (in 2020₹)										
Capital Cost (cr. ₹/MW)	10.7	10.65	10.63	10.61	5.9	17.1			B	3
- of which equipment (%)	18									1
- of which installation/development (%)	80									1
- of which is related to rent of land (%)	2								C	1
- of which is related to other costs (i.e. compensation of neighbours, etc.) (%)	0.3									1
Fixed O&M (cr. ₹/MW/year)	0.44	0.44	0.44	0.44	0.21	1.12				1
Variable O&M (₹/MWh)										

References

1) Value based on inputs from Indian stakeholder, including four local plants from Northern region

2) Hydro Review, CEA, 2019

3) CEA, Project monitoring - Quarterly review No. 104 (Jan-Mar 2021), 2021

Notes

A) As per the name plate efficiency of the equipment

B) Values changes according to plants and the uncertainty ranges are therefore rather large. Data for under-construction plants.

C) Land + Capitalized Value of Abatement of Land Revenue

Technology	07b Hydro power plants, ROR with storage									
Year of final investment decision	**2020**	**2030**	**2040**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data										
Generating capacity for one unit (MW)	20-250				20	250				1
Electricity efficiency, condensation mode, gross (%)	98								A	1
Forced outage (%)	3.5				0.06	6			B	1,2
Planned outage (weeks per year)	3.12				2.5	27.6			B	1,2
Auxiliary Power Consumption (%)	0.7				0.6	1.43				1
Technical lifetime (years)	40									1
Construction time (years)	8				3	11				1
Regulation ability										
Ramp Up Rate (% of Full Load/Minute)	58				14	100				1
Ramp Down Rate (% of Full Load/Minute)	60				14	100				1
Primary load support (% per 30 seconds)	36				7	100				1
Secondary load support (% per minute)	58				14	100				1
Minimum load (% of full load)	23				6	60				1
Financial data (in 2020₹)										
Capital Cost (cr. ₹/MW)	11.9	11.85	11.82	11.8	6.2	21.9			B	3
- of which equipment (%)	18				10	25				1
- of which installation/development (%)	79				68	88				1
- of which is related to rent of land (%)	1				0	5			C	1
- of which is related to other costs (i.e. compensation of neighbours, etc.) (%)	1				0	3				1
Fixed O&M (cr. ₹/MW/year)	0.41	0.41	0.41	0.41	0.13	0.89				1
Variable O&M (₹/MWh)										1

References

1) Value based on inputs from Indian stakeholder, including 12 plants in Northern and Eastern regions

2) Hydro Review, CEA, 2019

3) CEA, Project monitoring - Quarterly review No. 104 (Jan-Mar 2021), 2021

Notes

A) As per the name plate efficiency of the equipment

B) Values changes according to plants and the uncertainty ranges are therefore rather large. Data for under-construction plants.

C) Land + Capitalized Value of Abatement of Land Revenue

Technology	07c Small Hydro power plants, reservoir (<25 MW)									
Year of final investment decision	**2020**	**2030**	**2040**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data										
Generating capacity for one unit (MW)	1-5									1
Electricity efficiency, condensation mode, gross (%)	45				30	92				1,2
Forced outage (%)	3.5				1	6			B	3
Planned outage (weeks per year)	3.12								B	3
Auxiliary Power Consumption (%)	1									1
Technical lifetime (years)	40									1
Construction time (years)	3									1
Storage capacity (MWh)										
Discharge time (h)										
Regulation ability										
Ramp Up Rate (% of Full Load/Minute)	2.5									1
Ramp Down Rate (% of Full Load/Minute)	2.5									1
Primary load support (% per 30 seconds)										
Secondary load support (% per minute)										
Minimum load (% of full load)										
Financial data (in 2020₹)										
Capital Cost (cr. ₹/MW)	8.04	8.04	8.00	7.97					C	2
- of which equipment (%)										
- of which installation/development (%)										
- of which is related to rent of land (%)										
- of which is related to other costs (i.e. compensation of neighbours, etc.) (%)										
Fixed O&M (cr. ₹/MW/year)	0.24	0.24	0.24	0.24	0.24	0.43			B	2
Variable O&M (₹/MWh)										

References

1) Value based on inputs from Indian stakeholder

2) CERC (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2017

3) Hydro Review, CEA, 2019

Notes

A) As per the name plate efficiency of the equipment

B) Values changes according to plants and the uncertainty ranges are therefore rather large.

C) Data for this value is highly uncertain

Technology	07d Large Hydro power plants, reservoir (>25 MW)									
Year of final investment decision	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data										
Generating capacity for one unit (MW)	35-200				35	200				1, 2, 3
Electricity efficiency, condensation mode, gross (%)	96.9	96.9	96.9	96.9					A	1
Forced outage (%)	1				0.6	6			B	1, 4
Planned outage (weeks per year)	3.12				2.5	4.87			B	1, 4
Auxiliary Power Consumption (%)	0.6									1, 4
Technical lifetime (years)	40									1
Construction time (years)	5				4	7				1
Storage capacity (MWh)										
Discharge time (h)										
Regulation ability										
Ramp Up Rate (% of Full Load/Minute)	30				2.5	50				1
Ramp Down Rate (% of Full Load/Minute)	30				2.5	50				1
Primary load support (% per 30 seconds)	15									1
Secondary load support (% per minute)	30									1
Minimum load (% of full load)	9				0.0	15				1
Financial data (in 2020₹)										
Capital Cost (cr. ₹/MW)	8.3	8.26	8.25	8.23	3.7	17.6			B	5
- of which equipment (%)	9									1
- of which installation/development (%)	88									1
- of which is related to rent of land (%)	3									1
- of which is related to other costs (i.e. compensation of neighbours, etc.) (%)	0									1
Fixed O&M (cr. ₹/MW/year)	0.91	0.90	0.90	0.90						1
Variable O&M (₹/MWh)										

References

1) Value based on inputs from Indian stakeholder

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4) Hydro Review, CEA, 2019

5) CEA, Project monitoring - Quarterly review No. 104 (Jan-Mar 2021), 2021

Notes

A) As per the name plate efficiency of the equipment

B) Values changes according to plants and the uncertainty ranges are therefore rather large. Data for under-construction plants.

Technology	07e Hydro power plants, Pumped storage on-river									
Year of final investment decision	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data										
Generating capacity for one unit (MW)										
Electricity efficiency, condensation mode, gross (%)										
Forced outage (%)										
Planned outage (weeks per year)										
Auxiliary Power Consumption (%)										
Technical lifetime (years)	40									1
Construction time (years)	8									1
Storage capacity (MWh)										
Charging efficiency (%)	80	80							A	1
Discharge time (h)										
Regulation ability										
Ramp Up Rate (% of Full Load/Minute)	50									1
Ramp Down Rate (% of Full Load/Minute)	50									1
Primary load support (% per 30 seconds)										
Secondary load support (% per minute)										
Minimum load (% of full load)										
Financial data (in 2020₹)										
Capital Cost (cr. ₹/MW)	6.00	5.94	5.94	5.94						1
- of which equipment (%)										
- of which installation/development (%)										
- of which is related to rent of land (%)										
- of which is related to other costs (i.e. compensation of neighbours, etc.) (%)										
Fixed O&M (cr. ₹/MW/year)	0.15	0.15	0.15	0.15						1
Variable O&M (₹/MWh)										

References

1) Report on Optimal Generation Capacity Mix for 2029-30; Central Electricity Authority, 2020

Notes

A) Round-trip efficiency

Technology	07f Hydro power plants, Pumped storage closed loop									
Year of final investment decision	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data										
Generating capacity for one unit (MW)										
Electricity efficiency, condensation mode, gross (%)										
Forced outage (%)										
Planned outage (weeks per year)										
Auxiliary Power Consumption (%)										
Technical lifetime (years)	40									1
Construction time (years)	8									1
Storage capacity (MWh)										
Charging efficiency (%)	70									2
Discharge time (h)										
Regulation ability										
Ramp Up Rate (% of Full Load/Minute)	50									1
Ramp Down Rate (% of Full Load/Minute)	50									1
Primary load support (% per 30 seconds)										
Secondary load support (% per minute)										
Minimum load (% of full load)										
Financial data (in 2020₹)										
Capital Cost (cr. ₹/MW)	3.85	3,81	3,81	3,81	2.00	5.70				1
- of which equipment (%)										
- of which installation/development (%)										
- of which is related to rent of land (%)										
- of which is related to other costs (i.e. compensation of neighbours, etc.) (%)										
Fixed O&M (cr. ₹/MW/year)	0.10	0.10	0.10	0.10						1
Variable O&M (₹/MWh)										

References

1) Report on Optimal Generation Capacity Mix for 2029-30; Central Electricity Authority, 2020

2) Flexible Operation of Thermal Power Plant for Integration of Renewable Generation, Central Electricity Authority, 2019

Notes

A) Round-trip efficiency

9. Nuclear

9.1. Brief technology description

Nuclear power plants utilize the energy released during nuclear fission, namely the process by which a neutron colliding with an atom causes that atom to split and, as a by-product, produces heat (Ref. 1). This process is combined with a Rankine cycle[7] in order to produce electricity.

The nuclear reactors can be distinguished between thermal reactors, which require a moderator, and fast neutrons reactors[8], which don't use a moderator. Thermal reactors are the most commonly used in nuclear power plants (NPPs), therefore the rest of the chapter focus on these.

The main components of a nuclear thermal reactor core are:

- **Fuel**, Natural or slightly enriched uranium fuel encased in fuel rods to prevent the escape of dangerous fission products.
- **Moderator**, usually light water but it can be heavy water or carbon. It slows down the neutrons.
- **Control rods**, made of material that is highly absorbent of neutrons so that the insertion or withdrawal of the rods can be used to control the production of energy.
- **Cooling system**, which removes the heat, namely the energy produced. It can be water (Light or Heavy) or gas. Water is often used as both the coolant and the moderator.

Three basic types of thermal reactors are (Ref. 1):

1. Light water reactors (LWRs) are by far the most common type used for power generation and include the common pressurized water reactors[9] (PWRs) and boiling water reactors[10] (BWRs). They use regular water (so called light water) as both the coolant and the moderator but need somewhat enriched uranium fuel (about 2% 235U). In India, two BWRs plants of 150 MW capacity each have been installed in 1969, no other BWR plants have been commissioned since then. All currently operational and planned LWRs in India are imported / of foreign origin.

2. Heavy water reactors (HWRs) use natural, unenriched uranium fuel and achieve the needed increase in reactivity by using deuterium oxide (heavy water) as the moderator and coolant

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[7] The Rankine Cycle is the process widely used in power plants (coal and nuclear), where fuel is used to produce heat within a boiler, converting water into steam which then expands through a turbine producing energy.
[8] A category of nuclear reactors in which fission chain reaction is sustained by fast neutrons as opposed to conventional reactors where a moderator is used to slow speed of neutrons. Therefore, the use of a moderator is avoided. This approach provides an advantage of efficient use of fuel (natural uranium) and reduction in nuclear waste.
[9] In PWRs the steam is generated outside of the reactor core. The cooling system transfers the heat to the water in the rankine cycle through a heat exchanger.
[10] In BWRs water is pumped up through the reactor core and heated by fission, which turns it into steam. Pipes then feed the steam directly to a turbine to produce electricity.

rather than light water. The Canadian CANDU reactor is the best known example of this type. As for the LWRs, both pressurized (PHWRs) and boiling[11] (HBWRs) heavy water reactors have been designed. In India, the most commonly used type is the India Pressurized Heavy Water Reactor (IPHWR) designed by Bhaba Atomic Research Center, based on the CANDU design.

3. Gas-cooled reactors (GCRs) in which the primary coolant loop utilizes a gas (for example carbon dioxide or helium) rather than water. Typically, these use graphite as the moderator. Examples are the high temperature gas-cooled reactor (HTGR) and the advanced gas-cooled reactor (AGR) manufactured respectively in the USA and UK. There is no nuclear reactor of this type in India.

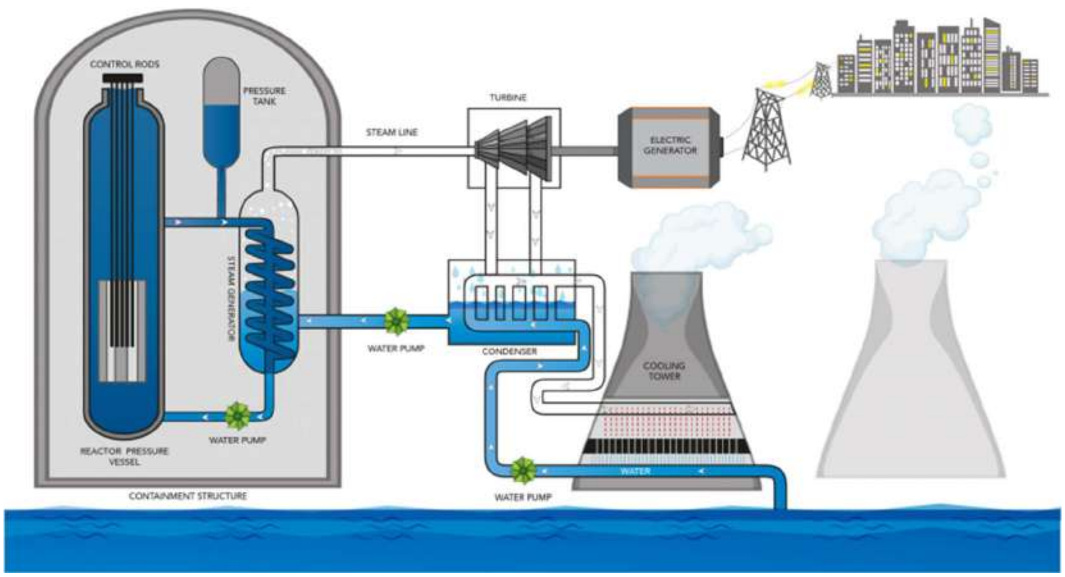

Figure 9-1: Pressurized water Reactors (Ref. 1)

[11] Examples can be found in
"Middleton, J.E. (1975). The Steam Generating Heavy Water Reactor. Journal of the Institution of Nuclear Engineers, 16(5), 131-140" and
"Roar, R. (1963). The Halden boiling heavy water reactor (HBWR). Atomwirtschaft (West Germany) Changed to ATW, Atomwirtsch., Atomtech."

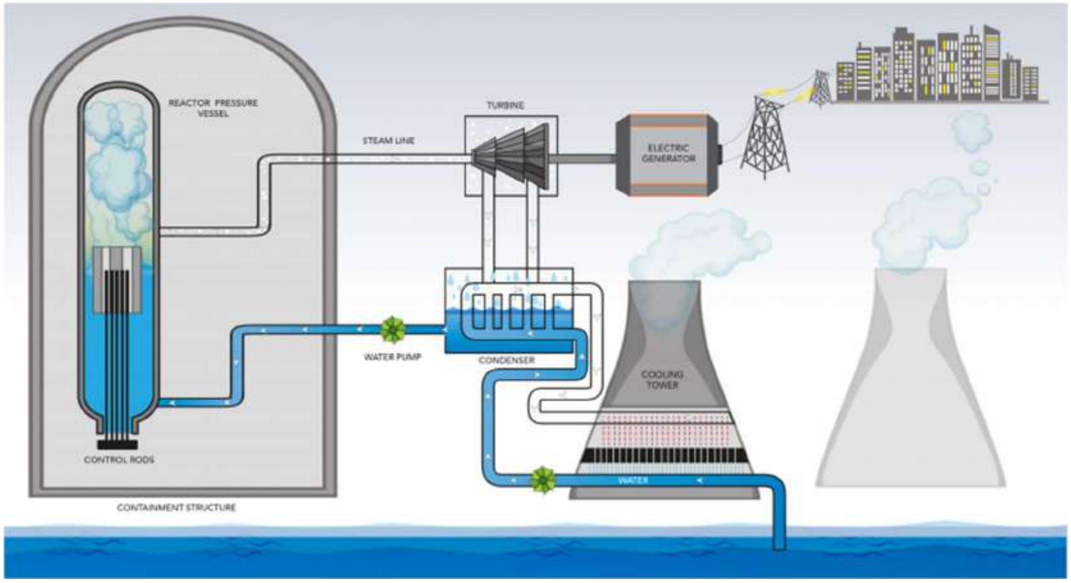

Figure 9-2: Boling water reactors (Ref. 1)

9.2. Input/output

Uranium is the basic fuel for almost all the currently operating NPPs in India and globally. It is usually used in form of pellets of Uranium Oxide (UO2). Alternatively, a mixture of UO2 and PuO2 (plutonium dioxide) called a mixed oxide (MOX fuel) can be used.

When uranium is mined, it consists of approximately 99.3% uranium-238 (U238), 0.7% uranium-235 (U235), and < 0.01% uranium-234 (U234) (Ref. 2). The nuclear fuel used in a nuclear reactor needs to have a higher concentration of the U235 isotope than the one present in the natural uranium. The process of increasing the concentration of U235 is called enrichment. Commercially, the U235 isotope is enriched to 3 to 5% (from the natural state of 0.7%) and is then further processed to create nuclear fuel. The enrichment process involves the separation of U235 and U238, which is a difficult and laborious process since U238 and U235 are almost identical chemically and physically (Ref. 1).

Typically, the fuel rods, which contains the nuclear fuel, are placed in the reactor at the commissioning and only replaced during major planned maintenance, as this involves opening the nuclear reactor.

The spent fuel is a radioactive waste and consists of many radioactive isotopes such as Plutonium, Barium, etc. and needs to be disposed underground (in case of civilian reactors). Alternatively, the fuel may be reprocessed in order to recycle the useful remnants. Reprocessing involves separating the uranium and plutonium from the waste products. The recovered uranium is usually a little richer in U235 than in nature and is reused after enrichment. The plutonium can be combined with uranium to make MOX fuel that can be used as a substitute for enriched uranium in mixed oxide reactors (Ref. 1).

The environmental issues of nuclear power plants are presented in section 9.6.

The output consists of heat, which is used by steam turbines for power production.

9.3. Typical capacities

Most of the installed reactors are of a 220 MWe (IPHWR-220) design. The design has later been expanded with additional 540 MWe and 700 MWe capacities. Currently there exists two IPHWR-540 and a single IPHWR-700 reactor in India. In addition, two Russian made pressurized water reactor plants of 1000 MWe (VVER-1000) have been installed.

All nuclear power plants are currently being operated by Nuclear Power Corporation of India (NPCIL), a public sector undertaking wholly owned by Government of India. NPCIL operates 22 nuclear power reactors with an installed capacity of 6780 MW (Ref. 9) which are provided in the table below.

Power station	State	Reactor type	Units	Total capacity (MW)
Kaiga	Karnataka	IPHWR-220	220 × 4	880
Kakrapar	Gujarat	IPHWR-220 IPHWR-700	220 × 2 700 × 1	1140
Kudankulam	Tamil Nadu	VVER-1000	1000 × 2	2,000
Chennai (Kalpakkam)	Tamil Nadu	IPHWR-220	220 × 2	440
Narora	Uttar Pradesh	IPHWR-220	220 × 2	440
Rajasthan	Rajasthan	CANDU CANDU IPHWR-220	100 × 1 200 x 1 220 × 4	1,180
Tarapur	Maharashtra	BWR IPHWR-540	160 x 2 540 × 2	1,400

Table 9-1: Currently operating Nuclear Power Plants in India (Ref. 9)

9.4. Regulation ability and power system services

Nuclear reactors are in many cases not well-suited for load and frequency control for grid balancing as nuclear units are generally less flexible than other thermal power plant units. Modern nuclear units generally have greater flexibility as compared to the older plants, but because of the effect of thermal transients during load changes, even modern nuclear units are restricted in their operations for safety reasons (Ref. 10).

Nuclear units have high capital costs, but relatively low fuel costs, so for purely commercial reasons, it is also preferable to operate nuclear units at full load, and to use other generating units (e.g. units that have higher fuel cost) to do load following or provide automatic frequency control. International experience from operating nuclear units indicates that frequent operation in load following or automatic frequency control modes leads to poorer reliability of the nuclear plant, less efficient use of the nuclear fuel, increased maintenance requirements and possibly shorter plant life (Ref. 10).

Because of this, the most preferred mode of operation of NPPs is at steady full load, with load reductions only when required for shut down for maintenance and refuelling. The second preferred mode of operation is normally at steady load with the possibility of increasing or reducing load at a controlled rate on a limited number of occasions when required by grid conditions.

9.5. Advantages/disadvantages

Advantages

- Produces no polluting gases/carbon emission during operations.
- Low quantity of fuel requirement reduces mining and transportation requirements (as compared to coal).
- Low operational costs in terms of material inputs to the reactor during operations.
- The power generation from NPPs is predictable and can provide base load to the grid. Their operations are less vulnerable to issues such as fuel supplies considerations (e.g. thermal power plants) as well as variable power produced by renewable sources.

Disadvantages

- Uranium mining presents significant environmental risks, especially in relation to the disposal of produced trailing to surface water bodies such as ponds. These includes exposure to Radon emissions and windblown dust emissions as well as groundwater/surface water contamination due to leaching of pollutants such as heavy metals and arsenic.
- Safety risk – large scale accidents can be catastrophic to people and environment.
- The fuel waste is radioactive and safe disposal is very difficult and expensive. Disposal in deep geological formations is considered to be the only solution for long-term safe disposal of nuclear waste. At present there are no such operating facilities in India.
- Discharge of heated water (thermal plume) may lead to adverse impacts on marine life. These impacts are limited to NPPs located on the coastline that uses seawater for cooling purposes. The NPPs located inland usually employ large cooling towers and does not require discharge of heated water.
- Capital costs for construction and installation is very high.
- Decommissioning of NPPs is a very challenging, expensive and time-consuming process.
- Not suited for grid balancing, i.e. NPPs cannot react quickly to changes in electricity demand.

9.6. Environment

The environmental issues with nuclear power plants are associated with the whole life cycle of the plant operations. Uranium mining involves emission of Radon gas and is considered to be more dangerous than other mining activities. Further, uranium mill tailings risk contamination of surface water bodies and may lead to radioactive contamination of water, soils and air around the mining sites.

The used nuclear fuel from NPPs contains a wide range of carcinogenic radionuclide isotopes, its leakage or disposal to the environment could have catastrophic consequences on humans and environment. India has adopted a closed fuel cycle option, which involves reprocessing and recycling of used fuel. During reprocessing, only about two to three percent of the used fuel becomes waste and the rest is recycled (Ref. 11). Although reprocessing plants can reduce the volume of nuclear waste, they cannot completely eliminate the risk as significant amounts of used fuel would still require to be disposed. In the end, high level radioactive waste will need to be emplaced in geological disposal facilities. At present, Tarapur high level waste immobilization plant is operational where the highly radioactive waste is first immobilized in a solid matrix and stored in an engineered facility for 25 years (Ref. 13). At present, no information in the public domain is available with respect to underground final waste repository/disposal sites in India.

The nuclear power plants and the supporting infrastructure carries risks of low-level radioactive emissions during normal operations. Therefore, they suffer from "not in my backyard" syndrome and the general public is often against setting up NPPs within their neighbourhood. In addition, setting up NPPs and the associated infrastructure requires significant parcels of land to be acquired. Therefore, they are often being resisted by local and indigenous people, leading to social unrest. Many nuclear facilities in India such as Kudankulam NPP (Ref. 12) have faced significant social unrest during the development phases.

Pursuant to the Atomic Energy Act (1960), the Atomic Energy Regulatory Board (AERB), is the Competent Authority as the Regulatory Body for granting, renewal, withdrawal and revocation of consents for Nuclear and Radiation Facilities. The Regulatory Body also exercises control over nuclear installations and the use of radioactive substances and radiation generating plants outside such installation. Following rules in relation to safe operations and environmental impacts are promulgated by AERB, and are applicable to all nuclear facilities (Ref. 14):

- Atomic Energy (Radiation Protection) Rules 2004
- Atomic Energy (Factories) Rules, 1996
- Atomic Energy (Safe Disposal of Radioactive Waste) Rules 1987
- Atomic Energy (Working of Mines and Handling of Prescribed Substances) Rules, 1984

9.7. Research and development

Several generations of reactors are commonly distinguished. Generation I reactors were developed in 1950-60s, and the last one shut down in the UK in 2015. Generation II reactors are typified by the present US and French fleets and most in operation elsewhere. So-called Generation III (and III+) are the advanced reactors, though the distinction from Generation II is arbitrary. The first ones are in operation in Japan and others are under construction in several countries. Generation IV designs are still on the drawing board and will not be operational before the 2020s (Ref. 4).

Indian nuclear programme

India is developing its own advanced technology to utilize thorium as a nuclear fuel. In fact, currently, all operating NPPs in India are based on Uranium fuel cycle. However, India has limited reserves of uranium, but large thorium reserves (Ref. 6).

In view of this resource position, India has chalked out a three-stage programme (Ref. 6) which aims at the development of:

1. Pressurized Heavy Water Reactors (PHWRs) that uses natural uranium as fuel,
2. Fast Breeder Reactors[12] (FBRs) that uses plutonium and depleted uranium fuel,
3. Advanced Heavy Water Reactors (AHWRs) that will use thorium and Uranium-233 as fuel.

In (Ref. 6), the Department of atomic energy states "Nuclear power employing closed fuel cycle is the only sustainable option for meeting a major part of the world energy demand". A closed fuel cycle means that the spent fuel is reused. The Indian nuclear programme is designed according to this principle. At each stage it is produced/bred some of the fuel necessary for the following stage. At the first stage, the PHWRs breed plutonium. At the second stage, the FBRs consume plutonium-based fuel to breed U233 from thorium, and finally, at the third stage, advanced nuclear power systems, as the AHWRs, will use the U233. The used fuel will be reprocessed to recover fissile materials for recycling.

Prototype nuclear reactors

A prototype Fast Breeder Reactor (500 MWe) is under construction at the Madras Atomic Power Station in Kalpakkam, Tamil Nadu. It is designed to use Uranium-238 to breed plutonium in a sodium cooled fast reactor design. The reactor is expected to attain criticality in December 2021 and to be operational by October 2022. Based on this prototype, India plans to commercialize the design and has planned development of FBRs-600 reactors for commercial use.

Bhabha Atomic Research Center (BARC) has been developing a 300 MWe AHWR, which will be fuelled by thorium, cooled by light water and moderated by heavy water.

BARC is also working on an Indian Molten Salt Breeder Reactor Program. The Indian molten salt breeder reactor (IMSBR) is the platform to burn thorium as part of the third stage of the Indian nuclear power programme. The fuel in IMSBR is in the form of a continuously circulating molten fluoride salt which flows through heat exchangers for ultimately transferring heat for power production to Super-critical CO_2 based Brayton cycle (SCBC) to have larger energy conversion ratio as compared to existing power conversion cycle. Because of the fluid fuel, online reprocessing is possible, extracting the 233Pa (formed in conversion chain of 232Th to U233) and allowing it to decay to U233 outside the core, thus making it possible to breed even in thermal neutron spectrum. Hence IMSBR can operate in self-sustaining 233U-Th fuel cycle. Additionally, being a thermal reactor, the 233U requirement is lower (as compared to fast spectrum), thus allowing higher deployment potential (Ref. 23).

In addition, BARC is also developing the Innovative High Temperature Reactor (IHTR) with an aim to provide high temperature process heat for hydrogen production by thermochemical water splitting. This reactor is a molten salt cooled pebble bed type reactor. It uses TRISO

[12] A fast breeder reactors (FBRs) is a type of fast neutron reactors that is designed to produce more plutonium than the uranium and plutonium they consume (Ref. 5)

type particle fuel made into a form of pebbles, cooled with molten fluoride salts. Thus, coolant temperatures up to 665°C can be reached which allows for efficient interface with a hydrogen plant. Currently, a 20 MWth IHTR is being designed as a demonstration reactor.

9.8. Prediction of performance and cost

Projections about the future investment costs of nuclear power plants can be made by looking at past prices and global capacity developments. Due to the maturity of the technology and the low increase in capacity expected for future years, it is assumed that there will be a low variation in nuclear power plant costs.

Using the learning rate methodology, which translates the variation in installed capacity into a cost variation, the future prices for nuclear power plants were projected. In 2050, nuclear power plant investment costs are at most around 3% lower than in 2020.

The resulting cost development trend can be observed in Figure 9-3.

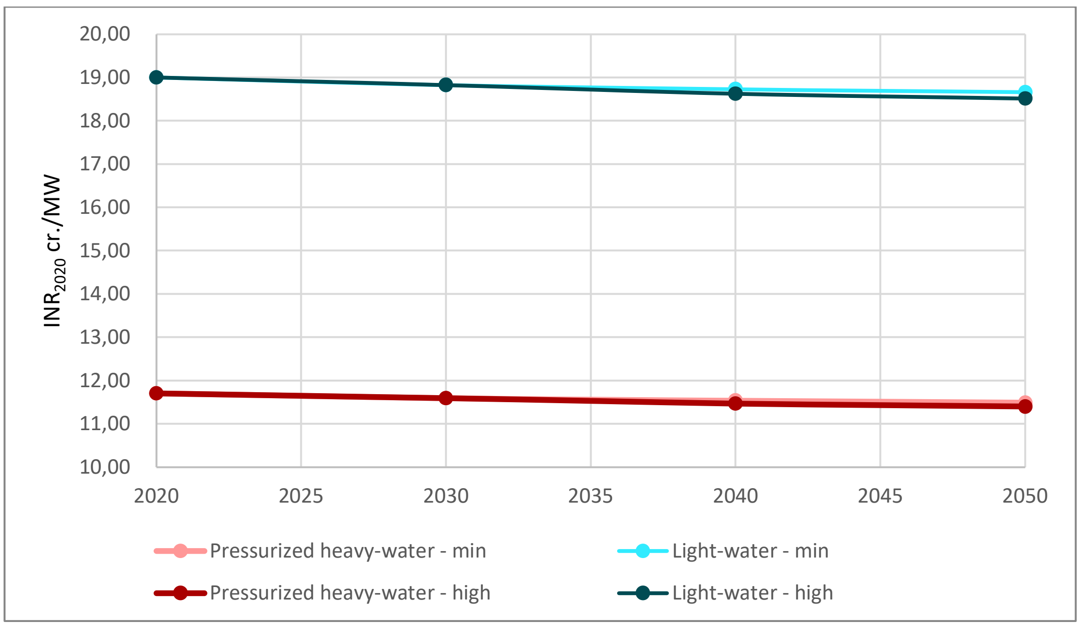

Figure 9-3: Projected nuclear power plant investment costs development from 2020 to 2050 considering a minimum and high development scenario.

Examples of market standard technology

Based on the review of currently operational NPPs globally, the Light Water Reactors are the most common Generation III reactors (Ref. 4). The typical size of the new LWRs varies between 1000-1650 MWe for European, Russian and US designed reactors. However, in India, PHWRs are the most prevalent type of nuclear reactors currently installed with IPHWR-220 being the most common unit. However, going forward, IPHWR-700 will be the most common reactor unit when the planned and under construction NPPs are finalized (Ref. 18). Currently

NPCIL has eight reactors under various stages of construction with a total capacity of 6200 MW as presented in the table below (Ref. 19).

Power station	State	Unit name	Capacity (MWe)	Expected Date of Commercial Operation
Kakrapar - unit 3&4	Gujarat	IPHWR-700	2 x 700	Unit 3 – Mar. 2021 Unit 4 – Under Review
Rajasthan - unit 7&8	Rajasthan	IPHWR-700	2 x 700	Unit 7 – Under Review Unit 8 – Under Review
Kudankulam - unit 3&4	Tamil Nadu	VVER-1000	2 x 1000	Unit 3 – Mar. 2023 Unit 4 – Nov. 2023
Gorakhpur Haryana Anu Vidhyut Pariyojna (Ref. 20)	Haryana	IPHWR-700	2 x 700	Unit 1 & 2 – 2025

Table 9-2: Planned future nuclear reactors in India

9.9. Examples of existing projects

1. Kudankulam Nuclear Power Plant

Kudankulam Nuclear Power Plant (KKNPP) is the largest nuclear power station in India, situated in Kudankulam in the Tirunelveli district of the southern Indian state of Tamil Nadu. It is based on Russian VVER-1000 reactor design, which is a Light Water Reactor.

The construction of the power plant began in 2002, and the first unit was synchronized with the grid in 2013 and the second unit in 2016. Once completed, KKNPP will house 6 VVER-1000 reactors, with a total installed capacity of 6 GWe. The significant increase in prices for the later units are attributed to passage of India's Nuclear Liability Act (2010), under which the equipment supplier is liable for the damages in case of an accident.

In 2020, KKNPP Unit 1 supplied around 5 TWh of electricity to the grid at a PLF of 60.7% (Ref. 26), whereas KKNPP Unit 2 supplied 5.9 TWh of electricity at a PLF of 71.9% (Ref. 27).

Figure 9-4: Kundankulam Nuclear Power Plant (Ref. 21)

2 Kakrapar Atomic Power Station

Kakarapar Atomic Power Station is located in Surat district in Gujarat. The plant is based on PHWR type reactors. The plant is being developed in two phases. Phase-I consists of two Indian PHWRs of 220 MWe (IPHWR-220) capacity and is operational whereas the Phase-II (Kakarapar unit 3 & 4), once completed (expected during 2021) would consist of two reactors of IPHWR-700 design.

The construction of Phase-I (unit 1 & 2) commenced in 1984 and both reactors commenced operations in 1995. The construction cost of the Phase-I is estimated as INR 1,335 Crore (1995 prices). In 2020, unit 1 supplied 1.9 TWh of electricity at a PLF of 90.2% (Ref. 29) and unit 2 approximately 1.7 TWh at a PLF of 96.4% (Ref. 30). However, in terms of lifetime performance the PLF for both the units are 58.5% and 67% respectively (Ref. 29 and Ref. 30). The discrepancy between lifetime PLF and PLF in 2020 is likely due to a long closure between 2015 and 2018.

The reactors being developed under Phase-II have not been made operational yet, although Kakarapar unit 3 (first IPHWR-700 reactor) has attained criticality in July 2020 and connected to the grid in January 2021 (Ref. 31). The estimated cost of the Phase-II is INR 16,580 Crores (2021 prices) (Ref. 32).

Figure 9-5: Kakrapar Atomic Power Station (Ref. 22)

Image	Location	Technology provider / Location	Type	Year	Efficiency and output	Ref.
	Kudankulam, Tamil Nadu	Rosatom	LWR	2013	60-70%	26, 27
	Kakarapar, Gujarat	Bhaba Atomic Research Centre	PHWR	1985	58-67%	29, 30
	Kalpakkam, Near Channai, Tamil Nadu	Bhaba Atomic Research Centre	PHWR	1986	50%	34
	Peny France	EDF, France	LWR	1990	75.7%	35

Table 9-3: Example of market standard technology for nuclear power reactors.

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25 News reported in a national newspaper, The Hindu, Jan 2018 https://www.thehindubusinessline.com/news/kudankulam-is-still-the-cheapest-of-all-foreignbuilt-nuclear-plants/article9231231.ece
26 IEIA, Power Reactor Information System – Kundankulam -1 https://pris.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=852
27 IEIA, Power Reactor Information System – Kundankulam -2 https://pris.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=853
28 News article on The Indian express, (Sept 2019) https://www.newindianexpress.com/states/tamil-nadu/2019/sep/25/global-report-on-nuclear-energy-flays-kudankulam-units-performance-2038664.html
29 IEIA, Power Reactor Information System – Kakrapar-1 https://pris.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=308
30 IEIA, Power Reactor Information System – Kakrapar-2 https://pris.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=286
31 IEIA, Power Reactor Information System – Kakrapar-3 https://pris.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=986
32 Infrastructure and Project Monitoring Division, Ministry of statistics and programme implementation. Government of India. http://www.cspm.gov.in/ocmstemp/PROJ_SUMMARY?prcd=N02000010&stat=O
33 Wikipedia https://en.wikipedia.org/wiki/Kakrapar_Atomic_Power_Station
34 Madras Atomic Power Station https://pris.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=304
35 Penly Nuclear Power Plant https://pris.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=221

9.11. Datasheet

Technology	08a Nuclear power plant, Pressurized heavy-water reactor									
	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	460				220	700				1
Electricity efficiency, condensation mode, gross (%), name plate	31								B	2
Heat rate at 55% loading (MCal/MWh)	2777									3
Heat Rate at 65% loading (MCal/MWh)										
Heat Rate at 75% loading (MCal/MWh)										
Heat Rate at max. loading (MCal/MWh)	2777									3
Auxiliary Power Consumption (%)	10.78				10.2	11.75				1
Forced outage (%)										
Planned outage (weeks per year)	1.2								B	4
Technical lifetime (years)	30								A	3
Construction time (years)	6				5	11				1, 2, 3
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)	1.7 MW/min									4
Minimum load without secondary fuel support (% of full load)	100%									4
Ramp Up Rate (% of Full Load/Minute)										
Ramp Down Rate (% of Full Load/Minute)										
Minimum Up time (hours)	6									3
Minimum Down time (hours)	4									3
Hot start-up time (hours)										
Warm start-up time (hours)										
Cold start-up time (hours)										
Hot Start-up fuel consumption (MCal)										
Warm Start-up fuel consumption (MCal)										
Cold Start-up fuel consumption (MCal)										
Financial data (in 2020₹)										
Capital cost (cr. ₹/MW)	11.70	11.59	11.50	11.45						2
- of which equipment (%)										
- of which installation (%)										
Fixed O&M (cr. ₹/MW/year)	0.43	0.43	0.42	0.41	0.26	0.60				15
Variable O&M (₹/MWh)										
Hot Startup cost (₹/MW/startup)										
Warm Startup cost (₹/MW/startup)										

Cold Startup cost (₹/MW/startup)										

References

1) Value based on inputs from various Indian stakeholders

2) Technology Brief E03, IEA ETSAP, 2010

3) Report on Optimal Generation Capacity Mix for 2029-30; Central Electricity Authority, 2020

4) Least-cost pathways for India's electronic power sector, National Renewable Energy Laboratory; 2020

5) Department of Atomic Energy norms for determination of tariff for nuclear power plants

Notes

A) Examples of longer lifetimes in India exist. For example Tarapur 1&2 has operated for more than 50 years. NAPP 1&2 is being extended beyond 30 years.

B) Value based only on international sources

Technology	08b Nuclear power plant, Light-water Reactor									
	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)	1000-1600				1000	1600				1, 2
Electricity efficiency, condensation mode, gross (%), name plate	31								A	2
Heat rate at 55% loading (MCal/MWh)	2777									3
Heat Rate at 65% loading (MCal/MWh)										
Heat Rate at 75% loading (MCal/MWh)										
Heat Rate at max. loading (MCal/MWh)	2777									3
Auxiliary Power Consumption (%)	7.8									1
Forced outage (%)										
Planned outage (weeks per year)										
Technical lifetime (years)	30									3
Construction time (years)	6				5	11				1, 3
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Minimum load without secondary fuel support (% of full load)										
Ramp Up Rate (% of Full Load/Minute)										
Ramp Down Rate (% of Full Load/Minute)										
Minimum Up time (hours)	6									3
Minimum Down time (hours)	4									3
Hot start-up time (hours)										
Warm start-up time (hours)										
Cold start-up time (hours)										
Hot Start-up fuel consumption (MCal)										
Warm Start-up fuel consumption (MCal)										
Cold Start-up fuel consumption (MCal)										
Financial data (in 2020₹)										
Capital cost (cr. ₹/MW)	19.00	18.83	18.51	18.11						2, 3, 4
- of which equipment (%)										
- of which installation (%)										
Fixed O&M (cr. ₹/MW/year)	0.26	0.26	0.25	0.25						5
Variable O&M (₹/MWh)										
Hot Startup cost (₹/MW/startup)										
Warm Startup cost (₹/MW/startup)										
Cold Startup cost (₹/MW/startup)										

References

1) Value based on inputs from various Indian stakeholders

2) Technology Brief E03, IEA ETSAP, 2010

3) Report on Optimal Generation Capacity Mix for 2029-30; Central Electricity Authority, 2020

4) World Energy Outlook 2020, International Energy Agency, 2020

5) Department of Atomic Energy norms for determination of tariff for nuclear power plants

Notes

A) Value based only on international sources

10. Battery Storage

This section describes battery storage using Lithium-Ion batteries. There are other battery technologies, which might be relevant to utility scale installations, and there are other energy storage technologies that may also be relevant. Lithium-Ion batteries are in focus here because this technology is relevant across a very broad spectrum of applications, it has demonstrated a reasonable longevity, and the ongoing R&D into Lithium-Ion batteries has resulted in an aggressive development in cost. For the moment, Lithium-Ion offers the highest degree of versatility at a reasonable cost.

10.1. Brief technology description

A lithium-ion battery or Li-ion battery (abbreviated as LIB) can store electric energy as chemical energy. Both non-rechargeable and rechargeable LIBs are commercially available. The non-rechargeable LIBs (also called primary cells) have long shelf-life and low self-discharge rates and are typically fabricated as small button cells for e.g. portable consumer electronics, arm watches and hearing aids. Rechargeable LIBs (also named secondary cells) are applied in all kinds of consumer electronics and is currently entering new markets such as electric vehicles and large-scale electricity storage. The rechargeable LIBs can be used to supply system level services such as primary frequency regulation, voltage regulation, energy arbitrage/energy shifting, peak shaving and ramp rate control, as well as for local electricity storage at individual households. Below we only focus on the rechargeable LIBs.

A LIB contains two porous electrodes separated by a porous membrane. A liquid electrolyte fills the pores in the electrodes and membrane. Lithium salt (e.g. $LiPF_6$) is disolved in the electrolyte to form Li^+ and PF_6^- ions. The ions can move from one electrode to the other via the pores in the electrolyte and membrane. Both the positive and negative electrode materials can react with the Li^+ ions. The negative electrode in a LIB is typically made of carbon and the positive of a Lithium metal oxide. Electrons cannot migrate through the electrolyte and the membrane physically separates the two electrodes to avoid electrons crossing from the negative to the positive electrode and thereby internally short circuiting the battery. The individual components in the LIB are presented in the figure below.

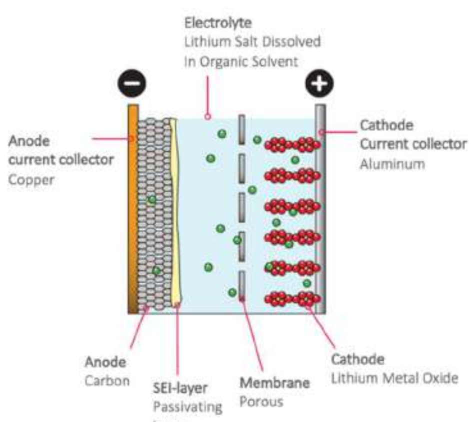

Figure 10-1: Schematic diagram of a typical LIB system displaying the individual components in the battery.

When the two electrodes are connected via an external circuit the battery start to discharge. During the discharge process electrons flow via the external circuit from the negative electrode to the positive. At the same time Li^+ ions leaves the negative electrode and flows through the electrolyte towards the positive electrode where they react with the positive electrode. The process runs spontaniously since the two electrodes are made of different materials. In popular terms the positive electrode "likes" the electrons and the Li^+ ions better than the negative electrode.

The energy released by having one Li^+ ion, and one electron, leaving the negative electrode and entering the positive electrode is measured as the battery voltage times the charge of the electron. In other words the battery voltage - also known as the *electromotive force*: *EMF* - measures the energy per electron released during the discharge process. *EMF* is typically around 3-4 Volts and depends on the LIB cell chemistry, the temperature and the state of charge (SOC – see below). When e.g. a light bulb is inserted in the external circuit the voltage primarily drops across the light bulb and therefore the energy released in the LIB is dissipated in the light bulb. If the light bulb is substituted with a voltage source (e.g. a power supply) the process in the battery can be reversed and thereby electric energy can be stored in the battery.

The discharge and charge process is outlined in the figure below. The battery is fully discharged when nearly all the Lithium have left the negative electrode and reacted with the positive electrode. If the battery is discharged beyond this point the electrode chemistries become unstable and start degrading. When the LIB is fully discharged the *EMF* is low compared to when it is fully charged. Each LIB chemistry has a safe voltage range for the *EMF* and the endpoints of the range typically define 0% and 100% state of charge (SOC). The discharge capacity is measured in units of Ampere times hours, Ah, and depends on the type and amount of material in the electrodes.

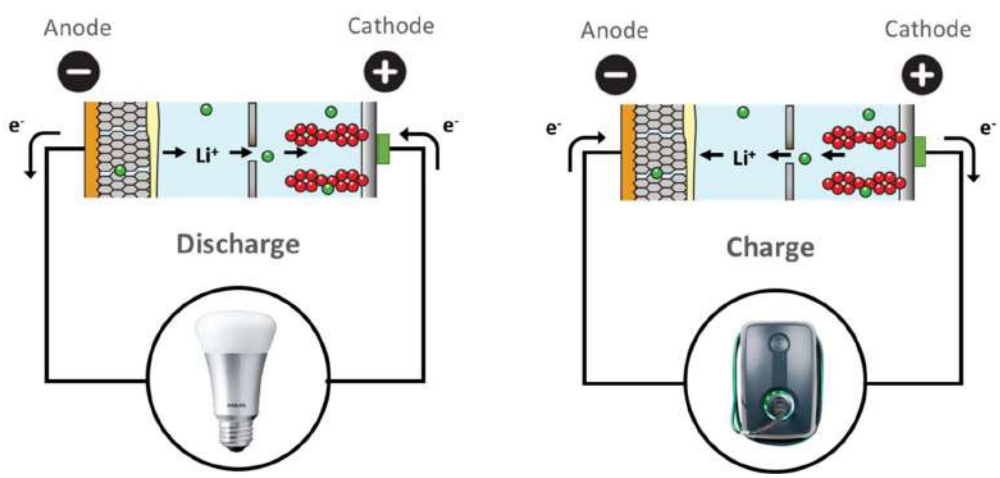

Figure 10-2: Schematic diagram of a LIB system in charge and discharge mode. During discharge the green Li^+ ions move from the negative electrode (left side) to the positive electrode. The process is reversed during charge mode (right side).

The first lithium batteries were developed in the early 1970'ies and Sony released the first commercial lithium-ion battery in 1991. During the '90s and early 2000s the LIBs gradually matured via the pull from the cell-phone market. The Tesla Roadster was released to customers in 2008 and was the first highway legal serial production all-electric car to use lithium-ion battery cells. Further, around 2010 the LIBs expanded into the energy storage sector.

Lithium-ion chemistries

The table below shows a comparison of the three most widely used LIB chemistries for grid-connected LIB systems and the major manufactures. Other LIB chemistries such as LCO, LMO and NCA are not used for grid electricity storage and are therefore not included in the table. The numbers in the table are taken from cell manufactures, product or system suppliers. NMC is the most widely used of the three chemistries due to the increased production volume and lower prices lead by the automotive sector. The NMC battery has a high energy density but uses cobalt. The environmental challenges in using cobalt are described in the section "Environment".

The LFP batteries do not use cobalt in the cathode, but are not as widely used as NMC, and are therefore generally higher priced, primarily due to the lower production volumes.

Both NMC and LFP batteries have graphite anodes. The main cause for degradation of NMC and LFP LIBs is graphite exfoliation and electrolyte degradation which in particular occur during deep cycling.

LTO LIBs are the most expensive cell chemistry of the three. In LTOs the graphite anode is replaced with a Lithium Titanate anode. The cathode of a LTO battery can be NMC, LFP or other battery cathode chemistries. The LTO battery is characterized by long calendar lifetime and high number of cycles.

Short name	Name	Anode	Cathode	Energy density Wh/kg	Cycles	Calendar life	Major manufactures	Ref.
NMC	Lithium Nickel Manganese Cobalt Oxide	Graphite	Li $Ni_{0.6}Co_{0.2}Mn_{0.2}O_2$	150-300	3000-10000	10-20 years	Samsung SDI LG Chem SK Innovation Leclanche Kokam	1, 2, 3, 4, 5
LFP	Lithium Iron Phosphate	Graphite	$LiFePO_4$	90-120	6000-8000	10-20 years	BYD/Fenecon SAFT	6, 7

							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	1, 3, 4, 8

Table 10-1: A comparison of three widely used LIB chemistries.

*Residential energy storage system. All other systems are multi-MWh size.

Lithium-ion battery packaging

The most common packaging styles for LIB cells are presented in the figure below. Figure 10-3 (a) shows a schematic drawing of a cylindrical LIB cell. Cylindrical cells find widespread applications ranging from laptops and power tools to Tesla's battery packs. Figure 10-4 (a) shows Tesla's 21700 cylindrical LIB cell which is 21 mm in diameter and 70 mm in length. The cell is produced in Tesla's Gigafactory 1 for Tesla Model 3 (Ref. 9). Figure 10-3 (b) shows a coin LIB cell. Coin cells are usually used as primary cells in portable consumer electronics, watches and hearing aids. Since they are not used for secondary cells (rechargeable) in grid-connected LIB Battery Energy Storage Systems they are not described further in this text. Figure 10-3 (c) displays a schematic drawing of a prismatic LIB cell. Prismatic LIB cells are often used in industrial applications and grid-connected LIB Battery Energy Storage Systems. The Samsung SDI prismatic LIB cell is shown in Figure 10-4 (b). This cell type is used in the BMW i3 (Ref. 10). Figure 10-3 (d) shows a schematic drawing of a pouch LIB cell. Figure 10-4 (c) shows an LG Chem pouch NMC LIB cell used in LG Chem's grid-connected LIB Battery Energy Storage Systems. Pouch LIB cells are also used in electric vehicles such as the Nissan Leaf (Ref. 11).

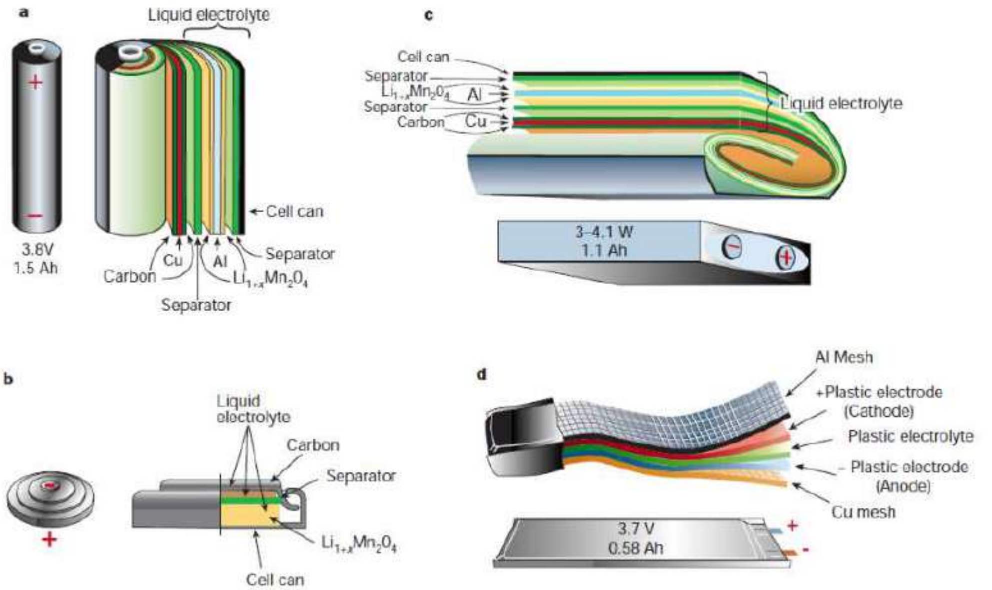

Figure 10-3: Schematic drawing showing the shape, packaging and components of various Li-ion battery configurations (Ref. 12). (a) Cylindrical; (b) coin; (c) prismatic; and (d) pouch.

Figure 10-4: Examples of LIB cells. (a) Tesla 21700 cylindrical NMC LIB cell. (b) Samsung SDI prismatic LIB cells. (c) LG Chem pouch NMC LIB cell. (Ref. 12, 13, 14, 15).

Components in a lithium-ion battery energy storage system

The figure below provides an overview of the components in a LIB storage system with interface to the power grid. In LIB storage systems battery cells are assembled into modules that are assembled into racks. The battery packs include a Battery Management System (BMS). BMS has the three different levels as Module BMS, Rack BMS and System BMS which are implemented to manage different functionalities in the BESS system. The BMS is an electronic system that protects the cells from operating outside the safe operating area. A Thermal Management System (TMS) regulates the temperature for the battery and storage system. The TMS depends on the environmental conditions, e.g. whether the system is placed indoor or outdoor. Further, an Energy Management System (EMS) controls the charge/discharge of the grid-connected LIB storage from a system perspective. Depending on the application and power configuration, the power conversion system may consist of one or multiple power converter units (DC/AC link). For system coupling a transformer may be needed for integration with higher grid voltage levels. The grid integration provides services to the grid such as increased reliability, load shifting, frequency regulation etc. The services are described further below in the section "Regulation ability and power system services". Value generation and profit is created by selling the services to grid Transmission System Operators (TSOs). Appropriate sizing of the battery and power conversion systems is essential to maximize the revenue.

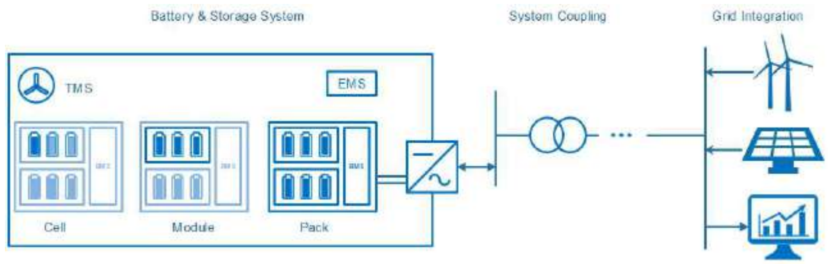

Figure 10-5: Schematic drawing of a battery storage system, power system coupling and grid interface components. Keywords highlight technically, and economically relevant aspects. Modified from (Ref. 16).

10.2. Input/output

Input and output are both electricity. Electricity is converted to electrochemical energy during charge and converted back to electricity during discharge.

The losses in a LIB can be divided in operational and standby losses. The operational losses occur when energy is discharged or charged to/from the grid. It includes the conversion losses in the battery and the power electronics.

The LIB provides a DC current during discharge and needs a DC current input for charging. Before the electricity is sent to the grid the inverter converts the DC current to AC. The inverter loss typically increases gradually from around 1% to 2% when increasing the relative conversion power from 0% to 100% (Ref. 17).

LIB electricity storage systems require power to operate the auxiliary balance of plant (BOP) components. The relative energy loss to the BOP components depends on the application, and a careful operation strategy is important to minimize their power consumption (Ref. 17). The standby loss is the sum of the energy losses during standby due to self-discharge and power consumption in the BOP components.

The conversion roundtrip efficiency of the LIB cell is the discharged energy divided with the charged energy. The battery conversion efficiency decreases with increasing current. An example of a LIB cell conversion efficiency is shown in the figure below. The C-rate is the inverse of the time it takes to discharge a fully charged battery. At a C-rate of 2 it takes ½ hour and at a C-rate of 6 it takes 10 minutes.

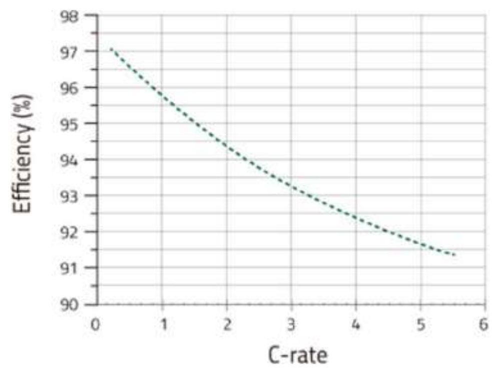

Figure 10-6: Conversion round trip efficiency vs. C-rate for one of Kokam's NMC-based lithium polymer batteries (Ref. 19).

To summarise, the total roundtrip loss typically consists of 2-5% related to the cell, 2-4% to the power electronics and the rest to standby losses.

10.3. Typical capacities

Battery storage is currently in nascent stage in India. The first grid connected BESS (Battery Energy Storage System) was installed by Tata Power in New Delhi and provides storage capacity of 10 MW.

Internationally, battery storage is evolving in multiple directions. On the micro scale, integration of electric vehicles and household sized BESS installations are gaining traction. These provide storage capacities between 5 and 100 kWh. Harnessing such small units requires coordinating the charging and discharging either through price signals or 3rd party aggregators. On the other end of the scale multi-MW installations like the one in New Delhi are emerging to provide vital system services such as inertia, frequency response, fast ramping and short term (0-12 hours) load shifting. In the UK, large scale BESS has been contracted to supply system services on commercial terms in technology neutral auctions (Ref. 23).

10.4. Regulation ability and power system services

Grid-connected LIBs can absorb and release electrical energy fast. The response time of grid-connected LIBs are strongly dependent on control components, EMS, BMS and TMS as well as the power conversion system.

The relatively low electricity storage costs make grid-connected LIB BESS suitable for a broad range of applications (Ref. 24) such as peak load shaving and peak ramp rate reduction where the BESS provides or consumes energy to reduce peaking and peak ramping in a power system. In relation to this, BESS can promote renewable integration, e.g. time or load shifting of photovoltaic power from day to night. Further, the BESS can provide transmission congestion relief where locally deployed BESS reduces the load in the transmission and distribution system. In this way the BESS can help defer expensive upgrades of the transmission and distribution network.

In grids with a working electricity market mechanism in place, BESS can also provide the opportunity for energy arbitrage. Owners of generation capacity – especially variable renewable energy – may use BESS to delay delivery of energy to the grid until electricity prices are favourable. Likewise, the owner of the BESS may choose to charge the BESS while electricity is cheap and discharge again when electricity is expensive. These actions go hand in hand with peak shaving and load shifting. The value of electricity and energy storage varies over the day, week, and seasons. Energy arbitrage is the act of maximising the value of not only the BESS itself, but also connected generation capacity. In some cases, BESS can serve several purposes at the same time, thus generating revenue from several sources. This is called revenue stacking and is a major contributor to BESS becoming a stable element in e.g., the UK energy and capacity markets (Ref. 56).

The fast response time enables the use of BESS for a broad range of primary control provisions. These include frequency regulation where the BESS are used to alleviate deviations in the AC frequency. The BESS can also be used to improve network reliability by reacting immediately after a contingency. Here the BESS can help maintaining stability in the power system until the operator has re-dispatched generation. Moreover, the BESS can effectively be used for black-starting distribution grids and BESS systems are suitable for enhancing the power quality and reducing voltage deviations in distribution networks. The BESS can further be used to provide spinning reserves and regulate active and reactive power thereby improving the network voltage profile. This can improve the integration of renewable energy because it reduces the events triggering the protections of the inverters.

Typical storage period

Several aspects of the LIB technology put an upper limit to the feasible storage period. The self-discharge rate makes storage periods of several months unfeasible. The BOP power for standby operation adds parasitic losses to the system which further limits the feasible standby time. Unwanted chemical reactions in the LIB gradually degrade the battery and limit the calendar lifetime. This calls for shorter storage periods in order to obtain enough cycles to reach positive revenue.

For LIBs the total number of full charge-discharge cycles within the battery lifetime is limited between a few thousands up to some ten-thousands. The exact number depends on the chemistry, manufacturing method, design and operating conditions such as temperature, C-rate and calendar time. This impacts the type of suitable applications. For instance, due to the different degree of usage, the LTO chemistry may find more use on the FCR-N[13] market while others like NMC may be preferred for the FCR-D market.

Until now the majority of the current LIB systems have been deployed to perform fast reactive renewables smoothing and firming with storage periods ranging from seconds to minutes (Ref. 25). But more recently, the systems are increasingly used for renewables time shifting with typical storage periods of a few hours (Ref. 17 and 25).

[13] FCR-N: Frequency Containment Reserve for Normal operation. FCR-D: Frequency Containment Reserve for Disturbances

Space requirement

The racks and battery packs are assembled in containers and the energy per 40 feet container is 4-6 MWh for NMC batteries (Ref. 2 and 26). The footprint of a 40-feet container is 29.7 m^2. This gives a space requirement around 5-7.5 MWh/m^2.

10.5. Advantages/disadvantages

Advantages

- The commercial interest for electricity storage using LIB systems has increased dramatically within the last decade.
- The production volume is still limited and there is a promising potential for cost reductions through upscaling.
- The technology is stand-alone and requires a minimum of service after the initial installation.
- High energy density & roundtrip efficiency.

Disadvantages

- Containers come in standard sizes. For small systems this impacts the LIB system CAPEX, however when the system size exceeds several container units, the price can be considered fairly linear.
- Compared to e.g. fuel cell technology the CAPEX per storage capacity is relatively high. This is because the electricity is stored in the battery electrodes whereas for fuel cells the electricity is stored as a separate fuel.
- The relatively high energy specific CAPEX combined with the gradual self-discharge and parasitic losses in the BOP make the technology less attractive for long-term storage beyond a few days.
- Low DoD compared to Nas & flow technology and poor recycling.

10.6. Environment

A US-EPA report stated in 2013 that across the battery chemistries, the global warming potential impact attributable to LIB production including mining is substantial (Ref. 27). More specifically a recent review on life-cycle analysis (LCA) of Li-Ion battery production estimates that "on average, producing 1 Wh of storage capacity is associated with a cumulative energy demand of 328 Wh and causes greenhouse gas (GHG) emissions of 110 g $CO_{2\ eq}$" (Ref. 28).

The LIB cathode material NMC contains toxic cobalt and nickel oxides. About 60% of the global production of cobalt comes from Congo and the environmental health risks and work conditions in relation to the cobalt mining rises ethical concerns (Ref. 29). Visual capitalist believes the cobalt content in NMC could decrease to 10% already in 2020 (Ref. 30).

Starting about two years ago, fears of a lithium shortage almost tripled prices for the metal (Ref. 31). Demand for lithium won't slacken anytime soon - according to Bloomberg New Energy Finance the electric car production alone is expected to increase more than thirtyfold from 2017 to 2030. However, the next dozen years will drain less than 1 percent of the reserves in the ground, BNEF says. But battery makers are going to rapidly increase mining capacity to meet the demand.

Battery disposal and recycling is highly important. Proper recycling of the Li-Ion batteries can recover critical and strategic materials and prevent the release of toxic materials. The technology for recycling batteries is continually evolving allowing recovery of an increasing number of materials including Cobalt, graphite, aluminium, copper, lithium, manganese and nickel (Ref. 57).

10.7. Research and development

Currently, a wide range of government and industry-sponsored LIB material, cell and system level research is taking place. Some of the ongoing material research to further increase the energy density of LIB cells includes high-voltage electrolytes allowing charging voltages of up to 5 volts and silicon nanoparticle-based anodes to boost the charge capacity. Several research and development activities focus on improving the cycle lifetime of LMO cells exist (Ref. 33, 34, 35, 36, 37).

Some of the most promising post Li-ion technologies include Lithium Sulphur batteries that use Sulphur as an active material. Sulphur is abundantly available at reasonable price and allows for very high energy densities of up to 400 Wh/kg. Also, Lithium air batteries have received considerable attention. Since one of the active materials, oxygen, can be drawn from the ambient air, the lithium-air battery features the highest potential energy and power density of all battery storage systems. Due to the existing challenges with electrode passivation and low tolerance to humidity, large-scale commercialization of the lithium-air battery is not expected within the next years.

Several non-lithium-based battery chemistries are being investigated. Aluminium Sulphur batteries may reach up to 1000 Wh/kg with relatively abundant electrode materials but are still in the very early development phase (Ref. 38).

Besides the materials research, improved cell design, BMS, TMS and EMS technology and operation strategy can improve storage efficiency considerably (Ref. 17). Although LIB systems for electricity storage are now commercially available, the R&D is still in its relatively early phase and is expected to contribute to future cost reductions and efficiency improvements.

10.8. Prediction of performance and cost

Worldwide, the utilization of battery storage is increasing rapidly, and it is expected to continue to grow. The improvements in battery technologies and their large deployment can result in large cost reductions.

Towards 2050, Li-ion batteries are expected to become more efficient and long-lasting. The gross electrical efficiency is projected to be around 94% in 2050 compared to around 90% in 2020, and the number of battery cycles are estimated to be around three times higher than today.

The Government of India has recently announced various incentives for increasing local manufacturing of Li-ion batteries. Current costs for Li-ion batteries in India are 6.7 INR cr./MW for systems with battery management systems included and 2.4 INR cr./MWh for the battery itself.

Using the learning rate methodology, which translates the growth in installed capacity into a cost reduction, the future prices for battery storage systems were projected. As a result, investment costs in 2050 are expected to be between 3.8 and 2.2 INR cr./MW, or between 1.3 and 0.8 INR cr./MWh for different scenarios of battery capacity installations. This equates to a reduction between 44% and 67% compared to 2020 prices.

The resulting cost development trend can be observed in Figure 10-7.

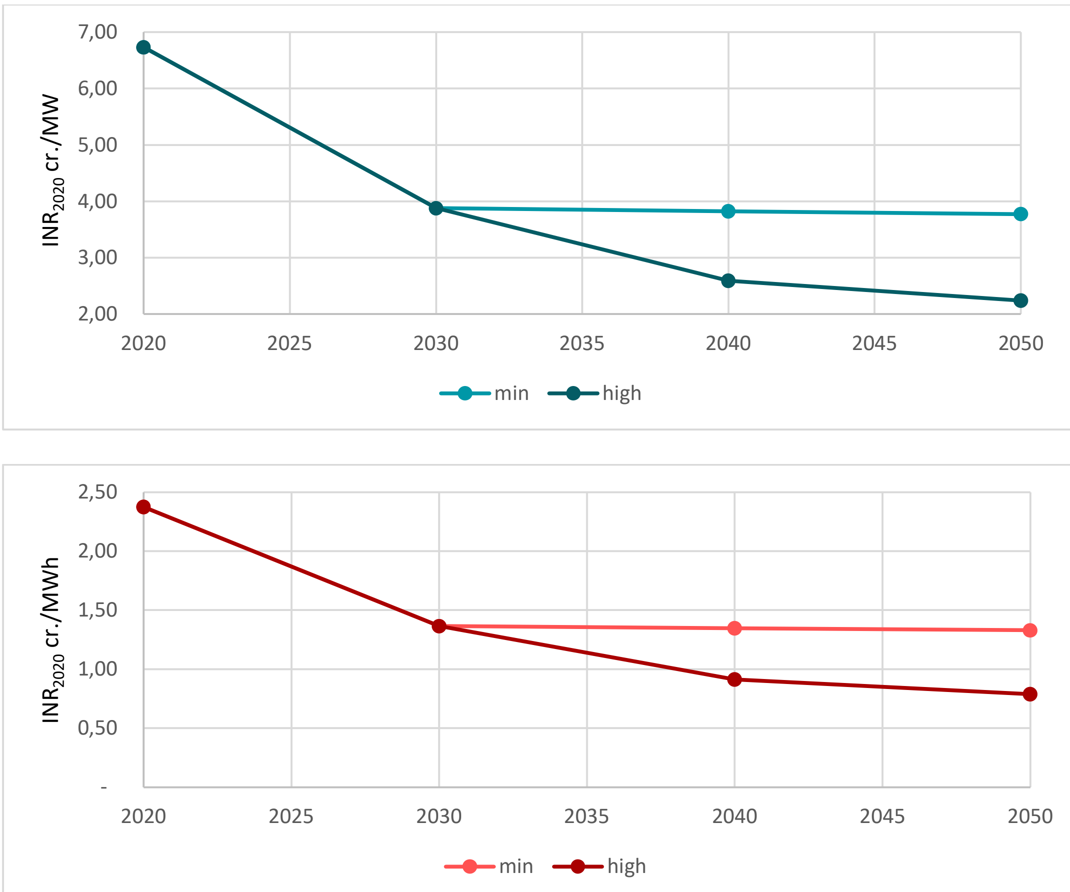

Figure 10-7: Projected battery storage investment costs development from 2020 to 2050 considering a minimum and high development scenario.

10.9. Examples of market standard technology

Grid scale turn-key LIB systems are commercially available from a wide range of suppliers.

Two larger grid-connected LIB systems are installed in Denmark: **A)** In Copenhagen, Denmark a 630 kW/460 kWh was installed by ABB in 2017. This set the scene for Ørsted's first steps into commercial battery storage. For Ørsted the following energy storage projects are under development: a 20 MW battery storage near Liverpool in UK, a 1 MW storage pilot project in Taiwan and a 55 MW battery storage for the Bay State Wind project in USA (Ref. 39). **B)** Lem Kær Wind Farm was a Vestas pilot project for energy storage. Vestas is working on Kennedy Power Plant that integrates wind and solar with grid-scale energy storage and will feature a 2

MW/4 MWh grid-scale LIB storage system providing flexibility and increasing the energy production.

Globally, two very large grid-scale LIB storage systems are the Moss Landing Energy Storage Facility in California at 300MW/1,200MWh providing peak load management (Ref. 40) and the Neoen’s Hornsdale Wind Farm which feature a 150MW/194MWh providing peak shaving (Ref. 41 and 42).

The Mira Loma Substation in California features a 20MW/80MWh project using 400 Tesla Powerpack 2 and provides peak shaving (Ref. 43 and 44). The Laurel Mountain, West Virginia, USA grid-scale LIB storage system with a size of 32MW/8MWh (Ref. 45) is designed for frequency regulation and with high power to energy ratio compared to the Tesla grid-scale LIB storage system, which is designed for peak shaving with a low power to energy ratio.

10.10. Examples of existing projects

India’s first grid-scale battery is installed at a substation located at Rohini, New Delhi, which is operated by Tata Power-Delhi Distribution Limited (DDL) since March 2019. The capacity of the storage system is 10 MW if storing for one hour and Li-ion battery is used.

Tata Power collaborated with AES Corporation and Mitsubishi Corporation to set up the grid-scale battery energy storage system which is the largest grid-scale battery energy storage system in Asia.

It has been extensively used for peak load management and deviation settlement mechanism management and provides enhanced power supply by addressing various technical issues. The battery occupies 625 m², covering the BESS, isolation transformer and firefighting installation.

Figure 10-8: Rohini BESS, New Delhi (Ref. 46)

Image	Location	Primary usage	Year	Power capacity	Techn. provider	Ref.
	Moss Landing, Monterey County, California, USA	Peak load management	2020	300 MW 1,200 MWh	Vistra	40
	Rohini, New Delhi	Peak load management	2019	10 MW	AES Corporation and Mitsubishi Corporation	47
	Energylab Nordhavn, Copenhagen, Denmark	Frequency Regulation Peak Shaving Voltage Regulation Harmonic Filtering	2017	630 kW 460 kWh NMC	ABB for Radius Elnet / Ørsted	48
	Lem Kær Wind Farm, Denmark	Frequency regulation	2014	400 kW LFP and 1.2 MW LTO	Altairnano and A123 for Vestas	49
	Mira Loma Substation, California, USA	Peak Shaving	2016	20 MW 80 MWh	Tesla	43, 44

	Neoen's Hornsdale Wind Farm, South Australia	Peak Shaving	2017	150 MW 194 MWh	Tesla	41, 42
	Laurel Mountain, Belington, West Virginia, USA	Frequency Regulation and Renewable Energy Integration	2011	32 MW 8 MWh	AES and A123	45

Table 10-2: Example of market standard technology for grid-connected LIB systems.

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10.12. Datasheet

Technology	09 Battery storage system (Lithium-ion)									
Year of final investment decision	**2020**	**2030**	**2040**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data										
Generating capacity for one unit (MW)	1-100	1-200	1-300	1-500	1	100	1	500		1
Electricity efficiency, gross (%)	90	92.5	94.0	94	88	92	90	98	A	1
Forced outage (%)	1	0.5	0.5	0.5	0.4	1.3	0	1		1
Planned outage (weeks per year)	1.5	1.5	1	1	1	2	1	1		1
Auxiliary Power Consumption (%)	1.0	1.0	0.8	0.6	1.0	7.5	0.1	1.0		1
Technical inverter lifetime (years)	16.7	22.5	25	25	8	20	15	25		1
Lifetime (battery cycles)	6000	>8000	~10000	~20000	4500	8000	15000	20000		1
Construction time (years)	0.9	0.50	0.33	0.33	0.75	2	0.17	0.75		1
Storage capacity (MWh)	1-200	1-800	1-1800	1132254	1-100	1-300	1-500	1-12000	B	1
Charging efficiency (%)	95	96	97	97	95	94	96	99	C	1
Depth of Discharge (%)	92	95	99	99	80	80	95	100		1
Discharge time (h)	2	4	6	10	1	4	6	12		1
Regulation ability										
Primary load support (% per 30 seconds)	100	100	100	100						1
Secondary load support (% per minute)	100	100	100	100						1
Minimum load (% of full load)	0	0	0	0						1
Financial data (in 2020₹)										
Capital cost										
- per MWh basis (cr. ₹/MWh)	2.38	1.37	1.19	1.09	1.13	2.50	0.50	1.2	D	1
- per MW basis (cr. ₹/MW)	6.73	3.87	3.38	3.09	5.00	9.00				1
Fixed O&M (cr. ₹/MW/year)	0.08	0.05	0.04	0.03						1
Variable O&M (₹/MWh)	500.000									1

References

1) Value based on inputs from various Indian stakeholders

Notes

A) The DC efficiency of the system is 96.5%

B) Assuming number of hours of storage on basis of power capacity given

C) It is assumed a conversion from AC to DC and back to AC at the battery level.

D) Assuming 2 hours Storage in 2020, 4 hours Storage in 2030, 6 hours Storage in 2040 and 10 hours Storage in 2050

Appendix

A. Forecasting methodology for electricity production costs

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

Three 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.
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.** Projection based on historic trends in cost reductions combined with estimates of future deployment of the technology. Learning curves expresses 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 contain advantages and disadvantages.

	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 to carry out survey. • 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. • 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.

Table 0-1: Advantages and disadvantages of different methodologies for forecasting technology costs

For the purpose of the present technology catalogue, the 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, and thirdly, it does not involve costly and time-consuming surveys.

The learning curve assumptions are compared with projections from international literature.

Learning curve based cost projections are dependent on two key inputs: a projection of the capacity of the technologies and an estimated learning rate of each technology. Only these two inputs are required to perform the cost projections and these inputs therefore have significant influence on the technology cost developments.

Future technology deployment

To estimate the future deployment of each of the technologies a variety of projections can be used. In similar studies from other countries, global projections have been applied assuming that the global developments will have spill-over effects on most countries. However, for the purpose of this technology catalogue it was decided to use projections only for India as the country is of such a scale that it can influence the development of entire technologies. Hence, the "Report on optimal generation capacity mix for 2029-30, CEA, 2020" has been used for the current and 2030 capacity development. In the years after 2030 capacity development has been based on projected maximum potentials for various technologies and internal CEA consultations. As capacity developments are uncertain by nature ranges have been developed for the years 2040 and 2050. This chapter displays the low and high range of this capacity development. The future cost projections given in previous chapters contain projections for the medium range for each technology.

The capacity development is displayed in the table below.

Technology deployment (Index is in relation to 2020)		**2020**	**2030**	**2040**	**2050**
Coal	Index	1	1.2	1.1-1.2	1-1.3
	GW	215	267	241-269	215-269
Gas	Index	1	1	1-1.4	1-1.8
	GW	25	25	25-35	25-46
Biomass	Index	1	1	1.2-1.5	1.3-2
	GW	10	10	12-15	13-20
Onshore wind	Index	1	2.4	2.4-5.2	2.5-8.0
	GW	58	140	141-300	144-460
Offshore wind	Index*	-	-	-	-
	GW	-	30	33-68	35-105
Photovoltaics	Index	1	2.8	6.4-11.4	10-20
	GW	100	280	640-1,140	1,000-2,000
Large hydropower	Index	1	1.4	1.4-1.8	1.5-2.2
	GW	45	61	64-80	67-99
Small hydropower	Index	1	1	1.3-1.6	1.5-2.2
	GW	5	5	6-8	8-11
Pumped Hydro storage	Index	1	1.9	2-2.1	2-2.2
	GW	5	10	10-11	10-12
Nuclear	Index	1	1.9	2.7-3.9	3.5-6.0
	GW	10	19	27-40	35-60
Batteries (Li-ion)	Index*	-	-	-	-
	GW	-	27	29-134	30-240

Table 0-2: Capacity deployment in the various years used for technology cost projections. Values for 2020 are equal to 2021-22 data and 2030 values are directly from CEA Report on

optimal generation capacity mix for 2029-30. No index is provided for offshore wind and batteries as the current capacity is limited.*

Learning rates

Learning rates indicate the expected cost reductions every time the installed capacity of a specific technology doubles, i.e. if the installed capacity of a technology increases from 50 GW to 100 GW the learning rate will be applied once. Learning rates typically vary between 1% and 25% and can change significantly depending on the technology in question. Some technologies such as thermal power plants are mature and are therefore expected to have little potential for cost improvements while other technologies such as PV and batteries are still improving and are therefore expected to have higher potentials for cost reductions in the coming decades. The learning rates are applied for the capital costs of the technologies.

Literature indicates 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." (Rubin et al., 2015). This has to be considered when using the learning rate inputs.

The majority of the learning rates across the technologies are expected to be 1-5%. PV, offshore wind and batteries have higher learning rates as these are still under rapid development.

The learning rates applied for this study are specified in the table below.

Technology	Single-factor learning rate	Primary Source
Coal Power Plant	2.1%	JRC, 2018
Gas Power Plant	2.2%	JRC, 2018
Biomass power plant	5%	JRC, 2018
Wind onshore	5%	JRC, 2018
Wind offshore	11%	JRC, 2018
Photovoltaic	20%	JRC, 2018
Hydro power	1%	JRC, 2018
Nuclear	1%	Internal assessment
Lithium-Ion Batteries	16%	Kittner et al., 2020.

Table 0-3: Learning rates applied for the cost projections

When the abovementioned learning rates and capacity deployments are combined, an estimate of the cost development over time can be deduced.

Technology cost compared to 2020 (2020 = 100%)	2030	2040	2050
Coal	99%	99-100%	99-100%
Gas	100%	99-100%	98-100%
Biomass	100%	97-99%	95-98%
Onshore wind	94%	88-94%	86-93%
Offshore wind	60%	52-59%	48-58%
Photovoltaic	72%	46-55%	38-48%
Large hydropower	100%	99%	99%
Small hydropower	100%	99%	99%

Pumped storage	100%	99%	99%
Nuclear	99%	98-99%	97-98%
Batteries (Li-Ion)	65%	44-65%	38-64%

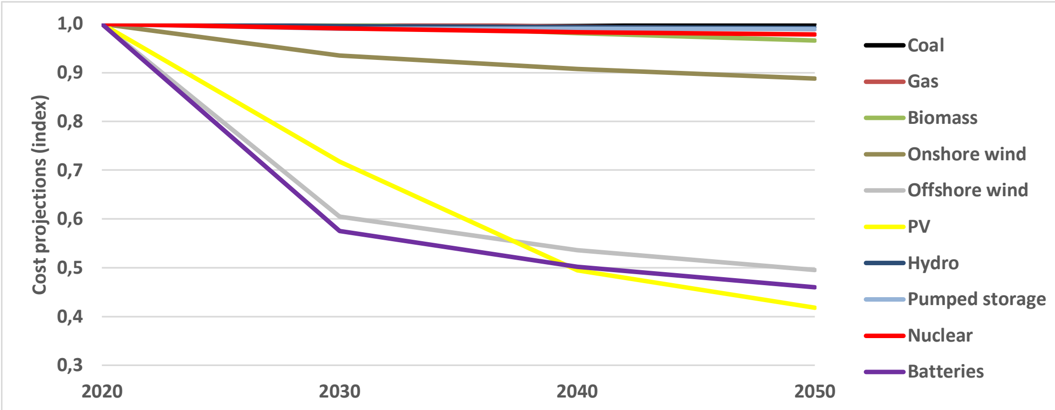

Figure 0-1: Cost projections as an index of 2020

For all thermal technologies, i.e. coal, natural gas, nuclear and biomass power, moderate cost decreases are projected of less than 10% 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, offshore wind and batteries 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 in combination with a significant expected deployment growth.

Onshore wind power is already widely deployed, and hence, the projected cost development is also moderate, a reduction of approximately 5-15% is projected by 2050. It should be mentioned that almost all the learning curve studies for wind power focus 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 energy generation, is likely to be higher. This trend is likely to prevail in the future.

Global and regional learning

The learning effects found in this technology catalogue express a regional Indian perspective on technology learning. Considering the size of the Indian market this seems to be a reasonable assumption. However, the majority of technology providers today are global players and there could therefore be global developments outside of India that are not accounted for in this study.

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