Appendix A – Method for Computing Environmental Impact Metrics

Purpose

The IRP used a multi-component scorecard analysis of ranking and strategic metrics for evaluating the impacts of the planning strategies. In addition to the metrics used to establish the rank order of the planning strategies (cost and risk) with emissions costs imbedded, TVA developed strategic metrics, such as the environmental impact metric, to more clearly depict environmental stewardship attributes.

Process

In developing the criteria for the environmental impact metric, TVA staff wanted to create a metric representative of the trade-offs between energy resources rather than identifying a single resource with the "best" environmental performance. The final evaluation criteria relied on some surrogate measures as a proxy for environmental impacts, but when used comparatively with the other attributes, they provided a reasonable and balanced method for evaluating planning strategies. By considering air, water and waste in the IRP scorecard, coupled with the broader qualitative discussion of anticipated environmental impacts in the EIS, a robust comparison of the environmental footprint of the planning strategies better informed the selection of the Recommended Planning Direction.

Method

Outlined below is the methodology that was used for the environmental impact metric, by attribute, including a revised scoring of the strategies that were considered in the Draft IRP, excluding Strategies A and D, and inclusion of Strategy R – Recommended Planning Direction.

Air Impact Metric and Ranking

Model results provided data on the production of four emissions: CO_2, SO_2, NO_X and Hg by generation source (e.g., coal and lignite). The suite of emissions selected to evaluate the air impacts of the IRP strategies were meant to represent a range of emissions primarily associated with fossil-fueled power generation. It was suspected that evaluating the strategies on the basis of all four emissions would give the same results (i.e., declining emissions trends) as just using CO_2 alone, but emission trend plots were developed to confirm this assumption. Emission trends were plotted against averaged, historic TVA generation data from 2007 to 2009 for coal and combustion turbines. The most recent three years were used to provide a better representation of average air emissions, as 2009 was a historically low year for air emissions due partly to the economic recession and decreased electricity demands. Historic mercury emissions for lignite sources were unavailable, so projected data for 2010 was used and added to the other totals. Figure A-1 provides a summary of the baseline emissions that data emissions trends were plotted against.

	SO_2 (tons)	NO_x (tons)	CO_2 (tons)	Hg (lbs)
TVA Coal	302,818	140,528	94,879,125	2,597
TVA CTs	27	359	1,954,211	N/A
Lignite	817	1,235	2,092,848	55
Totals	**303,622**	**142,122**	**98,926,184**	**2,652**

Figure A-1 – Summary of 2007-2009 Average Emissions Data

Again using model results by generation sources for each of the cases, excluding cases associated with Strategies A and D, CO_2 emissions data from all emission sources were summed for selected spot years (five-year increments) 2010, 2015, 2020, 2025 and 2028. Then for each of these years, the CO_2 emissions for each strategy, excluding Strategies A and D, were summed across all eight scenarios, which gives a value for the total CO_2 emissions associated with each strategy. These totals were divided by eight to provide a representative average value for each spot year that could be compared to the 2007–2009 averaged historical baseline data. These data were plotted to demonstrate how CO_2 emissions vary over time (Figure A-2).

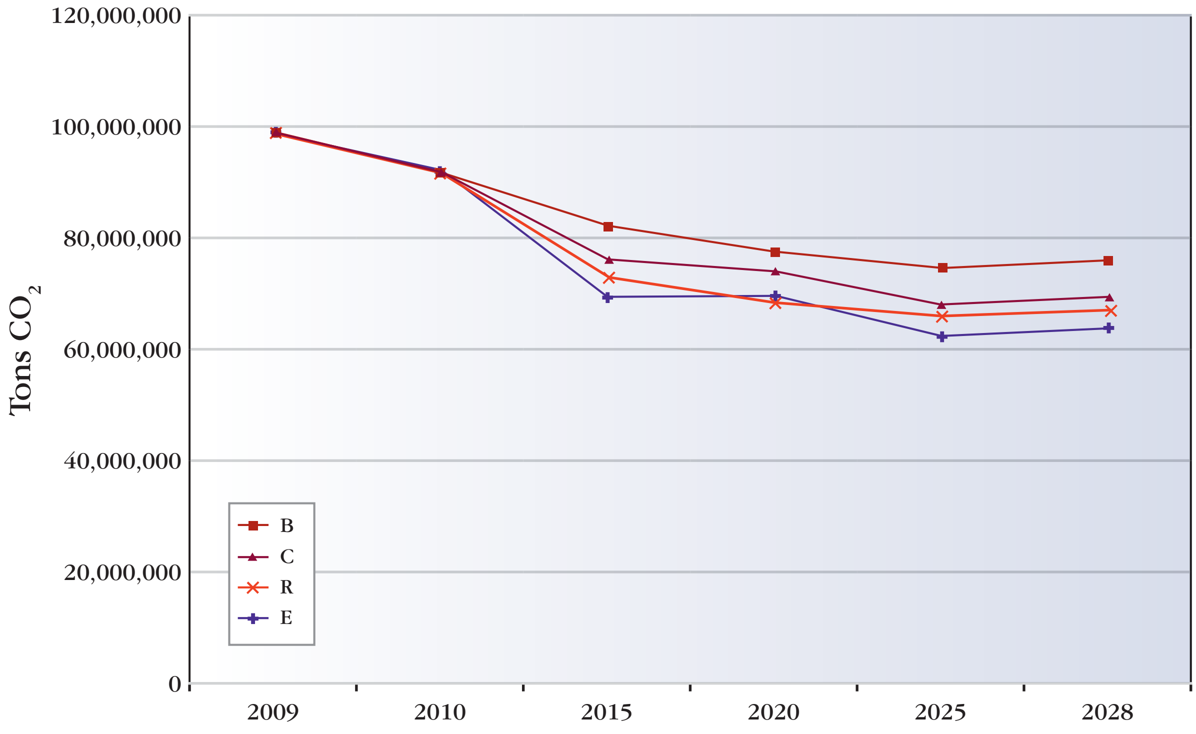

Figure A-2 – Tons CO_2 by Strategy

Similar calculations were also done for SO_2, NO_x and Hg as shown in Figures A-3, A-4 and A-5.

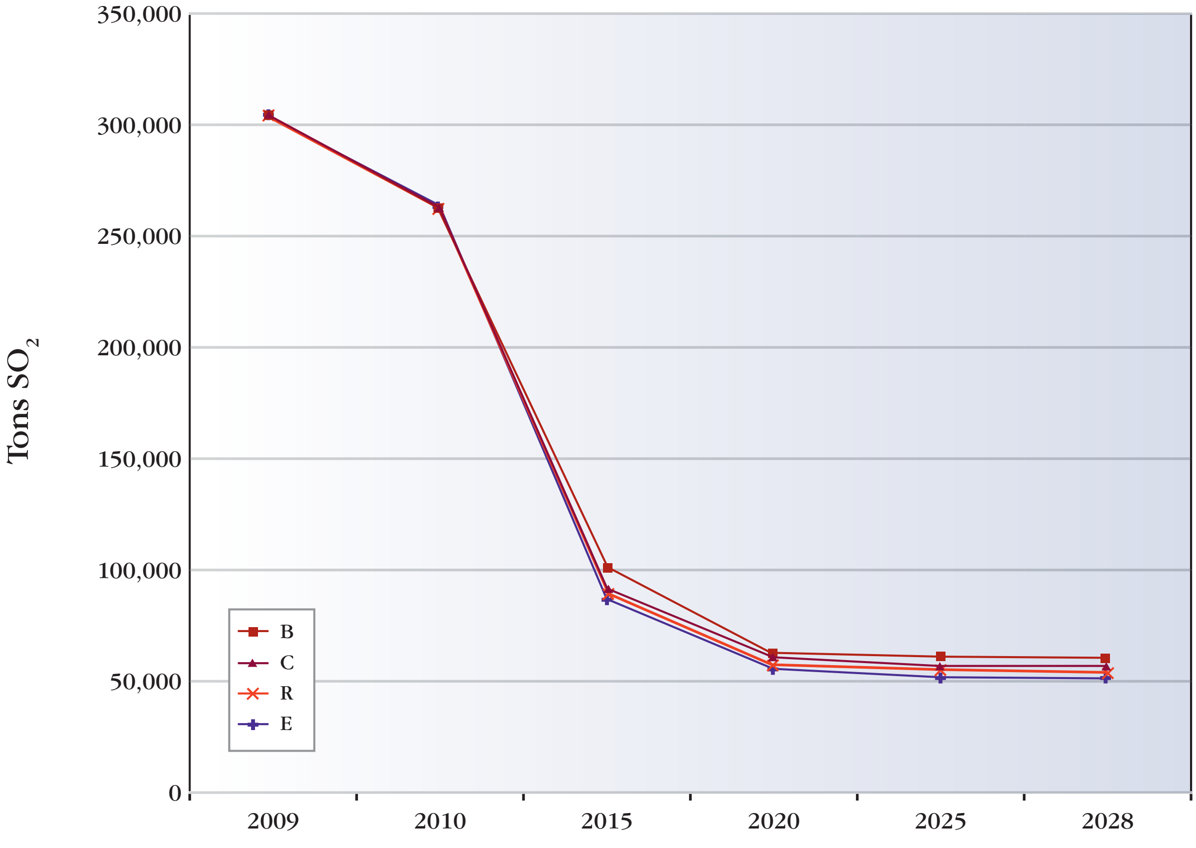

Figure A-3 – Tons SO_2 by Strategy

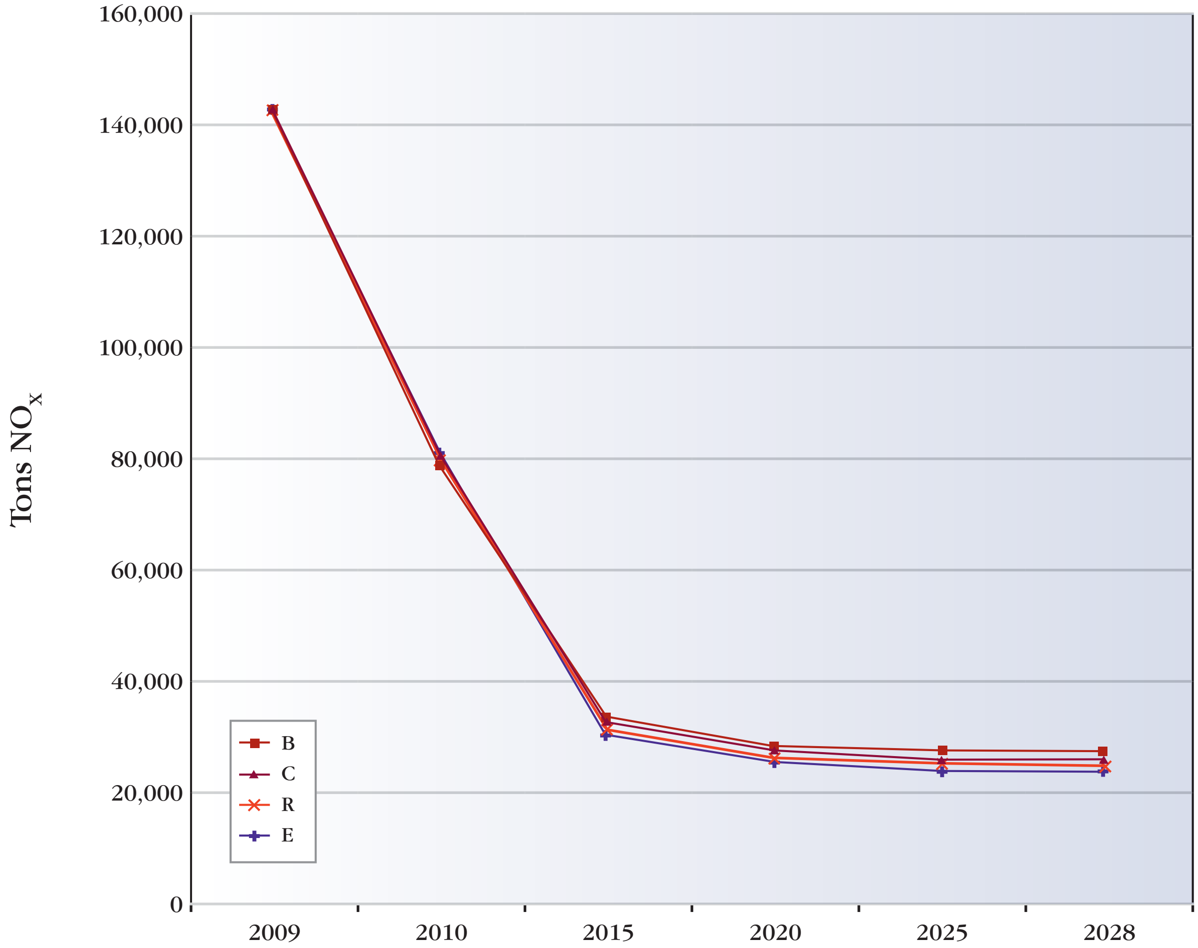

Figure A-4 – Tons NO$_X$ by Strategy

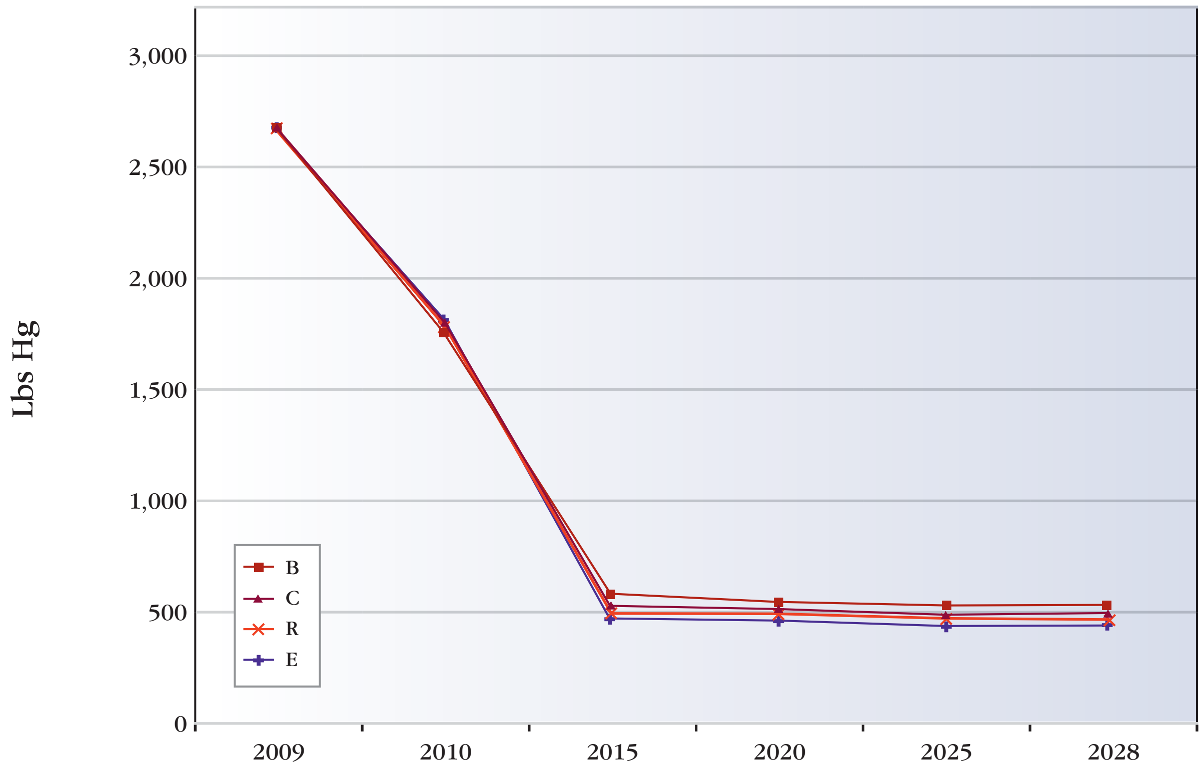

Figure A-5 – Lbs Hg by Strategy

These plots confirm that all emissions decrease over the planning horizon, and thus selecting CO_2 as a surrogate measure was an appropriate proxy for the trend in all air emissions.

To further verify that all evaluated strategies' performance on all four emissions give the same rankings, the total yearly emissions from all sources for each strategy, across all eight scenarios, were summed for five spot years and used to rank the strategies for each emission. Figure A-6 shows the results of these rankings, again confirming that the CO_2 ranking alone gives the same information as using information on all four emissions.

Strategy	SO_2	NO_X	Hg	CO_2
B	4	4	4	4
C	3	3	3	3
E	1	1	1	1
R	2	2	2	2

Figure A-6 – Strategy Rankings for All Four Emissions

Water Impact Metric and Ranking

The major way thermal generating plants impact water is by the amount of heat they reject to the environment. IRP strategies were evaluated on the basis of the BTUs delivered to the plants' condensers, which is where rejected heat is transferred. The calculation involved taking the generation sources shown in Figure A-7 and multiplying their generation (GWh) by heat rate (BTU/kWh) (with unit conversions) by a design factor for the specific generation technology.

Generation Source	Design Factor
Coal	51%
Combined cycle (CC)	11%
Future integrated gasification CC	27%
Future super critical pulverized coal (SCPC)	46%
Lignite	51%
Uranium	66%

Figure A-7 – Design Factors for Generation Sources

The heat rejected to the environment (BTUs) is summed for all five spot years (2010, 2015, 2020, 2025, 2028) and all generation sources for each case, excluding cases associated with Strategies A and D. For each scenario (1–8), the strategies, excluding Strategies A and D, were compared to each other and ranked. A preferred strategy (R) is described by being the most robust, meaning it performs the best across all eight scenarios. Therefore, the rankings of each strategy in each scenario were summed and re-ranked on the basis of their total score. A strategy that performed the best in each of the eight scenarios would have a total score of 8 (1 x 8), and a strategy that performed the worst in all eight scenarios would have a score of 32 (4 x 8). The total scores and associated final ranking is shown in Figure A-8.

Scenarios	Strategies			
	B	C	E	R
1	4	3	1	2
2	4	2	1	3
3	4	3	1	2
4	4	3	1	2
5	4	3	1	2
6	4	3	1	2
7	4	3	1	2
8	4	3	1	2
Sum of Rankings	32	23	8	17
Final Ranking	4	3	1	2

Figure A-8 – Final Strategy Water Impact Ranking

Waste Calculations

The metric used to rank strategies in terms of their waste impact (coal and nuclear) was the cost of handling the waste generated—the assumption is that the costs of disposal, in accordance with all applicable regulations, is a proxy for the wastes' impacts on the environment. Handling costs are based on actual, historical TVA averages, and expected future handling costs are based on operations and transportation estimates.

Coal waste comes from two sources: coal burning and scrubber sludge. Coal waste for TVA plants was calculated using weighted coal ash[1] and heat content (BTU/lb) values from 2009 historical data. The weighted averages are shown in Figures A-9 and A-10.

Year	Strategy			
	B	C	E	R
2010	8.19%	8.19%	8.19%	8.19%
2015	8.04%	7.91%	8.15%	7.85%
2020	8.04%	7.91%	8.15%	7.85%
2025	8.04%	7.91%	8.15%	7.85%
2028	8.04%	7.91%	8.15%	7.85%

Figure A-9 – Weighted Ash Percentage

Year	Strategy			
	B	C	E	R
2010	11,033	11,033	11,033	11,033
2015	11,004	10,948	11,134	10,941
2020	11,004	10,948	11,134	10,941
2025	11,004	10,948	11,134	10,941
2028	11,004	10,948	11,134	10,941

Figure A-10 – Weighted Heat Content (BTU/lb)

For each evaluated strategy, from the model results, the fuel consumed (mmBTU) for TVA coal was multiplied by one million to get the units into BTUs, then multiplied by the coal fuel conversion values (from the weighted BTU/lb figure), and then multiplied by the percentage ash value (from the weighted ash figure). The product was then divided by 2000 to get an answer in tons. A handling cost ($/ton) was then applied to the calculation.

Coal waste from the lignite plant under contract to TVA was calculated based on fuel consumed (mmBTU), divided by 5,234 BTU/lb, multiplied by 14.64 percent ash content (based on Mississippi lignite source information) and divided by 2000 to get an answer in tons. A handling cost ($/ton) was then applied to the calculation.

Coal waste from future Integrated Gasification Combined Cycle (IGCC) was calculated by multiplying generation times 62lb/MWh (slag production) and divided by 2000 to get an answer in tons. For 2010 scrubber waste, waste was calculated by taking fuel consumed (mmBTU), multiplied by 0.5 (about 50 percent of TVA generation is now scrubbed), then

[1]Coal ash consists of both fly and bottom ash

multiplied by 11 lbs/mmBTU (average of TVA existing fleet). For future year calculations, it was assumed that all remaining TVA coal generation (based on coal-fired idling assumptions) are scrubbed. Waste was calculated by multiplying fuel consumed by 11 lbs/mmBTU. A handling cost ($/ton) was then applied to the calculation.

The combined coal and nuclear waste handling costs were used to rank all strategies, excluding Strategies A and D. All coal waste costs, including lignite and future base generation, and nuclear waste costs were summed for all five spot years (2010, 2015, 2020, 2025, 2028) and all generation sources for each case, excluding cases associated with Strategies A and D. For each scenario (1–8), the evaluated strategies were compared to each other and ranked with the strategy having the lowest waste handling cost (ranked #1) and the strategy with the highest costs (ranked #4).

A preferred strategy is the most robust, meaning it performs the best across all eight scenarios. Therefore, we summed the rankings of each strategy in each scenario, and re-ranked them on the basis of their total score. A strategy that performed the best in each of the eight scenarios would have a total score of 8 (1 x 8), and a strategy that performed the worst in all eight scenarios would have a score of 32 (4 x 8). The total scores and associated final ranking is shown in Figure A-11.

Scenario	Strategy B	Strategy C	Strategy E	Strategy R
1	4	3	1	2
2	4	2	1	3
3	4	3	1	2
4	4	3	1	2
5	4	2	1	3
6	4	3	1	2
7	4	3	1	2
8	4	2	1	3
Sum of Rankings	32	21	8	19
Final Ranking	4	3	1	2

Figure A-11 – Final Strategy Waste Impact Ranking (Based on Total Coal and Nuclear Waste Disposal Costs)

Appendix B – Method for Computing Economic Impact Metrics

Purpose

Economic metrics are included in the IRP scoring to provide a general indication of the impact of each strategy on the economic conditions in the TVA service area. The impacts are represented by the change in total employment and personal income indicators as compared to the impacts under Strategy B – Baseline Plan Resource Portfolio, in Scenario 7 – Reference Case: Spring 2010.

Process

The process used is the same as has been used by TVA for programmatic region-wide EIS studies dating back to the 1979-1980 PURPA study and is also used by other models and studies. As shown in Figure B-1, direct expenses by TVA in the region for labor, equipment and materials stimulate economic activity. At the same time, the costs of electricity for customers (the bills customers pay, including savings from energy efficiency) reduces customers' income, which could be used to buy goods and services in the region.

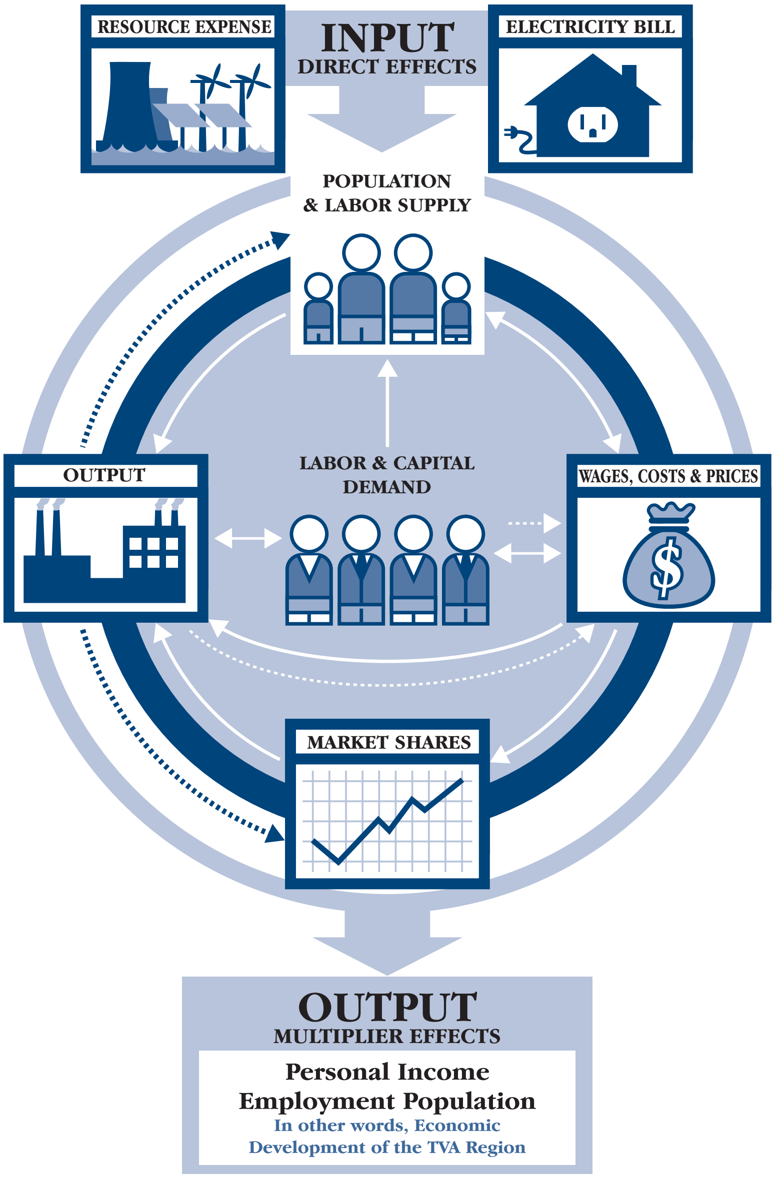

Figure B-1–Input and Output Impacts

These "direct effects" are input into a regional economic model, which captures the interactions within the regional economy—the so-called multiplier effect. TVA uses a Regional Economic Models Inc. (REMI) model of the economies of the TVA region and surrounding areas.

This model maps the TVA region's economic structure, its inter-industry linkages and responses to TVA rate and customer cost changes, including changes from energy efficiency. The model also captures interactions with areas outside the region, such as coal purchases.

The analysis includes data on direct TVA expenditures, including applicable payrolls, material and supply purchases and fuel costs for all energy resource options that comprise a particular strategy for both construction and operations. It also includes data on TVA rates and total resource costs resulting from each strategy, as well as savings to customer bills from energy efficiency and demand reduction programs.

Methodology

Annual construction expenses were entered into the regional economic model for each strategy and scenario analyzed. The model then calculated two types of indirect effects from these construction expenses:

1. Increases in goods manufactured in the TVA region resulting from purchasing materials and supplies associated with a project
2. Additional income generated in the regional economy resulting from the spending of workers hired for construction

The analysis of operations was similar to the construction analysis. Annual operations expense data for the strategy portfolio was entered into the economic model. Since most fuel purchases came from outside the region, they were entered into the analysis as expenses in areas outside the region.

The analysis also estimated the effects of cost differences among strategies. Differences in customer costs or electric bills either add to or subtract from the spending capacity of customers. Therefore, the differences affect the amount of income and revenue available for other uses.

When the income is returned to the economy, it generates additional economic growth. Estimates of annual total resource costs for each strategy, as well as net savings from energy efficiency and demand reduction programs, were used to estimate net cost differences among strategies. The net cost differences were used with the TVA regional economic model to compute the impacts.

Analysis

All IRP strategies were analyzed for Scenario 1 and Scenario 6. These scenarios were used to define the upper and lower range of the impacts on the various strategies. The factors discussed above were incorporated into the regional economic model for each strategy and scenario to measure the overall economic development effects.

Overall, economic impacts are the net effect of both resource expenses and customer electricity bills. Both factors are measured in terms of employment and income changes from the base case, represented in Strategy B – Baseline Plan Resource Portfolio, in Scenario 7 – Reference Case: Spring 2010.

Findings

The major finding is that there was no significant change in both the short- and long-term for the range of strategies and scenarios.

Even though none of the strategies had significant differences from the base case, there were minimal differences of 1 percent or less for each strategy. The differences are outlined in Figure B-2.

		Percent Difference from IRP Reference Portfolio			
		Total Employment		Total Personal Income	
Strategy	Scenario	Average 2011-2028	Average 2011-2015	Average 2011-2028	Average 2011-2015
A	1	0.1%	-0.4%	0.1%	-0.2%
	6	-0.4%	-0.4%	-0.4%	-0.3%
B	1	1.0%	0.3%	0.8%	0.3%
	6	-0.3%	-0.4%	-0.3%	-0.3%
C	1	0.9%	0.2%	0.6%	0.2%
	6	0.2%	-0.2%	0.1%	-0.1%
D	1	1.2%	0.4%	1.0%	0.3%
	6	-0.1%	-0.4%	-0.2%	-0.4%
E	1	0.8%	0.0%	0.6%	0.0%
	6	0.3%	-0.1%	0.2%	-0.1%
R	1	0.9%	0.2%	0.7%	0.2%
	6	0.2%	-0.2%	0.1%	-0.1%

Scenario
1 Economy Recovers Dramatically
2 Environmental Focus is a National Priority
3 Prolonged Economic Malaise
4 Game-Changing Technology
5 Energy Independence
6 Carbon Legislation Creates Economic Downturn
7 Reference Case: Spring 2010
8 Reference Case: Great Recession Impacts Recovery

Planning Strategy
A Limited Change in Current Resource Portfolio
B Baseline Plan Resource Portfolio
C Diversity Focused Resource Portfolio
D Nuclear Focused Resource Portfolio
E EEDR and Renewables Focused Resource Portfolio
R Recommended Planning Direction

Reference Portfolio: Spring 2010 is Scenario 7, Strategy B

Figure B-2- Final Summary Economic Impacts of IRP Cases

Listed below is an outline of the strategies and analysis results:

- Strategy A performed worse than any of the other strategies for the scenario range
- Strategies B, C, D and E had more comparable results, with only a few tenths of a percent difference
- The impacts of Strategies B and D were very similar
- Both strategies performed better in the high growth Scenario 1 than Strategies C or E
- However, both strategies performed worse in the low growth Scenario 6 than Strategies C or E or the reference portfolio
- These results are consistent with strategies that lean toward building to meet load
- On the other hand, Strategies C and E lean toward conservation
- Strategy C and Strategy E's impacts were very similar
- Both performed above the reference portfolio in the long-term for both Scenarios 1 and 6
- The Recommended Planning Direction results are similar to the results for Strategy C

Appendix C – Energy Efficiency and Demand Response

Previous: Demand-Focused Portfolio

In May 2007, the TVA Board of Directors adopted a strategic plan that recognized the need for a comprehensive approach to meet the Tennessee Valley region's future electrical power needs, including increased energy efficiency and demand response (EEDR) initiatives. On May 19, 2008, the TVA Board of Directors approved the guiding principles of an EEDR plan, which included recommendations for reducing the growth in peak demand by up to 1,400 MW by the end of 2012.

The plan recognized that improving peak demand reduction can help slow demand growth in a cost-effective manner while addressing air pollution and global climate change. TVA recognized this goal could only be achieved through a broad cooperative effort with strong support from TVA's customers and stakeholders.

At this time, TVA did not have an energy reduction goal. Therefore, TVA's EEDR program efforts were targeted to achieve the maximum power demand reductions during the periods of highest demand on the TVA system. TVA's existing energy efficiency programs would reduce energy consumption over all hours of the day, but were designed to achieve maximum effect on the peak periods in the early years of the plan. Under this goal, achievements for EEDR programs were measured in MW.

Renewed Vision: To Become a Leader in Energy Efficiency

Since 2007, changes in economic, environmental and power supply market conditions, along with the initiation of TVA's IRP process, provided additional opportunities to assess the potential of energy efficiency program contributions to TVA's resource mix. From the additional work of this IRP and benchmarking research of other utilities in the Southeast, in August 2010, the TVA Board of Directors adopted a renewed vision – to become one of the nation's leading providers of low-cost, cleaner energy by 2020.

To help achieve this renewed vision, TVA set a goal to lead the Southeast in increased energy efficiency by achieving 3.5 percent of sales in energy efficiency savings by 2015. Therefore, EEDR will track both energy and demand savings, and achievements for energy efficiency programs will be measured in GWh.

The actual measure of this effort is the sum of total program results that have the net effect of reducing future load requirements by 3.5 percent. This percentage would result in an energy savings of about 6,000 GWh by the end of 2015. Meeting this goal would:

- Save residential and commercial power customers more than $350 million in FY15
- Provide 1,900 MW of extra power capacity on the TVA system
- Prevent TVA from having to build at least two new power plants

Achievements in FY10 toward the new goal resulted in 211 GWh of energy savings – enough to power about 13,000 homes and avoid carbon emissions equal to 22,700 vehicles. For FY11, TVA has increased its energy efficiency goal to 550 GWh and its associated budget by 50 percent to $135 million. Additional steps in the process to achieve this goal include:

- Refocusing of existing energy efficiency program incentives from demand to energy
- Third-party potential study with renewed energy goal focus amidst today's economic climate
- Development of a five-year EEDR action plan for achieving greater energy savings and to begin implementing new programs by the start of FY12

Program Infrastructure to Support Renewed Vision

TVA's energy efficiency strategy includes incentive programs, price structure changes and education efforts to raise awareness and encourage smart consumer choices. Currently, TVA offers eight energy efficiency programs through participating power distributors under the TVA EnergyRight® Solutions brand.

In May 2009, TVA added the three following programs for residential, business and large industrial markets: In-Home Energy Evaluation, EnergyRight® Solutions for Business and the Major Industrial Program.

Portfolio Design

Energy efficiency and demand-side management programs have been a part of TVA's energy supply resource mix since the late 1970s. The programs were initiated in response to the rising cost of energy and construction of new electric generating units. These programs promoted energy conservation and the efficient use of electricity.

From 1975 to 1988, TVA's efforts resulted in a 1,200 MW reduction in peak demand and more than 3,200 GWh of annual energy savings. These efforts positioned TVA as a national leader in energy efficiency improvements. TVA's achievement was a result of programs such as home energy audits, energy-efficient equipment and weatherization installations. During this period, TVA had a direct impact on the energy efficiency of more than one million homes in the Tennessee Valley region.

In the 1990s, TVA's focus shifted toward the promotion of energy-efficient electro-technologies. The aim was for end users to adopt these technologies when it was economically sensible, in terms of their total energy cost. These programs also delivered demand reduction benefits.

Subsequently, from 1996 to 2008, TVA programs offered in conjunction with distributors of TVA power resulted in a cumulative demand reduction of more than 545 MW. Nearly 90 percent of this total was derived from TVA's EnergyRight® residential program. The program provides items such as low-interest heat pump loans and incentives for energy efficient new home construction. The remaining percentage of the reduction was attributed to residential direct load control programs for air conditioning and water heating and large commercial and industrial programs.

About TVA and Power Delivery Structure

As a wholesale provider of electricity, TVA's operational structure has unique distinctions. TVA differs from prevalent, vertically-integrated utilities because it does not have direct interaction with the majority of end-use consumers.

TVA sells the power it produces to 155 municipal and cooperative power distributors who in turn sell that power to end-use consumers, both residential and commercial. The distributor community is made up of independently operated companies. TVA also directly serves 56 large industries and federal agencies across its service territory.

TVA Program Development

In 2007, TVA retained the services of PA Consulting (PA) to identify potential demand reduction-focused programs that could be implemented to reduce summer peak demand by 1,400 MW in 2012. The recommendations PA provided were derived from a review of industry programs and selected based on economic capability. TVA reviewed PA's designs for applicability to the TVA market, and the programs were prioritized for customization to the demographic and climatic parameters of the region. The programs were prioritized based on qualitative factors to select candidates for design that were highly likely to succeed.

Once preliminary program designs were constructed, the estimated costs and system impacts were documented in a format to permit financial analysis. These inputs were reviewed for consistency and used to create a load shape for each program effort. The load shapes and financial inputs were subjected to a basic financial review to determine their scores on the typical evaluation tests of Total Resource Cost (TRC), Utility Cost Test (UCT) and Rate Impact Measure (RIM).

Performance against these tests was used to fine-tune the program designs to achieve positive impacts. Once the program designs were solidified, more detailed analysis was performed when the load shapes and costs were compared to other resource options in the IRP modeling process.

Because TVA does not serve the majority of end users directly, its program design process includes not only consumer research, but also close involvement by the power distributor community. TVA and distributors coordinate these design activities through the Tennessee Valley Public Power Association's (TVPPA) Energy Services Committee.

TVA's development process was driven by customer insight gained through primary market research conducted with distributors and their customers. Initial program hypotheses were derived from regional market segment data and secondary research on successful programs from across the country. The hypotheses were tested and refined through qualitative and quantitative market research to craft program concepts that best fit TVA's unique relationship with distributors and their customers.

Once program concepts had been refined, TVA worked with distributors and TVPPA to develop program delivery mechanics needed to successfully offer new programs for residential, commercial and industrial customers, as well as education and outreach initiatives. The programs were further refined through market testing prior to system-wide expansion. This process considerably enhances TVA's potential for success and to help keep electricity rates low.

Currently, TVA is engaged in evaluating these new programs and their delivery process following test markets in FY10 and expansion for FY11. These programs will continue to evolve in response to new assumptions, influences and research and market test results. TVA is also establishing measurement and verification protocols to evaluate programs, validate assumptions in program design, document verifiable program impacts and influence new program development.

By using energy more efficiently, the amount of electricity TVA needs to generate to meet the power demand of more than nine million consumers in the Tennessee Valley region will reduce. When fully implemented, these programs will help:

- Reduce reliance on power purchased from other suppliers
- Reduce the impact of power production on the environment
- Mitigate rate pressures by providing direct benefits to the TVA system and consumers

TVA's Long-Term Plan

TVA's view is that EEDR improvement over the long term ultimately must be accomplished through a transformation in the marketplace. The transformation would increase consumer demand for energy-efficient products and services and provides the delivery channels to meet their needs.

The transformation will not be made through TVA purchasing the marketplace, but rather by accomplishing the following important supporting mechanisms:

- Educating the public to make informed choices about their energy use and energy-related purchases
- Electricity rates that send appropriate price signals to encourage consumers to reduce usage during periods of high demand
- Advanced electric metering and other technologies that allow communication between end users and their power provider

- A strong, vibrant infrastructure for end-use generation technologies
- A robust network of commercial providers offering a wide array of energy-efficient products and services
- Exploration and development research of end-use efficiency technology

Program Offerings and Initiatives

TVA continues to offer programs under the EnergyRight® Solutions brand that include residential, commercial, industrial, renewable, education/outreach and demand response initiatives. Figure C-1 outlines existing and new EEDR programs.

Type of Program	Program Name
Energy efficiency	New Homes Plan Heat Pump Plan Water Heater Plan Manufactured Homes Plan Do-It-Yourself Home Energy Evaluation In-Home Energy Evaluation Program EnergyRight® Solutions for Business Major Industrial Program
End-use generation	Generation Partners℠ Green Power Switch®
Demand response	Commercial and Industrial Demand Response Pilot Direct Load Control Program Conservation Voltage Reduction Program (new)
Education and outreach	National Theatre for Children Alliance to Save Energy Green Schools Program Trade Ally Network Internal Energy Management Program (IEMP)

Figure C-1 – Existing and New EEDR Programs

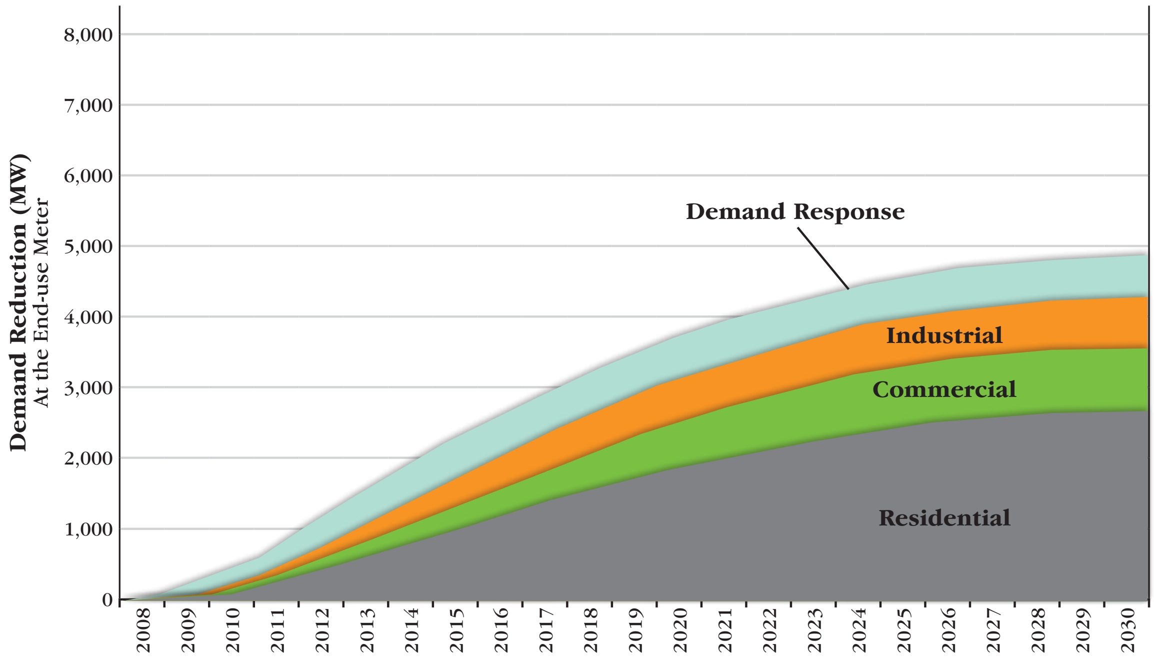

Figure C-2 – EEDR Program Demand Reduction (MW)

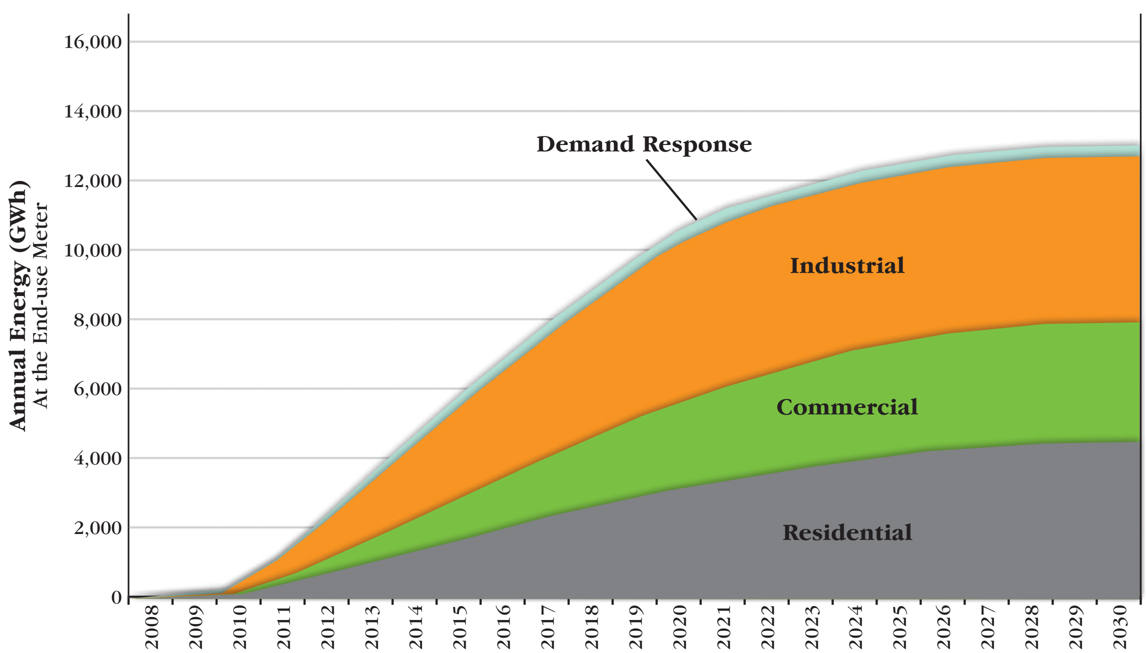

Figure C-3 – EEDR Program Energy Savings (GWh)

Next Steps

The EEDR portfolios used by the IRP process are shown in Figures C-2 and C-3. TVA is building on the results of the analyses performed in the process and refining the EEDR portfolio contained in the Recommended Planning Direction into a more expansive, fully defined five-year plan to accomplish the energy and demand savings identified. As such, the modest post 2020 range for EEDR growth does not preclude further investments in these resources during the decade. Development of the five-year plan will involve improvement of existing efforts as well as implementation of new program designs.

Appendix D – Development of Renewable Energy Portfolios

TVA's Current Renewable Energy Landscape

In addition to nuclear energy and energy efficiency, expansion of TVA's long history as a renewable energy provider can help achieve TVA's renewed vision for a cleaner and more secure energy future, with less reliance on carbon intensive sources of generation. In addition, a federal renewable energy standard (RES) or, alternatively, a clean energy standard, is expected to be adopted within the next few years, prior to enactment of any additional state-level Renewable Portfolio Standards (RPS) requirements in the Tennessee Valley region.

TVA defines renewable energy as energy production that is sustainable and often naturally replenished (e.g., solar, wind, methane, biomass, geothermal and hydro). There is currently no federal statutory definition of renewable energy resources, but recent federal renewable energy legislative proposals would exclude most of TVA's extensive 3,300 MW conventional hydropower installations. Therefore, TVA has been taking significant strides to increase the non-conventional hydro renewable energy portfolio.

These actions are being taken in part to reduce the risk associated with potential renewable energy requirements, and more importantly, to align with the approved TVA Board of Directors renewed vision, policies and other strategic aspirations (e.g., Strategic Plan, Environmental Policy, Renewable and Clean Energy Guiding Principles, Federal Renewable Portfolio Standard Compliance for Customers, State RPS Compliance for Customers). Actions to date that support these policies are described below:

- Since 1992, TVA has increased generating capacity at its conventional hydropower plants by 565 MW through the Hydro Modernization Program (HMOD). Generation associated with these HMOD improvements could be eligible to meet federal RPS
- Green Power Switch® (GPS) was launched in 2000 to offer Tennessee Valley residents the choice to support renewable energy. 100 percent of the renewable energy produced from GPS is from Tennessee Valley resources, including 14 solar sites, 18 wind turbines, two methane gas sites and nearly 400 Generation Partners solar and wind installations. The GPS program was the first green power pricing program in the Southeast and currently has approximately 12,000 participants. GPS is sold to residential and business consumers in 150 KWh blocks. Each block is $4, which is added to the consumers' power bill each month
- Generation Partners℠ (GP) was launched as a pilot program in 2003 and provides technical support, incentives and premium rates to purchase energy from small-scale (<200 kW) renewable generation systems from eligible resources such as solar photovoltaics, wind, biomass and small hydro. The renewable power generated from GP currently goes towards GPS supply. In the winter of 2009, GP capacity was close to 9 MW, made up of approximately 1 MW of biomass, 7 MW of solar and a little less than 1 MW in wind
- The TVA Board of Directors authorized the purchase of up to 2,000 MW of renewable and clean energy. By February 2011, more than 1,600 MW of solar, wind and methane contracts had been signed. Other proposals are being evaluated
- TVA developed a renewable power purchase plan, known as the Renewable Standard Offer, to further encourage small renewable energy projects in the service territory. This initiative offers a set price for renewable energy projects from 201 kW to 20 MW. The first agreement was signed under this program in January 2011 with Waste Management Renewable Energy LLC for a 4.8 MW landfill gas (i.e., methane) facility

Considering all of these efforts, TVA's current 2012 estimated non-conventional hydro renewable energy portfolio, including commitments for renewable resources not yet online, is approximately 1,800 MW.

Further, TVA is taking initiatives that will advance development of renewable energy efforts, including:

- Completing a biomass conversion feasibility, fuel supply and cost assessment study
- Collaborating with the Tennessee Valley and Eastern Kentucky Wind Working Group to update Tennessee Valley wind energy resource assessments and transmission capabilities using newer wind turbine technology and taller towers
- Partnering with the State of Kentucky to evaluate Kentucky renewable energy resources
- Reviewing waste heat recovery capabilities
- Collaborating with Tennessee Solar Institute to host a solar forum in late 2011
- Partnering to explore a variety of smart grid technologies designed to increase energy efficiency
- Involvement in a multi-partner initiative, called the Electric Vehicle Project, which is the largest deployment of electric vehicles and charging infrastructure in history

Renewable Energy Needs

In 2007, North Carolina became the first state in the Southeast to adopt a RES and energy efficiency standard. Investor-owned utilities operating in North Carolina will be required to meet up to 12.5 percent of their retail sales through renewable energy resources or energy efficiency measures by 2021.

The combination of TVA's renewed vision, the growth in customer demand for renewable energy, the increasing regulatory stringency related to coal burning sources of generation and the anticipation of future federal and state mandates is prompting TVA to move towards generation that reduces or eliminates emissions altogether. Renewable energy is a generation resource that meets many of these challenges. Renewables aid in the reduction of air emissions from electric generation activities and use readily available "fuel" sources that are easily replenished.

IRP Renewable Additions

Two renewable energy portfolios were developed for use in the IRP modeling process in summer and fall 2010. This appendix provides background on information needed by modelers, development of estimates and assumptions common to all portfolios, preparation of 2,500 MW and 3,500 MW portfolios and recent/ongoing events.

Modeling Process

IRP scenarios were developed using two different fixed and given schedules for the introduction of new renewable capacity at TVA, including both self-builds and long-term PPAs. One renewables portfolio was developed to achieve a target of 2,500 MW of new renewable generating capacity (busbar) by 2020. The other portfolio was developed to achieve a target of 3,500 MW of new renewable capacity by that same year.

These portfolio development schedules were designed to be feasible and reasonable in terms of achievability, current and future cost, resource availability and diversity, and federal renewable energy and tax policies. They were intended to be treated in expansion planning models as "must-take" capacity for the Draft IRP (i.e., the capacity additions specified in a schedule were incorporated into the system irrespective of any other alternatives or their costs). This ensures that the scheduled quantities are included in a modeling output no matter the other features of the scenario. The approach was initially applied so the schedule also represented the maximum limit of renewable capacity additions. Subsequent tests were run allowing the model to choose between four different portfolios for the final IRP.

Model Inputs

Inputs provided to model renewable capacity included:

- New renewable capacity at the busbar, by type, by year, in MW (either self-build or PPA)
- Equipment lifetime or PPA term (years)
- Annual capacity factor by year, for intermittent resources (wind and solar) and an assumed hourly profile
- Energy delivered to busbar by year in MWh
- Real "all-in" cost per kilowatt for constructing and operating (including fuel, where applicable) generating equipment over the lifetime and for self-builds (constant 2010 dollars per kW)
- Real "all-in" cost per kW for energy delivery under a PPA over its term (constant 2010 dollars per kW)
- Nominal annual expenditures for use in estimating budget impacts ($ million as spent)

Assumptions for Developing Renewable Portfolios

A number of common assumptions were applied in the development of both the 2,500 MW and 3,500 MW renewable energy portfolios, either across the board or specific to a given resource type. These include:

- Real discount rate (5.5 percent) applied for discounting purposes to all resource types
- Equipment lifetimes or PPA terms by resource type
- Federal investment tax credits, grants and production incentives (except if TVA-owned)
- Capacity factors by resource type
- Per kW all-in cost or cost range by resource type
- A wind generation profile and a solar generation profile representative of Tennessee Valley resources
- Existing or planned capacity already included in power planning models in summer 2010
- Existing or planned capacity not included in power planning models in summer 2010
- Capacity excluded (e.g., existing hydro)

Renewable Resource Types and Components

Figure D-1 shows the resource types, assumed lifetimes, capacity factors, all-in costs and resulting levelized cost.

Resource	Lifetime	Capacity Factor	All-in Cost[1] 2010$/KW	LCOE 2010$/ MWh[2]	Simplifying Assumptions
Hydro modernization	30 years	12%-17%	$454	$30	All cost loaded into first year, including lifetime fuel & O&M
Landfill gas	20 years	85%	$3,851	$38	All cost loaded into first year, including lifetime fuel & O&M. LCOE net of Production Tax Credit
Additional hydro	30 years	33%-45%	$1,688	$40	All cost loaded into first year, including lifetime fuel & O&M
Co-firing (Biomass)	25 years	78%	$3,977-$4,048	$45-$47	All cost loaded into first year, including lifetime fuel & O&M. Revised nominal expenditures
Wind – out-of-Valley (market)	20 years	35%	$4,500	$82	Cost spread over lifetime, one payment per year (revised)
Wind – in Valley	25 years	20%	$4,618	$207	All cost loaded into first year, including lifetime fuel & O&M. Revised nominal expenditures
Dedicated bio-mass (market)	25 years	89%	$7,038	$40	Cost spread over lifetime, one payment per year (revised)
Dedicated biomass (conversion)	25 years	70%	$4,634	$59	All cost loaded into first year, including lifetime fuel & O&M. Revised nominal expenditures
Solar PV	25 years	15%	$5,217	$219	All cost loaded into first year, including lifetime fuel & O&M. LCOE net of tax credits/grants

1 – All-in cost estimates in real 2010$ (including all capital and expense), but excluding any tax incentives.

2 – Levelized Cost of Electricity, real 2010$. Includes relevant tax incentives.

Figure D-1 – Renewable Resource Types and Components

The cost estimates were developed or adapted from a variety of sources, including consultant and industry estimates, internal TVA project estimates and existing PPA price quotes.

Existing and planned renewable capacity already incorporated into power planning by summer 2010 included 580-618 MW of hydro unit modernization and 2 MW of wind in the Tennessee Valley region at Buffalo Mountain (TVA-owned). Existing or planned capacity not already incorporated into power planning in the summer of 2010 included approximately 5 MW of landfill gas (Chestnut Ridge and Middle Point), approximately 3 MW of biomass co-firing at Colbert and Allen coal plants, 27 MW of in-valley wind at Buffalo Mountain (lease agreement with Invenergy) and approximately 2 MW of solar through Generation Partners[SM] or other resources.

"New" capacity was set for renewables over and above the amounts listed in Figure D-1. A reasonable deployment schedule was developed for each of the two requested portfolios (2,500 MW and 3,500 MW), with consideration given to the following:

- Cost
- Technology maturity and future advances
- Regional renewable resource availability
- A diversified renewable portfolio strategy
- Anticipated federal legislation/regulation and tax policy

In the Draft IRP, the new renewables were scheduled into the model to meet anticipated renewable energy mandates by 2020. Because of the generally higher cost of renewables and given the use of a model whose objective is minimizing cost of service, the more costly alternatives would not have been picked over more traditional capacity. The modeled portfolio growth in renewables capacity mostly tapers off after 2020 due to higher cost and/or regulatory uncertainty.

The modest post 2020 growth range for renewable energy modeled in the portfolios does not preclude further investments in these resources during the decade. TVA has committed to begin the next IRP effort by 2015. With the development of new data and knowledge the renewable portfolios will be developed further.

An effective improvement of 0.5 percent per year in solar photovoltaic energy output per unit cost was incorporated into the IRP portfolios associated with anticipated technology advancements and declining module cost over time. No other performance or real cost improvements were assumed through 2029 for any of the other resource types. Future market demand and innovation for these resources was dependent on unknown technology-by-technology treatment under future energy and environmental regulation or legislation, as well as future tax policy.

Additional Sensitivities

Sensitivities were explored with targets at 2,000 MW (at a variant of the 2,500 MW portfolio) and at 3,000 MW (at a variant of the 3,500 MW portfolio). These capacity values were targeted for the year 2020. TVA evaluated a model-portfolio selection approach that employed the two core renewable portfolios and the two sensitivities, where the selection of a single portfolio in a model run was driven by a cost criterion that includes costs for emissions and carbon, in addition to traditional cost elements.

Figures D-2 and D-3 contain the capacity values for the 2,500 MW and 3,500 MW renewables portfolios, respectively, prepared for this IRP in summer and fall 2010. These reflect target MW values for the year 2020.

	Net Capacity (MW Cumulative)																	
FY:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
HMOD						9.6	20.2	31.6	42.9	53.9	64.5	74.7	82.8	88.8	88.8	88.8	88.8	88.8
Landfill gas	1.8	3.7	12.0	15.6	18.4	21.4	25.2	27.9	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3
Addl hydro		24.3	24.3	48.6	48.6	75.6	75.6	107.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6
Co-firing		60.0	118.0	118.0	118.0	118.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0
Wind – out-of-Valley (PPA)	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0
Wind – in Valley			50.0	100.0	150.0	200.0	250.0	300.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0
Ded Biomass – PPA		35.0	35.0	67.0	67.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
Ded Biomass – Conv			80.0	80.0	80.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Solar	20.0	25.0	40.0	45.0	60.0	65.0	80.0	85.0	100.0	105.0	120.0	125.0	140.0	145.0	160.0	165.0	180.0	185.0
Total	**1,401.8**	**1,528.0**	**1,739.3**	**1,854.2**	**1,922.0**	**2,156.6**	**2,264.0**	**2,365.1**	**2,489.8**	**2,505.8**	**2,531.4**	**2,546.6**	**2,569.7**	**2,580.7**	**2,595.7**	**2,600.7**	**2,615.7**	**2,620.7**

Figure D-2 – New Renewable Capacity at 2,500 MW

	Net Capacity (MW Cumulative)																	
FY:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
HMOD						9.6	20.2	31.6	42.9	53.9	64.5	74.7	82.8	88.8	88.8	88.8	88.8	88.8
Landfill gas	1.8	3.7	12.0	15.6	18.4	21.4	25.2	27.9	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3
Addl hydro	0.0	24.3	24.3	48.6	48.6	75.6	75.6	107.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6
Co-firing	0.0	60.0	118.0	118.0	118.0	118.0	141.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
Wind – out-of-Valley (PPA)	1,380.0	1,480.0	1,630.0	1,780.0	1,930.0	2,080.0	2,230.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0
Wind – in Valley			50.0	100.0	150.0	200.0	250.0	300.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0
Ded Biomass – PPA	0.0	35.0	35.0	67.0	67.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
Ded Biomass – Conv	0.0	0.0	80.0	80.0	80.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Solar	35.0	45.0	75.0	85.0	115.0	125.0	155.0	165.0	195.0	205.0	235.0	245.0	275.0	285.0	315.0	325.0	355.0	365.0
Total	**1,416.8**	**1,648.0**	**2,024.3**	**2,294.2**	**2,527.0**	**2,939.6**	**3,212.0**	**3,468.1**	**3,607.8**	**3,628.8**	**3,669.4**	**3,689.6**	**3,727.7**	**3,747.7**	**3,773.7**	**3,783.7**	**3,813.7**	**3,823.7**

Figure D-3 – New Renewable Capacity at 3,500 MW

Appendix E – Draft IRP Phase Expansion Plan Listing

Year	Defined Model Inputs			Capacity Additions by Scenario						
	EEDR	Renewables	Idled Capacity	1	2	3	4	5	6	7
2010	246	35	-							
2011	408	48	-							
2012	421	137	-	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	666	155	-	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	1733	155	-							
2015	1434	160	-	GL CT Ref	GL CT Ref		GL CT Ref	GL CT Ref		GL CT Ref
2016	1557	160	-							
2017	1684	160	-							
2018	1812	160	-							
2019	1940	160	-							
2020	2051	160	-							
2021	2069	160	-							
2022	2014	160	-							
2023	2061	160	-							
2024	2131	160	-							
2025	2085	160	-							
2026	2226	160	-							
2027	2076	160	-							
2028	1980	160	-							
2029	1905	160	-							

Figure E-1 – Planning Strategy A – Limited Change in Current Portfolio

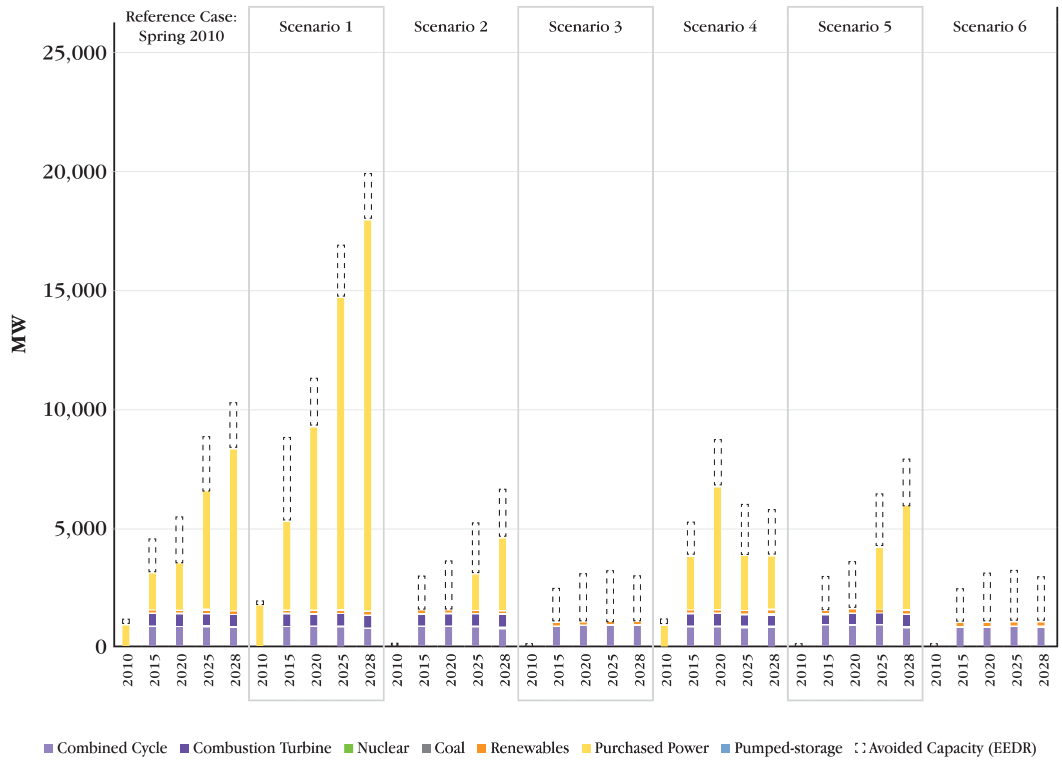

Figure E-2 – Planning Strategy A – Capacity Additions by Scenario

Year	Defined Model Inputs			Capacity Additions by Scenario						
	EEDR	Renewables	Idled Capacity	1	2	3	4	5	6	7
2010	229	35	-	PPAs & Acq			PPAs & Acq			
2011	385	48	(226)							
2012	384	137	(226)	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	610	155	(935)	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	1363	155	(935)	CTa CT GL CT Ref			CTa		GL CT Ref	
2015	1496	160	(2,415)	CT CC	GL CT Ref		GL CT Ref CT CC	GL CT Ref		GL CT Ref CTa
2016	1622	160	(2,415)	CT			CT			CT
2017	1751	160	(2,415)	CT			CT			CTa
2018	1881	160	(2,415)	BLN1			BLN1	BLN1		BLN1
2019	2012	160	(2,415)	CT	BLN1					
2020	2124	160	(2,415)	BLN2			BLN2	BLN2		BLN2
2021	2216	160	(2,415)	CC	BLN2					
2022	2294	160	(2,415)	CT CC				CTa		CC
2023	2362	160	(2,415)	CT				CTa		CT
2024	2429	160	(2,415)	NUC						
2025	2470	160	(2,415)	IGCC	NUC			CC		CT
2026	2495	160	(2,415)	NUC						
2027	2509	160	(2,415)	CT	NUC			CT		CT
2028	2516	160	(2,415)	CC						
2029	2520	160	(2,415)	IGCC, Cta	Cta	Cta		CT		CC

Key:

PPAs & Acq = purchased power agreements, including potential acquisition of third-party-owned projects (primarily combined cycle technology)

JSF CC = the combined cycle unit to be sited at the John Sevier plant (TVA Board of Directors' approved project, currently under development)

WBN2 = Watts Bar Unit 2 (TVA Board of Directors' approved project, currently under development)

GL CT Ref = the proposed refurbishment of the existing Gleason CT units

CC = combined cycle

CT/CTa = combustion turbines

PSH = pumped-storage hydro

BLN1/BLN2 = Bellefonte Units 1 & 2

NUC = nuclear unit

IGCC = integrated gasification combined cycle (coal technology)

Figure E-3 – Planning Strategy B – Baseline Plan Resource Portfolio

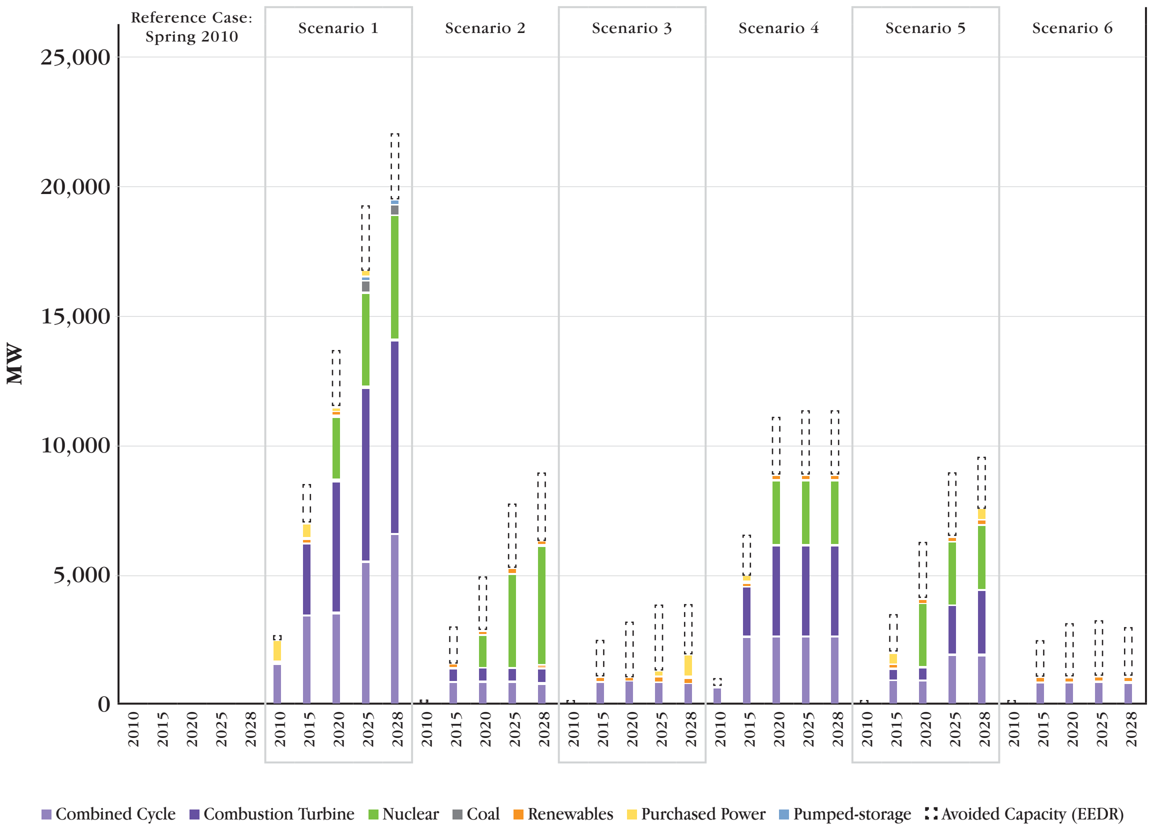

Figure E-4 – Planning Strategy B – Capacity Additions by Scenario

Year	Defined Model Inputs			Capacity Additions by Scenario						
	EEDR	Renewables	Idled Capacity	1	2	3	4	5	6	7
2010	298	35	-	PPAs & Acq						
2011	389	48	(226)							
2012	770	145	(226)	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	1334	286	(935)	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	1596	44	(935)	CTa			CTa			
2015	2069	515	(3,252)	GL CT Ref CT CC			GL CT Ref CT CC	GL CT Ref		GL CT Ref CTa
2016	2537	528	(3,252)	CT			CT			
2017	2828	715	(3,252)							
2018	3116	768	(3,252)	BLN1			BLN1			BLN1
2019	3395	822	(3,252)							
2020	3627	883	(3,252)	BLN2 PSH	PSH	PSH	BLN2 PSH	PSH	PSH	BLN2 PSH
2021	3817	896	(3,252)	CT						
2022	3985	911	(3,252)	CC	BLN1			BLN1		
2023	4143	922	(3,252)	CC						
2024	4295	935	(3,252)	NUC	BLN2			BLN2		
2025	4412	942	(3,252)	IGCC						CT
2026	4502	947	(3,252)	NUC						
2027	4561	948	(3,252)	CT						CC
2028	4602	953	(3,252)	CT						
2029	4638	954	(3,252)	IGCC, Cta	NUC			CTa		CTa

Figure E-5 – Planning Strategy C – Diversity Focused Resource Portfolio

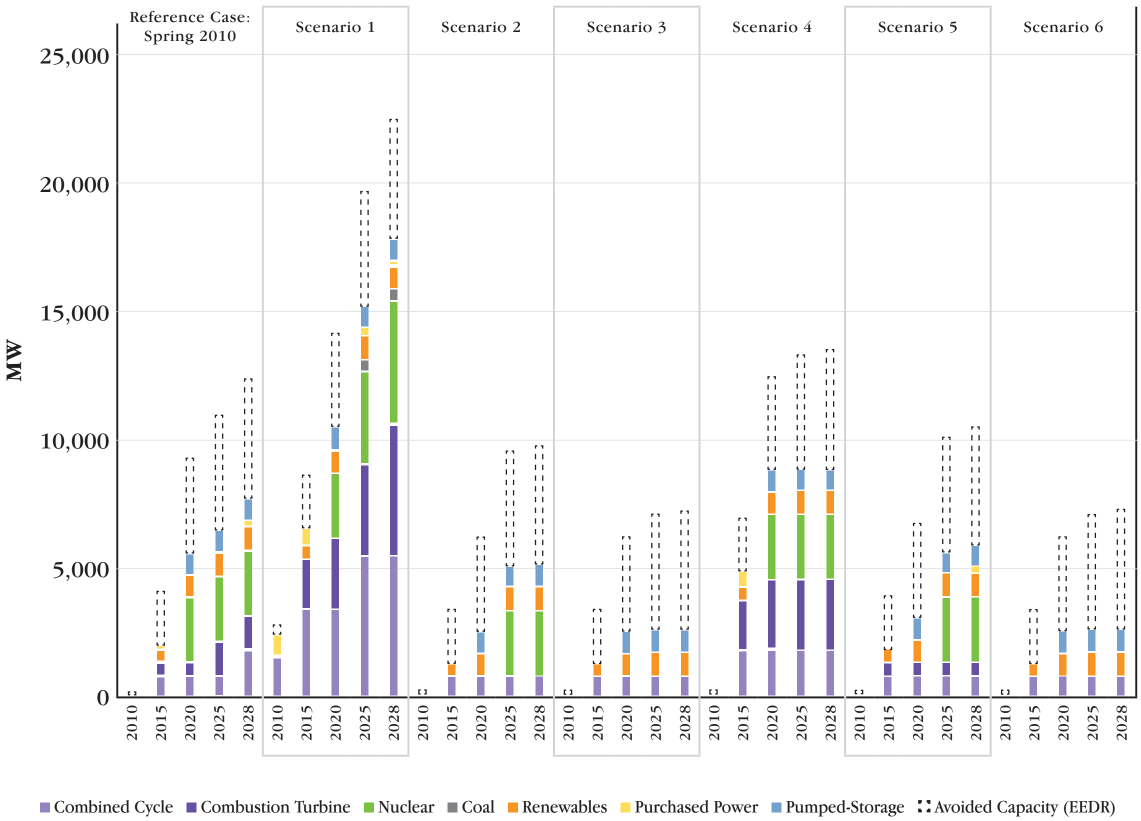

Figure E-6 – Planning Strategy C – Capacity Additions by Scenario

Year	Defined Model Inputs			Capacity Additions by Scenario						
	EEDR	Renewables	Idled Capacity	1	2	3	4	5	6	7
2010	1300	35	-	PPAs & Acq						
2011	1126	48	(226)							
2012	1394	145	(226)	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	1795	286	(935)	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	2228	442	(935)	CTa		GL CT Ref	GL CT Ref CT CTa			
2015	2612	515	(5,718)	GL CT Ref CT(2) CC(2)	GL CT Ref		CT(2) CC(2)	GL CT Ref CC		GL CT Ref CTa(2) CC
2016	2846	528	(5,718)	CT			CC	CC		CC
2017	3104	715	(6,972)	CC	CC		CC			CTa
2018	3389	768	(6,972)	BLN1	BLN1		BLN1	BLN1		BLN1
2019	3704	822	(6,972)							
2020	3993	883	(6,972)	BLN2 PSH	BLN2 PSH	PSH	BLN2 PSH	BLN2 PSH	PSH	BLN2 PSH
2021	4092	896	(6,972)							
2022	4040	911	(6,972)	CC (2)						
2023	4042	922	(6,972)							CTa
2024	4303	935	(6,972)	NUC						
2025	4991	942	(6,972)	IGCC	NUC					
2026	5201	947	(6,972)	NUC						
2027	5711	948	(6,972)		NUC					
2028	6198	953	(6,972)	IGCC						
2029	6316	954	(6,972)	SCPC						

Key:

PPAs & Acq = purchased power agreements, including potential acquisition of third-party-owned projects (primarily combined cycle technology)

JSF CC = the combined cycle unit to be sited at the John Sevier plant (TVA Board of Directors' approved project, currently under development)

WBN2 = Watts Bar Unit 2 (TVA Board of Directors' approved project, currently under development)

GL CT Ref = the proposed refurbishment of the existing Gleason CT units

CC = combined cycle

CT/CTa = combustion turbines

PSH = pumped-storage hydro

BLN1/BLN2 = Bellefonte Units 1 & 2

NUC = nuclear unit

IGCC = integrated gasification combined cycle (coal technology)

Figure E-7 – Planning Strategy D – Nuclear Focused Resource Portfolio

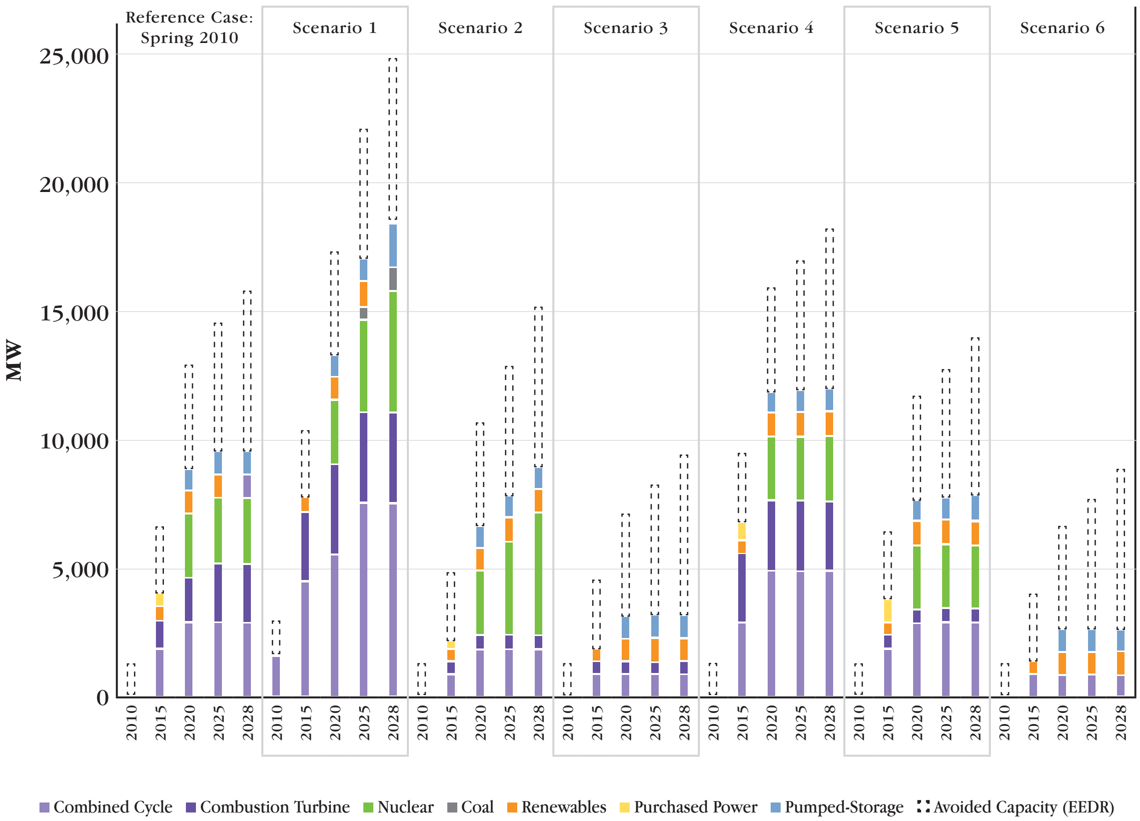

Figure E-8 – Planning Strategy D – Capacity Additions by Scenario

Year	Defined Model Inputs			Capacity Additions by Scenario						
	EEDR	Renewables	Idled Capacity	1	2	3	4	5	6	7
2010	34	35	-	PPAs & Acq						
2011	181	48	(226)							
2012	1136	178	(226)	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	1664	314	(935)	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	2431	493	(935)							
2015	3479	580	(4,730)	GL CT Ref CTa CC(2)			GL CT Ref CTa CC(2)	GL CT Ref		GL CT Ref CTa
2016	3843	616	(4,730)	CT			CT			
2017	4183	846	(4,730)							
2018	4504	921	(4,730)	CT			CT			CC
2019	4811	994	(4,730)	CC (2)						
2020	5074	1060	(4,730)	CC (2)			CC			
2021	5353	1074	(4,730)	CTa						
2022	5460	1094	(4,730)	BLN1	BLN1			BLN1		BLN1
2023	5599	1107	(4,730)	CT						
2024	5739	1124	(4,730)	BLN2	BLN2			BLN2		BLN2
2025	5815	1133	(4,730)	CT						
2026	5893	1142	(4,730)	CT						CT
2027	5961	1145	(4,730)	CT						
2028	6009	1154	(4,730)	NUC				CTa		CTa
2029	6043	1157	(4,730)	CT				CTa		CTa

Key:

PPAs & Acq = purchased power agreements, including potential acquisition of third-party-owned projects (primarily combined cycle technology)

JSF CC = the combined cycle unit to be sited at the John Sevier plant (TVA Board of Directors' approved project, currently under development)

WBN2 = Watts Bar Unit 2 (TVA Board of Directors' approved project, currently under development)

GL CT Ref = the proposed refurbishment of the existing Gleason CT units

CC = combined cycle

CT/CTa = combustion turbines

PSH = pumped-storage hydro

BLN1/BLN2 = Bellefonte Units 1 & 2

NUC = nuclear unit

Figure E-9 – Planning Strategy E – EEDR and Renewables Focused Portfolio

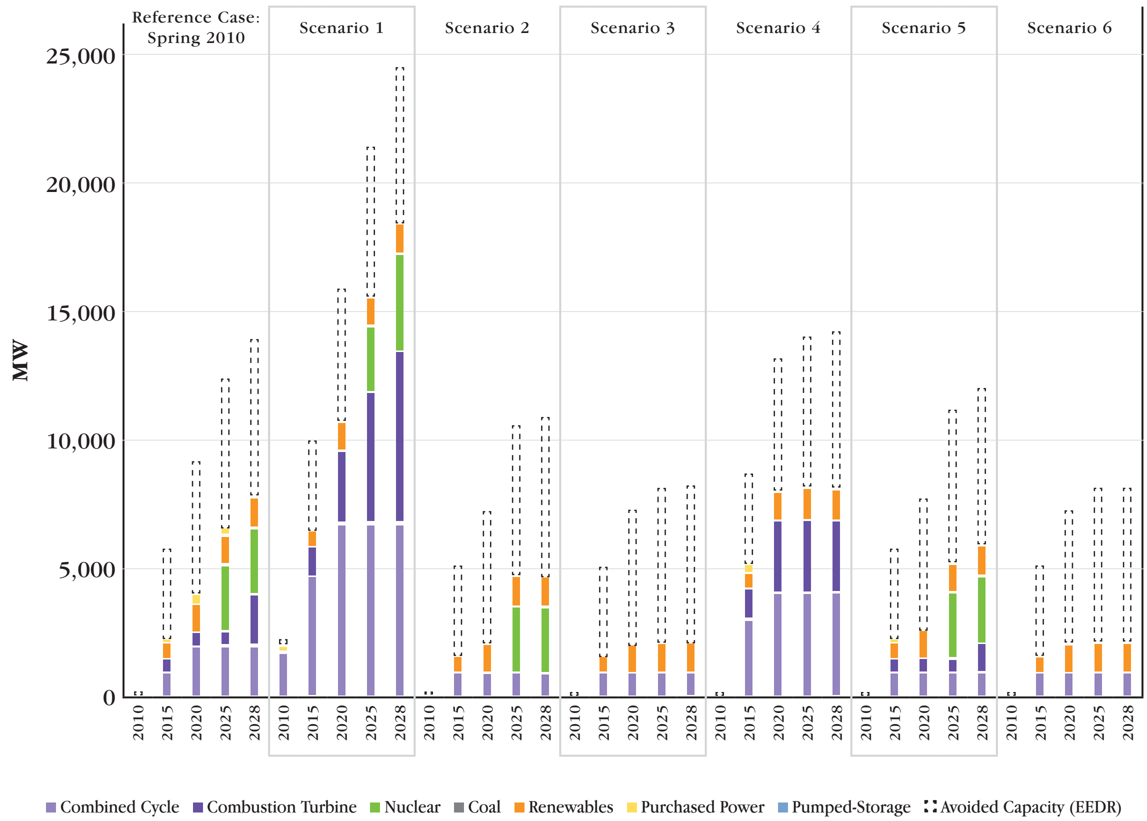

Figure E-10 – Planning Strategy E – Capacity Additions by Scenario

Input from Stakeholders	How Input was Incorporated
• Contribution of EEDR should be increased	• The range of EEDR considered in the planning strategies was broadened in this IRP
• Renewable investment (particularly within the Valley) should be increased	• Renewable portfolios were expanded beyond existing contracts and include in-Valley resources • Additional renewable power can be selected as part of the market supply identified by this IRP
• EEDR and renewable portfolios with significant growth beyond 2020 should be evaluated	• An additional sensitivity with EEDR and renewable portfolios that grew dramatically after 2020 was tested
• Biomass is the most viable renewable resource within the Valley and should be expanded where sustainable	• Biomass was included in the renewable portfolios evaluated in this IRP
• Combined Heat and Power (CHP) should be included as a resource option	• CHP was able to be selected as part of the market supplied power identified in this IRP
• A large amount of the aging coal fleet should be idled • TVA should consider the impacts of more stringent environmental requirements	• Range of idled coal capacity considered was expanded in the development of the planning strategies
• Capability for energy storage should be increased	• A pumped-storage unit was included in the development of the Recommended Planning Direction
• A strategy that does not include nuclear after WBN2 should be considered	• Strategy A did not allow any capital expansion beyond WBN2 • An additional sensitivity was completed to test a "no nuclear" case
• The use of natural gas should be significantly expanded	• The Recommended Planning Direction supported a broad range of potential natural gas capacity expansion
• Price forecast for natural gas should be lower based on emergence of shale gas • Forecast should not change because shale gas has yet to be demonstrated as a reliable source of supply	• Forecast was based upon recent market conditions as well as long-term economic views of the market that include shale gas
• Engagement with distributors is the key to successfully implementing EEDR programs	• TVA is committed to maintaining a strong partnership with the distributors of TVA power
• Distributor-owned generation should be increased	• TVA is engaged in dialogue to identify opportunities for distributor-owned generation outside this IRP
• The public should have more opportunities to interact with the IRP process	• TVA initiated quarterly briefings with the public in November 2009
• TVA should explore alternatives that allow for greater participation in public events	• TVA began broadcasting quarterly briefings via webinar in February 2010 • All meetings during the public comment period (October 2010) were also available via webinar

Stakeholder Input Considered and Incorporated

Input from Stakeholders	How Input was Incorporated
• The debt ceiling should be raised in order to minimize rate impacts from capital expansion	• The IRP scorecard included a short-term rate impact measure • Stakeholder desire for an increased debt ceiling was shared with appropriate groups within TVA
• Potential economic impacts of carbon legislation being implemented were not represented in scenarios	• Scenario 6 – Carbon Legislation Creates Economic Downturn was created to address this concern
• Scenarios should reflect forecasts for demand that are flat and possibly negative	• Scenario 3 – Prolonged Economic Malaise had nearly-flat load growth and Scenario 6 had a load forecast that is slightly negative
• TVA should use "true cost accounting" to monetize all external impacts related to operations	• TVA used industry standard methods for accounting for project and operations cost • Environmental impact measures were included in the IRP scorecard
• A technology innovation metric is out of context for this IRP and should not be included in the IRP scorecard	• Technology innovation metric was dropped, but was included as a separate discussion from the IRP scorecard
• Graphical indicators for economic impact in the IRP scorecard may imply greater differences than actually exist	• The IRP scorecard was modified to show the percentage difference from the baseline for economic impacts
• Strategic metrics should be populated for all planning strategies considered in the Draft IRP	• Process was modified to create fully populated scorecards for all planning strategies
• Other emissions (e.g., SO_2 and NO_x) should be added as a separate environmental measure from CO_2 emissions	• TVA determined that CO_2 emissions were a suitable proxy for other emissions and documented the supporting facts in Appendix A – Method for Computing Environmental Impact Metrics
• New approaches that combine components of different planning strategies should be tested	• Analysis to identify the Recommended Planning Direction optimally selected strategy components
• Requests were received to extend the 45-day public comment period on the Draft IRP	• The public comment period was extended seven days to allow additional time to submit comments
• The IRP should be a recurring process for TVA	• TVA has committed to begin the next IRP effort by 2015

Acronym Index

BLN1/ BLN2 – Bellefonte Nuclear Plants Units 1&2
B&W – Babcock and Wilcox
CAES – Compressed air energy storage
CEQ – Council on Environmental Quality
CC – Combined cycle
CCS – Carbon capture and sequestration
CO_2 – Carbon dioxide
CRP – Conservation Reserve Program
CSP – Concentrating solar power
CT – Combustion turbine
DOE – Department of Energy
EEDR – Energy efficiency and demand response
EERE – Energy efficiency and renewable energy
EIS – Environmental Impact Statement
EPRI – Electric Power Research Institute
EV2020 – Energy Vision 2020
FBC – Fluidized bed combustion
FERC – Federal Energy Regulatory Commission
GWh – Gigawatt hour
HAP – Hazardous Air Pollutant
Hg – Mercury
IGCC – Integrated gasification combined cycle
IRP – Integrated Resource Plan
MACT – Maximum Achievable Control Technology
MAPE – Mean annual percent error
MSW – Municipal solid waste
MW – Megawatt
MWh – Megawatt hour
NEPA – National Environmental Policy Act
NO_x – Nitrogen oxide or Nitrous oxide
NRC – Nuclear Regulatory Commission
NREL – National Renewable Energy Laboratory
NUC – Nuclear unit
PC – Pulverized coal
PPAs – Power purchase agreements
PSH – Pumped-storage hydro
PV – Photovoltaic
PVRR – Present Value of Revenue Requirements
SCPC – Supercritical pulverized coal
SEER – Seasonal energy efficiency ratio
SEIS – Supplemental environmental impact statement
SO_2 – Sulfur dioxide
SRG – Stakeholder Review Group
TVA – Tennessee Valley Authority
TVPPA – Tennessee Valley Public Power Association
WBN2 – Watts Bar Unit 2