4. COST AND EFFICIENCY ANALYSIS

4.1 Cost and Other Factors for Recommended and Alternative Facilities

Table 4-1 below shows comparative costs, service life, and estimated annual availability for Options 1 through 5.

Table 4-1 Cost and Efficiency Factors for Options 1- 5

	Option 1 115 kV Conversion	Option 2 69 kV Uprate	Option 3 69 kV Split System	Option 4 69 kV New Source	Option 5 Generation
Present Value Cost	$9,550,000	$15,979,000	$18,431,000	$12,268,000	$75,759,000
Cost per kW	$ 52	$ 87	$ 100	$ 67	$ 411
Service Life (Years)	30	30	30	30	30
Est. Annual Availability	99.99%	99.99%	99.99%	99.99%	95%

The cost figures include the combined costs to be incurred by GRE and WHCEA, including the present cost of future losses to be anticipated under each of the options in addition to the actual capital outlay required for construction of facilities. GRE and its members utilize a Least Cost Plan in determining a transmission/distribution plan. The Least Cost Plan is determined by selecting the minimum total cost of the required transmission costs of GRE and the required distribution costs of the member.

The first step for evaluating the cost of each alternative was to identify the various investments by year in current dollars and escalate these costs to the appropriate year at four percent inflation per year through the year 2026. The present value of these costs was determined using 6.5%, GRE's estimated long-term borrowing rate.

Second, based upon the annual investments, GRE determined the incremental costs related to the investment, such as property taxes, operation and maintenance, general and administrative, and insurance. The present values of these annual costs were also computed. Third, the annual loss factor savings was determined. The present value of these savings was also computed.

Finally, the sum of these three present value amounts (investments, incremental costs related to the investments, and the loss factor savings) were summed to arrive at a net present value cost of each project. It should be noted that operational and fuel costs are not included in the Option 5 (generation) costs.

Service life has been assumed to be 30 years for all facilities, although from a practical standpoint, transmission infrastructure is rarely completely retired.

The availability of the transmission options is high, as noted, because the lines and facilities are built to withstand most weather extremes encountered in the region (with the exception of tornadoes, heavy ice storms or other extreme weather conditions) or accidental human impacts.

In determining availability factors for the generation alternatives, GRE has not provided specific figures for the wind, microturbine, and diesel generator facilities because these technologies are not reasonably feasible in the densely developed areas that are creating the increased load demand. The limitations on these technologies are discussed more fully in Section 3.3.2. However, if availability were analyzed, it would be lower than that for transmission facilities due to the complexity of the generation equipment and the correspondingly greater demand for maintenance and repair activities. The availability figure shown in Table 4-1 for the generation alternative is based upon the use of gas combustion turbines. GRE believes that gas combustion turbines are the only generation technology that could reliably satisfy the anticipated load demand. For combustion turbines, the primary factor limiting availability is the limitation of discharges under state and federal air quality regulations. GRE's estimate of availability is based upon its experience with its existing gas combustion turbine facilities in other areas of Minnesota.

Annual operating and maintenance costs associated with 115 kV transmission lines in GRE's system have averaged approximately $ 4,250 per mile of line over the last several years. Costs for 69 kV transmission lines would be equivalent. At both voltages, costs for all of the transmission options (Options 1-4) could be moderately higher than the above figures due to the urban setting of the lines. Annual operating and maintenance expenses for Option 5 (generation) are assumed to be approximately $4,000 per kilowatt hour (kWh); this is based upon GRE's experience with existing combustion turbine units. It should be noted that this figure does not include fuel costs for the generation units, and the figure could vary significantly depending on how much a unit is on line.

4.2 Effect on Rates

Recovery of the costs incurred under each of the five options would require estimated adjustments to GRE's and WHCEA's rate structures as shown in Tables 4-2 and 4-3 below. The effect on member rates is the average yearly rate increase over 26 years beginning in 2005. To provide a uniform basis for comparison, the estimates for all options assume an in service date of 2007, even though some components of some options may not be completed until later dates. It should be noted that the incidental increases in Connexus Energy member and Xcel Energy customer rates have not been shown.

The capital recovery of the annual investment costs (depreciation and interest), the incremental costs related to the investments, less the annual loss factor savings were summed annually. This amount was compared to the forecasted annual member energy sales.

Table 4-2 Effect on GRE Member Rates

	Option 1 115 kV Conversion	Option 2 69 kV Uprate	Option 3 69 kV Split System	Option 4 69 kV New Source	Option 5 Generation
Ave. Rate Increase (Cents/kWh)	0.0021	0.0085	0.0100	0.0067	0.0465

Table 4-3 Effect on WHCEA Member Rates

	Option 1 115 kV Conversion	Option 2 69 kV Uprate	Option 3 69 kV Split System	Option 4 69 kV New Source	Option 5 Generation
Ave. Rate Increase (Cents/kWh)	0.0328	*	*	*	*

***** Option 1 is the only option that would result in rate increases to WHCEA customers beyond those to GRE member cooperatives in general. This is because Option 1 requires WHCEA substation upgrades, and those costs would be the responsibility of WHCEA in the Least Cost Plan arrangement.

4.3 Efficiency Factors

To measure the efficiency of the various options in transporting power generated to the consumer, GRE performed an analysis of potential line and substation losses. Losses result because heat is generated when current is passed through a conductor. For a given amount of power transfer, the lower the voltage the higher the current required, and therefore the greater the amount of energy dissipated as heat. The end result of the heat loss is that a portion of the electrical power produced at the generator is lost in the transmission system before getting to the consumer.

GRE has analyzed losses for the transmission options considering the transmission system serving the entire WHCEA area. Analysis of losses at substations has similarly included the substation facilities serving the entire WHCEA area. This approach was used because of the interrelationship of all of the transmission and substation components and the fact that each of the options creates different losses in different components of the system.

Loss computations were analyzed for the years 2007, 2012 and 2026, to demonstrate the varying impact of losses over time. At each reference date, losses for each option were calculated under the assumption that system improvements discussed in Section 3 would have occurred as anticipated. Loss computations under projected maximum loading and under projected average loading conditions are also based upon projected loads at the reference dates.

Tables 4-4 and 4-5 below compare the losses associated with each transmission option under projected maximum loading conditions and under average loading conditions at each of the reference dates.

Under Option 5 (generation) efficiency is determined by evaluating the estimated heat rate for the proposed generation facilities. Under this Option, GRE explored the use of combustion turbine-generators with a total of three units proposed to be installed near the Arbor Lake, Cedar Island, and Plymouth substations. These units have an assumed heat rate of 12,000 Btu/kW.

Review of the above efficiency factors shows that the proposed 115 kV line (Option 1) results in significantly lower losses than under any of the other four options, and this is true at every point in the 21 years analyzed by GRE. It is also significant that the lower losses under Option 1 begin immediately and continue to accumulate with the passage of time.

4.4 Assumptions Made in Cost Analysis

The major assumptions made in preparation of the data shown at Sections 4.1 through 4.3 above are included in the discussions in each section.

Table 4-4 System Losses at Peak Load

	SYSTEM LOSSES AT PEAK LOAD (MW)				
Year	Option 1	Option 2	Option 3	Option 4	Option 5
2005	29.55	31.97	31.81	30.21	31.60
2006	30.13	32.37	32.20	30.82	31.97
2007	30.72	32.77	32.60	31.44	32.34
2008	31.33	33.17	33.01	32.08	32.71
2009	31.94	33.59	33.41	32.73	33.09
2010	32.57	34.00	33.83	33.39	33.48
2011	33.21	34.42	34.25	34.06	33.87
2012	33.86	34.85	34.67	34.75	34.26
2013	34.01	35.20	35.05	34.93	34.46
2014	34.15	35.55	35.44	35.12	34.67
2015	34.30	35.91	35.83	35.31	34.87
2016	34.45	36.27	36.22	35.50	35.08
2017	34.60	36.63	36.62	35.68	35.29
2018	34.74	37.00	37.02	35.87	35.50
2019	34.89	37.37	37.43	36.07	35.71
2020	35.04	37.74	37.84	36.26	35.92
2021	35.20	38.12	38.25	36.45	36.13
2022	35.35	38.50	38.67	36.64	36.35
2023	35.50	38.89	39.10	36.84	36.56
2024	35.65	39.28	39.53	37.03	36.78
2025	35.81	39.67	39.96	37.23	37.00
2026	35.96	40.07	40.40	37.43	37.22

Table 4-5 System Losses at Average Load

	SYSTEM LOSSES AT AVERAGE LOAD (MW)				
Year	Option 1	Option 2	Option 3	Option 4	Option 5
2005	28.69	29.87	29.79	29.19	29.71
2006	29.08	30.16	30.07	29.60	29.99
2007	29.48	30.46	30.36	30.01	30.27
2008	29.89	30.76	30.65	30.43	30.55
2009	30.30	31.06	30.94	30.86	30.84
2010	30.72	31.36	31.23	31.29	31.13
2011	31.14	31.67	31.53	31.73	31.42
2012	31.57	31.98	31.83	32.17	31.71
2013	31.60	32.14	32.01	32.22	31.78
2014	31.64	32.29	32.19	32.27	31.86
2015	31.67	32.45	32.38	32.33	31.93
2016	31.71	32.61	32.56	32.38	32.00
2017	31.74	32.77	32.75	32.43	32.07
2018	31.77	32.93	32.93	32.48	32.15
2019	31.81	33.09	33.12	32.53	32.22
2020	31.84	33.25	33.31	32.59	32.29
2021	31.88	33.41	33.50	32.64	32.37
2022	31.91	33.57	33.69	32.69	32.44
2023	31.95	33.73	33.88	32.74	32.52
2024	31.98	33.90	34.07	32.79	32.59
2025	32.02	34.06	34.27	32.85	32.67
2026	32.05	34.23	34.46	32.90	32.74