

**How the Timing of Climate Change Policy Affects Infrastructure Turnover in
the Electricity Sector: Engineering, Economic and Policy Considerations**

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Abstract

The electricity sector is responsible for producing 35% of US greenhouse gas (GHG) emissions. Estimates suggest that ideally, the electricity sector would be responsible for approximately 85% of emissions abatement associated with climate policies such as America's Clean Energy and Security Act (ACES). This is equivalent to ~50% cumulative emissions reductions below projected cumulative business-as-usual (BAU) emissions. Achieving these levels of emissions reductions will require dramatic changes in the US electricity generating infrastructure: almost all of the fossil-generation fleet will need to be replaced with low-carbon sources and society is likely to have to maintain a high build rate of new capacity for decades. Unfortunately, the inertia in the electricity sector means that there may be physical constraints to the rate at which new electricity generating capacity can be built. Because the build rate of new electricity generating capacity may be limited, the timing of regulation is critical—the longer the U.S. waits to start reducing GHG emissions, the faster the turnover in the electricity sector must occur in order to meet the same target. There is a real, and thus far unexplored, possibility that the U.S. could delay climate change policy implementation for long enough that it becomes infeasible to attain the necessary rate of turnover in the electricity sector.

This dissertation investigates the relationship between climate policy timing and infrastructure turnover in the electricity sector. The goal of the dissertation is to answer the question: How long can we wait before constraints on infrastructure turnover in the electricity sector make achieving our climate goals impossible?

Using the Infrastructure Flow Assessment Model, which was developed in this work, this dissertation shows that delaying climate change policy increases average retirements rates by 200-400%, increases average construction rates by 25-85% and increases maximum construction rates by 50-300%. It also shows that delaying climate policy has little effect on the age of retired plants or the stranded costs associated with premature retirement. In order for the electricity sector to reduce emissions to a level required by ACES while limiting construction rates to within achievable levels, it is necessary to start immediately. Delaying the process of decarbonization means that more abatement will be necessary from other sectors or geoengineering. By not starting emissions abatement early, therefore, the US forfeits its most accessible abatement potential and increases the challenge of climate change mitigation unnecessarily.

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In *Gift from the Sea*, Anne Morrow Lindbergh wrote, “ ‘No man is an island’, said John Donne. I feel we are all islands--in common sea.” She was talking about something else altogether, but Ms. Lindbergh summarized the experience of getting a PhD far better than I can. I’ve had a lot of island time over the past four and a half years--if it weren’t for the common sea here at Carnegie Mellon, I would have never had the fortitude to finish this process.

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Contents

Dissertation Committee	ii
Abstract	iv
Acknowledgments	v
Contents	vii
Table of Figures	x
Table of Tables	xiii
CHAPTER 1: Introduction And Background.....	1
1.1 Motivation	1
1.2 Dissertation overview and research questions.....	4
1.3 Background	6
1.3.1 The US Electricity Sector and Climate Change.....	7
1.3.2 Optimal Timing of Climate Change Mitigation	10
1.3.3 Pathways to Achieving Emissions Reductions	12
CHAPTER 2: Integrated Infrastructure Flow Analysis Model.....	2
2.1 Existing Models of the Electricity Sector.....	2
2.1.1 Energy-Economic Models	7
2.1.2 Other models.....	12
2.2 IFAM Model Structure	16
2.2.1 User Defined Inputs.....	18

2.2.2	IFAM Model Outputs	21
2.3	Model Algorithm.....	22
2.3.1	Overview.....	22
2.3.2	Dispatching Units to Meet Demand.....	25
2.3.3	Meeting an Emissions Cap with Re-Dispatch.....	27
2.3.4	Calculating the emissions profile	29
2.3.5	Individual Plant Behavior.....	32
2.3.6	Constructing new units.....	35
2.4	Data.....	36
2.4.1	Generating Units.....	36
2.4.2	Fuel Prices.....	41
2.4.3	Load	41
2.4.4	Regional Parameters	42
2.4.5	Providing Firm Wind Power.....	43
2.5	Model Initialization and Calibration	46
2.5.1	Initialization	46
2.5.2	Calibration	47
2.6	Model Validation	49
CHAPTER 3: Reference Case Results.....		54
3.1	Intermediate Results.....	56
3.2	Infrastructure Turnover	66
3.3	Premature Retirement.....	73
3.4	Infeasibility Frontier.....	77

3.5	Regional Considerations.....	79
CHAPTER 4: Sensitivity Analyses and Policy Interventions		86
4.1	Sensitivity Analyses.....	86
4.1.1	Coal and Natural Gas Prices.....	86
4.1.2	Gas/Wind Ratio	90
4.2	Policy Interventions.....	91
4.2.1	Demand	91
4.2.2	BAU Construction Scenarios.....	95
4.2.3	Low-Carbon Construction Scenarios	100
4.3	Infeasibility Frontiers.....	104
CHAPTER 5: Conclusions and Future Work.....		106
5.1	Research Questions Revisited.....	106
5.2	Final Thoughts: How Long Can We Wait?.....	112
5.3	Research Contributions	116
5.4	Future Work.....	117
REFERENCES.....		120

Table of Figures

Figure 1-1 US electricity generation by fuel source.	8
Figure 1-2 Installed US generating capacity, by fuel type and vintage year.	10
Figure 2-1 Model structure.....	24
Figure 2-2 Economic Dispatch.....	25
Figure 2-3 Example emissions pathways for the US.	31
Figure 2-4 Comparison of modeled capacity factors and actual capacity factors for the year 2009.	52
Figure 3-1 Annual generation for 25% cumulative emissions reductions below BAU for four policy start year scenarios: 2014, 2020, 2026, and 2032.	57
Figure 3-2 Annual capacity mix for 25% cumulative emissions reductions below BAU for four policy start year scenarios: 2014, 2020, 2026, and 2032.	58
Figure 3-3 Annual capacity retirements for 25% cumulative emissions reductions below BAU for four policy start year scenarios: 2014, 2020, 2026, and 2032.	59
Figure 3-4 Annual construction for four PSYs (2014, 2020, 2026, 2032) for the 25% cumulative emissions reductions below BAU scenario.	61
Figure 3-5 Annual electricity price for 25% cumulative emissions reductions below BAU	62
Figure 3-6 Average annual carbon price for cumulative emissions reductions of 25% below BAU.....	64
Figure 3-7 Annual emissions for cumulative emissions reductions of 25% below BAU ..	65
Figure 3-8 Average annual retirements after emissions reductions start as a function of policy start year compared to IFAM's BAU projections.....	67

Figure 3-9 Average annual construction after emissions reductions start as a function of policy start year.....	69
Figure 3-10 Average annual construction during the 5-year period of maximum construction (calculated using a moving average) as a function of policy timing. ...	70
Figure 3-11 NPV of construction costs (\$2012; real discount rate of 1.1%) as a function of policy start year.....	72
Figure 3-12 Average age of plants retired due to emissions reduction policy, as a function of policy start year.	74
Figure 3-13 Box-and-whisker plot of the age of retired plants for the 25% cumulative emissions reduction scenario.	75
Figure 3-14 Stranded costs in \$2012 from prematurely retired plants (US) as a function of emissions target and reduction start year.....	76
Figure 3-15 Contour map of average annual construction as a function of emissions target and policy start year.	78
Figure 3-16 Average annual construction after emissions reductions start (GW) by region.	81
Figure 3-17 NPV of stranded costs from plants retired prematurely due to emissions reduction policy.	82
Figure 3-18 Infeasibility frontier by region.	84
Figure 4-1 Average annual construction after emissions reductions start for 20% and 40% emissions reduction targets and five fuel price scenarios.	88
Figure 4-2 NPV of stranded costs from prematurely retired plants for 20% and 40% emissions reduction target scenarios and five fuel price scenarios.....	89
Figure 4-3 Comparison of demand scenarios for 20% and 40% emissions reduction scenarios for five demand growth scenarios.	93

Figure 4-4 Difference in construction costs between reference case and demand growth scenarios.....	94
Figure 4-5 Comparison of average annual construction after emissions reductions start between three pre-emissions-policy construction portfolios, for the 20%, 30% and 40% emissions reduction scenarios.	97
Figure 4-6 Comparison of average construction during the period of maximum activity between three BAU construction portfolios, for the 20%, 30% and 40% emissions target scenarios.	98
Figure 4-7 Comparison of stranded costs for three BAU construction portfolio scenarios, for 20%, 30% and 40% reduction scenarios.	99
Figure 4-8 Average annual construction rates for four low-carbon portfolio scenarios and three emissions target scenarios (20%, 30%, 40%)......	102
Figure 4-9 NPV of stranded costs from prematurely retired plants.	103
Figure 4-10 Comparison of the infeasibility frontier for the various sensitivity analyses.	105
Figure 5-1 Tradeoff frontiers between emissions reduction targets and policy start years for the infeasibility frontier as well as three physical constraint scenarios:	115

Table of Tables

Table 2-1 Important model features of several of major energy models	6
Table 2-2 NERC regions	17
Table 2-3 Fuel emissions factors	38
Table 2-4 Technical and Financial parameters for new units.....	40
Table 2-5 Fuel Prices.....	41
Table 2-6 Load slice categories.....	42
Table 2-7 Regional BAU generation portfolios and demand growth rates.....	43
Table 2-8 Comparison of cumulative construction and retirements (2012-2035) for IFAM and the AEO and calibration parameters	48
Table 2-9 Comparison of IFAM model results to historical data for the year 2008; generation mix and total generation.	50
Table 2-10 Comparison of modeled capacity factors and actual capacity factors for the year 2009, by plant size and fuel type. RMSE=root mean squared error; overall RMSE=0.26.	52
Table 4-1 Sensitivity analysis for fuel prices. Scenarios and data from (U S Energy Information Administration 2011) for the year 2025.	87
Table 4-2 Growth rates in each region for each scenario in the demand growth sensitivity analysis.....	92
Table 4-3 High Coal Scenario BAU construction generating portfolio standards	96
Table 4-4 Fuel mix in Low-Carbon construction portfolio sensitivity analysis.....	101

CHAPTER 1: INTRODUCTION AND BACKGROUND

1.1 MOTIVATION

Electricity is the most important energy carrier in modern life, enabling the comfortable, healthy, and prosperous life enjoyed by people in the United States. Along with these benefits, however, come the undesirable environmental externalities associated with electricity production, including air and water pollution and solid waste. A major negative externality associated with the electricity sector are greenhouse gas (GHG) emissions; the electricity sector is responsible for 35% of US GHG emissions each year. (Environmental Protection Agency, 2012) GHG emissions are responsible for climate change, which is expected to have major impacts on the Earth's systems, including but not limited to drought, species extinction, sea level rise, increased frequency of severe weather events and ocean acidification. These impacts are projected to cause significant disruption to human welfare (IPCC 2007)

The Intergovernmental Panel on Climate Change recommends cutting emissions to 80% below 1990 levels by 2050 in order to keep climate change to a "safe" level. (IPCC 2007) The question of how much emissions abatement each country should be responsible for is a difficult one, and depends on one's opinion of whether countries should be responsible for their historic emissions or just current emissions and whether

the developed countries, should bear more of the burden than developing countries. In the US, a National Research Council report suggested that an appropriate cumulative emissions target (2012-2050) for the US would be 170-200 Gt/CO₂e (a 33-45% reduction below projected business-as-usual (BAU) emissions¹). (America's Climate Choices Panel on Limiting the Magnitude of Climate Change 2010) The emissions profile required by America's Clean Energy and Security Act (ACES; Waxman & Markey 2009) would have limited cumulative emissions over the same period to 240 Gt/CO₂e (a 20% reduction below projected BAU emissions). (Environmental Protection Agency, 2009)

Several studies have shown that the electricity sector will have to bear more than an equal share of the burden of decarbonization. In its analysis of ACES the EPA found that the electricity sector would be responsible for about 85% of cumulative abatement (equivalent to reducing cumulative electricity emissions by 50 Gt/CO₂e) under the bill. (Environmental Protection Agency, 2009) Two other studies have found that meeting California's goal of reducing emissions to 80% below 1990 levels will require not only decarbonizing the existing electricity grid (to 0.025 kg CO₂e/kWh), but also a massive electrification program that will require additional low-carbon electricity sources. (J. H. Williams et al. 2012; Long & John 2011) Achieving these large emissions reductions from the electricity sector will require an enormous change in the technology mix of U.S. generating capacity. (K. C. Johnson 2010; Morgan et al. 2005; J. H. Williams et al. 2012)

Reducing carbon dioxide emissions from the electric power sector requires a sustained commitment to new capacity construction: society is likely to have to maintain a high annual build rate of new capacity for decades. However, there may be physical constraints on the rate at which electricity infrastructure can be built (Kramer & Haigh

¹ The EPA (2009) estimates that BAU cumulative emissions from 2012-2050 are ~300 Gt/CO₂e.

2009; America's Energy Future Panel on Electricity from Renewable Resources 2010). Kramer and Haigh (2009) have argued that there are empirical limits to the build rate for new electricity technologies, which may limit the potential for climate change mitigation from the electricity sector. These limits are a function of the inertia inherent to the electricity sector, which is largely driven by the longevity of electricity infrastructure. Even if the US overcomes the challenge of designing and implementing a carbon reduction policy, there will be specific challenges limiting the possible build rate for new capacity including: large investment costs, long construction lead times due to permitting and regulation, and global competition for skilled labor, materials, and resources.

Because the build rate of new electricity generating capacity may be limited, the timing of regulation is critical—the longer the U.S. waits to start reducing GHG emissions, the faster the turnover in the electricity sector must occur in order to meet the same target. There is a real, and thus far unexplored, possibility that the U.S. could delay climate change policy implementation for long enough that it becomes infeasible to attain the necessary rate of turnover in the electricity sector. This is a particularly acute problem in the current political climate (2010-2012), which seems unlikely to lead to climate change regulation in the near future.

This dissertation investigates the relationship between climate policy timing and infrastructure turnover in the electricity sector. The goal of the dissertation is to answer the question: How long can we wait before constraints on infrastructure turnover in the electricity sector make achieving our climate goals impossible? In order to answer this question, the dissertation explores six themes: how policy timing affects infrastructure turnover in the electricity sector; how policy timing affects premature retirements in the electricity sector; the “infeasibility frontier” (those combinations of climate targets and

policy timing that are impossible to achieve); regional variation; the sensitivity of infrastructure turnover to fuel prices, regional aggregation, and demand; and policy interventions that could “buy time”, or increase the period of time before climate targets become impossible to achieve. For all of these themes, this dissertation explores a range of climate targets and policy timing options, in the hopes of contributing to the national conversation about the urgency of climate change mitigation.

1.2 DISSERTATION OVERVIEW AND RESEARCH QUESTIONS

This dissertation asks the following fundamental question: how long can we wait to start reducing GHG emissions before the changes required in the electricity sector become impossible to achieve? There are many approaches to answering this question, each of which has been treated as a theme with associated research questions. The first four themes are answered in Chapter 3, while themes 5 and 6 are addressed in Chapter 4. Chapter 2 describes the model, and Chapter 5 offers some final thoughts.

The following themes and supporting research questions will be addressed:

1. INFRASTRUCTURE TURNOVER

- a. How does infrastructure turnover (construction and retirements) change as climate change policy is delayed?
- b. Is the relationship between policy timing and infrastructure turnover dependent on the level of emissions reductions?
- c. What capital costs are associated with infrastructure turnover?

2. PREMATURE RETIREMENT

- a. Does delaying the implementation of climate change policy cause existing power plants to retire prematurely?
- b. Does the level of emissions reductions affect the relationship between timing and premature retirement?
- c. What stranded costs are associated with premature retirement of existing units?

3. INFEASIBILITY FRONTIER

- a. Is it possible to wait so long that achieving a particular emissions target is infeasible? What does this frontier look like?

4. REGIONAL VARIATION

- a. How do Themes 1-3 vary by region?

5. SENSITIVITY TO MODEL PARAMETERS

- a. How does the price of fuel affect the answers to Themes 1-3?

- b. How does the amount of gas needed to balance the variability from wind power production affect the answers to Themes 1-3?

6. POLICY INTERVENTIONS

- a. How does demand growth affect the answers to Themes 1-3? Can a policy that encourages increased energy efficiency reduce the impact of delaying emissions reductions?
- b. Can a policy of only building low-carbon generating capacity in the period before emissions reductions start improve the answers to Themes 1-3? Conversely, does building carbon-intensive generating capacity in the period before emissions reductions start adversely affect the answers to Themes 1-3?
- c. How does the choice of fuel mix of low carbon generating capacity affect Themes 1-3? How would a policy encouraging nuclear, wind or gas generation affect the electricity sector's response to delaying climate policy?

1.3 BACKGROUND

This section discusses some of the relevant background to this dissertation: a discussion of the US electricity sector and its contribution to climate change; an introduction to the literature about the optimal timing of climate change mitigation; and a summary of the literature that identifies which technological pathways can be used to achieve climate change mitigation. Section 2.1 in Chapter 2 provides background specific to electricity sector modeling.

1.3.1 The US Electricity Sector and Climate Change

While there is not yet a federal climate policy, the EPA is in the process of regulating greenhouse gas (GHG) emissions under the Clean Air Act, including those from power plants. The EPA has proposed a regulation requiring that all new electricity generating units meet an emissions standard of 454 kg CO₂e/MWh of generation (EPA 2010b); the current average emissions intensity in the US is 675 kg CO₂e/MWh. ¹⁰ In the past, Congress has considered regulations to limit GHG emissions (e.g., America's Clean Energy Security Act, in 2009), although a bill has yet to make it past both houses of Congress. Some states are also acting to limit GHG emissions, either directly or as a side effect from policies such as Renewable Portfolio Standards. California's AB32 requires the state to reduce emissions to 1990 levels by 2020 and includes a cap-and-trade program. (CARB 2008) Several states are also developing voluntary regional agreements with GHG emissions reductions goals, such as the Regional Greenhouse Gas Initiative in the Northeast, which caps emissions from power plants under a cap-and-

trade. (RGGI 2008) Conforming with any of these regulations will require some level of change in the electricity sector, which has evolved without concern for GHG emissions.

The fleet of electricity generating units in the United States consists of approximately 5500 individual power plants, totaling about 1000 GW of nameplate capacity. (EPA 2012a) These units produce about 4,000 TWh of electricity each year, of which approximately 40% comes from coal, 30% from natural gas, 20% from nuclear, and the remaining 10% from all other fuel sources (Figure 1-1). (Energy Information Agency 2013)

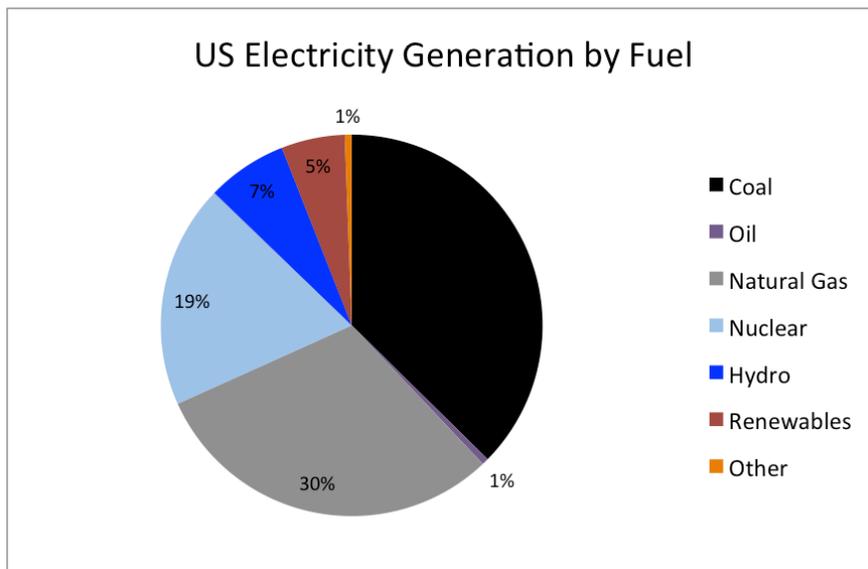


Figure 1-1 US electricity generation by fuel source. Total US electricity generation was ~4,000 GWh in 2012. Data from (Energy Information Agency 2013).

Figure 1-2 shows the US fleet of installed generating capacity, by fuel type and vintage. In terms of installed capacity, the US fleet is approximately 45% natural gas plants, 30% coal plants, 10% nuclear plants, 8% hydropower, and 4% renewables. Most generating

capacity, especially the coal and nuclear units that provide most of our electricity generation, was constructed during the period between 1965-1985. The last decade has been a boom period for natural gas, with 200 GW of new natural gas capacity installed during the years 2000-2005. The last decade has also seen rapid growth in the amount of wind capacity installed—the amount of installed wind capacity in the US increased by a factor of 15 between 2000 and 2012, though it still only accounts for 3.5% of installed capacity.

The electricity sector is responsible for 35% of US GHG emissions, and this share has been relatively constant over the last two decades. (Environmental Protection Agency, 2012) US emissions have grown since 1990, however, and absolute emissions from the electricity sector have grown approximately 20% since 1990. (Environmental Protection Agency, 2012) Emissions from the electricity sector are projected to grow 8% over the period 2012-2040. (U S Energy Information Administration 2011) Projected future growth rates in GHG emissions are slower than in previous decades due in part to the reduction in emissions during the Great Recession.

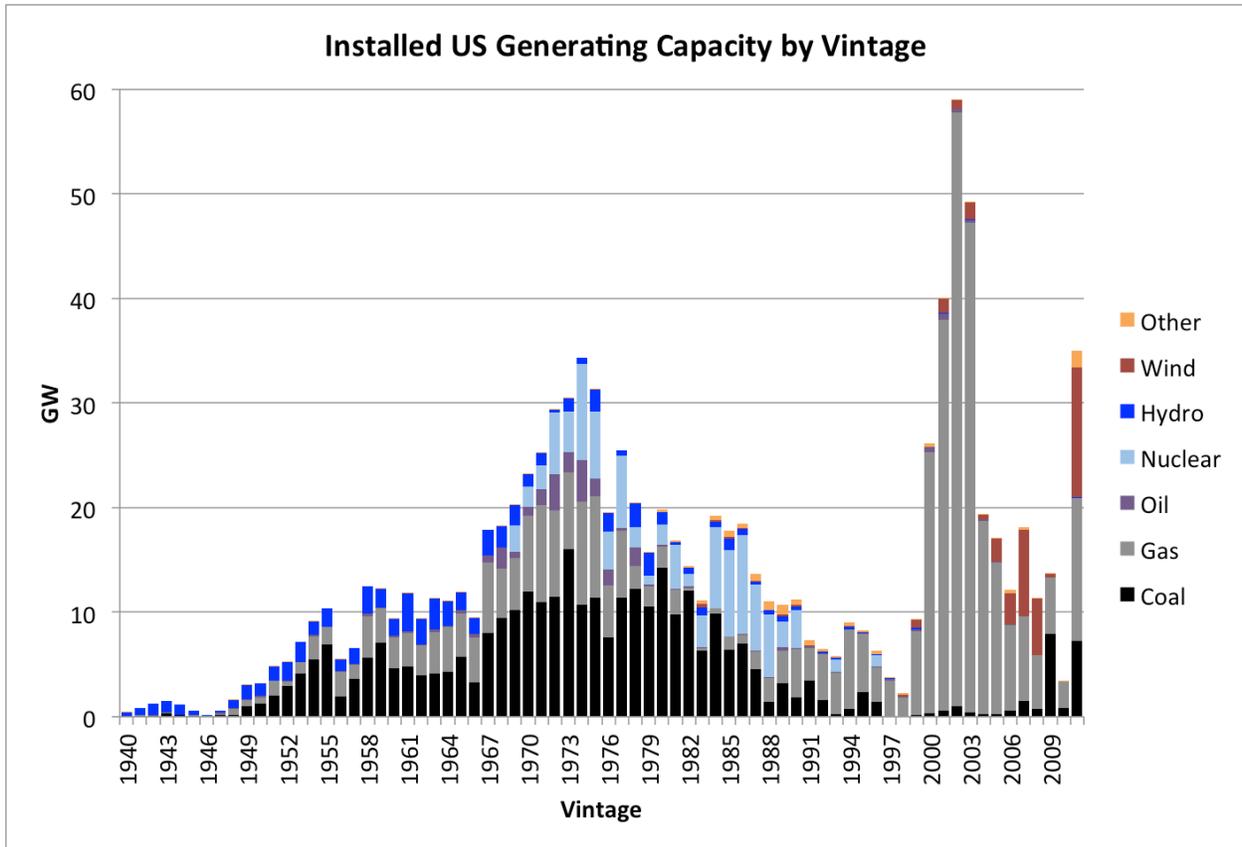


Figure 1-2 Installed US generating capacity, by fuel type and vintage year. Data from (EPA 2012a).

1.3.2 Optimal Timing of Climate Change Mitigation

There is a significant body of literature using integrated assessment models to optimize greenhouse gas reduction pathways. The central question is whether it is more

efficient to mitigate GHG reductions now, or whether (for any number of reasons) it is more efficient to continue emitting as usual now, and then engage in more severe mitigation (or a combination of mitigation, adaptation, and/or geoengineering) in the future. The literature has found an enormous variety of “optimal” mitigation pathways, some arguing for strong, immediate action (e.g. Stern 2007) and some arguing for a “wait and see” approach (e.g. Nordhaus 1999) This variation is due almost entirely to the choice of modeling decisions. (Heal 2009) Some of these modeling choices are technical, such as whether the model includes inertia, uncertainty and/or technological learning. Grubb (1997) discusses how while technological learning will bring down future costs, this is not a reason to delay mitigation, since technological learning will not happen without investment. Grubb also points out the importance of systemic, multi-decadal inertia in the socio-economic system, which is incapable of responding quickly to mitigation efforts. Several studies have shown that if the ultimate emissions target is uncertain, it is optimal to hedge by reducing emissions in the near-term as compared to if the final emissions target is deterministic. (e.g. Bosetti et al. 2009; Kandlikar & Morel 2008; Ha-Duong et al. 1997; Yohe et al. 2004) Yohe (2004) found that not only is it economically optimal to hedge when the final emissions target is unknown, but that not hedging can make some long-term emissions levels infeasible. Ha-Duong et al (Ha-Duong et al. 1997) emphasized that the optimal path is more sensitive to inertia in the technological system than with a deterministic emissions target.

While these modeling decisions reflect technical decisions on the modeler’s part, other crucial assumptions reflect an ethical viewpoint, and can determine whether a model’s optimal emissions profile is “act-now” or “wait and see”. Heal (2009) summarizes the recent debate on this point. He argues that five assumptions determine the outcome of a model: 1. Cost of climate change impacts; 2. Pure rate of time

preference; 3. Elasticity of marginal utility of consumption; 4. Whether the model includes consumption of ecosystem services; and 5. Whether the model includes uncertainty in the impacts and the probability of a “fat tail” in the damage function. Heal argues that an ethically defensible choice for any one or two of these assumptions is enough to motivate immediate action and that therefore, this part of the debate is settled.

More recently, a body of work has developed calculating the tradeoffs between current and future emissions on a global scale. Mignone et al (2008) showed that there is a tradeoff between when mitigation starts and the rate of future emissions reductions. Assuming a maximum reduction of 1% per year, every year of delay increases peak atmospheric concentration by 9 ppm. Meinshausen (Meinshausen et al. 2009) approached the same problem a little differently, calculating the cumulative amount of GHG emissions allowable by 2050 in order to have a less than 25% probability of exceeding a 2°C temperature increase. Stocker (2013) calculated the contours of warming given a reduction rate (percent reductions per year) and a starting year. For example, limiting warming to 2°C would require a reduction rate of 3.2% per year starting in 2020, which more than doubles if reductions do not start until 2035.

1.3.3 Pathways to Achieving Emissions Reductions

A second body of literature looks for technological pathways to attain these “optimal” mitigation scenarios and asks whether they are feasible. Most of these studies use an

emission profile consistent with the IPCC target emissions profile (IPCC 2007). These studies often take a more bottom-up approach, starting with existing infrastructure and working within resource constraints to find feasible emissions reduction pathways. This literature started with Wigley et al. (1996) who pointed out that the key concern is the total amount of GHGs emitted, and therefore there can be any number of mitigation pathways. Hoffert et al (1998; 2002) built on this work to calculate the amount of zero-carbon energy sources that must exist in 2100 to meet both emissions and economic development scenarios. In their famous “wedges” paper, Pacala and Socolow (2004) identified a suite of 15 strategies, all available for immediate deployment, that could each reduce cumulative emissions from 2004-2054 by 25 GtC. Pacala and Socolow estimated that if society implemented seven such wedges we could stabilize CO₂ concentrations at 500ppm.

Several such analyses have been done on the regional level. Long (2011) and Williams (2012) both identify pathways by which California can meet its goals of 80% emissions reductions by 2050, primarily via aggressive efficiency gains, large scale electrification and decarbonization of the electricity grid. Olabisi et al. (2009) find similar results for Minnesota, as do Johnson and Chertow (2009) for Hawaii Island.

The models discussed above are purely physical models, estimating emissions profiles without modeling the techno-economic details associated with them. However, several groups have extended this kind of physical analysis to include technological and economic aspects. Bossetti (Bosetti et al. 2009) uses a hybrid integrated assessment model to identify both the optimal stabilization pathway and the associated optimal technology portfolio for mitigation under an uncertain final emissions target. O’Neil et al (2010) also use an integrated assessment model to quantify the importance of mid-

century targets in determining the technological feasibility of end-century emissions targets. They find that for every 2100 goal, there is both an optimal 2050 emissions level and a 2050 emissions threshold beyond which the 2100 goal is technologically infeasible.

CHAPTER 2: INTEGRATED INFRASTRUCTURE FLOW ANALYSIS MODEL

The Integrated Infrastructure Flow Analysis Model (IFAM) models the dispatch, generation, emissions, retirements, and construction in the US electricity sector. IFAM is designed to examine how the stock of electricity generating capacity in the U.S. would respond to climate change policy over a period of several decades. While IFAM was specifically intended to examine the impact of climate change policy timing on infrastructure turnover, IFAM could be easily modified to look at other pollution prevention policies, such as the new EPA regulations on hazardous materials and conventional air pollutants (e.g. the Cross State Air Pollution Rule (EPA 2011) and the Mercury and Air Toxics Standard (EPA 2012b)).

This chapter describes IFAM's methods and data. Section 2.1 discusses existing models of the electricity sector and puts IFAM in context. Sections 2.2 and 2.3 explain the model approach and implementation. Section 2.4 describes the data, and Section 2.5 describes the model initialization, calibration, and validation.

2.1 EXISTING MODELS OF THE ELECTRICITY SECTOR

There are a number of models that are designed to examine the impact of policy on the electricity sector. These models are designed to be fully representative of the

electricity sector, and can be used to predict the impact of many kinds of policy— transportation, climate change, deregulation, taxation, etc. Some, like the National Energy Modeling System (NEMS) (DOE & EIA 2009), are country specific. Others, like Market Allocation (MARKAL) (Loulou et al. 2004), are designed to take regional specifications as inputs and can be used for any region. Some of these models are much broader than just the electricity sector, and include modules that represent technical and economic characteristics of the entire energy sector at a national or international level, and are sometimes linked to a broader macro-economic module. The electricity sector itself is represented to varying degrees of detail.

These large energy/economic models are usually computable general equilibrium (CGE) or partial equilibrium (PE) optimization models. Due to their size and complexity, they often require advanced computing resources and/or the purchase of proprietary software. Furthermore, they often have to sacrifice resolution (both temporal and spatial) for computing efficiency. For example, NEMS runs for a model period of only 30 years. (DOE & EIA 2009) EPA-IPM runs for 50 years but only in 5-year increments. (EPA 2010a) All of the large energy/economic models combine existing generating units into so-called “aggregate plants” in order to reduce the number of variables, which prevents those models from examining the impact of policy on a sub-regional level or on specific existing plants. A final downside to using large energy/economic models is that their complexity, lack of transparency, and impossibility of validation makes it very difficult to understand intuitively how the electricity sector responds to external policy. (DeCarolis et al. 2012; Craig et al. 2002)

Other researchers have taken a different approach to electricity sector modeling, developing smaller scale models to evaluate specific policy problems. These models often, but not exclusively, use an economic-dispatch framework to simulate behavior in

the electricity sector. For example, Newcomer and Apt (2009) examine what would happen in the jurisdictions of three system operators if the construction of new power plants were forbidden. Newcomer et al (2008) looks at the impact of a carbon tax in the short run (before utilities respond by building new units). The Electric Power Research Institute's (EPRI 2007a; 2008a; 2007b) CO₂ Framework divides the United States into five regions and uses an economic-dispatch framework to model the response of the electricity sector to a national carbon price. While these smaller models provide the reproducibility, transparency, and specificity that larger models lack, they are generally limited in their geographic and/or temporal scope.

This work employs a hybrid approach between the large-scale models for the U.S. electricity sector and local or regional models. IFAM is an economic-dispatch based simulation model with the geographic and temporal scope of the larger optimization models. This allows IFAM to combine some of the features of both types of models. IFAM's smaller size allows IFAM to model every currently existing generating unit in the US, rather than the aggregated model plants that are used in larger energy/economic models. This gives IFAM the ability to perform detailed analysis of the regional and local effects of regulation, such as examining the likelihood of plant closure and the associated impact on local jobs.

It should be noted that IFAM is a simulation model, not a CGE/PE or optimization model—IFAM does not calculate the least-cost energy mix or find the socially optimal investment levels for mitigating GHG emissions. Instead, IFAM was designed to be simple and transparent enough to allow an intuitive understanding of how the electricity industry might respond to policy levers. The disadvantages of optimization models for applications like this have been well documented (Craig et al. 2002; DeCarolus et al. 2012; J. H. Williams et al. 2012). In particular, the uncertainty of the parameters

required for an optimization model (fuel prices, economic parameters, technology availability, behavioral responses, etc) is such that we feel that it is more useful to explore the decision-space using scenario analysis, which allows a much clearer understanding of the relationship between scenario input and result.

Following is a non-exhaustive discussion of several of the major existing models of the electricity sector as well as some smaller models. The key features of the models are summarized in Table 2-1.

Table 2-1 Important model features of several of major energy models

Model	Scope	Algorithm resolution	Policy Angle	Transmission Constraints	Model Type	Regions	Fuel Prices	Planning Horizon
NEMS	Energy Sector	Sequential	General	Y	Forecast/Iterative	Varies by module	Endogenous	2035
MARKAL	Energy Sector	Simultaneous	General	N?	Intertemporal PE**	Varies by module	Endogenous	-
EPA-IPM	Electricity Sector	Simultaneous	General	Y	Dynamic LP**	32	Endogenous	2050
Haiku	Electricity Sector	Simultaneous	Deregulation; Airborne pollution prevention	Y	Intertemporal PE**	21	Endogenous	2030
IFAM (this study)	Electricity Sector	Sequential	Pollution prevention	N	Forecast	3+	Exogenous	2050

*Note, Prism is not included since it is not yet published

**PE=Partial Equilibrium; LP=Linear Programming

2.1.1 Energy-Economic Models

2.1.1.1 National Energy Modeling System (NEMS)

NEMS is the energy/economic model used by the U.S. Energy Information Administration (EIA) to generate the Annual Energy Outlook (AEO) forecasts. NEMS is primarily used by government agencies, although ~1500 journal papers using NEMS have been published in the literature (estimated using a Google Scholar search). NEMS is a technology-rich integrated equilibrium model of the U.S. energy sector (with less detailed representation of global markets). (DOE & EIA 2009) The model has regional resolution, a 25-year time horizon, and projects U.S. energy production, consumption, imports, conversion, and prices subject to macroeconomic factors, world energy markets, resource availability and costs, behavioral and technological decision-making, technology cost and performance, and demographics. The baseline version of NEMS incorporates existing federal, state, and local regulations and is updated annually. NEMS is often used by the EIA to predict the effects of proposed regulations.

There are 12 separate modules to NEMS, plus one integrating module. The four demand modules (residential, commercial, industrial, transportation), two conversion modules (electricity market and petroleum market), and four supply modules (oil and gas, natural gas transmission and distribution, coal, and renewable fuels) modules are executed iteratively until end-use prices and quantities converge. A macroeconomic

activity module and an international energy module are also iterated to include international and economic feedback interactions with the energy system.

The electricity market module of NEMS uses linear-programming to dispatch generating capacity to meet load at the minimum cost, subject to technical, transmission, and emissions constraints. Electricity prices are determined on a regional level using either cost-of-service or competitive pricing, depending on whether the region is regulated or restructured. Generating capacity is retired when both the expected revenue from an individual plant is less than going-forward costs (fuel plus operation and maintenance) and building replacement capacity reduces the overall cost of electricity. New capacity is built as needed to meet expected future demand. The type of new facility is determined by finding the lowest-cost technology available that meets the expected utilization (base- or peak-load), timing, construction, and operating constraints for the new generating unit.

As NEMS is used for all types of analyses of the energy sector and for forecasting, there is no specific “result” from the model.

2.1.1.2 MARKet ALlocation (MARKAL)

MARKAL (Loulou et al. 2004; Shay et al. 2007) is a technologically rich, multi-regional partial equilibrium model of the energy system. MARKAL is more widely used in academia than NEMS, with about 5700 papers. The user inputs end-use demand estimates, the existing stock of energy equipment, the characteristics of future technologies, and energy supply resources. MARKAL then optimizes the energy supply

to maximize total surplus (minimize total cost), subject to system constraints, by making regional investment and operating decisions. MARKAL is a multi-period model, and total surplus is maximized over the entire time horizon. MARKAL assumes price elastic demands, competitive markets, and perfect foresight.

The electricity sector is modeled using six time slices per year (night/day; summer/winter/shoulder). Electricity capacity can be designated as baseload, in which case it is constrained to run 100% of the time it is not down for maintenance. All plants can also carry a designated “peak load” capacity, which is held in reserve except for when needed to meet peak load. Electricity capacity is also defined as centralized or decentralized. Only centralized plants incur transmission losses, although both types incur distribution costs.

MARKAL has additional options beyond the standard module that include damage costs, lumpy investments, endogenous technological learning, and stochastic programming (to relax the assumption of perfect foresight by allowing agents to assign probabilities to future events). The MARKAL-MACRO extension combines MARKAL with a single producing sector general equilibrium model of the broader economy.

As with NEMS, because MARKAL is used for all types of analyses of the energy sector and for forecasting there is no specific “result” from the model.

2.1.1.3 Environmental Protection Agency Integrated Planning Model (EPA-IPM)

Unlike NEMS or MARKAL which represent the entire energy sector, EPA-IPM is a model of the US electricity sector only. (EPA 2010a) EPA-IPM is rarely used in academia,

although it is often used for agency regulatory analysis. It has a richer depiction of the technological features of the electricity sector than many other models. EPA-IPM uses a dynamic, deterministic linear program to minimize the cost of meeting U.S. electricity demand over the planning horizon subject to operational and environmental constraints. The model solves for the optimal generation mix, capacity expansion, inter-regional transmission, emissions allowances, and fuel quantity and qualities in each of the 23 model regions. EPA-IPM has the capacity to model various pollution-prevention regulations, including cap-and-trade, command-and-control, and renewable portfolio standards. Regional and seasonal variation of regulations is possible.

In EPA-IPM, the US electricity generating fleet is represented using 4,738 aggregated “model plants” that correspond to groups of existing plants with similar characteristics. Model plants can be either retired or retrofitted as necessary to meet system constraints at the least cost. New units are constructed to meet demand as needed, subject to regional and cost constraints. EPA-IPM uses a region-specific, two season, six-step piecewise representation of demand. Within regions, capacity is economically dispatched subject to plant operating constraints. Inter-regional trade is allowed subject to transmission capacity constraints.

EPA-IPM has detailed representation of operating constraints in the electricity sector. Power plant availability (including both scheduled maintenance and forced outages) is used to specify an upper bound on generation for each unit. Generation by renewable technologies (hydro, wind, and solar) is constrained by seasonally and regionally variable capacity factors. Turndown and ramping constraints are addressed by requiring steam units produce a minimum of 50% (coal) or 25% (oil/gas) of their capacity during base/mid load periods to prevent being used as strictly peaking units.

EPA-IPM also requires the system to maintain regionally specific reserve margins, which are defined using availability-weighted capacity available above peak demand.

While EPA-IPM is specifically devoted to analysis of the electricity sector (unlike NEMS and MARKAL, which address the entire energy sector), it shares the broad applicability of those models.

2.1.1.4 HAIKU

Haiku was developed by Resources for the Future (RFF) (Paul et al. 2009) to analyze policies that address either airborne pollutants from the electricity sector and/or reforms to the structure of the electricity market. (Paul et al. 2009) Haiku is less commonly used than other models, with about 200 publications. Haiku finds the equilibrium solution across 21 regions for all model years simultaneously, assuming perfect foresight for the following variables: electricity prices, demand, generation, and reserve; generating capacity; fuel consumption; interregional trade; pollution control capacity; emissions (NO_x, SO_x, Hg, CO₂); emissions allowances; and economic surplus.

Existing capacity in the US is aggregated into model plants representing generation technologies with similar operating characteristics in each region. Investment and retirement decisions are made by adjusting the marginal capacity of each of these model plants. Retirements occur when the going forward profits (excluding capital costs, which are sunk for existing plants) for a plant are negative in the current year and the Net Present Value (NPV) of going forward profits are negative over the remaining planning horizon. Similarly, investments in new capacity occur when going forward profits

(including amortized capital costs for new plants) are positive both in the current year and the NPV of the remaining planning horizon. Equilibrium fuel prices are found using supply curves. Demand is modeled regionally for four load blocks in each of three seasons, and is price responsive in three demand classes (residential, commercial, and industrial).

In order to account for a number of features of the electricity market that Haiku does not address (including transmission constraints below the regional level; local laws and regulation; and details of generator and system operation) Haiku is calibrated to the U.S. Energy Information Administration's Annual Energy Outlook. (U S Energy Information Administration 2011) The operational mode for Haiku is a "delta analysis": Haiku generates output comparing a given policy scenario to a baseline scenario. This helps mitigate the impact of factors that are not included in the model.

HAIKU is similar to EPA-IPM in its scope—electricity sector only—and it was specifically designed to analyze policies pertaining to deregulation and airborne pollution prevention.

2.1.2 Other models

While the above models are representations of the entire electricity (or energy) sector designed for flexible analysis of many types of questions, The Electric Power Research Institute (EPRI) has developed several small models that specifically address the question of climate change. These models are rarely used outside of EPRI, and Prism 2.0 is still in development as of the winter of 2012.

2.1.2.1 Electric Power Research Institute's CO₂ Framework

The CO₂ Framework uses a company-level decision-making framework to model the response of the electricity sector to a CO₂ price. (EPRI 2007a; EPRI 2008a; EPRI 2007b)

The model divides the nation into 5 regions that are treated separately. Every year, a dispatch curve of existing capacity is created in each region. This is then used with load information to determine the price of electricity and identify which plants produce, how much they produce, and what their revenues are. This process is repeated annually.

Plants that whose revenues do not exceed costs for five years are retired. New generation is constructed when revenue is expected to cover capital costs. The type of new construction is selected by minimizing the total costs to the system, subject to exogenous constraints on the introduction of nuclear, renewables and CCS coal. Consumer demand is modeled with an elasticity of -0.5.

The CO₂ Framework model can be used to estimate the effects of a CO₂ price on the emissions, production, and technology portfolios in the electricity sector. It can also be used to calculate the amount of new construction that would be stimulated by a CO₂ price. The model can also be used in reverse, to calculate the CO₂ price needed to produce certain emissions levels. In general, a CO₂ price results in lower emissions due to: different generation mixes, re-dispatch of existing generation, and consumer price response. Consumer price response is a major factor leading to emissions reductions. To meet current policy goals, electricity prices would be about 50% higher than the base case. The results are very sensitive to the availability of nuclear and CCS—without those

technologies, emissions reductions are limited due to higher use of coal and gas. Results are also sensitive to the cost of construction, load growth, and natural gas prices.

2.1.2.2 EPRI's MERGE & PRISM

This analysis uses two models, the Prism analysis and the Model for Estimating the Regional and Global Effects of GHG reductions (MERGE). (EPRI 2008b; EPRI & James 2009; EPRI 2009; Manne & Richels 2004)The Prism model is a bottom-up estimate of the maximum GHG reduction potential available from the electricity sector under (almost) best-case scenario assumptions for technology development and deployment. It assumes significant GHG reductions from: end use efficiency (6.5% CO₂ reductions below 2005 levels); transmission and distribution efficiency (0.9%); increased nuclear (11%); increased non-hydro renewables (13%); fossil fuel efficiency (3.7%); CCS (11%); PHEVs (9.3%); and electro-technologies (switching from primary fuel to electricity; 6.5%).

MERGE is a global general equilibrium model that “analyse[s] the cost of CO₂ emissions mitigation as a function of technology cost, availability, and performance.” Price response is a top-down production function, while the energy sector is modeled with a bottom-up model defining separate technologies for each source of energy-related emissions. The model identifies the least-cost technology portfolio needed to meet demand—reductions are allocated across the entire economy, not just the electricity sector. There are a number of technology, resource availability, and policy constraints (ie limits on nuclear etc). Technological R&D seems to be exogenous. MERGE can model

both market and non-market damages from climate change, although it is not clear if damages are included in EPRI's analysis.

The Prism analysis finds that if all available electricity sector options are pursued, emissions can be reduced by 41% relative to 2005 by 2030. If PHEVs and electro-technology fuel switching are also deployed, emissions reductions can be increased to 58% below 2005 levels. The MERGE analysis finds that the optimal electricity mix in 2050 relies heavily on demand reduction, renewables, CCS, and nuclear to meet emissions caps. The limited portfolio is \$1 trillion more expensive than the full scenario, due to increased wholesale electricity, natural gas, and CO₂ permit prices.

Overall, the Prism/MERGE analysis concludes that efficient decarbonization of the US economy requires: advanced distribution systems (to enable demand reductions and PHEVs); advanced transmission systems (to enable high renewable penetration); deployment of lots of nuclear power generation (including R&D in new technology and extending the life of existing capacity); and CCS coal (mostly R&D).

EPRI is currently working on Prism 2.0, which regionalizes the Prism model. (la Chesnaye 2010; Hannegan 2010) The regional formulation incorporates improved treatment of renewable energy (with region-specific resource constraints for wind, CCS, etc), expanded demand-side detail, and all of the new EPA environmental regulations (new NO_x and SO_x, Hg, coal ash, and cooling water rules). When complete, the electricity sector process model will be integrated with MERGE (a GE macro model). The resulting model will minimize total cost of the electricity system over decision variables of plant retirement, retrofit, or new build, subject to CO₂ emissions and other system constraints.

Prism includes a database of existing capacity at a unit level (and makes decisions at a unit level also). When looking forward over long time scales, the model uses 5 year

time steps and aggregates generation into representative units in each region. Over shorter times scales, such as a year or a week, the model can be run on the unit level to look at issues of intermittency and cycling. Electricity demand is deterministic and divided into 50 time slices each year. Investment decisions are made with perfect foresight, and there is a delay between investment and capacity coming on line to account for construction. When complete, the model will also consider demand-side reductions as a “negawatt” investment.

2.2 IFAM MODEL STRUCTURE

IFAM is a capacity model of the U.S. electricity sector. It is specifically designed to simulate how the timing of climate change policy imposed by the federal government affects stocks and flows (construction, retirements, and existing units) of generating capacity. Table 2-1 compares IFAM to previously discussed electricity models. IFAM takes a user-defined policy scenario for Greenhouse Gas (GHG) emissions reductions and estimates how electricity generating capacity responds (retirements and new construction) to that policy over the model time horizon (2014-2050) assuming that the policy takes effect in 2014. This analysis is then repeated for every “policy starting year” (PSY) over the period 2014-2040 to examine the impact of policy timing. IFAM uses economic dispatch to meet consumer demand for electricity, subject to plant operating constraints and emissions constraints. IFAM retires uneconomic generating units and builds new capacity as needed according to a user-specified Generation Portfolio Standard (GPS). IFAM can be configured to run at several levels of regional

aggregation: the national level, interconnect level, and National Electricity Reliability Council (NERC) region level. There are eight NERC regions in the US, shown in Table 2-2. It is relatively straightforward to change the geographic resolution of the model to any level by modifying the input data and look-up tables.

Table 2-2 NERC regions

NERC Region	Geographic Region
ERCOT	Texas
FRCC	Florida
MRO	Western Midwest
NPCC	New England, New York
RFC	Mid-Atlantic, Eastern Midwest
SERC	Southeast
SPP	Oklahoma, Kansas
WECC	West of the Rockies

IFAM is implemented in Matlab 2011 using an object-oriented framework. Every generating unit in the United States is characterized as an object of the Generating Unit class, which contains information on the financial and technical characteristics, operation, emissions, and retirement status of the unit. Generating Unit objects are populated via a series of look-up methods, which query separate storage objects ('oracles') that store scenario- and region-specific data. An object of the System Operator class is responsible for dispatching generating units to meet demand and emissions constraints and for building and retiring generating units.

There are two implementations of IFAM for use depending on the size of the region of interest. For smaller regions, with approximately 7000 or fewer initial generating units, the model is parallelized within Matlab to run on a four-core, 2 GHz desktop computer. Each scenario takes several hours (this varies depending on the size

of the region). For very large regions (the Eastern Interconnect or the whole U.S.), it is preferable to run IFAM on a larger cluster (ideally, 18 cores are used). IFAM has thus been implemented as a stand-alone program for use on parallel computing networks without Matlab using the Matlab Compiler Runtime engine. The stand-alone version of IFAM can run a single scenario for a large region in a few hours on a cluster of 24 dual-quad-core Xeon (E5600) computers.

2.2.1 User Defined Inputs

IFAM requires the user to input several scenario parameters for each model run of a master scenario. These are designed to enable easy sensitivity analysis of important model variables and policy designs.

Region: IFAM is enabled to run at three levels of regional aggregation: the national level, the interconnect level (Eastern, Western, and ERCOT), and the NERC-region level. IFAM stores the following region specific data, which is endogenously accessed by the model: Business-as-usual (BAU) Generating Portfolio Standard (GPS); existing units database; reserve margin; load profile; demand growth rate; and wind capacity factors.

Demand Scenario: The rate of demand growth in each region is constant over the model period and can be modified for different scenarios.

Fuel Price Scenario: Eight fuels are assigned non-zero prices in IFAM (biomass, bituminous coal, lignite coal, subbituminous coal, distillate fuel oil, natural gas, petroleum coke, and nuclear). Section 2.4.2 describes fuel assumptions in more detail. These prices are in 2012 dollars and remain fixed over the duration of the model run.

Emissions Scenario: Two possibilities are currently enabled for the shape of the emissions curve modeled in IFAM: linear and cumulative. In the linear scenario, emissions decrease linearly from the emissions reduction start year to the 2050 target goal. In the cumulative emissions scenario, the model assumes a fixed cumulative emissions cap over the period 2014-2050. Once emissions reductions start, emissions decline linearly at a rate such that the cumulative emissions over the period 2014-2050 do not exceed the total cap. See Section 2.3.4 for more detail on this calculation.

Emissions Reduction Target: Because global temperature increases are insensitive to the emissions pathway (Allen et al. 2009) the most useful metric for discussing climate change emissions is the total amount of GHGs accumulated in the atmosphere (Meinshausen et al. 2009; Arora et al. 2011; Matthews et al. 2009; Allen et al. 2009).

Because the allocation of a carbon budget between countries is a morally and politically difficult question, IFA operates by setting emissions reduction targets as a function of the region's projected BAU emissions. This provides a neutral way for the user to explore the impact of a particular emission target across regions. Thus, the user specifies a target emissions reduction (in percent) below the BAU scenario. In the case of cumulative emissions reduction scenario, this is the percent reduction in cumulative emissions between 2012-2050 as compared to projected cumulative BAU emissions over

the same period. In the case of linear reductions, this is the percent reduction below projected BAU emissions in 2050.

Gas/Wind Generation Ratio: This is the ratio of gas-to-wind generation that is required in order to provide firm wind power (i.e., if the gas/wind generation ration is 20%, when is 1 MWh of firm wind generation is produced, it is comprised of .8MWh of wind power and .2MWh of gas power). This parameter allows a sensitivity analysis on the emissions associated with producing firm wind power. See Section 0 for more discussion of the gas/wind ratio.

Turndown Constraints: Turndown constraints are the amount of maximum capacity that steam boilers must use at all times in order to preserve the ability to ramp up production quickly. The use of turndown constraints can be turned on or off. The default “on” turndown constraints are 50% for coal and nuclear steam boilers and 0% for oil or natural gas steam boilers. See Section 2.4.1.

Low-Carbon Generation Portfolio Standard: Generation Portfolio Standard for after emissions reductions start. The following technologies are currently available for modelling: wind, nuclear, and natural gas combined cycle. The default low-carbon GPS is 47% wind, 36% nuclear and 17% natural gas. This is derived from the EIA’s analysis of America’s Clean Energy and Security Act (Waxman & Markey 2009), which found the lowest-cost portfolio of new capacity construction for meeting the target of 80% emissions reductions below 2005 levels. ((EIA 2009); no international offsets scenario) The share of the EIA’s optimal new capacity mix that was assigned to carbon capture and

storage (CCS) was redistributed between wind and nuclear since CCS is not enabled in IFAM.

Model End Year: Year the model ends. The default is 2050, however the model end year should be set to 2060 when running at BAU (no emissions reductions) scenario in order to tell the model that there is no emissions constraint.

2.2.2 IFAM Model Outputs

IFAM outputs a number of three-dimensional arrays. Most have the dimensions $n \times \text{model years} \times \text{Policy Starting Years (PSYs)}$. For each scenario described by the parameters outlined in Section 2.2.1 IFAM outputs the following results:

Emissions: $1 \times 19 \times 18$; total emissions in each year for each PSY [Mt].

Electricity Price: $1 \times 19 \times 18$; average annual electricity price in each year for each PSY [\$/kWh].

Carbon Price: $1 \times 19 \times 18$; carbon price in each year for each PSY [\$/t CO₂].

Construction: $8 \times 19 \times 18$; new capacity construction by fuel type in each year for each PSY [MW].

Retirements: $8 \times 19 \times 18$; capacity retirements by fuel type in each year for each PSY [MW].

Existing Capacity: 8 x 19 x 18; existing capacity by fuel type in each year for each PSY [MW].

Generation: 8 x 19 x 18; generation by fuel type in each year for each PSY [MWh].

Retired Plants: An n x 18 object array of all plants retired during each PSY.

2.3 MODEL ALGORITHM

2.3.1 Overview

IFAM is a model focused on estimating how the timing of GHG reduction policy affects capacity flows in the electricity sector. IFAM thus models what happens to capacity flows if the same policy is implemented in every possible PSY over the period 2014-2040.

Changes in the electricity sector are modeled over the model years 2012-2050 for each separate PSY within the user-specified master scenario (see Section 2.2.1). Figure 2-1 depicts the model structure.

IFAM is built on a database of existing generating units. At a high level, IFAM works as follows: every model year, these units are dispatched so that demand is met at the lowest possible cost for each of 12 load periods. IFAM then calculates the annual emissions and generation. If an emissions cap is in place during this year, IFAM adjusts the carbon price and repeats this process until the emissions cap is met (see Section 2.3.3). At the end of the year, plants that have been un-economic for two years are retired. New capacity is built according to the GPS (BAU before emissions reductions start and low-carbon after emissions reductions start). This process is repeated for a given PSY over all the model years (2012-2050). IFAM then starts over from the

beginning with a new PSY. At the end of a master scenario run, IFAM has evaluated the electricity sector for 546 years (39 model years for each of 14 PSYs). Figure 2-1 depicts IFAM's structure. The following sections describe this information in more detail.

Emissions Reduction Start Year j

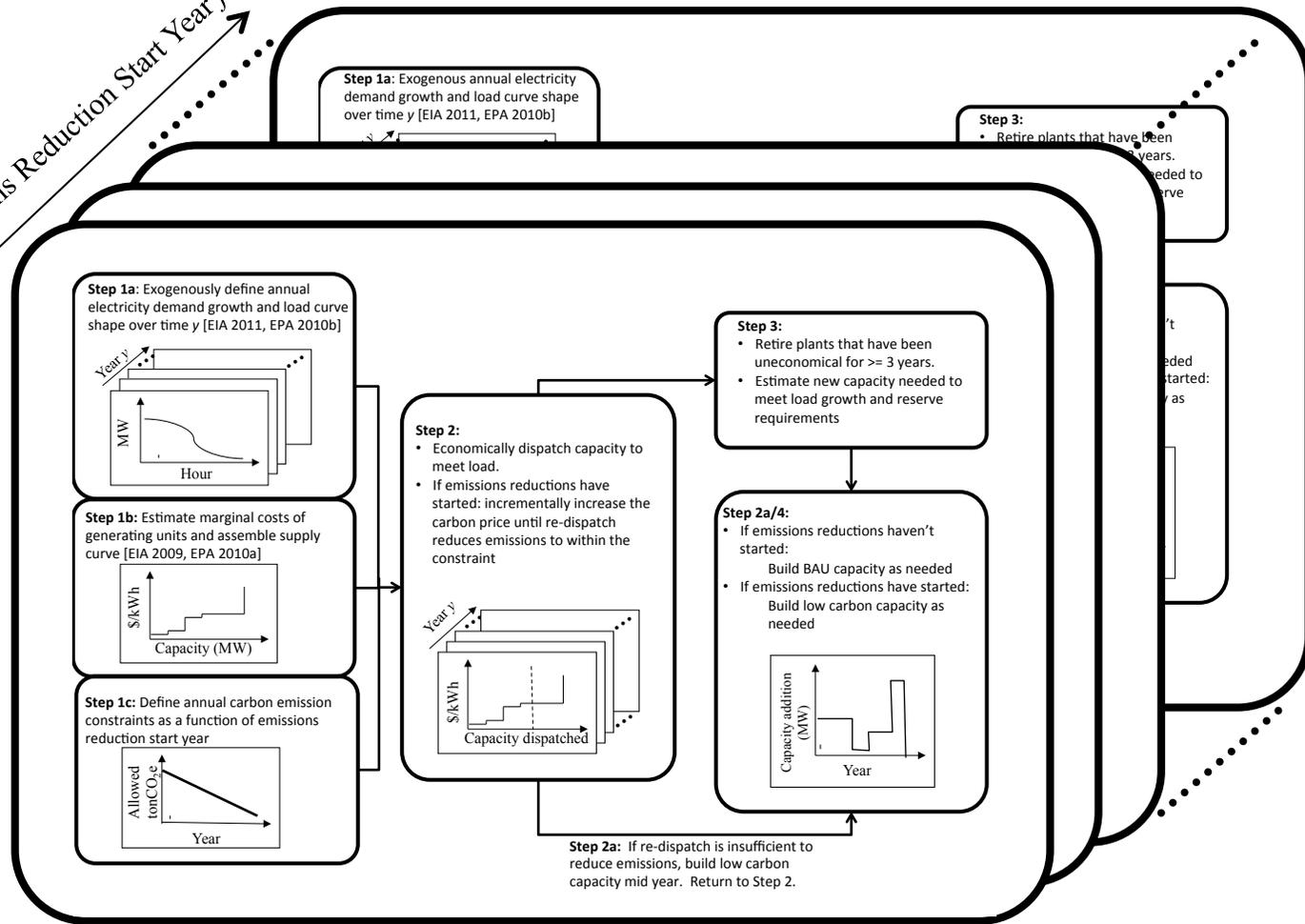


Figure 2-1 Model structure

2.3.2 Dispatching Units to Meet Demand

At the beginning of every model year, the annual production from each generating unit (together with associated emissions) is calculated using an economic dispatch process. The shape of electricity demand is modeled using a 12 period load curve (six load levels for each of two seasons; see Section 0). In every load time period, economic dispatch deploys generators in order from lowest marginal cost to highest marginal cost to produce the required amount of electricity at the lowest cost, subject to the following plant operating constraints:

- Plants do not produce when they are down for scheduled maintenance. This is accomplished by downscaling the available capacity at each plant (i.e., a 1000 MW plant with a summer availability of 89% would have a summer available capacity of 890 MW).
- Hourly generation from each plant is at least equal to turndown production levels. This ensures that production from steam boilers is constrained to a minimum level that allows for appropriate ramping. (See Section 2.3.5.1)
- Non-dispatchable power sources (wind and solar) do not exceed their seasonal capacity factors. (See Section 2.4.1)

Demand in each load period is reduced accordingly to account for production from turndown and non-dispatchable units.

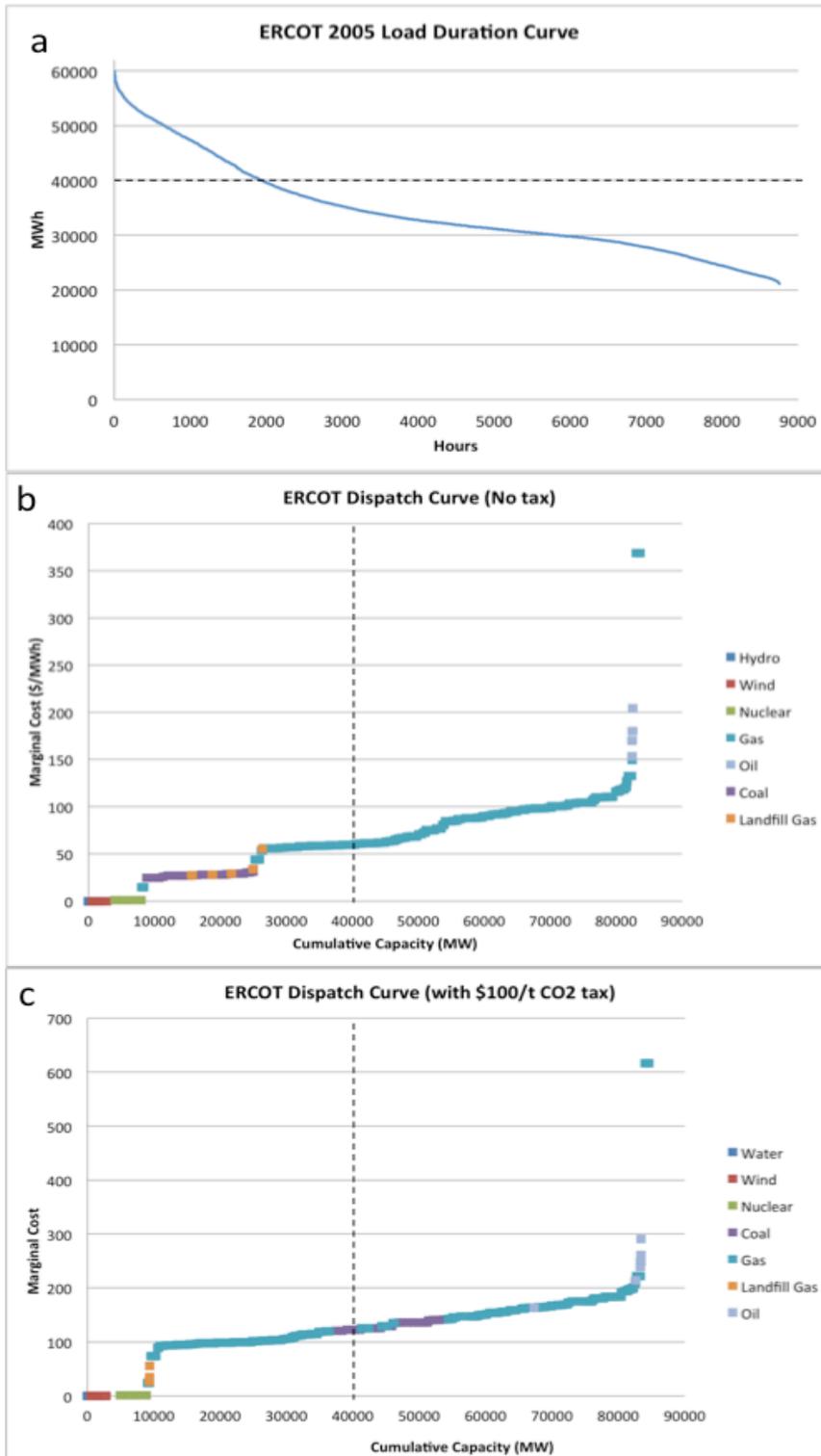


Figure 2-2 Economic Dispatch.
 a) Load curve b) Supply Stack c) Supply stack, redispached after \$100/t CO₂e tax.
 The marginal generating unit changes from coal to gas after the tax is imposed.

The remaining capacity (available capacity minus turndown/non-dispatchable capacity) from each plant is then ranked in order of increasing marginal costs to build a supply curve of generation. The price of electricity is found by identifying the marginal producing plant, which is at the point on the supply curve (Figure 2-2b) where cumulative generating capacity intersects adjusted demand (Figure 2-2a). All plants below this point on the supply curve are assigned full production; all plants above this point are assigned zero production (except for any turndown-constrained generation).

This process is repeated for all 12 of the annual time periods in the load curve. At the end of the year, the model records their annual generation, emissions, revenue and operating costs.

2.3.3 Meeting an Emissions Cap with Re-Dispatch

It is possible to reduce emissions from the electricity sector by a small amount without new construction using a process called re-dispatch (Newcomer et al. 2008; EPRI 2007a; EPRI 2008a). Re-dispatch substitutes generation from emissions intensive fuels (i.e. coal) with generation from lower carbon fuels (renewables, nuclear, gas). A simple mechanism for accomplishing this substitution in a de-regulated electricity market is to attach a price to carbon emissions. This raises the marginal cost of electricity from carbon intensive fuels relative to the marginal cost of lower carbon fuels, therefore re-ordering the supply stack (Figure 2-2c). Because low-cost generators produce first in an economically dispatched market, a high enough carbon price means that low carbon

generators produce more electricity than high carbon generators, reducing total system wide emissions. For example, coal has a lower marginal cost than natural gas, but also has a higher carbon content. A high enough carbon price will cause the coal's disadvantage in carbon content to overwhelm its advantage in marginal cost, and natural gas will be dispatched before coal.

IFAM tries to attain as much emissions reduction as possible in a given year using re-dispatch. This is accomplished by finding the lowest price on carbon that reduces total electricity emissions to below the annual emissions cap (see Section 2.3.4 for how the annual emissions cap is calculated). IFAM starts each year by finding the total emissions from the system assuming that the carbon price is the same as it was last year (or zero, if this is the first year that an emissions cap is imposed). If that carbon price does not keep emissions below the cap, the carbon price is increased by \$1/t. Then, new marginal costs are calculated for each generating unit and the annual dispatch for the entire system is recalculated. This process repeats until annual emissions are below the cap. The final carbon price is reported. It is important to note that in IFAM, the carbon price is used strictly as an endogenous mechanism for reducing electricity emissions via re-dispatch, and not as a policy lever. If it is infeasible to reduce emissions by re-dispatch alone, IFA builds new low-carbon generating units during the year. Each year, IFAM uses the previous year's carbon price as the starting point and increases or decreases the carbon price as needed.

Intra-year construction

In the case where very rapid emissions reductions must occur (with aggressive targets or with a late PSY) it may be that there is not enough low-carbon capacity in the supply stack to both meet demand for electricity and stay below the emissions cap. If

this occurs, IFAM builds new low-carbon capacity (according to the low-carbon GPS) during the annual dispatch process.

2.3.4 Calculating the emissions profile

IFAM is enabled to model two different types of emissions reduction: linear and cumulative. In the linear option, emissions in the year 2050 are fixed regardless of PSY (cumulative emissions vary with PSY). In the cumulative option, cumulative emissions over the period 2012-2050 are fixed regardless of the PSY (year 2050 emissions vary with PSY). While the linear emissions model is commonly talked about in policy frameworks (for example, the target in ACES (2009) was 83% below 2005 levels), it is less relevant from a scientific perspective than cumulative emissions because radiative forcing is a function of the stock of GHGs in the air. (Stocker 2013) Since IFAM is interested in the timing of climate change policy, it is important to consider cumulative emissions reductions. Every year of delay increases the stock of GHG in the atmosphere, which means that decarbonization must occur faster in order to maintain the same level of cumulative emissions. This effect is not included if emissions reductions are modeled linearly. To my knowledge, IFAM is the only model of the electricity sector that models cumulative emissions reductions.

2.3.4.1 Cumulative Emissions Reductions

During model set-up, the user chooses an emissions reduction target and thus, in conjunction with BAU emissions (estimated during a BAU run of IFAM) establishes a cumulative emissions cap for the model run. For example, if ERCOT were projected to have 100Mt of cumulative emissions reductions in the BAU scenario between 2012-2050, then a 20% reduction target would cap emissions in ERCOT to 80Mt over the same period.

IFAM calculates the emissions profile for each PSY as follows: before the PSY, emissions occur as usual, without any limit. In the year emissions reductions start, IFAM calculates the rate of decarbonization needed in order to ensure that the cumulative emissions cap is met. From this, IFAM calculates an annual emissions cap, which is used in the dispatch process. Because the dispatch process does not exactly meet the annual emissions cap, IFAM re-calculates the emissions profile each year.

Figure 2-3 shows two example pathways (reductions starting in 2020 and 2028) for emissions reductions in the electricity sector with cumulative emissions totaling 68 Gt CO₂e². Because the cumulative emissions are fixed, starting later requires both lower emissions in 2050 and a faster rate of decarbonization. After 2028, it is not possible to stay within the 68 Gt CO₂e carbon budget without pulling carbon out of the air, which is not a technology included in IFAM. IFAM issues an error when meeting the cumulative emissions cap is impossible and stops the model run.

² Non-CO₂ emissions from electricity plants include methane and nitrous oxide, both of which are included in IFAM's GHG calculations.

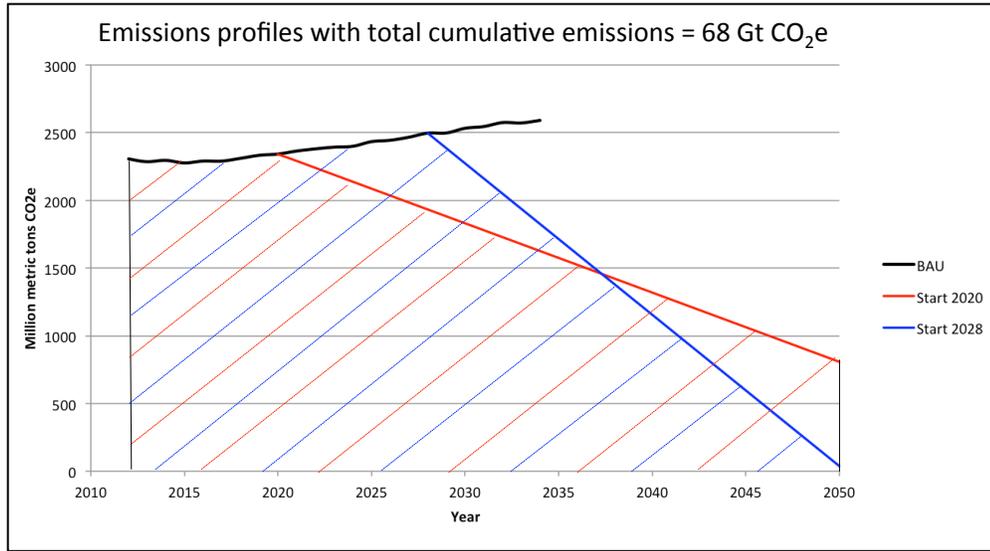


Figure 2-3 Example emissions pathways for the US. Cumulative emissions (2012-2050) are 68 Gt CO₂e. BAU emissions from (U S Energy Information Administration 2011).

2.3.4.2 Linear Emissions Reductions

In the linear emissions reduction scenario, the amount of emissions allowed in 2050 is fixed. IFAM calculates the annual emissions cap by assuming that emissions are reduced linearly from the year before the PSY to the 2050 target. Thus, the cumulative amount of emissions over the period 2014-2050 varies with PSY.

2.3.5 Individual Plant Behavior

2.3.5.1 Plant Operation and Finances

Plants are initialized with the following technical and financial parameters: Name, Unit ID, Unit Type, Region, Capacity, Heat Rate, Vintage, Fuel Type, Availability (Summer and Winter), Capacity Factor (Summer and Winter), Fuel Cost, Fuel GHG Emissions Rate, Variable Operations & Maintenance Cost (VOM), Fixed Operation & Maintenance Cost (FOM), Capital Cost, and Capital Charge Rate. Section 2.4.1 describes these parameters and their sources in detail. There are several additional parameters, derived from those listed above, which IFAM calculates prior to the dispatch process:

Turndown Capacity (seasonal): The amount of a plant's generating capacity that is not available for dispatch (either because it is a variable power source as in the case of wind or because it is a steam unit with ramping constraints, as in the case of coal), adjusted to account for scheduled and unscheduled maintenance outages.

$$\text{Eq 1.} \quad \textit{Turndown Capacity} = \textit{Total Capacity} * (1 - \textit{Turndown Constraint}) * \textit{Availability} * \textit{Capacity Factor}^3$$

³ Note, here Capacity Factors are the maximum achievable capacity factor (i.e. 100%) except in the case of wind, solar and hydro, in which cases they are determined by the resource availability in the region. See Section 2.4.1.

Available Capacity (seasonal): The amount of a plant's generating capacity that is available for dispatch, adjusted to account for scheduled and unscheduled maintenance outages.

$$\text{Eq 2.} \quad \text{Available Capacity} = \text{Total Capacity} * \text{Turndown Constraint} * \text{Availability} * \text{Capacity Factor}^4$$

$$\text{Eq 3.} \quad \text{Total Capacity} = \text{Available Capacity} + \text{Turndown Capacity}$$

Marginal Cost: The cost of producing one extra unit of electricity. Note that costs are linear so the marginal cost is independent of quantity.

$$\text{Eq 4.} \quad \text{Marginal Cost} = \text{Fuel Cost} * \text{Heat Rate} + \text{VOM} + \text{Carbon Price} * \text{Emissions Intensity}$$

Fixed Costs: Plant expenses that are independent of generation. Capital costs are incurred only for new plants or existing plants that require a renovation in order to prolong the lifespan.

$$\text{Eq 5.} \quad \text{Fixed Costs} = \text{Total Capacity} * (\text{FOM} + \text{Capital Cost} * \text{Capital Charge Rate})$$

During each load-slice of the dispatch process, each plant is assigned a production level, which allows the calculation of revenues during that load-slice, which can be summed to calculate total revenues during the year. Similarly, generation during each load-slice can be summed to calculate total annual generation for each plant, where i indexes load-slices and $hours_i$ is the number of hours in each load-slice.

⁴ *ibid*

$$\text{Eq 6.} \quad \text{Annual Revenues} = \sum_i \text{Generation}_i * \text{Electricity Price}_i * \text{hours}_i$$

$$\text{Eq 7.} \quad \text{Annual Generation} = \sum_i \text{Generation}_i * \text{hours}_i$$

Plants also calculate their annual emissions, costs, and profits:

$$\text{Eq 8.} \quad \text{Annual Emissions} = \text{Annual Generation} * \text{Emissions Intensity}$$

$$\text{Eq 9.} \quad \text{Annual Costs} = \text{Annual Generation} * \text{Marginal Cost} - \text{Fixed Costs}$$

$$\text{Eq 10.} \quad \text{Annual Profit} = \text{Annual Revenues} - \text{Annual Costs}$$

2.3.5.2 Plant Retirement

At the end of the model year, plants calculate their annual profits by summing up the hourly costs and revenues. Plants then evaluate whether they have met a profitability criterion, retiring if they are unprofitable for two consecutive years. Plants are retired after two years of unprofitability as a balance between giving them the opportunity to regain profitability with changing conditions and not letting unprofitable plants remain active for too long. A retired plant sets its capacity to zero and is no longer dispatchable. A closed plant cannot reopen. Nuclear plants retire when they reach age 60 in accordance with the Atomic Energy Act of 1954.

Plants are defined as unprofitable if profits are less than zero, with a small amount of tolerance—if Eq. 11 is true, a plant is deemed unprofitable.

$$\text{Eq 11.} \quad \text{Profit} + \varepsilon * \text{Annual Revenue} < 0$$

The profitability criteria was designed with this tolerance in order to provide plants with some flexibility in order to mitigate the effects of uncertainty in the value of various plant parameters. The criterion incorporates annual revenue in order to scale the profitability criterion to plant size. The retirement profitability threshold, ϵ , is calibrated to the 2011 AEO (U S Energy Information Administration 2011) separately for each region. See Section o for more on the calibration process.

2.3.6 Constructing new units

After retiring uneconomic plants, IFAM determines the amount of capacity in the supply stack. IFAM then builds enough new capacity to ensure that demand will be met in year $n+2$, including the regionally specified reserve margin. For capacity planning purposes, IFAM assumes that wind will have a capacity factor of 12.5% (GE Energy 2010) and that hydro will have a capacity factor as stated in EPA IPM Table 3-8, which range from 15-55% depending on location. (EPA 2010a)

IFAM builds new capacity according to the user-specified GPS. Before pollution prevention measures are implemented, IFAM builds a region-specific BAU scenario. In the base case, this is the average new construction portfolio projected by the AEO (U S Energy Information Administration 2011). IFAM builds new capacity in units of whole plants only (i.e., no partial plants). For example, if 1000MW of new capacity is required and the BAU GPS is 50% coal, 50% NGCC, IFAM will build one 600MW coal plant and one 560 MW NGCC plant. While this approach may over-build in a given year, it results

in less construction in future years. This approach also more realistically models actual power plant construction.

Starting six years before PSY, IFAM switches to building a low-carbon GPS, although dispatch proceeds as usual. This is intended to mimic a period after a carbon reduction policy is established but before it takes effect, during which utilities are unlikely to build carbon-intensive generating units.

Under circumstances in which either the supply stack is largely decarbonized or the emissions reduction target is un-ambitious, it is possible that annual emissions will be significantly lower than the annual emissions cap (in this scenario, the carbon price will not increase). This implies that the supply stack is more decarbonized than needed to meet the emissions target; in this case, the low-carbon GPS is adjusted to build more gas. The increased share of gas construction is compensated by decreasing wind and nuclear construction.

2.4 DATA

2.4.1 Generating Units

2.4.1.1 Existing Units

The IFAM database of existing generating units comes largely from the EPA's National Electric Energy Data System (NEEDS) (EPA 2010a). NEEDS includes all 14,468 electricity-sector generating units that were operating at the end of 2006, plus additional

planned or committed units that were scheduled to come online before the end of 2011. NEEDS is therefore a complete representation of the electricity sector generating capacity of the US at the beginning of the year 2012. While NEEDS includes pumped storage units IFAM does not.

NEEDS reports the capacity, plant location, vintage year, unit configuration, heat rate, fuel, pollution control technology type, and SO_x, NO_x, and mercury emissions rates of generating units at the boiler level for steam units and at the generator level for non-steam units. NEEDS lists fuel types for each plant in order of primacy. Since IFAM does not allow fuel switching, IFAM uses the first listed fuel type. There are several other types of plant specific data required by IFA:

Turndown Constraints: Turndown constraints are the minimum level of production that a steam unit can operate at when they are operating. Turndown constraints are used to prevent steam units from operating as peaking units. As with EPA IPM Section 3.5.3 (EPA 2010a), IFAM assumes that nuclear and coal units have a turndown constraint equal to 50% of capacity.

Availability: Availability is the fraction of time that a unit is online and able to provide electricity to the grid (i.e., when a plant is not down for planned maintenance or unplanned outages). Availability different in each of IFA's two seasons, summer and winter. Data comes from EPA IPM (EPA 2010a) Appendix 3-9.

Fuel Emissions Factors: IFAM assumes the average fuel emissions factors reported in Table 11.4 of EPA IPM (EPA 2010a). Emissions factors are shown in Table 2-3.

Table 2-3 Fuel emissions factors

Fuel	Emissions Intensity (lbs CO₂/MMBtu)
Bituminous	205.9
Subbituminous	212.9
Lignite	215.3
Natural Gas	117.1
Distillate Fuel Oil	161.4
Fossil Waste	321.1
Petroleum Coke	225.1

Capacity Factors: Capacity factors are calculated endogenously in the model, except for the cases of wind, solar and hydro. Capacity factors for hydro are regional and come from EPA IPM (EPA 2010a) Table 3-8. Capacity factors for wind and solar come from the EPA IPM (EPA 2010a) Appendices 4-1 and 4-2, respectively. EPA IPM (EPA 2010a) provides hourly capacity factors over a year for wind in Northern California (Class 4 is assumed to be representative) and Arizona/New Mexico for solar. These capacity factors are aggregated into their respective load categories and adjusted according to the average wind capacity factors in each region⁵. Regional data was unavailable for solar, so the capacity factors from Arizona/New Mexico given in EPA IPM were used for all regions. While this overestimates solar generation in most regions, the amount of solar capacity in each region is negligible and thus this approximation has no effect on model results.

⁵ Regional average capacity factors were calculated by Kyle Siler Evans using data from GE Energy (2010) and EnerNEX (2010).

Variable Operation & Maintenance Costs: Variable operation & maintenance (VOM) costs are the non-fuel costs of producing electricity, including the operation of pollution control equipment. IFAM uses VOM costs from the EPA IPM (EPA 2010a), given in Table 4.8 for non-nuclear generating units and in Appendix 4-3 for nuclear generating units.

Fixed Operation & Maintenance Costs: Fixed operation & maintenance (FOM) costs are those operating costs that are not dependent on the amount of electricity generated. FOM costs increase as plants age. IFAM uses VOM costs from the EPA IPM (EPA 2010a), given in Table 4.9.

Capital Costs: Capital costs for existing units are assumed to be sunk costs and are not included in IFAM. Capital costs are incurred, however, during major retrofits of existing plants or during the construction of new plants. Similar to EPA IPM, IFAM assumes that after several decades, existing fossil units need a major retrofit in order to remain operable. This threshold occurs at age 40 for coal, oil and nuclear units and at age 30 for gas units. Renewable units do not require retrofits due to aging. Capital costs for retrofits are found in EPA IPM (EPA 2010a) Table 4-10. Capital costs for new fossil and renewable units are found in EPA IPM (EPA 2010a) Table 4-13 and Table 4-16, respectively. As with all prices, IFAM uses constant 2012 dollars. When making annual profit calculations for each plant, capital costs are amortized over the financial life of the plant using the capital charge rate (below).

Capital Charge Rate: The capital charge rate is used to convert capital costs to levelized annual payments. IFAM uses capital charge rates from EPA IPM (EPA 2010a) Table 8-1, which range from 10-12% depending on technology. When calculating the capital charge rates, EPA used different discount rates (ranging from 5.5-6.5%) for each technology. (EPA 2010a)

2.4.1.2 New Units

Assumptions for new plants come from EPA IPM (EPA 2010a) Tables 4-13 and 4-16 and are summarized in Table 2-4. IFAM does not incorporate technological learning, so these assumptions are fixed across the entire planning horizon. Capital charge rates for new units are also from EPA IPM (EPA 2010a) Tables 4-13.

Table 2-4 Technical and Financial parameters for new units

Fuel	Capacity (MW)	Heat Rate (Btu/kWh)	Fuel	Availability	VOM (\$/MWh)	FOM (\$/kWh -yr)	Capital Cost	Capital Charge Rate
Coal	600	8424	Bituminous	0.85	1.32	47.9	3265	11.30%
NGCC	560	6810	Natural Gas	0.87	2.57	14.4	976	12.10%
NGCT	170	10720	Natural Gas	0.92	3.59	12.3	698	12.90%
Nuclear	1350	10400	Nuclear	0.9	0.77	92.4	4621	10.80%
Wind	50	0	Wind	0.95	0	30.3	1954	12.20%
Firm Wind	100	*	Firm Wind	0.95	*	*	*	*

*indicates that the value is a combination of the parameters for NGCC and wind as well as the gas/wind ratio

2.4.2 Fuel Prices

IFAM assumes that fuel prices are constant over the entire model planning horizon.

Data largely come from EPA IPM (EPA 2010a) and the Energy Information

Administration's *Cost and Quality for Fuels for Electric Plants* (U S Energy Information

Administration 2010) and are from the year 2009. Assumed fuel prices are summarized

in Table 2-5.

Table 2-5 Fuel Prices

Fuel	Price (\$/MMBtu)	Source and notes
Bituminous	2.76	EIA Table 4 -- utility sector only
Subbituminous	1.62	EIA Table 4
Lignite	1.45	EIA Table 4
Liquid Petroleum	10.26	EIA Table 6
Natural Gas	4.74	EIA Table 13
Biomass	1.83	2012 biomass cost of production from IPM Appendix 11-1
Petroleum Coke	1.61	EIA Table 9
Fossil Waste	0	IPM Table 11-3
Landfill Gas	0	IPM Table 11-3
Nuclear	0.71	IPM Sec 11.3

2.4.3 Load

Load curves come from EPA IPM (EPA 2010a) Appendix 2-1, which provides hourly load

data for the year 2012 for each IPM model region, which are then aggregated into load

curves for each interconnect.

IFAM has two seasons, summer (May 1-Sept. 30) and winter (Oct. 1-April 31). This allows IFAM to account for differences in seasonal electricity demand. Because of the massive computational expense required to analyze every hour of the year separately, IFAM (as with most electricity models) aggregates each season into six load slices that are the average of the load during the hours in that category. Table 2-6 shows how load is partitioned into slices.

Table 2-6 Load slice categories

Load Slice	Share of Load
Peak of Peak	1%
Peak	4%
High Shoulder	10%
Low Shoulder	30%
High Baseload	30%
Low Baseload	25%

2.4.4 Regional Parameters

Table 2-7 summarizes the regional parameters used in IFAM. BAU GPS (i.e. construction portfolios) are calculated from the 2011 AEO (U S Energy Information Administration 2011) projections over the period 2011-2035. IFAM assumes that these scenarios continue to 2050. Demand growth rates are similarly estimated from the 2011 AEO (U S Energy Information Administration 2011).

Table 2-7 Regional BAU generation portfolios and demand growth rates

Region	BAU Generation Portfolio Standard					Demand Growth Rate
	<i>Coal</i>	<i>NGCC</i>	<i>NGCT</i>	<i>Nuclear</i>	<i>Wind</i>	
ERCOT	6%	38%	54%	0%	2%	0.70%
FRCC	0%	100%	0%	0%	0%	1.12%
MRO	20%	36%	36%	0%	9%	0.55%
NPCC	10%	60%	6%	0%	35%	0.66%
RFC	6%	38%	54%	0%	2%	0.65%
SERC	1%	19%	53%	17%	5%	0.67%
SPP	0%	27%	28%	0%	45%	0.48%
WECC	2%	39%	17%	0%	42%	0.89%

2.4.5 Providing Firm Wind Power

The variability of wind power, especially at the sub-hour level, requires fast-ramping units (such as gas or hydro) in the electric grid to respond in order to maintain system stability. The balancing response from gas needed to provide so-called “firm wind” power has two major impacts: first, because it triggers gas operations, wind power is not zero-carbon. Second, there needs to be enough fast-ramping reserve capacity in the grid to provide balancing services for wind. At low wind penetration levels, these effects are limited. However, at the higher wind penetration levels expected in a low-carbon electric grid, these effects are likely to be significant. A final concern with very high wind penetration levels is the possibility of a “drought”, or long-term, widespread period of reduced wind. Katzenstein et al (2010) found that the wind droughts do occur (the standard deviation of annual wind production is 6% of the annual mean), although they

are half as severe as is seen with hydropower. The possibility of a drought in wind production will be included in future versions of the model.

2.4.5.1 Emissions Associated with Wind

Because wind variability occurs at a high frequency relative to grid operations, balancing wind requires frequent changes in power outputs at gas plants, and high penetration levels may force more frequent start-ups and shut-downs in balancing units. (Valentino et al. 2012)

These cycling and start-up events have higher emissions than regular gas plant operations, which together with the emissions from gas power production needed for balancing, means that the emissions benefit from wind production will be less than expected. (Valentino et al. 2012; Katzenstein & Apt 2008) Valentino et al. (2012) find that there are diminishing returns to increased wind penetration. Their study, in Illinois, found that 10% wind penetration (measured on a generation basis) had 12% emissions reductions relative 0% wind penetration, but by 40% wind penetration the emissions reductions were only 30%. Katzenstein and Apt (2008), however, find the opposite: both wind and solar plants achieve approximately 80% of expected reductions, independent of penetration levels. IFAM addresses this effect using a Gas/Wind Generation Ratio. The GWGR is the amount of generation from a gas plant resulting from balancing wind output. With a GWGR of 20%, each 100MWh of firm wind power produced is 80MWh of pure wind power and 20MWh of gas, with the resulting GHG emissions from the gas plant. The base-case assumption for GWGR is 20% and is subject to a sensitivity analysis in Chapter 4.

2.4.5.2 The Effect of Variability on Operating Reserves

Several studies have examined the impact of high levels of wind penetration on operating reserves. The Western Wind and Solar Integration and Transmission Study (2010) (GE Energy 2010), found that wind penetration levels of 30% (on an energy basis) requires approximately doubling operating reserves. The Eastern Wind Integration and Transmission Study (2010) (EnerNEx Corporation, 2010) similarly found that increasing wind penetration to 20% and 30% (on an energy basis) increases the operating reserve requirements by 160% and 210%, respectively over the entire Eastern Interconnect. Another study in Minnesota ((EnerNEx Corporation, 2006) as cited in (National Renewable Energy Lab, 2008)) found that 25% wind penetration levels required increasing operating reserve requirements by 7% of the installed wind capacity, of which 90% was contingency reserve, 5% was frequency reserve, and 5% was load-following reserve.

IFAM adds additional operating reserve to deal with variability using the heuristic developed in the Western Wind Integration Study, which finds that operating reserves equal to 1% of load plus 5% of wind nameplate capacity are sufficient to cover expected variability. (GE Energy 2010) This is calculated at the end of the dispatch process by ensuring that there remains enough un-dispatched fast-ramping capacity at the end of each hour to equal 1% of load plus 5% of wind capacity. In the event that operating reserves are inadequate, new gas plants are built until the reserve requirement is met.

2.5 MODEL INITIALIZATION AND CALIBRATION

2.5.1 Initialization

Power plants provide several services in addition to electricity generation, such as reactive power and load control, load following, and other ancillary services as well as reserve capacity. Usually, generators are compensated for providing these services either directly by an ISO or via mechanisms such as a forward capacity or reserve market. Because IFAM models only revenues from electricity generation, IFAM does not fully capture the revenue streams from operating a generating unit. As a result, there are some plants that are clearly economically viable in reality (as evidence by their continued operation) but are uneconomic in the model. These plants are usually smaller, older oil or gas units with very high marginal costs that operate as peaking units and receive most of their revenue from capacity payments rather than generation. These benefits are ignored in the model.

IFAM initializes the existing capacity of generating units by retiring these uneconomic plants in the first year of each run. This means that in the year 2012 only, plants need only be uneconomic for one year before retiring. Plants retiring as a result of the initialization period represent less than 4% of initial capacity for all regions except MRO and NPCC, which retire 7% and 8% of capacity, respectively. In the case of MRO, there is not enough existing capacity to meet peak demand in the first year, requiring immediate construction. MRO builds 2100 MW (3% of existing capacity) during the initialization period.

2.5.2 Calibration

IFAM is calibrated separately for each region, which allows IFAM to incorporate the effects of any regional differences that are not already included in the model. IFAM is calibrated using two parameters: the planning reserve margin and the profitability threshold parameter, ϵ . Each parameter was incremented in a two-dimensional search until the best possible fit that did not trigger unrealistic behavior in the model was achieved. As discussed in Section 2.3.5.2, plants retire when they are unprofitable for more than two years, where “unprofitability” is defined according to the following criteria:

$$\text{Eq 12.} \quad \text{Profit} + \epsilon * \text{Annual Revenue} < 0$$

The BAU scenario for IFAM is calibrated to the 2011 AEO (EIA, 2011) using cumulative projected retirements and construction over the period 2012-2035. Cumulative, rather than annual, figures are used for the calibration process because it is both likely and acceptable that IFAM and the AEO disagree by a year or two on the specific date of construction or retirement for a given plant. Since IFAM is interested in long-term trends, it is more important to calibrate to total activity over a given period. Table 2-8 shows the best-fit profitability threshold parameter (ϵ) and reserve margin for each region, together with a comparison of cumulative retirements and construction over the period 2012-2035 for both IFAM and AEO (both are BAU scenarios).

Table 2-8 Comparison of cumulative construction and retirements (2012-2035) for IFAM and the AEO and calibration parameters

Region	Retirements (GW)		Construction (GW)		Calibration Parameters	
	IFAM	AEO	IFAM	AEO	ϵ	Reserve Margin
ERCOT	9.6	10.5	12.3	14.7	-0.2	16%
FRCC	2.0	1.5	19	13.7	-0.5	27%
MRO	4.9	1.1	22	23.6	-0.55	25%
NPCC	6.4	6.2	15.9	11.6	-0.25	15%
RFC	8.5	6.9	26	20.0	-0.3	20%
SERC	9.9	10.2	35	44.7	-0.05	22%
SPP	2.0	1.8	8.2	10.1	-0.55	34%
WECC	0.85	1.1	44	34.2	-0.15	11%

Because retirements and construction are tightly linked (retirements drive construction), there were some cases where it was necessary to choose between a good fit for retirements or a good fit for construction (e.g. SERC, FRCC). In those cases, I chose a better fit for retirements. Regions that have worse fits in both retirements and construction (MRO, RFC, SPP, all of which are 15-30% different from the AEO in both retirements and construction) are also regions that have low system-wide availability (MRO, RFC, and SPP have system-wide availabilities of 85%, 83%, and 85%, respectively, as compared to ERCOT, FRCC, NPCC and WECC, which all have a system-wide availability of 89%). A low system-wide availability means that there is a large discrepancy between total capacity (used when calculating the amount of new capacity needed to meet future demand) and available capacity (used during the dispatch process). This discrepancy drives strange construction (and thus retirement) behavior in the model when the calibration parameters are tight. These regions were calibrated to be as close as possible to the AEO without triggering unrealistic behavior.

2.6 MODEL VALIDATION

Because IFAM was developed with the specific intention of being a simple, easily used model of how the timing of pollution-prevention policy affects the stock of electricity generating units, there are many aspects of the electricity sector that are not included. IFAM does not include some market and grid operations features (e.g. ancillary services, out-of-merit-order-dispatch, pricing and market structures). IFAM also does not include transmission constraints, which can have an effect on capacity investments both regionally and locally. IFAM attempts to mitigate this uncertainty by operating at a NERC-region level (less than 1% of delivered power is transmitted between NERC regions; EIA 2011). Future investment in inter-regional transmission could, however, make NERC regions a less relevant unit of study.

Local congestion (along with economics and resource availability) can affect capacity planning, which IFAM does not incorporate. Additional uncertainty arises from model assumptions about fuel prices, the gas/wind ratio, and other variables. Many of these uncertainties are addressed with sensitivity analyses in Chapter 4. Given the above limitations, IFAM is most suited to analyzing long-term capacity changes of the kind described here.

Because IFAM was calibrated using retirements and construction, it is not possible to validate using those results. Instead, IFAM was validated by comparing results for the generation mix to historical output in the year 2008. IFAM was modified to simulate the year 2008 by removing generators of vintage 2009 and greater from the database, using

2008 average fuel prices (EIA, 2011) and by adjusting 2012 demand levels to 2008 levels (2008 demand is reported in the 2011 AEO (EIA, 2011)).

Table 2-9 compares both the generation mix and total generation for each NERC region to historical data. Overall, IFAM compares very favorably to historical data for both the generation mix and total output. The biggest discrepancies occur in SPP and MRO.

These are also among the regions with the highest share of coal production. This is most likely due to the turndown constraint, which is fixed at 50% for all coal steam units in IFAM, possibly forcing coal units to produce differently than they would prefer to when they are at the margin. In reality, the turndown constraint will vary across units.

Table 2-9 Comparison of IFAM model results to historical data for the year 2008; generation mix and total generation.

Historical data from the AEO 2011 (EIA, 2011).

Region	Coal		Oil/Gas		Nuclear		Other		Total Generation (MWh)	
	IFAM	AEO	IFAM	AEO	IFAM	AEO	IFAM	AEO	IFAM	AEO
ERCOT	38%	38%	42%	43%	13%	13%	7%	6%	300	310
FRCC	28%	30%	58%	53%	11%	15%	2%	2%	270	210
MRO	64%	72%	10%	5%	15%	13%	11%	10%	280	240
NPCC	11%	14%	48%	40%	27%	30%	14%	17%	300	270
RFC	63%	65%	7%	6%	28%	28%	2%	2%	920	980
SERC	58%	59%	12%	12%	26%	26%	4%	3%	1080	1040
SPP	70%	61%	19%	27%	5%	4%	6%	8%	180	200
WECC	31%	29%	27%	32%	10%	10%	32%	29%	760	710

IFAM was also validated on an individual plant level by comparing the modeled plant capacity factors to actual capacity factors for the year 2009 (as reported in the eGRID 2012 database (EPA 2012a)). IFAM was modified to represent the year 2009 as described above. Figure 2-4 plots modeled capacity factors against actual capacity

factors, with the point size scaled according to plant capacity. While there is some scatter, model results for the majority of US generating capacity match well with historic values. This is especially true for coal, nuclear, and peaking oil and gas plants (those near the origin). Hydro plants have quite a lot of scatter. This is likely due to the fact that IFAM uses average historic capacity factors for hydro plants, which may not represent actual water levels in the year 2009.

There are several large plants that had actual capacity factors of zero, which indicates that these units did not operate in the year 2009. IFAM cannot capture unplanned outages of this nature, and thus modeled higher capacity factors for those plants. This also explains why IFAM tends to overestimate plant capacity factors (more dots are in the northwest quadrant than the southeast)—this indicates that these plants produced less than expected in 2009, which may be due to unplanned maintenance.

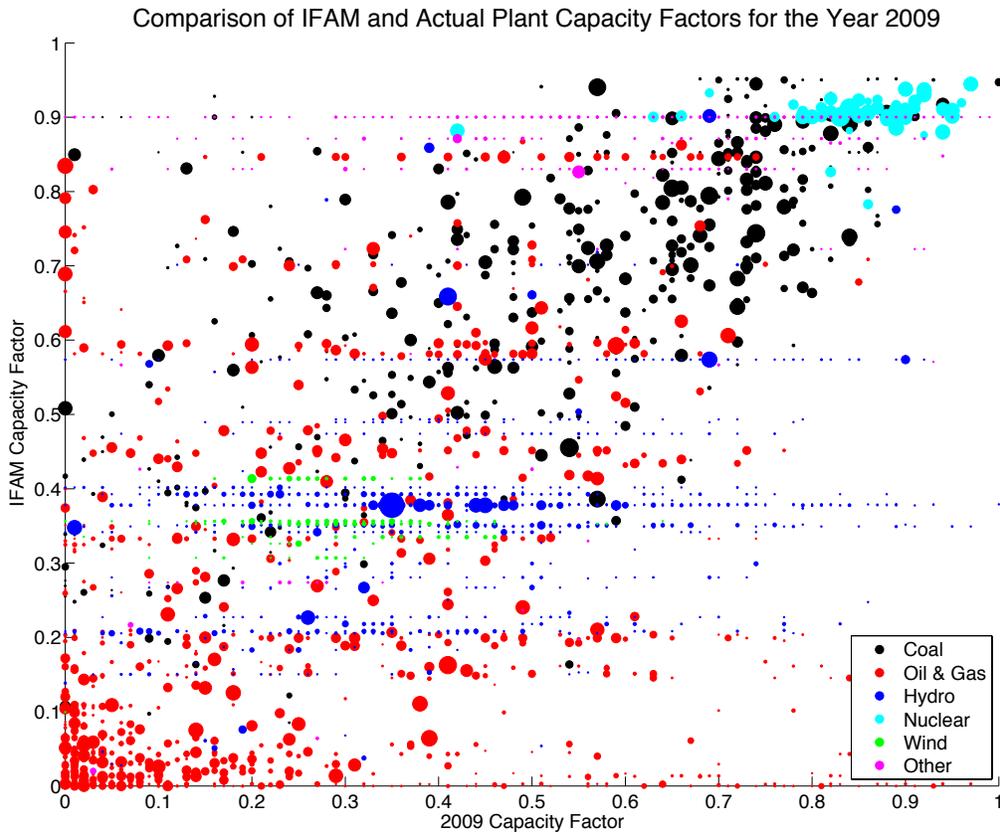


Figure 2-4 Comparison of modeled capacity factors and actual capacity factors for the year 2009. Points are scaled according to the capacity of the plants. Overall root mean squared error is 0.26.

Table 2-10 Comparison of modeled capacity factors and actual capacity factors for the year 2009, by plant size and fuel type. RMSE=root mean squared error; overall RMSE=0.26.

Fuel Type	Small (<200 MW)			Medium (200-800 MW)			Large (>800 MW)		
	eGRID	IFAM	RMSE	eGRID	IFAM	RMSE	eGRID	IFAM	RMSE
Coal	46%	65%	0.31	49%	64%	0.22	59%	72%	0.21
Oil & Gas	15%	10%	0.30	24%	25%	0.23	25%	30%	0.24
Nuclear	-	-	-	-	-	-	86%	91%	0.10
Hydro	40%	34%	0.23	37%	37%	0.17	41%	44%	0.17
Other	57%	80%	0.35	26%	54%	0.27	55%	83%	0.28
Wind	30%	36%	0.12	-	-	-	-	-	-

Table 2-10 aggregates the results shown in Figure 2-4 into summary figures that compare modeled capacity factors to actual capacity factors by fuel type and plant size and shows the root mean square error (RMSE; a measure of the average deviation between modeled and actual results) for each category. The overall RMSE is 0.26. IFAM compares well to actual data for wind, hydro, and nuclear plants for all plant sizes. IFAM tends to overestimate the capacity factor of coal plants, which is likely due (at least in part) to ancillary services and out-of-merit-order dispatch (which IFAM does not model) as well as unplanned outages. On aggregate, IFAM closely models the capacity factors of Oil & Gas plants, however the relatively high RMSE indicates that IFAM performs less well on an individual plant bases.

IFAM poorly models plants in the “other” category. This category includes geothermal, solar, biomass, landfill gas, municipal solid waste, and other miscellaneous fuel sources and is only a very small share of US capacity. The discrepancy between IFAM and reality in the other category thus does not materially affect IFAM’s results.

CHAPTER 3: REFERENCE CASE RESULTS

This chapter presents the results from IFAM’s reference case, which is defined as follows:

Reference Case

- BAU demand
- BAU fuel prices
- “Optimal” low-carbon generating portfolio (47% wind, 36% nuclear, 17% gas)
- Gas/Wind generation ratio of 20%
- AEO 2011 (U S Energy Information Administration 2011) projections for the BAU generating portfolio standard

The chapter begins with a presentation of intermediate results from IFAM for a 25% emissions reduction scenario (chosen for illustrative purposes), which are discussed in order to provide a deeper understanding of the model and build intuition about the results. Next, this chapter approaches the question of “How long can we wait?” from four different perspectives. First, the chapter looks at the impact of policy timing and severity on infrastructure turnover in the electricity sector. Next, the chapter looks at the impact of policy timing and severity on the age of retired plants. Third, the chapter explores the “infeasibility frontier”, or the combinations of policy timing and policy

severity that are impossible to achieve. Finally, the chapter explores regional differences and considers issues of inter-regional equity.

The first three sections of the chapter present national results that are calculated by aggregating regional results. This means that in a scenario with 25% cumulative emissions reductions, every region reduced emissions 25% below their own BAU. It should be noted that it is unlikely that a national emissions policy would be structured this way. In a national cap-and-trade plan, for example, inter-regional trading would mean that some regions reduce emissions more than others, in accordance with their ability. In theory, this kind of trading reduces the total cost of emissions abatement—the aggregated results presented here are thus an upper bound on the impact of a national policy on infrastructure turnover. Modeling this type of policy would require equilibrating carbon prices across all regions in every year, which IFAM cannot do in its current incarnation. However, requiring regions to meet the same target does allow for direct comparison between regions, which is why results are presented as they are. This issue will be discussed more in Section **Error! Reference source not found.**

Keep in mind that the fuel mix of new capacity construction (and hence also total construction levels) are a function of the chosen construction portfolios (BAU and low-carbon) in the reference scenario. The impact of these choices is discussed in Chapter 4. Also bear in mind that the question IFAM answers is “how much turnover (retirements/construction) *must* happen in order to meet climate goals”, not “how much turnover *can* we realistically accomplish”. There are therefore no limits on construction or retirement rates built into the model. The question of how much turnover is realistic and how this affects the US’s chances of meeting climate goals is briefly discussed in Chapter 5.

In order to place these results in the context of national policy, consider the impact of the proposed America's Clean Energy and Security Act (2009) on cumulative emissions. ACES, which reduced emissions to 83% of 1990 levels by 2050, starting in 2020, was estimated to produce cumulative emissions (2012-2050) of 240 Gt/CO₂e (a 20% reduction below projected BAU emissions). (Environmental Protection Agency, 2009) The EPA (2009b) also estimated that the electricity sector would be responsible for about 85%, or 50 Gt/CO₂e, of cumulative emissions abatement under the bill. Since IFAM projects that cumulative BAU emissions from the electricity sector are 100 Gt/CO₂e, ACES can be approximated by the 50% emissions target/PSY 2020 scenario presented here.

3.1 INTERMEDIATE RESULTS

This section presents intermediate results from IFAM for one emissions reductions scenario (25% reductions) of the reference case in order to clarify how the model works. Figure 3-1 shows annual generation for policy start years (PSYs) of 2014, 2020, 2026, and 2032. All four scenarios have a drop in coal and gas generation and a significant

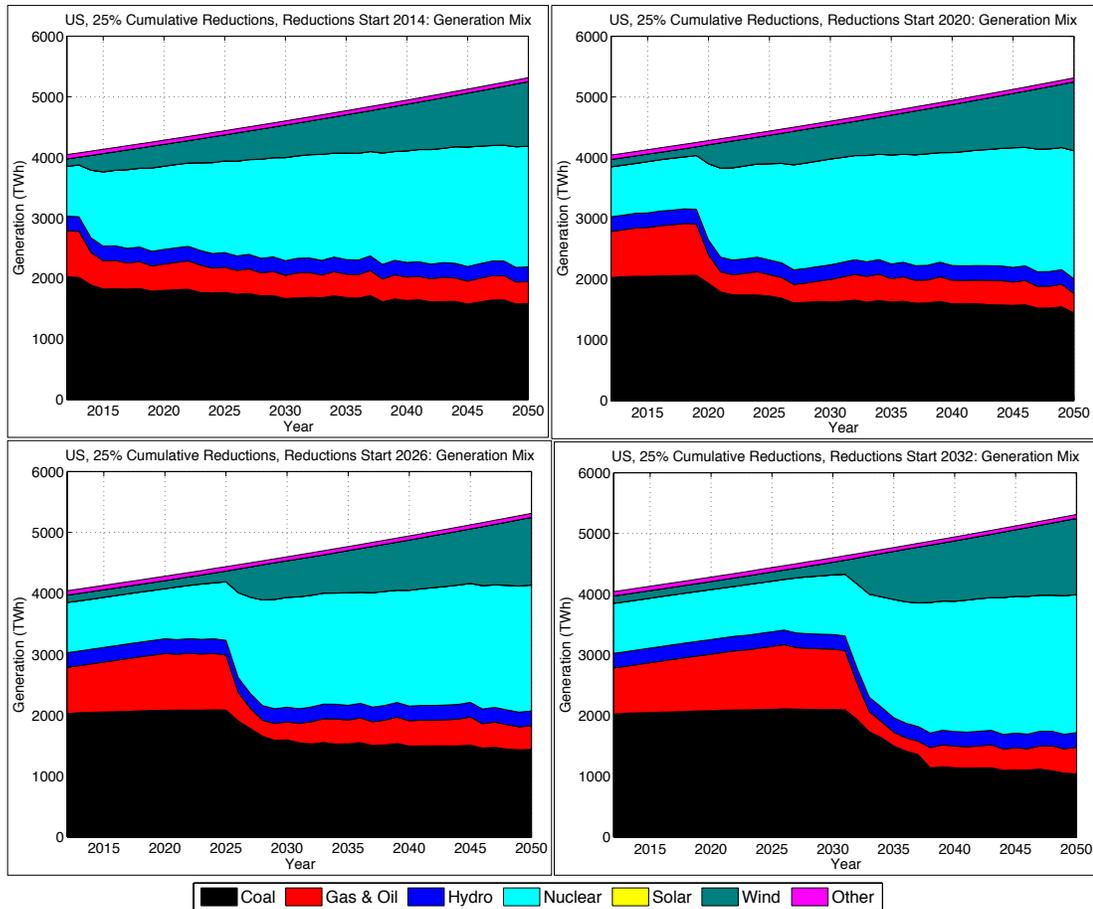


Figure 3-1 Annual generation for 25% cumulative emissions reductions below BAU for four policy start year scenarios: 2014, 2020, 2026, and 2032.

increase in nuclear and wind generation. The difference between PSY 2014 and PSY 2032 is striking; with a later start year, the eventual decrease in coal generation is much more severe. For PSY 2014, coal drops from 50% of total generation to 40%, while for PSY 2032, coal drops from 50% of total generation to 20%. This is because later start years use more of the cumulative emissions cap during the pre-policy period and consequently must reduce emissions much more severely once emissions reductions start. All PSY scenarios see large increases in wind and nuclear generation. Nuclear

generation is 20% in 2012 and increases to 50% of total generation for PSY 2014 and 55% for PSY 2032. Wind generation is 3% and increases to 26% and 31% for PSYs 2014 and 2032, respectively.

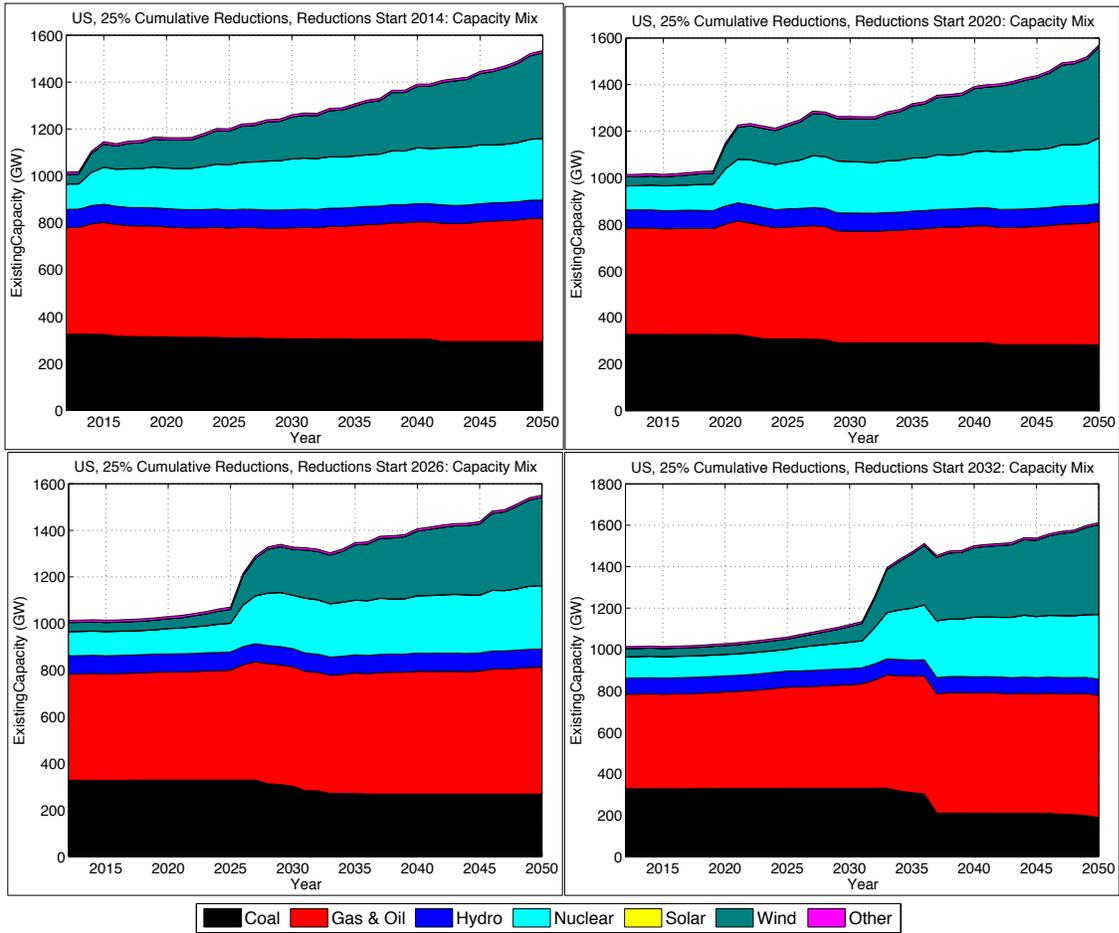


Figure 3-2 Annual capacity mix for 25% cumulative emissions reductions below BAU for four policy start year scenarios: 2014, 2020, 2026, and 2032.

The drop in fossil fuels is also apparent in Figure 3-2, which shows the capacity mix for the same scenarios. Coal capacity decreases slightly, especially for reductions starting in 2032, but the decrease in absolute terms is not as sharp as it is for generation. However, the share of total coal capacity decreases from 32% to 10% (for a 2032 policy start year).

Gas capacity similarly decreases from 45% to 35%. Wind and nuclear see steady increases in capacity resulting from the emissions reduction policy: nuclear increases from 10% to 20% of total capacity and wind increases dramatically from 4% to almost 30%.

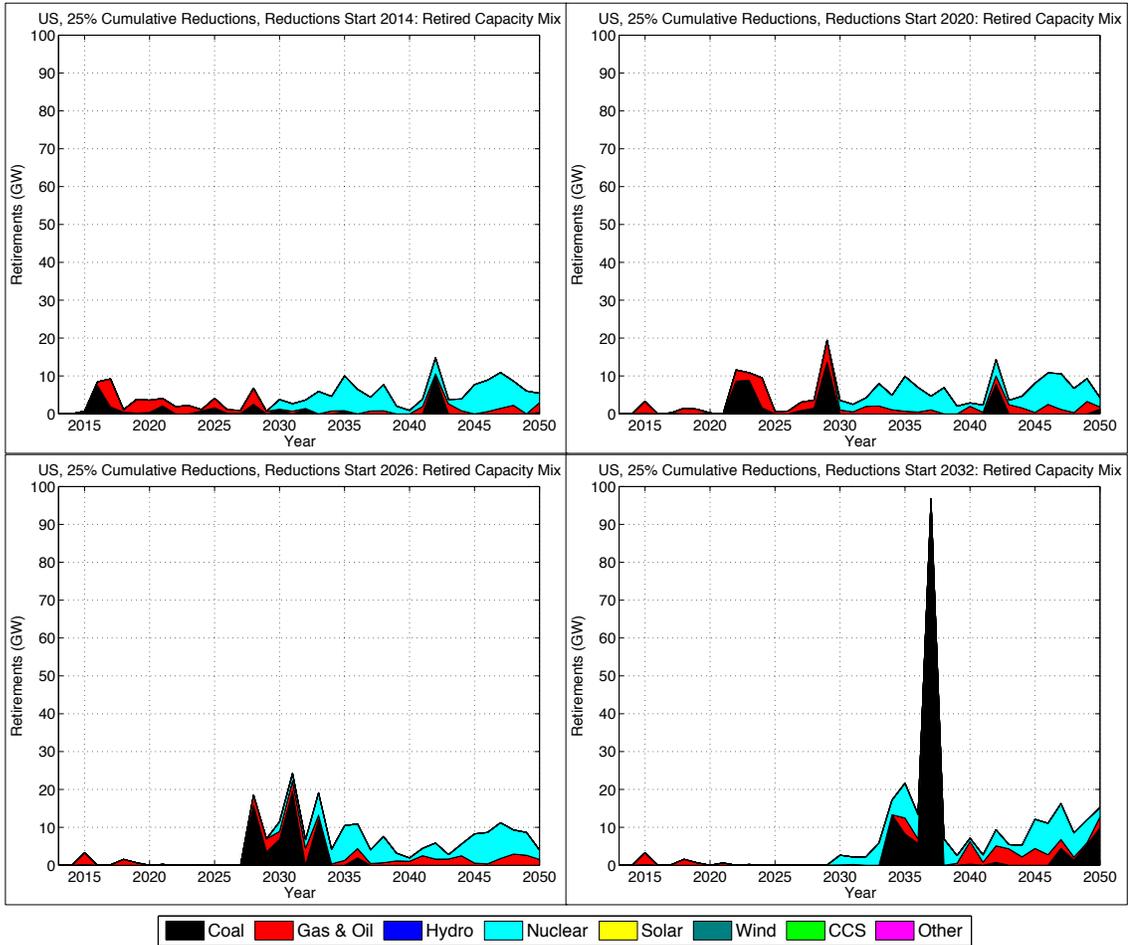


Figure 3-3 Annual capacity retirements for 25% cumulative emissions reductions below BAU for four policy start year scenarios: 2014, 2020, 2026, and 2032.

Figure 3-3 shows retirements for each of the four start year scenarios. Nuclear retirements are the same for all four scenarios (as well as the BAU) since nuclear has a fixed retirement age of 60 in accordance with regulations. Later policy start years have

significantly higher retirements than earlier policy start years; PSY 2015 has a total of 185GW retirements while PSY 2030 has a total of 290 GW retirements, which is equal to 17% and 29% of total US capacity in 2012, respectively. This is largely due to coal retirements, which increase steadily as the policy start year gets later (from 30 GW total for PSY 2014 to 140 GW total for PSY 2032). Gas retirements are more stable; 56 GW of gas retires for PSY 2014 while 52GW of gas retires for PSY 2032. Later policy start years also have much higher peak retirements. (Some of the large increase in peak retirements for PSY 2030 is due to a simultaneous increase in BAU retirements during those years—these are nuclear plants that retire in the same year in all scenarios. The same is true for the bump in retirements around 2045-2050.) Non-nuclear retirements for PSY 2014 are distributed relatively evenly over the model period, while retirements for PSY 2032 are front-loaded during the first five years after the PSY. This is because under a cumulative emissions cap, the penalty for extra years of high emissions is that more rapid decarbonization of the electricity sector is required once emissions reductions start.

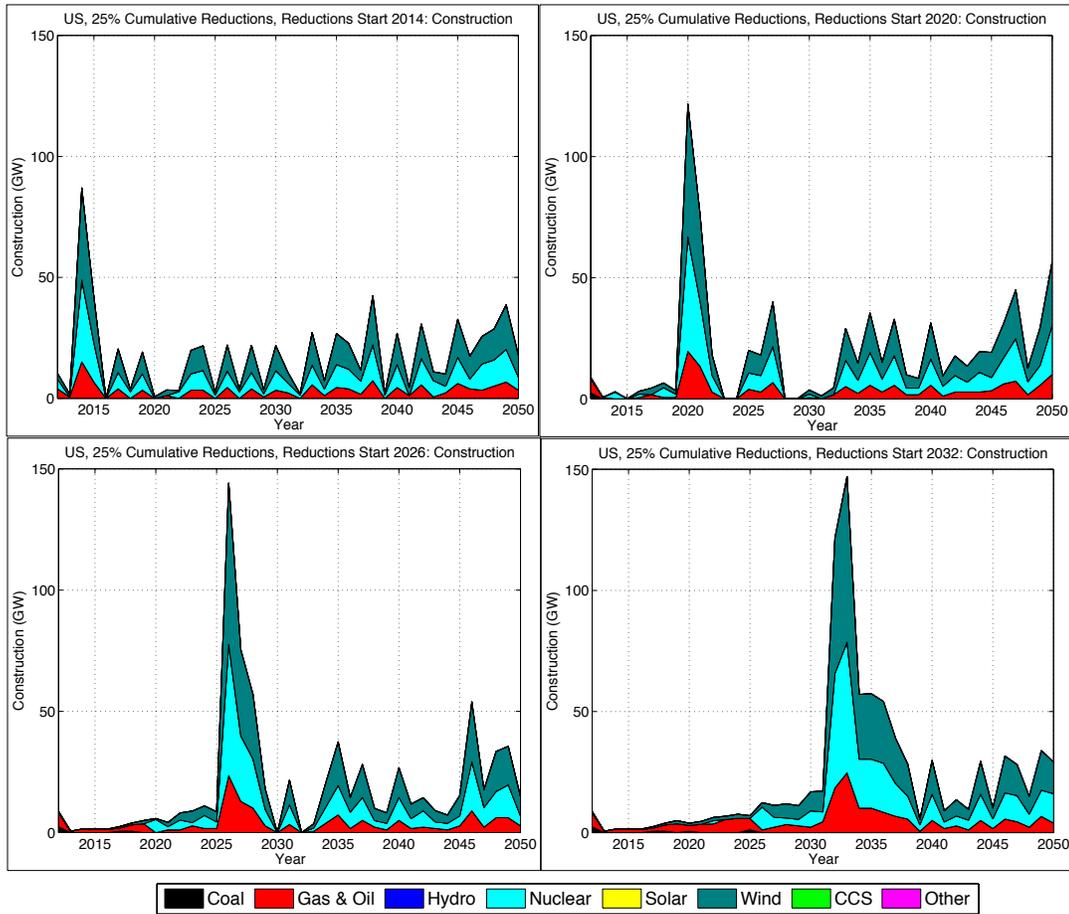


Figure 3-4 Annual construction for four PSYs (2014, 2020, 2026, 2032) for the 25% cumulative emissions reductions below BAU scenario.

Figure 3-4 shows annual capacity construction for four different PSYs under a 25% emissions cap. For all scenarios, the construction is far higher than simply replacing retired plants. This due to two factors: first, construction is also needed to meet future demand, which is growing. Second, retired plants are primarily high-capacity factor coal plants, while new construction is 47% low-capacity factor wind plants. Because wind plants are considered to have a capacity factor of 12.5% for planning purposes, IFAM needs to build approximately eight times more wind capacity than would be needed if

coal was being constructed. Total construction is 25% higher for PSY 2032 than it is for PSY 2014, and peak construction is 90% higher for PSY 2032 than PSY 2014 (55% higher when adjusted for construction that replaces retired nuclear plants common to both scenarios).

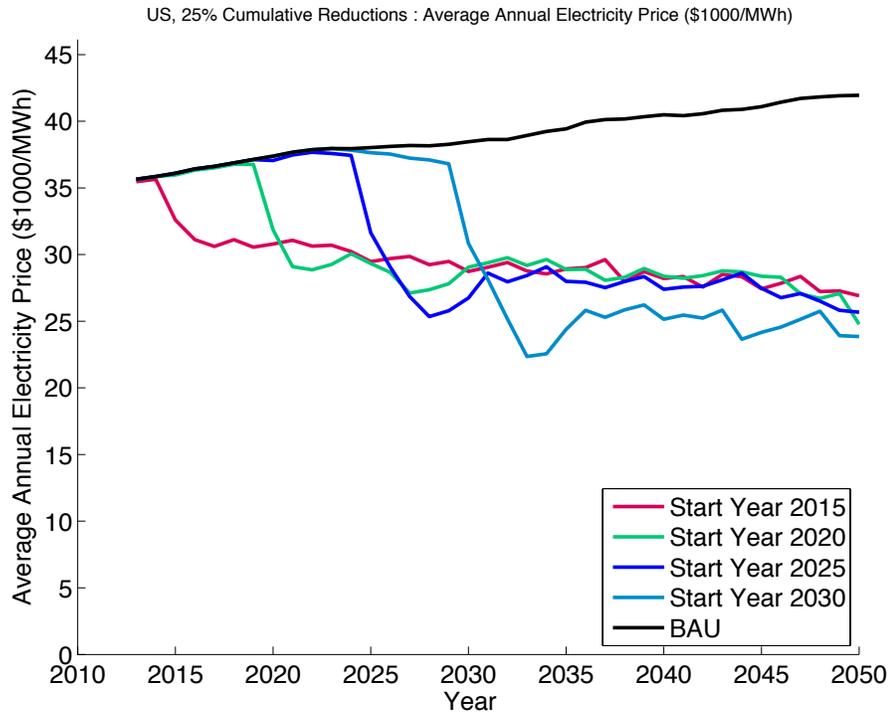


Figure 3-5 Annual electricity price for 25% cumulative emissions reductions below BAU

Figure 3-5 shows the wholesale electricity price from IFAM for four PSYs: 2015, 2020, 2025, and 2030. Electricity prices are lower after emissions reductions than in the BAU case for all scenarios. This is because the low-carbon generating portfolio standard used in IFAM’s reference case builds mostly wind and nuclear. These plants bid marginal costs of zero into the dispatch process, which brings down the average electricity price as

wind and nuclear penetration increases. It should be noted that the electricity price shown is the average price of the winning bid in a competitive electricity market and does not include capital or other costs that would be included in a cost-of-service market. It also does not include transmission, distribution, and other charges that are included in a retail bill in competitive markets. This figure is thus intended for illustrative purpose only and should not be interpreted as IFAM's prediction of future electricity prices.

The electricity price decreases more rapidly as the PSY gets later. This is because turnover occurs more rapidly in these scenarios and thus wind/nuclear penetration increases faster, bringing down the electricity price more quickly. The small deviations between the emissions curve and BAU before the PSY is because IFAM builds the low carbon generating portfolio for six years before the PSY, which begins reducing electricity prices slightly before the policy takes effect.

Like the electricity price, the carbon price in IFAM should not be interpreted as an estimate of what the price of carbon would be under an emissions cap. IFAM uses the carbon price as a mechanism for re-ordering the dispatch curve and it is strictly an endogenous variable. A true national carbon price would be affected many factors, such as the cost of emissions reductions in other sectors, the price of offsets (domestic and international), and whether credits were auctioned or given away. However, it is interesting to examine the carbon price in order to understand model results. Figure 3-6 shows the carbon price under a policy of 25% emissions below BAU for four policy start years. In all four scenarios, the carbon price increases over the whole period. As the start year gets later, the initial carbon price increases dramatically (from \$20/t for PSY 2015 to \$85/t for PSY 2030). However, the 2050 carbon price does not have a direct

relationship to PSY—PSY 2015 has the highest carbon price in 2050 and PSY 2020 the lowest.

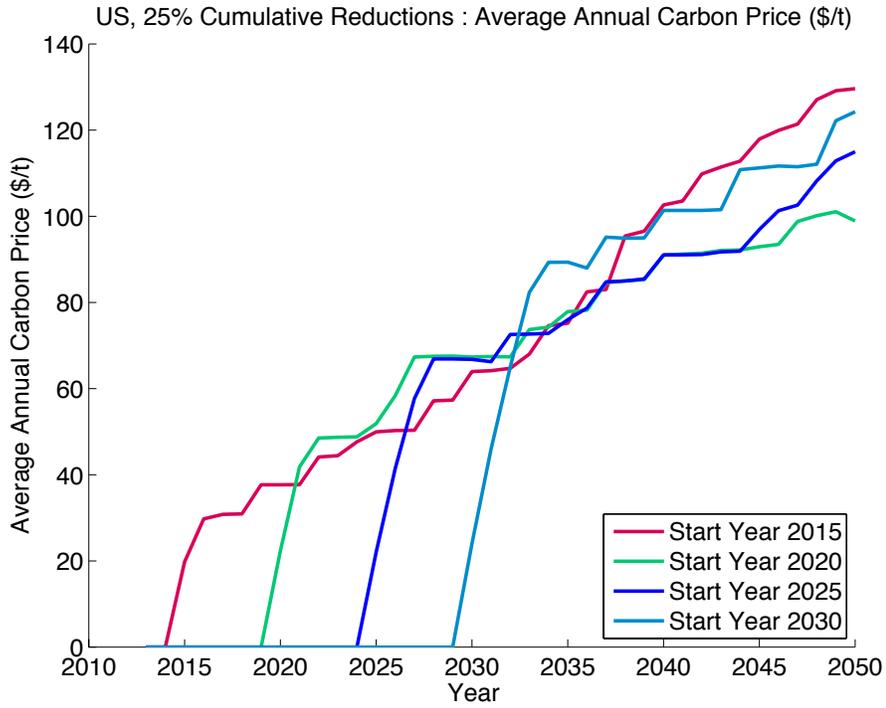


Figure 3-6 Average annual carbon price for cumulative emissions reductions of 25% below BAU.

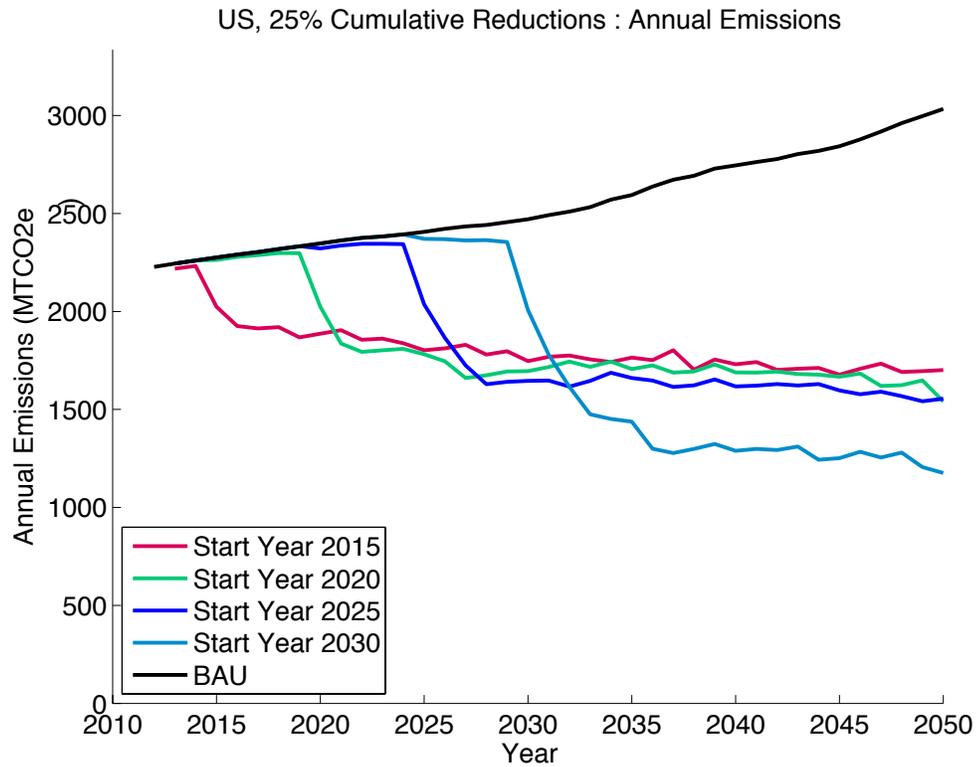


Figure 3-7 Annual emissions for cumulative emissions reductions of 25% below BAU

Figure 3-7 shows emissions profiles for four PSYs for 25% cumulative emissions reductions. The area under each emissions curve is equal to 75% of the area under the BAU curve. As expected, later start years have more aggressive reductions than earlier start years in order to keep cumulative emissions under the cap. As with the electricity price, the small deviations between the emissions curve and BAU before the PSY is because IFAM builds the low carbon generating portfolio for six years before the PSY, which begins reducing emissions slightly even before the policy takes effect.

3.2 INFRASTRUCTURE TURNOVER

Figure 3-3 and Figure 3-4 showed that even a modest emissions target of 25% cumulative reductions below BAU triggers large amounts of retirement and construction, especially with later policy start years. This section analyzes this effect in greater detail, addressing how the timing and aggressiveness of climate change policy affect infrastructure turnover in the electricity sector. Figure 3-8 shows average annual retirements after emissions reductions start as a function of PSY, with different emissions targets shown as contour lines. For example, for an emissions target of 35% cumulative reductions below BAU starting in 2014, average retirements over the period 2014-2050 are ~6GW/yr. As the emissions target gets higher, the contour lines get shorter. This is because there are some combinations of PSY and emissions target that are impossible to achieve from the electricity sector alone; Section 3.4 discusses this phenomenon.

Average retirements are 3 GW/yr for the BAU scenario. Average annual retirements exceed BAU for all emissions reduction scenarios. For PSY 2020, average annual retirements range between 4-5 GW/yr for the 5-20% emissions target scenarios. This is equivalent to retiring between 0.4-0.5% of the total US capacity in 2012 every year (or between 12-14% of the 2012 US fleet over the 30 years of emissions reductions).

Delaying the PSY to 2030 increases these numbers to 5-13 GW/yr for the same scenarios, or 15-39% of the 2012 fleet over the 20 years of emissions reductions.

For a given emissions target, average annual retirements increase with increasing PSY.

For a 20% target, average annual retirements increase by 375% when the PSY is delayed

from 2015 to 2035. The marginal penalty (for an extra year of delay) also increases as the PSY increases: for a 20% target, the penalty for delaying from PSY 2015 to 2016 is a 1% increase in the retirement rate, while the penalty for delaying from 2035 to 2036 is a 5% increase in the retirement rate.

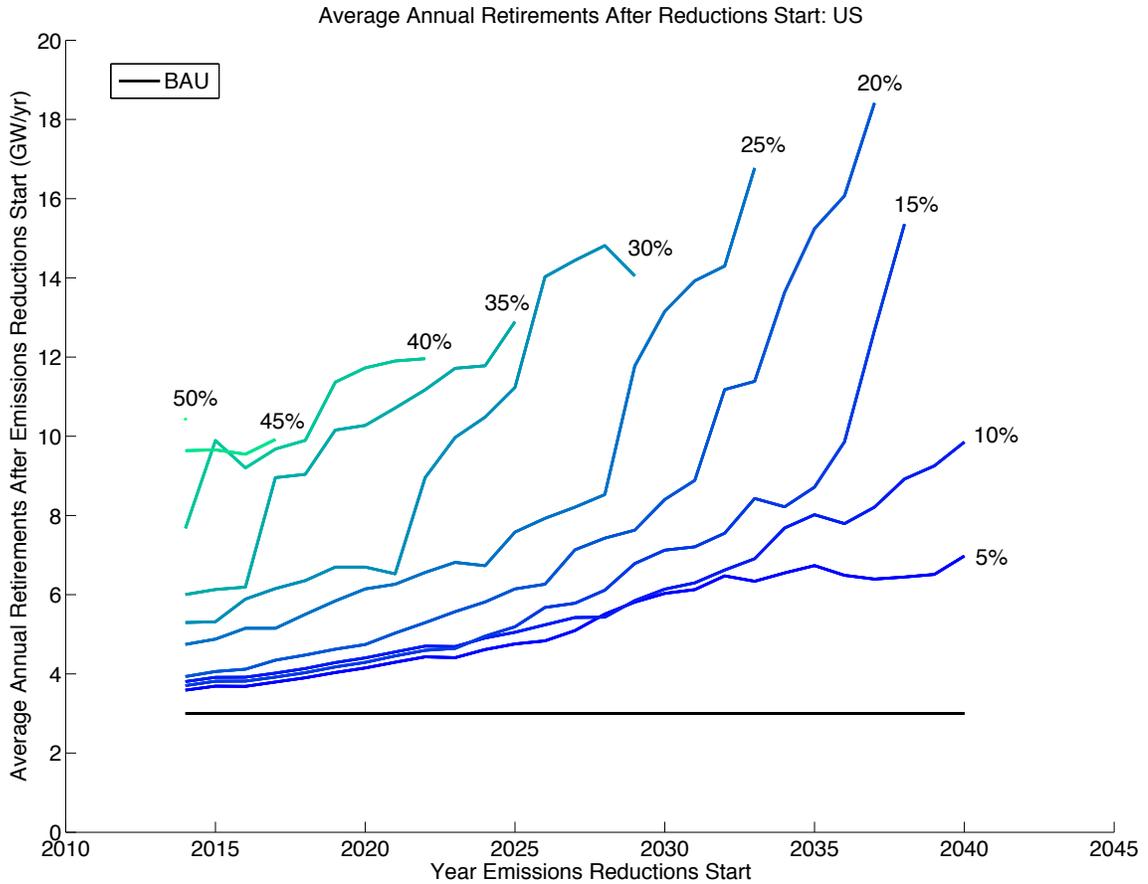


Figure 3-8 Average annual retirements after emissions reductions start as a function of policy start year compared to IFAM's BAU projections. Each contour line represents an emissions reduction target (cumulative emissions reductions below BAU, in percent)

Similarly, for a given PSY, average annual retirements increase with increasing emissions targets. For PSY 2015, average annual retirements for a 35% target are 70%

higher than for a 5% target. For PSY 2025, average annual retirements for a 35% target are 270% higher than a 5% target.

Figure 3-9 shows average annual construction after emissions reductions start as a function of PSY for ten emissions target contours and compares it to the historical average construction (mean; 1940-2012), projected BAU construction from IFAM, and historical maximum construction (1940-2012). For all combinations of PSY and emissions target, average construction is at least one and a half times the historical average. This means that any policy scenario, no matter how modest, requires building at least one and a half times as much new capacity every year once reductions start as the US has historically built on average. All scenarios, however, are below the US's maximum single year construction (2002; 59 GW of mostly gas). Unlike the historical maximum, which was mostly natural gas, these scenarios are 36% nuclear. Even modest emissions target/PSY combinations require at least 20 GW construction a year, of which ~7 GW are nuclear plants. Building 3-4 nuclear plants every year for 20-30 years is a massive undertaking. For comparison, during the period of nuclear build out (1958-1988) the US built an average of 2 GW/yr.

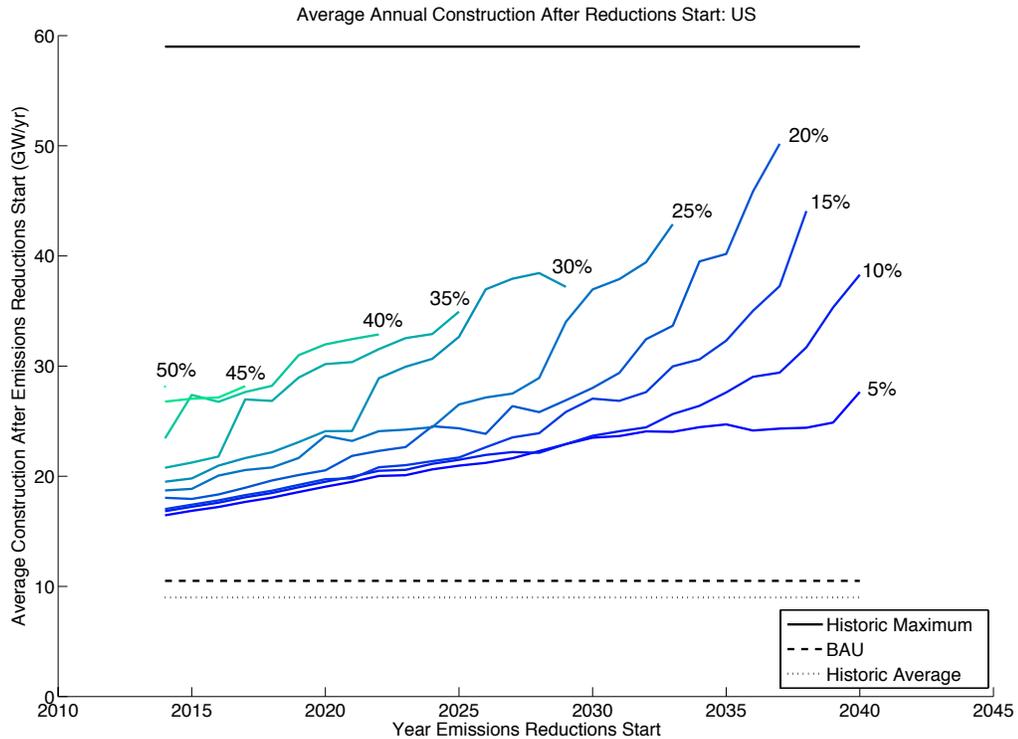


Figure 3-9 Average annual construction after emissions reductions start as a function of policy start year. Compared to historical average construction, IFAM’s BAU average construction and historical maximum construction. The historical maximum construction occurred in 2002 and was primarily natural gas (calculated from EPA 2012a). Each contour line represents an emissions reduction target.

As with retirements (Figure 3-8) there is a steep increase in average construction with both higher emissions targets and later PSYs. For a 20% target, delaying the PSY by 10 years increases the rate of construction by 25% while delaying for 20 years increases the rate of construction by 85%. Also similar to retirements, the penalty for delay increases with increasing emissions targets; delaying the PSY by 10 years increases the rate of construction by 25%, 30%, and 55% for a 15%, 25% and 35% target, respectively.

While Figure 3-9 shows the average annual construction resulting from emissions reduction policies, Figure 3-4 showed that much of the construction occurs during a few years at the beginning of the emissions reduction period, implying that the maximum

construction levels are much higher than the average construction level. Figure 3-10 shows the average annual construction during the five-year period of maximum construction for each PSY/emissions target scenario (calculated using a moving average of annual construction).

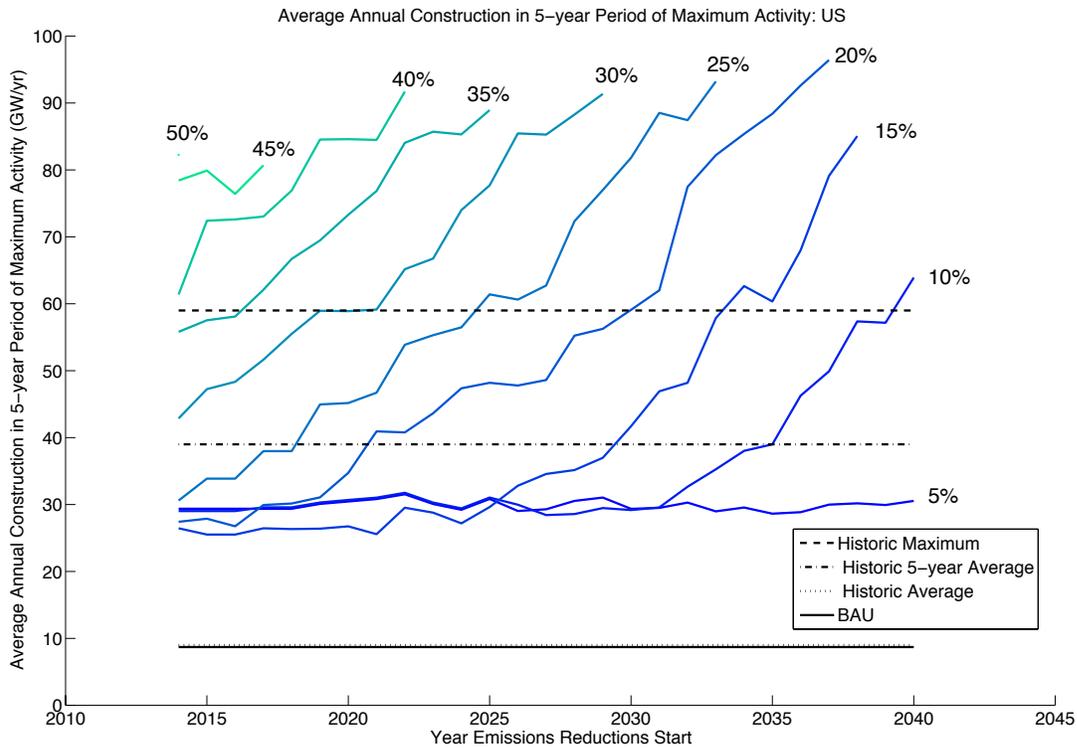


Figure 3-10 Average annual construction during the 5-year period of maximum construction (calculated using a moving average) as a function of policy timing. Compared to the historic maximum construction, historic average construction (1940-2012) during the 5-year period of maximum activity, average BAU construction during the 5-year period of maximum activity, and the historic average. Each contour represents an emissions reduction target.

Average construction rates during the period of maximum activity are very sensitive to PSY, although for low emissions targets (5-15%) there is a window of 10-15 years where construction rates are flat. For most emissions targets, however, a ten-year delay increases construction during the most active period by 150-200%.

For scenarios with high emissions targets and/or late starting years, annual construction rates during the period of maximum activity dramatically exceed the historical maximum for the US—by up to 160% (20% cumulative emissions reductions starting in 2034).

Because this is a five year average, this implies that for that scenario, the US would build 480 GW over five years—an amount equivalent to replacing half of the 2012 US fleet over a five year period. For comparison, the maximum 5-year moving average of US construction is 38 GW. The US has never seen a sustained push in electricity construction of the magnitudes shown here.

Like average construction, maximum construction levels are sensitive to PSY. Unlike average construction, the marginal change in maximum construction levels is insensitive to PSY for all but very low emissions targets. Each extra year of delay increases the rate of maximum construction levels by ~3 GW/yr, regardless of PSY or emissions target (for targets >20%).

There are significant costs associated with the build-out of new capacity required to meet emissions targets. Figure 3-11 shows the net present value of the construction scenarios shown in Figure 3-9, calculated using the 30 year government real discount rate of 1.1%. (OMB 2012) IFAM estimates BAU construction costs over the period 2012-2050 to be approximately \$500 billion. Costs for emissions reduction scenarios range between 2-5 times as much as BAU (\$1-2.5 trillion over 38 years; \$26-65 billion per year). This is equivalent to approximately 0.2-0.4% of US GDP per year. For comparison, the *Stern Review* (2007) found that the costs of mitigating climate change for the entire global economy (not just the US electricity sector) are on the order of 1% of global GDP per year.

For low to moderate emissions targets, construction costs are declining to flat as the PSY increases. This is due to the effect of discounting, which compensates for increasing construction rates as policy is delayed (as shown in Figure 3-9). For higher emissions targets (>25%) the increased construction costs overwhelm the effect of discounting, causing construction costs to increase as emissions reduction policy is delayed.

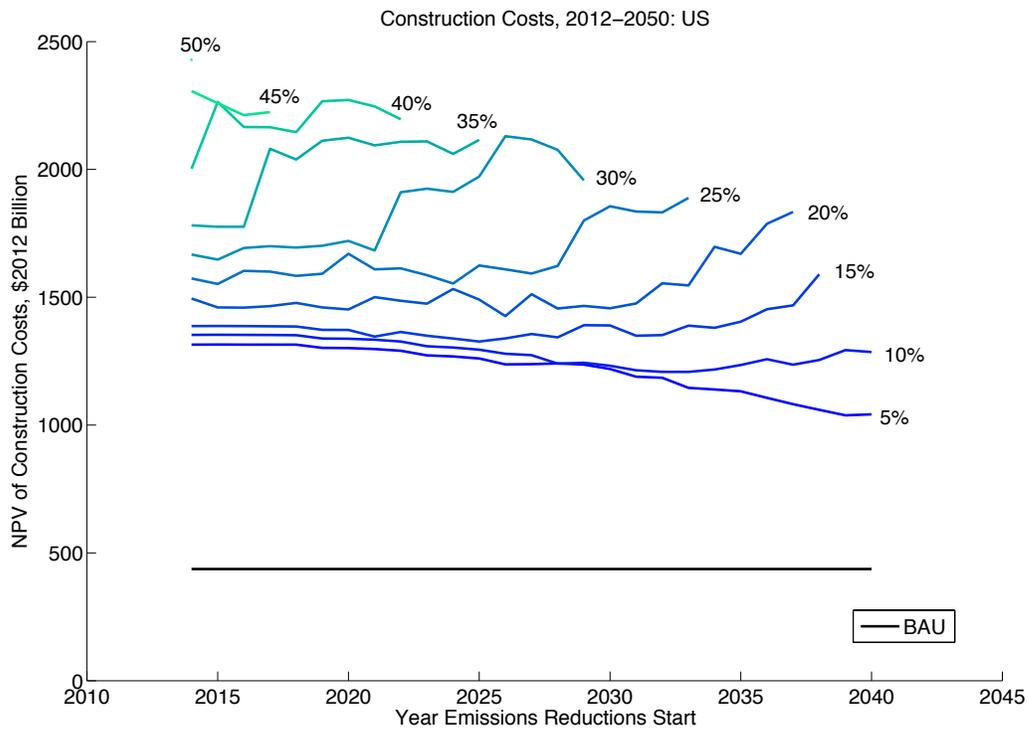


Figure 3-11 NPV of construction costs (\$2012; real discount rate of 1.1%) as a function of policy start year. Each contour represents an emissions reduction target.

3.3 PREMATURE RETIREMENT

A commonly heard argument for starting emissions reductions early is that it will prevent the premature retirement of fossil fuel plants.(e.g. Morgan et al. 2005; Wigley et al. 1996; Toth & Mwandosya 2001) The argument is qualitative, and is as follows: if the US delays implementing a climate policy and new fossil units are constructed today, once an emissions policy is enacted those new units will be quickly retired, likely at a young age. Retiring young plants (where young is defined as younger than the financial lifetime of the plant—30-40 years (EPA, 2010)) is expensive because the plant operator will be left with stranded capital costs that he is unable to recoup (during the deregulation process, many states passed these costs on to consumers with a temporary surcharge on electricity consumption).

Figure 3-12 shows the average (capacity-weighted) age of plants retired due to emissions reduction policy, as compared to BAU. The average age of plants retired in IFAM’s BAU scenario is 60 years. Overall, delaying emissions reduction policy does not decrease the retirement age. Furthermore, the average age of plants retired due to the emissions policy is never younger than the financial life of plants—the minimum average retirement age for any scenario is 50 years.

The average age of retired plants gets steadily younger as the emissions target increases (for PSY 2014, the average age of retired plants with a 5% target and a 50% target are 65 years and 51 years, respectively). The situation is more complicated for the PSY: for a 5% emissions target, the average age of retired plants increases as the PSY gets later until ~PSY 2025, after which the average age decreases. This inverted-U shape represents the

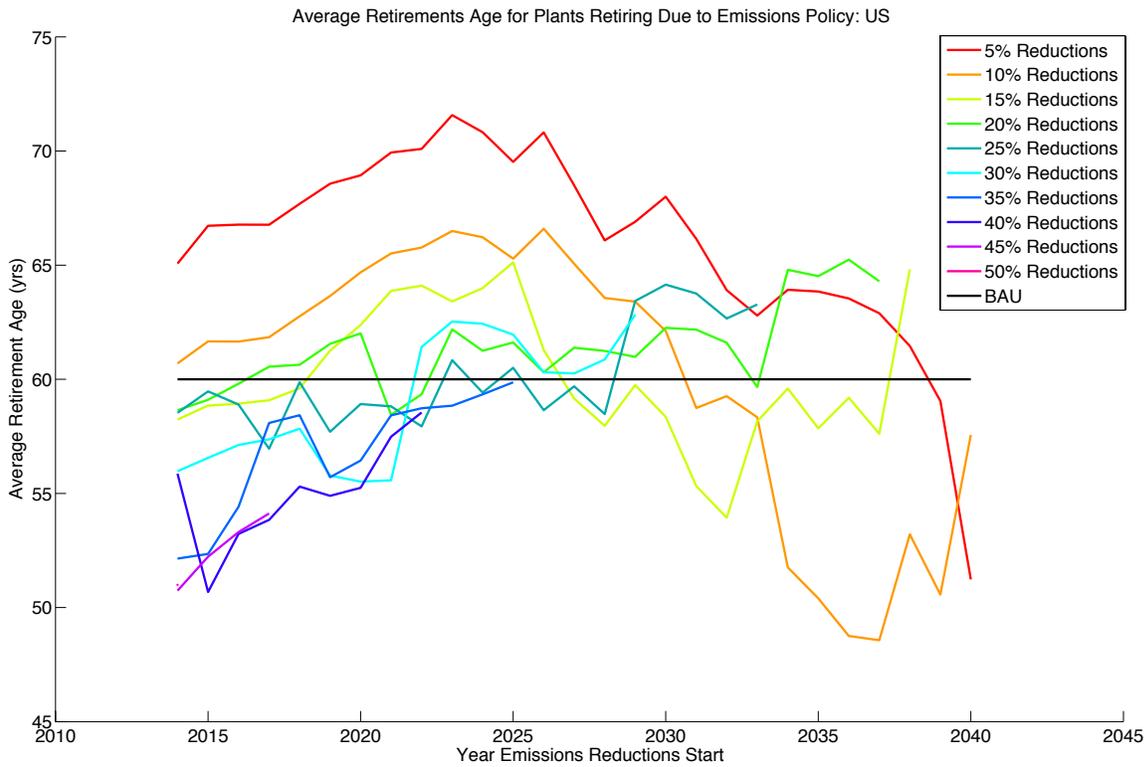


Figure 3-12 Average age of plants retired due to emissions reduction policy, as a function of policy start year. Each contour represents an emissions reduction target.

balance between two forces: as policy is delayed, existing plants get older naturally. But once policy is implemented, plants may retire quickly (depending on how aggressive the policy is). This effect is only seen in lower emissions targets, because higher targets become infeasible before the retirement age peaks. Generally, plants retire younger than BAU for either high emissions targets or late PSYs. Plants retire older than BAU in scenarios with low emissions targets and early PSYs. This is due to the dispatch mechanism-- in the early years of emissions reduction policy, utilization from inefficient gas plants temporarily increases to compensate for decreasing utilization of coal plants

(due to the carbon price) which prolongs the life of inefficient gas plants for a few years. In the BAU scenario, more efficient gas plants are constructed which replace inefficient gas plants.

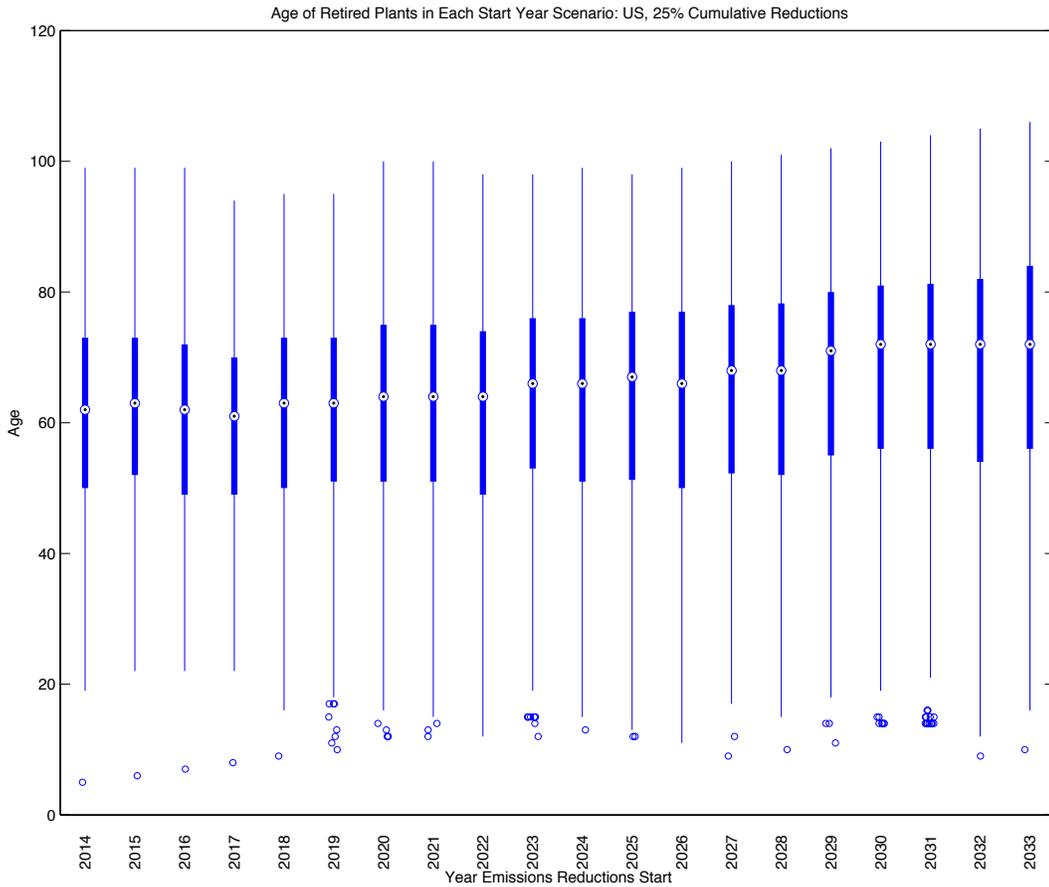


Figure 3-13 Box-and-whisker plot of the age of retired plants for the 25% cumulative emissions reduction scenario. The circle in the middle of each bar is the median plant, the thick bars show the middle 50%, the thin bars show the 5th and 95th percentile, and the dots show outliers.

While Figure 3-12 shows that the *average* age of retired plants under all emissions reduction scenarios is greater than the financial life of fossil fuel plants, there are plants that do retire younger than their financial lifetime. Figure 3-13 shows a box-and-whisker plot of the age of plants retired due to climate change policy for the 25% cumulative

reductions scenario. For all PSYs, there about 10% of plants are retired younger than 30 years. These plants will have stranded capital costs that will be of concern to plant owners, and may concern policy makers. The number of plants retired prematurely is not correlated with increasing PSY, suggesting that policy delay will not increase the number of prematurely retired plants.

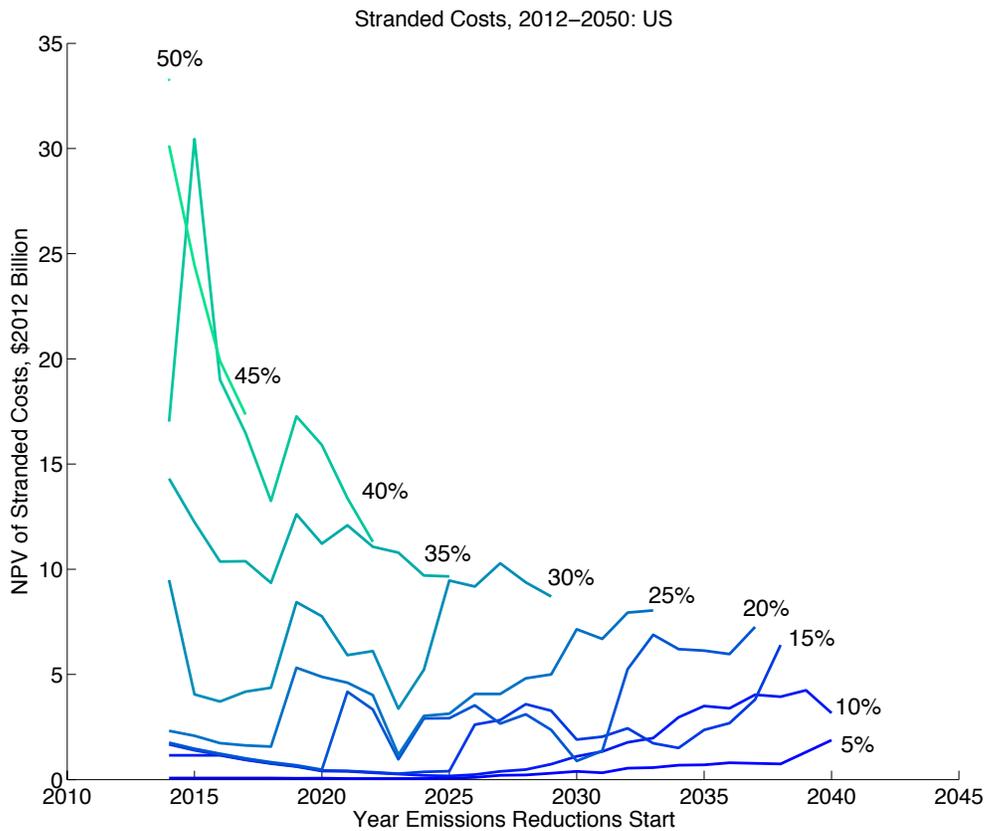


Figure 3-14 Stranded costs in \$2012 from prematurely retired plants (US) as a function of emissions target and reduction start year.

Stranded costs were calculated assuming a real discount rate of 1.1%, straight-line depreciation and zero salvage value for financial lifetimes of 30 years for natural gas and 40 years for coal.

Figure 3-14 estimates stranded costs from prematurely retired plants. Assuming straight-line depreciation over the whole financial life of the plant (30 years for natural

gas, 40 years for coal), a salvage value of zero, and a real discount rate of 1.1%, the book value (stranded cost) of prematurely retired plants was calculated for each start year/emissions target scenario. Total stranded costs for the US range from \$80M (\$2012; PSY 2014, 1% reductions) to \$35B (PSY 2014, 50% reductions), which is three orders of magnitude smaller than construction costs associated with emissions reductions. The average stranded cost per prematurely retired MW ranges from \$6/MW (PSY 2022, 5% reductions) to \$4200/MW (PSY 2014, 50% reductions). Stranded costs are zero in the BAU scenario (not shown).

Stranded costs are relatively insensitive to PSY, although there is quite a lot of variability for higher emissions targets. Stranded costs are very sensitive, however, to emissions target. Increasing the emissions target from 5% to 35% increases stranded costs from approximately \$80 million to \$12 billion.

3.4 INFEASIBILITY FRONTIER

Figure 3-8 to Figure 3-10 do not show all possible combinations of PSY and emissions target. That is because some combinations are impossible to achieve by the electricity sector alone. This “area of infeasibility” is shown in the grey area of Figure 3-15, which presents average annual construction (Figure 3-9) as a two-dimensional contour plot. Each year of delay decreases the achievable emissions target by 1.4 percentage points.

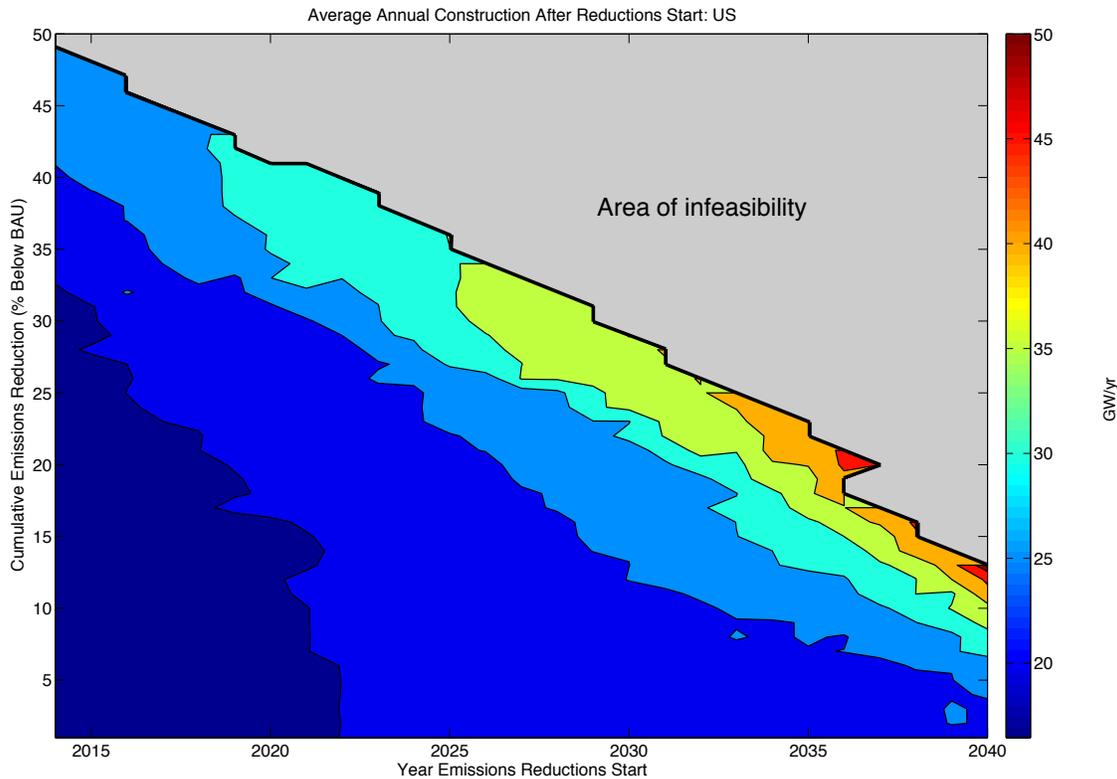


Figure 3-15 Contour map of average annual construction as a function of emissions target and policy start year.

The grey area is the combination of PSY and emissions target that is impossible to achieve without pulling CO₂ out of the air. The boundary between feasibility and infeasibility shown here is drawn as soon as one region cannot achieve the emissions target; for regional infeasibility curves see Figure 3-18.

This boundary line can be considered the tradeoff frontier between emissions targets and timing; as policy implementation is delayed, some levels of emissions targets become infeasible for the electricity sector alone (i.e. meeting the cumulative cap requires negative emissions). The area of infeasibility shown here is the point at which the electricity sector cannot achieve the emissions target. (Note that since the electricity sector is responsible for most emissions reductions under an economy-wide policy, (Environmental Protection Agency, 2009; J. H. Williams et al. 2012; Long & John 2011; K. C. Johnson 2010) if the emissions target is infeasible for the electricity sector it is likely to also be infeasible for the rest of the economy.) If there are other limiting

factors—for example, if the US’s construction capabilities are less than the rates estimated here, then the area of infeasibility will move inward. For example, if average annual construction is capped at three times the historical average, then the boundary of the area of infeasibility would be at the line between light blue and aqua in Figure 3-15. The implication of such physical limitations are discussed in Section 5.2

3.5 REGIONAL CONSIDERATIONS

Sections 3.1 -3.4 of this chapter showed results for the entire US, aggregated using a uniform emissions target across regions (i.e., 30% reductions for the US were calculated by aggregating the 30% scenarios for each region). As discussed at the beginning of the chapter, the significant differences between regions mean that it is unlikely that a national emissions target will manifest uniformly across regions (unless uniform distribution is mandated by policy or regions act independently). This section discusses how and why regions respond differently to emissions policy by examining the capacity turnover, stranded costs and tradeoff frontiers for each region. Table 2-2 describes the geographical boundaries of each NERC region.

There are significant differences across regions in how a region responds to a climate policy. Figure 3-16 shows average annual construction after emissions reductions start in each region for four policy start years (2014, 2020, 2026, 3032; vertical bars in each region’s group). The colored bars show how average annual construction changes with increasing emissions targets, with the additional construction from increasing the target stacked successively for four emissions targets: 20%, 30%, 40%, and 50%. In cases where an emissions target is not shown, the PSY/emissions target combination is

infeasible. Each region's historical average construction (solid black line; 1940-2012) and single-year historical maximum construction (dotted black line; 1940-2012) are also shown.

As with the US as a whole, average construction increases in all regions both as the PSY gets later and as the emissions target increases. For all scenarios for all regions, average construction is higher than the historical average. FRCC, SERC and WECC have much higher construction for most PSYs in the 20% reduction scenario than the historical average. This suggests that these regions will have a harder time reaching more aggressive emissions targets. Under a cap and trade, these regions would probably buy credits from regions such as NPCC that have an easier time decarbonizing. For no scenario in any region does the average annual construction under an emissions reduction policy exceed the historical maximum in that region; in fact even the most aggressive scenarios have average annual construction of approximately half the historical maximum in most regions (SERC reaches 80% of the historical maximum in its most aggressive scenario). It should be noted, however, that an average annual construction rate of half the historical maximum is an unprecedented level of sustained construction. As Figure 3-10 showed, these averages obscure periods of much higher activity when annual construction drastically exceeds the historical maximum.

Figure 3-16 makes clear the differences between how regions respond to increasing emissions targets. Some regions (FRCC) have little difference in infrastructure turnover between a 20% target and a 40% target. Other regions (RFC, SERC) have large increases in average construction as the emissions target increases.

Figure 3-16 also shows that some regions pay higher penalties for delaying policy implementation. For the 20% reduction scenario, SPP has a 130% increase in annual construction, after delaying from PSY 2014 to PSY 2032. FRCC sees only a 15% increase for the same delay. For the 40% reduction scenario, RFC has a 100% increase in average annual construction after delaying policy implementation from 2014 to 2032, respectively, while NPCC has only a 20% increase.

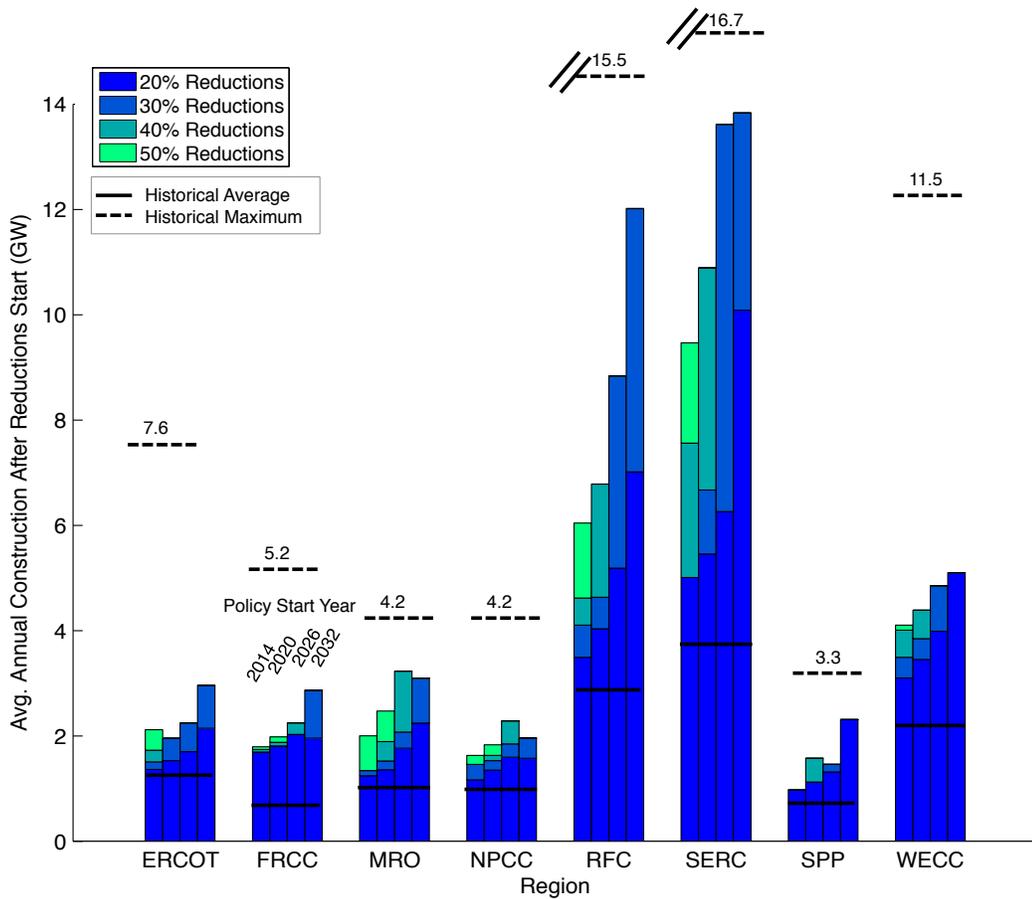


Figure 3-16 Average annual construction after emissions reductions start (GW) by region. Each bar in a regional group represents a different start year (PSYs 2014, 2020, 2026, 2032). Each color represents increasing emissions targets (20-50%), where the colors are stacked additively (e.g. for ERCOT in PSY 2014, average annual construction is 1.3GW for a 20% target and 1.4GW for a 30% target). The solid black lines are the historical average construction in each region (1940-present) and the dotted black lines are the historical single-year maximum construction in each region. Where an emissions target is not shown, that combination of PSY and target is infeasible.

Figure 3-17 shows stranded costs from prematurely retired plants in each region for four PSYs (2014, 2020, 2026, and 2032) and four emissions targets (20%, 30%, 40%, and 50%). There are striking differences across regions in the cost of prematurely retired plants. For most emissions targets, stranded costs are concentrated in only a few regions. For the 20% reduction scenario, only SPP and SERC have prematurely retired plants for all four PSYs; for PSYs 2026 and 2032, MRO also has significant stranded costs. For the 30% reduction scenario, MRO dominates for all PSYs.

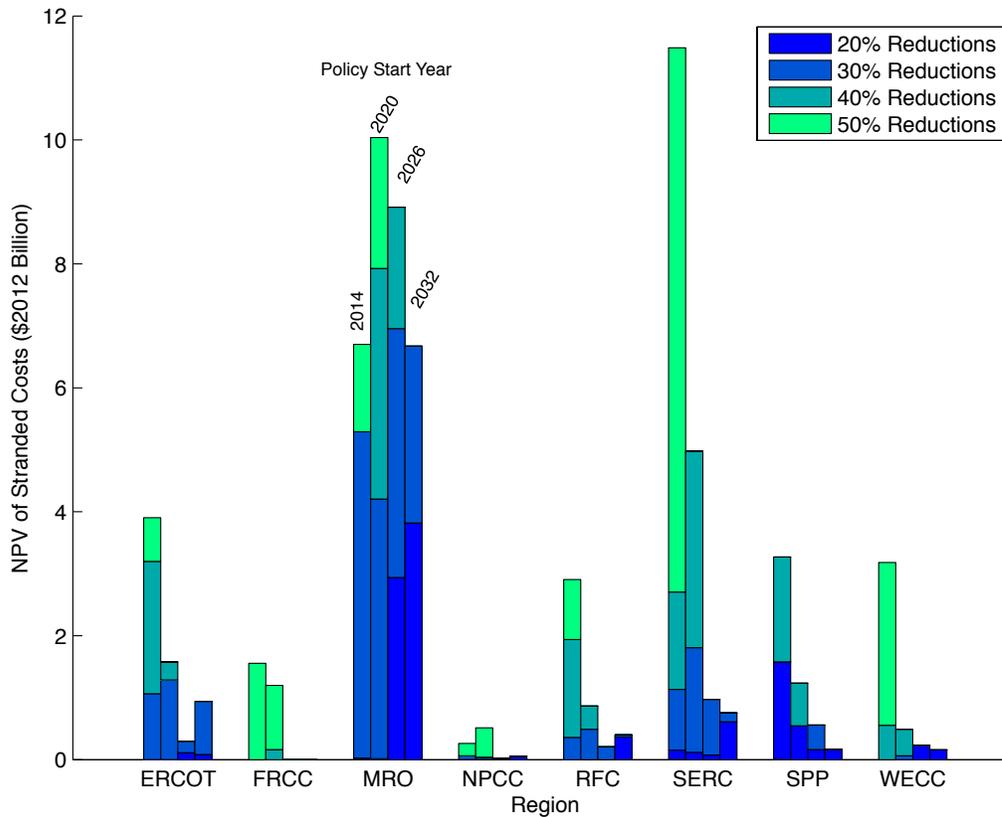


Figure 3-17 NPV of stranded costs from plants retired prematurely due to emissions reduction policy. Each bar in a regional group represents a different start year (PSYs 2014, 2020, 2026, 2032). Each color represents increasing emissions targets (20-50%), where the colors are stacked additively (e.g. for ERCOT in PSY 2014, the NPV of stranded costs is \$1 billion for a 20% target and \$2.2 billion for a 30% target).

In general, regions with young fleets and high emissions intensity have higher stranded costs: ERCOT, MRO and SPP have young fleets (averaging 25, 29, and 29 years, respectively) and moderate (ERCOT) to high (MRO, SPP) emissions intensities and have high stranded costs, especially relative to their size. NPCC and RFC, on the other hand, have older fleets (33 and 34 years, respectively) and low stranded costs for their size. FRCC, which has a young fleet (25 years) is buffered against stranded costs by its low emissions intensity (500g/kWh, the third lowest) until higher emissions targets. SERC is similarly buffered by the age of its fleet (32 years) and moderate emissions intensity (600 g/kWh) until higher emissions targets.

Some regions, such as FRCC, NPCC, and WECC, do not see significant stranded costs until very high emissions targets. ERCOT, MRO, RFC, and SPP do not see significant increases in stranded costs with higher reduction targets, but this is because they are already retiring all of their young plants at lower targets. SERC sees an enormous increase in stranded costs in the 50% scenario. The differences between regions due to emission target may be of concern to policymakers who are concerned with inter-regional equity resulting from climate change policy, since some regions bear a higher burden from high emissions targets. Allowing regions to achieve different emissions reductions, as would be expected under a cap and trade policy, could mitigate this problem.

With the exception of MRO, most regions do not see a significant increase in stranded costs as policy is delayed. In fact, for most regions stranded costs go down as policy is delayed because plants age out of the “premature” category.

The differences between the regions are summarized in Figure 3-18, which shows the regional infeasibility frontier (note that the axes are reversed from Figure 3-15, which shows the national infeasibility frontier). In Figure 3-15, the infeasibility frontier was identified at the point where the first region was unable to meet the emissions target without using air carbon capture technology. Figure 3-15 is thus a lower bound on the US infeasibility frontier, since under a national policy regions with later frontiers could theoretically compensate for underperformance in regions with earlier frontiers.

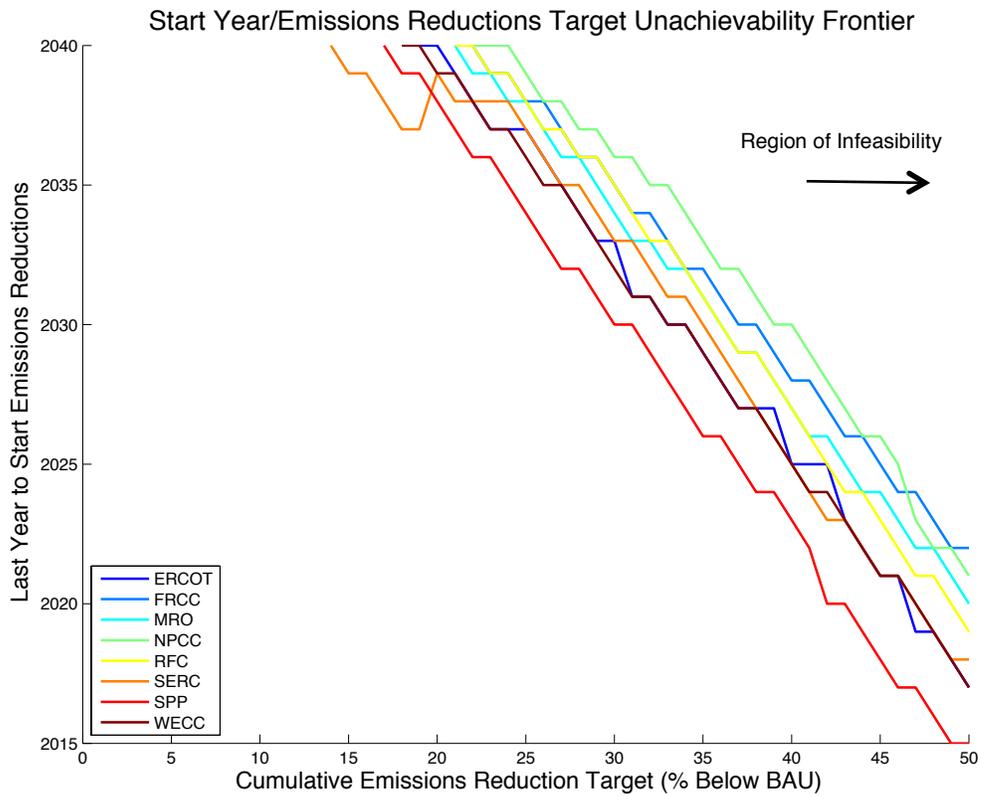


Figure 3-18 Infeasibility frontier by region. Emissions target/policy start year combinations to the north east of the lines are impossible without carbon air capture technology.

SPP has the earliest infeasibility frontier for most emissions targets (for emissions targets between 15%-20%, SERC has an earlier frontier, which explains the jag in Figure 3-15) while NPCC has the latest frontier for all but the very highest emissions targets. This means that if regions choose to delay as long as possible before starting reductions, NPCC can wait 5-7 years longer than SPP to start reducing emissions for a given reduction target. The variance between regions increases as the emissions reduction target increases.

The differences between regions, both in the infeasibility frontiers and in the construction rates and stranded costs shown in Figure 3-16Figure 3-17, are partly due to the fossil intensity of the existing grid in each region. Regions with higher emissions intensity generally have a few extra years before reaching the infeasibility frontier. (IFAM modeled NPCC's 2012 emissions intensity as 260 g/kWh and SPP's as 783 g/kWh.) The location of the frontiers is also due, however, to the projected BAU emissions growth. Regions with high BAU emissions growth (due to a combination of demand growth and the BAU generation portfolio standard) have higher cumulative BAU emissions, which means that their cumulative emissions cap (which is relative to BAU) will also be higher than it would be with lower BAU emissions. WECC, for example, has relatively low BAU emissions growth (2050 emissions are 30% higher than 2012 emissions), which brings its infeasibility frontier to the left even though WECC has a low emissions intensity grid (430 g/kWh in 2012). RFC has relatively high BAU emissions growth (2050 emissions are 50% higher than 2012 emissions) which brings its infeasibility frontier to the right, even though RFC's 2012 emissions intensity was a relatively high 610 g/kWh.

CHAPTER 4: SENSITIVITY ANALYSES AND POLICY INTERVENTIONS

This chapter explores the sensitivity of model results to various model parameters. Three of these parameters (fuel prices, the gas/wind ratio, and the level of aggregation) test the sensitivity of IFAM to model choices or uncertain inputs. The other three parameters (demand growth rate, BAU construction portfolio, and low-carbon construction portfolio) represent possible policy interventions that could affect how vulnerable US climate change goals are to the timing of policy implementation.

4.1 SENSITIVITY ANALYSES

4.1.1 Coal and Natural Gas Prices

It has been widely documented that natural gas prices are one of the most important factors determining the financial sustainability for power plants. (Lu et al. 2012; T. Johnson & Keith 2004; Kaplan 2010) Coal plants, in particular, are strongly affected by the relative prices of natural gas and coal. In fact, the Electric Power Research Institute found that natural gas prices affected coal plants more than climate change policies. (EPRI & James 2009)

In IFAM’s reference case, which uses 2009 fuel prices, the ratio of natural gas prices to coal prices is 1.72. For the sensitivity analysis, I identified the scenarios from the AEO 2011 (U S Energy Information Administration 2011) with the highest and lowest ratio of gas prices to coal prices in the year 2025 (“low shale gas reserves and low recovery from each well” and “high coal prices”, respectively). These two scenarios, together with their opposite (“low coal prices”, “high shale gas reserves and well recovery”) and the reference scenario are used to test the sensitivity of IFAM’s results to natural gas and coal prices. I used projections for fuel prices for the year 2025 so that the scenarios develop enough to change relative fuel prices (2012 prices are virtually the same as 2009 prices and thus are not suitable for a sensitivity analysis). The sensitivity analysis uses the gas and coal prices shown in Table 4-1 (since the AEO does not distinguish between types of coal, all coal is given the same price). All other fuel prices remain the same.

Table 4-1 Sensitivity analysis for fuel prices. Scenarios and data from (U S Energy Information Administration 2011) for the year 2025.

Scenario	NG Price (\$/mmBtu)	Coal Price (\$/mmBtu)	Ratio of Gas/Coal Prices
IFAM reference case	4.74	2.76	1.7
AEO reference case	5.91	2.24	2.6
High coal prices	6.1	3.03	2
Low coal prices	5.85	1.71	3.4
Low gas prices: high shale gas reserves and high recovery from each well	4.6	2.15	2.1
High gas prices: low shale gas reserves and low recovery from each well	8.23	2.31	3.6

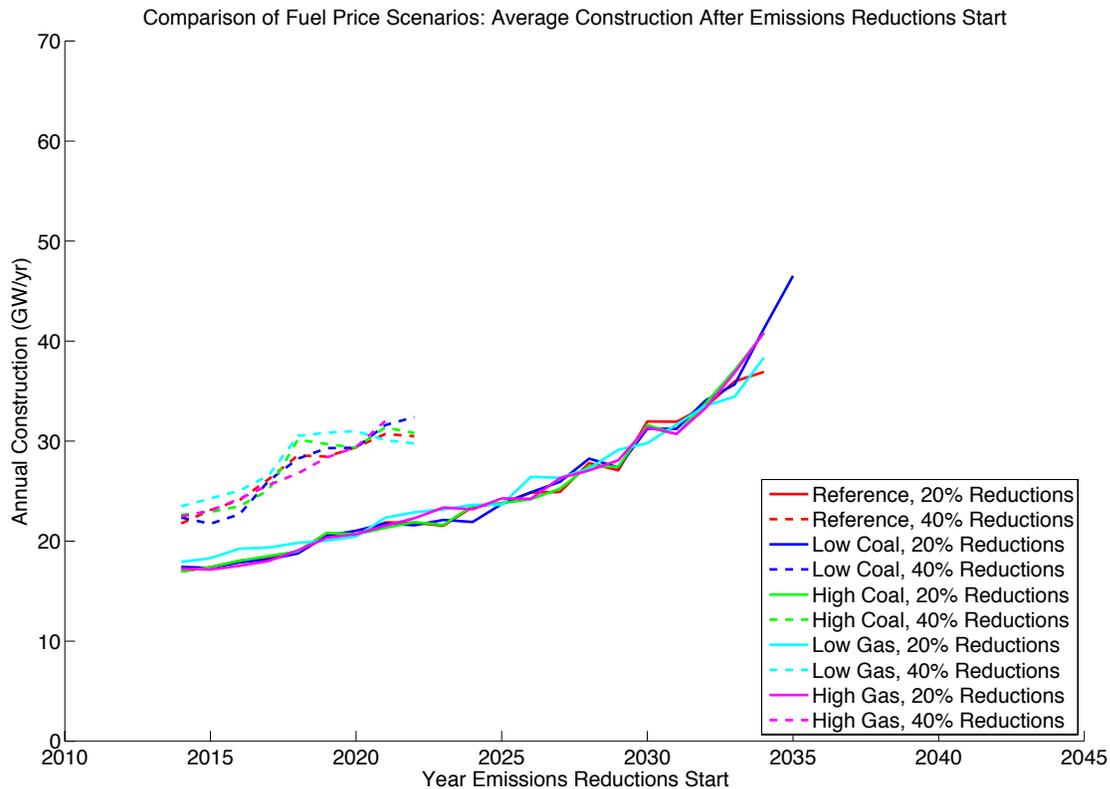


Figure 4-1 Average annual construction after emissions reductions start for 20% and 40% emissions reduction targets and five fuel price scenarios.

Figure 4-1 shows average annual construction after emissions reductions start for the 20% and 40% cumulative emissions reductions below BAU for all five fuel price scenarios. While there is some variability in the 40% emissions reduction scenario, fuel price does not significantly affect construction rates. This is not entirely unexpected; in order to meet emissions targets most of the US fossil generating fleet must be replaced. This replacement happens independent of the relative economics of various fuel types—if coal is more or less expensive relative to natural gas, IFAM adjusts the carbon price to force coal to retire. This means that fuel prices do not significantly affect the rate of infrastructure turnover.

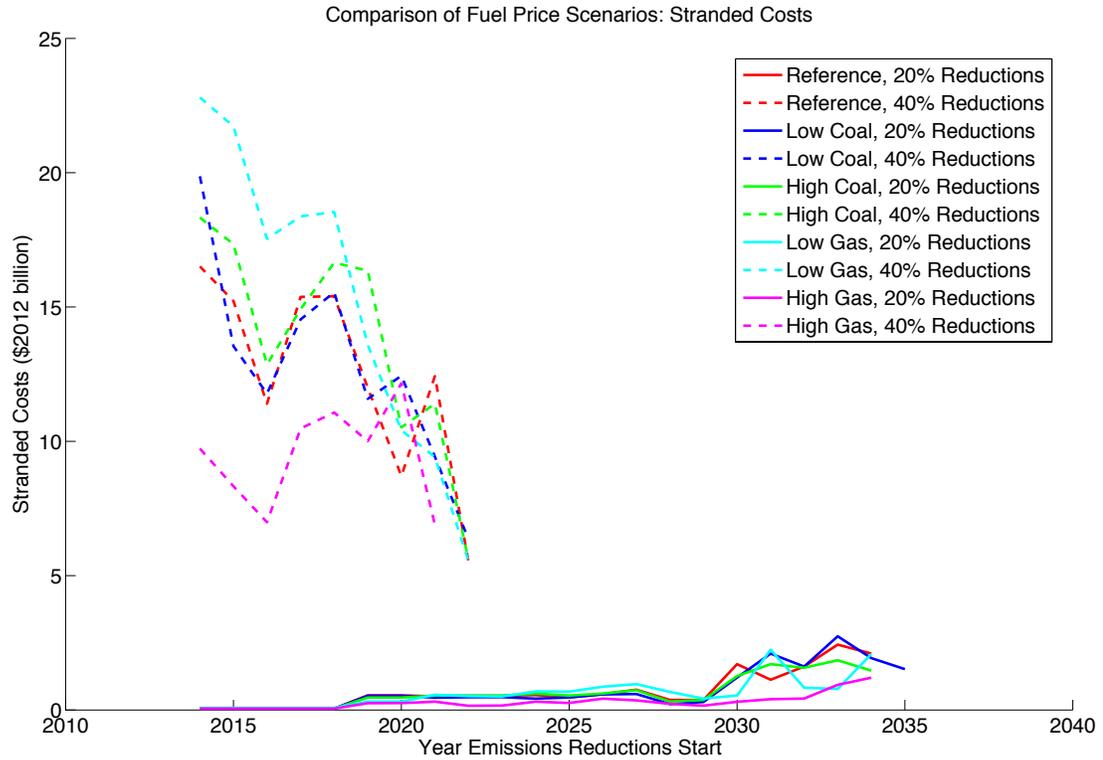


Figure 4-2 NPV of stranded costs from prematurely retired plants for 20% and 40% emissions reduction target scenarios and five fuel price scenarios. Calculated using a real discount rate of 1.1%

Fuel prices do, however, affect the cost of that turnover. Figure 4-2 shows the net present value of stranded costs from prematurely retired plants (calculated using a real discount rate of 1.1%). While stranded costs are very low for all fuel price scenarios for the 20% emissions reduction target, fuel prices have a strong effect on the 40% scenario. This is especially true for early start years (costs are higher for early start years because as the start year is delayed, plants age out of the “premature retirement” category). Stranded costs for the low gas price scenario are more than double stranded costs for the high gas price scenario for PSY 2014. This happens because low gas prices cause coal

plants to become less profitable relative to gas, causing coal plants to retire earlier (with increased stranded costs) than they do with high gas prices.

4.1.2 Gas/Wind Ratio

The gas/wind ratio (GWR) is the amount of gas that must be paired with wind to compensate for the variability in wind production (see Section 2.4.5). When the GWR is 20%, for example, 20% of each MWh of wind generation actually comes from gas generation that was used to balance wind variability. This also implies that there are emissions associated with wind generation, since some natural gas production is required.

In order to test the sensitivity of IFAM's results to the GWR, the GWR was varied from 0%-40% in increments of 10% (the reference case has GWR=20%). Changing the GWR slightly affects the generation mix—a low GWR has slightly higher (<5%) gas and coal generation, and slightly lower (~3%) wind generation than high GWRs. This result is a little bit counterintuitive, since one would expect a high GWR (where more gas is produced for each MWh of wind generation) to cause more gas generation. However, with a high GWR, there are more emissions associated with wind generation, leaving less room for emissions associated with coal and gas generation under the cap and reducing coal and gas output. Still, this effect is so small as to be barely noticeable. In fact, the GWR ratio has no impact on any of the metrics discussed in Chapter 3 (construction and retirement rates, costs).

4.2 POLICY INTERVENTIONS

The following three sensitivity analyses represent possible policy interventions that could buy time for implementing climate policy by reducing the impact of policy delay on infrastructure turnover in the electricity sector.

4.2.1 Demand

Demand is an important driver of construction in the electricity sector, since increased demand for electricity must be met with new capacity investments. This new capacity is in addition to whatever capacity construction is needed to replace fossil fuel plants that are retired due to climate policy. Reduced demand, conversely, reduces the need for new investments in electricity generating capacity. Energy efficiency, therefore, may be a way to reduce the impact of climate policy delay on turnover in the electricity sector, since it reduces the additional new capacity construction that is needed to meet demand growth. Here I test this hypothesis with four demand scenarios: the highest and lowest demand growth projections from the AEO 2011 (U S Energy Information Administration 2011) and two extreme cases of zero growth and a very high growth rate (growth rate doubles).

IFAM's reference case (taken from the AEO 2011's reference case) projects electricity demand growth at 0.8%. The highest and lowest growth scenarios in the AEO 2011 (EIA 2011) project national electricity growth rates of 1.1% (high economic growth scenario) and 0.4% (high technology price scenario), respectively. Regional growth rates are

adjusted so that they increase/decrease at the same rate as the national rate. For example, the low growth rate is 50% of the reference case at the national level. ERCOT, which has a BAU growth rate of 0.7%, thus has a low growth rate of 0.7% * 50% = 0.35%.) Additionally, I test two extreme cases of zero growth (growth rate is zero in all regions) and very high growth (growth rate doubles). Table 4-2 shows the growth rates in each region for each scenario.

Table 4-2 Growth rates in each region for each scenario in the demand growth sensitivity analysis.

NERC Region	Demand Growth Scenarios				
	Reference	Zero	Low	High	Very High
ERCOT	0.7%	0%	0.4%	1.0%	1.4%
FRCC	1.1%	0%	0.6%	1.5%	2.2%
MRO	0.6%	0%	0.3%	0.8%	1.2%
NPCC	0.7%	0%	0.4%	1.0%	1.4%
RFC	0.7%	0%	0.4%	1.0%	1.4%
SERC	0.7%	0%	0.4%	1.0%	1.4%
SPP	0.5%	0%	0.3%	0.7%	1.0%
WECC	0.9%	0%	0.5%	1.3%	1.8%

Figure 4-3 shows average annual construction after emissions reductions start for all five demand growth scenarios for 20% and 40% emissions reduction targets. As expected, average annual construction increases steadily with increasing demand growth rates. If demand doubles from the reference case (very high demand scenario), infrastructure turnover increases by 180%-260%, depending on the emissions target and start year. There is thus a high penalty in terms of infrastructure turnover for increasing demand growth rates.

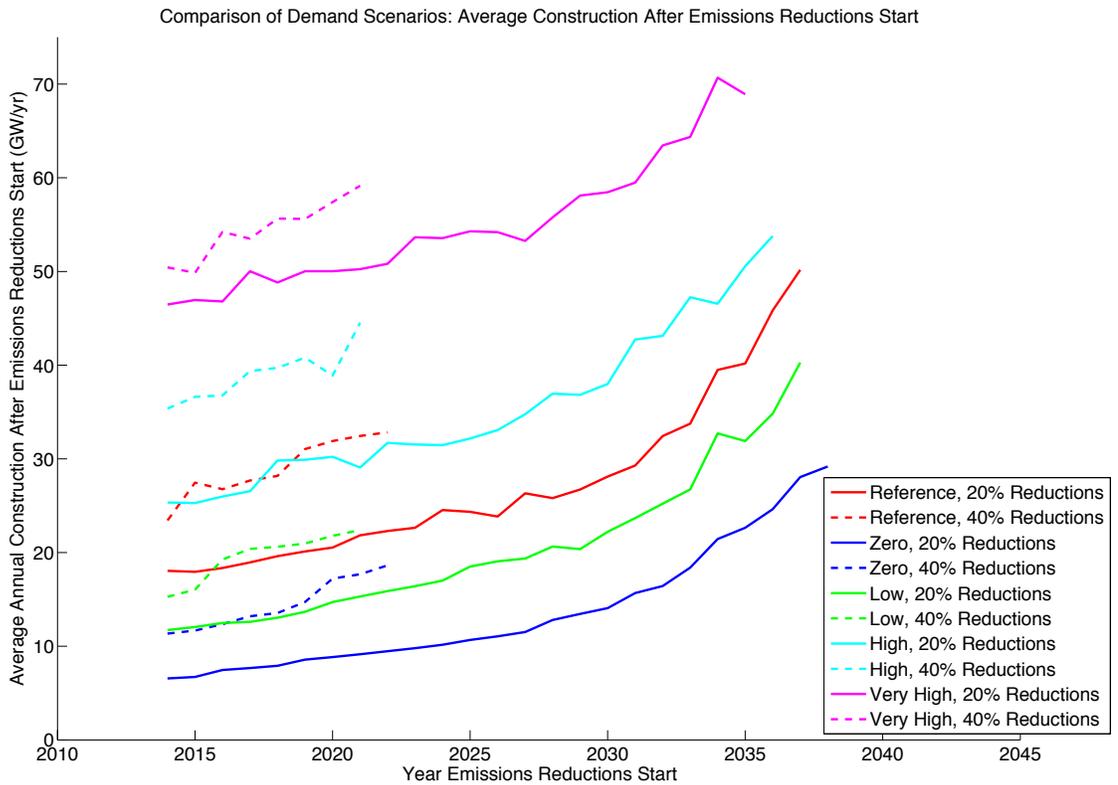


Figure 4-3 Comparison of demand scenarios for 20% and 40% emissions reduction scenarios for five demand growth scenarios.

The 0% demand growth lines show infrastructure turnover due exclusively to climate policy. Depending on the start year, therefore, between one half and one third of turnover in the reference scenario is due to demand growth. This implies that an energy efficiency policy could significantly reduce the amount of infrastructure investment needed in the electricity sector to achieve emissions reduction targets.

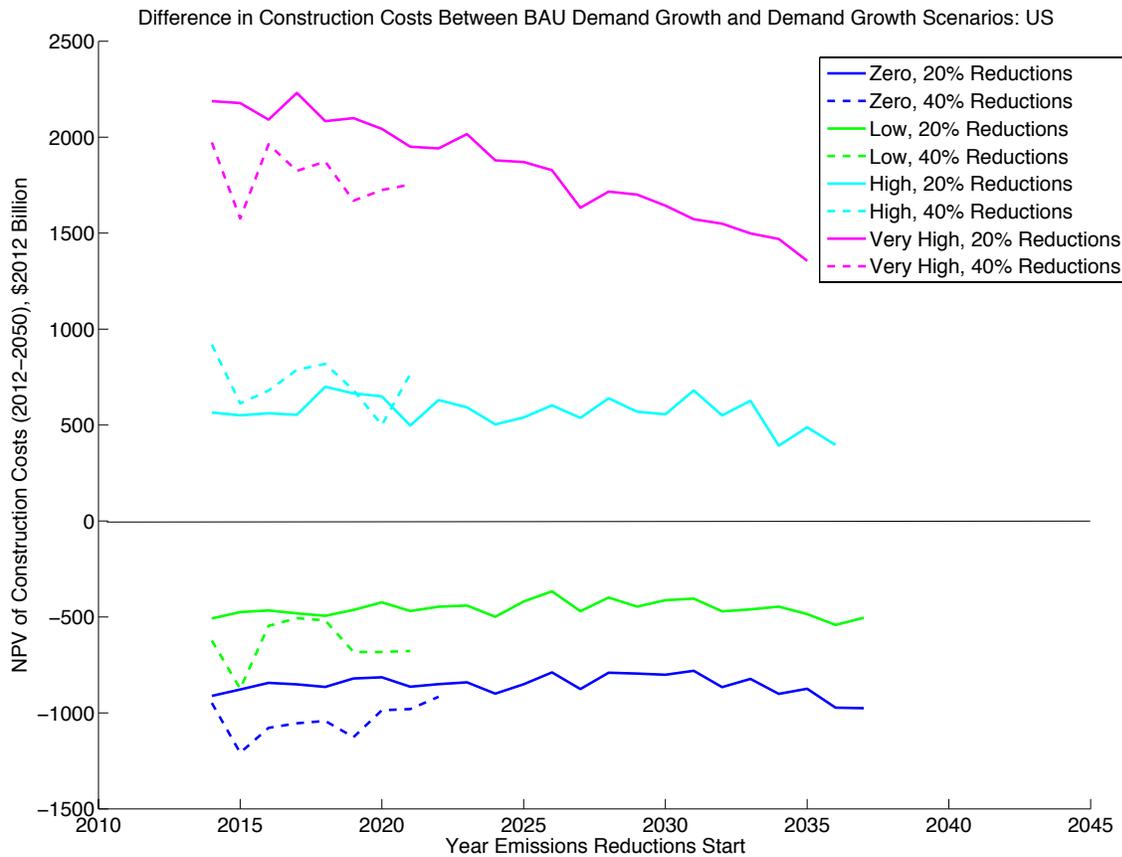


Figure 4-4 Difference in construction costs between reference case and demand growth scenarios. Calculated using a real discount rate of 1.1%.

Figure 4-4 shows the difference in the NPV of construction costs between the reference scenario and the various demand growth scenarios (calculated using a real discount rate of 1.1%). The high and very high demand growth scenarios cost significantly more than the reference case--\$500 B for the high growth scenario and \$2 trillion for the very high growth scenario. Both the zero growth and low growth scenarios have lower costs than the reference scenario, by \$500-1000 billion. The difference in electricity generation between the reference and low growth scenarios is approximately 700 TWh in 2050.

4.2.2 BAU Construction Scenarios

The type of generating capacity built before an emissions reduction policy is implemented affects the impact of that policy because building new high-carbon-intensity generating units will use up the cumulative emissions cap faster than if low-carbon generating units were built. Using up the emissions cap quickly means that reductions must proceed faster after a policy is implemented than if there were more room in the cap. If this effect is significant, policymakers might consider incentivizing low-carbon construction prior to an emissions policy with the goal of reducing the eventual cost of emissions reduction. Newcomer and Apt (2009) considered a variation on this idea in their paper, which looked at the near-term effects of a ban on new coal-fired power plant construction. They found that banning the construction of coal-fired power plants has limited impact on future emissions, although natural gas consumption increased dramatically. However, their model did not incorporate an emissions reduction policy and so did not address how the mix of current construction affects the implementation of future policy. Furthermore, the Newcomer and Apt model only considered three ISOs (ERCOT, MISO, and PJM) and was limited to the period before 2030.

The pre-policy implementation (BAU) construction portfolio in IFAM's Reference case is derived from forecasts for future construction in the AEO 2011, which is mostly natural

gas. (U S Energy Information Administration 2011) Here I test two alternate scenarios for BAU construction: a high coal scenario where BAU construction matches the existing generation mix (rather than projected future construction), and a low-carbon scenario where the US builds only low-carbon generating units starting in 2012. These two scenarios represent bounding cases for possible construction pathways.

For the high-coal scenario, the existing capacity mix in each region (shown in Table 4-3) was calculated and scaled so that it equals 100% (some regions have high shares of technologies that are not enabled for construction in IFAM, such as hydro). Gas construction is split between combustion turbine and combined cycle in the same ratio as the BAU GPS. For the low-carbon scenario, the same construction portfolio that is used after emissions reductions begin (47% wind, 36% nuclear, 17% gas) is used starting in 2012.

Table 4-3 High Coal Scenario BAU construction generating portfolio standards

Region	Coal	NGCC	NGCT	Nuclear	Wind
ERCOT	20%	26%	37%	5%	26%
FRCC	18%	74%	0%	8%	74%
MRO	49%	15%	15%	9%	15%
NPCC	10%	63%	6%	18%	63%
RFC	51%	13%	19%	16%	13%
SERC	43%	11%	30%	15%	11%
SPP	37%	28%	28%	2%	28%
WECC	25%	41%	18%	7%	41%

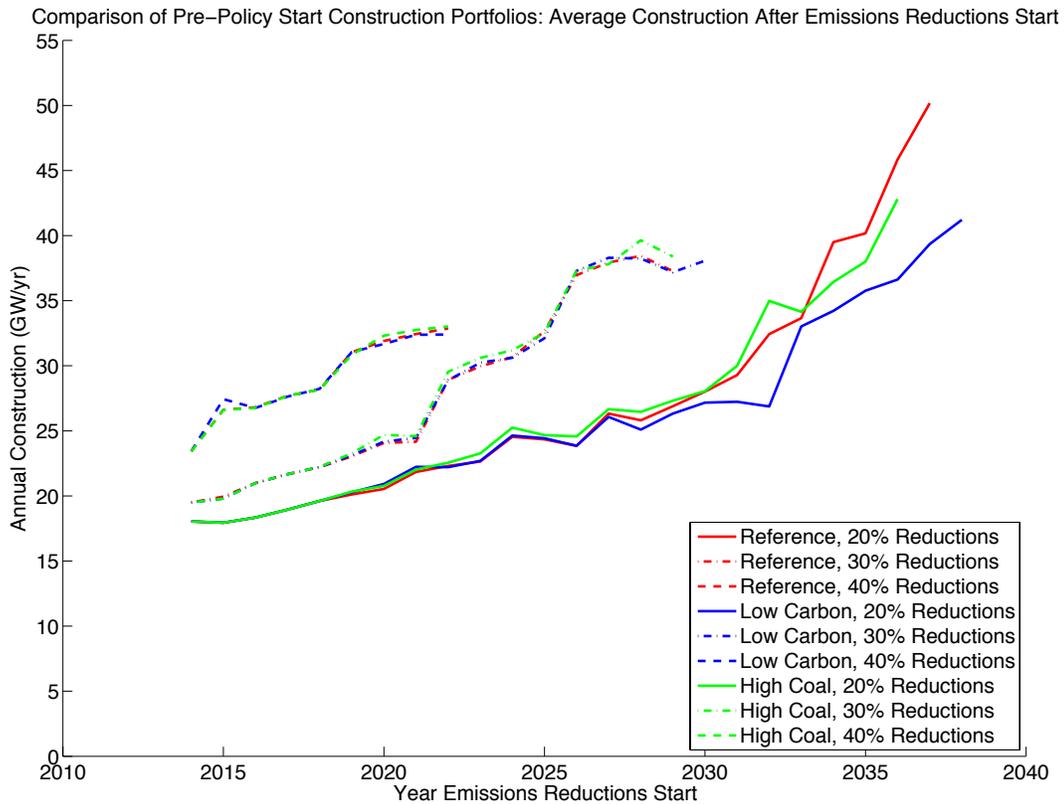


Figure 4-5 Comparison of average annual construction after emissions reductions start between three pre-emissions-policy construction portfolios, for the 20%, 30% and 40% emissions reduction scenarios.

Figure 4-5 compares average annual construction for these three BAU construction portfolios for the 20%, 30%, and 40% emissions reduction targets. There is little difference between the three BAU construction portfolios except for when the PSY is quite late (<2030). This is because the BAU construction portfolio is only used before the PSY. For early PSYs, there is not enough time in the BAU phase for the BAU construction portfolio to have much impact. For late start years, the low-carbon construction portfolio slightly reduces average annual construction. This is

unsurprising, since building only low-carbon generating units during the BAU phase means that fewer units will need to be replaced after reductions start.

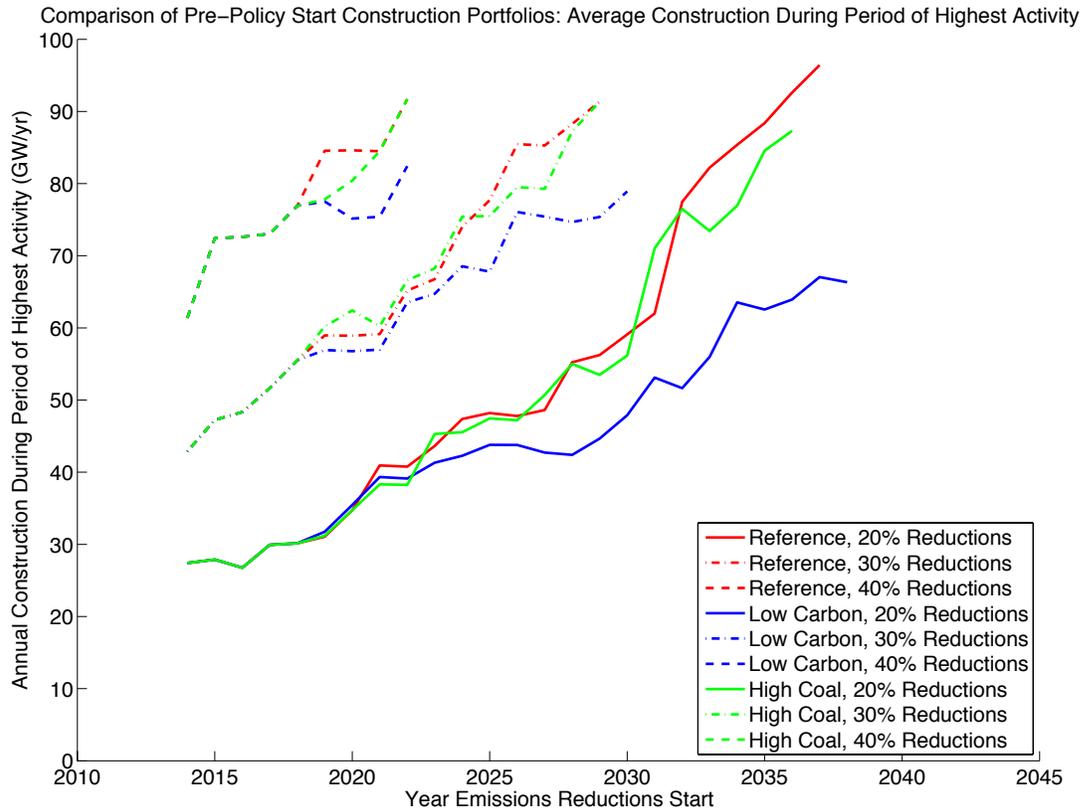


Figure 4-6 Comparison of average construction during the period of maximum activity between three BAU construction portfolios, for the 20%, 30% and 40% emissions target scenarios.

Figure 4-6 shows average construction during the period of maximum activity for the same scenarios. The BAU construction portfolio has more impact on maximum construction levels than it did on average construction. While there is little difference between the reference and high coal scenarios, the low carbon BAU construction portfolio reduces maximum construction levels below BAU by between 10-30%,

depending on emissions target and PSY. As with average construction, this effect is stronger for later PSYs.

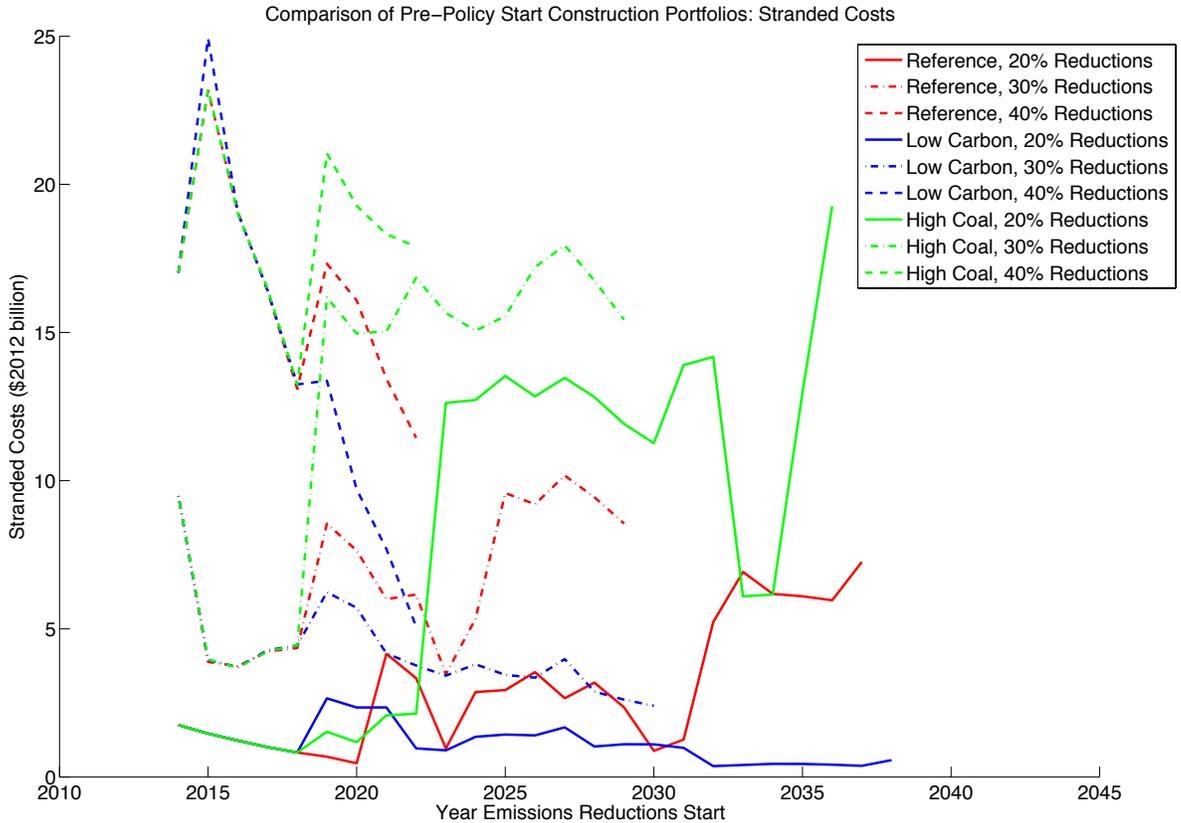


Figure 4-7 Comparison of stranded costs for three BAU construction portfolio scenarios, for 20%, 30% and 40% reduction scenarios. Calculated using a real discount rate of 1.1%.

The BAU construction portfolio also has an impact on stranded costs from prematurely retired plants. Figure 4-7 shows stranded costs for the same scenarios as above. For all emissions targets, stranded costs for the high coal scenario are higher than other BAU construction portfolios. In many cases, stranded costs for the high coal scenario are 2-5 times as high as the BAU scenario. Again, this effect gets stronger as policy

implementation is delayed. Costs are higher for the high coal scenario because many of the newly-built fossil generating units are quickly retired once an emissions policy is implemented.

In conclusion, the BAU construction portfolio has little impact on overall turnover in the electricity sector, but does have a moderate impact on the level of construction during the years of maximum activity. Stranded costs from high-carbon BAU construction, however, are significantly higher than the reference case. This may be of concern to plant operators who build carbon-intensive generating units, especially coal, in the near term.

4.2.3 Low-Carbon Construction Scenarios

A final model parameter that could be directly influenced by policymakers is the low-carbon construction portfolio. In the reference case, IFAM builds a mix of 47% wind, 36% nuclear, and 14% gas after emissions reductions start. This mix was chosen because the Energy Information Administration estimated it to be the least-cost generation mix under an emissions reduction regime. (EIA 2009) However, changing technology costs, policy incentives, and public opinion could easily change the fuel mix that eventually gets built. Here I test three other possible low-carbon construction portfolios: a high wind scenario, a high nuclear scenario, and a high gas scenario. The portfolios are summarized in Table 4-4.

Table 4-4 Fuel mix in Low-Carbon construction portfolio sensitivity analysis

Scenario	Fuel Mix		
	Wind	Nuclear	Gas
Reference (Optimal)	47%	36%	17%
High Wind	65%	18%	17%
High Nuclear	18%	65%	17%
High Gas	25%	25%	50%

Figure 4-8 shows average construction costs after emissions reductions start for each of the four low-carbon construction portfolios, for 20%, 30% and 40% emissions reduction targets. Unsurprisingly, the low-carbon construction portfolio has a large impact on construction rates. The high nuclear scenario has the lowest construction rates and the high wind scenario the highest construction rates, consistent with the fact that nuclear and wind have the lowest and highest capacity factors, respectively, among the three technologies. The optimal (reference) and high gas scenarios, which have a more even mix of technologies and thus capacity factors, fall in the middle.

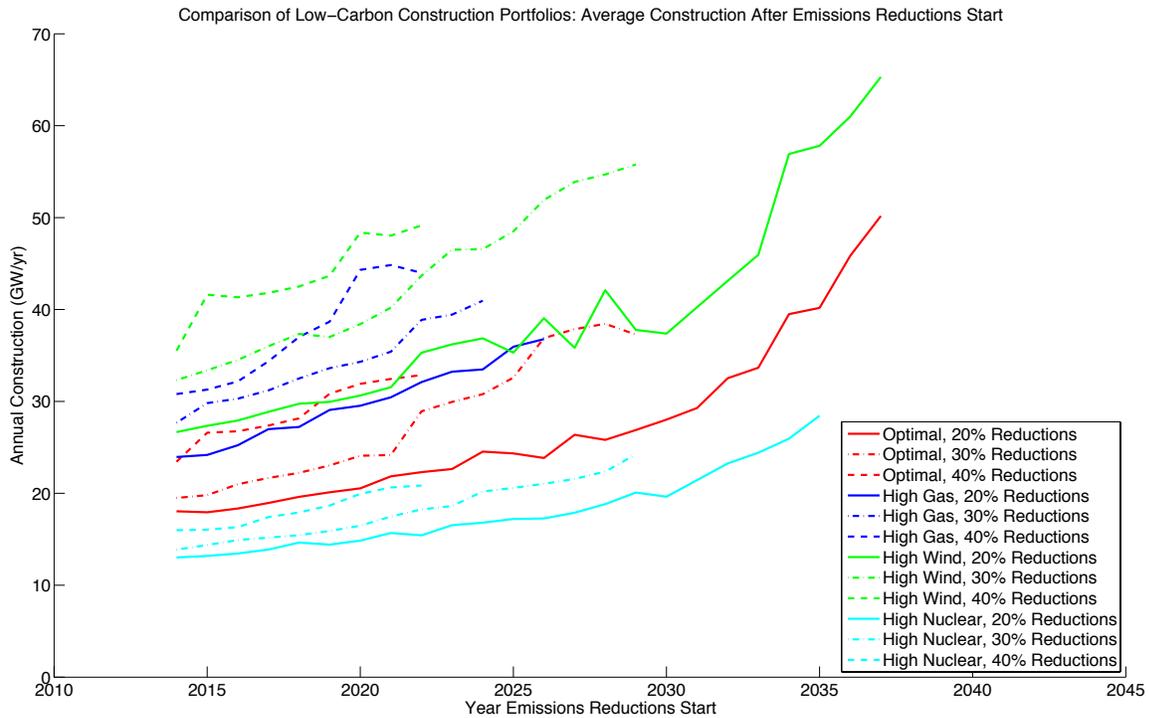


Figure 4-8 Average annual construction rates for four low-carbon portfolio scenarios and three emissions target scenarios (20%, 30%, 40%). The "Optimal" portfolio is IFAM's Reference case. Table 4-4 describes the fuel mix in each scenario.

Figure 4-9 shows the NPV of stranded costs from prematurely retired plants for each of the three Low-Carbon construction portfolios, for three emissions target scenarios. (Calculated with a real discount rate of 1.1%). Stranded costs for the high gas scenario are an order of magnitude larger than the reference case. This is because increasing the share of gas units in the construction mix makes it more difficult to meet the emissions cap. These units are then forced to retire quickly—the average age of retired plants is 30 years in the high gas scenario. These are gas plants that it would have been better not to build in the first place, suggesting that it will be un-economical to build too much gas under an emissions reduction regime.

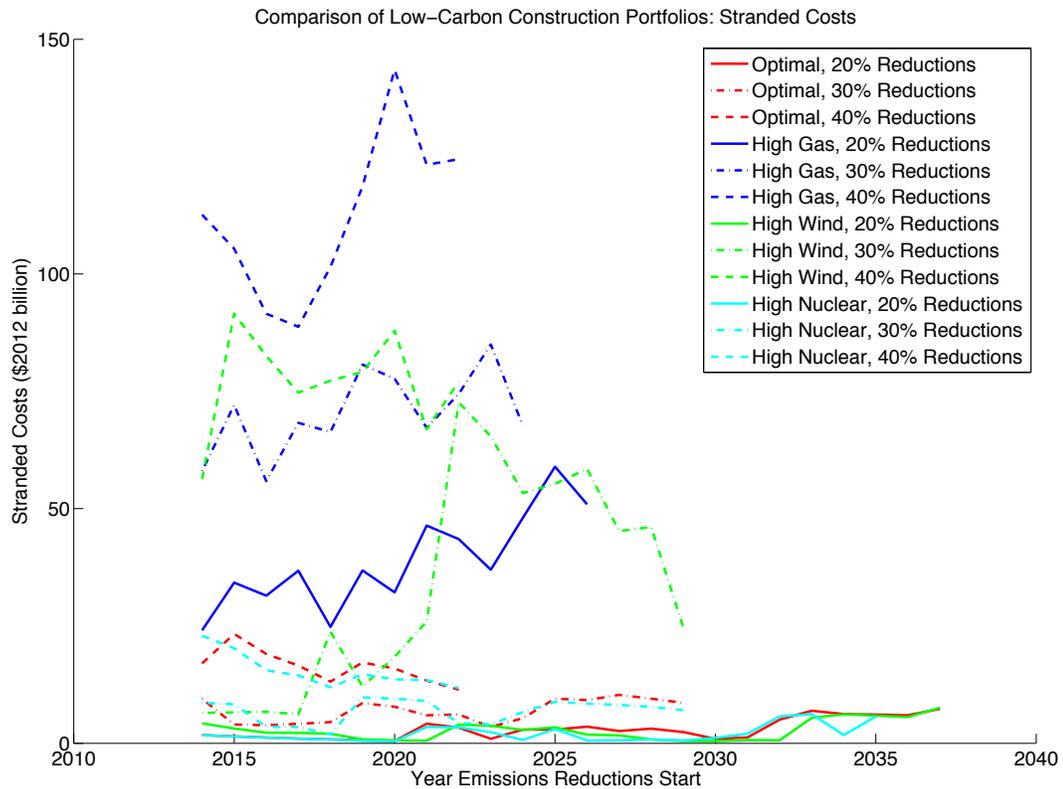


Figure 4-9 NPV of stranded costs from prematurely retired plants. (\$2012, calculated with a 1.1% real discount rate) for four low-carbon portfolio scenarios and three emissions target scenarios (20%, 30%, 40%). The "Optimal" portfolio is IFAM's Reference case. Table 4-4 describes the fuel mix in each scenario.

While the high wind scenario has similar stranded costs to the reference case for a 20% emissions target, it has higher stranded costs than the reference case for higher emissions targets. This is because with high levels of wind penetration, additional gas plants must be constructed in order to provide sufficient operating reserve to manage wind variability. These natural gas plants suffer the same fate as those in the high gas scenario (although there are many fewer of them) and are not profitable long enough to recover their capital costs. At very high levels of wind penetration, therefore,

policymakers may need to consider an additional incentive for balancing plants in order to maintain sufficient operating reserve margins.

4.3 INFEASIBILITY FRONTIERS

As with the reference case, some combinations of PSY/emissions target are infeasible under the various sensitivity analyses discussed above. The infeasibility frontiers for the various sensitivity analyses, which represent the last possible policy start year for each emissions target, are shown in Figure 4-10. Some of the sensitivity analyses had no effect on the infeasibility frontier and are not shown (all GWR scenarios, the high demand growth scenario, the high wind and high nuclear low-carbon construction portfolio scenarios, and the high coal BAU construction portfolio).

None of the scenarios have much effect on the infeasibility frontier for higher emissions targets. This is because so much turnover is required for high emissions targets under any scenario that small changes to demand growth or the fuel mix have little impact. For lower emissions targets, however, the various alternate scenarios have a big impact. For a 30% emissions target, reducing demand growth buys up to four years of policy delay before meeting the target becomes impossible. For lower emissions targets, it is possible to delay beyond 2040 if demand growth is lower than the reference case. High levels of demand growth have the opposite effect—if demand growth is twice as fast as the reference case (very high growth scenario) then it becomes impossible to meet the 20% emissions target three years earlier than the reference case.

The choice of fuel mix also affects the infeasibility frontier. Building a low-carbon construction portfolio starting in 2012 allows an extra four years of policy delay in the 30% reduction scenario. Building a high-gas portfolio after emission reductions start (50% gas; high gas scenario) has the opposite effect, moving the infeasibility to the left. Depending on the emissions target, the relying on gas for emissions reductions forces the US to act up to 10 years earlier than the reference case for the same emissions target.

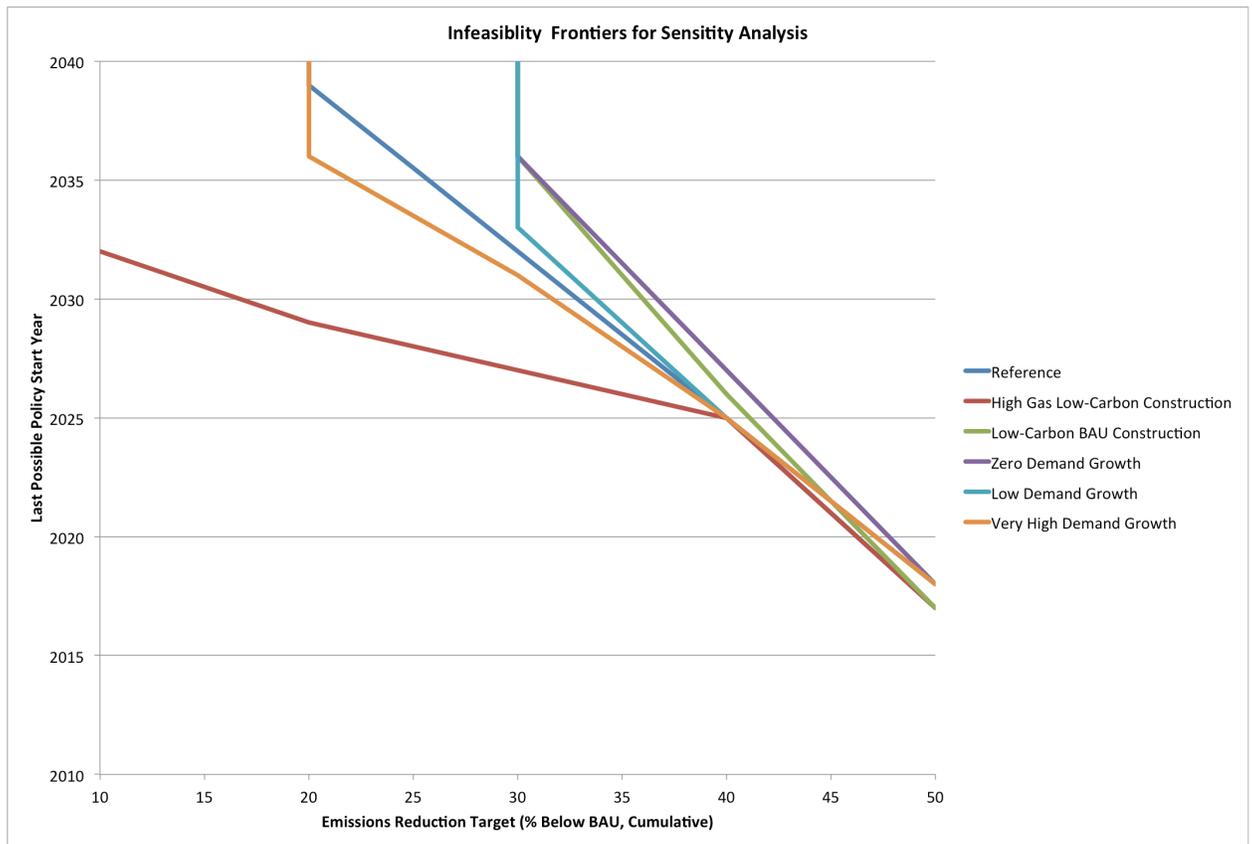


Figure 4-10 Comparison of the infeasibility frontier for the various sensitivity analyses. Only sensitivity analyses that affect the infeasibility frontier are shown. The infeasibility frontier was drawn where the first region is unable to meet the emissions target for a given start year.

CHAPTER 5: CONCLUSIONS AND FUTURE WORK

This chapter summarizes the results presented in this dissertation, offers some final thoughts on the work and its relevance to policymakers, describes the research contributions, and proposes future model improvements and areas for analysis.

5.1 RESEARCH QUESTIONS REVISITED

Here I revisit the original research questions and briefly summarize the results.

1. INFRASTRUCTURE TURNOVER

- *How does infrastructure turnover (construction and retirements) change as climate change policy is delayed?*

Delaying the implementation of climate change policy increases infrastructure turnover in the electricity sector. For a 20% emissions reduction target, delaying the implementation of climate policy from 2020 to 2035 increases average retirements from 200% of BAU to >400% of BAU retirement rates. For the same emissions reduction target, delaying climate policy implementation by 10 years and 20 years increases average construction rates by 25% and 85% respectively and maximum construction rates by 50% and 300%, respectively. Furthermore, the marginal change (for

a one year delay) in infrastructure turnover increases with increasing PSY. A one year delay starting in 2015 increases average construction rates by 2% while a one year delay starting in 2035 increases average construction rates by 14%.

- *Is the relationship between timing and infrastructure turnover dependent on the level of emissions reductions?*

The relationship between timing and infrastructure turnover is dependent on the emissions target—infrastructure turnover rates increase with increasing emissions targets. Delaying the PSY by 10 years increases the rate of construction by 25%, 30%, and 55% for a 15%, 25% and 35% emissions reduction target, respectively.

- *What capital costs are associated with infrastructure turnover?*

The changes to the electricity sector modeled here are associated with very large capital costs: \$1-2.5 trillion (\$2012) over the period 2012-2050, or 2-5 times expected BAU capital costs. Costs increase with increasing emissions reduction targets: for PSY 2025, capital costs are ~\$1.5 trillion for a 20% target and ~\$2.2 trillion for a 35% target. The net present value of capital expenditures decreases as policy is delayed for emissions reduction targets of less than 10% and increases with increasing PSY for higher targets, where increased capital costs overwhelm the effect of discounting.

2. PREMATURE RETIREMENT

- *Does delaying the implementation of climate change policy cause existing power plants to retire prematurely?*

On average, delaying the implementation of climate policy does not cause existing power plants to retire prematurely. In fact, emissions reduction targets that <30% have average retirement ages equal or greater than BAU for most PSYs. For higher emissions targets the average retirement age is below BAU but is still well above the financial lifetime of fossil power plants. However, in all scenarios there are a few outlying plants that are retired prematurely.

- *Does the level of emissions reductions affect the relationship between timing and premature retirement?*

While the emissions reduction target affects the average age of retired plants (higher targets cause younger retirements), the emissions target does not have a strong effect on the relationship between policy timing and average retirement age. This is because plants continue to age as policy is delayed, compensating for the effect of faster retirement rates once a policy is implemented.

- *What stranded costs are associated with premature retirement of existing units?*

Stranded costs for the few plants that are retired prematurely range from \$0-20 billion (NPV, \$2012). While highly variable, stranded costs are

insensitive to policy timing. Stranded costs do increase significantly for increasing emissions reduction targets—for PSY 2020, stranded costs for the 40% scenario are three times higher than the 25% scenario.

3. INFEASIBILITY FRONTIER

- *Is it possible to wait so long that achieving a particular emissions target is impossible? What does this frontier look like?*

For all emissions reduction targets, there comes a point where policy has been delayed so long that it is no longer possible to achieve the emissions reduction target without pulling GHGs out of the atmosphere. Roughly, each year of delay reduces the achievable emissions target by 1.4%.

4. REGIONAL VARIATION

- *How do Themes 1-3 vary by region?*

Regions respond very differently to both emissions reduction targets and PSY. Some regions (FRCC) react very little to increasing emissions reduction targets, while others (RFC, SERC) see large increases in infrastructure turnover as the emissions target increases. RFC pays a particularly high penalty for delaying policy implementation (80%) while FRCC has only 10-25% increase in infrastructure turnover. Stranded costs are highly concentrated: SERC and MRO have high stranded costs for most scenarios, while NPCC has very low stranded costs in any scenario. The regions each have a different infeasibility frontier, with NPCC able to wait the 5-7 years

longer than SPP for the same emissions targets. Regional differences are due to a number of factors, including: the carbon intensity and age of the existing fleet and projected BAU emissions.

5. SENSITIVITY TO MODEL PARAMETERS

- *How does the price of fuel affect the answers to Themes 1-3?*

Fuel prices have little impact on infrastructure turnover or the infeasibility frontier. Gas prices do, however, affect stranded costs: low gas prices cause coal plants to retire more quickly since they are less competitive relative to gas.

- *How does the amount of gas needed to balance the variability from wind power production affect the answers to Themes 1-3?*

The amount of gas needed to balance the variability from wind generation has a slight impact on the generation fuel mix, but a negligible impact on infrastructure turnover or costs.

6. POLICY INTERVENTIONS

- *How does demand growth affect the answers to Themes 1-3? Can a policy that encourages increased energy efficiency reduce the impact of delaying emissions reductions?*

Demand growth rates have a significant impact on infrastructure turnover and costs: higher demand growth rates have higher turnover rates and thus higher capital costs. For emissions reduction targets less than 30%, a low

demand growth rate can also buy a few years (<4) of extra delay in implementing a climate policy before achieving the target is impossible.

- *Can a policy of only building low-carbon generating capacity in the period before emissions reductions start improve the answers to Themes 1-3? Conversely, does building carbon-intensive generating capacity in the period before emissions reductions start adversely affect the answers to Themes 1-3?*

Building a low-carbon fuel mix starting right away can reduce infrastructure turnover by a small amount (10%) for later PSYs, although it has a greater impact on maximum construction levels (30% decrease below the reference scenario). A policy requiring a low-carbon construction portfolio starting today also moves the infeasibility frontier to the right by 2-4 years, depending on the emissions target. A high-coal construction portfolio before emissions reductions start has little impact on infrastructure turnover, but does increase stranded costs from premature retirement by a factor of 2-5.

- *How does the choice of fuel mix of low carbon generating capacity affect Themes 1-3? How would a policy encouraging nuclear, wind or gas generation affect the electricity sector's response to delaying climate policy?*

The choice of fuel mix affects infrastructure turnover commensurate with the capacity factors of the respective technologies. A high-nuclear portfolio has average construction rates that are a factor of two lower than a high-wind portfolio. The relative difficulty of constructing nuclear may outweigh this advantage, however. A high-gas portfolio results in stranded costs that are

an order of magnitude higher than the reference case. A high-gas portfolio also requires climate policy implementation up to ten years earlier than the reference case.

5.2 FINAL THOUGHTS: HOW LONG CAN WE WAIT?

This dissertation has explored what impact the timing of climate change policy has on the infrastructure turnover in the electricity sector required in order to achieve an emissions reduction target. I have shown that delaying climate change policy increases average retirements rates by 200-400%, increases average construction rates by 25-85% and increases maximum construction rates by 50-300%. I have also shown that delaying climate policy has little effect on the age of retired plants or the stranded costs associated with premature retirement.

These observations do not, however, answer the question of how long we can wait. The infeasibility frontier represents the theoretical maximum length of policy delay before achieving an emissions target becomes impossible for the electricity sector alone. But the infeasibility frontier only applies if there are no physical or financial limits to the rate of infrastructure turnover the US can achieve. In all likelihood, there is a practical threshold for construction that moves the infeasibility frontier earlier than the theoretical maximum.

The question of how long we can wait also depends on the emissions target chosen. The selection of an emissions target is an inherently subjective process, depending on one's opinion of how much responsibility the US should take for the stock of GHGs in the atmosphere. In a report entitled *Limiting the Magnitude of Future Climate Change*, a National Research Council committee suggested that the US adopt a carbon budget of 170-200 Gt CO₂e for the period 2012-2050. (America's Climate Choices Panel on Limiting the Magnitude of Climate Change 2010) Assuming the electricity sector maintains the same share of emissions in the future as it does today (35%; Environmental Protection Agency, 2012) the budget for the electricity sector is 60-70 Gt CO₂e, or a 30-40% reduction below BAU. A more realistic estimate of the necessary emissions reductions comes from America's Clean Energy and Security Act, which limited emissions to IPCC-recommended levels and would result in 50% cumulative emissions reductions from the electricity sector (see the beginning of Chapter 3 for discussion of this estimate).

Figure 5-1 shows contours for three estimates of possible physical constraints to infrastructure turnover and compares them to both the infeasibility frontier and the 35% emissions target. The physical constraints are:

1. An estimate of maximum feasible low-carbon penetration rates by the National Research Council in the report *America's Energy Future*. (2009 34 GW/yr)⁶.

⁶ The study estimated maximum wind penetration levels of 16 GW/yr and nuclear penetration levels of 10-20 GW/yr. Here I used the report's wind estimates and calculated nuclear and gas levels such that the ratio is consistent with IFAM's low carbon construction portfolio, for a total limit of 34 GW/yr (16 GW/yr wind, 12 GW/yr nuclear, and 6 GW/yr gas).

This is also approximately four times the historical average and one half the historical maximum construction rates.

2. Limiting annual construction to two times the historical maximum (calculated over the period 1940-2012; 18GW/yr).
3. Limiting average construction during the 5-year period of maximum activity to the historic single-year maximum (over the period 1940-2012; 59 GW/yr or 295 GW over five years).

The three estimates of physical limits to infrastructure turnover all move the infeasibility frontier earlier. In order to achieve the 50% emissions reduction target that is the optimal way to comply with ACES, it is necessary to start reductions immediately and annual construction rates need to be on par with the AEF study's estimate of the US's maximum capacity. If average annual construction rates are limited to the level of either the historic average or the historic single-year maximum, the ACES target will still be unachievable for the electricity sector alone. Since the US is unlikely to begin an emissions reduction program in time for the electricity sector to achieve the ACES target, it is worth discussing a less ambitious target for the electricity sector, such as 35% (representing an equal share of reductions from the electricity sector for the national cap recommended by the NRC).

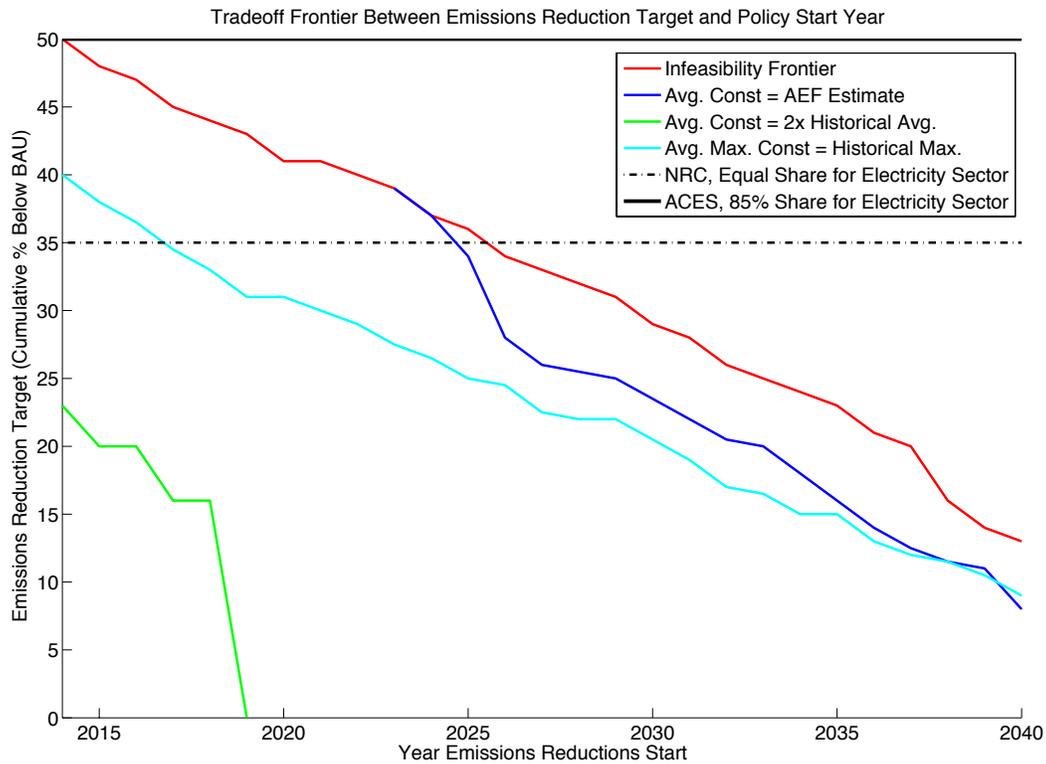


Figure 5-1 Tradeoff frontiers between emissions reduction targets and policy start years for the infeasibility frontier as well as three physical constraint scenarios:

1. Average construction limited to construction limits proposed by (34 GW/yr; Committee on America's Energy Future 2009);
 2. Average construction limited to two times the historical average (18 GW/yr);
 3. Average construction during the 5-year period of maximum activity limited to the historical maximum single-year level (59 GW/yr).
- The 35% emissions target is the electricity sector's share of the carbon budget for the years 2012-2050 proposed by the National Research Council (2010 assuming the electricity sector maintains a 35% share of emissions). The 50% target is the EPA's estimate (EPA, 2009b) of the electricity sector's responsibility for meeting the target in ACES (2009).

If construction rates are limited to two times the historical maximum, it is impossible to achieve the 35% target recommended by the NRC, even starting today. If maximum construction rates are limited to the historic maximum (but sustained over five years), the latest possible starting date is 2017. If construction rates are limited to those proposed by the *America's Energy Future* report, achieving the 35% target requires starting no later than 2025.

Figure 5-1 thus shows that unless abatement starts immediately, the US is unlikely to achieve the desired level abatement from the electricity sector. However, studies that estimate optimal abatement patterns find that the electricity sector bears so much responsibility because its abatement is easiest in the electricity sector. (R. Williams 2010; T. Johnson & Keith 2004; Environmental Protection Agency, 2009) If policy is delayed for so long that the electricity sector is unable to achieve those levels of emissions reductions, the shortfall must be compensated for by abatement from other sectors and/or geoengineering, which is more difficult to achieve. By not starting emissions abatement early, therefore, the US forfeits its most accessible abatement potential and increases the challenge of climate change mitigation unnecessarily.

5.3 RESEARCH CONTRIBUTIONS

A primary contribution of this research is the development of IFAM. IFAM has several advantages over other electricity models: it is (relatively) simple and intuitive, reproducing the major features of the electricity sector without all the layers of complexity found in other models; it is accessible to anyone with intermediate-level programming ability; it can be run on a typical computer without proprietary software (beyond Matlab) or databases; it is capable of modeling cumulative emissions caps, which to my knowledge have not been studied using other electricity sector models.

To the best of my knowledge, this research is the first bottom-up model to address the question of policy timing, the first to explicitly examine the impact of policy timing on the electricity sector, and the first study focused on the electricity sector to model a

cumulative emissions cap. This research also showed for the first time that policy timing has little effect on plant retirement age and stranded costs. This research is also unique in its focus on physical infrastructure flows as a possible constraint to policy timing.

5.4 FUTURE WORK

Over the course of this research, several additional areas of interest were identified that would be worth pursuing in future work:

1. *Model Expansion*: it would be interesting to implement and examine the impact of the following model features.
 - Other low-carbon technologies, especially solar and carbon capture and storage.
 - Sensitivity analysis of the impact of wind on operating reserves—this is a highly uncertain model parameter that it was not possible to examine during the dissertation work since changing the operating reserves requires a complete re-calibration of the model. However, the operating reserves do drive gas construction at high levels of wind penetration (seen mostly during the High Wind low-carbon construction portfolio sensitivity analysis) and could affect model results.
 - Sensitivity analysis of model calibration: IFAM is highly sensitive to the calibration parameters. Since the projected construction and retirement

estimates in the *Annual Energy Outlook* can vary significantly from year to year, it would be useful to calibrate IFAM to several other *Annual Energy Outlooks*, in addition to the 2011 version used in IFAM's reference case.

- Incorporating uncertainty: it could be useful to incorporate stochastic modeling of some model parameters (i.e., fuel prices, capital costs, etc) in IFAM. While this would not be difficult to implement, it could come at significant cost in operating time.
- Equilibrating the carbon price across regions—a national climate policy would involve either a cap-and-trade or carbon tax, either of which would cause the carbon price to be the same in each region. It would be interesting to examine the difference between the results shown here, where the emissions cap is held constant across regions, and a scenario where the carbon price was constant across regions. Implementing this feature would be relatively straightforward, but it would dramatically increase the model run time.

2. *Impact of forthcoming EPA regulations:* The U.S. Environmental Protection Agency (EPA) is developing several rules to limit production of conventional air pollutants, hazardous material (including mercury and acid chemicals), fly ash, and power plant cooling water. These policies will come into effect over the next several years, and (together with low natural gas prices) are expected to cause significant retrofits and/or retirement among existing coal power plants.

(Macedonia et al. 2011; McCarthy & Copeland 2011; Bradley et al. 2011; North American Electric Reliability Corporation, 2011; US Department of Energy 2011)

The retirements caused by EPA regulations, together with projected low natural

gas prices, may allow natural gas to act as a “bridge,” reducing future emissions from the electricity sector in the short term. It is possible that by beginning the decarbonization process, these EPA regulations can push the infeasibility frontier for climate change action out a few years. IFAM could easily be used to investigate this effect.

3. *Resource constraints and their impact:* This dissertation has shown that transitioning the electricity sector under a climate policy will require enormous capital resources. But the transition will also require an enormous quantity of physical resources: cement, steel, skilled labor. It would be interesting to quantify those resources and identify any possible supply constraints.
4. *Life Cycle Effects:* IFAM considers only direct emissions from electricity generation. It does not consider life-cycle emissions associated with electricity. Life-cycle emissions from renewable electricity are front-loaded and create a carbon “debt” that can take decades to repay, while fossil fuel plants have more uniform emissions over the life cycle. (Myhrvold & Caldeira 2012) Thus, significant investment in low-carbon technologies could cause a temporary increase in economy-wide emissions, affecting the cumulative emissions cap and thus moving the infeasibility frontier. Broadening IFAM’s system boundary to include life-cycle emissions would enable IFAM to consider the effect of different life-cycle emissions time profiles across technologies.

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