4. Generating Resources

Existing, planned-committed, and potential are the three types of generating units modeled in EPA Platform v6. Electric generating units currently in operation are termed as existing units. Units that are anticipated to be in operation in the near future, for having broken ground or secured financing, are planned-committed units. Potential units refer to new generating options that IPM builds to meet industry capacity expansion projections. Existing and planned-committed units enter IPM as exogenous inputs, whereas potential units are endogenous to IPM in that the model determines the location and size of the potential units to build.

This chapter is organized as follows.

(1) Section 4.1 provides background information on the National Electric Energy Data System (NEEDS), the database that serves as the repository for information on existing and planned-committed electric generating units modeled,

(2) Section 4.2 provides detailed information on existing non-nuclear generating units,

(3) Section 4.3 provides detailed information on planned-committed units,

(4) Section 4.4 provides detailed information on potential units, and

(5) Section 4.5 describes assumptions pertaining to existing and potential nuclear units.

4.1 National Electric Energy Data System (NEEDS)

EPA Platform v6 uses the NEEDS v6 database as its source for data on all existing and planned-committed units. Section 4.2 discusses the sources used in developing data on existing units. The population of existing units in the NEEDS v6 represents electric generating units that were in operation through the end of 2017. Section 4.3 discusses the sources used in developing data on planned-committed units. The population of planned-committed includes units online or scheduled to come online from 2018 through June 30, 2021, with the exception of Vogtle nuclear units 3 and 4 that are scheduled to come online after 2021.

4.2 Existing Units

The sections below describe the procedures for determining the population of existing units in NEEDS v6, as well as the capacity, location, and configuration information of each unit in the population. Details are also given on the model plant aggregation scheme and associated cost and performance characteristics of the units.

4.2.1 Population of Existing Units

The October 2017 EIA Form 860M is the primary data source on existing units. Table 4-2 specifies the screening rules applied to the data source to ensure data consistency and adaptability for use in EPA Platform v6. Table 4-50 lists all units that are excluded from the NEEDS v6 population based on application of the screening rules.

Table 4-1 Data Sources for NEEDS v6 for EPA Platform v6

Data Source[1]	Data Source Documentation
EIA Form 860	EIA Form 860 is an annual survey of utility and non-utility power plants at the generator level. It contains data such as summer, winter, and nameplate capacity, location (state and county), operating status, prime mover, energy sources and in-service date of existing and proposed generators. NEEDS v6 uses the annual 2015 EIA Form 860, annual 2016 Early Release EIA Form 860, 2017 Early Release EIA Form 860, May 2017 EIA Form 860M, October 2017 EIA Form 860M and the July 2018 EIA Form 860M as the primary generator data inputs. EIA Form 860 also collects data of steam boilers such as energy sources, boiler identification, location, operating status and design information; and associated environmental equipment such as NO_x combustion and post-combustion controls, FGD scrubber, mercury control and particulate collector device information. Note that boilers in plants with less than 10 MW do not report all data elements. The association between boilers and generators is also provided. Note that boilers and generators are not necessarily in a one-to-one correspondence. NEEDS v6 uses 2015 EIA Form 860 and 2016 Early Release EIA Form 860 as the primary boiler data inputs.
EIA's Annual Energy Outlook (AEO)	The Energy Information Administration (EIA) Annual Energy Outlook presents annually updated forecasts of energy supply, demand and prices covering a 30-year time horizon. The projections are based on results from EIA's National Energy Modeling System (NEMS). Information from AEO 2017 such as heat rates and planned-committed units were used in NEEDS v6.
EPA's Emission Tracking System	The Emission Tracking System (ETS) database is updated quarterly. It contains information including primary fuel, heat input, SO_2, NO_x, Mercury, and HCl controls, and SO_2 and NO_x emissions. NEEDS v6 uses annual and seasonal ETS (2017) data as one of the primary data inputs for NO_x rate development and environmental equipment assignment.
Utility and Regional EPA Office Comments	Comments from utilities, regional EPA offices and other stakeholders regarding the prior versions of NEEDS.

Note:
[1] Shown in Table 4-1 are the primary issue dates of the indicated data sources used. Other vintages of these data sources were also used in instances where data were not available for the indicated issued date, or where there were methodological reasons for using other vintages of the data.

Table 4-2 Rules Used in Populating NEEDS v6 for EPA Platform v6

Scope	Rule
Capacity	Excluded units with reported summer capacity, winter capacity and nameplate capacity of zero or blank.
Status	Excluded units that were out of service for three consecutive years (i.e., generators or boilers with status codes "OS" or "OA" in the latest three reporting years) and units that were no longer in service and not expected to be returned to service (i.e., generators or boilers with status codes of "RE"). Status of boiler(s) and associated generator(s) were taken into account for determining operation status
Planned or Committed Units	Included planned units that had broken ground or secured financing and were expected to be online by June 30, 2021; two nuclear units that are scheduled to come online after 2021 were also included
Firm/Non-firm Electric Sales	Excluded non-utility onsite generators that do not produce electricity for sale to the grid on a net basis Excluded all mobile and distributed generators

Note:

The two nuclear units are Vogtle, units 3&4

The NEEDS v6 includes steam units at the boiler level and non-steam units at the generator level (nuclear units are also at the generator level). A unit in NEEDS v6, therefore refers to a boiler in the case of a steam unit and a generator in the case of a non-steam unit. Table 4-3 provides a summary of the population and capacity of the existing units included in NEEDS v6 through 2017. The final population of existing units is supplemented based on information from other sources, including comments from utilities, submissions to EPA's Emission Tracking System, Annual Energy Outlook and other research.

EPA Platform v6 removes units from the NEEDS inventory based on public announcements of future closures. The removal of such units pre-empts IPM from making any further decisions regarding the operational status or configuration of the units. The units considered for removal from NEEDS are identified from reviewing several data sources including:

1. EIA Electric Generator Capacity data (EIA Form 860M), July 2018 release
2. PJM Future Deactivation Requests and PJM Generator Deactivations, July 2018 (updated frequently)
3. ERCOT Generator Interconnection Status Report, July 2018 (updated frequently)
4. MISO Generation Interconnection Queue, July 2018 (updated frequently)
5. Research by EPA and ICF staff

Units are removed from the NEEDS inventory only if a high degree of certainty could be assigned to future implementation of the announced action. The available retirement-related information was reviewed for each unit, and the following rules are applied to remove:

1. Units that are listed as retired in the July 2018 EIA Form 860M
2. Units with a planned retirement year prior to June 30, 2021 in July 2018 EIA Form 860M
3. Units that have been cleared by a regional transmission operator (RTO) or independent system operator (ISO) to retire before 2021, or whose RTO/ISO clearance to retire is contingent on actions that can be completed before 2021
4. Units that have committed specifically to retire before 2021 under federal or state enforcement actions or regulatory requirements
5. And finally, units for which a retirement announcement can be corroborated by other available information.

Units required to retire pursuant to enforcement actions or state rules in 2022 or later are retained in NEEDS v6. Such 2022-or-later retirements are captured as constraints on those units in IPM modeling, and the units are retired in future year projections per the terms of the related requirements. Table 4-50 and Table 4-51 list all units that are removed from the NEEDS v6 inventory.

Table 4-3 Summary Population (through 2017) of Existing Units in NEEDS v6

Plant Type	Number of Units	Capacity (MW)
Biomass	186	3,876
Coal Steam	593	226,339
Combined Cycle	1,837	246,866
Combustion Turbine	5,381	143,285
Energy Storage	81	659
Fossil Waste	81	1,049
Fuel Cell	72	130
Geothermal	164	2,396
Hydro	3,805	79,186
IGCC	5	815
Landfill Gas	1,576	1,913
Municipal Solid Waste	165	2,123
Non-Fossil Waste	216	2,027
Nuclear	90	92,260

Plant Type	Number of Units	Capacity (MW)
O/G Steam	443	74,999
Offshore Wind	1	29
Onshore Wind	1,185	87,185
Pumped Storage	148	22,196
Solar PV	2,452	24,144
Solar Thermal	16	1,754
Tires	2	52
US Total	**18,499**	**1,013,283**

4.2.2 Capacity

The unit capacity data implemented in NEEDS v6 reflects net summer dependable capacity[31]. Table 4-4 summarizes the hierarchy of data sources used in compiling capacity data. In other words, capacity values are taken from a particular source only if the sources listed above it do not provide adequate data for the unit in question.[32]

Table 4-4 Hierarchy of Data Sources for Capacity in NEEDS v6

Sources Presented in Hierarchy
Net Summer Capacity from Comments / ICF Research
July 2018 EIA Form 860M Net Summer Capacity
October 2017 EIA Form 860M Net Summer Capacity
May 2017 EIA Form 860M Net Summer Capacity
2015 EIA Form 860 Net Summer Capacity

Notes:

If the capacity of a unit is zero MW, the unit is excluded from NEEDS population.

As noted earlier, NEEDS v6 includes boiler-level data for steam units and generator-level data for non-steam units. Capacity data in EIA Form 860 are generator-specific, not boiler-specific. Therefore, it was necessary to develop an algorithm for parsing generator-level capacity to the boiler level for steam producing units.

The capacity-parsing algorithm used for steam units in NEEDS v6 took into account boiler-generator mapping. Fossil steam electric units have boilers attached to generators that produce electricity. There are generally four types of links between boilers and generators: one boiler to one generator, one boiler to many generators, many boilers to one generator and many boilers to many generators.

The capacity-parsing algorithm used for steam units in NEEDS v6 utilizes steam flow data with the boiler-generator mapping. Under EIA Form 860, steam units report the maximum steam flow from the boiler to the generator. There is, however, no further data on the steam flow of each boiler-generator link. Instead, EIA Form 860 contains only the maximum steam flow for each boiler. Table 4-5 summarizes the algorithm used for parsing capacity with data on maximum steam flow and boiler-generator mapping. In Table 4-5, MFB_i refers to the maximum steam flow of boiler i and MW_{Gj} refers to the capacity of generator j. The algorithm uses the available data to derive the capacity of a boiler, referred to as MW_{Bj} in Table 4-5.

[31] As used here, net summer dependable capacity is the net capability of a generating unit in megawatts (MW) for daily planning and operation purposes during the summer peak season, after accounting for station or auxiliary services.

[32] EIA Form 860M (July, 2018 release) was the most recent data available at the time when NEEDS v6 was finalized.

Table 4-5 Capacity-Parsing Algorithm for Steam Units in NEEDS v6

	Type of Boiler-Generator Links			
For Boiler B1 to BN linked to Generators G1 to GN	One-to-One	One-to-Many	Many-to-One	Many-to-Many
	MWBi = MWGj	MWBi = ΣjMWGj	MWBi = (MFBi / ΣiMFBi) * MWGj	MWBi = (MFBi / ΣiMFBi) * ΣjMWGj

Notes:
MF_{Bi} = maximum steam flow of boiler *i*
MW_{Gj} = electric generation capacity of generator *j*

Since EPA Platform v6 uses net energy for load as demand, the NEEDS includes only generators that sell the majority of their power to the electric grid. The approach is intended to be broadly consistent with the generating capacity used in the AEO projections where demand is net energy for load. The generators that should be in NEEDS v6 by this qualification are determined from the 2014 EIA Form 923 non-utility source and disposition data set.

4.2.3 Plant Location

The physical location of each unit in NEEDS is represented by the unit's model region, state, and county data.

State and County

NEEDS v6 uses the state and county data from October 2017 EIA Form 860M.

Model Region

For each unit, the associated model region was derived based on NERC assessment regions reported in EIA Form 860 and ISO/RTO reports. For units with no NERC assessment region data, state and county data were used to derive associated model regions. Table 3-1 in Chapter 3 provides a summary of the mapping between NERC assessment regions and EPA Platform v6 model regions.

4.2.4 Online Year

The EPA Platform v6 uses online year to capture when a unit entered service. NEEDS includes online years for all units in the population. Online years for boilers were from 2015 EIA Form 860, and online years for generators were derived primarily from reported in-service dates in May 2017 version of EIA Form 860M.

EPA Platform v6 includes constraints to set the retirement year for generating units that are firmly committed to retiring after June 30, 2021 based on state or federal regulations and enforcement actions. In addition, existing nuclear units must retire when they reach age 80. (See section 3.7 for a discussion of the nuclear lifetime assumption.) Economic retirement options are also provided to coal, oil and gas steam, combined cycle, combustion turbines, biomass, and nuclear units to allow the model the option to retire a unit if it finds economical to do so. In IPM, a retired unit ceases to incur FOM and VOM costs. The unit, however, continues to make annualized capital cost payment on any previously incurred capital cost for model-installed retrofits projected prior to retirement.

4.2.5 Unit Configuration

Unit configuration refers to the physical specification of a unit's design. Unit configuration in EPA Platform v6 drives model plant aggregation and modeling of pollution control options and mercury emission modification factors. NEEDS v6 contains for each unit, data on the firing and bottom type, as well as existing and committed emission controls the unit has. Table 4-6 shows the hierarchy of data sources used in determining a unit configuration. The sources listed below are also supplemented by recent ICF and EPA research to ensure the unit configuration data in NEEDS is the most comprehensive and up-to-date possible.

Table 4-6 Data Sources for Unit Configuration in NEEDS v6

Unit Component	Primary Data Source	Secondary Data Source	Tertiary Data Source	Other Sources	Default
Firing Type	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	--	--	--
Bottom Type	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	--	--	Dry
SO_2 Pollution Control	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	NSR Settlement or Comments	--	No Control
NO_x Pollution Control	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	NSR Settlement or Comments	--	No Control
Particulate Matter Control	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	NSR Settlement or Comments	--	--
Mercury Control	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	NSR Settlement or Comments	--	--
HCL Control	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	NSR Settlement or Comments	--	--

4.2.6 Model Plant Aggregation

While EPA Platform v6 using IPM is comprehensive in representing all the units contained in NEEDS v6, an aggregation scheme is used to combine existing units with similar characteristics into model plants. The aggregation scheme serves to reduce the size of the model, making the model manageable while capturing the essential characteristics of the generating units. The aggregation scheme is designed so that each model plant represents only generating units from a single state. The design makes it possible to obtain state-level results directly from IPM outputs. In addition, the aggregation scheme supports the modeling of plant-level emission limits on fossil generation.

The aggregation scheme encompasses a variety of different classification categories including location, size, technology, heat rate, fuel choices, unit configuration, SO_2 emission rates, and environmental regulations among others. Units are aggregated together only if they match on all the different categories specified for the aggregation. The 11 major categories used for the aggregation scheme in EPA Platform v6 are the following.

(1) Model Region

(2) Unit Technology Type

(3) Cogen

(4) Fuel Demand Region

(5) Applicable Environmental Regulations

(6) State

(7) Facility (ORIS) for fossil units

(8) Unit Configuration

(9) Heat Rates

(10) Fuel

(11) Size

Table 4-7 shows the number of actual units by generation technology type and the related number of aggregated model plants in the EPA Platform v6. For each plant type, the table shows the number of generating units and the number of model plants representing the generating units.[33]

Table 4-7 Aggregation Profile of Model Plants as Provided at Set up of EPA Platform v6

Existing and Planned/Committed Units		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Biomass	300	165
Coal Steam	675	527
Combined Cycle	2,032	891
Combustion Turbine	5,988	2,535
Energy Storage	85	41
Fossil Waste	86	25
Fuel Cell	72	35
Geothermal	174	31
Hydro	5,455	252
IGCC	5	2
IMPORT	1	1
Landfill Gas	1,643	307
Municipal Solid Waste	166	60
Non-Fossil Waste	267	140
Nuclear	115	115
O/G Steam	590	399
Offshore Wind	1	1
Onshore Wind	1,570	89
Pumped Storage	155	27
Solar PV	2,532	98
Solar Thermal	17	5
Tires	2	1
Total	**21,931**	**5,747**

New Units	
Plant Type	**Number of IPM Model Plants**
New Battery Storage	168
New Biomass	134

[33] (1) The "Number of IPM Model Plants" shown for many of the "Plant Types" in the "Retrofits" block in Table 4-7 exceeds the "Number of IPM Model Plants" shown for "Plant Type" "Coal Steam" in the block labeled "Existing and Planned - Committed Units", because a particular retrofit "Plant Type" can include multiple technology options and multiple timing options (e.g., Technology A in Stage 1 + Technology B in Stage 2 + Technology C in Stage 3, the reverse timing, or multiple technologies simultaneously in Stage 1).

(2) Since only a subset of coal plants is eligible for certain retrofits, many of the "Plant Types" in the "Retrofits" block that represent only a single retrofit technology (e.g., "Retrofit Coal with SNCR") have a "Number of IPM Model Plants" that is a smaller than the "Number of IPM Model Plants" shown for "Plant Type" "Coal Steam".

(3) The total number of model plants representing different types of new units often exceeds the 67 U.S. model regions and varies from technology to technology for several reasons. First, some technologies have multiple vintages (i.e., different cost and/or performance parameters depending on which run-year in which the unit is created), which must be represented by separate model plants in each IPM region. Second, some technologies are not available in particular regions (e.g., geothermal is geographically restricted to certain regions).

New Combined Cycle	456
New Combined Cycle with Carbon Capture	228
New Combustion Turbine	456
New Fuel Cell	150
New Geothermal	93
New Hydro	153
New Landfill Gas	379
New Nuclear	132
New Offshore Wind	894
New Onshore Wind	5,358
New Solar PV	1,373
New Solar Thermal	261
New Ultrasupercritical Coal with 30% CCS	266
New Ultrasupercritical Coal with 90% CCS	266
New Ultrasupercritical Coal without CCS	138
Total	**10,905**
Retrofits	
Plant Type	**Number of IPM Model Plants**
Retrofit Coal with ACI	74
Retrofit Coal with ACI + CCS	92
Retrofit Coal with ACI + CCS + HRI	92
Retrofit Coal with ACI + CCS + HRI + SCR	20
Retrofit Coal with ACI + CCS + HRI + SNCR	29
Retrofit Coal with ACI + CCS + SCR	20
Retrofit Coal with ACI + DSI	20
Retrofit Coal with ACI + DSI + HRI	20
Retrofit Coal with ACI + DSI + HRI + SCR	31
Retrofit Coal with ACI + DSI + HRI + SCR + Scrubber	22
Retrofit Coal with ACI + DSI + HRI + Scrubber	18
Retrofit Coal with ACI + DSI + HRI + Scrubber + SNCR	14
Retrofit Coal with ACI + DSI + HRI + SNCR	27
Retrofit Coal with ACI + DSI + SCR	31
Retrofit Coal with ACI + DSI + SCR + Scrubber	22
Retrofit Coal with ACI + DSI + Scrubber	18
Retrofit Coal with ACI + DSI + Scrubber + SNCR	14
Retrofit Coal with ACI + DSI + SNCR	31
Retrofit Coal with ACI + HRI	74
Retrofit Coal with ACI + HRI + SCR	62
Retrofit Coal with ACI + HRI + SCR + Scrubber	62
Retrofit Coal with ACI + HRI + Scrubber	53
Retrofit Coal with ACI + HRI + Scrubber + SNCR	74
Retrofit Coal with ACI + HRI + SNCR	61
Retrofit Coal with ACI + SCR	62
Retrofit Coal with ACI + SCR + Scrubber	62
Retrofit Coal with ACI + Scrubber	52

Retrofit Coal with ACI + Scrubber + SNCR	75
Retrofit Coal with ACI + SNCR	62
Retrofit Coal with C2G	454
Retrofit Coal with C2G + SCR	454
Retrofit Coal with CCS	791
Retrofit Coal with CCS + HRI	788
Retrofit Coal with CCS + HRI + SCR	252
Retrofit Coal with CCS + HRI + SCR + Scrubber	208
Retrofit Coal with CCS + HRI + Scrubber	232
Retrofit Coal with CCS + HRI + Scrubber + SNCR	152
Retrofit Coal with CCS + HRI + SNCR	180
Retrofit Coal with CCS + SCR	255
Retrofit Coal with CCS + SCR + Scrubber	212
Retrofit Coal with CCS + Scrubber	240
Retrofit Coal with CCS + Scrubber + SNCR	156
Retrofit Coal with CCS + SNCR	183
Retrofit Coal with DSI	21
Retrofit Coal with DSI + HRI	70
Retrofit Coal with DSI + HRI + SCR	75
Retrofit Coal with DSI + HRI + SCR + Scrubber	21
Retrofit Coal with DSI + HRI + Scrubber	26
Retrofit Coal with DSI + HRI + SNCR	69
Retrofit Coal with DSI + SCR	109
Retrofit Coal with DSI + SCR + Scrubber	33
Retrofit Coal with DSI + Scrubber	38
Retrofit Coal with DSI + SNCR	103
Retrofit Coal with HRI	482
Retrofit Coal with HRI + SCR	432
Retrofit Coal with HRI + SCR + Scrubber	450
Retrofit Coal with HRI + Scrubber	357
Retrofit Coal with HRI + Scrubber + SNCR	408
Retrofit Coal with HRI + SNCR	342
Retrofit Coal with SCR	242
Retrofit Coal with SCR + Scrubber	582
Retrofit Coal with Scrubber	224
Retrofit Coal with Scrubber + SNCR	544
Retrofit Coal with SNCR	203
Retrofit Combined Cycle with CCS	2787
Retrofit Oil/Gas steam with SCR	222
Total	**13,691**
Retirements	
Plant Type	**Number of IPM Model Plants**
Biomass Retirement	165
CC Retirement	891
Coal Retirement	5,394

CT Retirement	2,535
Geothermal Retirement	31
Hydro Retirement	252
IGCC Retirement	2
Landfill Gas Retirement	307
Nuke Retirement	115
Oil/Gas steam Retirement	1,075
Total	**10,767**
Grand Total (Existing and Planned/Committed + New + Retrofits + Retirements):41,110	

4.2.7 Cost and Performance Characteristics of Existing Units[34]

In EPA Platform v6, the cost and performance characteristics of an existing unit are determined by the unit's heat rates, emission rates, variable operation and maintenance cost (VOM), and fixed operation and maintenance costs (FOM). For existing units, only the cost of maintaining (FOM) and running (VOM) the unit are modeled because capital costs and all related carrying capital charges are sunk, and hence, economically irrelevant for projecting least-cost investment and operational decisions going forward. The section below discusses the cost and performance assumptions for existing units used in the EPA Platform v6.

Variable Operating and Maintenance Cost (VOM)

VOM represents the non-fuel variable cost associated with producing electricity. If the generating unit contains pollution control equipment, VOM includes the cost of operating the control equipment. Table 4-8 below summarizes VOM assumptions used in EPA Platform v6. The following further discusses the components of VOM costs and the VOM modeling methodology.

Variable O&M Approach: EPA Platform v6 uses a modeling construct termed as Segmental VOM to capture the variability in operation and maintenance costs that are treated as a function of the unit's dispatch pattern. Generally speaking the construct captures costs associated with major maintenance and consumables. The VOM for combined cycles and combustion turbine units includes the costs of both major maintenance and consumables while for coal steam and oil/gas steam units includes only the cost of consumables. The VOM cost of various emission control technologies is also incorporated.

Major maintenance: Major maintenance costs are those required to maintain a unit at its delivered performance specifications and whose terms are usually dictated through its long term service agreement (LTSA). The three main areas of maintenance for gas turbines include combustion inspection, hot gas path inspection, and major inspections. All of these costs are driven by the hours of operation and the number of starts that are incurred within that time period of operation. In a cycling or mid-merit type mode of operation, there are many starts, accelerating the approach of an inspection. As more starts are incurred compared to the generation produced, cost per generation increase. For base load operation there are fewer starts spread over more generation, lowering the cost per generation. While this nomenclature is for gas-turbine based systems, steam turbine based systems have a parallel construct.

Consumables: The model captures consumable costs, as purely a function of output and does not varies across the segmented time-period. In other words, the consumables cost component is held constant over both peak and off-peak segments. Consumables include chemicals, lube oils, make-up water, waste water disposal, reagents, and purchased electricity.

[34] All units excluding nuclear units.

Data Sources for Gas-Turbine Based Prime Movers:
ICF has engaged its deep expertise in operation & maintenance costs for these types of prime movers to develop generic variable O&M costs as a function of technology.

As mentioned above the variable O&M for gas-turbine based systems tracks Long Term Service Agreement costs, start-up and consumables.

Data Sources for Stand-Alone Steam Turbine Based Prime Movers:
The value levels of non-fuel variable O&M data for stand-alone steam turbine plants is based on ICF experience. The VOM cost adders of various emission control technologies are based on cost functions described in Chapter 5.

Table 4-8 VOM Assumptions in EPA Platform v6

Capacity Type	SO_2 Control	NO_x Control	Hg Control	Variable O&M (2016$/mills/kWh)
Biomass	--	--	--	7.29
Coal Steam	No SO_2 Control	No NO_x Control	No Hg Control	1.43
			ACI	2.90
		SCR	No Hg Control	2.39
			ACI	3.86
		SNCR	No Hg Control	2.36
			ACI	3.83
	Dry FGD	No NO_x Control	No Hg Control	3.5
			ACI	4.97
		SCR	No Hg Control	4.46
			ACI	5.93
		SNCR	No Hg Control	4.43
			ACI	5.9
	Wet FGD	No NO_x Control	No Hg Control	3.95
			ACI	5.43
		SCR	No Hg Control	4.91
			ACI	6.39
		SNCR	No Hg Control	4.88
			ACI	6.35
	DSI	No NO_x Control	No Hg Control	8.21
			ACI	9.68
		SCR	No Hg Control	9.17
			ACI	10.64
		SNCR	No Hg Control	9.14
			ACI	10.61
Combined Cycle	No SO_2 Control	No NO_x Control	No Hg Control	1.98 - 3.78
		SCR		2.12 - 3.92
		SNCR		2.61 - 4.41
Combustion Turbine	No SO_2 Control	No NO_x Control	No Hg Control	3.31 - 15.7
		SCR		3.45 - 15.84
		SNCR		3.94 - 16.33

Capacity Type	SO_2 Control	NO_x Control	Hg Control	Variable O&M (2016$/mills/kWh)
Fuel Cell	--	--	--	44.91
Geothermal	--	--	--	5.49
Hydro	--	--	--	2.66
IGCC	--	--	--	2.28-4.04
Landfill Gas / Municipal Solid Waste	--	--	--	6.54
Oil/gas Steam	No SO_2 Control	No NO_x Control	No Hg Control	0.83
		SCR		0.97
		SNCR		1.46
Pumped Storage	--	--	--	10.17
Solar PV	--	--	--	0
Solar Thermal	--	--	--	0
Wind	--	--	--	0

Fixed Operation and Maintenance Cost (FOM)

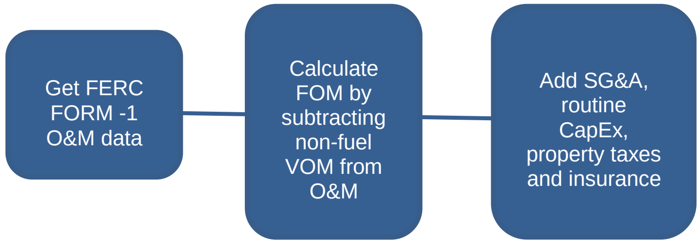
FOM represents the annual fixed cost of maintaining a unit. FOM costs are incurred independent of generation levels and signify the fixed cost of operating and maintaining the unit's availability to provide generation. Table 4-9 summarizes the FOM assumptions[35]. Note that FOM varies by the age of the unit, and the total FOM cost incurred by a unit depends on its capacity size. The values appearing in this table include the cost of maintaining any associated pollution control equipment. The values in Table 4-9 are based on FERC (Federal Energy Regulatory Commission) Form 1 data maintained by SNL and ICF research. The following further discusses the procedure for developing the FOM costs.

Stand Alone – Steam Turbines Based Prime Movers

O&M cost data for existing coal and oil/gas steam units were developed starting with FERC Form 1 data sets from the years 2011 to 2016. The FERC Form-1 database does not explicitly report separate fixed and variable O&M expenses. In deriving Fixed O&M costs, generic variable O&M costs are assigned to each individual power plant. Next, the assumed variable O&M cost is subtracted from the total O&M reported by FERC Form-1 to calculate a starting point for fixed O&M. Thereafter, other cost items which are not reported by FERC Form-1 are added to the raw FOM starting point. These unreported cost items are selling, general, and administrative expenses (SG&A), property taxes, insurance, and routine capex. A detailed description of the fixed O&M derivation methodology is provided below.

[35] Cogen units whose primary purpose is to provide process heat are called as bottoming cycle units and are identified based on Form EIA 860. Such units are provided a FOM of zero in EPA Platform v6. This is to acknowledge the fact that the economics of such a unit cannot be comprehensively modeled in a power sector focused model.

Figure 4-1 Derivation of Plant Fixed O&M Data



i) Assign generic VOM cost to each unit in FERC Form 1 based on the control configuration. Subtract this VOM from the total O&M cost from FERC Form 1 to calculate raw FOM cost. The FOM cost of operating the existing controls is estimated based on cost functions in Chapter 5 and deducted from the raw FOM cost. Aggregate this unit level raw FOM cost data into age based categories. The weighted average raw FOM costs for uncontrolled units by age group is the output of this step and is used as the starting point for subsequent steps.

ii) An owner/operator fee for SG&A services in the range of 20-30% is added to raw fixed O&M figures in step 1.

iii) Property tax and insurance cost estimates in $/kW-year are also added. These figures vary by plant type.

iv) A generic percentage value to cover routine capex is added to raw fixed O&M figures in step 1. The percentage varies by prime mover and is based on a review of FERC Form 1 data

v) Finally, generic FOM cost adders for various emission control technologies are estimated using cost functions described in Chapter 5. Based on the emission control configuration of each unit in NEEDS, the appropriate emission control cost adder is added to the FOM cost of an uncontrolled unit from step iv.

The fixed O&M derivation approach relies on top-down derivation of fixed costs based on FERC Form-1 data and ICF's own non-fuel variable O&M, SG&A, routine capex, property tax, and insurance.

<u>Gas-Turbine Based Prime Movers</u>

Similar to the stand-alone steam turbine based prime movers, the Fixed O&M for gas-turbine based systems tracks: labor, routine maintenance, property taxes, insurance, owner/operator SG&A, and routine capital expenditures. These generic Fixed O&M costs as a function of technology are based on ICF's deep expertise in fixed O&M costs for these types of prime movers

Table 4-9 FOM Assumptions in EPA Platform v6

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2016$ /kW-Yr)
Biomass	--	--	--	All Years	134.52
Coal Steam	No SO_2 Control	No NO_x Control	No Hg Control	0 to 40 Years	28.34
				40 to 50 Years	32.4
				Greater than 50 Years	41.63
			ACI	0 to 40 Years	28.42
				40 to 50 Years	32.49
				Greater than 50 Years	41.72
		SCR	No Hg Control	0 to 40 Years	29.12
				40 to 50 Years	33.18
				Greater than 50 Years	42.41
			ACI	0 to 40 Years	29.2
				40 to 50 Years	33.27

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2016$ /kW-Yr)
				Greater than 50 Years	42.5
		SNCR	No Hg Control	0 to 40 Years	28.62
				40 to 50 Years	32.69
				Greater than 50 Years	41.92
			ACI	0 to 40 Years	28.71
				40 to 50 Years	32.77
				Greater than 50 Years	42
	Dry FGD	No NO_x Control	No Hg Control	0 to 40 Years	38
				40 to 50 Years	42.06
				Greater than 50 Years	51.29
			ACI	0 to 40 Years	38.08
				40 to 50 Years	42.15
				Greater than 50 Years	51.38
		SCR	No Hg Control	0 to 40 Years	38.78
				40 to 50 Years	42.84
				Greater than 50 Years	52.07
			ACI	0 to 40 Years	38.86
				40 to 50 Years	42.93
				Greater than 50 Years	52.16
		SNCR	No Hg Control	0 to 40 Years	38.28
				40 to 50 Years	42.35
				Greater than 50 Years	51.58
			ACI	0 to 40 Years	38.36
				40 to 50 Years	42.43
				Greater than 50 Years	51.66
	Wet FGD	No NO_x Control	No Hg Control	0 to 40 Years	37.59
				40 to 50 Years	41.66
				Greater than 50 Years	50.89
			ACI	0 to 40 Years	37.68
				40 to 50 Years	41.75
				Greater than 50 Years	50.97
		SCR	No Hg Control	0 to 40 Years	38.37
				40 to 50 Years	42.44
				Greater than 50 Years	51.67
			ACI	0 to 40 Years	38.46
				40 to 50 Years	42.53
				Greater than 50 Years	51.75
		SNCR	No Hg Control	0 to 40 Years	37.88
				40 to 50 Years	41.95
				Greater than 50 Years	51.17
			ACI	0 to 40 Years	37.96
				40 to 50 Years	42.03
				Greater than 50 Years	51.26
	DSI	No NO_x Control	No Hg Control	0 to 40 Years	29.7
				40 to 50 Years	33.77
				Greater than 50 Years	43
			ACI	0 to 40 Years	29.78
				40 to 50 Years	33.85
				Greater than 50 Years	43.08

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2016$ /kW-Yr)
		SCR	No Hg Control	0 to 40 Years	30.48
				40 to 50 Years	34.55
				Greater than 50 Years	43.78
			ACI	0 to 40 Years	30.57
				40 to 50 Years	34.63
				Greater than 50 Years	43.86
		SNCR	No Hg Control	0 to 40 Years	29.98
				40 to 50 Years	34.05
				Greater than 50 Years	43.28
			ACI	0 to 40 Years	30.07
				40 to 50 Years	34.14
				Greater than 50 Years	43.37
Combined Cycle	No SO_2 Control	No NO_x Control	No Hg Control	-	29.19
		SCR	No Hg Control	-	30.54
		SNCR	No Hg Control	-	29.89
Combustion Turbine	No SO_2 Control	No NO_x Control	No Hg Control	-	18.7
		SCR	No Hg Control	-	20.72
		SNCR	No Hg Control	-	19.23
Fuel Cell	--	--	--	All Years	0
Geothermal	--	--	--	All Years	93.51
Hydro	--	--	--	All Years	14.89
IGCC	No SO_2 Control	No NO_x Control	--	All Years	102.34
Landfill Gas / Municipal Solid Waste	--	--	--	All Years	234.69
Oil/gas Steam	No SO_2 Control	No NO_x Control	No Hg Control	0 to 40 Years	16.94
				40 to 50 Years	25.72
				Greater than 50 Years	33.51
		SCR	No Hg Control	0 to 40 Years	18.05
				40 to 50 Years	26.84
				Greater than 50 Years	34.62
		SNCR	No Hg Control	0 to 40 Years	17.15
				40 to 50 Years	25.93
				Greater than 50 Years	33.72
Pumped Storage	--	--	--	All Years	17.27
Solar PV	--	--	--	All Years	27.99
Solar Thermal	--	--	--	All Years	77.93
Wind	--	--	--	All Years	28.18

Heat Rates

Heat Rates describe the efficiency of the unit expressed as BTUs per kWh. The treatment of heat rates is discussed in Section 3.8.

Lifetimes

Unit lifetime assumptions are detailed in Sections 3.7 and 4.2.8.

SO_2 Rates

Section 3.9.1 contains a detailed discussion of SO_2 rates for existing units.

NO_x Rates

Section 3.9.2 contains a detailed discussion of NO_x rates for existing units.

Mercury Emission Modification Factors (EMF)

Mercury EMF refers to the ratio of mercury emissions (mercury outlet) to the mercury content of the fuel (mercury inlet). Section 5.4.2 contains a detailed discussion of the EMF assumptions in EPA Platform v6.

Cogeneration Units

For cogeneration units, the dispatch decisions in IPM are only based on the benefits obtained from the electric portion of a cogeneration unit. In IPM, a cogeneration unit uses a net heat rate, which is calculated by dividing heat content of fuel consumed for power generation by electricity generated from this fuel. To capture the total emissions from the cogeneration unit, a multiplier is applied to the power only emissions. The multiplier is calculated as a ratio between the total heat rate and the net heat rate where the total heat rate is calculated by dividing the heat content of fuel consumed for power and steam generation by electricity generated from this fuel.

Coal Switching

Recognizing that boiler modifications and fuel handling enhancements may be required for unrestricted switching from bituminous to subbituminous coal, and vice versa, the following procedure applies in EPA Platform v6 to coal units that have the option to burn both bituminous and subbituminous coals.

(i) An examination of the EIA Form 923 coal delivery data for the period 2008-2016 is conducted for each unit to determine the unit's historical maximum share of bituminous coal and that of subbituminous coal. For example, if in at least one year during the period 2008-2016 a unit burned 90% or less subbituminous coal, its historical maximum share of subbituminous coal is set at 90%.

(ii) The following rules then apply.

Blending Subbituminous Coal:

If a unit's historical maximum share of subbituminous coal is greater than 90%, the unit incurs no fuel switching cost adder to increase its subbituminous coal burn. The unit is assumed to have already made the fuel handling and boiler investments needed to burn up to 100% subbituminous coal. It would therefore face no additional cost. In addition, the unit's heat rate is assumed to reflect the impact of burning the corresponding proportion of subbituminous coal.

If a unit's historical maximum share of subbituminous coal is less than 90%, the unit incurs a heat rate penalty of 5% and a fuel switching cost adder. The heat rate penalty reflects the impact of the higher moisture content subbituminous coal on the unit's heat rate. And the cost adder is designed to cover boiler modifications, or alternative power purchases in lieu of capacity deratings that would otherwise be associated with burning subbituminous coal with its lower heating value relative to bituminous coal. The cost adder is determined as follows:

- If the unit's historical maximum share of subbituminous coal is less than 20%, the unit can burn up to 20% subbituminous coal at no cost adder. Burning beyond 20% subbituminous coal, the unit incurs a cost adder of 270 (2016$ per kW).

- If the unit's historical maximum share of subbituminous coal is greater than 20% but less than 90%, the unit can burn up to its historical maximum share of subbituminous coal at no cost adder. Burning beyond its historical maximum share of subbituminous coal, the unit incurs a cost adder calculated by the following equation:

$$Fuel\ Switching\ Cost\ Adder\ (2016\$\ per\ kW) =$$

$$270\ \times \left\{\frac{(100 - Historical\ Maximun\ Share\ of\ Subbituminous)}{(100-20)}\right\}$$

Blending Bituminous Coal:

If a unit's historical maximum share of bituminous coal is greater than 90%, the unit incurs no fuel switching cost adder.

If a unit's historical maximum share of bituminous coal is less than 90%, the unit incurs a fuel switching cost adder determined as follows:

- If the unit's historical maximum share of bituminous coal is less than 20%, the unit can burn up to 20% bituminous coal at no cost adder. Burning beyond 20% bituminous coal, the unit incurs a cost adder of 54 (2016$ per kW).

- If the unit's historical maximum share of bituminous coal is greater than 20% but less than 90%, the unit can burn up to its historical maximum share of bituminous coal at no cost adder. Burning beyond its historical maximum share of bituminous coal, the unit incurs a cost adder calculated by the following equation:

$$Fuel\ Switching\ Cost\ Adder\ (2016\$\ per\ kW) =$$

$$54\ \times \left\{\frac{(100 - Historical\ Maximun\ Share\ of\ Bituminous)}{(100-20)}\right\}$$

4.2.8 Life Extension Costs for Existing Units

The modeling time horizon in EPA Platform v6 extends to 2050 and covers a period of almost 30 years. This time horizon requires consideration of investments, beyond routine maintenance, necessary to extend the life of existing units. The life extension costs for different unit types are summarized in Table 4-10 below. Each unit has the option to retire or incorporate the life extension costs. These costs were based on a review of 2007-2016 FERC Form 1 data maintained by SNL regarding reported annual capital expenditures made by older units. The life extension costs were added once the unit reaches its assumed lifespan. However, if the unit reaches its lifespan before the first run year, then the life extension cost was applied when the unit reaches twice its lifespan age. The assumption implies if the unit has reached its lifespan before the first run year, it has already incurred the necessary life extension related investment costs and is considered sunk. Life extension costs for nuclear units are discussed in Section 4.5.1.

Table 4-10 Life Extension Cost Assumptions Used in EPA Platform v6

Plant Type	Lifespan without Life Extension Expenditures	Life Extension Cost (2016$/kW)	Capital Cost of New Unit (2016$/kW)	Life Extension Cost as Proportion of New Unit Capital Cost (%)
Biomass	40	291	4,429	6.6
Coal Steam	40	212	3,639	5.84
Combined Cycle	30	89	978	9.06
Combustion Turbine	30	246	678	36.3
IC Engine	30	177	1,342	13.2
Oil/Gas Steam	40	182	3,311	5.5
IGCC	40	241	3,254	7.4
Landfill Gas	20	823	9,023	9.1

Notes:
Life extension expenditures double the lifespan of the unit.

4.3 Planned-Committed Units

EPA Platform v6 includes all planned-committed units that are likely to come online because ground has been broken, financing obtained, or other demonstrable factors indicate a high probability that the unit will be built before June 30, 2021.

4.3.1 Population and Model Plant Aggregation

Table 4-11 summarizes the extent of inventory of planned-committed units represented by unit types and generating capacity.

Table 4-11 Summary of Planned-Committed Units in NEEDS v6 for EPA Platform v6

Plant Type	Capacity (MW)	Year Range Described
Renewables/Non-conventional		
Biomass	12	2019 - 2019
Energy Storage	22	2018 - 2019
Hydro	244	2018 - 2020
Non-Fossil Waste	44	2018 - 2020
Onshore Wind	3,483	2018 - 2019
Solar PV	431	2018 - 2020
Subtotal	4,237	
Fossil/Conventional		
Combined Cycle	18,195	2018 - 2020
Combustion Turbine	2,302	2018 - 2021
Nuclear	2,200	2022 - 2023
O/G Steam	23	2018 - 2018
Subtotal	22,720	
Grand Total	26,957	

Table 4-12 gives a breakdown of planned-committed units by IPM region, plant type, and capacity.

Table 4-12 Planned-Committed Units by Model Region in NEEDS v6 for EPA Platform v6

IPM Region	Plant Type	Capacity (MW)
ERC_PHDL	Onshore Wind	588
ERC_REST	Combustion Turbine	1,061
	Non-Fossil Waste	23
	Onshore Wind	160
ERC_WEST	Onshore Wind	660
FRCC	Biomass	12
	Combined Cycle	1,640
	Solar PV	149
MIS_AMSO	Combined Cycle	1,000
MIS_IA	Onshore Wind	66
MIS_INKY	Combined Cycle	644
MIS_MAPP	Combustion Turbine	218
MIS_MNWI	Combustion Turbine	215
	Onshore Wind	40
MIS_WUMS	Combined Cycle	700
	Solar PV	2
NENG_CT	Combined Cycle	1,230
	Combustion Turbine	90
NENG_ME	O/G Steam	23
NY_Z_C&E	Solar PV	4
NY_Z_G-I	Combined Cycle	705
	Non-Fossil Waste	19
PJM_ATSI	Combined Cycle	273
PJM_Dom	Combined Cycle	1,585
	Combustion Turbine	300
PJM_EMAC	Combined Cycle	1,368
PJM_PENE	Combined Cycle	926
	Combustion Turbine	13
PJM_SMAC	Combined Cycle	755
PJM_West	Combined Cycle	1,187
PJM_WMAC	Combined Cycle	3,472
S_C_TVA	Combined Cycle	1,052
S_SOU	Nuclear	2,200
S_VACA	Combined Cycle	1,072
SPP_N	Combustion Turbine	6
SPP_SPS	Onshore Wind	800
SPP_WAUE	Onshore Wind	98
SPP_WEST	Combustion Turbine	399
	Onshore Wind	200
WEC_CALN	Combined Cycle	586
	Non-Fossil Waste	2
	Solar PV	200
WECC_CO	Onshore Wind	30
WECC_NM	Onshore Wind	580
WECC_PNW	Hydro	244
	Onshore Wind	60

IPM Region	Plant Type	Capacity (MW)
	Solar PV	56
WECC_SCE	Energy Storage	22
	Onshore Wind	171
	Solar PV	20
WECC_WY	Onshore Wind	30

Note:

Any unit in NEEDS v6 that has an online year of 2018 or later was considered a Planned/Committed Unit.

4.3.2 Capacity

The capacity data of planned-committed units in NEEDS v6 was obtained from the sources reported in Table 4-1.

4.3.3 State and Model Region

State location data for the planned-committed units in NEEDS v6 came from the information sources noted in Section 4.3.1. The state-county information was then used to assign planned-committed units to their respective model regions.

4.3.4 Online and Retirement Year

As noted above, planned-committed units included in NEEDS v6 are only those likely to come on-line before June 2021, as 2021 is the first analysis year in the EPA Platform v6. All planned-committed units were assigned an online year and given a default retirement year of 9999.

4.3.5 Unit Configuration, Cost, and Performance

All planned-committed units in NEEDS v6 assume the cost, performance, and unit configuration characteristics of potential units that are available in 2021. A detailed description of potential unit assumptions is provided below in Section 4.4.

4.4 Potential Units

The EPA Platform v6 includes options for developing a variety of potential units that may be built at a future date in response to electricity demand and the constraints represented in the model. Defined by region, technology, and the year available, potential units with an initial capacity of zero MW are inputs into IPM. When the model is run, the capacity of certain potential units is raised from zero to meet demand and other system and operating constraints. This results in the model's projection of new capacity.

In Table 4-7, the block labeled "New Units" provides the type and number of potential units available in EPA Platform v6. The following sections describe the cost and performance assumptions for the potential units represented in the EPA Platform v6.

4.4.1 Methodology Used to Derive the Cost and Performance Characteristics of Conventional Potential Units

The cost and performance characteristics of conventional potential units in EPA Platform v6 are derived primarily from assumptions used in the Annual Energy Outlook (AEO) 2017 published by the U.S. Department of Energy's Energy Information Administration.

4.4.2 Cost and Performance for Potential Conventional Units

Table 4-13 shows the cost and performance assumptions for potential conventional units. The cost and performance assumptions are based on the size (i.e., net electrical generating capacity in MW) indicated in the table. However, the total new capacity that is added in each model run for these technologies is not restricted to these capacity levels.

The table includes several components of cost. The total installed cost of developing and building a new plant is captured through capital cost. It includes expenditures on pollution control equipment that new units are assumed to install to satisfy air regulatory requirements. The capital costs shown are typically referred to as overnight capital costs. They include engineering, procurement, construction, startup, and owner's costs (for such items as land, cooling infrastructure, administration and associated buildings, site works, switchyards, project management, and licenses). The capital costs of new non-wind and non-solar units are increased to account for the cost of maintaining and expanding the transmission network. This cost based on AEO 2017 is equal to 97 $/kW outside of WECC and NY regions and 145 $/kW within these regions. The capital costs do not include interest during construction (IDC). IDC is added to the capital costs during the set-up of an IPM run. Calculation of IDC is based on the construction profile of the build option and the discount rate. Details on the discount rates used in the EPA Platform v6 are provided in Chapter 10 of this documentation.

Table 4-13 also shows fixed operating and maintenance (FOM) and variable operating and maintenance (VOM) components of cost. FOM is the annual cost of maintaining a generating unit. It represents expenses incurred regardless of the extent that the unit is run. It is expressed in units of $ per kW per year. VOM represents the non-fuel variable costs incurred in running an electric generating unit. It is proportional to the electrical energy produced and is expressed in units of $ per MWh.

In addition to the three components of cost, Table 4-13 indicates the first run year available, lead time, vintage periods, heat rate, and availability for each type of unit. Lead time represents the construction time needed for a unit to come online. Vintage periods are used to capture the cost and performance improvements resulting from technological advancement and learning-by-doing. Mature technologies and technologies whose first year available is not at the start of the modeling time horizon may have only one vintage period, whereas newer technologies may have several vintage periods. Heat rate indicates the efficiency of the unit and is expressed in units of energy consumed (Btus) per unit of electricity generated (kWh). Availability indicates the percentage of time that a generating unit is available to provide electricity to the grid once it is online. Availability takes into account estimates of the time consumed by planned maintenance and forced outages. The emission characteristics of the potential units can be found in Table 3-17.

4.4.3 Short-Term Capital Cost Adder

In addition to the capital costs shown in Table 4-13 and Table 4-16, EPA Platform v6 includes a short-term capital cost adder that kicks in if the new capacity deployed in a specific model run year exceeds certain upper bounds. This adder is meant to reflect the added cost incurred due to short-term competition for scarce labor and materials. Table 4-14 shows the cost adders for each type of potential unit for model run years through 2035. The adder is not imposed after 2035, assuming markets for labor and materials have sufficient time to respond to changes in demand.

The column labeled "Step 1" in Table 4-14 indicates the total amount of capacity of a particular plant type that can be built in a given model run year without incurring a cost adder. However, if the Step 1 upper bound is exceeded, then either the Step 2 or Step 3 cost adder is incurred by the entire amount of capacity deployed, where the level of the cost adder depends upon the total amount of new capacity added in that run year. For example, the Step 1 upper bound in 2021 for landfill gas potential units is 625 MW. If no more than this total new landfill gas capacity is built in 2021, only the capital cost shown in Table 4-16 is incurred. If the model builds between 625 and 1,088 MW, the Step 2 cost adder of $3,979/kW applies to the entire capacity deployed. If the total new landfill gas capacity exceeds the Step 2 upper bound of 1,088 MW, then the Step 3 capacity adder of $12,639/kW is incurred by the entire capacity deployed in that run year. The short-term capital cost adders shown in Table 4-14 were derived from AEO assumptions.

4.4.4 Regional Cost Adjustment

The capital costs reported in Table 4-13 are generic. Before implemented, the capital cost values are converted to region-specific costs by applying regional cost adjustment factors that capture regional differences in labor, material, and construction costs and ambient conditions. These factors are calculated by multiplying the regional cost and ambient condition multipliers. The regional cost multipliers are based on county level estimates developed by the Energy Institute at University of Texas at Austin[36]. The ambient condition multipliers are from AEO 2017. Table 4-15 summarizes the regional cost adjustment factors at the IPM region and technology level. The factors are applied to both conventional technologies shown in Table 4-13 and renewable and nonconventional technologies shown in Table 4-16. However, they are not applied to hydro and geothermal technologies as site-specific costs are used for these two technologies.

[36] New U.S. Power Costs: by County, with Environmental Externalities, University of Texas at Austin, Energy Institute. July 2016

Table 4-13 Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in EPA Platform v6

	Advanced Combined Cycle	Advanced Combined Cycle with CCS	Advanced Combustion Turbine	Nuclear	Ultrasupercritical Coal with 30% CCS	Ultrasupercritical Coal with 90% CCS	Ultrasupercritical Coal without CCS
Size (MW)	429	429	237	2234	650	650	650
First Year Available	2021	2021	2021	2023	2021	2021	2021
Lead Time (Years)	3	3	2	6	4	4	4
Availability	87%	87%	93%	90%	85%	85%	85%
Vintage #1 (2021)							
Heat Rate (Btu/kWh)	6,267	7,514	9,264	10,459	9,644	11,171	8,704
Capital (2016$/kW)	1,081	2,104	662	5,644	4,953	5,477	3,580
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #2 (2023)							
Heat Rate (Btu/kWh)	6,233	7,504	8,907	10,459	9,433	10,214	8,514
Capital (2016$/kW)	1,064	2,059	651	5,300	4,863	5,378	3,516
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #3 (2025)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323
Capital (2016$/kW)	1,041	2,003	636	5,164	4,746	5,249	3,431
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #4 (2030)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323
Capital (2016$/kW)	963	1,833	580	4,804	4,434	4,904	3,205
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #5 (2035)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323
Capital (2016$/kW)	902	1,698	536	4,527	4,198	4,642	3,035
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #6 (2040)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323

	Advanced Combined Cycle	Advanced Combined Cycle with CCS	Advanced Combustion Turbine	Nuclear	Ultrasupercritical Coal with 30% CCS	Ultrasupercritical Coal with 90% CCS	Ultrasupercritical Coal without CCS
Capital (2016$/kW)	857	1,589	505	4,283	3,991	4,413	2,885
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #7 (2045)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323
Capital (2016$/kW)	816	1,487	477	4,049	3,792	4,193	2,741
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #8 (2050)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323
Capital (2016$/kW)	778	1,390	454	3,810	3,585	3,965	2,592
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6

Notes:
[a] Capital cost represents overnight capital cost.

Table 4-14 Short-Term Capital Cost Adders for New Power Plants in EPA Platform v6 (2016$)

Plant Type		2021			2023			2025			2030			2035		
		Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3
Biomass	Upper Bound (MW)	1,904	3,312	No limit	1,270	2,208	No limit	1,270	2,208	No limit	3,174	5,520	No limit	3,174	5,520	No limit
	Adder ($/kW)	-	1,714	5,443	-	1,685	5,352	-	1,646	5,230	-	1,543	4,903	-	1,466	4,658
Coal Steam - UPC	Upper Bound (MW)	18,361	31,932	No limit	12,241	21,288	No limit	12,241	21,288	No limit	30,602	53,220	No limit	30,602	53,220	No limit
	Adder ($/kW)	-	1,640	5,209	-	1,610	5,115	-	1,572	4,992	-	1,468	4,664	-	1,390	4,415
Coal Steam - UPC30	Upper Bound (MW)	18,361	31,932	No limit	12,241	21,288	No limit	12,241	21,288	No limit	30,602	53,220	No limit	30,602	53,220	No limit
	Adder ($/kW)	-	2,269	7,206	-	2,228	7,076	-	2,174	6,906	-	2,031	6,452	-	1,923	6,108
Coal Steam - UPC90	Upper Bound (MW)	18,361	31,932	No limit	12,241	21,288	No limit	12,241	21,288	No limit	30,602	53,220	No limit	30,602	53,220	No limit
	Adder ($/kW)	-	2,509	7,969	-	2,463	7,825	-	2,404	7,636	-	2,246	7,134	-	2,126	6,754
Combined Cycle	Upper Bound (MW)	132,125	229,782	No limit	88,083	153,188	No limit	88,083	153,188	No limit	220,208	382,970	No limit	220,208	382,970	No limit
	Adder ($/kW)	-	490	1,555	-	481	1,528	-	469	1,491	-	433	1,376	-	406	1,290
Combustion Turbine	Upper Bound (MW)	66,275	115,260	No limit	44,183	76,840	No limit	44,183	76,840	No limit	110,458	192,100	No limit	110,458	192,100	No limit
	Adder ($/kW)	-	298	945	-	291	924	-	281	893	-	255	809	-	235	747
Fuel Cell	Upper Bound (MW)	1,725	3,000	No limit	1,150	2,000	No limit	1,150	2,000	No limit	2,875	5,000	No limit	2,875	5,000	No limit
	Adder ($/kW)	-	3,101	9,850	-	3,007	9,551	-	2,896	9,200	-	2,615	8,305	-	2,386	7,578
Geothermal	Upper Bound (MW)	883	1,536	No limit	589	1,024	No limit	589	1,024	No limit	1,472	2,560	No limit	1,472	2,560	No limit
	Adder ($/kW)	-	3,772	11,983	-	3,763	11,954	-	3,744	11,892	-	3,700	11,754	-	3,636	11,549
Landfill Gas	Upper Bound (MW)	625	1,088	No limit	417	725	No limit	417	725	No limit	1,042	1,813	No limit	1,042	1,813	No limit
	Adder ($/kW)	-	3,979	12,639	-	3,915	12,437	-	3,822	12,140	-	3,577	11,361	-	3,379	10,733
Nuclear	Upper Bound (MW)	32,327	56,220	No limit	21,551	37,480	No limit	21,551	37,480	No limit	53,878	93,700	No limit	53,878	93,700	No limit
	Adder ($/kW)	-	2,499	7,939	-	2,347	7,456	-	2,287	7,264	-	2,127	6,757	-	2,005	6,368
Solar Thermal	Upper Bound (MW)	2,830	4,921	No limit	1,886	3,281	No limit	1,886	3,281	No limit	4,716	8,202	No limit	4,716	8,202	No limit
	Adder ($/kW)	-	2,327	7,390	-	2,736	8,691	-	2,640	8,385	-	2,430	7,719	-	2,286	7,262
Solar PV	Upper Bound (MW)	25,858	46,265	No limit	18,406	32,011	No limit	18,406	32,011	No limit	46,016	80,027	No limit	46,016	80,027	No limit
	Adder ($/kW)	-	366	1,163	-	398	1,263	-	384	1,218	-	359	1,141	-	339	1,077
Onshore Wind	Upper Bound (MW)	33,941	67,466	No limit	30,238	52,588	No limit	30,238	52,588	No limit	75,595	131,470	No limit	75,595	131,470	No limit
	Adder ($/kW)	-	716	2,275	-	693	2,200	-	667	2,120	-	602	1,911	-	575	1,827
Offshore Wind	Upper Bound (MW)	1,725	3,000	No limit	1,150	2,000	No limit	1,150	2,000	No limit	2,875	5,000	No limit	2,875	5,000	No limit
	Adder ($/kW)	-	2,143	6,808	-	1,933	6,139	-	1,893	6,012	-	1,798	5,712	-	1,752	5,565
Hydro	Upper Bound (MW)	10,360	18,018	No limit	6,907	12,012	No limit	6,907	12,012	No limit	17,267	30,030	No limit	17,267	30,030	No limit
	Adder ($/kW)	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313

Table 4-15 Regional Cost Adjustment Factors for Conventional and Renewable Generating Technologies in EPA Platform v6

Model Region	Combined Cycle	Combined Cycle with Carbon Capture	Combustion Turbine	Nuclear	Biomass	Landfill Gas	Offshore Wind	Onshore Wind	Solar PV	Solar Thermal	Fuel Cell	Ultra supercritical Coal without CCS	Ultra supercritical Coal with 30% CCS	Ultra supercritical Coal with 90% CCS
ERC_PHDL	1.006	1.006	1.042	0.979	0.922	0.92	1.002	1.002	0.96	0.916	0.9	1.005	1.005	0.992
ERC_REST	0.977	0.977	1.027	0.969	0.922	0.92	0.968	0.968	0.94	0.889	0.9	0.981	0.981	0.969
ERC_WEST	0.999	0.999	1.038	0.976	0.922	0.92	0.989	0.989	0.95	0.909	0.9	0.997	0.997	0.985
FRCC	0.983	0.983	1.033	0.976	0.948	0.949	0.961	0.961	0.94	0.899	1	1.001	1.001	0.991
MIS_AMSO	0.955	0.955	1.015	0.963	0.93	0.933	0.949	0.949	0.92	0.865	0.9	0.958	0.958	0.947
MIS_AR	0.977	0.977	1.022	0.977	0.93	0.933	0.977	0.977	0.95	0.914	0.9	0.995	0.995	0.987
MIS_D_MS	0.958	0.958	1.013	0.968	0.93	0.933	0.958	0.958	0.93	0.884	0.9	0.972	0.972	0.962
MIS_IA	1.001	1.001	1.017	0.999	0.968	0.968	1.041	1.041	1.01	0.993	1	1.013	1.013	1.008
MIS_IL	1	1	1.016	0.999	1.017	1.019	1.014	1.014	1	0.99	1	1.021	1.021	1.02
MIS_INKY	0.987	0.987	1.007	0.998	1.01	0.994	1.003	1.003	0.99	0.972	1	1.009	1.009	1.008
MIS_LA	0.958	0.958	1.013	0.967	0.93	0.933	0.957	0.957	0.93	0.879	0.9	0.968	0.968	0.956
MIS_LMI	1.009	1.009	1.015	1.016	0.995	0.997	1.024	1.024	1.01	1.002	1	1.025	1.025	1.022
MIS_MAPP	0.97	0.97	1.003	0.986	0.968	0.968	1.035	1.035	0.99	0.945	1	0.976	0.976	0.967
MIS_MIDA	0.996	0.996	1.015	0.997	0.968	0.968	1.04	1.04	1.01	0.984	1	1.007	1.007	1
MIS_MNWI	1.006	1.006	1.02	1	0.968	0.968	1.05	1.05	1.02	1.008	1	1.015	1.015	1.01
MIS_MO	0.995	0.995	1.015	0.995	1.017	1.019	1.016	1.016	1	0.981	1	1.013	1.013	1.009
MIS_WOTA	0.956	0.956	1.01	0.966	0.93	0.933	0.956	0.956	0.92	0.875	0.9	0.964	0.964	0.952
MIS_WUMS	1.028	1.028	1.032	1.013	1.01	0.994	1.045	1.045	1.03	1.029	1	1.046	1.046	1.044
NENG_CT	1.181	1.181	1.146	1.068	1.03	1.009	1.081	1.081	1.08	1.103	1	1.112	1.112	1.116
NENG_ME	1.064	1.064	1.074	1.042	1.03	1.009	1.065	1.065	1.02	0.993	1	1.048	1.048	1.047
NENGREST	1.115	1.115	1.105	1.053	1.03	1.009	1.068	1.068	1.04	1.034	1	1.075	1.075	1.075
NY_Z_A	1.061	1.061	1.072	1.039	1.034	0.999	1.021	1.021	1	0.988	1	1.05	1.05	1.046
NY_Z_B	1.076	1.076	1.081	1.043	1.034	0.999	1.027	1.027	1	0.992	1	1.058	1.058	1.054
NY_Z_C&E	1.11	1.11	1.111	1.056	1.034	0.999	1.038	1.038	1.02	1.005	1	1.08	1.08	1.078
NY_Z_D	1.076	1.076	1.092	1.045	1.034	0.999	1.043	1.043	1.01	0.986	1	1.056	1.056	1.053
NY_Z_F	1.129	1.129	1.122	1.055	1.034	0.999	1.06	1.06	1.04	1.04	1	1.085	1.085	1.085
NY_Z_G-I	1.195	1.195	1.161	1.068	1.034	0.999	1.079	1.079	1.09	1.13	1	1.119	1.119	1.122

Model Region	Combined Cycle	Combined Cycle with Carbon Capture	Combustion Turbine	Nuclear	Biomass	Landfill Gas	Offshore Wind	Onshore Wind	Solar PV	Solar Thermal	Fuel Cell	Ultra supercritical Coal without CCS	Ultra supercritical Coal with 30% CCS	Ultra supercritical Coal with 90% CCS
NY_Z_J	1.257	1.257	1.205	1.074	1.227	1.26	1.093	1.093	1.12	1.216	1.2	1.157	1.157	1.162
NY_Z_K	1.241	1.241	1.196	1.073	1.227	1.26	1.092	1.092	1.1	1.163	1.2	1.153	1.153	1.158
PJM_AP	1.073	1.073	1.088	1.034	1.01	0.994	1.008	1.008	0.98	0.961	1	1.072	1.072	1.069
PJM_ATSI	1.031	1.031	1.046	1.018	1.01	0.994	1.007	1.007	0.99	0.974	1	1.043	1.043	1.039
PJM_COMD	1.022	1.022	1.026	1.009	1.01	0.994	1.04	1.04	1.03	1.042	1	1.039	1.039	1.039
PJM_Dom	1.144	1.144	1.153	1.046	0.913	0.911	1.018	1.018	0.99	0.964	0.9	1.13	1.13	1.127
PJM_EMAC	1.209	1.209	1.179	1.073	1.065	1.033	1.066	1.066	1.06	1.09	1	1.144	1.144	1.148
PJM_PENE	1.097	1.097	1.105	1.047	1.065	1.033	1.024	1.024	1	0.988	1	1.083	1.083	1.081
PJM_SMAC	1.155	1.155	1.144	1.063	1.065	1.033	1.036	1.036	1.01	0.99	1	1.118	1.118	1.118
PJM_West	0.991	0.991	1.019	1.004	1.01	0.994	0.989	0.989	0.97	0.939	1	1.012	1.012	1.008
PJM_WMAC	1.151	1.151	1.144	1.06	1.065	1.033	1.043	1.043	1.02	1.018	1	1.113	1.113	1.113
S_C_KY	0.981	0.981	1.015	0.99	0.934	0.933	0.979	0.979	0.95	0.919	0.9	1.006	1.006	1.004
S_C_TVA	0.957	0.957	1.003	0.979	0.934	0.933	0.968	0.968	0.94	0.899	0.9	0.981	0.981	0.975
S_D_AECI	0.989	0.989	1.014	0.992	1.017	1.019	1.013	1.013	0.99	0.971	1	1.005	1.005	0.999
S_SOU	0.963	0.963	1.02	0.969	0.925	0.925	0.953	0.953	0.92	0.873	0.9	0.982	0.982	0.972
S_VACA	1.015	1.015	1.059	1.003	0.913	0.911	0.975	0.975	0.94	0.896	0.9	1.033	1.033	1.025
SPP_N	1	1	1.032	0.986	0.973	0.975	1.016	1.016	0.98	0.948	1	1.009	1.009	0.998
SPP_NEBR	0.976	0.976	1.009	0.988	0.968	0.968	1.029	1.029	0.98	0.945	1	0.982	0.982	0.971
SPP_SPS	0.992	0.992	1.028	0.98	0.956	0.952	1.005	1.005	0.96	0.92	1	0.991	0.991	0.979
SPP_WAUE	0.974	0.974	1.006	0.987	0.968	0.968	1.034	1.034	0.99	0.947	1	0.979	0.979	0.97
SPP_WEST	0.978	0.978	1.02	0.978	0.956	0.952	0.991	0.991	0.96	0.918	1	0.989	0.989	0.978
WEC_BANC	1.232	1.232	1.173	1.072	1.076	1.055	1.124	1.124	1.1	1.112	1	1.208	1.208	1.203
WEC_CALN	1.23	1.23	1.172	1.071	1.076	1.055	1.123	1.123	1.1	1.109	1	1.207	1.207	1.201
WEC_LADW	1.183	1.183	1.141	1.055	1.076	1.055	1.104	1.104	1.07	1.076	1	1.167	1.167	1.151
WEC_SDGE	1.154	1.154	1.12	1.046	1.076	1.055	1.084	1.084	1.05	1.049	1	1.141	1.141	1.123
WECC_AZ	1.187	1.187	1.19	1.011	1	0.982	1.035	1.035	1	0.97	1	1.181	1.181	1.166
WECC_CO	1.157	1.157	1.194	0.988	0.936	0.947	1.027	1.027	0.98	0.932	1	1.156	1.156	1.142
WECC_ID	1.045	1.045	1.07	1.004	1.002	0.982	1.048	1.048	1	0.965	1	1.066	1.066	1.058
WECC_IID	1.262	1.262	1.236	1.036	1	0.982	1.069	1.069	1.04	1.028	1	1.252	1.252	1.233

Model Region	Combined Cycle	Combined Cycle with Carbon Capture	Combustion Turbine	Nuclear	Biomass	Landfill Gas	Offshore Wind	Onshore Wind	Solar PV	Solar Thermal	Fuel Cell	Ultra supercritical Coal without CCS	Ultra supercritical Coal with 30% CCS	Ultra supercritical Coal with 90% CCS
WECC_MT	1.021	1.021	1.054	0.992	1.002	0.982	1.039	1.039	0.99	0.953	1	1.037	1.037	1.03
WECC_NM	1.131	1.131	1.161	0.99	1	0.982	1.018	1.018	0.98	0.938	1	1.129	1.129	1.115
WECC_NNV	1.157	1.157	1.137	1.04	1.002	0.982	1.087	1.087	1.05	1.045	1	1.157	1.157	1.147
WECC_PNW	1.123	1.123	1.109	1.035	1.002	0.982	1.074	1.074	1.04	1.032	1	1.145	1.145	1.144
WECC_SCE	1.18	1.18	1.139	1.054	1.076	1.055	1.1	1.1	1.07	1.071	1	1.163	1.163	1.144
WECC_SNV	1.23	1.23	1.22	1.03	1	0.982	1.071	1.071	1.04	1.042	1	1.237	1.237	1.219
WECC_UT	1.05	1.05	1.075	1.002	1.002	0.982	1.043	1.043	1	0.962	1	1.063	1.063	1.051
WECC_WY	1.016	1.016	1.055	0.987	1.002	0.982	1.031	1.031	0.98	0.927	1	1.024	1.024	1.012

Table 4-16 Performance and Unit Cost Assumptions for Potential (New) Renewable and Non-Conventional Technology Capacity in EPA Platform v6

	Biomass-Bubbling Fluidized Bed (BFB)	Geothermal	Landfill Gas			Fuel Cells	Solar Photovoltaic	Solar Thermal	Onshore Wind	Offshore Wind
			LGHI	LGLo	LGVLo					
Size (MW)	50	50	50			10	100	100	100	600
First Year Available	2021	2021	2021			2021	2021	2021	2021	2021
Lead Time (Years)	4	4	3			3	1	3	3	3
Availability	83%	90% - 95%	90%			87%	90%	90%	95%	95%
Generation Capability	Economic Dispatch	Economic Dispatch	Economic Dispatch			Economic Dispatch	Generation Profile	Economic Dispatch	Generation Profile	Generation Profile
	Vintage #1 (2021-2054)					**Vintage #1 (2021)**				
Heat Rate (Btu/kWh)	13,500	30,000	18,000	18,000	18,000	8,653	0	0	0	0
Capital (2016$/kW)	3,733	3,072 - 21,106	8,556	10,780	16,598	6,889	1034	6,717	1,404	4,529
Fixed O&M (2016$/kW/yr)	110.34	105 - 542	410.32	410.32	410.32	0.00	11.35	62.69	49.46	116.64
Variable O&M (2016$/MWh)	5.49	0.00	9.14	9.14	9.14	44.9	0	3.5	0	0
						Vintage #2 (2023)				
Heat Rate (Btu/kWh)						7,807	0	0	0	0
Capital (2016$/kW)						6680	1009	6,555	1,372	4,169
Fixed O&M (2016$/kW/yr)						0.0	10.74	59.9	48.72	111.15
Variable O&M (2016$/MWh)						44.9	0	3.5	0	0
						Vintage #3 (2025)				
Heat Rate (Btu/kWh)						6,960	0	0	0	0

	Biomass-Bubbling Fluidized Bed (BFB)	Geothermal	Landfill Gas			Fuel Cells	Solar Photovoltaic	Solar Thermal	Onshore Wind	Offshore Wind
			LGHI	LGLo	LGVLo					
Capital (2016$/kW)						6434	984	6,396	1,337	4,122
Fixed O&M (2016$/kW/yr)						0.0	10.13	57.12	47.98	109.58
Variable O&M (2016$/MWh)						44.9	0	3.5	0	0
						Vintage #4 (2030)				
Heat Rate (Btu/kWh)						0	0	0	0	0
Capital (2016$/kW)						921	6,047	1,242	4,006	921
Fixed O&M (2016$/kW/yr)						10.13	50.15	46.13	105.66	10.13
Variable O&M (2016$/MWh)						0	3.5	0	0	0
						Vintage #5 (2035)				
Heat Rate (Btu/kWh)						0	0	0	0	0
Capital (2016$/kW)						870	5,762	1,234	3,952	870
Fixed O&M (2016$/kW/yr)						10.13	50.15	44.29	104.98	10.13
Variable O&M (2016$/MWh)						0	3.5	0	0	0
						Vintage #6 (2040)				
Heat Rate (Btu/kWh)						0	0	0	0	0
Capital (2016$/kW)						819	5,527	1,218	3,898	819
Fixed O&M (2016$/kW/yr)						10.13	50.15	42.44	104.29	10.13
Variable O&M (2016$/MWh)						0	3.5	0	0	0
						Vintage #7 (2045)				
Heat Rate (Btu/kWh)						0	0	0	0	0
Capital (2016$/kW)						772	5,354	1,195	3,837	772
Fixed O&M (2016$/kW/yr)						10.13	50.15	40.6	103.54	10.13
Variable O&M (2016$/MWh)						0	3.5	0	0	0
						Vintage #8 (2050)				
Heat Rate (Btu/kWh)						0	0	0	0	0
Capital (2016$/kW)						726	5,243	1,165	3,775	726
Fixed O&M (2016$/kW/yr)						10.13	50.15	38.75	102.8	10.13
Variable O&M (2016$/MWh)						0	3.5	0	0	0

4.4.5 Cost and Performance for Potential Renewable Generating and Non-Conventional Technologies

Table 4-16 summarizes the cost and performance assumptions in EPA Platform v6 for potential renewable and non-conventional technology generating units. The parameters shown in the table are based on AEO 2017 for biomass, landfill gas, and fuel cell. For onshore wind, solar PV, and solar thermal technologies, the parameters shown are based on the National Renewable Energy Laboratory's (NREL's) 2017 Annual Technology Baseline (ATB) mid-case. For offshore wind, the parameters shown are based on the NREL's 2016 ATB mid-case. The size (MW) shown in Table 4-16 represents the capacity on which unit cost estimates were developed and does not indicate the total potential capacity that the model can build of a given technology. Due to the distinctive nature of generation from renewable resources, some of the values shown are averages or ranges that are discussed in further detail in the following subsections. The short-term capital cost adder in Table 4-14 and the regional cost adjustment factors in Table 4-15 apply equally to the renewable and non-conventional generation technologies as to the conventional generation technologies.

Wind Generation

EPA Platform v6 includes onshore wind, offshore-shallow, offshore-mid depth, and offshore-deep wind generation technologies. The following sections describe key aspects of the representation of wind generation: wind quality and resource potential, distance to transmission, generation profiles, reserve margin contribution, and capital cost calculation.

Wind Quality and Resource Potential: The NREL resource base for onshore wind is represented by ten techno-resource groups (TRG). Based on a review of levelized cost of electricity, EPA Platform v6 only models the resource categories TRG1–TRG8. The NREL resource base for offshore wind is represented by shallow (TRG1-TRG4), mid-depth (TRG5-TRG7), and deep (TRG8-TRG10) categories. In EPA Platform v6, the resource categories TRG1, TRG2, TRG3, TRG5, TRG6, and TRG8 are modeled. Table 4-38, Table 4-17, Table 4-18, and Table 4-19 present the onshore, offshore shallow, offshore mid-depth, and offshore deep wind resource assumptions.

Table 4-17 Offshore Shallow Regional Potential Wind Capacity (MW) by Wind TRG and Cost Class in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_BC	BC	2	143		
		3	1,000	991	1,760
CN_MB	MB	3	997	997	13,978
CN_NB	NB	2	994	862	
		3	999	997	1,389
CN_NF	NF	1	982	1,017	10,824
		2	997	985	15,445
		3	952	1,014	11,688
CN_NL	NL	1	985	1,007	109,060
		2	980	1,017	102,486
		3	984	1,006	32,049
CN_NS	NS	1	727		
		2	985	997	16,158
		3	999	960	34,831
CN_ON	ON	2	999	370	
		3	995	992	46,890
CN_PE	PE	2	650		

IPM Region	State	TRG	Cost Class		
			1	2	3
		3	986	959	13,816
CN_PQ	PQ	1	989	970	46,105
		2	968	996	17,275
		3	959	984	53,478
ERC_REST	TX	2	2,990	2,992	5,030
		3	2,962	3,035	13,893
MIS_INKY	IN	3	385		
MIS_LMI	MI	2	2,499	306	
		3	2,482	2,512	8,878
MIS_MNWI	MI	3	53		
	WI	3	184		
MIS_WOTA	LA	3	983	108	
	TX	3	12		
MIS_WUMS	MI	1	302		
		2	489		
		3	1,484	1,502	6,397
	WI	2	743		
		3	1,498	1,499	2,031
NENG_CT	CT	3	259		
NENG_ME	ME	1	76		
		2	469	412	
		3	495	498	646
NENGREST	MA	1	2,474	2,459	6,487
		2	2,497	2,409	4,104
		3	2,403		
	NH	3	181		
	RI	1	0		
		2	707		
		3	416		
NY_Z_A	NY	3	389	544	1,203
NY_Z_B	NY	3	492	470	
NY_Z_C&E	NY	3	475	520	293
NY_Z_J	NY	3	355		
NY_Z_K	NY	2	930	1,064	4,102
		3	998	980	1,495
PJM_ATSI	OH	2	189		
		3	1,496	1,423	8,263
PJM_COMD	IL	2	973		
		3	971		
PJM_Dom	NC	2	2,449	2,510	2,953
		3	2,374	2,603	8,061
	VA	2	1,471		
		3	2,462	2,444	
PJM_EMAC	DE	3	2,989	879	
	MD	3	2,897	3,009	
	NJ	2	2,950	3,042	1,786

IPM Region	State	TRG	Cost Class		
			1	2	3
		3	2,905	3,028	5,414
	VA	2	948		
		3	2,944	2,903	7,832
PJM_PENE	PA	2	155		
		3	492	447	1,917
PJM_West	MI	3	1,134		
S_SOU	GA	3	2,892	2,958	3,740
S_VACA	NC	2	2,932	2,022	
		3	2,929	3,046	34,677
	SC	2	1,261		
		3	2,956	2,520	31,482
WEC_CALN	CA	2	42		
		3	147		
WECC_PNW	CA	2	39		
		3	134		
	OR	1	46		
		2	281		
		3	469		
	WA	3	1,018		
WECC_SCE	CA	2	75		
		3	151		

Table 4-18 Offshore Mid-Depth Regional Potential Wind Capacity (MW) by Wind TRG and Cost Class in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_BC	BC	6	987	1,012	2,526
CN_NB	NB	6	995	1,000	3,159
CN_NF	NF	5	989	1,008	7,419
		6	991	994	2,148
CN_NL	NL	5	996	993	28,647
		6	992	997	6,691
CN_NS	NS	5	994	962	8,245
		6	955	1,034	45,843
CN_ON	ON	6	986	998	3,149
CN_PE	PE	5	376		
		6	982	1,002	13,613
CN_PQ	PQ	5	975	946	89,535
		6	993	1,003	34,451
ERC_REST	TX	6	2,983	2,864	9,713
MIS_LMI	MI	6	2,487	2,511	1,480
MIS_WUMS	MI	5	619		
		6	1,169		
	WI	6	1,498	987	
NENG_ME	ME	5	500	111	
		6	489	501	643

IPM Region	State	TRG	Cost Class		
			1	2	3
NENGREST	MA	5	2,494	2,149	48,461
		6	2,469	2,365	4,730
	NH	6	5		
	RI	5	2,492	779	
		6	2,472	131	
NY_Z_K	NY	5	962	924	659
		6	878	1,013	20,641
PJM_COMD	IL	6	1,357		
PJM_Dom	NC	6	2,482	2,443	5,735
	VA	6	2,041		
PJM_EMAC	DE	6	342		
	MD	6	623		
	NJ	6	2,742	3,028	18,787
	VA	6	2,972	3,001	1,472
PJM_PENE	PA	6	37		
S_VACA	NC	6	2,887	2,999	14,190
	SC	6	2,825	587	
WEC_CALN	CA	5	48		
		6	308		
WECC_PNW	CA	6	18		
	OR	5	317		
		6	481		
WECC_SCE	CA	6	49		

Table 4-19 Offshore Deep Regional Potential Wind Capacity (MW) by Wind TRG and Cost Class in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_NF	NF	8	939	976	145,825
CN_NL	NL	8	992	991	448,905
CN_NS	NS	8	990	1,005	87,606
CN_PQ	PQ	8	989	1,010	198,807
MIS_WUMS	MI	8	1,489	1,348	27,571
NENG_ME	ME	8	422	560	75,668
NENGREST	MA	8	951	2,091	149,968
	RI	8	2,477	2,437	745
NY_Z_K	NY	8	725	1,087	20,795
WEC_CALN	CA	8	2,480	1,797	
WECC_PNW	CA	8	2,113		
	OR	8	2,973	3,008	118
WECC_SCE	CA	8	2,047		

Generation Profiles: Unlike other generation technologies, which dispatch on an economic basis subject to their availability constraint, wind and solar technologies can dispatch only when the wind blows and the sun shines. To represent intermittent renewable generating sources such as wind and solar, EPA Platform v6 uses hourly generation profiles. Each eligible wind and solar photovoltaic plant is provided with 8760 hourly generation profiles. These profiles are customized for each wind TRG within an IPM region and state combination.

The generation profile indicates the amount of generation (kWh) per MW of available capacity. The wind generation profiles were prepared with data from NREL. Table 4-39 shows the generation profiles for onshore and offshore wind plants in all model region, state, and TRG combinations for vintage 2021. Improvements in onshore wind and offshore wind capacity factors over time are modeled through three vintages (2021, 2030, and 2040) of new wind units.

To obtain the seasonal generation for the units in a particular wind class in a specific region, the installed capacity is multiplied by the number of hours in the season and the seasonal capacity factor. Capacity factor is the average “kWh of generation per MW” from the applicable generation profile. The annual capacity factors for wind generation that are used in EPA Platform v6 were obtained from NREL and are shown in Table 4-20, Table 4-22, Table 4-24, and Table 4-26.

Reserve Margin Contribution (also referred to as capacity credit): EPA Platform v6 uses reserve margins, discussed in detail in Section 3.6, to model reliability. Each region has a reserve margin requirement which is used to determine the total capacity needed to reliably meet peak demand. The ability of a unit to assist a region in meeting its reliability requirements is modeled through the unit’s contribution to reserve margin. If the unit has 100 percent contribution towards reserve margin, then the entire capacity of the unit is counted towards meeting the region’s reserve margin requirement. However, if any unit has less than a 100 percent contribution towards reserve margin, then only the designated share of the unit’s capacity counts towards the reserve margin requirement.

All units except those that depend on intermittent resources have 100% contributions toward reserve margin. This means that wind and solar have limited (less than 100 percent) contributions toward reserve margins.

Capacity credit assumptions for onshore wind, offshore wind, and solar PV units are estimated as the function of penetration of solar and wind in the EPA Platform v6. A two-step approach is developed to estimate the capacity credit at a unit level. In the first step, the method estimates the sequence of solar and wind units to build in each IPM region. To do so each solar and wind unit in an IPM Region is sorted from cheapest to most expensive in-terms of cost and potential revenue generation. Unit level capital costs, FOM costs, capital charge rate, and average energy price in each IPM region are used in this analysis. In the second step, capacity credit is calculated for each unit in the sequence as the ratio between the MW of peak reduced and the capacity of the unit. Unit level hourly generation profiles and regional hourly load curves are used in this analysis. These initial regional capacity credit curves are scaled at the NEMS region level to approximately result in capacity credits equal to those projected in AEO 2017 at the same level of penetration. This approach allows the EPA Platform v6 to endogenously account for the decline of capacity credit for intermittent resources with their rising penetration. Table 4-21, Table 4-23, Table 4-25 and Table 4-27 present the reserve margin contributions apportioned to new wind plants in the EPA Platform v6.

Table 4-20 Onshore Average Capacity Factor by Wind TRG

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	50.16%	52.30%	54.05%
2	49.05%	51.24%	53.01%
3	48.23%	50.71%	52.70%
4	46.92%	49.52%	51.63%
5	44.71%	47.76%	50.25%
6	41.12%	44.74%	47.67%
7	35.74%	39.48%	42.49%
8	28.93%	32.25%	34.95%
9	22.71%	26.13%	28.93%
10	14.32%	16.77%	18.79%

Table 4-21 Onshore Reserve Margin Contribution by Wind TRG

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	0% - 49%	0% - 51%	0% - 53%
2	0% - 84%	0% - 87%	0% - 90%
3	0% - 83%	0% - 87%	0% - 90%
4	0% - 82%	0% - 87%	0% - 90%
5	0% - 81%	0% - 86%	0% - 90%
6	0% - 78%	0% - 85%	0% - 90%
7	0% - 76%	0% - 84%	0% - 90%
8	0% - 75%	0% - 83%	0% - 90%
9	0% - 1%	0% - 1%	0% - 1%
10	0% - 1%	0% - 1%	0% - 1%

Table 4-22 Offshore Shallow Average Capacity Factor by Wind TRG

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	51%	52%	53%
2	47%	48%	48%
3	43%	44%	44%

Table 4-23 Offshore Shallow Reserve Margin Contribution by Wind TRG

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	0% - 88%	0% - 89%	0% - 90%
2	0% - 88%	0% - 89%	0% - 90%
3	0% - 88%	0% - 89%	0% - 90%

Table 4-24 Offshore Mid Depth Average Capacity Factor by Wind TRG

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
5	51%	52%	52%
6	48%	49%	49%

Table 4-25 Offshore Mid Depth Reserve Margin Contribution by Wind TRG

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
5	0% - 88%	0% - 89%	0% - 90%
6	0% - 88%	0% - 89%	0% - 90%

Table 4-26 Offshore Deep Average Capacity Factor by Wind TRG

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
8	53%	54%	55%

Table 4-27 Offshore Deep Reserve Margin Contribution by Wind TRG

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
8	0% - 87%	0% - 89%	0% - 90%

Capital cost calculation: Capital costs for wind units include spur-line transmission costs. The resources for wind and solar are highly sensitive to location. These spur-line costs represent the cost of needed spur lines, and are based on an estimated distance to transmission infrastructure. NREL develops these supply curves based on a geographic-information-system analysis, which estimates the resource accessibility costs in terms of supply curves based on the expected cost of linking renewable resource sites to the high-voltage, long-distance transmission network. For IPM modeling purposes, the NREL spur line cost curves are aggregated into a piecewise step curve for each resource class within each model region and state combination. The sizes of the initial steps are based on the model region load, while the last step holds the residual resource. The TRG level spur line cost curves for each model region and state combination are aggregated into a six-step cost curve for onshore wind and into a three-step cost curve for offshore wind. To obtain the capital cost for a particular new wind model plant, the capital cost adder applicable to the new plant by resource and cost class shown in Table 4-28, Table 4-29, Table 4-30, and Table 4-40 is added to the base capital cost shown in Table 4-16.

The tax credit extensions for new wind units as prescribed in H.R. 2029, the Consolidated Appropriations Act of 2016, are implemented through reductions in capital costs. As the credits are based on construction start date, the 2019 production tax credit (40% of initial value) is assigned to the 2021 run-year builds for wind units.

Table 4-28 Capital Cost Adder (2016$/kW) for New Offshore Shallow Wind Plants in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_BC	BC	2	1,010		
		3	1,004	1,040	1,091
CN_MB	MB	3	2,062	2,090	2,183
CN_NB	NB	2	746	802	
		3	242	597	741
CN_NF	NF	1	783	790	870
		2	791	800	958
		3	863	919	1,261
CN_NL	NL	1	228	289	839
		2	202	236	688
		3	148	230	785

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_NS	NS	1	867		
		2	89	187	570
		3	51	60	574
CN_ON	ON	2	797	912	
		3	172	202	1,116
CN_PE	PE	2	768		
		3	380	394	544
CN_PQ	PQ	1	715	722	842
		2	649	671	1,540
		3	623	628	1,535
ERC_REST	TX	2	17	43	82
		3	3	8	42
MIS_INKY	IN	3	3		
MIS_LMI	MI	2	54	99	
		3	5	15	50
MIS_MNWI	MI	3	74		
	WI	3	94		
MIS_WOTA	LA	3	39	82	
	TX	3	26		
MIS_WUMS	MI	1	76		
		2	116		
		3	8	23	69
	WI	2	57		
		3	4	12	52
NENG_CT	CT	3	10		
NENG_ME	ME	1	63		
		2	43	74	
		3	18	38	73
NENGREST	MA	1	12	45	86
		2	9	30	71
		3	24		
	NH	3	10		
	RI	1	75		
		2	44		
		3	25		
NY_Z_A	NY	3	5	7	12
NY_Z_B	NY	3	9	34	
NY_Z_C&E	NY	3	22	61	75
NY_Z_J	NY	3	2		
NY_Z_K	NY	2	1	3	34
		3	2	16	56
PJM_ATSI	OH	2	6		
		3	1	2	8
PJM_COMD	IL	2	7		
		3	5		
PJM_Dom	NC	2	15	56	119

IPM Region	State	TRG	Cost Class		
			1	2	3
		3	2	6	41
	VA	2	27		
		3	22	30	
PJM_EMAC	DE	3	6	24	
	MD	3	10	35	
	NJ	2	4	21	24
		3	3	9	22
	VA	2	24		
		3	17	30	44
PJM_PENE	PA	2	9		
		3	4	6	12
PJM_West	MI	3	6		
S_SOU	GA	3	6	13	25
S_VACA	NC	2	39	99	
		3	4	9	45
	SC	2	37		
		3	2	3	24
WEC_CALN	CA	2	63		
		3	73		
WECC_PNW	CA	2	19		
		3	17		
	OR	1	8		
		2	10		
		3	15		
	WA	3	36		
WECC_SCE	CA	2	96		
		3	171		

Table 4-29 Capital Cost Adder (2016$/kW) for New Offshore Mid Depth Wind Plants in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_BC	BC	6	1,037	1,116	1,151
CN_NB	NB	6	428	717	841
CN_NF	NF	5	766	775	851
		6	820	1,046	1,329
CN_NL	NL	5	262	430	955
		6	253	555	863
CN_NS	NS	5	585	760	847
		6	73	88	659
CN_ON	ON	6	318	365	678
CN_PE	PE	5	659		
		6	562	577	741
CN_PQ	PQ	5	681	689	872
		6	646	665	1,366
ERC_REST	TX	6	2	9	50

IPM Region	State	TRG	Cost Class		
			1	2	3
MIS_LMI	MI	6	15	44	90
MIS_WUMS	MI	5	77		
		6	95		
	WI	6	35	106	
NENG_ME	ME	5	53	95	
		6	32	50	87
NENGREST	MA	5	6	8	45
		6	20	56	78
	NH	6	36		
	RI	5	62	74	
		6	34	65	
NY_Z_K	NY	5	16	43	57
		6	1	4	20
PJM_COMD	IL	6	5		
PJM_Dom	NC	6	2	9	57
	VA	6	27		
PJM_EMAC	DE	6	1		
	MD	6	12		
	NJ	6	2	3	14
	VA	6	19	25	34
PJM_PENE	PA	6	8		
S_VACA	NC	6	6	19	49
	SC	6	38	38	
WEC_CALN	CA	5	74		
		6	64		
WECC_PNW	CA	6	15		
	OR	5	5		
		6	11		
WECC_SCE	CA	6	47		

Table 4-30 Capital Cost Adder (2016$/kW) for New Offshore Deep Wind Plants in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_NF	NF	8	759	761	1,158
CN_NL	NL	8	321	560	1,131
CN_NS	NS	8	566	588	913
CN_PQ	PQ	8	695	737	1,071
MIS_WUMS	MI	8	14	31	90
NENG_ME	ME	8	2	3	72
NENGREST	MA	8	2	3	42
	RI	8	66	72	75
NY_Z_K	NY	8	8	8	25
WEC_CALN	CA	8	71	95	
WECC_PNW	CA	8	12		
	OR	8	5	12	18
WECC_SCE	CA	8	51		

As an illustrative example, Table 4-31 shows the calculations that would be performed to derive the potential electric generation, reserve margin contribution, and cost of potential (new) onshore capacity in wind class 3, cost class 1 in the WECC_CO model region in run year 2021.

Table 4-31 Example Calculations of Wind Generation Potential, Reserve Margin Contribution, and Capital Cost for Onshore Wind in WECC_CO at Wind Class 3, Cost Class 1.

Required Data

Table 4-30	Potential wind capacity (C) =	951 MW
Table 4-31	Winter average generation (G_W) per available MW =	558 kWh/MW
Table 4-31	Winter Shoulder average generation (G_{WS}) per available MW =	569 kWh/MW
Table 4-31	Summer average generation (G_S) per available MW =	477 kWh/MW
	Hours in Winter (H_W) season (December - February) =	2160 hours
	Hours in Winter Shoulder (H_{WS}) season (Mar, Apr, Oct. Nov.) =	2928 hours
	Hours in Summer (H_S)season (May – September) =	3672 hours
Table 4-20b	Reserve Margin Contribution (RM) WECC_CO, Wind Class 3 =	19 percent
Table 4-16	Capital Cost (Cap_{2050}) in vintage range for year 2050 =	$1165/kW
Table 4-32	Capital Cost Adder ($CCA_{ON,C1}$) for onshore cost class 1 =	$342/kW
Table 4-15	Regional Factor (RF)	1.027

Calculations

$$\begin{aligned} \textit{Generation Potential} &= C \times G_W \times H_W + C \times G_{WS} \times H_{WS} + C \times G_S \times H_S \\ &= 951\ MW \times 558\ kWh/MW \times 2160\ hours + \\ &\quad 951\ MW \times 569\ kWh/MW \times 2928\ hours + \\ &\quad 951\ MW \times 477\ kWh/MW \times 3672\ hours \\ &= 4.395\ GWh \end{aligned}$$

$$\begin{aligned} \textit{Reserve Margin Contribution} &= RM \times C \\ &= 19\% \times 951\ MW \\ &= 185\ MW \end{aligned}$$

$$\begin{aligned} \textit{Capital Cost} &= \left(Cap_{2050} \times RF + CCA_{ON,C1}\right) \times C \\ &= (\$1,165/kW \times 1.027 + \$342) \times 951\ MW \\ &= \$1,463,507 \end{aligned}$$

Solar Generation

EPA Platform v6 includes solar PV and solar thermal generation technologies. The following sections describe four key aspects of the representation of solar generation: solar resource potential, generation profiles, reserve margin contribution, and capital cost calculation.

Solar Resource Potential: The resource potential estimates for solar PV and solar thermal technologies were developed by NREL by model region, state, and resource class. The NREL resource base for solar PV is represented by eight resource classes. In EPA Platform v6, the higher capacity factor resource classes of 3-8 are modeled for solar PV. The NREL resource base for solar thermal is represented by five resource classes. The solar thermal technology has a ten hour thermal energy storage (TES) and is considered a dispatchable resource for modeling purposes. These are summarized in Table 4-41 and Table 4-42.

Generation Profiles: Table 4-43 shows the generation profiles for solar PV plants in all model region, state, and resource combinations. The capacity factors for solar generation that are used in EPA Platform v6 were obtained from NREL and are shown in Table 4-46 and Table 4-47.

Reserve margin contribution (also referred to as capacity credit): The reserve margin contribution section for wind units summarizes the approach followed for calculating the reserve margin contribution for solar PV units. Table 4-32 presents the reserve margin contributions apportioned to new solar PV units in the EPA Platform v6. The solar thermal units are assumed to have 10 hour TES and are assigned 100% reserve margin contribution.

Table 4-32 Solar Photovoltaic Reserve Margin Contribution by Resource Class

	Resource Class						
	2	**3**	**4**	**5**	**6**	**7**	**8**
Reserve Margin Contribution	0% - 6%	0% - 71%	0% - 90%	0% - 90%	0% - 90%	0% - 90%	0% - 36%

Capital Costs: Similar to wind, capital costs for solar units include transmission spur line cost adders. The resource class level spur line cost curves for each model region and state combination are aggregated into a six-step cost curve. Table 4-44 and Table 4-45 illustrate the capital cost adder by resource and cost class for new solar plants.

The solar PV tariffs are incorporated through capital cost adders in 2021 run year. The tariffs are calculated as an average of the tariffs for 2018-2020 ((30% + 25% + 20%)/3 = 25%). The solar PV module cost in 2021 is assumed to be 350 2017$/kW based on an analysis performed by NREL.

The tax credit extensions for new solar units as prescribed in H.R. 2029, the Consolidated Appropriations Act of 2016, are implemented through reductions in capital costs. As the credits are based on construction start date, the 2020 Investment tax credit (ITC) of 26% is assigned to the 2021 run-year builds for solar PV units.

Geothermal Generation

Geothermal Resource Potential: Thirteen model regions in EPA Platform v6 have geothermal potential. The potential resource in each of these regions is shown in Table 4-33 and is based on NREL ATB 2016. GEO-Hydro Flash[37], GEO-Hydro Binary, GEO-NF EGS Flash and GEO-NF EGS Binary are the included technologies.

[37] In dual flash systems, high temperature water (above 400°F) is sprayed into a tank held at a much lower pressure than the fluid. This causes some of the fluid to "flash," i.e., rapidly vaporize to steam. The steam is used to drive a turbine, which, in turn, drives a generator. In the binary cycle technology, moderate temperature water (less than 400°F) vaporizes a secondary, working fluid, which drives a turbine and generator. Due to its use of more plentiful, lower temperature geothermal fluids, these systems tend to be most cost effective and are expected to be the most prevalent future geothermal technology.

Table 4-33 Regional Assumptions on Potential Geothermal Electric Capacity

IPM Model Region	Capacity (MW)
WEC_CALN	530
WEC_LADW	93
WECC_AZ	33
WECC_CO	26
WECC_ID	277
WECC_IID	3,203
WECC_MT	36
WECC_NM	178
WECC_NNV	1,900
WECC_PNW	1,272
WECC_SCE	561
WECC_UT	225
WECC_WY	48
Grand Total	**8,382**

Cost Calculation: EPA Platform v6 does not contain a single capital cost, but multiple geographically dependent capital costs for geothermal generation. The assumptions for geothermal were developed using NREL 2016 ATB cost and performance estimates for 152 sites. Both dual flash and binary cycle technologies were represented. The 152 sites were aggregated into 93 different options based on geographic location and cost and performance characteristics of geothermal sites in each of the 13 eligible IPM regions where geothermal generation opportunities exist. Table 4-34 shows the potential geothermal capacity and cost characteristics for applicable model regions.

Table 4-34 Potential Geothermal Capacity and Cost Characteristics by Model Region

IPM Region	Capacity (MW)	Capital Cost (2016$)	FO&M (2016$/kW-yr)
WEC_CALN	7	13,379	417
	10	19,535	518
	14	12,347	341
	15	20,164	535
	37	4,247	125
	68	4,988	128
	70	6,020	138
	111	8,767	259
	199	6,228	168
WEC_LADW	34	9,006	269
	59	5,976	169
WECC_AZ	33	19,005	501
WECC_CO	10	19,550	518
	15	13,945	379
WECC_ID	8	19,997	531
	10	21,106	542
	12	17,579	457
	13	16,325	439
	20	12,987	344
	23	18,113	497
	26	9,563	267

IPM Region	Capacity (MW)	Capital Cost (2016$)	FO&M (2016$/kW-yr)
	34	8,564	234
	46	11,742	331
	86	11,455	285
WECC_IID	6	7,898	236
	23	7,297	224
	25	8,885	267
	66	6,085	163
	79	9,470	278
	93	3,202	118
	119	4,630	143
	203	5,803	145
	2,589	4,050	107
WECC_MT	9	19,797	525
	11	16,457	443
	16	16,068	430
WECC_NM	6	17,611	408
	11	19,491	517
	34	6,047	169
	127	4,341	129
WECC_NNV	11	9,991	294
	12	15,737	375
	13	17,289	481
	14	20,232	536
	16	10,693	337
	16	13,199	351
	19	16,757	451
	30	11,792	342
	44	14,311	390
	50	12,296	344
	97	3,072	106
	103	6,335	195
	131	5,437	167
	139	9,420	280
	154	7,285	211
	171	8,617	259
	241	7,978	246
	262	4,542	153
	377	4,016	146
WECC_PNW	8	15,294	437
	10	9,883	263
	10	17,327	488
	11	14,223	413
	12	14,225	388
	12	15,323	403
	12	12,498	345
	13	12,648	366

IPM Region	Capacity (MW)	Capital Cost (2016$)	FO&M (2016$/kW-yr)
	16	11,821	318
	18	10,850	316
	19	19,668	522
	21	16,483	462
	28	15,623	413
	40	12,170	291
	50	8,752	258
	51	5,115	161
	126	7,132	212
	155	3,240	114
	202	7,023	203
	457	4,146	131
WECC_SCE	9	16,223	445
	25	7,936	260
	25	14,164	386
	45	6,671	156
	110	5,628	143
	347	3,072	105
WECC_UT	2	15,681	400
	7	11,025	343
	12	6,723	224
	15	16,101	462
	16	10,080	320
	64	3,072	115
	108	7,389	228
WECC_WY	48	13,175	348

Landfill Gas Electricity Generation

Landfill Gas Resource Potential: Estimates of potential electric capacity from landfill gas are based on the AEO 2014 inventory. EPA Platform v6 represents the “high”, “low”, and “very low” categories of potential landfill gas units. The categories refer to the amount and rate of methane production from the existing landfill site. Table 4-48 summarizes potential electric capacity from landfill gas.

There are several things to note about Table 4-48. The AEO 2014 NEMS region level estimates of the potential electric capacity from new landfill gas units are disaggregated to IPM regions based on electricity demand. The limits listed in Table 4-48 apply to the IPM regions indicated in column 1. In EPA Platform v6, the new landfill gas electric capacity in the corresponding IPM regions shown in column 1 cannot exceed the limits shown in columns 3-5. As noted earlier, the capacity limits for three categories of potential landfill gas units are distinguished in this table based on the rate of methane production at three categories of landfill sites: LGHI = high rate of landfill gas production, LGLo = low rate of landfill gas production, and LGLVo = very low rate of landfill gas production. The values shown in Table 4-48 represent an upper bound on the amount of new landfill capacity that can be added in each of the indicated model regions and states for each of the three landfill categories. The cost and performance assumptions for adding new capacity in each of the three landfill categories are presented in Table 4-16.

Energy Storage

Energy storage is the capture of energy produced at one time for use at a later time. Presently, the most common energy storage technologies are pumped storage and lithium-ion battery storage. EPA Platform v6 now includes battery storage by IPM region and state.

Table 4-35 summarizes the key cost and performance assumptions for new battery storage as implemented in November 2018 Reference Case. These assumptions are based on Annual Energy Outlook (AEO) 2018 inputs.

Table 4-35 Performance and Unit Cost Assumptions for Potential (New) Battery Storage

	Battery Storage
Size (MW)	30
First Year Available	2021
Lead Time (Years)	1
Availability (%)	96.4
Reserve Margin Contribution (%)	100
Generation Capability	Economic Dispatch
Storage System Efficiency (%)	85
Charge Capacity (Hours)	4
Fixed O&M (2016$/kW-Yr)	35
Variable O&M (2016$/MWh)	7.1
Capital Cost without IDC (2016$/kW)	
2021	2,048
2023	1,977
2025	1,906
2030	1,740
2035	1,574
2040	1,418
2045	1,271
2050	1,131

Multiple U.S. states have instituted standalone targets and mandates for energy storage procurement. Table 4-36 summarizes the state-specific energy storage mandates that are included in the November 2018 Reference Case. Under Assembly Bill No. 2514 and Assembly Bill No. 2868, the California Public Utilities Commission (CPUC) established energy storage targets for the state’s three investor-owned utilities (IOUs) Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric. Hence, the California state mandates are modeled at the utility level in the November 2018 Reference Case.

Table 4-36 Energy Storage Mandates in the November 2018 Reference Case

State/Region	Bill	Mandate Type	Mandate Specifications	Implementation Status
California	Assembly Bill No. 2514	Target in MW	Energy storage target of 1,325 megawatts for Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric by 2020, with installations required no later than the end of 2024.	2020
	Assembly Bill No. 2868	Target in MW	500 MW of distributed energy storage systems (166.66 MW for each of PG&E, SCE, and SDG&E).	2020
	Senate Bill No. 801	Target in MW	SB 801 directs LADWP to work with the city council of Los Angeles regarding potential deployment of 100 MW of energy storage solutions. SCE is procuring 20 MW.	2019
New York	New York State Energy Storage Target	Target in MW	1,500 Megawatts by 2025.	2025
New Jersey	Assembly Bill No. 3723	Target in MW	600 megawatts of energy storage by 2021 and 2,000 megawatts of energy storage by 2030.	2021
Oregon	House Bill 2193	Target in MWh per electric company	An electric company shall procure one or more qualifying energy storage systems that have the capacity to store at least five-megawatt hours of energy on or before January 1, 2020.	2020
Massachusetts	Chapter 188	Target in MWh	200 Megawatt hour (MWh) energy storage target for electric distribution companies to procure viable and cost-effective energy storage systems to be achieved by January 1, 2020.	2020

4.5 Nuclear Units

4.5.1 Existing Nuclear Units

Population, Plant Location, and Unit Configuration: To provide maximum granularity in forecasting the behavior of existing nuclear units, all 96 nuclear units in EPA Platform v6 are represented by separate model plants. As noted in Table 4-7, the 96 nuclear units include 94 currently operating units plus Vogtle Units 3 and 4, which are scheduled to come online post 2021. All are listed in Table 4-49. The population characteristics, plant location, and unit configuration data in NEEDS v6 were obtained primarily from EIA Form 860 and AEO 2018.

Capacity: Nuclear units are baseload power plants with high fixed (capital and fixed O&M) costs and relatively low variable (fuel and variable O&M) costs. Due to their low variable costs, nuclear units are run to the maximum extent possible, i.e., up to their availability. Consequently, a nuclear unit's capacity factor is equivalent to its availability. Thus, EPA Platform v6 uses capacity factor assumptions to define the upper bound on generation from nuclear units. Nuclear capacity factor assumptions in EPA Platform v6 are based on an Annual Energy Outlook projection algorithm. The nuclear capacity factor projection algorithm is described below:

- For each reactor, the capacity factor over time is dependent on the age of the reactor.
- Capacity factors increase initially due to learning, and decrease in the later years due to aging.
- For individual reactors, vintage classifications (older and newer) are used.
- For the older vintage (start before 1982) nuclear power plants, the performance peaks at 25 years:
  - Before 25 years: Performance increases by 0.5 percentage point per year;
  - 25-80 years: Performance remains flat; and
- For the newer vintage (start in or after 1982) nuclear power plants, the performance peaks at 30 years:
  - Before 30 years: Performance increases by 0.7 percentage points per year;
  - 30-80 years: Performance remains flat; and
- The maximum capacity factor is assumed to be 90 percent. Hence, a unit is not allowed to grow to a capacity factor higher than 90 percent. However, if a unit began with a capacity factor above 90 percent, it is allowed to retain that capacity factor. Given historical capacity factors are above 90 percent, the projected capacity factors range from 60 percent to 96 percent.

Cost and Performance: Unlike non-nuclear existing conventional units discussed in section 4.2.7, emission rates are not needed for nuclear units, since there are no SO_2, NO_x, CO_2, or mercury emissions from nuclear units.

As with other generating resources, EPA Platform v6 uses heat rate, variable O&M costs (VOM) and fixed O&M costs (FOM) to characterize the cost of operating existing nuclear units. The data are from AEO 2018 and are shown in Table 4-49.

EPA Platform v6 also uses the nuclear capacity uprates from AEO 2017 and ICF research. These are shown in Table 4-37**.**

Table 4-37 Nuclear Uprates (MW) as Incorporated in EPA Platform v6

Name	Plant ID	Unit ID	Year	Change in MWs
Columbia	371	1	2017	19.3
Browns Ferry	46	1	2017	164.7
Browns Ferry	46	2	2017	164.7
Browns Ferry	46	3	2017	164.7
Peach Bottom	3166	2	2017	21.7
Peach Bottom	3166	3	2017	21.7

EPA Platform v6 imposes lifetime extension costs for nuclear units (See Section 4.2.8) and a maximum lifetime of 80 years (See Section 3.7).

As nuclear units have aged, some units have been retired from service, or are planning to retire over the modeled time horizon. For a list of remaining nuclear units, see the NEEDS v6 database. Furthermore, IPM provides nuclear units with the choice to retire, based on the economics.

Zero Emission Credit (ZEC) Programs: New York and Illinois passed legislation in 2017 to provide support to selected existing nuclear units that could be at risk of early closure due to declining profitability.

The New York Clean Energy Standard for a 12-year period creates ZECs that are currently applicable for Fitzpatrick, Ginna, and Nine Mile Point nuclear power plants. The New York load-serving entities (LSEs) are responsible for purchasing ZECs equal to their share of the statewide load, providing an additional revenue stream to the nuclear power plants holding the ZECs. Similar to the New York program, the Illinois Future Energy Jobs Bill creates a ZEC program covering a 10-year term for Clinton and Quad Cities nuclear power plants.

EPA Platform v6 implicitly models the effect of ZECs by disabling the retirement options for Fitzpatrick, Ginna, Nine Mile Point, Clinton, and Quad Cities nuclear power plants in the 2021, 2023, and 2025 run years.

Nuclear Retirement Limits: In EPA Platform v6, endogenous retirements in 2021 of nuclear units are limited to 8,000 MW[38]. It is assumed that nuclear units will retire at a pace of 2000 MW per year during the 2018-2021 period. This 2000 MW per year rate is estimated based on a review of nuclear retirements in recent years.

Life Extension Costs: Attachment 4-1 summarizes the approach to estimate unit level life extension costs for existing nuclear units. Nuclear units are assumed to have a maximum lifetime of 80 years (see Section 3.7). Unlike other plant types, life extension costs for nuclear units are calculated as a function of age and are applied starting 2021 run year and continue through age 80.

4.5.2 Potential Nuclear Units

The cost and performance assumptions for nuclear potential units that the model has the option to build in EPA Platform v6 are shown in Table 4-13. The cost assumptions are from AEO 2017.

[38] The 8,000 MW limit includes the scheduled retirements of Oyster Creek, Three Mile Island, Pilgrim, and Indian Point nuclear units 2 and 3.

List of tables that are uploaded directly to the web: