2 Modeling Framework

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

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 model's structure and formulation, key methodological characteristics, and programming features, 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 section 2.2's discussion of model structure and formulation, and transmission modeling is covered as a key methodological feature in section 2.3.9. 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 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 (e.g. emission limits, transmission capabilities, renewable generation requirements, fuel market constraints) that are placed on the power, emissions, and fuel markets. In particular, the model is well-suited to consider complex treatment of emission regulations involving trading, banking, and special provisions affecting emission allowances (like 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 characteristics. While they are more numerous (for purposes of picking up local transmission behavior and bottlenecks), the model regions representing the U.S. power market in EPA Base Case v.4.10 are largely consistent with the regions and sub-regions constituting the North American Electric Reliability Council (NERC) regions and with the organizational structures of the Regional Transmission Organizations (RTOs) and Independent System Operators, which handle dispatch on most of the U.S. grid. IPM models the electric demand, generation, transmission, and distribution within each region as well as the inter-regional transmission grid. All existing utility power generation units, including renewable resources, are modeled, as well as independent power producers and cogeneration facilities that sell electricity to the grid.

IPM provides a detailed representation of new and existing resource options, including fossil generating options (coal steam, gas-fired simple cycle combustion turbines, combined cycles, and oil/gas steam), nuclear generating options, and renewable and non-conventional (e.g., fuel cells) resources. Renewable resource options include wind, landfill gas, geothermal, solar thermal, solar photovoltaic and biomass.

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 very adaptable and flexible. The necessary level of data, modeling capabilities exercised, and computational requirements can be tailored to the particular strategies and policy options being analyzed. This adaptability has made IPM suitable for a variety of applications. These include:

Air Regulatory Assessment: 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.

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

Strategic Planning: 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 data base.

Options Assessment: IPM allows industry and regulatory planners to "screen" alternative resource options and option combinations based upon their relative costs and contributions to meeting customer demands.

Cost and Price Estimation: 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," and
- A set of linear "constraints".
- The sections below describe the objective function, key decision variables, and constraints included in IPM for EPA Base Case v.4.10.

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. The total resulting cost is expressed as the net present value of all the component costs. 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 which the IPM model is “solving for,” 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 decision variables values are the model’s “outputs” and represent the optimal least-cost solution for meeting the assumed constraints. Key decision variables represented in IPM are described in detail below.

Generation Dispatch Decision Variables: IPM includes decision variables representing the generation from each model power plant[1]. 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.

Capacity Decision Variables: 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 also multiplied by the investment cost and capital charge rates to obtain the capital cost associated with the capacity addition.

Transmission Decision Variables: 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.

Emission Allowance Decision Variables: 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 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 (see section 1 and Table 9-4), and mercury content (see sections 5.4.1and 1 and Table 9-7). These fuel quality decision variables do not appear in the IPM objective function, but in constraints which 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.

[1]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 Base Case v.4.10, see section 4.2.6.

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 Base Case v.4.10 are:

Reserve Margin Constraints: Regional reserve margin constraints capture system reliability requirements by defining a minimum margin of reserve capacity (in megawatts) per year. If existing plus planned capacity is not enough to satisfy the annual regional reserve margin requirement, the model will "build" the required level of new capacity.

Demand Constraints: The model categorizes regional annual electricity demand into seasonal load segments which are used to form summer (May 1 - September 30) and winter (October 1 - April 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 region in the particular season for a particular model run year. As such, the LDC defines the minimum amount of generation required to meet the region's electrical demand during the specific season. These requirements are incorporated in the model's demand constraints.

Capacity Factor Constraints: These constraints specify how much electricity each plant can generate (a maximum generation level), given its capacity and seasonal availability.

Turn Down/Area Protection Constraints: The model uses these constraints to take into account the cycling capabilities of the units, i.e., whether or not they can be shut down at night or on weekends, or whether they must operate at all times, or at least at some minimum capacity level. These constraints ensure that the model reflects the distinct operating characteristics of peaking, cycling, and base load units.

Emissions Constraints: IPM can consider an array of emissions constraints for SO_2, NO_X, 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 scope, timing, and definition of the emission constraints 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 (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 but what might happen given the assumptions and methodologies used. Chapters 3-11 contain detailed discussions of the cost and performance assumptions specific to the EPA Base Case v.4.10. This section provides an overview of the essential methodological and structural features of IPM, that extend beyond the assumptions that are specific to EPA Base Case v.4.10.

2.3.1 Model Plants

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

Existing Units: Theoretically, there is no predefined limit on the number of 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 into 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 base case and anticipated policy case runs. For EPA Base Case v.4.10, IPM employed an aggregation algorithm which allowed 15,023 actual existing electric generating units to be represented by 4,738 model plants. Section 4.2.6 describes the aggregation procedure used in the EPA Base Case v.4.10.

Retrofit and Retirement Options: IPM also utilizes model plants to represent the retrofit and retirement options that are available to existing units. EPA Base Case v.4.10 provides existing model plants with the option to retire early and with a wide range of options for retrofitting with emission control equipment. (See Chapters 5 and section 7.2 in Chapter 7 for a detailed discussion of the options that are included in the EPA Base Case v.4.10.)

The options available to each model plant are pre-defined at the model's set-up. The retrofit and retirement options are themselves represented in IPM by model plants, which, if actuated in the course of a model run, take on all or a portion of the capacity initially assigned to a model plant which represents existing generating units. EPA Base Case v.4.10 model plants that represent potential (new) units are not given the option to take on a retrofit or retire. 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 in IPM unless the model finds it economical to engage one of the options provided, e.g., retrofit with particular emission controls or retire early.

Theoretically, there are no limits on the number of "child," "grandchild," and even "great-grandchild" model plants (i.e., 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 be limited. In EPA Base Case v.4.10, a maximum of two stages of retrofit options are provided (child and grandchild, but not great-grandchild). For example, an existing model plant may be retrofit with a limestone forced oxidation (LSFO) SO_2 scrubber and with a selective catalytic reduction (SCR) control for NO_X in one model run year (stage 1) and with an activated carbon injection (ACI) for mercury control in the same or subsequent run year (stage 2). However, if it exercises this succession of retrofit options, no further retrofit or retirement options are possible beyond the second 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, differentiated by type of technology, regional location, and years available. When it is economically advantageous to do so, IPM "builds" one or more of these predefined model plants by raising its generation capacity from zero during the course of a model run. In determining whether it is economically advantageous to "build" new plants, IPM takes into account 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.

Since EPA Base Case v.4.10 results are presented at the model plant level, EPA has developed a post-processor "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, pollution 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. 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. Although IPM reports results only for model run years, it takes into account the costs in all years in the planning horizon. (See section 2.3.3 below for further details.)

Often models like IPM include a final model run year that is not included 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 end point in the planning horizon, whereas, in reality, economic decisions are likely to persist beyond that end point. Due to the number of model run years required by EPA for analytical purposes (six in the 2012-2050 time period) and a greatly expanded suite of modeling capabilities, such an approach could not be used in EPA Base Case v.4.10. It would have increased model size too much. However boundary distortions are only a potential factor in 2050, the last modeled year. In addition, any tendency toward end-year distortions should be reduced by the longer modeling time horizon of this base case and by the relatively large number of calendar years (9) that are mapped into model run year 2050 (see Table 7-1). Nevertheless, the possibility of residual boundary effects is something to bear in mind when interpreting model results for 2050.

2.3.3 Cost Accounting

As noted earlier in the chapter, IPM is a dynamic linear programming model that finds the least cost investment and electricity dispatch strategy for meeting electric demand subject to resource availability and other operating and environmental constraints. The cost components that IPM takes into account 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 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 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 appearing in 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. This permits the model to capture more accurately the escalation of the cost components over time.

2.3.4 Modeling Wholesale Electric Markets

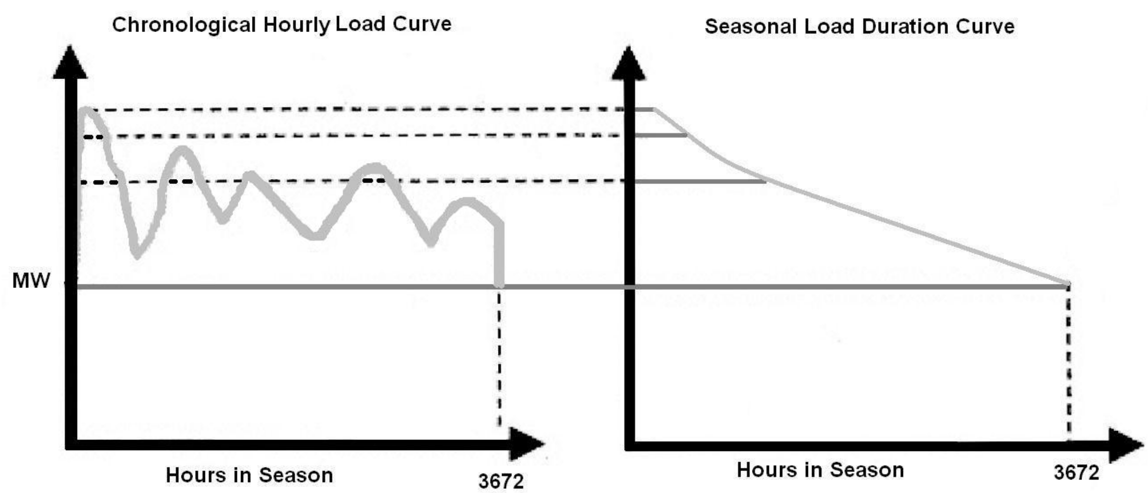
Another important methodological feature worth noting about IPM is that it is designed to depict production activity in deregulated wholesale electric markets, not in retail markets. The model captures transmission costs and losses between IPM model regions. It is not designed to capture retail distribution costs. However, the model implicitly includes distribution losses since net energy for load,[2] rather than delivered sales,[3] is used to represent electric demand in the model. Additionally, 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 that may be part of the retail cost.

2.3.5 Load Duration Curves (LDC)

IPM uses Load Duration Curves (LDCs) to provide realism to the dispatching of electric generating units. Unlike a chronological electric load curve, which is simply an hourly record of electric demand, the LDCs are created by rearranging the hourly chronological electric load data from the highest to lowest (MW) value. For modeling tractability a 6-step piecewise linear representation of the LDC is used in EPA applications of IPM.

IPM can include any number of separate LDCs for any number of user defined seasons. A season can be a single month or several months. For example, EPA Base Case v.4.10 contains two seasons: summer (May 1 – September 30) and winter (October 1– April 30). Separate summer and winter 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 season consisting of 3,672 hours.

Figure 2-1 Hypothetical Chronological Hourly Load Curve and Seasonal Load Duration Curve in EPA Base Case v.4.10



National electric demand growth assumptions (from AEO for EPA Base Case v.4.10) and NERC's forecasts of peak and energy demand in each region are used to derive future seasonal load duration curves for each IPM run year in each IPM region from the historical data. The results of this process are individualized seasonal LDCs that capture the unique hourly electric demand profile of each region. The LDCs change over time to reflect projected future variations in electricity consumption patterns.

Within IPM, LDCs are represented by a discrete number of load segments, or generation blocks, as illustrated in Figure 2-2. EPA Base Case v.4.10 uses six load segments in its seasonal LDCs

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[2]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.

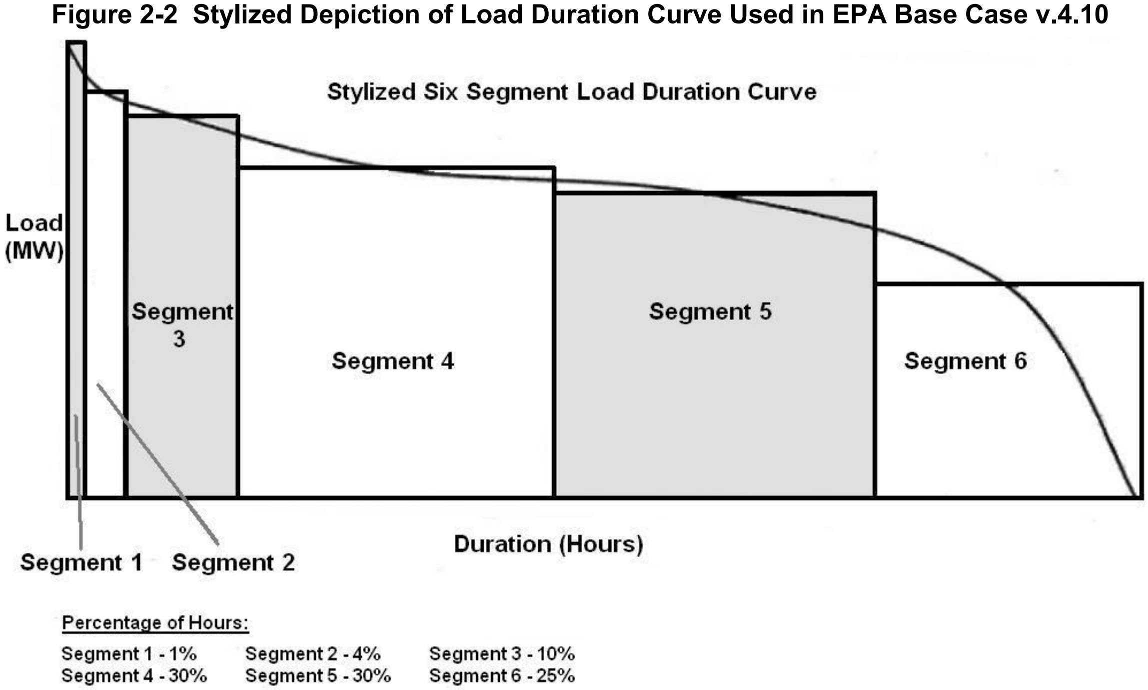
[3]Delivered sales is the electrical energy delivered under a sales agreement. It does not include distribution losses.

for model run years 2012-2030 and 4 load segments in its LDCs for model run years 2040 and 2050. The reduced number of load segments in the later years was adopted out of model size considerations and a view that having a finer grained representation of dispatch was less important that far into the future. Figure 2-3 illustrates and the following text describes the 6-segment LDCs used in the base case's earlier years. 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 must be producing (represented along the y-axis) to meet system load. Segment 1 in Figure 2-3 generally contains one percent of the hours in the period (i.e., "season") but represents the highest load demand value. IPM has the flexibility to model any number of load segments; however the greater the number of segments, the greater the computational time required to reach a solution. The LDC shows all the hourly electricity load levels that must be satisfied in a region in a particular season of a particular model run year. Segment 1 (the "super peak" load segment with 1% of all the hours in the season) and Segment 2 (the "peak" load segment with 4% of all the hours in the season) represent all the hours when load is at the highest demand levels. Segments 2 through 6 represent hourly loads at progressively lower levels of demand. Plants are dispatched to meet this load based on economic considerations and operating constraints. The most cost effective plants are assigned to meet load in all 6 segments of the load duration curve. This is discussed in greater detail in section 2.3.6 below.

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 generating 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.

Appendix 2-1 contains data and graphs of the 2012 summer and winter load duration curves in each of the 32 model regions in the lower continental U.S. for EPA Base Case v.4.10.

Figure 2-2 Stylized Depiction of Load Duration Curve Used in EPA Base Case v.4.10

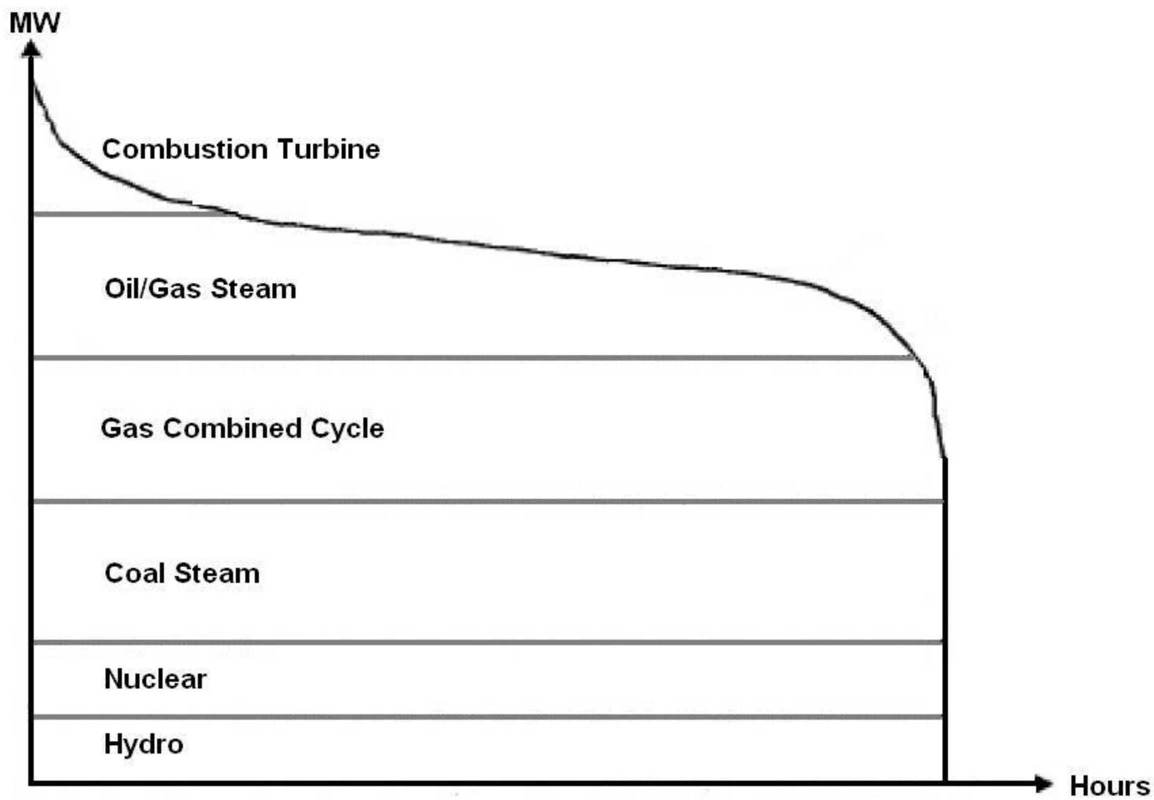


2.3.6 Dispatch Modeling

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 power plant 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 technically realistic fashion.

Figure 2-3 below depicts a highly stylized dispatch order based on the variable cost of generation of the resource options included in the EPA Base Case v.4.10. In Figure 2-3 a hypothetical load duration curve is subdivided according to the type of generation resource that responds to the load requirements represented in the curve. Notice that the generation resources with the lowest operating cost (i.e., hydro and nuclear) respond first to the demand represented in the LDC and so are 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.

Figure 2-3 Stylized Dispatch Order in EPA Base Case v.4.10



2.3.7 Reliability Modeling

Another methodological feature of IPM is its modeling of reliability through reserve margin requirements, which specify the amount of installed capacity that must be in excess of peak power demand. IPM includes regional reserve margin requirements for each run year. Section 3.6 contains a discussion of the reserve margin assumptions in EPA Base Case v.4.10.

2.3.8 Fuel Modeling

Another key methodological feature of IPM is its capability to model the full range of fuels used for electric power 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 EPA Base Case v.4.10 in one of three alternative ways: (1) through an embedded modeling capability that dynamically balances supply and demand to arrive at fuel prices (natural gas), (2) through a set of supply curves (coal and biomass) or (3) through an exogenous price stream (fuel oil and nuclear fuel). With the first and second approaches, the model endogenously determines the price for that fuel by balancing the supply and demand. IPM uses the fuel quality information (e.g., the sulfur or mercury content of different types of coal from different supply regions) to determine the emissions resulting from the combustion of that fuel.

The EPA Base Case v.4.10 includes coal, natural gas, fuel oil, nuclear fuel, biomass, and fossil and non-fossil waste as fuels for electric generation. The specific base case assumptions for these fuels are examined in chapters 9-11.

2.3.9 Transmission Modeling

IPM includes a detailed representation of existing transmission capabilities between model regions along with options for building new transmission lines. The maximum transmission capabilities between regions are specified in IPM's 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. Due to extensive unresolved policy issues and long-term uncertainty surrounding the building of new transmission lines in the U.S., EPA Base Case v.4.10 does not exercise IPM's capability to model the building of new transmission lines. The specific transmission assumptions in EPA Base Case v.4.10 are described in section 3.3.

2.3.10 Perfect Competition and Perfect Foresight

Two key methodological features of IPM are its assumptions of perfect competition and perfect foresight. The former means that IPM models production activity in wholesale electric markets on the premise that these markets subscribe to all assumptions of perfect competition. 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. Since the retail electric market is not modeled in IPM, there are no assumptions about the extent or timing of retail deregulation.

IPM's assumption of perfect foresight implies that economic agents know precisely the nature and timing of the constraints that will be imposed in future years. For example, under IPM there is complete foreknowledge of the levels, timing, and regulatory design of emission limits that will be imposed over the entire modeling time horizon. In making decisions, agents optimize based on this foreknowledge. However, by performing an iterative series of runs, in which new emission limits are successively added in subsequent model run years, imperfect foresight can be incorporated in IPM's projections.

2.3.11 Air Regulatory Modeling

One of the most notable features of IPM is its detailed and flexible modeling of air regulations. Treatment of air regulations is endogenous in IPM. That is, 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 produced in solving a linear programming problem.) IPM can capture a wide variety of regulatory program designs including cap-and-trade, command-and-control and renewable portfolio standards. IPM's representation of cap-and-trade programs can include allowance banking, trading, borrowing, bonus allowance mechanisms, progressive flow controls or emission taxes. Air regulations can be tailored to specific geographical regions and can be restricted to specific seasons. Many of these regulatory modeling capabilities are exploited in EPA Base Case v.4.10.

2.4 Hardware and Programming Features

IPM produces model files in standard MPS linear programming format. IPM runs on most PC-platforms. Its hardware requirements are highly dependent on the size of a particular model run. For example, with almost 7.3 million decision variables and 1.2 million constraints, EPA Base Case v.4.10 is run on a 64 bit Windows Enterprise Server 2008 platform with four Intel Xeon 2.93 GHz dual core processors and 32 GB of RAM. Due to the size of the EPA base case, a commercial grade solver is required. (Benchmarking tests performed by EPA's National Environmental Scientific Computing Center using research grade solvers yielded unacceptable results.) For current EPA applications of IPM, the FICO Xpress Optimization Suite 7 linear programming solvers are used.

Two data processors -- a front-end and the post-processing tool -- support the model. The front-end creates the necessary input files used in IPM, while the post-processing tool maps IPM model-plant level outputs to individual generating units (a process called "parsing," see section 2.3.1) and creates input files in ORL (one record line) format as needed by EPA's air quality models.

Before it can be run, the model requires an extensive set of input parameters. These are discussed in Section 2.4.1 below. Results of model runs are presented in a series of detailed reports. These are described in Section 2.4.2 below.

2.4.1 Data Parameters for Model Inputs

IPM requires input parameters that characterize the US electric system, economic outlook, fuel supply and air regulatory framework. Chapters 3-11 contain detailed discussions of the values assigned to these parameters in EPA Base Case v.4.10. This section simply lists the key input parameters required by IPM:

Electric System

Existing Utility Generating Resources

- Plant Capacities
- Heat Rates
- Maintenance Schedule
- Forced Outage Rate
- Minimum Generation Requirements (Turn Down Constraint)
- Fuels Used
- Fixed and Variable O&M Costs
- Emissions Limits or Emission Rates for NO_x, SO_2, CO_2, Mercury
- Existing Pollution Control Equipment and Retrofit Options
- Output Profile for Non-Dispatchable Resources

New Generating Resources

- Cost and Operating Characteristics
- Performance Characteristics
- Limitations on Availability

Other System Requirements

- Inter-regional Transmission Capabilities
- Reserve Margin Requirements for Reliability
- Area Protection
- System Specific Generation Requirements
- Regional Specification

Economic Outlook

Electric Demand

- Firm Regional Electric Demand
- Load Curves

Financial Outlook

- Capital Charge Rate
- Discount Rate

Fuel Supply

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

Air Regulatory Outlook

Air Regulations for NO_x, SO_2, CO_2, Mercury
Other Air Regulations

2.4.2 Model Outputs

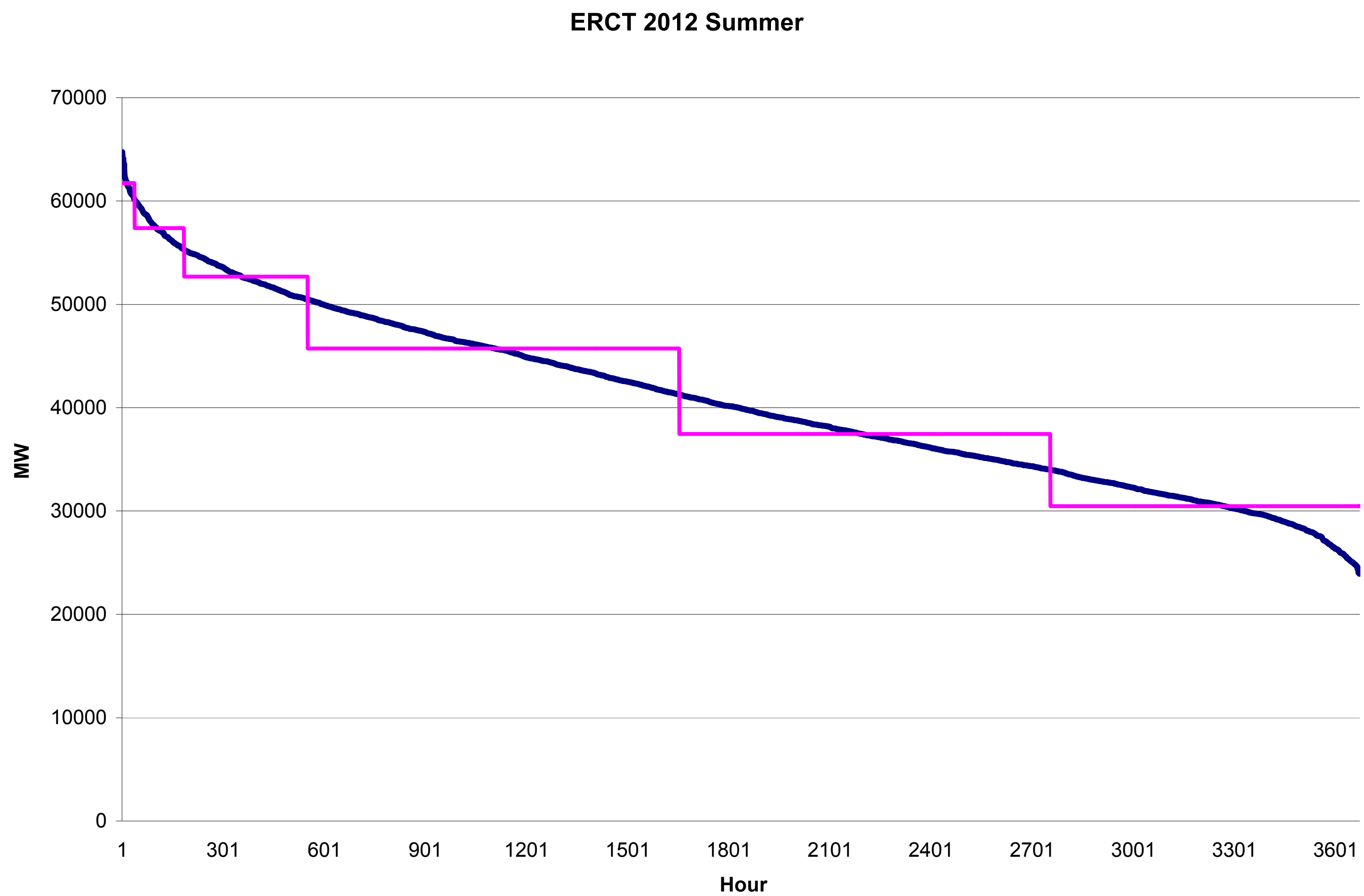
IPM produces a variety of output reports. These range from extremely detailed reports, which describe the results for each model plant and run year, to summary reports, which present results for regional and national aggregates. Individual topic areas can be included or excluded at the user's discretion.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

- Generation
- Capacity mix (by plant type and presence or absence of emission controls)
- Capacity additions and retirements
- Capacity and energy prices
- Power production costs (capital VOM, FOM and fuel costs)
- Fuel consumption
- Fuel supply and demand
- Fuel prices for coal, natural gas, and biomass
- Emissions (NO_X, SO_2, CO_2, and Hg)
- Emission allowance prices

Appendix 2-1 Load Duration Curves Used in EPA Base Case v.4.10

This is a small exerpt of the data and graphs in Appendix 2-1. The complete data set in spreadsheet format and complete set of graphs can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.htm

Month	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Hours	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Day Hours	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	1	2
AZNM	11,182	10,866	10,659	10,628	10,724	10,969	11,250	11,306	11,553	11,707	11,533	11,294	10,977	10,643	10,367	10,304	10,515	11,676	12,475	12,511	12,414	12,076	11,547	10,898	10,467	10,332
CA-N	11,127	11,196	11,477	11,976	12,082	12,262	12,645	12,877	12,812	12,615	12,457	12,274	12,418	13,410	15,256	15,213	14,885	14,386	13,566	12,501	11,793	11,242	10,899	10,829	10,943	11,443
CA-S	15,323	14,636	14,234	14,056	14,129	14,347	14,275	14,448	14,940	15,427	15,690	15,785	15,713	15,619	15,598	15,599	16,951	19,009	19,111	18,803	18,261	17,322	16,040	14,941	14,260	13,937
COMD	10,119	9,763	9,444	9,264	9,140	9,137	9,220	9,419	9,414	9,489	9,698	9,908	10,016	10,032	10,048	9,987	9,965	10,552	11,448	11,495	11,428	11,295	11,037	10,545	10,025	9,654
DSNY	2,861	2,708	2,597	2,526	2,497	2,519	2,575	2,638	2,758	2,936	3,107	3,229	3,291	3,286	3,256	3,282	3,454	3,711	3,710	3,611	3,489	3,283	2,999	2,718	2,520	2,421
ENTG	14,747	14,695	14,588	14,491	14,478	14,554	14,924	15,411	15,669	16,072	16,337	16,392	16,108	15,654	15,183	14,898	14,956	15,495	16,581	17,184	17,320	17,205	16,942	16,309	15,539	15,586
ERCT	29,987	29,796	29,710	29,857	30,395	31,487	32,637	33,019	33,024	33,208	32,996	32,351	31,188	30,011	28,906	28,277	28,409	30,699	34,030	34,697	35,016	34,568	33,283	31,783	30,789	30,379
FRCC	19,757	18,688	17,471	16,766	16,412	16,476	16,780	17,054	18,787	21,128	23,288	24,514	25,262	25,431	25,229	25,051	24,845	25,636	26,465	25,716	24,569	23,236	21,474	19,419	17,658	16,542
GWAY	9,016	8,918	8,852	8,782	8,857	8,995	9,200	9,298	9,475	9,781	10,000	10,019	9,874	9,718	9,546	9,509	9,863	10,775	10,895	10,860	10,778	10,558	10,140	9,725	9,516	9,436
LILC	2,189	2,080	1,991	1,937	1,910	1,909	1,927	1,949	1,995	2,085	2,192	2,276	2,325	2,342	2,348	2,369	2,485	2,615	2,607	2,568	2,517	2,416	2,256	2,085	1,959	1,892
MACE	14,997	14,408	13,928	13,663	13,575	13,629	13,818	14,003	14,204	14,781	15,363	15,771	16,002	16,044	16,064	16,133	16,702	17,567	17,540	17,324	17,013	16,389	15,520	14,538	13,919	13,590
MACS	6,474	6,267	6,056	5,908	5,885	5,961	6,070	6,114	6,194	6,458	6,742	6,963	7,051	7,022	6,934	6,938	7,038	7,519	7,543	7,500	7,355	7,149	6,793	6,456	6,198	6,060
MACW	6,418	6,000	5,606	5,463	5,441	5,552	5,719	5,905	6,206	6,713	7,208	7,495	7,516	7,418	7,246	7,254	7,591	8,267	8,286	8,185	8,036	7,644	6,976	6,300	5,973	5,745
MECS	9,332	9,063	8,867	8,732	8,683	8,758	8,882	9,032	9,078	9,272	9,582	9,829	9,938	9,946	9,912	9,955	10,149	10,693	10,910	10,846	10,765	10,575	10,231	9,833	9,553	9,342
MRO	20,437	19,616	19,012	18,599	18,593	18,901	19,603	20,370	20,737	21,386	21,798	21,936	21,733	21,288	20,761	20,829	21,990	25,094	26,505	26,416	25,724	24,612	23,102	21,442	20,074	19,395
NENG	12,380	11,716	11,272	11,035	11,020	11,181	11,502	11,867	12,438	13,283	14,097	14,625	14,769	14,685	14,545	14,670	15,597	16,268	16,043	15,595	14,985	14,039	12,816	11,738	11,053	10,664
NWPE	6,242	6,086	6,018	5,990	6,027	6,149	6,296	6,431	6,605	6,759	6,818	6,815	6,762	6,673	6,621	6,652	7,010	7,390	7,370	7,273	7,145	6,845	6,423	6,066	5,943	5,852
NYC	4,838	4,645	4,449	4,295	4,237	4,238	4,315	4,376	4,477	4,671	4,889	5,058	5,175	5,246	5,304	5,354	5,507	5,687	5,664	5,593	5,500	5,358	5,110	4,772	4,463	4,269
PNW	19,729	19,289	19,068	19,035	19,342	19,827	20,403	20,925	21,531	22,174	22,697	22,843	22,768	22,505	22,248	22,334	23,178	23,768	23,545	23,064	22,354	21,360	20,104	18,906	18,185	17,856
RFCO	17,029	16,735	16,335	16,166	16,167	16,397	16,785	17,214	17,480	17,852	18,625	19,267	19,642	19,673	19,682	19,755	20,141	21,036	21,358	21,162	20,915	20,370	19,687	18,920	18,246	17,890
RFCP	21,425	20,589	19,799	19,483	19,512	19,932	20,607	21,420	22,257	23,435	24,540	25,256	26,276	26,255	26,253	26,421	27,018	28,753	29,207	29,066	28,838	27,913	26,515	24,912	23,868	23,330
RMPA	5,995	5,904	5,914	6,068	6,205	6,281	6,484	6,718	6,783	6,736	6,613	6,641	6,568	6,599	7,137	8,185	8,384	8,247	8,069	7,693	6,966	6,355	5,998	5,773	5,681	5,732
SNV	2,666	2,637	2,609	2,601	2,602	2,621	2,595	2,515	2,486	2,488	2,494	2,491	2,477	2,446	2,432	2,439	2,576	2,786	2,805	2,788	2,762	2,712	2,648	2,559	2,500	2,465


ERCT 2012 Summer
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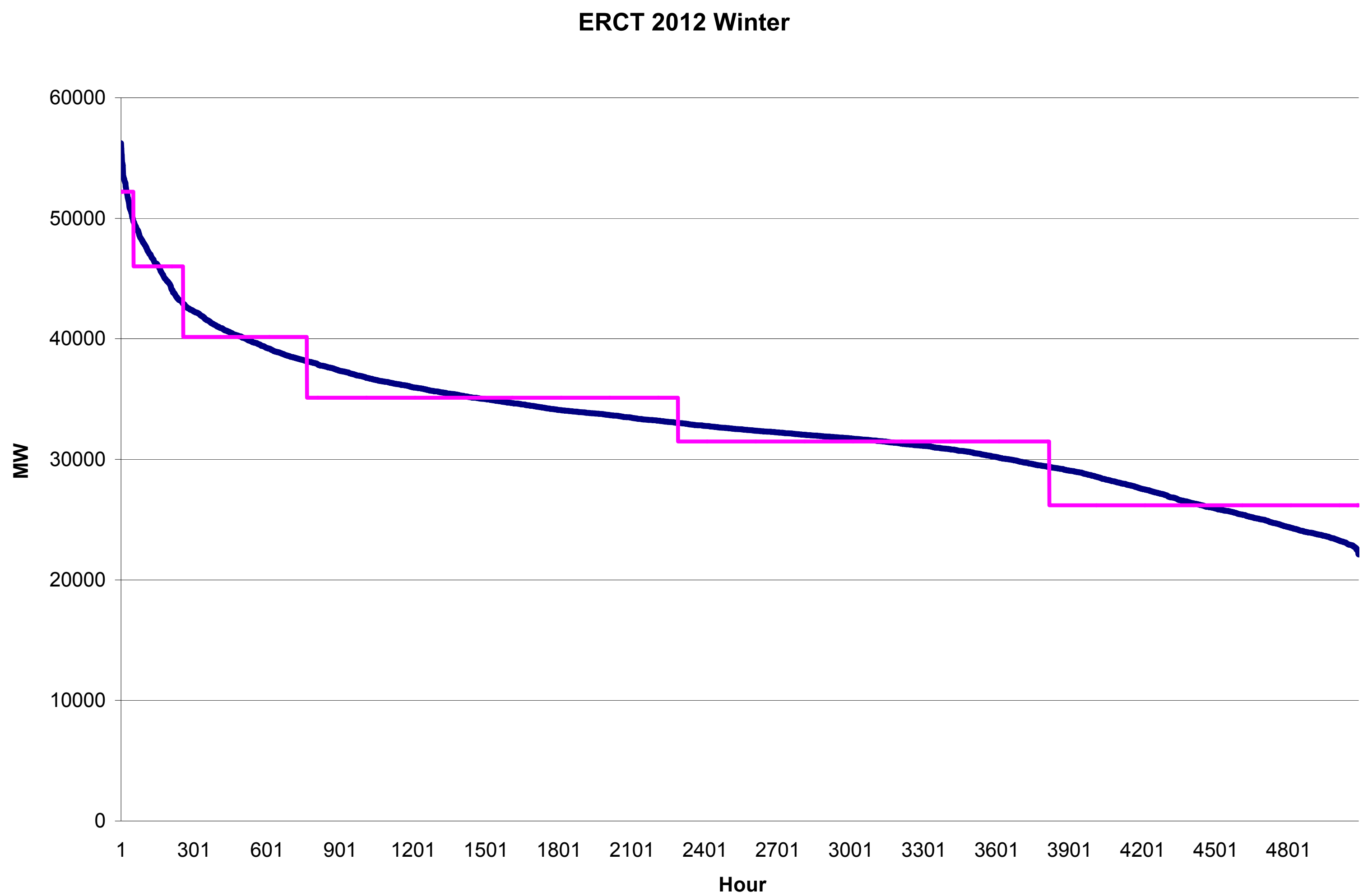
ERCT 2012 Winter
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