Large Filing Separator Sheet

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Description of Document: Long Term Forecast Report

Duquesne Light Company

Section 14

Public Information and Distribution

§57.154. Public Information and Distribution.

The Annual Resource Planning Report shall be accompanied by a summary which is suitable for public distribution. Utilities shall maintain copies of the summary open to public inspection during normal business hours.

(1) The summary shall include a 2-year implementation plan specifying activities scheduled for the acquisition and development of the least-cost resources delineated in this report, which are to take place during the ensuing 2 years.

(2) Informal sessions may be scheduled by the Bureau of Conservation, Economics, and Energy Planning for reviewing the 2-year implementation plans and providing an opportunity for interested parties to participate in the review process.

Response.

(1) - (2) The report summary is provided under separate cover, entitled "Annual Resource Planning Report - 1995 - Executive Summary." The summary includes a 2-year implementation plan specifying activities scheduled for the acquisition and development of the least-cost resources delineated in this report, which are to take place during the ensuing 2 years.

Duquesne Light Company

Appendix A

REQUIRED FILING FORMS

In Response to Section 57.152

Company Name: Duquesne Light Company

IRP-ELEC 1A. Historical and Forecast Energy Demand (MWH)

Load Growth Scenario (Circle one): BASE

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Sales For Resale (g)	Total Consumption (h)	System Losses (i)	Company Use (j)	Net Energy For Load (k)
-5	1991	3,285,561	5,450,145	3,041,679	71,693	12,420	11,861,498	764,634	54,867	12,680,999
-4	1992	3,069,087	5,358,492	3,058,651	70,966	11,780	11,568,976	709,687	53,041	12,331,704
-3	1993	3,230,508	5,490,114	3,046,465	71,318	12,224	11,850,628	802,348	51,622	12,704,598
-2	1994	3,219,263	5,562,955	3,256,257	71,008	12,356	12,121,839	710,489	47,310	12,879,638
-1	1995	3,378,533	5,728,904	3,237,130	70,692	12,872	12,428,131	767,458	48,204	13,243,793
0	1996	3,175,244	5,731,753	3,348,821	70,760	12,356	12,338,933	779,013	49,253	13,167,199
1	1997	3,166,553	5,757,128	3,717,398	70,760	12,356	12,724,196	822,128	49,253	13,595,577
2	1998	3,170,682	5,823,722	3,940,921	70,760	12,356	13,018,441	839,783	49,253	13,907,477
3	1999	3,175,624	5,909,905	4,013,419	70,760	12,356	13,182,064	849,601	49,253	14,080,918
4	2000	3,181,004	6,004,747	4,085,709	70,760	12,356	13,354,577	859,951	49,253	14,263,781
5	2001	3,186,565	6,102,073	4,160,091	70,760	12,356	13,531,845	870,587	49,253	14,451,685
6	2002	3,192,076	6,197,700	4,235,691	70,760	12,356	13,708,583	881,192	49,253	14,639,028
7	2003	3,197,711	6,295,028	4,313,096	70,760	12,356	13,888,951	892,014	49,253	14,830,218
8	2004	3,203,730	6,399,603	4,392,696	70,760	12,356	14,079,145	903,425	49,253	15,031,823
9	2005	3,209,794	6,504,630	4,474,152	70,760	12,356	14,271,692	914,978	49,253	15,235,923
10	2006	3,215,614	6,602,311	4,556,742	70,760	12,356	14,457,783	926,144	49,253	15,433,180
11	2007	3,221,380	6,697,409	4,639,832	70,760	12,356	14,641,736	937,181	49,253	15,628,171
12	2008	3,227,093	6,789,855	4,721,889	70,760	12,356	14,821,953	947,994	49,253	15,819,200
13	2009	3,233,064	6,886,971	4,803,742	70,760	12,356	15,006,893	959,090	49,253	16,015,236
14	2010	3,238,826	6,978,744	4,885,312	70,760	12,356	15,185,999	969,837	49,253	16,205,089
15	2011	3,244,747	7,073,249	4,969,649	70,760	12,356	15,370,762	980,922	49,253	16,400,937
16	2012	3,250,769	7,168,956	5,055,871	70,760	12,356	15,558,712	992,199	49,253	16,600,164
17	2013	3,256,720	7,265,962	5,141,894	70,760	12,356	15,747,692	1,003,614	49,253	16,800,559
18	2014	3,262,712	7,364,285	5,229,023	70,760	12,356	15,939,137	1,015,168	49,253	17,003,558
19	2015	3,268,761	7,463,943	5,317,792	70,760	12,356	16,133,612	1,026,863	49,253	17,209,728

* 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Company Name: Duquesne Light Company

IRP-ELEC 1A. Historical and Forecast Energy Demand (MWH)

Load Growth Scenario (Circle one): LOW

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Sales For Resale (g)	Total Consumption (h)	System Losses (i)	Company Use (j)	Net Energy For Load (k)
-5	1991	3,285,561	5,450,145	3,041,679	71,693	11,872	11,860,950	764,634	54,867	12,680,451
-4	1992	3,069,087	5,358,492	3,058,651	70,966	12,420	11,569,616	709,687	53,041	12,332,344
-3	1993	3,230,508	5,490,114	3,046,465	71,318	11,780	11,850,184	802,348	51,622	12,704,154
-2	1994	3,219,263	5,562,955	3,256,257	71,008	12,356	12,121,839	710,489	47,310	12,879,638
-1	1995	3,378,533	5,728,904	3,237,130	70,692	12,872	12,428,131	767,458	48,204	13,243,793
0	1996	3,029,089	5,650,947	3,358,468	70,760	12,356	12,121,621	765,974	49,253	12,936,848
1	1997	3,019,576	5,664,325	3,726,746	70,760	12,356	12,493,763	808,303	49,253	13,351,319
2	1998	3,023,223	5,725,671	3,939,354	70,760	12,356	12,771,364	824,959	49,253	13,645,576
3	1999	3,027,445	5,801,174	3,995,853	70,760	12,356	12,907,588	833,132	49,253	13,789,973
4	2000	3,032,176	5,889,254	4,055,146	70,760	12,356	13,059,693	842,258	49,253	13,951,204
5	2001	3,037,011	5,977,900	4,115,965	70,760	12,356	13,213,992	851,516	49,253	14,114,761
6	2002	3,041,849	6,066,262	4,177,648	70,760	12,356	13,368,876	860,809	49,253	14,278,938
7	2003	3,046,880	6,158,518	4,240,870	70,760	12,356	13,529,384	870,440	49,253	14,449,076
8	2004	3,052,218	6,256,286	4,305,355	70,760	12,356	13,696,975	880,495	49,253	14,626,723
9	2005	3,057,674	6,356,471	4,371,808	70,760	12,356	13,869,069	890,821	49,253	14,809,143
10	2006	3,062,827	6,447,909	4,437,932	70,760	12,356	14,031,784	900,584	49,253	14,981,621
11	2007	3,067,819	6,534,092	4,502,442	70,760	12,356	14,187,470	909,925	49,253	15,146,648
12	2008	3,072,814	6,619,011	4,564,758	70,760	12,356	14,339,699	919,059	49,253	15,308,010
13	2009	3,077,934	6,705,421	4,624,483	70,760	12,356	14,490,954	928,134	49,253	15,468,341
14	2010	3,082,999	6,789,977	4,682,881	70,760	12,356	14,638,973	937,015	49,253	15,625,241
15	2011	3,088,217	6,876,991	4,742,637	70,760	12,356	14,790,960	946,134	49,253	15,786,347
16	2012	3,093,520	6,964,784	4,803,076	70,760	12,356	14,944,496	955,346	49,253	15,949,096
17	2013	3,098,826	7,053,701	4,861,468	70,760	12,356	15,097,111	964,654	49,253	16,111,018
18	2014	3,104,204	7,143,756	4,919,443	70,760	12,356	15,250,519	974,058	49,253	16,273,830
19	2015	3,109,648	7,234,965	4,977,994	70,760	12,356	15,405,724	983,559	49,253	16,438,536

* 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Company Name: Duquesne Light Company

IRP-ELEC 1A. Historical and Forecast Energy Demand (MWH)

Load Growth Scenario (Circle one): HIGH

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Sales For Resale (g)	Total Consumption (h)	System Losses (i)	Company Use (j)	Net Energy For Load (k)
-5	1991	3,285,561	5,450,145	3,041,679	71,693	12,420	11,861,498	764,634	54,867	12,680,999
-4	1992	3,069,087	5,358,492	3,058,651	70,966	11,780	11,568,976	709,687	53,041	12,331,704
-3	1993	3,230,508	5,490,114	3,046,465	71,318	12,224	11,850,628	802,348	51,622	12,704,598
-2	1994	3,219,263	5,562,955	3,256,257	71,008	12,356	12,121,839	710,489	47,310	12,879,639
-1	1995	3,378,533	5,728,904	3,237,130	70,692	12,872	12,428,131	767,458	48,204	13,243,794
0	1996	3,373,633	5,837,742	3,382,954	70,760	12,356	12,677,445	799,323	49,253	13,526,022
1	1997	3,365,672	5,868,242	3,811,945	70,760	12,356	13,128,975	846,415	49,253	14,024,643
2	1998	3,370,826	5,943,969	4,192,875	70,760	12,356	13,590,787	874,124	49,253	14,514,164
3	1999	3,376,803	6,040,032	4,270,883	70,760	12,356	13,770,834	884,927	49,253	14,705,013
4	2000	3,383,075	6,142,544	4,407,848	70,760	12,356	14,016,584	899,672	49,253	14,965,508
5	2001	3,388,011	6,208,609	4,454,225	70,760	12,356	14,133,961	906,714	49,253	15,089,929
6	2002	3,395,148	6,330,756	4,517,419	70,760	12,356	14,326,439	918,263	49,253	15,293,955
7	2003	3,401,937	6,442,233	4,606,513	70,760	12,356	14,533,799	930,705	49,253	15,513,757
8	2004	3,408,852	6,554,252	4,697,192	70,760	12,356	14,743,412	943,281	49,253	15,735,946
9	2005	3,415,749	6,665,119	4,790,448	70,760	12,356	14,954,431	955,943	49,253	15,959,627
10	2006	3,422,551	6,772,299	4,886,126	70,760	12,356	15,164,092	968,522	49,253	16,181,867
11	2007	3,425,412	6,783,851	4,966,015	70,760	12,356	15,258,393	974,180	49,253	16,281,827
12	2008	3,434,044	6,932,316	5,071,400	70,760	12,356	15,520,876	989,929	49,253	16,560,058
13	2009	3,441,510	7,051,045	5,170,953	70,760	12,356	15,746,623	1,003,474	49,253	16,799,350
14	2010	3,448,367	7,154,916	5,269,457	70,760	12,356	15,955,856	1,016,028	49,253	17,021,137
15	2011	3,455,235	7,258,015	5,371,568	70,760	12,356	16,167,933	1,028,753	49,253	17,245,939
16	2012	3,462,073	7,359,279	5,476,512	70,760	12,356	16,380,980	1,041,536	49,253	17,471,769
17	2013	3,468,976	7,461,964	5,582,926	70,760	12,356	16,596,982	1,054,487	49,253	17,700,721
18	2014	3,475,988	7,566,089	5,692,098	70,760	12,356	16,817,291	1,067,609	49,253	17,934,153
19	2015	3,483,092	7,671,675	5,804,502	70,760	12,356	17,042,385	1,080,903	49,253	18,172,541

* 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Company Name: Duquesne Light Company

IRP-ELEC 1B. Historical and Forecast Peak Load (MW)

Load Growth Scenario (Circle one): BASE

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Sales For Resale (g)	Total Peak Load Requirements (h)	Annual Load Factor (i)
-5	1991	743	1,193	462	1	3	2,402	60.3%
-4	1992	639	1,167	499	1	2	2,308	61.0%
-3	1993	780	1,225	490	1	3	2,499	58.0%
-2	1994	778	1,219	534	1	3	2,535	58.0%
-1	1995	757	1,302	603	1	2	2,666	55.7%
0	1996	766	1,255	513	1	2	2,537	59.2%
1	1997	764	1,321	511	1	2	2,599	59.7%
2	1998	765	1,321	544	1	2	2,634	60.3%
3	1999	766	1,332	550	1	2	2,652	60.6%
4	2000	768	1,344	555	1	2	2,671	61.0%
5	2001	769	1,357	560	1	2	2,690	61.3%
6	2002	770	1,369	566	1	2	2,709	61.7%
7	2003	772	1,381	571	1	2	2,728	62.1%
8	2004	773	1,395	577	1	2	2,749	62.4%
9	2005	775	1,408	583	1	2	2,769	62.8%
10	2006	776	1,420	589	1	2	2,790	63.2%
11	2007	777	1,432	596	1	2	2,809	63.5%
12	2008	779	1,444	603	1	2	2,829	63.8%
13	2009	780	1,456	609	1	2	2,849	64.2%
14	2010	782	1,467	616	1	2	2,868	64.5%
15	2011	783	1,478	623	1	2	2,888	64.8%
16	2012	785	1,490	630	1	2	2,908	65.2%
17	2013	786	1,502	637	1	2	2,928	65.5%
18	2014	787	1,514	644	1	2	2,949	65.8%
19	2015	849	1,508	524	1	2	2,885	66.2%

* 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interde

Company Name: Duquesne Light Company

IRP-ELEC 1B. Historical and Forecast Peak Load (MW)

Load Growth Scenario (Circle one): LOW

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Sales For Resale (g)	Total Peak Load Requirements (h)	Annual Load Factor (i)
-5	1991	743	1,193	462	1	2	2,402	60.3%
-4	1992	639	1,167	499	1	3	2,308	61.0%
-3	1993	780	1,225	490	1	2	2,499	58.0%
-2	1994	778	1,219	534	1	3	2,535	58.0%
-1	1995	757	1,302	603	1	2	2,666	55.8%
0	1996	729	1,189	448	1	2	2,369	62.3%
1	1997	730	1,195	500	1	2	2,429	62.7%
2	1998	731	1,205	522	1	2	2,462	63.3%
3	1999	732	1,215	526	1	2	2,476	63.6%
4	2000	733	1,226	529	1	2	2,492	63.9%
5	2001	734	1,238	533	1	2	2,509	64.2%
6	2002	735	1,249	537	1	2	2,525	64.6%
7	2003	737	1,261	540	1	2	2,542	64.9%
8	2004	738	1,274	544	1	2	2,560	65.2%
9	2005	739	1,288	548	1	2	2,578	65.6%
10	2006	741	1,299	552	1	2	2,595	65.9%
11	2007	742	1,310	556	1	2	2,611	66.2%
12	2008	743	1,321	560	1	2	2,627	66.5%
13	2009	744	1,332	563	1	2	2,643	66.8%
14	2010	745	1,343	567	1	2	2,659	67.1%
15	2011	747	1,354	570	1	2	2,675	67.4%
16	2012	748	1,366	574	1	2	2,691	67.7%
17	2013	749	1,377	577	1	2	2,707	67.9%
18	2014	750	1,389	580	1	2	2,723	68.2%
19	2015	752	1,401	583	1	2	2,739	68.5%

* 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interde

Company Name: Duquesne Light Company

IRP-ELEC 1B. Historical and Forecast Peak Load (MW)

Load Growth Scenario (Circle one): HIGH

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Sales For Resale (g)	Total Peak Load Requirements (h)	Annual Load Factor (i)
-5	1991	743	1,193	462	1	2	2,402	60.3%
-4	1992	639	1,167	499	1	3	2,308	61.0%
-3	1993	780	1,225	490	1	2	2,499	58.0%
-2	1994	778	1,219	534	1	3	2,535	58.0%
-1	1995	757	1,302	603	1	2	2,666	55.8%
0	1996	814	1,319	541	1	2	2,678	57.7%
1	1997	812	1,403	523	1	2	2,742	58.4%
2	1998	814	1,422	584	1	2	2,823	58.7%
3	1999	815	1,434	590	1	2	2,843	59.0%
4	2000	816	1,445	605	1	2	2,840	59.5%
5	2001	818	1,454	607	1	2	2,882	59.8%
6	2002	819	1,471	610	1	2	2,904	60.1%
7	2003	821	1,486	617	1	2	2,927	60.5%
8	2004	823	1,500	624	1	2	2,950	60.9%
9	2005	824	1,514	631	1	2	2,973	61.3%
10	2006	826	1,527	639	1	2	2,996	61.6%
11	2007	827	1,526	651	1	2	3,007	61.8%
12	2008	829	1,546	658	1	2	3,036	62.3%
13	2009	831	1,561	666	1	2	3,061	69.3%
14	2010	832	1,574	674	1	2	3,084	63.0%
15	2011	834	1,586	684	1	2	3,107	63.4%
16	2012	836	1,598	693	1	2	3,130	63.7%
17	2013	837	1,610	703	1	2	3,154	64.1%
18	2014	839	1,622	713	1	2	3,178	64.4%
19	2015	841	1,635	724	1	2	3,203	64.8%

* 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interde

Company Name: Duquesne Light Company

IRP-ELEC 1C. Historical and Forecast Number of Customers (Year End)

Load Growth Scenario (Circle one): BASE

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Total Customers (j)
-5	1991	520,016	52,617	2,004	1,846	576,483
-4	1992	521,152	52,839	1,987	1,884	577,862
-3	1993	522,353	52,910	1,995	1,832	579,090
-2	1994	522,588	53,617	2,027	1,865	580,097
-1	1995	522,922	53,772	2,015	1,882	580,591
0	1996	523,071	56,805	2,091	1,882	583,849
1	1997	523,315	58,367	2,123	1,882	585,687
2	1998	523,559	59,089	2,155	1,882	586,685
3	1999	523,803	59,980	2,187	1,882	587,852
4	2000	524,047	60,976	2,219	1,882	589,124
5	2001	524,291	62,000	2,251	1,882	590,424
6	2002	524,535	63,005	2,283	1,882	591,705
7	2003	524,779	64,027	2,315	1,882	593,003
8	2004	525,023	65,125	2,347	1,882	594,377
9	2005	525,267	66,229	2,379	1,882	595,757
10	2006	525,511	67,256	2,411	1,882	597,060
11	2007	525,755	68,255	2,443	1,882	598,335
12	2008	525,999	69,225	2,475	1,882	599,581
13	2009	526,243	70,245	2,507	1,882	600,877
14	2010	526,487	71,208	2,539	1,882	602,116
15	2011	526,731	72,203	2,571	1,882	603,387
16	2012	526,975	73,207	2,603	1,882	604,667
17	2013	527,219	74,226	2,635	1,882	605,962
18	2014	527,463	75,258	2,667	1,882	607,271
19	2015	527,708	76,305	2,699	1,882	608,594

* 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways

Company Name: Duquesne Light Company

IRP-ELEC 1C. Historical and Forecast Number of Customers (Year End)

Load Growth Scenario (Circle one): LOW

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Total Customers (i)
-5	1991	520,016	52,617	2,004	1,846	574,524
-4	1992	521,152	52,839	1,987	1,884	576,527
-3	1993	522,353	52,910	1,995	1,832	577,810
-2	1994	522,588	53,617	2,027	1,865	579,123
-1	1995	522,922	53,772	2,059	1,882	580,112
0	1996	523,071	56,558	2,089	1,882	583,600
1	1997	523,315	57,990	2,119	1,882	585,306
2	1998	523,559	58,637	2,149	1,882	586,227
3	1999	523,803	59,432	2,179	1,882	587,296
4	2000	524,047	60,359	2,209	1,882	588,497
5	2001	524,291	61,291	2,239	1,882	589,703
6	2002	524,535	62,221	2,269	1,882	590,907
7	2003	524,779	63,192	2,299	1,882	592,152
8	2004	525,023	64,220	2,329	1,882	593,454
9	2005	525,267	65,274	2,359	1,882	594,782
10	2006	525,511	66,236	2,389	1,882	596,018
11	2007	525,755	67,141	2,419	1,882	597,197
12	2008	525,999	68,033	2,449	1,882	598,363
13	2009	526,243	68,940	2,479	1,882	599,544
14	2010	526,487	69,829	2,509	1,882	600,707
15	2011	526,731	70,743	2,539	1,882	601,895
16	2012	526,975	71,667	2,569	1,882	603,093
17	2013	527,219	72,602	2,599	1,882	604,302
18	2014	527,463	73,550	2,629	1,882	605,524
19	2015	527,708	74,510	2,659	1,882	606,759

* 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways

Company Name: Duquesne Light Company

IRP-ELEC 1C. Historical and Forecast Number of Customers (Year End)

Load Growth Scenario (Circle one): HIGH

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Total Customers (j)
-5	1991	520,016	52,623	2,004	1,884	576,527
-4	1992	521,152	52,839	1,987	1,832	577,810
-3	1993	522,353	52,910	1,995	1,865	579,123
-2	1994	522,588	53,617	2,027	1,880	580,112
-1	1995	522,922	53,772	2,059	1,882	580,635
0	1996	523,071	57,549	2,093	1,882	584,595
1	1997	523,315	59,167	2,127	1,882	586,491
2	1998	523,559	59,965	2,161	1,882	587,567
3	1999	523,803	60,977	2,195	1,882	588,857
4	2000	524,047	62,056	2,229	1,882	590,214
5	2001	524,291	62,752	2,263	1,882	591,188
6	2002	524,535	64,037	2,297	1,882	592,751
7	2003	524,779	65,210	2,331	1,882	594,202
8	2004	525,023	66,388	2,365	1,882	595,658
9	2005	525,267	67,555	2,399	1,882	597,103
10	2006	525,511	68,684	2,433	1,882	598,510
11	2007	525,755	68,805	2,467	1,882	598,909
12	2008	525,999	70,367	2,501	1,882	600,749
13	2009	526,243	71,615	2,535	1,882	602,275
14	2010	526,487	72,709	2,569	1,882	603,647
15	2011	526,731	73,795	2,603	1,882	605,011
16	2012	526,975	74,861	2,637	1,882	606,355
17	2013	527,219	75,942	2,671	1,882	607,714
18	2014	527,463	77,039	2,705	1,882	609,090
19	2015	527,708	78,152	2,739	1,882	610,481

* 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways

Company Name: Duquesne Light Company

IRP-ELEC 2A. Estimated Summer Peak Resources, Loads and Reserves (MW)

		Resources							Peak Load				Reserve		
Index Year (a)	Actual Year (b)	Total Capability (c)	Inoperable Capability (d)	Operable Capability (e)	Non-Utility Generators (f)	Scheduled Imports (g)	Scheduled Exports (h)	Net Resources (i)	Total Internal Peak Load (j)	Interruptible Load (k)	Load Management (l)	Net Internal Peak Load (m)	Reserve Margin (n)	Scheduled Maintenance (o)	Adjusted Margin (p)
-5	1991	3,327	529	2,798	21	0	0	2,819	2,402	93	0	2,309	510	0	510
-4	1992	3,327	529	2,798	21	0	0	2,819	2,308	93	0	2,215	604	0	604
-3	1993	3,327	529	2,798	21	0	0	2,819	2,499	93	0	2,406	413	0	413
-2	1994	3,327	529	2,798	21	0	0	2,819	2,535	93	0	2,442	377	0	377
-1	1995	3,327	529	2,798	21	0	0	2,819	2,666	93	0	2,573	246	0	246
0	1996	3,051	439	2,612	56	125	0	2,793	2,537	108	4	2,425	368	0	368
1	1997	3,051	439	2,612	56	125	0	2,793	2,599	149	33	2,417	376	0	376
2	1998	3,051	439	2,612	56	125	0	2,793	2,634	163	44	2,427	366	0	366
3	1999	3,026	114	2,912	56	150	300	2,818	2,652	163	52	2,437	381	0	381
4	2000	3,026	204	2,822	56	250	300	2,828	2,671	163	60	2,448	380	0	380
5	2001	3,089	0	3,089	56	0	300	2,845	2,690	163	61	2,466	379	0	379
6	2002	3,089	0	3,089	56	50	300	2,895	2,709	163	62	2,484	411	0	411
7	2003	3,089	0	3,089	56	50	300	2,895	2,728	163	63	2,502	393	0	393
8	2004	3,089	0	3,089	56	75	300	2,920	2,749	163	64	2,522	398	0	398
9	2005	3,089	0	3,089	56	100	300	2,945	2,769	163	64	2,542	403	0	403
10	2006	3,089	0	3,089	56	125	300	2,970	2,790	163	65	2,562	408	0	408
11	2007	3,089	0	3,089	56	125	300	2,970	2,809	163	66	2,580	390	0	390
12	2008	3,089	0	3,089	56	150	300	2,995	2,829	163	66	2,600	395	0	395
13	2009	3,229	0	3,229	56	50	300	3,035	2,849	163	66	2,620	415	0	415
14	2010	3,229	0	3,229	56	50	300	3,035	2,868	163	66	2,639	396	0	396
15	2011	3,229	0	3,229	56	75	300	3,060	2,888	163	66	2,659	401	0	401
16	2012	3,229	0	3,229	56	100	300	3,085	2,908	163	66	2,679	406	0	406
17	2013	3,229	0	3,229	56	125	300	3,110	2,928	163	66	2,699	411	0	411
18	2014	3,229	0	3,229	56	150	300	3,135	2,949	163	66	2,720	415	0	415
19	2015	3,369	0	3,369	56	50	300	3,175	2,970	163	66	2,741	434	0	434

Company Name: Duquesne Light Company

IRP-ELEC 2B. Estimated Winter Peak Resources, Loads and Reserves (MW)

		Resources							Peak Load				Reserve		
Index Year (a)	Actual Year (b)	Total Capability (c)	Inoperable Capability (d)	Operable Capability (e)	Non-Utility Generators (f)	Scheduled Imports (g)	Scheduled Exports (h)	Net Resources (i)	Total Internal Peak Load (j)	Interruptible Load (k)	Load Management (l)	Net Internal Peak Load (m)	Reserve Margin (n)	Scheduled Maintenance (o)	Adjusted Margin (p)
-5	1991	3,409	575	2,834	21	0	0	2,855	1,928	93	0	1,835	1,020	175	845
-4	1992	3,409	575	2,834	21	0	0	2,855	1,894	93	0	1,801	1,054	818	236
-3	1993	3,409	575	2,834	21	0	0	2,855	2,028	93	0	1,935	920	162	758
-2	1994	3,409	575	2,834	21	0	0	2,855	1,951	93	0	1,858	997	511	486
-1	1995	3,409	575	2,834	21	0	0	2,855	2,040	93	0	1,947	908	164	744
0	1996	3,133	463	2,670	56	0	0	2,726	2,062	108	2	1,952	774	175	599
1	1997	3,133	463	2,670	56	0	0	2,726	2,101	149	27	1,925	801	112	689
2	1998	3,133	463	2,670	56	0	0	2,726	2,126	163	35	1,928	798	175	623
3	1999	3,108	128	2,980	56	0	300	2,736	2,152	163	40	1,949	787	100	687
4	2000	3,108	240	2,868	56	0	300	2,624	2,179	163	45	1,971	653	(1)	653
5	2001	3,174	0	3,174	56	0	300	2,930	2,205	163	45	1,997	933	(1)	933
6	2002	3,174	0	3,174	56	0	300	2,930	2,232	163	45	2,024	906	(1)	906
7	2003	3,174	0	3,174	56	0	300	2,930	2,261	163	45	2,053	877	(1)	877
8	2004	3,174	0	3,174	56	0	300	2,930	2,290	163	45	2,082	848	(1)	848
9	2005	3,174	0	3,174	56	0	300	2,930	2,317	163	45	2,109	821	(1)	821
10	2006	3,174	0	3,174	56	0	300	2,930	2,345	163	45	2,137	793	(1)	793
11	2007	3,174	0	3,174	56	0	300	2,930	2,372	163	45	2,164	766	(1)	766
12	2008	3,174	0	3,174	56	0	300	2,930	2,400	163	45	2,192	738	(1)	738
13	2009	3,341	0	3,341	56	0	300	3,097	2,427	163	45	2,219	878	(1)	878
14	2010	3,341	0	3,341	56	0	300	3,097	2,454	163	45	2,246	851	(1)	851
15	2011	3,341	0	3,341	56	0	300	3,097	2,483	163	45	2,275	822	(1)	822
16	2012	3,341	0	3,341	56	0	300	3,097	2,511	163	45	2,303	794	(1)	794
17	2013	3,341	0	3,341	56	0	300	3,097	2,540	163	45	2,332	765	(1)	765
18	2014	3,341	0	3,341	56	0	300	3,097	2,569	163	45	2,361	736	(1)	736
19	2015	3,508	0	3,508	56	0	300	3,264	2,595	163	45	2,387	877	(1)	877

(1) Duquesne Light does not schedule maintenance beyond five years in advance.

Company Name: Duquesne Light Company

IRP-ELEC 3A. Existing Generating Capability (as of January 1 of current year)

				Primary Fuel		Alternate Fuel		Net Capability-MW		Changes During Past Year		%	
Station and Unit No. (a)	Location (b)	Date Installed (c)	Unit Type (d)	Fuel Type (e)	Transp. Method (f)	Fuel Type (g)	Transp. Method (h)	Summer (i)	Winter (j)	MW (k)	Reason (l)	Ownership Share (m)	Notes (n)
Phillips 1	South Heights,	Oct. 1942	ST	BIT	TK-WA			65	67			100%	(1)
Phillips 2	Allegheny County,	Oct. 1949	ST	BIT	TK-WA			66	67			100%	(1)
Phillips 3	Pennsylvania	Sep. 1950	ST	BIT	TK-WA			66	67			100%	(1)
Phillips 4		Jan. 1956	ST	BIT	TK-WA			128	134			100%	(2)
Station								325	335				(3)
Elrama 1	Elrama,	Apr. 1952	ST	BIT	TK-WA			97	100			100%	
Elrama 2	Washington County,	Jan. 1953	ST	BIT	TK-WA			97	100			100%	
Elrama 3	Pennsylvania	Sep. 1954	ST	BIT	TK-WA			109	112			100%	
Elrama 4		Nov. 1960	ST	BIT	TK-WA			171	175			100%	
Station								474	487				
Cheswick	Springdale, Allegheny County, Pennsylvania	Dec. 1970	ST	BIT	TK-WA			562	570			100%	
Brunot Island 1A	Pittsburgh,	Mar. 1972	GT	FO2	WA			18	22			100%	
Brunot Island 1B	Allegheny County,	Mar. 1972	GT	FO2	WA			18	22			100%	
Brunot Island 1C	Pennsylvania	Mar. 1972	GT	FO2	WA			18	22			100%	
Peaking Station								54	66				

Company Name: Duquesne Light Company

IRP-ELEC 3A. Existing Generating Capability (as of January 1 of current year)

Station and Unit No. (a)	Location (b)	Date Installed (c)	Unit Type (d)	Primary Fuel: Fuel Type (e)	Primary Fuel: Transp. Method (f)	Alternate Fuel: Fuel Type (g)	Alternate Fuel: Transp. Method (h)	Net Capability-MW: Summer (i)	Net Capability-MW: Winter (j)	Changes During Past Year: MW (k)	Changes During Past Year: Reason (l)	% Ownership Share (m)	Notes (n)
Brunot Island 2A	Pittsburgh,	June 1973	CT	FO2	WA			45	56			100%	(4)
Brunot Island 2B	Allegheny County,	June 1973	CT	FO2	WA			45	56			100%	(4)
Brunot Island 3	Pennsylvania	June 1973	CT	FO2	WA			45	56			100%	(4)
Brunot Island 4		July 1974	CA	WH-FO2	WA			69	72			100%	(4)
Combined Cycle								204	240				(5)
Brunot Station								258	306				
Fort Martin 1	Maidsville, Monongalia County, West Virginia	Sep. 1967	ST	BIT	TK-WA			276	276			50%	
Sammis 7	Stratton, Jefferson County, Ohio	Sep. 1971	ST	BIT	TK-WA			187	187			31.2%	
Eastlake 5	Eastlake, Lake County, Ohio	Sep. 1972	ST	BIT	RR			186	186			31.2%	

Company Name: Duquesne Light Company

IRP-ELEC 3A. Existing Generating Capability (as of January 1 of current year)

Station and Unit No.	Location	Date Installed	Unit Type	Primary Fuel: Fuel Type	Primary Fuel: Transp. Method	Alternate Fuel: Fuel Type	Alternate Fuel: Transp. Method	Net Capability-MW: Summer	Net Capability-MW: Winter	Changes During Past Year: MW	Changes During Past Year: Reason	% Ownership Share	Notes
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
Mansfield 1	Shippingport,	June 1976	ST	BIT	TK-WA			228	228			29.30%	
Mansfield 2	Beaver County,	Oct. 1977	ST	BIT	TK-WA			62	62			8.00%	
Mansfield 3	Pennsylvania	Sep. 1980	ST	BIT	TK-WA			110	110			13.74%	
Station								400	400				
Beaver Valley 1	Shippingport,	May 1977	NP	UR	TK			385	385			47.50%	
Beaver Valley 2	Beaver County, Pennsylvania	Nov. 1987	NP	UR	TK			113	113			13.74%	
Station								498	498				
Perry 1	Perry Township, Lake County, Ohio	Nov. 1987	NB	UR	TK			161	164			13.74%	
Total System								3327	3409				

Notes:

(1) Unit placed in cold reserve 1-1-87. Net capability values reflect MW at the time the unit was placed in cold reserve.

(2) Unit placed in cold reserve 12-1-87. Net capability values reflect MW at the time the unit was placed in cold reserve.

(3) Duquesne expects the Phillips Station to be restored to commercial operation in 1998 to support long term off-system sales. The net capability is expected to be 300 Mw summer and 310 Mw winter. Heat rate and forced outage rate for 1994 are undefined.

(4) Unit placed in cold reserve 5-1-86. Heat Rate and Forced Outage Rate for 1994 are Undefined.

(5) Duquesne expects the Brunot Island Simple Cycle Combustion Turbines to be restored to commercial operation in 2001, 2003, and 2005 to support retail load growth and long term off-system sales. The Combined Cycle Facility will be refurbished, converted to natural gas / oil dual firing, equipped with air and water pollution abatement equipment, and reactivated in 2007. The net capability is expected to be 267MW - summer and 306MW - winter.

Company Name: Duquesne Light Company

IRP-ELEC 3B. Existing Generating Capability (Supplemental Information)

Station and Unit No. (a)	Average Heat Rate Btu/kwh (b)	Maintenance Outage Rate (%) (c)	Forced Outage Rate (%) (d)	Unit Commitment Type (e)	Must-Run Order (f)	Emission Rates SOx lbs/MBtu (g)	Emission Rates NOx lbs/MBtu (h)	Emission Rates CO2 lbs/MBtu (i)	Notes (j)
Elrama 1	12179	6.42%	9.23%	(4)	(4)	0.3 (1)	0.45-0.5 (3)	203(3)	
Elrama 2	11887	5.07%	23.01%	(4)	(4)	0.3 (1)	0.45-0.5 (3)	203(3)	
Elrama 3	11749	23.27%	6.94%	(4)	(4)	0.3 (1)	0.45-0.5 (3)	203(3)	
Elrama 4	11002	13.56%	2.46%	(4)	(4)	0.3 (1)	0.45-0.5 (3)	203(3)	
Cheswick	10158	8.97%	5.98%	(4)	(4)	2.5	0.37	203(3)	
Brunot Island 1A	15730 (1)	0.00%	0.00%	(4)	(4)			121(3)	
Brunot Island 1B	15730 (1)	0.00%	0.00%	(4)	(4)			121(3)	
Brunot Island 1C	15730 (1)	0.00%	0.00%	(4)	(4)			121(3)	
Brunot Island 2A	(2)	(2)	(2)	(4)	(4)	(2)	(2)	(2)	
Brunot Island 2B	(2)	(2)	(2)	(4)	(4)	(2)	(2)	(2)	
Brunot Island 3	(2)	(2)	(2)	(4)	(4)	(2)	(2)	(2)	
Brunot Island 4	(2)	(2)	(2)	(4)	(4)	(2)	(2)	(2)	
Phillips 1	(2)	(2)	(2)	(4)	(4)	(2)	(2)	(2)	
Phillips 2	(2)	(2)	(2)	(4)	(4)	(2)	(2)	(2)	
Phillips 3	(2)	(2)	(2)	(4)	(4)	(2)	(2)	(2)	
Phillips 4	(2)	(2)	(2)	(4)	(4)	(2)	(2)	(2)	
Fort Martin 1	9878	23.32%	19.05%	(4)	(4)	2.8	0.7	203(3)	
Sammis 7	10012	17.93%	4.77%	(4)	(4)	1.5	1.1	203(3)	

(1) Data represents a plant average.
(2) Phillips and Brunot Island have been in cold reserve since 1986/87. No current data available.
(3) Estimated Data
(4) Commitment and must run order are not done on a unit basis, each unit is made up of several commitment blocks.

Company Name: Duquesne Light Company

IRP-ELEC 3B. Existing Generating Capability (Supplemental Information)

Station and Unit No. (a)	Average Heat Rate Btu/kwh (b)	Maintenance Outage Rate (%) (c)	Forced Outage Rate (%) (d)	Unit Commitment Type (e)	Must-Run Order (f)	Emission Rates SOx lbs/MBtu (g)	Emission Rates NOx lbs/MBtu (h)	Emission Rates CO2 lbs/MBtu (i)	Notes (j)
Eastlake 5	9703	14.24%	7.99%	(4)	(4)	4.6	0.8	203(3)	
Mansfield 1	10680	0.57%	2.94%	(4)	(4)	0.15	0.31	203(3)	
Mansfield 2	11078	32.76%	1.01%	(4)	(4)	0.15	0.31	203(3)	
Mansfield 3	10472	34.65%	5.40%	(4)	(4)	0.15	0.33 (3)	203(3)	
Beaver Valley 1	10985	16.50%	5.72%	(4)	(4)	0	0	0	
Beaver Valley 2	10882	12.55%	0.50%	(4)	(4)	0	0	0	
Perry 1	10514	1.91%	4.76%	(4)	(4)	0	0	0	

(1) Data represents a plant average.

(2) Phillips and Brunot Island have been in cold reserve since 1986/87. No current data available.

(3) Estimated Data

(4) Commitment and must run order are not done on a unit basis, each unit is made up of several commitment blocks.

IRP-ELEC 4. Future Generating Capability Installations, Changes and Removals

1995 -- 2014

Station and Unit No. (a)	Location (b)	Unit Type (c)	Primary Fuel: Fuel Type (d)	Primary Fuel: Transp. Method (e)	Alternate Fuel: Fuel Type (f)	Alternate Fuel: Transp. Method (g)	Net Capability (MW): Summer (h)	Net Capability (MW): Winter (i)	Effective Date (j)	Status (k)	Estimated Plant Cost in Current $/KW (l)	% Ownership Share (m)	Notes (n)
Fort Martin 1	Maidsville, Monongalia County, West Virginia	ST	BIT	TK-WA			-276	-276	10-96	R	600	100%	(1)
Phillips 1 - 3	South Heights, Allegheny County, Pennsylvania	ST	BIT	TK-WA			-15	-15	6-99	S	450	100%	(3)
Phillips 4	South Heights, Allegheny County, Pennsylvania	ST	BIT	TK-WA			-10	-10	6-99	S	450	100%	(2, 3)
Brunot Island 2A, 2B, 3	Pittsburgh, Allegheny County, Pennsylvania	CT	NG	PL	FO2	WA	45 45 45	56 56 56	6-96 6-96 6-01	S S S	37 37 37	100% 100% 100%	(2, 4) (2, 4) (2, 4)
Brunot Island 4	Pittsburgh, Allegheny County, Pennsylvania	CA	WH	XX	NG	PL	63	66	6-01	S	432	100%	(2, 4)
Peaking Resource 1	Unknown	Pker	NG	PL			140	167	4-09	P	300	100%	(2)
Peaking Resource 2	Unknown	Pker	NG	PL			140	167	4-15	P	300	100%	(2)

(1) Duquesne's share of the Fort Martin Unit 1 generating station was sold to the AYP Capital subsidiary of Allegheny Power System.

(2) Plant Cost Based on summer rating and in 1995 dollars. Fort Martin cost based on recent sale price.

(3) Phillips units 1 - 4 will be returned to service from cold reserve, derated from 325/335 MW to 300/310 MW.

(4) BICC will be returned to service from cold reserve.
Units 2A, 2B, and 3 will initially be reactivated with oil firing. When Unit 4 is reactivated, the combustion turbines will be converted to dual firing with natural gas/oil. Unit 4 will have only natural gas for auxiliary firing. Plant reactivation cost for Unit 4 includes the cost of the combustion turbine gas conversions.

IRP-ELEC 5. *Cogeneration and Independent Power Production Facilities*

Facility Name (a)	Location (b)	Energy Source (c)	Purchased Energy (KWH) (d)	Total Generation (KWH) (e)	Contract Capacity (KW) (f)	Total Capacity (KW) (g)	Effective Date(s) (h)	Status and Type (i)
AES Beaver Valley Unincorporated	Monaca PA	Coal	(1)			125,000	8/28/85	OL C
LTV Steel	Pittsburgh PA	Coke Oven Gas	14,305,000		17,200	40,000		OL C
U.S. Steel	Clairton PA	Coke Oven Gas	0			20,000		OL C
U.S. Steel Edgar Thompson	Pittsburgh PA	Blast Furnace Gas	0			50,000		OL C
H.J. Heinz	Pittsburgh PA	Coal & Natural Gas	0			7,500		OL C
Equitable Gas	420 Blvd. of Allies Pittsburgh PA 15217	Natural Gas	0			700		OL C
Riverview Center for Jewish Seniors	52 Goretla Ave. Pittsburgh PA 15217	Natural Gas	0			60		OL C
Shadyside Hospital	5230 Center Ave. Pittsburgh PA 15232	Natural Gas	0			1,600		OL C

IRP-ELEC 5. Cogeneration and Independent Power Production Facilities

Facility Name (a)	Location (b)	Energy Source (c)	Purchased Energy (KWH) (d)	Total Generation (KWH) (e)	Contract Capacity (KW) (f)	Total Capacity (KW) (g)	Effective Date(s) (h)	Status and Type (i)
Enertech Windmill (Grieco)	Route 931 Independence Twp. RD #1, Box 116B Imperial PA 15216	Wind	9			2	2/1/80	OL S
Enertech Windmill (Holloway)	Wilson Road, Rt. 472 Hanover Township RD #1, Box 265 Clinton PA 15026	Wind	0			4	3/1/82	OL S
Patterson Dam Beaver Valley Power Company	Sixth St & Second Ave Beaver Falls PA 15010	Hydro	5,140,000			1,800	8/18/82	OL S
Townsend Dam Beaver Falls Municipal Authority	1425 Eighth Ave. PO Box 400 Beaver Falls PA 15010	Hydro	17,096,000			5,000	2/28/85	OL S
Beechwood Farms Nature Preserve	Fox Chapel PA	Wind & Solar	0			2		OL S
O'Brien Energy Corporation	Clinton PA	Methane	6,676,000			3,000	12/21/89	OL S
Shenango, Inc.	200 Heville Road Pittsburgh, PA 15225	Coke Oven Gas	0			5,000	10/15/91	OL S

Company Name: Duquesne Light Company

IRP-ELEC 5. Cogeneration and Independent Power Production Facilities

Facility Name (a)	Location (b)	Energy Source (c)	Purchased Energy (KWH) (d)	Total Generation (KWH) (e)	Contract Capacity (KW) (f)	Total Capacity (KW) (g)	Effective Date(s) (h)	Status and Type (i)
Cogeneration Systems, Inc.	Clairton PA	Coke Oven Gas	0			150,000		PP C
City of Pittsburgh Frick Park Nature Center	Pittsburgh PA	Solar	0			6	1/17/92	OL S
Miller Spring Co.	Sharpsburg PA	Gas	0			300		PP C
City of Pittsburgh Lock & Dam No. 2	Pittsburgh PA	Hydro	0			11,600		PP S
County of Allegheny Dashields Dam	Sewickley PA	Hydro	0			20,000		PP S
Econeco, Inc. Montgomery Dam	Industry PA	Hydro	0			20,000		PP S
Emsworth Dam	Neville Island PA	Hydro	0			20,000		S

Notes:

(1) Energy from this Facility is not purchased by Duquesne. Duquesne provides transmission service only.

Company Name: Duquesne Light Company

IRP-ELEC 6. System Cost Data

Projected and Levelized Energy Costs (mills/KWH)

		Annual			Winter		Summer		Spring/Fall	
	Year	All Hours	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Actual	1995									
Projected	1996	14.02	15.40	12.18	16.59	12.73	16.07	12.16	14.32	12.04
	1997	15.36	17.08	13.07	17.95	13.87	18.15	13.29	15.90	13.10
	1998	16.24	18.08	13.78	18.59	14.00	18.63	13.62	17.42	13.68
	1999	16.61	18.47	14.13	18.00	14.12	18.95	14.05	17.64	14.20
	2000	15.26	16.37	13.77	15.61	13.70	17.62	13.79	14.58	13.59
	2001	15.61	16.93	13.85	17.43	14.23	18.26	13.93	16.35	13.78
	2002	16.21	17.69	14.24	17.37	14.69	19.05	14.42	16.82	14.04
	2003	17.12	18.76	14.93	20.01	15.81	21.19	15.23	17.41	14.70
	2004	18.66	20.82	15.77	22.41	16.13	22.08	15.71	19.55	15.56
	2005	19.66	22.26	16.19	24.70	16.97	23.14	16.33	20.91	15.97
Levelized		16.18	17.85	13.95	18.46	14.37	18.91	14.00	16.77	13.84

Company Name: Duquesne Light Company

IRP-ELEC 7A. Distribution of Net Generating Capability by Fuel Type

Season (Circle One): SUMMER

Index Year (a)	Actual Year (b)	Coal (c)	Oil/Gas Steam (d)	Nuclear (e)	Hydro (f)	Pumped Storage (g)	Oil CT/ICE (h)	Gas CT/ICE (i)	Total Capability (j)	Operable Capability (k)	Net Transactions (l)	Net Resources (m)
-5	1991	2405	0	656	0	0	258	0	3319	2790	456	3246
-4	1992	2410	0	659	0	0	258	0	3327	2798	21	2819
-3	1993	2410	0	659	0	0	258	0	3327	2798	21	2819
-2	1994	2410	0	659	0	0	258	0	3327	2798	21	2819
-1	1995	2410	0	659	0	0	258	0	3327	2798	21	2819
0	1996	2134	0	659	0	0	258	0	3051	2,612	181	2793
1	1997	2134	0	659	0	0	258	0	3051	2,612	181	2793
2	1998	2134	0	659	0	0	258	0	3051	2,612	181	2793
3	1999	2109	0	659	0	0	258	0	3026	2,912	-94	2818
4	2000	2109	0	659	0	0	258	0	3026	2,822	6	2828
5	2001	2109	0	659	0	0	54	267	3089	3,089	-244	2845
6	2002	2109	0	659	0	0	54	267	3089	3,089	-194	2895
7	2003	2109	0	659	0	0	54	267	3089	3,089	-194	2895
8	2004	2109	0	659	0	0	54	267	3089	3,089	-169	2920
9	2005	2109	0	659	0	0	54	267	3089	3,089	-144	2945
10	2006	2109	0	659	0	0	54	267	3089	3,089	-119	2970
11	2007	2109	0	659	0	0	54	267	3089	3,089	-119	2970
12	2008	2109	0	659	0	0	54	267	3089	3,089	-94	2995
13	2009	2109	0	659	0	0	54	407	3229	3,229	-194	3035
14	2010	2109	0	659	0	0	54	407	3229	3,229	-194	3035
15	2011	2109	0	659	0	0	54	407	3229	3,229	-169	3060
16	2012	2109	0	659	0	0	54	407	3229	3,229	-144	3085
17	2013	2109	0	659	0	0	54	407	3229	3,229	-119	3110
18	2014	2109	0	659	0	0	54	407	3229	3,229	-94	3135
19	2015	2109	0	659	0	0	54	547	3369	3,369	-194	3175

Company Name: Duquesne Light Company

IRP-ELEC 7A. Distribution of Net Generating Capability by Fuel Type

Season (Circle One): WINTER

Index Year (a)	Actual Year (b)	Coal (c)	Oil/Gas Steam (d)	Nuclear (e)	Hydro (f)	Pumped Storage (g)	Oil CT/ICE (h)	Gas CT/ICE (i)	Total Capability (j)	Operable Capability (k)	Net Transactions (l)	Net Resources (m)
-5	1991	2441	0	663	0	0	306	0	3410	2839	-203	2636
-4	1992	2441	0	662	0	0	306	0	3409	2834	21	2855
-3	1993	2441	0	662	0	0	306	0	3409	2834	21	2855
-2	1994	2441	0	662	0	0	306	0	3409	2834	21	2855
-1	1995	2441	0	662	0	0	306	0	3409	2834	21	2855
0	1996	2165	0	662	0	0	306	0	3133	2,670	56	2726
1	1997	2165	0	662	0	0	306	0	3133	2,670	56	2726
2	1998	2165	0	662	0	0	306	0	3133	2,670	56	2726
3	1999	2140	0	662	0	0	306	0	3108	2,980	-244	2736
4	2000	2140	0	662	0	0	306	0	3108	2,868	-244	2624
5	2001	2140	0	662	0	0	66	306	3174	3,174	-244	2930
6	2002	2140	0	662	0	0	66	306	3174	3,174	-244	2930
7	2003	2140	0	662	0	0	66	306	3174	3,174	-244	2930
8	2004	2140	0	662	0	0	66	306	3174	3,174	-244	2930
9	2005	2140	0	662	0	0	66	306	3174	3,174	-244	2930
10	2006	2140	0	662	0	0	66	306	3174	3,174	-244	2930
11	2007	2140	0	662	0	0	66	306	3174	3,174	-244	2930
12	2008	2140	0	662	0	0	66	306	3174	3,174	-244	2930
13	2009	2140	0	662	0	0	66	473	3341	3,341	-244	3097
14	2010	2140	0	662	0	0	66	473	3341	3,341	-244	3097
15	2011	2140	0	662	0	0	66	473	3341	3,341	-244	3097
16	2012	2140	0	662	0	0	66	473	3341	3,341	-244	3097
17	2013	2140	0	662	0	0	66	473	3341	3,341	-244	3097
18	2014	2140	0	662	0	0	66	473	3341	3,341	-244	3097
19	2015	2140	0	662	0	0	66	640	3508	3,508	-244	3264

Company Name: Duquesne Light Company

IRP-ELEC 7B. Scheduled Imports and Exports (MW)

Season (Circle One): SUMMER

Participant Type Code	Name of Participant	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
IPP	Zinc Corporation	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
NUG	Existing QF	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
PU	Long Term Sale	0	0	0	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300
PU	Firm Capacity	125	125	125	150	250	0	50	50	75	100	125	125	150	50	50	75	100	125	150	50
	Totals	181	181	181	-94	6	-244	-194	-194	-169	-144	-119	-119	-94	-194	-194	-169	-144	-119	-94	-194

Company Name: Duquesne Light Company

IRP-ELEC 7B. Scheduled Imports and Exports (MW)

Season (Circle One): WINTER

Participant Type Code	Name of Participant	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
IPP	St. Joe	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
NUG	Existing QF	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
PU	Long Term Sale	0	0	0	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300	-300
	Totals	56	56	56	-244	-244	-244	-244	-244	-244	-244	-244	-244	-244	-244	-244	-244	-244	-244	-244	-244

IRP-ELEC 8A. Distribution of Net Generation by Fuel Type (MWH)

Index Year (a)	Actual Year (b)	Coal (c)	Oil/Gas Steam (d)	Nuclear (e)	Hydro (f)	Pumped Storage (+) (g)	Oil CT/ICE (h)	Gas CT/ICE (i)	Total Net Generation (j)	Pumping Energy (-) (k)	Net Energy Import (Export)(1) (l)	Net Energy For Load (2) (m)
-5	1991	11,130	0	3,940	0	0	(7)	0	15,063	0	(2,382)	12,681
-4	1992	11,056	0	4,787	0	0	(12)	0	15,831	0	(3,499)	12,332
-3	1993	11,594	0	3,356	0	0	(6)	0	14,944	0	(2,239)	12,705
-2	1994	11,217	0	4,239	0	0	2	0	15,458	0	(2,578)	12,880
-1	1995	10,329	0	4,710	0	0	(1)	0	15,038	0	(1,794)	13,244
0	1996	10,425	0	4,638	0	0	7	0	15,070	0	(1,905)	13,165
1	1997	9,262	0	4,846	0	0	25	0	14,133	0	(547)	13,586
2	1998	8,688	0	5,344	0	0	40	0	14,072	0	(176)	13,896
3	1999	8,946	0	4,847	0	0	12	0	13,805	0	261	14,066
4	2000	8,799	0	5,110	0	0	10	0	13,919	0	329	14,248
5	2001	8,892	0	5,194	0	0	0	60	14,146	0	291	14,437
6	2002	9,232	0	4,994	0	0	0	61	14,287	0	336	14,623
7	2003	9,426	0	4,949	0	0	0	77	14,452	0	363	14,815
8	2004	9,073	0	5,358	0	0	0	95	14,526	0	491	15,017
9	2005	9,774	0	4,847	0	0	1	108	14,730	0	492	15,222
10	2006	9,719	0	5,098	0	0	1	105	14,923	0	496	15,419
11	2007	9,728	0	5,195	0	0	1	107	15,031	0	583	15,614
12	2008	10,113	0	5,011	0	0	1	120	15,245	0	560	15,805
13	2009	10,326	0	4,950	0	0	1	146	15,423	0	579	16,002
14	2010	9,816	0	5,344	0	0	1	276	15,437	0	754	16,191
15	2011	10,567	0	4,848	0	0	1	232	15,648	0	739	16,387
16	2012	10,461	0	5,113	0	0	1	239	15,814	0	772	16,586
17	2013	10,426	0	5,196	0	0	1	259	15,882	0	904	16,786
18	2014	10,805	0	4,996	0	0	1	276	16,078	0	912	16,990
19	2015	10,979	0	4,950	0	0	1	338	16,268	0	927	17,195

(1) The Net Energy Export values for 1999 and beyond include all of the output for Phillips, which will be reactivated to support a long term sale.

(2) Net Energy for Load values do not equal those shown on Form 01A due to projected curtailments of interruptible load and energy savings from the DSM program.

Company Name: Duquesne Light Company

IRP-ELEC 8B. Scheduled Imports and Exports (MWH)

Participant Type Code	Name of Participant	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
IPP	Zinc Corporation	93,680	66,610	67,600	63,510	59,330	64,780	65,830	67,240	85,630	87,410	90,210	98,480	96,660	100,740	125,180	123,210	130,740	142,980	147,450	157,420
IPP	J & L	33,810	32,980	33,170	32,850	32,570	32,580	32,690	34,510	35,970	36,540	36,580	36,800	37,150	37,580	37,690	38,150	38,260	38,160	38,160	38,170
NUG	Existing QF	47,030	46,490	46,480	46,400	46,600	46,430	46,410	46,730	46,890	46,970	47,060	47,040	47,230	47,220	47,460	49,310	50,100	52,050	54,150	55,070
PU	Firm Capacity	0	52,840	51,910	51,760	59,050	0	41,160	41,540	46,370	51,710	57,640	59,620	66,770	44,260	45,000	53,670	63,380	73,930	89,360	48,400
	Totals	174,520	198,920	199,160	194,520	197,550	143,790	186,090	190,020	214,860	222,630	231,490	241,940	247,810	229,800	255,330	264,340	282,480	307,120	329,120	299,080

Company Name: Duquesne Light Company

IRP-ELEC 9. Summary of Demands, Resources and Energy for the Past Year

	Peak Day		Calendar	
	Summer 1995	Winter 1995/96	Year 1995	Notes
01 Installed Generating Capacity (MW)	3327	3406		
02 Forced Outages (MW)	514	138		
03 Planned/Maintenance Outages (MW)	0	164		
04 Units in Cold Reserve (MW)	529	573		
05 Miscellaneous Unavailable Capacity (MW)	-90	0		
06 Total Capacity Not Available at Time of Peak (MW) (02+03+04+05)	953	875		
07 Firm Capacity Commitments from Others (MW)	329	33		
08 Firm Capacity Commitments to Others (MW)	0	210		
09 Reliable Capacity for Load (MW) (01-06+07-08)	2703	2354		
10 Peak Load in Season (MW)	2666	2040		
11 Operating Reserve at Time of Peak (MW) (09-10)	37	314		
12 Date and Hour of Peak	8/16/95 1600	2/5/96 1100		
13 Energy Produced by Company (Net MWH)			15,037,874	
14 Energy Received from Interconnection or Affiliated Company (MWH)			1,201,658	
15 Energy Delivered to Interconnection or Affiliated Company (MWH)			2,974,797	
16 System Losses and Company Use (MWH)			836,603	
17 Energy Delivered to Company Customers (MWH) (13+14-15-16)			12,428,132	

Company Name: Duquesne Light Company

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Smart Comfort (Low Income Usage Reduction Program)
Customer Class: Residential
Status: Existing __x__ Proposed ____

Contact Person: Barry Kukovich Phone No: (412) 393-6403

Program Objective:

To help low-income, residential customers reduce energy usage and improve bill paying behavior.

Details of Activity and Implementation Schedule:

The Smart Comfort Program (LIURP) is an ongoing program whereby highly trained Energy Managers (EMs) conduct on-site energy surveys on 600 to 700 residential customer housing units to determine what, if any, usage reduction measures would be appropriate to install.

During the home visit, the EM educates the customer on no cost / behavior change energy saving methods, performs an energy audit, and decides what measures to employ to save energy. Appliance replacement has become the major focus of the program. Any energy wasting appliance is a candidate for replacement, but refrigerators, water beds and incandescent lighting are the most frequently replaced items.

To be eligible for the program, customers must meet the following criteria: 1.) be a DLCo residential rate customer; 2.) have a household income at or below 150% of the poverty level; 3.) provide proof of income; 4.) own the dwelling or receive permission to participate from the landlord.

To participate, customers contact DLCo in response to community group appeals, media advertisements, dirct mail and through DLCo representatives referals.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings Electric (KWH)	Gas (CCF)	Oil (Gallons)	Coal (Tons)	Other Results
1994	N/A	N/A	1,511,100	N/A	N/A	N/A	N/A
1995	N/A	N/A	1,435,060	N/A	N/A	N/A	N/A
1996	N/A	N/A	1,541,800	N/A	N/A	N/A	N/A

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($) Payroll	Advertising*	Customer Grants	Other	Total
4,176	$105,000	$28,677	$583,347		$717,024
4,200	$105,000	$26,996	$512,932		$644,928
4,200	$105,000	$30,000	$570,000		$705,000

*Admin.

Company Name: Duquesne Light Company

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Energy Conservation Educational and Information Support Program
Customer Class: Residential, Commercial and Industrial
Status: Existing ___x___ Proposed ______

Contact Person: Estella Smith Phone No: (412) 393-6060

Program Objective:

To support the Company's Energy Conservation Personal Contact Program and promote among all customer classes the wise and efficient use of electric energy.

Details of Activity and Implementation Schedule:

The Duquesne Light Speakers Team offers a Safety Demonstration that visually displays the importance of electrical safety. This presentation was delivered to approximately 4500 students in over 50 schools located throughout Allegheny and Beaver Counties. The program was also presented to 53 special emphasis groups including: Boy and Girl Scout Troops, Safety Fairs, Fire Departments and libraries. In addition to the electric demonstrator, Duquesne Light provides videotapes, brochures and pamphlets on efficient energy usage, and energy conservation.

A new presentation topic "Lightening The Load" was developed this year to continue providing valuable information to our customers. This program gives simple, commonsense, home energy management techniques to maximize energy efficiency for homeowners.

At Duquesne Light we are committed to providing reliable electric service and to informing our customers about energy efficiency.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings Electric (KWH)	Energy Savings Gas (CCF)	Energy Savings Oil (Gallons)	Energy Savings Coal (Tons)	Other Results
1994	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1995*	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A

*Estimated

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($) Payroll	Advertising	Customer Grants	Other	Total
1,250	$26,000	$30,000			$56,000
1,300	$27,000	$25,000			$52,000
	Results from this program are no longer tracked				

Company Name: Duquesne Light Company

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Business and Industry Energy Conservation Education and Informational Personal Contact Program
Customer Class: Commercial and Industrial
Status: Existing x Proposed ____

Contact Person: Joseph Zagorski Phone No: (412) 393-2410
Donald Messner (412) 393-2780

Program Objective:

Continue to encourage and educate business and industries regarding the wise and efficient use of electric energy. Determine our customer's needs and meet those needs in an innovative, cost efficient manner.

Details of Activity and Implementation Schedule:

Company reps, backed by a technical support section, made personal one-on-one contacts with medium and large-size customers as well as architects, consulting engineers, developers and builders who are major users or specifiers of energy end uses. Company reps provided customers with the following:

* Rate structure information, including utilization of electricity off-peak, economic development discounts, and untransformed service credits.
* Power factor recommendations which can increase line capacity and reduce line losses.
* Economic feasibility studies for engineers, architects, builders and developers.
* Voltage, lighting and insulation recommendations, as well as onsite energy audits, all intended to provide greater electric energy efficiency to the customer.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings: Electric (KWH)	Energy Savings: Gas (CCF)	Energy Savings: Oil (Gallons)	Energy Savings: Coal (Tons)	Other Results
1994	3,411	N/A	N/A	N/A	N/A	N/A	N/A
1995	3,000	N/A	N/A	N/A	N/A	N/A	N/A
1996		*Results from this program are not tracked.*					

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($): Payroll	Advertising	Customer Grants	Other	Total
282	$33,200				$33,200
200	$25,000				$25,000
	Results from this program are not tracked.				

Company Name: Duquesne Light Company

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Residential Energy Conservation Education and Informal Personal Contact Program
Customer Class: Residential
Status: Existing __x__ Proposed _____

Contact Person: Joseph Zagorski Phone No: (412) 393-2410
Donald Messner (412) 393-2780

Program Objective:

Continue to encourage and create an awareness/understanding of wise and efficient enegy use among residential customers, builders, developers and realtors and optimize the use of company facilities.

Details of Activity and Implementation Schedule:

* Company representatives continue to encourage the wise and efficient use of energy when contacting the residential builders, developers, realtors and customers.
* Representatives provide guidance and advice regarding the importance of adequate dwelling insulation and the thermal integrity when installing electric heat.
* Emphasis continued to be placed on Act 222.
* Heat pumps are encouraged over resistance heating for conservation of energy.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings Electric (KWH)	Energy Savings Gas (CCF)	Energy Savings Oil (Gallons)	Energy Savings Coal (Tons)	Other Results
			Results for this program are not tracked				

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($) Payroll	Advertising	Customer Grants	Other	Total
	Results for this program are not tracked				

Company Name: Duquesne Light Company

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Commercial Cool Storage R & D Project
Customer Class: Commercial
Status: Existing ______ Proposed __x__

Contact Person: Gary Page Phone No: (412) 393-6497

Program Objective:

To create a succesful, fully functioning cool storage system in a customer's commercial space and to use as a showcase for other interseted customers.

Details of Activity and Implementation Schedule:

The program was intended to begin in July, 1990 and be completed in January, 1992, but due to construction delay was not installed until late 1994.

Commercial space cooling is the largest contributor to summer demand peaks. Cool storage offers significant potential for peak demand reduction.

Cool storage uses conventional cooling equipment and a storage tank to create cooling off-peak for on-peak needs. The customer benefits through lower demand charges and the utility benefits through an improved load factor.

Duquesne Light will invest R&D funds to defray the cost of cool storage, will monitor equipment operation, obtain actual information for case history development and determination of electric profiles and cost reduction.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings Electric (KWH)	Gas (CCF)	Oil (Gallons)	Coal (Tons)	Other Results
1994	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1995	150	150	N/A	N/A	N/A	N/A	N/A
1996	150	150	N/A	N/A	N/A	N/A	N/A

Monetary and Personnel Resources:

Year	Estimated Workhours	Categorized Program Expenses ($) Payroll	Advertising	Customer Grants	Other	Total
1994	N/A	N/A	N/A	N/A		N/A
1995	80	$2,500	$0	$40,000		$42,500
1996	20	$625	$0	$0		$625

Company Name: Duquesne Light Company

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Residential High Efficiency Lighting DSM Program
Customer Class: Residential
Status: Existing ________ Proposed ___x___

Contact Person: Gary Page Phone No: (412) 393-6497

Program Objective:

The objectives of this program are to provide Duquesne Light Company (DLCo) customers with the opportunity to purchase high efficiency lighting products and reduce their energy consumption and costs.

The program will encourage residential customers to use energy efficient compact fluorescent lamps (CFL's) in place of incandescent lamps via informational and financial incentives. The program is intended to educate and increase customer awareness about new lighting products and make the products easy to obtain.

Details of Activity and Implementation Schedule:

DLCo will contract with a third party to provide all services to process and ship orders, offer a catalog of energy efficient products, and provide a toll free number for the customer to call to answer questions about lighting and applications. The third party will offer dicounted prices on applicable lighting products which will be coupled with a per lamp rebate.

This program is due to be implemented in 1997 after DSM approval.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings Electric (KWH)	Energy Savings Gas (CCF)	Energy Savings Oil (Gallons)	Energy Savings Coal (Tons)	Other Results
1994	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1997	45	N/A	2,189,000	N/A	N/A	N/A	N/A

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($) Payroll	Advertising	Customer Grants	Other	Total
N/A	N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A
1,272	$99,000			$276,150	$375,150

Company Name: Duquesne Light Company

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Residential Load Management Pilot Research Program
Customer Class: Residential
Status: Existing ______ Proposed x

Contact Person: Gary Page Phone No: (412) 393-6497

Program Objective:

The program is designed to attract up to 1,000 customers to participate in air conditioning load management.

Details of Activity and Implementation Schedule:

Direct marketing will target potential participants in neighborhoods where communication infrastructure exists.

Participants will be selected based on their level of interest and their ability to utilize load management.

This program is due to be implemented in 1997 after DSM approval.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings Electric (KWH)	Energy Savings Gas (CCF)	Energy Savings Oil (Gallons)	Energy Savings Coal (Tons)	Other Results
1994	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1997	60	N/A	N/A	N/A	N/A	N/A	N/A

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($) Payroll	Advertising	Customer Grants	Other	Total
N/A	N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A
2,804	$79,000	N/A	N/A	$112,250	$191,250

Company Name: Duquesne Light Company

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Small/Medium Commercial Load Management DSM Program
Customer Class:
Status: Existing ______ Proposed __x__

Contact Person: Gary Page Phone No: (412) 393-6497

Program Objective:

To encourage chain account customers to install load control devices that limit peak demand.

Details of Activity and Implementation Schedule:

Marketing for this program will rely on direct mail pieces and sales calls. DLCo will develop customer education brochures to help explain load control.

National and regional chains will be targeted because unlike sole proprietors, they possess the central decision making that can leverage sales through multiple sites.

This program is due to be implemented in 1997 after DSM approval.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings: Electric (KWH)	Energy Savings: Gas (CCF)	Energy Savings: Oil (Gallons)	Energy Savings: Coal (Tons)	Other Results
1994	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1997	300	N/A	N/A	N/A	N/A	N/A	N/A

Monetary and Personnel Resources:

Year	Estimated Workhours	Categorized Program Expenses ($): Payroll	Advertising	Customer Grants	Other	Total
1994	N/A	N/A	N/A	N/A	N/A	N/A
1995	N/A	N/A	N/A	N/A	N/A	N/A
1996	N/A	N/A	N/A	N/A	N/A	N/A
1997	3,352	$112,300	N/A	N/A	$80,100	$192,400

Company Name: Duquesne Light Company

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Cool Storage Program
Customer Class: Commercial and Industrial
Status: Existing ________ Proposed __x__

Contact Person: Gary Page Phone No: (412) 393-6497

Program Objective:

The Cool Storage Program is designed to encourage customers with large air conditioning loads to install cool storage systems.

Details of Activity and Implementation Schedule:

Short term emphasis will be placed on raising the awarness level of customers, trade allies, vendors through partial funding of studies.

Mid to long term strategies will rely on direct customer contact and use of successfully installed and operating cool storage projects.

This program is due to be implemented in 1997 after DSM approval.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings Electric (KWH)	Energy Savings Gas (CCF)	Energy Savings Oil (Gallons)	Energy Savings Coal (Tons)	Other Results
1994	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1997	1,250	1,250	N/A	N/A	N/A	N/A	N/A

Monetary and Personnel Resources:

Year	Estimated Workhours	Categorized Program Expenses ($) Payroll	Advertising	Customer Grants	Other	Total
1994	N/A	N/A	N/A	N/A	N/A	N/A
1995	N/A	N/A	N/A	N/A	N/A	N/A
1996	N/A	N/A	N/A	N/A	N/A	N/A
1997	3,560	$157,500	N/A	$478,350	N/A	$635,850

Company Name: Duquesne Light Company

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Customer Generator DSM Program
Customer Class: Commercial and Industrial
Status: Existing ______ Proposed __x__

Contact Person: Gary Page Phone No: (412) 393-6497

Program Objective:

To use customer owned generators for dispatchable load management at times of system need throughout the year, thus reducing system peak demand.

Details of Activity and Implementation Schedule:

Target known owners of emergency generators and solicit their participation.

Generator installations will be selected that represent a variety of emergency generator installations found among DLCo customers.

This program is due to be implemented in 1997 after DSM approval.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings Electric (KWH)	Energy Savings Gas (CCF)	Energy Savings Oil (Gallons)	Energy Savings Coal (Tons)	Other Results
1994	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1997	2,000	N/A	200,000	N/A	N/A	N/A	N/A

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($)				
	Payroll	Advertising	Customer Grants	Other	Total
N/A	N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A
2,792	$102,000	N/A	N/A	$461,800	$563,800

Company Name: Duquesne Light Company

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Long-Term Contract Interruptible Program
Customer Class: Industrial
Status: Existing ________ Proposed __x__

Contact Person: Gary Page Phone No: (412) 393-6497

Program Objective:

To retain 100% of the existing interruptible load in the first two years of the program.

Details of Activity and Implementation Schedule:

Target existing interruptible customers to accept the stricter terms of this new program in exchange for a higher credit.

The first two years will be spent marketing the program benefits through Major Account Managers and Commercial/Industrial Representatives

This program is due to be implemented in 1997 after DSM approval.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings Electric (KWH)	Energy Savings Gas (CCF)	Energy Savings Oil (Gallons)	Energy Savings Coal (Tons)	Other Results
1994	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1997	75,000	N/A	N/A	N/A	N/A	N/A	N/A

Monetary and Personnel Resources:

Year	Estimated Workhours	Categorized Program Expenses ($) Payroll	Advertising	Customer Grants	Other	Total
1994	N/A	N/A	N/A	N/A	N/A	N/A
1995	N/A	N/A	N/A	N/A	N/A	N/A
1996	N/A	N/A	N/A	N/A	N/A	N/A
1997	1,653	$31,000	N/A	N/A	$1,350,000	$1,381,000

IRP-ELEC 10B. Conservation and Load Management Program Summary

Customer Class	Program Name	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Use Change (KWH)	Allocated Workhours	Categorized Program Expenses ($)				
						Payroll	Advertising	Customer Grants	Other	Total
R	Smart Comfort	N/A	N/A	1,511,100	4,176	$105,000	$28,677	$583,347	N/A	$717,024
R	Energy Consv. Educational and Info Support Program	N/A	N/A	N/A	1,250	$26,000	$30,000	N/A	N/A	$56,000
C, I	Business and Industry Energy Conservation Education Prog.	3,411	N/A	N/A	282	$33,200	N/A	N/A	N/A	$33,200
R	Resid. Energy Conservation Education Prog.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C	Cool Storage R & D Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
R	Residential High Efficiency Lighting DSM Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
R	Resid Load Management Pilot Research Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C, I	S/M Com. Load Management	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C, I	Cool Storage Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C, I	Customer Generator Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I	Long-Term Contract Interruptible Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Totals		3,411	0	1,511,100	5,708	$164,200	$58,677	$583,347	$0	$806,224

Note: For DSM Programs, advertising and customer grants are rolled into other.

IRP-ELEC 10B. Conservation and Load Management Program Summary

Customer Class	Program Name	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Use Change (KWH)	Allocated Workhours	Categorized Program Expenses ($) Payroll	Advertising	Customer Grants	Other	Total
R	Smart Comfort	N/A	N/A	1,435,060	4,200	$105,000	$26,996	$512,932	N/A	$644,928
R	Energy Consv. Educational and Info Support Program	N/A	N/A	N/A	1,300	$27,000	$25,000	N/A	N/A	$52,000
C, I	Business and Industry Energy Conservation Education Prog.	3,000	N/A	N/A	200	$25,000	N/A	N/A	N/A	$25,000
R	Resid. Energy Conservation Education Prog.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C	Cool Storage R & D Program	150	150	N/A	80	$2,500	N/A	N/A	$40,000	$42,500
R	Residential High Efficiency Lighting DSM Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
R	Resid Load Management Pilot Research Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C, I	S/M Com. Load Management	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C, I	Cool Storage Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C, I	Customer Generator Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I	Long-Term Contract Interruptible Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Totals		3,150	150	1,435,060	5,780	$159,500	$51,996	$512,932	$40,000	$764,428

Note: For DSM Programs, advertising and customer grants are rolled into other.

IRP-ELEC 10B. Conservation and Load Management Program Summary

Customer Class	Program Name	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Use Change (KWH)	Allocated Workhours	Categorized Program Expenses ($)				
						Payroll	Advertising	Customer Grants	Other	Total
R	Smart Comfort	N/A	N/A	1,541,800	4,200	$105,000	$30,000	$570,000	N/A	$705,000
R	Energy Consv. Educational and Info Support Program	N/A	N/A	N/A	1,300	$27,000	$25,000	N/A	N/A	$52,000
C, I	Business and Industry Energy Conservation Education Prog.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
R	Resid. Energy Conservation Education Prog.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C	Cool Storage R & D Program	150	150	N/A	20	$625	N/A	N/A	$0	$625
R	Residential High Efficiency Lighting DSM Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
R	Resid Load Management Pilot Research Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C, I	S/M Com. Load Management	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C, I	Cool Storage Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C, I	Customer Generator Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I	Long-Term Contract Interruptible Program	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Totals		150	150	1,541,800	5,520	$132,625	$55,000	$570,000	$0	$757,625

Note: For DSM Programs, advertising and customer grants are rolled into other.

IRP-ELEC 10B. Conservation and Load Management Program Summary

Customer Class	Program Name	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Use Change (KWH)	Allocated Workhours	Categorized Program Expenses ($) Payroll	Advertising	Customer Grants	Other	Total
R	Smart Comfort	N/A	N/A	1,541,800	4,200	$105,000	$30,000	$570,000	N/A	$705,000
R	Energy Consv. Educational and Info Support Program	N/A	N/A	N/A	1,300	$27,000	$25,000	N/A	N/A	$52,000
C, I	Business and Industry Energy Conservation Education Prog.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
R	Resid. Energy Conservation Education Prog.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
C	Cool Storage R & D Program	150	150	N/A	20	$625	N/A	N/A	$0	$625
R	Residential High Efficiency Lighting DSM Program	45	N/A	2,189,000	1,272	$99,000	N/A	N/A	$276,150	$375,150
R	Resid Load Management Pilot Research Program	60	N/A	N/A	2,804	$79,000	N/A	N/A	$112,250	$191,250
C, I	S/M Com. Load Management	300	N/A	N/A	3,352	$112,300	N/A	N/A	$80,100	$192,400
C, I	Cool Storage Program	1,250	1,250	N/A	3,560	$157,500	N/A	N/A	$478,350	$635,850
C, I	Customer Generator Program	2,000	N/A	200,000	2,792	$102,000	N/A	N/A	$461,800	$563,800
I	Long-Term Contract Interruptible Program	75,000	N/A	N/A	1,653	$31,000	N/A	N/A	$1,350,000	$1,381,000
Totals		78,805	1,400	3,930,800	20,953	$713,425	$55,000	$570,000	$2,758,650	$4,097,075

Note: For DSM Programs, advertising and customer grants are rolled into other.

Company Name: Duquesne Light Company

IRP-ELEC 10C. Conservation and Load Management Program Cost Benefit Analysis Inputs

Program Name: Smart Comfort
Customer Class: Residential
Year From: 1994
Year To: 1997

t	Year	No. of Part.	Annual Energy Savings (E) KWH	Cumulative Energy Savings (CE) KWH	Energy Shift (ES) KWH	Participant Demand Savings (D) KW	Utility Capacity Savings (G) KW	Participant Cost (PC) $	Incentive Costs (I) $	Utility Costs (UC) $	Discount Rates Part. (d) %	Discount Rates Non-Part. (d) %	Discount Rates Ratepayer (d) %	Discount Rates Utility (d) %	Average Energy Cost (ACE) $/KWH	Average Demand Cost (ACD) $/KW	Avoided Energy Cost (MCE) $/KWH	Avoided Capacity Cost (MCD) $/KW	System Sales (S) MWH
1	1994	657	1,511,100	1,511,100	N/A	N/A	338	N/A	N/A	$717,024	8.0%	8.0%	8.0%	8.0%	0.05	N/A	0.01795	N/A	15,332,489
2	1995	600	1,435,060	2,946,160	N/A	N/A	659	N/A	N/A	$644,928	8.0%	8.0%	8.0%	8.0%	0.05	N/A	0.01756	N/A	15,400,054
3	1996	600	1,541,800	4,487,960	N/A	N/A	1,005	N/A	N/A	$705,000	8.0%	8.0%	8.0%	8.0%	0.05	N/A	0.01826	N/A	15,598,751
4	1997	600	1,541,800	6,029,760	N/A	N/A	1,350	N/A	N/A	$705,000	8.0%	8.0%	8.0%	8.0%	0.05	N/A	0.01899	N/A	15,800,051
5	1998	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
6	1999	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
7	2000	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
8	2001	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
9	2002	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
10	2003	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
11	2004	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
12	2005	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
13	2006	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
14	2007	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
15	2008	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
16	2009	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
17	2010	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
18	2011	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
19	2012	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
20	2013	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
21	2014	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
22	2015	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
23	2016	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
24	2017	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
25	2018	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
26	2019	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
27	2020	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
28	2021	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
29	2022	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A
30	2023	N/A	N/A	6,029,760	N/A	N/A	1,350	N/A	N/A	N/A	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	N/A

Company Name: Duquesne Light Company

IRP-ELEC 10C. Conservation and Load Management Program Cost Benefit Analysis Inputs

Program Name: Residential High Efficiency Lighting DSM Program
Customer Class: Residential
Year From: 1997
Year To: 2001

t	Year	No. of Part.	Annual Energy Savings (E) KWH	Cumulative Energy Savings (CE) KWH	Energy Shift (ES) KWH	Participant Demand Savings (D) KW	Utility Capacity Savings (G) KW	Participant Cost (PC) $	Incentive Costs (I) $	Utility Costs (UC) $	Discount Rates Part. (d) %	Discount Rates Non-Part. (d) %	Discount Rates Ratepayer (d) %	Discount Rates Utility (d) %	Average Energy Cost (ACE) $/KWH	Average Demand Cost (ACD) $/KW	Avoided Energy Cost (MCE) $/KWH	Avoided Capacity Cost (MCD) $/KW	System Sales (S) MWH
1	1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2	1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	1997	7500	2,189,000	2,189,000	N/A	N/A	45	292,500	105,000	218,150	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.018	N/A	15,803,892
4	1998	25000	9,484,000	11,673,000	N/A	N/A	195	996,525	35,000	119,150	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.019	N/A	15,999,887
5	1999	12500	13,132,000	24,805,000	N/A	N/A	269	482,709	175,000	79,400	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.019	63	16,194,905
6	2000	2500	13,861,000	38,666,000	N/A	N/A	284	57,368	35,000	67,400	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.019	66	16,391,901
7	2001	2500	14,591,000	53,257,000	N/A	N/A	299	56,275	35,000	67,400	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.020	69	16,590,907
8	2002	N/A	14,591,000	67,848,000	N/A	N/A	299	(57,964)	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.020	72	16,792,690
9	2003	N/A	14,591,000	82,439,000	N/A	N/A	299	(59,703)	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.021	75	16,997,286
10	2004	N/A	13,497,000	95,936,000	N/A	N/A	277	127,599	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.021	78	17,205,826
11	2005	N/A	9,849,000	105,785,000	N/A	N/A	202	590,632	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.022	82	17,420,900
12	2006	N/A	8,025,000	113,810,000	N/A	N/A	165	290,312	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.022	85	17,640,721
13	2007	N/A	7,660,000	121,470,000	N/A	N/A	157	31,918	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.022	89	17,863,870
14	2008	N/A	7,296,000	128,766,000	N/A	N/A	150	34,606	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.023	93	18,090,384
15	2009	N/A	7,296,000	136,062,000	N/A	N/A	150	(35,644)	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.023	97	18,319,937
16	2010	N/A	7,296,000	143,358,000	N/A	N/A	150	(36,713)	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.024	101	18,552,569
17	2011	N/A	6,748,000	150,106,000	N/A	N/A	138	78,466	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.024	106	18,788,868
18	2012	N/A	4,925,000	155,031,000	N/A	N/A	101	363,201	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.025	111	19,030,149
19	2013	N/A	4,013,000	159,044,000	N/A	N/A	82	178,524	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.025	115	19,275,544
20	2014	N/A	3,830,000	162,874,000	N/A	N/A	79	19,628	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.026	121	19,524,363
21	2015	N/A	3,648,000	166,522,000	N/A	N/A	75	21,280	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.026	126	19,776,649
22	2016	N/A	3,648,000	170,170,000	N/A	N/A	75	(21,919)	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.027	131	20,032,263
23	2017	N/A	3,648,000	173,818,000	N/A	N/A	75	(22,576)	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.027	137	20,291,246
24	2018	N/A	3,374,000	177,192,000	N/A	N/A	69	48,289	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.028	143	20,553,918
25	2019	N/A	2,462,000	179,654,000	N/A	N/A	51	223,346	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.028	150	20,820,961
26	2020	N/A	2,006,000	181,660,000	N/A	N/A	41	109,741	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.029	156	21,091,963
27	2021	N/A	1,915,000	183,575,000	N/A	N/A	39	12,110	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.030	163	21,366,605
28	2022	N/A	1,824,000	185,399,000	N/A	N/A	37	13,044	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.030	170	21,644,933
29	2023	N/A	1,824,000	187,223,000	N/A	N/A	37	(13,479)	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.031	178	21,926,903
30	2024	N/A	1,687,000	188,910,000	N/A	N/A	37	(13,883)	N/A	N/A	8.0%	8.0%	8.0%	8.0%	0.1174	N/A	0.031	185	22,212,700

Company Name: Duquesne Light Company

IRP-ELEC 10C. Conservation and Load Management Program Cost Benefit Analysis Inputs

Program Name: Residential Load Management Pilot Research Program
Customer Class: Residential
Year From: 1997
Year To: 2024

t	Year	No. of Part.	Annual Energy Savings (E) KWH	Cumulative Energy Savings (CE) KWH	Energy Shift (ES) KWH	Participant Demand Savings (D) KW	Utility Capacity Savings (G) KW	Participant Cost (PC) $	Incentive Costs (I) $	Utility Costs (UC) $	Discount Rates Part. (d) %	Discount Rates Non-Part. (d) %	Discount Rates Ratepayer (d) %	Discount Rates Utility (d) %	Average Energy Cost (ACE) $/KWH	Average Demand Cost (ACD) $/KW	Avoided Energy Cost (MCE) $/KWH	Avoided Capacity Cost (MCD) $/KW	System Sales (S) MWH
1	1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2	1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	1997	50	N/A	N/A	N/A	75	81	0	1,250	706,950	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	15,806,081
4	1998	950	N/A	N/A	N/A	1,500	1,656	0	25,000	46,300	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	N/A	16,011,560
5	1999	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	47,132	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	63	16,219,710
6	2000	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	47,997	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	66	16,430,567
7	2001	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	48,897	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	69	16,644,164
8	2002	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	49,833	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	72	16,860,538
9	2003	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	50,806	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	75	17,079,725
10	2004	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	51,819	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	78	17,301,762
11	2005	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	52,871	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	82	17,526,685
12	2006	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	53,966	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	85	17,754,531
13	2007	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	55,105	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	89	17,985,340
14	2008	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	56,289	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	93	18,219,150
15	2009	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	57,521	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	97	18,455,999
16	2010	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	58,801	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	101	18,695,927
17	2011	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	60,134	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	106	18,938,974
18	2012	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	61,159	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	111	19,185,180
19	2013	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	62,960	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	115	19,434,588
20	2014	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	64,458	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	121	19,687,237
21	2015	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	66,016	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	126	19,943,171
22	2016	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	67,637	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	131	20,202,433
23	2017	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	69,322	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	137	20,465,064
24	2018	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	71,075	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	143	20,731,110
25	2019	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	72,898	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	150	21,000,615
26	2020	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	74,794	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	156	21,273,623
27	2021	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	76,766	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	163	21,550,180
28	2022	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	78,817	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	170	21,830,332
29	2023	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	80,949	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	178	22,114,126
30	2024	N/A	N/A	N/A	N/A	1,500	1,656	0	25,000	83,147	8.0%	8.0%	8.0%	8.0%	N/A	N/A	N/A	185	22,401,610

Company Name: Duquesne Light Company

IRP-ELEC 10C. Conservation and Load Management Program Cost Benefit Analysis Inputs

Program Name: Small/Medium Commercial Load Management DSM Program
Customer Class: Commercial
Year From: 1997
Year To: 2012

t	Year	No. of Part.	Annual Energy Savings (E) KWH	Cumulative Energy Savings (CE) KWH	Energy Shift (ES) KWH	Participant Demand Savings (D) KW	Utility Capacity Savings (G) KW	Participant Cost (PC) $	Incentive Costs (I) $	Utility Costs (UC) $	Discount Rates Part. (d) %	Discount Rates Non-Part. (d) %	Discount Rates Ratepayer (d) %	Discount Rates Utility (d) %	Average Energy Cost (ACE) $/KWH	Average Demand Cost (ACD) $/KW	Avoided Energy Cost (MCE) $/KWH	Avoided Capacity Cost (MCD) $/KW	System Sales (S) MWH
1	1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	18.47	N/A	N/A	N/A
2	1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	18.47	N/A	N/A	N/A
3	1997	30	N/A	N/A	N/A	600	325	150,000	0	192,400	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	N/A	15,806,081
4	1998	50	N/A	N/A	N/A	1,600	866	257,500	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	N/A	16,011,560
5	1999	70	N/A	N/A	N/A	3,000	1,623	371,315	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	63	16,219,710
6	2000	100	N/A	N/A	N/A	5,000	2,705	546,364	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	66	16,430,567
7	2001	100	N/A	N/A	N/A	7,000	3,787	562,754	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	69	16,644,164
8	2002	N/A	N/A	N/A	N/A	9,000	4,870	579,637	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	72	16,860,538
9	2003	N/A	N/A	N/A	N/A	11,000	5,952	597,026	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	75	17,079,725
10	2004	N/A	N/A	N/A	N/A	13,000	7,034	614,937	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	78	17,301,762
11	2005	N/A	N/A	N/A	N/A	14,000	7,575	316,693	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	82	17,526,685
12	2006	N/A	N/A	N/A	N/A	15,000	8,116	326,193	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	85	17,754,531
13	2007	N/A	N/A	N/A	N/A	16,000	8,657	335,979	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	89	17,985,340
14	2008	N/A	N/A	N/A	N/A	16,600	8,981	207,635	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	93	18,219,150
15	2009	N/A	N/A	N/A	N/A	17,200	9,306	213,864	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	97	18,455,999
16	2010	N/A	N/A	N/A	N/A	17,800	9,631	220,280	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	101	18,695,927
17	2011	N/A	N/A	N/A	N/A	17,800	9,631	0	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	106	18,938,974
18	2012	N/A	N/A	N/A	N/A	17,800	9,631	0	0	112,600	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	111	19,185,180
19	2013	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	115	19,434,588
20	2014	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	121	19,687,237
21	2015	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	126	19,943,171
22	2016	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	131	20,202,433
23	2017	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	137	20,465,064
24	2018	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	143	20,731,110
25	2019	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	150	21,000,615
26	2020	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	156	21,273,623
27	2021	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	163	21,550,180
28	2022	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	170	21,830,332
29	2023	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	178	22,114,126
30	2024	N/A	N/A	N/A	N/A	17,800	9,631	0	0	0	8.0%	8.0%	8.0%	8.0%	N/A	18.47	N/A	185	22,401,610

Company Name: Duquesne Light Company

IRP-ELEC 10C. Conservation and Load Management Program Cost Benefit Analysis Inputs

Program Name: Cool Storage DSM Program
Customer Class: Commercial
Year From: 1997
Year To: 2001

t	Year	No. of Part.	Annual Energy Savings (E) KWH	Cumulative Energy Savings (CE) KWH	Energy Shift* (ES) KWH	Participant Demand Savings (D) KW	Utility Capacity Savings (G) KW	Participant Cost (PC) $	Incentive Costs (I) $	Utility Costs (UC) $	Discount Rates Part. (d) %	Discount Rates Non-Part. (d) %	Discount Rates Ratepayer (d) %	Discount Rates Utility (d) %	Average Energy Cost (ACE) $/KWH	Average Demand Cost (ACD) $/KW	Avoided Energy Cost (MCE) $/KWH	Avoided Capacity Cost (MCD) $/KW	System Sales (S) MWH
1	1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	14.08	N/A	N/A	N/A
2	1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	14.08	N/A	N/A	N/A
3	1997	3	N/A	N/A	5,464,000	1,250	1,366	585,000	405,000	$719,450	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	N/A	15,806,081
4	1998	8	N/A	N/A	14,340,000	3,350	3,585	973,350	637,313	$745,993	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	N/A	16,011,560
5	1999	9	N/A	N/A	24,500,000	5,750	6,125	1,145,772	739,978	$853,005	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	63	16,219,710
6	2000	8	N/A	N/A	33,828,000	7,950	8,457	1,081,800	688,418	$805,966	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	66	16,430,567
7	2001	7	N/A	N/A	42,320,000	9,950	10,580	1,012,958	633,099	$755,349	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	69	16,644,164
8	2002	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$127,140	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	72	16,860,538
9	2003	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$132,226	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	75	17,079,725
10	2004	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$137,515	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	78	17,301,762
11	2005	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$143,015	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	82	17,526,685
12	2006	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$148,736	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	85	17,754,531
13	2007	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$154,685	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	89	17,985,340
14	2008	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$160,873	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	93	18,219,150
15	2009	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$167,308	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	97	18,455,999
16	2010	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$174,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	101	18,695,927
17	2011	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$180,960	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	106	18,938,974
18	2012	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$188,198	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	111	19,185,180
19	2013	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$195,726	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	115	19,434,588
20	2014	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$203,555	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	121	19,687,237
21	2015	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$211,698	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	126	19,943,171
22	2016	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$220,166	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	131	20,202,433
23	2017	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$228,972	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	137	20,465,064
24	2018	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$238,131	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	143	20,731,110
25	2019	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$247,656	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	150	21,000,615
26	2020	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$257,563	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	156	21,273,623
27	2021	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$267,865	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	163	21,550,180
28	2022	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$278,580	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	170	21,830,332
29	2023	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$289,723	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	178	22,114,126
30	2024	N/A	N/A	N/A	42,320,000	9,950	10,580	0	0	$301,312	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	185	22,401,610

* Energy shift estimated from 4 full-load cooling months and 1000 full-load cooling hours.

Company Name: Duquesne Light Company

IRP-ELEC 10C. Conservation and Load Management Program Cost Benefit Analysis Inputs

Program Name: Customer Generator DSM Program
Customer Class: Commercial
Year From: 1997
Year To: 2024

t	Year	No. of Part.	Annual Energy Savings (E) KWH	Cumulative Energy Savings (CE) KWH	Energy Shift (ES) KWH	Participant Demand Savings (D) KW	Utility Capacity Savings (G) KW	Participant Cost (PC) $	Incentive Costs (I) $	Utility Costs (UC) $	Discount Rates Part. (d) %	Discount Rates Non-Part. (d) %	Discount Rates Ratepayer (d) %	Discount Rates Utility (d) %	Average Energy Cost (ACE) $/KWH	Average Demand Cost (ACD) $/KW	Avoided Energy Cost (MCE) $/KWH	Avoided Capacity Cost (MCD) $/KW	System Sales (S) MWH
1	1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	14.08	N/A	N/A	N/A
2	1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	14.08	N/A	N/A	N/A
3	1997	4	200,000	200,000	N/A	N/A	2,000	$0	30,000	523,800	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	N/A	15,805,881
4	1998	21	2,700,000	2,900,000	N/A	N/A	27,000	$0	400,000	2,026,638	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	N/A	16,008,660
5	1999	7	3,500,000	6,400,000	N/A	N/A	35,000	$0	520,000	2,393,387	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	63	16,213,310
6	2000	5	4,000,000	10,400,000	N/A	N/A	40,000	$0	590,000	2,688,006	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	66	16,420,167
7	2001	5	4,500,000	14,900,000	N/A	N/A	45,000	$0	660,000	3,008,006	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	69	16,629,264
8	2002	N/A	4,748,000	19,648,000	N/A	N/A	47,838	$0	660,000	2,964,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	72	16,840,890
9	2003	N/A	4,748,000	24,396,000	N/A	N/A	47,838	$0	660,000	2,964,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	75	17,055,329
10	2004	N/A	4,748,000	29,144,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	78	17,272,618
11	2005	N/A	4,748,000	33,892,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	82	17,492,793
12	2006	N/A	4,748,000	38,640,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	85	17,715,891
13	2007	N/A	4,748,000	43,388,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	89	17,941,952
14	2008	N/A	4,748,000	48,136,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	93	18,171,014
15	2009	N/A	4,748,000	52,884,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	97	18,403,115
16	2010	N/A	4,748,000	57,632,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	101	18,638,295
17	2011	N/A	4,748,000	62,380,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	106	18,876,594
18	2012	N/A	4,748,000	67,128,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	111	19,118,052
19	2013	N/A	4,748,000	71,876,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	115	19,362,712
20	2014	N/A	4,748,000	76,624,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	121	19,610,613
21	2015	N/A	4,748,000	81,372,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	126	19,861,799
22	2016	N/A	4,748,000	86,120,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	131	20,116,313
23	2017	N/A	4,748,000	90,868,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	137	20,374,196
24	2018	N/A	4,748,000	95,616,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	143	20,635,494
25	2019	N/A	4,748,000	100,364,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	150	20,900,251
26	2020	N/A	4,748,000	105,112,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	156	21,168,511
27	2021	N/A	4,748,000	109,860,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	163	21,440,320
28	2022	N/A	4,748,000	114,608,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	170	21,715,724
29	2023	N/A	4,748,000	119,356,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	178	21,994,770
30	2024	N/A	4,748,000	124,104,000	N/A	N/A	47,838	$0	660,000	2,880,000	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	185	22,277,506

Company Name: Duquesne Light Company

IRP-ELEC 10C. Conservation and Load Management Program Cost Benefit Analysis Inputs

Program Name: Long-Term Contracted Interruptible DSM Program
Customer Class: Industrial
Year From: 1997
Year To: 2024

t	Year	No. of Part.	Annual Energy Savings (E) KWH	Cumulative Energy Savings (CE) KWH	Energy Shift (ES) KWH	Participant Demand Savings (D) KW	Utility Capacity Savings (G) KW	Participant Cost (PC) $	Incentive Costs (I) $	Utility Costs (UC) $	Discount Rates Part. (d) %	Non-Part. (d) %	Ratepayer (d) %	Utility (d) %	Average Energy Cost (ACE) $/KWH	Average Demand Cost (ACD) $/KW	Avoided Energy Cost (MCE) $/KWH	Avoided Capacity Cost (MCD) $/KW	System Sales (S) MWH
1	1995	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	14.08	N/A	N/A	N/A
2	1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	14.08	N/A	N/A	N/A
3	1997	6	4,017,400	200,000	N/A	N/A	81,158	N/A	90,000	1,092,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	N/A	15,805,881
4	1998	6	5,677,900	5,877,900	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	N/A	16,005,682
5	1999	0	5,677,900	11,555,800	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	63	16,208,155
6	2000	0	5,677,900	17,233,700	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	66	16,413,333
7	2001	0	5,677,900	22,911,600	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	69	16,621,252
8	2002	N/A	5,677,900	28,589,500	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	72	16,831,949
9	2003	N/A	5,677,900	34,267,400	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	75	17,045,458
10	2004	N/A	5,677,900	39,945,300	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	78	17,261,816
11	2005	N/A	5,677,900	45,623,200	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	82	17,481,061
12	2006	N/A	5,677,900	51,301,100	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	85	17,703,230
13	2007	N/A	5,677,900	56,979,000	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	89	17,928,361
14	2008	N/A	5,677,900	62,656,900	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	93	18,156,493
15	2009	N/A	5,677,900	68,334,800	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	97	18,387,664
16	2010	N/A	5,677,900	74,012,700	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	101	18,621,914
17	2011	N/A	5,677,900	79,690,600	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	106	18,859,283
18	2012	N/A	5,677,900	85,368,500	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	111	19,099,812
19	2013	N/A	5,677,900	91,046,400	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	115	19,343,541
20	2014	N/A	5,677,900	96,724,300	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	121	19,590,513
21	2015	N/A	5,677,900	102,402,200	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	126	19,840,769
22	2016	N/A	5,677,900	108,080,100	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	131	20,094,353
23	2017	N/A	5,677,900	113,758,000	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	137	20,351,306
24	2018	N/A	5,677,900	119,435,900	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	143	20,611,674
25	2019	N/A	5,677,900	125,113,800	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	150	20,875,501
26	2020	N/A	5,677,900	130,791,700	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	156	21,142,831
27	2021	N/A	5,677,900	136,469,600	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	163	21,413,710
28	2022	N/A	5,677,900	142,147,500	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	170	21,688,184
29	2023	N/A	5,677,900	147,825,400	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	178	21,966,301
30	2024	N/A	5,677,900	153,503,300	N/A	N/A	106,000	N/A	1,272,000	1,304,500	8.0%	8.0%	8.0%	8.0%	N/A	14.08	N/A	185	22,248,107

IRP-ELEC 10D. Conservation and Load Management Program Cost Benefit Analysis Results

Program Name: Smart Comfort (Low Income Usage Reduction Program)
Present Values Calculated for Year: 1994
Period of Analysis: Beginning Year: 1994
Ending Year: 1994

Participant Test

Utility Benefits (Bup) $	Utility Costs (Cup) $	Revenue Reduction Cost (Crp) $	Incentive Costs (Cip) $	Sales Ratio (f) $	Participant Revenue Requirement (Rp) $	Total Participant Benefits (Bp) $	Total Participant Costs (Cp) $	Net Present Value (NPVp) $	Benefit Cost Ratio (BCRp)	Discounted Payback Period (yrs)
N/A	N/A	N/A	N/A	N/A	524	1,066,378	0	1,066,378	999	30

Nonparticipant Test

Utility Benefits (Bunp) $	Utility Costs (Cunp) $	Revenue Reduction (Crnp) $	Incentive Costs (Cinp) $	Rate Impact Non-Part. (RIMnp) $/MWH	Net Present Value (NPVnp) $	Benefit Cost Ratio (BCRnp)
N/A	N/A	1,392,000	0	N/A	(2,752,608)	0.25

All Ratepayers Test

Total Ratepayers Benefits (Bua) $	Total Ratepayers Costs (Ca) $	Net Present Value (NPVa) $	Benefit Cost Ratio (BCRa)
426,405	762,735	(336,330)	0.56

Utility Revenue Requirement Test

Increased Revenue (Ruu) $	Total Utility Benefits (Buu) $	Total Utility Costs (Cuu) $	Incentive Costs (Ciu) $	Net Present Value (NPVu) $	Benefit Cost Ratio (BCRu)
(1,392,000)	409,845	762,735	0	(352,890)	0.54

Company Name: Duquesne Light Company

IRP-ELEC 10D. Conservation and Load Management Program Cost Benefit Analysis Results

Program Name: Residential High Efficiency Lighting DSM Program
Present Values Calculated for Year: 1997
Period of Analysis: Beginning Year: 1997
Ending Year: 2026

Participant Test

Utility Benefits (Bup) $	Utility Costs (Cup) $	Revenue Reduction Cost (Crp) $	Incentive Costs (Cip) $	Sales Ratio (f) $	Participant Revenue Requirement (Rp) $	Total Participant Benefits (Bp) $	Total Participant Costs (Cp) $	Net Present Value (NPVp) $	Benefit Cost Ratio (BCRp)	Discounted Payback Period (yrs)
N/A	N/A	N/A	N/A	N/A	217,343	14,255,098	2,579,684	11,675,414	5.53	30

Nonparticipant Test

Utility Benefits (Bunp) $	Utility Costs (Cunp) $	Revenue Reduction (Crnp) $	Incentive Costs (Cinp) $	Rate Impact Non-Part. (RIMnp) $/MWH	Net Present Value (NPVnp) $	Benefit Cost Ratio (BCRnp)
6,466,808	29,788,203	13,345,000	N/A	0.13	(23,321,396)	0.22

All Ratepayers Test

Total Ratepayers Benefits (Bua) $	Total Ratepayers Costs (Ca) $	Net Present Value (NPVa) $	Benefit Cost Ratio (BCRa)
3,139,566	3,038,949	100,617	1.03

Utility Revenue Requirement Test

Increased Revenue (Ruu) $	Total Utility Benefits (Buu) $	Total Utility Costs (Cuu) $	Incentive Costs (Ciu) $	Net Present Value (NPVu) $	Benefit Cost Ratio (BCRu)
0	2,862,547	1,091,884	632,619	1,770,663	2.62

Company Name: Duquesne Light Company

IRP-ELEC 10D. Conservation and Load Management Program Cost Benefit Analysis Results

Program Name: Residential Load Management Pilot Research Program
Present Values Calculated for Year: 1997
Period of Analysis: Beginning Year: 1997
Ending Year: 2026

Participant Test

Utility Benefits (Bup) $	Utility Costs (Cup) $	Revenue Reduction Cost (Crp) $	Incentive Costs (Cip) $	Sales Ratio (f) $	Participant Revenue Requirement (Rp) $	Total Participant Benefits (Bp) $	Total Participant Costs (Cp) $	Net Present Value (NPVp) $	Benefit Cost Ratio (BCRp)	Discounted Payback Period (yrs)
N/A	N/A	N/A	N/A	N/A	2,089	285,039	0	285,039	999.00	30

Nonparticipant Test

Utility Benefits (Bunp) $	Utility Costs (Cunp) $	Revenue Reduction (Crnp) $	Incentive Costs (Cinp) $	Rate Impact Non-Part. (RIMnp) $/MWH	Net Present Value (NPVnp) $	Benefit Cost Ratio (BCRnp)
4,943,827	2,548,148	0	N/A	(0.01000)	2,395,678	1.94

All Ratepayers Test

Total Ratepayers Benefits (Bua) $	Total Ratepayers Costs (Ca) $	Net Present Value (NPVa) $	Benefit Cost Ratio (BCRa)
1,410,679	1,052,397	358,282	1.34

Utility Revenue Requirement Test

Increased Revenue (Ruu) $	Total Utility Benefits (Buu) $	Total Utility Costs (Cuu) $	Incentive Costs (Ciu) $	Net Present Value (NPVu) $	Benefit Cost Ratio (BCRu)
0	1,410,679	1,337,346	285,039	73,243	1.05

Company Name: Duquesne Light Company

IRP-ELEC 10D. Conservation and Load Management Program Cost Benefit Analysis Results

Program Name: Cool Storage DSM Program
Present Values Calculated for Year: 1997
Period of Analysis: Beginning Year: 1997
Ending Year: 2026

Participant Test

Utility Benefits (Bup) $	Utility Costs (Cup) $	Revenue Reduction Cost (Crp) $	Incentive Costs (Cip) $	Sales Ratio (f) $	Participant Revenue Requirement (Rp) $	Total Participant Benefits (Bp) $	Total Participant Costs (Cp) $	Net Present Value (NPVp) $	Benefit Cost Ratio (BCRp)	Discounted Payback Period (yrs)
N/A	N/A	N/A	N/A	N/A	94,395	9,116,900	3,921,400	5,195,500	2.32	30

Nonparticipant Test

Utility Benefits (Bunp) $	Utility Costs (Cunp) $	Revenue Reduction (Crnp) $	Incentive Costs (Cinp) $	Rate Impact Non-Part. (RIMnp) $/MWH	Net Present Value (NPVnp) $	Benefit Cost Ratio (BCRnp)
47,789,000	37,664,300	8,242,000	N/A	(0.07000)	10,124,700	1.27

All Ratepayers Test

Total Ratepayers Benefits (Bua) $	Total Ratepayers Costs (Ca) $	Net Present Value (NPVa) $	Benefit Cost Ratio (BCRa)
13,220,100	6,193,900	7,026,200	2.13

Utility Revenue Requirement Test

Increased Revenue (Ruu) $	Total Utility Benefits (Buu) $	Total Utility Costs (Cuu) $	Incentive Costs (Ciu) $	Net Present Value (NPVu) $	Benefit Cost Ratio (BCRu)
N/A	13,122,000	4,763,400	2,641,352	8,358,600	2.75

IRP-ELEC 10D. Conservation and Load Management Program Cost Benefit Analysis Results

Program Name: Customer Generator DSM Program
Present Values Calculated for Year: 1997
Period of Analysis: Beginning Year: 1997
Ending Year: 2026

Participant Test

Utility Benefits (Bup) $	Utility Costs (Cup) $	Revenue Reduction Cost (Crp) $	Incentive Costs (Cip) $	Sales Ratio (f) $	Participant Revenue Requirement (Rp) $	Total Participant Benefits (Bp) $	Total Participant Costs (Cp) $	Net Present Value (NPVp) $	Benefit Cost Ratio (BCRp)	Discounted Payback Period (yrs)
N/A	N/A	N/A	N/A	N/A	910,561	18,305,100	0	18,305,100	999.00	30

Nonparticipant Test

Utility Benefits (Bunp) $	Utility Costs (Cunp) $	Revenue Reduction (Crnp) $	Incentive Costs (Cinp) $	Rate Impact Non-Part. (RIMnp) $/MWH	Net Present Value (NPVnp) $	Benefit Cost Ratio (BCRnp)
194,083,400	158,739,500	12,108,000	N/A	(0.24000)	35,343,900	1.22

All Ratepayers Test

Total Ratepayers Benefits (Bua) $	Total Ratepayers Costs (Ca) $	Net Present Value (NPVa) $	Benefit Cost Ratio (BCRa)
55,126,800	31,504,700	23,622,100	1.75

Utility Revenue Requirement Test

Increased Revenue (Ruu) $	Total Utility Benefits (Buu) $	Total Utility Costs (Cuu) $	Incentive Costs (Ciu) $	Net Present Value (NPVu) $	Benefit Cost Ratio (BCRu)
N/A	54,982,800	42,245,900	10,741,228	12,736,900	1.30

Company Name: Duquesne Light Company

IRP-ELEC 10D. Conservation and Load Management Program Cost Benefit Analysis Results

Program Name: Long-Term Contracted Interruptible DSM Program
Present Values Calculated for Year: 1997
Period of Analysis: Beginning Year: 1997
Ending Year: 2026

Participant Test

Utility Benefits (Bup) $	Utility Costs (Cup) $	Revenue Reduction Cost (Crp) $	Incentive Costs (Cip) $	Sales Ratio (f) $	Participant Revenue Requirement (Rp) $	Total Participant Benefits (Bp) $	Total Participant Costs (Cp) $	Net Present Value (NPVp) $	Benefit Cost Ratio (BCRp)	Discounted Payback Period (yrs)
N/A	N/A	N/A	N/A	N/A	(4,636,534)	12,818,139	0	12,818,139	999.99	30

Nonparticipant Test

Utility Benefits (Bunp) $	Utility Costs (Cunp) $	Revenue Reduction (Crnp) $	Incentive Costs (Cinp) $	Rate Impact Non-Part. (RIMnp) $/MWH	Net Present Value (NPVnp) $	Benefit Cost Ratio (BCRnp)
381,122,813	38,923,000	0	N/A	(2.37000)	342,199,813	9.79

All Ratepayers Test

Total Ratepayers Benefits (Bua) $	Total Ratepayers Costs (Ca) $	Net Present Value (NPVa) $	Benefit Cost Ratio (BCRa)
108,539,633	555,148	107,984,485	195.51

Utility Revenue Requirement Test

Increased Revenue (Ruu) $	Total Utility Benefits (Buu) $	Total Utility Costs (Cuu) $	Incentive Costs (Ciu) $	Net Present Value (NPVu) $	Benefit Cost Ratio (BCRu)
N/A	108,539,633	15,648,640	15,093,492	92,890,993	6.94

Company Name: Duquesne Light Company

IRP-ELEC 10E. Assessment of Conservation and Load Management Potential

Index	Actual	Residential		Commercial		Industrial		Other		Total		Utility Program Goals	
Year (a)	Year (b)	KW (c)	KWH (d)	KW (e)	KWH (f)	KW (g)	KWH (h)	KW (i)	KWH (j)	KW (k)	KWH (l)	KW (m)	KWH (n)
0	1996	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1	1997	45	2,189,000	3,691	200,000	81,158	4,017,400	N/A	N/A	84,894	6,406,400	84,894	6,406,400
2	1998	240	11,673,000	35,142	2,900,000	187,158	9,695,300	N/A	N/A	222,540	24,268,300	222,540	24,268,300
3	1999	509	24,805,000	77,890	6,400,000	293,158	15,373,200	N/A	N/A	371,557	46,578,200	371,557	46,578,200
4	2000	793	38,666,000	129,052	10,400,000	399,158	21,051,100	N/A	N/A	529,003	70,117,100	529,003	70,117,100
5	2001	1,092	53,257,000	188,419	14,900,000	505,158	26,729,000	N/A	N/A	694,669	94,886,000	694,669	94,886,000
6	2002	1,391	67,848,000	251,707	19,648,000	611,158	32,406,900	N/A	N/A	864,256	119,902,900	864,256	119,902,900
7	2003	1,690	82,439,000	316,077	24,396,000	717,158	38,084,800	N/A	N/A	1,034,925	144,919,800	1,034,925	144,919,800
8	2004	1,967	95,936,000	381,529	29,144,000	823,158	43,762,700	N/A	N/A	1,206,654	168,842,700	1,206,654	168,842,700
9	2005	2,169	105,785,000	447,522	33,892,000	929,158	49,440,600	N/A	N/A	1,378,849	189,117,600	1,378,849	189,117,600
10	2006	2,334	113,810,000	514,056	38,640,000	1,035,158	55,118,500	N/A	N/A	1,551,548	207,568,500	1,551,548	207,568,500
11	2007	2,491	121,470,000	581,131	43,388,000	1,141,158	60,796,400	N/A	N/A	1,724,780	225,654,400	1,724,780	225,654,400
12	2008	2,641	128,766,000	648,530	48,136,000	1,247,158	66,474,300	N/A	N/A	1,898,329	243,376,300	1,898,329	243,376,300
13	2009	2,791	136,062,000	716,254	52,884,000	1,353,158	72,152,200	N/A	N/A	2,072,203	261,098,200	2,072,203	261,098,200
14	2010	2,941	143,358,000	784,303	57,632,000	1,459,158	77,830,100	N/A	N/A	2,246,402	278,820,100	2,246,402	278,820,100
15	2011	3,079	150,106,000	852,352	62,380,000	1,565,158	83,508,000	N/A	N/A	2,420,589	295,994,000	2,420,589	295,994,000
16	2012	3,180	155,031,000	920,401	67,128,000	1,671,158	89,185,900	N/A	N/A	2,594,739	311,344,900	2,594,739	311,344,900
17	2013	3,262	159,044,000	988,450	71,876,000	1,777,158	94,863,800	N/A	N/A	2,768,870	325,783,800	2,768,870	325,783,800
18	2014	3,341	162,874,000	1,056,499	76,624,000	1,883,158	100,541,700	N/A	N/A	2,942,998	340,039,700	2,942,998	340,039,700
19	2015	3,416	166,522,000	1,124,548	81,372,000	1,989,158	106,219,600	N/A	N/A	3,117,122	354,113,600	3,117,122	354,113,600

Note: Values shown are cumulative amounts.

Planned utility programs attempt to attain the conservation and load management potential as defined in IRP-ELEC 10E with one exception.
The impacts for the Residential Load Management Pilot Research Program are not included in IRP-ELEC 10E since the implementation of this program is dependent upon successful negotiation of a multi-vendor research and development contract. Additionally, it should be noted that this estimate of practical and economical energy conservation and load management is valid only if cost recovery, lost revenue recovery and incentives are in place for the electric utilities in Pennsylvania.

IRP-ELEC 11. Comparison of Costs of Preferred Resource Plan with Alternative Plans

(Constant Dollars)

		Preferred Plan		Alternative Plan A		Alternative Plan B		Alternative Plan C	
Index Year (a)	Actual Year (b)	Annual Dollars (c)	Cents Per KWH Sold (d)	Annual Dollars (e)	Cents Per KWH Sold (f)	Annual Dollars (g)	Cents Per KWH Sold (h)	Annual Dollars (i)	Cents Per KWH Sold (j)
0	1995								
1	1996								
2	1997								
3	1998								
4	1999								
5	2000								
6	2001								
7	2002								
8	2003								
9	2004								
10	2005								
11	2006								
12	2007								
13	2008								
14	2009								
15	2010								
16	2011								
17	2012								
18	2013								
19	2014								
Levelized Cents Per KWH									

Note: Duquesne considers revenue requirements to be proprietary business information and is providing this data under separate cover.

Company Name: Duquesne Light Company

IRP-ELEC 12. Transmission Line Projection

Transmission Line Name (a)	Location (b)	Design Voltage (c)	Length (d)	Construction Start Date (e)	In Service Date (f)	Line Cost (g)
1) Crescent - North 138 kV Z-20 Circuit	Ohio Township, Allegheny County	138 kV	0.1 mi.	4-95	8-95	$125,000
2) Phillips - Valley 138 kV Z-82 Circuit	New Sewickley Twp Beaver County	138 kV	0.3 mi.	4-96	8-96	$200,000

Duquesne Light Company

Appendix B

PROMOD

Generation Production Costing Model

1. INTRODUCTION

1.1 Overview

The PROMOD III® system is a computer software package that simulates the operation of an electric utility power system. It is first and foremost a comprehensive production costing model for projecting future operating costs. It can also be used to evaluate system reliability.

PROMOD III differs from less sophisticated production costing programs in its treatment of generating unit forced outages. It is these forced outages that comprise the major factor in the disruption of fuel budget forecasts, operating cost estimates, and projected utilization of high-cost peaking and mid-range units. Since these outages are random and unpredictable, PROMOD III employs a special mathematical technique to properly consider their resultant impact on fuel requirements and operating costs.

Forced outages are treated within the program by a complete probabilistic model. Generating units can be represented by a seven-state failure model to give explicit consideration to partial loss of unit capability and forced outages of varying severity. All possible failure states of each unit are considered, in combination with all possible failure states of all other units, in order to obtain the best possible forecast of expected fuel consumption, operating costs, and plant capacity factors.

For fuel budget applications and system planning studies, PROMOD III will produce better results than less sophisticated programs because of the comprehensive representation provided for simulating detailed electric utility operations on an hourly basis while recognizing the importance of generating unit full and partial forced outages. Without explicit recognition of these forced outages, accurate recognition of fuel consumption is not possible. PROMOD III also serves as a generation reliability program, since loss-of-load hours and emergency energy requirements are standard outputs. Both measures are needed to determine appropriate reserve levels.

PROMOD III has developed into the most effective tool for studying a host of problems confronting utilities today:

- Making Fuel Budget Forecasts
- Examining New Plant Capacity Additions
- Planning Nuclear Refueling Outages
- Projecting Utility Operating Costs
- Pricing Firm Power and Energy
- Analyzing Fuel Conversion and Restricted Fuel Supplies
- Investigating Demand-Side Management Programs
- Projecting Hourly Marginal Energy Costs
- Calculating Avoided Energy Costs and Cogeneration Rates

- Evaluating New Power Supply Technologies

In power system operations, the relative efficiencies (operating costs) of the generating units are used to match generator output with electric demand in the most economical manner. Numerous operating restrictions must be observed: spinning and quick-start reserve requirements, minimum shutdown restrictions, limitations of the transmission network, and deliverability restrictions of fuel suppliers, to mention only a few. These and other operational considerations are explicitly modeled in the PROMOD III program. Its strength lies in the combination of probabilistic production costing techniques with detailed modeling of operating considerations to produce realistic estimates of fuel consumption and operating costs.

Critical user features include:

- *Flexibility* - PROMOD III can simulate more generating unit types, utility system characteristics, and operating modes than any other probabilistic production costing program. The user can model various situations with as little or as much detail as required. Computer run time can be controlled by selectively activating only those modeling capabilities that are required for the study.

- *Ease of Use* - PROMOD III has a simple user interface that allows data to be entered in any order. Input override capability facilitates quick setup of change case runs by selective replacement of base case data with changed values.

- *Convenient Reporting* - PROMOD III produces a generalized data base from which the user can obtain a wide variety of standard printed reports. The PROMOD III system includes post-processors that can transfer model results to corporate and financial models, and help the user build customized reports.

1.2 Basic System Description

Figure 1-1 is a simplified block diagram of the PROMOD III system. Basic inputs, shown on the left side of the diagram, are generally described in Chapter 2, "Utility System Representation", and are described in detail in Chapter I, "Input Data". Briefly, these inputs fall into five categories:

- *Generating Unit Data* - unit types, heat rates, fuel types, capacity states, forced outage rates, seasonal derations, maintenance requirements, minimum downtimes, and penalty factors. Specialized data is required for nuclear, pumped hydro, conventional hydro and combined cycle units.

- *Fuel Data* - cost, availability, and inventory information for various fuels used by the generating units.

- *Load Data* - demand and energy forecasts, chronological load shapes, and levels of interruptible load. Historical load data in EEI load data format can be directly input to define chronological load shapes.

- *Transaction Data* - type, capacity, energy, availability, timing, and costs.

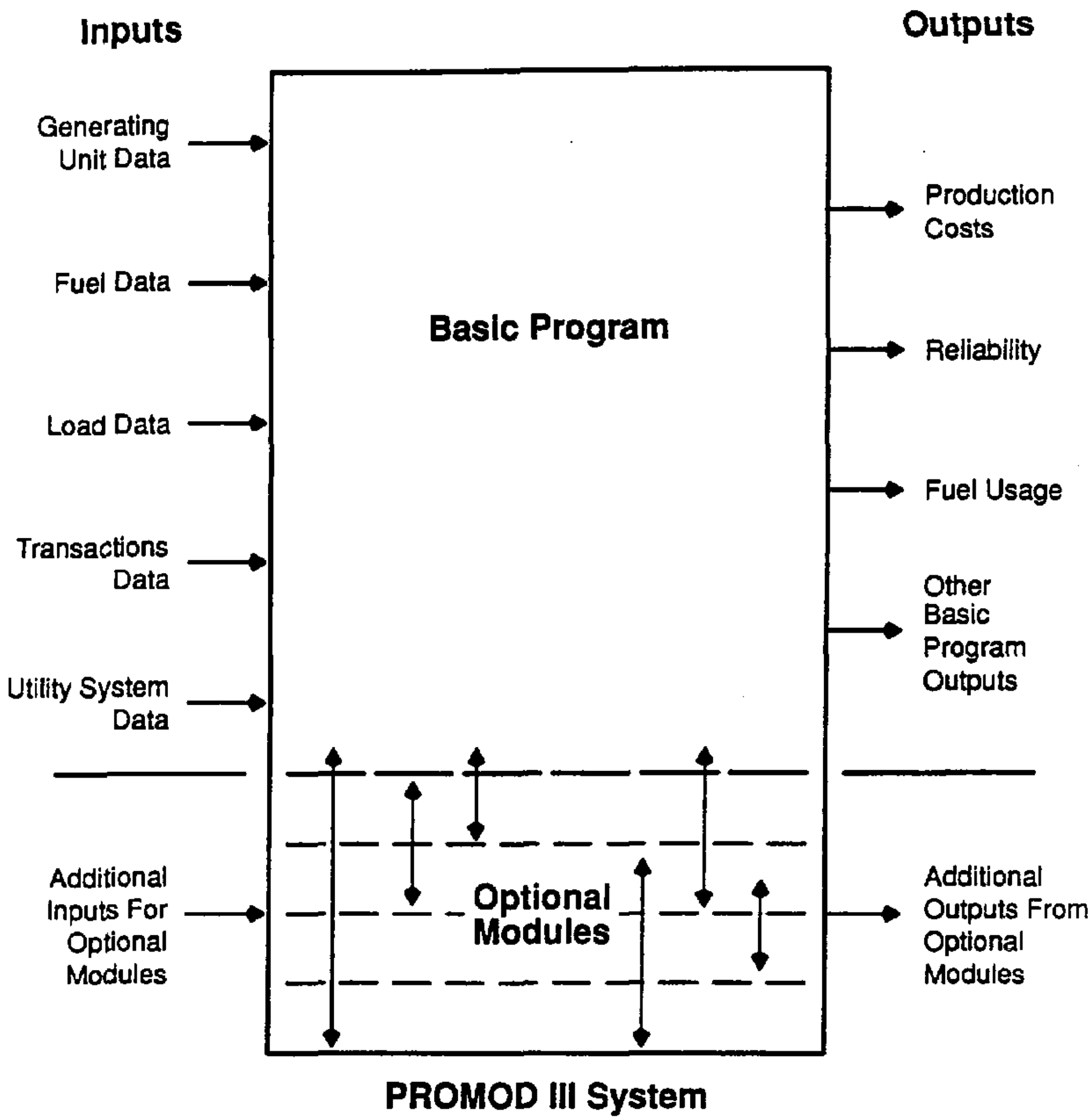


Figure 1-1. PROMOD III Block Diagram

- *Utility System Operating Data* - Operating reserve requirements, target reliability levels, emergency power purchase costs, available tie support, forbidden maintenance periods, and system-wide escalation rates.

Major outputs of the program, shown on the right side of Figure 1-1, are described and illustrated in Chapter O, "Output Reports".

Figure 1-1 shows how the optional modules interface with the basic program and with each other. These modules have been developed to:

- Model the behavior of unconventional generation resources, such as combined cycle units or pumped storage plants.

- Model utility system behavior under different operating modes, such as pooling (multi-area dispatch), emission restricted dispatch, and fuel supplies with limitations.

- Support studies by the rates (Hourly Marginal and Average Energy costs) and marketing (Controllable and End Use Load Management modules) departments.

- Develop customized reports and pass PROMOD III results to other models and databases (EXTRAC and Report Writer).

As shown in Figure 1-1, these optional modules usually require additional input data and provide additional output reports. Optional modules can be installed with the initial delivery of PROMOD III, or they may be added at any later time. The full set of optional modules offered is given below. Modules denoted by an asterisk (*) are described in this manual. Other modules have separate user's manuals.

* Hourly Marginal Energy Costing Module
* Hourly Average Energy Costing Module
* Combined-Cycle Unit Module
* Economy Energy Interchange Module
* Limited Fuel Module
* Nuclear Energy Allocation Module
* Energy Storage Module (pumped storage)
* Hourly Multi-Area Dispatch and Transmission Module (hourly interchange accounting)
* Multi-Company Reporting Module
* Environmental Dispatch & Reporting Module
End-Use Load Management Module
Controllable Load Management Module
Multi-Area Reliability Module
General Output Interface Module

With these capabilities, PROMOD III can be used to address a broad range of applications within the electric utility industry:

- *Production Costing* - This is the principal application of the program.

- *Fuel Budgeting* - Analyses can be performed on the basis of fuel costs, fuel requirements, fuel burns, inventory requirements or inventory values.

- *Reliability Analysis* - The program computes the amount of unsatisfied customer load (unserved energy) and the number of hours during which customer curtailments occur. PROMOD III automatically determines the amount of additional generating capacity needed to achieve a user-specified loss-of-load hours target. If capacity reserve levels exceed this acceptable service standard, then PROMOD III will determine the amount of surplus capacity which could be sold to neighboring systems on a firm basis.

- *Maintenance Evaluation* - Alternate maintenance schedules can be analyzed for their impact on production cost or system reliability.

- *Generation Planning* - Future capacity additions can be evaluated for production cost savings and improved system reliability. All types of generating unit alternatives can be studied, including coal, oil, nuclear, combined cycle, combustion turbines, hydro, and energy storage.

- *Marginal Energy Cost Analysis* - The program can report expected hour-by-hour marginal energy costs and hourly loss-of-load probability, key inputs to rate design studies. Interactive post-processing programs can be used in conjunction with these outputs to drive time-of-day and seasonal rates. This application requires the optional Hourly Marginal Energy Costing Module.

- *Energy Storage Evaluation* - The benefits of production cost savings and improved system reliability from pumped-hydro, compressed air energy storage projects, and battery storage can be determined. Selection of optimum capacity and storage reservoir size, and utilization of multiple projects can be studied. These evaluations require the optional Energy Storage Module.

- *Evaluation of Contract Transactions* - PROMOD III offers a number of modeling options for purchase and sale contracts.

- *Economy Energy Interchange Evaluation* - PROMOD III can be used to evaluate the effects of economy energy interchange, or changes in the opportunities for such interchange, on system operation, production costs and fuel consumption. The optional Economy Energy Interchange Module is required. In this case, an hourly price profile characterizes the neighboring systems' incremental operating costs for each month.

- *Hourly Multi-Area Dispatch* - When a number of utilities are operated as a pool, integrated operations can be analyzed with the PROMOD III Hourly Multiple Area Dispatch and Transmission Module. Centralized pool dispatch and the exchanges of economy energy between areas are modeled recognizing the bulk transmission network limitations. A flexible billing algorithm allows the user to test proposals for allocating the benefits of centralized dispatch simply by changing a few inputs. Using the Hourly Multiple Area Dispatch & Transmission Module, studies can be performed for a utility member company within a pool as well as for the entire pool. In these instances, fuel budgeting, generation planning, marginal energy cost analyses, energy storage economics and outside-system transaction evaluations can all reflect the benefits of pooled operation. Most importantly, the effects of adding transmission capabilities between areas can be studied.

- *Load Management* - PROMOD III can be used to analyze load management proposals at varying levels of detail. Overall daily, weekly, and seasonal load management strategies of various types can be modeled with the basic program. More precise study of modifications to user patterns (such as with hot water heaters or air conditioners) can be performed using the optional End-Use Load Management and Controllable Load Management modules.

- *Fuel Limitations* - The effects of fuel supply limitations and contractual restrictions on system operations and production costs can be analyzed with PROMOD III using the optional Limited Fuel Module. Minimum burn requirements, maximum available supply limits, take-or-pay contract provisions, maximum hourly consumption rates (e.g., gas flow rates), and suspension of coal deliveries can be modeled.

- *Environmental Constraints* - PROMOD III's optional Environmental Dispatch and Reporting Module calculates the release of atmospheric pollutants from fuel burned at utility plants. Restrictions can be imposed on the dispatch under varying environmental constraints allowing the user to analyze the system effects and direct costs which such conditions impose.

1.3 Illustration Of Probabilistic Modeling

At the heart of PROMOD III is a modeling technique which allows the explicit consideration of randomly occurring forced outages, forced derations and postponable maintenance outages of every generating unit and generation resource alternative. The probabilistic modeling technique accounts not only for the effects of a unit's outages and derations on its own operation, but also for the effects of a unit's outage on the operation of all other units in the utility system.

Probabilistic modeling is necessary from several standpoints:

1. Accurate prediction of peaking and mid-range capacity factors requires probabilistic treatment.

2. *Monte Carlo techniques require prohibitive computer run-times to obtain* statistically meaningful results.

3. PROMOD III's probabilistic technique, in effect, dispatches every possible configuration of the generation system, from one unit on outage at a time, two units on outage another time, and so on to the very unlikely but disastrous situation of all units on simultaneous outage. The properly weighted average of all such occurrences represents the best estimate of future operating costs.

4. Results must be repeatable from run to run. The probabilistic technique produces the best projection of the future; accurate forecasts are now possible in reasonable computer run times.

A simple example has been constructed below to provide an introduction to this technique. In this example, there is a single hour's load to be satisfied by two generating units. The value of the load is 150 MW. The generating unit to be considered first on the basis of cost, has a capacity of 80 MW and an 80% probability of being available, while the second unit has a capacity of 100 MW and an availability of 90%.

In Figure 1-2, the loading of the first unit is depicted. The unit may be either available for service (probability 0.8) or unavailable (probability 0.2). In the event the unit is available, it will satisfy 80 MWH of load and leave 70 MWH remaining. In the event the unit is unavailable, it will supply nothing and 150 MWH will remain. The expected generation of unit 1 is therefore 64 MWH, and the expected remaining load is 86 MWH.

In Figure 1-3, the loading of the second generating unit is illustrated. Because of the two possible outcomes from the loading of the first unit, there are now four possibilities for the loading of the second unit. The calculations show that the expected generation of unit 2 is 68.4 MWH and the expected remaining load is 17.6 MWH.

If more units existed, the number of outcomes would continue to expand exponentially. For example, a relatively small system with 32 generating units would have more than 4.2 billion outcomes.

PROMOD III employs a computationally efficient algorithm that produces results identical to those obtained with direct enumeration of all availability states.

The PROMOD III algorithms include much more than a multi-state version of the probabilistic calculation illustrated above. The basic program contains dispatch logic capable of simulating the effect of unit commitment and economic dispatch carried out under detailed utility operating procedures as well as special computations for limited-energy resources including fixed-energy transactions, hydraulic resources and fixed-energy thermal units. The economic dispatch details have been deliberately omitted from the simplified discussion above. Still further complexities in the calculations arise in the extended modeling capabilities of the optional modules.

PROMOD III combines probabilistic modeling with (1) the flexibility to analyze diverse types of generating units and complex purchase and sale arrangements and, (2) the capability to reflect real world utility operating procedures. PROMOD III can quickly supply management with accurate production cost estimates for a wide variety of generation expansion scenarios or operational strategies and soon becomes an indispensable tool for the utility system planner and operational planner. The probabilistic structure, detail and accuracy also make PROMOD III the perfect tool for related applications ranging from supplying cost information for use in rate proceedings to analyzing the benefits of load management programs. PROMOD III enables utility system planners and operators to develop efficiently and accurately the ever-increasing amount of information that is being demanded by management and by regulatory agencies.

Most importantly, the information is developed consistently from analysis to analysis. Users derive additional benefit from the combined experience of the planning staffs of PROMOD III's growing utility base. PROMOD III is continually maintained and enhanced by EMA, making it responsive to new production costing applications and modeling requirements. The continuing evolution of the program and EMA's commitment to keep PROMOD III as the industry standard will extend its useful life indefinitely.

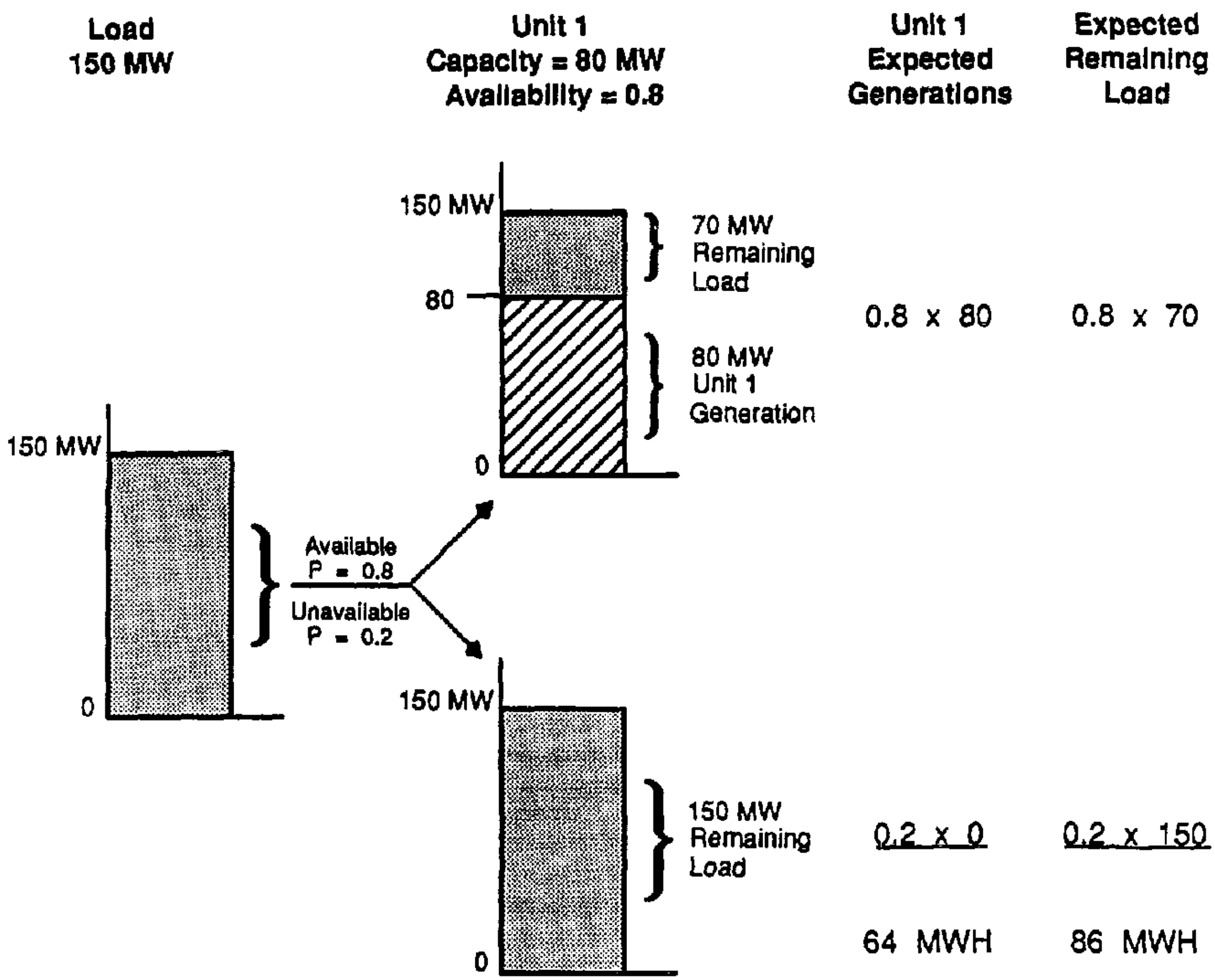


Figure 1-2. Probabilistic View of Loading One Unit

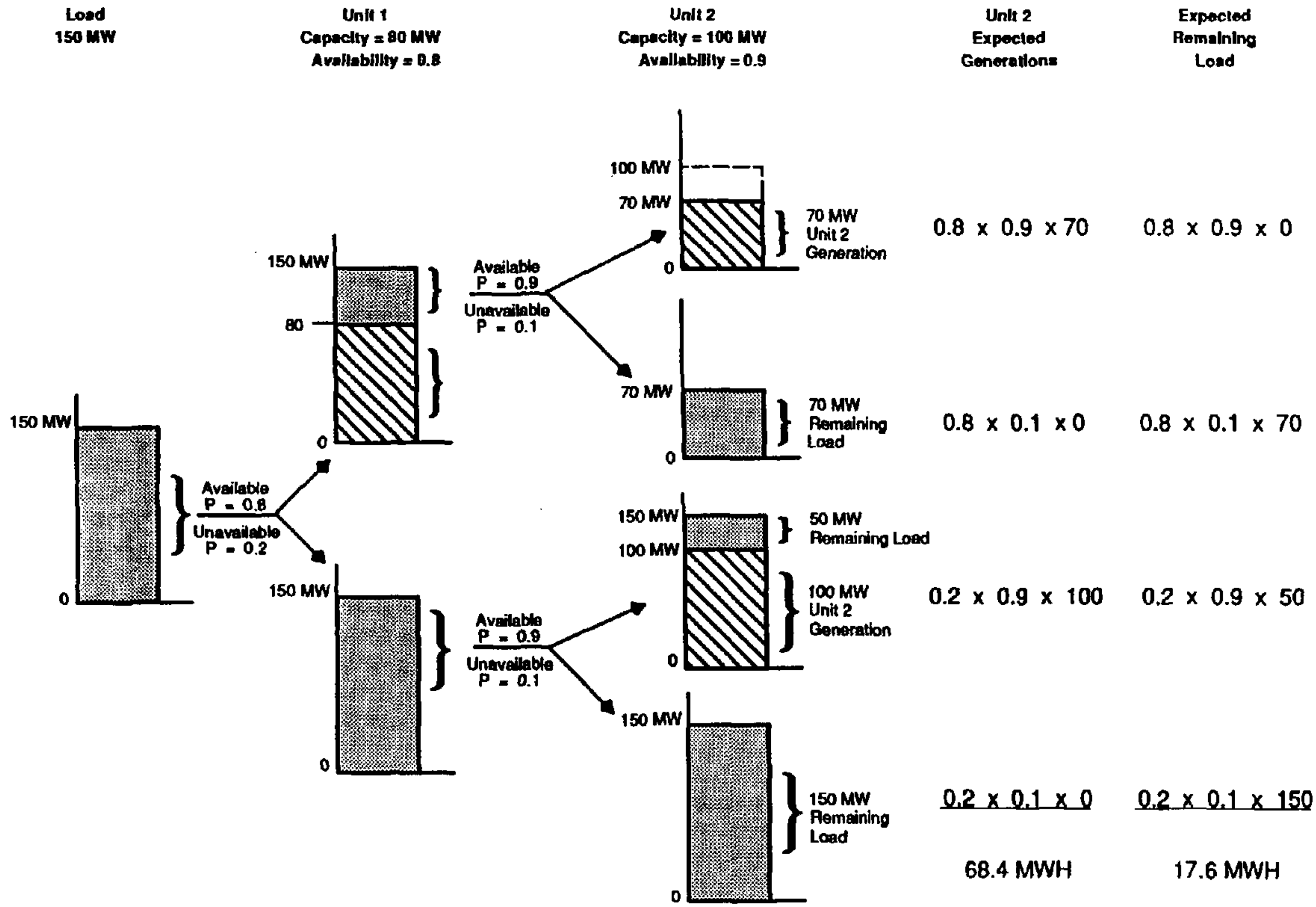
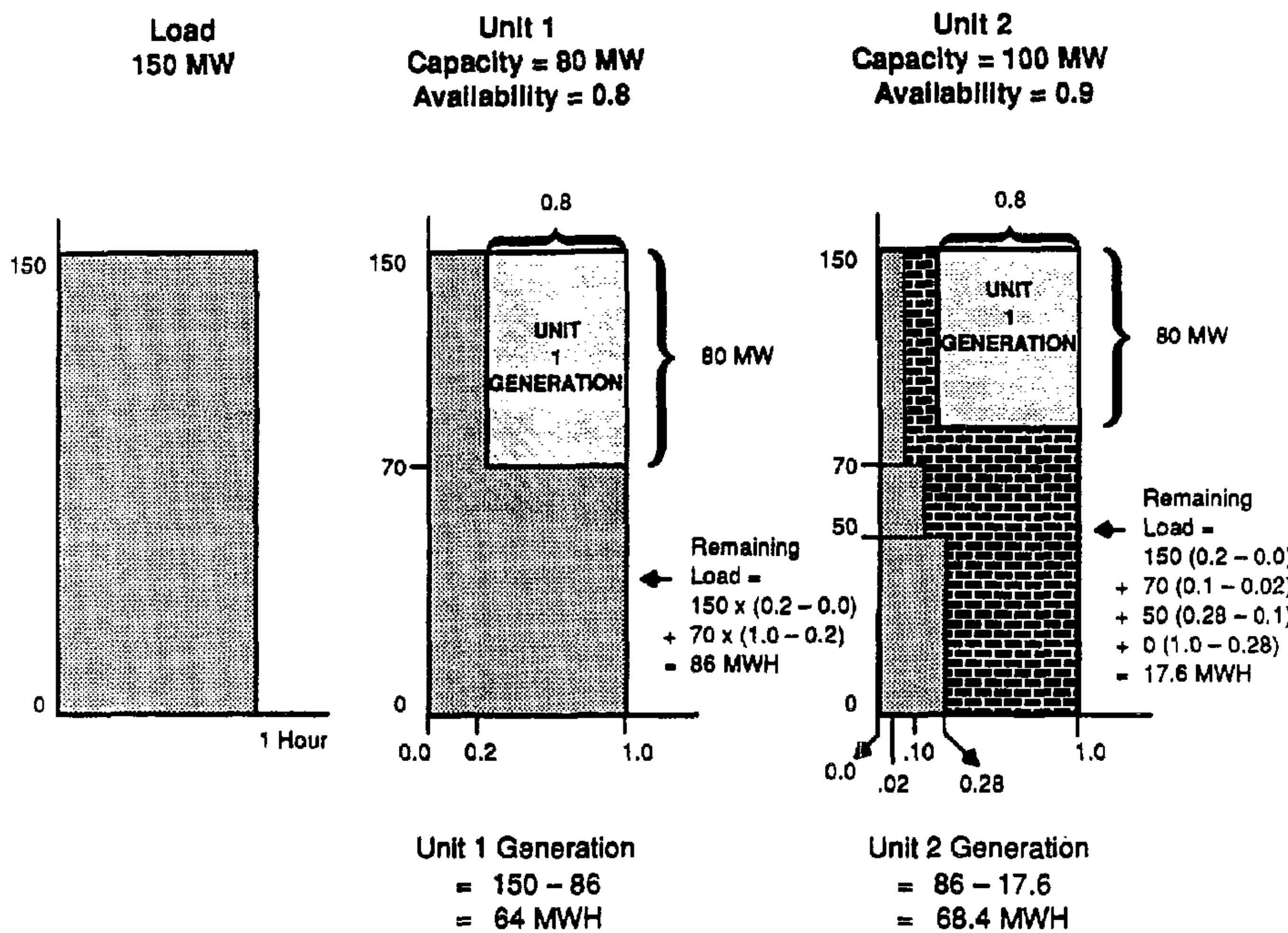


Figure 1–3. Probabilistic View of Loading Two Units



PROMOD III's Method Of Probabilistic Simulation

Duquesne Light Company

Appendix C

DUQUESNE LIGHT COMPANY

Federal Energy Regulatory Commission Filing
Point to Point and Network Transmission
Open Access Tariffs

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Duquesne Light Company) Docket No. ER96-___-000

REQUEST FOR ACCEPTANCE OF
OPEN ACCESS TRANSMISSION TARIFFS

Duquesne Light Company ("Duquesne") hereby submits an original and six copies of a Point-to-Point Transmission Service Tariff ("PTP Tariff") and a Network Transmission Service Tariff ("Network Tariff") that will provide wholesale customers comparable access to Duquesne's transmission system.

I. INTRODUCTION

Duquesne today is submitting a pro-competitive transmission pricing proposal that, if adopted by other utilities, would greatly enhance the efficiency of regional bulk power markets. Duquesne proposal is that each utility charge customers wheeling out or through the utility's system marginal-cost only rates. These customers would take service under a marginal cost "point-to-point" tariff. The only customers bearing an embedded cost rate would be the "native load customers" of each utility. These customers would pay <u>one</u> embedded cost charge for the use of the system under a "network"-style tariff. This contribution to the fixed costs of the system would entitle them to use the utility's system to import network resources and economy energy and to sell power off-system at no additional embedded cost charge.[1] Under Duquesne's approach, these customers also would be permitted use the systems of all other utilities on a marginal cost basis (using <u>their</u> point-to-point tariffs), thereby eliminating rate pancaking between utility systems.

This proposal is necessary to eliminate the inefficient method of rate pancaking that exists today. In today's bulk power market, the general practice is for each utility to charge customers desiring to wheel through its system an allocated share of its fixed transmission investment. This embedded cost rate may, at some times, be discounted to account for the value of the transaction; however, given that the provision of transmission service is, at present, a monopoly service, the

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[1] Duquesne's proposal eliminates the "headroom" issue because, while a network customer would be required to use the point-to-point tariff to make off-system sales, the point-to-point tariff would not include any embedded cost charges. As a result, all generators using the utility's transmission system would compete for power sales on the same basis: their relative marginal costs.

utility will establish a price that maximizes its profits, not societal efficiency. The effect of these pancaked embedded cost rates is to reduce the efficiency of regional bulk power markets.

Duquesne's proposal -- that transmission customers wheeling power out of or across a utility's system pay only marginal usage rates -- is entirely consistent with Commission policy. As the Commission explained in its Transmission Pricing Policy Statement:

> To the extent practicable, transmission rates should be designed to reflect marginal costs, rather than embedded costs . . . . We favor marginal cost prices in order to promote efficient decisionmaking by both transmission owners and users.

Transmission Policy Statement at 21, III FERC Stats. and Regs. ¶ 31,005, at 31,143 (1994).[2]

Duquesne proposes to implement this pro-competitive pricing proposal using the non-rate terms and

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[2] In the short-run, marginal costs include (i) the cost of transmission losses and (ii) the cost of redispatching generation to relieve transmission congestion. The marginal cost of losses varies with the location of generation and load and the marginal cost of generation that supplies the losses. The marginal cost of redispatch varies with the difference in "system lambda," or marginal generating cost, with and without the existence of the constraint. In the long-run, marginal costs include the cost of constructing new facilities necessary to increase the capacity of the transmission grid.

conditions of the Commission's _pro forma_ tariffs, with only a few changes. The most significant change proposed by Duquesne is a requirement that customers serving load within Duquesne's system pay an access fee under the Network Tariff. This change is necessary because, without it, a native load (or network) customer of Duquesne could rely entirely on point-to-point service -- which has no embedded cost charge -- and thereby avoid paying a fair share of _any_ embedded transmission costs. Duquesne's proposal envisions that each native load customer would pay one -- and only one -- access fee.

II. RATES

This section provides a detailed discussion of the proposed rates for service, including the reasons why they satisfy the Commission Transmission Pricing Policy Statement.

A. Overview of Duquesne Rate Proposal

The following is a description of the rate methodology used to price each of the services offered in Duquesne's Network and PTP Tariffs.

1. Network Service

Network service will be priced on the same basis as in the Commission's _pro forma_ network tariff. Under this approach, each network customer pays a monthly demand charge that represents its pro rata share of embedded transmission costs. This pro rata, or "load ratio," share is the ratio of the customer's coincident peak demand to the system coincident peak demand, calculated on a rolling twelve-month basis. The network customer also receives a load ratio share of any system congestion (redispatch) costs, as well as a load ratio share of any revenue credits from the sale of point-to-point service. As to transmission losses, the loss rate is based on an average system loss factor and the customer has the option of supplying the losses itself or purchasing them from Duquesne.

In the future, Duquesne anticipates proposing that the transmission usage rates for network customers be based on marginal costs, as opposed, for example, to average system losses. At the present time, however, Duquesne believes that the principle inefficiency in transmission pricing facing the industry today is the pancaking of embedded cost rates across utility control areas. That is a defect related to point-to-point service, not network service. In Duquesne's view, even with complete transmission pricing reform, all network customers would continue to pay an access, or grid connect, fee based on the embedded costs of the transmission system.

The only change to the Commission's network tariff would be the pricing of losses and congestion costs on a marginal, rather than an average, cost basis. While that level of reform is important, it need not delay pricing reform for point-to-point transmission service, which Duquesne can accomplish today.

2. Point-to-Point Service

Point-to-point customers on Duquesne's system will pay only marginal cost rates. In the short-run, these marginal costs will consist of line losses and congestion costs. In the long-run, marginal costs represent the cost of incremental facilities necessary to remove transmission constraints. The pricing proposal with respect to each is provided below.[3]

a. Marginal Line Losses

The marginal rate of transmission losses varies with (i) the location of the generation and the load being served, and (ii) loadings on the transmission lines at the time of the transfer. Duquesne's proposed method-

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[3] The following discussion applies principally to firm point-to-point service. Under Duquesne's proposal, non-firm customers will be interrupted at the time of system constraint and thus will not be subject to any congestion charges or incremental facilities charges. These customers will be charged only the marginal cost of transmission losses.

ology accounts for both factors on an ex ante basis. To measure locational differences, Duquesne has modeled transfers to and from various points of delivery and receipt on the Duquesne system.[4] To account for the variation in losses at different load periods, Duquesne has modeled these receipt and delivery point sets at four different load periods: summer and winter, on- and off-peak. The results of this modeling have been compiled in a set of "look up tables"[5] that allow the transmission customer to see the marginal line loss factor applicable to its proposed transaction at its proposed delivery and receipt points and load period(s).[6]

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4 If a transaction reduces marginal losses, it will receive a credit.

5 These look up tables include all transactions that are likely to occur in the future. If a customer requests service for a transaction not covered by the tables, Duquesne will compute the applicable loss factor at that time.

6 A necessary component of marginal cost pricing for transmission usage is that the marginal rates must be billed on the basis of actual flows, rather than "scheduled" amounts. Duquesne has developed its transmission usage charges so that customers will be charged only for the transmission losses and congestion costs that are reasonably associated with their transactions, not for the costs that would have been incurred if the full scheduled amounts had flowed over Duquesne's system.

To ensure comparability, Duquesne has used the same modeling techniques for computing marginal line loss factors for its own off-system sales. It has modeled these loss factors for both "slice of system" sales, where the marginal generating unit is deemed to be the point of receipt, and for unit sales. In each case, the look up tables for Duquesne's off-system sales provide Duquesne the same price signals as are provided for point-to-point customers transmitting energy through Duquesne's system.

Duquesne also would note that, under its proposal, the customer has the option of providing the marginal losses itself or purchasing them from Duquesne. If the customer chooses to purchase them from Duquesne, Duquesne will charge the customer its "system lambda" (its marginal generating cost). Duquesne will not assess a separate "demand" charge for losses.[7]

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[7] In a fully competitive market, such as a PoolCo, generators such as Duquesne will be able to recover only the market clearing price for the energy they generate. Over time, this market clearing price will approach the cost of new capacity, thereby encouraging a sufficient amount of new generation supplies to continue to satisfy customer demand. On Duquesne's system, a reasonable proxy for the market clearing price is Duquesne's system lambda. (The system lambda will be either the cost of the last generator run on the system or the cost of purchased

(continued...)

b. Congestion Costs

Marginal congestion costs represent the cost of operating generation out of economic merit order to relieve transmission congestion. Marginal congestion costs are, quite simply, the cost of running generation out of economic merit order. Duquesne will charge point-to-point customers the marginal cost of congestion for any transmission service that imposes flows on a constrained transmission facility.

Duquesne has used a load flow simulation to determine the manner in which various point-to-point transactions contribute to certain known constraints. At present, Duquesne has identified three transmission facilities that may be subject to congestion in the future. Using a load flow simulation, Duquesne has identified the point-to-point transfers that would contribute to these known constraints and in what magnitude.[8] Each transfer is then assigned a "transfer response factor," which represents the portion of the transfer (in percent-

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[7](...continued)
power.) If Duquesne's system lambda ever exceeded the market clearing price, presumably customers would simply elect to supply the losses themselves.

[8] If constraints other than these arise in the future, Duquesne will provide the same information for these constraints in an amended filing.

age terms) that impacts the constrained facility.[9] (There are four TRFs for each delivery and receipt point set, reflecting the differing loadings during winter and summer, on- and off-peak conditions.) These TRFs are then listed in a schedule attached to the point-to-point tariff.

Using these TRFs, Duquesne will compute marginal congestion costs for point-to-point transactions. The marginal congestion cost rate will be the product of (i) the flow on the constrained facility produced by the point-to-point transaction, as determined by the product of the TRF and the amount of energy scheduled, and (ii) the marginal cost of operating generation out of economic merit order.

c. Network Upgrades

Duquesne will charge point-to-point customers for the costs of any network upgrades necessitated by their use of the system. Duquesne will calculate the customer's cost responsibility on the basis of a differential revenue requirement calculation that compares the upgrade costs necessary with, and without, the additional

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[9] For example, a TRF of 10% would mean that a 100 MW transfer would impact the constrained facility by 10 MW.

point-to-point load. Point-to-point customers will have the option of paying the network upgrade charge even if it is lower than an embedded cost charge. This will ensure that point-to-point customers receive both short- and long-run marginal cost price signals. It also will hold Duquesne's native load customers harmless by reimbursing them for any incremental facilities costs they incur because of a point-to-point customer.

3. Ancillary Services

a. Losses

Duquesne's proposal regarding losses was described supra.

b. Reactive Power/Voltage Support

Duquesne is not proposing at this time to "refunctionalize" any embedded generation costs to the transmission revenue requirement to account for the fact that generators provide certain reactive support that benefits wheeling transactions. Duquesne also is not proposing a marginal cost rate to point-to-point customers for the provision of reactive support. Duquesne reserves the right, however, to propose such charges in the future.

c. System Protection/Load Following

The system protection and load following services contained in the pro forma tariffs are two services that are difficult to price on a marginal cost basis. Operating reserves (or "system protection") are purely a capacity product; they represent the cost of keeping generation capacity available should a system emergency occur. The cost of load following service is principally a function of the embedded cost of certain automatic generation control and other equipment designed to match generation and load levels on an instantaneous basis.

In the future, these services will likely be provided at market-determined prices, not "cost-based" rates. However, at present, Duquesne will adopt the Commission's "one mill" adder approach. To ensure that each service is separately priced, Duquesne will charge one-third of one mill per kilowatt-hour for each service. Duquesne reserves the right in the future to provide a more exact costing estimate for each service or to request market-based pricing for such services. The pricing is the same whether the customer is a network or point-to-point customer.

d. Energy Imbalance

Duquesne will use the <u>pro forma</u> tariff schedule for energy imbalance service. Unreturned imbalances will be priced at Duquesne's system lambda (marginal energy cost).

e. Scheduling and Dispatching

Duquesne is not proposing a separate scheduling and dispatching charge at this time.

B. Overview of Marginal Cost Pricing

Duquesne provides below an overview of marginal cost pricing and the benefits of it as applied to transmission service.

1. Marginal Cost Pricing and Rate Pancaking

Establishing an efficient electric market depends, in significant part, on establishing transmission pricing rules that ensure an economic dispatch of all generators, regardless of their location. The pricing rule that accomplishes this goal is marginal cost pricing. As Professor Kahn has written:

> The central policy prescription of microeconomics is the equation of prices and marginal cost. If economic theory is to have any relevance to public utility pricing, that is the point at which the inquiry must begin.
>
> * * *

> [W]hy does economic efficiency require prices equal to marginal, instead of, for example, average total costs? The reason is that the demand for all goods and services is in some degree, at some point, responsive to price. Then, if consumers are to decide intelligently whether to take somewhat <u>more</u> or somewhat <u>less</u> of any particular item, the price they have to pay for it (and the prices of all other goods and services with which they compare it) must reflect the cost of supplying somewhat more or somewhat less -- in short, <u>marginal</u> opportunity cost. If buyers are charged more than marginal cost for a particular commodity, for example because the seller has monopoly power, they will buy less than the optimum quantity; consumers who would willingly have had society allocate to its production the incremental resources required, willingly sacrificing the alternative goods and services that those resources could have produced, will refrain from making those additional purchases because the price to them exaggerates the sacrifices.

Alfred E. Kahn, The Economics of Regulation 65-67 (emphasis in original).

The Commission itself has long encouraged the use of marginal cost pricing. For example, in its notice of inquiry on the regulation or electricity markets, the Commission stated "[w]e are concerned that if prices do not reflect marginal costs, individuals may make purchase decisions that produce benefits that are less than costs. As a result, too few or too many resources may be devoted to electricity production and delivery." <u>Regulation of Electricity Sales-for-Resale and Transmission Service</u>

(Phase II), IV FERC Stats. & Regs. ¶ 35,519, at 35,642 (1985), docket terminated, 61 FERC ¶ 61,371 (1992). More recently, and more pertinent here, the Commission endorsed marginal cost pricing in the context of transmission services, stating:

> To the extent practicable, transmission rates should be designed to reflect marginal costs, rather than embedded costs . . . . We favor marginal cost prices in order to promote efficient decisionmaking by both transmission owners and users.

Transmission Policy Statement at 21, III FERC Stats. and Regs. at 31,143.

A corollary to the proposition that marginal cost pricing is the most efficient method for pricing transmission service is that the pancaking of embedded cost rates across utility systems reduces the efficiency of regional electric markets. Duquesne's proposal reflects the fundamental belief that regional bulk power markets will not realize their maximum efficient state if every utility within a region continues to impose an embedded cost charge for all power transfers across its system. This is not how tight power pools or utility control areas operate today. Rather, power pools and individual control areas dispatch generation on the basis of its relative marginal cost, including the marginal cost of transmission. Yet, for power transfers across power pools or control areas, this efficient mode of marginal cost dispatch is replaced by an inefficient pancaking of embedded cost rates.

Duquesne believes the most direct route to the efficient pricing of transmission service on a regional basis is for each utility to charge point-to-point customers the marginal cost of transmission usage, not embedded costs. Under such a framework, customers wheeling out[10] or through a utility's system would not pay an embedded cost charge. The only customers that would bear an embedded cost rate are the "native load customers" of each utility. These customers would pay one embedded cost charge for the use of that system, not more. This contribution to the fixed costs of the interconnected grid would entitle them to the use of all other systems on a marginal cost basis.

This model is similar to the result that would occur in a regional "PoolCo" or other region-wide, efficient transmission reform proposal. Each customer would

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10 Wheeling out service would, for example, be service provided to a network customer making off-system sales. The network customer would pay an access fee under the network tariff, but no additional embedded cost charges for off-system sales made under the point-to-point tariff.

bear an allocated portion of the pool's or region's fixed transmission costs and, in return, be permitted to use the entire system at marginal cost.[11] The benefits of Duquesne's approach are that it can be implemented on a company-by-company basis today.

C. The Commission's Transmission Pricing Policy Statement

Duquesne's transmission pricing proposal meets each of the tests embodied in the Commission's Transmission Pricing Policy Statement.

1. Conforming versus Nonconforming

A "conforming" proposal is one in which "transmission prices [are] based on the costs of the transmission service being provided." Transmission Pricing Policy Statement, III FERC Stats. and Regs. at 31,141. Duquesne's rates are conforming in every respect. The rate for network service includes a demand charge that allocates to each network customer a portion of Duquesne's embedded cost transmission revenue requirement based on its contribution to monthly system peak demand.

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[11] The only difference is that, under Duquesne's approach, the embedded cost burden of various groups of customers would vary because the per KW transmission rates of each utility vary. Presumably, under a region-wide approach, each customer would pay a single postage stamp rate based on the rolled in cost of all regional transmission facilities.

This revenue requirement is calculated using a traditional cost of service methodology under which embedded costs are calculated on net book values. The charges to network customers for losses and redispatch costs also are conforming. Network customers are charged average line losses and a pro rata share of congestion costs, as per the pro forma network tariff.

The pricing proposal for point-to-point customers also is conforming. Point-to-point customers are charged only marginal costs. This not only is a "conforming" proposal, but is consistent with the Commission's admonition that rates should track marginal costs to the greatest extent practicable. Id. at 31,143. As the Policy Statement recognizes, marginal cost pricing is the most efficient methodology for pricing any service, including transmission service. It sends consumers the correct information regarding the cost of transmitting the next unit of energy, or of avoiding that transfer. Its application to the pricing of transmission will greatly enhance the efficiency of regional electric markets. In the future, Duquesne intends to expand its marginal cost pricing proposal to include network customers, which too would receive marginal price signals associated with transmission losses and congestion costs.

2. Comparability

The Policy Statement indicates that the rule of comparability in transmission pricing has essentially three elements: (i) "costs must be allocated between jurisdictional and nonjurisdictional customers in a consistent way," (ii) "when a utility uses its own transmission system to make off-system sales, it should 'pay' for transmission service at the same price that third-party customers pay for the same service," and (iii) "[a] transmission customer should have pricing certainty comparable to that of the transmitting utility." Id. at 31,142-43. Duquesne's proposal meets each of these criteria.

First, Duquesne is proposing to allocate embedded transmission costs between similarly situated jurisdictional and nonjurisdictional customers in a consistent manner. Both native load and network customers will be charged an embedded cost rate, calculated on the net book value of the transmission system. Duquesne is not proposing, for example, to charge network customers an original cost, "levelized" rate and native load customers a rate based on depreciated book values. In addition, both groups of customers will be allocated embedded costs on a postage-stamp basis.[12]

Second, Duquesne will "go on" its PTP tariff for all its off-system sales. This means that Duquesne will pay the same marginal cost rates in selling its power off-system as any competitor would in purchasing point-to-point service. As discussed above, Duquesne has calculated marginal line loss factors and "transfer response factors" for its off-system sales to ensure that it can be charged marginal line loss and congestion costs on the same basis as other point-to-point customers. In accordance with the pro forma point-to-point tariff, Duquesne will book these marginal costs when it uses the PTP Tariff for off-system sales.

Third, point-to-point transmission customers will have the same relative transmission price certainty, and uncertainty, as Duquesne in competing to sell power over the Duquesne transmission system. Duquesne has adopted a pragmatic model of marginal cost pricing that allows the customer to know, in advance, what the margin-

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[12] Point-to-point customers are not similarly situated with native load and network customers in the sense that they already have paid an access, or embedded cost, charge to their host utility, and thus should not receive an additional embedded cost charge from Duquesne.

al loss factor will be. As to congestion costs, Duquesne has identified the three transmission constraints that may occur in the future, calculated transfer response factors for each likely point-to-point transaction and has indicated in testimony here the historical cost implications of alleviating transmission congestion. See Direct Testimony of Peter A. Wybierala. Duquesne would not object to putting similar information on a Real-Time Information Network ("RIN"), once the rules for RINs are established.

Finally, Duquesne would note that its proposal, if adopted by other utility systems, would achieve comparability on a regional basis. Under Duquesne's proposal, each generator would receive the same marginal cost transmission price signal in competing to make sales in the bulk power market. This would represent a significant improvement over the status quo. Today in Pennsylvania the generating units of four utility systems (Duquesne, GPU's Pennsylvania Electric Company, Pennsylvania Power Company, and APS' West Penn Power Company) operate within 50 miles of one another, but receive vastly different (and inefficient) price signals in attempting to compete in bulk power markets. Duquesne's proposal, if adopted by other companies, would end this inefficient and noncomparable practice.

3. Economic Efficiency

Duquesne's transmission pricing proposal is economically efficient. As indicated, marginal cost pricing is the most efficient manner in which to price transmission service. Duquesne has implemented marginal cost pricing for point-to-point service and intends to do so in the future for network service.

4. Fairness

The Commission's Pricing Policy Statement indicates that the fairness criterion has two central elements: (i) that retail customers should not subsidize wholesale customers and vice versa, and (ii) that any "economic harm that could be created during a period of transition from one pricing approach to another should be mitigated to the extent practicable." Id. at 31,143-44.

Duquesne's proposal satisfies both tests. First, Duquesne's proposal does not require one group of customers to subsidize another group of customers. Rather, Duquesne's native load customers will continue to pay an allocated share of the system's fixed costs when they convert to transmission only (network) service, and thus will not be able to shift costs to the remaining native load customers. In addition, network and native load customers will not be required to subsidize PTP customers, as PTP customers will pay the marginal costs of their transmission usage.

Second, Duquesne's proposal is sensitive to the fact that the transition to transmission pricing reform should not unfairly burden any existing ratepayers group and that it be focused on increasing economic efficiency, not reallocating sunk costs. As indicated, Duquesne's proposal requires native load customers to continue bearing a share of the system's fixed costs when they convert to transmission-only service from their existing bundled supply arrangements.

5. **Practicality**

The Policy Statement indicates that "[t]ransmission pricing should be practical and as easy to administer as appropriate . . . ." Policy Statement at 22. Duquesne agrees. Marginal cost pricing can be implemented in a number of ways, each varying in complexity. As a general matter, the greater the complexity the more likely the method is to send an accurate price signal. There becomes a point, however, at which the burdens associated with increased complexity outweigh the benefits gained. Duquesne has sought to balance these considerations in formulating its proposal, recognizing that Duquesne's transmission system is small and that the number of customers expected in the near term are relatively few.

For example, Duquesne will not measure marginal loss factors on an hour-by-hour basis. Rather, using load flow analyses, Duquesne will, ex ante, establish a representative marginal loss factor for the summer and winter, peak and off-peak periods. Duquesne has used a similar approach to charging marginal congestion costs. Instead of running hourly power flow simulations to determine each customer's contribution to a constraint in each hour, Duquesne has calculated transfer response factors from a representative peak load flow simulation. This, again, will allow customers to know in advance the whether their transaction will be deemed to contribute to a constraint when one arises.

D. Payment for Usage of CAPCO Facilities

Duquesne is a party to a series of agreements with Cleveland Electric Illuminating Co., Toledo Edison Co. and the Ohio Edison System[13] that provide for the joint use, and sharing of the costs of, certain transmis-

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[13] The Ohio Edison System consists of Ohio Edison Co. and Pennsylvania Power Co.

sion and generating facilities located in the service territories of these parties. These agreements are commonly referred to as the "CAPCO" agreements. (CAPCO is an acronym for Central Area Power Coordinating Group.)

The CAPCO agreements are a series of joint use agreements that predate the rule of open, comparable transmission access. In this respect, the agreements are similar to many other joint use/ownership arrangements in existence today. Given the changes in regulatory rules and market conditions, Duquesne believes that utilities have essentially two choices in applying these agreements to third-party requests for service. They can apply the agreements in a manner that has the effect of granting the signatories transmission services that are unavailable to third parties or they can apply the agreements in a manner that permits the signatories to provide comparable access if that is what the extant regulatory rules require. Duquesne prefers the latter interpretation. The former is, at best, a temporary position that is likely to invite a Section 206 complaint from a customer or the Commission.

Duquesne's PTP and Network tariffs therefore offer to third parties any service that is available to Duquesne under the CAPCO agreements. The following is an explanation of the manner in which Duquesne will charge third parties for the services it can provide over the CAPCO facilities.

There are essentially two categories of transactions that arise under the CAPCO agreements that are relevant here. The first category is power transactions between CAPCO parties. For these transactions, the CAPCO parties charge each other only the cost of losses as a transmission charge. Duquesne will thus charge third parties the CAPCO loss rate for any comparable transactions.[14]

An example of such a comparable transaction would be a request that Duquesne wheel power generated by a CAPCO party into Duquesne's system to serve one of Duquesne's network customers. In such an instance, the transmission rate charged will be only the cost of losses and a pro rata share of any congestion costs on Duquesne's system.[15] The converse of this example would

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14 These losses are computed on the same basis as Duquesne's loss charge included in the tariffs filed in this case.

15 Because Duquesne does not have the right to force the other CAPCO parties to "redispatch" their generation to accommodate a transaction, the only relevant congestion costs would be those occurring on Duquesne's system.

be a generator located within Duquesne's service territory requesting that its power be wheeled to one of the other CAPCO parties. (This is analogous to Duquesne selling power to one of the other CAPCO members.) This transaction also would bear only the cost of losses and congestion costs on Duquesne's system.[15]

The second category of transaction is imports or exports of power that use the non-CAPCO interconnection facilities of a CAPCO party other than Duquesne. For these transactions, the CAPCO party providing the transmission service over a non-CAPCO interconnection would charge an embedded cost transmission rate plus the cost of losses. To ensure comparability, Duquesne will charge third parties this embedded cost rate as a pass-through to the transmission customer. As an example, if the Allegheny Power System desired to purchase power from a Michigan utility interconnected with Toledo Edison and have it delivered to the Duquesne-APS interface, Duquesne would charge APS Duquesne's out-of-pocket costs, which is equal to the embedded cost transmission rate levied by

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[15] The difference between the two above hypotheticals is that the network customer would receive an average system loss factor, while the point-to-point customer would receive a marginal loss factor.

Toledo Edison plus the cost of losses and any congestion costs being incurred on Duquesne's system.

In sum, in each instance, Duquesne will charge third parties (i) the marginal cost of transmission losses and any congestion costs that are incurred on Duquesne's system, plus (ii) the out-of-pocket costs, if any, it is assessed by any other CAPCO party for the transaction.

III. NON-RATE TERMS AND CONDITIONS OF SERVICE

The non-rate terms and conditions of point-to-point and network service closely follow those contained in the Commission's pro forma tariffs. Duquesne believes that, at the present time, little would be gained by redrafting these tariffs in an effort to improve upon them.[17] Duquesne reserves the right, however, to file appropriate changes to the tariffs in the future, including those necessary to accommodate changes in regional electric markets and/or a move toward customer choice at the retail level.

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17 Duquesne has not drafted language for certain appendices to the two tariffs on the belief that the Commission may provide such language in a Final Rule. If this is not the case, Duquesne will add the necessary appendices whenever the Commission deems it appropriate to do so.

In the interim, Duquesne has sought to change the _pro forma_ tariffs only as necessary to adopt its marginal cost pricing proposal. The material changes in this regard are described below.

A. Availability of PTP Service

The most noteworthy change to the non-rate terms and conditions of the _pro forma_ tariffs is a requirement that all native load customers of Duquesne that convert to transmission-only service pay an access fee under the Network Tariff. This access fee will allocate to them a pro rata share of Duquesne's embedded transmission costs. This restriction is necessary so that these customers do not take point-to-point service only, and thereby pay only marginal cost rates.

Under Duquesne's PTP Tariff, a point-to-point customer is required to pay for the cost of transmission losses and congestion charges only, _not_ an embedded cost rate. This is a decidedly _pro_competitive proposal. This proposal will not work, however, if a native load customer of Duquesne could switch to point-to-point service (either from its existing bundled service or network service) and thereby avoid paying an allocated share of the transmission system's embedded costs. Clearly, each transmission customer should pay at least one embedded cost charge as a contribution to the fixed costs of the regional network. Duquesne believes each customer should pay only _one_ such charge.

In the future, this single charge may be a region-wide, embedded cost rate. At present, however, the only way to ensure fairness and prevent cost-shifting is for each utility to charge its native load customers an embedded cost rate. Duquesne has thus required its native load customers to take service under the network tariff. (Duquesne is retaining, however, the requirement in the _pro forma_ network tariff that all network customers use the PTP tariff for their off-system sales. This will ensure that their off-system sales compete on the same basis as Duquesne's sales, which also will use the PTP tariff.)

This is a critical aspect of Duquesne's proposal. The transition to competition cannot be accomplished smoothly if one group of customers can shift costs to other customers. To be sure, Duquesne's proposal differs somewhat from the _pro forma_ tariffs. Duquesne does not, however, believe the proposal is inconsistent with the cost allocation principles embodied in the _pro forma_ tariffs. Under the _pro forma_ tariffs, a native load customer has the option of taking either network or point-to-point service. However, regardless of which service it takes, the customer will be charged an allocated share of the transmission provider's embedded costs. The only difference in the pricing of point-to-point and network service is the method by which such embedded costs are allocated (1 CP versus 12 CP).

Duquesne is asking no more or less of its native load customers in this case. Duquesne is simply asking them to continue bearing a fair share of the embedded costs of the system. Duquesne does not believe that this proposal is in any way prejudicial to native load customers seeking transmission-only service. The Network Tariff is the most flexible service available and it allocates embedded transmission costs to network customers in a manner that is comparable to the way in which costs are allocated to native load customers.[19]

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[19] If a native load customer sought to switch power suppliers for only part of its requirements (i.e., become a partial requirements customer), Duquesne would unbundle the remaining portion of its sales to this customer and treat them as "network resources" under the Network Tariff. The customer's "access fee" thus would be based entirely on the network tariff, not a combination of transmission-only and bundled sales service charges.

B. Limitation on Reserved Amounts of Firm PTP Service

It is possible that the marginal cost pricing of point-to-point service will prompt some customers to "game" the system by reserving scarce transmission capacity with an intent to resell it at a mark up. This could occur given that point-to-point customers are only charged for their actual usage, and thus bear no penalty for failing to schedule up to reserved amounts. In theory, a customer could reserve the entire capacity of an interface and then seek to resell it to other customers at a rate that exceeds marginal costs. This would obviously reduce economic efficiency and be unfair to other customers.[19]

As a remedy, Duquesne has used the same principle that exists in the pro forma network tariff. There, network customers are entitled to reserve service from network resources only to the extent they have an executed contract for the delivery of the power or can show

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[19] Such a speculative reservation likely would affect only firm transactions. This is because, even if a customer sought to reserve the entire firm capacity of an interface, Duquesne could still offer non-firm service to the extent the firm customer was not using its full reservation. This would allow the economy market to function efficiently, despite the speculative reservation of firm capacity.

that execution of such a contract is contingent upon securing transmission service.[20] Duquesne has added a similar clause to its PTP Tariff, which would be applied only in times of transmission congestion. Duquesne is hopeful, however, that it will not have to use this provision at all -- i.e., that customers will reserve only the service that is needed for their own transactions.

IV. OTHER MATTERS

A. Reciprocity

Duquesne recognizes that, at present, it is the only utility in the region offering access to its transmission system at marginal cost rates. Thus, at present, Duquesne will be offering third parties access to its system at prices that are not available to Duquesne when it, in turn, seeks to deliver power over the transmission systems of other utilities in the region. To remedy this, Duquesne has carefully considered the option of offering a marginal cost rate only to those systems that would, on a reciprocal basis, offer the same rate to Duquesne.

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[20] Duquesne has extended this requirement to all firm network uses, given that Duquesne has provided network customers the ability to import non-network resources on a firm basis.

There is much to be said for such a reciprocity requirement, including the incentive it may have on inducing other utilities to adopt more efficient pricing methodologies for their own transmission systems. There also are drawbacks to reciprocity provisions, including the difficulty of applying them when power marketers are the nominal transmission customer. After balancing a number of factors, Duquesne has decided not to impose a reciprocity requirement at this time. Duquesne is hopeful that its proposal will encourage other utilities to file similar proposals. Duquesne reserves the right, however, to add a reciprocity requirement in the future should it become necessary or appropriate.

B. "Sham" Transactions

Duquesne's PTP rate will be the lowest point-to-point rate in the region. Duquesne recognizes that this poses the potential for a "gaming" of the system. It is possible that a transmission customer may take advantage of the marginal cost rates offered by Duquesne and "schedule" its transaction over Duquesne's transmission system despite the fact that other systems carry the predominant flow of power resulting from the transaction. Indeed, because of the configuration and location of Duquesne's transmission system, it may not carry more than 50% of the flows from certain transactions scheduled across its system. It is important to remember, however, that this is not a phenomenon produced by Duquesne's tariff filing; it is one that exists today and would exist no matter what transmission pricing methodology Duquesne were to adopt.

The only manner in which such potential gaming can be addressed is for Duquesne to use prevailing North American Electric Reliability Council ("NERC") and East Central Area Reliability Council ("ECAR") criteria in determining whether it can schedule a particular transaction. While these rules today are quite general, and indeed do not specifically address what many utilities call "sham" contract path transactions, there is no other accepted regional or national standard available to Duquesne. Accordingly, Duquesne will apply the NERC and ECAR guides in scheduling its transaction. Duquesne does not believe that this requires any changes to the pro forma tariffs.

V. PROCEDURES

Duquesne has supported its pricing proposal with a detailed explanation here of the reasons why it conforms to all the Commission's rules. Duquesne also has supplied a case-in-chief, consisting of the testimony of four witnesses, that will provide a basis upon which to build the appropriate evidentiary record in this case. Duquesne trusts that this information is more than sufficient to avoid a "deficiency" letter requesting further data or testimony. Duquesne is hopeful that this case can proceed on a somewhat expedited basis, so that the pricing rules governing the transition to a more competitive market do not lag behind the creation of such a market. Duquesne will use its good faith efforts to expedite this case as much as possible, and is hopeful that the Commission, its staff and the assigned administrative law judge can do so as well.

VI. PART 35 REQUIREMENTS

A. Waiver of Full Filing Requirements

In the AEP guidance order dated June 28, 1995, the Commission held that, for any public utility that does not have open access tariffs on file and that chooses to file such tariffs before the Final Rule issues, the Commission will waive the full filing requirements of 18 C.F.R. § 35.13. American Electric Power Serv. Corp., 71 FERC ¶ 61,393, at 62,543 (1995). Given that Duquesne does not have transmission tariffs on file, it qualifies for such a waiver and the waiver is hereby requested.

B. **Other Information Required by Part 35**

1. **List of Documents Submitted**

The following documents are being submitted with this application:

- a form of Federal Register notice;
- the direct testimony of Mark Freise, which provides an overview of Duquesne's transmission proposal;
- the direct testimony of James Lahtinen, which discusses the marginal cost rates proposed by Duquesne;
- the direct testimony of Peter Wybierala, which discusses the manner in which marginal costs will be calculated;
- the direct testimony of James Cater, which provides the embedded cost revenue requirement;
- the proposed point-to-point and network transmission tariffs; and
- a shaded version of the point-to-point and network tariffs that indicate any changes from the Commission's pro forma tariffs.

2. **Proposed Effective Date**

Duquesne requests that the tariffs take effect in sixty days.

3. **Persons to Whom the Filing Has Been Mailed**

This filing has been mailed to the Pennsylvania Public Utility Commission and the other CAPCO parties.

4. **Brief Description of Rate Filing**

The proposed transmission rates, terms and conditions are described in this application and the attached direct testimony.

a. **Reasons for the Filing**

The filing of the tariff is necessary to ensure that comparable transmission service will be available on Duquesne's system and that the rates for such service are economically efficient.

b. **Showing of Requisite Agreements**

No agreements were necessary to file the tariffs.

c. **Costs Adjudged Illegal, Duplicative or Unnecessary**

None of the costs reflected in the tariffs have been adjudged illegal, duplicative or unnecessary costs that are demonstrably the product of discriminatory employment practices.

d. **Information Regarding the Effect of the Rate Change**

(1) These rates do not constitute a rate change for any customer.

(2) No additional facilities are planned to be constructed pursuant to the tariffs at this time and thus no map or single line diagram is attached.

C. Official Service List

Please direct any correspondence or communications regarding this filing to the undersigned and place them on the official service list in this proceeding.

Duquesne appreciates your assistance in this matter.

Respectfully submitted,

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April 15, 1996

* Persons to whom correspondence should be directed.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Duquesne Light Company) Docket No. EC96-___-000

NOTICE OF FILING

Take notice that on April 15, 1996, Duquesne Light Company filed a Network Integration Service Tariff and Point-to-Point Transmission Service Tariff.

Copies of the filing were served on the Pennsylvania Public Utility Commission.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with Federal Energy Regulatory Commission, 888 First Street, N.E. Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 285.211 and 18 CFR 385.214). All such motions or protests should be filed on or before _________. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Lois D. Cashell
Secretary