The Empire District Electric Company
Cogeneration Rate Calculation
January 2019

		Summer	Winter	Source
1.	Avoided Energy Cost	0.03417	0.03054	Prosym Model
2.	Transmission Loss Factor	1.02184	1.02184	Loss Study 2014
3.	**Cogeneration Purchase Rate**	**0.0349**	**0.0312**	**Calculated: Line 1 * Line 2**
4.	Summer / Winter Differential	11.89%		

Costs are averaged for 2019-2020 cost years.
The Summer period is the four months of June through September.
The Winter period is the remaining eight months.

	2019		2020	
SUMMER	Avg Marg $	Hours	Avg Marg $	Hours
Average Marginal Costs On-Peak	36.96	1,696	40.42	1,712
Average Marginal Costs Off-Peak	29.02	1,976	31.49	1,960
		3,672		3,672
WINTER				
Average Marginal Costs On-Peak	32.59	2,384	35.28	2,416
Average Marginal Costs Off-Peak	26.50	2,704	28.54	2,696
		5,088		5,112

AVOIDED ENERGY COST
(Marginal cost *on-peak/off-peak hours) / total hours

SUMMER		**2019**	**2020**	
	On-Peak	17.07	18.85	
	Off-Peak	15.62	16.81	
		32.69	35.65	**$34.17** 2019-20 Average

WINTER		**2019**	**2020**	
	On-Peak	15.27	16.67	
	Off-Peak	14.08	15.05	
		29.35	31.73	**$30.54** 2019-20 Average

Assumptions

*Winter months are January-April, October - December
*Summer months are May-September
*Off peak hours are weekday hours HE1-6, 23-24, weekends, and NERC holidays
*On peak hours are M-F HE7-22

Average Marginal Costs $/Mwh					
Year	Annual Avg Marg Cost	Summer On-Peak Avg Marg Cost	Summer Off-Peak Avg Marg Cost	Winter On-Peak Avg Marg Cost	Winter Off-Peak Avg Marg Cost
2019	30.75	36.96	29.02	32.59	26.50
2020	33.37	40.42	31.49	35.28	28.54
2021	33.08	39.69	31.36	34.63	28.78
2022	32.29	38.50	30.47	34.08	28.14
2023	33.68	40.00	31.82	35.31	29.64
2024	34.74	41.32	33.08	36.23	30.51

The Empire District Electric Company
Load and Capability Forecast
Based on Load Forecast 2019-2024

Winter

Year	2019	2020	2021	2022	2023	2024
Projected :						
Gross Peak	1,180	1,193	1,148	1,155	1,163	1,169
Less Interruptibles	(7.6)	(7.6)	(7.6)	(7.6)	(7.6)	(7.6)
Net Peak	**1,172**	**1,185**	**1,140**	**1,147**	**1,155**	**1,161**
Asbury	200	200	200	200	200	200
Iatan	84	84	84	84	84	84
Iatan 2	106	106	106	106	106	106
Plum Point (own)	51	51	51	51	51	51
Riverton 10	18	18	18	18	18	18
Riverton 11	18	18	18	18	18	18
Riverton 12 C. C.	285	285	285	285	285	285
Energy Center 1	92	92	92	92	92	
Energy Center 2	92	92	92	92	92	92
Energy Center 3	52	52	52	52	52	52
Energy Center 4	52	52	52	52	52	52
State Line 1	105	105	105	105	105	105
State Line C.C.	331	331	331	331	331	331
Ozark Beach	16	16	16	16	16	16
Plum Point PPA	50	50	50	50	50	50
150 MW Elk River Wind Farm PPA	30	30	30	30	30	30
105 MW Meridian Way Windfarm PPA	31	31	31	31	31	31
Total Capacity	1,613	1,613	1,613	1,613	1,613	1,521
Reserve Margin Required	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Capacity Margin Required	10.7%	10.7%	10.7%	10.7%	10.7%	10.7%
Capacity Responsibility	1,313	1,328	1,277	1,285	1,294	1,301
Capacity Balance	300	285	336	328	319	220
Reserve Margin	37.6%	36.1%	41.4%	40.6%	39.6%	31.0%
Capacity Margin	27.3%	26.5%	29.3%	28.9%	28.4%	23.6%

Summer

Year	2019	2020	2021	2022	2023	2024
Projected :						
Gross Peak	1,130	1,078	1,084	1,088	1,097	1,103
Less Interruptibles	(8.4)	(8.4)	(8.4)	(8.4)	(8.4)	(8.4)
Net Peak	**1,122**	**1,070**	**1,076**	**1,080**	**1,089**	**1,095**
Asbury	200	200	200	200	200	200
Iatan	84	84	84	84	84	84
Iatan 2	106	106	106	106	106	106
Plum Point (own)	51	51	51	51	51	51
Riverton 10	13	13	13	13	13	13
Riverton 11	15	15	15	15	15	15
Riverton 12 C. C.	247	247	247	247	247	247
Energy Center 1	82	82	82	82	82	
Energy Center 2	80	80	80	80	80	80
Energy Center 3	40	40	40	40	40	40
Energy Center 4	40	40	40	40	40	40
State Line 1	95	95	95	95	95	95
State Line C.C.	292	292	292	292	292	292
Ozark Beach	16	16	16	16	16	16
Plum Point PPA	50	50	50	50	50	50
150 MW Elk River Wind Farm PPA	22	22	22	22	22	22
105 MW Meridian Way Windfarm PPA	9	9	9	9	9	9
Total Capacity	1,442	1,442	1,442	1,442	1,442	1,360
Reserve Margin Required	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Capacity Margin Required	10.7%	10.7%	10.7%	10.7%	10.7%	10.7%
Capacity Responsibility	1,256	1,198	1,205	1,209	1,219	1,226
Capacity Balance	186	244	237	233	223	134
Reserve Margin	28.6%	34.8%	34.1%	33.6%	32.5%	24.2%
Capacity Margin	22.2%	25.8%	25.4%	25.1%	24.5%	19.5%

12% Reserve Responsibility
Current Reserve Ratings

Empire District Electric Company
2014 Analysis of System Losses

TABLE 1
Loss Factors at Sales Level, Calendar Year 2014

Voltage Level of Service	Total EDE	Missouri	Arkansas	Kansas	Oklahoma
Demand (kW)					
Transmission	1.03071	1.03071	1.03071	1.03071	1.03071
Substation	1.03731	1.03777	1.03741	1.03741	1.03741
Primary	1.06244	1.06276	1.06362	1.06362	1.06362
Secondary	1.08450	1.08476	1.08604	1.08624	1.08646
Losses (MW) to Net System Input[1]	7.23%	7.25%	7.25%	7.41%	7.33%
Energy (kWh)					
Transmission	1.02184	1.02184	1.02184	1.02184	1.02184
Substation	1.03043	1.03122	1.03081	1.03081	1.03081
Primary	1.04857	1.04870	1.04899	1.04899	1.04899
Secondary	1.07516	1.07426	1.07632	1.07496	1.07610
Losses (MWH) to Net System Input[1]	6.21%	6.17%	5.92%	6.33%	6.06%

TABLE 2
Historical System MWH Losses[2]

Year	Firm Sales MWH	Total Losses	% Annual	% 5-Yr. Avg. Rolling
1998	4,162,607	303,175	7.28	
1999	4,163,824	304,747	7.32	
2000	4,424,768	366,028	8.27	
2001	4,494,199	304,067	6.77	
2002	4,566,262	334,287	7.32	7.39
2003	4,594,856	347,676	7.57	7.45
2004	4,628,759	338,035	7.30	7.45
2005	4,923,486	361,858	7.35	7.26
2006	5,049,599	273,483	5.42	6.99
2007	5,118,460	356,396	6.96	6.92
2008	5,124,277	353,204	6.89	6.78
2009	4,901,435	349,647	7.13	6.75
2010	5,202,277	363,250	6.98	6.68
2011	5,082,772	351,949	6.92	6.98
2012	4,922,036	311,275	6.32	6.85
2013	4,973,276	341,362	6.86	6.85
2014	5,037,140	333,810	6.63	6.74

[1] Net System Input equals firm (MW and MWH) sales plus losses, Company use less non-requirement sales. See Appendices A and B, Exhibit 1, for their calculations.
[2] Percent losses shown are based on Net System Output (metered sales basis).

Time of Day Marginal Cost
Data From the 2019-2024 Fuel and Purchase Power Budget
Average Marginal Cost $/MWh

2019			
Period	Total hours	% of hours	Average Marg Cost
Summer On-Peak	1,696	19.4%	36.96
Summer Off-Peak	1,976	22.6%	29.02
Total Summer	3,672	41.9%	32.69
Winter On-Peak	2,384	27.2%	32.59
Winter Off-Peak	2,704	30.9%	26.50
Total Winter	5,088	58.1%	29.35
Total	8,760	100.0%	30.75

2020			
Period	Total hours	% of hours	Average Marg Cost
Summer On-Peak	1,712	19.5%	40.42
Summer Off-Peak	1,960	22.3%	31.49
Total Summer	3,672	41.8%	35.65
Winter On-Peak	2,416	27.5%	35.28
Winter Off-Peak	2,696	30.7%	28.54
Total Winter	5,112	58.2%	31.72
Total	8,784	100.0%	33.37

2021			
Period	Total hours	% of hours	Average Marg Cost
Summer On-Peak	1,712	19.5%	39.69
Summer Off-Peak	1,960	22.4%	31.36
Total Summer	3,672	41.9%	35.24
Winter On-Peak	2,384	27.2%	34.63
Winter Off-Peak	2,704	30.9%	28.78
Total Winter	5,088	58.1%	31.52
Total	8,760	100.0%	33.08

2022			
Period	Total hours	% of hours	Average Marg Cost
Summer On-Peak	1,712	19.5%	38.50
Summer Off-Peak	1,960	22.4%	30.47
Total Summer	3,672	41.9%	34.21
Winter On-Peak	2,368	27.0%	34.08
Winter Off-Peak	2,720	31.1%	28.14
Total Winter	5,088	58.1%	30.90
Total	8,760	100.0%	32.29

2023			
Period	Total hours	% of hours	Average Marg Cost
Summer On-Peak	1,696	19.4%	40.00
Summer Off-Peak	1,976	22.6%	31.82
Total Summer	3,672	41.9%	35.60
Winter On-Peak	2,384	27.2%	35.31
Winter Off-Peak	2,704	30.9%	29.64
Total Winter	5,088	58.1%	32.30
Total	8,760	100.0%	33.68

2024			
Period	Total hours	% of hours	Average Marg Cost
Summer On-Peak	1,696	19.3%	41.32
Summer Off-Peak	1,976	22.5%	33.08
Total Summer	3,672	41.8%	36.89
Winter On-Peak	2,400	27.3%	36.23
Winter Off-Peak	2,712	30.9%	30.51
Total Winter	5,112	58.2%	33.20
Total	8,784	100.0%	34.74

Assumptions

*Winter months are January-April, October - December
*Summer months are May-September
*Off peak hours are weekday hours HE1-6, 23-24, weekends, and NERC holidays
*On peak hours are M-F HE7-22