2. Modeling Framework

ICF developed the Integrated Planning Model (IPM) to support analysis of the electric power sector. The EPA, in addition to other state air regulatory agencies, utilities, and public and private sector entities, has used IPM extensively for various air regulatory analyses, market studies, strategy planning, and economic impact assessments.

IPM is a long-term capacity expansion and production-costing model of the electric power sector. Its mathematical formulation is based on a Linear Programming (LP) structure. The structure provides several advantages, one of which is the guarantee of a globally optimal solution. Fast and efficient commercial solvers exist to solve LP models. The solved dual variables (also known as shadow prices) of each constraint modeled in IPM inform EPA rulemaking or policy analysis process in regard to the marginal cost pricing of energy, capacity, fuels, and emission allowances. Also, reasonable solution times for an LP model allow EPA to gain insights by modeling a large number of scenarios in a relatively short period of time.

The first section of this chapter provides a brief overview of the model's purpose, capabilities, and applications. The following sections are devoted to describing the IPM's model structure and formulation (2.2), key methodological characteristics (2.3), and programming features (2.4), including its handling of model inputs and outputs. Readers may find some overlap between sections. For example, transmission decision variables and constraints are covered in the discussion of model structure and formulation in section 2.2, and transmission modeling is covered as a key methodological feature in section 2.3.7. The different perspectives of each section are designed to provide readers with information that is complementary rather than repetitive.

2.1 IPM Overview

IPM is a well-established model of the electric power sector designed to help government and industry analyze a wide range of issues related to this sector. The model represents economic activities in key components of energy markets – fuel markets, emission markets, and electricity markets. Since the model captures the linkages in electricity markets, it is well suited for developing integrated analyses of the impacts of alternative regulatory policies on the power sector. In the past, applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and power plant asset valuation.

2.1.1 Purpose and Capabilities

IPM is a dynamic linear programming model that generates optimal decisions under the assumption of perfect foresight. It determines the least-cost method of meeting energy and peak demand requirements over a specified period. In its solution, the model considers a number of key operating or regulatory constraints that are placed on the power, emissions, and fuel markets. The constraints include, but are not limited to, emission limits, transmission capabilities, renewable generation requirements, and fuel market constraints. The model is designed to accommodate complex treatment of emission regulations involving trading, banking, and special provisions affecting emission allowances (e.g., bonus allowances and progressive flow control), as well as traditional command-and-control emission policies.

IPM represents power markets through model regions that are geographical entities with distinct operational characteristics. The model regions are largely consistent with the North American Electric Reliability Council (NERC) assessment regions and with the organizational structures of the Regional Transmission Organizations (RTOs) and the Independent System Operators (ISOs) that handle dispatch on most of the U.S. grid. IPM represents the least-cost arrangement of electricity supply (capacity and generation) within each model region to meet assumed future load (electricity demand) while constrained by a transmission network of bulk transfer limitations on interregional power flows. All utility-owned existing electric generating units, including renewable resources, as well as independent power producers and cogeneration facilities selling electricity to the grid, are modeled.

IPM provides a detailed representation of new and existing resource options. These include fossil, nuclear, renewable, storage, and non-conventional options. Fossil options include coal steam, oil/gas steam, combined cycles, and simple cycle combustion turbines. Renewable options include wind, landfill gas, geothermal, solar thermal, solar photovoltaic, and biomass. Storage options include pump storage and battery storage. Non-conventional options include fuel cells.

IPM can incorporate a detailed representation of fuel markets and can endogenously forecast fuel prices for coal, natural gas, and biomass by balancing fuel demand and supply for electric generation. The model also includes detailed fuel quality parameters to estimate emissions from electric generation.

IPM provides estimates of air emission changes, regional wholesale energy and capacity prices, incremental electric power system costs, changes in fuel use, and capacity and dispatch projections.

2.1.2 Applications

IPM's structure, formulation, and set-up make it adaptable and flexible. The necessary level of data, modeling capabilities exercised, and computational requirements can be tailored to the strategies and policy options being analyzed. This adaptability has made IPM suitable for a variety of applications. These include:

<u>Air Regulatory Assessment:</u> Since IPM contains extensive air regulatory modeling features, state and federal air regulatory agencies have used the model extensively in support of air regulatory assessment.

<u>Integrated Resource Planning:</u> IPM can be used to perform least-cost planning studies that simultaneously optimize demand-side options (load management and efficiency), renewable options and traditional supply-side options.

<u>Strategic Planning:</u> IPM can be used to assess the costs and risks associated with alternative utility and consumer resource planning strategies as characterized by the portfolio of options included in the input database.

<u>Options Assessment:</u> IPM allows industry and regulatory planners to screen alternative resource options and option combinations based on their relative costs and contributions to meeting customer demands.

<u>Cost and Price Estimation:</u> IPM produces realistic estimates of energy prices, capacity prices, fuel prices, and allowance prices. Industry and regulatory agencies have used these cost reports for due diligence, planning, litigation, and economic impact assessment.

2.2 Model Structure and Formulation

IPM employs a linear programming structure that is particularly well-suited for analysis of the electric sector to help decision-makers plan system capacity and model the dispatch of electricity from individual units or plants. The model consists of three key structural components:

- A linear objective function
- A series of decision variables
- A set of linear constraints
- The sections below describe the objective function, key decision variables, and constraints included in IPM for the EPA 2023 Reference Case.

2.2.1 Objective Function

IPM's objective function is to minimize the total, discounted net present value of the costs of meeting demand, power operation constraints, and environmental regulations over the entire planning horizon. The objective function represents the summation of all the costs incurred by the electricity sector on a net present value basis. These costs, which the linear programming formulation attempts to minimize, include the cost of new plant and pollution control construction, fixed and variable operating and maintenance costs, and fuel costs. Many of these cost components are captured in the objective function by multiplying the decision variables by a cost coefficient. Cost escalation factors are used in the objective function to reflect changes in cost over time. The applicable discount rates are applied to derive the net present value for the entire planning horizon from the costs obtained for all years in the planning horizon.

2.2.2 Decision Variables

Decision variables represent the values for which the IPM model is solving, given the cost-minimizing objective function described in Section 2.2.1 and the set of electric system constraints detailed in Section 2.2.3. The model determines values for these decision variables that represent the optimal least-cost solution for meeting the assumed constraints. Key decision variables represented in IPM are described in detail below.

<u>Generation Dispatch Decision Variables:</u> IPM includes decision variables representing the generation from each model power plant.[6] For each model plant, a separate generation decision variable is defined for each possible combination of fuel, season, model run year, and segment of the seasonal load duration curve applicable to the model plant. (See Section 2.3.5 below for a discussion of load duration curves.) In the objective function, each plant's generation decision variable is multiplied by the relevant heat rate and fuel price (differentiated by the appropriate step of the fuel supply curve) to obtain a fuel cost. It is also multiplied by the applicable variable operation and maintenance (VOM) cost rate to obtain the VOM cost for the plant.

<u>Capacity Decision Variables:</u> IPM includes decision variables representing the capacity of each existing model plant and capacity additions associated with potential (new) units in each model run year. In the objective function, the decision variables representing existing capacity and capacity additions are multiplied by the relevant fixed operation and maintenance (FOM) cost rates to obtain the total FOM cost for a plant. The capacity addition decision variables are multiplied by the investment cost and capital charge rates to obtain the annualized capital cost associated with the capacity addition.

<u>Operating Reserve Decision Variables:</u> IPM includes decision variables representing each model plant's contribution to meeting operating reserve requirements. While a model plant can contribute to both energy and operating reserve requirements, its total contribution is limited by its total capacity.

<u>Transmission Decision Variables:</u> IPM includes decision variables representing the electricity transmission along each transmission link between model regions in each run year. In the objective function, these variables are multiplied by variable transmission cost rates to obtain the total cost of transmission across each link.

<u>Emission Allowance Decision Variables:</u> For emission policies where allowance trading applies, IPM includes decision variables representing the total number of emission allowances for a given model run year that are bought and sold in that or subsequent run years. In the objective function, these year-differentiated allowance decision variables are multiplied by the market price for allowances prevailing in

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[6] Model plants are aggregate representations of real-life electric generating units. They are used by IPM to model the electric power sector. For a discussion of model plants in EPA 2023 Reference Case, see Section 4.2.6.

each run year. This formulation allows IPM to capture the inter-temporal trading and banking of allowances.

Fuel Decision Variables: For each type of fuel and each model run year, IPM defines decision variables representing the quantity of fuel delivered from each fuel supply region to model plants in each demand region. Coal decision variables are further differentiated according to coal rank (bituminous, sub-bituminous, and lignite), sulfur grade, chlorine content, and mercury content. These fuel quality decision variables do not appear in the IPM objective function but in constraints that define the types of fuel that each model plant is eligible to use and the supply regions that are eligible to provide fuel to each specific model plant.

2.2.3 Constraints

Model constraints are implemented in IPM to accurately reflect the characteristics of, and the conditions faced by, the electric sector. Among the key constraints included in EPA 2023 Reference Case are:

Reserve Margin Constraints: Regional reserve margin constraints capture system reliability requirements by defining a minimum margin of reserve capacity (in megawatts) per year beyond the total capacity needed to meet future peak demand that must remain in service to that region. These reserve capacity constraints are derived from reserve margin targets that are assumed for each region based on information from NERC, RTOs, or ISOs. If the existing plus planned capacity is not sufficient to satisfy the annual regional reserve margin requirement, the model will build the required level of new capacity. Section 3.6 further discusses reserve margin assumptions.

Operating Reserve Constraints: These constraints specify the operating reserve requirements by product type and region that the power system must meet.

Demand Constraints: The model categorizes regional annual electricity demand into seasonal load curves, which are used to form winter (December 1 – February 28), spring (March 1 – April 30), fall (October 1 – November 30), and summer (May 1 – September 30) load duration curves (LDC). The seasonal load segments, when taken together, represent all the hourly electricity load levels that must be satisfied in a particular region, season, and model run year. As such, the LDC defines the minimum amount of generation required to meet the region's electricity demand during the specific season. These requirements are specified by demand constraints.

Capacity Factor Constraints: These constraints specify how much electricity each plant can generate, given its capacity and seasonal availability.

Turn Down Constraints: The model uses turn down constraints to account for the cycling capabilities of generation resources, i.e., whether they can be shut down at night or on weekends, must operate at all times, or must operate at least at some minimum capacity level. The constraints ensure that the model reflects the distinct operating characteristics of peaking, cycling, and base-load units.

Emissions Constraints: IPM can endogenously consider an array of emissions constraints for SO_2, NO_x, HCl, mercury, and CO_2. Emission constraints can be implemented on a plant-by-plant, regional, or system-wide basis. The constraints can be defined in terms of a total tonnage cap (e.g., tons of SO_2) or a maximum emission rate (e.g., lb/MMBtu of NO_x). The emission constraints' scope, timing, and definition depend on the required analysis.

Transmission Constraints: IPM can simultaneously model any number of regions linked by transmission lines. The constraints define either a maximum capacity on each link or a maximum level of transmission on two or more links (i.e., joint limits) to different regions.

Fuel Supply Constraints: These constraints define the types of fuel that each model plant is eligible to use and the supply regions that are eligible to provide fuel to each specific model plant. A separate constraint is defined for each model plant.

2.3 Key Methodological Features of IPM

IPM is a flexible modeling tool for obtaining short- and long-term projections of production activity in the electric generation sector. The projections obtained using IPM are not statements of what will happen. Rather, they are estimates of what might happen, given the assumptions and methodologies used. Chapters 3 to 10 contain detailed discussions of the cost and performance assumptions specific to EPA 2023 Reference Case. The present section provides an overview of the essential methodological and structural features of IPM that extend beyond the assumptions that are specific to EPA 2023 Reference Case.

2.3.1 Model Plants

Model plants are a central structural component that IPM uses: (1) to represent aggregations of existing generating units, (2) to represent retrofit and retirement options that are available to existing generating units, and (3) to represent potential (new) generating units that the model can build.

Existing Units: Theoretically, there is no predefined limit on the number of generating units that can be included in IPM. However, to keep model size and solution time within acceptable limits, EPA utilizes model plants to represent aggregations of actual individual generating units. The aggregation algorithm groups units with similar characteristics for representation by model plants with a combined capacity and weighted-average characteristics that are representative of all the units comprising the model plant. Model plants are defined to maximize the accuracy of the model's cost and emissions estimates by capturing variations in key features of those units that are critical in the EPA 2023 Reference Case and anticipated policy case runs. For EPA 2023 Reference Case, EPA employed an aggregation algorithm, which allowed over 27,000 actual existing electric generating units to be represented by nearly 4,000 model plants. Section 4.2.6 describes the aggregation procedure.

Retrofit and Retirement Options: IPM also utilizes model plants to represent the retrofit and retirement options that are available to existing generating units. EPA 2023 Reference Case provides existing model plants with a wide range of options for retrofitting with emission control equipment as well as with an option to retire. (See Chapter 5 for a detailed discussion of the options that are included.) Model plants that represent potential (new) generation resources are not given the option to take on a retrofit or to retire.

The options available to each model plant are pre-defined at the model set-up. The retrofit and retirement options are themselves represented in IPM by model plants, which, if actuated during a model run, take on all or a portion of the capacity initially assigned to a model plant, which represents existing generating units.[7] In setting up IPM, parent-child-grandchild relationships are pre-defined between each existing model plant (parent) and the specific retrofit and retirement model plants (children and grandchildren) that may replace the parent model plant during the course of a model run. The child and grandchild model plants are inactive unless the model finds it economical to engage one of the options provided, e.g., retrofit with particular emission controls or retire.

Theoretically, there are no limits on the number of successive retrofit and retirement options that can be associated with each existing model plant. However, model size and computational considerations dictate that the number of successive retrofits is limited. In EPA 2023 Reference Case, a maximum of

[7] IPM has a linear programming structure whose decision variables can assume any value within the specified bounds subject to the constraints. Therefore, IPM can generate solutions where model plants retrofit or retire a portion of the model plants capacity. IPM's standard model plant outputs explicitly present these partial investment decisions.

three stages of retrofit options are provided. For example, an existing model plant may retrofit with an activated carbon injection (ACI) for mercury control in one model run year (stage 1), with a selective catalytic reduction (SCR) for NO_x control in the same or subsequent run year (stage 2), and with carbon capture and sequestration (CCS) for CO_2 control in the same or subsequent run year (stage 3). However, if it exercises this succession of retrofit options, no further retrofit or retirement options are possible beyond the third stage.

Potential (New) Units: IPM also uses model plants to represent new generation capacity that may be built during a model run. All the model plants representing new capacity are pre-defined at set-up. They are differentiated by type of technology, regional location, and years available. When it is economically advantageous to do so (or otherwise required by reserve margin constraints to maintain electric reliability), IPM builds one or more of these predefined model plants by raising its generation capacity from zero during a model run. In determining whether it is economically advantageous to build new plants, IPM considers cost differentials between technologies, expected technology cost improvements (by differentiating costs based on a plant's vintage, i.e., build year), and regional variations in capital costs that are expected to occur over time.

Parsing and post-processing: Since EPA 2023 Reference Case results are presented at the model plant level, EPA has developed a post-processor, a parsing tool, designed to translate results at the model plant level into generating unit-specific results. The parsing tool produces unit-specific emissions, fuel use, emission control retrofit, and capacity projections based on model plant results. Another post-processing activity involves deriving inputs for air quality modeling from IPM outputs. This entails using emission factors to derive the levels of pollutants needed in EPA's air quality models from emissions and other parameters generated by IPM. It also involves using decision rules to assign point source locators to these emissions. (See Figure 1-1 for a graphical representation of the relationship of the post-processing tools to the overall IPM structure.)

2.3.2 Model Run Years

Another important structural feature of IPM is the use of model run years to represent the full planning horizon being modeled. Although IPM can represent an individual year in an analysis time horizon, mapping each year in the planning horizon into a representative model run year enables IPM to perform multiple year analyses while keeping the model size manageable. IPM considers the costs in all years in the planning horizon while reporting results only for model run years. (See Section 2.3.3 below for further details.)

The analysis time horizon for EPA 2023 Reference Case extends from 2028 through 2059. The seven years designated as model run years and the mapping of calendar years to the model run years is shown in Table 2-1.

Table 2-1 Model Run Year and Year Mapping in the EPA 2023 Reference Case

Run Year	Years Represented
2028	2028-2029
2030	2030-2031
2035	2032-2037
2040	2038-2041
2045	2042-2047
2050	2048-2052
2055	2053-2059

Often, models like IPM include a final model run year that is not used in the analysis of results. This technique reduces the likelihood that modeling results in the last represented year will be skewed due to the modeling artifact of having to specify an endpoint in the planning horizon. In reality, economic decision-making will continue to take information into account from years beyond the model's time horizon. This should be considered when assessing model projections from the last output year.

2.3.3 Cost Accounting

As noted, IPM is a dynamic linear programming model that solves for the least cost investment and electricity dispatch strategy for meeting electricity demand subject to resource availability and other operating and environmental constraints. The cost components that IPM considers in deriving an optimal solution include the costs of investing in new capacity options, the cost of installing and operating pollution control technology, fuel costs, and the operation and maintenance costs associated with unit operations. Several cost accounting assumptions are built into IPM's objective function that ensures a technically sound and unbiased treatment of the cost of all investment options offered in the model. These features include:

- All costs in IPM's single multi-year objective function are discounted to a base year. Since the model solves for all run years simultaneously, discounting to a common base year ensures that IPM properly captures complex inter-temporal cost relationships.

- Capital costs in IPM's objective function are represented as the net present value of a levelized stream of annual capital outlays, not as a one-time total investment cost. The payment period used in calculating the levelized annual outlays never extends beyond the model's planning horizon: it is either the book life of the investment or the years remaining in the planning horizon, whichever is shorter. This approach avoids presenting artificially higher capital costs for investment decisions taken closer to the model's time horizon boundary simply because some of that cost would typically be serviced in years beyond the model's view. This treatment of capital costs ensures both realism and consistency in accounting for the full cost of each of the investment options in the model.

- The cost components informing IPM's objective function represent the composite cost over all years in the planning horizon rather than just the cost in the individual model run years. The approach permits the model to capture more accurately the escalation of the cost components over time.

2.3.4 Modeling Wholesale Electricity Markets

IPM is also designed to simulate electricity production activity in a manner that would minimize production costs, as is the intended outcome in wholesale electricity markets. For this purpose, although not designed to capture retail distribution costs, the model captures transmission costs and losses between IPM model regions. However, the model implicitly includes distribution losses since net energy for load,[8] rather than delivered sales,[9] is used to represent electricity demand in the model. Further, the production costs calculated by IPM are the wholesale production costs. In reporting costs, the model does not include embedded costs, such as carrying charges of existing units, which may ultimately be part of the retail cost incurred by end-use consumers.

2.3.5 Load Duration Curves (LDCs)

IPM uses LDCs to provide realism to the dispatching of electric generating units. Unlike a chronological electric load curve, which is simply an hourly record of electricity demand, the LDCs are created by rearranging the hourly chronological electric load data from the highest to lowest (MW) value. To aggregate such load detail into a format enabling this scale of power sector modeling, EPA 2023 Reference Case uses a 24-step piecewise linear representation of the LDC.

IPM can include any number of user-defined seasons. A season can consist of a single month or several months. EPA 2023 Reference Case contains four seasons: summer (May through September), winter

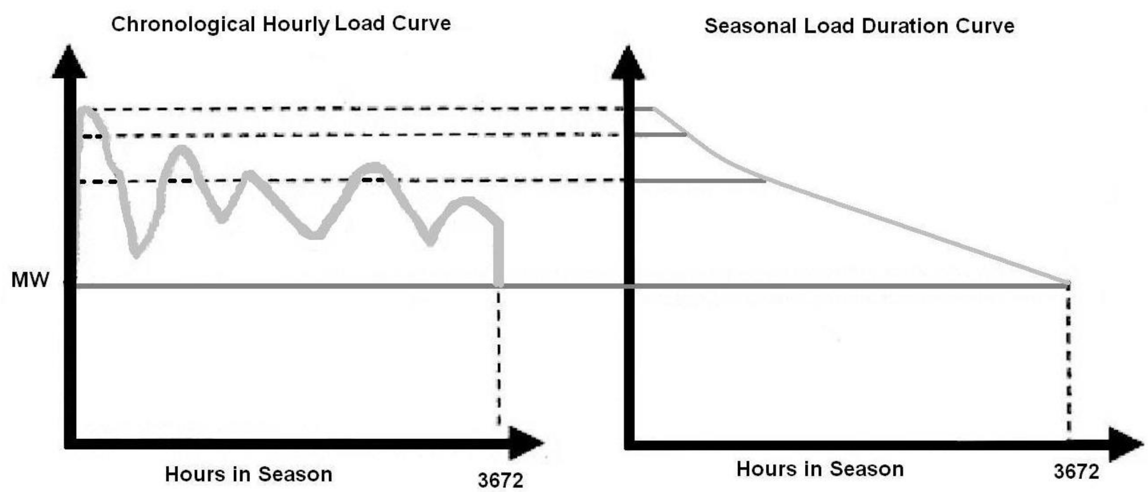
[8] Net energy for load is the electrical energy requirements of an electrical system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes distribution losses.

[9] Delivered sales is the electrical energy delivered under a sales agreement. It does not include distribution losses.

(December through February), spring (March and April), and a fall season (October, November). The summer season corresponds to the ozone season for modeling seasonal NO_x policies. The remaining seven months are split into a three-month winter season, two-month spring season, and a two-month fall season to better capture winter peak and seasonality in the wind and solar hourly generation profiles. Separate summer, winter, spring, and fall season LDCs are created for each of IPM's model regions. Figure 2-1 below presents side-by-side graphs of a hypothetical chronological hourly load curve and a corresponding load duration curve for a summer season.

The use of seasonal LDCs rather than annual LDCs allows IPM to capture seasonal differences in the level and patterns of customer demand for electricity. For example, in most regions, air conditioner cycling only impacts customer demand patterns during the summer season. The use of seasonal LDCs also allows IPM to capture seasonal variations in the generation resources available to respond to the customer demand depicted in an LDC. For example, power exchanges between utility systems may be seasonal in nature. Some air regulations affecting power plants are also seasonal in nature. This can impact the type of generation resources that are dispatched during a particular season. Further, because of maintenance scheduling for individual generating units, the capacity and utilization for these supply resources also vary between seasons.

Figure 2-1 Hypothetical Chronological Hourly Load Curve and Seasonal Load Duration Curve for Summer Season



In EPA 2023 Reference Case, regional forecasts of peak and total electricity demand from AEO 2023 and hourly load curves from FERC Form 714 and ISO/RTOs[10] are used to derive seasonal load duration curves for each IPM run year in each IPM region. The results of this process are individualized seasonal LDCs that capture the unique hourly electricity demand profile of each region. The LDCs change over time to reflect projected changes in load factors because of future variations in electricity consumption patterns.[11]

Within IPM, LDCs are represented by a discrete number of load segments, or generation blocks, as illustrated in Figure 2-2 for a six-load segment LDC. EPA 2023 Reference Case uses 24 load segments in its seasonal LDCs.

Figure 2-2 illustrates and the following text describes the 24-segment LDCs. Length of time and system demand are the two parameters, which define each segment of the load duration curve. The load segment represents the amount of time (along the x-axis) and the capacity that the electric dispatch mix

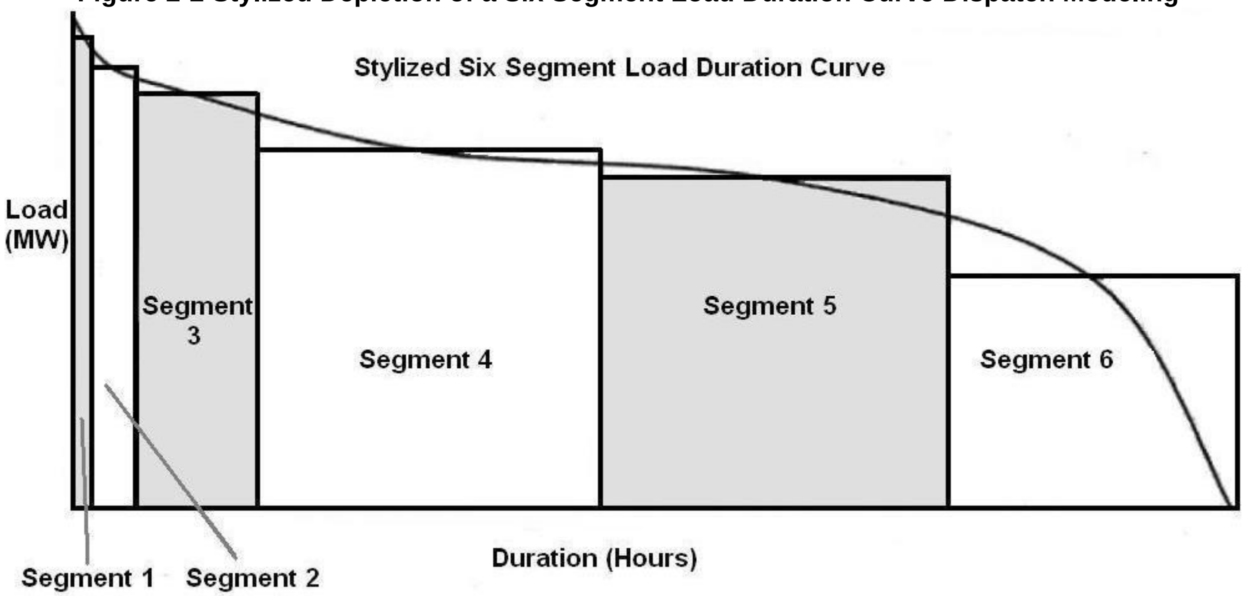
[10] The 2018 load curves are used for all IPM model regions. For further details, see Section 3.2.4.

[11] For further details regarding the source of the load factors used in EPA 2023 Reference Case, see Section 3.2.3.

must be producing (represented along the y-axis) to meet system load. The hours in the LDC are initially clustered into six groups. Group 1 incorporates 1% of all hours in the season with the highest load. Groups 2 to 6 have 4%, 10%, 30%, 30%, and 25% of the hours with progressively lower levels of demand. Each of these 6 groups of hours are further separated into four time of day categories to result in a possible maximum of 24 load segments. This approach better accounts for the impact of solar generation during periods of high demand. The four time-of-day categories are 8PM – 6AM, 6AM – 9AM, 9AM – 5PM, and 5PM – 8PM. Plants are dispatched to meet load based on economic considerations and operating constraints. The most cost-effective plants are assigned to meet load in all 24 segments of the load duration curve. Section 2.3.6 discusses dispatch modeling in more detail.

Table 2-2 contains data of the 2028 seasonal LDCs in each of the 67 model regions in the lower continental U.S.

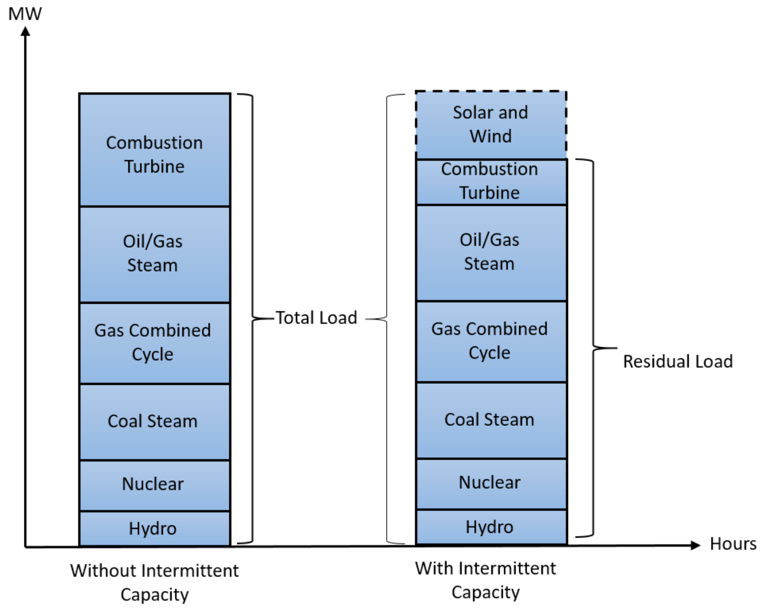
Figure 2-2 Stylized Depiction of a Six Segment Load Duration Curve Dispatch Modeling



In IPM, the dispatching of electricity is based on the variable cost of generation. In the absence of any operating constraints, units with the lowest variable cost generate first. The marginal generating unit, i.e., the generating unit that generates the last unit of electricity, sets the energy price. Physical operating constraints also influence the dispatch order. For example, IPM uses turndown constraints to prevent base load units from cycling, i.e., switching on and off. Turndown constraints often override the dispatch order that would result based purely on the variable cost of generation. Variable costs in combination with turndown constraints enable IPM to dispatch generation resources in a realistic fashion.

Figure 2-3 depicts a stylized dispatch order based on the variable cost of generation. Two hypothetical load segments are subdivided according to the type of generation resources available to respond to the load requirements represented in the segments. The generation resources with the lowest operating cost (i.e., hydro and nuclear) respond first to the demand represented in the LDC and are accordingly at the bottom of dispatch stack.” They are dispatched for the maximum possible number of hours represented in the LDC because of their low operating costs. Generation resources with the highest operating cost (i.e., peaking turbines) are at the top of the dispatch stack,” since they are dispatched last and for the minimum possible number of hours. In the load segment with a non-dispatchable generating resource (i.e., solar or wind), the conventional generation resources are dispatched to the residual load level, where residual load is defined as the difference between the total load and the load met by the non-dispatchable resource.

Figure 2-3 Stylized Dispatch Order in Illustrative Load Segments



Note: Figure 2-3 does not include all plant types modeled in EPA 2023 Reference Case. Intermittent renewable technologies such as wind and solar are considered non-dispatchable and are assigned a specific hourly generation profile.

2.3.6 Fuel Modeling

IPM can model the full range of fuels used for electric generation. The cost, supply, and (if applicable) quality of each fuel included in the model are defined during model set-up. Fuel price and supply are represented in one of two approaches: (1) through a set of supply curves (coal, natural gas, and biomass) or (2) through an exogenous price stream (fuel oil and nuclear fuel). With the first approach, the model endogenously determines the price for the fuel by balancing supply and demand. IPM uses fuel quality information (e.g., the sulfur, chlorine, or mercury content of different types of coal from different supply regions) to determine the emissions resulting from the combustion of the fuel.

EPA 2023 Reference Case includes coal, natural gas, fuel oil, nuclear fuel, biomass, hydrogen, and fossil and non-fossil waste as fuels for electric generation. Chapters 7 to 9 examine the specific assumptions for these fuels.

2.3.7 Transmission Modeling

IPM includes a detailed representation of existing transmission capabilities between model regions. The maximum transmission capabilities between regions are specified by transmission constraints. Additions to transmission lines are represented by decision variables defined for each eligible link and model run year. In IPM's objective function, the decision variables representing transmission additions are multiplied by new transmission line investment cost and capital charge rates to obtain the capital cost associated with the transmission addition. Section 3.3 describes the specific transmission assumptions.

2.3.8 Operating Reserves Modeling

Operating reserves are part of a set of services referred to as essential reliability services required to maintain the reliability and stability of the electric grid.[12] Although definitions vary by market and region, the main services required to ensure reliable grid operation in the U.S. include operating reserves, voltage support, and black start capability. Operating reserves consist of several services and products, including frequency responsive reserves, regulating reserves, contingency reserves, and ramping reserves. The grid operates across timescales ranging from milliseconds to years. Because supply and demand must always be balanced, services must be provided to ensure stability across all timescales. Energy and capacity services ensure that there is sufficient supply to meet demand over a specified period, with a reserve margin in the event of an outage of a generating unit. Operating reserves ensure that there are sufficient resources with the characteristics required to always balance supply and demand. IPM has the capability to model operating reserve services at a regional level and can account for the impact of solar and wind technologies on operating reserve requirements. Section 3.7 describes the specific operating reserve assumptions.

2.3.9 Perfect Competition and Perfect Foresight

IPM assumes perfect competition and perfect foresight. Perfect competition means that IPM models production activity in wholesale electric markets on the premise that these markets subscribe to all assumptions of a perfectly competitive market. The model does not explicitly capture any market imperfections such as market power, transaction costs, informational asymmetry, or uncertainty. However, if desired, appropriately designed sensitivity analyses or redefined model parameters can be used to gauge the impact of market imperfections on the wholesale electric markets.

Perfect foresight implies that agents precisely know the nature and timing of conditions in future years that affect the ultimate costs of decisions along the way. For example, under IPM there is complete foreknowledge of future electricity demand, fuel supplies, and other variables (including regulatory requirements) that are subject to uncertainty and limited foresight. Models like IPM frequently assume perfect foresight to establish a decision-making framework that can estimate cost-minimizing courses of action given the best-guess expectations of these future variables that can be constructed at the time the projections are made.

2.3.10 Scenario Analysis and Regulatory Modeling

IPM offers detailed and flexible modeling features that enable scenario analysis involving different outlooks of key drivers of the power sector and environmental regulations. In particular, the treatment of environmental regulations is endogenous in IPM. By providing a comprehensive representation of compliance options, IPM enables environmental decisions to be made within the model based on least cost considerations rather than exogenously imposing environmental choices on model results. For example, unlike other models that enter allowance prices as an exogenous input during model set-up, IPM obtains allowance prices as an output of the endogenous optimization process of finding the least cost compliance options in response to air regulations. (In linear programming terminology, they are the shadow prices of the respective emission constraints — a standard output from solving a linear programming problem.) IPM can capture a wide variety of regulatory program designs, including emissions trading policies, command-and-control policies, and renewable portfolio standards. Representation of emissions trading policies can include allowance banking, trading, borrowing, bonus allowance mechanisms, and progressive flow controls. Air regulations can be tailored to specific geographical regions and can be restricted to specific seasons. Many of these regulatory modeling capabilities are deployed in EPA 2023 Reference Case.

[12] Essential reliability services have also often been referred to as ancillary services.

2.4 Hardware and Programming Features

IPM produces model files in standard mathematical programming system (MPS) format. The model runs on most PC-platforms. Hardware requirements are dependent on the size of a particular model run. For example, with almost 13.1 million decision variables and 3.4 million constraints, EPA 2023 Reference Case is run on a 64-bit Windows Server 2019 Standard platform with Intel® Xeon® Gold 6240R Processor, 35.75MB Cache, 2.40 GHz (2 processor)/24Core and 512 GB of RAM. Due to the size of the EPA 2023 Reference Case, FICO Xpress Optimization Suite 8.8.0 (a 64-bit, commercial-grade solver with capability of optimizing mixed integer (MIP), linear and non-linear problems using multi-threaded parallel processing) is used.

Two data processors, a front end and the post-processing tool, support the model. The front end creates the necessary inputs that IPM uses. The post-processing tool maps IPM model-plant level outputs to individual electric generating units (a process referred to as parsing—see Section 2.3.1) and creates input files in flat file format as required by EPA's air quality models.

IPM requires an extensive set of input parameters in preparation for a model run. The input parameters are discussed in Section 2.5.1. Results from a model run are presented in a series of detailed reports, which are described in Section 2.5.2.

2.5 Model Inputs and Outputs

2.5.1 Data Parameters for Model Inputs

IPM requires input parameters that characterize the U.S. electric power system, economic outlook, fuel supply and air regulatory framework. Chapters 3-10 contain detailed discussions of the values assigned to these parameters in EPA 2023 Reference Case. The present section lists the key input parameters required by IPM:

Electric System

Existing Generation Resources

- Plant Capacity
- Heat Rate
- Fuels Used
- Emission Limits and Emission Rates for NO_x, SO_2, HCl, CO_2, and mercury
- Existing Pollution Control Equipment and Retrofit Options
- Availability
- Fixed and Variable Operation & Maintenance Costs
- Minimum Generation Requirements (Turn Down Constraints)
- Generation Profiles for Non-Dispatchable Resources

New Generation Resources

- Cost and Operating Characteristics
- Resource Limits and Generation Profiles
- Limitations on Availability

Other System Requirements

- Regional Specification
- Inter-regional Transmission Capabilities
- Reserve Margin Requirements for Reliability

- System Specific Generation Requirements

Economic Outlook

Electricity Demand

- Firm Regional Electricity Demand
- Load Curves

Financial Outlook

- Capital Charge Rates
- Discount Rate

Fuel Supply

Fuel Supply Curves for Coal, Gas, and Biomass

- Fuel Price
- Fuel Quality
- Transportation Costs for Coal, Natural Gas, and Biomass

Regulatory Outlook

Air Regulations for NO_x, SO_2, HCl, CO_2, and Mercury

- Other Air Regulations
- Non-air Regulations (affecting electric generating unit operations)

2.5.2 Model Outputs

IPM produces a variety of output reports. These range from detailed reports, which describe the results for each model plant and run year, to summary reports, which present results for regional and national aggregates. Individual topic areas can be included or excluded at the user's discretion. Standard IPM reports cover the following topics:

- Generation mix
- Capacity mix
- Capacity additions and retirements
- Capacity and energy prices
- Power production costs (capital, fixed and variable operation & maintenance costs, and fuel costs)
- Fuel consumption
- Fuel supply and demand
- Fuel prices for coal, natural gas, and biomass
- Emissions (NO_x, SO_2, HCl, CO_2, and mercury)
- Emission allowance prices

List of tables that are uploaded directly to the web:

Table 2-2 Load Curves used in EPA 2023 Reference Case