Minnesota Pilot Project
Overview of Proposed Modeling Assumptions

Presented by ICF International

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Introduction

- The US EPA is working with Minnesota to ensure stakeholders have the information and tools needed to meet upcoming electric utility sector rules in an integrated way. This approach will offer greater regulatory certainty to enable more informed investment decisions in the sector.

- ICF's Integrated Planning Model (IPM®), with detailed modeling of the power sector and expanded to represent emissions and emissions reduction opportunities for a broad range of sectors, is being used for this analysis. The IPM is the tool used by US EPA's Clean Air Markets Division for analysis of proposed regulations.

- The proposed model runs for this project are based on the US EPA's v4.10 Base Case using IPM. These proposed run specifications were developed during previous teleconferences with the Minnesota working group.

- Detailed documentation for the US EPA v4.10 Base Case assumptions are available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html

IPM® Overview

- Multi-regional, deterministic, dynamic linear programming model with perfect foresight.
- Long-term capacity expansion and production costing model for analyzing the electric power sector.
- Comprehensive natural gas supply, demand, and pipeline modeling capability.
- Finds the least-cost solution to meeting electricity and steam demand subject to environmental, transmission, fuel, reserve margin, and other system operating constraints.
- IPM has evolved over 30 years after millions of dollars in development costs.
- A core group of modelers update the tool on a continuous basis.

Run Definition Assumptions

Run Years

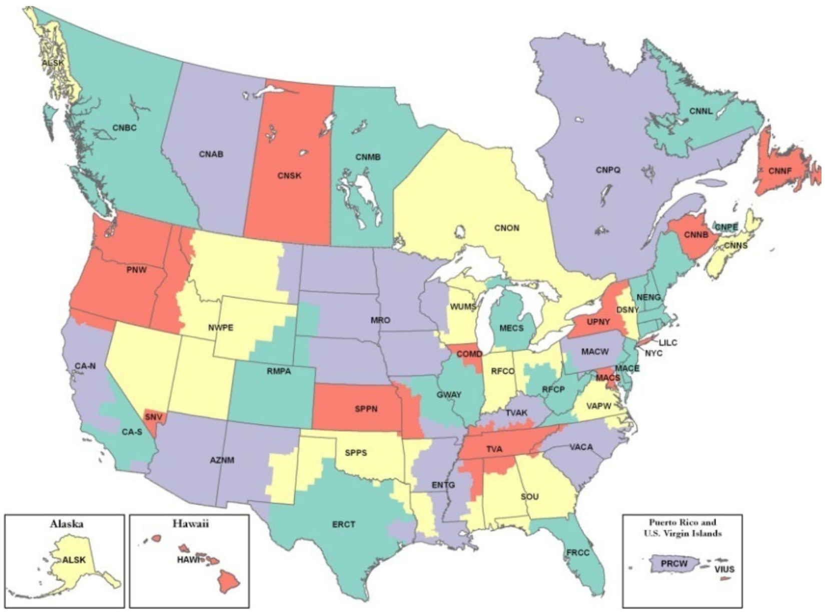
- IPM® is equipped with a year-mapping feature that enables simulations of long time horizons.
  - Several years in the time horizon can be mapped into a single run year.
  - Generation costs for all years that are mapped to a run year are computed and included in the objective function.
- The EPA Minnesota study will report six run years consistent with those in EPA v4.10 Base Case.

Run Year	Years Mapped
2012	2012-2013
2015	2014-2016
2020	2017-2024
2030	2025-2034
2040	2035-2045
2050	2046-2054

Each run year will be modeled with two seasons: Winter (October-April) and Summer (May-September).

Model Regions

- IPM Model regions are configured in order to:
  - Capture transmission bottlenecks.
  - Maintain consistencies with primary data sources.
  - Maintain consistency with NERC region and sub regions.
- The EPA Base Case v4.10 models 32 model regions in the continental USA and 11 model regions in Canada.



Market Assumptions

Electricity Demand in IPM®

- Demand is represented in IPM® at a model region level by a combination of the following variables:
  - **Peak Demand** – The maximum power load (MW) requirement for a model region.
  - **Energy Demand** – The total energy requirement (MWh) for a model region, defined annually.
  - **Hourly Load Profiles** – The 24-hour shape of demand level, defined for 8760 hours of a base year, for each model region, scaled to meet peak and energy demand. Hourly load files are created from the historical load data filed by each region's utilities (FERC Form 714) for a normal weather year.
- EPA Base Case v4.10 uses the electricity demand assumptions from AEO 2010 Reference Case.

Reserve Margin and Transmission Assumptions

- To maintain system stability and reliability, each IPM® model region must have a certain amount of backup capacity relative to its projected peak demand. Reserve margin is defined as the amount of capacity that needs to be built over and above the peak load.
- IPM being a multi region model, the various power market regions are interconnected by a transmission grid. Transmission between model regions allows for broad price equilibration and reserve sharing across the North American grid

Transmission Assumptions – Selected Links

Annual Transmission Capabilities from and to the MRO Model Region

From	To	Energy (MW)		From	To	Energy (MW)
MRO	CNMB	0		CNMB	MRO	2,175
MRO	CNON	100		CNON	MRO	150
MRO	CNSK	165		CNSK	MRO	215
MRO	COMD	610		COMD	MRO	825
MRO	ENTG	2,000		ENTG	MRO	150
MRO	GWAY	320		GWAY	MRO	405
MRO	NWPE	200		NWPE	MRO	150
MRO	RMPA	310		RMPA	MRO	310
MRO	SPPN	2,000		SPPN	MRO	600
MRO	WUMS	800		WUMS	MRO	270

Transmission Assumptions – Selected Links Cont.

Annual Joint Capacity and Energy Limits Between MRO and Neighboring Model Regions

Region Connections	Transmission Path	Joint Constraint Limit (MW)
MAIN to MAPP	COMD to MRO GWAY to MRO WUMS to MRO	962
MAPP to MAIN	MRO to COMD MRO to GWAY MRO to WUMS	1,238
WECC to MAPP	NWPE to MRO RMPA to MRO	660
MAPP to WECC	MRO to NWPE MRO to RMPA	710

Financial Assumptions

- **Discount Rate**
  - IPM® is a linear programming model that optimizes system performance in a least cost manner to meet market and policy requirements in the analysis.
  - All costs in EPA Base Case v4.10 are represented in real 2007$, and are then discounted back on a present value basis to determine the least cost way to meet the market and policy requirements defined. The discount rate is important in evaluating the tradeoffs of making investments and incurring costs in the near-term vs. incurring expenses over the longer-term.
- **Capital Charge Rate**
  - Capital investments in IPM® are annualized using a capital charge rate that takes into account the amount of debt and equity and their respective rates, taxes, depreciation schedule, book life and debt life. Capital charge rates are assigned to each technology type.

U.S. Discount Rates and Capital Charge Rates in EPA Base Case v4.10

Investment Technology	Capital Charge Rate	Discount Rate	Book Life
Environmental Retrofits	11.3%	5.5%	30
Advanced Combined Cycle	12.1%	6.2%	30
Advanced Combustion Turbine	12.9%	6.9%	30
Supercritical Pulverized Coal and Integrated Gasification Combined Cycle without Carbon Capture[1]	14.1%	7.8%	40
Advanced Coal with Carbon Capture	11.1%	5.5%	40
Nuclear without Production Tax Credit (PTC)	10.8%	5.5%	40
Nuclear with Production Tax Credit (PTC)[2]	9.1%	5.5%	40
Biomass with ARRA Loan Guarantees[3]	9.3%	4.6%	40
Biomass without ARRA Loan Guarantees	11.1%	6.2%	40
Wind and Landfill Gas with ARRA Loan Guarantees[2]	10.1%	4.6%	20
Wind and Landfill Gas without ARRA Loan Guarantees	12.2%	6.2%	20
Solar and Geothermal with ARRA Loan Guarantees[2]	10.1%	4.6%	20
Solar and Geothermal without ARRA Loan Guarantees	12.2%	6.2%	20

- Notes:

The discount rates appearing in the table were used in deriving these capital charge rates. However, a single U.S. discount rate of 6.15% is used across all technologies in EPA Base Case v.4.10.

[1]The capital charge rate for these technologies includes a 3% climate change uncertainty adder.

[2]The capital charge rate for this technology reflects the impact of the PTC provided under the Energy Policy Act of 2005.

[3]The capital charge rate for these technologies reflects the impact of ARRA loan guarantees.

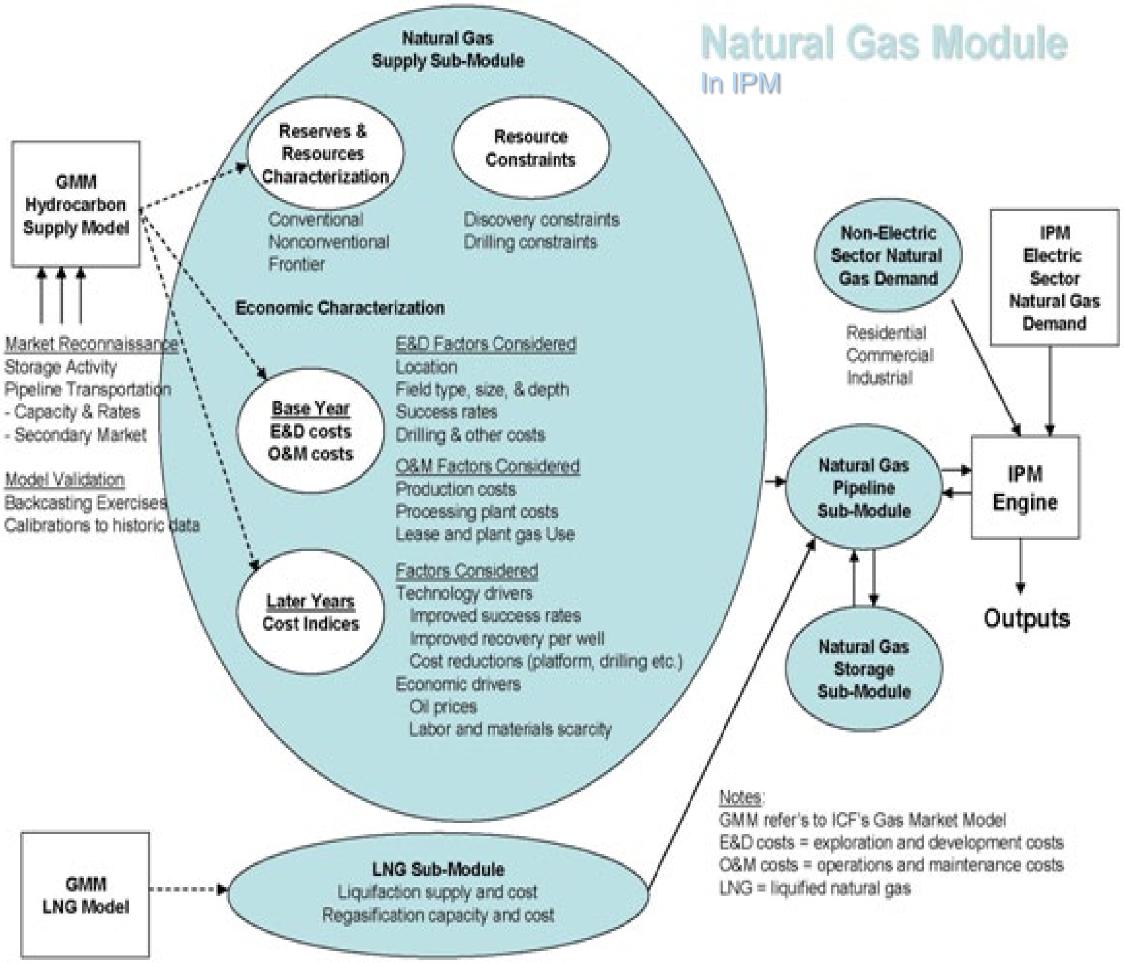
Fuel Assumptions

Gas Modeling Capabilities

§The EPA Base Case v4.10 using IPM takes advantage of the embedded comprehensive natural gas supply, demand, storage and pipeline model within IPM.

§In this system, natural gas supply curves are generated endogenously for each region, and the balance between the natural gas supply and demand is solved in all regions simultaneously. The direct interaction between the electric and the gas modules captures the overall gas supply and demand dynamic and requires no iteration.

§This version of the gas model will be slightly revised to capture the AEO 2011 crude oil price projections.



Coal Market Modeling

- EPA Base Case v4.10 relies on a supply curve structure to simulate coal markets. Having coal supply curves allows the model to simulate the price changes that would occur with substantial shifts in demand that might occur under environmental policies.

- Coal resources for each of 34 coal supply basins are disaggregated by the following characteristics:

  – Rank (Bituminous, Subbituminous, Lignite)

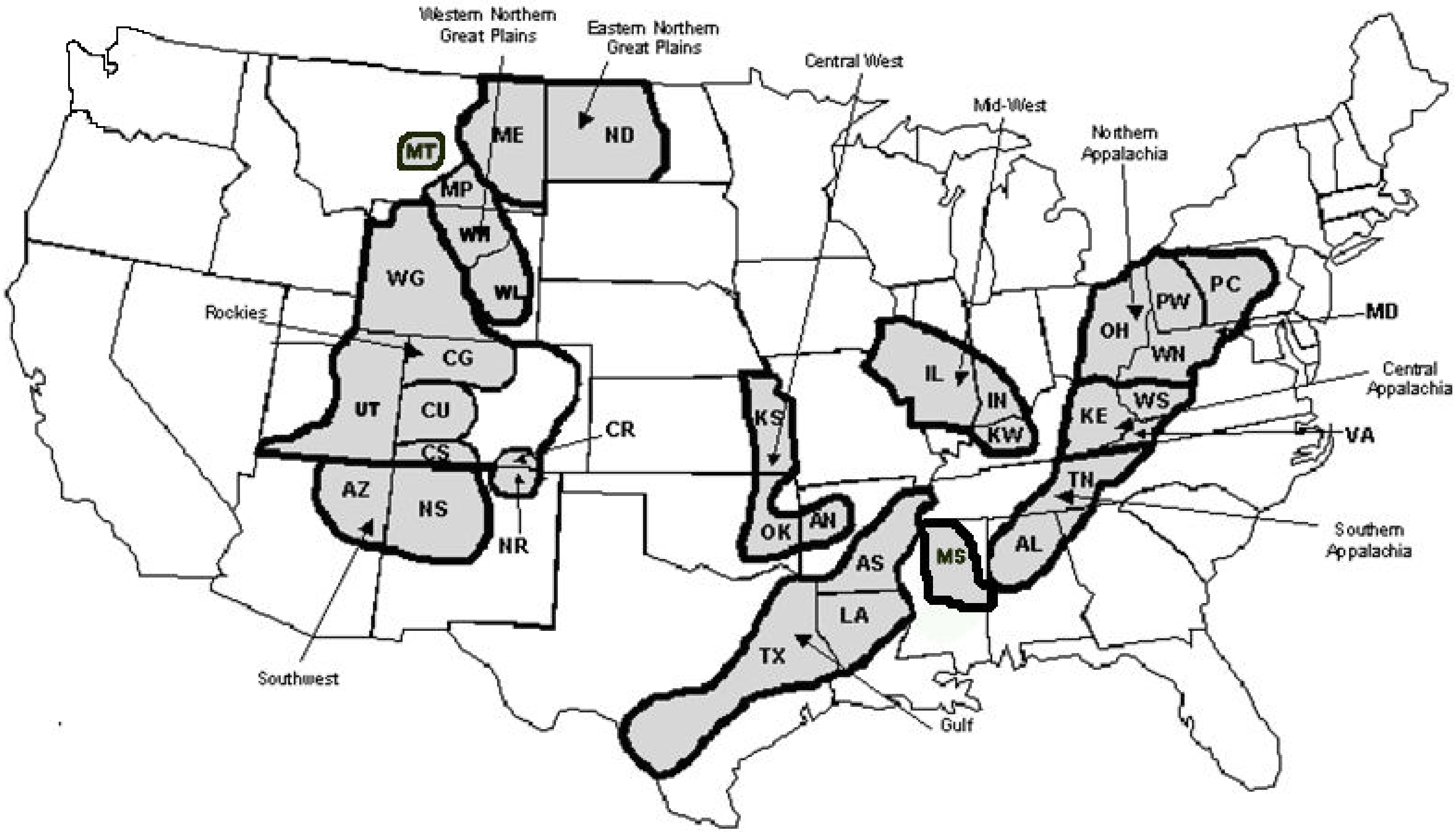
  – Sulfur content ranges

  – Existing and new mines

- Coal plants in EPA Base Case v4.10 using IPM® are assigned to one of 100+ different coal demand regions.

- A coal transportation matrix links supply and demand regions in IPM®, which determines the least cost means to meet power demand for coal as part of an integrated optimal solution for power, fuel, and emission markets.

Coal Supply Region Map



Biomass Supply Curves

- AEO 2010 models biomass through biomass supply curves. The biomass supply curves are defined for the 14 NEMS coal demand regions. These regions are subsets of census regions. In EPA Base Case v4.10, these regions are mapped to the IPM Regions.

- These supply curves model the following four biomass types:

  – Urban wood waste and mill residue
  – Energy crop
  – Forestry residue
  – Agricultural residue

- Biomass supply curves satisfy biomass demand for the electric power and the cellulosic ethanol sectors.

- Biomass will be modeled as having a net-zero CO_2 emission factor. This is a common assumption used in power sector modeling and reflects the life cycle emissions over the materials' growth cycle and ultimate combustion.

Technical Assumptions
Supply

Supply in IPM®

- Supply in IPM® is defined by a combination of the following options:
  - **Existing Capacity** – The generating capacity currently available to the grid.
  - **Firmly Planned Capacity** – The generating capacity that is firmly planned to be built.
  - **New build Cost and Performance** – The specifications for new potential capacity types, including assumptions about technology improvement over time and resource potential.

Existing Capacity – IPM® Power Plant Database

- IPM® requires detailed information on all existing and planned and committed grid-connected electric generators and boilers in the continental U.S.

- The IPM power plant database will be based on EPA's National Electric Energy Data System (NEEDS). NEEDS database contains the generation unit records used to construct the "model" plants that represent existing and planned/committed units in EPA modeling applications of IPM. NEEDS includes basic geographic, operating, air emissions, and other data on these generating units.

- Existing and planned committed units in the database, with the exception of nuclear units, are not provided with a specific retirement year. However, IPM can endogenously retire power plants based on economics. The life extension cost estimates are based on EPA Base Case v4.10.

Existing Capacity – Power Plant Availability

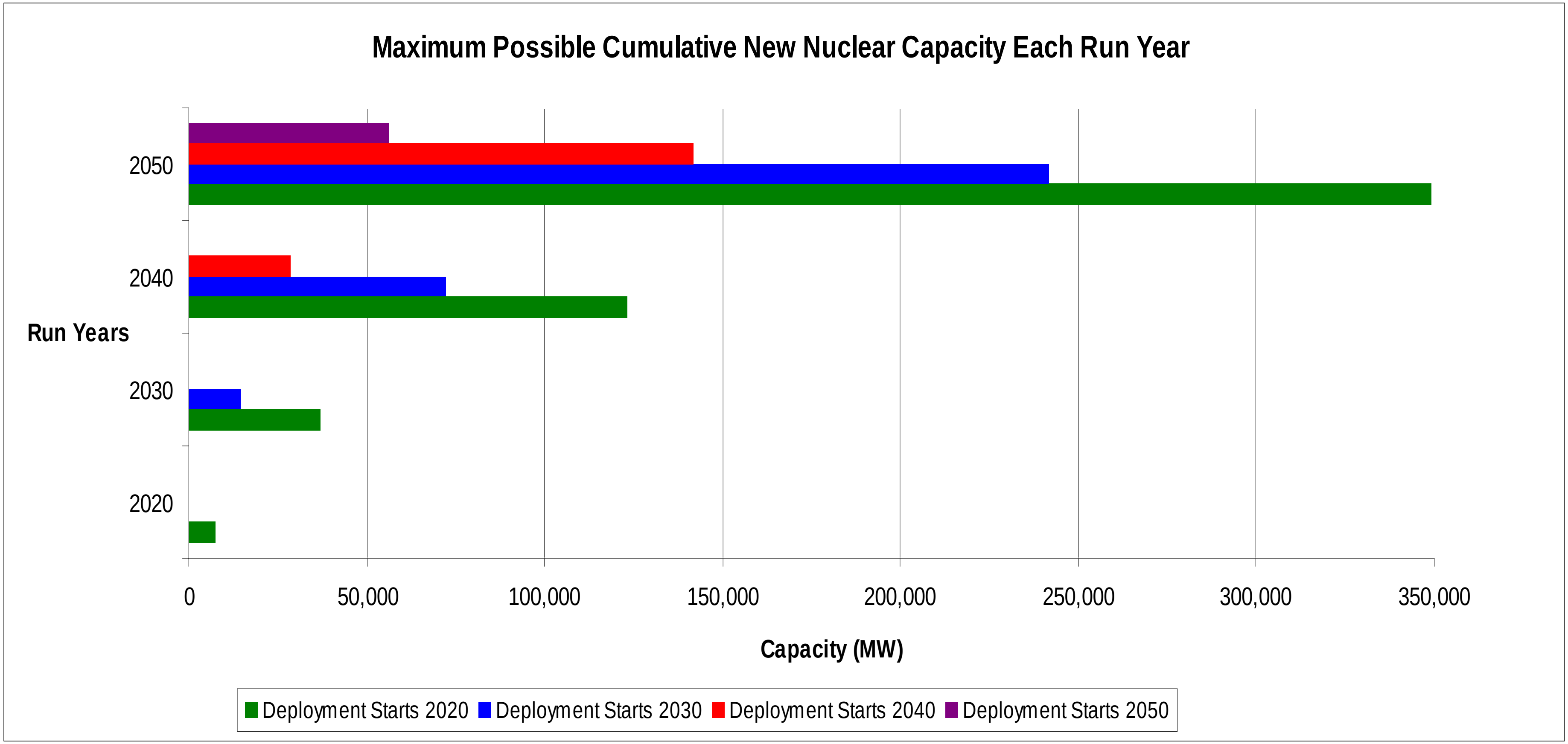
- Power plant availabilities for non coal fossil units are based on NERC GADS and AEO.

- For existing coal units, EPA Base Case v.4.10 adopts an approach similar to AEO 2010 of using historical capacity factors to define projected availabilities.

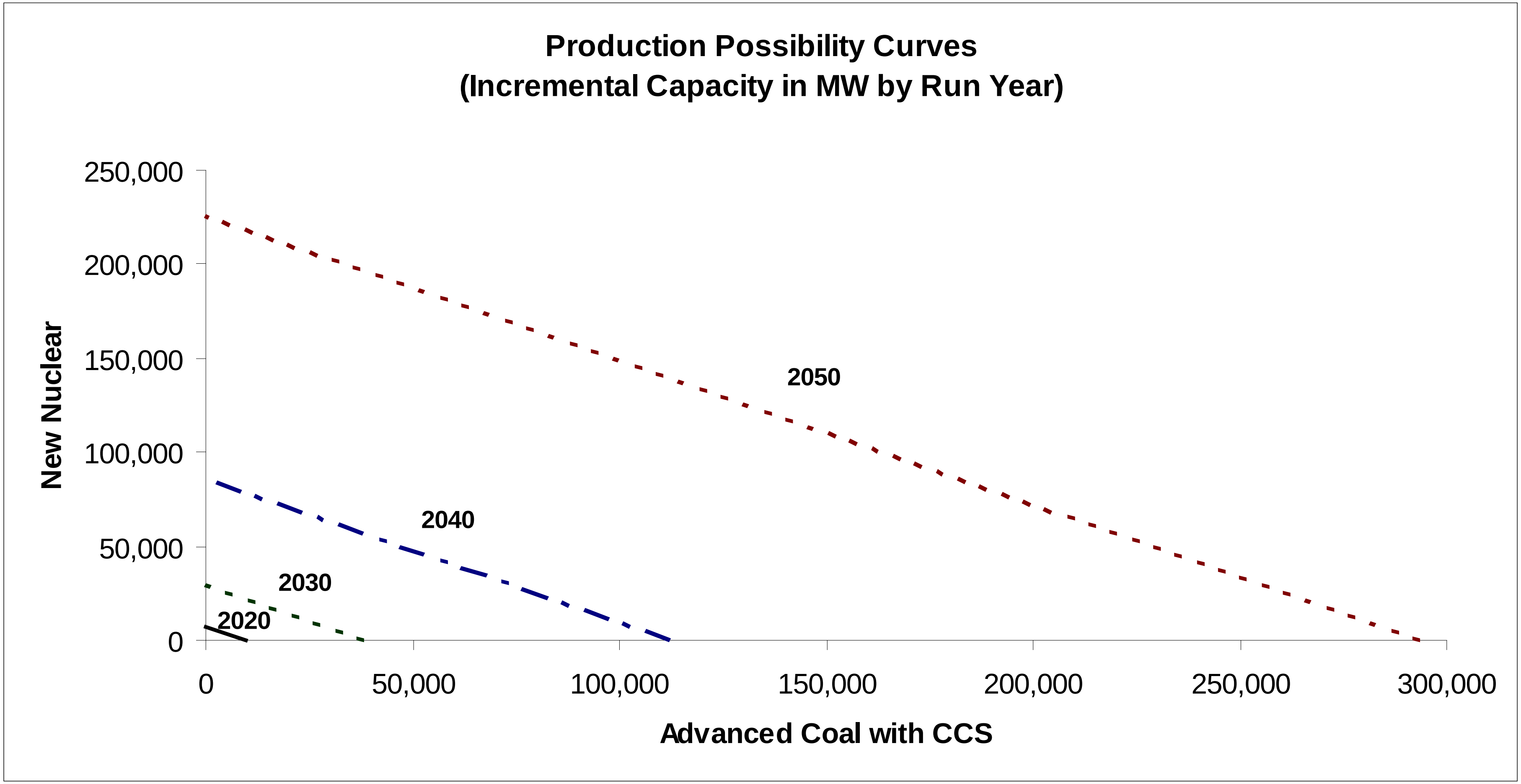
Performance and Unit Cost Assumptions for New Capacity from Conventional Technologies in EPA Base Case v4.10

	Advanced Combined Cycle	Advanced Combustion Turbine	Nuclear	Integrated Gasification Combined Cycle – Bituminous	Advanced Coal with Carbon Capture-Bituminous	Supercritical Pulverized Coal - Wet Bituminous
EPA Base Case v4.10						
Heat Rate (Btu/kWh)	6,810	10,720	10,400	8,424	10,149	8,874
Capital (2007$/kW)	976	698	4,621	3,265	4,720	2,918
Fixed O&M (2007$/kW/yr)	14.4	12.3	92.4	47.9	60.5	28.9
Variable O&M (2007$/MWh)	2.57	3.59	0.77	1.32	1.67	3.43

New Plant Investment Capacity Constraints - Nuclear



New Plant Investment Capacity Constraints – Nuclear & CCS



Emissions Control Technologies/Retrofits

Emissions Control Technologies/Retrofits

- Within the IPM® framework, units affected by air emissions regulations can comply by fuel-switching, buying allowances if the policy is market-based, reducing dispatch/shutting down, or installing emissions control technologies.

- EPA Base Case v4.10 using IPM explicitly models the most common existing control technologies, each of which impact the emissions rate for SO_2, NO_x, mercury, HCl and CO_2 emissions. Emission reduction factors are applied to the input content of the fuel to reflect the technology.

Pollutant	Technology
SO_2 and HCl	Wet Scrubber, Dry Scrubber, Dry Sorbent Injection
NO_x	SCR, SNCR
Mercury	ACI
CO_2	Carbon Capture, Biomass Cofiring, Coal-to-Gas Retrofit

Summary of Emission Control Technology Removal Rates

Emission Control Technology	% Reduction	Floor
Limestone Forced Oxidation (LSFO)	SO_2 - 96%, HCl – 99%	SO_2 - 0.06 lbs/MMBtu HCl - 0.0001 lbs/MMBtu
Lime Spray Dryer (LSD)	SO_2 - 92%, HCl – 99%	SO_2 - 0.08 lbs/MMBtu HCl - 0.0001 lbs/MMBtu
Dry Sorbent Injection with FF (DSI)	SO_2 - 70%, HCl – 90%	HCl - 0.0001 lbs/MMBtu
Selective Catalytic Reduction (SCR) - Coal	NO_x - 90%	Bit - 0.07 lbs/MMBtu Subbit - 0.05 lbs/MMBtu
Selective Non-Catalytic Reduction - PC (SNCR)	NO_x - 35%	--
Selective Non-Catalytic Reduction – FBC (SNCR)	NO_x - 50%	--
Activated Carbon Injection (ACI)	Hg - 90%	--
Coal-to-Gas Retrofit	NO_x - 50%	0.05 lbs/MMBtu
Carbon Capture (CCS)	CO_2 - 90%	

Illustrative Scrubber Costs (2007$)

Scrubber Technology	Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)
LSFO Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal SO_2 rate: 3 lb/MMBtu Heat Rate: 10,000 Btu/kWh	100	783	22.8	1.84
	300	573	10.8	
	500	496	8	
	700	451	7.4	
	1000	407	6.1	
LSD Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal SO_2 rate: 2 lbs/MMBtu Heat Rate: 10,000 Btu/kWh	100	670	16.7	2.36
	300	491	8.3	
	500	424	6.3	
	700	403	5.5	
	1000	403	5.1	

Illustrative Post-Combustion NO_X Control Costs (2007$)

Control Type	Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)
SCR - Coal Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal NO_X rate: 0.5 lb/MMBtu SO_2 rate: 2.0 lb/MMBtu Heat Rate: 10,000 Btu/kWh	100	240	2.5	1.24
	300	193	0.8	
	500	178	0.7	
	700	169	0.5	
	1000	162	0.4	

Illustrative Post-Combustion NO_X Control Costs Cont. (2007$)

Control Type	Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)
SNCR - Non-FBC Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal NOx rate: 0.5 lb/MMBtu SO2 rate: 2.0 lb/MMBtu Heat Rate: 10,000 Btu/kWh	100	47	1	0.98
	300	Size Not Modeled		
	500			
	700			
	1000			
SNCR - Fluidized Bed Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal NOx rate: 0.5 lb/MMBtu SO2 rate: 2.0 lb/MMBtu Heat Rate: 10,000 Btu/kWh	100	35	0.9	0.98
	300	19	0.4	
	500	14	0.2	
	700	12	0.2	
	1000	10	0.1	

Illustrative DSI and PM Control Costs (2007$)

Control Type	Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)
DSI - FF Assuming Bituminous Coal Heat Rate: 10,000 Btu/kWh	100	125	2.28	6.72
	300	57	0.89	
	500	40	0.58	
	700	31	0.43	
	1000	31	0.38	
Fabric Filter Assuming Bituminous Coal Heat Rate: 10,000 Btu/kWh	100	205	0.9	0.15
	300	167	0.7	
	500	151	0.6	
	700	141	0.6	
	1000	132	0.6	

Illustrative ACI Control Costs (2007$)

Control Type	Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)
ACI + Full Baghouse with a Sorbent Injection Rate of 2 lbs/MMBtu Assuming Bituminous Coal Heat Rate: 10,000 Btu/kWh	100	259	0.98	0.54
	300	197	0.75	
	500	176	0.67	
	700	163	0.62	
	1000	151	0.57	
ACI with a Sorbent Injection Rate of 2 lbs/MMBtu Assuming Bituminous Coal Heat Rate: 10,000 Btu/kWh	100	28.37	0.12	2.49
	300	11.16	0.05	
	500	7.23	0.03	
	700	5.43	0.02	
	1000	4.01	0.02	
ACI with a Sorbent Injection Rate of 5 lbs/MMBtu Assuming Bituminous Coal Heat Rate: 10,000 Btu/kWh	100	32.56	0.14	3.07
	300	12.80	0.05	
	500	8.29	0.03	
	700	6.23	0.03	
	1000	4.60	0.02	

Illustrative Coal-to-Gas Retrofit Costs (2007$)

Coal-to-Gas Retrofit Technology	Capacity (MW)	Incremental Capital Cost ($/kW)	Incremental Fixed O&M ($/kW-yr)	Incremental Variable O&M (mills/kWh)
Pulverized Coal Unit Minimum Cutoff: > 25 MW Maximum Cutoff: None	100	226	-10.0	0.41
	300	154	-8.9	0.33
	500	129	-8.5	0.30
	700	114	-8.2	0.28
	1000	101	-7.9	0.26
Cyclone Boiler Unit Minimum Cutoff: > 25 MW Maximum Cutoff: None	100	316	-10.0	0.41
	300	215	-8.9	0.33
	500	180	-8.5	0.30
	700	160	-8.2	0.28
	1000	141	-7.9	0.26

Illustrative CCS Control Costs (2007$)

Applicability (Original MW Size)	450-750 MW	> 750 MW
Incremental[1] Capital Cost (2007 $/kW)	1,972	1,599
Incremental[1] FOM (2007 $/kW-yr)	3	1.98
Incremental[1] VOM (2007 (mills/kWh)	2.35	2.35
Capacity Penalty (%)	-25%	-25%
Heat Rate Penalty (%)	33%	33%
CO_2 Removal (%)	90%	90%

Note:

[1]Incremental costs are applied to the derated (after retrofit) MW size.

CO_2 Transportation and Sequestration Modeling in IPM

CO_2 Transportation and Sequestration

- Coal power plants with CO_2 capture capability are grouped into CO_2 production regions.
- CO_2 storage sites are grouped into CO_2 storage regions.
- CO_2 production regions and CO_2 storage regions are interconnected by a CO_2 transportation network.
- The CO_2 transportation capability between production regions and storage region regions is considered unlimited and available at a constant unit cost of transportation.
- CO_2 storage cost in each CO_2 storage region is characterized by a CO_2 storage cost curve.
- CO_2 storage regions with enhanced oil recovery possibilities have negative costs in the CO_2 storage cost curve for that region.

Air Regulatory Policies

Federal and Regional Air Regulations

- SO_2, NO_x and Mercury Regulations:
  - Any policy already on the books (e.g., state policies, NSR settlements) are included in the EPA Base Case v4.10.