2020 Rate Case

Response to September 24, 2021 Ordering Paragraphs 9 & 10

PPL companies

Generation Planning & Analysis

December 22, 2021

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1 Ordering Paragraphs 9 and 10 from the September 24, 2021 Orders

On September 24, 2021, the Kentucky Public Service Commission issued orders in Case Nos. 2020-00349 and 2020-00350 with the following requirements for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"):

9. *Within 90 days of the date of entry of this Order, LG&E/KU shall submit a filing that details how LG&E/KU will increase the transparency of their PROSYM modeling to the Commission.*
10. *Within 90 days of the date of entry of this Order, LG&E/KU shall submit a filing that explains how non-fuel O&M costs are determined to be variable and fixed costs.*

The Companies' responses are contained in the following sections.

2 Companies' Response to Ordering Paragraph 9

2.1 The Companies propose to include in future filings a more granular summary of model inputs and outputs in the original filing.

The Companies reviewed all Rate Case responses, exhibits, and data requests pertaining to production cost model inputs and outputs. The Attachment to Filing Requirement Tab 16 - 807 KAR 5:001 Section 16(7)(c) Item G, Generation Forecast Process, contains a summary of the Companies' process for developing the generation forecast. The Attachment to Filing Requirement Tab 16 - 807 KAR 5:001 Section 16(7)(c) Item H, 2021 Business Plan Generation and OSS Forecast, summarizes a majority of key inputs and outputs. For example, emission allowance price assumptions are listed on Slide 16, and variable operation and maintenance ("O&M") costs by unit are listed on Slide 26. However, data is provided on an annual basis, whereas production cost model inputs are often more granular (i.e., seasonal, monthly, or hourly). Furthermore, a number of minor inputs were omitted, including a breakdown of variable O&M by cost component, emissions rates, and generating resource inputs such as SCR minimum and operating limits.

Therefore, to address the Commission's concerns regarding transparency moving forward, the Companies propose to provide in the original filing production cost model inputs and outputs in their native, most granular format. In addition, because the native format is oftentimes not intuitive to someone unfamiliar with the production cost model software syntax, the Companies propose to provide inputs and outputs in an Excel workbook. As examples, please see Attachment A for an updated Generation Forecast Process document, Attachments B and C for inputs and outputs in Excel workbooks, and Attachments D and E for inputs and outputs in native formats, all pertaining to the Companies' 2021 Business Plan. Attachments B and C are meant to accompany and correspond with Attachment A for ease of understanding.

The Companies' production cost model can summarize outputs on an annual, monthly, and hourly level. Because hourly outputs in native format require approximately 200 megabytes per year, and because hourly outputs are not always produced or utilized in the Companies' analyses, the Companies propose to provide annual and monthly outputs in the original filing and make hourly outputs available upon request, with the exception of filings focused on marginal cost for which the Companies will provide hourly marginal cost outputs. In future marginal cost filings, the granularity of inputs provided in the original filing will enable staff to independently verify the Companies' marginal costs in a software package of their choosing.

2.2 In future proceedings, the Companies propose to allow for one model re-run per intervening party and the Commission per proceeding, upon a party's request.

To accommodate this request, the Companies propose that a party submit an updated Attachment B highlighting their desired input changes as an attachment to their data request. The Companies will complete the model run and provide the associated model outputs at the end of the ten business-day period allotted for responding to data requests.

2.3 If desired, the Companies will support Commission Staff in developing the capabilities to re-run the Companies' models with alternative inputs.

With model inputs provided in native format, to re-run the Companies' production cost model, the Commission would need to license the Companies' production cost modeling software and members of the Commission Staff would need to be trained by the software vendor to model generation systems using the software. The Companies will support this process as requested.

2.4 The Companies or their counsel will provide secure online access to large data files as needed.

As noted above, hourly output data files are routinely very large (200 MB or more per year modeled) and exceed file size limitations of the Commission's website. To address this issue, the Companies or their counsel will provide secure online storage for and access to such files. This approach is similar to what the Companies and their counsel have done to provide access to confidential information and large data files for several years in electronic cases. This approach will ensure the Commission and intervenors can have rapid and appropriate access to the data as prescribed by the Commission without having to distribute multiple mass-storage devices (such as thumb drives) to the Commission and intervenors, which adds cost and delay, and can create cyber-security issues.

3 Companies' Response to Ordering Paragraph 10

The Companies distinguish between variable and fixed generation costs based on their chart of accounts in conjunction with the FERC Uniform System of Accounts (USofA). In accordance with the USofA, power production expenses must be segregated based on the type of production: steam, nuclear, hydro, and other. Further segregation is required for each production type between Operation (including fuel) and Maintenance expenses. In general, operating costs that are a function of a unit's output, e.g., fuel and consumables, are considered variable costs, while all other costs are considered fixed.

Costs such as fuel costs, emission allowance costs, and costs of consumables for environmental compliance are incurred as a function of a unit's output and are considered variable. Other variable costs, many of which are capitalized, are incurred as a function of a unit's operating hours (e.g. costs associated with Cane Run 7's long-term program contract), and others as a function of unit starts. Labor costs and the cost of routine maintenance are generally not impacted by minor variations in annual generation and are therefore considered fixed costs. However, in evaluating replacement generation, all costs for existing units are effectively variable because all generation costs are saved when the unit is retired.

Due to its intermittency and small size relative to the Companies' energy requirements, a single small or large qualifying renewable facility will likely have no material impact on the Companies' unit commitment decisions, the number of hours a unit operates, or the overall wear and tear of equipment. Therefore, in evaluating costs avoided by renewable qualifying facilities or Green Tariff Option #3 solar facilities, only costs incurred as a function of a unit's output level (i.e., fuel costs, emission allowance costs, and consumables for environmental compliance) are assumed to be avoided. However, as the amount of renewables in the Companies' generation portfolio increases to hundreds of megawatts ("MW"), unit commitment decisions will undoubtedly be impacted to some extent and costs incurred as a function of unit starts or operating hours will be avoided.

The Companies are planning to add 100 MW of nameplate solar in 2023 ("Rhudes Creek Solar") and an additional 125 MW of Green Tariff Option #3 solar in 2025. As discussed in the Companies' 2021 Integrated Resource Plan, the availability of solar under peak load conditions is uncertain.[1] As a result, the Companies plan to carefully evaluate the moment-to-moment availability of the Rhudes Creek solar facility and then incorporate lessons learned in unit commitment decisions.

[1] See Case No. 2021-00393 and discussion regarding Figure 6 on page 11 of the 2021 IRP Reserve Margin Analysis (Volume III).

Generation
Forecast Process

PPL companies

Generation Planning & Analysis
2020

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1 Introduction

The Generation Planning group annually prepares a generation and off-system sales ("OSS") forecast for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies"). This forecast provides the basis for – among other things – the Companies' forecasts of fuel costs, generation-related variable operating and maintenance costs, economy purchased power, and OSS margin. This document summarizes the process used to prepare the generation forecast.

2 Production Cost Model

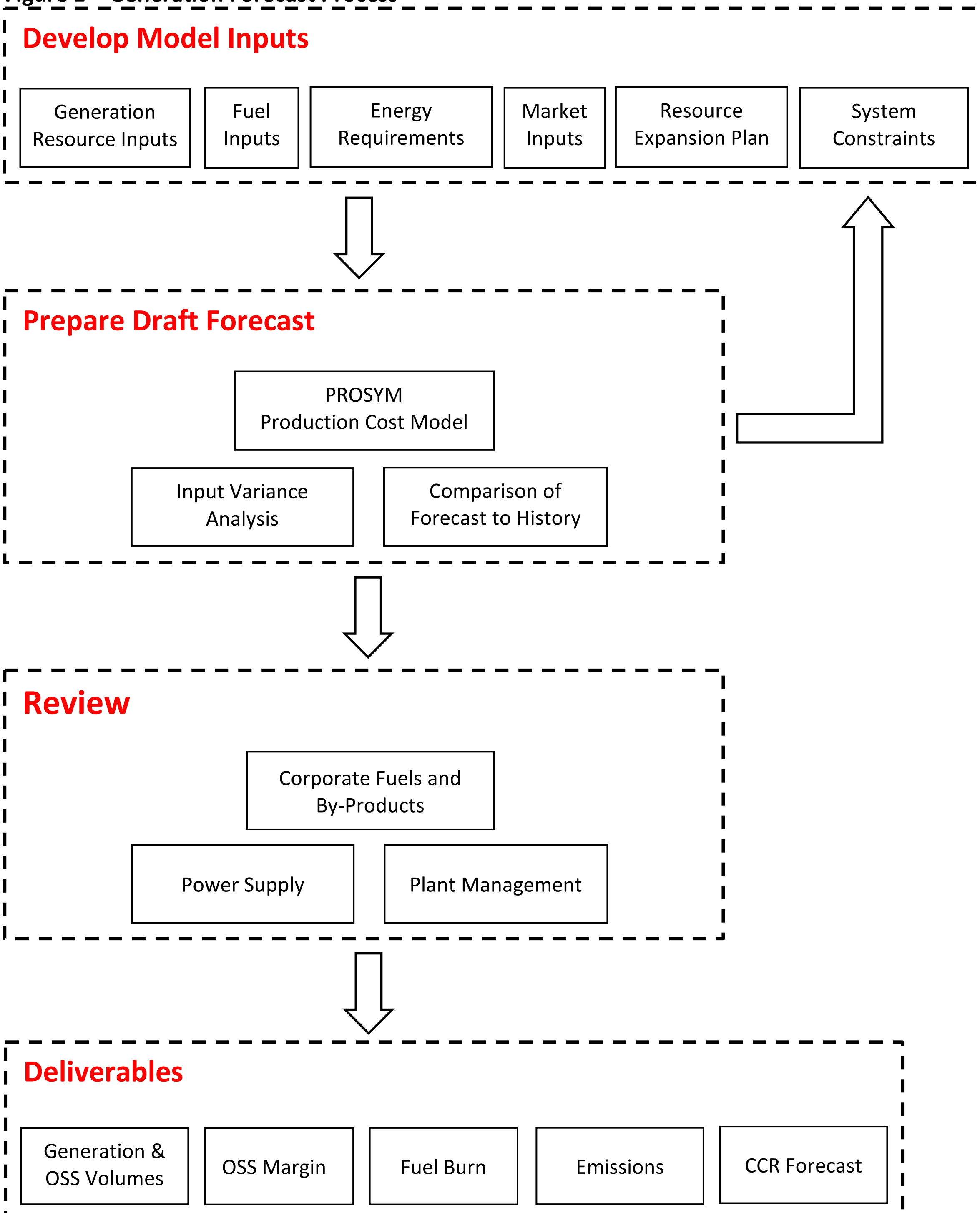
The Companies' generation forecast is developed using Hitachi ABB Power Grids' PROSYM, a proprietary production cost model. PROSYM is a chronological simulation engine that optimizes unit commitment and economic dispatch to meet the load for an interconnected electric system, considering the reserve requirements and other aspects of the electric system. PROSYM is a proven production cost model that has been used by utilities throughout the United States for decades.

In addition to PROSYM, SAS, R, Microsoft Access, and Microsoft Excel are used to develop inputs and process and analyze forecast results. Presentations containing forecast assumptions and results are prepared using Microsoft PowerPoint.

3 Process Overview

Figure 1 provides an overview of the process used to develop the Companies' generation forecast. In the first part of the process, model inputs are developed. Then, the model inputs are loaded into PROSYM and a draft generation forecast is prepared. PROSYM is a complex model, so extensive review takes place to ensure that the inputs are correctly loaded into the model and that the model results are reasonable. An input variance analysis evaluates the impact of changing each input or group of related inputs to ensure that the associated output changes are reasonable. Then, various elements of the generation forecast are compared to historical trends for reasonableness. If the forecast results are not deemed reasonable, the applicable model inputs are adjusted and the process is repeated. In the third part of the process, the results of the forecast are reviewed by other departments. This review process ensures that the forecast considers feedback from a broad range of perspectives. After all parties are satisfied with the results, the generation forecast is finalized and distributed to the groups who use the forecast to prepare financial budgets. Each part of this process is discussed further in the following sections.

Figure 1 – Generation Forecast Process



3.1 Develop Model Inputs

The first part of the process used to develop the Companies' generation forecast involves developing and vetting model inputs. Well-vetted inputs are essential to a good forecast. Wherever possible (and applicable), model inputs are initially developed based on an analysis of historical data. Then, these inputs are reviewed with plant management for reasonableness. Model inputs are adjusted when historical trends are not expected to continue in the future. Table 1 lists the six main categories of model inputs along with the inputs in each category. Each of these categories is discussed further in the following sections.

Table 1 - Key Inputs to the Generation Forecast

Input Category	Inputs
Generation Resource Inputs	Minimum and maximum capacity, heat rate, emissions rates, variable operating and maintenance costs, operating limits, unit availability, company allocation
Fuel Inputs	Coal prices, natural gas prices, oil prices, CCR adjustment, other fuel-related inputs
Energy Requirements	Hourly energy requirements
Market Inputs	Electricity prices, emission allowance prices, off-system sales and purchase limits, off-system sales and purchase price thresholds
Expansion Plan Inputs	Timing and type of expansion plan units
System Constraints	Transmission constraints, spinning reserve requirements, off-system sales constraints, dispatch order rules

3.1.1 Generation Resource Inputs

The generation resources modeled in PROSYM include the Companies' existing and (if applicable) planned generation resources. Generation resources include generating units owned by the Companies, power purchase agreements with other power producers, and the capacity associated with the Companies' curtailable service rider ("CSR") customers.[1]

Generation resource inputs define the operating characteristics of the generation resources. These inputs include the resource's minimum and maximum capacity, heat rate, emissions rates, variable operating and maintenance costs, operating limits, equivalent unplanned outage rate, and ownership allocation. Each of these inputs is discussed further in the following sections.

3.1.1.1 Minimum and Maximum Capacity

The operating minimum, SCR minimum, and maximum capacity (or output) is specified for each generation resource as a megawatt ("MW") value for the summer, winter, fall, and spring seasons. SCR minimum applies only to units with SCRs and is the minimum capacity at which the SCR can operate (i.e., operation at a capacity level lower than the SCR minimum requires that the SCR be nonoperational). Capacity inputs are specified based on an analysis of historical data and unit rating tests but rarely change materially from forecast to forecast.

Brown units 5 and 8-11 are equipped with Inlet Cooling ("ICE") to increase output if needed during the summer months. The Companies model these ICE units as separate units with rules to ensure they do not operate simultaneously with their non-ICE counterparts.

[1] The Companies own 75% of Trimble County 1 and 2. Model inputs reflect 75% ownership.

3.1.1.2 Heat Rate
The heat rate specifies the amount of fuel required to produce a megawatt-hour ("MWh") of electricity. Where applicable, a heat rate curve is specified for each generation resource for the summer, winter, fall, and spring seasons. The heat rate curves are specified based on an analysis of historical data and heat rate tests performed by the plants.

3.1.1.3 Emissions Rates
Where applicable, PROSYM models the emissions of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), and carbon dioxide ("CO_2") for each generation resource:

- SO_2 Emissions: For coal units, SO_2 emissions are modeled as a function of the unit's SO_2 removal rate and the sulfur content of the fuel. The SO_2 removal rate for each coal unit ranges between 91.2% and 99.1%, depending on the vintage of the unit's flue-gas desulfurization ("FGD") equipment.[2] The SO_2 removal rate is specified based on an analysis of historical data. The sulfur content of the fuel is provided by the Corporate Fuels and By-Products group. For gas units, SO_2 emissions are modeled as a function of an average SO_2 emission rate (specified in lb/MMBtu) estimated by the unit manufacturer.
- NO_x Emissions: For coal units, NO_x emissions are modeled as a function of a NO_x emission curve (specified in lb/MMBtu). NO_x emissions vary seasonally and with the unit's generation output and are lower for units retrofitted with selective catalytic reduction ("SCR") equipment. The NO_x emission curve is specified based on an analysis of historical data in conjunction with performance expectations associated with the timing of catalyst replacement. Cane Run 7's NO_x emission rate is specified based on an analysis of historical data. For other gas units, NO_x emissions are modeled as a function of an average NO_x emission rate (also specified in lb/MMBtu) estimated by the unit manufacturer.
- CO_2 Emissions: CO_2 emissions are modeled as a function of an average CO_2 emission rate (specified in lb/MMBtu). Average CO_2 emission rates are dependent on the type of fuel burned in the unit and are based on engineering estimates.

3.1.1.4 Variable Operating and Maintenance Cost
Variable operating and maintenance ("O&M") costs include all incremental non-fuel costs that are incurred when operating the generation resource. For coal units, variable O&M includes the cost of operating environmental controls, including Flue Gas Desulfurization ("FGD"), Selective Catalytic Reduction ("SCR"), Sulfuric Acid Mist ("SAM")/SO3 Mitigation, Fabric Filter ("FF")/Baghouse, and Process Water Systems ("PWS"), as applicable. For Cane Run 7, variable O&M is specified as "Operating Charge" in dollars per operating hour and "Start Cost Adder" in dollars per start. These inputs reflect the cost of its long-term program contract ("LTPC"), which is paid quarterly based on the number of starts and operating hours for the unit. For simple-cycle combustion turbines ("SCCTs"), the cost of major maintenance is specified as "Start Cost Adder" in dollars per start and considered in unit commitment and dispatch decisions but not included in the model's forecast of production costs.

3.1.1.5 Operating Limits
The following operating limits are modeled in PROYSM for each generation resource. Each of these inputs is specified based on operational experience.

- Minimum Up-Time: Minimum up-time is the minimum number of hours after coming online that a generation resource must remain online before it can be taken offline for economic reasons.

[2] Mill Creek Units 1-2 share the same FGD.

- Minimum Down-Time: Minimum down-time is the minimum number of hours after coming offline that a generation resource must remain offline before it can be brought back online.
- Mean Time to Repair: Mean time to repair is the average length (specified in hours) of forced outages.
- Ramp-Up Rate: Ramp-up rate is the rate (specified in MW/hour) at which a generation resource can increase its output.
- Ramp-Down Rate: Ramp-down rate is the rate (specified in MW/hour) at which a generation resource can decrease its output.
- Run-Up Rate: Run-up rate is the rate (specified in MW/hour) at which a generation resource can increase its output when it is first committed.
- Run-Up Hours: Run-up hours is the number of hours during which the run-up rate applies immediately after a generation resource is committed.

3.1.1.6 Unit Availability

The following unit availability inputs are modeled in PROSYM for each resource. These inputs determine the extent a resource is available for operation.

- Planned Maintenance Schedule: The planned maintenance schedule specifies the timing and duration of planned maintenance events. The schedule is developed with input from plant management, Generation Dispatch, and Project Engineering, such that the outages will have the least economic and reliability impact to customers.
- Equivalent Unplanned Outage Rate ("EUOR"): EUOR inputs determine the amount of time the generation resource is unavailable due either to a forced outage, derate, or maintenance outage. EUOR inputs are specified based on an analysis of historical data.

3.1.1.7 Company Allocation

The energy and capacity for all generation resources modeled in PROSYM are either wholly or jointly allocated to LG&E and/or KU. For each generation resource, the Companies' allocation is specified in PROSYM to facilitate the process of creating generation and other forecasts by company as well as forecasting the After-the-Fact Billing process used to calculate the Fuel Adjustment Clause.

3.1.1.8 Renewables

The Companies model renewable resources depending on the characteristics of each resource. KU's hydro facility, Dix Dam, is modeled using a monthly energy forecast which is based on history. LG&E's hydro facility, Ohio Falls, is modeled using monthly maximum capacity, also based on history. For solar facilities and power purchase agreements, the Companies model an hourly generation forecast which is correlated to the weather forecast on which the hourly energy requirements forecast is based.

3.1.2 Fuel Inputs

Each thermal generation resource is associated with one or more fuel forecasts for startup and for online operation. The fuel inputs in PROSYM specify the cost of fuel, the fuel's heat and SO_2 content, the quantity of fuel required for startup, and – for generation resources where the fuel price is a blend of multiple fuel forecasts – the blend ratio of each fuel forecast. For coal, the fuel inputs also include a fuel price adjustment for coal combustion residuals ("CCR") based on forecasted CCR revenues and costs.[3] The model makes commitment and dispatch decisions based on replacement fuel costs including the CCR adjustment, while an estimate of total fuel cost is based on inventory fuel costs including fixed costs.

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[3] Coal combustion residuals or CCRs are by-products such as fly ash and bottom ash left over after coal is burned, and gypsum which is created as sulfur dioxide is removed from flue gas.

3.1.2.1 Coal Prices

A forecast of delivered coal prices is developed for each station by the Corporate Fuels and By-products group. These forecasts reflect the cost curve for the Companies' contracted coal volumes, the assumed cost of coal that will be contracted in the future, and the cost of transporting fuel from mines to the stations. Based on the coal burn forecast by unit, the Corporate Fuels and By-Products group calculates the target coal purchase tonnage needed each year to maintain desired inventory levels while meeting the forecasted coal burn. The forecasted price per MMBtu for each coal type is the result of computing the volume weighted average of the price of coal already under contract and the market price of coal. In the first five years of the forecast, the market price is a blend of coal bids received, but not under contract, and a forecast from an independent third party consultant. Beyond the fifth year, prices are increased at the compound annual growth rate reflected in the U.S. Energy Information Administration's ("EIA") latest Annual Energy Outlook for the "All Coals, Minemouth" price forecast.

3.1.2.2 Natural Gas and Oil Prices

A forecast of Henry Hub natural gas prices is developed as a starting point for undelivered gas. The initial years of the Henry Hub price forecast reflect monthly forward market prices from NYMEX as of a specific recent quote date, which reflects a current view of forward prices at the time the forecast is prepared. In the subsequent years, the market prices are blended with a price forecast published in the EIA's most recent Annual Energy Outlook. The Henry Hub forward market prices are then adjusted to local delivered prices to KU and LG&E units using an average annual loss factor and a variable O&M charge per MMBtu, which also adjusts for average assumed basis differentials. For each station that uses natural gas for startup or online operations, a forecast of delivered natural gas prices is developed by adding transportation costs and a cost for pipeline losses to the forecast of Henry Hub prices.

A forecast of delivered oil prices is developed for coal units that use fuel oil for startup and for SCCTs that can use fuel oil for online operation as an alternative to natural gas. The fuel oil price forecast consists of market prices in the short term that are then interpolated to a long-term forecast. The Companies' delivered oil price forecast first uses NYMEX New York Harbor #2 fuel oil monthly contract settled prices as far out in time as there is some market liquidity.

Long-term #2 fuel oil prices are developed by applying the historical relationship between New York Harbor #2 fuel oil and West Texas Intermediate ("WTI") oil prices to forecasted WTI prices derived from IHS Global Insight's latest 30-year macro forecast. To integrate the two forecast periods, the short-term market-based fuel oil price forecast is interpolated to the long-term regression-based price forecast. The forecasted #2 fuel oil prices are then multiplied by the historical average ratio of the Companies' fuel purchase price to the New York Harbor #2 fuel oil price to arrive at the Companies' delivered fuel oil purchase price forecast.

3.1.2.3 Fuel Cost Multiplier

Fuel cost multipliers ("FCMs") are defined for large-frame combustion turbines to align the generation forecast to history and prevent an unreasonable forecast of generation from energy-limited resources. The model uses FCMs as a factor applied to fuel cost in order to determine the fuel cost used for commitment and dispatch decisions, but it is not included in the model's forecast of total fuel costs. The Companies develop the FCMs by setting an artificial price floor at a cost that allows the capacity factors of the large-frame combustion turbines to more closely reflect historical usage and remain below any environmental or operational restrictions. The Companies also use FCMs to distribute generation across the combustion turbines from more efficient units like those at Trimble County to less efficient units like those at Brown to reflect real-world consumption decisions such as the availability of firm delivery capacity.

3.1.2.4 CCR Adjustment

A forecast of revenues and costs resulting from the Companies' sales and management of CCR is developed for each station based on inputs from plant management and the Corporate Fuels and By-products department. CCR revenues and costs are combined to calculate a CCR adjustment to the fuel price (in ¢/MMBtu), to account for the value and cost of CCR production and management. The CCR adjustment to the fuel price is considered in commitment and dispatch decisions but is not included in the model's forecast of total fuel costs.

3.1.2.5 Other Fuel-Related Inputs

Other fuel inputs include the fuel blend ratio, the quantity of startup fuel, and the fuel's heat and SO_2 content.

- Fuel Type: For each generation unit, the type of fuel burned during operation is specified.
- Fuel Blend Ratio: Trimble County 2 burns a blend of Illinois Basin and Powder River Basin coals. Because the prices of these coals are specified in separate forecasts in PROSYM, the fuel blend ratio determines the weighting that is used to compute the price of coal for Trimble County 2.
- Type and Quantity of Startup Fuel: For each generating unit, the startup fuel type and quantity are the type and amount of fuel required to start the unit. These inputs are specified by fuel type and in MMBtu based on an analysis of historical data with input from plant management.
- Heat Content and SO_2 Content: Fuel heat and SO_2 contents are provided by the Corporate Fuels and By-products group.

3.1.3 Energy Requirements

PROSYM simulates the dispatch of the Companies' generating units to meet hourly energy requirements. The forecast of hourly energy requirements, which consists of native load sales and transmission and distribution losses, is developed by the Sales Analysis and Forecasting group.

3.1.4 Market Inputs

Market inputs define the market in which the Companies operate. These inputs include spot hourly wholesale electricity prices, emission allowance prices, hourly OSS and economy purchase volume limits, and OSS and economy purchase price threshold values. Together, these inputs determine when the model should make economy purchases or OSS. Each of the market inputs is discussed in the following sections.

3.1.4.1 Electricity Prices

A forecast of spot hourly electricity prices is developed to model the Companies' interactions with the electricity market. The Companies buy and sell electricity primarily with PJM through the PJM-South Import ("PJM-SI") interface/pricing point, which is used in the planning process to represent the electricity market.[4] In the initial years, monthly forward market prices for PJM West Hub ("PJM-WH")[5] quoted by Intercontinental Exchange as of a specific recent quote date are used as a basis for developing an hourly forecast of PJM-SI prices, reflecting the most current view of forward prices at the

[4] The Companies also transact electricity with counterparties other than PJM. The Companies model PJM as a representative market, considering liquidity and availability of market data.

[5] The PJM market is used as a proxy for all markets available to the Companies because most of the Companies' off-system sales and purchases are expected to be transacted with the PJM market.

time the forecast was prepared.[6] In the subsequent years, the market prices are interpolated to a long-term PJM-WH forecast developed by S&P Global/Platts. Monthly PJM-SI prices are derived by applying seasonal discount factors by peak type to the PJM-WH prices. The discount factors are based on historical ratios between actual PJM-SI and PJM-WH spot prices.

Monthly average PJM-SI prices are shaped to daily average prices by peak type by maintaining a correlation between the Companies' forecasted daily average energy and the forecasted daily average electricity price in each month, based on their historical correlation. This relationship serves as a proxy for the correlation between the daily load level in the PJM market and the corresponding daily average electricity price. The daily average prices are derived by multiplying the forecasted monthly average prices (by peak type) by a daily weighting that reflects the correlated variances between forecasted daily vs. average monthly loads and forecasted daily vs. average monthly electricity prices, based on historical observations. Hourly prices are then derived by multiplying the daily prices by hourly price multipliers that reflect the historical average ratios of hourly prices to daily prices by month and by peak type.

3.1.4.2 Emission Allowance Prices

The dispatch cost for each unit includes the unit's fuel cost, variable O&M costs, and the cost of emission allowances. Emission allowance price forecasts are developed for SO_2, ozone seasonal NO_x, and annual NO_x emission allowances. Initial prices reflect market prices as of a specific recent quote date for allowances under the Cross-State Air Pollution Rule. Longer-term prices reflect those in IHS Energy's most recent long-term planning scenario. No CO_2 emission allowance prices are included.

3.1.4.3 Hourly Off-System Sales and Purchase Volume Limits

The OSS and purchase limit inputs determine the maximum quantity (in MW) of OSS and economy purchases that can be made in any given hour. Because the volatility of available transmission capacity cannot be effectively modeled in PROSYM, limits on hourly OSS and economy purchases are used to align the volume of modeled OSS and economy purchase transactions with recent historical experience.

3.1.4.4 Off-System Sales and Purchase Price Thresholds

When making an OSS or economy purchase, the Companies incur various costs related to the transaction. These costs are referred to as OSS and purchase "thresholds." OSS and purchase thresholds include the cost of transmission and transmission losses, independent system operator balancing charges, and a risk premium the Companies' Power Supply group uses to manage the uncertainty that exists between real-time prices and aggregated hourly (or settled) prices.

3.1.5 Resource Expansion Plan Inputs

The expansion plan inputs specify the timing and type of generation resources planned, if any, to be added to the Companies' generation portfolio to meet customers' needs for energy and capacity. These generation resources can take the form of new generating units or power purchase agreements with a third-party provider. Generation resource inputs are discussed in Section 3.1.1.

3.1.6 System Constraints

PROSYM enables the user to model a variety of physical constraints that exist within the Companies' transmission system and generation portfolio. These constraints are discussed in the following sections.

[6] The quoted "off-peak wrap" forward prices for PJM-WH are split into off-peak (7x8) and weekend (2x16) peak types using historical ratios.

3.1.6.1 Transmission Constraints

The Companies' transmission and distribution system is designed to deliver electricity from generation resources to load under a variety of circumstances. Despite the flexibility that is afforded the Companies, some constraints can occur in real time. For example, there are limits to the energy that can flow from LG&E to KU. PROSYM enables the Companies to model this and other transmission constraints.

3.1.6.2 Spinning Reserve Requirements

As a NERC balancing area, the Companies are required to carry contingency reserves to ensure the reliability of the grid. To meet these obligations in a least-cost manner, the Companies are party to a reserve sharing agreement with TVA. By sharing reserves with TVA, the Companies are able to reduce the amount of contingency reserves they need to carry. In the current plan, the Companies need to maintain 254 MW of contingency reserves at all times. In addition, the Companies typically target approximately 75 MW of regulating reserves to follow load fluctuations in real time. PROSYM models these reserve requirements.

3.1.6.3 Off-System Sales Constraints

As a general rule, because hourly market prices can fluctuate, potential OSS margins from SCCTs do not justify the wear and tear associated with starting a unit in anticipation of potential OSS margins. Therefore, the Companies' SCCTs are generally only committed to meet customers' need for peak energy. For this reason, a constraint is modeled in PROSYM that reduces OSS by limiting modeled OSS when SCCTs are operating, which results in a proportion of OSS from SCCTs in line with historical volumes.

3.1.6.4 Dispatch Order Rules

Dispatch order rules determine the order in which different types of generation resources are dispatched. The majority of generation resources are dispatched economically, as specified with the "Commit" variable as "=economic" or "3." However, some units are specified with "Commit" as "4" or "5," meaning these units are not available for commitment until all of the economically dispatched units are online. For example, curtailment of the Companies' CSR customers is limited to times when most or all other company-owned resources have been or are being dispatched. The dispatch order rules enable the Companies to model this constraint.

3.2 Prepare Draft Generation Forecast

In the second part of the process used to develop the Companies' generation forecast, model inputs are loaded into PROSYM and PROSYM is used to prepare a draft generation forecast. PROSYM is a complex model, so extensive review takes place to ensure that the inputs are correctly loaded and that the model results are reasonable. An input variance analysis evaluates the impact of changing each input or group of related inputs to ensure that the associated output changes are reasonable. Then, various elements of the generation forecast are compared to historical trends for reasonableness. The input variance analysis and comparison of the forecast to history are discussed in more detail in the following sections.

3.2.1 Input Variance Analysis

The process of performing an input variance analysis begins with the previous year's generation forecast and is completed in steps. As each input or group of inputs is updated, PROSYM is used to create a new forecast. A comparison of forecast results for each step reveals the impact of changing each input (or group of related inputs) incrementally, and includes a comparison of native load production costs, OSS margin, generation volumes, unit capacity factors, fuel burn, and other factors. In most cases, the change from the previous year's forecast to the current year's forecast is explained primarily by a limited number of factors. Despite this fact, the impact of all input changes is evaluated carefully. If the impact of a change is not deemed reasonable, the model inputs are adjusted and the process is repeated.

3.2.2 Comparison of Forecast to History

The goal of the generation forecasting process is to produce the most accurate forecast possible. In addition to the input variance analysis, numerous elements of the forecast are compared to historical trends to further assess the reasonableness of the forecast. In many cases, the forecast should be consistent with historical trends. When this is not the case, it is important to ensure that forecasted deviations from historical trends are reasonable. The following is a sample of forecast elements that are compared to historical data.

- Annual/monthly/hourly generation by generation resource
- Annual/monthly fuel burn by generation resource
- Annual startup fuel by generation resource
- Annual SCCT starts and run hours
- Annual/monthly/hourly OSS volumes by peak type
- Annual/monthly/hourly OSS margin by peak type
- Annual/monthly/hourly economy purchase volumes by peak type
- Annual SO_2/NO_x emissions
- Annual/monthly capacity factor by generation resource
- Annual/monthly intercompany transaction volumes
- Annual/monthly dispatch order

3.3 Review

In the third part of the process used to develop the Companies' generation forecast, the results of the forecast are reviewed by other departments. This review process ensures that the forecast considers feedback from a broad range of perspectives.

The following groups are primary consumers of the forecast results and review various elements of the forecast to help ensure that the results are reasonable:

- Corporate Fuels and By-products: The Corporate Fuels and By-Products group reviews the fuel burn forecast by generating station and fuel type.
- Power Supply: The Power Supply group reviews the forecasts of OSS margin, OSS volumes, and economy purchase volumes by peak type.
- Plant Management: Plant managers review the forecasts of generation by station and fuel type.

3.4 Deliverables

After forecast reviews are completed, the forecast deliverables are distributed to the groups within the company who use the forecast to prepare financial budgets. The following is a list of key deliverables:

- Generation Forecast
- Fuel Burn Forecast
- Fuel Expense Forecast
- OSS Margin Forecast
- Emissions Forecast
- CCR Production Forecast

Attachment B is Confidential and provided separately under seal in Excel format.

Attachment C is Confidential and provided separately under seal in Excel format.

Attachment D is Confidential and provided separately under seal.

Attachment E is Confidential and provided separately under seal.