EPA's Updates to EPA Base Case 2009
Using the Integrated Planning Model (IPM)

This document catalogs the list of updates in EPA Base Case 2009 from EPA Base Case 2006 (v3.01) using the Integrated Planning Model (IPM).

IPM and EPA Modeling Applications Using IPM:

EPA uses the Integrated Planning Model (IPM®) to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous states and the District of Columbia. Developed by ICF Resources, Inc. and used to support public and private sector clients, IPM is a multi-regional, dynamic, deterministic linear programming model of the electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting electricity demand, environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon dioxide (CO_2), and mercury (Hg) from the electric power sector and is used extensively by EPA to support regulatory activities.

Among the factors that make IPM particularly well suited to model multi-emissions control programs are (1) its ability to capture complex interactions among the electric power, fuel, and environmental markets; (2) its detail-rich representation of emission control options encompassing a broad array of retrofit technologies along with emission reductions through fuel switching, changes in capacity mix and electricity dispatch strategies; (3) its capability to model a variety of environmental market mechanisms, such as emissions caps, allowances, trading, and banking; and its ability to generate the detailed, location-specific emission data required for air quality modeling. IPM's ability to capture the dynamics of the allowance market and its provision of a wide range of emissions reduction options are particularly important for assessing the impact of multi-emissions environmental policies for the power sector.

IPM is a single sector, linear programming model that captures the economic behavior of the power sector. By itself, IPM is limited in its ability to capture broader energy and environmental policy, such as an economy wide cap and trade program. However, the model is often employed by EPA in conjunction with broader macroeconomic models to help provide deeper resolution of the power sector in the shorter term, which is an inherent weakness of broader econometric models which do not have detailed technology or power sector representation.

EPA's IPM Base Case 2006 (v3.0) and v3.01:

In the Fall of 2006, EPA released Base Case 2006 (v3.0) using IPM, which included extensive updates of IPM's assumptions, inputs, and capabilities. The model was again updated in the Summer of 2007 for purposes of climate modeling (v3.01). In preparing these base cases, EPA obtained input from nationally recognized experts in fuels, technology, and power system operation. Power companies provided information on generating resources and emission controls. EPA also obtained input from Regional Planning Organizations, States, and their constituent organizations. Key updates included:

- Coal Supply and Transportation Assumptions
- Natural Gas Assumptions

- Federal and State Emission Regulations and Enforcement Actions
- Cost and Performance of Generating Technologies and Emission Controls
- Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x) emissions
- Power System Operating Characteristics and Structure
- Electric Generating Unit Inventory
- Modeling Time Horizon and Run Years (2010, 2015, 2020, 2025)
- Carbon capture and storage for potential (new) units
- Biomass co-firing capability for existing coal boilers
- Updated constraints on new nuclear and renewable capacity builds

More recently, EPA released Base Case 2009 using IPM. This version of the model provides additional modeling capabilities, includes several important updates, and incorporates key provisions of the Energy Independence and Security Act of 2007 (EISA). Among the notable features of this base case are:

1) Revised electricity demand*[*]
2) Updated power technology costs*
3) Carbon capture and storage for *existing* coal plants
4) Updated natural gas supply and price projection
5) Renewable portfolio standards and climate programs at the State level*
6) Updated constraints on new nuclear, renewable, and coal with CCS capacity

The detailed assumptions for IPM v3.0, titled "Documentation for EPA Base Case 2006 (v3.0) Using the Integrated Planning Model" (November 2006), can be found at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html#docs.

The following document summarizes the key features and changes found in EPA's Base Case Base Case 2009 using IPM.

[*] Assumption derived from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2009 Reference Case (March version), (http://www.eia.doe.gov/oiaf/aeo/).

1a. Electricity Demand

The electric load assumptions in EPA Base Case 2009 are shown in the table below. These values were derived based on the electricity sales forecast in EIA's AEO 2009. The revised growth rate used in the reference case is just under 1%, compared to a growth rate of 1.5% in past IPM modeling applications.

Net Energy for Load in EPA Base Case 2009 (GWh)	
2010	4,055,098
2015	4,182,129
2020	4,395,125
2025	4,619,295

1b. Demand Elasticity

EPA traditionally does not apply an endogenous demand response in IPM for electricity demand. In the context of climate analyses, EPA will include an endogenous demand response for some scenarios when revised demand projections are not available from macroeconomic models, or when otherwise warranted to provide additional insights from IPM. EPA employs an elasticity of 0.5 within IPM to be consistent with computable general equilibrium models that the Agency employs[1]. Scenarios with this feature are indicated as such.

2. Potential (New) Unit Costs

All costs for potential units have been updated to reflect AEO 2009 levels, and are generally 50% higher than past IPM modeling applications employed by EPA (v3.0). The tables below show the cost and performance characteristics of the modeled potential (new) build units.

In addition to the potential build units modeled in EPA Base Case v3.0, one additional potential build unit is included in EPA Base Case 2009 - an Integrated Gasification Combined Cycle (IGCC) with Carbon Capture and Sequestration (CCS) technology. Previously, an Advanced Combined Cycle (ACC) with CCS was modeled (v3.01), but this technology has since been removed from Base Case 2009. The cost and performance characterization of IGCC with CCS is based on the characteristics of the IGCC, but also includes cost adders and heat rate penalties attributable to the CCS component. The IGCC with CCS is assumed to have a 90% CO_2 capture rate and incur a $15 per metric ton of CO_2 transportation and storage cost, which is added to the variable operating cost of the unit.[2]

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[1] For more detail on the economy-wide models EPA employs, see http://www.epa.gov/climatechange/economics/modeling.html.

[2] Dooley, et al. Carbon Dioxide Capture and Geologic Storage (pg 36). Battelle Memorial Institute, April 2006.

Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in EPA Base Case 2009

	Advanced Combined Cycle	Advanced Combustion Turbine	Nuclear	Integrated Gasification Combined Cycle	Integrated Gasification Combined Cycle with Carbon Capture	Supercritical Pulverized Coal
Size (MW)	400	230	1350	550	380	600
Lead Time (Years)	3	2	6	4	4	4
Vintage #1(years covered)	2010-2014	2010-2014	2015-2035	2010-2014	2010-2014	2010-2014
Vintage #2(years covered)	2015-2019	2015-2019		2015-2019	2015-2019	2015-2019
Vintage #3(years covered)	2020-2024	2020-2024		2020-2024	2020-2024	2020-2024
Vintage #4(years covered)	2025-2031	2025-2031		2025-2031	2025-2031	2025-2031
Vintage #5(years covered)	2032-2035	2032-2035		2032-2035	2032-2035	2032-2035
Availability	87%	92%	90%	80%	80%	85%
Vintage #1						
Heat Rate (Btu/kWh)	6,752	9,289	-	-	-	-
Capital (2004$/kW)	854	569	-	-	-	-
Fixed O&M (2004$/kW/yr)	10.8	9.7	-	-	-	-
Variable O&M (2004$/MWh)	1.84	2.91	-	-	-	-
Vintage #2						
Heat Rate (Btu/kWh)	6,752	9,289	10,434	8,765	10,781	9,200
Capital (2004$/kW)	824	552	2954	2,056	2,981	1,823
Fixed O&M (2004$/kW/yr)	10.8	9.7	82.7	35.5	42.4	25.3
Variable O&M (2004$/MWh)	1.84	2.91	0.45	2.68	4.08	4.22
Vintage #3						
Heat Rate (Btu/kWh)	6,752	9,289	-	8,765	10,781	9,200
Capital (2004$/kW)	796	537	-	2,004	2,906	1,785
Fixed O&M (2004$/kW/yr)	10.8	9.7	-	35.5	42.4	25.3
Variable O&M (2004$/MWh)	1.84	2.91	-	2.68	4.08	4.22
Vintage #4						
Heat Rate (Btu/kWh)	6,752	9,289	-	8,765	10,781	9,200
Capital (2004$/kW)	758	519	-	1,910	2,770	1,763
Fixed O&M (2004$/kW/yr)	10.8	9.7	-	35.5	42.4	25.3
Variable O&M (2004$/MWh)	1.84	2.91	-	2.68	4.08	4.22
Vintage #5						
Heat Rate (Btu/kWh)	6,752	9,289	-	8,765	10,781	9,200
Capital (2004$/kW)	723	503	-	1,795	2,603	1,748
Fixed O&M (2004$/kW/yr)	10.8	9.7	-	35.5	42.4	25.3
Variable O&M (2004$/MWh)	1.84	2.91	-	2.68	4.08	4.22

Note: Capital costs represent overnight capital costs

Performance and Unit Cost Assumptions for Potential (New) Renewable and Non-Conventional Technology Capacity in EPA Base Case 2009

	Biomass Gasification Combined Cycle	Geothermal	Landfill Gas			Solar Photovoltaic	Solar Thermal	Wind
Size (MW)	80	50	30			5	100	50
First Year Available	2010	2010	2010			2010	2010	2010
Lead Time (Years)	3	4	3			2	3	3
Vintage #1(years covered)	2010-2019	2010-2035	2010-2035	2010-2035	2010-2035	2010-2035	2010-2035	2010-2035
Vintage #2(years covered)	2020-2035							
Vintage #3(years covered)								
Availability	83%	87%	90%			90%	90%	95%
Generation Capability	Economic Dispatch	Economic Dispatch	Economic Dispatch			Generation Profile	Generation Profile	Generation Profile
Vintage #1			LGHI	LGLo	LGVLo			
Heat Rate (Btu/kWh)	9,646	29,029 - 397,035	13,648	13,648	13,648	0	0	0
Capital (2004$/kW)	3,342	2631 - 96,850	2,218	2,794	4,301	5,116	1,901	1,410-4,229
Fixed O&M (2004$/kW/yr)	59.2	73 - 2472	105.0	105.0	105.0	10.7	52.2	27.8
Variable O&M (2004$/MWh)	6.17	0.00	0.01	0.01	0.01	0	0	0.00
Vintage #2								
Heat Rate (Btu/kWh)	9,646	-	-	-	-	-	-	-
Capital (2004$/kW)	2,864	-	-	-	-	-	-	-
Fixed O&M (2004$/kW/yr)	59.2	-	-	-	-	-	-	-
Variable O&M (2004$/MWh)	6.17	-	-	-	-	-	-	-

Note: Capital costs represent overnight capital costs

3. CCS Retrofit for Existing Units

EPA has also included a new CCS retrofit option for existing units larger than 400 MW in Base Case 2009, available to the more efficient units in the coal fleet. This assumption is based upon a 2006 study commissioned by the National Energy Technology Laboratory (NETL) and reflects the cost of the capture technology as well as the energy penalty and subsequent capacity de-rating associated with capturing carbon from a power plant.[3]

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[3] Carbon Dioxide Capture from Existing Coal-Fired Power Plants, DOE/NETL-401/110907, December 2006.

Carbon Capture Retrofit Assumptions for Existing Coal-fired Units In EPA Base Case 2009*

	Retrofit for Existing Coal Units of Capacity 400-775 MW	Retrofit for Existing Coal Units Larger than 775 MW
Capacity Penalty (%)	28.0%	28.0%
Heat Rate Penalty (%)	38.9%	38.9%
Availability (%)	85%	85%
Capital Cost (2004$/kW)	1,127	914
FOM (2004$/kW)	3	2
VOM (2004mills/kWh)	2	2
CO2 Removal (%)	90%	90%

* Costs apply to de-rated capacity of retrofitted unit.

4. Updated Natural Gas Supply and Price Projection

The natural gas supply curves are based on the same assessment of available gas resource through the U.S. and Canada as used in ICF's Gas Market Model (GMM), including resources in Alaska and the Mackenzie Delta area of the Canadian arctic. The Base Case assumes that pipelines will be built to transport gas from these two areas to North American demand markets. The curves assumes a Mackenzie Delta gas pipeline is built in 2015 with a capacity of 1 Bcfd, and an Alaska pipeline is built in 2020 with an initial capacity of 4 Bcfd, which is expanded in 2023 to 6 Bcfd. Together, gas production from Mackenzie Delta and Alaska make up roughly 11 percent of gas supplies by 2030.

The gas supply curves also assume significant growth in North American liquefied natural gas (LNG) imports, based on projected growth in liquefaction capability and taking into account the expect growth in gas demand in other importing countries in Europe and Asia. LNG imports are expected to grow to over 7 Bcfd, or roughly 11 percent of gas supplies by 2030.

5. Renewable portfolio standards and climate programs at the State level

A number of States have recently established renewable portfolio standards (RPS), and EPA has incorporated those requirements in Base Case 2009. They are modeled based upon EIA's updated AEO 2009[4] and result in considerably more renewable energy penetration in EPA's reference case 2009 using IPM. Although many States are considering RPS policies, EIA generally includes only policies that were firmly in place and reasonably fleshed out at the time AEO 2009 was finalized.

EPA has also updated the existing stock of renewables that is assumed to be in place at the beginning of the IPM modeling time horizon. To reflect the recent growth in renewables, particularly wind, the existing renewable generation capacity has been calibrated to EIA's AEO 2008 results for 2010.

A number of States have also adopted either State-level or regional climate programs. EPA includes those State and regional programs with sufficient specificity on emission targets, applicability, coverage, and policy mechanism to allow representation in IPM. The Northeast Regional Greenhouse Gas Initiative (RGGI) was the only regional program that met these criteria and was therefore included in Base Case 2009 modeling.

[4] Energy Information Administration's Annual Energy Outlook 2009, Legislation and Regulations (http://www.eia.doe.gov/oiaf/archive/aeo08/leg_reg.html).

State programs in Oregon and Washington State, which also have sufficiently specific requirements, were carried forward from v3.0.[5]

6. Feasibility Constraints

EPA Base Case 2009 includes feasibility constraints, which are designed to limit the market penetration of the various electricity generating sources in order to ensure realistic build patterns from IPM as CO_2 regulatory policies are modeled. These limits are imposed on all renewable potential (new) build types individually, all renewable potential build types collectively, new nuclear units, coal with CCS, and CCS retrofits for existing coal units. In addition, a 20% cap is set on the amount of electricity generation in a model region that can come from intermittent power (e.g., wind).

New nuclear builds are not allowed until after 2015 because of the time needed for licensing and construction, and new coal with CCS is limited in 2015 to those projects that have dedicated funding or are otherwise incentivized (this is typically dependant upon features or provisions of specific proposals that are analyzed with this version of the model). New coal with CCS can not be built in 2015 on an economic basis in this version of IPM.

The feasibility assumptions for new nuclear, new coal with CCS, and total new renewable capacity are developed using factors based on the current capacity to design, manufacture, engineer, and construct these types of power generating technologies. For new nuclear and new coal with CCS, analysis indicates that only a few large engineering and construction firms currently have the capacity to handle these very large and complicated projects. It was assumed that these firms could build either type of technology and that resources would become available to support an increase in their capacity to handle these projects by 50% over each successive 5 year time period.

The constraints on these technologies thus reflect a generating capacity limitation (in gigawatts) based upon the ability to design and construct these projects, factoring in the aforementioned growth rate over time. In addition, there is a relationship between the amount of new nuclear and new coal with CCS that can be built, depending on the relative amount of resources required by each technology. Assuming that the same firms can generally undertake and manage the design, engineering, and construction of either type of technology, they are able to design and build more of one technology and less of the other in response to the relative economics and the demand for the technologies. This relationship is captured in Production Possibility Curves for nuclear and IGCC with CCS within the model. These curves are presented at the end of this section.

A CCS retrofit option is also available for existing coal units in Base Case 2009, and this technology is also limited in the model. The CCS retrofit option is allowed after 2015 and its growth rate is similar to nuclear and new coal with CCS capacity (i.e., incrementally increasing by 50% in each successive five year period). However, unlike nuclear and new coal with CCS, it is assumed that CCS retrofit projects can be handled by smaller firms since they do not require the same magnitude of resources that the larger, new power plants require. Thus, they are constrained independently and are not affected by the extent of growth in other technologies.

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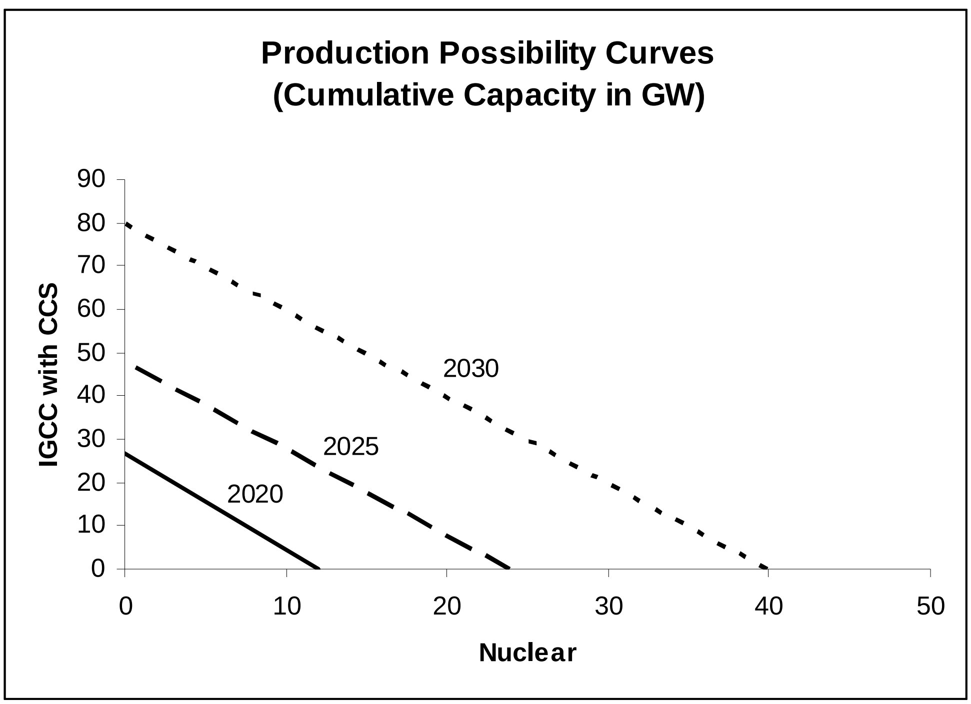
[5] Documentation for EPA Base Case 2006 (v3.0), Section 3: Power System Operation Assumptions (http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html).

Renewable energy technologies are also limited in the model. The initial 2015 limit was derived from recent build patterns and also incorporated a 50% growth rate for every 5 year time period, the same rate for new nuclear and new coal with CCS. Wind power is constrained separately from all other renewables and also assumes a 50% growth rate every 5 years. Other renewables are limited to 10 GW in 2015 and a linear growth of 5 GW every five years thereafter.

A tabular summary of the EPA Base Case 2009 feasibility constraints and a graph of the Production Possibilities Curves are presented below.

Technology Limits for Base Case 2009 using IPM (Cumulative, GW)

		2010	2015	2020	2025
Nuclear	Incremental	0	0	Curve	Curve
	Cumulative	0	0	Curve	Curve
New Coal with CCS	Incremental	0	Policy Dependent	Curve	Curve
	Cumulative	0	Policy Dependent	Curve	Curve
Renewables (All)	Incremental	0	40	60	85
	Cumulative	0	40	100	185
Wind	Incremental	0	30	45	65
	Cumulative	0	30	75	140
Other Renewables	Incremental	0	10	15	20
	Cumulative	0	10	25	45



Technology Limit Curve for New Nuclear, New Coal with CCS, and CCS Retrofit for Existing Coal (Cumulative, GW)

	Nuclear	IGCC with CCS	Nuclear	IGCC with CCS	CCS Retrofit
Year	*Curve*				*Independent*
2010	N/A	N/A	N/A	N/A	0
2015	N/A	Policy Dependant	N/A	Policy Dependant	0
2020	12	0	0	27	5
2025	24	0	0	48	13
2030	40	0	0	80	33

Notes: Retrofit CCS constraints apply to existing coal capacity prior to de-ratings for factors like parasitic load, etc. The constraints are applied independently to CCS retrofits alone (i.e., there is no curve jointly constraining CCS retrofits and other types of builds).