AN ASSESSMENT OF THE EFFICACY AND COST OF ALTERNATIVE CARBON MITIGATION POLICIES FOR THE STATE OF INDIANA

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ABSTRACT

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A nation-wide climate policy targeting the power sector might lead to dramatic changes to Indiana's electricity generation system. This is because Indiana relies heavily on coal as its primary source for electricity generation and coal is much more carbon-intensive than other fossil fuels. In the possible event that Indiana will have to take action on carbon mitigation, for example because of a national climate policy in the future, it is important for state policymakers to understand the costs and efficacy of alternative strategies. In addition, assessing the impacts of the policy alternatives on Indiana serves as guidance for the national policy design process regarding the subnational impacts.

A linear-programming optimization model was created based on the MARKAL energy system model framework to analyze the impact of a potential national climate policy on the state of Indiana. This model is named IN-MARKAL and is built based on comprehensive research into Indiana's energy-economic system, including primary resource supply, energy conversion sectors and end-use sectors.

Alternative scenarios explored in this study include a base case scenario and six renewable portfolio standard (RPS) scenarios, including two without trading in renewable energy credits (RECs) and four with REC trading at various costs. In addition, three carbon tax scenarios and two rate-based carbon cap scenarios are studied. The results of the model show that an RPS is a very cost effective option among the policy tools examined. An RPS can achieve substantial emissions reductions for the power

sector of Indiana, but it may also lead to a less reliable generation mix. A carbon tax appears to be the least cost effective tool to reduce carbon emissions for Indiana based on the tax trajectories modeled. The emission cap is effective for realizing deep carbon reductions with moderate cost and leads to a diverse generation portfolio for Indiana, but the intermediate goal for Indiana specified in the current EPA proposal may not be achievable, resulting in a large increase in the marginal cost of electricity during the policy phase in, rather than the smooth electricity cost trajectory observed in some other scenarios.

CHAPTER 1. INTRODUCTION

1.1 Research Motivation

Continued emission of greenhouse gases will cause further warming and long-lasting changes in all components of the climate system, increasing the likelihood of severe, pervasive and irreversible impacts for people and ecosystems (IPCC, 2014). The Intergovernmental Panel on Climate Change has sounded the alarm regarding the urgent need to mitigate climate change through substantial and sustained reductions in greenhouse gas emissions in order to avoid potentially disastrous outcomes due to climate change. As the world's second largest source of CO_2 emissions (EIA, 2012a), a nation-wide climate policy could provide a pathway for the U.S. to achieve the CO_2 reduction goal announced by President Obama in the United Nations climate change conferences in Copenhagen to join the international efforts to combat global warming.

The two policy alternatives that appear to have the greatest likelihood of implementation for curbing carbon emissions in the U.S. are through legislation from the Congress or regulation under the Clean Air Act (CAA) from the U.S. Environmental Protection Agency (EPA). The legislative proposals thus far include several versions of cap-and-trade program and clean energy standard for the power sector. None of these proposals were enacted into law. On the regulatory side, EPA has finalized standards and regulations for controlling greenhouse gas emissions from new motor vehicles and engines. To tackle the largest sources of carbon pollution, EPA proposed the Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric tility Generating Units (EGUs) on March 27, 2012 (EPA, 2012a). After considering numerous comments submitted by the public in response to the 2012 proposal, EPA issued a new proposal for carbon pollution from new power plants on September 20th, 2013 (EPA, 2013a). In terms of curbing carbon emissions from existing stationary sources, EPA proposed the Clean Power Plan under the direction of President Obama's Climate Action Plan on June 2, 2014 (EPA, 2014a). The two EPA proposals targeting power plants are expected to be finalized by mid-summer 2015. However, whether the finalized regulations will survive likely legal challenges is uncertain.

Although there are great uncertainties surrounding a national climate policy, dramatic impacts on Indiana's power sector are expected if a nation-wide climate policy is enacted. The reason is that Indiana relies heavily on coal as the primary fuel for electricity generation. Around 90% of total electricity generation in Indiana was from coal in 2010. Natural gas contributed about 5% of total electricity generation in-state. Renewable resources accounted for less than 3% of total generation, with wind playing the dominant role among renewables (EIA, 2010a). At the same time, only 45% of electricity was generated from coal at the national level, 24% from natural gas, 10% from renewables and 20% from nuclear (EIA, 2010b). Since coal is much more carbon intensive than other fossil fuels (see fuel emission factors in Table 1-1), such a coal-dominated generation portfolio for Indiana has caused tremendous amounts of CO_2 emissions, resulting in Indiana ranking among the top 10 carbon emissions states in the country on the basis of total CO_2 emissions for the last two decades (EIA, 2011).

Table 1-1 Fuel Emission Factors in $kgCO_2/MMBtu$

Fuel	Emission Factor
Coal	95.52
Natural gas	53.06
Distillate fuels	73.15
Heavy fuel oil	78.80
Petroleum Coke	102.12

Note: Fuel emission factors are from Appendix H of the instructions to Form EIA-1605, available at: www.eia.gov/survey/form/eia_1605/excel/Fuel_Emission_Factors.xls.

While some other states are actively creating mechanisms to address carbon emissions from power plants even without a national climate policy, e.g. renewable portfolio standard (RPS) programs for 29 states plus Washington, D.C. and 2 territories

(DSIRE, 2014) and the regional cap-and-trade program for 9 states located in northeastern U.S. (RGGI, 2014), Indiana does not have a state policy to limit carbon emissions. Since Indiana's electricity generation portfolio is in a disadvantageous position with respect of carbon emissions when compared to the country as a whole, one would anticipate a dramatic transformation of the generation system and substantial costs to electric utilities associated with the transformation.

In the possible event that Indiana will have to take action on carbon mitigation driven by a national climate policy in the future, it is important for state policymakers to understand the costs and efficacy of alternative strategies. Although there is no lack of literature on the impact of alternative climate policies, the majority of the analyses are at the national level. Most importantly, no research has been conducted to address this issue for Indiana which could be viewed as a representative of states with generation portfolios that rely substantially on coal.

From the perspective of a national climate policy design, assessing the policy impact on Indiana provides a case study that will help inform the policy process. While designing a national policy, it is important to assess the impact on states with coal dominated electricity generation systems regarding the cost-effectiveness of carbon reductions achieved with alternative policy instruments. A study of Indiana provides useful insights into this issue and will serve as a potentially useful input to the policy design process. The Clean Power Plan provides states with the flexibility to establish their own implementation strategies to comply with federal carbon regulations, and this study provides the state government with working knowledge to assist their construction of an implementation plan.

1.2 Objectives

This dissertation aims to provide an assessment of the efficacy and cost of alternative policies for reducing carbon emissions for the state of Indiana. The analysis will be based on a least-cost linear-optimization model of Indiana's energy-economic system created using the MARKAL energy system model. Representing the state's electricity generation system and end-use sectors in detail, this model serves as a framework to systematically understand the state energy-economic system and provides a useful tool for quantifying policy impacts.

Scenario analysis is used to reflect climate policy uncertainties. The analysis includes a base case scenario; six renewable portfolio standard (RPS) scenarios, including two without trading in renewable energy credits (RECs) and four with REC trading at various costs; three carbon tax scenarios; and two rate-based carbon cap scenarios.

This dissertation identifies the costs of alternative strategies for Indiana to comply with a potential nation-wide climate policy as well as the efficacy of these policies for achieving their environmental goals at the state level. For each scenario, the evolution of the capacity portfolio and the generation portfolio, investment in new capacity over time, the carbon emissions trajectory, the trajectory of electricity marginal costs, cumulative carbon emissions and the levelized marginal cost of electricity (LMCOE) are presented. The policy alternatives are compared with each other based on efficacy in achieving emissions reductions, and the increase in the LMCOE, as well as other indicators constructed to reflect cost-effectiveness of carbon mitigation.

CHAPTER 2. REVIEW OF LITERATURE

This chapter provides a review of energy-economy modeling literature. Section 2.1 briefly discusses various kinds of energy–economy models and explains why MARKAL is chosen for this research. The second section of this chapter (Section 2.2) reviews works conducted using the MARKAL framework in the U.S.

2.1 Energy-Economy Modeling

2.1.1 A Brief Discussion of Energy-Economy Models

Before 1973, the relationship between the economy and the energy sector was simply considered to be a one-way link. The perspective was that economic growth drives the demand for energy. The interaction between the economy and the energy sector was recognized later. Energy demand were expressed as a function of income and energy price in a Cobb-Douglas functional form, with GDP and energy prices viewed as two independent variables (Samouilidis and Mitropoulos 1982). After the Arab oil embargo of October 1973, world oil prices jumped dramatically due to curtailed oil supplies from the Persian Gulf, which led to significant GDP reductions and posed a security crisis in the United States. GDP and energy prices were no longer considered independent variables. Impacts of the energy system on the rest of the economy started to draw peoples' attention. Energy modeling for policy studies exploded in the U.S. since then (Hogan 2002). Several papers have provided detailed summaries of energy-economy models thus far. Samouilidis and Mitropoulos (1982) surveyed models developed in the middle to late 1970s in the U.S. and the European area for energy policy analysis and formulation. Nakata (2004) examined and compared a large set of more recent energy-economic models good for environmental policy analysis. Bhattacharyya (1996) did a survey for applied general equilibrium (AGE) models, also referred to as computational general equilibrium (CGE) models, used for energy studies that gained popularity among energy modelers by offering a framework capturing the relationship of energy policy issues (including environmental regulation issues) and various aspects of the economy. Mundaca et al. (2010) identified and described the various methodological approaches used in bottom-up energy-economic models for the purpose of multidisciplinary energy efficiency policy evaluation studies, and summarized the main structure of a variety of modeling tools.

It is widely known that top-down and bottom-up are the two basic approaches to examine the linkages between the economy and the energy system. Since the mid-1990s, those two tribes began to engage in productive dialogue (Hourcade et al. 2006), which led to the integration of both perspectives and gave birth to a model type called "linked" or "hybrid" model. Following sub-sections provide information to facilitate understanding of the different approaches used for energy-economy modeling.

2.1.1.1 Top-Down Models

Top-down models usually represent the energy-economy system with a relatively small number of aggregate economic variables and equations. A summary of the crucial characteristics of the top-down models is shown in Table 2-1.

Table 2-1 Essential Characteristics of Top-Down Models

	Top-down models
Notable feature	Technologies are represented implicitly. Different combinations of inputs are transformed into outputs through production functions. The mixture of inputs is determined by the choice of functional form and the degree of substitutability among inputs.
Purpose	Study impacts of energy policies on the economy and focus on aggregate economic variables
Model structure	The energy-economic system is represented by aggregate variables and equations. Econometric techniques are usually applied to historical data to draw relationships between aggregate variables.
Treatment of technological improvement	Parameter estimation of production function based on historical data may not well reflect future technological changes, thus likely to underestimate potential for technological improvements.
Major advantage	Behavior of the models is more stable with aggregate variables, suitable for analysis with long time horizon.
Major disadvantage	Do not capture the needed sector details and complexity of demand and supply; Enable to capture the potential for new technologies.

Note: information summarized from Nakata (2004)

Table 2-2 summarizes a few typical top-down models from 1970s to the present, including their methodology, geographic scope and general model structure. The table does not reflect a comprehensive list of top-down models, but it highlights certain features of such models.

Table 2-2 Typical Top-Down Energy-Economic Models

Modeling tool	Methodological approach	Geographic scope	General structure	Reference
Hudson-Jorgenson	Econometric, AGE, Recursive-dynamic	National (US)	This model consists of production models for nine industrial sectors, a model of consumer demand and a macro-econometric growth model for the U.S. economy. The macro-econometric model links the state of the economy through time by a capital services variable. A general equilibrium in all markets is determined in each period sequentially.	Hudson and Jorgenson, 1974
PIES	Econometric, Equilibrium, Simulation, Accounting, Optimization (depends on sub-model)	National (US)	The model system consists of 1) the engineering analysis and process oriented descriptions of the supply models, 2) a behavioral econometric demand model, 3) an equilibrium balancing component, 4) an econometric model of macroeconomic activities, and 5) resource constraint elements including coefficients of demand for non-energy resources for the alternate energy activities included in the system.	Hogan, 1975
GREEN	AGE, Recursive-dynamic	Global-regionalized	GREEN has a special focus on energy production and consumption. Global economic activity is divided into twelve regions. Economic activity is divided into eight sectors, five energy-based sectors and three other sectors, with seven energy backstop substitutes introduced in later years. The model has three kinds of factors of production: labor, capital, and sector specific fixed factors.	OECD, 1994
GEM-E3	AGE, Recursive-dynamic	Multinational (EU and World)	GEM-E3 provides details on the macro-economy and its interaction with the environment and the energy system. It covers all production sectors (aggregated to 26) and institutional agents of the economy.	Capros et al., 1997
POLES	Simulation, Econometric, Recursive-dynamic, partial equilibrium	Global-regionalized	The model simulates the energy demand and supply for 32 countries and 18 world regions. There are 15 energy demand sectors, about 40 technologies of power and hydrogen production. For the demand, behavioral equations take into account the combination of price and revenue effects, technical-economic constraints and technological trends.	LEPII-EPE, 2006
Phoenix (replace the earlier SGM)	AGE, Recursive-dynamic	Global-regionalized	Phoenix represents the world by twenty-four regions, each with twenty-six industrial sectors and two representative agents (the government and a representative consumer).Each industrial sector produces a single output that is consumed by the representative consumer and the government and used by the production sectors as intermediate inputs. The distribution of goods in each period is based upon optimizing behavior by both the producers and consumers; producers minimize costs given a particular nested constant elasticity of substitution (CES) production technology and consumers maximize nested CES utility given a budget constraint.	Wing, 2011

The Hudson-Jorgenson model was a groundbreaking work in modeling the energy-economic system of the Unites States based on an integration of econometric modeling and input-output analysis, which was first used to project economic activity and energy utilization for the period from 1975 to 2000 (Hudson and Jorgenson, 1974). The Project Independence Evaluation System (PIES) model and the associated PIES algorithm were fruits of the program named Project Independence (PI), initiated by President Nixon in 1974 for achieving U.S. energy independence by 1980 (Hogan, 2002). This model assisted the evaluation of U.S. energy problems and provided a framework for developing a national energy policy (Hogan, 1975). The successor of the PIES model, the National Energy Modeling System (NEMS), is still used by the Energy Information of Administration (EIA) to conduct policy analysis and produce annual reports.

The top-down energy economic model has been dominated by AGE models since the late 1980s (Hourcade et al., 2006). Typical examples include GREEN, POLES and SGM. SGM was later replaced by Phoenix. (Please refer to Table 2-2 for model details.) Earlier AGE models were applied to study impacts of different energy policies on the economies; since the 1980s, more and more AGE models have focused on the economic impacts of controlling pollution and greenhouse gases. Bhattacharyya (1996) provided a comprehensive survey of AGE models applied to energy studies and reported their special features, evolution through time as well as their limitations.

2.1.1.2 Bottom-Up Models

Distinct from top-down models, bottom-up models have a very detailed representation of technologies, especially for end-use technologies, which are captured in an engineering sense: a given technique, with given inputs, outputs, conversion factors, efficiencies, and other vital technical and economic characteristics. Between primary energy supplies and end-use energy services are a large number of logically linked technologies. Although weak in addressing the feedback between the energy sector and the macro-economy, bottom-up models with detailed specification of technologies lead to a representation of energy sector closer to reality. They are most suitable for assessing technology-specific policies and exploring explicit technological options in response to energy policies. In addition, modeling results are useful and practical for directing energy system planning. Table 2-3 provides a summary of several representative and widely applied bottom-up models.

Table 2-3 Typical Bottom-Up Energy-Economic Models

Modeling tool	Methodological approach	Geographic scope	General structure	Reference
MESSAGE	Optimization, Equilibrium,	Multi-regional	MESSAGE consists of a demand data module, a supply data module, an optimization module, a results module, and supporting programs. The model computes all primary energy supply flows that match useful energy demand subject to user-defined constraints.	Messner and Strubegger, 1995
LEAP	Accounting	Defined by user	LEAP, as a tool that can be used to create models of different energy systems, is based on comprehensive accounting of energy consumption, production and resource extraction in all sectors of an economy. It is a fixed coefficient model that runs on EXCEL spreadsheet.	Lazarus et al., 1997
PRIMES	Optimization. Equilibrium	Multinational (EU)	PRIMES determines an equilibrium by finding the prices of each energy form such that the quantity producers find best to supply matches the quantity consumers wish to use. The equilibrium is static (within each time period) but repeated in a time-forward path, under dynamic relationships. The model consists of different fuel supply modules, energy conversion technologies, end-use demand sectors and end-use technologies.	Capros et al, 2000
META-Net	Optimization, Equilibrium	National (US)	META-Net models a market economy as a network of nodes representing resources, conversion processes, markets, and end-use demands. Commodities flow through this network from resources, conversion processes and market, to the end-users. The model then finds the multi-period equilibrium prices and quantities.	Lamont, 1994
MARKAL	Optimization, Equilibrium	Defined by user	A user-defined 'Reference Energy System' depicts a network of energy sources, conversion and process technologies (including transmission), energy carriers, demand technologies and end-use sectors. The model is data-driven, and can be as comprehensive as needed.	Loulou et al, 2004

In general, there are three basic methodologies among bottom-up models: optimization, simulation and accounting. Mundaca et al. (2010) identified the main feature of each approach as shown in table 2-4.

Table 2-4 Modeling Methodologies of Bottom-Up Energy-Economic Models

Methodology	Main feature
Optimization	This approach attempts to find least-cost solutions of technology choices to satisfy energy demand subject to various constraints.
Simulation	This approach represents observed and expected microeconomic decision-making behavior that is not related to an optimal or rational pattern, but considering different drivers.
Accounting	This approach requires modelers to determine and introduce technology choices exogenously, rather than modeling the behavior of market agents and resulting technological changes. The primary purpose of this model type is to manage data and results.

2.1.1.3 Hybrid Models

Neither the top-down nor the bottom-up method is ideal. Traditional top-down models are good at capturing the economic relationships between aggregate variables. But since those relationships are estimated based on historical data, their validity is questionable when facing a medium to long time horizon into the future. They also lack necessary technological details and have difficulty in modeling technology-specific policies. Traditional bottom-up models have the ability to capture both existing and future technologies in detail, but they ignore market factors (such as hidden costs and other constraints) which may affect decision making behavior in reality. The lack of linkages between the energy sector and the rest of the economy is another deficiency. Hybrid models fill the gap between the top-down and bottom-up approach and seek to compensate for the limitations of one approach or the other.

Table 2-5 lists several hybrid models. The previous Hudson-Jorgenson model was married to a process analysis model from the Brookhaven National Laboratory for analyzing the economic impact of new energy technologies. This is the Hoffman-Jorgenson model (Hoffman and Jorgenson, 1977), an example of incorporating technological explicitness into a top-down model, which might be the earliest attempt for a hybrid model of the United States. In the opposite direction, some bottom-up models strive to include macro-economic feedbacks, such as MARKAL-MACRO and ETA-MACRO, or estimate micro-economic behavioral parameters for technology choices, such as CIMS. The NEMS model, the grandchild of the PIES model, is an example of a full linkage between several technology rich modules of the various sectors of the energy system and a set of macro-economic equations (EIA, 2009a). Each module can be executed separately or together. Each sector is represented with the methodology and the level of detail most appropriate for that sector. The modularity also facilitates the analysis, maintenance and testing of the NEMS component modules in the multi-user environment. However, due to a loose linkage between modules, an iterative resolution method is required to achieve general market equilibrium.

Table 2-5 Energy-Economic Models with A Hybrid Approach

Modeling tool	Methodological approach	Geographic scope	General structure	Reference
Hoffman-Jorgenson	Econometric, Equilibrium, Optimization	National (US)	This model is an integration of the Hudson-Jorgenson econometric model and the process analysis model of the energy sector developed at the Brookhaven National Laboratory. The econometric model provides a description of both the energy and the non-energy sector and generates a complete description of the U.S. economy; the energy sector optimization model provides a very detailed characterization of both existing and potential technologies and permits the analysis of the effects of introducing new technologies.	Hoffman and Jorgenson, 1977
ETA-MACRO	Econometric, Equilibrium, Optimization	National (US), Global-regionalized	A non-linear optimization process analysis model for energy technology assessment (ETA) with energy demands represented by two end products ---- electricity and nonelectric energy, is merged with a macroeconomic growth model (MACRO) providing for substitution between capital, labor and energy input.	Manne, 1977
CIMS	Simulation, CGE, Macro-econometric	Multi-national (US-Canada)	The CIMS model has a detailed representation of energy technologies used in all sectors of the economy. The model forecasts energy demand and emissions by simulating the consumption of energy services and the choice of energy-using technologies. Meanwhile, It uses a market share function to simulate real-world preferences and realistic decision-making behavior.	Bataille et al., 2006
NEMS	Optimization, Simulation, Equilibrium (Each sector is represented with the methodology and the level of detail deemed most appropriate for that sector.)	National (US)	NEMS comprises 13 detailed modules. There are four supply modules (renewable fuels, coal market, oil and gas, and natural gas transmission and distribution); two conversion modules (electricity market and petroleum market); four end-use demand modules (residential, commercial, industrial and transportation demand); one module to simulate the interactions between energy sector and US economy (macro-economic activity); one module to simulate interactions between US liquid fuels markets and non-US liquid fuels markets (international energy); and one module to control interactions among all modules by a mechanism to execute all the component modules iteratively until a general market equilibrium is achieved annually throughout the projection period for each region and across all the NEMS modules (integrating module).	EIA, 2009
MARKAL-INFORUM	Optimization, Equilibrium	National (US)	This system is coupling of MARKAL with INFORUM LIFT, a large- scale model of the U.S. economy with inter-industry, government, and consumer behavioral dynamics. EPA USNM MARKAL provides a rich description of the technologies in the energy system including the end-use devices. LIFT captures the structure of the U.S. economy that governs the demand for all products including energy related products.	Steckley et al., 2011

2.1.2 Suitability of MARKAL for This Research

The purpose of this research is to explore the impacts of a potential federal climate policy on the electricity generation system of Indiana. While at the same time, the cost effectiveness of carbon reduction resulting from various forms of climate policy is evaluated by taking Indiana as an example. Explicit technological options in response to the policy and associated costs are expected to be investigated through modeling. This modeling purpose suggests that a bottom-up, rather than a top-down approach should be adopted.

The standard MARKAL model might be the most typical representative of the bottom-up approach using optimization method. Compared with models with similar approaches, MARKAL brings great flexibility to modelers, from time horizon and geographic scope, to the network representing the entire energy system. As a data-driven model, parameter assumptions, technology characteristics, projections of energy service demands, etc. are all specified by the user. From this perspective, MARKAL provides a practical framework to model Indiana's energy system. Based on the issues to be addressed in this research, we have the flexibility to equip the electric sector with rich details, and to simplify some components of the system, such as fuel supply. In addition, MARKAL has been widely used in the U.S. and worldwide to address environmental issues at different geographic scopes. Therefore, accumulated knowledge and experience from predecessors offer an easier path to understand the general energy system, to construct the model, to analyze problems and to interpret results. Last but not least, MARKAL includes a family of models allowing for the possibility of future expansions. The standard MARKAL provides a reasonable start for modeling Indiana's energy system. It provides the foundation to be extended to include more features, such as price-elastic energy demand, feedbacks between the energy system and the macro-economy, incorporation of stochastics, etc. in the future, without changing the basic modeling framework.

Besides the energy-economic models reviewed in the previous section, several electric sector models were applied to analyze the impacts of a CES or EPA carbon regulation for the U.S. (McGuinness, 2011, Paul et al., 2011, and EPA, 2012b). However, those models fail to capture the interactions between various sectors within the energy system. For instance, the change of fuel supply and energy consumption mix due to a climate policy cannot be directly addressed by such models. That is the major reason that such models are not adopted for this research. For completeness, Table 2-6 lists a few of them and their associated characteristics.

In summary, MARKAL provides a flexible framework to capture the necessary details for this research. Predecessors' experiences have revealed its suitability for analyzing technological-specific energy policies and providing practical insights into energy system planning in response to such policies. Rather than focusing on the electricity generation system alone, it captures the interplay between various sectors of the energy system including substitutions on the fuel side and substitutions on the demand side. All of the reasons listed above lead to the choice of MARKAL as a tool for the analysis of the impacts of a potential national climate policy on the electricity generation system of Indiana.

Table 2-6 Electric Sector Models

Modeling Tool	Top-down or Bottom-up	Methodological approach	Geographic scope	General structure	Reference
HAIKU Electricity Market Model	Top-down	Equilibrium, Simulation	National-regionalized (U.S.)	HAIKU is a simulation model of regional electricity markets and interregional electricity trade in the continental United States. Electricity demand curves for residential, commercial and industrial sectors are determined exogenously and are characterized by price responsive functions for each region and time period. While supply curves are constructed by simulating 46 model plants, each of which represents the aggregated existing generation capacity of similar technology characteristics. By employing an iterative algorithm, Haiku strives to achieve equilibrium in each of the 21 regions.	Paul et al., 2009
IPM	Bottom-up	Optimization, Equilibrium	Defined by user	IPM uses a linear programming formulation to select investment options and to dispatch generating and load management resources to meet overall electric demand today and on an ongoing basis over the chosen planning horizon. The IPM has an accurate engineering representation of every power plant, every transmission link, and every fuel supply option available to the power system of concern. This allows the end-result with the IPM to reflect how actual decisions are made by power system operators when subject to any slate of operational constraints. Demand for electricity is exogenously determined.	ICF International, 2008
ReEDS	Bottom-up	Optimization	National-regionalized (U.S.)	ReEDS is a geographic information system (GIS) and linear programming model of capacity expansion and dispatch in the electric sector of the United States, which minimizes system-wide costs of meeting electric loads, reserve requirements and emission constraints by building and operating new generators and transmission. Fuel costs and electric loads for each region are exogenously specified. Price elasticities of electricity demand and demand elasticities of fuel prices are integrated in the model. The primary focus of this model is to address considerations for integrating renewable electric technologies into the power grid.	NREL ReEDS, 2012

2.2 MARKAL Model and Applications

MARKAL (acronym for MARKet ALlocation) was developed in a cooperative multinational project over a period of almost two decades by the Energy Technology Systems Analysis Programme (ETSAP) of the International Energy Agency (IEA). The number of users of the MARKAL family of models has multiplied to 77 institutions in 37 countries (ETSAP, 2011).

The MARKAL model is a bottom-up, dynamic, and mostly linear programming energy model using optimization methods. It brings great flexibility to modelers, from modeling horizon, geographic scope, to the network representing the entire energy system. The model is data-driven, and can be as comprehensive as needed.

A user-defined 'Reference Energy System' (RES) depicts a network that includes all energy carriers involved with primary supplies (e.g., mining, petroleum extraction, etc.), conversion and processing (e.g., power plants, refineries, etc.), and end-use demand for energy services (e.g., automobiles, residential space cooling, etc.). The model minimizes the discounted sum over time of total system cost of satisfying end-use demand for energy services subject to various user-defined technological, environmental, economic and political constraints.

Typical inputs of the model include current and projected demand for energy services, technological characteristics and costs of various technologies used in the energy system in all time periods of the model, primary energy supply (e.g., coal, natural gas), and emissions factors. Typical outputs of the model include a determination of the evolution of the fuel mix and technology portfolio over time, estimates of total system cost, projection of energy demand and associated greenhouse gas (GHG) emissions, and estimates of energy commodity prices based on a least-cost criterion.

Therefore, MARKAL is very useful for identifying cost-effective responses to political restrictions, evaluating new technologies, evaluating the effect of regulations, taxes and subsidies and projecting inventories of air pollutant emissions. Seebregtz et al. (2002) provides a succinct overview of MARKAL model developments and selected applications. More detailed and systematic information pertaining to the MARKAL family of models can be found in the Documentation for the MARKAL Family of Models (LouLou et al., 2004).

In the U.S., the MARKAL framework is used by the Environmental Protection Agency (EPA) for numerous technology and emissions evaluations. A national MARKAL database and a 9-region MARKAL database have been developed and are regularly maintained and updated by the U.S EPA National Risk Management Research Laboratory Air Pollution Prevention and Control Division, which are available to the public upon request (EPA, 2014b). The two databases represent the major sectors in the U.S. energy system, including the residential, commercial, industrial, transportation and electricity generation sectors. Energy supply, demand, technology characterizations and emissions factors are all derived from recognized authoritative sources. Here are a few of many studies using EPA MARKAL database as an analysis tool. Sarica and Tyner (2013) modified the standard U.S. MARKAL model and used it to estimate the impacts of four different policy and technology choice scenarios relative to the U.S. Renewable Fuel Standard on corn ethanol and thermochemical biofuel production. Brown et al. (2013) applied the EPA-MARKAL model of the U.S. electricity sector to examine how imposing emissions fees based on estimated health and environmental damages might change electricity generation. Balash et al. (2013) adopted EPA 9-region MARKAL model for a multi-regional evaluation of the U.S. electricity sector under technology and policy uncertainties.

In addition to EPA MARKAL databases, a few regional or state level MARKAL models have been developed in the U.S. thus far. The Ohio MARKAL (OH-MARKAL) was developed by Shakya (2007) for the fulfillment of his Ph.D. degree. It was used to evaluate the prospects of biomass co-firing in Ohio to generate commercial electricity and to analyze key economic, environmental, and policy issues related to energy needs for Ohio’s future. The OH-MARKAL model is a comprehensive power sector model, but it lacks details in other sectors. It was later used by Khadka Mishra (2009) to evaluate the impact of internalizing the externality costs of electricity generation from coal on coal generation and carbon emissions.

Levin et al. (2010) published a MARKAL model for the state of Georgia and applied it to analyze the evolution of its electricity generation portfolio under different scenarios with regard to the cost of efficiency improvements. They also used this model to address state-level impacts of a renewable electricity standard (RES) and a carbon tax in Georgia (Levin et al., 2011). This model represents the electricity system with 16 generation technologies with aggregated capacity for each technology. No end-use sectors are presented in this model. Demand for electricity in the base year and beyond are specified explicitly and exogenously.

The NE-MARKAL initiative, which began in 2003 through collaboration between Northeast States for Coordinated Air Use Management (NESCAUM) and the U.S. EPA Office of Research and Development, has resulted in the development of a MARKAL model tailored specifically to the energy infrastructure of the Northeast (NE-MARKAL). NE-MARKAL is a comprehensive energy system model including detail in residential, commercial, industrial, transportation and electricity generation sectors and simplified structures for resource supply and refineries. The model was mainly designed to facilitate a comprehensive understanding of technology, economic, environmental and public health consequences of air quality and climate initiatives (NESCAUM, 2014). A thorough model description is included in NE-12 MARKAL Final Report: Structure, Data, and Calibration (Goldstein et al., 2008).

The CA-TIMES model was developed by UC Davis (partially funded by California Air Resources Board) to provide guidance regarding the least-cost and most appropriate options to achieve greenhouse gas emissions mitigation goals outlined in AB32 (California Global Warming Solutions Act of 2006) (STEP, 2014). TIMES (The Integrated MARKAL-EFORM System) is the evolutionary replacement for MARKAL. This modeling framework was introduced in 1999, and it expands the robustness with which MARKAL can address new application areas, ranging from local energy planning to technology-rich global modeling (Seebregts et al., 2002). CA-TIMES covers all sectors of the

California energy economy, including primary energy resource extraction, imports/exports, electricity production, fuel conversion, and the residential, commercial, industrial, transportation, and agricultural end-use sectors. McCollum et al. (2012) used CA-TIMES to explore low carbon scenarios with focus on the potential evolution of the transportation, fuel supply, and electric generation sectors over the next several decades in response to various energy and climate policies in California.

CHAPTER 3. METHODOLOGY

This chapter includes a detailed introduction of the Indiana MARKAL (IN-MARKAL) model as a tool for the analyses conducted in this research. Section 3.1 presents the overview of the model through outlining the model structure and specifying the global assumptions. Section 3.2 provides comprehensive information for IN-MARKAL by sector.

3.1 IN-MARKAL Model Structure

IN-MARKAL is a comprehensive energy-economy model representing major sectors of Indiana's energy system. It has a planning horizon spanning the years 2007 to 2045 divided into 13 three year periods. The year 2007 was chosen as the base year mainly due to the fact that it was the most recent year for which all the data required for MARKAL was available when the model construction process started in 2010. Model input data for 2007 are calibrated to historic data retrieved from numerous sources. The majority of input data for 2010 are calibrated to historic data as well depending on data availability.

Figure 3-1 is a simplified representation of Indiana's energy system reflected in IN-MARKAL. It has four major components. From left to right are resource supply, conversion sectors, end-use technologies, and end-use energy service demand.

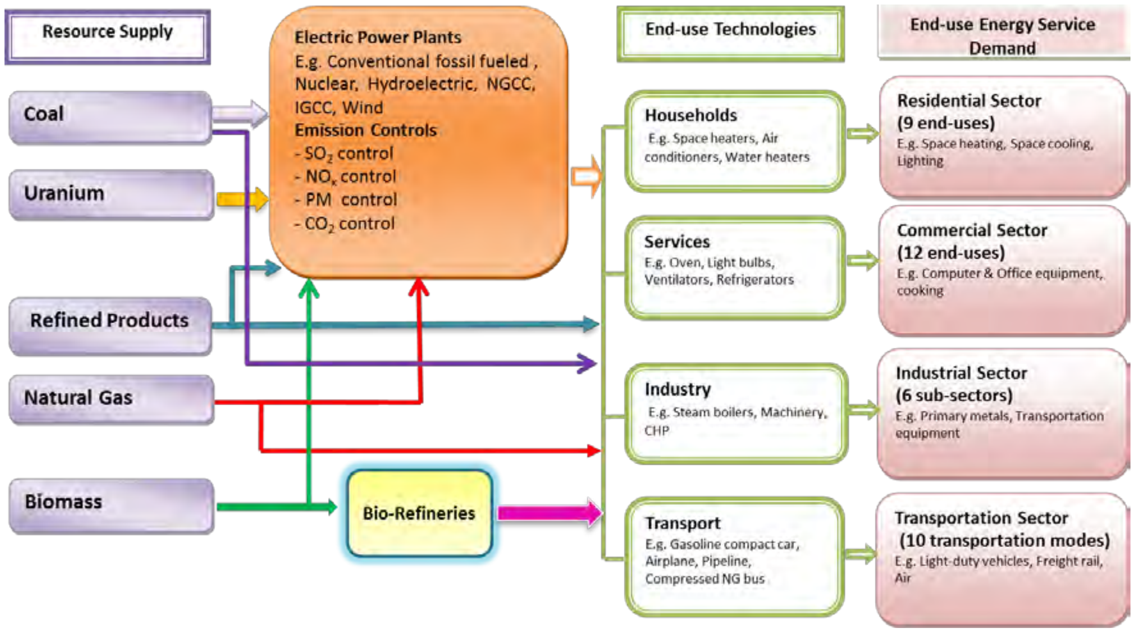

Figure 3-1 IN-MARKAL Model Structure

Five categories of resource supply are modeled in IN-MARKAL. They are coal, uranium, refined products, natural gas and biomass. Renewable resources, such as wind and river flows, also provide energy to Indiana. But those resources do not incur costs for extraction or transportation, so they are not reflected by resource supply technologies in the model. (Use of them for electricity generation does incur costs, which are included in the power sector.) Among all modeled resources, uranium is only available for electricity generation; biomass can be used for biofuel production and electricity generation; and the rest are available for electricity generation or direct use in the end-use sectors. The conversion sector of IN-MARKAL includes the electricity generation system and the biofuel production system, with electricity generation system being represented with very detailed information. Petroleum refineries in Indiana are not modeled. Rather the supply of various types of refined products is modeled directly through supply curves. The reason for such design is mentioned in Section 3.2.1.3. IN-MARKAL models four end-use sectors — residential, commercial, industrial, and transportation sectors. Each sector is composed of multiple types of end-use energy service demand, each of which is met by corresponding end-use technologies of different fuels, vintages and efficiencies chosen by the model based on the criterion of system cost minimization.

In IN-MARKAL, all costs are expressed in 2007 dollars. The majority of energy carriers are expressed in petajoules (PJ). Table 3-1 shows energy unit conversion factors which are widely used in IN-MARKAL. A discount rate of 5% is applied to the whole modeling system, which is overridden only if a technology-specific discount rate is specified. A representative modeling year is divided into twelve time slices by season (summer, winter and intermediate) and time-of-day (day-AM, day-PM, night and peak). Table 3-2 shows the fractions by time slice which describe the duration of the time slices within a typical year following assumptions made in the EPA U.S. 9-region MARKAL Database (EPAUS9r). These values are used as the defaults when constructing the load curve for electricity and heat. An efficiency of 93.5% is used to reflect electricity losses occurring across transmission and distribution lines. The reserve capacity for electricity is assumed to be 15%, which ensures that total available capacity of electricity generation technologies per period exceeds the average load of the peaking time-slice by 15% to maintain the reliability of the electricity system at an acceptable level.

Table 3-1Energy Unit Conversion Factors

Energy unit conversion	Conversion factor
Btu to PJ	1.055E-12
mmBtu to PJ	1.055E-06
KWh to PJ	3.6E-09

Table 3-2 Fraction of A Representative Modeling Year by Time Slice Used in IN-MARKAL

Time Slice	Specification	Fraction
I-DAM	Intermediate day - AM	0.0822
I-DPM	Intermediate day - PM	0.0957
I-N	Intermediate night	0.1532
I-P	Intermediate peak	0.0032
S-DAM	Summer day - AM	0.0975
S-DPM	Summer day - PM	0.1087
S-N	Summer night	0.1253
S-P	Summer peak	0.0027
W-DAM	Winter day - AM	0.0815
W-DPM	Winter day - PM	0.1087
W-N	Winter night	0.1381
W-P	Winter peak	0.0032

3.2 IN-MARKAL Model Details

This section introduces the specific details of IN-MARKAL. It is composed of three major sub-sections. Sub-section 3.2.1 covers resource supply, followed by sub-section 3.2.2 focusing on the conversion sector. Sub-section 3.2.3 provides a comprehensive description of end-use sectors, including end-use energy service demand and end-use technologies.

3.2.1 Resource Supply

3.2.1.1 Coal Supply

For the state of Indiana, coal plays the most import role in electricity generation, contributing roughly 94% of total electricity generation in-state in 2007 and 90% in 2010 (EIA, 2010a). It is also widely used in the state industrial sector, serving around 30% of industrial net energy need in 2007 (EIA, 2007a). Therefore, coal supply is modeled in detail with IN-MARKAL.

According to data on coal supply to Indiana contained in the Indiana Coal Report 2009 (CCTR, 2009) and definitions of coal supply regions in EIA's Annual Energy Outlook (AEO) 2012 (EIA, 2012b), 19 types of coal are modeled with IN-MARKAL. These coal types are characterized by their supply region, grade, sulfur content and mine type, as shown in Table 3-3. The BTU content of each coal type is shown in Table 3-4.

Table 3-3 Coal Types Modeled with IN-MARKAL

Coal type	Specification
EIBMU	East Interior bituminous medium sulfur underground coal
EIBHU	East Interior bituminous high sulfur underground coal
EIBMS	East Interior bituminous medium sulfur surface coal
EIBHS	East Interior bituminous high sulfur surface coal
NABMU	Northern Appalachia bituminous medium sulfur underground coal
NABHU	Northern Appalachia bituminous high sulfur underground coal
NABMS	Northern Appalachia bituminous medium sulfur surface coal
NABHS	Northern Appalachia bituminous high sulfur surface coal
NAPMU	Northern Appalachia premium medium sulfur underground coal
CABLU	Central Appalachia bituminous low sulfur underground coal
CABMU	Central Appalachia bituminous medium sulfur underground coal
CABLS	Central Appalachia bituminous low sulfur surface coal
CABMS	Central Appalachia bituminous medium sulfur surface coal
CAPMU	Central Appalachia premium medium sulfur underground coal
SAPLU	Southern Appalachia premium low sulfur underground coal
NWSLS	Wyoming Northern PRB sub-bituminous low sulfur surface coal
NWSMS	Wyoming Northern PRB sub-bituminous medium sulfur surface coal
SWSLS	Wyoming Southern PRB sub-bituminous low sulfur surface coal
RMBLU	Rocky Mountain bituminous low sulfur underground coal

Table 3-4 Average BTU Content of Coal by Type

Coal type	Average BTU content (million Btu per short ton)
EIBMU	22.65
EIBHU	22.89
EIBMS	22.65
EIBHS	22.89
NABMU	25.15
NABHU	24.70
NABMS	25.15
NABHS	24.70
NAPMU	26.30
CABLU	24.76
CABMU	24.77
CABLS	24.76
CABMS	24.77
CAPMU	26.30
SAPLU	26.30
NWSLS	16.82
NWSMS	16.17
SWSLS	17.60
RMBLU	22.85

For the East Interior (EI) region, 39.05% of the region's coal production was delivered to Indiana in 2007 (EIA, 2007b). This information indicates that Indiana is a key player in the EI coal market. As a major purchaser of EI coal, Indiana purchase decisions will affect the price of EI coal. Therefore, four step-wise supply curves (11 steps) are used to represent EIBMU, EIBHU, EIBMS and EIBHS delivered to Indiana, respectively. Each step specifies the price and the maximum amount of additional supply available at that price for each period from 2007 to 2043. These supply curves are developed from the coal supply curves by type from the AEO 2010 reference case, which are annual data in 2010 dollars per short ton for price and in million short tons for quantity. Three-year average quantities and prices for each step are calculated (because IN-MARKAL models three years in each period) and then scaled down by a factor of 39.05% to reflect the portion serving Indiana. Data on EIBMU, EIBHU, EIBMS and EIBHS supply to Indiana are shown in Table 3-5 to Table 3-8. Note that price data are specified in millions of 2007 dollars per PJ, reflecting the internal units used for energy and value in IN-MARKAL.

Table 3-5 Supply of EIBMU to Indiana

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/PJ													
MINCEIBMUA	1.4128	2.0717	2.1591	2.1448	2.0901	2.1594	2.2153	2.2440	2.2841	2.3382	2.3936	2.4502	2.5083
MINCEIBMUB	1.4423	2.1047	2.1843	2.1639	2.1237	2.2006	2.2466	2.2775	2.3195	2.3715	2.4246	2.4790	2.5346
MINCEIBMUC	1.5263	2.1499	2.2232	2.1975	2.1695	2.2534	2.2912	2.3243	2.3681	2.4187	2.4704	2.5232	2.5771
MINCEIBMUD	1.5748	2.1683	2.2394	2.2118	2.1883	2.2749	2.3097	2.3435	2.3880	2.4382	2.4893	2.5416	2.5950
MINCEIBMUE	1.5939	2.1749	2.2451	2.2168	2.1949	2.2824	2.3162	2.3503	2.3951	2.4450	2.4960	2.5481	2.6013
MINCEIBMUF	1.6043	2.1942	2.2779	2.2594	2.2183	2.2961	2.3447	2.3735	2.4242	2.4708	2.5184	2.5668	2.6162
MINCEIBMUG	1.6148	2.1959	2.2788	2.2598	2.2202	2.2986	2.3463	2.3751	2.4263	2.4724	2.5193	2.5671	2.6158
MINCEIBMUH	1.6374	2.1996	2.2810	2.2610	2.2245	2.3042	2.3498	2.3787	2.4310	2.4758	2.5214	2.5678	2.6151
MINCEIBMUI	1.7203	2.2142	2.2898	2.2663	2.2408	2.3251	2.3635	2.3927	2.4489	2.4893	2.5304	2.5721	2.6145
MINCEIBMUJ	2.5499	2.2942	2.3438	2.3038	2.3172	2.4343	2.4395	2.4714	2.5220	2.5661	2.6110	2.6567	2.7031
MINCEIBMUK	4.8275	2.5290	2.5395	2.4488	2.4396	2.6977	2.5670	2.7263	2.6307	2.8127	3.0074	3.2156	3.4381
Maximum available quantity in PJ													
MINCEIBMUA	91.7083	34.3770	31.3174	26.9492	26.5595	27.1040	24.5898	24.2963	23.6708	23.5481	23.4261	23.3048	23.1840
MINCEIBMUB	53.8288	20.1778	18.3819	15.8180	15.5893	15.9089	14.4331	14.2609	13.8937	13.8217	13.7501	13.6789	13.6080
MINCEIBMUC	35.8858	13.4519	12.2546	10.5453	10.3928	10.6059	9.6221	9.5073	9.2625	9.2145	9.1667	9.1193	9.0720
MINCEIBMUD	11.9619	4.4840	4.0849	3.5151	3.4643	3.5353	3.2074	3.1691	3.0875	3.0715	3.0556	3.0398	3.0240
MINCEIBMUE	3.9873	1.4947	1.3616	1.1717	1.1548	1.1784	1.0691	1.0564	1.0292	1.0238	1.0185	1.0133	1.0080
MINCEIBMUF	1.9937	0.7473	0.6808	0.5859	0.5774	0.5892	0.5346	0.5282	0.5146	0.5119	0.5093	0.5066	0.5040
MINCEIBMUG	1.9937	0.7473	0.6808	0.5859	0.5774	0.5892	0.5346	0.5282	0.5146	0.5119	0.5093	0.5066	0.5040
MINCEIBMUH	3.9873	1.4947	1.3616	1.1717	1.1548	1.1784	1.0691	1.0564	1.0292	1.0238	1.0185	1.0133	1.0080
MINCEIBMUI	11.9619	4.4840	4.0849	3.5151	3.4643	3.5353	3.2074	3.1691	3.0875	3.0715	3.0556	3.0398	3.0240
MINCEIBMUJ	16.2701	13.4519	12.2546	10.5453	9.3829	10.1308	9.5063	9.5073	7.7956	9.2145	10.8917	12.8741	15.2174
MINCEIBMUK	13.2639	7.4960	13.3174	15.7279	7.6001	2.8528	8.1482	6.2690	8.2404	6.7576	5.5416	4.5444	3.7267

Note: The naming convention of EI coal supply technologies is as follow.
Characters 1-3: MIN means mining
Characters 4: C means coal
Characters 5-9: coal type as listed in Table 3-2
Characters 10: A to K represents 11 steps.

Table 3-6 Supply of EIBHU to Indiana

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/PJ													
MINCEIBHUA	1.4586	1.6796	1.7470	1.8013	1.8247	1.8518	1.8494	1.8875	1.9387	2.0044	2.0722	2.1424	2.2149
MINCEIBHUB	1.5017	1.7067	1.7666	1.8180	1.8405	1.8745	1.8761	1.9175	1.9779	2.0434	2.1111	2.1810	2.2532
MINCEIBHUC	1.5755	1.7403	1.7944	1.8435	1.8655	1.9056	1.9106	1.9552	2.0239	2.0897	2.1577	2.2279	2.3003
MINCEIBHUD	1.6133	1.7539	1.8058	1.8542	1.8759	1.9184	1.9246	1.9704	2.0422	2.1082	2.1763	2.2467	2.3193
MINCEIBHUE	1.6277	1.7587	1.8098	1.8579	1.8796	1.9229	1.9296	1.9758	2.0487	2.1147	2.1829	2.2533	2.3259
MINCEIBHUF	1.6356	1.7647	1.8257	1.8785	1.9024	1.9379	1.9388	1.9839	2.0523	2.1187	2.1871	2.2578	2.3308
MINCEIBHUG	1.6432	1.7665	1.8267	1.8791	1.9029	1.9391	1.9404	1.9859	2.0555	2.1217	2.1900	2.2606	2.3334
MINCEIBHUH	1.6596	1.7705	1.8289	1.8806	1.9042	1.9417	1.9439	1.9902	2.0623	2.1283	2.1963	2.2665	2.3390
MINCEIBHUI	1.7199	1.7853	1.8375	1.8866	1.9095	1.9521	1.9569	2.0063	2.0873	2.1523	2.2193	2.2885	2.3598
MINCEIBHUJ	2.2107	1.8549	1.8854	1.9230	1.9426	2.0087	2.0260	2.0804	2.2065	2.2698	2.3350	2.4020	2.4710
MINCEIBHUK	4.3359	2.0056	1.9947	2.0451	2.0603	2.1191	2.2322	2.2499	2.7351	2.7860	2.8379	2.8907	2.9445
Maximum available quantity in PJ													
MINCEIBHUA	168.4616	287.8352	261.3361	243.2417	235.6617	252.2958	251.2488	257.0843	282.1571	292.9690	304.1951	315.8514	327.9544
MINCEIBHUB	98.8796	168.9467	153.3929	142.7723	138.3232	148.0867	147.4721	150.8973	165.6140	171.9600	178.5493	185.3910	192.4950
MINCEIBHUC	65.9198	112.6312	102.2619	95.1815	92.2154	98.7244	98.3147	100.5982	110.4093	114.6400	119.0329	123.5940	128.3300
MINCEIBHUD	21.9733	37.5437	34.0873	31.7272	30.7385	32.9081	32.7716	33.5327	36.8031	38.2133	39.6776	41.1980	42.7767
MINCEIBHUE	7.3244	12.5146	11.3624	10.5757	10.2462	10.9694	10.9239	11.1776	12.2677	12.7378	13.2259	13.7327	14.2589
MINCEIBHUF	3.6622	6.2573	5.6812	5.2879	5.1231	5.4847	5.4619	5.5888	6.1339	6.3689	6.6129	6.8663	7.1294
MINCEIBHUG	3.6622	6.2573	5.6812	5.2879	5.1231	5.4847	5.4619	5.5888	6.1339	6.3689	6.6129	6.8663	7.1294
MINCEIBHUH	7.3244	12.5146	11.3624	10.5757	10.2462	10.9694	10.9239	11.1776	12.2677	12.7378	13.2259	13.7327	14.2589
MINCEIBHUI	21.9733	37.5437	34.0873	31.7272	30.7385	32.9081	32.7716	33.5327	36.8031	38.2133	39.6776	41.1980	42.7767
MINCEIBHUJ	51.3650	98.4529	102.2619	95.1815	92.2154	98.7244	98.3147	88.1858	65.9428	77.4166	90.8868	106.7007	125.2662
MINCEIBHUK	41.4396	17.4307	76.4131	99.7717	107.4003	61.4757	26.4648	22.7661	0.0000	0.0000	0.0000	0.0000	0.0000

Table 3-7 Supply of EIBMS to Indiana

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/PJ													
MINCEIBMSA	1.3646	2.1435	2.2234	2.1631	2.0825	2.0868	2.0915	2.1063	2.1523	2.2038	2.2565	2.3104	2.3657
MINCEIBMSB	1.3899	2.2043	2.2497	2.1886	2.1094	2.1259	2.1268	2.1545	2.2138	2.2710	2.3296	2.3898	2.4515
MINCEIBMSC	1.4418	2.2730	2.2893	2.2271	2.1486	2.1757	2.1734	2.2123	2.2834	2.3458	2.4100	2.4759	2.5436
MINCEIBMSD	1.4720	2.3003	2.3058	2.2431	2.1649	2.1959	2.1924	2.2355	2.3110	2.3754	2.4416	2.5097	2.5797
MINCEIBMSE	1.4839	2.3099	2.3116	2.2488	2.1706	2.2030	2.1990	2.2436	2.3206	2.3858	2.4527	2.5216	2.5923
MINCEIBMSF	1.4906	2.3384	2.3410	2.2778	2.1957	2.2169	2.2142	2.2555	2.3264	2.3940	2.4635	2.5351	2.6087
MINCEIBMSG	1.4970	2.3451	2.3420	2.2788	2.1968	2.2195	2.2162	2.2594	2.3321	2.4006	2.4712	2.5438	2.6185
MINCEIBMSH	1.5108	2.3595	2.3443	2.2810	2.1994	2.2251	2.2206	2.2679	2.3443	2.4148	2.4875	2.5623	2.6394
MINCEIBMSI	1.5618	2.4070	2.3538	2.2902	2.2098	2.2460	2.2374	2.2987	2.3883	2.4659	2.5460	2.6287	2.7141
MINCEIBMSJ	1.9897	2.2827	2.4109	2.3454	2.2702	2.3552	2.3273	2.4422	2.6016	2.7158	2.8350	2.9595	3.0894
MINCEIBMSK	5.1958	2.4942	2.6146	2.5422	2.4771	2.5554	2.6053	2.4958	3.4643	3.7010	3.9539	4.2241	4.5128
Maximum available quantity in PJ													
MINCEIBMSA	37.7631	16.8503	14.0760	12.4763	11.0621	11.2352	10.4464	10.8527	11.6021	11.9890	12.3889	12.8021	13.2290
MINCEIBMSB	22.1653	9.8904	8.2620	7.3230	6.4930	6.5946	6.1316	6.3701	6.8099	7.0371	7.2717	7.5143	7.7649
MINCEIBMSC	14.7768	6.5936	5.5080	4.8820	4.3286	4.3964	4.0877	4.2467	4.5400	4.6914	4.8478	5.0095	5.1766
MINCEIBMSD	4.9256	2.1979	1.8360	1.6273	1.4429	1.4655	1.3626	1.4156	1.5133	1.5638	1.6159	1.6698	1.7255
MINCEIBMSE	1.6419	0.7326	0.6120	0.5424	0.4810	0.4885	0.4542	0.4719	0.5044	0.5213	0.5386	0.5566	0.5752
MINCEIBMSF	0.8209	0.3663	0.3060	0.2712	0.2405	0.2442	0.2271	0.2359	0.2522	0.2606	0.2693	0.2783	0.2876
MINCEIBMSG	0.8209	0.3663	0.3060	0.2712	0.2405	0.2442	0.2271	0.2359	0.2522	0.2606	0.2693	0.2783	0.2876
MINCEIBMSH	1.6419	0.7326	0.6120	0.5424	0.4810	0.4885	0.4542	0.4719	0.5044	0.5213	0.5386	0.5566	0.5752
MINCEIBMSI	4.9256	2.1330	1.8360	1.6273	1.4429	1.4655	1.3626	1.4156	1.5133	1.5638	1.6159	1.6698	1.7255
MINCEIBMSJ	10.4130	2.7591	5.5080	4.8820	4.3286	4.3964	4.0877	3.5911	3.1541	2.5437	2.0514	1.6544	1.3342
MINCEIBMSK	4.3127	3.6876	8.1424	7.2813	5.8301	2.9380	3.4178	1.8764	0.0000	0.0000	0.0000	0.0000	0.0000

Table 3-8 Supply of EIBHS to Indiana

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/PJ													
MINCEIBHSA	1.3733	1.7004	1.7477	1.8919	1.9851	2.0359	2.0673	2.0957	2.1385	2.1892	2.2411	2.2942	2.3486
MINCEIBHSB	1.4074	1.7215	1.7894	1.9505	2.0366	2.0807	2.0982	2.1333	2.1885	2.2449	2.3028	2.3621	2.4230
MINCEIBHSC	1.4822	1.7499	1.8360	2.0126	2.0932	2.1319	2.1376	2.1787	2.2449	2.3065	2.3699	2.4349	2.5018
MINCEIBHSD	1.5232	1.7615	1.8544	2.0369	2.1155	2.1522	2.1536	2.1969	2.2672	2.3308	2.3963	2.4635	2.5327
MINCEIBHSE	1.5392	1.7656	1.8609	2.0453	2.1233	2.1593	2.1592	2.2033	2.2750	2.3393	2.4055	2.4735	2.5435
MINCEIBHSF	1.5481	1.7769	1.8761	2.0666	2.1327	2.1643	2.1679	2.2093	2.2802	2.3473	2.4165	2.4877	2.5609
MINCEIBHSG	1.5566	1.7780	1.8806	2.0739	2.1381	2.1683	2.1698	2.2121	2.2849	2.3530	2.4232	2.4954	2.5698
MINCEIBHSH	1.5751	1.7805	1.8905	2.0896	2.1497	2.1770	2.1740	2.2182	2.2950	2.3652	2.4375	2.5120	2.5888
MINCEIBHSI	1.6427	1.7901	1.9257	2.1464	2.1914	2.2085	2.1897	2.2406	2.3314	2.4088	2.4887	2.5713	2.6567
MINCEIBHSJ	2.4974	1.8425	1.9253	2.4688	2.3734	2.3508	2.2720	2.3514	2.5055	2.6128	2.7248	2.8416	2.9634
MINCEIBHSK	4.3371	1.9848	1.9856	3.5052	3.2129	2.7111	2.5392	2.5766	3.2367	3.4764	3.7339	4.0104	4.3075
Maximum available quantity in PJ													
MINCEIBHSA	134.9099	137.5004	164.2444	203.5959	211.9090	210.2327	189.5306	198.9185	218.7514	233.9869	250.2836	267.7152	286.3610
MINCEIBHSB	79.1862	80.7068	96.4043	119.5019	124.3814	123.3974	111.2462	116.7565	128.3975	137.3401	146.9056	157.1372	168.0814
MINCEIBHSC	52.7908	53.8045	64.2695	79.6679	82.9209	82.2650	74.1641	77.8377	85.5984	91.5601	97.9370	104.7581	112.0543
MINCEIBHSD	17.5969	17.9348	21.4232	26.5560	27.6403	27.4217	24.7214	25.9459	28.5328	30.5200	32.6457	34.9194	37.3514
MINCEIBHSE	5.8656	5.9783	7.1411	8.8520	9.2134	9.1406	8.2405	8.6486	9.5109	10.1733	10.8819	11.6398	12.4505
MINCEIBHSF	2.9328	2.9891	3.5705	4.4260	4.6067	4.5703	4.1202	4.3243	4.7555	5.0867	5.4409	5.8199	6.2252
MINCEIBHSG	2.9328	2.9891	3.5705	4.4260	4.6067	4.5703	4.1202	4.3243	4.7555	5.0867	5.4409	5.8199	6.2252
MINCEIBHSH	5.8656	5.9783	7.1411	8.8520	9.2134	9.1406	8.2405	8.6486	9.5109	10.1733	10.8819	11.6398	12.4505
MINCEIBHSI	17.5969	17.9348	21.4232	25.6789	27.6403	27.4217	24.7214	25.9459	28.5328	30.5200	32.6457	34.9194	37.3514
MINCEIBHSJ	23.3130	53.8045	23.4031	0.1586	34.2025	62.5387	74.1641	74.8773	56.1746	43.1676	33.1723	25.4914	19.5889
MINCEIBHSK	25.0770	52.4770	23.8278	0.0000	0.0000	2.6105	45.5627	22.6043	0.0000	0.0000	0.0000	0.0000	0.0000

For the various types of coal mined from Northern Appalachia (NA), Central Appalachia (CA), Southern Appalachia (SA), Northern Wyoming (NW), Southern Wyoming (SW) and Rocky Mountain (RM) regions, only a very small portion of each type (usually less than 5%) is delivered to Indiana. Thus, Indiana is assumed to be a price taker of those coal types (listed in Table 3-3 from row 6 to row 20). A single price is used to represent the supply of each of these coal types per period. The price for each coal type by period is determined via the following three steps: (1) retrieve the 11-step coal supply curve (annual data) from the AEO 2010 reference case (EIA, 2010e) and calculate the three-year average quantities and prices for each step to develop a supply curve by period; (2) obtain forecast data on coal production by region and type from the AEO 2013 reference case (EIA, 2013); and (3) use the forecasted coal production to locate its price on the corresponding supply curve identified in step (1) for each period. The price of coal supply by coal type and period used in IN-MARKAL is displayed in Table 3-9.

Table 3-9 Supply of Various Coal Types to Indiana

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/PJ													
MINCNABMU	1.6501	2.4977	2.2889	2.1455	2.4945	2.3356	2.6063	2.3898	2.6187	2.5336	2.4513	2.3716	2.2946
MINCNABHU	1.5425	1.8129	1.9381	2.1101	2.2388	2.2906	2.3593	2.3930	2.4411	2.4974	2.5550	2.6140	2.6743
MINCNABMS	1.5712	1.9862	1.9045	2.0061	2.1005	2.1706	2.2248	2.2158	2.3224	2.3169	2.3114	2.3059	2.3004
MINCNABHS	1.6007	1.8238	2.0903	2.2078	2.5188	2.6313	2.6331	2.6289	2.7047	2.7881	2.8740	2.9626	3.0540
MINCNAPMU	2.6965	3.0415	3.2367	3.7499	4.1112	4.5931	5.1845	5.5700	5.8712	6.1538	6.4500	6.7605	7.0859
MINCCABLU	1.9399	2.7581	2.9871	3.0903	3.0224	2.9846	2.9753	3.0606	3.1146	3.1597	3.2054	3.2518	3.2989
MINCCABMU	2.3432	3.1321	2.9540	2.9716	2.7886	2.7893	2.8440	2.9291	3.2397	3.2433	3.2468	3.2503	3.2539
MINCCABLS	2.4667	2.6488	2.8589	3.0296	2.9448	2.9231	2.9688	2.9859	3.0132	3.0480	3.0832	3.1187	3.1547
MINCCABMS	2.0226	2.4895	2.5658	2.6566	2.5973	2.5702	2.6187	2.6236	2.6392	2.6630	2.6869	2.7111	2.7354
MINCCAPMU	2.8677	3.6860	4.3093	4.9897	5.5935	6.0312	6.4956	6.7317	7.0141	6.5697	6.1536	5.7637	5.3986
MINCSAPLU	3.6991	3.4222	3.7269	4.2898	4.5659	4.8527	5.1813	5.5034	5.8017	6.0793	6.3701	6.6749	6.9942
MINCNWSLS	0.5555	0.6103	0.6927	0.7968	0.8532	0.9172	1.0028	1.0850	1.1601	1.2182	1.2793	1.3434	1.4107
MINCNWSMS	0.4774	0.5631	0.7628	0.9977	1.1106	1.1945	1.3167	1.3972	1.4898	1.5525	1.6179	1.6861	1.7571
MINCSWSLS	0.6345	0.6874	0.7457	0.8144	0.8576	0.9238	1.0079	1.0872	1.1626	1.2201	1.2804	1.3436	1.4101
MINCRMBLU	1.2076	1.4217	1.4715	1.4997	1.5153	1.5619	1.6975	1.7830	1.8602	1.9095	1.9601	2.0120	2.0654

Note: The naming convention of coal supply technologies is as follow.

Characters 1-3: MIN means mining

Characters 4: C means coal

Characters 5-9: coal type as listed in Table 3-2.

The costs shown in the supply curves mentioned previously are mine mouth prices, not including expenses of delivering coal from production origins to the specific sectors in Indiana. Therefore, transportation costs are specified separately. Data on coal transportation costs for the base year (2007) are requested from EIA,[1] which are characterized by coal type (supply region, grade, sulfur content and mine type as shown in Table 3-2), demand region and end-use sector and are expressed in million dollars per ton transported. Indiana is located in the ENC region; therefore

[1] Source: EMMDB209 Table CMM_ORIGIN_DEST_RATE (EIA contact: Michael.Mellish@eia.doe.gov or Diane.Kearney@eia.gov)

ENC as the demand region in the transportation data is used to represent Indiana as delivery destination. EIA also provides a set of escalation factors for the purpose of developing transportation rates for the future periods. The rate escalation factors are categorized into two groups — Western US and Eastern US. The Eastern US rate escalation factors are used in IN-MARKAL to extrapolate coal transportation costs. Data on coal transportation cost by coal type and destination sector in Indiana are displayed in Table 3-10.

Table 3-10 Coal Transportation Cost by Coal Type and Destination

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/PJ													
XCNABMURES	0.3943	0.3943	0.3943	0.3943	0.3943	0.3889	0.3887	0.3888	0.3917	0.3943	0.3941	0.3939	0.3934
XCNABMUCOM	0.3943	0.3943	0.3943	0.3943	0.3943	0.3889	0.3887	0.3888	0.3917	0.3943	0.3941	0.3939	0.3934
XCNABMUCTL	0.5258	0.5258	0.5258	0.5258	0.5258	0.5186	0.5183	0.5184	0.5222	0.5258	0.5254	0.5252	0.5245
XCNABMUELC	0.5258	0.5258	0.5258	0.5258	0.5258	0.5186	0.5183	0.5184	0.5222	0.5258	0.5254	0.5252	0.5245
XCNABHUCTL	0.7747	0.7747	0.7747	0.7747	0.7747	0.7641	0.7637	0.7639	0.7695	0.7747	0.7742	0.7738	0.7728
XCNABHUELC	0.2758	0.2758	0.2758	0.2758	0.2758	0.2720	0.2719	0.2719	0.2739	0.2758	0.2756	0.2755	0.2751
XCNABMSIND	0.1228	0.1228	0.1228	0.1228	0.1228	0.1211	0.1211	0.1211	0.1220	0.1228	0.1227	0.1227	0.1225
XCNABMSCTL	0.0950	0.0950	0.0950	0.0950	0.0950	0.0937	0.0937	0.0937	0.0944	0.0950	0.0950	0.0949	0.0948
XCNABMSELC	0.6763	0.6763	0.6763	0.6763	0.6763	0.6671	0.6667	0.6669	0.6718	0.6763	0.6759	0.6756	0.6747
XCNABHSCTL	0.0577	0.0577	0.0577	0.0577	0.0577	0.0569	0.0568	0.0569	0.0573	0.0577	0.0576	0.0576	0.0575
XCNABHSELC	0.0577	0.0577	0.0577	0.0577	0.0577	0.0569	0.0568	0.0569	0.0573	0.0577	0.0576	0.0576	0.0575
XCNAPMUMET	0.1674	0.1674	0.1674	0.1674	0.1674	0.1651	0.1650	0.1651	0.1663	0.1674	0.1673	0.1672	0.1670
XCCABLURES	1.0436	1.0436	1.0436	1.0436	1.0436	1.0293	1.0287	1.0290	1.0365	1.0436	1.0429	1.0424	1.0410
XCCABLUIND	1.3854	1.3854	1.3854	1.3854	1.3854	1.3664	1.3657	1.3660	1.3760	1.3854	1.3845	1.3838	1.3820
XCCABLUCTL	0.5008	0.5008	0.5008	0.5008	0.5008	0.4940	0.4937	0.4938	0.4974	0.5008	0.5005	0.5003	0.4996
XCCABLUELC	0.5202	0.5202	0.5202	0.5202	0.5202	0.5131	0.5128	0.5130	0.5167	0.5202	0.5199	0.5196	0.5190
XCCABMURES	0.0567	0.0567	0.0567	0.0567	0.0567	0.0559	0.0559	0.0559	0.0563	0.0567	0.0567	0.0566	0.0566
XCCABMUCOM	0.0567	0.0567	0.0567	0.0567	0.0567	0.0559	0.0559	0.0559	0.0563	0.0567	0.0567	0.0566	0.0566
XCCABMUIND	0.9281	0.9281	0.9281	0.9281	0.9281	0.9154	0.9149	0.9152	0.9219	0.9281	0.9275	0.9271	0.9259
XCCABMUCTL	0.4965	0.4965	0.4965	0.4965	0.4965	0.4897	0.4894	0.4896	0.4932	0.4965	0.4962	0.4960	0.4953
XCCABMUELC	0.3321	0.3321	0.3321	0.3321	0.3321	0.3275	0.3273	0.3274	0.3298	0.3321	0.3318	0.3317	0.3312
XCCABLSRES	0.8470	0.8470	0.8470	0.8470	0.8470	0.8354	0.8350	0.8352	0.8413	0.8470	0.8465	0.8461	0.8449
XCCABLSIND	0.6285	0.6285	0.6285	0.6285	0.6285	0.6199	0.6196	0.6198	0.6243	0.6285	0.6281	0.6278	0.6270
XCCABLSCTL	0.6123	0.6123	0.6123	0.6123	0.6123	0.6039	0.6035	0.6037	0.6081	0.6123	0.6119	0.6116	0.6108
XCCABLSELC	0.4996	0.4996	0.4996	0.4996	0.4996	0.4927	0.4925	0.4926	0.4962	0.4996	0.4993	0.4990	0.4984
XCCABMSRES	0.6030	0.6030	0.6030	0.6030	0.6030	0.5947	0.5944	0.5946	0.5989	0.6030	0.6026	0.6023	0.6015
XCCABMSCOM	0.6030	0.6030	0.6030	0.6030	0.6030	0.5947	0.5944	0.5946	0.5989	0.6030	0.6026	0.6023	0.6015
XCCABMSIND	0.8443	0.8443	0.8443	0.8443	0.8443	0.8328	0.8323	0.8325	0.8386	0.8443	0.8438	0.8434	0.8423
XCCABMSCTL	0.5142	0.5142	0.5142	0.5142	0.5142	0.5071	0.5068	0.5070	0.5107	0.5142	0.5138	0.5136	0.5129
XCCABMSELC	0.3636	0.3636	0.3636	0.3636	0.3636	0.3586	0.3584	0.3585	0.3611	0.3636	0.3633	0.3632	0.3627
XCCAPMUMET	0.4856	0.4856	0.4856	0.4856	0.4856	0.4790	0.4787	0.4788	0.4823	0.4856	0.4853	0.4851	0.4844
XCSAPLUMET	1.4829	1.4829	1.4829	1.4829	1.4829	1.4626	1.4618	1.4621	1.4728	1.4829	1.4819	1.4812	1.4792
XCEIBMURES	0.3248	0.3248	0.3248	0.3248	0.3248	0.3204	0.3202	0.3203	0.3226	0.3248	0.3246	0.3245	0.3240
XCEIBMUCOM	0.3248	0.3248	0.3248	0.3248	0.3248	0.3204	0.3202	0.3203	0.3226	0.3248	0.3246	0.3245	0.3240
XCEIBMUIND	1.0772	1.0772	1.0772	1.0772	1.0772	1.0625	1.0619	1.0622	1.0699	1.0772	1.0765	1.0760	1.0746
XCEIBMUCTL	0.3200	0.3200	0.3200	0.3200	0.3200	0.3156	0.3154	0.3155	0.3178	0.3200	0.3198	0.3196	0.3192
XCEIBMUELC	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
XCEIBMSRES	0.6419	0.6419	0.6419	0.6419	0.6419	0.6331	0.6328	0.6329	0.6376	0.6419	0.6415	0.6412	0.6403
XCEIBMSCOM	0.6419	0.6419	0.6419	0.6419	0.6419	0.6331	0.6328	0.6329	0.6376	0.6419	0.6415	0.6412	0.6403
XCEIBMSIND	0.7085	0.7085	0.7085	0.7085	0.7085	0.6988	0.6984	0.6986	0.7037	0.7085	0.7081	0.7077	0.7068
XCEIBMSCTL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
XCEIBMSELC	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
XCEIBHUIND	0.9531	0.9531	0.9531	0.9531	0.9531	0.9400	0.9395	0.9397	0.9466	0.9531	0.9525	0.9520	0.9507
XCEIBHUCTL	0.2980	0.2980	0.2980	0.2980	0.2980	0.2939	0.2937	0.2938	0.2959	0.2980	0.2978	0.2976	0.2972
XCEIBHUELC	0.2177	0.2177	0.2177	0.2177	0.2177	0.2147	0.2146	0.2146	0.2162	0.2177	0.2176	0.2174	0.2172
XCEIBHUEL0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Table 3-10 Continued

XCEIBHSIND	1.1438	1.1438	1.1438	1.1438	1.1438	1.1282	1.1275	1.1278	1.1361	1.1438	1.1431	1.1425	1.1410
XCEIBHSCTL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
XCEIBHSELC	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
XCNWSLSRES	1.9856	1.9856	1.9856	1.9856	1.9856	1.9562	1.9927	2.0295	2.0861	2.1728	2.2797	2.3985	2.5262
XCNWSLSCOM	1.9856	1.9856	1.9856	1.9856	1.9856	1.9562	1.9927	2.0295	2.0861	2.1728	2.2797	2.3985	2.5262
XCNWSLSIND	1.5137	1.5137	1.5137	1.5137	1.5137	1.4913	1.5191	1.5472	1.5903	1.6564	1.7380	1.8285	1.9259
XCNWSLSCTL	1.8006	1.8006	1.8006	1.8006	1.8006	1.7739	1.8070	1.8404	1.8917	1.9703	2.0673	2.1749	2.2908
XCNWSLSELC	1.8006	1.8006	1.8006	1.8006	1.8006	1.7739	1.8070	1.8404	1.8917	1.9703	2.0673	2.1749	2.2908
XCNWSMSIND	2.0489	2.0489	2.0489	2.0489	2.0489	2.0185	2.0561	2.0941	2.1525	2.2420	2.3524	2.4749	2.6067
XCNWSMSCTL	1.2457	1.2457	1.2457	1.2457	1.2457	1.2272	1.2501	1.2732	1.3087	1.3631	1.4302	1.5047	1.5848
XCNWSMSELC	1.2457	1.2457	1.2457	1.2457	1.2457	1.2272	1.2501	1.2732	1.3087	1.3631	1.4302	1.5047	1.5848
XCSWSLSRES	1.8986	1.8986	1.8986	1.8986	1.8986	1.8705	1.9053	1.9406	1.9947	2.0775	2.1798	2.2933	2.4155
XCSWSLSCOM	1.8986	1.8986	1.8986	1.8986	1.8986	1.8705	1.9053	1.9406	1.9947	2.0775	2.1798	2.2933	2.4155
XCSWSLSIND	1.4474	1.4474	1.4474	1.4474	1.4474	1.4259	1.4525	1.4794	1.5206	1.5838	1.6618	1.7483	1.8415
XCSWSLSCTL	1.1342	1.1342	1.1342	1.1342	1.1342	1.1174	1.1382	1.1593	1.1916	1.2411	1.3022	1.3700	1.4430
XCSWSLSELC	1.0271	1.0271	1.0271	1.0271	1.0271	1.0119	1.0308	1.0499	1.0791	1.1240	1.1793	1.2407	1.3068
XCRMBLUIND	2.3027	2.3027	2.3027	2.3027	2.3027	2.2686	2.3109	2.3537	2.4193	2.5198	2.6439	2.7815	2.9297
XCRMBLUCTL	0.8317	0.8317	0.8317	0.8317	0.8317	0.8194	0.8346	0.8501	0.8738	0.9101	0.9549	1.0046	1.0581
XCRMBLUELC	0.5977	0.5977	0.5977	0.5977	0.5977	0.5888	0.5998	0.6109	0.6280	0.6540	0.6862	0.7220	0.7604

Note: The naming convention of coal transportation technologies is as follow.
Characters 1: X means transportation technology
Characters 2: C means coal
Characters 3-7: coal type as listed in Table 3-2
Characters 8-10: destination sector in Indiana (RES: residential, COM: commercial, IND: industrial, ELC: electricity, CTL: coal to liquid).

3.2.1.2 Natural Gas Supply

According to data shown in Table 3-11 (EIA, 2010c), Indiana consumes a very small portion of total U.S. natural gas delivered to consumers in various sectors of the economy. Therefore, Indiana is assumed to be a price taker in the natural gas market.

Table 3-11 Share of U.S. Natural Gas Delivered to Indiana by Sector

Year	Residential Deliveries (%)	Commercial Deliveries (%)	Industrial Deliveries (%)	Vehicle Fuel Deliveries (%)	Electric Utility Deliveries (%)
2007	3.02	2.51	4.10	0.52	0.55
2008	3.12	2.69	4.09	0.48	0.51
2009	2.92	2.53	3.97	0.28	0.53
2010	2.88	2.43	4.27	0.28	0.83

The natural gas price by sector (residential, commercial, industrial, transportation and electric power) for the East North Central (ENC) region is retrieved from Table 118 of AEO 2010 (for 2007) and Table 13 of AEO 2013 (for periods beginning in 2010). Projections of natural gas price by sector are not available at the state level. Therefore, natural gas price at the ENC region level is adjusted by a factor to represent the natural gas delivered price for Indiana. The factor for each sector is the ratio between the average natural gas prices of 2007 and 2010 for Indiana (historic data retrieved from the EIA State Energy Data System (SEDS)) and that for ENC (obtained from AEO 2010 and AEO 2013 as mentioned before). Factors applied to the five end-use sectors are displayed in Table 3-12. Natural gas delivered prices serve as input to IN-MARKAL are shown in Table 3-13 and Figure 3-2.

Table 3-12 IN-MARKAL Natural Gas Price Conversion Factor

Sector	Conversion factor (from ENC to Indiana)
Residential	0.92
Commercial	0.93
Industrial	0.99
Transportation	0.38
Electric power	1.03

Table 3-13 Natural Gas Delivered Prices to Indiana by Sector in 2007 Million Dollars/PJ

	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Residential	9.8340	8.3495	7.4432	7.3740	8.1370	8.5532	8.9121	9.2158	9.5410	10.0966	11.0830	11.8229	12.3457
Commercial	9.0279	7.1799	6.3966	6.3918	7.0782	7.4375	7.7339	7.9690	8.2208	8.6954	9.6026	10.2697	10.7098
Industrial	7.1902	5.7005	4.6162	4.9596	5.5642	5.8845	6.1670	6.3900	6.6287	7.0904	7.9927	8.6627	9.1288
Transportation	5.0911	5.2019	4.9542	5.0442	5.3076	5.5031	5.7915	6.0784	6.2816	6.5123	6.8630	7.1299	7.3183
Electric power	6.7794	4.6237	3.1182	3.7099	4.3001	4.6102	4.9279	5.1684	5.4082	5.9268	6.8286	7.5724	8.0484

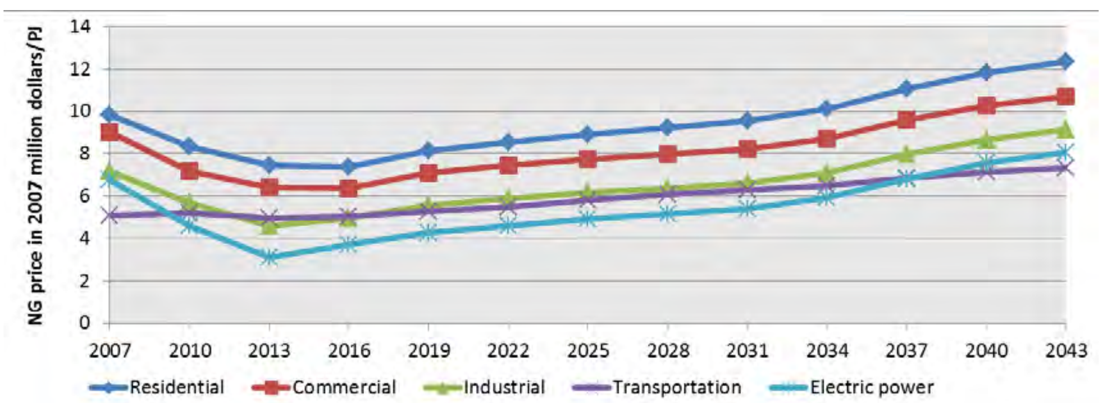

Figure 3-2 Natural Gas Delivered Prices to Indiana by End-Use Sector

For each end-use sector, an upper bound is placed on the amount of natural gas available for Indiana in each period. The upper bounds are developed based on the forecast of U.S. natural gas consumption by end-use sector from the AEO 2010 and AEO 2013 and historic data (1999-2010) on the Indiana share of total U.S. natural gas delivered to consumers by end-use sector retrieved from EIA. Because the data on Indiana shares is only available to 2010, historical data is used for 2007 and 2010 for all sectors; the maximum Indiana shares among the historical data from 1990-2010 is used to represent future Indiana share for each one of residential, commercial, industrial and transportation sectors. For the electric power sector, a 10% Indiana share is used for periods beginning in 2013, which is much higher than historic records (usually less than 1%). By doing this, a great expansion of natural gas generation capacity is allowed. Since Indiana relies heavily on coal for electricity production compared with other states, a big potential for the growth of natural gas capacity in-state is assumed, considering future retirement of old coal plants and moderate natural gas prices forecasted by EIA. The shares applied for the calculation of maximum available supply are displayed in Table 3-14. The maximum amount of natural gas available for each end-use sector of Indiana is shown in Table 3-15.

Table 3-14 Indiana Share of Total U.S. Natural Gas Delivery by End-Use Sector

	2007	2010	2013 - 2043
Residential	3.02%	2.88%	3.43%
Commercial	2.51%	2.43%	2.84%
Industrial	4.10%	4.27%	4.27%
Transportation	0.52%	0.28%	5.62%
Electric power	0.55%	0.83%	10.00%

Table 3-15 Maximum Amount of Natural Gas Available for Indiana by End-Use Sector in PJ

	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Residential	154.18	148.65	178.31	171.26	167.92	166.06	164.21	162.57	160.50	157.96	155.26	153.15	151.07
Commercial	82.11	81.31	100.14	102.00	101.65	102.09	102.76	104.00	105.46	107.16	108.35	110.35	111.84
Industrial	294.57	300.45	313.50	335.62	351.33	358.82	360.25	358.83	359.43	360.45	361.82	364.00	369.87
Transportation	3.73	2.13	45.98	45.61	46.35	47.57	50.29	55.16	63.07	75.29	91.35	108.51	133.97
Electric power	40.78	66.11	884.64	943.42	890.64	887.06	910.04	942.03	975.59	1,008.83	1,022.56	1,022.99	1,046.79

3.2.1.3 Refined Products Supply

Petroleum products consumed in the state of Indiana are mainly from two sources: outputs of in-state refineries and direct imports from other regions of the country.

Indiana has two refineries. One is the BP Whiting facility located in northern Indiana. The other is the Country Mark refining facility located in southern Indiana. According to the Whiting Refinery Facility Fact Sheet (BP, 2012), the BP Whiting facility is currently the 5th largest refinery in the USA. The refinery processes up to 405,000 barrels of raw crude oil each day and produces up to 15 million gallons of refined products. It receives raw crude oil via pipeline from Canada, Gulf of Mexico and West Texas. It ships refined products via pipeline to the entire Midwest. The Country Mark refining facility is much smaller, with daily capacity around 27,500 barrels of crude oil. It mainly serves farms, fleets and families located in the state of Indiana.

According to EIA data on petroleum products movements by tanker, pipeline and barge between Petroleum Administration for Defense Districts (PADDs) (EIA, 2012c), PADD2, to which Indiana belongs, receives petroleum products from PADD1 (East Coast), PADD3 (Gulf Coast) and PADD4 (Rocky Mountain). There are also petroleum products which flow from PADD2 to PADD1, PADD3 and PADD4. Petroleum products are traded nation-wide, except for PADD5 (West Coast). Those facts make things very complicated if petroleum products from in-state refineries and those directly from other regions of the country are modeled separately. Therefore, Indiana is considered as a price taker of petroleum products in IN-MARKAL.

Here is the list of refined products import technologies modeled with IN-MARKAL, as shown in Table 3-16. Refined products used by the end-use sectors of Indiana are modeled by product category and end-use sector. Costs of refined products are obtained from the AEO 2010 & AEO 2013 Table 13 Energy Prices by sector, source and census division. The ENC census division data are adjusted to represent delivered costs of refined products to Indiana. The conversion factor is calculated as the ratio between the product's average price of 2007 and 2010 for Indiana (historic data retrieved from the EIA SEDS) and that for ENC (obtained from AEO 2010 & AEO 2013 Table 13 as mentioned before). Cost data of refined products delivered to Indiana used in IN-MARKAL is shown in Table 3-17.

For each refined product import technology listed in Table 3-16, an upper bound is placed on supply for each period starting from 2013. Data on 2010 by end-use sector are retrieved from various sources of EIA, as listed in Table 3-18, and are used as the base for upper bound projections. For periods beginning in 2013, the maximum available quantities of various refined products for Indiana are assumed to keep the same trend with ENC region. Forecast of energy consumption by sector and source for the ENC is obtained from AEO 2013 reference case. The maximum available quantity to Indiana for each refined product is shown in Table 3-19.

Table 3-16 Refined Products Import Technologies Modeled with IN-MARKAL

Refined products	Description
Distillate fuel oil (DFO)	
IMPDFORES	DFO to Indiana residential sector
IMPDFOCOM	DFO to Indiana commercial sector
IMPDFOIND	DFO to Indiana industrial sector
IMPDSLTRN	DFO to Indiana transportation sector
IMPDFOELC	DFO to Indiana electric sector
Residual fuel oil (RFO)	
IMPRFOCOM	RFO to Indiana commercial sector
IMPRFOIND	RFO to Indiana industrial sector
IMPRFOTRN	RFO to Indiana transportation sector
Liquefied petroleum gas (LPG)	
IMPLPGRES	LPG to Indiana residential sector
IMPLPGCOM	LPG to Indiana commercial sector
IMPLPGIND	LPG to Indiana industrial sector
IMPLPGTRN	LPG to Indiana transportation sector
Motor gasoline (GSL)	
IMPGSLIND	GSL to Indiana industrial sector
IMPGSLTRN	GSL to Indiana transportation sector
Jet fuel (JF)	
IMPJFLTRN	JF to Indiana transportation sector
Aviation gasoline (AG)	
IMPGSLBTRN	AG to Indiana transportation sector
Kerosene (KER)	
IMPKERRES	KER to Indiana residential sector
IMPKERCOM	KER to Indiana commercial sector
Other petroleum (OTH)	
IMPOTHIND	OTH to Indiana industrial sector
Petrochemical feedstock (PFS)	
IMPPFSIND	PFS to Indiana industrial sector

Table 3-17 Delivered Cost of Refined Product to Indiana

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/PJ													
IMPDFORES	18.3032	18.9038	22.1301	20.5102	21.5835	22.6484	23.8616	25.0299	26.2373	27.5569	29.1787	30.5697	31.4974
IMPDFOCOM	14.9777	17.5568	20.5641	17.7581	18.8456	19.9397	20.9992	21.9929	22.9987	24.2074	25.7125	26.9998	27.6749
IMPDFOIND	15.3633	18.4239	21.5835	18.8009	19.9749	21.1659	22.1966	23.1428	24.0837	25.3031	26.8358	28.1441	28.8274
IMPDSLTRN	18.7845	18.8074	20.6099	20.5368	21.7723	23.0297	24.0694	25.0152	25.9398	27.1966	28.7760	30.1196	31.1190
IMPDFOELC	13.4396	16.1198	18.8733	16.7446	17.7274	18.7025	19.8135	20.8832	21.9889	23.1972	24.6823	25.9560	26.7327
IMPRFOCOM	8.2348	11.7400	19.4426	21.8032	22.7646	23.9855	25.1920	26.6602	27.9622	29.4537	31.2323	32.9637	34.7637
IMPRFOIND	9.6049	10.3700	17.1708	19.7534	20.6244	21.7305	22.8236	24.1537	25.3333	26.6847	28.2960	29.8647	31.5775
IMPRFOTRN	7.6321	7.1852	11.9053	15.8679	16.6064	17.3652	18.1653	19.0214	19.8170	20.7437	21.8389	22.8946	24.4614
IMPLPGRES	19.9103	21.3267	17.0070	16.2414	17.4299	18.1831	18.7458	19.2109	19.5903	20.0180	20.6073	21.1711	21.4089
IMPLPGCOM	16.8708	19.6488	15.0686	14.1089	15.6117	16.5916	17.3368	17.9605	18.4735	19.0557	19.8656	20.6510	20.9918
IMPLPGIND	21.3786	19.0172	15.7681	14.7039	16.3590	17.4458	18.2767	18.9736	19.5476	20.2001	21.1097	21.9934	22.3719
IMPLPGTRN	22.4312	21.2486	20.3766	19.5069	20.8795	21.7488	22.3981	22.9338	23.3694	23.8595	24.5357	25.1837	25.4669
IMPGSLIND	20.5420	19.1151	22.2840	21.3875	22.3840	23.4877	23.8017	24.4105	25.2648	26.3543	27.8081	29.4537	30.1280
IMPGSLTRN	20.5420	19.1151	22.2840	21.3875	22.3840	23.4877	23.8017	24.4105	25.2648	26.3543	27.8081	29.4537	30.1280
IMPJFLTRN	14.5665	14.8813	18.4509	17.3708	18.3708	19.5141	20.7480	22.0102	23.1670	24.4714	26.1032	27.3613	28.2344
IMPGSLBTRN	22.7132	22.6004	26.5295	25.3574	26.4873	27.7696	28.9175	30.1690	31.3959	32.8132	34.6107	36.1378	37.0717
IMPKERRES	21.1648	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499
IMPKERCOM	21.1648	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499	23.0499
IMPOTHIND	21.2468	21.2468	21.2468	21.2468	21.2468	21.2468	21.2468	21.2468	21.2468	21.2468	21.2468	21.2468	21.2468

Table 3-18 Data Source of Refined Products Indiana Sales

Fuel	EIA table name	Source website
DFO	Indiana Sales of Distillate Fuel Oil by End Use	http://www.eia.gov/dnav/pet/pet_cons_821dst_dcu_sin_a.htm
RFO	Indiana Sales of Residual Fuel Oil by End Use	http://www.eia.gov/dnav/pet/pet_cons_821rsd_dcu_sin_a.htm
LPG	Indiana Sales of LPG by End Use	http://www.eia.gov/beta/state/search/#?2=196&6=133&1=90&5=126&r=false
GSL	Indiana Sales of Motor Gasoline by End Use	http://www.eia.gov/beta/state/search/#?2=196&6=133&1=90&5=126&r=false
JF	Indiana Sales of Jet Fuel by End Use	http://www.eia.gov/beta/state/search/#?2=196&6=133&1=90&5=126&r=false
AG	Indiana Sales of Aviation Gasoline by End Use	http://www.eia.gov/beta/state/search/#?2=196&6=133&1=90&5=126&r=false
KER	Indiana Sales of Kerosene by End Use	http://www.eia.gov/beta/state/search/#?2=196&6=133&1=90&5=126&r=false

Table 3-19 Refined Product Maximum Available Quantity to Indiana

Year	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Maximum available quantity in PJ											
IMPDFORES	2.5357	2.3293	2.1456	1.9803	1.8277	1.6895	1.5687	1.4561	1.3489	1.2497	1.1690
IMPDFOCOM	3.0751	3.6808	3.6324	3.5821	3.5319	3.4888	3.4509	3.4090	3.3588	3.3173	3.2188
IMPDFOIND	32.0934	32.7185	32.4241	31.9924	31.7556	31.5755	31.5141	31.6740	32.1766	32.7138	32.7138
IMPDSLTRN	214.9548	238.5906	245.1733	246.9839	246.4024	243.9331	242.5565	240.6489	239.5025	239.4205	243.0298
IMPDFOELC	1.5709	1.3664	1.4017	1.4169	1.4179	1.4181	1.4171	1.4174	1.4182	1.4189	1.5013
IMPRFOCOM	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
IMPRFOIND	2.4326	2.4676	2.5777	2.5074	2.3412	2.1453	2.0406	2.0410	2.0775	2.1122	2.0495
IMPRFOTRN	0.6357	0.6753	0.6668	0.6541	0.6432	0.6337	0.6256	0.6171	0.6075	0.5977	0.5888
IMPLPGRES	18.6530	18.5764	18.4535	18.4100	18.4068	18.4399	18.4940	18.5474	18.5999	18.6648	18.7209
IMPLPGCOM	2.5979	2.7131	2.6317	2.6120	2.6095	2.6149	2.6307	2.6495	2.6596	2.6745	2.7149
IMPLPGIND	9.6343	10.5453	11.2689	11.7080	11.7806	11.6034	11.5189	11.3909	11.2261	11.0231	11.1226
IMPLPGTRN	0.9530	0.9601	0.9559	0.9834	0.9855	1.0120	1.0482	1.0882	1.1381	1.2048	1.2340
IMPGSLIND	15.7523	17.2447	17.9568	18.1526	18.3587	18.3882	18.2869	18.2949	18.4814	18.7484	19.0879
IMPGSLTRN	367.3331	336.2855	324.3478	306.3852	284.4166	264.6333	251.7746	241.9764	237.6094	235.3707	223.5698
IMPJFLTRN	44.1368	44.4532	44.6208	44.5755	44.6691	44.7013	44.6370	44.4179	44.2196	43.9829	43.9829
IMPGSLBTRN	0.4302	0.4364	0.4348	0.4301	0.4255	0.4220	0.4190	0.4154	0.4127	0.4098	0.4024
IMPKERRES	0.3857	0.3198	0.2997	0.2805	0.2623	0.2452	0.2292	0.2141	0.1992	0.1860	0.1734
IMPKERCOM	0.1139	0.0859	0.0940	0.1008	0.1055	0.1092	0.1133	0.1177	0.1217	0.1275	0.1317
IMPOTHIND	—	—	—	—	—	—	—	—	—	—	—

3.2.1.4 Biomass Supply

IN_MARKAL models 14 types of biomass feedstock for biofuel production. They are corn, soybean oil, yellow grease, corn stover, agricultural residues, forest residues, unused primary and secondary mill residues, used mill residues, urban wood waste, grassy energy crops, woody energy crop, annual energy crop and municipal solid waste.

Data on corn and soybean oil supply (price and upper bound on supply quantity) is developed from data contained in EPAUS9r, which was originally retrieved from the Food and Agricultural Policy Research Institute (FAPRI) Center for Agricultural and Rural Development (CARD) International Ethanol Model.

To calculate the upper bound of corn available for Indiana ethanol production, total corn production from the Corn Belt is scaled down by the ratio of Indiana corn planted area to Corn Belt corn planted area, and then multiplied by the share of Indiana corn available for ethanol (assumed 50% of total production). The cost of corn is obtained from the U.S. farm price of corn in the FAPRI-CARD database. Three-year averages are calculated to represent the cost for each year in one period. Data on corn supply used in IN-MARKAL is shown in Table 3-20.

Table 3-20 Indiana Corn Supply for Ethanol Production

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Corn price in million dollars/million short ton	142.9006	163.6480	182.3575	185.3281	185.5140	184.0533	178.5802	178.5802	178.5802	178.5802	178.5802	178.5802	178.5802
Maximum available quantity in million short tons	14.6681	12.5790	14.9479	15.8177	14.9451	16.5186	17.7751	17.7751	17.7751	17.7751	17.7751	17.7751	17.7751

To estimate the maximum quantity of soybean oil available in Indiana for biodiesel production by period, projections of total soybean production from the Corn Belt is multiplied by the projections of the Indiana share of Corn Belt planted soybean area to estimate Indiana's soybean production first. Then, the Indiana soybean production is multiplied by the share of soybean used for oil crushing and by soybean oil crushing yield in pounds of oil per bushel of soybean to estimate Indiana soybean oil production. Finally, the share of soybean oil available for biodiesel (assume 50% of total soybean oil production) is multiplied with Indiana soybean oil production to derive the maximum quantity of Indiana soybean oil available for biodiesel production. Cost of soybean oil (excluding the cost of oil crushing) is based on FAPRI-CARD data. Data on soybean oil supply used in IN-MARKAL is shown in Table 3-21.

Table 3-21 Indiana Soybean Oil Supply for Biodiesel Production

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Soybean oil price in million dollars/million short ton	1105.3982	962.2026	964.3249	1013.6923	1065.5322	1111.9911	1155.0325	1155.0325	1155.0325	1155.0325	1155.0325	1155.0325	1155.0325
Maximum available quantity in million short tons	0.4114	0.3592	0.3470	0.3551	0.3648	0.3761	0.3880	0.3880	0.3880	0.3880	0.3880	0.3880	0.3880

The supply of yellow grease is developed using a different method. According to a National Renewable Energy Laboratory study (Wiltsee, 1998), the urban waste grease resources collected from restaurants are on average 9 pounds/year/person. Therefore, the total amount of yellow grease is predicted based on population. Indiana population projections are obtained from STATS Indiana (2010). Assuming that all of the yellow grease from restaurants can be gathered, projections of the maximum availability of yellow grease in PJ are shown in Table 3-22. The cost of yellow grease, including transportation to and from the restaurants, is assumed to be constant at 5.34 million 2007 dollars/PJ, which is converted from the information used in EPAUS9r.

Table 3-22 Indiana Yellow Grease Supply for Biodiesel Production

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Maximum available quantity for yellow grease in PJ	1.0841	1.1078	1.1276	1.1469	1.1647	1.1816	1.1978	1.2114	1.2241	1.2349	1.2443	1.2529	1.2605

For the other 11 types of biomass feedstock, supplies are represented by step-wised supply curves obtained from the U.S. Department of Energy Bioenergy Knowledge Discovery Framework's U.S. Billion Ton Update — Biomass Supply for a Bioenergy and Byproducts Industry (Bioenergy KDF, 2011). The Billion Ton Update provides county level biomass supplies, which are aggregated to the state level in order to be used in IN-MARKAL. (Due to their bulky nature and low energy content, we assume interstate imports and exports of biomass will be negligible.) Table 3-23 displays the data on Indiana corn stover supply. It is modeled with 9 steps for each period. The upper block displays the cost of corn stover, with higher costs associated with higher step numbers. In addition, the cost of stover declines over time and stays constant after 2019 within each step. The lower block displays additional maximum quantities of supply available at each step for each period. For example, in 2013, 1.8806 million short tons (Mt) of corn stover would be available at the cost of 35.2094 million dollars/million short ton (M$/Mt); at the cost of 39.6106 M$/Mt, additional 1.2162 Mt will be available, making the aggregated amount of corn stover available to supply equal to 3.0968 Mt when the cost is no more than 39.61 M$/Mt. For other biomass feedstock, relevant data is shown in Table 3-24 to Table 3-32. All of the biomass feedstock supply curves have taken into account the cost and energy associated with production and collection of biomass.

Table 3-23 Indiana Corn Stover Supply

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/million short ton													
Corn stover step 1	40.0000	37.5843	35.2094	32.9800	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679
Corn stover step 2	45.0000	42.2824	39.6106	37.1025	35.5138	35.5138	35.5138	35.5138	35.5138	35.5138	35.5138	35.5138	35.5138
Corn stover step 3	50.0000	46.9804	44.0118	41.2251	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598
Corn stover step 4	55.0000	51.6784	48.4129	45.3476	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058
Corn stover step 5	60.0000	56.3765	52.8141	49.4701	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518
Corn stover step 6	65.0000	61.0745	57.2153	53.5926	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978
Corn stover step 7	70.0000	65.7725	61.6165	57.7151	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437
Corn stover step 8	75.0000	70.4706	66.0176	61.8376	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897
Corn stover step 9	80.0000	75.1686	70.4188	65.9601	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357
Maximum available quantity (incremental) in million short tons													
Corn stover step 1	0.0000	0.0000	1.8806	2.0994	2.2877	2.5446	2.7329	2.9088	3.0412	3.2049	3.3686	3.5323	3.6960
Corn stover step 2	0.0000	0.0000	1.2162	1.5760	1.6292	1.6939	1.9015	2.1664	2.5095	2.8163	3.1230	3.4298	3.7365
Corn stover step 3	0.0000	0.0000	0.7376	0.4969	0.7866	1.0047	1.0997	1.0927	1.1436	1.1539	1.1641	1.1744	1.1846
Corn stover step 4	0.0000	0.0000	0.8519	1.3622	1.4181	1.2985	1.2405	1.1547	1.0620	1.0140	0.9660	0.9179	0.8699
Corn stover step 5	0.0000	0.0000	0.3646	0.5262	0.5316	0.5529	0.5966	0.7398	0.7885	0.8564	0.9244	0.9923	1.0603
Corn stover step 6	0.0000	0.0000	0.1294	0.1506	0.3610	0.4825	0.6005	0.7272	0.7980	0.9008	1.0036	1.1063	1.2091
Corn stover step 7	0.0000	0.0000	0.0945	0.1045	0.1220	0.1997	0.3214	0.4002	0.5223	0.6058	0.6894	0.7729	0.8564
Corn stover step 8	0.0000	0.0000	0.1118	0.1138	0.1022	0.1585	0.2086	0.3738	0.6150	0.8119	1.0087	1.2055	1.4024
Corn stover step 9	0.0000	0.0000	0.0246	0.0096	0.0140	0.0000	0.1111	0.3003	0.1556	0.1849	0.2142	0.2435	0.2728

Table 3-24 Indiana Agricultural Residues Supply

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/million short ton													
Agricultural residues step 1	40.0000	37.5843	35.2094	32.9800	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679
Agricultural residues step 2	45.0000	42.2824	39.6106	37.1025	35.5138	35.5138	35.5138	35.5138	35.5138	35.5138	35.5138	35.5138	35.5138
Agricultural residues step 3	50.0000	46.9804	44.0118	41.2251	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598
Agricultural residues step 4	55.0000	51.6784	48.4129	45.3476	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058
Agricultural residues step 5	60.0000	56.3765	52.8141	49.4701	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518
Agricultural residues step 6	65.0000	61.0745	57.2153	53.5926	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978
Maximum available quantity (incremental) in million short tons													
Agricultural residues step 1	0.0000	0.0000	0.3608	0.3856	0.4495	0.4660	0.4994	0.5542	0.6256	0.6904	0.7552	0.8200	0.8848
Agricultural residues step 2	0.0000	0.0000	0.2085	0.2964	0.2993	0.3098	0.2996	0.2817	0.2608	0.2397	0.2185	0.1973	0.1761
Agricultural residues step 3	0.0000	0.0000	0.0656	0.0472	0.0611	0.0585	0.0762	0.0861	0.0685	0.0647	0.0610	0.0573	0.0536
Agricultural residues step 4	0.0000	0.0000	0.0212	0.0221	0.0145	0.0142	0.0190	0.0157	0.0233	0.0256	0.0278	0.0300	0.0322
Agricultural residues step 5	0.0000	0.0000	0.0074	0.0049	0.0062	0.0043	0.0019	0.0015	0.0037	0.0041	0.0046	0.0051	0.0056
Agricultural residues step 6	0.0000	0.0000	0.0107	0.0091	0.0060	0.0022	0.0027	0.0023	0.0025	0.0027	0.0028	0.0029	0.0030

Table 3-25 Indiana Forest Residues Supply

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/million short ton													
Forest residues step 1	20.0000	18.7922	17.6047	16.4900	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839
Forest residues step 2	30.0000	28.1882	26.4071	24.7350	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759
Forest residues step 3	40.0000	37.5843	35.2094	32.9800	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679
Forest residues step 4	50.0000	46.9804	44.0118	41.2251	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598
Forest residues step 5	60.0000	56.3765	52.8141	49.4701	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518
Forest residues step 6	70.0000	65.7725	61.6165	57.7151	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437
Forest residues step 7	80.0000	75.1686	70.4188	65.9601	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357
Forest residues step 8	90.0000	84.5647	79.2212	74.2051	71.0277	71.0277	71.0277	71.0277	71.0277	71.0277	71.0277	71.0277	71.0277
Forest residues step 9	100.0000	93.9608	88.0235	82.4501	78.9196	78.9196	78.9196	78.9196	78.9196	78.9196	78.9196	78.9196	78.9196
Forest residues step 10	110.0000	103.3569	96.8259	90.6951	86.8116	86.8116	86.8116	86.8116	86.8116	86.8116	86.8116	86.8116	86.8116
Forest residues step 11	120.0000	112.7529	105.6282	98.9401	94.7036	94.7036	94.7036	94.7036	94.7036	94.7036	94.7036	94.7036	94.7036
Forest residues step 12	130.0000	122.1490	114.4306	107.1851	102.5955	102.5955	102.5955	102.5955	102.5955	102.5955	102.5955	102.5955	102.5955
Forest residues step 13	140.0000	131.5451	123.2329	115.4301	110.4875	110.4875	110.4875	110.4875	110.4875	110.4875	110.4875	110.4875	110.4875
Forest residues step 14	150.0000	140.9412	132.0353	123.6752	118.3794	118.3794	118.3794	118.3794	118.3794	118.3794	118.3794	118.3794	118.3794
Forest residues step 15	160.0000	150.3373	140.8376	131.9202	126.2714	126.2714	126.2714	126.2714	126.2714	126.2714	126.2714	126.2714	126.2714
Forest residues step 16	170.0000	159.7333	149.6400	140.1652	134.1634	134.1634	134.1634	134.1634	134.1634	134.1634	134.1634	134.1634	134.1634
Forest residues step 17	180.0000	169.1294	158.4423	148.4102	142.0553	142.0553	142.0553	142.0553	142.0553	142.0553	142.0553	142.0553	142.0553
Forest residues step 18	190.0000	178.5255	167.2447	156.6552	149.9473	149.9473	149.9473	149.9473	149.9473	149.9473	149.9473	149.9473	149.9473
Forest residues step 19	200.0000	187.9216	176.0470	164.9002	157.8393	157.8393	157.8393	157.8393	157.8393	157.8393	157.8393	157.8393	157.8393
Maximum available quantity (incremental) in million short tons													
Forest residues step 1	0.0000	0.0000	0.1276	0.1284	0.1288	0.1294	0.1302	0.1306	0.1314	0.1320	0.1326	0.1332	0.1338
Forest residues step 2	0.0000	0.0000	0.2762	0.2774	0.2788	0.2799	0.2808	0.2817	0.2831	0.2841	0.2852	0.2863	0.2874
Forest residues step 3	0.0000	0.0000	0.1462	0.1461	0.1468	0.1469	0.1472	0.1482	0.1480	0.1485	0.1489	0.1493	0.1497
Forest residues step 4	0.0000	0.0000	0.0381	0.0382	0.0379	0.0376	0.0381	0.0376	0.0375	0.0373	0.0370	0.0368	0.0366
Forest residues step 5	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Forest residues step 6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Forest residues step 7	0.0000	0.0000	0.0321	0.0339	0.0357	0.0372	0.0385	0.0397	0.0408	0.0419	0.0431	0.0442	0.0453
Forest residues step 8	0.0000	0.0000	0.0103	0.0109	0.0114	0.0119	0.0123	0.0126	0.0131	0.0136	0.0140	0.0144	0.0148
Forest residues step 9	0.0000	0.0000	0.0184	0.0194	0.0205	0.0213	0.0220	0.0228	0.0234	0.0242	0.0249	0.0256	0.0263
Forest residues step 10	0.0000	0.0000	0.0088	0.0095	0.0098	0.0104	0.0108	0.0110	0.0111	0.0112	0.0112	0.0113	0.0114
Forest residues step 11	0.0000	0.0000	0.0113	0.0120	0.0125	0.0131	0.0134	0.0139	0.0145	0.0150	0.0156	0.0161	0.0166
Forest residues step 12	0.0000	0.0000	0.0105	0.0112	0.0118	0.0122	0.0127	0.0131	0.0134	0.0138	0.0141	0.0145	0.0149
Forest residues step 13	0.0000	0.0000	0.0118	0.0125	0.0131	0.0136	0.0141	0.0145	0.0150	0.0154	0.0159	0.0164	0.0169
Forest residues step 14	0.0000	0.0000	0.0084	0.0089	0.0094	0.0098	0.0102	0.0105	0.0107	0.0109	0.0112	0.0114	0.0116
Forest residues step 15	0.0000	0.0000	0.0078	0.0083	0.0086	0.0090	0.0093	0.0096	0.0099	0.0102	0.0105	0.0108	0.0111
Forest residues step 16	0.0000	0.0000	0.0072	0.0077	0.0081	0.0084	0.0087	0.0090	0.0094	0.0099	0.0103	0.0107	0.0111
Forest residues step 17	0.0000	0.0000	0.0078	0.0083	0.0087	0.0090	0.0093	0.0096	0.0098	0.0100	0.0103	0.0105	0.0107
Forest residues step 18	0.0000	0.0000	0.0071	0.0074	0.0076	0.0081	0.0084	0.0087	0.0090	0.0092	0.0095	0.0097	0.0099
Forest residues step 19	0.0000	0.0000	0.0059	0.0064	0.0068	0.0070	0.0072	0.0074	0.0077	0.0079	0.0082	0.0084	0.0086

Table 3-26 Indiana Primary Mill Residues Supply

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/million short ton													
Primary mill residues step 1	10.0000	9.3961	8.8024	8.2450	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920
Primary mill residues step 2	20.0000	18.7922	17.6047	16.4900	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839
Maximum available quantity (incremental) in million short tons													
Primary mill residues step 1	0.0000	0.0000	0.0108	0.0109	0.0110	0.0111	0.0111	0.0111	0.0112	0.0113	0.0113	0.0114	0.0115
Primary mill residues step 2	0.0000	0.0000	0.0435	0.0435	0.0435	0.0435	0.0435	0.0435	0.0435	0.0435	0.0435	0.0435	0.0435

Table 3-27 Indiana On-Site Mill Residues Supply

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/million short ton													
On-site mill residues step 1	10.0000	9.3961	8.8024	8.2450	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920
Maximum available quantity (incremental) in million short tons													
On-site mill residues step 1	0.2342	0.2342	0.2530	0.2718	0.2810	0.2825	0.2936	0.3019	0.3101	0.3183	0.3266	0.3348	0.3430

Table 3-28 Indiana Urban Wood Waste Supply

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/million short ton													
Urban wood waste step 1	10.0000	9.3961	8.8024	8.2450	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920	7.8920
Urban wood waste step 2	20.0000	18.7922	17.6047	16.4900	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839
Urban wood waste step 3	30.0000	28.1882	26.4071	24.7350	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759
Urban wood waste step 4	40.0000	37.5843	35.2094	32.9800	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679
Urban wood waste step 5	50.0000	46.9804	44.0118	41.2251	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598
Maximum available quantity (incremental) in million short tons													
Urban wood waste step 1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Urban wood waste step 2	0.0000	0.0000	0.0906	0.0909	0.0908	0.0911	0.0915	0.0917	0.0922	0.0926	0.0929	0.0933	0.0937
Urban wood waste step 3	0.0000	0.0000	0.1386	0.1384	0.1386	0.1390	0.1393	0.1396	0.1409	0.1416	0.1422	0.1429	0.1436
Urban wood waste step 4	0.0000	0.0000	0.0672	0.0670	0.0665	0.0667	0.0670	0.0677	0.0675	0.0680	0.0684	0.0688	0.0692
Urban wood waste step 5	0.0000	0.0000	0.1582	0.1583	0.1592	0.1591	0.1596	0.1606	0.1612	0.1619	0.1627	0.1635	0.1643

Table 3-29 Indiana Grassy Energy Crop Supply

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/million short ton													
Grassy energy crop step 1	50.0000	46.9804	44.0118	41.2251	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598
Grassy energy crop step 2	55.0000	51.6784	48.4129	45.3476	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058
Grassy energy crop step 3	60.0000	56.3765	52.8141	49.4701	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518
Grassy energy crop step 4	65.0000	61.0745	57.2153	53.5926	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978
Grassy energy crop step 5	70.0000	65.7725	61.6165	57.7151	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437
Grassy energy crop step 6	75.0000	70.4706	66.0176	61.8376	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897
Grassy energy crop step 7	80.0000	75.1686	70.4188	65.9601	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357
Maximum available quantity (incremental) in million short tons													
Grassy energy crop step 1	0.0000	0.0000	0.0000	0.0006	0.0113	0.0326	0.0662	0.1501	0.2295	0.2782	0.3270	0.3758	0.4246
Grassy energy crop step 2	0.0000	0.0000	0.0023	0.0494	0.1468	0.2447	0.2885	0.3127	0.3450	0.3964	0.4478	0.4992	0.5506
Grassy energy crop step 3	0.0000	0.0000	0.0044	0.0627	0.1743	0.3148	0.4560	0.5945	0.7696	0.9031	1.0366	1.1700	1.3035
Grassy energy crop step 4	0.0000	0.0000	0.0168	0.2734	0.4853	0.5817	0.4666	0.6589	0.6987	0.8131	0.9275	1.0419	1.1563
Grassy energy crop step 5	0.0000	0.0000	0.0160	0.2637	0.4047	0.4286	0.2918	0.2630	0.2948	0.3384	0.3820	0.4256	0.4691
Grassy energy crop step 6	0.0000	0.0000	0.0469	0.5786	0.8331	0.9018	0.4050	0.6425	0.7652	0.8754	0.9856	1.0958	1.2060
Grassy energy crop step 7	0.0000	0.0000	0.0386	0.5707	0.8304	0.9756	0.5747	0.6594	0.8845	1.0202	1.1558	1.2914	1.4271

Table 3-30 Indiana Woody Energy Crop Supply

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/million short ton													
Woody energy crop step 1	50.0000	46.9804	44.0118	41.2251	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598
Woody energy crop step 2	55.0000	51.6784	48.4129	45.3476	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058	43.4058
Woody energy crop step 3	60.0000	56.3765	52.8141	49.4701	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518
Woody energy crop step 4	65.0000	61.0745	57.2153	53.5926	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978
Maximum available quantity (incremental) in million short tons													
Woody energy crop step 1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0056	0.0102	0.0104	0.0104	0.0104	0.0104	0.0104
Woody energy crop step 2	0.0000	0.0000	0.0000	0.0011	0.0049	0.0451	0.0587	0.0912	0.1187	0.1187	0.1187	0.1187	0.1187
Woody energy crop step 3	0.0000	0.0000	0.0000	0.0065	0.0338	0.1352	0.0764	0.0977	0.1499	0.1499	0.1499	0.1499	0.1499
Woody energy crop step 4	0.0000	0.0000	0.0000	0.0030	0.0090	0.1026	0.0592	0.1050	0.1990	0.1990	0.1990	0.1990	0.1990

Table 3-31 Indiana Annual Energy Crop Supply

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/million short ton													
Annual energy crop step 1	60.0000	56.3765	52.8141	49.4701	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518	47.3518
Annual energy crop step 2	65.0000	61.0745	57.2153	53.5926	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978	51.2978
Annual energy crop step 3	70.0000	65.7725	61.6165	57.7151	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437	55.2437
Annual energy crop step 4	75.0000	70.4706	66.0176	61.8376	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897	59.1897
Annual energy crop step 5	80.0000	75.1686	70.4188	65.9601	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357	63.1357
Maximum available quantity (incremental) in million short tons													
Annual energy crop step 1	0.0000	0.0000	0.0076	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Annual energy crop step 2	0.0000	0.0000	0.0177	0.0330	0.0022	0.0230	0.0229	0.0125	0.0000	0.0000	0.0000	0.0000	0.0000
Annual energy crop step 3	0.0000	0.0000	0.0444	0.0452	0.0725	0.1058	0.1735	0.1525	0.1722	0.1722	0.1722	0.1722	0.1722
Annual energy crop step 4	0.0000	0.0000	0.0919	0.1137	0.0410	0.0655	0.1181	0.2287	0.1648	0.1648	0.1648	0.1648	0.1648
Annual energy crop step 5	0.0000	0.0000	0.1194	0.2269	0.1096	0.0583	0.3822	0.3393	0.4280	0.4280	0.4280	0.4280	0.4280

Table 3-32 Indiana Municipal Solid Waste Supply

Year	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
Cost in 2007 million dollars/million short ton													
Municipal solid waste step	20.0000	18.7922	17.6047	16.4900	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839	15.7839
Municipal solid waste step	30.0000	28.1882	26.4071	24.7350	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759	23.6759
Municipal solid waste step	40.0000	37.5843	35.2094	32.9800	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679	31.5679
Municipal solid waste step	50.0000	46.9804	44.0118	41.2251	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598	39.4598
Maximum available quantity (incremental) in million short tons													
Municipal solid waste step	1.9336	1.9336	0.2358	0.2352	0.2366	0.2376	0.2385	0.2393	0.2409	0.2421	0.2434	0.2447	0.2459
Municipal solid waste step	0.2559	0.2559	0.0312	0.0318	0.0306	0.0304	0.0301	0.0306	0.0302	0.0302	0.0302	0.0302	0.0302
Municipal solid waste step	0.1353	0.1353	0.0165	0.0158	0.0164	0.0165	0.0167	0.0166	0.0166	0.0164	0.0162	0.0161	0.0159
Municipal solid waste step	0.2510	0.2510	0.0306	0.0309	0.0303	0.0305	0.0305	0.0307	0.0311	0.0315	0.0320	0.0324	0.0329

CO_2 uptake during the biomass production process is tracked through a group of emission accounting technologies with negative emission factors based on data used in EPAUS9r. Biomass collection technologies follow CO_2 uptake accounting technologies, with no costs specified because costs associated with biomass collection are included in the supply curves. But an input-output ratio reflecting feedstock losses during storage and transportation for corn stover and agricultural residues is included in the collection technologies.

After collection, biomass feedstocks are transported for various uses. Biomass transportation technologies include the costs of diesel fuel for biomass transportation via trucks. A variable O&M cost (non-fuel costs) and a fixed O&M cost associated with the transport of cellulosic feedstocks are included as well, based on data in EPAUS9r.

Biomass feedstocks are used mainly for biofuel production and electricity production. On-site mill residues and forest residues are the only two categories that can be used in the industrial sector. They serve as supplemental energy sources for black liquor in the pulp and paper industry.

For electricity production, feedstocks are converted from Mt to PJ based on their energy content as shown in Table 3-33 through two sets of collectors. One set of collectors creates paths to use biomass co-fired with coal to generate electricity and the other set of collectors creates paths to use biomass in an integrated gasification combined cycle (IGCC) generator.

Table 3-33 Biomass Feedstock Energy Content

Biomass feedstock	Conversion factor (PJ/Mt)
Corn stover	13.5000
Agricultural residues	13.5000
Grassy energy crops	13.0827
Woody energy crops	15.0000
Forest residues	15.0000
Primary mill residues	15.0000
Urban wood waste	15.0000

For biomass feedstocks that are burned with coal for electricity generation, CO_2 emissions associated with production, transportation and combustion are accounted for on the input fuel through emission accounting technologies. However, their electric-sector CO_2 emissions (CO2E) are tracked separately, by using the data on life cycle CO_2 equivalent emissions from electricity generation using biomass feedstock retrieved from a Master's thesis titled An Economic and Emissions Analysis of Electricity Generation Using Biomass Feedstock in Co-fired and Direct Fired Facilities (Allen, 2011). Because CO_2 absorbed during growth offsets the CO_2 emitted during combustion, the life cycle CO_2 emissions only comprise emissions associated with biomass production and transportation. In this set up, biomass is treated as a very low CO_2 emission source for electricity generation. For biomass feedstock going to biomass fired IGCC generators, emissions are accounted for using a separate set of emissions accounting technologies.

3.2.1.5 Uranium Supply

Uranium supply to Indiana is modeled with a cost of 0.0850 million dollars per ton. This is based on data used in EPAUS9r. The quantity available is not constrained.

3.2.2 Conversion Sector

This section describes how the power generation system and biofuel production system are modeled with IN-MARKAL.

3.2.2.1 Power Generation System

3.2.2.1.1 Existing Coal Fleet

In IN-MARKAL, existing coal fleet is modeled unit by unit (non-coal generation fleet modeled with aggregated capacities by technology) in order to precisely reflect the majority of Indiana's generation capacity in 2007. Each coal-fired generation unit in the state is represented by a separate generation technology, with only one exception. Warrick Unit 4 is represented with two technologies because one half of its capacity is used for on-site electricity generation, which is treated as a decentralized plant without transmission losses in the model. And the other half is treated as a regular centralized plant, which incurs transmission losses on the grid. The other coal-fired generation units are all categorized as centralized plants in IN-MARKAL.

Table 3-34 is the list of units in the existing coal fleet represented by IN-MARKAL generation technologies. For each unit, its unit type, plant name and boiler ID, input coal type (BIT—bituminous coal, SUB—sub-bituminous coal), vintage and the type of the cooling system are shown in column two. The majority of the data relevant to coal-fired units is retrieved from EPAUS9r, supplemented by the data from the National Electric Energy Data System (NEEDS) v4.10 (EPA, 2013b) and Form EIA-860 (EIA, 2010d).

Table 3-34 Existing Coal Fleet Modeled with IN-MARKAL

Coal technology	Specification
ECSTMI01BR	Residual coal steam; A B Brown 1; BIT; 1970; Recirculating cooling
ECSTMI02BR	Residual coal steam; A B Brown 2; BIT; 1980; Recirculating cooling
ECSTMI03BO	Residual coal steam; Bailly 7; BIT; 1960; Open loop cooling
ECSTMI04BO	Residual coal steam; Bailly 8; BIT; 1960; Open loop cooling
ECSTMI05BO	Residual coal steam; Cayuga 1; BIT; 1970; Open loop cooling
ECSTMI06BO	Residual coal steam; Cayuga 2; BIT; 1970; Open loop cooling
ECSTMI07SO	Residual coal steam; Clifty Creek 1; SUB; 1950; Open loop cooling
ECSTMI08SO	Residual coal steam; Clifty Creek 2; SUB; 1950; Open loop cooling
ECSTMI09SO	Residual coal steam; Clifty Creek 3; SUB; 1950; Open loop cooling
ECSTMI10SO	Residual coal steam; Clifty Creek 4; SUB; 1950; Open loop cooling
ECSTMI11SO	Residual coal steam; Clifty Creek 5; SUB; 1950; Open loop cooling
ECSTMI12SO	Residual coal steam; Clifty Creek 6; SUB; 1950; Open loop cooling
ECSTMI13BR	Residual coal steam; Crawfordsville 4; BIT; 1950; Recirculating cooling
ECSTMI14BR	Residual coal steam; Crawfordsville 5; BIT; 1960; Recirculating cooling
ECSTMI15BO	Residual coal steam; Eagle Valley 3; BIT; 1950; Open loop cooling
ECSTMI16BO	Residual coal steam; Eagle Valley 4; BIT; 1950; Open loop cooling
ECSTMI17BO	Residual coal steam; Eagle Valley 5; BIT; 1950; Open loop cooling
ECSTMI18BO	Residual coal steam; Eagle Valley 6; BIT; 1950; Open loop cooling
ECSTMI19BO	Residual coal steam; F B Culley 2; BIT; 1960; Open loop cooling
ECSTMI20BO	Residual coal steam; F B Culley 3; BIT; 1970; Open loop cooling
ECSTMI21BO	Residual coal steam; Frank E Ratts 1; BIT; 1970; Open loop cooling
ECSTMI22BO	Residual coal steam; Frank E Ratts 2; BIT; 1970; Open loop cooling
ECSTMI23BR	Residual coal steam; Gibson 1; BIT; 1970; Recirculating cooling
ECSTMI24BR	Residual coal steam; Gibson 2; BIT; 1970; Recirculating cooling
ECSTMI25BR	Residual coal steam; Gibson 3; BIT; 1970; Recirculating cooling
ECSTMI26BR	Residual coal steam; Gibson 4; BIT; 1970; Recirculating cooling
ECSTMI27BR	Residual coal steam; Gibson 5; BIT; 1980; Recirculating cooling
ECSTMI28BO	Residual coal steam; Harding Street 50; BIT; 1950; Open loop cooling
ECSTMI29BO	Residual coal steam; Harding Street 60; BIT; 1960; Open loop cooling
ECSTMI30BO	Residual coal steam; Harding Street 70; BIT; 1970; Open loop cooling
ECSTMI31BR	Residual coal steam; Jasper 2 1; BIT; 1960; Recirculating cooling
ECSTMI32BO	Residual coal steam; Logansport 5; BIT; 1950; Open loop cooling
ECSTMI33BO	Residual coal steam; Logansport 6; BIT; 1960; Open loop cooling
ECSTMI34BR	Residual coal steam; Merom 1; BIT; 1980; Recirculating cooling
ECSTMI35BR	Residual coal steam; Merom 2; BIT; 1980; Recirculating cooling
ECSTMI36SR	Residual coal steam; Michigan City 12; SUB; 1970; Recirculating cooling
ECSTMI37BO	Residual coal steam; Peru 2; BIT; 1950; Open loop cooling
ECSTMI38BO	Residual coal steam; Peru 5; BIT; 1940; Open loop cooling
ECSTMI39BO	Residual coal steam; Petersburg 1; BIT; 1960; Open loop cooling
ECSTMI40BO	Residual coal steam; Petersburg 2; BIT; 1960; Open loop cooling
ECSTMI41BO	Residual coal steam; Petersburg 3; BIT; 1970; Open loop cooling
ECSTMI42BO	Residual coal steam; Petersburg 4; BIT; 1980; Open loop cooling
ECSTMI43BO	Residual coal steam; R Gallagher 1; BIT; 1950; Open loop cooling
ECSTMI44BO	Residual coal steam; R Gallagher 2; BIT; 1950; Open loop cooling
ECSTMI45BO	Residual coal steam; R Gallagher 3; BIT; 1960; Open loop cooling

Table 3-34 Continued

ECSTMI46BO	Residual coal steam; R Gallagher 4; BIT; 1960; Open loop cooling
ECSTMI47SR	Residual coal steam; R M Schahfer 14; SUB; 1970; Recirculating cooling
ECSTMI48SR	Residual coal steam; R M Schahfer 15; SUB; 1970; Recirculating cooling
ECSTMI49BR	Residual coal steam; R M Schahfer 17; BIT; 1980; Recirculating cooling
ECSTMI50BR	Residual coal steam; R M Schahfer 18; BIT; 1980; Recirculating cooling
ECSTMI51SR	Residual coal steam; Rockport MB1; SUB; 1980; Recirculating cooling
ECSTMI52SR	Residual coal steam; Rockport MB2; SUB; 1980; Recirculating cooling
ECSTMI53SO	Residual coal steam; State Line 3; SUB; 1950; Open loop cooling
ECSTMI54SO	Residual coal steam; State Line 4; SUB; 1960; Open loop cooling
ECSTMI55BO	Residual coal steam; Tanners Creek U1; BIT; 1950; Open loop cooling
ECSTMI56BO	Residual coal steam; Tanners Creek U2; BIT; 1950; Open loop cooling
ECSTMI57BO	Residual coal steam; Tanners Creek U3; BIT; 1950; Open loop cooling
ECSTMI58SO	Residual coal steam; Tanners Creek U4; SUB; 1960; Open loop cooling
ECSTMI59BO	Residual coal steam; Wabash River 2; BIT; 1950; Open loop cooling
ECSTMI60BO	Residual coal steam; Wabash River 3; BIT; 1950; Open loop cooling
ECSTMI61BO	Residual coal steam; Wabash River 4; BIT; 1950; Open loop cooling
ECSTMI62BO	Residual coal steam; Wabash River 5; BIT; 1950; Open loop cooling
ECSTMI63BO	Residual coal steam; Wabash River 6; BIT; 1960; Open loop cooling
ECSTMI64BO	Residual coal steam; Warrick 1; BIT; 1960; Open loop cooling
ECSTMI65BO	Residual coal steam; Warrick 2; BIT; 1960; Open loop cooling
ECSTMI66BO	Residual coal steam; Warrick 3; BIT; 1960; Open loop cooling
ECSTMI67BO	Residual coal steam; Warrick 4A; BIT; 1970; Open loop cooling
ECSTMI68BO	Residual coal steam; Warrick 4B; BIT; 1970; Open loop cooling
ECSTMI69BR	Residual coal steam; Whitewater Valley 1; BIT; 1950; Recirculating cooling
ECSTMI70BR	Residual coal steam; Whitewater Valley 2; BIT; 1970; Recirculating cooling
ECSTMI71BO	Residual coal steam; Dean H Mitchell 4; BIT; 1950; Open loop cooling
ECSTMI72BO	Residual coal steam; Dean H Mitchell 6; BIT; 1950; Open loop cooling
ECSTMI73BO	Residual coal steam; Dean H Mitchell 5; BiT; 1950; Open loop cooling
ECSTMI74BO	Residual coal steam; Dean H Mitchell 11; BiT; 1970; Open loop cooling
ECSTMI75SO	Residual coal steam; State Line Energy 4A; SUB; 1960; Open loop cooling
ECSTMI76SO	Residual coal steam; State Line Energy 3A; SUB; 1950; Open loop cooling
ECSTMI77BO	Residual coal steam; Edwardsport 8; BIT; 1950; Open loop cooling
ECSTMI78BO	Residual coal steam; Edwardsport 7; BIT; 1940; Open loop cooling

The major parameters associated with existing coal generation technologies include the following.

INP(ENT)c: input-output ratio for electricity generation technology in PJ fuel input per PJ electricity output (ENT means energy carrier; c means conversion technology, which electricity generation technology is categorized as in MARKAL). This parameter is derived from heat rate in Btu fuel input per kWh electricity output.

Every generation technology shown in Table 3-34 uses its own unit-specific input-output ratio.

OUT(ELC)_TID: an indicator (always equal to 1) as to which electric grid an electricity conversion technology is connected (There is only one in IN-MARKAL.)

CAPUNIT: a factor equal to 31.5360, which is used to convert generation capacity in GW to electricity output in PJ, assuming the capacity is operated 8760 hours a year. (Availability factors by time-slice (AF(Z)(Y)) will be applied to take into consideration of both planned and unplanned outages in operation.)

FIXOM: fixed O&M cost in 2007 million dollars per GW electricity generation capacity. The same number (19.1564) converted from data in EPAUS9r is used across units.

VAROM: variable O&M cost (excluding fuel cost) in 2007 million dollars per PJ electricity output. The same number (2.0600) converted from data in EPAUS9r is used across units.

RESID(t): the capacity of a generation technology due to investments that were made prior to 2007 and is still available at time period t. The RESID parameter is specified for each coal generation technology and for each one of the 13 periods in IN-MARKAL. If the time of retirement is known for a unit, RESIDs are specified based on the retirement information, which is either retrieved from EIA-860 or directly reported to the State Utility Forecasting Group (SUFG) from individual utilities in Indiana. For example, the Dean H Mitchell Unit 4, Unit 5, Unit 6 and Unit 11 were shut down in 2011. For the four technologies in IN-MARKAL representing the four units, their RESIDs are specified as shown in Table 3-35. The unit of the RESID capacity is GW. Because MARKAL models three years in each period, retirement in

2011 is approximated by retirement in 2010, with RESID equal to zero beginning in 2010. Another example would be Edwardsport Unit 7 and Unit 8. They were retired in 2012 and replaced with an integrated gasification combined cycle (IGCC) unit. Their RESIDs are set equal to zero beginning in 2013 (see Table 3-36). The IGCC unit is represented with a new technology with forced investment in 2013 in the amount equal to the capacity of the Edwardsport IGCC plant. The units, for which there is no information pertaining to retirement, are allowed to continue operation until 2018, and their RESIDs are set to zero starting from 2019. The purpose is to let the model decide for a unit to either retire or to continue operation in 2019. The mechanism for this treatment is explained in the description of the INVCOST parameter.

Table 3-35 RESID Specification for Dean H Mitchell Unit 4, 5, 6 and 11 in IN-MARKAL

Existing coal-fired generation technology	RESID 2007	RESID 2010	RESID 2013	RESID 2016	RESID 2019	RESID 2022	RESID 2025	RESID 2028	RESID 2031	RESID 2034	RESID 2037	RESID 2040	RESID 2043
ECSTMI71BO	0.1250	0	0	0	0	0	0	0	0	0	0	0	0
ECSTMI72BO	0.1250	0	0	0	0	0	0	0	0	0	0	0	0
ECSTMI73BO	0.1250	0	0	0	0	0	0	0	0	0	0	0	0
ECSTMI74BO	0.1100	0	0	0	0	0	0	0	0	0	0	0	0

Table 3-36 RESID Specification for Edwardsport Unit 7 and 8 in IN-MARKAL

Existing coal-fired generation technology	RESID 2007	RESID 2010	RESID 2013	RESID 2016	RESID 2019	RESID 2022	RESID 2025	RESID 2028	RESID 2031	RESID 2034	RESID 2037	RESID 2040	RESID 2043
ECSTMI77BO	0.0690	0.0690	0	0	0	0	0	0	0	0	0	0	0
ECSTMI78BO	0.0402	0.0402	0	0	0	0	0	0	0	0	0	0	0

INVCOST(2019): the total cost of investments associated with continued operation of an existing coal-fired unit after 2019. This parameter is only specified for the 2019 period. The INVCOST is specified in 2007 million dollars per GW generation capacity, which is composed of two major components. The first component is the generation capacity life extension cost if the unit has a vintage before 1980. (This cost is assumed to be 7% of the capital cost of a new coal steam unit[2] and extends the life of the plant by an additional 40 years.) The second component of the INVCOST includes all the costs of environmental retrofits in order to satisfy the EPA regulations on sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM)

[2] IPM NEEDS EPA v.4.10 Documentation Chapter 4 Table 4-10, available at: http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v410/Chapter4.pdf.

and mercury based on any existing retrofits for each individual unit. To comply with EPA regulations on SO_2, NO_x, PM and mercury, it is assumed that a coal-fired unit must have flue gas desulfurization (FGD) system[3], selective catalytic reduction (SCR) system[4] and electrostatic precipitator (ESP) upgrade[5]. Table 3-37 provides a breakdown of the investment cost by unit. Column two exhibits the generation capacity life extension cost, with empty spaces indicating that corresponding units were built after 1980. Columns three, four and five show the costs of upgrading SOx, NOx and PM controls respectively. An empty space in those columns indicates the corresponding retrofit requirement has been satisfied by the unit, and upgrade is not needed. The last column is the total investment cost, which includes all the costs covered in columns two through five. Note that all the costs are expressed in 2007 million dollars per GW generation capacity. The data on retrofit capital costs are obtained from EPAUS9r. They are expressed in 2005 million dollars/PJ retrofit capacity. They are converted to IN-MARKAL input through the following equation:

Investment cost in 2007 million dollars per GW of generation capacity = Investment cost in 2005 million dollars per PJ retrofit capacity * Dollar conversion factor * INP(ENT)c * CAPUNIT * AF

Dollar conversion factor: the factor to convert 2005 dollar to 2007 dollar, which is equal to 1.0623[6]

INP(ENT)c: unit specific input-output ratio in PJ fuel input/PJ electricity output

CAPUNIT: factor used to convert electricity generation capacity in GW to output in PJ

AF: a time-slice weighted average availability factor is used for the existing coal fleet in Indiana, which is equal to 0.8291. The definition of AF is explained later in this section. The CAPUNIT multiplied by the AF results in the actual electricity output in PJ per GW of coal-fired generation capacity.

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[3] For the coal-fired units located in Indian which already have SO_2 controls by 2010, they use FGD system rather than dry sorbent injection (DSI). Therefore, we assume FGD will be installed in the future for the compliance of SO_2 regulation for those without SO_2 retrofits.

[4] Based on the Regulatory Impact Analysis (RIA) for the Final Mercury and Air Toxics Standards (MATS) (EPA, 2011), operating a wet FGD for SO_2 control alongside SCR for NOx control with sufficient halogen present will remove more than 90 percent of the mercury within the flue gas stream.

[5] Fabric filter can be used as well for PM control. However, the majority of Indiana coal fleet has been equipped with ESP system by 2010. Therefore, we consider ESP upgrade as the option to comply with EPA regulations on PM and mercury.

[6] Calculation is based on implicit price deflators for gross domestic product retrieved on Aug 28th, 2012 from the Bureau of Economic Analysis.

Table 3-37 Investment Cost for Continued Operation by Unit in 2007 Million Dollars/GW

Technology	Life extention cost	SO2 retrofit cost	NOX retrofit cost	PM retrofit cost	INVCOST (total investment cost)
ECSTMI01BR	190.5316			67.0425	257.5741
ECSTMI02BR	190.5316			67.0113	257.5429
ECSTMI03BO	190.5316			71.5580	262.0895
ECSTMI04BO	190.5316			71.3488	261.8804
ECSTMI05BO	190.5316		53.0599	62.1259	305.7174
ECSTMI06BO	190.5316		54.5053	63.8184	308.8553
ECSTMI07SO	190.5316	161.5714		67.3554	419.4583
ECSTMI08SO	190.5316	157.4660		65.6439	413.6415
ECSTMI09SO	190.5316	156.5232		65.2509	412.3057
ECSTMI10SO	190.5316	155.8694		64.9784	411.3793
ECSTMI11SO	190.5316	152.5090		63.5775	406.6181
ECSTMI12SO	190.5316	154.5770	62.6207	64.4396	472.1688
ECSTMI19BO	190.5316		64.9646	76.0648	331.5610
ECSTMI20BO	190.5316			64.9720	255.5036
ECSTMI21BO	190.5316	181.6401	52.8487	61.8787	486.8991
ECSTMI22BO	190.5316	179.3328	52.1774	61.0927	483.1345
ECSTMI23BR	190.5316			62.5126	253.0442
ECSTMI24BR	190.5316			62.8612	253.3928
ECSTMI25BR	190.5316			61.5808	252.1124
ECSTMI26BR	190.5316			63.1084	253.6400
ECSTMI27BR				65.6883	65.6883
ECSTMI30BO	190.5316			62.0886	252.6202
ECSTMI34BR				63.6155	63.6155
ECSTMI35BR				69.9669	69.9669
ECSTMI36SR	190.5316	162.1340		67.5899	420.2555
ECSTMI39BO	190.5316		54.7544	64.1100	309.3959
ECSTMI40BO	190.5316			66.2588	256.7904
ECSTMI41BO	190.5316			69.0605	259.5921
ECSTMI42BO			58.1975	68.1414	126.3389
ECSTMI47SR	190.5316	201.9692		72.2933	464.7940
ECSTMI48SR	190.5316	204.2713	60.7460	73.1173	528.6662
ECSTMI49BR			60.8827	71.2854	132.1681
ECSTMI50BR			58.7118	68.7436	127.4554
ECSTMI51SR		171.5454	51.0140	61.4033	283.9627
ECSTMI52SR		173.1923	51.5037	61.9928	286.6889
ECSTMI58SO	190.5316	147.3392	59.6886	61.4223	458.9818
ECSTMI64BO	190.5316		59.4751	69.6373	319.6440
ECSTMI65BO	190.5316		59.6429	69.8338	320.0083
ECSTMI66BO	190.5316		59.8541	70.0810	320.4667
ECSTMI67BO	190.5316			66.0369	256.5685
ECSTMI68BO	190.5316			66.0369	256.5685
ECSTMI69BR	190.5316	252.6021	63.8284	111.8676	618.8297
ECSTMI70BR	190.5316	252.6021	63.8284	111.8676	618.8297

IBOUND(UP): specifies the upper bound on the level of investment for each time period in GW. For the existing coal fleet, this parameter works with the INVCOST parameter to give the model the freedom to choose if a unit will be retired in 2019.

The IBOUND(UP) parameters in periods other than 2019 are specified to be zero. For 2019, this parameter is specified to be equal to the capacity of the unit.

AF(Z)(Y): availability factor by season (Z) and time of day(Y). This is the fraction of the specified time slice that the capacity is available to operate. For the existing Indiana coal fleet, the availability factor is differentiated by season only. An 11.10% annual planned outage rate and a 6% annual unplanned outage rate (EPRI, 1993) are used to develop the AF by season. In Indiana, peak demand usually occurs in the summer when the demand for air conditioning surges, and thus summer is avoided for planned outages. A 94.00% (=1.00-6.00%) availability factor is used for summer. Two thirds of the planned outages that might happen in summer are assumed to be shifted to the intermediate time and the rest are assumed to be shifted to winter. Therefore, a 75.50% (=1.00-6.00%-11.10%*(1+2/3)) AF is used for the Intermediate season and a 79.20% (=1.00-6.00%-11.10%*(1+1/3)) AF is used for the winter season. The same set of AFs is applied to all existing coal-fired units and is shown in Table 3-38.

Table 3-38 AF of Existing Coal Fleet

	I-DAM	I-DPM	I-N	I-P	S-DAM	S-DPM	S-N	S-P	W-DAM	W-DPM	W-N	W-P
AF(Z)(Y)	0.7550	0.7550	0.7550	0.7550	0.9400	0.9400	0.9400	0.9400	0.7920	0.7920	0.7920	0.7920

PEAK(CON): specifies the fraction of a plant's capacity that should be credited toward the peaking requirement. IN-MARKAL uses a number of 0.96, the same as EPAUS9r.

3.2.2.1.2 Environmental Retrofits for the Existing Coal Fleet

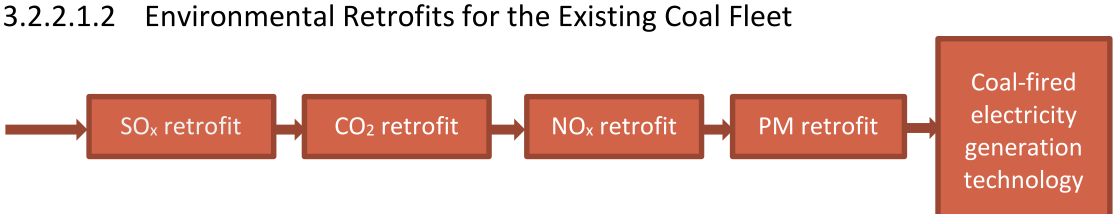

Figure 3-3 A Simplified Structure of Environmental Retrofits

Figure 3-3 is a simplified representation of how environmental retrofits are modeled in IN-MARKAL. For each coal-fired generation unit, its environmental retrofits are located upstream of the generation technology. After emission accounting, coal goes through SO_2 retrofit first, then through a CO_2 retrofit (if it is installed), then a NO_x retrofit and finally a PM retrofit before entering into the generation technology. The energy carrier (coal in this case) has its name changed each time it goes through a technology.

SO_2 retrofit

Each unit has one technology to specify its existing SO_2 retrofit condition as of 2007, either FGD retrofit or FGD passthrough (which means no FGD but a path is still created to let the energy carrier flow forward). The naming convention of the technology is as follows:

Letters 1-3: SEC- environmental retrofit technology
Letters 4-5: coal grade (B-bituminous, S-sub-bituminous) and sulfur content (L-low, M-medium, H-high)
Letters 6-7: retrofit condition (FG-FGD retrofit, PT-FGD passthrough)
Letters 8-10: coal-fired unit code from I01 to I78

For a unit with FGD retrofit that uses BM (bituminous medium sulfur) coal in 2007, another technology is created with letters 4-5 replaced with BH (bituminous high sulfur coal) starting from 2010. This design allows units with FGD retrofits to completely or partially switch to the higher sulfur content coal within the same coal grade in the future if it makes economic sense. A constraint is placed on the two technologies to ensure that the usage of BH and BM coal together does not exceed the capacity of the unit. The same idea applies to units that use sub-bituminous coal. However, as of 2007, all the units with FGD retrofits use bituminous coal as fuel input in Indiana. Variable O&M cost is specified for each technology, with 0.3193 million dollars/PJ fuel input for the one with FGD retrofit and zero for the one without FGD retrofit.

For plants without FGD retrofit in 2007, the option to install FGD in 2019 to comply with the EPA regulation is modeled. The naming convention of the newly constructed FGD system is as follows:

Letters 1-3: SEC- environmental retrofit technology
Letters 4-5: coal grade (B-bituminous, S-sub-bituminous) and sulfur content (L-low, M-medium, H-high)
Letters 6-7: FG- FGD new construction
Letters 8-10: coal-fired unit code (these exist only for units without FGD in 2007)

As mentioned previously, multiple technologies are created in order to allow for the possibility of fuel switching. A plant using BM coal is allowed to shift to BH coal after FGD installation; a plant using BL coal is allowed to shift to BM or BH coal; and a plant using SL coal is allowed to shift to SM coal. Taking unit I16 as an example, SECBMFGI16 and SECBHFGI16 are created to represent the installation of FGD to the unit in 2019. Although two technologies are created, the investment cost is only specified once and is included in the INVCOST parameter of its corresponding generation technology (ECSTMI16BO), rather than in the two FGD construction technologies. The investment cost used in this case is the average of investment costs of FGD installed on a unit using BM coal and FGD installed on a unit using BH coal (which is the average of the first two numbers in the fourth column of Table 3-39). This design allows the model to determine if a unit will continue operation after 2019 which will require costs to extend the life of generation facility and to install environmental upgrade. If the decision is to continue operation, then the SO_2 retrofit technologies will be used after 2019 and relevant variable O&M costs will be incurred. If the decision is to cease operation of the unit, no costs will be incurred even with those technologies specified.

Relevant data on SO_2 retrofit are shown in Table 3-39, which are retrieved from EPAUS9r and the units are converted to be compatible with IN-MARKAL. All costs and emission data are categorized by input coal grade, sulfur content and retrofit condition.

Table 3-39 Data on SO_2 Retrofit by Coal Grade, Sulfur Content and Retrofit Condition

Coal grade + sulfur content + retrofit	Specification	Variable O&M 2007 $M/PJ	Investment cost 2007 $M/PJ/Year	NOx emission rate thousand tons/PJ
BHFG	Bituminous high sulfur coal; FGD retrofit	0.3193	2.7961	-1.1269
BMFG	Bituminous medium sulfur coal; FGD retrofit	0.2315	2.0606	-0.5048
BLFG	Bituminous low sulfur coal; FGD retrofit	0.3717	3.3342	-0.1401
SMFG	Sub-bituminous medium sulfur coal; FGD retrofit	0.2408	1.9844	-0.3411
SLFG	Sub-bituminous low sulfur coal; FGD retrofit	0.2681	2.6379	-0.1969
BHPT	Bituminous high sulfur coal; FGD passthrough	0.0000	0.0000	0.0000
BMPT	Bituminous medium sulfur coal; FGD passthrough	0.0000	0.0000	0.0000
BLPT	Bituminous low sulfur coal; FGD passthrough	0.0000	0.0000	0.0000
SMPT	Sub-bituminous medium sulfur coal; FGD passthrough	0.0000	0.0000	0.0000
SLPT	Sub-bituminous low sulfur coal; FGD passthrough	0.0000	0.0000	0.0000

CO_2 retrofit

For the units with FGD retrofits, CO_2 retrofits are permitted to be installed. Without the FGD, the option to install CO_2 retrofit is not available. Here is the naming convention of the CO_2 retrofit technology:

Letters 1-3: SEC- environmental retrofit technology
Letters 4-5: coal grade (B-bituminous, S-sub-bituminous) and sulfur content (L-low, M-medium, H-high)
Letters 6-7: CO_2 retrofit (CC-carbon capture and storage (CCS), CP-CCS passthrough)
Letters 8-10: coal-fired unit code

As with SO_2 retrofit technologies, multiple paths are created to accommodate possible switches to coal with higher sulfur content within the same coal grade. The CCS technology is available for installation from period 2016 and later with a life of 50 years. All the data pertaining to CCS technology before conversion to IN-MARKAL units are obtained from the EPAUS9r.

We use a 35% energy penalty for CCS installed on existing coal plants, which means that the carbon capture process consumes 35% of a plant's regular electricity output. This energy penalty is reflected by the INP(ENT)p parameter (input-output ratio for process technology) of the CCS technology, which is equal to:
CCS fuel input / CCS fuel output = 1/(1-35%) = 1.54.

In addition to the energy penalty, the capacity of the coal-fired power plant is reduced with the installation of a CCS technology. In IN_MARKAL, coal input goes through emission accounting, SO_2 control, CO_2 control, NO_x control and PM control successively before going into existing coal generation technology. The capacity of the SO_2 control is calibrated to the level based on the capacity of its corresponding generation unit, which is the maximum level of fuel input required to run the generation capacity at its actual maximum level. Therefore,

Capacity of SO_2 control in PJ = Capacity of coal generation unit in GW * 365 *24 * AF * GWh to PJ conversion * INP(ENT)c.

365*24: the number of hours in a typical year

AF: availability factor of the generation unit, which is the amount of time that a power plant is able to produce electricity over a certain period divided by the amount of the time in the period. Rather than using the AF(Z)(Y) (availability by time-slice) as mentioned in the Section 3.2.2.1.1, a time-slice weighted average AF is used here, which is equal to 0.8291.

GWh to PJ conversion: a factor equal to 0.0036

INP(ENT)c: input-output ratio of a generation unit in terms of PJ fuel input/PJ electricity output, which is unit specific.

Due to the constrained level of SO_2 control, the amount of fuel flowing out from SO_x control and then flowing into the CCS technology, if CCS is installed, is limited as well. As mentioned before, there is an energy penalty associated with CCS technology, which makes the amount of energy 35% less after going through the CCS technology. Therefore, the CCS capacity is implicitly constrained at the level equal to the capacity of SO_2 control in PJ * (1-35%). There are no energy penalties for NO_x and PM controls downstream of the CCS technology. Thus, the energy remaining after going through CCS technology serves as the input for final electricity generation. Due to the fact that the maximum amount of energy for electricity generation is reduced because of the installation of CCS, the generation capacity is penalized as well.

Careful attention is required to reflect the capacity penalty in the process of converting the investment costs and fixed O&M costs to the units compatible with IN-MARKAL. Please note that the capacity of a CCS technology is expressed as the maximum amount of energy output from CCS technology in PJ. Here is the conversion processes for all the costs:

Investment cost in million dollars per PJ CCS capacity = Investment cost in million dollars per GW of generation capacity / (365 * 24 * AF * (1-35%) * GWh to PJ conversion * INP(ENT)c)

Fixed O&M cost in million dollars per PJ CCS capacity per year = Fixed O&M cost in million dollars per GW of generation capacity per year / (365 * 24 * AF * (1-35%) * GWh to PJ conversion * INP(ENT)c)

Variable O&M cost in million dollars per PJ fuel output from CCS technology = Variable O&M cost in million dollars per PJ electricity output / INP(ENT)c

365*24: the number of hours in a typical year

AF: time-slice weighted average AF, which is equal to 0.8291

GWh to PJ conversion: a factor equal to 0.0036

INP(ENT)c: input-output ratio of generation technology in terms of PJ fuel input to generation unit/PJ of electricity output. Indiana existing coal fleet capacity weighted input-output ratio is used here, which is equal to 3.0447.

In addition, it is assumed that the CCS technology is able to capture 85% of CO_2 emissions from electricity generation. Therefore, the CCS technology has a negative CO_2 emission factor, which is calculated through the following process:

CO_2 emission factor in thousand tons per PJ of fuel output from the CCS technology = (-1) * CO2 emission factor for coal * Emission capture efficiency * INP(ENT)p.

CO_2 emission factor for coal: CO_2 emissions from coal combustion for electricity generation, which is in thousand tons of CO_2 emissions/PJ coal input to the CCS technology in this case

Emission capture efficiency: 85%

INP(ENT)p: input-output ratio of CCS technology

The DISCRATE parameter (discount rate) used for CCS technology is 15%.

NO_X retrofit

NO_x retrofit is placed downstream of the CO_2 retrofit. Several technologies are used to describe the NO_x retrofits already installed at the beginning of the model horizon. The NO_x retrofit conditions for the existing Indiana coal fleet fall into five categories: low NO_x burner (LNB) only, LNB plus SCR, LNB plus selective non-catalytic reduction (SNCR), SCR only, and no control. The general naming convention for existing NO_x control is as follows:

Letters 1-3: SEC- environmental retrofit technology
Letters 4: coal grade (B-bituminous coal, S-sub-bituminous coal)
Letters 5-7 (5-6 in the PT case): NO_x retrofit condition (LNB- LNB, SCR- SCR after existing LNB, SNC- SNCR after existing LBN, PT - passthrough after existing LNB, SC2- SCR only, PT2 - no control)
Letters 8-10 (7-9 in the PT case): coal-fired unit code

For a unit with LNB only, LNB plus SCR, or LNB plus SNCR, the NO_x retrofit is represented by two successive technologies. Take AB Brown unit 1 as an example (with unit code I01). That unit has LNB plus SCR already installed as of 2007, and these are represented by two technologies — SECBLNBI01 and SECBSCRI01. For a unit with SCR only or no control, its NO_x retrofit condition is represented by a single technology. An example would be Clifty Creek Unit 6 (with unit code I12), which has no NO_x control and is represented by a single technology named SECSPT2I12.

A plant without any existing NO_x control is permitted to install SCR in 2019 to comply with EPA regulations. The naming convention of such technology is as follows:

Letters 1-3: SEC- environmental retrofit technology
Letters 4: coal grade (B-bituminous coal, S-sub-bituminous coal)
Letters 5-7: SC2- SCR to plant without existing control
Letters 8-10: coal-fired unit code (units without pre-existing NO_x control)

For a plant that has LNB only, the model allows it to install SCR followed LNB in 2019 to comply with EPA regulations. The naming convention of such technology is as follows:

Letters 1-3: SEC- environmental retrofit technology
Letters 4: coal grade (B-bituminous coal, S-sub-bituminous coal)
Letters 5-7: SCR- new SCR to plant with existing LNB
Letters 8-10: coal-fired unit code (units with LNB only)

For all NO_x retrofit technologies, only variable O&M costs are specified. Investment costs related to new installation are included in the corresponding electricity generation technologies. If a generation unit is chosen by the model to continue operation after 2019, its corresponding retrofits will be used; otherwise, they are not used and relevant variable costs are not incurred.

Data on NO_x retrofits are shown in Table 3-40, which are retrieved from EPAUS9r and are converted to be compatible with IN-MARKAL. All costs and emission data are categorized by input coal grade and retrofit condition. Hyphens in the Investment cost column mean that corresponding options are not available for new investment in IN-MARKAL.

Table 3-40 Data on NO_x Retrofit by Coal Grade and Retrofit Condition

Coal grade + retrofit condition	Specification	Variable O&M 2007 $M/PJ	Investment cost 2007 $M/PJ/Year	NOx emission rate thousand tons/PJ
BLNB	Bituminous coal; LNB	0.0062	—	-0.1164
BSCR	Bituminous coal; SCR follows LNB	0.1589	0.7065	-0.1822
BSNC	Bituminous coal; SNCR follows LNB	0.0482	—	-0.1106
BPT	Bituminous coal; passthrough follows LNB	0.0000	—	0.0000
BSC2	Bituminous coal; SCR only	0.1231	0.8107	-0.2697
BPT2	Bituminous coal; no NOx control	0.0000	—	0.0000
SLNB	Sub-bituminous coal; LNB	0.0062	—	-0.1431
SSCR	Sub-bituminous coal; SCR follows LNB	0.1043	0.6873	-0.1773
SPT	Sub-bituminous coal; passthrough follows LNB	0.0000	—	0.0000
SSC2	Sub-bituminous coal; SCR only	0.1256	0.8039	-0.2817
SPT2	Sub-bituminous coal; no NOx control	0.0000	—	0.0000

PM control

PM control is the last step before the energy input flows into the generation technology. A set of PM control technologies is specified to describe the current conditions as of 2007. The majority of coal-fired units located in Indiana have ESPs. It is known that the two which do not have ESPs will be retired before 2019. Therefore, no retrofits are modeled for these units to comply with EPA regulations. The naming convention for existing PM controls is as follows:

Letters 1-3: SEC- environmental retrofit technology
Letters 4: coal grade (B-bituminous coal, S-sub-bituminous coal)
Letters 5-7: PM retrofit condition (ESP- electrostatic precipitator, CYC- cyclone and FFR-fabric filter)
Letters 8-10: coal-fired unit code

To comply with EPA regulations, another set of PM control technologies is created to let units with ESP have a further ESP upgrade[7]. The naming convention of such technologies is as follows:

Letters 1-3: SEC- environmental retrofit technology
Letters 4: coal grade (B-bituminous coal, S-sub-bituminous coal)
Letters 5-7: EPU- ESP plate upgrade
Letters 8-10: coal-fired unit code

Key data on PM retrofit technologies are shown in Table 3-41. These are retrieved from EPAUS9r, and the units are converted to be compatible with IN-MARKAL. All costs and emission data are categorized by input coal grade and the size of generation capacity (over 100 MW or under 100 MW).

[7] Based on the RIA for MATS, ESPs are less flexible for fuel switching since they are designed for use with a specific intended fuel. Fuel switching or blending that increase gas flow rate, ash resistivity, or particle loading may render an existing ESP insufficient for removing particulate matter. But an ESP with sufficient design margin may succeed with fuel alterations. Therefore, when considering retrofit PM control, a unit with an existing ESP will examine upgrading the precipitator to achieve sufficient PM emission reductions.

Table 3-41 Data on PM Retrofit by Coal Grade and Size of Generation Capacity

Coal grade + ESP + size of generation capacity	Specification	Variable O&M	Investment cost	PM_{10} emission rate	PM_{25} emission rate
		2007 $M/PJ	2007 $M/PJ/Year	thousand tons/PJ	thousand tons/PJ
BEPUO	Bituminous Coal; ESP plate upgrade; generation capacity over 100 MW	0.0307	0.8273	-6.4759E-05	-4.4036E-05
SEPUO	Sub-bituminous Coal; ESP plate upgrade; generation capacity over 100 MW	0.0307	0.8273	-5.7855E-05	-3.9341E-05
BEPUU	Bituminous Coal; ESP plate upgrade; generation capacity under 100 MW	0.0307	1.2383	-5.3411E-05	-3.6320E-05
SEPUU	Sub-bituminous Coal; ESP plate upgrade; generation capacity under 100 MW	0.0307	1.2383	-5.7588E-05	-3.9160E-05

3.2.2.1.3 Existing Non-Coal Capacity

Existing plants already built in 2007 which are not fired by coal are modeled by technology type, which means that the total capacity of the same technology type is aggregated together and is represented with a single technology.

Table 3-42 shows the list of non-coal existing generation technologies modeled with IN-MARKAL. Technological and economic descriptions of those technologies follow those in the EPAUS9r. The RESID parameters shown in Table 3-43 indicate the availability of existing capacity for Indiana over the model horizon. Those for 2007 and 2010 are aggregated from historic data on plants located in Indiana retrieved from EIA Form-860. Capacities of natural gas steam turbine generators and natural gas combined cycle generators with open loop cooling system already existing in 2007 were all retired in 2010. Wind generation developed very fast beginning in 2008 in Indiana, and the total wind capacity as of 2010 is treated as existing capacity in IN_MARKAL as is specified by its RESID parameter for 2010. Generation capacities available in the 2010 period are assumed to still exist to the end of the modeling horizon.

Table 3-42 Non-Coal Existing Generation Technologies Modeled with IN-MARKAL

Technology	Description
ENGASTMRR	Natural gas steam; recirculating cooling
ENGASTMRO	Natural gas steam; open Loop cooling
EDSLCTR	Diesel oil combustion turbine
ENGACTR	Natural gas combustion turbine
ENGACCRR	Natural gas combined-cycle; recirculating cooling
ENGACCRO	Natural gas combined-Cycle; open Loop cooling
EHYDCONR	Hydroelectric, conventional
EWNDR	Wind
ELFGICER	Landfill gas engine

Table 3-43 RESID Specifications for Non-Coal Existing Generation Technologies

Existing non-coal generation technology	RESID 2007	RESID 2010	RESID 2013	RESID 2016	RESID 2019	RESID 2022	RESID 2025	RESID 2028	RESID 2031	RESID 2034	RESID 2037	RESID 2040	RESID 2043
ENGASTMRR	0.1400	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
ENGASTMRO	0.1381	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
EDSLCTR	0.3108	0.3088	0.3088	0.3088	0.3088	0.3088	0.3088	0.3088	0.3088	0.3088	0.3088	0.3088	0.3088
ENGACTR	3.9365	3.9315	3.9315	3.9315	3.9315	3.9315	3.9315	3.9315	3.9315	3.9315	3.9315	3.9315	3.9315
ENGACCRR	2.6799	2.7677	2.7677	2.7677	2.7677	2.7677	2.7677	2.7677	2.7677	2.7677	2.7677	2.7677	2.7677
ENGACCRO	0.1500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
EHYDCONR	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
EWNDR	0.0000	1.3387	1.3387	1.3387	1.3387	1.3387	1.3387	1.3387	1.3387	1.3387	1.3387	1.3387	1.3387
ELFGICER	0.0302	0.0302	0.0302	0.0302	0.0302	0.0302	0.0302	0.0302	0.0302	0.0302	0.0302	0.0302	0.0302

3.2.2.1.4 New Generation Capacity

` Investment in new generation capacity is modeled by technology type as listed in Table 3-44. Parameter specifications for the technologies are the same as those in the EPAUS9r.

Table 3-44 Generation Technologies Available for New Investment

Technology	Description
ECOALSTM	Pulverized coal steam
ENGAACC	Natural gas - advanced combined-cycle (turbine), available from 2016
ENGAACT	Natural gas - advanced combustion turbine, available from 2016
EBIOIGCC	Biomass integrated gasification combined cycle
ECOALIGCC	Integrated coal gasification combined cycle
ENGACC05	Natural gas - combined cycle (turbine), available from 2010
ENGACT05	Natural gas - combustion turbine, available from 2010
ENGAACCHS	Natural gas - advanced combined-cycle (turbine), converted from Harding Street 5 and 6
ESOLPVCEN	Solar PV centralized generation
ESOLSTCEN	Solar thermal centralized generation
EWNDCL4A	Wind generation class 4 cost category A
EURNALWR15	Nuclear generation - light water reactor
ELFGICE	Landfill gas to energy - engines
ELFGGTR	Landfill gas to energy - gas turbines
EMSWSTM	Municipal solid waste

The technology named ENGAACCHS is a newly created one used to represent the Harding Street units 5 and 6 after being converted to natural gas units from coal units in 2016. This technology is specified with fixed investment (IBOND(FX) parameter) in 2016 amounting to 0.2271 GW, with the INVCOST parameter representing the cost of coal-to-natural gas conversion equal to 160.9465 million dollars/GW.[8] The other parameters of this technology are specified the same as the technology titled ENGAACC. For the technology named ECOALIGCC, an investment (IBOND(FX)) of 0.625 GW is specified in 2013 to reflect the operation of Edwardsport IGCC generation station, which replaces the coal-fired plant formerly located at that site. The technology named ELFGICE is specified with 0.0134 GW capacity investments (IBOND(FX)) in 2010 to reflect the construction of four landfill gas power plants in Indiana in 2009 and 2010.

Based on Indiana's wind speed at 50 meters height (SUFG, 2013), the majority of wind resource available in-state is classified as Class 4 wind. Therefore, the wind generation technology for Class 4 wind with the lowest cost category in the EPAUS9r is used in IN-MARKAL.

For generation technologies mentioned in Sections 3.2.2.1.3 and 3.2.2.1.4, emissions accounting for various fuels are placed up stream of generation technologies.

3.2.2.1.5 Combined Heat and Power (CHP) Technologies

IN-MARKAL includes several CHP technologies in its power generation system. The CHP technologies are available for investment beginning in the 2013 period. The list of CHP technologies are shown in Table 3-45. Parameters related to those technologies are specified as in EPAUS9r.

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[8] Source: Megawatt Daily issue of August 30, 2013.

Table 3-45 CHP Technologies in IN-MARKAL

Technology	Description
ECHPBSTBIO	Boiler steam turbine CHP, Biomass
ECHPBSTNGA	Boiler steam Turbine CHP, natural gas (NGA)
ECHPBSTOIL	Boiler steam turbine CHP, oil
ECHPBSTWAS	Boiler steam turbine CHP, waste
ECHPCCTBIO	Combustion turbine CHP, biomass
ECHPCCTNGA	Combustion turbine CHP, NGA
ECHPCCTOIL	Combustion turbine CHP, oil
ECHPFCLBIO	Fuel cell CHP, biomass
ECHPMTTBIO	Microturbine CHP, biomass
ECHPMTTNGA	Microturbine CHP, NGA
ECHPREGBIO	Reciprocating engine CHP, biomass
ECHPREGNGA	Reciprocating engine CHP, NGA
ECHPREGOIL	Reciprocating engine CHP, oil

3.2.2.1.6 Biomass Co-firing with Coal

Biomass co-fired with coal for electricity generation is realized through another set of emission accounting technologies in IN-MARKAL. In Section 3.2.1.4, it is mentioned that biomass feedstock co-fired with coal goes through collection technologies that to convert its units from thousand short tons to PJ and then emission technologies to have CO_2 and SO_2 emissions taken into account. Here, another set of emission accounting technologies is created for all coal-fired generation units to account for NO_X and PM emissions and to merge the biomass feedstocks into the coal input. Biomass feedstocks have their names changed to coal input names after going through this set of technologies. Constraints enforce that biomass input does not exceed 10% of total fuel input to a generation unit by heat content expressed in PJ.

To facilitate the understanding of the electric sector design for coal-fired units (including environmental controls, biomass co-firing with coal and generation), an example is presented with IN-MARKAL energy carriers and technologies as shown in Figure 3-4. The coal-fired unit selected here is I51 (Rockport MB1). Technologies are placed in boxes and energy carriers are located above arrows in the graph. The flow chart starts from the upper left corner and ends with ELC at the lower left corner. Descriptions of energy carriers and technologies are included in the notes following the chart.

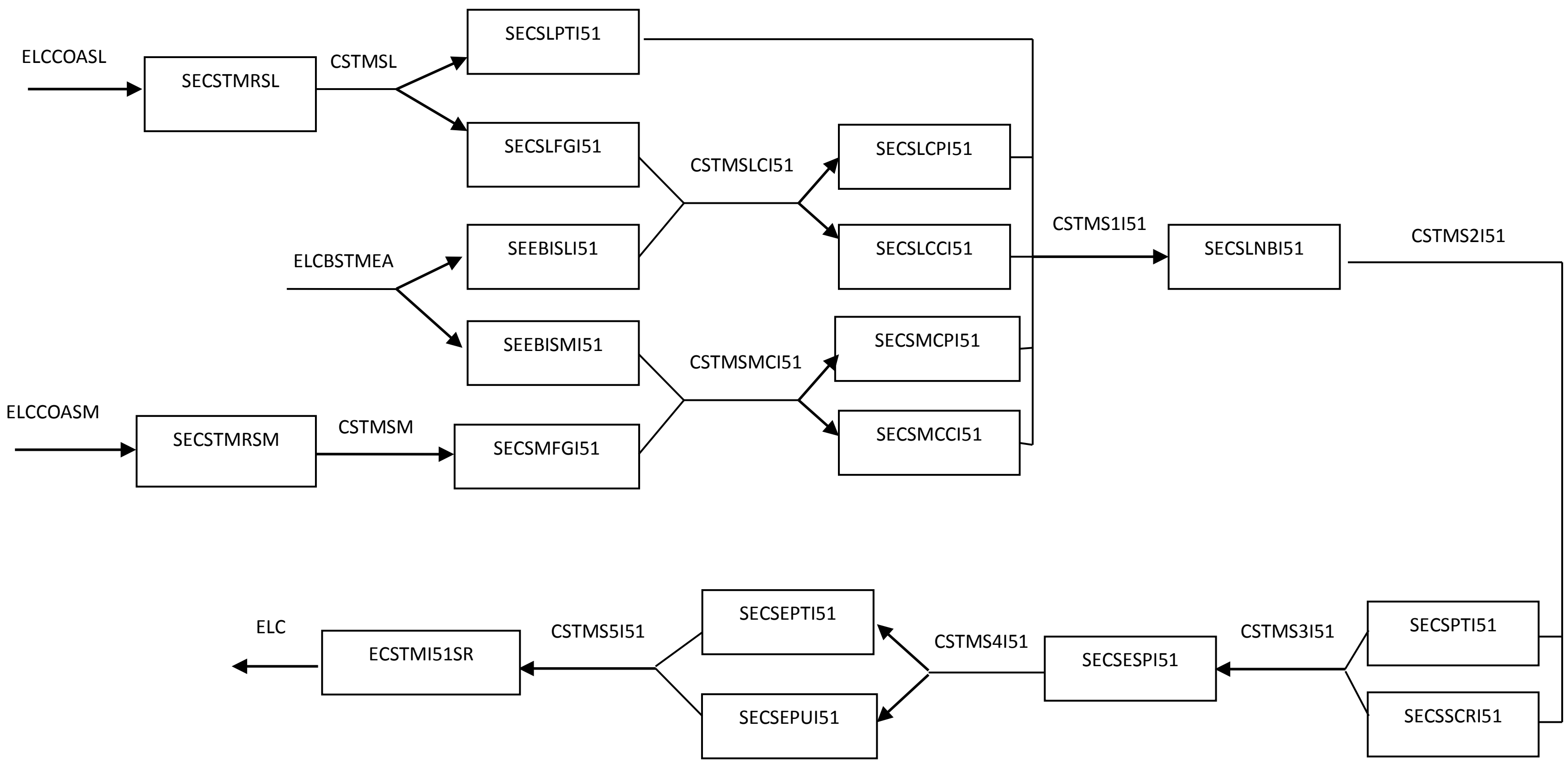

Figure 3-4 Exhibition of Electric Sector Design for Coal-Fired Unit Taking Rockport MB1 as An Example

Notes:
ELCCOASL: Sub-bituminous low sulfur (SL) coal to electricity generation system
ELCCOASM: Sub-bituminous medium sulfur (SM) coal to electricity generation system

SECSTMRSL: Emissions accounting technology for SL coal to existing coal fleet
SECSTMRSM: Emissions accounting technology for SM coal to existing coal fleet

CSTMSL: SL coal to SO_2 retrofit
CSTMSM: SM coal to SO_2 retrofit
ELCBSTMEA: Biomass going to be co-fired with coal for electricity generation after CO_2 and SO_2 emissions accounting

SECSLPTI51: FGD pass-through (PT); SL coal; Rockport MB1 (This unit does not have FGD retrofit in 2007. Coal goes through FGD PT until FGD retrofit is installed.)
SECSLFGI51: New FGD retrofit for plants without SO_2 control; SL coal; Rockport MB1 (The unit is forced to install FGD in 2019 if it will continue operation after 2019. The SM coal is allowed to use as well if FGD retrofit is installed. Therefore, SECSMFGI51 is created to provide a path for SM coal if the model chooses to partially or fully switch to SM coal. But investment cost for FGD only occurs once and is included in the corresponding generation technology.)
SEEBISLI51: NO_x and PM emissions accounting technology for biomass co-firing with SL coal for electricity generation; Rockport MB1
SEEBISMI51: NO_x and PM emissions accounting technology for biomass co-firing with SM coal for electricity generation; Rockport MB1
SECSMFGI51: New FGD retrofit for plants without SO_2 control; SM coal; Rockport MB1 (The unit is forced to install FGD in 2019 if it continues operation after 2019.)

CSTMSLCI51: SL coal or combination of SL coal and biomass between SO_x and CO_2 control or PT; Rockport MB1
CSTMSMCI51: SM coal or combination of SM coal and biomass between SO_x and CO_2 control or PT; Rockport MB1

SECSLCPI51: CO_2 retrofit PT; existing coal steam; SL coal; Rockport MB1
SECSLCCI51: CO_2 retrofit; existing coal steam; SL coal; Rockport MB1
SECSMCPI51: CO_2 retrofit PT; existing coal steam; SM coal; Rockport MB1
SECSMCCI51: CO_2 retrofit; existing coal steam; SM coal; Rockport MB1

CSTMS1I51: Sub-bituminous coal to NO_x control; Rockport MB1

SECSLNBI51: Low NOx burner (LNB); sub-bituminous coal; Rockport MB1 (existing NO_x control for Rockport MB1)

CSTMS2I51: Sub-bituminous coal from the 1st step of NO_x control to the 2nd step of NO_x control

SECSPTI51: Selective catalytic reactor SCR PT follows LNB; sub-bituminous coal; Rockport MB1 (Rockport MB1 does not have SCR installed in 2007.)
SECSSCRI51: New SCR to plant with existing LNB; sub-bituminous coal; Rockport MB1 (SCR must be installed in 2019 if Rockport MB1 will continue operation.)

CSTMS3I51: Sub-bituminous coal to particulate matter (PM) control; Rockport MB1

SECSESPI51: Electrostatic precipitator (ESP) for PM control; sub-bituminous coal; Rockport MB1

CSTMS4I51: Sub-bituminous coal from the 1st step of PM control to the 2nd step of PM control

SECSEPTI51: ESP plate upgrading PT; sub-bituminous coal; Rockport MB1
SECSEPUI51: ESP plate upgrading; sub-bituminous coal; Rockport MB1 (Existing ESP plate must be upgraded in 2019 for continued operation of the generation station.)

CSTMS5I51: Sub-bituminous coal after all environmental retrofits; Rockport MB1

ECSTMI51SR: Existing coal steam generation facility; Rockport MB1; sub-bituminous coal; vintage: 1980; recirculating cooling system

ELC: Electricity

3.2.2.2 Biofuel Production

3.2.2.2.1 Corn-Based Ethanol Production

IN-MARKAL includes one existing and two new corn-based ethanol production technologies as shown in Table 3-46. Based on information aggregated from data in the Fact Sheet of Biofuels Plants in Indiana (ISDA, 2013), Indiana has corn-based ethanol production capacity (dry mill) of 475 and 988 million gallons per year for 2007 and 2010 respectively. They are converted to PJ and specified with RESID parameters for 2007 and 2010 for the existing technology named PCRNETHDE. The capacity available in 2010 is assumed to have a life lasting to the end of the modeling horizon. The conversion factor for denatured ethanol is 8.9762E-08 PJ/gallon. Parameters other than RESID for existing and new corn-based ethanol production technologies follow those specified in EPAUS9r.

Table 3-46 Corn-Based Ethanol Production Technologies

Tehcnology	Description
PCRNETHDE	Production of corn-based ethanol, dry mill, existing
PCRNETHDN	Production of corn-based ethanol, dry mill, New
PCRNETHDC	Production of corn-based ethanol, dry mill, with CHP

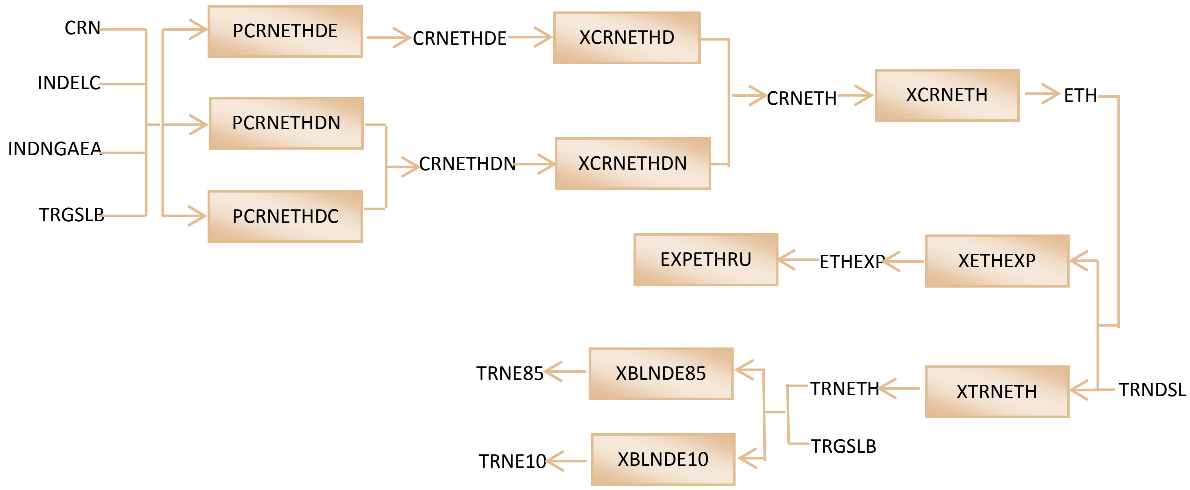

Figure 3-5 RES for Corn-Based Ethanol

Notes:
CRN: corn
INDELC: electricity to industrial sector
INDNGAEA: natural gas to industrial sector after emissions accounting
TRGSLB: gasoline (serve as the denaturant in the ethanol production process in this case)

PCRNETHDE: corn-based ethanol production technology, dry mill, existing
PCRNETHDN: corn-based ethanol production technology, dry mill, new
PCRNETHDC: corn-based ethanol production technology, dry mill, with CHP, new
CRNETHDE: corn-based ethanol from existing dry mill
CRNETHDN: corn-based ethanol from new technology

XCRNETHDE: Count the revenue from the sale of co-products of the process, existing technology
XCRNETHDN: Count the revenue from the sale of co-products of the process, new technologies

CRNETH: denatured corn-based ethanol

XCRNETH: rename corn-based ethanol and apply subsidies

ETH: ethanol
TRNDSL: diesel to transportation sector

XETHEXP: collector technology, ethanol exporting from Indiana to the rest of the U.S.
XTRNETH: collector technology, ethanol blending for use in Indiana transportation sector

ETHEXP: ethanol going to be exported
TRNETH: ethanol going to be blended for use in Indiana transportation sector
TRGSLB: gasoline to be blended with ethanol

EXPTHRUS: ethanol exporting technology
XBLNDE85: process for blending gasoline and ethanol to E85
XBLNDE10: process for blending gasoline and ethanol to E10

TRNE85: E85 to Indiana transportation sector
TRNE10: E10 to Indiana transportation sector

Figure 3-5 is a reference energy system (RES)[9] for corn-based ethanol. Technologies are displayed in boxes and energy commodities are displayed with arrows. Following the three corn-based ethanol production technologies are two collector technologies (XCRNETHDE and ECRNETHDN), accounting for the revenues generated from selling dried distillers grains (DDGs) and corn oil as by-products of the ethanol production process for the existing and new technologies respectively. Another collector technology (XCRNETH) counts the federal monetary credits for ethanol blending and merges the corn-based ethanol into ethanol (ETH). (Cellulosic ethanol is merged into ethanol as well, and will be discussed in Section 3.2.2.2.2.) Ethanol can either be exported, creating revenue for Indiana, or be used in Indiana's transportation sector directly (the latter case avoids purchase of ethanol-blended fuel from out of state), depending on which option is more economical in terms of the energy system cost. The technology named XETHEXP is the collector technology for ethanol exporting, followed by the exporting technology (EXPETHRUS) with negative costs specified for each period to represent the revenue generated per PJ from ethanol exports. Revenues are based on the ethanol wholesale prices by time period reported in AEO2010 Table 12. If ethanol is going to be blended and used in Indiana, it goes through a transportation technology (XTRNETH) first, where the cost of diesel used for truck transportation is taken into account. Then the ethanol is blended with gasoline through blending technologies (XBLNDE85 and XBLNDE10) to produce E85 (an ethanol fuel blend of 85% denatured ethanol fuel and 15% gasoline by volume) and E10 (a low-concentration blend composed of 10% ethanol and 90% gasoline), which are used in the state's transportation system.

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[9] A RES is a network diagram that summarizes the relationships among various entities (demands, energy sources, technologies, commodities and sinks) in a MARKAL model.

3.2.2.2.2 Cellulosic Ethanol Production

Information related to cellulosic ethanol production used in IN-MARKAL is based on a study from the National Academy of Sciences named Liquid Transportation Fuels from Coal and Biomass: Technological Status, Costs and Environmental Impacts (NAS, 2009).

Three scenarios were developed in this study that provide possible process cost estimates: current technology (low), reasonable evolutionary advances in technology (medium), and the optimistic technology advances (high) for the biochemical conversion of cellulosic feedstocks. Data pertaining to the three scenarios is shown in Table 3-47. According to the authors' judgment, the low case best represents where the technology would be for 2010 deployment and the medium case for 2020 deployment. Due to the fact that Indiana did not have any cellulosic ethanol production capacity installed as of 2013, the time of earliest feasible adoption in IN-MARKAL is set to 2016. Thus, the cost estimate in the low case is assumed to represent a technology available from 2016 and that in the medium case is assumed to describe a technology available from 2025.

Table 3-47 Costs and Operation Characteristics of A Cellulosic Ethanol Plant with A Capacity of 40 Million Gallons per Year under Three Scenarios

Technology information	Units	Poplar			HGBM		
		Low	Medium	High	Low	Medium	High
Total capital	2008 $ millions	223	194	174	166	140	128
Total capacity	million gallons of ethanol per year	40	40	40	40	40	40
Total capital per unit of capacity	2008 $/annual gallon	5.65	4.85	4.34	4.15	3.49	3.20
Operation cost (including cellulose cost)	2008 $/gallon output	1.95	1.40	0.90	1.70	1.20	0.80
Cellulose Cost	2008 $/gallon output	0.40	0.25	0.10	0.40	0.25	0.10
Operation cost (excluding cellulose cost)	2008 $/gallon output	1.55	1.15	0.80	1.30	0.95	0.70
Yield	gallon of ethanol per dry ton of biomass	67	78	87	83	95	106

Notes: 1) Poplar woodchips, rich in lignin, can be considered an outlier as a feedstock with respect to the other biomass types.

2) HGBM means high-sugar/glucan biomass, which has a composition closer to most of the other cellulosic biomass types.

3) Poplar is widely used as woody energy crop.

4) The capital cost requirements for a bio-refinery that uses poplar woodchips is about 35 percent higher than the requirements for one that uses HGBM primarily because of the increased cost of the boiler and steam electrical generator associated with the increased lignin content of the feedstock. However, the higher capital cost is offset by the high electricity generation from the lignin-rich residue of poplar.

5) The operation cost takes into account the reduction of cost due to the generation of excess electricity sold to market at 0.05$/KWh.

6) Data in this table are retrieved from Table 3.2 and Table 3.3 of the study.

Biomass feedstocks in Table 3-47 are roughly grouped into two categories (poplar and high-sugar/glucan biomass (HGBM)). Therefore, another set of data which contains costs by feedstock types is used as well, and is shown in Table 3-48. This dataset is only for technologies available for deployment from 2025 on. Therefore, data in Table 3-47 (the relationships between the low and medium cases for various items shown in the first column of the table) is used to scale the corresponding items in Table 3-48 in order to develop costs by feedstock types for technologies available for deployment from 2016, which is shown in Table 3-49. Feedstocks other than poplar are scaled by the data on HGBM in Table 3-47. For example, to calculate the total capital cost for the cellulosic ethanol plant using miscanthus as input (2016 deployment), the corresponding data in Table 3-48 (176 millions) is scaled by the ratio of capital costs for the low and medium cases for HGBM shown in Table 3-47 (166/140), which gives the number (209 millions) shown in Table3-49.

Table 3-50 is a summary of information displayed in Table 3-48 and Table 3-49. Note that the averages of data on Miscanthus and Switchgrass are used to represent ECG (grassy energy crop) in IN-MARKAL. Poplar is used to represent ECW (woody energy crop) and wheat straw is for AGR (agricultural residues).

Table 3-51 displays parameter specifications for cellulosic ethanol production technologies in IN-MARKAL, which are converted from information in Table 3-50. INP(ENT)p represents the input-output ratio in million tons of biomass input per PJ of ethanol output (ENT indicates energy carrier and p indicates process technology). INVCOST characterizes investment cost in 2007 million dollars per PJ of capacity. VAROM is the variable O&M cost in 2007 million dollars per PJ of ethanol output. Finally, OUT(ENC)p-ELC_CELB specifies the amount of excess electricity produced for sale in PJ resulted from a PJ of ethanol production. Due to the fact that the operation cost has taken into account the cost reduction resulted from the generation of excess electricity sold to the market at 0.05$/KWh, no additional benefit is specified for the electricity sale.

Table 3-48 Costs and Operation Characteristics of A Cellulosic Ethanol Plant with A Capacity of 40 Million Gallons per Year by Input (2025 Deployment)

Technology information	Units	Poplar	Miscanthus	Switchgrass	Corn stover	Wheat straw
Total capital	2008 $ millions	194	176	156	150	123
Total capital per unit of capacity	2008 $/annual gallon	4.85	4.40	3.90	3.80	3.10
Operation cost (including cellulose cost)	2008 $/gallon output	1.40	1.35	1.35	1.25	1.20
Cellulose Cost	2008 $/gallon output	0.25	0.25	0.25	0.25	0.25
Operation cost (excluding cellulose cost)	2008 $/gallon output	1.15	1.10	1.10	1.00	0.95
Yield	gallon of ethanol per dry ton of biomass	78	79	80	76	88
Revenue from electricity sales	2008 $/gallon of ethanol output	0.40	0.28	0.02	0.08	0.00

Notes: 1) Data retrieved from Tables 3.2 and 3.4 of the study.
2) Judging from the data on poplar shown in column three, information displayed in this table is consistent with the medium case shown in Table 3-47. Therefore, the data set is used to represent technologies for deployment in 2025.

Table 3-49 Costs and Operation Characteristics of A Cellulosic Ethanol Plant with A Capacity of 40 Million Gallons per Year by Input (2016 Deployment)

Technology information	Units	Poplar	Miscanthus	Switchgrass	Corn Stover	Wheat Straw
Total capital	2008 $ millions	223	209	185	178	146
Total capital per unit of capacity	2008 $/annual gallon	5.65	5.23	4.64	4.52	3.69
Operation cost (including cellulose cost)	2008 $/gallon output	1.95	1.91	1.91	1.77	1.70
Cellulose Cost	2008 $/gallon output	0.40	0.40	0.40	0.40	0.40
Operation cost (excluding cellulose cost)	2008 $/gallon output	1.55	1.51	1.51	1.37	1.30
Yield	gallon of ethanol per dry ton of biomass	67	69	70	66	77
Revenue from electricity sales	2008 $/gallon of ethanol output	0.40	0.28	0.02	0.08	0.00

Table 3-50 Summary Information for Cellulosic Ethanol Production Technologies

Technology information	Units	Stover, 2016	Stover, 2025	ECG, 2016	ECG, 2025	ECW, 2016	ECW, 2025	AGR,2016	AGR,2025
Investment cost	2008 $/annual gallon	4.52	3.80	4.93	4.15	5.65	4.85	3.69	3.10
Operating and maintenance	2008 $/gallon output	1.37	1.00	1.51	1.10	1.55	1.15	1.30	0.95
Input output ratio	dry ton biomass/ gallon output	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Yeild	gallon of ethanol/dry ton of biomass	66.40	76.00	69.46	79.50	67.00	78.00	76.88	88.00
Output of electricity	KWh of ELC/gallon of output	1.60	1.60	3.00	3.00	8.00	8.00	0.00	0.00

Table 3-51 Parameter Specifications for Cellulosic Ethanol Production Technologies in IN-MARKAL

Feedstock type	INP(ENT)p		INVCOST		VAROM		OUT(ENC)p-ELC_CELB	
	2016	2025	2016	2025	2016	2025	2016	2025
STV	0.1694	0.1480	49.7251	41.8171	15.0853	11.0045	0.0648	0.0648
ECG	0.1620	0.1415	54.3051	45.6686	16.6443	12.1049	0.1215	0.1215
ECW	0.1679	0.1442	62.1754	53.3718	17.0570	12.6552	0.3240	0.3240
AGR	0.1463	0.1278	40.5653	34.1139	14.3058	10.4543	0.0000	0.0000

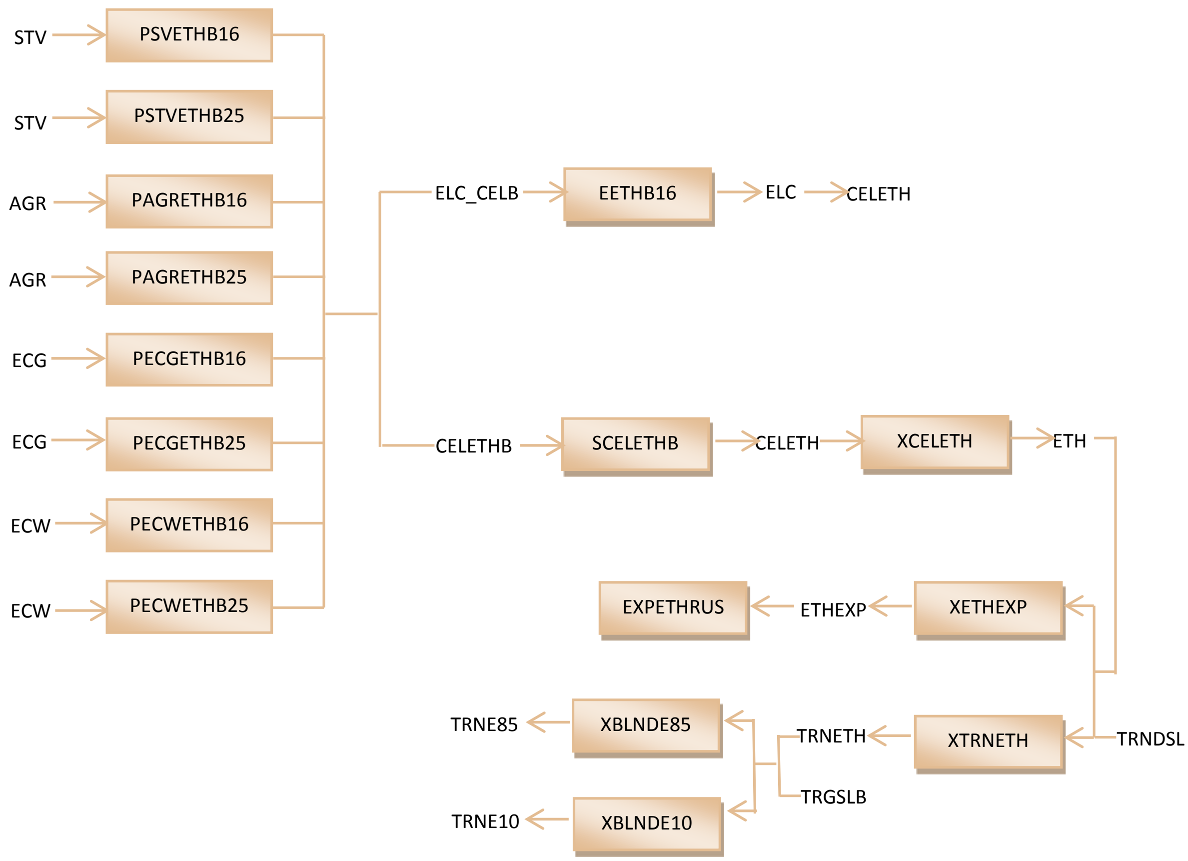

Figure 3-6 RES for Cellulosic Ethanol

Notes:
STV: corn stover
AGR: agricultural residues
ECG: grassy energy crop
ECW: woody energy crop

PSTVETHB16: production of cellulosic (STV) ethanol, biochemical process, available from 2016
PSTVETHB25: production of cellulosic (STV) ethanol, biochemical process, available from 2025
PAGRETHB16: production of cellulosic (AGR) ethanol, biochemical process, available from 2016
PAGRETHB25: production of cellulosic (AGR) ethanol, biochemical process, available from 2025
PECGETHB16: production of cellulosic (ECG) ethanol, biochemical process, available from 2016
PECGETHB25: production of cellulosic (ECG) ethanol, biochemical process, available from 2025
PECWETHB16: production of cellulosic (ECW) ethanol, biochemical process, available from 2016
PECWETHB25: production of cellulosic (ECW) ethanol, biochemical process, available from 2025

ELC_CELB: excess electricity produced as by product of the biochemical process
CELETHB: cellulosic ethanol from biochemical processes

EETHB16: collector of electricity from cellulosic ethanol production
SCELETHB: collector of cellulosic ethanol

ELC: electricity
CELETH: cellulosic ethanol

XCELETH: rename cellulosic ethanol and apply subsidies

ETH: ethanol
TRNDSL: diesel to transportation sector

XETHEXP: collector technology for ethanol export from Indiana to the rest of U.S.
XTRNETH: collector technology for ethanol blending for use in Indiana transportation sector

ETHEXP: exported ethanol
TRNETH: ethanol going to be blended for use in Indiana transportation sector
TRGSLB: gasoline to be blended with ethanol

EXPTHRUS: ethanol exporting technology
XBLNDE85: process for blending gasoline and ethanol to E85
XBLNDE10: process for blending gasoline and ethanol to E10

TRNE85: E85 to Indiana transportation sector
TRNE10: E10 to Indiana transportation sector

Figure 3-6 is a RES exhibiting the flow of cellulosic ethanol. Four types of biomass feedstocks are fed into biochemical processes (two processes (2016 and 2025 deployment) for each type of biomass feedstock) for the production of cellulosic ethanol. The excess electricity produced as a by-product is collected by a technology named EETHB16 and merge into ELC (electricity produced from electricity generation system). Cellulosic ethanol is collected by a technology named SCELETHB first and then goes through a technology named XCELETH, at where the cellulosic ethanol production tax credit is applied and cellulosic ethanol is renamed as ETH (ethanol). At this point, cellulosic ethanol and corn-based ethanol merge. The ensuing steps are the same as explained at the end of Section 3.2.2.2.1.

3.2.2.2.3 Biodiesel Production

Soybean oil and yellow grease (waste oil) are used to produce biodiesel. IN-MARKAL models four biodiesel production technologies, one of which uses soybean oil and the other three use waste oil.

Based on the Fact Sheet of Biofuels Plants in Indiana, Indiana had 98 million gallons of biodiesel production capacity as of 2007, which uses soybean oil as an input. This capacity is assumed to be available through the end of the modeling horizon and is specified by the RESID parameters for the technology. Other parameters of biodiesel production technologies follow those specified in EPASU9r.

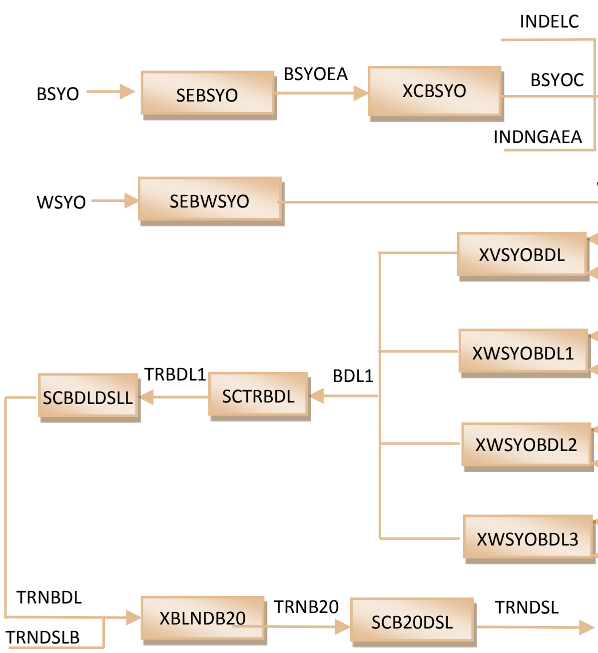

Figure 3-7 RES for Biodiesel

Notes:
BSYO: soybean oil available for biodiesel production, excluding the cost of oil crushing
WSYO: waste oil available for biodiesel production

SEBSYO: emission accounting technology for soybean oil, CO_2 uptake during soybean growing process
SEBWSYO: emission accounting technology for waste soybean oil, CO_2 uptake during soybean growing process (emission factor assumed to be the same as soybean oil)

BSYOEA: soybean oil after emission accounting
WSYOEA: waste oil after emission accounting
XCBSYO: soybean oil collection technology (no costs specified because costs of collection have already been included in the price of soybean oil supply)

INDELC: electricity to industrial sector
BSYOC: collected soybean oil
INDNGAEA: natural gas to industrial sector after emission accounting

PSYOCSH: add the cost of soybean oil crushing

CSYOEA: soybean oil available for biodiesel production, including cost of crushing

XCSYOPRO: rename soybean oil and convert it from million ton to PJ

VSYOEA: soybean oil going into biodiesel production process

PVSYOBDL: production of biodiesel from soybean oil
PWSYOBDL1: production of biodiesel from waste oil, process 1
PWSYOBDL2: production of biodiesel from waste oil, process 2
PWSYOBDL3: production of biodiesel from waste oil, process 3

BDLV: biodiesel from PVSYOBDL
BDLW1: biodiesel from PWSYOBDL1
BDLW2: biodiesel from PWSYOBDL2
BDLW3: biodiesel from PWSYOBDL3
GLYC: glycerin as a by-product of biodiesel manufacturing process

XCOGLYC: count the revenue generated by selling glycerin

GLYC1: glycerin after revenue accounting

XVSYOBDL: add the revenue from glycerin to biodiesel from soybean oil
XWSYOBDL1: add the revenue from glycerin to biodiesel from waste oil, process 1
XWSYOBDL2: add the revenue from glycerin to biodiesel from waste oil, process 2
XWSYOBDL3: add the revenue from glycerin to biodiesel from waste oil, process 3

BDL1: biodiesel after counting revenue from by-product and all the costs

SCRTBDL: collector technology, biodiesel to transportation sector

TRBDL1: biodiesel to transportation sector

SCBDLDSL: collector technology, biodiesel to blending process

TRNBDL: biodiesel available for blending
TRNDSLB: diesel for blending

XBLNDB20: process for blending diesel and biodiesel to B20

TRNB20: B20

SCB20DSL: Collector technology, B20 to transportation sector
TRNDSL: B20 to transportation sector

Figure 3-7 is a RES for biodiesel. Soybean oil (excluding the cost of oil crushing) passes through an emission accounting technology (SEBSYO) first and then through a collection technology (XCESYO). Collected soybean oil flows into a technology named

PSYOCSH, where costs of the oil crushing are added to the soybean. Then the soybean oil (including the cost of oil crushing) flows into another technology named XCSYOPRO, which converts the unit of soybean oil from million tons to PJ. A technology named PVSYOBDL follows and represents the biodiesel production technology using soybean oil. If waste oil is used for biodiesel production, it goes through an emission accounting technology (SEBWSYO) before flowing into biodiesel production technologies (PWSYOBDL1, PWSYOBDL2 or PWSYOBDL3). Biodiesel tax credit is applied directly to the four biodiesel production technologies. Glycerin as a by-product of biodiesel manufacturing process has its value counted (XCOGLYC) and added to biodiesel through four technologies (XCSYOBDL, XWSYOBDL1, XWSYOBDL2 and XWSYOBDL3), which reduces the cost of biodiesel production. A collector technology (SCRTBDL) follows and delivers biodiesel to the Indiana transportation sector. Another collector technology (SCBDLDSL) further delivers biodiesel to the blending process. The technology named XBLNDB20 stands for the process for blending diesel and biodiesel to B20 (a mixture composed of 20% biodiesel with 80% of diesel). B20 is collected to be finally used in the transportation sector through a technology named SCB20DSL.

3.2.2.2.4 Synthetic Fuel Production

Biomass to liquids (BTL) technology is a technology to derive synthetic fuels thermochemically via biomass gasification. Ligno-cellulosic feedstocks, such as forest residues and energy crops, are used in the thermochemical process for fuel production, avoiding the food price impacts and indirect land use impacts created by using food crops for making biofuels. IN-MARKAL models the thermochemical processes based on a study named Fischer Tropsch Fuels from Coal and Biomass (Kreutz at el., 2008). Information on the BTL technology drawn from the study is shown in Table 3-52.

Table 3-52 Information on Thermochemical Process for Synthetic Fuel Production

Technology information	Unit	Data
Total plant Cost	million 2007$	636
Capacity	bbl. gasoline/day	4412.53
O&M charges	2007$/GJ gasoline gallon equivalent (GGE) output	3.23
Yield	liters gasoline equivalent (LGE) per dry metric ton biomass	249
ELC sale price	2007$/KWh	0.06
Life	year	20
Diesel output	PJ synthetic diesel/PJ GGE output	0.6060
Gasoline output	PJ synthetic gasoline/PJ GGE output	0.3940
Electricity output	2007$/GJ GGE output	2.0700
Available year	year technology available	2020

Note: The year that the technology becomes available is based on the judgment of Dr. Wallace Tyner.

Table 3-53 Parameter Specifications of Thermochemical Process in IN-MARKAL

IN-MARKAL parameter	Unit	Data
INVCOST	2007 M$/PJ capacity in GGE output	71.2517
VAROM	million dollars/PJ GGE output	3.2300
INP(ENT)p	million ton biomass/PJ of GGE output	0.1270
OUT(ENC)p-SYNDSL	PJ synthetic diesel output/PJ gasoline equivalent output	0.6060
OUT(ENC)p-SYNGWL	PJ synthetic gasoline output/PJ gasoline equivalent output	0.3940
OUT(ENC)p-ELC_THEB	PJ ELC output/PJ gasoline equivalent output	0.1242
START	year available	2022

Table 3-53 displays parameter specifications for the thermochemical processes modeled in IN-MARKAL. They are directly based on or converted from information in Table 3-52. The conversion processes for those parameters are shown as the follows:

INVCOST = Total plant cost in million 2007 dollars/ (Capacity in bbl. gasoline per day * 356 * 42 gallons per bbl. * 1.3196E-07 gasoline PJ per gallon)

Note that IN-MARKAL uses HHV (higher heating value) for gasoline energy content if not indicating specifically.

VAROM = O&M charges in 2007 dollars per GJ GGE output

INP(ENT)p = 1/(Yield in LGE per dry metric ton biomass/3.785 liters per gallon/1.1 short ton per metric ton)/10E-6/1.3196E-07 gasoline PJ per gallon

OUT(ENC)p-ELC_THEB = Electricity output in 2007 dollars per GW GGE output / ELC sale price in 2007 dollars per KWh * 3.6E-09 PJ per KWh *10E-6

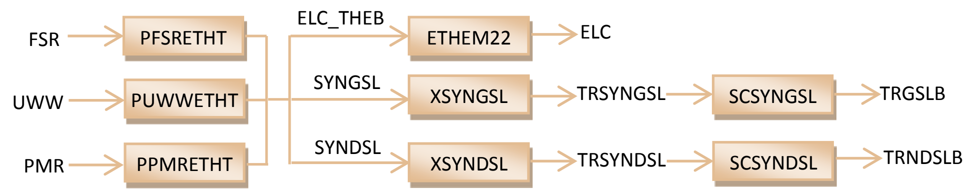

Figure 3-8 RES for Synthetic Fuels

Notes:
FSR: forest residues
UWW: urban wood waste
PMR: primary mill residues

PFSRETHT: synthetic fuel production through thermochemical process, FSR
PUWWETHT: synthetic fuel production through thermochemical process, UWW
PPMRETHT: synthetic fuel production through thermochemical process, PMR

ELC_THEB: electricity from thermochemical process
SYNGSL: synthetic gasoline
SYNDSL: synthetic diesel

ETHEM22: collector of electricity from thermochemical process
XSYNGSL: technology applying subsidy to synthetic gasoline
XSYNDSL: technology applying subsidy to synthetic diesel

ELC: electricity
TRSYNGSL: synthetic gasoline with subsidy applied
TRSYNDSL: synthetic diesel with subsidy applied

SCRYNGSL: collector technology, synthetic gasoline merged into gasoline
SCSYNDSL: collector technology, synthetic diesel merged into diesel

TRGSLB: gasoline
TRNDSLB: diesel

Figure 3-8 is the RES for synthetic fuels. Three types of biomass feedstocks (FSR, UWW and PMR) are used. They go through the corresponding synthetic fuel production processes (PFSRETHT, PUWWETHT, and PPMRETHT) first. The same set of parameters is used for all three processes. Three outputs from the thermochemical processes — electricity (ELC_THEB), synthetic gasoline (SYNGSL) and synthetic diesel (SYNDSL). ELC_THEB then flows into a collector technology (ETHEM22) and merges into ELC. Synthetic gasoline (SYNGSL) and synthetic diesel (SYNDSL) flows into two process technologies (XSYNGSL and XSYNDSL) respectively, where subsidies for renewable gasoline and renewable diesel are applied. Finally, two collector technologies merge synthetic gasoline into gasoline and synthetic diesel into diesel respectively.

3.2.3 End-Use Sectors

In this section, the setup of the four end-use sectors in IN-MARKAL are described. The four end-use sectors are residential, commercial, industrial and transportation sectors. For each sector, various types of end-use energy service demand and the corresponding technologies used for meeting those demand are depicted.

3.2.3.1 Residential Sector

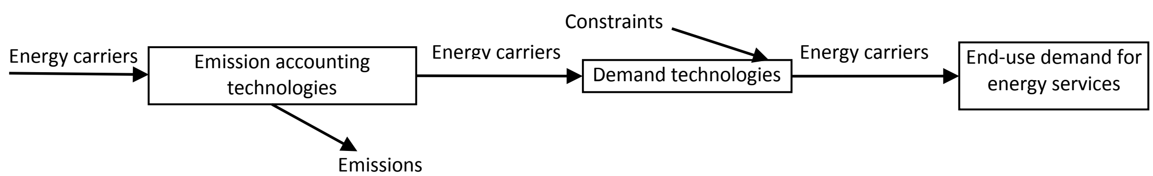

Figure 3-9 Residential Sector RES

Figure 3-9 is the RES for the residential sector. Energy carriers flow through emission accounting technologies and demand technologies to meet end-use demand for energy services.

3.2.3.1.1 Residential Demand for Energy Services

IN-MARKAL models nine categories of energy services for the residential sector. They are shown in Table 3-54.

Table 3-54 Residential Energy Services Modeled with IN-MARKAL

Name	Description
RSH	Residential space heating
RSC	Residential space cooling
RWH	Residential water heating
RRF	Residential refrigeration
RFZ	Residential freezing
RLT	Residential lighting
ROE	Residential other appliances - electricity
ROG	Residential other appliances - natural gas
ROL	Residential other appliances - liquefied petroleum gas (LPG)

Generally speaking, the method for deriving the residential base-year demand for various energy services starts from the estimation of base-year energy consumption by energy service and fuel. Then, the corresponding end-use equipment efficiencies are applied to energy consumption to estimate demand for various energy services by fuel. Finally, aggregating across various fuels for each energy service leads to the estimation of the demand for various energy services for the base year as inputs to IN-MARKAL.

There are three approaches used to derive residential energy consumption by energy service and fuel, based on data availability. They all start with Indiana residential energy consumption estimates from the U.S. Energy Information Administration (EIA)'s State Energy Data System (SEDS), as shown in Table 3-55. Nine categories of fuel are estimated in SEDS, but only five categories are included in IN-MARKAL residential sector. They are electricity, natural gas, distillate fuel oil (DFO), liquefied petroleum gas (LPG) and other. The other category in IN-MARKAL is an aggregation of coal, biomass, solar, geothermal and kerosene reported from SEDS, which together constitute 5.43% of Indiana residential energy consumption.

Table 3-55 Indiana Residential Energy Consumption Estimates, 2007

	Electricity	Natural gas	DFO	LPG	Other					Total
					Coal	Biomass (wood and waste)	Solar	Geothermal	Kerosene	
Quantity in trillion Btu	118.20	145.90	2.80	15.50	0.40	12.80	0.10	2.20	0.70	298.60
Percentage	39.58%	48.86%	0.94%	5.19%	5.43%					100%

Note: DFO is short for distillate fuel oil (diesel); LPG is short for liquefied petroleum oil.

Electricity, natural gas and DFO

The first approach to split residential fuel consumption into various end-use energy services is applied to three fuel categories – electricity, natural gas and DFO. Figure 3-10 shows the process, which is explained in detail in the following paragraphs.

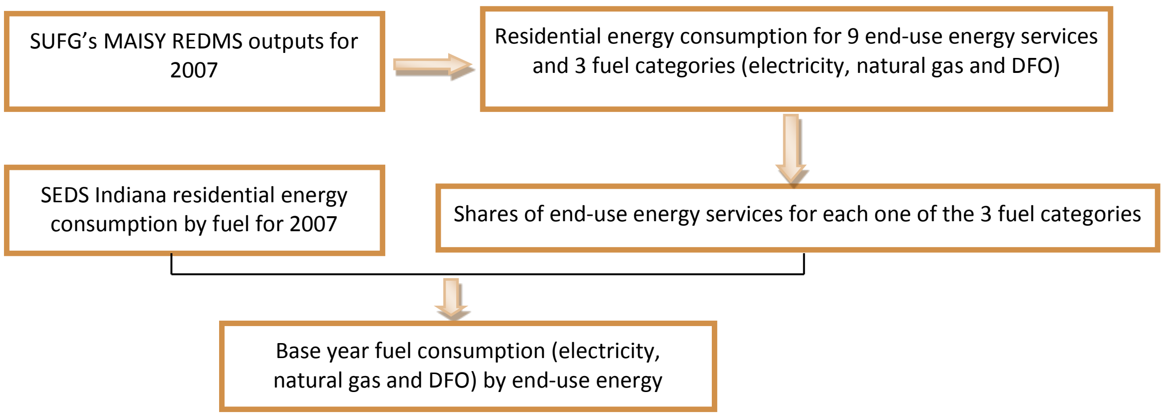

Figure 3-10 Process of Deriving Indiana Residential Energy Consumption (Electricity, Natural Gas and DFO) by End-Use Energy Service for the Base Year

As shown in Figure 3-10, the State Utility Forecasting Group (SUFG)'s MAISY (Market Analysis and Information System) REDMS (Residential Energy Demand Model System) outputs for 2007 are used to calculate shares of end-use energy services for each one of the 3 fuel categories.

MAISY was designed by a consulting firm named Jackson Associates for the SUFG. Figure 3-11 displays the methodology for estimating Indiana residential electricity, natural gas and DFO consumption by end-use energy service. The eight light blue boxes on the far left hand side of Figure 3-11 display Indiana major electric utilities. The first five are investor-owned utilities — Indiana Michigan Power Company (IMPC), Indianapolis Power and Light Company (IP&L), Northern Indiana Power Service Company (NIPSCO), Duke Energy (DUKE) and Southern Indiana Gas Electric Company (SIG&EC). Hoosier Energy Rural Electric Cooperative (HEREC) and Wabash Valley Power Association (WVPA) are member-owned rural electric cooperatives. Indiana Municipal

Power Agency (IMPA) is an association of municipally owned electric utilities. Each one of the eight utilities serve certain areas of Indiana and their service areas do not overlap. MAISY REDMS only provides estimations for the five investor-owned utilities in Indiana.

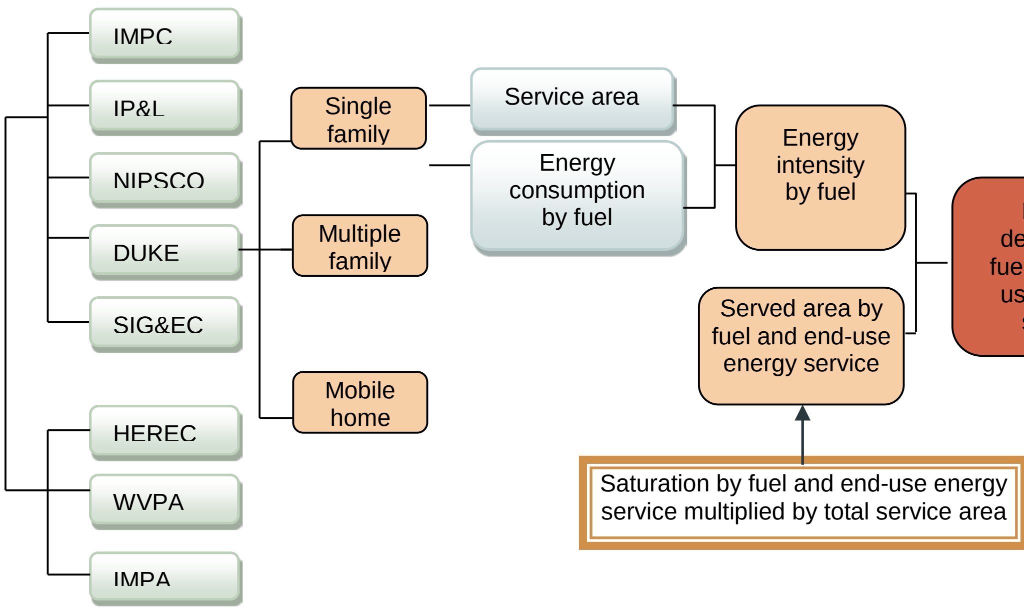

Figure 3-11 MAISY REDMS Methodology

For each one of the five investor-owned utilities, the service area is divided into three types — single family home, multiple family home and mobile home. For each one of the three home types, the total energy consumption by fuel is divided by the total service area in number of dwelling units to derive energy intensities by fuel. Energy intensity for electricity is expressed in MWh/dwelling unit and those for natural gas and DFO are expressed in million British thermal units (MBtu)/dwelling unit. On the other hand, Jackson Associates surveyed utility- and home type-specific equipment stocks saturation by fuel and end-use energy service, which represents the percentage of dwelling units (utility- and home type-specific) having a certain category of end-use technologies. An example would be the percentage of single family homes served by Duke Energy which have electric space heating equipment. Multiplying saturation by fuel and end-use energy service with the total service area in number of dwelling units gives an estimate of served dwelling units by fuel and end-use energy service. Finally, energy demand by fuel and end-use energy service for each home type served by each utility is estimated by multiplying corresponding energy intensities by fuel type with served area in dwelling units by fuel type and end-use energy service.

Aggregating energy demand by fuel and end-use energy service (home type- and utility-specific) across the three home types and across the five investor-owned utilities gives the total energy demand by fuel and end-use energy service for Indiana's five investor-owned utilities. By rule of thumb, the total supply from the 5 investor-owned utilities composes roughly 80% of the total energy consumption of Indiana residential sector. Therefore, the five investor-owned utilities' total energy demands by fuel and end-use energy services are scaled up by dividing the estimated totals by 80% to represent total Indiana electricity, natural gas and DFO consumption by end-use energy service, as shown in Table 3-56 (this step is represented by the first right box in Figure 3-10). Based on data displayed in Table 3-56, Indiana residential end-use energy service shares for electricity, natural gas and DFO are estimated and presented in Table 3-57 (this step is represented by the second right box in Figure 3-10). For each fuel type, summing across end-use energy service shares equals 100%. Multiplying end-use energy service shares for electricity, natural gas and DFO in Table 3-57 with the corresponding Indiana residential electricity, natural gas and DFO consumption estimates in Table 3-55 results in Indiana's residential electricity, natural gas and DFO consumption by end-use energy service calibrated to EIA's SEDS.

Table 3-56 Indiana Electricity, Natural Gas and DFO Demand by End-Use Energy Service Estimated from MASIY REDMS Output in Trillion Btu

Demand	Description	Electricity	Natural gas	DFO
RSH	Residential space heating	12.64	113.86	10.97
RSC	Residential space cooling	18.04		
RWH	Residential water heating	7.78	30.42	0.83
RRF	Residential refrigeration	10.25		
RCook	Residential cooking	2.47		
RCD	Residential cloth dryer	4.77		
RFZ	Residential freezer	3.80		
RLT	Residential lighting	9.07		
RDW	Residential dish washer	1.39		
RMisELE	Residential miscellaneous-electricity	28.41		
RMisNGZ	Residential miscellaneous-natural gas		6.19	

Table 3-57 End-use Energy Services Shares for Electricity, Natural Gas and DFO Estimated from MASIY REDMS Output

Demand	Description	Electricity	Natural Gas	DFO
RSH	Residential space heating	12.81%	75.67%	93.01%
RSC	Residential space cooling	18.29%		
RWH	Residential water heating	7.89%	20.21%	6.99%
RRF	Residential refrigeration	10.39%		
RCook	Residential cooking	2.51%		
RCD	Residential cloth dryer	4.84%		
RFZ	Residential freezer	3.85%		
RLT	Residential lighting	9.20%		
RDW	Residential dish washer	1.41%		
RMisELE	Residential miscellaneous-electricity	28.80%		
RMisNGZ	Residential miscellaneous-natural gas		4.11%	

LPG

Indiana residential LPG consumption is split into various end-use energy services through a method referred to as matrix balancing. Matrix balancing is typically applied when the analyst has a set of prior beliefs about the allocations specified in the matrix, but these prior beliefs are not consistent with known values for the sums of the matrix elements across rows and columns. In this case, an algorithm iterates between row and column scaling until the matrix is balanced (Schneider and Zenios, 1990). The following paragraphs describe the process in detail.

Table 3-58 contains data on LPG consumption, which is available on three geographic scales — national level (US), regional level (ENC) and state level (IN). ENC is an acronym for East North Central, which is one of the nine geographic divisions within U.S. officially recognized by the United States Census Bureau. ENC contains Illinois, Indiana, Michigan, Ohio and Wisconsin. According to EIA AEO 2010 reference case Table 4 Residential Sector Key Indicators and Consumption, LPG supplies four end-use energy services — space heating, water heating, cooking and other uses. The category named other uses is referred to as RmisLPG (Residential miscellaneous-LPG) in IN-MARKAL as shown in Table 3-58, which includes LPG consumed by appliances such as outdoor grills and mosquito traps. At regional and state levels, only the total amount of LPG consumption by residential sector is available. Data for ENC is from EIA AEO 2010 reference case Table 3 Energy Consumption by Sector and Source. Data for IN is from EIA SEDS Table 8 Residential Sector Energy Consumption Estimates, Selected Years, 1960-2008, Indiana. The purpose of using matrix balancing is to derive Indiana residential LPG consumption by end-use energy service as highlighted by the green block in Table 3-58 based on available data displayed in the table. The assumption embedded here is that Indiana residential LPG consumption comes from the same four end-use energy services as the national LPG consumption.

Table 3-58 LPG Consumption in Trillion Btu, 2007

Energy service	Description	US	ENC	IN
RSH	Residential space heating	216.02		
RWH	Residential water heating	92.21		
Rcook	Residential cooking	31.19		
RmisLPG	Residential miscellaneous-LPG	142.04		
Total	Total LPG consumption	481.46	108.75	15.50

To do matrix balancing, a table is created first as shown in Table 3-59 based on data in Table 3-58. Cells with blue and yellow shades contain national LPG consumptions by end-use energy service. The three pink cells at the bottom are US residential LPG consumption minus ENC residential LPG consumption, ENC residential LPG consumption minus Indiana residential LPG consumption and Indiana residential LPG consumption respectively. The cell at the bottom right corner is the U.S. total residential LPG consumption, which is equal to the sum across pink cells and the sum of yellow cells as well.

Table 3-59 Table of Residential LPG Consumption Prepared for Matrix Balancing

Energy service	Description	US-ENC	ENC-IN	IN	US total
RSH	Residential space heating	216.02	216.02	216.02	216.02
RWH	Residential water heating	92.21	92.21	92.21	92.21
Rcook	Residential cooking	31.19	31.19	31.19	31.19
RmisLPG	Residential miscellaneous-LPG	142.04	142.04	142.04	142.04
Total	Total LPG consumption	372.71	93.25	15.50	481.46

If no other information regarding LPG consumption at the three geographic scales is available, matrix balancing would be directly performed on Table 3-59. However, data on housing units (HUs), LPG price and heating degree days (HDDs) at the three geographic scales are obtained from the U.S. Census Bureau Population Division, SEDS and AEO 2010, as well as the National Climatic Data Center Historical Climatology Series to capture the differences between the Indiana residential LPG consumption pattern and that of the U.S. as a whole. These data are used to adjust the data in Table 3-59 before matrix balancing is conducted.

Data on HUs, LPG price and HDDS at the three geographic scales are shown in Table 3-60. They are used to create energy indices for the four end-uses of LPG at three geographic scales. The basic idea is that space heating should be proportional to the product of the number of HUs and the number of HDDs, while the other uses of LPG (water heating, cooking, and miscellaneous uses) should be proportional to the number of HUs. For RSH, energy index at each geographic scale is calculated by dividing the multiplication of HUs and HDDs by the LPG price at the corresponding geographic scale. For example, the energy index for RSH at the national level (2.0771E+10 in table 3-61) is equal to 128,132,164 (HUs for US in Table 3-60) × 4,255 (HDDs for US in Table 3-60) ÷ 26.25 (LPG price for US in Table 3-60). For RWH, Rcook and RmisLPG, energy indices for each geographic scale are represented by the HUs at the corresponding geographic scale. For example, the energy index for RWH at national level is equal to 128,132,164 (HU for US in Table 3-60). Energy indices in Table 3-61 are then used to calculate multipliers as shown in Table 3-62 to adjust numbers highlighted in the blue area of Table 3-59. Let E_{ij} denotes the energy index of end-use energy service *i* at geographic scale *j* (data in Table 3-61), where *i* =RSH, RWH, Rcook and RmisLPG, and *j*= US, ENC and IN. Multipliers shown in the columns named “US-ENC”, “ENC-IN” and “IN” in Table 3-62 are calculated based on the following three formulas respectively:

$(E_{i\,US} - E_{i\,ENC})/E_{i\,US}$,

$(E_{i\,ENC} - E_{i\,IN})/E_{i\,US}$, and

$E_{i\,IN} / E_{i\,US}$.

Table 3-60 Data on HUs, LPG Price and HDDs at Three Geographic Scales

	US	ENC	IN
Housing units (HUs)	128,132,164	20,199,028	2,782,638
LPG price	26.25	22.56	23.32
Heating degree days (HDDs)	4,255	6,096	5,521

Table 3-61 Energy Index by End-Use and Geographic Scale

Energy service	Description	US	ENC	IN
RSH	Residential space heating	2.0771E+10	5.4586E+09	6.5879E+08
RWH	Residential water heating	128,132,164	20,199,028	2,782,638
Rcook	Residential cooking	128,132,164	20,199,028	2,782,638
RmisLPG	Residential miscellaneous-LPG	128,132,164	20,199,028	2,782,638

Table 3-62 Multipliers for Table 3-59

Energy service	Description	US-ENC	ENC-IN	IN
RSH	Residential space heating	0.7372	0.2311	0.0317
RWH	Residential water heating	0.8424	0.1359	0.0217
Rcook	Residential cooking	0.8424	0.1359	0.0217
RmisLPG	Residential miscellaneous-LPG	0.8424	0.1359	0.0217

Each data item in the blue area of Table 3-59 has a corresponding multiplier in Table 3-62. Those multipliers change relative values in columns (blue area) of Table 3-59. After applying the multipliers, the adjusted Table 3-59 is referred to as the A matrix as shown in Table 3-63. Summing across columns by end-use energy service matches U.S. total LPG consumption by end-use energy service (numbers displayed in the yellow shade of Table 3-63). But summing across rows for the columns does not yield the column totals that appear in the bottom row of the table.

Table 3-63 A Matrix for Residential LPG Consumption

Energy service	Description	US-ENC	ENC-IN	IN	US End-Use Total
RSH	Residential space heating	159.25	49.92	6.85	216.02
RWH	Residential water heating	77.67	12.53	2.00	92.21
Rcook	Residential cooking	26.27	4.24	0.68	31.19
RmisLPG	Residential miscellaneous-LPG	119.65	19.31	3.08	142.04
Total	Total LPG consumption	372.71	93.25	15.50	481.46

Starting from Table 3-63, iterative column scaling and row scaling are repeated for data shown in the blue shade until the matrix elements match both the specified row sums and column sums respectively. Please refer to Schneider and Zenios (1990) for more details on the scaling algorithm. The balanced matrix is shown in Table 3-64. Estimates of Indiana LPG consumption by end-use energy service through matrix balancing are displayed in the last column of the table.

Table 3-64 Balanced Matrix for Residential LPG Consumption in Trillion Btu, 2007

Energy service	Description	US-ENC	ENC-IN	IN
RSH	Residential space heating	153.83	53.82	8.37
RWH	Residential water heating	76.04	13.70	2.48
Rcook	Residential cooking	25.72	4.63	0.84
RmisLPG	Residential miscellaneous-LPG	117.13	21.10	3.82

Other fuel

As shown in Table 3-55, the other fuel category in the residential sector consists of coal, biomass, solar, geothermal and kerosene. They are all aggregated into space heating based on expert opinion.[10]

[10] Judgment of Dr. Gotham Douglas, director of SUFG

Table 3-65 is a summary of estimates of Indiana residential energy consumption by end-use energy service and fuel derived according to the three approaches described above. They are calibrated to EIA's SEDS data as shown in Table 3-55.

Table 3-65 Indiana Residential Energy Consumption by End-Use Energy Service and Fuel in Trillion Btu, 2007

Energy service	Description	Electricity	Natural gas	DFO	LPG	Other	Total
RSH	Residential space heating	15.14	110.41	2.60	8.37	16.20	152.72
RSC	Residential space cooling	21.62					21.62
RWH	Residential water heating	9.33	29.49	0.20	2.48		41.49
RRF	Residential refrigeration	12.28					12.28
RCook	Residential cooking	2.97			0.84		3.80
RCD	Residential cloth dryer	5.72					5.72
RFZ	Residential freezer	4.55					4.55
RLT	Residential lighting	10.87					10.87
RDW	Residential dish washer	1.66					1.66
RMisELE	Residential miscellaneous-electricity	34.05					34.05
RMisNGZ	Residential miscellaneous-natural gas		6.00				6.00
RMisLPG	Residential miscellaneous-LPG				3.82		3.82
Total		118.20	145.90	2.80	15.50	16.20	298.60

Note that MARKAL requires demand for end-use energy services as inputs to the model, rather than energy demand. In order to derive residential demand for energy services, residential equipment efficiencies are applied to residential energy consumption by energy service and fuel.

Data on equipment efficiency is drawn from AEO 2010 Table 31 Residential Sector Equipment Stock and Efficiency. A few assumptions are made here. For RSC (residential space cooling), it is assumed that 70% of base-year stock in Indiana is central air conditioning equipment and 30% is room air conditioning units.[11] For RLT (residential lighting), we have assumed that 80% of base-year stock is incandescent lighting and 20% is fluorescent lighting. For these two energy services, stock-weighted average efficiencies are applied to the corresponding fuel consumption to calculate demand for energy services. All residential demand for end-use energy services is expressed in PJ per year, except lighting which is expressed in billion lumen years. Indiana residential demand for energy services by fuel is as shown in Table 3-66.

[11] Estimation based on EIA 2009 Residential Energy Consumption Survey (RECS) Table HC7.9 Air Conditioning in Homes in Midwest Region, divisions, and States, 2009.

Table 3-66 Indiana Residential Demand for Energy Services by Fuel, 2007

Energy service	Description	Unit	Electricity	Natural gas	DFO	LPG	Other	Total
RSH	Residential space heating	PJ	15.98	95.68	2.25	6.89	17.09	137.89
RSC	Residential space cooling	PJ	72.98					72.98
RWH	Residential water heating	PJ	8.72	17.57	0.11	1.48		27.88
RRF	Residential refrigeration	PJ	5.35					5.35
RCook	Residential cooking	PJ	3.13			0.88		4.01
RCD	Residential cloth dryer	PJ	6.04					6.04
RFZ	Residential freezer	PJ	2.77					2.77
RLT	Residential lighting	Billion lumen year	9.17					9.17
RDW	Residential dish washer	PJ	1.75					1.75
RMisELE	Residential miscellaneous-electricity	PJ	35.92					35.92
RMisNGZ	Residential miscellaneous-natural gas	PJ		6.33				6.33
RMisLPG	Residential miscellaneous-LPG	PJ				4.03		4.03

In IN_MARKAL, the residential sector is represented with 9 end-use energy services as shown in Table 3-54. Therefore, RMisELE, RCook, RCD and RDW fueled by electricity as shown in Table 3-66 are aggregated into ROE (Residential other appliances-electricity). RmisNGZ in Table 3-66 is renamed as ROG (Residential other appliances-natural gas) and RMisLPG is renamed as ROL (Residential other appliances-LPG) in IN_MARKAL. Aggregated data are shown in columns four through eight in Table 3-67.

In order to derive base year residential demand for energy services that will serve as final inputs to IN_MARKAL, aggregation across fuel types for each end-use energy service is required and results are shown in the last column of Table 3-67.

Table 3-67 IN-MARKAL Residential Demand for Energy Services by Fuel, 2007

Energy service	Description	Unit	Electricity	Natural gas	DFO	LPG	Other	Total
RSH	Residential space heating	PJ	15.98	95.68	2.25	6.89	17.09	137.89
RSC	Residential space cooling	PJ	72.98					72.98
RWH	Residential water heating	PJ	8.72	17.57	0.11	1.48		27.88
RRF	Residential refrigeration	PJ	5.35					5.35
RFZ	Residential freezing	PJ	2.77					2.77
RLT	Residential lighting	Billion lumen year	9.17					9.17
ROE	Residential other appliances - electricity	PJ	46.84					46.84
ROG	Residential other appliances - natural gas	PJ		6.33				6.33
ROL	Residential other appliances - liquefied petroleum gas (LPG)	PJ				4.91		4.91

Projections of residential demand for energy services fueled by electricity, natural gas and DFO are driven by MAISY REDMS outputs. MAISY REDMS provides projections to 2050, which can be aggregated through the process described previously to have annual electricity, natural gas and DFO consumption by end-use energy service to 2050. Before aggregation, energy demand is adjusted to exclude implicit efficiency improvement over time (because efficiency improvements are explicitly factored in to IN-MARKAL). Projections of demand for energy services by fuel keep the same trends as corresponding projections of electricity, natural gas and DFO consumption by end-use energy service from MAISY REDMS outputs.

For end-use energy services fueled by LPG and Other fuel, projections are not available from MAISY REDMS output. Therefore, it is assumed that:

1) RSH served by LPG grows at the same rate as RSH served by natural gas;
2) RWH served by LPG grows at the same rate as RWH served by natural gas;
3) Rcook served by LPG grows at the same rate as Rcook served by natural gas;
4) RMisLPG grows at the same rate as RMisNGZ;
5) RSH served by the Other fuel category grows at the same rate as RSH served by natural gas.

Finally, projections of end-use energy services are aggregated from 12 categories of energy services to 9 categories in IN-MARKAL as described before. Table 3-68 and Figure 3-12 display Indiana demand for residential energy services for the base-year and future periods over the model horizon. Space heating (RSH), space cooling (RSC) and other appliances-electricity (ROE) are the biggest three residential end-use energy service categories as shown in Figure 3-12. Substantial growth for those three categories is observed when compared with the rest of the energy service categories.

Table 3-68 IN-MARKAL Demand for Residential Energy Services

Energy service	Unit	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
RSH	PJ	137.89	135.18	138.33	142.02	145.37	148.83	152.59	157.15	160.90	166.61	171.79	178.47	185.27
RSC	PJ	72.98	74.14	78.19	82.49	86.68	92.22	96.98	102.42	108.22	114.60	121.07	127.78	135.37
RWH	PJ	27.88	27.98	28.96	29.92	30.98	32.27	33.43	34.77	36.17	37.72	39.37	41.09	42.92
RRF	PJ	5.35	5.34	5.45	5.62	5.79	6.02	6.21	6.43	6.68	6.99	7.32	7.66	8.03
RFZ	PJ	2.77	2.73	2.75	2.78	2.82	2.87	2.92	2.97	3.03	3.10	3.19	3.28	3.38
RLT	Billion lumen year	9.17	9.17	9.43	9.70	9.97	10.32	10.71	11.18	11.65	12.23	12.78	13.38	14.02
ROE	PJ	46.84	50.61	54.93	58.95	62.57	66.46	70.17	74.55	78.82	83.21	87.75	93.18	97.60
ROG	PJ	6.33	6.29	6.40	6.53	6.64	6.76	6.88	7.03	7.20	7.34	7.50	7.69	7.89
ROL	PJ	4.91	4.88	4.97	5.07	5.15	5.24	5.34	5.45	5.59	5.69	5.82	5.97	6.12

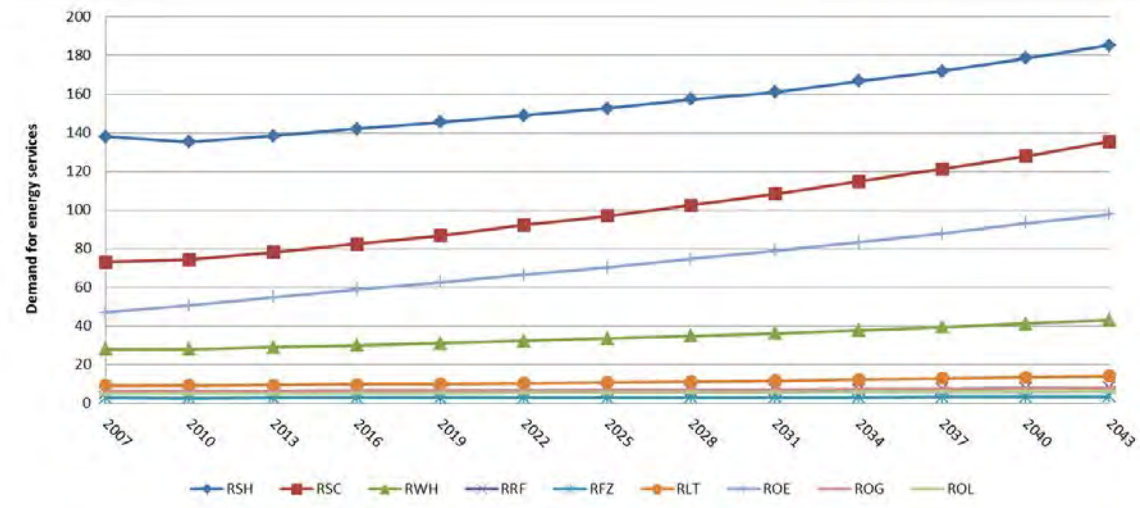

Figure 3-12 IN-MARKAL Demand for Residential Energy Services
Note: RLT is in billion lumen year. The rest of energy services are in PJ.

3.2.3.1.2 Residential Demand Technologies

Demand technologies consume various fuels (energy carriers) to meet demand for end-use energy services. Examples of end-use technologies in the residential sector include air conditioner, freezers, furnaces, water heaters etc.

There are 154 demand technologies in the residential sector, grouped into nine end-use energy service categories. Within each energy service category are different technologies powered by a variety of fuels with different efficiency levels competing to serve the end-use energy service based on costs. The number of technologies in each category is as follows:

RSH	54 technologies
RSC	34 technologies
RSH	30 technologies
RRF	8 technologies
RFZ	5 technologies
RLT	29 technologies
ROE	1 technology
ROG	1 technology
ROL	1 technology

The naming conventions for residential demand technologies are shown in Table 3-69.

Table 3-69 Naming Convention of Residential Demand Technologies

Demand technologies - residential						
Characters						
1	2/3		4/5/6/7/8		9/10	
Sector	Category	Description	Fuel type	Description	Tech type	Description
R	SH	Space heating	E	Electric	RD	Radiator
			N	Natural gas	HP	Heat pump
			K	Kerosene	FR	Furnace
			L	LPG	H	Heater
			D	DFO		
			WD	Wood		
			G	Geothermal		
	SC	Space cooling	R	Room	AC	Air conditioner
			C	Central	HP	Heat pump
			E	Electric		
			G	Geothermal		
			N	Natural gas		
	WH	Water heating	N	Natural gas	WH	Water heater
			E	Electric		
			D	DFO		
			G	Geothermal		
			S	Solar		
	RF	Refrigeration	E	Electric	RF	Refrigerator
	FZ	Freezer	E	Electric	FZ	Freezer
	LT	Lighting	INC	Incandescent		
			CFL	Compact fluorescent		
			HAL	Halogen		
			SSL	Solid state		
			RLINC	Reflector Lamps - incandescent		
			RLCFL	Reflector Lamps - fluorescent		
			RLHAL	Reflector Lamps - halogen		
	OA	Other appliances	ELC	Electric		
			NGA	Natural gas		
			LPG	LPG		

Note: Additional characters may be included to reflect the version of the technology and the model year (the year available for deployment). The naming convention of technology version is shown as below.

Version	Description
BS	Base technology
V1	Version 1
V2	Version 2
V3	Version 3
V4	Version 4
V5	Version 5
TY	Typical
ST	Standard
HE	High efficiency

For demand technologies already installed at the beginning of the modeling horizon (2007), their base year capacities are estimated through working backward from the base-year demand for residential energy services by fuel displayed in columns four through eight of table 3-67.

In the case that an energy service provided by a certain fuel (such as RSH fueled by LPG) is met by a single technology, base-year capacity of the technology is estimated by dividing the corresponding demand for energy service by the capacity factor of the technology. If multiple technologies are used to meet the demand for an energy service provided by a certain type of fuel, the demand for energy service is first shared out among multiple technologies according to shares derived from the most recent Residential Energy Consumption Survey (RECS) (EIA, 2009b), and then divided by the capacity factors of corresponding technologies.

Taking residential space heating as an example, data for the base-year capacity calculation is shown in Table 3-70. Columns two and three display demand for RSH in PJ provided by various fuel types. Values for electricity, natural gas, LPG and DFO are retrieved from Table 3-67. Values for kerosene and wood are taken directly from Table 3-55 and are converted to PJ. Value for other (solar and coal together) combines data on the consumption of solar and coal in Table 3-55 and are converted to PJ. Geothermal is used by heat pumps in Indiana in the base year, and heat pumps serve both space heating and space cooling. Therefore, geothermal consumption in Table 3-55 is split into space heating and space cooling by a ratio equal to 1.28/1, which is specified in EPAUS9r (2012 version) for ENC (R3). The quantity of geothermal used for space heating is included here and is converted to PJ. Columns four and five of Table 3-70 display names and descriptions of residential space heating technologies available in 2007. Column seven contains their corresponding capacity factors, which represent the ratio of the actual output over a period of time to the potential output of a demand technology if it is operated at full nameplate capacity. The cost and performance parameters of those technologies are based on EPAUS9r (2010 version) with costs converted to 2007 dollars. Column six includes shares by technology if multiple technologies use the same type of fuel to serve RSH. For RSH served by electricity, 100% of the demand is satisfied through electric radiant space heaters.[12] For RSH served by natural gas, 95.65% depends on natural gas furnace and the remaining 4.35% uses natural gas radiant heaters. This information is derived from Table HC6.9. Space Heating in U.S. Homes in Midwest Region, Divisions, and States, 2009 of EIA's RECS, as shown in Table 3-71. Data relevant to the share calculation is highlighted with yellow color in the table. There is no data specifically for Indiana from the RECS. Therefore, aggregate data for Indiana and Ohio is used. The share of natural gas furnace is 95.65% (=4.4 (main heating fuel and equipment natural gas central warm-air furnace in Table 3-71) ÷ 4.6 (main heating fuel and equipment natural gas in Table 3-71)) and the share of natural gas radiant is 4.35% (=0.2 (main heating fuel and equipment natural gas steam or hot water system in Table 3-71) ÷ 4.6 (main heating fuel and equipment natural gas in Table 3-71)). Finally, base-year capacity for each technology is calculated through this formula:

Demand for energy service by fuel in PJ (in column 3 of Table 3-70) * technology share (in column 6 of Table 3-70) / capacity factor (in column 7 of Table 3-70). Results are shown in column eight.

[12] Based on the judgment of Dr. Gotham Douglas, director of SUFG

Table 3-70 Residential Space Heating Base-Year Capacity Calculation

	Demand for RSH by fuel						
	Fuel type	Quantity in PJ	Technology name	Technology description	Technology share	Capacity factor	2007 capacity in PJ
RSH	Electricity	15.98	RSHERDBS07	Electric radiant Base.RSH.ELC.07	100.00%	0.16	99.86
			RSHEHPBS07	Electric heat pump Base.RSH.ELC.07	0.00%	0.16	0.00
	Natural gas	95.68	RSHNFRBS07	Natural gas furnace Base.RSH.NGA.07	95.65%	0.16	572.02
			RSHNRDBS07	Natural gas radiant Base.RSH.NGA.07	4.35%	0.16	26.00
	Kerosene	0.74	RSHKFRBS07	Kerosene furnace Base.RSH.KER.07		0.16	4.62
	LPG	6.89	RSHLFRBS07	Liquid gas furnace Base.RSH.LPG.07		0.16	43.03
	DFO	2.25	RSHDFRBS07	Distillate furnace Base.RSH.DST.07		0.16	14.08
	Wood	13.50	RSHWDHBS07	Wood heat Base.RSH.BWD.07		0.16	84.40
	Other (solar and coal)	0.53	RSHOTHBS07	Other RSH technology Base.RSH.OTH.07		0.16	3.30
	Geothermal	1.30	RSHGHPBS07	Geothermal heat pump Base.RSH.ELC.07		0.16	8.14

Table 3-71 Space Heating in U.S. Homes in Midwest Region, Divisions and States in Million Housing Units, 2009

		Midwest Census Region									
			East North Central Census Division					West North Central Census Division			
Space heating	Total U.S. (millions)	Total Midwest	Total East North Central	IL	MI	WI	IN, OH	Total West North Central	MO	IA, MN ND, SD	KS, NE
Main Heating Fuel and Equipment											
Natural Gas...	55.6	17.9	13.1	3.9	3.0	1.6	4.6	4.8	1.2	2.3	1.3
Central Warm-Air Furnace..................	44.3	15.9	11.7	3.2	2.7	1.4	4.4	4.2	1.1	1.9	1.2
For One Housing Unit......................	42.5	15.1	11.0	2.9	2.4	1.4	4.3	4.1	1.1	1.8	1.2
For Two or More Housing Units.......	1.8	0.8	0.7	Q	0.3	Q	Q	0.1	Q	0.1	Q
Steam or Hot Water System...............	6.9	1.7	1.3	0.7	0.3	0.2	0.2	0.4	Q	0.4	Q
For One Housing Unit......................	3.7	0.9	0.7	0.3	Q	0.1	0.2	0.2	Q	0.2	Q
For Two or More Housing Units.......	3.2	0.9	0.6	0.4	Q	Q	N	0.2	Q	0.2	Q
Built-In Room Heater..........................	2.3	0.1	Q	N	N	Q	Q	0.1	Q	Q	Q
Floor or Wall Pipeless Furnace...........	1.2	Q	Q	Q	N	N	N	Q	Q	Q	Q
Other Equipment................................	0.9	0.1	Q	N	Q	N	N	0.1	Q	Q	Q

Notes:

1. Total U.S. includes all primary occupied housing units in the 50 States and the District of Columbia. Vacant housing units, seasonal units, second homes, military housing, and group quarters are excluded.
2. Q = Data withheld either because the Relative Standard Error (RSE) was greater than 50 percent or fewer than 10 households were sampled.
3. N = No cases in reporting sample.

Source: Energy Information Administration, Office of Energy Consumption and Efficiency Statistics, Forms EIA-457 A and C of the 2009 Residential Energy Consumption Survey.

The following paragraphs describe the major parameters used to characterize residential demand technologies in IN_MARKAL. All costs are expressed in millions of 2007 U.S. dollars. Energy quantities are expressed in PJ, with the exception of lighting, which are expressed in billion lumen years.

Availability and Utilization Parameters

CF: Capacity factor is the ratio of the actual output over a period of time to the potential output of a demand technology if it is operated at full nameplate capacity. The values are drawn from the 2010 version of EPAUS9r and are shown as follows:

RSH = 0.16
RSC = 0.15
RWH = 0.10
RRF = 1.00
RFZ = 1.00
RLT = 1.00
ROE = 1.00
ROG = 1.00
ROL = 1.00

IBOND(BD): This parameter specifies a user-defined bound on new investment. Values of BD can be LO (lower bound), UP (upper bound) or FX (fixed bound). Usually, upper bounds on existing technologies are set at zero for all periods to prevent investing into existing technologies. Sometimes, upper bounds of zero are placed on new technologies for certain periods in order to prevent investment into older versions of technologies when newer versions become available.

LIFE: This parameter specifies the lifetime of a technology in years, which are obtained from EPAUS9r.

START: This parameter specifies the year a technology becomes available. Relevant data comes from EPAUS9r.

Efficiency and Cost Parameters

EFF: Efficiency is expressed in terms of the ratio of energy service to the energy input. This is the amount of energy service provided in PJ per PJ of energy input for most cases in the residential sector. Lighting is an exception with EFF specified as billion lumen years of lighting service per PJ of energy input. Data are obtained from EPAUS9r.

INVCOST: Investment cost is specified in millions of 2007 dollars per PJ of capacity. (Lighting is in 2007 million dollars per billion lumens lighting capacity.) Data are obtained from EPAUS9r and are converted to 2007 dollars.

Input and Output Parameters

MA(ENT): This parameter is used when a technology utilizes multiple energy carriers as inputs. MA(ENT) specifies the usage share of each energy carrier. ENT indicates energy carrier.

OUT(DM): This parameter is 1 when the energy activity of the technology contributes to a single end-use energy service. This applies to all demand technologies of residential sector. DM indicates energy service category.

Other MARKAL Parameters

CAPUNIT: This is the parameter used to transform capacity to activity level. The value for all residential technologies is 1.00, because capacity and activity are expressed in the same units.

RESID: This parameter specifies the residual capacity in each model period for technology already installed at the beginning of the modeling horizon (2007). The estimation process of the RESIDs for base-year technologies has been described previously.

3.2.3.1.3 Residential Energy Carriers

Table 3-72 contains the naming conventions for energy going into residential end-use technologies, except for solar. The first three letters represent the sector (RES-residential), the fourth through sixth letters stand for the fuel type and the final two letters indicate the path (EA-after emissions accounting). SOL represents solar energy, which is used with electricity for water heating by a few technologies.

Table 3-72 Residential Sector Energy Carriers

Name	Description
RESELC	Electricity to residential sector
RESNGA	Natural gas to residential sector
RESNGAEA	Natural gas to residential sector after emissions accounting
RESDSL	Diesel to residential sector
RESDSLEA	Diesel to residential sector after emissions accounting
RESKER	Kerosene to residential sector
RESKEREA	Kerosene to residential sector after emissions accounting
RESLPG	LPG to residential sector
RESLPGEA	LPG to residential sector after emissions accounting
RESCOA	Coal to residential sector
RESBIO	Biomass-wood to residential sector
RESBIOEA	Biomass-wood to residential sector after emissions accounting
SOL	Solar energy

3.2.3.2 Commercial Sector

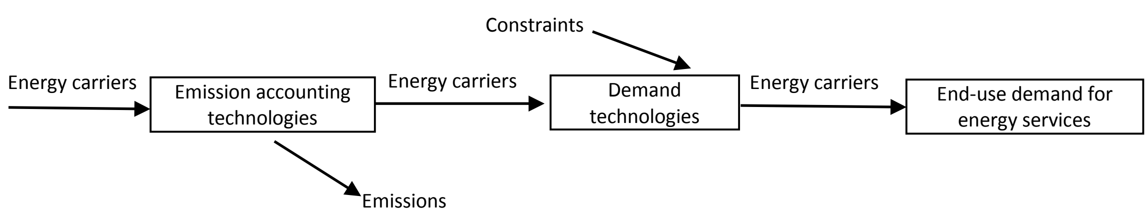

Figure 3-13 Commercial Sector RES

Figure 3-13 is the RES for the commercial sector, which is the same as the residential sector. It consists of emission accounting technologies, end-use demand technologies and end-use demand for energy services.

3.2.3.2.1 Commercial Demand for Energy Services

IN-MARKAL models twelve categories of energy services for the commercial sector. They are shown in Table 3-73.

Table 3-73 Commercial Energy Services Modeled with IN-MARKAL

Name	Description
CSC	Commercial space cooling
COF	Commercial office equipment
CSH	Commercial space heating
CLT	Commercial lighting
CCK	Commercial cooking
CMD	Commercial miscellaneous - diesel
CME	Commercial miscellaneous - electricity
CMN	Commercial miscellaneous - natural gas
CMO	Commercial miscellaneous - other fuel
CRF	Commercial refrigeration
CVT	Commercial ventilation
CWH	Commercial water heating

The method used to derive the commercial base-year demand for various energy services is similar to the residential sector. Beginning with the estimation of energy consumption by energy service and fuel, the corresponding end-use equipment efficiencies are applied to energy consumption to estimate demand for various energy services by fuel. Finally, aggregating across various fuels for each energy service leads to the estimation of the demand for various energy services for the base year as inputs to IN-MARKAL.

To derive commercial energy consumption by energy service and fuel, Indiana commercial sector energy consumption estimates are obtained from the SEDS of EIA, as shown in Table 3-74. Nine categories of fuel are reported in SEDS for the commercial sector, but only four categories are included in IN-MAKAL. Coal, biomass, LPG, motor gasoline, geothermal and kerosene are combined to form the Other fuel category for the commercial sector. Together they constitute 5.68% of commercial energy consumption for 2007.

Table 3-74 Indiana Commercial Energy Consumption Estimates, 2007

				Other						
	Electricity	Natural gas	DFO	Coal	Biomass (wood and waste)	LPG	Motor gasoline	Geothermal	Kerosene	Total
Quantity in trillion Btu	84.5	77.3	5.8	3.5	2.8	1.7	1.4	0.5	0.2	177.7
Percentage	47.55%	43.50%	3.26%	5.68%						100%

Note: DFO is short for distillate fuel oil (diesel); LPG is short for liquefied petroleum oil.

The method used to split commercial fuel (electricity, natural gas and DFO) consumption into various end-use energy services is shown in Figure 3-14. SUFG's MAISY CEDMS (Commercial Energy Demand Model System) outputs for 2007 are used to calculate the end-use energy services shares for each of the 3 fuel categories.

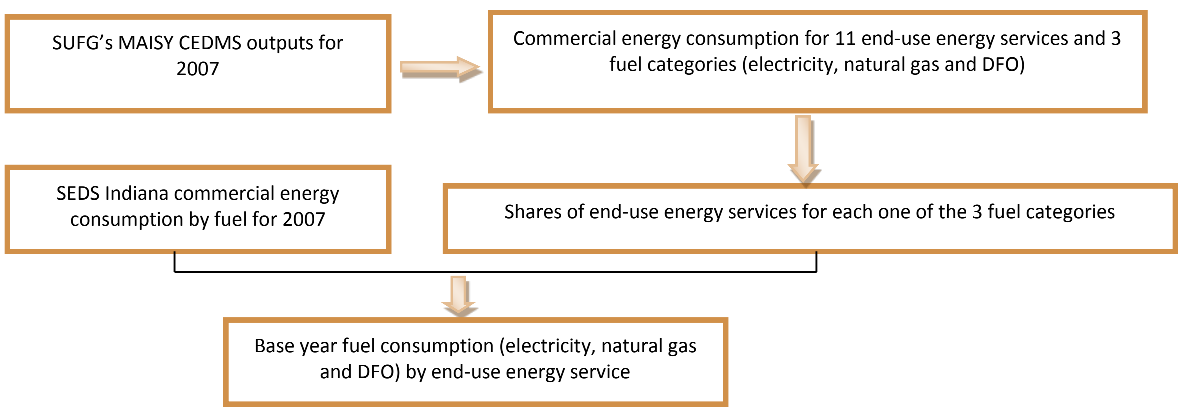

Figure 3-14 Process for Deriving Indiana Commercial Energy Consumption (Electricity, Natural Gas and DFO) by End-Use Energy Services for the Base Year

Figure 3-15 displays the method Jackson Associates used to estimate Indiana electricity, natural gas and DFO consumption by commercial end-use energy services. The eight light blue boxes on the far left hand side of Figure 3-15 display Indiana's major electric utilities. MAISY CEDMS only provides estimates for the five investor-owned utilities. For each one of the five investor-owned utilities, the service area in terms of floor space is divided into 21 business types — office, retail, mall, grocery, refrigerating warehouse, dry warehouse, assembly, educational, restaurant, hospital, nursing home, hotel, religious, college office, college dorm, college other, federal government office, federal government other, state local government office, state local government other and miscellaneous. For each business type, the total energy consumption by fuel is divided by the total floor space in square feet (SF) to derive energy intensities by fuel. Energy intensity for electricity is expressed in MWh/SF and those for natural gas and DFO are expressed in million Btu/SF. Jackson Associates surveyed utility- and business-specific equipment stock saturation by fuel and end-use energy service, which represents the percentage of floor space having a certain category of end-use technologies (for example space heating equipment fueled by electricity). Multiplying saturation by fuel and end-use energy service with the total floor space in SF gives estimates of floor space served by fuel and end-use energy service. Finally, energy demand by fuel and end-use energy service for each business type served by each utility is estimated by multiplying corresponding energy intensities by fuel with total served area in floor space by fuel and end-use energy service.

Aggregating energy demand by fuel and end-use energy service (business type- and utility- specific) across the 21 business types and across the five investor-owned utilities leads to the total energy demand by fuel and end-use energy service for Indiana's five investor-owned utilities. By rule of thumb, the total supply from the 5 investor-owned utilities composes roughly 85% of the total energy consumption of Indiana commercial sector. Therefore, the five investor-owned utilities' total energy demand by fuel and end-use energy service are scaled up by dividing 85% to represent Indiana electricity, natural gas and DFO consumption by end-use energy service, as shown in columns three through five of Table 3-75 (this step is showed by the upper right box in Figure 3-14). In the last column of Table 3-75, consumption for the Other fuel category is displayed, and all of this consumption is aggregated into the end-use energy service named CMO (commercial miscellaneous-other).

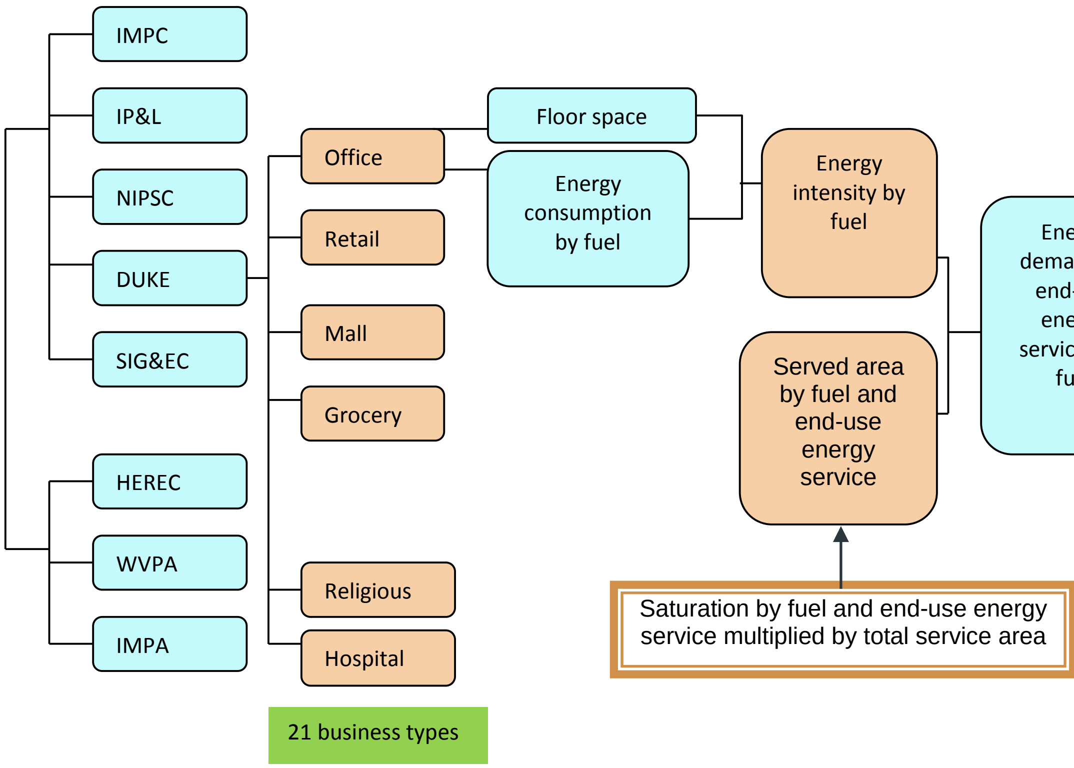

Figure 3-15 MAISY CEDMS Methodology

Table 3-75 Indiana Commercial Energy Consumption by End-Use Energy Service and Fuel in Trillion Btu, 2007

Demand	Description	Electricity	Natural gas	DFO	Other
CSC	Commercial space cooling	13.45	0.22		
COF	Commercial office equipment	7.37			
CSH	Commercial space heating	3.93	69.04	12.27	
CLT	Commercial lighting	35.27			
CCK	Commercial cooking	2.20	5.93		
CME	Commercial miscellaneous- electricity	12.15			
CMN	Commercial miscellaneous- natural gas		3.75		
CMD	Commercial miscellaneous -distillate fuel oil			0.20	
CMO	Commercial miscellaneous- other				10.10
CRF	Commercial refrigeration	7.84			
CVT	Commercial ventilation	8.84			
CWH	Commercial water heating	0.20	14.07	0.92	

Based on data displayed in Table 3-75, Indiana commercial end-use energy service shares for various fuels are estimated and presented in Table 3-76 (this step is represented by the second right box in Figure 3-14). For each fuel, summing across end-use energy services for shares equals 100%.

Table 3-76 Indiana Commercial Energy Consumption Shares by End-Use Energy Service, 2007

Demand	Description	Electricity	Natural gas	DFO	Other
CSC	Commercial space cooling	14.74%	0.24%		
COF	Commercial office equipment	8.08%			
CSH	Commercial space heating	4.30%	74.23%	91.64%	
CLT	Commercial lighting	38.65%			
CCK	Commercial cooking	2.41%	6.38%		
CME	Commercial miscellaneous- electricity	13.32%			
CMN	Commercial miscellaneous- natural gas		4.03%		
CMD	Commercial miscellaneous -distillate fuel oil			1.47%	
CMO	Commercial miscellaneous- other				100.00%
CRF	Commercial refrigeration	8.59%			
CVT	Commercial ventilation	9.69%			
CWH	Commercial water heating	0.21%	15.12%	6.89%	

Applying end-use energy service shares as shown in Table 3-76 to the corresponding Indiana commercial energy consumption by fuel in Table 3-74 results in Indiana's commercial electricity, natural gas, DFO and Other fuel consumption by end-use energy service calibrated to EIA's SEDS, as shown in Table 3-77.

Table 3-77 Indiana Commercial Energy Consumption by Energy Service and Fuel in Trillion Btu Calibrated to EIA SEDS

Energy service	Description	Electricity	NG	DFO	Other
CSC	Commercial space cooling	12.45	0.19	0.00	0.00
COF	Commercial office equipment	6.83	0.00	0.00	0.00
CSH	Commercial space heating	3.64	57.38	5.32	0.00
CLT	Commercial lighting	32.66	0.00	0.00	0.00
CCK	Commercial cooking	2.04	4.93	0.00	0.00
CME	Commercial miscellaneous- electricity	11.25	0.00	0.00	0.00
CMN	Commercial miscellaneous- natural gas	0.00	3.12	0.00	0.00
CMD	Commercial miscellaneous -distillate fuel oil	0.00	0.00	0.08	0.00
CMO	Commercial miscellaneous- other	0.00	0.00	0.00	10.10
CRF	Commercial refrigeration	7.26	0.00	0.00	0.00
CVT	Commercial ventilation	8.19	0.00	0.00	0.00
CWH	Commercial water heating	0.18	11.69	0.40	0.00

The next step is to derive demand for end-use energy services based on energy demand by energy service and fuel. Data on equipment efficiency is draw from AEO

2010 Table 32 Commercial Sector Energy Consumption, Floor Space, and Equipment Efficiency, and is displayed in Table 3-78.

For CSC (commercial space cooling), CSH (commercial space heating), CCK (commercial cooking), CRF (commercial refrigeration) and CWH (commercial water heating), efficiencies are all expressed in Btu energy output/Btu energy input. Demand for energy services are calculated through the following formula:

energy demand in trillion Btu * equipment efficiency * 1.0550 PJ/trillion Btu.

For COF (commercial office equipment), CME (commercial miscellaneous-electricity), CMN (commercial miscellaneous-natural gas), CMD (commercial miscellaneous-distillate fuel oil) and CMO (commercial miscellaneous-other), their efficiencies are treated as 1. Demand for energy services are calculated through the following formula:

energy demand in trillion Btu * 1 * 1.0550 PJ/trillion Btu.

For CLT (commercial lighting), the efficiency is expressed in lumens per watt. Demand for lighting served by electricity is calculated through the following formula:

energy demand in trillion Btu * equipment efficiency in lumens per watt * (1.0E12 Btu/trillion Btu) / (3.4121 Btu/watt hour) / (8760 hours/year) / (1.0E9 lumens/billion lumens).

For CVT (commercial ventilation), the efficiency is expressed in cubic feet per minute per Btu.[13] Demand for ventilation service served by electricity is calculated through the following formula:

[13] In EIA AEO, ventilation efficiency is in terms of cubic feet per minute (cfm) of ventilation air delivered divided by Btu of energy input. To understand this concept, we need to think it in this way. The function of ventilation service is to move air. It does not make sense to say that one Btu energy input into ventilation equipment can move five cubic feet air, because moving five cubic feet air in one minute is so different from moving five cubic feet air in one year in terms of changing air. Also, moving five cubic feet air for a minute is different from moving five cubic feet air for a year. Therefore, ventilation efficiency expressed in cfm of ventilation air delivered per Btu of energy input (for example, 5 cfm/Btu) means that one Btu energy input to ventilation equipment can move the air at the speed of 5 cubic feet per minute for a minute. Later, ventilation service in cfm of ventilation air delivered (for instance 5 cfm) means that 5 cubic feet air delivered at the speed of 5 cfm for a minute.

energy demand in trillion Btu * (1.0E12 Btu/trillion Btu) * equipment efficiency in cubic feet per minute per Btu * / (1.0E12 cubic feet/trillion cubic feet).

Table 3-78 Commercial Sector Equipment Efficiency by Energy Service and Fuel, 2007

Energy service	Description	Unit	Electricity	Natural gas	DFO	Other
CSC	Commercial space cooling	Btu energy output/Btu energy input	2.83	0.85	—	—
COF	Commercial office equipment	—	1.00	—	—	—
CSH	Commercial space heating	Btu energy output/Btu energy input	1.25	0.75	0.79	—
CLT	Commercial lighting	Lumens per watt	43.75	—	—	—
CCK	Commercial cooking	Btu energy output/Btu energy input	0.72	0.52	—	—
CME	Commercial miscellaneous- electricity	—	1.00	—	—	—
CMN	Commercial miscellaneous- natural gas	—	—	1.00		—
CMD	Commercial miscellaneous -distillate fuel oil	—	—	—	1.00	—
CMO	Commercial miscellaneous- other	—	—	—	—	1.00
CRF	Commercial refrigeration	Btu energy output/Btu energy input	1.97	—	—	—
CVT	Commercial ventilation	Cubit feet per minute per Btu	0.54	—	—	—
CWH	Commercial water heating	Btu energy output/Btu energy input	0.99	0.82	0.78	—

Columns four through seven of Table 3-79 display Indiana demand for commercial energy services by fuel for the based year. Aggregating across fuel types for end-use energy services results in demand for commercial energy services for the base year, which serve as input to IN-MARKAL and are displayed in the last column of Table 3-79.

Table 3-79 Indiana Commercial Demand for Energy Services by Fuel, 2007

Energy service	Description	Unit	Electricity	Natural gas	DFO	Other	Total
CSC	Commercial space cooling	PJ	37.16	0.17	0.00	0.00	37.33
COF	Commercial office equipment	PJ	7.21	0.00	0.00	0.00	7.21
CSH	Commercial space heating	PJ	4.81	45.45	4.43	0.00	54.69
CLT	Commercial lighting	Billion lumen year	47.80	0.00	0.00	0.00	47.80
CCK	Commercial cooking	PJ	1.56	2.70	0.00	0.00	4.26
CME	Commercial miscellaneous- electricity	PJ	11.87	0.00	0.00	0.00	11.87
CMN	Commercial miscellaneous- natural gas	PJ	0.00	3.29	0.00	0.00	3.29
CMD	Commercial miscellaneous -distillate fuel oil	PJ	0.00	0.00	0.09	0.00	0.09
CMO	Commercial miscellaneous- other	PJ	0.00	0.00	0.00	10.66	10.66
CRF	Commercial refrigeration	PJ	15.11	0.00	0.00	0.00	15.11
CVT	Commercial ventilation	Trillion cubic feet per minute	4.42	0.00	0.00	0.00	4.42
CWH	Commercial water heating	PJ	0.19	10.16	0.33	0.00	10.68

Projections of commercial demand for energy services fueled by electricity, natural gas and DFO are driven by data from the MAISY CEDMS output. MAISY CEDMS provides projections to 2050, which can be aggregated through the process described previously to obtain annual electricity, natural gas and DFO consumption by end-use energy services to 2050. Before aggregation, energy demand is adjusted to exclude implicit efficiency improvements over time (because efficiency improvements are explicitly taken into consideration in IN-MARKAL). Projections of demand for energy services by fuel keep the same trends as corresponding projections of electricity, natural gas and DFO consumption by end-use energy service from MAISY CEDMS outputs. Finally, aggregating across fuels for various energy services results in projections of the 11 energy services covered in MAISY CEDMS. The growth rate for CMO (commercial miscellaneous-other) is based on data from EIA AEO 2010 Table 3 energy Consumption by Sector and Source. Projections of commercial consumption of coal, biomass, LPG, motor gasoline, geothermal and kerosene for the ENC region are aggregated to be consistent with the Other fuel category identified in Table 3-74. The growth of demand for CMO has the same trend as the aggregated fuel consumption for the Other fuel category. Table 3-80 displays the demand for commercial energy services by period as input to IN-MARKAL. Figure 3-16 displays the data in Table 3-80 graphically.

Table 3-80 IN-MARKAL Demand for Commercial Energy Services

Energy service	Unit	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
CSC	PJ	37.33	37.54	39.15	40.37	41.38	42.42	43.44	45.24	46.91	48.61	50.37	52.23	54.16
COF	PJ	7.21	7.43	8.11	8.76	9.45	10.19	11.06	11.52	11.94	12.38	12.83	13.30	13.79
CSH	PJ	54.69	52.90	53.12	52.61	51.83	51.24	49.85	50.46	50.80	51.52	52.34	52.23	54.16
CLT	Billion lumen year	47.80	46.98	48.39	49.50	50.45	51.47	52.39	54.57	56.59	58.64	60.78	63.03	65.36
CCK	PJ	4.26	4.29	4.50	4.68	4.83	4.97	5.12	5.23	5.31	5.43	5.55	5.66	5.77
CME	PJ	11.87	11.68	12.10	12.40	12.68	12.98	13.36	13.92	14.44	14.96	15.50	16.08	16.67
CMN	PJ	3.29	3.15	3.34	3.49	3.58	3.69	3.80	3.83	3.84	3.89	3.95	3.99	4.02
CMD	PJ	0.09	0.07	0.06	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CMO	PJ	10.66	10.06	10.46	10.45	10.47	10.47	10.48	10.48	10.49	10.49	10.49	10.50	10.50
CRF	PJ	15.11	14.87	15.31	15.59	15.84	16.09	16.34	17.02	17.65	18.29	18.96	19.66	20.39
CVT	Trillion cubic feet per minute	4.42	4.26	4.16	4.06	3.89	3.73	3.67	3.82	3.96	4.10	4.25	4.41	4.57
CWH	PJ	10.68	10.29	10.44	10.28	10.15	10.38	10.52	10.62	10.67	10.80	10.96	11.07	11.18

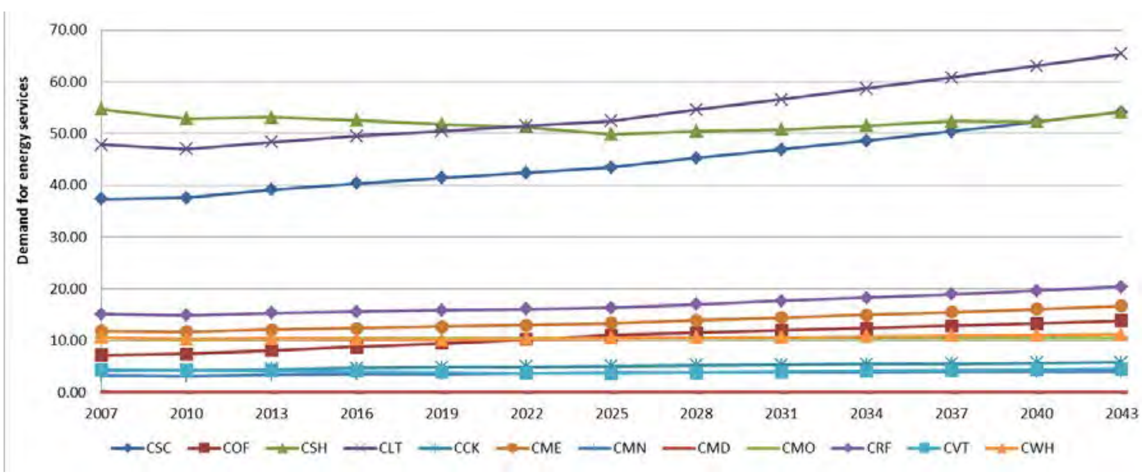

Figure 3-16 IN-MARKAL Demand for Commercial Energy Services

Note: CLT is in billion lumen years. CVT is in trillion cubic feet per minute. The rest of energy services are in PJ.

3.2.3.2.2 Commercial Demand Technologies

There are 162 demand technologies in the commercial sector, grouped into 12 end-use energy service categories. The naming conventions for commercial demand technologies are shown in Table 3-81. Most energy service categories include various technologies powered by a variety of fuels with different efficiency levels. The number of technologies in each energy service category is as follows:

CSC	49 technologies
COF	1 technology
CSH	28 technologies
CLT	29 technologies
CCK	4 technologies
CME	1 technology
CMN	1 technology
CMD	1 technology
CMO	1 technology
CRF	24 technologies
CVT	9 technologies
VWH	14 technologies

Table 3-81 Naming Convention of Commercial Demand Technologies

Demand technologies - commercial				
Characters				
1	2/3		4/5/6/7/8/9/10	
Sector	Category	Description	Fuel/tech type	Description
C	SH	Space heating	AHP	Rooftop air-source heat pump
			GHP	Ground-source heat pump
			ELB	Electric boiler
			ELO	Other electric packaged space heat
			NHP	Natural gas heat pump
			NGF	Natural gas furnace
			NGB	Natural gas boiler
			DSF	Diesel furnace
			DSB	Diesel boiler
	SC	Space cooling	AHP	Rooftop air-source heat pump
			GHP	Ground-source heat pump
			CSC	scroll chiller
			CSW	Screw chiller
			CRC	Reciprocating chiller
			CCC	Centrifugal chiller
			RAC	Rooftop air conditioner
			WAC	Wall/winder room air conditioner
			CAC	Central air conditioner
			NHP	Natural gas heat pump
			NRC	Natural gas rooftop air conditioner
			NCH	Natural gas chiller
	WH	Water heating	SLN	Solar water heater
			EHP	Heat pump water heater
			EWH	Electric water heater
			NGI	Natural gas instantaneous water heater
			NWH	Natural gas water heater
			DWH	Diesel water heater
	VT	Ventilation	CAV	Constant air volume ventilation system
			VAV	Variable air volume ventilation system
	CK	Cooking	ELR	Electric range with 4 burners
			NGR	Natural gas range with 4 burners
	LT	Lighting	INC100	Incandescent, 100W
			INC72	Incandescent, 70W
			CFL	Compact fluorescent
			HAL90	Halogen, 90W
			HAL70	Halogen, 70W
			T12	T12 fluorescent light bulb
			T5	T5 fluorescent light bulb
			T5LB	T5 fluorescent low bay lighting
			T5HB	T5 fluorescent high bay lighting
			T8L	F96T8 fluorescent lighting
			T8	F32T8 fluorescent lighting
			T8MAG	T8 magnetic ballast
			HIDMVHB	High-intensity discharge mercury-vapor lighting, high bay
			HIDMHHB	High-intensity discharge metal-halide lighting, high bay
			HIDHSHB	High-intensity discharge high pressure sodium, high bay
			HIDMVLB	High-intensity discharge mercury-vapor lighting, low bay
			HIDMHLB	High-intensity discharge metal-halide lighting, low bay
			HIDHSLB	High-intensity discharge high pressure sodium, low bay
			LED	Light-emitting diode lamp
	RF	Refrigeration	CEN	Central refrigeration
			WIR	Walk-in refrigeration
			WIR	Walk-in freezer
			RIR	Reach-in refrigeration
			RIF	Reach-in freezer
			ICM	Ice machine
			BVM	Beverage merchandiser
			RVM	Refrigerated vending machine
	OF	Office	ELCBS	Office equipment, electric
	M	Miscellaneous	ELC	Electric
			NGA	Natural gas
			DSL	Diesel
			OTH	Other fuel

Note: Additional characters may be included to reflect the version of the technology and the model year (the year available for deployment). The naming convention of technology version is shown as below.

Version	Description
BS	Base technology
TY	Typical
ST	Standard
HE	High efficiency

For demand technologies already installed at the beginning of the modeling horizon (2007), base year capacities are estimated by working backward from the demand for commercial energy services displayed in the last column of table 3-79.

In the EPAUS9r, shares of various technologies for each end-use energy service for the ENC region (R3 in EPAUS9r) are provided. For each technology, the base year capacity is calculated by multiplying the technology share with the corresponding demand for energy service and dividing the capacity factor of the technology. Taking base year space heating technologies as an example, data relevant to the calculation are shown in Table 3-82. The first column displays Indiana demand for commercial space heating in PJ, which is shown as the third number in the last column of table 3-79. Column two and column three list space heating technologies available in the base year and their descriptions. Columns four and five display corresponding technology shares and capacity factors. Base year capacity for each single technology shown in the last column is derived by multiplying demand for CSH (54.69 PJ) with technology share (in column four) and then dividing the capacity factor (in column five).

Table 3-82 Commercial Space Heating Base-Year Capacity Calculation

Demand for CSH in PJ	Technology name	Technology description	Technology share	Capacity factor	2007 capacity in PJ
54.69	CSHAHPBS07	Electric air source heat pump (rooftop),2007	1.35%	0.28	2.6374
	CSHGHPBS07	Electric ground source heat pump,2007	1.16%	0.28	2.2581
	CSHELBBS07	Electric boiler,2007	5.71%	0.28	11.1632
	CSHELOBS07	Electric other,2007	9.82%	0.28	19.1855
	CSHNHPBS07	Natural gas heat pump,2007	0.22%	0.28	0.4304
	CSHNGFBS07	Natural gas furnace,2007	43.62%	0.28	85.2098
	CSHNGBBS07	Natural gas boiler,2007	36.73%	0.28	71.7417
	CSHDSFBS07	Oil furnace,2007	0.63%	0.28	1.2330
	CSHDSBBS07	Oil boiler,2007	0.75%	0.28	1.4717

The following list describes parameters used to characterize commercial demand technologies in IN_MARKAL. All costs are expressed in millions of 2007 U.S. dollars. Energy quantities are expressed in PJ, with the exception of lighting and ventilation, which are expressed in billion lumen years and trillion cubic feet per minute respectively.

Availability and Utilization Parameters

CF: Capacity factor is the ratio of the actual output over a period of time to the potential output of a demand technology if it is operated at full nameplate capacity. The values are drawn from the 2010 version of EPAUS9r and are shown as follows:

CSC = 0.17
COF = 1.00
CSH = 0.28
CLT = 0.42
CCK = 0.20
CME = 1.00
CMN = 1.00
CMD = 1.00
CMO = 1.00
CRF = 1.00
CVT = 0.85
CWH = 0.44

IBOND(BD): This parameter specifies a user-defined bound on new investment. BD can be set as LO (lower bound), UP (upper bound) or FX (fixed bound). For base year technologies in the commercial sector, their IBOND(UP) for all periods are specified as 0, which means no new investments on base year technologies. Sometimes, upper bounds of zero are placed on new technologies for certain periods in order to prevent investment into older versions of technologies when newer versions become available.

LIFE: This parameter specifies the lifetime of a technology in years, which are also obtained from EPAUS9r.

START: This parameter specifies the year a technology becomes available. Data for specific technology comes from EPAUS9r.

Efficiency and Cost Parameters

EFF: Efficiency is expressed in terms of ratio of energy service to the energy input. For ventilation technologies, efficiencies are expressed in trillion cubic feet per minute ventilation service per PJ energy input. For lighting technologies, efficiencies are expressed in billion lumen years of lighting service per PJ energy input. Efficiencies of all other technologies are expressed in PJ service provided by per PJ energy input. Data are obtained from EPAUS9r.

INVCOST: Investment cost is specified in millions of 2007 dollars per PJ of capacity for technologies under various energy service categories, except lighting technologies and ventilation technologies. Investment costs for lighting technologies are in million 2007 dollars/billion lumens and that for ventilation technologies are in million 2007 dollars/trillion cubic feet per minute capacity. Data are obtained from EPAUS9r and are converted to 2007 dollars.

FIXOM: Fixed operation and maintenance costs are expressed in the same units as investment costs.

Input and Output Parameters

MA(ENT): This parameter specifies the usage share of each energy carrier going into a technology. ENT indicates energy carrier. Taking solar water heater technology as an example, it uses both electricity and solar power to heat water. Forty five percent of the energy input in terms of heat content is solar energy, with MA(COMSOL) specified as 45% (COMSOL is short for solar power used in commercial sector). Fifty five percent of energy input is electricity, with MA(COMELC) specified as 55% (COMELC represents electricity used by commercial sector). Technologies with single fuel input have the MA(ENT) parameter specified as 1.

OUT(DM): This parameter is 1 for all commercial demand technologies. It means the energy activity of a technology contributes to a single end-use energy service. DM indicates energy service category.

Other MARKAL Parameters

RESID: This parameter specifies the residual capacity in each model period for technology already installed at the beginning of the modeling horizon (2007). Estimation of RESIDs for base-year technologies is described previously.

3.2.3.2.3 Commercial Energy Carriers

Table 3-79 contains energy going into the commercial sector end-use technologies. The naming convention is as follows. The first three letters represent the sector (COM-commercial), the fourth through sixth letters stand for the fuel type and the final two letters indicate the path (EA-after emissions accounting).

Table 3-83 Commercial Sector Energy Carriers

Name	Description
COMELC	Electricity to commercial Sector
COMNGA	Natural gas to commercial sector
COMNGAEA	Natural gas to commercial sector after emissions accounting
COMDSL	Diesel to commercial sector
COMDSLEA	Diesel to commercial sector after emissions accounting
COMLPGEA	LPG to commercial sector
COMLPG	LPG to commercial sector after emissions accounting
COMOTH	Other fuels to commercial sector
COMSOL	Solar to commercial sector

3.2.3.3 Industrial Sector

The industrial sector of IN-MARKAL has a three-layer structure consisting of one end-use demand layer, one demand technology layer and one process technology layer, as shown in Figure 3-17. Unlike the residential and commercial sectors, demand for end-use energy services in the industrial sector is categorized into 6 sub-sectors, with each sub-sector having seven end-uses consuming energy; and the energy demand of each end-use can be met by one or multiple fuels. With only one demand technology available for each sub-sector, various industrial demand technologies do not compete with each other; instead process technologies with different fuels and efficiency levels are chosen based on a least cost criterion to meet the energy demand for each end-use in each sub-sector. Emissions are counted by fuel, and emission factors are placed on process technologies. Constraints are assigned to process technologies to control the energy portfolio for each end-use of each sub-sector based on 2007 data.

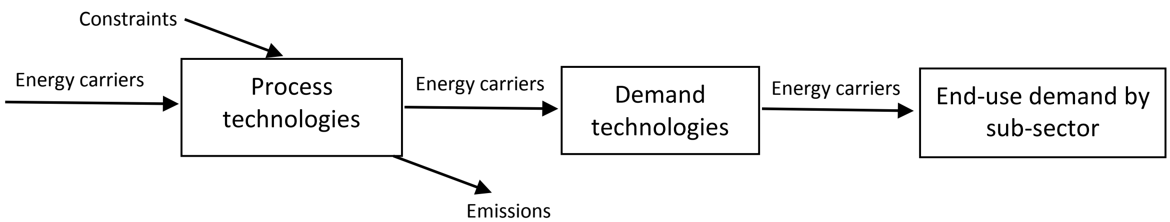

Figure 3-17 Industrial Sector RES

3.2.3.3.1 Industrial Demand for Energy Services

IN-MARKAL models 6 sub-sectors for the industrial sector, as shown in Table 3-84.

Table 3-84 Sub-Sectors Modeled in the Industrial Sector of IN-MARKAL

Name	Description
IOD	Other durables
IOND	Other non-durables
IPM	Primary metals
ITE	Transportation equipment
IO	Other industries
IXNONM	Non-manufacturing

To derive base-year industrial demand for energy services by sub-sector, base-year industrial energy consumption by industry and fuel is estimated first. Indiana industrial fuel consumption is split into various industries through matrix balancing as described in detail in Section 3.2.3.1.1. Table 3-85 contains data on industrial energy consumption available at three geographic scales —national level (US), regional level (ENC) and state level (IN) for nine fuel categories. National data are retrieved from EIA

AEO 2010 Tables 34 through 44. ENC data are obtained from EIA AEO 2010 Table 3 and Indiana data are obtained from SEDS CT6. Industrial sector is composed of 20 industries. Industrial energy consumption by fuel and industry is available at the national level. However, at regional and state levels, only energy consumption by fuel is available. The purpose of using matrix balancing is to derive Indiana industrial energy consumption by fuel and industry as the area highlighted by the green color in Table 3-85 from available data.

To do matrix balancing, a table is created first for each fuel with data drawn from Table 3-85 (Industrial electricity consumption is chosen as an example and is shown in Table 3-86). Cells with blue and yellow shades contain national electricity consumption by industry. The three pink cells at the bottom display US industrial electricity consumption minus ENC industrial electricity consumption, ENC industrial electricity consumption minus Indiana industrial electricity consumption and Indiana industrial electricity consumption respectively. The cell at the bottom right corner is the U.S. total industrial electricity consumption, which is equal to the sum across pink cells and the sum of yellow cells as well.

Table 3-85 Industrial Fuel Consumption in Trillion Btu, 2007

	US								
Industry	ELC	NGA	DFO	LPG	RFO	OP	Coal	REN	GSL
Refining industry	160.51	1127.58	2.45	9.59	11.59	2271.44	62.42	0.00	0.00
Food industry	249.75	584.15	18.79	4.88	6.20	0.00	190.79	49.87	0.00
Paper industry	201.49	412.04	12.10	3.83	95.56	19.11	247.07	1102.46	0.00
Bulk chemical industry heat and power	502.35	1709.07	8.77	62.00	82.69	369.89	208.43	0.06	0.00
Bulk chemical industry feedstock	0.00	560.26		1973.89	0.00	1306.55	0.00	0.00	0.00
Cement industry	45.93	22.67	11.86	0.00	1.11	92.86	252.03	0.00	0.00
Glass industry	41.00	145.75	20.86	0.00	2.27	0.00	0.00	0.00	0.00
Iron and steel industry	207.43	427.93	5.65	0.00	20.06	76.94	713.52	4.43	0.00
Aluminum industry	184.03	125.56	0.76	0.76	0.03	38.01	0.00	7.08	0.00
Fabricated metal product consumption	166.72	195.45	3.20	1.90	2.51	0.00	4.10	0.00	0.00
Machinery consumption	90.26	75.88	0.74	1.12	0.00	0.00	2.65	0.00	0.00
Computers consumption	120.28	63.63	1.08	0.52	1.02	0.00	12.38	0.01	0.00
Transportation equipment consumption	167.20	175.90	1.51	1.65	8.80	0.00	5.49	0.00	0.00
Electrical equipment consumption	48.55	47.52	0.68	0.71	0.00	69.83	0.00	0.04	0.00
Wood products consumption	77.05	41.86	7.69	3.73	0.00	0.00	1.29	210.04	0.00
Plastics consumption	174.47	111.55	0.89	4.18	6.55	0.00	15.84	0.01	0.00
Balance of manufacturing consumption	560.27	764.10	30.65	8.76	25.68	60.26	161.35	22.96	0.00
Agriculture	138.27	85.90	515.96	88.48	0.65	0.00	0.00	21.12	164.48
Construction	102.83	234.56	450.25	0.00	0.00	1183.52	0.00	0.00	142.03
Mining	216.52	1804.34	120.54	0.00	0.02	0.00	10.86	2.26	15.20
Total	3454.90	8715.69	1214.41	2166.00	264.74	5488.41	1888.23	1420.34	321.71

	ENC								
Industry	ELC	NGA	DFO	LPG	RFO	OP	Coal	REN	GSL
Refining industry									
Food industry									
Paper industry									
Bulk chemical industry heat and power									
Bulk chemical industry feedstock									
Cement industry									
Glass industry									
Iron and steel industry									
Aluminum industry									
Fabricated metal product consumption									
Machinery consumption									
Computers consumption									
Transportation equipment consumption									
Electrical equipment consumption									
Wood products consumption									
Plastics consumption									
Balance of manufacturing consumption									
Agriculture									
Construction									
Mining									
Total	730.00	1158.71	172.14	98.52	18.93	774.63	721.83	143.32	53.00

	IN								
Industry	ELC	NGA	DFO	LPG	RFO	OP	Coal	REN	GSL
Refining industry									
Food industry									
Paper industry									
Bulk chemical industry heat and power									
Bulk chemical industry feedstock									
Cement industry									
Glass industry									
Iron and steel industry									
Aluminum industry									
Fabricated metal product consumption									
Machinery consumption									
Computers consumption									
Transportation equipment consumption									
Electrical equipment consumption									
Wood products consumption									
Plastics consumption									
Balance of manufacturing consumption									
Agriculture									
Construction									
Mining									
Total	170.60	278.80	36.10	8.90	2.00	130.00	297.00	25.00	13.20

Note: ELC-electricity, NGA-natural gas, DFO-distillate fuel oil (diesel), LPG-liquefied petroleum gas, RFO-residual fuel oil, OP-other petroleum (includes lubricants, petroleum coke, miscellaneous petroleum products, petrochemical feedstock, asphalt and road oil), REN-renewables, GSL-gasoline.

Table 3-86 Table of Industrial Electricity Consumption Prepared for Matrix Balancing

Industry	US-ENC	ENC-IN	IN	US total
Refining industry	160.51	160.51	160.51	160.51
Food industry	249.75	249.75	249.75	249.75
Paper industry	201.49	201.49	201.49	201.49
Bulk chemical industry heat and power	502.35	502.35	502.35	502.35
Bulk chemical industry feedstock	0.00	0.00	0.00	0.00
Cement industry	45.93	45.93	45.93	45.93
Glass industry	41.00	41.00	41.00	41.00
Iron and steel Industry	207.43	207.43	207.43	207.43
Aluminum industry	184.03	184.03	184.03	184.03
Fabricated metal product consumption	166.72	166.72	166.72	166.72
Machinery consumption	90.26	90.26	90.26	90.26
Computers consumption	120.28	120.28	120.28	120.28
Transportation equipment consumption	167.20	167.20	167.20	167.20
Electrical equipment consumption	48.55	48.55	48.55	48.55
Wood products consumption	77.05	77.05	77.05	77.05
Plastics consumption	174.47	174.47	174.47	174.47
Balance of manufacturing consumption	560.27	560.27	560.27	560.27
Agriculture	138.27	138.27	138.27	138.27
Construction	102.83	102.83	102.83	102.83
Mining	216.52	216.52	216.52	216.52
Total	2724.90	559.40	170.60	3454.90

Data on industrial employment by industry at the three geographic scales (as shown in Table 3-87) are used to represent energy indices by industry and geographic scale in order to capture the differences between Indiana industrial fuel consumption pattern and that of the U.S. as a whole. The basic idea is that fuel consumption should be proportional to employment within each industry. Energy indices in Table 3-87 are then used to calculate multipliers as shown in Table 3-88 to adjust numbers highlighted in the blue area of Table 3-86 (The same multipliers are applied to other fuels in the industrial sector as well). Let E_{ij} denotes the energy index of industry *i* at geographic scale *j* (data in Table 3-87), where *i* = refining industry, food industry, paper industry, bulk chemical industry heat and power, bulk chemical industry feedstock, cement industry, glass industry, iron and steel industry, aluminum industry, fabricated metal product consumption, machinery consumption, computers consumption, transportation equipment consumption, electrical equipment consumption, wood products consumption, plastics consumption, balance of manufacturing consumption, agriculture, construction and mining, and j = US, ENC and IN. Multipliers shown in the columns named "US-ENC", "ENC-IN" and "IN" in Table 3-88 are calculated based on the following three formulas respectively:

$(E_{i\ US} - E_{i\ ENC})/E_{i\ US}$,

$(E_{i\ ENC} - E_{i\ IN})/E_{i\ US}$, and

$E_{i\ IN} / E_{i\ US}$.

Table 3-87 Data on Employment by Industry and Geographic Scale

Industry	US	ENC	IN
Refining industry	117,000	15,445	3,479
Food industry	1,540,200	265,642	33,648
Paper industry	458,900	110,007	11,430
Bulk chemical industry heat and power	881,400	173,635	32,271
Bulk chemical industry feedstock	881,400	173,635	32,271
Cement industry	517,300	89,320	14,943
Glass industry	517,300	89,320	14,943
Iron and steel Industry	462,300	166,773	45,990
Aluminum Industry	462,300	166,773	45,990
Fabricated metal product consumption	1,611,800	454,145	60,244
Machinery consumption	1,230,600	367,076	45,520
Computers consumption	1,291,300	130,958	20,705
Transportation equipment consumption	1,726,400	561,845	130,913
Electrical equipment consumption	442,100	109,244	11,308
Wood products consumption	568,800	86,520	19,389
Plastics consumption	780,900	225,953	40,741
Balance of manufacturing consumption	757,600	136,332	32,895
Agriculture	2,664,000	391,899	64,421
Construction	11,462,000	1,475,693	224,933
Mining	1,013,300	70,643	9,943

Source: Bureau of Economic Analysis (BEA) Regional Economic Accounts Employment Data, 2007

Table 3-88 Multipliers for Data in Table 3-86

Industry	US-ENC	ENC-IN	IN
Refining industry	0.8680	0.1023	0.0297
Food industry	0.8275	0.1506	0.0218
Paper industry	0.7603	0.2148	0.0249
Bulk chemical industry heat and power	0.8030	0.1604	0.0366
Bulk chemical industry feedstock	0.8030	0.1604	0.0366
Cement industry	0.8273	0.1438	0.0289
Glass industry	0.8273	0.1438	0.0289
Iron and steel Industry	0.6393	0.2613	0.0995
Aluminum Industry	0.6393	0.2613	0.0995
Fabricated metal product consumption	0.7182	0.2444	0.0374
Machinery consumption	0.7017	0.2613	0.0370
Computers consumption	0.8986	0.0854	0.0160
Transportation equipment consumption	0.6746	0.2496	0.0758
Electrical equipment consumption	0.7529	0.2215	0.0256
Wood products consumption	0.8479	0.1180	0.0341
Plastics consumption	0.7107	0.2372	0.0522
Balance of manufacturing consumption	0.8200	0.1365	0.0434
Agriculture	0.8529	0.1229	0.0242
Construction	0.8713	0.1091	0.0196
Mining	0.9303	0.0599	0.0098

After applying multipliers, the adjusted Table 3-86 is referred to as the A matrix as shown in Table 3-89. Iterative column scaling and row scaling are performed for data shown in the blue shade of Table 3-89 until the matrix elements match both the specified row sums and column sums respectively. The balanced matrix is shown in Table 3-90. Estimates of Indiana electricity consumption by industry through matrix balancing are displayed in the last column of the table.

Table 3-89 A Matrix for Industrial Electricity Consumption

Industry	US-ENC	ENC-IN	IN	US total
Refining industry	139.32	16.42	4.77	160.51
Food industry	206.67	37.62	5.46	249.75
Paper industry	153.19	43.28	5.02	201.49
Bulk chemical industry heat and power	403.39	80.57	18.39	502.35
Bulk chemical industry feedstock	0.00	0.00	0.00	0.00
Cement industry	38.00	6.60	1.33	45.93
Glass industry	33.92	5.90	1.18	41.00
Iron and steel Industry	132.60	54.20	20.64	207.43
Aluminum Industry	117.64	48.08	18.31	184.03
Fabricated metal product consumption	119.74	40.74	6.23	166.72
Machinery consumption	63.34	23.59	3.34	90.26
Computers consumption	108.09	10.27	1.93	120.28
Transportation equipment consumption	112.79	41.74	12.68	167.20
Electrical equipment consumption	36.55	10.75	1.24	48.55
Wood products consumption	65.33	9.09	2.63	77.05
Plastics consumption	123.98	41.38	9.10	174.47
Balance of manufacturing consumption	459.45	76.49	24.33	560.27
Agriculture	117.93	17.00	3.34	138.27
Construction	89.59	11.22	2.02	102.83
Mining	201.43	12.97	2.12	216.52
Total	2724.90	559.40	170.60	3454.90

Table 3-90 Balanced Matrix for Industrial Electricity Consumption in Trillion Btu, 2007

Industry	US-ENC	ENC-IN	IN
Refining industry	139.25	15.60	5.65
Food industry	207.36	35.90	6.49
Paper industry	154.10	41.41	5.98
Bulk chemical industry heat and power	403.82	76.71	21.82
Bulk chemical industry feedstock	0.00	0.00	0.00
Cement industry	38.06	6.29	1.58
Glass industry	33.98	5.62	1.41
Iron and steel Industry	131.86	51.25	24.32
Aluminum Industry	116.98	45.47	21.58
Fabricated metal product consumption	120.35	38.95	7.42
Machinery consumption	63.71	22.56	3.98
Computers consumption	108.22	9.78	2.29
Transportation equipment consumption	112.58	39.62	15.00
Electrical equipment consumption	36.78	10.29	1.48
Wood products consumption	65.29	8.64	3.11
Plastics consumption	124.23	39.43	10.81
Balance of manufacturing consumption	458.82	72.65	28.79
Agriculture	118.11	16.19	3.97
Construction	89.74	10.69	2.40
Mining	201.65	12.35	2.52
Total	2724.90	559.40	170.60

Matrix balancing is performed for each one of the nine fuel categories shown in table 3-85. Estimates of Indiana base year industrial energy consumption by fuel and industry are summarized in Table 3-91.

Table 3-91 Estimates of Indiana Industrial Energy Consumption by Fuel and Industry in Trillion Btu, 2007

Industry	ELC	NGA	DFO	LPG	RFO	OP	Coal	REN	GSL
Refining industry	5.65	31.41	0.10	0.03	0.06	58.40	5.91		
Food industry	6.49	12.15	0.55	0.01	0.02		13.28	0.78	
Paper industry	5.98	9.99	0.40	0.01	0.46	0.42	19.03	20.52	
Bulk chemical industry heat and power	21.82	59.85	0.43	0.26	0.56	11.81	23.44	0.00	
Bulk chemical industry feedstock		19.62		8.41		41.72			
Cement industry	1.58	0.62	0.46		0.01	2.33	22.89		
Glass industry	1.41	4.00	0.80		0.01				
Iron and steel Industry	24.32	42.49	0.73		0.44	6.83	185.63	0.35	
Aluminum Industry	21.58	12.47	0.10	0.01	0.00	3.38		0.56	
Fabricated metal product consumption	7.42	7.20	0.16	0.01	0.02		0.46		
Machinery consumption	3.98	2.78	0.04	0.01			0.29		
Computers consumption	2.29	0.95	0.02	0.00	0.00		0.66	0.00	
Transportation equipment consumption	15.00	13.22	0.15	0.02	0.14		1.14		
Electrical equipment consumption	1.48	1.19	0.02	0.00	0.00	1.57		0.00	
Wood products consumption	3.11	1.34	0.35	0.01			0.14	5.00	
Plastics consumption	10.81	5.73	0.06	0.03	0.07		2.39	0.00	
Balance of manufacturing consumption	28.79	31.49	1.76	0.04	0.20	2.28	21.38	0.71	
Agriculture	3.97	1.96	16.62	0.24	0.00			0.36	7.57
Construction	2.40	4.32	11.78			20.07			5.34
Mining	2.52	16.32	1.58		0.00		0.36	0.01	0.29

The twenty industries as shown in Table 3-91 are then aggregated into six categories as shown in Table 3-84 for use in IN-MARKAL. Refining and mining industries (shown in Table 3-91) are removed from the industrial sector because refined products supply and coal supply are modeled directly in the resource supply sector as described in Sector 3.2.1. Other durables (IOD) sub-sector in IN-MARKAL is an aggregation of the following industries: cement, glass and wood products consumption. The other non-durables (IOD) sub-sector is an aggregation of the following industries: food, paper, bulk chemical heat and power, bulk chemical feedstock and balance of manufacturing consumption. The primary metals (IPM) sub-sector is an aggregation of iron and steel and aluminum industries. The transportation equipment consumption industry as shown in Table 3-91 is renamed as the transportation equipment (ITE) sub-sector in IN-MARKAL. The other industries (IO) sub-sector in IN-MARKAL is an aggregation of the following industries: computers consumption, electrical equipment consumption, fabricated metal product consumption, machinery consumption and plastics consumption. Finally, the non-manufacturing (IXNONM) sub-sector is an aggregation of agriculture and construction. Estimates of Indiana industrial fuel consumption for the six sub-sectors in trillion Btu are shown in Table 3-92. Data in Table 3-92 are then converted to PJ and aggregated across fuel types for each sub-sector to serve as base year industrial demand for energy services specified in IN-MARKAL (shown in the last column of Table 3-93). Please note that gasoline consumption from the IXNONM sub-sector is not aggregated into the total fuel consumption from the sub-sector because it is handled separately in the transportation sector as off-highway energy demand.

Table 3-92 Estimates of Indiana Industrial Fuel Consumption for Six Sub-Sectors in Trillion Btu, 2007

Name	Description	ELC	NGA	DFO	LPG	RFO	OP	Coal	REN	GSL
IOD	Other durables	6.0925	5.9673	1.6050	0.0142	0.0178	2.3317	23.0262	5.0039	0.0000
IOND	Other non-durables	63.0883	133.1064	3.1372	8.7446	1.2517	56.2267	77.1299	22.0064	0.0000
IPM	Primary metals	45.8972	54.9507	0.8307	0.0105	0.4360	10.2081	185.6302	0.9170	0.0000
ITE	Transportation equipment	14.9998	13.2224	0.1506	0.0166	0.1401	0.0000	1.1442	0.0000	0.0000
IO	Other industries	25.9825	17.8450	0.3027	0.0452	0.0907	1.5678	3.7949	0.0011	0.0000
IXNONM	Non-manufacturing	6.3648	6.2771	28.3966	0.2377	0.0028	20.0682	0.0000	0.3568	12.9100

Table 3-93 Estimates of Indiana Industrial Fuel Consumption for Six Sub-Sectors in PJ, 2007

Name	Description	ELC	NGA	DFO	LPG	RFO	OP	Coal	REN	GSL	Total
IOD	Other durables	6.4279	6.2958	1.6934	0.0150	0.0188	2.4601	24.2941	5.2794	0.0000	46.4845
IOND	Other non-durables	66.5620	140.4352	3.3100	9.2260	1.3206	59.3225	81.3767	23.2181	0.0000	384.7711
IPM	Primary metals	48.4243	57.9763	0.8764	0.0111	0.4600	10.7702	195.8510	0.9674	0.0000	315.3368
ITE	Transportation equipment	15.8257	13.9505	0.1589	0.0175	0.1478	0.0000	1.2072	0.0000	0.0000	31.3076
IO	Other industries	27.4131	18.8276	0.3194	0.0477	0.0957	1.6541	4.0039	0.0012	0.0000	52.3627
IXNONM	Non-manufacturing	6.7152	6.6227	29.9602	0.2507	0.0030	21.1731	0.0000	0.3765	13.6208	65.1014

Projections of Indiana industrial energy consumption for the six sub-sectors are aggregated from projections of Indiana industrial energy consumption for each industry displayed in Table-3-91 (excluding refining industry and mining industry). The projections are driven by Indiana Gross State Product (GSP) Long-Range Projection 2011 produced by the Center for Econometric Model Research (CEMR) located at Indiana University. Table 3-94 is the list of projection drivers by industry. Aggregations from industry to sub-sectors in IN-MARKAL performed here are consistent with aggregations done for the base-year data described previously. Indiana industrial energy demand for the six sub-sectors expressed in PJ is shown in Table 3-95, which serves as input to IN-MARKAL. The data are also exhibited with Figure 3-18.

Table 3-94 Industrial Energy Consumption Projection Drivers

Sub-industry	Projection driver
Food industry	CEMR's Indiana GSP forecasting for other non-durables industry
Paper industry	CEMR's Indiana GSP forecasting for other non-durables industry
Bulk chemical industry heat and power	CEMR's Indiana GSP forecasting for other non-durables industry
Bulk chemical industry feedstock	CEMR's Indiana GSP forecasting for other non-durables industry
Cement Industry	CEMR's Indiana GSP forecasting for other durables industry
Glass Industry	CEMR's Indiana GSP forecasting for other durables industry
Iron and Steel Industry	CEMR's Indiana GSP forecasting for primary metal (including steel) industry
Aluminum Industry	CEMR's Indiana GSP forecasting for primary metal (including steel) industry
Fabricated metal product consumption	CEMR's Indiana GSP forecasting for fabricated metal industry
Machinery consumption	CEMR's Indiana GSP forecasting for non-electric machinery industry
Computers consumption	CEMR's Indiana GSP forecasting for computer and electronic products industry
Transportation equipment consumption	CEMR's Indiana GSP forecasting for transportation equipment industry including autos & parts
Electrical equipment consumption	CEMR's Indiana GSP forecasting for electric equipment industry
Wood products consumption	CEMR's Indiana GSP forecasting for other durables industry
Plastics consumption	CEMR's Indiana GSP forecasting for plastic products industry
Balance of manufacturing consumption	CEMR's Indiana GSP forecasting for other non-durables industry
Agriculture	CEMR's Indiana GSP forecasting for agricultural
Construction	CEMR's Indiana GSP forecasting for construction

Table 3-95 IN-MARKAL Demand for Industrial Energy Services by Sub-Industry

Name	Description	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
IOD	Other durables	46.4845	42.8642	47.2630	52.5430	56.4248	59.9007	63.2629	66.9429	70.6102	74.6020	78.8195	83.2754	87.9833
IOND	Other non-durables	384.7711	475.3411	515.4477	570.8003	612.1450	644.3704	672.5747	702.3961	732.3202	764.6403	798.3868	833.6226	870.4136
IPM	Primary metals	315.3368	240.0255	252.0148	275.2458	291.3553	304.9048	317.4359	331.1192	344.2862	358.5250	373.3526	388.7935	404.8730
ITE	Transportation equipment	31.3076	25.4089	30.4311	36.3788	42.1847	48.3821	55.2255	63.1824	72.0805	82.3267	94.0294	107.3956	122.6618
IO	Other industries	52.3627	44.3903	49.7174	57.3714	64.2020	71.2141	78.8074	87.6430	97.4693	108.1913	120.0928	133.3034	147.9673
IXNONM	Non-manufacturing	65.1014	61.4635	65.5718	73.0138	79.9714	87.0128	94.3873	102.5847	111.2250	120.7262	131.0390	142.2327	154.3827

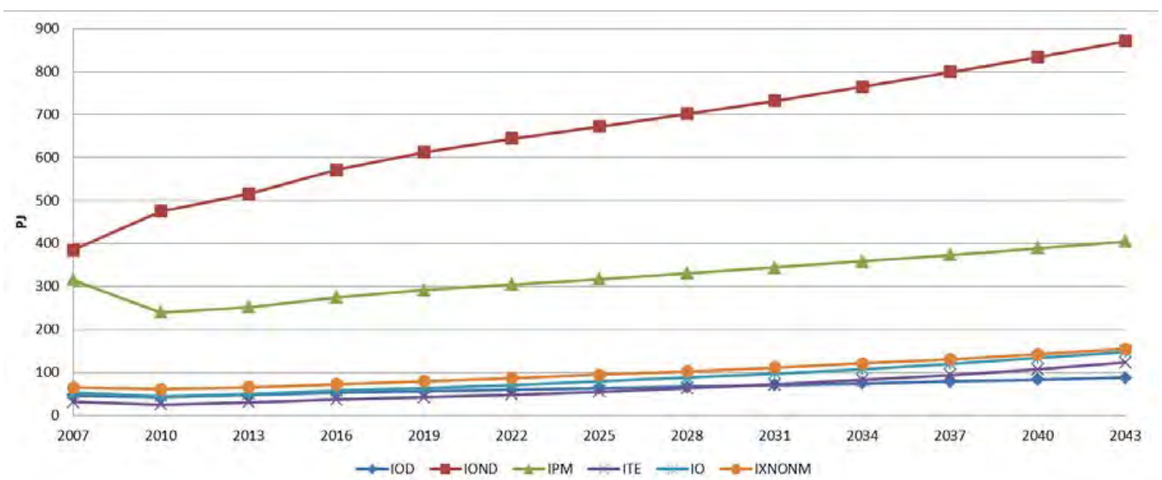

Figure 3-18 IN-MARKAL Demand for Industrial Energy Services

3.2.3.3.2 Industrial Process and Demand Technologies

Industrial process technologies

Except the IXNONM sub-sector, each one of the rest of the five sub-sectors in the industrial sector has seven end-uses powered by various fuels. Those seven end-uses provide steam, process heat, machine drive, electro-chemical process, feedstock, other heat, and other demand respectively to satisfy the total energy demand for each sub-sector. Each end-use of each sub-sector is represented by a group of process technologies that differ by fuel. The naming conventions for those process technologies are shown in Table 3-96.

Table 3-96 Naming Convention of Industrial Process Technologies

Process technologies - industrial						
Characters						
1	2/3/4		5		6/7/8/9	
Sector	Sub-sector	Description	End-use	Description	Fuel/tech type	Description
I	OND	Other non-durables	B	Steam (boiler)	COA	Coal
	PM	Primary metals	P	Process heat	DST	Distillate fuel oil (diesel)
	TE	Transportation equipment	M	Machine drive	RFL	Residual fuel oil
	OD	Other durables	E	Electro-chemical	NGA	Natural gas
	O	Other industries	F	Feedstock	LPG	Liquefied petroleum gas
			O	Other heat	ELC	Electricity
			Y	Other demand (facility uses)	PFS	Petrochemical feedstock
					SNGA	Super natural gas
					OTH	Other petroleum
					BIO	Renewables

Note: Additional characters may be included to reflect the model year.

For process technologies already installed in 2007, base-year capacities are estimated by working backward from the base-year industrial energy consumption by fuel and sub-sector as shown in Table 3-93. Because industrial CHP technologies are separately modeled from the seven end-uses, steam (in terms of energy content) produced by CHP technologies to meet industrial energy demand are subtracted from the industrial energy consumption by fuel and sub-sector reported in Table 3-93 and electricity (in terms of energy content) provided by CHP technologies is added to electricity consumption by sub-sector[14] before base-year industrial energy consumption is split into the seven end-uses for each fuel of each sub-sector.

To estimate steam and electricity produced from industrial CHP technologies, data on combined heat and power units located in Indiana are retrieved from ICF International (2014). They are aggregated by sub-sector, fuel and prime-mover, and are displayed in Table 3-97. Based on the data, industrial CHP units in Indiana are distributed in the IOND, IPM, ITE, and IXNONM sub-sectors.

Table 3-97 Indiana Industrial CHP Capacity by Sub-Sector and Fuel in KW

Sub-sector	Fuel	Prime mover	Capacity
IOND			
Food	Coal	Steam turbine	9400
	Natural gas	Steam turbine	16000
Chemical	Natural gas	Steam turbine	4875
IPM	Coal	Steam turbine	755000
	Natural gas	Combustion turbine	227000
		Microturbine	120
	Waste and other	Steam turbine	487720
ITE	Natural gas	Microturbine	68
	Biomass	Combustion turbine	15500
IXNONM	Biomass	Reciprocating engine	3050

Data on electricity to steam ratio (REH)[15] are obtained from EPAUS9r in order to estimate steam and electricity produced from CHP technologies, which are shown in Table 3-98. Column one of Table 3-98 shows the geographic scale of the data based on availability. For the IOND sub-sector, ENC data (R3) are used. The rest of the sub-sectors use national level data. Data on REH are shown in column five of Table 3-98, from which the share of steam produced in the total output in terms of energy content (Steam% shown in column six) and the share of electricity produced in the total output in terms

[14] Electricity produced from industrial CHP technologies is fed back into the industrial sector rather than being delivered to the grid. Therefore, the actual electricity consumption in the industrial sector is the sum of electricity purchased from the grid (number reported in Table 3-93) and the electricity produced from industrial CHP technologies. Of course, the same amount of energy is subtracted from source fuels.
[15] REH represents the ratio of electricity to steam in terms of energy content in the total output of a CHP technology.

of energy content (ELC% shown in column seven) are calculated based on the following two formulas respectively:

Steam% = 1÷ (1+ REH)

ELC% = REH ÷ (1+ REH).

Table 3-98 Electricity to Steam Ratio (REH) for Industrial CHP Technologies by Sub-Sector, Fuel and Prime Mover

Geographic scale	Sub-sector	Fuel	Prime-mover	Electricity to steam ratio (REH)	Steam%	ELC%	Steam (PJ)	ELC (PJ)
R3	IOND-Food	Coal	Steam turbine	0.6000	0.6250	0.3750	0.1686	0.1012
R3	IOND-Food	Natural gas	Steam turbine	0.1225	0.8909	0.1091	0.4091	0.0501
R3	IOND-Chemical	Natural gas	Steam turbine	0.9200	0.5208	0.4792	0.0729	0.0670
National	IPM	Coal	Steam turbine	0.1300	0.8850	0.1150	19.1742	2.4926
National	IPM	Natural gas	Combustion turbine	0.8657	0.5360	0.4640	3.4916	3.0228
National	IPM	Waste and other	Steam turbine	0.1300	0.8850	0.1150	12.3863	1.6102
National	IPMI	Natural gas	Microturbine	0.6000	0.6250	0.3750	0.0022	0.0013
National	ITE	Biomass	Combustion turbine	0.7900	0.5587	0.4413	0.2485	0.1963
National	ITE	Natural gas	Microturbine	0.6000	0.6250	0.3750	0.0012	0.0007
National	IXNONM	Biomass	Reciprocating engine	1.0000	0.5000	0.5000	0.0438	0.0438

For each category of CHP units shown in Table 3-97 (for example, steam turbine CHP units in Indiana's food industry fueled by coal), it has a corresponding REH, Steam% and ELC% shown in Table 3-98. The amounts of steam and electricity produced from each category of CHP units in Indiana are estimated from the following formulas respectively:

Steam produced in PJ = capacity in kW ÷ (1.0E6kW/GW) × CAPUNIT × AF × Steam%

Electricity produced in PJ = capacity in kW ÷ (1.0E6kW/GW) × CAPUNIT × AF × ELC%.

CAPUNIT: a factor equal to 31.5360, which is used to convert generation capacity in GW to output in PJ, assuming the capacity is operated 8760 hours a year.

AF: availability factor of CHP technology, which is equal to 0.91 for all industrial CHP technologies based on EPAUS9r.

Estimates of steam and electricity produced from industrial CHP units are displayed in column eight and column nine of Table 3-98. They are aggregated respectively by fuel and sub-sector (as shown in Tables 3-99 and 3-100), and then are used to adjust the base-year industrial energy consumption by fuel and sub-sector as shown in Table 3-93. For each sub-sector, electricity produced from CHP units is subtracted from source fuels and are added to electricity consumption; steam produced from CHP units is subtracted from corresponding source fuels.[16] Taking the IOND sub-sector as an example, consumption of purchased electricity from this sub-sector is 66.5620 (the second number in the third column of Table 3-93). Electricity production from CHP units in the IOND industry is 0.2183 PJ (0.1012 PJ (the second number in the second column of Table 3-100) + 0.1171 PJ (the second number in the third column of Table 3-100)). Therefore, the adjusted electricity consumption from the IOND industry is equal to 66.7803 (the second number in the third column of Table 3-101) (= 66.5620 + 0.2183). Natural gas consumption from the IOND sub-sector is 140.4352 PJ based on estimates from SEDS (the second number in the fourth column of Table 3-93). The combined energy content of the steam and electricity produced from CHP units fired by natural gas in this sub-sector is 0.5991 PJ (0.4819 PJ (the second number on the third column of Table 3-99) + 0.1171 (the second number on the third column of Table 3-100))**.** Therefore, the adjusted natural gas consumption from the IOND sub-sector is equal to 139.8362 PJ (the second number in the fourth column of Table 3-101) (=140.4352 – 0.5991).

Table 3-99 Steam Produced from Industrial CHP Units by Sub-Sector and Fuel in PJ

Sub-Sector	Coal	NGA	Waste	REN
IOD	0.0000	0.0000	0.0000	0.0000
IOND	0.1686	0.4819	0.0000	0.0000
IPM	19.1742	3.4938	12.3863	0.0000
ITE	0.0000	0.0012	0.0000	0.2485
IO	0.0000	0.0000	0.0000	0.0000
IXNONM	0.0000	0.0000	0.0000	0.0438

[16] The purpose of doing adjustments on industrial energy consumption reported in Table 3-93 is to estimate capacities of the seven end-uses for each fuel of each sub-sector. Steam from CHP units has a separate collector from the seven end-uses for each sub-sector. Therefore, it is subtracted from industrial energy consumption. Electricity produced from industrial CHP technologies are fed back into the industrial sector rather than being delivered to the grid. Therefore, the actual electricity consumption in the industrial sector is the sum of electricity purchased from the grid (numbers reported in Table 3-93) and the electricity produced from industrial CHP technologies. Of course, same amounts of energy are subtracted from source fuels because they are used to produce electricity from CHP units.

Table 3-100 Electricity Produced from Industrial CHP Units by Sub-Sector and Fuel in PJ

Sub-Sector	Coal	NGA	Waste	REN
IOD	0.0000	0.0000	0.0000	0.0000
IOND	0.1012	0.1171	0.0000	0.0000
IPM	2.4926	3.0240	1.6102	0.0000
ITE	0.0000	0.0007	0.0000	0.1963
IO	0.0000	0.0000	0.0000	0.0000
IXNONM	0.0000	0.0000	0.0000	0.0438

Table 3-101 Adjusted Indiana Base-Year Industrial Fuel Consumption by Sub-Sector in PJ

Name	Description	ELC	NGA	DFO	LPG	RFO	OP	Coal	REN
IOD	Other durables	6.4279	6.2958	1.6934	0.0150	0.0188	2.4601	24.2941	5.2794
IOND	Other non-durables	66.7803	139.8362	3.3100	9.2260	1.3206	59.3225	81.1069	23.2181
IPM	Primary metals	55.5512	51.4584	0.8764	0.0111	0.4600	10.7702	174.1842	0.9674
ITE	Transportation equipment	16.0227	13.5037	0.1589	0.0175	0.1478	0.0000	1.2072	0.0000
IO	Other industries	27.4131	18.8276	0.3194	0.0477	0.0957	1.6541	4.0039	0.0012
IXNONM	Non-manufacturing	6.7590	6.6227	29.9602	0.2507	0.0030	21.1731	0.0000	0.2890

Notes: Steam produced from CHP units using waste as the energy source in the IPM sub-sector is not subtracted from fuel consumption in the sub-sector because waste is not counted in the industrial sector of SEDS.

Based on estimates from SEDS (Table 3-93), renewables consumption in the ITE sub-sector is zero. Subtracting electricity and steam produced from CHP units fueled by renewables in the ITE sub-sector from the renewables consumption from the sub-sector results in negative renewables consumption. Therefore, they are arbitrarily subtracted from natural gas consumption of the ITE industry.

Adjusted base-year industrial energy consumption by fuel and sub-sector as shown in Table 3-101 is split into seven end-uses based on EIA's Manufacturing Energy Consumption Survey (MECS) released on February 2010 (EIA, 2010f). MECS provides national level data on industrial fuel consumption by end-use (MECS Table 5.2) and nonfuel (feedstock) use of combustible energy (MECS Table 2.2) for each industry defined by the North American Industry Classification System (NAICS). To match sub-sectors defined in IN-MARKAL, data from the MECS are aggregated based on the industry mapping information shown in Table 3-102. Industries and their NAICS codes used in the MECS are shown on the left side of the table and IN-MARKAL sub-sectors are shown on the right side of the table. In addition, the end-uses in the MECS are mapped onto IN-MARKAL end-uses based on information shown in Table 3-103.

Table 3-102 Mapping of MECS Industries onto IN-MARKAL Sub-Sectors

MECS	IN-MARKAL
Nonmetallic mineral production (327) Wood products (321)	IOD
Food (311) Paper (322) Chemical (325)	IOND
Primary metals (331)	IPM
Transportation equipment (336)	ITE
Plastic and rubber products (326) Fabricated metal products (332) Machinery (333) Computer and electronic products (334) Electric equipment, appliances, components (335)	IO

Table 3-103 Mapping of MECS End-Uses onto IN-MARKAL End-Uses

MECS	IN-MARKAL
Conventional boiler use	Steam (boiler)
Process heating % of process cooling and refrigeration	Heat
Machine drive % of process cooling and refrigeration	Machine drive
Electro-chemical processes	Electro-chemical
Total non-process	Other demand (facility uses)
End use not reported	Other heat
Nonfuel (feedstock) use	Feedstock

Note: Splitting of energy consumption from process cooling and refrigeration in the MECS into energy consumption from heat and machine drive in IN-MARKAL is based on shares specified in EPAUS9r for different industries

Based on aggregated data from the MECS, shares of seven end-uses for each fuel (except other petroleum (OP)[17] in Table 3-101) of each sub-sector (except the non-manufacturing sub-sector (IXNONM)[18] in Table 3-101) are estimated as displayed in Table 3-104. For each sub-sector in IN-MARKAL, shares of the seven end-uses for each fuel add up to 100%. They are applied to the corresponding adjusted fuel consumption

[17] Other petroleum (OP) consumption is directly allocated to six sub-sectors based on data shown in the eighth column of Table 3-101.
[18] Energy consumption from the IXNONM industry is handled by demand technologies directly and will be described later.

by sub-sector shown in Table 3-101 to split each one of them into seven end-uses to serve as base-year capacities (RESIDs) for base-year industrial process technologies. For example, the adjusted electricity consumption from the IOD industry is 6.4279 PJ (the first number in the third column of Table 3-101). Electricity consumption from machine drive of the IOD industry (base-year capacity of the process technology named IODMELC07) is equal to 4.1768 PJ (6.4279 × 64.98% (the fourth number in the second column of Table 3-104)).

Table 3-104 Shares of Seven End-Uses for Each Fuel of Each Sub-Sector

	ELC	NGA	DFO	LPG	RFO	COA	REN
IOD							
Feedstock	0.00%	0.19%	12.00%	0.00%	0.00%	0.00%	3.15%
Steam (boiler)	0.42%	6.74%	2.00%	0.00%	0.00%	33.33%	0.00%
Heat	18.99%	76.40%	12.00%	14.29%	60.00%	0.00%	0.00%
Machine drive	64.98%	1.12%	28.00%	0.00%	0.00%	66.67%	0.00%
Electro-chemical	0.42%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Other demand (facility uses)	13.92%	4.87%	44.00%	71.43%	0.00%	0.00%	0.00%
Other heat	1.27%	10.67%	2.00%	14.29%	40.00%	0.00%	96.85%
IOND							
Feedstock	0.00%	14.52%	2.86%	99.35%	48.85%	9.04%	3.22%
Steam (boiler)	2.50%	37.86%	25.71%	0.13%	25.19%	67.47%	0.00%
Heat	9.08%	34.97%	17.54%	0.22%	22.14%	11.45%	0.00%
Machine drive	66.49%	4.12%	13.89%	0.00%	1.53%	2.41%	0.00%
Electro-chemical	4.11%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Other demand (facility uses)	17.02%	5.58%	34.29%	0.30%	2.29%	1.20%	0.00%
Other heat	0.81%	2.95%	5.71%	0.00%	0.00%	8.43%	96.78%
IPM							
Feedstock	0.00%	7.01%	16.67%	0.00%	0.00%	94.62%	17.07%
Steam (boiler)	0.22%	5.01%	0.00%	0.00%	0.00%	0.00%	0.00%
Heat	30.02%	78.20%	16.67%	66.67%	75.00%	3.76%	0.00%
Machine drive	29.89%	1.60%	0.00%	0.00%	0.00%	0.00%	0.00%
Electro-chemical	31.81%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Other demand (facility uses)	7.84%	6.84%	66.67%	33.33%	0.00%	0.81%	0.00%
Other heat	0.22%	1.34%	0.00%	0.00%	25.00%	0.81%	82.93%
ITE							
Feedstock	0.00%	0.00%	0.00%	33.33%	0.00%	0.00%	5.56%
Steam (boiler)	1.03%	17.62%	0.00%	0.00%	100.00%	100.00%	0.00%
Heat	17.13%	35.90%	0.00%	0.00%	0.00%	0.00%	0.00%
Machine drive	41.85%	2.19%	0.00%	0.00%	0.00%	0.00%	0.00%
Electro-chemical	1.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Other demand (facility uses)	38.46%	42.38%	100.00%	66.67%	0.00%	0.00%	0.00%
Other heat	0.51%	1.90%	0.00%	0.00%	0.00%	0.00%	94.44%
IO							
Feedstock	0.00%	0.00%	0.00%	0.00%	0.00%	67.22%	87.50%
Steam (boiler)	0.53%	26.57%	0.00%	0.00%	100.00%	21.61%	0.00%
Heat	17.58%	47.64%	0.00%	0.00%	0.00%	6.04%	0.00%
Machine drive	49.79%	0.79%	0.00%	0.00%	0.00%	1.10%	0.00%
Electro-chemical	0.71%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Other demand (facility uses)	31.03%	24.61%	100.00%	100.00%	0.00%	0.92%	0.00%
Other heat	0.35%	0.39%	0.00%	0.00%	0.00%	3.11%	12.50%

The following list describes parameters used to characterize industrial process technologies. All costs are expressed in millions of 2007 U.S. dollars. Energy quantities are expressed in PJ.

START: This parameter specifies the year a technology becomes available.

CAPUNIT: This parameter is used to convert capacity to activity level. It is equal to one for all industrial process technologies mentioned previously in this section, because both capacity and activity are expressed in PJ.

LIFE: This parameter specifies the lifetime of a technology in years. These values are obtained from EPAUS9r.

DISCRATE: This parameter specifies the discount rate associated with an individual technology. These values are obtained from EPAUS9r.

IBOND (BD): This parameter specifies a user-defined bound on new investment. BD can be set as LO (lower bound), UP (upper bound) or FX (fixed bound). Upper bounds on existing technologies are set at zero for the base year.

RESID: This parameter specifies the residual capacity in each model period for technology already installed at the beginning of the modeling horizon (2007). Estimation of RESIDs for base-year technologies has been described previously.

INVCOST: Investment cost is specified in millions of 2007 dollars per PJ of capacity.

FIXOM: Fixed operation and maintenance costs are expressed in millions of 2007 dollars per PJ of capacity.

AF: This parameter specifies the annual availability of a process technology, which is the fraction of the year that the capacity is available to operate. It is equal to 1 for all industrial process technologies mentioned previously in this section.

INP(ENT)p: This is the input-output ratio for a process technology. ENT indicates energy and p indicates process technology. This parameter specifies the amount of energy consumed in PJ to generate one PJ of output from a process. For each process technology in the industrial sector mentioned previously, INP(ENT)p is specified for all time periods and declines overtime , which means that the efficiency of the technology is improving over time. Data on INP(ENT)p are obtained from EPAUS9r.

In addition to process technologies mentioned previously, steam produced by industrial CHP units is collected by collector technologies in each sub-sector. The naming conventions for collector technologies are shown in Table 3-105. There are two CHP steam collector technologies for each sub-sector. One collects steam produced from fossil fuels and merges it into the process heat of the corresponding sub-sector; the other one collects steam produced from renewables and merges it into the other heat of the corresponding sub-sector.

Table 3-105 Naming Convention of CHP Steam Collector Technologies

CHP steam collector technologies - industrial				
Characters				
1	2/3/4		6/7/8/9	
Sector	Sub-sector	Description	Fuel category	Description
I	OND	Other non-durables	BFSTM	CHP fossil steam collector
	PM	Primary metals	ORSTM	CHP renewable steam collector
	TE	Transportation equipment		
	OD	Other durables		
	O	Other industries		

Existing capacities (RESIDs) of collector technologies for each sub-sector are derived by aggregating estimates of steam production from CHP units shown in table 3-99 into two categories — fossil fuel (as the energy source) and renewable fuel (as the energy source). For example, the base-year capacity of CHP fossil steam collector in the IOND industry is equal to 0.6505 PJ (0.1686 PJ (steam produced from coal shown as the second number in the second column of Table 3-99) + 0.4819 PJ (steam produced from natural gas shown as the second number in the third column of Table 3-99)).

Demand technologies

Except the IXNONM sub-sector, all of the sub-sectors in the industrial sector have one demand technology specified in IN-MARKAL. The function of a demand technology is to add together the heat content of the seven end-uses in each sub-sector to obtain the energy service demand of the sub-sector as a whole. The naming conventions of the demand technologies in the five sub-sectors are shown in Table 3-106.

Table 3-106 Naming Convention of Industrial Demand Technologies in Five Sub-Sectors

Demand technologies-industrial				
Characters				
1	2/3/4		5/6/7/8/9/10	
Sector	Sub-sector	Description	Technology	Description
I	OND	Other non-durables	TECHEX	Existing technologies
	PM	Primary metals		
	TE	Transportation equipment		
	OD	Other durables		
	O	Other industries		

The role of a demand technology is fulfilled through a parameter named MA(ENT), which is specified for each input of a multiple-input technology. Each demand technology has seven end-uses serving as inputs. MA(ENT) indicates the share of an end-use over all end-uses in terms of energy content to serve the corresponding sub-sector energy demand. Shares of seven end-uses for each sub-sector add up to one. They are calibrated to base-year capacities of process technologies. For each sub-sector, base year capacities of process technologies are aggregated across fuels for each end-use and are then divided by the total capacity of all process technologies in that sub-sector to derive shares of the seven end-uses within the sub-sector.

There are no process technologies in the IXNONM sub-sector due to a lack of data to break out its fuel consumption into seven end-uses. The IXNONM sub-sector is represented with seven demand technologies directly in IN-MARKAL. The naming conventions of the demand technologies in the IXNONM sub-sector are shown in Table 3-107. They differ by fuel only. Base year capacities of the demand technologies in the IXNONM sub-sector are drawn from the last row of Table 3-101 (Coal consumption from the IXNONM sub-sector is zero as shown in Table 3-101. Therefore, it is omitted from demand technologies in the IXNONM sub-sector.)

Table 3-107 Naming Convention of Demand Technologies in the IXNONM Sub-Sector

Demand technologies-IXNONM				
Characters				
1	2/3/4/5/6		7/8/9/10	
Sector	Sub-sector	Description	Fuel	Description
I	XNONM	Non-manufacturing	DST	Distillate fuel oil (diesel)
			RFL	Residual fuel oil
			NGA	Natural gas
			LPG	Liquefied petroleum gas
			ELC	Electricity
			OTH	Other petroleum
			BIO	Renewables

There is only one CHP steam collector technology in the IXNONM sub-sector, which is named as IXNONMRSTM. This technology collects steam produced from renewables by CHP units in the IXNONM sub-sector (i.e., steam produced from CHP located at Fair Oaks Farm). (No steam is produced from fossil fuels by CHP units in the IXNONM sub-sector based on estimates shown in Table 3-99.) Base year capacity for the renewable steam collector (IXNONMRSTM) is drawn from Table 3-99 (the last number in the fifth column).

3.2.3.3.3 Industrial CHP Technologies

Industrial CHP technologies produce both electricity and steam for use in the industrial sector. Steam produced from CHP technologies is collected by fossil steam and renewable steam collector technologies and merges into process heat and other heat respectively for satisfying final energy demand. Electricity produced from industrial CHP technologies goes through collector technologies and merges into electricity generated from the power system to serve as energy input to industrial process technologies.

Base-year capacities (RESIDs) of existing CHP technologies are shown in Table 3-97, which are converted from kW to GW in order to be used here. New CHP technologies are specified in IN-MARKAL as well, based on information obtained from EPAUS9r.

The following is the list of parameters for industrial CHP technologies.

START: This parameter specifies the year a technology becomes available.

LIFE: This parameter specifies the lifetime of a technology in years, which are obtained from EPAUS9r. All industrial CHP technologies have a life of 30 years.

CAPUNIT: This parameter is used to convert generation capacity in GW to output in PJ. It is equal to 31.5360, assuming the capacity is operated 8760 hours a year.

OUT(ENC)p: This parameter specifies output (electricity or steam) in PJ per PJ of energy input for a CHP technology. ENC indicates energy and p indicates process technology in IN-MARKAL. For each CHP technology, OUT(ENT)p is specified for electricity and steam respectively. They are calculated through the following formulas:

PJ electricity produced per PJ of energy input = REH ÷ (1+ REH) × Efficiency

PJ steam produced per PJ of energy input = 1 ÷ (1+ REH) × Efficiency

REH: electricity to steam ratio, which represents the ratio of electricity to steam in energy content in the total output of a CHP technology.

Efficiency: efficiency of a CHP technology, which represents the total output of a CHP technology in PJ per PJ of energy input.

DISCRATE: This parameter specifies the discount rate associated with an individual technology, which is obtained from EPAUS9r.

INVCOST: Investment cost is specified in millions of 2007 dollars per GW of CHP capacity.

FIXOM: Fixed operation and maintenance costs are expressed in millions of 2007 dollars per GW of capacity per year.

VAROM: Variable operation and maintenance costs are expressed in millions of 2007 dollars per PJ of activity.

AF: This parameter specifies the annual availability of a technology, which is the fraction of the year that the capacity is available to operate. It is equal to 0.91 for all industrial CHP technologies in IN-MARKAL.

IBOND (BD): This parameter specifies a user-defined bound on new investment. BD can be set as a LO (lower bound), UP (upper bound) or FX (fixed bound).

RESID: This parameter specifies the residual capacity in each model period for technology already installed at the beginning of the modeling horizon (2007).

3.2.3.3.4 Industrial Energy Carriers

Table 3-108 contains energy going into the industrial sector of IN-MARKAL. The first three letters represent the sector (IND-industrial), the fourth through sixth letters stand for the fuel type and the final two letters indicate the path (EA-after emissions accounting).

Table 3-108 Industrial Sector Energy Carriers

Name	Description
INDELC	Electricity to industrial sector
INDCOA	Coal to industrial sector
INDNGA	Natural gas to industrial sector
INDDST	Diesel to industrial sector
INDLPG	Liquefied petroleum gas (LPG) to Industrial sector
INDRFO	Residual fuel oil (RFO) to industrial sector
INDBIO	Biomass to industrial sector
INDGSL	Gasoline (mixture of conventional and renewable gasoline) to Industrial sector
INDPTC	Petrochemical feedstock (PTC) to Industrial sector
INDOTH	Other petroleum to industrial sector
INDCOAEA	Coal to industrial sector after emissions accounting
INDNGAEA	Natural gas to industrial sector after emissions accounting
INDDSTEA	Diesel to industrial sector after emissions accounting
INDLPGEA	LPG to Industrial sector after emissions accounting
INDRFOEA	RFO to industrial sector after emissions accounting
INDBIOEA	Biomass to industrial sector after emissions accounting
INDGSLEA	Gasoline to Industrial sector after emissions accounting
INDPTCEA	PTC to Industrial sector after emissions accounting

3.2.3.4 Transportation Sector

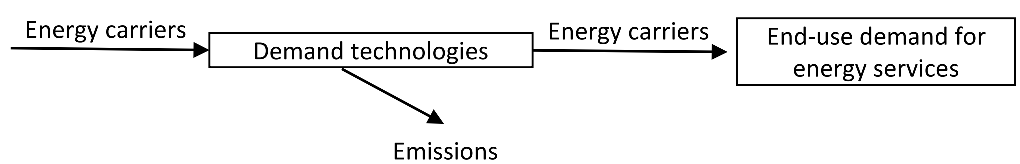

Figure 3-19 Transportation Sector RES

Figure 3-19 is the reference energy system (RES) for the transportation sector. Energy carriers flow through demand technologies to meet end-use demand for energy services. Emissions from the transportation sector are tracked at transportation demand technologies.

3.2.3.4.1 Transportation Demand for Energy Services

IN-MARKAL includes ten end-use demands in the transportation sector, which are characterized by transportation modes as shown in Table 3-109.

Table 3-109 Transportation End-Uses Modeled with IN-MARKAL

End-use	Description	Unit
TL	Light-duty vehicle	billion vehicle-mile travelled (bn-vmt)
TC	Commercial light trucks	bn-vmt
TH	Freight trucks	bn-vmt
TRF	Freight rail	billion ton-mile travelled (bn-tmt)
TS	Total shipping (domestic and international)	bn-tmt
TA	Air transportation	billion passenger-mile travelled (bn-pmt)
TB	Total bus (transit, intercity and school)	bn-vmt
TRP	Commuter rail	bn-pmt
TOHDSL	Off-highway diesel use	PJ
TOHGSL	Off-highway gasoline use	PJ

Note: Off-highway includes land-based transport not using the highway system or other paved roadways.

Different methodologies are used to estimate demand for energy services for various end-uses. The first eight end-uses in Table 3-109 use one methodology. The other two end-uses use a different methodology, which will be discussed separately later in the section.

To derive base-year transportation demand for energy services for the first eight end-uses in Table 3-109, base-year transportation energy consumption by end-use and fuel consumption is estimated first. Indiana transportation fuel consumption is split into the eight end-uses through matrix balancing as described in detail in Section 3.2.3.1.1. Table 3-110 contains data on transportation energy consumption available at three geographic scales — national level (US), regional level (ENC) and state level (IN) for eight fuel categories. National data are retrieved from EIA AEO 2010 Tables 46[19] (EIA, 2010e). ENC data are obtained from EIA AEO 2010 Table 3[20] (EIA, 2010e) and Indiana data are obtained from EIA SEDS[21] (EIA, 2007a). The national level data retrieved from EIA

[19] Source: EIA AEO 2010 Table 46. Transportation Sector Energy Use by Fuel Type Within a Mode
[20] Source: EIA AEO 2010 Table 3. Energy Consumption by Sector and Source — East North Central
[21] Source: EIA SEDS Table 11. Transportation Sector Energy Consumption Estimates, Selected Years, 1960-2008, Indiana

includes 17 transportation modes. However, at regional and state levels, only energy consumption by fuel is available. The purpose of using matrix balancing is to derive Indiana transportation energy consumption by fuel and mode as the area highlighted by the green color in Table 3-110 from available data.

Table 3-110 Transportation Fuel Consumption in Trillion Btu, 2007

	US								ENC								IN							
Transportation	ELC	NGA	DFO	LPG	RFO	OP	MG	JF	ELC	NGA	DFO	LPG	RFO	OP	MG	JF	ELC	NGA	DFO	LPG	RFO	OP	MG	JF
Light duty vehicle	0.70	12.19	229.06	7.23	0.00	0.00	16367.12	0.00																
Commercial light trucks	0.00	0.00	268.20	0.00	0.00	0.00	382.14	0.00																
Freight trucks	0.00	7.84	4629.56	22.90	0.00	0.00	352.51	0.00																
Freight rail	0.00	0.00	605.03	0.00	0.00	0.00	0.00	0.00																
Domestic shipping	0.00	0.00	214.57	0.00	84.74	0.00	0.00	0.00																
International shipping	0.00	0.00	65.41	0.00	895.04	0.00	0.00	0.00																
Air transportation	0.00	0.00	0.00	0.00	0.00	31.59	0.00	2717.56																
Military use	0.00	0.00	144.48	0.00	13.86	0.00	0.00	550.45																
Transit bus	0.00	19.18	86.58	0.47	0.00	0.00	2.44	0.00																
Intercity bus	0.00	0.00	31.73	0.00	0.00	0.00	0.00	0.00																
School bus	0.00	0.95	109.74	0.10	0.00	0.00	13.13	0.00																
Intercity rail	1.52	0.00	14.58	0.00	0.00	0.00	0.00	0.00																
Transit rail	15.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00																
Commuter rail	4.77	0.00	10.31	0.00	0.00	0.00	0.00	0.00																
Recreational boats	0.00	0.00	47.63	0.00	0.00	0.00	205.32	0.00																
Lubricants usage	0.00	0.00	0.00	0.00	0.00	152.23	0.00	0.00																
Pipeline fuel natural gas usage	0.00	640.33	0.00	0.00	0.00	0.00	0.00	0.00																
Total	22.16	680.49	6456.87	30.70	993.64	183.82	17322.66	3268.01	2.48	68.77	957.26	5.29	4.09	25.42	2568.07	272.39	0.10	7.30	205.10	0.50	1.80	4.30	401.50	42.20

Note: ELC-electricity, NGA-natural gas, DFO-distillate fuel oil (diesel), LPG-liquefied petroleum gas, RFO-residual fuel oil, OP-other petroleum (includes lubricants, petroleum coke, miscellaneous petroleum products, petrochemical feedstock, asphalt and road oil), MG-motor gasoline, JF-jet fuel.

To do the matrix balancing, a table is created first for each fuel with data drawn from Table 3-110 (Transportation electricity consumption is chosen as an example and is shown in Table 3-111). Cells with blue and yellow shades contain national electricity consumption by transportation mode. The three pink cells at the bottom display US transportation electricity consumption minus ENC transportation electricity consumption, ENC transportation electricity consumption minus Indiana transportation electricity consumption and Indiana transportation electricity consumption respectively. The cell at the bottom right corner is the U.S. total transportation electricity consumption, which is equal to the sum across pink cells and the sum of yellow cells as well.

Table 3-111 Table of Transportation Electricity Consumption Prepared for Matrix Balancing

Transportation mode	US-ENC	ENC-IN	IN	US total
Light duty vehicle	0.70	0.70	0.70	0.70
Commercial light trucks	0.00	0.00	0.00	0.00
Freight trucks	0.00	0.00	0.00	0.00
Freight rail	0.00	0.00	0.00	0.00
Domestic shipping	0.00	0.00	0.00	0.00
International shipping	0.00	0.00	0.00	0.00
Air transportation	0.00	0.00	0.00	0.00
Military use	0.00	0.00	0.00	0.00
Transit bus	0.00	0.00	0.00	0.00
Intercity bus	0.00	0.00	0.00	0.00
School bus	0.00	0.00	0.00	0.00
Intercity rail	1.52	1.52	1.52	1.52
Transit rail	15.17	15.17	15.17	15.17
Commuter rail	4.77	4.77	4.77	4.77
Recreational boats	0.00	0.00	0.00	0.00
Lubricants usage	0.00	0.00	0.00	0.00
Pipeline fuel natural gas usage	0.00	0.00	0.00	0.00
Total	19.68	2.38	0.10	22.16

Before matrix balancing is performed, the data in Table 3-111 are adjusted to capture the differences among the three geographic scales within each transportation mode. Various indicators of the 17 transportation modes at the three geographic scales for 2007 are shown in Table 3-112. (Sources of the indicators are shown in Table 3-113.)

They are used to create energy indices for the 17 end-uses at the three geographic scales as shown in Table 3-114. Except for the commercial light trucks and the transit bus, each one of the other transportation modes has only one indicator at three geographic scales, which is directly used as its energy index. For example, the energy index for the freight trucks at the national level is equal to 13,083,855 (freight truck shipments for US in Table 3-112). The basic idea is that demand for a transportation mode should be proportional to its corresponding indicator. The commercial light trucks use the product of its two indicators (highway vmt and commercial employment) as the energy index. For example, the energy index for commercial light trucks at the national level (4.5084E+14 in table 3-114) is equal to 3,029,822 (annual highway vehicle miles travelled (vmt) for US in Table 3-112) × 148,801,400 (commercial sector employment number for US in Table 3-112). While the transit bus uses the product of its two indicators (transit bus ridership in percentage and population number) as its energy index. Energy indices in Table 3-114 are then used to calculate multipliers as shown in Table 3-115 to adjust the numbers highlighted in the blue area of Table 3-111. Let E_{ij} denotes the energy index of transportation mode *i* at geographic scale *j* (data in Table 3-114), where *i* =any one of the 17 transportation modes shown in Table 3-114, and *j*= US, ENC and IN. Multipliers shown in the columns named “US-ENC”, “ENC-IN” and “IN” in Table 3-115 are calculated based on the following three formulas respectively:

$(E_{i\,US} - E_{i\,ENC})/E_{i\,US}$,

$(E_{i\,ENC} - E_{i\,IN})/E_{i\,US}$, and

$E_{i\,IN} / E_{i\,US}$.

Table 3-112 Indicators by Transportation Mode at Three Geographic Scales

Transportation mode	Indicator	US	ENC	IN
Light duty vehicle	Population number	301,579,895	46,298,763	6,346,113
Commercial light trucks	Highway vmt in millions	3,029,822	453,699	71,478
	Commercial sector employment number	148,801,400	21,838,532	2,829,725
Freight trucks	Freight truck shipments in thousand tons	13,083,855	2,151,403	401,470
Freight rail	Freight rail shipments in thousand tons	2,040,961	265,403	58,936
Domestic shipping	Waterborne shipments - domestic in thousands of short tons	706,193	168,450	13,494
International shipping	Waterborne shipments - international in thousands of short tons	466,781	27,526	139
Air transportation	Number of airline passengers	835,436,440	94,698,960	4,300,049
Military use	Number of personnel in military bases and major installations	2,291,321	215,774	28,477
Transit bus	Transit bus ridership in percentage	53	86	97
	Population number	301,579,895	46,298,763	6,346,113
Intercity bus	Intercity bus pmt in thousands	96,361,063	3,600,843	104,913
School bus	School bus registration in thousands	677,191	104,667	27,755
Intercity rail	Intercity rail annual train miles traveled in thousands	48,337	830	0
Transit rail	Transit rail annual train miles traveled in thousands	94,211	13,338	0
Commuter rail	Commuter rail annual train miles traveled in thousands	53,932	7,931	803
Recreational boats	Recreational boat registration	11,966,627	2,241,016	239,018
Lubricants usage	Pipeline transportation in thousand tons	1,592,790	168,503	2,183
Pipeline fuel natural gas usage				

Table 3-113 Transportation Sector Indicator Sources

Indicator	Source
Highway vmt	Federal Highway Administration (FHA) Functional System Travel - 2007, available at: http://www.fhwa.dot.gov/policyinformation/statistics/2007/vm2.cfm
Commercial sector employment number	Bureau of Economic Analysis (BEA), Regional Economic Accounts, available at: http://www.bea.gov/regional/index.htm
Freight truck shipments	FHA, Freight Analysis Framework (FAF), available at: http://www.ops.fhwa.dot.gov/freight/freight_analysis/faf/
Freight rail shipments	FHA, FAF, available at: http://www.ops.fhwa.dot.gov/freight/freight_analysis/faf/
Waterborne shipments - domestic	FHA, FAF, available at: http://www.ops.fhwa.dot.gov/freight/freight_analysis/faf/
Waterborne shipments - international	FHA, FAF, available at: http://www.ops.fhwa.dot.gov/freight/freight_analysis/faf/
Number of airline passengers	United States Department of Transportation (DOT), Bureau of Transportation Statistics (BTS), available at:
Personnel in military bases and major installations	About.com, US Military, available at: http://usmilitary.about.com/od/theorderlyroom/l/blstatefacts.htm
Transit bus ridership	DOT, BTS, available at: http://www.bts.gov/publications/state_transportation_statistics/state_transportation_statistics_2008/html/table_04_03.html
Population number	STATS Indiana, available at: http://www.stats.indiana.edu/population/PopTotals/2009_stateest.asp
Intercity bus pmt	National Transit Database, Table 19, available at: http://www.ntdprogram.gov/ntdprogram/pubs/dt/2007/DataTables07TOC.htm
School bus registration	FHA, Highway Statistics 2007, Buses Registrations - 2007, available at: http://www.fhwa.dot.gov/policyinformation/statistics/2007/mv10.cfm
Intercity rail annual train miles traveled	National Transit Database, Table 20, available at: http://www.ntdprogram.gov/ntdprogram/pubs/dt/2007/DataTables07TOC.htm
Transit rail annual train miles traveled	National Transit Database, Table 20, available at: http://www.ntdprogram.gov/ntdprogram/pubs/dt/2007/DataTables07TOC.htm
Commuter rail annual train miles traveled	National Transit Database, Table 20, available at: http://www.ntdprogram.gov/ntdprogram/pubs/dt/2007/DataTables07TOC.htm
Recreational boat registration	DOT, BTS, available at: http://www.rita.dot.gov/bts/publications/state_transportation_statistics/state_transportation_statistics_2008/html/table_05_06.html
Pipeline transportation	FHA, FAF, available at: http://www.ops.fhwa.dot.gov/freight/freight_analysis/faf/

Table 3-114 Energy Index by Transportation Mode and Geographic Scale

Transportation mode	US	ENC	IN
Light duty vehicle	301,579,895	46,298,763	6,346,113
Commercial light trucks	4.5084E+14	9.9081E+12	2.0226E+11
Freight trucks	13,083,855	2,151,403	401,470
Freight rail	2,040,961	265,403	58,936
Domestic shipping	706,193	168,450	13,494
International shipping	466,781	27,526	139
Air transportation	835,436,440	94,698,960	4,300,049
Military use	2,291,321	215,774	28,477
Transit bus	1.6044E+10	3.9766E+09	6.1430E+08
Intercity bus	96,361,063	3,600,843	104,913
School bus	677,191	104,667	27,755
Intercity rail	48,337	830	0
Transit rail	94,211	13,338	0
Commuter rail	53,932	7,931	803
Recreational boats	11,966,627	2,241,016	239,018
Lubricants usage	1,592,790	168,503	2,183
Pipeline fuel natural gas usage	1,592,790	168,503	2,183

Table 3-115 Multipliers for Table 3-111

Transportation mode	US-ENC	ENC-IN	IN
Light duty vehicle	0.8465	0.1325	0.0210
Commercial light trucks	0.9780	0.0215	0.0004
Freight trucks	0.8356	0.1337	0.0307
Freight rail	0.8700	0.1012	0.0289
Domestic shipping	0.7615	0.2194	0.0191
International shipping	0.9410	0.0587	0.0003
Air transportation	0.8866	0.1082	0.0051
Military use	0.9058	0.0817	0.0124
Transit bus	0.7521	0.2096	0.0383
Intercity bus	0.9626	0.0363	0.0011
School bus	0.8454	0.1136	0.0410
Intercity rail	0.9828	0.0172	0.0000
Transit rail	0.8584	0.1416	0.0000
Commuter rail	0.8530	0.1322	0.0149
Recreational boats	0.8127	0.1673	0.0200
Lubricants usage	0.8942	0.1044	0.0014
Pipeline fuel natural gas usage	0.8942	0.1044	0.0014

After applying multipliers, the adjusted Table 3-111 is referred to as the A matrix as shown in Table 3-116. Iterative column scaling and row scaling are performed for data shown in the blue shaded area of Table 3-116 until the matrix elements match both the specified row sums and column sums respectively. The balanced matrix is shown in Table 3-117. Estimates of Indiana transportation electricity consumption by transportation mode through matrix balancing are displayed in the last column of the table.

Table 3-116 A Matrix for Transportation Electricity Consumption

Transportation mode	US-ENC	ENC-IN	IN	US total
Light duty vehicle	0.59	0.09	0.01	0.70
Commercial light trucks	0.00	0.00	0.00	0.00
Freight trucks	0.00	0.00	0.00	0.00
Freight rail	0.00	0.00	0.00	0.00
Domestic shipping	0.00	0.00	0.00	0.00
International shipping	0.00	0.00	0.00	0.00
Air transportation	0.00	0.00	0.00	0.00
Military use	0.00	0.00	0.00	0.00
Transit bus	0.00	0.00	0.00	0.00
Intercity bus	0.00	0.00	0.00	0.00
School bus	0.00	0.00	0.00	0.00
Intercity rail	1.49	0.03	0.00	1.52
Transit rail	13.02	2.15	0.00	15.17
Commuter rail	4.07	0.63	0.07	4.77
Recreational boats	0.00	0.00	0.00	0.00
Lubricants usage	0.00	0.00	0.00	0.00
Pipeline fuel natural gas usage	0.00	0.00	0.00	0.00
Total	19.68	2.38	0.10	22.16

Table 3-117 Balanced Matrix for Transportation Electricity Consumption in Trillion Btu, 2007

Transportation mode	US-ENC	ENC-IN	IN
Light duty vehicle	0.61	0.08	0.02
Commercial light trucks	0.00	0.00	0.00
Freight trucks	0.00	0.00	0.00
Freight rail	0.00	0.00	0.00
Domestic shipping	0.00	0.00	0.00
International shipping	0.00	0.00	0.00
Air transportation	0.00	0.00	0.00
Military use	0.00	0.00	0.00
Transit bus	0.00	0.00	0.00
Intercity bus	0.00	0.00	0.00
School bus	0.00	0.00	0.00
Intercity rail	1.50	0.02	0.00
Transit rail	13.40	1.77	0.00
Commuter rail	4.17	0.52	0.08
Recreational boats	0.00	0.00	0.00
Lubricants usage	0.00	0.00	0.00
Pipeline fuel natural gas usage	0.00	0.00	0.00
Total	19.68	2.38	0.10

The process described above is performed for each of the eight fuel categories shown in table 3-110. Estimates of Indiana base year transportation energy consumption by fuel and transportation mode are summarized in Table 3-118.

Table 3-118 Estimates of Indiana Transportation Energy Consumption by Fuel and Transportation Mode in Trillion Btu, 2007

Transportation mode	ELC	NGA	DFO	LPG	RFO	OP	MG	JF
Light duty vehicle	0.02	0.87	5.52	0.09			383.98	
Commercial light trucks			0.14				0.19	
Freight trucks		0.79	162.46	0.40			12.05	
Freight rail			19.93					
Domestic shipping			4.73		1.47			
International shipping			0.02		0.20			
Air transportation						1.84		28.49
Military use			2.05		0.13			13.71
Transit bus		2.41	3.81	0.01			0.10	
Intercity bus			0.04					
School bus		0.13	5.13	0.00			0.60	
Intercity rail								
Transit rail								
Commuter rail	0.08		0.18					
Recreational boats			1.09				4.58	
Lubricants usage						2.46		
Pipeline fuel natural gas usage		3.10						

The 17 transportation modes shown in Table 3-118 are then aggregated into the first eight end-uses as shown in Table 3-109 for use in IN-MARKAL. Excluded from the transportation sector are four transportation modes shown in Table 3-118: military use, recreational boats, lubricants usage and pipeline fuel natural gas usage. They together contribute only 4% of total energy consumption in the transportation sector. Plus, modeling corresponding technologies creates very limited benefit, but requires data that is difficult to collect. Domestic shipping and international shipping are aggregated and renamed as total shipping (TS) in IN-MARKAL. In addition, total bus (TB) in IN-MARKAL is an aggregation of the following transportation modes: transit bus, intercity bus and school bus. The rest of transportation modes in Table 3-118 have matched end-uses in IN-MARKAL.

Estimates of Indiana transportation fuel consumption for the eight end-uses in trillion Btu are shown in columns three through ten of Table 3-119. Aggregating across fuels for each end-use leads to transportation energy consumption by end-use (shown in the last column of Table 3-119).

Table 3-119 Estimates of Indiana Transportation Fuel Consumption for Eight End-Uses in Trillion Btu, 2007

End-use	Description	ELC	NGA	DFO	LPG	RFO	OP	MG	JF	Total
TL	Light-duty vehicle	0.02	1.21	5.44	0.09			383.52		390.28
TC	Commercial light trucks			0.13				0.18		0.31
TH	Freight trucks		1.12	164.68	0.41			12.37		178.58
TRF	Freight rail			21.50						21.50
TS	Total shipping (domestic and international)			5.14		1.70				6.84
TA	Air transportation						0.40		35.09	35.49
TB	Total bus (transit, intercity and school)		0.18	5.24	0.00			0.61		6.04
TRP	Commuter rail	0.08		0.12						0.20

Transportation energy demand for an end-use is converted to energy service demand by applying the energy intensity data for the end-use as shown in Table 3-120. For light-duty vehicle (TL), commercial light trucks (TC) and freight trucks (TH), their energy intensities are obtained by dividing energy use[22] (EIA, 2010e) by vehicle miles traveled (vmt)[23] (EIA, 2010e) for each of the three end-uses. For freight rail (TRF) and total shipping (TS), their energy intensities are converted directly from their energy efficiency indicators[24] (EIA, 2010e) expressed in ton-miles per thousand Btu. We assume identical efficiencies for domestic and international shipping. Air transportation (TA) energy intensity expressed in Btu per passenger mile traveled (pmt) is retrieved from the Bureau of Transportation Statistics[25] (BTS, 2013). It is assumed that domestic air and international air have similar energy intensity. Finally, energy intensities of total bus

[22] Source: EIA AEO 2010 Table 46. Transportation sector energy use by fuel type within a mode, available at: http://www.eia.gov/forecasts/aeo/data.cfm#summary.
[23] Source: EIA AEO 2010 Table 7. Transportation sector key indicators and delivered energy consumption, available at: http://www.eia.gov/forecasts/aeo/data.cfm#summary.
[24] Source: EIA AEO 2010 Table 7. Transportation sector key indicators and delivered energy consumption, available at: http://www.eia.gov/forecasts/aeo/data.cfm#summary.
[25] Source: BTS, National Transportation Statistics, Table 4-21. Energy intensity of certified air carriers, all services, available at: http://www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/index.html.

(TB) and commuter rail (TRP) are obtained from the Oak Ridge National Laboratory's Transportation Energy Data Book[26] (ORNL, 2009).

Table 3-120 Transportation Energy Intensity by End-Use

End-use	Description	Unit	Energy intensity
TL	Light-duty vehicle	Btu per vmt	6,051.6958
TC	Commercial light trucks	Btu per vmt	8,829.6882
TH	Freight trucks	Btu per vmt	20,794.6609
TRF	Freight rail	Btu per tmt	320.0000
TS	Total shipping (domestic and international)	Btu per tmt	511.9740
TA	Air transportation	Btu per pmt	3,040.0000
TB	Total bus (transit, intercity and school)	Btu per vmt	39,408.0000
TRP	Commuter rail	Btu per vmt	90,328.0000

Projections of Indiana transportation energy services by end-use are driven by various data as detailed in Table 3-121. The TL is driven by national total vmt for light-duty vehicles[27] (EIA, 2010e) scaled by the ratio of Indiana population to U.S. population. This method takes into consideration the proximity of the ratios of general population to licensed population at the state and national levels (67.91% and 68.21% respectively) based on data from U.S. Department of Transportation Federal Highway Administration[28] (FHWA, 2007). The TC projection is based on Gross State Product (GSP) of Indiana's service sector (excluding freight truck transportation) from Indiana University Center for Macroeconomic Model Research's 2011 Long-Range Forecast[29] (CEMR, 2011) divided by national level commercial light truck energy intensity in Btu per vmt[30]. The assumption made here is that commercial light truck service demand is proportional to GSP of the state service sector and commercial light truck energy

[26] Source: ORNL Transportation Energy Data Book: Edition 28-2009, Table 2.12, Passenger Travel and Energy Use, 2007, available at: http://cta.ornl.gov/data/chapter2.shtml.
[27] Source: EIA AEO 2010 Table 7. Transportation sector key indicators and delivered energy consumption, available at: http://www.eia.gov/forecasts/aeo/data.cfm#summary.
[28] Source: DOT Federal Highway Administration's (FHWA) 2007 – Highway Statistics – Travelers (or System Users) – Licensed Drivers: Ratio of Licensed Drivers to Population – Table 6.4.1., available at: http://www.fhwa.dot.gov/policyinformation/statistics/2007/dl1c.cfm.
[29] Source: IU CEMR 2011 – LONG-RANGE PROJECTIONS 2010-2031, available at: http://www.iu.edu/~cemr/subscribers/forecast.html#imi.
[30] Energy consumption from EIA AEO 2010 Table 46 divided by vmt from EIA AEO 2010 Table 7 by year for commercial light trucks

efficiency improvements at the state level follow those of the national level over time. The TH projection is driven by CEMR's projection of GSP of Indiana's truck transportation industry (freight truck) divided by the national level energy intensity of freight trucks in Btu per vmt.[31] The freight rail, TRF, is driven by CEMR's projection of Indiana total GSP divided by the national level energy intensity of freight rail in Btu per tmt.[32] The TS transportation demand is driven by CEMR's projection of Indiana total GSP divided by the national level energy intensity of domestic shipping in Btu per tmt.[33] Here we take into account the fact that the majority of Indiana's shipments are domestic.[34] The TA is driven by the projection of the U.S. total pmt for air transportation[35] (EIA, 2010e) scaled by the ratio of Indiana commercial service airport enplanements to the U.S. total commercial service airport enplanements[36] (BTS, 2012). Total bus, TB, is driven by the national energy consumption from bus transportation[37] (EIA, 2010e) scaled by the ratio of Indiana population to national population. Finally, commuter rail, TRP, is driven by the national energy consumption from commuter rail[38] (EIA, 2010e) scaled by the ratio of Indiana population to national population. Projections of Indiana demand for transportation energy services by end-use are displayed in Table 3-112, with data graphed in Figure 3-20 as well.

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[31] Energy consumption from EIA AEO 2010 Table 46 divided by vmt from EIA AEO 2010 Table 7 by year for freight trucks

[32] Energy consumption from EIA AEO 2010 Table 46 divided by tmt from EIA AEO 2010 Table 7 by year for freight rail

[33] EIA AEO 2010 Table 7 energy efficiency indicators in ton miles per thousand Btu for domestic shipping converted to energy intensity in Btu per tmt

[34] Based on U.S. Army Corps of Engineers' U.S. Waterway system transportation facts 2008 fact card, available at: http://www.ndc.iwr.usace.army.mil/factcard/temp/factcard.htm

[35] Source: EIA AEO 2010 Table 7. Transportation sector key indicators and delivered energy consumption, available at: http://www.eia.gov/forecasts/aeo/data.cfm#summary

[36] Source: Bureau of Transportation Statistics, State Transportation Statistics, Table 1-44, available at: http://www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/html/table_01_44.html.

[37] Source: EIA AEO 2010 Table 46. Transportation sector energy use by fuel type within a mode, available at: http://www.eia.gov/forecasts/aeo/data.cfm#summary

[38] Source: EIA AEO 2010 Table 46. Transportation sector energy use by fuel type within a mode, available at: http://www.eia.gov/forecasts/aeo/data.cfm#summary

Table 3-121 Transportation Energy Service Projection Drivers by End-Use

End-use	Projection driver
TL	U.S. total vmt for light-duty vehicle * (IN population/U.S. population)
TC	CEMR's Indiana GSP of the service sector excluding truck transportation/Btu per vmt for commercial light trucks
TH	CEMR's Indiana GSP of truck transportation/Btu per vmt for freight trucks
TRF	CEMR's Indiana total GSP/Btu per tmt for freight rail
TS	CEMR's Indiana total GSP/Btu per tmt for domestic shipping
TA	U.S. total pmt for air transportation * (IN commercial service airport enplanements/U.S. commercial service airport enplanements)
TB	U.S. total energy consumption for bus transportation * (IN population/U.S. population)
TRP	U.S. total energy consumption for commuter rail * (IN population/U.S. population)

Table 3-122 IN-MARKAL Demand for Transportation Energy Services for Eight End-Uses

End-use	Description	Unit	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
TL	Light-duty vehicle	bn-vmt	64.49	63.07	65.06	66.34	69.17	72.79	76.45	79.56	82.38	85.10	87.75	90.63	93.60
TC	Commercial light trucks	bn-vmt	0.03	0.04	0.04	0.05	0.05	0.06	0.07	0.08	0.09	0.09	0.11	0.12	0.13
TH	Freight trucks	bn-vmt	8.59	7.91	8.86	9.92	11.07	12.19	13.31	14.45	15.62	17.17	18.88	20.79	22.90
TRF	Freight rail	bn-tmt	67.17	67.37	73.77	81.59	89.58	97.97	107.14	117.26	128.32	140.40	153.61	168.06	183.88
TS	Total shipping (domestic and international)	bn-tmt	13.35	10.10	11.09	12.30	13.55	14.86	16.30	17.90	19.65	21.56	23.66	25.96	28.49
TA	Air transportation	bn-pmt	11.68	12.00	12.54	13.30	13.98	14.57	15.06	15.51	15.95	16.37	16.82	17.28	17.77
TB	Total bus (transit, intercity and school)	bn-vmt	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.18	0.18	0.18
TRP	Commuter rail	bn-pmt	0.07	0.07	0.07	0.07	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10	0.10

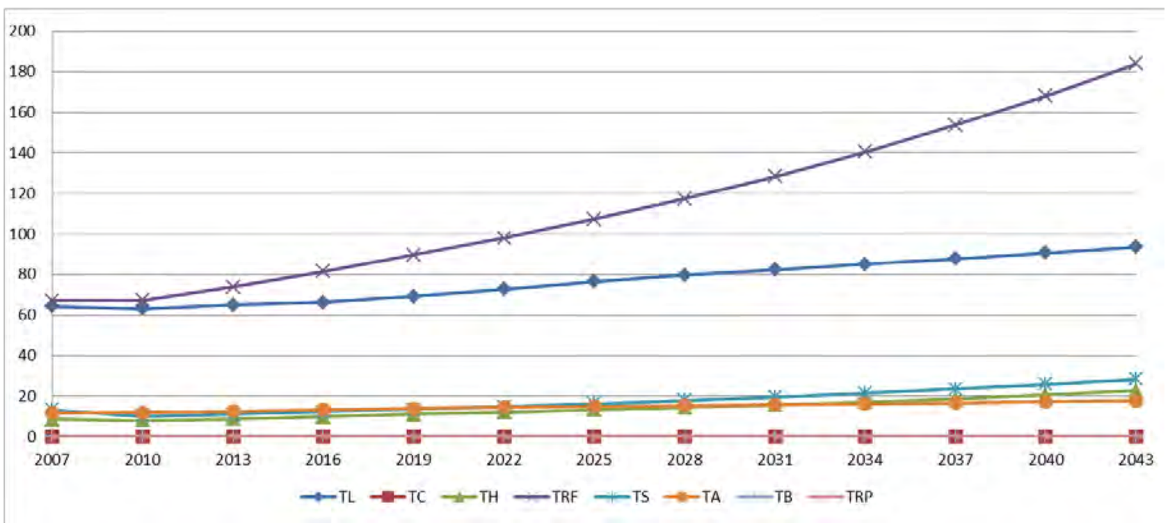

Figure 3-20 IN-MARKAL Demand for Transportation Energy Services for Eight End-Uses
Note: Various end-uses are in different units. Please refer to Table 3-109 for units by end-use.

For the last two end-uses as shown in Table 3-109 — off-highway diesel use (TOHDSL) and off-highway gasoline use (TOHGSL), base-year demand estimates are based on data from the EPA Non-Road Model[39] (ORNL, 2010) where 2008 off-highway transportation-related gasoline and diesel consumption in trillion Btu for five sectors (agriculture, industrial and commercial, construction, personal and recreational and

[39] Source: Transportation Energy Databook, Edition 29, Table 2.9 Off-Highway Transportation-Related Fuel Consumption from the Non-Road Model

other) at the national level are aggregated across sectors respectively to derive national total transportation-related off-highway gasoline and diesel consumption for 2008. They are then adjusted to 2007 based on data from EIA AEO 2010 Table 44 and Table 46, where projections of fuel consumption (diesel and gasoline respectively) from agriculture, construction and recreational boats are aggregated by year (from 2007 to 2035). The aggregated fuel consumption data for 2007 and 2008 are then used to scale the 2008 gasoline and diesel consumption from the EPA Non-Road Model to 2007 estimates. Estimates of diesel and gasoline consumption for 2007 at the national level are then shared out to Indiana based on the Indiana share of non-highway use of gasoline over the nation calculated according to data from the Federal Highway Administration[40] (FHWA, 2007). Due to the lack of data for non-highway diesel consumption, it is assumed that identical state share is applied to diesel as well.

Projections of Indiana off-highway diesel and gasoline use are driven by the aggregated fuel consumption data from AEO2010 mentioned in the previous paragraph. Because AEO2010 data end at 2035, projections beyond 2035 are driven by the annual growth rate from 2034 to 2035. Results are shown in Table 3-123 and graphed in Figure 3-21.

Table 3-123 IN-MARKAL Off-Highway Diesel and Gasoline Use

End-use	Description	Unit	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
TOHDSL	Off-highway diesel use	PJ	50.58	44.65	50.59	51.07	51.31	51.03	51.11	51.20	51.35	51.60	52.13	52.39	52.65
TOHGSL	Off-highway gasoline use	PJ	6.47	5.95	6.58	6.64	6.68	6.65	6.65	6.66	6.66	6.66	6.68	6.69	6.69

[40] Source: FHWA, Highway Statistics Report 2007, Private and commercial non-highway use of gasoline – 2007

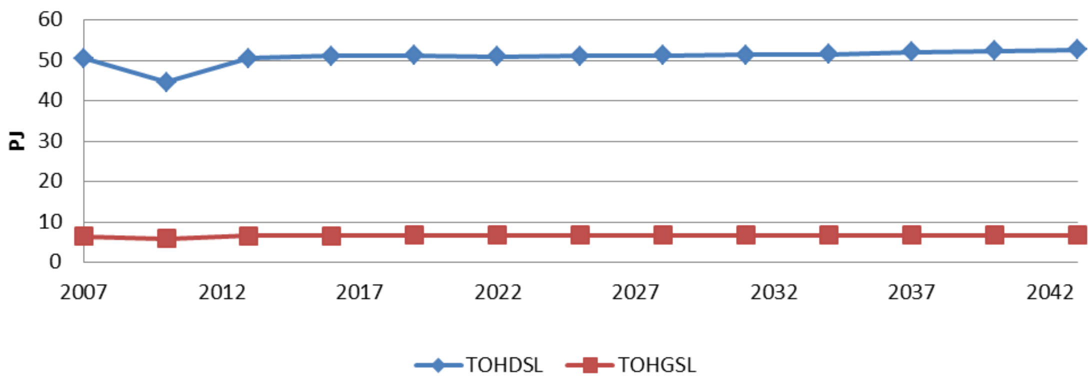

Figure 3-21 IN-MARKAL Off-Highway Diesel and Gasoline Use

3.2.3.4.2 Transportation Demand Technologies

The demand technologies in the transportation sector are grouped into nine categories. The naming conventions of the transportation technologies already existing at the beginning of the model horizon are shown in Table 3-124. Light-duty vehicle is the only end-use category represented with demand technologies which differ by vehicle type and fuel. Air transportation includes two demand technologies representing jet passenger and general aviation respectively. The other end-uses have demand technologies which differ by fuel only. New technologies in the transportation sector follow specifications in EPAUS9r.

Table 3-124 Naming Convention of Existing Transportation Demand Technologies

Demand technologies - transportation						
Characters						
1	2		3/4/5		6/7/8	
Sector	End-use	Description	Type	Description	Fuel	Description
T	L	Light-duty vehicle	EMC	Mini-compact, existing	GSL	Gasoline
			EC	Compact, existing	DSL	diesel
			EF	Full-size car, existing	ETHX	E85
			ESS	SUV-small, existing	CNGX	Compressed natural gas (CNG)
			ELS	SUV-large, existing	LPGX	Liquefied petroleum gas (LPG)
			EM	Minivan, existing	ELC	Electricity
			EP	Pickup, existing		
			E	Flexible fuel vehicle, , existing		
	C	Commercial light trucks			GSLE	Gasoline, existing
					DSLE	Diesel, existing
	H	Heavy trucks			CNGE	CNG, existing
					DSLE	Diesel, existing
					GSLE	Gasoline, existing
					LPGE	LPG, existing
	RF	Freight rail			DSLE	Diesel, existing
	S	Shipment			DSHE	Residual oil, existing
					DSLE	Diesel, existing
	A	Airplane	JE	Jet passenger, existing		
			PE	General aviation, existing		
	B	Bus			DSLE	Diesel, existing
					GSLE	Gasoline, existing
					NGE	CNG, existing
	P	Commuter rail			DSLCR	Diesel, commuter rail
					ELCCR	Electricity, commuter rail
	O	Off-highway			DSL1	Diesel
					GSL1	Gasoline

To estimate base-year capacities of existing transportation demand technologies, different methodologies are used.

Light-duty vehicle (TL)

TL is the most complicated end-use category. Our estimation starts with the base-year energy service demand for the TL in bn-vmt as shown in the first column of Table 3-125 (number drawn from Table 122). This number is shared out between passenger cars and light trucks based on shares derived from 2007 vmt for passenger cars and two-axle, four-tire trucks from FHWA' Highway Statistics 2009 (FHWA, 2009), as shown in columns two and three of Table 3-125.

Table 3-125 Base-Year Capacity Estimation for Light-Duty Vehicle Demand Technologies

TL base-year energy service demand	Size class	Share	Car type	Share	Fuel type	Share	RESID
64.4913	Passenger cars	60.06%	Mini-compact	3.14%	Gasoline	100.00%	1.2157
			Compact	52.94%	Gasoline	100.00%	20.5045
			Full size	43.92%	Gasoline	95.75%	16.2899
					Diesel	1.50%	0.2551
					E85	1.68%	0.2854
					CNG	0.20%	0.0344
					LPG	0.83%	0.1417
					Electric	0.03%	0.0057
	Light trucks	39.94%	SUV-small	14.84%	Gasoline	100.00%	3.8223
			SUV-large	12.64%	Gasoline	100.00%	3.2565
			Minivan	29.01%	Gasoline	100.00%	7.4720
			Pickup	43.51%	Gasoline	95.75%	10.7322
					Diesel	1.50%	0.1680
					E85	1.68%	0.1880
					CNG	0.20%	0.0226
					LPG	0.83%	0.0934
					Electric	0.03%	0.0038

Passenger cars include three types — mini-compact car, compact car and full size car. Total energy service demand for passenger cars is distributed into the three car types based on shares calculated from new car purchases by type (mini-compact, compact and full size) retrieved from EPA.[41] Shares of the three types of passenger cars add up to one and are shown in the upper block of columns four and five of Table 3-115.

Light trucks include four vehicle types — small SUV, large SUV, minivan and pickup. Total energy service demand for light trucks is distributed into three vehicle types first based on portions calculated from vehicle numbers by type (SUV, minivan and pickup) for ENC obtained from EIA's Transportation Energy Consumption Survey (TECS) Table A16. Then the share of SUV is further split into small SUV and large SUV based on EPA data on new car purchases by type (small SUV and large SUV).[42] Shares of the four vehicle types within light trucks add up to one and are shown in the lower block of columns four and five.

[41] Source: EPA contact Carol Shay
[42] Source: EPA contact Carol Shay

Energy service demand for a car type is shared out among various fuels for full size car and pickup. The other car types are fueled by gasoline only. Therefore, 100% of their energy service demands are allocated to gasoline. The same set of data is used to split full size and pickup into various fuels. Based on AEO2010 Table 60, light-duty vehicle bn-vmt by fuel (aggregated across technologies by fuel) is used to calculate shares of gasoline, diesel and other (95.75%, 1.50% and 2.75% respectively). The other fuel category is further split into E85, CNG, LPG and electricity according to number of alternative refuel sites by fuel for the ENC[43] (ORNL, 2010). Shares of fuels for each car type are shown in columns six and seven of Table 3-125.

Base-year capacities of light-duty vehicle demand technologies are shown in the eighth column of Table 3-125. They are calculated based on previously-estimated shares. For example, existing full size gasoline vehicle (TLEFGSL) has base-year capacity amounting to 16.2899 bn-vmt (the third number in the eighth column of Table 3-125), which is equal to 64.4913 (column one of Table 3-125) × 60.06% (first number in the third column of Table 3-125) × 43.92% (third number in the fifth column of Table 3-125) × 95.75% (third number in the seventh column of Table 3-125). Base-year capacities of full size car and pick-up fueled by E85, CNG, LPG and electricity are aggregated by fuel and serve as input to IN-MARKAL. For, example, the base-year capacity of existing flexible fuel vehicle fueled by CNG (TLECNGX) is 0.0570 bn-vmt, which is the sum of 0.0344 (the sixth number in the eighth column of Table 3-125) and 0.0226 (the fifteenth number in the eighth column of Table 3-125).

Air transportation (TA)

To estimate base-year capacities of existing air transportation demand technologies, the demand for TA expressed in bn-pmt is used (the number in the first column of Table 3-126). The TA is categorized into two classes — jet passenger and general aviation. Shares of the two classes are retrieved from the EPAUS9r 2010 version

[43] Source: ORNL Transportation Energy Data Book: Edition 29, Table 6.4 Number of alternative refuel sites by state and fuel type, available at: http://cta.ornl.gov/data/chapter6.shtml.

as shown in the third column of Table 3-126. Base-year capacity of an air transportation technology is calculated by multiplying energy service demand for the TA by the share of the technology. Results are shown in the fourth column of Table 3-126.

Table 3-126 Base-Year Capacity Estimation for Air Transportation Demand Technologies

Demand for TA in bn-pmt	Type	Share	RESID
11.6757	Jet passenger	97.73%	11.4110
	General aviation	2.27%	0.2647

The rest end-uses

For the other end-uses, demand technologies for each end-use differ by fuel only. Base-year capacities are based on data from Table 3-119 converted to their energy service units based on corresponding energy intensity data in Table 3-120.

The following list describes parameters used to characterize transportation demand technologies. All costs are expressed in millions of 2007 U.S. dollars. Energy quantities are expressed in various units as shown in Table 3-109

START: This parameter specifies the year a technology becomes available.

LIFE: This parameter specifies the lifetime of a technology in years, which is obtained from EPAUS9r.

DISCRATE: This parameter specifies the discount rate associated with an individual technology, which is obtained from EPAUS9r. Most existing transportation demand technologies have a discount rate of 0.18 (i.e. 18 percent per year). New technologies have equal or higher discount rates vary from 0.18 to 0.44.

RESID: This parameter specifies the residual capacity in each model period for technology already installed at the beginning of the modeling horizon (2007). Estimation of base-year RESIDs for existing technologies has been described previously. RESIDs for existing light-duty vehicle demand technologies for periods after 2007 are calculated based on estimated scrappage rates from EPAUS9r.

IBOND (BD): This parameter specifies a user-defined bound on new investment. BD can be set as LO (lower bound), UP (upper bound) or FX (fixed bound). Usually, upper bounds on existing technologies are set at zero to prevent investing into existing technologies. Sometimes, upper bounds of zero are placed on new technologies for certain periods in order to prevent investment into older versions of technologies when newer versions become available.

EFF: This parameter specifies the technical efficiency of a transportation demand technology, which is expressed in energy service output per PJ of energy input. Energy service output is in different units for different end-uses as shown in Table 3-109.

INVCOST: Investment cost is specified in millions of 2007 dollars per unit of technology capacity, which is in units specified in Table 3-109 for different end-uses.

FIXOM: Fixed operation and maintenance costs are expressed in millions of 2007 dollars per unit of technology capacity.

3.2.3.4.3 Transportation Energy Carriers

Table 3-127 lists energy carriers fed into transportation demand technologies in IN-MARKAL. The first two or three letters represent a combination of sector and end-use or sector alone, the rest letters stand for the fuel type.

Table 3-127 Transportation Sector Energy Carriers

Name	Description
TRNELC	Electricity to transportation sector
TRNNGA	Natural gas to transportation sector
TRNCNG	Compressed natural gas (CNG) to transportation sector
TBCNG	CNG to transportation sector buses
TRNDSL	Diesel to transportation sector
TBDSL	Diesel to transportation sector buses
TLGSL	Gasoline to transportation sector light-duty vehicles
TBGSL	Gasoline to transportation sector buses
TCGSL	Gasoline to transportation sector commercial light trucks
THGSL	Gasoline to transportation sector heavy trucks
TBB20X	B20 to transportation sector buses
TCB20X	B20 to transportation sector commercial light trucks
THB20X	B20 to transportation sector heavy trucks
TRB20X	B20 to transportation sector commuter rail
TLE85X	E85 to transportation sector light-duty vehicles
TCE85X	E85 to transportation sector commercial light trucks
TRNLPG	LPG to transportation sector
TRNLPGX	Liquefied petroleum gas (LPG) to transportation sector light-duty vehicles
TRNJTF1	Jet fuel to transportation sector
TRNRFH1	Residual fuel oil to transportation sector shipments
TRNGSLB	Aviation gasoline to transportation sector general aviation
TRNH2	H2 to transportation sector commercial light trucks

CHAPTER 4. SCENARIO FORMATION

In this chapter, focus will be placed on major scenarios modeled with IN-MARKAL. They are renewable portfolio standard (RPS) scenarios, carbon tax scenarios and rate-based (lbs CO_2/MWh) carbon cap scenarios. In each one of the following sections, a brief introduction of the policy is included, and relevant literature is surveyed. Finally, details of each model scenario are described.

4.1 Renewable Portfolio Standard and Renewable Energy Credit

A Renewable Portfolio Standard (RPS) is a regulatory tool which requires power suppliers to source a certain percentage (amount) of their retail electricity sales (or a certain amount of generating capacity) from renewable resources according to a specified schedule. The purpose of a RPS is to encourage the deployment of renewable technologies in electricity generation and thus to reduce the reliance on fossil fuels as power sources. Since renewables have zero or low carbon emissions compared with conventional sources, the growth of renewable generation is expected to have a positive impact on carbon mitigation.

By March 2013, 29 states plus Washington, D.C. and 2 territories (Northern Mariana Islands and Puerto Rico) have RPS programs (DSIRE, 2014). Detailed information of these programs can be obtained from the Database of State Incentives for Renewables & Efficiency.[44] In fact, no two states have the same RPS. There are many elements in the design of a RPS. One of the key elements is the renewable generation

[44] Available at: http://www.dsireusa.org/.

target expected to be achieved by the state and the schedule for achieving the target. Most states have a series of phased targets, which start at a low level and gradually increase over time. Some states set more ambitious goals and some only pursue a small or moderate increase in renewable generation. In summary, the target set by U.S. states ranges from 10% to 40% by 2015-2030. Here are a few of the many factors taken into consideration when a state sets a RPS target: the endowment of renewable resources in-state, local economic and environmental benefits from the development of green power, and the acceptable level of electricity rate increases attributable to RPS compliance.

Another important element of a RPS design is the definition of eligible sources, which differs markedly by state. The three major criteria defining eligible sources include technology, geography and start-up date. For example, Maryland includes ocean as qualifying source for RPS, while Pennsylvania does not. In terms of geographic eligibility and start-up date, an example would be New Jersey. Its RPS requires eligible energy to be generated within or delivered into the PJM region. If the latter, the energy must have been generated at a facility that commenced construction on or after January 1, 2003 (PJM EIS, 2014).

Some states divide RPS mandates into multiple tiers based on technology, and/or start-up date as well. For instance, Massachusetts has Class I and Class II RPS.[45] Under the Class I RPS, all retail electricity suppliers must provide a minimum percentage of KWh sales to end-use customers in Massachusetts from eligible renewable energy resources installed after December 31, 1997. Class II renewables include eligible facilities operating before December 31, 1997. Another example would be New Hampshire,[46] which breaks RPS into four distinct standards for different types of energy resources. Class I applies to a collection of renewable energy technologies operating after January 1, 2006. Class II addresses electricity generated by solar technologies

[45] Source: DSIRE website, available at: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MA05R&re=0&ee=0.
[46] Source: DSIRE website, available at: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NH09R&re=0&ee=0.

operating after January 1, 2006. Class III applies to generation from biomass systems with a capacity up to 25 MW and methane gas which began operation before January 1, 2006. Class IV addresses small hydroelectric power stations that began operation before January 1, 2006.

For a specific RPS, only generation from those facilities defined as eligible qualifies for renewable energy credits (RECs), which are authorized for the compliance of the specific RPS. In other words, RECs are labeled in terms of RPS eligibility and a new REC product is created for every new RPS[47] (PLATTS, 2012). As mentioned, the state of New Hampshire has four distinct RPSs. Therefore, four REC products are created and are named New Hampshire Class I, New Hampshire Class II, New Hampshire Class III and Hampshire Class IV respectively. Although most states allow RECs to be traded within a state or even across state lines, the trading is constrained by the geographic eligibility of a RPS. Because of this, it makes no sense for a power producer to buy RECs generated from sources outside of the eligible geographic area defined in its RPS mandate for the purpose of RPS compliance. In the case that a state's RPS includes a wide geographic area including regions beyond its borders, the impact of such a policy might be weakened in terms of in-state green power development and carbon mitigation. However, a very tight geographic definition might result in dramatic cost increases in power generation and related REC products, which will be borne by ratepayers eventually.

The REC price is difficult to predict in the compliance market. The price of a REC product is largely determined by its supply demand balance on an annual basis. The supply and demand for a REC product is influenced by the design of the RPS. Usually, an oversupply will keep REC prices lower and an undersupply will push REC prices higher. However, if banking of credits is allowed, other factors, such as phase-in schedules and expectations for future compliance alternatives and their costs, also play a role. In some

[47]Source: Special Report of Renewable Energy Certificates by PLATTS published in April 2012, available at: http://www.platts.com/IM.Platts.Content/InsightAnalysis/IndustrySolutionPapers/RECSpecialReport1112.pdf. This publication provides thorough information pertain to the REC market, covering REC demand, supply, trading and pricing.

RPS designs there are alternative compliance payments (ACPs),[48] and these provide a cap on the REC price.

In current market for RECs, we see REC prices varying widely. In a publication by PLATTS[49] (PLATTS, 2012), the author contends that REC supply and demand are unresponsive to price in both short run and long run. In the short run, capacity is assumed to be fixed because it typically takes years to build a new project. Suppliers of REC can ramp existing facilities up or down, but with that ability being limited due to fixed capacity in the short run and exacerbated by the intermittent nature of some renewables. At the same time, demand for RECs is fixed by a state's RPS requirement without any substitute product. In the long run, demand for RECs is still determined by the RPS requirement and is inelastic to price. The only variability in demand may be due to a change in retail load associated with the macro-economic situation. On the supply side, developers will eventually build new facilities to boost the supply if projects are economically feasible. Ideally, supply would increase incrementally to match demand. But evidence suggests that, because of lumpy capacity, there can be dramatic increases in supply that outpaces demand in numerous cases. This famine-to-feast phenomenon sends REC prices plummeting. Developers eventually respond to that price signal by halting construction, but the market remains over-supplied until demand catches up. Therefore, the author concludes that the REC market exists in a continuous state of disequilibrium, which explains the huge variability of REC prices over time. Figures 4-1 and 4-2 illustrate the compliance market (primary tier) REC prices from January 2008 to July 2013.[50] Dramatic changes in price are observed for most REC products in the New

[48] The ACP is a penalty fee borne by a load-serving entity if it fails to generate sufficient renewable energy and purchase RECs to comply with RPS. It is measured in dollars per MWh of RPS requirement not satisfied. In the case that the REC price exceeds the cost of the equivalent ACP, a load-serving entity would choose the ACP instead of buying RECs in the market. Thus, there is no role for RECs if they are priced higher than the ACP.

[49] Please refer to the Special Report of Renewable Energy Certificates for detailed explanation of REC market dynamics.

[50] Graphs were retrieved from the Green Power Network, which is operated and maintained by the National Renewable Energy Laboratory (NREL) for the U.S. Department of Energy. It provides up-to-date

England region and PJM Interconnection over the 6-year period. Especially for the states within the New England region, REC prices range from close to zero to more than $60/MWh. The REC market in Texas is an exception to this pattern; REC prices to serve the Texas RPS have stayed at relatively low levels (under $5/MWh) due to the enormous capacity of wind resources in the state resulting in a large volume of available RECs while the RPS requirements in the state are relatively low. According to the annual compliance report,[51] Texas surpassed its 2025 target of 10,000MW renewable energy capacity in 2009 and had 13,650 MW of renewable energy capacity (12,933 MW of which was wind) in 2014.

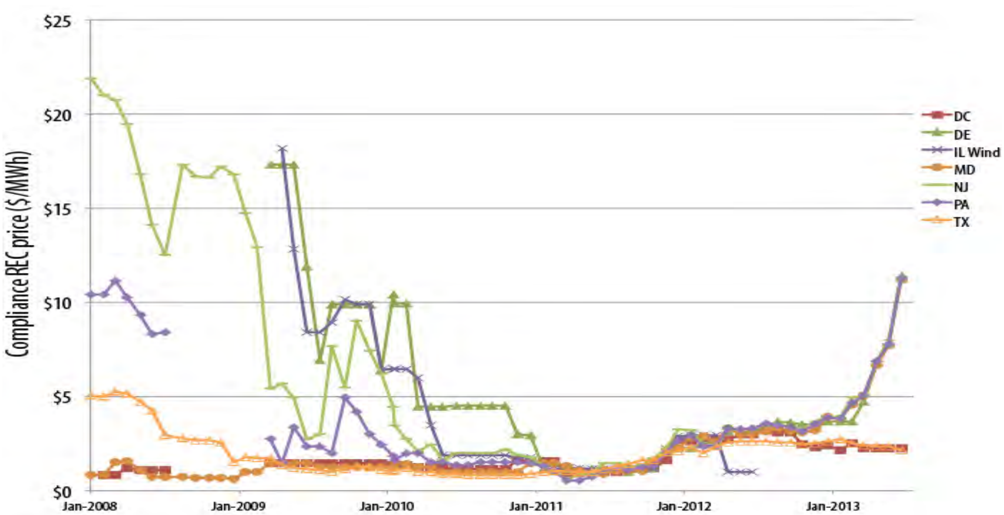

Figure 4-1 Compliance Market (Primary Tier) REC Prices, January 2008 to July 2013
Source: MarexSpectron (2013), retrieved from The Green Power Network at
http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5

information on green power providers, product offerings, consumer protection issues, and policies affecting green power markets.
[51] Source: DSIRE website, available at:
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=TX03R&re=0&ee=0.

Figure 4-2 New England Compliance Market (Primary Tier) REC Prices, January 2008 to July 2013

Source: MarexSpectron (2013), retrieved from The Green Power Network at http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5

Note: Plotted values are the last trade (if available) or the mid-point of bid and offer prices for the current or nearest compliance year for various state compliance RECs.

In this research, two alternative potential RPS programs for Indiana are modeled — a less stringent RPS target and a more stringent RPS target. The less stringent target requires that at least 7% of electricity generation from renewable sources must be achieved by 2019 and 10% by 2025 and after. This is based on the target specified in Indiana's Clean Energy Portfolio Goal adopted in 2012. (That goal is a voluntary program including not only renewable technologies but also a number of additional low-emission or zero-emission technologies as eligible sources. The program provides financial incentives for utilities to pay for compliance projects if they meet the program goals (EPA, 2012c). However, no utilities have filed the application to participate in the program thus far.[52]) A more stringent case specifies target of at least 16% of renewable generation in 2019 and 25% in 2025 and thereafter. This target roughly lies in the middle of the range of U.S. state RPS targets already in place. Eligible renewable generation sources include solar photovoltaic (PV), wind, biomass for integrated

[52] Information was obtained from a conversation with Bradley Borum from Indiana Utility Regulatory Commission in April 2014.

gasification combined cycle (IGCC) and combined heat and power (CHP), municipal solid waste, landfill gas and hydro.

For both targets, scenarios where all eligible renewable generation needs to come from internal resources are modeled. For the more stringent RPS target, four additional scenarios are modeled which allow RECs produced out-of-state to be purchased freely across state lines to comply with Indiana RPS at a constant cost of $15/MWh, $40/MWh, $45/MWh, and $50/MWh. Please refer to Table 4-1 for a description of all RPS scenarios.

Table 4-1 RPS Scenarios Name and Description

Case Name	Name Description
RPSLSWO	RPS less stringent case (7% by 2019 and 10% by 2025); RECs produced out-of-state not eligible
RPSMSWO	RPS more stringent case (16% by 2019 and 25% by 2025); RECs produced out-of-state not eligible
RPSMSW15	RPS more stringent case (16% by 2019 and 25% by 2025); RECs produced out-of-state eligible; RECs cost $15/MWh
RPSMSW40	RPS more stringent case (16% by 2019 and 25% by 2025); RECs produced out-of-state eligible; RECs cost $40/MWh
RPSMSW45	RPS more stringent case (16% by 2019 and 25% by 2025); RECs produced out-of-state eligible; RECs cost $45/MWh
RPSMSW50	RPS more stringent case (16% by 2019 and 25% by 2025); RECs produced out-of-state eligible; RECs cost $50/MWh

Modeling of RPS is realized through rule-based constraints. Technology filters are created to group renewable generation technologies (ELC-RNW) and all generation technologies (ELC-ALL). Taking RPSLSWO scenario as an example, specifications of the constraint are shown in Table 4-2. The RAT_RHS parameter specifies the number on the right hand side of the constraint and LO represents a lower bound (the left hand side greater or equal to the right hand side). RATRULE_ACT specifies coefficient of technology activity level for specific technology and specific period. (ELC-ALL in this case tracks total electricity generation; ELC-RNW tracks electricity generation from renewable resources.) For 2019, the relationship presented in Table 4-2 can be translated into $1.00*\text{ELC-RNW} - 0.07*\text{ELC-ALL} \geq 0$. For the period between 2019 and 2025, although constraint is not exogenously specified, it is incorporated into the model automatically by linear interpolation of the constraints specified for 2019 and 2025.

Table 4-2 RPS Specifications in IN-MARKAL

ConstrName	TechName	RAT__RHS LO 2019-2043	RATRULE_ACT 2019	RATRULE_ACT 2025-2043
IN_RPSLSWO	ELC-ALL	0.00	-0.07	-0.10
	ELC-RNW		1.00	1.00

4.2 Carbon Tax

A carbon tax sets a price on carbon dioxide emitted from a fuel, which weakens the economic competitiveness of fossil fuels relative to renewable forms of energy through extra costs incurred. Therefore, a carbon tax offers a way of reducing greenhouse gas emissions by creating economic incentives.

Thus far, no nationwide carbon tax has been imposed in the United States. But a few carbon tax programs created in smaller jurisdictional areas have been implemented. In November 2006, Boulder (CO) voters passed the Climate Action Plan tax to mitigate carbon emissions, which was renewed in 2012.[53] Residents and businesses of Boulder are taxed based on the amount of electricity they consume. But customers who subscribe to wind-generated power through Xcel Energy's Windsource program are not taxed for that portion of their electricity use. In May 2008, the San Francisco Bay Area Air Quality Management District's board passed a carbon tax on businesses at a cost of 4.4 cents per ton of CO_2 emissions.[54] Seven local power plants and oil refineries are the biggest payers of this carbon tax. In the state of Maryland, Montgomery County established the nation's first county-level carbon tax in May, 2010.[55] The cost of the carbon tax was set at $5 per ton of emissions and applies to any source that emits over one million tons of carbon dioxide in a calendar year.

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[53] Source: https://bouldercolorado.gov/climate.
[54] Source: http://www.environmentalleader.com/2008/05/22/sf-bay-area-passes-carbon-tax/.
[55] Source: http://www6.montgomerycountymd.gov/content/council/mem/berliner_r/pdfs/carbon_tax_fact_sheet.pdf.

In this study, scenarios where a carbon tax is charged for CO_2 emissions from Indiana power generator beginning in 2016 are modeled. Three carbon tax trajectories are developed in accordance with the methods summarized by Parry (2009) who classifies the methods for developing the trajectories into two distinct categories. One is called the cost-effectiveness approach and the other one is referred as the welfare maximizing approach. The cost-effectiveness approach seeks to find the economically optimal carbon emissions pricing trajectories for stabilizing the amount of projected climate change or atmospheric GHG accumulations at a certain level. The paper mentions that one particularly good study in this category is by Clarke et al (2007), in which results from three modeling teams are included. According to their projections, CO_2 emissions should be priced at about $5 to $25 per ton by 2025 and $10 to $70 per ton by 2050 in order to limit atmospheric CO_2 concentrations to 550 parts per million (ppm) at lowest cost. Mostly favored by economists, the welfare maximizing approach seeks to make the cost of CO_2 emissions at each point in time reflect the value of worldwide future warming damages caused by the marginal ton of CO_2 releases at that point in time. Parry indicates that there is a general consensus in the economics literature that the damages from a warming of around 2-3 degrees Celsius occurring in about 2100 would amount to about 1 to 3 percent of world GDP and most estimates of marginal damages from current emissions are around $5 to $25 per ton of CO_2 with an annual increase of about 2-3 percent in real terms.

Based on projections by Clarke et al (cost-effectiveness approach), one scenario for the work in this thesis is developed by using upper bounds of their estimation ($25/ton by 2025 and $70/ton by 2050). This scenario is named “carbon tax high growth rate case” (CTaxHGR) and the tax trajectory was obtained through linear interpolation and extrapolation of the two target points mentioned. In addition, there are two scenarios developed according to the welfare maximizing approach. One is referred to as the “carbon tax low start case” (CTaxLS), which starts with the tax at $5/ton in 2016 and grows at 2% annually; the other one is called carbon tax high start case (CTaxHS), beginning at $25/ton in 2016 and growing annually at 2% as well. The three carbon tax trajectories are shown in Figure 4-3 with data displayed in Table 4-2.

Table 4-3 Carbon Tax Scenarios (Tax Rate in 2007 $/Metric Ton of CO_2 Emissions)

Case	Name Description	2016	2019	2022	2025	2028	2031	2034	2037	2040	2043
CTaxLS	Carbon tax low start case	5.00	5.31	5.63	5.98	6.34	6.73	7.14	7.58	8.04	8.53
CTaxHS	Carbon tax high start case	25.00	26.53	28.15	29.88	31.71	33.65	35.71	37.89	40.21	42.67
CTaxHGR	Carbon tax high growth rate case	8.80	14.20	19.60	25.00	30.40	35.80	41.20	46.60	52.00	57.40

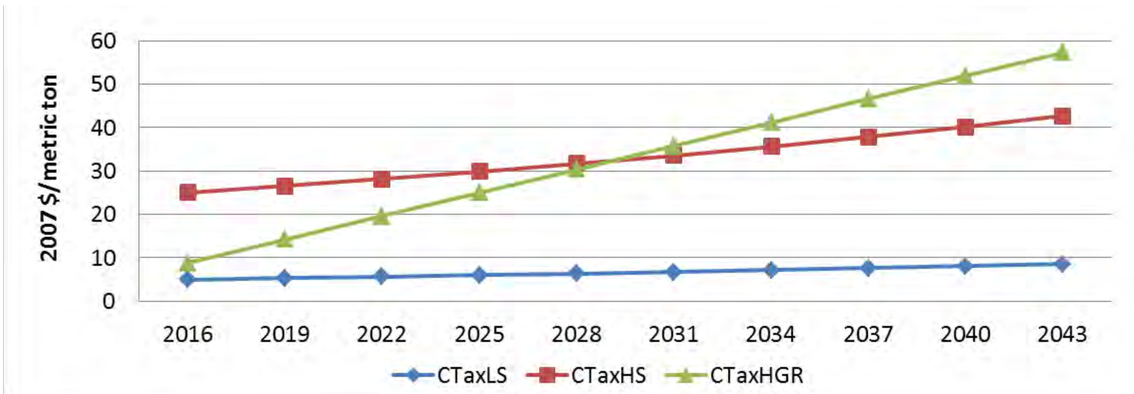

Figure 4-3 Carbon Tax Trajectories

Carbon tax is modelled in IN-MARKAL with a parameter specified for CO2E (CO_2 emissions from the power sector). The parameter is named ENV_COST and carbon tax is expressed in 2007 million dollars per thousand tons of CO_2 emissions from the power sector.

4.3 Rate-Based Carbon Cap

Cap and trade is an environmental policy tool that places a mandatory cap on emissions while providing sources flexibility in how emitters can comply.[56] Emission sources can choose to prevent additional emissions above its limit through reduced activity, installation of pollutant control devices, fuel switching, efficiency improvement, or combinations of these measures. They can also purchase emission permits in the market for the amount of emissions above the quantity allowed. The decision to control

[56] Definition by EPA, available at: http://www.epa.gov/captrade/.

the extra amount of the pollutant or continue to emit, but offsetting those emissions with purchased permits is purely based on the economic efficiency of the two alternatives. Therefore, cap and trade offers a market-based approach to achieve the emission reduction goal.

Cap and trade has been successfully applied for the control of SO_2 and NO_x emissions by the U.S. Environmental Protection Agency (EPA) since 1995 and 2003, respectively. They are the nationwide Acid Rain Program (targets SO_2 emissions from fossil fuel-fired power plants and NO_x emissions from coal-fired electric utility boilers to reduce acid deposition and improve air quality; cap and trade applied on SO_2 emissions only),[57] the regional NO_x Budget Trading Program (targets NO_x emissions from power plants and other large combustion sources in the eastern U.S. to reduce ground-level ozone (smog) during the warm summer months; cap and trade program created to reduce NO_x emissions),[58] and Clean Air Interstate Rule (targets SO_2 and NO_x from power plants located in 27 eastern states and the District of Columbia to deal with the problem of power plant pollution that drifts from one state to another; cap and trade applied for reducing both SO2 and NOx).[59]

Nationwide, no cap and trade program intending to curb CO_2 emissions has been implemented by the EPA or through a federal legislation to date. In 2009 and 2010, a few legislative proposals for a nationwide cap and trade program for the reduction of CO_2 emissions were introduced, including American Clean Energy and Security Act, Clean Energy Jobs and American Power Act, Carbon Limits and Energy for American's Renewal Act and American Power Act. However, the U.S. Senate failed to adopt any of them at the end.

In the absence of action by the federal government, a few states have established state or regional level cap and trade programs. The Regional Greenhouse Gas Initiative

[57] Source: http://www.epa.gov/airmarkets/progsregs/arp/basic.html.
[58] Source: http://www.epa.gov/airmarkets/progsregs/nox/sip.html.
[59] Source: http://www.epa.gov/airmarkets/progsregs/cair/index.html.

(RGGI)[60] is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap and reduce power sector CO_2 emissions. The RGGI CO_2 cap represents a regional budget for CO_2 emissions from the power sector, with each CO_2 allowance representing a limited authorization to emit one short ton of CO_2. Regulated sources include fossil fuel-fired electric power generators with a capacity of 25 MW or greater. CO_2 allowances are allocated through quarterly, regional CO_2 allowance auctions. Proceeds from the allowance auctions are invested in programs to improve end-use energy efficiency, to accelerate the deployment of renewable energy technologies and to help reduce electricity consumers' energy bill. Carbon offsets certified for carbon emissions reduction or sequestration projects outside the capped sector, but located within one of the RGGI States, are allowed to help regulated sources meet their compliance obligations. The RGGI States cooperatively developed prescriptive regulatory requirements for the five project categories eligible for offset allowances. CO_2 offset allowances may be used to satisfy a limited portion (3.3 percent) of a regulated power plant's compliance obligation. This mechanism provides compliance flexibility and creates opportunities for low-cost emissions reductions and other co-benefits across sectors.

Another example of a regional program is California's cap and trade program established according to the AB 32, the California Global Warming Solutions Act signed into law in 2006.[61] This program took effect in early 2012 and the enforceable compliance obligation began on January 1, 2013. It sets a statewide limit on sources responsible for 85 percent of California's greenhouse gas emissions, including large industrial facilities and electric utilities. The emission cap is progressively more stringent over time. Banking of allowances[62] is permitted to guard against shortages and price

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[60] Source: http://www.rggi.org/design.

[61] Source: http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.

[62] Allowances for a current or previous compliance period may be banked, while allowances for a future period may also be held. Allowances do not expire until they are surrendered to and retired by the Executive Officer, are voluntarily retired, or are retired by an external trading system linked to the

swings. Carbon offsets limited to emission-reduction projects in the U.S. are allowed for up to 8 percent of a facility's compliance obligation. Every year, capped industries submit allowances and offsets for 30 percent of previous year's emissions for compliance; and every three years, these industries submit allowance and offsets covering the remainder of emissions in that three-year compliance period. In the event that a firm is unable to reduce emissions or acquire sufficient allowances and offsets to be in compliance, penalties will be imposed. The penalty requires the firm to purchase four tons of allowances or offsets for every ton of emissions for which it is late in complying.

The carbon cap scenarios developed in this study are based on an EPA proposal published on June 2, 2014. This proposal is named Clean Power Plan, which has the goal of cutting carbon emissions from the power sector by 30 percent from the 2005 levels by 2030 nationally, and making progress toward meaningful reductions in 2020 (EPA, 2014c). By recognizing the existing mix of power sources for each state, the EPA sets state-specific goals based on the so-called the best system of emission reductions (BSER) under the Clean Air Act, which identifies a mix of four "building blocks." (The four "building blocks" are (1) making coal steam units more efficient, (2) using NGCC units more, (3) expanding renewable generating capacity and using more renewable sources, and (4) increasing demand-side energy efficiency.) However, each state has the flexibility to choose how to meet the goal using a combination of measures.

The state goals are rate-based caps in terms of CO_2 emissions from fossil fuel-fired power plants in pounds (lbs) divided by the sum of state electricity generation from fossil-fuel fired power plants and certain low- or zero-emitting power sources in megawatt hours (MWh). These state goals are not requirements on individual electric generating units. Rather, each state has broad flexibility to meet the rate by 2030 by lowering the overall carbon intensity of the power sector in the state. The EPA proposed a two-part goal structure: an "interim goal" that a state must meet on average over the

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California system. However, the California Cap and Trade program limits the maximum number of allowances held by any entity in a calendar year.

ten-year period from 2020-2029 and a "final goal" that a state must meet in 2030 and thereafter. The EPA also proposed to give states the option to convert the rate-based goal to a mass-based goal (in terms of total metric tons of total CO_2 emissions) based upon a demonstration that the state's plan would achieve the equivalent in stringency, including compliance timing, to the state-specific rate-based goal set by the EPA. In addition, states have the freedom to develop a state only plan or collaborate with each other to develop plans on a multi-state basis to meet the goals outlined in the proposal.

For the state of Indiana, the interim goal proposed by EPA is 1,607 lbs/MWh on average for the 2020-2029 period and the final goal is 1,531 lbs/MWh in 2030 and thereafter, which is identified as Option 1 in Table 4-3. In addition to the proposed state goals, the EPA has developed for public comment an alternate set of goals reflecting less stringent application rate-based requirements and a shorter implementation period. The alternate final goals represent emission performance that would be achievable by 2025, with interim goals that would apply during the 2020-2024 period.[63] The alternate state goals for Indiana are shown as Option 2 in Table 4-3, with an interim goal of 1,715 lbs/MWh on average for the 2020-2024 period and a final goal of 1,683 lbs/MWh in 2025 and forward (EPA, 2014d).

Table 4-4 State Goals for Indiana Proposed by the EPA (Pounds of CO_2 per MWh Electricity)

State	Option 1		Option 2	
	Interim goal (2020-2029)	Final goal (2030 forward)	Interim goal (2020-2024)	Final goal (2025 forward)
Indiana	1,607	1,531	1,715	1,683

Because IN-MARKAL is focused only on Indiana, the scenarios modeled are for a state only plan to comply with this regulation, rather than collaborating with other states.

[63] Source: Section VII of the Clean Power Plan proposed rule, available at: https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

Due to the fact that IN-MARKAL models three years in each period, the actual time periods on which emission goals are imposed do not precisely match those in the rulemaking. For Option 1, the interim goal is applied for periods from 2019 to 2028 and the final goal is applied in period 2031 and thereafter. For Option 2, the interim goal is applied for periods from 2019 to 2022 and the final goal is applied in period 2025 and thereafter.

In addition, for interim goals in the two options, two declining trajectories of emission rates are developed for the corresponding periods so that the average emission rate across those periods equals the corresponding interim goal identified in the rulemaking and the marginal cost of emission reduction falls smoothly over time. (MARKAL does not allow imposition of an average goal across the periods defined in the interim goal as one constraint. In MARKAL, this average constraint across time periods must be approximated with period-wise constraints. If these constraints have equal marginal values, they are equivalent to the average constraint. In attempting to find a trajectory of period-wise restrictions that yielded equal marginal values while satisfying the average emission rate requirement, it becomes apparent that the relationship between the restriction and the marginal is extremely sensitive, and so a trajectory was adopted that the marginal cost of emission reduction falls smoothly over time.) The emission rate goals modelled with IN-MARKAL are displayed in Table 4-4 and Figure 4-4. The two scenarios are named CERO1 (carbon emission rate goal option 1) and CERO2 (carbon emission rate goal option 2) respectively.

Table 4-5 Carbon Emission Rate Goal in lbs/MWh Modelled with IN-MARKAL

Case	2019	2022	2025	2028	2031	2034
CERO1	1652	1629	1596	1552	1531	1531
CERO2	1730	1701	1683	1683	1683	1683

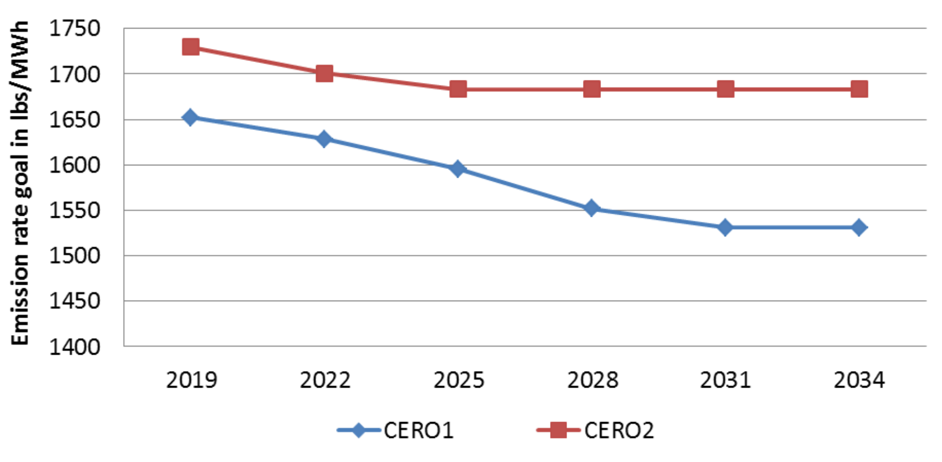

Figure 4-4 Emission Rate Trajectory

The rate-based carbon cap is modelled with rule-based constraint in IN-MARKAL. A technology filter is created to group all electricity generation technologies (ELC-ALL). The total amount of carbon emissions from the electricity generation system is tracked through commodity named CO2E. Taking the CERO1 case as an example, specifications of the constraint are shown in Table 4-6. The RAT_RHS parameter specifies the number on the right hand side of the constraint and UP represents upper bound (the left hand side less or equal to the right hand side). RAT_EM specifies the coefficient of total emissions (CO2E in this case). RATRULE_ACT specifies the coefficient of technology activity level for a specific period. (ELC-ALL in this case tracks total electricity generation.) For 2019, the relationship presented in Table 4-6 can be translated into the following constraint: $1.00*CO2E - 208.1488*ELC\text{-}ALL \leq 0$. Coefficient of ELC-ALL is the emission rate goal (1652 lbs/MWh shown in Table 4-5) converted to lbs/PJ to be used in IN-MARKAL. Constraints are also created in the model for other periods based on stricter emission rates specified over time (numbers shown in the second row of Table 4-6).

Table 4-6 Emission Rate Goal Specifications in IN-MARKAL

ConstrName	TechName	RAT__RHS	RAT_EM	RATRULE_ACT	RATRULE_ACT	RATRULE_ACT	RATRULE_ACT	RATRULE_ACT	RATRULE_ACT	RATRULE_ACT	RATRULE_ACT	RATRULE_ACT
		UP										
		2019-2043	2019-2043	2019	2022	2025	2028	2031	2034	2037	2040	2043
IN_ERC	CO2E	0.00	1.00									
	ELC-ALL			-208.15	-205.19	-201.03	-195.55	-192.90	-192.90	-192.90	-192.90	-192.90

CHAPTER 5. RESULTS

5.1 Base Scenario

This section provides a succinct summary of results observed for the BASE case. In the following sections (5.2 through 5.4), the BASE case is compared with each group of carbon policy scenarios, and details of it are discussed.

In the BASE scenario additional electricity demand is mostly met by the construction of advanced natural gas combined cycle (NGCC) plants. Among those new capacities, 0.23 GW added in 2016 represents the conversion of Harding Street Unit 5 and Unit 6 owned by Indianapolis Power Light Company (IPL) from coal steam plants to NGCC facilities at a cost of $175/KW (in 2012 dollars).[64] The rest of the 5.68 GW of new NGCC capacity is added over time based upon model choice, with the first capacity investment occurring in 2016. Small amounts of generation capacity fired by landfill gas and municipal solid waste (MSW) get constructed but not in significant quantities (0.01GW of landfill gas in 2010 and 0.02 GW of MSW in 2019). Please refer to Figure 5-1 and Figure 5-2 for capacity portfolio and investment portfolio over the entire modeling horizon.

[64]Source: Megawatt Daily issue of August 30, 2013

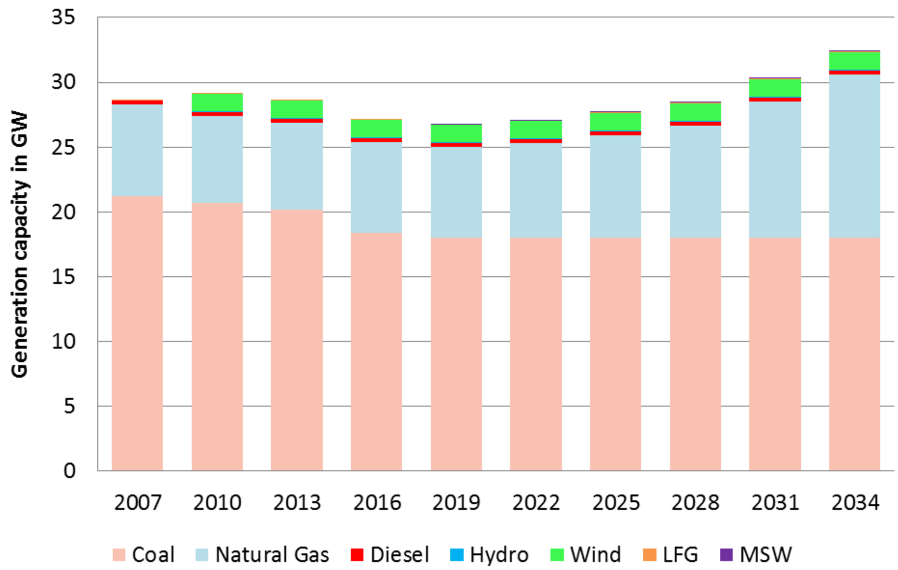

Figure 5-1 Indiana Power System Capacity Portfolio for the BASE Case

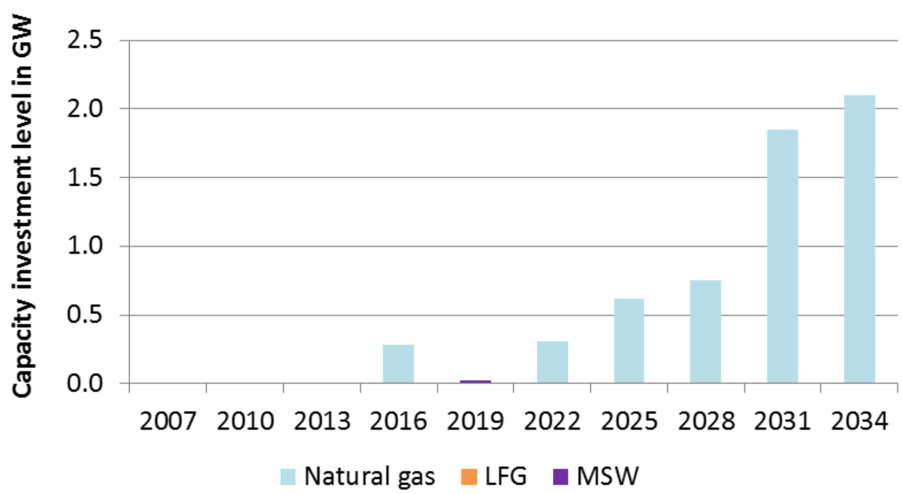

Figure 5-2 Indiana Power System Capacity Investment for the BASE Case

The role played by coal in Indiana generation portfolio diminishes significantly in the BASE case. More than 95% of total generation is from coal in 2007; but 76% by 2034 (see Figure 5-3). In regard to absolute value (see Figure 5-4), total electricity generation from coal is relatively stable over time. The share of natural gas grows dramatically and reaches almost a quarter of total generation in 2034. The amount of generation from natural gas in 2034 is around eight times of that in 2007. Without policy incentives, the percentage of wind generation varies very slightly. Diesel drops from the generation portfolio after 2013. Hydro generation does not change in quantity; but the share of hydro shrinks slightly over time due to increases of the amount of total generation. Total electricity generation experiences an annual compound growth rate of 0.94% in the period of 2007- 2034.

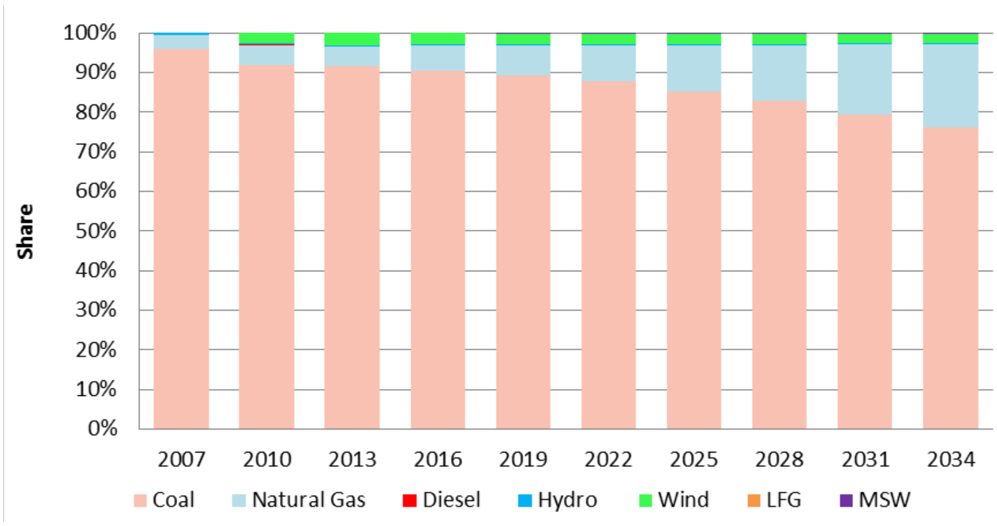

Figure 5-3 Indiana Power System Generation Portfolio in Percentage of Total Generation for the BASE Case

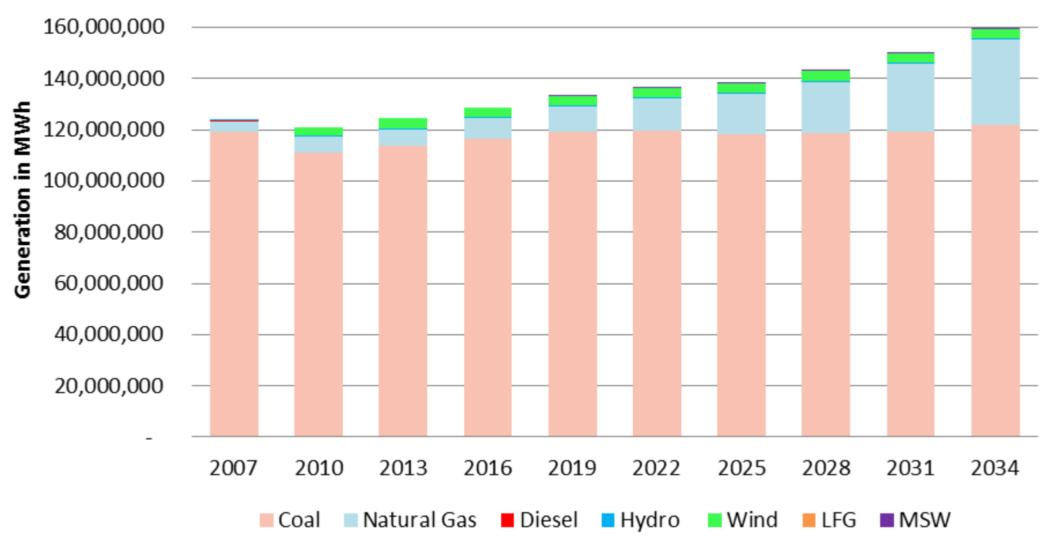

Figure 5-4 Indiana Power System Generation Portfolio in MWh for the BASE Case

Figure 5-5 displays the discounted marginal cost of electricity for Indiana. This cost indicates the incremental energy system cost induced by one more KWh of electricity generation, which can be considered a proxy for the Indiana wholesale electricity price. All costs are expressed in real 2007 dollars. The cost of electricity starts around 3.5 cents/KWh in 2007. A general growth trend is observed from the graph, except a small dip in 2025. The compound annual growth rate of electricity cost is about 1.2% over the modeling horizon.

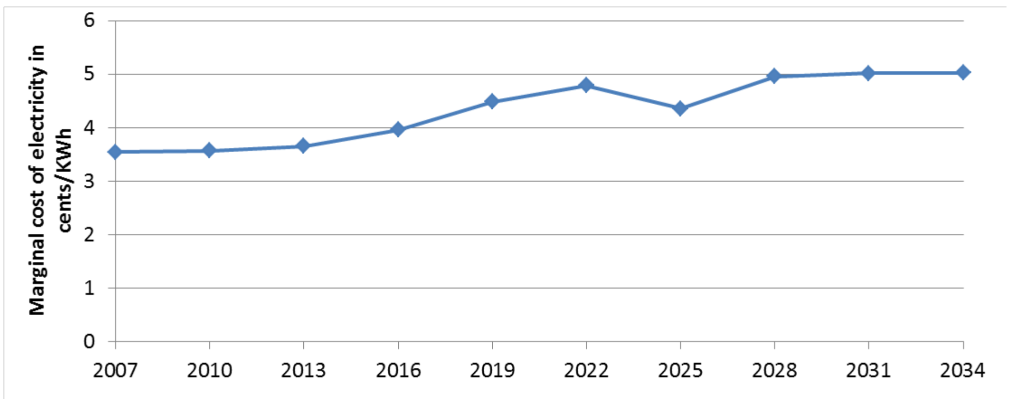

Figure 5-5 Discounted Marginal Cost of Electricity for the BASE Case

Figure 5-6 displays CO_2 emissions from the Indiana power sector in million metric tons, and the CO_2 emission rate in lbs/MWh over the modeling horizon. The total amount of CO_2 emissions from power sector is about 125 million metric tons in 2007. It decreases after 2007 due mainly to reduced demand, slowly rebounding until 2019. The total amount stabilizes from 2019 to 2028 and experiences slight growth thereafter. There are mainly two factors determining the total amount of CO_2 emissions from power sector — the quantity of electricity generation and power system average emission rate based on the generation portfolio. For example, the average emission rate decreases continuously after 2019 in Figure 5-6. But the same trend does not occur for total CO_2 emissions. This is due to the growth of electricity generation, and the degree of generation growth outpaces decreases of the emission rate caused by a higher share of natural gas and lower share of coal in the generation portfolio in the latter periods. On the other hand, the average emission rate and total generation move downward simultaneously from 2007 to 2010. In this period, the total amount of CO_2 emissions declines further than the emission rate.

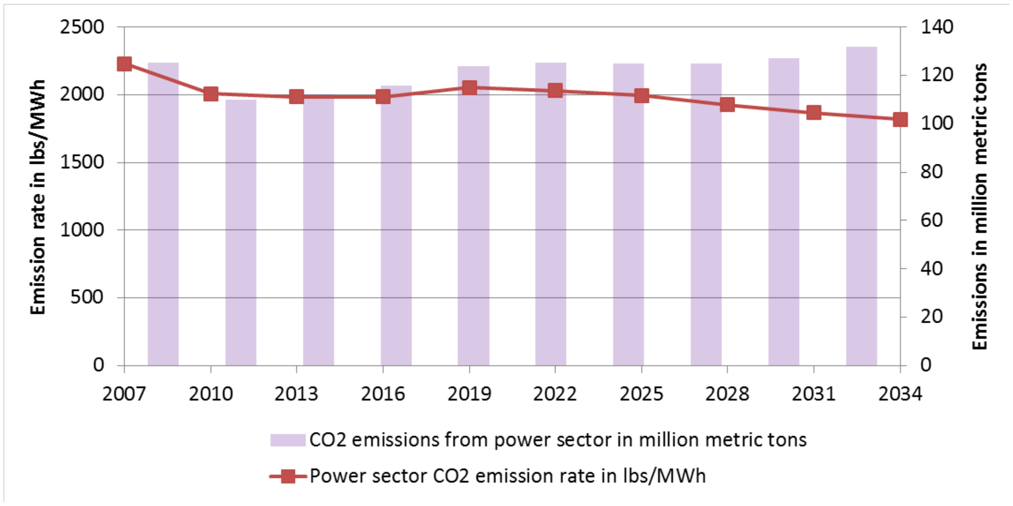

Figure 5-6 Power Sector CO_2 Emissions and Emission Rate for the BASE Case

5.2 RPS Scenarios

Figure 5-7 compares Indiana electricity system capacity portfolios in the base case and the two RPS scenarios. For each time period shown in the graph, the three cases from left to right are base, RPSLSWO and RPSMSWO respetively. Only in-state sources are eligible to comply with the standard in the two RPS cases shown in the graph. The less stringent RPS case without the option of purchasing RECs from other states (RPSLSWO) calls for at least 7% of renewable generation by 2019 and 10% by 2025 and thereafter; the more stringent case without RECs generated out-of-state as a compliance option (RPSMSWO) requires at least 16% of renewable generation by 2019 and 25% by 2025 and thereafter.

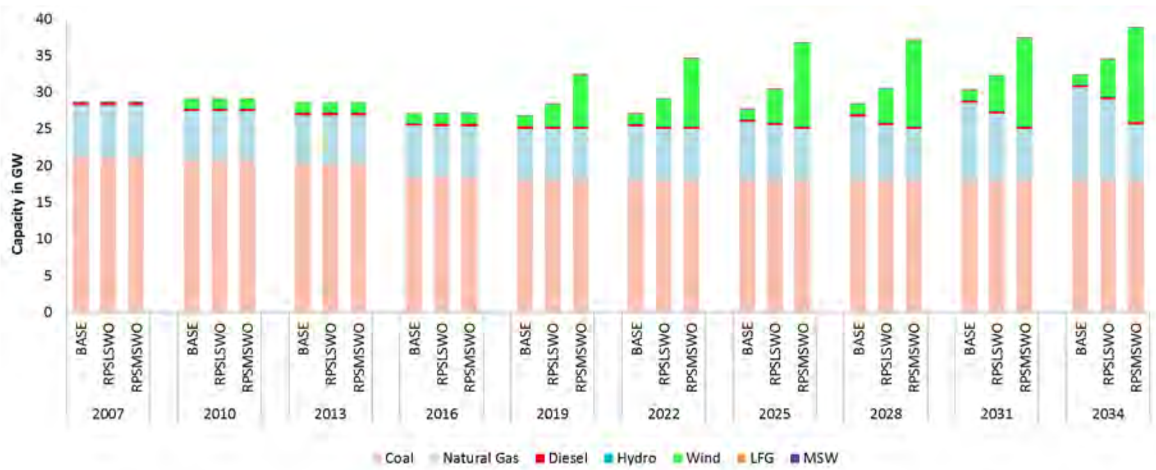

Figure 5-7 Indiana Electricity Capacity Portfolio in GW in the BASE and RPS Scenarios

As is shown in Figure 5-7, the RPS is mostly satisfied in both scenarios by the growth of wind power in the state of Indiana. Wind capacity stays at the level of 1.34 GW until 2016 and starts to grow gradually from 2019 onward in the two RPS scenarios. A fourfold increase in wind capacity occurs in the RPSLSWO case by 2034, and wind capacity grows around an order of magnitude in the RPSMSWO by 2034. Total capacity of coal plants is barely affected by the RPS. We observe retirement of some coal plants in each period before 2019. A majority of those retirements are driven by information received from utilities; some are determined by the model endogenously (details are provided in the next paragraph). The system maintains around 18 GW of coal units from 2019 and on across scenarios. But a fair amount of growth in natural gas capacity observed in the base case is replaced by the growth in wind capacity in both RPS scenarios and the decrease in natural gas capacity growth is more than offset by wind capacity addition, which results in a larger amount of total generation capacity from 2019 in the two RPS cases than in the base case. This phenomenon is largely due to the intermittent nature of wind generation resulting in a much lower availability factor of wind turbines than conventional generation technologies. Usually, more wind capacity is needed to achieve a given level of generation which can be satisfied by a smaller amount of fossil fuel capacity. Comparing between the two RPS scenarios, the tighter the RPS, the higher the investment in wind capacity is and the greater the total generation capacity. In addition, the RPS leads to a negligible amount of municipal solid waste (MSW) waste-to-energy facilities added to the capacity portfolio earlier than it occurs in the base case. The amount is too small to be observed in Figure 5-6. Forward

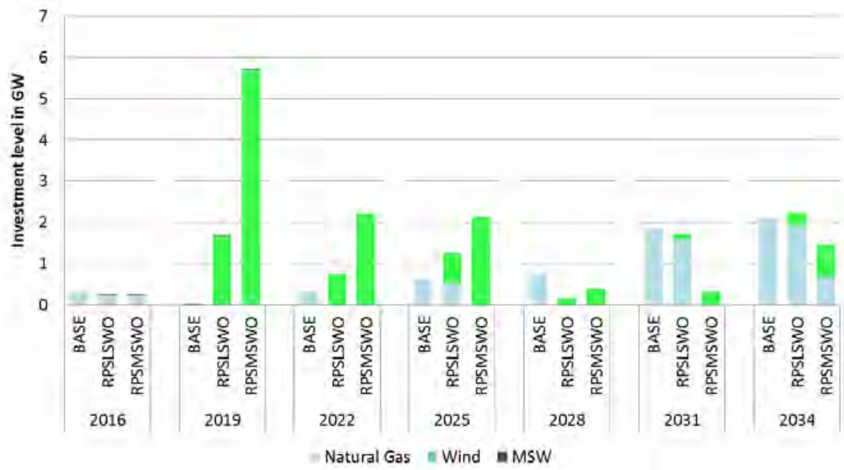

Figure 5-8 Indiana Electricity System Generation Capacity Investment Level in GW in the BASE and RPS Scenarios

Figure 5-8 shows capacity additions for the Indiana electricity generation system by period. The information pertaining to coal capacity is not shown in this graph, and it is the same across scenarios. Our model includes 0.63 GW investment into integrated coal gasification combined cycle (IGCC) capacity in 2013 to reflect the commercial operation of Edwardsport plant located in southern Indiana. Based on planned retirements indicated by Indiana utilities, 3.42 GW coal steam capacity is retired between 2007 and 2016. For the other 17.79 GW of capacity for the existing coal steam fleet, 17.38 GW will continue operation, which means the model determines that it is economical to pay the plant life extension cost given the units' vintages and environmental retrofit costs, to install new or upgrade existing controls contingent upon their current environmental retrofits conditions to make sure they comply with EPA regulations on SO_x, NO_x, PM and mercury by 2019. We now consider investment in other technologies. For the base case, investment in new capacity is due to the retirement of very old coal plants in early periods and the growth of electricity load over time; natural gas dominates the added capacity over the modeling horizon. For the RPS scenarios, investment in new capacity is motivated by the need to comply with RPS in addition to satisfying increasing electricity demand. In the RPSMSWO case, large amounts of wind capacity are added to the system in the three successive periods beginning in 2019, where the RPS starts. The same happens with the RPSLSWO case, but with the level of wind additions smaller. Knowing that more renewable capacity has to be added starting in 2019, less natural gas capacity is added before 2019 for the two RPS scenarios (0.23 GW) compared with the base case (0.28 GW). Since the RPS target stabilizes after 2025, smaller amounts of wind additions and some natural gas capacity additions are observed in the latter periods to satisfy growing demand for electricity while maintaining the percentage of renewable generation at the required level. MSW realizes a small amount of investment in both 2016 and 2019 for the RPS scenarios and in 2019 only for the base case.

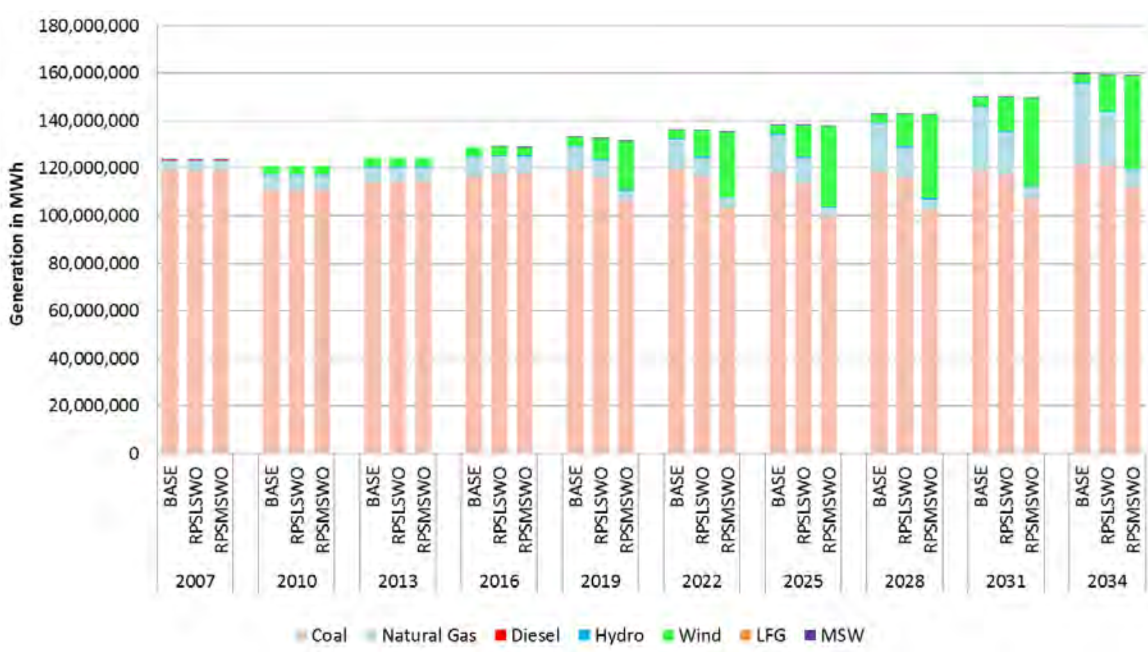

Figure 5-9 Indiana Electricity Generation Portfolio in MWh in the BASE and RPS Scenarios

In terms of generation portfolio (shown in Figure 5-9), coal drops from more than 95% of total generation in 2007 to around 76% in 2034 for the base case. In the RPSLSWO case, the percentage of coal generation is slightly smaller than that in the base case for each period since 2019 and reaches a number a little bit smaller than 76% in 2034. The changes that occur in the more stringent RPS case are more substantial. The share of coal generation decreases gradually to less than 71% by 2034 in the more stringent case. Without the constraint of the RPS, the share of natural gas generation rises rapidly over modeling horizon and reaches 21% by 2034. With the less stringent RPS, the share of natural gas experiences less growth, reaching around 14% of total generation in 2034. However, with the more stringent RPS, the portion of generation from natural gas barely grows, and it varies between 3%-6% over time. Additionally, almost the entire RPS is satisfied by wind capacity. Without the RPS as an incentive, generation from wind experiences very limited growth in absolute value from 2010 to 2013, and it stays around the 2013 level thereafter. But due to increasing total generation over time, the share of wind generation actually shrinks from around 3% in 2013 to about 2% in 2034 in the base case.

For the more stringent RPS target, several cases with the option of purchasing RECs generated from out-of-state sources at different costs to satisfy Indiana RPS are modeled. RECs are available at $15/MWh (RPSMSW15 case), $40/MWh (RPSMSW40 case), $45/MWh (RPSMSW45 case) and $50/MWh (RPSMSW50 case) respectively in the four scenarios. Please refer to table 4-1 for specific definitions of more stringent RPS scenarios with non-Indiana generated RECs as a compliance option.

Table 5-1 Share of Indiana Electricity Generation from In-State Renewable Sources in the BASE Case and More Stringent RPS Cases with and without Out-of-State Derived RECs as A Compliance Option

Scenario	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034
BASE	0.37%	2.97%	3.34%	3.17%	3.20%	3.12%	3.07%	3.03%	2.89%	2.72%
RPSMSW15	0.37%	2.97%	3.34%	3.17%	3.28%	3.19%	3.15%	3.06%	2.91%	2.73%
RPSMSW40	0.37%	2.97%	3.34%	3.17%	3.37%	3.28%	3.22%	3.09%	2.93%	2.76%
RPSMSW45	0.37%	2.97%	3.34%	3.30%	15.64%	15.36%	15.25%	14.75%	17.19%	16.20%
RPSMSW50	0.37%	2.97%	3.34%	3.29%	16.00%	20.51%	23.05%	22.24%	21.71%	23.03%
RPSMSWO	0.37%	2.97%	3.34%	3.29%	16.00%	20.51%	25.02%	25.03%	25.04%	25.06%

Table 5-1 displays the percentages of Indiana electricity generation from renewable resources located within the state for various RPS cases. The table shows that the share of renewable generation in-state barely grows during the modeling horizon in the base case, except a jump from 0.4% to 3.0% from 2007 to 2010 due to the construction of large-scale wind farms during this period. For each time period after 2016, the gap between the RPS target and the share of renewable generation in-state already achieved in the base case must be satisfied either through purchased RECs produced from out-of-state renewable resources or additional in-state renewable generation — the model will choose the option that is most cost effective. Generally speaking, RECs from out-of-state resources play a major role in satisfying RPS when they are available at lower costs (see Table 5-2); while at the same time, the share of renewable generation are relatively stagnant in those cases (see Table 5-1).

Table 5-2 Purchase of RECs from Out-of-State Renewable Generation at Different Costs (Absolute Amount of REC Purchases in MWh and Share as Indiana Total Generation)

Scenario	2007	2010	2013	2016	2019	2022	2025	2028	2031	2034
RPSMSW15	0	0	0	0	16,838,894	23,533,340	30,183,342	31,327,786	33,113,898	35,566,677
	0	0	0	0	12.72%	17.32%	21.87%	21.98%	22.14%	22.32%
RPSMSW40	0	0	0	0	16,397,227	22,980,562	29,652,786	31,091,675	33,005,565	35,333,343
	0	0	0	0	12.63%	17.23%	21.81%	21.94%	22.12%	22.29%
RPSMSW45	0	0	0	0	475,000	6,961,113	13,469,448	14,650,004	11,744,448	14,047,226
	0	0	0	0	0.36%	5.15%	9.77%	10.28%	7.86%	8.86%
RPSMSW50	0	0	0	0	0	0	2,719,445	3,986,112	5,000,001	3,219,445
	0	0	0	0	0.00%	0.00%	1.97%	2.79%	3.34%	2.03%

Note: There is a drop of REC purchase in 2031 in the RPSMSW45 case. A similar situation happens in 2034 with the RPSMSW50 case. They are both attributable to the expansion of wind capacity in the corresponding periods. Please refer to Figure 5-12.

Based on results shown in Figure 5-10 and Figure 5-11, small changes in Indiana capacity and generation portfolios are observed for cases where RECs are available at $15/MWh and $40/MWh (the second and third bars respectively from the left for each time period) compared with the base case (the first bar from the left for each period). When RECs are low in cost, buying RECs from other states in order to meet the RPS is more economical than changing the in-state capacity portfolio. Those minor differences in total capacity in the base, RPSLSW15 and RPSLSW40 cases are attributable to different levels of capacity investment in natural gas in the three cases (see Figure 5-12).

But we do observe total generation for each period since 2019 is slightly smaller for the RPSMSW15 case than the base case and that for the RPSMSW40 case is slightly smaller than that for the RPSMSW15 case. This is because satisfying the RPS mainly through purchasing RECs from out-of-state sources still raises the cost of electricity compared with the base case. Higher electricity rates lead to less electricity usage in residential, commercial and industrial sectors, which mainly is substituted for by natural gas; and the higher the REC cost, the more the electricity cost gets raised and the more the fuel switching observed. When REC price passes $45/MWH, far fewer RECs are purchased and the compliance with the RPS relies more on shifts of in-state capacity and generation portfolios to place heavier weight on renewable resources. In-state expansion of wind capacity makes economic sense when the REC cost is high enough (see Figure 5-12). When the REC price reaches 50$/MWh, the majority of Indiana RPS target is satisfied through in-state renewable generation; both capacity and generation portfolios in this case (the second bar from the very right for each period in Figure 5-10 and Figure 5-11) are pretty close to those in the RPSMSWO case (the first bar from the very right for each period in Figure 5-10 and Figure 5-11).

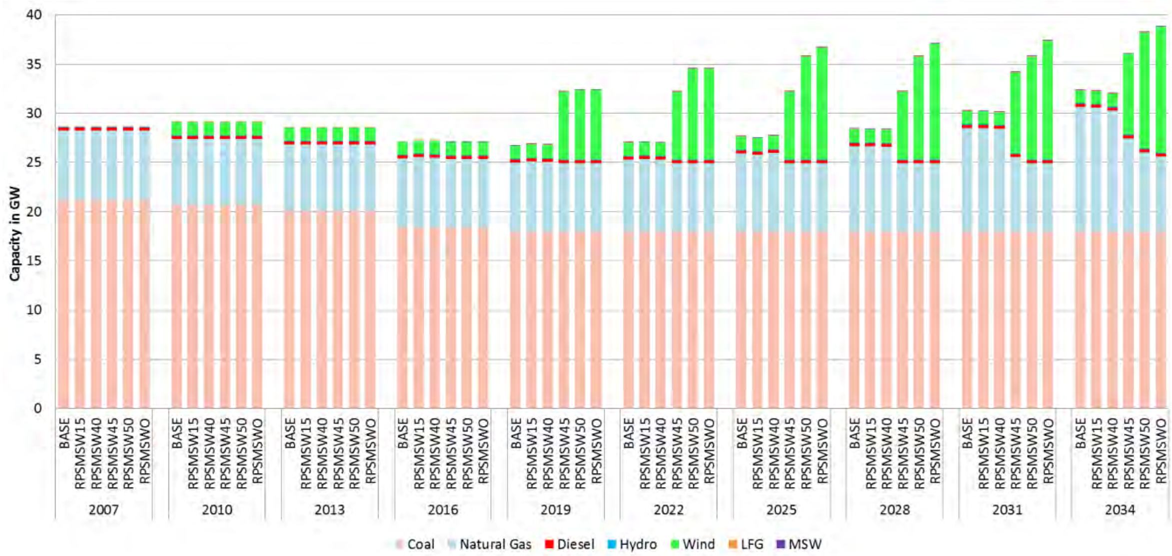

Figure 5-10 Indiana Electricity Capacity Portfolio in GW in the BASE Case and More Stringent RPS Cases with and without Out-of -State Derived RECs as A Compliance Option

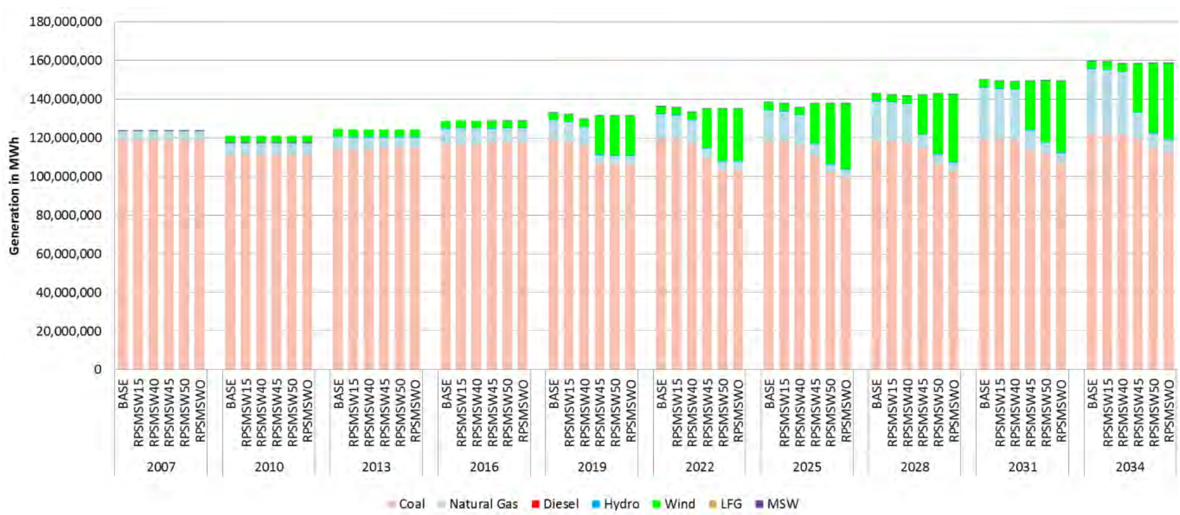

Figure 5-11 Indiana Electricity Generation Portfolio in MWh in the BASE Case and More Stringent RPS Cases with and without Out-of -State Derived RECs as A Compliance Option

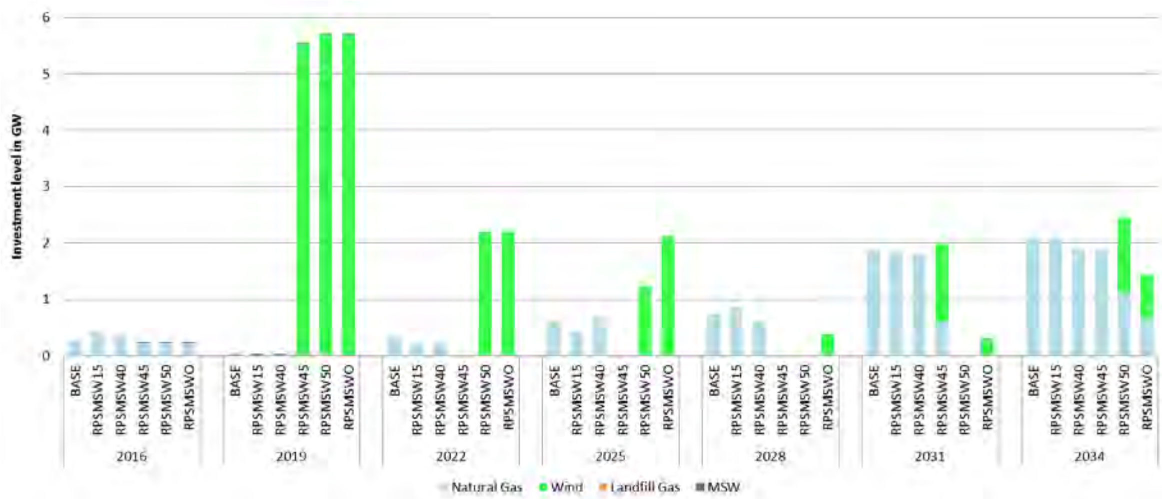

Figure 5-12 Indiana Electricity System Capacity Investment Level in GW in the BASE Case and More Stringent RPS Cases with and without Out-of -State Derived RECs as A Compliance Option

Figure 5-13 exhibits the REC costs endogenously determined by IN-MARKAL for the RPSLSWO and RPSMSWO cases. The number represents the additional energy system cost will occur to raise the RPS target by one MWh, which indicates the upper bound of the cost of satisfying the RPS through in-state renewable generation alone. For the RPSLSWO case, the REC cost varies between \$39/MWh and \$49/MWh over time. The RPSMSWO case indicates more stringent requirements, thus higher cost (between \$44/MWh and \$55/MWh over time). Those results are consistent with the information in Table 5-1 and Table 5-2. Even when out-of-state resources are eligible for satisfying the Indiana RPS, only a small amount of RECs are purchased in the RPSMSW50 case because the marginal cost of satisfying the RPS is less than \$50/MWh for the majority of the time. But when RECs are available at less than \$40/MWh, a very limited amount of in-state renewable generation is added to the BASE case level, because the marginal cost of satisfying the RPS with in-state resources is higher than \$40/MWh over almost the entire modeling horizon.

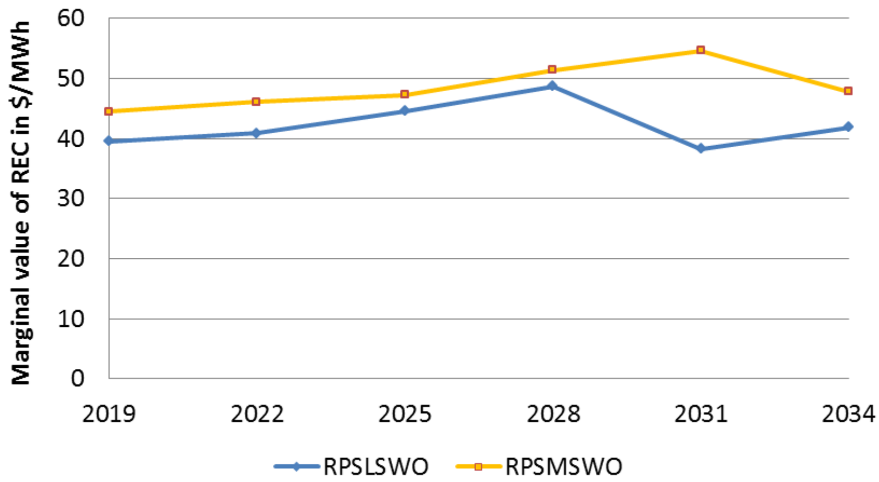

Figure 5-13 REC Cost Internally Determined by IN-MARKAL in RPS Scenarios

Figure 5-14 and Figure 5-15 display the CO_2 emissions over time in the base case and various RPS scenarios. The general trend is similar across scenarios before 2019. Starting at a high level in 2007, CO_2 emissions fall in 2010 and gradually escalate after. The dramatic down (about 12%) in 2010 can be attributed to three major reasons. First, the economic recession triggered by the financial crisis of 2007-2008 caused a 3% drop in total electricity demand in Indiana. Second, the electricity generation portfolio experiences structural adjustments during this period. Although coal still plays the most important role in electricity generation, its share drops from more than 95% in 2007 to less than 92% in 2010. While at the same time, shares of natural gas and wind grow close to 2% and 3% respectively, replacing the heavy-emission sources with lower-emission and zero-emission sources. The third reason can be summarized as efficiency improvement of coal generation as a whole. In IN-MARKAL, coal generation is modeled by unit rather than aggregate capacity. Coal units differ widely in heat rate, thus efficiency. Low efficiency indicates that the unit is less cost-effective and is less likely to be used when load is lower. With a decrease of coal generation in absolute value from 2007 to 2010 (about 7%), some less efficient units which are used when load is higher are not included in the generation portfolio of 2010. Therefore, when considering the coal generation fleet as a whole, the capacity that gets used in 2010 is more efficient on average than it was in 2007. This leads to further reductions in CO_2 emissions.

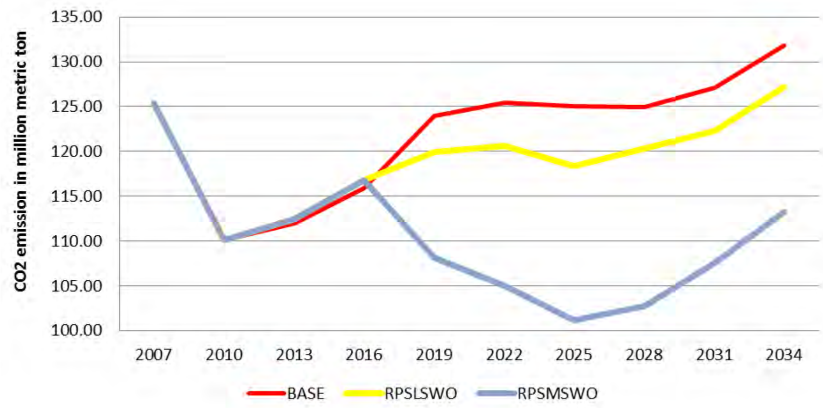

Figure 5-14 CO_2 Emission from Electricity System in the BASE and RPS Scenarios without Out-of -State Derived RECs as A Compliance Option

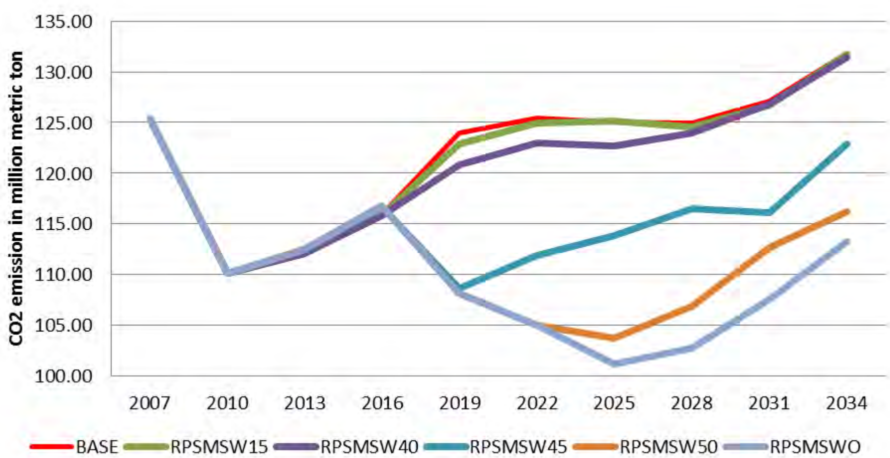

Figure 5-15 CO_2 Emission from Electricity System in the BASE and More Stringent RPS Cases with and without Out-of -State Derived RECs as A Compliance Option

Comparing the RPSLSWO case and the base case, it is obvious that the less stringent RPS target is not very helpful in achieving CO_2 emissions reduction (the yellow line in Figure 5-14). Annual emission reduction is no more than 5% of the base level after RPS phases in. But the more stringent target (RPSMSWO case) has a remarkable impact on carbon mitigation (the gray blue line in Figure 5-14). On average, the annual emission reduction attained is about 15% of the emission level in the base case from 2019. However, if RECs generated out-of-state are permitted as a strategy to comply with the RPS targets, even the more stringent target does not have a noticeable effect on CO_2 emissions if RECs are available to be purchased at low costs (refer to Figure 5-15).

In terms of cumulative CO_2 emissions from the electricity system over the modeling horizon (2007 to 2036), the RPSMSWO case realizes cumulative emissions around 10% less than the base case and the RPSLSWO case only reaches emission reduction of a bit more than 2% (please refer to the third column in the yellow block of Table 5-3). When comparing cumulative CO_2 emissions from the electricity system and that from the entire energy system[65] for each policy scenario (please refer to the second column in the yellow and blue blocks respectively in Table 5-3), it is found that accumulated emission reduction achieved by the entire energy system is generally smaller than that achieved by the electricity system alone. This is due to the spillover effect of an electricity system-only carbon policy. Changes in the cost of electricity induced by carbon policy lead to alternation of fuel mix in the end-use sectors, thus emissions from those sectors. However, based on the results of this study, this slippage in emission reduction is not dramatic. From the perspective of the entire energy system, RPSMSWO is capable of achieving more than 6% of cumulative carbon mitigation from the base case, with interstate REC trading weakening the policy influence on in-state carbon mitigation. RPSLSWO only reduces energy system cumulative carbon emissions by about 1% from the Base.

[65] CO_2 emissions from the energy system covers CO_2 emissions from Indiana electricity generation system, residential, commercial, industrial and transportation sectors, as well as CO_2 sequestered during biomass growing process. Thus, any CO_2 emissions savings from the electricity generation sector that are affected by increases in other sectors (e.g. due to fuel substitution) are reflected in the energy system CO_2 emissions.

Table 5-3 Accumulated CO_2 Emissions over the Modeling Horizon for the BASE and RPS Scenarios

Case	Electricity system cumulative CO_2 emission in million metric ton	Electricity system cumulative CO_2 emission reduction from the BASE in million metric ton	% change of electricity system cumulative CO_2 emission from the BASE	Energy system cumulative CO_2 emission in million metric ton	Enegy system cumulative CO_2 emission reduction from the BASE in million metric ton	% change of energy system cumulative CO_2 emission from the BASE
BASE	3665.38			5699.26		
RPSLSWO	3580.88	84.50	-2.31%	5627.31	71.95	-1.26%
RPSMSW15	3657.84	7.54	-0.21%	5693.66	5.61	-0.10%
RPSMSW40	3636.21	29.16	-0.80%	5673.97	25.29	-0.44%
RPSMSW45	3463.61	201.77	-5.50%	5502.49	196.78	-3.45%
RPSMSW50	3352.05	313.32	-8.55%	5389.22	310.04	-5.44%
RPSMSWO	3308.18	357.20	-9.75%	5345.57	353.70	-6.21%

The marginal cost of electricity is internally determined by the model for each time slice. This marginal cost reflects the additional energy system cost that will be incurred to generate one more unit of electricity for that time slice. IN-MARKAL models 12 time slices per year for each period. They are combinations of three seasons — summer, winter and intermediate and four time slices within the day — day AM, day PM, peak and night. The time slice-weighted average marginal electricity cost is calculated for each period and is shown in Figures 5-16 and 5-17. Generally speaking, an upward movement in marginal electricity cost is observed for all RPS scenarios. The RPSMSWO case does not raise marginal cost of electricity a lot more than the RPSLSWO case in early years; but cost trends of the two cases diverge after 2019, with the RPSMSWO case having costs up to 15% more than that of RPSLSWO case in 2028. However, the cost difference between the two cases narrows after 2028. Trends for the more stringent RPS cases with RECs trading at different costs are very difficult to discern from Figure 5-17. Fluctuations within each scenario make cost comparison across scenarios almost impossible.

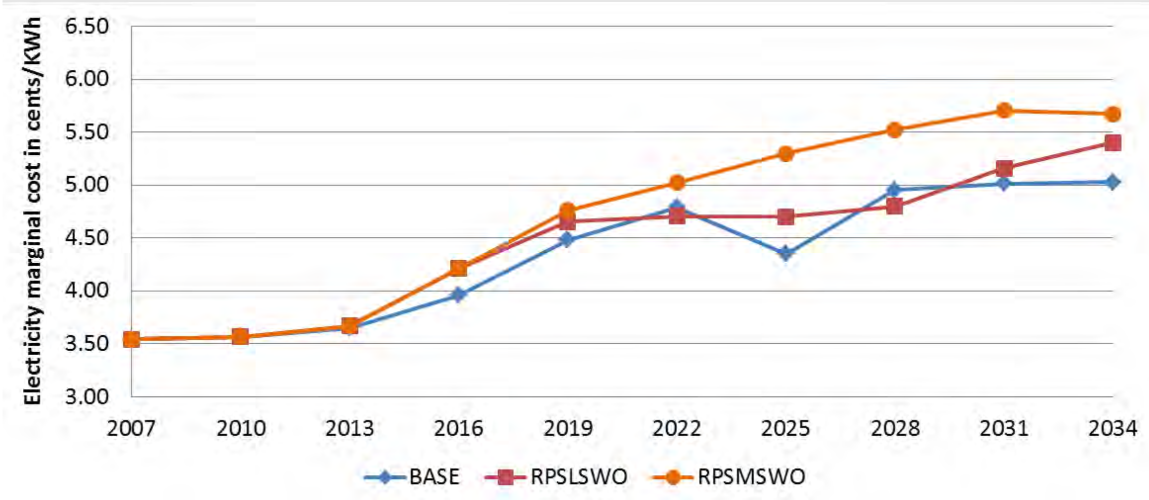

Figure 5-16 Discounted Marginal Cost of Electricity in the BASE and RPS Scenarios without Out-of -State Derived RECs as A Compliance Option

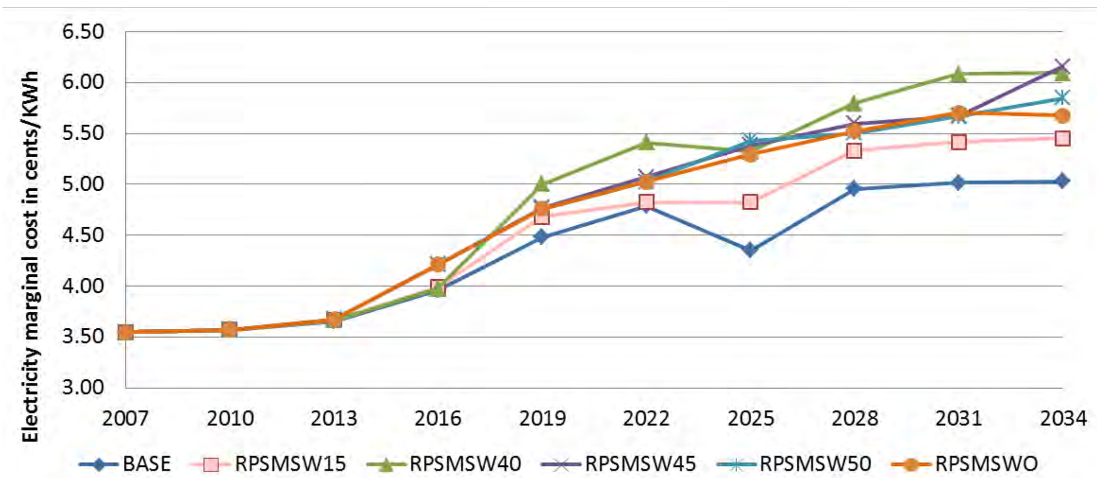

Figure 5-17 Discounted Marginal Cost of Electricity in the BASE and More Stringent RPS Cases with and without Out-of -State Derived RECs as A Compliance Option

Therefore, an indicator called levelized marginal cost of electricity (LMCOE) is constructed in order to make cost comparison among cases easy and clear. The LMCOE is calculated by summing the product of electricity generation and discounted marginal cost of electricity for each period and dividing by the sum of discounted electricity generation from each period as shown in the formula below:

$$\text{LMCOE}=\frac{\sum_{t=2007}^{2034} 3*GEN(t)*MCOE(t)}{\sum_{t=2007}^{2034}(1+r)^{-(t-2007)}\sum_{i=0}^{2} GEN(t)*(1+r)^{-i}} \ .$$

t=2007, 2010, 2013, …… 2034;
i=0,1,2;
GEN(t): annul electricity generation for period t;
MCOE(t): discounted marginal cost of electricity for period t;
r: discount factor of 5%.

The LMCOE under the BASE and RPS scenarios are shown in column two of Table 5-4. Another column is added to the right end to display the percentage rise of LMCOE in each RPS scenario from the BASE scenario. For a 10% RPS entirely satisfied with in-state resources, the LMCOE would grow by 2.53% to reach 8.63 cents/KWh; alternatively, a 25% RPS results in an increase of 8.66% if no out-of-state resources are eligible. The results also suggest that a RPS with interstate trade in offset credits will help relieve pressure on electricity cost when those credits are fairly inexpensive. But meanwhile, the level of carbon mitigation can be achieved in state is weakened as well, so is the substantial environmental benefit of a RPS.

Table 5-4 LMCOE in the BASE and RPS scenarios

Scenario	LMCOE in cents/KWh	LMCOE % change from BASE
BASE	8.41	
RPSLSWO	8.63	2.53%
RPSMSW15	8.81	4.69%
RPSMSW40	9.44	12.16%
RPSMSW45	9.28	10.34%
RPSMSW50	9.20	9.32%
RPSMSWO	9.14	8.66%

Due to the fact that different RPS scenarios have dissimilar levels of impact on cost and carbon reduction, looking at cost change or carbon reduction alone does not provide a complete story. Thus, two indicators are calculated for each case to reveal its cost effectiveness regarding carbon mitigation. In the second column of Table 5-5, the percentage change of LMCOE from the BASE case is divided by the percentage reduction of Indiana power sector CO_2 emissions from the BASE case for each RPS scenario. This indicator shows the average percentage increase of LMCOE in order to achieve a one percent decrease of carbon emissions from the Indiana electricity system. The lower the indicator, the more cost effective the case is in terms of reducing carbon emissions from in-state power sector. According to the results shown in column two of Table 5-5, a 25% RPS by 2025 solely satisfied by in-state resources is the winner over the rest RPS scenarios for obtaining economically efficient CO_2 reduction. RPSMSWO case will result in a 0.89% LMCOE increase per 1% drop of carbon emissions from Indiana electricity system on an average basis. The third column of Table 5-5 displays abatement costs of carbon emissions for the various RPS scenarios. This indicator is derived through dividing the absolute value of the increase in the discounted energy system cost from the BASE case by the amount of decrease in energy system CO_2 emissions from the BASE case. The abatement cost in terms of \$/metric ton denotes the average cost of reducing one metric ton of CO_2 emissions from the entire energy system of Indiana. Obviously, a lower abatement cost is preferred. The results shown in column three are consistent with those in column two. RPSMSWO is also the case with the lowest abatement cost, which is equal to \$35/metric ton. However, careful attention is required when interpreting the two indicators for more stringent RPS cases with RECs generated in other states as a compliance option. Those cases seem to not be very effective in achieving carbon mitigation. The major reason is that a substantial amount of emissions reduction is achieved out of state, particularly for cases with inexpensive RECs. If we take emissions reduced out of state into consideration, the cost effectiveness of the cases with RECs purchased across state line might be better than the corresponding case without interstate REC trading. But it is impossible to trace the exact emissions reductions beyond Indiana's borders in our model. In reality, the amount of carbon reduction depends on how much high-emission generation is replaced by low or zero-emission generation in other states induced by Indiana RPS.

Table 5-5 Comparison of Cost Effectiveness of Carbon Reduction for RPS Scenarios

Scenario	$\frac{\text{\% change of LMCOE from BASE}}{\text{\% reduction of electricity sector CO2 emissions from BASE}}$	Energy system CO2 emissions abatement cost in $/metric ton
RPSLSWO	1.10	54.58
RPSMSW15	22.80	742.11
RPSMSW40	15.28	436.42
RPSMSW45	1.88	61.31
RPSMSW50	1.09	39.74
RPSMSWO	0.89	35.00

5.3 Carbon Tax Scenarios

Results comparing the BASE case and the three carbon tax scenarios are discussed in this section. As exhibited in Figure 5-18, the impact of a carbon tax on Indiana power sector capacity portfolio is limited for the three carbon tax scenarios. The construction of additional renewable generation capacity does not occur in any of the three carbon tax scenarios (see Figure 5-19). The carbon tax low start case (CTaxLS) (starts at a tax rate of $5/ton in 2016 and grows at 2% annually to reach around $7/ton in 2034) has no impact on coal capacity when comparing with the BASE case. The tax stimulates slightly more natural gas capacity investment before 2022, but less in the three successive periods after than the BASE case. In the carbon tax high start case (CTaxHS) (starts at $25/ton in 2016 and grows at 2% annually to reach close to $36/ton in 2034) and the carbon tax high growth rate case (CTaxHGR) (which for comparison with CTaxLS starts at around $9/ton in 2016 and grows to $41/ton in 2034), another 0.46 GW capacity of the existing coal fleet is retired in 2019 due to the economic penalty from carbon tax. The CTaxHS case has the most natural gas capacity additions in 2016 (1.29 GW) compared with 1.04 GW in the CTaxHGR case, 0.62 GW in the CTaxLS case and 0.28 GW in the BASE case.

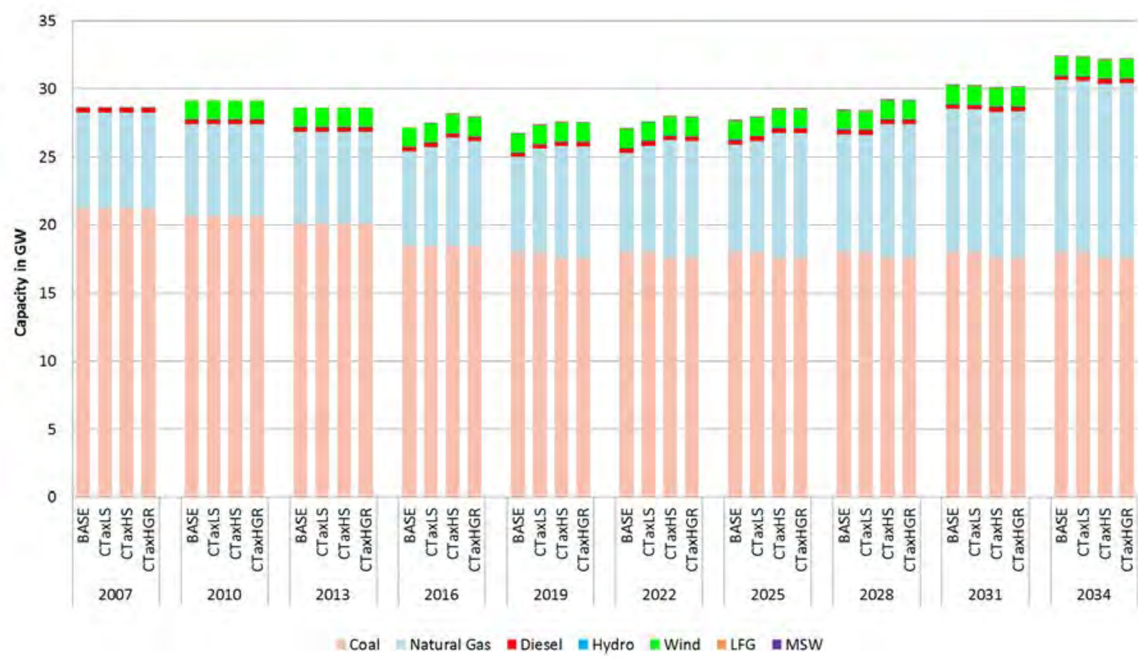

Figure 5-18 Indiana Electricity Capacity Portfolio in GW in the BASE and Carbon Tax Scenarios

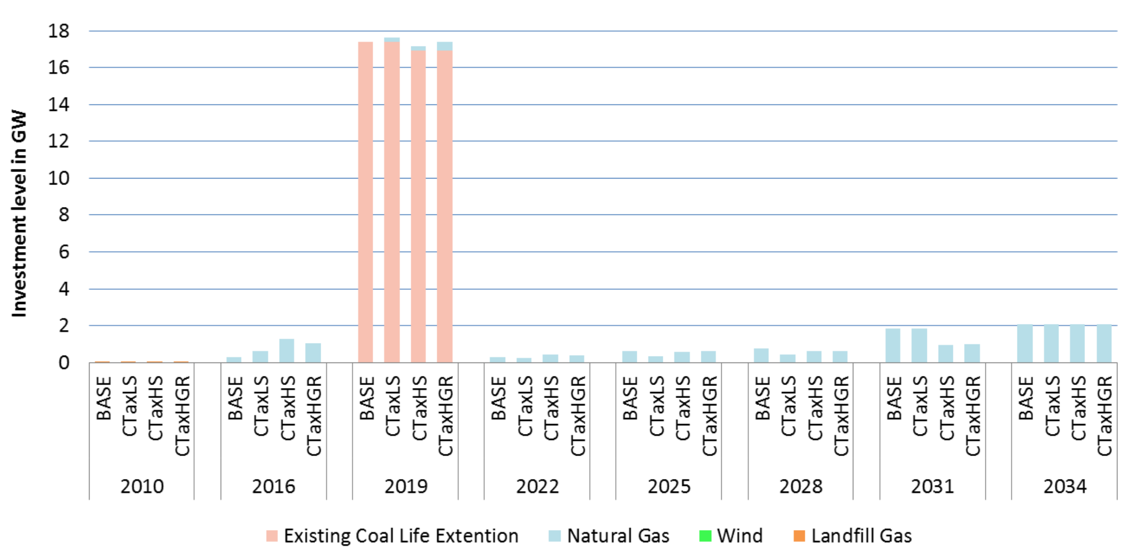

Figure 5-19 Indiana Electricity System Generation Capacity Investment Level in GW in the BASE and Carbon Tax Scenarios

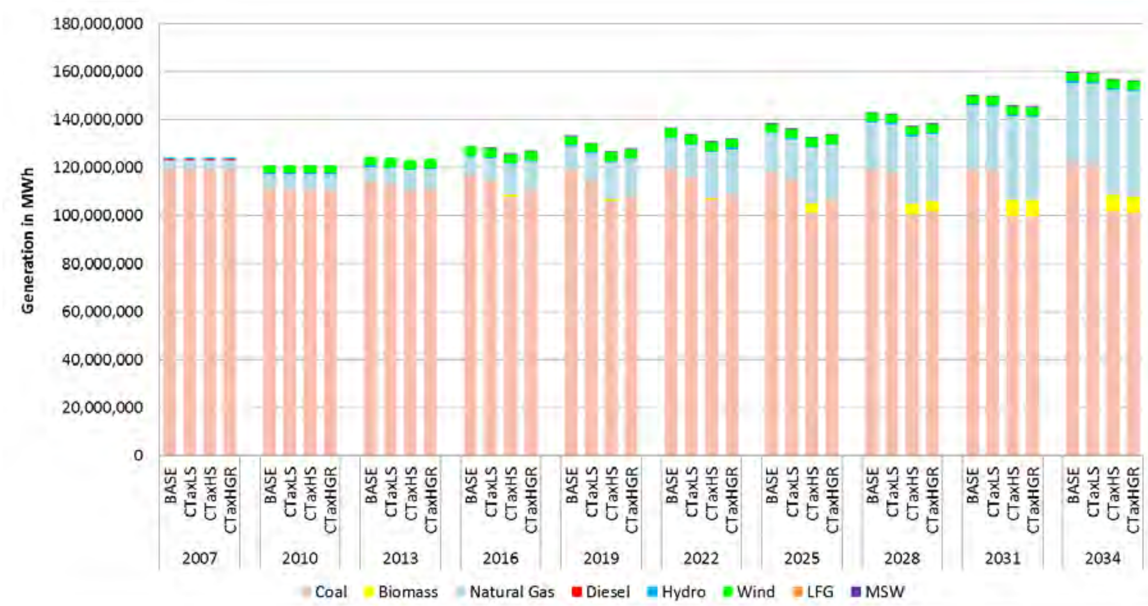

Figure 5-20 Indiana Electricity Generation Portfolio in MWh in the BASE and Carbon Tax Scenarios

Figure 5-20 displays the generation portfolio for the Indiana power system. One key observation is that total electricity generation per period in each of the three carbon tax scenarios is less than that for the BASE case from 2013 on. This impact of the carbon tax on the total amount of generation is very small for the CTaxLS case, but significant for the CTaxHS case (especially in the periods between 2019 and 2031) and CTaxHGR case (especially after 2031). Although the carbon tax trajectories modeled in the three scenarios are not high enough to encourage additional investment in wind capacity and thus wind generation compared with the BASE case, these taxes obviously raise the marginal cost of electricity (see Figure 5-22), causing a proportion of electricity consumption shown in the BASE case to be replaced by other fuels in the end-use sectors. The higher the cost of electricity induced by the carbon tax, the more the observed reduction of the total amount of generation is observed. Coal generation declines over time in terms of absolute value in MWh and the share of total generation. The portion of coal drops to about 69% in 2034 for both of the CTaxHS and CTaxHGR cases, but the reduction of coal generation in the CTaxLS case is relatively small compared with the BASE case except for periods from 2019 to 2025. Biomass co-firing with coal occurs in both CTaxHS and CTaxHGR cases. In IN-MARKAL, biomass is allowed to co-fire with coal to amount up to 10% of fuel input in terms of heat content if the cost of generation justifies. Biomass co-firing with coal appears first in 2016 in the CTaxHS case with an annual generation of nearly 641 GWh. It increases dramatically in 2025 (to 3,988 GWh) and reaches about 6,681 GWh in 2034. For the CTaxHGR case, biomass co-firing starts at a very low level of 134 GWh in 2019; and then grow substantially in 2028 (to 4,032 GWh) and the growth continues until reaching 6,632 GWh in 2034. Finally, generation from natural gas moves upward in both absolute value and proportion in the three carbon tax scenarios. But for the CTaxLS case, changes are not large. For the CTaxHS and CTaxHGR cases, the realized share of natural gas is over 28% in 2034 compared with around 21% in the BASE case.

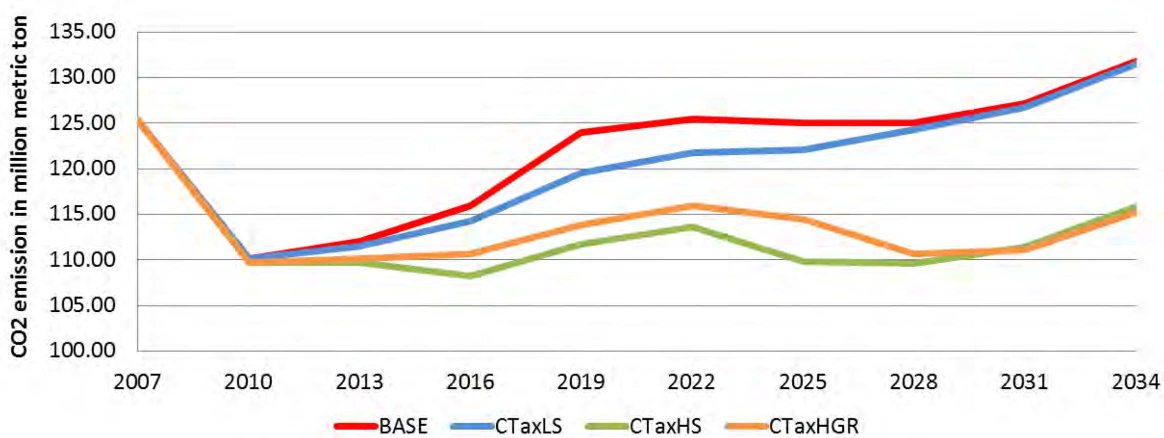

Figure 5-21 CO_2 Emission from Electricity System in the BASE and Carbon Tax Scenarios

Figure 5-21 exhibits total CO_2 emissions from the power system of Indiana in the BASE and carbon tax scenarios. The CTaxLS case results in emission reductions mainly in the periods between 2016 and 2028, where the reduction varies from 1.5% to 3.5% of BASE case emission levels for each period. The carbon mitigation reached in the CTaxHS and CTaxHGR cases is much more significant than in the CTaxLS case. This is attributable to a combination of less total electricity generation and a generation portfolio that emits less CO_2, involving biomass, more natural gas and less coal. On average, emission levels in the CTaxHS case are reduced by 9.6% of the BASE case emission levels; the average reduction for the CTaxHGR case is 8.4%. The CTaxHS case results in greater reductions before 2031 compared with the CTaxHGR case, but slightly less reductions after.

Table 5-6 compares cumulative CO_2 emissions from the power sector and the entire energy system of Indiana across carbon tax scenarios. For each carbon tax scenario, the cumulative carbon reduction achieved from the power sector alone is greater than that from the entire energy system, which is due to the slippage effect of a power sector-only carbon policy. A certain amount of electricity generated by some less carbon-intensive sources gets replaced by some more carbon-intensive fuels in the end-use sectors when the cost of electricity is increased by the carbon tax. However, this slippage effect is very small according to modeling results. In summary, the CTaxLS case is capable of reducing carbon emissions from the power sector by only 1.2%; while the CTaxHS case and CTaxHGR case is able to reach CO_2 mitigation of 7.9% and 6.9% respectively of the BASE case emission level from the power sector. In terms of energy system CO_2 emissions, CtaxLS reduces emissions by no more than 1% from the BASE case level, compared with 4.6% and 4.0% for the CTaxHS case and CTaxHGR case respectively.

Table 5-6 Accumulated CO_2 Emission over the Modeling Horizon for the BASE and Carbon Tax Scenarios

Case	Electricity system cumulative CO2 emission in million metric ton	Electricity system cumulative CO2 emission reduction from the BASE in million metric ton	% change of electricity system cumulative CO2 emission from the BASE	Energy system cumulative CO2 emission in million metric ton	Enegy system cumulative CO2 emission reduction from the BASE in million metric ton	% change of energy system cumulative CO2 emission from the BASE
BASE	3,665.38			5699.26		
CTaxLS	3,620.92	44.46	-1.21%	5657.77	41.49	-0.73%
CTaxHS	3,375.04	290.33	-7.92%	5438.62	260.64	-4.57%
CTaxHGR	3,411.16	254.22	-6.94%	5468.66	230.60	-4.05%

The marginal cost of electricity for each carbon tax scenario displays a similar trend to the corresponding carbon tax trajectory (see Figure 5-22 and Figure 4-3). In the three cases, the carbon tax is imposed from 2016 on, where we observe divergence of cost trend among the BASE case and the three carbon tax scenarios. The CTaxHS case starts at the highest tax level among the three cases. Thus, a dramatic increase in the marginal cost of electricity is shown in 2016 (from 3.62 cents/KWh in 2013 to 6.64 cents/KWh in 2016). The CTaxLS and CTaxHGR cases both start at relatively low tax levels. Therefore, increases of the electricity cost are smaller in 2016 for the two cases. After 2016, the CTaxLS and CTaxHS cases have almost parallel electricity cost trajectories, likely because that tax trajectories in the two cases grow at the same rate of 2% annually. The CTaxHGR case has electricity cost lower than that in the CTaxHS case in the earlier periods but higher in the latter periods. The swiching point is between 2028 and 2031. This is consistent with the trend observed for the relevant carbon tax trajectories. The cost of electricity reaches peak value in 2034, with 8.86 cents/KWh for the CTaxHGR case, 8.31 cents/KWh for the CTaxHS case, 5.89 cents/KWh for the CTaxLS case and 5.03 cents/KWh for the BASE case.

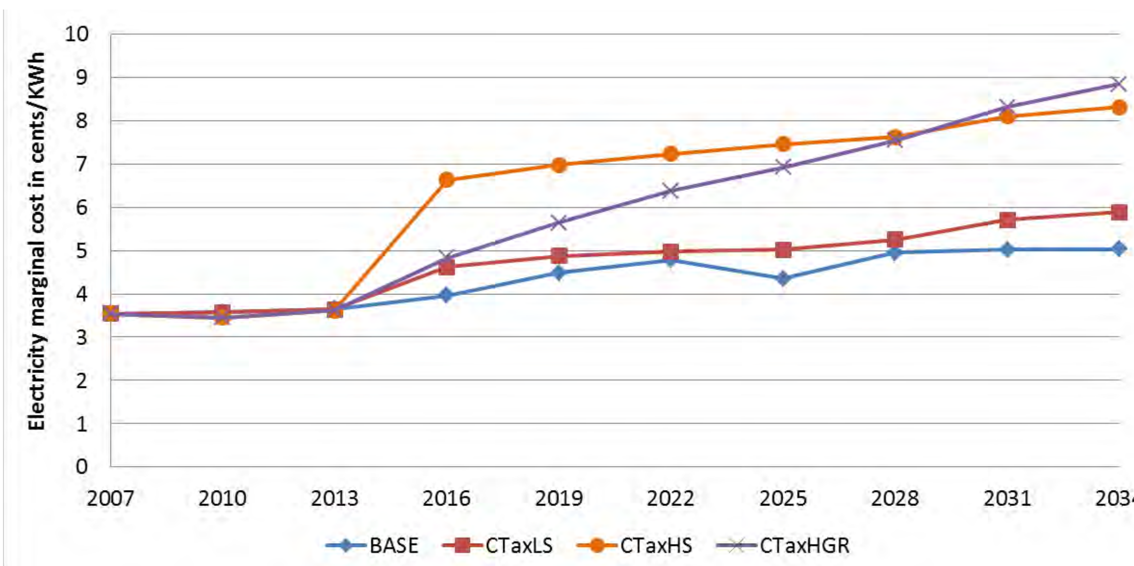

Figure 5-22 Discounted Marginal Cost of Electricity in the BASE and Carbon Tax Scenarios

Table 5-7 displays the LMCOE in the BASE and carbon tax scenarios. The CTaxHS case realizes the highest level of carbon mitigation while having the highest LMCOE among the three carbon tax scenarios (12.26 cents/KWh and about 46% above the BASE case level). The CTaxLS case increases the LMCOE to 9.17 cents/KWh, a 9% growth from the BASE. The CTaxHGR case falls in the middle of the three cases, with a 38% increase in the LMCOE from the BASE, reaching a LMCOE of 11.57 cents/KWh.

Table 5-7 LMCOE in the BASE and Carbon Tax Scenarios

Scenario	LMCOE in cents/KWh	LMCOE % change from BASE
BASE	8.41	
CTaxLS	9.17	8.92%
CTaxHS	12.26	45.71%
CTaxHGR	11.57	37.52%

Table 5-8 compares the cost effectiveness of CO_2 taxes for carbon mitigation for the various scenarios. The CTaxLS case is the most ineffective among the three scenarios, and on average results in a 7.36% increase in LMCOE to achieve a one percent decrease in power sector CO_2 emissions with an abatement cost of $150.40/metric ton of CO_2 emissions reduction from the entire energy system. These results combined with the emission and cost data shown in Tables 5-6 and 5-7 indicate that a carbon tax trajectory which starts at a relatively low level and grows slowly over time is unable to accomplish a substantial level of carbon mitigation in the state of Indiana but it nonetheless increases the cost of electricity in state. The CTaxHS case and the CTaxHGR case perform much better in terms of reducing carbon emissions economically. However, between the two, CTaxHGR excels with a 5.41% increase in the LMCOE for a one percent reduction of power sector carbon emissions on average and an abatement cost of $103.66/metric ton carbon mitigation. Therefore, focusing on these two cases, the carbon tax trajectory that starts at a relatively low tax level but grows faster is more cost effective in reducing carbon emissions than the one that starts at a relatively high tax level but increases slowly over time.

Table 5-8 Comparison of Cost Effectiveness of Carbon Reduction for Carbon Tax Scenarios

Scenario	$\frac{\text{\% change of LMCOE from BASE}}{\text{\% reduction of electricity sector CO2 emissions from BASE}}$	Energy system CO2 emissions abatement cost in $/metric ton
CTaxLS	7.36	150.40
CTaxHS	5.77	118.08
CTaxHGR	5.41	103.66

5.4 Rate-Based Carbon Cap Scenarios

This section focuses on the results of the two rate-based carbon cap scenarios. The cap is not imposed on any single utility; we model the situation that electric utilities located in Indiana work collectively in achieving the proposed cap. The power sector of Indiana is considered as a whole, so trade of carbon allowances among utilities is not included; but the design of IN_MARKAL (economic optimization) insures that the rate-based carbon cap is met in the most cost-effective way. The CERO1 case models a relatively stringent emission rate trajectory which requires the overall carbon intensity of the state's power sector to be reduced to 1,531lbs/MWh in 2030 and thereafter. The CERO2 case is less stringent, with a final goal of 1,683 lbs/MWh, but it requires earlier compliance, i.e. by 2025. (Please refer to Table 4-4 and Figure 4-4 for emission rate paths for the two scenarios.)

Figure 5-23 compares capacity portfolios in the BASE and the two carbon cap scenarios. Due to the fact that emission rate goals begin in 2019, substantial changes in the capacity portfolio are observed for the two carbon cap scenarios starting in that period. The CERO1 case adds 3.96 GW of wind capacity to the system in 2019 and the CERO2 case adds 2.29 GW of wind (see Figure 5-24). More natural gas capacity is installed for the two carbon cap cases from 2016 to 2022. These investments help satisfy the need to reduce carbon intensity dramatically from previous levels for the two cases (see Figure 5-25). Total capacity of the existing coal fleet for the CERO2 case is the same as the BASE case over the modeling horizon. But the CERO1 case retires another 0.54 GW of coal capacity in 2019. In terms of total generation capacity, the CERO1A case has the most from 2019 on, the CERO2A case has less, and the BASE case has the least. This capacity increase is mainly attributable to large amounts of investment in wind capacity in the two carbon cap scenarios in 2019. While wind serves the purpose of reducing the carbon intensity of the power generation in-state, wind technology has a relatively low capacity factor compared with fossil fuel-fired generation, and thus more overall capacity is needed to serve the load.

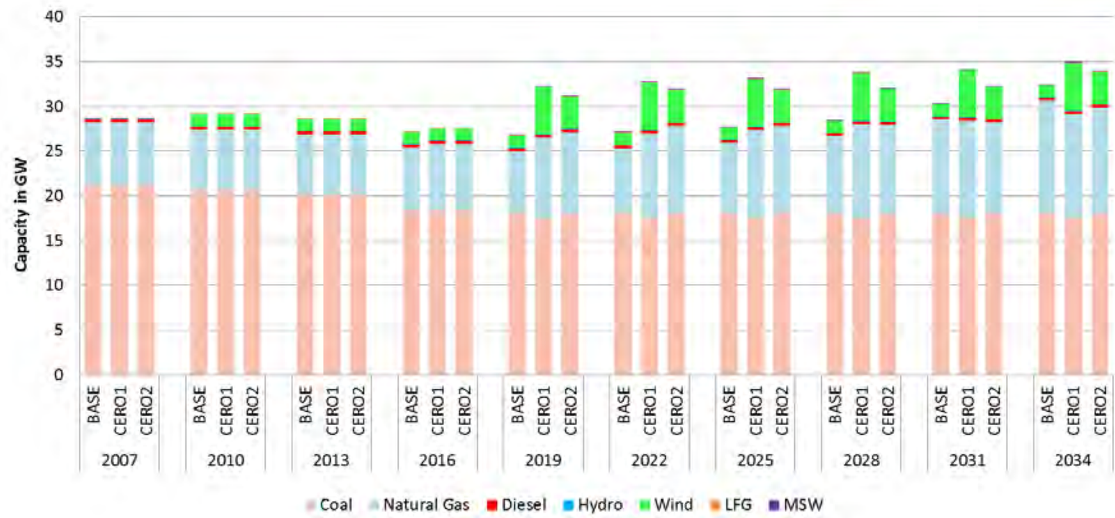

Figure 5-23 Indiana Electricity Capacity Portfolio in GW in the BASE and Carbon Cap Scenarios

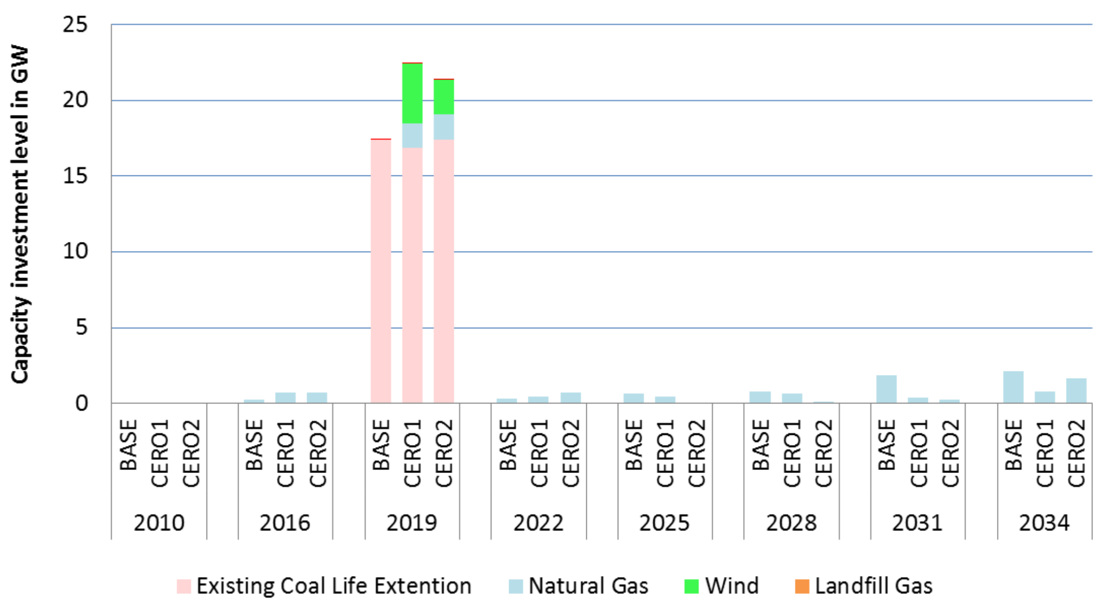

Figure 5-24 Indiana Electricity System Capacity Investment Level in GW in the BASE Case and Carbon Cap Scenarios

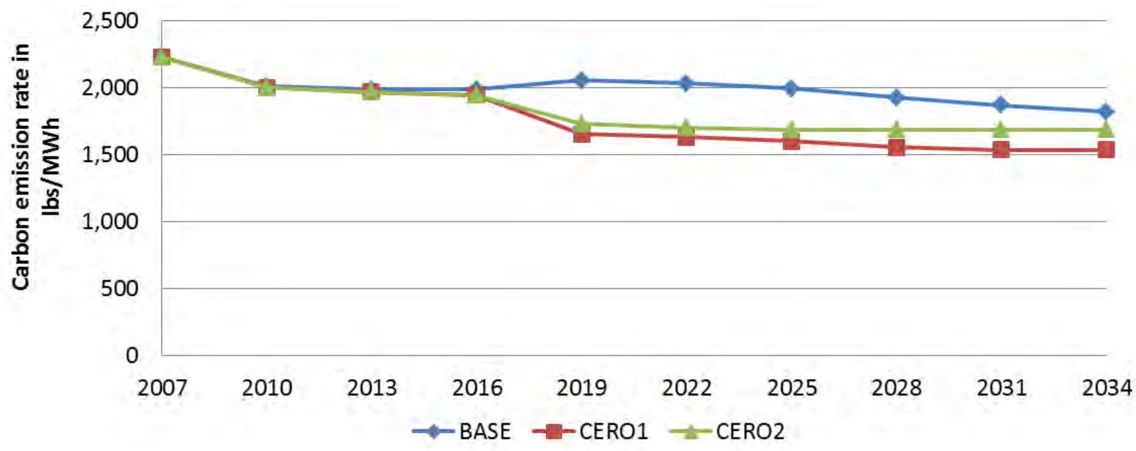

Figure 5-25 Power Sector Carbon Emission Rate in the BASE and the Two Carbon Cap Cases

Figure 5-26 displays generation portfolios in the BASE and the two carbon cap scenarios. The total amount of electricity generation is reduced from the BASE case level in the two carbon cap scenarios in the early periods after the policy phases in (from 2019 to 2025), which is largely due to dramatic increases in the cost of electricity generation during those periods (see Figure 5-27). The amount of coal generation starts to deviate from the BASE case level for the two carbon cap scenarios starting in 2013. The share of generation from coal drops dramatically in 2019 to 70.17% in the CERO1 case and 73.61% in the CERO2 case, compared with 89.37% in the BASE case. After 2019, the percentage of coal generation continues to decline. For the CERO1 case, only 61.58% of Indiana's electricity generation comes from coal-fired generators in 2034, and this share for the CERO2 case is 65.09% in 2034. Biomass comes into play from 2019. Generation from biomass co-firing with coal constitutes 4.59% of total generation in 2019 and gradually decreases over time to 2.63% in 2034 in the CERO1 case. For the CERO2 case, share of biomass is slightly higher at 4.97% in 2019 and it goes down slowly to reach 4.28% in 2034. The role of natural gas becomes more important in both carbon cap scenarios relative to in the BASE case. A substantial increase in the share of natural gas is observed in 2019 for the CERO1 case (12.91%) and the CERO2 case (12.86%) compared with 7.43% in the BASE case. In 2034, generation from natural gas reaches

25.51% in the CERO1 case and 23.56% in the CERO2 case. Wind generation is encouraged by the carbon cap, especially for the more stringent case (CERO1). The share of wind grows to 11.83% in 2019 for the CERO1 case; although it shrinks slightly thereafter (to 9.87% in 2034) because of the growth of total generation. Note that while the share is falling, the absolute amount of wind generation increases slightly over time. For the CERO2 case, the percentage of wind generation jumps to 8.06% in 2019, with absolute amount of wind generation increasing slightly thereafter, but with the share of wind decreasing (6.68% in 2034).

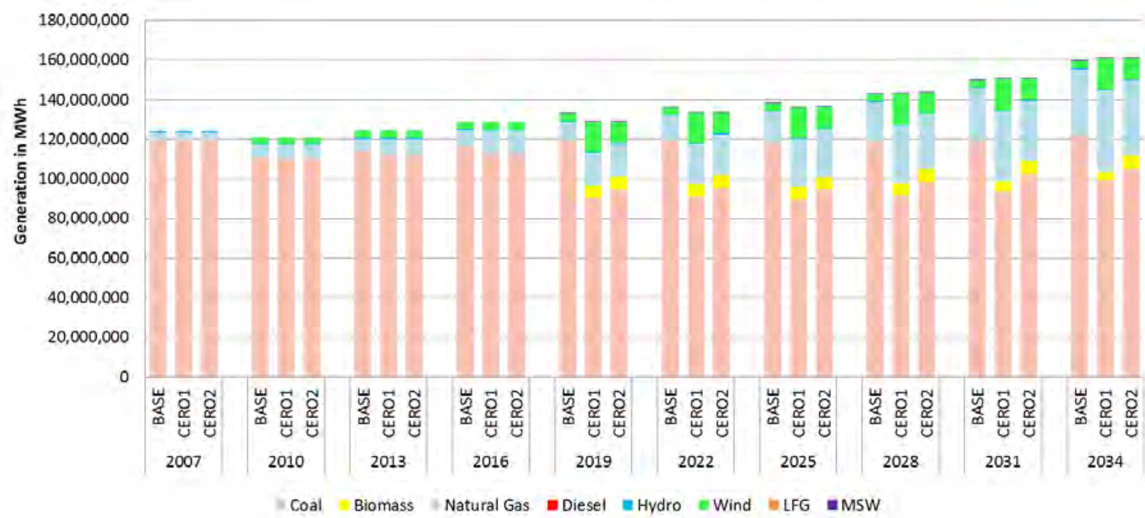

Figure 5-26 Indiana Electricity Generation Portfolio in MWh in the BASE Case and Carbon Cap Scenarios

Focusing on CO_2 emissions from the electricity generation system, the two carbon cap scenarios realize dramatic emission reductions overall, but the reductions achieved in the earlier years after the policy phases in are more significant than those achieved in the latter years (see Figure 5-27). The major reason is that the emission rate stabilizes after 2030 and 2025 respectively for the two carbon cap scenarios (see Figure 5-25), but the amount of total generation continues to grow in the latter years (see Figure 5-26). Beginning in 2019, the average annual emission reduction achieved in the CERO1 case is 19% and that for the CERO2 case is 13%.

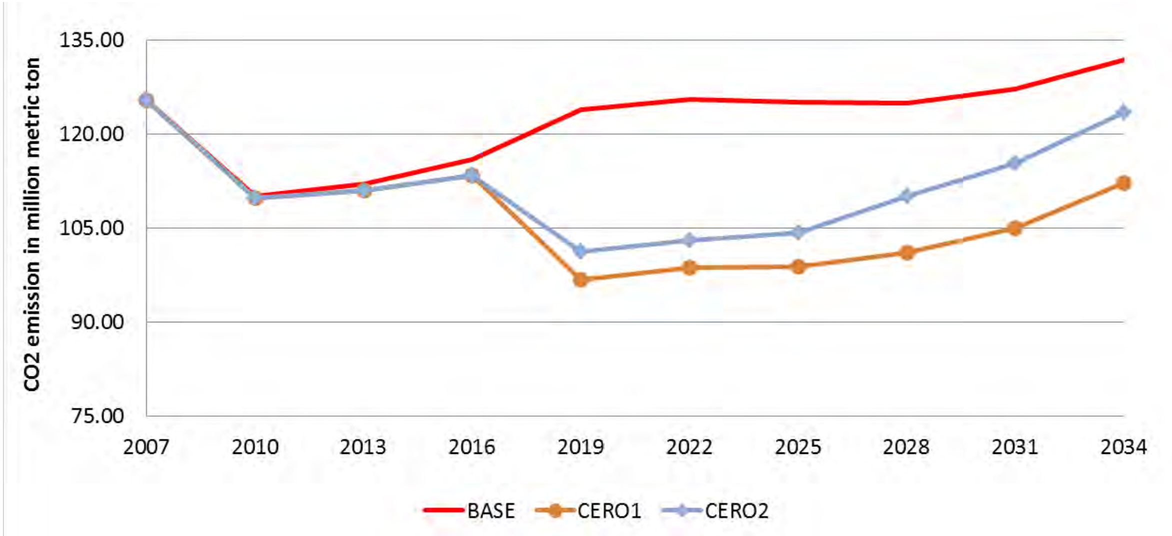

Figure 5-27 CO_2 Emissions from Electricity System in the BASE and Carbon Cap Scenarios

Table 5-9 displays the cumulative CO_2 emissions in the BASE and the two carbon cap scenarios. Considering electricity system alone, the CERO1 case mitigates around 449 million metric tons of CO_2 emissions, which accounts for around 12% of the BASE case cumulative emissions. The CERO2 case has a smaller impact on emissions, with a reduction of about 315 million metric tons of CO_2 emissions, which is equivalent to 8.58% of the BASE case level. In terms of the entire energy system, the amount of CO_2 emission mitigation accomplished in the two carbon cap scenarios are fairly close to the levels when considering power sector alone, indicating very limited slippage effects on carbon emissions from the rest of the energy system. The CERO1 scenario leads to 7.85% of emission reduction versus 5.45% for the CERO2 case.

Table 5-9 Accumulated CO_2 Emissions over the Modeling Horizon for the BASE and Carbon Cap Scenarios

Case	Electricity system cumulative CO2 emission in million metric ton	Electricity system cumulative CO2 emission reduction from the BASE in million metric ton	% change of electricity system cumulative CO2 emission from the BASE	Energy system cumulative CO2 emission in million metric ton	Enegy system cumulative CO2 emission reduction from the BASE in million metric ton	% change of energy system cumulative CO2 emission from the BASE
BASE	3,665.38			5699.26		
CERO1	3,215.87	449.51	12.26%	5251.65	447.61	7.85%
CERO2	3,350.83	314.55	8.58%	5388.55	310.71	5.45%

As for the marginal cost of electricity, a divergence between the BASE case and the two carbon cap scenarios occurs starting in 2019 (see Figure 5-28). With the more stringent emission rate goals but a longer time to comply (CERO1), a 42% jump in the marginal cost of electricity is observed in 2019 followed by relatively stable prices until 2028. After 2028, the cost of electricity slowly decreases and gradually approaches the electricity cost trajectory in the BASE case. For the case with less stringent emission rate targets but a shorter time to comply (CERO2), dramatic increases in the marginal cost of electricity are observed for earlier periods after the policy takes effect, especially in 2019 (a 53% rise from 2016 level). After 2022, the cost declines and moves toward the BASE case level.

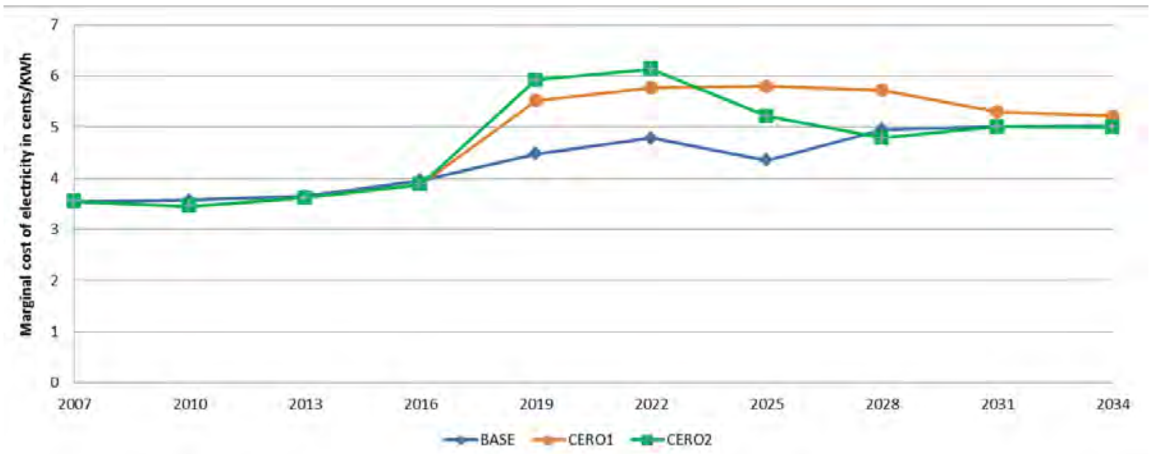

Figure 5-28 Discounted Marginal Cost of Electricity in the BASE and Carbon Cap Scenarios

Focusing on the rate impact over the entire modeling horizon, the LMCOEs are compared across the BASE case and the two carbon cap scenarios in Table 5-10. Overall, the CERO1 case raises the LMCOE 0.88 cents/KWh, which is equivalent to 10.45% of the BASE case level. The CERO2 case results in a rate increase of 0.61 cents/KWh, equivalent to 7.27% above the BASE case level.

Table 5-10 LMCOE in the BASE and Carbon Cap Scenarios

Scenario	LMCOE in cents/KWh	LMCOE % change from BASE
BASE	8.41	
CERO1	9.29	10.45%
CERO2	9.03	7.27%

Table 5-11 compares the cost effectiveness of emission-rate caps for emission mitigation for the various cases. By examining the extent of the change of LMCOE resulting from a one percent reduction of CO_2 emissions from the power sector, CERO2 seems slightly more efficient, with a 0.8475% increase in the LMCOE per one percent power sector emission reduction on an average basis compared with 0.8525% for the CERO1 case. When assessing the average amount of energy system cost increase caused by reducing one metric ton of CO_2 emissions from the entire energy system, the CERO2 case does slightly better as well with an average abatement cost of $15.81/metric ton versus $17.75/metric ton for the CERO1 case.

Table 5-11 Comparison of Cost Effectiveness of Carbon Reduction for Carbon Cap Scenarios

Scenario	$\frac{\text{\% change of LMCOE from BASE}}{\text{\% reduction of electricity sector CO2 emissions from BASE}}$	Energy system CO2 emissions abatement cost in $/metric ton
CERO1	0.8525	17.75
CERO2	0.8475	15.81

For the emission-rate goals modeled in CERO1 case, two additional scenarios are developed, which allow purchasing of carbon permits from the national market to comply at a cost of $10/metric ton and $50/metric ton respectively. When purchasing of carbon permits from out of state is allowed at a relatively inexpensive cost ($10/metric ton), the compliance of carbon regulation for the state of Indiana relies heavily on purchased carbon permits, rather than transforming the in-state power sector to a less carbon-intensive system. With carbon permits available at a higher cost ($50/metric ton), moderate amounts of carbon permits are purchased to meet the emission requirements. Substantial changes in Indiana’s power generation portfolio are observed, but not as significant as in the CERO1 case. The two scenarios with carbon permits purchases do reduce discounted total system cost compared with the scenario without carbon permits purchases. However, emissions reductions achieved in-state are significantly reduced as well, especially when carbon permits are available at $10/metric ton.

5.5 Comparison across Policies

In this section, different policy instruments are compared in terms of their effectiveness in achieving CO_2 abatement in the state of Indiana. For RPS and carbon tax respectively, the scenario with the best performance in terms of the least percent electricity rate impact per percent of carbon dioxides emissions mitigation ($\frac{\text{\% change of LMCOE from BASE}}{\text{\% reduction of electricity sector CO2 emissions from BASE}}$) is selected as a representative of that policy. For carbon cap, the CERO1 scenario is selected as a representative of the policy because emission rate goals modeled in this case are goals proposed by the EPA in the Clean Power Plan. (This means that the RPSMSWO case, the CTaxHGR case and the CERO1 case are selected for comparison in this section.)

Based on the results discussed in the previous sections of Chapter 5, a carbon tax seems to be the least effective option for cutting Indiana's power sector carbon emissions. In other words, even the carbon tax trajectory in the CTaxHGR case is not high enough to result in substantial changes in Indiana's electricity generation portfolio (Figure 5-29) and thus the impact on CO_2 emissions reduction are also not as substantial (see Figure 5-30 and Figure 5-31) as those achieved in the RPSMSWO and CERO1 cases. But the CTaxHGR case by far leads to the highest marginal cost of electricity of the three cases (see Figure 5-32).

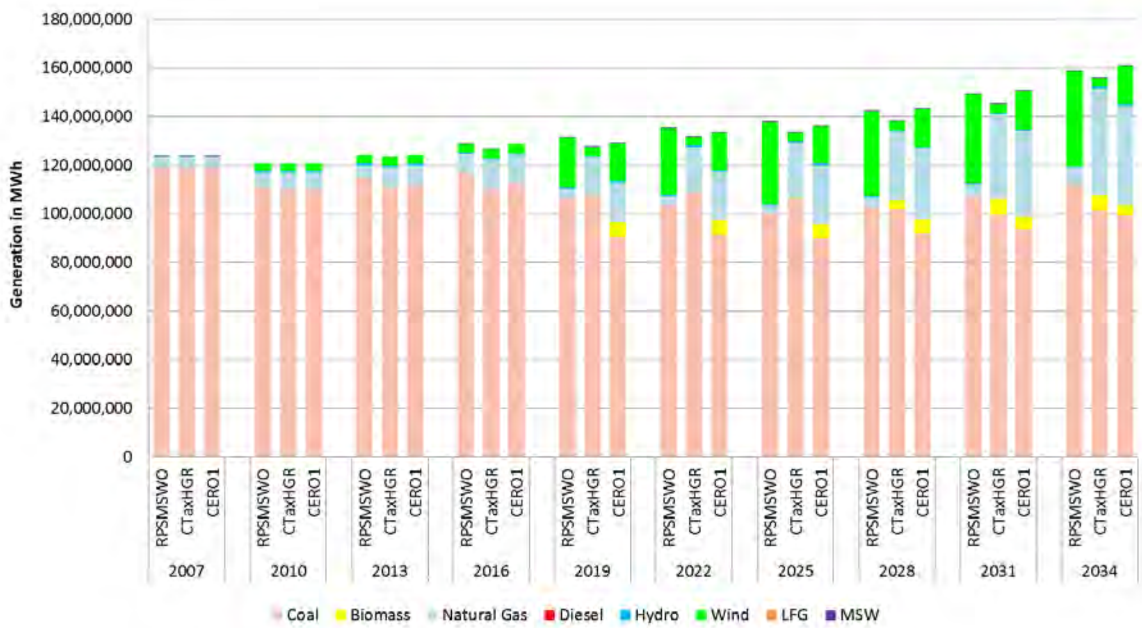

Figure 5-29 Electricity Generation Portfolio in the RPSMSWO, CTaxHGR and CERO1 Cases

Note: The RPSMSWO case models a renewable portfolio standard which requires at least 16% of renewable generation in 2019 and 25% in 2025 and thereafter. Only in-state resources are eligible for compliance.

The CTaxHGR case models a carbon tax trajectory starts at $8.8/metric ton of CO_2 emissions in 2016 and reaches $41.20/ metric ton of CO_2 emissions in 2034.

The CERO1 case models a emission rate trajectory with an average emission rate between 2019 and 2028 equal to 1607 lbs/MWh and a final goal of 1531 lbs/MWh from 2031 and forward.

The RPSMSWO case and the CERO1 case both lead to dramatic changes in Indiana's electricity generation portfolio (see Figure 5-20). However, the RPSMSWO relies almost solely on increased wind generation to reduce carbon emissions, rather than transforming to a more diverse portfolio that includes biomass, more natural gas and wind, and less coal as observed in the CERO1 case. In terms of CO_2 emissions, the CERO1 case leads to deeper reductions than the RPSMSWO case, especially in the early periods after the policy phases in (see Figures 5-30 and 5-31). But the RPSMSWO case indicates a smooth growth trajectory of the marginal cost of electricity, rather than a dramatic cost increase in 2019 as observed in the CERO1 case (see Figure 5-32). Speaking of the rate impact induced by carbon mitigation, the RPSMSWO case raises the LMCOE slightly more than the CERO1 case for a one percent decrease of power sector

CO_2 emissions (see column 2 of Table 5-12). The CERO1 scenario performs much better with regard to the average system cost increase resulted from one metric ton of system-wide CO_2 mitigation compared with the RPSMSWO case (see column 3 of Table 5-12).

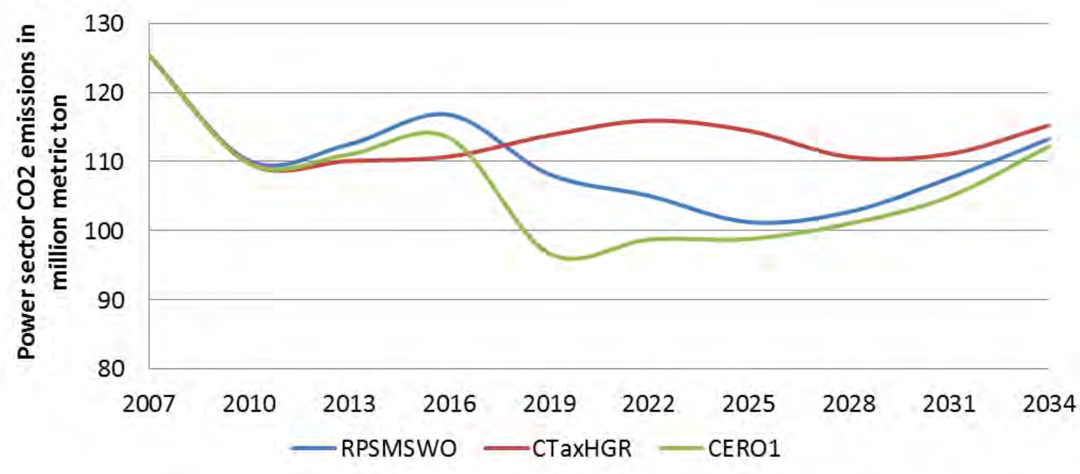

Figure 5-30 Power Sector CO_2 Emissions in the RPSMSWO, CTaxHGR and CERO1 Cases

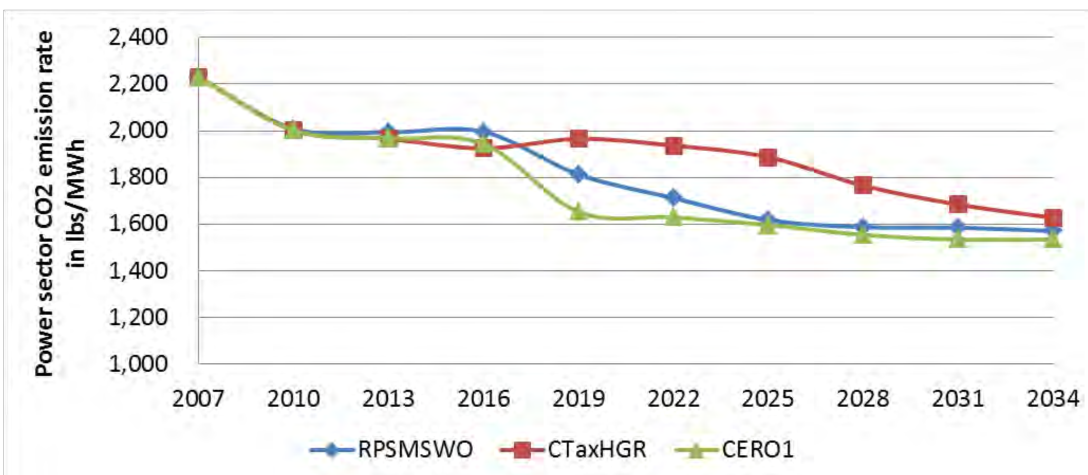

Figure 5-31 Power Sector CO_2 Emission Rate in the RPSMSWO, CTaxHGR and CERO1 Cases

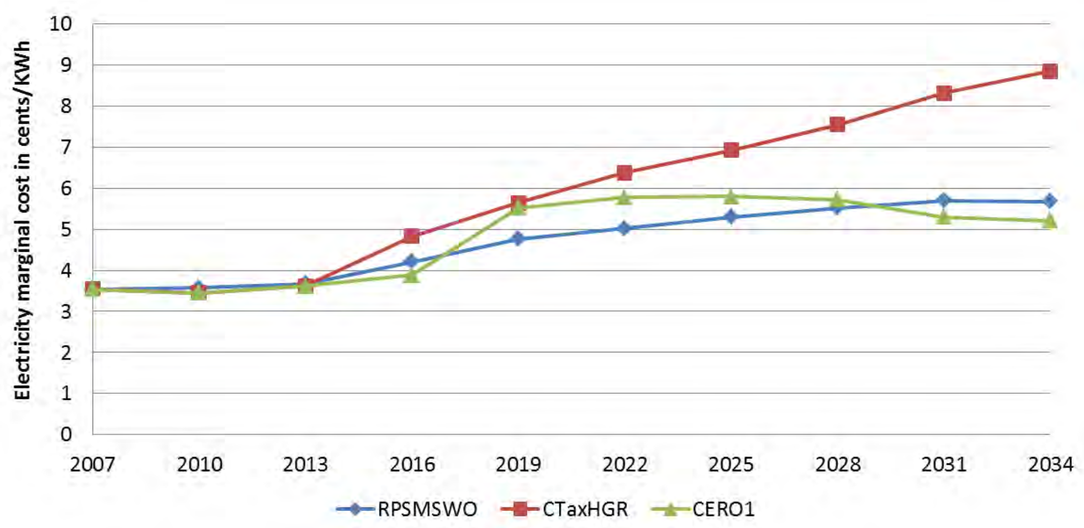

Figure 5-32 Discounted Marginal Cost of Electricity in the RPSMSWO, CTaxHGR and CERO1 Cases

Table 5-12 Comparison of Cost Effectiveness of Carbon Reduction for the RPSMSWO CTaxHGR and CERO1 Cases

Scenario	% change of LMCOE from BASE / % reduction of electricity sector CO2 emissions from BASE	Energy system CO2 emissions abatement cost in $/metric ton
RPSMSWO	0.89	35.00
CTaxHGR	5.41	103.66
CERO1	0.85	17.75

In order to make a carbon tax trajectory more comparable with other policy instruments, an additional scenario is constructed, where a carbon cap trajectory based on power sector CO_2 emissions realized in the RPSMSWO case is imposed on IN-MARKAL. This scenario is referred to as the CCAPvsRPSMS case, which allows us to identify the carbon tax levels sufficient to achieve power sector CO_2 emissions reduction accomplished in the RPSMSWO case.

As shown in Table 5-13, the level of carbon tax would have to be as high as around $30/metric ton in 2019 and grow quickly to reach over $100/metric ton in 2025 in order to limit power sector carbon emissions in Indiana to a level equivalent to the RPSMSWO case. The tax level declines after 2025, because the RPS goal stabilized after 2025 in the RPSMSWO case. However, the tax level is still close to $40/metric ton in 2034.

Table 5-13 Carbon Tax Trajectory Identified in the CCAPvsRPSMS Case in 2007$/Metric Ton

	2019	2022	2025	2028	2031	2034
CCAPvsRPSMS	29.60	44.60	104.30	63.30	59.10	38.90

Although the carbon tax trajectory endogenously determined in the CCAPvsRPSMS case is much higher than the ones in the three carbon tax scenarios modelled in Section 5.3, the changes in the capacity portfolio are still relatively small compared with the BASE case (see Figure 5-33), including 0.54 GW more of coal capacity retirements, 0.05 GW more of wind capacity additions and small amounts of natural gas additions over time.

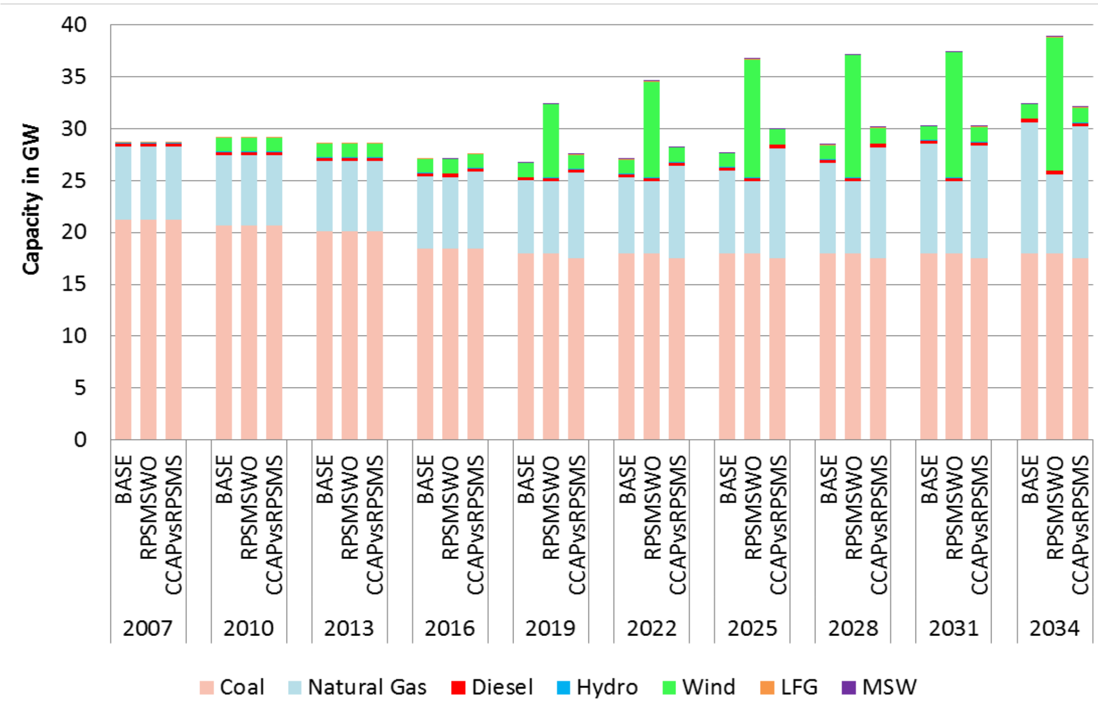

Figure 5-33 Capacity Portfolio in the BASE, RPSMSWO and CCAPvsRPSMS Cases

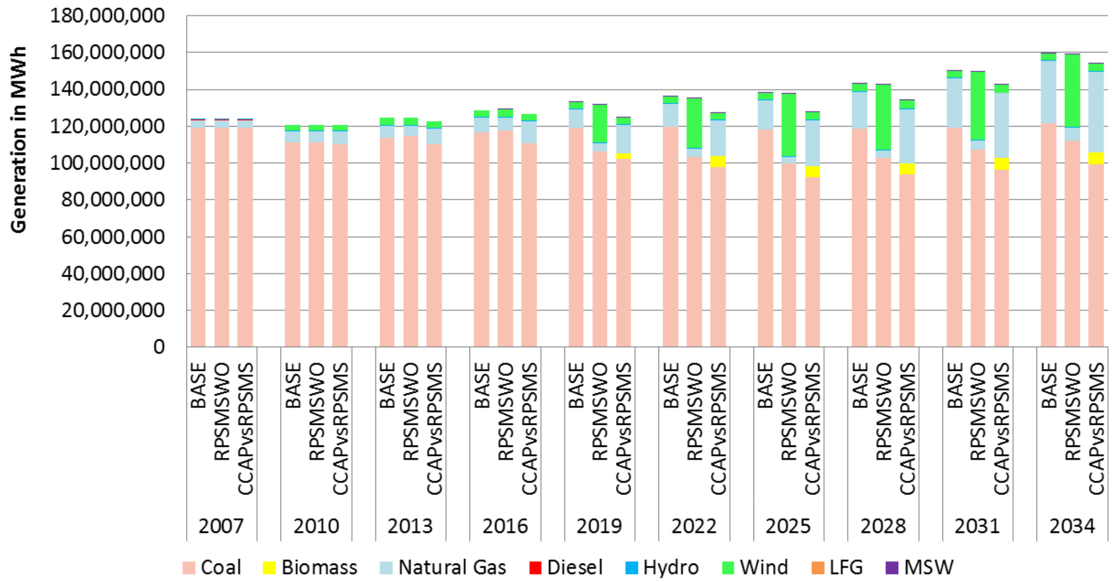

Figure 5-34 Generation Portfolio in the BASE, RPSMSWO and CCAPvsRPSMS Cases

Emissions reductions in the CCAPvsRPSMS case are attained mainly through reducing the total amount of electricity generation (by 6% on average from 2019 and on), reducing the amount of coal generation (by around 19% on average from 2019 and on), incorporating biomass co-firing with coal (reaches about 4% of total generation on average since 2019) and increasing generation from natural gas (by about 45% on average since 2019), rather than substantially increasing the share of wind generation and suppressing natural gas generation as observed in the RPSMSWO case (see Figure 5-33).

As for the discounted marginal cost of electricity, a divergence between the RPSMSWO scenario and the CCAPVSRPSMS scenario occurs starting in 2016 (see Figure 5-35). The marginal cost of electricity increases dramatically in the period from 2016 to 2025 and reaches its peak in 2025 at 14.53 cents/KWh for the CCAPVSRPSMS scenario and drops after 2025. But for the RPSMSWO scenario, the cost trajectory is relatively smooth.

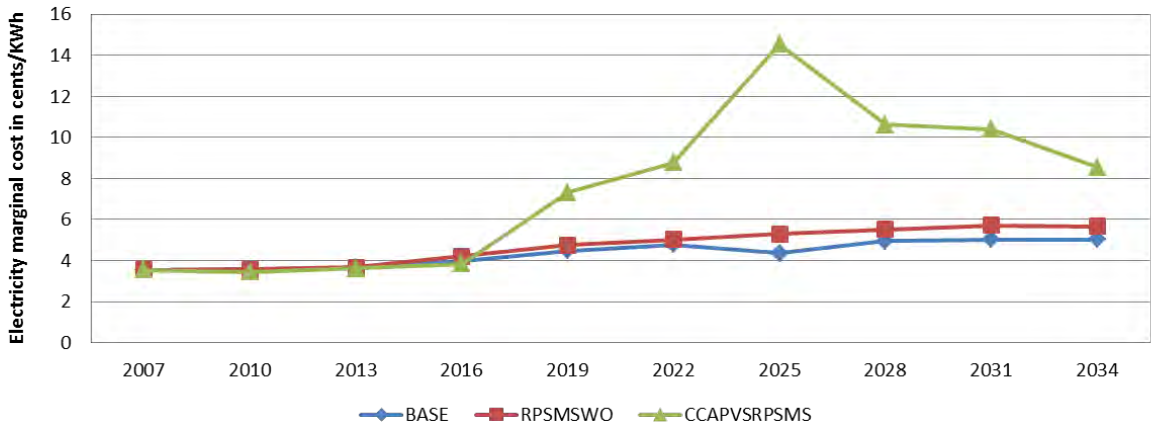

Figure 5-35 Discounted Marginal Cost of Electricity in the BASE, RPSMSWO and CCAPVSRPSMS Scenarios.

Comparing the LMCOEs between the RPSMSWO case and the CCAPvsRPSMS case, the latter has a higher impact on power cost. The RPSMSWO case raises the LMCOE to 9.14 cents/KWh, a 8.66% rise from the BASE case. But the CCAPvsRPSMS case causes an increase of 71.64% from the BASE case to 14.44 cents/KWh.

Table 5-14 LMCOE in the BASE, RPSMSWO and CCAPvsRPSMS Cases

Scenario	LMCOE in cents/KWh	LMCOE % change from BASE
BASE	8.41	
RPSMSWO	9.14	8.66%
CCAPVSRPSMS	14.44	71.64%

Next consider the percentage change of LMCOE resulted from a one percent reduction of carbon emissions from the power sector, the RPSMSWO case still performs better. However, when consider from the perspective of the entire energy system, the CCAPvsRPSMS case indicates a much lower average abatement cost ($14.17/metric ton) than the RPSMSWO case ($35.00/metric ton). Examining results from IN-MARKAL, the higher LMCOE observed in the CCAPvsRPSMS case stimulates earlier and larger amounts of adoption of high efficiency electric appliances as well as switching from electricity to less expensive fuels in the end-use sectors compared with the RPSMSWO case, which leads to a savings of total system costs over time that more than offset the additional cost induced by higher electricity prices. This is the major reason that the CCAPvsRPSMS case results in a lower energy system carbon abatement cost, but with a higher electricity cost impact from carbon reduction.

Table 5-15 Comparison of Cost Effectiveness of Carbon Reduction for the RPSMSWO and CCAPvsRPSMS Cases

Scenario	$\frac{\text{\% change of LMCOE from BASE}}{\text{\% reduction of electricity sector CO2 emissions from BASE}}$	Energy system CO2 emissions abatement cost in $/metric ton
RPSMSWO	0.89	35.00
CCAPvsRPSMS	6.83	14.17

CHAPTER 6. CONCLUSIONS

A nation-wide climate policy which targets the power sector could provide a path leading to carbon abatement in the United States. Because Indiana depends heavily on coal as its primary source for electricity generation, substantially reducing carbon emissions will likely mean a significant transformation of the state's electric power generation. Understanding the efficacy and cost of national climate policy in Indiana will help the state be prepared to exploit any flexibility in the policy to its advantage. In addition, assessing the impacts of the policy alternatives on Indiana serves as guidance for the national policy design process regarding the subnational impacts. To the extent that Indiana is representative of states whose generation portfolio relies substantially on coal, this research also serves as a case study for the impacts of national climate policy on states in similar circumstances.

To analyze the impact of a potential national climate policy on the state of Indiana, a linear-programming optimization model was created by using the MARKAL energy system model framework. This model is named as IN-MARKAL and is built based on comprehensive research into Indiana's energy-economic system, including primary resource supply, energy conversion sectors and end-use sectors. The level of detail in the electricity generation system makes this model suitable to conduct energy policy analysis to assess impacts of policy on the Indiana power sector while taking into consideration interactions between various energy sectors, including fuel and technology substitutions. Not limited to this research, IN-MARKAL is a powerful tool that can be tailored for the analysis of additional energy policy research related to Indiana in the future.

The results from scenario analysis indicate that the increment to the levelized marginal cost of electricity (LMCOE) is in the range of 2.53-71.64% by 2036 relative to the case where no policy is imposed. Meanwhile, the reduction of cumulative carbon emissions from the electricity generation system realized by 2036 is in the range of 1.21-12.26%.

Overall, a carbon tax seems to be the least effective option for cutting Indiana's power sector carbon emissions. The three carbon tax trajectories modeled in this study are based on consensus carbon emissions pricing from the literature. However, they fail to achieve remarkable emissions reductions for Indiana. None of the three carbon tax trajectories leads to substantial changes of Indiana's capacity portfolio. Carbon emissions reductions for the two higher tax trajectories among the three are realized through deductions of total electricity generation caused by substantial increases in electricity cost stemmed from carbon tax, more frequent dispatch of natural gas units and inclusion of biomass to be co-fired with coal. It is estimated that in order to achieve carbon emissions reductions realized in the 25% RPS scenario (a close to 10% reduction), the carbon tax imposed on Indiana's electricity generation system needs to be above $104/metric ton in 2025.

A 25% RPS by 2025 is very cost-effective among modelled policy tools in achieving carbon mitigation from the state's electricity generation system. However, capacity additions induced by RPS are mostly satisfied by wind. RPS suppresses the expansion of natural gas units and does not substantially reduce coal's role in the capacity portfolio, which results in a generation mix dominated by coal and wind. The reliability of such a power generation system might be an issue because coal plants may not be able to provide the rapid ramping services needed to support a substantial wind generation capacity. Although RECs generated out-of-state as a compliance option do help relieve pressure of a RPS on electricity cost when they are available at low costs, this state-level analysis suggests that RECs push almost all renewable investment required by the RPS outside Indiana when they are available at under $40/MWh.

The emission-rate cap policy modeled in this study outperforms the 25% RPS by 2025 in terms of the cost-effectiveness in reducing electricity generation system carbon emissions (i.e., the percentage increase in LMCOE resulting from a one percent decrease in cumulative carbon emissions from the electricity generation system) and the energy system CO_2 abatement cost (i.e., the average increase in energy system cost per ton of carbon emissions reduction realized in the entire energy system) among all policy instruments examined. Additionally, the carbon cap policies lead to more diverse generation portfolios for Indiana which reduce coal generation, increase natural gas and wind generation and incorporate biomass.

In summary, an RPS might be a very cost effective option to achieve substantial emissions reductions for the power sector of Indiana, but it may also lead to a less reliable generation mix. A carbon tax might be the least cost effective tool to reduce carbon emissions for Indiana based on the tax trajectories modeled. These results highlight the importance of choosing the right tax trajectory in order to reduce emissions at a reasonable cost. An emission cap is effective for realizing deep carbon reductions with moderate cost and leads to a diverse generation portfolio for Indiana; but the intermediate goal for Indiana specified in the current EPA proposal may not be achievable, resulting in a huge increase in marginal cost of electricity during the policy phase in, rather than the smooth electricity cost trajectory observed in some other scenarios.

This analysis was conducted solely on the basis of economic optimization. The reliability concerns of the generation system were simplified and expressed through a reserve margin in the model, without considering the impact on the functioning of the electricity generation system caused by the integration of renewable resources. The approach to modeling reliability could be improved by adding constraints on the amount of fast-ramping capacity that is needed to offset expected demand fluctuations and additional ramping capacity needed to respond to fluctuations from intermittent renewable generation. Electricity losses occurring across transmission lines were reflected by transmission efficiency, but other costs related to transmission were not incorporated. Changes to the transmission system are not modeled, and neither are the precise locations of generation capacity expansions, making the model appropriate for analysis of energy policies, but not for planning expansions of the electricity system. No electricity imports or exports are modeled in IN-MARKAL. No limits are place on REC purchases from out-of state for RPS scenarios with RECs as a compliance option. No limits are imposed on the expansion of wind generation capacity in the model. However, the maximum wind capacity expansion across scenarios modeled in this study is around 13GW by 2034 (RPSMSWO scenario), which does not exceed the wind capacity potential for Indiana estimated by NREL based on current technology (2014).[66] In addition, the difficulty in policy enforcement and the costs associated with policy enforcement were not considered in the analysis.

While this research leaves room for improvements, it has established a modeling framework to conduct analysis of energy policy research related to Indiana in the future. It also facilitates understanding of the efficacy and cost of alternative policy instruments for carbon mitigation for a state with coal-dominated electricity generation portfolio.

[66] Based on NREL's estimation, potential wind installed capacity for Indiana is 41.25GW for 2008 turbine technology, 158.75GW for 2014 turbine technology and 179.68GW for near future turbine technology.

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An Assessment of the Efficacy and Cost of Alternative Carbon Mitigation Polices for the State of Indiana

- Analyzed large volume of energy-related data collected from federal agencies and research institutions
- Estimated and projected demand for various energy services of Indiana's four end-use sectors
- Investigated Indiana's power generation system, petroleum refineries and bio-refineries; accumulated detailed knowledge of electric utilities, electricity market and pricing and electricity regulation
- Researched primary energy sources supplying Indiana with focus on their availability, prices and use

- Established a bottom-up optimization model of Indiana's energy-economic system for policy analysis based on a comprehensive understanding of energy supply, conversion and demand in state
- Surveyed U.S. federal climate policy efforts and developed alternative policy scenarios
- Evaluated the impact of alternative carbon mitigation policies on Indiana's power system capacity and generation mixes with special focus on the economic costs and carbon reductions achieved under different scenarios

Assessment of the Reliability of Indiana's Electricity Generation System (IEGS)

- Examined Indiana's power generation system and established a database of generation capacity and load
- Developed generation model, load model and simulation techniques to analyze the reliability of IEGS
- Conducted simulation with 10 billion iterations to build IEGS capacity availability probability distribution
- Evaluated the result accuracy of Monte Carlo Methods for the generation capacity model
- Estimated IEGS loss of load probability and analyzed related statistics based on simulation results
- Determined the adequacy of the rule-of-thumb reserve margin and identified new reserve margins of IEGS
- Delivered results in a written report to the Indiana Utility Regulatory Commission

SKILLS

Analytical skills

- Mathematical programming and economic optimization; Cost benefit analysis; Statistical and econometric analysis; Probabilistic simulation and stochastic modeling; Financial and feasibility analysis

Software

- Microsoft Office Suite (proficient in Excel and @Risk); GAMS; R; SAS; MATLAB, EViews

Language skills

- English (fluent); Chinese (native speaker)

PRESENTATIONS & PUBLICATIONS

- IN-MARKAL: Modeling Indiana's Energy-Economic System (End-Use Energy Services), presented with Emrah Ozkaya at the Integrated Modeling Workshop held by Indiana University at Bloomington, Indiana, Nov. 2011
- IN-MARKAL: Modeling Indiana's Energy System (Work-in-Progress), presented with Emrah Ozkaya at the Third Annual MARKAL-TIMES Symposium held by the U.S. Environmental Protection Agency at Durham, North Carolina, Oct. 2011
- Lu, Liwei; Preckel, Paul; Gotham, Douglas; "Assessment of the Reliability of Indiana's Electricity Generation System," North American Power Symposium (NAPS), 2009, vol., no., pp.1-6, 4-6 Oct. 2009 (also presented at the conference)
- Lu, Liwei; Liu, Chen; "Risk Management of Chinese Electric Appliance Retail Chain Store Enterprise - A Case Study of GOME, "Journal Of Sichuan Normal University (Social Sciences Edition), vol.34, no.1, Jan. 2007
- Liu, Chen; Lu, Liwei; "The Dynamic Analysis on the FDI's Time Lag Effect under the Framework of VAR Model," The Journal of Quantitative & Technical Economics, vol.6, no., 101-110, Oct. 2006

INTERNSHIP EXPERIENCE

Informa Economics, Inc.
Memphis, USA
Intern, Economic Research Analyst, Business Consulting Group May 2011 – Aug. 2011

- Analyzed grain storage markets of Australia and Ukraine, forecasted market growth and prepared reports
- Developed a stochastic time series model for short-term livestock commodity prices forecasting
- Established a user-friendly data inquiry system for agricultural commodities in Excel
- Designed and conducted two sessions of advanced Excel training

Citibank (China) Co., Ltd
Chengdu, China
Intern, Industry Analyst, Corporate and Investment Banking Division May 2008 – Aug. 2008

- Surveyed potential capital needs of companies in various industries to identify new business opportunities
- Established business profiles of target companies covering ownership, company structure, product lines, revenues, costs, competition, as well as operational risks and threats

COURSE PROJECTS

- 2010 Cost Benefit Analysis of Bosnia's Power Sector Development Program, Purdue University
- 2008 Financial Analysis of China Mengniu Dairy Company Limited, Purdue University
- 2008 Econometric Analysis of Productivity of Foreign-Born Faculty of Agricultural and Applied Economics, Purdue University
- 2007 Smith Farms Custom Harvesting Venture - A Financial Analysis, Purdue University
- 2007 Quantitative Analysis of a New Product Introduction - A Case Study of Fresh Juice Inc., Purdue University
- 2007 Marketing Plan for Launching Clif Luna Bar in the U.K. Market, Purdue University
- 2006 Social, Economic and Natural Resources Profile Survey of TaiPuSiQi County of Inner Mongolia, Beijing Normal University

GRANT, SCHOLARSHIPS, AWARDS & HONOR

- 2009 North American Power Symposium Travel Grant
- 2009 Scholarship for Krannert School of Management Applied Management Principles Program, Purdue University (the only nominee by the Department of Agricultural Economics in 2009)
- 2007 Honor of Best Undergraduate Thesis, Beijing Normal University
- 2006 First Prize Scholarship for Outstanding Academic Performance, Beijing Normal University
- 2006 First Prize Zhong Lang Scholarship for Academic Excellence, Beijing Normal University
- 2005 Leadership Award, White Dove Young Volunteer Association, Beijing Normal University
- 2005 Award for Outstanding Academic Performance, Beijing Normal University
  2004 LIYUN Scholarship for Academic Excellence, Beijing Normal University