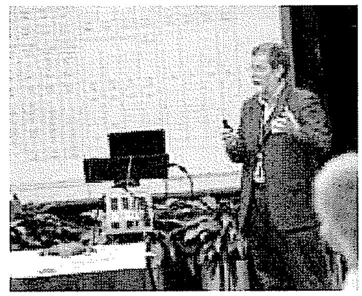
Public input was a vital part of developing TVA's Integrated Resource Plan.



Through public meetings, webinars and various forms of gaining insight from the people we serve, TVA was able to integrate their ideas and concerns into the plan.

Stakeholder Review Group

Lance Brown, Executive Director
Partnership for Affordable Clean Energy
Montgomery, Alabama

Dana Christensen, Associate Director
Oak Ridge National Laboratory
Oak Ridge, Tennessee

Ryan Gooch, Director, Energy Policy
Tennessee Dept. of Economic & Community Development
Nashville, Tennessee

Louise Gorenflo, TVA Committee Chair
Sierra Club
Crossville, Tennessee

Richard Holland, Vice President
Tennessee Paper Council
Nashville, Tennessee

Tom King, Director for Energy Efficiency & Electricity Technologies Program
Oak Ridge National Laboratory
Oak Ridge, Tennessee

George Kitchens, General Manager
Joe Wheeler Electric Membership Corporation
Trinity, Alabama

Henry List, Deputy Secretary
Kentucky Energy and Environment Cabinet
Frankfort, Kentucky

David McKinney, Environmental Services Division Chief
Tennessee Wildlife Resource Agency
Nashville, Tennessee

Jerry Paul, Distinguished Fellow on Energy Policy
Howard Baker, Jr. Center for Public Policy
Knoxville, Tennessee

David Reister
Environmental Stakeholder
Knoxville, Tennessee

Jan Simek, Professor of Science
University of Tennessee
Knoxville, Tennessee

Jack Simmons, President and CEO
Tennessee Valley Public Power Association
Chattanooga, Tennessee

Stephen Smith, Executive Director
Southern Alliance for Clean Energy
Knoxville, Tennessee

Lloyd Webb
Tennessee Valley Industrial Committee
Cleveland, Tennessee

Deborah Woolley, President
Tennessee Chamber of Commerce and Industry
Nashville, Tennessee

TVPPA believes the overall process TVA used in conducting the IRP was sound, transparent and that it afforded opportunity for external input to TVA from the public and the other stakeholders.

—Jack Simmons, President and CEO
Tennessee Valley
Public Power Association

TVA's current planning process, including the formation of the Stakeholder Review Group, is a significant step forward not only for TVA's planning processes, but also for TVA's relationship with the nine million people it serves.

— Stephen Smith, Executive Director
Southern Alliance for Clean Energy

TVA wanted to demonstrate transparency by including the public as much as possible during the IRP process. For example, the need for a Stakeholder Review Group was an outcome of the seven public meetings held last summer.

— Randy Johnson, Manager
Integrated Resource Planning
Tennessee Valley Authority

3 Public Participation

TVA is the largest public power company in the nation. An objective of this IRP was to understand the needs of the people it serves and how to address those needs in a cost-effective, reliable manner. Since the needs of the people vary, some people are more concerned about the cost of power, some on reliability, while others are concerned about environmental impacts. Therefore, it is TVA's ultimate responsibility to balance these competing needs as it plans for the future.

A transparent and participatory approach was utilized in the development of this IRP. Many opportunities were available to the public that influenced the development – and ultimately the outcome – of this IRP. For example, public briefings and meetings were held across the region, and an advisory review group was created. The following key objectives of public involvement were:

- Engage numerous stakeholders with differing viewpoints and perspectives throughout the entire IRP process
- Incorporate public opinions and viewpoints into the development of the IRP, including activities and opportunities for stakeholders to review and comment on various inputs, analyses and options considered
- Encourage open and honest communication in order to facilitate a sound understanding of the process
- Provide multiple communication channels to provide several ways for members of the public to learn about the IRP process and to provide input

TVA involved the public in each critical step of the IRP process. The involvement helped TVA identify the most effective ways to serve the people of the Tennessee Valley region. Public participation was actively solicited three times during the IRP process.

1. Public scoping period
2. Analysis and evaluation period
3. Draft IRP public comment period

3.1 Public Scoping Period

Public Comment Process:

Step 1 - Public Scoping Period

- Public Meetings
- Written Comments
- Scoping Questionnaire

Step 2 - Analysis and Evaluation Period

Step 3 - Draft IRP Public Comment Period

The TVA IRP process began with a 60-day public scoping period June 15, 2009. TVA announced the start of the process in newspapers throughout the region via media releases and on TVA's website.

In addition, the EPA published the official EIS Notice of Intent in the Federal Register. This notice is required by the NEPA guidelines which require federal agencies such as TVA to prepare an EIS whenever its actions, such as the development of an IRP, have the potential to affect the environment.

During the scoping period, TVA disseminated a broad range of information to the public, including the reasons for developing an IRP, what it would focus on, the process for how an IRP is developed and how the results will be used to guide strategic decision making. Public scoping provided an early and open process to ensure:

- Stakeholder issues and concerns were identified early and properly studied
- Reasonable alternatives and environmental resources were considered
- Key uncertainties that could impact costs or performance of certain energy resources were identified
- Input received was properly considered and would lead to a thorough and balanced final IRP

TVA also reiterated the need to have a balanced approach when considering the tradeoffs of one energy resource for another. While developing this IRP, TVA sought public input on a variety of issues and asked the following questions:

- How will any changes affect system reliability and the price of electricity?
- Should the current power generation mix (e.g., coal, nuclear power, natural gas, hydro, renewable) change?

- Should energy efficiency and demand response be considered in planning for future energy needs?
- Should renewables be considered in planning for future energy needs?
- How can TVA directly affect electricity usage by consumers?

The scoping period helped shape the initial development and framework of this IRP. TVA used the input received to determine what resource options should be considered to meet future demand. TVA used two primary techniques, public meetings and written comments, to collect public input during the scoping period.

3.1.1 Public Meetings

During the scoping period, TVA held seven public meetings across the Tennessee Valley between July 20 and Aug. 6, 2009 (Figure 3-1). The meetings were conducted in an informal, open house format to give participants an opportunity to express concerns, ask questions and provide comments. Exhibits, fact sheets and other materials were available at each public meeting to provide information about the Draft IRP and the associated EIS.

Date	Location
July 20, 2009	Nashville, Tenn.
July 21, 2009	Chattanooga, Tenn.
July 23, 2009	Knoxville, Tenn.
July 28, 2009	Huntsville, Ala.
July 30, 2009	Hopkinsville, Ky.
Aug. 4, 2009	Starkville, Miss.
Aug. 6, 2009	Memphis, Tenn.

Figure 3-1 – Public Scoping Meetings

Attendees included members of the general public, representatives from state agencies and local governments, TVA's congressional delegation representatives, distributors of TVA power, non-governmental organizations and other special interest groups.

Approximately 200 attended the public scoping meetings. TVA subject-matter experts attended each meeting to discuss issues and respond to questions about the IRP planning process and TVA's power system and programs.

3.1.2 Written Comments

During the scoping period, TVA accepted comments via email, fax, letters, TVA's website, public scoping meetings and a scoping questionnaire. At the public scoping meetings, verbal comments were recorded by court reporters and attendees were able to submit written comments by logging onto TVA's website using TVA supplied computers.

Overall, TVA received approximately 1,000 comments from the following communication tools:

- Scoping questionnaire
- Email
- TVA's website
- Public meetings

Comments were received from four federal agencies and 20 state agencies representing six of the seven TVA region states. Some of these responses included specific comments, while others stated they had no comments, but asked to review the Draft IRP and the associated EIS. Figure 3-2 shows the distribution of scoping comments by geographic area.

Some agencies, organizations and individuals provided comments specific to TVA's natural and cultural resource stewardship activities. These comments were not included in the scoping report because they focused on another planning process – TVA's Natural Resource Plan (NRP) and associated EIS. The full scoping report on this IRP as well the NRP can be found on TVA's website.

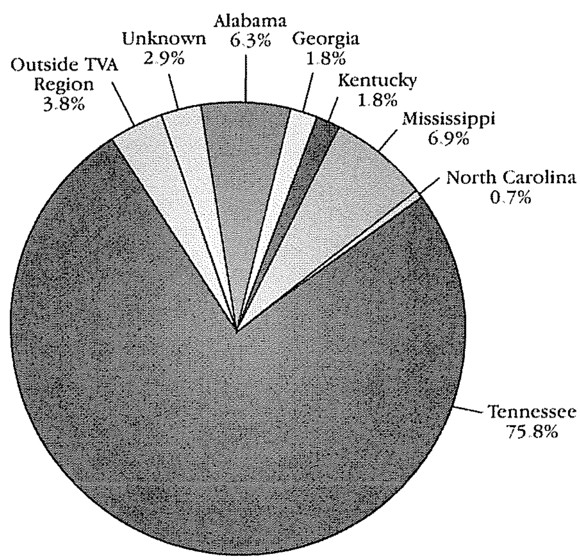


Figure 3-2 – Distribution of Scoping Comments by Geographic Area

3.1.3 Scoping Questionnaire

An 11-part scoping questionnaire was distributed at public meetings and made available on TVA's website. The questionnaire was developed to elicit public opinion on TVA's future generation and efficiency options. At least part of the scoping questionnaire was completed by 845 people, and 640 of the respondents answered the write-in questions as well as the multiple-choice questions.

Many of those who completed the questionnaire expressed a willingness to take various measures to reduce their energy use or pay higher rates for cleaner energy. The willingness to undertake some measures increased with the availability of financial incentives.

After further analysis, the results of the questionnaire indicated that the findings were not statistically significant and the survey population was not fully representative of the entire Tennessee Valley region. Therefore, TVA decided to conduct a phone survey of approximately 1,000 individuals across the entire region in the summer of 2010.

3.2 Analysis and Evaluation Period

The analysis and evaluation period took key themes and results identified from the scoping period and developed the framework for analysis and evaluation. The findings were considered when TVA developed the range of strategies for IRP analysis.

During this phase, TVA used the following three techniques to collect public input:

1. Stakeholder Review Group
2. Public briefings
3. Phone survey

Public Comment Process:

Step 1 - Scoping Period

Step 2 - Analysis and Evaluation Period

- Stakeholder Review Group
- Public Briefings
- Phone Survey

Step 3 - Draft IRP Public Comment Period

3.2.1 Stakeholder Review Group

Early in the IRP process, TVA recognized it would be difficult to get specific and continuous input from the public beyond the scoping period. To obtain more in-depth, ongoing input from the public, TVA established an advisory Stakeholder Review Group (SRG) in July 2009.

The formation of this diverse 16-member review group (listed on page 42) was the cornerstone of the public input process. It consisted of representatives from business and industry, state agencies, government, distributors of TVA power, academia, special interest groups and civic organizations. In addition to providing their individual views to TVA, SRG members represented their constituency and reported to them on the IRP process.

The SRG met approximately every month with TVA. Ten meetings were held prior to the release of the Draft IRP and the associated EIS at various locations throughout the region. Five additional meetings were held between the release of the Draft IRP and approval of the Recommended Planning Direction to facilitate ongoing feedback and guidance for this IRP. Figure 3-3 shows the dates and locations of all the SRG meetings.

Date	Location
July 29, 2009	Nashville, Tenn.
Aug. 18, 2009	Knoxville, Tenn.
Sept. 24, 2009	Chattanooga, Tenn.
Oct. 22 & 23, 2009	Chattanooga, Tenn.
Dec. 10 & 11, 2009	Nashville, Tenn.
Feb. 17, 2010	Knoxville, Tenn.
May 13, 2010	Knoxville, Tenn.
June 29, 2010	Murfreesboro, Tenn.
July 20 & 21, 2010	Chattanooga, Tenn.
Aug. 12, 2010	Chattanooga, Tenn.
Aug. 26, 2010	Chattanooga, Tenn.
Oct. 28, 2010	Knoxville, Tenn.
Nov. 18, 2010	Murfreesboro, Tenn.
Dec. 15, 2010	Chattanooga, Tenn.
Jan. 26, 2011	Knoxville, Tenn.
Feb. 24, 2011	Chattanooga, Tenn.

Figure 3-3 – Stakeholder Review Group Meetings

The meetings were designed to encourage dialogue on all facets of the IRP process, and to facilitate information sharing, collaboration and expectations for this IRP. Topics included energy efficiency best practices, TVA's power delivery structure, load and commodity forecasts and supply resource options.

The individual views of SRG members were collected on the entire range of assumptions, analytical techniques and proposed energy resource options and strategies. Given the diverse makeup of the SRG, there were a wide range of views on specific issues, such as the value of energy efficiency programs, environmental concerns and the appropriateness of some new technologies. Open discussions supported by the best available data facilitated better comprehension of the specific issues.

To increase public access and transparency to the IRP process, all non-confidential SRG meeting material (i.e., presentations, agenda and minutes) was posted on TVA's website. In addition, TVA developed an internal website specifically for SRG members to post information on and to request data from TVA staff.

3.2.2 Public Briefings

In addition to the public scoping and SRG meetings, TVA held four public briefings (Figure 3-4). The public briefings informed the general public of the IRP process.

Date	Location
Oct. 23, 2009	Chattanooga, Tenn.
Nov. 16, 2009	Chattanooga, Tenn.
Feb. 17, 2010	Knoxville, Tenn.
May 13, 2010	Knoxville, Tenn.

Figure 3-4 – Public Briefings

Participants had the option to attend in person or by webinar. The format of the public briefings included a brief presentation followed by a moderated Q&A session with the audience.

Topics discussed at the public briefings included an overview of the integrated resource planning process, resource options, development of scenarios and strategies and evaluation metrics.

The public briefings attendance averaged 15 to 20 in-person participants and approximately 30 to 40 participants by webinar. Videos of the briefings and presentation materials were posted on the IRP project website.

TVA also briefed the public on the IRP process through presentations given at local organizations, clubs and associations including the following:

- Association of Energy Engineers
- Tennessee Renewable Energy and Economic Development Council
- Chattanooga Engineers Club
- City of Chattanooga
- Chattanooga Green Spaces
- EPRI Environmental Aspects of Renewable Energy Interest Group Workshop
- Clean Energy Speakers Series at Georgia Tech
- Howard H. Baker, Jr. Center for Public Policy
- Technical Society of Knoxville

3.2.3 Phone Survey

To ensure an even wider representation of opinions on IRP choices were considered, TVA partnered with Harris Interactive to develop a statistically representative phone survey of approximately 1,000 Tennessee Valley residents. The customer phone survey was conducted during June and July 2010 for the following reasons:

- Determine primary power generation concerns among the Tennessee Valley residents (i.e., cost, reliability, use of renewables, etc.)
- Determine market potential for voluntary and financially incentivized energy efficiency programs
- Determine market potential of renewable programs, including Green Power Switch® and other existing or planned energy efficiency and demand response programs
- Estimate potential market pricing for renewable power programs, including the additional amounts Tennessee Valley residents are willing to pay each month for energy from renewable sources
- Assess Tennessee Valley residents' attitudes of and satisfaction with TVA, including analysis of the services that it provides to the Tennessee Valley

Survey results indicated that the Tennessee Valley residents have a favorable attitude of TVA, consider system reliability a critical component of utility services and want to see TVA focused on keeping prices affordable.

Key findings included:

TVA quality of service	• 94 percent of respondents agreed that providing a reliable supply of electricity is very important in assessing TVA's quality of service • 92 percent indicated that keeping electricity rates affordable is important
Meeting future energy needs	• 70 percent of respondents also deemed it very important for TVA to reduce air pollutants and emissions

Renewable energy	• 42 percent of respondents believed that adding different energy sources, such as solar and wind, into TVA resource portfolio should be emphasized the most to meet future energy needs
	• 42 percent of respondents indicated they likely would pay more for renewable energy, with the following breakdown:
	  ◦ Those indicating they would definitely pay more would pay an average of \$12.60 per month to ensure that 10 percent of their energy comes from renewable sources
	  ◦ This same group would pay an average of \$26.91 more per month to ensure that all of their energy is renewable
	  ◦ Tennessee Valley residents indicating they would definitely or probably pay more were willing to pay \$11 to \$20 per month to reduce CO_2 emissions
	  ◦ Opportunities exist for additional Green Power Switch® awareness among Tennessee Valley residents

Biggest concerns related to electricity production	• Cost and billing • Environmental impact • Quality of power supply

3.3 Draft IRP Public Comment Period

After the Draft IRP was completed in the fall of 2010, TVA provided an opportunity for the public to provide comments and give input. Following the Sept. 15, 2010 publication of the Draft IRP with EPA, a 52-day comment period was provided to solicit input about the Draft IRP from the public.

Originally set to close Nov. 8, 2010, the 45-day comment period was extended an additional seven days to accommodate several external stakeholders' requests. For this phase of the IRP process, TVA presented the results to both internal TVA stakeholders and the general public in the Draft IRP and the associated EIS.

Public Comment Process:

Step 1 - Scoping Period

Step 2 - Analysis and Evaluation Period

Step 3 - Draft IRP Public Comment Period

- Public Meetings
- Webinars
- Written Comments

TVA used the following three techniques to collect input during the Draft IRP:

1. Public meetings
2. Webinars
3. Written comments

3.3.1 Public Meetings

TVA had five meetings with the public across the Tennessee Valley region in October 2010 (Figure 3-5). These meetings gave the public an opportunity to present their views on the Draft IRP to TVA leadership and subject-matter experts.

Date	Location
Oct. 5, 2010	Bowling Green, Ky.
Oct. 6, 2010	Nashville, Tenn.
Oct. 7, 2010	Olive Branch, Miss.
Oct. 13, 2010	Knoxville, Tenn.
Oct. 14, 2010	Huntsville, Ala.

Figure 3-5 – Public Comment Period Meetings

TVA publicized the meetings and webinars by placing advertisements in major newspapers and issuing news releases prior to each meeting that many local newspapers carried. Before each of the meetings, TVA met with local reporters in each location who frequently write about TVA and the IRP process so that they, in turn, could write articles to help the public understand the IRP process and draft document.

Online advertising (i.e., announcements on TVA's Facebook page) was used to reach an even wider audience. TVA's website was also regularly updated with the latest news regarding the IRP process and logistics for each public meeting.

At each of these meetings, TVA presented an overview of the Draft IRP followed by a moderated Q&A session supported by a panel of TVA subject-matter experts. Attendees were able to address comments or questions to the panel. Attendees also had the option to submit written and verbal comments to a court reporter before or after the presentations. A transcript and video of each meeting was recorded. The presentation slides and video of the meeting in Bowling Green, Ky., and videos of each Q&A session were posted on the TVA's website.

TVA encouraged comments from the public on the Draft IRP and the associated EIS. Comments received enabled TVA staff to identify public concerns and recommendations concerning the future operation of the TVA power system. The public comments and TVA's responses are included in the associated EIS.

3.3.2 Webinars

To encourage as much participation as possible, members of the public who were not able to attend public meetings were able to participate by webinar. Attendees registered in advance and were able to access the presentation and participate in the Q&A session from personal computers.

3.3.3 Written Comments

During the 52-day public comment period, comments were submitted via TVA's website, email, U.S. mail and fax. Comments and questions recorded at each of the public meetings were also considered.

In all, TVA received approximately 500 responses from a multitude of individuals, organizations and agencies. These responses contained 748 comments of which 372 were unique and addressed in the associated EIS. A general summary of unique comments received during the public comment period on the Draft IRP can be seen in Figure 3-6.

Method of Comment	Number Received
Email	38
Online comment form	104
Webinar comment/question from IRP meetings	16
Oral comment/question from IRP meetings	30
Letters	16
Form Letters (pre-printed post cards)	297
Total	501

Figure 3-6 – Type of Responses Submitted

The following organizations and agencies submitted comments:

- Environmental Protection Agency
- Natural Resource Defense Council
- Southern Alliance for Clean Energy
- Sierra Club
- Earth Justice
- Distributors of TVA power
- State agencies
- Tennessee Valley Public Power Association
- Industry groups (i.e., solar energy, natural gas, etc.)

3.4 Public Input Received During the IRP Process

Public input received during the IRP process covered a wide spectrum of subjects. From public scoping to the comments received on the Draft IRP, the ongoing feedback assisted TVA in identifying the relevant concerns of the public with respect to resource planning. Input received during the IRP process also provided beneficial insight to common public perceptions of TVA programs and willingness to invest in certain resource options. For example, the SRG and public input encouraged TVA to consider larger renewable portfolio targets beyond current resource plans, resulting in consideration of portfolios of 2,500 and 3,500 MW.

Moreover, public input helped develop the framework for analysis and addressed a wide range of issues, including the cost of power, recommended resource options, the environmental impacts of different resource options and the integrated resource planning process. The following sections briefly summarize the issues raised with additional detail provided in the associated EIS.

Costs of New Capacity, Financing Requirements and Rate Implications

Concerns about the ability of TVA to design, build and deliver major new capacity on time and within budget were expressed. Questions about the validity of construction cost estimates for new nuclear capacity were raised.

The public also expressed concerns about TVA's ability to fund future resource additions due to the $30 billion limit on TVA's statutory borrowing authority. TVA's financing options to cover the costs of construction for major capital investments are limited to borrowing, increasing rates or other less traditional forms of financing. There were also concerns about potential impacts on short-term rates. However, some believed that higher rates may promote energy efficiency investments.

While a large number of people were opposed to any future price increases, a number of those who completed the scoping questionnaire expressed a willingness to pay $1-$20 more per month for TVA to increase generation from non-greenhouse gas emitting sources.

Recommended Energy Resource Options

The public made recommendations about TVA's future supply- and demand-side resource options. TVA's future resource portfolio should:

- Avoid or minimize rate increases
- Minimize or reduce pollution and other environmental impacts
- Maximize reliability
- Contain a diversity of fuel sources

The following resources options were mentioned:

Nuclear expansion	• Supported nuclear additions if implemented in a cost-effective, responsible way • Concerned with rising costs and nuclear waste issues related to additions to the nuclear portfolio
EEDR initiatives	• Pleased with the contribution of EEDR in the planning strategies retained in the Draft IRP • Comments regarding the target level of EEDR being studied and the potential for larger amounts of EE to displace new nuclear capacity • Uncertainty about cost, lost revenue impacts and program effectiveness; and questioned measurement and verification of benefits
Renewable additions	• Supported increased renewable generation (including wind, solar, locally-sourced biomass and low-impact hydro) as long as costs are competitive • Stated the need for a stronger commitment to developing renewables within the Tennessee Valley region, particularly solar, as opposed to imported wind power • Questioned system operational impacts caused by intermittent or off-peak resources (i.e., wind and solar)
Idling coal-fired capacity	• Commended TVA on the strategy for coal-fired capacity idling and to consider larger quantities of idled capacity • Concerned with the economic and environmental implications of idling certain coal-fired units • Concerned about TVA's risk exposure for pending carbon legislation and issues related to lead-time for positioning coal-fired assets for idling, retirement and/or return to service
Energy storage	• Recommended an increase in energy storage capability
Natural gas	• Supported additional natural gas-fired generation

Environmental Impacts of Power System Operations

A general concern about pollution was a frequently mentioned issue in regards to the TVA power system. Additionally, much of the public felt the issues with air pollutants, greenhouse gas emissions, climate change, spent nuclear fuel and coal combustion by-products were of high importance.

Many comments encouraged TVA to decrease its emissions of greenhouse gases while others questioned the human influence on climate change. The issue was also raised of the impacts of buying coal from surface mines, particularly mountaintop removal mines, and recommended that TVA stop this practice. The Kingston Fossil Plant ash spill in December 2008 was frequently mentioned.

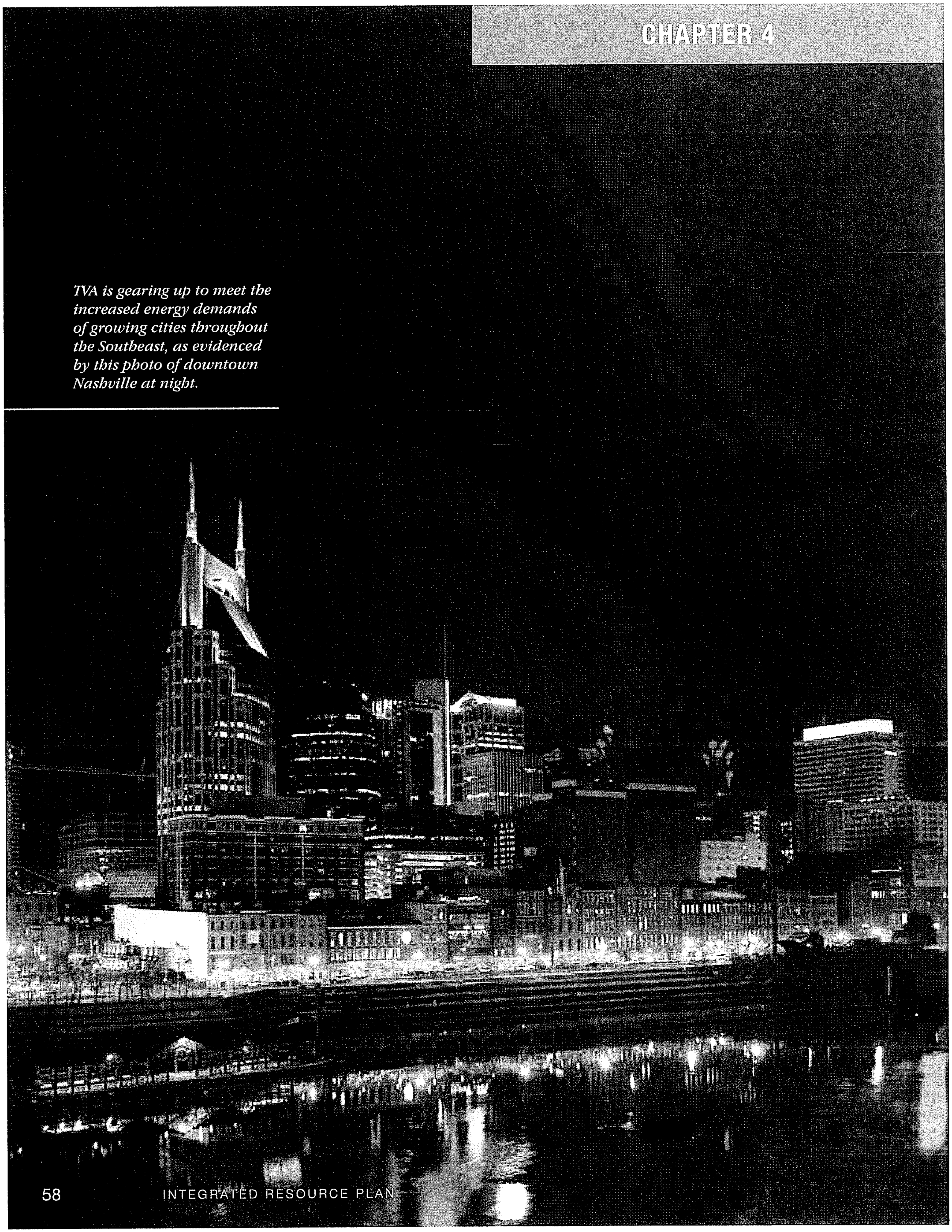
The Integrated Resource Planning Process

Several people addressed the IRP process. Their comments recommended that TVA continue to follow industry standard practices; enter the process without preconceptions about the adequacy of various resource options; be open and transparent throughout the planning process; treat energy efficiency and renewable energy as priority resources and address the total societal costs and benefits.

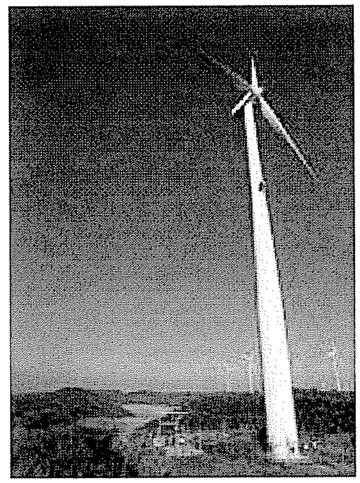
3.5 Response to Public Input and Comments

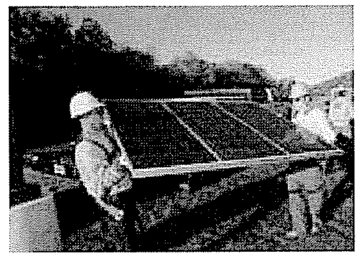
Input received from the general public and stakeholders was a key part of the IRP process. Listening to different stakeholders' perspectives, viewpoints and sometimes competing objectives played a prominent role in choosing a Recommended Planning Direction for TVA. Appendix F – Stakeholder Input Considered and Incorporated provides examples on how key themes were incorporated into the IRP analysis.

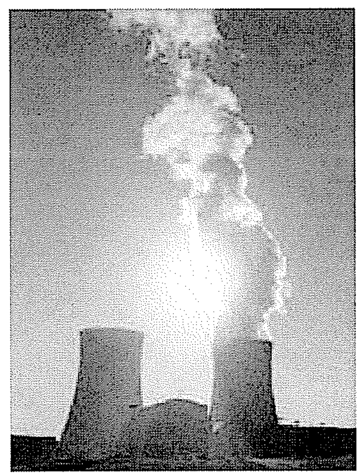
CHAPTER 4



TVA is gearing up to meet the increased energy demands of growing cities throughout the Southeast, as evidenced by this photo of downtown Nashville at night.





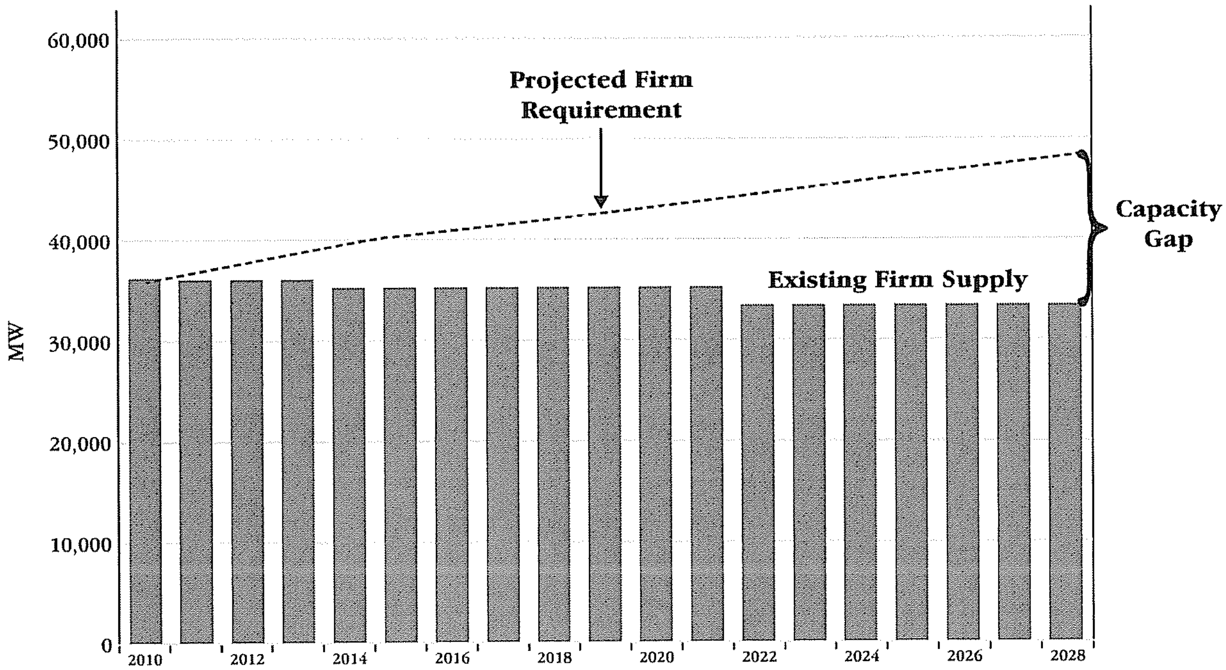


Increasing TVA's production from cleaner energy sources like wind, solar and nuclear are at the core of the overall strategy for the future.

Estimating the Capacity Gap

Projected Firm Requirements are TVA's forecasted electricity requirements to meet demand over time.

Capacity Gap is the difference between total supply and total demand for electricity.



Existing Firm Supply is TVA's existing energy resources to meet projected electricity demand.

4 Need for Power Analysis

The need for power analysis determines the ability of TVA's existing energy resources to meet projected electricity demand. It defines the capacity gap which is the difference between supply and demand over the IRP study period. These needs will continue to vary from season to season, day to day and even minute to minute. For the purposes of this IRP, the need for power was analyzed through 2029.

The execution of this analysis included the following four steps:

1. Estimate demand
2. Determine reserve capacity needs
3. Estimate supply
4. Estimate capacity gap

Demand
+ Reserve Capacity
– Supply
____
Capacity Gap

4.1 Estimate Demand

Determination of a need for power begins with long-term forecasts of the growth in demand for electricity, both in terms of electricity sales to the end-user and the peak demands those end-users place on the TVA system. These forecasts were developed from individual, detailed forecasts of residential, commercial and industrial sales, which served as the basis for all resource and financial planning activities. Historical forecast accuracy was monitored to ensure errors in data or methodology were quickly identified and fixed. A range of forecasts (high, expected and low) were also generated to ensure that TVA's plans were not too dependent on the accuracy of a single forecast. The following sections provide more detail on the processes used to develop the forecasted demand.

4.1.1 Load Forecasting Methodology

TVA's load forecasting is a complex process that starts with the best available data and is carried out using both econometric (statistical economic) and end-use models. TVA's econometric models link electricity sales to several key economic factors in the market, such as the price of electricity, the price of competing energy source options and the growth in overall economic activity. Specific values for key variables were used to develop forecasts of sales growth in the residential and commercial sectors, as well as in each industrial sector. Underlying trends within each sector, such as the use of various types of equipment or processes, played a major role in forecasting sales.

To capture these trends, along with expected changes in the stock and efficiency of equipment and appliances, TVA used a variety of end-use forecasting models. For example, in the residential sector, sales were forecasted for space heating, air conditioning, water heating and several other uses after accounting for important factors (i.e., changes in efficiency over time, appliance saturation and replacement rates and growth in the average size of the American home). In the commercial sector, a number of categories, including lighting, cooling, refrigeration and space heating, were examined with a similar attention to changes in important variables such as efficiency and saturation.

Since forecasting is inherently uncertain, TVA supplemented its modeling with industry analyses and studies of specific major issues that may have the potential to impact those forecasts. TVA also produced alternative regional forecasts based on different outcomes for key drivers (i.e., economic growth, population growth and economic behaviors) of some of TVA's largest wholesale customers. Two of these alternative forecasts, referred to as the "high-load" and "low-load" forecasts, defined a range of possible future outcomes with a high level of confidence that the true outcome will fall within this range. This ensured that TVA's resource planning took into account the variability that is the hallmark of year-to-year peak demand and energy sales.

Several key inputs were used as drivers of the long-term forecasts of residential, commercial and industrial demand. The most important of these were economic activity, the price of electricity, customer retention and the price of other sources of energy such as natural gas. These key inputs are described in the following sections.

Economic Activity

Periodically, but at least annually, TVA produces a forecast of regional economic activity for budgeting, long-range planning and economic development purposes. These forecasts are based on national forecasts developed by internationally recognized economic forecasting services.

The economy of the TVA service territory has historically been more dependent on manufacturing than the United States on average. Industries such as pulp and paper, aluminum, steel and chemicals have been drawn to the region because of the wide availability of natural resources, access to a skilled workforce and the supply of reliable and affordable electricity. In recent years, regional growth has outpaced national growth as manufacturing activities have grown at a faster pace than non-manufacturing activities. However, this can also mean that in periods of recession, regional growth will contract faster and more sharply given this relatively higher degree of dependence on manufacturing. As evidenced by the ongoing recovery from the most recent recession, the regional economy tends to recover more quickly and robustly.

Future growth is expected to be lower than historical averages as a result of the impacts of the recent recession and ongoing recovery as well as the trend of declining U.S. manufacturing intensity. As markets for manufacturing industries have become global in reach, production capacity has moved overseas from the TVA region for many of the same industries. The decline in demand associated with these off-shore industries has been offset to some degree by the continued growth of the automobile industry in the Southeast over the last 20 years. The TVA region is expected to retain its comparative advantage in the automotive industry, as exemplified by the new Volkswagen auto plant under construction in Chattanooga, Tenn. However, reduced long-term prospects for the U.S. automotive industry will also have an impact on the regional industry.

Other impacts from the recent recession such as increased financial market regulation and tighter credit conditions may also work toward restraining economic growth. These impacts could continue in the long-term resulting in a slowdown in future economic growth for the TVA region and nation.

Despite the impacts of a slowed economy, population growth in the Tennessee Valley region continues to be strong. Most movement into the region is still primarily driven by economic opportunities in the contracting sectors and other expanding sectors in the region. Part of this growth is to serve the existing population (i.e., retail and other services), but, more importantly, a large part of this growth is related to export services that are sold to areas outside the region. Notable examples are corporate headquarters such as Nissan (automobile manufacturing) in Franklin, Tenn., Hospital Corporation of America (the largest private operator of hospitals in the world) in Nashville, Tenn. and FedEx, AutoZone, International Paper and Service Master in Memphis, Tenn.

In addition, the Tennessee Valley has become an attractive region for the growing ranks of America's retirees looking for a moderate climate and a more affordable region than traditional retirement locations and is increasingly fueled as Baby Boomers exit the workforce. The increase in the retiree population has a multiplier effect in the service sector, increasing the need for employees to meet growing demand.

Customer Retention

In the last 20 years, the electric utility industry has undergone a fundamental change in most parts of the nation. In many states, an environment of regulated monopoly has been replaced with varying degrees of competition.

While TVA has contracts with the 155 distributors of TVA power, it is not immune to competitive pressures. The contracts allow distributors to give TVA notice of contract cancellation, after which they may procure power from other sources. Many of TVA's large directly served customers have the option to shift production from plants in the TVA service area to plants in other utilities' service territories if TVA's rates become non-competitive.

The spring 2010 forecast expected TVA's average price of electricity to remain competitive with the rates of other utilities. As a result, the net impact of competition in the medium forecast is that TVA will retain the majority of its current customer base.

Price of Electricity

Forecasts of the retail price for electricity are based on long-term estimates of TVA's total costs to operate and maintain the power system and are adjusted to include an estimate of the historical markups charged by distributors of TVA power. These costs, known in the industry as revenue requirements, are based on estimates of the key costs of generating and delivering electricity, including fuel, variable operations and maintenance costs, capital investment and interest. High and low electricity price forecasts are also derived using high and low values for these same factors after accounting for any relationships that may exist between variables.

Price of Substitute Fuels

Considering electricity is a source of energy, the service derived from consuming electricity can also be obtained, where applications allow, using other sources of energy. If the price of electricity is not competitive with the price of other fuels that can provide the same energy services as electricity, such as water and space heating, customers may move away from electricity in the long-term and substitute cheaper sources of energy. The potential for this type of substitution will depend on the relative prices of other fuels, the ability of the fuel to provide a comparable service and the physical capability to make the change. For example, while consumers can take action to change out electric water heaters and replace electric heat pumps with natural gas furnaces, the ability to utilize another form of energy to power consumer electronics, lighting and many appliances is far more limited by current technology.

Changes in the price of TVA's electricity compared to the price of natural gas and other fuels will influence consumers' choices of appliances—either electric, gas or other fuels. While other substitutions are possible, natural gas prices serve as the benchmark for determining substitution impacts in the load forecasts.

4.1.2 Forecast Accuracy

Forecast accuracy is generally measured in part by error in the forecasts, whether day ahead, year ahead, or multiple years ahead. Figures 4-1 and 4-2 show annual forecasts from 2000 through 2010 for peak load requirements and net system requirements. Figure 4-1 is a comparison of actual and forecasted summer peak demand in MW. Figure 4-2 is a comparison of actual and forecasted net system requirements in GWh. Note that the "Norm.Actual" line represents the normalized value of the annual energy, meaning abnormal weather impacts have been removed.

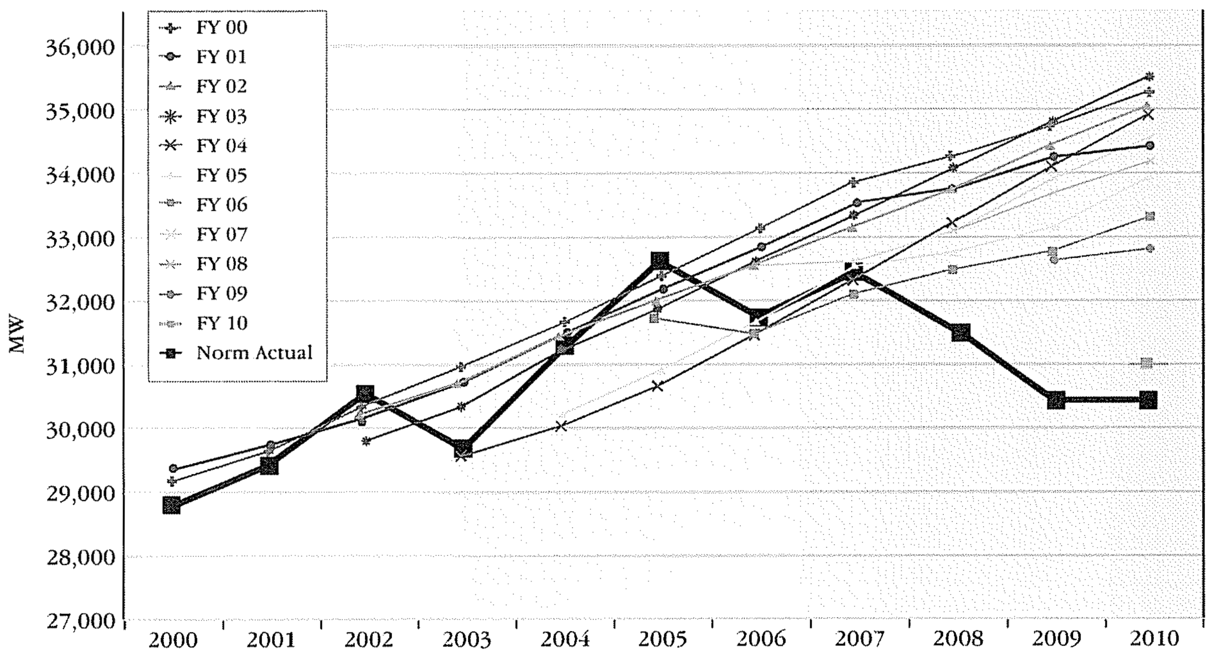


Figure 4-1 – Comparison of Actual and Forecasted Summer Peak Demand (MW)

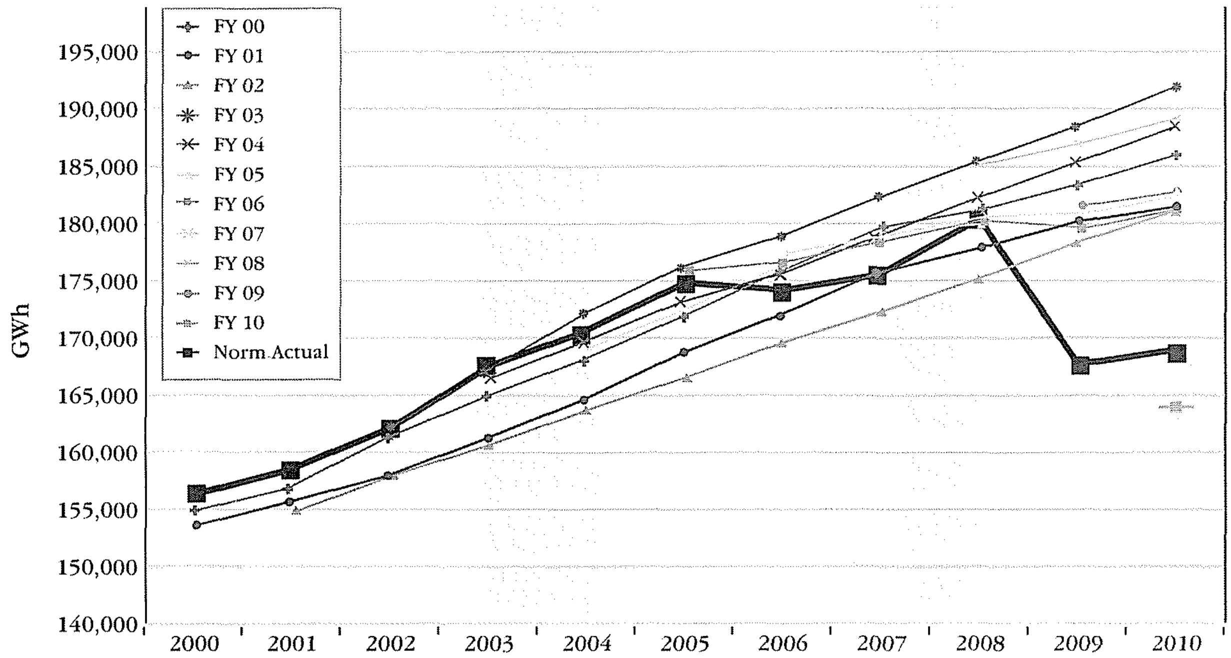


Figure 4-2 – Comparison of Actual and Forecasted Net System Requirements (GWh)

The mean annual percent error (MAPE)[1] of TVA's forecast of net system energy and peak load requirements for the 2000 to 2009 period was 1.9 percent and 2.8 percent, respectively. These include large errors in 2009 as the ramifications of the 2008 financial crisis and resulting economic slowdown impacted the economy. In the TVA service area, the most significant reductions were in the industrial sector, but it has already begun to show signs of recovery. The 2000 to 2008 MAPE was 1.1 percent for net system requirements and 2.2 percent for peak load, which is more representative of the accuracy of TVA year-in and year-out load forecasts. From informal conversations with peer utilities, TVA's MAPE of approximately 1 to 2 percent is in alignment with that of other utilities.

As mentioned previously in Section 4.1.1, while the economy in the Tennessee Valley region may be slightly stimulated by the creation of export services sold to areas outside the TVA region, future growth is expected to be lower than historical averages.

[1]MAPE is the average absolute value of the error each year; it does not allow over-predictions and under-predictions to cancel each other out.

This is a result of a number of factors, which include the impacts of the recent recession and subsequent recovery, the trend of declining U.S. manufacturing and the projected loss of some TVA customer load.

Figures 4-1 and 4-2 show the magnitude of the downturn of TVA net system requirements and summer peak loads due in part to the recession in the region. These trends are the result of a decline in energy usage by TVA customers due to a combination of factors including changes in the regional economy, improved energy efficiency and rising electricity prices.

4.1.3 Forecasts of Peak Load and Energy Requirements

To deal with the inherent uncertainty in forecasting, TVA developed a range of forecasts. Each forecast corresponds to different load scenarios. Scenarios are described in more detail in Chapter 6 – Resource Plan Development and Analysis. Forecasts of net system peak load and energy requirements for the IRP reference case and the highest and lowest scenarios are respectively shown in Figures 4-3 and 4-4. Peak load grew at an average annual rate of 1.3 percent in the Reference Case: Spring 2010, varying from 0 percent in the lowest scenario to 2 percent in the highest scenario. Net system energy requirements grew at an average annual rate of 1 percent in the IRP reference case, varying from 0 percent in the lowest scenario to 1.9 percent in the highest scenario.

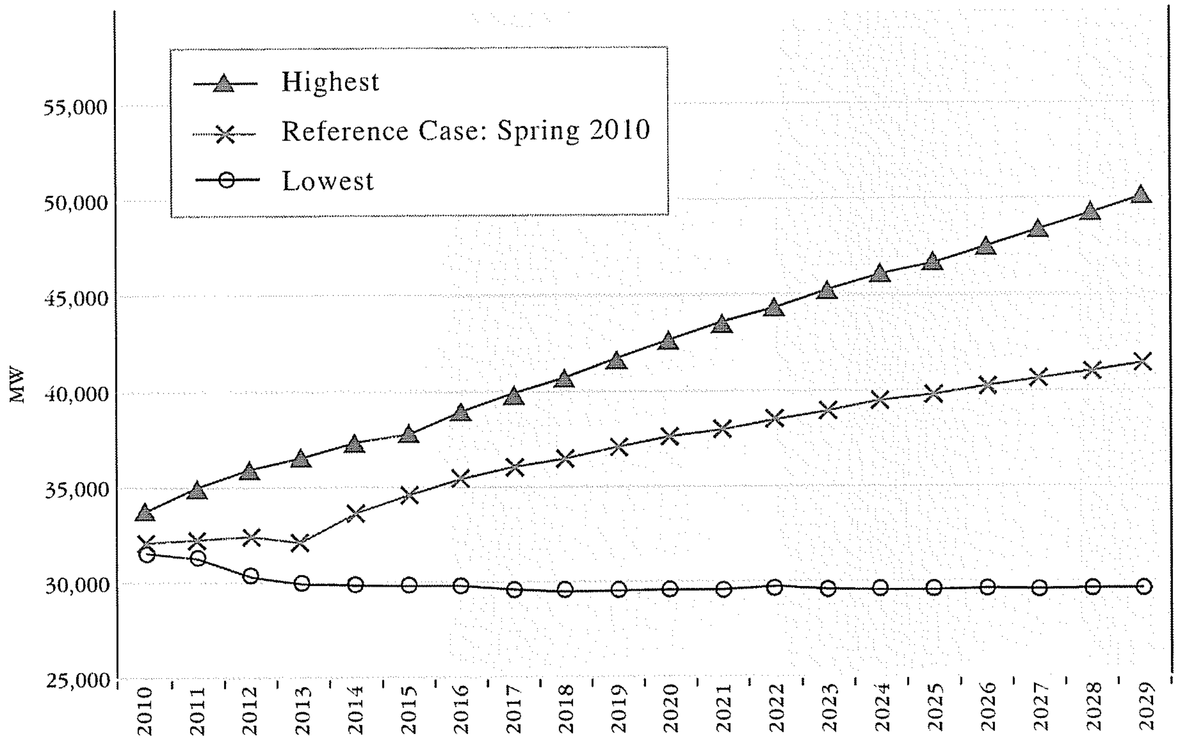


Figure 4-3 – Peak Load Forecast (MW)

The use of ranges ensured that TVA considered a wide spectrum of electricity demand in its service territory and reduced the likelihood that its plans are too dependent on the achievement of single-point estimates of demand growth that make up the midpoints of the forecasts. These ranges are used to inform planning decisions beyond pure least-cost considerations given a specific demand in each year.

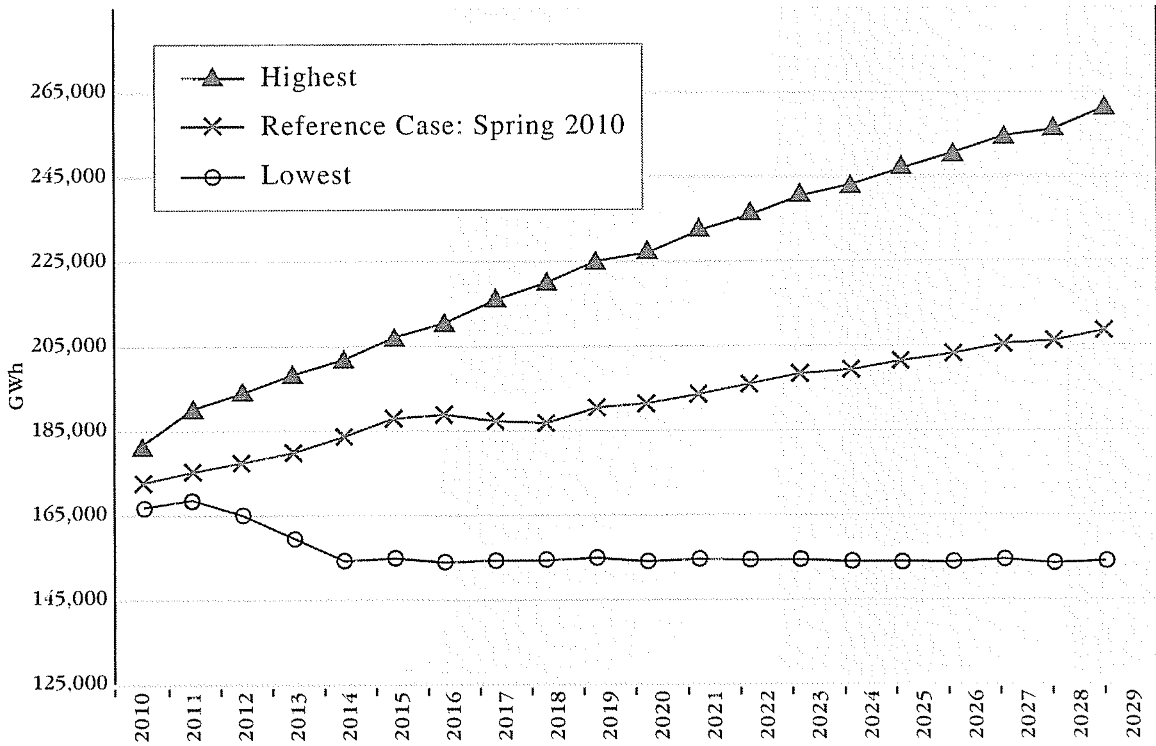


Figure 4-4 – Energy Forecast (GWh)

4.2 Determine Reserve Capacity Needs

To ensure that enough capacity is available to meet peak demand, including contingency for unforeseen events, additional generating capacity beyond which is needed to meet expected peak demand is maintained. This additional generating capacity (reserve capacity) must be large enough to cover the loss of the largest single operating unit (contingency reserves), be able to respond to moment-by-moment changes in system load (regulating reserves) and replace contingency resources should they fail (replacement reserves). Total reserves must also be sufficient to cover uncertainties such as unplanned unit outages, undelivered purchased capacity and load forecasting error.

TVA identified a planning reserve margin based on minimizing overall cost of reliability to the customer. This reserve margin was based on a stochastic analysis that considered the uncertainty of unit availability, transmission capability, economic growth and weather to compute expected reliability costs. From this analysis a target reserve margin was selected such that the cost of additional reserves plus the cost of reliability events to the customer was minimized. This target or optimal reserve margin was adjusted based on TVA's risk tolerance in producing the reserve margin used for planning studies. Based on this methodology, TVA's current planning reserve margin is 15 percent and is applied during both the summer and winter seasons.

4.3 Estimate Supply

Next, the current supply- and demand-side resources available to meet this demand were identified. TVA's generation supply consists of a combination of existing TVA-owned resources, budgeted and approved projects – such as new plant additions and updates to existing assets – and PPAs. Each type of generation can be categorized based on its degree of utilization in serving electricity demand. Generation can also be categorized by capacity, energy type and how it is measured.

4.3.1 Baseload, Intermediate, Peaking and Storage Resources

Figure 4-5 illustrates the uses of baseload, intermediate and peaking resources. Although these categories are useful, the distinction between them is not always clear. For example, a peaking unit, which is typically used to serve only intermittent but short-lived spikes in demand, may from time to time be called on to run continuously for an amount of time even though it may be less economical to do so. This may be due to transmission or other constraints. Similarly, many baseload units are capable of operating at different power levels, which gives them some characteristics of an intermediate or peaking unit. This IRP considered strategies that take advantage of this range of operations.

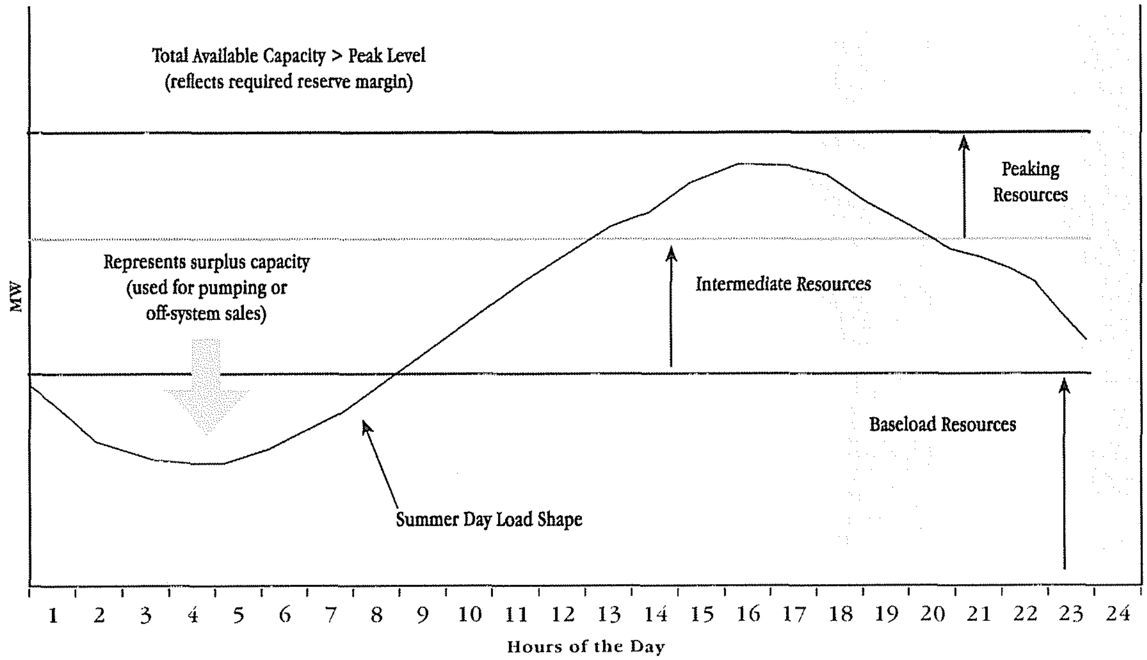


Figure 4-5 – Illustration of Baseload, Intermediate and Peaking Resources (MW)

Baseload Resources

Baseload generators are primarily used to meet energy needs during most hours of the year due to their lower operating costs and high availability. Even though baseload resources typically have higher construction costs than other alternatives, they have much lower fuel and variable costs, especially when fixed costs are expressed on a unit basis. An example of a baseload resource that provides continuous, reliable power over long periods of uniform demand is a nuclear power plant. Some energy providers may also consider natural gas-fired combined cycle plants for use as incremental baseload generators. However, given the historical tendency for natural gas prices to be higher than coal and nuclear fuel prices when expressed on a unit basis, a combined cycle unit may be a more expensive option for larger continuous generation needs. As the fundamentals of fuel supply and demand continue to change and if access to shale gas continues to grow, this relationship may change in the future.

Intermediate Resources

Intermediate resources are primarily used to fill the gap in generation between baseload and peaking needs. These units are required to produce more or less output as the energy demand increases and decreases over time, both during the course of a day and seasonally. Given current fuel prices and relative generating efficiencies, intermediate units are more costly to operate than baseload units, but cheaper than peaking units. This type of generation typically comes from natural gas-fired combined cycle plants and smaller coal-fired plants. Corresponding back-up balancing supply needed for intermittent renewable generation, such as wind or solar, also comes from intermediate resources. It is possible to use the energy generated from a solar or wind project as an intermediate resource with the use of energy storage technologies.

Peaking Resources

Peaking units are expected to operate infrequently during shorter duration, high demand periods. They are essential for maintaining system reliability requirements, as they can ramp up quickly to meet sudden changes in either supply or demand. Typical peaking resources include natural gas-fired combustion turbines (CTs), conventional hydroelectric generation and pumped-storage generation.

Storage Resources

Storage units usually serve the same power supply function as peaking units but use low-cost off-peak electricity to store energy for generation at peak times. An example of a storage unit is a pumped-storage plant that pumps water to a reservoir during periods of low demand and releases it to generate electricity during periods of high demand. Consequently, a storage unit is both a power supply source and an electricity user.

4.3.2 Capacity and Energy

Peaks in a power system are measured in terms of capacity (e.g., MW), which is the instantaneous maximum amount of energy that can be supplied by a generating plant or system. For long-term planning purposes, capacity can be specified in many forms such as nameplate (the maximum design generation), dependable (the maximum that can typically be expected in normal operation), seasonal (the maximum that can be expected during different seasons of the year) and firm (dependable capacity less all known adjustments).

Overall power system usage is measured in terms of energy (e.g., MWh or GWh). Energy is the total amount of power that an asset delivers in a specified time frame.

For example, 1 MW of power delivered for 1 hour equals 1 MWh of energy and 1,000 MWh is equal to 1 GWh. Capacity factor is a measure of the actual energy delivered by a generator compared to the maximum amount it could have produced. Assets that are run constantly, such as nuclear or coal-fired plants, provide a significant amount of energy with capacity factors of more than 90 percent. Assets that are used infrequently, such as combustion turbines, provide relatively little energy with low capacity factors of less than five percent. However, the energy they do produce is crucial because it is often delivered at peak times.

Energy efficiency can also be measured in terms of capacity and energy. Even though energy efficiency does not input power into the system, the effect is similar as it represents power that is not required from another resource. Demand reduction is also measured in capacity and energy, but unlike energy efficiency, it is not a significant reduction in total energy used.

4.3.3 TVA's Generation Mix

TVA's power generation system employs a wide range of technologies to produce electricity and meet the needs of the Tennessee Valley residents, businesses and industries. Figure 4-6 shows a breakdown of firm capacity by technology for TVA's Reference Case: Spring 2010. Figure 4-7 shows a breakdown of energy by technology for TVA's Reference Case: Spring 2010.

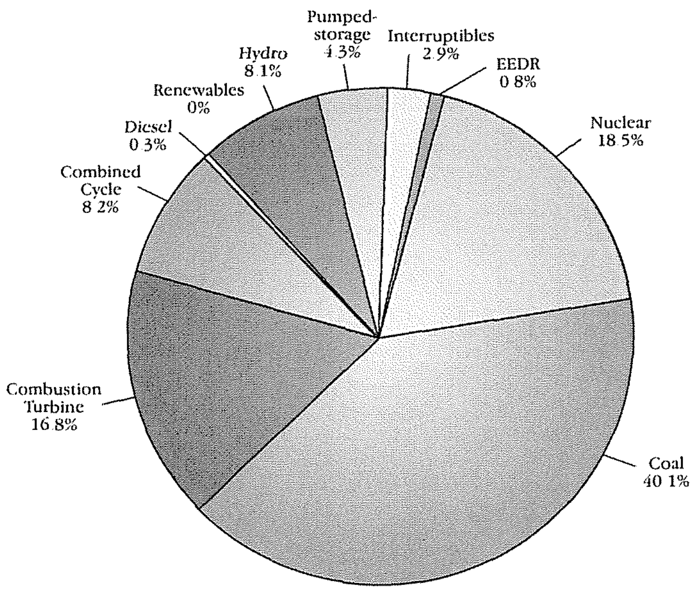


Figure 4-6 – Reference Case: Spring 2010 – Firm Capacity (MW)

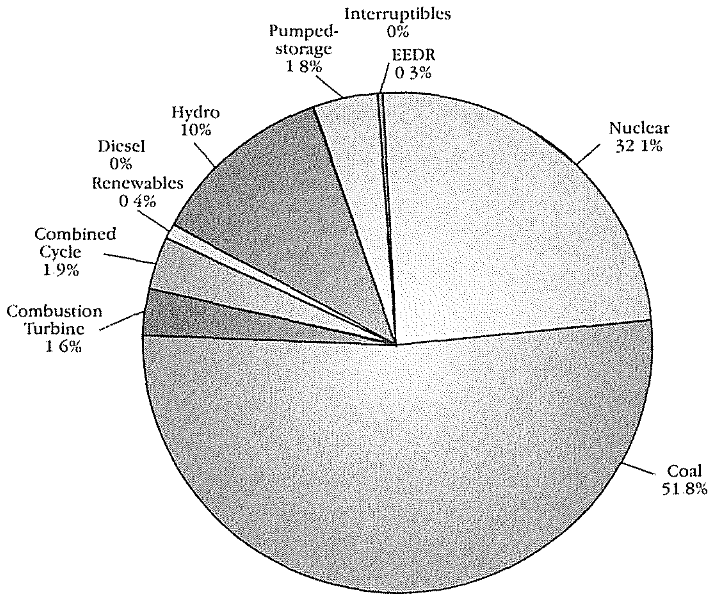


Figure 4-7 – Reference Case: Spring 2010 – Energy (GWh)

In 2010, approximately 56 percent of TVA's electricity was produced from coal-fired and natural gas-fired plants. Nuclear plants produced about 32 percent and hydroelectric plants produced approximately 12 percent. Other generation came from renewable and avoided generation sources such as EEDR.

Figure 4-8 illustrates the changing composition of existing generating resources that are assumed in planning or currently anticipated to be operated through 2029. Figure 4-8 includes only those resources that currently exist or are under contract, such as PPAs and EEDR programs, and changes to existing resources that are planned and approved, such as projects approved by TVA Board of Directors.

The total capacity of existing resources decreases through 2029 primarily because of the potential to idle coal-fired capacity. Total capacity also decreases as PPAs expire and are not extended or replaced. The renewable energy component of the existing portfolio is primarily composed of wind PPAs, which are discussed in the associated EIS. The current EEDR programs are 0.8 percent of the capacity and are also explained in further detail in associated EIS. All IRP strategies included additional renewable resources and EEDR programs beyond those depicted in Figure 4-8, as described in Chapter 7 – Draft Study Results.

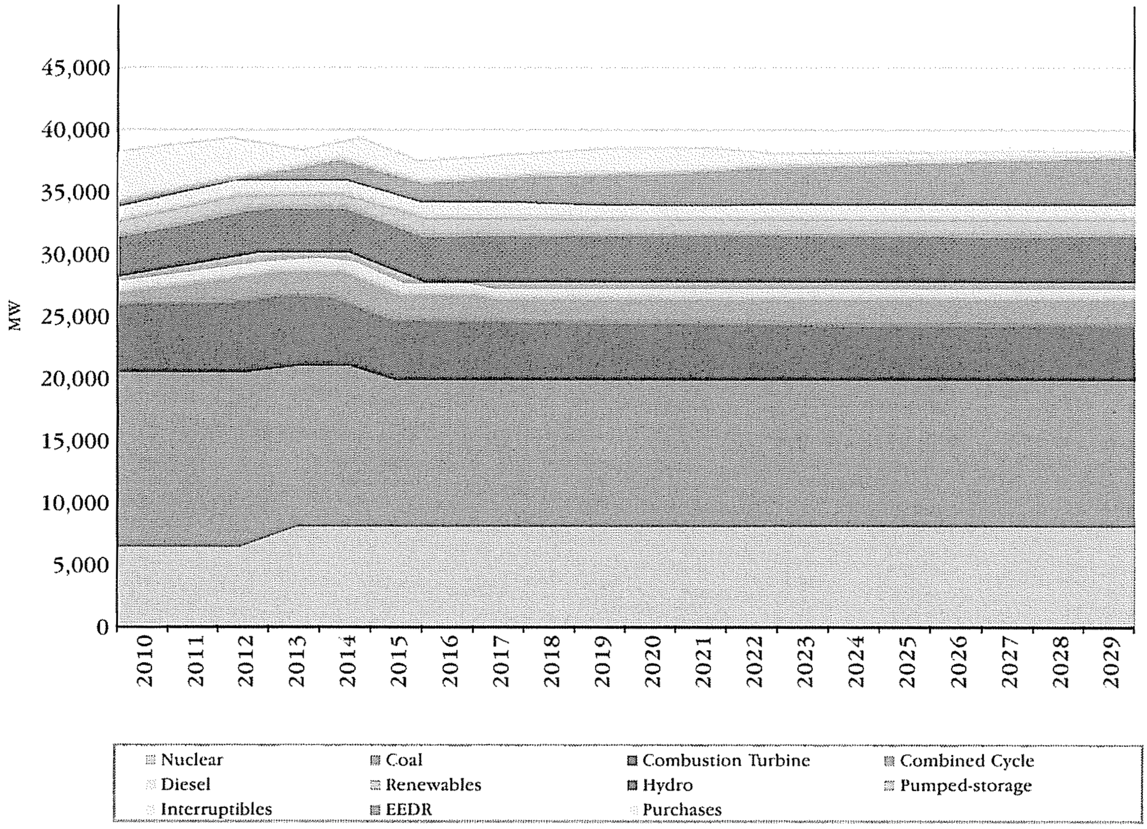


Figure 4-8 – Existing Firm Supply (MW)

The variety of resource types and the different ways they can be used provides TVA with a diverse portfolio of coal, nuclear, hydroelectric, natural gas and oil, market purchases and renewable resources. Used together, they are designed to provide reliable, low-cost power, while minimizing the risk of disproportionate reliance on any one type of resource.

4.4 Estimate the Capacity Gap

The need for power can be expressed by either the capacity or energy gap. Capacity gap is the difference, specified in MW, between the existing firm supply (Figure 4-8) and the expected firm requirements, which are the load forecasts (Figure 4-3) adjusted for any interruptible customer loads plus reserve requirements. In other words, the capacity gap is the difference between total supply and total net demand. This chapter's key reference illustrates the supply, demand and resulting capacity gap.

Energy gap is the amount of energy, specified in GWh, provided by existing resources and the new resources added in the reference case minus the energy required to meet net system requirements. Net system requirement is the required energy needed to serve the load over the entire year. It includes the energy consumed by the end-users plus distribution and transmission losses.

Figure 4-9 shows the resulting capacity gaps based on the spring 2010 peak load forecast as represented in the IRP Reference Case: Spring 2010 scenario, as well as the range corresponding to the highest and lowest capacity gap scenarios.

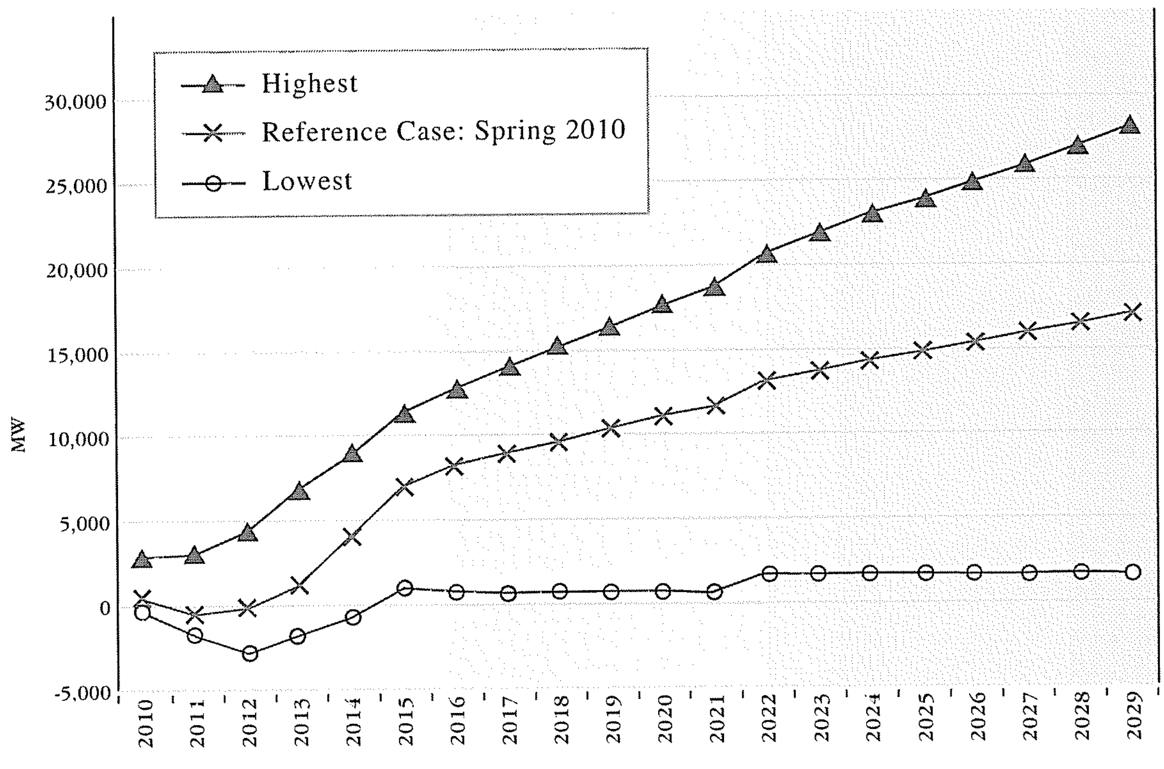


Figure 4-9 – Capacity Gap (MW)

Figure 4-10 shows the same comparison for the energy gaps.

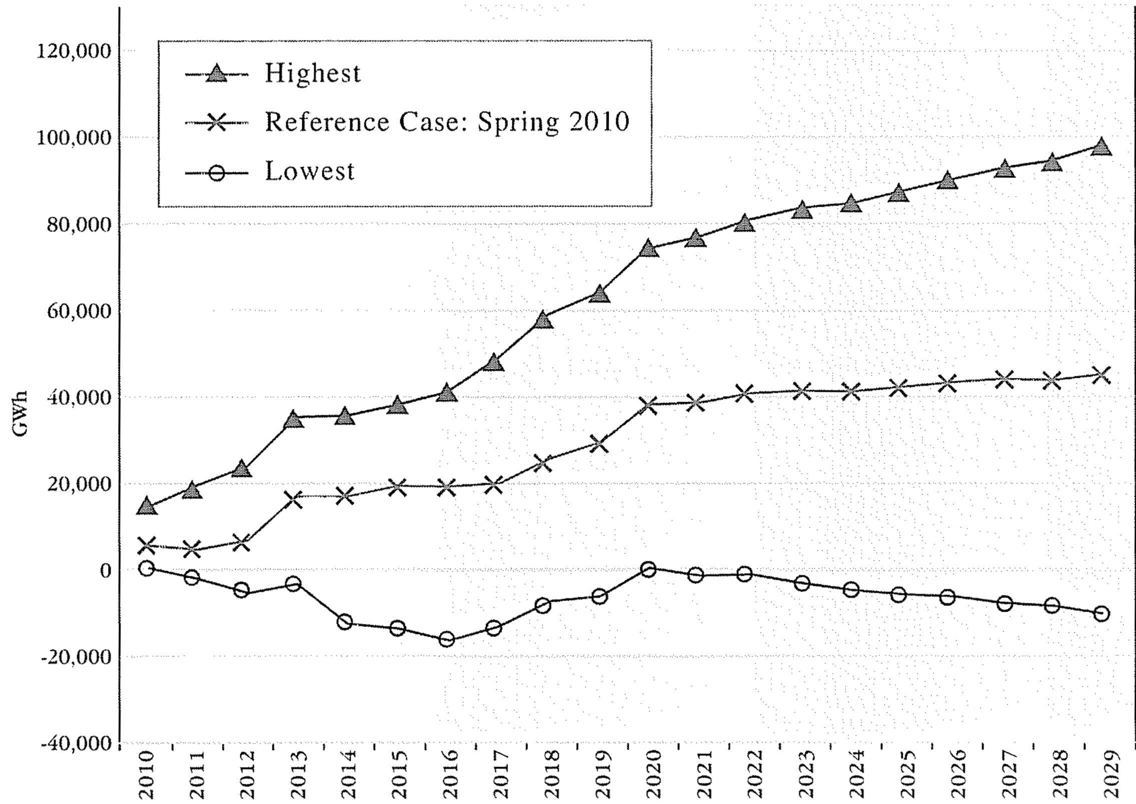
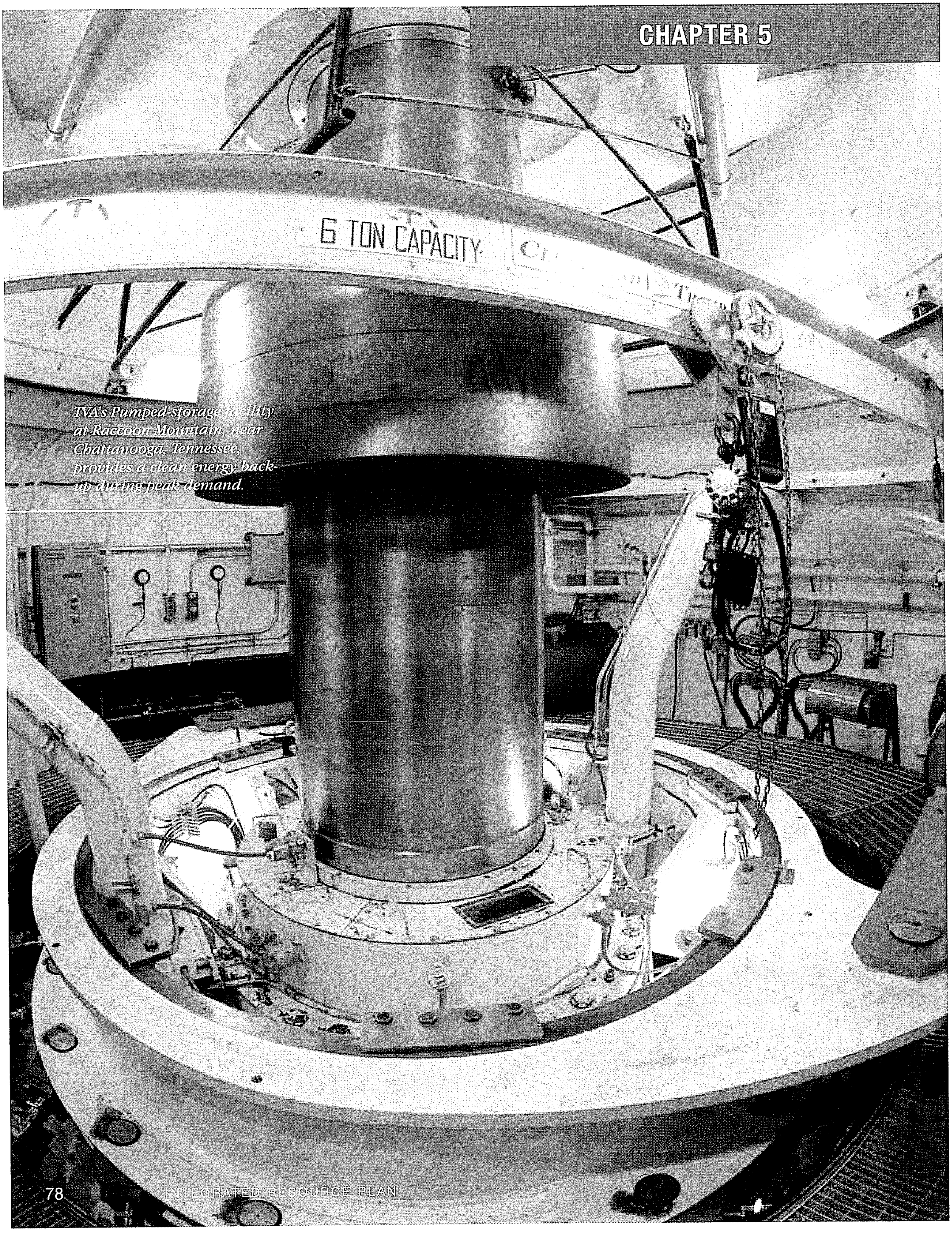


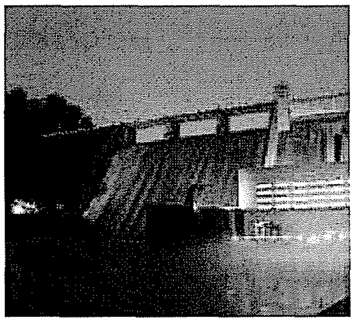
Figure 4-10 – Energy Gap (GWh)

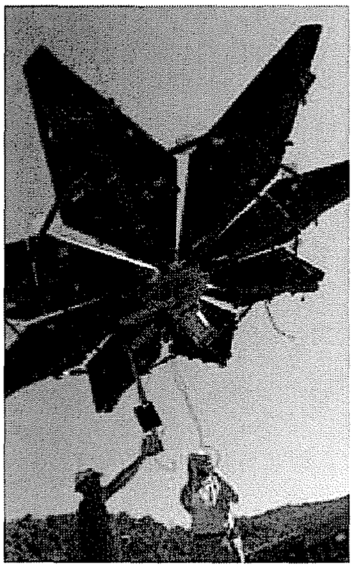
In most scenarios and years, TVA requires additional capacity and energy of 9,600 MW and 29,000 GWh in 2019, increasing to 15,500 MW and 45,000 GWh by 2029. The alternative strategies considered by TVA to meet this gap are detailed in Chapter 7 – Draft Study Results – with the Recommended Planning Direction described in Chapter 8 – Final Study Results and Recommended Planning Direction.

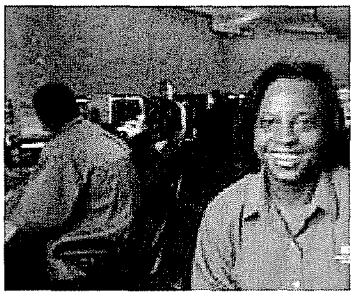


TVA's Pumped-storage facility at Raccoon Mountain, near Chattanooga, Tennessee, provides a clean energy back-up during peak demand.

Energy Resource Options

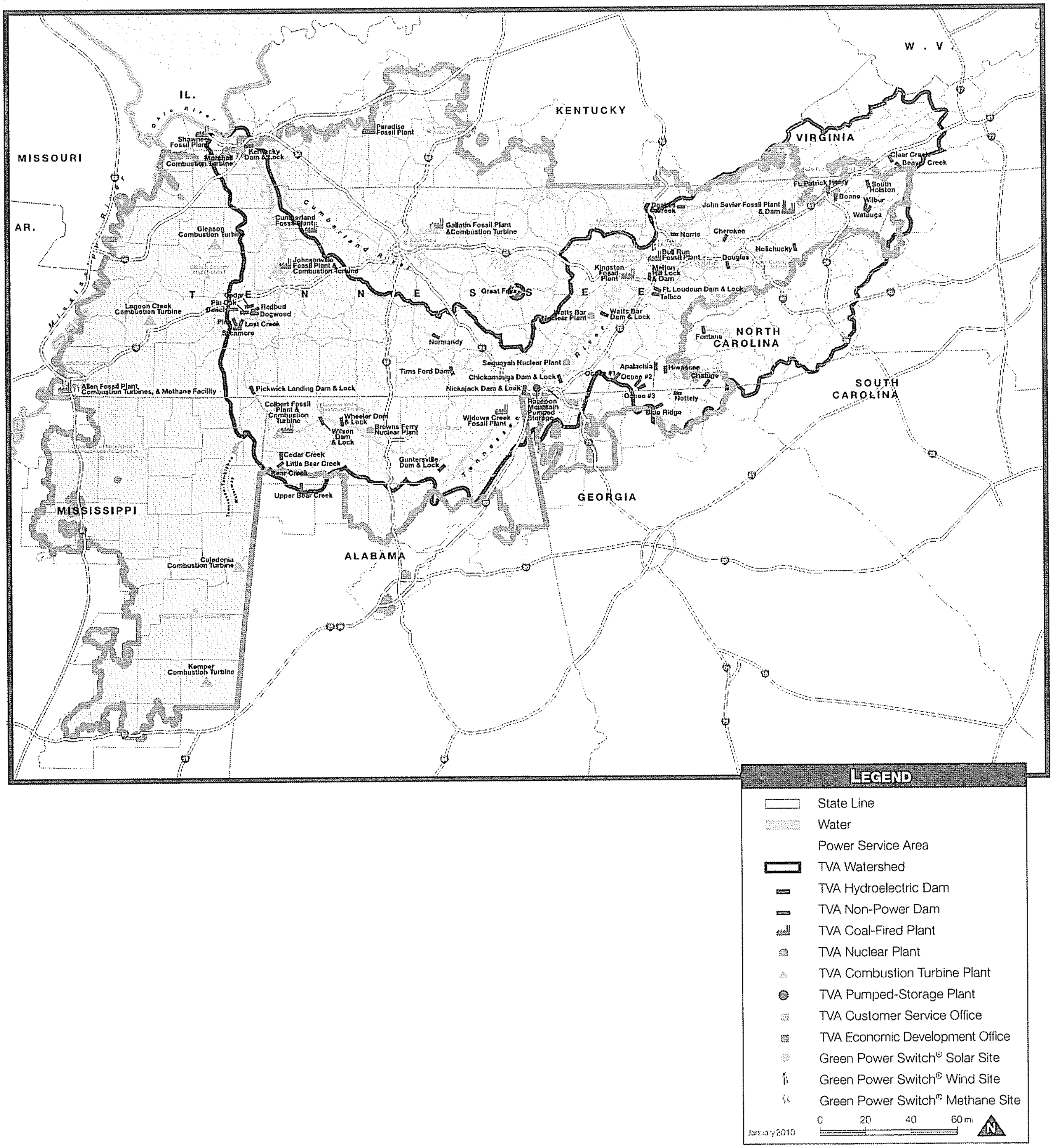






TVA utilizes a wide variety of assets to meet the energy needs for the people living in the Tennessee Valley.

TVA Regional Assets Map



5 Energy Resource Options

Maintaining the diversity of TVA's energy resource options is fundamental to the ability of providing low-cost, reliable power. In order to fill the forecasted capacity gap defined in Chapter 4 – Need for Power Analysis, TVA considered the addition of a wide range of supply-side generating resources as well as energy efficiency and other demand-side resource options.

TVA's future portfolio of generating assets consists of various fuel sources and diverse technologies that support varying power demand and the other services required for reliable operation of the power system. TVA's resource portfolio also includes power purchases through both short- and long-term contracts, as well as increasing the use of renewable resources and demand-side options (i.e., EEDR programs).

5.1 Selection Criteria

During the scoping process, TVA identified a broad range of resource options. The criteria, listed in Sections 5.1.1 and 5.1.2, were applied to these options to narrow down and establish a more manageable portfolio. A complete list of resource options considered is in the associated EIS.

5.1.1 Criteria for Considering Resource Options

The following criteria were applied to determine what resource options should be considered as viable for the IRP analysis:

- The resource option must utilize a developed and proven technology, or one that has reasonable prospect of becoming commercially available before 2029
- The resource option must be available to TVA, either within the TVA region or importable through market purchases
- The resource option must be economical and contribute to the reduction of air pollutants, including greenhouse gases, from the TVA power supply portfolio in alignment with overall TVA objectives

5.1.2 Criteria for Not Considering Resource Options

The following criteria were applied to determine what resource options should not be considered for further analysis in this IRP:

- The technology is still in very early stages in terms of maturity, in the research phase or under development and not widely available during the IRP planning period
- The resource option was previously considered by TVA and found to be uneconomic or not technically feasible
- The resource option is considered part of what private developers or individuals could elect to do as part of their participation in EEDR programs or their development of renewable resource purchase options for TVA's consideration, but is not a resource option TVA would implement on its own

5.2 Options Included in IRP Evaluation

Resource options that TVA considered in the IRP evaluation included existing assets in TVA's current generation portfolio from TVA-owned facilities and power purchases. Options for new generation also included TVA-owned assets and power purchases as well as repowering of current assets. The primary resource options are nuclear, fossil and renewable generation, energy storage and EEDR. A comprehensive description of all resource options, components, characteristics and technologies is included in the associated EIS.

5.2.1 Nuclear Generation

Nuclear – Existing Generation

The capacity of TVA's existing nuclear units is approximately 6,900 MW, which includes three reactors at Browns Ferry Nuclear Plant, two reactors at Sequoyah Nuclear Plant and one at Watts Bar Nuclear Plant. On Aug. 1, 2007, the TVA Board of Directors approved the completion of the 1,150 MW Unit 2 reactor at the Watts Bar Nuclear Plant. This project is included as a current resource in TVA's generating portfolio and is scheduled for completion in 2013.

Nuclear – New Generation

TVA included Bellefonte Units 1 and 2 at the Bellefonte brownfield site as options in this IRP. In addition to the Bellefonte units, non-site specific options based on the Advanced Passive 1000 reactor design were also considered.

5.2.2 Fossil-Fueled Generation

Coal

Coal – Existing Generation

TVA currently operates 11 coal-fired power plants consisting of 56 active coal-fired generating units and three idled units with a total capacity of 14,500 MW. While some strategies assumed the continued operation of all the remaining coal-fired assets, others assumed placing varying amounts of coal-fired generating capacity into long-term idle status. Three of TVA's coal-fired units were idled in fall 2010. The goal of long-term idling is to preserve the asset, so that with modifications and environmental additions it could be reintroduced into TVA's generating portfolio in the future if power system conditions warrant.

In addition to its owned coal-fired assets, TVA also has access to the output from a coal-fired power plant (of approximately 430 MW) through a long-term PPA.

Coal – New Generation

TVA included supercritical pulverized coal (SCPC) plants with carbon capture and sequestration (CCS) technology as well as integrated gasification combined cycle (IGCC) plants with CCS technology as resource options in the IRP evaluation.

Natural Gas

Natural Gas – Existing Generation

TVA has 87 combustion turbines (CT) at nine power plants, with a combined generating capacity of approximately 6,000 MW. In addition, TVA has the capacity to generate up to 890 MW from its distributor partnership with the Southaven Combined Cycle (CC) Plant and 540 MW at the Lagoon Creek CC Plant, which came online in summer 2010. TVA is also in the process of completing the construction of an 880 MW combined cycle plant at John Sevier that is expected to be operational in 2012.

Power purchases from natural gas-fired units owned by independent power producers are also part of the current resource portfolio. TVA is currently a party to a long-term lease of a 900 MW CC plant and has PPAs of more than 1,000 MW related to natural gas-fired combined cycle plants.

Natural Gas – New Generation

The IRP evaluation includes both combustion turbine and combined cycle natural gas fueled options. Resource options evaluated in this IRP included procurement of power from existing merchant combined cycle plants along with self-built TVA or customer-owned combined cycle plants of up to 1,730 MW without specific site locations. The refurbishment of the natural gas-fired Gleason plant, consisting of three natural gas-fired combustion turbines, was evaluated as a resource option in this IRP, which increases the available capacity from 360 to 530 MW.

Petroleum Fuels

Petroleum Fuels – Existing Generation

Currently, TVA contracts for a number of diesel fuel generated power purchases, totaling 120 MW.

Petroleum Fuels – New Generation

Petroleum power purchases are expected to be phased out by 2029. There are no diesel fuels or other petroleum based resource options as a primary fuel source under consideration in this IRP because of emissions from these facilities.

5.2.3 Renewable Generation

TVA defines renewable energy as energy production that is sustainable and often naturally replenished (e.g., solar, wind, methane, biomass, geothermal and hydro). TVA presently provides renewable energy from TVA facilities and from energy acquired by PPAs. For purposes of the IRP analysis, planning strategies were developed to test a broad range of renewable additions. Therefore, renewable additions incorporated into this IRP were scheduled based on two given renewable portfolio amounts–2,500 MW and 3,500 MW. These targets are beyond TVA's current renewable resource plan (represented as the 1,500 MW portfolio), but would be in addition to TVA's existing clean energy generation sources, which include existing hydro and nuclear. As described below, renewable energy from these resources is also considered in this IRP. Additional detail can be found in Appendix D – Development of Renewable Energy Portfolios.

Conventional Hydroelectric

Hydroelectric – Existing Generation

TVA operates 109 conventional hydroelectric generating facilities at 29 of its dams. These facilities have the capacity to generate 3,538 MW of electricity. TVA is also systematically updating aging turbines and other equipment in its hydro plants.

Hydroelectric – New Generation

TVA included additional as-yet-unapproved modernization projects (a total of 90 MW by 2029) as a resource option for its IRP evaluation as well as up to 144 MW of small hydro by 2029. TVA also included small- and low-head hydropower as an IRP resource option.

Energy Storage

Energy Storage – Existing Generation

TVA operates one large energy storage facility, the 1,615 MW Raccoon Mountain Pumped-Storage Plant, which provides critical flexibility to the TVA system by storing power at off-peak times for use when demand is high.

Energy Storage – New Generation

An additional pumped-storage resource option of 850 MW was included in all cases going forward. In addition, a compressed air energy storage (CAES) option is evaluated in this IRP. TVA did not evaluate any electric battery storage options because of operational limitations.

Wind

Wind – Existing Facilities

TVA currently purchases the output from the Southeast's largest wind farm, consisting of 15 turbines on Buffalo Mountain near Oak Ridge, Tenn. In addition, TVA owns an additional three turbines at that location.

TVA has also entered into contracts with other third-party developers for the long-term purchase of wind power. Requests for proposals were issued in December 2008 for additional wind power. By the end of 2010, TVA had contracted to receive power from approximately 1,600 MW of wind power. Iberdrola Renewables began supplying 300 MW from the Streator Cayuga Ridge Wind Farm in Livingston County, Ill. Additional wind power agreements exist with Horizon Wind Energy LLC (115 MW which started in fall 2010), CPV Renewable Energy Company (365 MW starting 2012) and Invenergy LLC (600 MW starting in 2012). All contracts are contingent on meeting applicable environmental requirements and obtaining firm transmission paths to TVA.

All wind contracts selected were competitive with forecasted market electricity prices at the time those contracts were evaluated. In December 2008, when TVA issued the request for proposals, no economically feasible in-Valley proposals were received.

Wind – New Generation

TVA cannot take direct advantage of the current investment incentives offered to wind power developers. These incentives help make wind power more economically competitive with other generation resources. As such, the option of constructing its own wind power facilities in the TVA region was not included. Instead, TVA has taken the approach of procuring wind power resources through PPAs and included this as a resource option in this IRP. The procurement of wind resources, whether in or imported to the TVA region, through a *request for proposal* process ensures lower costs to TVA customers. This approach could change to a self-build option in the future if investment incentives and/or future federal or state renewable mandates change.

Solar

Solar – Existing Generation

TVA owns 14 photovoltaic (PV) installations with a combined capacity of about 280 kW of capacity. TVA also purchases power from PV installations through TVA's Generation Partners℠ program.

Solar – New Generation

For reasons similar to new wind generation, TVA cannot take advantage of the current investment incentives offered to solar power developers that help make solar power more economically competitive with other resource options. As a result, TVA has taken the approach of procuring solar power resources through PPAs and included it as a resource option in this IRP. This approach could change to a self-build option in the future if investment incentives and/or federal or state renewable mandates change.

Biomass

Biomass – Existing Generation

TVA generates electricity by co-firing methane from a nearby sewage treatment plant at Allen Fossil Plant and by co-firing wood waste at Colbert Fossil Plant. In addition, TVA currently purchases about 91 MW of biomass-fueled generation. These purchases include 9.6 MW of landfill gas generation, 70 MW of wood waste generation and 11 MW of corn milling residue generation.

Biomass – New Generation

TVA included up to 490 MW of biomass generation and landfill gas generation as resource options to be evaluated in this IRP. Most of this biomass is generated through PPAs, while some of it is not. TVA also included the conversion of existing coal-fired units to biomass-fired units and co-firing biomass with coal at existing coal-fired units as IRP resource options to be evaluated. TVA is currently performing biomass fuel availability surveys in the region, and a comprehensive study is underway to assess the feasibility of converting one or more coal-fired units to biomass fuel.

5.2.4 Energy Efficiency and Demand Response

EEDR – Existing Program

TVA has an existing portfolio of programs focused on EEDR. As currently implemented, TVA's EEDR portfolio focuses on reduction in peak demand and has an avoided peak capacity in excess of 300 MW, as of FY10.

EEDR – New Program

This IRP reflects TVA's increased focus on EEDR. These reductions are in addition to energy savings from laws, policies and independent programs of distributors of TVA power. The IRP reference strategy includes an EEDR program that reduces required energy and capacity needs by approximately 14,000 GWh and 4,700 MW, respectively, by 2029.

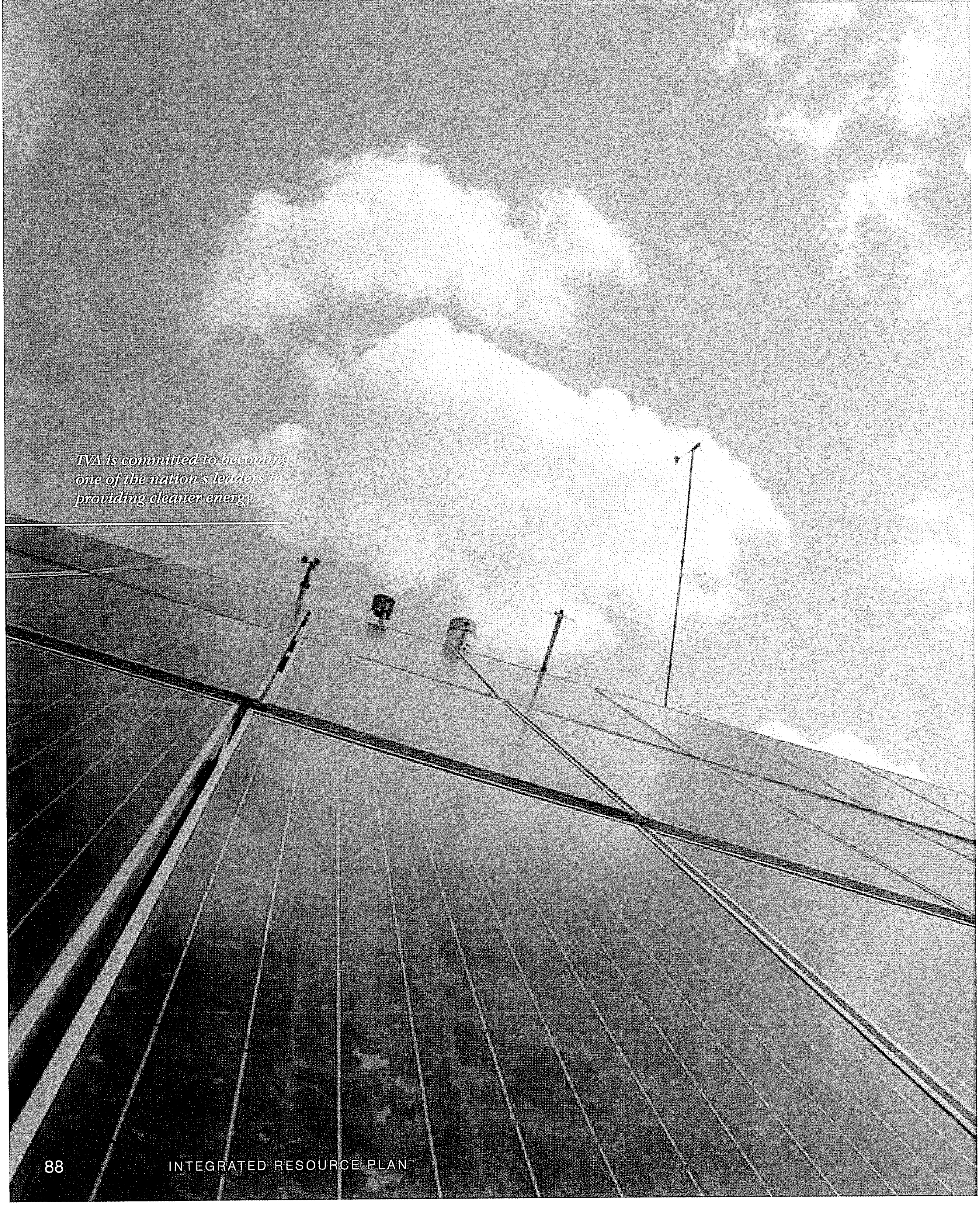
A list of proposed EEDR programs for TVA implementation is listed in the associated EIS.

5.2.5 Power Purchases

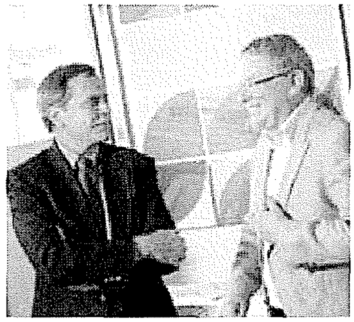
Power purchases refer to the procurement of energy and/or capacity from other suppliers for use on the TVA system in lieu of TVA constructing and operating its own resources. Power purchases provide additional diversity for TVA's portfolio. TVA is currently a party to numerous short- and long-term PPAs. PPA options are included in the IRP evaluation. For all PPAs, it is assumed that the supplier will either interconnect with TVA transmission or obtain a transmission path to TVA if outside the TVA region.

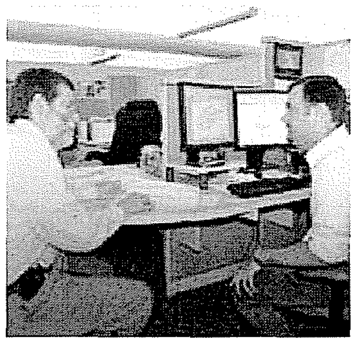
5.2.6 Repowering Resources

Repowering electrical generating plants is the process by which utilities update and change the fuel source or technology of existing plants to realize gains in efficiency or output that was not possible at the time the plant was constructed. TVA has included approved repowering projects in its forecast for existing resources and included other as-yet-unapproved repowering options in the IRP evaluation.



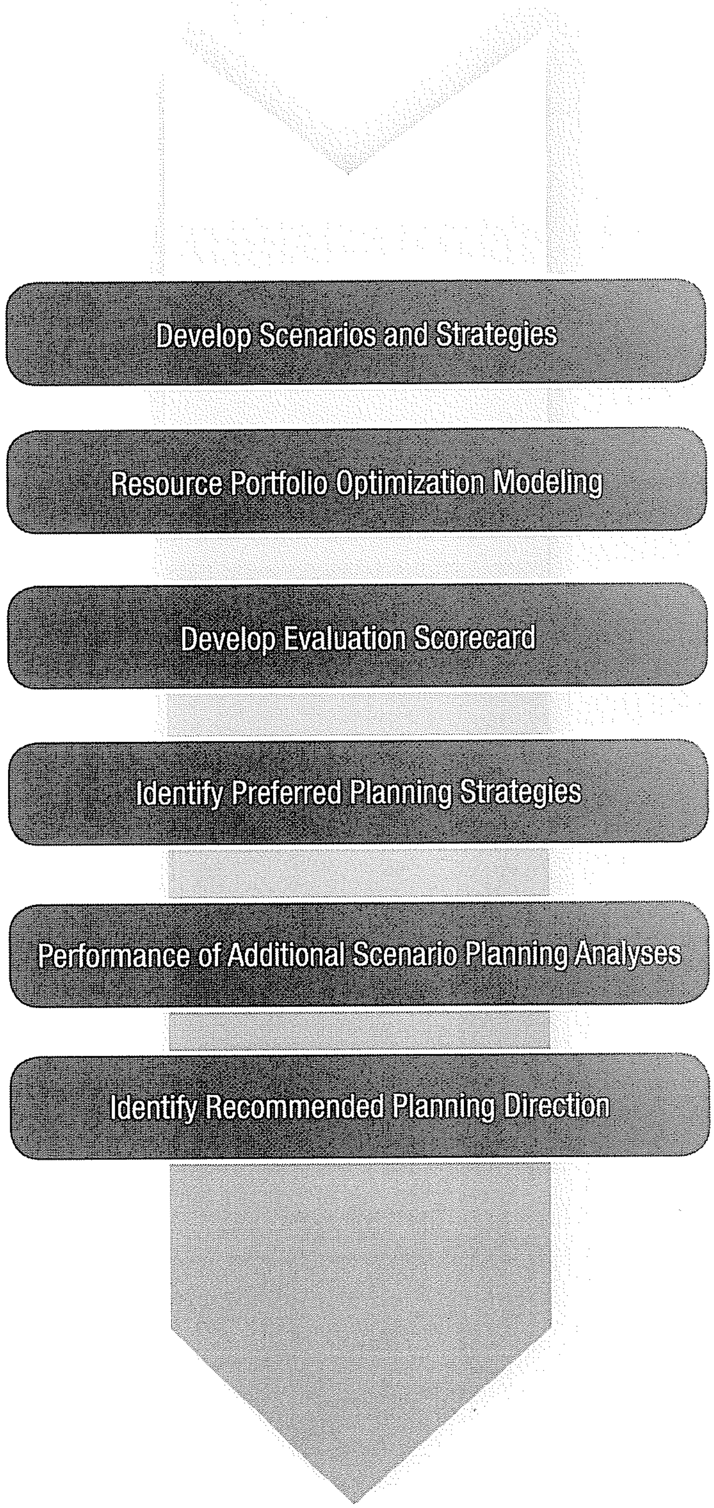
TVA is committed to becoming one of the nation's leaders in providing cleaner energy.





TVA's Integrated Resource Plan is a synthesis of public input and strategic planning and professional analysis.

Process for Identifying the Recommended Planning Direction



6 Resource Plan Development and Analysis

TVA employed a scenario planning approach in the development of the Draft and the final IRP. This approach is commonly used in the utility industry. The goal of this approach was to develop a "no-regrets" strategy that was relatively insensitive to uncertainty. In other words, once strategic decisions were made, the strategy would perform well regardless of how the future unfolds. The processes used in the scenario planning approach, including evaluation methods and strategy selection, are outlined in this chapter.

This chapter describes the following six steps of the Draft IRP process:

1. Development of the scenarios and strategies used to conduct the scenario planning analysis
2. Resource portfolios optimization modeling
3. Development of scenario planning scorecards to measure the performance of the portfolios and strategies developed in the scenario planning analysis
4. Identification of preferred planning strategies for publication in the Draft IRP
5. Incorporation of public input and performance of additional scenario planning analyses
6. Identification of the Recommended Planning Direction

6.1 Development of Scenarios and Strategies

Scenario planning is useful for determining how various business decisions will perform in an uncertain future. Multiple strategies, which represented business decisions that TVA can control, were modeled against multiple scenarios, which represented uncertain futures that TVA cannot control. The intersection of a single strategy and a single scenario resulted in a resource portfolio.[1] A portfolio is a 20-year capacity expansion plan that is unique to that strategy and scenario combination.

Modeling multiple strategies within multiple scenarios resulted in a large number of portfolios. Proper analysis of these portfolios was a challenge. Accordingly, during early stages of the analysis, it was more important to observe trends or common characteristics that strategies exhibited over multiple scenarios rather than focusing on specific outcomes in individual portfolios. If a strategy behaved in a similar manner in most scenarios, the modelers could be confident of its robustness. Characteristics of robustness included increased flexibility, less risk over the long term and the ability to mitigate the impacts of

[1]Portfolios are also referred to as capacity expansion plans or resource portfolios

uncertainty. Conversely, a strategy that behaved differently or poorly in each scenario that it was modeled within was considered more risky and indicated a higher probability for disappointment and future regret.

6.1.1 Development of Scenarios

Most quantitative models focus on what is statistically likely based on history, market data and projected future patterns. The scenarios developed for the planning approach operated differently by utilizing assumptions that the future evolves along paths not suggested by history. They were not assigned a probability that one particular future is more likely to occur than another. Using this approach, scenarios identified and framed plausible futures that were studied in the development of the long-range resource plan.

The following three-step process was used to develop scenarios used in this IRP:

1. Identification of key uncertainties
2. Development of scenarios
3. Determination of scenario uncertainty values

Scenarios represent future conditions that TVA cannot control but must adapt to.

Identification of Key Uncertainties

TVA, with input from the SRG, identified uncertainties that were used as building blocks to develop scenarios for this IRP. The key uncertainties are listed in Figure 6-1.

Key Uncertainty	Description
Greenhouse gas (GHG) requirements	• Reflects level of emission reductions (CO_2 and other GHG) mandated by federal legislation plus the cost of carbon allowances
Environmental outlook	Changes in regulations addressing: • Air emissions (exclusive of GHG) • Land • Water • Waste
Energy efficiency and RES	• Reflects mandates for minimum generation from renewables and the viability of renewable generation sources • It includes the percentage of the RES standard that can be met with energy efficiency
Total load	• Reflects variance of actual load to what is forecast • Accounts for benefits of EEDR penetration
Capital expansion viability & costs	For nuclear, fossil, other generation and transmission, includes risks associated with: • Licensing • Permitting • Project schedule
Financing	• Financial cost (interest rate) of securing capital
Commodity prices	• *Includes natural gas, coal, oil, uranium and spot price of electricity*
Contract purchase power cost	• Reflects demand cost, availability of power and transmission constraints
Change in load shape	Includes effects of factors such as: • Time-of-use rates • Plug-in Hybrid Electric Vehicles (transportation) • Distributed generation • Economics changing customer base • Energy storage • Energy efficiency • Smart grid / demand response
Construction cost escalation	Includes the following for nuclear, fossil and other generation: • Commodity cost escalation • Labor and equipment cost escalation

Figure 6-1 – Key Uncertainties

Development of Scenarios

Scenarios were constructed by utilizing various combinations of the key uncertainties in Figure 6-1. They were then further refined to ensure that the following characteristics for each scenario:

- Represented a plausible, meaningful future "world" (e.g., uncertainties related to cost, regulation and environment)
- Were unique among the scenarios being considered for study
- Reflected a future that TVA could find itself in during the timeframe studied in this IRP

- Placed sufficient stress on the resource selection process
- Provided a foundation for analyzing the robustness, flexibility and adaptability of each combination of various supply- and demand-side options
- Captured relevant key stakeholder interests

A summary of the scenarios selected for the IRP analysis is shown in Figure 6-2. During the scoping phase in summer 2009, Scenarios 1 through 6 were developed for use in the Draft IRP analysis. Scenario 7 was also developed as a reference case in the Draft IRP. It closely resembled TVA's long-term planning outlook at the time the original scenarios were developed. Another reference case, Scenario 8 was added after the publication of the Draft IRP. It captured the impacts of the recent recession and was used in subsequent analysis.

Scenario	Key Characteristics
1 Economy Recovers Dramatically	• Economy recovers stronger than expected and creates high demand for electricity • Carbon legislation and renewable electricity standards are passed • Demand for commodity and construction resources increases • Electricity prices are moderated by increased gas supply
2 Environmental Focus is a National Priority	• Mitigation of climate change effects and development of a "green economy" is a priority • The cost of CO_2 allowances, gas and electricity increase significantly • Industry focus turns to nuclear, renewables, conservation and gas to meet demand
3 Prolonged Economic Malaise	• Prolonged, stagnant economy results in low to negative load growth and delayed expansion of new generation • Federal climate change legislation is delayed due to concerns of adding further pressure to the economy
4 Game-changing Technology	• Strong economy with high demand for electricity and commodities • High price levels and concerns about the environment incentivize conservation • Game-changing technology results in an abrupt decrease in load served after strong growth
5 Energy Independence	• The U.S. focuses on reducing its dependence on non-North American fuel sources • Supply of natural gas is constrained and prices for gas and electricity rise • Energy efficiency and renewable energy move to the forefront as an objective of achieving energy independence
6 Carbon Regulation Creates Economic Downturn	• Federal climate change legislation is passed and implemented quickly • High prices for gas and CO_2 allowances increase electricity prices significantly • U.S. based energy-intensive industry is non-competitive in global markets and leads to an economic downturn
7 Reference Case: Spring 2010	• Economic growth lower than historical averages • Carbon legislation is passed and implemented by 2013 • Natural gas and electricity prices are moderate
8 Reference Case: Great Recession Impacts Recovery	• Economic outlook includes economic recovery, but growth is at a slightly lower rate than Scenario 7 due to lingering recession impacts • Natural gas prices are lower to reflect recent market trends

Figure 6-2 – Scenarios Key Characteristics

Determination of Scenario Uncertainty Values

Once each of the key uncertainties were defined, specific numerical values for each aspect of the scenarios were developed utilizing the following assumptions:

- Climate change uncertainty will be based upon stringency of requirements and timeline required for compliance and cost of CO_2 allowances
- An aggressive EPA regulatory schedule is expected to create additional compliance requirements (e.g., Hazardous Air Pollutants Maximum Achievable Control Technology [HAPs MACT], revised ambient air standards, etc.)
- Command and control regulations for HAPs MACT will likely drive plant-by-plant compliance
- RES will help accomplish GHG reduction required at the federal level
- The spot price of electricity will be correlated with the price of natural gas and coal
- Demand, primarily driven by economic conditions, will be affected by energy efficiency, demand response and other factors
- Schedule risk will be related to demand as well as the uncertainty of permitting and licensing generation and transmission projects
- Economic conditions and associated inflationary pressures will become the primary drivers for changes in financing costs
- Construction costs will be driven by demand as well as availability of labor, equipment, design and raw materials
- Economic conditions will become the primary driver, but the legislative/regulatory environment will apply additional pressure by introducing uncertainty related to potential schedule impacts
- Cost and availability of contract power purchases will be primarily driven by economic conditions and local area demand (i.e., load growth)

A detailed description of each scenario's uncertainty values is shown in Figure 6-3.

Uncertainty	Scenario 1 Economy Recovers Dramatically	Scenario 2 Environmental Focus is a National Priority	Scenario 3 Prolonged Economic Malaise	Scenario 4 Game-Changing Technology	Scenario 5 Energy Independence	Scenario 6 Carbon Legislation Creates Economic Downturn	Scenario 7 Reference Case: Spring 2010	Scenario 8 Reference Case: Great Recession Impacts Recovery
GHG requirements	CO_2 price \$27/ ton (\$30/metric ton) in 2014 and \$82 (\$90/metric ton) by 2030 77% allowance allocation, 41% by 2030	CO_2 price \$17/ ton (\$19/metric ton) in 2012 and \$94 (\$104/metric ton) by 2030 77% allowance allocation, 28% by 2030	No federal requirement (CO_2 price = \$0/ton)	CO_2 price \$18/ ton (\$20/metric ton) in 2013 and \$45 (\$50/metric ton) by 2030 77% allowance allocation, 41% by 2030	CO_2 price \$18/ ton (\$20/metric ton) in 2013 and \$45 (\$50/metric ton) by 2030 77% allowance allocation. 41% by 2030	CO_2 price \$17/ ton (\$19/metric ton) in 2012 and \$94 (\$104/metric ton) by 2030 77% allowance allocation, 28% by 2030	CO_2 price \$15/ ton (\$17/metric ton) in 2013 and \$56 (\$62/metric ton) by 2030 77% allowance allocation, 39% by 2030	Same as Scenario 7
Environmental outlook	Same as Scenario 7	SO_2 controls 2017 NO_X controls Dec 2016 *Hg MACT 2014* HAP MACT 2015	No additional requirements (CAIR requirements, with *no MACT requirements*)	Same as Scenario 7	Same as Scenario 7	Same as Scenario 7	SCR all units by 2017 FGD all units by 2018 HAPs MACT by 2015	Same as Scenario 7
Energy efficiency and RES	RES – 3% by 2012, 20% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	RES – 5% by 2012, 30% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	No federal requirement	RES – 5% by 2012, 20% by 2021 (adjusted total retail sales) EE can meet up to 40% or requirement	RES – 5% by 2012, 20% by 2021 (adjusted total retail sales) EE can meet up to 40% or requirement	RES – 5% by 2012, 30% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	RES – 3% by 2012, 15% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	Same as Scenario 7
Total load	Med grow to High by 2015; High Dist; Alcoa Returns in 2010+; USEC stays forever; Dept Dist same as Scenario 7	Medium case, then 2012 40% rate increase; Low Dist; DS customer reductions (steel/ paper plants); USEC stays forever; Dept Dist same as Scenario 7	Low load case; Low Dist; Alcoa not returning, No HSC & Wacker, USEC leaves June 2013; Dept Disc same as Scenario 7	Med-High load growth through 2020 then 20% decrease 2021-2022 including USEC departure, reduced dist sales & extended TOU	Medium case, then 20% rate increase in 2014; unrestricted PHEV Included; TOU	Medium load case 2010-2011; 2012 low case then flat w/no growth; USEC leaves 2013, Alcoa not returning, HSC & Wacker not in; TOU	Moderate growth	Moderate to low growth
Capital expansion viability & costs	Moderate schedule risk	High schedule risk	Low schedule risk	Moderate schedule risk	Moderate schedule risk	Low schedule risk	Moderate schedule risk	Moderate schedule risk
Financing	Higher than Scenario 7 – higher inflation due to higher economic growth	*Higher than* Scenario 7 – higher inflation due to looser monetary policy supporting economic growth	Lower than Scenario 7 – lower inflation due to lower economic growth	Same as Scenario 7 – increased productivity due to technology leads to stronger economic wealth and non-inflationary money growth	Higher than Scenario 7 – higher inflation due to looser monetary policy supporting economic growth	Lower than Scenario 7 – lower inflation due to lower economic growth	Based on current borrowing rate	Based on current borrowing rate
Commodity prices	Gas & coal higher than Scenario 7	Gas higher; coal lower than Scenario 7	Gas much lower & coal much higher than Scenario 7	Gas lower & coal slightly higher than Scenario 7	Gas & coal higher than Scenario 7	Gas & coal much lower than Scenario 7	Gas - \$6-8/mmBTU Coal - \$40/ton	Gas - \$5-7/mmBTU Coal - \$40/ton
Contract purchase power cost	Much higher cost & lower *availability*	Higher cost & lower availability	Same as Scenario 7, then much lower cost with high availability	Higher cost & lower availability, then much lower cost with high availability after load decrease	Higher cost & lower availability	Lower cost with high availability	Moderate cost & availability	Moderate cost & availability
Construction cost escalation	Much higher than Scenario 7 – high economic growth causes high demand for new plants and high escalation rate	Somewhat higher than Scenario 7 – due to "construction costs escalating *at high rate* due to large volume of nuclear, renewables and env controls projects" High regulatory scrutiny adds to project costs	*Lower than* Scenario 7 – low load growth leads to low escalation	This scenario has two stages of escalation: 1) higher than Scenario 7 due to high load growth early, then 2) lower escalation when game-changing technology hits	Somewhat higher than Scenario 7 – moderately strong economy and load growth leads to somewhat higher than base escalation	Lower than Scenario 7 – negative load growth, very weak economy and high renewables lead to low escalation	Moderate escalation	Moderate escalation

Figure 6-3 – Scenario Descriptions

6.1.2 Development of Planning Strategies

After development of the scenarios, planning strategies were designed to test the various business decisions and portfolio choices that TVA has control over and might consider. Strategies are very different from the scenarios. Whereas, scenarios describe plausible futures and include factors that TVA cannot control, strategies describe business decisions over which TVA has full control. In the end, a well-designed strategy would perform well in many possible scenarios whereas a poorly designed strategy would frequently not perform well.

The following three-step process was used to design the strategies in this IRP:

1. Identification of key components
2. Development of strategies using key components
3. Definition of strategy

Planning strategies represent decisions and choices over which TVA has full control.

Identification of Key Components

To define the planning strategies, nine distinct categories of components were identified. The choice of components was influenced by comments received during the public scoping period and input from the SRG. Comments stated that TVA should challenge its targets for EEDR and renewables beyond the current portfolios. Accordingly, the ranges for both components were significantly expanded. The components for the planning strategies are described in Figure 6-4.

Component	Description	Type
EEDR portfolio	The level of EEDR included in each strategy	Defined Model Input
Renewable additions	The amount of renewable resources added in each strategy	Defined Model Input
Coal-fired capacity idling	A proposed schedule of coal-fired unit idling that will be tested in each strategy	Defined Model Input
Energy storage	Option to include a pumped-storage unit in selected strategies	Defined Model Input
Nuclear	Constraints related to the addition of new nuclear capacity	Constraint
Coal	Limitations on technology and timing for new coal-fired plants	Constraint
Gas-fired supply (self-build)	Limitations on gas-fired unit expansion	Constraint
Market purchases	Level of market reliance allowed in each strategy	Constraint
Transmission	Type and level of transmission infrastructure required to support resource options in each strategy	Constraint

Figure 6-4 – Components of Planning Strategies

As noted in Figure 6-4, there were two types of components, used in the model.

Defined model inputs	These components were scheduled or predetermined. This applied to both the timing and the quantity of specific asset decisions
Constraints in the model optimization	These components constrained the optimization of asset choices such as minimum build times, technology limitations and other strategic constraints including limits on market purchases. The capacity optimization model selected resources that were consistent with these constraints

Development of Strategies Using Key Components

TVA combined these nine components and created five distinct planning strategies for the Draft IRP analysis. Figure 6-5 lists the five distinct planning strategies and their key characteristics.

Planning Strategy	Key Characteristics
A Limited Change in Current Resource Portfolio	• Retain and maintain existing generating fleet (no additions beyond Watts Bar Unit 2) • Rely on the market to meet future resource needs
B Baseline Plan Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Assumes idling of approximately 2,000 MW of coal-fired capacity • Includes EEDR portfolios and wind PPAs
C Diversity Focused Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Increases the contribution from EEDR portfolio and new renewables • Adds a pumped-storage unit • Assumes idling of approximately 3,000 MW of coal-fired capacity
D Nuclear Focused Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Includes an increased EEDR portfolio compared to other strategies • Assumes idling of approximately 7,000 MW of coal-fired capacity • Includes new renewables (same as Strategy C) • Includes a pumped-storage unit
E EEDR and Renewables Focused Resource Portfolio	• Assumes greatest reliance on EEDR portfolio of any strategy and includes largest new renewable portfolio • Assumes idling of approximately 5,000 MW of coal-fired capacity • Delays nuclear expansion until 2022

Figure 6-5 – Planning Strategies Key Characteristics

Definition of Strategy

Once each strategy's key characteristics were defined, specific numerical values for each component of each strategy were defined as shown in Figure 6-6.

Components	Strategy A Limited Change in Current Resource Portfolio	Strategy B Baseline Plan Resource Portfolio	Strategy C Diversity Focused Resource Portfolio	Strategy D Nuclear Focused Resource Portfolio	Strategy E EEDR and Renewable Focused Resource Portfolio
EEDR	1,940 MW & 4,725 annual GWh reductions by 2020	2,100 MW & 5,900 annual GWh reductions by 2020	3,600 MW & 11,400 annual GWh reductions by 2020	4,000 MW & 8,900 annual GWh reductions by 2020	5,100 MW & 14,400 annual GWh reductions by 2020
Renewable additions	1,300 MW & 4,600 GWh competitive renewable resources or PPAs by 2020	Same as Strategy A	2,500 MW & 8,600 GWh competitive renewable resources or PPAs by 2020	Same as Strategy C	3,500 MW & 12,000 GWh competitive renewable resources or PPAs by 2020
Idled coal-fired capacity	No fossil fleet reductions	2,400 MW total fleet reductions by 2017	3,200 MW total fleet reductions by 2017	7,000 MW total fleet reductions by 2017	4,700 MW total fleet reductions by 2017
Energy storage	No new additions	Same as Strategy A	Add on pumped-storage unit	Same as Strategy C	Same as Strategy A
Nuclear	No new additions after WBN2	First unit online no earlier than 2018 Units at least 2 years apart	Same as Strategy B	First unit online no earlier than 2018 Units at least 2 years apart	First unit online no earlier than 2022 Units at least 2 years apart Additions limited to 3 units
Coal	No new additions	New coal units are outfitted with CCS First unit online no earlier than 2025	Same as Strategy B	Same as Strategy B	No new additions
Gas-fired supply (self-build)	No new additions	Meet remaining supply needs with gas-fired units	Same as Strategy B	Same as Strategy B	Same as Strategy B
Market purchases	No limit on market purchases beyond current contracts and extensions	Purchases beyond current contracts and contract extensions limited to 900 MW	Same as Strategy B	Same as Strategy B	Same as Strategy B
Transmission	Potentially higher level of transmission investment to support market purchases Transmission expansion (if needed) may have impact on resource timing and availability	Complete upgrades to support new supply resources	Increase transmission investment to support new supply resources and ensure system reliability Pursue inter-regional projects to transmit renewable energy	Same as Strategy C	Potentially higher level of transmission investment to support renewable purchases Transmission expansion (if needed) may have impact on resource timing and availability

Defined model inputs ☐ Optimized model inputs

Figure 6-6 – Strategy Descriptions

Strategy components were utilized in the modeling in several different ways. For example, Strategy A has specific defined constraints, such as including no new coal additions and 1,300 MW of renewable resource additions. Other components specified timing, such as adding nuclear resources no earlier than 2018 and no new coal additions in Strategy B. Reactive constraints were also identified, such as the need to build additional transmission capacity if imports from renewables exceed a certain limit.

6.2 Resource Portfolios Optimization Modeling

The generation of resource portfolios was a two-step process. First, an optimized capacity expansion plan was generated, which was then followed by a financial analysis. This process was repeated for each strategy/ scenario combination and for additional sensitivity runs.

6.2.1 Development of Optimized Capacity Expansion Plan

TVA utilized a capacity optimization model, System Optimizer, which is an industry standard software model developed by Ventyx. This model utilized an optimization technique where an "objective function" (i.e., total resource plan cost) was minimized and subject to a number of constraints by using mixed integer linear programming.

Resources were selected by adding or subtracting assets based on minimizing the present value of revenue requirements (PVRR). PVRR represents the cumulative present value of total revenue requirements for the study period based on an eight percent discount rate. In other words, it is the today's value of all future costs for the study period discounted to reflect the time value of money and other factors, such as investment risk.

In addition, the following constraints were observed:

- Balance of supply and demand
- Energy balance
- Reserve margin
- Generation and transmission operating limits
- Fuel purchase and utilization limits
- Environmental stewardship

System Optimizer uses a simplified dispatch algorithm to compute production costs. The model used a "representative hours" approach in which average generation and load values in each representative period within a week were scaled up appropriately to span all hours of the week and days of the months.

Year-to-year changes in the resource mix were then evaluated and infeasible states were eliminated. The least-cost path (based on lowest PVRR) from all possible states in the study period was retained in the Draft IRP as the optimized capacity expansion plan.

6.2.2 Evaluation of Detailed Financial Analysis

Next, each capacity expansion plan was evaluated using an hourly production costing algorithm, which calculated detailed production costs of each plan, including fuel and other variable operating costs. These detailed cost simulations provided total strategy costs and financial metrics that were used for evaluation of the results.

This analysis was accomplished using another Ventyx product called Strategic Planning (MIDAS). This software tool uses a chronological production costing algorithm with financial planning data used to assess plan cost, system rate impacts and financial risk. It also utilized a variant of Monte Carlo analysis[1], which is a sophisticated analytical technique that varies important drivers in multiple runs, to create a distribution of total costs rather than a single point estimate, which allows for risk analysis. The Monte Carlo analysis in MIDAS utilized 13 key variables.

The following variables were selected by TVA for the analysis:

- Commodity prices – natural gas, coal, CO_2, SO_2 and NO_x allowances
- Financial parameters – interest rates and electricity market prices
- Operating costs – capital as well as operation and maintenance
- Dispatch costs – hydro generation, fossil and nuclear availability
- Load forecast uncertainty

Total PVRR for each resource plan was calculated taking into account additional considerations. These considerations included the cash flows associated with financing. The model generated multiple combinations of the key assumptions for each year of the study period and computed the costs of each combination. Capital costs for supply-side options were amortized for investment recovery using a real economic carrying cost method that accounted for unequal useful lives of generating assets.

[1]Monte Carlo analysis is also referred to as stochastic analysis

Present value calculations are widely used in business and economics to provide a means to compare cash flows at different times on a meaningful basis. It also ensures that assets with higher capital costs and longer service lives are not unduly penalized relative to assets with lower capital costs and relatively shorter economic lives.

The short-term rate metric was also calculated and provided an alternative representation of the revenue requirements for the 2011-2018 timeframe expressed per MWh. This metric was developed to focus on the near-term impacts to system cost in recognition of TVA's current debt cap of $30 billion and the likelihood that the majority of capital expenditures in the short–term[1] may have to be funded primarily from rates.

6.2.3 Development of Portfolio

Portfolios are the output of the modeling process described in Section 6.2 – Resource Portfolios Optimization Modeling, and represent the outcome of choices made for a given view of the future. During the Draft IRP process, an optimized portfolio was developed for each of the five planning strategies within each of the six scenarios and for the Reference Case: Spring 2010. The end result was 35 distinct portfolios. Each portfolio represented a 20-year capacity expansion plan. The portfolios consisted of assets that represented various resource selections and cost characteristics optimized to meet TVA's capacity and energy needs for the IRP study period.

Due to the nature of the analysis, certain elements (i.e., emphasis on EEDR and nuclear energy) of some strategies remained relatively constant across the scenarios. However, other elements (i.e., amount of natural gas-fired capacity and market purchases) were variable and determined by the interplay between each planning strategy and the scenario within which it was analyzed.

6.3 Development of Evaluation Scorecard

The use of a scenario planning approach, combined with multiple strategies to be considered, resulted in a large number of distinct 20-year resource portfolios that required analysis and evaluation. Rather than looking for the best single solution contained within a large number of portfolios, the scenario planning approach looked for trends or characteristics common to multiple portfolios with a focus on outcomes considered to be successful and the strategies that guided those outcomes. Definition of what is considered successful, although difficult, was a key component in the evaluation of the planning strategies. Development of a scorecard to communicate the success or failure of the different portfolios was vital to the success of this evaluation process.

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[1]prior to 2018

The following sections describe the creation of the IRP scorecard, including development of the ranking and strategic metrics. Although not part of the scorecard, the development of a technology innovation narrative is also discussed below.

6.3.1 Scorecard Design

Identification of preferred planning strategies in the Draft IRP and development of the Recommended Planning Direction in the final IRP involved a trade-off analysis. The analysis was focused on multiple metrics of cost, risk, environmental impacts and other aspects of TVA's overall mission.

A scorecard was designed for each strategy and was used to facilitate this trade-off analysis. The scorecard template (Figure 6-7) was comprised of two sections – ranking metrics and strategic metrics. A technology innovation narrative was included apart from the scorecard to help identify which strategies would be supported by particular technology innovations.

	Ranking Metrics			Strategic Metrics				
	Financial Impact			Environmental Stewardship			Economic Impact	
Portfolio	Cost	Risk	Ranking Metric Score	Carbon Footprint	Water Impact	Waste Impact	Total Employment	Growth in Personal Income
		Total Score:						

Figure 6-7 – Planning Strategy Scorecard

Ranking Metrics

Ranking metrics were used to quantify the financial impact of each given portfolio. Two metrics, cost and risk, were selected based on their ability to highlight differences between the portfolios. To further highlight differences, the ranking metric score was calculated as a blend of the two metric's scores.

Cost Metric

Production of the financial metrics PVRR and short-term rates was described in Section 6.2.1. The cost metric used in the strategy scorecard combined these two metrics using the following weighted formula:

Cost = 0.65 * PVRR + 0.35 * short-term rates

By considering the expected values for PVRR and short-term rates, TVA was able to better evaluate the cost and rate implications for various portfolios. The inclusion of both short-term rates and total revenue requirements helped to facilitate a trade-off analysis of alternative resource plans. This allowed TVA to explicitly evaluate funding implications, consistent with stakeholder concerns regarding increasing rate pressures.

Risk Metric

The PVRR risk metric was computed using both a risk ratio and a risk/benefit ratio metric for each portfolio, as shown in Figure 6-8.

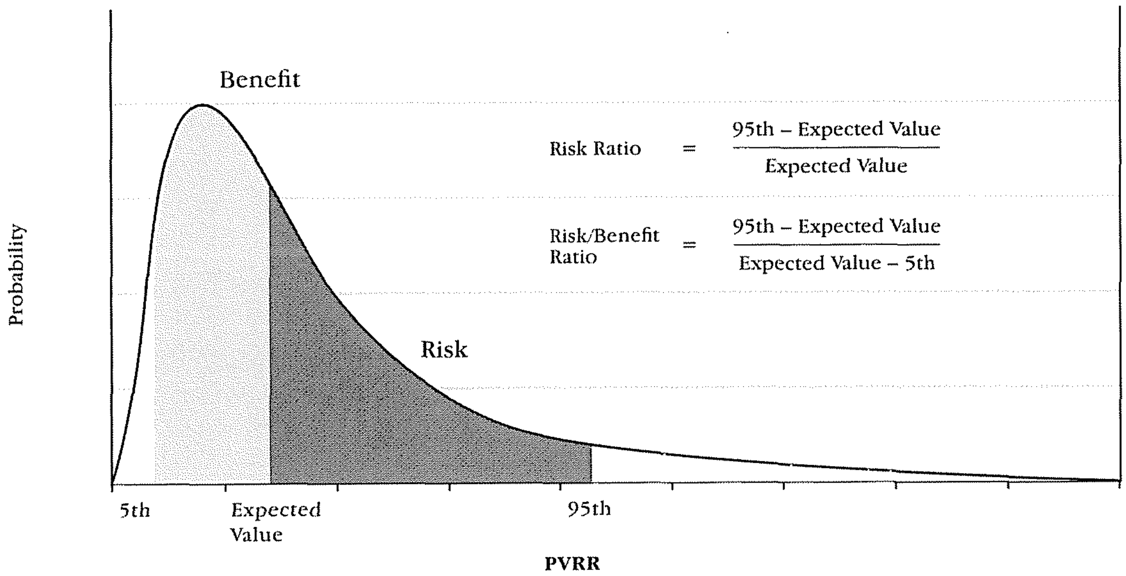


Figure 6-8 – Financial Risk Metrics

The risk metric used in the strategy scorecard combined these two metrics using the following weighted formula.

Risk = 0.65 * risk ratio + 0.35 * risk/benefit ratio

The risk ratio was expressed as the ratio of the difference between the 95th percentile of PVRR from the stochastic analysis and the expected value. It is a measure of the absolute "size" of the risk relative to the expected cost under each strategy within each scenario. A higher value signifies a portfolio with a relatively higher level of risk. The risk/benefit ratio captured the "risk" of a portfolio by examining the potential of exceeding the expected PVRR compared to the benefit of not exceeding the expected PVRR, expressed as a ratio. It compared the potential risks and the potential benefits of a strategy to determine whether or not the "risks and rewards" balance was weighted in favor of the customer.

Ranking Metric Score

The ranking metrics score combined the cost and risk metrics using the following weighted formula.

Ranking metrics score = 0.65 * cost + 0.35 * risk

This metric allowed evaluation of the interaction between financial risks and overall plan cost. For example, desirable low costs may require accepting a greater risk exposure, or to achieve an acceptable level of financial risk may mean selecting a plan with costs that are slightly higher than the least-cost option. The trade-offs required to balance these competing objectives helped identify the preferred planning strategies in the Draft IRP and the Recommended Planning Direction in the final IRP.

Strategic Metrics

Strategic metrics developed to consider other parts of TVA's mission were paired with ranking metrics to complete the IRP scorecard. Two strategic metrics were developed – environmental stewardship and economic impact.

Environmental Stewardship Metric

The environmental stewardship metric was developed to evaluate air, water and waste impacts. In the air metric evaluation, CO_2, SO_2, NO_x and Hg emissions were calculated for each portfolio. Emissions trends for SO_2, NO_x and Hg were steeply reduced because all cases chose large levels of coal-fired unit idling (2,000-7,000 MW) and controlled (90 percent or better emission removal rates) operating units in the future. For simplicity, the air metric was represented as a CO_2 impact footprint factor (annual average tons) because similar trend lines were tracked in all cases for CO_2. No additional significant insight was gained using all air emissions as opposed to using only CO_2. Therefore, the air metric is represented as a CO_2 impact "footprint" factor (annual average tons).

The water component of the environmental stewardship metric represents the thermal load produced through the condenser cooling cycle from steam generating plants to measure thermal impacts to the environment. The water impact was estimated based on the total heat dissipated by the condenser in the generation cooling cycle.

In addition to air and water impacts, certain generation sources produce waste streams that require disposal. The waste component used in this analysis focused on coal and nuclear generation, which are the primary sources of waste streams. The volumetric and disposal costs were used to better normalize differences in mass generated (tons). Waste streams that were estimated included coal ash, flue gas desulfurization/scrubber waste and high- and low-level nuclear waste.

The final evaluation criteria for both water and waste relied on surrogate measures as a proxy for environmental impacts. Both provided a reasonable and balanced method for evaluating planning strategies when compared with other components. Additional detail on the environmental stewardship metrics is in Appendix A – Method for Computing Environmental Impact Metrics.

Economic Impact Metric

Economic impact metrics were included to provide an indication of the impact of each strategy on the general economic conditions in the Tennessee Valley region. The economic metrics were represented by total employment and personal income. These metrics were compared to the impacts of Strategy B – Baseline Plan Resource Portfolio, in Scenario 7.

The IRP study defined economic impact as growth in regional economic activity. Measurement criteria included total personal income in "constant" dollars (i.e., with inflation accounted for) and total employment. These provided measures for the effects of the various planning strategies on the overall, long-term health and welfare of the economy over the next 20 years. This analysis concentrated on changes to the welfare of the general economy due to the strategies. It did not address changes to the distribution of income or employment.

In general, the greater the direct regional expenditures associated with a particular portfolio, the more positive were the effects on the regional economy. This can be offset by the fact that higher rates caused by higher costs have a negative effect on the regional economy. Thus, a resource portfolio that has high expenditures in the Tennessee Valley region may also have high costs and high rates.

The economic impact metrics for a particular planning strategy could be positive or negative depending on the net sum of the expenditure effects and the cost effects. More details about the methodology used to determine the economic impact metrics for the planning strategies is in Appendix B – Method for Computing Economic Metrics.

Scorecard Calculation and Color Coding

The ranking metrics in the scorecard for this IRP were expressed in terms of a 100-point score while ensuring that the relative relationship between the actual values for each portfolio in the strategy was maintained. The following process was used to compute the scores:

- Actual values of ranking metrics (i.e., PVRR, short-term rate impacts) were converted to a relative score on a 100-point scale. This type of scoring helped to assess and prioritize risk and identify the best possible solution
- The highest ranked ("best") value received a 100
- The rest of the scores were based on their relative position to the "best" value (e.g., a value that is 75 percent of the "best" would receive a 75)
- A color-coding method was used to assist in visual comparison of portfolio results. The coding was done within a given scenario. The "best" value for each metric was coded green, the "worst" value was coded red and the values in between were shown with a shaded color that corresponded to the relationship of the score values

An example of the translation from actual values to ranking metric scores is shown in Figure 6-9. The figure shows the conversion for the short-term rate metric.

Raw ranking metric value for short-term rate impacts in Scenario 1 are shown to right

Ranking Metric Scores		
	Strategy	Scenario 1
Average of ST Rates $/MWh (level 2011-18)	A	76.82
	B	78.67
	C	79.95
	D	84.61
	E	80.41

The "best" (in this case lowest) value within a scenario gets a score of 100

Strategy D is 10.13% higher than the "best" value and receives a score of 89.87

Scores are converted from the raw scores as shown and are included in the planning strategy score cards

Converted Ranking Metric Scores		
	Strategy	Scenario 1
Average of ST Rates (level 2011-18)	A	100.00
	B	97.59
	C	95.93
	D	89.87
	E	95.34

All other scores are assigned a value based on their relative position to the "best" score

Figure 6-9 – Ranking Metrics Example

The strategic metrics were included in the scorecard in two ways. First, the environmental stewardship metrics values were translated into a relative scoring system, known as a Harvey Ball rating system. Second, the economic impact metrics were represented by a percent change from a reference case.

For the environmental stewardship metrics, the data was coded in a given scenario so that the relative relationship (rank order) among the strategies was indicated by the amount of the ball that was filled in. Figure 6-10 shows an example of how this translation was done.

- This is an example of how the Harvey Ball ratings were applied to the Carbon Footprint strategic metric
- Expected values for annual CO_2 emissions from stochastic analysis are shown to the right
- Planning strategies were ranked based on their performance within each scenario

  In this example, 1=highest and 5=lowest
- In this example, quantitative data was available to support the ranking, however, other strategic metrics may have required qualitative assessment for ranking
- The appropriate Harvey Ball was assigned based on the rankings

Legend	
●	Better
◕	↑
◑	
◔	
○	

Average Annual CO_2 Emissions (Million Tons)

	Scenario						
Strategy	1	2	3	4	5	6	7
A	2,054	1,719	1,402	1,775	1,723	1,190	1,767
B	1,774	1,461	1,317	1,518	1,480	1,138	1,533
C	1,673	1,418	1,210	1,408	1,422	1,035	1,427
D	1,468	1,170	1,058	1,256	1,204	962	1,249
E	1,613	1,299	1,106	1,410	1,303	959	1,352

Carbon Footprint Rankings Within Scenarios

	Scenario						
Strategy	1	2	3	4	5	6	7
A	5	5	5	5	5	5	5
B	4	4	4	4	4	4	4
C	3	3	3	2	3	3	3
D	1	1	1	1	1	2	1
E	2	2	2	3	2	1	2

Populated Carbon Footprint Strategic Metric

	Scenario						
Strategy	1	2	3	4	5	6	7
A	○	○	○	○	○	○	○
B	◔	◔	◔	◔	◔	◔	◔
C	◑	◑	◑	◕	◑	◑	◑
D	●	●	●	●	●	◕	●
E	◕	◕	◕	◑	◕	●	◕

Figure 6-10 – Example of Draft IRP Scoring Process – Carbon Footprint

For the economic impact metrics, data were included in the scorecard as a percent change from the reference portfolio (Strategy B in Scenario 7). Instead of computing impacts for all 35 portfolios, only the range of possible impacts was evaluated.

The range of possible impacts was evaluated by computing the values for each planning strategy in Scenarios 1 and 6. The changes in employment and personal income in these scenarios relative to the reference portfolio (Strategy B in Scenario 7) indicated the maximum impacts that could result in any of the other scenario/strategy combinations.

6.3.2 Technology Innovations Narrative

In addition to the ranking and strategic metrics, a brief narrative of technology innovations associated with each planning strategy was prepared for the TVA Board of Directors. The narrative gave insight into the technology utilization implicit in each strategy for the Draft IRP.

This narrative was not a metric, but included as a supplement to the fully populated scorecard as background information to consider for selection of a Recommended Planning Direction. The technology innovation narrative discussed which technologies would justify investment to enable the resource mix identified in each strategy (e.g., a planning strategy with extensive EEDR may need smart grid investments for energy savings to be fully realized). A full description of the technology innovation matrix is in Chapter 7 – Draft Study Results.

6.4 Identification of Preferred Planning Strategies in the Draft IRP

Identification of preferred planning strategies was the key deliverable of the Draft IRP. The preferred planning strategies were identified by using the following three steps:

1. Scoring
2. Sensitivity analysis
3. Identification of preferred planning strategies

6.4.1 Scoring

For the Draft IRP, the identification of preferred planning strategies began by computing a score for each of the 35 portfolios evaluated in the study. Scores were based on the expected value for the cost and risk metrics. A total planning score was then calculated by summing the scores (ranking metrics) for each portfolio produced. Strategic metrics were combined with the ranking metrics for each of the selected reference resource portfolios to complete the scorecard. The technology innovation narrative was also utilized to help inform the scorecard. The initial scorecard was publicly shared during the Draft IRP and associated EIS public comment period and helped to facilitate discussion of trade-offs, constraints and compromises by considering the scorecard values of cost, risk and the strategic metrics.

6.4.2 Sensitivity Analyses

Sensitivity analyses were conducted to refine the preliminary results. The results focused on key assumptions in the strategies based on review of the scorecard results. For the

Draft IRP, sensitivity analyses consisted of selected cases intended to assess the robustness of the top performing strategies prior to selecting which strategies would be retained for further analysis for the final IRP.

6.4.3 Identification of Preferred Planning Strategies

By utilizing the ranking metrics, strategic metrics and technology innovation narrative, the preferred planning strategies were identified. Three strategies were retained in the Draft IRP – Strategies C, E and B. Resource portfolios were then identified from the preferred planning strategies. These resource portfolios represented the planning strategies for the purpose of comparative analysis and impact assessment and were used to define the broad range of options considered in the Draft IRP.

6.5 Incorporation of Public Input and Performance of Additional Scenario Planning Analyses

Following publication of the Draft IRP, the data used for analysis was re-evaluated and refreshed for key assumptions like load forecasts and commodity prices. Also during this time, the Scenario 8 reference case was created to better capture the impacts of the recent economic recession. Figure 6-3 has more details on that scenario. In other cases, suggestions received from the SRG and general public were incorporated into the analysis. The modeling and evaluation processes were also carefully examined and changes were made to further improve the quality of the analysis.

6.6 Identification of Recommended Planning Direction

After the Draft IRP public comment period, efforts continued to prepare the final IRP. The primary deliverable for this phase was the identification of the Recommended Planning Direction. This strategy will help define TVA's short- and long-term strategic direction and identify short-term actions that need to be accomplished. The preparation of the final IRP consisted of the following steps:

1. Identification of key components
2. Definition of boundary conditions
3. Development of Recommended Planning Direction candidates
4. Identification of the Recommended Planning Direction

6.6.1 Identification of Key Components

Components of the preferred planning strategies from the Draft IRP were evaluated for characteristics that would likely comprise the Recommended Planning Direction.

The revised approach reduced the number of inputs that were included in model optimization to produce a more focused result while allowing other unique combinations of resources to be tested that were not directly considered in the Draft IRP.

A key variable that was retained as a defined input was the level of idled coal-fired capacity. Idled capacity was not optimally selected within the model runs and required model iterations to test the different levels. This constraint meant that the optimum renewable and EEDR portfolio amounts were then selected for each assumed level of idled coal-fired capacity.

Portfolios for renewable additions and EEDR levels were optimized in the final analysis, along with the components identified in the Draft IRP. The model selected the best renewable and EEDR portfolio from the iterations provided as a part of optimizing all other resource alternatives.

6.6.2 Definition of Boundary Conditions

As described above, the Recommended Planning Direction was identified based on a blended optimization analysis using certain components from Strategies B, C and E. Figure 6-11 outlines the boundary conditions used in this stage of the analysis.

Components	Boundaries
EEDR	The EEDR portfolio will be no less than 2,100 MW & 5,900 annual GWh reduction by 2020
Renewable additions	Renewable additions will be no less than the existing wind contracts
Coal-fired capacity idled	Coal-fired capacity idled will be between 2,400 MW and 4,700 MW
Energy storage	The pumped-storage hydro unit (850 MW) will be included in all cases
Nuclear	Nuclear units cannot be added any earlier than 2018 and large units must be a minimum of two years apart – B&W technology at BLN cannot be added any later than 2020
Coal	New units cannot be added prior to 2025 and must be equipped with carbon capture and sequestration
Market purchases and transmission	If more than 900 MW/year are purchased beyond current contracts and extensions, potential transmission costs should be considered
Transmission	Transmission upgrades will be made to support new supply resources and maintain system readability

Figure 6-11 – Recommended Planning Direction Boundary Conditions

Within these boundaries, the capacity optimization model selected a resource plan that met the study constraints for reliability and least cost. To identify the optimum resource plan, multiple iterations were run within the model using the ranges of EEDR, renewable additions and idled coal-fired capacity as shown in Figure 6-12.

Components	Range of Options Tested				
EEDR	2,100 MW & 5,900 annual GWh reductions by 2020	3,600 MW & 11,400 annual GWh reductions by 2020	5,100 MW & 14,400 annual GWh reductions by 2020		
Renewable additions	1,500 MW competitive resources or PPAs by 2020	2,500 MW competitive resources or PPAs by 2020	2,500 MW competitive resources or PPAs by 2029	3,500 MW competitive resources or PPAs by 2020	3,500 MW competitive resources or PPAs by 2029
Coal-fired capacity idled	2,400 MW total fleet reductions by 2017	3,200 MW total fleet reductions by 2017	4,000 MW total fleet reductions by 2017	4,700 MW total fleet reductions by 2017	

Figure 6-12 – Recommended Planning Direction Range of Options Tested

Figure 6-12 also indicates the coal-fired capacity idling levels that were studied. As previously stated, these levels were not selected by the optimization model based on the full incremental costs of retaining these assets as part of the portfolios, but functioned as defined model inputs. As a result, the options shown for renewables and EEDR, along with any other resource options, were available for selection during optimization for each of the four assumed coal-fired idling levels.

6.6.3 Development of Recommended Planning Direction Candidates

Optimization results were produced by testing the four coal-fired idling levels across a subset of the scenarios originally developed for the Draft IRP.

The following scenarios were used to efficiently test the full range of possible futures for a total of 12 optimized cases:

- Scenario 1 – represented the upper bound
- Scenario 8 – represented a mid range of possible futures
- Scenario 3 – represented the lower bound and did not include climate change regulation

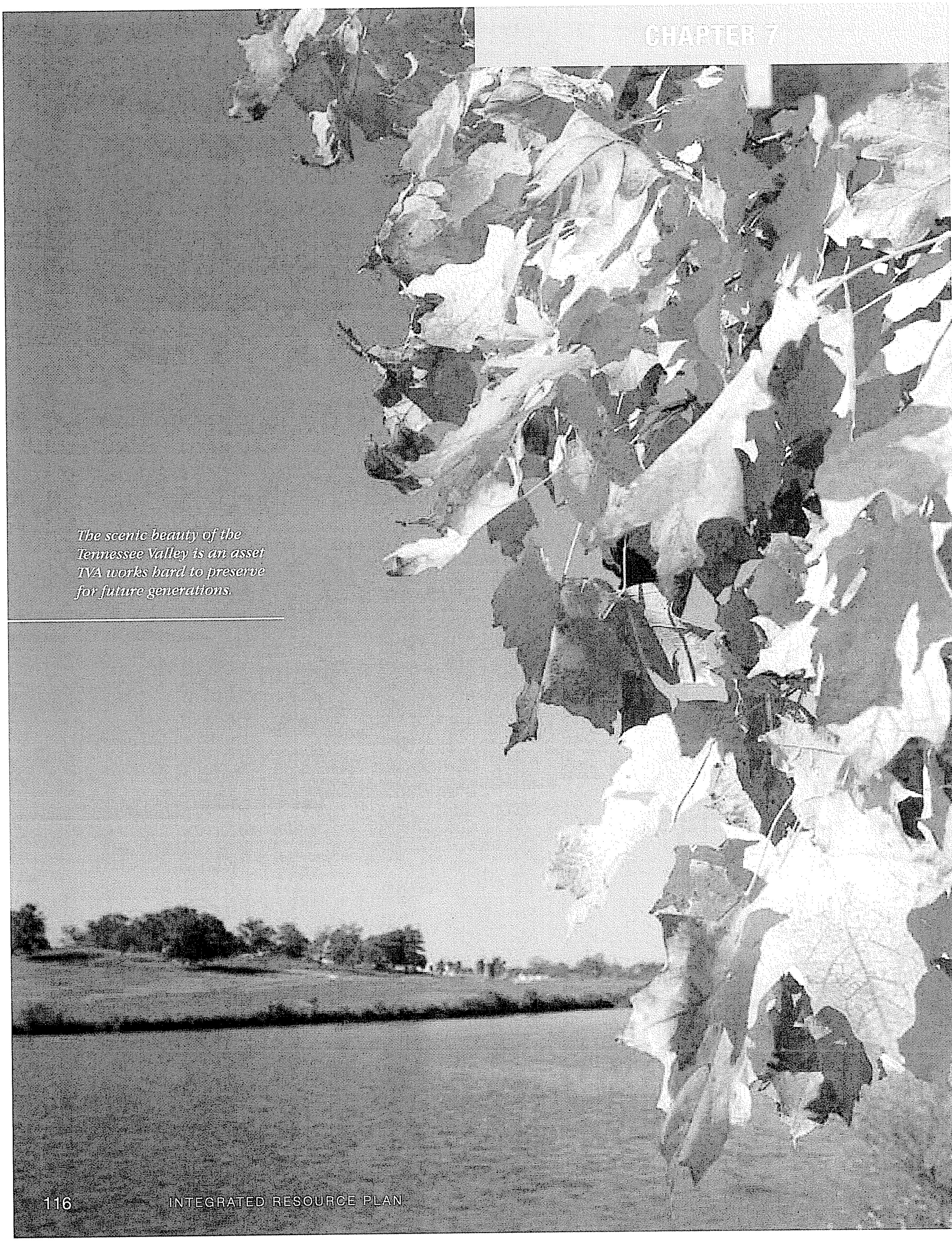
The following iterative six-step approach was used to produce the case results for the final IRP:

1. Incremental changes were made to strategy components in an attempt to improve upon the preferred planning strategies identified in the Draft IRP
2. The new strategy was tested in Scenarios 1 – 8 to evaluate new component combinations
3. The results were rescored to build a fully populated scorecard with ranking and strategic metrics
4. The completed scorecard was compared with results in the Draft IRP and previously considered alternatives to identify improvement, if any
5. Components common to strategies that exhibited improvement were selected to describe the proposed Recommended Planning Direction
6. Steps 1-5 were repeated until no further improvements were identified

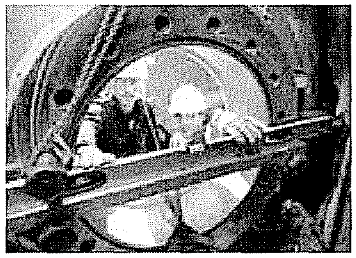
6.6.4 Identification of Recommended Planning Direction

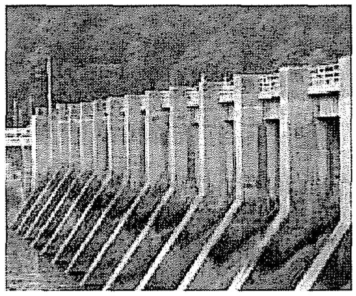
A Recommended Planning Direction was identified and is fully described in Chapter 8 – Final Study Results and Recommended Planning Direction. The identification of the Recommended Planning Direction was an iterative process that utilized the results of more than 3,000 modeling runs and evaluation of the results. The scorecard, along with stakeholder input and other considerations, was used to identify changes from the preferred planning strategies identified in the Draft IRP.

Resource Plan Development and Analysis



The scenic beauty of the Tennessee Valley is an asset TVA works hard to preserve for future generations.





The Guntersville Dam in Marshall County, Ala., has a generating capacity of 140,400 kilowatts of electricity.

Draft Planning Scenarios and Strategies

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 Regulation Creates Economic Downturn
7 Reference Case: Spring 2010

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

7 Draft Study Results

This chapter describes the results and findings from the Draft IRP, published in September 2010. The Draft IRP studied five strategies in a total of six scenarios and one reference case scenario. As a result, 35 distinct 20-year portfolios or capacity expansion plans were created. These portfolios were scored and the results were evaluated as described in Chapter 6 – Resource Plan Development and Analysis. Results of this IRP are fully described in Chapter 8 – Final Study Results and Recommended Planning Direction

7.1 Analysis Results

7.1.1 Firm Requirements and Capacity Gap

Forecasted capacity needs for the range of scenarios considered were presented in Section 4.3 – Estimate Supply. Consistent with TVA's scenario planning approach, variations from the expected forecast were studied as well. These variations were grouped into scenarios that represented different plausible futures in which TVA may have to operate. The key components of each scenario were translated into a forecast of firm requirements (demand plus reserves), which was used to identify the resulting capacity gap and need for power, driving the selection of resources in the capacity planning model.

Figure 7-1 illustrates the firm requirements forecasts for the seven scenarios that were studied in the Draft IRP. Six of the seven scenarios were specifically designed for the IRP study and are discussed in Section 6.1 – Development of Scenarios and Strategies. The seventh scenario represented the spring 2010 market view and was considered the reference case for analysis in the Draft IRP.

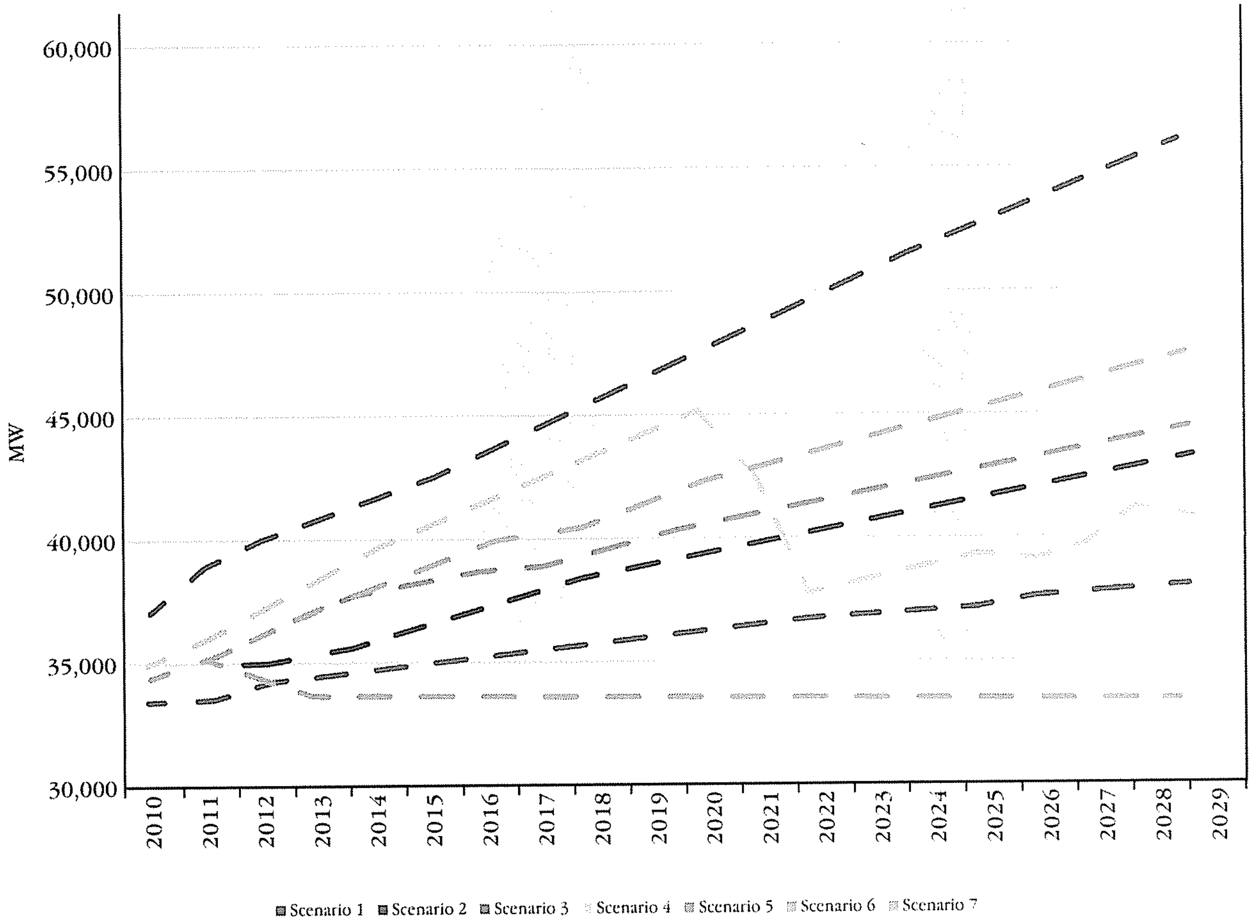


Figure 7-1 – Firm Requirements by Scenario

Firm requirements were greatest in Scenario 1 (highest load growth scenario) and lowest in Scenario 6 (flat to slightly negative load growth). The remaining scenarios fell within this range and generally displayed smooth but unique growth trends, with the exception of Scenario 4 (game-changing technology scenario). Firm requirements for Scenario 4 experienced a dramatic drop in load in 2021, reflecting that scenario's assumptions of rapid commercialization of alternative technologies displacing the need for traditional resources.

The shape of the firm requirements curves influenced the type and timing of resource additions in the strategies, especially in Scenario 4 where resource additions were reduced or eliminated in the latter years. The timing of additional resources was a function of the existing system capacity and the impact of the defined model inputs for each strategy.

Figure 7-2 summarizes the range of the capacity gaps at the end of the study period for the cases studied in the Draft IRP. The range of the capacity gaps in this figure is based on the minimum and maximum gaps found in the five planning strategies developed for the Draft IRP. The maximum gap represents the largest capacity gap and is based on Scenario 1. The minimum gap represents the smallest capacity gap or potentially a surplus of generation and is based on Scenario 6.

Strategy	Max Capacity Gap (MW)	Min Capacity Gap (MW)
A	18,000	(4,800)
B	20,000	(3,000)
C	17,000	(6,000)
D	19,000	(4,000)
E	18,000	(5,000)

Figure 7-2 – Range of Capacity Gaps by Strategy

This broad range of capacity gaps resulted in a wide range of expansion plans across the 35 portfolios developed in the Draft IRP.

7.1.2 Expansion Plans

The amount and type of resource additions for the five planning strategies that were evaluated in the Draft IRP are consistent with the following assumptions that define each of the scenarios:

- The largest amount of resource additions occurred in Scenario 1
- Scenario 7, representing the Reference Case: Spring 2010, required an average amount of new resources over the study period
- Scenarios 3 and 6 had the least amount of resource additions
- Small amounts of new resources were added in Scenarios 2 and 5
- In Scenario 4, no resources were added after 2020, consistent with the dramatic drop in load beginning in 2021

The individual capacity expansion plans for each of the five planning strategies are presented in Appendix E – Draft IRP Phase Expansion Plan Listing, and are grouped by scenario. These plans reflect the contributions from the TVA Board of Directors' approved projects. In addition, the impacts of the defined model inputs, particularly the capacity associated with the renewable resource portfolios and the avoided capacity value from EEDR, are also included. Figure 7-3 illustrates the range of capacity additions by resource type across all the strategies.

Type	Minimum (MW)[1,2]	Maximum (MW)[1,3]
Nuclear	0	4,754 (4)
Combustion turbine	0	8,092 (11)
Combined cycle	0	6,700 (7)
IGCC	0	934 (2)
SCPC	0	800 (1)
Avoided capacity (EEDR)[4]	1,905	6,361
Renewables[4]	160	1,157
Pumped-storage[4]	0	850
Coal-fired capacity idled[4]	0	7,000

Notes:

1 – Values shown are for dependable capacity at the summer peak. Nameplate capacity of renewables range from 1,300 to 3,500 MW

2 – Minimums exclude Board-approved projects (WBN 2, JSFCC, and Lagoon Creek)

3 – Number of units shown in ( )

4 – Defined model input

Figure 7-3 – Capacity Additions by 2029

To provide a different view of the expansion plan results for the strategies evaluated in the Draft IRP, a set of histograms was developed that presents data on the frequency of selection of key resource types across the 35 portfolios. Figures 7-4 through 7-7 are plots that illustrate the number of portfolios and the specific number of nuclear, coal, combined cycle and combustion turbine units that may be added.

Nuclear capacity beyond Watts Bar Unit 2 was prominent in the analysis results, as illustrated in Figure 7-4. At least two nuclear units, and up to four, were added in 19 of the 28 possible portfolios, and the first nuclear unit was added between 2018 and 2022. Nuclear capacity was not added to portfolios in scenarios with nearly flat load growth. In one strategy, nuclear was not a permitted resource expansion option.

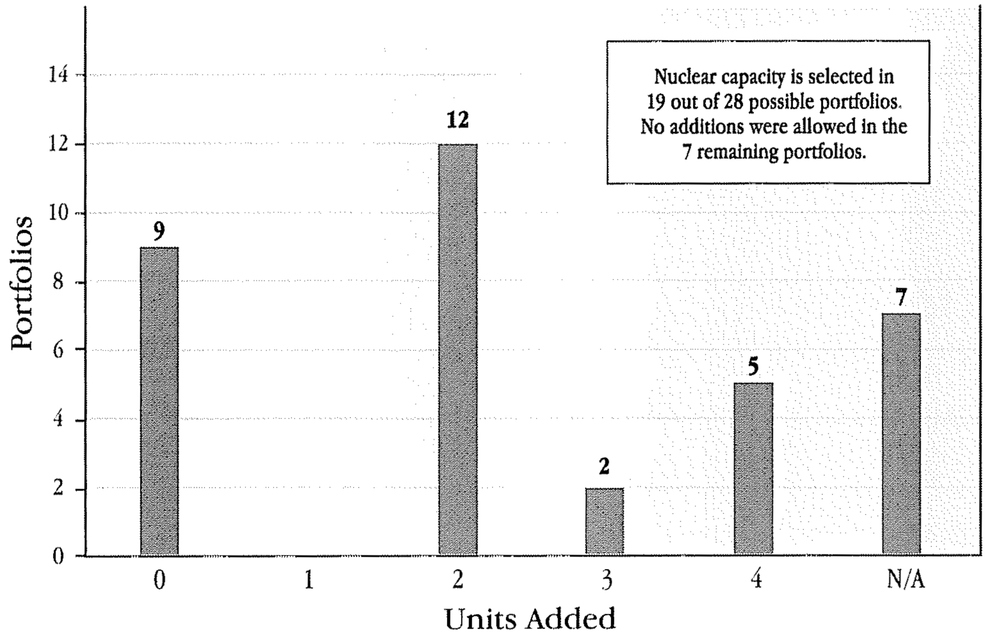


Figure 7-4 – Number of Nuclear Units Added

Coal capacity additions were very infrequent (Figure 7-5). Integrated gasification combined cycle (IGCC) units with carbon capture were selected only after 2025 and in just three of the 21 possible portfolios. Supercritical pulverized coal (SCPC) with carbon capture was added after 2035 and in only one of the 21 possible portfolios. Two strategies do not permit additional coal-fired units.

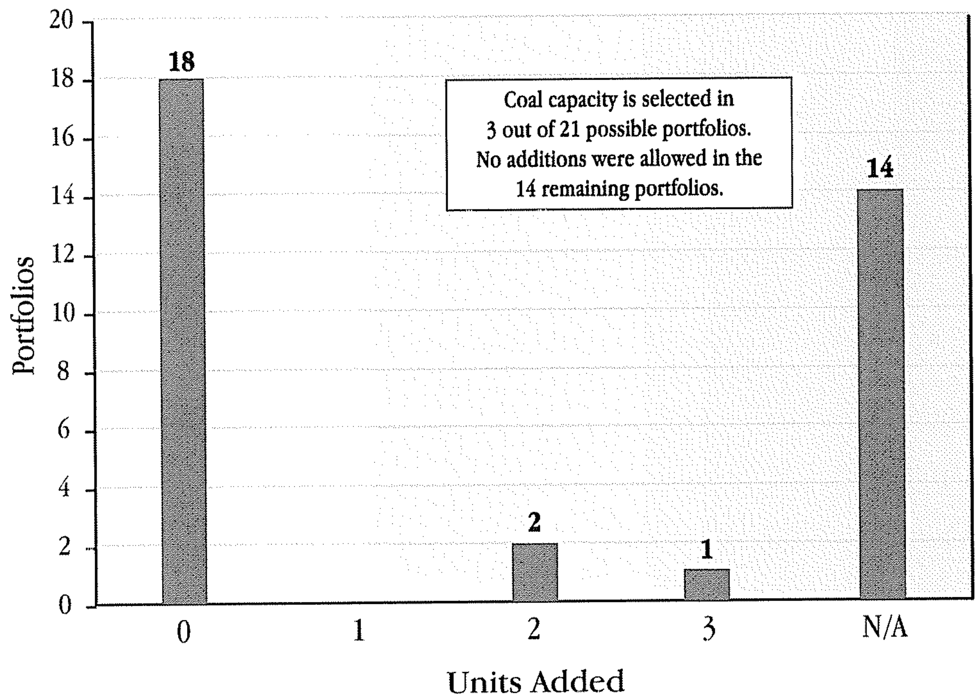


Figure 7-5 – Number of Coal Units Added

Additions of combined cycle capacity (including potential acquisitions of IPP projects) ranged from 0–7 units (0-6,700MW) as shown in Figure 7-6. Combined cycle capacity was selected in 15 of 28 possible portfolios.

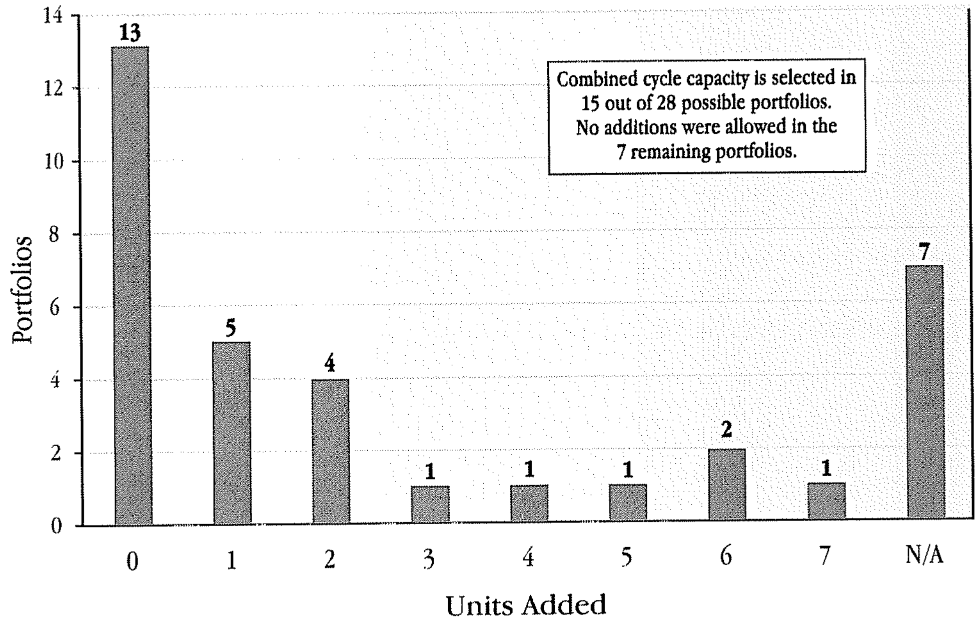


Figure 7-6 – Number of Combined Cycle Units Added

As illustrated in Figure 7-7, combustion turbine capacity additions ranged from 0–11 units (0-8,000 MW) and the majority of portfolios that selected combustion turbine capacity added just a single unit. Natural gas capacity (CT/CC) was not selected for portfolios in scenarios with nearly flat load growth or scenarios with the largest avoided capacity from EEDR.

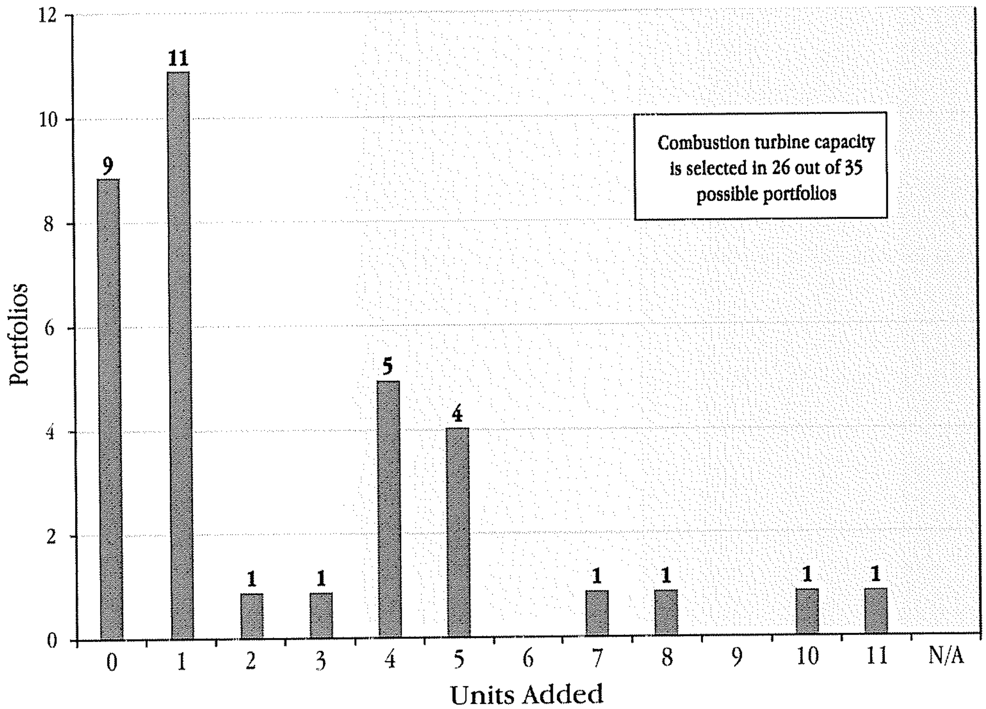


Figure 7-7 – Number of Combustion Turbine Units Added

7.1.3 System Energy Mix

Figure 7-8 lists the minimum and maximum percentage contributions to total energy production by type in 2029 from the 35 portfolios produced in the Draft IRP. Values represent the highest and lowest percentages for each type and are not from a single portfolio; therefore, they do not add to 100 percent.

Type	Minimum	Maximum
Combined Cycle	0%	13%
Combustion Turbine	0%	3%
Nuclear	27%	47%
Coal	24%	47%
Renewables	2%	8%
EEDR (savings)	2%	11%

Figure 7-8 – Range of Energy Production by Type in 2025

Nuclear and coal had the greatest swings in percentage contribution to total energy. In the majority of scenario and strategy planning combinations, nuclear overtook coal to produce the greatest percentage of total energy. Strategy A is the exception with coal remaining the largest energy producer in that strategy.

7.1.4 Plan Cost and Risk

A comparison of the expected value of PVRR by scenario for the strategies evaluated in the Draft IRP is illustrated in Figure 7-9. Scenario 1 resulted in the highest value for PVRR, while the lowest PVRR values were found in Scenario 6. Within each scenario, Strategy D generally produced the highest cost portfolios due to the larger amount of coal-fired capacity idled that must be replaced by new resources. Strategy A resulted in the set of portfolios with the next highest cost, caused by retaining a higher level of coal-fired capacity compared to other strategies, exposing it to more significant CO_2 compliance costs. Strategy C produced the lowest PVRR values in six of the seven scenarios. However, Strategy C was near the middle of the pack on short-term rate impacts which are discussed in the next section.

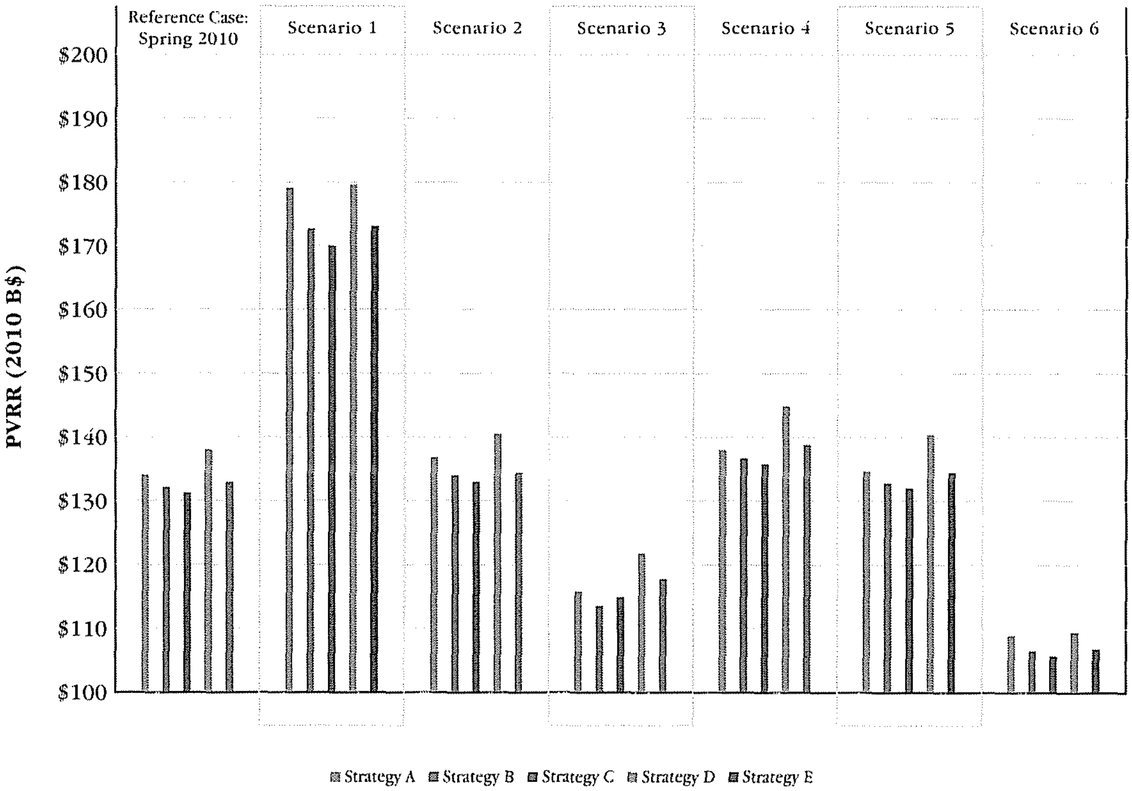


Figure 7-9 – Expected Value of PVRR by Scenario

Figure 7-10 presents the short-term rate impacts (average system costs) by scenario. The strategy with the highest expected value of short-term rates was Strategy D because this strategy had the most new capacity additions in the 2011–2018 timeframe. Strategy A produced the lowest short-term rate values in five of the seven scenarios because no new capacity was added to any portfolios within that strategy. However, Scenarios 3 and 6 included higher CO_2 compliance costs, which drove up the cost of the coal-heavy portfolios in Strategy A (in those scenarios). Strategy A's exclusive reliance on the market to serve load growth also has greater risk as shown in the discussion of risk metrics in the next section.

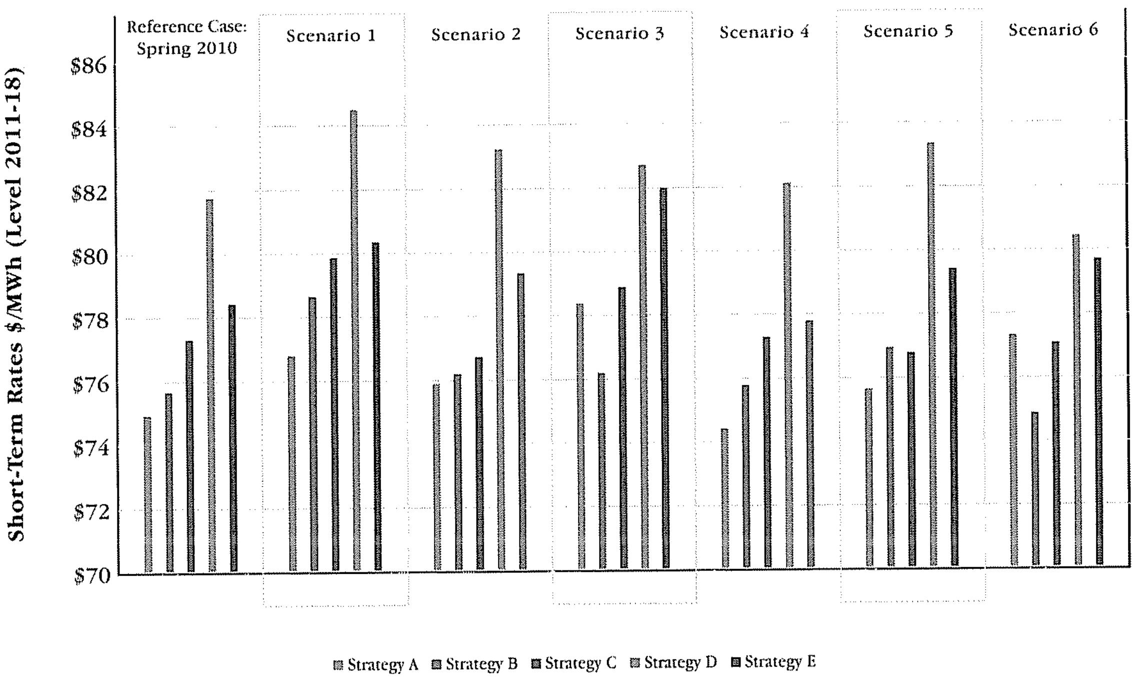


Figure 7-10 – Expected Values for Short-Term Rates by Scenario

Figures 7-11 and 7-12 compare the two risk metrics for the planning strategies. Lower ratios indicated less risky portfolios based on the probability distributions of the portfolio PVRR values. The relative relationship across the scenarios for both the risk ratio and the risk/benefit ratio were consistent. The highest values occurred in Scenario 1, the risk ratio was lowest in Scenario 3 and the risk/benefit ratio was lowest in Scenario 6.

In both cases, these low values were caused by much lower load forecasts in those scenarios, which resulted in lower PVRR values with more narrow probability distributions. Strategy A had the highest risk profile in five of the seven scenarios, which was caused by the retention of coal-fired capacity. Strategy C was the least risky strategy in six of the seven scenarios due to its generally balanced resource mix.

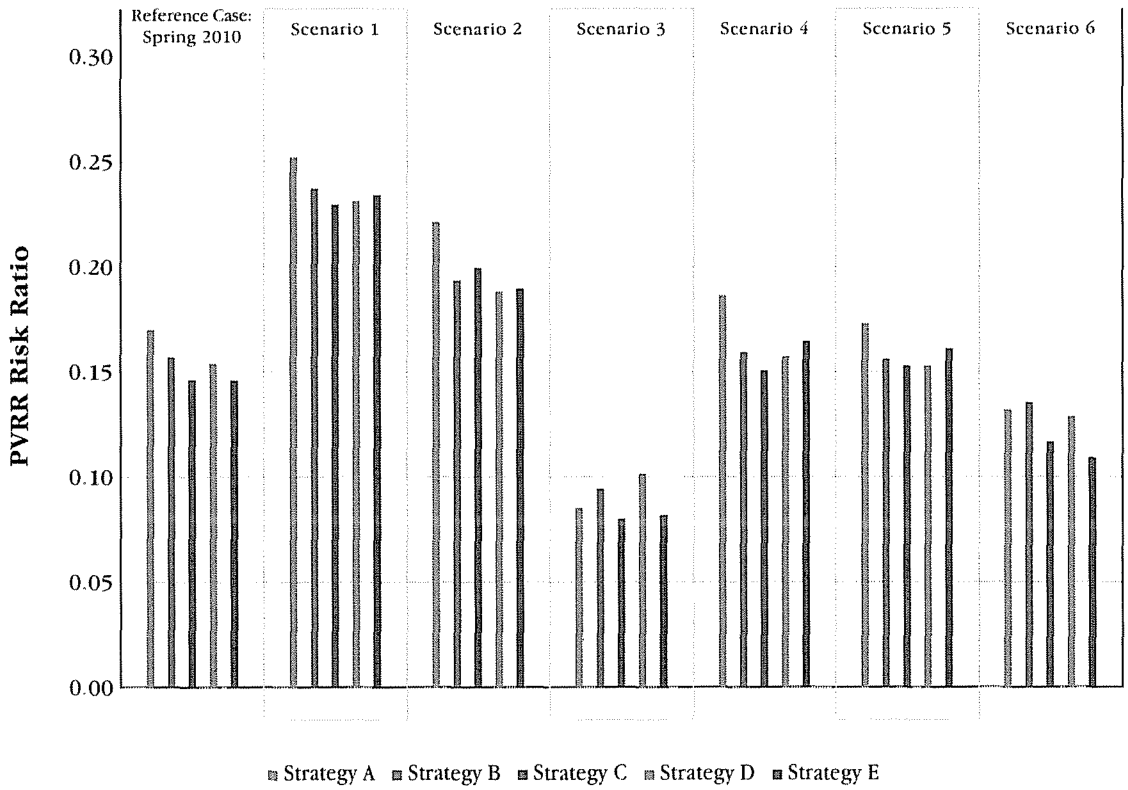


Figure 7-11 – PVRR Risk Ratio by Scenario

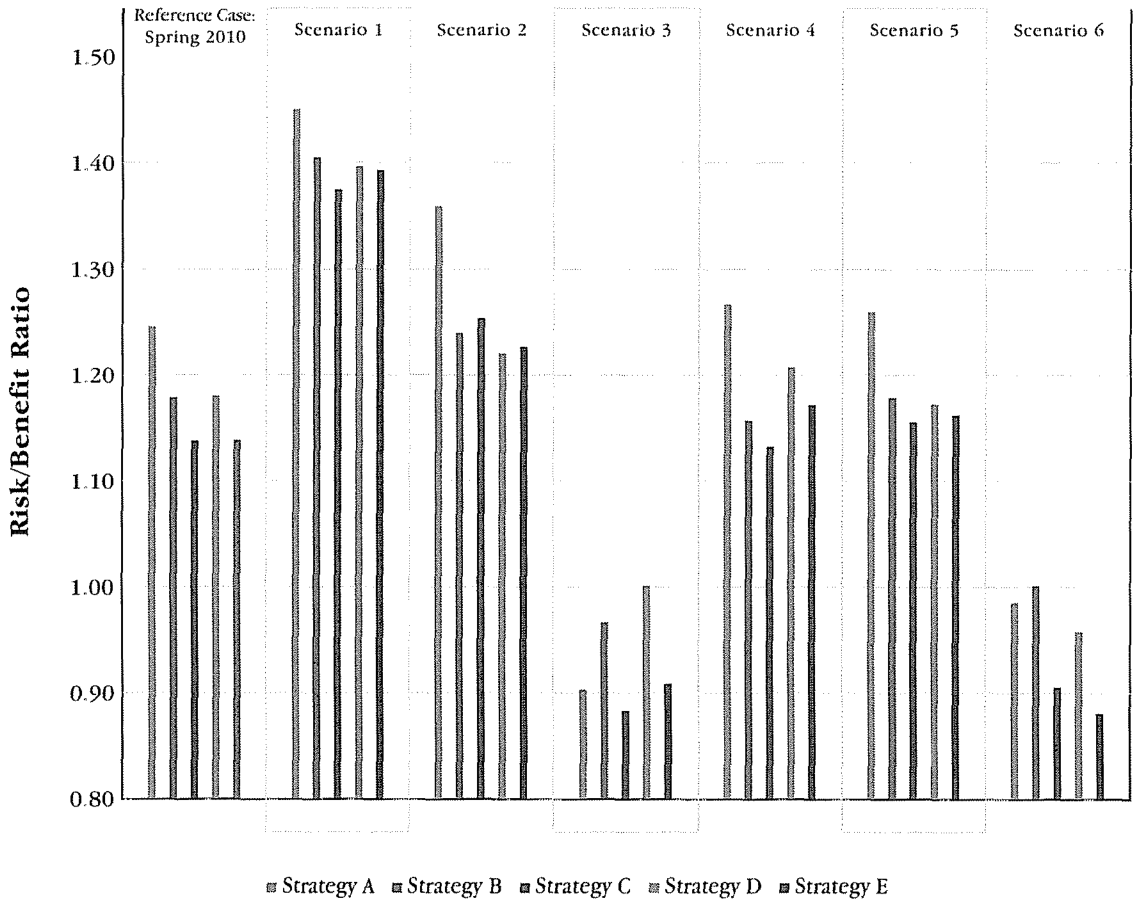


Figure 7-12 – PVRR Risk/Benefit by Scenario

7.2 Selection Process

The process that was used to rank and identify the preferred planning strategies was discussed in Chapter 6 – Resource Plan Development and Analysis. That process involved the following four steps:

1. Planning strategies were scored (based on cost and risk metrics) and ranked
2. Strategic metrics were added to the ranking metrics to complete the scorecard for the top ranked strategies
3. Selected strategies were released for public comment in the Draft IRP and the associated EIS
4. Sensitivity analyses were done as a result of public comments

The ranking of each strategy was based on the expected values of the cost and risk metrics generated by the stochastic analysis, which is described in Chapter 6 – Resource Plan Development and Analysis. The expected values were translated into a score, and the scores across all seven scenarios were combined to produce a total strategy score. Strategies were ranked based on total score from highest to lowest. A subset of strategies was selected for further consideration based on scores and other strategic considerations such as potential environmental impacts.

7.2.1 Scorecard Results

Scorecards were generated by translating the expected values from the modeling results into a standardized score that was summed across the scenarios for each planning strategy. Figure 7-13 summarizes the average expected values of PVRR, short-term rates, risk/benefit and risk computed for the five planning strategies in each of the seven scenarios.

		Scenarios							
	Strategy	1	2	3	4	5	6	7	**Average**
Average of PVRR (2010 B $)	A	180	137	116	138	135	109	134	**136**
	B	179	136	114	137	133	107	133	**134**
	C	175	133	114	135	131	105	130	**132**
	D	181	137	115	138	134	103	132	**134**
	E	174	131	115	136	131	104	130	**132**
Average of ST Rates (level 2011-18)	A	76.82	75.92	78.42	74.47	75.75	77.31	74.97	**76.24**
	B	82.49	77.49	76.22	75.88	77.04	74.91	75.72	**77.11**
	C	83.57	74.60	77.40	76.00	75.64	75.55	75.94	**76.96**
	D	84.83	79.54	75.24	75.98	76.80	72.70	75.13	**77.17**
	E	78.91	75.94	78.23	74.78	76.01	75.90	75.14	**76.42**
Average of Risk/Benefit	A	1.45	1.36	0.91	1.27	1.26	0.99	1.25	**1.21**
	B	1.43	1.24	0.97	1.16	1.18	1.00	1.18	**1.17**
	C	1.41	1.29	0.89	1.14	1.16	0.91	1.14	**1.14**
	D	1.45	1.26	1.06	1.25	1.20	1.00	1.23	**1.21**
	E	1.42	1.24	0.93	1.19	1.18	0.90	1.15	**1.15**
Average of Risk	A	0.25	0.22	0.09	0.19	0.19	0.13	0.17	**0.18**
	B	0.23	0.19	0.10	0.16	0.17	0.14	0.16	**0.16**
	C	0.23	0.20	0.08	0.15	0.17	0.12	0.15	**0.16**
	D	0.23	0.19	0.11	0.17	0.18	0.14	0.16	**0.17**
	E	0.24	0.20	0.08	0.17	0.17	0.11	0.15	**0.16**

Figure 7-13 – Ranking Metrics Worksheet

After applying the methodology for translating actual values into color-coded scores, which is described in Chapter 6 – Resource Plan Development and Analysis, a scorecard was produced for each of the five planning strategies. In Figure 7-14, planning Strategy A was used to demonstrate how scores were computed and then summed to produce the total ranking score.

	Ranking Metrics				
Scenarios	PVRR	Short-Term Rate Impact	Risk/Benefit	Risk	Ranking Metric Score
1	93.87	100.00	95.07	91.26	94.82
2	95.76	99.25	90.32	85.74	93.61
3	98.28	95.78	98.39	94.38	96.84
4	97.49	100.00	88.75	77.41	92.42
5	97.09	99.85	91.73	87.21	94.81
6	94.14	93.66	90.08	80.82	90.51
7	96.74	100.00	90.59	85.43	94.15
				Total Ranking Metric Score:	657.15

Total Ranking Metric Score=Sum of Ranking Metrics Scores for all seven scenarios

Ranking Metric Score=65%*(65%*PVRR + 35%*ST Rate) + 35%*(35%*Risk/Benefit + 65%*Risk)
=65%*(65%*97.09 + 35%*99.85) + 35%*(35%*91.73 + 65%*87.21)=94.81

Legend

Better

Figure 7-14 – Planning Strategy A – Limited Change in Current Resource Portfolio

Scorecards for the remaining four strategies are shown in Figures 7-15, 7-16, 7-17 and 7-18.

	Ranking Metrics				
Scenarios	PVRR	Short-Term Rate Impact	Risk/ Benefit	Risk	Total Plan Score
1	97.71	97.59	98.40	97.34	97.68
2	97.76	98.85	100.00	99.98	98.79
3	99.61	98.70	91.37	83.79	94.79
4	98.38	98.11	98.25	93.79	97.26
5	98.44	98.14	98.61	98.94	98.51
6	96.55	96.96	88.56	78.46	91.55
7	98.01	99.01	96.50	94.26	97.20
				Total Ranking Metric Score:	**675.78**

Legend

Better

Figure 7-15 – Planning Strategy B – Baseline Plan Resource Portfolio

	Ranking Metrics				
Scenarios	PVRR	Short-Term Rate Impact	Risk/ Benefit	Risk	Total Plan Score
1	100.00	97.48	100.00	100.00	99.43
2	99.58	100.00	96.20	96.17	98.49
3	100.00	97.13	100.00	100.00	99.35
4	100.00	97.94	100.00	100.00	99.53
5	100.00	100.00	100.00	100.00	100.00
6	98.59	96.09	98.19	93.22	96.75
7	100.00	98.71	100.00	100.00	99.71
				Total Ranking Metric Score:	**693.25**

Legend

Better

Figure 7-16 – Planning Strategy C – Diversity Focused Resource Portfolio

	Ranking Metrics				
Scenarios	PVRR	Short-Term Rate Impact	Risk/ Benefit	Risk	Total Plan Score
1	97.40	97.54	96.41	96.81	97.18
2	97.90	98.51	99.04	98.90	98.40
3	99.41	100.00	81.31	69.12	90.43
4	97.40	97.97	90.14	92.05	95.42
5	97.86	98.47	96.57	92.60	96.64
6	100.00	100.00	89.16	78.46	93.77
7	98.56	99.79	92.15	91.33	96.41
				Total Ranking Metric Score:	668.26

Legend

Better

Figure 7-17 – Planning Strategy D – Nuclear Focused Resource Portfolio

	Ranking Metrics				
Scenarios	PVRR	Short-Term Rate Impact	Risk/ Benefit	Risk	Total Plan Score
1	99.43	99.21	97.82	96.78	98.58
2	100.00	99.22	99.79	100.00	99.80
3	99.15	96.03	95.91	97.73	97.72
4	99.45	99.58	95.32	89.57	96.73
5	99.83	99.50	98.87	99.47	99.56
6	99.16	95.61	100.00	100.00	98.64
7	99.68	99.77	98.98	98.96	99.45
				Total Ranking Metric Score:	690.47

Legend

Better

Figure 7-18 – Planning Strategy E – EEDR and Renewables Focused Resource Portfolio

The scores assigned to each strategy and the associated color coding was done within a given scenario. To properly interpret the scoring for each strategy, the values for each individual ranking metric in all five strategies were compared within a particular scenario.

7.2.2 Ranking of Strategies

Detailed descriptions of strategies were introduced in Chapter 6 – Resource Plan Development and Analysis. Figure 7-19 shows the rank order of the five planning strategies evaluated in the Draft IRP based on the total ranking metrics scores. The total strategy scores range from 657 to 693 out of a possible 700 points.

Rank	Planning Strategy	Preliminary Observations
1	C	• Performs the best against PVRR and risk metrics • Near the median for short-term rates
2	E	• Near the median for short-term rates • Performs near the best for PVRR
3	B	• Ranks near the median for PVRR, short-term rates and risk
4	D	• Ranks below the median for PVRR, rates and risk
5	A	• Performs the worst on PVRR and risk • Ranks the best for short-term rates in some scenarios

Figure 7-19 – Planning Strategy Ranking Order

A key element of a "no-regrets" strategy is that a portfolio performs relatively well in most scenarios, not just the reference case scenario. Using the initial planning results, Strategy C was the top-ranked planning strategy on the basis of the total ranking metric score. However, the separation between the scores of Strategies C and E was not statistically significant. Strategy C represented an attempt to define a balanced approach to the resource mix and performed best in five of the seven scenarios based on total plan score, performed second best in another and third in just one scenario. The ranking metrics implied that Strategy C was the most robust in many possible futures. Strategy C was the top performer for PVRR and for both risk metrics. It performed reasonably well on short-term rates, but it was not the best strategy in that category.

The second best planning strategy, based on total ranking metric score, was Strategy E. As with Strategy C, this strategy represented an expanded commitment to cleaner resource options, especially pertaining to EEDR and renewable energy options. The strategy performed well in all four of the ranking metrics and performed best in two of the seven scenarios based on total plan score, resulting in a total strategy score that was very close to Strategy C.

The third best planning strategy was Strategy B. This strategy represented a "business-as-usual" approach that did not significantly deviate from existing portfolio mixes over the long term. This strategy performed reasonably well with scores in the four ranking metrics that were in the mid range for each metric, but did not rank first in any of the scenarios.

Strategy B was retained for further analysis in this IRP as a baseline strategy for impact analysis.

Strategies A and D were in the lower tier of the total strategy scores and did not represent options that offer preferable planning approaches. These two strategies represented approaches that tended to define the boundary conditions within which the other strategy results could be placed. Strategy A was an approach that included retention of all existing coal-fired capacity, with a high level of clean air capital and maintenance spending and heavy reliance on the market. The scorecard for this strategy showed it to be the worst performer in most metrics for most of the scenarios, except for the short-term rate metric where it performed quite well. Strategy D was characterized by the largest level of coal-fired capacity idled which called for the most new capacity additions. This resulted in poor strategy scores across the scenarios, although this strategy outperformed Strategy A.

7.2.3 Sensitivity Cases

In addition to the initial 35 portfolios developed from the five planning strategies, TVA also performed certain sensitivity analyses. These analyses focused on key assumptions within those strategies based on review of the scorecard results. In the Draft IRP, the sensitivity analyses consisted of four cases involving Strategies C and E (the top-ranked strategies based on the results to date). The characteristics of these sensitivity cases are described in Figure 7-20.

Sensitivity Description	Basis for Selection
C1 – Strategy C with pumped-storage hydro removed	Test for improvement in short-term rate impacts by removing defined model input for pumped-storage hydro unit
C2 – Same as Sensitivity C1 with no capacity additions prior to 2018	Test for improvements in short-term rate impacts by defining near-term capacity additions. Modeled after Strategy A, which performs the best on rates
E1 – Strategy E with greater (7,000 MW) coal-fired idling (same as Strategy D)	Test to see if largest values for EEDR, renewables, and coal unit idling significantly improve the PVRR and short-term rate impacts of Strategy E
E2 – Strategy E with lower (2,500 MW) renewable portfolio (same as Strategy C)	Improve PVRR and short-term rates by using the lower renewable portfolio applied in Strategy C

Figure 7-20 – Sensitivity Characteristics

When these sensitivity cases were evaluated using the same ranking metrics applied to the original five planning strategies, a new rank order of strategies was established, as shown in Figure 7-21. The scores now range from 655 to 689.

Rank	Planning Strategy
1	C1 – Strategy C without pumped-storage hydro
2	C – Diversity Focused Resource Portfolio
3	C2 – same as C1 with no capacity additions prior to 2018
4	E – EEDR and Renewables Focused Resource Portfolio
5	E2 – Strategy E with greater coal unit idling
6	E1 – Strategy E with lower renewable portfolio
7	B – Baseline Plan Resource Portfolio
8	D – Nuclear Focused Resource Portfolio
9	A – Limited Change in Current Resource Portfolio

Figure 7-21 – Rank Order of Strategies

Sensitivity C1 was a slight improvement over planning Strategy C and now has the highest-ranking metric score among the options considered in the Draft IRP. Sensitivity C2 was slightly lower than Strategy C. As components changed, the stability of Strategy C represented a noteworthy quality. Sensitivities E1 and E2 did not improve the results as compared to Strategy E and were removed from further consideration for the final IRP.

7.2.4 Other Strategic Considerations

In addition to the metrics used to establish the rank order of the planning strategies, TVA included strategic metrics in the fully populated scorecard. These strategic metrics included environmental and regional economic impact measures that recognize other aspects of TVA's mission. These strategic metrics are fully discussed in Chapter 6 – Resource Plan Development and Analysis. Note that for the economic impact measures, all of the IRP strategies were analyzed only for Scenarios 1 and 6 – the scenarios that defined the upper and lower range of strategy impacts within the scenario range.

Figure 7-22 shows the strategic metrics for each of the five planning strategies.

Planning Strategy A

	Strategic Metrics				
	Environmental Stewardship			Economic Impact	
Scenarios	CO_2 Footprint	Water	Waste	Total Employment	Growth in Personal Income
1	○	◑	◑	0.1%	0.1%
2	○	◔	◔		
3	○	○	○		
4	○	◔	◑		
5	○	◔	◔		
6	○	○	◔	-0.4%	-0.4%
7	○	◔	◑		

Planning Strategy D

	Strategic Metrics				
	Environmental Stewardship			Economic Impact	
Scenarios	CO_2 Footprint	Water	Waste	Total Employment	Growth in Personal Income
1	●	◕	●	1.2%	1.0%
2	●	◕	●		
3	●	●	●		
4	●	◕	●		
5	●	●	●		
6	◕	●	●	-0.1%	-0.2%
7	●	●	●		

Planning Strategy B

	Strategic Metrics				
	Environmental Stewardship			Economic Impact	
Scenarios	CO_2 Footprint	Water	Waste	Total Employment	Growth in Personal Income
1	◔	○	○	1.0%	0.8%
2	◔	○	○		
3	◔	◔	◔		
4	◔	○	○		
5	◔	○	○		
6	◔	◔	○	-0.3%	-0.3%
7	◔	○	○		

Planning Strategy E

	Strategic Metrics				
	Environmental Stewardship			Economic Impact	
Scenarios	CO_2 Footprint	Water	Waste	Total Employment	Growth in Personal Income
1	◕	●	◕	0.8%	0.6%
2	◕	●	◕		
3	◕	◕	◕		
4	◑	●	◕		
5	◕	◕	◕		
6	●	◕	◕	0.3%	0.2%
7	◕	◕	◕		

Planning Strategy C

	Strategic Metrics				
	Environmental Stewardship			Economic Impact	
Scenarios	CO_2 Footprint	Water	Waste	Total Employment	Growth in Personal Income
1	◑	◔	◔	0.9%	0.6%
2	◑	◑	◑		
3	◑	◑	◑		
4	◕	◑	◔		
5	◑	◑	◑		
6	◑	◑	◑	0.2%	0.1%
7	◑	◑	◔		

Legend	
●	Better
◕	↑
◑	
◔	
○	

Figure 7-22 -- Strategic Metrics for Five Planning Strategies

Results of the CO_2 metric showed that Strategy D had the best performance (lowest emissions), followed by Strategies E, C, B and A. Each strategy showed a declining rate of emissions and the variance between each strategy was quite low since all coal-fired units that will remain in service are assumed to receive environmental controls. With that being said, all five strategies will be fully compliant with applicable air emissions regulations.

Results of the water metric indicated that Strategy D had the best performance, followed by Strategies E, C, A and B. Results of the waste metric show Strategy D had the best performance, followed by Strategies E, C, A and B. Additional information on all environmental metrics calculations can be found in Appendix A – Method for Computing Environmental Impact Metrics.

Based on the Draft IRP results, planning Strategies D and E had the best relative performance across the environmental metrics. Strategy C was average to slightly above average, and Strategies A and B had the lowest relative performance.

For the economic impact metrics, Strategy A was the worst performer. Strategies B, C, D and E had comparable results, within a few tenths of a percentage difference from the impacts computed for the reference portfolio (Strategy B in Scenario 7). Strategies C and E had very similar impacts, performing above the reference portfolio in the long term under both Scenarios 1 and 6.

Along with the strategic metrics, innovations that enable the utilization of key technologies in the planning strategies have been identified and summarized in Figure 7-23. The figure shows which of the five planning strategies would be impacted by each of the innovations in the future.

Technology Innovation	Description	A	B	C	D	E
Smart Grid Technologies	Advancements in this area are necessary to fully realize the EEDR benefits included in certain planning strategies		X	X	X	X
Transmission Design & Infrastructure	Improvements in transmission system devices to manage power flows and advancement in dc line technologies will be needed to facilitate power transfers and the import of additional wind-sourced power			X	X	X
Advanced Energy Storage	More research is needed to improve the design of pumped-storage hydro (PSH) and identify new storage technologies that might offer advantages similar PSH			X	X	X
Small Modular Nuclear Reactors	This technology may offer some flexibility for siting and operating nuclear capacity in those strategies that include a reliance on new nuclear capacity later in the planning period		X	X	X	X
Advanced Emission Controls for Coal-Fired Units	To enable full use of coal-fired resources, advances in emission controls (especially carbon capture and sequestration) are needed to achieve a more balanced long-term generation portfolio	X	X	X		

Figure 7-23 – Technology Innovation Matrix

TVA will closely monitor and possibly invest in these and other technology innovations during the planning period. The particular technology innovations that are necessary to implement the Recommended Planning Direction will likely shift as more information becomes available about each technology area and as power supply needs change.

In addition to the PVRR risk metrics discussed in Chapter 6 – Resource Plan Development and Analysis, there are other risks that were considered when evaluating the merits of alternative strategies. The financial risk measures included in the ranking metrics portion of the planning strategy scorecard may have indirectly accounted for some of these risks, but only in part. Examples of these broader, more difficult to quantify, risk considerations include:

- The ability of EEDR programs to stimulate distributor and customer participation and the programs' ability to deliver forecasted energy savings and demand reductions. The planning strategies with higher EEDR targets have a greater exposure to these risks
- The availability and deliverability of natural gas. There is finite capacity in the existing natural gas infrastructure. Risks of being limited by deliverability and availability will likely increase as natural gas generation capacity is increased
- The ability to achieve schedule targets for licensing/permitting, developing and constructing new generation capacity. Risks of meeting schedule targets will likely increase as the number and complexity of construction projects increase. In addition, projects with more extensive licensing/permitting requirements will likely have greater exposure to schedule risk
- The timely build-out of transmission infrastructure to support future resources. This is a particular concern with projects that may require transmission expansion outside of the TVA system, such as power purchase agreements for wind energy. Risks will likely increase as the amount of construction required increases and if that construction is undertaken by entities other than TVA
- Legislative and regulatory risks that could strand certain investments in coal-fired assets by, for example, applying a more stringent regulatory framework around coal-fired assets, or by mandating certain other types of generation, including renewables, that could crowd out existing sources of generation
- Game-changing technologies, either on the supply or demand side, that could either dramatically increase (i.e., new sources of demand) the need for electricity or dramatically decrease (i.e., distributed generation) the need for electricity in the long term

The list above is not intended to be exhaustive. It provides examples of other strategic components that TVA considered when it identified the preferred planning strategies in the Draft IRP as well as the Recommended Planning Direction in the final IRP. In addition, the analysis results and public input were considered. TVA encouraged those commenting on the Draft IRP to provide information about and share their views on these other risks.

7.3 Preferred Planning Strategies

Based on the Draft IRP results, TVA retained the top three ranked planning strategies for further analysis for the final IRP (Chapter 8 – Final Study Results and Recommended Planning Direction). Strategies C, E and B were retained from the Draft IRP to be subjected to additional analysis and sensitivity testing in an effort to determine improved combinations of planning components.

Illustrative portfolios (20-year resource plans) were identified as part of the evaluation. In the Draft IRP, a broad set of portfolios were identified that corresponded to the three planning strategies that were retained in the Draft IRP.

Four representative resource portfolios were selected from planning Strategies C, E and B. The 12 implementing portfolios for the Draft IRP are shown in Figure 7-24. These portfolios described a relatively broad set of resource plan options that were subjected to additional analysis before completing the final IRP. Portfolios produced in Scenario 1 represented the largest amount of new resource additions, while those produced in Scenario 3 represented the least amount of new resources that could be added over the planning period.

Year	Planning Strategy C				Planning Strategy E				Planning Strategy B			
	SC 1	SC 2	SC 3	SC 7	SC 1	SC 2	SC 3	SC 7	SC 1	SC 2	SC 3	SC 7
2010	PPAs & Acq				PPAs & Acq				PPAs & Acq			
2011												
2012	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	CTa								CTa CT GL CT Ref			
2015	CT GL CT Ref CC			GL CT Ref CC	GL CT Ref CTa CC (2)			GL CT Ref CC	CT CC	GL CT Ref		GL CT Ref CTa MKT
2016	CT			MKT	CT			MKT	CT			CT MKT
2017	MKT			MKT				MKT	CT			CTa MKT
2018	BLN1			BLN1	CT			CC	BLN1			BLN1
2019	MKT				CC				CT	BLN1		
2020	BLN2 PSH	PSH	PSH	BLN2 PSH	CC			MKT	BLN2			BLN2
2021	CT				CTa			MKT	CC	BLN2		
2022	CC MKT	BLN1			BLN1 MKT	BLN1		BLN1 MKT	CT CC			CC
2023	CC MKT				CT MKT			MKT	CT			CT
2024	NUC	BLN2		MKT	BLN2	BLN2		BLN2	NUC MKT			
2025	IGCC			CT	CT				IGCC	NUC		CT
2026	NUC			MKT	CT			CT	NUC		MKT	MKT
2027	CT			CC	CT				CT	NUC	MKT	CT
2028	CT				NUC			CTa	CC		MKT	MKT
2029	IGCC CTa	NUC		CTa	CT			CTa	IGCC CTa	CTa	CTa MKT	CC

Defined Model Inputs	
Coal-fired capacity idled	3,252 MW by 2015
Renewable firm capacity	953 MW by 2029
	8,791 GWh by 2029
EEDR	4,638 MW by 2029
	14,032 GWh by 2029

Defined Model Inputs	
Coal-fired capacity idled	4,730 MW by 2015
Renewable firm capacity	1,157 MW by 2029
	12,251 GWh by 2029
EEDR	6,043 MW by 2029
	16,455 GWh by 2029

Defined Model Inputs	
Coal-fired capacity idled	2,415 MW by 2015
Renewable firm capacity	160 MW by 2029
	4,231 GWh by 2029
EEDR	2,520 MW by 2029
	7,276 GWh by 2029

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

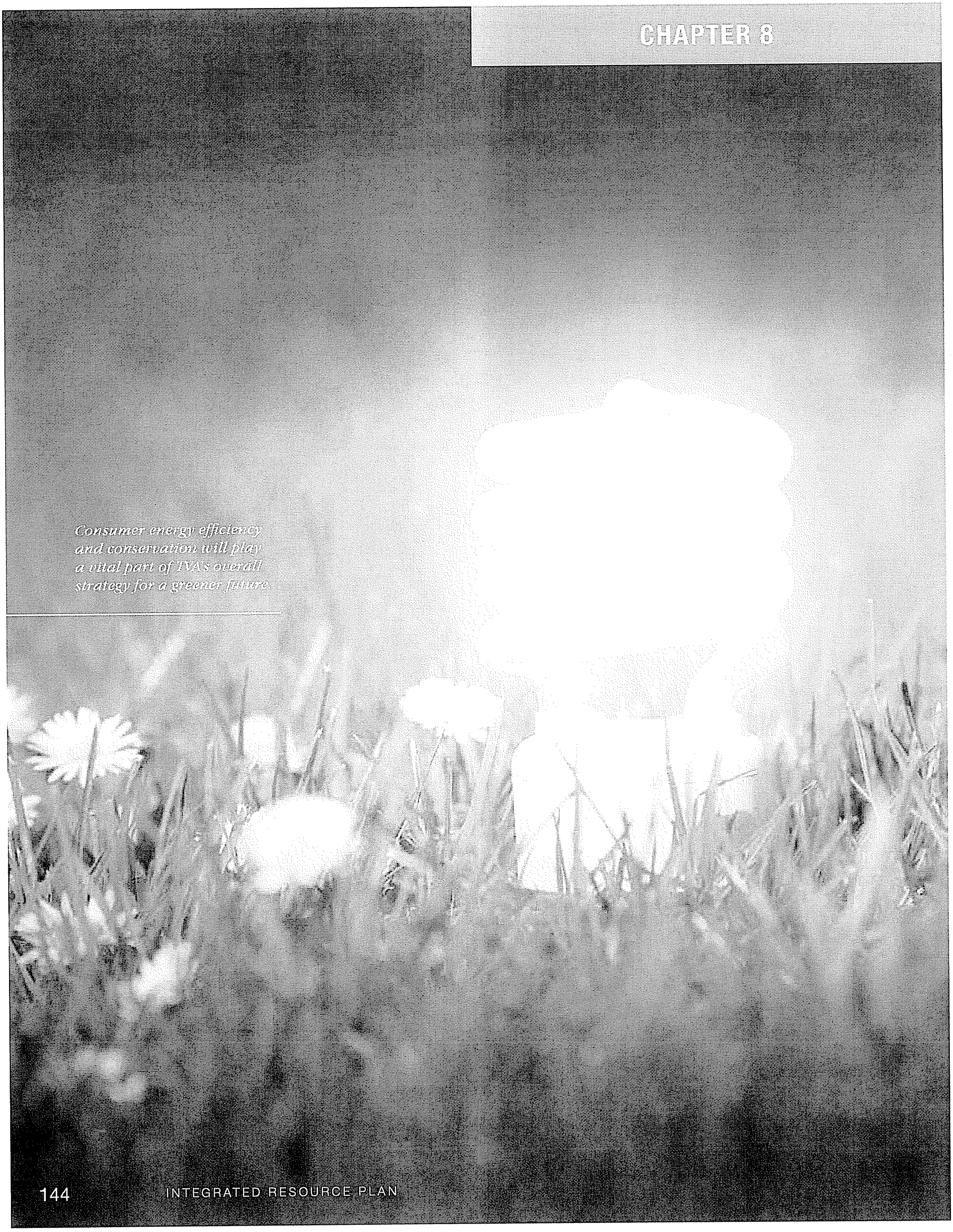
NUC = nuclear unit

IGCC = integrated gasification combined cycle (coal technology)

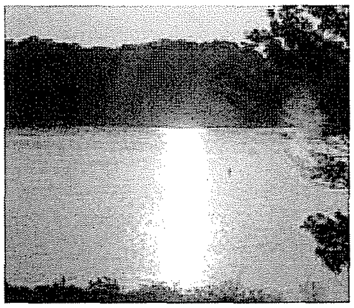
MKT = Purchased Power

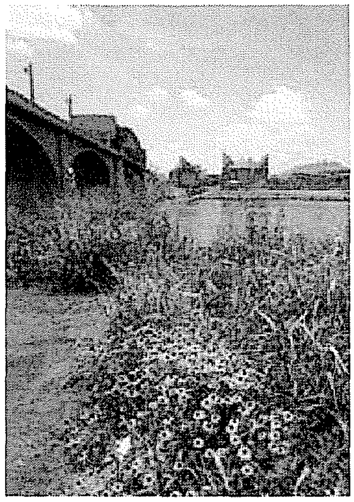
Figure 7-24 – Implementing Portfolios (Initial Phase)

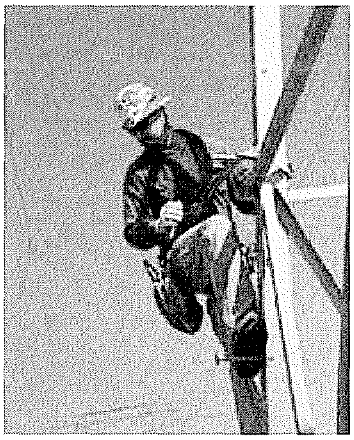
CHAPTER 8



Consumer energy efficiency and conservation will play a vital part of TVA's overall strategy for a greener future







TVA's resource portfolio will continue to diversify in the future with the pursuit of new ways to harness renewable energy sources that are environmentally conscious and sustainable.

Scenarios and Strategies

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 Regulation 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

8 Final Study Results and Recommended Planning Direction

TVA's IRP was developed in two major phases – the draft and final. The Draft IRP recommended retaining three of the five original planning strategies. This provided the starting point for the development of the final IRP in fall 2010. Considering updated forecast information and public comments, additional analyses were conducted with the goal of developing a "no-regrets" strategy. This was accomplished by fine-tuning and improving the strategies selected in the Draft IRP. The analyses included rescoring the ranking and strategic metrics in order to evaluate new component combinations identified in the analyses. This chapter describes the final analysis results and the Recommended Planning Direction that was produced by evaluating the analysis results, stakeholder input and other considerations.

8.1 Results Analysis

8.1.1 Firm Requirements and Capacity Gap

The final IRP used the same firm requirements and capacity gaps as discussed in Chapter 7 – Draft Study Results. In addition to the scenarios used in the Draft IRP, an additional reference case was created to reflect the lingering economic recession as shown in Figure 8-1.

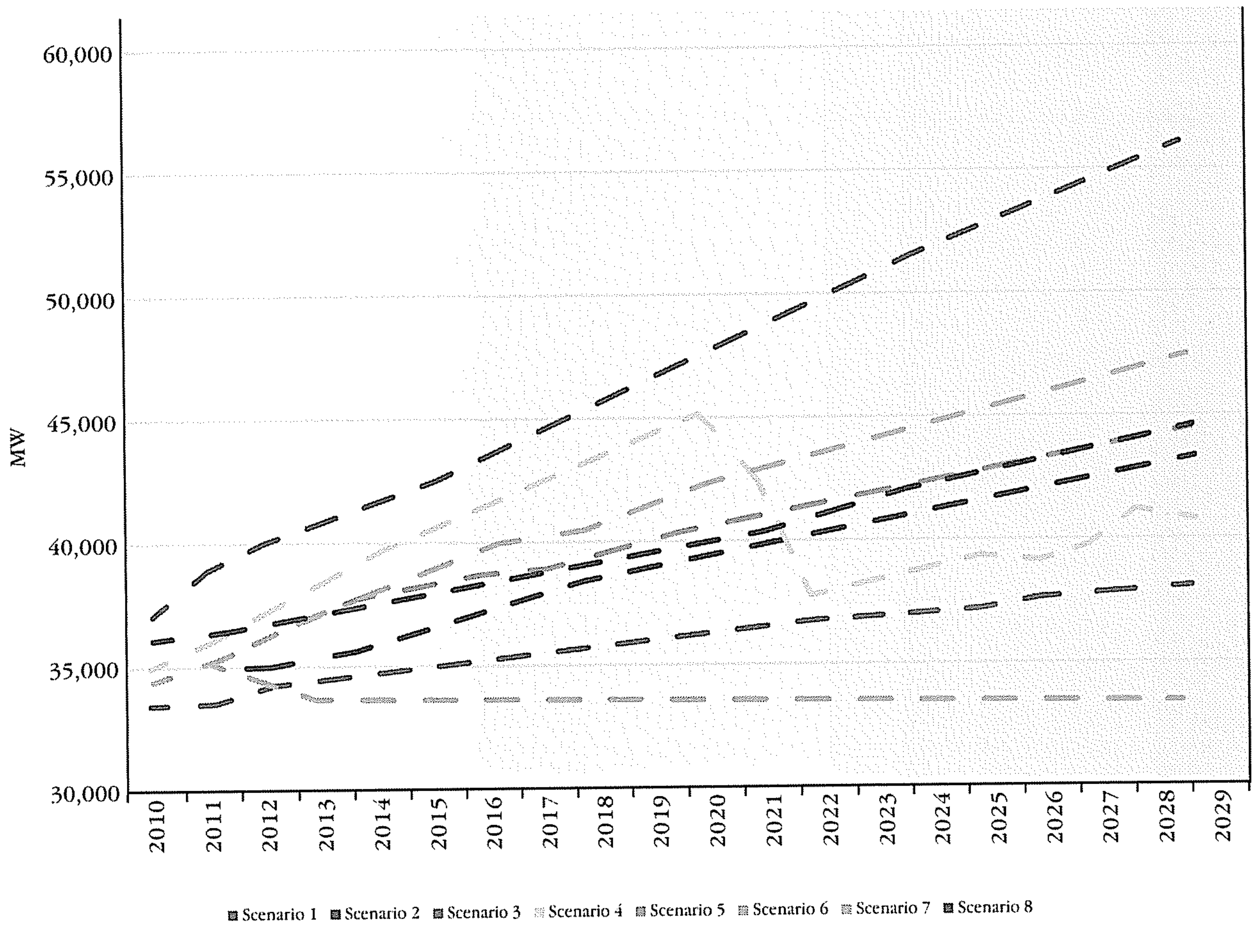


Figure 8-1 – Firm Requirements by Scenario

8.1.2 Previously Identified Sensitivities

Additional sensitivity cases were identified from work done for the Draft IRP and feedback received from stakeholders. The type of sensitivity, the purpose for analysis and the method that was incorporated into the final IRP analysis are listed in Figure 8-2.

Sensitivity Description	Basis for Selection	Method for Addressing
Evaluate increment/decrement of renewable additions for Strategy C	To identify the optimum level of renewable additions given the other assumptions already set in this strategy	• The range of renewable additions retained in the Draft IRP (along with additional increments) will be a selectable resource in the blended optimization
Evaluate alternate idled capacity values for Strategy C	To test the impact of varying idled capacity values	• The range of idled capacity retained in the Draft IRP will be evaluated with all other resources in the blended optimization
Evaluate increment/decrement of EEDR impacts for Strategy C	To identify the optimum level of EEDR given the other assumptions already set in this strategy	• The range of EEDR portfolios retained in the Draft IRP will be a selectable resource in the blended optimization
Test "gas-only" expansion in Strategy C	To evaluate the impact of gas capacity expansion on the short-term rate metric score	• "Gas-only" expansion will not allow nuclear additions • To be tested with 3,200 MW of idled capacity • All other factors will be optimized
Evaluate an aggressive EEDR portfolio that targets 50% of the capacity gap beginning in 2015	To evaluate the impact on plan cost and risk for a more aggressive portfolio of EEDR programs	• The 50% target will be based upon the capacity gap in the latest reference case (Scenario 8) with 3,200 MW of idled capacity • All other factors will be optimized
Test deferral of nuclear expansion in Strategy C until 2020	To identify the capacity additions that would be required if nuclear was not available	• Schedule of nuclear additions will be optimally selected based on the options and constraints described previously

Figure 8-2 – Sensitivity Runs Identified From Draft IRP

8.1.3 Final Study Results

The study approach in the final IRP produced 12 portfolios that resulted from a blended optimization. The boundaries (resource constraints) were defined by the planning strategies (Strategies B, C and E) retained in the Draft IRP. The 12 cases were produced by testing four possible levels of idled coal-fired capacity in each of the three representative scenarios (Scenarios 1, 3 and 8) which represent the high, medium and low load forecasts described in Section 6.1 – Development of Scenarios and Strategies. Multiple iterations were used to test all levels of idled coal-fired capacity. Optimum renewable and EEDR portfolios were selected for each assumed level of idled coal-fired capacity. Figure 8-3 summarizes the results of those cases.

	Scenario 1 Capacity Additions				Scenario 8 Capacity Additions				Scenario 3 Capacity Additions			
Idled Capacity[1]	2,400	3,200	4,000	4,700	2,400	3,200	4,000	4,700	2,400	3,200	4,000	4,700
Renewable Portfolio	2,500	2,500	2,500	2,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
EEDR Portfolio	5,074	5,074	5,074	5,074	3,627	3,627	5,074	5,074	3,627	3,627	3,627	3,627
2010	PPAs	PPAs	PPAs	PPAs								
2011												
2012	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2
2014												
2015	CTb PPAs	CTb PPAs MKT	CC CTb PPAs	CC (2) CTb PPAs	CTb	CTb	CTb	CC CTb				CC
2016	MKT	CC	CTa	CTa								
2017	CC	CTa	CT	CTa								
2018	BLN 1	BLN 1	BLN 1	BLN 1								
2019						MKT						
2020	BLN 2 PSH	BLN 2 PSH	BLN 2 PSH	BLN 2 PSH	BLN 1 PSH	BLN 1 PSH	BLN 1 PSH	BLN 1 PSH	PSH	PSH	PSH	PSH
2021												
2022	CT CTa	CC CT	CC CT	CC CT	BLN 2	BLN 2	BLN 2	BLN 2				
2023	CT	CT	CTa	CT								
2024	NUC	NUC	NUC	NUC								
2025	IGCC	MKT	IGCC	IGCC								
2026	NUC	NUC	NUC	NUC		CTa						
2027	CT	CT	IGCC	IGCC		MKT						
2028	CT	CT	CT	CTa IGCC	CTa	CT	CTa	CTa				
2029	CC	CT IGCC	CT IGCC	CTa IGCC	CT	CT	CTa	CTa				

1 – MW values based on maximum net dependable capacity

Abbreviation	Name
BLN 1	Bellefonte Nuclear Unit
CC	Combined Cycle Combustion Turbine (Natural Gas)
CT	Combustion Turbine (Natural Gas) ~800 MW
CTa	Combustion Turbine (Natural Gas) ~600 MW
CTb	Combustion Turbine Refurbishment (Natural Gas)
IGCC	Integrated Gasification Combined Cycle (Coal)
JSF CC	John Sevier Combined Cycle (Natural Gas)
MKT	Annual market purchases greater than 400 MW
NUC	AP 1000 Nuclear Unit
PPAs	Purchased Power Agreements and Acquisitions
PSH	Pumped-storage Hydro
WBN 2	Watts Bar Nuclear Unit 2

Figure 8-3 – The 12 Portfolios

Referring to the blended optimization results, the following general observations were made:

- Nuclear expansion is present in the majority of portfolios with the first unit on line between 2018 and 2020
- Expanded energy efficiency and demand response (EEDR) portfolios performed well in the optimization cases. The mid level portfolio (3,600 MW and 11,400 annual GWh reductions by 2020) was chosen in half of the cases
- Renewable generation above existing wind contracts plays a key role in future resource portfolios
- Expansion of natural gas capacity is needed, but typically occurs after 2024. Gas may serve as the most advantageous way to address any emerging supply shortage
- Preliminary financial results show that component ranges considered produced relatively robust plans with little variation in total plan costs (PVRR) within scenarios

The cost and risk metrics for the portfolios produced in the blended optimization were relatively constant across the coal-fired capacity levels, especially in Scenarios 3 and 8. This is illustrated in Figure 8-4 which compares the short-term rates ranking metrics for the portfolios organized by idled coal-fired capacity level (2,400/3,200/4,000/4,700 MW).

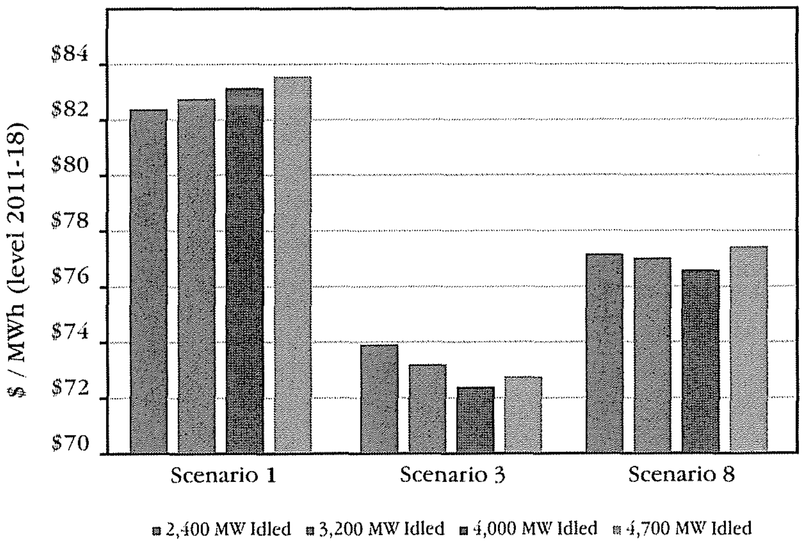


Figure 8-4 – Short-Term Rate Impacts by Scenario

This outcome was primarily driven by two characteristics. First, new unit additions are very similar in these two scenarios for all four coal-fired idling levels. Second, as the amount of idled coal-fired capacity increased from 3,200 to 4,700 MW, a larger EEDR portfolio was selected in Scenario 8. This larger portfolio had similar costs in comparison to the smaller EEDR portfolio chosen at the 2,400 MW and 3,200 MW levels. In addition, no expansion resources were selected in Scenario 3. As a result, overall PVRR for the plans was essentially unchanged.

The two metrics that measure financial risk for these resource plans were also essentially unchanged across the levels of idled coal-fired capacity except for Scenario 3. The variation seen in Scenario 3 was the result of increasing idling levels, which had an impact on the dispatch of resources in the existing system since there were no expansion resources added in that scenario.

In general, the ranking metrics show that the 12 cases produced in the blended optimization represented robust expansion solutions. The overall results were clustered closely together despite the changes in idled coal-fired capacity assumed and the variation of the key assumptions tested in the stochastic analysis. This set of portfolios represents a more focused set of possible expansion alternatives and was used to define the characteristics of the Recommended Planning Direction.

8.2 Component Identification

The Recommended Planning Direction was designed by utilizing the findings from the blended optimization to select the components that became part of the strategy. The strategy design considered the following major factors:

Stakeholder input	• Continuous dialogue with the Stakeholder Review Group • Input received from the fall 2010 Draft IRP public comment period • Quarterly public briefings conducted by TVA staff and responses to surveys
Analysis results	• Output from the resource optimization cases and associated financial modeling translated into ranking and strategic metrics
Recognition of non-quantified risks	• "No-regrets" approach • Broader considerations not fully captured in the quantitative analysis, but have some impact on the selection process

8.2.1 Idled Coal-Fired Capacity

Selection of the preferred level of idled coal-fired capacity was the next step in producing the case results in the final IRP. Cost and risk ranking metrics used in the Draft IRP were applied to select a level of idled coal-fired capacity from the options considered. Each idled capacity level was given an ordinal rank for each metric within a scenario.

The ordinal rankings for each scenario were weighted using the same formula as applied in the Draft IRP. Scores were summed for each idled coal-fired capacity level to create total ranking scores. Results are shown in Figure 8-5.

	Idled Capacity	Scenarios			Total
		Sc 1	Sc 3	Sc 8	
Weighted Ranking	2,400	1.7	3.0	2.4	7.1
	3,200	2.7	2.2	2.7	7.7
	4,000	2.5	1.7	1.7	5.9
	4,700	3.1	3.1	3.2	9.4

Figure 8-5 – Weighted Ranking Scores

Based on the ranking results, the 4,000 MW level performed the best across the three scenarios and was used as the scorecard value. This level of idled coal-fired capacity was used as a fixed assumption for further refinement of the remaining components of the Recommended Planning Direction. Model results were then reviewed to identify optimal values for the renewable resources portfolio and the level of EEDR.

8.2.2 Renewable Portfolio

In the least-cost optimized plans, results tended to favor the 1,500 MW portfolio, which represented the current wind contracts as the preferred level. However, based on stakeholder comments and feedback on the Draft IRP desiring an increased emphasis on renewable development, the Recommended Planning Direction was increased to incorporate the 2,500 MW portfolio which was used as the scorecard value. This reflects projected growth of 1,000 MW of additional renewables above existing and contracted amounts. Figure 8-6 shows a potential mix of components in this renewable portfolio.

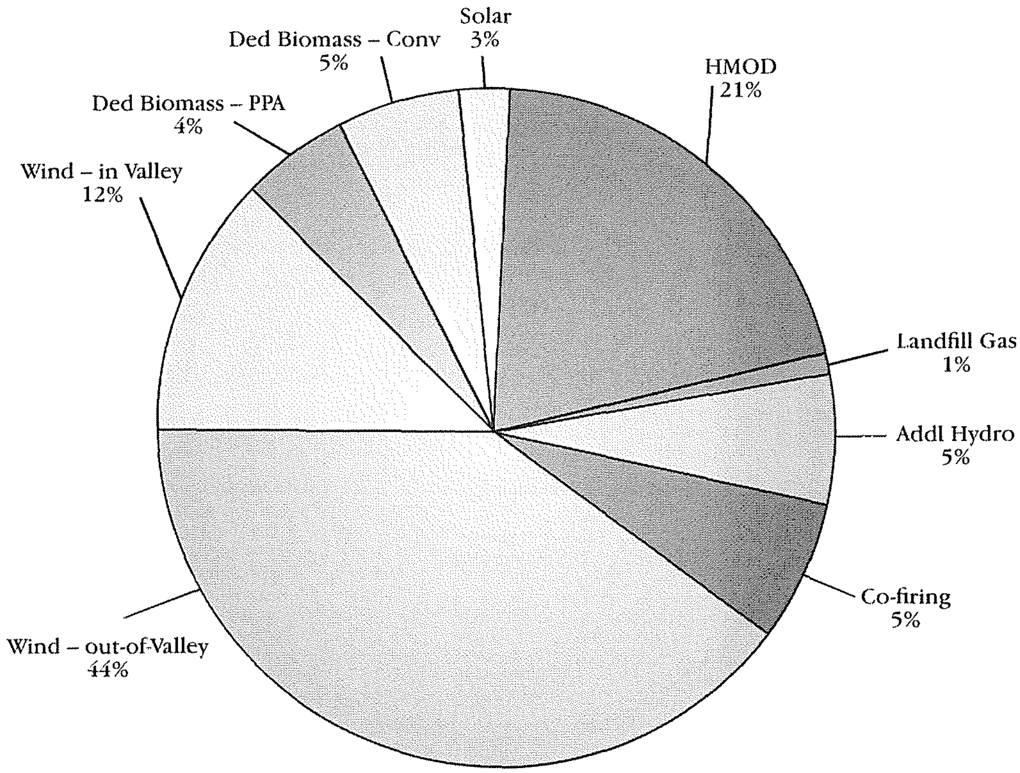


Figure 8-6 – Potential 2,500 MW Renewable Portfolio

Prior to making this decision, the cost premium to increase to the 2,500 MW portfolio was calculated. It was determined to be relatively small (typically less than 1 percent of total plan cost). Not all of this cost change was directly attributable to the renewable portfolio itself because of other changes in the resource plan. This premium was deemed acceptable given TVA's objectives to increase reliance on cleaner and more environmentally responsible energy sources.

8.2.3 EEDR Portfolio

The modeling results were evenly split in selecting either the mid level EEDR portfolio (3,600 MW by 2020) or the larger portfolio (5,100 MW by 2020). For reference, the mid level portfolio was part of Strategy C, and the larger portfolio was included in Strategy E in the Draft IRP.

Given the uncertainty about the pace of customer participation and the implementation challenge for TVA associated with the larger portfolio, the mid level EEDR portfolio was used as the scorecard value. This selection also recognized there are similar non-quantified risks associated with implementation of this mid level portfolio. Those risks were deemed to be sufficiently manageable to include the portfolio in the Recommended Planning Direction.

For a more complete discussion of the non-quantified risks that were part of TVA's assessment of the planning strategies, see Chapter 6 – Resource Plan Development and Analysis.

8.3 Recommended Planning Direction Development

8.3.1 Key Characteristics

After the key components of idled coal-fired capacity, EEDR and renewables were determined, the key characteristics of the strategies following the blended optimization were observed. These observations are shown in Figure 8-7.

Component	Observations
Nuclear additions	Nuclear expansion is present in the majority of portfolios. Up to three[1] units are added between 2013 and 2029
Coal additions	New coal capacity is only selected after 2025 in scenarios with dramatic load growth
Natural gas additions	Expansion of natural gas is needed, but typically occurs after 2024 with simple-cycle combustion turbines. The dramatic load growth scenario is an exception as combined cycles and combustion turbines are chosen as early as 2015. Additional units may be required for reliability and/or grid stability
Renewable additions	Model results tend to favor the current wind contracts (1,500 MW) as the least cost plan. The renewable portfolio that delivers 2,500 MW by 2029 is selected in the dramatic load growth scenario
EEDR	Results evenly split in selecting either the 3,600 MW by 2020 portfolio and the 5,000 MW by 2020 portfolio

1 – Included in number of nuclear units is TVA Board of Directors' approved project Watts Bar Unit 2

Figure 8-7 – Observations Developed from Preliminary Results

The remaining components of the Recommended Planning Direction were selected with consideration of these outcomes. Figure 8-8 is a tabular summary of the Recommended Planning Direction.

Component	Guideline MW Range	Window of Time	Recommendations
EEDR	3,600-5,100 (11,400-14,400 GWh)	By 2020[1]	Expand contribution of EEDR in the portfolio
Renewable additions	1,500-2,500[2]	By 2020[1]	Pursue cost-effective renewable energy
Coal-fired capacity idled	2,400-4,700[3]	By 2017	Consider increasing amount of coal capacity idled
Energy storage	850[4]	2020-2024	Add pumped-storage capacity
Nuclear additions	1,150-5,900[5]	2013-2029	Increase contribution of nuclear generation
Coal additions	0-900[6]	2025-2029	Preserve option of generation with carbon capture
Natural gas additions	900-9,300[7]	2012-2029	Utilize natural gas as an intermediate supply source

1 – This range includes EEDR savings achieved through 2020. The 2020 range for EEDR and renewable energy does not preclude further investment in these resources during the following decade

2 – TVA's existing wind contracts that total more than 1,600 MW are included in this range. Values are nameplate capacity. Net dependable capacity would be lower

3 – TVA has previously announced plans to idle 1,000 MW of coal-fired capacity, which is included in this range. MW values based on maximum net dependable capacity

4 – This is the expected size of a new pumped-storage hydro facility

5 – The completion of Watts Bar Unit 2 represents the lower end of this range

6 – Up to 900 MW of new coal-fired capacity is recommended between 2025 and 2029

7 – The completion of John Sevier combined cycle plant represents the lower end of this range

Figure 8-8 – Recommended Planning Direction

The above figure contains seven components that comprise the strategy and shows a range of the amount for each component as well as the timing of when these components would be added to the system.

8.3.2 Recommended Planning Direction Illustrative Portfolios

After the Recommended Planning Direction was defined, it was evaluated to determine if it represented an improvement over the strategies evaluated in the Draft IRP. A group of portfolios was developed and scored.

To produce the portfolios, the Recommended Planning Direction was tested in each of the eight scenarios. These portfolios were based on scorecard values for the key components of the Recommended Planning Direction (idled coal-fired capacity, EEDR and renewables) with optimized additions of the other resources that made up the capacity plans.

The resultant portfolios are illustrative in nature and based on the particular set of assumptions contained in each of the scenarios. Figure 8-9 is a tabular summary of the illustrative portfolios for the Recommended Planning Direction and shows the resource plans that result in each of the eight scenarios.

Year	Capacity Additions by Scenario									
	EEDR	Renewables	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
2010	300 MW	300 MW	PPAs							
2011										
2012			JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013			WBN 2 PPAs	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2
2014			CT			CTb PPAs				
2015			CC CTb CT PPAs			CC PPAs	CTb PPAs		CTb PPAs	CTb PPAs
2016			CT			CT	MKT		MKT	MKT
2017			MKT			MKT			MKT	
2018			BLN 1	BLN 1		BLN 1			BLN 1	
2019			MKT			MKT	MKT		MKT	MKT
2020	3,600 MW	2,500 MW	BLN 2 PSH	BLN 2 PSH	PSH	BLN 2 PSH	BLN 1 PSH	PSH	BLN 2 PSH	BLN 1 PSH
2021			CC							
2022			CC MKT				BLN 2			BLN 2
2023			CT MKT						CTa	
2024			NUC							
2025			IGCC MKT						CT	
2026			NUC						MKT	CT
2027			CT				MKT		CT	MKT
2028			CT				CT		MKT	CT
2029	4,600 MW	2,600 MW	CT IGCC	CT			CT		CT	CT

*Illustrative portfolios assume 4,000 MW of idled coal-fired capacity by 2015

Additions			
Natural Gas		Pumped Hydro	
Coal		Renewables	
Nuclear		EEDR	
Purchased Power			

Figure 8-9 – Illustrative Portfolios for the Recommended Planning Direction

After reviewing the resource plans in Figure 8-9, the following observations can be made about near-term and long-term additions:

- Near-term additions (0-5 years) were generally consistent across the scenarios, reflecting the addition of approved projects by the TVA Board of Directors, which include additions at John Sevier and Watts Bar. Resource additions in this time frame also included new natural gas plants and purchased power arrangements, depending on load growth

- Long-term additions (5-20 years) were somewhat more flexible. Nuclear capacity was a major component of the capacity plans in this period, with the first nuclear unit typically added between 2018 and 2020. Expansion of natural gas capacity often occurred after 2024

8.3.3 Recommended Planning Direction Validation

The Recommended Planning Direction was scored using the same ranking and strategic metrics utilized in the Draft IRP. The scorecard results of the Recommended Planning Direction were compared to the scorecard results of the strategies retained from the Draft IRP. Figure 8-10 is a fully populated scorecard for the Recommended Planning Direction, and Figures 8-11 and 8-12, respectively, show scorecards from the Draft IRP for Strategy C and Strategy E.

	Ranking Metrics					Strategic Metrics				
	Financial Impact					Environmental Stewardship			Economic Impact	
Scenarios	PVRR	Short-Term Rate Impact	PVRR Risk/ Benefit	PVRR Risk	Total Plan Score	CO_2 Foot-print	Water	Waste	Total Em-ploy-ment	Growth in Per-sonal Income
1	99.00	95.13	100.00	99.53	98.36	◕	◕	◕	0.9%	0.7%
2	100.00	95.58	99.40	95.30	97.85	◕	◑	◑		
3	100.00	100.00	99.81	89.37	97.56	◕	◕	◕		
4	100.00	97.40	100.00	95.37	98.36	●	◕	◕		
5	100.00	96.43	100.00	100.00	99.19	◕	◕	◑		
6	100.00	100.00	100.00	86.69	96.97	◕	◕	◕	0.2%	0.1%
7	100.00	97.24	100.00	97.03	98.70	◕	◕	◕		
8	99.84	96.66	98.35	97.93	98.50	◕	◕	◑		
				Total Ranking Metric Score	785.49					

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Legend	
●	Better
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○	

Figure 8-10 – Recommended Planning Direction

	Ranking Metrics					Strategic Metrics				
	Financial Impact					Environmental Stewardship			Economic Impact	
Scenarios	PVRR	Short-Term Rate Impact	PVRR Risk/ Benefit	PVRR Risk	Total Plan Score	CO_2 Foot-print	Water	Waste	Total Em-ploy-ment	Growth in Per-sonal Income
1	99.22	94.09	97.68	100.00	98.04	◑	◑	◑	0.9%	0.6%
2	96.35	100.00	96.46	95.85	97.08	◑	◕	◕		
3	95.56	94.68	100.00	100.00	96.91	◑	◑	◑		
4	97.39	98.37	98.19	100.00	98.30	◕	◑	◑		
5	98.90	100.00	97.49	99.17	99.04	◑	◑	◕		
6	95.08	94.41	97.83	93.22	94.82	◑	◑	◑	0.2%	0.1%
7	98.88	98.94	99.45	100.00	99.22	◑	◑	◑		
8	99.56	99.63	99.03	99.31	99.45	◑	◑	◕		
				Total Ranking Metric Score	782.86					

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(shading, darkest to lightest)	Better ↑

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Figure 8-11 – Planning Strategy C – Updated Scorecard

	Ranking Metrics					Strategic Metrics				
	Financial Impact					Environmental Stewardship			Economic Impact	
Scenarios	PVRR	Short-Term Rate Impact	PVRR Risk/ Benefit	PVRR Risk	Total Plan Score	CO_2 Foot-print	Water	Waste	Total Em-ploy-ment	Growth in Per-sonal Income
1	100.00	100.00	96.78	95.46	98.57	●	●	●	0.8%	0.6%
2	97.74	98.20	99.96	98.54	98.30	●	●	●		
3	94.67	93.55	95.91	97.73	95.26	●	●	●		
4	96.83	100.00	93.42	89.57	95.48	◑	●	●		
5	98.72	99.50	96.33	98.64	98.59	●	●	●		
6	95.62	93.91	99.65	100.00	96.72	●	●	●	0.3%	0.2%
7	98.56	100.00	98.42	98.96	98.96	●	●	●		
8	100.00	100.00	100.00	100.00	100.00	●	●	●		
				Total Ranking Metric Score	781.88					

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(shading, darkest to lightest)	Better ↑

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Figure 8-12 – Planning Strategy E – Updated Scorecard

Comparing the Recommended Planning Direction to the top two strategies from the Draft IRP (Strategy C and Strategy E) shows that the Recommended Planning Direction represents the most favorable blending of portfolio components. The performance of the Recommended Planning Direction across all scenarios implies that it is a more robust approach with a lower likelihood of regret. The following are additional observations based on the scorecard results:

- The Recommended Planning Direction was the top performer on total plan cost (PVRR) in six of the eight scenarios tested
- The Recommended Planning Direction was the top performer on the risk/benefit ratio metric in five of the eight scenarios
- The strategic metrics for the Recommended Planning Direction were improved from metrics for Strategy C (the top-ranked strategy from the Draft IRP), but were not as good as the strategic metrics for Strategy E
- The economic impact metrics for the Recommended Planning Direction were similar to the metrics for the strategies retained from the Draft IRP, indicating there was no significant difference among the strategies in terms of macroeconomic impacts

The Recommended Planning Direction provided a more effective balance between plan cost and financial risk, as shown in Figure 8-13. The graph presents a cost versus risk curve, and the Recommended Planning Direction provided the lowest combination of plan cost (PVRR) and financial risk of any of the strategies that were considered in this IRP.

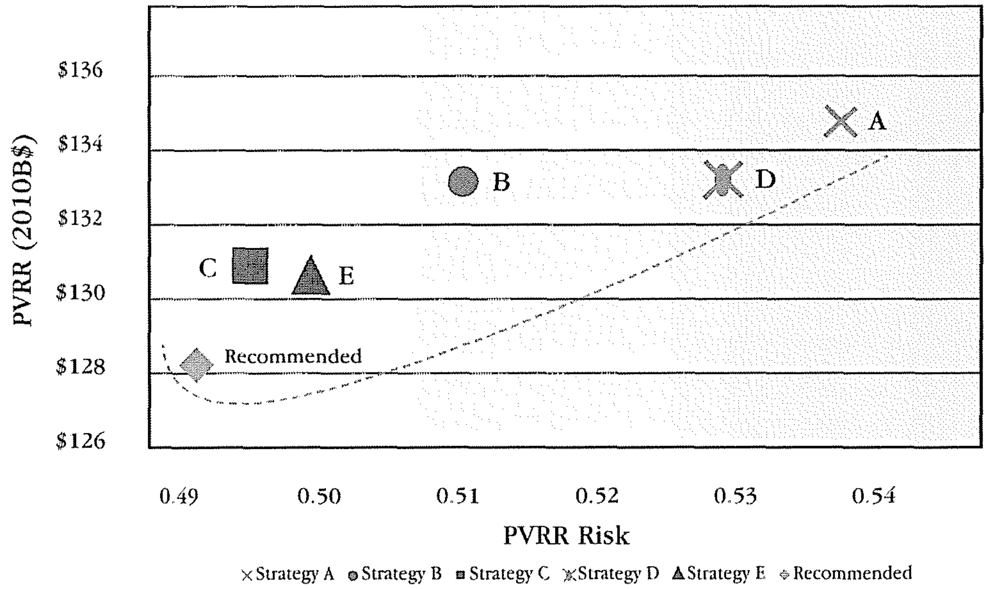


Figure 8-13 – Plan Costs vs. Financial Risk

Figure 8-14, a risk trade-off graph that compares financial risk versus the risk/benefit ratio, reinforces the conclusion drawn from Figure 8-13. This shows that improved risk performance comes at a higher overall plan cost.

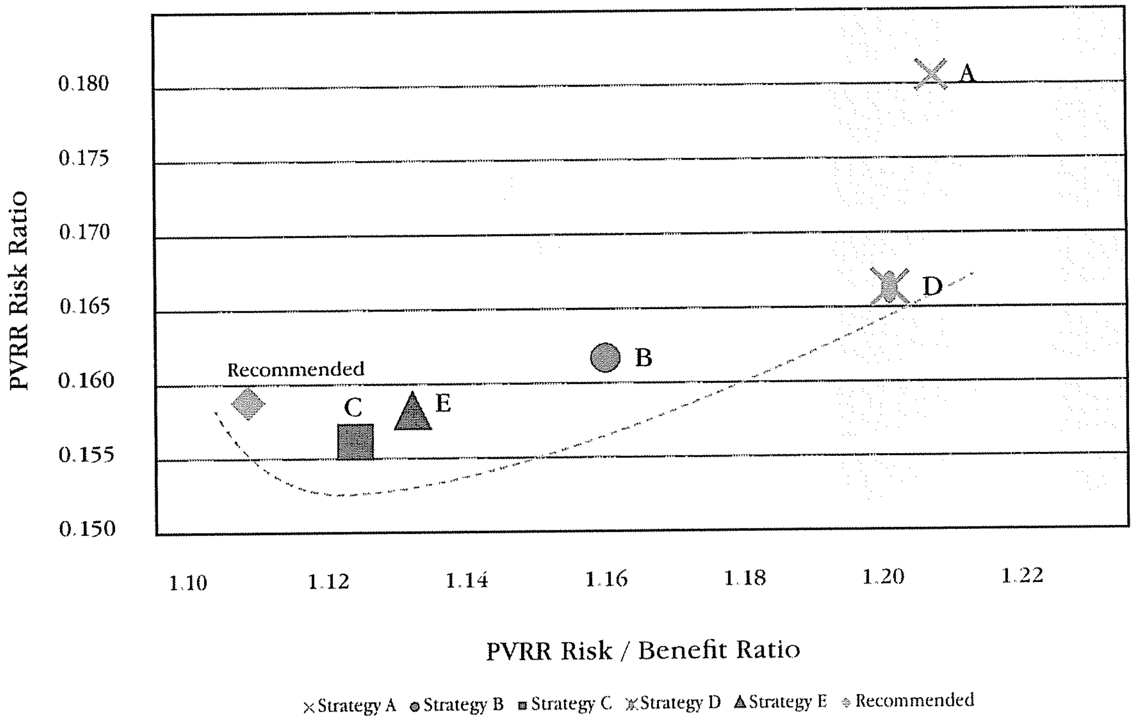


Figure 8-14 – Comparison of Financial Risks of Strategies

The uncertainty range in PVRR across the scenarios was another measure of performance used to assess the Recommended Planning Direction. Figure 8-15 is a tornado diagram of the variation in total plan cost (PVRR) from the stochastic analysis of the strategies in each of the eight scenarios. The width of the bars indicates the variation and uncertainty in plan cost. This figure shows that in most scenarios the Recommended Planning Direction (R) had the smallest range of cost uncertainty and that the expected value of the total plan cost was lower compared to the other strategies (C or E).

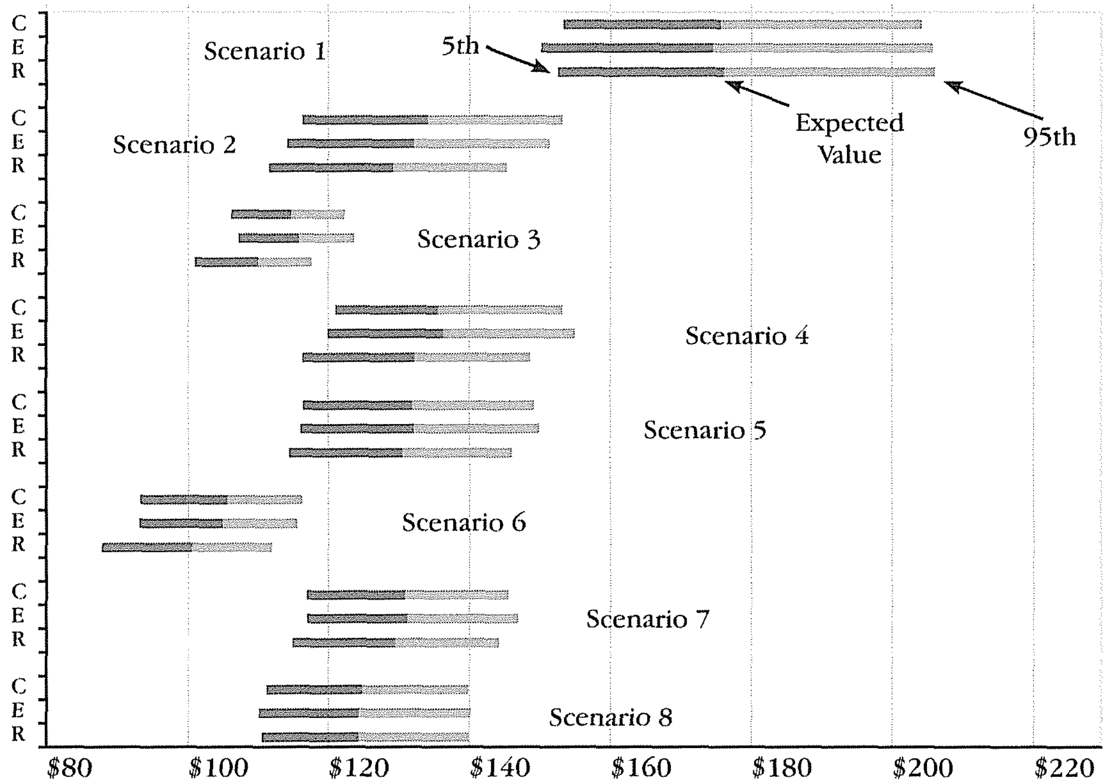


Figure 8-15 – PVRR (2010 $B)

In addition to financial trade-offs, the Recommended Planning Direction also provided the best balance of plan cost and environmental footprint, represented by the graph of plan cost versus CO_2 tons shown in Figure 8-16.

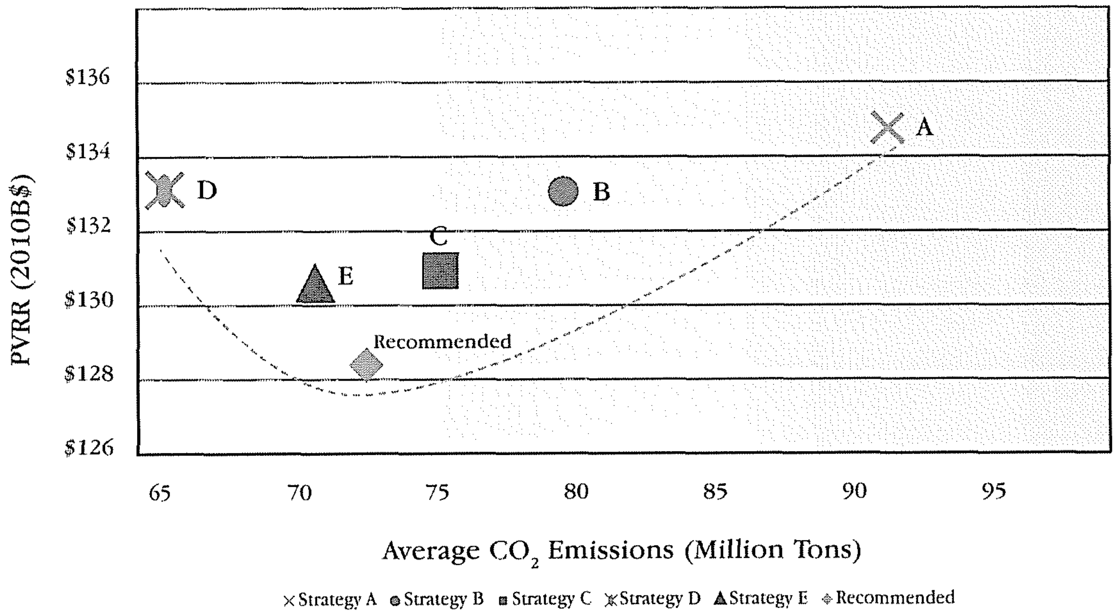


Figure 8-16 – Plan Costs vs. Annual CO_2 Emissions

8.3.4 Other Considerations

The modeling results represented by the ranking and strategic metrics, along with other financial and risk assessments discussed in the preceding section, provided strong support for the Recommended Planning Direction. However, as indicated in Section 7.2.4 – Other Strategic Considerations, the analytics are not the only considerations that were factored into the selection of TVA's Recommended Planning Direction. Certain non-quantified risk concerns, also known as "no-regrets considerations," were included, either directly or indirectly, when making the selection. Figure 8-17 shows the key items of the "no-regrets considerations."

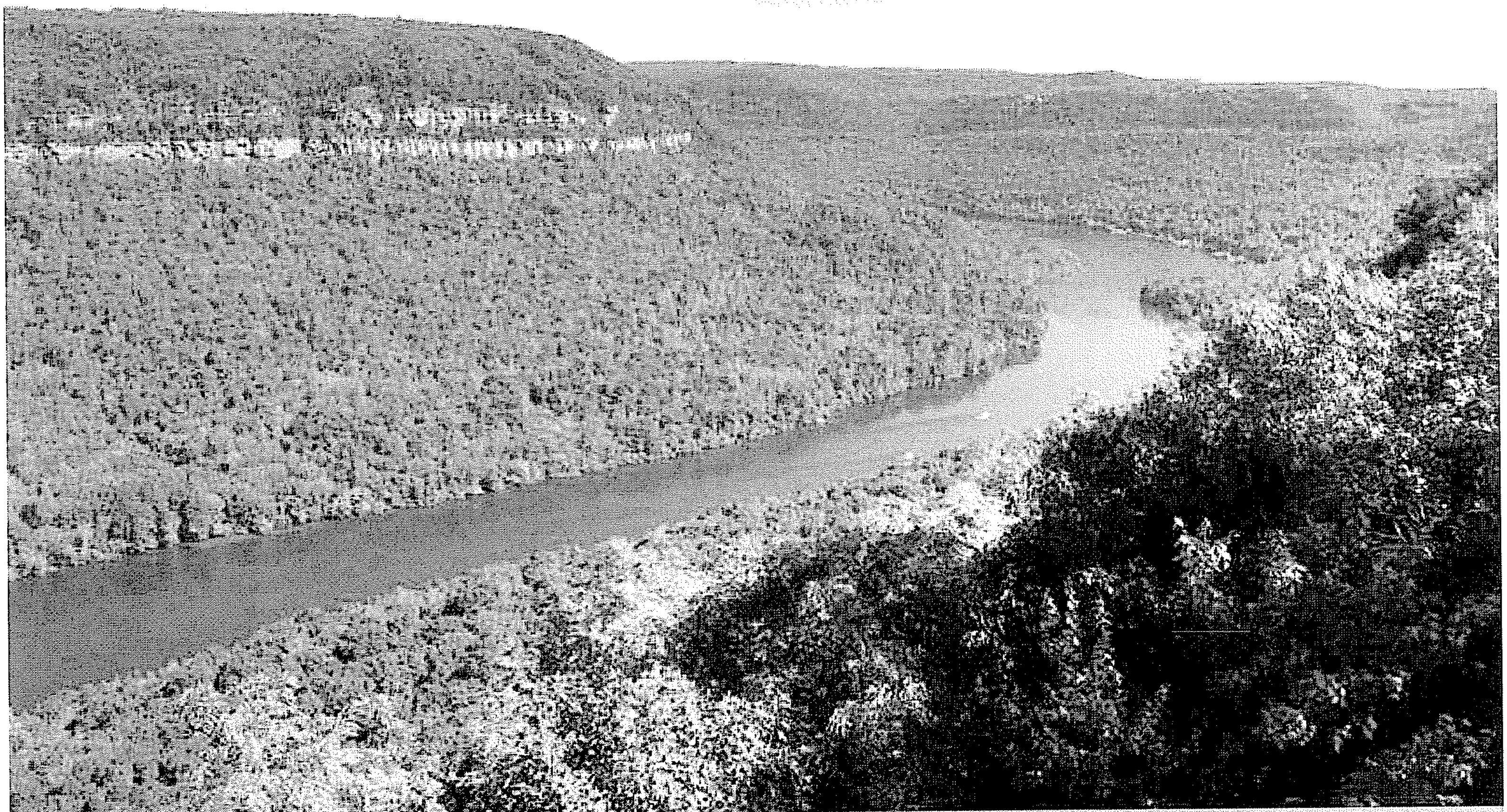
Other Risk Considerations	Potential Implications	Potential Early Warning Signs
Establishing a successful partnership with distributor group to administer EEDR programs and deliver forecasted reductions	• Planning strategies with higher EEDR targets will have a greater exposure to this risk	• Delays in establishing formal agreement with distributors by end of FY 2012
The ability of EEDR programs to stimulate customer participation and deliver forecasted reductions	• Planning strategies with higher EEDR targets will have a greater exposure to this risk	• Measurement and verification data of actual reductions is significantly below forecast
The ability to achieve schedule targets for licensing/permitting, developing and constructing large baseload generation	• Risks of meeting schedule targets will likely increase as the number and complexity of construction projects increase • Projects with more extensive permitting requirements may have greater exposure to schedule risk	• Critical internal resources for permitting, design, and construction are not maintained for upcoming projects • Dramatic changes in licensing/ permitting requirements
The timely build-out of transmission and distribution (smart grid) infrastructure to support future resources	• Risks will likely increase as the amount of construction required increases; particularly if that construction is undertaken by entities other than TVA	• Diminished availability of transmission design and construction resources • Limited smart grid capability added to distribution system by 2015
The ability to maintain appropriate operational flexibility after significant changes in resource mix	• Risks of limiting operational flexibility increase as the quantity of baseload, dispatchable, and non-dispatchable resources change	• Prolonged increases in system load factor • Emergence of barriers that delay addition of energy storage

Figure 8-17 – Other Risk Considerations

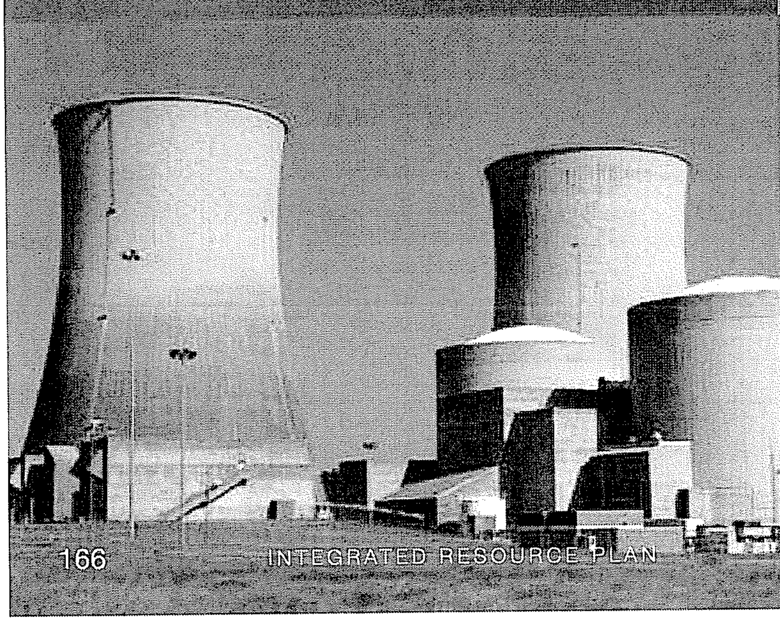
The Recommended Planning Direction provides the most balanced approach to mitigating the risk associated with these non-quantified factors while providing the best performance in key metrics.

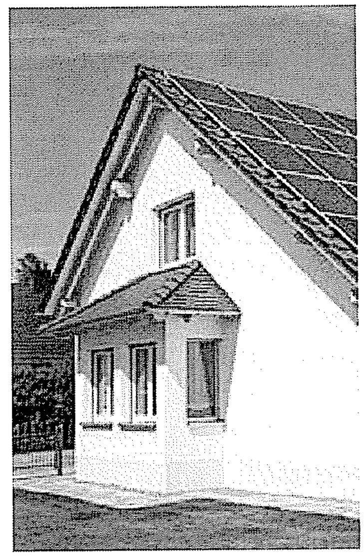
8.4 Conclusion

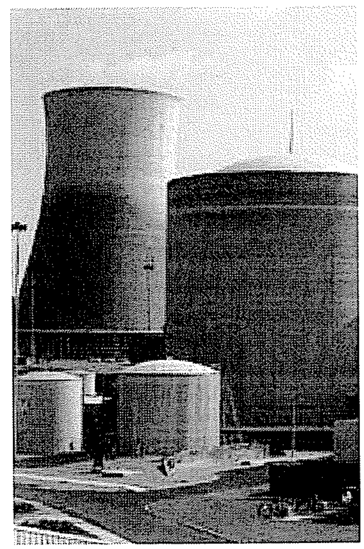
Based on the results of the analysis conducted in the Draft and final IRP, as well as the consideration of non-quantified risk factors, the Recommended Planning Direction positions TVA with the best balance of flexibility and "no-regrets" risk mitigation. A discussion of next steps and recommendations for implementation of this strategy is discussed in Chapter 9 – Next Steps.



Renewable, sustainable, environmentally-friendly initiatives, as well as consumer education regarding energy efficiency in the home and at work are all key components of TVA's future strategy for the Tennessee Valley.





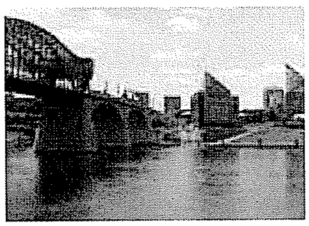


Implementing this strategy will help TVA meet its renewed vision–to be one of the nation's leading providers of low-cost and cleaner energy by 2020.

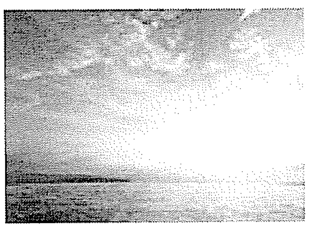
Elements of Vision 2020

Low Rates

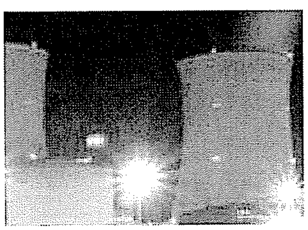
High Reliability



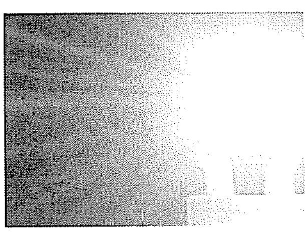
Responsibility



Cleaner Air



More Nuclear Generation



Greater Energy Efficiency

9 Next Steps

After two years of extensive analysis and the issuance of the Draft IRP, the final IRP has been completed. Another key piece of the puzzle is defining the next steps that follow this IRP's completion. For that reason, it is important to remember that this IRP is meant to serve as a roadmap for making future asset decisions and not meant to define specific decisions.

Approval of this IRP provides an updated strategic direction that will help TVA fulfill its renewed vision and set the direction for many decisions that will be proposed in the future. This chapter defines some of the key areas that need additional work or investigation to help determine TVA's "next steps" in these specific areas.

9.1 Path Forward

TVA formulated this IRP to help prepare for a wide range of future conditions and ensure a sustainable future for the Tennessee Valley region. This IRP will serve as a guide to achieve TVA's renewed vision – to become one of the nation's leading providers of low-cost and cleaner energy by 2020. TVA takes great pride in the reliable service it provides to its customers. Transmission reliability will remain a key focus of all future operations. TVA will also strive to maintain the proper generation mix in order to ensure reliable and flexible power system operation.

Furthermore, TVA remains committed to reducing air emissions from its power generation facilities. Emissions reduction will help TVA plan for and promote a sustainable future. Coal-fired plant idling and the addition of scrubbers and other emissions control equipment are essential for TVA to provide cleaner energy.

The reputation of delivering reliable, competitively priced power makes the Tennessee Valley region an attractive place to start or expand a business. Therefore, TVA will continue to support and encourage economic development in the region. TVA offers an array of services that include capital investment loans for new or growing businesses, site-selection assistance and other business support services. These services help attract companies to the region and provide more jobs to aid in economic stability of the region, which is especially important with the current sluggish economy.

TVA President and CEO Tom Kilgore stated, "TVA's basic missions have not changed, but the times have changed and requirements are changing for the energy industry." The analysis performed within this IRP will help TVA prepare for future uncertainties and properly position itself to effectively continue its mission to serve the people of the Tennessee Valley.

9.2 Application

While this strategy will help guide TVA in making important decisions in the years to come, this IRP does not dictate a specific series of actions. It is important to understand what analysis was considered to be within the scope of this IRP and what areas may require more analysis. Figure 9-1 lists what was considered in-scope versus outside-of-scope in this IRP.

This IRP Does	This IRP Does Not
Articulate a 20-year planning direction	• Finalize specific asset decisions • Serve as a substitute for the "fine-tuning" of the annual planning and budgeting processes
Present recommended strategy alternatives	• Narrow the breadth of NEPA coverage established in the Draft IRP and the associated EIS • Does not discard analyses done for alternative strategies
Describe guideline ranges for key components of the Recommended Planning Direction (i.e., EEDR, idling of coal-fired units, etc.)	• Make specific commitments for key components of the Recommended Planning Direction
Present illustrative portfolio(s) that show potential asset additions by year	• Commit to a specific 20-year capacity addition schedule
Highlight key asset additions by showing a specific value within the guideline range in the illustrative portfolio	• Imply that any asset addition or in-service date shown in the illustrative portfolio represents a formal decision or is not subject to change
Discuss other strategic considerations and non-quantified risk considerations	• Quantify all risks in the analysis or imply all decision criteria are within the IRP scope
Commit to beginning the next IRP by 2015	• Expect to provide NEPA coverage for the same duration as EV2020 • Limit TVA's ability to continue to do analysis and amend this IRP in the future

Figure 9-1 – Scope of the IRP

9.3 Areas That Require Further Work

By closely evaluating the areas that require more analysis, a number of recommendations have been identified and summarized on the next page. This list is not designed to be exhaustive but does provide insight into additional work that TVA will consider undertaking.

Issue	Recommendation
Idling coal-fired units	• Perform detailed optimization analyses to determine both the optimum level of idling and the best units for idling after accounting for risks, uncertainty and all known costs
Renewables	• Analyze renewable technologies and business models and monitor market trends for strategic options to develop cost-effective renewable resources
Nuclear power	• Complete project specific evaluation of B&W technology at Bellefonte site and refine timing • Continue to study development of small modular reactors as part of the continuing effort to advance carbon-free, baseload power generation alternatives
EEDR	• Proactively pursue the Southeast leadership goal, monitor results and evaluate programs
Gas-fired supply	• Analyze gas-fired supply opportunities to cost effectively fill short lead time capacity gaps
Pumped-storage	• Study more detailed project economics of and justification for additional pumped-storage with a goal of making a recommendation on how to proceed
Stakeholder involvement	• Continue to solicit input from external stakeholders and incorporate that input into future IRP planning and decision making processes
Next IRP	• TVA has committed to begin the next IRP effort by 2015

Figure 9-2 – Areas That Require Further Work

9.4 Conclusion

Fifteen years separated the completion of this IRP and the 1995 IRP, EV2020. Comments TVA received from SRG members and the public recommend that TVA needs to regularly update its IRP. Frequently updating this IRP would enhance TVA's ability to effectively respond to future developments. For that reason, TVA is committed to begin the next IRP effort by 2015.

TVA's IRP has produced an energy resource strategy that will help TVA meet the Tennessee Valley region's energy demands in the future in a sustainable manner. Implementing this strategy will also help TVA meet its renewed vision – to be one of the nation's leading providers of low-cost and cleaner energy by 2020. More specifically, this IRP will help TVA lead the nation in improved air quality and increased nuclear production, and lead the Southeast in increased energy efficiency.

This concludes the 2011 TVA Integrated Resource Plan,
TVA's Environmental and Energy Future.

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).

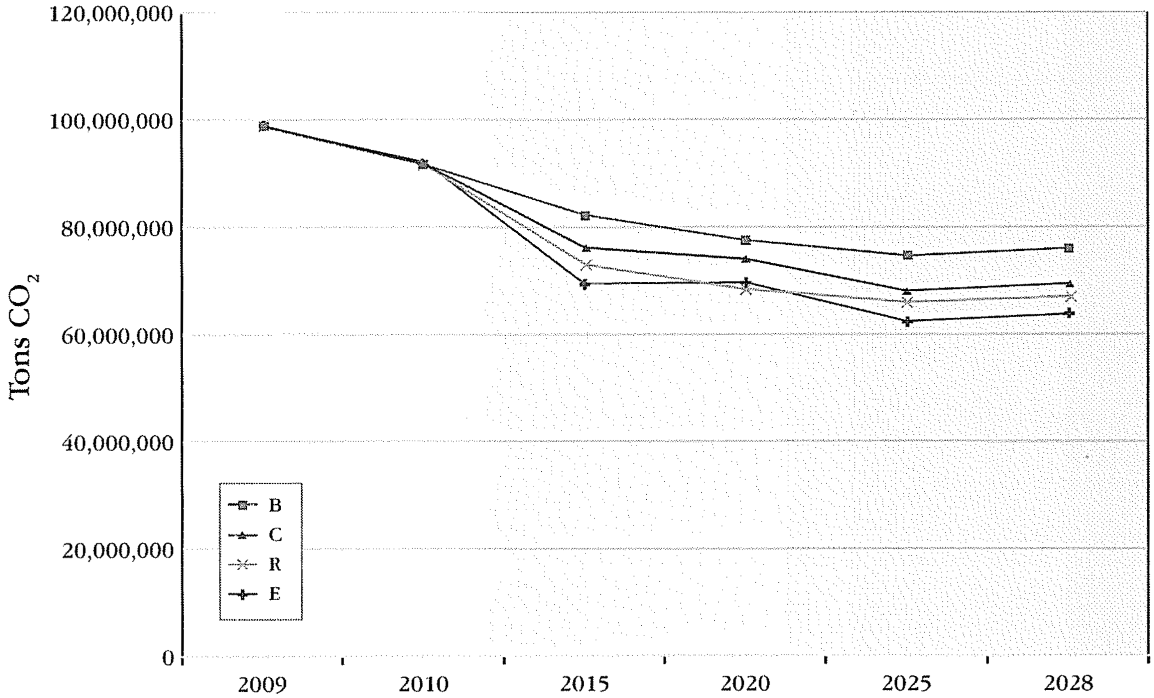


Figure A-2 – Tons CO_2 by Strategy

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

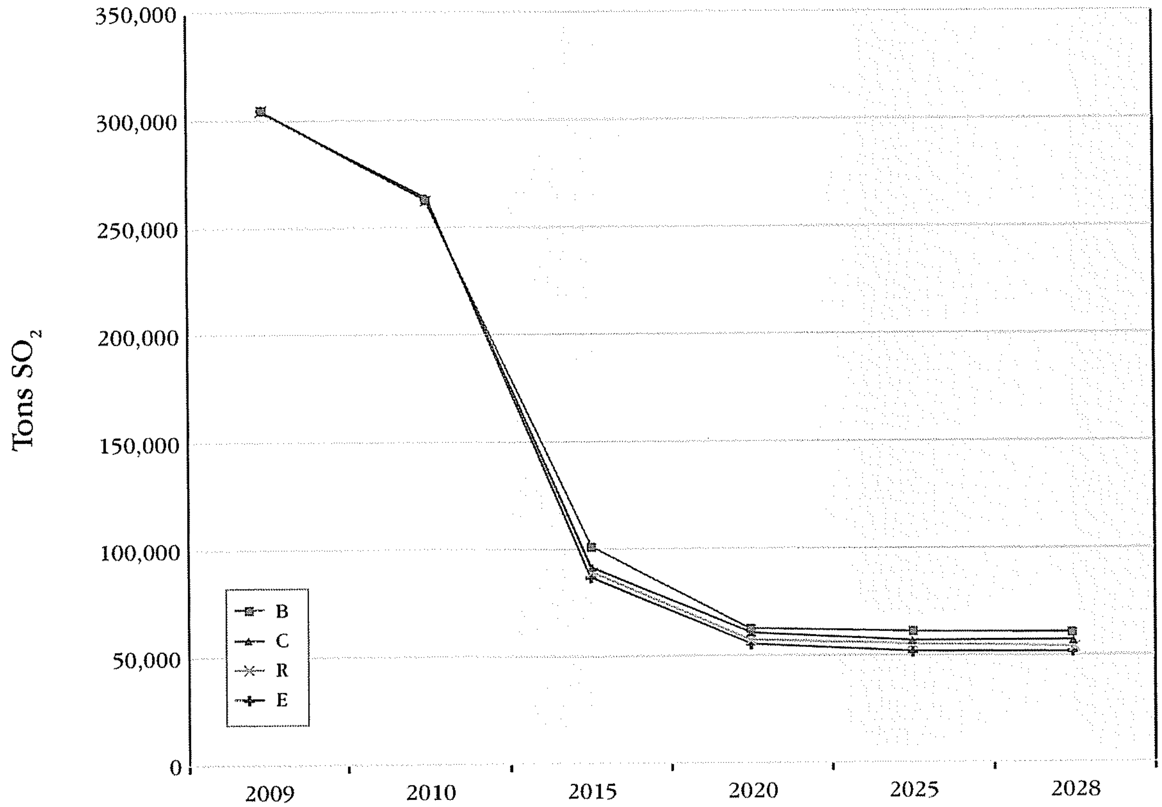


Figure A-3 – Tons SO_2 by Strategy

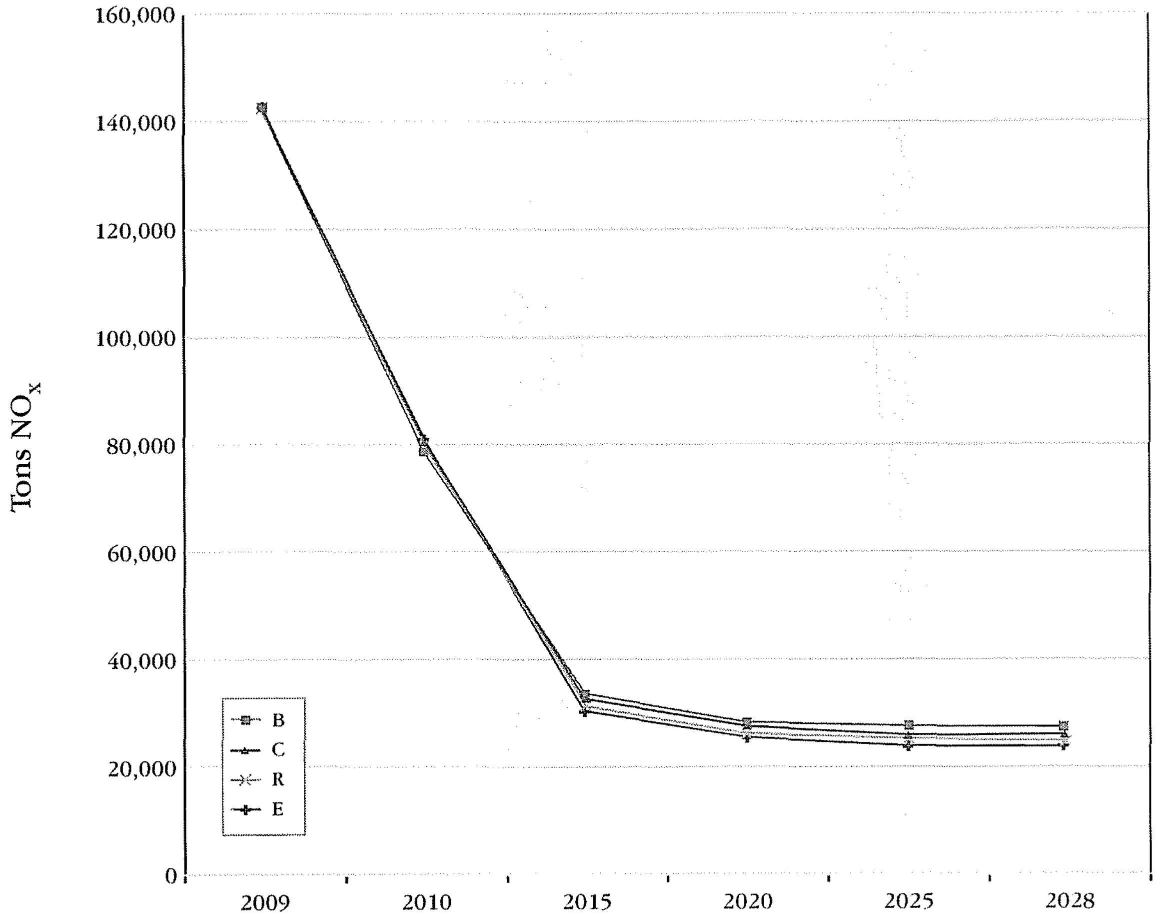


Figure A-4 – Tons NO_x by Strategy

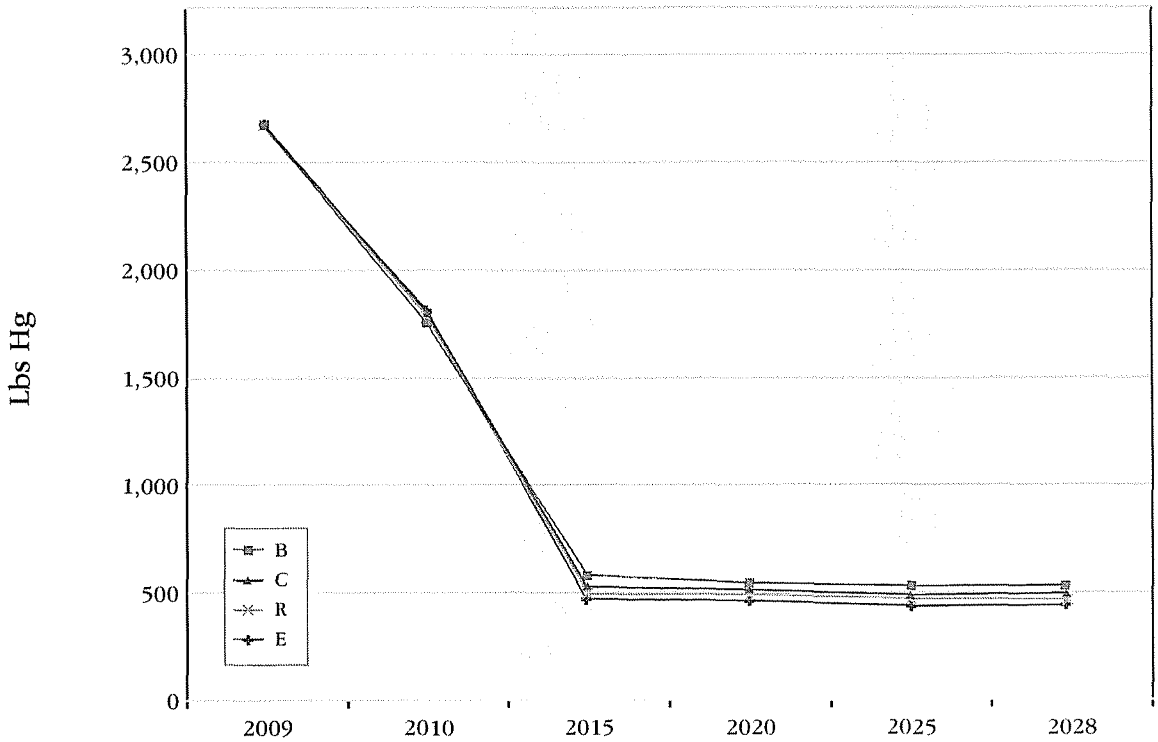


Figure A-5 – Lbs Hg by Strategy

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.

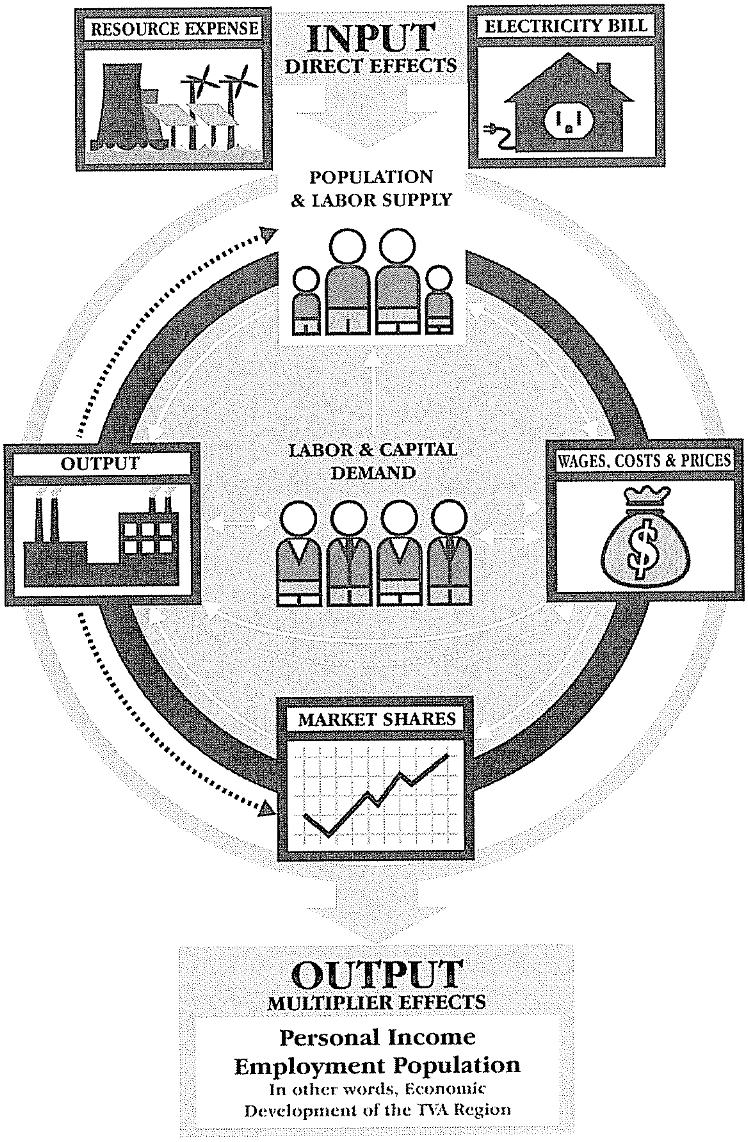


Figure B-1–Input and Output Impacts

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

Method for Computing Economic Metrics

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

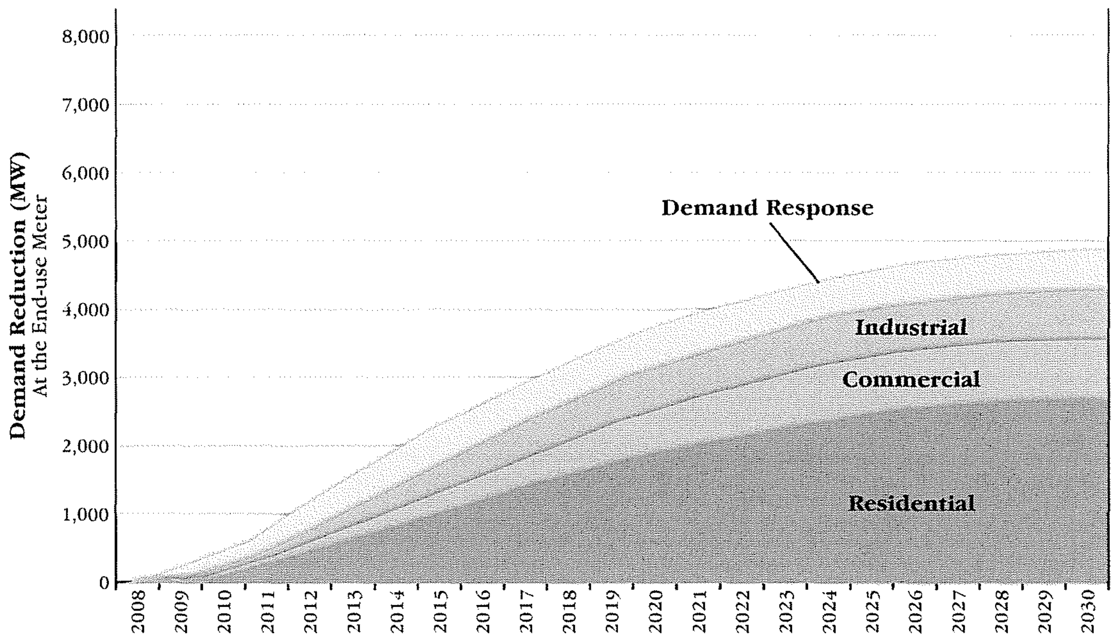


Figure C-2 – EEDR Program Demand Reduction (MW)

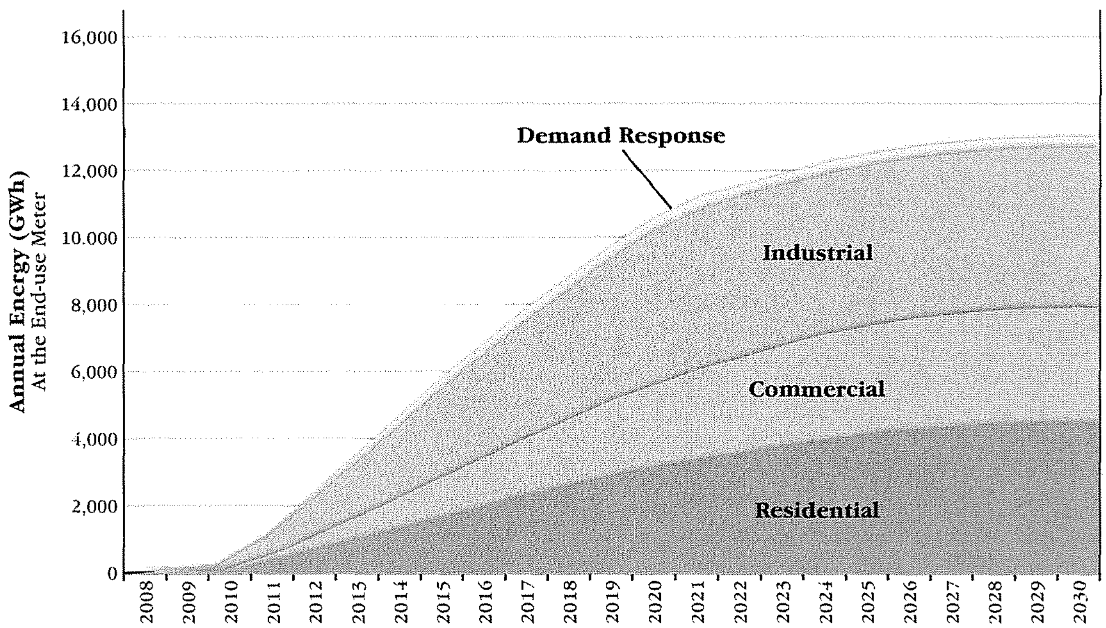


Figure C-3 – EEDR Program Energy Savings (GWh)

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

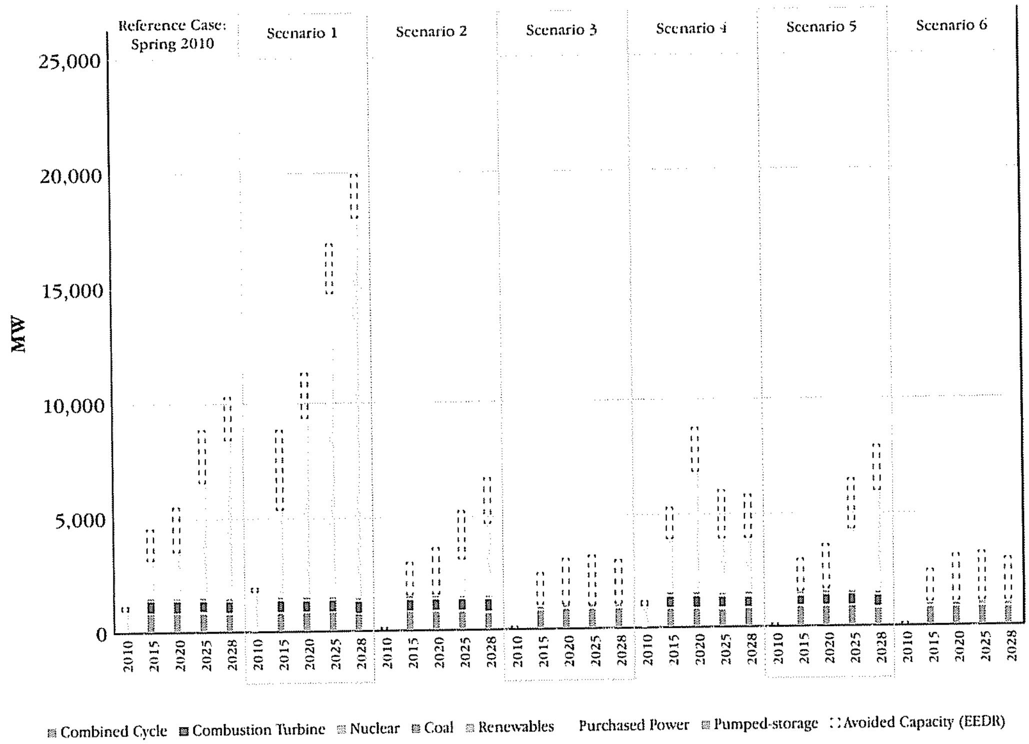


Figure E-2 – Planning Strategy A – Capacity Additions by Scenario

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

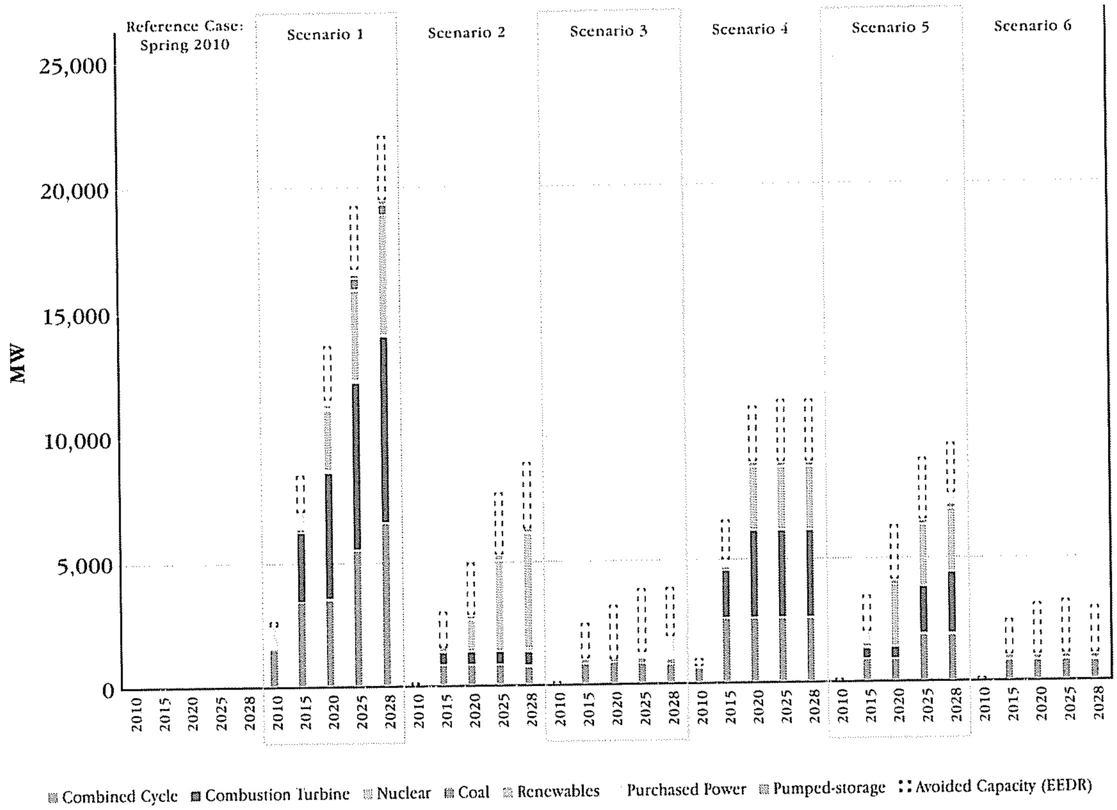


Figure E-4 – Planning Strategy B – Capacity Additions by Scenario

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

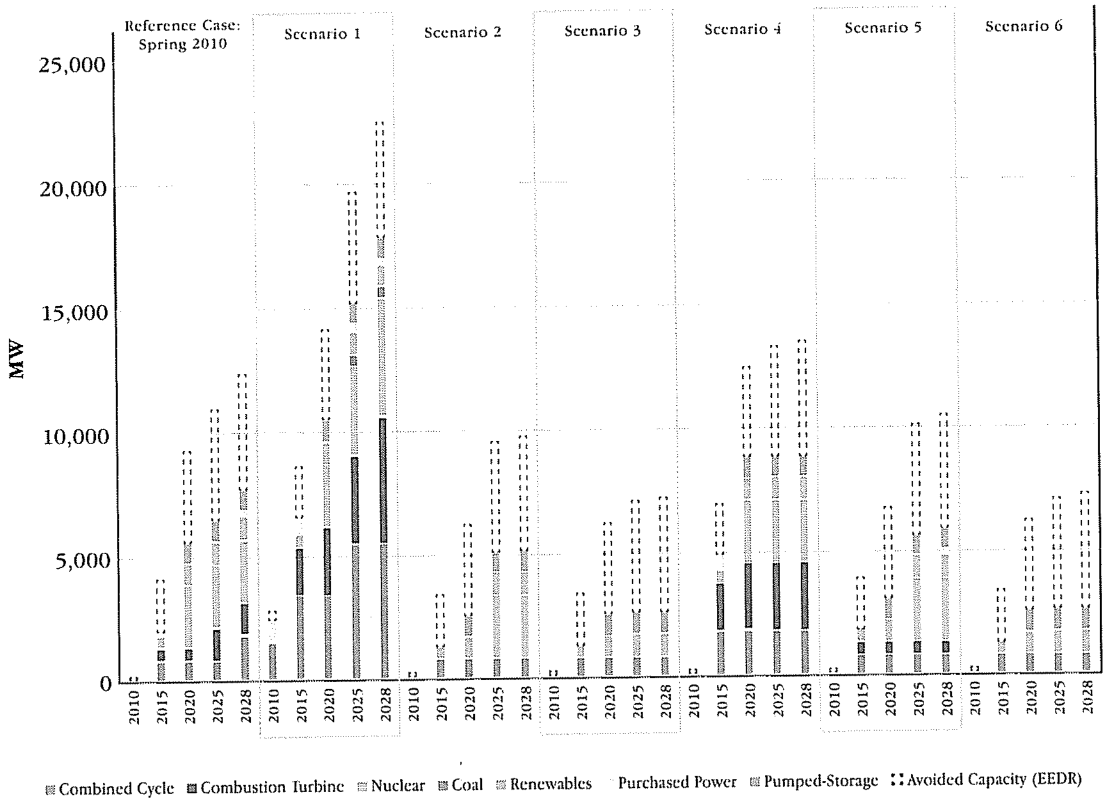


Figure E-6 – Planning Strategy C – Capacity Additions by Scenario

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

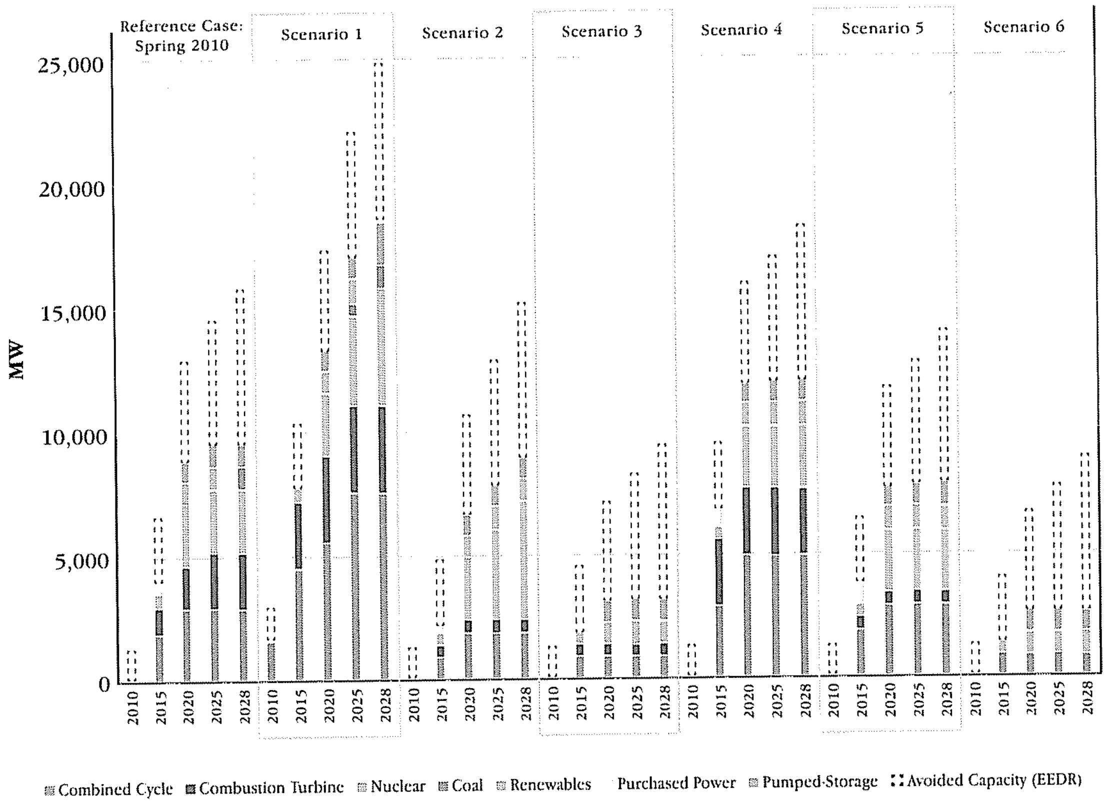


Figure E-8 – Planning Strategy D – Capacity Additions by Scenario

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

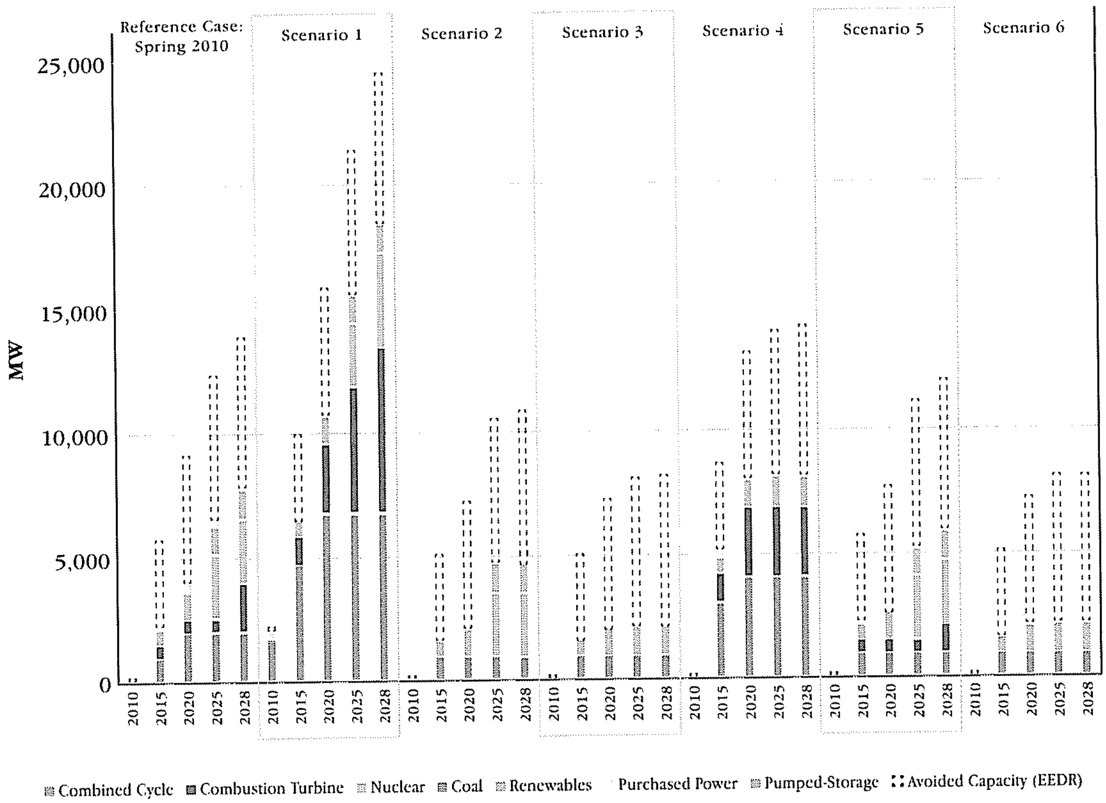


Figure E-10 – Planning Strategy E – Capacity Additions by Scenario

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

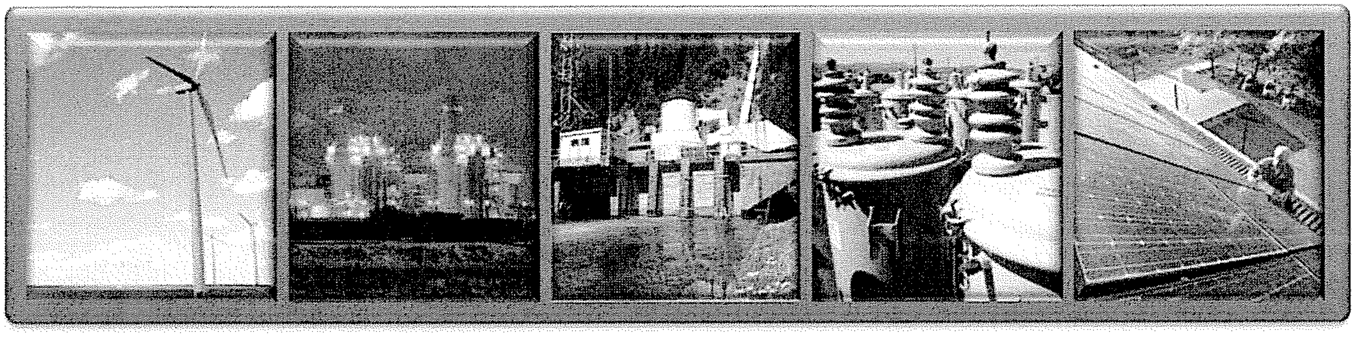
Acronym Index

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

PacifiCorp
Rocky Mountain Power
Pacific Power
PacifiCorp Energy

2011 Integrated Resource Plan

Volume II - Appendices



Let's turn the answers on.

March 31, 2011

This 2011 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Wind: *McFadden Ridge I*
Thermal-Gas: *Lake Side Power Plant*
Hydroelectric: *Lemolo 1 on North Umpqua River*
Transmission: *Distribution Transformers*
Solar: *Salt Palace Convention Center Photovoltaic Solar Project*
Wind Turbine: *Dunlap I Wind Project*

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APPENDIX A – LOAD FORECAST DETAILS

Introduction

This appendix reviews the load forecast used during the 2011 Integrated Resource Plan and scenario development for case sensitivities to varying levels in the load forecast. The load forecasting review starts with the final system level retail sales forecast reflecting the chosen Class 2 DSM efficiencies from the 2011 IRP preferred portfolio. The next section elaborates the methodology for long-range load forecasting and provides an overview of the modeling involved. For the state level summaries, retail sales at the customer meter are discussed at the state-level reflecting the chosen Class 2 DSM efficiencies from the 2011 IRP preferred portfolio. Finally, the system level and state level load forecast at the generation as used in the 2011 IRP modeling are discussed.

Load Forecast

Table A.1 shows the final retail sales values at the customer meter for the total system as well as individual state level after the load reduction impacts of Class 2 DSM programs included in the 2011 IRP preferred portfolio.

Table A.1 – System Annual Sales forecast (in Gigawatt-hours) 2011 through 2020

System Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	16,272	16,949	20,469	1,285	141	436	**55,553**
2012	16,522	17,699	20,688	1,301	141	437	**56,789**
2013	16,454	18,004	21,524	1,302	141	436	**57,861**
2014	16,567	18,247	22,233	1,302	141	436	**58,927**
2015	16,715	18,529	22,629	1,302	141	436	**59,752**
2016	16,896	18,973	23,050	1,302	142	437	**60,801**
2017	16,953	19,190	23,250	1,302	141	436	**61,273**
2018	17,078	19,452	23,553	1,302	141	436	**61,963**
2019	17,215	19,723	23,842	1,302	141	436	**62,660**
2020	17,335	20,036	24,202	1,303	142	437	**63,454**
Average Annual Growth Rate							
2011-20	**0.7%**	**1.9%**	**1.9%**	**0.2%**	**0.1%**	**0.0%**	**1.5%**

Methodology Overview

PacifiCorp estimates total load by starting with customer class sales forecasts in each state and then adds line losses to the customer class forecasts to determine the total load required at the generators to meet customer demands. Forecasts are based on statistical and econometric modeling techniques and customer-specific sales forecast for large customers. These models incorporate the county and state level forecasts that are provided by public agencies or purchased from commercial econometric forecasting services.

The 2010 load forecast was used for the development of the load and resource balance and portfolio evaluations. Portfolio analysis started in November 2010 with preliminary load forecast and continued through December 2010.

In 2008, to improve sales and load forecasting methods, capabilities, and accuracy, several improvements in the load forecasting approach were identified jointly by the Company and the Company's consultant, ITRON (a firm specializing in load forecasting software and services), and the load forecast methodology was changed to incorporate some improvements. The major assumption changes driving the forecast improvements were discussed in detail in 2008 IRP. Those assumptions were revisited and updated as a part of routine forecast development in this IRP. First, load research data was updated to include six years (2004 -2009) of daily data. This data is used to model the impact of weather on monthly retail sales and peaks by state by class. The Company collects hourly load data from a sample of customers for each class in each state. These data are primarily used for rate design, but they also provide an opportunity to better understand usage patterns, particularly as they relate to changes in temperature. The greater frequency and data points associated with this daily data make it better suited to capture load changes driven by changes in temperature.

Second, in 2008, the time period used to define normal weather was updated from the National Oceanic and Atmospheric Administration's 30-year period of 1971-2000 to a 20-year time period – the latest forecast is based on 1990-2009 as the 20 year time period. The Company identified a trend of increasing summer and winter temperatures in the Company's service territory that was not being captured in the thirty year data. ITRON surveys have identified that many other utilities are also using more recent data for determining normal temperatures. Based on this review and on the recommendation from ITRON, the Company adopted a 20-year rolling average as the basis for determining normal temperatures. This better captures the trend of increasing temperatures observed in both summer and winter.

Third, The Company updated the economic forecasts from IHS Global Insight using the most recent information available for each of the Company's jurisdictions.

Fourth, the historical data period used to develop the monthly retail sales forecasts was updated to cover January 1997 through July 2010 for all classes except for industrial class which goes back to January 2002. The Company updated the forecast of individual industrial customer usage based on the best information available as of August 2010.

Fifth, monthly jurisdictional peaks were forecasted for each state using a peak model and estimated with historical data from 1990-2009. As discussed in the 2008 IRP, as an improvement to the forecasting process, the Company developed a model that relates peak loads to the weather that generated the peaks. This model allows the Company to better predict monthly and seasonal peaks. The peak model is discussed in greater detail in the following section.

Sixth, system line losses were updated to reflect actual losses for the 5-years ending December 31, 2009. Prior to 2008, the Company relied on periodic line loss studies. The Company observed that actual losses were higher than those from the previous line loss study. The use of actual losses is a reasonable basis for capturing total system losses and has been incorporated in this forecast.

Class 2 Demand-side Management Resources in the Load Forecast

PacifiCorp modeled Class 2 DSM as a resource option to be selected as part of a cost-effective portfolio resource mix using the Company's capacity expansion optimization model, System Optimizer. The load forecast used for IRP portfolio development excluded forecasted load reductions from Class 2 DSM. System Optimizer then determines the amount of Class 2 DSM—expressed as supply curves that relate incremental DSM quantities with their costs—given the other resource options and inputs included in the model. The use of Class 2 DSM supply curves, along with the economic screening provided by System Optimizer, determines the cost-effective mix of Class 2 DSM for a given scenario. For retail load forecast reporting, PacifiCorp develops a load forecast reflecting the chosen Class 2 DSM efficiencies from the 2011 IRP preferred portfolio.

Modeling overview

This section describes the modeling techniques used to develop the load forecast.

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential, commercial, irrigation, public street lighting, and sales to public authority sales forecasts by jurisdiction is developed as a use per customer times the forecasted number of customers.

The customer forecasts are generally based on a combination of regression analysis and exponential smoothing techniques using historical data from January 1997 to July 2010. For the residential class, the Company forecasts the number of customers using IHS Global Insight's forecast of each state's number of households as the major driver. For the commercial class, the Company develops the forecast for number of customers with the forecasted residential customer numbers used as the major driver. For irrigation and street lighting classes, the forecast of number of customers is fairly static and developed using regression models without any economic drivers.

The residential use-per-customer is forecasted by statistical end-use forecasting techniques. This approach incorporates end use information (saturation forecasts and efficiency forecasts) but is estimated using monthly billing data. Saturation trends are based on analysis of the Company's saturation survey data and efficiency trends are based on EIA forecasts that incorporate market forces as well as changes in appliance and equipment efficiency standards. Major drivers of the statistical end use based residential model are weather-related variables, end-use information such as equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price. The company updated the residential use-per-customer-per-day model with appliance saturation and efficiency results released in June 2009. The SAE models also reflect impacts associated with the Energy Independence and Security Act of 2007, which mandates stricter efficiency standards for incandescent bulbs beginning in 2012.

The commercial, irrigation, street lighting, and sales to public authority use-per-customer forecast is developed using an econometric model. For the commercial class, the Company forecasts sales per customer using regression analysis techniques with employment used as the major economic driver in addition to weather-related variables. For other classes, the Company forecasts sales per customer through regression analysis techniques using time trend variables.

The sales forecast for the residential, commercial and irrigation classes is the product of the number of customer forecast and the use-per-customer forecast. However, the development of the forecast of monthly commercial sales involves an additional step. To reflect the addition of a large "lumpy" change in sales such as a new data center, monthly commercial sales are increased based on input from the Customer Account Managers ("CAMs"). Although the scale is much smaller, the treatment of large commercial additions is similar to the methodology for industrial sales which is discussed below.

Monthly sales for lighting and public authority are forecasted directly for the class, instead of the product of the use-per-customer and number of customers. The forecast is developed by class because the customer sizes in these two classes are more diverse.

The industrial sales forecast is developed for each jurisdiction using a model which is dependent on input for the Customer Account Managers (CAMs). The industrial customers are separated into three categories: existing customers that are tracked by the CAMs, new large customers or expansions by existing large customers, and industrial customers that are not tracked by the CAMs. Customers are tracked by the CAMs if (1) they have a peak load of five MW or more or if (2) they have a peak load of one MW or more and have a history of large variations in their monthly usage. The forecast for the first two categories is developed through the data gathered by the CAM assigned to each customer. The account managers have ongoing direct contact with large customers and are in the best position to know about the customer's plans for changes in business processes, which might impact their energy consumption.

The Company develops the total industrial sales forecast by aggregating the forecast for the three industrial customer categories. The portion of the industrial forecast related to new large customers and expansion by existing large customers is developed based on direct input of the customers, forecasted load factors, and the probability of the project occurrence. Projected loads associated with new customers or expansions of existing large customers are categorized into three groups. Tier 1 customers are those with a signed master electric service agreement ("MESA") and Tier 2 customers are those with a signed engineering material and procurement agreement ("EMPA"). When a customer signs a MESA or EMPA, this contractually commits the Company to provide services under the terms of agreement. Tier 3 includes customers with a signed engineering services agreement (ESA). This means that customer paid the Company to perform a study that determines what improvements the Company will need to make to serve the requested load. Tier 4 consists of customers who made inquiries but have not signed a formal agreement. Projected loads from customers in each of these tiers are assigned probabilities depending on project-specific information received from the customer.

Smaller industrial customers are more homogeneous and are modeled using regression analysis with trend and economic variables. Manufacturing employment serves as the major economic driver. The total industrial sales forecast is developed by aggregating the forecast for the three industrial customer categories.

The segments are forecasted differently within the industrial class because of the diverse makeup of the customers within the class. In the industrial class, there is no "typical" customer. Large customers have very diverse usage patterns and power requirements. It is not unusual for the entire class to be strongly influenced by the behavior of one customer or a small group of customers. In contrast, customer classes that are made up of mostly smaller, homogeneous customers are best forecasted as a use per customer multiplied by number of customers. Those customer classes are generally composed of many smaller customers that have similar behaviors and usage patterns. No small group of customers, or single customer, influences the movement of the entire class. This difference requires the different processes for forecasting.

After monthly energy by customer class is developed, hourly loads are estimated in two steps. First, PacifiCorp derives monthly and seasonal peak forecasts for each state. The monthly peak model uses historic peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables which drive heating and cooling usage. These weather variables include the average temperature on the peak day and average daily temperatures for two days prior to the peak day. The peak forecast is based on average monthly historical peak-producing weather for the period 1990-2009.

Second, hourly load forecasts for each state are obtained from the hourly load models using state-specific hourly load data and daily weather variables. Hourly load forecasts are developed using a model that incorporates the 20-year average temperatures, the actual weather pattern for a year, and day-type variables such as weekends and holidays. The model incorporates both mild and extreme days in weather patterns by mapping the normal temperatures to an actual weather pattern. This method effectively represents the daily volatility in weather experienced during a typical year. Also, the method preserves the extreme temperatures and maps them to a year to produce a more accurate estimate of daily temperatures. The hourly load forecasts are adjusted for line losses and calibrated to monthly and seasonal peaks. After PacifiCorp develops the hourly load forecasts for each state, hourly loads are aggregated to the total Company system level. System coincident peaks are then identified as well as the contribution of each jurisdiction to those monthly system peaks.

Sales Forecast at the Customer Meter

This section provides total system and state-level forecasted retail sales summaries measured at the customer meter. The factors influencing the forecasted sales growth rates also influence the forecasted peak demand growth rates.

State Summaries

Oregon

Table A.2 summarizes Oregon state forecasted retail sales growth by customer class.

Table A.2 – Forecasted Sales Growth in Oregon

Oregon Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	5,624	5,142	2,298	266	38	0	**13,368**
2012	5,672	5,399	2,324	282	38	0	**13,715**
2013	5,573	5,490	2,367	283	38	0	**13,750**
2014	5,563	5,526	2,368	283	38	0	**13,778**
2015	5,570	5,557	2,355	283	38	0	**13,803**
2016	5,612	5,603	2,350	283	38	0	**13,886**
2017	5,610	5,616	2,325	283	38	0	**13,872**
2018	5,641	5,647	2,310	283	38	0	**13,920**
2019	5,675	5,677	2,299	283	38	0	**13,971**
2020	5,705	5,720	2,297	283	38	0	**14,043**
Average Annual Growth Rate							
2011-20	**0.2%**	**1.2%**	(0.0)%	**0.7%**	**0.0%**	-	**0.5%**

The forecast of residential sales is expected to grow at a relatively slower rate of 0.2% annually compared to average annual growth rate of around 1.3% experienced in the past ten years. This slow down is mainly attributed to housing market deterioration worsening economic conditions in the service territory. Beyond2012, use per customer is expected to decline – this decline is mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

Over the forecast horizon, forecasted commercial class sales are projected to grow annually at 1.2%, and are higher than the ten year average annual growth rate in history. Annual growth rate is much higher in the near term as a result of new data centers in the service territory. Usage per customer is projected to decline slightly due to increased equipment efficiency.

As an aftermath of housing market slowdown and economic recession affecting wood products and semi-conductor manufacturing, forecasted industrial class sales are projected to grow at a very slow rate in the forecast horizon. Continued diversification in the manufacturing base in the state and good export opportunities may continue to add to some positive growth in the area.

Washington

Table A.2 summarizes Washington state forecasted retail sales growth by customer class.

Table A.3 – Forecasted Sales Growth in Washington

Washington Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	1,639	1,445	843	160	10	0	**4,097**
2012	1,652	1,471	858	160	10	0	**4,150**
2013	1,636	1,481	865	160	10	0	**4,151**
2014	1,638	1,487	866	160	10	0	**4,161**
2015	1,645	1,493	866	160	10	0	**4,174**
2016	1,662	1,503	868	160	10	0	**4,203**

Washington Retail Sales – Gigawatt-hours (GWh)							
2017	1,665	1,504	865	160	10	0	**4,204**
2018	1,676	1,508	864	160	10	0	**4,217**
2019	1,686	1,510	863	160	10	0	**4,229**
2020	1,696	1,515	864	160	10	0	**4,245**
Average Annual Growth Rate							
2011-20	**0.4%**	**0.5%**	**0.3%**	**0.0%**	**0.0%**	-	**0.4%**

The forecast of residential sales is expected to grow at a slower average annual growth rate of 0.4% compared to ten year historical growth rates of around 1.4% due to the continuing impact of housing market slowdown and economic recession. The slight growth in residential class sales is due to continuing customer growth driven by population growth and household formation in the service area. Beyond 2012, use per customer is expected to decline – this decline is mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

Over the forecast horizon, forecasted commercial class sales are projected to grow at an average annual rate of 0.5% due to the aftermath of economic recession.

The industrial class sales are projected to grow at an average annual growth rate of 0.3% reflecting slow recovery in wood products and food processing sectors.

California

Table A.4 summarizes California state forecasted sales growth by customer class.

Table A.4 – Forecasted Retail Sales Growth in California

California Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	398	288	40	98	2	0	**827**
2012	402	290	44	98	2	0	**836**
2013	398	294	45	98	2	0	**837**
2014	399	297	44	98	2	0	**840**
2015	401	297	43	98	2	0	**842**
2016	405	298	42	98	2	0	**846**
2017	405	298	41	98	2	0	**845**
2018	407	299	40	98	2	0	**847**
2019	409	300	39	98	2	0	**849**
2020	411	302	38	98	2	0	**851**
Average Annual Growth Rate							
2011-20	**0.3%**	**0.5%**	(0.6)%	**0.0%**	**0.0%**	-	**0.3%**

The residential sales are expected to grow at an average annual rate of 0.3%. Beyond 2012, use per customer is expected to decline – this decline is mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

The continuing population growth also affects sales in the commercial sector through continued commercial customer growth. However, some of this growth is being offset from increased equipment efficiency over the forecast horizon.

Declines over the decade in the lumber and wood product industries production resulted in an overall decline in the industrial sales for the past two years, and is still facing hardship.

Utah

Table A.5 summarizes Utah state forecasted sales growth by customer class.

Table A.5 – Forecasted Retail Sales Growth in Utah

Utah Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	6,776	8,104	8,377	188	77	436	**23,958**
2012	6,908	8,508	8,221	187	77	437	**24,339**
2013	6,943	8,655	8,594	187	77	436	**24,893**
2014	7,023	8,804	8,873	187	77	436	**25,401**
2015	7,120	9,005	8,978	187	77	436	**25,803**
2016	7,206	9,346	9,114	187	77	437	**26,368**
2017	7,245	9,520	9,185	187	77	436	**26,650**
2018	7,307	9,711	9,299	187	77	436	**27,018**
2019	7,374	9,914	9,395	187	77	436	**27,384**
2020	7,430	10,135	9,513	187	77	437	**27,779**
Average Annual Growth Rate							
2011-20	**1.0%**	**2.5%**	**1.4%**	(0.0)%	**0.0%**	**0.0%**	**1.7%**

Utah continues to see natural population growth that is faster than many of the surrounding states. During the historical period, Utah experienced rapid population growth with a high rate of in-migration. However, the rate of population growth is expected to be relatively lower in the coming decade as in-migration into the state slows down relative to history. Over the forecast horizon, residential sales are expected to grow at a slower rate of 1.0% compared to what has been experienced historically in the past ten years due to slower in-migration and slow recovery in housing market in near-term. Beyond 2012, the decline in use per customer is driven by the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

The continuing population growth also affects sales in the commercial sector by continued commercial customer growth. Commercial sales are growing at an average annual rate of 2.5% in the forecast horizon mainly due to several data centers starting services in Utah. However some of this growth is being slightly offset from equipment efficiency gains over the forecast horizon.

The industrial class in the state is diversified and will continue to cause sales growth in the sector. Utah has a strategic location in the western half of the United States, which provides easy access into many regional markets. The industrial base has become more linked to the region and is less dependent on the natural resource base within the state. This provides a strong foundation for continued growth into the future. As a result of economic slowdown, over the forecast horizon, industrial sales are growing at a moderate 1.4% as compared to the recent ten year growth rate of 1.6%, but are lower than the pre recession annual average growth rate. As the economy recovers, industrial expansions in a broad range of industries are expected to pick up, and industrial sales are expected to grow again reflecting improvement in overall economic conditions. In 2011, the industrial sales are higher due to a one year load increase by a large industrial customer.

Idaho
Table A.6 summarizes Idaho state forecasted sales growth by customer class.

Table A.6 – Forecasted Retail Sales Growth in Idaho

Idaho Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	732	432	1,665	550	3	0	**3,381**
2012	756	450	1,690	550	3	0	**3,448**
2013	764	467	1,778	550	3	0	**3,562**
2014	784	484	1,883	550	3	0	**3,704**
2015	805	499	1,950	550	3	0	**3,806**
2016	829	512	2,007	550	3	0	**3,901**
2017	846	522	2,016	550	3	0	**3,937**
2018	865	533	2,020	550	3	0	**3,972**
2019	885	544	2,025	550	3	0	**4,007**
2020	905	557	2,033	550	3	0	**4,048**
Average Annual Growth Rate							
2011-20	**0.4%**	**0.5%**	**0.3%**	**0.0%**	**0.0%**	-	**0.4%**

Over the forecast horizon, the residential sales are projected to grow at 2.4% annually compared to historical ten year average annual growth rate of 2.8%. Beyond 2012, use per customer is expected to decline – this decline is mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

The growth rate for commercial class sales is expected to continue to be strong due to customer growth in response to the increasing residential customer growth resulting in increasing service sector demand such as education and health care services. Usage per customer growth is somewhat offset by equipment efficiency gains over the forecast horizon.

Industrial sales are expected to grow at an average annual rate of 2.2%. This growth is primarily due to expansions by a few large industrial customers.

Wyoming
Table A.7 summarizes Wyoming state forecasted sales growth by customer class.

Table A.7 – Forecasted Retail Sales Growth in Wyoming

Wyoming Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	1,103	1,538	7,246	23	12	0	9,921
2012	1,134	1,581	7,552	23	12	0	10,301
2013	1,141	1,617	7,875	23	12	0	10,668
2014	1,159	1,650	8,199	23	12	0	11,043
2015	1,173	1,678	8,437	23	12	0	11,324
2016	1,182	1,710	8,669	24	12	0	11,596
2017	1,181	1,730	8,818	24	12	0	11,765
2018	1,182	1,753	9,019	24	12	0	11,990
2019	1,186	1,778	9,221	24	12	0	12,220
2020	1,188	1,808	9,457	24	12	0	12,489
Average Annual Growth Rate							
2011-20	**0.8%**	**1.8%**	**3.0%**	**0.5%**	**0.0%**	-	**2.6%**

Residential sales is expected to grow at an average annual rate of 0.8%, compared to an average annual growth rate of around 2.4% experienced during the past ten years. Population growth is still expected to continue in the service area, which contributes to some of the sales growth. Beyond 2012, use per customer is expected to decline – this decline is mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

Over the forecast horizon, commercial class sales are projected to grow at an annual growth rate of 1.8%. Sales growth is driven mainly by the customer growth in response to still continuing residential customer growth and the growth of the office sector.

Wyoming industrial sales growth, driven by expansion in oil and gas extraction industries, is expected to continue, but at a much reduced rate in the near years due to uncertainty in energy prices. As the economy recovers, industrial growth continues in outer years. Continuing growth in industrial customers in the service area also contributes to the load growth in the residential and commercial customer sectors.

Load Forecast at the Generator

This section provides the load forecast at the generator information used for 2011 IRP portfolio modeling for each state and the system as a whole by year for 2011 through 2020 before Class 2 DSM load reductions are applied.

Energy Forecast

Table A.8 shows average annual energy load growth rates for the PacifiCorp system and individual states. Growth rates are shown for the forecast period 2011 through 2020.

Table A.8 – Forecasted Average Annual Energy Growth Rates for Load

Date Range	Total	OR	WA	CA	UT	WY	ID	SE-ID
2011-2020	2.1%	1.4%	1.2%	0.9%	2.4%	2.9%	2.4%	1.7%

The total net control area load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.1% percent annually from year 2011 to 2020. Table A.9 shows the forecasted load for each specific year for each state served by PacifiCorp and the average annual growth (AAG) rate over the entire time period.

Table A.9 – Annual Load forecasted (in Megawatt-hours) 2011 through 2020

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2011	63,131,207	14,968,933	4,579,565	954,604	26,106,815	10,611,408	3,721,679	2,188,202
2012	64,958,409	15,487,788	4,676,478	969,067	26,746,468	11,040,464	3,804,258	2,233,885
2013	66,388,259	15,669,033	4,703,107	972,280	27,389,581	11,451,701	3,937,679	2,264,877
2014	68,035,127	15,853,824	4,754,379	982,164	28,151,361	11,883,924	4,106,332	2,303,143
2015	69,442,054	16,038,453	4,809,526	991,175	28,805,998	12,220,507	4,234,971	2,341,424
2016	71,110,972	16,283,652	4,880,687	1,002,320	29,650,389	12,548,966	4,357,547	2,387,412
2017	72,151,300	16,419,176	4,921,944	1,009,109	30,196,791	12,770,304	4,415,978	2,417,998
2018	73,424,134	16,602,014	4,977,007	1,018,716	30,840,594	13,055,537	4,473,968	2,456,298
2019	74,713,621	16,789,205	5,030,425	1,028,331	31,491,637	13,346,735	4,532,675	2,494,611
2020	76,136,508	16,998,651	5,089,930	1,039,248	32,188,156	13,680,764	4,598,606	2,541,153
Average Annual Growth Rate								
2011-20	2.1%	1.4%	1.2%	0.9%	2.4%	2.9%	2.4%	1.7%
2021-30	1.7%	0.9%	0.9%	0.8%	1.9%	2.5%	1.2%	1.4%
2011-30	1.9%	1.1%	1.1%	0.9%	2.1%	2.7%	1.8%	1.5%

Jurisdictional Peak Load Forecast

The economies, industry mix, appliance and equipment adoption rates, and weather patterns are different for each jurisdiction that PacifiCorp serves. Because of these differences the jurisdictional hourly loads have different daily and hourly patterns. In addition, the growth for the jurisdictional peak demands can be different from the growth in the jurisdictional contribution to the system peak demand. As explained in the methodology section, development of the coincident peaks is based on jurisdictional peaks. However, the jurisdictional peak forecast is not directly used in the IRP portfolio development process.

System-Wide Coincident Peak Load Forecast

The system coincident peak load is the maximum load required on the system in any hourly period. Forecasts of the system peak for each month are prepared based on the load forecast produced using the methodologies described above. From these hourly forecasted values, the coincident system peaks and the non-coincident peaks (within each state) during each month are extracted.

Since 2000, the annual system peak has generally occurred in the summer. The summer system peak is a result of several factors. First, the increasing demand for summer space conditioning in the residential and commercial classes and a decreasing demand for electric related space conditioning in the winter contributes to a summer peak. This trend in space conditioning is expected to continue. Second, Utah with a summer peak that is relatively higher than the winter peak has been growing faster than the system. This growth also contributed to a summer peaking system.

Total system load factor is expected to be relatively stable over the 2011 to 2020 time period. There are several factors working in opposite directions, leading to this result. First, the relatively high growth in high load factor industrial sales, particularly in Wyoming, tends to push up the system load factor. Second, as discussed above, the shift in space conditioning tends to push down the system load factor. And, third, advancing lighting efficiency standards, such as those found in the 2007 Energy Independence and Security Act, which begin to take effect in 2012, also tend to push down the system load factor.

Table A.10 – Forecasted Coincidental Peak Load Growth Rates

Average Annual Growth Rate	Total	OR	WA	CA	UT	WY	ID	SE-ID
2011-2020	2.1%	1.4%	1.6%	0.9%	2.4%	2.6%	2.7%	1.6%

PacifiCorp's eastern system peak is expected to continue growing faster than the western system peak, with average annual growth rates of 2.4 percent and 1.4 percent, respectively, over the forecast horizon. The main drivers for the higher coincident peak load growth for the eastern states include the following:

- Customer growth in residential and commercial classes
- New large commercial customers such as data centers
- Increased usage by Industrial class due to addition of new large industrial customers or expansion by existing customers

Table A.11 below shows that for the same time period the total peak is expected to grow by 2.1 percent.

Table A.11 – Forecasted Coincidental Peak Load in Megawatts

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2011	10,449	2,332	775	160	4,840	1,329	679	336
2012	10,716	2,396	813	163	4,935	1,376	691	341
2013	10,960	2,429	802	164	5,074	1,423	721	346
2014	11,252	2,466	817	163	5,231	1,471	750	353
2015	11,501	2,496	830	166	5,354	1,509	787	359
2016	11,740	2,528	843	169	5,474	1,545	817	365
2017	11,960	2,557	855	171	5,602	1,574	831	370
2018	12,194	2,584	893	173	5,726	1,601	842	376
2019	12,378	2,611	880	174	5,845	1,633	854	381
2020	12,607	2,644	894	174	5,975	1,668	864	388
Average Annual Growth Rate								
2011-20	2.1%	1.4%	1.6%	0.9%	2.4%	2.6%	2.7%	1.6%
2021-30	1.7%	0.9%	1.3%	1.0%	2.0%	2.3%	1.4%	1.4%
2011-30	1.9%	1.2%	1.4%	1.0%	2.2%	2.4%	2.0%	1.5%

Alternative Load Forecast Scenarios

The main purpose of the alternative load forecast cases is to determine the resource type and timing impacts resulting from a structural change in the economy. The focus of the load growth scenarios is from 2014 onward. The Company assumes that economic changes begin to significantly impact loads beginning in 2014, the currently planned acquisition date for the next CCCT resource.

The October 2010 forecast was considered to be the baseline (Medium) scenario. For the high and low growth scenarios, assumptions from IHS Global Insight were applied to the economic drivers in the Company's load forecasting models. These growth assumptions were extended for the entire forecast horizon.

Recognizing the volatility associated with oil and gas extraction industries, PacifiCorp applied additional assumptions for Utah and Wyoming industrial classes for the high scenario. For 2014 and 2015, industrial sales were projected based on historic average growth rates for boom years (2003-2008), and for 2016 and beyond, industrial sales were projected based on historic average growth rates for 2000-2008 (time period with one economic boom and one recession). For Oregon, the probability of new loads from data centers is increased, and a steady growth rate based on the historical average is applied for 2014 onwards for the industrial class.

For the low scenario, the Company assumed a reduced probability of data center growth materializing. Also, for Utah and Wyoming, a double dip recession starting with slower 2011 and 2012 growth was assumed, accompanied by a recovery track from the double-dip recession less than complete for the forecast horizon.

For the 1-in-10 year (10% probability) extreme weather scenario, the Company used 1-in-10 year peak weather for winter (January) and summer (July) months for each state. The 1-in-10 year peak weather is defined as the year for which the peak has the chance of occurring once in 10 years.

Figure A.1 shows the comparison of the above scenarios relative to the Medium scenario. Figure A.2 compares the system coincident peak load forecast with those used for the 2008 IRP Update and 2008 IRP.

Figure A.1 – Load Forecast Scenarios for Low, Medium, High and Peak

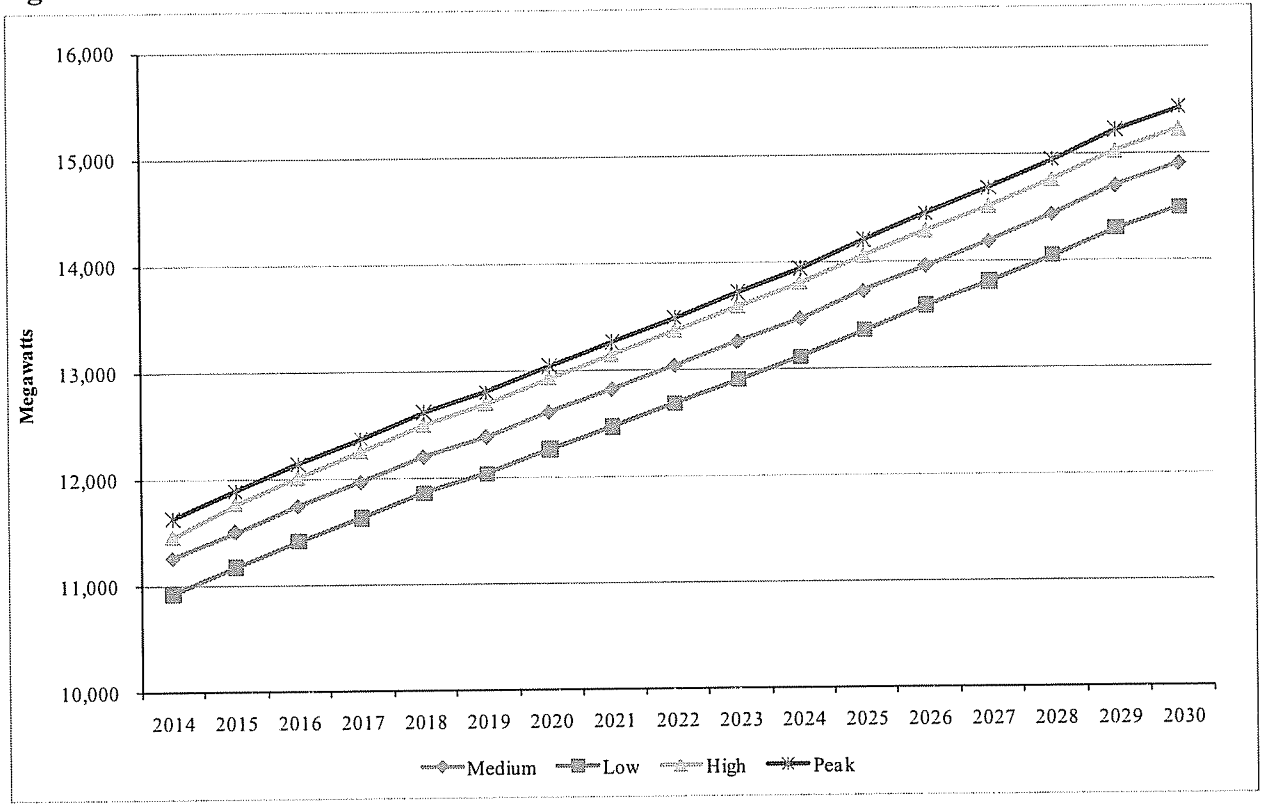
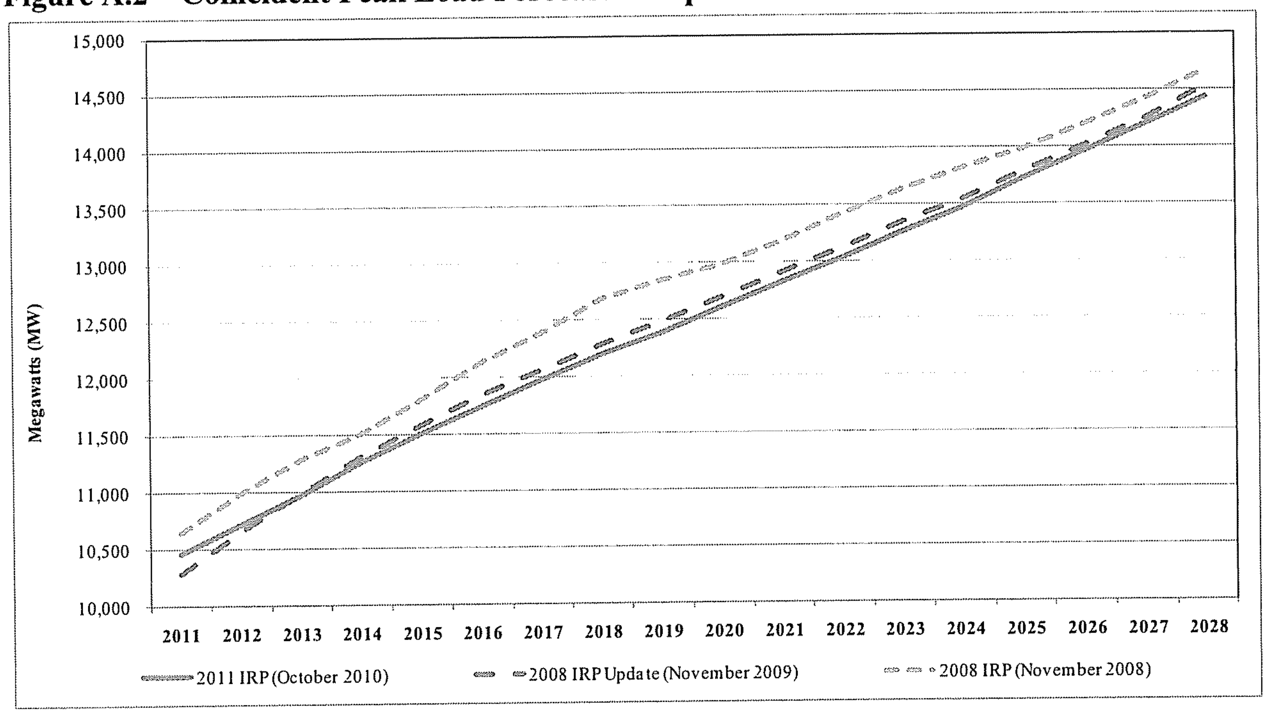


Figure A.2 – Coincident Peak Load Forecast Comparison to Past IRPs



APPENDIX B – IRP REGULATORY COMPLIANCE

Introduction

This appendix describes how PacifiCorp's 2011 IRP complies with (1) the various state commission IRP standards and guidelines, (2) specific analytical requirements stemming from acknowledgment orders for the Company's last IRP ("2008 IRP"), and (3) state commission IRP requirements stemming from other regulatory proceedings.

Included in this appendix are the following tables:

- Table B.1 – Provides an overview and comparison of the rules in each state for which IRP submission is required.[1]
- Table B.2 – Provides a description of how PacifiCorp addressed the 2008 IRP acknowledgement requirements and other commission directives.
- Table B.3 – Provides an explanation of how this plan addresses each of the items contained in the new Oregon IRP guidelines issued in January 2007.
- Table B.4 – Provides an explanation of how this plan addresses each of the items contained in the Utah Public Service Commission IRP Standard and Guidelines issued in June 1992.
- Table B.5 – Provides an explanation of how this plan addresses each of the items contained in the Washington Utilities and Trade Commission IRP guidelines issued in January 2006.
- Table B.6 – Provides an explanation of how this plan addresses each of the items contained in the Wyoming Public Service Commission IRP guidelines.

General Compliance

PacifiCorp prepares the IRP on a biennial basis and files the IRP with the state commissions. The preparation of the IRP is done in an open public process with consultation between all interested parties, including commissioners and commission staff, customers, and other stakeholders. This open process provides parties with a substantial opportunity to contribute information and ideas in the planning process, and also serves to inform all parties on the planning issues and approach. The public input process for this IRP, described in Volume 1, Chapter 2, as well as in Appendix F, fully complies with the IRP Standards and Guidelines.

The IRP provides a framework and plan for future actions to ensure PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP evaluates, over a twenty-year planning period, the future loads of PacifiCorp customers and the capability of existing resources to meet this load.

[1] California guidelines exempt a utility with less than 500,000 customers in the state from filing an IRP. However, renewable portfolio standard rules require that PacifiCorp file IRP supplements that address how the Company is complying with RPS compliance requirements.

To fill any gap between changes in loads and existing resources, the IRP evaluates all available resource options, as required by state commission rules. These resource alternatives include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Chapters 7 and 8 meets this requirement and includes the impact to system costs, system operations, supply and transmission reliability, and the impacts of various risks, uncertainties and externality costs that could occur. To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western Interconnection. The models allow for a rigorous testing of a reasonably broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP Standards and Guidelines, and is described in detail in Chapter 7.

The IRP analysis is designed to define a resource plan that is least cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual CO_2 emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Chapter 8.

Consistent with the IRP Standards and Guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan (See Chapter 9). The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. Chapter 9 also provides a progress report on action items contained in the 2008 IRP Update Action Plan.

The 2011 IRP and the related Action Plan are filed with each commission with a request for prompt acknowledgement. Acknowledgement means that a commission recognizes the IRP as meeting all regulatory requirements at the time the acknowledgement is made. In the case where a commission acknowledges the IRP in part or not at all, PacifiCorp works with the commission to modify and re-file an IRP that meets acknowledgement standards.

State commission acknowledgement orders or letters typically stress that an acknowledgement does not indicate approval or endorsement of IRP conclusions or analysis results. Similarly, an acknowledgement does not imply that favorable ratemaking treatment for resources proposed in the IRP will be given.

California

Subsection (i) of California Public Utilities Code, Section 454.5, states that utilities serving less than 500,000 customers in the state are exempt from filing an Integrated Resource Plan for California. PacifiCorp serves only 45,072 average customers in the most northern parts of the state. PacifiCorp filed for and received an exemption on July 10, 2003.

Idaho

The Idaho Public Utilities Commission's Order No. 22299, issued in January 1989, specifies integrated resource planning requirements. The Order mandates that PacifiCorp submit a

Resource Management Report (RMR) on a biennial basis. The intent of the RMR is to describe the status of IRP efforts in a concise format, and cover the following areas:

> *Each utility's RMR should discuss any flexibilities and analyses considered during comprehensive resource planning, such as: (1) examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3) consideration of demand and supply side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold.*

This IRP is submitted to the Idaho PUC as the Resource Management Report for 2007, and fully addresses the above report components. The IRP also evaluates DSM using a load decrement approach, as discussed in Chapters 6 and 7. This approach is consistent with using an avoided cost approach to evaluating DSM as set forth in IPUC Order No. 21249.

Oregon

This IRP is submitted to the Oregon PUC in compliance with its new planning guidelines issued in January 2007 (Order No. 07-002). These guidelines supersede previous ones, and many codify analysis requirements outlined in the Commission's acknowledgement order for PacifiCorp's 2004 IRP.

The Commission's new IRP guidelines consist of substantive requirements (Guideline 1), procedural requirements (Guideline 2), plan filing, review, and updates (Guideline 3), plan components (Guideline 4), transmission (Guideline 5), conservation (Guideline 6), demand response (Guideline 7), environmental costs (Guideline 8, Order No. 08-339), direct access loads (Guideline 9), multi-state utilities (Guideline 10), reliability (Guideline 11), distributed generation (Guideline 12), and resource acquisition (Guideline 13). Consistent with the earlier guidelines (Order 89-507), the Commission notes that acknowledgement does not guarantee favorable ratemaking treatment, only that the plan seems reasonable at the time acknowledgment is given. Table C.3 provides considerable detail on how this plan addresses each of the requirements.

Utah

This IRP is submitted to the Utah Public Service Commission in compliance with its 1992 Order on Standards and Guidelines for Integrated Resource Planning (Docket No. 90-2035-01, "Report and Order on Standards and Guidelines"). Table C.4 documents how PacifiCorp complies with each of these standards.

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring least cost planning (Washington Administrative Code 480-100-238), and the rule amendment issued on January 9, 2006 (WAC 480-100-238, Docket No. UE-030311). In addition to a least cost plan, the rule requires provision of a two-year action plan and a progress report that "relates the new plan to the previously filed plan."

The rule amendment also now requires PacifiCorp to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, the resource assessment method, and timing and extent of public participation. PacifiCorp filed a work plan with the Commission on February 21, 2006, and had a follow-up conference call with WUTC staff to make sure the work plan met staff expectations.

Finally, the rule amendment now requires PacifiCorp to provide an assessment of transmission system capability and reliability. This requirement was met in this IRP by modeling the company's current transmission system along with both generation and transmission resource options as part of its resource portfolio analyses. These analyses used such reliability metrics as Loss of Load Probability and Energy Not Served to assess the impacts of different resource combinations on system reliability. The stochastic simulation and risk analysis section of Chapter 7 reports the reliability analysis results.

Wyoming

In 2008, Wyoming proposed draft rule 253 for any utility serving Wyoming to file their Integrated Resource Plan with the commission. The rule went into effect in September 2009.

> ***Rule 253: Integrated Resource Planning.***
> *Any utility serving in Wyoming required to file an integrated resource plan (IRP) in any jurisdiction, shall file that IRP with the Wyoming Public Service Commission. The Commission may require any utility serving in Wyoming to prepare and file an IRP when the Commission determines it is in the public interest. Commission advisory staff shall review the IRP as directed by the Commission and report its findings to the Commission in open meeting. The review may be conducted in accordance with guidelines set from time to time as conditions warrant.*

Table B.1 – Integrated Resource Planning Standards and Guidelines Summary by State

Topic	Oregon	Utah	Washington	Idaho	Wyoming
Source	Order No. 07-002, *Investigation Into Integrated Resource Planning*, January 8, 2007, as amended by Order No. 07-047. Order No. 09-041, New Rule OAR 860-027-0400, implementing Guideline 3, "Plan Filing, Review, and Updates".	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-251 Least cost planning, May 19, 1987, and as amended from WAC 480-100-238 *Least Cost Planning Rulemaking*, January 9, 2006 (Docket # UE-030311)	Order 22299 *Electric Utility Conservation Standards and Practices* January, 1989.	Wyoming General Regulations, Chapter 2, Section 253.
Filing Requirements	Least-cost plans must be filed with the Commission.	An Integrated Resource Plan (IRP) is to be submitted to Commission.	Submit a least cost plan to the Commission. Plan to be developed with consultation of Commission staff, and with public involvement.	Submit "Resource Management Report" (RMR) on planning status. Also file progress reports on conservation and low-income programs.	Any utility serving in Wyoming required to file an integrated resource plan (IRP) in any jurisdiction, shall file that IRP with the Wyoming Public Service Commission.
Frequency	Plans filed biennially, within two years of its previous IRP acknowledgement order. An annual update to the most recently acknowledged IRP is required to be filed on or before the one-year anniversary of the acknowledgment order date. While informational only, utilities may request acknowledgment of proposed changes to the action plan.	File biennially.	File biennially.	RMP to be filed at least biennially. Conservation reports to be filed annually.	The Commission may require any utility serving in Wyoming to prepare and file an IRP when the Commission determines it is in the public interest.

Topic	Oregon	Utah	Washington	Idaho	Wyoming
Commission response	Least-cost plan (LCP) *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgement order is issued. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP acknowledged if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying Commission requirements.	Commission advisory staff shall review the IRP as directed by the Commission and report its findings to the Commission in open meeting.
Process	The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Order 07-002 requires that the utility present IRP results to the OPUC at a public meeting prior to the deadline for written public comments. Commission staff and parties should complete their comments and recommendations within six months after IRP filing. Competitive secrets must be protected.	Planning process open to the public at all stages. IRP developed in consultation with the Commission, its staff, with ample opportunity for public input.	In consultation with Commission staff, develop and implement a public involvement plan. Involvement by the public in development of the plan is required. For the amended rules issued in January 2006, PacifiCorp is required to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, resource assessment method, and timing and extent of public participation.	Utilities to work with Commission staff when reviewing and updating RMRs. Regular public workshops should be part of process.	The review may be conducted in accordance with guidelines set from time to time as conditions warrant. The Public Service Commission of Wyoming, in its Letter Order on PacifiCorp's 2008 IRP (Docket No. 2000-346-EA-09) adopted Commission Staff's recommendation to expand the review process to include a technical conference, an expanded public comment period, and filing of reply comments.

Topic	Oregon	Utah	Washington	Idaho	Wyoming
Focus	20-year plan, with end-effects, and a short-term (two-year) action plan. The IRP process should result in the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs.	20-year plan, with short-term (four-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed. The IRP process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	20-year plan, with short-term (two-year) action plan. The plan describes mix of resources sufficient to meet current and future loads at "lowest reasonable" cost to utility and ratepayers. Resource cost, market volatility risks, demand-side resource uncertainty, resource dispatchability, ratepayer risks, policy impacts, and environmental risks, must be considered.	20-year plan to meet load obligations at least-cost, with equal consideration to demand side resources. Plan to address risks and uncertainties. Emphasis on clarity, understandability, resource capabilities and planning flexibility.	Identification of least-cost/least-risk resources and discussion of deviations from least-cost resources or resource combinations.
Elements	Basic elements include: • All resources evaluated on a consistent and comparable basis. • Risk and uncertainty must be considered. • The primary goal must be least cost, consistent with the long-run public interest. • The plan must be consistent with Oregon and federal energy policy. • External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). • Identify acquisition	IRP will include: • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis. • Analysis of the role of competitive bidding • A plan for adapting to different paths as the future unfolds. • A cost effectiveness methodology. • An evaluation of the financial, competitive, reliability and operational risks associated with	The plan shall include: • A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses. • An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	Discuss analyses considered including: • Load forecast uncertainties; • Known or potential changes to existing resources; • Equal consideration of demand and supply side resource options; • Contingencies for upgrading, optioning and acquiring resources at optimum times; • Report on existing resource stack, load forecast and additional resource menu.	Proposed Commission Staff guidelines issued on January 2009 cover: • Sufficiency of the public comment process • Utility strategic goals and preferred portfolio • Resource need and changes in expected resource acquisitions • Environmental impacts • Market purchase evaluation • Reserve margin analysis • Demand-side management and energy efficiency

Topic	Oregon	Utah	Washington	Idaho	Wyoming
	strategies for action plan resources, assess advantages/disadvantages of resource ownership versus purchases, and identify benchmark resources considered for competitive bidding. • Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. • Avoided cost filing required within 30 days of acknowledgement.	resource options, and how the action plan addresses these risks. • Definition of how risks are allocated between ratepayers and shareholders • DSM and supply side resources evaluated at "Total Resource Cost" rather than utility cost.	• Assessment of a wide range of conventional and commercially available nonconventional generating technologies • An assessment of transmission system capability and reliability (Added per amended rules issued in January 2006). • A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using "lowest reasonable cost" criteria. • Integration of the demand forecasts and resource evaluations into a long-range (at least 10 years) plan. • All plans shall also include a progress report that relates the new plan to the previously filed plan.		

Table B.2 – Handling of 2008 IRP Acknowledgement and Other IRP Requirements

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
Idaho		
Acceptance of Filing, Case No. PAC-E-09-06, p. 7.	Prior to its next IRP filing, Staff requests that the Company explain and justify why its integration costs have more than doubled. Staff further recommends that the Company perform stochastic modeling to ascertain a value as part of its next IRP.	The Company provided its 2010 wind integration study to IPUC staff in September 2010. This study, included as Appendix I, thoroughly describes the methodology used to derive wind integration cost results. Stochastic modeling is considered impractical given the modeling technology. For example, one key methodology step involved importing unit commitment data from one production cost run into another. This step is not currently possible with multiple stochastic iterations due to the volume of data being processed.
Acceptance of Filing, Case No. PAC-E-09-06, p. 8.	Staff is concerned that the [portfolio performance measure importance weights] were chosen arbitrarily and may ultimately impact the selection of one portfolio over another having equal or greater merit. Staff requests that the Company correct this discrepancy in future planning processes and document the weight deviation in the final plan.	The Company dropped the numerical weighting scheme from the portfolio selection process. See Chapter 7, "Modeling and Portfolio Evaluation Approach".
Acceptance of Filing, Case No. PAC-E-09-06, p. 8.	Staff does not believe that PacifiCorp has adequately quantified the cost associated with meeting an RPS. Staff believes comparing portfolios with and without RPS constraints may facilitate discussions regarding cost allocation and trading rules for renewable energy credits.	PacifiCorp included a portfolio development scenario for which RPS requirements were removed as resource selection constraints (Case #30). Chapter 8 documents the resource and portfolio cost impact of removing RPS requirements (See the section entitled, "Renewable Portfolio Standard Impact".
Acceptance of Filing, Case No. PAC-E-09-06, p. 7.	Staff recommends that the Company conduct sensitivity analyses on the choice of discount rates on resource timing and selection. A standard inflation Treasury bond rate, Staff contends, may serve as a potential lower bound, and the after-tax WACC may serve well as an upper bound.	Due to time constraints for preparation of this IRP, PacifiCorp intends to conduct the recommended sensitivity analysis as part of the 2011 IRP Update, to be filed with the state commissions in 2012.
PURPA QF Wind, ID PAC-E-07-07, p. 6.	Expected wind integration cost information will be included in the Company's integrated resource planning (IRP) process in the same way that costs for other generating resources are included in the IRP.	The wind integration cost information is included in the 2011 IRP as Appendix I. The Company also filed the wind integration study as an attachment to its stipulation commitment compliance filing under Order No. 30497, dated February 14, 2011.
PURPA QF Wind, ID PAC-E-07-07, p. 6.	(PacifiCorp) shall hereafter file notice with the Commission of any changes to its wind integration charge as reflected in subsequent changes to its IRP.	In its stipulation commitment compliance filing under Order No. 30497, the Company did not request a change to the current Commission approved wind integration rate of $6.50/MWh.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
PURPA QF Wind, ID PAC-E-07-07, p. 7.	Idaho wind developers will be notified as part of the public meeting process and can contribute their input at those meetings to discuss PacifiCorp s wind integration study and new data related to wind integration costs prior to the publishing of the Company s next IRP.	PacifiCorp continued to invite Idaho wind developers to IRP public input meetings. Information on the 2010 wind integration study and wind resource modeling in general is posted to the Company's IRP Web site.
Oregon		
Order No. 10-066, Docket No. LC 47, p. 26.	Action Item 3 (Peaking/Intermediate/Base-load Supply-side Resources) - In recognition of the unsettled U.S. economy, expected volatility in natural gas markets, and regulatory uncertainty, continue to seek cost-effective resource deferral and acquisition opportunities in line with near-term updates to load/price forecasts, market conditions, transmission plans and regulatory developments. PacifiCorp will reexamine the timing and type of gas resources and other resource changes as part of a comprehensive assumptions update and portfolio analysis to be conducted for the 2008 RFP final short-list evaluation in the RFP, approved in Docket UM 1360, the next business plan and the 2008 IRP update.	PacifiCorp updated its resource needs assessment and modeling input assumptions as part of the all-source RFP bid evaluation process, 2011 business planning process, and 2011 IRP process. Documentation on these updates was provided as part of the Company's application for approval of its 2008 RFP bidder final shortlist by the Oregon Commission (Docket UM 1360). This IRP also fully documents the comprehensive assumptions update for the 2011 IRP. See Chapter 5, "Resource Needs Assessment", Chapter 7, "Modeling and Portfolio Evaluation Approach", and Appendix A, "Load Forecast Review".
Order No. 10-066, Docket No. LC 47, p. 26.	Additional Action Item 4 - For future IRP planning cycles, include on-going financial analysis with regard to transmission, which includes: a comparison with alternative supply side resources, deferred timing decision criteria, the unique capital cost risk associated with transmission projects, the scenario analysis used to determine the implications of this risk on customers, and all summaries of stochastic annual production cost with and without the proposed transmission segments and base case segments.	Energy Gateway financial analysis is included in Chapter 4 of the 2011 IRP. Supporting information is included as Appendix C.
Order No. 10-066, Docket No. LC 47, p. 26.	Additional Action Item 5 - By August 2, 2010, complete a wind integration study that has been vetted by stakeholders through a public participation process.	PacifiCorp completed the wind integration study and distributed it to the public via email and Web site posting on September 1, 2010 in accordance with the Oregon Commission granting a deadline extension from August 1 to September 1, 2010. The study is included in the 2011 IRP as Appendix I.
Order No. 10-066, Docket No. LC 47, p. 26.	Additional Action Item 6 - During the next planning cycle, work with parties to investigate carbon dioxide emission levels as a measure for portfolio performance scoring.	Total CO_2 emissions for the 20-year simulation period were included as a final screening performance measure for portfolio evaluation and determination of the 2011 IRP preferred portfolio. See the "Final Screening" section of Chapter 7 and

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
		portfolio evaluation results in Chapter 8, "Modeling and Portfolio Evaluation Results".
Order No. 10-066, Docket No. LC 47, p. 27.	Additional Action Item 7 - In the next IRP, provide information on total CO_2 emissions on a year-to year basis for all portfolios, and specifically, how they compare with the preferred portfolio.	CO_2 emissions trend charts for each portfolio, including the preferred portfolio, are included in Appendix D.
Order No. 10-066, Docket No. LC 47, p. 27.	Additional Action Item 8 - For the next IRP planning cycle, PacifiCorp will work with parties to investigate a capacity expansion modeling approach that reduces the influence of out-year resource selection on resource decisions covered by the IRP Action Plan, and for which the Company can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan.	PacifiCorp used portfolio development case number 9 for testing how out-year resource selection (years 2021-2030) impacts selection of near-term resources (years 2011-2020). The Company compared two portfolios: a base 20-year System Optimizer run and a test 20-year run where resources for the first 10 years are fixed based on a prior 10-year simulation. Results are summarized in Chapter 8, "Modeling and Portfolio Evaluation Results".
Order No. 10-066, Docket No. LC 47, p. 27.	Additional Action Item 9 - In the next IRP planning cycle, PacifiCorp will incorporate its assessment of distribution efficiency potential resources for planning purposes.	PacifiCorp is conducting a conservation voltage reduction study, targeting 19 distribution feeders in Washington. The study is expected to be completed by the end of May 2011. Based on preliminary data provided by the contractor for the study, PacifiCorp developed a distribution efficiency resource for testing with the System Optimizer model. Results of the portfolio development testing are provided in Chapter 8, "Modeling and Portfolio Evaluation Results".
Order No. 10-066, Docket No. LC 47, p. 26.	Revised Action Item 9 (Planning Process Improvements) - For the next IRP planning cycle complete the implementation of System Optimizer capacity expansion model enhancements for improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level. Use the enhanced model to provide more detailed analysis of potential hard-cap regulation of carbon dioxide emissions and achievement of state or federal emissions reduction goals. Also use the capacity expansion model to evaluate the cost-effectiveness of coal facility retirement as a potential response to future regulation of carbon dioxide emissions.	PacifiCorp successfully implemented the System Optimizer model enhancements, and defined five emission hard cap evaluation cases for modeling (nos. 15-18, plus a hard cap case for coal plant utilization scenario analysis). PacifiCorp conducted System Optimizer modeling for five coal plant utilization scenarios in which coal units are allowed to be replaced by CCCT resources, taking into account coal plant incremental costs. Modeling results are described in Chapter 8, "Modeling and Portfolio Evaluation Results". As noted in this chapter, the coal utilization study is intended as a modeling proof-of-concept only.
Order No. 10-066, Docket No. LC 47, p. 26.	Revised Action Item 9 (Planning Process Improvements) - In the next IRP planning cycle provide an evaluation of, and continue to investigate, the formulation of satisfactory proxy intermediate-term market purchase resources for purposes of portfolio modeling and contingent on acquiring suitable market data.	PacifiCorp's All-source RFP, reactivated in December 2009, yielded no satisfactory proxy intermediate-term market purchase resources.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
Order No. 10-066, Docket No. LC 47, p. 27.	Additional Action Item [not numbered] - In addition, the Company will file its 2008 IRP Update approximately one year after the date of this Order, in compliance with Guideline 3.	The 2011 IRP fulfills the filing requirement, given that the March 31, 2011 filing date is approximately one year after the acknowledgment of the 2008 IRP (February 24, 2010).
Order No. 10-066, Docket No. LC 47, p. 24.	With regard to NWEC's suggestion that appropriate reserves be separately determined, we direct the parties to discuss this issue in the next planning.	PacifiCorp discussed planning reserve margin analysis at its August 4, 2010, public input meeting. The Company outlined a loss of load study to determine an appropriate planning reserve margin to apply for portfolio development. Public stakeholders did not take issue with the study approach. The study was distributed for IRP participant review November 18, 2010.
Utah		
UT Docket No. 09-2035-01, Report & Order, p. 24.	At a minimum, we direct the Company to perform a sensitivity case in its next IRP or IRP update wherein the ENS cost is flat and based on the Federal Energy Regulatory Commission price cap.	This sensitivity analysis is described in the section entitled, "Cost of Energy Not Served (ENS) Sensitivity Analysis" in Chapter 8.
UT Docket No. 09-2035-01, Report & Order, p. 24-25.	Additionally, in an IRP public input meeting, we direct the Company to identify a reasonable number of cases, including high and low load growth cases, to compare the costs and risks to customers, or to identify a reasonable alternative method, e.g., a LOLP study, for evaluating an appropriate planning reserve.	PacifiCorp conducted a stochastic loss of load study for this IRP, which was published November 18, 2010 for review by stakeholders, and is presented as Appendix J. The Company also developed high/low economic growth and 1-in-10 peak-producing temperature scenarios for evaluating portfolio impacts of alternative load forecasts. The results of these alternative load forecasts are described in Chapter 8. Stochastic production cost results are reported in Appendix E.
UT Docket No. 09-2035-01, Report & Order, p. 30.	At a minimum, we direct the Company to include the costs of hedging in its IRP analysis of resources that rely on fuels subject to volatile prices.	PacifiCorp addresses hedging costs in Appendix G, "Hedging Strategy".
UT Docket No. 09-2035-01, Report & Order, p. 30.	We also direct the Company to perform sensitivity analysis to determine a hedging strategy which minimizes costs and risks for customers.	The Company discusses hedging strategies and the impacts of various hedging levels on risk and expected cost in Appendix G, "Hedging Strategy".
UT Docket No. 09-2035-01, Report & Order, p. 30.	Additionally, we direct the Company to include an analysis of the adequacy of the western power market to support the volumes of purchases on which the Company expects to rely. We concur with the Office [of Consumer Services], the WECC is a reasonable source for this evaluation. We direct the Company to identify whether customers or shareholders will be expected to bear the risks associated with its reliance on the wholesale market.	The Company's analysis of western resource adequacy is provided as Appendix H. Identification of who bears the risk of market reliance (customers versus shareholders) is identified as well.
UT Docket No. 09-2035-01, Report & Order, p. 30.	Finally, we direct the Company to discuss methods to augment the Company's stochastic analysis of this issue [WECC market depth and liquidity] in an IRP	Based on feedback from parties attending the June 2010 Utah IRP stakeholder input meeting, PacifiCorp developed a market purchase stress test proposal, which was vetted at the October 5th IRP

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
	public input meeting for inclusion in the next IRP or IRP update.	general public input meeting. The results of the stress test, which used stochastic production cost simulation, are described in Appendix H.
UT Docket No. 09-2035-01, Report & Order, p. 35.	We direct the Company to discuss methods for improving the evaluation of nontraditional resources in an IRP public input meeting. At a minimum, this discussion should include ideas for improving the evaluation of distributed solar technologies which provide opportunities for customer participation, i.e., a solar rooftop customer buy-down program, and options for improving the evaluation of storage technologies designed to enhance the value and performance of intermittent renewable resources.	PacifiCorp discussed the evaluation of nontraditional resources, including energy storage, at the August 4, 2010 IRP public input meeting. A consultant study on incremental capacity value and ancillary service benefits of energy storage is planned for 2011 or 2012. This study is identified in the 2011 IRP action plan.
UT Docket No. 09-2035-01, Report & Order, p. 35.	We also concur with the Division and Office regarding the need for review of geothermal resources and direct the Company to file a geothermal resource study as described by the Division within 60 days of the date of this order. We will initiate a comment period upon its filing and this information can be included in the next IRP or IRP update.	The geothermal resource report was filed with the Utah Commission on August 10, 2010 in accordance with the Commission's deadline extension. A conference call with Utah parties to discuss the report and the Company's follow-up activities was held December 9, 2010.
UT Docket No. 09-2035-01, Report & Order, p. 35.	In the future, the Company is directed to omit from its core cases any resource for which it does not already have a signed final procurement contract or certificate of public convenience and necessity. However, this does not preclude the Company from including such resources in sensitivity cases. This will assist with the consistent and comparable treatment of resources going forward.	No resource has been fixed in the core portfolios, except for the 2011 business plan core case #19, which is intended as a reference case for planned resources identified in the business plan.
UT Docket No. 09-2035-01, Report & Order, p. 38.	... we again direct the Company to address these issues in the next IRP or IRP update: i.e., • Number of years relied upon for developing stochastic parameters. • Role of planning reserve in managing the risks of forecast error.	PacifiCorp discussed stochastic parameter updates at the December 15, 2010 IRP public meeting. Due to time constraints, PacifiCorp targeted its load stochastic parameters for updating in the 2011, using a three-year data set originally prepared for the 2010 wind integration study.
UT Docket No. 09-2035-01, Report & Order, p. 39.	[We] direct the Company and interested parties to examine and consider all of the suggestions contained in [the GDS] report. At a minimum, the Company is directed to provide a range of load forecasts that comport with industry standards as recommended by GDS. Further, as recommended by GDS, we direct the Company to provide the	As noted above, PacifiCorp adopted the GDS recommendations for inclusion of load growth scenarios based on different assumptions concerning economic drivers. The Company also developed a 1-in-10 peak-producing temperature scenario. The results of these alternative load forecasts are described in Chapter 8. Appendix A constitutes the Company's standalone

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
	Commission with a comprehensive stand-alone load forecast report when the forecast is updated. The GDS suggestions could reduce last minute revisions due to load forecast changes and thereby assist in the timely completion of future IRPs.	load forecast report.
UT Docket No. 09-2035-01, Report & Order, p. 40.	We again direct the Company to address [hydro capacity accounting] in its next IRP or IRP update and provide the results of its analysis. For example, it may be useful to conduct sensitivity analysis regarding this assumption to identify potential risks or shortcomings of the current methodology.	PacifiCorp provided a detailed analysis of 18-hour sustained hydro peaking capability and its applicability to hydro capacity accounting in the load & resource balance in Appendix H.
UT Docket No. 09-2035-01, Report & Order, p. 41.	We concur with the Division and direct the Company to complete its own wind integration study. We understand this process is underway and that the Company is circulating the study for review. We direct the Company to address the Division's concerns and include this study in the next IRP or IRP update.	PacifiCorp completed the wind integration study and distributed it to the public via email and Web site posting on September 1, 2010. The study is included in the 2011 IRP as Appendix I.
UT Docket No. 09-2035-01, Report & Order, p. 42.	[W]e direct the Company to solicit and discuss further improvements to its resource acquisition path analysis and decision mechanism and address the Division's concerns in its next IRP or IRP update.	PacifiCorp expanded the acquisition path analysis to include alternative regulatory policy scenarios, and applied sensitivity analysis results to identify acquisition paths and resource quantities for load growth and natural gas price forecast trends. A more extensive discussion of the decision mechanism has been provided in response to the Utah Division of Public Utilities written comments on the 2008 IRP.
UT Docket No. 09-2035-01, Report & Order, p. 54.	In order to ensure timely and meaningful information exchange, we direct the Company to adopt two of the Division's recommendations on improving public input meetings. • First, materials should be distributed one week prior to the public input meeting. • Secondly, a written report should be provided after each meeting to provide follow-up to issues or questions raised in the meeting.	PacifiCorp has complied with the requirement to distribute meeting materials one week prior to public meetings. Written reports on public meetings have been prepared and distributed to participants via email and postings to the IRP Web site.
UT Docket No. 09-2035-01, Report & Order, p. 55.	We concur with the Division and UAE, training on the Company's models in order for parties to validate the models and to gain confidence in the modeling results is worthwhile. We direct the Company to convene at least a full-day meeting to this end.	PacifiCorp is planning to hold tutorial sessions during the second quarter of 2011 for both System Optimizer and the Planning and Risk model. A non-disclosure agreement between participants and the model vendor, Ventyx, will be required due to sharing of proprietary information.
Utah Commission Docket No. 08-035-56, DSM Potential Study, Report &	The Company proposes to adjust the technical potential using its assumptions regarding achievable levels of DSM to serve as the supply curves in its IRP. It	PacifiCorp ran System Optimizer with DSM supply curves based on unadjusted technical potential. Given the particular input assumptions used, the model deferred CCCT resources. The results of this

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
Order, p. 8.	would then use these adjusted supply curves in IRP to determine cost-effective amounts of DSM. UCE and WRA disagree and propose that the Company use the unadjusted technical potential to form the supply curves in IRP to determine the full cost-effective level of DSM and then make provision in its path or contingency analysis for the possibility that the cost-effective amount of DSM may not be achieved in the time-frame modeled...we direct the Company to evaluate the two approaches in its next IRP or IRP update. We encourage the Company to solicit input from interested parties on methods for evaluating the two approaches. We will request parties' comments on the Company's evaluation of the two approaches in an appropriate IRP or IRP update docket.	study are described in Chapter 8, "Demand-side Management Cases."
DSM Potential Study, Docket No. 08-035-56, Report & Order, p. 9.	With respect to estimating the cost of solar resources, UCE and WRA provide considerably different cost estimates than PacifiCorp. The differences are large enough that we would expect significant differences to appear in the Company's IRP action plan depending on the assumptions used in the IRP process. We direct the Company to perform sensitivity analysis with respect to the assumed cost of solar resources in its next IRP or IRP update.	PacifiCorp updated all distributed generation cost estimates for the 2011 IRP, including solar resources. The Cadmus Group prepared input assumptions memos that were distributed to public stakeholders for review and comment in July and August, 2010.
DSM Potential Study, Docket No. 08-035-56, Report & Order, p. 9.	Going forward, the Company shall provide information on both the total cost of solar resources in comparison to other resources, and also the cost to the utility of a utility-sponsored program to encourage customer adoption of this resource. The Company could begin such analysis with preliminary data from the solar incentive pilot program. We direct PacifiCorp to work with interested parties regarding how to evaluate solar resources in the ongoing IRP process and we will consider comments on this effort in an appropriate IRP proceeding.	PacifiCorp discussed with interested parties System Optimizer portfolio development scenarios reflecting a solar PV cost buy-down program. A conference call was held January 27, 2011, to finalize the study approach. The modeling approach is described in the section titled "Case Definitions" in Chapter 7. Modeling results are summarized in the section titled, "Renewable Resource Cases" in Chapter 8.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
Washington		
Letter Order, UE-080826, Attachment p. 1.	Transmission Planning (Chapter 4). The next IRP should discuss alternative transmission options.	Chapter 4 outlines an analysis of seven Energy Gateway deployment scenarios that considers alternative transmission footprints, investment costs, in-service dates, and economic drivers.
Letter Order, UE-080826, Attachment p. 1.	Transmission Planning (Chapter 4). The next IRP should discuss alternative deployment schedules for the transmission projects it considers and the benefits of each of the alternative deployment schedules of any transmission segments considered in the modeling.	Chapter 4 focuses on two deployment scenarios based on alternative directions for state and federal resource policies: a Green Resource Future and Incumbent Resource Future. Additionally, the section entitled "Customer Load and Resources" in Chapter 4 summarizes the process that PacifiCorp follows, in compliance with its Open Access Transmission Tariff, to plan for and invest in transmission to meet network customer load requirements.
	Specifically, the various portfolios have different resource selections during the first five years of the planning period. This might result in PacifiCorp, in its planning process, choosing a set of early resources because they are in a portfolio with lower risks in the later years of the planning horizon, even though the portfolios with higher risks could be mitigated by future flexibility rather than by choosing a different portfolio. • PacifiCorp should address this issue in its next IRP	PacifiCorp conducted a sensitivity analysis to isolate the near-term resource selection impact of out-year resources in the context of capacity expansion optimization modeling. The results of the sensitivity analysis are provided in Chapter 8.
Letter Order, UE-080826, Attachment p. 4.	The action plan does not specifically mention the utility's obligation under RCW 19.285 to determine and meet certain energy efficiency targets. The Commission reminds the Company that it needs to meet this obligation.	Action Item Number 6, Class 2 DSM, explicitly mentions PacifiCorp's obligation to meet energy efficiency targets under RCW 19.285.
Wyoming		
The Wyoming Public Service Commission provided the following comment in its Letter Order (Docket No. 20000-346-EA-9, dated 11/23/2010) on PacifiCorp's 2008 IRP: *Pursuant to open meeting action taken on January 11, 2008, PacifiCorp d/b/a Rocky Mountain Power's 2007 Integrated Resource Plan (IRP) is hereby placed in the Commission's files. No further action will be taken and this docketed matter is closed.*		

Table B.3 – Oregon Public Utility Commission IRP Standard and Guidelines

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
Guideline 1. Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis: All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	PacifiCorp considered a wide range of resources including renewables, demand-side management, distributed generation, energy storage, power purchases, thermal resources, and transmission. Chapters 4 (Transmission Planning), 6 (Resource Options), and 7 (Modeling and Portfolio Evaluation Approach) document how PacifiCorp developed these resources and modeled them in its portfolio analysis. All these resources were established as resource options in the Company's capacity expansion optimization model, System Optimizer, and selected by the model based on relative economics, resource size, availability dates, and other factors.
1.a.2	All resources must be evaluated on a consistent and comparable basis: Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	All portfolios developed with System Optimizer were subjected to Monte Carlo production cost simulation. These portfolios contained a variety of resource types with different fuel types (coal, gas, biomass, nuclear fuel, "no fuel" renewables), lead-times (ranging from front office transactions to nuclear plants), in-service dates, life-times, and locations.
1.a.3	All resources must be evaluated on a consistent and comparable basis: Consistent assumptions and methods should be used for evaluation of all resources.	PacifiCorp fully complies with this requirement. The company developed generic supply-side resource attributes based on a consistent characterization methodology. For demand-side resources, the company used the Cadmus Group's supply curve data developed in 2010 for representation of DSM and distributed generation resources, which was also based on a consistently applied methodology for determining technical, market, and achievable DSM potentials. All portfolio resources were evaluated using the same sets of price and load forecast inputs. These inputs are documented in Chapters 6 and 7.
1.a.4	All resources must be evaluated on a consistent and comparable basis: The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PacifiCorp applied its after-tax WACC of 7.17 percent to discount all cost streams.
1.b.1	Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	PacifiCorp fully complies with this requirement. Each of the sources of risk identified in this guideline is treated as a stochastic variable in Monte Carlo production cost simulation with the exception of CO_2 emission compliance costs, which are treated as a scenario risk. See the stochastic modeling methodology section in Chapter 7.
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	PacifiCorp complied with this guideline by discussing resource risk mitigation in Chapter 9 as well as addressing market reliance risk and hedging strategies in Appendix G and H, respectively. Topics covered include: (1) managing carbon risk for existing plants, (2) the use of physical and

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
		financial hedging for electricity price risk, and (3) managing gas supply risk. Regulatory and financial risks associated with resource and transmission investments are highlighted in several areas in the IRP document, including Chapters 4 and 8.
1.c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers ("best cost/risk portfolio").	PacifiCorp evaluated cost/risk tradeoffs for each of the portfolios considered, See Chapter 8 for the company's portfolio cost/risk analysis and determination of the preferred portfolio.
1.c.1	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	PacifiCorp used a 20-year study period for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects consistent with past IRP practice.
1.c.2	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	PacifiCorp fully complies. Chapter 7 provides a description of the PVRR methodology.
1.c.3.1	To address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	PacifiCorp uses the standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates several measures, including stochastic upper-tail mean PVRR (mean of highest five Monte Carlo iterations) and the 95th percentile stochastic production cost PVRR.
1.c.3.2	To address risk, the plan should include, at a minimum: 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	A discussion on costs and risks of hedging is provided in Appendix G.
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapter 8 summarizes the results of PacifiCorp's cost/risk tradeoff analysis, and describes what criteria the company used to determine the best cost/risk portfolios and the preferred portfolio.
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and potential state and federal energy/pollutant emission policies in portfolio modeling. Chapter 7 describes the decision process used to derive portfolios, which includes consideration of state resource policies. The IRP action plan chapter also presents an acquisition path analysis that describes resource strategies based on regulatory trigger events.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	PacifiCorp fully complies with this requirement. Chapter 2 provides an overview of the public process, while Appendix D documents the details on public meetings held for the 2008 IRP.
2.b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	Both IRP volumes provide non-confidential information the company used for portfolio evaluation, as well as other data requested by stakeholders. PacifiCorp also provided stakeholders with non-confidential information to support public meeting discussions via email.
2.c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PacifiCorp distributed a partial draft IRP document for external review on February 23, 2011 and the remaining chapters on March 7, 2011.
Guideline 3: Plan Filing, Review, and Updates		
(3)	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	This Plan complies with this requirement.
(4)	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	Not applicable; activity conducted subsequent to filing this IRP.
(5)	Commission staff and parties must complete their comments and recommendations within six months of IRP filing.	Not applicable; activity conducted subsequent to filing this IRP.
(6)	The Commission must consider comments and recommendations on an energy utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the energy utility an opportunity to revise the IRP before issuing an acknowledgment order.	Not applicable; activity conducted subsequent to filing this IRP.
(7)	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable; activity conducted subsequent to filing this IRP.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
(8)	Each energy utility must submit an annual update on its most recently acknowledged IRP. The update is due on or before the acknowledgment order anniversary date. The energy utility must summarize the annual update at a Commission public meeting. The energy utility may request acknowledgment of changes, identified in its update, the IRP action plan. The annual update is an informational filing that: (a) Describes what actions the energy utility has taken to implement the action plan to select best portfolio of resources contained in its acknowledged IRP; (b) Provides an assessment of what has changed since the acknowledgment order that affects the action plan to select best portfolio of resources, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and (c) Justifies any deviations from the action plan contained in its acknowledged IRP.	Not applicable; activity conducted subsequent to filing this IRP.
(9)	As soon as an energy utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the energy utility is within six months of filing its next IRP. This update must meet the requirements set forth in section (8) of this rule.	Not applicable; activity conducted subsequent to filing this IRP.
	If the energy utility requests Commission acknowledgement of its proposed changes to the action plan contained in its acknowledged IRP: (a) The energy utility must file its proposed changes with the Commission and present the results of its proposed changes to the Commission at a public meeting prior to the deadline for written public comment; (b) Commission staff and parties must file any comments and recommendations with the Commission and present such comments and recommendations to the Commission at a public meeting within six months of the energy utility's filing of its request for acknowledgement of proposed changes; (c) The Commission may provide direction to an energy utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable; activity conducted subsequent to filing this IRP.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
Guideline 4. Plan Components (at a minimum, must include…)		
4.a	An explanation of how the utility met each of the substantive and procedural requirements.	The purpose of this table is to comply with this guideline.
4.b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	PacifiCorp developed low and high load growth forecasts for scenario analysis based on economic growth assumptions using the System Optimizer model for portfolio development. Stochastic variability of loads was also captured in the risk analysis. See Chapters 5, 7, and 8, as well as Appendix A, for load forecast information. Chapter 8 also describes how loads are handled in the stochastic modeling.
4.c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested.	This Plan complies with the requirement. See Chapter 5 for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies, as mentioned in Chapter 7.
4.d	For gas utilities only	Not applicable
4.e	Identification and estimated costs of all supply-side and demand side resource options, taking into account anticipated advances in technology	Chapter 6 identifies the resources included in this IRP, and provides their detailed cost and performance attributes. See Tables 6.2 through 6.10 for supply-side resources, and Tables 6.15 through 6.20 for demand-side resources.
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs	In addition to incorporating a planning reserve margin for all portfolios evaluated, the company used several measures to evaluate relative portfolio supply reliability. These are described in Chapter 7 (Energy Not Served and Loss of Load Probability). PacifiCorp conducted a stochastic loss of load study in 2010 to support selection of the planning reserve margin. This study is included as Appendix J.
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered	Chapter 7 describes the key assumptions and alternative scenarios used in this IRP.
4.h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system	This Plan documents the development and results of 67 portfolios designed to determine resource selection under a variety of input assumptions (Chapter 8).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties	Chapter 8 and Appendix E present the stochastic portfolio modeling results, and describes portfolio attributes that explain relative differences in cost and risk performance.
4.j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapter 8 provides tables and charts with performance measure results, including rank ordering.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	PacifiCorp fully complies with this guideline. See the responses to 1.b.1 and 1.b.2 above.
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is presumed to have no inconsistencies.
	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Chapters 9 and 10 presents the 2011 IRP and transmission expansion action plans, respectively.
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	PacifiCorp evaluated proxy transmission resources on a comparable basis with respect to other proxy resources in this IRP. Fuel transportation costs were factored into resource costs.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	A multi-state demand-side management potentials study was completed in late 2010, and those results were incorporated into this plan.
6.b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	PacifiCorp's energy efficiency supply curves incorporate Oregon resource potential. Oregon potential estimates were provided by the Energy Trust of Oregon. See the demand-side resource section in Chapter 6.
6.c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1. Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and 2. Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	See the response for 6.b above.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	PacifiCorp evaluated demand response resources (Class 3 DSM) on a consistent basis with other resources in a portfolio sensitivity study. Class 3 DSM programs are addressed in Item 7 of the IRP action plan in Chapter 9.
Guideline 8: Environmental Costs		
8	a. Base Case and Other Compliance Scenarios b. Testing Alternative Portfolios Against the Compliance Scenarios c. Trigger Point Analysis d. Oregon Compliance Portfolio	This IRP fully complies with the CO_2 compliance cost analysis requirements in Order No. 08-339. Performance results for CO_2 compliance scenario portfolios are reported in Chapter 8, including hard cap scenarios using the Oregon emission targets in HB 3543.
Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	PacifiCorp continues to plan for load for direct access customers.
Guideline 10: Multi-state Utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2011 IRP conforms to the multi-state planning approach as stated in Chapter 2 ("The Role of PacifiCorp's Integrated Resource Planning"). The Company notes the challenges in complying with multi-state integrated planning given differing state energy policies and resource preferences.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	PacifiCorp fully complies with this guideline. See the response to 1.c.3.1 above. Chapter 8 describes the role of reliability, cost, and risk measures in determining the preferred portfolio. Scatter plots of portfolio cost versus risk at different CO_2 cost levels were used to inform the cost/risk tradeoff analysis. (Chapter 8).
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PacifiCorp evaluated several types of distribution generation, including combined heat and power and solar. The results of these evaluations are documented in Chapter 8.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
Guideline 13: Resource Acquisition		
13.a	An electric utility should, in its IRP: 1. Identify its proposed acquisition strategy for each resource in its action plan. 2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party 3. Identify any Benchmark Resources it plans to consider in competitive bidding	Chapter 9 outlines the procurement approaches for resources identified in the preferred portfolio. A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 9. Company resources included in RFPs is addressed in the action plan (Table 9.1 and accompanying narrative).
13.b	For gas utilities only	Not applicable

Table B.4 – Utah Public Service Commission IRP Standard and Guidelines

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Utah Public Service Commission responsibility.
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the IRP process.
3	Prudence Reviews of new resource acquisitions will occur during ratemaking proceedings.	Not addressed; ratemaking occurs outside of the IRP process.
4	PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.	PacifiCorp's public process is described in Chapter 2. A record of public meetings is provided as Appendix D.
5	Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.	PacifiCorp used a scenario analysis approach along with externality cost adders to model environmental externality costs. See Chapter 7 for a description of the methodology employed, including how CO_2 cost uncertainty is factored into the determination of relative portfolio performance.
6	The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.	Supply, transmission, and demand-side resources were evaluated on a comparable basis using PacifiCorp's capacity expansion optimization model. Also see the response to number 4.b.ii below.
7	Avoided Cost should be determined in a manner consistent with the Company's Integrated Resource Plan.	Consistent with the Utah rules, PacifiCorp determination of avoided costs will be handled in a manner consistent with the IRP, with the caveat that the costs may be updated if better information becomes available.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
8	The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.	This IRP was developed in consultation with parties from all state jurisdictions, and meets all formal state IRP guidelines.
9	The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.	Chapter 9 describes the linkage between the 2011 IRP preferred portfolio and 2011 business plan resources approved in December 2010. Significant resource differences are highlighted.
Standards and Guidelines		
1	Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	Chapter 7 outlines the portfolio performance evaluation and preferred portfolio selection process, while Chapter 8 chronicles the modeling and preferred portfolio selection process. This IRP also addresses concerns expressed by Utah stakeholders and the Utah commission concerning comprehensiveness of resources considered, consistency in applying input assumptions for portfolio modeling, and explanation of PacifiCorp's decision process for selecting top-performing portfolios and the preferred portfolio.
2	The Company will submit its Integrated Resource Plan biennially.	The company submitted its last IRP on May 28, 2009, and filed this IRP on March 31, 2011. PacifiCorp files the IRP with all commissions on March 31 in each odd-numbered year.
3	IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	PacifiCorp's public process is described in Chapter 2. A record of public meetings is provided as Appendix F.
4.a	PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic variability, covering both capacity and energy. Details concerning the load forecasts used in the 2011 IRP are provided in Appendix A. Figure 7.4 in Chapter 7 shows the range of forecasts used for capacity expansion modeling. Figures 7.18 through 7.24 show the range of stochastic loads modeled for each load area by the Monte Carlo production cost simulations.
4.a.i	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have	Price risk associated with market sales is captured in the company's stochastic simulation results. Current off-system sales agreements are included in the IRP models.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
	some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	Appendix A documents how demographic and price factors are used in PacifiCorp's new load forecasting methodology.
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the System Optimizer model and Planning and Risk production cost model.
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp included supply curves for Class 1 DSM (dispatchable/schedulable load control) and Class 2 DSM (energy efficiency measures) in its capacity expansion model. Details are provided in Chapter 6. A sensitivity study of demand-response programs (Class 3 DSM) was also conducted (See Chapter 8).
4.b.ii	An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, energy storage, and Energy Gateway transmission segments. Chapters 4, 6 and 7 document how PacifiCorp developed and assessed these technologies and resources.
4.b.iii	The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.	PacifiCorp captures and models these resource attributes in its IRP models. Resources are defined as providing capacity, energy, or both. The DSM supply curves and distributed generation resources used for portfolio modeling explicitly incorporate estimated rates of program and event participation. Dispatchability is accounted for in both IRP models used; however, the Planning and Risk model provides a more detailed representation of unit dispatch than System Optimizer, and includes modeling of unit commitment and reserves.
4.c	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions	A description of the role of competitive bidding and other procurement methods is provided in Chapter 9.
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2011-2030)
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	The IRP action plan is provided in Chapter 9. A status report of the actions outlined in the previous action plan (2008 IRP update) is provided in Chapter 9 as well. The action plan (Table 9.1) also identifies actions anticipated to extend beyond the next two years, or occur after the next two years

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
4.f	A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.	Chapter 9 includes an acquisition path analysis that presents broad resource strategies based on regulatory trigger events, combinations of load growth and gas price futures, and procurement delays. The associated decision mechanism is also described in more detail relative to the 2008 IRP.
4.g	An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.	PacifiCorp provides resource-specific utility and total resource cost information in Chapter 7. The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways: • Portfolios were evaluated using a range of CO_2 cost futures. • A discussion of environmental policy status and impacts on utility resource planning is provided in Chapter 3. • State and proposed federal public policy preferences for clean energy are considered for development of the preferred portfolio, which is documented in Chapter 8. • Appendix L reports historical water consumption for PacifiCorp's thermal plants.
4.h	An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.	The handling of resource risks is discussed in Chapter 9, and covers managing carbon risk for existing plants and managing gas supply risk. Transmission expansion risks are discussed in Chapter 3. Appendix G discusses hedging. Appendix H discusses market reliance risks and identifies who bears associated risks. Resource capital cost uncertainty and technological risk is addressed in Chapter 6 ("Handling of Technology Improvement Trends and Cost Uncertainty"). For reliability risks, the stochastic simulation model incorporates stochastic volatility of forced outages for new thermal plants and hydro availability. These risks are factored into the comparative evaluation of portfolios and the selection of the preferred portfolio upon which the action plan is based. Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Chapter 9.
4.i	Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.	Flexibility in the planning and procurement processes is highlighted in Chapter 9 and the action plan (Table 9.1).
4.j	An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.	PacifiCorp examined the trade-off between portfolio cost and risk. This trade-off analysis is documented in Chapter 8, and highlighted through the use of scatter-plot graphs showing the relationship between stochastic mean and upper-tail mean stochastic PVRR.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
4.k	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.	PacifiCorp incorporated environmental externality costs for CO_2, NO_X, SO_2, and mercury with use of cost adders and assumptions regarding the form of compliance strategy (for example, a per-ton tax and hard emissions caps for CO_2). For CO_2 externality costs, the company used scenarios with various cost levels to capture a reasonable range of cost impacts. These cost assumptions are described in Chapter 7.
4.l	A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.	The role of Class 3 DSM (price response programs) at PacifiCorp and how these resources are modeled in the IRP are described in Chapter 6.
5	PacifiCorp will submit its IRP for public comment, review and acknowledgement.	PacifiCorp distributed a partially completed draft IRP document for public review and comment on February 23, 2011, and the complete draft IRP document (Volume 1) on March 7, 2011.
6	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgement of the Integrated Resource Plan might be appropriate but are not required.	Not addressed; this is a post-filing activity.
7	Acknowledgement of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.
8	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	Not addressed; this refers to a post-filing activity.

Table B.5 – Washington Utilities and Transportation Commission IRP Standard and Guidelines (WAC 480-100-238)

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
(4)	Work plan filed no later than 12 months before next IRP due date.	PacifiCorp filed the IRP work plan on March 31, 2010, given an anticipated IRP filing date of March 31, 2011.
(4)	Work plan outlines content of IRP.	See pages 1-2 of the Work Plan document for a summarization of IRP contents.
(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See pages 2-5 of the Work Plan document for a summarization of resource analysis.
(5)	Work plan outlines timing and extent of public participation.	See pages 6-7 of the Work Plan. Figure 2, page 6, document for the IRP schedule.
(4)	Integrated resource plan submitted within two years of previous plan.	The Commission issued an Order on December 11, 2008, under Docket no. UE-070117, granting the Company permission to file its IRP on March 31 of each odd numbered year. PacifiCorp filed the 2011 IRP on March 31, 2011.
(5)	Commission issues notice of public hearing after company files plan for review.	Not applicable; activity conducted subsequent to filing this IRP.
(5)	Commission holds public hearing.	Not applicable; activity conducted subsequent to filing this IRP.
(2)(a)	Plan describes the mix of energy supply resources.	Chapter 5 describes the mix of existing resources, while Chapter 8 describes the 2011 IRP preferred portfolio. For example, see Tables 8.16 and 8.17, as well as Figures 8.11 and 8.12.
(2)(a)	Plan describes conservation supply.	See Chapter 8 for a description of how conservation supplies are represented and modeled. Refer to Tables 8.16 and 8.17, as well as Figures 8.11 and 8.12. The 2010 resource potential study upon which conservation supplies are based is available from PacifiCorp's demand-side management Web site, http://www.pacificorp.com/es/dsm.html.
(2)(a)	Plan addresses supply in terms of current and future needs.	The 2011 IRP preferred portfolio was based on a resource needs assessment that accounted for forecasted load growth, expiration of existing power purchase contracts, resources under construction, contract, or reflected in the Company's capital budget, as well as a capacity planning reserve margin. Details on PacifiCorp's findings of resource need are described in Chapter 5. For example, see Table 5.11 for PacifiCorp's capacity load and resource balance.
(2)(b)	Plan uses lowest reasonable cost (LRC) analysis to select the mix of resources.	PacifiCorp uses portfolio performance measures based on the Present Value of Revenue Requirements (PVRR) methodology. See the section on portfolio performance measures in Chapter 7.
(2)(b)	LRC analysis considers resource costs.	Chapter 6, Resource Options, provides detailed information on costs and other attributes for all resources analyzed for the IRP. For example, see Tables 6.1 through 6.8, 6.10, and 6.12.
(2)(b)	LRC analysis considers market-volatility risks.	PacifiCorp employs Monte Carlo production cost simulation with a stochastic model to characterize market price and gas price volatility. See the section entitled, "Monte Carlo Production Cost Simulation" in Chapter 7 for a summary of the modeling approach.
(2)(b)	LRC analysis considers demand side resource uncertainties.	PacifiCorp captured demand-side resource uncertainties through the development of numerous portfolios based on different sets of input assumptions.
(2)(b)	LRC analysis considers resource dispatchability.	PacifiCorp uses two IRP models that simulate the dispatch of existing and future resources based on such attributes as heat rate, availability, fuel cost, and variable O&M cost. The chronological production cost simulation model also incorporates unit

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
		commitment logic for handling start-up, shutdown, ramp rates, minimum up/down times, and run up rates, and reserve holding characteristics of individual generators.
(2)(b)	LRC analysis considers resource effect on system operation.	PacifiCorp's IRP models simulate the operation of its entire system, reflecting dispatch/unit commitment, forced/unforced outages, access to markets, and system reliability and transmission constraints,
(2)(b)	LRC analysis considers risks imposed on ratepayers.	PacifiCorp explicitly models risk associated with uncertain CO_2 regulatory costs, wholesale electricity and natural gas price escalation and volatility, load growth uncertainty, resource reliability, renewable portfolio standard requirement uncertainty, plant construction cost escalation, and resource affordability. These risks and uncertainties are handled through stochastic modeling and scenarios depicting alternative futures. In addition to risk modeling, the IRP discusses a number of resource risk topics not addressed in the IRP system simulation models. For example, Chapter 9 covers the following topics: (1) managing carbon risk for existing plants, (2) managing gas supply risk, and (3) procurement delays. Chapter 4 covers similar risks associated with transmission system expansion.
(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	The IRP modeling incorporates resource expansion constraints tied to renewable portfolio standards (RPS) currently in place for Washington, Oregon, California, and Utah. (See Chapter 7, "Representation and Modeling of Renewable Portfolio Standards", as well as Appendix A for RPS compliance reports developed for each resource portfolio assessed for the IRP). PacifiCorp also evaluated various CO_2 regulatory schemes, including a CO_2 tax, hard cap, and cap-and-trade. Future modeling enhancements are planned for improved representation of state-level resource regulations.
(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	Criteria pollutant and CO_2 emissions under the Clean Air Act are discussed in Chapter 3. A description of PacifiCorp's modeling of CO_2 cost risk is provided in Chapter 7. Chapter 9 discusses the implications of CO_2 cost uncertainty on resource acquisition plans.
(2)(c)	Plan defines conservation as any reduction in electric power consumption that results from increases in the efficiency of energy use, production, or distribution.	A description of how PacifiCorp classifies and defines energy conservation is provided in Chapter 6, "Demand-side Resources".
(3)(a)	Plan includes a range of forecasts of future demand.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic short-term and long-term variability. Details concerning the load forecasts used in the 2011 IRP are provided in Chapters 5 and 8, and Appendix A. Figures 7.4 in Chapter 7 show the range of forecasts used for capacity expansion modeling. Figures 7.18 through 7.24 show the range of stochastic loads modeled for each load area by the Monte Carlo production cost simulations.
(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of electricity.	PacifiCorp's load forecast methodology employs econometric forecasting techniques that include such economic variables as household income, employment, and population. See Chapter 5, "Load Forecast", for a description of the load forecasting methodology.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of electrical end-uses.	Residential sector load forecasts use a statistically-adjusted end-use model that accounts for equipment saturation rates and efficiency. See Appendix A, Load Forecast Details, for a description of the residential sector load forecasting methodology.
(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	PacifiCorp updated the system-wide demand-side management potential study in 2010, which served as the basis for developing DSM resource supply curves for resource portfolio modeling. The supply curves account for technical and achievable (market) potential, while the IRP capacity expansion model identifies a cost-effective mix of DSM resources based on these limits and other model inputs. As noted above, the 2010 DSM potentials study is available on PacifiCorp's DSM Web site.
(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	A description of the current status of DSM programs and on-going activities to implement current and new programs is provided in Chapter 5, Resource Needs Assessment ("Existing Resources").
(3)(c)	Plan includes an assessment of a wide range of conventional and commercially available nonconventional generating technologies.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), customer standby generation, power purchases, thermal resources, energy storage, and transmission. Chapters 6 and 7 document how PacifiCorp developed and assessed these technologies.
(3)(d)	Plan includes an assessment of transmission system capability and reliability (as allowed by current law).	PacifiCorp modeled transmission system capability to serve its load obligations, factoring in updates to the representation of major load and generation centers, regional transmission congestion impacts, import/export availability, external market dynamics, and significant transmission expansion plans (See Chapters 4 and 7). System reliability given transmission capability was analyzed using stochastic production cost simulation and measures of insufficient energy and capacity for a load area (Energy Not Served and Unmet Capacity, respectively).
(3)(e)	Plan includes a comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using LRC.	PacifiCorp's capacity expansion optimization model (System Optimizer) is designed to compare alternative resources—including transmission expansion options—for the least-cost resource mix. System Optimizer was used to develop numerous resource portfolios for comparative evaluation on the basis of cost, risk, reliability, and other performance attributes. The DSM potentials study considered improvements in conservation Distribution considered alternative transmission expansion options.
(3)(f)	Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	PacifiCorp integrates demand forecasts, resources, and system operations in the context of a system modeling framework described in Chapter 7. Portfolio evaluation covers a 20-year period (2011-2030). PacifiCorp developed its preferred portfolio of resources judged to be least-cost after considering load requirements, risk, uncertainty, supply adequacy/reliability, and government resource policies in accordance with this rule.
(3)(g)	Plan includes a two-year action plan that implements the long range plan.	See Table 9.1, Chapter 9, for PacifiCorp's 2011 IRP action plan.
(3)(h)	Plan includes a progress report on the implementation of the previously filed plan.	A status report on action plan implementation is provided in the "Progress on Previous Action Plan Items" section of Chapter 9.
(5)	Plan includes description of consultation with commission staff. (Description not required)	Chapter 2 includes a summary of the 2011 IRP public process, while Appendix F provides details on specific meetings held.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
(5)	Plan includes description of completion of work plan. (Description not required)	Not applicable; the IRP schedule was modified to accommodate planning events. See the response to WAC 480-100-238(4).

Table B.6 – Wyoming Public Service Commission IRP Standard and Guidelines (Docket 90000-107-XO-09)

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
A	The public comment process employed as part of the formulation of the utility's IRP, including a description, timing and weight given to the public process;	PacifiCorp's public process is described in Chapter 2. A record of public meetings is provided as Appendix F.
B	The utility's strategic goals and resource planning goals and preferred resource portfolio	Chapters 9 and 10 presents the 2011 IRP and transmission expansion action plans, respectively. Chapter 8 presents the preferred portfolio. Additionally, the acquisition path analysis (Table 9.2) describes alternative resource strategies based on trigger events and trends.
C	The utility's illustration of resource need over the near-term and long-term planning horizons;	See Chapter 5, Resource Needs Assessment.
D	A study detailing the types of resources considered;	Chapter 6, Resource Options, presents the resource options used for resource portfolio modeling for this IRP.
F	Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP;	A comparison of resource changes relative to the 2008 IRP Update is presented as Table 9.3 in Chapter 9. A chart comparing the peak load forecasts for the 2008 IRP, 2008 IRP Update, and 2011 IRP is included in Appendix A.
G	The environmental impacts considered;	Tables and graphs showing CO_2 and EPA criteria pollutant emissions are presented in Chapter 8 and Appendix E.
H	Market purchases evaluation;	Modeling of firm market purchases (front office transactions) and spot market balancing transactions is included in this IRP.
H	Reserve Margin analysis; and	PacifiCorp's stochastic loss of load study and selection of a capacity planning reserve margin is included as Appendix J.
I	Demand-side management and conservation options;	See Chapter 6 for a detailed discussion on DSM and conservation resource options.

APPENDIX C – ENERGY GATEWAY SCENARIO PORTFOLIOS

This appendix provides additional modeling inputs and results for the Energy Gateway transmission scenarios documented in Chapter 4 of Volume 1. The appendix consists of detailed transmission cost information incorporated into System Optimizer and portfolio Present Value Revenue Requirements (PVRR) reporting, as well as resource tables indicating resource differences between the base Energy Gateway portfolio (developed assuming only the Energy Gateway Central segments are built) and portfolios developed with incremental Energy Gateway segments.

Transmission Scenario Analysis and Cost Details

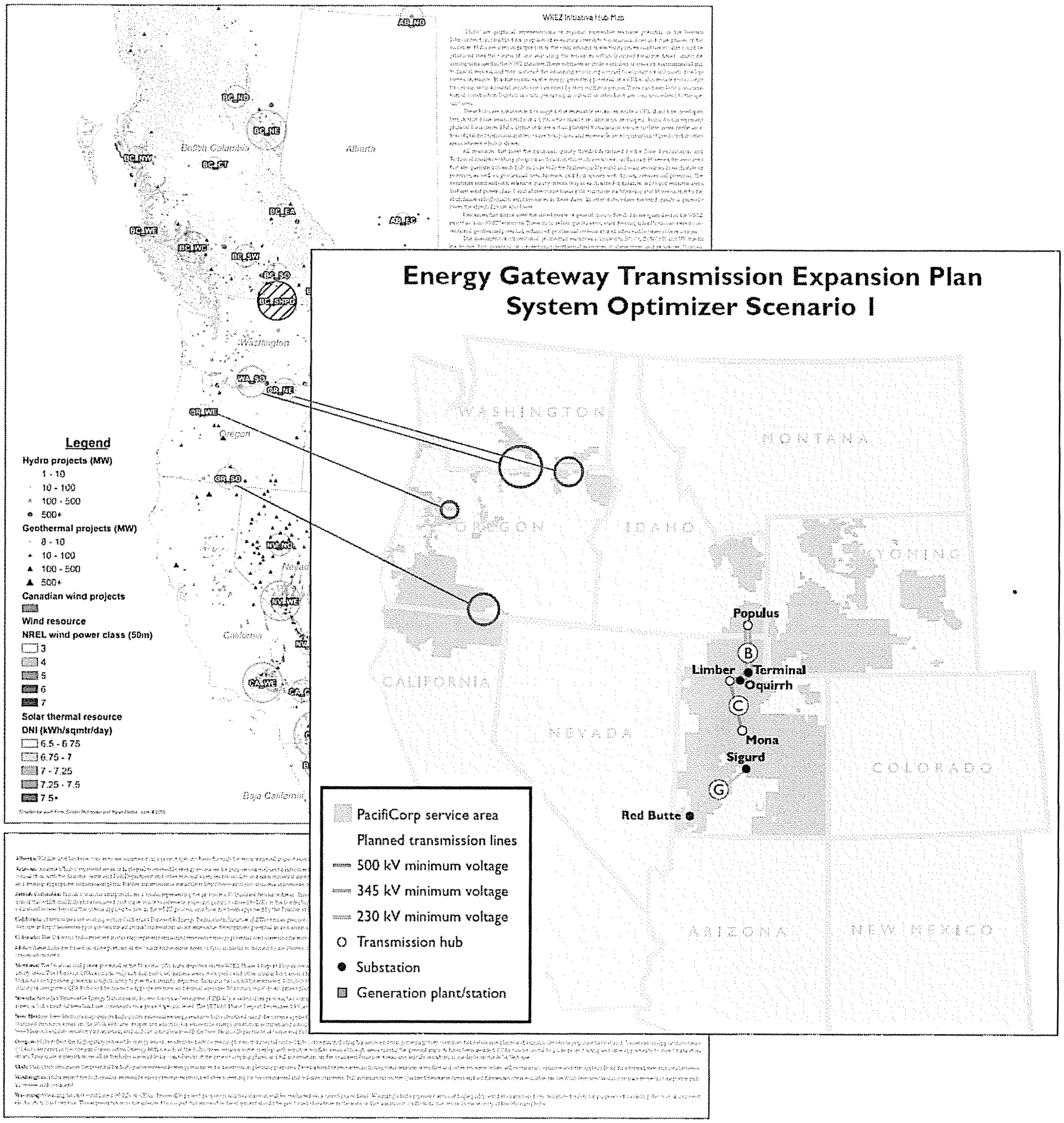
The *Transmission Scenario Analysis* section of Chapter 4, Transmission Planning, assesses resource additions and 20-year present value revenue requirement (PVRR) for various Energy Gateway scenarios. These scenarios range from a "base case" strategy with the minimal planned transmission (Scenario 1 – including the Populus to Terminal, Mona to Oquirrh, and Sigurd to Red Butte projects) to the full "incremental" Energy Gateway strategy (Scenario 7 – including Gateway Central, Gateway West, Gateway South and west-side projects). The PVRR calculations are for 20-years discounted back to 2011 dollars assuming a 7.17 percent discount rate in order to be consistent with other IRP analyses. However, a full financial analysis would assume a 58-year lifecycle and include stochastic analysis through the Planning and Risk (PaR) model as described in Chapter 7.

The System Optimizer's selection of wind resources for the "Green Resource Future" used various Energy Gateway scenarios as input assumptions and then determined general placement of additional wind resources. Wind resource requirements were assumed at the Waxman-Markey level (20 percent by 2020). The System Optimizer acts as a screening tool for resource selection but has limited ability to take into account transmission constraints and/or operational requirements. This limitation requires Transmission Planning, in some cases, to choose between planning adequate transmission facilities appropriate for the resource location, moving wind resources to alternative renewable energy zones, or both.

PacifiCorp's Transmission Planning Department did not pre-determine the entire transmission infrastructure/cost for each scenario, other than providing the Energy Gateway scenarios as tested using System Optimizer. However, The Transmission Planning Department determined whether the wind resources selected by the System Optimizer had adequate location-based transmission facilities and, in one scenario, relocated wind resources in consideration of transmission constraints and operational considerations. Placement and megawatt capacity of wind resources in scenarios 1, 3 and 7 selected by the System Optimizer were left as is; however, resource-location-dependent transmission was added to accommodate the incremental resources. In scenario 2, The Transmission Planning Department determined that some of the resources selected for Wyoming had to be relocated to Utah due to transmission constraints and operational limits.

West-side wind resource additions under the "Green Resource Future" (see Table 4.1) for Scenario 1 range between 871 MW and 1,021 MW of new wind generation primarily in Washington. Figure C.1, the Western Renewable Energy Zones map, shows "bubbles" in Washington and Oregon where wind resources are strongest, plus the Energy Gateway Scenario 1 map which shows PacifiCorp's service area in blue.

Figure C.1 – Western Renewable Energy Zones plus Energy Gateway Scenario 1



Source: Western Renewable Energy Zones – Phase 1 Report (http://www.westgov.org/rtep/219)

Tables C.1 and C.2 outline the line item details for the transmission costs presented in Tables 4.2 and 4.4 of Chapter 4. Given that Scenario 1 includes no incremental transmission capacity on the west side and lacked available capacity in this region, new transmission additions would be required to bring up to 1,021 MW of west-side wind generation to customer load centers in Oregon, Washington and California. PacifiCorp estimated that $1.5 billion (20-Year PVRR) in new west-side transmission investment would be required to deliver this energy to customers under the Green Resource Scenario. [2]

[2] See the west side line items in Table C.1.

Table C.1 – Transmission Cost Details, Green Resource Future

Transmission Cost, Present Value of Revenue Requirement ($ millions)

Transmission Cost Detail Table 4.2	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Capital Recovery (Energy Gateway)								
Gateway Central (Populus - Terminal and Mona-Oquirrh)	$1,118	$920	$945	$738	$1,118	$920	$945	$738
Sigurd - Red Butte	295	295	295	295	295	295	295	295
Harry Allen Upgrade	9	9	9	9	9	9	9	9
Windstar to Populus	0	657	657	657	0	657	657	657
Aeolus - Mona	0	0	477	307	0	0	477	307
Populus - Hemingway	0	0	0	270	0	0	0	270
Hemingway - Boardman - Cascade Crossing	0	0	0	207	0	0	0	207
Resource Location Dependent Transmission								
Wyoming/Idaho	142	107	105	45	142	107	105	45
Utah	0	475	0	0	0	475	0	0
West side [1/]	1,503	0	0	0	1,503	0	0	0
Wheeling Charge (Southwest, UT - Mead, NV)	35	35	35	36	35	35	35	35
Total (20-year PVRR) [2/]	**$3,103**	**$2,499**	**$2,524**	**$2,564**	**$3,103**	**$2,499**	**$2,524**	**$2,563**
Gross Capital								
Energy Gateway Capital	$1,776	$3,329	$4,609	$5,888	$1,776	$3,329	$4,609	$5,888
Resource Location Dependent Transmission:								
Wyoming/Idaho	337	253	248	107	337	253	248	107
Utah	0	1,124	0	0	0	1,124	0	0
West side [1/]	2,802	0	0	0	2,802	0	0	0
Total Gross Capital [3/]	**$4,915**	**$4,706**	**$4,857**	**$5,995**	**$4,915**	**$4,706**	**$4,857**	**$5,995**

Transmission Cost Detail Table 4.2	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	High	High	High	High	High	High	High	High
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Capital Recovery								
Gateway Central (Populus - Terminal and Mona-Oquirrh)	$1,118	$920	$945	$738	$1,118	$920	$945	$738
Sigurd - Red Butte	295	295	295	295	295	295	295	295
Harry Allen Upgrade	9	9	9	9	9	9	9	9
Windstar to Populus	0	657	657	657	0	657	657	657
Aeolus - Mona	0	0	477	307	0	0	477	307
Populus - Hemingway	0	0	0	270	0	0	0	270
Hemingway - Boardman - Cascade Crossing	0	0	0	207	0	0	0	207
Resource Location Dependent Transmission								
Wyoming/Idaho	142	107	105	45	142	107	105	45
Utah	0	475	0	0	0	475	0	0
West side [1/]	1,503	0	0	0	1,503	0	0	0
Wheeling Charge (Southwest, UT - Mead, NV)	35	35	35	35	36	36	36	36
Total (20-year PVRR) [2/]	**$3,103**	**$2,499**	**$2,524**	**$2,563**	**$3,104**	**$2,500**	**$2,525**	**$2,564**
Gross Capital								
Energy Gateway Capital	$1,776	$3,329	$4,609	$5,888	$1,776	$3,329	$4,609	$5,888
Resource Location Dependent Transmission:								
Wyoming/Idaho	337	253	248	107	337	253	248	107
Utah	0	1,124	0	0	0	1,124	0	0
West side [1/]	2,802	0	0	0	2,802	0	0	0
Total Gross Capital [3/]	**$4,915**	**$4,706**	**$4,857**	**$5,995**	**$4,915**	**$4,706**	**$4,857**	**$5,995**

[1/] Westside Resource Location Dependent Transmission assumed to be in-service the beginning of year 2016.

[2/] Transmission depreciable assets have a 58-year book life, however the present value revenue requirements were based on 20-years of future transmission costs using a 7 17% discount rate in order to be consistent with IRP date parameters.

[3/] Gross capital estimates came from standard transmission base assemblies priced in 2009 except for the Populus - Terminal segment where 2010 forecasted completion costs were used

Table C.2 – Transmission Cost Details, Incumbent Resource Future

Transmission Cost, Present Value of Revenue Requirement ($ millions)

Transmission Cost Detail Table 4.4	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Capital Recovery (Energy Gateway)								
Gateway Central (Populus - Terminal and Mona-Oquirrh)	$1,118	$920	$945	$738	$1,118	$920	$945	$738
Sigurd - Red Butte	295	295	295	295	295	295	295	295
Harry Allen Upgrade	9	9	9	9	9	9	9	9
Windstar to Populus	0	657	657	657	0	657	657	657
Aeolus - Mona	0	0	477	307	0	0	477	307
Populus - Hemingway	0	0	0	270	0	0	0	270
Hemingway - Boardman - Cascade Crossing	0	0	0	207	0	0	0	207
Resource Location Dependent Transmission								
Wyoming/Idaho	0	0	0	0	0	0	0	0
Utah	0	0	0	0	0	0	0	0
West side	0	0	0	0	0	0	0	0
Wheeling Charge (Southwest, UT - Mead, NV)	35	35	35	35	35	35	35	35
Total (20-year PVRR) [1/]	**$1,458**	**$1,916**	**$2,419**	**$2,518**	**$1,457**	**$1,916**	**$2,419**	**$2,518**
Gross Capital								
Energy Gateway Capital	$1,776	$3,329	$4,609	$5,888	$1,776	$3,329	$4,609	$5,888
Resource Location Dependent Transmission:								
Wyoming/Idaho	0	0	0	0	0	0	0	0
Utah	0	0	0	0	0	0	0	0
West side	0	0	0	0	0	0	0	0
Total Gross Capital [2/]	**$1,776**	**$3,329**	**$4,609**	**$5,888**	**$1,776**	**$3,329**	**$4,609**	**$5,888**

Transmission Cost Detail Table 4.4	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	High	High	High	High	High	High	High	High
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Capital Recovery								
Gateway Central (Populus - Terminal and Mona-Oquirrh)	$1,118	$920	$945	$738	$1,118	$920	$945	$738
Sigurd - Red Butte	295	295	295	295	295	295	295	295
Harry Allen Upgrade	9	9	9	9	9	9	9	9
Windstar to Populus	0	657	657	657	0	657	657	657
Aeolus - Mona	0	0	477	307	0	0	477	307
Populus - Hemingway	0	0	0	270	0	0	0	270
Hemingway - Boardman - Cascade Crossing	0	0	0	207	0	0	0	207
Resource Location Dependent Transmission								
Wyoming/Idaho	0	0	0	0	142	107	105	45
Utah	0	0	0	0	0	475	0	0
West side	0	0	0	0	0	0	0	0
Wheeling Charge (Southwest, UT - Mead, NV)	35	35	35	35	36	36	36	36
Total (20-year PVRR) [1/]	**$1,458**	**$1,916**	**$2,419**	**$2,518**	**$1,600**	**$2,499**	**$2,525**	**$2,564**
Gross Capital								
Energy Gateway Capital	$1,776	$3,329	$4,609	$5,888	$1,776	$3,329	$4,609	$5,888
Resource Location Dependent Transmission:								
Wyoming/Idaho	0	0	0	0	337	254	248	107
Utah	0	0	0	0	0	1,123	0	0
West side	0	0	0	0	0	0	0	0
Total Gross Capital [2/]	**$1,776**	**$3,329**	**$4,609**	**$5,888**	**$2,113**	**$4,706**	**$4,857**	**$5,995**

[1/] Transmission depreciable assets have a 58-year book life, however the present value revenue requirements were based on 20-years of future transmission costs using a 7.17% discount rate in order to be consistent with IRP date parameters.

[2/] Gross capital estimates came from standard transmission base assemblies priced in 2009 except for the Populus - Terminal segment where 2010 forecasted completion costs were used.

System Optimizer Portfolio Tables

This section presents System Optimizer portfolio output tables for the Energy Gateway transmission scenarios discussed in Chapter 4, Transmission Planning. Table C.3 summarizes the input assumptions used for developing each Energy Gateway portfolio. Table C.4 reports the portfolio PVRRs, indicating post-model-run adjustments for transmission costs and reversal of the stochastic value adjustment applied to CCCT resources. (See Chapter 7 for a discussion of this adjustment). Table C.5 consists of the resource capacity difference tables. The base Energy Gateway scenario is shown first, followed by the resource difference tables for scenarios with the matching input assumptions. For example, resource differences for scenarios EG2, EG3, and EG4 are shown with respect to EG1. Portfolios designated with the “WM” suffix correspond to the Green Resource Future strategy outlined in Chapter 4.

Table C.3 – Energy Gateway Scenario Development Table

Case #	Assumption Alternatives									
	Carbon Policy		Gas Price 2/	Load Growth 3/	Renewable PTC and Wind Integration Cost 4/	Renewable Portfolio Standards 5/	Demand-Side Management	Distributed Solar 10/	Coal Plant Utilization	Energy Gateway Trans 12/
	Type 1/ CO2 Tax Hard Cap	Cost Medium High Low to Very High	Low Medium High	Low Econ. Growth Medium Econ. Growth High Growth High Peak Demand	Extension to 2015 Extension to 2020 Alt. Wind Integ. Cost	None Current RPS Federal RPS	High Achievable 6/ Class 3 Included 7/ Technical Potential 8/ Distribution Efficiency 9/	Current Incentives UT Buydown Levels	No shutdowns Optimized 11/	Base Scenario 1 Scenario 2 Scenario 3
Energy Gateway Scenario Evaluation Cases										
EG1	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG2	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG3	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG4	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG5	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG6	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG7	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG8	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG9	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG10	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG11	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG12	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG13	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG14	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG15	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG16	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG1-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG2-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG3-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG4-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG5-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG6-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG7-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG8-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG9-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG10-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG11-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG12-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG13-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG14-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG15-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG16-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3

Table C.4 – Energy Gateway Scenario PVRR Results

Case	System Optimizer Output PVRR ($ millions)	Post-run transmission adjustment ($ millions)	Apply CCCT option value adjustment ($ millions)	Adjusted PVRR ($ millions)	Scenario	PVRR Difference from Base ($ millions)
EG 1	40,789	142	193	41,124	Base	41,124
EG 2	41,232	583	193	42,007	1	883
EG 3	41,734	105	193	42,032	2	908
EG 4	40,501	45	204	40,750	3	(374)
EG 5	41,890	142	132	42,165	Base	42,165
EG 6	42,278	583	132	42,994	1	829
EG 7	42,781	105	132	43,019	2	854
EG 8	41,656	45	157	41,858	3	(307)
EG 9	45,820	142	193	46,155	Base	46,155
EG 10	46,261	583	193	47,036	1	881
EG 11	46,763	105	193	47,061	2	906
EG 12	45,558	45	204	45,807	3	(348)
EG 13	46,941	0	132	47,074	Base	47,074
EG 14	47,737	0	132	47,869	1	795
EG 15	47,174	0	132	47,306	2	233
EG 16	46,581	0	157	46,737	3	(336)

Case	System Optimizer Output PVRR ($ millions)	Post-run transmission adjustment ($ millions)	Apply CCCT option value adjustment ($ millions)	Adjusted PVRR ($ millions)	Scenario	PVRR Difference from Base ($ millions)
EG 1_WM	41,739	-1,503	204	40,439	Base	40,439
EG 2_WM	40,847	0	204	41,050	1	611
EG 3_WM	40,870	0	204	41,074	2	635
EG 4_WM	40,909	0	204	41,113	3	674
EG 5_WM	42,693	-1,503	204	41,394	Base	41,394
EG 6_WM	41,797	0	204	42,001	1	607

Case	System Optimizer Output PVRR ($ millions)	Post-run transmission adjustment ($ millions)	Apply CCCT option value adjustment ($ millions)	Adjusted PVRR ($ millions)	Scenario	PVRR Difference from Base ($ millions)
EG 7_WM	41,821	0	204	42,024	2	630
EG 8_WM	41,859	0	204	42,062	3	668
EG 9_WM	46,706	-1,503	204	45,406	Base	45,406
EG 10_WM	45,793	0	204	45,997	1	591
EG 11_WM	45,815	0	204	46,019	2	612
EG 12_WM	45,854	0	204	46,057	3	651
EG 13_WM	47,691	-1,503	204	46,392	Base	46,392
EG 14_WM	46,775	0	204	46,979	1	587
EG 15_WM	46,752	0	204	46,956	2	564
EG 16_WM	46,784	0	204	46,988	3	596

Table C.5 – Energy Gateway Scenario Portfolio Results

Energy Gateway Case 1

PVRR $41,124 million

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum, FOT Average 10 Year	Resource Sum, FOT Average 20 Year *
	Capacity (MW)																					
East																						
Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	0	-	-	-	2
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	0	-	-	-	2
CHP - Biomass	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	50	100
CHP - Reciprocating Engine	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	19.8	-	-	-	-	-	-	-	-	-	-	-	-	0.9	4.0	-	20	25
DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21
DSM, Class 1, Utah-DLC-Residential	21.0	10.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
DSM, Class 1 Total	26.5	40.6	-	-	19.8	-	-	-	-	-	-	-	-	-	-	-	-	0.9	4.0	-	87	92
DSM, Class 2, Idaho	2.0	2.5	2.2	2.8	3.4	3.9	4.2	4.4	4.3	4.6	4.7	4.8	5.7	6.1	6.5	6.1	6.5	6.1	6.1	5.6	34	92
DSM, Class 2, Utah	83.9	92.1	93.9	40.1	41.4	43.9	45.1	46.1	47.8	50.1	51.4	54.9	51.3	53.1	53.0	57.4	52.0	54.6	53.8	56.2	584	1,122
DSM, Class 2, Wyoming	3.6	4.6	4.8	5.5	5.6	6.3	6.9	8.7	8.7	9.3	10.9	11.5	13.3	16.3	17.4	22.5	23.9	28.1	35.0	37.2	64	280
DSM, Class 2 Total	89.6	99.2	100.9	48.4	50.3	54.1	56.2	59.1	60.8	64.0	66.9	71.1	70.3	75.6	76.8	86.0	82.4	88.8	94.9	99.1	683	1,494
Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	2	-	-	-	-	-	2	-	-	-	24	28
Micro Solar - Photovoltaic	1	51	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	54
FOT Mead 3rd Qtr HLH	-	168	264	254	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	785	785
FOT Utah 3rd Qtr HLH	154	200	200	-	200	-	-	78	174	87	-	-	-	-	-	-	-	-	-	-	1,092	1,092
FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	25	134	238	290	300	300	300	300	300	300	225	237
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	2	37	65	69	105	173	83	172	143	151	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	27	282	343	328	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	5	17	59	100	36	259	273	252	N/A	100
West																						
Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	4	41	-	56
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	4	41	-	56
CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
DSM, Class 1, Califiornia-DLC-Irrigation	-	-	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Oregon-Curtailment	-	-	-	-	-	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon-DLC-Irrigation	-	-	-	-	0.5	-	-	12.7	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	3.6	6.5	-	-	-	-	-	-	-	-	-	-	-	10	10
DSM, Class 1, Washington-DLC-Irrigation	-	-	-	-	3.8	-	-	4.7	-	-	-	-	-	-	-	-	-	-	-	-	9	9
DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1 Total	-	-	-	-	4.3	-	-	48.4	6.5	-	-	-	-	-	-	-	-	-	-	-	59	59
DSM, Class 2, California	0.6	0.8	0.8	1.1	1.3	1.4	1.5	1.5	1.4	1.6	1.6	1.6	2.0	2.1	2.2	2.0	2.0	1.9	1.9	1.9	12	31
DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
DSM, Class 2, Washington	10.0	12.5	8.2	8.0	8.4	8.2	8.5	8.8	9.3	9.5	10.0	10.9	10.9	11.4	11.8	9.3	8.1	8.5	8.6	8.9	91	190
DSM, Class 2 Total	63.2	66.1	65.0	69.8	71.4	70.4	70.3	62.7	63.1	63.4	63.9	64.9	65.3	65.9	66.3	63.7	54.1	46.4	46.5	46.9	665	1,249
OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	1	1	1	1	-	-	1	-	-	-	16	21
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	393	400	400	400	400	400	400	400	400	400	400	400	400	400	400	359	380
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	193	147	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	17
FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	26	50	-	36	50	50	50	-	-	-	-	-	-	-	-	-	-	26	13
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	65	205	-	172	N/A	44
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	125	-	-	N/A	12
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	77	61	26	-	169	149	175	52	177	146	N/A	103
Annual Additions, Long Term Resources	206	295	191	760	268	753	140	192	189	141	145	146	146	152	187	159	151	156	159	196		
Annual Additions, Short Term Resources	304	1,112	1,311	1,131	1,099	693	736	828	924	837	503	632	733	777	1,037	1,205	1,350	1,465	1,636	1,749		
Total Annual Additions	510	1,406	1,502	1,890	1,367	1,446	876	1,020	1,113	978	649	778	879	928	1,224	1,364	1,501	1,621	1,795	1,945		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 2 compared to Energy Gateway Case 1

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $883 million

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum, FOT Average 10 Year	20 Year *
		Capacity (MW)																					
East																							
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Wyoming	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	-	-	(2)	-	-	-	-	(4)
	FOT Utah 3rd Qtr HLH	-	-	-	-	-	-	-	(0)	(0)	(0)	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	1	1	6	10	-	-	-	-	-	-	-	17
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(2)	(13)	6	4	40	(27)	-	(8)	-	-	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	39	(11)	(46)	(8)	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	(5)	(12)	(45)	(38)	87	13	28	(27)	N/A	(0)
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	-	(0)
	DSM, Class 2 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	-	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	-	-	(1)	-	-	-	-	(5)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	40	-	-	-	28	N/A	7
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(125)	-	-	-	N/A	(12)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	2	14	(5)	-	1	1	3	10	22	12	N/A	6
	Annual Additions, Long Term Resources	-	-	-	-	-	-	0	-	-	-	(3)	(1)	(1)	(1)	-	-	1	(2)	(1)	(7)		
	Annual Additions, Short Term Resources	-	-	-	-	-	-	(0)	(0)	(0)	(0)	1	1	2	2	2	2	3	4	4	5		
	Total Annual Additions	-	-	-	-	-	-	0	(0)	(0)	(0)	(2)	0	1	1	2	2	4	2	3	(2)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 3 compared to Energy Gateway Case 1

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $908 million

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum. FOT Average 10 Year	Resource Sum. FOT Average 20 Year *
		Capacity (MW)																					
East																							
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Wyoming	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	-	-	(2)	-	-	-	-	(4)
	FOT Utah 3rd Qtr HLH	-	-	-	-	-	-	-	(0)	(0)	(0)	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	1	1	6	10	-	-	-	-	-	-	-	17
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(2)	(13)	6	4	40	(27)	-	(8)	-	-	-	-
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	39	(11)	(51)	(3)	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	(5)	(12)	(45)	(38)	87	13	33	(32)	N/A	(0)
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	-	(0)
	DSM, Class 2 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	-	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	-	-	(1)	-	-	-	-	(5)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	40	-	-	-	28	N/A	7
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(125)	-	-	-	N/A	(12)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	2	14	(5)	-	1	1	3	10	22	12	N/A	6
	Annual Additions, Long Term Resources	-	-	-	-	-	-	0	-	-	-	(3)	(1)	(1)	(1)	-	-	1	(2)	(1)	(7)		
	Annual Additions, Short Term Resources	-	-	-	-	-	-	(0)	(0)	(0)	(0)	1	1	2	2	2	2	3	4	4	5		
	Total Annual Additions	-	-	-	-	-	-	0	(0)	(0)	(0)	(2)	0	1	1	2	2	4	2	3	(2)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 4 compared to Energy Gateway Case 1

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR ($374) million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	CCCT F 2x1	-	-	-	-	597	(597)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Geothermal, Blundell 3	-	-	-	-	-	-	-	-	(45)	45	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	6	9	4	34	-	74
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	6	9	4	34	-	74
	CHP - Reciprocating Engine	(1)	(1)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	(19.8)	-	-	-	-	-	-	-	-	-	-	-	-	(0.9)	0.9	-	-	(0)
	DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	(3.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)
	DSM, Class 1, Utah-Curtailment	-	(19.5)	19.5	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Utah-DLC-Residential	(21.0)	(10.7)	-	-	-	-	25.7	-	-	11.3	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 Total	(21.0)	(28.2)	19.5	19.8	(19.8)	-	32.0	-	-	11.3	-	-	-	-	-	-	-	(0.9)	0.9	-	14	14
	DSM, Class 2, Idaho	(0.5)	(0.7)	(0.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)
	DSM, Class 2, Utah	(40.6)	(45.5)	(54.9)	-	-	-	1.9	2.0	2.1	3.4	-	-	-	-	-	-	-	-	-	-	(132)	(132)
	DSM, Class 2, Wyoming	(0.2)	(0.2)	0.3	0.6	0.7	0.8	1.0	-	-	0.2	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 2 Total	(41.3)	(46.4)	(54.8)	0.6	0.7	0.8	2.9	2.0	2.1	3.6	-	-	-	-	-	-	-	-	-	-	(130)	(130)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	0	2	2	0	-	-	(2)	-	-	-	-	3
	Micro Solar - Photovoltaic	(1)	(51)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54)	(54)
	FOT Mead 3rd Qtr HLH	-	-	-	10	(99)	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(27)
	FOT Utah 3rd Qtr HLH	96	50	50	63	(200)	-	62	122	(174)	113	-	-	-	-	-	-	-	-	-	-	183	183
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	275	166	62	10	-	-	-	-	-	-	-	513
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(2)	7	56	102	(4)	(57)	0	(48)	(26)	(30)	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	(27)	9	10	6	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	(5)	(2)	(51)	(6)	(36)	93	(59)	65	N/A	(0)
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	DSM, Class 1, California-DLC-Irrigation	-	-	5.5	-	-	-	-	(5.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	(17.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	(0.5)	-	-	(12.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Residential	-	-	3.6	-	-	-	-	(3.6)	(6.5)	0.3	-	-	-	-	-	-	-	-	-	-	(6)	(6)
	DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	(3.8)	-	6.4	(4.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	0.7	-	-	-	4.1	(4.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	42.2	-	(4.3)	-	10.5	(48.4)	(6.5)	0.3	-	-	-	-	-	-	-	-	-	-	(6)	(6)
	DSM, Class 2, California	0.1	-	-	-	-	-	-	-	0.2	0.2	-	-	-	-	-	-	-	-	-	(0.2)	0	0
	DSM, Class 2, Washington	0.1	0.1	-	0.4	-	0.1	-	0.3	-	0.1	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.2	0.1	-	0.4	-	0.1	-	0.3	0.2	0.3	-	-	-	-	-	-	-	-	-	(0.2)	1	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	(1)	-	-	-	-	-
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	(59)	7	-	-	(29)	-	(84)	-	-	-	-	-	-	-	-	-	(8)	(8)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	51	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	6
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	24	(50)	50	14	-	(50)	-	-	-	-	-	-	-	-	-	-	-	9	4
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	205	113	(0)	13	195	16	N/A	54
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	180	-	-	-	N/A	18
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	(77)	(61)	(2)	1	(40)	59	(6)	46	(8)	57	N/A	(3)
	Annual Additions, Long Term Resources	(64)	(127)	5	21	574	(596)	45	(46)	(49)	60	0	2	2	0	1	21	3	(3)	0	(7)		
	Annual Additions, Short Term Resources	96	151	160	97	(408)	120	75	122	(253)	113	113	112	111	111	111	111	112	113	113	114		
	Total Annual Additions	32	24	165	117	165	(476)	121	76	(302)	174	113	115	114	111	112	132	115	111	113	107		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 5

PVRR $42,165 million

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource sum, FOT Average: 10 Year	20 Year *
East																						
Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
CCCT F 2x1	-	-	-	625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	625	625
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CHP - Biomass	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	50	100
CHP - Reciprocating Engine	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	19.8	-	-	-	-	-	-	-	-	-	-	-	4.9	-	-	-	20	25
DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Utah-Curtailment	-	21.5	-	-	3.2	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	-	31.7	-	-	-	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Wyoming-Curtailment	-	-	-	-	5.4	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
DSM, Class 1 Total	5.5	61.6	-	-	28.4	8.4	-	-	-	-	-	-	-	-	-	-	4.9	-	-	-	104	109
DSM, Class 2, Idaho	2.0	2.5	2.5	3.0	3.7	4.4	4.7	4.9	5.0	5.4	5.2	5.6	6.7	7.3	7.6	7.2	7.7	7.6	7.6	7.1	38	108
DSM, Class 2, Utah	83.9	92.1	101.2	44.0	64.3	67.2	66.5	50.6	61.3	69.5	55.5	59.6	57.8	60.1	60.2	63.5	57.2	60.1	59.3	62.1	701	1,296
DSM, Class 2, Wyoming	3.9	5.0	5.3	6.2	6.3	7.3	8.1	8.9	9.0	9.7	11.1	11.8	13.7	16.8	17.9	23.5	25.0	29.5	36.7	39.9	70	295
DSM, Class 2 Total	89.8	99.6	109.0	53.2	74.3	78.9	79.3	64.5	75.2	84.6	71.8	77.0	78.2	84.2	85.7	94.1	89.9	97.2	103.6	109.1	808	1,699
Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0	-	-	-	-	24	37
Micro Solar - Photovoltaic	1	51	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	54
FOT Mead 3rd Qtr HLH	-	168	264	214	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	845	845
FOT Utah 3rd Qtr HLH	175	200	200	-	63	176	200	-	-	200	-	-	-	-	-	-	-	-	-	-	1,213	1,213
FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	225	263
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	15	6	17	28	89	107	114	140	211	274	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	109	187	205	243	256	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	1	45	52	36	92	207	-	204	174	188	N/A	100
West																						
Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	35	70	-	70	70	-	-	-	-	-	-	-	-	-	70	315	385
Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Oregon-Curtailment	-	-	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon-DLC-Irrigation	-	-	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	3.6	-	6.8	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
DSM, Class 1, Washington-DLC-Irrigation	-	-	-	-	8.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
DSM, Class 1, Washington-DLC-Residential	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1 Total	-	-	-	-	52.8	-	6.8	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, California	0.7	0.8	0.9	1.2	1.5	1.6	1.7	1.7	1.7	1.8	1.8	1.9	2.2	2.4	2.6	2.3	2.4	2.2	2.2	2.3	14	36
DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
DSM, Class 2, Washington	12.0	12.6	9.0	8.8	8.9	8.7	8.9	9.2	9.4	9.6	10.8	11.8	11.5	12.1	12.4	9.6	8.3	8.7	8.6	9.2	97	200
DSM, Class 2 Total	65.3	66.2	65.9	70.8	72.1	71.2	70.9	63.3	63.4	63.8	65.0	66.1	66.1	66.8	67.3	64.3	54.7	46.9	46.9	47.5	673	1,264
OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	1	1	1	-	-	-	-	-	16	23
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	365	395	400	71	385	400	400	400	400	400	400	400	400	356	361
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	143	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23	12
FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	50	50	50	-	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	196	-	43	18	N/A	28
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	-	-	-	N/A	7
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	225	-	61	102	268	162	183	308	356	336	N/A	200
Annual Additions, Long Term Resources	188	416	200	766	399	225	276	150	267	232	153	157	157	164	166	168	159	153	160	236		
Annual Additions, Short Term Resources	325	1,111	1,304	1,114	962	1,025	950	665	695	950	612	736	830	866	1,149	1,312	1,448	1,558	1,726	1,772		
Total Annual Additions	513	1,527	1,505	1,880	1,361	1,250	1,226	815	962	1,182	765	892	987	1,030	1,315	1,479	1,606	1,711	1,886	2,008		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 6 compared to Energy Gateway Case 5

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR **$829 million**

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum, FOT Average 10 Year	Resource Sum, FOT Average 20 Year *
		Capacity (MW)																					
East																							
	CCCT F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Geothermal, Blundell 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Idaho	-	-	-	-	-	(0.1)	-	-	-	-	-	(0.2)	-	-	-	-	(0.2)	-	-	-	(0)	(1)
	DSM, Class 2, Utah	-	-	-	-	(18.9)	(19.0)	-	-	(0.5)	-	-	-	(2.0)	-	-	-	-	-	-	-	(38)	(40)
	DSM, Class 2, Wyoming	-	-	-	-	-	-	0.1	0.1	0.1	0.1	-	-	(0.1)	0.3	0.3	-	-	(0.1)	0.8	-	0	2
	DSM, Class 2 Total	-	-	-	-	(18.9)	(19.1)	0.1	0.1	(0.4)	0.1	-	(0.2)	(2.1)	0.3	0.3	-	(0.2)	(0.1)	0.8	-	(38)	(39)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)	-	-	-	-	-	(0)
	Micro Solar - Photovoltaic	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FOT Mead 3rd Qtr HLH	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Utah 3rd Qtr HLH	-	-	-	-	15	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	15
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(8)	23	31	39	119	(7)	(34)	(2)	(69)	(91)	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	(187)	55	37	61	N/A	-
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	3	(6)	(14)	(6)	(92)	98	-	(44)	14	48	N/A	0
West																							
	Geothermal, Greenfield	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	70	-	(70)	35	35
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	0.1	-	-	0.0	0.0	-	0.1	-	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	0	1
	DSM, Class 2 Total	-	0.1	-	-	0.0	0.0	-	0.1	-	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	0	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	(0)	0	-	(71)	(103)	-	-	-	-	-	-	-	(58)	0	(12)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(6)	-	(43)	(18)	N/A	(9)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	222	-	-	-	N/A	22
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	76	86	(15)	(31)	(25)	(97)	6	(70)	-	58	N/A	(1)
	Annual Additions, Long Term Resources	-	0	-	-	(19)	16	0	0	(0)	0	-	(0)	(1)	0	0	(0)	(0)	70	1	(70)		
	Annual Additions, Short Term Resources	-	(0)	(0)	(0)	15	0	-	(0)	0	-	-	0	2	1	1	1	1	(61)	(61)	1		
	Total Annual Additions	-	0	(0)	(0)	(3)	16	0	0	(0)	0	-	(0)	0	2	1	1	1	9	(60)	(69)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 7 compared to Energy Gateway Case 5

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $854 million

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum, FOT Average 10 Year	20 Year *
East																							
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Idaho	-	-	-	-	-	(0.1)	-	-	-	-	-	(0.2)	-	-	-	-	(0.2)	-	-	-	(0)	(1)
	DSM, Class 2, Utah	-	-	-	-	(18.9)	(19.0)	-	-	(0.5)	-	-	-	(2.0)	-	-	-	-	-	-	-	(38)	(40)
	DSM, Class 2, Wyoming	-	-	-	-	-	-	0.1	0.1	0.1	0.1	-	-	(0.1)	0.3	0.3	-	-	(0.1)	0.8	-	0	2
	DSM, Class 2 Total	-	-	-	-	(18.9)	(19.1)	0.1	0.1	(0.4)	0.1	-	(0.2)	(2.1)	0.3	0.3	-	(0.2)	(0.1)	0.8	-	(38)	(39)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)	-	-	-	-	-	(0)
	FOT Mead 3rd Qtr HLH	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Utah 3rd Qtr HLH	-	-	-	-	15	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	15
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(4)	23	31	39	119	(12)	(34)	(2)	(69)	(91)	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	(187)	37	24	92	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	(1)	(6)	(14)	(6)	(92)	102	-	(26)	26	17	N/A	(0)
West																							
	Geothermal, Greenfield	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	70	-	(70)	35	35
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	0.1	-	-	0.0	0.0	-	0.1	-	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	0	1
	DSM, Class 2 Total	-	0.1	-	-	0.0	0.0	-	0.1	-	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	0	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	(0)	0	-	(71)	(103)	-	-	-	-	-	-	-	(58)	0	(12)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(6)	-	(43)	(18)	N/A	(9)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	222	-	-	-	N/A	22
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	76	86	(15)	(31)	(25)	(97)	6	(70)	-	58	N/A	(1)
	Annual Additions, Long Term Resources	-	0	-	-	(19)	16	0	0	(0)	0	-	(0)	(1)	0	0	(0)	(0)	70	1	(70)		
	Annual Additions, Short Term Resources	-	(0)	(0)	(0)	15	0	-	(0)	0	-	(0)	0	2	1	1	1	1	(61)	(61)	1		
	Total Annual Additions	-	0	(0)	(0)	(3)	16	0	0	(0)	0	(0)	(0)	0	2	1	1	1	9	(60)	(69)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 8 compared to Energy Gateway Case 5

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR (\$307) million

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum, FOT Average 10 Year	20 Year *
		Capacity (MW)																					
East	CCCT F 2x1	-	-	-	-	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	597
	Geothermal, Greenfield	-	-	-	-	-	-	(35)	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	(19.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	(3.5)	-	-	-	-	-	-	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	(1.6)	-	-	-	1.6	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	6.6	(6.6)	-	-	-	(5.4)	-	-	-	5.4	-	-	-	-	-	-	-	-	-	-	-	(0)
	DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	(5.4)	(1.4)	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	6.6	(4.7)	-	19.8	(25.2)	(8.4)	-	-	-	11.9	-	-	-	-	-	-	-	-	-	-	-	(0)
	DSM, Class 2, Idaho	(0.5)	(0.6)	(0.4)	-	-	(0.1)	(0.1)	0.1	-	-	-	(0.2)	-	-	-	-	(0.2)	-	-	-	(1)	(2)
	DSM, Class 2, Utah	(38.1)	(42.7)	(57.5)	-	(17.7)	(19.0)	(3.4)	15.5	5.7	-	-	-	(2.0)	-	-	-	-	-	-	-	(157)	(159)
	DSM, Class 2, Wyoming	(0.1)	(0.2)	(0.1)	-	-	(0.0)	0.1	0.3	0.2	0.1	-	-	(0.1)	0.3	0.3	-	-	(0.1)	(0.2)	-	0	1
	DSM, Class 2 Total	(38.6)	(43.5)	(58.0)	-	(17.7)	(19.1)	(3.4)	15.9	6.0	0.1	-	(0.2)	(2.1)	0.3	0.3	-	(0.2)	(0.1)	(0.2)	-	(158)	(161)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)	-	-	-	-	-	(0)
	Micro Solar - Photovoltaic	(1)	(51)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54)	(54)
	FOT Mead 3rd Qtr HLH	-	-	-	50	-	(99)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(49)	(49)
	FOT Utah 3rd Qtr HLH	25	(7)	-	-	137	(176)	(200)	-	-	-	-	-	-	-	-	-	-	-	-	-	(221)	(221)
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	34	44	58	65	47	53	(34)	(7)	(105)	(155)	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	(187)	15	61	76	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	(1)	(45)	(50)	(36)	13	16	3	(26)	27	99	N/A	0
West	Geothermal, Greenfield	-	-	-	-	-	(35)	-	70	-	-	-	-	-	-	-	-	-	70	-	(70)	35	35
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CHP - Reciprocating Engine	-	0	0	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, California-DLC-Irrigation	-	-	5.5	-	(5.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	(17.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	(13.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Residential	-	-	10.3	-	(3.6)	-	(6.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	4.8	(6.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	(1.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	49.5	4.8	(47.6)	-	(6.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2, California	0.1	0.1	-	-	0.0	0.0	-	0.2	0.2	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	1	1
	DSM, Class 2, Washington	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	0.1	0.2	-	-	0.0	0.0	-	0.2	0.2	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	1	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	(62)	(46)	35	5	-	(71)	(106)	-	-	-	-	-	-	-	(43)	(7)	(14)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	102	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	11
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	(50)	15	39	-	-	-	-	-	-	-	-	-	-	-	0	0
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(24)	-	(43)	(18)	N/A	(11)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	219	-	-	-	N/A	22
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	39	107	(6)	(28)	(59)	(77)	24	(43)	-	43	N/A	(0)
	Annual Additions, Long Term Resources	(33)	(99)	(9)	25	(90)	535	(45)	86	7	48	0	(0)	(1)	0	0	(0)	(0)	70	0	(70)		
	Annual Additions, Short Term Resources	25	94	111	50	137	(336)	(296)	50	44	-	0	0	2	1	1	1	1	(61)	(61)	1		
	Total Annual Additions	(8)	(5)	102	74	47	198	(341)	136	51	48	0	(0)	0	2	1	1	1	9	(60)	(69)		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 9

PVRR $46,155 million

	Capacity (MW)																				Resource Sum, FOT Average	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	4
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	0	-	-	2
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	4	-	-	6
CHP - Biomass	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	50	100
CHP - Reciprocating Engine	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	19.8	-	-	-	-	-	-	-	-	0.9	1.3	2.7	-	-	-	-	20	25
DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	-	31.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	-	-	6.7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
DSM, Class 1 Total	5.5	61.6	-	-	19.8	-	-	11.6	-	-	-	-	-	0.9	1.3	2.7	-	-	-	-	99	103
DSM, Class 2, Idaho	2.0	2.5	2.2	2.8	3.4	3.9	4.2	4.5	4.7	5.1	5.2	5.4	6.5	7.0	7.3	6.8	7.2	6.8	7.1	6.5	35	101
DSM, Class 2, Utah	83.9	92.1	93.9	40.1	41.4	43.9	45.1	48.1	49.9	52.3	54.2	58.1	54.4	56.4	57.9	61.3	55.4	58.2	57.3	59.9	591	1,164
DSM, Class 2, Wyoming	3.6	4.6	4.8	6.1	6.2	7.1	7.9	8.7	8.7	9.3	10.9	11.8	13.6	16.7	17.8	23.0	24.5	28.8	35.9	38.9	67	289
DSM, Class 2 Total	89.6	99.3	100.9	49.0	51.0	54.9	57.2	61.3	63.3	66.6	70.3	75.3	74.5	80.1	83.0	91.2	87.1	93.8	100.3	105.3	693	1,554
Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	-	-	24	44
Micro Solar - Photovoltaic	1	51	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	54
FOT Mead 3rd Qtr HLH	-	168	264	230	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	761	761
FOT Utah 3rd Qtr HLH	175	200	200	-	194	-	-	56	157	69	-	-	-	-	-	-	-	-	-	-	1,051	1,051
FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	5	111	216	270	300	300	300	300	300	300	225	233
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	6	73	112	117	159	124	148	141	120	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	123	294	552	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	199	23	325	303	150	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	70	105
Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	2
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	2
CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
DSM, Class 1, California-DLC-Irrigation	-	-	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Oregon-Curtailment	-	-	-	-	-	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon-DLC-Irrigation	-	-	-	-	0.5	-	-	12.7	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	10	10
DSM, Class 1, Washington-DLC-Irrigation	-	-	-	-	8.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	-	-	3.3	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	-	-	-	-	9.0	-	-	48.7	-	-	-	-	-	-	-	-	-	-	-	-	58	58
DSM, Class 2, California	0.7	0.8	0.8	1.1	1.3	1.4	1.7	1.7	1.6	1.7	1.8	1.9	2.2	2.4	2.5	2.2	2.3	2.2	2.2	2.0	13	34
DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
DSM, Class 2, Washington	10.1	12.5	8.5	8.5	8.6	8.4	8.8	9.1	9.4	9.6	10.7	11.7	11.4	12.1	12.4	9.6	8.3	8.7	8.6	9.0	93	196
DSM, Class 2 Total	63.3	66.2	65.3	70.3	71.5	70.6	70.7	63.2	63.3	63.7	64.8	65.9	66.0	66.8	67.2	64.2	54.6	46.9	46.9	47.0	668	1,259
OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	1	1	1	1	1	-	-	-	-	-	16	21
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	386	400	400	400	400	-	26	391	308	400	400	146	-	-	-	359	263
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	143	96	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	12
FOT South Central Oregon/Northern Cal 3rd Qtr HLH	-	50	50	50	50	-	29	50	50	50	-	-	-	-	-	-	-	-	-	-	38	19
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	25	53	173	49	204	96	202	199	N/A	100
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	366	-	38	596	N/A	100
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	478	464	-	-	8	51	106	420	306	168	N/A	200
Annual Additions, Long Term Resources	186	316	192	761	273	754	142	207	185	144	151	154	153	160	199	170	153	156	161	919		
Annual Additions, Short Term Resources	325	1,111	1,310	1,130	1,093	686	729	806	907	819	482	608	705	744	997	1,158	1,300	1,412	1,583	2,085		
Total Annual Additions	510	1,427	1,502	1,891	1,366	1,440	870	1,013	1,093	963	633	762	858	904	1,196	1,328	1,454	1,568	1,744	3,004		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 10 compared to Energy Gateway Case 9

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $881 million

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum, FOT Average 10 Year	Resource Sum, FOT Average 20 Year *
		Capacity (MW)																					
East																							
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4)	-	-	(4)
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	7	4	34	-	45
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	7	(1)	34	-	41
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	-	2
	DSM, Class 2, Wyoming	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	0	3
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(2)	(2)	(2)	(2)	(2)	-	-	-	(12)
	FOT Mead 3rd Qtr HLH	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Utah 3rd Qtr HLH	-	-	-	-	(0)	-	-	(0)	(0)	(0)	-	-	-	-	-	-	-	-	-	-	(1)	(1)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	(0)	(0)	(0)	19	-	-	-	-	-	-	-	18
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	(55)	(58)	15	116	(44)	57	(31)	0	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	116	(111)	(18)	13	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(14)	(10)	152	22	(150)	N/A	0
West																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(35)	-	(35)
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 1 Total	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 2, California	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(0)	-	-	-	(1)	-	-	-	-	-	-	(1)
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	(0)	-	-	-	-	-	(26)	(37)	(49)	-	-	146	-	-	-	(0)	2
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	69	88	(13)	(48)	0	(96)	0	0	N/A	(0)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(132)	-	(38)	169	N/A	(0)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	0	27	24	-	0	(51)	(73)	3	70	1	N/A	0
	Annual Additions, Long Term Resources	-	-	0	-	-	0	-	(0)	-	-	(0)	-	(0)	(2)	(3)	(2)	(2)	3	(1)	1		
	Annual Additions, Short Term Resources	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	1	2	3	4	5	5	34		
	Total Annual Additions	-	-	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(2)	(1)	0	2	7	4	35		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 11 compared to Energy Gateway Case 9

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $906 million

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum, FOT Average 10 Year	20 Year *
	Capacity (MW)																					
East																						
Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4)	-	-	(4)
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	7	4	34	-	45
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	7	(1)	34	-	41
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 2, Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	-	2
DSM, Class 2, Wyoming	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 2 Total	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	0	3
Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(2)	(2)	(2)	(2)	(2)	-	-	-	(12)
FOT Mead 3rd Qtr HLH	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
FOT Utah 3rd Qtr HLH	-	-	-	-	(0)	-	-	(0)	(0)	(0)	-	-	-	-	-	-	-	-	-	-	(1)	(1)
FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	(0)	(0)	(0)	19	-	-	-	-	-	-	-	18
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	(55)	(57)	15	83	(34)	49	0	0	-	(0)
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	14	(3)	(11)	N/A	0
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	97	34	(4)	(126)	N/A	0
West																						
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(35)	-	(35)
Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
DSM, Class 1 Total	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
DSM, Class 2, California	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 2 Total	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(0)	-	-	-	(1)	-	-	-	-	-	-	(1)
FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	(0)	-	-	-	-	-	(26)	(17)	(49)	-	-	126	-	-	-	(0)	2
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	49	88	(13)	(28)	0	(96)	0	0	N/A	(0)
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(132)	-	(38)	169	N/A	(0)
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	0	27	24	-	0	(51)	(53)	3	50	1	N/A	(0)
Annual Additions, Long Term Resources	-	-	0	-	-	0	-	(0)	-	-	(0)	-	(0)	(2)	(3)	(2)	(2)	3	(1)	1		
Annual Additions, Short Term Resources	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	1	2	3	4	5	5	34		
Total Annual Additions	-	-	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(2)	(1)	0	2	7	4	35		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 12 compared to Energy Gateway Case 9

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR (\$348) million

		Capacity (MW)																				Resource Sum. FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	CCCT F 2x1	-	-	-	-	597	(597)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4)	-	-	(4)
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	8	7	4	34	-	71
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	8	7	(1)	34	-	66
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	(19.8)	-	-	-	-	-	-	-	-	1.3	(1.3)	-	-	-	-	-	-	0
	DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	(3.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	6.6	(6.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	(6.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	6.6	(4.8)	-	19.8	(19.8)	-	6.3	(11.6)	-	-	-	-	-	1.3	(1.3)	-	-	-	-	-	(3)	(3)
	DSM, Class 2, Idaho	(0.5)	(0.7)	(0.1)	-	-	-	-	(0.2)	(0.4)	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)
	DSM, Class 2, Utah	(38.1)	(42.7)	(50.4)	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	2.2	(129)	(127)
	DSM, Class 2, Wyoming	0.1	0.2	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	(38.5)	(43.2)	(50.1)	-	-	-	1.9	(0.2)	(0.4)	-	-	-	-	-	-	-	-	-	-	2.2	(131)	(128)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)	-	-	-	(5)
	Micro Solar - Photovoltaic	(1)	(51)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54)	(54)
	FOT Mead 3rd Qtr HLH	-	-	-	34	(99)	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(53)	(53)
	FOT Utah 3rd Qtr HLH	25	(8)	-	13	(194)	-	41	123	(157)	123	-	-	-	-	-	-	-	-	-	-	(33)	(33)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	295	189	84	30	-	-	-	-	-	-	-	598
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	1	(55)	(84)	(41)	68	22	71	18	1	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	57	78	22	(157)	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	151	34	(45)	(150)	N/A	0
West																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(35)	-	(35)
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
	CHP - Reciprocating Engine	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	-	-	-	(5.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	(17.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	(0.5)	-	-	(12.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Residential	-	-	10.3	-	-	-	-	(10.0)	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	(8.5)	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	-	-	-	(3.3)	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)
	DSM, Class 1 Total	-	-	49.5	-	(9.0)	-	6.4	(48.7)	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)
	DSM, Class 2, California	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2, Washington	0.1	0.2	0.2	-	-	-	(0.3)	(0.3)	(0.1)	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 2 Total	0.1	0.2	0.3	-	-	-	(0.3)	(0.3)	(0.1)	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	(109)	14	-	-	(90)	-	-	181	9	69	-	-	254	157	-	-	(18)	24
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	101	110	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	11
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	(50)	50	21	-	(50)	-	-	-	-	-	-	-	-	-	-	-	(3)	(1)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	(6)	106	36	(40)	(0)	(96)	(0)	(0)	N/A	(0)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(366)	-	(38)	404	N/A	-
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	(172)	(246)	92	-	129	85	7	(119)	168	57	N/A	(0)
	Annual Additions, Long Term Resources	(33)	(99)	(1)	20	568	(597)	14	(61)	(1)	(0)	-	(0)	-	1	(1)	18	6	3	(1)	1		
	Annual Additions, Short Term Resources	25	94	110	47	(452)	76	63	123	(297)	123	123	123	123	122	123	123	124	125	125	154		
	Total Annual Additions	(7)	(5)	109	67	116	(521)	77	62	(298)	123	123	123	123	123	122	141	130	128	124	155		

* For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.

Energy Gateway Case 13

PVRR $47,074 million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
	CCCT F 2x1	-	-	-	625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	625	625
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1
	CHP - Biomass	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	50	100
	CHP - Reciprocating Engine	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	19.8	-	-	-	-	-	-	2.2	-	-	-	2.7	-	-	-	-	20	25
	DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Utah-Curtailment	-	21.5	-	-	3.2	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	31.7	-	-	-	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	5.4	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 Total	5.5	61.6	-	-	28.4	8.4	-	-	-	-	-	2.2	-	-	-	2.7	-	-	-	-	104	109
	DSM, Class 2, Idaho	2.0	2.5	2.5	3.0	3.7	4.4	4.7	5.1	5.0	5.4	5.4	5.6	7.0	7.6	8.0	7.6	8.0	7.6	7.6	7.1	38	110
	DSM, Class 2, Utah	83.9	92.1	101.2	44.0	45.4	48.2	61.8	50.6	60.8	69.5	57.2	61.5	57.8	60.1	60.2	63.5	57.2	60.1	59.3	62.1	657	1,256
	DSM, Class 2, Wyoming	3.9	5.0	5.3	6.2	6.3	7.3	8.1	9.0	9.1	9.8	11.1	11.8	13.9	17.2	18.3	23.6	25.1	30.1	37.5	39.9	70	298
	DSM, Class 2 Total	89.8	99.6	109.0	53.2	55.5	59.9	74.6	64.6	74.8	84.7	73.8	78.9	78.7	84.9	86.5	94.7	90.3	97.8	104.4	109.1	766	1,665
	Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	24	42
	Micro Solar - Photovoltaic	1	51	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	54
	FOT Mead 3rd Qtr HLH	-	168	264	214	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	844	844
	FOT Utah 3rd Qtr HLH	175	200	200	-	74	172	200	-	-	200	-	-	-	-	-	-	-	-	-	-	1,221	1,221
	FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	74	225	251
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	7	32	75	76	137	184	143	123	104	117	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	165	353	458	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	138	159	111	60	139	19	20	220	135	-	N/A	100
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	70	70	-	70	70	-	-	-	-	-	-	35	35	-	-	350	420
	Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	100	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Oregon-Curtailment	-	-	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	3.6	-	6.8	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	-	8.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 Total	-	-	-	-	52.8	-	6.8	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, California	0.7	0.9	0.9	1.2	1.5	1.6	1.7	1.7	1.7	2.0	1.8	1.9	2.3	2.5	2.6	2.3	2.7	2.5	2.5	2.3	14	37
	DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
	DSM, Class 2, Washington	12.0	12.7	9.0	8.8	8.9	8.7	8.9	9.2	9.4	9.6	10.8	11.8	11.5	12.5	12.8	9.9	8.5	8.9	8.9	9.3	97	202
	DSM, Class 2 Total	65.3	66.4	65.9	70.8	72.1	71.2	70.9	63.3	63.4	63.9	65.0	66.2	66.2	67.3	67.8	64.6	55.2	47.5	47.5	47.6	673	1,268
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	-	-	16	28
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	365	395	400	-	-	298	400	400	400	400	44	400	-	356	295
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	143	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23	12
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	50	50	50	-	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	190	189	48	187	-	N/A	61
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	43	-	N/A	5
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	166	238	40	23	166	182	185	398	26	576	N/A	200
	Annual Additions, Long Term Resources	188	417	200	766	480	241	271	150	267	232	155	161	159	166	167	175	193	190	163	2,489		
	Annual Additions, Short Term Resources	325	1,111	1,304	1,114	974	1,021	950	665	695	950	611	730	824	859	1,141	1,299	1,408	1,486	1,654	767		
	Total Annual Additions	513	1,527	1,505	1,880	1,454	1,262	1,221	815	962	1,182	765	891	982	1,025	1,309	1,474	1,601	1,676	1,816	3,256		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 14 compared to Energy Gateway Case 13

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $795 million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,600)	-	(1,600)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	141	200	26	29	-	996
	Total Wind	-	-	-	-	-	-	160	-	-	-	-	-	-	200	200	200	141	200	26	29	160	1,156
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Idaho	-	-	-	-	-	-	-	(0.3)	(0.1)	(0.2)	-	-	(0.3)	-	-	-	-	-	-	-	(1)	(1)
	DSM, Class 2, Utah	-	-	-	-	-	-	(0.3)	(1.3)	(9.7)	(14.6)	-	-	-	-	-	-	-	-	-	-	(26)	(26)
	DSM, Class 2, Wyoming	-	0.0	-	-	-	0.1	0.1	(0.0)	(0.2)	(0.2)	0.2	0.2	-	(0.1)	0.3	0.4	0.5	-	-	-	(0)	1
	DSM, Class 2 Total	-	0.0	-	-	-	0.1	(0.2)	(1.6)	(10.0)	(14.9)	0.2	0.2	(0.3)	(0.1)	0.3	0.4	0.5	-	-	-	(27)	(25)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	-	-	-	-	(0)
	FOT Mead 3rd Qtr HLH	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Utah 3rd Qtr HLH	-	-	-	-	(0)	(0)	-	-	-	(9)	-	-	-	-	-	-	-	-	-	-	(10)	(10)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226	-	226
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	37	5	19	3	14	(53)	(65)	7	33	0	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(24)	(165)	(67)	(179)	435	N/A	-
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	(29)	(43)	26	(6)	(114)	35	(20)	(75)	17	209	N/A	0
West																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	35	-	-	-	-	-	35	-	-	(35)	(35)	-	-	35	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	0.1	-	-	-	0.0	-	-	-	-	(0.2)	0.1	-	-	0.3	0.3	0.3	-	-	-	-	(0)	1
	DSM, Class 2 Total	0.1	-	-	-	0.0	-	-	-	-	(0.2)	0.1	-	-	0.3	0.3	0.3	-	-	-	-	(0)	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	(30)	(22)	-	-	51	(14)	(14)	-	-	-	356	-	-	(5)	16
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(35)	-	184	N/A	15
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	239	-	(43)	366	N/A	56
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	(17)	(21)	(40)	(23)	59	-	-	(166)	192	16	N/A	0
	Annual Additions, Long Term Resources	0	0	-	-	0	0	160	33	(10)	(15)	0	(2)	2	235	201	201	106	165	26	(1,571)		
	Annual Additions, Short Term Resources	-	(0)	(0)	(0)	(0)	(0)	-	(30)	(22)	(9)	(9)	(7)	(9)	(41)	(41)	(42)	(11)	20	20	1,436		
	Total Annual Additions	0	(0)	(0)	(0)	(0)	(0)	160	4	(32)	(24)	(9)	(9)	(7)	195	160	159	95	185	46	(135)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 15 compared to Energy Gateway Case 13

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $233 million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,600)	-	(1,600)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	3	200	200	200	200	200	199	200	-	1,402
	Total Wind	-	-	-	-	-	-	160	-	-	-	-	-	3	200	200	200	200	200	199	200	160	1,562
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8.3	(8.3)	-	-	-	-	-	2.2	(2.2)	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	56.5	(56.6)	-	11.5	(9.8)	0.7	-	-	-	-	21.0	(2.2)	-	-	-	24.3	-	-	-	21.0	2	66
	DSM, Class 2, Idaho	(0.2)	0.3	0.7	0.4	0.5	0.5	0.6	1.1	0.7	0.7	0.6	0.7	0.8	0.9	0.9	1.0	(0.0)	2.1	(0.1)	1.0	5	13
	DSM, Class 2, Utah	(4.8)	(5.3)	(1.8)	1.1	8.4	8.0	3.0	12.6	2.5	(2.6)	12.4	3.0	7.0	10.5	10.2	11.2	21.0	23.5	23.0	25.3	21	168
	DSM, Class 2, Wyoming	8.4	8.9	9.6	10.1	12.1	11.7	11.0	12.2	12.8	12.9	7.7	8.4	5.5	3.7	2.3	(3.0)	(2.4)	(2.0)	(12.2)	(11.7)	110	106
	DSM, Class 2 Total	3.4	3.9	8.4	11.5	21.0	20.2	14.6	26.0	16.0	11.0	20.7	12.0	13.3	15.1	13.4	9.2	18.5	23.6	10.7	14.6	136	287
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	-	-	-	-	(0)
	FOT Mead 3rd Qtr HLH	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	FOT Utah 3rd Qtr HLH	(52)	-	-	-	14	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(36)	(36)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226	-	226
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	96	66	19	(16)	(72)	(112)	23	(36)	(3)	34	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	35	-	9	(24)	(165)	(142)	(176)	462	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	(109)	(32)	56	(31)	(122)	(19)	(20)	(54)	25	305	N/A	(0)
West																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	(35)	-	-	-	-	70	35	-	(35)	(35)	-	-	(35)	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	20.9	-	9.0	(23.5)	-	(6.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 2, California	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.7	0.7	0.5	0.5	0.5	0.6	0.6	1.0	1.0	0.3	1.1	0.2	0.6	4	10
	DSM, Class 2 Total	(1.9)	(1.8)	(0.9)	(1.1)	(0.2)	(0.4)	1.0	1.0	0.4	0.3	1.2	(0.7)	0.0	(1.6)	(1.3)	(1.1)	(7.2)	(2.6)	(3.4)	(2.9)	(4)	(23)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	(18)	4	-	-	-	(222)	(46)	-	-	-	190	-	-	(1)	(5)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(22)	(36)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(6)	(3)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	1	(48)	0	184	N/A	9
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(6)	-	(43)	-	N/A	(5)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	(22)	(71)	66	(23)	31	15	3	(59)	42	17	N/A	-
	Annual Additions, Long Term Resources	58	(34)	8	31	(62)	20	169	27	(19)	11	43	9	16	283	247	232	176	186	206	(1,367)		
	Annual Additions, Short Term Resources	(52)	(22)	(36)	(50)	14	1	-	(18)	4	-	(35)	(38)	(45)	(115)	(153)	(182)	(163)	(149)	(156)	1,229		
	Total Annual Additions	6	(56)	(28)	(19)	(48)	22	169	9	(14)	11	8	(29)	(29)	168	94	51	13	37	50	(138)		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 16 compared to Energy Gateway Case 13

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR ($336) million

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum. FOT Average 10 Year	20 Year *
East																							
	CCCT F 2x1	-	-	-	-	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	597
	Geothermal, Greenfield	-	-	-	-	-	-	(35)	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,600)	-	(1,600)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	188	200	200	200	200	200	200	199	200	-	1,786
	Total Wind	-	-	-	-	-	-	160	-	-	-	-	188	200	200	200	200	200	200	199	200	160	1,946
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	(19.8)	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	(3.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	(1.6)	-	-	-	1.6	-	-	-	-	-	-	-	-	-	-	-	(0)
	DSM, Class 1, Utah-DLC-Residential	6.6	(6.6)	-	-	-	(5.4)	-	-	-	5.4	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	(5.4)	(1.4)	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	(3)	(3)
	DSM, Class 1 Total	6.6	(4.7)	-	19.8	(25.2)	(8.4)	-	-	-	8.4	-	(2.2)	2.2	-	-	-	-	-	-	-	(2)	(2)
	DSM, Class 2, Idaho	(0.5)	(0.6)	(0.4)	-	-	(0.1)	(0.1)	-	-	-	-	-	(0.3)	-	-	-	-	-	-	-	(150)	(150)
	DSM, Class 2, Utah	(38.1)	(42.7)	(57.5)	-	-	-	(12.4)	-	0.6	-	-	-	-	-	-	-	-	-	-	-	(0)	1
	DSM, Class 2, Wyoming	(0.1)	(0.2)	(0.1)	-	(0.0)	(0.0)	0.1	0.1	0.1	-	0.2	0.2	-	(0.1)	0.3	0.4	0.5	-	-	-	(152)	(151)
	DSM, Class 2 Total	(38.6)	(43.5)	(58.0)	-	(0.0)	(0.1)	(12.5)	0.1	0.7	-	0.2	0.2	(0.3)	(0.1)	0.3	0.4	0.5	-	-	-	-	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	-	-	-	(54)	(54)
	Micro Solar - Photovoltaic	(1)	(51)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(49)	(49)
	FOT Mead 3rd Qtr HLH	-	-	-	50	-	(99)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(228)	(228)
	FOT Utah 3rd Qtr HLH	25	(7)	-	-	126	(172)	(200)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226	-	(0)
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	52	15	62	(49)	(36)	(53)	(64)	(0)	1	73	N/A	-
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	40	(165)	(164)	(186)	453	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	(40)	(108)	(83)	(60)	(139)	(19)	(20)	(91)	66	493		
West																							
	Geothermal, Greenfield	-	-	-	-	-	(35)	-	70	-	-	-	-	-	35	-	-	(35)	(35)	-	-	35	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CHP - Reciprocating Engine	-	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, California-DLC-Irrigation	-	-	5.5	-	(5.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	(17.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	(13.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Residential	-	-	10.3	-	(3.6)	-	(6.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	4.8	(6.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	(4.1)	-	-	-	-	2.9	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	49.5	4.8	(50.4)	-	(6.8)	-	-	2.9	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2, California	0.1	-	0.0	-	0.0	-	-	-	0.2	-	0.1	-	-	-	0.3	0.3	-	-	-	-	0	1
	DSM, Class 2, Washington	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	0.1	-	0.0	-	0.0	-	-	-	0.2	-	0.1	-	-	-	0.3	0.3	-	-	-	-	0	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	(92)	(65)	35	5	-	132	333	61	-	-	-	-	356	-	-	(12)	38
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	102	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	11
	FOT South Central Oregon/Northern Cal 3rd Qtr HLH	-	-	-	-	-	(1)	(50)	8	6	-	-	-	-	-	-	(80)	(4)	(3)	(0)	184	(4)	(2)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248	-	(43)	-	N/A	10
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	(144)	(238)	(40)	77	121	80	4	(68)	192	16	N/A	20
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	0
	Annual Additions, Long Term Resources	(33)	(99)	(9)	25	(76)	553	106	70	36	11	0	186	202	235	201	201	165	165	199	(1,400)		
	Annual Additions, Short Term Resources	25	94	111	50	126	(363)	(315)	43	11	-	(0)	2	(0)	(31)	(32)	(32)	(1)	30	30	1,446		
	Total Annual Additions	(8)	(5)	102	75	50	190	(210)	113	47	11	0	187	202	204	170	169	164	195	228	46		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Table C.4 – Energy Gateway Scenario Evaluation Results (WM Studies)

Energy Gateway Case 1_WM

PVRR $40,439 million

		Capacity (MW)																				Resource sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	66	98	35	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	100	100	100	18	88	43	29	-	22	-	-	-	-	300	500
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	2	0	0	-	-	-	-	-	-	-	-	-	-	2	2
	Total Wind	-	-	-	-	-	-	66	200	135	100	18	88	43	29	-	22	-	-	-	-	502	702
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
	DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9	-	-	20	25
	DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	9.0	-	-	-	-	5.4	-	-	12.3	-	-	-	-	-	-	-	-	-	-	27	27
	DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 Total	5.5	40.9	-	19.8	-	-	11.6	-	-	12.3	-	-	-	-	-	-	-	4.9	-	-	90	95
	DSM, Class 2, Idaho	1.5	1.8	2.0	2.8	3.4	3.9	4.2	4.4	4.3	4.6	4.7	4.8	5.7	6.1	6.5	6.1	6.5	6.1	6.1	5.6	33	91
	DSM, Class 2, Utah	43.3	46.6	39.0	40.1	41.4	43.9	45.1	46.1	47.8	50.1	51.4	54.9	51.3	53.1	53.0	57.4	52.0	54.6	53.8	56.2	443	981
	DSM, Class 2, Wyoming	3.5	4.3	4.5	5.5	6.2	7.1	7.9	8.7	8.7	9.3	10.9	11.5	13.3	16.3	17.4	22.5	23.9	28.1	35.0	37.2	66	282
	DSM, Class 2 Total	48.3	52.8	45.5	48.4	51.0	54.9	57.2	59.1	60.8	64.0	66.9	71.1	70.3	75.6	76.8	86.0	82.4	88.8	94.9	99.1	542	1,354
	Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	-	24	47
	FOT Mead 3rd Qtr HLH	-	168	266	266	-	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	789	789
	FOT Utah 3rd Qtr HLH	-	229	250	72	-	-	109	243	-	250	-	-	-	-	-	-	-	-	-	-	1,152	1,152
	FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	225	263
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	29	102	107	153	161	-	229	130	89	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	265	321	406	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	156	-	257	272	309	N/A	100
West																							
	Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	65	100	-	-	-	28	24	100	58	95	46	100	164	616
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	86	-	86
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	-	-	-	200	-	-	-	65	100	-	-	-	28	24	100	58	95	46	186	364	902
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, Oregon-DLC-Residential	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 Total	-	-	42.8	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	-	53	53
	DSM, Class 2, California	0.7	0.8	0.8	1.1	1.3	1.4	1.5	1.5	1.4	1.5	1.6	1.6	2.0	2.1	2.2	2.0	2.0	1.9	1.9	1.7	12	31
	DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
	DSM, Class 2, Washington	7.4	8.0	8.2	8.0	8.4	8.2	8.5	8.8	9.0	9.2	10.0	10.9	10.9	11.4	11.8	9.3	8.1	8.5	8.6	8.9	84	182
	DSM, Class 2 Total	60.7	61.6	65.0	69.8	71.4	70.4	70.3	62.7	62.8	63.1	63.9	64.9	65.3	65.9	66.3	63.7	54.1	46.4	46.5	46.7	658	1,241
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	-	16	31
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	27	400	400	400	365	400	400	400	400	400	369	400	400	400	400	400	400	400	400	400	359	378
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	-	50	50	50	15	50	-	-	-	-	-	-	-	-	-	-	36	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	29	-	-	133	116	190	186	106	104	N/A	86
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	470	-	-	62	N/A	53
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	43	102	142	251	267	194	26	310	283	N/A	162
	Annual Additions, Long Term Resources	136	188	173	776	1,017	153	225	340	333	394	161	234	188	208	177	281	205	244	196	337		
	Annual Additions, Short Term Resources	177	1,268	1,476	1,238	715	840	859	993	715	1,000	669	801	904	949	1,242	1,409	1,554	1,664	1,838	1,953		
	Total Annual Additions	312	1,456	1,649	2,013	1,732	993	1,084	1,332	1,048	1,394	830	1,034	1,092	1,157	1,419	1,690	1,759	1,908	2,033	2,290		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 2_WM compared to Energy Gateway Case 1_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $611 million

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum. FOT Avg 10 Year	Resource Sum. FOT Avg 20 Year *
		Capacity (MW)																					
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(29)	-	(22)	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	200	200	15	73	38	48	20	99	50	80	39	154	398	1,016
	Total Wind	-	-	-	-	-	-	94	(200)	65	100	(4)	(15)	(5)	19	20	78	50	80	39	154	58	476
	DSM, Class 1, Utah-DLC-Residential	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 1 Total	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 2, Utah	-	-	-	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 2, Wyoming	-	-	0.1	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	-	-	0.1	0.6	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	4	4
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	-	-	(8)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	FOT Utah 3rd Qtr HLH	-	0	-	(1)	-	-	(2)	7	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	4	53	75	(17)	(13)	-	(123)	(10)	32	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	49	-	(35)	(10)	(5)	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	(35)	-	4	23	(9)	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(164)	(616)
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(86)	-	(86)
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	(27)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(27)
	Total Wind	-	-	-	-	(27)	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(186)	(191)	(729)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2, Washington	0.3	-	-	0.4	-	0.1	-	-	0.3	0.3	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.3	-	-	0.4	-	0.1	-	-	0.3	0.5	-	-	-	-	-	-	-	-	-	-	2	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(2)	(1)	(1)	-	-	(5)
	FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	1	1
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	37	-	-	7	47	1	(38)	8	(59)	N/A	0
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	1	-	-	(15)	N/A	(1)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(41)	(53)	(75)	(6)	(47)	(0)	196	(6)	61	N/A	3
	Annual Additions, Long Term Resources	0	(0)	0	1	(27)	0	102	(200)	0	12	(4)	(15)	(5)	(9)	(5)	(23)	(13)	(19)	(10)	(32)		
	Annual Additions, Short Term Resources	(0)	(0)	(0)	(1)	0	0	(2)	7	11	-	-	-	(0)	(0)	0	1	2	4	5	5		
	Total Annual Additions	0	(0)	(0)	0	(26)	0	100	(193)	11	12	(4)	(15)	(5)	(9)	(4)	(23)	(10)	(15)	(5)	(27)		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 3_WM compared to Energy Gateway Case 1_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $635 million

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum. FOT Avg 10 Year	Resource Sum. FOT Avg 20 Year *
		Capacity (MW)																					
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(29)	-	(22)	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	200	200	15	73	39	47	20	101	51	80	42	177	398	1,043
	Total Wind	-	-	-	-	-	-	94	(200)	65	100	(4)	(15)	(5)	18	20	79	51	80	42	177	58	503
	DSM, Class 1, Utah-DLC-Residential	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 1 Total	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 2, Utah	-	-	-	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 2, Wyoming	-	-	0.1	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	-	-	0.1	0.6	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	4	4
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)	(3)	(2)	-	-	(10)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	FOT Utah 3rd Qtr HLH	-	0	-	(1)	-	-	(2)	7	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	1	53	75	(15)	(14)	-	(123)	(10)	32	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	-	(16)	(9)	1	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	(9)	-	(14)	23	(15)	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(164)	(616)
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(86)	-	(86)
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	(27)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(27)
	Total Wind	-	-	-	-	(27)	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(186)	(191)	(729)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2, Washington	0.3	-	-	0.4	-	0.1	-	-	0.3	0.3	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.3	-	-	0.4	-	0.1	-	-	0.3	0.5	-	-	-	-	-	-	-	-	-	-	2	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(2)	(1)	(1)	-	-	(6)
	FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	1	1
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	39	-	-	7	48	2	(38)	7	(59)	N/A	0
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	2	-	-	(13)	N/A	(1)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(41)	(53)	(75)	(6)	(47)	(0)	197	(6)	61	N/A	3
	Annual Additions, Long Term Resources	0	(0)	0	1	(27)	0	102	(200)	0	12	(4)	(15)	(5)	(10)	(5)	(24)	(12)	(19)	(7)	(9)		
	Annual Additions, Short Term Resources	(0)	(0)	(0)	(1)	0	0	(2)	7	11	-	-	0	(0)	0	1	2	3	5	6	6		
	Total Annual Additions	0	(0)	(0)	0	(26)	0	100	(193)	11	12	(4)	(15)	(5)	(10)	(4)	(22)	(9)	(14)	(1)	(3)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 4_WM compared to Energy Gateway Case 1_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $674 million

		Capacity (MW)																				Resource Sum. FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(29)	-	(22)	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	200	200	15	73	39	47	20	101	51	80	43	200	398	1,067
	Total Wind	-	-	-	-	-	-	94	(200)	65	100	(4)	(15)	(5)	18	20	79	51	80	43	200	58	527
	DSM, Class 1, Utah-DLC-Residential	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 1 Total	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 2, Utah	-	-	-	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 2, Wyoming	-	-	0.1	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	-	-	0.1	0.6	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	4	4
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)	(3)	(2)	-	-	(10)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	FOT Utah 3rd Qtr HLH	-	0	-	(1)	-	-	(2)	7	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	(29)	53	72	6	(15)	-	(88)	(10)	11	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	-	(17)	(9)	1	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(6)	(8)	-	(63)	23	54	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(164)	(616)
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(86)	-	(86)
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	(27)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(27)
	Total Wind	-	-	-	-	(27)	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(186)	(191)	(729)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2, Washington	0.3	-	-	0.4	-	0.1	-	-	0.3	0.3	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.3	-	-	0.4	-	0.1	-	-	0.3	0.5	-	-	-	-	-	-	-	-	-	-	2	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(2)	(1)	(1)	-	-	(6)
	FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	1	1
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	69	-	-	7	51	2	(23)	7	(59)	N/A	5
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	2	-	-	(62)	N/A	(6)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(41)	(53)	(72)	(6)	(51)	(0)	197	(5)	61	N/A	3
	Annual Additions, Long Term Resources	0	(0)	0	1	(27)	0	102	(200)	0	12	(4)	(15)	(5)	(10)	(5)	(24)	(12)	(19)	(6)	13		
	Annual Additions, Short Term Resources	(0)	(0)	(0)	(1)	0	0	(2)	7	11	-	-	0	(0)	0	0	2	3	5	6	6		
	Total Annual Additions	0	(0)	(0)	0	(26)	0	100	(193)	11	12	(4)	(15)	(5)	(10)	(4)	(22)	(9)	(14)	(0)	19		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 5_WM

PVRR $41,394 million

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource sum, FOT Average 10 Year	Resource sum, FOT Average 20 Year *
East	Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	66	77	-	-	-	-	-	-	-	-	-	-	-	29	143	172
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	100	100	100	19	87	43	29	-	20	-	-	-	-	300	500
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	2	-	0	-	-	-	-	-	-	-	-	-	-	2	2
	Total Wind	-	-	-	-	-	-	66	178	100	100	19	87	43	29	-	20	-	-	-	29	445	673
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
	DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	-	-	-	-	-	-	-	-	2.2	-	-	2.7	-	-	-	-	20	25
	DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 Total	5.5	37.0	-	19.8	-	-	6.3	-	-	-	-	-	2.2	-	-	2.7	-	-	-	-	69	73
	DSM, Class 2, Idaho	1.5	1.8	2.1	3.0	3.6	4.2	4.5	4.8	4.7	5.2	5.2	5.4	6.7	7.3	7.6	7.2	7.5	7.6	7.6	7.1	35	105
	DSM, Class 2, Utah	43.3	47.8	41.7	42.9	44.3	47.0	48.2	50.6	52.4	54.9	55.5	59.6	55.8	60.1	60.2	63.5	57.2	60.1	59.3	62.1	473	1,067
	DSM, Class 2, Wyoming	3.8	4.8	5.1	6.2	6.3	7.2	8.0	8.9	8.9	9.5	11.1	11.8	13.6	17.1	18.2	23.5	25.0	29.3	36.5	39.9	69	295
	DSM, Class 2 Total	48.6	54.4	48.9	52.1	54.2	58.4	60.7	64.3	66.0	69.6	71.8	76.8	76.1	84.5	86.0	94.1	89.7	97.0	103.5	109.1	577	1,466
	Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	24	50
	FOT Mead 3rd Qtr HLH	-	168	266	266	-	82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	781	781
	FOT Utah 3rd Qtr HLH	-	231	250	69	-	-	103	235	-	250	-	-	-	-	-	-	-	-	-	-	1,138	1,138
	FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	225	263
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	49	100	75	165	172	-	175	172	91	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	92	-	195	291	422	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	166	-	251	265	298	N/A	100
West	Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	22	100	100	-	-	-	28	24	100	58	95	46	100	222	672
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	56	-	56
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	-	-	-	200	-	-	22	100	100	-	-	-	28	24	100	58	95	46	156	422	928
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, Oregon-DLC-Residential	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 Total	-	-	42.8	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	-	53	53
	DSM, Class 2, California	0.7	0.9	0.9	1.2	1.5	1.6	1.7	1.7	1.7	1.8	1.9	1.9	2.3	2.5	2.6	2.3	2.4	2.2	2.5	2.3	14	36
	DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
	DSM, Class 2, Washington	8.0	8.4	8.6	8.8	8.9	8.7	8.9	9.2	9.4	9.6	10.8	11.8	11.5	12.1	12.4	9.6	8.3	8.7	8.6	9.2	88	191
	DSM, Class 2 Total	61.3	62.1	65.5	70.7	72.1	71.2	70.8	63.3	63.4	63.8	65.0	66.2	66.2	66.9	67.3	64.3	54.7	46.9	47.2	47.5	664	1,256
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	16	33
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	26	400	400	400	310	400	400	400	367	400	366	400	400	400	400	400	400	400	400	400	350	373
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	50	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	40	20
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	163	-	-	42	N/A	28
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	432	-	-	-	N/A	43
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	43	90	153	330	166	217	300	360	340	N/A	200
	Annual Additions, Long Term Resources	136	186	177	780	1,021	157	224	346	384	343	168	240	198	218	187	291	213	248	205	350		
	Annual Additions, Short Term Resources	176	1,270	1,476	1,234	710	832	853	985	667	1,000	666	793	890	929	1,215	1,373	1,513	1,621	1,789	1,892		
	Total Annual Additions	313	1,457	1,653	2,014	1,730	989	1,077	1,331	1,051	1,343	834	1,033	1,087	1,147	1,402	1,664	1,725	1,870	1,994	2,242		

Capacity (MW) for years 2011–2030.

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 6_WM compared to Energy Gateway Case 5_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $607 million

		Capacity (MW)																				Resource Sum. FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Geothermal, Blundell 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(77)	-	-	-	-	-	-	-	-	-	-	-	(29)	(143)	(172)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(19)	(87)	(43)	(29)	-	(20)	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	178	200	20	75	35	50	23	110	45	75	39	146	376	995
	Total Wind	-	-	-	-	-	-	94	(178)	78	100	0	(13)	(8)	20	23	90	45	75	39	118	93	483
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1 Total	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	(2.2)	2.2	-	-	-	-	-	-	13	13
	DSM, Class 2, Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.5)	-	-	-	(1)
	DSM, Class 2, Utah	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Wyoming	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.1)	0	(1)
	DSM, Class 2 Total	-	-	0.1	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	(0.5)	-	(1.1)	1	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	(2)	-	(10)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FOT Utah 3rd Qtr HLH	-	0	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	20	24	(6)	(2)	49	-	(58)	(54)	27	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(31)	-	32	(6)	6	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	(51)	-	31	41	(24)	N/A	(0)
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(222)	(672)
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(56)	-	(56)
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Wind	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(156)	(222)	(728)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)
	DSM, Class 2, Washington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2 Total	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(2)	(1)	(1)	-	(6)
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	-	7	-	0	-	-	-	-	-	-	-	-	-	1	0
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(21)	20	-	23	0	N/A	2
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(19)	(22)	6	-	55	(20)	(2)	1	1	N/A	(0)
	Annual Additions, Long Term Resources	-	(0)	0	-	-	-	100	(200)	(22)	7	0	(13)	(10)	(5)	(1)	(11)	(17)	(25)	(10)	(43)		
	Annual Additions, Short Term Resources	-	0	-	-	-	-	-	7	7	-	0	0	2	0	0	1	2	4	5	10		
	Total Annual Additions	-	(0)	0	-	-	-	100	(193)	(15)	7	0	(13)	(8)	(5)	(1)	(11)	(15)	(21)	(5)	(33)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 7_WM compared to Energy Gateway Case 5_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $630 million

		Capacity (MW)																				Resource Sum. FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(77)	-	-	-	-	-	-	-	-	-	-	-	(29)	(143)	(172)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(19)	(87)	(43)	(29)	-	(20)	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	178	200	20	75	35	50	23	111	48	73	48	159	376	1,018
	Total Wind	-	-	-	-	-	-	94	(178)	78	100	0	(13)	(8)	20	23	90	48	73	48	130	93	506
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1 Total	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	(2.2)	2.2	-	-	-	-	-	-	13	13
	DSM, Class 2, Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.5)	-	-	-	(1)
	DSM, Class 2, Utah	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Wyoming	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.1)	0	(1)
	DSM, Class 2 Total	-	-	0.1	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	(0.5)	-	(1.1)	1	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	(2)	-	(10)
	FOT Utah 3rd Qtr HLH	-	0	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	20	24	(6)	(2)	39	-	(56)	(45)	27	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(13)	-	94	(21)	(60)	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	(59)	-	(31)	64	24	N/A	-
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(222)	(672)
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(56)	-	(56)
	Total Wind	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(156)	(222)	(728)
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)
	DSM, Class 2 Total	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(2)	(2)	(1)	(1)	-	(7)
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	-	7	-	0	-	-	-	-	-	-	-	-	-	1	0
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(21)	21	-	7	0	N/A	1
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(19)	(22)	6	-	56	(20)	(2)	1	1	N/A	0
	Annual Additions, Long Term Resources	-	(0)	0	-	-	-	100	(200)	(22)	7	0	(13)	(10)	(5)	(1)	(11)	(15)	(27)	(1)	(30)		
	Annual Additions, Short Term Resources	-	0	-	-	-	-	-	7	7	-	0	0	2	0	0	1	2	4	5	10		
	Total Annual Additions	-	(0)	0	-	-	-	100	(193)	(15)	7	0	(13)	(8)	(5)	(1)	(10)	(12)	(22)	5	(20)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 8_WM compared to Energy Gateway Case 5_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $668 million

		Capacity (MW)																				Resource Sum FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(77)	-	-	-	-	-	-	-	-	-	-	-	(29)	(143)	(172)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(19)	(87)	(43)	(29)	-	(20)	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	178	200	20	75	35	50	29	108	52	69	59	173	376	1,045
	Total Wind	-	-	-	-	-	-	94	(178)	78	100	0	(13)	(8)	20	29	88	52	69	59	144	93	534
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1 Total	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	(2.2)	2.2	-	-	-	-	-	-	13	13
	DSM, Class 2, Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.5)	-	-	-	(1)
	DSM, Class 2, Utah	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Wyoming	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.1)	0	(1)
	DSM, Class 2 Total	-	-	0.1	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	(0.5)	-	(1.1)	1	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	(2)	-	(10)
	FOT Utah 3rd Qtr HLH	-	0	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	20	24	(6)	20	46	-	(53)	(31)	(19)	-	-
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(90)	-	16	(21)	95	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(14)	-	44	56	(67)	N/A	(0)
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(222)	(672)
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(56)	-	(56)
	Total Wind	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(156)	(222)	(728)
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	(0.3)	-	-	(0)
	DSM, Class 2 Total	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	(0.3)	-	-	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(2)	(2)	(1)	(1)	-	(7)
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	-	7	-	0	-	-	-	-	-	-	-	-	-	1	0
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	21	-	-	0	N/A	2
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(19)	(22)	6	-	56	(21)	(2)	1	1	N/A	0
	Annual Additions, Long Term Resources	-	(0)	0	-	-	-	100	(200)	(22)	7	0	(13)	(10)	(5)	4	(13)	(11)	(30)	9	(16)		
	Annual Additions, Short Term Resources	-	0	-	-	-	-	-	7	7	-	0	0	2	0	0	1	2	4	6	10		
	Total Annual Additions	-	(0)	0	-	-	-	100	(193)	(15)	7	0	(13)	(8)	(5)	4	(12)	(9)	(26)	15	(6)		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 9_WM

PVRR $45,406 million

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource sum, FOT Average 10 Year	20 Year *
East																							
	Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	66	98	35	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	100	100	100	18	88	43	51	-	-	-	-	-	29	300	529
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	2	0	0	-	-	-	-	-	-	-	-	-	-	2	2
	Total Wind	-	-	-	-	-	-	66	200	135	100	18	88	43	51	-	-	-	-	-	29	502	731
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
	DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	-	-	-	-	-	-	-	-	0.2	2.0	-	2.7	-	-	-	-	20	25
	DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	8.2	-	-	-	-	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	14	14
	DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 Total	5.5	40.0	-	19.8	-	-	11.6	-	-	-	-	-	0.2	2.0	-	2.7	-	-	-	-	77	82
	DSM, Class 2, Idaho	1.5	1.8	2.0	2.8	3.4	3.9	4.5	4.8	4.7	5.1	5.2	5.4	6.5	7.0	7.3	6.8	7.2	6.8	7.1	6.5	34	100
	DSM, Class 2, Utah	43.3	46.6	39.0	40.1	41.4	45.8	47.0	49.1	51.1	53.5	54.2	58.1	54.4	56.4	57.9	61.3	55.4	58.2	57.3	62.1	457	1,032
	DSM, Class 2, Wyoming	3.5	4.8	5.1	6.1	6.2	7.1	8.0	8.9	8.9	9.5	10.9	11.8	13.6	16.7	17.8	23.0	24.5	28.8	35.9	38.9	68	290
	DSM, Class 2 Total	48.3	53.2	46.1	49.0	51.0	56.8	59.5	62.8	64.7	68.1	70.3	75.3	74.5	80.1	83.0	91.2	87.1	93.8	100.3	107.5	559	1,422
	Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	24	50
	FOT Mead 3rd Qtr HLH	-	168	266	266	-	88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	787	787
	FOT Utah 3rd Qtr HLH	-	229	250	71	-	-	105	236	-	250	-	-	-	-	-	-	-	-	-	-	1,141	1,141
	FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	225	263
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	144	256	86	236	233	45	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	83	287	563	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	49	39	242	281	389	N/A	100
West																							
	Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	65	100	-	-	-	6	46	100	58	97	100	100	165	671
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	-	-	-	200	-	-	-	65	100	-	-	-	6	46	100	58	97	100	100	365	871
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, Oregon-DLC-Residential	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 Total	-	-	42.8	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	-	53	53
	DSM, Class 2, California	0.7	0.8	0.8	1.1	1.3	1.6	1.7	1.7	1.6	1.7	1.8	1.9	2.2	2.4	2.5	2.2	2.3	2.2	2.2	2.0	13	35
	DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
	DSM, Class 2, Washington	7.7	8.0	8.6	8.5	8.6	8.6	8.8	9.1	9.3	9.6	10.7	11.7	11.4	12.1	12.4	9.6	8.3	8.7	8.6	9.0	87	189
	DSM, Class 2 Total	60.9	61.6	65.4	70.3	71.5	71.1	70.7	63.2	63.2	63.7	64.8	65.9	66.0	66.8	67.2	64.2	54.6	46.9	46.9	47.0	662	1,252
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	-	16	32
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	27	400	400	400	364	400	400	400	366	400	367	400	400	400	400	400	400	335	114	-	356	339
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	24	74	132	95	189	115	187	184	N/A	100
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	377	-	-	623	N/A	100
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	95	171	163	249	285	68	327	407	234	N/A	200
	Annual Additions, Long Term Resources	136	188	174	777	1,017	156	228	344	383	341	165	239	193	215	206	268	210	247	256	1,014		
	Annual Additions, Short Term Resources	177	1,268	1,476	1,237	714	838	855	986	666	1,000	667	795	896	936	1,225	1,386	1,527	1,638	1,808	2,338		
	Total Annual Additions	312	1,456	1,650	2,013	1,732	993	1,083	1,330	1,048	1,341	832	1,034	1,089	1,151	1,431	1,653	1,737	1,885	2,064	3,352		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 10_WM compared to Energy Gateway Case 9_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $591 million

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum. FOT Avg 10 Year	Resource Sum. FOT Avg 20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(51)	-	-	-	-	-	43	(300)	(457)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	105	200	200	15	71	26	39	24	100	45	67	37	93	505	1,023
	Total Wind	-	-	-	-	-	-	94	(93)	65	100	(4)	(17)	(17)	(11)	24	100	45	67	37	136	165	526
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(3.6)	-	-	-	8.8	18.3	-	-	-	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	(3.6)	-	-	-	15.1	12.0	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	24	24
	DSM, Class 2, Idaho	-	-	-	-	0.2	0.3	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Utah	-	2.0	2.7	2.8	4.0	2.4	2.4	3.0	4.4	16.0	-	-	-	-	-	-	-	-	-	-	40	40
	DSM, Class 2, Wyoming	0.3	-	0.0	0.1	0.1	0.1	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.3	2.0	2.7	2.9	4.3	2.8	2.4	3.0	4.4	16.3	-	-	-	-	-	-	-	-	-	-	41	41
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(3)	-	(8)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	FOT Utah 3rd Qtr HLH	-	2	-	(9)	-	-	14	14	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	(11)	65	(5)	(6)	(44)	-	-
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(12)	56	(38)	(5)	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	119	24	19	(230)	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Total Wind	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 2, California	-	0.1	0.1	0.1	0.2	-	-	0.1	0.0	0.1	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Washington	0.2	0.4	-	0.4	0.4	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 2 Total	0.2	0.4	0.1	0.5	0.5	0.1	0.1	0.2	0.1	0.1	-	-	-	-	-	-	-	-	-	-	2	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(2)	(2)	(1)	-	-	(6)
	FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	32	-	-	-	14	-	0	-	-	-	-	-	-	65	(50)	-	5	3
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	(11)	76	(6)	(19)	0	(40)	0	0	N/A	(0)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(236)	-	-	236	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	12	(76)	5	(37)	65	(96)	79	49	N/A	0
	Annual Additions, Long Term Resources	0	(1)	3	10	(45)	22	98	(83)	5	17	(4)	(17)	(17)	(17)	(22)	(1)	(15)	(34)	(66)	33		
	Annual Additions, Short Term Resources	(0)	2	(0)	(9)	32	11	14	14	14	-	0	-	0	(0)	0	1	1	3	4	5		
	Total Annual Additions	0	1	3	1	(13)	33	112	(69)	18	17	(4)	(17)	(17)	(17)	(22)	(1)	(14)	(31)	(62)	38		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 11_WM compared to Energy Gateway Case 9_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $612 million

		Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(51)	-	-	-	-	-	(29)	(300)	(529)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	105	200	200	15	71	26	39	24	100	47	67	37	153	505	1,085
	Total Wind	-	-	-	-	-	-	94	(93)	65	100	(4)	(17)	(17)	(11)	24	100	47	67	37	124	165	515
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(3.6)	-	-	-	8.8	18.3	-	-	-	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	(3.6)	-	-	-	15.1	12.0	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	24	24
	DSM, Class 2, Idaho	-	-	-	-	0.2	0.3	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Utah	-	2.0	2.7	2.8	4.0	2.4	2.4	3.0	4.4	16.0	-	-	-	-	-	-	-	-	-	-	40	40
	DSM, Class 2, Wyoming	0.3	-	0.0	0.1	0.1	0.1	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.3	2.0	2.7	2.9	4.3	2.8	2.4	3.0	4.4	16.3	-	-	-	-	-	-	-	-	-	-	41	41
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(3)	(3)	-	(11)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	FOT Utah 3rd Qtr HLH	-	2	-	(9)	-	-	14	14	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	21	42	7	(27)	(44)	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	44	(38)	5	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	144	23	40	(244)	N/A	(0)
West	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Total Wind	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 2, California	-	0.1	0.1	0.1	0.2	-	-	0.1	0.0	0.1	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Washington	0.2	0.4	-	0.4	0.4	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 2 Total	0.2	0.4	0.1	0.5	0.5	0.1	0.1	0.2	0.1	0.1	-	-	-	-	(1)	(2)	(2)	(2)	(1)	-	2	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(7)
	FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	32	-	-	-	14	-	0	-	-	-	-	-	-	65	(44)	-	5	3
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	(11)	76	(6)	(19)	0	(40)	0	0	N/A	(0)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(236)	-	-	236	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	12	(76)	5	(37)	64	(96)	74	54	N/A	0
	Annual Additions, Long Term Resources	0	(1)	3	10	(45)	22	98	(83)	5	17	(4)	(17)	(17)	(17)	(22)	(2)	(16)	(34)	(66)	21		
	Annual Additions, Short Term Resources	(0)	2	(0)	(9)	32	11	14	14	14	-	0	-	0	(0)	0	1	3	4	6	7		
	Total Annual Additions	0	1	3	1	(13)	33	112	(69)	18	17	(4)	(17)	(17)	(17)	(22)	(1)	(14)	(30)	(60)	28		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 12_WM compared to Energy Gateway Case 9_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $651 million

		Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(51)	-	-	-	-	-	(29)	(300)	(529)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	105	200	200	15	71	26	39	24	100	47	67	37	153	505	1,085
	Total Wind	-	-	-	-	-	-	94	(93)	65	100	(4)	(17)	(17)	(11)	24	100	47	67	37	124	165	515
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(3.6)	-	-	-	8.8	18.3	-	-	-	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	(3.6)	-	-	-	15.1	12.0	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	24	24
	DSM, Class 2, Idaho	-	-	-	-	0.2	0.3	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Utah	-	2.0	2.7	2.8	4.0	2.4	2.4	3.0	4.4	16.0	-	-	-	-	-	-	-	-	-	-	40	40
	DSM, Class 2, Wyoming	0.3	-	0.0	0.1	0.1	0.1	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.3	2.0	2.7	2.9	4.3	2.8	2.4	3.0	4.4	16.3	-	-	-	-	-	-	-	-	-	-	41	41
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(3)	(3)	-	(11)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	FOT Utah 3rd Qtr HLH	-	2	-	(9)	-	-	14	14	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	120	(29)	(50)	(44)	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	70	(38)	(21)	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	62	207	27	93	(389)	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Total Wind	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 2, California	-	0.1	0.1	0.1	0.2	-	-	0.1	0.0	0.1	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Washington	0.2	0.4	-	0.4	0.4	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 2 Total	0.2	0.4	0.1	0.5	0.5	0.1	0.1	0.2	0.1	0.1	-	-	-	-	-	-	-	-	-	-	2	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(2)	(2)	(2)	(1)	-	-	(7)
	FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	32	-	-	-	14	-	0	-	-	-	-	-	-	65	(44)	-	5	3
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	(11)	76	(6)	(25)	0	(34)	0	0	N/A	(0)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(377)	-	-	377	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	12	(76)	5	(37)	65	(96)	44	84	N/A	0
	Annual Additions, Long Term Resources	0	(1)	3	10	(45)	22	98	(83)	5	17	(4)	(17)	(17)	(17)	(22)	(2)	(16)	(34)	(66)	21		
	Annual Additions, Short Term Resources	(0)	2	(0)	(9)	32	11	14	14	14	-	0	-	0	(0)	0	1	3	4	6	7		
	Total Annual Additions	0	1	3	1	(13)	33	112	(69)	18	17	(4)	(17)	(17)	(17)	(22)	(1)	(14)	(30)	(60)	28		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 13_WM

PVRR $46,392 million

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource sum, FOT Average 10 Year	20 Year *
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	67	-	-	-	-	-	-	-	-	-	-	-	-	79	67	146
Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	100	100	100	21	88	43	48	-	-	-	-	-	-	300	500
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	2	-	0	-	-	-	-	-	-	-	-	-	-	2	2
Total Wind	-	-	-	-	-	-	67	102	100	100	21	88	43	48	-	-	-	-	-	79	368	648
CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	-	-	-	-	-	-	-	2.2	-	-	-	2.7	-	-	-	-	20	25
DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	-	3.7	-	-	-	-	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
DSM, Class 1 Total	5.5	35.5	-	19.8	-	-	10.7	-	-	-	-	2.2	-	-	-	2.7	-	-	-	-	71	76
DSM, Class 2, Idaho	1.5	1.9	2.1	3.0	3.6	4.2	4.6	4.9	4.9	5.4	5.4	5.6	7.0	7.6	8.0	7.6	8.0	7.6	7.6	7.1	36	108
DSM, Class 2, Utah	44.4	48.6	41.7	42.9	44.3	48.2	49.4	50.6	52.4	54.9	57.2	61.5	57.8	60.1	60.2	63.5	57.2	60.1	59.3	62.1	477	1,076
DSM, Class 2, Wyoming	3.8	4.8	5.2	6.2	6.3	7.2	8.0	9.1	9.1	9.7	11.3	12.0	13.9	17.2	18.6	24.0	25.6	30.1	37.5	39.9	69	299
DSM, Class 2 Total	49.7	55.3	49.0	52.1	54.2	59.6	62.0	64.6	66.3	70.0	73.9	79.1	78.7	84.9	86.8	95.1	90.8	97.8	104.4	109.1	583	1,483
Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	24	50
FOT Mead 3rd Qtr HLH	-	168	266	266	-	81	-	-	-	-	-	-	-	-	-	-	-	-	-	-	780	780
FOT Utah 3rd Qtr HLH	-	231	250	69	-	-	96	235	-	250	-	-	-	-	-	-	-	-	-	-	1,131	1,131
FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	225	263
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	69	72	104	83	145	126	86	221	26	69	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	39	196	269	492	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33	158	89	250	248	223	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Wind, Yakima, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	98	100	100	-	-	-	9	45	100	92	80	98	100	298	821
Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	-	-	-	200	-	-	98	100	100	-	-	-	9	45	100	92	80	98	100	498	1,021
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1, Oregon-DLC-Residential	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1 Total	-	-	42.8	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	-	53	53
DSM, Class 2, California	0.7	0.9	0.9	1.2	1.5	1.6	1.7	1.7	1.7	1.8	1.9	1.9	2.6	2.8	2.9	2.6	2.7	2.5	2.5	2.3	14	39
DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
DSM, Class 2, Washington	8.0	8.4	9.0	8.8	8.9	8.7	8.9	9.2	9.4	9.6	10.8	11.8	11.5	12.5	12.8	9.9	8.5	8.9	8.9	9.3	89	194
DSM, Class 2 Total	61.3	62.1	65.9	70.8	72.1	71.2	70.9	63.3	63.4	63.8	65.0	66.2	66.5	67.7	68.1	64.9	55.2	47.5	47.5	47.6	665	1,261
OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	-	16	32
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	26	400	400	400	309	400	400	400	367	400	295	400	400	400	400	400	400	266	276	270	350	350
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	50	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	40	20
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	134	189	-	186	195	N/A	70
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	210	-	162	438	N/A	81
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	16	80	140	330	244	191	379	310	311	N/A	200
Annual Additions, Long Term Resources	138	186	177	780	1,021	158	230	346	384	343	172	246	198	219	209	272	248	234	258	1,066		
Annual Additions, Short Term Resources	176	1,270	1,476	1,234	709	831	846	985	667	1,000	664	787	884	922	1,208	1,365	1,504	1,611	1,778	2,299		
Total Annual Additions	313	1,456	1,653	2,014	1,730	989	1,076	1,331	1,051	1,343	836	1,033	1,082	1,141	1,417	1,638	1,751	1,846	2,036	3,365		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 14_WM compared to Energy Gateway Case 13_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $587 million

		Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	(79)	(67)	(146)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(21)	(88)	(43)	(48)	-	-	-	-	-	84	(300)	(416)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	105	200	200	15	71	26	39	176	-	-	134	-	44	505	1,010
	Total Wind	-	-	-	-	-	-	93	5	100	100	(6)	(17)	(17)	(8)	176	-	-	134	-	49	299	609
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(1.6)	-	-	-	7.4	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	29	29
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	(1.6)	-	-	-	13.6	16.9	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	29	29
	DSM, Class 2, Idaho	0.1	-	-	-	0.1	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Utah	0.7	-	1.1	1.1	1.1	-	-	3.4	-	9.2	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 2, Wyoming	0.0	-	-	-	-	0.1	0.1	0.1	0.1	0.2	-	-	-	(0.1)	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.8	-	1.1	1.1	1.2	0.2	0.2	3.7	0.3	9.3	-	-	-	(0.1)	-	-	-	-	-	-	18	18
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(2)	-	(5)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	19
	FOT Utah 3rd Qtr HLH	-	1	-	(7)	-	-	18	15	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(19)	30	80	78	42	25	(86)	(65)	(23)	(61)	-	-
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	(39)	(13)	(12)	50	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)	(79)	(89)	30	(21)	181	N/A	-
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
	Total Wind	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
	Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 2, California	-	-	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	0
	DSM, Class 2, Washington	-	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	0.3	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	-	-	(3)
	FOT MidColumbia 3rd Qtr HLH	(1)	-	-	-	36	-	-	-	14	-	(202)	(12)	-	-	-	-	-	134	124	(270)	5	(9)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	26	0	46	0	(11)	N/A	9
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	215	-	68	(163)	N/A	16
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	222	(16)	(80)	(77)	(45)	(26)	(0)	(130)	(133)	286	N/A	0
	Annual Additions, Long Term Resources	1	(1)	1	7	(49)	17	101	(89)	0	16	(6)	(19)	(15)	(17)	132	(101)	(93)	53	(101)	(54)		
	Annual Additions, Short Term Resources	(1)	1	(0)	(7)	36	19	18	15	14	-	(0)	2	0	0	0	0	1	1	2	11		
	Total Annual Additions	0	(0)	1	0	(13)	36	118	(74)	15	16	(6)	(17)	(15)	(17)	132	(100)	(92)	54	(99)	(43)		

* *For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 15_WM compared to Energy Gateway Case 13_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $564 million

		Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	(79)	(67)	(146)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(21)	(88)	(43)	(48)	-	-	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	-	(0)	-	42	200	200	200	200	200	200	200	18	(2)	1,458
	Total Wind	-	-	-	-	-	-	93	(102)	(100)	(100)	(21)	(47)	157	152	200	200	200	200	200	(61)	(208)	972
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(2.2)	-	-	-	7.4	23.8	-	-	-	-	-	-	-	-	-	-	-	-	-	29	29
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	(2.2)	-	-	-	13.6	17.5	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	29	29
	DSM, Class 2, Idaho	0.1	-	-	-	0.1	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Utah	0.7	0.8	1.1	1.1	1.1	-	-	2.6	-	9.2	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 2, Wyoming	0.0	-	-	-	-	0.1	0.1	0.1	0.1	0.2	-	-	-	(0.1)	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.8	0.8	1.1	1.1	1.2	0.2	0.2	2.9	0.3	9.3	-	-	-	(0.1)	-	-	-	-	-	-	18	18
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	-	(8)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	19
	FOT Utah 3rd Qtr HLH	-	1	-	(7)	-	-	17	15	-	-	-	-	-	-	-	-	-	-	-	-	25	25
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(19)	91	80	102	(30)	16	(86)	(104)	(26)	(23)	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	(39)	20	(8)	2	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	7	43	36	39	(80)	(89)	(49)	(68)	160	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
	Total Wind	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
	Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 2, California	-	-	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	0
	DSM, Class 2, Washington	-	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	0.3	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	-	-	(3)
	FOT MidColumbia 3rd Qtr HLH	(1)	-	-	-	36	-	-	-	14	-	(242)	(80)	(42)	-	-	-	-	134	124	(270)	5	(16)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	58	-	-	-	52	24	0	84	0	(11)	N/A	21
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	215	-	68	(133)	N/A	19
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	203	(16)	(80)	(138)	(61)	(25)	(0)	(83)	(86)	286	N/A	0
	Annual Additions, Long Term Resources	1	(1)	1	7	(49)	17	101	(197)	(200)	(184)	(21)	(49)	159	143	155	99	107	117	99	(164)		
	Annual Additions, Short Term Resources	(1)	1	(0)	(7)	36	19	17	15	14	-	(0)	2	0	0	0	0	1	2	3	12		
	Total Annual Additions	0	(0)	1	0	(13)	36	118	(182)	(185)	(184)	(21)	(47)	159	144	156	100	108	119	102	(152)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 16_WM compared to Energy Gateway Case 13_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $596 million

		Capacity (MW)																				Resource Sum. FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	(79)	(67)	(146)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(21)	(88)	(43)	(48)	-	-	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	-	(0)	-	200	200	200	200	200	200	200	200	200	(2)	1,798
	Total Wind	-	-	-	-	-	-	93	(102)	(100)	(100)	(21)	112	157	152	200	200	200	200	200	121	(208)	1,312
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(1.6)	-	-	-	7.4	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	29	29
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	(1.6)	-	-	-	13.6	16.9	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	29	29
	DSM, Class 2, Idaho	0.1	-	-	-	0.1	0.1	0.1	0.1	0.1	-	-	-	(0.3)	-	-	-	-	-	-	-	1	0
	DSM, Class 2, Utah	0.7	-	1.1	1.1	1.1	-	-	3.4	-	9.2	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 2, Wyoming	0.0	-	-	-	-	0.1	0.1	0.1	0.1	0.2	-	-	-	(0.1)	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.8	-	1.1	1.1	1.2	0.2	0.2	3.7	0.3	9.3	-	-	(0.3)	(0.1)	-	-	-	-	-	-	18	18
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	-	(8)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	19
	FOT Utah 3rd Qtr HLH	-	1	-	(7)	-	-	18	15	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	114	80	64	86	(52)	(54)	(86)	(87)	5	(69)	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(39)	(55)	50	48	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	31	-	14	8	3	58	(89)	9	73	(109)	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
	Total Wind	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
	Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 2, California	-	-	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	0
	DSM, Class 2, Washington	-	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	0.3	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	-	-	(3)
	FOT MidColumbia 3rd Qtr HLH	(1)	-	-	-	36	-	-	-	14	-	(205)	(63)	-	-	-	-	-	134	124	(270)	5	(12)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	(3)	0	57	0	(11)	N/A	11
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	215	-	(162)	136	N/A	19
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	61	(16)	(77)	(94)	(21)	3	(0)	(56)	(86)	286	N/A	0
	Annual Additions, Long Term Resources	1	(1)	1	7	(49)	17	101	(196)	(200)	(184)	(21)	109	159	143	155	99	107	117	99	18		
	Annual Additions, Short Term Resources	(1)	1	(0)	(7)	36	19	18	15	14	-	0	2	0	0	0	1	1	2	4	12		
	Total Annual Additions	0	(0)	1	0	(13)	36	118	(181)	(185)	(184)	(21)	112	159	144	156	100	108	119	103	30		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

APPENDIX D – SYSTEM OPTIMIZER DETAILED MODELING RESULTS

This appendix reports the detailed portfolio resource selection tables for each of the scenario development cases outlined in Chapter 7. These tables are outputs from the System Optimizer model used during portfolio development.

Table D.1 – Resource Name and Description

Resource List	Detailed Description
East Resources	
CCCT F 2x1	Combine Cycle Combustion Turbine F-Machine 2x1 with Duct Firing
CCCT H	Combine Cycle Combustion Turbine H-Machine 1x1 with Duct Firing
CCS Hunter - Unit 3 (Replaces Original Unit)	IRP Carbon Capture & Sequestration Hunter 3
CHP - Biomass	Combined Heat and Power - Biomass
CHP - Reciprocating Engine	Combined Heat and Power - Reciprocating Engine
Coal Plant Turbine Upgrades	Coal Plant Turbine Upgrades
DSM, Class 1, Goshen-DLC-Irrigation	IRP DSM Class 1 [Bubble] Direct Load Control-Irrigation
DSM, Class 1, Utah-CoolKeeper	DSM - Class 1 - Utah CoolKeeper
DSM, Class 1, Utah-Curtailment	IRP DSM Class 1 [Bubble] Curtailment
DSM, Class 1, Utah-DLC-Irrigation	IRP DSM Class 1 [Bubble] Direct Load Control-Irrigation
DSM, Class 1, Utah-DLC-Residential	IRP DSM Class 1 [Bubble] Direct Load Control-Residential
DSM, Class 1, Utah-Sched Therm Energy Storage	IRP DSM Class 1 [Bubble] Scheduled-Thermal Energy Storage
DSM, Class 1, Wyoming-Curtailment	IRP DSM Class 1 [Bubble] Curtailment
DSM, Class 2, Goshen	DSM, Class 2, Goshen
DSM, Class 2, Utah	DSM, Class 2, Utah
DSM, Class 2, Wyoming	DSM, Class 2, Wyoming
DSM, Class 3, Utah, Critical Peak Pricing, Comm/Indus	DSM, Class 3, Utah, Critical Peak Pricing, Commercial - Industrial
DSM, Class 3, Utah, Demand Buyback, Comm/Indus	DSM, Class 3, Utah, Demand Buyback, Commercial - Industrial
DSM, Class 3, Utah, Real-Time Pricing, Comm/Indus	DSM, Class 3, Utah, Real-Time Pricing, Commercial - Industrial
DSM, Class 3, Utah, Time of Use, Irrigation	DSM, Class 3, Utah, Time of Use, Irrigation
DSM, Class 3, Utah, Time of Use, Residential	DSM, Class 3, Utah, Time of Use, Residential
DSM, Class 3, Wyoming, Critical Peak Pricing, Comm/Indus	DSM, Class 3, Wyoming, Critical Peak Pricing, Comm/Indus
DSM, Class 3, Wyoming, Demand Buyback, Comm/Indus	DSM, Class 3, Wyoming, Demand Buyback, Comm/Indus
DSM, Class 3, Wyoming, Real-Time Pricing, Comm/Indus	DSM, Class 3, Wyoming, Real-Time Pricing, Comm/Indus
DSM, Class 3, Wyoming, Time of Use, Irrigation	DSM, Class 3, Wyoming, Time of Use, Irrigation
FOT Mead 3rd Qtr HLH	Front Office Transaction - 3rd Quarter HLH Product
FOT Mona-3 3rd Qtr HLH	Front Office Transaction - 3rd Quarter HLH Product
FOT Mona-4 3rd Qtr HLH	Front Office Transaction - 3rd Quarter HLH Product

Resource List	Detailed Description
FOT Utah 3rd Qtr HLH	Front Office Transaction - 3rd Quarter HLH Product
Geothermal, Blundell 3	Geothermal (East-Blundell, East-Greenfield, West-Greenfield)
Geothermal, Greenfield	Geothermal (East-Blundell, East-Greenfield, West-Greenfield)
Growth Resource Goshen	Growth Resource (Goshen)
Growth Resource Utah North	Growth Resource (Utah North)
Growth Resource Wyoming	Growth Resource (Wyoming)
Micro Solar - Water Heater	Micro Solar - Solar Water Heating
Nuclear	Nuclear
SCCT Aero Utah	Simple Cycle Combustion Turbine Aero
Wind, Wyoming NE, 35% Capacity Factor	Wind, Project II
Wind, Utah, 29% Capacity Factor	Wind, Utah, 29% Capacity Factor
Wind, Wyoming, 35% Capacity Factor	[Bubble] Wind 35% Capacity Factor
West Resources	
CCS Bridger - Unit 1 (Replaces Original Unit)	IRP Carbon Capture & Sequestration Bridger 1 (Replaces Original Unit)
CCS Bridger - Unit 2 (Replaces Original Unit)	IRP Carbon Capture & Sequestration Bridger 2 (Replaces Original Unit)
CHP - Biomass	Combined Heat and Power - Biomass
CHP - Reciprocating Engine	Combined Heat and Power - Reciprocating Engine
Coal Plant Turbine Upgrades	Coal Plant Turbine Upgrades
Distribution Energy Efficiency, Walla Walla	Distribution Energy Efficiency, Walla Walla
Distribution Energy Efficiency, Yakima	Distribution Energy Efficiency, Yakima
DSM, Class 1, Oregon/California-Curtailment	IRP DSM Class 1 [Bubble] Curtailment
DSM, Class 1, Oregon/California-DLC-Irrigation	IRP DSM Class 1 [Bubble] Direct Load Control-Irrigation
DSM, Class 1, Oregon/California-DLC-Residential	IRP DSM Class 1 [Bubble] Direct Load Control-Residential
DSM, Class 1, Oregon/California-DLC-Water Heater	IRP DSM Class 1 [Bubble] Direct Load Control-Water Heater
DSM, Class 1, Walla Walla-DLC-Irrigation	IRP DSM Class 1 [Bubble] Direct Load Control-Irrigation
DSM, Class 1, Walla Walla-DLC-Residential	IRP DSM Class 1 [Bubble] Direct Load Control-Residential
DSM, Class 1, Yakima-DLC-Irrigation	IRP DSM Class 1 [Bubble] Direct Load Control-Irrigation
DSM, Class 1, Yakima-DLC-Residential	IRP DSM Class 1 [Bubble] Direct Load Control-Residential
DSM, Class 2, Oregon/California	DSM, Class 2, - Oregon/California
DSM, Class 2, Walla Walla	DSM, Class 2, - Walla Walla

Resource List	Detailed Description
DSM, Class 2, Yakima	DSM, Class 2, - Yakima
DSM, Class 3, California, Time of Use, Irrigation	DSM, Class 3, California, Time of Use, Irrigation
DSM, Class 3, Goshen, Critical Peak Pricing, Comm/Indus	DSM, Class 3, Goshen, Critical Peak Pricing, Commercial - Industrial
DSM, Class 3, Goshen, Time of Use, Irrigation	DSM, Class 3, Goshen, Time of Use, Irrigation
DSM, Class 3, Oregon, Critical Peak Pricing, Comm/Indus	DSM, Class 3, Oregon, Critical Peak Pricing, Comm/Indus
DSM, Class 3, Oregon, Time of Use, Irrigation	DSM, Class 3, Oregon, Time of Use, Irrigation
DSM, Class 3, Walla Walla, Time of Use, Irrigation	DSM, Class 3, Walla Walla, Time of Use, Irrigation
DSM, Class 3, Yakima, Time of Use, Irrigation	DSM, Class 3, Yakima, Time of Use, Irrigation
FOT COB 3rd Qtr HLH	Front Office Transaction - [Bubble] 3rd Quarter HLH Product
FOT MidColumbia 3rd Qtr HLH	Front Office Transaction - [Bubble] 3rd Quarter HLH Product
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	Front Office Transaction - [Bubble] 3rd Quarter HLH Product
FOT South Central Oregon/Northern California 3rd Qtr HLH	Front Office Transaction - [Bubble] 3rd Quarter HLH Product
Growth Resource Oregon/California	Growth Resource (Oregon/California)
Growth Resource Walla Walla	Growth Resource (Walla Walla)
Growth Resource Yakima	Growth Resource (Yakima)
Micro Solar - Photovoltaic	Micro Solar - Photovoltaic
Oregon Solar Cap Standard	Oregon Solar Capacity Standard
Oregon Solar Pilot	Oregon Solar Pilot program
Utility Biomass	Utility Biomass
Utility Scale Solar - Photovoltaic	Utility Scale Solar - Photovoltaic
Wind, Goshen, 29% Capacity Factor	Wind, Goshen, 29% Capacity Factor
Wind, Oregon, 29% Capacity Factor	Wind, Oregon, 29% Capacity Factor
Wind, Walla Walla, 29% Capacity Factor	Wind-Walla Walla, 29% Capacity Factor
Wind, Walla Walla, 29% Capacity Factor	Wind-Walla Walla, 29% Capacity Factor
Wind, Washington, 29% Capacity Factor	Wind, Washington, 29% Capacity Factor
Wind, Yakima, 29% Capacity Factor	Wind-Yakima, 29% Capacity Factor
Wind, Yakima, 29% Capacity Factor	Wind-Yakima, 29% Capacity Factor

Notes on Market and Topology Bubbles:
Please see the Transmission Topology chart in Chapter 7 for the "bubbles" used for location of modeled resource options.

Portfolio Case Build Tables

This section provides the System Optimizer portfolio build tables for each of the case scenarios as described in the portfolio development section of Chapter 7.

- Core Case Studies – Case 1 to 19
- Hard Cap Studies – Case 15 to 18
- Business Plan Case Study – Case 19
- Coal Utilization Sensitivity Case Studies – Case 20 to 24
- Load Forecasting Sensitivity Case Studies – Case 25 to 27
- Renewable Resource Sensitivity Cases – 28 to 30a
- Demand-side Management Sensitivity Cases – 31 to 33

Table D.2 – Total Portfolio Cumulative Capacity Additions by Case and Resource Type, 2011 – 2030

20-year resource totals (MW capacity)

Case	Core 1	Core 2	Core 3	Core 4	Core 5	Core 6	Core 7	Core 8	Core 9	Core 9a	Core 10	Core 11	Core 12	Core 13	Core 14	Core 15	Core 16	Core 17	Core 18	Core 19
CO_2 cost	None	None	Medium	High	Low to very high	Low to very high	Medium	High	Low to very high	Low to very high	Low to very high	Medium	High	Low to very high	Low to very high	Medium	Medium	Medium	Medium	Business Plan (BP)
Natural gas cost	Medium	Medium	Low	Low	Low	Low	Medium	Medium	Medium	Medium	Medium	High	High	High	High	Low	Medium	High	Medium	BP
Transmission scenario [1]	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Resource																				
East																				
Coal																				
Coal Plant Turbine Upgrades	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
CCS																				
CCS Hunter - Unit 3 (Replaces Original Unit)	0	0	0	280	280	280	0	280	280	280	280	0	280	280	280	280	280	280	280	0
CHP																				
CHP - Biomass	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	10
CHP - Reciprocating Engine	4	6	5	2	5	2	2	2	2	3	2	3	2	3	5	6	2	2	2	0
DSM, Class 1	95	102	97	102	97	96	100	99	99	92	99	102	99	102	101	97	92	99	86	102
DSM, Class 2	1,300	1,361	1,384	1,441	1,431	1,402	1,380	1,457	1,461	1,460	1,451	1,553	1,527	1,562	1,599	1,404	1,446	1,568	1,463	1,532
Gas																				
CCCT F 2x1	1,222	1,222	1,222	1,222	1,819	1,819	1,222	1,222	1,819	1,819	1,819	1,222	1,222	1,222	625	1,222	1,222	1,222	1,222	1,819
CCCT H	475	475	475	1,425	2,375	2,375	475	475	1,425	1,425	950	0	0	0	475	1,425	1,900	0	2,375	0
SCCT Aero Utah	0	0	0	0	0	0	0	0	0	0	118	0	0	0	118	0	0	0	0	0
Geothermal																				
Geothermal, Blundell 3	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Geothermal, Greenfield	35	0	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	0
Nuclear																				
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	1,600	1,600	0	0	1,600	0	0
Solar																				
Micro Solar - Water Heater	28	24	37	39	36	26	29	34	37	23	26	37	42	45	45	37	34	45	34	0
Wind																				
Wind, Wyoming NE, 35% Capacity Factor	0	0	0	0	0	160	160	0	0	0	160	0	160	0	160	0	0	160	0	160
Wind, WY 35% CF	143	0	139	136	227	145	55	50	500	418	600	0	1,800	1,600	2,000	139	50	2,240	308	1,100
FOT (20yr Average)																				
FOT Mead 3rd Qtr HLH	40	37	36	36	36	40	36	36	36	40	37	40	40	40	45	38	38	40	36	40
FOT Mona-3 3rd Qtr HLH	255	255	255	255	210	210	255	255	240	240	240	255	255	255	255	255	246	255	195	255
FOT Utah 3rd Qtr HLH	57	54	54	52	54	60	44	52	53	56	51	50	50	50	71	53	53	50	52	60
FOT Mona-4 3rd Qtr HLH	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Growth Resource (10yr Average)																				
Growth Resource Goshen	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Growth Resource Utah North	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	46	10	100	0	100
Growth Resource Wyoming	100	100	100	100	100	100	100	100	100	100	100	100	100	100	80	100	97	100	21	100
West																				
Coal																				
Coal Plant Turbine Upgrades	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
CCS																				
CCS Bridger - Unit 1 (Replaces Original Unit)	0	0	0	227	227	227	0	227	227	227	227	0	227	227	227	227	227	227	227	0
CCS Bridger - Unit 2 (Replaces Original Unit)	0	0	0	216	216	216	0	216	216	216	216	0	216	216	216	216	216	216	216	0
CHP																				
CHP - Biomass	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	42
CHP - Reciprocating Engine	2	3	1	1	1	1	1	1	1	1	1	1	1	1	2	2	1	0	1	0
DSM, Class 1	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	56	60	56	60
DSM, Class 2	1,226	1,239	1,239	1,257	1,253	1,247	1,243	1,260	1,260	1,260	1,258	1,266	1,269	1,270	1,269	1,251	1,259	1,274	1,261	1,272
Geothermal																				
Geothermal, Greenfield	70	0	105	105	70	105	70	140	245	280	490	420	420	420	408	105	140	420	105	0
Other																				
Utility Biomass	50	50	0	0	0	0	0	0	0	50	50	50	50	50	50	0	0	50	0	0
Solar																				
Oregon Solar Cap Standard	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Oregon Solar Pilot	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Micro Solar - Water Heater	15	16	18	21	20	15	19	20	21	12	18	24	29	30	29	16	19	31	20	0
Wind																				
Wind, Yakima, 29% CF	0	0	0	0	0	0	0	0	0	0	0	100	100	100	200	0	0	100	100	0
Wind, Walla Walla, 29% CF	0	0	0	0	0	0	0	0	0	0	0	0	100	0	0	0	0	100	0	0
FOT (20yr Average)																				
FOT COB 3rd Qtr HLH	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
FOT MidColumbia 3rd Qtr HLH	372	370	337	231	243	248	354	279	275	270	275	355	333	315	313	315	280	332	197	368
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	22	22	23	23	23	23	24	23	23	22	23	22	22	22	22	23	23	22	22	22
FOT South Central Oregon/Northern California 3rd Qtr HLH	39	40	18	18	18	18	18	18	18	18	20	17	13	16	18	33	37	35	30	20
Growth Resource (10yr Average)																				
Growth Resource Walla Walla	100	78	100	100	0	0	48	100	23	23	47	20	73	18	38	0	0	0	0	7
Growth Resource Oregon / California	4	68	100	100	50	38	41	100	45	14	76	29	56	0	0	0	0	20	0	0
Growth Resource Yakima	119	100	100	200	120	129	200	200	200	200	200	200	200	200	200	100	100	100	100	166

1. Transmission Scenario is referencing the scenario as described in the Portfolio Case Development paper.

Table D.3 – Core Case System Optimizer PVRR Results

PVRR by Case ($ millions)

Core Case	CO_2 Policy Type	CO_2 cost	Natural gas cost	Renewable PTC	RPS	PVRR
Case-01	None	None	Medium	Extension to 2015	Current RPS	$30,936
Case-02	None	None	Medium	Extension to 2015	None	$30,884
Case-03	CO_2 Tax	Medium	Low	Extension to 2015	Current RPS	$39,581
Case-04	CO_2 Tax	High	Low	Extension to 2015	Current RPS	$44,346
Case-05	CO_2 Tax	Low to very high	Low	Extension to 2015	Current RPS	$40,058
Case-06	CO_2 Tax	Low to very high	Low	Extension to 2020	Current RPS	$39,814
Case-07	CO_2 Tax	Medium	Medium	Extension to 2015	Current RPS	$40,772
Case-08	CO_2 Tax	High	Medium	Extension to 2015	Current RPS	$46,015
Case-09	CO_2 Tax	Low to very high	Medium	Extension to 2015	Current RPS	$41,599
Case-09a	CO_2 Tax	Low to very high	Medium	Extension to 2015	Current RPS	$41,616
Case-10	CO_2 Tax	Low to very high	Medium	Extension to 2020	Current RPS	$41,277
Case-11	CO_2 Tax	Medium	High	Extension to 2015	Current RPS	$42,092
Case-12	CO_2 Tax	High	High	Extension to 2015	Current RPS	$46,954
Case-13	CO_2 Tax	Low to very high	High	Extension to 2015	Current RPS	$42,705
Case-14	CO_2 Tax	Low to very high	High	Extension to 2020	Current RPS	$41,982
Case-15	Hard Cap - Base	Medium	Low	Extension to 2015	Current RPS	$31,049
Case-16	Hard Cap - Base	Medium	Medium	Extension to 2015	Current RPS	$32,845
Case-17	Hard Cap - Base	Medium	High	Extension to 2015	Current RPS	$34,968
Case-18	Hard Cap - OR	Medium	Medium	Extension to 2015	Current RPS	$34,926
Case-19	$19/ton	Medium	Medium	Extension to 2015	Current RPS	$42,556

Table D.4 – Core Case Portfolios (Case 1 to 14)

Case 1

	Resource	Capacity (MW)																				Resource Totals **	
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	23	12	23	6	35	-	143
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	23	12	23	6	35	-	143
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
	DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	17	50	-	23	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	90	95
	DSM, Class 2, Goshen	1	1	1	1	1	1	2	2	1	2	1	2	2	3	3	3	3	3	3	2	13	36
	DSM, Class 2, Utah	46	55	59	44	64	41	44	44	45	48	51	55	52	55	55	60	56	59	59	62	489	1,053
	DSM, Class 2, Wyoming	3	4	4	5	5	5	6	6	6	7	8	9	10	12	13	17	18	21	26	28	51	211
	DSM, Class 2 Total	49	59	64	50	70	47	51	52	53	56	61	65	64	69	71	79	76	82	88	92	552	1,300
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	2.37	2.37	-	-	-	-	-	23	28
	FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
	FOT Utah 3rd Qtr HLH	200	200	200	0	200	-	4	154	-	191	-	-	-	-	-	-	-	-	-	-	115	57
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	8	22	116	103	107	131	123	123	127	140	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	87	182	347	376	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	64	8	130	156	178	202	263	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	4	4	4	5	5	5	5	4	4	3	3	3	44	85
	DSM, Class 2, Oregon/California	51	51	54	59	60	59	59	51	51	51	51	51	52	52	52	52	44	36	36	36	547	1,009
	DSM, Class 2, Yakima	10	11	6	6	6	6	6	6	6	6	7	7	7	8	8	6	5	6	6	6	68	133
	DSM, Class 2 Total	65	66	65	70	71	69	69	61	61	61	62	63	63	64	64	62	53	45	45	45	659	1,226
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	0.97	1.29	0.97	0.97	0.97	-	-	0.97	0.97	0.97	-	-	-	-	-	12	15
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	400	337	400	309	400	400	400	400	400	400	400	400	400	354	372
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	2	50	50	-	50	-	33	50	50	50	50	50	50	50	50	35	39
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	183	140	110	174	204	188	N/A	100
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	-	-	N/A	4
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	138	200	284	182	177	210	N/A	119
	Annual Additions, Long Term Resources	153	210	199	792	310	740	129	130	597	171	131	133	133	142	223	170	146	160	144	177		
	Annual Additions, Short Term Resources	350	1,213	1,419	1,164	1,099	702	754	904	637	941	617	756	866	917	1,185	1,359	1,510	1,626	1,807	1,928		
	Total Annual Additions	503	1,422	1,618	1,956	1,409	1,443	883	1,034	1,234	1,112	748	889	999	1,059	1,408	1,529	1,656	1,786	1,951	2,105		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 2

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	0.8	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	2	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	17	48	-	20	-	-	10	-	-	2	-	-	-	-	-	-	-	5	-	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	46	57	59	43	44	47	52	55	56	74	51	55	53	55	55	60	56	59	63	66	535	1,109
	DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	8	9	10	12	13	17	18	21	26	28	55	214
	DSM, Class 2 Total	49	62	64	48	51	55	60	64	65	84	61	66	65	70	71	79	76	82	92	95	603	1,361
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	-	-	-	-	-	24	24
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73	37
	FOT Utah 3rd Qtr HLH	200	200	200	16	-	-	62	200	-	200	-	-	-	-	-	-	-	-	-	-	108	54
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	70	125	149	148	109	111	125	138	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	109	150	377	344	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	50	116	193	150	273	219	-	N/A	100
West	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	0.3	0.3	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	4	5	5	5	5	4	4	3	3	4	45	87
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	51	51	52	52	52	52	44	36	36	36	550	1,011
	DSM, Class 2, Yakima	10	11	6	6	6	6	7	7	7	7	7	7	7	8	8	6	5	6	6	7	73	141
	DSM, Class 2 Total	65	66	65	70	71	70	71	63	63	64	63	63	63	64	64	62	53	46	46	46	669	1,239
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	-	-	-	-	-	-	-	-	-	-	16	16
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	315	400	400	400	371	400	320	400	400	400	400	400	400	400	400	400	349	370
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	43	50	50	50	50	50	50	50	50	35	40
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90	-	146	107	203	236	N/A	78
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	685	N/A	68
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	53	-	99	199	245	48	203	153	N/A	100
	Annual Additions, Long Term Resources	153	210	200	776	817	154	162	146	614	205	131	135	134	139	140	147	134	138	142	147		
	Annual Additions, Short Term Resources	350	1,213	1,419	1,180	665	789	812	950	671	950	626	763	872	925	1,225	1,398	1,550	1,666	1,844	1,961		
	Total Annual Additions	503	1,423	1,619	1,956	1,482	943	974	1,096	1,285	1,155	757	897	1,006	1,064	1,365	1,545	1,684	1,804	1,986	2,108		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 3

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	Resource Totals ** 20-year
	Capacity (MW)																					
East																						
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	13	49	21	8	9	4	34	-	139
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	13	49	21	8	9	4	34	-	139
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	17	50	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	-	-	97	97
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
DSM, Class 2, Utah	46	55	59	43	44	47	50	53	55	64	52	60	57	59	60	65	60	63	64	69	517	1,125
DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	8	9	10	12	13	17	20	23	29	28	55	221
DSM, Class 2 Total	49	59	64	48	51	55	58	62	64	74	62	70	69	74	75	84	82	89	95	99	586	1,384
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	-	24	37
FOT Mead 3rd Qtr HLH	-	168	264	264	-	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	57	198	-	200	-	-	-	-	-	-	-	-	-	-	107	54
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	32	68	90	179	109	196	161	139	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	168	352	353	107	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	334	-	329	336	-	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	5	5	4	5	5	5	5	4	4	3	3	4	45	87
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	51	51	52	52	52	52	44	36	36	36	550	1,014
DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	7	7	7	7	7	8	8	6	5	6	6	7	70	138
DSM, Class 2 Total	63	66	65	70	71	70	70	63	63	64	63	63	64	65	65	63	53	46	46	46	665	1,239
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	-	-	0.97	0.97	-	-	-	-	-	-	16	18
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	299	400	400	400	370	400	-	69	400	400	400	400	400	400	400	400	347	337
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	52	131	209	-	205	-	203	200	N/A	100
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	279	-	-	721	N/A	100
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	318	369	78	11	142	82	-	-	-	-	N/A	100
Growth Resource Oregon/California *	151	210	200	776	837	153	150	144	613	202	135	141	142	161	267	173	149	149	150	184		
Annual Additions, Short Term Resources	350	1,213	1,420	1,181	649	774	807	948	670	950	624	758	862	910	1,144	1,314	1,461	1,577	1,752	1,867		
Total Annual Additions	501	1,422	1,620	1,957	1,486	927	958	1,092	1,283	1,152	759	899	1,004	1,071	1,411	1,487	1,610	1,726	1,902	2,051		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 4

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	Resource Totals ** 20-year
	Capacity (MW)																					
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	475	475	475	1,425
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	12	49	20	8	9	4	34	-	136
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	12	49	20	8	9	4	34	-	136
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	11	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	16	51	-	20	-	-	10	-	-	-	-	-	-	-	-	5	-	-	-	-	97	102
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	41
DSM, Class 2, Utah	47	54	59	43	44	51	52	54	57	60	56	63	61	63	64	68	63	67	68	74	520	1,166
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	14	15	19	20	24	29	28	56	233
DSM, Class 2 Total	50	58	64	49	51	58	60	63	66	69	67	74	74	80	82	90	86	94	100	104	590	1,441
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	24	39
FOT Mead 3rd Qtr HLH	-	168	264	264	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	44	185	-	200	-	-	-	-	-	-	-	-	-	-	105	52
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	32	137	97	185	97	167	123	136	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	242	287	366	-	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	144	177	204	173	302	-	-	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	91
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,018
DSM, Class 2, Yakima	8	11	6	6	6	6	7	7	7	7	8	8	8	9	9	7	6	7	6	7	71	147
DSM, Class 2 Total	63	66	65	70	72	71	71	63	63	64	64	65	66	67	67	64	55	47	47	47	668	1,257
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.48	0.97	0.97	-	-	-	-	-	-	16	21
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	357	400	-	-	107	312	400	350	-	-	-	-	345	231
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	3	150	-	43	-	204	200	202	199	N/A	100
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	214	-	221	565	N/A	100
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	313	426	261	-	-	-	151	204	443	202	N/A	200
Annual Additions, Long Term Resources	152	210	200	777	837	156	161	144	614	188	143	149	148	168	276	187	154	155	631	1,388		
Annual Additions, Short Term Resources	350	1,213	1,420	1,181	648	771	794	935	657	950	619	748	850	893	1,121	1,282	1,426	1,538	1,290	1,402		
Total Annual Additions	502	1,422	1,620	1,957	1,485	927	955	1,079	1,271	1,138	762	897	998	1,060	1,397	1,468	1,580	1,693	1,920	2,790		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 5

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	1,222	1,819
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	475	475	475	475	475	2,375
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	13	139	21	8	9	4	34	-	227
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	13	139	21	8	9	4	34	-	227
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	17	50	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	-	-	97	97
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	14	41
	DSM, Class 2, Utah	46	54	59	43	44	47	52	53	56	61	56	60	57	63	64	68	64	67	68	74	517	1,158
	DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	9	9	11	13	15	19	20	24	29	28	55	232
	DSM, Class 2 Total	49	59	64	48	51	55	60	62	66	71	67	71	70	80	82	90	87	94	100	105	586	1,431
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.64	2.64	2.64	2.37	-	-	-	-	-	24	36
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	56	196	-	200	-	-	-	-	-	-	-	-	-	-	107	54
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	-	-	-	210	210
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	32	45	110	161	144	171	173	139	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	494	160	-	-	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	224	218	412	132	-	N/A	100
West	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	45	90
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	550	1,017
	DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	7	7	8	8	8	9	9	7	6	7	6	7	70	145
	DSM, Class 2 Total	63	66	65	70	71	70	70	63	63	64	64	65	65	66	67	64	55	47	47	47	666	1,253
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	0.97	-	-	-	-	-	-	16	20
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	299	400	400	400	368	400	314	400	400	284	-	-	-	-	-	-	347	243
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HL	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	74	-	-	-	35	18
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	31	122	269	-	-	-	-	-	-	N/A	50
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	388	145	151	157	186	170	N/A	120
	Annual Additions, Long Term Resources	152	209	200	776	837	153	152	144	614	199	142	145	144	167	330	181	630	630	631	1,985		
	Annual Additions, Short Term Resources	350	1,213	1,420	1,181	649	774	806	946	668	950	620	751	855	898	1,158	1,324	1,047	739	491	308		
	Total Annual Additions	502	1,422	1,620	1,957	1,486	927	958	1,091	1,282	1,149	762	896	999	1,066	1,488	1,505	1,677	1,369	1,121	2,294		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.
** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 6

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	1,222	1,819
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	475	475	475	475	475	2,375
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	40	-	-	-	-	29	21	8	9	4	34	40	145
Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160	160
Total Wind	-	-	-	-	-	-	-	-	-	200	-	-	-	-	29	21	8	9	4	34	200	305
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	8	8
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	10	21	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	36	36
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	16	51	-	-	-	-	-	29	-	-	-	-	-	-	-	-	-	-	-	-	96	96
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	14	41
DSM, Class 2, Utah	46	53	59	38	44	47	49	50	52	54	56	60	57	63	64	68	64	67	68	74	492	1,134
DSM, Class 2, Wyoming	3	4	4	4	5	5	6	7	6	7	9	9	11	13	15	19	20	24	29	28	51	228
DSM, Class 2 Total	49	57	64	43	50	54	56	59	60	63	67	71	70	80	82	90	87	94	100	105	557	1,402
Micro Solar - Water Heater	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	2.37	2.37	-	-	-	-	-	21	26
FOT Mead 3rd Qtr HLH	-	168	264	264	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
FOT Utah 3rd Qtr HLH	200	200	200	41	-	12	158	200	-	198	-	-	-	-	-	-	-	-	-	-	121	60
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	-	-	-	210	210
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	33	46	107	160	150	168	172	139	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	319	464	218	-	-	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38	189	227	414	132	-	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	-	-	-	35	-	35	-	-	-	-	35	-	-	-	-	-	70	105
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	44	89
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	51	52	52	52	52	52	53	52	44	37	37	36	549	1,016
DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	6	6	8	8	8	9	9	7	6	7	6	7	67	142
DSM, Class 2 Total	63	66	65	69	71	70	70	62	61	62	64	65	65	66	67	64	55	47	47	47	660	1,247
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	-	-	-	-	-	-	0.97	-	-	-	-	-	14	15
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	385	400	400	400	339	400	313	400	400	326	-	-	-	-	-	-	352	248
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	32	124	229	-	-	-	-	-	-	N/A	38
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	396	214	154	160	189	173	N/A	129
Annual Additions, Long Term Resources	155	209	199	751	766	152	136	249	646	365	138	141	141	153	222	181	630	630	631	1,985		
Annual Additions, Short Term Resources	350	1,213	1,420	1,205	735	861	908	950	639	948	619	752	857	901	1,160	1,326	1,049	741	492	312		
Total Annual Additions	505	1,421	1,620	1,955	1,501	1,012	1,043	1,199	1,285	1,313	757	893	997	1,054	1,382	1,507	1,679	1,371	1,123	2,297		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 7

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
		Capacity (MW)																				Resource Totals **	
East																							
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	9	4	34	-	55
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	8	9	4	34	-	215
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	6	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	6	62	-	20	-	-	8	-	-	-	-	-	-	-	-	-	-	-	5	-	95	100
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	46	55	59	43	44	47	49	50	52	54	56	60	57	60	60	65	60	63	64	69	499	1,113
	DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	55	229
	DSM, Class 2 Total	49	59	64	48	51	55	57	59	61	64	67	71	70	76	77	86	82	89	95	99	568	1,380
	Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	2	2	0	-	-	-	-	-	-	-	24	29
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	-	200	200	22	-	-	57	200	-	193	-	-	-	-	-	-	-	-	-	-	87	44
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	34	81	184	237	-	238	169	57	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	306	335	358	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	53	-	261	290	395	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	45	90
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	550	1,015
	DSM, Class 2, Yakima	6	6	6	6	6	6	6	7	7	7	8	8	8	9	9	7	6	7	6	7	63	138
	DSM, Class 2 Total	61	62	65	70	71	70	70	63	63	63	64	65	65	66	66	64	54	47	47	47	658	1,243
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.3	1.3	1.0	1.0	1.0	1.0	-	-	-	-	-	-	15	19
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	25	400	400	400	303	400	400	400	376	400	96	292	388	400	400	400	400	400	400	400	350	354
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	12	-	-	56	52	167	-	32	165	N/A	48
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	412	-	-	-	N/A	41
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	217	140	126	114	250	316	225	115	264	231	N/A	200
	Annual Additions, Long Term Resources	138	217	200	776	837	153	155	140	607	216	142	145	142	148	308	155	150	150	155	185		
	Annual Additions, Short Term Resources	175	1,239	1,425	1,186	653	778	807	950	676	943	612	744	848	895	1,190	1,358	1,505	1,621	1,791	1,906		
	Total Annual Additions	313	1,456	1,625	1,962	1,490	931	962	1,090	1,283	1,159	754	889	990	1,043	1,498	1,513	1,655	1,770	1,946	2,090		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 8

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
		Capacity (MW)																				Resource Totals **	
East	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	50
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	50
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	10	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	1	-	2	-	-	-	-	11	14
	DSM, Class 1 Total	16	48	-	20	-	-	10	-	-	-	-	-	-	2	-	3	-	-	-	-	94	99
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	42
	DSM, Class 2, Utah	47	57	59	43	46	50	52	54	55	60	59	63	61	63	65	69	64	67	68	77	524	1,181
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	10	11	14	15	19	20	24	29	28	56	234
	DSM, Class 2 Total	51	62	64	49	53	57	61	63	65	69	70	75	74	80	83	91	87	94	100	108	594	1,457
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	-	-	-	24	34
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	43	184	-	200	-	-	-	-	-	-	-	-	-	-	104	52
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	19	32	44	58	195	144	195	171	136	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117	205	308	370	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	222	185	365	228	-	N/A	100
West	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	92
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,019
	DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
	DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	47	670	1,260
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	0.97	-	-	-	-	-	-	16	20
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	297	400	400	400	317	400	-	99	400	371	400	400	400	103	-	-	341	279
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	0	47	142	206	-	204	-	201	199	N/A	100
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,000	N/A	100
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	312	328	68	-	121	131	41	334	466	200	N/A	200
	Annual Additions, Long Term Resources	153	210	200	777	839	156	161	144	658	143	146	150	149	193	225	163	150	155	156	916		
	Annual Additions, Short Term Resources	350	1,213	1,420	1,181	647	770	793	934	617	950	617	746	847	857	1,085	1,247	1,390	1,503	1,674	2,205		
	Total Annual Additions	503	1,423	1,620	1,957	1,486	926	955	1,078	1,275	1,093	764	896	996	1,049	1,311	1,411	1,541	1,658	1,830	3,121		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 9

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
	Capacity (MW)																				Resource Totals **	
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	1,222	1,819
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	475	475	475	1,425
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	13	49	21	8	9	200	200	-	500
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	13	49	21	8	9	200	200	-	500
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	10	21	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	11	14
DSM, Class 1 Total	16	48	-	20	-	-	5	-	-	5	-	-	-	-	-	5	-	-	-	-	94	99
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	42
DSM, Class 2, Utah	47	57	59	43	44	50	52	54	57	60	56	63	61	63	65	69	64	70	70	77	523	1,183
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	14	15	19	20	24	30	29	56	236
DSM, Class 2 Total	51	62	64	49	51	58	60	63	66	69	67	75	74	80	83	91	88	97	103	109	594	1,461
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	24	37
FOT Mead 3rd Qtr HLH	-	168	264	264	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	53	194	-	200	-	-	-	-	-	-	-	-	-	-	106	53
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	-	210	240
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	48	48	69	59	82	97	169	196	227	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	33	114	172	82	164	344	92	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	10	9	20	83	17	287	260	314	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	70	70	70	245
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	92
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	37	551	1,019
DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	48	669	1,260
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	1.29	0.97	0.97	0.97	-	-	-	-	-	16	21
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	366	400	313	400	400	400	400	119	-	-	-	-	346	275
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	205	-	-	-	-	N/A	23
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	452	-	-	-	N/A	45
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	57	-	143	408	392	433	371	196	N/A	200
Annual Additions, Long Term Resources	152	210	200	777	837	156	152	144	614	197	143	150	149	168	278	187	156	158	901	2,227		
Annual Additions, Short Term Resources	350	1,213	1,420	1,181	648	771	803	944	666	950	619	748	849	892	1,119	1,279	1,421	1,532	1,218	737		
Total Annual Additions	502	1,423	1,620	1,957	1,485	927	955	1,088	1,280	1,147	762	898	998	1,060	1,397	1,466	1,577	1,690	2,119	2,964		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 9a

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	597	1,222	1,819
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	475	475	475	1,425
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	9	200	200	-	418
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	9	200	200	-	418
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
	DSM, Class 1, Utah-DLC-Residential	10	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	11	14
	DSM, Class 1 Total	16	48	-	23	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	87	92
	DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	42
	DSM, Class 2, Utah	47	57	59	47	62	47	49	50	52	54	56	63	61	63	65	69	64	70	70	77	525	1,184
	DSM, Class 2, Wyoming	3	4	4	5	5	5	6	7	7	8	9	9	11	14	15	19	20	24	30	29	54	234
	DSM, Class 2 Total	51	62	64	53	68	54	56	59	61	64	67	75	74	80	83	91	88	97	103	109	593	1,460
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	-	-	-	-	-	2.64	2.64	2.64	2.64	2.37	-	-	-	-	-	11	23
	FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
	FOT Utah 3rd Qtr HLH	200	200	200	0	200	-	-	146	-	179	-	-	-	-	-	-	-	-	-	-	113	56
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	-	210	240
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	7	20	77	75	59	82	99	151	196	233	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	24	85	143	89	238	332	89	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	36	173	264	252	267	N/A	100
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	35	-	-	70	70	70	280
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	91
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	37	550	1,019
	DSM, Class 2, Yakima	10	11	7	7	7	6	6	7	7	7	8	9	9	9	9	7	6	7	6	7	73	150
	DSM, Class 2 Total	65	66	66	71	72	70	70	62	63	63	65	66	66	67	67	64	55	47	47	48	669	1,260
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	-	-	-	-	-	0.97	0.97	0.97	0.97	0.97	-	-	-	-	-	7	12
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	400	328	400	281	396	400	400	400	-	-	-	-	-	353	270
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	245	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	50	2	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	206	-	-	-	-	N/A	23
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	136	-	-	-	N/A	14
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	16	-	153	502	413	423	318	175	N/A	200
	Annual Additions, Long Term Resources	154	210	200	793	311	744	132	135	604	177	143	150	149	156	229	201	156	158	901	2,227		
	Annual Additions, Short Term Resources	350	1,213	1,419	1,164	1,099	702	750	896	628	929	588	716	817	860	1,087	1,216	1,359	1,469	1,156	675		
	Total Annual Additions	504	1,423	1,619	1,957	1,410	1,446	882	1,031	1,232	1,106	730	866	966	1,016	1,316	1,417	1,515	1,627	2,057	2,901		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 10

	Resource	Capacity (MW)																				Resource Totals **	
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	1,222	1,819
	CCCT H	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	475	475	-	950
	SCCT Aero Utah	-	-	-	-	-	-	-	-	-	118	-	-	-	-	-	-	-	-	-	-	118	118
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200	200	200	600
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	-	160	200	-	-	-	-	-	-	-	-	200	200	360	760
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	2	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	9	22	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	3	-	-	-	-	11	14
	DSM, Class 1 Total	15	49	-	-	-	-	-	-	-	30	-	-	-	-	-	5	-	-	-	-	94	99
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	42
	DSM, Class 2, Utah	47	56	59	43	44	47	49	52	55	59	56	63	61	63	65	69	64	70	70	77	512	1,172
	DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	9	11	14	15	19	20	24	31	29	56	237
	DSM, Class 2 Total	51	60	64	49	51	55	57	61	65	69	67	75	74	80	83	91	88	97	104	109	583	1,451
	Micro Solar - Water Heater	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	-	-	-	-	-	26	26
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74	37
	FOT Utah 3rd Qtr HLH	200	200	200	36	-	-	-	76	117	200	-	-	-	-	-	-	-	-	-	-	103	51
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	-	210	240
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	44	32	45	59	98	97	193	214	211	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	7	5	134	69	269	-	329	187	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	-	342	400	241	N/A	100
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	-	70	70	70	70	70	-	-	-	-	-	-	-	-	70	70	350	490
	Utility Biomass	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	92
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	37	550	1,019
	DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	7	7	8	9	9	9	9	7	6	7	6	7	71	148
	DSM, Class 2 Total	63	66	65	70	71	71	70	63	63	64	64	66	66	67	67	64	55	47	47	48	668	1,258
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	-	-	-	-	-	-	-	-	-	-	18	18
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	380	400	400	400	400	400	315	400	400	400	400	-	-	-	-	-	358	275
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	46	50	50	50	-	-	-	-	-	-	-	-	-	-	40	20
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	105	-	159	205	-	-	-	-	N/A	47
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	757	-	-	-	N/A	76
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	11	19	200	459	336	436	186	353	N/A	200
	Annual Additions, Long Term Resources	156	210	200	757	767	223	242	212	413	620	139	146	146	152	155	166	148	149	902	2,227		
	Annual Additions, Short Term Resources	350	1,213	1,420	1,200	730	792	746	826	867	950	621	751	853	898	1,188	1,348	1,490	1,601	1,287	805		
	Total Annual Additions	506	1,422	1,620	1,957	1,497	1,016	988	1,038	1,280	1,570	760	897	999	1,050	1,343	1,513	1,638	1,749	2,189	3,032		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 11

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																						
CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	0.0	0.8	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	2	1	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	10	22	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	16	48	-	22	1	-	-	-	-	10	-	-	-	-	-	-	5	-	-	-	97	102
DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	44
DSM, Class 2, Utah	47	57	59	47	58	52	54	71	72	74	61	65	62	67	68	72	66	70	70	77	591	1,269
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	8	8	8	9	10	11	14	15	19	20	24	31	29	57	240
DSM, Class 2 Total	51	62	64	53	65	60	62	80	81	85	72	77	76	84	86	94	90	97	104	109	664	1,553
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	-	24	37
FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
FOT Utah 3rd Qtr HLH	200	200	200	-	200	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	100	50
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	50	72	77	132	139	96	149	145	135	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	170	-	246	259	325	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	174	-	178	254	326	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	35	70	70	70	70	-	-	-	-	-	-	-	35	-	-	385	420
Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	6	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	93
DSM, Class 2, Oregon/California	51	51	54	59	61	60	59	52	52	52	52	52	52	53	53	52	44	37	37	37	552	1,021
DSM, Class 2, Yakima	10	11	7	7	7	7	7	7	7	7	8	9	9	9	9	7	6	7	6	7	75	152
DSM, Class 2 Total	65	66	66	71	72	71	71	64	64	64	65	66	66	67	67	64	55	47	47	48	674	1,266
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.29	0.97	-	-	-	-	-	16	24
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	311	342	400	400	400	81	393	400	400	400	400	400	400	400	365	345	355
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
FOT South Central Oregon/Northern California 3rd Qtr HL	-	50	50	50	50	50	-	6	34	50	-	-	-	-	-	-	-	-	-	-	34	17
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23	174	-	-	-	N/A	20
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	292	-	-	-	N/A	29
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	229	-	70	104	268	124	205	273	356	371	N/A	200
Growth Resource Oregon/California *	155	310	201	790	310	791	213	232	269	275	149	153	152	160	162	164	155	184	157	162		
Annual Additions, Short Term Resources	350	1,213	1,415	1,164	1,099	661	642	706	734	950	616	743	842	881	1,168	1,330	1,467	1,546	1,714	1,822		
Total Annual Additions	505	1,523	1,616	1,954	1,409	1,452	854	938	1,003	1,225	765	895	994	1,042	1,330	1,494	1,621	1,730	1,871	1,983		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 12

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	35	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	-	1,800
Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	160	160
Total Wind	-	-	-	-	-	-	-	-	160	-	-	200	200	200	200	200	200	200	200	200	160	1,960
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	2	1	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	10	22	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	1	-	-	2	-	-	-	-	11	14
DSM, Class 1 Total	16	48	-	22	1	-	-	-	-	7	-	-	2	-	-	3	-	-	-	-	94	99
DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	45
DSM, Class 2, Utah	47	57	59	47	54	52	54	55	57	73	62	67	64	68	68	72	66	70	70	77	554	1,240
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	8	8	9	10	11	14	15	20	21	25	31	29	57	242
DSM, Class 2 Total	51	62	64	53	61	60	62	65	67	83	74	79	78	85	87	95	91	98	104	109	627	1,527
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	24	42
FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
FOT Utah 3rd Qtr HLH	200	200	200	-	200	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	100	50
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	59	79	88	63	120	125	95	115	121	134	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	3	-	184	304	459	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	91	21	59	-	-	115	-	190	202	321	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	70	70	70	70	70	-	-	-	-	-	-	-	-	-	-	420	420
Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	100	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	6	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	93
DSM, Class 2, Oregon/California	51	51	54	59	61	60	59	52	52	52	52	52	52	53	53	53	45	37	37	37	552	1,023
DSM, Class 2, Yakima	10	11	7	7	7	7	7	7	7	7	8	9	9	9	10	7	6	7	7	7	75	154
DSM, Class 2 Total	65	66	66	71	72	71	71	63	64	64	65	66	66	68	68	65	55	48	47	48	674	1,269
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.29	0.97	0.97	-	-	16	29
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	313	311	388	397	400	134	339	387	400	400	400	400	400	400	-	341	333
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
FOT South Central Oregon/Northern California 3rd Qtr HL	-	50	50	50	50	17	-	-	-	50	-	-	-	-	-	-	-	-	-	-	27	13
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	111	189	59	187	184	N/A	73
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	286	-	-	271	N/A	56
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	30	-	-	110	288	262	185	316	218	592	N/A	200
Annual Additions, Long Term Resources	155	310	201	790	405	825	213	216	450	234	151	355	356	362	365	372	355	351	357	1,085		
Annual Additions, Short Term Resources	350	1,213	1,415	1,164	1,099	630	611	688	697	950	614	739	834	873	1,158	1,316	1,455	1,564	1,732	2,261		
Total Annual Additions	505	1,523	1,616	1,954	1,504	1,456	823	904	1,147	1,184	765	1,094	1,191	1,235	1,523	1,688	1,809	1,915	2,089	3,346		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 13

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	1,600
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	-	1,600
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	-	1,600
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	0.8	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	2	1	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	10	22	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	1	-	2	-	-	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	16	48	-	22	1	-	-	-	-	10	-	-	-	2	-	3	-	-	-	-	97	102
DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	45
DSM, Class 2, Utah	47	57	59	47	58	52	54	71	72	74	61	67	64	68	68	72	66	70	70	73	591	1,271
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	8	8	8	9	10	11	14	15	20	21	25	31	33	57	246
DSM, Class 2 Total	51	62	64	53	65	60	62	80	81	85	72	79	78	85	87	95	91	98	104	109	664	1,562
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	24	45
FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
FOT Utah 3rd Qtr HLH	200	200	200	-	200	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	100	50
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	41	67	78	120	125	118	160	152	134	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81	162	19	342	396	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	71	97	70	149	211	193	210	-	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	35	70	70	70	70	-	-	-	-	-	35	-	-	-	-	385	420
Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	6	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	93
DSM, Class 2, Oregon/California	51	51	54	59	61	60	59	52	52	52	52	52	52	53	53	53	45	37	37	37	552	1,022
DSM, Class 2, Yakima	10	11	7	7	7	7	7	7	7	8	8	9	9	9	10	7	6	7	7	7	75	154
DSM, Class 2 Total	65	66	66	71	72	71	71	64	64	64	65	66	66	67	68	65	55	48	47	48	674	1,270
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.29	1.29	0.97	0.97	-	16	30
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	341	342	400	400	400	310	400	400	400	400	400	400	102	-	-	348	315
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	20	-	6	34	50	-	-	-	-	-	-	-	-	-	-	31	16
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	137	-	40	-	N/A	18
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	190	150	240	437	603	380	N/A	200
Annual Additions, Long Term Resources	155	310	201	790	310	790	213	232	269	275	149	155	354	364	365	407	355	354	358	2,685		
Annual Additions, Short Term Resources	350	1,213	1,415	1,164	1,099	661	642	706	734	950	616	741	838	875	1,160	1,287	1,425	1,533	1,701	814		
Total Annual Additions	505	1,523	1,616	1,954	1,409	1,452	854	938	1,003	1,225	765	896	1,192	1,239	1,525	1,693	1,780	1,887	2,059	3,499		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 14

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	625	625
CCCT H	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	-	475	475
SCCT Aero Utah	-	-	-	-	-	118	-	-	-	-	-	-	-	-	-	-	-	-	-	-	118	118
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	1,600
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	200	200	200	-	-	-	200	200	200	200	200	200	200	600	2,000
Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	160
Total Wind	-	-	-	-	-	-	-	200	200	200	-	160	-	200	200	200	200	200	200	200	600	2,160
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	8	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	10	22	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	-	11	-	-	-	-	-	-	-	-	1	-	2	-	-	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1 Total	16	48	-	-	20	-	12	-	-	-	-	-	-	2	-	3	-	-	-	-	96	101
DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	16	45
DSM, Class 2, Utah	47	57	60	47	68	71	71	62	72	74	61	67	64	67	68	72	66	70	70	73	628	1,308
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	8	8	9	10	11	14	15	20	21	25	31	33	57	246
DSM, Class 2 Total	51	62	65	53	75	79	79	71	81	85	72	79	78	84	87	95	91	98	104	109	701	1,599
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	24	45
FOT Mead 3rd Qtr HLH	-	168	264	264	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	89	45
FOT Utah 3rd Qtr HLH	200	200	200	32	200	188	200	-	-	200	-	-	-	-	-	-	-	-	-	-	142	71
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	19	85	98	120	126	111	147	155	134	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	136	172	316	323	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	21	53	77	138	126	48	177	164	-	N/A	80
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	70	70	-	70	70	-	-	-	-	-	58	-	-	-	-	350	408
Wind, Yakima, 29% Capacity Factor	-	-	-	-	100	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
Total Wind	-	-	-	-	100	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	4	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	49	-	4	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	93
DSM, Class 2, Oregon/California	51	51	54	59	61	60	60	52	52	52	52	52	52	53	53	53	45	37	37	37	552	1,022
DSM, Class 2, Yakima	10	11	7	7	7	7	7	7	7	7	8	9	9	9	10	7	6	7	7	7	75	154
DSM, Class 2 Total	65	66	66	71	72	71	71	63	64	64	65	66	66	67	68	65	55	48	47	48	674	1,269
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.29	0.97	0.97	0.97	-	16	29
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	364	391	400	310	400	400	400	400	400	400	-	-	-	355	313
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	50	50	-	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	203	-	173	-	N/A	38
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149	179	171	574	567	360	N/A	200
Annual Additions, Long Term Resources	155	210	201	762	440	367	384	827	469	428	149	315	154	364	365	430	355	354	358	2,685		
Annual Additions, Short Term Resources	350	1,213	1,419	1,196	1,099	1,037	950	664	691	950	616	741	838	875	1,160	1,266	1,405	1,513	1,681	794		
Total Annual Additions	505	1,423	1,619	1,957	1,539	1,404	1,334	1,491	1,161	1,378	765	1,056	992	1,239	1,525	1,696	1,760	1,867	2,039	3,479		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.5 – Hard Cap CO2 Policy Core Case (15 to 18)

Case 15

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	475	475	-	-	475	1,425
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	14	49	21	8	9	4	34	-	139
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	14	49	21	8	9	4	34	-	139
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	0.8	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	17	50	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	-	-	97	97
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	40
	DSM, Class 2, Utah	46	55	59	43	44	47	50	53	56	60	56	60	57	60	60	65	63	66	67	69	515	1,136
	DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	8	9	11	13	14	18	20	23	29	28	54	228
	DSM, Class 2 Total	49	59	64	48	50	55	58	62	66	70	66	71	70	76	77	86	85	92	99	99	583	1,404
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	-	24	37
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	38
	FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	53	193	-	200	-	-	-	-	-	-	-	-	-	-	106	53
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	32	45	59	180	202	155	161	139	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	58	384	16	-	-	-	N/A	46
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	243	307	57	196	197	N/A	100
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	0.3	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	45	89
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	37	37	36	550	1,016
	DSM, Class 2, Yakima	8	11	6	6	6	6	7	7	7	7	8	8	8	9	9	7	6	6	6	7	71	145
	DSM, Class 2 Total	63	66	65	70	71	70	71	63	63	64	64	65	65	66	66	64	54	47	47	47	667	1,251
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	-	-	-	-	-	-	-	-	-	-	16	16
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	299	400	400	400	364	400	193	400	400	400	400	147	153	159	187	400	346	315
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	-	50	50	-	50	-	-	-	50	50	50	50	50	50	50	30	33
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	122	33	124	108	268	-	-	-	-	345	N/A	100
	Annual Additions, Long Term Resources	152	210	200	776	836	154	154	145	615	195	140	144	143	164	270	177	628	628	154	907		
	Annual Additions, Short Term Resources	350	1,213	1,420	1,181	649	773	803	943	664	950	621	753	857	903	1,135	1,303	1,028	722	894	1,431		
	Total Annual Additions	502	1,422	1,620	1,957	1,486	927	957	1,087	1,278	1,145	761	897	1,000	1,067	1,405	1,480	1,656	1,349	1,048	2,338		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 16

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
	Capacity (MW)																				Resource Totals **	
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	475	475	475	-	475	1,900
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	11	14
DSM, Class 1 Total	26	37	-	20	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	5	87	92
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	42
DSM, Class 2, Utah	47	57	59	43	44	47	51	52	54	57	59	63	62	65	65	69	64	67	68	74	513	1,170
DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	10	11	14	15	19	20	24	29	28	56	233
DSM, Class 2 Total	51	62	64	49	51	55	59	62	63	67	71	75	76	82	83	91	87	94	100	104	583	1,446
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	-	-	24	34
FOT Mead 3rd Qtr HLH	-	168	264	264	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	38
FOT Utah 3rd Qtr HLH	189	200	200	17	-	-	58	200	-	188	-	-	-	-	-	-	-	-	-	-	105	53
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	122	300	210	246
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	32	116	110	223	99	133	125	136	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	96	-	-	-	-	N/A	10
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	107	256	453	114	41	-	-	N/A	97
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	56	56
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	92
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,018
DSM, Class 2, Yakima	8	11	6	6	6	6	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	47	669	1,259
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	-	-	-	-	-	-	-	16	19
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	334	400	-	305	163	9	389	148	400	160	188	400	343	280
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	-	50	50	-	50	50	50	50	50	50	50	50	50	-	48	30	37
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	250	60	289	294	-	-	29	-	-	79	N/A	100
Annual Additions, Long Term Resources	163	200	200	777	837	153	149	143	656	175	147	150	151	156	225	161	626	630	631	918		
Annual Additions, Short Term Resources	339	1,213	1,420	1,181	648	773	808	950	634	938	606	734	834	876	1,104	1,269	992	684	436	964		
Total Annual Additions	503	1,412	1,620	1,957	1,485	926	957	1,093	1,290	1,114	752	884	985	1,032	1,330	1,430	1,618	1,315	1,066	1,882		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 17

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	1,600
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	40	200	200	200	200	200	200	200	200	200	200	200	-	440	2,240
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	200	200	200	-	600	2,400
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	1	-	-	-	-	1	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	2	1	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	10	22	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	1	-	-	-	-	2	-	-	-	-	11	14
	DSM, Class 1 Total	16	48	-	22	1	-	-	-	-	7	2	-	-	-	-	3	-	-	-	-	94	99
	DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	16	46
	DSM, Class 2, Utah	47	57	60	47	54	52	58	71	72	74	63	67	64	68	68	72	66	70	70	77	593	1,279
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	8	8	8	9	10	12	14	15	20	21	25	31	29	58	243
	DSM, Class 2 Total	51	62	66	53	60	60	67	80	81	85	74	80	79	85	87	95	91	98	104	109	666	1,568
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	24	45
	FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
	FOT Utah 3rd Qtr HLH	200	200	200	-	200	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	100	50
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	4	18	37	67	128	159	95	189	170	134	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82	38	94	344	441	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	327	-	334	339	-	N/A	100
West	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	35	70	70	70	70	35	-	-	-	-	-	-	-	-	-	385	420
	Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	100	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	-	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	6	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	6	5	4	4	4	4	47	94
	DSM, Class 2, Oregon/California	51	51	54	59	61	60	60	52	52	52	52	52	53	53	53	53	45	37	37	37	552	1,024
	DSM, Class 2, Yakima	10	11	7	7	7	7	7	7	7	8	8	9	9	9	10	7	6	7	7	7	76	156
	DSM, Class 2 Total	65	66	66	71	72	71	71	64	64	64	66	67	67	68	68	65	55	48	47	48	675	1,274
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.29	0.97	-	16	31
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	361	338	400	398	400	-	59	400	400	400	400	400	312	396	376	350	332
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	50	-	-	2	-	50	50	50	50	50	50	50	50	50	50	-	25	35
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	196	-	-	-	N/A	20
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	226	278	14	23	164	8	286	-	-	-	N/A	100
	Annual Additions, Long Term Resources	154	311	201	790	405	791	218	432	505	436	389	356	356	363	365	372	356	354	358	2,485		
	Annual Additions, Short Term Resources	350	1,213	1,415	1,164	1,099	661	638	702	698	950	580	705	801	840	1,125	1,282	1,421	1,529	1,696	810		
	Total Annual Additions	504	1,523	1,616	1,954	1,504	1,452	855	1,134	1,203	1,386	970	1,061	1,157	1,202	1,490	1,655	1,776	1,883	2,054	3,294		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.
** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 18

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	475	475	-	475	475	-	-	475	2,375
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	42	28	21	8	9	200	-	-	308
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	42	28	21	8	9	200	-	-	308
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21
DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1 Total	26	37	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	83	86
DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	43
DSM, Class 2, Utah	47	57	59	43	46	50	51	52	54	58	61	65	62	65	66	70	64	68	70	74	518	1,183
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	10	11	14	15	19	20	24	30	28	56	237
DSM, Class 2 Total	51	62	64	49	53	57	60	62	64	68	72	77	76	82	84	92	88	95	103	105	589	1,463
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	-	24	34
FOT Mead 3rd Qtr HLH	-	168	264	264	-	16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	71	36
FOT Utah 3rd Qtr HLH	189	200	200	13	-	-	55	196	-	184	-	-	-	-	-	-	-	-	-	-	104	52
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	272	120	249	-	-	-	260	210	195
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	168	171	44	58	83	98	111	124	135	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	59	152	-	-	-	-	-	-	-	N/A	21
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	70	105
Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	56	56
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	92
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	53	53	52	44	37	37	36	551	1,019
DSM, Class 2, Yakima	8	11	6	6	7	7	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	47	670	1,261
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	-	-	-	-	-	-	-	16	20
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	150	156	145	169	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	243	400	400	400	280	400	-	-	-	-	-	-	-	-	-	-	332	197
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	203	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	50	50	50	50	50	50	50	50	-	-	5	-	-	-	-	45	30
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	244	150	153	132	139	144	-	-	39	-	N/A	100
Annual Additions, Long Term Resources	163	300	200	777	840	156	146	143	656	176	149	152	151	673	659	183	631	631	390	882		
Annual Additions, Short Term Resources	339	1,213	1,417	1,177	643	766	805	946	630	934	599	727	826	448	317	482	248	267	309	564		
Total Annual Additions	503	1,512	1,617	1,954	1,483	922	951	1,089	1,287	1,110	748	878	977	1,121	977	664	879	898	699	1,446		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.
** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.6 – 2011 Business 10-year Plan Case Study 19

Case 19

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	-	597	-	-	597	-	-	-	-	-	-	-	-	-	-	-	1,819	1,819
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	-	-	-	-	-	-	-	-	80	-	-	-	-	-	-	-	-	80
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	200	300	200	200	200	-	-	-	-	-	-	-	500	1,100
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	-	360	300	200	200	200	-	-	-	-	-	-	-	660	1,260
	CHP - Biomass	-	-	-	-	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	-	10
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	3	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	26	37	-	-	26	-	7	-	-	-	-	-	-	-	-	-	-	5	-	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	15	39
	DSM, Class 2, Utah	58	65	70	98	104	47	49	50	52	54	56	60	57	60	60	65	60	63	64	69	648	1,261
	DSM, Class 2, Wyoming	3	4	4	6	6	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	58	232
	DSM, Class 2 Total	61	70	75	105	112	55	57	59	61	64	67	71	70	76	77	86	82	89	95	99	720	1,532
	FOT Mead 3rd Qtr HLH	-	168	264	255	99	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	40
	FOT Utah 3rd Qtr HLH	183	196	200	-	200	-	50	200	-	168	-	-	-	-	-	-	-	-	-	-	120	60
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	7	21	33	46	60	194	123	253	125	138	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	353	338	309	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31	339	171	194	264	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	-	-	-	-	-	-	-	-	-	-	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	-	42
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	43	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	5	6	7	7	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	51	95
	DSM, Class 2, Oregon/California	51	51	55	59	61	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
	DSM, Class 2, Yakima	10	11	9	12	12	6	6	7	7	7	8	8	8	9	9	7	6	6	6	7	87	161
	DSM, Class 2 Total	65	67	70	78	80	71	70	63	63	63	64	65	65	66	66	64	54	46	47	47	689	1,272
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	400	274	400	282	400	400	400	400	400	400	400	400	400	347	368
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	50	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	40	20
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	19	-	-	-	40	N/A	7
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	1	22	57	330	317	241	31	323	340	N/A	166
	Annual Additions, Long Term Resources	169	197	198	811	238	741	134	130	1,080	427	338	341	421	147	148	155	142	145	147	151		
	Annual Additions, Short Term Resources	333	1,209	1,419	1,155	1,099	755	800	950	574	918	589	721	755	803	1,097	1,261	1,403	1,510	1,680	1,790		
	Total Annual Additions	502	1,406	1,617	1,967	1,337	1,495	935	1,080	1,654	1,344	927	1,063	1,176	949	1,246	1,416	1,545	1,655	1,827	1,941		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.
** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.7 – Portfolio Development Assumptions and System Optimizer PVRR Results for Sensitivity Cases (20 to 33)

Case #	Assumption Alternatives											PaR Model	PVRR
	Carbon Policy		Gas Price	Load Growth	Renewable PTC and Wind Integration Cost	Renewable Portfolio Standards	Demand-Side Management	Distributed Solar	Coal Plant Utilization	Energy Gateway Trans			
	Type CO2 Tax Hard Cap	Cost Medium High Low to Very High	Low Medium High	Low Econ. Growth Medium Econ. Growth High Growth High Peak Demand	Extension to 2015 Extension to 2020 Alt. Wind Integ. Cost	None Current RPS Federal RPS	High Achievable Class 3 Included Technical Potential Distribution Efficiency	Current Incentives UT Buydown Levels	No shutdowns Optimized	Base Scenario 1 Scenario 2 Scenario 3			$ Millions
Coal Plant Utilization Sensitivity Cases													
20	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario		X	$41,123
21	CO2 Tax	Medium	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario		X	$39,702
22	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario		X	$46,207
23	CO2 Tax	High	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario		X	$44,494
24	Hard Cap - Base	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario		X	$32,929
Load Forecast Sensitivity Cases													
25	CO2 Tax	Medium	Medium	Low Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario		X	$38,810
26	CO2 Tax	Medium	Medium	High Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario		X	$42,674
27	CO2 Tax	Medium	Medium	High Peak Demand	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario			$41,443
Renewable Resource Sensitivity Cases													
28	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	None	High Achievable	Current Incentives	None	Base or Scenario			$40,995
29	CO2 Tax	Medium	Medium	Med. Econ. Growth	Alt. Wind Integ. Cost	Current RPS	High Achievable	Current Incentives	None	Base or Scenario			$41,020
30	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	UT $1.50/Watt Incentive	None	Base or Scenario			$41,038
30a	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	UT $2.00/Watt Incentive	None	Base or Scenario			$41,041
DSM Sensitivity Cases													
31	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Class 3 Included	Current Incentives	None	Base or Scenario			$40,536
32	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Technical Potential	Current Incentives	None	Base or Scenario			$40,521
33	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Distribution Energy	Current Incentives	None	Base or Scenario			$40,772

Table D.8 – Coal Plant Utilization Sensitivity Cases (20 to 24)

Case 20

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	11	49	20	8	9	4	34	-	134
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	11	49	20	8	9	4	34	-	134
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	1	-	-	-	1	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	1	-	-	-	2	-	-	-	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	26	41	-	20	-	-	5	-	-	5	-	2	-	-	-	3	-	-	-	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	14	39
	DSM, Class 2, Utah	47	54	59	43	44	51	52	53	56	60	56	60	57	60	60	65	60	63	66	72	519	1,138
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
	DSM, Class 2 Total	50	58	64	49	51	58	60	63	66	69	67	71	70	76	77	86	82	89	97	102	589	1,406
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	24	39
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	190	200	200	17	-	-	50	190	-	200	-	-	-	-	-	-	-	-	-	-	105	52
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	19	115	136	65	143	97	158	124	137	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	51	-	290	302	357	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	10	-	116	-	328	316	230	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	91
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	37	36	551	1,016
	DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	72	146
	DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	669	1,254
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	-	-	-	-	16	25
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	362	400	372	400	400	400	400	400	400	400	400	400	346	372
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	50	50	50	50	50	50	50	50	50	35	40
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	39	-	-	208	205	-	148	201	199	N/A	100
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	606	-	-	131	N/A	74
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	46	60	165	179	138	34	188	190	N/A	100
	Annual Additions, Long Term Resources	162	200	200	777	837	157	156	144	614	193	143	148	145	162	271	181	150	150	153	188		
	Annual Additions, Short Term Resources	340	1,213	1,420	1,181	648	770	800	940	662	950	679	807	911	956	1,188	1,445	1,592	1,707	1,881	1,994		
	Total Annual Additions	502	1,412	1,620	1,957	1,485	927	955	1,084	1,276	1,143	822	956	1,056	1,119	1,458	1,626	1,741	1,857	2,034	2,182		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 21

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East	Coal Utilization - Utah Coal replaced with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289	-	289
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	3	34	-	48
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	3	34	-	48
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	1	-	-	-	-	1	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	1	-	-	-	-	2	-	-	-	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	17	50	-	20	-	-	5	-	-	5	2	-	-	-	-	3	-	-	-	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	46	55	59	43	44	47	50	53	55	64	56	60	57	60	60	65	60	63	64	69	517	1,130
	DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	8	9	10	13	14	18	20	23	29	28	55	226
	DSM, Class 2 Total	49	59	64	48	51	55	58	62	64	74	66	70	69	76	77	86	82	89	95	99	586	1,394
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	-	24	34
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	57	198	-	200	-	-	-	-	-	-	-	-	-	-	107	54
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	19	32	44	118	182	118	173	173	137	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	66	374	327	164	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	270	-	323	407	-	N/A	100
West	Coal Utilization - Bridger with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	-	389
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	5	5	5	5	5	5	5	4	4	3	4	4	45	88
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	550	1,015
	DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	7	7	7	7	7	8	9	7	6	6	6	7	70	140
	DSM, Class 2 Total	63	66	65	70	71	70	70	63	63	64	63	64	64	65	66	63	54	46	46	47	665	1,243
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.70	1.81	1.81	1.81	-	-	-	-	-	-	16	23
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	299	400	400	400	370	400	400	400	400	400	400	400	400	400	400	400	347	373
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	153	141	71	-	204	29	202	200	N/A	100
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294	-	-	706	N/A	100
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	15	134	73	119	316	151	135	35	-	22	N/A	100
	Annual Additions, Long Term Resources	151	210	200	776	837	153	150	144	613	202	143	144	143	161	253	157	141	140	150	862		
	Annual Additions, Short Term Resources	350	1,213	1,420	1,181	649	774	807	948	670	950	771	903	1,007	1,054	1,255	1,421	1,568	1,684	1,859	1,979		
	Total Annual Additions	501	1,422	1,620	1,957	1,486	927	958	1,092	1,283	1,152	913	1,047	1,150	1,215	1,508	1,579	1,709	1,824	2,009	2,841		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.
** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 22

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East	Coal Utilization - Utah Coal replaced with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289	-	289
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	475	475	950
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	4	34	-	46
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	4	34	-	46
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	1	-	-	-	-	1	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	7	-	3	26	36
	DSM, Class 1, Utah-DLC-Residential	10	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	1	-	-	-	-	2	-	-	-	-	11	14
	DSM, Class 1 Total	16	48	-	20	-	-	10	-	-	-	2	-	-	-	-	3	-	7	-	3	94	108
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	42
	DSM, Class 2, Utah	47	57	59	43	46	50	52	54	55	60	59	63	62	65	65	69	64	69	70	77	524	1,188
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	10	11	14	15	19	20	24	30	28	56	235
	DSM, Class 2 Total	51	62	64	49	53	57	61	63	65	69	71	75	76	82	83	91	87	96	103	108	594	1,465
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	-	24	39
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	43	184	-	200	-	-	-	-	-	-	-	-	-	-	104	52
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	19	105	53	121	147	97	157	161	136	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	57	148	339	456	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	4	-	42	218	34	360	344	-	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	92
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,019
	DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
	DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	47	670	1,260
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.42	0.97	0.97	0.97	-	-	-	-	-	16	22
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	297	400	400	400	317	400	400	400	400	400	400	400	400	400	400	400	341	371
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	62	118	104	-	28	-	-	-	N/A	31
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	353	-	-	647	N/A	100
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	12	127	74	84	217	223	128	35	101	-	N/A	100
	Annual Additions, Long Term Resources	153	210	200	777	839	156	161	144	658	143	150	151	151	192	229	166	147	164	159	960		
	Annual Additions, Short Term Resources	350	1,213	1,420	1,181	647	770	793	934	617	950	767	895	995	1,006	1,233	1,394	1,537	1,641	1,811	1,533		
	Total Annual Additions	503	1,423	1,620	1,957	1,486	926	955	1,078	1,275	1,093	916	1,046	1,146	1,198	1,462	1,560	1,684	1,805	1,969	2,493		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 23

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
Coal Utilization - Utah Coal replaced with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289	-	-	-	-	289	-	578
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	475	475	475	1,425
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	49
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	49
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	1	-	-	-	-	1	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	11	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	1	-	-	-	2	-	-	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	16	51	-	20	-	-	10	-	-	-	1	1	-	-	-	3	-	-	-	-	97	102
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	41
DSM, Class 2, Utah	47	54	59	43	44	51	52	54	57	60	56	63	61	63	64	69	64	67	68	74	520	1,169
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	14	15	19	20	24	29	28	56	233
DSM, Class 2 Total	50	58	64	49	51	58	60	63	66	69	67	75	74	80	82	91	87	94	100	104	590	1,444
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	-	-	24	36
FOT Mead 3rd Qtr HLH	-	168	264	264	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	44	185	-	200	-	-	-	-	-	-	-	-	-	-	105	52
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	19	100	98	151	118	115	134	123	136	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	134	353	446	57	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	27	35	130	76	283	302	148	-	N/A	100
West																						
Coal Utilization - Bridger with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	-	-	778
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	91
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,018
DSM, Class 2, Yakima	8	11	6	6	6	6	7	7	7	7	8	8	8	9	9	7	6	7	6	7	71	147
DSM, Class 2 Total	63	66	65	70	72	71	71	63	63	64	64	65	66	67	67	64	55	47	47	47	668	1,257
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	-	-	-	-	-	-	-	-	16	18
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	357	400	400	400	400	400	400	400	400	400	400	400	345	373
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	259	119	N/A	38
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	16	130	123	130	237	298	18	-	47	-	N/A	100
Annual Additions, Long Term Resources	152	210	200	777	837	156	161	144	614	188	143	151	148	189	515	941	150	155	631	954		
Annual Additions, Short Term Resources	350	1,213	1,420	1,181	648	771	794	935	657	950	771	899	1,000	1,013	1,278	1,377	1,520	1,632	1,384	1,005		
Total Annual Additions	502	1,422	1,620	1,957	1,485	927	955	1,079	1,271	1,138	914	1,049	1,148	1,202	1,793	2,318	1,670	1,787	2,014	1,959		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 24

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																							
	Coal Utilization - Utah Coal replaced with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289	-	-	-	-	-	289
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	475	475	475	1,425
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	49
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	49
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	1	-	-	2	-	-	-	-	11	14
	DSM, Class 1 Total	26	37	-	20	-	-	5	-	-	-	-	-	2	-	-	3	-	-	-	-	88	93
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	42
	DSM, Class 2, Utah	47	57	59	43	44	47	51	52	54	57	59	63	61	65	65	69	64	67	68	77	513	1,171
	DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	10	11	14	15	19	20	24	29	28	56	234
	DSM, Class 2 Total	51	62	64	49	51	55	59	61	63	67	71	75	74	82	83	91	87	94	100	108	583	1,447
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	-	-	24	36
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	38
	FOT Utah 3rd Qtr HLH	189	200	200	17	-	-	57	199	-	187	-	-	-	-	-	-	-	-	-	-	105	52
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	41	122	151	178	97	126	123	136	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	66	184	-	579	170	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	146	239	256	-	189	169	-	N/A	100
West																							
	Coal Utilization - Bridger with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	-	778
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	56	56
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	92
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,018
	DSM, Class 2, Yakima	8	11	6	6	6	6	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
	DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	47	668	1,259
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	-	-	-	-	-	-	-	16	19
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	333	400	400	400	400	400	400	400	400	400	400	400	343	372
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	-	50	50	-	50	50	50	50	50	50	50	50	50	50	50	30	40
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	408	-	33	70	N/A	51
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	0	115	192	8	46	84	277	-	149	127	N/A	100
	Annual Additions, Long Term Resources	163	200	200	777	837	153	150	142	656	175	147	150	152	156	228	452	927	155	631	668		
	Annual Additions, Short Term Resources	339	1,213	1,420	1,181	648	773	807	949	633	937	756	885	984	1,026	1,253	1,452	1,532	1,644	1,395	1,084		
	Total Annual Additions	503	1,412	1,620	1,957	1,485	926	957	1,091	1,289	1,112	903	1,035	1,135	1,182	1,481	1,904	2,459	1,799	2,026	1,752		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.9 – Load Forecast Sensitivity Cases (25 to 27)

Case 25

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																							
	CCCT F 2x1	-	-	-	-	625	-	-	597	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	-	20
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	20	-	180
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	0.8	-	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	3	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	6	58	-	26	-	7	-	-	-	-	-	-	-	-	-	-	-	-	5	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	39
	DSM, Class 2, Utah	47	63	62	65	49	52	59	53	56	64	56	60	57	60	60	65	60	63	64	69	571	1,184
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	13	14	18	20	23	29	28	56	231
	DSM, Class 2 Total	51	68	67	71	55	59	67	63	66	74	67	71	70	76	77	86	82	89	95	99	642	1,453
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	-	-	-	-	-	-	-	-	-	-	24	24
	FOT Mead 3rd Qtr HLH	-	168	264	264	4	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
	FOT Utah 3rd Qtr HLH	-	195	199	200	-	68	200	-	-	200	-	-	-	-	-	-	-	-	-	-	106	53
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	83	120	201	201	-	213	150	31	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	-	322	273	364	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	43	-	232	343	381	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	0.3	-	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	43	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	91
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
	DSM, Class 2, Yakima	6	6	7	7	7	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	67	141
	DSM, Class 2 Total	62	62	66	71	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	665	1,249
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	-	-	-	-	-	-	-	-	-	-	16	16
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	23	400	400	400	400	400	400	258	396	400	-	249	342	359	400	400	400	400	400	400	348	341
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	50	50	-	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	58	-	-	40	86	173	-	17	158	N/A	53
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	408	-	-	-	N/A	41
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	319	140	123	113	237	270	200	119	262	217	N/A	200
	Annual Additions, Long Term Resources	140	223	197	199	870	166	149	741	139	227	138	142	141	147	308	155	142	141	152	171		
	Annual Additions, Short Term Resources	173	1,234	1,423	1,364	804	917	950	558	696	950	619	747	848	892	1,179	1,342	1,481	1,586	1,745	1,851		
	Total Annual Additions	314	1,456	1,620	1,563	1,674	1,083	1,099	1,299	835	1,177	758	889	989	1,038	1,487	1,497	1,623	1,727	1,897	2,022		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.
** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 26

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	597	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	1,819	1,819
	SCCT Aero Utah	-	-	-	-	-	-	-	-	-	118	-	-	-	-	-	-	-	-	-	-	118	118
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52	-	52
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	52	-	212
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	0.8	-	-	-	-	-	0.8	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	3	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	6	62	-	23	-	-	-	-	7	-	-	-	-	-	-	-	-	-	5	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	39
	DSM, Class 2, Utah	46	55	59	54	47	51	52	55	71	74	56	60	57	60	60	65	60	63	64	72	563	1,179
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
	DSM, Class 2 Total	49	59	64	60	53	58	60	64	81	84	67	71	70	76	77	86	82	89	95	102	633	1,447
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.4	2.4	2.4	2.4	-	-	-	-	-	24	36
	FOT Mead 3rd Qtr HLH	-	168	264	264	45	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84	42
	FOT Utah 3rd Qtr HLH	-	200	200	200	-	119	-	-	8	200	-	-	-	-	-	-	-	-	-	-	93	46
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	45	35	155	186	120	146	-	198	103	12	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	318	300	382	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	-	241	263	391	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	91
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
	DSM, Class 2, Yakima	6	6	7	7	7	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	67	141
	DSM, Class 2 Total	61	62	66	71	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	664	1,248
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.0	1.0	1.0	1.0	1.0	-	-	-	-	-	16	21
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	25	400	400	400	400	400	208	360	400	400	14	255	280	318	400	400	400	400	400	400	339	333
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	50	-	-	50	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	38	28	-	-	185	160	173	-	178	174	N/A	94
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	393	-	-	-	N/A	39
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	227	142	133	113	201	260	249	171	254	250	N/A	200
	Annual Additions, Long Term Resources	138	217	200	803	890	157	738	145	206	311	142	145	144	150	312	155	142	141	152	206		
	Annual Additions, Short Term Resources	175	1,239	1,424	1,364	845	968	508	660	758	950	624	761	869	917	1,207	1,371	1,514	1,628	1,797	1,908		
	Total Annual Additions	313	1,456	1,625	2,167	1,735	1,125	1,246	805	963	1,261	766	906	1,013	1,067	1,518	1,526	1,656	1,769	1,948	2,114		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 27

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	Resource Totals ** 20-year
	Capacity (MW)																					
East																						
CCCT F 2x1	-	-	-	625	597	-	-	597	-	-	-	-	-	-	-	-	-	-	-	-	1,819	1,819
SCCT Aero Utah	-	-	-	236	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	236	236
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	9
Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	9	-	169
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	0.8	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	3	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	6	58	-	23	-	2	-	-	-	9	-	-	-	-	-	-	-	5	-	-	97	102
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	39
DSM, Class 2, Utah	46	59	59	46	49	52	53	61	71	74	56	60	57	60	60	65	60	63	64	69	569	1,183
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
DSM, Class 2 Total	49	63	64	52	55	59	62	70	81	84	67	71	70	76	77	86	82	89	95	99	640	1,452
Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	-	-	-	-	-	-	-	-	-	-	24	24
FOT Mead 3rd Qtr HLH	-	168	264	264	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
FOT Utah 3rd Qtr HLH	-	200	200	177	-	50	200	-	-	200	-	-	-	-	-	-	-	-	-	-	103	51
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	57	119	96	213	-	255	135	125	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	310	356	334	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52	-	275	293	380	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	0.3	0.3	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	1	-	-	-	2	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	6	-	1	-	-	-	2	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	91
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
DSM, Class 2, Yakima	6	6	6	7	7	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	66	140
DSM, Class 2 Total	61	62	66	71	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	664	1,248
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.0	1.0	-	-	-	-	-	-	-	-	16	18
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	25	400	400	400	400	400	400	266	400	400	198	342	400	400	400	400	400	400	400	400	349	362
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	22	50	50	-	0	50	-	-	-	-	-	-	-	-	-	-	32	16
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	208	161	203	-	146	170	N/A	89
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	418	-	-	-	N/A	42
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	131	128	127	119	241	296	256	156	252	293	N/A	200
Annual Additions, Long Term Resources	138	218	200	1,025	892	162	143	750	155	250	139	143	141	147	308	155	142	145	147	160		
Annual Additions, Short Term Resources	175	1,239	1,425	1,341	772	900	950	566	700	950	630	771	883	938	1,244	1,422	1,577	1,696	1,883	2,002		
Total Annual Additions	313	1,457	1,625	2,366	1,664	1,062	1,093	1,316	855	1,200	769	913	1,024	1,084	1,553	1,577	1,719	1,842	2,030	2,162		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.
** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.10 – Renewable Resource Sensitivity Cases (28 to 30a)

Case 28

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	26	41	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	5	-	97	102
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
DSM, Class 2, Utah	47	54	59	43	44	51	52	53	56	60	56	60	57	60	60	65	60	63	64	72	519	1,135
DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
DSM, Class 2 Total	50	58	64	49	51	58	60	63	66	69	67	71	70	76	77	86	82	89	95	102	589	1,403
Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	-	-	-	-	-	-	-	-	-	-	24	24
FOT Mead 3rd Qtr HLH	-	168	264	264	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	190	200	200	17	-	-	53	194	-	200	-	-	-	-	-	-	-	-	-	-	105	53
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	56	100	114	154	100	159	154	138	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	-	287	343	346	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	-	342	213	340	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	91
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
DSM, Class 2, Yakima	8	11	6	6	7	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	72	147
DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	669	1,254
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	-	-	-	-	-	-	-	-	-	-	16	16
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	366	400	-	268	377	395	400	400	400	400	400	400	346	345
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	21	-	-	165	128	180	-	156	155	N/A	80
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	327	-	-	-	N/A	33
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	315	145	126	111	222	259	208	142	236	237	N/A	200
Annual Additions, Long Term Resources	162	200	200	777	837	157	152	144	614	197	138	142	141	147	148	155	142	141	152	154		
Annual Additions, Short Term Resources	340	1,213	1,420	1,181	648	770	803	944	666	950	621	754	859	906	1,201	1,369	1,515	1,631	1,801	1,915		
Total Annual Additions	502	1,412	1,620	1,957	1,485	927	955	1,088	1,279	1,147	759	895	999	1,053	1,349	1,524	1,657	1,772	1,953	2,068		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 29

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	8	9	4	34	-	58
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	4	8	9	4	34	-	218
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	26	41	-	20	-	-	5	-	-	-	-	-	-	-	-	-	-	-	5	-	92	97
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	47	54	59	43	44	47	49	50	52	54	56	60	57	60	60	65	60	63	64	69	500	1,113
	DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	55	229
	DSM, Class 2 Total	50	58	64	48	51	55	57	59	61	64	67	71	70	76	77	86	82	89	95	99	568	1,380
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	-	-	-	-	-	-	-	-	-	-	24	24
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	190	200	200	17	-	-	57	200	-	193	-	-	-	-	-	-	-	-	-	-	106	53
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	36	83	141	158	100	156	162	138	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33	-	269	362	336	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81	-	366	212	341	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	58	58
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	45	90
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	550	1,015
	DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	7	7	8	8	8	9	9	7	6	7	6	7	70	145
	DSM, Class 2 Total	63	66	65	70	71	70	70	63	63	63	64	65	65	66	66	64	54	47	47	47	665	1,249
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.0	1.0	1.0	-	-	-	-	-	-	-	-	-	15	16
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	299	400	400	400	376	400	117	281	389	400	400	400	400	400	400	400	347	353
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	2	-	-	101	75	165	-	92	161	N/A	59
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	317	-	-	-	N/A	32
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	190	144	126	115	252	315	226	134	265	234	N/A	200
	Annual Additions, Long Term Resources	162	200	200	776	837	153	150	140	607	216	139	142	141	147	308	159	150	150	155	185		
	Annual Additions, Short Term Resources	340	1,213	1,420	1,181	649	774	807	950	676	943	613	746	851	898	1,193	1,362	1,508	1,624	1,794	1,909		
	Total Annual Additions	502	1,412	1,620	1,957	1,486	927	957	1,090	1,283	1,158	753	888	992	1,045	1,501	1,520	1,658	1,773	1,949	2,093		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 30

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	4	48	21	8	9	4	34	-	127
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	4	48	21	8	9	4	34	-	127
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	26	41	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	5	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	47	53	59	43	44	48	52	53	55	60	56	60	57	60	60	65	60	63	64	69	514	1,127
	DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
	DSM, Class 2 Total	50	57	64	49	51	56	60	62	64	69	67	71	70	76	77	86	82	89	95	99	584	1,395
	Micro Solar - Photovoltaic	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	-	-	12	22
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.4	-	-	-	-	-	24	37
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	190	200	200	16	-	-	53	194	-	200	-	-	-	-	-	-	-	-	-	-	105	53
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	51	92	151	154	100	145	144	137	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	-	308	352	316	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	103	-	303	258	302	N/A	100
West	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	91
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
	DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	72	146
	DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	669	1,253
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.3	1.3	1.3	1.0	1.0	-	-	-	-	-	16	22
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	297	400	400	400	366	400	-	266	377	395	400	400	400	400	400	400	346	345
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	20	-	-	30	25	164	-	21	168	N/A	43
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	258	-	-	-	N/A	26
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	313	145	125	111	215	290	223	103	253	222	N/A	200
	Annual Additions, Long Term Resources	163	200	201	778	838	155	153	145	613	198	144	147	146	156	271	177	151	150	155	185		
	Annual Additions, Short Term Resources	340	1,213	1,420	1,180	647	771	803	944	666	950	619	750	853	898	1,129	1,298	1,443	1,559	1,729	1,844		
	Total Annual Additions	503	1,412	1,621	1,958	1,485	926	956	1,088	1,280	1,148	763	897	999	1,054	1,401	1,474	1,594	1,709	1,884	2,029		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 30a

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	Resource Totals ** 20-year
	Capacity (MW)																					
East																						
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	7	49	21	8	9	4	34	-	132
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	7	49	21	8	9	4	34	-	132
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	26	41	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	5	-	97	102
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
DSM, Class 2, Utah	47	53	59	43	44	48	52	53	55	60	56	60	57	60	60	65	60	63	64	69	514	1,127
DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
DSM, Class 2 Total	50	57	64	49	51	56	60	62	64	69	67	71	70	76	77	86	82	89	95	99	584	1,395
Micro Solar - Photovoltaic	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	-	-	-	-	-	-	-	-	-	-	12	12
Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.4	-	-	-	-	-	24	37
FOT Mead 3rd Qtr HLH	-	168	264	264	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	190	200	200	16	-	-	53	194	-	200	-	-	-	-	-	-	-	-	-	-	105	53
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	52	93	151	154	100	145	142	137	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	-	309	358	306	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	100	-	303	257	315	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	91
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	72	146
DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	669	1,253
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.3	1.3	1.3	1.0	1.0	-	-	-	-	-	16	22
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	297	400	400	400	366	400	-	266	377	396	400	400	400	400	400	400	346	345
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	20	-	-	40	28	167	-	23	169	N/A	45
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261	-	-	-	N/A	26
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	313	145	125	111	216	291	219	106	253	220	N/A	200
Annual Additions, Long Term Resources	163	200	201	778	838	155	153	145	613	198	142	146	145	157	270	176	150	150	155	185		
Annual Additions, Short Term Resources	340	1,213	1,420	1,180	647	771	803	944	666	950	620	751	854	900	1,132	1,300	1,447	1,562	1,733	1,848		
Total Annual Additions	503	1,412	1,621	1,958	1,485	926	956	1,088	1,280	1,148	762	896	999	1,057	1,402	1,476	1,596	1,712	1,888	2,032		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.11 – Demand-Side Management Sensitivity Cases (31 to 33)

Case 31

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	9	4	34	-	55
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	8	9	4	34	-	215
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 3, Goshen, Critical Peak Pricing, Comm/Indu	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 3, Goshen, Time of Use, Irrigation	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 3, Utah, Critical Peak Pricing, Comm/Indus	-	-	-	19	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	28	28
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	DSM, Class 3, Utah, Demand Buyback, Comm/Indus	-	6	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, Utah-DLC-Residential	-	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29	29
	DSM, Class 3, Utah, Real-Time Pricing, Comm/Indus	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 3, Utah, Time of Use, Irrigation	-	-	-	117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117	117
	DSM, Class 3, Wyoming, Critical Peak Pricing, Comm/In	-	-	-	11	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	21	21
	DSM, Class 3, Wyoming, Demand Buyback, Comm/Indu	-	5	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 3, Wyoming, Real-Time Pricing, Comm/Indu	-	-	-	3	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 3, Wyoming, Time of Use, Irrigation	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 Total	6	66	-	221	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	322	322
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	58	65	64	43	44	47	49	50	52	54	56	60	57	60	60	65	60	63	64	69	526	1,140
	DSM, Class 2, Wyoming	3	4	4	4	5	5	6	7	7	8	9	9	11	13	14	18	20	23	29	28	54	228
	DSM, Class 2 Total	61	70	70	48	50	54	57	59	61	64	67	71	70	76	77	86	82	89	95	99	595	1,406
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	-	-	-	-	-	24	28
	FOT Mead 3rd Qtr HLH	-	168	264	204	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74	37
	FOT Utah 3rd Qtr HLH	-	178	200	-	151	-	-	88	194	82	-	-	-	-	-	-	-	-	-	-	89	45
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	3	38	54	133	177	76	210	194	116	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	282	355	319	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	190	229	254	296	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Oregon/California-Curtailment	-	-	16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16	16
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 3, Oregon, Critical Peak Pricing, Comm/Indu	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 3, California, Time of Use, Irrigation	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 3, Oregon, Time of Use, Irrigation	-	-	-	72	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	72
	DSM, Class 3, Walla Walla, Time of Use, Irrigation	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 3, Yakima, Time of Use, Irrigation	-	-	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	DSM, Class 1 Total	-	-	23	131	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	155	155
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	45	90
	DSM, Class 2, Oregon/California	51	51	55	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	550	1,015
	DSM, Class 2, Yakima	6	6	6	6	6	6	6	7	7	7	8	8	8	9	9	7	6	6	6	7	62	136
	DSM, Class 2 Total	61	62	65	70	71	70	70	62	63	63	64	65	65	66	66	64	54	46	47	47	657	1,241
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	0.97	0.82	-	-	-	-	-	-	15	19
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	15	400	400	400	400	348	394	400	400	400	202	330	400	400	400	400	400	400	400	400	356	364
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	-	50	-	-	50	50	50	-	-	-	-	-	-	-	-	-	-	30	15
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	104	123	-	-	172	N/A	42
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	189	206	229	58	151	167	N/A	100
	Annual Additions, Long Term Resources	150	232	179	1,108	239	749	137	140	178	640	142	145	142	182	308	155	150	149	150	185		
	Annual Additions, Short Term Resources	165	1,217	1,425	1,054	1,051	648	694	838	944	832	502	633	738	754	1,048	1,217	1,363	1,479	1,654	1,769		
	Total Annual Additions	316	1,449	1,604	2,163	1,290	1,397	831	977	1,122	1,472	643	778	879	936	1,357	1,372	1,513	1,629	1,804	1,954		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.
** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 32

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	-	7
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	7	-	167
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	-	-	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	1	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
	DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	11	14
	DSM, Class 1 Total	6	58	-	21	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	87	92
	DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	16	45
	DSM, Class 2, Utah	54	59	55	54	57	61	63	65	67	71	75	80	77	79	79	87	81	85	85	92	608	1,428
	DSM, Class 2, Wyoming	4	5	5	6	6	6	8	9	9	9	11	12	14	17	18	23	24	29	36	35	67	284
	DSM, Class 2 Total	59	65	61	61	65	70	74	76	78	83	88	94	93	99	100	113	108	117	124	129	691	1,758
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	-	-	-	-	-	-	-	-	-	-	24	24
	FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
	FOT Utah 3rd Qtr HLH	-	194	200	-	200	-	-	91	181	81	-	-	-	-	-	-	-	-	-	-	95	47
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	13	70	66	91	222	155	139	133	111	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	202	205	N/A	58
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	206	212	233	349	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	57	57
	DSM, Class 2, Walla Walla	5	5	5	5	5	5	5	5	5	5	5	6	6	6	6	5	4	4	4	4	48	98
	DSM, Class 2, Oregon/California	51	52	55	59	61	60	59	52	52	52	52	52	52	53	53	52	45	37	37	37	552	1,020
	DSM, Class 2, Yakima	7	7	8	8	8	7	8	8	8	8	9	10	10	10	10	8	7	8	8	8	76	164
	DSM, Class 2 Total	63	63	67	72	73	72	72	64	64	65	66	68	68	68	69	66	56	49	48	49	677	1,283
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.0	1.0	1.0	-	-	-	-	-	-	-	-	15	17
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	18	400	400	400	400	382	400	400	400	400	-	-	-	21	400	400	400	400	400	400	360	301
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	269	208	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	-	14	50	50	50	-	-	-	-	-	-	-	-	-	-	36	18
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	182	280	307	316	155	168	152	82	186	173	N/A	200
	Annual Additions, Long Term Resources	148	219	198	798	309	766	155	158	197	632	163	168	166	173	369	184	170	171	178	195		
	Annual Additions, Short Term Resources	168	1,231	1,422	1,164	1,099	682	714	841	931	831	482	593	677	703	946	1,090	1,213	1,304	1,454	1,538		
	Total Annual Additions	316	1,451	1,621	1,962	1,408	1,448	869	1,000	1,129	1,463	645	761	843	876	1,315	1,274	1,383	1,475	1,632	1,733		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 33

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	9	4	34	-	55
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	8	9	4	34	-	215
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	6	62	-	20	-	-	8	-	-	-	-	-	-	-	-	-	-	-	5	-	95	99
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	46	55	59	43	44	47	49	50	52	54	56	60	57	60	60	65	60	63	64	69	499	1,113
	DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	55	229
	DSM, Class 2 Total	49	59	64	48	51	55	57	59	61	64	67	71	70	76	77	86	82	89	95	99	568	1,380
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.4	2.4	0.0	-	-	-	-	-	-	-	24	29
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	-	200	200	22	-	-	57	200	-	193	-	-	-	-	-	-	-	-	-	-	87	44
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	34	80	184	237	-	238	170	57	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	306	335	358	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	53	-	262	290	395	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	45	90
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	550	1,015
	DSM, Class 2, Yakima	6	6	6	6	6	6	6	7	7	7	8	8	8	9	9	7	6	7	6	7	63	138
	DSM, Class 2 Total	61	62	65	70	71	70	70	63	63	63	64	65	65	66	66	64	54	47	47	47	658	1,243
	Distribition Energy Efficiency, Walla Walla	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Distribition Energy Efficiency, Yakima	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.3	1.3	1.0	1.0	1.0	1.0	-	-	-	-	-	-	15	19
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	25	400	400	400	303	400	400	400	376	400	98	290	388	400	400	400	400	400	400	400	350	354
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	12	-	-	56	52	167	-	32	164	N/A	48
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	412	-	-	-	N/A	41
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	214	142	126	115	250	316	226	115	264	231	N/A	200
	Annual Additions, Long Term Resources	138	217	200	776	837	153	155	140	607	216	142	145	142	148	308	155	150	150	155	185		
	Annual Additions, Short Term Resources	175	1,239	1,425	1,186	653	778	807	950	676	943	612	744	848	895	1,190	1,358	1,505	1,621	1,791	1,906		
	Total Annual Additions	313	1,456	1,625	1,962	1,490	931	961	1,090	1,283	1,159	754	889	990	1,043	1,498	1,513	1,655	1,770	1,946	2,091		

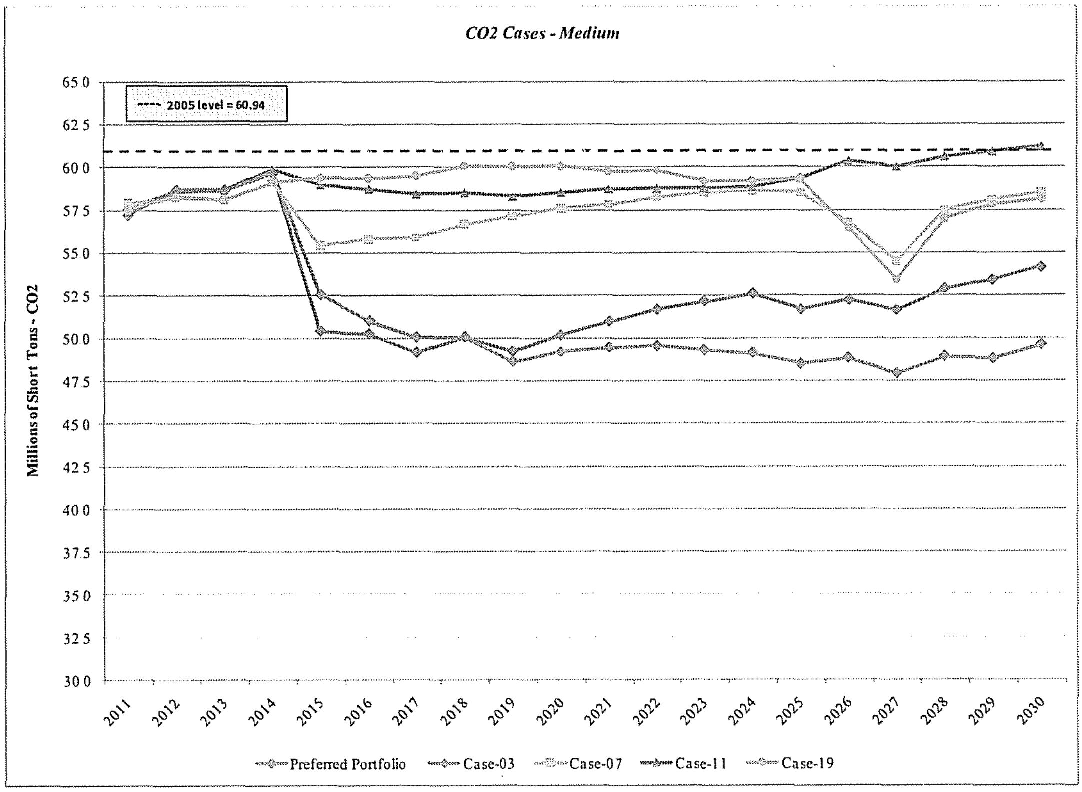
* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Annual Carbon Dioxide Emission Trends

Figure D.1 shows the Preferred Portfolio added to the medium CO2 emission profile chart from Chapter 8.

Figure D.1 – Core Cases: CO_2 Emission Profile for Medium CO_2 Tax Costs



APPENDIX E – STOCHASTIC PRODUCTION COST SIMULATION RESULTS

This appendix reports additional results for the Monte Carlo production cost simulations conducted with PacifiCorp's Planning and Risk (PaR) model, including certain sensitivity portfolios: coal utilization cases 20 through 24, and high/low economic growth cases 25 and 26. These results supplement the data presented in Chapter 8 of the main IRP document. The results presented include the following:

- Stochastic mean PVRR versus upper-tail mean PVRR scatter-plot diagrams that include all CO_2 hard cap portfolios
- The full complement of stochastic risk and other portfolio performance measures for the portfolios simulated using PaR.
- Stochastic mean PVRR component cost details for the portfolios.

Core Case Study Stochastic Results

Mean versus Upper-tail Mean PVRR Scatter-plot Charts

The following set of scatter-plot charts incorporates all 19 core cases. The scatter-plot charts in Chapter 8 excluded a number of the CO_2 emission hard cap portfolios due to high PVRRs that impacted axis scaling and legibility of the data points.

Figure E.1 – Stochastic Cost versus Upper-tail Risk, Zero CO_2 Tax Scenario

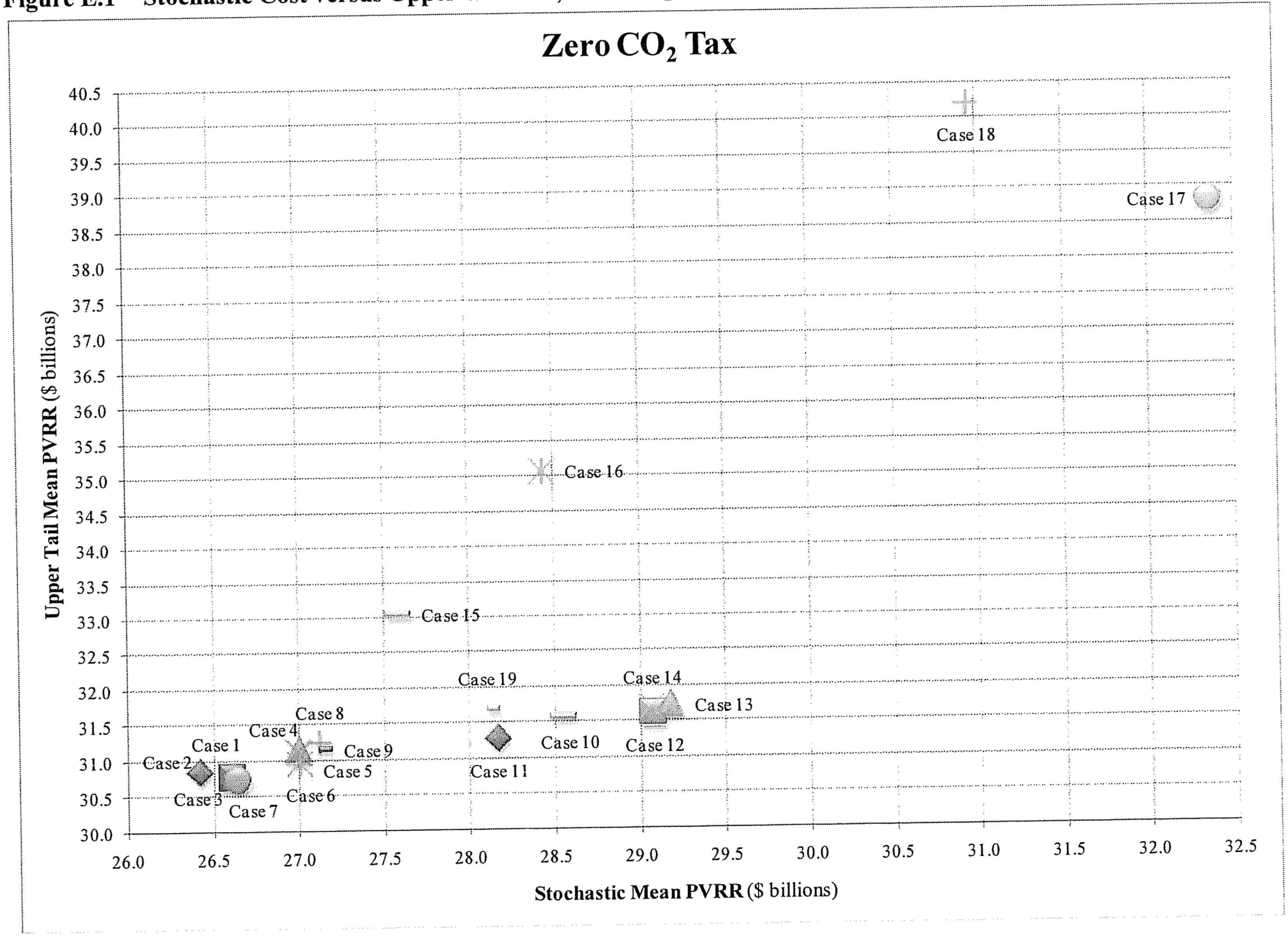


Figure E.2 – Stochastic Cost versus Upper-tail Risk, Medium CO_2 Tax Scenario

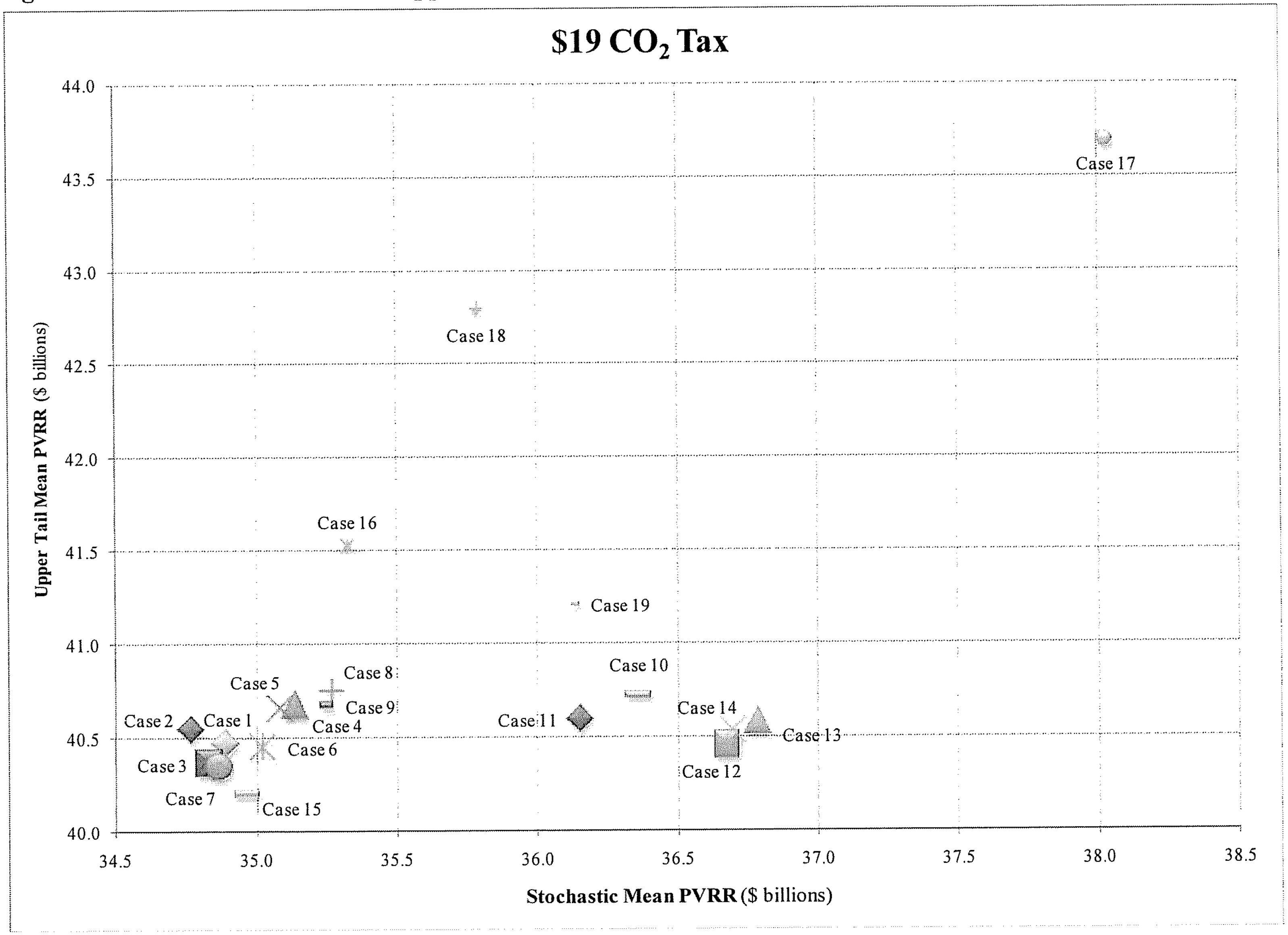


Figure E.3 – Stochastic Cost versus Upper-tail Risk, Low to Very High CO_2 Tax Scenario

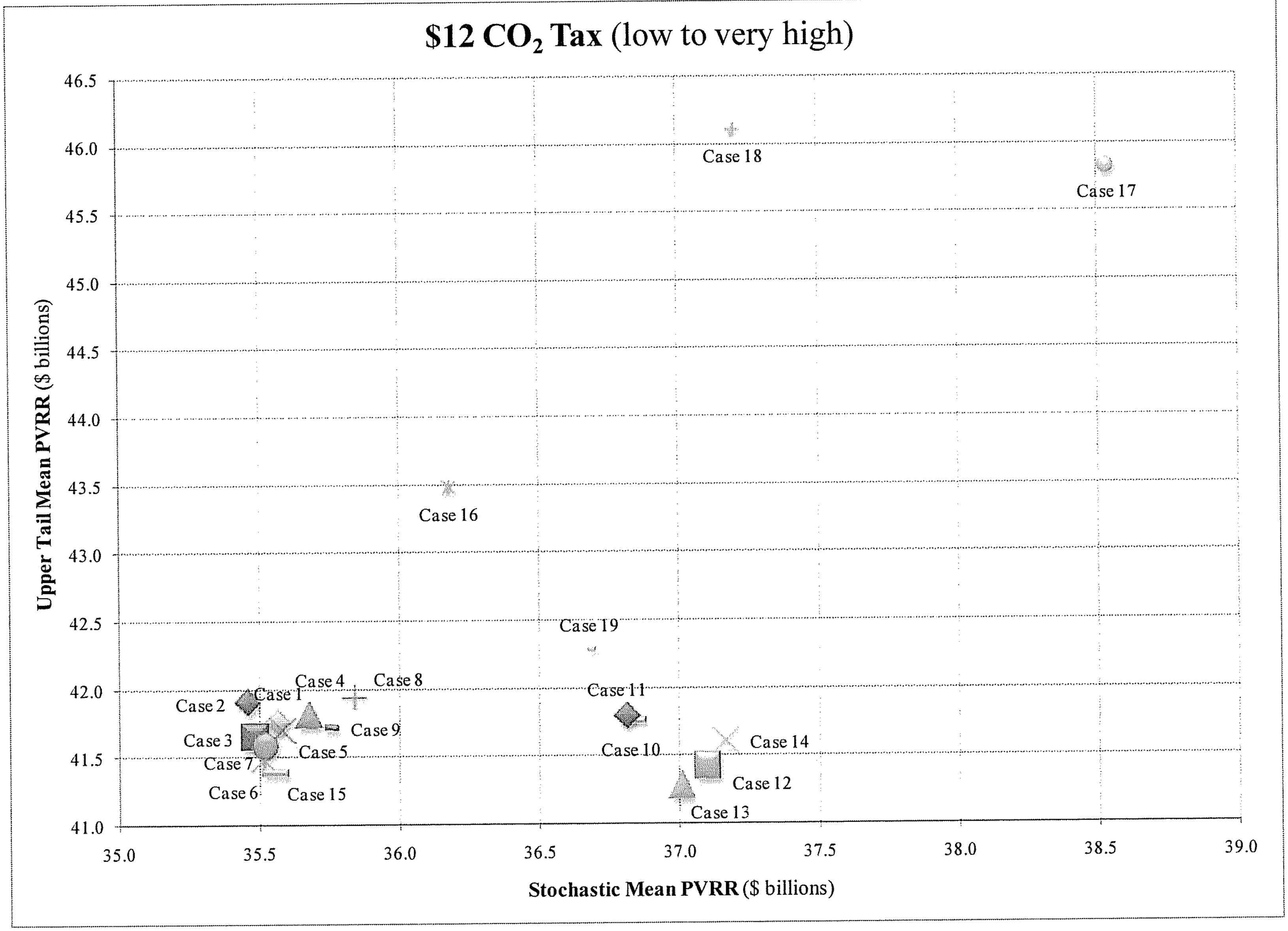


Figure E.4 – Stochastic Cost versus Upper-tail Risk, Average for CO_2 Tax Scenarios

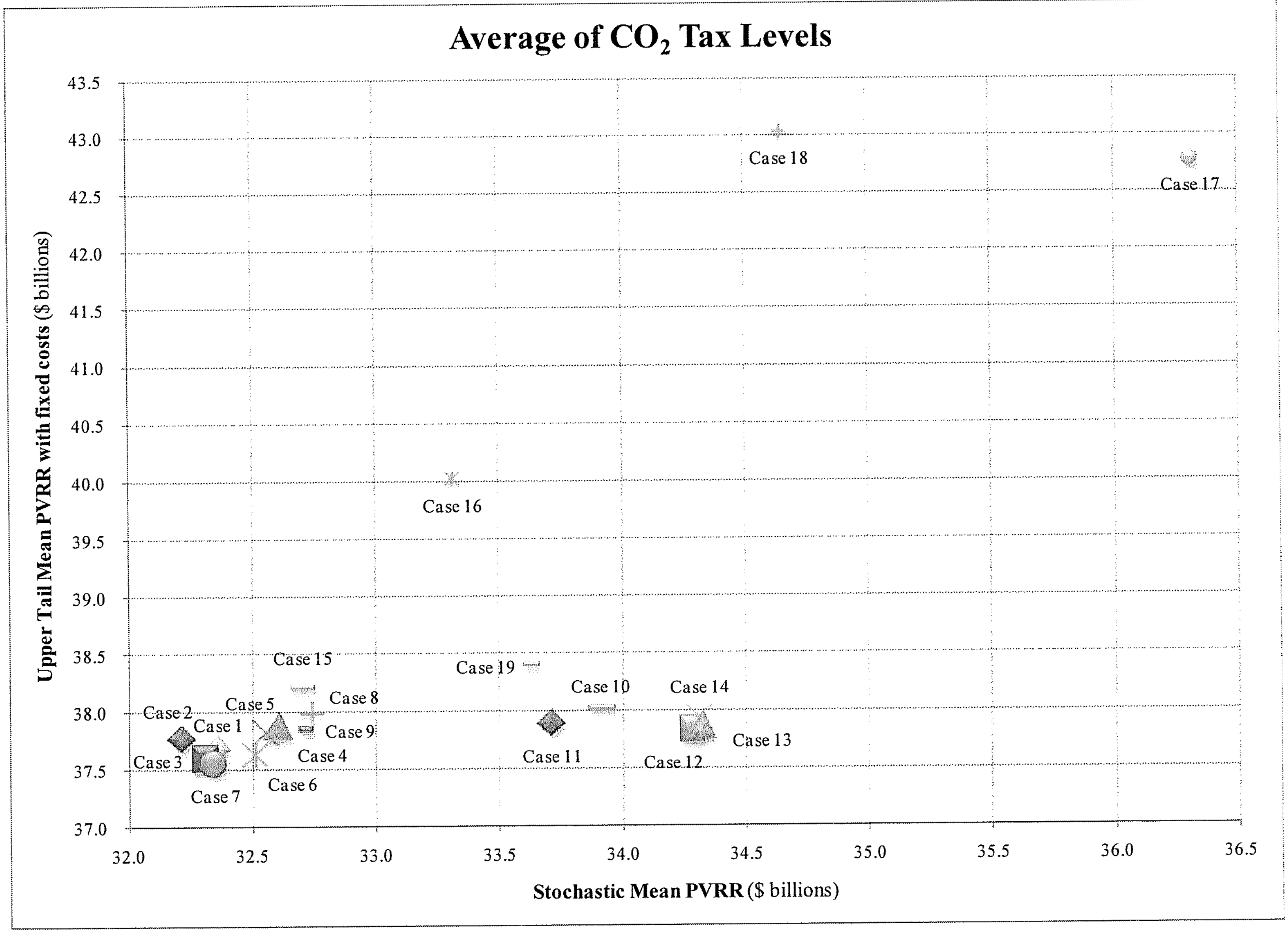


Table E.1– Stochastic Mean PVRR by CO_2 Tax Level, Core Case Portfolios

	CO_2 tax level Million Dollars (2011$)			
Case	**$0/ton**	**$12/ton** (low to very high)	**$19/ton**	**Average**
Case 1	26,623	35,567	34,892	32,360
Case 2	26,424	35,462	34,768	32,218
Case 3	26,616	35,488	34,835	32,313
Case 4	27,002	35,681	35,139	32,607
Case 5	27,000	35,585	35,087	32,558
Case 6	27,008	35,516	35,024	32,516
Case 7	26,650	35,527	34,868	32,348
Case 8	27,122	35,841	35,271	32,744
Case 9	27,122	35,738	35,231	32,697
Case 10	28,555	36,838	36,362	33,918
Case 11	28,172	36,816	36,154	33,714
Case 12	29,082	37,103	36,678	34,288
Case 13	29,182	37,009	36,789	34,327
Case 14	29,073	37,167	36,698	34,312
Case 15	27,591	35,560	34,969	32,707
Case 16	28,441	36,181	35,328	33,317
Case 17	32,369	38,539	38,036	36,315
Case 18	30,957	37,206	35,791	34,651
Case 19	28,108	36,679	36,128	33,638

Table E.2 – Stochastic Risk Results by CO_2 Tax Level, Core Case Portfolios

	CO_2 tax level: $0/ton Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Case 1	1,948	23,551	29,799	30,808
Case 2	2,029	23,289	29,825	30,836
Case 3	1,934	23,563	29,796	30,752
Case 4	1,954	23,892	30,191	31,139
Case 5	1,974	23,836	30,194	31,092
Case 6	1,919	23,901	30,093	30,938
Case 7	1,915	23,604	29,784	30,727
Case 8	1,930	24,066	30,277	31,232
Case 9	1,918	24,031	30,239	31,140
Case 10	1,515	25,956	30,751	31,556
Case 11	1,550	25,530	30,601	31,267
Case 12	1,351	26,681	30,984	31,603
Case 13	1,337	26,817	31,096	31,715
Case 14	1,368	26,678	31,099	31,678
Case 15	3,094	22,909	32,060	33,036
Case 16	3,852	22,803	34,100	35,053
Case 17	3,702	27,139	37,948	38,792

	CO_2 tax level: $0/ton Million Dollars (2011$)			
Case	Production cost standard deviation	5th percentile	95th percentile	Upper-tail mean
Case 18	5,372	23,619	39,270	40,182
Case 19	1,754	25,198	30,890	31,688

	CO_2 tax level: $12/ton (low to very high) Million Dollars (2011$)			
Case	Production cost standard deviation	5th percentile	95th percentile	Upper-tail mean
Case 1	3,538	30,185	40,773	41,748
Case 2	3,629	29,986	40,833	41,897
Case 3	3,530	30,116	40,643	41,639
Case 4	3,535	30,308	40,860	41,801
Case 5	3,588	30,125	40,857	41,685
Case 6	3,537	30,112	40,621	41,470
Case 7	3,497	30,198	40,653	41,578
Case 8	3,492	30,527	40,943	41,929
Case 9	3,485	30,425	40,852	41,709
Case 10	2,992	32,117	40,806	41,749
Case 11	3,031	32,052	41,074	41,787
Case 12	2,779	32,666	40,627	41,417
Case 13	2,710	32,664	40,457	41,270
Case 14	2,794	32,693	40,772	41,597
Case 15	3,366	30,376	40,526	41,375
Case 16	4,362	29,774	42,618	43,469
Case 17	4,271	32,485	44,974	45,819
Case 18	5,419	29,490	45,353	46,097
Case 19	3,378	31,435	41,467	42,276

	CO_2 tax level: $19/ton Million Dollars (2011$)			
Case	Production cost standard deviation	5th percentile	95th percentile	Upper-tail mean
Case 1	3,109	30,050	39,270	40,465
Case 2	3,204	29,836	39,513	40,542
Case 3	3,103	30,012	39,230	40,360
Case 4	3,115	30,300	39,523	40,667
Case 5	3,158	30,177	39,517	40,653
Case 6	3,111	30,173	39,350	40,445
Case 7	3,076	30,080	39,198	40,342
Case 8	3,080	30,479	39,618	40,747
Case 9	3,070	30,426	39,534	40,666
Case 10	2,573	32,206	39,619	40,718
Case 11	2,612	31,976	39,524	40,592
Case 12	2,390	32,783	39,859	40,452

	CO_2 tax level: $19/ton Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Case 13	2,365	32,896	39,979	40,576
Case 14	2,391	32,821	39,968	40,528
Case 15	2,806	30,683	39,117	40,197
Case 16	3,543	29,877	40,405	41,519
Case 17	3,381	32,874	42,757	43,692
Case 18	4,210	29,456	41,637	42,791
Case 19	2,960	31,450	40,155	41,203

Table E.3 – Carbon Dioxide and Other Pollutant Emissions

	Emissions				Emissions				Emissions			
	CO2	SO2	NOx	Hg	CO2	SO2	NOx	Hg	CO2	SO2	NOx	Hg
	000 Tons	000 Tons	000 Tons	Pounds	000 Tons	000 Tons	000 Tons	Pounds	000 Tons	000 Tons	000 Tons	Pounds
Case	$0 CO2 Tax				$19 CO2 Tax				$12 Low to Very High CO2 Tax			
1	941,203	753	1,092	6,289	842,439	653	939	5,700	801,497	641	912	5,492
2	943,810	754	1,093	6,298	847,689	656	944	5,721	807,175	644	918	5,516
3	937,901	751	1,087	6,277	837,918	649	932	5,681	796,784	638	906	5,473
4	930,958	745	1,075	6,389	829,216	643	918	5,881	787,440	631	891	5,697
5	929,942	740	1,066	6,338	826,233	635	906	5,813	782,864	622	877	5,637
6	924,985	737	1,061	6,320	820,706	631	900	5,791	777,600	619	872	5,618
7	938,503	752	1,088	6,280	838,639	650	933	5,683	797,611	638	907	5,476
8	931,497	748	1,079	6,433	830,673	646	923	5,912	789,817	635	897	5,722
9	930,726	745	1,074	6,369	828,225	642	916	5,860	785,834	630	889	5,683
10	917,430	747	1,076	6,363	807,771	641	912	5,834	764,891	627	882	5,648
11	932,265	756	1,095	6,293	825,486	651	934	5,672	784,279	638	906	5,462
12	907,039	741	1,067	6,347	793,839	631	898	5,792	751,203	618	869	5,595
13	906,120	742	1,068	6,282	793,834	633	900	5,735	750,460	620	871	5,559
14	911,849	742	1,067	6,322	799,548	633	900	5,771	755,998	618	869	5,591
15	814,681	645	916	5,875	859,920	670	958	6,029	800,509	639	905	5,736
16	770,990	604	854	5,634	810,905	626	890	5,766	746,912	586	828	5,434
17	673,465	543	766	5,253	711,580	566	803	5,377	651,663	525	745	5,062
18	677,562	506	709	5,114	757,444	568	804	5,447	682,971	516	723	5,068
19	922,446	740	1,068	6,219	821,231	636	911	5,610	779,075	623	883	5,393

Table E.4 – Cumulative 10-year Customer Rate Impact, Core Case Portfolios

Case	$0 CO_2	$ 19 CO_2	$ 12 CO_2 (low - very high)	Average	Rank
1	22.6%	39.6%	33.6%	31.9%	3
2	22.3%	39.4%	33.3%	31.7%	1
3	22.6%	39.5%	33.5%	31.9%	2
4	22.9%	39.8%	33.8%	32.2%	6
5	22.7%	39.6%	33.6%	32.0%	5
6	23.3%	39.9%	34.0%	32.4%	9
7	22.7%	39.6%	33.6%	31.9%	4
8	23.0%	40.0%	33.9%	32.3%	8
9	22.9%	39.9%	33.8%	32.2%	7
10	27.3%	43.4%	37.8%	36.2%	17
11	26.3%	42.6%	36.9%	35.2%	13

Case	\$0 CO_2	\$ 19 CO_2	\$ 12 CO_2 (low - very high)	Average	Rank
12	26.9%	43.0%	37.5%	35.8%	16
13	26.3%	42.6%	36.9%	35.2%	14
14	28.3%	44.0%	38.7%	37.0%	18
15	24.1%	39.6%	33.8%	32.5%	10
16	26.0%	39.9%	35.3%	33.7%	11
17	33.4%	45.0%	41.6%	40.0%	19
18	29.5%	40.6%	37.1%	35.7%	15
19	25.5%	42.3%	36.3%	34.7%	12

Figure E.5 – Average Annual Energy Not Served (2011 – 2030), \$19 CO_2 Core Case Portfolios

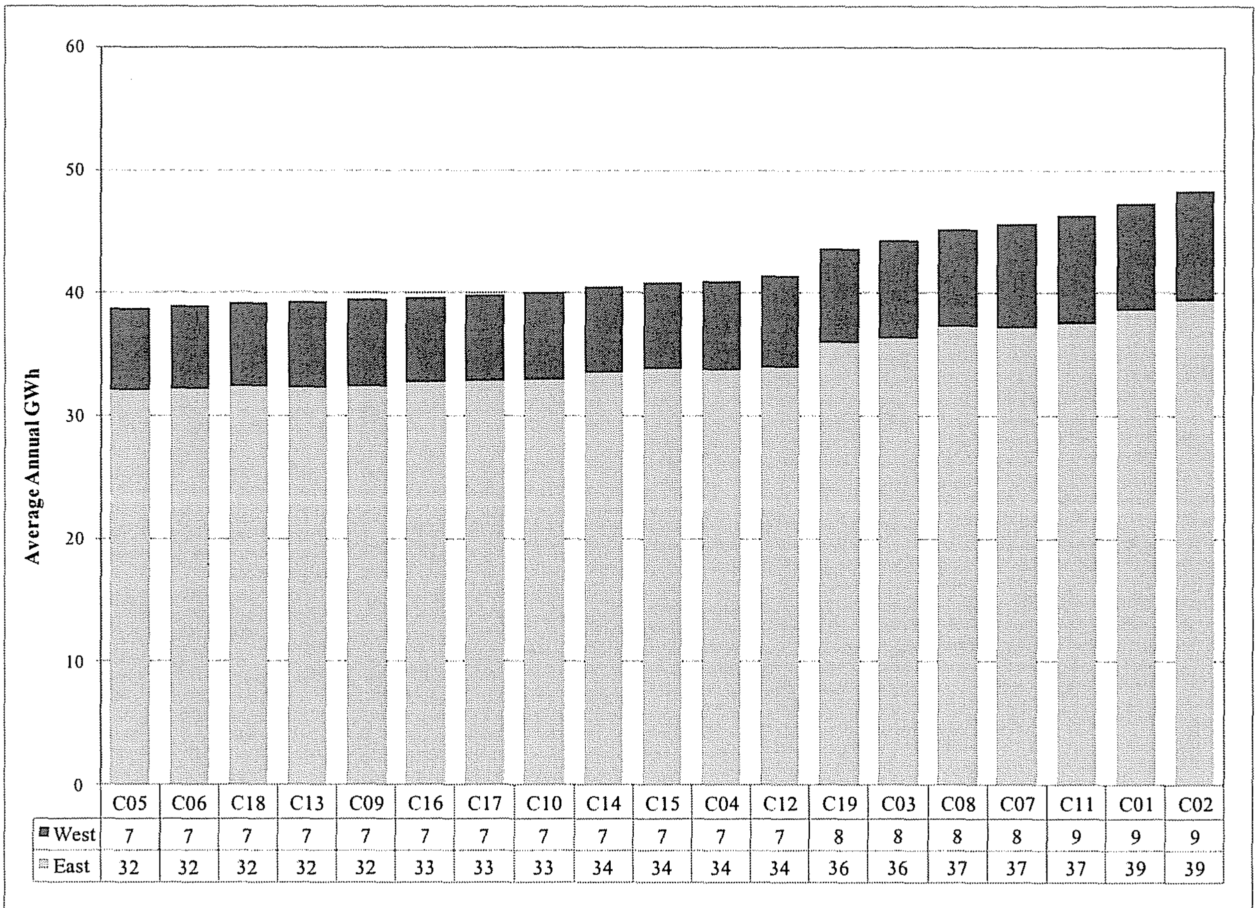


Table E.5 – Loss of Load Probability for a Major (> 25,000 MWh) July Event, Core Case Portfolios

Year	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
2011	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
2012	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
2013	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
2014	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
2015	13%	12%	12%	12%	12%	12%	12%	12%	12%	13%
2016	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
2017	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%
2018	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
2019	26%	26%	26%	26%	26%	26%	26%	25%	26%	25%
2020	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%
2021	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
2022	21%	21%	21%	21%	21%	21%	17%	21%	18%	19%
2023	9%	13%	16%	16%	16%	16%	6%	16%	15%	16%
2024	21%	18%	27%	17%	33%	33%	16%	33%	27%	33%
2025	18%	14%	23%	21%	17%	26%	23%	26%	26%	26%
2026	17%	16%	13%	13%	14%	14%	20%	13%	21%	20%
2027	24%	27%	27%	28%	19%	16%	28%	19%	28%	28%
2028	31%	31%	24%	25%	16%	16%	30%	24%	25%	23%
2029	39%	39%	33%	37%	24%	24%	38%	30%	24%	21%
2030	50%	51%	49%	39%	35%	35%	50%	47%	28%	29%

Year	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16	Case 17	Case 18	Case 19
2011	7%	7%	7%	7%	7%	7%	7%	7%	7%
2012	6%	6%	6%	6%	6%	6%	6%	6%	6%
2013	8%	8%	8%	8%	8%	8%	8%	8%	8%
2014	10%	10%	10%	10%	10%	10%	10%	10%	10%
2015	13%	13%	13%	13%	12%	12%	13%	12%	13%
2016	10%	10%	10%	10%	10%	10%	10%	10%	10%
2017	19%	19%	19%	19%	19%	19%	19%	19%	19%
2018	27%	27%	27%	27%	27%	27%	27%	27%	27%
2019	25%	25%	25%	25%	25%	26%	25%	25%	26%
2020	21%	21%	21%	21%	21%	21%	21%	21%	21%
2021	24%	20%	24%	24%	24%	24%	24%	24%	24%
2022	18%	13%	19%	21%	21%	21%	21%	6%	22%
2023	13%	11%	14%	16%	16%	16%	16%	2%	16%
2024	25%	27%	24%	33%	32%	19%	32%	32%	32%
2025	15%	15%	15%	19%	26%	17%	14%	26%	26%
2026	15%	16%	16%	12%	13%	11%	13%	21%	14%
2027	28%	28%	23%	12%	14%	27%	25%	27%	23%
2028	29%	29%	23%	27%	18%	20%	20%	22%	20%
2029	36%	37%	32%	33%	28%	32%	27%	32%	37%
2030	50%	46%	36%	36%	43%	39%	43%	35%	48%

Table E.6 – Average Loss of Load Probability During Summer Peak

Average for operating years 2011 through 2020										
Event Size (MWh)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
> 0	92%	93%	93%	93%	93%	93%	93%	93%	93%	93%
> 1,000	75%	75%	75%	75%	75%	74%	75%	75%	75%	75%
> 10,000	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%
> 25,000	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
> 50,000	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
> 100,000	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
> 500,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Average for operating years 2011 through 2030										
Event Size (MWh)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
> 0	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
> 1,000	73%	74%	74%	74%	74%	74%	74%	74%	74%	76%
> 10,000	32%	32%	32%	31%	31%	31%	31%	32%	31%	31%
> 25,000	20%	20%	20%	19%	18%	19%	20%	20%	19%	19%
> 50,000	11%	11%	11%	10%	9%	10%	11%	10%	10%	10%
> 100,000	4%	4%	4%	3%	3%	3%	4%	3%	3%	3%
> 500,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Average for operating years 2011 through 2020									
Event Size (MWh)	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16	Case 17	Case 18	Case 19
> 0	93%	93%	93%	93%	92%	92%	92%	92%	92%
> 1,000	75%	75%	75%	75%	74%	74%	74%	74%	75%
> 10,000	26%	26%	26%	26%	26%	26%	26%	26%	26%
> 25,000	15%	15%	15%	15%	15%	15%	15%	15%	15%
> 50,000	6%	6%	6%	6%	6%	6%	6%	6%	6%
> 100,000	2%	2%	2%	2%	2%	2%	2%	2%	2%
> 500,000	0%	0%	0%	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%
Average for operating years 2011 through 2030									
Event Size (MWh)	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16	Case 17	Case 18	Case 19
> 0	92%	92%	92%	93%	92%	92%	93%	92%	92%
> 1,000	74%	74%	74%	76%	74%	74%	74%	73%	75%
> 10,000	31%	31%	31%	31%	31%	31%	31%	31%	32%
> 25,000	20%	19%	19%	19%	19%	19%	19%	19%	20%
> 50,000	11%	10%	10%	10%	10%	10%	10%	10%	11%
> 100,000	4%	3%	3%	3%	3%	3%	3%	3%	3%
> 500,000	0%	0%	0%	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%

Coal Plant Utilization Sensitivity and Load Forecast Scenario Stochastic Study Results

The following tables report stochastic production cost modeling results for Cases 21 through 24 (coal utilization sensitivities) and Cases 25 and 26 (low and high economic growth sensitivities). Note that the Case 20 coal utilization portfolio (medium CO_2 tax and gas prices) did not result in any coal plant replacements, so the Company did not consider it worthwhile to conduct a stochastic production cost simulation with this portfolio. Similarly, the Case 27 portfolio, which assumed high peak loads driven by one-in-ten peak load producing temperatures, was not sufficiently different in resource mix relative to the high economic growth portfolio to warrant stochastic production cost modeling.

Table E.7 – Stochastic Mean PVRR by CO_2 Tax Level, Sensitivity Portfolios

	CO_2 tax level Million Dollars (2011$)			
Case	**$0/ton**	**$12/ton** (low to very high)	**$19/ton**	**Average**
Coal Plant Utilization Sensitivity Cases				
Case 21	26,648	35,495	34,857	32,334
Case 22	27,053	35,877	35,241	32,724
Case 23	27,553	36,079	35,561	33,064
Case 24	27,976	36,499	35,529	33,335
Load Forecast Sensitivity Cases				
Case 25	25,142	33,710	34,071	30,974
Case 26	28,059	37,233	36,583	33,958

Table E.8 – Stochastic Risk Results by CO_2 Tax Level, Sensitivity Portfolios

	CO_2 tax level: $0/ton Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Coal Plant Utilization Sensitivity Cases				
Case 21	1,939	23,579	29,863	30,802
Case 22	1,907	24,013	30,189	31,112
Case 23	2,269	24,106	31,624	32,514
Case 24	2,222	24,571	31,968	32,801
Load Forecast Sensitivity Cases				
Case 25	1,450	22,694	27,296	28,137
Case 26	2,284	24,621	32,049	33,059

	CO_2 tax level: $12/ton (low to very high) Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Coal Plant Utilization Sensitivity Cases				
Case 21	3,542	30,099	40,691	41,664
Case 22	3,500	30,536	41,013	41,925
Case 23	3,876	30,344	42,058	43,169
Case 24	3,825	30,815	42,396	43,437
Load Forecast Sensitivity Cases				
Case 25	2,966	29,066	37,655	38,642
Case 26	3,935	31,400	43,150	44,340

	CO_2 tax level: $19/ton Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Coal Plant Utilization Sensitivity Cases				
Case 21	3,111	30,015	39,303	40,396
Case 22	3,072	30,448	39,594	40,692
Case 23	3,416	30,404	40,850	41,859
Case 24	3,368	30,412	40,641	41,696
Load Forecast Sensitivity Cases				
Case 25	2,534	30,003	37,280	38,432
Case 26	3,528	31,223	41,953	43,046

Portfolio PVRR Cost Component Comparison

Tables E.9 and E.10 show the breakdown of each portfolio's stochastic mean PVRR by variable and fixed cost components. These costs reflect the \$19/0ton CO_2 cost adder scenario. Table E.11 reports the cost component breakdown for the core case portfolios, and table E.12 reports the cost component breakdown for the sensitivity cases.

Core Case Portfolios

Table E.9 – Core Cases 1 through 8, Portfolio PVRR Cost Components (\$19 CO_2 Tax Level)

Cost Component (\$ 000,000)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
Variable Costs								
Fuel & O&M	15,710	15,853	15,729	16,006	15,832	15,755	15,668	15,945
Emission Cost	7,473	7,531	7,424	7,338	7,307	7,245	7,431	7,353
FOT's & Long Term Contracts	4,087	4,060	3,956	3,788	3,753	3,793	4,014	3,867
Demand Side Management	3,682	3,746	3,670	3,957	3,836	3,687	3,735	4,112
Renewables	843	696	848	848	827	787	848	870
System Balancing Sales	(5,986)	(5,923)	(5,937)	(5,987)	(5,918)	(5,963)	(5,975)	(6,015)
System Balancing Purchases	3,173	3,225	3,168	3,081	3,119	3,085	3,170	3,091
Nuclear	-	-	-	-	-	-	-	-
Energy Not Served	139	140	137	132	130	130	136	139
Dump Power	(117)	(116)	(117)	(117)	(115)	(115)	(117)	(117)
Reserve Deficiency	2	4	2	1	0	0	1	2
Total Variable Costs	**29,004**	**29,214**	**28,882**	**29,046**	**28,771**	**28,405**	**28,911**	**29,247**
Capital and Fixed Costs	5,887	5,554	5,954	6,093	6,316	6,619	5,956	6,024
Total PVRR	**34,892**	**34,768**	**34,835**	**35,139**	**35,087**	**35,024**	**34,868**	**35,271**

Table E.10 – Core Cases 9 through 16, Portfolio PVRR Cost Components ($19 CO_2 Tax Level)

Cost Component ($ 000,000)	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16
Variable Costs								
Fuel & O&M	15,884	15,046	15,180	14,812	14,724	14,765	16,130	15,710
Emission Cost	7,329	7,100	7,284	6,953	6,968	7,009	7,734	7,179
FOT's & Long Term Contracts	3,855	3,932	3,997	3,957	3,913	3,998	3,961	3,882
Demand Side Management	4,033	4,553	4,516	4,414	4,534	4,630	3,676	3,830
Renewables	866	1,298	1,328	1,379	1,328	1,315	843	870
System Balancing Sales	(6,040)	(6,120)	(6,166)	(6,315)	(6,256)	(6,330)	(6,353)	(5,798)
System Balancing Purchases	3,067	2,975	2,954	2,801	2,845	2,831	2,730	3,333
Nuclear	-	-	-	-	88	-	-	-
Energy Not Served	131	133	138	131	130	133	133	130
Dump Power	(116)	(118)	(117)	(120)	(117)	(119)	(116)	(116)
Reserve Deficiency	0	1	4	3	2	2	0	0
Total Variable Costs	**29,009**	**28,800**	**29,118**	**28,015**	**28,157**	**28,233**	**28,738**	**29,021**
Capital and Fixed Costs	6,222	7,562	7,036	8,664	8,631	8,464	6,232	6,307
Total PVRR	**35,231**	**36,362**	**36,154**	**36,678**	**36,789**	**36,698**	**34,969**	**35,327**

Table E.11 – Core Cases 17 through 19, Portfolio PVRR Cost Components ($19 CO_2 Tax Level)

Cost Component ($ 000,000)	Case 17	Case 18	Case 19
Variable Costs			
Fuel & O&M	13,909	15,239	15,446
Emission Cost	6,112	6,524	7,246
FOT's & Long Term Contracts	4,001	3,639	4,054
Demand Side Management	4,535	3,939	4,808
Renewables	1,363	843	668
System Balancing Sales	(5,586)	(5,197)	(6,093)
System Balancing Purchases	3,545	3,941	3,070
Nuclear	44	-	-
Energy Not Served	131	128	137
Dump Power	(119)	(114)	(115)
Reserve Deficiency	2	0	1
Total Variable Costs	**27,937**	**28,942**	**29,221**
Capital and Fixed Costs	10,099	6,849	6,907
Total PVRR	**38,036**	**35,790**	**36,128**

Table E.12 – Coal Plant Utilization Sensitivity and Load Forecast Scenario ($19 CO_2 Tax Level)

Cost Component ($000,000)	Coal	Coal	Coal	Coal	Low Economic Growth	High Economic Growth
Description	**Case 21**	**Case 22**	**Case 23**	**Case 24**	**Case 25**	**Case 26**
Variable Costs						
Fuel & O&M	15,653	15,594	15,822	15,773	14,954	16,599
Emission Cost	7,420	7,409	7,226	7,227	7,199	7,656
FOT's & Long Term Contracts	4,054	4,043	4,048	4,032	3,981	3,954
Demand Side Management	3,675	4,117	3,991	4,003	3,920	3,817
Renewables	848	871	847	873	832	851
System Balancing Sales	(5,958)	(5,962)	(5,983)	(5,983)	(6,142)	(5,940)
System Balancing Purchases	3,156	3,145	3,123	3,116	2,978	3,235
Nuclear	-	-	-	-	-	-
Energy Not Served	148	147	145	119	111	166
Dump Power	(116)	(116)	(116)	(116)	(119)	(113)
Reserve Deficiency	2	1	1	1	1	2
Total Variable Costs	**28,881**	**29,249**	**29,103**	**29,046**	**27,715**	**30,228**
Capital and Fixed Costs	5,976	5,992	6,458	6,458	6,356	6,356
Total PVRR	**34,857**	**35,241**	**35,561**	**35,504**	**34,071**	**36,583**

Table E.13 – Coal Plant Utilization Sensitivity and Load Forecast Scenario ($0 CO_2 Tax Level)

Cost Component ($000,000)	Coal	Coal	Coal	Coal	Low Economic Growth	High Economic Growth
Description	**Case 21**	**Case 22**	**Case 23**	**Case 24**	**Case 25**	**Case 26**
Variable Costs						
Fuel & O&M	15,765	15,721	15,879	15,849	15,139	16,798
Emission Cost	2	2	2	2	2	2
FOT's & Long Term Contracts	3,848	3,839	3,843	3,831	3,792	3,770
Demand Side Management	3,675	4,117	3,991	4,003	3,920	3,817
Renewables	788	803	789	807	777	818
System Balancing Sales	(5,572)	(5,577)	(5,574)	(5,577)	(5,769)	(5,754)
System Balancing Purchases	2,134	2,126	2,137	2,128	1,964	2,191
Nuclear	-	-	-	-	-	-
Energy Not Served	149	148	147	145	112	173
Dump Power	(120)	(120)	(120)	(120)	(122)	(114)
Reserve Deficiency	2	1	1	1	1	2
Total Variable Costs	**20,672**	**21,061**	**21,095**	**21,069**	**19,815**	**21,704**
Capital and Fixed Costs	5,976	5,992	6,458	6,907	5,327	6,356
Total PVRR	**26,648**	**27,053**	**27,553**	**27,976**	**25,142**	**28,059**

Table E.14 – Coal Plant Utilization Sensitivity and Load Forecast Scenario ($12 CO_2 Tax Level)

Cost Component ($000,000)	Coal	Coal	Coal	Coal	Low Economic Growth	High Economic Growth
Description	**Case 21**	**Case 22**	**Case 23**	**Case 24**	**Case 25**	**Case 26**
Variable Costs						
Fuel & O&M	14,111	14,050	14,324	14,280	13,484	15,013
Emission Cost	7,309	7,299	6,950	6,957	7,104	7,610
FOT's & Long Term Contracts	3,813	3,805	3,809	3,793	3,745	3,723
Demand Side Management	3,675	4,117	3,991	4,003	3,920	3,817
Renewables	847	870	847	873	830	845
System Balancing Sales	(4,126)	(4,133)	(4,152)	(4,159)	(4,319)	(4,112)
System Balancing Purchases	3,852	3,840	3,818	3,811	3,619	3,920
Nuclear	-	-	-	-	-	-
Energy Not Served	153	152	150	148	117	171
Dump Power	(116)	(116)	(116)	(116)	(118)	(112)
Reserve Deficiency	2	1	1	1	1	2
Total Variable Costs	**29,519**	**29,886**	**29,621**	**29,592**	**28,383**	**30,877**
Capital and Fixed Costs	5,976	5,992	6,458	6,907	5,327	6,356
Total PVRR	**35,495**	**35,877**	**36,079**	**36,499**	**33,710**	**37,233**

APPENDIX F – THE PUBLIC INPUT PROCESS

A critical element of this resource plan is the public input process. PacifiCorp has pursued an open and collaborative approach involving the Commissions, customers and other stakeholders in PacifiCorp's planning process prior to making resource planning decisions. Since these decisions can have significant economic and environmental consequences, conducting the resource plan with transparency and full participation from Commissions and other interested and affected parties is essential.

The public has been involved in this resource plan from its earliest stages and at each decisive step. Participants have both shared comments and ideas and received information. As reflected in the report, many of the comments provided by the participants have been adopted by PacifiCorp and have contributed to the quality of this resource plan. PacifiCorp will adopt further comments going forward, either as elements of the Action Plan or as future refinements to the planning methodology.

The cornerstone of the public input process has been full-day public input meetings held approximately throughout the year-long plan development period. These meetings have been held jointly in two locations—Salt Lake City, Utah and Portland Oregon—using telephone and video conferencing technology.

IRP public process continued with state stakeholder dialogue sessions from mid-June through August 2010. These goal of these sessions, targeting a state-specific audience, were to (1) capture key resource planning issues of most concern to each state, and discuss how these can be tackled from a system planning perspective, (2) ensure that stakeholders understand PacifiCorp's planning principles and the logic behind its planning process, and (3) set expectations for what can be accomplished in the current IRP/business planning cycle. These State focused meetings continued to enhance interaction with stakeholders in the planning cycle, and provided a forum to directly address stakeholder concerns regarding equitable representation of state interests during general public meetings.

As far as agenda setting is concerned, PacifiCorp solicited recommendations from the state stakeholders in advance of the session, as well as allowing open time to ensure that participants had adequate time for dialogue. Some follow-up activities arising from the sessions were addressed in subsequent public meetings.

The 2010 public input meetings were augmented by a series of focused technical workshops to provide an opportunity to discuss complex topics for a multi-state utility in more detail.

Participant List

Among the organizations that were represented and actively involved in this collaborative effort were:

Commissions

- Idaho Public Utilities Commission
- Oregon Public Utilities Commission

- Public Service Commission of Utah
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission

Intervenors

- Attorney General of Washington
- Brigham Young University
- Citizen's Utility Board of Oregon
- Committee for Consumer Services State of Utah
- ECOS Consulting
- Encana Corporation
- enXco
- Energy Trust of Oregon
- Energy Strategies, LLC
- HEAL Utah and Utah Physicians for a Healthy Environment
- Health Environment Alliance of Utah (HEAL)
- Horizon Wind Energy
- Iberdrola
- Industrial Customers of Northwest Utilities
- Interwest Energy Alliance
- Kennecott
- Mountain West Consulting, LLC
- Northwest Power and Conservation Council
- Northwest Pipeline GP
- NW Energy Coalition
- Oregon Department of Energy
- Powder River Basin Resource Council
- Renewables Northwest Project
- Salt Lake City
- Salt Lake Community Action Program
- Southwest Energy Efficiency Project
- Sierra Club , Utah Chapter
- U.S. Department of Energy - Intermountain Clean Energy Application Center
- U.S. Department of Energy - Northwest Clean Energy Application Center
- Utah Association of Energy Users
- Utah Clean Energy Alliance
- Utah Division of Air Quality
- Utah Division of Public Utilities
- Utah Energy Office
- Utah Geological Survey
- Wasatch Clean Air Coalition
- Western Resource Advocates
- West Wind Wires
- Wyoming Industrial Energy Consumers

- Wyoming Office Of Consumer Advocacy

Others

- Avista Utilities
- Cadmus Group Inc.
- GDS Associates
- Idaho Power Company
- John Klingele (Washington Customer)
- Portland General Electric (PGE)

PacifiCorp extends its gratitude for the time and energy these participants have given to the resource plan. Your participation has contributed significantly to the quality of this plan, and your continued participation will help as PacifiCorp strives to improve its planning efforts going forward.

Public Input Meetings

PacifiCorp hosted five full-day public input meetings, two half day meetings, one conference call and six state meetings during the 2010. During the 2011 IRP process presentations and discussions covered various issues including inputs and assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public input meetings and the technical workshops.

General Meetings

April 28, 2010

- IRP Group and Support Team
- Discussion on the wind integration study methodology white paper
- IRP Regulatory Compliance (2008 IRP / 2011 IRP)
- IRP Preparation Schedule and Public Process
- IRP Modeling Plan and Initiatives
- 2008 IRP Update

August 4, 2010

- Demand-side management / distributed generation
- Supply-side Resources
- Planning Reserve Margin (PRM) analysis
- Proposed portfolio development cases

October 5, 2010

- IRP Schedule Update
- Energy Gateway Transmission Construction Update and Evaluation
- Load Forecast
- Hedging Strategy
- Market Reliance Analysis
- Capacity Load & Resource Balance
- Portfolio Development Cases

December 15, 2010

- Planning Reserve Margin and LOLP
- Update on Assumptions
  - Load Forecast Scenarios
  - DSM Supply Curves
- Update Load and Resource Balance
- Preliminary Results for Core Cases and Transmission

January 27, 2011

- Solar photovoltaic resource modeling

January 31, 2011

- Review of System Optimizer Core Case Results – Cases 1 to 19

February 23, 2011

- Stochastic production cost modeling results
- preferred portfolio selection
- coal utilization study results

March 23, 2011

- Preferred portfolio discussion,
- Remaining portfolio sensitivity results, and
- the IRP action plan

State Meetings

June 16, 2010 – Oregon / California

- Evaluating distribution efficiency potential
- Wind integration study
- Transmission financial analysis
- Assumptions update for portfolio analysis / All-source RFP
- Intermediate-term Market Purchases
- Out-year resource selection
- Enhanced regulatory impact modeling
- Use of carbon dioxide emissions for portfolio performance scoring
- Open Discussion Items – Smart Grid and PacifiCorp Modeling

June 29, 2010 – Utah

- Renewable/non-traditional Resource Evaluation
  Wind integration study

Distributed solar
Resource modeling and characterization
Sensitivity analysis of incentive programs (e.g., level of incentive needed to make distributed solar cost-effective)
Hybrid intermittent/storage technologies
Commercial geothermal potential study

- DSM Potential Study
  Treatment of achievable potential adjustments
  Application of the Utility Cost Test
- Market Risk Assessment
  Price hedging strategy
  Inclusion of hedging costs in portfolio resources
  Sensitivity analysis of hedging strategies to minimize costs and risks for customers
  Market purchase risk assessment
  WECC Power Supply Assessment
  Stochastic simulation and risk analysis
- Resource Adequacy
  Planning reserve margin evaluation
  Sensitivity analysis of Energy Not Served (ENS) price; i.e., flat vs. tiered approach
  Hydro sustained peaking capability
  Treatment of planned resources
- Load Forecasting
  GDS Consulting recommendations for the 2008 IRP
  Load forecast scenarios
  Standalone load forecast report
  Stochastic parameter estimation
- Model Training

July 28, 2010 – Idaho
- 2008 IRP Acknowledgement Letter
- Discount rate impact on resource timing and selection
- Wind integration costs – justification and stochastic modeling support
- Quantifying Renewable Portfolio Standard costs and other jurisdictional mandates
- Portfolio selection process and weighting scheme

August 11, 2010 – Wyoming
- ENS in Portfolio Modeling
- Planning Reserve Margin
- CO2 Modeling: Tax versus Cap-n-Trade
- Supply-side Option Table
- LOLP
- Weighting Schemes

Parking Lot Issues

During the course of the public input meetings, certain concerns or questions needed additional follow-up from PacifiCorp. These questions or issues were taken off-line and addressed in a meeting report or at a subsequent public input meeting or workshop.

Public Review of IRP Draft Document

PacifiCorp distributed the draft document materials on February 23 and March 7, 2011 for public review. Public comments were requested by March 24, 2011. Parties that submitted comments include:

- Encana Corporation
- HEAL Utah and Utah Physicians for a Healthy Environment
- Interwest Energy Alliance
- Powder River Basin Resource Council
- Renewable Northwest Project
- Sierra Club
- Utah Association of Energy Users
- Utah Clean Energy
- Utah Public Service Commission Staff
- U.S. Department of Energy - Northwest Clean Energy Application Center
- U.S. Department of Energy - Intermountain Clean Energy Application Center
- Washington Utility and Transportation Commission
- Western Resource Advocates

Many of the clarifications and information requested through the written comments, verbal suggestions from the March 23, 2011 conference call, and data requests, have been incorporated into the final version of the IRP.

Contact Information

PacifiCorp's IRP internet website contains many of the documents and presentations that support recent Integrated Resource Plans. To access it, please visit the company's website at http://www.PacifiCorp.com click on the menu "Energy Sources" and select "Integrated Resource Planning".

PacifiCorp requests that any informal request be sent in writing to the following address or email address below.

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Portland, Oregon 97232

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APPENDIX G – HEDGING STRATEGY

Introduction

This appendix addresses two Public Service Commission of Utah analysis requirements pertaining to price hedging.

- "At a minimum, we direct the Company to include the costs of hedging in its IRP analysis of resources that rely on fuels subject to volatile prices."
- "We also direct the Company to perform sensitivity analysis to determine a hedging strategy which minimizes costs and risks for customers."[3]

To address these requirements, this appendix presents a comparison among hedging strategies to demonstrate that while the expected value of all hedging strategies is the same, different strategies have differing risk profiles. The consequence is that selection of a hedging strategy is made not by expected outcome but by risk tolerance, and that hedging outcomes net to a zero expected value on a long-term basis.

Hedging

Purpose of Hedging

Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market price changes. The Company has exposure to power and natural gas wholesale market price changes due to its responsibility to serve retail load and to economically dispatch its resources. The Company cannot avoid such exposure but can reduce it through hedging. A long forward power position occurs when the amount of energy anticipated to be economically produced by the Company's resources exceeds the amount of energy forecast to be consumed by retail customers, and the Company risks financial loss if wholesale power market prices fall. A short forward natural gas position occurs when the Company's natural gas generation is expected to economically convert natural gas to power and the Company risks financial loss if wholesale natural gas market prices rise. The Company may also have short power positions and, at times, long natural gas positions. All of these open positions result in price risk.

Need for Hedging

Perfect foresight of future wholesale market prices is unattainable by any hedging entity, including the Company. While the Company may have a view of where it believes prices are heading – up, down, or no change – it does not have the ability to predict without error such price changes. The Company has incentive to protect against unfavorable wholesale market

[3] Public Service Commission of Utah, "In the Matter of the Acknowledgment of PacifiCorp's Integrated Resource Plan", Report and Order, Docket No 09-2035-01, April 1, 2009, p. 30.

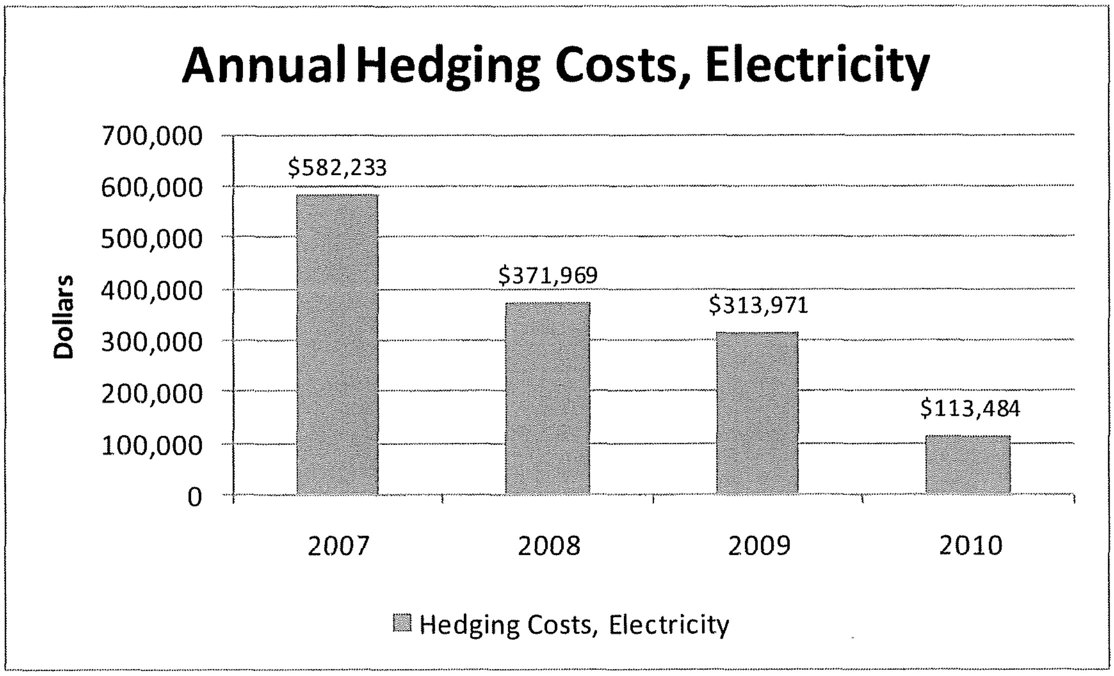
price changes and does so by hedging to reduce the range of net power cost outcomes for any wholesale market price changes.

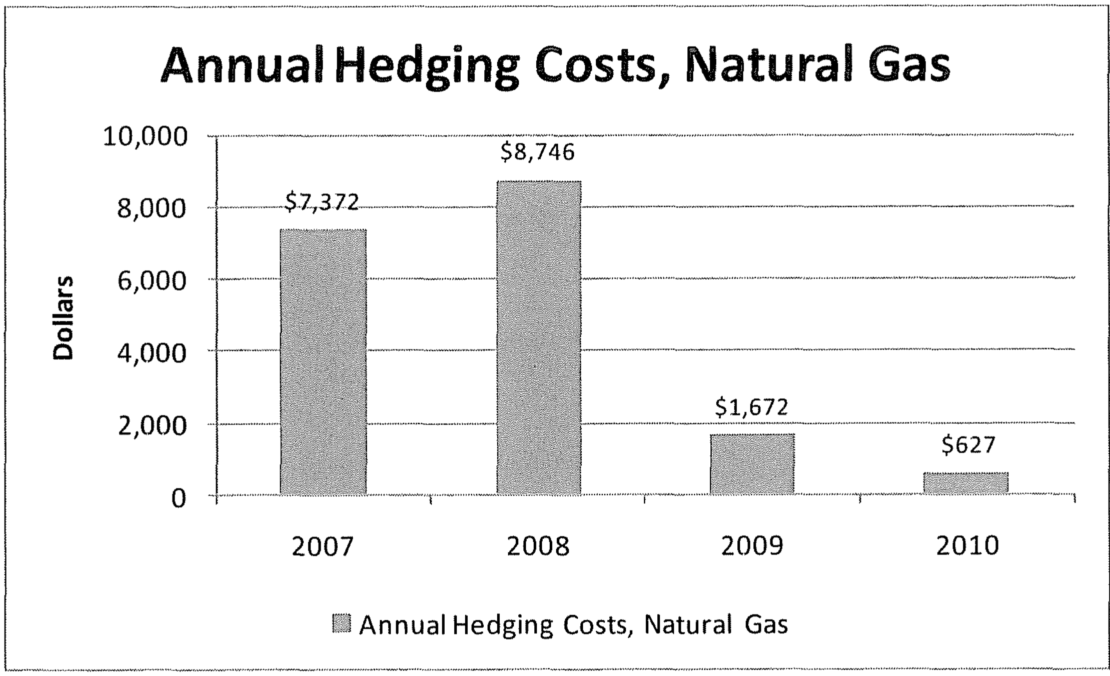
Impact of Hedging and Hedging Costs

Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. Increased hedging reduces both the potential losses and potential gains. Therefore, if the Company has a low risk tolerance it would hedge a greater amount than if it has a high risk tolerance. *Hedging does not, however, modify the expected outcome of net power costs associated with wholesale market price changes.* Any hedging program, whether it utilizes fixed-price forward or option products, would result in the same expected net power costs from the perspective of the time the hedges are transacted. Historical gains and losses due to hedging are only indicative of potential opportunity costs for having pursued an alternate hedging strategy once the outcome is already known.

With respect to hedging costs, which the Company defines as hedging program expenses, Figure G.1 shows the trend in the Company's annual costs for both electricity and natural gas hedging activities (broker fees). As can be seen, the hedging costs are too small to be used as a meaningful distinguishing factor among resources and portfolios.

Figure G.1 – PacifiCorp's Annual Electricity and Natural Gas Hedging Costs





Hedge Products

The basic hedge products available to the company are fixed-price forwards and, to a lesser extent, vanilla options. All basic hedging strategies are in theory implementable using combinations of these two types of products. In practice, however, the Company almost exclusively employs fixed-priced forwards. This is because forward markets relevant to the Company are liquid, and the costs have been determined to be recoverable.

In contrast, options have a number of disadvantages to the Company. There are not liquid regional options markets, meaning that any options available have a high additional cost reflected in the spread between the buyer's bid price and the seller's ask price. There is an active natural gas options market at Henry Hub, but the price of natural gas in the Company's region does not necessarily move in lock-step with the price of natural gas at Henry Hub. This is known as basis risk, and is undesirable. Finally, because options require payment up-front for benefits that may or may not occur in the future, it is not clear that the Company would be able to recover the cost of unexercised options in rates.

No "Best" Hedging Strategy

Among the myriad conceivable hedging strategies there is no purely objective optimization method resulting in the best strategy. Determining a strategy that is best for the Company is necessarily in part a subject evaluation. Parameters that must be considered are market liquidity, types and availability of desired hedge products, customer risk tolerance, and cost of hedge program management, to name a few.

Sample Portfolio Simulations

Various hedging programs have been simulated to demonstrate the impact to the range of net power cost outcomes and to demonstrate there is no change to the expected outcome. The measurement of range of net power cost outcomes is the "to-expiry value-at-risk" distribution. This TEVaR distribution is a statistically-generated distribution of outcomes that is wider or narrower based upon the aggregate volatility of the combined power and natural gas portfolio. Inasmuch as being short natural gas naturally offsets being long power, one would expect the TEVaR distribution of a long-power/short-natural gas portfolio to be significantly narrower than the distribution of either individual component.

Five portfolios were simulated using Monte Carlo technique to calculate to-expiry value-at-risk. The first portfolio, entitled "Reference portfolio," is comprised of a 500 average MW power long position and a (100,000) MMBtu/day natural gas short position. This represents the Company's hypothetical combination of retail load, economic generation and transactions that partially hedge the position. The long power and short natural gas positions are largely offsetting. This is used as the reference portfolio for the following scenario analyses.

The second portfolio, entitled "less hedged," is comprised of 625 average MW power long position and (125,000) MMBtu/day natural gas short position. Relative to the reference portfolio, this demonstrates the change in risk profile of a portfolio with 25% less hedged position. In this portfolio, there are 125 average MW fewer hedge transactions resulting in more power length, and 25,000 MMBtu/day fewer hedge transactions resulting in a shorter natural gas short position.

The third portfolio, entitled "more hedged," is comprised of 375 average MW power long position and (75,000) MMBtu/day natural gas short position. Relative to the reference portfolio, this demonstrates the change in risk profile of a portfolio with 25% more hedged position. In this portfolio, there are 125 average MW more hedge transactions resulting in less power length and 25,000 MMBtu/day more hedge transactions resulting in less short natural gas position.

The fourth portfolio, entitled "Hedge only power," is comprised of a fully hedged power position and (100,000) MMBtu/day natural gas short position. Relative to the reference portfolio, this demonstrates hedging all power but no natural gas.

The fifth portfolio, entitled "Hedge only natural gas," is comprised of a 500 average MW power long position and a fully hedged natural gas position. Relative to the reference portfolio, this demonstrates hedging all natural gas but no power.

Results

Charts of the results are shown below (Figures G.2 through G.5). In addition, for ease of comparison among portfolios, Table G.1 below shows the expected value, the fifth percentile outcome (very unfavorable prices), and the 95th percentile outcome (very favorable prices). These values shown are relative, so that \$0 expected value indicates the potential change in portfolio value due to market price changes is expected to be neutral. This is the statistical equivalent of the earlier assertion that hedging can only reduce the range of potential net power costs, but cannot reduce expected net power costs. .

The reference portfolio, shown in blue in each of the four charts, has an unsymmetrical fifth and 95th percentile result due to the likelihood that prices may increase more than decrease, and due to the reference portfolio being net short. A log-normal price distribution is used to represent this effect.

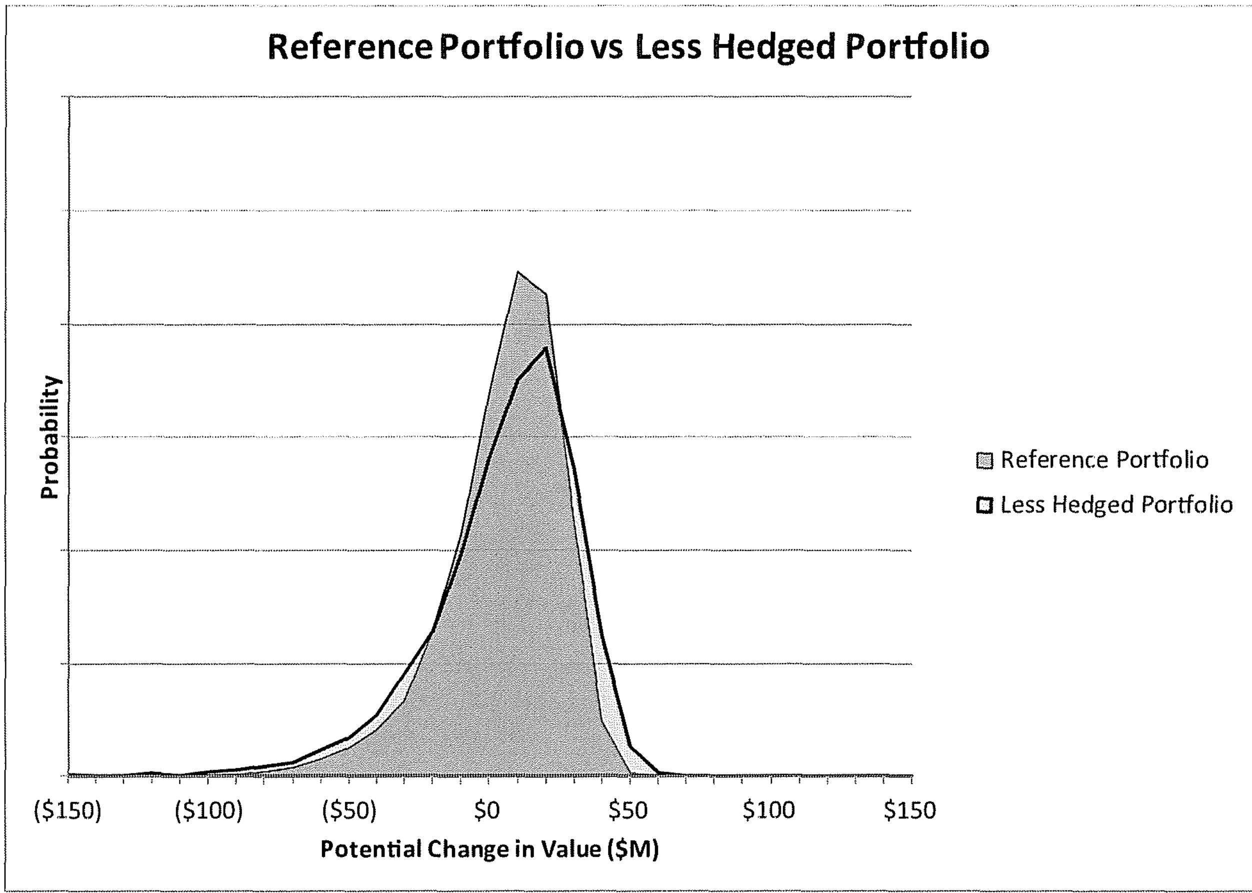
In the less hedged sample portfolio, both the power and natural gas volumes are 25 percent larger than the reference portfolio. Conversely in the more hedged sample portfolio, both the power and natural gas volumes are 25 percent smaller than the reference portfolio. As expected, the less hedged portfolio shows a wider distribution of outcomes representing a higher risk to price changes. Similarly, the more hedged portfolio shows a narrower distribution.

The "hedge only power" portfolio shows a much wider distribution due to the severe reduction in the natural offset between power and natural gas in the reference portfolio. The "hedge only natural gas" has a similar distribution. Of note is the 5th percentile "hedge only power" portfolio is much greater downside than the "hedge only natural gas" portfolio, and this is due to the log-normal prices.

Table G.1 – Comparison of Multiple Sample Portfolios

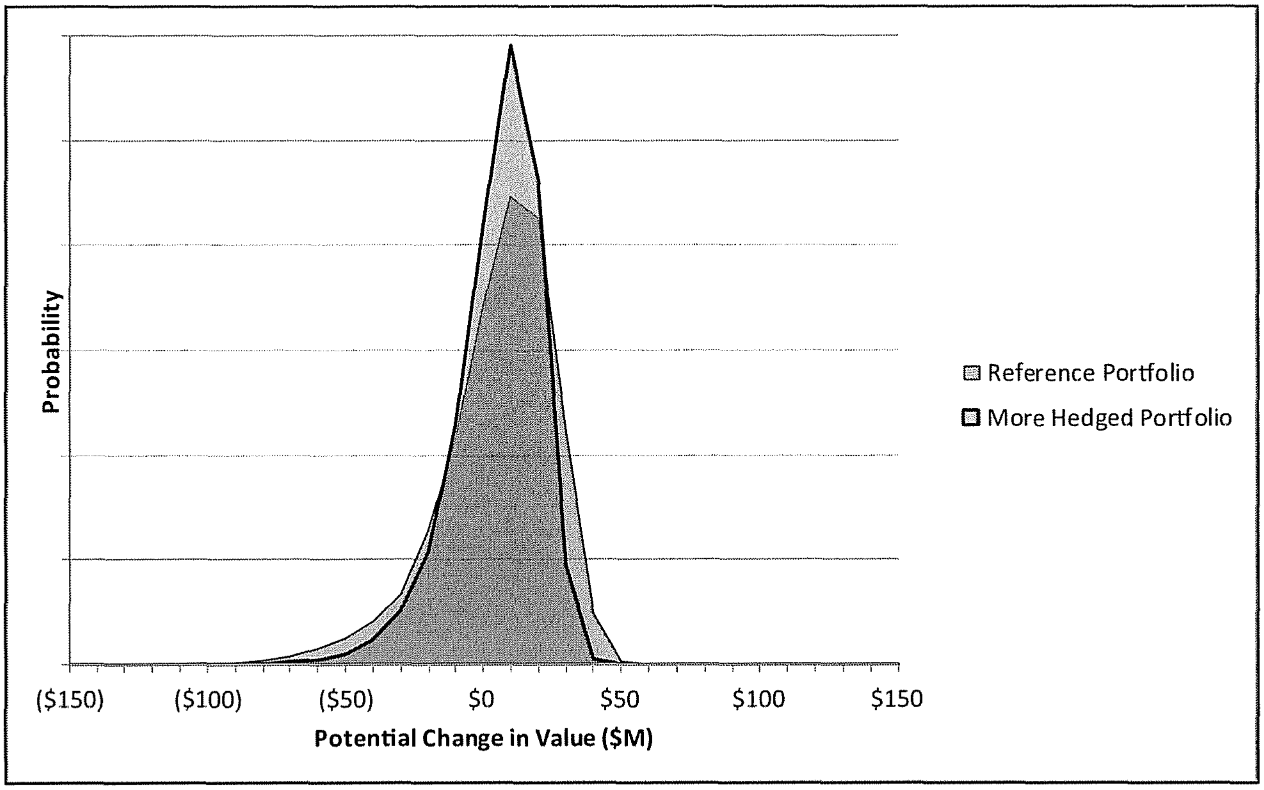
Portfolio Simulation (open hedged positions)	5th Percentile (million $)	Expected Value (million $)	95th Percentile (million $)
Reference portfolio 500 average MW power (100,000) MMBtu/day natural gas	($40)	$0	$27
Less hedged 625 average MW power (125,000) MMBtu/day natural gas	($48)	$0	$33
More hedged 375 average MW power (75,000) MMBtu/day natural gas	($29)	$0	$20
Hedge only power 0 average MW power (100,000) MMBtu/day natural gas	($92)	$0	$66
Hedge only natural gas 500 average MW power 0 MMBtu/day natural gas	($48)	$0	$62

Figure G.2 – Reference Portfolio versus Less Hedged Portfolio



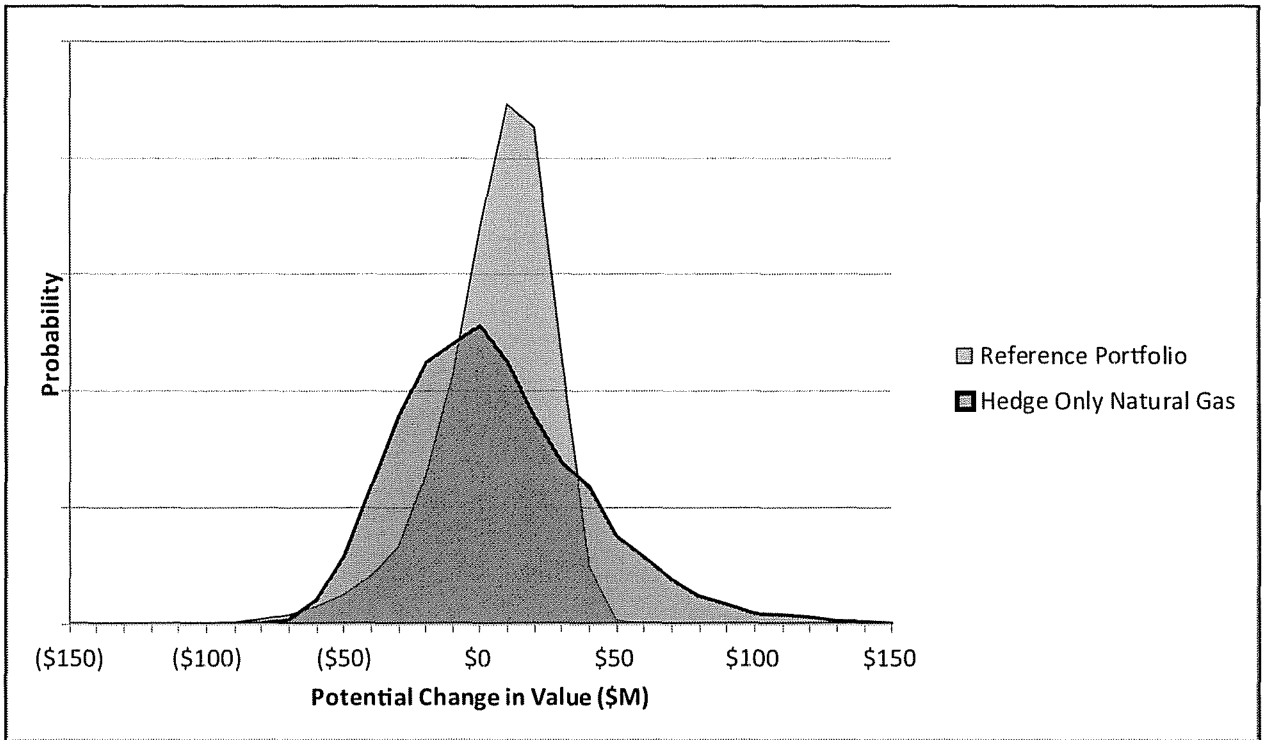
In the "Reference Portfolio versus Less Hedged Portfolio" chart, the less hedged portfolio has a wider distribution of results than the reference portfolio. While both portfolios have an expected value of zero over all potential scenarios, the less hedged portfolio will return a wider range of outcomes.

Figure G.3 – Reference Portfolio versus More Hedged Portfolio



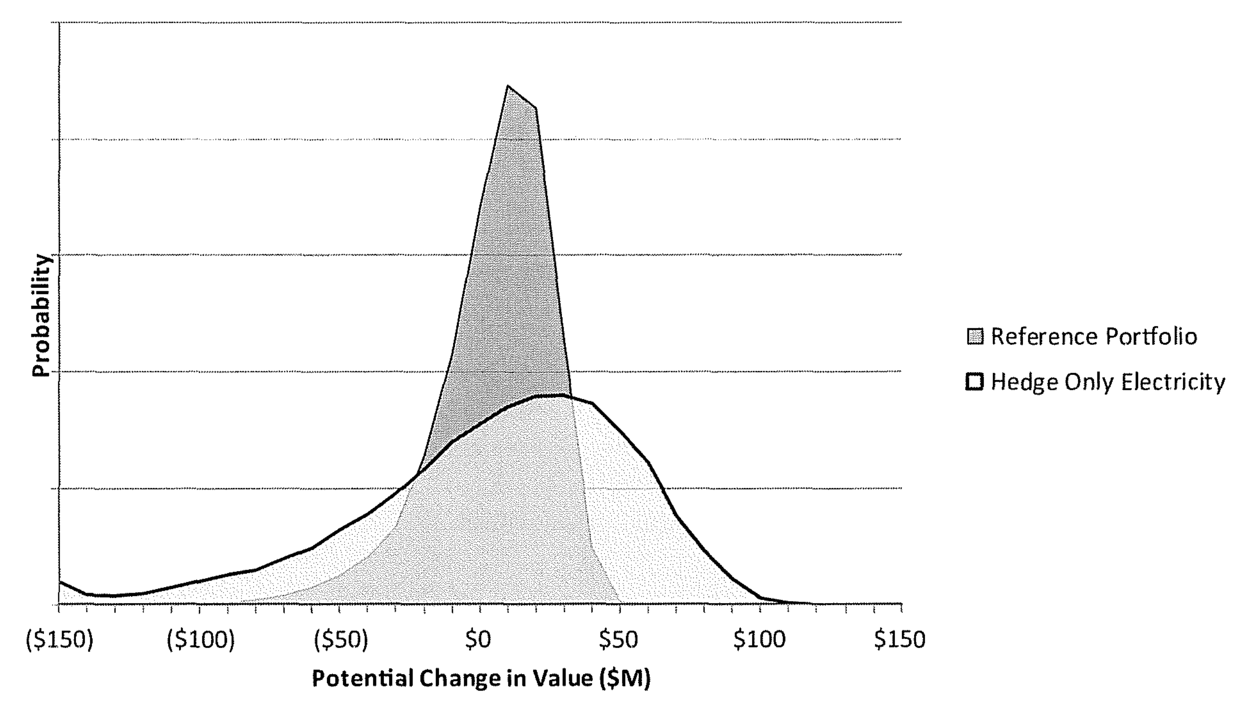
In the "Reference Portfolio versus More Hedged Portfolio", the more hedged portfolio has a tighter distribution of results than the reference portfolio. While both portfolios have an expected value of zero over all potential scenarios, the more hedged portfolio will return a tighter range of outcomes.

Figure G.4 – Reference Portfolio versus Hedging Only Natural Gas



In the "Reference Portfolio versus Hedging Only Natural Gas", the portfolio where only natural gas has been hedged (and electricity positions left unhedged) has a significantly wider distribution of results than the reference portfolio. While both portfolios have an expected value of zero over all potential scenarios, the alternate portfolio will return a significantly wider range of outcomes. This is due to removing the natural offsetting features of one commodity (i.e., hedging the short natural gas position) while leaving the long electricity position unhedged.

Figure G.5 – Reference Portfolio versus Hedging Only Electricity



In the "Reference Portfolio versus Hedging Only Electricity", the portfolio where only electricity has been hedged (and natural gas positions left unhedged) has a significantly wider distribution of results than the reference portfolio. While both portfolios have an expected value of zero over all potential scenarios, the alternate portfolio will return a significantly wider range of outcomes. This is due to removing the natural offsetting features of one commodity (i.e., hedging the long electricity position) while leaving the short natural gas position unhedged.

Conclusion

Hedging does not modify the expected outcome of net power costs associated with wholesale market price and natural gas price changes. Consequently, the long-term gains and losses from hedging are expected to net to zero. As shown in Figure G.1 above, the Company's hedging costs are not material enough to warrant adjustment to resource costs or influence portfolio selection.

In regard to assessment of hedging strategies, a hedging strategy should be tailored to fall within a designated risk tolerance and conform to Company financial and administrative capabilities. A rationale must be created taking into account risk tolerance for adverse impacts to net power costs, and effects including market liquidity and hedge product availability, credit risk, and costs such as collateral funding for margining,

Finally, PacifiCorp shows that there is no objective measurement to indicate the optimum amount of hedging, as demonstrated by a sensitivity analysis that compares a reference portfolio, a less hedged portfolio, and a more hedged portfolio. Nevertheless, the analysis shows that hedging should take full advantage of any natural offsets between long power and short natural gas positions. Not taking advantage results in high risk (a wider distribution of outcomes) as indicated in the "hedge only power" and "hedge only natural gas" portfolios.

APPENDIX H – WESTERN RESOURCE ADEQUACY EVALUATION

Introduction

The Utah Commission, in its 2008 IRP acknowledgment order, directed the Company to conduct two analyses pertaining to the Company's ability to support reliance on market purchases:

> *Additionally, we direct the Company to include an analysis of the adequacy of the western power market to support the volumes of purchases on which the Company expects to rely. We concur with the Office [of Consumer Services], the WECC is a reasonable source for this evaluation. We direct the Company to identify whether customers or shareholders will be expected to bear the risks associated with its reliance on the wholesale market. Finally, we direct the Company to discuss methods to augment the Company's stochastic analysis of this issue in an IRP public input meeting for inclusion in the next IRP or IRP update.*[4]

To fulfill the first requirement, PacifiCorp evaluated the Western Electricity Coordinating Council (WECC) Power Supply Assessment reports to glean trends and conclusions from the supporting analysis. This evaluation, along with a discussion on risk allocation associated with reliance on market purchases, is provided below. As part of this evaluation, the Company also reviewed the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

Finally, this appendix describes a study that involved the development and stochastic simulation of a market "stress" scenario. In developing this study, the Company received input from participants at the June 29, 2010 Utah IRP stakeholder's meeting, and described its proposed study approach at the October 5, 2010, IRP general public input meeting. This appendix describes the study methodology and presents results of the stochastic simulations.

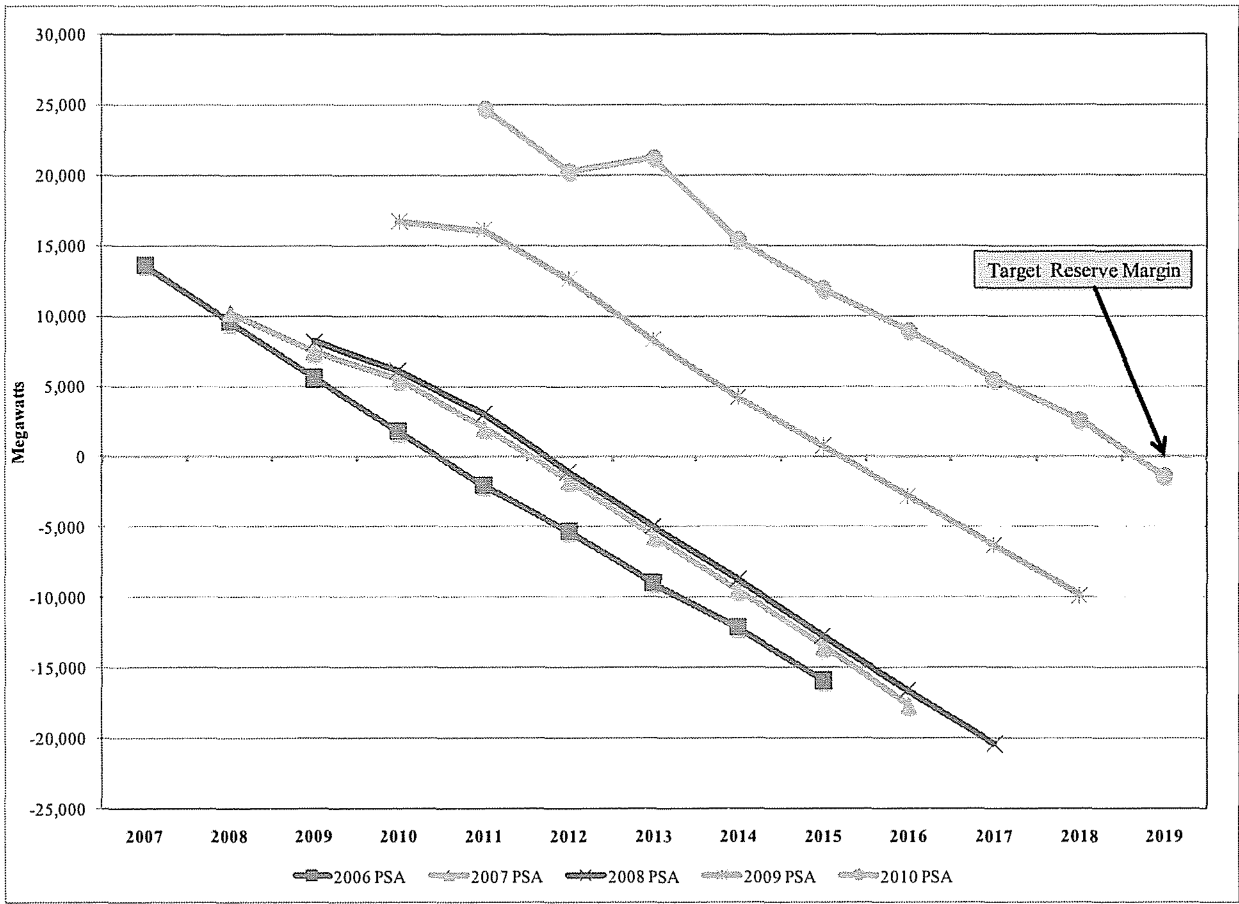
Western Electricity Coordinating Council Resource Adequacy Assessment

The Western Electricity Coordinating Council (WECC) 2010 Power Supply Assessment (PSA) shows WECC needing additional resources in 2019. Resource need is identified when load (including a target reserve margin) exceeds available resources[5]. Since 2006, each subsequent PSA study defers resource need to later years. This deferment is a function of net changes to: load growth expectations, class I capacity entrants, scheduled retirements, resource performance, transfer capabilities and modeling convention.[6]

[4] Public Service Commission of Utah, PacifiCorp 2008 Integrated Resource Plan, Report and Order, Docket No. 09-2035-01, p. 30.
[5] Available resources = Existing Generation + Class I Add/Retire - Outage/Derate Adjustments + Net Imports.
[6] The 2010 PSA defines Class I capacity as being actively under construction and online before January 1, 2014. The 2009 & 2008 PSA require Class I resources to be online by January 1, 2013 and January 1, 2012, respectively.

As seen in Figure 1, there were two significant capacity deferments: from 2012 (per 2008 PSA) to 2016 (per 2009 PSA) followed by 2019 as seen in WECC's 2010 PSA. While the forecast power supply margins (PSM) of the studies from 2006 through 2009 are comparable, the 2010 PSA employed a different, and superior, modeling convention. Namely, the 2010 PSA used PROMOD IV, a chronological production cost model to assess WECC resource adequacy[7]. PROMOD IV, unlike WECC's previous model, uses coincident peak demand and employs a more robust optimization of sub-regional transfers. It is noteworthy that even the 2009 PSA, using the old modeling convention and non-coincident peak demands, did not forecast a capacity need until 2016.

Figure H.1 – WECC Forecasted Power Supply Margins



Note: WECC Power Supply Assessments includes Class 1 Planned Resources Only

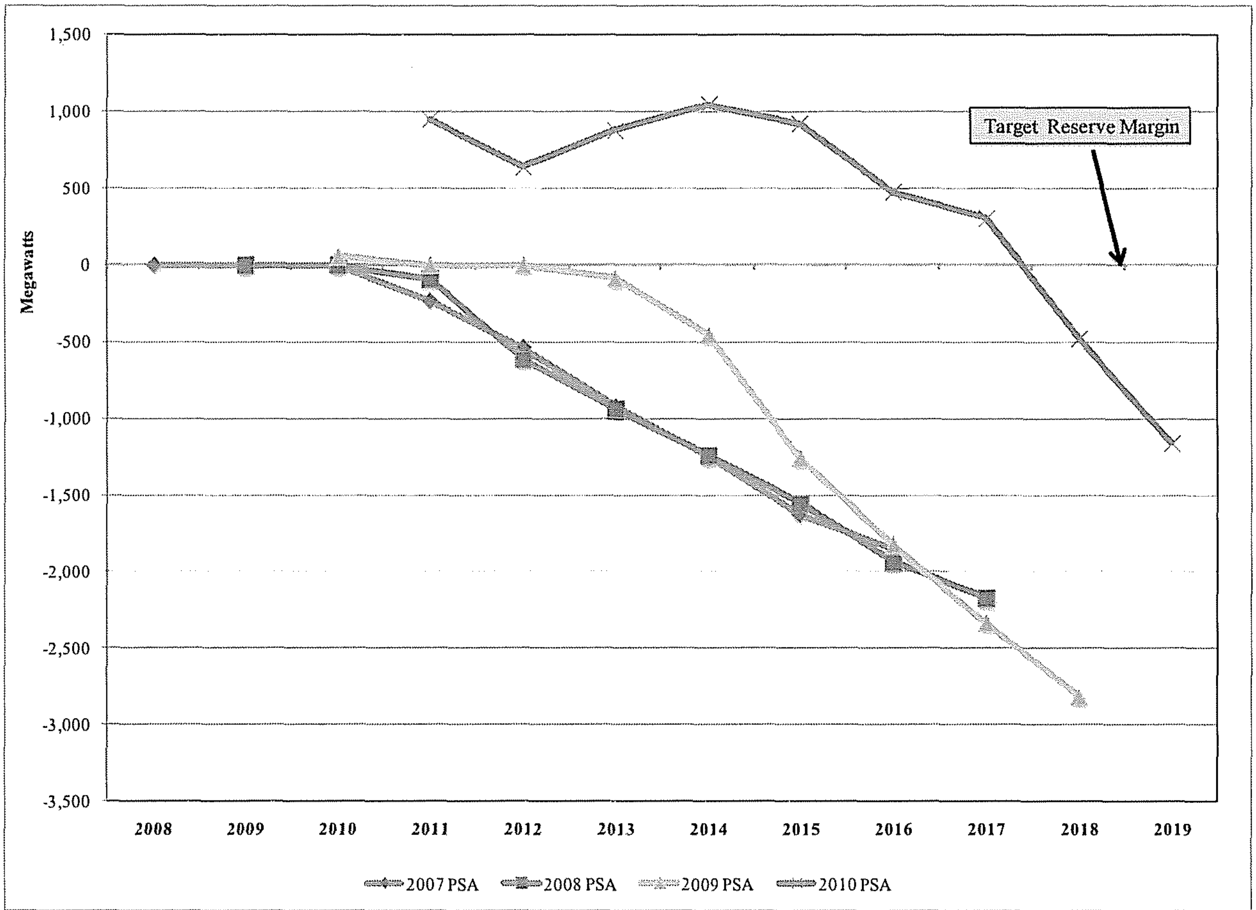
Of particular interest is Basin, a summer peaking sub-region comprised of Utah, Idaho, and northern Nevada. A review of PSA studies from 2007 through 2010 reveals a similar pattern to that of WECC.[8] The 2009 PSA identified a capacity need in 2013; the 2010 PSA defers the need until 2018. As seen in Figure 2, the target reserve margin is maintained at the "zero" horizontal axis.

[7] PROMOD IV is electricity market simulation software licensed through Ventyx, an ABB Company. http://www.ventyx.com/analytics/promod.asp

[8] Basin was not broken out as a sub-region in WECC's 2006 PSA.

The PSA's target reserve margins, as developed by WECC, are not mandated. Instead, they serve as a reasonable proxy for expected target reserve margins in WECC's modeling construct.

Figure H.2 – Basin Forecasted Power Supply Margins



Note: WECC Power Supply Assessments includes Class 1 Planned Resources Only

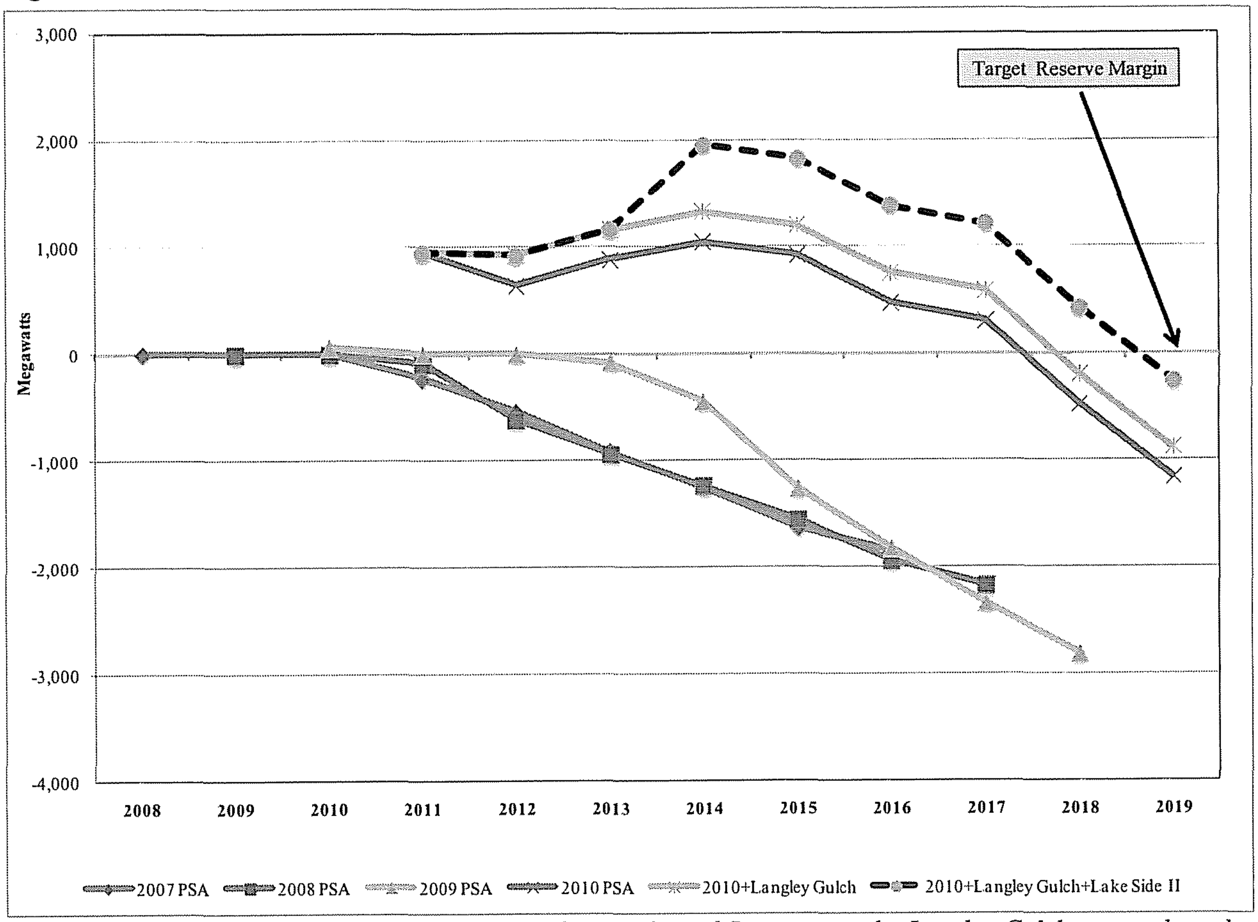
The 2010 PSA, and previous PSA versions, use a four-tier building block approach to calculating a sub-region's target reserve margin. The first block, contingency reserves, is set at 6% of a balancing authority's (BA) load. The second block, regulating reserves, is the amount of spinning reserves needed to instantly match increases in electric load. Expected regulating reserve levels were furnished by BAs to WECC in a 2010 data request. The third block covers additional forced outages beyond what is covered by operating reserves in the event of a second contingency event. The fourth block, temperature adders, is the incremental amount of reserves needed to cover a 1-in-10 temperature event. For modeling purposes, a BA's load requirement is the sum of the BA's peak demand forecast plus the WECC's four-tier target reserve margin[9].

As such, a sub-region's calculated target reserve margin should cover a second contingency event in tandem with a 1-in-10 temperature event. Moreover, with the addition of Idaho Power's

[9] A BA's peak demand forecast incorporates a 1-in-2 chance of temperature exceedance.

Langley Gulch[10] in 2012 and PacifiCorp's Lake Side 2[11] in 2014, additional capacity will not be needed until 2019 as shown in Figure H.3 (Note: Figure H.3 is a modified version of the Original PSA chart that includes the Langley Gulch and Lake Side 2 resources.)

Figure H.3 –Basin Forecasted Power Supply Margins with Selected Capacity Additions



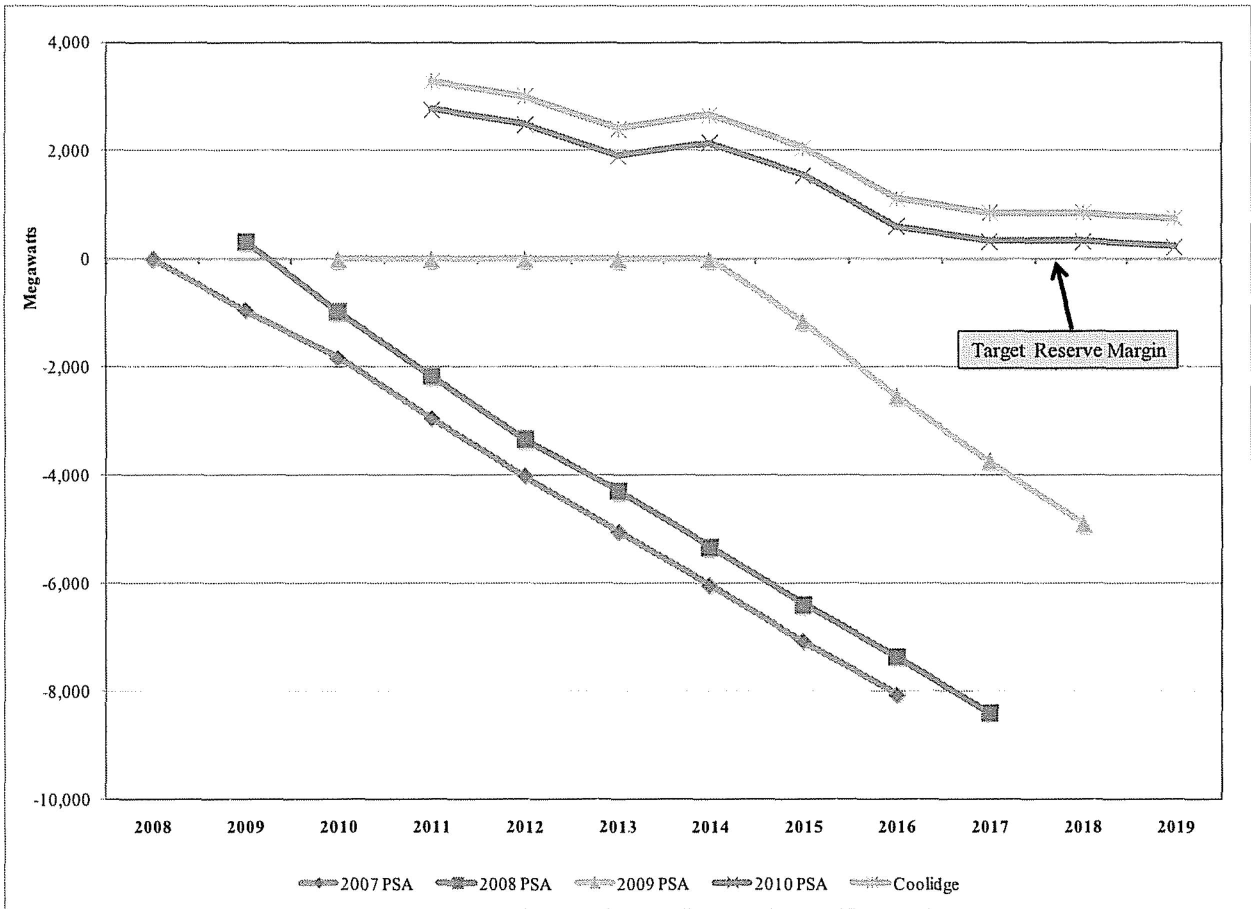
Note: WECC Power Supply Assessment includes Class 1 Planned Resources only. Langley Gulch, currently under construction, and Lake Side 2 as proposed by PacifiCorp are included here to better reflect Basin's capacity status in later years.

[10] Langley Gulch is a 280-MW summer rated combined cycle under construction in Idaho. It was not included in the 2010 PSA as a Class I entrant since it was not under construction at publishing time.

[11] PacifiCorp is seeking to acquire Lake Side 2, a 637-megawatt combined-cycle combustion turbine plant at the Lake Side site in Utah.

As seen in Figures 4 and 5, neither the Desert Southwest nor the Rockies subregions are expected to need additional capacity prior to 2020.[12]

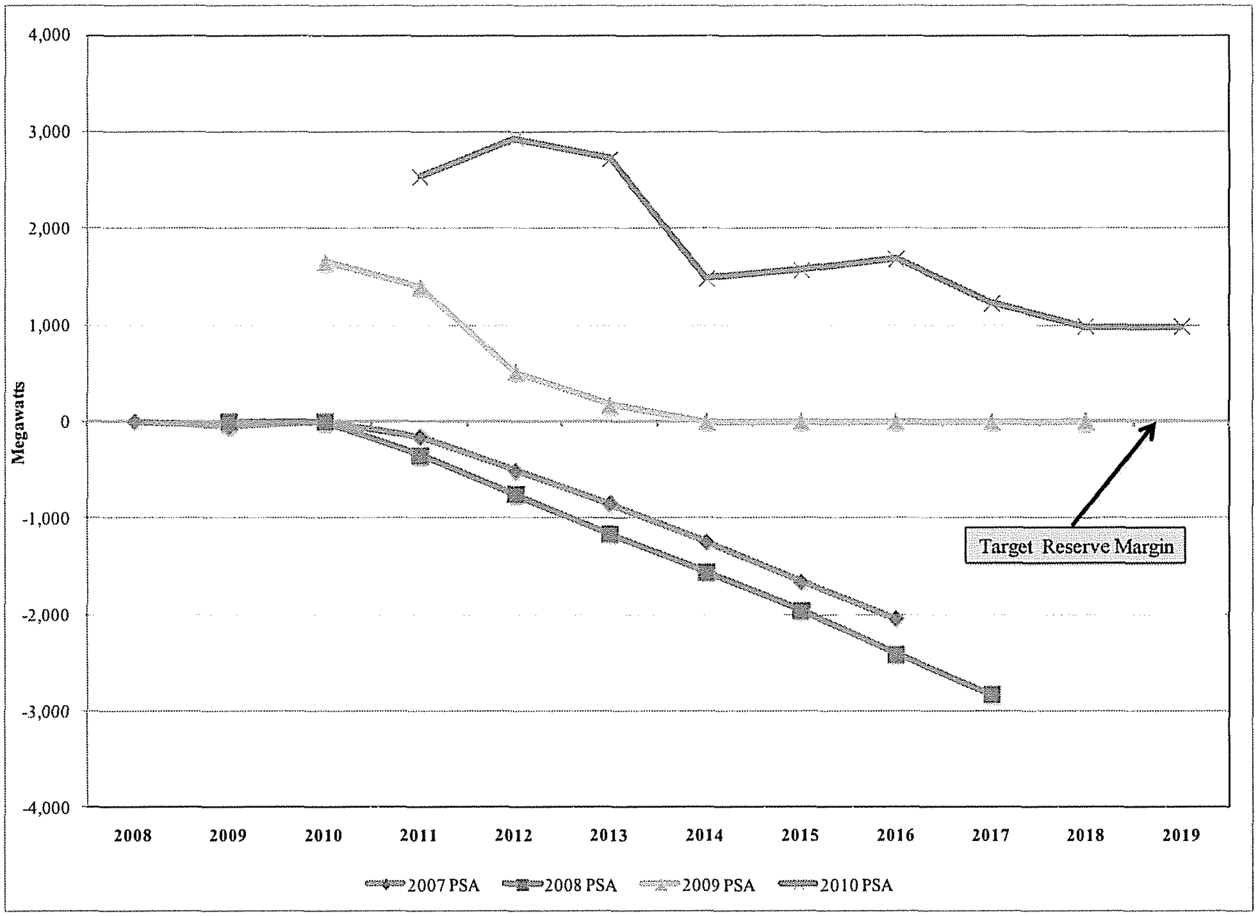
Figure H.4 – Desert Southwest Forecasted Power Supply Margins



Note: WECC Power Supply Assessments includes Class 1 Planned Resources Only. Coolidge Generating is included.

[12] Coolidge Generating is 512-MW gas turbine under construction in Arizona. It was not included in the 2010 PSA as a Class I entrant since it was not under construction at publishing time.

Figure H.5 – Rockies Forecasted Power Supply Margins



Note: WECC Power Supply Assessments includes Class 1 Planned Resources Only.

Market depth refers to a market's ability to accept individual transactions without a perceptible change in market price. While different from market liquidity[13] the two are linked in that a deep market tends to be a liquid market. Market depth in electricity markets is a function of the number of economic agents, market period, generating capacity, transmission capability, transparency, and institutional and/or physical constraints. Based on the 2010 PSA, WECC maintains a positive PSM through 2018. The Desert Southwest, Northwest[14], and Rockies subregions are forecasted to maintain a positive PSM through 2019. Only Basin is forecast to need capacity in 2018.[15] In total, known market transactions, generation resources, load requirements, and the optimization of transfers within WECC show adequate market depth to maintain positive target reserve margins for several years.

[13] Market liquidity refers to having ready and willing buyers and sellers for large transactions.
[14] The Northwest is comprised of the Pacific Northwest and Montana.
[15] Langely Gulch and Lake Side 2, as discussed earlier, will defer Basin's need until 2019.

Pacific Northwest Resource Adequacy Forum's Adequacy Assessment

The Pacific Northwest Resource Adequacy Forum issued resource adequacy standards in April 2008, which were subsequently adopted by the Northwest Power and Conservation Council. The standard calls for assessments three and five years out, conducted every year. The 2008 analysis of 2011 through 2013, conducted before the economic downturn, indicated that "the region has ample supplies over the next five years to avoid significant power curtailments."[16] A resource adequacy report update for 2015 is under development. However, the resource adequacy methodology is now undergoing review. The release of the 2015 report is now expected sometime in 2011. Based on WECC's adequacy evaluation, the Pacific Northwest adequacy situation is expected to remain adequate through 2015 and beyond.

Market Reliance Stress Test

Market Stress Test Design

PacifiCorp's underlying assumptions for the stress test are as follows:

- Based on the WECC resource adequacy assessment, the market reliance risk does not become a factor until at least 2015. Consequently, the market stress period was defined as 2015 through 2020.
- Availability of front office transactions for this period is reduced to 50% of levels assumed for development of the test portfolio.
- Market prices experience a corresponding increase, reflecting reduced market liquidity; the June 2008 Official Forward Price Curve was applied to simulate high market prices as shown in Figure H.6
- To make up for the reduced front office transaction availability, PacifiCorp assumed that it would lease mobile simple-cycle combustion turbine units with a fixed cost of $267/kW for a three-month period (July-September). The annual SCCT capacity requirement ranges from 330 to 550 MW to cover the lost FOT capacity.

PacifiCorp selected a portfolio from the core case group, Case 14, as the test portfolio for the analysis. Case 14 had the highest front office transaction reliance of the core case portfolios for 2015 - 2020. Table H.1 shows the replacement SCCT resource capacity added to the portfolio by year to make up for the reduced FOT, as well as the annual dollars/kW fixed cost assumed for leasing the peaking units.

The Company then simulated this portfolio with the Planning and Risk model, applying the above set of market stress assumptions. Portfolio cost (stochastic mean PVRR and stochastic upper-tail mean PVRR) are compared against the original stochastic run for Case 14.

[16] The Pacific Northwest Resource Adequacy Forum's Web page can be accessed with the following link: http://www.nwcouncil.org/energy/resource/Default.asp. The 2008 resource assessment paper is available for download.

Figure H.6 – Front Office Transaction Market Price Comparison

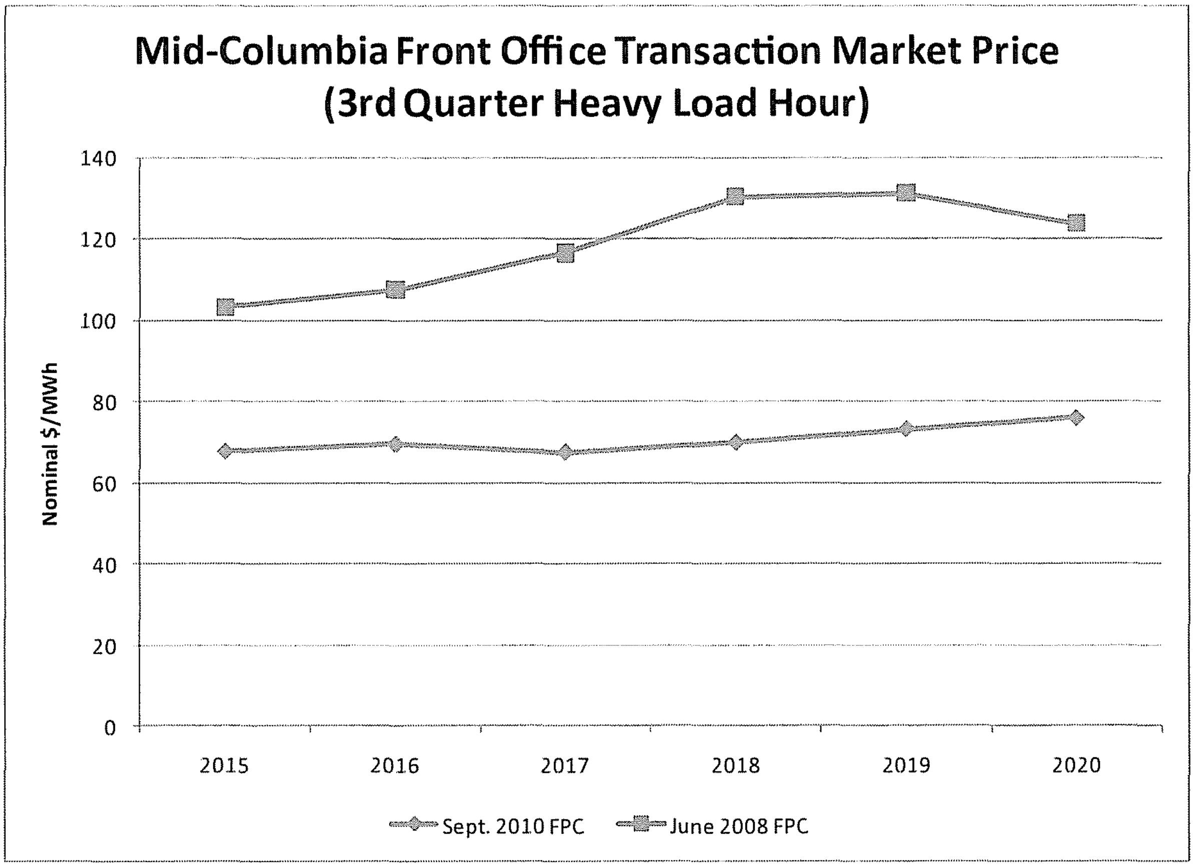


Table H.1 – Peaking Resource Megawatt Capacity Requirements and Fixed Costs

FOT Product and Location	2015	2016	2017	2018	2019	2020
Mead Q3, Heavy Load Hour	50	50	0	0	0	0
Utah Q3, Heavy Load Hour	100	94	100	0	0	100
Mona, Q3, Heavy Load Hour	150	150	150	150	150	150
COB Q3, Heavy Load Hour	25	0	0	0	0	0
Mid-Columbia Q3, Heavy Load Hour	200	200	200	184	197	200
West Main Q3, Heavy Load Hour	25	25	25	0	0	25
Total	550	519	475	334	347	475
Annual Fixed Cost of Peaking Resources, 2010$	$36,683,030	$34,624,326	$31,706,250	$22,272,873	$23,176,101	$31,706,250

Stress Test Results

Table H.2 reports the PVRR line items details for the base stochastic simulation and the stress test stochastic simulation. The stress test conditions resulted in a $387.3 million increase in the stochastic mean PVRR.

Table H.2 – Stochastic PVRR Details for Stress Test and Base Portfolio Simulations

Cost Component	Case 14	Stress Test Case 14	Case 14 less Stress Test Case 14
Variable Costs			
Fuel & O&M	8,461.6	9,312.7	851.1
Emission Cost	3,098.1	3,533.6	435.5
FOT's & Long Term Contracts	2,647.2	2,415.5	(231.7)
Demand Side Management	$1,715	$1,715	-
Renewables	$657	$671	13.35
System Balancing Sales	(3,389.3)	(4,273.9)	(884.6)
System Balancing Purchases	1,710.3	1,805.5	95.2
Energy Not Served	70.9	71.1	0.1
Dump Power	(23.0)	(24.0)	(1.0)
Reserve Deficiency	0.0	0.0	(0.0)
Total Variable Costs	14,947.9	15,225.7	277.8
Capital and Fixed Costs	2,973.2	3,082.6	109.4
Total PVRR	17,921.1	18,308.4	**$387.3**

The higher costs for the stress test portfolio are driven by greater generation costs resulting from increased thermal resource utilization to cover the replaced FOT, as well as the higher fixed costs of the replacement peaking units. These costs were partially offset by increased market sales and lower purchases stemming from use of the replacement peaking resources during peak periods.

Customer versus Shareholder Risk Allocation

Market purchase costs are reflected in rates. Consequently, customers bear the price risk of the Company's reliance on a given level of market purchases. However, customers also bear the cost impact of the Company's decision to build or acquire resources if those resources exceed market alternatives and result in an increase in rates. These offsetting risks stress the need for robust IRP analysis, efficient RFPs and ability to capture opportunistic procurement opportunities when they arise.

APPENDIX I – WIND INTEGRATION STUDY

This appendix provides the 2010 Wind Integration Study conducted during the 2011 IRP planning process. This is the version sent to participants on September 1, 2010.

PacifiCorp

2010 Wind Integration Resource Study

September 1, 2010

2010 Wind Integration Resource Study

1. Executive Summary

The purpose of the 2010 Wind Integration Study (the "Study") is twofold. First, the Study quantifies how wind generation affects the amount of operating reserve needed to maintain historical levels of reliability. Second, the Study tabulates the cost of integrating wind generation by measuring how system costs change with changes in operating reserve demand and by measuring how system costs are affected by daily system balancing practices.

Based upon historical and simulated wind generation data and historical load data, the Study shows that operating reserve demand for both regulation reserve service and load following reserve service increases with higher wind penetration levels. For purposes of this Study, regulation reserve service refers to operating reserves required by variability in both load and wind over ten-minute time intervals and load following reserve service refers to operating reserves required by both load and wind variability over hourly time intervals. Table 1 summarizes how operating reserve demand for both regulation and load following services increases as wind penetration levels grow from approximately 425 MW to approximately 1,833 MW. Table 2 depicts the change in operating reserve demand that is incremental to a load only calculation of the same types of reserve service.

Table 1. Annual average operating reserve demand by penetration scenario.

		Load Only	425 MW	1372 MW	1833 MW
West	Regulation Up	97	105	137	137
	Regulation Down	72	84	120	120
	Load Following Up	101	114	139	141
	Load Following Down	106	113	132	133
East	Regulation Up	138	140	201	231
	Regulation Down	107	110	185	222
	Load Following Up	139	144	207	245
	Load Following Down	144	147	198	237

Table 2. Annual average operating reserve demand incremental to the load only scenario.

		Load Only	425 MW	1372 MW	1833 MW
West	Regulation Up	0	7	39	39
	Regulation Down	0	12	48	48
	Load Following Up	0	13	38	39
	Load Following Down	0	7	26	27
East	Regulation Up	0	3	63	93
	Regulation Down	0	3	78	116
	Load Following Up	0	4	68	106
	Load Following Down	0	3	54	93

The costs of integrating wind as calculated in this Study include costs associated with increased operating reserve demand as outlined above and the costs from daily system balancing practices. Both types of costs were calculated using the Planning and Risk model (PaR), which is a production cost simulation model configured with a detailed representation of PacifiCorp's system. For each wind penetration scenario, a series of PaR simulations were completed to isolate each wind integration cost component by using a "with and without" approach. For instance, PaR was first used to calculate system costs without any incremental operating reserve demand and then again with the added incremental reserve demand. The change in system costs between the two PaR simulations drives the integration cost calculation. Table 3 summarizes the wind integration costs established in this Study alongside those costs calculated as part of the 2008 Integrated Resource Plan.

Table 3. Wind integration costs per MWh of wind generated as compared to those in the 2008 IRP.

Study	2008 IRP	2010 Wind Integration Study	2010 Wind Integration Study
Wind Capacity Penetration	2,734 MW	1,372 MW	1,833 MW
Tenor of Cost	20-Year Levelized	3-Year Levelized	3-Year Levelized
Interhour / System Balancing ($/MWh)	$2.45	$0.82	$0.86
Reserve ($/MWh)	$7.51	$8.03	$8.85
Total Wind Integration ($/MWh)	$9.96	**$8.85**	**$9.70**

As shown above, the Study finds that operating reserve demand and the associated costs increase with wind capacity penetration. System balancing costs, driven by day-ahead forecast errors for wind and load, trend similarly as wind penetration increases from 1,372 MW to 1,833 MW; however, as expected, system balancing integration costs are much lower than integration costs for operating reserves.

2. Data Collection

2.1 Overview

The calculation of Operating Reserve demand was based on load and production data over the 2007 to 2009 period (the "Initial Term"). Figure 1 shows that over this period, ten-minute interval data was not available for all wind resources included in the Study. Nonetheless, PacifiCorp chose to use this data because it represented the best base of observed data available within the company, it includes significant concurrent load and wind generation data, and it includes year-on-year variability in weather and other variables affecting load and wind generation levels.

Figure 1. Raw historical wind production and load data inventory.

Timeline			2007				2008				2009				2010			
			Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Wind	Plant name	Size, MW																
	Foote Creek	45																
	Stateline*	175																
	Combine Hills	41																
	Leaning Juniper	99																
	Wolverine Creek	64.5																
	Marengo	140																
	Goodnoe Hills	94																
	Marengo II	70.2																
	Mountain Wind I	60.9																
	Spanish Fork	19																
	Mountain Wind II	79.8																
	Rolling Hills	99																
	Glenrock	99																
	Glenrock III	39																
	Seven Mile Hill	99	Data to be Developed															
	Seven Mile Hill II	20																
	High Plains	99																
	McFadden Ridge I	28.5																
	Three Buttes	99																
	Dunlap I	111																
	Rock River	50																
	Composite of Small Projects	81																
	Top of the World	201.5																
Load	PACW Load																	
	PACE Load																	

Key
= Internal fine resolution data (10-min, 1-hour)
= Data to be developed by technical advisor
* Capacity represents portion of the plant in PacifiCorp's control area.

The data inventory summarized in Figure 1 contains as much real, observed, concurrent data as possible, owing to the volatile and unpredictable nature of wind generation output as well as the many fine variations available in real load data that can be difficult to capture with simulated data. Nonetheless, the data set selected for the Study contains gaps, and as a result, PacifiCorp utilized the services of the Brattle Group, the technical advisor that assisted with this study, to simulate missing wind data pertaining to the Initial Term. The simulation of wind data is discussed at length in its own section later in this report.

2.2 Historical Load and Load Forecast Data

The historical load data for the East and West Balancing Authority Areas was collected for the Initial Term from the PacifiCorp PI system[17]. These data were used for all the calculations involving historical load in the Study. The hourly day-ahead load forecasts were gathered from PacifiCorp's load forecast group, as were the day-ahead hourly load forecasts used to set up the generation system through the Initial Term period.

2.3 Historical Wind Generation and Wind Generation Forecast Data

2.3.1 Overview of the Wind Generation Data Used in the Analysis

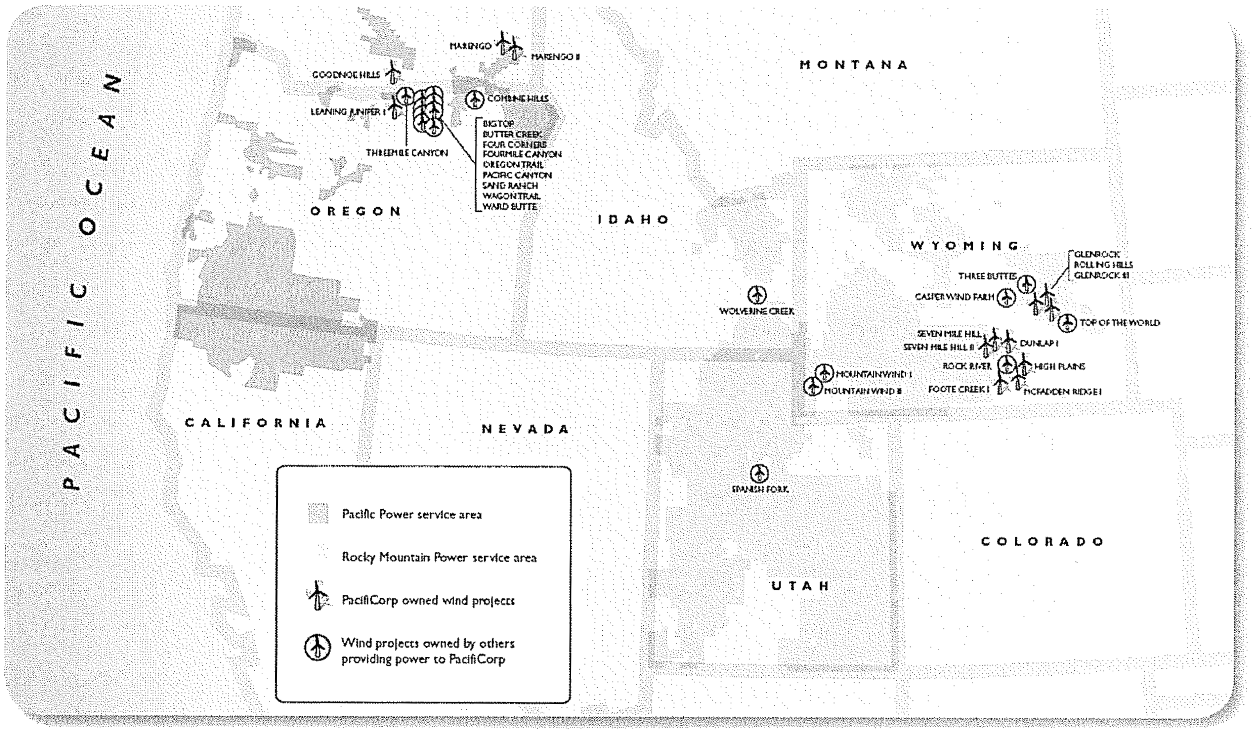
Ten-minute interval metered wind generation data were available for a subset of the wind sites as summarized in Figure 1. The wind output data were collected by PacifiCorp at each physical project location using the PI software system. In addition to historical wind generation data, the Study required historical day-ahead wind forecasts, modeled day-ahead wind forecasts for simulated data, and the creation of an ideal wind profile. All of these data sets were needed to establish wind integration costs using PaR and are discussed in turn below.

2.3.2 Historical Wind Generation Data

As shown in Figure 2, a cluster of PacifiCorp owned and contracted wind generation plants is located in Pacific Power's service area (PacifiCorp's West Balancing Authority Area) and another is located in the Rocky Mountain Power service area (PacifiCorp's East Balancing Authority Area). It is worth noting that two wind sites, Wolverine Creek in Idaho, and Spanish Fork in Utah are part of the East Balancing Authority Area, but are geographically distant from both the western and the eastern clusters.

[17] The PI system collects load and generation data and is supplied to PacifiCorp by OSISoft http://www.osisoft.com/software-support/what-is-pi/what_is_PI_.aspx .

Figure 2. Map of PacifiCorp wind generating stations used in this study.



The available historical ten-minute wind generation data were examined to produce some initial statistical diagnostics for each site and between sites. For each site, Table 4 shows: (1) number of 10-minute interval data observations available, (2) standard deviation of observed capacity factors, (3) the minimum capacity factor, and (4) the maximum capacity factor. Small negative capacity factor values (that show up as the minimum) in the data are the result of power consumption associated with routine operation of the wind projects even during times when the project itself is not producing energy. Table 5 shows the correlation observed among aggregate hourly load and wind generation data in 2008. By and large, hourly changes in load and wind generation output, which drive operational planning, do not appear to be correlated.

Table 4. Statistical properties of wind site capacity factor data.

Plant Name	Number of Observations	Standard Deviation	Min	Max
Goodnoe	83,520	32%	0%	100%
Leaning Juniper	157,824	35%	0%	100%
Combine Hills	157,824	38%	-3%	100%
Stateline	157,824	24%	-1%	100%
Marengo	79,776	33%	-11%	100%
Wolverine Creek	157,824	29%	-1%	100%
Spanish Fork	74,736	29%	-4%	87%
Mountain Wind	66,096	29%	0%	100%
Foote Creek	157,824	30%	-2%	100%
Seven Mile Hill	52,704	31%	0%	100%
McFadden Ridge	11,952	34%	-1%	100%
High Plains	15,840	21%	0%	67%
Glenrock	50,256	29%	0%	100%

Table 5. Hourly correlation of system wind and system load.

	Overall	Rolling 6 hour	Rolling 12 Hour
January	-2.5%	-2.9%	-3.4%
February	-2.8%	-0.6%	-1.7%
March	-0.4%	-1.4%	-2.2%
April	-6.4%	-3.5%	-5.9%
May	-10.4%	-3.0%	-6.4%
June	-12.0%	-9.2%	-11.9%
July	-12.4%	-12.3%	-14.2%
August	-9.1%	-8.4%	-9.8%
September	-6.5%	-0.6%	-4.0%
October	-3.5%	-4.8%	-6.7%
November	-7.5%	-3.6%	-4.4%
December	-2.0%	0.3%	-1.1%

2.3.3 Historical Day-ahead Wind Generation Forecasts

Day-ahead wind forecasts were collected from daily historical files maintained by PacifiCorp commercial operations. The files contained day-ahead hour-by-hour wind generation forecasts for the wind projects operating during the Initial Term. For those projects not operating during the Initial Term, day-ahead forecasts were created using the daily volumetric day-ahead forecast error from projects having complete data sets. As such, these data were used to bootstrap[18] the daily day-ahead forecast volumetric errors for the 1,372 MW and 1,833 MW scenarios, and the daily error (positive or negative) was applied to simulated wind generation data to create a

[18] Bootstrapping is a common statistical method used to estimate data by extrapolating from existing data.

modeled day-ahead forecast. The modeled day-ahead forecast maintained the same general hourly shape as the simulated wind generation data but was shifted vertically hour-by-hour on an equal percentage basis to keep the aggregate volumetric error constant.

2.3.4 Ideal Shape Wind Generation

In order to isolate wind integration costs from other system costs, a flat production profile is required for PaR modeling. This profile, deemed the ideal wind shape for purposes of the Study, treats all the energy produced by wind projects as monolithic blocks. Comporting with standard trading products among forward energy markets in the Western Interconnect, the energy produced in each 16-hour daily block between hour ending seven and hour ending 22 was treated as a single block. Similarly, energy produced in the 8-hour block between hour ending 23 and hour ending six was treated as a single block. For each block, the total energy delivered from wind generation is averaged, thereby flattening the generation pattern.

2.4 Wind Generation Data Simulation

The technical advisor assisted PacifiCorp in developing the Study methodology and in supplementing the historical wind generation data with simulated ten-minute interval wind generation data. This section summarizes the methodology used to simulate wind generation data and provides sample data and graphics to illustrate the details involved in each step of the process.

The overall approach to simulating wind generation data involved taking an historical data inventory; addressing data quality issues in the data inventory; identifying gaps requiring simulation; and finding the best suited relationship between pairs of sites; and using that relationship to approximate the wind output for periods with missing historical observations. However, it is worth noting that for sites with no historical data, the necessary numerical relationships were estimated between relevant locations by using simulated wind data made available by the National Renewable Energy Laboratory (NREL). Additional detail on simulation procedures is available in Appendix A.

2.4.1 Categorization of Historical Wind Data to Determine Simulation Scope

The historical wind data were classified into three groups to determine the periods requiring simulation for each site. The three categories are defined in turn below, and Figure 3 depicts how each site was categorized.

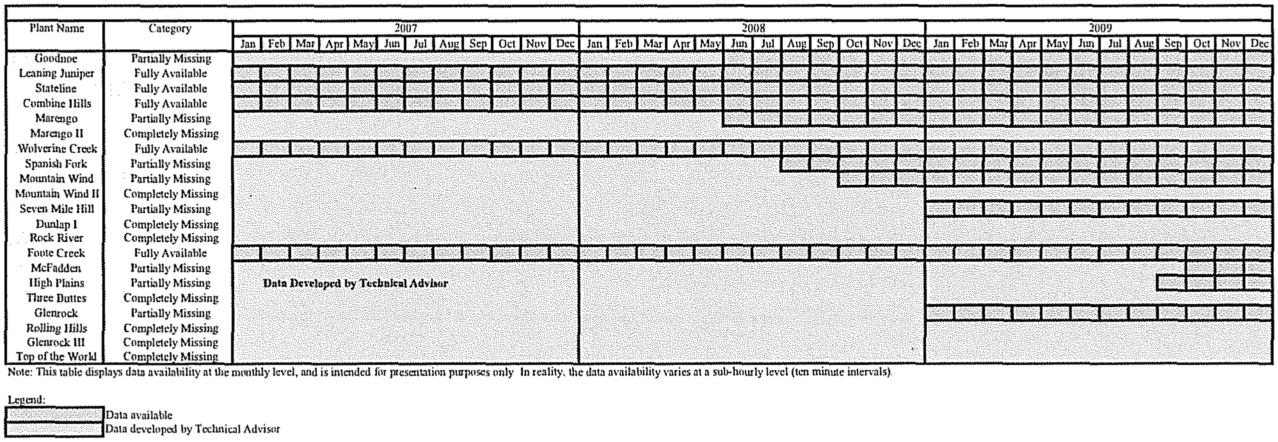
(1) *Fully Available*—this category refers to sites for which output data are available for the entirety of the Initial Term. Specifically, these wind plants include: Leaning Juniper, Combine Hills, Stateline, Wolverine Creek, and Foote Creek. These plants sum to 425 MW of capacity.

(2) *Partially Missing*—refers to sites for which output data are unavailable for a portion of the Initial Term. The wind plants that fall into this category are: Goodnoe Hills, Seven Mile Hill, Marengo, Spanish Fork, Mountain Wind, McFadden Ridge, High Plains, and Glenrock. One important feature of the partially missing data profiles is that the missing portions are always chronologically located at the beginning of the time period—once a

partially missing data profile begins, it contains no further data "holes". These plants sum to 848 MW of capacity.

(3) *Completely Missing*—refers to wind projects, for which no output data are available for the 2007-2009 Initial Term. Those sites are: Dunlap I, Rock River, Rolling Hills, Three Buttes, and Top of the World. These plants sum to 560 MW of capacity.

Figure 3. Categorization of wind generation data.



2.4.2 Simulation Process

The simulation process used in the Study evolved to become iterative in nature to ensure that simulated wind generation data used to establish operating reserve demand was reasonably aligned to the operating reserve demand calculated using observed wind generation data. As such, different methods of error sampling and simulation techniques (multiple linear, Tobit; for example) were evaluated in this manner. Tables 6 illustrates an example of how operating reserve demand calculated from observed and simulated data were used to evaluate different error sampling and re-addition methods used in this iterative process for the West Balancing Authority Area.

Table 6. Comparison of operating reserve demand calculated from actual wind generation plant data and simulated wind generation plant data estimated using a least squares regression and applying different scaling of errors added back into the raw prediction.

Actual Wind Generation Data			
	Load Following Up	Load Following Down	Regulation
	15.0	(19.1)	15.5
Test (Developed Wind Data)			
Error Scaling (%)	Load Following Up	Load Following Down	Regulation
10	9.9	(13.0)	11.1
50	10.6	(13.9)	12.3
75	11.7	(14.2)	14.3
100	12.4	(15.9)	17.1

Several simulation attempts ended with values above the feasible generation capacity range, or values beneath zero. Attempts to add the error term back into the prediction (a necessary simulation step) also faced significant hurdles in developing reasonable results. The highly variable ten-minute output led to error terms with ranges larger than the simulated values in many cases, which would also test the boundaries of either zero or maximum plant capacity delivered. Several processes were attempted to return a sampled error estimation back to the modeled estimate, per proper regression, including sampling of truncated error distributions, medians of the error distributions, and various bins of errors sampled and added back to the regression estimate. Various combinations of these methods were put through the operating reserve demand estimation calculations to assess whether the results were reasonable. Ultimately, the Tobit simulation method (described in more detail in section A.4.3) and a 3-step smoothed median of the sampled errors proved to offer reasonably stable results.

Ultimately, the iterative simulation process produced a simulation methodology comprised of several sequential steps:

(1) estimate the *Tobit* regressions;

(2) using the regression coefficients, generate estimates of the mean output of the *predicted variable*[19]

(3) calculate the regression residuals;

(4) randomly sample the residuals according to predefined simulated output ranges;

(5) apply a non-linear 3-step median smoother to the sampled residuals;

(6) add the smoothed residual series to the predicted mean output.

A more detailed description of each step appears in Appendix A, and the resulting regression coefficients appear in Appendix B.

[19] These are generally referred to in the literature as "y hat"

3. Methodology

3.1 Method Overview

This section of the Study presents the approach used to establish the enumeration of operating reserve demand and the method for calculating wind integration costs. Ten minute interval load and wind data is used to estimate the amount of operating reserve, both up and down, needed to manage fluctuations in load and fluctuations in wind within PacifiCorp's Balancing Authority Areas. The operating reserve discussed here is limited to spinning reserve and non-spinning reserve, which are needed for regulation, load following, and contingency reserve services. For purposes of this Study, regulation service refers to the operating reserve required to manage the variability of load and wind generation in ten minute periods, and load following service represents the operating reserve required to manage the variability as measured in hourly periods.[20] Contingency reserve, although mentioned, is supplied in accordance with the North American Reliability Corporation (NERC) standards and remains unchanged by the wind generation contemplated in this Study. Therefore, the operating reserve quantities discussed herein are only pertinent to supplying the demands of regulation and load following services, which are assessed in for load, and load net wind scenarios.

Once the amount of operating reserve is established for different levels of wind penetration, the cost of holding the reserve on PacifiCorp's system is calculated using PaR. In addition to using PaR for evaluating operating reserve cost, the PaR model is used to estimate wind integration cost associated with daily system balancing activities. These system balancing costs result from the unpredictable nature of wind generation on a day-ahead basis and can be characterized as system costs borne from committing generation resources against a forecast of load and wind generation and then dispatching generation resources under actual load and wind conditions.

3.2 Incremental Operating Reserve Demand

A dense data set of ten-minute interval wind generation and system load drives the calculation of the marginal reserve requirement in two components: (1) regulation, which is developed using the ten-minute interval data, and (2) load following, which is calculated using the same data but estimated using hourly variability. The approach for calculating incremental operating reserve necessary to supply adequate capacity for regulation and load following at levels required to maintain current control performance was based on merging current operational practice with a survey of papers on wind integration, as well as advisory from the technical advisor.[21] The Initial Term load data is used as the baseline case (zero wind generation) in each scenario. Coincident wind data (as observed, plus that simulated by the technical advisor) were added in increasing levels of wind capacity penetration to gauge the change in operating reserve demand. For purposes of the Study, the regulation calculation compares observed ten-minute interval load

[20] PacifiCorp's definitions for regulation and load following are based on PacifiCorp's operational practice, and not intended to describe the operational practices or terminology used by other power suppliers or system operators.

[21] The external studies PacifiCorp has relied on can mostly be found on the Utility Wind Integration Group (UWIG) website at the following link: http://www.uwig.org/opimpactsdocs.html

and wind generation production to a ten minute interval estimate, and load following compares observed hourly averages to an average hourly forecast.

3.2.1 Regulation Operating Reserve Service Demand

With no sub-hourly clearing or imbalance market, PacifiCorp must plan to meet sub-hourly load (and load net of wind) deviations with its own resources. This includes generating units on automatic generation control (AGC), demand side management (DSM), and the ramping of flexible generation units in real time operation, which requires that existing units be committed and then dispatched to provide operating reserve. Wind variability among ten-minute intervals can represent a quantity of generation required to ramp up or down to maintain system stability. Regulation service demand for wind generation variability was considered first. To parse the ten-minute interval wind variability from the ensuing load following analysis, a persistence forecast of the rolling prior 60 minutes was used to analyze the variation of each ten minute interval. The actual wind generation in each ten minute interval was subtracted from the rolling average of the prior six ten-minute intervals, and the standard deviation was computed for each monthly period. This approach follows the one used by the National Renewable Energy Laboratory (NREL) for its recent "Eastern Wind Integration and Transmission Study".[22]

$$\textbf{Regulation}_{wind10min} = \mathbf{P}_{cps2}\,(\textbf{Wind}_i)$$

Where:

$\mathbf{P_{CPS2}}$ = The percentile of a two-tailed distribution equaling the Balancing Authority Area's CPS2 performance[23]

$\mathbf{Wind_i}$ = the wind forecast error defined as $(\mathbf{Wind}_{Actual10min} - \mathbf{Wind}_{10\text{-}min\text{-}forecast})$

$\mathbf{Wind_{10\text{-}min\text{-}forecast}}$ = the rolling average of the wind generation in prior six ten-minute intervals, also referred to as a persistence forecast of the rolling prior 60 minutes

$\mathbf{Wind_{Actual10min}}$ = the observed wind generation for a given ten-minute interval

The load variability and uncertainty was analyzed comparing the ten-minute actual load values to a line of intended schedule, which was represented by a line interpolated between an actual top-of-the-hour load value and the next hour's load forecast target at the bottom of that (next) hour. A sample of how the intended schedule compares to actual load data is shown in Figure 4. The method approximately mimics real time operations process for each hour. At the top of the given hour, the actual load is known and a forecast for the next hour was made. For the purposes of this study, a line joining the two points was made to represent the ideal path for the ramp or decline expected within the given hour. The resulting actual ten-minute load values were compared to this straight line so as to produce a strip of error terms, as depicted in Figure 5 with data from February 2009.

[22] NREL, *Eastern Wind Integration and Transmission Study*, prepared by EnerNex Corporation, (January 10, 2010), p. 143. The report is available for download from the following hyperlink: http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf

[23] The Control Performance 2 is a reliability standard is maintained by the North American Electric Reliability Council. A definition is available on page 3of the document at the following hyperlink: http://www.nerc.com/files/Reliability_Standards_Complete_Set_2010Jan25.pdf

The errors were assembled monthly and their Regulation demand estimated similarly to the method used for the 10-minute values of the wind data:

$$\mathbf{Regulation}_{\text{load10min}} = \mathbf{P}_{\text{cps2}}\,(\mathbf{Load}_{\text{i}})$$

Where:

$\mathbf{Load}_i$ = the load forecast error, calculated similarly to $\mathbf{Wind}_i$

Figure 4. Sample of intended schedule ten-minute load estimate and observed system load.

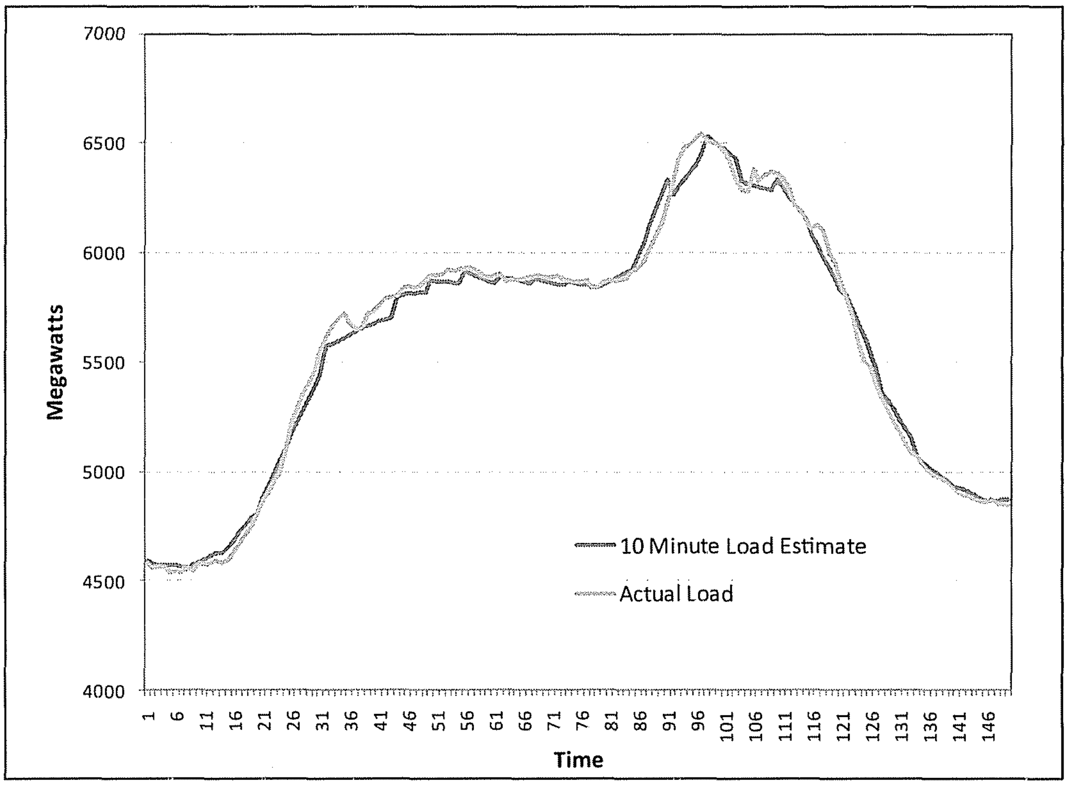
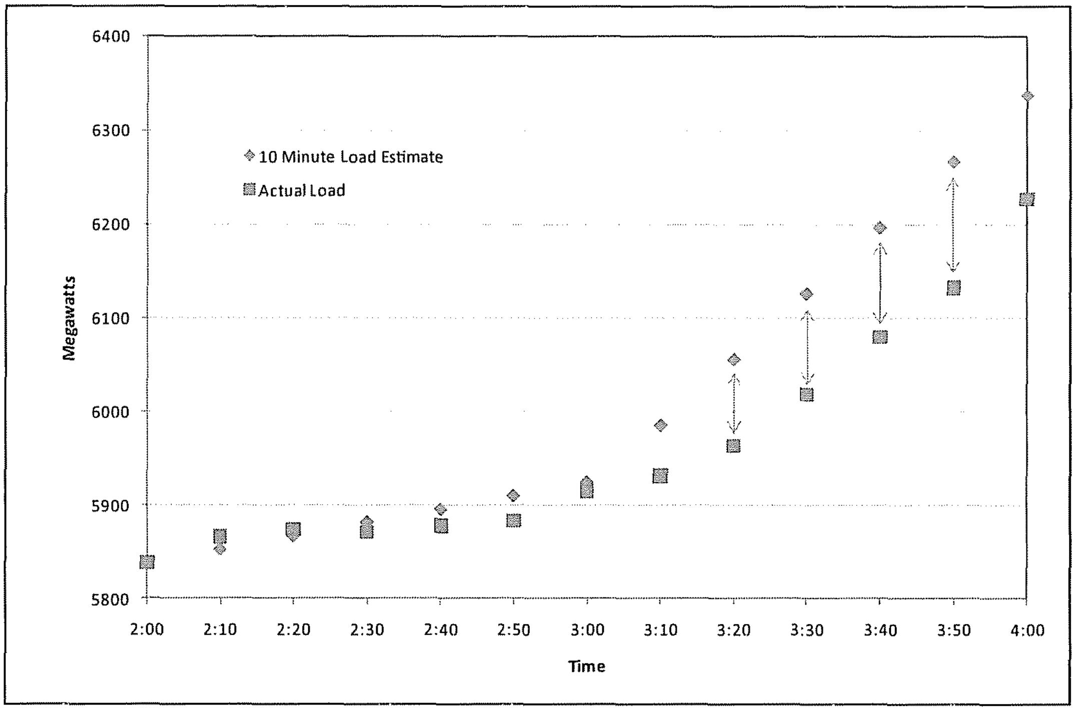


Figure 5. Variability between the line of intended schedule and observed load with errors highlighted by green arrows.

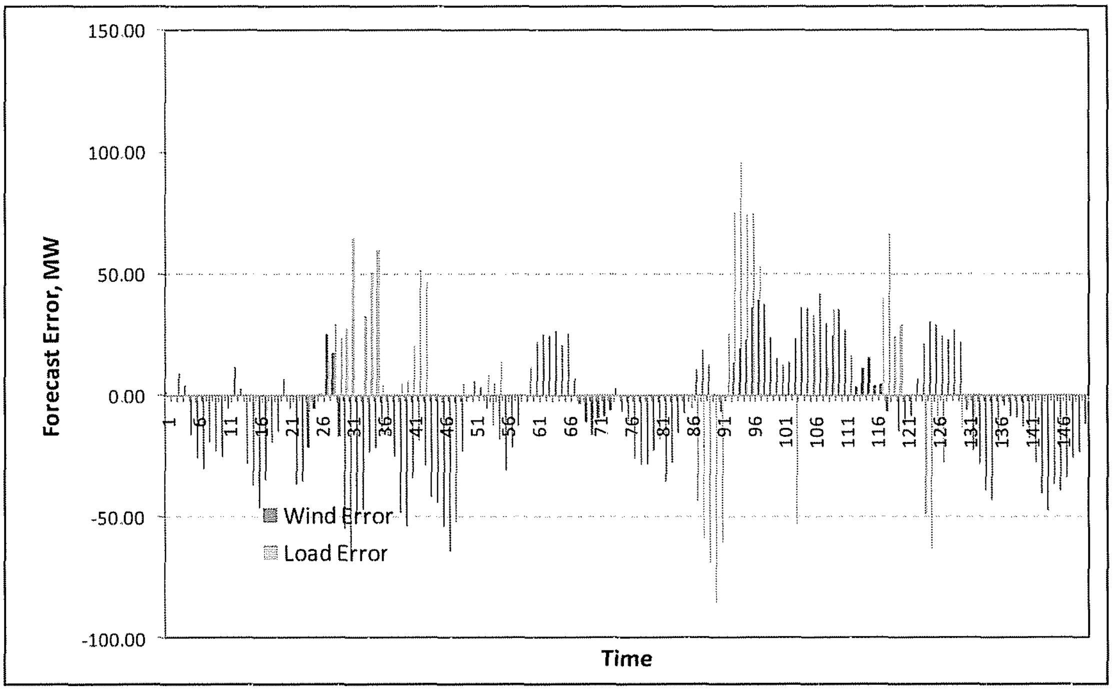


As the ten-minute load and wind errors each represent unpredictable change in the need for dispatchable generation, their variability was assessed separately and combined. The regulation demand of load net wind generation was estimated assuming short term variations in load are not correlated with changes in aggregate wind generation output through the use of a geometric average (shown for Regulation Up):

As the need for regulation service can vary whether the wind is up or down, both Regulation Up and Regulation Down services were estimated at each end of the error distributions.

A sample of the errors logged for the same period, for load and wind, are shown in Figure 6. The independence of the forecast errors for wind and load was assumed. These errors, or differences between forecast and actual, comprised an estimate of the demand made on regulation service operating reserves during power system operations. These differences were calculated for every ten minutes of operation through the Initial Term period, and separated into monthly bins for further analysis.

Figure 6. Independent forecast errors in ten-minute interval load and wind generation (December 2008, approximately 890 MW of wind penetration).



Analyzing the results on a monthly basis as opposed to grouping all the calculations together annually allowed for the fact that some months' power service actually required less regulation (for example, July and August) than others, and so costs could be more accurately attributed with a weighted average of results as opposed to grouping the entire year's operations into a single analysis bin. This is due to operating reserve being employed to manage the tails of the distributions involved, and a single annual bin would apply the greatest tail occurrences to the entire year, as opposed to only the month in which it occurs. Figure 7 demonstrates the resulting distributions of regulation demand for wind generation, where regulation down demand is the negative side of the distribution. The vertical lines drawn on Figure 7 illustrate the operating reserve threshold defined in the Study and data labels are added to denote outlying data points. Similarly, Figure 8 illustrates the resulting distribution of regulation demand for load, where regulation up demand is the positive side of the distribution.

Figure 7. Wind Regulation errors plotted for the Mays of the Initial Term at the 1,372 MW wind capacity penetration level.

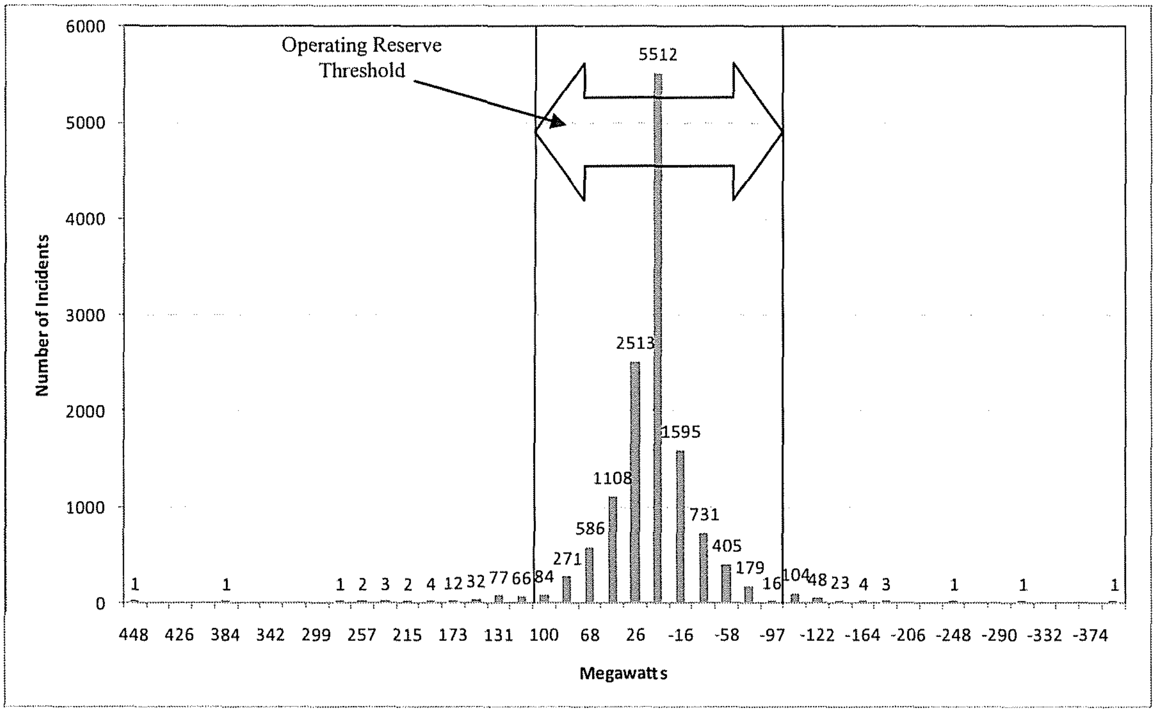
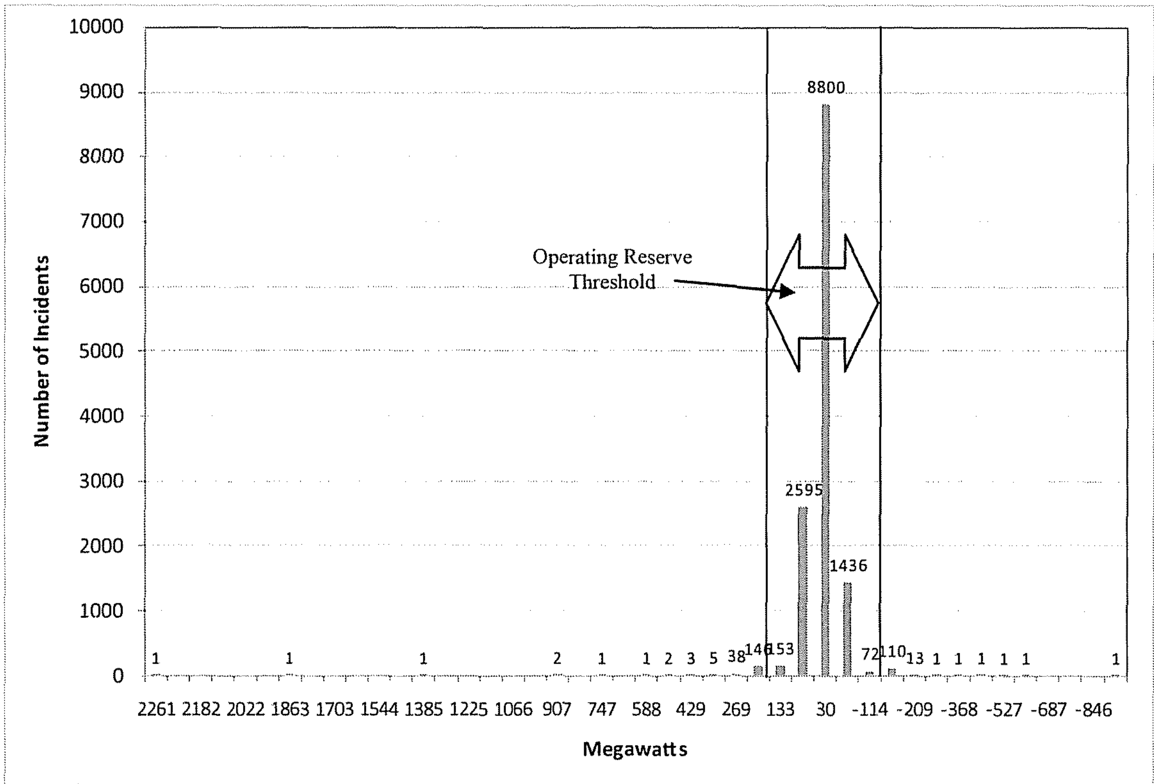


Figure 8. Load Regulation errors plotted for the Mays of the Initial Term.



3.2.2 Load Following Operating Reserve Demand

PacifiCorp maintains system balance by optimizing its operations to an hourly forecast with changes in generation and market activity. This planning interval represents hourly changes in generation which are assessed within roughly 20 minutes each hour to account for a bottom-of-the-hour (:30 after) scheduling deadline. Taking into account the conditions of the present and the expected load and wind generation, PacifiCorp must schedule generation to meet demands with an expectation of how much higher or lower system load (net of wind generation) may be.

PacifiCorp's real-time desk updates the next hour's system load forecast forty minutes prior to each operating hour. This forecast is created by comparing the current hour load to the load of a similar-load-shaped day. The hour-to-hour change in load from the similar day and hours (the load delta) was applied to the "current" hour load and the sum is used as the forecast for the ensuing hour. For example, on a given Monday the PacifiCorp operator may be forecasting hour to hour changes in system load by referencing the hour to hour changes on the prior Monday, a similar-load-shaped day. If the hour to hour load change between the prior Monday's like hours was 5%, the operator will use a 5% change in load as the next hour forecast.

As for the corresponding short term operational wind forecast, the hourly wind forecast is done by persistence; applying the instantaneous sample of the wind generation output 20 minutes past the current hour to the next hour as a forecast and balancing the system to that point. The resulting operational modeling process therefore went as follows; at the top of the hour, wind generation output, dispatchable generation output, and load values were summarized, and trended using the methods above. The result was compared to the next hour's schedule for gaps as soon as possible, with the generation and load values updated at roughly 20 minutes past the hour. In real time operations, this result would then be balanced through a combination of market transactions and scheduling adjustments to PacifiCorp resources to produce a balanced schedule for the ensuing hour; with all transactions having to be complete by 30 minutes past the hour. Meanwhile, for purposes of the calculation made in this Study, the hourly wind forecast consisted of the 20th minute output from the prior hour, and the load forecast was modeled per the approximation described above with a shaping factor calculated using the day from one week prior, and applying a prior Sunday to shape any NERC holiday schedules.

Using the Initial Term data for PacifiCorp's Balancing Authority Areas, a comparison of the load and wind forecasts was implemented to measure the seasonal or annual trends in the variability between the hourly interval load and wind forecasts and the observed average hourly load and wind generation values. These differences were segmented into bins by load magnitude and wind generation magnitude using load and wind data, in order to facilitate making a weighted average of the reserves demand by load level and wind generation output level. An example of load and wind data segmented into bins appears in Figures 9 through 12. Figure 9 depicts forecast load in West Balancing Authority Area with a range of over and under predictions tied to Control Performance 2 (CPS2) performance level. Figure 10 shows the same data for the East Balancing Authority Area. In similar fashion, Figure 11 displays forecasted wind generation in the West Balancing Authority Area with a range of over and under predictions consistent with a

97% CPS2 performance level. Figure 12 shows the same wind generation forecast data for the East Balancing Authority Area.

Figure 9. Example of bin analysis for load following reserve service from load variability in the West Balancing Authority Area (May 2007-2009).

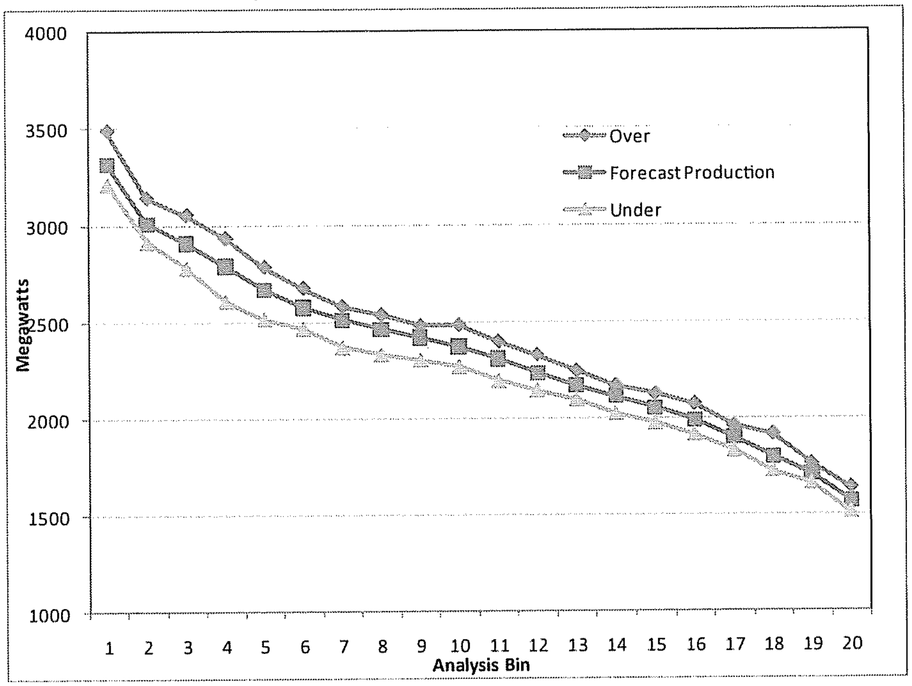


Figure 10. Example of bin analysis for load following reserve service from load variability in the East Balancing Authority Area (May 2007-2009).

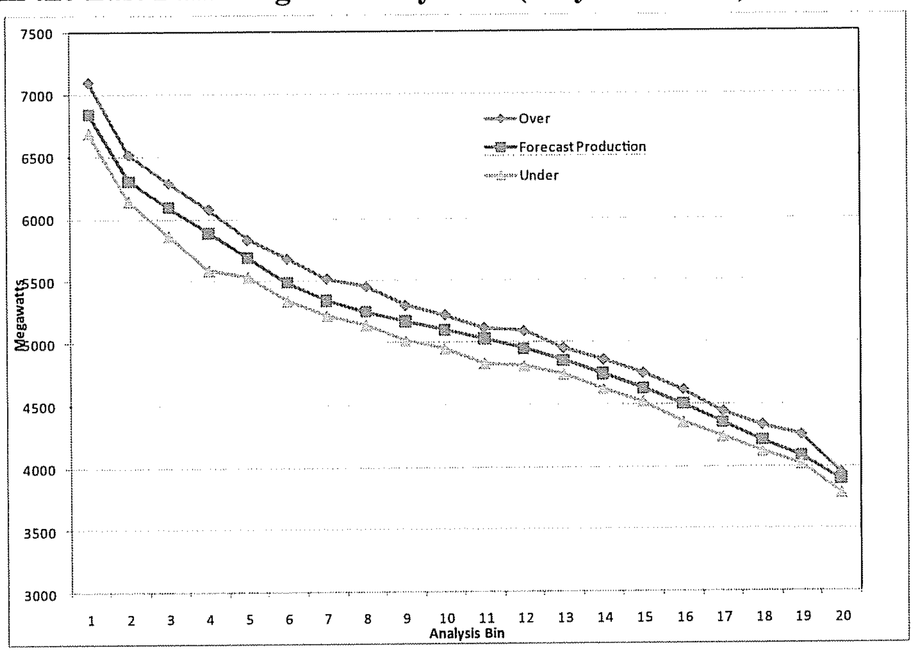


Figure 11. Example of bin analysis for load following reserve service from wind variability at the 1,372 MW penetration level for the West Balancing Authority Area (May 2007-2009).

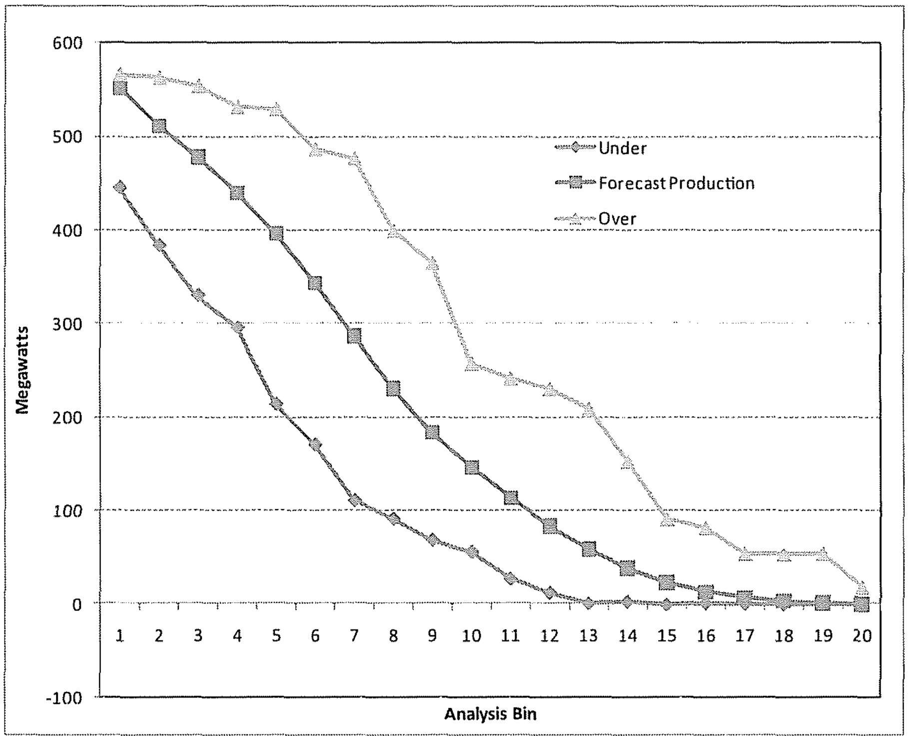
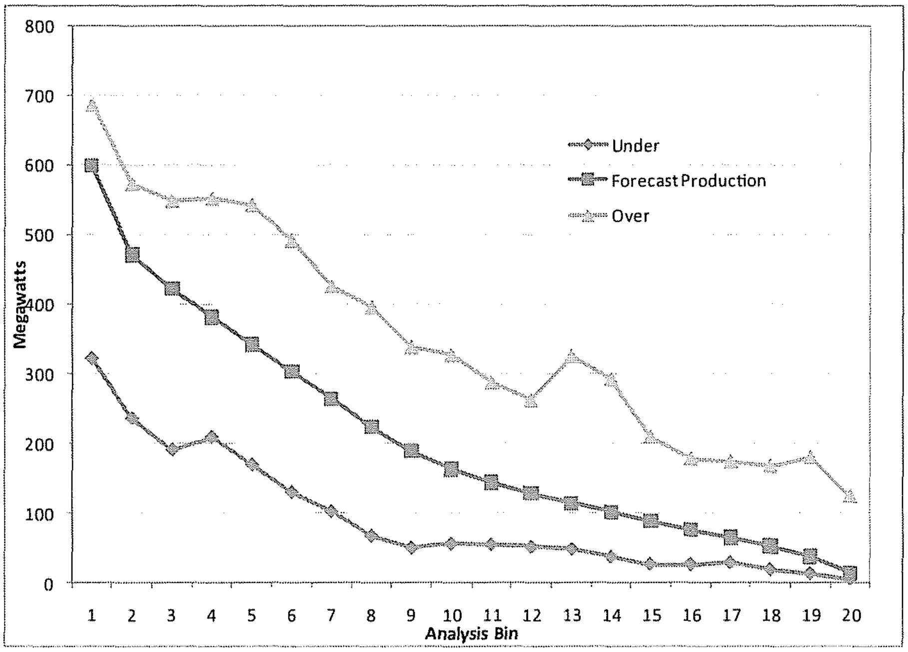


Figure 12. Example of bin analysis for load following reserve service from wind variability at the 1,372 MW penetration level for the East Balancing Authority Area (May 2007-2009).



Probabilities implied by the population of each bin, representing the expected amount of time spent in each load state, were represented by the historical data. The percentile equivalent to the historical CPS2 performance of PacifiCorp was sampled above and below the median of each of the bins. The average CPS2 performance for PacifiCorp's East and West Balancing Authority Areas over the period 2004 to 2009 was just below 97%. As the goal of this Study is to incorporate wind integration in PacifiCorp's current operations, the CPS2 performance of 97% was emphasized in these calculations. An assessment of the overall system power quality is a standalone topic that is beyond the scope of this Study, and thus, the Company assumed this level of reliability will be maintained. The difference between the CPS2 percentiles and the median of the bins represents the implied incremental load following service for operating reserve demand within that bin. As each respective bin also has an implied probability by the number of data points falling within it, the volumetric position over the study period was calculated as a simple weighted average.

To further explain the calculation method for load following reserve demand, the following example follows from the illustration in Figure 10. To assess the load following up reserve position for Bin 5, subtract the lower bound value (5,532 MW) from the system load forecast of 5,687 MW to arrive at an estimate of 154 MW for the occurrences within that bin. Integrating this process through all bins produced a composite load following up position for the East Balancing Authority Area in May, and the process was repeated for each month in the up and down directions. Wind generation was analyzed in exactly the same procedure, but with generation output representing the individual state variable. The wind and load reserve positions were combined using the root sum square calculation in each direction (up and down), assuming their variability in the short term is independent.

3.3 Determination of Wind Integration Cost

3.3.1 Overview

Owing to the variability and uncertainty of wind generation, each hour of power system operations features a need to set aside increased operating reserve (both spinning and non-spinning reserve), in addition to those set aside explicitly to cover load and contingency events which are inherent to the PacifiCorp system with or without wind. Additional costs are incurred with daily system balancing practice that is influenced by the unpredictable nature of wind generation on a day-ahead basis. To derive how wind generation affects operating reserve costs and system balancing costs, the Study utilizes the PaR model.

PacifiCorp's PaR model, developed and licensed by Ventyx Energy LLC, uses the PROSYM chronological unit commitment and dispatch production cost simulation engine and is configured with a detailed representation of the PacifiCorp system. For this study, four different PaR simulations were developed for a range of wind penetration scenarios as defined in Table 7. By carefully designing the four simulations, we were able to isolate wind integration costs associated with operating reserves and to separately calculate wind integration costs associated with system balancing practice. The former reflects integration cost that arises from short-term (within the hour and hour ahead) variability in wind generation and the latter reflects integration costs that arise from errors in forecasting load and wind generation on a day-ahead basis.

Table 7. Wind penetration scenarios used in PaR, as a percentage of total fleet capacity.

Representative Timing	Baseline	2007 End of Year	2009 End of Year	2010 End of Year
Installed Wind Capacity (Megawatts)	0	425	1,372	1,833
Wind Penetration Percentage	0%	3%	10%	12%

The four PaR simulations used for each penetration scenario in the Study are summarized in Table 8. The first two simulations are used to tabulate operating reserve wind integration costs, while the third and forth simulations support the calculation of system balancing wind integration costs. Table 8 identifies how key input variables change among the simulations. The simulations were run over the 2011 to 2013 forward term (three years), wherein 2007 wind generation and load data are used as inputs for 2011, 2008 wind generation and load data are used for 2012, and 2009 wind generation and load data are used for 2013. This calculation method combines the benefits of using actual system data available for the historic three-year Initial Term period with current forward price curves pertinent to setting the cost for wind integration service on a forward basis.[24] PacifiCorp resources used in the simulations are based upon the 2008 IRP Update resource portfolio.[25]

[24] The Study uses the March 31, 2010 official forward price curve.

[25] The 2008 Integrated Resource Update report, filed with the state utility commissions on March 31, 2010. The report is available for download from PacifiCorp's IRP Web page using the following hyperlink: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2008IRPUpdate/PacifiCorp-2008IRPUpdate_3-31-10.pdf

Table 8. Wind integration cost simulations in PaR.

PaR Model Simulation	Forward Term	Load (Initial Term)	Wind Profile (Initial Term)	Incremental Reserve	Day-ahead Forecast Error
1	2011 - 2013	Actual	Ideal Shape	None	None
2	2011 - 2013	Actual	Actual	Yes	None
Operating Reserve Integration Cost = System Cost from PaR simulation 2 less system costs from PaR simulation 1					
3	2011 - 2013	Day-ahead Forecast	Day-ahead Forecast	Yes	None
4	2011 - 2013	Actual	Actual	Yes	Yes (Commitment from PaR Simulation 3)
System Balancing Integration Cost = System Cost from PaR simulation 4 less system costs from PaR simulation 2					

3.3.2 Calculating Operating Reserve Wind Integration Costs

To assess the effects of various levels of wind capacity added to the Balancing Authority Areas on operating reserve costs, each penetration scenario was simulated in PaR using both ideal (Simulation 1) and actual (Simulation 2) wind profiles. Both the ideal and actual PaR simulations excluded System Balancing costs. The ideal wind profile is a "flattened" representation of the actual profile, where wind generation is averaged across on- and off-peak blocks. Such a profile requires no additional operating reserve to support wind generation variability, and as such, Simulation 1 only included an operating reserve needed for load variability. In summary, Simulation 1 included actual historical loads, ideal wind profiles, and no incremental operating reserve to account for wind variability.

Simulation 2 used the actual wind generation profiles, which reflect the 2007 to 2009 observed and developed Initial Term wind data as inputs for the 2011 to 2013 forward period. These actual wind generation profiles reflect the same variability used to derive the incremental operating reserve requirements needed to integrate wind generation. Thus, the second PaR simulation includes the incremental operating reserve demand created by the variable nature of wind generation as well as the actual, variable wind generation profiles.

The system cost differences between these two simulations were divided by the total volume of wind generation in each penetration scenario to derive the wind integration costs associated with having to hold incremental operating reserve on a per unit of wind production basis.

3.3.3 Calculating System Balancing Wind Integration Costs

PacifiCorp conducted another series of PaR simulations to estimate daily system balancing wind integration costs consistent with the wind penetration scenarios studied. In this phase of the analysis, PacifiCorp generation assets were committed consistent with a day-ahead forecast of wind and load, but dispatched against actual wind and load. To simulate this operational behavior, two additional PaR simulations were necessary for each wind penetration scenario.

Simulation 3 was used to determine the unit commitment state of generation assets given the day-ahead forecast of wind generation and load. Simulation 4 used the unit commitment state from Simulation 3, but dispatches units based on actual wind generation and load. This actual wind and load data is pulled from the Initial Term , and thus, is identical to the actual wind generation and load inputs used to derive operating reserve wind integration costs as described above. In both of these PaR simulations, the amount of incremental reserve required for each penetration scenario was applied.

The change in system costs between Simulation 4 and the system costs from Simulation 2 already produced in the estimation of operating reserve integration costs isolates the wind integration cost due to system balancing. Dividing the change in system costs by the volume of wind generation in each penetration scenario produced a system balancing integration costs on a per-unit of wind production basis.

3.3.4 Allocation of Operating Reserve Demand in PaR

PaR Simulations 2 through 4 require operating reserve demand inputs that must be applied consistent with the ancillary services structure native to the model. The PaR model distinguishes reserve types by the priority order for unit commitment scheduling, and optimizes them to minimize cost in response to demand changes and the quantity of reserve required on an hour-to-hour basis. The highest-priority reserve types are regulation up and regulation down followed in order by spinning, non-spinning, and finally, 30-minute non-spinning.[26] Reserve requirements in the model need to be allocated into these PaR reserve categories and are expressed as a percentage of load.

The regulation up and regulation down reserves in PaR are a type of spinning reserve that must be met before traditional spinning and non-spinning reserve demands are satisfied. The incremental operating reserve demand needed to integrate wind generation was assigned in PaR as regulation up and regulation down. The traditional spinning and non-spinning reserve inputs are used for contingency reserve requirements, which remain unchanged among all PaR simulations in the Study. The 30-minute non-spinning reserve is not applicable to PacifiCorp's system, and thus it is not used in this Study.

[26] In PaR, spinning reserve is defined as unloaded generation which is synchronized, ready to serve additional demand and able to reach reserve amount within 10 minutes. Non-spinning Reserve is defined as unloaded generation which is non-synchronized and able to reach required generation amount within 10 minutes.

Note that given the hourly granularity in PaR, there is no distinction between operating reserve categorized as regulation and load-following in terms of how the model optimizes their use. Thus both regulation reserve service demand and load following reserve service demand are combined as a geometric average and input in PaR as regulation up and regulation down. Further, owing to the hourly granularity of PaR and the fact that PaR optimizes dispatch for each distinct hour, regulation reserves are effectively released for economic dispatch from one hour to the next. The PaR model requires separate inputs for spinning operating reserve and non-spinning operating reserve. Table 9 summarizes how the services for operating reserves are applied in PaR.

Table 9. Allocation of operating reserve demand to regulation, spinning and non-spinning reserve categories in PaR.[27]

Reserve Service	PaR Regulation Up	PaR Regulation Down	PaR Spinning Reserves	PaR Non-Spin Reserves
$RegulationUp_{10Min}$	$RegulationUp_{10Min}$	0	0	0
$RegulationDown_{10Min}$	0	$RegulationDown_{10Min}$	0	0
Load Following Up	Load Following Up	0	0	0
Load Following Down	0	Load Following Down	0	0
Contingency	0	0	0.5*(5% of Hydro and Wind Generation output + 7% of Thermal generation output)	0.5*(5% of Hydro and Wind Generation output + 7% of Thermal generation output)
Total	Geometric Average of the above	Geometric Average of the above	Sum of the above	Sum of the above

3.3.5 Satisfying Reserve Service Demand in PaR

PacifiCorp's thermal and hydro units are able to meet the reserve demand entered in PaR as shown in Table 10. Regulation reserve is typically held by units operating in automatic generation control (AGC) mode.

[27] Contingency Reserve is specified by the North American Energy Corporation in per http://www.nerc.com/files/BAL-STD-002-0.pdf.

Table 10. Reserve service capability of each generating unit in PaR.

Unit Name	Regulation Up	Regulation Down	Spin	Non-Spin
BEAR RIVER	No	No	No	Yes
CARBON 1	No	No	Yes	Yes
CARBON 2	No	No	Yes	Yes
CHEHALIS	Yes	Yes	Yes	Yes
CHOLLA 4	Yes	Yes	Yes	Yes
CLEARWATER 1 & 2	No	No	No	Yes
COLSTRIP 3 & 4	No	No	No	Yes
COPCO 1 & 2	No	No	Yes	Yes
CRAIG 1 & 2	No	No	No	Yes
CURRANT CREEK	Yes	Yes	Yes	Yes
DAVE JOHNSTON 1	No	No	Yes	Yes
DAVE JOHNSTON 2	No	No	Yes	Yes
DAVE JOHNSTON 3	No	No	Yes	Yes
DAVE JOHNSTON 4	Yes	Yes	Yes	Yes
FISH CREEK	No	No	No	Yes
GADSBY 1	No	No	Yes	Yes
GADSBY 2	No	No	Yes	Yes
GADSBY 3	Yes	Yes	Yes	Yes
GADSBY 4	Yes	Yes	Yes	Yes
GADSBY 5	Yes	Yes	Yes	Yes
GADSBY 6	Yes	Yes	Yes	Yes
HAYDEN 1 & 2	No	No	No	Yes
HERMISTON 1	Yes	Yes	Yes	Yes
HERMISTON 2	Yes	Yes	Yes	Yes
HUNTER 1	Yes	Yes	Yes	Yes
HUNTER 2	Yes	Yes	Yes	Yes
HUNTER 3	Yes	Yes	Yes	Yes
HUNTINGTON 1	Yes	Yes	Yes	Yes
HUNTINGTON 2	Yes	Yes	Yes	Yes
JC BOYLE	No	No	No	Yes
JIM BRIDGER 1	Yes	Yes	Yes	Yes
JIM BRIDGER 2	Yes	Yes	Yes	Yes
JIM BRIDGER 3	Yes	Yes	Yes	Yes
JIM BRIDGER 4	Yes	Yes	Yes	Yes
LAKE SIDE	Yes	Yes	Yes	Yes
LEMOLO	No	No	No	Yes
LITTLE MOUNTAIN	No	No	No	Yes
MERWIN	No	No	No	Yes
MID-COLUMBIA	Yes	Yes	Yes	Yes
NAUGHTON 1	No	No	Yes	Yes
NAUGHTON 2	Yes	Yes	Yes	Yes
NAUGHTON 3	Yes	Yes	Yes	Yes
SWIFT	Yes	Yes	Yes	Yes
TOKETEE-SLIDE	No	No	No	Yes
WYODAK	Yes	Yes	Yes	Yes
YALE	Yes	Yes	Yes	Yes

3.3.6 Modeling gas plant utilization in PaR

One of the objectives in calculating wind integration costs using PaR was to emulate observed real-time unit commitment and dispatch behavior of PacifiCorp's thermal plants during the simulation period. A specific focus was placed on east-side gas plants capable of providing regulation reserve service. The commitment status of these gas plants, consisting of Currant Creek, Lake Side, and Gadsby units 4 through 6, was initially set to "must run" in PaR to mirror recent utilization of these units. In the PaR framework, must run status means that the unit is committed, but not necessarily fully dispatched, at all times. PacifiCorp then compared the resulting simulated capacity factors for the simulation year 2013 against actual plant capacity factors for 2009 keeping in mind that 2009 wind generation and load data are used as inputs for the 2013 PaR simulation year. Differences in the capacity factors were reasonably small.

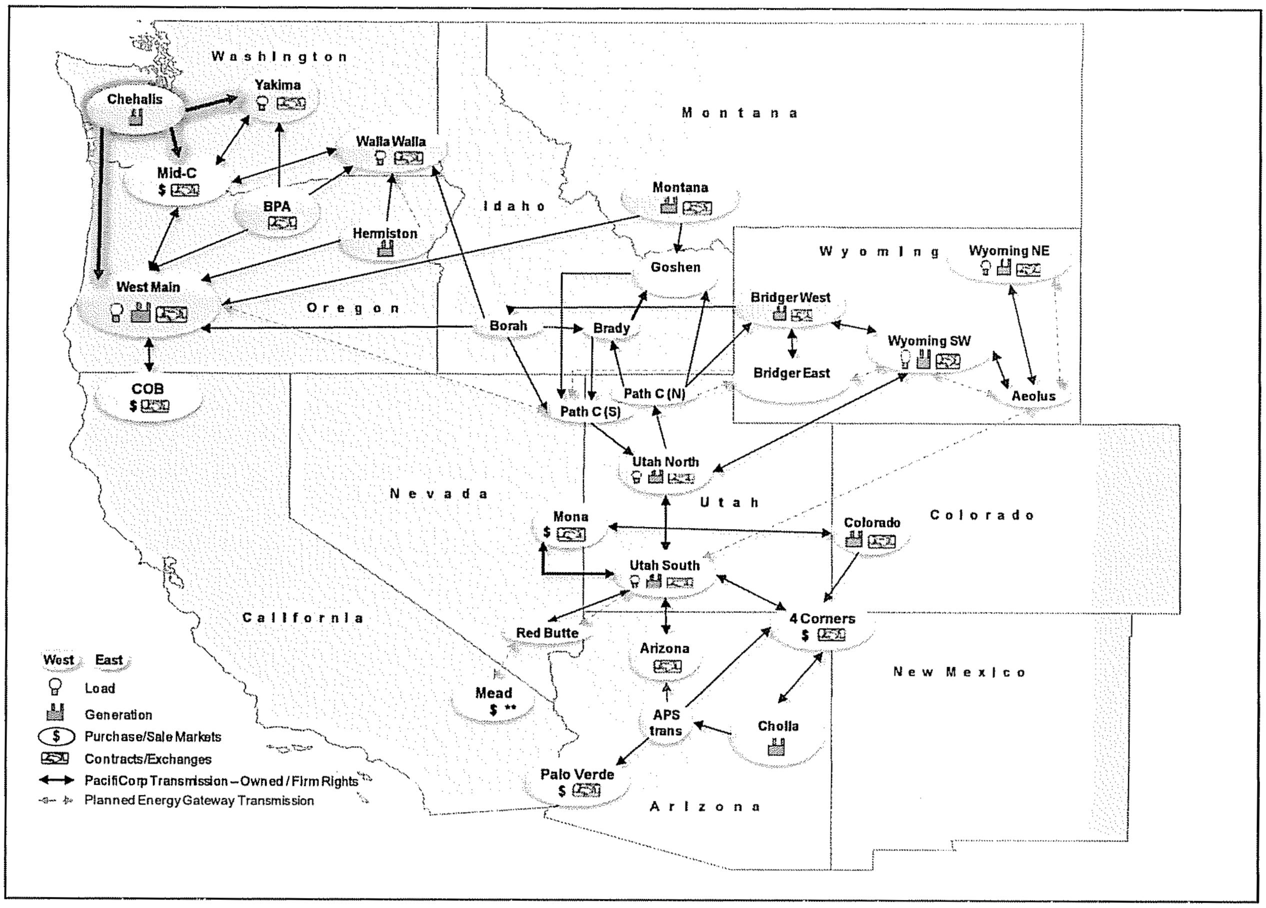
Given these findings, PacifiCorp concluded that PaR was reasonably aligned with actual operational characteristics of the east-side gas plants when setting Current Creek and Gadsby units 4 through 6 as must run. Consequently, this must run configuration was applied in PaR to circumvent the fact that PaR establishes unit commitment on price and not necessarily on operating reserve requirements. In this way, and consistent with recent operational practice, the Current Creek and Gadsby units 4 through 6 are available for meeting operating reserve obligations even when out-of-the-money from a pure market dispatch perspective.

The must run setting on Currant Creek and Gadsby units 4 through six was applied in PaR Simulations 2 through 4. In each of these simulations, incremental operating reserve demand needed to integrate wind is applied in the model, and must-run configuration ensures that the select set of east-side gas units will be available to meet the added reserve obligation even at times when they are out-of-the-money. In contrast, PaR Simulation 1 does not include any incremental operating reserve demand, and thus, the must-run setting was not used.

3.3.7 Transmission Topology in PaR

PacifiCorp used the PaR transmission topology consistent with the 2008 IRP Update as shown in Figure 13.

Figure 13. PaR transmission topology.



3.3.8 Carbon Dioxide Cost Assumptions in PaR

Given the 2011 to 2013 forward term used in the Study, there was no CO_2 cost applied to fossil-fired thermal generating resources. This assumption simplifies any comparison of the calculated wind integration cost among the three forward simulation years and avoids the possibility of disparity between plant dispatch costs and wholesale electricity market forward prices used over the term. This is in contrast to the 2008 IRP Update, in which PacifiCorp assumed that federal cap and trade carbon dioxide (CO_2) allowance prices go into effect in 2013, with prices starting at $8.58/ton in 2013 dollars and escalating at 1.8 percent per year thereafter.

4. Results

4.1 Operating Reserve Demand

Based upon historical and simulated wind generation data and historical load data, the Study shows that operating reserve demand for both regulation reserve service and load following reserve service increases with higher wind penetration levels. Table 11 summarizes how operating reserve demand for both regulation and load following services increases as wind penetration levels grow from approximately 425 MW to approximately 1,833 MW.

Table 11. Annual average operating reserve demand by penetration scenario.

		Load Only	425 MW	1372 MW	1833 MW
West	Regulation Up	97	105	137	137
	Regulation Down	72	84	120	120
	Load Following Up	101	114	139	141
	Load Following Down	106	113	132	133
East	Regulation Up	138	140	201	231
	Regulation Down	107	110	185	222
	Load Following Up	139	144	207	245
	Load Following Down	144	147	198	237

The increase in operating reserve necessary to support wind generation in grid operations is apparent in each of the penetration scenarios. For example, very little wind generation is added to the East Balancing Authority Area between the load-only and 425 MW scenarios, and understandably, there is little increase in the resultant incremental operating reserve demand. The same situation occurs between the 1,372 MW and 1,833 MW penetration scenarios on the West Balancing Authority Area, where again, there is little change to the calculated operating reserve demand. Additionally, as significant wind generation development impacts the East Balancing Authority Area between the 425 MW and 1,372 MW scenarios, and again between the 1,372 MW and 1,833 MW scenarios, there is clearly a proportionate growth of the operating reserve required to satisfy higher levels of wind penetration.

Tabular monthly results for each Balancing Authority Area and for each type of reserve service appear in Appendix C. For convenience, Figures 14 through 21 summarize monthly operating reserve demand results. In reviewing these figures, it is helpful to compare the growth of estimated reserve demand per MW of wind penetration recognizing that most of the wind capacity in the 425 MW penetration scenario is in the West Balancing Authority Area and that most of the incremental wind capacity in the 1,372 and 1,833 MW penetration scenarios is in the East Balancing Authority Area.

Figure 14. Load following up operating reserve service demand in the West Balancing Authority Area.

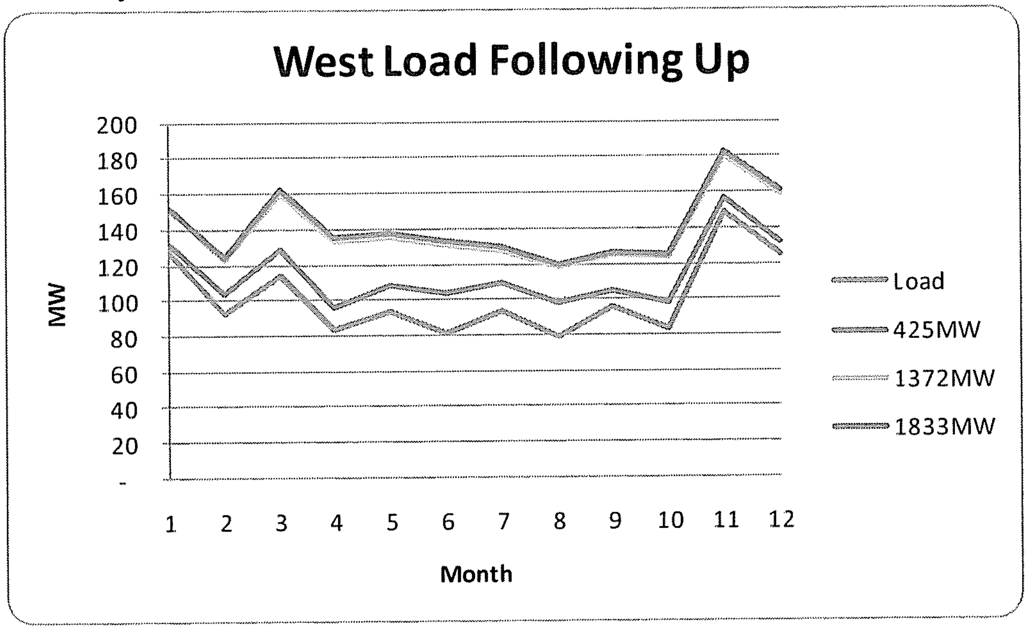


Figure 15. Load following down operating reserve service demand in the West Balancing Authority Area.

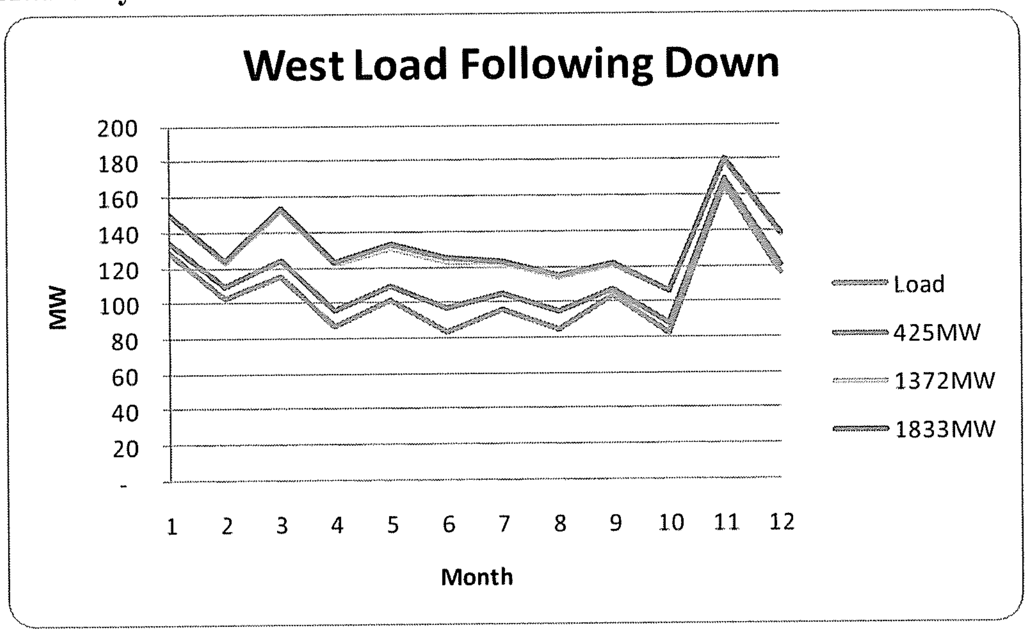


Figure 16. Regulation up operating reserve service demand in the West Balancing Authority Area.

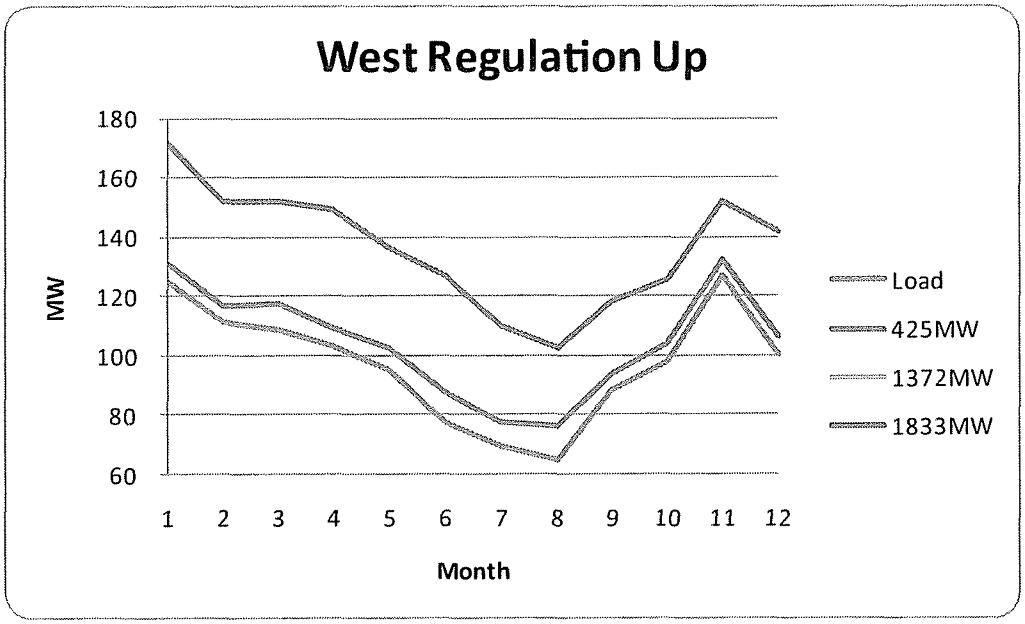


Figure 17. Regulation down operating reserve service demand in the West Balancing Authority Area.

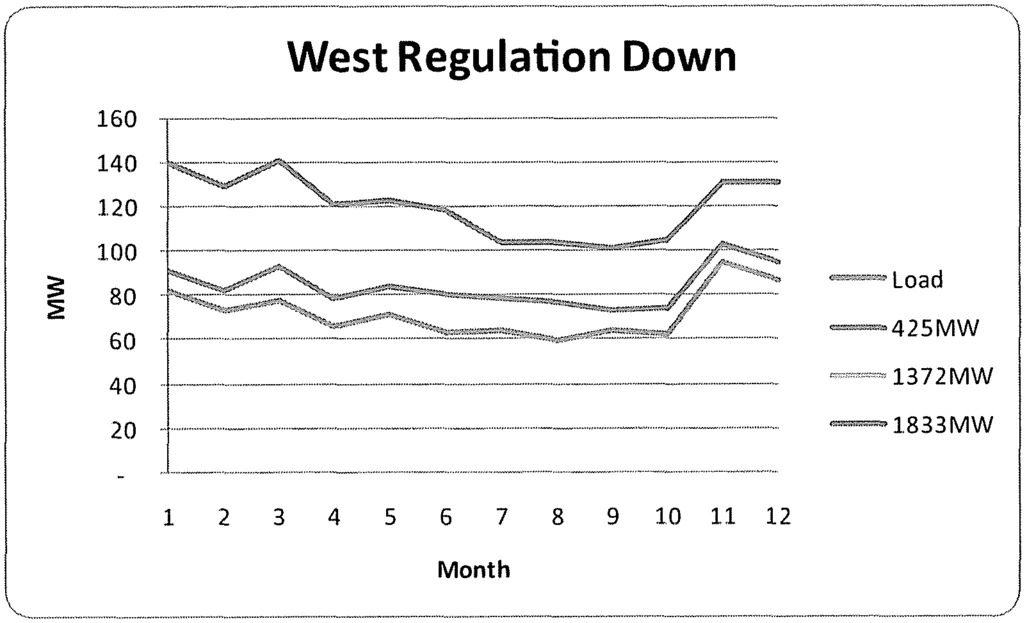


Figure 18. Load following up operating reserve service demand in the East Balancing Authority Area.

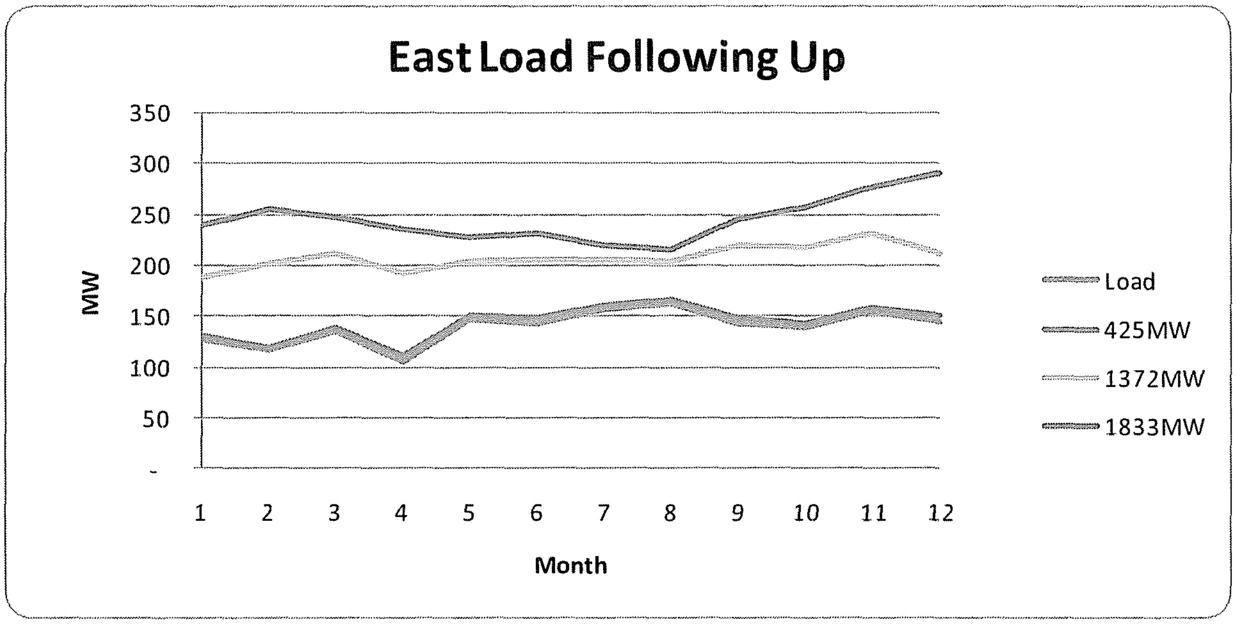


Figure 19. Load following down operating reserve service demand in the East Balancing Authority Area.

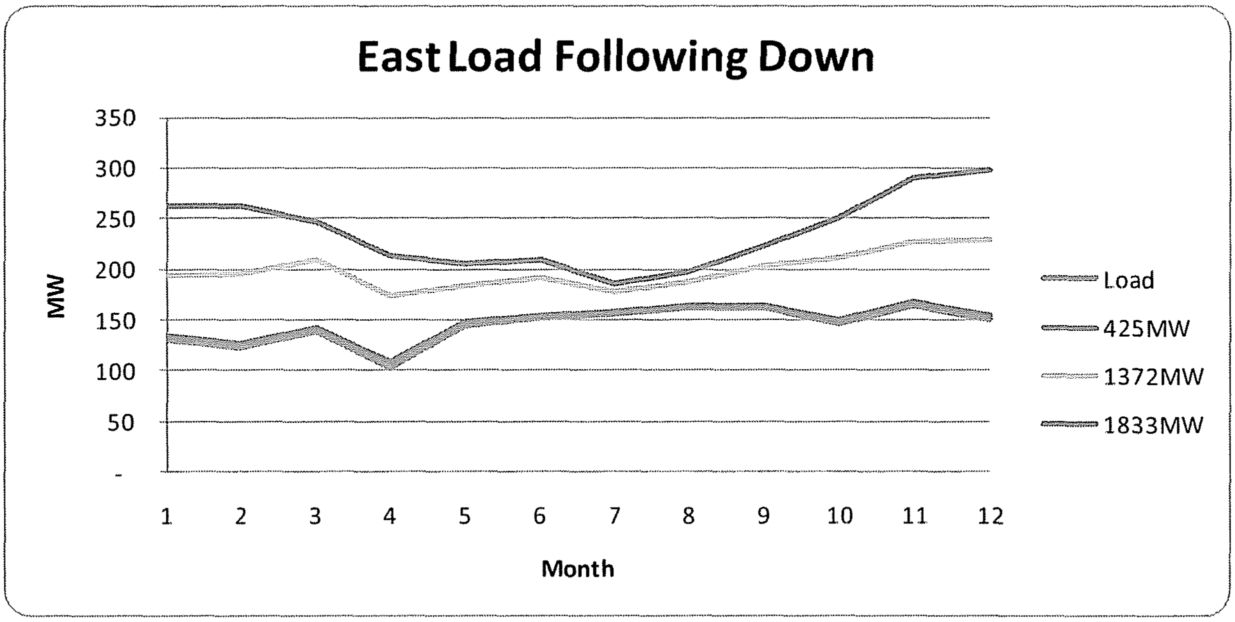


Figure 20. Regulation up operating reserve service demand in the East Balancing Authority Area.

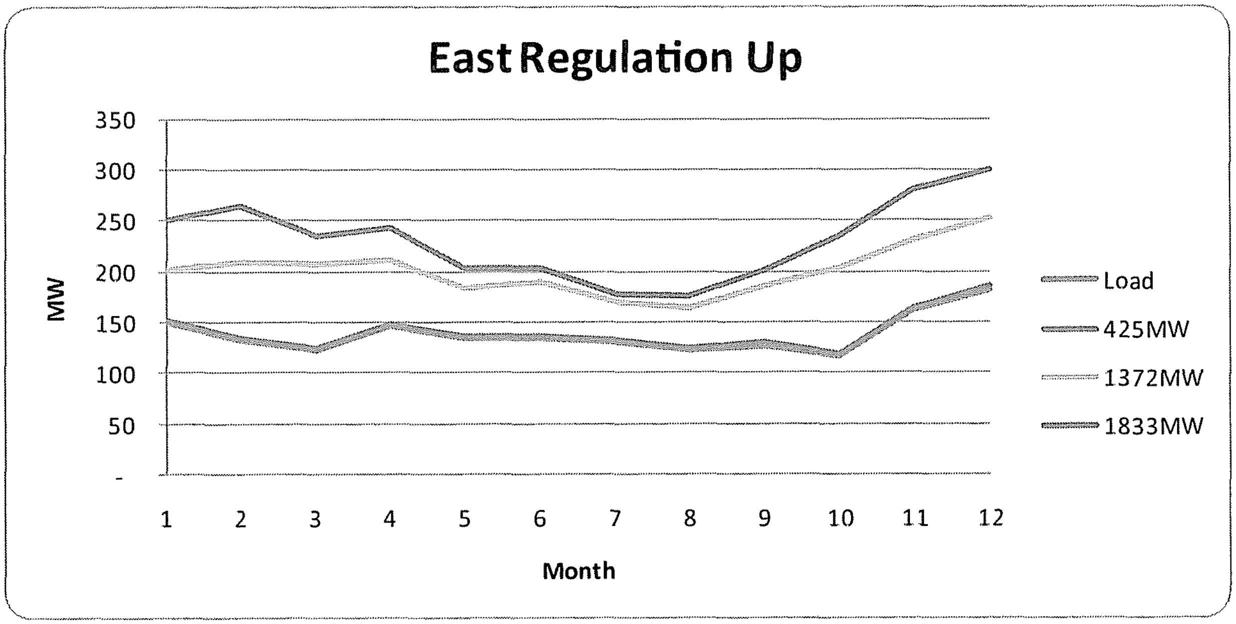
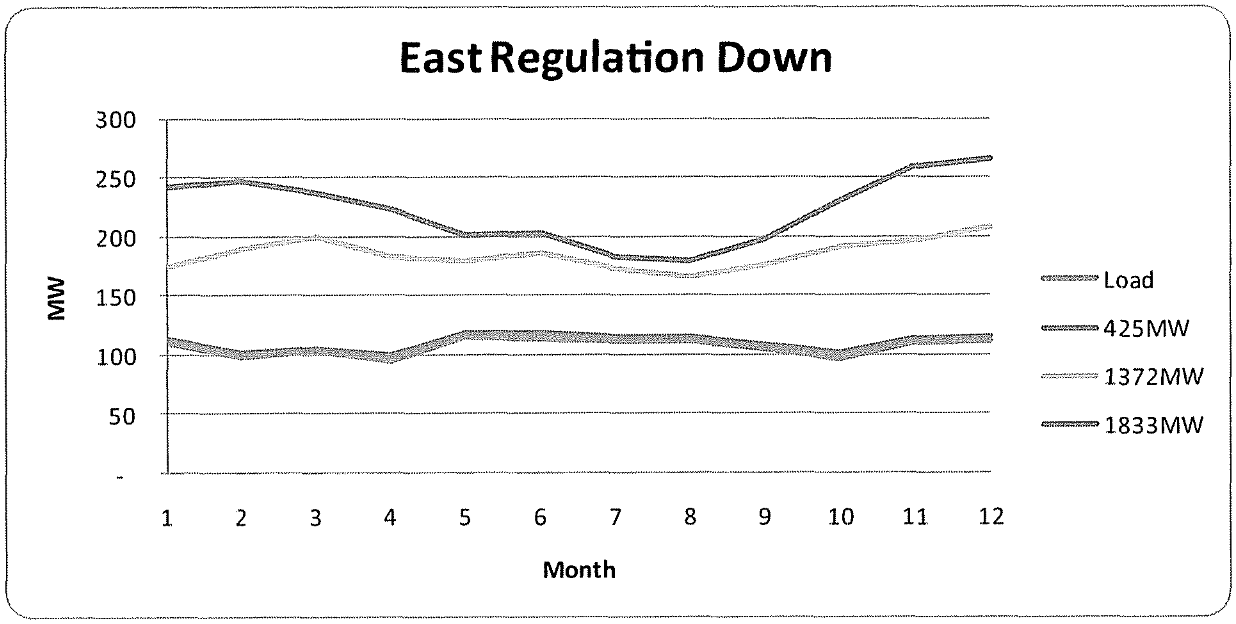


Figure 21. Regulation down operating reserve service demand in the East Balancing Authority Area.



Figures 14 through 21 identify both the seasonal nature of the operating reserve required to cover wind integration services and the tendency for the services' demand to be increased in months where more wind energy is generated. The monthly variation in operating reserve demand is built into the costing of the services in PaR, considering that the allocation of operating reserve for wind generation is less in the months where there is less need.

4.2 Wind Integration Costs

Tables 12 and 13 present the wind integration cost results for each wind penetration scenario. Costs are reported in both present value revenue requirement (PVRR) dollars and dollars per megawatt-hour of wind generation for each year in the study period. Levelized costs across the three year study term are also included in the far right column of each scenario table.

Table 12. PaR simulation results for the load only scenario and the 425 MW wind penetration scenario.

		Load Only				425 MW			
Total variable costs		2011	2012	2013	Levelized	2011	2012	2013	Levelized
Base (No Wind)	thousands	$ 1,192,794	$ 1,311,178	$ 1,301,577		$ 1,192,794	$ 1,311,178	$ 1,301,577	
Simulation 1		$ 1,192,794	$ 1,311,178	$ 1,301,577		$ 1,141,308	$ 1,251,695	$ 1,249,391	
Simulation 2		N/A	N/A	N/A		$ 1,150,552	$ 1,261,783	$ 1,259,733	
Simulation 3		$ 1,188,903	$ 1,300,920	$ 1,286,758		$ 1,145,876	$ 1,251,190	$ 1,241,733	
Simulation 4		$ 1,201,530	$ 1,322,377	$ 1,313,055		$ 1,152,348	$ 1,264,907	$ 1,264,277	
Calculation of Integration Costs									
Operating Reserve (Sim 2 less Sim 1)	thousands	$ -	$ -	$ -	$ -	$ 9,244	$ 10,088	$ 10,342	$ 25,830
System Balancing (Sim 4 less Sim 2)		$ -	$ -	$ -	$ -	$ 1,796	$ 3,124	$ 4,544	$ 8,094
Total	thousands	$ -	$ -	$ -	$ -	$ 11,040	$ 13,212	$ 14,886	$ 33,924
Wind Generation (Actual)									
East Wind	GWh	-	-	-	-	534	603	520	1,446
West Wind		-	-	-	-	754	794	665	1,937
Total	GWh	-	-	-	-	1,288	1,396	1,185	3,383
Operating Reserve	$/MWh	$ -	$ -	$ -	$ -	$ 7.18	$ 7.22	$ 8.73	$ 7.64
System Balancing		$ -	$ -	$ -	$ -	$ 1.39	$ 2.24	$ 3.83	$ 2.39
Total Wind Integration	$/MWh	$ -	$ -	$ -	$ -	$ 8.57	$ 9.46	$ 12.56	$ 10.03

Table 13. PaR simulation results for the 1,372 MW and 1,833 MW wind penetration scenarios.

Total variable costs		1400 MW 2011	1400 MW 2012	1400 MW 2013	Levelized	1750 MW 2011	1750 MW 2012	1750 MW 2013	Levelized
Base (No Wind)	thousands	$ 1,192,794	$ 1,311,178	$ 1,301,577		$ 1,192,794	$ 1,311,178	$ 1,301,577	
Simulation 1		$ 1,046,895	$ 1,141,572	$ 1,148,139		$ 1,014,831	$ 1,103,397	$ 1,112,343	
Simulation 2		$ 1,075,215	$ 1,172,782	$ 1,180,728		$ 1,053,713	$ 1,145,954	$ 1,156,774	
Simulation 3		$ 1,080,733	$ 1,179,114	$ 1,176,686		$ 1,068,866	$ 1,163,768	$ 1,163,482	
Simulation 4		$ 1,077,117	$ 1,175,126	$ 1,186,073		$ 1,057,087	$ 1,149,484	$ 1,162,164	
Calculation of Integration Costs									
Operating Reserve (Sim 2 less Sim 1)	thousands	$ 28,320	$ 31,210	$ 32,589	$ 80,135	$ 38,882	$ 42,557	$ 44,431	$ 109,512
System Balancing (Sim 4 less Sim 2)		$ 1,902	$ 2,344	$ 5,345	$ 8,165	$ 3,374	$ 3,530	$ 5,390	$ 10,609
Total	thousands	$ 30,222	$ 33,554	$ 37,934	$ 88,300	$ 42,256	$ 46,087	$ 49,821	$ 120,121
Wind Generation (Actual)									
East Wind	GWh	2,319	2,520	2,232	6,175	3,230	3,483	3,106	8,576
West Wind		1,462	1,556	1,332	3,805	1,462	1,556	1,332	3,805
Total	GWh	3,781	4,076	3,564	9,980	4,692	5,040	4,438	12,380
Operating Reserve	$/MWh	$ 7.49	$ 7.66	$ 9.14	$ 8.03	$ 8.29	$ 8.44	$ 10.01	$ 8.85
System Balancing		$ 0.50	$ 0.58	$ 1.50	$ 0.82	$ 0.72	$ 0.70	$ 1.21	$ 0.86
Total Wind Integration	$/MWh	$ 7.99	$ 8.23	$ 10.64	$ 8.85	$ 9.01	$ 9.14	$ 11.23	$ 9.70

The PaR model results demonstrate interesting trends in the component costs. Most notable is the reduction of system balancing costs for the 1,372 MW and 1,833 MW wind capacity penetration scenarios when compared to the 425 MW wind capacity penetration scenario. This is due to the domination of load forecast error in the 425 MW scenario system balancing integration cost line item, where total system costs are divided by wind energy production to derive system costs on a per unit of wind generation basis. The system balancing costs stabilize as wind generation increases in the higher penetration scenarios. Additionally, the operating reserve integration costs increase with additional wind capacity penetration. The rate of increase in costs is outpacing the increased wind energy produced, resulting in a higher price per megawatt-hour of wind energy produced. Finally, it is noteworthy that the addition of wind generation capacity lowers overall system costs.

Table 14 compares the results of the Study to integration costs developed for the 2008 IRP on a component by component basis using Levelized costs over the applicable terms. The primary differences in results are most apparent for inter-hour (2008 IRP)/system balancing (2010 Study) wind integration costs. This difference is explained by improvements in method. In the 2008 IRP, market transaction costs were used to estimate inter-hour integration costs, whereas the current Study calculates system balancing integration costs derived from the operation of PacifiCorp resources.