This exhibit summarizes the salient inputs to the TCA locational price-forecasting model (GE MAPS) for the US Midwest region, which is currently configured to simulate the combined regions of MAPP, MAIN, ECAR, Ontario, SERC, SPP and ERCC. In this memo, we have described in detail our data sources and methodology for representing generation and transmission elements. We have also included actual data for MAIN.

In general, TCA relies on publicly available data, obtained from FERC submissions, independent market research and provided by General Electric in their model. TCA has verified, refined and/or replaced the data as appropriate, based on its own data sources. We have included in-house analysis to ensure data integrity, validity, and consistency of plant operations with market developments.

The following is a list of the major data components, followed by a description of each component and the associated data sources:

(1) Load Inputs
(2) Thermal Unit Characteristics
(3) Planned Additions and Retirements
(4) Nuclear Unit Analysis
(5) Fuel Price Forecasts
(6) Transmission System Representation
(7) Environmental Regulations
(8) Conventional Hydro & Pumped Storage Units
(9) External Region Supply Curves
(10) NUG Contracts
(11) Dispatchable Demand (Interruptible Load)
(12) Market Model Assumptions

# 1. Load Inputs

***Description**:* GE MAPS uses hourly annual load profiles for every load serving entity. Loads for future years are scaled based on a forecast of annual peak demand and energy. GE MAPS adjusts the load profile in every year to account for the change in the day of the week at the start of every year. As an illustration, the energy and load forecast for MAIN, MAPP and ECAR regions for the years 2003 through 2014 is included in Appendix 1.

*Data Source:* **We use company's FERC 714 filings and EIA-411 (Load and Capability) reports from the relevant power pools for both the actual hourly loads (1996) and publicly available recent load forecast series (2001) for each power pool.**

# 2. Thermal Unit Characteristics

***Description**:* GE MAPS models generation units in detail, in order to accurately simulate their operational characteristics and therefore project realistic hourly dispatch and prices. These characteristics include:

- Unit type (steam, combined-cycle, combustion turbine, cogeneration, etc.)
- Heat rate values and curve
- Summer and Winter Capacity
- Variable Operation and Maintenance costs (all values are in real 2001 $)
- Fixed Operation and Maintenance costs
- Forced and Planned Outage rates
- Minimum up and down times
- Quick start and spinning reserves capabilities
- Startup costs

We have developed heat rate curves for different units based on technology type and data points obtained from the data sources described below.

Note that all prices are reported in real 2002 dollars. We use real prices throughout the analysis and then apply an inflation rate to get nominal prices, if needed.

***Data Sources:*** Our primary data source for generation characteristics is the NERC Electricity, Supply and Demand (ES&D) database, which contains unit type, fuel type (primary and secondary), capacity, and heat rate data through 1996. We use the NERC Generation Availability Data System (GADS) 1999 database, as a reference for forced and unforced outage rates. GADS bases outage rates on plant type, size and vintage. We estimate operation and maintenance costs based on plant size, technology and age, and supplement our data with FERC Form 1 submissions, particularly for nuclear units. Fixed Operation and Maintenance (FOM) costs are based on FERC Form 1 historical data and represent values for the last three years, averaged by unit type and size. The resulting values are increased to account for general and administrative costs (around 20%), and then reduced by a similar amount to account for competitive market response. Exhibits 1a and 1b show the representative, industry-average assumptions we use when specific unit information is unavailable. The FOM values include property taxes, insurance, and major overhauls. These additional FOM values could vary by location and we estimate the following: $1.50/kW-yr for insurance, $3/kW-yr for property taxes, 10% of base FOM (before insurance and taxes) for capital improvements.

**Exhibit 1a – Thermal Unit Characteristics - MAIN**

| Unit Type | Size (MW) | FOM ($/kW-yr) | VOM ($/MWh) | Minimum down time (Hours) | Minimum up time (Hours) | Heat rate Shape |
|---|---|---|---|---|---|---|
| **Combined Cycle** | | 23 | 2 | 6 | 6 | 2 blocks, 50%@FLHR, 50%@FLHR |
| **Steam Coal** | **<100** | 26 | 2.5 | 6 | 8 | 4 blocks, 50%@106% FLHR, 15%@90%, 30%@95%, 5% @ 100% |
| | **<200** | 25 | 2.5 | 8 | 8 | 4 blocks, 50%@106% FLHR, 15%@90%, 30%@95%, 5% @ 100% |
| | **>200** | 21 | 1.5 | 12 | 24 | 4 blocks, 50%@106% FLHR, 15%@90%, 30%@95%, 5% @ 100% |
| **Steam Gas/Oil** | **<100** | 15/16 | 1 | 6 | 10 | 4 blocks, 25%@118% FLHR, 30%@90%, 35%@95%, 10% @ 103% |
| | **<200** | 10/16 | 1.5/2.5 | 6 | 10 | 4 blocks, 25%@118% FLHR, 30%@90%, 35%@95%, 10% @ 103% |
| | **>200** | 9/7 | 2.5 | 8 | 16 | 4 blocks, 25%@118% FLHR, 30%@90%, 35%@95%, 10% @ 103% |
| **Nuclear** | | - | - | 164 | 164 | One Block |
| **Hydro** | | - | - | 0 | 0 | One Block |
| **Combustion Turbine** | | 14 | 4 | 1 | 1 | One Block |
| **Wind/Solar** | | - | - | 1 | 1 | One Block |

FOM and VOM are for the MAIN Area. Other regions may vary.

**Exhibit 1b – Thermal Unit Characteristics**

| Unit Type | Size (MW) | Quick Start Capability (% of Capacity) | Spinning Reserves (% of Capacity) | Forced Outage Rate (% of Year) | Planned Outage Rate (% of Year) | Total Unavailability |
|---|---|---|---|---|---|---|
| **Combined Cycle** | | 0% | 10% | 1.5% | 7.0% | 8.5% |
| **Steam Coal** | **<100** | 0% | 10% | 3.0% | 9.5% | 12.5% |
| | **<200** | 0% | 10% | 3.5% | 8.5% | 12% |
| | **>200** | 0% | 10% | 4.5% | 10.0% | 14.5% |
| **Steam Gas/Oil** | **<100** | 0% | 10% | 2.5% | 7.5% | 10% |
| | **<200** | 0% | 10% | 4.0% | 10.5% | 14.5% |
| | **>200** | 0% | 10% | 3.5% | 12.0% | 15.5% |
| **Nuclear** | | 0% | 0% | 9.3% | * | * |
| **Hydro** | | 0% | 100% | 0% | 0% | 0% |
| **Combustion Turbine** | | 100% | 90% | 1.5% | 7.0% | 8.5% |

Source: Utility engineers, NERC Generator Availability Data System

* See Nuclear units Section

# 3. Planned Additions and Retirements

***Description:*** Planned entry and retirements impact the fuel mix of installed capacity and composition of plants on the margin, since most retirements are oil or coal plants, which are likely to be replaced by combined cycle gas plants. New entry before 2005 is based on existing projects already in the construction phase or in advanced stages of permitting, as indicated by environmental permit applications and internal knowledge. In addition to known projects, we add capacity based on economic criteria and market conditions. That is, we enter only as much capacity as is profitable. A list of new entry and retirement (subject to additional economic new entry and retirement) for the MAIN region is included in Appendix 2. Capacity balance for the MAIN region is included in Appendix 3.

New generation capacity is most likely to be either gas-fired combined-cycle (CCGT) or simple-cycle gas turbines (SCGT), based on market requirements and the relative economics of their entry. Below are the capital cost, performance and financing assumptions we use for new entry:

**Exhibit 2 – New Entry Assumptions (2001$)**

| Cost Component | CCGT | SCGT |
|---|---|---|
| All-In Capital Cost ($/kW) | 600-700 | 350-450 |
| Debt:Equity Ratio | 65:35 | 40:60 |
| Return on Equity | 16% | 16% |
| Cost of Debt | 8% | 8% |
| Term of Debt | 20 years | 20 years |
| Fixed O&M ($/kW-yr) | 15 | 5 |
| Variable O&M ($/MWh) | 2 | 2.5 |
| Full Load Heat Rate (Btu/kWh) | 6,900 | 10,000 -10,200 |
| Forced Outage Rate | 3% | 4% |
| Planned Outage Rate | 4% | 3% |

Heat rates for new combined cycle units are decreased to 6,800 Btu/KWh after 2005 to reflect advancement in technology. Using our financial model, we calculate the annual carrying charge for new SCGT and CCGT units to be about $57/Kw-yr and $76/Kw-yr respectively (in real 2002$).

We track planned and announced retirements from power pool load and capacity reports as well as trade press announcements. Nuclear retirements are critical to the analysis and are discussed in the next section. In addition, we monitor the profitability of units for every model run and retire those units that are not profitable, based on their performance in the model and external judgment about the likelihood of those plants improving profitability in later years.

***Data Sources****:* Environmental permitting data from State Departments of Environmental Protection (DEP) are our primary source of planned projects that have a reasonably high degree of certainty. We also incorporate trade press announcements, power pool load and capacity reports and internal knowledge in our analysis to compile this list.

# 4. Nuclear Units Representation

***Description****:* We use a combination of market knowledge, the Nuclear Regulatory Commission's (NRC) watch list and economic performance as reflected in model runs to determine whether any nuclear units should be retired prior to their license expiration. Appendix 4 shows the nuclear units in MAIN that are modeled in this simulation. Retirement dates are based on license expiration dates with the exception of TVA 's Browns Ferry 1, which is treated as retired. While the current TVA plan is to revive the unit in 2012, because of the surrounding uncertainties and possible delays, we will not model Browns Ferry 1 as coming back on line. Also Prairie Island 2 is assumed that it will not file for a license extension and will retire in 2014 due to waste storage issues. All other units are assumed to be in operation throughout the simulation period by filing license extensions to the NRC.

Appendix 5, Table 7 shows the planned unit upgrades and planned capacity additions, which are already approved by the NRC, for the MAIN units. The capacity upgrades will take place during the units' planned maintenance outages in the corresponding years. Another point to notice, although not included in the table, is that several Ontario units are planned to be back in service after being laid for over a decade.
Planned outage for U.S. plants are based on a fixed schedule as exhibited in Appendix 6, Table 8. The outages for these plants will be scheduled on a fixed cycle starting from the most recently known or announced outage date with the outage length also being fixed. Planned outage for the non-US (Ontario) units are set at a 7% annual rate but without any specific refueling schedules. That is, all units are de-rated by 7% year-round to model the unknown maintenance schedule since these units, known as the CANDU units, are capable of re-fueling while online. In addition, all nuclear units have a forced outage rate of 9.3% every year. Therefore the total unavailability for an Ontario nuclear plant is 16.3%. Forced outages occur randomly in GE-MAPS while the planned outages are scheduled in shoulder seasons. Finally, a four-year ('94-'97) average of O&M costs and revenue projections from model runs is used to assess units' economic performance.

***Data Sources****:* *NRC*, trade press announcements, FERC Form 1 data (for O&M costs) and announced retirements in power pool load and capacity reports, along with other public domain sources are used.

# 5. Fuel Price Forecasts

***Description****:* GE MAPS takes as input the monthly fuel price for each plant. Our fundamental assumption of bidding behavior in competitive energy markets is that generators will bid in their marginal cost into the energy market. The marginal cost is the opportunity cost of fuel purchased (in addition to variable O&M and environmental adders), or the spot price of gas at the location closest to the plant. We therefore use forecasts of spot prices at regional hubs, and further refine these based on historical differentials between price points and their associated hubs. For oil and coal we use estimates of the price delivered to generators on a regional basis.

***Fuel Switching Methodology:*** A number of generators have the ability to utilize a secondary fuel type. We have modeled this ability as follows:

Natural Gas Primary: Units with natural gas as their primary fuel may burn fuel oil at most in one month of the year. Since gas prices are generally highest in the month of January, we allow the unit to switch to fuel oil for the month of January, if the oil price at that location is lower than the natural gas price.

Fuel Oil Primary: Units that primarily burn oil may switch to gas whenever it is economically justified. However we assume natural gas shortages prevent this from happening in the winter months (November – March). Also we assume a 3% heat rate degradation results when the unit switches to natural gas. Therefore we switch the fuels in any month from April-October when the price of natural gas plus 3% is less than the price of fuel oil.

**We will send you a separate memo on fuel prices that has a more detailed description of fuel price forecast. Since you have provided us with commodity forecasts for gas at Henry Hub and oil, we will use our forecast for the regional basis differentials and local distribution charges.**

# 6. Transmission System Representation

***Description****:* We model the entire Midwest and Southeast transmission system, including transformers, lines, phase shifters and buses. We use a solved 2001 peak load flow case (PTI file). We identify and monitor potentially binding lines, interfaces and single- and multiple-contingency constraints. We include in our representation all of NERC's defined flowgates. GE provided the initial set of lines based on their contingency analysis.[1] We verified, refined and added to this list of monitored transmission lines, interface and contingency definitions based on the data sources shown below. FRCC is represented by the Georgia-Florida interface.

***Data Sources****: We* use the following studies to refine and add to the transmission database provided by GE:

- FERC 715 filings and load flow cases
- Seasonal transmission assessment reports and transmission studies published by the reliability regions
- NERC Flowgate book

# 7. Environmental Regulations

***Description****:* To account for $SO_2$ trading under EPA's Acid Rain Program, we model costs of $SO_2$ tradable permits based on unit emission rates, and current allowance trading prices. The cost of $SO_2$ tradable permits is assumed to be \$160/ton of sulfur emission through 2006, and \$150/ton thereafter. $SO_2$ emissions are tracked year-round.

We also implement the impact of compliance with the NOx budget and cap-and-trade program in states that are part of the EPA NOx SIP call. Generators have the option of installing NOx abatement equipment, or of purchasing allowances in the market. Since total tradable allowances fall far short of total emissions at existing levels of generation, some generators, most likely base load and coal plants, will be forced to retrofit. Generators have to choose the most economic path based on expected costs of investment and market allowance prices. Generators that opt to invest in abatement technology, and those that buy allowances, will have different bidding behavior and impact market prices differently, since the purchasers of permits will bid the cost of allowances in their energy bids.

We track announced current and future abatement technology installations, and modify emission rates of the plants based on the technology they plan to install. Commonly, these installations are in the form of SCR (Selective Catalytic Reduction) or SNCR (Selective Non-Catalytic Reduction), which reduce $NO_x$ emission levels by up to 75-85%. Additionally, we model an increase in fixed and variable operating costs to account for the SCR or other technology installed.

[1] GE contingency analysis: GE iteratively performed load flow simulations with every line in the system taken out individually, and extracted for monitoring the cumulative set of lines that had flows over 80 percent of their emergency rating in any of the iterations.

We believe holders (and purchasers) of allowances will bid in the value of their allowances into the energy market, since each unit of generation results in an opportunity cost (or real cost) of trading (or purchasing) its associated emission allowance in the allowance market. In equilibrium, the trading price of allowances should settle at the incremental cost of abatement technology plus a premium for the option of having the flexibility of trading, rather than having to make a permanent investment. We therefore include the value of allowances in the bid price for all holders of allowances. NOx trading is modeled in summer months only (May-Oct). For plants located in states that are not part of the SIP call, we assume they do not engage in any $NO_x$ allowance trading, and do not modify their bid price to account for $NO_x$ emissions.

Our NOx allowance prices are set at $4500/ton through the analysis period. We believe that allowance prices are likely to always include a premium for the flexibility inherent in trading, and hence are likely to settle at a higher price than the value of incremental abatement technology.

***Data Sources***: We use EPA's Emission Inventory and E-GRID database, showing plant heat input, NOx and SO2 emissions, and emission rates for power plants that are required to comply with the Acid Rain program. Capital costs for NOx abatement technology are obtained from EPA's Regulatory Impact Assessment report for the NOx Budget Program, originally provided by Bechtel Corporation. Allowance prices are derived from market publications that track allowance trades, principally from the Cantor Fitzgerald Environmental Brokerage Service.

# 8. Conventional Hydro and Pumped Storage Units

***Description***: GE MAPS has special provisions for modeling hydro units. These data do not require any significant analysis or manipulation, except to provide seasonal patterns of water flow for conventional hydro units.

***Data Sources:*** The NERC ES&D database is used for all hydro unit information.

# 9. External Region Supply Curves

The model explicitly models the full Midwest system, including MAPP, MAIN, ECAR, SERC, SPP, FRCC, and Ontario. Regions outside this study area are modeled as a series of load profiles (to represent exports). We use historic flows, combined with our expectation of future conditions in these areas, to project export levels for each of the forecast years. Specifically, we have external load curves for PJM, WSCC and Manitoba.

# 10. NUG Contracts

***Description:*** We model Non-Utility Generation units effectively as must-run units in the short term by assigning them a very low fuel cost. We include all NUGs in the Midwest that are generating in net. Recently, there have been many market and structural changes that affect these contracts and many utilities are considering or are in the process of re-negotiation of these contracts. If the re-negotiations are successful then the associated generation units will run based on their economics only and thus become dispatchable. We assume all the NUGs in the Midwest will be dispatchable by 2004.

# 11. Dispatchable Demand (Interruptible Load)

***Description:*** We include in our modeling a representation of interruptible load to capture the effects on electricity prices. The presence of demand response is important to the energy and installed capacity prices. In the energy market the value of energy to interruptible load caps the prices and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value.

We spread this dispatchable demand among companies based on their load share of the total system load (unless we have more detailed information). The dispatchable demand units are modeled as generators with a dispatch price of $600/MWh for the first block (50% of a company's dispatchable demand) and $800/MWh for the second block. These units rarely run in our model, as the high energy prices they require are assumed to indicate a supply shortfall and prompt new entry to meet the local demand. These units play an insignificant role in the energy market, but an important role in the capacity market. If these loads can truly be interrupted during peak hours, they will be paid the capacity market-clearing price. Thus they have strong incentives to make themselves available during peak hours. When these units are included in the required reserve margin calculation they reduce the requirement of installed capacity and thus reduce the new entry and help increase the energy prices consistent with market behavior.

***Data Sources***: We used interruptible load values based on EIA-411 filings (2001). These data are subject to some uncertainty as utilities report a combination of interruptible load and Demand Side Management reduction in peak load and total energy. We then distribute the interruptible load uniformly among the Load Serving Entities.

# 12. Market Model Assumptions

- *Marginal Cost Bidding:* We assume all generation units bid marginal cost (opportunity cost of fuel plus VOM plus opportunity cost of tradable permits). It is reasonable to assume that the real markets are not perfectly competitive and thus our prices tend to underestimate the prices in the real markets.
- *Installed Capacity:* We assumed installed capacity requirements of 15% to 18% depending on the pool for the entire simulation period. Reserve margin for the MAIN region is modeled as 15% until 2005 and 17% for 2006 and after.
- *ISO Boundaries and Regional Wheeling Charges*: Due to the continuously changing market boundaries, no wheeling charges between the U.S. pools are modeled for this simulation. It can be modeled upon request. Furthermore, the effect of ComEd joining PJM is believed to be minimal if any since the transmission system is physically integrated in the Midwest system and the PJM-MISO planning of an integrated market.
- *Operating Reserves (spinning and standby)*: The operating reserves are based on the specific requirements instituted by each NERC region. These requirements are based on the loss of the largest single generator or the largest single generator and half the second largest generator. The spinning reserves market affects the energy market prices since the units that spin cannot produce electricity under normal conditions. The energy prices are higher when reserves markets are modeled. Exhibit-3 shows the operating reserves by region.
- Transmission Losses: We do not model loses at this stage because the logic in GE MAPS is not accurate and introduces significant error to our analysis. We are working with GE on updating the losses logic such that it is consistent with various proposals for loss pricing. Specifically, we are planning to include the cost of marginal losses in the spot prices.

**Exhibit-3 – Reserve Margin Assumptions**

| Pool | Total Operating Reserves: As a % of Hourly Load | Total Operating Reserves: As a MW value | % of Operating Reserves that is Quick Start |
|---|---|---|---|
| SPP | - | 1782 | 35% |
| ECAR | 4% | - | 35% |
| SERC | 4% | - | 35% |
| FRCC | - | 853 | 35% |
| MAPP | - | 871 | 35% |
| MAIN | - | 1174 | 35% |
| ONTARIO | - | 1322 | 35% |

# APPENDIX 1: Energy and Load Forecast

**Table-1: Energy Forecast for ECAR, MAIN and MAPP Region**

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|---|
| ECAR | 579508000 | 587932000 | 598134000 | 604617000 | 612718000 | 622655197 |
| MAIN | 275870040 | 279501640 | 283865939 | 287811960 | 291506895 | 295812668 |
| MAPP | 157599680 | 160800640 | 163421440 | 166275200 | 168959927 | 171874258 |

(MWh)

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|
| ECAR | 632397236 | 643032488 | 653002476 | 663128863 | 673714344 | 684099449 |
| MAIN | 299285671 | 303471483 | 307948417 | 312211403 | 316862988 | 321358665 |
| MAPP | 174625576 | 177455447 | 180244566 | 183195332 | 186232524 | 189413068 |

(MWh)

**Table-2: Load Forecast for ECAR, MAIN and MAPP Region**

| Pool | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|---|
| ECAR | 106130 | 107964 | 109905 | 111169 | 112711 | 114374 |
| MAIN | 57054 | 58105 | 59156 | 60170 | 61103 | 62143 |
| MAPP | 30697 | 31272 | 31803 | 32333 | 32974 | 33584 |

(MW)

| Pool | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|
| ECAR | 116068 | 117559 | 119569 | 121602 | 123509 | 125396 |
| MAIN | 63092 | 64250 | 65188 | 66140 | 67200 | 68309 |
| MAPP | 34239 | 35093 | 35553 | 36018 | 36670 | 37327 |

(MW)

# APPENDIX 2: New Entry and Retirement

Additional new entry after 2005 is done on an economic basis.

**Table-3: New Entry for ECAR, MAIN and MAPP Region**

| Region | Year | Unit Name | State | Type | Installation Date | Capacity | Heat Rate |
|---|---|---|---|---|---|---|---|
| ECAR | 2003 | Bay Windpower | MI | WND | Jan-2003 | 4.5 | 10 |
| | | Bowling Green Additions (PGE) | OH | GTg | Jan-2003 | 42.1 | 10000 |
| | | Columbia Electric | WV | GTg | Sep-2003 | 460 | 10000 |
| | | Dresden Energy | OH | CCg | Jul-2003 | 506 | 6900 |
| | | Fremont Energy Center | OH | CCg | Dec-2003 | 645 | 6900 |
| | | Hanging Rock | OH | CCg | May-2003 | 1140 | 6900 |
| | | Jackson (Bloomfield) | OH | GTg | Jun-2003 | 500 | 10000 |
| | | Napoleon Additions (PGE) | OH | GTg | Jan-2003 | 42.1 | 10000 |
| | | Noblesville 3 | IN | CCg | Jul-2003 | 275 | 6900 |
| | | PG&E National Van Buren (Covert) | MI | CCg | Oct-2003 | 1075 | 6900 |
| | | PSEG Lawrenceburg 1 | IN | CCg | Dec-2003 | 529 | 6900 |
| | | PSEG Lawrenceburg 2 | IN | CCg | Dec-2003 | 529 | 6900 |
| | | Springdale 3-5 | PA | CCg | Sep-2003 | 490 | 8000 |
| | | Waterford Energy CC | OH | CCg | Apr-2003 | 460 | 6900 |
| | | Waterford Energy GT | OH | CCg | Apr-2003 | 320 | 6900 |
| | | West End | OH | GTg | Jun-2003 | 75 | 10000 |
| | 2005 | Cogentrix (Jackson County) | OH | CCg | Jan-2005 | 980 | 6800 |
| | 2006 | St. Joseph County (Allegheny) | IN | CCg | Jun-2006 | 580 | 6900 |
| MAIN | 2003 | Clinton Upgraded | IL | NU | Oct-2003 | 1116 | 10602 |
| | | Goose Creek (Aquila) | IL | GTg | Jun-2003 | 470 | 12000 |
| | | LS Power/Dixon (Nelson Lee) | IL | CCg | Sep-2003 | 535 | 6900 |
| | | LS Power/Dixon (Nelson Lee) | IL | CCg | Sep-2003 | 535 | 6900 |
| | | Power Iowa 4 | IA | WND | Jun-2003 | 250 | 10 |
| | 2004 | Kaukauna Gas & Diesel upgraded | WI | GTgo | Apr-2004 | 60 | 13500 |
| | | Riverside Project (Calpine) | WI | CCg | Jul-2004 | 580 | 6800 |
| MAPP | 2003 | Greater Des Moines Energy Center CT | IA | GTg | Jun-2003 | 305 | 10000 |
| | | Moraine Wind Project | MN | WND | Oct-2003 | 50 | 10 |
| | 2005 | Greater Des Moines Energy Center CC | IA | CCg | Jan-2005 | 495 | 6900 |

**Table-4: Retirement for ECAR, MAIN and MAPP Region**

| Region | Year | Unit Name | State | Type | Retirement Date | Capacity | Heat Rate |
|---|---|---|---|---|---|---|---|
| ECAR | 2003 | Edwardsport 6 | IN | STo | Dec-2003 | 40 | 12966 |
| | | Edwardsport 7 | IN | STc | Dec-2003 | 45 | 12727 |
| | | Edwardsport 8 | IN | STc | Dec-2003 | 75 | 12754 |
| | | Sugar Creek Energy | IN | GTg | May-2003 | 275 | 10000 |
| | 2004 | Connersville 1 | IN | GTo | Dec-2004 | 42 | 11814 |
| | | Connersville 2 | IN | GTo | Dec-2004 | 43 | 11814 |
| | | Glen Lyn 5 | VA | STc | Dec-2004 | 90 | 11449 |
| MAIN | 2003 | Clinton | IL | NU | Oct-2003 | 930 | 10602 |
| | 2004 | Kaukauna Gas & Diese | WI | GTgo | Mar-2004 | 17 | 15000 |
| | | Port Washington 2 | WI | STc | Oct-2004 | 80 | 10274 |
| | | Port Washington 3 | WI | STc | Oct-2004 | 80 | 10368 |
| | | Port Washington 4 | WI | STc | Oct-2004 | 80 | 10274 |
| MAPP | 2004 | Greater Des Moines Energy Center CT | IA | GTg | Dec-2004 | 305 | 10000 |

# APPENDIX 3: **Capacity Balance**

Listed below is the capacity balance for the MAIN region for the years 2004 through 2014.

**Table-5: MAIN Region Capacity Balance**

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|---|
| Total Internal Demand | 57,054 | 58,105 | 59,156 | 60,170 | 61,103 | 62,143 |
| Interruptible Demand | 2,731 | 2,722 | 2,739 | 2,753 | 2,770 | 2,784 |
| Net Internal Demand | 54,323 | 55,383 | 56,417 | 57,417 | 58,333 | 59,359 |
| Reserve Margin % | 15 | 15 | 15 | 17 | 17 | 17 |
| Load + Reserve | 62,471 | 63,690 | 64,880 | 67,178 | 68,250 | 69,450 |
| Purchases | 345 | 375 | 375 | 375 | 375 | 375 |
| Sales | 5 | 5 | 5 | 5 | 5 | 5 |
| New Entry | 2,906 | 640 | 0 | 0 | 0 | 0 |
| Retirement | 930 | 257 | 0 | 0 | 0 | 0 |
| Installed Capacity | 68,339 | 69,148 | 68,908 | 68,908 | 68,908 | 68,908 |
| Balance | 6,208 | 5,828 | 4,398 | 2,100 | 1,028 | -172 |

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|
| Total Internal Demand | 63,092 | 64,250 | 65,188 | 66,140 | 67,200 | 68,309 |
| Interruptible Demand | 2,798 | 2,814 | 2,814 | 2,814 | 2,814 | 2,814 |
| Net Internal Demand | 60,294 | 61,436 | 62,374 | 63,326 | 64,386 | 65,495 |
| Reserve Margin % | 17 | 17 | 17 | 17 | 17 | 17 |
| Load + Reserve | 70,544 | 71,880 | 72,978 | 74,091 | 75,332 | 76,629 |
| Purchases | 375 | 375 | 375 | 375 | 375 | 375 |
| Sales | 5 | 5 | 5 | 5 | 5 | 5 |
| New Entry | 1,250 | 1,250 | 1,000 | 1,250 | 1,250 | 1,250 |
| Retirement | 0 | 0 | 0 | 0 | 0 | 0 |
| Installed Capacity | 70,158 | 71,408 | 72,408 | 73,658 | 74,908 | 76,158 |
| Balance | -16 | -102 | -200 | -63 | -54 | -101 |

# APPENDIX 4: Nuclear Units

**Table-6: MAIN Nuclear Unit List**

| Full Name | Summer Capacity (MW) | Winter Capacity (MW) | Final HR (kW/Btu) | Pool | State | Installation Date | Retirement Date |
|---|---|---|---|---|---|---|---|
| Braidwood 1 | 1116 | 1145 | 10295 | MAIN | IL | 01Jul1987 | 17Oct2026 |
| Braidwood 2 | 1116 | 1145 | 10295 | MAIN | IL | 01May1988 | 18Dec2027 |
| Byron 1 | 1114 | 1145 | 10399 | MAIN | IL | 01Feb1985 | 31Oct2024 |
| Byron 2 | 1114 | 1145 | 10191 | MAIN | IL | 01Jan1987 | 06Nov2026 |
| Callaway | 1127 | 1161 | 10500 | MAIN | MO | 01Oct1984 | 18Oct2024 |
| Clinton | 930 | 944 | 10602 | MAIN | IL | 01Apr1987 | 29Sep2026 |
| Dresden 2 | 784 | 800 | 11139 | MAIN | IL | 01Dec1969 | 22Dec2009 |
| Dresden 3 | 784 | 800 | 11113 | MAIN | IL | 01Mar1971 | 12Jan2011 |
| Kewaunee | 498 | 511 | 11004 | MAIN | WI | 01Dec1973 | 21Dec2013 |
| La Salle 1 | 1077 | 1105 | 10585 | MAIN | IL | 01Aug1982 | 17May2022 |
| La Salle 2 | 1087 | 1105 | 10716 | MAIN | IL | 01Mar1984 | 16Dec2023 |
| Point Beach 1 | 505 | 510 | 10400 | MAIN | WI | 01Oct1970 | 05Oct2010 |
| Point Beach 2 | 507 | 512 | 10505 | MAIN | WI | 01Mar1973 | 08Mar2013 |
| Quad Cities 1 | 762 | 784 | 10946 | MAIN | IL | 01Dec1972 | 14Dec2012 |
| Quad Cities 2 | 762 | 784 | 10967 | MAIN | IL | 01Dec1972 | 14Dec2012 |

# APPENDIX 5: Capacity Upgrade and Unit Additions

**Table-7 Increase in MAIN Nuclear Capacity**

| Unit | Current Capacity | Increased Capacity | Upgrade Timing (from Source) | Reference |
|---|---|---|---|---|
| Dresden 2 | 784MW | 912MW | 2001-2002 | NRC Press Release 12/26/2001 |
| Dresden 3 | 784MW | 912MW | 2002-2003 | NRC Press Release 12/26/2001 |
| Quad City 1 | 762MW | 912MW | 2002-2003 | NRC Press Release 12/26/2001 |
| Quad City 2 | 762MW | 912MW | 2002-2003 | NRC Press Release 12/26/2001 |
| Clinton | 930MW | 1116MW | After 2002 in two phases | NRC Press Release 4/4/2002 |

# Appendix 6: Nuclear Unit Planned Outage Schedules

Nuclear unit refueling outages are scheduled as the table below

**Table-8 MAIN Nuclear Units Planned Outage Schedules**

| Full Name | Typical Refueling Outage Length (days) | Typical Outage Cycle Length (Months) | Most Recent Outage Start Date |
|---|---|---|---|
| Braidwood 1 | 17 | 18 | 04/01/03 |
| Braidwood 2 | 17 | 18 | 04/19/02 |
| Byron 1 | 50 | 18 | 03/12/02 |
| Byron 2 | 50 | 18 | 04/04/01 |
| Callaway | 45 | 18 | 04/07/01 |
| Clinton | 30 | 18 | 04/02/02 |
| Dresden 2 | 25 | 24 | 09/01/00 |
| Dresden 3 | 25 | 24 | 10/21/01 |
| Kewaunee | 60 | 18 | 09/22/01 |
| La Salle 1 | 30 | 24 | 01/10/02 |
| La Salle 2 | 30 | 24 | 02/1/03 |
| Point Beach 1 | 35 | 18 | 04/07/01 |
| Point Beach 2 | 35 | 18 | 04/13/02 |
| Quad Cities 1 | 20 | 24 | 01/10/02 |
| Quad Cities 2 | 20 | 24 | 02/12/02 |