

Kentucky Public Service Commission

Staff Report On the 2009 Integrated Resource Plan of Kentucky Power Company

Case No. 2009-00339

March 2011

SECTION 1

INTRODUCTION

Administrative Regulation 807 KAR 5:058, promulgated in 1990 and amended in 1995 by the Kentucky Public Service Commission (“Commission”), established an integrated resource planning (“IRP”) process that provides for regular review by the Commission Staff (“Commission Staff” or “Staff”) of the long-range resource plans of the Commonwealth’s six major jurisdictional electric utilities. The goal of the Commission in establishing the IRP process was to ensure that all reasonable options for the future supply of electricity were being examined and pursued, and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost.

Kentucky Power Company (“Kentucky Power”) submitted its 2009 IRP to the Commission on August 17, 2009. The IRP includes Kentucky Power’s plan for meeting its customers’ electricity requirements for the period 2009-2023. Kentucky Power is a subsidiary of American Electric Power (“AEP”) and is also an operating company within the American Electric Power System East Zone (“AEP-East”). AEP-East is planned and operated on an integrated basis which requires Kentucky Power’s resource plans to be considered as a sub-set of the larger zone’s resource plans.

Kentucky Power serves roughly 176,000 customers in its eastern Kentucky service area. Industries served by Kentucky Power include metals, chemicals and allied products, petroleum refining and coal mining. Kentucky Power is also a wholesale power provider to electric utilities, municipalities, cooperatives, and non-utility entities participating in the wholesale energy market.

Kentucky Power, generally a winter peaking utility, reached a record system peak of 1,678 megawatts (“MW”) in January 2008. In 2008, residential, commercial, and industrial sales accounted for 31, 18, and 42 percent of its load, respectively. Approximately 9 percent of its load was attributed to street lighting and all other

categories. Kentucky Power's load accounts for about 5 percent of AEP-East's total load. Kentucky Power owns and operates the Big Sandy Plant in Louisa, Kentucky, a coal-fired plant with a capacity of 1,060 MW, comprised of an 800 MW unit and a 260 MW unit. Kentucky Power also has a contract under which it purchases 393 MW of capacity from the affiliate-owned Rockport Plant located in southern Indiana.

AEP's transmission system has been under the functional control of the PJM Interconnection, LLC ("PJM") since 2004. This functional control transfer was approved by the Commission in Case No. 2002-00475.¹ PJM directs the dispatch of the AEP-East generation resources and determines reserves required to maintain resource adequacy. AEP-East's transmission system, which extends from Virginia to Michigan, contains 345 kV, 500 kV, and 765 kV lines, and provides interconnection to many neighboring power systems. The number of interconnections that AEP has to other large control areas provides increased reliability to the region.

The purpose of this report is to review and evaluate Kentucky Power's IRP in accordance with 807 KAR 5:058, Section 12(3), which requires Commission Staff to issue a report summarizing its review of each IRP filing made with the Commission and make suggestions and recommendations to be considered in future IRP filings. The Staff recognizes that resource planning is a dynamic ongoing process. Thus, this review is designed to offer suggestions and recommendations to Kentucky Power on how to improve its resource plan in the future.

Specifically, the Staff's goals are to ensure that:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions and methodologies for all aspects of the plan

are adequately documented and are reasonable; and

¹ Case No. 2002-00475, Application of Kentucky Power Company d/b/a American Electric Power, for Approval, to the Extent Necessary, to Transfer Functional Control of Transmission Facilities Located in Kentucky to PJM Interconnection, L.L.C. Pursuant to KRS 278.218 (Ky. PSC May 19, 2004).

o The report also includes an incremental component, noting any significant changes from Kentucky Power's most recent IRP filed in 1999. (Kentucky Power submitted an IRP in 2002 but experienced certain changes to its resource pool after the IRP was filed. These changes rendered the 2002 IRP, as submitted, inaccurate. Kentucky Power made a formal request to the Commission to hold the 2002 IRP filing in abeyance, which request was granted.² Following this action, Kentucky Power extended its Rockport purchased power agreement and resolved the uncertainties regarding its resource pool. As a condition of the Commission's approval of the purchased power agreement extension, Kentucky Power was ultimately required to file a new IRP in 2009).³

In the current IRP, Kentucky Power states that the objective of power system planning is to maintain a reliable, adequate, and economical supply of power to its customers in an environmentally conscious manner. Kentucky Power strives to maximize efficiency of the operation of its power system and encourage the efficient use of energy by its customers. Kentucky Power further states that its ideal resource plan should include flexibility, an optimum asset mix, adaptability to risk, and should also stress the affordability of its options. Environmental compliance must also be considered as Kentucky Power recognizes that anticipated long-term environmental requirements are pending.

Kentucky Power described its resource planning process as being a continuous activity. Assumptions are reviewed and modified as new information becomes available. The resource expansion plan reflects assumptions that are likely to change

² Case No. 2002-00377, The 2002 Integrated Resource Planning Report of Kentucky Power Company d/b/a/ American Electric Power to the Kentucky Public Service Commission (Ky. PSC Mar. 9, 2005).

³ Case No. 2004-00420, Application of Kentucky Power Company for Approval of a Stipulation and Settlement Agreement Resolving State Regulatory Matters (Ky. PSC Dec. 13, 2004).

over time. Kentucky Power states that it does not submit this IRP as a commitment to a specific course of action. Economic conditions, movement toward an increased reliance on renewable generation, an emphasis on end-use efficiency, and proposals designed to control greenhouse gases can all result in retirement or retrofit of existing units and have significant effects on Kentucky Power's resource strategy. All these factors make planning increasingly difficult and make flexibility in any plan more necessary than ever before.

Kentucky Power's winter peak load is expected to increase from 1,639 MW in 2009 to 1,799 MW in 2023, reflecting a growth rate of 0.7 percent once the impacts of its energy efficiency programs are acknowledged. Its summer peak load is expected to increase from 1,308 MW to 1,483 MW over the same period, reflecting a growth rate of 0.9 percent. These growth rates are lower than those reported in Kentucky Power's 1999 IRP when its winter peak annual growth rate was 1.8 percent and its summer peak growth rate was 1.6 percent.

Kentucky Power expects to meet its customer's load requirements by reducing its peak demand 86 MW by 2023 through expected participation in demand-side management ("DSM") programs. Participation in its renewable program is shown by the purchase of the output of two 50 MW nameplate wind energy projects, one in 2010 and the other in 2011. The renewable program also includes co-firing biomass at Rockport Units 1 and 2 by 2013, as well as injection of biomass at Big Sandy Unit 2 by 2015. Kentucky Power plans to add 342 MW of peaking capacity combustion turbines in 2018 and 360 MW of intermediate, combined-cycle capacity in 2023. Environmental controls are expected to be added in the form of flue gas desulfurization ("FGD") systems at Big Sandy Unit 2 (2015), Rockport Unit 1 (2017), and Rockport Unit 2 (2019).

The remainder of this report is organized as follows:

- Section 2, Load Forecasting, reviews Kentucky Power's projected load growth and load forecasting methodology.

- Section 3, Demand-Side Management, summarizes Kentucky Power's evaluation of DSM opportunities.
- Section 4, Supply-Side Resource Assessment, focuses on supply resources available to meet Kentucky Power's load requirements and environmental compliance planning.
- Section 5, Integration and Plan Optimization, discusses Kentucky Power's overall assessment of supply-side and demand-side options and their integration into an overall resource plan.

SECTION 2

LOAD FORECASTING

INTRODUCTION

Kentucky Power's forecasts of energy consumption for the major customer classes were developed using both short-term and long-term econometric models and supplemented by statistically adjusted end use ("SAE") models. Energy forecasts begin with forecasts of the regional economy which is driven by national economic forecasts supplied by Moody's Economy.com. Seasonal peak-demand forecasts are based upon analysis of energy use, customer class load shapes and load factors.

In the short term, Kentucky Power assumes that the effect on electricity consumption of an increase in electricity price is muted. There may be some slight decrease in consumption by turning off lights or adjusting thermostat settings, but customers are not able to significantly alter their consumption levels. The ability to substitute other fuels or to switch to more energy efficient technology, such as energy efficient appliances and buildings, is limited in the short run. The price of electricity is not included in the short-term Autoregressive Integrated Moving Average ("ARIMA") models. However, electricity prices are included in the long-term models.

In the long term, energy consumers are better able to substitute more efficient technology for relatively energy inefficient technology. Higher electricity prices will spur the development and availability of more energy efficient appliances, equipment and structures. Consumers are able to substitute away from inefficient technology and to purchase more energy efficient appliances, heating and cooling technology and other equipment. Also, more energy efficient structures will be built and existing buildings can be made more energy efficient. Over time, because consumers are better able to alter their electricity consumption levels, the long-term forecasting models include energy price variables.

SHORT-TERM FORECASTING MODELS

The goals of the short term forecasting models are to produce accurate forecasts for the first full year into the future, during which changes are minimal. The company relies upon ARIMA models. Monthly and seasonal binary variables, usage, time trends and monthly heating and cooling degree days are used in the models. Heating and cooling degree days are calculated from weather data taken from weather stations throughout the company's territory. Binary variables are used to model discrete one-time events.

For both the residential and commercial customer classes, ARIMA models are used to forecast energy usage and the number of customers. Model variables include lagged energy usage, lagged number of customers, heating and cooling degree days, lagged error terms, and binary variables. The residential and commercial energy sales are derived from forecasts of the number of customers and the usage per customer.

Concerning short-term industrial energy sales, Kentucky Power produces separate forecasts for its 10 largest industrial customers. The other industrial customers are then segregated into manufacturing and mining load categories. These 12 separate ARIMA models forecast industrial energy sales using lagged energy sales, lagged error terms, and binary variables. The industrial energy forecast is the sum of the 12 separate forecasts.

The All Other Energy Sales category includes street lighting and sales to municipal customers. The street lighting forecast ARIMA model uses lagged energy sales and binary variables. The municipal sales for resale ARIMA model variables include heating and cooling degree days, lagged energy sales, and error terms. Losses are forecast based upon the historical relationship between energy sales and energy generation.

LONG-TERM FORECASTING MODELS

The goal of the long-term forecasting models is to produce an accurate forecast for up to 30 years in the future, during which changes can be significant. Kentucky Power uses various structural models to produce load forecasts based upon the economic outlook of the U.S. economy, its service territory, and relative energy prices. The long-term forecast is developed by blending the last half of the second year of the short-term forecast with the preliminary long-term forecast.

Kentucky Power uses a natural gas pricing model which relates state natural gas prices to U.S. natural gas prices in four sectors: residential, commercial, industrial and electric utilities. It also maintains a regional coal production model. Coal production forecasts are used as an input in the mine power energy sales forecast. Both the U. S. natural gas price forecasts and the coal production forecasts were obtained from the U.S. Department of Energy (“DOE”)/Energy Information Administration’s “2008 Annual Energy Outlook.”

Residential Energy Sales

Residential energy sales are forecast using two models: 1) the projected number of residential customers, and 2) the projected usage per customer. The residential customer model is a function of the mortgage rate, employment, lagged customer, and binary variables. This model is blended with the short-term customer forecast to produce a final forecast.

The residential energy usage model is produced using an SAE Model, which was developed by Itron Inc. Three variables are developed for the energy use forecast: Xheating, Xcooling and Xother. The Xheating variable is derived by multiplying a heat index variable to a heating use variable. The heating index variable is a function of heating equipment saturation, heating equipment efficiency standards and trends, and the thermal integrity and size of homes. The heating use variable is a function of

average monthly billing days, heating degree days, household size, real personal income, natural gas prices and electricity prices.

The Xcooling variable is similarly derived by multiplying a cooling index by a cooling use variable. The cooling index is a function of cooling equipment saturation, cooling equipment efficiency standards and trends, and the thermal integrity and size of homes. The cooling use variable is a function of average monthly billing days, cooling degree days, household size, real personal income, gas prices and electricity prices.

Finally, the Xother variable is designed to forecast non-weather-sensitive sales. Similar to the Xheating and Xcooling variables, Xother is a function of appliance and equipment saturation levels, average monthly billing days, household size, real personal income, natural gas and electricity prices.

Appliance saturation data comes from Kentucky Power's residential customer surveys, and forecasts are based on DOE forecasts and Itron analysis. Similarly, appliance and equipment efficiency trends are based on DOE forecasts and Itron analysis. Thermal integrity and house size data comes from Itron and East North Central Census Region data. Economic and demographic forecasts are obtained from Moody's Economy.com. The SAE model is a monthly linear regression model and incorporates the effects of both the Energy Policy Act of 2005 ("EPAct") and the Energy Independence and Security Act of 2007 ("EISA") on residential energy use. The final long-term residential energy sales forecast is derived by multiplying the blended customer forecast with the usage forecast from the SAE model.

From 1990–2008, Kentucky Power's residential energy sales grew from 1,718 GWH to 2,481 GWH, which represents an average annual growth rate of 1.4 percent. Over the 2009–2023 forecast period, Kentucky Power's residential energy sales are projected to decline slightly. In 2009, Kentucky Power's residential energy sales are projected to be 2,492 GWH. By 2023, Kentucky Power's sales are projected to be 2,460 GWH, which represents an average annual growth rate of -0.1 percent.

Commercial Energy Sales

The commercial energy sales forecast also employs an SAE model. Similar to the residential SAE model, commercial energy sales are a function of three variables: Xheating, Xcooling, Xother. Similar to the residential model, Xheating is obtained by multiplying a heating index variable by a heat use variable. Xheating is ultimately a function of heating degree days, heating equipment saturation levels, heating equipment operating efficiencies and trends, building size, average monthly billing days, commercial output and electricity prices.

Xcooling is obtained by multiplying a cooling index variable by a cool use variable. Xcooling is ultimately a function of cooling degree days, cooling equipment saturation levels, cooling equipment operating efficiencies and trends, building size, average monthly billing days, commercial output and electricity prices.

The Xother variable captures non-weather-sensitive commercial load. It is a function of non-weather-sensitive equipment saturation levels and efficiencies, average monthly billing days, commercial output and electricity prices. Itron supplied the building size, equipment saturation and efficiency data, which is based on DOE's 2008 Annual Energy Outlook. Commercial output is measured by real commercial gross regional product from Moody's Economy.com. Equipment stock and building size information is obtained from census data.

From 1990–2008, Kentucky Power's commercial energy sales grew from 920 GWH to 1,429 GWH, an average annual rate of 1.7 percent. Over the 2009–2023 forecast period, Kentucky Power's sales were expected to grow from 1,447 GWH to 1,721 GWH, which represents an average annual growth rate of 1.2 percent.

Industrial Energy Sales

The manufacturing energy sales forecast is a function of real natural gas prices, real electricity prices, production indexes for primary metals and petroleum, and binary variables. The mine power energy sales forecast is a function of coal production and

real electricity prices. Both the manufacturing and mine power energy sales models are log linear regression models. Over the 2009–2023 forecast period, Kentucky Power’s overall industrial energy sales are projected to grow from 3,259 GWH to 3,934 GWH, an average annual growth rate of 1.4 percent. Manufacturing accounts for about two-thirds of the industrial category and mine power energy sales represent about one-third. Over the forecast period, the majority of the growth in sales is in the manufacturing sector, which is projected to grow at an average annual rate of 1.6 percent. Mine power sales are projected to grow at an average annual rate of 0.2 percent.

All Other Internal Energy Sales

This category is made up of public street and highway lighting and sales to municipalities. The public street and highway lighting energy sales forecast is a function of service area commercial employment and binary variables. The municipal energy sales are a function of service area gross regional product, heating and cooling degree days, and binary variables. Both the lighting and municipal energy sales models are linear regression models. Final forecasts are obtained by blending the short-term and long-term forecasts. This category represents a small fraction of Kentucky Power’s overall load. Over the forecast period, sales are projected to grow from 111 GWH to 131 GWH, an annual average rate of 1.2 percent.

Energy Losses

Energy losses from electricity transmission and distribution from the production source to the end user is measured as the average ratio of all Federal Energy Regulatory Commission (“FERC”) revenue class energy sales measured at the customer meter to the net internal energy requirements metered at the production source. Losses are applied to each revenue class. Factoring in line losses over the 2009–2023 forecasting period, Kentucky Power’s overall total internal energy requirements are projected to grow from 7,907 GWH to 9,007 GWH. This equates to an average annual growth rate of 0.9 percent.

SEASONAL PEAK INTERNAL DEMAND

The peak demand forecast model is a series of algorithms for allocating the monthly blended FERC revenue class sales to hourly demand. The hourly demand forecast is a function of blended FERC revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar data. Weather data is developed from representative weather stations in Kentucky Power's service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree days of specific geographic locations are taken from the last 30 years of historical data. The 24-hour load profiles are developed from historical hourly company or jurisdictional load and end-use or revenue-class hourly load profiles. Load profiles were derived by segregating, indexing and averaging hourly load profiles by season, day type (weekend, midweek, and Monday/Friday), and average daily temperature ranges. Itron supplied the end-use and class profile data. Finally, the profiles are benchmarked to the aggregate energy and seasonal peaks through adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of the individual utility companies in the AEP system, which can then be aggregated across the spectrum from end-use and revenue classes to total AEP-PJM or total AEP system. Net internal energy requirements are the sum of these hourly values to a total company energy-need basis. Peak demand is the maximum of the hourly values from a stated period (monthly, seasonally or annually).

Historically, Kentucky Power's winter peak demand has been greater than its summer peak. Over the 2009–2023 forecasting period, that trend is expected to continue. The summer peak is expected to grow from 1,308 MW in 2009 to 1,483 MW in 2023, or an average annual rate of 0.9 percent. The winter peak is expected to grow from 1,639 MW in 2009 to 1,799 MW in 2023, an average annual rate of 0.7 percent.

CONSERVATION AND DEMAND-SIDE MANAGEMENT

At the time it filed its 2009 IRP, Kentucky Power offered DSM programs to only the residential customer class.⁴ The estimated impact of these DSM programs on the forecast energy requirements and on peak demand levels is fairly insignificant, primarily due to the small size of the programs. Kentucky Power's internal energy requirements forecast for 2009 without these DSM programs was 7,964 GWH and 7,963 GWH when these DSM programs were included. For 2023, energy requirements are forecast to be 9,009 GWH without these DSM programs and 9,007 GWH with them. Over the forecast period, these programs have no effect on summer peak demand. The winter peak demand in 2009 is 1,640 MW without them and 1,639 MW with them. In 2023, winter peak demand is forecast to be 1,800 MW without these DSM programs and 1,799 MW with them. However, if Kentucky Power bears a proportionate share of the expanded DSM programs planned for the AEP-East Zone, it projects a 20 MW reduction in winter peak demand and a reduction of 86 MW in summer peak demand.⁵

Again, due to their small size, Kentucky Power's existing DSM programs have no effect on forecast growth rates for either internal energy requirements or peak demand. Over the 2009–2023 forecast period, Kentucky Power's average annual growth of internal energy requirements is estimated to be 0.9 percent. Similarly, the average annual peak demand growth rate is forecast to be 0.7 percent.

⁴ Since the filing of its IRP, Kentucky Power has proposed, and the Commission has approved, new programs targeted toward commercial customers. See Case No. 2010-00095, Kentucky Power Company (Ky. PSC Aug. 10, 2010); and Case No. 2010-00198, Kentucky Power Company (Ky. PSC Oct. 15, 2010).

⁵ It must be noted that Section 7(3) of the IRP regulation, 807 KAR 5:058, does not permit a utility's base forecast to include the impacts of new DSM programs planned for the future, but does permit their impacts to be included in the resource assessment and acquisition plan, pursuant to Section 8(4).

FORECAST UNCERTAINTY ANALYSIS

AEP creates individual load forecasts for each of its operating companies, which are then aggregated into a seven state regional AEP-East Zone model and load. For AEP, forecast uncertainty is of primary interest at the total system level as opposed to the individual operating company level. Therefore, the analysis begins with AEP-East Zone load.

An aggregated “mini model” of AEP-East Zone internal energy requirements is calculated. The mini model is intended to represent the full forecasting structure employed in producing a base case forecast for the AEP-East Zone, of which Kentucky Power is a part. Excluding sales to aluminum companies, AEP-East Zone internal energy requirements is the dependent variable. Independent variables include real service area gross regional product, AEP-East Zone service area employment, the average real price of electricity for all customer classes, the AEP-East Zone average real price of natural gas, and AEP-East Zone service area heating and cooling degree days. The mini model load forecast is not identical to that produced by summing the individual operating company base load forecasts, but is in rough agreement. The aluminum load is a relatively large and volatile component of total load and its forecast is treated separately and added back into the overall base case load forecast.

Once a base case energy forecast is produced with the mini model, high and low values for the independent variables are determined based upon professional judgment. The base case growth rate for real service area gross regional product is 1.5 percent annually. The low and high cases are 0.9 percent and 2.0 percent annually. Similarly the average annual employment base case growth rate was 0.3 percent. The corresponding low and high average annual growth rates are 0.0 percent and 0.6 percent. The base case average annual growth rate for real natural gas prices was 0.5 percent. The corresponding low and high growth rates are -0.2 percent and 0.9 percent.

For the AEP-East Zone and correspondingly for Kentucky Power, the low case, high case and peak demand forecasts for the final forecast year are about 9 percent below and 10 percent above the base case forecast. For Kentucky Power with DSM, the 2023 base case internal energy requirement is 9,007 GWH. The low and high case forecasts are 8,185 GWH and 9,888 GWH, respectively. Similarly, the 2023 base case summer peak demand is 1,483 MW. The corresponding low and high case forecasts are 1,348 MW and 1,629 MW. For the 2023 winter peak, the base case forecast is 1,799 MW. The corresponding low and high case forecasts are 1,628 MW and 1,983 MW. The average annual growth rates over the forecast period for Kentucky Power's internal energy requirements are 0.9 percent in the base case with low and high case growth rates of 0.4 percent and 1.4 percent. Average annual summer peak growth rates are 0.9 percent in the base case with low and high case growth rates of 0.4 percent and 1.4 percent. Winter peak annual average growth rates range from a low case of 0.3 percent to a high case of 1.1 percent with a base case of 0.7 percent.

SIGNIFICANT CHANGES

Kentucky Power now uses Moody's Economy.com as the source for its regional economic forecasts, rather than Woods & Poole Economics, which it used at the time it submitted its last IRP. Residential and commercial long-term energy are now forecast using SAE models, which was not the case in the last IRP. This allows for a more explicit reflection of appliance efficiency and other end-use trends.

Kentucky Power has changed how it develops and uses its forecasts. While it now uses its short-term forecasting models primarily to produce forecasts for the first year into the future, it had previously used its short-term models to produce forecasts for five years into the future. Similarly, it now blends the last half of the second year of its short-term forecast with its preliminary long-term forecast to develop its final long-term forecast, whereas it had previously used only the last year generated by its long-term

forecasting models and used linear interpolation to forecast the period from year six up to the last year of the forecast period.

Kentucky Power's last IRP was filed with the Commission in 1999. Since then, it has made a number of significant changes to its forecasting methodology, data sources and forecast results.

The 1999 forecast projected total internal energy requirements for Kentucky Power of 9,688 GWH in 2016 and an average annual growth rate of 1.6 percent. The 2009 forecast projects total internal energy requirements of 8,596 GWH for 2016 and an average annual growth rate of only 1.1 percent. The year 2016 is used for comparison purposes because it was the final year of the 1999 forecast. The 2009 GWH forecast for 2016 is 11.3 percent below the 1999 forecast for the same year. Similarly, the 1999 winter peak demand forecast for 2016 was 1,991 MW as opposed to a 2009 forecast for that year of 1,717 MW, which is lower by 13.7 percent. Winter peak demand was forecast to grow at an average annual growth rate of 1.7 percent in 1999 as opposed to a 2009 growth-rate forecast of 0.9 percent.

Breaking out the changes by customer class sectors sheds additional light on the forecast changes. The 2009 forecasts of residential and commercial class energy requirements for 2016 are 26.0 percent and 17.1 percent, respectively, lower than in the 1999 forecasts. The 2016 industrial and other retail energy sales are 4.5 percent and 7.5 percent, respectively, lower in the latest forecast compared to 10 years ago. The losses forecast also increased by 42.5 percent.

Kentucky Power has enhanced its forecasting methodology over the last ten years. Peak demand is now estimated using hourly load shapes, weather response functions and average daily temperature. Short-term industrial energy sales are now modeled using 12 models, comprised of 10 large-customer models, a small-manufacturing model and a small-mine-power-load model.

Finally, Kentucky Power states that the reduced growth in demand and energy sales, as reflected in its 2009 forecasts, is a result of federal legislation mandating more stringent efficiency standards (EPAct and EISA), as well as the rate impacts of complying with emission requirements that have been established since its last IRP.

DISCUSSION OF REASONABLENESS

In general, Staff is satisfied with Kentucky Power's forecasting. In its report on Kentucky Power's 1999 IRP, Staff offered the following forecasting recommendations:

- Provide a full explanation for any changes in forecasting methodology.
- Provide a comparison of forecasted winter and summer peak demands with actual results for the period following Kentucky Power's 1999 IRP, along with a discussion of the reasons for the differences between forecasted and actual peak demands.
- Provide a comparison of the annual forecast of residential energy sales, using the current econometric models, with actual results for the period following the 1999 IRP. Include a discussion of the reasons for the differences between forecasted and actual results.
- Kentucky Power should, to the extent possible, report on and reflect in its forecasts, the impacts of increasing wholesale and retail competition in the electric industry.
- Kentucky Power should, either in its forecasts or in its uncertainty analysis, attempt to incorporate the impacts of potential environmental costs such as those associate with potential NO_x reductions imposed on sources in the Eastern United States.

Kentucky Power addressed Staff's prior recommendations in various sections of its chapter on load forecasting. Staff accepts the responses of Kentucky Power to Staff's recommendations.

STAFF OBSERVATIONS AND RECOMMENDATIONS

Staff makes the following observations on Kentucky Power's forecasting in its 2009 IRP and recommendations for its next IRP filing.

Observations

- Kentucky Power's forecasting methodology is robust and has improved over the last ten years.
- As over the last ten years, Kentucky Power should continue to refine its forecast methodology and improve the accuracy of its forecasts. It should identify and describe any changes in forecasting methodology.
- Staff notes that the forecast results contain several interesting trends. The service area population has declined slightly over the last ten years and is projected to decline further over the forecast period. Over the forecast period, the growth and robustness of Kentucky Power's service area economy is not expected to keep pace with the regional economy.
- Kentucky Power's existing DSM programs are limited and are projected to have little effect on either internal energy requirements or peak demand.

Recommendations

- Kentucky Power should consider disaggregating its residential customer class in its SAE models to gain further insight into usage patterns and future energy needs. Disaggregating the commercial customer class may also provide additional insights.
- Provide a comparison of forecasted peak demands and residential energy sales with actual results for the period following Kentucky Power's 2009 IRP. Include a discussion of the reasons for the differences between forecasted and actual results.
- Given that Kentucky Power's service area economy is not expected to perform as well as the rest of the region, the possibility of either federal emissions-limiting legislation or targeted EPA actions limiting various emissions may have

significant impacts on Kentucky Power's service territory. In its next IRP, Kentucky Power should explicitly account for potential federal legislation imposing stricter emissions limits on its generation in its forecasts and risk analysis. Potential EPA actions limiting emissions should also be explicitly accounted for in the forecasts and risk analysis.

SECTION 3

DEMAND-SIDE MANAGEMENT

INTRODUCTION

This section addresses the DSM portion of Kentucky Power's 2009 IRP. At the time its IRP was filed, Kentucky Power had seven DSM programs in place that were developed in conjunction with its DSM Collaborative. Those programs are:

1. Targeted Energy Efficiency;
2. High Efficiency Heat Pump–Mobile Home;
3. Mobile Home New Construction;
4. Modified Energy Fitness;
5. High Efficiency Heat Pump;
6. Community Outreach Compact Fluorescent Lighting; and
7. Energy Education for Students.

Kentucky Power's DSM Collaborative includes local stakeholders plus other parties interested in the development and implementation of DSM, conservation or energy efficiency programs.

The Commission has been regularly updated on these programs through Kentucky Power's semi-annual DSM filings. Pursuant to various Commission orders, the existing programs are approved to continue through 2011.

CURRENT KENTUCKY POWER DSM PROGRAMS

This section describes each of Kentucky Power's seven existing DSM programs.⁶

Targeted Energy Efficiency

This program is designed to help low-income customers reduce their energy consumption and energy costs. The program focuses on those customers eligible for Low Income Home Energy Assistance Program "LIHEAP" assistance. This program provides an in-home audit to identify potential energy savings, as well as direct installation of weatherization and seal-up to targeted customers. Budgeted amounts for 2009 were \$233,430 targeted to reach 210 all-electric homes and 78 non-all-electric homes.

High Efficiency Heat Pump – Mobile Home

This program provides financial incentives to mobile home owners to encourage them to install the highest efficiency equipment practical. Such incentives are designed to help offset the higher initial costs of higher efficiency equipment. The budgetary level for 2009 was \$50,000 projected to serve 110 customers.

⁶ On February 26, 2010, Kentucky Power filed an application seeking approval to implement three new programs: (1) Residential Efficient Products Program, which provides incentives for the purchase of lighting products meeting the ENERGY STAR standards; (2) HVAC Diagnostic and Tune-up Program, which provides incentives to customers to have a diagnostic assessment of their central air conditioner or heat pump system; and (3) Commercial High Efficiency Heat Pump/Air Conditioner Program, which provides incentives to purchase qualifying systems with a Consortium for Energy Efficiency rating. The application, which was docketed as Case No. 2010-00095, was approved by the Commission on August 10, 2010.

On July 9, 2010, Kentucky Power filed an application seeking approval to implement a Commercial Incentive Program, which will promote high efficiency lighting, HVAC, pumps and motors; and a Residential and Small Commercial Load Management Pilot Program, intended to determine whether peak demand can be reduced through the installation of load-control devices on central air conditioners, heat pumps and/or water heaters. The application, which was docketed as Case No. 2010-00198, was approved by the Commission on October 15, 2010.

Mobile Home New Construction

This program provides financial incentives to both customers and vendors to encourage the purchase of new mobile homes containing high efficiency heat pumps and upgraded insulation packages. Projected participant and budgetary levels for 2009 were 150 and \$101,750, respectively.

Modified Energy Fitness

This program provides energy audits, blower door testing, duct sealing and direct installation of low-cost conservation measures to residential customers with electric space heating and electric water heating. The program funds the cost of vendor labor and the cost of the conservation measures. Budgeted amounts for 2009 were \$304,000 projected to reach 800 customers.

High Efficiency Heat Pump

This is a new program which was implemented in mid-2009. It provides financial incentives to residential customers living in site-built homes to encourage them to install high efficiency heat pumps. Such incentives are designed to help offset the higher initial costs of higher efficiency equipment. Targeted participation levels for 2009 were projected to include the replacement of 50 resistant heat systems and 50 heat pumps. The budgeted amount for 2009 was \$53,000. For 2010, the participation goals included the replacement of 100 resistant heat systems and 100 existing heat pumps. The budget for 2010 was \$105,000.

Community Outreach Compact Fluorescent Lighting

This program was implemented in 2009. It is designed to influence residential customers to purchase and install compact fluorescent lights ("CFLs") in their homes. To encourage purchase of CFLs, customers attending community outreach activities sponsored by Kentucky Power are given a package of four 23-watt CFLs. For the first three years of availability, participation levels are projected to be approximately 4,000 customers per year. Annual budgets for that period average just under \$50,000.

Energy Education for Students

The Energy Education for Students program, in which Kentucky Power partners with the National Energy Education Development Project,⁷ provides education information on energy, electricity, environment and economics to seventh grade students at participating schools throughout Kentucky Power's service territory. Students also receive a package of four 23-watt CFLs to install in their homes. For the first three years of availability, projected participation levels slightly exceed 1,600 students per year, with approximately 6,500 CFLs distributed annually. Average annual budget amounts for that period are \$29,000.

DSM SCREENING AND COST-EFFECTIVENESS

Kentucky Power evaluates the cost-effectiveness of potential DSM measures when making decisions whether to include those measures in its DSM portfolio. The net present value of costs vs. benefits is assessed, i.e., the costs to implement the measures are valued against the savings or avoided costs. The resultant benefit/cost ratios, or tests, provide a summary of the measure's cost-effectiveness relative to the benefits of its projected load impacts.

The main tests Kentucky Power uses to screen DSM measures are the Utility Cost Test ("UCT"), the Total Resource Cost Test ("TRC"), and the Ratepayer Impact Measure Test ("RIM"). The UCT compares utility benefits to utility costs by comparing the cost to the utility to implement the measure with the savings or avoided costs to the utility resulting from the change in magnitude and/or the pattern of electricity use caused by implementing the measure. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected market price of power including environmental compliance costs. The cost-effectiveness analyses also include avoided transmission and distribution costs, line losses, and avoided ancillary services.

⁷ Kentucky's segment of the National Energy Education Development program.

The TRC test compares total benefits to the utility and participants to the utility's cost to implement the program and the cost to participate. Benefits to the utility are the same as with the UCT. The RIM test, or non-participant test, indicates if market prices and rates increase or decrease over the long-run as a result of implementing the program. The costs associated with implementing measures in DSM programs include incentives offered to consumers plus vendor delivery and installation costs, if applicable.

FUTURE KENTUCKY POWER DSM PROGRAMS

Kentucky Power did not model any specific new programs. However, the IRP indicated that AEP had internally developed plans to reduce peak demand by 1,000 MW by year-end 2012.⁸ To achieve these types of results, Kentucky Power will be required to significantly increase the number of programs it offers. At projected levels, Kentucky Power's share of the expanded DSM programs planned for the AEP-East Zone results in a 20 MW reduction in its winter peak demand and a reduction of 86 MW in its summer peak demand.

DISCUSSION OF REASONABLENESS AND RECOMMENDATIONS

Kentucky Power's current DSM programs are scheduled to continue in effect through 2011. While several past programs offered by Kentucky Power have been short-lived due to low participation rates,⁹ Staff recognizes the effort Kentucky Power and its collaborative have made in developing and expanding its DSM programs.¹⁰ Staff notes that, historically, Kentucky Power has not significantly targeted reducing its peak demand, which was understandable in light of its ability to rely on the AEP-East Pool to

⁸ This is a system-wide goal, based on generic DSM programs representative of programs that may be offered in the AEP-East Zone.

⁹ According to its latest semi-annual DSM filing, Kentucky Power has discontinued seven programs since it began offering DSM programs pursuant to KRS 278.285.

¹⁰ This included the programs for which approval was granted in Case Nos. 2010-00095 and 2010-00198.

meet its peak. With the recent implementation of a direct load control program, however, Kentucky Power may see its DSM programs having a greater impact on peak demand and, eventually, on its load forecast. It appears that the relatively broad scope of the programs, plus their specific attributes, meet the needs of Kentucky Power's customers while being part of its long-term resource plan. However, consistent with the aggressive demand-reduction goals established by AEP, Staff makes the following recommendations:

- Kentucky Power should work to increase its portfolio of DSM programs to assist in achieving the demand reductions targeted by AEP.
- Kentucky Power should evaluate whether the size of existing DSM programs can be increased.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT

INTRODUCTION

This section summarizes and comments on Kentucky Power's evaluation of supply-side resources and includes a discussion of environmental compliance planning.

Kentucky Power is one of the seven operating companies of the AEP East Zone which is planned, constructed and operated as an integrated power system. In addition to Kentucky Power, AEP-East includes Appalachian Power, Columbus Southern Power, Indiana & Michigan Power, Kingsport Power, Ohio Power, and Wheeling Power.¹¹ Under the AEP Interconnection Agreement ("Interconnection Agreement"), a "pool agreement" among the five generating AEP-East member companies (Appalachian Power, Columbus Southern Power, Indiana & Michigan Power, Kentucky Power, and Ohio Power), each pool member is responsible for a proportionate share of the aggregate AEP-East generating capacity. Each member is required to provide sufficient generating capacity to meet its own internal load requirements, plus an adequate reserve margin.¹²

When a member's generating capability is insufficient to supply its demand, it draws upon the resources of the other AEP-East members in accordance with the provisions of the Interconnection Agreement. When a member has generating capacity in excess of its own needs, the excess generation is utilized, as necessary, to supply part of the load requirements of other AEP-East members.¹³ According to Kentucky

¹¹ Application, Vol. A, Overview and Summary, at 1-1 and 4. Resource Forecast at 4-1.

¹² For planning purposes, Kingsport Power and Wheeling Power are treated as part of Appalachian Power.

¹³ Application, Vol. A, Resource Forecast, at 4-1.

Power, the adequacy and reliability of its generating capability must be based on consideration of the total generating capacity of AEP-East in relation to the aggregate AEP-East load.¹⁴

Kentucky Power's internal load usually peaks in the winter. Kentucky Power's all-time system peak demand of 1,678 MW occurred on January 25, 2008, while its all-time summer peak of 1,358 MW occurred on August 24, 2007.¹⁵

Kentucky Power owns and operates the 1,060 MW coal-fired Big Sandy Plant located at Louisa Kentucky. This plant consists of a 260 MW unit placed in service in 1953 and an 800 MW unit placed in service in 1969.¹⁶ Kentucky Power has a unit power agreement with AEP Generating Company, a non-regulated affiliate, to purchase 393 MW from the Rockport plant in southern Indiana through December 7, 2022.¹⁷ AEP-East's total generating capability of 28,976 MW, which is predominantly coal-fired, also includes conventional hydroelectric, pumped storage and nuclear capacity.¹⁸

The AEP-East generating companies, including Kentucky Power, are electrically interconnected by a high-capacity transmission system extending from Virginia to Michigan. The transmission system consists of an integrated 765 KV, 500 KV, and 345 KV extra-high-voltage network, an underlying 138 KV transmission network, and numerous interconnections with neighboring power systems.

In 2004, AEP-East became a member of PJM, a Regional Transmission Organization ("RTO"), when functional control of its transmission facilities was

¹⁴ Id.

¹⁵ Application, Vol. A, Overview and Summary, at 1-3.

¹⁶ Id., at 1-4 and 4. Resource Forecast, Exhibit 4-2, at 2.

¹⁷ Application, Vol. A, Overview and Summary, at 1-4.

¹⁸ Id.

transferred to PJM. AEP-East continues to maintain and physically operate all of its transmission facilities and it retains operational responsibility for the lower voltage facilities that are not under PJM functional control. AEP-East is involved in the various operations and planning stakeholder processes of PJM to help ensure the reliability of the transmission system.¹⁹

PJM directs the dispatch of AEP-East's generating resources to meet minute-to-minute loads and determines the planning reserve required to maintain generation resource adequacy.²⁰ As a result, Kentucky Power's Big Sandy units are centrally dispatched in conjunction with other AEP-East operating companies and other units in PJM, based on offers made to PJM for each unit.²¹

Reliability Criteria

A reserve margin is required in order for a utility to have sufficient capacity available to allow for (1) unexpected loss of generation, (2) reduced generation capacity due to equipment problems, (3) unanticipated load growth, (4) variances in load due to extreme weather conditions, and (5) disruptions in contracted purchased power. A utility's required reserve capacity can be supplied via its own generation, purchased power, or a combination thereof. "Reserve Margin" is derived as follows:

Reserve Margin Percent = (Total Supply Capability-Peak Load)/Peak Load.

Kentucky Power explained that PJM instituted a new capacity planning regime called the Reliability Pricing Model ("RPM") effective with the 2007-2008 delivery year. The purpose of RPM is to develop a long-term price signal for capacity resources as well as load-serving entity obligations that are intended to encourage the construction of new generating capacity in the region. The reserve margin determined each year by

¹⁹ Id.

²⁰ Id.

²¹ Application, Vol. A, Resource Forecast at 4-1.

PJM is intended to maintain a one-day-in-ten-years loss of load expectation which is similar to the criterion used by Kentucky Power and AEP-East for many years.²²

PJM offers an alternative to RPM called Fixed Resource Requirement (“FRR”). Under FRR, the reserve margin is built upon the fixed PJM Installed Reserve Margin (“IRM”) requirement as it was prior to RPM being implemented. The FRR allows opting entities to meet their reserve requirement with a lower capacity requirement than might have resulted under the RPM requirement. AEP-East has elected to opt-out of the RPM and will use the FRR through the 2012/2013 delivery year. According to Kentucky Power, AEP-East will evaluate each year whether to continue to use FRR for an additional year or participate in the RPM for a minimum commitment of five years.²³

For this IRP, Kentucky Power assumed that the commitment to use the FRR alternative would continue indefinitely. As set for the 2012/2013 delivery year, the PJM IRM factor is 16.2 percent. The AEP-East IRM is calculated considering its effective coincidence factor within the RTO of about 96 percent, which reduces its reserve requirement to a range of 11 to 12 percent.²⁴ It was also assumed that the underlying PJM Equivalent Forced Outage Rate-demand (“EFORd”) used for the 2012/2013 delivery year of 6.44 percent would remain constant. However, it was assumed that the AEP-East EFORd would decline from 8.41 percent in 2009/2010 to 6.56 percent in 2018/2019. This tends to reduce the amount of new capacity needed to meet PJM requirements.²⁵ The reserve margin used in AEP-East’s modeling program was 15.5 percent.²⁶

²² Id., at 4-2.

²³ Id.

²⁴ Id.

²⁵ Id., at 4-3.

²⁶ Id., at 4-48.

SUPPLY-SIDE RESOURCE EVALUATION

Kentucky Power as a Stand-Alone System

While it believes its resource plans must be considered in the context of AEP-East,²⁷ as directed by the Commission in its Order in Case No. 2004-00420,²⁸ Kentucky Power identified the resources available to it as a stand-alone utility as well as those available to it as a member of a power-pooling arrangement. There are several exhibits which identify the resources available as a stand-alone utility as well as a brief discussion of the impact of operating as a stand-alone system.²⁹

As previously stated, Kentucky Power's resources as a stand-alone utility are the two Big Sandy units totaling 1,060 MW and its share of Rockport Units 1 and 2 (total of 393 MW) through a purchased power agreement.

Kentucky Power indicated that its future supply-side resources included two proposed 50 MW wind power purchase agreements.³⁰ In addition, the AEP-East plan includes over 300 MW of peaking capacity in 2018 and about 300 MW of intermediate capacity in 2023. By including 86 MW of demand resources at the summer peak and 24 MW of demand resources at the winter peak in 2015, Kentucky Power, as a stand-alone utility would have negative reserve margins through 2017. The addition of

²⁷ Application, Vol. A, Overview and Summary, at 1-1.

²⁸ Case No. 2004-00420, Application of Kentucky Power Company for Approval of a Stipulation and Settlement Agreement Resolving State Regulatory Matters (Ky. PSC Dec. 13, 2004).

²⁹ Application, Vol. A, Overview and Summary, at 1-11 to 1-12.

³⁰ Finding, in part, that Kentucky Power had not shown the wind power contract to be least cost when compared to its available energy resources, the Commission denied Kentucky Power's application for a renewable purchased power agreement for 100 MWs of wind energy by its ruling in Case No. 2009-00545, Application of Kentucky Power Company for Approval of Renewable Energy Purchase Agreement for Wind Energy Resources Between Kentucky Power Company and FPL Illinois Wind, LLC. (Ky. PSC Jun. 28, 2010).

peaking capacity in 2018 would bring its reserve margin to near zero. According to Kentucky Power, if it operated on a stand-alone basis, the large size of Big Sandy Unit 2 would require a large reserve margin. If that reserve margin were 20 percent, Kentucky Power would need an additional 800 MW of capacity in the near-term and another 400 MW after 2018.³¹

As a stand-alone utility, if Kentucky Power were a member of PJM, it would need to maintain a summer reserve margin of 12 to 16 percent. Therefore, it appears that Kentucky Power would need to either install additional generating capacity or purchase capacity earlier than it does as a part of AEP-East,³² even before consideration of the Commission's denial of the wind power purchase agreements. Therefore, the IRP filed by Kentucky Power and this Staff Report focus on the resource requirements of AEP-East in addition to the needs of Kentucky Power.

Kentucky Power as part of AEP-East

AEP-East used the *Strategist* optimization model to determine its least-cost resource mix based on a number of modeling constraints including reliability and environmental emissions.³³ In addition to its normal screenings, AEP-East created nine additional portfolios to test issues relating to coal generation, nuclear generation, carbon capture and sequestration ("CCS"), renewables, reduction in demand, increased demand response and energy efficiency, and CO₂ emissions limitations based on the prospect of continued federal climate change legislation.³⁴

Based on the array of results from varying pricing scenarios and strategic portfolios, AEP-East developed several resource portfolios for comparison using

³¹ Application, Vol. A, Overview and Summary, at 1-13.

³² Id.

³³ Application, Vol. A, Resource Forecast, Technical Appendix, at 4-47 to 4-48.

³⁴ Id., at 4-53 to 4-57.

Strategist. Of those portfolios, the Reference Case Optimal Portfolio was determined to be a reasonable basis for the development of the final AEP-East Hybrid Plan (“Hybrid Plan”).³⁵ This portfolio generally provided the lowest Cumulative Present Worth (“CPW”) across the various scenarios when compared to the alternative plans.³⁶

None of the portfolios called for baseload capacity prior to 2022. This provides a level of certainty that any short-term decisions made based on the Reference Case Optimal Portfolio would be equally valid under other portfolios. During the development of the Hybrid Plan, the timing and number of units added in the Reference Case Optimal Plan were adjusted to reflect reductions in peak loads based on the AEP-East April 2009 revised load forecast. In addition, the CCS retrofits identified in the CO₂ Limited optimization runs were also added as part of the Hybrid Plan, as well as part of the revised Renewable Energy Plan. The reduction in peaking requirements resulting from the revised load forecast allowed the number of peaking resources beyond 2018 to be reduced from 24 in the Reference Case Optimal Portfolio to 12 in the Hybrid Plan. However, an intermediate resource was added in place of four of these combustion turbines to diversify the energy mix. The least-cost Hybrid Plan and the resource additions for AEP-East are identified in the table on the following page.³⁷

³⁵ The Hybrid Plan was developed to reflect the impact of the updated 2009 AEP-East load forecast, long-term reductions in its carbon footprint, and a revised renewable plan that includes an acceleration in wind power additions.

³⁶ *Id.*, at 4-60.

³⁷ Derived from Application, Vol. A, Overview and Summary, Table 1, at 1-2 and 4; Resource Forecast, Technical Appendix, Exhibit T, 1-4; Hybrid Plan, at 4-61.

2009 AEP-East IRP

	Planned Resource Reductions ¹		DSM ³	Planned Resource Additions ¹			Thermal		
	Unit Retires ²	CCS Retrofits		Solar ⁴	Wind ⁴	Biomass	Duty Cycle Type ⁵	Ownership	
2009			58	0	200				
2010	(440)	(4)	324	3	350				
2011			625	3	600				
2012	(560)		806	9	700	60			
2013			987	14	500		540 MW	APCo	
2014	(395)	(31)	1,166	14			45 MW	I&M	
2015	(415)		1,346	14			168 MW	I&M	
2016			1,346	14	100		68 MW	I&M	
2017	(600)		1,346	13			68 MW	I&M	
							68 MW		
2018	(580)		1,346	17		127	628 MW	PKG ⁶	
2019	(480)		1,346	17					
2020		(160)	1,346	16	200				
2021	(690)		1,346	35	150	127	611 MW	APCo	
2022			1,346	52	100		628 MW	APCo	
2023	(660)		1,346	0	100		611 MW	⁷	
Nameplate	(4,820)	(195)	1,346	221	3,000	314	3,435		
Total (Nameplate)			16%	3%	36%	4%	41%		
Total (Capacity)			24%	3%	7%	6%	61%		
NET CAPACITY RESOURCE ADDITIONS:							Total New Peaking Capacity	1,256	37%
Additions - Reductions = 624							Total New Intermediate Capacity	1,762	51%
							Total New Baseload Capacity	417	12%
							Total Capacity	3,435	

¹ All Resource reductions and additions shown in MW
² Summer Rating
³ Total contribution of New & Embedded Demand
⁴ Nameplate rating
⁵ Duty Cycle Type: BL=Baseload, INT=Intermediate/Cyclic, PKG=Peaking
⁶ BL - Indiana & Michigan, PKG - Appalachian Power/Kentucky Power 50/50
⁷ PKG - Appalachian Power/Kentucky Power 50/50

The optimal AEP-East plan includes 3,534 MW of renewables represented by 220 MW of solar power, 3,000 MW of wind power and 314 MW of biomass power. It also includes 3,435 MW of traditional generation in the form of 1,256 MW of peaking capacity, 1,762 MW of intermediate capacity and 417 MW of baseload capacity³⁸ in addition to 4,820 MW of unit retirements and a reduction of 195 MW due to CCS retrofits.³⁹ As referenced above, the resource additions specific to Kentucky Power include 342 MW of peaking capacity (modeled as natural gas-fired combustion turbines) in 2018 and 360 MW of intermediate capacity (modeled as natural gas-fired combined cycle capacity) in 2023.^{40 41} In addition, Big Sandy Unit 1 was identified as a potential candidate for retirement late in the fifteen-year planning horizon (a date past the winter peak of 2023 has been used in this plan).⁴²

The following sections provide discussion of AEP-East's consideration of renewable and other resources as required by Kentucky's IRP regulation. The impact of more stringent environmental regulation on AEP-East's resource needs is addressed in the environmental compliance section.

Renewables

Kentucky Power stated that Renewable Portfolio Standards ("RPS") and goals have been enacted in over two-thirds of the states across the nation and that adoption of further RPS at the state level or the enactment of federal carbon limitations or a federal RPS will require that it acquire more renewables. In 2007, AEP committed to

³⁸ Application, Vol. A, Overview and Summary, at 1-11.

³⁹ Id., at 1-2.

⁴⁰ Id., at 1-11.

⁴¹ The amounts of the Kentucky Power resource additions are based on its fifty percent ownership of the proposed additions with Appalachian Power Company.

⁴² Application, Vol. A, Resource Forecast, at 4-6.

acquiring 1,000 MW of wind generation by the end of 2010 via long-term purchased power agreements as part of its comprehensive strategy to address greenhouse gas (“GHG”) emissions. The goal was expanded in early 2009 to 2,000 MW by the end of 2011.⁴³

At the time the IRP was filed, one AEP operating company was already receiving energy from a 75 MW wind project and four additional contracts had been executed for other AEP operating companies for an additional 551 MW to be placed in service in 2009 and 2010. As part of this commitment, Kentucky Power’s IRP included power purchase agreements for a 50 MW wind project by year end 2010 and a second 50 MW project by year end 2012.⁴⁴ As stated earlier, Kentucky Power’s request for approval to enter into the wind power purchase agreements was denied.

When modeling the potential resource portfolios for this IRP, management commitments outlined in the *AEP 2009 Corporate Sustainability Report* were considered. Two of the commitments for the AEP-East resource portfolios include:

- (1) Renewable Resources: On an AEP system-wide basis, to achieve 7 percent of energy sales from renewable energy sources by 2013, 10 percent by 2020 and 15 percent by 2030. Recognize the potential for a federal RPS and mandatory state RPS in Ohio, Texas, Michigan, and West Virginia and voluntary RPS in Virginia.
- (2) Assumptions on “early mover” commitment to these GHG and renewable strategies: Limit exposure to scarce resource pricing; take advantage of current tax credit for renewable generation; reduce exposure to potential GHG legislation as initial mitigation requirements unfold; plan

⁴³ Id., at 4-7.

⁴⁴ Id.

to be in concert with other CO₂/GHG reduction options (offsets, allowances, etc.).⁴⁵

An Enhanced Renewable portfolio was created based on meeting increased AEP system-wide renewable energy targets as outlined in the AEP Corporate Sustainability Report discussed above. The Enhanced Renewable portfolio adds one less combined cycle unit than the Reference Case Optimal Portfolio. However, the cost of the Enhanced Renewable Portfolio is approximately \$580 million more than the cost of the Reference Case Optimal Portfolio, indicating that increasing the amount of renewable energy is not cost effective under Reference Case conditions. However, under the Constrained Case conditions, the Enhanced Renewable portfolio provides some savings over the Constrained Case optimal portfolio.⁴⁶

To test the economics of a portfolio with very low emissions profiles, a Green Plan Portfolio with the same renewable energy targets as the Enhanced Renewables Portfolio that also included a nuclear unit in 2023 was created. The cost of the Green Plan Portfolio is approximately \$1.2 billion more than the cost of the Reference Case Optimal Portfolio. These results indicate that increasing the amount of renewable energy and the addition of a nuclear unit to offset emissions is not cost-effective under Reference Case conditions.⁴⁷

The renewable program for Kentucky Power includes *co-firing biomass* in Rockport Units 1 and 2 by 2013 and separate injection of biomass in Big Sandy Unit 2 by 2015. The renewable plan for the AEP-East Zone includes solar energy by the end

⁴⁵ Id., at 4-50 to 4-51.

⁴⁶ Id., at 4-55.

⁴⁷ Id., at 4-55 to 4-46.

of 2009, which is driven by requirements in Ohio. Kentucky Power's plan does not include solar energy.⁴⁸

Cogeneration

Kentucky Power offers two cogeneration tariffs to customers with cogeneration and/or small power production facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978. No customers were receiving service under either tariff at the time the IRP was filed. Kentucky Power stated that because it offers low electric rates, cogeneration is a less attractive option from an economic standpoint, even when gains in thermal efficiency are included. According to Kentucky Power, cogeneration may be a more viable option if its rates were to increase to the point where it makes cogeneration a serious economic consideration.⁴⁹

Distributed Generation and Net Metering

Distributed technologies such as solar panels and batteries, while still expensive, are being explored as possible planning options. Costs are projected to decline for these technologies, which will increase their viability as cost-effective alternatives for generation, transmission, and distribution infrastructure. While any application of these non-traditional assets would be highly site-specific in the near future, the evolution of these technologies is continuously monitored by Kentucky Power.⁵⁰ Kentucky Power initiated a Net Metering Service Tariff in 2005, which was amended in 2009 pursuant to net metering guidelines established by the Commission to comply with Senate Bill 83 enacted by the Kentucky General Assembly during the 2008 Regular Session. As of June 2009, Kentucky Power had no net metering customers. Kentucky Power stated that distributed generation technology options will continue to be developed for

⁴⁸ Id., 4-7.

⁴⁹ Application, Vol. A, Demand-Side Management Programs, at 3-12.

⁵⁰ Id., at 3-11.

customers. However, it believes that promotion of distributed generation and green power through net metering must be reviewed closely in order to avoid the subsidy of such options by the remaining customers or by the utility.⁵¹

Non-utility Generation, Coordination with Other Utilities and New Capacity Alternatives

According to Kentucky Power, the information available when this IRP was filed indicated that, in the next five years, capacity reserve margins in the Reliability First Corporation Regional Reliability Organization (“RFC”) region that includes PJM and AEP-East will decline to the point that new generation will be needed. Additional pressure for capacity will come from new emissions reduction requirements and potential additional environmental compliance legislation. As a result, the capacity requirements included in this IRP are self-planned AEP-East alternatives.⁵²

Alternative technologies considered for this IRP were divided into baseload, intermediate and peaking cycles for the screening analysis that was performed. Supply alternatives considered included: combustion turbines, natural gas combined cycle units, ultra supercritical pulverized coal generation with CCS retrofits, and nuclear generation.⁵³

Transmission Improvements

The AEP-East transmission system consists of the facilities of its seven operating companies. It is comprised of approximately 15,000 miles of circuitry operating at or above 100 kV. The AEP-East Zone includes over 2,100 miles of 765 kV, 3,800 miles of 345 kV, and over 8,800 miles of 138-kV circuitry. The system allows AEP-East to economically and reliably deliver electric power to approximately 24,200 MWs of

⁵¹ Id., at 3-12.

⁵² Application, Vol. A, Resource Forecast, at 4-8.

⁵³ Id., at 4-8 to 4-9.

customer demand that takes transmission service under the PJM open access transmission tariff.⁵⁴

The AEP-East transmission system is directly connected to 19 neighboring systems at 144 interconnection points. These interconnections provide an electric pathway to facilitate access to off-system resources and serve as a delivery mechanism to adjacent systems. The AEP-East transmission system conforms to the North American Electric Reliability Council Reliability Standards and the applicable RFC standards and performance criteria.⁵⁵

From a transmission perspective, there have been two significant changes since Kentucky Power's 1999 IRP filing. The first significant change is AEP-East's transfer of functional control of its transmission facilities to PJM. The second significant change is the 90-mile Wyoming-Jacksons Ferry 765-kV line, which was completed and placed in service in West Virginia and Virginia in 2006. At the time of the 1999 IRP filing, this was an alternative to the originally proposed Wyoming-Cloverdale 765 kV line.⁵⁶

Despite the robust nature of the AEP-East transmission system, certain outages, coupled with extreme weather conditions and/or power-transfer conditions, can potentially stress the system beyond acceptable limits.⁵⁷ In addition, the system is aging and some station equipment is becoming obsolete. Therefore, in order to maintain acceptable levels of reliability, significant investments will have to be made over the next ten years to proactively replace the most critical aging and obsolete equipment and transmission lines.⁵⁸

⁵⁴ Id., at 4-11.

⁵⁵ Application, Vol. A, Overview and Summary, at 1-18.

⁵⁶ Id., at 1-14.

⁵⁷ Application, Vol. A, Resource Forecast, at 4-11.

⁵⁸ Application, Vol. A, Overview and Summary, at 1-18.

Kentucky Power identified three projects planned for its transmission system over next few years. First, to improve reliability, alleviate thermal overloading and heaving loading conditions and to provide for future growth in the South Neal-Coalton-Bellefonte area, it will tap the Chadwick-KES 138 KV circuit and install a new 138/69 KV 200 MVA transformer at the Coalton station. This project is currently projected to be in service in 2012.⁵⁹

Second, the Thelma-Paintsville Area Project will provide single contingency reliability to the Paintsville area by adding a 138/69 KV, 90 MVA transformer at Thelma Station, constructing 1.8 miles of 69 KV line from the West Paintsville Station to the Paintsville Station, and converting the Thelma-Paintsville 46 KV line to 69 KV to close the 69 KV loop. This project is projected to be in service between 2012 and 2013.⁶⁰

Finally, the Hazard Area Improvements Project will provide single contingency reliability to the Hazard area subtransmission system and double contingency reliability to the 138 KV systems by providing another 138 KV source into the Hazard area. This project is currently projected to be in service between 2013 and 2015.⁶¹

Distribution Improvements

Kentucky Power did not identify any specific improvements planned for its distribution facilities. It indicated, however, that AEP continues to evaluate distribution technologies that operate off its gridSMART platform. These include “smart meters” that allow customers to receive pricing signals, or variable rates, encouraging the migration of consumption from times of peak demand to times when power is more readily available. Pilot programs employing smart meters are currently underway in Ohio and

⁵⁹ Id.

⁶⁰ Id., at 4-11 to 4-12.

⁶¹ Id., at 4-12.

Indiana. The results of these pilots will greatly inform the utilities of the impacts assigned to larger roll-outs of these meters, should they ultimately be approved.⁶²

Efficiency Improvements - Generation

Kentucky Power indicates that, with proper maintenance and operation, coal-fired units can expect to achieve operating lifetimes beyond the traditional nominal 35 to 40 years; however, the optimum achievable lifetime is highly unit-specific. Kentucky Power states that AEP has developed programs that attempt to achieve optimal operating lifetimes as economically as possible. The work of component refurbishment or replacement is planned and carried out over a long period so as to minimize total cost and the outage time required.⁶³

Kentucky Power did not identify or discuss any generation efficiency projects under way at the Big Sandy Station. However, it pointed out that the impact of any potential carbon-related cap-and-trade regime will compound the deteriorating cost profile of older, non-environmentally-controlled, higher heat-rate coal-fired plants. According to Kentucky Power, the retirement of older units must be considered as they become less economic. Based on a financial analysis that considered several factors, the cost of environmental allowances among them, Big Sandy Unit 1 was identified as a candidate for retirement in 2023, late in the 15-year planning horizon.⁶⁴

Environmental Compliance

The IRP is based on current mandatory environmental requirements (the existing SO₂ reduction programs under the Clean Air Act Amendments [“CAAA”], AEP’s 2007 settlement of its the New Source Review case, as well as the NO_x State Implementation Plan [“SIP”] Call requirements for reductions in the Midwestern U.S.). It also assumes a

⁶² Application, Vol. A, Demand-Side Management Programs, at 3-6.

⁶³ Application, Vol. A, Resource Forecast, at 4-6.

⁶⁴ *Id.*, at 4-6, 4-7.

need to reduce the production of CO₂ similar in many respects to legislation that has been proposed at the federal level in recent months.⁶⁵

In addition to the compliance strategy for meeting the CAAA Title IV (Acid Rain Program) Phase I and II emission requirements for SO₂ and NO_x included in the 1999 IRP,⁶⁶ AEP-East has developed compliance strategies to meet the requirements of the CAAA as each rule becomes known. Such rules include the NO_x SIP Call, Clean Air Interstate Rule ("CAIR"), Clean Air Mercury Rule ("CAMR"), and Clean Air Visibility Rule ("CAVR"). According to Kentucky Power, electric utilities, as major producers of CO₂ will be significantly affected by any GHG legislation.⁶⁷

Beginning in May 2004, AEP was required to meet more stringent NO_x emission limitations during the May-through-September ozone season as part of the NO_x SIP Call. These requirements included the Big Sandy plant. The compliance plan for the Big Sandy plant to meet this requirement included installation of an overfire air burner modification and water injection system and boiler tubes overlay on Unit 1 and installation of a selective catalytic reduction system ("SCR") on Unit 2. The SCR installation required upgrading the Unit 2 electrostatic precipitator. Similar technologies were implemented throughout the AEP system.⁶⁸

In 2008, the United States Court of Appeals for the D.C. Circuit Court remanded the CAIR rules to the EPA for further rule-making. The D.C. Circuit Court's ruling leaves CAIR in place until EPA develops new rules to take its place or appropriately modifies it. This includes NO_x reduction requirements beginning in 2009 and SO₂ reduction requirements in 2010. While there is uncertainty over how EPA will rewrite CAIR, for

⁶⁵ Application, Vol. A, Overview and Summary, at 1-1.

⁶⁶ *Id.*, at 1-14.

⁶⁷ Application, Vol. A, Resource Forecast, at 4-3.

⁶⁸ *Id.*

purposes of planning, AEP-East expects the CAIR program to be replaced with a more restrictive policy. AEP-East has postulated a scenario in which SO₂ and NO_x emissions will be 10 percent below the CAIR Phase II limits (fully implemented by 2025) and exclude an allowance bank to meet emission targets.⁶⁹

The D.C. Circuit Court also vacated the CAMR, thereby eliminating any compliance requirements for mercury until EPA develops a new rule. Kentucky Power indicated that new rules could become effective in 2014 when a command-and-control policy could require all coal units to install either a mercury-specific control technology such as activated carbon injection (“ACI”) or FGD/SCR emissions control equipment that, in combination, also reduce mercury emissions. Kentucky Power believes there is also a strong possibility that a plant-by-plant standard will replace a mercury trading system. If this is the case, a dispatch price would not be required, but additional controls such as baghouses or ACI would be needed. According to Kentucky Power, this could have an impact on proposed retirement dates of older, non-controlled units and, ultimately, the timing for new capacity.⁷⁰

On October 9, 2007, AEP entered into a consent decree with the U.S. Department of Justice to settle all complaints filed against AEP and its eastern affiliates under the New Source Review program of the Clean Air Act. The consent decree includes a schedule for installation of emissions control technology on certain AEP-East units and annual caps on NO_x and SO₂ emissions from the AEP-East fleet of coal units. Kentucky Power was bound by the decree to continuously operate low NO_x burners on Big Sandy Unit 1 beginning October 9, 2007 and an SCR on Big Sandy Unit 2 beginning January 1, 2009. Kentucky Power is also required to install and continuously operate

⁶⁹ Since the filing of the 2009 IRP, EPA has announced the Air Transport Rule as the replacement for CAIR.

⁷⁰ Id., at 4-4.

an FGD system on Big Sandy Unit 2 by December 31, 2015. FGD and SCR systems will also be installed on Rockport Unit 1 by December 31, 2017 and on Rockport Unit 2 by December 31, 2019.⁷¹

For the 2009 IRP, the impact of CO₂/GHG legislation on AEP-East's long-term planning is essentially modeled as a simple CO₂ price that would impact fossil unit dispatch cost reflecting a scaled annual "cap" on the price of CO₂. AEP-East's post-2010 strategy regarding CO₂/GHG is to voluntarily reduce or offset an additional five million tons of CO₂ per year by purchasing offsets from projects such as forestry, reducing methane from agriculture, adding more renewable energy, and improving the efficiency of its power plants.⁷²

The AEP-East IRP is based on current environmental compliance requirements which have a major influence on the supply-side resources considered for inclusion in the IRP due to their potential effects on both capital and operational costs. Further, ongoing debate over CO₂/GHG emissions, particulate matter, and regional haze ("CAVR") will likewise influence future capacity resource planning decisions to retrofit, modify operations, or retire/mothball generating assets. The current forecast of the existing AEP-East generating fleet's capability through the year 2023 reflects 425 MW in unit deratings associated with environmental retrofits. The net impact to the AEP-East existing units from these deratings, together with planned efficiency improvements, is a 6 MW reduction in available capacity on the existing fleet. The net impact for Kentucky Power is a reduction of 71 MW of capacity (See Exhibits 4-8 for further details).⁷³

⁷¹ Id.

⁷² Id.

⁷³ Id., at 4-5.

DISCUSSION OF REASONABLENESS – RECOMMENDATIONS

In its next IRP, Kentucky Power will be required to include the same type of information as filed in this IRP which identifies the resources available to it as both a member of the AEP-East Power Pool and as a stand-alone utility. Kentucky Power should also include a detailed discussion of the then-current status of the AEP-East Power Pool, any changes or modifications that are under consideration, and the potential impacts to Kentucky Power. Additional recommendations include the following:

- Provide a specific discussion of the consideration given to renewable generation by both AEP-East and Kentucky Power.
- Specifically discuss the existence of any cogeneration within its service territory and the consideration given to cogeneration in the resource plan.
- Specifically identify and describe the net metering equipment and systems installed. A detailed discussion of the manner in which such resources are considered in its IRP should also be provided.
- Provide a detailed discussion of the consideration given to distributed generation.
- Provide a specific discussion of the improvements and more efficient utilization of transmission and distribution facilities as required by 807 KAR, Section 8 (2)(a). This information should be provided for the past three years and should address Power's plans for the next three years.
- In addition to describing how AEP-East has addressed currently pending environmental regulations and perhaps new legislation, describe how Kentucky Power has specifically addressed such legislation. The next IRP should also address the expected impact on AEP-East and Kentucky Power of any then-potential environmental regulation or legislation.

SECTION 5

INTEGRATION AND PLAN OPTIMIZATION

The final step in the IRP process is the integration of supply-side and demand-side options to achieve an optimal resource plan. This section discusses the integration process and the resulting Kentucky Power plan.

THE INTEGRATION PROCESS

An ultimate resource assessment and acquisition plan was developed based on minimizing expected costs over the 2009-2023 planning horizon measured in CPW revenue requirements. For modeling purposes, *Strategist* constructed portfolios through 2030. Differences were evaluated by changing assumptions and calculating the total costs based on the changes with lower costs as the objective.

Strategist used variables which included but were not limited to forecasts of fuels, load, emissions, emission retrofits, and construction costs for capital projects to study resource alternatives. The analysis was focused on emissions, renewables, commodity prices and evolving economic conditions.⁷⁴

DSM programs were evaluated in *Strategist* to determine which programs were qualified to move to the next level of analysis, the incorporation with supply-side options to determine the optimal plan. Programs that performed well under all economic scenarios resulted in peak reductions for AEP-East of about 375 MW from energy efficiency and 600 MW from commercial and industrial demand response by the year 2015.

The PROMOD computer program is used to assist Kentucky Power as it makes decisions about dispatching its available units. PROMOD uses forecasted load, forecasted fuel data, resource data, and rules for committing and dispatching units to provide information on generation by unit, fuel-use data by unit and contract, and

⁷⁴ Id., at 4-9.

energy transactions cost and revenues. PROMOD shows how the system will operate by economically dispatching resources subject to constraints. This gives Kentucky Power a better understanding of how each of its actions may affect the distribution of power to the load.⁷⁵

The PROVIEW module of *Strategist* assists Kentucky Power as the least cost expansion plan is formulated from possible resource options. These options are used as starting points for the addition of new resources necessary to meet current reserve requirements. To reduce the number of modeling runs required, constraints are added to existing variables to make the analysis manageable and provide the best outputs.⁷⁶

Technology Screening

Based on economic screenings, supply-side alternatives were modeled in *Strategist* by AEP-East as:

1. Peaking capacity in blocks of four 165 MW CTs available beginning in 2017;
2. Intermediate capacity as two natural gas combined-cycle units each rated 650 MW also available in 2017; and
3. Baseload capacity which is expected to burn eastern coal. Alternatives for solid fuel were units with CCS capabilities, either retrofitted or built new. Beginning in the year 2020, the option of an 800 MW share of a 1,600 MW nuclear reactor is available to *Strategist* in its modeling.⁷⁷

⁷⁵ Id., at 4-14.

⁷⁶ Id., at 4-48.

⁷⁷ Id., at 4-49.

Demand response and energy efficiency blocks were evaluated using all economic scenarios. In the full optimization analysis for AEP-East, the demand response impact was assumed to be 1,074 MW.⁷⁸

Given constraints, commitments and pricing scenarios developed by AEP, four basic portfolios “cases” were developed. These are identified as a Business as Usual (“BAU”) Case, an Abundance Case, a Reference Case Optimization, and a Constrained Case for AEP-East. The analysis shows that baseload capacity was added only in extreme pricing scenarios. No cost was assumed in the BAU Case for CO₂ emissions and the coal alternative benefited by not having CCS equipment cost. Under the Business as Usual Case, coal additions were added to replace retiring units in the 2015-2025 timeframe. Nuclear additions become economic replacements for retiring units in the Constrained Case where commodity prices are the highest and CCS equipment is required on new coal units. When the cost of CCS equipment is accounted for, the nuclear additions are \$70 million less expensive.

In the Reference Case, combined cycle additions operate at between 20 and 60 percent capacity, increasing usage as older coal units are retired. In this case, a plan that adds a pulverized coal (“PC”) unit with CCS in 2023 is \$65 million more expensive than the plan with combined cycle units.⁷⁹

The Abundance Case shows that, when commodity prices are low enough, the additional cost of a PC unit with CCS equipment is not economical, being \$160 million more expensive than the optimal plan.

Strategist is used to develop resource portfolios that have different costs when applying scenarios and sensitivities. Portfolios that perform best under all scenarios and sensitivities are evaluated further to determine the optimum portfolio. When

⁷⁸ *Id.*, at 4-50.

⁷⁹ *Id.*, at 4-52 through 4-53.

building resource profiles, management commitments regarding renewable resources and energy efficiency are considered. Ultimately, nine more portfolios were developed to analyze the economics of factors and influences other than commodity prices.

Best Contrary Base/High Plan for Baseload Coal Solution

This portfolio was analyzed to determine the additional cost associated with solid fuel additions under different pricing scenarios. This portfolio was shown to be only \$65 million more expensive than the Reference Case optimal portfolio.

Best Contrary Base/High Plan for Baseload Nuclear Solution

This portfolio was examined to determine the additional cost of a nuclear addition to the different pricing scenarios. This nuclear portfolio was approximately \$365 million more expensive than the Reference Case optimal portfolio.

Optimization without post-2020 CCS Requirement on New Coal

This portfolio was examined to test the viability of coal additions without increased cost of CCS equipment. The optimization produced a portfolio that needed a pollution control device at the end of the planning period. This shows that, even without the CCS equipment, prices do not warrant the cost of a solid fuel addition early on in the planning period. This portfolio costs \$55 million more than the optimal portfolio for the Reference Case.

Enhanced Renewables

This portfolio was created to assess the cost of meeting increased system-wide renewable energy targets. The requirements for this scenario were set at 7 percent of system-wide energy sales to be met with renewable energy resources by 2013, 15 percent by 2020, and 20 percent by 2030. The cost of this portfolio is approximately \$580 million more than the Reference Case optimal portfolio. However, this portfolio does provide savings over the Constrained Case optimal portfolio.

Green Portfolio

From the Enhanced Renewables portfolio, a Green Plan portfolio was created under the Reference Case conditions. This portfolio was designed to meet the same targets as the Enhanced Renewables portfolio but included a nuclear unit in 2023. This portfolio is \$1.2 billion more expensive than the Reference Case optimal portfolio. This indicates that this is not cost-effective under the Reference Case conditions.

Demand Destruction

This portfolio was based on a forecast reflecting a 2.8 percent reduction in 2008 peak and energy levels through 2010. Beginning in 2011, peak and energy load would remain flat through 2013. From 2014 through 2035, the load would grow at an annual rate of 1 percent. This was shown to cause capacity additions from the Reference Case to be delayed from 2018 to 2021 with one less combined-cycle unit being added. This portfolio is \$12 billion less expensive than the Reference Case optimal portfolio, but, due to the reduced sales volumes, has the second highest dollar-per-MWh cost of all the scenarios.

Demand Destruction plus "Accelerated" Coal Unit Retirements

There is a three-year acceleration in the timing of expected retirements in this scenario. This was facilitated by a reduction in peak loads and energy from the Demand Destruction forecast. Accelerating retirements provides \$1 billion in savings over the Demand Destruction portfolio. This is mainly due to the fact that there is no combined-cycle unit in this portfolio.

High Demand Response/Energy Efficiency Bandwidth

Demand response and energy efficiency impacts from the Reference Case were increased by 50 percent to create this scenario. The additional savings from the increased impacts totaled \$640 million over the Constrained Case portfolio. These savings were the result of avoiding a combined-cycle addition found in the Constrained Case.

CO₂ Limited

CO₂ emission limits were assumed in this scenario based on the likelihood of comprehensive Climate Change/CO₂ legislation that would seek emissions level reductions. House Resolution 2454 (Waxman-Markey Bill passed in U.S. House in June 2009) was used as a proxy for such reductions. In 2020, the CO₂ emission limit was based on a 15 percent reduction (Waxman-Markey called for 17 percent) from the 2005 CO₂ emissions level, a limit of approximately 110 million metric tons for the AEP-East system. In 2030, limits were based on a 40 percent reduction (Waxman-Markey called for 42 percent) from the 2005 CO₂ emission levels, or a limit of approximately 82 million metric tons for AEP-East. These limits took into account that AEP would receive a maximum of 20 million metric tons of carbon offsets. These offsets were assigned to the East and West systems based on a prorated share of 2005 CO₂ emissions. The East system was allocated 15.5 million metric tons and West system received 4.5 million metric tons.⁸⁰ This portfolio is approximately \$640 million more expensive than the Reference Case optimal portfolio.

Hybrid Plan

After creating the nine supplemental portfolios discussed above, the *Strategist* analysis was used to create the AEP-East Hybrid Plan to compare against those plans. The Hybrid Plan took into account peak demand reduction due to economic factors and deferred capacity additions that had been added in the various optimization runs. CCS additions were introduced into the AEP-East plan in line with expected CO₂ emissions limits. The Renewable Energy Plan used in optimization runs was also revised to account for wind resource additions being needed sooner than originally expected. This was due to the expectation that a federal RPS might be implemented.

The Reference Case Optimal Portfolio was chosen to be the basis for the development of the AEP-East Hybrid Plan. This portfolio consistently produced the

⁸⁰ *Id.*, at 4-55 through 4-57.

lowest CPW across the various scenarios when compared to other options. The CCS retrofits from the CO₂ limited plan were incorporated into the Hybrid Plan. The number of peaking resources beyond 2018 was reduced for the Hybrid Plan, but an intermediate resource was added to diversify the resource mix.⁸¹

The portfolios selected for further stress testing included: (1) Reference Case Optimal Plan; (2) Best Contrary Base/High Plan for Baseload Coal Solution; (3) Best Contrary Base/High Plan for Nuclear Solution; (4) Enhanced Renewables; (5) Green Plan; (6) CO₂ Limited; and (7) the Hybrid Plan.⁸² These portfolios were analyzed using the Utility Risk Simulation Analysis (“URSA”) developed by AEP Market Risk Oversight. The results of the URSA analysis, which uses Monte Carlo simulation of the AEP-East Zone, take the form of a distribution of possible CPW revenue requirement outcomes for each plan. The final analysis provides results at both the 50th and 95th percentiles. The Hybrid had the lowest cost at both the 50 percent and 95 percent probability levels and, therefore, was chosen as the optimal resource plan.

Staff is generally satisfied with Kentucky Power’s responses to its previous recommendations and the information contained therein. It believes these responses adequately address the previous recommendations. All Staff recommendations for Kentucky Power’s next IRP filing, which will be due in the fall of 2012, are contained in Sections 2, 3 and 4 of this report.

⁸¹ Id., at 4-60.

⁸² Id., at 4-62.