Supplemental Documentation for Scenario Suite

EPA's Power Sector Modeling Platform v6 using IPM

May 2018

1. Introduction

This document describes a suite of scenario runs conducted with EPA's Power Sector Modeling Platform v6 using IPM (EPA Platform v6). It is supplemental to the full-fledged documentation of EPA Platform v6, which explains the model parameters, assumptions, and data inputs used in the initial run. This supplemental document details the input assumptions, data or parameters changed, and tested in each scenario run incremental to the initial run. Table 1 lists the scenario runs documented in the following sections of this document.

Table 1 Suite of Scenario Runs Incremental to the Initial Run using EPA Platform v6

IPM Run Name	IPM Run Description
High Demand	Adopted from AEO 2018 high electricity demand case
Low Demand	Adopted from AEO 2018 low electricity demand case
High RE Technology Cost	Using NREL ATB 2017 high RE technology cost case
Low RE Technology Cost	Using NREL ATB 2017 low RE technology cost case
Higher Natural Gas Cost	Reflecting lower resource recovery and higher LNG exports
Tax Law Update	Reflecting The Tax Cuts and Jobs Act of 2017

For any information pertaining to any other parameters, input data, and modeling assumptions (that is not contained in this document), please consult the EPA Platform v6 full-fledged documentation available at https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6

2. High Demand

EPA Platform v6 high demand scenario run has adopted the growth in demand underlying the AEO 2018 high economic growth case. The electricity demand is calculated as the summation of AEO 2017 no CPP case demand and the difference in demands between the AEO 2018 High Economic Growth with no CPP and AEO 2018 no CPP cases. The scenario run implies 2.3% higher demand by 2030 and 8.7% higher demand by 2050 incremental to the initial run.

For the high demand scenario, Table 2 and Table 3 present the net energy for load on a national and regional basis respectively. Table 4 illustrates the national sum of each region's seasonal peak demand and Table 43 presents each region's seasonal peak demand. In the EPA Platform v6 full-fledged documentation, Table 2 and Table 3 correspond to Table 3-2 and Table 3-3 respectively and Table 4 and Table 43 correspond to Table 3-4 and Table 3-18 respectively.

Table 2 Electric Load Assumptions for the High Demand Scenario

Year	Net Energy for Load (Billions of kWh)
2021	4,107
2023	4,201
2025	4,288
2030	4,463
2035	4,643
2040	4,890
2045	5,138
2050	5,400

Table 3 Regional Electric Load Assumptions for the High Demand Scenario

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	349	361	372	396	418	447	473	498
ERC_WEST	28	29	30	31	33	35	38	40
FRCC	233	238	245	260	274	291	307	326
MIS_AMSO	31	32	33	35	37	40	43	45
MIS_AR	37	38	39	42	44	47	50	53
MIS_D_MS	22	23	23	25	26	28	30	32
MIS_IA	22	22	23	24	25	26	28	29
MIS_IL	48	49	50	52	54	56	59	62
MIS_INKY	97	100	102	105	109	114	120	127
MIS_LA	46	48	49	52	55	59	63	66
MIS_LMI	101	103	104	108	111	117	123	129
MIS_MAPP	8	9	9	9	10	10	11	11
MIS_MIDA	30	31	31	33	34	36	38	40
MIS_MNWI	90	92	94	98	103	108	115	121
MIS_MO	41	42	42	44	46	48	50	53
MIS_WOTA	32	34	35	37	39	42	44	47
MIS_WUMS	55	56	57	59	61	65	69	73
NENG_CT	30	30	31	31	31	32	33	33
NENG_ME	11	11	11	11	11	11	11	12
NENGREST	79	79	80	80	82	83	85	86
NY_Z_A	15	15	15	15	15	16	16	17
NY_Z_B	9	10	10	10	10	10	10	10
NY_Z_C&E	23	23	23	23	24	24	25	25
NY_Z_D	6	6	6	6	6	6	7	7
NY_Z_F	11	11	11	11	11	12	12	12

IPM Region	Net Energy for Load (Billions of kWh)							
	2021	2023	2025	2030	2035	2040	2045	2050
NY_Z_G-I	18	19	19	19	18	19	19	19
NY_Z_J	51	51	50	50	49	49	49	50
NY_Z_K	22	22	22	22	22	22	22	22
PJM_AP	48	49	50	51	53	56	59	62
PJM_ATSI	70	72	73	76	78	82	86	91
PJM_COMD	102	105	107	110	114	120	126	133
PJM_Dom	98	101	104	110	115	123	130	138
PJM_EMAC	139	141	143	146	149	155	160	167
PJM_PENE	17	17	17	18	18	19	20	20
PJM_SMAC	64	65	65	67	68	71	73	76
PJM_West	213	218	222	230	238	250	263	278
PJM_WMAC	56	56	57	58	59	62	64	66
S_C_KY	33	34	35	36	38	40	42	44
S_C_TVA	179	185	190	199	207	218	230	244
S_D_AECI	18	19	19	20	20	21	22	24
S_SOU	251	260	267	281	294	312	329	348
S_VACA	226	233	240	253	266	283	300	319
SPP_KIAM	0	0	0	0	0	0	0	0
SPP_N	71	73	75	78	81	85	90	95
SPP_NEBR	34	35	35	37	38	41	43	45
SPP_SPS	30	31	32	34	36	38	40	43
SPP_WAUE	23	24	24	25	26	28	29	31
SPP_WEST	132	136	141	149	157	168	178	188
WEC_BANC	14	14	14	14	15	15	16	16
WEC_CALN	112	112	113	114	116	120	125	129
WEC_LADW	28	28	28	28	28	30	31	32
WEC_SDGE	22	22	22	22	22	23	24	25
WECC_AZ	89	91	93	99	104	110	115	120
WECC_CO	63	64	66	70	73	78	82	86
WECC_ID	23	23	23	24	25	26	27	28
WECC_IID	4	5	5	5	5	5	5	6
WECC_MT	13	13	13	14	14	15	16	16
WECC_NM	23	24	24	26	27	29	30	32
WECC_NNV	13	13	13	13	14	15	15	16
WECC_PNW	174	176	178	184	190	199	209	217
WECC_SCE	110	110	110	111	114	118	122	127
WECC_SNV	26	27	28	29	31	33	34	36
WECC_UT	28	28	29	29	30	32	33	35
WECC_WY	17	17	18	18	19	20	21	22

Table 4 National Non-Coincidental Net Internal Demand for the High Demand Scenario

Year	Peak Demand (GW)		
	Winter	Winter Shoulder	Summer
2021	657	607	775
2023	672	620	791
2025	688	634	809
2030	720	663	847
2035	753	693	888
2040	796	731	939
2045	841	772	994
2050	887	813	1048

3. Low Demand

EPA Platform v6 low demand scenario run has adopted demand data from AEO 2018 with CPP case. This scenario run implies 4.2% lower demand by 2030 and 5.2% lower demand by 2050 incremental to the initial run.

For the low demand scenario, Table 5 and Table 6 present the net energy for load on a national and regional basis respectively. Table 7 illustrates the national sum of each region's seasonal peak demand and Table 44 presents each region's seasonal peak demand. In the EPA Platform v6 full-fledged documentation, Table 5 and Table 6 correspond to Table 3-2 and Table 3-3 respectively and Table 7 and Table 44 correspond to Table 3-4 and Table 3-18 respectively.

Table 5 Electric Load Assumptions for the Low Demand Scenario

Year	Net Energy for Load (Billions of kWh)
2021	4,066
2023	4,084
2025	4,109
2030	4,178
2035	4,266
2040	4,404
2045	4,549
2050	4,711

Table 6 Regional Electric Load Assumptions for the Low Demand Scenario

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	351	356	361	374	388	406	423	440
ERC_WEST	28	28	29	30	31	32	34	35
FRCC	239	240	242	248	257	269	282	296
MIS_AMSO	33	34	34	36	37	39	40	41

IPM Region	Net Energy for Load (Billions of kWh)							
	2021	2023	2025	2030	2035	2040	2045	2050
MIS_AR	39	40	41	42	43	45	47	48
MIS_D_MS	23	23	24	25	25	27	27	28
MIS_IA	22	22	22	23	23	24	25	25
MIS_IL	46	46	47	47	48	50	51	53
MIS_INKY	93	93	94	95	97	99	102	105
MIS_LA	48	48	49	51	53	55	57	59
MIS_LMI	102	102	102	103	105	107	110	114
MIS_MAPP	8	8	9	9	9	9	10	10
MIS_MIDA	30	30	30	31	32	33	34	35
MIS_MNWI	89	90	91	93	95	99	102	105
MIS_MO	39	39	40	40	41	42	44	45
MIS_WOTA	35	35	36	37	38	40	42	43
MIS_WUMS	65	65	66	67	68	70	72	74
NENG_CT	30	29	29	28	28	28	28	28
NENG_ME	10	10	10	10	10	10	10	10
NENGREST	77	75	75	73	72	72	72	72
NY_Z_A	16	16	16	15	15	15	15	16
NY_Z_B	10	10	10	10	10	10	10	10
NY_Z_C&E	24	24	24	23	23	23	24	24
NY_Z_D	7	6	6	6	6	6	6	6
NY_Z_F	12	12	11	11	11	11	11	11
NY_Z_G-I	18	18	18	18	17	17	17	18
NY_Z_J	47	46	46	44	43	42	42	43
NY_Z_K	20	20	19	19	18	18	19	19
PJM_AP	45	45	46	46	47	48	50	51
PJM_ATSI	67	67	67	68	70	71	73	75
PJM_COMD	97	97	98	100	101	104	107	110
PJM_Dom	97	98	99	102	105	109	114	119
PJM_EMAC	138	137	136	135	136	138	141	145
PJM_PENE	17	17	17	17	17	17	17	18
PJM_SMAC	63	63	62	62	62	63	65	66
PJM_West	203	203	205	208	212	217	223	230
PJM_WMAC	55	55	54	54	54	55	56	58
S_C_KY	31	32	32	33	34	35	36	38
S_C_TVA	173	175	177	182	187	193	200	207
S_D_AECI	18	18	18	18	18	19	20	20
S_SOU	237	240	243	250	257	267	278	288
S_VACA	224	226	228	235	243	253	263	274
SPP_KIAM	0	0	0	0	0	0	0	0
SPP_N	71	71	72	74	75	78	81	84
SPP_NEBR	34	34	34	35	36	37	38	39
SPP_SPS	29	29	30	31	32	33	35	36

IPM Region	Net Energy for Load (Billions of kWh)							
	2021	2023	2025	2030	2035	2040	2045	2050
SPP_WAUE	23	23	23	24	24	25	26	27
SPP_WEST	128	130	132	137	142	148	154	160
WEC_BANC	14	14	14	14	13	14	14	14
WEC_CALN	110	110	108	107	106	108	110	114
WEC_LADW	27	27	27	26	26	26	27	28
WEC_SDGE	21	21	21	21	20	21	21	22
WECC_AZ	90	91	92	94	97	102	107	113
WECC_CO	66	67	68	70	72	75	79	83
WECC_ID	22	22	22	23	23	24	24	25
WECC_IID	4	5	5	5	5	5	5	5
WECC_MT	13	13	13	13	13	14	14	15
WECC_NM	24	24	24	25	26	27	28	30
WECC_NNV	13	13	13	13	13	13	14	14
WECC_PNW	172	172	173	174	176	181	188	195
WECC_SCE	108	107	106	105	104	106	108	112
WECC_SNV	27	27	27	28	29	30	32	33
WECC_UT	28	28	28	28	28	29	30	31
WECC_WY	17	17	17	18	18	19	19	20

Table 7 National Non-Coincidental Net Internal Demand for the Low Demand Scenario

Year	Peak Demand (GW)		
	Winter	Winter Shoulder	Summer
2021	651	602	767
2023	653	604	769
2025	659	608	775
2030	673	620	792
2035	694	638	818
2040	722	663	853
2045	754	690	892
2050	790	721	938

4. High Renewable Energy Technology Cost

EPA Platform v6 high renewable energy technology cost scenario run uses cost data from NREL ATB high levelized cost for energy (LCOE) case as opposed to mid-level LCOE case in the initial run. This translates into 42% higher LCOE for onshore wind and 77% higher LCOE for solar PV over the 2030 to 2050 period. While the high LCOE assumptions for new solar PV, new solar thermal, and new onshore wind units are from NREL ATB 2017, the assumptions for new offshore wind units are from NREL ATB 2016.

Table 8 lists updates included in EPA Platform v6 high renewable energy technology cost scenario that are supplemental to the EPA Platform v6.

Table 8 Updates in the High Renewable Energy Technology Cost Scenario

Description	Table	Corresponding Table in EPA Platform v6
Short-Term Capital Cost Adders for New Power Plants in High RE Technology Cost Scenario	Table 9	Table 4-14
Performance and Unit Cost Assumptions for Potential (New) Renewable Capacity in High RE Technology Cost Scenario	Table 10	Table 4-16
Onshore Average Capacity Factor by Wind TRG[1] and Vintage in High RE Technology Cost Scenario	Table 11	Table 4-20
Onshore Reserve Margin Contribution by Wind TRG and Vintage in High RE Technology Cost Scenario	Table 12	Table 4-21
Offshore Shallow Average Capacity Factor by Wind TRG and Vintage in High RE Technology Cost Scenario	Table 13	Table 4-22
Offshore Shallow Reserve Margin Contribution by Wind TRG and Vintage in High RE Technology Cost Scenario	Table 14	Table 4-23
Offshore Mid-Depth Average Capacity Factor by Wind TRG and Vintage in High RE Technology Cost Scenario	Table 15	Table 4-24
Offshore Mid-Depth Reserve Margin Contribution by Wind TRG and Vintage in High RE Technology Cost Scenario	Table 16	Table 4-25
Offshore Deep Average Capacity Factor by Wind TRG and Vintage in High RE Technology Cost Scenario	Table 17	Table 4-26
Offshore Deep Reserve Margin Contribution by Wind TRG and Vintage in High RE Technology Cost Scenario	Table 18	Table 4-27
Solar Photovoltaic Reserve Margin Contribution by Resource Class in High RE Technology Cost Scenario	Table 19	Table 4-32
Wind Generation Profiles in High RE Technology Cost Scenario	Table 45	Table 4-37
Solar Photovoltaic Generation Profiles in High RE Technology Cost Scenario	Table 46	Table 4-41
Solar Photovoltaic Capacity Factor by Resource Class and Cost Class in High RE Technology Cost Scenario	Table 47	Table 4-44

[1] TRG – Techno-resource group

Table 9 Short-Term Capital Cost Adders for New Power Plants in the High Renewable Energy Technology Cost Scenario

Plant Type		2021			2023			2025			2030			2035		
		Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3
Biomass	Upper Bound (MW)	1,904	3,312	No Limit	1,270	2,208	No Limit	1,270	2,208	No Limit	3,174	5,520	No Limit	3,174	5,520	No Limit
	Adder ($/kW)	-	1,714	5,443	-	1,685	5,352	-	1,646	5,230	-	1,543	4,903	-	1,466	4,658
Coal Steam - UPC	Upper Bound (MW)	18,361	31,932	No Limit	12,241	21,288	No Limit	12,241	21,288	No Limit	30,602	53,220	No Limit	30,602	53,220	No Limit
	Adder ($/kW)	-	1,640	5,209	-	1,610	5,115	-	1,572	4,992	-	1,468	4,664	-	1,390	4,415
Combined Cycle	Upper Bound (MW)	132,125	229,782	No Limit	88,083	153,188	No Limit	88,083	153,188	No Limit	220,208	382,970	No Limit	220,208	382,970	No Limit
	Adder ($/kW)	-	490	1,555	-	481	1,528	-	469	1,491	-	433	1,376	-	406	1,290
Combustion Turbine	Upper Bound (MW)	66,275	115,260	No Limit	44,183	76,840	No Limit	44,183	76,840	No Limit	110,458	192,100	No Limit	110,458	192,100	No Limit
	Adder ($/kW)	-	298	945	-	291	924	-	281	893	-	255	809	-	235	747
Fuel Cell	Upper Bound (MW)	1,725	3,000	No Limit	1,150	2,000	No Limit	1,150	2,000	No Limit	2,875	5,000	No Limit	2,875	5,000	No Limit
	Adder ($/kW)	-	3,101	9,850	-	3,007	9,551	-	2,896	9,200	-	2,615	8,305	-	2,386	7,578
Geothermal	Upper Bound (MW)	883	1,536	No Limit	589	1,024	No Limit	589	1,024	No Limit	1,472	2,560	No Limit	1,472	2,560	No Limit
	Adder ($/kW)	-	3,772	11,983	-	3,763	11,954	-	3,744	11,892	-	3,700	11,754	-	3,636	11,549
Landfill Gas	Upper Bound (MW)	625	1,088	No Limit	417	725	No Limit	417	725	No Limit	1,042	1,813	No Limit	1,042	1,813	No Limit
	Adder ($/kW)	-	3,979	12,639	-	3,915	12,437	-	3,822	12,140	-	3,577	11,361	-	3,379	10,733
Nuclear	Upper Bound (MW)	32,327	56,220	No Limit	21,551	37,480	No Limit	21,551	37,480	No Limit	53,878	93,700	No Limit	53,878	93,700	No Limit
	Adder ($/kW)	-	2,499	7,939	-	2,347	7,456	-	2,287	7,264	-	2,127	6,757	-	2,005	6,368
Solar Thermal	Upper Bound (MW)	2,830	4,921	No Limit	1,886	3,281	No Limit	1,886	3,281	No Limit	4,716	8,202	No Limit	4,716	8,202	No Limit
	Adder ($/kW)	-	2,340	7,432	-	2,840	9,022	-	2,830	8,989	-	2,806	8,913	-	2,771	8,801
Solar PV	Upper Bound (MW)	25,858	46,265	No Limit	18,406	32,011	No Limit	18,406	32,011	No Limit	46,016	80,027	No Limit	46,016	80,027	No Limit
	Adder ($/kW)	-	513	1,629	-	590	1,874	-	590	1,874	-	590	1,874	-	590	1,874
Onshore Wind	Upper Bound (MW)	33,941	67,466	No Limit	30,238	52,588	No Limit	30,238	52,588	No Limit	75,595	131,470	No Limit	75,595	131,470	No Limit
	Adder ($/kW)	-	700	2,222	-	699	2,219	-	697	2,213	-	693	2,200	-	687	2,181
Offshore Wind	Upper Bound (MW)	1,725	3,000	No Limit	1,150	2,000	No Limit	1,150	2,000	No Limit	2,875	5,000	No Limit	2,875	5,000	No Limit
	Adder ($/kW)	-	2,475	7,863	-	2,472	7,853	-	2,466	7,832	-	2,451	7,786	-	2,429	7,717
Hydro	Upper Bound (MW)	10,360	18,018	No Limit	6,907	12,012	No Limit	6,907	12,012	No Limit	17,267	30,030	No Limit	17,267	30,030	No Limit
	Adder ($/kW)	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313

Table 10 Performance and Unit Cost Assumptions for Potential (New) Renewable Capacity in the High Renewable Energy Technology Cost Scenario

	Solar PV	Solar Thermal	Onshore Wind	Offshore Wind
Size (MW)	150	100	100	400
First Year Available	2021	2021	2021	2021
Lead Time (Years)	1	3	3	3
Availability	90%	90%	95%	95%
Generation Capability	Generation Profile	Economic Dispatch	Generation Profile	Generation Profile
		Vintage #1 (2021)		
Capital (2016$/kW)	1,514	6,983	1,560	5,521
Fixed O&M (2016$/kW/yr)	13.17	66.87	51.67	137.22
Variable O&M (2016$/MWh)	0.0	4.1	0.0	0.0
		Vintage #2 (2023)		
Capital (2016$/kW)	1,514	6,983	1,560	5,521
Fixed O&M (2016$/kW/yr)	13.17	66.87	51.67	137.22
Variable O&M (2016$/MWh)	0.0	4.1	0.0	0.0
		Vintage #3 (2025)		
Capital (2016$/kW)	1,514	6,983	1,560	5,521
Fixed O&M (2016$/kW/yr)	13.17	66.87	51.67	137.22
Variable O&M (2016$/MWh)	0.0	4.1	0.0	0.0
		Vintage #4 (2030)		
Capital (2016$/kW)	1,514	6,983	1,560	5,521
Fixed O&M (2016$/kW/yr)	13.17	66.87	51.67	137.22
Variable O&M (2016$/MWh)	0.0	4.1	0.0	0.0
		Vintage #5 (2035)		
Capital (2016$/kW)	1,514	6,983	1,560	5,521
Fixed O&M (2016$/kW/yr)	13.17	66.87	51.67	137.22
Variable O&M (2016$/MWh)	0.0	4.1	0.0	0.0
		Vintage #6 (2040)		
Capital (2016$/kW)	1,514	6,983	1,560	5,521
Fixed O&M (2016$/kW/yr)	13.17	66.87	51.67	137.22
Variable O&M (2016$/MWh)	0.0	4.1	0.0	0.0
		Vintage #7 (2045)		
Capital (2016$/kW)	1,514	6,983	1,560	5,521
Fixed O&M (2016$/kW/yr)	13.17	66.87	51.67	137.22
Variable O&M (2016$/MWh)	0.0	4.1	0.0	0.0
		Vintage #8 (2050)		
Capital (2016$/kW)	1,514	6,983	1,560	5,521
Fixed O&M (2016$/kW/yr)	13.17	66.87	51.67	137.22
Variable O&M (2016$/MWh)	0.0	4.1	0.0	0.0

Table 11 Onshore Average Capacity Factor by Wind TRG and Vintage in the High Renewable Energy Technology Cost Scenario

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	47%	47%	47%
2	46%	46%	46%
3	45%	45%	45%
4	44%	44%	44%
5	41%	41%	41%
6	36%	36%	36%
7	31%	31%	31%
8	25%	25%	25%
9	18%	18%	18%
10	11%	11%	11%

Table 12 Onshore Reserve Margin Contribution by Wind TRG and Vintage in the High Renewable Energy Technology Cost Scenario

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	0% - 69%	0% - 69%	0% - 69%
2	0% - 89%	0% - 89%	0% - 89%
3	0% - 89%	0% - 89%	0% - 89%
4	0% - 85%	0% - 85%	0% - 85%
5	0% - 78%	0% - 78%	0% - 78%
6	0% - 58%	0% - 58%	0% - 58%
7	0% - 45%	0% - 45%	0% - 45%
8	0% - 27%	0% - 27%	0% - 27%

Table 13 Offshore Shallow Average Capacity Factor by Wind TRG and Vintage in the High Renewable Energy Technology Cost Scenario

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	47%	47%	47%
2	43%	43%	43%
3	40%	40%	40%

Table 14 Offshore Shallow Reserve Margin Contribution by Wind TRG and Vintage in the High Renewable Energy Technology Cost Scenario

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	1% - 82%	1% - 82%	1% - 82%
2	0% - 82%	0% - 82%	0% - 82%
3	0% - 84%	0% - 84%	0% - 84%

Table 15 Offshore Mid-Depth Average Capacity Factor by Wind TRG and Vintage in the High Renewable Energy Technology Cost Scenario

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
5	47%	47%	47%
6	44%	44%	44%

Table 16 Offshore Mid-Depth Reserve Margin Contribution by Wind TRG and Vintage in the High Renewable Energy Technology Cost Scenario

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
5	0% - 78%	0% - 78%	0% - 78%
6	0% - 76%	0% - 76%	0% - 76%

Table 17 Offshore Deep Average Capacity Factor by Wind TRG and Vintage in the High Renewable Energy Technology Cost Scenario

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
8	49%	49%	49%

Table 18 Offshore Deep Reserve Margin Contribution by Wind TRG and Vintage in the High Renewable Energy Technology Cost Scenario

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
8	0% - 68%	0% - 68%	0% - 68%

Table 19 Solar Photovoltaic Reserve Margin Contribution by Resource Class in the High Renewable Energy Technology Cost Scenario

	Resource Class						
	2	3	4	5	6	7	8
Reserve Margin Contribution	0% - 11%	0% - 29%	0% - 49%	0% - 46%	0% - 47%	0% - 51%	0% - 45%

5. Low Renewable Energy Technology Cost

EPA Platform v6 low renewable energy technology cost scenario run has uses data from NREL ATB low LCOE case as opposed to mid-level LCOE case in the initial run. This translates into 26% lower LCOE for onshore wind and 30% lower LCOE for solar PV over the 2030 to 2050 period. While the low LCOE assumptions for new solar PV, new solar thermal, and new onshore wind units are from NREL ATB 2017, the assumptions for new offshore wind units are from NREL ATB 2016.

Table 20 lists updates included in EPA Platform v6 low renewable energy technology cost scenario that are supplemental to the EPA Platform v6.

Table 20 Updates in the Low Renewable Energy Technology Cost Scenario

Description	Table	Corresponding Table in EPA Platform v6
Short-Term Capital Cost Adders for New Power Plants in Low RE Technology Cost Scenario	Table 21	Table 4-14
Performance and Unit Cost Assumptions for Potential (New) Renewable Capacity in Low RE Technology Cost Scenario	Table 22	Table 4-16
Onshore Average Capacity Factor by Wind TRG and Vintage in Low RE Technology Cost Scenario	Table 23	Table 4-20
Onshore Reserve Margin Contribution by Wind TRG and Vintage in Low RE Technology Cost Scenario	Table 24	Table 4-21
Offshore Shallow Average Capacity Factor by Wind TRG and Vintage in Low RE Technology Cost Scenario	Table 25	Table 4-22
Offshore Shallow Reserve Margin Contribution by Wind TRG and Vintage in Low RE Technology Cost Scenario	Table 26	Table 4-23
Offshore Mid-Depth Average Capacity Factor by Wind TRG and Vintage in Low RE Technology Cost Scenario	Table 27	Table 4-24
Offshore Mid-Depth Reserve Margin Contribution by Wind TRG and Vintage in Low RE Technology Cost Scenario	Table 28	Table 4-25
Offshore Deep Average Capacity Factor by Wind TRG and Vintage in Low RE Technology Cost Scenario	Table 29	Table 4-26
Offshore Deep Reserve Margin Contribution by Wind TRG and Vintage in Low RE Technology Cost Scenario	Table 30	Table 4-27
Solar Photovoltaic Reserve Margin Contribution by Resource Class in Low RE Technology Cost Scenario	Table 31	Table 4-32
Wind Generation Profiles in Low RE Technology Cost Scenario	Table 48	Table 4-37
Solar Photovoltaic Generation Profiles in Low RE Technology Cost Scenario	Table 49	Table 4-41
Solar Photovoltaic Capacity Factor by Resource Class and Cost Class in Low RE Technology Cost Scenario	Table 50	Table 4-44

Table 21 Short-Term Capital Cost Adders for New Power Plants in the Low Renewable Energy Technology Cost Scenario

Plant Type		2021			2023			2025			2030			2035		
		Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3
Biomass	Upper Bound (MW)	1,904	3,312	No limit	1,270	2,208	No limit	1,270	2,208	No limit	3,174	5,520	No limit	3,174	5,520	No limit
	Adder ($/kW)	-	1,714	5,443	-	1,685	5,352	-	1,646	5,230	-	1,543	4,903	-	1,466	4,658
Coal Steam - UPC	Upper Bound (MW)	18,361	31,932	No limit	12,241	21,288	No limit	12,241	21,288	No limit	30,602	53,220	No limit	30,602	53,220	No limit
	Adder ($/kW)	-	1,640	5,209	-	1,610	5,115	-	1,572	4,992	-	1,468	4,664	-	1,390	4,415
Combined Cycle	Upper Bound (MW)	132,125	229,782	No limit	88,083	153,188	No limit	88,083	153,188	No limit	220,208	382,970	No limit	220,208	382,970	No limit
	Adder ($/kW)	-	490	1,555	-	481	1,528	-	469	1,491	-	433	1,376	-	406	1,290
Combustion Turbine	Upper Bound (MW)	66,275	115,260	No limit	44,183	76,840	No limit	44,183	76,840	No limit	110,458	192,100	No limit	110,458	192,100	No limit
	Adder ($/kW)	-	298	945	-	291	924	-	281	893	-	255	809	-	235	747
Fuel Cell	Upper Bound (MW)	1,725	3,000	No limit	1,150	2,000	No limit	1,150	2,000	No limit	2,875	5,000	No limit	2,875	5,000	No limit
	Adder ($/kW)	-	3,101	9,850	-	3,007	9,551	-	2,896	9,200	-	2,615	8,305	-	2,386	7,578
Geothermal	Upper Bound (MW)	883	1,536	No limit	589	1,024	No limit	589	1,024	No limit	1,472	2,560	No limit	1,472	2,560	No limit
	Adder ($/kW)	-	3,772	11,983	-	3,763	11,954	-	3,744	11,892	-	3,700	11,754	-	3,636	11,549
Landfill Gas	Upper Bound (MW)	625	1,088	No limit	417	725	No limit	417	725	No limit	1,042	1,813	No limit	1,042	1,813	No limit
	Adder ($/kW)	-	3,979	12,639	-	3,915	12,437	-	3,822	12,140	-	3,577	11,361	-	3,379	10,733
Nuclear	Upper Bound (MW)	32,327	56,220	No limit	21,551	37,480	No limit	21,551	37,480	No limit	53,878	93,700	No limit	53,878	93,700	No limit
	Adder ($/kW)	-	2,499	7,939	-	2,347	7,456	-	2,287	7,264	-	2,127	6,757	-	2,005	6,368
Solar Thermal	Upper Bound (MW)	2,830	4,921	No limit	1,886	3,281	No limit	1,886	3,281	No limit	4,716	8,202	No limit	4,716	8,202	No limit
	Adder ($/kW)	-	2,171	6,897	-	2,368	7,523	-	2,094	6,653	-	1,427	4,532	-	1,253	3,982
Solar PV	Upper Bound (MW)	25,858	46,265	No limit	18,406	32,011	No limit	18,406	32,011	No limit	46,016	80,027	No limit	46,016	80,027	No limit
	Adder ($/kW)	-	312	991	-	327	1,039	-	308	979	-	261	830	-	235	747
Onshore Wind	Upper Bound (MW)	33,941	67,466	No limit	30,238	52,588	No limit	30,238	52,588	No limit	75,595	131,470	No limit	75,595	131,470	No limit
	Adder ($/kW)	-	672	2,135	-	630	2,001	-	584	1,856	-	462	1,469	-	444	1,410
Offshore Wind	Upper Bound (MW)	1,725	3,000	No limit	1,150	2,000	No limit	1,150	2,000	No limit	2,875	5,000	No limit	2,875	5,000	No limit
	Adder ($/kW)	-	1,978	6,283	-	1,781	5,657	-	1,710	5,430	-	1,537	4,883	-	1,446	4,593
Hydro	Upper Bound (MW)	10,360	18,018	No limit	6,907	12,012	No limit	6,907	12,012	No limit	17,267	30,030	No limit	17,267	30,030	No limit
	Adder ($/kW)	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313

Table 22 Performance and Unit Cost Assumptions for Potential (New) Renewable and Non-Conventional Technology Capacity in the Low Renewable Energy Technology Cost Scenario

	Solar PV	Solar Thermal	Onshore Wind	Offshore Wind
Size (MW)	150	100	100	400
First Year Available	2021	2021	2021	2021
Lead Time (Years)	1	3	3	3
Availability	90%	90%	95%	95%
Generation Capability	Generation Profile	Economic Dispatch	Generation Profile	Generation Profile
		Vintage #1 (2021)		
Capital (2016$/kW)	887	6,123	1,245	4,096
Fixed O&M (2016$/kW/yr)	10.13	60.28	47.24	113.40
Variable O&M (2016$/MWh)	0.0	3.5	0.0	0.0
		Vintage #2 (2023)		
Capital (2016$/kW)	839	5,552	1,186	3,736
Fixed O&M (2016$/kW/yr)	10.13	55.89	45.77	109.80
Variable O&M (2016$/MWh)	0.0	3.5	0.0	0.0
		Vintage #3 (2025)		
Capital (2016$/kW)	791	4,982	1,120	3,628
Fixed O&M (2016$/kW/yr)	10.13	51.50	44.29	107.80
Variable O&M (2016$/MWh)	0.0	3.5	0.0	0.0
		Vintage #4 (2030)		
Capital (2016$/kW)	671	3,551	928	3,357
Fixed O&M (2016$/kW/yr)	10.13	40.53	40.60	102.90
Variable O&M (2016$/MWh)	0.0	3.5	0.0	0.0
		Vintage #5 (2035)		
Capital (2016$/kW)	604	3,159	935	3,222
Fixed O&M (2016$/kW/yr)	10.13	40.53	38.75	100.90
Variable O&M (2016$/MWh)	0.0	3.5	0.0	0.0
		Vintage #6 (2040)		
Capital (2016$/kW)	536	3,008	928	3,087
Fixed O&M (2016$/kW/yr)	10.13	40.53	36.91	98.80
Variable O&M (2016$/MWh)	0.0	3.5	0.0	0.0
		Vintage #7 (2045)		
Capital (2016$/kW)	470	2,885	908	2,965
Fixed O&M (2016$/kW/yr)	10.13	40.53	35.06	97.40
Variable O&M (2016$/MWh)	0.0	3.5	0.0	0.0
		Vintage #8 (2050)		
Capital (2016$/kW)	403	2,783	877	2,843
Fixed O&M (2016$/kW/yr)	10.13	40.53	33.22	96.10
Variable O&M (2016$/MWh)	0.0	3.5	0.0	0.0

Table 23 Onshore Average Capacity Factor by Wind TRG and Vintage in the Low Renewable Energy Technology Cost Scenario

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	53%	56%	58%
2	51%	55%	57%
3	51%	55%	57%
4	50%	54%	56%
5	48%	53%	56%
6	45%	51%	54%
7	40%	46%	49%
8	33%	38%	41%
9	26%	32%	35%
10	17%	21%	23%

Table 24 Onshore Reserve Margin Contribution by Wind TRG and Vintage in the Low Renewable Energy Technology Cost Scenario

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	0% - 91%	0% - 96%	0% - 100%
2	0% - 91%	0% - 97%	0% - 100%
3	0% - 89%	0% - 96%	0% - 100%
4	0% - 89%	0% - 96%	0% - 100%
5	0% - 87%	0% - 95%	0% - 100%
6	0% - 70%	0% - 79%	0% - 84%
7	0% - 67%	0% - 77%	0% - 82%
8	0% - 80%	0% - 93%	0% - 100%

Table 25 Offshore Shallow Average Capacity Factor by Wind TRG and Vintage in the Low Renewable Energy Technology Cost Scenario

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	53%	54%	54%
2	48%	49%	50%
3	44%	45%	46%

Table 26 Offshore Shallow Reserve Margin Contribution by Wind TRG and Vintage in the Low Renewable Energy Technology Cost Scenario

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	0% - 57%	0% - 58%	0% - 58%
2	0% - 83%	0% - 85%	0% - 86%
3	0% - 93%	0% - 94%	0% - 96%

Table 27 Offshore Mid-Depth Average Capacity Factor by Wind TRG and Vintage in the Low Renewable Energy Technology Cost Scenario

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
5	52%	53%	54%
6	49%	50%	50%

Table 28 Offshore Mid-Depth Reserve Margin Contribution by Wind TRG and Vintage in the Low Renewable Energy Technology Cost Scenario

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
5	0% - 57%	0% - 58%	0% - 58%
6	0% - 62%	0% - 63%	0% - 63%

Table 29 Offshore Deep Average Capacity Factor by Wind TRG and Vintage in the Low Renewable Energy Technology Cost Scenario

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
8	55%	56%	56%

Table 30 Offshore Deep Reserve Margin Contribution by Wind TRG and Vintage in the Low Renewable Energy Technology Cost Scenario

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
8	0% - 41%	0% - 42%	0% - 42%

Table 31 Solar Photovoltaic Reserve Margin Contribution by Resource Class in the Low Renewable Energy Technology Cost Scenario

	Resource Class						
	2	3	4	5	6	7	8
Reserve Margin Contribution	0% - 13%	0% - 62%	0% - 73%	0% - 64%	0% - 87%	0% - 97%	0% - 92%

6. Higher Natural Gas Cost

EPA Platform v6 high gas price scenario run uses natural gas supply curves that reflect lower Estimated Ultimate Recovery (EUR) growth and higher LNG exports. Natural gas prices in this scenario run are between $3.27 and $5.61. This translates into 16% higher prices in 2030 and 31% higher prices by 2050 incremental to the initial run. The following summarizes the key drivers and associated assumptions that are different from those in the initial run.

Exploration and Production Uncertainty

Natural gas market development remains imperative for continued supply growth. Petrochemical activity both domestically and internationally as well as continued increases in power generation fueled by natural gas will underpin the market growth. Absent such growth, development of incremental oil and gas from lower cost plays will do nothing more than cannibalize development from less cost effective plays. Awareness of which plays have a cost advantage and will hold up the best in such an environment is important for capital preservation. Identifying the most robust assets is critical.

Corresponding Well EUR Growth Adjustment

ICF employs a “learning curve” concept to estimate the contributions of changing technologies to the hydrocarbon resource. The “learning curve” describes the aggregate influence of learning and new technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or feet drilled per rig per day) for each doubling of cumulative output volume or other measure of industry/technology maturity. The learning curve shows that advances are rapid (measured as percent improvement per period of time) in the early stages when industries or technologies are immature and that those advances decline through time as the industry or technology matures.

In GMM, the learning curve concept is applied to the well EUR, the cumulative volume of hydrocarbon that can be produced throughout the life of a well. In the EPA Platform v6 initial run, ICF estimates an average of 20% EUR learning curve growth for every doubling of well completions. In other words, the average EUR of a well is increased by 20% for every doubling of well completions. In the high gas price scenario, the EUR improvement is assumed to be cut in half.

LNG Exports Uncertainty

In the global LNG market, there is significant uncertainty surrounding the total size of the market and the market share that the US will be able to capture. Factors that could increase the size of the global LNG market include:

- Less natural gas supply development in other areas around the world
- Less competition from international pipeline development
- Environmental regulations in global markets that favor natural gas over coal and renewables
- Faster rates of economic growth, particularly in Asia
- Faster rates of natural gas demand growth in the power generation sector, also particularly in Asia
- Higher oil prices
- Shift towards a larger spot market for LNG
- Other LNG exporting nations have slower supply development

Corresponding LNG Exports Adjustment

The EPA Platform v6 high gas price scenario run assumes that there will be higher demand for LNG exports from the U.S. and that there will be more export capacity built to accommodate that increased demand. In addition to the export facilities assumed to be built in the EPA Platform v6 initial run, the high gas price scenario run assumes that Corpus Christi Stage 3, Cameron LNG trains 4 and 5, Jordan Cove LNG, Magnolia LNG, Lake Charles LNG, Driftwood LNG, and Rio Grande LNG will be built. Table 32 summarizes the LNG export assumptions in the EPA Platform v6 Initial run and the high gas price scenario run. The high gas price scenarios run includes 8.2 Bcf/d of additional LNG exports from the US in 2035 and 10.8 Bcf/d of additional LNG exports from the US in 2050.

Table 32 LNG Export Assumptions (Bcf/d)

	EPA Platform v6 Initial Run	EPA Platform v6 High Gas Price Scenario Run
2021	6.83	6.83
2023	8.42	8.42
2025	10.03	10.67
2030	12.72	15.78
2035	12.72	20.92
2040	12.98	23.74
2045	12.98	23.74
2050	12.98	23.74

The natural gas supply curves and the natural gas seasonal price adders as implemented in the high gas price scenario are shown in Table 51 and Table 52 respectively.

7. Tax Law Update

EPA Platform v6 tax law update scenario run incorporates updates to reflect The Tax Cuts and Jobs Act of 2017[2]. The capital charge rates in the tax law update run now vary by run year and are slightly lower (less than 10% reduction) than those in the initial run. The discount rate increases from 3.9% to 4.25%.

The discussion below summarizes the revised assumptions.

7.1 Introduction

The new law lowered the federal corporate tax rate from 35% to 21% and made other changes in corporate income tax provisions. As a result, the financing costs of power sector investments are now expected to be lower than was the case prior to the passage of the bill, and lower than was in the EPA Platform v6 initial run. The financing costs will decrease, all else held equal, because financing costs include payment of income and other taxes necessary to recover and earn a return on capital; that level is now lower. The two key financing parameters used in EPA's case—capital charge rate and discount rate—reflect the now lower corporate income taxes:

- **Capital Charge Rate** – The capital charge rate equals the ratio of the annuitized Earnings Before Interest, Taxes, Depreciation, and Amortization (EBITDA) to investment (I) (i.e., EBITDA/I). EBITDA equals the funds available to pay taxes and provide the required return on and of capital.
- **Weighted Average After Tax Cost of Capital (WACC)** – The IPM model minimizes the discounted costs and uses the WACC as its discount rate for calculating the present value of all costs. The WACC is the average of two components: equity and debt. First, the WACC weights required return on equity on an after tax basis by the equity share of capitalization. Second, the WACC weights the debt interest expense rate (usually the interest rate) on an after tax basis; the interest rate is multiplied by (1-income tax rate). The tax rate decreases the cost of interest because of the tax deductibility of interest. The WACC is now higher because the corporate tax rate is lower. As a result, future costs are discounted more relative to near term costs.

As discussed further below, interest expense is no longer fully deductible for a portion of the industry in a given year, but is deductible in later years. In addition, the degree of deductibility in a given year varies year by year with the variation affected by more than one factor. While the impact of various tax code changes can cause the effectiveness of the tax shield as calculated to vary across time, a single WACC is used in IPM.

7.2 Summary of Results

7.2.1 Capital Charge Rates

The real capital charge rate for a new combined cycle coming on-line in 2021 is the representative investment for the real capital charge rate for exposition purposes. The first run year for EPA Platform v6 using IPM is 2021, and the combined cycle is the most frequently added new thermal power plant. (Table 37, Table 38, and Table 39 below present year-by-year and technology-by-technology results.) The real capital charge rate for a new combined cycle on-line in 2021 decreases by approximately 0.49 percentage points due to the new tax law from the previous level of 9.15% (see Table 33). The decrease is modestly higher for the independent power producer (IPP) sector compared to the utility sector as

[2] The Tax Cuts and Jobs Act of 2017, Pub.L. 115-97.

shown in Table 33. For example, the real capital charge rate of a new IPP combined cycle decreases 0.79 percentage points from 11.68% to 10.89%, which is a 6.8% decrease in the capital charge rate.

Table 33 Real Capital Charge Rate for New Combined Cycle

First Model Run Year (%)[3]

Sector	Previous (A)	New (B)	Absolute Change (B)-(A)	% Change ((B-A) /(A))*100
IPP	11.68	10.89	-0.79	-6.8
Utility	8.06	7.67	-0.39	-4.8
Blended (70% utility, 30% IPP)	9.15	8.66	-0.49	-5.4

7.2.2 WACC

Table 34 shows the absolute increase in the nominal WACC of 0.35 percentage point and the percentage increase of approximately 6.0%. The WACC increases because the tax shield on debt decreases from 39.2% to 26.1%.[4] In other words, as the tax rate decreases, the net, after-tax cost of debt increases and incremental investments require a higher return. The increase in returns means future costs, including return of and on capital, are discounted more relative to near term costs; having dollars sooner is more valuable as the opportunity cost of deferring earnings increases. This is because discounting is the inverse of compounding growth. The increase is larger for IPPs because of their higher debt interest rate and debt share of capital.

The real WACC given an inflation assumption of 1.83%[5] increases from 3.9% to 4.25%.

Table 34 After Tax Weighted Average Cost of Capital (WACC) – Nominal (%)

Sector	Previous (A)	New (B)	Absolute Change (B)-(A)	% Change ((B-A) /(A))*100
IPP	7.88	8.40	+0.52	+6.6
Utility	4.92	5.20	+0.28	+5.7
Blended (70% utility 30% IPP)	5.81	6.16	+0.35	+6.0

[3] The EPA Platform v6 initial run reflected a real capital charge rate for a new Combined Cycle of 9.13%. This was the effect of weighting each parameter (e.g., debt share, ROE) by 70%:30% for utility and IPP builds, respectively, and then calculating the actual capital charge rate. We are now calculating each capital charge rate (utility and IPP) separately and then weight the results by the 70%:30% utility/IPP build ratio. This is because of the much greater divergence between utilities and IPPs in terms of tax law. Specifically, utilities are the only companies exempted from key provisions on depreciation, net operating losses, and tax deductibility. This minor refinement of the methodology has a small impact on the calculation. Under the proposed new methodology, the real CCR for CC is higher by much less than a percent - i.e., increases from 9.13% to 9.15%.

[4] As noted, these tax rates include the impact of the average state income tax rate of 6.45%, which is deductible for federal tax purposes.

[5] Financial literature frequently uses nominal terms, and hence, we frequently present nominal results to facilitate explanation. The expected inflation rate used to convert future nominal to constant real dollars is 1.83%. The future inflation rate of 1.83% is based on an assessment of implied inflation from an analysis of yields on 10 year U.S. Treasury securities and U.S. Treasury Inflation Protected Securities (TIPS) over a period of 5 years (2012-2016) with a downward adjustment to account for the historically higher Consumer Price Index (CPI) inflation rate than Gross Domestic Product (GDP) deflator (GDP deflator is the preferred measure of general economy wide inflation) inflation rate over the 2007 to 2016 period.

7.3 Federal Income Tax Law Changes

The four most significant changes in the federal corporate income tax code are:

- **Rate** - Corporate tax rate is lowered 14 percentage points from 35%[6] to 21%; the 21% rate is in place starting in 2018 and remains in place indefinitely; the lower tax rate decreases financing costs in all periods and all sectors, all else held equal. When state income taxes are included, the average rate decreases 13.1 percentage points, from 39.2% to 26.1%.
- **Depreciation** – The new tax law expands near term bonus depreciation (also referred to as expensing) for the IPP sector until 2027.
- **Interest Expense** – The new law lowers tax deductibility of interest expense for the IPP sector, which continues indefinitely.
- **Net Operating Losses** – The new law limits the use of Net Operating Losses (NOL).

Other important features of the new tax law include:

- **Annual Variation of Provisions** - The legislation specifies permanent changes (tax rate and NOL usage limit), and temporary changes that vary year-by-year through to 2027 (depreciation and tax deductibility of interest) (See Table 35). This creates different capital charge rates for each year through 2027. We calculate these parameters for IPM run years 2021, 2023, 2025, and 2030 and thereafter. This set covers a wide range of financing conditions even though we do not estimate every year.

Table 35 Summary Tax Changes

Parameter	Previous	2021[7]	2023	2025	2030 and Later
Marginal Tax Rate - Federal	35	21	21	21	21
Maximum NOL (Net Operating Loss) Carry Forward Usage	No limit. All losses in excess of income are carried forward and usable immediately.	Carry Forward cannot exceed 80% of Taxable Income	Carry Forward cannot exceed 80% of Taxable Income	Carry Forward cannot exceed 80% of Taxable Income	Carry Forward cannot exceed 80% of Taxable Income
Tax Deductibility of Interest Expense	100%[8]	IPP 30% of EBITDA; Utilities MACRS	30% of EBIT; Utilities MACRS	30% of EBIT; Utilities MACRS	30% of EBIT; Utilities MACRS
Bonus Depreciation[9]	0[10]	IPP 100%; Utilities 0%	IPP 80%[11]; Utilities 0%	IPP 40%[12]; Utilities 0%	0

- **Utilities Versus IPPs** - The legislation treats utilities and non-utilities (Independent Power Producers – IPPs) differently. The new tax code exempts utilities from changes in tax deductibility of interest and accelerated depreciation. The financing assumptions used in IPM modeling are a blend (weighted average) of the utility and IPP average. The weighting is 70%

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[6] The average state income tax rate is 6.45 percent. State income tax is deductible, and hence, the combined rate is 39.2% (39.2=35+(1-0.35)*6.45). Under the new 21% rate, the new average combined rate is 26.1%.

[7] IPM run years in the near term are 2021, 2023, 2025, and 2030.

[8] No limit except losses in excess of income can be carried forward. The losses were limited to first few years.

[9] Referred to as expensing. If depreciation exceeds income in first year, it can be carried forward to succeeding years up to 80% of EBITDA.

[10] Bonus depreciation was available but only in the period before IPM runs, and only for new equipment.

[11] For thermal power plants coming on line in 2023, the 100% would apply only to costs incurred through end of 2022. We are hence assuming practically all capital costs are incurred prior to 2023.

[12] Remaining basis depreciated at MACRS schedule.

utility and 30% IPP, and hence, the greatest weight is on the least affected sector. This partly mitigates the impacts of the changes. However, potentially offsetting is the IPP sector's heavy reliance on high cost debt financing, and the high capital intensity of power production.

- **Partly Offsetting Effects** - The changes in the tax code affecting IPPs include offsetting effects that yield net lower costs. The constraints on interest expense deductions and NOL usage raise financing costs, while bonus depreciation and the lower tax rate lower costs (all else held equal). If the only change for IPPs was the federal corporate tax rate being set to 21% - i.e., other tax law changes affecting IPPs only did not occur – the impact on the real capital charge rate would have been similar. That is, the real IPP capital charge rate would have been 10.99% versus 10.89% for the impact of all changes.

- **Near Term Versus Long Term** – Over time, IPP costs increase because of the higher interest costs due to restricted deductibility and lower IPP decreased bonus depreciation (see Table 36).

Table 36 Impacts Over Time – Capital Charge Rate New Combined Cycle (%)

Year	Utility	IPP	Blended
2021	7.67	10.89	8.64
2023	7.67	10.89	8.64
2025	7.67	10.97	8.66
2030 and Beyond	7.67	11.33	8.77

- **Renewables** - The legislation has minor direct potential impacts on the renewable sector's tax credits via the Base Erosion Anti-Abuse Tax (BEAT). The maximum effect of BEAT could decrease the value of PTC and ITC by up to 20%[13]; estimates of the expected impact are not yet available. In addition, the total decrease in corporate income taxes may decrease tax credit appetite accordingly. Nevertheless, as we lack requisite data at this time we do not apply any additional changes to renewable financing beyond the above-mentioned changes, which affect all capacity types.

7.4 Capital Charge Rates: Utility, IPP, Blended Impacts – All Technologies

We summarize capital charge rates by plant types in Table 37, Table 38 and Table 39; these vary because of different financing risks and costs, lifetimes, and depreciation schedules.

[13] https://www.congress.gov/115/bills/hr1/BILLS-115hr1enr.xml. "Part VII – Base Erosion and Anti-Abuse Tax, Sec 59A, Tax in Base Erosion Payments of Taxpayers with Substantial Gross Receipts, (b), (1), (B), (ii), (II) the portion of the applicable section 38 credits not in excess of 80 percent of the lesser of the amount …"

See also https://www.mwe.com/en/thought-leadership/publications/2017/12/renewable-energy-tax-bill-update-no-change-ptc-itc. A company's regular tax liability reflects certain credits that make it more likely that such a company is subject to the BEAT. However, the Bill provides that only 20 percent of the PTC and ITC be taken into account. Thus, 20 percent of the PTC and ITC might be denied depending on a company's BEAT status and relevant computations in a given year.

Table 37 Real Capital Charge Rate – Blended (%)

New Investment Technology Capital Hybrid (70/30 Utility/Merchant)	Previous Capital Charge Rate[14]	Revised to Incorporate New Tax Code - 2021	Revised to Incorporate New Tax Code – 2023	Revised to Incorporate New Tax Code - 2025	Revised to Incorporate New Tax Code – 2030 and Beyond
Environmental Retrofits - Utility Owned	11.29%	10.77%	10.77%	10.77%	10.77%
Environmental Retrofits - Merchant Owned	15.62%	14.05%	14.05%	14.12%	14.54%
Advanced Combined Cycle	9.13%	8.64%	8.64%	8.66%	8.77%
Advanced Combustion Turbine	9.42%	9.02%	9.02%	9.02%	9.10%
Ultra Supercritical Pulverized Coal without Carbon Capture[15]	11.80%	10.96%	10.96%	11.01%	11.18%
Ultra Supercritical Pulverized Coal with Carbon Capture	8.76%	8.31%	8.31%	8.32%	8.43%
Nuclear	8.56%	8.31%	8.31%	8.33%	8.43%
Nuclear without Production Tax Credit	8.56%	8.31%	8.31%	8.33%	8.43%
Nuclear with Production Tax Credit[16]	7.20%	7.10%	7.09%	7.10%	7.19%
Biomass	8.47%	8.14%	8.12%	8.12%	8.12%
Wind, Landfill Gas, Solar and Geothermal	10.00%	9.79%	9.78%	9.77%	9.77%
Hydro	8.53%	8.09%	8.09%	8.11%	8.21%

Table 38 Real Capital Charge Rate – IPP (%)

New Investment Technology Capital (IPP)	Previous Capital Charge Rate – 100% IPP	Revised to Incorporate New Tax Code - 2021	Revised to Incorporate New Tax Code - 2023	Revised to Incorporate New Tax Code - 2025	Revised to Incorporate New Tax Code – 2030 and Beyond
Environmental Retrofits - Merchant Owned	15.62%	14.05%	14.05%	14.12%	14.54%
Advanced Combined Cycle	11.68%	10.89%	10.89%	10.97%	11.33%
Advanced Combustion Turbine	12.84%	11.83%	11.81%	11.81%	12.07%
Ultra Supercritical Pulverized Coal without Carbon Capture	15.90%	14.05%	14.06%	14.23%	14.78%
Ultra Supercritical Pulverized Coal with Carbon Capture	12.48%	11.22%	11.22%	11.27%	11.62%
Nuclear without Production Tax Credit	11.99%	11.22%	11.22%	11.29%	11.62%
Nuclear with Production Tax Credit	9.99%	9.71%	9.69%	9.71%	10.00%
Biomass	10.83%	10.60%	10.56%	10.53%	10.53%

[14] These capital charge rates are from the EPA Platform v6 initial run and were estimated by weighting each parameter (e.g., debt share, ROE) by 70%:30% for utility and IPP builds, respectively, and then calculating the actual capital charge rate.

[15] EPA has adopted the procedure followed in EIA's Annual Energy Outlook 2013; the capital charge rates shown for Supercritical Pulverized Coal and Integrated Gasification Combined Cycle (IGCC) without Carbon Capture include a 3% adder to the cost of debt and equity. See *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013* (p.2), http://www.eia.gov/forecasts/aeo/er/pdf/electricity_generation.pdf

[16] The Energy Policy Act of 2005 (Sections 1301, 1306, and 1307) provides a production tax credit (PTC) of 18 mills/kWh for 8 years up to 6,000 MW of new nuclear capacity. The financial impact of the credit is reflected in the capital charge rate shown in for "Nuclear with Production Tax Credit (PTC)." NEEDS v6 integrates 2,200 MW of new nuclear capacity at Vogtle nuclear power plant. Therefore, in EPA Platform v6 only 3,800 MW of incremental new nuclear capacity will be provided with this tax credit.

New Investment Technology Capital (IPP)	Previous Capital Charge Rate – 100% IPP	Revised to Incorporate New Tax Code - 2021	Revised to Incorporate New Tax Code - 2023	Revised to Incorporate New Tax Code - 2025	Revised to Incorporate New Tax Code – 2030 and Beyond
Wind, Landfill Gas, Solar and Geothermal	11.92%	11.77%	11.73%	11.70%	11.70%
Hydro	11.32%	10.61%	10.61%	10.67%	11.01%

Table 39 Real Capital Charge Rate – Utility (%)

New Investment Technology Capital Utility	Previous Capital Charge Rate – 100% Utility	Revised to Incorporate New Tax Code - 2021	Revised to Incorporate New Tax Code - 2023	Revised to Incorporate New Tax Code - 2025	Revised to Incorporate New Tax Code – 2030 and Beyond
Environmental Retrofits - Utility Owned	11.29%	10.77%	10.77%	10.77%	10.77%
Advanced Combined Cycle	8.06%	7.67%	7.67%	7.67%	7.67%
Advanced Combustion Turbine	8.17%	7.82%	7.82%	7.82%	7.82%
Ultra Supercritical Pulverized Coal without Carbon Capture	10.20%	9.63%	9.63%	9.63%	9.63%
Ultra Supercritical Pulverized Coal with Carbon Capture	7.41%	7.06%	7.06%	7.06%	7.06%
Nuclear without Production Tax Credit	7.36%	7.06%	7.06%	7.06%	7.06%
Nuclear with Production Tax Credit	6.17%	5.98%	5.98%	5.98%	5.98%
Biomass	7.36%	7.08%	7.08%	7.08%	7.08%
Wind, Landfill Gas, Solar and Geothermal	9.18%	8.94%	8.94%	8.94%	8.94%
Hydro	7.42%	7.01%	7.01%	7.01%	7.01%

7.5 Background, Caveats, Implications and Perspectives

7.5.1 Combined Cycle Parameters

As a reminder, the EPA Platform v6 financing assumptions and results include the following parameters for a new combined cycle (see Table 40).

Table 40 New Combined Cycle - Selected Unchanged Parameters (%)

Parameter	Value
Debt Equity Utility	50:50
Debt Equity IPP – Combined Cycle	55:45
ROE – Utility	7.2
ROE – IPP	12.16
Debt Interest Rate – Utility	4.33
Debt Interest Rate – IPP	7.2
Share of Utility and IPP in Blended Average	70:30
State income tax rate	6.45
General Inflation Rate	1.83
Risk Free Rate	3.45

7.5.2 Capital Charge Rate Change – Illustrative Example of Price Impacts

In a competitive market, price equals marginal cost. If a new combined cycle is the marginal new power plant, the lower capital charge rate would lower marginal cost and power price. The determination of average wholesale power price involves many factors including reserve costs, fuel costs, the variation in demand and supply fundamentals, etc. However, the average cost of a combined cycle correlates with long term average price if it is the marginal unit on a prolonged basis. Therefore, to understand approximately the impact on power price of the change in the capital charge rate, the following calculation is presented in Table 41.

If a new combined cycle costs approximately $1,000/kW to build, the new tax law lowers the annual levelized real costs by $4.90/kW (0.49 % percentage point change shown above in Table 37, times a capital cost of $1000/KW). If the unit dispatches at an annual capacity factor of 55%[17] , this reduction in capital charge rate decreases the levelized costs of the unit by $1.01/MWh[18]. If fuel costs are assumed to be $24.5/MWh[19] and non-fuel operating and maintenance costs are assumed to be $5/MWh, the reduction in levelized real cost are about 2.1%.[20] The impact is less than the 5.3% decrease in the capital cost (i.e., a decrease of 2.1% a compared to a decrease of 5.3%) because two-thirds of the costs are not capital related. The summary results are shown in Table 41.

Table 41 Illustrative Costs of New Combined Cycle ($/MWh)

Cost	Previous	Revised	Absolute Change	% Change
Fuel	24.5	24.5	0	0
Non Fuel Operating and Maintenance	5.0	5.0	0	0
Capital	19.0	18.0	-1	-5.3
Total	48.5	47.5	-1	-2.1

7.5.3 Capital Charge Rate Changes – Share of Total Income Tax Contribution to Capital Charge Rates

If under the previous corporate income tax law, the corporate tax rate was zero (i.e., no income taxes state or federal), and there were no other changes, the capital charge rate would have fallen from 9.15% to 8.06% (absolute decrease of 1.09%), or approximately 12% decrease on a percentage basis. Thus, the 9.15% to 8.67% actual decrease of 0.48% percentage point is approximately 44% of the maximum decrease (0.48/1.09).

Table 42 Illustrative Capital Charge Rate[21] - New Combined Cycle %)

Federal Tax Rate (%)	Capital Charge Rate – New Combined Cycle (%)
35	9.15
21	8.67
0	8.06

[17] The average capacity factor for natural gas fired combined cycle units in the U.S. in the last three years was approximately 55%. See https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a

[18] This compares to the original annualized capital costs of $18.99/MWh based on a capital charge rate of 9.15% (0.0915*$1000/kW*1000kW/MW*(1/8760 hrs)*(1/0.55 CF) = $18.99/MWh). The reduction in levelized costs is 0.0049*$1000/kW*1000kW/MW *(1/8760 hrs) x (1/0.55CF)=$1.01/MWh.

[19] Assumes for illustrative purposes, heat rate of 7,000 Btu/KWh and a delivered natural gas fuel cost of $3.5/MMBtu.

[20] Total Levelized costs of $48.5/MWh = $19/MWh annualized capital +24.5/MWh fuel +$5.0/MWh O&M. $1.01/MWh is 2.1 % of this cost.

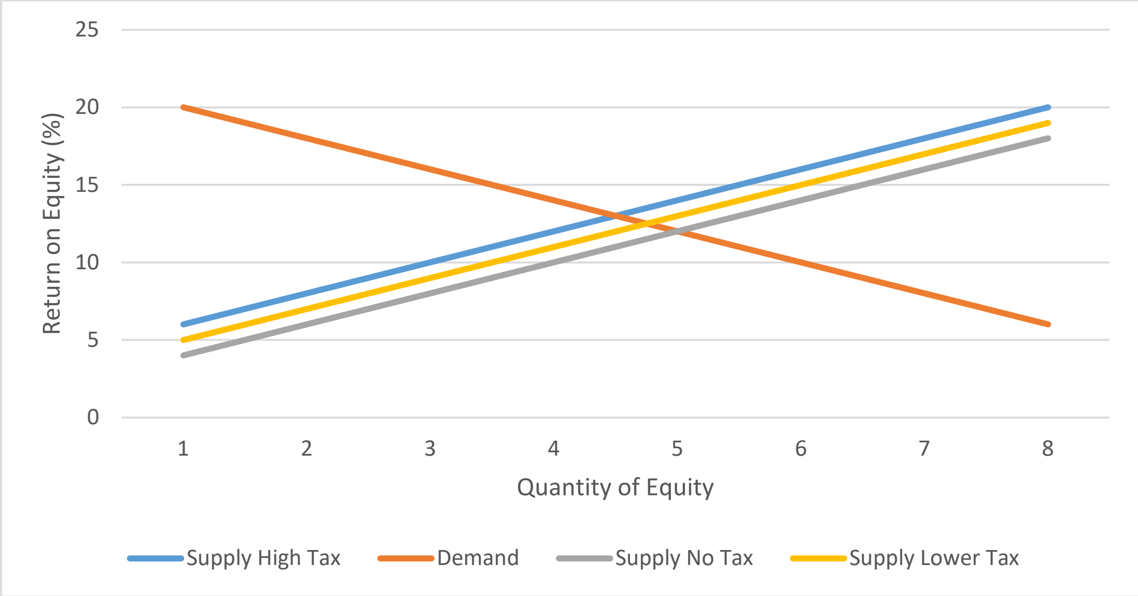
[21] Blended combining utility and IPP capital charge rates.

7.5.4 Taxes and After Tax Return on Equity Levels

This analysis assumes that the after tax required return on equity (ROE) does not increase. However, it is possible that as the tax rate is lowered, the after tax cost of equity capital increases, all else held equal. For illustration, see Figure 7-1 where the lowering of the tax increases the after tax ROE (Y-axis is return in percentage, and the x-axis is quantity of equity). In this illustration, the vertical distance between the supply curves (for a given quantity of equity supplied to the market) going from no tax to a higher tax level is the extra return required to cover corporate income taxes. As the tax rate decreases, the equilibrium point (intersection of demand and supply curves) implies greater investment[22] and a higher after tax ROE. This analysis would apply also to any tax reduction, and vice versa, all else held equal.

It is beyond the scope of the present analysis to try to estimate the effects of the change in tax rates on required returns. The supply and demand for equity is economy wide and modeling it would require an analysis of the entire economy.

Figure 7-1 Supply and Demand of Equity under Varying Tax Rates - Illustrative



[22] This corresponds to either great capital intensity, greater production, or both.

List of tables that are directly uploaded to the web: