Appendix F.6- RMATS Economic Comparison Tables

Purpose

The purpose of the economic comparison tables is to compare the value of resource and transmission expansion alternatives on a screening study basis. The comparison takes into account the production (fuel and other variable O&M) costs of scenarios, the capital investment requirements in new resources and transmission, and associated annualized fixed costs. The annualized costs of each alternative are then compared to Reference Cases to measure annual net savings or costs.

Economic Comparison Tables

The data in the economic comparison tables were developed in three steps: 1) determine production costs 2) determine total initial capital investment requirements; 3) calculate annualized costs associated with each required investment.

Step 1:

Production costs were determined using ABB Market Simulator, as described in detail in Chapter 2 and Appendix F.2.

Step 2:

Total initial capital investments requirements of each alternative are shown in the column labeled "Initial Investment" and are grouped into generating resource and transmission investments.

Resource costs include wind, gas and coal capital investment amounts as well as associated transmission integration costs. (Table F.6.1, lines 5:11).

In the case of Recommendation 2, the resource costs are adjusted downward to the extent that the Rocky Mountain region builds resources for export (Table F.6.1, line 12). This adjustment is necessary because the study assumes that gas –fired generation will be built to meet load growth in regions outside the Rocky Mountain states.

Resource capital investment requirements are based on the development and construction cost estimates by resource category from draft Northwest Power and Conservation Council's (NWP&CC) reports, "*New Resource Characterization for the Fifth Power Plan"* and from a California Energy Commission report on renewable resources.

Transmission costs include capital investment amounts associated with transmission lines as well as any customized equipment (Table F.6.1, lines 21:24).

Table F.6. 1: Sample Table

		Initial Investment
1	**Production Costs (Fuel & Other VOM)**	
2	Change from All Gas Case [Column A]	
3	Change from IRP- Based Case [Column B]	
4		
5	**Resource Costs:**	
6	**RM Resource Additions Capex**	
7	Wind	3,766
8	Gas thermal	373
9	Coal thermal	7,857
10	Incremental Transmission Integration Capex	311
11	**RM Resource Capex Sub Total**	**12,306**
12	**Adj. Outside RM Resource Additions Capex**	(2,257)
13	**Other RM Costs**	
14	Incremental Capital Charge @ 10%	
15	Incremental Fixed O&M	
16	Wind "wear and tear"	
17	**Subtotal Other RM Costs**	
18	Adj. Other Costs Outside RM	
19	**Total Resource Costs**	
20		
21	**Transmission Costs:**	
22	Incremental Line Capex	3,872
23	Customized Equipment Capex	393
24	**RM Transmission Capex Sub Total**	**4,265**
25		
26	Incremental Fixed O&M	
27	Incremental Capital Charge @ 10%	
28	**RM Transmission Costs**	**4,265**
29		
30	**Annualized Costs**	
31		
32	**Total Initial Investment**	**14,315**
33	**Annual Net (Savings)/Cost from All Gas Case**	
34	**Annual Net (Savings)/Cost from IRP- Based Case**	

Transmission costs were estimated on a line by line basis using historical data and professional judgment of the members of the RMATS Resource and Transmission Addition Work Groups.

Step 3:

Annualized costs associated with each alternative are shown in the column labeled "Representative Year". In this column, the production costs developed by ABB Market Simulator (as described in Chapter 2) are combined with annual fixed costs associated with the investment of each scenario.

Table F.6. Sample Table

		Representative Year
1	**Production Costs (Fuel & Other VOM)**	**18,458**
2	Change from All Gas Case [Column A]	(2,560)
3	Change from IRP- Based Case [Column B]	(1,588)
4		
5	**Resource Costs:**	
6	**RM Resource Additions Capex**	
7	Wind	
8	Gas thermal	
9	Coal thermal	
10	Incremental Transmission Integration Capex	
11	**RM Resource Capex Sub Total**	
12	**Adj. Outside RM Resource Additions Capex**	
13	**Other RM Costs**	
14	Incremental Capital Charge @ 10%	1,231
15	Incremental Fixed O&M	245
16	Wind "wear and tear"	94
17	**Subtotal Other RM Costs**	**1,570**
18	Adj. Other Costs Outside RM	**(254)**
19	**Total Resource Costs**	**1,316**
20		
21	**Transmission Costs:**	
22	Incremental Line Capex	
23	Customized Equipment Capex	
24	**RM Transmission Capex Sub Total**	
25		
26	Incremental Fixed O&M	85
27	Incremental Capital Charge @ 10%	427
28	**RM Transmission Costs**	**512**
29		
30	**Annualized Costs**	**1,828**
31		
32	**Total Initial Investment**	
33	**Annual Net (Savings)/Cost from All Gas Case**	**(986)**
34	**Annual Net (Savings)/Cost from IRP- Based Case**	**(525)**

The production costs are fuel and other variable O&M and are compared to each of the Reference Cases' production costs (Table F.6.2, lines 1:3).

Annualized fixed costs include resource and transmission capital charges associated with initial investment and fixed O&M (Table F.6.1, lines 13:19 and lines 26:28).

Annual capital charges are shown as a percentage of the initial investment. In concept, the annual capital charge reflects real levelized annual cost of the investment. It is determined by:

1) Calculating the present value of the streams of depreciation, return on capital, property and income taxes, interest, replacements and administrative and general costs.
2) Determining a real discount rate by removing the inflation component from the discount rate.
3) Using the real discount rate to calculate a levelized payment from the calculated present value. This levelized payment is a real levelized annual cost of the investment.

In the RMATS analysis, the capital charge is assumed to be 10% of the initial investment for both generation and transmission resources based on research by Cambridge Energy Research Associates (CERA) (Table F.6.1, line 14 and 27).

Fixed O&M amounts are calculated separately for each type of resource based on estimates provided by NWP&CC (Table F.6.1, line 15).

In the case of wind resources, a "wear and tear" impact on non- wind resources was included (line 16). Transmission fixed O&M is assumed to be 20% of the annual capital charge based on a recent transmission study by CERA. (Table F.6.1, line 26).

Resource and transmission capital charges and fixed O&M were combined to produce annualized costs of each alternative (Table F.6.1, line 30). The production costs as well as annualized fixed costs associated with each alternative were compared to the Reference Cases and other alternatives to obtain annual net savings and confirm economic viability.

Distribution of Economic Gains and Losses

The economic comparison tables show the costs and savings on an aggregate, interconnection-wide basis. The question then becomes where the economic gains and losses may fall within the West. Table F.6.3 below takes a first look at the spatial distribution of costs and savings by regional area and by load (consumers) and generator category.

These tables are predicated on LMPs, which are driven by loads, fuel prices, generation levels, and other variables at the nodal level. (See Chapter 2 for a discussion of LMPs.) LMPs are transitory, and arguably they are insufficient for predicting where benefits will fall.

The distributions reflect fuel and other VOM on an economic modeling basis. They do not include capital & fixed O&M costs. Effectively, the distributions assume a real-time competitive market in which pricing is on an hourly, LMP basis. In fact, state regulatory treatment of these gains and losses could change the mix between loads and generators substantially. The net impact on a region can be estimated by subtracting the Generator Gross Margin column from the Load column

LMP is the Load Cost divided by GWh- Essentially this is the average regional LMP for the year

LMP is the Generator Revenue divided by GWh- Essentially this is the average regional LMP for the year

Total generator production cost- includes fuel and other VOM

Table F.6. 2: Economic Gross Gains & Losses Table

	Load			Generator					
Region	*GWh*	*LMP*	*Cost (MM)*	*GWh*	*LMP*	*Revenue (MM)*	*VOM (MM)*	*Gross Margin (MM)*	*Load Minus Generator*
Rocky Mountain	161,635	48.24	7,797	195,545	47.10	9,209	2,361	6,848	949
Northwest	193,131	49.22	9,505	201,812	48.67	9,821	2,404	7,418	2,088
Canada	142,702	48.83	6,968	146,257	48.63	7,113	1,996	5,117	1,850
Mexico	19,848	48.20	957	25,404	47.75	1,213	879	334	623
California	335,938	51.47	17,291	221,372	52.04	11,521	6,117	5,404	11,887
Desert Southwest	162,512	49.02	7,967	225,373	48.36	10,899	6,024	4,875	3,091
Total	1,015,766	49.70	50,484	1,015,763	49.00	49,777	19,780	29,997	20,488

Total energy demanded by loads represented in GWh

The hourly demand at each load node times the hourly LMP ($), summed for the year.

Total energy generated in GWh

The hourly generation at each generator node times the hourly LMP, summed for the year.

Revenues minus VOM= Generator Gross Margin

Load Cost minus Generator Gross Margin, used to calculate total benefits in Chapter 3

Tables B.6.4 – B.6.7 display the gross amounts used to calculate the regional gains and losses in Chapter 3. For example, to calculate the Load Benefit for the Rocky Mountain Region in Table 3.7 (chapter 3), subtract the Rocky Mountain Load Cost in Table B.6.4 ($7,797 Million) from the Rocky Mountain Load Cost in Table B.6.7 ($7,920 million). This yields a load benefit of $123 million.

Table F.6. 3: Recommendation 1

	Load			Generator					
Region	GWh	LMP	Cost (MM)	GWh	LMP	Revenue (MM)	VOM (MM)	Gross Margin (MM)	Load Minus Generator
Rocky Mountain	161,635	48.24	7,797	195,545	47.10	9,209	2,361	6,848	949
Northwest	193,131	49.22	9,505	201,812	48.67	9,821	2,404	7,418	2,088
Canada	142,702	48.83	6,968	146,257	48.63	7,113	1,996	5,117	1,850
Mexico	19,848	48.20	957	25,404	47.75	1,213	879	334	623
California	335,938	51.47	17,291	221,372	52.04	11,521	6,117	5,404	11,887
Desert Southwest	162,512	49.02	7,967	225,373	48.36	10,899	6,024	4,875	3,091
Total	1,015,766	49.70	50,484	1,015,763	49.00	49,777	19,780	29,997	20,488

Table F.6. 4: Recommendation 2

	Load			Generator					
Region	GWh	LMP	Cost (MM)	GWh	LMP	Revenue (MM)	VOM (MM)	Gross Margin (MM)	Load Minus Generator
Rocky Mountain	161,635	43.57	7,042	217,225	41.75	9,070	2,340	6,729	313
Northwest	193,131	46.88	9,053	196,704	46.38	9,123	2,178	6,945	2,108
Canada	142,702	47.52	6,781	144,743	47.34	6,852	1,919	4,933	1,847
Mexico	19,848	47.24	938	25,173	46.84	1,179	867	312	626
California	335,938	49.71	16,699	216,187	49.75	10,755	5,562	5,193	11,505
Desert Southwest	162,512	47.32	7,689	215,731	46.73	10,081	5,592	4,489	3,200
Total	1,015,766	47.45	48,202	1,015,762	46.33	47,060	18,458	28,602	19,600

Table F.6. 5: IRP Based Reference Case

	Load			Generator					
Region	GWh	LMP	Cost (MM)	GWh	LMP	Revenue (MM)	VOM (MM)	Gross Margin (MM)	Load Minus Generator
Rocky Mountain	161,635	48.21	7,793	190,671	47.30	9,018	2,465	6,554	1,239
Northwest	193,131	49.55	9,570	202,593	49.02	9,931	2,435	7,496	2,075
Canada	142,702	48.97	6,988	146,500	48.77	7,144	2,007	5,137	1,851
Mexico	19,848	48.24	957	25,421	47.79	1,215	880	335	622
California	335,938	51.63	17,345	224,726	52.19	11,728	6,214	5,514	11,831
Desert Southwest	162,512	49.08	7,976	225,851	48.39	10,930	6,046	4,884	3,091
Total	1,015,766	49.84	50,629	1,015,762	49.19	49,966	20,046	29,920	20,709

Table F.6. 6: All Gas Reference Case

	Load			Generator					
Region	GWh	LMP	Cost (MM)	GWh	LMP	Revenue (MM)	VOM (MM)	Gross Margin (MM)	Load Minus Generator
Rocky Mountain	161,635	49.00	7,920	188,658	48.58	9,165	3,300	5,865	2,055
Northwest	193,131	49.88	9,634	203,853	49.38	10,066	2,488	7,578	2,055
Canada	142,702	49.08	7,004	146,785	48.86	7,171	2,019	5,152	1,852
Mexico	19,848	48.17	956	25,432	47.72	1,214	880	333	623
California	335,938	51.74	17,381	224,434	52.29	11,736	6,256	5,480	11,901
Desert Southwest	162,512	49.02	7,966	226,603	48.32	10,950	6,075	4,875	3,091
Total	1,015,766	50.07	50,862	1,015,765	49.52	50,303	21,018	29,284	21,577