3. Power System Operation Assumptions

This section describes the assumptions pertaining to the North American electric power system as represented in EPA Platform v6.

3.1 Model Regions

EPA Platform v6 models the U.S. power sector in the contiguous 48 states and the District of Columbia and the Canadian power sector in the 10 provinces (with Newfoundland and Labrador represented as two regions on the electricity network even though politically they constitute a single province[12]) as an integrated network[13].

There are 67 IPM model regions covering the U.S. 48 states and District of Columbia. The IPM model regions are approximately consistent with the configuration of the NERC assessment regions in the NERC Long-Term Reliability Assessments. These IPM model regions reflect the administrative structure of regional transmission organizations (RTOs) and independent system operators (ISOs). Further disaggregation of the NERC assessment regions and RTOs allows a more accurate characterization of the operation of the U.S. power markets by providing the ability to represent transmission bottlenecks across RTOs and ISOs, as well as key transmission limits within them.

The IPM regions also provide approximate disaggregation of the regions of the National Energy Modeling System (NEMS) to provide for a more accurate correspondence with the demand projections of the Annual Energy Outlook (AEO). Notable disaggregations are further described below:

NERC assessment regions 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, the 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, where the IPM regions are selected to represent planning areas within each RTO and/or areas with internal transmission limits.

New York is now 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 U.S. 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 three 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.

The 11 Canadian model regions are defined along provincial political boundaries.

Figure 3-1 contains a map showing all 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

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

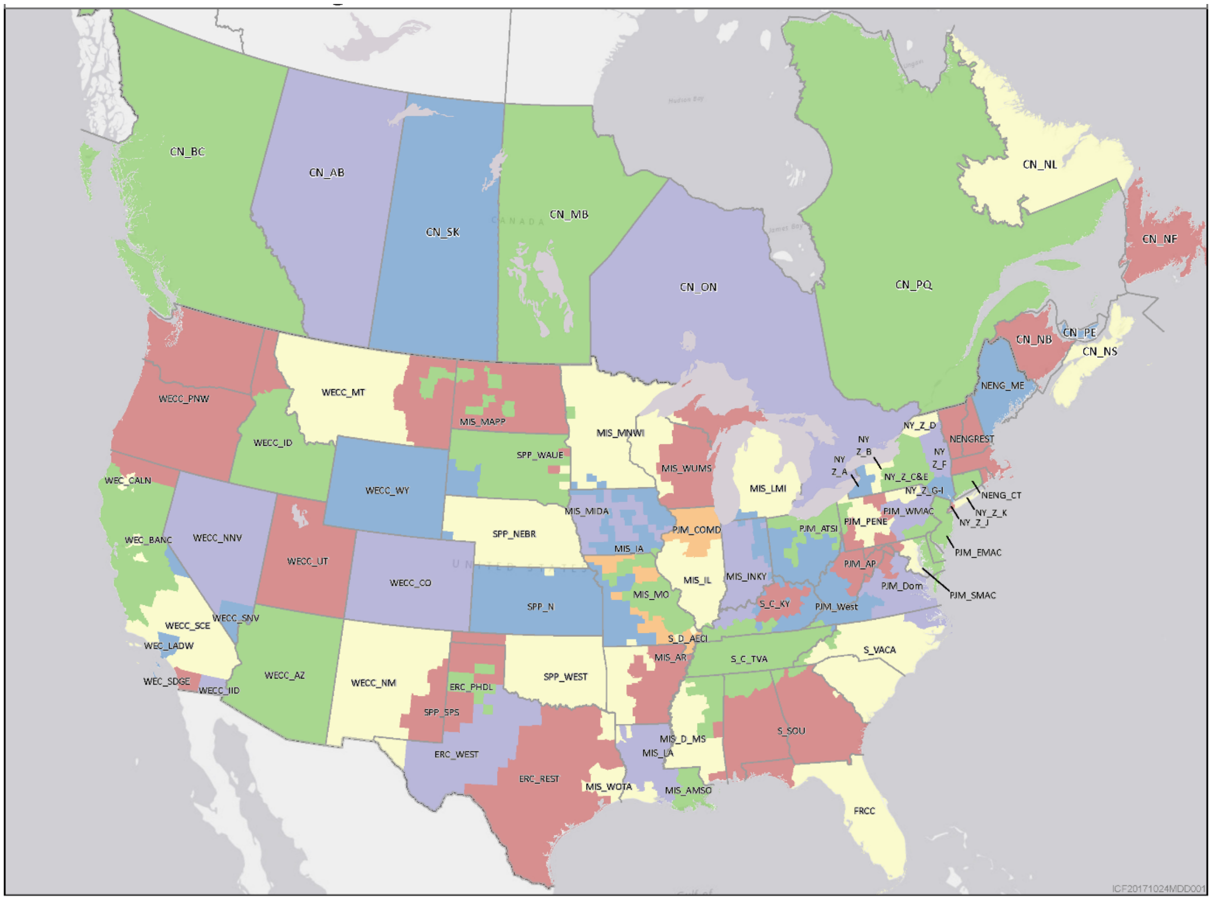
[13] Because United States and the Canadian power markets are being modeled in an integrated manner, IPM can model the transfer of power in between these two countries endogenously. This transfer of power is limited by the available transmission capacity in between the two countries. Hence, it is possible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

Administration's (EIA's) National Energy Model System (NEMS) that is the basis for EIA's Annual Energy Outlook (AEO) reports.

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 electric 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 2017.[14]

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 basis respectively. EPA Platform v6 models regional breakdowns of net energy for load in each of the 67 IPM U.S. regions in the following steps:

- The net energy for load in each of the 22 NEMS electricity regions is taken from the NEMS reference case.

[14] 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 73-120 at http://www.eia.gov/forecasts/aeo/tables_ref.cfm.

- 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.
  - Map the NERC Balancing Authorities/ Planning Areas in the US to the 67 IPM regions.
  - Map the Balancing Authorities/ Planning Areas in the US to the 22 NEMS regions.
  - Using the 2007 data from FERC Form 714 for non WECC regions and 2011 data for WECC regions on net energy for load in each of the balancing areas, calculate the proportional share of each of the net energy for load in 22 NEMS regions that falls in each of the 67 IPM Regions.
- Using these shares of each NEMS region net energy for load that falls in each IPM region, calculate the total net energy for load for each IPM region from the NEMS regional load in AEO 2017.

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

NERC Assessment Region	AEO 2017 NEMS Region	Model Region	Model Region Description
ERCOT	ERCT (1)	ERC_REST	ERCOT_Rest
	ERCT (1)	ERC_GWAY	ERCOT_Tenaska Gateway Generating Station
	ERCT (1)	ERC_FRNT	ERCOT_Tenaska Frontier Generating Station
	ERCT (1)	ERC_WEST	ERCOT_West
	ERCT (1)	ERC_PHDL	ERCOT_Panhandle
FRCC	FRCC (2)	FRCC	FRCC
MAPP	MROW (4)	MIS_MAPP	MISO_MT, SD, ND
MISO	SRGW (13)	MIS_IL	MISO_Illinois
	RFCW (11), SRCE (15)	MIS_INKY	MISO_Indiana (including parts of Kentucky)
	MROW (4)	MIS_IA	MISO_Iowa
	MROW (4)	MIS_MIDA	MISO_Iowa-MidAmerican
	RFCM (10)	MIS_LMI	MISO_Lower Michigan
	SRGW (13)	MIS_MO	MISO_Missouri
	MROE (3), RFCW (11)	MIS_WUMS	MISO_Wisconsin- Upper Michigan (WUMS)
	MROW (4)	MIS_MNWI	MISO_Minnesota and Western Wisconsin
	SRDA (12)	MIS_WOTA	MISO_WOTAB (including Western)
	SRDA (12)	MIS_AMSO	MISO_Amite South (including DSG)
	SRDA (12)	MIS_AR	MISO_Arkansas
	SRDA (12)	MIS_D_MS	MISO_Mississippi
	SPSO (18)	MIS_LA	MISO_Louisiana
ISO-NE	NEWE (5)	NENG_CT	ISONE_Connecticut
	NEWE (5)	NENGREST	ISONE_MA, VT, NH, RI (Rest of ISO New England)
	NEWE (5)	NENG_ME	ISONE_Maine
NYISO	NYUP (8)	NY_Z_C&E	NY_Zone C&E
	NYUP (8)	NY_Z_F	NY_Zone F (Capital)
	NYUP (8)	NY_Z_G-I	NY_Zone G-I (Downstate NY)
	NYCW (6)	NY_Z_J	NY_Zone J (NYC)
	NYLI (7)	NY_Z_K	NY_Zone K (LI)
	NYUP (8)	NY_Z_A	NY_Zone A (West)
	NYUP (8)	NY_Z_B	NY_Zone B (Genesee)
	NYUP (8)	NY_Z_D	NY_Zone D (North)
PJM	RFCE (9)	PJM_WMAC	PJM_Western MAAC
	RFCE (9)	PJM_EMAC	PJM_EMAAC

NERC Assessment Region	AEO 2017 NEMS Region	Model Region	Model Region Description
	RFCE (9)	PJM_SMAC	PJM_SWMAAC
	RFCW (11)	PJM_West	PJM West
	RFCW (11)	PJM_AP	PJM_AP
	RFCW (11)	PJM_COMD	PJM_ComEd
	RFCW (11)	PJM_ATSI	PJM_ATSI
	SRVC (16)	PJM_Dom	PJM_Dominion
	RFCE (9)	PJM_PENE	PJM_PENELEC
SERC-E	SRVC (16)	S_VACA	SERC_VACAR
SERC-N	SRCE (15)	S_C_KY	SERC_Central_Kentucky
	SRDA (12)	S_D_AECI	SERC_Delta_AECI
	SRCE (15)	S_C_TVA	SERC_Central_TVA
SERC-SE	SRSE (14)	S_SOU	SERC_Southeastern
SPP	MROW (4)	SPP_NEBR	SPP Nebraska
	SPNO (17), SRGW (13)	SPP_N	SPP North- (Kansas, Missouri)
	SPSO (18)	SPP_KIAM	SPP_Kiamichi Energy Facility
	SPSO (18), SRDA (12)	SPP_WEST	SPP West (Oklahoma, Arkansas, Louisiana)
	SPSO (18)	SPP_SPS	SPP SPS (Texas Panhandle)
	MROW (4)	SPP_WAUE	SPP_WAUE
California/Mexico (CA/MX)	CAMX (20)	WEC_CALN	WECC_Northern California (not including BANC)
	CAMX (20)	WEC_LADW	WECC_LADWP
	CAMX (20)	WEC_SDGE	WECC_San Diego Gas and Electric
	CAMX (20)	WECC_SCE	WECC_Southern California Edison
Northwest Power Pool (NWPP)	NWPP (21)	WECC_MT	WECC_Montana
	CAMX (20)	WEC_BANC	WECC_BANC
	NWPP (21)	WECC_ID	WECC_Idaho
	NWPP (21)	WECC_NNV	WECC_Northern Nevada
	AZNM (19)	WECC_SNV	WECC_Southern Nevada
	NWPP (21)	WECC_UT	WECC_Utah
	NWPP (21)	WECC_PNW	WECC_Pacific Northwest
Rocky Mountain Reserve Group (RMRG)	RMPA (22)	WECC_CO	WECC_Colorado
	NWPP (21), RMPA (22)	WECC_WY	WECC_Wyoming
Southwest Reserve Sharing Group (SRSG)	AZNM (19)	WECC_AZ	WECC_Arizona
	AZNM (19)	WECC_NM	WECC_New Mexico
	AZNM (19)	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 EPA Platform v6

Year	Net Energy for Load (Billions of kWh)
2021	4,090
2023	4,172
2025	4,241
2030	4,363
2035	4,489
2040	4,654
2045	4,804
2050	4,970

Notes:

The data represents an aggregation of the model-region-specific net energy loads used in the EPA Platform v6.

Table 3-3 Regional Electric Load Assumptions in EPA Platform v6

IPM Region	Net Energy for Load (Billions of kWh)							
	2021	2023	2025	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	0
ERC_REST	347	357	367	386	403	424	444	461
ERC_WEST	28	28	29	31	32	34	35	37
FRCC	231	236	242	254	265	278	290	304
MIS_AMSO	31	32	33	34	36	37	39	40
MIS_AR	36	38	39	40	42	44	46	48
MIS_D_MS	22	23	23	24	25	26	27	28
MIS_IA	22	22	23	23	24	25	26	27
MIS_IL	48	49	49	51	52	54	56	58
MIS_INKY	97	99	100	103	105	108	112	116
MIS_LA	46	47	48	51	53	55	58	60
MIS_LMI	100	102	103	105	108	111	115	119
MIS_MAPP	8	9	9	9	9	10	10	10
MIS_MIDA	30	31	31	32	33	34	35	37
MIS_MNWI	90	92	93	96	99	102	106	110
MIS_MO	41	41	42	43	44	46	47	49
MIS_WOTA	32	33	34	36	37	39	41	42
MIS_WUMS	55	56	56	58	59	61	63	65
NENG_CT	30	30	30	31	31	31	31	31
NENG_ME	11	11	11	11	11	11	11	11
NENGREST	78	79	79	79	80	81	81	81
NY_Z_A	15	15	15	15	15	15	15	15
NY_Z_B	9	9	10	9	9	9	9	10
NY_Z_C&E	23	23	23	23	23	23	23	23
NY_Z_D	6	6	6	6	6	6	6	6
NY_Z_F	11	11	11	11	11	11	11	11

IPM Region	Net Energy for Load (Billions of kWh)							
	2021	2023	2025	2030	2035	2040	2045	2050
NY_Z_G-I	18	18	19	18	18	18	18	19
NY_Z_J	51	51	51	50	49	49	49	50
NY_Z_K	22	22	22	22	22	22	22	22
PJM_AP	48	49	49	50	51	53	54	56
PJM_ATSI	70	71	72	74	75	78	80	83
PJM_COMD	102	104	106	108	110	113	117	121
PJM_Dom	97	100	102	107	111	116	121	126
PJM_EMAC	139	140	142	143	145	148	150	154
PJM_PENE	17	17	17	17	18	18	18	19
PJM_SMAC	64	64	65	65	66	68	69	71
PJM_West	212	217	220	225	230	237	244	253
PJM_WMAC	55	56	56	57	58	59	60	62
S_C_KY	32	33	34	35	36	38	39	40
S_C_TVA	179	184	188	194	200	207	214	222
S_D_AECI	18	19	19	19	20	21	21	22
S_SOU	250	258	263	274	283	295	306	318
S_VACA	225	231	236	247	256	268	279	292
SPP_KIAM	0	0	0	0	0	0	0	0
SPP_N	71	72	74	76	79	82	85	88
SPP_NEBR	34	34	35	36	37	38	40	41
SPP_SPS	30	31	32	33	34	36	38	39
SPP_WAUE	23	23	24	25	25	26	27	28
SPP_WEST	131	135	139	145	151	159	166	172
WEC_BANC	14	14	14	14	14	15	15	15
WEC_CALN	112	112	112	112	113	116	118	120
WEC_LADW	28	27	27	27	28	28	29	29
WEC_SDGE	22	22	22	21	22	22	23	23
WECC_AZ	88	90	92	97	101	105	108	112
WECC_CO	62	64	65	68	71	74	76	78
WECC_ID	22	23	23	23	24	25	25	26
WECC_IID	4	5	5	5	5	5	5	5
WECC_MT	13	13	13	13	14	14	14	15
WECC_NM	23	24	24	25	26	28	28	29
WECC_NNV	13	13	13	13	13	14	14	14
WECC_PNW	173	175	176	179	184	189	194	199
WECC_SCE	110	110	109	109	110	113	115	118
WECC_SNV	26	27	27	29	30	31	32	33
WECC_UT	28	28	28	29	29	30	31	32
WECC_WY	17	17	18	18	18	19	20	20

3.2.1 Demand Elasticity

EPA Platform v6 has the capability to consider endogenously the relationship of the price of power to electricity demand. However, the 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, must be met as IPM solves for least-cost electricity supply. This 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 AEO2017 reference case).

3.2.2 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 2021-2027 period were estimated based on NERC ES&D 2017 load factors[15], and the estimated energy demand projections shown in Table 3-2. For post 2027 years when NERC ES&D 2017 load factors were not available, the NERC ES&D 2017 load factors for 2027 were projected forward using growth factors embedded in the AEO 2017 load factor projections.

Table 3-4 illustrates the national sum of each region’s seasonal peak demand and Table 3-19 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

Year	Peak Demand (GW)		
	Winter	Winter Shoulder	Summer
2021	655	605	772
2023	668	616	785
2025	680	627	800
2030	704	648	829
2035	730	671	863
2040	763	700	904
2045	798	730	948
2050	833	761	993

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

[15] Load factors can be calculated at the NERC assessment region level based on the NERC ES&D 2017 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.

3.2.3 Regional Load Shapes

As of 2013, EPA has adopted year 2011 as the meteorological year in its air quality modeling. In order for EPA Platform v6 to be consistent, the year 2011 was selected as the "normal weather year"[16] 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 HHDs 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 United States and Canada can be broken down into several power markets that are interconnected by a transmission grid. As discussed earlier, EPA Platform v6 characterizes the US lower 48 states, the District of Columbia, and Canada into 78 different model regions by means of 64 power market regions and 3 power switching regions[17] in the US and 11 power market regions in Canada. EPA Platform v6 includes explicit assumptions regarding the transmission grid connecting these modeled power markets. This section details the assumptions about the transfer capabilities, wheeling costs and inter-regional transmission used in EPA Platform v6.

3.3.1 Inter-regional Transmission Capability

Table 3-20[18] 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 key 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"). They 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 of the modeled transmission links have the same Total Transfer Capabilities for all seasons, which means that the maximum firm and non-firm TTCs for each link is the same for winter, winter shoulder, and summer. 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.

[16] 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.

[17] Power switching regions are regions with no market load that represent individual generating facilities specifically configured so they can sell directly into either ERCOT or SPP: these plants are implemented in IPM as regions with transmission links only to ERCOT and to SPP.

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

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 3-20 represents a one-directional flow of power on that link. This implies 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.

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.

Table 3-20, the transfer capabilities from New England to New York for the individual links are:

- NENG_CT to NY_Z_G-I: 600 MW
- NENGREST to NY_Z_F: 800 MW
- NENG_CT to NY_Z_K: 760 MW

Without any simultaneous transfer limits, the total transfer capability from New England to New York would be 2,160 MW. However, current system conditions and reliability requirements limit the total simultaneous transfers from New England to New York to 1,730 MW. 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 EPA Platform 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	282	
ISO NE to NYISO	NENG_CT to NY_Z_G-I NENGREST to NY_Z_F NENG_CT to NY_Z_K	1,730	
NYISO to ISO NE	NY_Z_G-I to NENG_CT NY_Z_F to NENGREST NY_Z_K to NENG_CT	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	7,881	12,000
PJM_ATSI to PJM West & PJM_PENELEC & PJM_AP	PJM_ATSI to PJM_West PJM_ATSI to PJM_PENE	7,881	12,000

Region Connection	Transmission Path	Capacity TTC (MW)	Energy TTC (MW)
	PJM_ATSI to PJM_AP		
PJM_West & PJM_Dominion to SERC VACAR	PJM_West to S_VACA PJM_Dom to S_VACA	2,208	3,424
SERC VACAR to PJM_West & PJM_Dominion	S_VACA to PJM_West S_VACA to PJM_Dom	2,208	3,424
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

3.3.3 Transmission Link Wheeling Charge

Transmission wheeling charge is the cost of transferring electric power from one region to another using the transmission link. The EPA Platform v6 has no charges within individual IPM regions and no charges between IPM regions that fall within the same RTO. Charges between other regions vary to reflect the cost of wheeling. The wheeling charges in 2016 mills/kWh are shown in Table 3-20 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 WECC interconnect and 2.4 percent inter-regional transmission loss of energy transferred in ERCOT and Eastern interconnects. This is based on average loss factors calculated from standard power flow data developed by the transmission providers.

3.4 International Imports

The US 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 US and Mexico is represented by an assumption of net imports based on information from AEO 2017. Table 3-6 summarizes the assumptions on net imports into the US from Mexico.

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

	2021	2023	2025	2030	2035	2040	2045	2050
Net Imports from Mexico	6.34	6.34	6.34	6.34	6.34	6.34	6.34	6.34

Note 1: Source: AEO 2017

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 that the model makes. 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 full in Chapter 4.

A unit's generation over a time period is defined by its dispatch pattern over that duration of time. 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 and turndown constraints. However, for some unit types, capacity factors are used to capture the resource or other physical constraints on generation. The two cases are discussed in more detail in the following sections.

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 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. They are based on data from NERC Generating Availability Data System (GADS) 2011-2015 and AEO 2017. 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 3-26 shows the availability assumptions for all generating units in EPA Platform v6.

Table 3-7 Availability Assumptions in EPA Platform v6

Unit Type	Annual Availability (%)
Biomass	83
Coal Steam	76 - 85
Combined Cycle	85
Combustion Turbine	84 - 91
Energy Storage	90
Fossil Waste	90
Fuel Cell	87
Geothermal	87
Hydro	79 - 84
IGCC	79 - 85
Landfill Gas	90
Municipal Solid Waste	90
Non-Fossil Waste	90
Nuclear	75 - 97
Oil/Gas Steam	69 - 89
Offshore Wind	95
Onshore Wind	95
Pumped Storage	82
Solar PV	90
Solar Thermal	90

Notes:
Values shown are a range of all of the values modeled within the EPA Platform v6.

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 3-26, seasonal availabilities differ only in that no planned maintenance is assumed to be conducted during the onpeak- summer (June, July, and August) months for summer peaking regions and onpeak – 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

Generation from certain types of units is constrained by resource limitations. These technologies include hydro, wind, and solar. For such technologies, IPM uses capacity factors or generation profiles, not availabilities, to define the upper bound on the generation obtainable from the unit. The capacity factor is the percentage of the maximum possible power generated by the unit. For example, a photovoltaic solar unit would have a capacity factor of 27% if the usable sunlight were only available that percent of the time. For such units, explicit capacity factors or generation profiles mimic the resource availability. The seasonal capacity factor assumptions for hydro facilities contained in Table 3-8 were derived from EIA Form-923 data for the 2007-2016 period. A discussion of capacity factors and generation profiles for wind and solar technologies is contained in section 4.4.5 and Table 4-20, Table 4-22, Table 4-24, Table 4-26, Table 4-44 and Table 4-45.

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

Model Region	Winter Capacity Factor	Winter Shoulder Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
ERC_REST	10%	11%	17%	13%
FRCC	51%	42%	35%	42%
MIS_AR	44%	40%	46%	43%
MIS_IA	42%	48%	57%	50%
MIS_IL	56%	61%	60%	59%
MIS_INKY	70%	76%	84%	78%
MIS_LA	62%	56%	64%	61%
MIS_LMI	61%	76%	48%	60%
MIS_MAPP	76%	76%	84%	79%
MIS_MIDA	26%	29%	32%	29%
MIS_MNWI	47%	57%	62%	57%
MIS_MO	36%	43%	55%	47%
MIS_WOTA	20%	20%	20%	20%
MIS_WUMS	51%	62%	54%	56%
NENG_CT	41%	42%	37%	40%
NENG_ME	65%	58%	57%	59%
NENGREST	39%	43%	33%	38%
NY_Z_A	70%	66%	63%	66%
NY_Z_B	35%	31%	24%	29%
NY_Z_C&E	53%	52%	51%	52%
NY_Z_D	71%	75%	79%	76%
NY_Z_F	55%	54%	49%	52%
NY_Z_G-I	34%	34%	33%	33%
PJM_AP	64%	56%	50%	55%
PJM_ATSI	17%	20%	25%	21%
PJM_COMD	38%	42%	50%	44%

Model Region	Winter Capacity Factor	Winter Shoulder Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
PJM_Dom	24%	19%	15%	18%
PJM_EMAC	44%	40%	24%	35%
PJM_PENE	58%	57%	36%	48%
PJM_West	34%	31%	29%	31%
PJM_WMAC	41%	40%	23%	33%
S_C_KY	31%	25%	22%	25%
S_C_TVA	52%	36%	30%	37%
S_D_AECI	13%	18%	21%	18%
S_SOU	30%	22%	16%	21%
S_VACA	27%	20%	17%	20%
SPP_N	13%	16%	20%	17%
SPP_NEBR	30%	34%	43%	37%
SPP_WAUE	32%	34%	43%	37%
SPP_WEST	26%	26%	32%	29%
WEC_BANC	16%	19%	31%	23%
WEC_CALN	21%	26%	40%	31%
WEC_LADW	12%	13%	21%	16%
WEC_SDGE	25%	30%	49%	37%
WECC_AZ	27%	28%	32%	29%
WECC_CO	30%	24%	34%	30%
WECC_ID	31%	32%	46%	38%
WECC_IID	30%	37%	61%	45%
WECC_MT	37%	37%	50%	43%
WECC_NM	23%	24%	32%	27%
WECC_NNV	38%	49%	55%	49%
WECC_PNW	44%	41%	45%	43%
WECC_SCE	19%	25%	46%	32%
WECC_SNV	19%	24%	26%	24%
WECC_UT	28%	29%	39%	33%
WECC_WY	15%	22%	53%	34%

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

Capacity factors are also used to define the upper bound on generation obtainable from nuclear units. This rests on the assumption that nuclear units will dispatch to their availability, and, consequently, capacity factors and availabilities 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, capacity factors for oil/gas steam units are treated separately and 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 stakeholders expect will continue to occur based on observed market outcomes to date. These comments note that these units often operate due to 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 reflect better the real-world behavior of these units where drivers of that behavior are not fully represented in the model itself. This approach is designed to balance the continued operation of these units in the near term while also allowing economic forces to influence decision-making over the modeling time horizon; as a result, the minimum capacity factor limitations are imposed for limited time horizons (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; in order 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:

1) For each oil/gas steam unit, calculate an annual capacity factor over a ten-year baseline (2007-2016).
2) Identify the minimum capacity factor over this baseline period for each unit.
3) 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 2021, remove minimum constraint from units with capacity factor < 5%
   - For model year 2023, remove minimum constraint from units with capacity factor < 10%
   - For model year 2025, remove minimum constraint from units with capacity factor < 15%
   - For model year 2030, remove minimum constraint from units with capacity factor < 25%
   - For model year 2035, remove minimum constraint from units with capacity factor < 35%
   - For model year 2040, remove minimum constraint from units with capacity factor < 45%

3.5.3 Turndown

Turndown assumptions in EPA Platform v6 are used to prevent coal and oil/gas steam units from operating strictly as peaking units, which would be inconsistent with their operating capabilities. Specifically, 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. The unit level turndown percentages for coal units were estimated based on a review of recent hourly Air Markets Program Data (AMPD) data and are shown in Table 3-21.

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 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 depict the reliability standards that are in effect in each NERC region. Individual reserve margins for each NERC region are derived either directly or indirectly from NERC's electric reliability reports. They are based on reliability standards such as loss of load expectation (LOLE), which is defined as the expected number of days in a specified period in which the daily peak load will exceed the available capacity. These 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 EPA Platform v6

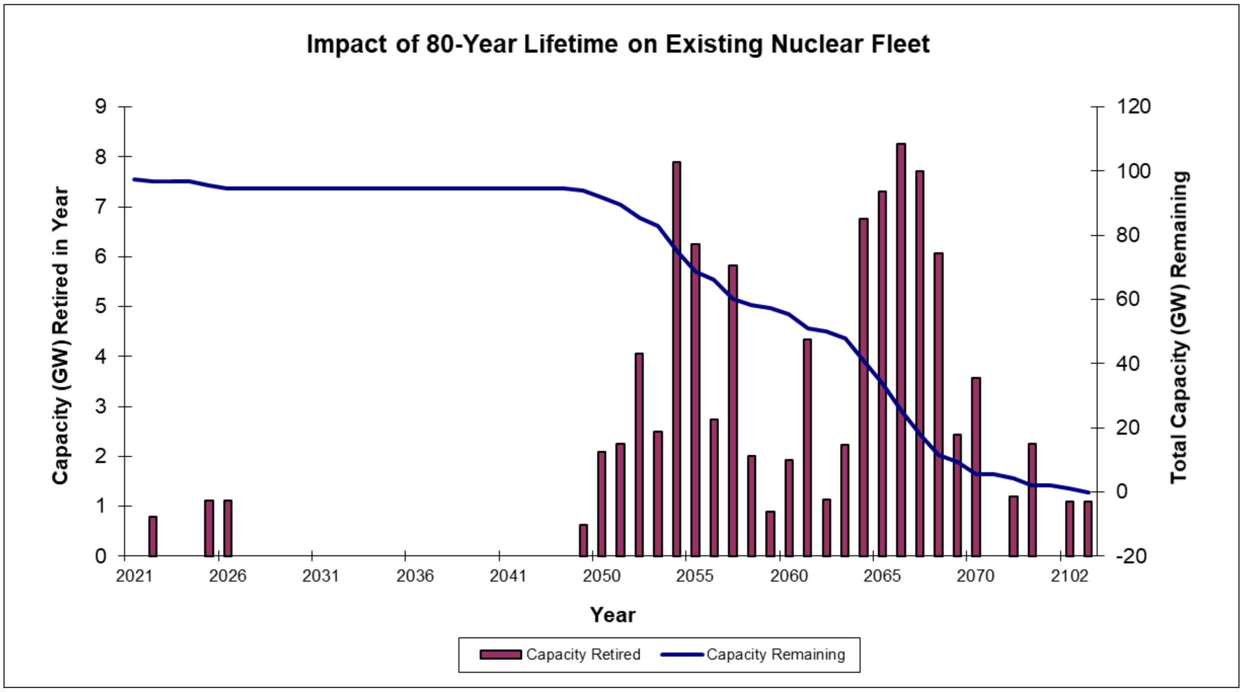
Model Region	Reserve Margin	Model Region	Reserve Margin
CN_AB	11.0%	NY_Z_G-I	15.0%
CN_BC	12.1%	NY_Z_J	15.0%
CN_MB	12.0%	NY_Z_K	15.0%
CN_NB	20.0%	PJM_AP	16.5%
CN_NF	20.0%	PJM_ATSI	16.5%
CN_NL	20.0%	PJM_COMD	16.5%
CN_NS	20.0%	PJM_Dom	16.5%
CN_ON	17.00%	PJM_EMAC	16.5%
CN_PE	20.0%	PJM_PENE	16.5%
CN_PQ	12.70%	PJM_SMAC	16.5%
CN_SK	11.00%	PJM_West	16.5%
ERC_FRNT	13.8%	PJM_WMAC	16.5%
ERC_GWAY	13.8%	S_C_KY	15.0%
ERC_PHDL	13.8%	S_C_TVA	15.0%
ERC_REST	13.8%	S_D_AECI	15.0%
ERC_WEST	13.8%	S_SOU	15.0%
FRCC	18.6%	S_VACA	15.0%
MIS_AR	15.2%	SPP_KIAM	12.0%
MIS_D_MS	15.2%	SPP_N	12.0%
MIS_IA	15.2%	SPP_NEBR	12.0%
MIS_IL	15.2%	SPP_SPS	12.0%
MIS_INKY	15.2%	SPP_WAUE	12.0%
MIS_LA	15.2%	SPP_WEST	12.0%
MIS_LMI	15.2%	WEC_BANC	16.3%
MIS_MAPP	15.2%	WEC_CALN	16.2%
MIS_MIDA	15.2%	WEC_LADW	16.2%
MIS_MNWI	15.2%	WEC_SDGE	16.2%
MIS_MO	15.2%	WECC_AZ	15.8%
MIS_AMSO	15.2%	WECC_CO	14.1%
MIS_WOTA	15.2%	WECC_ID	16.3%
MIS_WUMS	15.2%	WECC_IID	15.8%
NENG_CT	15.9%	WECC_MT	16.3%
NENG_ME	15.9%	WECC_NM	15.8%
NENGREST	15.9%	WECC_NNV	16.3%
NY_Z_A	15.0%	WECC_PNW	16.3%
NY_Z_B	15.0%	WECC_SCE	16.2%
NY_Z_C&E	15.0%	WECC_SNV	16.3%
NY_Z_D	15.0%	WECC_UT	16.3%
NY_Z_F	15.0%	WECC_WY	14.1%

3.7 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 assumes an 80-year life. EPA Platform v6 incorporates life extension costs to enable these operating life extensions. (See Sections 4.2.8 and 4.5)

Figure 3-2 Scheduled Retirements of Existing Nuclear Capacity Under 80-Year Life Assumption



3.8 Heat Rates

Heat rates, expressed in British thermal units (Btus) per kilowatt-hour (kW-hr), are a measure of an Electric Generating Unit's (EGU's) generating 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:

1. Plant efficiencies tend to degrade over time, and
2. Increased maintenance and component replacement 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 Annual Energy Outlook 2017 (AEO 2017) 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.

Based on engineering analysis, the upper and lower heat rate limits shown in Table 3-10 were applied to coal steam, oil/gas steam, combined cycle, combustion turbine, and Internal Combustion (IC) 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 3-10 Lower and Upper Limits Applied to Heat Rate Data in EPA Platform 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

EPA Platform v6 is capable of offering to coal steam model plants a heat rate improvement option that is fully integrated into the Integrated Planning Model (IPM) framework. This capability enables IPM to determine economic uptake of heat rate improvements at each model plant, and it can be activated or deactivated as an investment option in any given scenario analyzed in IPM. Note that the heat rate improvement option is deactivated in EPA Platform v6, and is assumed to remain deactivated unless otherwise noted in EPA analyses using EPA Platform v6.

As an EGU's heat rate improves, less fuel is needed to produce the same amount of electricity. Because less fuel is combusted to produce the same amount of electricity, pollutant emissions are reduced per kW-hr of electricity produced. Furthermore, heat rate improvement has accompanying economic benefits, such as reducing fuel costs associated with generating the same amount of electricity. EPA is aware that a variety of technical approaches has been applied at existing coal steam EGUs to reduce auxiliary power consumption and fuel consumption and thereby increase net electrical output per unit of heat input. Heat rate improvement studies have examined opportunities for efficiency improvements as a means of reducing heat rate and regulating air pollutant emissions from coal-fired power plants. EPA is also aware that a diverse range of factors affects site-specific EGU heat rate improvements. Heat rate improvement cost and performance assumptions will be documented for any scenario analysis that activates the heat rate improvement option, and EPA welcomes further technical engagement on that option accordingly.

3.9 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 the EPA Platform v6. EPA Platform v6 also includes three non-air federal rules affecting EGUs: Cooling Water Intakes (316(b)) Rule and Coal Combustion Residuals from Electric Utilities (CCR), both promulgated in 2014, and the Effluent Limitations and Guidelines Rule finalized in 2015. The first four subsections discuss national and regional regulations. The next four subsections describe state level environmental regulations, a variety of legal settlements, emission assumptions for potential units and renewable portfolio standards. The last subsection presents Canadian regulations for CO_2 and renewables.

3.9.1 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 year 2000, affects all SO_2 emitting electric generating units greater than 25 MWs. 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 2021 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 initial run year of 2021 (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 2021 allowances involved deducting allowance surrenders due to NSR settlements and state regulations from the 2021 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 3-22 and Table 3-23.

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 3-14.

3.9.2 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), and the CSAPR Update Rule are represented. Table 3-14 shows the specification for the entire modeling time horizon.

By assigning unit-specific NO_x rates based on 2017 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).[19] Unlike SO_2 emission rates, NO_x rates are calculated off historical data and reflect the fuel mix for that particular year and burn at the unit. NEEDs represents up to four scenario NO_x rates based on historical data to capture seasonal and existing control

[19] 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.

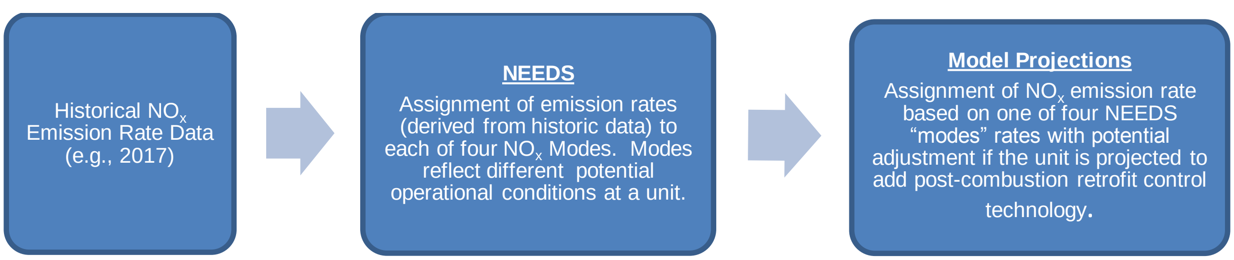
variability. These rates are constant and do not change independent of fuel mix assumed in the model. If the unit undertakes a post-combustion control retrofit or a coal-to-gas retrofit, then these rates would change in the model projections.

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 particular 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 3-4 below. The four modes address whether or not 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 mode it adjusts downward its emission rate 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 3-3 below.

Figure 3-3 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 2017.[20] The emission rates themselves reflect the impact of applicable NO_x regulations[21]. For coal-fired units, NO_x rates were used in

[20] By assigning unit-specific NO_x rates based on 2017 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%.

[21] Because 2017 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.

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.

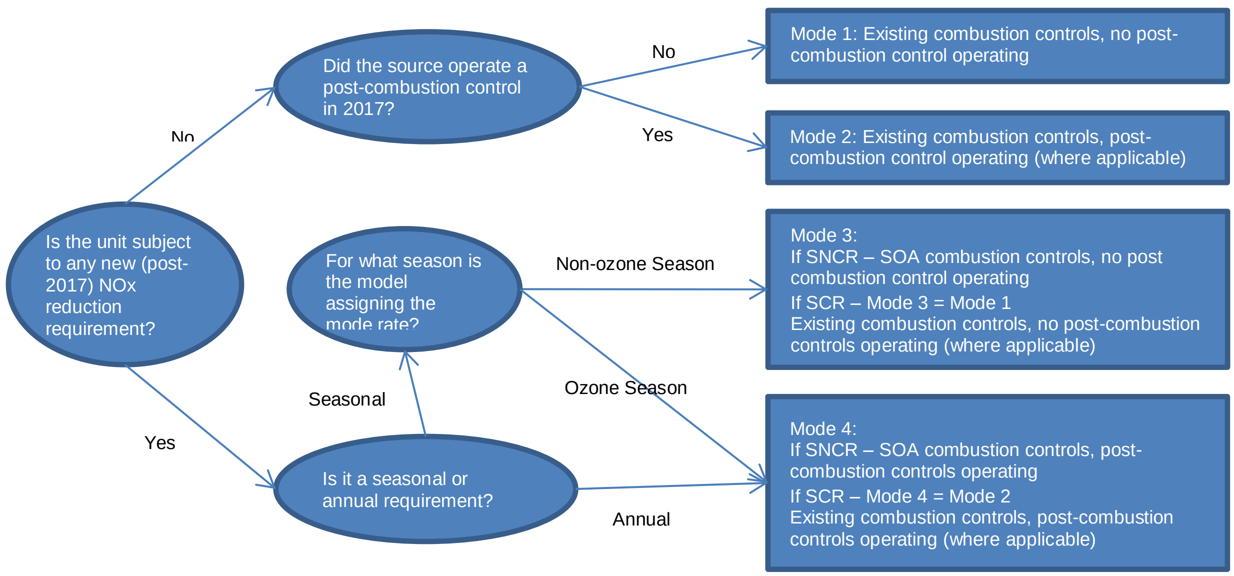
- For a unit with an existing post-combustion control, mode 1 reflects the existing post-combustion control not operating and mode 2 the existing post-combustion control operating. However:
    - If a unit has <u>operated its post-combustion control year round</u> during 2017, 2016, 2015, 2014, 2011, 2009, and 2007 years then mode 1 = mode 2, which reflects that the control will likely continue to operate year round.
    - If a unit has <u>not operated its post-combustion control</u> during 2017, 2016, 2015, 2014, 2011, 2009, and 2007 years, mode 1 will be based on historic data and mode 2 will be calculated using the method described under Question 3 in Attachment 3-1.
    - If a unit has <u>operated its post-combustion control seasonally</u> 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.

Figure 3-4 How One of the Four NO_x Modes Is Ultimately Selected for a Unit



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

The definition of “state-of-the-art” varies depending on the unit type and configuration. Table 3-11 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-2017) NO_x reduction requirement (i.e., a NO_x reduction requirement that did not apply to the unit during its 2017 operation that forms the historic basis for deriving NO_x rates for units in EPA Platform v6). Existing reduction requirements as of 2017 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 3-11 State-of-the-Art Combustion Control Configurations by Boiler Type

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 NO_x Burner Technology, LNC1 = Low NO_x coal-and air nozzles with close-coupled overfire air, LNC2 = Low NO_x Coal-and-Air Nozzles with Separated Overfire Air, LNC3 = Low NO_x 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, please see Attachment 3-1.

3.9.3 Multi-Pollutant Environmental Regulations

CSAPR

EPA Platform v6 includes the Cross-State Air Pollution Rule (CSAPR) Rule and 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 thousand tons SO_2 for CSAPR SO_2 Group 1;[22] 597.579 thousand tons SO_2 for CSAPR SO_2 Group 2;[23] and 1,069.256 thousand tons for annual NO_x.[24] 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 remanded budgets were not included in the EPA Platform v6. 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 are shown in Table 3-12. 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 the table below. 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 and, furthermore, 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 18% or 21% of the state's budget, are also implemented. The starting allowance bank in 2021 is 98,670 tons, which is equal to the number of banked allowances at the start of the CSAPR Update program after old CSAPR allowances were converted. 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.

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

[23] Alabama, Georgia, Kansas, Minnesota, Nebraska, South Carolina

[24] 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, Wisconsin

Table 3-12 CSAPR Update State Budgets, Variability Limits, and Assurance Levels for Ozone-Season NO_x (Tons)

	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
Illinois	14,601	3,066	17,667
Indiana	23,303	4,894	28,197
Kansas	8,027	1,686	9,713
Kentucky	21,115	4,434	25,549
Louisiana	18,639	3,914	22,553
Maryland	3,828	804	4,632
Michigan	17,023	3,575	20,598
Missouri	15,780	3,314	19,094
Mississippi	6,315	1,326	7,641
New Jersey	2,062	433	2,495
New York	5,135	1,078	6,213
Ohio	19,522	4,100	23,622
Oklahoma	11,641	2,445	14,086
Pennsylvania	17,952	3,770	21,722
Tennessee	7,736	1,625	9,361
Texas	52,301	10,983	63,284
Virginia	9,223	1,937	11,160
Wisconsin	7,915	1,662	9,577
West Virginia	17,815	3,741	21,556
CSAPR Update Region Total	**313,626**	**N/A**	**N/A**
Georgia Budget, Variability Limit, and Assurance Level for Ozone-Season NO_x			
Georgia	24,041	5,049	29,090

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 August 2017) that will be in place for EGUs are represented in the 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 3-27 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.

3.9.4 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 York, Rhode Island, and Vermont.[25] Table 3-14 shows the specifications for RGGI that are implemented in EPA Platform v6.

[25] As of this publication, the states of New Jersey and Virginia have expressed intent to join RGGI but have not yet concluded state regulatory proceedings to do so. If/when RGGI's composition and/or policy details change through

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 targets 1990 emission levels by 2020.[26] The cap begins 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 AEO2017 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 of the Clean Power Plan.[27] 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).[28] Although this rule is also being reviewed,[29] the standards of performance are legally in effect until such review is completed and/or revised (unlike the Clean Power Plan, which has been stayed by the Supreme Court).

3.9.5 Non-Air Regulations Impacting EGUs

<u>Cooling Water Intakes (316(b)) Rule</u>

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

applicable final rules by participating states, we will adjust that program's representation in our modeling platform and issue updated documentation accordingly.

[26] In July of 2017, AB 398 was signed into law. AB 398 extends the timeframe for cap-and-trade program through 2030 and further lowered the cap to at least 40% below the 1990 levels. This new regulation will be considered in future updates to IPM.

[27] 80 FR 64662 (Clean Power Plan, which has been stayed by the Supreme Court) and 82 FR 16329 (Clean Power Plan Review).

[28] 80 FR 64510

[29] 82 FR 16330

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 http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm

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 in the 2014 Regulatory Impact Analysis (RIA) 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.

For more information on CCR, go to http://www2.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).[30] 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. EPA estimated that approximately 12% of steam electric power plants would incur some compliance cost. 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

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

the model inputs and were applied starting in 2023, by which point the requirements were expected to be fully implemented.

In August of 2017, EPA noted that it would conduct a rulemaking to potentially revise the limitations and standards for bottom ash transport water and flue gas desulfurization wastewater. EPA noted that, given the typical timeline to propose and finalize a rulemaking, it would postpone earliest compliance dates by 2 years. Therefore, in EPA Platform v6, EPA has postponed the full implementation by 2 y, but has not made any capital or FOM adjustments reflecting new limitations and standards as no new standards have been finalized at the time of model update.

3.9.6 State-Specific Environmental Regulations

EPA Platform v6 represents enacted laws and regulations in 27 states affecting emissions from the electricity sector. Table 3-22 summarizes the provisions of state laws and regulations that are represented in EPA Platform v6.

3.9.7 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. EPA Platform v6 includes NSR settlements with 34 electric power companies. A summary of the units affected and how the settlements were modeled can be found in Table 3-23.

Eight state settlements and nine citizen settlements are also represented in EPA Platform v6. These are summarized in Table 3-24 and Table 3-25 respectively.

3.9.8 Emission Assumptions for Potential (New) Units

Emissions from existing and planned/committed units vary from installation to installation based on the performance of the generating unit and the emissions regulations that are in place. In contrast, 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 3-16. (Note: Nuclear, wind, solar, and fuel cell technologies are not included in Table 3-16 because they do not emit any of the listed pollutants.) For additional details on the modeling of potential new units, see Chapter 4.

3.9.9 Energy Efficiency and Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) generally refers to various state-level policies that require the addition of renewable generation to meet a specified share of statewide generation. In EPA Platform v6, the state RPS requirements are represented at a state level based on requirements. Table 3-18 shows the state level RPS requirements. In addition, state level solar carve-out requirements have been implemented in EPA Platform v6.

3.9.10 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 apply to both new 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 the 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. British Columbia's carbon tax sets a tax rate of $35 per tonne of CO_2 equivalent emissions beginning April 1, 2018 and increases it each year by $5 per tonne until it reaches $50 per tonne in 2021. 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 3-13 shows the province level renewable electricity requirements as a percentage of electricity sales.

Table 3-13 Canada Renewable Electricity Requirements (%) in EPA Platform v6

Province	2021	2023	2025	2030	2035	2040	2045	2050
British Columbia	93	93	93	93	93	93	93	93
Alberta				30	30	30	30	30
Saskatchewan				50	50	50	50	50
New Brunswick	40	40	40	40	40	40	40	40
Nova Scotia	40	40	40	40	40	40	40	40
Prince Edward Island	30	30	30	30	30	30	30	30

3.10 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 Region 1, SO_2 Region 2, Annual NO_x, CSAPR Update Rule Ozone Season NO_x Region 1, and CSAPR Update Rule Ozone Season NO_x Region 2; 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 3-14 and Table 3-15 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.

3.10.1 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 to compute the increase in allowance price for cap-and-trade programs when banking is engaged as a compliance strategy. 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, please see Section 10.3.

Table 3-14 Trading and Banking Rules in EPA Platform 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 2021 is assumed to be zero	The bank starting in 2021 is assumed to be zero	2021: 49,442
Total Allowances (MTons)	2016 - 2054: 72.845	2018 - 2054: 89.6	2021: 75,148 2022: 72,873 2023: 70,598 2024: 68,323 2025: 66,048 2026: 63,773 2027: 61,498 2028: 59,223 2029: 56,948 2030 - 2054: 54,673

Notes:

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

2 New Mexico, Utah, Wyoming

3 Connecticut, Delaware, Maine, New Hampshire, New York, Vermont, Rhode Island, Massachusetts, Maryland

Table 3-15 CASPR Trading and Banking Rules in EPA Platform v6 – Part 2

	CSAPR - SO_2 - Region 1	CSAPR - SO_2 - Region 2	CSAPR - Annual NO_x	CSAPR Update Rule - Ozone Season NO_x - Region 1	CSAPR Update Rule - Ozone Season NO_x - Region 2
Coverage	All fossil units > 25 MW[1]	All fossil units > 25 MW[2]	All fossil units > 25 MW[3]	All fossil units > 25 MW[4]	All fossil units > 25 MW[5]
Timing	Annual	Annual	Annual	Ozone Season (May - September)	Ozone Season (May - September)
Size of Initial Bank (MTons)	The bank starting in 2021 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 assumed to be zero
Total Allowances (MTons)	2021 - 2054: 1372.631	2021 - 2054: 597.579	2021 - 2054: 1069.256	2021: 411.9106 2022 - 2054: 313.24	2021 - 2054: 24.041

Notes:

1 Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, Wisconsin

2 Alabama, Georgia, Kansas, Minnesota, Nebraska, 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, 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, West Virginia

5 Georgia

Table 3-16 Emission and Removal Rate Assumptions for Potential (New) Units in EPA Platform 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 Carbon Sequestration	Advanced Combustion Turbine	Biomass-Bubbling Fluidized Bed (BFB)	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% 0.001 lbs/MMBtu	99% 0.001 lbs/MMBtu	99% 0.001 lbs/MMBtu						

Table 3-17 Recalculated NO_x Emission Rates for SCR Equipped Units Sharing Common Stacks with Non-SCR Units

Plant Name	UniqueID_Final	Capacity (MW)	NO_x Post-Comb Control	SCR_Online_Year	Mode 1 NO_x Rate	Mode 2 NO_x Rate	Mode 3 NO_x Rate	Mode 4 NO_x Rate
Ghent	1356_B_2	484			0.340	0.253	0.340	0.253
Ghent	1356_B_3	480	SCR	2004	0.075	0.075	0.075	0.075
Chalk Point LLC	1571_B_1	331	SCR	2009	0.075	0.075	0.075	0.075
Chalk Point LLC	1571_B_2	336	SNCR		0.270	0.237	0.270	0.237
FirstEnergy W H Sammis	2866_B_5	300	SNCR		0.283	0.258	0.283	0.258
FirstEnergy W H Sammis	2866_B_6	600	SCR	2010	0.075	0.075	0.075	0.075
FirstEnergy W H Sammis	2866_B_7	600	SCR	2010	0.075	0.075	0.075	0.075
Charles R Lowman	56_B_1	80			0.252	0.723	0.155	0.155
Charles R Lowman	56_B_2	235	SCR	2008	0.302	0.075	0.302	0.075
Crist	641_B_4	75	SNCR		0.285	0.285	0.139	0.139
Crist	641_B_5	75	SNCR		0.285	0.285	0.139	0.139
Crist	641_B_6	291	SCR	2012	0.075	0.075	0.075	0.075
Crist	641_B_7	465	SCR	2004	0.075	0.075	0.075	0.075
Gorgas	8_B_10	703	SCR	2002	0.100	0.100	0.100	0.100
Gorgas	8_B_8	161			0.355	0.296	0.355	0.296
Gorgas	8_B_9	170			0.355	0.296	0.355	0.296
Clifty Creek	983_B_4	196	SCR	2003	0.260	0.075	0.260	0.075
Clifty Creek	983_B_5	196	SCR	2003	0.258	0.075	0.258	0.075
Clifty Creek	983_B_6	196			0.325	0.309	0.325	0.309

Table 3-18 Renewable Portfolio Standards in EPA Platform v6

State Renewable Portfolio Standards in % - AEO 2017								
State	**2021**	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Arizona	6.3%	7.4%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%
California	34.8%	38.3%	41.7%	50.0%	50.0%	50.0%	50.0%	50.0%
Colorado	21.2%	21.2%	21.2%	21.2%	21.2%	21.2%	21.2%	21.2%
Connecticut	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%
District of Columbia	20.0%	20.0%	26.0%	42.0%	50.0%	50.0%	50.0%	50.0%
Delaware	15.2%	16.6%	18.1%	18.1%	18.1%	18.1%	18.1%	18.1%
Iowa	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%
Illinois	9.8%	11.5%	13.1%	14.0%	14.0%	14.0%	14.0%	14.0%
Massachusetts	21.5%	23.5%	25.5%	30.5%	35.5%	40.5%	45.5%	50.5%
Maryland	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
Maine	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Michigan	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Minnesota	25.7%	25.7%	28.4%	28.4%	28.4%	28.4%	28.4%	28.4%
Missouri	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%
Montana	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%
North Carolina	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
New Hampshire	19.8%	21.2%	23.0%	23.0%	23.0%	23.0%	23.0%	23.0%
New Jersey	23.9%	24.0%	24.2%	24.5%	24.5%	24.5%	24.5%	24.5%
New Mexico	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%
Nevada	17.3%	17.3%	21.9%	21.9%	21.9%	21.9%	21.9%	21.9%
New York	25.3%	28.9%	32.5%	41.4%	41.4%	41.4%	41.4%	41.4%
Ohio	6.7%	8.5%	10.2%	11.1%	11.1%	11.1%	11.1%	11.1%
Oregon	14.1%	14.1%	21.0%	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	17.5%	20.5%	23.5%	31.0%	38.5%	38.5%	38.5%	38.5%
Texas	4.3%	4.2%	4.1%	3.9%	3.7%	3.5%	3.4%	3.2%
Vermont	62.4%	67.6%	68.8%	79.8%	85.0%	85.0%	85.0%	85.0%
Washington	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%
Wisconsin	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%	9.65%
State RPS Solar Carve-outs								
State	**2021**	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
District of Columbia	1.9%	2.5%	2.9%	4.5%	5.0%	5.0%	5.0%	5.0%
Delaware	1.8%	2.2%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Illinois	1.05%	1.23%	1.41%	1.50%	1.50%	1.50%	1.50%	1.50%
Massachusetts	0.17%	0.18%	0.20%	0.24%	0.28%	0.32%	0.36%	0.40%
Maryland	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Minnesota	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%
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	3.47%	3.65%	3.83%	4.10%	4.10%	4.10%	4.10%	4.10%
New Mexico	3.167%	3.167%	3.167%	3.167%	3.167%	3.167%	3.167%	3.167%
Nevada	1.04%	1.04%	1.31%	1.31%	1.31%	1.31%	1.31%	1.31%
Ohio	0.27%	0.34%	0.41%	0.45%	0.45%	0.45%	0.45%	0.45%
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%

Note 1: The Renewable Portfolio Standard percentages are applied to modeled electricity sale projections.
Note 2: North Carolina standards are adjusted to account for swine waste and poultry waste set-asides.

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