ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM QUALIFYING FACILITIES THAT QUALIFY FOR SCHEDULE NO. 37

UTAH – June 2010

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The starting point for the avoided cost calculation is the load and resource balance developed for the Company's 2008 Update Integrated Resource Plan (IRP). It should be noted that many of the input assumptions for the IRP were fixed in November 2009, in order to enable filing of the IRP in March 2010. Some of the inputs have been updated for known changes for purposes of this avoided cost calculation.

Loads and Resources (L&R)

The Company updated the load forecast from the November 2009 forecast to the March 2010 forecast. Company owned wind resources and long-term sales and purchase contracts were updated to include information available as of early May 2010. These changes include the addition or revision of several long-term purchase contracts[1].

Table 1 presents the Company's load and resource balance. Table 1 shows an energy surplus from 2010 through 2012 and then an energy deficit of 62 average megawatts (aMW) in 2013. Summer peak capacity shows a surplus of 218 megawatts (MW) in 2010 and a deficit of 3 MW starting in 2011, growing to 1,344 MW in 2013.

In the Commission order in Docket No. 09-035-T14, the Company is directed "to label Table 1 with the applicable planning reserve margin assumption (e.g., 12 or 15 percent) in all subsequent filings of Schedule No. 37 rates." The purpose of Table 1 is to demonstrate when the Company is short on resources after meeting all obligations including operating reserves, which are seven percent for thermal resources and five percent for hydro and wind resources, plus regulating margin to follow the fluctuation of load. Therefore, the planning reserve margin assumed in Table 1 is equal to the operating reserve margin. In addition, the Company reviewed its presentation of reserve requirement for this filing, and discovered that the capacity requirement has been overstated due to the inclusion of regulating margin as a line item when it is already included in the spinning reserves because of the similar requirements on resources to provide for such obligations.

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[1] Additions and revisions to the long-term contracts portfolio include power purchase agreements with Cargill, NV Energy, Southern California Edison, Pacific Gas and Electric, and Shell. Weyerhaeuser contracts have expired.

Avoided Cost Calculation

Based on the load and resource balance shown in **Table 1**, the avoided cost calculation is separated into two distinct periods: (1) the Short Run – a period of resource sufficiency (2010 through 2012); and (2) the Long Run – a period of resource deficiency (2013 and beyond).

1. Short Run Avoided Costs

During periods of resource sufficiency, the company's avoided energy costs are based on the displacement of purchased power and existing thermal resources as modeled by the company's GRID model. The model input data includes the monthly load and resource data, which are the basis for the annual summary of loads and resources shown in **Table 1**.

To calculate short-run avoided costs, two production cost studies are prepared. The only difference between the two studies is an assumed 10 aMW increase, at zero running cost. The 10 aMW resource serves as a proxy for qualifying facility generation. The avoided energy cost could be viewed as the highest variable cost incurred to serve total system load from existing and non-deferrable resources. The outputs of the production cost model run are provided as **Table 2**.

Capacity costs in this period are based on capacity purchases for the number of months that the company is capacity deficit. For example, if the company is capacity deficit for five months in a given year, the purchases would be for five twelfths of the year and the annual value as shown in **Table 3** would be five twelfths of the capacity cost of a simple cycle combustion turbine (SCCT).

2. Long Run Avoided Costs

During the resource deficiency period (2013 and beyond) in which new resources are required to provide both summer and winter capacity and energy to meet the Company's resource requirements, avoided costs are the fixed and variable costs of a proxy resource that could be avoided or deferred. The current proxy resource is a combined cycle combustion turbine (CCCT)[2].

Since CCCTs are built as base load units that provide both capacity and energy, it is appropriate to split the fixed costs of this unit into capacity and energy components. The fixed cost of a single cycle combustion turbine (SCCT), which is usually acquired as a capacity resource, defines the portion of the fixed cost of the blended resource that is assigned to capacity. Consistent with the Commission Order in Docket 03-035-14, 50% of the fixed costs associated with the construction of the CCCT resource in excess of the

[2] 607 MW CCCT (Wet "F" 2x1) - East Side Options (4500') as listed in Table A.4 of the 2008 IRP Update. Fuel costs are from the Company's March 2010 (0310) Official Forward Price Curve.

fixed costs of a SCCT is assigned to energy and is added to the variable production (fuel) cost of the CCCT resource to determine the total avoided energy costs. **Table 3** shows the capitalized energy costs.

The fuel cost of the CCCT defines the avoided variable energy costs. The gas price forecast used as the basis for the CCCT fuel cost is discussed later in this document. **Table 4** shows the CCCT fuel cost, the addition of capitalized energy costs at an assumed 50.5% capacity factor and the total avoided energy costs.

Because energy generated by a qualifying facility may vary, the total avoided costs at 75%, 85% and 95% capacity factor are prepared to illustrate the impact of differing generation levels. This calculation is shown in **Table 5**.

Avoided energy costs can be differentiated between on-peak and off-peak periods. To make this calculation, the Company assumed that all capacity costs are incurred to meet on-peak load requirements. On an annual basis, approximately 57% of all hours are on-peak and 43% are off-peak. **Table 6** shows the calculation of on-peak and off-peak avoided energy prices.

For informational purposes, **Table 7** shows a comparison between the avoided costs currently in effect in Utah and the proposed avoided costs in this filing.

Table 8 shows the calculation of the total fixed costs and fuel costs of the CCCT and SCCT that are used in **Table 3** and **Table 4**. In this filing, the Company's next deferrable resource is a CCCT located on the east side of the Company's system. This result is consistent with the Company's addition of an east side Combined Cycle Combustion Turbine (CCCT) as shown in Table A.4 of the 2008 IRP Update.

In the Commission order in Docket No. 09-035-T14, the Company is directed to provide additional discussion on the use of the capacity factor to allocate avoided capital costs to the on-peak energy price. An on-peak capacity factor is used to allocate the avoided capital costs. The on-peak capacity factor is derived from the annual capacity factor of the proxy resource, and is based on the assumption that the proxy resource will mainly generate in the on-peak hours. The on-peak capacity factor is defined as the percent of on-peak hours that the proxy resource would generate given its overall annual capacity factor. In the current filing, the annual capacity factor of the proxy resource is 50.5%, and the on-peak capacity factor is 88.6 % (50.5% / 57% on-peak hours). Such an on-peak capacity factor captures the capital costs of the proxy resource that would be avoid by not having to generate during 88.6% of the on-peak hours.

In the Commission order in Docket No. 09-035-T14, the Commission also directed the Company to provide additional discussion regarding existing environmental costs and increase in transportation costs. The cost in the "Environmental" column of the IRP supply side tables includes the cost for existing sulfur dioxide (SO_2) compliance. For a new gas-fired resource, these costs are below the rounding level used in the study and round to zero. The Company has not included anticipated future environmental costs related to carbon dioxide (CO2), sulfur dioxide (SO2) and oxides of nitrogen (NOx) in the current filing because the Company has not incurred such environmental costs. The transportation costs in the current update are based on the Company's 2008 IRP Update. The increase in the fixed gas transportation in the 2008 IRP Update as compared with the one in the Company's 2004 IRP Update is due to the addition of lateral pipeline costs based on the assumption that natural gas would need to be delivered through a lateral pipeline in addition to the main gas pipeline.

Price Forecast for Electricity and Natural Gas

The electricity and natural gas prices used in this filing are from the Company's Official Forward Price Curve dated March 31, 2010. Both the electricity and natural gas prices are part of the inputs to the Company's GRID model in the calculation of the proposed avoided costs in this filing. In addition, **Table 9** shows the natural gas price used to calculate the fuel costs of the CCCT that is the proxy resource for the Long Run avoided costs, and Table 10 shows the electricity prices at Mid Columbia and Palo Verde that are used in the Company's avoided costs calculation on a heavy-load hour and light-load hour basis.

For the period from April 2010 through April 2016, the official forward prices are based on the information from the market forward transactions. For the period from May 2016 through April 2017, the official forward prices are the average of market information and the long-term price forecast. For period beginning in May 2017, the official forward prices are based on long-term price forecast.