ORNL/TM-2016/382

The Oak Ridge Competitive Electricity Dispatch Model Version 9

Stanton W. Hadley
Youngsun Baek

November 2016

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ORNL/TM-2016/382

Electronics and Electrical Systems Research Division

THE OAK RIDGE COMPETITIVE ELECTRICITY DISPATCH MODEL VERSION 9

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November 2016

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managed by
UT-BATTELLE, LLC
for the
US DEPARTMENT OF ENERGY
under contract DE-AC05-00OR22725

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ACRONYMS

AEO	*Annual Energy Outlook* (EIA)
BAU	business as usual
DG	distributed generation
DR	demand response
ECAR	East Central Area Coordination Agreement
EIA	Energy Information Administration
EMM	Electricity Market Module
EPA	US Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FOR	forced outage rate
GAR	Generating Availability Report (NERC)
LDC	load duration curve
LOLP	loss-of-load probability
NADR	National Assessment of Demand Response (FERC model)
NEL	net electric load
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
O&M	operations and maintenance
ORCED	Oak Ridge Competitive Electricity Dispatch
ORFIN	Oak Ridge Financial (model)
ORNL	Oak Ridge National Laboratory
PHEV	plug-in hybrid electric vehicle
POR	planned outage rate

ELECTRIC ENTITIES REFERRED TO IN TEXT OR FIGURES

AZNM	WECC Southwest
CAMX	WECC California
ECAR	East Central Area Coordination Agreement
ERCOT	Electric Reliability Council of Texas
ERCT	Electric Reliability Council of Texas
FRCC	Florida Reliability Coordinating Council
ISO	Independent System Operator
MRO	Midwest Reliability Organization
MROE	MRO East
MROW	MRO West

NEWE	NPCC-New England
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool Area (WECC Northwest)
NYCW	NPCC–New York City-Westchester
NYLI	NPCC-Long Island
NYUP	NPCC-Upstate New York
PJM	PJM Interconnection; regional transmission organization operating in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia
RFC	Reliability First Corporation
RFCE	RFC East
RFCM	RFC Michigan
RFCW	RFC West
RMPA	WECC Rockies
SERC	SERC Reliability Corporation
SPNO	SPP North
SPP	Southwest Power Pool
SPSO	SPP South
SRCE	SERC Central
SRDA	SERC Delta
SRGW	SERC Gateway
SRSE	SERC Southeastern
SRVC	SERC Virginia-Carolina
WECC	Western Electricity Coordinating Council

ABSTRACT

The Oak Ridge Competitive Electricity Dispatch (ORCED) model dispatches power plants in a region to meet the electricity demands for any single given year up to 2030. It uses publicly available sources of data describing electric power units such as the National Energy Modeling System and hourly demands from utility submittals to the Federal Energy Regulatory Commission that are projected to a future year. The model simulates a single region of the country for a given year, matching generation to demands and predefined net exports from the region, assuming no transmission constraints within the region. ORCED can calculate a number of key financial and operating parameters for generating units and regional market outputs including average and marginal prices, air emissions, and generation adequacy. By running the model with and without changes such as generation plants, fuel prices, emission costs, plug-in hybrid electric vehicles, distributed generation, or demand response, the marginal impact of these changes can be found.

1. INTRODUCTION

In the mid-1990s the electric utility industry was faced with the potential for major changes in how it would operate. Restructuring would cause utilities to buy and sell most of their power through the wholesale market, and many utilities would no longer receive their expected return on investment. Instead, prices would be based on the market and not on cost of service. The transition could mean stranded costs on expensive plants or long-term contracts. To evaluate the impacts, researchers at the Oak Ridge National Laboratory (ORNL) developed a model called ORFIN (Oak Ridge Financial) (Hadley 1996). It calculated a utility's costs and revenues over a multiyear time period and allowed a financial comparison between a regulated market and market-based pricing. Among its most notable analyses was an examination of the stranded costs for each utility in North Carolina.

While ORFIN could examine a single utility over multiple years, it only coarsely modeled the production and sales in a regional market. The Oak Ridge Competitive Electricity Dispatch (ORCED) model was developed to better capture regional market dynamics. Its first test was an analysis of the impact of different technologies and carbon reduction strategies on the nation as reported in *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond* (Interlaboratory Working Group 1997). Since that time, the model has been used in a variety of studies including the following.

- Impact of restructuring on power prices in California and the Pacific Northwest (Hadley and Hirst 1998) (Hadley and Hirst 1998a)
- Effect of carbon taxes on power production in Ohio and the East Central Area Coordination Agreement (ECAR) region (Hadley 1998)
- Market incentives for adequate generation capacity in a restructured electricity market (Hirst and Hadley 1999)
- Impacts of hydropower relicensing on carbon emissions in each North American Electric Reliability Corporation (NERC) region (Sale and Hadley 2002)
- Impacts of restructuring on prices and transmission in Oklahoma (Hadley et al. 2001a; Hadley et al. 2001b)

- Benefits of distributed generation (DG) to utilities, customers, and society (Hadley and Van Dyke 2003; Hadley, Van Dyke, Poore, and Stovall 2003; Hadley, Van Dyke, and Stovall 2003)

- Potential for economic biomass cofiring on a state and regional basis (English et al. 2005)

- Air pollutant concentration changes across the Southeast due to demand reductions (O'Neal, Imhoff, Condrey, and Hadley 2006)

- Impact of plug-in hybrid electric vehicles (PHEVs) on electric generation in individual regions across the country (Hadley 2006; Hadley and Tsvetkova 2008)

- Marginal CO_2 emission changes from PHEV operation for a PHEV value proposition study (Sikes, Hadley, McGill, and Cleary 2010)

- Impact of energy efficiency and demand response (DR) programs on the US electricity market (Baek and Hadley 2012)

The model was modified as needed for each of the studies. Modifications included expanding the number of plants analyzed, modeling two neighboring regions simultaneously, modeling three different customer classes simultaneously, calculating cost-based pricing as well as market-based pricing, optimizing additions of new capacity to minimize overall cost, increasing the number of seasons studied, improving demand modeling to include specified hourly loads, and adding a reserves market. Some of these modifications were carried on into future iterations of the model, while others were only used for specific studies.

IN 2007-2008, the model was used to analyze the potential impact of PHEVs in each of the 13 NERC regions within the United States (Hadley and Tsvetkova 2008), followed by analysis of PHEV carbon impacts for California and Ohio (Sikes, Hadley, McGill, and Cleary 2010). Some of the examples used in this report will be from these analyses. More recently, the model was used to examine the impact of DR on generation (Baek et al. 2012). Several versions of the model are available from the lead author.

Chapter 2 describes the overall organization of the model, while Chapters 3 through 5 describe the modeling of demands, supplies, and dispatch, respectively. Chapter 6 explains some of the key results from the model, and Chapter 7 summarizes the report. The appendix, a summary user manual for Version 9, describes the procedures to manipulate the various files used to perform an analysis.

2. ORGANIZATION

2.1 OVERVIEW

The original ORCED model was a single Excel spreadsheet that dispatched 25 power plants in two seasons using simple three-segment demand curves. The current version pulls power plant data from a database of over 20,000 generating units plus other data sources, segregates plants by region and aggregates them into 200 plant groups, converts hourly load data from over 100 utilities into three seasons with 11-segment regional demand curves, and calculates market-based and cost-based prices, air emissions, and full financial statements for each power plant.

The overall flow of information is shown in Figure 1. On the left, the demand information is gathered and converted. On the right, the supply information is gathered and converted for use in the dispatch section. At the bottom, the demand and supply are brought together so that supply is dispatched to meet the demands. Lastly, the results for the scenario are stored for comparison to other scenarios.

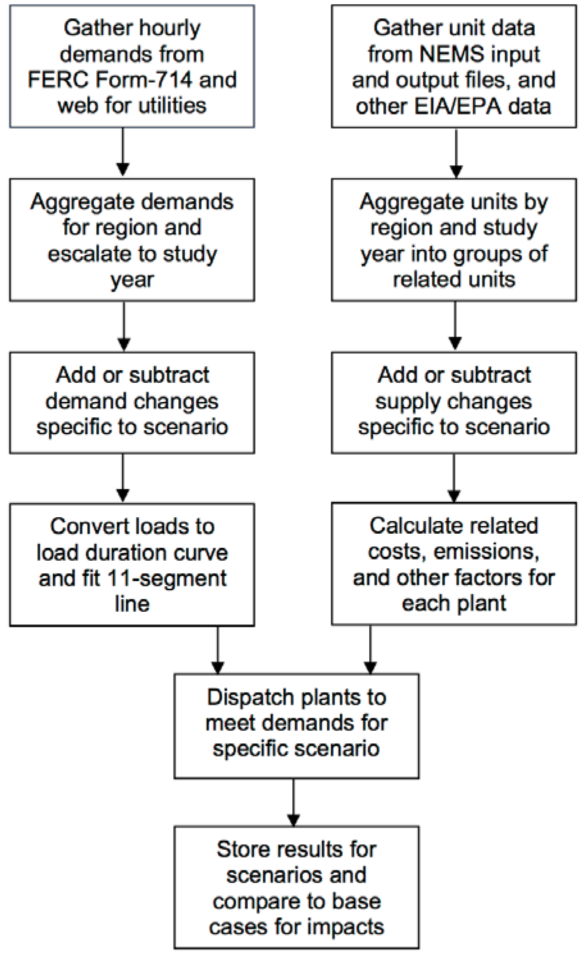


Figure 1. ORCED flow diagram.

Raw data are gathered from independent sources such as the Federal Energy Regulatory Commission (FERC), US Department of Energy's Energy Information Administration (EIA), US Environmental Protection Agency (EPA), NERC, state utility commissions, independent system operators, nongovernment organizations, and utilities themselves. Sufficient data to operate the model can be found from open sources, although some studies have used purchased, proprietary information on power plant statistics.

The data is typically collected into spreadsheets for further manipulation. While the model could be developed in another computer language or architecture, spreadsheets offer the flexibility that lends itself well to the varied tasks used for the model. Some of the processes involved, including hydropower capacity allocation and probabilistic dispatch, involve complex calculations that use Visual Basic routines. These have been translated to FORTRAN but just for testing purposes. Other techniques used, such as histogram calculations and Solver optimization for the load duration curves (LDCs), rely on built-in functions of Microsoft Excel. Unfortunately, the formulas within the spreadsheets can be quite intricate, which makes documentation and error-checking more difficult than with other languages.

A set of spreadsheets is used sequentially for the various steps in the process. Data can be either linked between spreadsheets to ensure consistency or manually copied to reduce calculation time. Various macros are used to ease the calculations and connections between process steps.

2.2 REGIONS DEFINITION

For ORCED, an important step is to define a region that is large enough to capture essentially all of the geographical area that could reasonably be served by plants in the domain. ORCED does not account for transmission constraints within a region or dynamic transmission to regions outside of the domain. Many of these constraints result from facilities or engineering constraints that are unique to each system. Such complexity can only be modeled with system details that are often proprietary to the power companies. Because of this lack of transmission constraint, it is important to define a region such that distant plants that would not in reality be responsive to scenario changes are not included. (There is an optional calculation that can adjust the demand curves based on net transmission imports into the region.)

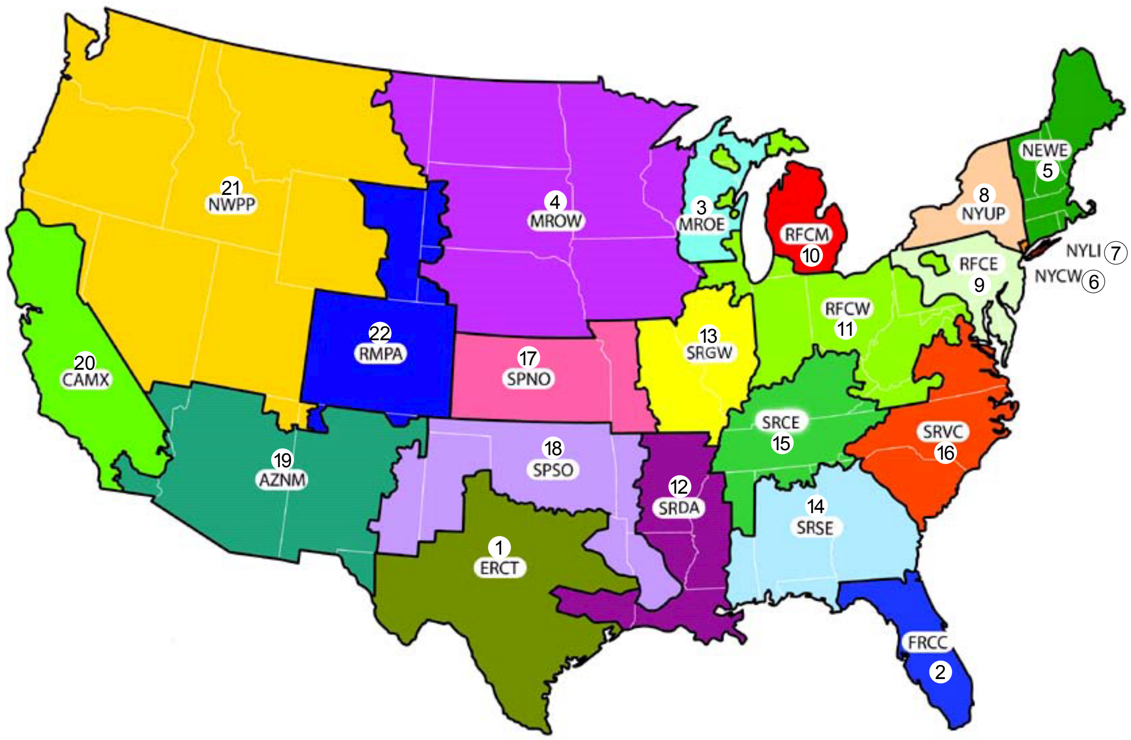
Over the years, several different regions have been used: single states, NERC reliability regions, and NERC subregions. The first major ORCED study treated the entire United States as a single region. The most common approach has been to use the NERC regions. However, these have recently changed significantly through consolidation and utilities switching to neighboring regions.

A ready source for much of the information used in the model is the results from the National Energy Modeling System (NEMS). This system is developed and used by EIA to conduct long-term analyses of the US energy sector. The most widely used results in the model are from the *Annual Energy Outlook* (AEO) for the latest year available at the time (EIA 2016). Until 2010, NEMS provided results up to the year 2030 for each of the NERC regions of the United States, using the NERC regions as defined in 2004. However, the 2011 and later versions of NEMS subdivides the 13 electricity sector regions into 22 regions and provides results up to the year 2040. Figure 2 illustrates the newly defined regions for the Electricity Market Module (EMM) in NEMS. The regions are identified by four-character abbreviations of their full names and are spelled out in the Acronyms table.

For recent studies (Baek and Hadley 2012; Baek et al. 2012), the regional supply dataset was updated based on the 2011 AEO (EIA 2011) Input file Pltf860.txt in NEMS, which provides a variety of information on summer/winter capacity, heat rate, emission rates of NO_X and SO_X for 18,570 existing and planned plants. These studies also used the cumulative unplanned additions forecast of from the 2011 AEO to consider not only the existing and planned plants but also 525 unplanned (but expected) plant additions by the year 2030. They provide the impact of DR programs on the grid by 22 EMM regions.

An older study involving multiple regions compared the impacts of creating market-based pricing (restructuring) in California and the Pacific Northwest (Hadley and Hirst 1998a). This used the two-region version of ORCED that explicitly modeled transmission between the two regions, as described in the original ORCED documentation (Hadley and Hirst 1998b). An interesting outcome was the heightened impact on prices with a restructured market, especially during times of drought. These results foreshadowed some of the problems with the California market in 2000–2001.

The year of analysis will depend on the nature of the study. Dates have been anywhere from the current year up to 25 years in the future. If future years are to be modeled then projections of supply and demand will be needed; this is one reason for the use of the NEMS model inputs and outputs. However, other sources for projected supply and/or demand are available, or have been left as part of the study itself. One study (Hirst and Hadley 1999) looked at the capacity needed to provide optimum generation adequacy, while the earliest study (Interlaboratory Working Group 1997) looked at the amount of capacity and generation that would result from different carbon policies and technologies.



- 1. ERCT (ERCOT All)
- 2. FRCC (FRCC All)
- 3. MORE (MRO East)
- 4. MROW (MRO West)
- 5. NEWE (NPCC New England)
- 6. NYCW (NPCC NYC/Westchester)
- 7. NYLI (NPCC Long Island)
- 8. NYUP (NPCC Upstate NY)
- 9. RFCE (RFC East)
- 10. RFCM (RFC Michigan)
- 11. RFCW (RFC West)
- 12. SRDA (SERC Delta)
- 13. SRGW (SERC Gateway)
- 14. SRSE (SERC Southeastern)
- 15. SRCE (SERC Central)
- 16. SRVC (SERC VACAR)
- 17. SPNO (SPP North)
- 18. SPSO (SPP South)
- 19. AZNM (WECC Southwest)
- 20. CAMX (WECC California)
- 21. NWPP (WECC Northwest)
- 22. RMPA (WECC Rockies)

Figure 2. Electricity Market Module regions as specified in the 2011 *Annual Energy Outlook* (EIA 2011).

3. DEMANDS

Demand manipulations are carried out by collecting data from a variety of sources, selecting the data for a specific region, manipulating it for the different scenarios to be studied, and storing the results for use in the ORCED Dispatch workbook. The data and demand calculations are done in a workbook called "Demand."

3.1 HOURLY DATA

Demands are estimated by first finding the hourly demands for the region of study. Utilities or their regional system operators have to submit their hourly loads to FERC on a yearly basis on FERC Form 714 (FERC 2011). Hourly demands for each control area for 2011 and earlier years can be found on the FERC website (http://www.ferc.gov/). The FERC-714 data used to be provided within a standardized pdf form and is also provided in .CSV form on the FERC website (http://www.ferc.gov/docs-filing/forms/form-714/data.asp). Spreadsheets have been developed to convert a utility's data from the various formats into a single column of 8,760 hours (8,784 hours for leap years). Care has to be taken to identify how each utility handled Daylight Saving Time. Some may place a zero for the missing hour in April and combine 2-hour values in October, while others report their loads using Standard Time for the entire year. There can be other variations as well. The best method to ensure consistency is to compare the change in hourly loads for several days before and after the spring and fall shifts. The morning rise in demand should look similar, and there should be approximately a 1-hour lag in early evening shapes, even though loads overall may differ due to temperatures (Figure 3). To further automate this, algorithms have been created that compare the slope of each line to see whether the morning hour slope peaks at the same time or is off by an hour in the week before or after the change. In most cases, this establishes whether prevailing time or standard time is used. In some cases, further visual examination is needed.

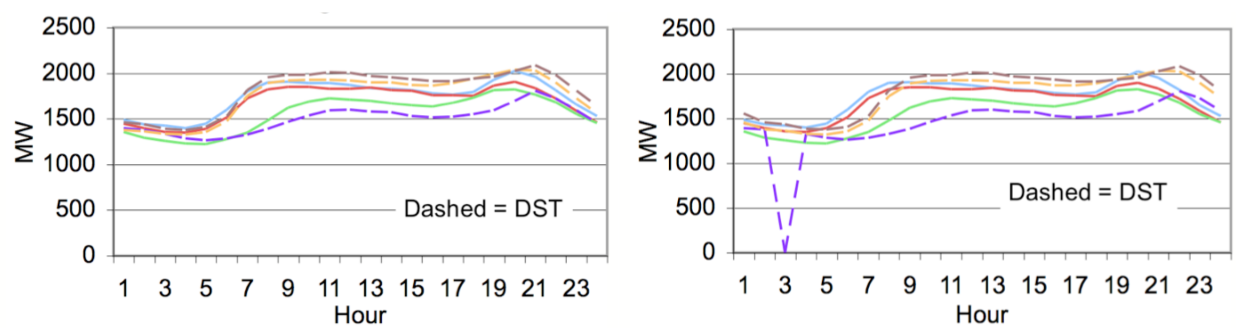


Figure 3. Hourly loads for 3 days before and after Daylight Saving Time where reported loads are based on prevailing time (left) or standard time (right).

A number of utilities' loads must be collected for each region to be studied, the higher the proportion of the total region's sales, the better. In some cases, the region's system controller can provide the data for an entire region or its sub-parts, either on their website or by direct contact. Examples include the Independent System Operator for New England (ISO-NE), New York ISO, California ISO, PJM Interconnection, and ERCOT.

Once the utility dataset is retrieved and converted to a consistent format, they can be summed to determine an hourly profile for the region. However, because the utilities may not represent the entire load in the region, the hourly values need to be adjusted based on the ratio of the total demands (sum of the load over the entire year) to the actual net electric load (NEL) for the region. This latter value can be found from NERC's Electric Supply & Demand database (NERC 2007) or from EIA's *Electric Power Annual* (EIA 2007).

In the following examples, hourly load data for 2005 from about 100 utilities or control areas were retrieved and aggregated into each of the 13 regions. The resulting hourly loads were then escalated and extrapolated to match the region's total NEL in the year being studied as defined in the 2011 AEO. Net interregional imports or exports from the 2011 AEO were then added to the demands, with the transfers mainly added during lower demand periods. As an example, Figure 4 gives the projected hourly loads for 2020 for the ERCOT region. The year is separated into three seasons: peak (summer), winter, and off-peak.

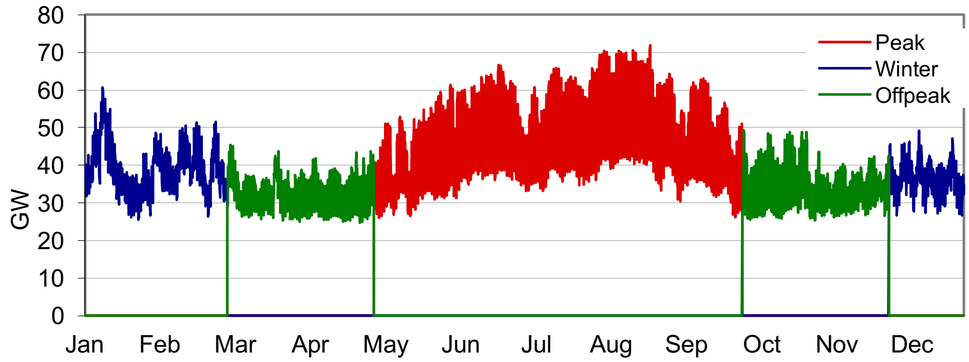


Figure 4. Hourly system load of ERCOT in 2020 under a "business as usual" scenario.

In any study, a template year's set of demands must be selected; the above example uses 2005 data. Dataset is available for other historical years as well. It is better to use a single year's values rather than an average of several years. Averages will blur the peaks and valleys; what may be a peak hour one year is not the next, and the resulting demand curves will be different from any actual year's curves. (Even using the utility's hourly data involves some averaging of the peaks within each hour.) In any case, the pattern in any future year could very well have demand patterns similar to a selected historical year. A more robust procedure would be to analyze the load shapes from multiple years and pick one that is more typical. For example, 2005 had several hurricanes across the southeast, with consequent impacts on load shapes for those regions. Other years may be more suitable for future projections, unless it turns out that hurricane activity remains high.

3.2 CHANGES TO DEMAND

3.2.1 Change in Demand Patterns

The objective of many of the studies done with ORCED has been to understand the impact of changes in demand on production-related parameters such as emissions, energy, or cost. Depending on the purpose of each study, different types of changes in parameters were made. The changes can be simple percentage changes or for specific quantities in specific hours. For example, the studies on benefits from DG looked at the impact of reducing demand by adding 100 MW of DG, either from 8:00 a.m. to 8:00 p.m. Monday through Friday or operating the equipment all of the time. The study on air emission reductions in the Southeast considered demand reductions of 4%, 6%, and 8% applied to all hours.

The PHEV studies evaluated additions to demand either in the evening or nighttime, with a pattern based on the charging characteristics of the vehicles. Figure 5 shows the impact of the added power for each of the scenarios on the peak day for the ECAR region in 2020. All days had similar additions to their hourly demands.

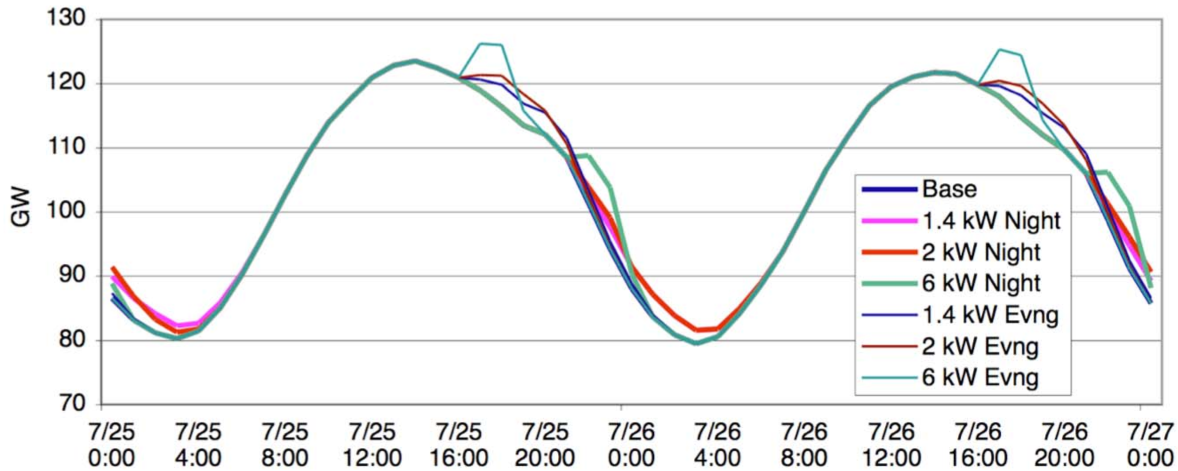


Figure 5. Added demand from plug-in hybrid electric vehicle scenarios on the peak day in ECAR for 2020.

A more complex pattern was established in the *PHEV Value Proposition Study* (Sikes et al. 2010). Vehicles with different amounts of battery capacity installed were operated through a simulation of the EPA driving patterns to establish a rough average amount of weekly driving. Multiple charging of the vehicles at different times (at work, during dinner, overnight, on weekends) and power levels were combined in different patterns to establish the amount needed to charge at these times. An example resulting charging pattern is shown in Figure 6. In this example, the PHEVs have a 40-mile range and charge up largely at nighttime, with 10% of them in the early evening.

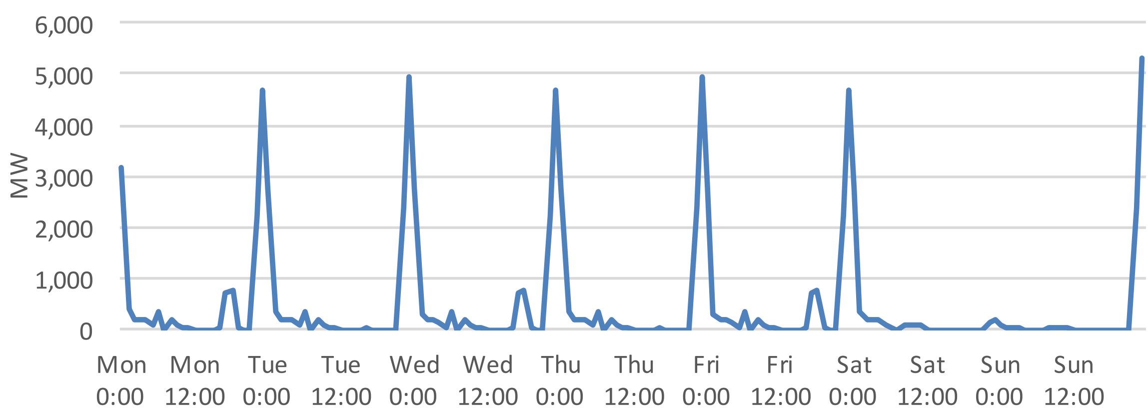


Figure 6. Plug-in hybrid electric vehicle 40-mile range demand shape in ECAR for a week in 2030.

Worksheets inside the Demand workbook can be used to calculate the hourly changes in demand. Changes can be defined by quantities or percentages and set based on hour of day, day of week, or month of year. These then get incorporated into the final hourly demand. ORCED Version 9 includes worksheets for these calculations.

3.2.2 Demand Response

Changes in hourly load caused by DR programs would affect not only the dispatch of existing plants but also the additions of advanced generation technologies, the retirements of old coal-firing plants, and the finances of the market. ORCED Version 9 contains additional equations that facilitate modeling different levels of DR and calculating the consequent benefits such as system peak impact, system reliability impact, generation cost impact, and environmental impact. ORNL published a DR potential study for the eastern interconnection area (Baek et al. 2012), and it presented the DR benefit results calculated by ORCED. The energy load shape under different DR scenarios varies depending on the percentage peak load reduction (%PLR) and the peak period when DR programs work. Therefore, the way DR is modeled affects the magnitude of system benefits from DR. The tab named “DR Schedule” in the Demand workbook enables you to adjust regional %PLR by region. Figures 7–10 show the energy load shape under three different DR scenarios built in ORCED Version 9.

No demand response case. This case considers a situation before DR programs are deployed. It is used as a reference case. Figure 7 shows the hourly load curve for 1 week out of the representative year studied for New England, one of the regions.

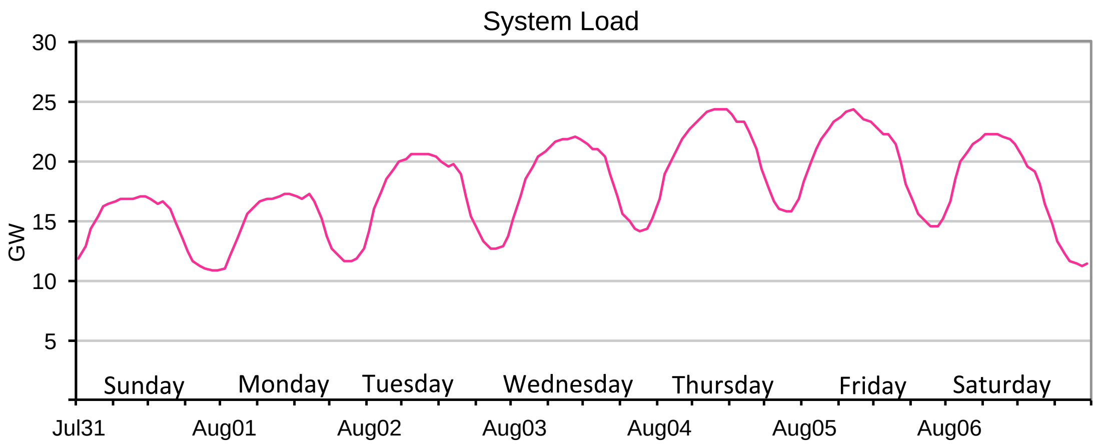


Figure 7. Energy load shape under a “no demand response case” scenario (NEWE region, August 1–August 6).

Demand response notch case. This case assumes that the peak demand declines consistently by a certain percentage only during pre-specified peak hours. This case refers to specific time periods representing when DR has a high probability of being used. “Peak hours” on a “typical event day” is defined as hours between 2:00 and 6:00 p.m. on the top 15 system load days (60 hours a year) (FERC 2009). Regional % PLR is applied to define the scale of DR impact in each region. This scenario does not consider load shifting between peak and off-peak hours. This “notch” was only applied to the business as usual (BAU) scenario because under a high DR penetration it was unrealistic that all DR would be used only during the specific 4 hours on the 15 highest summer days. Figure 8 shows the same week as above but with DR applied on the 2 highest days because those 2 days are among the 15 days with highest demands.

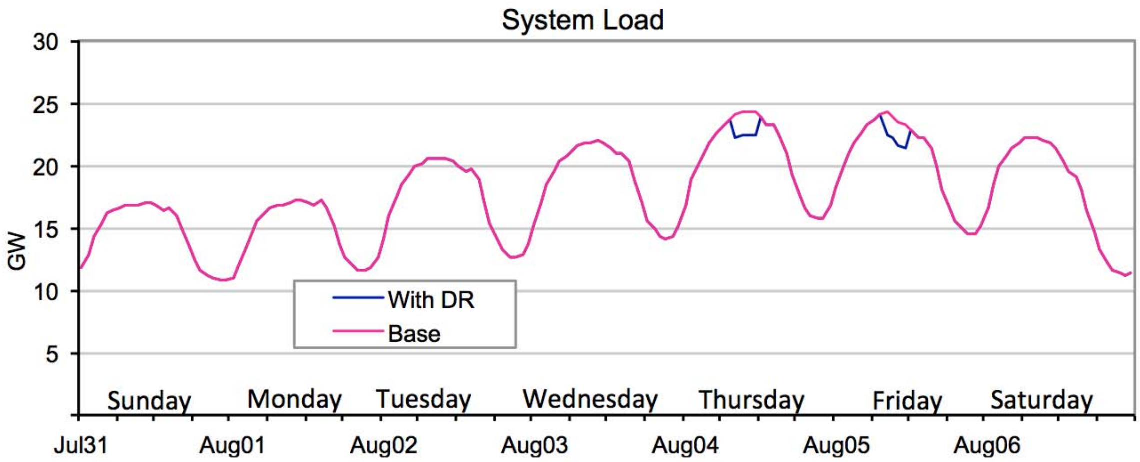


Figure 8. Energy load shape under the "demand response notch case" scenario (NEWE region, August 1–August 6).

Demand response smart case. This case assumes that DR is designed and implemented to meet a certain target power level over a year. First, the energy avoided by the peak load impacts forecast by the ORNL–National Assessment of Demand Response (NADR) model[1] was estimated, assuming it to be equivalent to that in the DR notch case. A peak demand level (P) was calculated so as to make the amount of avoided energy from the smart case the same as that from the notch case. In other words, the peak demands above P are clipped throughout the year while the total energy saved is the same as in the notch definition. DR may be applied more times than the notch's 15 days and in more hours than the 2:00 to 6:00 p.m. range, but the total energy over the year is equal. Figure 9 shows the impact on the same week as the previous two graphs. Less DR is used on these days, but DR is applied to more days of the year. Total demand is never above the new peak amount, in this case 23.5 GW.

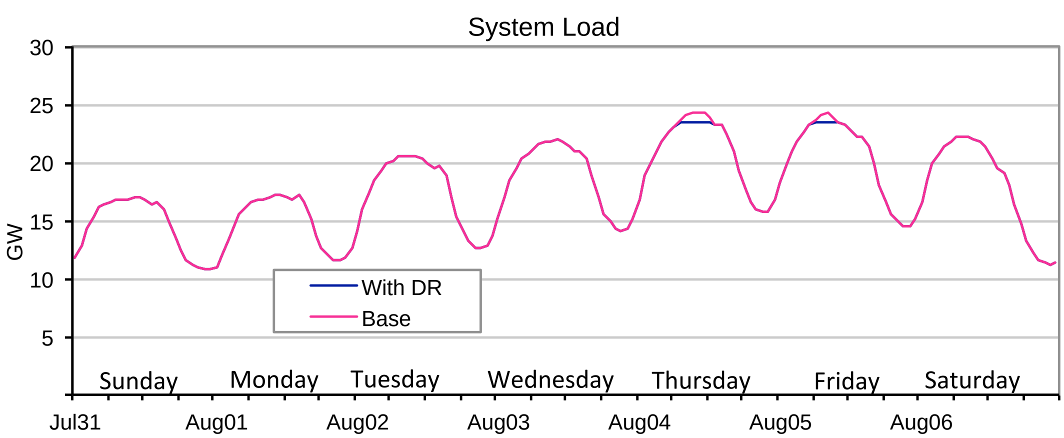


Figure 9. Energy load shape under the "demand response smart case" scenario (NEWE region, August 1–August 6).

In practical terms, the actual response of DR will be more complex than either of these methods. The notch method does not capture peaks outside of its summertime block, such as winter mornings or high demands after 6:00 p.m. The smart DR assumes that DR resources are flexible enough to precisely shave

[1] The ORNL NADR model is a modified version of the FERC NADR model (FERC 2009) and is more fully described in (Baek et al. 2012).

the peak demands and in some hours calls on more capacity reductions than are available. (To examine this, a "constrained" BAU scenario was added such that the DR in any hour could not exceed the ORNL-NADR–calculated amount, even if it was only called upon for a few hours. The other DR scenarios are not affected by this problem.) In none of the cases are the DR resources adjusted based on supply changes such as outages from power plants.

3.2.3 Export and Import Modifications

A feature of the demand calculations is the capability to add or subtract interregional electricity trades. Data on the hourly in-flows or out-flows are not readily available from NEMS results. Instead, the total amount of trading over a year can be estimated. For example, the NEMS model reports both the total net energy load for a region and the total production. The difference is the net trading in or out over the year. In reality, this trading is not a constant amount for every hour, nor is it a constant fraction of overall demand. Often, trading is most heavy when demands are neither at the peak (when lines are already fully loaded to meet local demand) nor at the minimum (when all regions have low-cost baseload plants available). A simple algorithm was added to demand that lets the user specify the ratio of the megawatts traded at the demand peak and demand minimum, as compared to the megawatts at the midpoint of demands. A value of 100% for both the peak and minimum will set the trading to be a constant value over all hours, while a value of 0% will reduce trading to zero at the extremes and raise the amount at the midpoint so that total energy traded matches the amount from NEMS. The traded amounts are added to the base hourly demands before changes such as PHEV charging are added. This keeps the scenario amounts of change distinct from trading amounts.

3.3 CONVERSION TO LOAD DURATION CURVE

3.3.1 Seasons

As shown in Figure 4, the year is broken into three seasons for the analysis. While the months assigned to each season can be changed, they are currently set as June–September for summer and December–February for winter, with the other 5 months categorized as off-peak. The off-peak "season" is longer because power plants are treated somewhat differently during this season, having their capacities derated for planned outages. This is discussed more fully in a later section.

3.3.2 Histograms

The minimum and maximum demand level in megawatts for each season is found in the Demand workbook. The difference between them is then separated into 200 equally spaced bins to create a histogram. The number of times the hourly demand is between any of these two points is collected and summed. For example, of the 2,928 hours in the summer season, there may be 22 hours between 76,239 MW and 76,589 MW and similar amounts between each of the other 200 bins. The peak bin, from 123,197 MW to 123,547 MW, will have at least the peak point and maybe a few other hours within it.

A cumulative curve can be calculated by summing the number of hours from highest demand to lowest. The first bin will only have the number of hours within it. The second bin will have the sum of the first and second bins. Each subsequent cumulative bin will increase until the last bin has 2,928 hours (for summer). Dividing the sum for each bin by 2,928 will create the LDC that shows the percentage of time that demand equaled or exceeded a given power level. Figure 10 shows the curves for each season in the example system. During the summer season, demand exceeded 100 GW 17% of the time, but only 2% of the time during the winter season. Demand exceeded 80 GW roughly 60% of the time in both the summer and winter seasons and 18% of the off-peak season.

The shape of the LDC tells much about the system characteristics. A summer-peaking system will have the highest points during that season, but not all points will be above those of the other systems. In the example above, the base loads during the winter season are higher than the summer base loads. The steepness of the curve indicates the system's load factor, the ratio of the average load to the peak load. Flat curves indicate a high load factor, meaning that plant use will be relatively even. Steep curves will mean that many plants will be used for only a small fraction of the season.

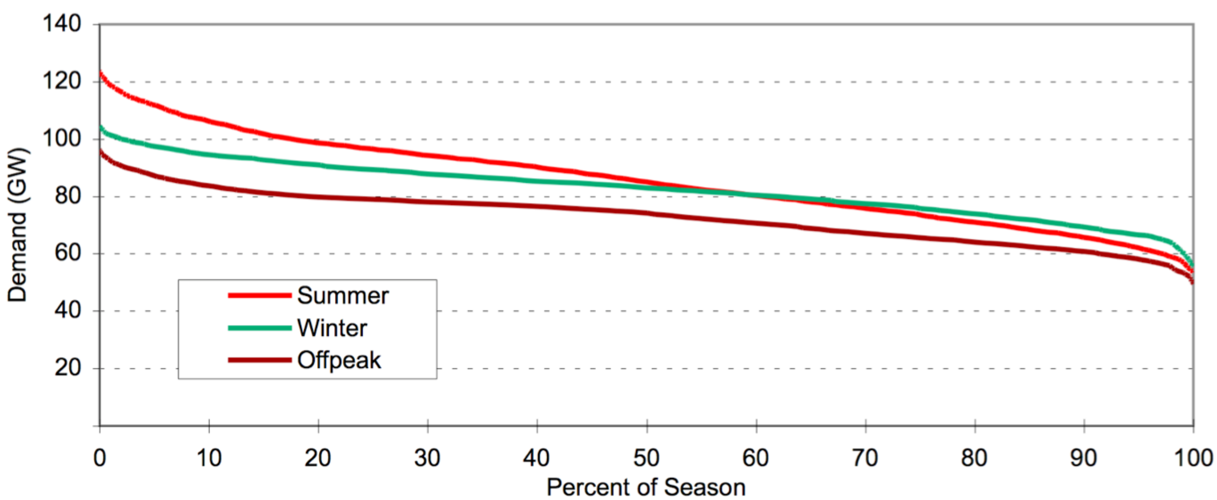


Figure 10. Load duration curve for ECAR in 2020 with no PHEVs.

3.3.3 Optimization

The LDC for each season has been defined using 200 points. However, the Dispatch workbook uses a simpler 12-point, 11–line segment model to reduce the computation time requirements. The 11–line segment model is produced using the Excel Solver function to fit points to the lines while minimizing the variance and keeping the total production constant. The result will usually place more of the points where the curve bends rather than having them all equidistant (Figure 11).

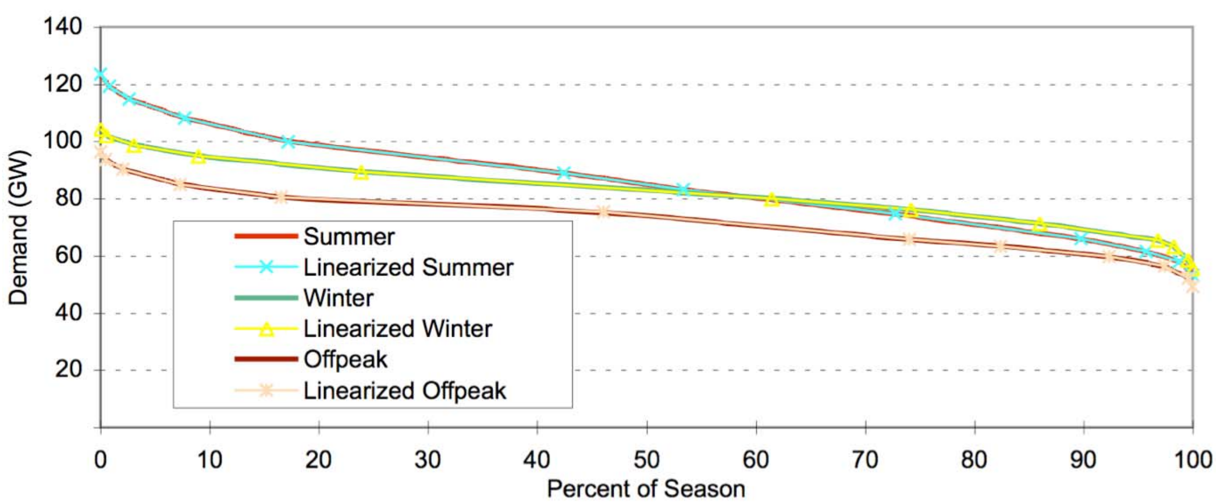


Figure 11. Load duration curves for ECAR in 2020 with linearized line segments showing the match to the original lines.

The Solver solution may need to be run several times. Macros have been created in the workbook to automate the calculation of the segment curves for one or more seasons. The objective function to be minimized is the variance between the 200-point curve and the 12-point linearized curve, plus the difference in total load described by each curve. This latter constraint forces the linearized curve to have the same demand as the original 200-point curve. After the Solver runs, the last point on the curve (at 100%) is raised or lower so that the total energy is the same for both. The Solver can get trapped into solving for local optima and does not reach the lowest variance value, so the calculation may need repeating until the user is satisfied.

Figure 12 shows the change in LDC with the addition of PHEVs charging at three different power levels. At the low power levels (1.4 kW and 2 kW), most demand increases occur in the middle of the night during the low power fraction of the season, the right side of the curve. The higher power scenario will charge the batteries faster but means more hours will have power levels in the evening, the middle portion of the LDC. None of the demand occurs during the peak of the season, reflected by the points being zero at the left side of the curve. The curves are somewhat jagged because they show the difference between the curves after being linearized to 12 points. The additional demand is small compared to the overall demand, and optimization can move points somewhat. Taking the difference between curves shows off this difference.

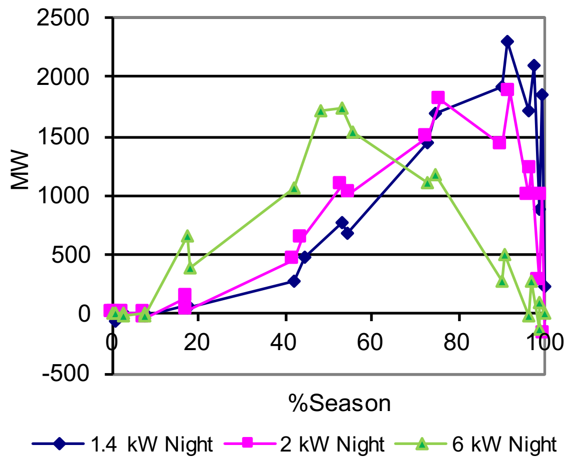


Figure 12. Addition of night charging of plug-in hybrid electric vehicles to the ECAR 2020 summer season load duration curve.

When demands are added or subtracted, the shape of the curves will change. A constant megawatt increase or decrease (such as 100 MW of distributed power at all hours) will raise or lower the curve equally at all points. A percentage decrease (such as a 4% efficiency savings) will lower the higher demand levels more, flattening the curve. Demand changes at specified hours will change the shape of the curve depending on whether the changes are during peak or off-peak hours. For example, one study examined increasing the power level of PHEVs while still having them charge only at night.

3.4 STORAGE OF RESULTS

The result of the linearizing operation is three 12-point lines defining the LDCs for each season. In addition, descriptive information on the scenario inputs, the total demand and variance of the curve can be useful for identification and future use. These are copied to a separate worksheet to be used in the Dispatch workbook. Multiple demand scenarios can be stored covering changes in demands for the 22 regions of the country.

4. SUPPLIES

To get a full picture of a region's power situation, both supply and demand must be characterized. Supplies must include all of the power plants in the region; plants outside the region are treated as a change in demand (described in Chapter 3.2.3). Some studies use a constant set of plants while other studies have focused on the effect of changing power plant types and capacities.

The ORCED model can dispatch up to 200 power plant groups. To simulate the actual generation supply in a region, it is necessary to aggregate or "bin" all of the plants available into 200 or fewer bins that capture the representative values of key parameters for the plants. These are then fed to the Dispatch workbook for analysis. Energy-limited hydroelectric and pumped storage plants are modeled separately from the 200 dispatchable plant groups.

4.1 POWER PLANT LIST

Several publicly available lists of plants, as well as proprietary lists, have been used for different ORCED studies. The most frequently used list for ORNL studies comes from EIA's NEMS. Personnel at EIA attempt to keep this list up to date for their numerous studies. Other datasets that have been used include the EPA eGRID and National Electric Energy Data System databases, as well as proprietary datasets from commercial firms.

The input file to NEMS includes a list of 18,570 generating units in the country. This list contains a large number of parameters for each unit, including nameplate, summer and winter capacity, heat rate, generating technology, fuel type (up to three), emission rates for NO_X and SO_2, operating costs, and age. A large Plant List workbook is created that contains all of the generating units. The data taken from the NEMS data file for sorting and binning are shown in Table 1.

Table 1. Variables from the National Energy Modeling System database used for aggregating units[a]

Plant ID	Name Plate Capacity	Fuel Code (1, 2, 3)
Unit ID	Summer Capacity	Fuel Share (1, 2, 3)
Plant Name	Winter Capacity	Fixed O&M Cost ($/kW)
Company ID	Average Heat Rate	Variable O&M Cost ($/MWh
Ownership Type	Online Year	Percent Sold to Grid
Must Run Code	Online Month	NO_X Emission Rate (lb/MBtu)
Region Code for Plant Location	Retire Year	NO_X Controls (Ctrls) Flags
State Abbreviation for Plant Location	Retire Month	NO_X Ctrls—Overnight Cost
Census Region Number	Scrubber Efficiency for SO_2	NO_X Ctrls—Fixed O&M
EFD Plant Type	Average Capacity Factor	NO_X Ctrls—Variable O&M
	Monthly Capacity Factor (1–12)	NO_X Ctrls—Reduction Factor

[a] Acronyms: ID = identifier, O&M = operations and maintenance, and EFD = electricity fuel dispatch

To supplement the list of generating units, data are needed on forced and planned outage rates (FORs and PORs), fuel costs, and emission credit prices. Outage rates can be found either from NEMS input files (e.g., pltdata.v1.148.txt) or from the annual NERC Generating Availability Report (GAR) (NERC 2011). Some of the proprietary datasets include plant-specific outage data.

Fuel costs are not specified as they will vary by year and type of fuel. However, fuel cost per million British thermal units (MBtu, sometimes referred to as mmBtu) for each region and year is an output of NEMS and can be used to approximate the fuel costs for each plant. Past studies have used plant-specific fuel costs from other sources, but these can sometimes be misleading if a single plant has multiple units that use different fuels. Also, historical prices may be dependent on preexisting fuel contracts that may not be applicable in future years.

Besides the list of current and planned units, the NEMS model calculates the amount of additional unplanned capacity needed for each region and simulates the construction of this capacity. Output tables show the amount of unplanned capacity added. These amounts can be converted to a set number of generating units based on standard sizes within the Plant List workbook. The plant parameters of heat rate, emissions, operating cost, etc. for these plants can be found from NEMS input files or the output tables.

Some of the studies with ORCED have used the model to find the optimum amount of capacity for a region. In these cases, an initial set of plants is input, including generic values for unplanned capacity. The model is then allowed to vary the capacity of the different plants to find an optimum for a given objective function. Existing plants could only go down in capacity (retired) while either more or fewer new plants were built.

4.2 SORTING AND BINNING

The existing, planned, and unplanned units for the country are calculated and consolidated into a single table in the Plant List workbook. This list is copied from the Plant Separator workbook to the Supply workbook for further sorting and binning. In Supply, macros are used to sort the list by a combination of region, plant type, fuel, and variable cost.

Variable cost is found by calculating the generation, energy input, and emissions for the unit. The generation is found by multiplying the capacity by the capacity factors found in the NEMS database. Because units can have different capacities in the summer and winter, the monthly capacity factors are applied to the appropriate capacity. Multiplying the generation for a unit by its average heat rate determines the amount of energy used in million British thermal units (MBtu, sometimes referred to as mmBtu). Fuel costs and emissions can be found by applying the appropriate rates to the amount of energy consumed. Similarly, total variable costs, including emissions credits, can be calculated.

The resulting variable cost is converted to cents per kilowatt hour for sorting within a specific plant type and fuel category. In some cases, additional sorting criteria are used. For example, one study needed to keep track of the location of major units, so the state and county codes were included in the sorting for nuclear plants or plants with large NO_X emissions.

After sorting, the units are assigned to one of up to 200 plant groups used in the dispatch routines. The approximate number of bins for each plant fuel and technology is found by dividing the total capacity for that group by a user-selected average size. This value can be raised or lowered to get the total number of plant groups below 200. For example, if there is 3,000 MW of combustion turbine (CT) capacity and the average plant group size is entered as 200 MW, then the model will initially create 15 bins. The units are then placed in each bin in increasing variable cost. If a single unit is over 200 MW in size, one bin may get completely skipped. Similarly, if two units are at the same plant site, such as a unit 1 and unit 2, then both will be put in the same bin. As a result, what began as 15 bins for that fuel type and technology, could end with only eight or nine plant groups, with individual plant group sizes ranging from 50 MW to 350 MW, or higher.

The results of such an assignment are shown in Figure 13. First shown are the oil-fired plant groups: steam, then turbine. Next are the gas-fired plant groups: steam, turbine, and combined cycle. Renewable fuels are plant groups 130–150. These are largely biomass and municipal solid waste plants in this region. Coal plant groups follow (not many in New England). The must-run plant groups contain a variety of cogeneration plants that are not dispatchable. Next are four nuclear plants in the region. There are empty slots in plant groups 195–200. Plant group 201 is the hydroelectric capacity of the region, while plant group 202 is the pumped storage capacity. Every region will follow this lineup of plant groups, but of course will have a different proportion of the various plant types.

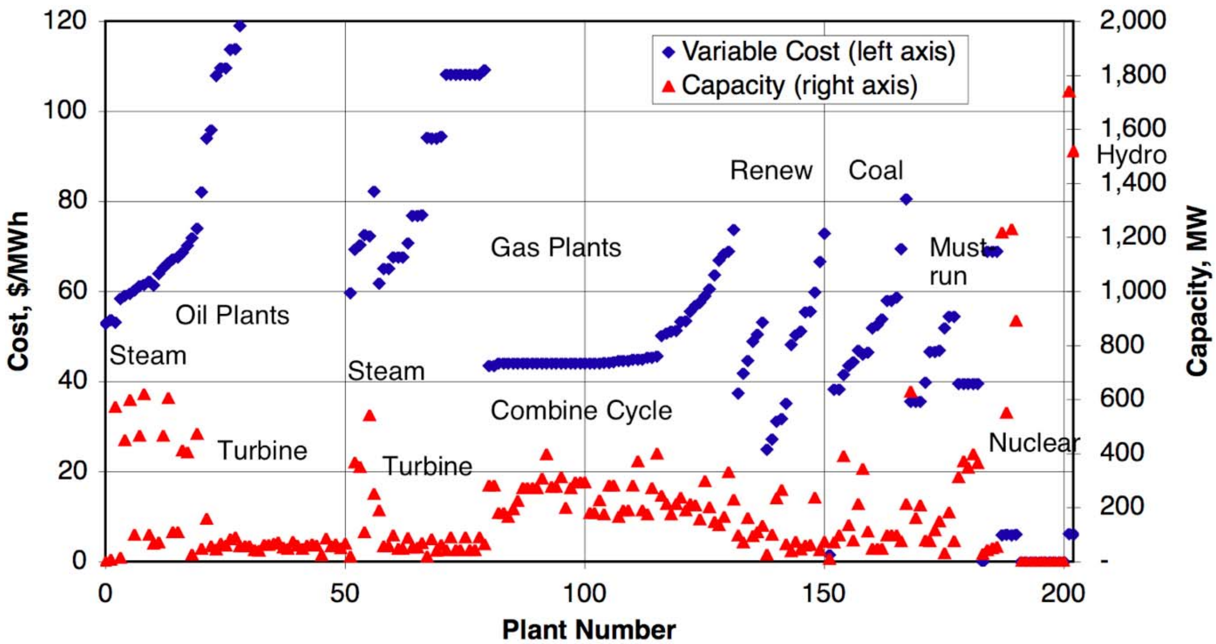


Figure 13. New England power plant aggregation for 2020.

4.3 CALCULATION OF AGGREGATED VARIABLES

Once the power plant units have been aggregated into the ~200 simulated plant groups, the weighted average key variables can be calculated. For variable factors [fuel, emissions, heat rate, variable operations and maintenance (O&M)] the weighting factor used is the expected amount of generation. For capacity-related factors (fixed O&M, capital cost, age) the nameplate capacity of each individual unit is the weighting factor.

Table 2 shows a simplified example of combining several units into a single plant group. The resulting averaged factors are shown in Table 3. These values are for plant group 120 in Figure 13.

Table 2. Aggregation of several combined cycle units into a single plant group[a]

Unit	Capacity (MW)	Generation (GWh)	Energy (TBtu)	Fuel Cost ($M)	Variable Cost ($M)	Fixed Cost ($M)	NO_X (Tons)	SO_2 (Tons)
Plant1-Gen2	31	158	1.29	7.6	0.4	0.1	162	0.4
Plant2-Gen3	80	342	2.81	16.6	0.8	0.4	354	0.8
Plant3-Gen1	127	865	7.18	42.4	2.0	0.6	662	2.1
Total	238	1364	11.28	66.7	3.2	1.1	1178	3.3

Table 3. Calculated key variables for example combined cycle plant group[a]

Plant	Capacity (MW)	Heat Rate (Btu/kWh)	Fuel (¢/kWh)	Var O&M (¢/kWh)	Fixed O&M ($/kWyear)	NO_X (lb/MBtu)	SO_2 (lb/MBtu)
Gas CC-49	238	8268	4.89	0.23	4.74	0.209	0.001

[a]Abbreviations and acronyms: Var = variable, O&M = operations and maintenance, and CC = combined cycle.

The FORs and PORs for the plants require some additional calculations and data. The NERC GAR (NERC 2011) provides a variety of national generating statistics by plant type, size, and fuel. These can be converted to provide a FOR (the percentage of time the plant will not be available on a random basis) and POR (the percentage of time the plant is scheduled to not be available). Some plant types are not available from the GAR; for these, the NEMS input data on FORs and PORs for new plants are used.

The NEMS database includes a monthly capacity factor for each unit. For dispatched units, the factors are likely lower than the availability factor (1 – FOR – POR); however, for non-dispatchable plants such as must-run and intermittent plants, these values can be used to calculate equivalent FORs and PORs. In some cases, such as intermittents with higher availability in the off-peak season, the equivalent planned outage can actually be negative to counteract the higher FOR used for the winter and off-peak seasons.

4.4 STORAGE OF RESULTS

The resulting table of plant groups, with key modeling parameters, is passed to the ORCED Dispatch workbook. There are three main ranges that need to be copied from Supply to Dispatch. One, called ORCEDInput, contains the 202 plant groups. The second range is FuelCost, the average fuel costs for the six different fuels. The last is the SO_2 and NO_X credit costs for the region being studied.

Depending on the analysis, it is sometimes helpful to store the three ranges in an intermediate file to make replication of results easier. The tables are copied from the Supply workbook to either the Dispatch workbook or the intermediate file. Multiple Supply results, either variations for a single region or separate parameters for each region, are then kept in the Dispatch workbook, and a flag can be used to select the correct set of data.

Some studies have called for analyzing changes in the amount of supply, either by retiring plants or adding new plants. For example, an early study examined generation adequacy by determining the optimal amount of capacity to reduce overall costs. By setting the number of plant groups to less than 200, empty slots are available for adding plant groups as needed during the analysis.

5. DISPATCH

Once data on supply and demand are made available, the model dispatches plant groups to meet the demand. The steps involved begin with altering the LDCs for hydroelectric and pumped storage production. It then proceeds to dispatch the plants for each season using a modified Balleriaux-Booth procedure. Details on the underlying method can be found in Vardi’s textbook (Vardi and Avi-Ithak 1981) Unserved energy calculations follow. The amount of generation by each plant is then calculated. Lastly, time-dependent prices and revenues are calculated. The seasonal results are then combined for a yearly result. Emissions and other financial parameters are calculated last. The results are stored so that comparisons between cases can easily be done.

Beyond these basic calculations, some ORCED studies have added capabilities. The 1998 study on California and the Pacific Northwest under a restructured market (Hadley and Hirst 1998a) used a version that modeled each region separately and then traded between them over a limited connection. The 2001 study on Oklahoma restructuring (Hadley et al 2001a and 2001b) disaggregated demands into residential, commercial, and industrial sectors and calculated regulated and unregulated electricity prices for each. The 2003 study on DG (Hadley, Van Dyke, and Stovall 2003) added a calculation on the amount of reserve power needed at each point in time and the consequent reserves price. This was reformulated in the most recent version, described below. Early studies on generation adequacy put the model into optimization mode so that plants could be added or retired to minimize avoidable costs depending on the short-term and long-term elasticity of demand.

5.1 BASIC DISPATCHING THEORY

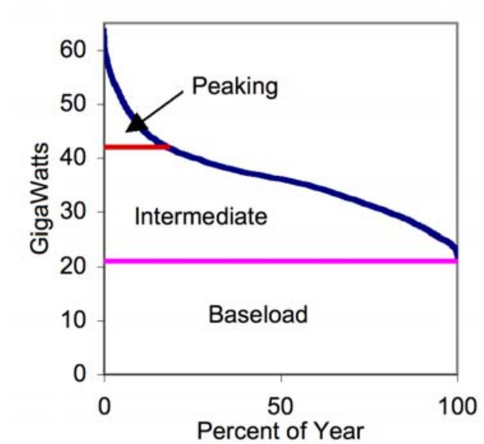


Figure 14. Load duration curve and different power plant classes.

Because demand fluctuates over the year, some plants will be called on more often than others, and any power system will have a mix of supply types. Figure 14 shows an example of the LDC for a region and the types of plants that are used to fulfill those demands. Some plants are most effective at providing power essentially all the time (baseload power). They typically have low variable costs but may have high fixed costs. Their low variable costs translate into low bid prices or marginal costs, while the fixed costs are best paid for by being spread over a large number of sales. Intermediate or "load-following" plants are called on to come on a significant fraction of the year but will still cycle on and off. Peaking plants are called on the least frequently, during high demand times or to meet capacity emergencies. They have the highest marginal costs but typically have low fixed costs, either because of their low-cost technology or because they are old, fully depreciated plants.

5.2 HYDROELECTRIC DISPATCH CALCULATION

Hydroelectric plants are typically energy limited rather than capacity limited. There is only so much water upstream that can be used for generation. As a consequence, dispatch optimizations calls for hydropower to be used to the extent possible to replace the production from the highest cost, peaking plants. The easiest way to simulate this is to lower the LDC near the top by the capacity of the hydroelectric plants and to extend this reduction to higher percentages of the year until the full energy available from the plant is consumed. This is shown in Figure 15. California in 2020 has in the model 10.8 GW of hydropower in the summer, with a capacity factor of 44%. The hydropower generation is equal to the area between the blue and pink lines. The LDC between 0% and 20% of the season is reduced by the full capacity of the generation. However, the points at 35% of the season and higher cannot be lowered by the full capacity because of the lack of water for generation. The end result is that hydropower displaces the higher cost peaking and intermediate plants. A portion of the hydroelectric capacity can be represented as just another plant group in the list of 200 groups. Its generation and capacity must be subtracted and new capacity factors calculated for the energy limited hydropower so that total hydroelectric generation remains the same.

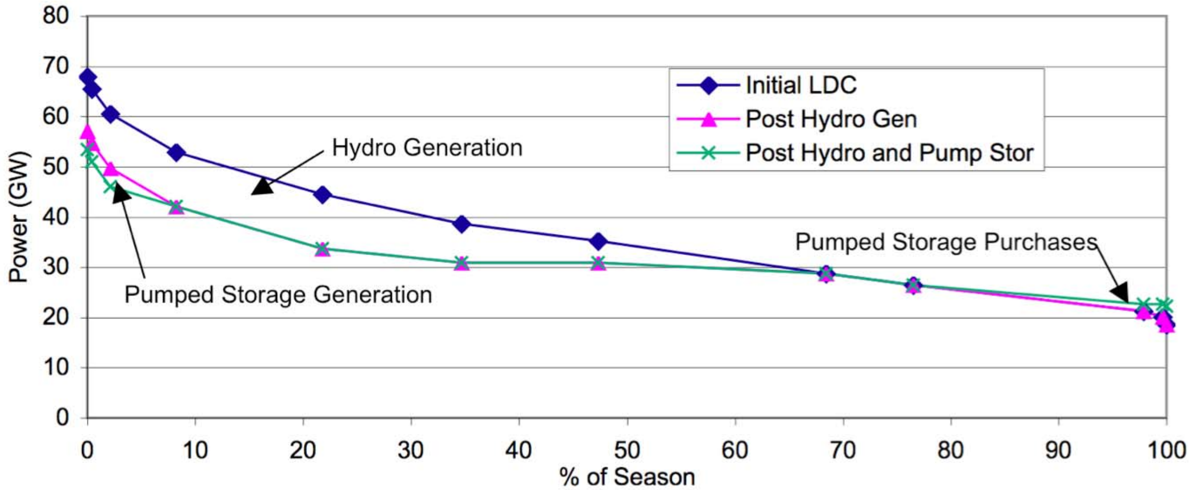


Figure 15. Load duration curve (LDC) changes due to hydroelectric (hydro) generation (California, 2020 summer).

The dispatch model calculates the new LDC by first dropping the first point by the hydroelectric capacity or to the power level of the second point. It calculates the resulting hydroelectric generation and compares it to the total available. If more is available, it will then drop both the first and second points by the capacity or to the level of the third point, recalculate the generation, and compare it to the total. The model continues dropping the subsequent points in the LDC until the area between the two curves matches the amount of hydropower available.

Pumped storage capacity is calculated similarly, but in addition to lowering the peak of the LDC, it will also raise the lowest portions to represent the amount of electricity purchased from the grid to supply the peak portion (Figure 16). California in 2020 is estimated to have 3,700 MW of pumped storage with a 5% capacity factor. The LDC post-hydroelectric generation in Figure 15 is further lowered by the capacity and generation available (on the left side of the figure.) The amount of electricity needed is determined and the points on the right side of the LDC are raised. The amount these points are raised is constrained by the requirement that the LDC must be either flat or declining. An efficiency factor can be used so that more power will be purchased than is sold to allow for losses in the pumping system. The remaining 200 plants will be dispatched against the post-hydroelectric and pump storage LDC.

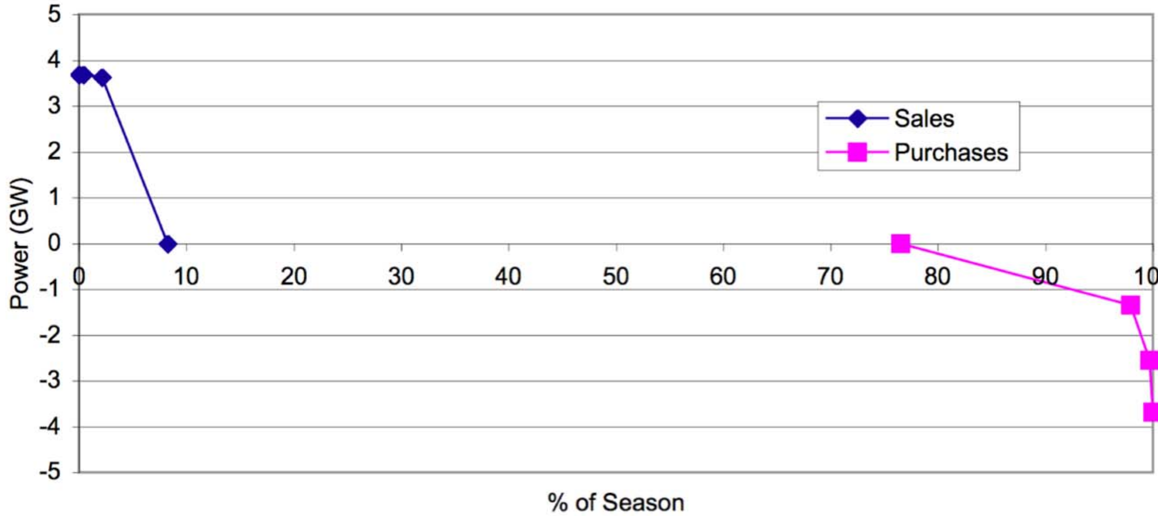


Figure 16. Sales and purchases of electricity for pumped storage (California, 2020 summer).

The result of this operation is that power is purchased at low demand, low cost times and used during high cost times. Because power prices are calculated throughout the season (described later), the revenues and costs of the power can be determined and profitability of the pumped storage measured. Similarly, revenues for hydroelectric production can be calculated to determine financial factors.

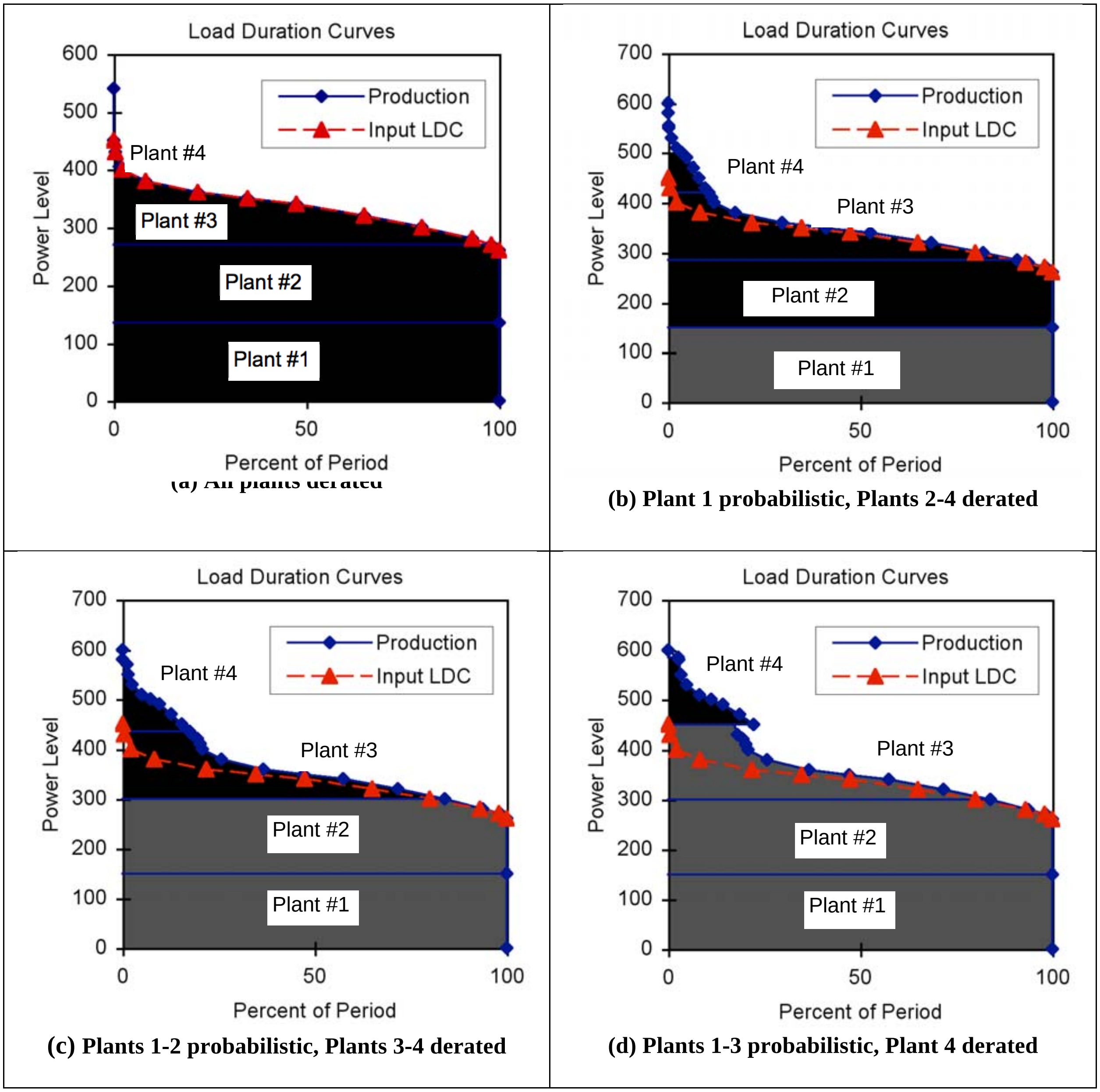
5.3 PLANT DISPATCH METHOD

For each season, the 200 plants from the Supply workbook are sorted in order of increasing variable cost in the Dispatch workbook. The order may be different in each season because some costs (e.g., NO_X emission credits) might only be added to the summer season, depending on the scenario. The power capacities must be adjusted for planned and forced outages.

There are two ways to treat forced outages: probabilistically or through capacity deratings. Probabilistic treatment provides a more accurate mechanism but increases the calculation time exponentially as more plants are treated that way. The ORCED model allows the user to specify how many plants can be treated as such up to 25; typically 10 to 12 plants are specified.

If the power plant is treated probabilistically, its capacities in the summer and winter seasons are its input summer and winter capacities. If the plant is derated, the capacity is reduced by the input FOR.

The results of having an increasing number of plants treated probabilistically are shown in the series of LDCs in Figure 17. In this example, there are four plants of 150 MW each, with FORs of 10%. A simple LDC is shown in red with maximum demand at 450 MW. In the first graph, all plants are derated to 135 MW. The second graph shows the first plant at 150 MW but the others at 135 MW. The gray color represents that the plant is treated probabilistically. The third and fourth graphs show more of the plants probabilistically.



(a) All plants derated

(b) Plant 1 probabilistic, Plants 2-4 derated

(c) Plants 1-2 probabilistic, Plants 3-4 derated

(d) Plants 1-3 probabilistic, Plant 4 derated

Figure 17. Plant dispatch with 0 to 3 plants probabilistic: (a) all plants derated to 135 MW and (b) plant 1 at 150 MW and the others at 135 MW. Graphs (c) and (d) show more of the plants probabilistically.

Using the graph as an analogy, the total amount of ink inside of the area for a plant is equal to the generation. If the plant is derated, the maximum capacity is lowered, but the plant has no forced outages and so its area is totally black. On the other hand, if a plant is probabilistically treated, then it has the full capacity available but the ink is diffused and is represented by a level of gray. Note that in 17(c) and (d), Plant 4 is called upon much more than in 17(a) and (b). The total amount of energy is the same, but the relative amount of production from higher cost plants increases. Table 4 shows the production amounts for each of the examples in Figure 17, as well as the case with all plants probabilistic. Plant 1 is always baseloaded (running at 100%), but Plants 2 and 3 see slight reductions as demand is shifted to Plant 4 or not met at all (unserved energy).

Table 4. Production for Plants 1–4 and unserved energy with varying number of plants probabilistic

	No Probabilistic	1 Probabilistic	2 Probabilistic	3 Probabilistic	4 Probabilistic
Plant 1	135.0	135.0	135.0	135.0	135.0
Plant 2	134.9	134.1	132.3	132.4	132.3
Plant 3	63.6	58.2	55.4	52.1	52.0
Plant 4	0.3	6.5	10.3	12.7	11.8
Unserved	0.0	0.0	0.8	1.6	2.8
Total	**333.9**	**333.9**	**333.9**	**333.9**	**333.9**

With a high number of plants involved (e.g., 200 versus 4), the changes in production for the plants do not change significantly once the number of probabilistic plants increases past 10 or so (Figure 18). However, the calculation time roughly doubles for each additional plant, so while with 10 plants probabilistic the time to recalculate can be on the order of seconds, with 25 plants it takes overnight for a single run. While the figure shows little change overall, the most significant change is at the peak demand. In this example, with no plants probabilistic the last five plants are never dispatched, but at the higher probabilistic values, the plants may operate for several hours over the season.

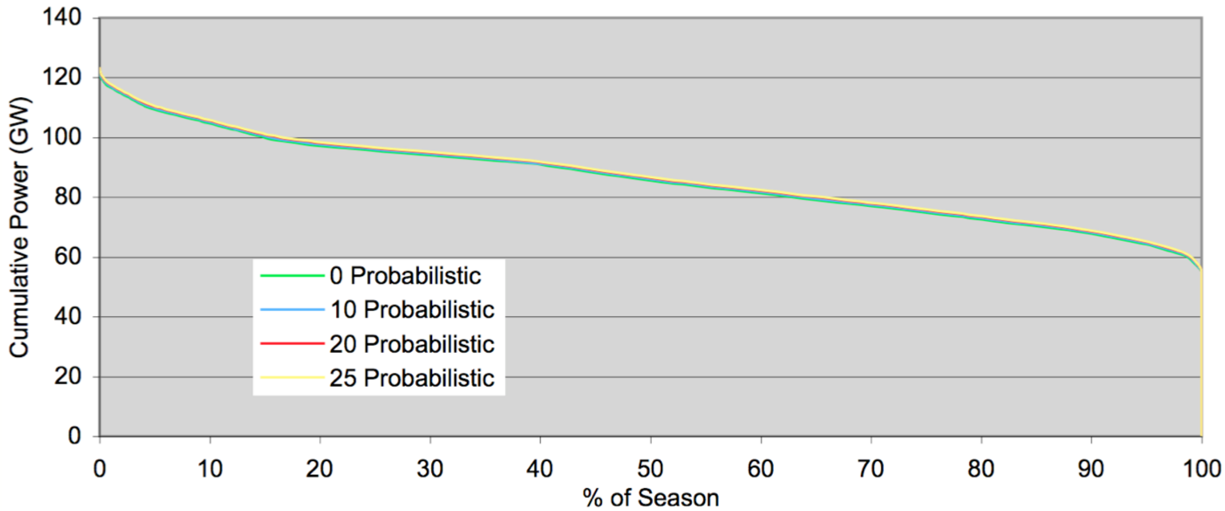


Figure 18. Load duration curves for plants dispatched in ECAR in summer 2020, with 0 to 25 plants treated probabilistically.

The model calculates up to 231 power levels (points along the y-axis) for which the plants are dispatched. These levels are determined by finding the cumulative capacity level as each plant is added to the loading order (giving 201 points). In addition, the LDC's 12 points, plus variations on the points by adding probabilistic plant capacities to them, give another 30 points.

The equations used to dispatch plants have the independent value as the power level (the y-axis in the figures) and the dependent value as the fraction of the season that plants are dispatched at that power level. The first plant starts out being dispatched for 100% of the season. For the simplest case, where none of the plant groups are treated probabilistically, the dispatch is a simple sum of the derated plant capacities to meet the power required for each point on the LDC. However, when any of the plant groups are treated in a probabilistic manner, the contribution from every other plant group depends on the likelihood of the probabilistic plants being online. To maximize the impact, typically the model selects plants at or near the bottom of the loading order for treating probabilistically. A set of recursive formulas is therefore used to solve for the percentage of time that each particular plant group is contributing toward the demand represented by the LDC. The bottom equation in the hierarchy is simply the percentage of time on the LDC as a function of the power level and is based on a linear interpolation between the 12 points that define the curve.

$$T_i(p) = (1 - F_i) \times T_{i-1}(p) + F_i \times T_{i-1}(p - C_i)$$

$$T_{i-1}(p) = (1 - F_{i-1}) \times T_{i-2}(p) + F_{i-1} \times T_{i-2}(p - C_{i-1})$$

$$\ldots$$

$$T_0 = LDC(p),$$

where

$T_i(p)$ = Time T (%) that demand plus outages would exceed power level p with *i* number of plants treated probablilistically,
i = the number of plants being treated probabilistically up to power level p,
p = power level,
F_i = forced outage rate for probabilistic plant i,
C_i = capacity of probabilistic plant i,
LDC(p) = the percentage of the season that the load duration curve equals power level p.

$T_i(p)$ is not a function of the plant that is operating at power level p. The parameter *i* does not represent the specific plant that T is being calculated for but rather the number of plants that are to be treated probabilistically up to the power level that is being analyzed. In the above example, if the maximum number of plants treated probabilistically is two, then for power levels between 0 and 150 MW (within the range of Plant 1), *i* would equal zero. Between 150 MW and 300 MW, *i* would equal one; above 300 MW *i* would equal two. Both Plants 3 and 4 would use *i* equal to two as neither is treated probabilistically.

For any plant, the only power levels p of interest and needing calculation are those when the plant is the marginal plant, meaning it is the highest in the loading order. The variable T will only need to be calculated during those power levels. For example, for Plant 2 in Figure 17, T is calculated for up to five different power levels, depending on whether Plant 1 and 2 are probabilistic or not (Table 5). If Plant 1 is not probabilistic (first two columns), then Plant 2 begins operation at 135 MW, and $T_0(135) = 100\%$. Then P is set to 260 MW, the lowest point on the LDC, and $T_0(260) = 100\%$. Finally, P is set to 270 MW (full derated capacity for Plants 1 and 2). $T_0(270)$ is found by linear interpolation on the LDC line segment to equal 98%.

Table 5. Time and power levels for Plant 2

0 Probabilistic		**1 Probabilistic**		**2 Probabilistic**	
P	T	P	T	P	T
135	100	150	100	150	100
260	100	260	100	260	100
270	98	270	98.2	270	98.2
		280	93.7	280	93.7
		285	90.8	300	82

With the first plant probabilistic (the second set of columns in Table 5), the first P is set to the un-derated capacity of Plant 1, 150 MW, and T_1=100%. Likewise, $T_1(260)$ = 100%. However, the next point is calculated recursively using the value for $T_0(270)$ calculated in the first 2 columns:

$$T_1(270) = (1 - 10\%) \times T_0(270) + 10\% \times T_0(270-150)$$

$$= 90\% \times 98\% + 10\% \times 100\% = 98.2\% \ .$$

The values for $T_1(280)$ and $T_1(285)$ are calculated similarly, giving 93.7% and 90.8%. The last power level, 285 MW, represents the cumulative capacity when Plant 1 is probabilistic (150 MW) and Plant 2 is derated (135 MW.) If Plant 2 is also probabilistic, then the cumulative capacity is 300 MW and $T_1(300)$ = 82%. Plant 3 then uses these numbers in the recursive formula as it is dispatched, followed by Plant 4.

To further explain the exponential growth of the calculations, Figure 19 shows the hierarchical tree to find T_3 for any power level of Plant 4. This calculation also applies to any other nonprobabilistic plants above Plant 4 if only three plants are probabilistic. Adding a fourth plant as probabilistic doubles this tree, first setting power equal to p and then power equal to $p - C_4$. Some shortcuts can be used when p (or its subordinates $p - C_i$, $p - C_i - C_{i-1}$, etc.) is below the lowest point of the LDC. On those branches T_i equals 100% and no further calculations are needed.

Figure 19. Recursive calculations to find the time T that demand plus outages would exceed power level p with three plants probabilistic.

To incorporate planned outages, the capacity available during the off-peak season is derated by an amount so that the total capacity available for the year reflects the reduction from the input annual FORs and PORs. In other words, planned outages are modeled to only occur during the off-peak season when demand is low, while the winter and summer seasons have capacity reduced solely by FOR. Because POR is based on annual generation, the calculation on the POR derating amount must start on the basis that the planned outages occur throughout the year, thus also accounting for summer and winter capacities that may be different. Total possible generation, G_{tot}, is found from the following equation:

$$G_{tot} = Cap_S \times (1 - FOR_S - POR) \times \%_S + Cap_W \times (1 - FOR_W - POR) \times (\%_W + \%_O)$$

$$G_{tot} = G_{Summer} + G_{Winter} + G_{Offpeak} \ ,$$

where

G	=	generation,
Cap	=	capacity,
FOR	=	forced outage rate for each season,
POR	=	planned outage rate,
%	=	percent of year for each season.

The summer and winter season calculations do not include POR; an equivalent Cap_O can be defined that assigns all the planned outages internally to that season.

$$G_{Summer} = Cap_S \times (1 - FOR_S)$$

$$G_{Winter} = Cap_W \times (1 - FOR_W)$$

$$G_{Offpeak} = Cap_O \times (1 - FOR_W)$$

The G_{tot} equations can then be rearranged to calculate Cap_O:

$$Cap_O = [Cap_W \times (1 - FOR_W) \times \%_O - POR \times (\%_O + \%_W)] - Cap_S \times POR \times \%_S)/(1-FOR_W)/\%_O \ .$$

As mentioned above, POR and FOR are calculated in the Supply worksheet and passed to the Dispatch workbook. The values can either reflect the typical operations of dispatchable plants or reflect the difference in operating capabilities in the off-peak season versus winter and summer seasons.

5.4 PLANT DISPATCH STACK

As mentioned above, the Supply workbook has room to model 200 power plant groups. These provide 200 power points from which to calculate the generation times within each season. In addition, another 30 points are added, including the 12 LDC points and the LDC plus the main plants that will be treated probabilistically. These latter are to catch the points when the final dispatch curve will have possible nonlinear slope changes. Calculating the times at these points will lessen any errors due to approximations.

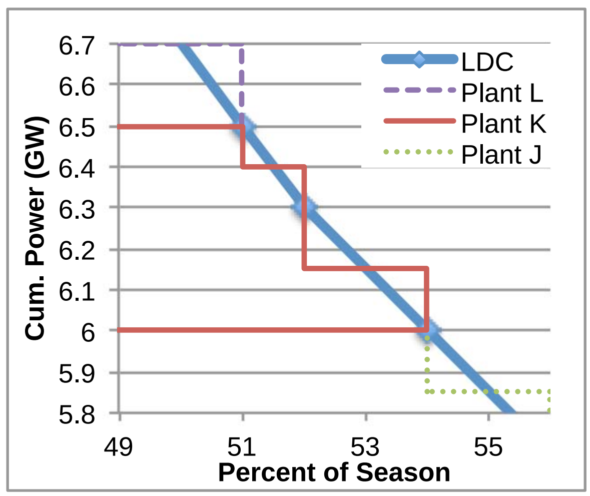


Figure 20. Plant dispatch detail.

Figure 20 is an expansion of one area of the LDC and the plants being dispatched to meet demand. In this example Plant K is 500 MW. It begins getting dispatched at 54% of the season where the cumulative capacity below it is 6 GW. It is fully dispatched at 51% and 6.5 GW. Besides the minimum and maximum points, there is also one of the 12 LDC points on the curve at 52%, 6.3 GW.

ORCED will simulate Plant K's operation by having it operate halfway between two adjacent points for the period of time between those two points. In this example, Plant K operates at 150 MW (6.15 GW cumulative) between 52% and 54% of the season. It operates at 400 MW (6.4 GW cumulative) between 51% and 52% and then runs at 500 MW (6.5 GW cumulative) for the remaining 51% of the season. Plant L operates at partial load beginning at 51%. If there hadn't been the extra point on the LDC at 52%, then Plant K would have operated at 250 MW between 51% and 54% of the season instead of the two steps in its dispatch. A vertical slice of the dispatch between 52% and 54% represents a fraction of the season where Plant K is operating at 30% of capacity (150 MW/500 MW) and all plants below it are operating at full capacity.

In this example, Plant K was not treated probabilistically. It may have actually had a capacity of 625 MW but a FOR of 20%, so derating caused it to be dispatched as a 500 MW plant available 100%. Alternatively, if it had been treated probabilistically then ORCED would shift the points above the plant on the LDC to the right. In such an example, Plant L might have started production at 51% or a similar value, but the cumulative power point would have been at 6.625 GW instead of 6.5 GW.

5.5 OPERATING RESERVES

An additional complication in real power systems is that some fraction of plants must be available for operating reserves in case of outages or unforeseen demand increases. To accomplish this, utilities will operate some of the plants that were not dispatched at a minimum level so they may be able to come online and provide power quickly. In addition, they may choose to run some of the dispatched plants at less than full capacity to have a fraction of their capacity available for reserves. The plants that are used will vary over the year depending on the demand level and the mix of plants that are operating or not yet called upon for energy. The amount of reserves required at any one step on the dispatch curve is an input fraction of demand (e.g., 7%).

To simulate a reserves provision, ORCED calculates the marginal cost of providing reserves from the plants that have not been dispatched based on their minimum operating levels, the variable costs to run at those levels, and the amount of reserves created by running the plants at minimum levels. For example, a 100 MW gas combustion turbine may have a marginal cost of \$50/MWh and a minimum operating level of 20 MW. Because it can ramp relatively quickly, it could provide 80 MW of reserves. The plant would be paid the market price for its generation. If the market price for energy is \$30/MWh, then the consequent cost of those reserves would be

$$(\$50/\text{MWh} - \$30/\text{MWh}) \times 20\ \text{MWh}/80\ \text{MWh} = \$5/\text{MWh} \ .$$

Other plants may have higher minimums and less ability to provide reserves. Or their marginal costs may be closer to the marginal price for that period. All plants would have a marginal price equal to or higher than the market rate or they would have been dispatched.

The model then reorders all the plants that have not yet been dispatched in that segment from lowest reserve cost to highest. ORCED will have the plants with a minimum operating level to generate that amount. As a consequence, it will lower the production of the most expensive plants that were dispatched so that total generation remains the same. This means that the plants that have reduced production can also provide reserves and contribute to the total.

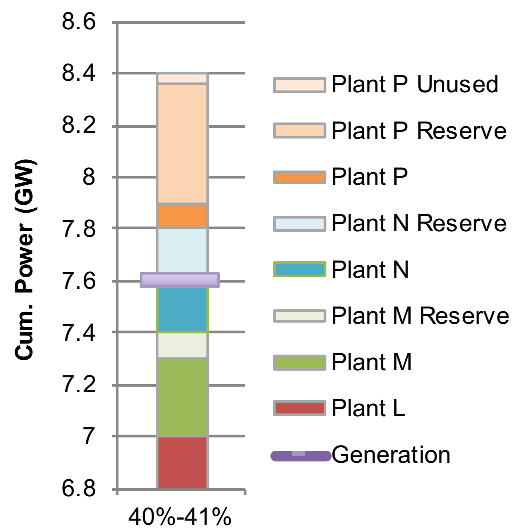


Figure 21. Operating reserves during one part of the load duration curve.

Figure 21 shows the calculation for a single slice of the dispatch curve. Total demand and hence generation equals 7.6 GW, and Plant N (400 MW) is at 50% capacity. Assuming a 10% operating reserve, the system needs 760 MW. The remainder of Plant N provides 200 MW. Plant P (600 MW) can provide 500 MW but has a minimum operating level of 100 MW. Consequently, Plant M must reduce by 100 MW and so also supplies 100 MW of reserves. The three plants combined can provide 800 MW of reserves, but only 760 MW are needed, so 40 MW from Plant P are unused.

5.6 PRICING

At any point in time, whatever plant is the last plant being dispatched is considered as being “on the margin.” In a deregulated market, its variable cost of production would set the wholesale market price for power for itself and all plants lower in the dispatch order. So in the example in Figure 17 with one plant probabilistic, Plant 2 would set the price between the 100% and 90.8% points. It would receive its variable cost for the power it sells. Plant 1 would be infra-marginal; it would earn more than its variable cost during this time. Plant 3 would be on the margin between 10.7% and 90.8% of the season, so Plants 1 and 2 would receive the variable cost price of Plant 3 during this fraction of the year. As a further example, Figure 22 shows the dispatch of plants in the PJM region from a recent study (Hadley and Tsvetkova 2008).

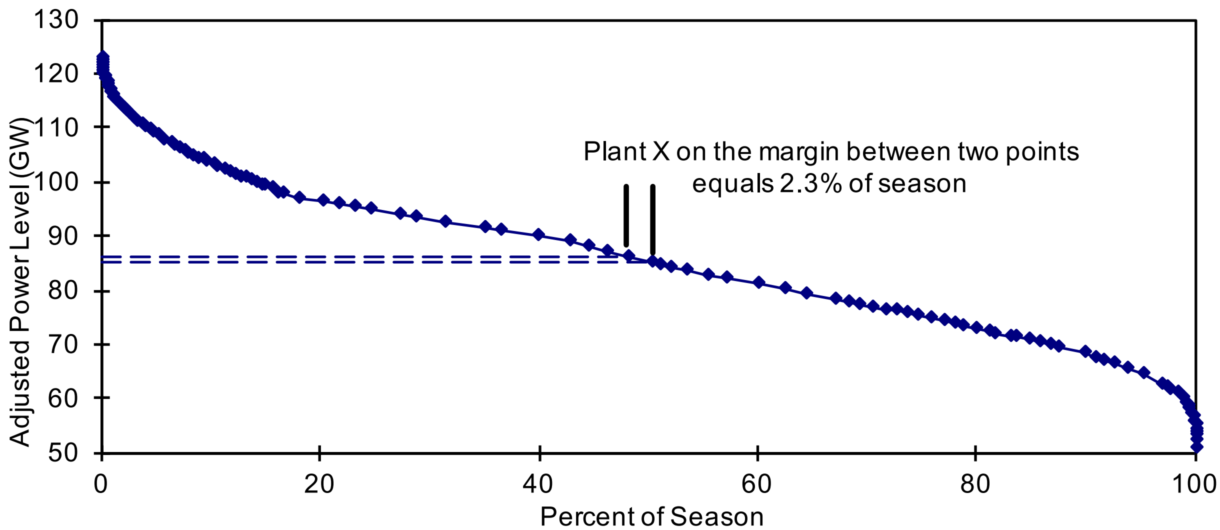


Figure 22. Dispatch of plants in the PJM region showing plant production amounts and marginal time.

ORCED has the capability for a plant to use a price other than its variable cost for its bid price into the market. By default, ORCED sets the price of "must-run" and intermittent plants to zero so that they are always called upon. However, their FORs will lower their available production so that their capacity factors match their defined amounts. As another option, a plant's revenues can be based on its variable costs, fixed costs, depreciation, taxes, and allowed rate of return. This mimics the revenues received if the plant is regulated.

Reserves prices are also calculated for each segment of the dispatch curve. Because plants that are above the marginal plant and run at their minimum level have higher costs than the marginal energy price, they will lose money on that generation. Their reserve price bids are based on the difference between their marginal costs and the system energy price, as shown in the equation in Sect. 5.5. Those plants that have to reduce production to make room for other plants' minimum production will lose revenue on those lost sales. Their consequent reserve bid price will be the difference between the marginal generation price and their variable costs. ORCED evaluates the reserve bid prices of all plants that provide reserves during a slice of the dispatch curve and sets the overall reserve price for that period at the highest reserve price, the "market-clearing" reserve price. Those plants providing reserves will then receive revenues based on that price and the reserves supplied.

5.7 UNSERVED ENERGY

When there are not enough plants to meet all of the demand, then some power is "unserved." Even with the last plant at full power, T_i will be greater than zero. This value is the loss of load probability (LOLP). The LDC can be calculated for the additional power points to measure the amount of energy that is unserved (Figure 23). As with plant dispatching, this curve is dependent on the number of probabilistic plants. The model uses 12 power points for which to calculate T_i. The top point is equal to the peak demand plus the capacity of all of the probabilistic plants and by definition has a T_i of zero. The bottom point is the total capacity available with a T_i equal to LOLP as mentioned above. Intermediate points are simply fractional values between the top and bottom to define the curve.

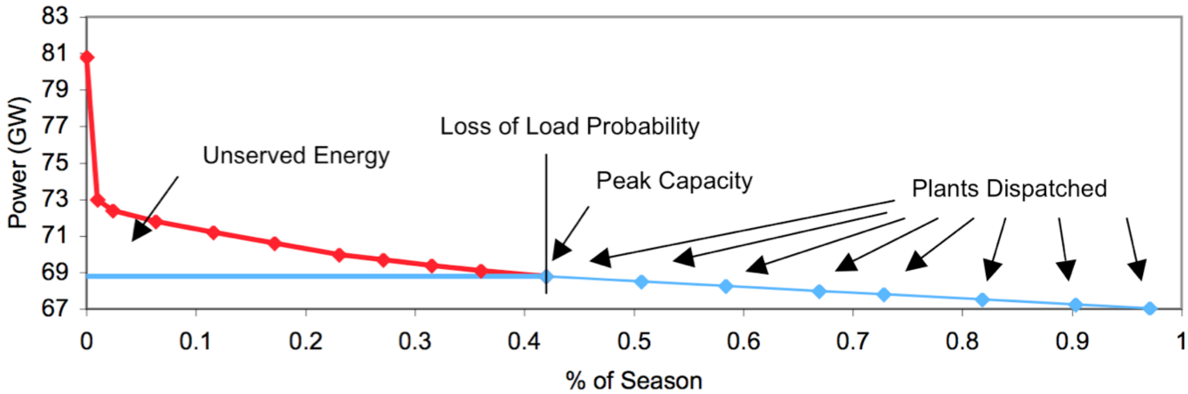


Figure 23. Loss of load probability and unserved energy calculation. Unserved energy is the area between the peak capacity and the load duration curve.

In the example shown in Figure 23, total capacity (excluding hydroelectric) equals 68.8 GW, but demand rises above that level at 0.42% of the season. This represents more than 12 hours during the season where demand exceeds supply. Multiplying the percentage by 3,650 gives an LOLP of 15 days per 10 years. This curve is from a summer season, so the yearly value would be offset by the lower probabilities in the off-peak and winter seasons.

From the unserved energy LDC the model calculates a price at each point that would lower demand to the level of the peak capacity. It does this using an input price elasticity factor, typically –0.05. This value means that a 100% increase in price will lower demand 5%.

5.8 START-UP COSTS

Most power plants have an added cost to start up. This is often in terms of dollars per megawatt, so as the length of time the plant operates increases, the cost per megawatt-hour declines. However, if the plants typically operate for a few hours between start-ups, this cost can be a significant add-on to their variable costs. The original ORCED model only added a surcharge to the prices and variable costs of plants with capacity factors below 10% to account for the start-up costs. To gage the adequacy of this, an analysis of the results from a study on the hours of operation and start-up times was conducted using the LCG Consulting UPLAN model (Hadley 2011). This study showed that many plants in the load-following mode would start up daily, operate during the day, and then shut down at night. Plants with capacity factors up to 60% still had frequent enough start-ups to make a small difference in their variable costs.

In the study, a number of different scenarios were run that operated the power plants in the Southwest Power Pool region and Southeast as either separate or unified balancing areas. The UPLAN model reported the number of start-ups and capacity factors for each plant. As can be seen in Figure 24, there was a wide variation in the resulting values, but an overall trend line can be observed.

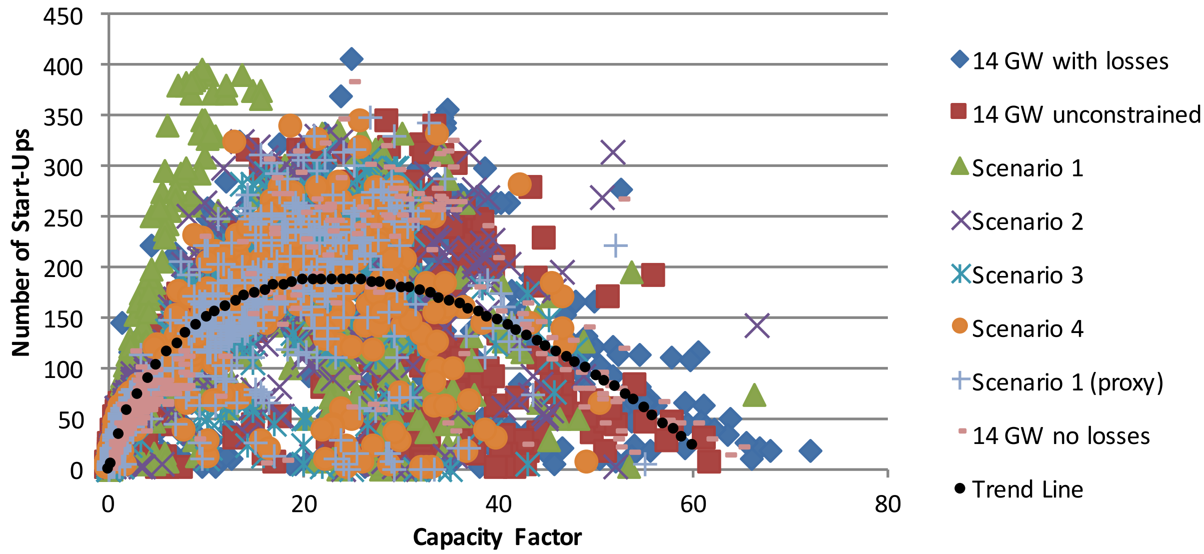


Figure 24. Number of start-ups (combined cycle + combustion turbine) versus capacity factor (Hadley 2011).

A trend line was calculated to find the number of start-ups as a function of the capacity factor using a logarithmic equation. Then the equation was converted to calculate the number of hours per start-up. Separately, ORCED has an input cost per start-up in dollars per megawatt per start-up. Dividing this value by the hours per start-up gives a cost per megawatt-hour.

$$P_x = S \times [-0.0429 - 0.0924 \times LN(CF_x)] \ ,$$

where

P	=	price addition for plant x, in dollars per megawatt-hour;
S	=	start-up cost used for all plants, in dollars per megawatt per start-up;
CF_x	=	capacity factor for plant x;
LN	=	natural logarithm function.

The equation was derived to provide a declining cost curve between a .01% capacity factor and 60% to roughly reflect the number of start-ups and impact on price. At very low capacity factors, the added cost peaks at S dollars per megawatt, with the default value of $50/MW/start-up. As the capacity factor increases, the hours per start-up increase and the price declines. By the 60% capacity factor, the price addition is negligible and is turned off. This price addition does not affect loading orders or dispatch decisions as it is applied to all plants regardless of type.

5.9 ENERGY AND REVENUES

Between each point on the plant production curve (Figure 22) the generation from each plant can be calculated from its power level and the difference in time the two points represent. All but the top plant in the stack will be at full power level, while the last one will be at partial load based on its average power level between the two points. (If the plant is probabilistically treated, then the production level is reduced by the plant's FOR. If the plant is nonprobabilistic, then the capacity has already been derated so the forced outage rate is one.) Summing up for all fractions of the season will give the total generation for each plant. Also, as the price is known for each fraction of the season, the generation for each plant during each vertical slice of the curve can be multiplied by the price to determine the plant's revenues during that period.

Figure 25 shows a "slice" of an LDC between 52% and 56% of the season's demand and eight plants dispatched to meet the demand. All but the last plant operate at full capacity, but the top plant operates at 60 MW at the 56% point and 80 MW at the 52% point, an average of 70 MW. (As described in Sect. 5.4, ORCED would actually treat the plant as operating at 70 MW over the period.) In this example, if the "season" is a full year, then Plant H would have generated 70 MW × 4% × 8,760 hours or 24,528 MWh during this slice. If its variable cost and consequent bid price was 3¢/kW, then it would have earned $736,000 but would have also had to pay the same amount in fuel or other variable costs. The plants below it would have earned 3¢/kWh as well, but their variable costs would be lower, and they would have earned some operating income. By performing these same calculations for each slice for each season, each plant's generation and revenues can be found.

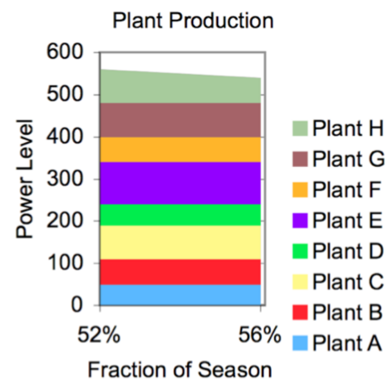


Figure 25. "Slice" of a load duration curve showing stack of plants dispatched.

5.10 FINANCIAL CALCULATIONS

Although most revenues are calculated as described in the previous section, other revenues can be added. For example, the user can include an uplift charge in cents per kilowatt-hour that adds an energy revenue to all plants based on their generation, or a fixed capacity payment can be added based on dollars per kilowatt. A nongeneration charge can be added to prices, but these revenues do not go to plants. These serve rather to represent the transmission, distribution, and other costs that may be included in customer rates.

A user can designate certain plants to be funded based on their expected financial costs rather than through wholesale marginal cost rates. To calculate these costs, as well as to provide a fuller picture of each plant's finances, the model calculates the depreciation, interest payments, taxes, and expected return on equity. The EIA NEMS database includes the year of construction for each plant and the capital cost for different technologies in 1987 dollars. The Supply workbook converts these values into nominal dollars in the year the unit was built. The costs for the aggregated plants are a weighted average of the costs of the units that are combined into the plant. The Dispatch workbook calculates for the study year the amount of depreciation and amount left undepreciated using an input depreciation (or "book") life. The model will add capital additions as an input percentage of the initial cost, and these additions are depreciated using the separate input depreciation life of the plant. This helps to simulate book value for plants long after their initial costs have been fully depreciated.

The capital structure of the plant is split between debt and equity based on the selected type of ownership for the plant. A traditional utility may have a split of 50% debt/50% equity, while an independent power producer may be more heavily leveraged with a ratio of 70% debt/30% equity. Because the model calculates accelerated depreciation for tax purposes using the tax life of that type of plant, there can also be some deferred taxes on the books as a liability. Accelerated depreciation for taxes reduces the taxes early in the life of a plant only to be repaid later once regular depreciation catches up with tax depreciation. In one sense, accelerated tax depreciation creates a "no interest loan" to the plant from taxpayers.

A balance sheet and income statement is generated for each plant so that income taxes can be calculated. In addition, a property tax is charged based on the net asset value of the plant and input property tax rate.

Tables 6 and 7, from the 2001 Oklahoma restructuring analysis (Hadley et al. 2001a and 2001b), show values for a single 122 MW unit at a gas-fired steam plant. Note that in this example, the unit makes essentially no profit using market-based prices, while its regulated rate of return would provide it with $712K.

Table 6. Example balance sheet for 122 MW gas-fired steam plant ($M)

Assets		Liabilities	
Initial Construction	19.6	Debt	7.3
Capital Expenditures	3.9		
Total Gross	23.5		
Accumulated Depreciation		Deferred Taxes	1.4
Initial Construction	6.2		
Capital Expenditures	2.2		
Total Depreciation	8.4		
Net Undepreciated		Equity	6.5
Initial Construction	13.4		
Capital Expenditures	1.8		
Total	**15.1**	**Total**	**15.1**

Table 7. Example income statement for 122 MW gas-fired steam plant ($M)

Revenue	8.387
Expenses:	
Fuel	5.418
Variable Operations and Maintenance (O&M)	0.143
Fixed O&M	0.895
Net Operating Income	1.930
Depreciation	1.044
Property Taxes	0.303
Interest	0.581
Pretax Income	0.002
Income Tax	0.001
Net Income	0.001
Allowed Net Income	**0.712**

5.11 ENVIRONMENTAL CALCULATIONS

Environmental and energy use data are calculated for each plant from the generation amounts and the input energy and emissions factors. Total annual generation is found by summing the results for each of the three seasons. Multiplying this amount by the average heat rate (in British thermal units per kilowatt-hour) provides the total primary energy used by each plant, be it from coal, natural gas, residual oil, distillate oil, uranium, or other. Each plant's fuel type and average heat rate have been carried forward from the initial supply calculations.

Fossil fuels have an input amount of carbon content per million British thermal units, as shown in Table 8. The values are currently entered in units of kilograms of carbon per million British thermal units, but the resulting calculation gives total CO_2 in tons. Earlier studies conducted all calculations in metric tonnes and kilograms of carbon rather than English units and CO_2, but recent studies have shifted to using CO_2 instead.

Table 8. Example carbon emissions rates for fossil fuels (kg/MBtu)

Fuel Type	Carbon Emission Rates
Gas	14.47
Coal	25.72
Residual Oil	21.49
Distillate Oil	21.49

Emission rates for SO_2 and NO_X are calculated similarly to those for CO_2 except that the emission rates are plant-specific rather than dependent solely on the fuel. Sulfur dioxide emissions are typically only attributed to the coal plants, although oil-burning or biomass plants may also have SO_2 releases. The NO_X emissions can come from any of the plants that burn fuel. The values used are from EIA or EPA databases and are typically in values of pounds per million British thermal units. The model applies a cost based on the input price per ton. The NO_X price can either be applied to all NO_X emissions or only those that occur during the summer season.

The model does not explicitly have the capability to set a cap on emissions, with emissions prices and dispatch decisions changed to maintain the cap. It is possible for the analyst to iterate the analysis to find a new emissions price that will maintain a constant rate of emissions. However, any answer would be only a rough approximation of how a cap and trade market would work. The model analyzes only one region of the country at a time, but many of the cap and trade formulas span multiple regions. Furthermore, the model does not allow individual plants to modify their emissions rates (e.g., scrubbing the coal, using low sulfur coal, operating NO_X catalytic reduction equipment more or less).

It is more appropriate to interpret the results by stating that in reality emissions would remain constant but the prices paid would adjust so that supply and demand of emission credits would balance. Because the base prices of credits are already included in the financial calculations, the emissions to a large extent have been monetized. Changes in emissions as determined in the model (e.g., because of DG, energy efficiency, or demands from PHEVs) would actually result in changes in credit prices rather than emissions changes. The change in prices depends on the regional or national supply and demand for credits and is thus generally beyond the intended capabilities of ORCED to determine.

6. RESULTS

The calculations and results for each of the 200 plants are displayed on worksheets that show the financial and environmental metrics (labeled $Results and EnvResults). In addition, a summary worksheet gives results for the total system, aggregated by fuel type and by plant technology. A series of charts are provided on a separate sheet that shows some of the key metrics such as the supply curve, marginal prices, and various LDCs.

6.1 SUMMARY TABLES

The first system-wide tables show results for demand, production, and reliability (Table 9). The reserve margin shows the amount of capacity available above the peak customer demand for the season. The annual value uses the nameplate capacity of the plants as summer and winter capacities are often different for each plant. LOLP is shown in percent of the period or year for the first column. The load factor represents the ratio of average demand to peak demand and gives an indication of how flat or peaky the demand is. Peak demand and total energy are from the input demands, while generation is calculated during the dispatch. The difference represents the unserved energy that could not be provided by the region's generating plants. In Table 9, only the summer season had insufficient capacity, as indicated by a nonzero LOLP, although the unserved amount is less than 1 GWh.

Table 9. Production-related system-wide results

	Annual	**Summer**	**Winter**	**Off-Peak**
Reserve Margin	24.1%	14.4%	35.4%	29.9%
LOLP, % of period	0.0014	0.00	0.00	0.00
LOLP, day/10 year	0.05	0.16	0.00	0.00
Load Factor	58.1%	65.5%	58.0%	52.3%
Peak Demand, MW	206,855	206,855	181,459	157,465
Energy, GWh	1,053,022	396,861	259,147	397,014
Generation, GWh	1,053,022	396,861	259,147	397,014
Unserved Energy, GWh	0	0	—	—

Table 10 shows the system-wide price and cost results. The average price is the total revenue for all plants divided by total sales. The total with unserved energy includes the unserved energy and its imputed cost in the total revenue and sales. These two values will only diverge if there is a large amount of unserved energy due to lack of capacity. The variable costs include the fuel and variable O&M costs of production.

Table 10. System-wide cost results

	Total (¢/kwh)	**Total with Unserved Energy (¢/kwh)**
Average Price (¢/kWh)	4.50	4.50
Average Variable Cost	2.40	2.40
Average Variable Cost + Avoidable Cost	2.93	2.93
Total Expected Cost per kWh	5.31	5.31
Avoidable Cost ($M)	30,852	
Total Expected Cost ($M)	55,906	

The avoidable cost figures are used for some studies when certain plants in the year being analyzed have not been built. In these cases, the total cost of these plants is "avoidable" as the plants could be canceled if not needed. The costs of these plants are annualized so that their costs are put on the same basis as variable costs. This allows for an analysis to look at minimizing avoidable costs instead of just minimizing costs assuming all plants will be built.

The total expected cost represents the variable and fixed production costs (fuel plus O&M) plus the capital costs (depreciation and interest) plus the expected pretax return on equity if the plants were owned by regulated utilities. This gives an indication of the average price if all plants were regulated and receiving their required return on equity.

The fuel-aggregated table (Table 11) shows some of the key production and emissions metrics aggregated by the type of fuel used by the plants. Capacity shown is the nameplate capacity. Capacity factor is the generation in megawatt-years divided by the capacity and so represents the proportion of the year that the plant produced compared to full production. The time on the margin indicates what fraction of the year the plants with that type of fuel were the last plants dispatched and so on the margin. It indicates the fraction of the year that each fuel set the wholesale price. Primary energy is reported in trillion British thermal units (TBtu). Emissions (CO_2, SO_2, and NO_X) are in thousands of English tons.

Table 11. ORCED results aggregated by fuel type

Fuel Type	Capacity		Generation		Capacity Factor	Time on Margin	Energy TBtu	CO_2 kTon	SO_2 kTon	NO_X kTon
	MW	% of Total	MW-year	% of Total						
Gas	98,219	38%	14,262	12%	15%	58%	1,057	61,833	0	53
Coal	85,283	33%	62,435	52%	73%	41%	5,495	571,374	2,017	504
Residual Oil	2,054	1%	338	0%	16%	0%	30	2,624	11	4
Distillate Oil	5,372	2%	11	0%	0%	0%	2	136	0	0
Uranium	45,225	18%	38,460	32%	85%	0%	3,426	0	0	0
Water	19,632	8%	4,233	4%	22%	0%	375	0	0	0
Other	989	0%	468	0%	47%	1%	60	0	22	2
Total	**256,775**	**100%**	**120,208**	**100%**	**47%**	**100%**	**10,445**	**635,966**	**2,051**	**562**

The plant technology table in the Summary worksheet includes the information from Table 11 plus additional details on emissions and finances. For readability and to fit the format of this report, it has been broken into four tables, Tables 12–15. Table 12 shows the production-related results; Table 13 shows the emissions-related results; Table 14 shows the income statement; and Table 15 shows the balance sheet.

Table 12. Production results aggregated by fuel and plant technology[a]

Plant Type	Capacity				Generation			Capacity Factor	Time on Margin
	MW	% of Total	Summer	Winter	MW-year	TWh	% of Total		
Coal-Unscrubbed	49,616	19%	45,338	45,607	33,480	293.3	28%	67%	39
Coal-Scrubbed	35,667	14%	34,037	34,602	28,955	253.6	24%	81%	2
Oil ST	2,054	1%	1,864	1,881	338	3.0	0%	16%	0
Oil CT	5,270	2%	4,183	5,203	11	0.1	0%	0%	0
Oil CC	102	0%	84	106	0	0.0	0%	0%	0
Gas ST	18,370	7%	16,793	17,246	3,509	30.7	3%	19%	0
Gas CC	45,011	18%	39,979	42,720	10,124	88.7	8%	22%	55
Gas CT	34,779	14%	29,457	33,507	628	5.5	1%	2%	3
Nuclear	45,225	18%	43,350	43,767	38,460	336.9	32%	85%	0
MuniSW	369	0%	298	303	216	1.9	0%	59%	1
Biomass	560	0%	504	510	237	2.1	0%	42%	1
Gas DG	59	0%	59	59	1	0.0	0%	1%	0

Table 12 (continued)

Plant Type	Capacity				Generation			Capacit y Factor	Time on Margin
	MW	% of Total	Summer	Winter	MW-year	TWh	% of Total		
Other	60	0%	60	60	15	0.1	0%	25%	0
Geothermal	0	0%	—	—	0	0.0	0%	0%	0
Fuel Cell	0	0%	—	—	0	0.0	0%	0%	0
Hydroelectric	12,083	5%	12,592	12,080	4,233	37.1	4%	35%	0
Pumped Storage	7,549	3%	8,002	7,994	0	0.0	0%	0%	0
Totals	**256,775**	**100%**	**236,601**	**245,645**	**120,208**	**1,053.0**	**100%**	**47%**	**100**

[a]Acronyms and abbreviations: ST = steam turbine, CT = combustion turbine, CC = continuous cycle, SW = solid waste, and DG = distributed generation.

Table 13. Emissions results aggregated by fuel and plant technology[a]

Plant Type	Energy	CO_2	SO_2			NOx		
	TBtu	kTon	kTon	lb/MBtu	lb/MWh	kTon	lb/MBtu	lb/MWh
Coal-Unscrubbed	3,005	312,463	1,806	1.20	12.31	369	0.25	2.52
Coal-Scrubbed	2,490	258,911	212	0.17	1.67	135	0.11	1.07
Oil ST	30	2,624	11	0.73	7.47	4	0.26	2.65
Oil CT	2	135	0	0.18	2.91	0	0.14	2.21
Oil CC	0	0	0	0.23	2.70	0	0.12	1.37
Gas ST	352	20,570	0	0.00	0.01	39	0.22	2.55
Gas CC	645	37,704	0	0.00	0.00	11	0.03	0.25
Gas CT	61	3,555	0	0.00	0.01	2	0.08	0.88
Nuclear	3,426	0	0	0.00	0.00	0	0.00	0.00
MuniSW	28	0	0	0.00	0.00	0	0.03	0.41
Biomass	30	0	22	1.44	21.18	1	0.09	1.29
Gas DG	0	4	0	0.00	0.01	0	0.02	0.21
Other	1	0	0	0.00	0.00	0	0.00	0.00
Geothermal	0	0	0	0.00	0.00	0	0.00	0.00
Fuel Cell	0	0	0	0.00	0.00	0	0.00	0.00
Hydroelectric	375	0	0	0.00	0.00	0	0.00	0.00
Pumped Storage	0	0	0	0.00	0.00	0	0.00	0.00
Totals	**10,445**	**635,966**	**2,051**	**0.39**	**3.90**	**562**	**0.11**	**1.07**

[a]Acronyms and abbreviations: ST = steam turbine, CT = combustion turbine, CC = continuous cycle, SW = solid waste, and DG = distributed generation.

Table 14. Income statement results aggregated by fuel and plant technology[a]

Plant Type	Revenues	Variable Costs	Fixed O&M	Interest + Depreciation	Pretax Income	Income Taxes	Net Income	Expected Net Income
Coal-Unscrubbed	12,670	9,377	817	887	1,590	572	1,017	167
Coal-Scrubbed	10,781	6,296	570	2,653	1,262	454	807	881
Oil ST	238	218	25	14	(18)	(7)	(12)	4

Table 14 (continued)

Plant Type	Revenues	Variable Costs	Fixed O&M	Interest + Depreciation	Pretax Income	Income Taxes	Net Income	Expected Net Income
Oil CT	28	18	10	25	(25)	(9)	(16)	5
Oil CC	0	0	0	0	(0)	(0)	(0)	0
Gas ST	2,539	2,242	187	112	(3)	(1)	(2)	40
Gas CC	4,454	3,911	148	1,082	(686)	(247)	(439)	244
Gas CT	645	415	64	508	(343)	(123)	(219)	139
Nuclear	14,305	1,894	3,475	10,404	(1,469)	(529)	(940)	4,104
MuniSW	139	70	7	69	(7)	(2)	(4)	9
Biomass	108	94	9	11	(5)	(2)	(3)	2
Gas DG	1	1	1	15	(16)	(6)	(10)	9
Other	5	0	1	4	(0)	(0)	(0)	1
Geothermal	0	0	0	0	0	0	0	0
Fuel Cell	0	0	0	0	0	0	0	0
Hydroelectric	403	238	165	0	0	0	0	0
P.Storage	1,109	448	150	511	0	0	(0)	0
Totals	**47,426**	**25,222**	**5,630**	**16,296**	**278**	**100**	**178**	**5,605**

[a]Acronyms and abbreviations: O&M = operations and maintenance, ST = steam turbine, CT = combustion turbine, CC = continuous cycle, SW = solid waste, and DG = distributed generation.

Table 15. Balance sheet results aggregated by fuel and plant technology[a]

Plant Type	Gross Assets	Accumulated Depreciation	Net Assets	Debt	Deferred Taxes	Equity
Coal-Unscrubbed	36,672	31,069	5,603	2,676	737	2,190
Coal-Scrubbed	53,137	24,844	28,294	13,538	3,183	11,573
Oil ST	1,009	934	76	30	0	46
Oil CT	1,239	1,106	133	60	13	60
Oil CC	14	13	1	1	0	1
Gas ST	8,347	7,721	626	205	0	422
Gas CC	23,460	13,919	9,541	4,479	1,922	3,140
Gas CT	11,988	7,527	4,461	1,943	831	1,687
Nuclear	199,167	75,724	123,443	59,253	10,159	54,031
MuniSW	1,829	1,510	318	151	56	111
Biomass	605	555	51	22	1	28
Gas DG	240	4	235	113	0	122
Other	73	26	47	22	5	20
Geothermal	0	0	0	0	0	0
Fuel Cell	0	0	0	0	0	0
Hydroelectric	5,035	5,035	0	0	0	0
P.Storage	18,274	10,782	7,493	7,492	0	1
Totals	**361,090**	**180,770**	**180,321**	**89,983**	**16,907**	**73,430**

[a]Acronyms and abbreviations: ST = steam turbine, CT = combustion turbine, CC = continuous cycle, SW = solid waste, and DG = distributed generation.

6.2 SUMMARY CHARTS

Figure 26 shows the supply curve, the cumulative amount of capacity versus the marginal cost for that capacity. This graph is based on summer data; winter and off-peak seasons would have different capacities and potentially different costs for the plants. Normally, the curve should increase from left to right. There can be occasional blips in the curve because of extra costs for start-ups that influence their calculated price but are only applied after dispatching. Since those costs are influenced by results in other years, a plant may show a higher marginal cost.

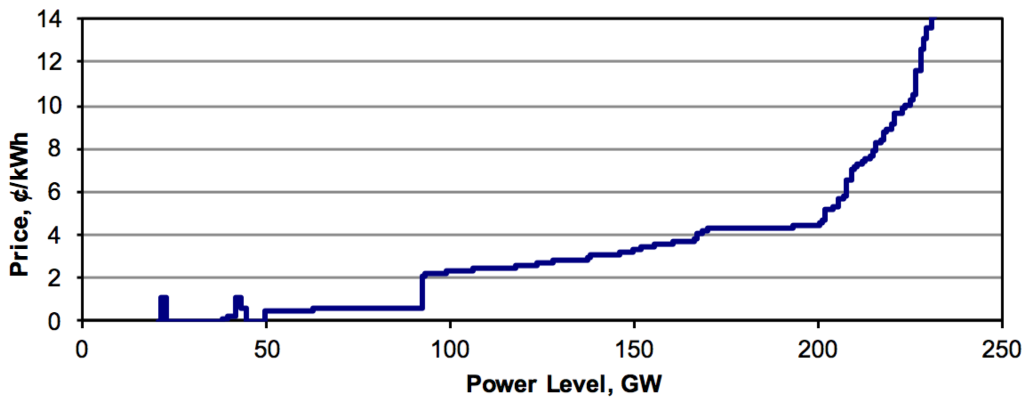


Figure 26. Supply curve for the Southeast Electric Reliability Council.

The marginal prices over the course of each season give an indication of when plants at different costs are on the margin (Figure 27). Prices are highest at the left, early in the season when most or all plants have been dispatched. If there is insufficient capacity, then the price will shoot very high at the point when all capacity is used. As discussed previously, a rising unserved energy cost is calculated and prices are set to that cost during the time when all plants are dispatched.

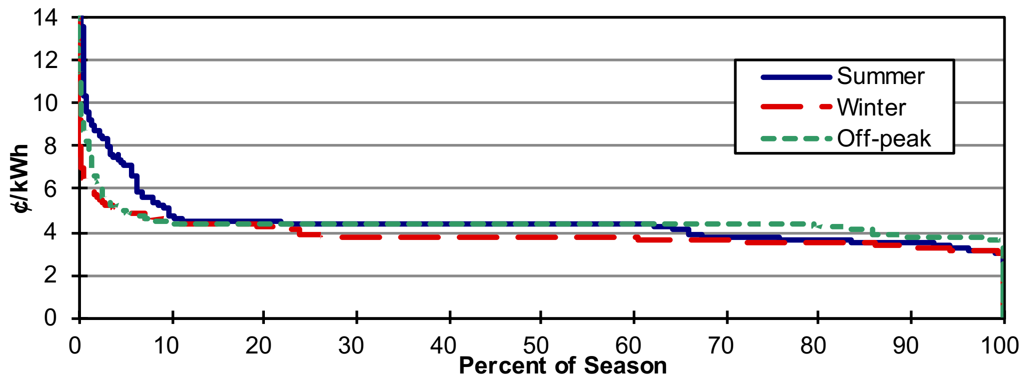


Figure 27. Seasonal prices for the Southeast Electric Reliability Council.

6.3 COMPARISON BETWEEN SCENARIOS

This summary information can be saved into a separate spreadsheet so that individual scenarios can be compared. Differences between scenarios (production, emissions, costs) can be evaluated to see the impact of changes in scenarios, whatever they are. This method has been used in most of the ORCED studies, comparing DG, PHEVs, energy efficiency, new plant technologies, or other variations. Depending on the nature of the study, tables and/or graphs can be created that display the changes in results for easier comprehension.

7. SUMMARY

The ORCED model provides a flexible, detailed system to evaluate the impacts of a variety of demands or resources on the electrical grid. The focus of the model is on regional generation markets. The model was developed to examine a variety of issues, including

- the environmental effects of electricity production in a competitive industry and policies that affect emissions,
- the profitability (and therefore the market acceptance) of different types of generators, including those that might become available because of more research and development,
- the effects of competition at the bulk-power and retail levels on consumers and producers, and
- the effects of consumer-owned technologies on demands and consequent generation changes.

Because ORCED is a relatively transparent model, analysts can use it to model a variety of situations. It is sufficiently flexible to permit modification or expansion with little difficulty. Compared to more accurate but much more complicated models, ORCED's simplicity reduces the amount of time and effort required to prepare inputs for the model, run the model, and review and interpret outputs from the model.

Over the years, enhancements to the supply and demand calculations have greatly increased its real-world applicability but at the expense of initial data collection and setup. However, these are enhancements and so can be overridden if a less detailed analysis is all that is required. The complex connections between workbooks are not necessary for operation of the model. Furthermore, after initial setup of data, variations are relatively easy to examine, allowing hundreds of cases to be run for a single project.

As is true of any mathematical representation of complicated physical and economic systems, ORCED contains many assumptions and limitations.

- It treats only 1 year at a time. (Although it is feasible to run ORCED for several years, linking the results from 1 year to the next is not simple.)
- It treats generation only (i.e., it treats transmission in a very simple fashion and ignores distribution and customer-service costs).
- Its use of LDCs to model system demand subsumes the details of hour-to-hour load variations, which eliminates some opportunities for cost-effective trading between regions.
- It ignores the detailed operating characteristics of generating units, such as minimum start-up and shutdown times and the variation in heat rates as a unit goes from minimum to maximum output.
- It treats at most only two regions at a time, which ignores the opportunities for trading electricity with other regions.
- Its use of "derating" factors for many power plants, rather than probabilistic treatment of forced outages, may lead to underestimation of market prices.

Although ORCED was developed as an in-house research tool, it is available for use by others. Those interested in using ORCED should contact the lead authors by email at hadleysw@ornl.gov, hadleysw@mac.com, youngsun.baek@gmail.com, or the Power and Energy Systems Group at ORNL.

In summary, ORCED includes the key features required for analysis of competitive bulk-power markets. Although it lacks the details of large, sophisticated models, it offers important strengths. In particular, after initial setup the model is easy to use and can be run very quickly. Thus, analysts can test many different situations in a short time. Finally, the model's transparency enhances the ability to glean insights from model runs. As Barker et al. (1997) note, “You cannot be a true believer in competition and remain an agnostic about sector structure.” ORCED, as the multiple studies that used it attest, allows one to analyze bulk-power sector structure, operations, competition, and costs.

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APPENDIX A. OPERATIONS: ORCED VERSION 9 USER MANUAL

ORCED USER MANUAL FOR VERSION 9

Introduction
The Oak Ridge Competitive Electricity Dispatch (ORCED) model (Figure A-1) simulates the operation of a regional bulk-power market for a single year. It uses inputs gathered from other sources to establish the supplies and demands. Besides simple simulation, optimization routines can be used to manipulate various parameters within the model. This appendix describes the procedures to manipulate the various files used to do an analysis. There are four Excel files used to develop and run ORCED (Version 9): SupplyAEO2011.xlsb, Demand_v9c.xlsb, Dispatch-DRv9.xlsb, and Results-DRv9.xlsb.

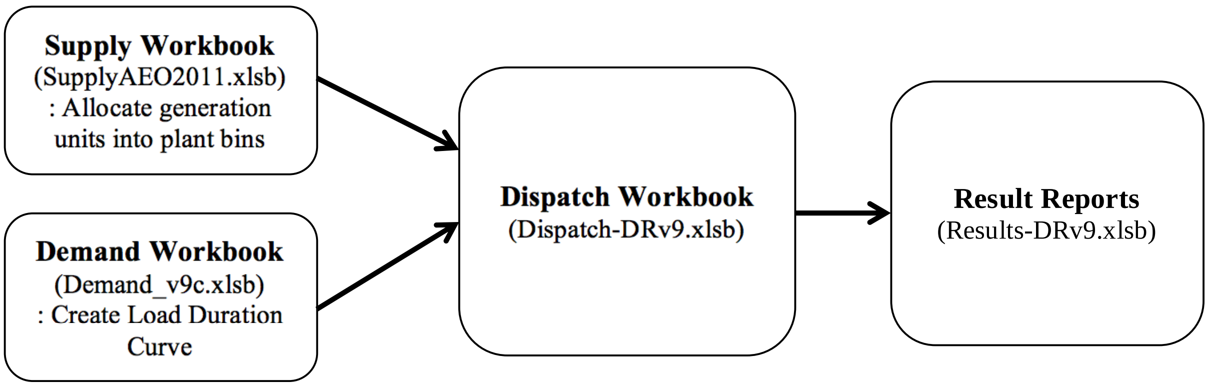

Figure A-1. Structure of ORCED model.

The Supply workbook contains plant-by-plant information on all of the plants in all of the Energy Information Administration's (EIA's) 22 Electricity Market Module (EMM) regions. It also includes the formulas for consolidating the plants into the 200 bins that ORCED requires for analysis. The Demand workbook contains the hourly load data for each North American Electric Reliability Council (NERC) region. Separate worksheets also calculate the changes to hourly demands from such activities as demand response (DR), plug-in vehicles, distributed generation, wind production as a demand modifier, etc. This specific version calculates DR changes to load. It also includes the formulas for converting the hourly data into a load duration curve (LDC) for each season that can then be copied to the Dispatch workbook. The Dispatch workbook contains the ORCED dispatch program itself. In the workbook, the 200 plant bins in each region are dispatched to meet the regional demand for a given year. The Results workbook stores and displays the summary results from multiple runs to allow summaries and comparisons between cases.

Supply Workbook
The Supply workbook allocates all plants data in each region into 200 or less plant bins. Much of the input data for Supply is collected from various resources as described in the main body. This needs to be done at the beginning of a study but is not further modified during different scenarios, as described in this appendix. The worksheet ORCEDInput aggregates the information from the other sheets and puts it into a format that can be copied into the Supplies worksheet. The Supplies worksheet collects all regions' plant bins data that are finally imported to the Dispatch workbook. The Supply workbook (SupplyAEO2011.xlsb) will only be needed if the user wishes to change the characteristics of specific plants or rearrange the major plant definitions used in the model. The following numbered steps indicate how to create a new supply scenario.

1. Open the Units worksheet. The Units worksheet stores the data for each of the individual plants. The data was imported from EIA's National Energy Modeling System (NEMS) pltf860 file. Several macro functions are defined to sort and filter the plant data.

2. Run "***FilterNEMS***" macro (Go to Developer →Macros→FilterNEMS). This macro filters plants according to first and last operating year, whether or not plant provides capacity to the grid, and NERC region (ownership). You can adjust the four variables in cellsCI4:CL4.

3. Go to the Assign worksheet. The Assign worksheet has user inputs to allocate the plants into 200 or fewer bins. Adjust the average size in cell J1 so that total number is below 200.

4. The Chart1 worksheet graphically displays the costs and capacities of each of the 200 bins. It displays all the plants in the region on the two dimensional space by cost (dollars per megawatt-hour) and capacity (megawatts). Use the Chart1 worksheet to review the assignments that have been made. Try not to have the capacity in one bin far exceeding the others. Also, try to consolidate the very small bins with others that have similar characteristics. Note that the names on the chart may not match the actual names of the fuels assigned. A bug in Excel does not update the chart label names sometimes.

5. Run "***Sort NEMS.***" The macro sorts plant data by combination assignment and variable cost.

6. Run "***Copy Region***" copies the regionally filtered/sorted data and puts them in the designated place in the Supplies worksheet. The Supplies worksheet finally collects and stores regional plant bins data used for the Dispatch workbook. If you want to filter, sort, and copy all regions for a specific year at once, run "***FilterSortCopyAllRegions.***" If you want to do it for a single region, run "***FilterSortCopyOneRegion***."

The Codes worksheet contains the fuel prices and SO_2 for each type of fuel, capital costs, forced outage rates, and planned outage rates for each type of plant. Each plant in the data has a primary, secondary, and tertiary fuel code assigned to it in columns BF:BH in the Units worksheet. The model will evaluate the amount of generation by each fuel type and select the highest. There are 53 fuel codes available, listed in B2:B55 in the Codes worksheet. Prices may be found through other sources, such as the EIA's short-term energy outlook or market reports. In addition to fuel data, the Codes worksheet includes data specific to plant types. Columns P through AF, starting with Row 37, are the 22 possible plant types in the EIA database. Column W has the default overnight capital cost for each plant type in 1987 dollars per kilowatt. The spreadsheet uses these values, inflating or deflating them to the nominal dollars at the time the plant came online using a 3% inflation rate.

Demand Workbook

The Demand workbook (Demand_v9c.xlsb) creates the LDC for each region. The year 2011 hourly loads were retrieved from all utilities that submitted data to the FERC Form 714 database, as well from regional transmission organizations. These were converted to LDC, rearranging the demands from highest to lowest. These were consolidated into the 22 EMM regions and escalated to match the 2030 demands based on the 2011 *Annual Energy Outlook* reference case (EIA 2011). The Demand workbook then consolidated the 8,760 hours of demands into three LDCs, one each for summer, winter, and off-peak seasons. The LDC workbook calculates a simplified LDC for three seasons of a year based on the hourly demands for a region. The Hours worksheet lists demands for all 8,760 hours. The values for each region are based on the sum of the demands for that region's utilities reporting their hourly loads from the FERC database. Other sources could be used instead. This workbook will need to be changed only if the user wants different LDCs with different hourly demands or a change in the length of time for the peak season. The procedures to create a new regional demand scenario (or LDC) are as follows.

1. Go to the Inputs worksheet, where you can specify desired year and region and the slot to store the generated LDC and the DR modeling.

2. Hit "***Run Region***" button to create an LDC for a region. By using a built-in macro, "***RunAllRegions***," you can create all the LDCs for all 22 regions at once.

3. Run "***CopyResults***" macro to update the newly generated LDCs for the Dispatch workbook.

The "SeasonSolver" macro assists in fitting the curves. It is helpful to manually enter approximate values in the three-segment (summer, winter, and off-peak) LDC definitions. Once the curves have been fitted to your satisfaction, the values for ORCED are stored in the boxed areas.

If you want to fix some erroneous values in the generated LDC, you can manually improve LDCs by running the following macros.

1. Set up Input region and slot in the Inputs worksheet,
2. Run ***GoalSeekExport***,
3. Run ***Histogram200***,
4. Copy values in blue from LDC,
5. Run ***SeasonSolver***, and highlight the cell you want to fix,
6. Run ***CopyAvg,***
7. Run ***SeasonSolver*** again,
8. Run ***ZeroDiff,*** and then
9. Run ***CopyResults***.

If you want to change the impact of the DR program on the load for each region, you can adjust the magnitude of impact of DR in cells D19:L20 in the DR_Schedule worksheet. Other than the magnitude of impact, the DR modeling can be specified in the Inputs worksheet (cells B17:B24). The notch method does not capture peaks outside of its summertime block, such as winter mornings or high demands after 6 pm. The smart DR assumes that DR resources are flexible enough to precisely shave the peak demands and in some hours calls on more capacity reductions than are available. (To examine this, a "constrained" business as usual scenario was added where the DR in any hour could not exceed the amount calculated in ORNL-NADR, even if it was only called upon for a few hours. The other DR scenarios are not affected by this problem.) In none of the cases are the DR resources adjusted based on supply changes such as outages from power plants.

Dispatch Workbook

The binned (grouped) plants are dispatched to meet the created LDCs in the Dispatch workbook (Dispatch-DRv9.xlsb). The procedure is as follows.

1. Copy the cells in the LDC worksheet from the Demand workbook and those in the Supplies worksheet from the Supply workbook over to the worksheets with the same names in the Dispatch workbook. The ***CopyResults*** macro in the Demand workbook has been written to ease transfer of data from the Inputs and LDC workbooks: Before running either of them, be sure to have the relevant Input or LDC workbook open. The macro will ask for the name of the workbook. Type this in, and the macro will copy the relevant ranges into spaces on the Input sheet of the Dispatch workbook.

2. Any cells on the ***Input*** worksheet that are highlighted in sky blue are inputs that can be changed. This allows the user to see the effects of changing start-up costs, capacities, emissions costs, fuel prices, reserved need (%), price elasticity, etc. Plant-by-plant and system summary results are shown on the Results and Charts worksheets.

If only small parts of the inputs are changing, then it is easier to just store the areas that are changing. Then, to rerun the cases, it is only necessary to paste the stored values back into Input. These small parts can be stored along with any relevant outputs from the run, thereby allowing the user to build up a set of duplicable results for comparison purposes.

Result Reports

Users are able to pull many useful reports such as generation by fuel type, capacity factor, reserve margin, and greenhouse gas emissions out of Results-DRv9.xlsb. The LDC worksheet stores all the LDCs created in the Demand workbook. The Multiscenario worksheet shows comparisons across scenarios, and the Multiregion worksheet shows those across regions.