Table A- 13. System Configuration for Wind Turbine Classes

Parameter	Class I Turbine	Class II Turbine	Class III Turbine
Rated Output	2,000 kW	2,000 kW	2,000 kW
Hub Height	80 m	80 m	80 m
Rotor Diameter	77 m	82.5 m	100 m
Shear Coefficient	0.14	0.14	0.14
Total Losses	16.7 %	16.7 %	16.7 %

Power Density

To assign a maximum available installable capacity for PV and wind developments, we used a single value for PV and wind as the power density in MW/km^2, as denoted below:

Table A- 14. Power Density of Solar PV and Wind Technologies

Technology	Power Density (MW/km^2)
Utility-Scale PV	32
Wind	3

Land Exclusions

To model locations that are available for development, we used geospatial data that helped inform land characteristics, uses, and cover (Table A- 15).

Table A- 15. Land Exclusions

Technology	Utility-Scale PV	Distributed Utility-Scale PV	Wind
Slope Included (deg)	< 5%	n/a	< 20%
Urban	Exclude	Include	Exclude
Rural	Include	Exclude	Include
Protected Areas	Exclude	n/a	Exclude
Croplands	Exclude	n/a	Include
Forest	Exclude	n/a	Exclude
Grassland	Include	n/a	Include
Bare	Include	n/a	Include
Wetland	Exclude	n/a	Exclude
Water Bodies	Exclude	n/a	Exclude
Airports	Include	n/a	Exclude

Capacity Factors

The maps below show the resulting annual mean (wind) and multiyear mean (PV) capacity factors using the weather data and system configurations outlined above. These capacity factors are used for calculating the site levelized cost of electricity (LCOE), which contributes to the overall cost of a new system when added to the transmission LCOE.

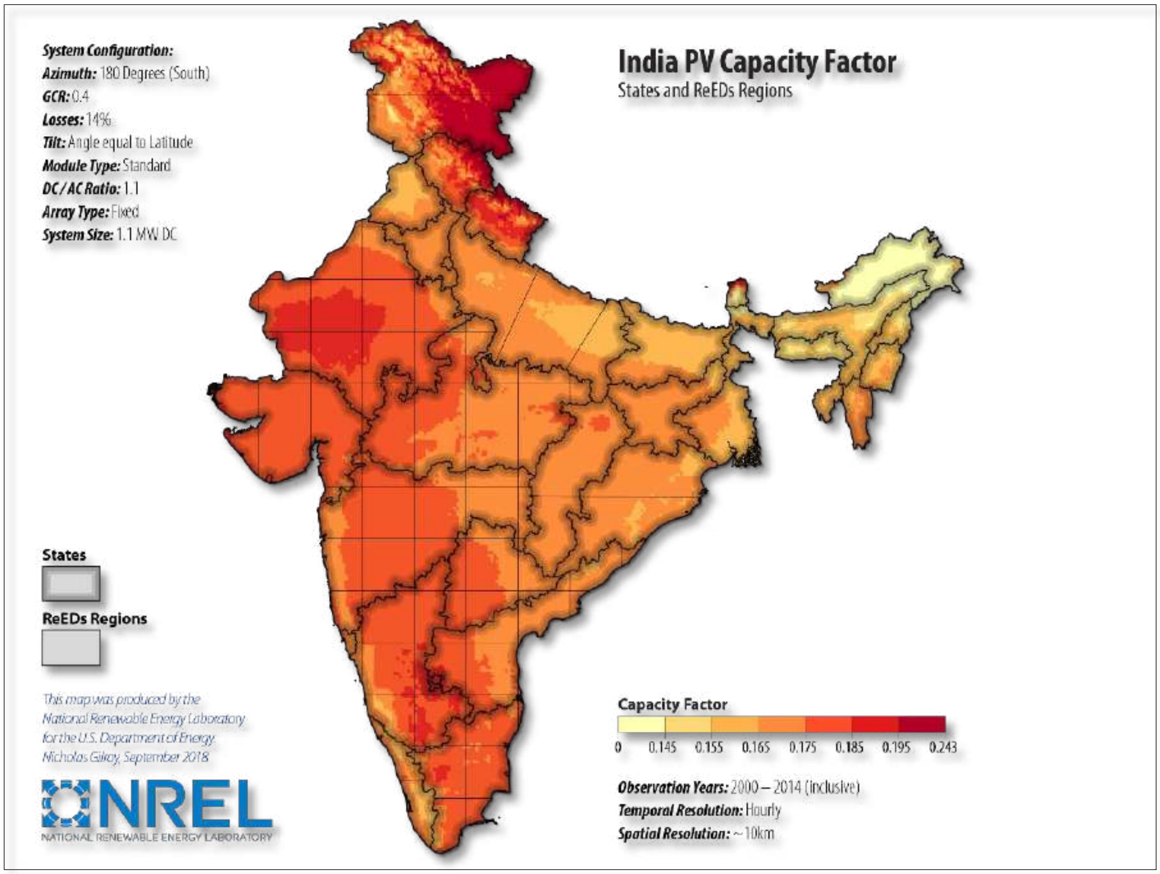


Figure A- 2. Map of Capacity Factors for Solar PV in India

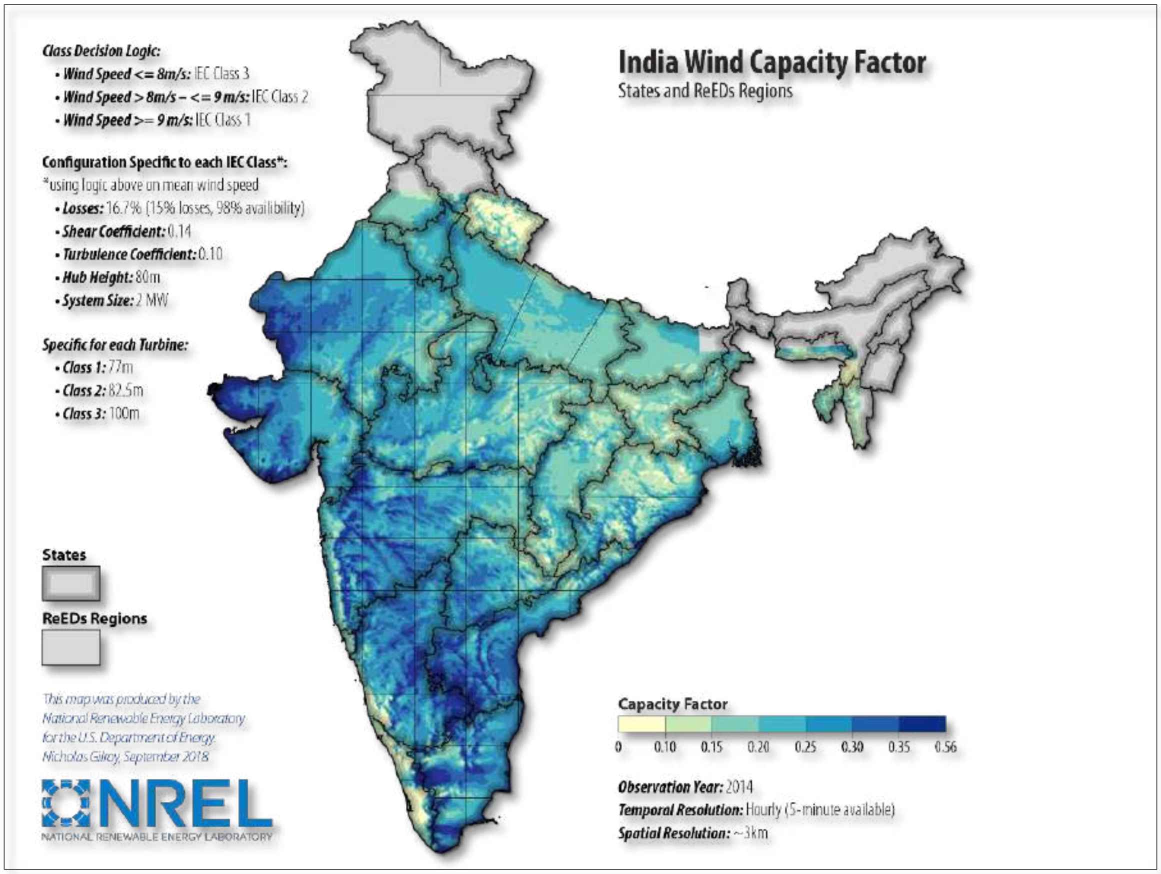


Figure A- 3. Map of Capacity Factors for Wind in India

ReEDs uses supply curves of wind and solar to characterize the potential sites available for development and directly evaluates the investments of these generation sources using the curves. These supply curves are estimated from detailed weather data, geospatial constraints, and economic assumptions.

Supply curve cost inputs are used to calculate site and transmission LCOE for new wind and PV developments. The components that comprise the LCOE are: capital costs, fixed operating costs, and grid integration costs (i.e., transmission), as well as other financing costs.[30] The following table gives the assumptions of the transmission line components of the LCOE:

Table A- 16. Transmission Spur Line Cost

Technology	Transmission line ($/MW-mile)
PV	423
Wind	423

[30] Based on Heimiller, Donna, Philipp Beiter, Nick Grue, Galen Maclaurin, and July Tran. 2018. South Asia Wind and Solar Supply Curves. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71679. https://www.nrel.gov/docs/fy19osti/71679.pdf.

The capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow. The fixed operating costs represent the cost of operating the plant over its lifetime. The transmission line cost is only added to the LCOE if current substation capacities are not sufficient for the new capacity.

Transmission

Existing Transmission Capacity

Transfer capacity between states was calculated based on Greening the Grid transmission capacity, which included all plans from PowerGrid out to 2022 (as of March 2016), separately for AC and DC lines.

Cost for New Transmission Investment

Transmission investment costs were based on the cost list provided by CEA (as of February 2017):

Table A- 17. Transmission Capital Costs

Line Type	Cost (Lakhs ₹/km)
765 KV	413
400 KV	124
220 KV	51

ReEDS-India uses both distance and energy capacity to assess the total capital cost of a transmission line. To convert ₹/km to ₹/MW/km, we estimated the state-wise total carrying capacity based on average line capacity for the highest voltage lines. The final ₹/MW/km values were obtained by dividing the costs in Table A- 17 by the average carrying capacity of the highest voltage lines in each state.

Table A- 18. Average Cost for New Transmission by Voltage Class

Line Type	Average Cost (₹/MW/km)
765 KV	18025
400 KV	21915
220 KV	23181

Total cost for new transmission investment between any two states was calculated as the average cost multiplied by the approximate distance between states. Distance between states was estimated using the largest population center of each state.

Substation Supply Curves

The substation supply curves are designed to capture the cost of stepping up the voltage within a balancing area to reach the voltage of the inter-balancing area transmission line within ReEDS. It is an attempt to estimate the costs of distributing the power from large, high-voltage, inter-balancing area lines that are built by ReEDS to the existing intra-balancing area infrastructure. For example, if ReEDS builds enough transmission between two balancing areas to require two 500-kV lines, the two lines can go to different 500-kV buses if they already exist at no extra cost. However, if only one 500-kV bus is available, the second 500-kV line may need to be split between two 345-kV stations, with the added cost of two transformers. If no voltage change is required and the carrying capacity of the transmission infrastructure is large enough to accommodate more energy flowing through the system, the cost to distribute the power will be assumed to be negligible.

In the case of adding generation within a balancing area, it is assumed that new renewables can use existing infrastructure to step-up the voltage to the high-voltage buses to get the power out. If there are not enough buses in an area to distribute/collect the power, the cost of purchasing new infrastructure to step up the voltage from the output of each generator to transmission level voltages will be added to the total transmission infrastructure cost.

The supply curves were created based on the following input data: (1) count of buses by voltage in each balancing area, (2) cost of transformers (₹/MW) at different voltage levels, and (3) estimate of how much new line capacity (MW) can be tied into a specific bus by voltage. All data for the number of buses by balancing area and the max voltage for inter-balancing area connections are based on the Greening the Grid database. After a review of Greening the Grid data and Volume II Transmission of the National Electricity Plan, we reduced the number of possible voltages to 765 kV, 400 kV, 220 kV, and 132 kV.

Table A- 19. Substation Cost and Carrying Capacity by Voltage Class

Voltage	Substation Cost (Lakh)	Carrying Capacity (MW)[31]	Notes
765 kV	1,500	2250	Substation cost per bay
400 kV	1,500	691	Substation cost for 2 bays
220 kV	440	132	Substation cost per bay

These two values, the substation cost and carrying capacity, were used to calculate the cost of new substations in ₹/MW. The final supply curve consists of a carrying capacity (MW) and marginal cost (₹/MW) for each voltage class by balancing area. The carrying capacity is calculated as the number of substations in each balancing area at a specified voltage times the carrying capacity for that voltage. The marginal cost to distribute power in each balancing area is equal to the cost to step up the voltage from each class to the voltage for inter-balancing area transmission lines.

Planning and Operating Reserves

The planning reserve margin requirement was based on 15% of peak demand by region in each year. The planning reserve must be held within each region, with trade allowed for reserve capacity between regions.

Operating reserves were held at 5% of total national demand in each time slice. The contribution of different technologies to the operating reserve requirement is limited by the ramping

[31] Based on POSOCO SIL data for transmission lines (Table 3) http://nerldc.org/Docs/DEC14/NER%20REACTIVE%20POWER%20MANAGEMENT%20MANUAL%202014.pdf

capability for the given technology. The assumptions for operation reserve costs and technology-specific contributions were based on U.S. ReEDS assumptions.

Table A- 20. Operating Reserve Parameters

Technology	Cost for Providing Operating Reserve (₹/MW)	Contribution of Capacity to Operating Reserve Capacity
Combined Cycle Gas Turbine-Gas	421.2	30%
Combined Cycle Gas Turbine-Liquified Natural Gas	421.2	30%
Combined Cycle Gas Turbine-Naphtha	421.2	30%
Combustion Turbine-Gas	280.8	30%
Diesel	280.8	20%
Hydro – Pumped	140.4	100%
Hydro – Storage	140.4	100%
Subcritical Coal	702	10%
Subcritical Lignite	702	10%
Subcritical Oil	280.8	10%
Supercritical Coal	1,053	10%

Generation Availability

Seasonal Capacity Factors for Hydro Technologies

To account for regional and seasonal changes in water availability for hydropower generation, ReEDS includes seasonal capacity factors by state for each type of hydro plant.[32] Using CEA's monthly generation data for over 350 hydropower plants during 2015–2016 and 2016–2017, we calculated average seasonal capacity factors for each plant in the report. Using the hydro plant database from Greening the Grid and other publicly available sources, we classified each plant as ROR, pondage, storage, or pumped.

The tables below contain the inputs used in the ReEDS-India for average hydropower capacity factors by season, state, and plant type.

Notes on capacity factor data:

- Seasonal capacity factors are only calculated for combinations of states and technology types where hydropower plants currently exist, are under construction, or could be built in the future.
- In cases where historic generation data for particular states were not available, we used regional averages for plants of the same type.

[32] As per CEA's recommendation, seasons are defined as follows: Winter: December-January, Spring: February-March, Summer: April-June, Rainy: July-September, Autumn: October-November.

- Given the potentially high variability in seasonal and interannual weather patterns, we would ideally consider more than 2 years of generation data but were limited by available data.

Table A- 21. Seasonal Capacity Factors for Storage Plants

State	Autumn	Rainy	Spring	Summer	Winter
Andhra Pradesh	0.11	0.12	0.19	0.08	0.14
Arunachal Pradesh	0.67	0.81	0.22	0.38	0.47
Assam	0.67	0.81	0.22	0.38	0.47
Chhattisgarh	0.37	0.44	0.03	0.14	0.03
Goa	0.27	0.32	0.18	0.17	0.17
Gujarat	0.18	0.31	0.12	0.13	0.04
Himachal Pradesh	0.15	0.38	0.14	0.24	0.13
Jammu Kashmir	0.29	0.41	0.24	0.20	0.30
Jharkhand	0.01	0.10	0.00	0.03	0.00
Karnataka	0.14	0.25	0.24	0.18	0.12
Kerala	0.28	0.41	0.32	0.38	0.24
Madhya Pradesh	0.30	0.31	0.24	0.13	0.32
Maharashtra	0.25	0.21	0.31	0.28	0.30
Manipur	0.94	0.94	0.28	0.43	0.70
Meghalaya	0.40	0.69	0.16	0.34	0.24
Mizoram	0.67	0.81	0.22	0.38	0.47
Nagaland	0.67	0.81	0.22	0.38	0.47
Odisha	0.21	0.37	0.17	0.23	0.11
Punjab	0.31	0.59	0.21	0.38	0.27
Rajasthan	0.38	0.26	0.37	0.01	0.47
Sikkim	0.00	0.00	0.08	0.00	0.00
Tamil Nadu	0.24	0.27	0.15	0.14	0.22
Telangana	0.16	0.10	0.08	0.00	0.07
Uttar Pradesh	0.39	0.34	0.20	0.08	0.36
Uttarakhand	0.24	0.50	0.30	0.30	0.29
West Bengal	0.67	0.96	0.22	0.43	0.31

Table A- 22. Seasonal Capacity Factors for ROR Plants

State	Autumn	Rainy	Spring	Summer	Winter
Arunachal Pradesh	0.42	0.76	0.10	0.40	0.14
Assam	0.58	0.73	0.14	0.39	0.23
Bihar	0.49	0.64	0.15	0.37	0.18
Chhattisgarh	0.25	0.35	0.16	0.14	0.19
Gujarat	0.14	0.33	0.07	0.03	0.10
Haryana	0.35	0.59	0.30	0.43	0.29
Himachal Pradesh	0.27	0.82	0.15	0.65	0.15
Jammu Kashmir	0.33	0.48	0.37	0.46	0.24
Jharkhand	0.49	0.64	0.15	0.37	0.18
Karnataka	0.31	0.35	0.12	0.17	0.17
Kerala	0.43	0.58	0.30	0.41	0.27
Madhya Pradesh	0.45	0.43	0.24	0.20	0.28
Maharashtra	0.17	0.28	0.18	0.18	0.19
Manipur	0.42	0.76	0.10	0.40	0.14
Meghalaya	0.26	0.78	0.06	0.41	0.05
Mizoram	0.42	0.76	0.10	0.40	0.14
Nagaland	0.42	0.76	0.10	0.40	0.14
Odisha	0.49	0.64	0.15	0.37	0.18
Punjab	0.56	0.69	0.57	0.48	0.57
Rajasthan	0.35	0.59	0.30	0.43	0.29
Sikkim	0.42	0.74	0.12	0.33	0.18
Tamil Nadu	0.22	0.17	0.13	0.13	0.13
Tripura	0.42	0.76	0.10	0.40	0.14
Uttar Pradesh	0.22	0.33	0.16	0.12	0.19
Uttarakhand	0.36	0.64	0.23	0.44	0.27
West Bengal	0.55	0.54	0.18	0.42	0.17

Table A- 23. Seasonal Capacity Factors for Pondage Plants

State	Autumn	Rainy	Spring	Summer	Winter
Andhra Pradesh	0.21	0.33	0.26	0.35	0.16
Arunachal Pradesh	0.23	0.60	0.12	0.28	0.11
Assam	0.58	0.85	0.21	0.56	0.24
Gujarat	0.41	0.43	0.33	0.16	0.44
Himachal Pradesh	0.22	0.68	0.15	0.49	0.12
Jammu Kashmir	0.33	0.66	0.39	0.66	0.21
Jharkhand	0.58	0.85	0.21	0.56	0.24
Karnataka	0.12	0.19	0.30	0.39	0.12
Kerala	0.30	0.47	0.22	0.30	0.20
Madhya Pradesh	0.40	0.39	0.26	0.19	0.35
Maharashtra	0.40	0.41	0.29	0.17	0.40
Meghalaya	0.58	0.85	0.21	0.56	0.24
Odisha	0.58	0.85	0.21	0.56	0.24
Punjab	0.29	0.83	0.27	0.67	0.17
Sikkim	0.69	0.93	0.28	0.63	0.32
Tamil Nadu	0.21	0.33	0.26	0.35	0.16
Telangana	0.21	0.33	0.26	0.35	0.16
Uttar Pradesh	0.36	0.74	0.17	0.54	0.23
Uttarakhand	0.24	0.62	0.15	0.41	0.15
West Bengal	0.46	0.76	0.15	0.49	0.16

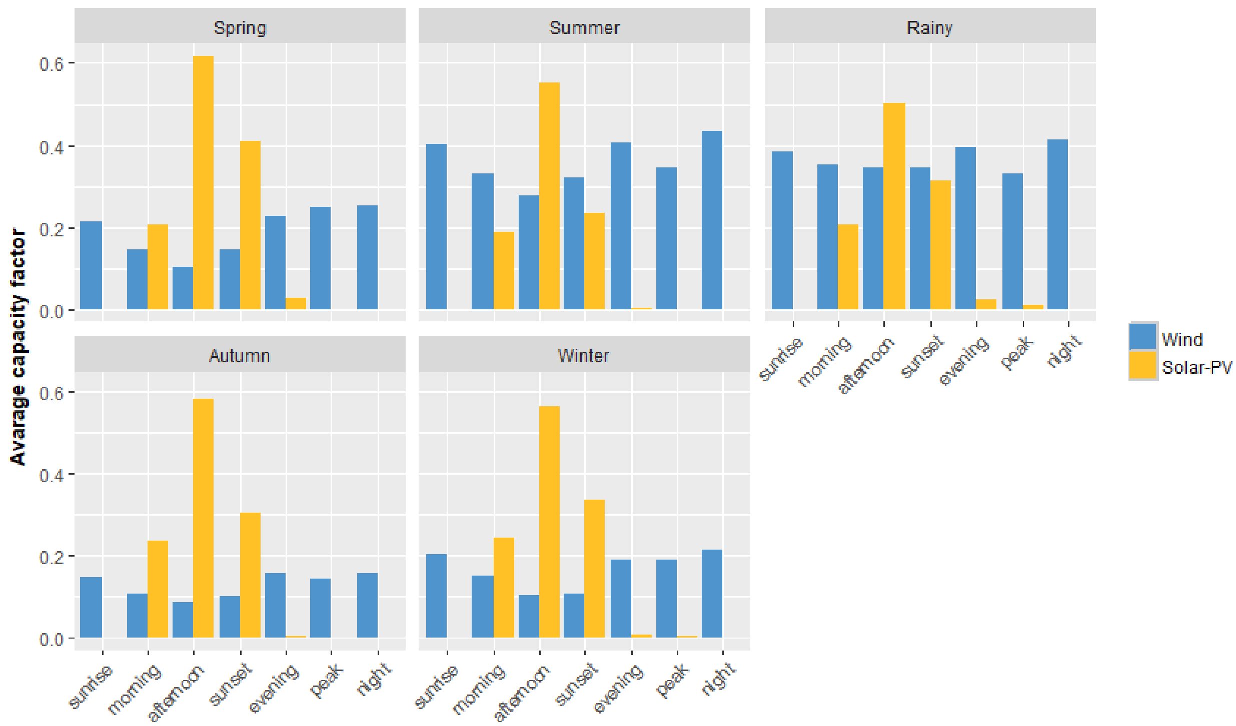
Table A- 24. Seasonal Capacity Factors for Pumped Storage Plants

State	Autumn	Rainy	Spring	Summer	Winter
Jharkhand	0.13	0.15	0.13	0.11	0.14
Karnataka	0.17	0.17	0.15	0.08	0.14
Kerala	0.17	0.17	0.15	0.08	0.14
Maharashtra	0.14	0.13	0.14	0.12	0.23
Odisha	0.13	0.15	0.13	0.11	0.14
Tamil Nadu	0.09	0.08	0.13	0.09	0.11
Telangana	0.04	0.05	0.04	0.01	0.04
West Bengal	0.13	0.15	0.13	0.11	0.14

RE Capacity Factor by Time Slice

Capacity factors for wind and solar technologies were estimated for each time slice based on the resource data for each resource region. The figures below show the average for each season and time slice; however, each resource region has a unique capacity factor when input to the model.

Table A- 25. National Average Capacity Factors for RE Technologies, by Season and Time Slice



Financial

Construction Schedule

The construction schedule is the percentage of the plant that is completed in each year of construction. The schedules were based on the CEA National Electricity Plan 2018 Annexure 11.2 "Assumptions For Estimating Capital Cost Of Power Projects" (pg. 11.5).

Table A- 26. Construction Schedules

Technology type	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Total
Coal	10%	10%	20%	30%	30%					100%
Hydro (pumped, storage)	20%	25%	25%	20%	10%					100%
Solar PV (Utility)	80%	20%								100%
Wind	60%	40%								100%
Biomass; Hydro (pondage, ROR)	30%	40%	30%							100%
Nuclear	3%	1%	4%	5%	10%	15%	21%	26%	15%	100%
Gas	40%	50%	10%							

For technologies not given in the CEA table, the following assumptions were used:

- Distributed PV (rooftop) and BESS: 1 year construction schedule
- Diesel and Subcritical-Oil: same construction schedule as gas technologies
- Waste Heat Recovery: same construction schedule as biomass
- Concentrated Solar Power: same construction schedule as solar PV (utility)

- Subcritical-Lignite: same construction schedule as coal.

Financial Parameters

Table A- 27. Financial Parameters

Financial Parameter	Value	Notes
Real Discount Rate	9%	CEA 2018 National Electricity Plan Table 5.6
Nominal Interest Rate	11.5%	CEA 2018 National Electricity Plan Table 5.6
Federal Tax Rate	34.6%	Based on corporate tax rate for 2015-2018 (https://tradingeconomics.com/india/corporate-tax-rate)
Inflation Rate	4.5%	Based on average inflation rate for 2015-2018 (https://tradingeconomics.com/india/inflation-cpi)
Debt Coverage Ratio	1.4	Based on U.S. ReEDS assumption
Initial Debt Fraction	70%	CEA 2018 National Electricity Plan Table 5.6
Financial Lifetime	Same as plant lifetime	Except for hydro technologies, which are given 100 year financial lifetime. This is based on the assumption used in U.S. ReEDS.
Depreciation Schedule	12 years for all technologies	CEA 2018 National Electricity Plan Table 5.6
Finance Period	Coal and nuclear: 20 years Pumped hydro: 30 years All other technologies: 15 years	Based on U.S. ReEDS assumptions

Appendix B. PCM Inputs

The PCMs developed by NREL in previous studies formed the basis of this study (D. Palchak et al. 2017; McBennett et al. 2019; Joshi, Hurlbut, and Palchak 2020). The assumptions remained the same for the base network in 2022, and the PCM is developed for future years based on publicly available data and certain assumptions discussed later. The assumptions regarding load projections and generation buildouts for all South Asian countries (including India) has been discussed in Sections 3.3 and 3.4, respectively. Considering the various uncertainties associated with commissioning of any new power plant, we have considered the new generators available from the next year of its expected commissioning year. This may lead to some differences between the generation capacity numbers mentioned in the various master plans of each country and the numbers considered in this study. Standard technical parameters have been used for future interconnections between South Asian countries based on the proposed conductor type wherever available The other assumptions used for building this PCM are given below.

ReEDS to PLEXOS and India PCM

We translated the output of ReEDs-India to PLEXOS for doing production cost analysis. While ReEDS-India outputs a continuous value of capacity, for most resources (excluding solar and wind), PLEXOS requires generators to be discrete units. The attributes for future buildouts (such as generator size, forced outage rate, mean time to repair, minimum stable level, VO&M charges, fuel charges, and transport charge) were assigned average value by state or region when possible and assigned country-wide historical average when state/regional data was unavailable or nonexistent. For transmission buildouts, we identified the largest existing transmission lines between states and replicated these lines when constructing new capacity for a given corridor. ReEDs-India also provided cumulative capacity by state/fuel/class for each year. We retired generators by construction date.

Load

Bhutan: The monthly average load shape for Bhutan was assumed similar to 2019 based on quarterly reports of Bhutan Power System Operator.

Bangladesh: The load shape for Bangladesh was assumed similar to 2018–2019.

Load: The load shape for Nepal was assumed based on our previous study ((McBennett et al. 2019).

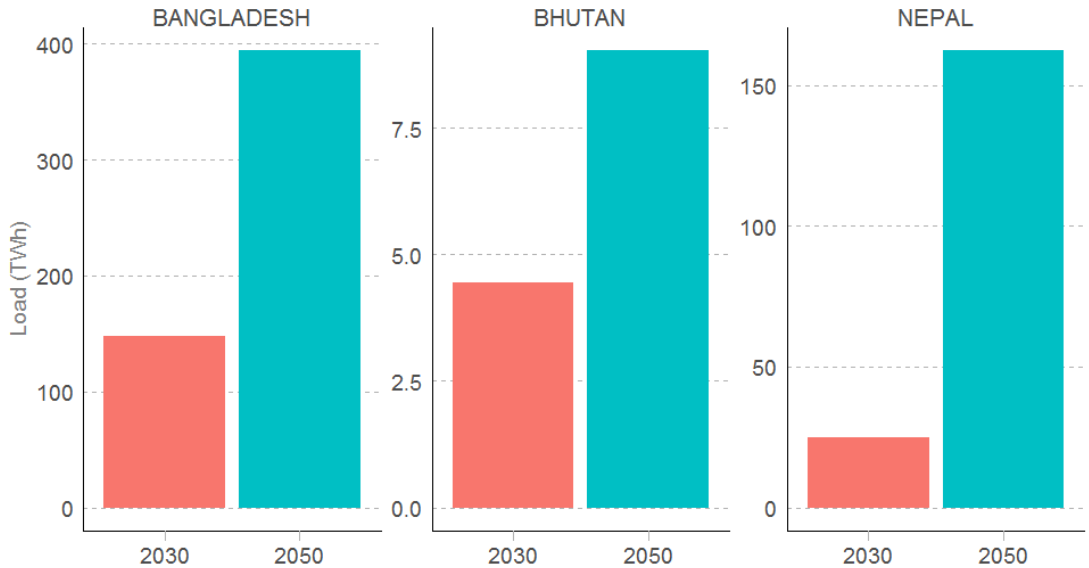


Figure B- 1. Electricity Demand in Bangladesh, Bhutan, and Nepal

Generation

Bhutan: We modeled all the existing generators of Bhutan and added future buildouts (transmission and generation) based on the transmission master plan of Bhutan. The technical attributes such as ramp rate, minimum stable level, etc., for existing and future generators have been assumed based on the similar generators from India. Because all of the existing generators are ROR type and there is no indication of any storage type generator in future plans, we have assumed future buildouts to be ROR type as well. All the generators are modeled with daily energy limits, minimum generation level, and maximum possible generation based on monthly average numbers provided in the 2019 quarterly reports published by Bhutan Power System Operator. For future generators, energy, minimum and maximum generation limits were assumed similar to the nearby existing generator in the same river basin. In the absence of any nearby existing generator, the average of whole Bhutan was assumed for that generator.

Bangladesh: The technical attributes (such as forced outage rate, mean time to repair, minimum stable level, ramp rate, etc.) of existing and future generators were based on the average of similar existing plants in India. Future buildouts were based on the power system master plan of Bangladesh. The variable charges of existing generators were assumed based on the annual report of Bangladesh Power Development Board for 2018–19. Considering the availability of domestic gas and share of imported gas in future, we used the following cost projections:

Table B- 1. Natural Gas Price Assumptions

Year	Simulated Price of Domestic Natural Gas ($/MMBTU)	Simulated Blended Price of Domestic Natural Gas and Imported Liquified Natural Gas, Assuming That Liquified Natural Gas Offsets Decreases in Domestic Production
2020	$1.43	$1.93
2021	$1.43	$1.93
2022	$1.43	$1.93
2023	$1.46	$2.06
2024	$2.03	$3.71
2025	$2.22	$4.12
2026	$2.43	$4.51
2027	$2.55	$4.73
2028	$2.82	$5.14
2029	$2.93	$5.28
2030	$3.01	$5.38
2031	$3.12	$5.51
2032	$3.18	$5.57
2033	$3.37	$5.77
2034	$3.41	$5.81
2035	$3.87	$6.16
2036	$3.92	$6.19
2037	$4.18	$6.33
2038	$4.29	$6.38
2039	$4.45	$6.44
2040	$4.45	$6.44

Source: Projections done by David Hurlbut, NREL

Variable charges of coal/diesel/fuel oil-based generators for the future were assumed based on the power system master plan of Bangladesh.

Nepal: The future projected generation capacity was assumed based on Nepal's Ministry of Energy's white paper and the transmission system development plan of Nepal. The total storage-based hydro capacity for 2040 was calculated based on individual proposed plants mentioned in the transmission system development plan of Nepal. All other hydro capacity was assumed to be ROR type. A linear growth was assumed for ROR and storage-based hydro based on existing and 2040 projected capacity, duly considering the total capacity projections.

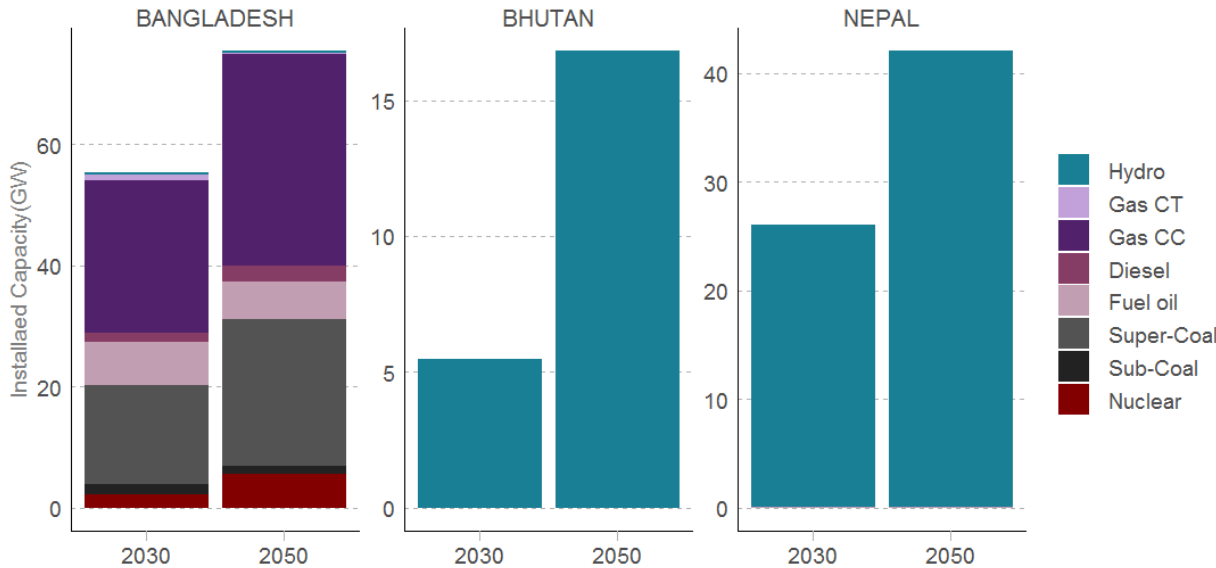


Figure B- 2. Installed Capacity in Bangladesh, Bhutan, and Nepal

Transmission

We have added the future interconnections between the South Asian countries based on various official plans mentioned in Section 3.4. The interconnection capacity between the South Asian countries in 2030 and 2050 scenario is given below:

Table B- 2. Transmission Capacity Between South Asian Countries

	2030	2050
India-Bhutan	6.6 GW	12.9 GW
India-Nepal	8.2 GW	14.7 GW
India-Bangladesh	3.5 GW	11 GW