3. Power System Operation Assumptions

This chapter describes the assumptions pertaining to the North American electric power system as represented in the EPA Platform v6 Summer 2021 Reference Case (EPA Platform v6).

3.1 Model Regions

EPA Platform v6 models the power sector in the contiguous United States, and 10 Canadian provinces (with Newfoundland and Labrador represented as two regions on the electricity network even though politically they constitute a single province[13]) as an integrated network.[14]

There are 67 IPM model regions covering the contiguous United States.[15] The IPM model regions are largely consistent with the regional configuration presented in the NERC Long-Term Reliability Assessments.[16] IPM model regions reflect the administrative structure of regional transmission organizations (RTOs) and independent system operators (ISOs). Further disaggregation allows a more accurate characterization of the operation of the United States power markets by providing the ability to represent transmission bottlenecks across RTOs and ISOs, as well as key transmission limits within them. Other items of note in the IPM regional definition include:

- The NERC assessment regions of MISO, PJM, and SPP cover the areas of the corresponding RTOs and are designed to better represent transmission limits and dispatch in each area. In IPM, model regions are designed to represent planning areas within each RTO and/or areas with internal transmission limits. Accordingly, MISO area is disaggregated into 14 IPM regions. PJM assessment area is disaggregated into 9 IPM regions, and SPP is disaggregated into 5 IPM regions.

- New York is disaggregated into 8 IPM regions, to better represent flows around New York City and Long Island, and to better represent flows across New York State from Canada and other United States regions. The NERC assessment region SERC is divided into Kentucky, TVA, AECI, the Southeast, and the Carolinas. New England is disaggregated into CT, ME, and rest of New England regions. ERCOT is also disaggregated into 3 IPM regions. IPM retains the NERC assessment areas within the overall WECC regions, and further disaggregates these areas using sub-regions from the WECC Power Supply Assessment. In total, WECC is disaggregated into 16 IPM regions.

Figure 3-1 contains a map showing the EPA Platform v6 model regions.

Table 3-1 defines the abbreviated region names appearing on the map and gives a crosswalk between the IPM model regions, the NERC assessment regions, and regions used in the Energy Information Administration's (EIA's) National Energy Model System (NEMS) that is the basis for EIA's Annual Energy Outlook (AEO) reports.

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[13] This results in a total of 11 Canadian model regions being represented in EPA Platform v6.

[14] Because United States and the Canadian power markets are being modeled in an integrated manner, IPM can model the transfer of power in between the two countries endogenously. This transfer of power is limited by the available transmission capacity in between the two countries. Hence, it is possible for the model to build capacity in one country to meet demand in the other country when economic and is operationally feasible.

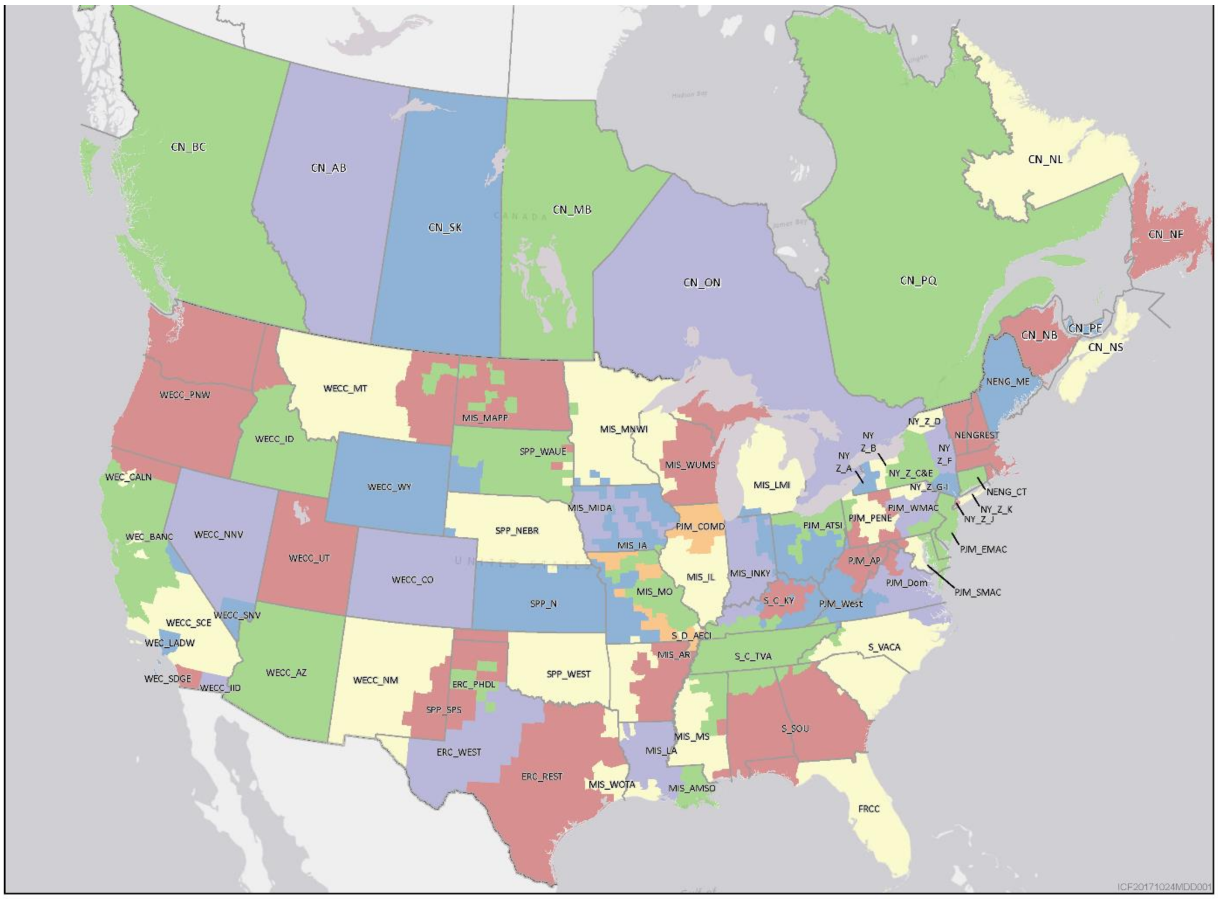
[15] The 67 U.S. IPM model regions include 64 power market regions and 3 power switching regions.

[16] IPM regions also generally conform to the boundaries of the National Energy Modeling System (NEMS) model to provide for a more accurate translation of demand projections taken from the Annual Energy Outlook (AEO).

3.2 Electric Load Modeling

Net energy for load and net internal demand are inputs to IPM that together are used to represent the grid-demand for electricity. Net energy for load is the projected annual electricity grid-demand, prior to accounting for intra-regional transmission and distribution losses. Net internal demand (peak demand) is the maximum hourly demand within a given year after removing interruptible demand. Table 3-2 shows the electricity demand assumptions (expressed as net energy for load) used in EPA Platform v6. It is based on the net energy for load in AEO 2020 Reference Case.[17]

Figure 3-1 EPA Platform v6 Model Regions



For purposes of documentation, Table 3-2 and Table 3-3 present the net energy for load on a national- and regional-level, respectively. EPA Platform v6 models net energy for load in each of the 67 U.S. IPM regions in the following steps:

- The net energy for load in each of the 25 NEMS electricity regions is taken from the AEO 2020 Reference Case.
- NERC balancing areas are assigned to both IPM regions and NEMS regions to determine the share of the NEMS net energy for load in each NEMS regions that falls into each IPM region. These shares are calculated in the following steps.

[17] The electricity demand in EPA Platform v6 for the U.S. lower 48 states and the District of Columbia is obtained for each IPM model region by disaggregating the Total Net Energy for Load projected for the corresponding NEMS Electric Market Module region as reported in the Electricity and Renewable Fuel Tables 54.1-54.25 at https://www.eia.gov/outlooks/archive/aeo20/tables_ref.php.

- Map the NERC Balancing Authorities/ Planning Areas in the United States to the 67 IPM regions.
- Map the Balancing Authorities/ Planning Areas in the United States to the 25 NEMS regions.
- Using the 2016 hourly load data from FERC Form 714, ISOs, and RTOs, calculate the proportional share of load in the 25 NEMS regions that share a geography with the 67 IPM regions.
- Using the calculated load shares for each NEMS region that falls into each IPM region, calculate the total net energy for load for each IPM region from the NEMS regional load in the AEO 2020 Reference Case.

Table 3-1 Mapping of NERC Regions and NEMS Regions with v6 Model Regions

NERC Assessment Region	AEO 2020 NEMS Region	Model Region	Model Region Description
ERCOT	TRE (1)	ERC_REST	ERCOT_Rest
	TRE (1)	ERC_GWAY	ERCOT_Tenaska Gateway Generating Station
	TRE (1)	ERC_FRNT	ERCOT_Tenaska Frontier Generating Station
	TRE (1)	ERC_WEST	ERCOT_West
	TRE (1)	ERC_PHDL	ERCOT_Panhandle
FRCC	FRCC (2)	FRCC	FRCC
MAPP	MISW (3), SPPN (19)	MIS_MAPP	MISO_MT, SD, ND
MISO	MISC (4)	MIS_IL	MISO_Illinois
	MISC (4)	MIS_INKY	MISO_Indiana (including parts of Kentucky)
	MISW (3)	MIS_IA	MISO_Iowa
	MISW (3)	MIS_MIDA	MISO_Iowa-MidAmerican
	MISE (5)	MIS_LMI	MISO_Lower Michigan
	MISC (4)	MIS_MO	MISO_Missouri
	MISW (3)	MIS_WUMS	MISO_Wisconsin- Upper Michigan (WUMS)
	MISW (3)	MIS_MNWI	MISO_Minnesota and Western Wisconsin
	MISS (6)	MIS_WOTA	MISO_WOTAB (including Western)
	MISS (6)	MIS_AMSO	MISO_Amite South (including DSG)
	MISS (6)	MIS_AR	MISO_Arkansas
	MISS (6)	MIS_MS	MISO_Mississippi
	MISS (6)	MIS_LA	MISO_Louisiana
ISO-NE	ISNE (7)	NENG_CT	ISONE_Connecticut
	ISNE (7)	NENGREST	ISONE_MA, VT, NH, RI (Rest of ISO New England)
	ISNE (7)	NENG_ME	ISONE_Maine
NYISO	NYUP (9)	NY_Z_C&E	NY_Zone C&E
	NYUP (9)	NY_Z_F	NY_Zone F (Capital)
	NYUP (9)	NY_Z_G-I	NY_Zone G-I (Downstate NY)
	NYCW (8)	NY_Z_J	NY_Zone J (NYC)
	NYCW (8)	NY_Z_K	NY_Zone K (LI)
	NYUP (9)	NY_Z_A	NY_Zone A (West)
	NYUP (9)	NY_Z_B	NY_Zone B (Genesee)
	NYUP (9)	NY_Z_D	NY_Zone D (North)
PJM	PJME (10)	PJM_WMAC	PJM_Western MAAC
	PJME (10)	PJM_EMAC	PJM_EMAAC
	PJME (10)	PJM_SMAC	PJM_SWMAAC
	PJMW (11)	PJM_West	PJM West
	PJMW (11)	PJM_AP	PJM_AP

NERC Assessment Region	AEO 2020 NEMS Region	Model Region	Model Region Description
	PJMC (12)	PJM_COMD	PJM_ComEd
	PJMW (11)	PJM_ATSI	PJM_ATSI
	PJMD (13)	PJM_Dom	PJM_Dominion
	PJME (10)	PJM_PENE	PJM_PENELEC
SERC-E	SRCA (14)	S_VACA	SERC_VACAR
SERC-N	SRCE (16)	S_C_KY	SERC_Central_Kentucky
	MISC (4), SPPS (17)	S_D_AECI	SERC_Delta_AECI
	SRCE (16)	S_C_TVA	SERC_Central_TVA
SERC-SE	SRSE (15)	S_SOU	SERC_Southeastern
SPP	SPPN (19)	SPP_NEBR	SPP Nebraska
	SPPC (18)	SPP_N	SPP North- (Kansas, Missouri)
	SPPS (17)	SPP_KIAM	SPP_Kiamichi Energy Facility
	SPPS (17)	SPP_WEST	SPP West (Oklahoma, Arkansas, Louisiana)
	SPPS (17)	SPP_SPS	SPP SPS (Texas Panhandle)
	SPPN (19)	SPP_WAUE	SPP_WAUE
California/Mexico (CA/MX)	CANO (21)	WEC_CALN	WECC_Northern California (not including BANC)
	CASO (22)	WEC_LADW	WECC_LADWP
	CASO (22)	WEC_SDGE	WECC_San Diego Gas and Electric
	CASO (22)	WECC_SCE	WECC_Southern California Edison
Northwest Power Pool (NWPP)	NWPP (23)	WECC_MT	WECC_Montana
	CANO (21)	WEC_BANC	WECC_BANC
	BASN (25)	WECC_ID	WECC_Idaho
	BASN (25)	WECC_NNV	WECC_Northern Nevada
	BASN (25), SRSG (20)	WECC_SNV	WECC_Southern Nevada
	BASN (25)	WECC_UT	WECC_Utah
	NWPP (23)	WECC_PNW	WECC_Pacific Northwest
Rocky Mountain Reserve Group (RMRG)	RMRG (24)	WECC_CO	WECC_Colorado
	BASN (25), RMRG (24)	WECC_WY	WECC_Wyoming
Southwest Reserve Sharing Group (SRSG)	SRSG (20)	WECC_AZ	WECC_Arizona
	SRSG (20)	WECC_NM	WECC_New Mexico
	SRSG (20)	WECC_IID	WECC_Imperial Irrigation District (IID)
Canada		CN_AB	Canada_Alberta
		CN_BC	Canada_British Columbia
		CN_MB	Canada_Manitoba
		CN_NB	Canada_New Brunswick
		CN_NF	Canada_New Foundland
		CN_NL	Canada_Labrador
		CN_PE	Canada_Prince Edward island
		CN_NS	Canada_Nova Scotia
		CN_ON	Canada_Ontario
		CN_PQ	Canada_Quebec
		CN_SK	Canada_Saskatchewan

Table 3-2 Electric Load Assumptions in v6

Year	Net Energy for Load (Billions of kWh)
2023	4,186
2025	4,229
2028	4,302
2030	4,366
2035	4,542
2040	4,757
2045	5,000
2050	5,283

Notes:
The data represents an aggregation of the model-region-specific net energy loads used in the EPA Platform v6 and includes the demand met by distributed solar photovoltaics.

Table 3-3 Regional Electric Load Assumptions in v6

IPM Region	Net Energy for Load (Billions of kWh)							
	2023	2025	2028	2030	2035	2040	2045	2050
ERC_FRNT	0	0	0	0	0	0	0	0
ERC_GWAY	0	0	0	0	0	0	0	0
ERC_PHDL	0	0	0	0	0	0	0	1
ERC_REST	362	368	375	382	401	424	450	478
ERC_WEST	32	32	33	34	35	37	40	42
FRCC	246	248	253	257	270	285	301	321
MIS_AMSO	35	35	36	37	39	41	43	45
MIS_AR	41	42	43	43	45	48	50	53
MIS_MS	25	26	26	27	28	29	31	32
MIS_IA	22	22	23	23	24	24	25	26
MIS_IL	50	51	52	52	54	56	58	60
MIS_INKY	96	97	99	100	103	106	110	115
MIS_LA	54	55	56	57	59	63	66	70
MIS_LMI	103	104	105	107	110	113	117	122
MIS_MAPP	8	8	9	9	9	9	10	10
MIS_MIDA	27	28	28	28	29	30	31	33
MIS_MNWI	90	91	93	94	97	100	104	108
MIS_MO	39	40	40	41	42	43	45	47
MIS_WOTA	36	37	38	38	40	42	44	47
MIS_WUMS	66	67	68	69	71	74	76	79
NENG_CT	31	31	32	32	34	35	37	39
NENG_ME	12	12	12	12	13	13	14	15
NENGREST	84	85	86	87	91	95	99	105
NY_Z_A	14	14	14	14	15	15	16	16
NY_Z_B	9	9	9	9	9	10	10	10
NY_Z_C&E	22	21	22	22	22	23	24	25
NY_Z_D	4	4	4	4	4	4	4	5
NY_Z_F	11	11	11	11	11	12	12	13
NY_Z_G-I	17	17	17	17	18	18	19	20
NY_Z_J	60	60	60	60	62	64	66	70
NY_Z_K	24	24	24	24	25	26	27	28
PJM_AP	49	49	50	51	52	54	56	59
PJM_ATSI	69	69	70	71	73	76	79	82
PJM_COMD	97	97	99	100	103	106	110	114
PJM_Dom	104	105	107	109	114	120	126	135
PJM_EMAC	142	142	143	145	150	156	162	170
PJM_PENE	18	18	18	18	19	20	20	21
PJM_SMAC	64	64	65	66	68	71	73	77
PJM_West	203	204	207	210	217	224	232	242

IPM Region	Net Energy for Load (Billions of kWh)							
	2023	2025	2028	2030	2035	2040	2045	2050
PJM_WMAC	57	57	58	58	60	63	65	69
S_C_KY	34	34	35	35	36	38	39	41
S_C_TVA	170	172	175	177	182	189	196	204
S_D_AECI	18	18	18	19	19	20	21	22
S_SOU	245	247	252	256	266	278	292	307
S_VACA	245	248	253	257	269	283	298	315
SPP_KIAM	0	0	0	0	0	0	0	0
SPP_N	76	77	78	79	82	85	88	92
SPP_NEBR	30	31	31	32	33	34	35	37
SPP_SPS	34	35	36	36	38	40	43	45
SPP_WAUE	25	25	25	26	27	28	29	30
SPP_WEST	102	104	106	108	114	120	127	135
WEC_BANC	15	15	15	15	16	17	18	19
WEC_CALN	116	116	117	118	123	130	139	149
WEC_LADW	28	29	29	29	30	32	34	37
WEC_SDGE	20	20	21	21	22	23	24	26
WECC_AZ	96	98	102	104	111	118	127	137
WECC_CO	67	69	71	73	77	83	89	95
WECC_ID	24	25	26	26	28	30	32	35
WECC_IID	4	4	5	5	5	5	6	6
WECC_MT	13	13	13	13	14	15	15	17
WECC_NM	22	23	24	24	26	27	29	32
WECC_NNV	14	14	14	15	16	17	18	19
WECC_PNW	172	173	175	176	184	195	208	223
WECC_SCE	105	106	106	107	111	118	126	135
WECC_SNV	27	27	28	29	31	33	35	38
WECC_UT	37	38	39	40	43	46	49	53
WECC_WY	23	24	24	25	26	28	30	33

3.2.1 Distributed Solar Photovoltaics

Distributed solar photovoltaic (DPV) generation constitutes a significant and growing source of new electricity generation in the United States. As a result, DPV generation has become increasingly pertinent from an integrated resource planning perspective because it has the potential to significantly impact the shapes of the residual load curves that are available for the grid-connected generation sources to meet. The DPV implementation in EPA Platform v6 seeks to reflect this impact to the load shape by directly representing the magnitude and timing of the electricity demand projected to be satisfied by distributed solar PV as part of the total net energy for load.

<u>Electricity Demand Assumptions:</u> Electricity demand assumptions are represented by the total net energy for load from the AEO 2020 Reference Case. To account for DPV generation, the AEO 2020 Reference Case projections of end-use solar photovoltaic generation are added to AEO 2020 Reference Case projections of net energy for load.

<u>Unit-Level Data Assumptions:</u> Non-dispatchable DPV model plants at the IPM region and state level are implemented in IPM to capture the impact of the DPV generation on the shapes of the residual load curves available for the grid-connected generation sources to meet. Their generation patterns are governed by assumed DPV generation profiles provided by NREL.

The capacity and capacity factors of DPV model plants are calculated as follows. First, the AEO 2020 Reference Case end-use solar photovoltaic generation and capacity data that are available at the NEMS region level are apportioned to IPM region level, using the methodology for mapping the electricity demand projections from NEMS regions to IPM regions. Then, the IPM region level data are further apportioned to the state level, using state shares of regional energy sales as reported by the 2016 EIA Form 861. The data are next used to derive IPM region and state level capacity factor data. Finally, the resulting IPM region and state level capacity data are hardwired to the DPV model plants, while the capacity factor data are implemented by appropriately scaling the NREL's IPM region and state level DPV hourly generation profiles. For this analysis, NREL's DPV hourly generation profiles for the highest resource class in each of the IPM region and state categories were scaled by multiplying the hourly generation values with the ratio between the AEO 2020 Reference Case capacity factor and the capacity factor underlying the NREL's hourly generation profiles.

3.2.2 Demand Elasticity

EPA Platform v6 has the capability to endogenously adjust electricity demand based on changes to with the price of power. However, this capability is exercised only for sensitivity analyses where different price elasticities of demand are specified for purposes of comparative analysis. The default assumption is that the electricity demand shown in Table 3-2, which was derived from EIA modeling that already considered price elasticity of demand, is static as IPM solves for least-cost electricity supply. The approach maintains a consistent expectation of future load between the EPA Platform and the corresponding EIA Annual Energy Outlook reference case (e.g., between EPA Platform v6 and the AEO 2020 Reference Case).

3.2.3 Net Internal Demand (Peak Demand)

EPA Platform v6 has separate regional winter, winter shoulder, and summer peak demand values, as derived from each region's seasonal load duration curve (found in Table 2-2). Peak projections for the 2023-2029 period were estimated based on NERC ES&D 2019 load factors[18], and the estimated energy demand projections shown in Table 3-3. For post 2029 years when NERC ES&D 2019 load factors were not available, the NERC ES&D 2019 load factors for 2029 were projected forward using growth factors embedded in the AEO 2020 Reference Case load factor projections.

Table 3-4 illustrates the national sum of each region's seasonal peak demand, and Table 3-27 presents each region's seasonal peak demand. Because each region's seasonal peak demand need not occur at the same time, the national peak demand is defined as non-coincidental (i.e., national peak demand is a summation of each region's peak demand at whatever point in time that region's peak occurs across the given time period).

Table 3-4 National Non-Coincidental Net Internal Demand in v6

Year	Peak Demand (GW)		
	Winter	Winter Shoulder	Summer
2023	658	597	783
2025	664	603	790
2028	676	613	802
2030	688	624	818
2035	723	655	862
2040	767	693	917
2045	817	736	983
2050	875	786	1,058

Notes:

This data is an aggregation of the model-region-specific peak demand loads.

[18] Load factors can be calculated at the NERC assessment region level based on the NERC ES&D 2019 projections of net energy for load and net internal demand. All IPM regions that map to a particular NERC assessment region are assigned the same load factors. In instances where sub regional level load factor details could be estimated in selected ISO/RTO zones, those load factors were assigned to the associated IPM region.

3.2.4 Regional Load Shapes

EPA Platform v6 uses the year 2011 as the "normal weather year"[19] for all IPM regions except for ERCOT, where 2016 data was used. The proximity of the 2011 cumulative annual heating degree days (HDDs) and cooling degree days (CDDs) to the long-term average cumulative annual HDDs and CDDs over the period 1981 to 2010 was estimated and found to be reasonably close. The 2011 and 2016 chronological hourly load data were assembled by aggregating individual utility load curves taken from Federal Energy Regulatory Commission Form 714 data and individual ISOs and RTOs.

3.3 Transmission

The contiguous United States and Canada can be represented by several power markets that are interconnected by a transmission grid. This section details the assumptions about the transfer capabilities and costs used to represent this transmission grid in EPA Platform v6.

3.3.1 Inter-regional Transmission Capability

Table 3-28[20] shows the firm and non-firm Total Transfer Capabilities (TTCs) between model regions. TTC is a metric that represents the capability of the power system to import or export power reliably from one region to another. The purpose of TTC analysis is to identify the sub-markets created by commercially significant constraints. Firm TTCs, also called Capacity TTCs, specify the maximum power that can be transferred reliably, even after the contingency loss of a single transmission system element such as a transmission line or a transformer (a condition referred to as N-1, or "N minus one"). Firm TTCs provide a high level of reliability and are used for capacity transfers. Non-firm TTCs, also called Energy TTCs, represent the maximum power that can be transferred reliably when all facilities are under normal operation (a condition referred to as N-0, or "N minus zero"). Non-firm TTCs specify the sum of the maximum firm transfer capability between sub-regions and incremental curtailable non-firm transfer capability. Non-firm TTCs are used for energy transfers since they provide a lower level of reliability than Firm TTCs, and transactions using Non-firm TTCs can be curtailed under emergency or contingency conditions.

The amount of energy and capacity transferred on a given transmission link is modeled on a seasonal basis for all run years in the EPA Platform v6. All the modeled transmission links have the same TTCs for all seasons. The maximum values for firm and non-firm TTCs were obtained from public sources such as market reports and regional transmission plans, wherever available. Where public sources were not available, the maximum values for firm and non-firm TTCs are based on ICF's expert view. ICF analyzes the operation of the grid under normal and contingency conditions, using industry-standard methods, and calculates the transfer capabilities between regions. To calculate the transfer capabilities, ICF uses standard power flow data developed by the market operators, transmission providers, or utilities, as appropriate.

Furthermore, each transmission link between model regions shown in Table 3-28 represents a one-directional flow of power on that link. This means that the maximum amount of flow of power possible from region A to region B may be more or less than the maximum amount of flow of power possible from region B to region A, due to the physical nature of electron flow across the grid.

[19] The term "normal weather year" refers to a representative year whose weather is closest to the long-term (e.g., 30 year) average weather. The selection of a "normal weather year" can be made, for example, by comparing the cumulative annual heating degree days (HDDs) and cooling degree days (CDDs) in a candidate year to the long-term average. For any individual day, heating degree days indicate how far the average temperature fell below 65 degrees F; cooling degree days indicate how far the temperature averaged above 65 degrees F. Cumulative annual heating and cooling degree days are the sum of all the HDDs and CDDs, respectively, in a given year.

[20] In the column headers in Table 3-28, the term "Energy TTC (MW)" is equivalent to non-firm TTCs and the term "Capacity TTC (MW)" is equivalent to firm TTCs.

3.3.2 Joint Transmission Capacity and Energy Limits

Table 3-5 shows the annual joint limits to the transmission capabilities between model regions, which are identical for the firm (capacity) and non-firm (energy) transfers. The joint limits were obtained from public sources where available or based on ICF's expert view. A joint limit represents the maximum simultaneous firm or non-firm power transfer capability of a group of interfaces. It restricts the amount of firm or non-firm transfers between one model region (or group of model regions) and a different group of model regions. For example, the New England market is connected to the New York market by four transmission links:

- NENG_CT to NY_Z_G-I: 600 MW
- NENGREST to NY_Z_F: 800 MW
- NENGREST to NY_Z_D: 0 MW
- NENG_CT to NY_Z_K: 734 MW

Without any simultaneous transfer limits, the total transfer capability from New England to New York would be 2,134 MW. However, current system conditions and reliability requirements limit the total simultaneous transfers from New England to New York to 1,730 MW, as shown in Table 3-5. ICF uses joint limits to ensure that this and similar reliability limits are not violated. Therefore, each individual link can be utilized to its limit as long as the total flow on all links does not exceed the joint limit.

Table 3-5 Annual Joint Capacity and Energy Limits to Transmission Capabilities between Model Regions in v6

Region Connection	Transmission Path	Capacity TTC (MW)	Energy TTC (MW)
NY_Zone G-I (Downstate NY) & NY_Zone J (NYC) to NY_Zone K (LI)	NY_Z_G-I to NY_Z_K NY_Z_J to NY_Z_K	1,528	
NY_Zone K(LI) to NY_Zones G-I (Downstate NY) & NY_Zone J (NYC)	NY_Z_K to NY_Z_G-I NY_Z_K to NY_Z_J	104	
ISO NE to NYISO	NENG_CT to NY_Z_G-I NENGREST to NY_Z_F NENG_CT to NY_Z_K NENGREST to NY_Z_D	1,730	
NYISO to ISO NE	NY_Z_G-I to NENG_CT NY_Z_F to NENGREST NY_Z_K to NENG_CT NY_Z_D to NENGREST	1,730	
PJM West & PJM_PENELEC & PJM_AP to PJM_ATSI	PJM_West to PJM_ATSI PJM_PENE to PJM_ATSI PJM_AP to PJM_ATSI	9,925	
PJM_ATSI to PJM West & PJM_PENELEC & PJM_AP	PJM_ATSI to PJM_West PJM_ATSI to PJM_PENE PJM_ATSI to PJM_AP	9,925	
PJM_West & PJM_Dominion to SERC VACAR	PJM_West to S_VACA PJM_Dom to S_VACA	2,208	3,424
	S_VACA to PJM_West	2,208	3,424

Region Connection	Transmission Path	Capacity TTC (MW)	Energy TTC (MW)
SERC VACAR to PJM_West & PJM_Dominion	S_VACA to PJM_Dom		
MIS_MAPP & SPP_WAUE to MIS_MNWI	MIS_MAPP to MIS_MNWI SPP_WAUE to MIS_MNWI	3,000	5,000
MIS_MNWI to MIS_MAPP & SPP_WAUE	MIS_MNWI to MIS_MAPP MIS_MNWI to SPP_WAUE	3,000	5,000
SERC_Central_TVA & SERC_Central_Kentucky to PJM West	S_C_TVA to PJM_West S_C_KY to PJM_West	3,000	4,500
PJM West to SERC_Central_TVA & SERC_Central_Kentucky	PJM_West to S_C_TVA PJM_West to S_C_KY	3,000	4,500
MIS_INKY to PJM_COMD & PJM_West	MIS_INKY to PJM_COMD MIS_INKY to PJM_West	4,586	6,509
PJM_COMD & PJM_West to MIS_ INKY	PJM_COMD to MIS_INKY PJM_West to MIS_INKY	5,998	8,242
NY_Z_J & NY_Z_G-I to PJM_EMAC	NY_Z_J to PJM_EMAC NY_Z_G-I to PJM_EMAC	1,975	
PJM_EMAC to NY_Z_J & NY_Z_G-I	PJM_EMAC to NY_Z_J PJM_EMAC to NY_Z_G-I	2,975	
NY_Z_C&E & NY_Z_A to PJM_PENELEC	NY_Z_C&E to PJM_PENE NY_Z_A to PJM_PENE	1,050	
PJM_PENELEC to NY_Z_C&E & NY_Z_A	PJM_PENE to NY_Z_C&E PJM_PENE to NY_Z_A	1,365	
PJM_SMAC & PJM_WMAC to PJM_EMAC	PJM_SMAC to PJM_EMAC PJM_WMAC to PJM_EMAC	9,752	
PJM_AP, PJM_DOM, PJM_EMAC & PJM_WMAC to PJM_SMAC	PJM_AP to PJM_SMAC PJM_DOM to PJM_SMAC PJM_EMAC to PJM_SMAC PJM_WMAC to PJM_SMAC	9,158	
PJM_AP, PJM_ATSI & PJM_DOM to PJM_PENELEC, PJM_SMAC & PJM_WMAC	PJM_AP to PJM_PENE PJM_AP to PJM_SMAC PJM_AP to PJM_WMAC PJM_ATSI to PJM_PENE PJM_DOM to PJM_SMAC	2,252	6,500
CN_AB to CN_BC & WECC_MT	CN_AB to WECC_MT CN_AB to CN_BC	1,000	
CN_BC & WECC_MT to CN_AB	WECC_MT to CN_AB CN_BC to CN_AB	1,110	

3.3.3 Transmission Link Wheeling Charge

The transmission link wheeling charge is the cost of transferring electric power from one region to another. The EPA Platform v6 has no wheeling charges within individual IPM regions and no charges between IPM regions that fall within the same RTO. The wheeling charges, expressed in 2019 mills/kWh, are shown in Table 3-28 in the column labeled "Transmission Tariff."

3.3.4 Transmission Losses

The EPA Platform v6 assumes a 2.8 percent inter-regional transmission loss of energy transferred in the Western interconnection and a 2.4 percent inter-regional transmission loss of energy transferred in Eastern Interconnection and ERCOT. These factors are based on average loss factors calculated from standard power flow data developed by the transmission providers.

3.3.5 New Transmission Builds

EPA Platform v6 includes new endogenous transmission build options starting in 2028.[21] An important dynamic driving this change is the increased deployment of new renewable generation capacity that is at a significant distance from the load centers driving its deployment. Consequently, the inability to deploy additional transmission capacity endogenously may be unduly limiting the economic potential of new renewable capacity. More generally, enabling transmission capacity expansion allows IPM to co-optimize generation and transmission builds and solve for the optimal mix of generation and transmission additions to meet capacity and energy needs.

For these transmission build options, representative costs were derived from NREL's Jobs and Economic Development Impact (JEDI) model. Inputs to the JEDI model included the likely voltage rating, a representative length of line between each region, and the type of terrain expected to be traversed. The approach included:

- Determination of likely voltage rating. The cost of transmission lines varies with voltage rating. Higher voltage ratings typically have higher costs per unit length. To minimize maintenance, inventory, and other costs, it is likely that a new transmission line in an area will be rated at a voltage similar to transmission lines already existing in the area. Further, it is likely that an interregional line would be rated at or close to the highest voltage rating of the area's backbone transmission system due to economies of scale. ICF reviewed the backbone transmission system in each of the model regions to determine the likely voltage rating that would be used for new transmission lines. For example, the backbone transmission system in the Northeast (New York and the New England states) is rated 345 kV. While the systems also have underlying 230 kV and lower voltage transmission lines, it is likely that new inter-regional transmission lines would be rated 345 kV. In most of the southeastern U.S. states the backbone voltage is 500 kV; therefore, we assume that a line between Florida and Southern Company, for example, would likely be rated 500 kV.

- Estimation of representative line lengths. The cost of transmission lines also varies with the length of line. The length of a particular line will depend on several factors, including the location of existing interconnecting substations, existing rights-of-way, area of need within the zone, and other factors. The length cannot be determined in advance without knowing the specific application. For this analysis EPA made a simplifying assumption that lines would be built between the geographic centers of the regions. In instances where the transmission line lengths that are calculated using the centroid approach are longer than a typical maximum for

[21] New transmission options in EPA Platform v6 are built simultaneously in both directions as transmission lines when built can allow bidirectional flows.

the assumed line voltage, the typical maximum[22] length was used to estimate the unit cost of the line.

- Assessment of terrain. Transmission line costs also vary with terrain. For example, a line traversing a mountainous region would have a higher capital cost than a line in a flat, rural area. Terrain classifications in the JEDI model include “Desert/Remote”, “Mountainous”, and “Flat With Access”. The model also allows for specification of population densities, including “In Town”, “Near Town”, and “Rural”. Terrain classifications and population densities were assigned that best represented the area that lines between the regions would likely traverse. For example, the terrain traversed by a line between New York City and Long Island was classified as Flat With Access and the population density was specified as In Town, while a line between Nebraska and the Oklahoma-Missouri area was classified as Flat With Access and Rural.

Together, this information was used to determine the total cost of a new transmission line between each pair of contiguous IPM regions. ICF then calculated a unit cost in $/kW for each transmission link using estimates of the power (MW) ratings for each transmission line. The bidirectional unit costs for new transmission lines are shown in Table 3-28.

3.4 International Imports

The United States electric power system is connected with the transmission grids in Canada and Mexico and the three countries actively trade in electricity. The Canadian power market is endogenously modeled in EPA Platform v6, but Mexico is not. International electric trading between the United States and Mexico is represented by an assumption of net imports based on information from AEO 2020 Reference Case. Table 3-6 summarizes the assumptions on net imports into the United States from Mexico.

Table 3-6 International Electricity Imports (billions kWh) in v6

	2023	2025	2028	2030	2035	2040	2045	2050
Net Imports from Mexico	5.41	5.41	5.41	5.41	5.41	5.13	5.13	5.13

Note 1: Source: AEO 2020 Reference Case
Note 2: Imports & exports transactions from Canada are endogenously modeled in IPM.

3.5 Capacity, Generation, and Dispatch

While the capacity of existing units is an exogenous input into IPM, the dispatch of those units is an endogenous decision. The capacity of existing generating units included in EPA Platform v6 can be found in the National Electrical Energy Data System (NEEDS v6), a database which provides IPM with information on all currently operating and planned-committed electric generating units. NEEDS v6 is discussed in Chapter 4.

A unit’s generation over a time period is defined by its dispatch pattern. IPM determines the optimal economic dispatch profile given the operating and physical constraints imposed on the unit. In EPA Platform v6, unit-specific operational and physical constraints are represented through availability, capacity factor, and turndown constraints.

[22] The typical maximum line lengths by voltage class were estimated based on a review of projects that were under construction or complete in 2015-2018 EIA Form 411 datasets. The EIA Form 411 data was supplemented with information from the year 2016 EEI report Transmission Projects: At a Glance that describes major high voltage projects proposed by investor-owned utilities.

3.5.1 Availability

Power plant availability is the percentage of time that a generating unit is available to provide electricity to the grid. Availability takes into account both scheduled maintenance and forced outages; it is formally defined as the ratio of a unit's available hours adjusted for the derating of capacity (due to partial outages) to the total number of hours in a year when the unit was in an active state. For most types of units in IPM, availability parameters are used to specify an upper bound on generation to meet demand. Table 3-7 summarizes the availability assumptions used in EPA Platform v6, which are based on data from NERC Generating Availability Data System (GADS) 2014-2018 and AEO 2020 Reference Case. NERC GADS summarizes the availability data by plant type and size class. Unit-level availability assignments in EPA Platform v6 are made based on the unit's plant type and size as presented in NEEDS v6. Table 3-34 shows the availability assumptions for all generating units in EPA Platform v6.

Table 3-7 Availability Assumptions in v6

Plant Type	Annual Availability (%)
Biomass	83
Coal Steam	73 - 84
Combined Cycle	85
Combustion Turbine	85 - 91
Energy Storage	96
Fossil Waste	90
Fuel Cell	87
Geothermal	87
Hydro	76 - 83
IGCC	77 - 84
Landfill Gas	90
Municipal Solid Waste	90
Non-Fossil Waste	90
Nuclear	68 - 99
Oil/Gas Steam	68 - 84
Offshore Wind	95
Onshore Wind	95
Pumped Storage	82
Solar PV	90
Solar Thermal	90

Notes:

Ranges in unit level availabilities are based on varying plant sizes.

In the EPA Platform v6, separate seasonal (winter, winter shoulder, and summer) availabilities are defined. For the fossil and nuclear unit types shown in Table 3-34, seasonal availabilities differ only in that no planned maintenance is assumed to be conducted during the on-peak – summer (June, July, and August) months for summer peaking regions and on-peak – winter (December, January, and February) months for winter peaking regions. Characterizing the availability of hydro, solar, and wind technologies is more complicated due to the seasonal and locational variations of the resources. The procedures used to represent seasonal variations in hydro are presented in Section 3.5.2 and of wind and solar in Section 4.4.5.

3.5.2 Capacity Factor

For non-dispatchable technologies - such as run-of-river hydro, wind, and solar - IPM uses generation profiles, not availabilities, to define the upper bound on the generation obtainable from the unit. The capacity factors that result from the implementation of generation profiles are the percentage of the maximum possible power generated by the unit. The seasonal capacity factor assumptions for hydro facilities contained in Table 3-8 were derived from EIA Form 923 data for the 2009-2018 period. A discussion of capacity factors and generation profiles for wind and solar technologies is contained in Section 4.4.5 and Table 4-18, Table 4-19, Table 4-34, Table 4-43, and Table 4-44.

Table 3-8 Seasonal Hydro Capacity Factors (%) in v6

Model Region	Winter Capacity Factor	Winter Shoulder Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
ERC_REST	11%	12%	14%	12%
FRCC	51%	45%	38%	44%
MIS_AR	44%	43%	47%	45%
MIS_IA	40%	47%	55%	49%
MIS_IL	57%	63%	63%	61%
MIS_INKY	47%	47%	61%	53%
MIS_LA	56%	63%	64%	62%
MIS_LMI	57%	68%	48%	57%
MIS_MAPP	72%	72%	79%	75%
MIS_MIDA	19%	22%	23%	22%
MIS_MNWI	47%	54%	58%	54%
MIS_MO	37%	43%	50%	45%
MIS_WOTA	22%	22%	20%	21%
MIS_WUMS	56%	66%	59%	60%
NENG_CT	41%	43%	36%	40%
NENG_ME	61%	58%	53%	57%
NENGREST	40%	44%	34%	39%
NY_Z_A	72%	69%	66%	68%
NY_Z_B	46%	45%	43%	45%
NY_Z_C&E	52%	52%	52%	52%
NY_Z_D	85%	77%	77%	79%
NY_Z_F	54%	53%	50%	52%
NY_Z_G-I	30%	30%	29%	29%
PJM_AP	49%	48%	41%	45%
PJM_ATSI	19%	21%	24%	22%
PJM_COMD	38%	42%	47%	43%
PJM_Dom	24%	20%	17%	20%
PJM_EMAC	43%	42%	29%	37%
PJM_PENE	53%	55%	43%	50%
PJM_West	33%	31%	30%	31%
PJM_WMAC	43%	44%	31%	38%
S_C_KY	31%	27%	25%	27%
S_C_TVA	54%	41%	35%	42%
S_D_AECI	16%	18%	19%	18%
S_SOU	30%	24%	18%	23%
S_VACA	28%	22%	19%	23%
SPP_N	14%	16%	18%	16%
SPP_NEBR	35%	40%	47%	42%
SPP_WAUE	36%	40%	48%	42%

Model Region	Winter Capacity Factor	Winter Shoulder Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
SPP_WEST	24%	24%	29%	26%
WEC_BANC	21%	23%	31%	26%
WEC_CALN	23%	27%	41%	32%
WEC_LADW	14%	16%	24%	19%
WEC_SDGE	25%	29%	46%	35%
WECC_AZ	27%	28%	31%	29%
WECC_CO	30%	24%	33%	29%
WECC_ID	35%	36%	47%	40%
WECC_IID	29%	34%	54%	41%
WECC_MT	38%	39%	50%	43%
WECC_NM	20%	21%	27%	23%
WECC_NNV	42%	53%	60%	53%
WECC_PNW	46%	42%	45%	44%
WECC_SCE	22%	28%	48%	35%
WECC_SNV	19%	24%	26%	24%
WECC_UT	33%	35%	43%	38%
WECC_WY	19%	25%	54%	36%

Note: Annual capacity factor is provided for information purposes only. It is not used for modeling purposes.

Capacity factor limits are used to define the upper bound on generation obtainable from nuclear units because nuclear units will typically dispatch to their availability, and, consequently, capacity factor and availability limits are equivalent. The capacity factors (and, consequently, the availabilities) of existing nuclear units in EPA Platform v6 vary from region to region and over time. Further discussion of the nuclear capacity factor assumptions in EPA Platform v6 is contained in Section 4.5.

In EPA Platform v6, oil/gas steam units are assigned minimum capacity factors under certain conditions. These minimum capacity factor constraints reflect stakeholder comments that if left unconstrained, IPM does not project as much operation from oil/gas steam units as has occurred historically. This dynamic is often the result of local transmission constraints, unit-specific grid reliability requirements, or other drivers that are not captured in EPA's modeling. EPA examined its modeling treatment of these units and introduced minimum capacity factor constraints to better reflect the real-world behavior of these units. The approach is designed to balance the continued operation of these units in the near-term with allowing economic forces to influence decision-making over the modeling time horizon. As a result, the minimum capacity factor limitations are relaxed over time (and are terminated even earlier if the capacity in question reaches 60 years of age). Historical operational data indicate that oil/gas steam units with high-capacity factors have maintained a high level of generation over many years. To reflect persistent operation of these units, minimum capacity factors for higher capacity factor units are phased out more slowly than those constraints for lower capacity factor units. The steps in assigning these capacity constraints are as follows:

i) For each oil/gas steam unit, calculate an annual capacity factor over a ten-year baseline (2009-2018).
ii) Identify the minimum capacity factor over this baseline period for each unit.
iii) Terminate the constraints in the earlier of (a) the run-year in which the unit reaches 60 years of age, or (b) based on the assigned minimum capacity factor and the model year indicated in the following schedule:
   - For model year 2023, remove minimum constraint from units with capacity factor < 5%
   - For model year 2025, remove minimum constraint from units with capacity factor < 10%
   - For model year 2028, remove minimum constraint from units with capacity factor < 15%
   - For model year 2030, remove minimum constraint from units with capacity factor < 20%.

3.5.3 Turndown

Turndown assumptions in EPA Platform v6 are used to prevent coal and oil/gas steam units from operating as peaking units, which would be inconsistent with their operational capabilities and assigned costs. The turndown constraints in EPA Platform v6 require coal steam and oil/gas steam units to dispatch no less than a fixed percentage of the unit capacity in the 23 base and mid-load segments of the load duration curve in order to dispatch 100% of the unit in the peak load segments of the LDC. Oil/gas steam units are required to dispatch no less than 25% of the unit capacity in the 23 base- and mid-load segments of the LDC in order to dispatch 100% of the unit capacity in the peak load segment of the LDC. Operating under the fixed percentage of base- and mid-load segments does not preclude the unit from operating during peak hours, it merely reduces the share of peak hours in which it can operate. The unit level turndown percentages for coal units were estimated based on a review of hourly Air Markets Program Data (AMPD) data and are shown in Table 3-29.

3.6 Reserve Margins

A reserve margin is a measure of the system's generating capability above the amount required to meet the net internal demand (peak load) requirement. It is defined as the difference between total dependable capacity and annual system peak load divided by annual system peak load. The reserve margin capacity contribution for variable renewable units is described in Section 4.4.5; the reserve margin capacity contribution for other units is the capacity in the NEEDS for existing units or the capacity build by IPM for new units. In practice, each NERC region has a reserve margin requirement, or comparable reliability standard, which is designed to encourage electric suppliers in the region to build beyond their peak requirements to ensure the reliability of the electric generation system within the region.

In IPM, reserve margins are used to represent the reliability standards that are in effect in each NERC region. Individual reserve margins for each NERC region are derived from reliability standards in NERC's electric reliability reports. The IPM regional reserve margins are imposed throughout the entire time horizon. EPA Platform v6 reserve margin assumptions are shown in Table 3-9.

Table 3-9 Planning Reserve Margins in v6

Model Region	Reserve Margin
CN_AB	10.2%
CN_BC	10.2%
CN_MB	12.0%
CN_NB	20.0%
CN_NF	20.0%
CN_NL	20.0%
CN_NS	20.0%
CN_ON	24.7%
CN_PE	20.0%
CN_PQ	12.8%
CN_SK	11.0%
ERC_FRNT	13.8%
ERC_GWAY	13.8%
ERC_PHDL	13.8%
ERC_REST	13.8%
ERC_WEST	13.8%
FRCC	18.5%
MIS_AR	16.8%
MIS_ MS	16.8%
MIS_IA	16.8%
MIS_IL	16.8%

Model Region	Reserve Margin
NY_Z_G-I	15.0%
NY_Z_J	15.0%
NY_Z_K	15.0%
PJM_AP	15.7%
PJM_ATSI	15.7%
PJM_COMD	15.7%
PJM_Dom	15.7%
PJM_EMAC	15.7%
PJM_PENE	15.7%
PJM_SMAC	15.7%
PJM_West	15.7%
PJM_WMAC	15.7%
S_C_KY	15.0%
S_C_TVA	15.0%
S_D_AECI	15.0%
S_SOU	15.0%
S_VACA	15.0%
SPP_KIAM	12.0%
SPP_N	12.0%
SPP_NEBR	12.0%
SPP_SPS	12.0%

Model Region	Reserve Margin
MIS_INKY	16.8%
MIS_LA	16.8%
MIS_LMI	16.8%
MIS_MAPP	16.8%
MIS_MIDA	16.8%
MIS_MNWI	16.8%
MIS_MO	16.8%
MIS_AMSO	16.8%
MIS_WOTA	16.8%
MIS_WUMS	16.8%
NENG_CT	17.8%
NENG_ME	17.8%
NENGREST	17.8%
NY_Z_A	15.0%
NY_Z_B	15.0%
NY_Z_C&E	15.0%
NY_Z_D	15.0%
NY_Z_F	15.0%

Model Region	Reserve Margin
SPP_WAUE	12.0%
SPP_WEST	12.0%
WEC_BANC	15.9%
WEC_CALN	13.8%
WEC_LADW	13.8%
WEC_SDGE	13.8%
WECC_AZ	11.0%
WECC_CO	12.5%
WECC_ID	15.9%
WECC_IID	11.0%
WECC_MT	15.9%
WECC_NM	11.0%
WECC_NNV	15.9%
WECC_PNW	15.9%
WECC_SCE	13.8%
WECC_SNV	15.9%
WECC_UT	15.9%
WECC_WY	12.5%

3.7 Operating Reserves

EPA Base Case v6 models operating reserve requirements in IPM to ensure that an appropriate mix of supply resources will be included that is consistent with maintaining reliability standards, especially in later years as new capacity deploys more rapidly. Operating reserves are typically deployed in order of the response speed, from fast to slow. In general, the categories of reserves include:[23]

- Frequency-Responsive Reserves. This is the fastest response. It has traditionally been provided through automatic action of synchronous generators that react to slow down and arrest frequency deviations as a result of the inertia of the machines or their governor action (also referred to as primary frequency response or PFR). As a result of the increase in renewable integration and loss of generators that provide inertial response, other products are emerging to provide frequency response on a very fast (sub-minute) timescale.

- Regulating Reserves. This is rapid response by generators to balance supply and demand to maintain system frequency. Regulation reserve can address the random fluctuations in load that create imbalances in supply and demand.

- Contingency Reserves. These reserves are deployed to cover the unplanned loss of power plants or transmission lines. Contingency reserves generally include spinning, non-spinning, and supplemental reserves. Spinning reserves respond quickly and are then supplemented or replaced with non-spinning and supplemental reserves that are usually less costly.

- Ramping Reserves. This is used to address slower variations or events that occur over a longer period, such as variable generation forecast errors. Ramping reserves, also known as load-following or flexibility reserves, are an emerging product that is becoming more important with the increasing penetration of variable generation sources such as wind and solar.

[23] Denholm, Paul, Yinong Sun, and Trieu Mai. 2019. An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72578. https://www.nrel.gov/docs/fy19osti/72578.pdf.

The operating reserves products currently procured in United States electricity markets include regulating reserves, contingency reserve, and ramping reserves. FERC Order No. 842 requires that new generation resources that participate in the electricity markets provide some form of frequency-responsive reserve to support the reliability of the grid, but the Order does not mandate explicit compensation for the product. EPA's implementation of operating reserve requirements is consistent with the products offered in the electricity markets. The operating reserves modeled explicitly in EPA Platform v6 are regulating reserves, contingency reserves, and ramping reserves. The plant types that can provide these reserves are listed in Table 3-12. Based on current regulations, new generation resources that are built in the EPA Platform v6 are assumed to have the capability to provide frequency-responsive reserves. It is reasonable to expect that sufficient frequency-responsive reserves will be available to support grid reliability in IPM analyses even if the requirement is not modeled explicitly.

3.7.1 Operating Reserve Requirements

Operating reserve requirements typically depend on the load and load forecast error. As variable renewable generation increase, it is likely that the operating reserve requirements will increase due to the variability of the renewable resources.[24,25] Table 3-10 shows operating reserve assumptions, which are based on the National Renewable Energy Laboratory (NREL) report, Operating Reserves in Long-term Planning Models.[26] The long-term requirements include components that depend on the penetration of wind and solar resources to address the expected increase in variability as more variable resources enter the market.

Table 3-10 Operating Reserve Requirement Assumptions by Type in v6

Product	Operating Reserve Load Requirement	Operating Reserve Requirement for Wind	Operating Reserve Requirement for Solar	Operating Reserve Timescale
Spinning	3% of load	-	-	10 minutes
Regulation	1% of load	0.5% of wind capacity	0.3% of solar PV capacity	5 minutes
Flexibility	-	10% of wind capacity	4% of solar PV capacity	60 minutes

The operating reserve requirements when modeled in IPM have a significant impact on model size. To counter this effect, EPA made two simplifying assumptions. First, the spinning reserve, regulation, and flexibility requirements are combined into a single product. Second, these constraints may be implemented only in the later years when renewable penetration and operating reserve requirements are highest; this representation of operating reserve requirements can be activated or deactivated by run year for any scenario analyzed using IPM. The operating reserve requirements in v6 are applied at the 17 regional groups summarized in Table 3-11.

Table 3-11 Operating Reserve Regions in v6

Operating Reserve Region	v6 Model Region
ERCOT	ERC_PHDL, ERC_REST, and ERC_WEST
FRCC	FRCC
ISO-NE	NENG_CT, NENGREST and NENG_ME
MISO East	MIS_WUMS, MIS_MIDA, MIS_IA, MIS_IL, MIS_LMI, MIS_INKY and MIS_MO
MISO South	MIS_MS, MIS_AR, MIS_AMSO, MIS_WOTA and MIS_LA
MISO West	MIS_MAPP and MIS_MNWI
NYISO	NY_Z_A, NY_Z_B, NY_Z_C&E, NY_Z_D, NY_Z_F, NY_Z_G-I, NY_Z_J and NY_Z_K
PJM East	PJM_PENE, PJM_EMAC, PJM_WMAC and PJM_SMAC
PJM West	PJM_West, PJM_AP, PJM_COMD, PJM_Dom and PJM_ATSI

[24] Western Wind and Solar Integration Study (WWSIS) Phase 1, National Renewable Energy Laboratory (GE Energy), May 2010

[25] Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements, Electric Reliability Council of Texas (GE Energy), March 2008

[26] Cole, W. et al., Operating Reserves in Long-term Planning Models (NREL), June 2018

Operating Reserve Region	v6 Model Region
SERC-E	S_VACA
SERC-N	S_C_TVA and S_C_KY
SERC-SE	S_SOU
SPP	SPP_WAUE, SPP_SPS, SPP_WEST, SPP_NEBR, SPP_N and S_D_AECI
WECC-CAMX	WEC_SDGE, WECC_SCE, WEC_CALN and WEC_LADW
WECC-NWPP	WECC_MT, WECC_ID, WECC_PNW, WECC_NNV, WECC_UT, WECC_SNV and WEC_BANC

3.7.2 Generation Characteristics

The ability of a generator to provide operating reserves varies with the technology type. The more flexible a unit (i.e., faster ramp rate), the higher its operating reserve capability. Table 3-12 shows the assumed operating reserve capabilities for different generation technologies and are based on the NREL's report, Operating Reserves in Long-term Planning Models. For example, gas combustion turbines and combined cycles have faster ramp rates than coal plants; therefore, the gas plants can provide more operating reserves per unit capacity than coal plants. EPA also assumed that capacity meeting energy needs cannot provide operating reserves at the same time. For example, if 75% of a generator's capacity is serving the energy market, only 25% will be available to be offered into the operating reserve market. Table 3-12 summarizes the ramp rates of power plant technologies. Since EPA Platform v6 is incorporating a single composite operating reserves product, the maximum operating reserve contributions are based on the 10-minute spinning reserve requirement.

Table 3-12 Operating Reserve Contribution Assumptions by Technology in v6

Technology	Assumed Ramp Rate (%/minute)	Maximum Operating Reserve Contribution (%)
Combustion Turbine	8	80
Combined Cycle	5	50
Coal Steam	4	40
Geothermal	4	40
CSP with Storage	10	100
Biomass	4	40
Oil/Gas Steam	4	40
Hydro	100	100
Energy Storage	100	100

Generation resources that are not fast-starting cannot provide operating reserves unless they are already operating. To provide operating reserves, the plant must also be dispatching into the energy market.

3.8 Power Plant Lifetimes

EPA Platform v6 does not include any pre-specified assumptions about power plant lifetimes (i.e., the duration of service allowed) except for nuclear units. All conventional fossil units (coal, oil/gas steam, combustion turbines, and combined cycle), nuclear, and biomass units can be retired during a model run if their retention is deemed uneconomic.

Nuclear Retirement at Age 80: EPA Platform v6 assumes that commercial nuclear reactors will be retired upon license expiration, which includes two 20-year operating extensions that are assumed to be granted for each reactor by the Nuclear Regulatory Commission (NRC). EPA Platform v6 incorporates life extension costs to enable these operating life extensions. (See Sections 4.2.8 and 4.5). EPA Platform v6 assumes an 80-year life for all existing nuclear capacity and most of the nuclear units hit 80 years beyond the model time horizon. For unit specific retirement years, see NEEDS.

3.9 Heat Rates

Heat rates, expressed in British thermal units (Btus) per kilowatt-hour (kWh), are a measure of an electric generating unit's (EGU's) efficiency. As in previous versions of NEEDS, it is assumed in NEEDS v6 that, with the exception of deploying the heat rate improvement option described below, heat rates of existing EGUs remain constant over time. This assumption reflects two offsetting factors:

i) Plant efficiencies tend to degrade over time, and
ii) Increased maintenance and component replacement costs act to maintain, or improve, an EGU's generating efficiency.

The heat rates for the model plants in EPA Platform v6 are based on values from the AEO 2020 Reference Case and are informed by fuel use and net generation data reported on Form EIA-923. These values were screened and adjusted using a procedure developed by EPA (as described below) to ensure that the heat rates used in EPA Platform v6 are within the engineering capabilities of the various EGU types.

The result of an earlier EPA engineering analysis, the upper and lower heat rate limits shown in Table 3-13 were applied to coal steam, oil/gas steam, combined cycle, combustion turbine, and internal combustion engines. If the reported heat rate for such a unit was below the applicable lower limit or above the upper limit, the upper or lower limit was substituted for the reported value.

Table 3-13 Lower and Upper Limits Applied to Heat Rate Data in v6

Plant Type	Heat Rate (Btu/kWh)	
	Lower Limit	Upper Limit
Coal Steam	8,300	14,500
Oil/Gas Steam	8,300	14,500
Combined Cycle - Natural Gas	5,500	15,000
Combined Cycle - Oil	6,000	15,000
Combustion Turbine - Natural Gas - 80 MW and above	8,700	18,700
Combustion Turbine - Natural Gas < 80 MW	8,700	36,800
Combustion Turbine - Oil and Oil/Gas - 80 MW and above	6,000	25,000
Combustion Turbine - Oil and Oil/Gas < 80 MW	6,000	36,800
IC Engine - Natural Gas	8,700	18,000
IC Engine - Oil and Oil/Gas - 5 MW and above	8,700	20,500
IC Engine - Oil and Oil/Gas < 5 MW	8,700	42,000

3.10 Existing Environmental Regulations

This section describes the existing federal, regional, and state SO_2, NO_x, mercury, HCl and CO_2 emissions regulations that are represented in EPA Platform v6. EPA Platform v6 also includes three non-air federal rules affecting EGUs: Cooling Water Intakes (316(b)) Rule, Coal Combustion Residuals from Electric Utilities (CCR), and the Effluent Limitations and Guidelines Rule. The first four subsections discuss national and regional regulations. The next five subsections describe state level environmental regulations, a variety of legal settlements, emission assumptions for potential units, renewable portfolio standards, and Canadian regulations for CO_2 and renewables.

3.10.1 SO_2 Regulations

Unit-level Regulatory SO_2 Emission Rates and Coal Assignments: Before discussing the national and regional regulations affecting SO_2, it is important to note that unit-level SO_2 permit rates including SO_2 regulations arising out of State Implementation Plan (SIP) requirements, which are not only state-specific but also county-specific, are captured at model set-up in the coal choices given to coal fired existing units in EPA Platform v6. Since SO_2 emissions are dependent on the sulfur content of the fuel used, the SO_2 permit rates are used in IPM to define fuel capabilities.

For instance, a unit with a SO_2 permit rate of 3.0 lbs/MMBtu would be provided only with those combinations of fuel choices and SO_2 emission control options that would allow the unit to achieve an out-of-stack rate of 3.0 lbs/MMBtu or less. If the unit finds it economical, it may elect to burn a fuel that would achieve a lower SO_2 rate than its specified permit limit. In EPA Platform v6, there are six different sulfur grades of bituminous coal, four different grades of subbituminous coal, four different grades of lignite, and one sulfur grade of residual fuel oil. There are two different SO_2 scrubber options and one DSI option for coal units. Further discussion of fuel types and sulfur content is contained in Chapter 7. Further discussion of SO_2 control technologies is contained in Chapter 5.

National and Regional SO_2 Regulations: The national program affecting SO_2 emissions in EPA Platform v6 is the Acid Rain Program established under Title IV of the Clean Air Act Amendments (CAAA) of 1990, which set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. The program, which became operational in 2000, affects all SO_2 emitting electric generating units greater than 25 MW. The program provides trading and banking of allowances over time across all affected electric generation sources.

The annual SO_2 caps over the modeling time horizon in EPA Platform v6 reflect the provisions in Title IV. For allowance trading programs like the Acid Rain Program that allow banking of unused allowances over time, we usually estimate an allowance bank that is assumed to be available by the first year of the modeling horizon (which is 2023 in EPA Platform v6). However, the Acid Rain Program has demonstrated a substantial oversupply of allowances that continues to grow over time, and we anticipate projecting that the program's emission caps will not bind the model's determination of SO_2 emissions regardless of any level of initial allowance bank assumed. Therefore, EPA Platform v6 does not assume any Title IV SO_2 allowance bank amount for the year of 2023 (notwithstanding that a large allowance bank will exist in that year in practice), because such an assumption would have no material impact on projections given the nonbinding nature of that program. Calculating the available 2023 allowances involved deducting allowance surrenders due to NSR settlements and state regulations from the 2023 SO_2 cap of 8.95 million tons. The surrenders totaled 977 thousand tons in allowances, leaving 7.973 million of 2021 allowances remaining. Specifics of the allowance surrender requirements under state regulations and NSR settlements can be found in Table 3-30 and Table 3-31.

EPA Platform v6 also includes a representation of the Western Regional Air Partnership (WRAP) Program, a regional initiative involving New Mexico, Utah, and Wyoming directed toward addressing visibility issues in the Grand Canyon and affecting SO_2 emissions starting in 2018. The WRAP specifications for SO_2 are presented in Table 3-23.

3.10.2 NO_x Regulations

Much like SO_2 regulations, existing NO_x regulations are represented in EPA Platform v6 through a combination of system level NO_x programs and generation unit-level NO_x limits. In EPA Platform v6, the NO_x SIP Call trading program, Cross State Air Pollution Rule (CSAPR), the CSAPR Update, and the Revised CSAPR Update Rule are represented. Table 3-23 shows the specification for the entire modeling time horizon.

By assigning unit-specific NO_x rates based on 2019 data, EPA Platform v6 is implicitly representing Title IV unit-specific rate limits and Clean Air Act Reasonably Available Control Technology (RACT) requirements for controlling NO_x emissions from electric generating units in ozone non-attainment areas or in the Ozone Transport Region (OTR).[27] Unlike SO_2 emission rates, NO_x rates are calculated off historical data and reflect the fuel mix for that particular year at the unit. NEEDS represents up to four

[27] The OTR consists of the following states: Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, District of Columbia, and northern Virginia.

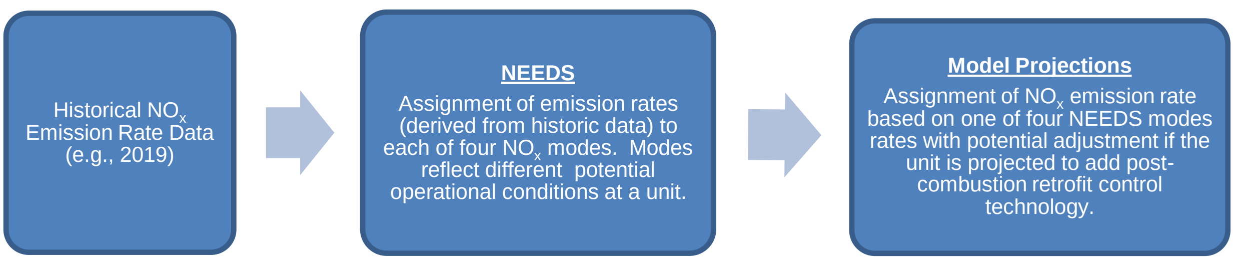
scenario NO_x rates based on historical data to capture seasonal and existing control variability. These rates are constant and do not change independent of fuel mix assumed in the model. If the unit undertakes a post-combustion control retrofit or a coal-to-gas retrofit, then these rates would change in the model projections.

NO_x Emission Rates

Future emission projections for NO_x are a product of a unit's utilization (heat input) and emission rate (lbs/MMBtu). A unit's NO_x emission rate can vary significantly depending on the NO_x reduction requirements to which it is subject. For example, a unit may have a post-combustion control installed (i.e., SCR or SNCR), but only operate it during the time of the year in which it is subject to NO_x reduction requirements (e.g., the unit only operates its post-combustion control during the ozone season). Therefore, its ozone-season NO_x emission rate would be lower than its non-ozone-season NO_x emission rate. Because the same individual unit can have such large variation in its emission rate, the model needs a suite of emission rate modes from which it can select the value most appropriate to the conditions in any given model scenario. The different emission rates reflect the different operational conditions a unit may experience regarding upgrades to its combustion controls and operation of its existing post-combustion controls. Four modes of operation are developed for each unit, with each mode carrying a potentially different NO_x emission rate for that unit under those operational conditions.

The emission rates assigned to each mode are derived from historical data (where available) and presented in NEEDS v6. When the model is run, IPM selects one of these four modes through a decision process depicted in Figure 3-3 below. The four modes address whether units upgrade combustion controls and/or operate *existing* post-combustion controls; the modes themselves do not address what happens to the unit's NO_x rate if it is projected to add a *new* post-combustion NO_x control. If a unit is projected to add a new post-combustion control, then after the model selects the appropriate input mode it adjusts that mode's emission rate downwards to reflect the retrofit of SCR or SNCR; the adjusted rate will reflect the greater of a percentage removal from the mode's emission rate or an emission rate floor. The full process for determining the NO_x rate of units in EPA Platform v6 model projections is summarized in Figure 3-2.

Figure 3-2 Modeling Process for Obtaining Projected NO_x Emission Rates



NO_x Emission Rates in NEEDS v6 Database

The NO_x rates were derived, wherever possible, directly from actual monitored NO_x emission rate data reported to EPA under the Acid Rain and Cross-State Air Pollution Rule in 2019.[28] The emission rates

[28] By assigning unit-specific NO_x rates based on 2019 data, EPA Platform v6 is implicitly representing Title IV unit-specific rate limits and Clean Air Act Reasonably Available Control Technology (RACT) requirements for controlling NO_x emissions from electric generating units in ozone non-attainment areas or in the Ozone Transport Region (OTR). Unlike SO_2 emission rates, NO_x emission rates are assumed not to vary with coal type but are dependent on the combustion properties of the generating unit. Under the EPA Platform v6, the NO_x emission rate of a unit can only change if the unit is retrofitted with NO_x post-combustion control equipment or if it is assumed to install state-of-the-art NO_x combustion controls. In instances where a coal steam unit converts to natural gas, the NO_x rate is assumed to reduce by 50%.

themselves reflect the impact of applicable NO_x regulations.[29] For coal-fired units, NO_x rates were used in combination with empirical assessments of NO_x combustion control performance to prepare a set of four possible starting NO_x rates to assign to a unit, depending on the specific NO_x reduction requirements affecting that unit in a model run.

The reason for having a framework of four potential NO_x rate modes applicable to each unit in NEEDS is to enable the model to select from a range of NO_x rates possible at a unit, given its configuration of NO_x combustion controls and its assumed operation of existing post-combustion controls. There are up to four basic operating states for a given unit that significantly impact its NO_x rate, and thus there are four NO_x rate modes.

Mode 1 and mode 2 reflect a unit's emission rates with its existing configuration of combustion and post-combustion (i.e., SCR or SNCR) controls.

- For a unit with an existing post-combustion control, mode 1 reflects the existing post-combustion control not operating and mode 2 the existing post-combustion control operating. However:
  - If a unit has operated its post-combustion control year-round during the most recent of 2019, 2017, 2016, 2015, 2014, 2011, 2009, or 2007 years then mode 1 = mode 2, which reflects that the control will likely continue to operate year-round (and thus a "not run" emission rate option is not needed as justified by historical data).
  - If a unit has not operated its post-combustion control during the most recent of 2019, 2017, 2016, 2015, 2014, 2011, 2009, or 2007 years, mode 1 will be based on this data and mode 2 will be calculated using the method described under Question 3 in Attachment 3-1.
  - If a unit has operated its post-combustion control seasonally in recent years (i.e., either only in the summer or winter, but not both), mode 1 will be based on historic data from when the control was not operating, and mode 2 will be based on historic data from when the SCR was operating.
- For a unit without an existing post-combustion control, mode 1 = mode 2 which reflects the unit's historic NO_x rates from a recent year.

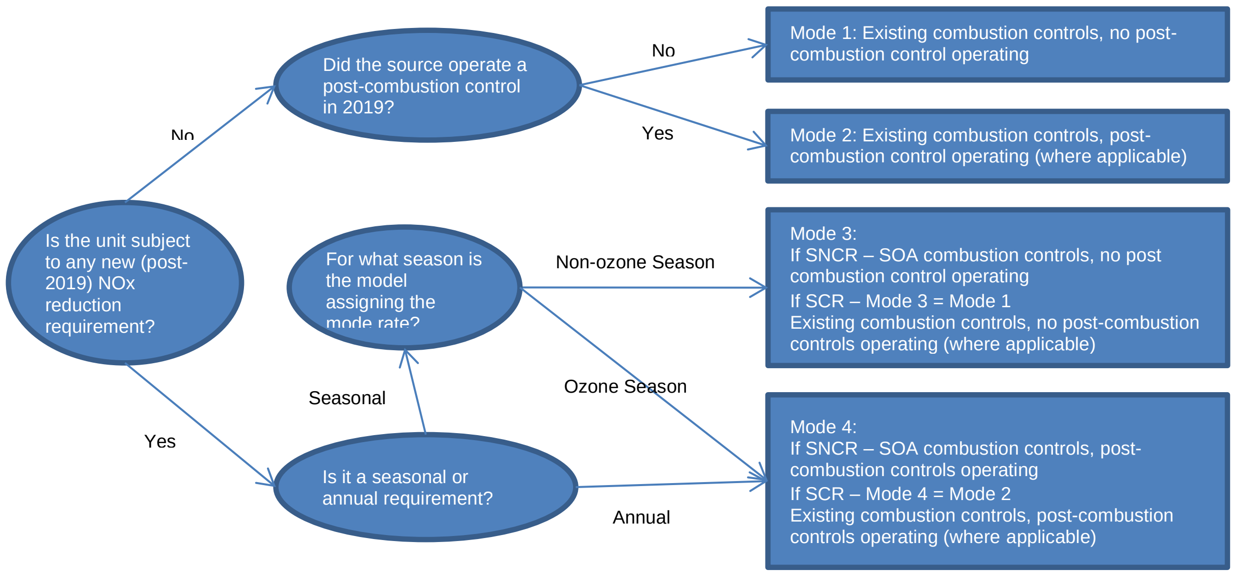
Mode 3 and mode 4 emission rates parallel modes 1 and 2 emission rates but are modified to reflect installation of state-of-the-art combustion controls on a unit if it does not already have them.

- For units that already have state-of-the-art combustion controls: mode 3 = mode 1 and mode 4 = mode 2.

Emission rates derived for each unit operating under each of these four modes are presented in NEEDS v6. Note that not every unit has a different emission rate for each mode, because certain units cannot in practice change their NO_x rates to conform to all potential operational states described above.

[29] Because 2019 NO_x rates reflect CSAPR, we no longer apply any incremental CSAPR related NO_x rate adjustments exogenously for CSAPR affected units in EPA Platform v6.

Figure 3-3 How One of the Four NO_x Modes Is Ultimately Selected for a Unit



<ins>State-of-the-art combustion controls (SOA combustion controls)</ins>

The definition of state-of-the-art varies depending on the unit type and configuration. Table 3-14 indicates the incremental combustion controls that are required to achieve a state-of-the-art combustion control configuration for each unit. For instance, if a wall-fired, dry bottom boiler (highlighted below) currently has LNB but no overfire air (OFA), the state-of-the-art rate calculated for such a unit would assume a NO_x emission rate reflective of overfire air being added at the unit. As described in the attachment of this chapter, the state-of-the-art combustion controls reflected in the modes are only assigned to a unit if it is subject to a *new* (post-2019) NO_x reduction requirement (i.e., a NO_x reduction requirement that did not apply to the unit during its 2019 operation that forms the historic basis for deriving NO_x rates for units in EPA Platform v6). Existing reduction requirements as of 2019 under which units have already made combustion control decisions would not trigger the assignment of the state-of-the-art modes that reflect additional combustion controls.

Table 3-14 State-of-the-Art Combustion Control Configurations by Boiler Type in v6

Boiler Type	**Existing NO_x Combustion Control**	**Incremental Combustion Control Necessary to Achieve State-of-the-Art**
Tangential Firing	Does not Include LNC1 and LNC2	LNC3
	Includes LNC1, but not LNC2	CONVERSION FROM LNC1 TO LNC3
	Includes LNC2, but not LNC3	CONVERSION FROM LNC2 TO LNC3
	Includes LNC1 and LNC2 or LNC3	-
Wall Firing, Dry Bottom	Does not Include LNB and OFA	LNB + OFA
	Includes LNB, but not OFA	OFA
	Includes OFA, but not LNB	LNB
	Includes both LNB and OFA	-

Note:
LNB = Low NOx Burner Technology, LNC1 = Low NOx coal-and air nozzles with close-coupled overfire air, LNC2 = Low NOx Coal-and-Air Nozzles with Separated Overfire Air, LNC3 = Low NOx Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air, OFA = Overfire Air.

The emission rates for each generating unit under each mode are included in the NEEDS v6 database, described in Chapter 4. Attachment 3-1 gives further information on the procedures employed to derive the four NO_x mode rates.

Because of the complexity of the fleet and the completeness/incompleteness of historic data, there are instances where the derivation of a unit's modeled NO_x emission rate is more detailed than the description provided above. For a more complete step-by-step description of the decision rules used to develop the NO_x rates, see Attachment 3-1.

3.10.3 Multi-Pollutant Environmental Regulations

CSAPR

EPA Platform v6 includes the Cross-State Air Pollution Rule (CSAPR) Rule, CSAPR Update Rule, and the Revised CSAPR Update Rule federal regulatory measures affecting 23 states to address transport under the 1997, 2006, and 2008 National Ambient Air Quality Standards (NAAQS) for fine particle pollution and ozone. CSAPR requires fossil-fired EGUs greater than 25 MW in a total of 22 states to reduce annual SO_2 emissions, annual NO_x emissions, and/or ozone season NO_x emissions to assist in attaining the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS). The CSAPR Phase 2 combined annual emissions budgets are 1,372,631 tons SO_2 for CSAPR SO_2 Group 1;[30] 597,579 tons SO_2 for CSAPR SO_2 Group 2;[31] and 1,069,256 tons for annual NO_x.[32] As the budgets are significantly above current emission levels, i.e., they are not binding, the EPA did not include a starting bank of allowances for these programs for simplicity.

The original Phase 2 combined ozone season NO_x emissions budget was 0.59 million tons. However, several of the state budgets were remanded. As the CSAPR Update Rule addresses the D.C. Circuit's remand, the budgets for these states were updated to reflect those promulgated in the CSAPR Update Rule. The programs' assurance provisions, which restrict the maximum amount of exceedance of an individual state's emissions budget in a given year through the use of banked or traded allowances to 18% or 21% of the state's budget are also included. For more information on CSAPR, go to https://www.epa.gov/csapr/overview-cross-state-air-pollution-rule-csapr.

The state budgets for Ozone Season NO_x for the CSAPR Update Rule (that were not further adjusted in the Revised CSAPR Update Rule) are shown in Table 3-15. Additionally, Georgia was modeled as a separate region, with Georgia units unable to trade allowances with units in other states, and received its CSAPR Phase 2 budget and assurance level, as shown in Table 3-15. This is because Georgia, unlike the other states covered by the CSAPR Update Rule, did not significantly contribute to a downwind nonattainment or maintenance receptor for the 2008 NAAQS. Further, Georgia did not have a remanded Ozone Season NO_x budget related to a D.C. Circuit Court decision on the original Cross-State Air Pollution Rule.

The programs' assurance provisions, which restrict the maximum amount of exceedance of an individual state's emissions budget in each year through the use of banked or traded allowances to 21% of the state's budget, are also implemented. This is equal to one-and-a-half times the sum of the states' 21% variability limits. For more information on CSAPR, go to https://www.epa.gov/csapr. For more information on the CSAPR Update, go to https://www.epa.gov/airmarkets/final-cross-state-air-pollution-rule-update.

[30] Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin.

[31] Alabama, Georgia, Kansas, Minnesota, Nebraska, and South Carolina.

[32] Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

Table 3-15 G1 and G2 CSAPR Update State Budgets, Variability Limits, and Assurance Levels for Ozone-Season NO_x (Tons) – 2021 through 2054

State	Budget	Variability Limit	Assurance Level
Alabama	13,211	2,774	15,985
Arkansas	9,210	1,934	11,144
Iowa	11,272	2,367	13,639
Kansas	8,027	1,686	9,713
Missouri	15,780	3,314	19,094
Mississippi	6,315	1,326	7,641
Oklahoma	11,641	2,445	14,086
Tennessee	7,736	1,625	9,361
Texas	52,301	10,983	63,284
Wisconsin	7,915	1,662	9,577
Georgia Budget, Variability Limit, and Assurance Level for Ozone-Season NO_x			
Georgia	24,041	5,049	29,090

On March 15, 2021, EPA finalized the Revised Cross-State Air Pollution Rule Update for the 2008 ozone National Ambient Air Quality Standards (NAAQS) to address the D.C. Circuit's remand of the CSAPR Update Rule. Starting in the 2021, 12 of the 22 states covered in the CSAPR Update Rule will revised ozone season NO_x budgets consistent with Table 3-16. The programs' assurance provisions, which restrict the maximum amount of exceedance of an individual state's emissions budget in each year through the use of banked or traded allowances to 21% of the state's budget, are also implemented. The starting allowance bank in 2023 is 22,488 tons, which is equal to the number of banked allowances at the start of the Revised CSAPR Update program after old CSAPR Update allowances were converted. This is equal the sum of the states' 21% variability limits.

Table 3-16 Revised CSAPR Update State Budgets, Variability Limits, and Assurance Levels for Ozone-Season NO_x for G3 states (tons)

State	Budget (tons)	Variability Limit (tons)	Assurance Level (tons)
2021			
Illinois	9,102	1,911	11,013
Indiana	13,051	2,741	15,792
Kentucky	15,300	3,213	18,513
Louisiana	14,818	3,112	17,930
Maryland	1,499	315	1,814
Michigan	12,727	2,673	15,400
New Jersey	1,253	263	1,516
New York	3,416	717	4,133
Ohio	9,690	2,035	11,725
Pennsylvania	8,379	1,760	10,139
Virginia	4,516	948	5,464
West Virginia	13,334	2,800	16,134

State	Budget (tons)	Variability Limit (tons)	Assurance Level (tons)
2022			
Illinois	9,102	1,911	11,013
Indiana	12,582	2,642	15,224
Kentucky	14,051	2,951	17,002
Louisiana	14,818	3,112	17,930
Maryland	1,266	266	1,532
Michigan	12,290	2,581	14,871
New Jersey	1,253	263	1,516
New York	3,416	717	4,133
Ohio	9,773	2,052	11,825
Pennsylvania	8,373	1,758	10,131
Virginia	3,897	818	4,715
West Virginia	12,884	2,706	15,590
2023			
Illinois	8,179	1,718	9,897
Indiana	12,553	2,636	15,189
Kentucky	14,051	2,951	17,002
Louisiana	14,818	3,112	17,930
Maryland	1,266	266	1,532
Michigan	9,975	2,095	12,070
New Jersey	1,253	263	1,516
New York	3,421	718	4,139
Ohio	9,773	2,052	11,825
Pennsylvania	8,373	1,758	10,131
Virginia	3,980	836	4,816
West Virginia	12,884	2,706	15,590
2024 -2054			
Illinois	8,059	1,692	9,751
Indiana	9,564	2,008	11,572
Kentucky	14,051	2,951	17,002
Louisiana	14,818	3,112	17,930
Maryland	1,348	283	1,631
Michigan	9,786	2,055	11,841
New Jersey	1,253	263	1,516
New York	3,403	715	4,118
Ohio	9,773	2,052	11,825
Pennsylvania	8,373	1,758	10,131
Virginia	3,663	769	4,432
West Virginia	12,884	2,706	15,590

MATS

Finalized in 2011, the Mercury and Air Toxics Rule (MATS) establishes National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for the “electric utility steam generating unit” source category, which includes those units that combust coal or oil for the purpose of generating electricity for sale and distribution through the electric grid to the public. EPA Platform v6 applies the input-based (lbs/MMBtu) MATS control requirements for mercury and hydrogen chloride to covered units.

EPA Platform v6 assumes that all active coal-fired generating units with a capacity greater than 25 MW have complied with the MATS filterable PM requirements through the operation of either electrostatic precipitator (ESP) or fabric filter (FF) particulate controls. No additional PM controls beyond those in NEEDS v6 are modeled in EPA Platform v6.

EPA Platform v6 does not model the alternative SO_2 standard offered under MATS for units to demonstrate compliance with the rule’s HCl control requirements. Coal steam units with access to lignite in the modeling are required to meet the “existing coal-fired unit low Btu virgin coal” standard. For more information on MATS, go to http://www.epa.gov/mats/.

Regional Haze

The Clean Air Act establishes a national goal for returning visibility to natural conditions through the “prevention of any future, and the remedying of any existing impairment of visibility in Class I areas [156 national parks and wilderness areas], where impairment results from manmade air pollution.” On July 1, 1999, EPA established a comprehensive visibility protection program with the issuance of the regional haze rule (64 FR 35714). The rule implements the requirements of section 169B of the CAAA and requires states to submit State Implementation Plans (SIPs) establishing goals and long-term strategies for reducing emissions of air pollutants (including SO_2 and NO_x) that cause or contribute to visibility impairment. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. Among the components of a long-term strategy is the requirement for states to establish emission limits for visibility-impairing pollutants emitted by certain source types (including EGUs) that were placed in operation between 1962 and 1977. These emission limits are to reflect Best Available Retrofit Technology (BART). States may perform individual point source BART determinations, or meet the requirements of the rule with an approved BART alternative. An alternative regional SO_2 cap for EGUs under Section 309 of the regional haze rule is available to certain western states whose emission sources affect Class 1 areas on the Colorado Plateau.

Since 2010, EPA has approved regional haze State Implementation Plans (SIPs) or, in a few cases, put in place regional haze Federal Implementation Plans for several states. The BART limits approved in these plans (as of January 2021) that will be in place for EGUs are represented in EPA Platform v6 as follows.

- Source-specific NO_x or SO_2 BART emission limits, minimum SO_2 removal efficiency requirements for FGDs, limits on sulfur content in fuel oil, constraints on fuel type (e.g., natural gas only or prohibition of certain fuels such as petroleum coke), or commitments to retire units are applied to the relevant EGUs.
- EGUs in states that rely on CSAPR trading programs to satisfy BART must meet the requirements of CSAPR.
- EGUs in states that rely on state power plant rules to satisfy BART must meet the emission limits imposed by those state rules.
- For the three western states (New Mexico, Wyoming, and Utah) with approved Section 309 SIPs for SO_2 BART, emission constraints were not applied as current and projected emissions are well under the regional SO_2 cap.

Table 3-35 lists the NO_x and SO_2 limits applied to specific EGUs and other implementations applied in IPM. For more information on the Regional Haze Rule, go to https://www.epa.gov/visibility.

On June 28, 2021 EPA filed a status update with the United States Court of Appeals for the District of Columbia Circuit noting that "the agency is convening a proceeding for reconsideration" of the August 2020 rule known as the "Texas Regional Haze BART and Interstate Visibility Transport FIP." Any changes from the that effort will be incorporated into EPA modeling when finalized.

3.10.4 CO_2 Regulations

The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 cap and trade program affecting fossil fired electric power plants 25 MW or larger in Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia. Table 3-23 shows the specifications for RGGI that are implemented in EPA Platform v6. If/when other states join RGGI and finalize/implement regulations, EPA will adjust its representation accordingly.

As part of California's Assembly Bill 32 (AB32), the Global Warming Solutions Act, a multi-sector GHG cap-and-trade program was established that establishes long-term economy-wide emission targets, starting in 2013 for electric utilities and large industrial facilities, with distributors of transportation, natural gas, and other fuels joining the capped sectors in 2015. In addition to in-state sources, the cap-and-trade program also covers the emissions associated with qualifying, out-of-state EGUs that sell power into California. Due to the inherent complexity in modeling a multi-sector cap-and-trade program where the participation of out-of-state EGUs is determined based on endogenous behavior (i.e., IPM determines whether qualifying out-of-state EGUs are projected to sell power into California), EPA has developed a simplified methodology to model California's economy-wide cap-and-trade program as follows.

- Adopt the AB32 cap-and-trade allowance price from EIA's AEO2020 Reference Case, which fully represents the non-power sectors. All qualifying fossil-fired EGUs in California are subject to this price signal, which is applied through the end of the modeled time horizon since the underlying legislation requires those emission levels to be maintained.
- Assume the marginal CO_2 emission rate for each IPM region that exports power to California to be 0.428 MT/MWh.
- For each IPM region that exports power to California, convert the \$/ton CO_2 allowance price projection into a mills/kWh transmission wheeling charge using the marginal emission rate from the previous step. The additional wheeling charge for qualifying out-of-state EGUs is equal to the allowance price imposed on affected in-state EGUs. Applying the charge to the transmission link ensures that power imported into California from out-of-state EGUs must account for the cost of CO_2 emissions represented by its generation, such that the model may clear the California market in a manner consistent with AB32 policy treatment of CO_2 emissions.

Federal CO_2 standards for existing sources are not modeled, given ongoing litigation and regulatory review.[33] For new fossil fuel-fired sources, EPA Platform v6 continues to include the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units (New Source Rule).[34] Although this rule is also being reviewed,[35] the standards of performance are legally in effect until such review is completed and/or revised.

3.10.5 Non-Air Regulations Impacting EGUs

[33] EPA Memorandum: "Status of Affordable Clean Energy Rule and Clean Power Plan," February 12, 2021. Available at https://www.epa.gov/sites/default/files/2021-02/documents/ace_letter_021121.doc_signed.pdf.

[34] 80 FR 64510

[35] 82 FR 16330

Cooling Water Intakes (316(b)) Rule

Section 316(b) of the Clean Water Act requires that National Pollutant Discharge Elimination System (NPDES) permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures reflect the best technology available to minimize harmful impacts on the environment. Under a 1995 consent decree with environmental organizations, EPA divided the section 316(b) rulemaking into three phases. All new facilities except offshore oil and gas exploration facilities were addressed in Phase I in December 2001; all new offshore oil and gas exploration facilities were later addressed in June 2006 as part of Phase III. This final rule also removes a portion of the Phase I rule to comply with court rulings. Existing large electric-generating facilities were addressed in Phase II in February 2004. Existing small electric-generating and all manufacturing facilities were addressed in Phase III (June 2006). However, Phase II and the existing facility portion of Phase III were remanded to EPA for reconsideration because of legal proceedings. This final rule combines these remands into one rule and provides a holistic approach to protecting aquatic life impacted by cooling water intakes. The rule covers roughly 1,065 existing facilities that are designed to withdraw at least 2 million gallons per day of cooling water. EPA estimates that 544 power plants are affected by this rule.

The final regulation has three components for affected facilities: 1) reduce fish impingement through a technology option that meets best technology available requirements, 2) conduct site-specific studies to help determine whether additional controls are necessary to reduce entrainment, and 3) meet entrainment standards for new units at existing facilities when additional capacity is added. EPA Platform v6 includes cost of complying with this rule. The cost assumptions and analysis for 316(b) can be found in Chapter 8.7 of the Rule's Technical Development Document for the Final Section 316(b) Existing Facilities Rule at https://www.epa.gov/sites/production/files/2015-04/documents/cooling-water_phase-4_tdd_2014.pdf.

For more information on 316(b), go to https://www.epa.gov/cooling-water-intakes.

Combustion Residuals from Electric Utilities (CCR)

In December of 2014, EPA finalized national regulations to provide a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCRs), commonly known as coal ash, from coal-fired power plants. The final rule is the culmination of extensive study on the effects of coal ash on the environment and public health. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act.

EPA Platform v6 includes cost of complying with this rule's requirements by taking the estimated plant-level compliance cost identified for the CCR final rule and apportioning them into unit-level cost. Three categories of unit-level cost were quantified: capital cost, fixed operating and maintenance cost (FOM), and variable operating and maintenance (VOM) cost. The method for apportioning these costs to the unit-level for inclusion in EPA Platform is discussed in the Addendum to the RIA for EPA's 2015 Coal Combustion Residuals (CCR) Final Rule. The initial plant-level cost estimates are discussed in the Rule's Regulatory Impact Analysis.

In September of 2017, EPA granted petitions to reconsider some provisions of the rule. In granting the petitions, EPA determined that it was appropriate, and in the public's interest to reconsider specific provisions of the final CCR rule based in part on the authority provided through the Water Infrastructure for Improvements to the Nation (WIIN) Act. At time of this modeling update, EPA had not committed to changing any part of the rule or agreeing with the merits of the petition – the Agency is simply granting petitions to reconsider specific provisions. Should EPA decide to revise specific provisions of the final CCR rule, it will go through notice and comment period, and the rules corresponding model specification would be subsequently changed in future base case platforms.

On July 29, 2020, the U.S. Environmental Protection Agency (EPA) finalized several changes to the regulations for this rule to implement the court's vacatur of certain closure requirements. In response to court rulings, this final rule specified that all unlined surface impoundments are required to retrofit or close, not just those that have detected groundwater contamination above regulatory levels. The rule also changed the classification of compacted-soil lined or "clay-lined" surface impoundments from "lined" to "unlined," which means that formerly defined clay-lined surface impoundments are no longer considered lined surface impoundments and need to be retrofitted or closed. These changes, and corresponding requirements and cost, are reflected in this version of IPM using the same methodology described in the Addendum for the RIA for EPA's 2015 CCR Rule mentioned above.

For more information on CCR, go to http://www.epa.gov/coalash/coal-ash-rule.

Effluent Limitation and Guidelines (ELG)

In September of 2015, EPA finalized a rule revising the regulations for Steam Electric Power Generating category (40 CFR Part 423).[36] The rule established federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. The rule established or updated standards for wastewater streams from flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels.

On October 13, 2020 – EPA published a reconsideration rule that revised the requirements for flue gas desulfurization (FGD) wastewater and bottom ash (BA) transport water; revised the voluntary incentives program for FGD wastewater; added subcategories; and established new compliance dates. These changes, and corresponding requirements and cost, are reflected in EPA Platform v6. EPA reflects this rule in this base case by apportioning the estimated total capital and FOM costs to likely affected units based on controls and capacity. The cost adders are reflected in the model inputs and were applied starting in 2025, by which point the requirements were expected to be fully implemented.

On July 26, 2021 EPA announced it was initiating a supplemental rulemaking to strengthen certain discharge limits in the Steam Electric Power Generating category. EPA undertook a science-based review of the 2020 Steam Electric Reconsideration Rule under Executive Order 13990, finding that opportunities for improvement exist. EPA intends to issue a proposed rule for public comment in the fall of 2022. The current rule will continue to be implemented (and reflected in IPM) and any additional or updated requirements from this supplemental rulemaking will be incorporated when final.

For more information on ELG, go to https://www.epa.gov/eg/effluent-guidelines-plan.

3.10.6 State-Specific Environmental Regulations

EPA Platform v6 represents enacted laws and regulations in states affecting emissions from the electricity sector. Table 3-30 summarizes the provisions of state laws and regulations that are represented in EPA Platform v6.

3.10.7 New Source Review (NSR) Settlements

New Source Review (NSR) settlements refer to legal agreements with companies resulting from the permitting process under the CAAA which requires industry to undergo an EPA pre-construction review of proposed environmental controls either on new facilities or as modifications to existing facilities where there would result a "significant increase" in a regulated pollutant. A summary of the units affected and how the settlements were modeled can be found in Table 3-31.

State settlements and citizen settlements are also represented in EPA Platform v6. These are summarized in Table 3-32 and Table 3-33 respectively.

3.10.8 Emission Assumptions for Potential (New) Units

[36] https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2015-final-rule

There are no location-specific variations in the emission and removal rate capabilities of potential new units. In IPM, potential new units are modeled as additional capacity and generation that may come online in each model region. Across all model regions, the emission and removal rate capabilities of potential new units are the same, and they reflect applicable federal emission limitations on new sources. The specific assumptions regarding the emission and removal rates of potential new units in EPA Platform v6 are presented in Table 3-25. (Note: Nuclear, wind, solar, and fuel cell technologies are not included in Table 3-25 because they do not emit any of the listed pollutants.) For additional details on the modeling of potential new units, see Chapter 4.

3.10.9 Renewable Portfolio Standards and Clean Energy Standards

Renewable Portfolio Standards (RPS) generally refer to various state-level policies that require renewable generation to meet a specified share of generation or sales. In EPA Platform v6, the state RPS requirements are represented at a state level based on existing requirements. Table 3-17 and Table 3-18 show the state-level RPS and solar carve-out requirements.

Table 3-17 Renewable Portfolio Standards in v6

State	2023	2025	2028	2030	2035	2040	2045	2050
Arizona	7.4%	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%
California	38.5%	44.0%	52.0%	57.3%	70.7%	84.0%	97.3%	100.0%
Colorado	21.2%	21.2%	21.2%	21.2%	21.2%	21.2%	21.2%	21.2%
Connecticut	30.0%	34.0%	40.0%	44.0%	44.0%	44.0%	44.0%	44.0%
District of Columbia	38.8%	52.0%	73.0%	87.0%	100.0%	100.0%	100.0%	100.0%
Delaware	16.4%	17.8%	17.8%	17.8%	17.8%	17.8%	17.8%	17.8%
Iowa	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Illinois	11.6%	13.3%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%
Massachusetts	23.5%	25.5%	28.5%	30.5%	35.5%	40.5%	45.5%	50.5%
Maryland	34.7%	40.0%	47.5%	50.0%	50.0%	50.0%	50.0%	50.0%
Maine	51.0%	59.0%	71.0%	80.0%	85.0%	90.0%	95.0%	100.0%
Michigan	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Minnesota	25.8%	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%
Missouri	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%
Montana	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%
North Carolina	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%
New Hampshire	21.2%	23.0%	23.0%	23.0%	23.0%	23.0%	23.0%	23.0%
New Jersey	30.5%	37.5%	46.5%	52.5%	52.5%	52.5%	52.5%	52.5%
New Mexico	28.1%	36.1%	41.6%	45.2%	57.2%	69.2%	70.7%	72.3%
Nevada	21.6%	28.1%	34.8%	41.4%	41.4%	41.4%	41.4%	41.4%
New York	39.3%	48.1%	61.2%	70.0%	70.0%	70.0%	70.0%	70.0%
Ohio	6.2%	7.1%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%
Oregon	14.1%	21.0%	21.6%	27.6%	36.1%	41.1%	42.6%	42.6%
Pennsylvania	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
Rhode Island	20.5%	23.5%	28.0%	31.0%	38.5%	38.5%	38.5%	38.5%
Texas	4.1%	4.1%	4.0%	3.9%	3.7%	3.6%	3.4%	3.2%
Virginia	14.7%	19.6%	27.1%	32.0%	46.2%	62.6%	78.9%	81.6%
Vermont	67.6%	68.8%	74.6%	79.8%	85.0%	85.0%	85.0%	85.0%
Washington	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%
Wisconsin	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%	9.65%

Notes:
The Renewable Portfolio Standard percentages are applied to modeled electricity sale projections.
North Carolina standards are adjusted to account for swine waste and poultry waste set-asides.

Table 3-18 State RPS Solar Carve-outs in v6

State	2023	2025	2028	2030	2035	2040	2045	2050
District of Columbia	2.9%	3.5%	4.5%	5.0%	7.0%	9.5%	10.0%	10.0%
Delaware	2.1%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Illinois	1.23%	1.41%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Massachusetts	0.18%	0.20%	0.22%	0.24%	0.28%	0.32%	0.36%	0.40%
Maryland	8.75%	11.50%	14.50%	14.50%	14.50%	14.50%	14.50%	14.50%
Minnesota	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
Missouri	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%
North Carolina	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
New Hampshire	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%
New Jersey	5.10%	4.80%	3.74%	2.21%	1.10%	1.10%	1.10%	1.10%
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%

Clean Energy Standards require a certain percentage of electricity sales be met through zero carbon resources, such as renewables, nuclear, and hydropower. Several states, including California, New Mexico, Nevada, New York, and Washington, have recently implemented clean energy standards. These requirements are summarized in Table 3-19. In addition, multiple U.S. states have recently adopted offshore wind energy policies, which are summarized in Table 3-20. Thermal generation limits are imposed in states where RPS or CES standards exceed 50% of sales to ensure that the states do not generate excess thermal power to satisfy exports. Table 3-21 summarizes the limits imposed in EPA Platform v6. These limits are not provided in affected PJM and New England states as these states can meet their RPS requirements within PJM or ISONE.

Table 3-19 Clean Energy Standards in v6

State	2023	2025	2028	2030	2035	2040	2045	2050
Colorado	-	-	-	-	-	-	-	52.6%
Massachusetts	26%	30%	36%	40%	50%	60%	70%	80%
California	-	-	-	-	-	-	-	100%
New Mexico	-	-	-	-	-	-	69.5%	90.4%
Nevada	-	-	-	-	-	-	-	100%
New York	-	-	-	-	-	100%	100%	100%
Washington - Alternative Compliance Payment Standards*	-	-	-	20%	20%	20%	-	-
Washington	-	-	-	100%	100%	100%	100%	100%

Notes:
*For the compliance period beginning January 1, 2030, through December 31, 2044, an electric utility may satisfy up to twenty percent of its compliance obligation with an alternative compliance option.

Table 3-20 Offshore Wind Mandates in v6

State	Bill/Act	Mandate Specifications	Implementation Year
Maryland	Senate Bill 516	400 MW, 800 MW, and 1,200 MW of offshore wind capacity by 2026, 2028 and 2030 respectively	2030
	Maryland Offshore Wind Energy Act of 2013	368 MW of offshore wind capacity (248 MW of US Wind, Inc. and 120 MW of Skipjack Offshore Energy, LLC projects)	2023
New Jersey	Executive Order No. 8	3,500 MW of offshore wind capacity by 2030	2030
Connecticut	House Bill 7156	2,000 MW of offshore wind capacity by 2030	2030
Massachusetts	Massachusetts Energy Diversity Act	1,600 MW of offshore wind capacity by 2027	2028
New York	Climate Leadership and Community Protection Act	9,000 MW of offshore wind capacity by 2035	2035
Maine	Final Report of the Ocean Energy Task Force, 2009	Goal of 5,000 MW of offshore wind capacity by 2030	Not implemented

Table 3-21 Fossil Generation Limits (GWh) in v6

State	2023	2025	2028	2030	2035	2040	2045	2050
California	-	-	139,719	126,457	94,785	63,473	28,911	22,977
Colorado	-	-	-	-	-	-	-	45,417
New Mexico	-	-	-	-	12,623	10,248	10,471	5,381
Nevada	-	-	-	-	-	-	-	5,047
New York	-	-	65,932	53,802	54,883	10,665	10,992	11,522
Virginia	-	-	-	-	-	58,892	38,793	37,111
Washington	-	-	-	9,319	9,770	10,451	11,282	12,182

3.10.10 Canada CO_2 and Renewable Regulations

Several CO_2 regulations in Canada are represented in EPA Platform v6. Under the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations, the CO_2 standard of 420 tonne /GWh of electricity produced applies to both coal-fired electricity generating units commissioned after July 1, 2015, and existing coal units that have reached their end-of-life date as defined by the regulation. EPA Platform v6 also models British Columbia's carbon tax, Manitoba's Emissions Tax on Coal and Petroleum Coke Act, and the Ontario and Quebec's participation in Western Climate Initiative (WCI) cap-and-trade program. Coming into force on January 1, 2012, Manitoba's Emissions Tax on Coal and Petroleum Coke Act requires a tax rate of $10 per tonne of CO_2 equivalent emissions on coal-fired and petroleum coke-fired units. Ontario and Quebec's participation in WCI is modeled through the application of the CO_2 allowance price from CA AB32. EPA Platform v6 also models the province level renewable electricity programs in Canada. Table 3-22 shows the province level renewable electricity requirements as a percentage of electricity sales.

Table 3-22 Canada Renewable Electricity Requirements (%) in v6

Province	2023	2025	2028	2030	2035	2040	2045	2050
British Columbia	93.0%	93.0%	93.0%	93.0%	93.0%	93.0%	93.0%	93.0%
Alberta				30.0%	30.0%	30.0%	30.0%	30.0%
Saskatchewan	30.0%	34.0%	40.0%	50.0%	50.0%	50.0%	50.0%	50.0%
New Brunswick	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Nova Scotia	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Prince Edward Island	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.00%

3.11 Emissions Trading and Banking

Several environmental air regulations included in EPA Platform v6 involve regional trading and banking of emission allowances. This includes the five programs of the Cross-State Air Pollution Rule (CSAPR) – SO_2 Group 1, SO_2 Group 2, NO_x Annual, NO_x Ozone Season Group 1, NO_x Ozone Season Group 2, and NO_x Ozone Season Group 3; the Regional Greenhouse Gas Initiative (RGGI) for CO_2; the SIP Call Ozone Season NO_x; and the West Region Air Partnership's (WRAP) program regulating SO_2 (adopted in response to the federal Regional Haze Rule).

Table 3-23 and Table 3-24 summarize the key parameters of these trading and banking programs as incorporated in EPA Platform v6. EPA Platform v6 does not include any explicit assumptions on the allocation of emission allowances among model plants under any of the programs.

3.11.1 Intertemporal Allowance Price Calculation

Under a perfectly competitive cap-and-trade program that allows banking (with a single, fixed future cap, and full banking allowed), the allowance price always increases by the discount rate between periods if affected sources have allowances banked between those two periods. This is a standard economic result for cap-and-trade programs and is consistent with producing a least-cost solution.

EPA Platform v6 uses the same discount rate assumption that governs all intertemporal economic decision-making in the model. The approach assumes that allowance trading is a standard activity engaged in by generation asset owners and that their intertemporal investment decisions as related to allowance trading will not fundamentally differ from other investment decisions. For more information on how this discount rate was calculated, see Section 10.4.

Table 3-23 Trading and Banking Rules in v6 – Part 1

	SIP Call - Ozone Season NO_x	WRAP- SO_2	RGGI - CO_2
Coverage	All fossil units > 25 MW[1]	All fossil units > 25 MW[2]	All fossil units > 25 MW[3]
Timing	Ozone Season (May - September)	Annual	Annual
Size of Initial Bank (MTons)	The bank starting in 2016 is assumed to be zero	The bank starting in 2018 is assumed to be zero	2023: 113,656
Total Allowances (MTons)	2016 - 2054: 72.845	2018 - 2054: 89.6	2023: 112,458 2024: 108,803 2025: 105,148 2026: 101,493 2027: 97,838 2028: 94,183 2029: 90,528 2030 - 2054: 86,873

Notes:

[1] Rhode Island, Connecticut, Delaware, District of Columbia, Massachusetts, North Carolina, and South Carolina are the NOx SIP Call states not covered by the CSAPR Ozone Season program.

[2] New Mexico, Utah, and Wyoming.

[3] Connecticut, Delaware, Maine, New Hampshire, New York, Vermont, Rhode Island, Massachusetts, Maryland, Virginia, and New Jersey.

Table 3-24 CASPR Trading and Banking Rules in v6 – Part 2

	CSAPR - SO_2 - Region 1	CSAPR - SO_2 - Region 2	CSAPR - Annual NO_x	CSAPR Update Rule - Ozone Season NO_x - Group 1	CSAPR Update Rule - Ozone Season NO_x - Group 2	Revised CSPR Update Rule – Ozone Season – Group 3
Coverage	All fossil units > 25 MW[1]	All fossil units > 25 MW[2]	All fossil units > 25 MW[3]	All fossil units > 25 MW[5]	All fossil units > 25 MW[4]	All fossil units > 25 MW[6]
Timing	Annual	Annual	Annual	Ozone Season (May - September)	Ozone Season (May - September)	Ozone Season (May - September)
Size of Initial Bank (MTons)	The bank starting in 2023 is assumed to be zero	The bank starting in 2023 is assumed to be zero	The bank starting in 2021 is assumed to be zero	The bank starting in 2021 is assumed to be zero	The cap in 2021 includes 21% of banking	The bank starting in 2021 is 21% of the starting aggregate state budgets
Total Allowances (MTons)	2023 - 2054: 1372.631	2023 - 2054: 597.579	2023 - 2054: 1069.256	2023 - 2054: 24.041	2023 - 2054: 313.24	2023- 100,526 2024 through 2054 – 96,975

Notes:

[1] Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin.
[2] Alabama, Georgia, Kansas, Minnesota, Nebraska, and South Carolina.
[3] Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.
[4] Alabama, Arkansas, Iowa, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Missouri, Mississippi, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, Wisconsin, and West Virginia.
[5] Georgia.
[6] Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia.

Table 3-25 Emission and Removal Rate Assumptions for Potential (New) Units in v6

	Controls, Removal, and Emissions Rates	Ultra Supercritical Pulverized Coal	Ultra Supercritical Pulverized Coal with 30% CCS	Ultra Supercritical Pulverized Coal with 90% CCS	Advanced Combined Cycle	Advanced Combined Cycle with CCS	Advanced Combustion Turbine	Biomass	Geothermal	Landfill Gas
SO_2	**Removal / Emissions Rate**	98% with a floor of 0.06 lbs/MMBtu	98% with a floor of 0.06 lbs/MMBtu	98% with a floor of 0.06 lbs/MMBtu	None	None	None	0.08 lbs/MMBtu	None	None
NO_x	**Emission Rate**	0.07 lbs/MMBtu	0.07 lbs/MMBtu	0.07 lbs/MMBtu	0.011 lbs/MMBtu	0.011 lbs/MMBtu	0.011 lbs/MMBtu	0.02 lbs/MMBtu	None	0.09 lbs/MMBtu
Hg	**Removal / Emissions Rate**	90%	90%	90%	Natural Gas: 0.000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	Natural Gas: 0.000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	Natural Gas: 0.000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	0.57 lbs/MMBtu	3.70	None
CO_2	**Removal / Emissions Rate**	202.8 - 215.8 lbs/MMBtu	30%	90%	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	90%	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	None	None	None
HCL	**Removal / Emissions Rate**	99% with a floor of 0.001 lbs/MMBtu	99% with a floor of 0.001 lbs/MMBtu	99% with a floor of 0.001 lbs/MMBtu						

Table 3-26 Recalculated NO_x Emission Rates for SCR Equipped Units Sharing Common Stacks with Non-SCR Units in v6

Plant Name	UniqueID_Final	Capacity (MW)	NOx Post-Comb Control	SCR Online Year	Mode 1 NO_x Rate (lbs/MMBtu)	Mode 2 NO_x Rate (lbs/MMBtu)	Mode 3 NO_x Rate (lbs/MMBtu)	Mode 4 NO_x Rate (lbs/MMBtu)
Ghent	1356_B_2	495			0.305	0.305	0.305	0.305
Ghent	1356_B_3	485	SCR	2004	0.075	0.075	0.075	0.075
Cooper	1384_B_1	116			0.273	0.273	0.199	0.199
Cooper	1384_B_2	225	SCR	2012	0.075	0.075	0.075	0.075
J H Campbell	1710_B_1	260			0.179	0.179	0.179	0.179
J H Campbell	1710_B_2	348	SCR	2013	0.047	0.047	0.047	0.047
W H Sammis	2866_B_5	290	SNCR		0.245	0.245	0.199	0.199
W H Sammis	2866_B_6	600	SCR	2010	0.075	0.075	0.075	0.075
W H Sammis	2866_B_7	600	SCR	2010	0.075	0.075	0.075	0.075
Crist	641_B_4	75	SNCR		0.406	0.119	0.147	0.1
Crist	641_B_5	75	SNCR		0.376	0.116	0.147	0.1
Crist	641_B_6	299	SCR	2012	0.248	0.068	0.248	0.068
Crist	641_B_7	475	SCR	2005	0.062	0.062	0.062	0.062
Clifty Creek	983_B_4	196	SCR	2003	0.075	0.075	0.075	0.075
Clifty Creek	983_B_5	196	SCR	2002	0.075	0.075	0.075	0.075
Clifty Creek	983_B_6	196			0.667	0.3	0.667	0.3

3.12 45Q – Credit for Carbon Dioxide Sequestration

Bipartisan Budget Act of 2018, Section 45Q – which amended a Credit for Carbon Dioxide Sequestration originally passed in 2008 (hereafter referred to as the 45Q tax credit) is implemented in EPA Platform v6. The tax credit extension from Consolidated Appropriations Act of 2021 is also incorporated.

The updated 45Q tax credit (2018) offers increased monetary incentives by way of a tax credit for the capture and geologic storage of CO_2 that would otherwise be emitted by electric power plants and other industrial sources in the United States. The basic features of the tax credit are as follows:

- $12.83 per metric ton in 2016 for carbon dioxide (CO_2) captured and injected into existing oil wells for enhanced oil recovery (EOR). The credit increases to $35 per metric ton by 2026. The credit for intermediate years is determined by linear interpolation. The credit is adjusted for inflation post 2026.
- $22.66 per metric ton in 2016 for CO_2 captured and sequestrated in geologic formation (Non-EOR). The credit increases to $50 per metric ton by 2026. The credit for intermediate years is determined by linear interpolation. The credit is adjusted for inflation post 2026.
- The dollar amounts of credit are in 2017 nominal dollars. The difference in the amounts of credit between EOR and Non-EOR is by design to recognize the fact that the EOR captured CO_2 can be used to produce oil that may not otherwise be recovered, while the Non-EOR stored CO_2 does not bring additional revenue.
- Credits are available to plants that start construction or begin a retrofit before January 1, 2026 and are assumed to be applied for the first 12 years of operation.

The 45Q tax credit is implemented by applying the value of the credit through an adjustment to the step prices in the CO_2 storage cost curves.[37] The process involves converting the dollar amounts of credit into 2019 real dollars, calculating weighted average tax credits by run year, and applying the weighted average tax credits to the individual step prices in the CO_2 storage cost curves.

Although the 45Q tax credit expires in 2026, due to an assumed construction lead time of 5 years for new coal units, a 2030 vintage plant is assumed to qualify for the tax credit.

List of tables and attachments that are uploaded directly to the web:

Table 3-27 Regional Net Internal Demand in EPA Platform v6 Summer 2021 Reference Case

Table 3-28 Annual Transmission Capabilities of U.S. Model Regions in EPA Platform v6 Summer 2021 Reference Case

Table 3-29 Turndown Assumptions for Coal Steam Units in EPA Platform v6 Summer 2021 Reference Case

Table 3-30 State Power Sector Regulations included in EPA Platform v6 Summer 2021 Reference Case

Table 3-31 New Source Review (NSR) Settlements in EPA Platform v6 Summer 2021 Reference Case

Table 3-32 State Settlements in EPA Platform v6 Summer 2021 Reference Case

Table 3-33 Citizen Settlements in EPA Platform v6 Summer 2021 Reference Case

Table 3-34 Availability Assumptions in EPA Platform v6 Summer 2021 Reference Case

Table 3-35 BART Regulations included in EPA Platform v6 Summer 2021 Reference Case

Attachment 3-1 NO_x Rate Development in EPA Platform v6 Summer 2021 Reference Case

[37] For more information on the CO_2 storage cost curves, see Chapter 6 – CO_2 Capture, Storage, and Transport in the Documentation for EPA's Power Sector Modeling Platform v6 Using Integrated Planning Model. The documentation is available online at https://www.epa.gov/airmarkets/documentation-ipm-platform-v6-all-chapters.