The Empire District Electric Company
Cogeneration Rate Calculation
January 2015

	Summer	Winter	Source
1. Avoided Energy Cost	0.04391	0.03468	Prosym Model
2. Transmission Loss Factor	1.02336	1.02336	Loss Study 2011
3. Cogeneration Purchase Rate	**0.0449**	**0.0355**	**Calculated: Line 1 * Line 2**
4. Summer / Winter Differential	26.60%		

Costs are averaged for 2015-2016 cost years.
The Summer period is the four months of June through September.
The Winter period is the remaining eight months.

	2015		2016	
SUMMER	Avg Marg $	Hours	Avg Marg $	Hours
Average Marginal Costs On-Peak	51.53	1,131	50.70	1,131
Average Marginal Costs Off-Peak	35.35	1,797	43.40	1,797
		2,928		2,928
WINTER				
Average Marginal Costs On-Peak	36.45	2,784	35.11	2,800
Average Marginal Costs Off-Peak	33.52	3,048	33.84	3,056
		5,832		5,856

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

SUMMER	**2015**	**2016**	
On-Peak	19.90	19.58	
Off-Peak	21.70	26.64	
	41.60	46.22	**$43.91** 2015-16 Average

WINTER	**2015**	**2016**	
On-Peak	17.40	16.79	
Off-Peak	17.52	17.66	
	34.92	34.45	**$34.68** 2015-16 Average

THE EMPIRE DISTRICT ELECTRIC COMPANY

ESTIMATED MARGINAL ENERGY COSTS BY ON-PEAK & OFF-PEAK PERIODS

Winter: January-May and October-December
On-Peak Hours: Weekdays 6 AM thru 9 PM
Off-Peak Hours: All other hours

Summer: June, July, August, September
On-Peak Hours: Weekdays 10 AM thru 10 PM
Off-Peak Hours: All other hours

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
2015	38.10	51.53	35.35	36.45	33.52
2016	38.51	50.70	43.40	35.11	33.84
2017	39.05	52.86	44.10	35.10	38.02
2018	49.12	63.87	49.49	48.63	42.87
2019	47.54	76.35	46.07	43.68	38.50

The Empire District Electric Company
Load and Capability Forecast
Based on Load Forecast 2015-2019

Year	2015	2016	2017	2018	2019
Projected :					
Gross Peak	1,155	1,159	1,162	1,165	1,168
Less Interruptibles	(8.4)	(8.4)	(8.4)	(8.4)	(8.4)
Net Peak	**1,147**	**1,151**	**1,154**	**1,157**	**1,160**
Asbury	194	194	194	194	194
Iatan	85	85	85	85	85
Iatan 2	105	105	105	105	105
Plum Point (own)	50	50	50	50	50
Riverton 7	0	0	0	0	0
Riverton 8	54	0	0	0	0
Riverton 9	12	0	0	0	0
Riverton 10	16	16	16	16	16
Riverton 11	17	17	17	17	17
Riverton 12	142	250	250	250	250
Energy Center 1	82	82	82	82	82
Energy Center 2	82	82	82	82	82
Energy Center 3	49	49	49	49	49
Energy Center 4	49	49	49	49	49
State Line 1	94	94	94	94	94
State Line C.C.	297	297	297	297	297
Ozark Beach	16	16	16	16	16
Plum Point PPA	50	50	50	50	50
150 MW Elk River Wind Farm PPA	17	17	17	17	17
105 MW Meridian Way Windfarm PPA	19	19	19	19	19
Total Capacity	1,430	1,472	1,472	1,472	1,472
Capacity Resp. (12%)	1,303	1,308	1,311	1,315	1,318
Capacity Balance	127	164	161	157	154
Capacity Margin	19.79%	21.81%	21.60%	21.40%	21.20%

12% Capacity Responsibility
Current Capacity Ratings

Empire District Electric Company
2011 Analysis of System Losses

TABLE 1
Loss Factors at Sales Level, Calendar Year 2011

Voltage Level of Service	Total EDE	Missouri	Arkansas	Kansas	Oklahoma
Demand (kW)					
Transmission	1.02870	1.02870	1.02870	1.02870	1.02870
Substation	1.03597	1.03624	1.03580	1.03580	1.03580
Primary	1.06298	1.06268	1.06725	1.06725	1.06725
Secondary	1.08725	1.08658	1.09171	1.09590	1.09137
Energy (kWh)					
Transmission	1.02336	1.02336	1.02336	1.02336	1.02336
Substation	1.03225	1.03275	1.03252	1.03252	1.03252
Primary	1.04914	1.04887	1.04988	1.04988	1.04988
Secondary	1.07636	1.07479	1.07991	1.07944	1.07583
Losses – Net System Input[1]	6.30	6.21	6.01	6.73	6.36

TABLE 2
Historical System MWH Losses

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
2018	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

[1] Net System Input equals firm sales plus losses, Company use less non-requirement sales and related losses. See Appendices A and B, Exhibit 1, for their calculations.

Time of Day Marginal Cost Summary
Data From the 2015-2019 Fuel and Purchased Power Budget
Average Marginal Cost $/MWh

2015

Period	Total hours	% of hours	Average Marg Cost
Summer On-Peak	1,131	12.9%	51.53
Summer Off-Peak	1,797	20.5%	35.35
Total Summer	2,928	33.4%	44.21
Winter On-Peak	2,784	31.8%	36.45
Winter Off-Peak	3,048	34.8%	33.52
Total Winter	5,832	66.6%	35.03
Total	8,760	100.0%	38.10

2016

Period	Total hours	% of hours	Average Marg Cost
Summer On-Peak	1,131	12.9%	50.70
Summer Off-Peak	1,797	20.5%	43.40
Total Summer	2,928	33.3%	46.60
Winter On-Peak	2,800	31.9%	35.11
Winter Off-Peak	3,056	34.8%	33.84
Total Winter	5,856	66.7%	34.47
Total	8,784	100.0%	38.51

2017

Period	Total hours	% of hours	Average Marg Cost
Summer On-Peak	1,131	12.9%	52.86
Summer Off-Peak	1,797	20.5%	44.10
Total Summer	2,928	33.4%	47.70
Winter On-Peak	2,784	31.8%	35.10
Winter Off-Peak	3,048	34.8%	38.02
Total Winter	5,832	66.6%	34.71
Total	8,760	100.0%	39.05

2018

Period	Total hours	% of hours	Average Marg Cost
Summer On-Peak	1,131	12.9%	63.87
Summer Off-Peak	1,797	20.5%	49.49
Total Summer	2,928	33.4%	56.03
Winter On-Peak	2,784	31.8%	48.63
Winter Off-Peak	3,048	34.8%	42.87
Total Winter	5,832	66.6%	45.64
Total	8,760	100.0%	49.12

2019

Period	Total hours	% of hours	Average Marg Cost
Summer On-Peak	1,131	12.9%	76.35
Summer Off-Peak	1,797	20.5%	46.07
Total Summer	2,928	33.4%	60.25
Winter On-Peak	2,784	31.8%	43.68
Winter Off-Peak	3,048	34.8%	38.50
Total Winter	5,832	66.6%	41.16
Total	8,760	100.0%	47.54