Economic Parameter Inputs
Sensitivity Case No. 1 - $250M Capital Costs

	Input Assumptions
Case Number Selection:	19
Technology	Wet FGD Units 1 & 2, 455 MW
Tax Depreciation	IRS Pub 535
Fuel Type	HS Coal - N Appl
Basis for Fixed Charges (NHPUC, Regulated, or Deregulated)	NHPUC
Evaluation Period (years)	20
Book Life - Regulated (years)	10
Loan Period - Deregulated (years)	20
Equity Recovery Period - Deregulated (years)	20
Base Year for Expressing Costs	2005
Commercial Operating Date	2013
Escalation Rates	
Capital Costs (%/year)	2.50%
O&M Costs (%/year)	2.50%
Purchased Power Costs (%/ye	2.50%
Load (%/year)	0.00%
Property Taxes (%/year) *	5.00%
Federal Income Tax Rate	35.000%
State Income Tax Rate	8.500%
Property Tax Rate	2.370%
Insurance Rate	0.050%
Tax Rate for Deferred Taxes	37.275%
Common Equity Fraction	0.45
Preferred Equity Fraction	0.00
Debt Fraction	0.55
Return on Common Equity	9.62%
Return on Preferred Equity	6.00%
Return on Debt	6.00%
Investment Tax Credit Rate	0.00%

* Property Taxes are applied to market value

Effective tax rate, %	40.53%
After tax cost of money	6.29%
Weighted Annuity Factor	8.93%
Total Capital Requirement	250,022,657
Total Plant Cost (base year $'s)	250,022,657
Base Year TPL, Total	250,022,657
Escalation, Constr. Total	-
Escalated TPL, Total	250,022,657
Other Outlays, Total	-
Gross Outlays, Total	250,022,657
Inv. Tax Credits, Total	-
Net Outlays, Total	250,022,657
AFUDC, Equity, Total	-
AFUDC, Preferred, Total	-
Total Investment	250,022,657
Gross Depreciable Investment	250,022,657
Non-Depreciable Investment	-
Net Investment	250,022,657
Fixed Charge Rate Parameters	
Investment Book Depreciation	25,002,266
ITC Normalized	-
Preferred AFUDC Recovery	-
Equity AFUDC Recovery	-
Debt Book Depreciation	13,751,246
Preferred Book Depreciation	-
Equity Book Depreciation	11,251,020

Table B-19: Annual Revenue Requirements - Case 19

Wet FGD Units 1 & 2, 455 MW
HS Coal - N Appl
Sensitivity Case No. 1 - $250M Capital Costs

Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Operating Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Annual Factors and Prices:																				
Input Assumptions																				
Tax Depreciation																				
20-yr MACRS	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%
15-yr MACRS	5.000%	9.500%	8.550%	7.700%	6.930%	6.230%	5.900%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	2.950%	0.000%	0.000%	0.000%	0.000%
IRS Pub 535	12.750%	13.444%	13.335%	13.235%	13.143%	1.057%	0.978%	0.904%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%
5-yr SL	20.000%	20.000%	20.000%	20.000%	20.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Fuel Prices ($/mmBtu)																				
HS Coal - N Appl	2.4660	2.4993	2.5321	2.5667	2.6022	2.6394	2.6792	2.7194	2.7554	2.7916	2.8256	2.8597	2.8937	2.9247	2.9559	2.9864	3.0197	3.0543	3.1306	3.2089
Natural Gas	8.2791	8.7676	9.1831	9.3393	9.6110	10.1541	10.7887	11.3281	11.8594	12.3041	12.6523	13.1812	13.7414	14.0849	14.4371	14.7980	15.1679	15.5471	15.9358	16.3342
Natural Gas - B&M	6.9800	7.2800	7.6600	7.8600	8.0300	8.1000	8.1900	8.5600	9.0100	9.1400	9.3200	9.4900	9.6600	9.8500	10.0500	10.2500	10.4600	10.6700	10.8800	11.0976
HS Coal - N Appl - B&M	2.2027	2.2468	2.2917	2.3375	2.3843	2.4320	2.4806	2.5302	2.5808	2.6325	2.6851	2.7388	2.7936	2.8495	2.9064	2.9646	3.0239	3.0843	3.1460	3.2089
HS Unit 2, LS (1/3) Unit 1	2.5354	2.5699	2.6038	2.6408	2.6795	2.7197	2.7626	2.8059	2.8453	2.8851	2.9227	2.9605	2.9983	3.0331	3.0683	3.1029	3.1404	3.1793	3.2588	3.3402
Low Sulfur Blend (1/2)	3.3222	3.4053	3.4904	3.5777	3.6671	3.7588	3.8527	3.9491	4.0478	4.1490	4.2527	4.3590	4.4680	4.5797	4.6942	4.8115	4.9318	5.0551	5.1815	5.3110
Low Sulfur Blend (1/3)	2.7293	2.7668	2.8041	2.8476	2.8951	2.9441	2.9956	3.0474	3.0964	3.1461	3.1938	3.2419	3.2900	3.3358	3.3820	3.4280	3.4773	3.5283	3.6165	3.7069
Allowance Prices																				
SO_2 ($/ton) 1,277.63	1,354.28	1,435.54	1,521.67	1,612.97	1,709.75	1,812.34	1,921.08	2,036.34	2,158.52	2,288.03	2,345.24	2,403.87	2,463.96	2,525.56	2,588.70	2,653.42	2,719.75	2,787.75	2,857.44	2,928.88
NOx ($/ton) 1,300.00	1,836.87	1,882.79	1,929.86	1,978.10	2,027.56	2,557.84	2,621.79	2,687.33	2,754.51	2,823.38	2,893.96	2,966.31	3,040.47	3,116.48	3,194.39	3,274.25	3,356.11	3,440.01	3,526.01	3,614.16
Allowance Allocations (tons)																				
SO_2	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946
NOx	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973
Calculated Values																				
Tax Depreciation - Selected	12.750%	13.444%	13.335%	13.235%	13.143%	1.057%	0.978%	0.904%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%
Adjusted for Evaluation Period	12.750%	13.444%	13.335%	13.235%	13.143%	1.057%	0.978%	0.904%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	1.338%
Fixed Charge Rate	23.87%	23.10%	22.04%	21.10%	20.20%	19.51%	19.05%	18.60%	18.16%	17.74%	7.66%	7.93%	8.21%	8.51%	8.82%	9.15%	9.50%	9.87%	10.26%	10.66%
O&M Escalation Factor	1.2489	1.2801	1.3121	1.3449	1.3785	1.4130	1.4483	1.4845	1.5216	1.5597	1.5987	1.6386	1.6796	1.7216	1.7646	1.8087	1.8539	1.9003	1.9478	1.9965
Purchased Power Escalation Factor	1.2489	1.2801	1.3121	1.3449	1.3785	1.4130	1.4483	1.4845	1.5216	1.5597	1.5987	1.6386	1.6796	1.7216	1.7646	1.8087	1.8539	1.9003	1.9478	1.9965
Capacity Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
Annual Generation (MWh)	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640	3,188,640
Purchased Power - Incremental ($/MWh)	46.21	47.36	48.55	49.76	51.00	52.28	53.59	54.93	56.30	57.71	59.15	60.63	62.14	63.70	65.29	66.92	68.60	70.31	72.07	73.87
Fuel Price - Selected ($/mmBtu)	2.4660	2.4993	2.5321	2.5667	2.6022	2.6394	2.6792	2.7194	2.7554	2.7916	2.8256	2.8597	2.8937	2.9247	2.9559	2.9864	3.0197	3.0543	3.1306	3.2089
Fuel Consumption (mmBtu/year)	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169	32,288,169
SO_2 Emissions (tons/year):																				
29,736 ### 29,736 22,302	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549
3-year rolling average (tons/year)	27,258	17,862	8,467	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549
	25,709	16,313	6,918	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO_2 Incentive Allowances Earned (tons/ye	0	20,000	16,313	6,918	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx Emissions (tons/year)	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324	2,324
Present Value Factor	0.9408	0.8851	0.8327	0.7834	0.7371	0.6934	0.6524	0.6138	0.5774	0.5433	0.5111	0.4808	0.4524	0.4256	0.4004	0.3767	0.3544	0.3334	0.3137	0.2951
Evaluation Period Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Annual Revenue Requirements:																				
Incremental Revenue Requirements																				
Fixed Charges NHPUC Basis	59,679,947	57,745,899	55,095,718	52,759,873	50,506,987	48,791,753	47,630,648	46,505,306	45,413,426	44,352,862	19,153,540	19,821,715	20,526,644	21,269,476	22,052,180	22,877,283	23,747,475	24,665,382	25,641,650	26,656,876
Fixed O&M	20,074,723	20,576,591	21,091,006	21,618,281	22,158,738	22,712,706	23,280,524	23,862,537	24,459,101	25,070,578	25,697,343	26,339,776	26,998,271	27,673,227	28,365,058	29,074,184	29,801,039	30,546,065	31,309,717	32,092,460
Variable O&M	15,910,639	16,308,405	16,716,115	17,134,018	17,562,369	18,001,428	18,451,463	18,912,750	19,385,569	19,870,208	20,366,963	20,876,137	21,398,041	21,932,992	22,481,317	23,043,349	23,619,433	24,209,919	24,815,167	25,435,546
Fuel	79,622,726	80,698,122	81,756,272	82,872,659	84,021,275	85,220,596	86,505,572	87,805,288	88,966,056	90,135,073	91,232,693	92,334,181	93,433,580	94,434,153	95,439,890	96,424,391	97,500,741	98,616,955	101,082,379	103,609,438
SO_2 Allowance Costs	2,097,786	2,223,654	2,357,073	2,498,497	2,648,407	2,807,311	2,975,750	3,154,295	3,343,553	3,544,166	3,632,770	3,723,589	3,816,679	3,912,096	4,009,898	4,110,146	4,212,900	4,318,222	4,426,178	4,536,832
SO_2 Allowance Credits	-5,344,006	-34,375,473	-30,828,097	-17,522,815	-6,746,684	-7,151,485	-7,580,574	-8,035,409	-8,517,533	-9,028,585	-9,254,300	-9,485,657	-9,722,799	-9,965,869	-10,215,016	-10,470,391	-10,732,151	-11,000,455	-11,275,466	-11,557,353
NOx Allowance Costs	4,268,877	4,375,598	4,484,988	4,597,113	4,712,041	5,944,421	6,093,031	6,245,357	6,401,491	6,561,528	6,725,567	6,893,706	7,066,048	7,242,700	7,423,767	7,609,361	7,799,595	7,994,585	8,194,450	8,399,311
NOx Allowance Credits	-3,624,137	-3,714,740	-3,807,608	-3,902,799	-4,000,369	-5,046,619	-5,172,784	-5,302,104	-5,434,657	-5,570,523	-5,709,786	-5,852,531	-5,998,844	-6,148,815	-6,302,535	-6,460,099	-6,621,601	-6,787,141	-6,956,820	-7,130,740
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenue Requirements	172,686,556	143,838,057	146,865,466	160,054,828	170,862,763	171,280,111	172,183,630	173,148,020	174,017,006	174,935,307	151,844,789	154,650,916	157,517,620	160,349,960	163,254,559	166,208,225	169,327,431	172,563,533	177,237,254	182,042,370
Busbar Electricity Price ($/MWh)	54.16	45.11	46.06	50.20	53.58	53.72	54.00	54.30	54.57	54.86	47.62	48.50	49.40	50.29	51.20	52.13	53.10	54.12	55.58	57.09
Levelized ($/MWh) 51.58																				
Present Value (PVRR)	162,464,799	127,313,748	122,298,727	125,392,562	125,936,370	118,771,278	112,330,348	106,273,143	100,484,351	95,035,303	77,608,293	74,363,785	71,258,861	68,246,336	65,369,709	62,612,998	60,012,270	57,539,026	55,599,290	53,726,366
Cumulative PVRR	162,464,799	289,778,547	412,077,274	537,469,836	663,406,206	782,177,484	894,507,832	1,000,780,974	1,101,265,325	1,196,300,628	1,273,908,921	1,348,272,706	1,419,531,567	1,487,777,904	1,553,147,613	1,615,760,611	1,675,772,881	1,733,311,907	1,788,911,197	1,842,637,562
Net Present Value = 1,842,637,562																				
Levelized ($/year) 164,474,227																				
Incremental PSNH Net Income	10,532,587	9,558,229	8,281,670	7,124,141	5,990,477	5,066,244	4,357,654	3,652,027	2,947,839	2,243,596	1,879,205	1,854,695	1,830,329	1,805,832	1,781,227	1,756,728	1,732,573	1,708,930	1,689,207	1,664,465

* Existing revenue requirements are already built into the "incremental" values.

Technology Base Year Cost and Performance Inputs
Sensitivity Case No. 1 - $250M Capital Costs

	Wet FGD Units 1 & 2, 455 MW
	19
Input Assumptions	
Net Plant Capacity (MW)	455
Capacity Factor (at In-Service Date)	80.00%
Equivalent Availability Factor	80.00%
Net Plant Heat Rate (Btu/kWh)	10,126
Qualifies for "Bonus" Allowances?	Yes: 3-Year Average
Eligible for SO_2 Incentive Allowances?	Yes
SO_2 Allowances	3,946
Bonus SO_2 Allowances to Retain	0
Total SO_2 Allowances	3,946
NOx Allowances	1,973
Bonus NOx Allowances to Retain	0
Total NOx Allowances	1,973
Construction Duration (months)	42.0
Tie-In Outage Duration (months)	2.0
Amount in Excess of Normal Outage (mo	0.5
Base Year	2005
In-Service Year	2013
Capital Investment Costs	
Direct Costs	174,230,000
Owner's Costs *	10,453,800
Interest During Construction	12,121,018
Outage Replacement Power	4,915,820
Working Capital and Inventories	3,484,600
Total Base-Year Value	205,205,238
Value at In-Service Date	250,022,657
$/kW	550
Fixed O&M ($/year)	
Labor	
Materials and Supplies	
Administrative and General	
Fixed O&M	13,824,400
Major Maintenance	2,250,000
Other	
Total Base-Year Value	16,074,400
$/kW-year	35.33
Variable O&M ($/year at given capacity factor)	
Variable O&M	12,740,100
Major Maintenance	0
Other	0
Total Base-Year Value	12,740,100
$/MWh	4.00
Total Fixed and Variable O&M ($/year)	28,814,500
$/MWh	9.04
Purchased Power Cost ($/MWh) - incremental	37.00
Total Purchased Power ($/MWh)	62.00
Calculated Values	
Fuel Consumption (mmBtu/year)	32,288,169
SO_2 Emissions (tons/year)	1,549
NOx Emissions (tons/year)	2,324

* Owners development costs, oversight, legal fees, financing fees, startup & testing, and training.

Fixed Charges - NHPUC Basis (Average Rate Base)

Wet FGD Units 1 & 2, 455 MW
HS Coal - N Appl
Sensitivity Case No. 1 - $250M Capital Costs

Calendar Year			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Operating Year			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Book Life																										
Parameter			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Evaluation Period Factor			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00	0.00
Tax Depreciation			12.750%	13.444%	13.335%	13.235%	13.143%	1.057%	0.978%	0.904%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	0.892%	1.338%	0.000%	0.000%	0.000%	0.000%
Deferred Income																										
Tax			2,562,888	3,209,482	3,108,458	3,015,262	2,928,776	-8,334,513	-8,408,511	-8,476,730	-8,487,914	-8,488,100	831,681	831,494	831,681	831,494	831,681	831,494	831,681	831,494	831,681	1,247,335	0	0	0	0
O&M (all non-capitalized expenses			113,006,609	86,092,158	91,769,749	107,294,955	120,355,777	122,488,358	124,552,982	126,642,715	128,603,579	130,582,445	132,691,249	134,829,201	136,990,976	139,080,483	141,202,379	143,330,942	145,579,956	147,898,150	151,595,604	155,385,494	0	0	0	0
Book Depreciation			25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Property Taxes and Insurance			8,939,416	9,386,386	9,855,706	10,348,491	10,865,915	11,409,211	11,979,672	12,578,655	13,207,588	13,867,968	14,561,366	15,289,434	16,053,906	16,856,601	17,699,431	18,584,403	19,513,623	20,489,304	21,513,769	22,589,458	0	0	0	0
Return on Investment:																										
Plant in Service		250,022,657	250,022,657	250,022,657	250,022,657	250,022,657	250,022,657	250,022,657	250,022,657	250,022,657	250,022,657	250,022,657	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Accumulated Depreciation			25,002,266	50,004,531	75,006,797	100,009,063	125,011,328	150,013,594	175,015,860	200,018,125	225,020,391	250,022,657	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Plant in Service			225,020,391	200,018,125	175,015,860	150,013,594	125,011,328	100,009,063	75,006,797	50,004,531	25,002,266	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working capital for 45 days based on O&M			14,125,826	10,761,520	11,471,219	13,411,869	15,044,472	15,311,045	15,569,123	15,830,339	16,075,447	16,322,806	16,586,406	16,853,650	17,123,872	17,385,060	17,650,297	17,916,368	18,197,494	18,487,269	18,949,450	19,423,187	0	0	0	0
Accumulated Deferred Taxes			-2,562,888	-5,772,370	-8,880,828	-11,896,090	-14,824,865	-6,490,352	1,918,159	10,394,889	18,882,803	27,370,904	26,539,223	25,707,729	24,876,048	24,044,554	23,212,873	22,381,379	21,549,698	20,718,204	19,886,524	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189
Materials Inventory			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate Base end of the period		250,022,657	236,583,329	205,007,275	177,606,250	151,529,374	125,230,935	108,829,755	92,494,079	76,229,760	59,960,516	43,693,709	43,125,629	42,561,379	41,999,920	41,429,614	40,863,171	40,297,747	39,747,193	39,205,473	38,835,974	38,062,376	18,639,189	18,639,189	18,639,189	18,639,189
Average Rate Base			243,302,993	220,795,302	191,306,762	164,567,812	138,380,154	117,030,345	100,661,917	84,361,919	68,095,138	51,827,113	43,409,669	42,843,504	42,280,649	41,714,767	41,146,392	40,580,459	40,022,470	39,476,333	39,020,724	38,449,175	0	0	0	0
Cost of Capital			10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	10.58%	0.00%	0.00%	0.00%	0.00%
	Levelized Values																									
Return on Rate Base	11,737,168		25,738,266	23,357,247	20,237,747	17,409,116	14,638,806	12,380,276	10,648,711	8,924,385	7,203,573	5,482,629	4,592,174	4,532,281	4,472,738	4,412,875	4,352,749	4,292,880	4,233,852	4,176,078	4,127,881	4,067,418	0	0	0	0
Book Depreciation	16,200,945		25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	25,002,266	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Property Taxes and Insura	13,400,841		8,939,416	9,386,386	9,855,706	10,348,491	10,865,915	11,409,211	11,979,672	12,578,655	13,207,588	13,867,968	14,561,366	15,289,434	16,053,906	16,856,601	17,699,431	18,584,403	19,513,623	20,489,304	21,513,769	22,589,458	0	0	0	0
Total Capital Charges	41,338,955		59,679,947	57,745,899	55,095,718	52,759,873	50,506,987	48,791,753	47,630,648	46,505,306	45,413,426	44,352,862	19,153,540	19,821,715	20,526,644	21,269,476	22,052,180	22,877,283	23,747,475	24,665,382	25,641,650	26,656,876	0	0	0	0
Annual Rate (% of initial capital investment)			23.87%	23.10%	22.04%	21.10%	20.20%	19.51%	19.05%	18.60%	18.16%	17.74%	7.66%	7.93%	8.21%	8.51%	8.82%	9.15%	9.50%	9.87%	10.26%	10.66%	0.00%	0.00%	0.00%	0.00%
Levelized Rate	16.53%																									

Fixed Charges - NHPUC Basis (Avera

Wet FGD Units 1 & 2, 455 MW
HS Coal - N Appl
Sensitivity Case No. 1 - $250M Capita

Calendar Year		2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Operating Year		25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Book Life																	
Parameter		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Evaluation Period Factor		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax Depreciatior		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Deferred Income Tax		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O&M (all non-capitalized expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Book Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Property Taxes and Insurance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on Investment:																	
Plant in Service	250,022,657	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Plant in Service		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working capital for 45 days based on O&M		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Accumulated Deferred Taxes		18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189
Materials Inventory		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate Base end of the period	250,022,657	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189	18,639,189
Average Rate Base		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Capital		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Levelized Values																
Return on Rate Base	11,737,168	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Book Depreciation	16,200,945	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Property Taxes and Insura	13,400,841	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Charges	41,338,955	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Rate (% of initial capital investment)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Levelized Rate	16.53%																

Wet FGD Units 1 & 2, 455 MW
HS Coal - N Appl
Sensitivity Case No. 1 - $250M Capital Costs
Financial Summary

Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Revenue Requirements	$ 172,686,556	$ 143,838,057	$ 146,865,466	$ 160,054,828	$ 170,862,763	$ 171,280,111	$ 172,183,630	$ 173,148,020	$ 174,017,006	$ 174,935,307	$ 151,844,789	$ 154,650,916	$ 157,517,620	$ 160,349,960	$ 163,254,559	$ 166,208,225	$ 169,327,431	$ 172,563,533	$ 177,237,254	$ 182,042,370
Incremental O&M	$ 113,006,609	$ 86,092,158	$ 91,769,749	$ 107,294,955	$ 120,355,777	$ 122,488,358	$ 124,552,982	$ 126,642,715	$ 128,603,579	$ 130,582,445	$ 132,691,249	$ 134,829,201	$ 136,990,976	$ 139,080,483	$ 141,202,379	$ 143,330,942	$ 145,579,956	$ 147,898,150	$ 151,595,604	$ 155,385,494
Busbar Electricity Price ($/MWh)	54.16	45.11	46.06	50.20	53.58	53.72	54.00	54.30	54.57	54.86	47.62	48.50	49.40	50.29	51.20	52.13	53.10	54.12	55.58	57.09
Incremental PSNH Net Income	$ 10,532,587	$ 9,558,229	$ 8,281,670	$ 7,124,141	$ 5,990,477	$ 5,066,244	$ 4,357,654	$ 3,652,027	$ 2,947,839	$ 2,243,596	$ 1,879,205	$ 1,854,695	$ 1,830,329	$ 1,805,832	$ 1,781,227	$ 1,756,728	$ 1,732,573	$ 1,708,930	$ 1,689,207	$ 1,664,465
Return on Investment/Equity	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%

Northeast
Utilities System

Clean Air Project
Merrimack Station

Clean Air Project
Merrimack Station – PSNH

Progress Update

April 25, 2008

Agenda

- Previous RaCC Approval
- Project Schedule
- Cost
- 2008 Engineering Activities
- Risk Assessment
- Financial Viability
- Appendix

Previous RaCC Approvals

- Approval on September 24, 2007, to sign a contract for the Program Manager for up to $35 Million with Washington Group International (WGI)
  - **Contract signed in September 2007**
- Approval on September 24, 2007, of initial project expenditure of $10 Million through June 2008
  - **Project expenditures $5.5 Million through March 2008**
  - **Estimated total project expenditures $8 Million through June 2008**

Project Schedule

Clean Air Project
Merrimack Station

Project	2006	2007	2008	2009	2010	2011	2012	2013
HB 1673	▲							
Preliminary Engineering	▪▪▪▪▪▪▪▪▪▪							
Program Manager Hired		▲						
Detailed Engineering		▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪				
Major Contracts Awarded			▪▪▪					
Permitting		▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪
Preliminary Site Prep.			▪▪▪					
Major Construction				▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪	
Testing & Commissioning							▪▪▪▪▪▪▪▪▪▪	
In Service								▲

4.

Cost

- Original project estimate of $250 Million based on Sargent & Lundy 2006 study
- Anticipated softening in costs do not seem to be occurring
  - **Clean Air Interstate Rule (CAIR) Phase II (2015) requirement for scrubbers driving costs higher**
  - **New coal plant construction still strong**
  - **Steel fabrication shops still operating at high capacity**
  - **Materials escalation continues at a high rate (domestic and global)**
- Updated project cost estimate due in May 2008

2008 Engineering Activities

Clean Air Project
Merrimack Station

- Award Major Island Contracts
  - **FGD System Q2**
  - **Chimney Q2**
  - **Wastewater Treatment System Q3**
  - **Materials Handling System Q3**
- Permitting
  - **Air**
  - **Water**
  - **Local (Town of Bow, etc.)**
- Site Survey & Soil Borings
- Additional Detailed Engineering
  - **Booster Fans**
  - **Transformers**
  - **Foundation Design**

Risk Assessment, Major Risk Concerns

Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Bids received from vendors are significantly higher than expected resulting in increased costs to perform jobs which exceed initial cost estimate of $250 M	2008	$75 million	84%	$63 million	Currently carrying out the procurement phase of the project. The project is being rebudgeted and will be presented to RaCC for approval in the second quarter of 2008. The purchasing area is working to stimulate competition during the bid process. The legislatively required implementation date allows for some slippage in the schedule.
Lack of sufficient, qualified construction labor results in increased costs to import labor resources resulting in schedule delays	2009-12	$50 million	66%	$33 million	WGI will initiate a Project Labor agreement (PLA). Meetings have been held with the union trades to discuss the project and labor requirements up front.
Inability to lock in firm prices during contracting phase exposes the project to price volatility and currency risk	2008-9	$25 million	78%	$19.5 million	The RFPs are being structured for fixed/lump sum pricing. The contracts will be negotiated with this as a priority.

Risk Assessment, Major Risk Concerns

Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Vendors unable to meet project design criteria resulting in non-conforming bids	2008-9	$25 million	48%	$12 million	In the event this occurs, an acceptable outcome will need to be negotiated during the procurement process.
Inability to design appropriate plant integration plans resulting in MK1 bypass, boiler implosion and/or noise issues	2008-9	$12.5 million	50%	$6.25 million	PSNH contracted with experienced contract program manager in scrubber installations. Additionally, NU personnel will be reviewing design specifications.
Scope definition changes drastically during construction resulting in additional expenditures and/or potential schedule delays	2008-12	$18.75 million	32%	$6 million	PSNH team will work closely with WGI & EPC contractors to minimize the impact.
Proposed design is inadequate and does not meet operability/reliability/ constructability requirements resulting in complete redesign	2008-9	$12.5 million	42%	$5.25 million	PSNH contracted with experienced contract program manager in scrubber installations. Additionally, NU personnel will be reviewing design specifications.

Merrimack Station is Expected to Remain Economic for Customers Following Scrubber Installation

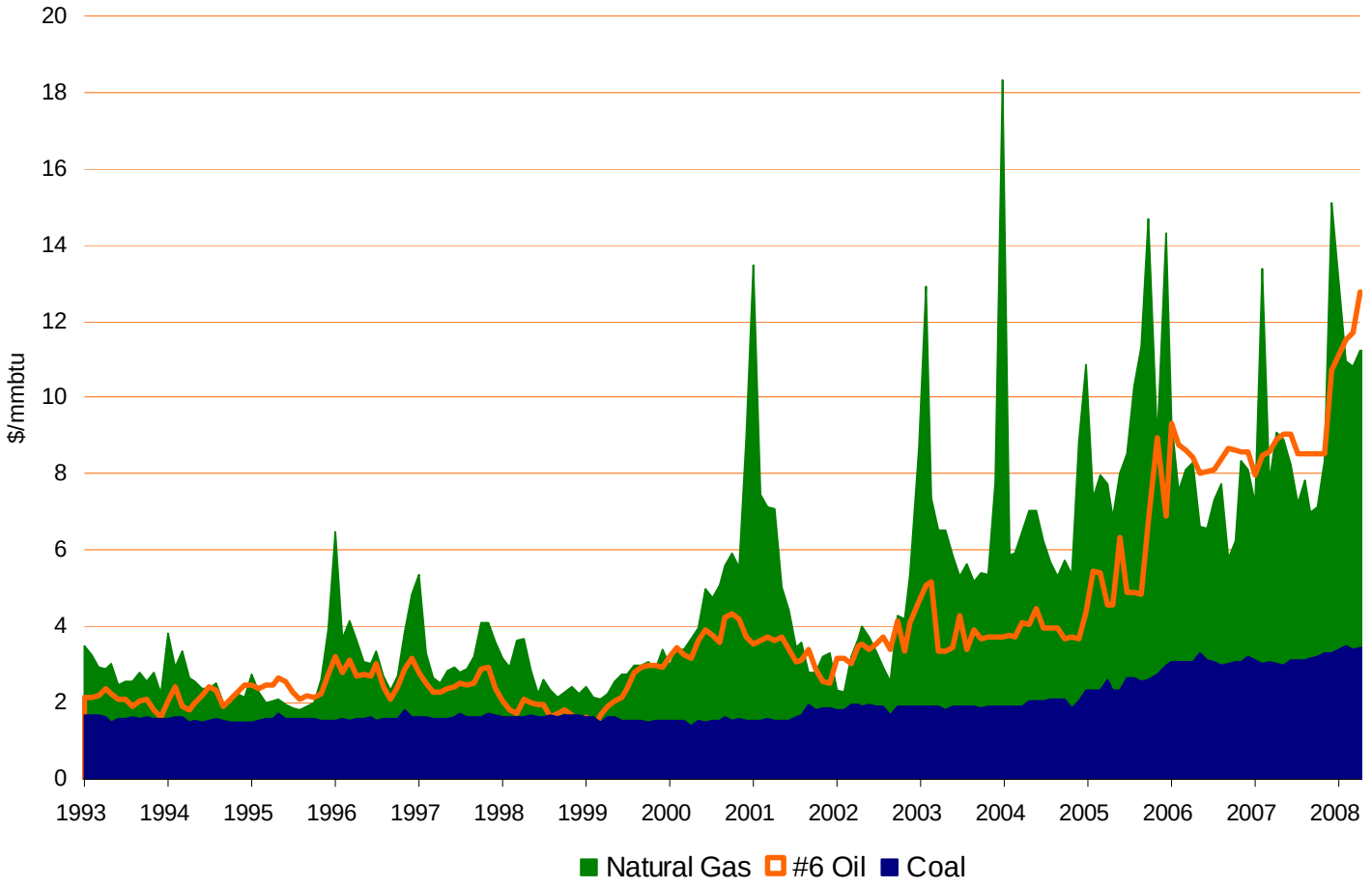
Clean Air Project
Merrimack Station

- With scrubber in service, SO_2 emissions will be reduced by 30,000 tons per year
  - Equates to a reduction of between $3 and $4/MWh
  - Will allow Merrimack to burn higher sulfur fuels, expected to be less costly, while remaining compliant with SO_2 requirements
  - Will ensure fleet mercury compliance, including Schiller
- Coal remains the most abundant domestic fuel source in the US
  - Highest and best use for coal will be for "stationary sources" predominantly power boilers
- Next generation of "IGCC Clean Coal" boilers is still many years away before becoming industry standard
  - Coal power boilers make up about 50% of the domestic electric power fleet today
  - It will take a generation to replace existing infrastructure with a new coal power fleet
  - Utilities with a greater investment in coal generating stations have less overall risk to "experiment" with new coal technologies, than PSNH
    - One 600 MW IGCC station for Southern Co or AEP is a small fraction of their fleet
    - One 600 MW IGCC station is 115% of the PSNH coal fleet

Historic Price Volatility Suggests Coal Will Find a Way to be Cheaper than Alternatives

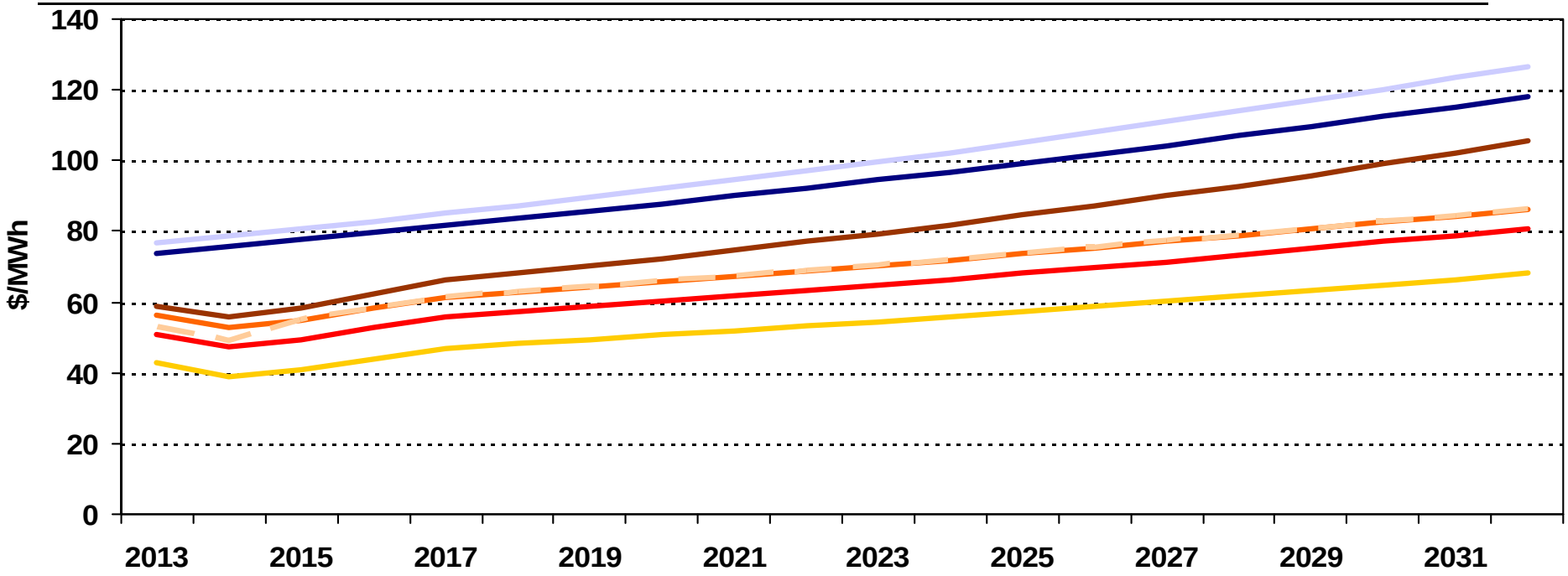
Clean Air Project
Merrimack Station

PSNH Actual/Quoted Delivered Fuel Costs



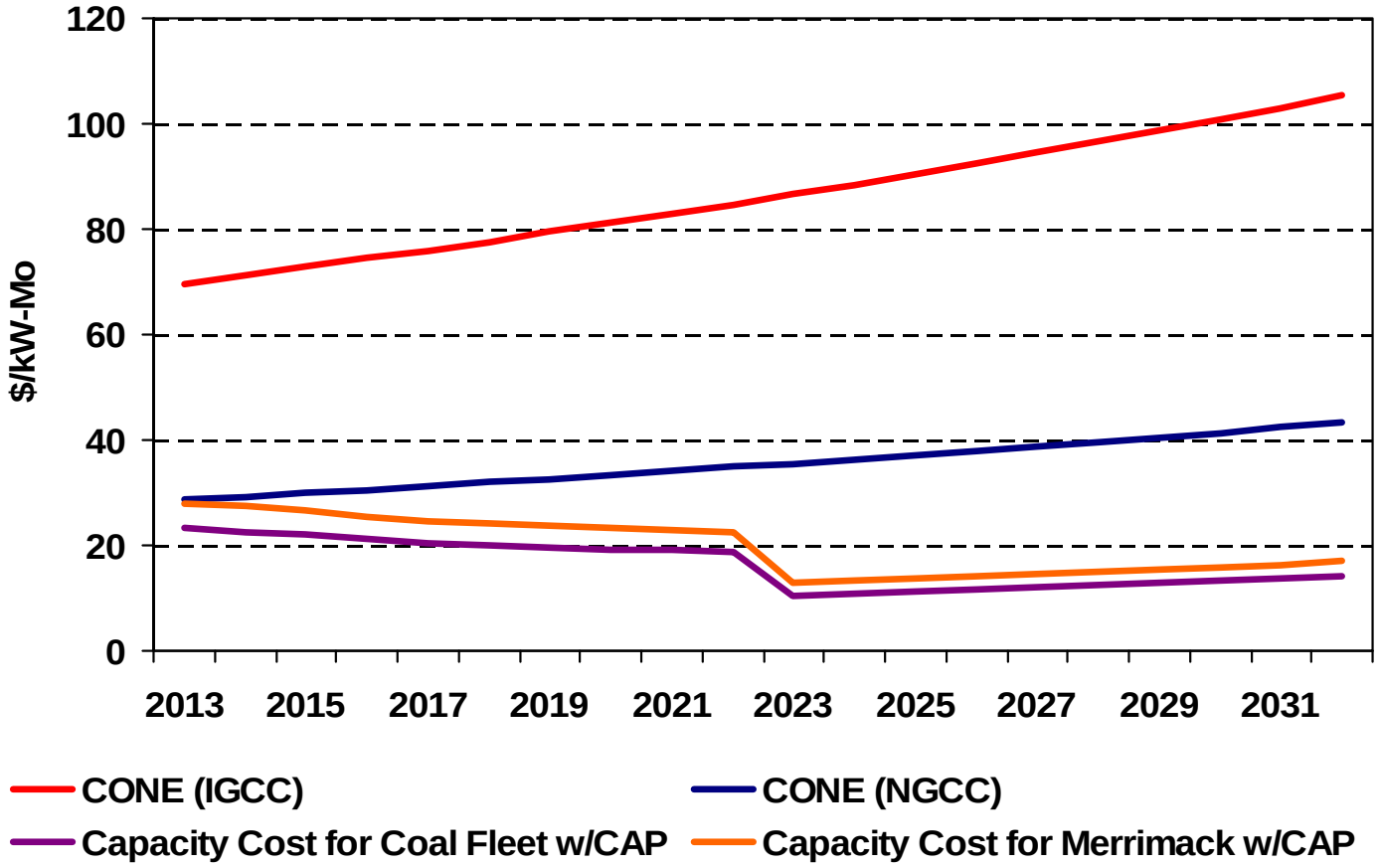
Economic analysis supports that Merrimack Station with Scrubber will dispatch

Clean Air Project
Merrimack Station



- Natural Gas fuel price starting at $10.74/mmbtu (delivered to New England)
- Natural Gas plant heat rate of 6,500 Btu/kWh
- Coal fuel price starting at $4/mmbtu, delivered
- CO_2 starting at $7/ton with rebates over $5/ton
- 1.5 million allowances in 2013 and 2014
- SO_2 starting at $650/ton, NOx starting at $1,300/ton

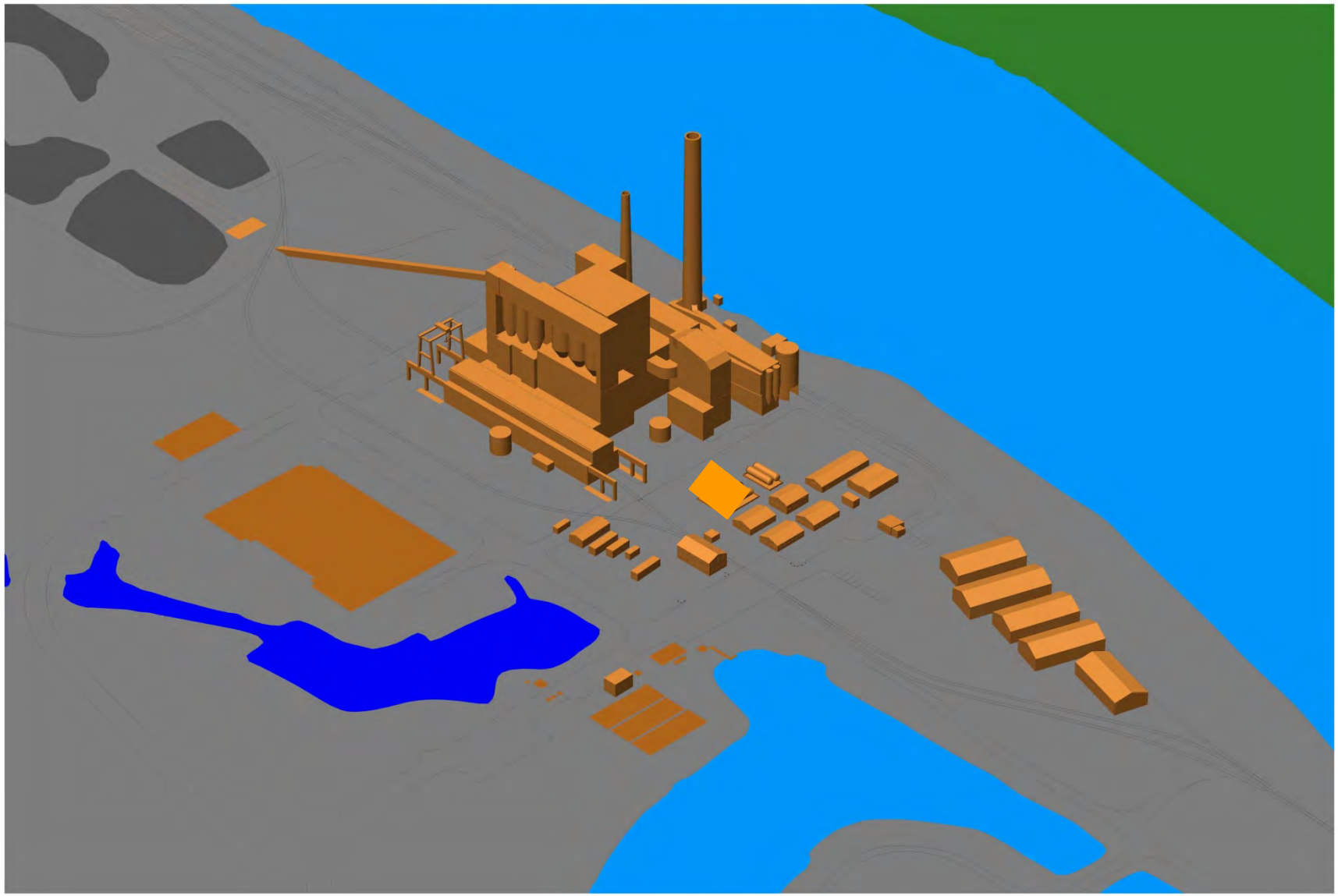
Merrimack capital costs with Scrubber will be competitive with new gas combined cycle plants



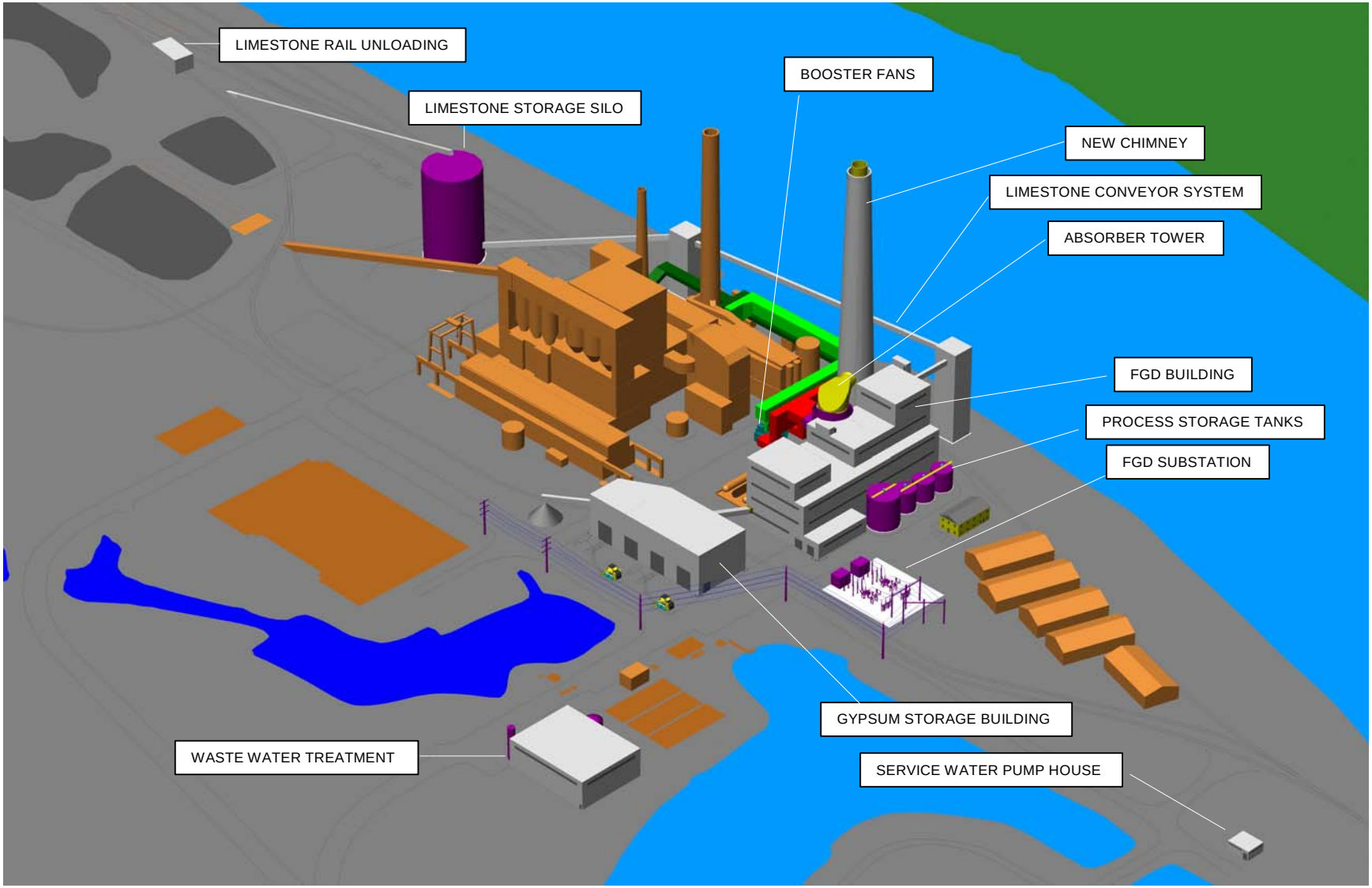
- 600 MW IGCC: $3,000/kW installed capital cost
- 400 MW NGCC: $1,400/kW installed capital cost
- Merrimack CAP: $425M capital investment

Appendix

Merrimack Station: 2008



Merrimack Station: 2013



2008 Site Preparation Activities

Clean Air Project
Merrimack Station

- Perform Plant Entrance Modifications
  - **Relocate Guard Gate**
  - **Vehicle Staging Area off River Road**
  - **North Access Road Improvements**
- Prepare Contractor Parking Area
- Prepare Construction Management & Contractors Trailers Area
- Prepare Construction Laydown Area
- Perform Demolition of Existing Buildings in FGD Area
- Install New Transformer for Construction Power
- Prepare Chimney Liner Fabrication Area
- Relocate Septic System

Additional Information

- Project Labor Agreement in progress (URS is signatory to National Maintenance Agreement).
- URS purchased Washington Group International (now known as URS – Washington Division).

Northeast Utilities System

Clean Air Project
Merrimack Station

Public Service Company of New Hampshire

Clean Air Project

Capital Project Review and Approval

Northeast Utilities

Risk and Capital Committee

Gary Long/John MacDonald/Jim Vancho

June 25, 2008

~~Privileged and Confidential. Prepared at the direction of counsel. Prepared in anticipation of litigation.~~

Executive Summary

Clean Air Project
Merrimack Station

- New Hampshire legislation mandates compliance to mercury emissions standards set forth in the NH Mercury Reduction Act
  - Wet scrubber technology will reduce power plant mercury emissions required by New Hampshire law and is the technology specified by the law
  - There is no other technology which will guarantee capture of 80% of the mercury input of our coal fleet
- Cost estimates have been defined by a competitive bidding process
  - Prices have escalated from original estimates made in 2006 due to much higher raw material pricing and higher costs of engineering service
- Bid proposals indicate that an in-service date of mid-2012 is achievable if two key contracts can be given a limited notice to proceed by June 30
  - Earlier in-service date reduces cost (AFUDC), risk, and allows PSNH to take advantage of incentives built into the New Hampshire legislation for "early reductions" of mercury
- Despite the capital cost increases, the project remains economic for customers and provides a significant investment opportunity for PSNH
  - The NPV of Revenue Requirements of adding the Scrubber versus replacing Merrimack Station energy and capacity supply with market purchases is a benefit to customers of $132 Million
  - Busbar cost increases to $94.55/MWh in 2013
  - The scrubber avoids about $15 Million in sulfur credit purchases annually, included in the customer benefit above
  - Incremental Net Income estimated at $18.5 M in 2013 – first full year of operation

Background – Merrimack Station Benefits PSNH Customers

Clean Air Project
Merrimack Station

- Merrimack Station produces 3 million MWh of low cost power annually, about 35% of PSNH's total energy service requirement. The low cost energy produced at Merrimack Station off-sets the higher cost of market purchases in the overall energy service rate
- Operating Merrimack Station in a cost-effective manner has been one of the major reasons why PSNH's energy service rate is the lowest in the region, as much as 25% lower than the average of energy service supply that we track in NE
- Merrimack Station has control technology to satisfy NOx and particulate emissions requirements. With a scrubber, SO_2 and Mercury emissions will be controlled and Merrimack will be among the cleanest coal burning plants nationally
- Coal is the most abundant domestic fossil fuel resource in the United States supplying more than 50% of the nation's power generation fleet, but only 15% of New England's generation. Maintaining the use of this secure fuel resource is important for the diversity of the region's future energy supply
- Historically, coal has maintained a significant price advantage over oil or natural gas as fuel for the power generation sector. Operated as Regulated Generation, this cost savings flows directly to customers

Continued operation of Merrimack Station with a scrubber will maintain fuel diversity and security of domestic fuel supply in the ISO-NE region, while providing PSNH's customers with low cost energy.

Background - NH Clean Power Act

Clean Air Project
Merrimack Station

- The NHCPA, in 2002, was the first four-pollutant bill in the nation (SO_2, NOx, Mercury and CO_2)
- The New Hampshire Mercury Reduction Act, enacted in 2006, was the mercury reduction next-step envisioned by the original NHCPA
- The law was developed in a collaborative effort with PSNH, representatives from the environmental community, and the Executive and Legislative branches of state government
- The New Hampshire Mercury Reduction Act specifies the installation of scrubber technology at Merrimack 1 and 2 no later than July 1, 2013
- The law stipulates that PSNH must capture a minimum of 80% of the total amount of mercury contained in the coal burned at all of PSNH's coal-fired units (Merrimack and Schiller)
- Installation of scrubber technology holds the added benefit of significantly reducing SO_2 emissions from the Merrimack Station boilers (anticipated to be 90% reduction or greater)

The New Hampshire Mercury Reduction Act Specifics:

Clean Air Project
Merrimack Station

- "It is in the public interest to achieve significant mercury emissions reductions at the coal-burning electric power plants in the state as soon as possible. The requirements of this subdivision will prevent, at a minimum, 80 percent of the aggregate mercury content of the coal burned at these plants from being emitted into the air by no later than the year 2013"
- "The Department of Environmental Services has determined that the best known commercially available technology is a wet flue gas desulphurization system…as it achieves significant emissions reduction benefits, including but not limited to, cost effective reductions in sulfur dioxide, sulfur trioxide, small particulate matter and improved visibility (regional haze)"
- "The owner of the affected coal burning sources shall work to bring about early reductions (of mercury emissions) and shall be provided incentives to do so"
- "The installation of scrubber technology will not only reduce mercury emissions significantly but will do so without jeopardizing electric reliability and with reasonable costs to consumers"
- "The installation of such technology is in the public interest of the citizens of New Hampshire and the customers of the affected sources"
- "The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of costs, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components"

Estimate of Project Costs

Clean Air Project
Merrimack Station

Direct Project Costs

➢ Major Contract Islands: (firm price bids)	
• FGD System	$100M
• Material Handling	$45M
• Waste Water Treatment	$15M
• Chimney	$13M
➢ PSNH Project Costs	$30M
➢ Program Manager Costs (URS Washington Group)	
• Balance of Plant & Interconnection	$93M
• Engineering and Construction Management	$59M
TOTAL DIRECT PROJECT COSTS	**$355M**

➢ PSNH Project Contingency	$10M
➢ Program Manager Contingencies	
• Materials Escalation	$23M
• Contingency	$15M
• Scope Growth	$ 4M
TOTAL PROJECT CONTINGENCIES	**$53M**

➢ Power Advocate's Defined Costs Savings	
• Project cost deduction	($6M)
➢ Anticipated Value Engineering*	
• Scope reduction	($5M)
TOTAL ANTICIPATED COST REDUCTIONS	**($11M)**

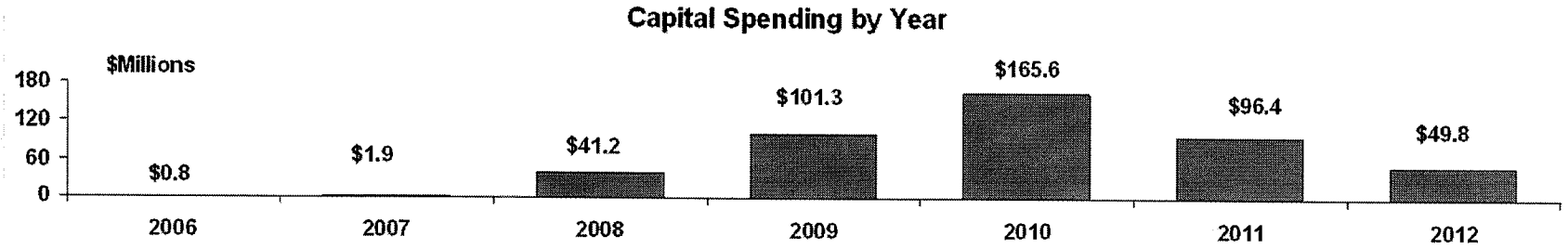
➢ NU Corporate Costs	
• AFUDC	$55M
• Indirect Costs	$5M
TOTAL CORPORATE COSTS/AFUDC	**$60M**

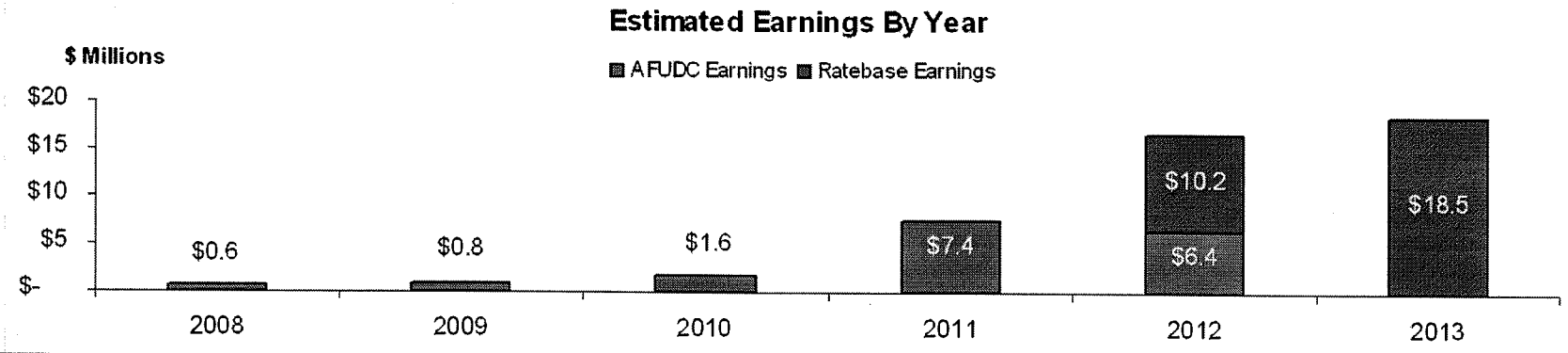
Total Project Cost Estimate = $457M

*Note: Alternative material handling proposal in consideration that would reuse existing station equipment and reduce project costs by about $5M

Cashflow and Earnings Projection

Clean Air Project
Merrimack Station





EPS	$.00	$.00	$.01	$.02	$.03	$.04

Assumptions:

- Base-case project costs are estimated at $457M
- Project expected to be in-service on June 30, 2012
- Assumes 9.81% ROE on 47.23% of Capital Structure
- Average Shares outstanding per 2009-2013 Forecast

Financial Sensitivities

Clean Air Project
Merrimack Station

- Base-case assumptions result in net customer benefit of $132 Million and a 2013 busbar cost of $94.55
- Net customer cost is most sensitive to expected future natural gas and coal prices

Assumption Category	Assumptions			2008 PV of Net Customer Cost[1] 2012-2027 ($Mil)					2013 Plant Busbar Cost ($/MWh)						
	Downside	Base	Upside	($225)	($175)	($132)	($100)	$0	$91	$92	$93	$94.55	$96	$97	$98
Capital Cost	+10%	$457.5 mil	-10%	($159)	$(27)	$27	($105)		$92.31	$(2.24)	$2.24	$96.79			
2012 Gas Prices, MMBTU[3]	-5%	$11.00	+5%	($213)	$(81)	$81	($51)								
2012 Coal Prices, MMBTU[3]	+5%	$4.82	-5%	($180)	$(48)	$48	($84)		$92.02	$(2.53)	$2.53	$97.08			
2012 RGGI/Federal Carbon Costs per Ton[2,3]	+50%	$7/$21	-50%	($158)	$(26)	$26	($106)		$92.53	$(2.02)	$2.02	$96.57			

White text in bars represents change in values;
Black text beside bars represents sensitivity result.

Notes:

1. NPV Net Customer Cost = (2008 Present Value of Merrimack Plant Revenue Requirements from 2012 to 2027) minus (2008 Present Value of Market Energy plus 2008 Present Value of Capacity Payments from 2012 to 2027).
2. Amounts presented reflect RGGI/federal (Lieberman-Warner) cost estimates. Impacts are equivalent at given prices since RGGI does not provide for carbon allowances but federal proposals are assumed to include Merrimack allocations starting at 67% (per Lieberman-Warner).
3. Fuel and carbon costs are escalated at 2.5% per annum off of the 2012 estimate.

Financial Scenarios

Clean Air Project
Merrimack Station

	Unlikely Low	Possible Low	Base	Possible High	Unlikely High
NPV - Net Customer Cost[1]	$210 MIL	$43.4 MIL	($132 MIL)	($296 MIL)	($461 MIL)
Monthly Residential Customer Cost Impact[4]	$1.61	$0.33	($1.01)	($2.28)	($3.54)
2013 Plant Busbar Cost ($/MWH)	$104.44	$100.77	$94.55	$89.52	$84.49
Net Inc - 2013 (First Full Year In-Service)	$21.5 MIL	$20.1 MIL	$18.5 MIL	$18.1 MIL	$17.7 MIL
Assumed Probability	5%	25%	-	25%	5%
Parameters					
Capital Costs, Millions	$532	$497	$457	$447	$497
2012 Gas Prices, MMBTU[3]	$9.90	$10.45	$11.00	$11.55	$12.10
2012 Coal Prices, MMBTU[3]	$5.30	$5.06	$4.82	$4.58	$4.34
2012 Carbon Costs, Ton (RGGI/Federal)[2,3]	$15/$45	$10/$30	$7/$21	$3.5/$10.6	$0/$0

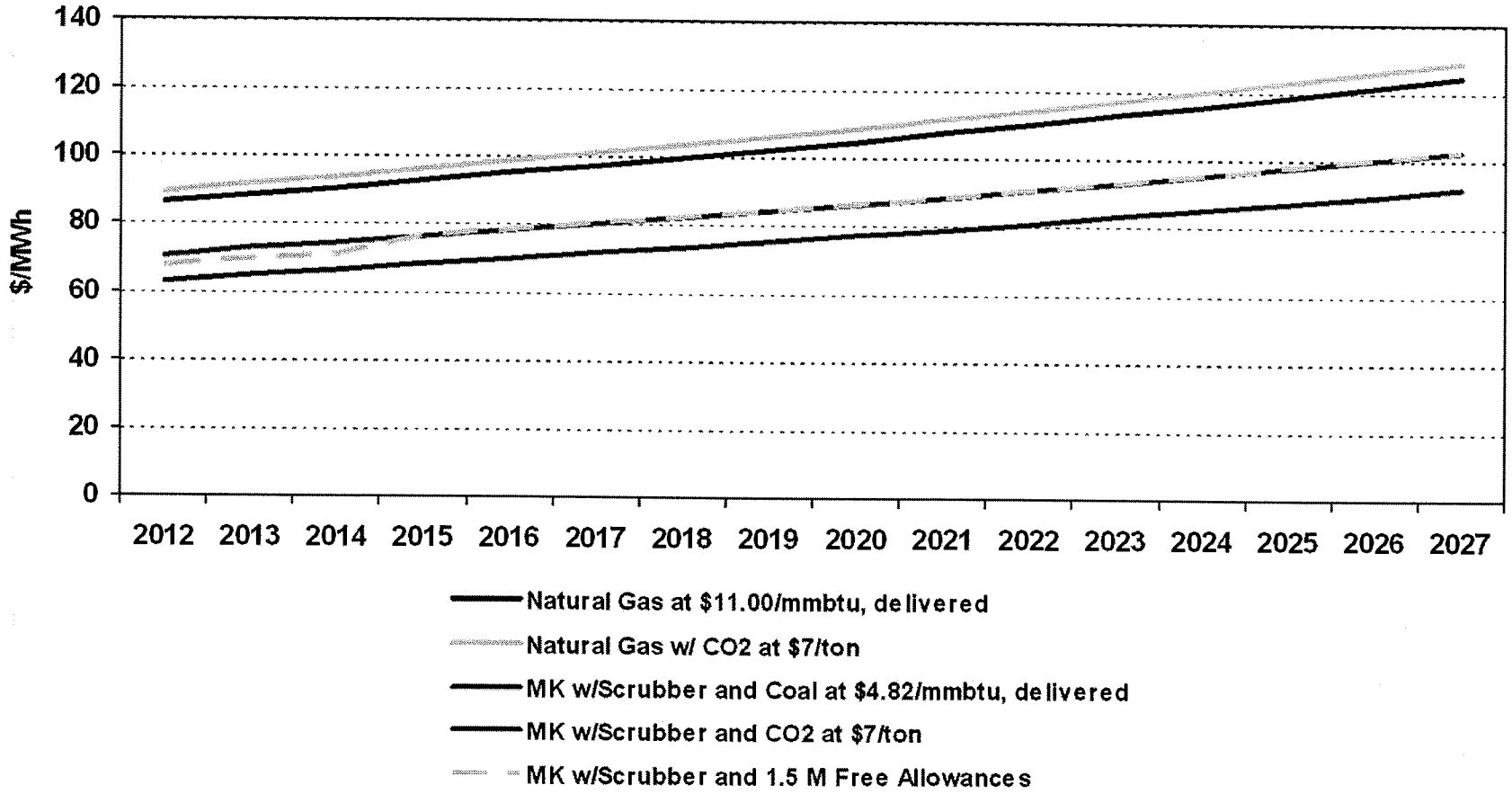
CASE LEGEND

Unlikely Low	CASE REFLECTS PROJECT IN-SERVICE DELAYED ONE YEAR AND COST OVERUN ($45M), COOLING TOWER ADDITION ($30M), MINIMAL GAS/COAL SPREAD
Possible Low	CASE REFLECTS PROJECT IN-SERVICE ON-TIME WITH COST OVERUN ($10M), COOLING TOWER ADDITION ($30M), DECREASED GAS/COAL SPREAD
Base	CURRENT ASSUMPTIONS
Possible High	CASE REFLECTS PROJECT IN-SERVICE 6 MONTHS EARLY ($10M), PROJECT COSTS AS EXPECTED, BENIGN CARBON LEGISLATION, INCREASED GAS/COAL SPREAD
Unlikely High	CASE REFLECTS PROJECT IN-SERVICE 6 MONTHS EARLY ($10M) WITH LOWER THAN EXPECTED COSTS ($10M), NO CARBON LEGISLATION, MAXIMUM GAS/COAL SPREAD

1. NPV Net Customer Cost = (2008 Present Value of Merrimack Plant Revenue Requirements from 2012 to 2027) minus (2008 Present Value of Market Energy plus 2008 Present Value of Capacity Payments from 2012 to 2027).
2. Amounts presented reflect RGGI/federal (Lieberman-Warner) cost estimates. Impacts are equivalent at given prices since RGGI does not provide for carbon allowances but federal proposals are assumed to include Merrimack allocations starting at 67% (per Lieberman-Warner).
3. Fuel and carbon costs are escalated at 2.5% per annum off of the 2012 estimate.
4. Based on NPV Net Customer Cost levelized over the period 2012-2027, and average residential usage of 500 kWh per month.

Economic Analysis Supports That Merrimack Station With Scrubber Will Be Dispatched

Clean Air Project
Merrimack Station



- Natural Gas plant heat rate of 7,620 Btu/kWh in a Combined Cycle unit
- SO_2 at $500/ton, NOx at $1,300/ton

Key Financial Takeaways

Clean Air Project
Merrimack Station

- Customer value of scrubber installation extremely sensitive to future expected natural gas/coal price spread
  - At assumed 2012 price levels and other base case parameters, a spread of approximately $5.29/mmbtu (escalating) is required to create customer benefits
- Impact of RGGI/Federal carbon legislation is not expected to render scrubber investment uneconomic to customers at current projected costs
  - Assumes any Federally imposed carbon legislation would grant carbon allowances to generators (approximately 67% of Merrimack's requirement)
  - Absent Federal allocations (or under RGGI), assuming all other base case assumptions, a 2012 carbon cost of $30/ton (escalating) or greater would eliminate customer value of scrubber installation
- Assuming base case fuel and carbon assumptions, capital cost estimates have meaningful headroom before rendering investment uneconomic
  - However, reductions in natural/gas coal spread and increases in carbon costs would put pressure on ability to construct within the current projection

Investment is essentially a long spread position on natural gas/coal with carbon and construction risk

Project Benefits are Accentuated by Advancing the In-Service Date to mid-2012

Clean Air Project
Merrimack Station

- Financial
  - Reduces AFUDC cost by $10 Million
  - Limits exposure to material or labor cost escalation for project elements not covered by firm price contracts
  - Generates real earnings one year sooner
- Environmental
  - Eliminates an additional 31,350 tons of SO_2
  - Eliminates an additional 229 pounds of Mercury
  - Reduces particulate emissions to less than 1% one year sooner
- Customer
  - Produces "early reduction mercury credits" that can be used for
    - Compliance in future years if operational issues with the scrubber arise
    - Conversion to fungible SO_2 allowances (estimated at 12,500 allowances)

Revised Project Schedule

Clean Air Project
Merrimack Station

Project	2006	2007	2008	2009	2010	2011	2012
NH Mercury Reduction Act	▲						
Preliminary Engineering	▪▪▪▪▪▪▪▪						
Program Manager Hired		▲					
Detailed Engineering		▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪			
Major Contracts Awarded			▪▪▪				
Permitting		▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪
Preliminary Site Prep.			▪▪▪				
Major Construction				▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	
Testing & Commissioning						▪▪▪▪	
In Service							▲

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Regional Barriers to Adding New Base Load Generation in New England Cause Merrimack to be Strategically Positioned for Re-Investment

Clean Air Project
Merrimack Station

- New base load power plants (coal, nuclear, IGCC) are not on the near or mid-term horizon for the region, making re-investment in environmental technology at existing assets the necessary strategy to maintain appropriate base-load supply
- Current market players are engaged in blocking opportunities for new, lower cost, regulated generation assets, making preservation of existing assets increasingly important
- ISO-NE market rules, and the current economic climate, make it nearly impossible for prospective generators to secure financing and overcome the substantial "barriers to entry" to build new generation in the region
- New England electric energy supply is highly dependent on natural gas, and costs are subject to corresponding commodity price volatility, and long-term price increases
- In addition to the support these barriers provide for continued operation of existing base-load plants:
  - Brattle Group analysis of future NE energy markets indicates that all coal generation, including Merrimack, will continue to operate economically
  - Operation of Merrimack Station on coal provides stability to the power supply in the region
  - Loss of PSNH's Merrimack Station would call into question the viability of operating the remaining generating assets as a fleet

Conclusion

Clean Air Project
Merrimack Station

- Installation of the scrubber is required by NH law to meet mercury emissions requirements
- Merrimack Clean Air Project capital costs have increased significantly since the original project costs estimates were prepared in 2006, and stand at $457M
- Under the base case and with varying assumptions, continued operation of Merrimack Station with the Clean Air Project remains economically beneficial for customers
- State law allows for recovery of prudently incurred costs to construct and operate the scrubber
- The project team is in place and prepared to execute contracts now and begin construction in earnest late this year, with a project in-service date of mid-2012
- The proposal to construct and operate a scrubber at Merrimack Station, in conformance with the NH Mercury Reduction Law, is in the best interest of PSNH's customers and shareholders

Appendix Materials

PSNH Clean Air Project

June 25, 2008

Risk Assessment, Major Risk Concerns

Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Remaining bids received from vendors are significantly higher than expected related to material and handling costs. Note: The bids on the major equipment have been received.	2008	$10 million	20%	$2 million	Currently carrying out the procurement schedule. The Purchasing area is trying to stimulate competition during the bid process. Lastly as the required implementation date allows for some slippage in the schedule.
Lack of sufficient, qualified construction labor results in increased costs to import labor resources, schedule delays to wait for resources to become available.	2009-12	$50 million	10%	$5 million	WGI will initiate the National Maintenance Agreement. Meetings have been held with the union trades to discuss the project and labor requirements up front.
Inability to lock in firm prices during contracting phase exposes the project to price volatility and currency risk.	2008-9	$25 million	20%	$5 million	The RFP is being structured for fixed/lump sum pricing. The contract will be negotiated to try and include these parameters.

Risk Assessment, Major Risk Concerns

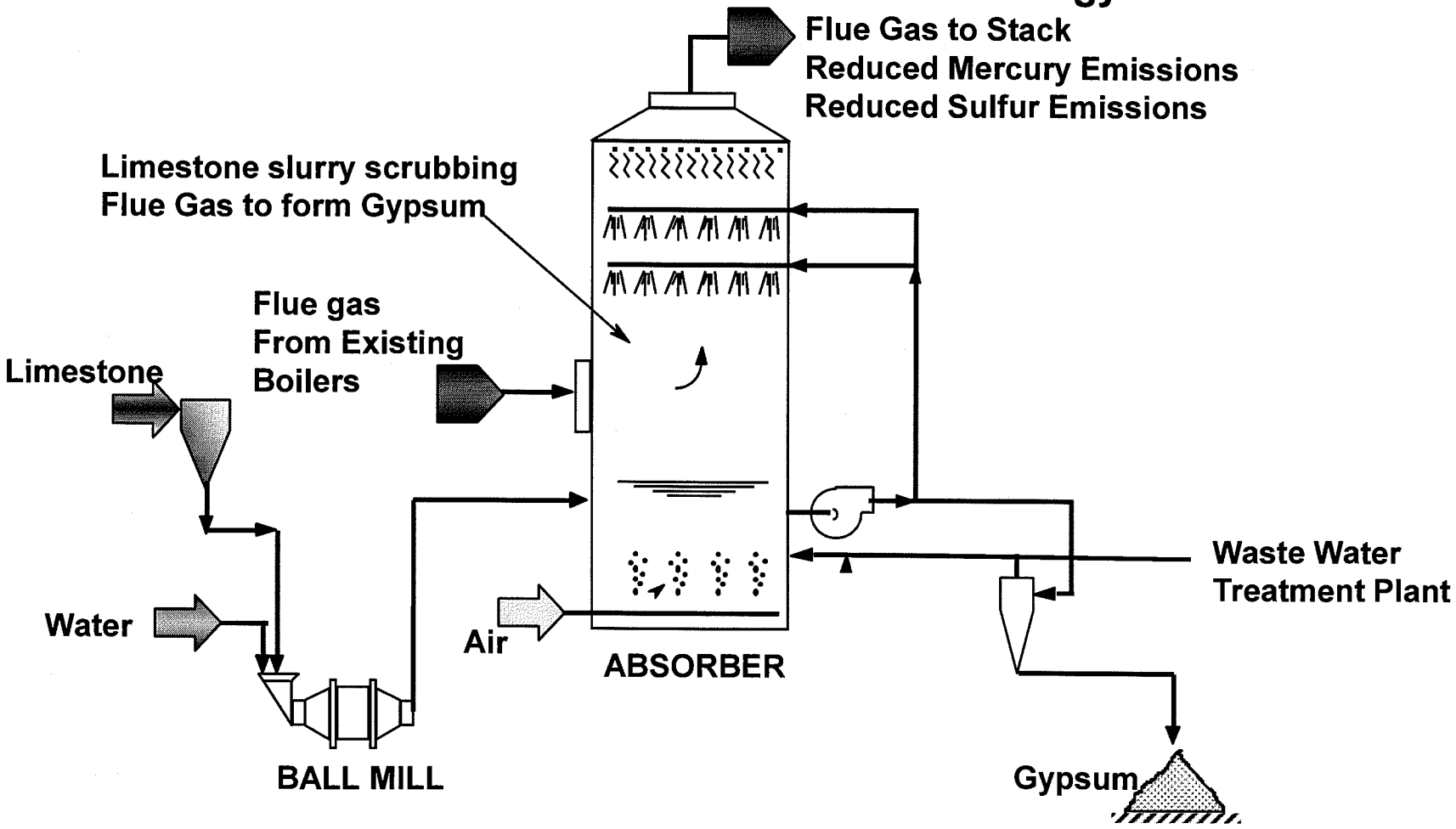
Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Vendors unable to meet project design criteria resulting in non-conforming bids. Note: bids received with mercury criteria. Risk relates to remaining design specifications.	2008-9	$25 million	25%	$6.25 million	In the event this occurs, an acceptable outcome will be negotiated during the procurement process.
Inability to design appropriate plant integration plans resulting in MK1 bypass, boiler implosion and noise issues.	2008-9	$12.5 million	50%	$6.25 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.
Scope definition changes drastically during construction resulting in additional expenditures and/or potential schedule delays.	2008-12	$18.75 million	20%	$3.75 million	PSNH team will work closely with WGI & EPC contractors to minimize the impact.
Proposed design is inadequate and does not meet operability/reliability/ constructability requirements resulting in complete redesign.	2008-9	$12.5 million	30%	$3.75 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.

Scrubber Schematic

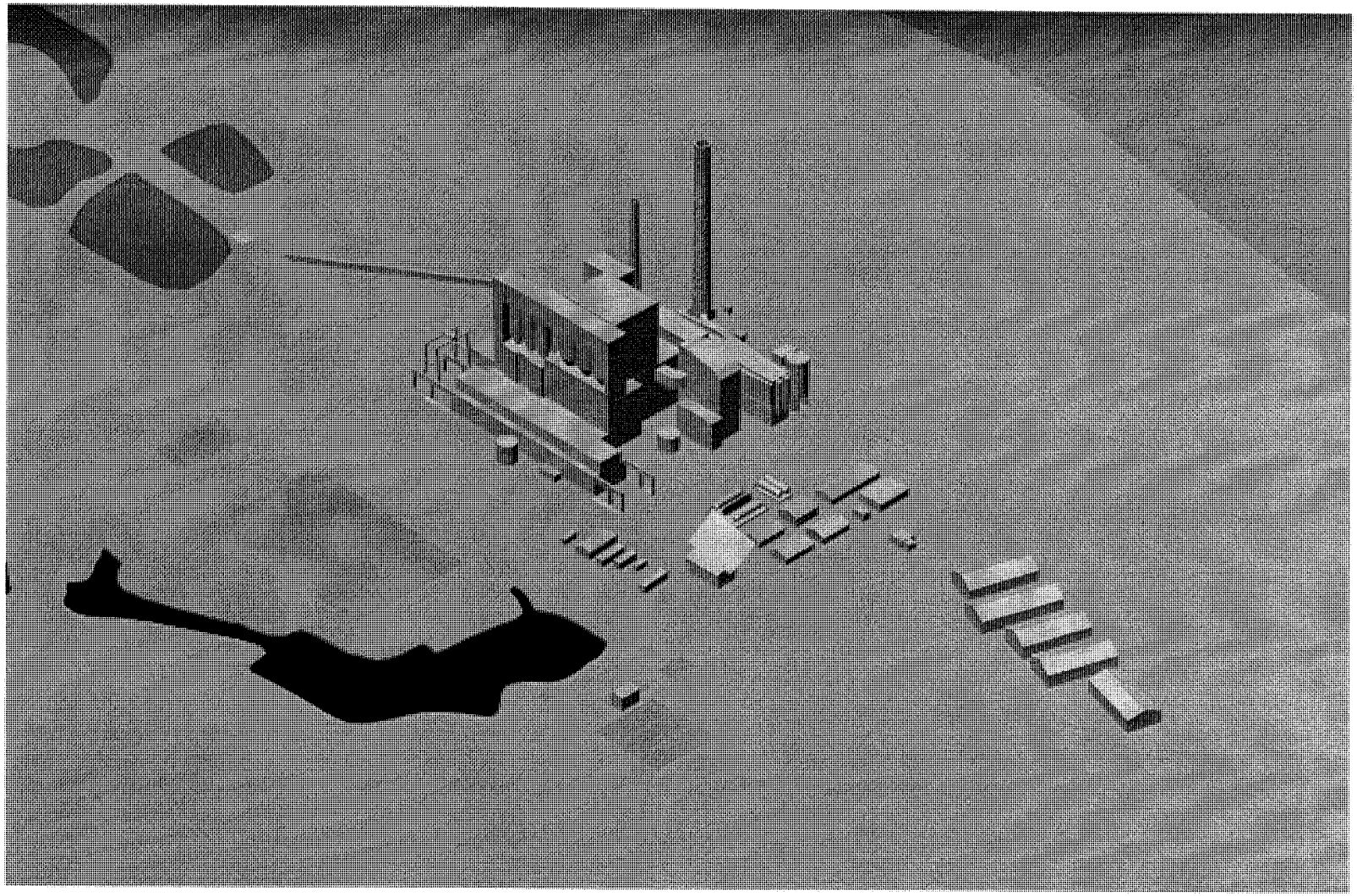
Clean Air Project
Merrimack Station

Wet Flue Gas Desulfurization Technology



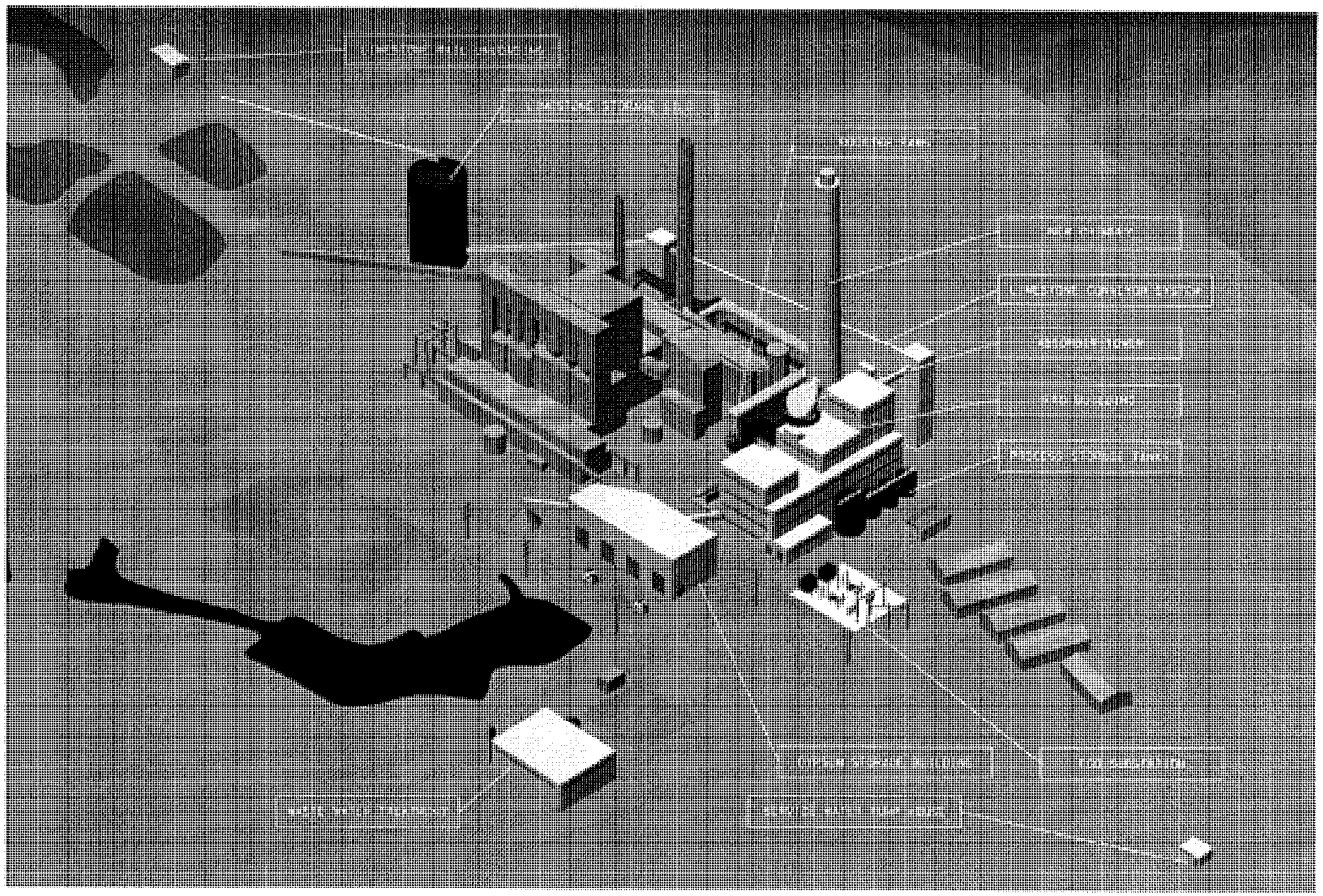
Merrimack Station: 2008

Clean Air Project
Merrimack Station



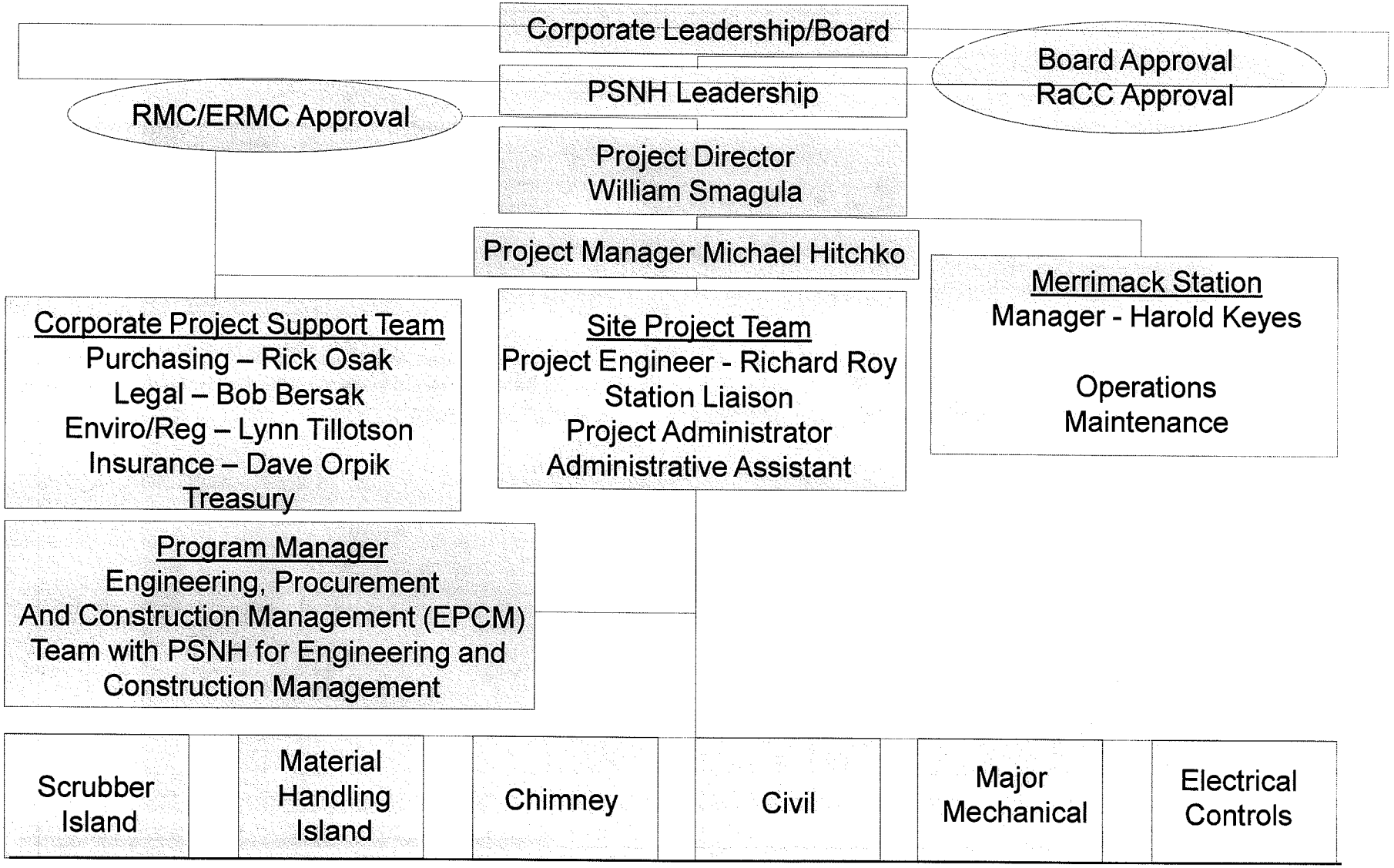
Merrimack Station: 2013

Clean Air Project
Merrimack Station



Project Organization

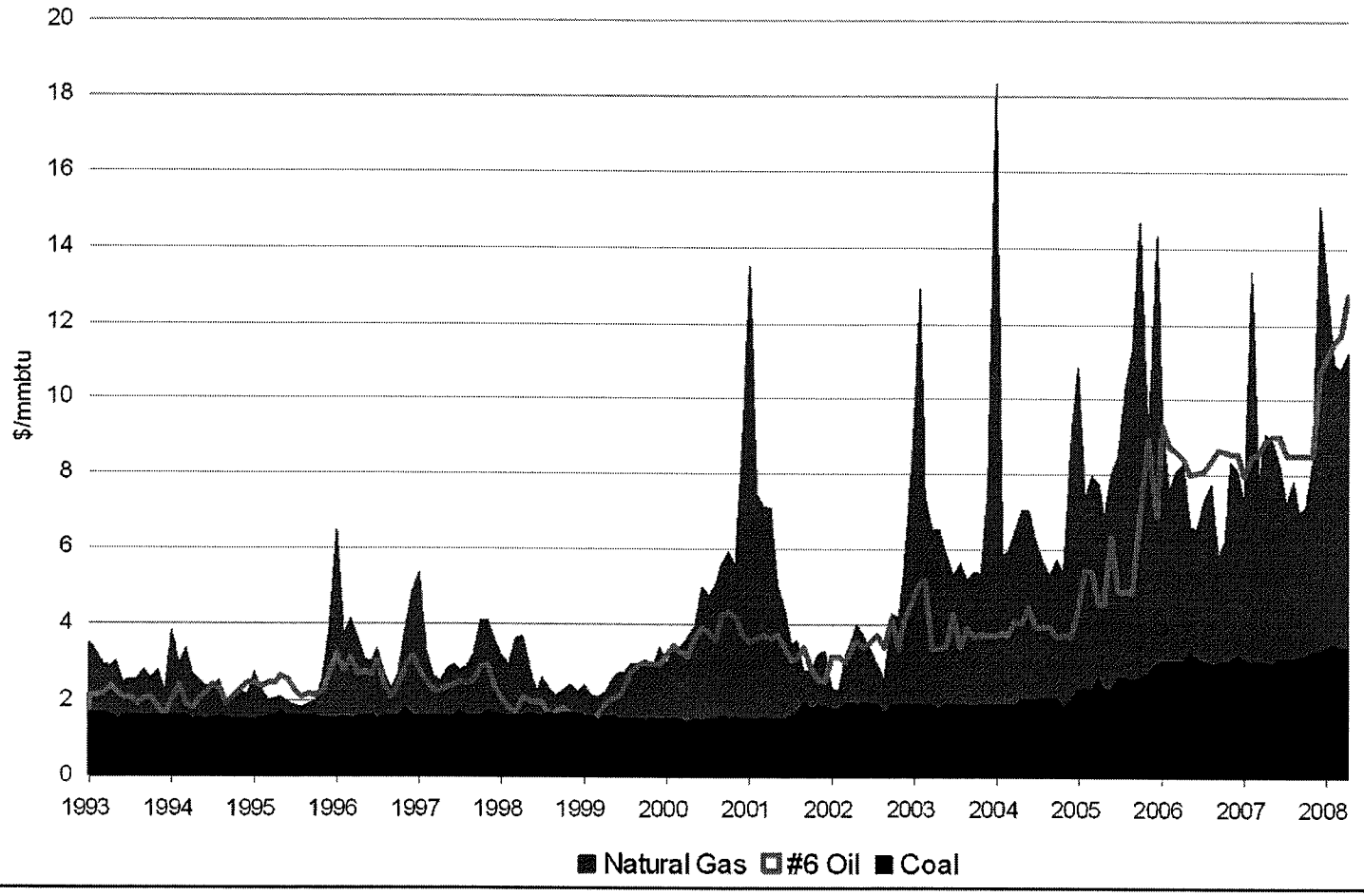
Clean Air Project
Merrimack Station



Historic Price Volatility Suggests Coal Will Find a Way to be Cheaper than Alternatives

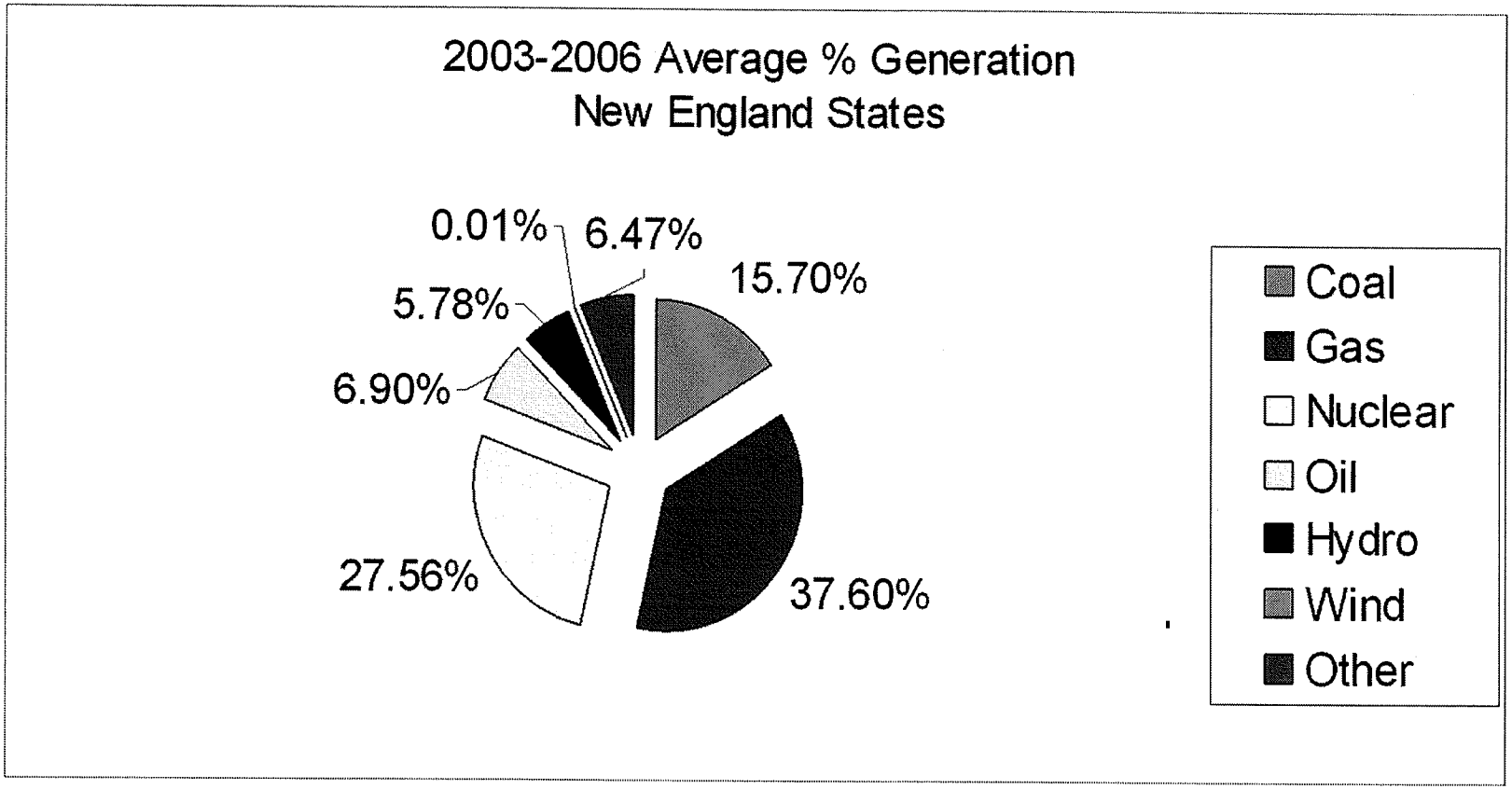
Clean Air Project
Merrimack Station

PSNH Actual/Quoted Delivered Fuel Costs



ISO-NE Energy Supply by Fuel Type

Clean Air Project
Merrimack Station



Northeast Utilities System

Clean Air Project
Merrimack Station

Public Service Company of New Hampshire

Clean Air Project

Capital Project Review and Approval

Northeast Utilities

Board of Trustees

Gary Long/Cameron Bready

July 15, 2008

~~Privileged and Confidential. Prepared at the direction of counsel. Prepared in anticipation of litigation.~~

Executive Summary

Clean Air Project
Merrimack Station

- New Hampshire legislation mandates compliance to mercury emissions standards set forth in the NH Mercury Reduction Act
  - Wet scrubber technology will reduce power plant mercury emissions required by New Hampshire law and is the technology specified by the law
  - There is no other technology which will guarantee capture of 80% of the mercury input of our coal fleet
- Cost estimates have been defined by a competitive bidding process
  - Prices have escalated from original estimates made in 2006 due to much higher raw material pricing and higher costs of engineering service
- Bid proposals indicate that an in-service date of mid-2012 is achievable
  - Earlier in-service date reduces cost (AFUDC), risk, and allows PSNH to take advantage of incentives built into the New Hampshire legislation for “early reductions” of mercury
- Despite the capital cost increases, Merrimack Station remains economic for customers under expected conditions and provides a significant investment opportunity for PSNH
  - The NPV of Revenue Requirements of adding the Scrubber versus replacing Merrimack Station energy and capacity supply with market purchases is a benefit to customers of $132 Million
  - The scrubber avoids about $15 Million in sulfur credit purchases annually, included in the customer benefit above
  - Incremental Net Income estimated at $18.5 M in 2013 – first full year of operation

Background – Merrimack Station Benefits PSNH's Customers

- Merrimack Station produces 3 million MWh of low cost power annually, about 35% of PSNH's total energy service requirement. The low cost energy produced at Merrimack Station off-sets the higher cost of market purchases in the overall energy service rate
- Operating Merrimack Station in a cost-effective manner has been one of the major reasons why PSNH's energy service rate is the lowest in the region, as much as 25% lower than the average of energy service supply that we track in NE
- Merrimack Station has control technology to satisfy NOx and particulate emissions requirements. With a scrubber, SO_2 and Mercury emissions will be controlled and Merrimack will be among the cleanest coal burning plants nationally
- Coal is the most abundant domestic fossil fuel resource in the United States supplying more than 50% of the nation's power generation fleet, but only 15% of New England's generation. Maintaining the use of this secure fuel resource is important for the diversity of the region's future energy supply
- Historically, coal has maintained a price advantage over oil or natural gas as fuel for the power generation sector. Operated as Regulated Generation, this cost savings flows directly to customers

Continued operation of Merrimack Station with a scrubber will maintain fuel diversity and security of domestic fuel supply in the ISO-NE region, while providing PSNH's customers with low cost energy.

Financial Assessment – Summary Metrics

Total Installed Capital Costs	$457M
Capital Cost $ / kW	$1,000[1]
NPV of Base Case Customer Benefit	$132M
2013 Net Income Contribution	$18.5M
2013 EPS Contribution (Diluted)	$.04/share
Busbar Cost (2013)	$94.55/MWh

Key assumptions :

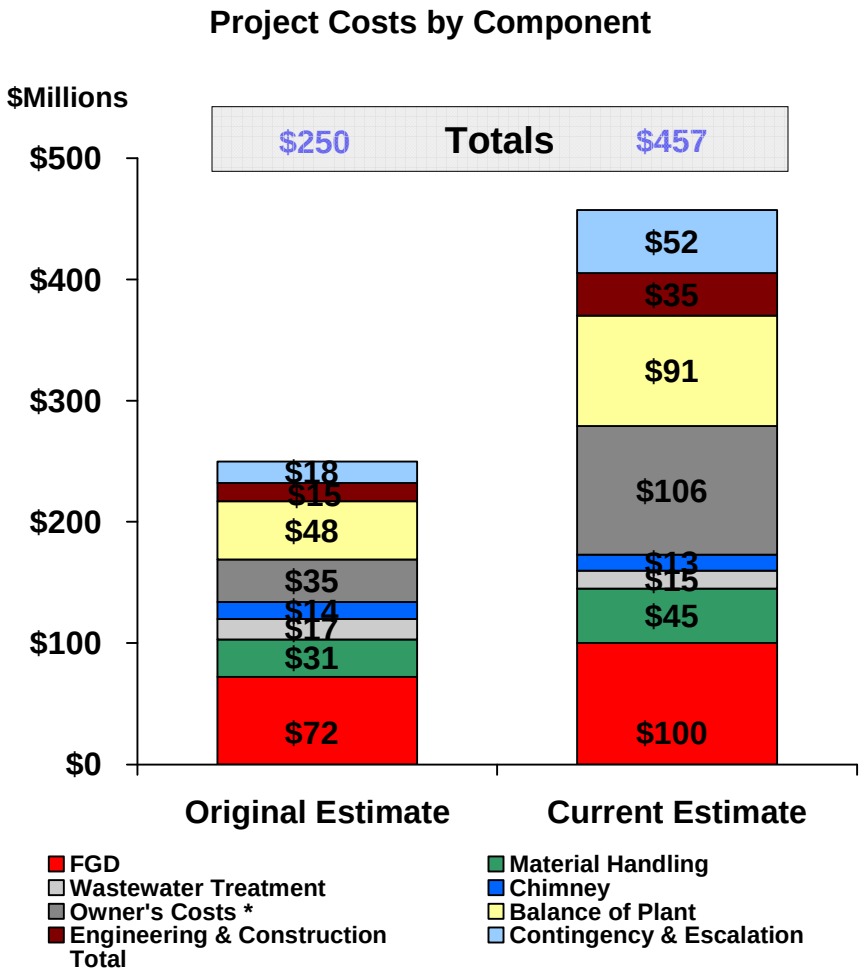
- Project in-service on June 30, 2012
- 9.81% ROE on 47.23% equity component of capital structure
- Base case natural gas price of $11/mmbtu, coal of $4.82/mmbtu and carbon of $7/ton

Note:

1. For reference, capital costs for a new CCGT would be approximately $1,600 - $1,700/kw. A new peaker would be approximately $950 – 1,000/kw.

Estimate of Project Costs

Major Island Contracts (Firm-Price Bids)	
FGD System	$100M
Material Handling	$45M
Waste-water Treatment	$15M
Chimney	$13M
PSNH Project Costs	$44M
Other Program Manager Costs	
Balance of Plant and Interconnection	$91M
Engineering and Construction	$35M
Contingency and Escalation	$52M
AFUDC	$57M
Total Direct Costs	**$452M**
NU Indirect Costs	**$5M**
Project Total	**$457M**



* Includes PSNH Project Costs, Indirect Costs, and AFUDC

Financial Assessment - Overview

- Customer benefit/cost of scrubber installation is dependent upon customer alternatives for securing the energy and capacity provided by Merrimack
  - Analysis assumes that customers will procure energy and capacity from the market if Merrimack is not operational
  - Market price for energy will likely continue to be set by natural gas units for the foreseeable future
    - → Expected future price for natural gas and the spread between natural gas prices and coal prices are critical to assessment of customer impacts
- Financial customer benefit/cost determined as follows:
  - PV of net revenue requirements of Merrimack facility (including new scrubber) – PV of market energy and market capacity costs
  - Customer benefit is achieved when the revenue requirements of Merrimack are lower than the costs of procuring the energy and capacity that would otherwise be provided by Merrimack from the market
- Future impact of carbon may play an important role in determining ultimate customer benefit/cost
  - Carbon costs are expected to impact electricity rates, but coal plants will likely be disproportionally affected given their emission rates versus natural gas plants

Financial Sensitivities

- Base-case assumptions result in net customer benefit of $132 million
- Net customer benefit is most sensitive to expected future natural gas and coal prices and the relative spread between the two commodities

Assumption Category	Assumptions			2008 PV of Net Customer Cost[1] 2012-2027 ($Mil)	Net Customer Impact Break-Even Rates
	Downside	**Base**	Upside	($300) ($180) **($132)** ($50) $40	
Capital Cost	**+10%**	**$457 mil**	**-10%**	$(159) $(27) $27 $(105)	**$684 mil**
2012 gas Prices, MMBTU[2]	**-10%**	**$11.00**	**+10%**	$(295) $(163) $163 $31	**$10.10**
2012 coal prices, MMBTU[2]	**+10%**	**$4.82**	**-10%**	$(228) $(96) $96 $(36)	**$5.49**
Implied Gas/coal Spread	**$4.60**	**$6.18**	**$7.76**	N/A[4]	**$5.29[4]**
2012 Carbon Costs[2,3]	**+50%**	**$7**	**-50%**	$(167) $(35) $35 $(97)	**$30.13**

Text in bars represents change in values;
text beside bars represents sensitivity result.

Notes:

1. NPV Net Customer Cost = (2008 Present Value of Merrimack Plant Revenue Requirements from 2012 to 2027) minus (2008 Present Value of Market Energy plus 2008 Present Value of Capacity Payments from 2012 to 2027).
2. Fuel and carbon costs are escalated at 2.5% per annum off of the 2012 estimate.
3. Reflects net impact on a $/ton basis for either RGGI or Federal policies excluding any allocations of allowances.
4. Spread not sensitized as impact depends on underlying natural gas and coal prices. Break even is based on a $4.82/mmbtu Coal Price (~$130 per delivered ton).

Financial Scenarios

Clean Air Project
Merrimack Station

- The following scenarios, denoted by their assumed probability of occurrence, demonstrate the compounding impacts of a variety of assumption changes on the key financial metrics for the project:

	Unlikely Low	Possible Low	Base	Possible High	Unlikely High
NPV - Net Customer Cost	**$481 MIL**	**$194 MIL**	**($132 MIL)**	**($413 mil)**	**($719 mil)**
Monthly Residential Customer Cost Impact	**$3.70**	**$1.49**	**($1.01)**	**($3.17)**	**($5.52)**
2013 Plant Busbar Cost ($/MwH)	**$102.41**	**$100.37**	**$94.55**	**$87.86**	**$79.44**
Net Income - 2013 (First full Year In-Service)	**$21.5 mil**	**$20.1 MIL**	**$18.5 MIL**	**$18.1 mil**	**$17.7 mil**
Assumed probability	***5%***	***25%***	**-**	***25%***	***5%***
Parameters					
Capital Costs, Millions	$532	$497	$457	$447	$437
2012 Gas Prices, MMBTU	$8.80	$9.90	$11.00	$12.10	$13.20
2012 Coal Prices, MMBTU	$5.78	$5.30	$4.82	$4.34	$3.86
2012 Carbon Costs, Ton	$30	$20	$7	$5	$0

Case Legend

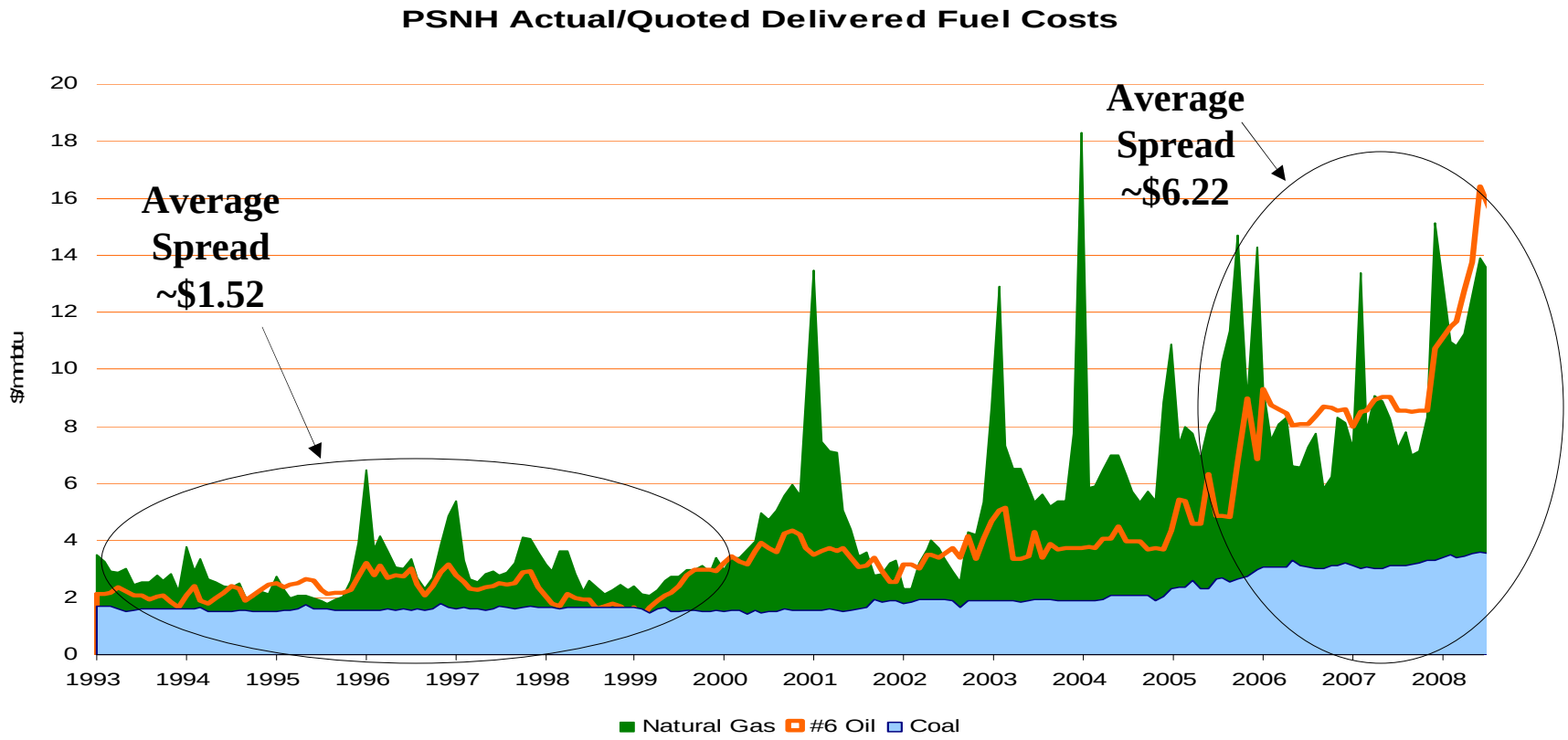
Unlikely Low	Case reflects project in-service delayed one year and cost overun ($45M), cooling tower addition ($30M), minimal Gas/coal Spread
Possible Low	Case reflects project in-service on-time with cost overun ($10M), cooling tower addition ($30M), decreased Gas/coal Spread
Base	Current assumptions
Possible High	Case reflects project in-service 6 months early ($10M), project costs as expected, benign carbon legislation, increased gas/coal spread
Unlikely High	Case reflects project in-service 6 months early ($10M) with lower than expected costs ($10M), no carbon legislation, maximum gas/coal spread

- Other scenarios considered:

	Customer Cost/(Benefit)
• $200 Oil Scenario:	($437 million)
• $50 Carbon Cost:	$70 million

Historic Fuel Spreads

- Gas/Coal spread has averaged $3.18/mmbtu over the last 15 years, as compared to the required customer break-even level of $5.29/mmbtu (based on current price levels)
  - However, post the hurricane season of 2005, the spread has averaged $6.22/mmbtu
- Since January 2007, the spread has averaged nearly $6.63/mmbtu and current spreads are more than ~$9/mmbtu



Key Financial Takeaways

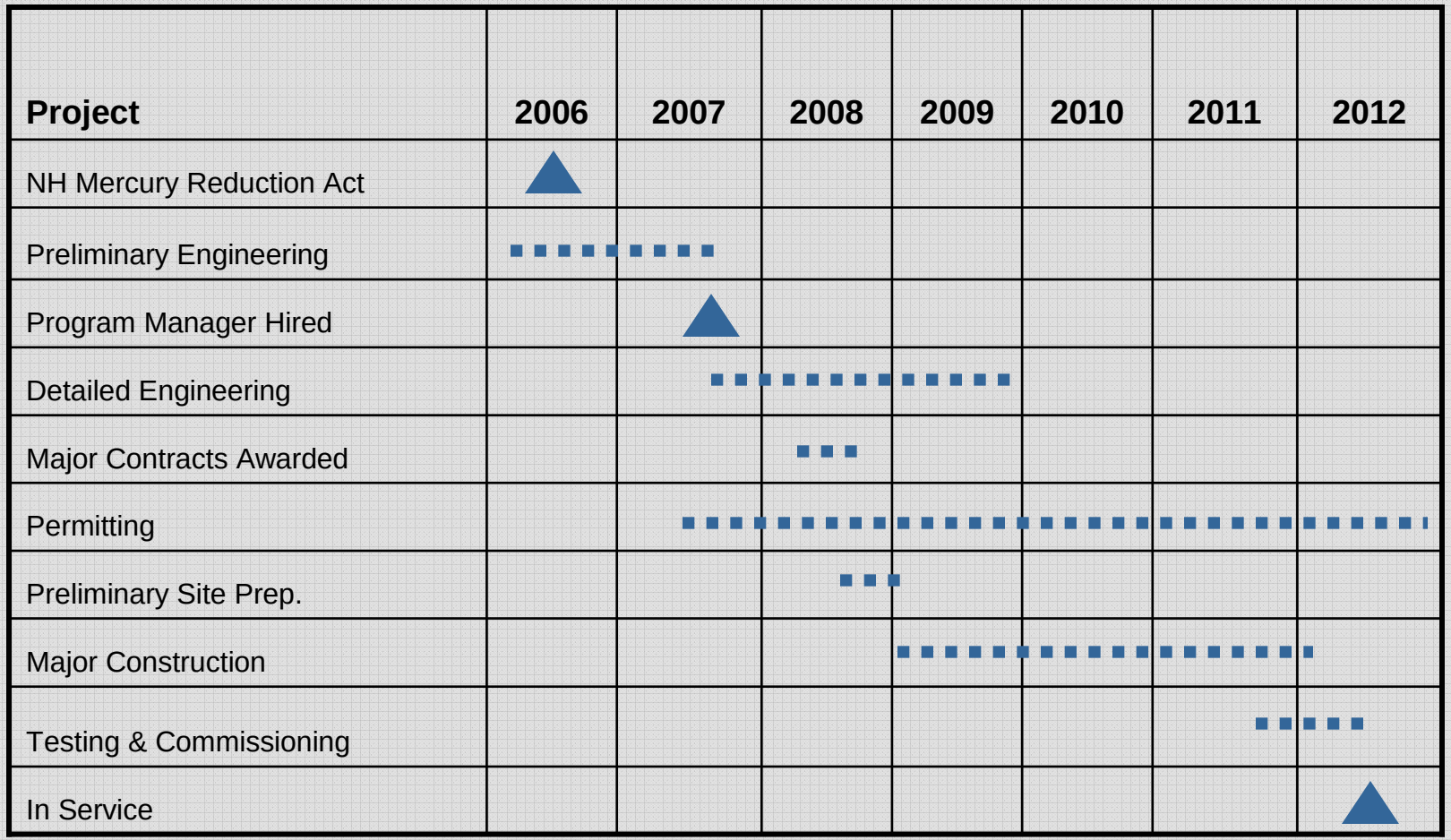
Clean Air Project
Merrimack Station

- Customer value of scrubber installation extremely sensitive to future expected natural gas/coal price spread
  - At assumed 2012 natural gas and coal price levels and other base case parameters, a spread of approximately $5.29/mmbtu (escalating) is required to create customer benefits
  - Recent spreads suggest that this level is realistic; however, historic spread levels have averaged lower
- Impact of carbon legislation is not expected to render scrubber investment uneconomic to customers at current projected costs under RGGI
  - Absent allocations, assuming all other base case assumptions, a net carbon cost of $30/ton (escalating) or greater would diminish customer value of scrubber installation
- Assuming base case fuel and carbon assumptions, capital cost estimates have meaningful headroom before rendering investment uneconomic
  - All other base case assumptions being held constant, capital costs can increase to ~$684 million before eliminating customer economic benefits
  - However, reductions in natural/gas coal spread and increases in carbon costs would put pressure on base case capital cost estimates
- Generation ratemaking making structure allows for PSNH to earn 9.81% ROE on equity invested in the project under all scenarios presented
  - Assumes that project capital costs are deemed prudent

Investment is essentially a long spread position on natural gas/coal with carbon and construction risk

Revised Project Schedule

Clean Air Project
Merrimack Station



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Conclusion

- Installation of the scrubber is required by NH law to meet mercury emissions requirements
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- Under the base case, continued operation of Merrimack Station with the Clean Air Project remains economically beneficial for customers
- State law allows for recovery of prudently incurred costs to construct and operate the scrubber
- The project team is in place and prepared to execute contracts now and begin construction in earnest late this year, with a project in-service date of mid-2012
- The proposal to construct and operate a scrubber at Merrimack Station, in conformance with the NH Mercury Reduction Law, is in the best interest of PSNH's customers and shareholders

Appendix Materials

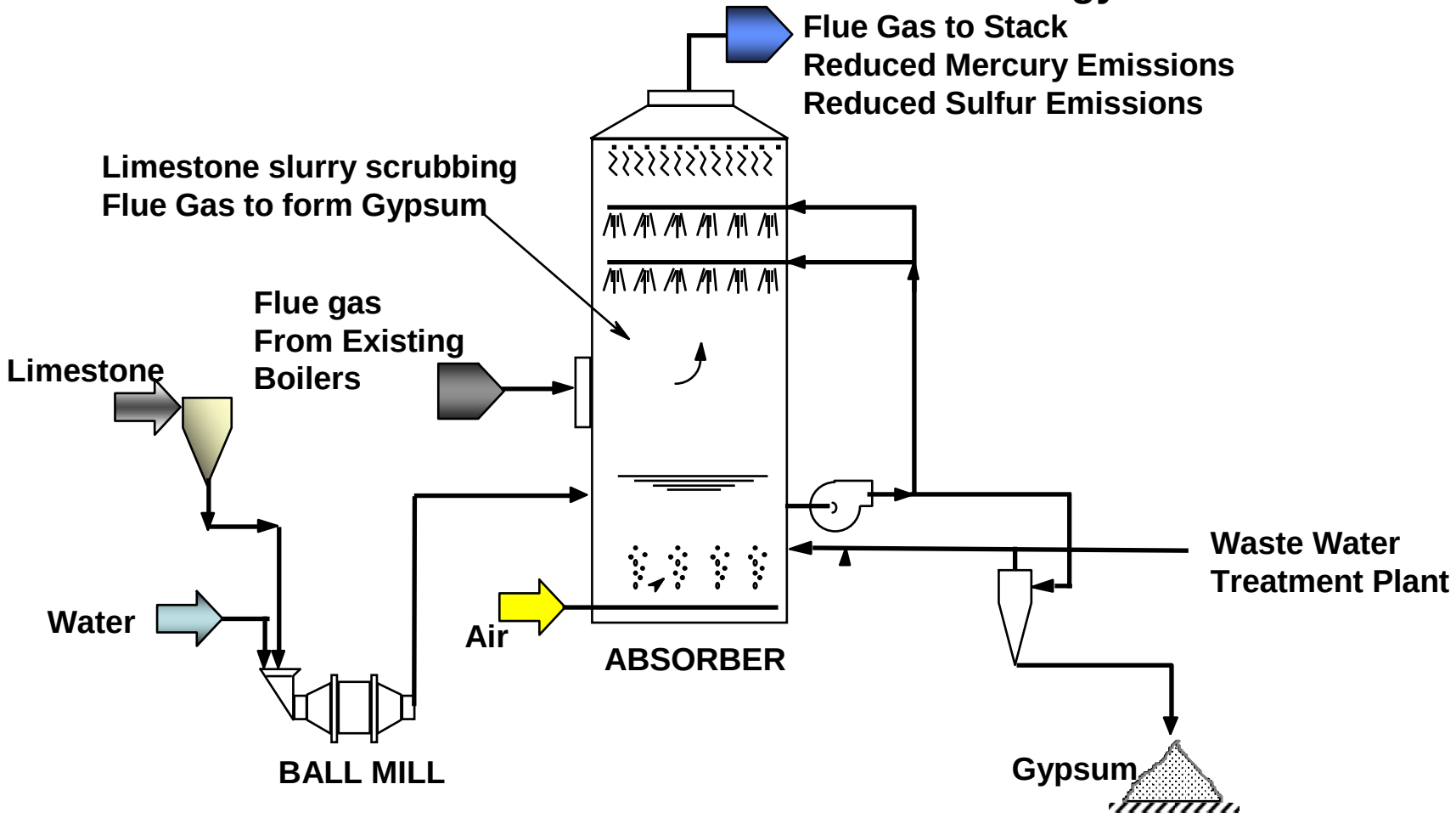
PSNH Clean Air Project

July 15, 2008

Scrubber Schematic

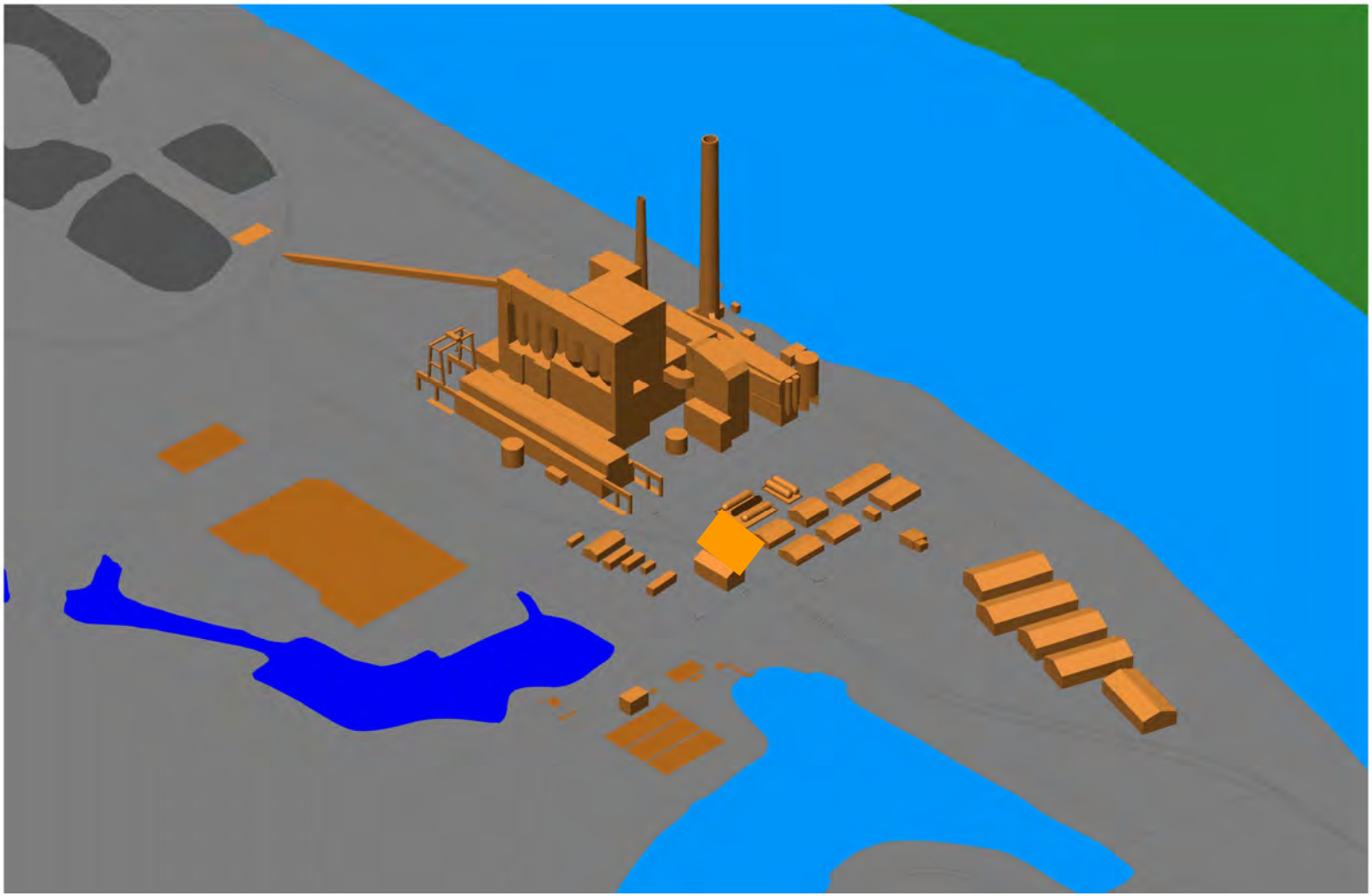
Clean Air Project
Merrimack Station

Wet Flue Gas Desulfurization Technology



Merrimack Station: 2008

Clean Air Project
Merrimack Station

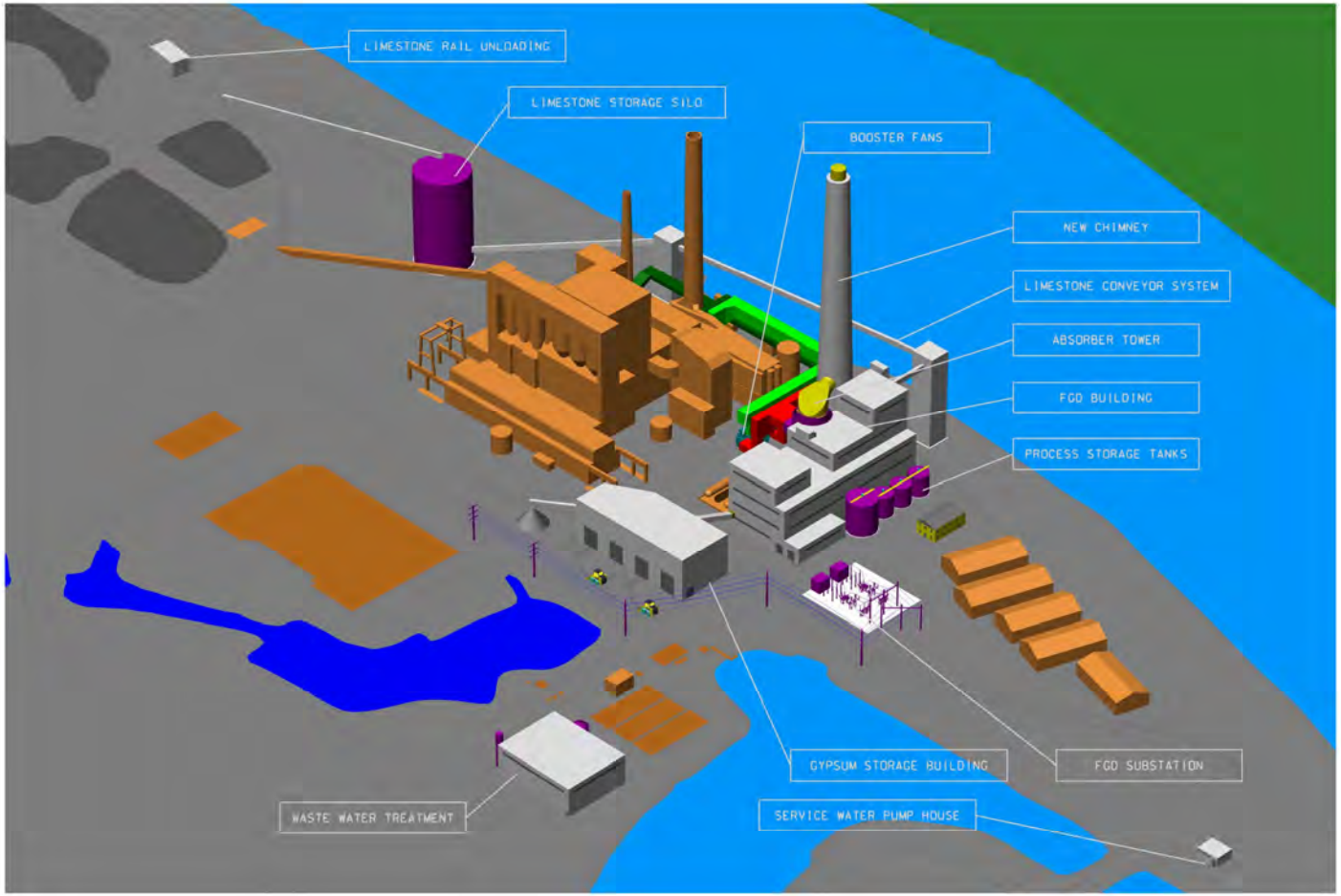


Northeast Utilities System

~~Privileged and Confidential. Prepared at the direction of Counsel. Prepared in Anticipation of Litigation.~~

Merrimack Station: 2013

Clean Air Project
Merrimack Station



Risk Assessment, Major Risk Concerns

Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Remaining bids received from vendors are significantly higher than expected related to material and handling costs. Note: The bids on the major equipment have been received.	2008	$10 million	20%	$2 million	Currently carrying out the procurement schedule. The Purchasing area is trying to stimulate competition during the bid process. Lastly as the required implementation date allows for some slippage in the schedule.
Lack of sufficient, qualified construction labor results in increased costs to import labor resources, schedule delays to wait for resources to become available.	2009-12	$50 million	10%	$5 million	WGI will initiate the National Maintenance Agreement. Meetings have been held with the union trades to discuss the project and labor requirements up front.
Inability to lock in firm prices during contracting phase exposes the project to price volatility and currency risk.	2008-9	$25 million	20%	$5 million	The RFP is being structured for fixed/lump sum pricing. The contract will be negotiated to try and include these parameters.

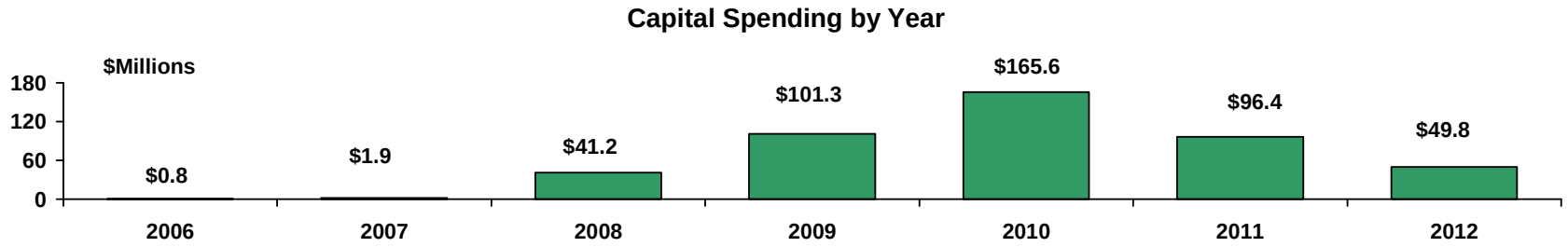
Risk Assessment, Major Risk Concerns

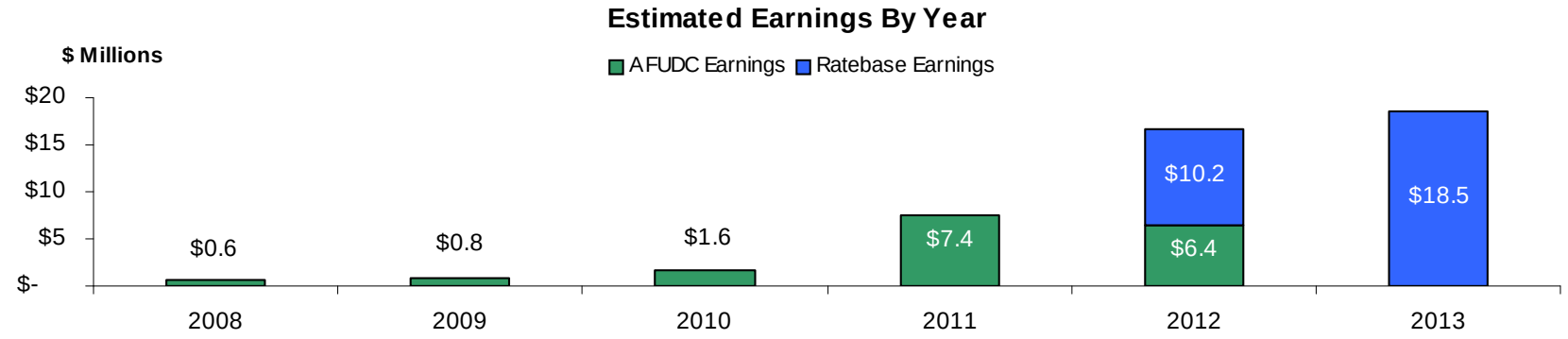
Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Vendors unable to meet project design criteria resulting in non-conforming bids. Note: bids received with mercury criteria. Risk relates to remaining design specifications.	2008-9	$25 million	25%	$6.25 million	In the event this occurs, an acceptable outcome will be negotiated during the procurement process.
Inability to design appropriate plant integration plans resulting in MK1 bypass, boiler implosion and noise issues.	2008-9	$12.5 million	50%	$6.25 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.
Scope definition changes drastically during construction resulting in additional expenditures and/or potential schedule delays.	2008-12	$18.75 million	20%	$3.75 million	PSNH team will work closely with WGI & EPC contractors to minimize the impact.
Proposed design is inadequate and does not meet operability/reliability/ constructability requirements resulting in complete redesign.	2008-9	$12.5 million	30%	$3.75 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.

Cashflow and Earnings Projection

Clean Air Project
Merrimack Station





EPS	$.00	$.00	$.01	$.02	$.03	$.04

Assumptions:

- Base-case project costs are estimated at $457M
- Project expected to be in-service on June 30, 2012
- Assumes 9.81% ROE on 47.23% of Capital Structure
- Average Shares outstanding per 2009-2013 Forecast

Project Benefits are Accentuated by Advancing the In-Service Date to mid-2012

Clean Air Project
Merrimack Station

- Financial
  - Reduces AFUDC cost by $10 Million
  - Limits exposure to material or labor cost escalation for project elements not covered by firm price contracts
  - Generates real earnings one year sooner
- Environmental
  - Eliminates an additional 31,350 tons of SO_2
  - Eliminates an additional 229 pounds of Mercury
  - Reduces particulate emissions to less than 1% one year sooner
- Customer
  - Produces “early reduction mercury credits” that can be used for
    - Compliance in future years if operational issues with the scrubber arise
    - Conversion to fungible SO_2 allowances (estimated at 12,500 allowances)

Public Service of New Hampshire

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longga@psnh.com

The Northeast Utilities System

Gary A. Long
President and Chief Operating Officer

September 2, 2008

Ms. Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 Fruit Street
Concord, New Hampshire 03301

Re: ***Docket No. DE 08-103***
Public Service Company of New Hampshire
Merrimack Station Scrubber Project
Request for Information

Dear Secretary Howland:

Pursuant to the Commission's Secretarial Letter, dated August 22, 2008, Public Service Company of New Hampshire ("PSNH" or the "Company") provides this response to the Request for Information regarding the legislatively mandated installation of wet flue gas desulphurization technology ("scrubber" technology) at Merrimack Station, to be installed as soon as possible but in no case later than July 2013. We have enclosed an original and six copies of PSNH's response.

This filing demonstrates that following the installation of the scrubber, Merrimack Station will continue to be a vital base-load source for reliable and affordable power in the State of New Hampshire, and will have the added benefit of being among the cleanest coal-burning plants in the nation. PSNH is confident that up to the initiation of this inquiry, it was diligently pursuing and complying with the legal mandates contained in 2006 N.H. Laws, Chapter 105, the mercury emissions reduction law ("Scrubber Law"), by moving forward rapidly with the installation of scrubber technology at Merrimack Station.

As required by the Commission's Request for Information, PSNH is providing a memorandum of law, project status report, and response to specific economic inquiries. This information will serve to support the legislature's finding that the installation of the scrubber at Merrimack Station ("the scrubber project" or "Clean Air Project") is "in the public interest of the citizens of New Hampshire and the customers of the affected sources." RSA 125-O:11, VI. The legislature, in reaching its conclusion that the scrubber installation is in the public interest, did

not limit itself to economic considerations, but rather performed a careful balancing of the costs and the ensuing benefits to the public health, welfare, economy, and environment (including improved air quality and the protection of natural resources)—benefits which contribute to sustaining the vibrancy of the State and its citizens as a whole. As part of its inquiry, the Commission must review and comply with the General Court's Statement of Purpose and Findings (RSA 125-O:11) as well as the larger statutory context as delineated in the Findings and Purpose of the Multiple Pollutant Reduction Program (RSA 125-O:1)("the Clean Power Act") in which these societal prerogatives are prioritized.

PSNH has a long history of collaboration with state policymakers and the resolution of difficult and challenging environmental issues. We are proud of our consistently proactive environmental stewardship which includes: installation of the first-in-the-nation utility-owned selective catalytic reduction system at Merrimack Station Unit 2 in 1995 and Unit 1 in 1999 to capture NOx emissions; the successful, internationally lauded conversion of a fossil-fuel unit (Schiller Unit 5) in our fleet to a wood-burning facility; our vigorous collaboration on, and crafting of, the first-in-the-nation groundbreaking four-pollutant bill, the Clean Power Act, RSA Chapter 125-O; and now, the aggressive installation of a scrubber system at Merrimack Station to significantly reduce mercury and sulfur dioxide emissions in compliance with the Scrubber Law. At its core, the Scrubber Law is an environmentally motivated law which will result in improvements to air quality. With the Clean Air Project, PSNH will capture, at a minimum, 80% of the mercury entering its coal-fired power boilers which otherwise could be released to the atmosphere. Additionally, the scrubber technology will remove more than 30,000 tons of SO2 emissions each year. These significant environmental benefits were viewed by the legislature as critical goals, in the public interest, to be accomplished on an accelerated basis.

The Scrubber Law is itself another example of PSNH's willingness to work with state policymakers in resolving critical issues. It is the product of a lengthy collaborative effort that PSNH spearheaded along with the Governor's Office, the Office of Energy and Planning, the Department of Environmental Services, and a number of legislators and environmental groups. (See the legislative history included in PSNH's Memorandum of Law.) The legislature, recognizing that the Scrubber Law represented the delicate balancing of numerous interests, found the law in its entirety to be in the public interest, as it has plainly and clearly stated within the law itself, and, in fact, further determined to protect the integrity of the statutory language with a finding emphasizing the non-severability of the law's provisions. (RSA 125-O:11, VIII: "The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of cost, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components.")

The Clean Air Project is a vast and complex engineering and craft labor challenge that is in progress and will take another four years to complete. At its peak, and in addition to the engineering and management support services, the project will require the efforts of more than 300 union craft workers. PSNH has reached a written accord with organized labor leadership to utilize union labor on this project to ensure the availability of critical skilled craft workers and to prioritize work safety on the job. In a recessionary national economy, the importance of this

project to craft labor in terms of steady in-state employment cannot be over-emphasized—one more example of an important public interest.

Because of its size and complexity, the Clean Air Project must be an extremely well managed, carefully orchestrated project, and must firmly adhere to critical milestones established in the overarching project schedule which will control the work of numerous contractors and subcontractors. PSNH has already completed a number of critical milestones to ensure project success, as further detailed in this filing.

At this juncture, PSNH has diligently gone through competitive bidding processes for each major "island" of work and has proceeded to negotiate fixed-price contracts with selected vendors. The contracts for the scrubber itself and for the new chimney stand ready to be finalized and executed; the contract for the waste-water treatment facility and site preparation are in final negotiations. Any delay in issuing these contracts will be a major setback for this project and will result in additional costs to our customers. Contractors and their subcontractors are only willing to hold fixed prices for an abbreviated period of time given the rapid escalation of the prices of raw materials and their need to lock in shop time well in advance for the manufacturing of components. If any one of PSNH's major contractors is unwilling to hold prices or contractual terms or to extend the deadline for execution of contracts, the scrubber project schedule has the potential to be irreparably disrupted and harmed. This is because the nature of the scrubber project and the site layout require the sequential completion of many of the construction islands (for example, consider the new chimney: the foundation work must be done in non-winter months, followed by the construction of the chimney "shell" which must be completed in order for the area surrounding the chimney or "drop zone" to be released before other work can proceed for obvious safety reasons). As a result, this means that even a short delay now will have a domino effect and a greater than day-for-day impact on the entire project with the likely result of significant additional costs to the project.

We are mindful of the legislature's mandate that the scrubber project proceed on an accelerated basis and refer the Commission, once again, to the Statement of Purpose and Findings, as well as the legislative history (see PSNH's Memorandum of Law). Any delay in this project will result in added costs, while, conversely, an accelerated schedule will save money. Shaving six months to a year off the project timeline saves significantly on AFUDC costs, avoids escalation in costs of materials and labor, and will result in early compliance credits for PSNH's customers (Economic Performance Incentives, RSA 125-O:16). We respectfully ask the Commission's assistance in complying with the law by expediting the resolution of this inquiry.

It should surprise no one that the costs of this project have increased significantly over the original preliminary estimates made in late 2004-2005. On May 15, 2008, the *Wall Street Journal* reported on the escalation in prices of commodities due to unrelenting global demand--steel prices, just five months into the new year, were already up 40-50% for the year; coking coal and scrap steel, key ingredients in steelmaking, had soared 100%; along with a 71% increase in iron ore prices--all of which are "part of a broader surge in raw-materials prices amid tight supplies and soaring global demand, fueled in part by the rapid industrialization of India, China and other developing nations." However, the cost increases involved in a plant modification are

dwarfed by the costs of constructing a new plant which have more than doubled in recent years. According to the Cambridge Energy Research Associates, "the construction of new generating capacity that would have cost $1 billion in 2000 would cost $2.31 billion if construction began today" with most of that increase occurring since 2005. (*Wall Street Journal*, May 27, 2008.) PSNH would like to emphasize: time is money in this market.

Merrimack Station's continued operation ensures that New England has continued fuel diversity and energy security. The New England region is already highly reliant on natural gas, and subject to its high price volatility and the vagaries of the natural gas market, as a fuel source for the power generation sector. Even so, there is very limited activity, and to this point in time, very unsuccessful efforts, to add new base-load power generation to the New England grid. As the economy remains difficult, and credit markets tight, the ability to site, permit, finance, and construct new base-load generation has become nearly impossible. Preservation of the key existing base-load generation resources like Merrimack Station, while maintaining its positive economics for customers, is critical to the region's future. This is particularly true in the case of Merrimack Station which provides not only low-cost energy but has a remarkable record of reliability characterized by record-breaking periods of lengthy continuous operation (in 2004, Merrimack Unit 1 and Merrimack Unit 2 both outperformed previous station operation records—Merrimack Unit 1 ran continuously 122 days and Merrimack Unit 2 ran 147 days). In addition, in 2007, Merrimack Station produced more energy than it ever has in its decades of operation. Clearly, the Station is functioning extremely well, as a direct result of strategic equipment repairs and replacements, well executed maintenance work, well performed operations activities, a dedicated workforce, and a strong and experienced management team.

Beyond the benefits PSNH's operation of Merrimack Station provides to customers in terms of lower electric energy prices and reliability to the New England electric grid, it should be recognized that the operation of Merrimack Station is a significant contributor to the local and state economy—another fact supporting the legislature's public interest finding. Merrimack Station employs approximately 100 highly skilled and dedicated employees in what has become an increasingly limited "manufacturing" sector of our state's economy. In addition, there is significant company support staff for the Station. During annual outages and construction projects, the number of jobs provided increases substantially. PSNH, through its operation of Merrimack Station, contributes annually $758,000 in state utility/property taxes and $2.7 million in local property taxes. This in-state support to the economy reaches beyond wages and tax benefits and extends to the large quantity of materials and supplies and services for which PSNH contracts to operate and maintain the facility on an annual basis.

PSNH has met every environmental challenge head on and met or exceeded expectations in achieving environmental benefits, all of which have been in the public interest. Today, the challenge is mercury—a challenge we are striving to meet. With the installation of a scrubber at Merrimack Station, PSNH will maintain and enhance its standing as the lowest emitting coal-fired power generator in the region. We are excited about this project and the positive impact it will have on our environment. We remain confident that this can be achieved while continuing to provide economic, reliable base-load power for our customers over the period of the scrubber's operation.

PSNH urges the Commission to act expeditiously to resolve this inquiry so that PSNH may resume the commitment of capital and manpower necessary to install the scrubber technology at its Merrimack Station as mandated by law. PSNH stands ready and willing to keep the Commission up to date on the status and progress of the Clean Air Project once we are able to proceed in accordance with the law.

Sincerely,

Gary A Long

Gary A. Long
President and Chief Operating Officer

THE STATE OF NEW HAMPSHIRE
before the
PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire
Merrimack Station Scrubber Project
Request for Information

Docket No. DE 08-103

Report

In its Secretarial Letter dated August 22, 2008 in this docket, the Commission notified Public Service Company of New Hampshire (PSNH) that it was conducting an inquiry into the status of PSNH's efforts to install a wet flue gas desulphurization system (scrubber technology) at Merrimack Station in Bow. Installation of the scrubber (the "Clean Air Project") is mandated by RSA 125-O:11 through 18 (the "Scrubber Law") to achieve reductions in mercury emissions. The Commission directed PSNH to file, by September 12, 2008:

I. a comprehensive status report on its installation plans;

II. a detailed cost estimate for the project;

III. an analysis of the anticipated effect of the project on energy service rates; and

IV. an analysis of the effect on energy service rates if Merrimack Station were not in the mix of fossil and hydro facilities operated by PSNH.

This report provides the information concerning PSNH's scrubber installation project (the Clean Air Project) requested by the Commission's secretarial letter.

I. SCRUBBER STATUS

PSNH is moving rapidly forward with the Clean Air Project to comply with the Scrubber Law's mandate to achieve significant reductions in mercury emissions at the coal-burning electric power plants in the state as soon as possible. RSA 125-O:11, I. Unless further delayed, PSNH will meet the statutory installation deadline of July 1, 2013, and is striving to have the scrubber operational sooner than that deadline. The scope of the Clean Air Project will encompass planning and design; schedule and cost development; oversight of multiple competitive bidding processes for engineering; equipment and system procurement, selection of contractors, contract negotiations and execution; sequential construction management of the various project components and interfaces, followed by the integration of those components into a functioning system; and operational start-up activities. All work on the Clean Air Project will be performed with safety as a high priority. To date, PSNH has spent approximately $10 million on the Clean Air Project.

A. Activities Performed during 2006

1. Merrimack Station began investigating operational changes at the facility that would provide the necessary flexibility in the design and engineering of a scrubber system. The catalyst replacement program on the previously installed selective catalytic reduction systems was reviewed and updated to accommodate operating requirements of a new scrubber and potentially improve the overall performance of the equipment.

2. Merrimack Station revised, tested and modified its ash handling operations and capabilities to provide necessary options for ash management in order to maximize unit operations when a new scrubber is installed.

3. Initial engineering was completed by Sargent and Lundy ("S&L") based upon information provided in 2005. S&L also evaluated a number of equipment options integral to the scrubber project and completed a layout of the project. Budgetary quotes and lead times were solicited from major scrubber vendors, also during 2005.

4. General specifications for the scrubber island, material handling system and the chimney were provided to PSNH by S&L to further develop project requirements. To complement this preliminary engineering work, site visits to the other scrubber installations were completed by PSNH/Merrimack Station personnel.

5. Preliminary work in support of the temporary air permit application was completed including emissions netting calculations and suggested modeling protocol.

6. Water quality testing was completed to define and identify appropriate sources for make-up water to the scrubber system.

7. Electrical work was reviewed with PSNH transmission and distribution divisions to outline the power requirements for the new scrubber system. A two phase approach was defined. Plans were made to relocate and upgrade an existing, old construction yard in order for the land to be used for construction power for the scrubber system. A new substation will be installed to power the scrubber operations.

8. Also in preparation for the scrubber installation, an unused oil tank was removed from the north side of the plant. This space will eventually house portions of the material handling system required by the scrubber project.

9. A study of the Merrimack property's south yard was performed to ensure an adequate layout area for the necessary equipment and building surrounding the scrubber. A number of contractor facilities in the south end of the plant, as well as the existing training facility, were identified for relocation.

10. A portion of the southern-most yard was cleared to make room for a new warehouse building. Although a separate effort from construction of the scrubber project itself, it

was necessary to complete this work prior to the extensive construction and labor effort that will be underway during the construction of the scrubber islands. Preliminary engineering, design, surveying and permitting for this new warehouse were completed.

11. A number of appropriate purchasing and procurement efforts were completed including contract options and strategy analysis and vendor lists for scrubber manufacturers and architect/engineers.

12. Engineering efforts included review of the latest equipment options, equipment integration capabilities, and mercury capture capabilities.

13. Also initial investigation into gypsum disposal and sale opportunities was pursued with various wallboard manufacturers.

B. Activities Performed during 2007

1. Merrimack Station continued operational changes at the facility that would provide the necessary flexibility to accommodate the design and engineering of a scrubber system. The station worked to modify boiler combustion temperatures. Tube shields were removed from the boiler reheater to increase heat transfer and improve steam temperatures.

2. The station's south yard was cleared for the new warehouse on schedule. This new warehouse will initially house displaced inventory from existing warehouse buildings. The building permit application was submitted on May 17, 2007. Preliminary design of the building was completed.

3. PSNH went out to bid for the Program Manager for the Clean Air Project on May 15, 2007. URS Washington Division ("URS") was hired in October 2007 following lengthy contract negotiations.

4. PSNH submitted a Temporary Air Permit application for the Clean Air Project with NHDES on June 6, 2007. An emissions netting calculation and determination of a stack height consistent with good engineering practice ("GEP") were required information to support the Temporary Air Permit application submittal. Necessary air dispersion modeling services were contracted for and have begun.

5. The first legislative update, as required annually by RSA 125-O:13, IX was completed on June 26, 2007. PSNH is required to report on the progress, status, and cost of complying with the provisions of the scrubber law to the legislative oversight committee on electric utility restructuring, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee,. A brief summary of that first update follows:

- Engineering
    i. Specifications developed for key components
    ii. Possible site plan layouts developed
    iii. Equipment options identified
    iv. Vendor lists and contacts established
    v. Industry impact of high number of scrubber installations analyzed
- Commercial and Purchasing
    i. Contract strategy determined and approved
    ii. Program Manager specification written
    iii. Program Manager out to bid
- Permits and Approvals
    i. Temporary Air Permit Application submitted to NHDES-ARD June 7, 2007
    ii. Town of Bow presentations and submittals underway
    iii. Company financing approvals initiated
- Site work
    i. Existing oil tank removal completed
    ii. Site surveys completed
    iii. South Yard studies completed

C. Activities Performed during 2008 to date

1. Construction of the major components of the Clean Air Project has been broken down into the engineering, procurement, and construction of four major work islands which include the scrubber, chimney, waste water treatment facility, and material handling system. Construction must occur on a sequential basis. Of these islands, the chimney and scrubber require completion first for safety reasons given the physical orientation of the equipment and constraints of the site. Following foundation work, the chimney "shell" construction must precede all work because of the necessity of preserving a "drop zone" or area around the chimney for evident safety reasons. As a result of these sequential construction requirements, both the scrubber island and chimney specifications were prioritized and sent out to bid first, vendor bid proposals were received, bid proposals were reviewed to identify the lowest evaluated bidder and negotiations with lowest evaluated bidders were undertaken. The negotiations are in final stages on both contracts and the contracts were expected to be executed this week; however, as a result of the initiation of this inquiry, such contracts must await the Commission's action in this inquiry. The material handling system and waste water treatment system followed with specifications sent out to bid, bid proposals received and evaluated, and negotiations well under way. Contracts will be finalized in short order and will be ready to execute in the near-term.

2. A second annual legislative update was completed on June 18, 2008. The status of the scrubber installation and mercury reductions was reported on to the legislative oversight committee on electric utility restructuring, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee. A summary of that update follows:

- Engineering
    i. Project's components
    ii. Specifications developed for 4 key components
- Commercial and Purchasing
    i. Program Manager hired Sept 2007
    ii. Scrubber Island and Chimney proposals are in negotiations
    iii. Vendor Proposals requested and received for Wastewater Treatment Facility and Material Handling System
- Review, Permits and Approvals
    i. NHDES – May 12 presentation
    ii. Temporary Permit expected October 2008
    iii. Town of Bow –Local permitting
    iv. Regional Planning Commission
- Site work
    i. Existing oil tank removed
    ii. Site surveys and studies completed
    iii. Warehouse construction underway
    iv. On-site engineering facilities completed
- Schedule and Costs
    i. Tie-ins: MK#1 Fall 2012, MK#2 Spring 2013
    ii. Project costs will be updated with review of major equipment bids

3. It was reiterated at this update that PSNH was focused on expediting the schedule; and with two major equipment islands in negotiations, it would soon be known to what extent the critical path of this project could be potentially shortened. These negotiations would also provide updated costs associated with a new timeline.

4. As referenced earlier, negotiations with the scrubber island and chimney are now in their final phase. Recently completed boiler implosion, burner management and electrical supply studies are being reviewed. Multiple meetings have been attended in the Town of Bow focusing on local permitting requirements and also addressing any Regional Impact considerations. With that, public outreach and education meetings have been conducted and/or scheduled with a variety of organizations, such as the Southern New Hampshire Planning Commission, the Town of Pembroke, Town of Hooksett, etc.

5. Finally, air modeling is being completed with current engineering and equipment design information and proposed site orientation. Drafting of the Temporary Air Permit continues by the New Hampshire Department of Environmental Services (NHDES) Air Division.

D. Schedule Status

1. As the project has moved forward steadily, PSNH has obtained more detailed information from major equipment and system suppliers, and has adjusted the schedule accordingly. The current optimized schedule shows that completion of the Clean Air Project in 2012 is

possible if there are no additional delays. PSNH's efforts are now focused on an early completion, as required by RSA 125-O:11, I. The early completion date is attributable to PSNH's diligence in complying with the Scrubber Law's mandates as rapidly as reasonably possible. Early completion will be beneficial to customers because AFUDC will be reduced, customers will benefit from early reductions credits provided by the Scrubber Law's Economic Performance Incentives at RSA 125-O:16, and, most importantly, mercury and sulfur oxide emissions will be reduced. In addition, by finalizing fixed price contracts and locking in prices, additional escalation of commodities can be avoided to some extent.

2. An early completion date is predicated on successful completion of a number of critical activities on a timely basis. These activities include obtaining permits to proceed with construction in the Fall of 2008 from the Town of Bow, and the receipt of a Temporary Air Permit from the New Hampshire Department of Environmental Services in the Fall of 2008. Moreover, procurement of engineering services and equipment must proceed on an aggressive schedule. Even a short delay at this time could trigger a six to eight month delay in completion of the project because foundation construction work must commence in the Fall of 2009. If foundation construction work is not completed in the Fall of 2009, the work will have to be delayed until the Spring of 2010 because it cannot be performed during winter months. This illustrates the valid concern that even a brief delay has the potential for creating a domino effect on project schedule with far more than a day-for-day delay.

3. The schedule is aggressive and has only a small tolerance for unpredictable delays due to inclement weather, equipment delivery problems, resolving engineering or design problems, or start-up and testing problems. Consequently, any delays caused by regulatory actions or other unanticipated events could jeopardize PSNH's ability to adhere to the schedule. Any such delay would increase the cost of the project.

E. Engineering Status

1. URS has overall responsibility to develop the cost and schedule, subject to PSNH's review and approval.

2. The initial estimated cost of the project was based on a Sargent & Lundy estimate performed in 2005. There have been significant increases in the cost of raw materials, steel, labor, and energy, since this estimate was made, as noted by the *Wall Street Journal* in a May 27, 2008 article entitled "Costs to Build Power Plants Pressure Rates" (Atch 1) and echoed by the FERC's Office of Enforcement's report to the FERC Commissioners on Increasing Costs in Electric Markets, presented on June 19, 2008 (Atch 2). URS has more current information and experience with this type of work, and they developed a revised estimated project cost based on their experience with such projects and on bids received from the four major system vendors (Scrubber, Stack, Material Handling, and Waste Water Treatment Islands).

3. Approximately 60% to 70% percent of the revised project cost is now based on firm contracts or firm bids PSNH has received. Only small system and interconnection field systems (electrical, ductwork, piping, yard work, etc.) have yet to be finalized by bids. If bids in hand are not acted on in a timely manner, such delay in execution of contracts can and will result in a delay in project completion and higher costs.

4. URS has 30 engineers currently working on the project in the following areas:
    a. Electrical engineering
    b. Civil engineering
    c. Structural engineering
    d. Controls
    e. Fire Protection
    f. Estimators
    g. Schedulers
    h. Draftsmen.

5. URS's efforts are approaching peak workload. This is a critical time in their efforts and any upset will create risk of delay and added cost.

6. Current work activities include site preparation, planning, and design. Once the shovel is in the ground, construction activities will go on for approximately four years. Because there will be more than 300 people working on the project at peak periods, the work must be carefully planned and performed. Construction will be performed by union craft labor, and an organized labor National Maintenance Agreement has been executed to ensure availability of workers and eliminate the potential for labor disputes as well as to prioritize safety on the job.

7. Parts lay-down and storage areas must be developed, site trench layout for electrical and piping systems need to be designed, and contractor parking and access paths need to be built.

F. Current Procurement and Construction Activities

1. PSNH has been actively engaged in negotiating contracts for various aspects of the project. PSNH has completed bid evaluations for the waste water treatment system and material handling system and those contracts are under negotiation. Bidding is currently in progress for items like the construction power electrical switching panel, booster fans and motors, and a new electrical substation.

2. Negotiations are about to be finalized on the scrubber and chimney. However, as noted in the Motion to Accelerate Schedule filed with the Commission on August 25th, PSNH and its corporate parent, Northeast Utilities, cannot continue to commit additional dollars to the scrubber project until the Commission determines its actions in this inquiry. PSNH will initiate discussions with various bidders and contractors to seek ways to continue to allow limited critical path work to proceed, if possible. However, as stated above,

escalating costs for global commodities such as steel and cabling make it likely that any delay in the receipt of Commission action will increase the cost of the project.

3. PSNH has also been designing and procuring equipment for the two substations that will be constructed to support the project. One substation is replacing an existing substation and will eventually be used for construction and a second larger substation will be needed to provide power to the scrubber once it is operational.

4. Site drawings have been developed to show new gates, new access roads, the construction guard house, office trailer locations, new parts lay-down and storage locations, security, and first aid locations. Work is progressing on soil borings to support foundation design, site surveys are being conducted for general equipment locations, and extensive underground surveying is being performed to locate all buried items.

5. Other current activities include developing specifications for booster fans and duct work, designing yard fire protection systems, conducting noise studies, and performing electrical usage studies. Myriad other tasks are also currently being performed in order to successfully complete the project.

G. Permitting Activities

1. The permitting activities began with submittal of the Temporary Air Permit application submitted to NHDES on June 7, 2007. NHDES has indicated that it will facilitate the permitting process however possible and has offered to provide a staff liaison to assist.

2. Other permitting activities have occurred over the last six months and are ongoing. Most notably, PSNH must receive approval from the Town of Bow. PSNH currently expects to receive the necessary approvals within the next few months.

II. PROJECT COST ESTIMATE

A. PSNH, in consultation with URS, has developed a revised project cost estimate of $457 million. This cost equates to approximately $830 per kW for all of the "affected sources" subject to the emissions limitations of the Scrubber Law (RSA 125-O:12, I) or $1,054 per kW installed for Merrimack Station alone. This estimate includes the cost of the project, project management costs, AFUDC, indirect costs, and contingency. Confidential Attachment 3 hereto provides a detailed breakdown of project costs.

B. The current project cost estimate is in-line with recently published information on other multiple unit scrubber installations occurring elsewhere in the country. SNL Financial reported in their July 8, 2008 edition that the Wisconsin PSC had given verbal authorization for Wisconsin Energy Corp to proceed with its plans to install Scrubber and Selective Catalytic Reduction technologies to its Oak Creek units 5-8, a total of 525 MW's of existing Coal fired generating capacity at a cost of $774 Million. While this cost includes the addition of two emissions reduction technologies, the installed cost equates to $1,474 per kW at Oak Creek.

III. EFFECT OF CLEAN AIR PROJECT ON ENERGY SERVICE RATES

A. PSNH has assured the cost of energy produced by Merrimack Station will remain lower cost for customers than reasonable potential alternatives, even when the costs of the Clean Air Project are included. An analysis consisting of a detailed net present value of revenue requirements including capital and operating costs over the expected 15 year depreciation life of the scrubber demonstrates the continued economics of installing the scrubber provides this assurance. The spreadsheets which contain this analysis are included as Attachment 4 to this filing.

B. The primary assumptions used as inputs to the revenue requirements analysis include:

Capital cost: $457M
Capital structure: 47.23% Equity, 52.77% Debt
Assumed Return on Equity: 9.81% (PSNH's current allowed ROE on generation)
In-Service Date: July 1, 2012
Coal cost: $4.82 per Million BTU escalated at 2.5% per year for the period of the analysis
RGGI or equivalent CO2 allowance cost: $7 per ton escalated at 2.5% per year for the period of the analysis

Utilizing these inputs produced the following summary results:
First year bus bar cost: $94.55/MWh
Levelized (15 year) bus bar cost: $99.28/MWh

C. Using the 2012 - 2027 average bus bar cost, the effect that the Clean Air Project will have on energy service rates is estimated to be approximately one-third of a cent per kWh (1/3¢/kWh). In the first year of operation, the year with the highest cost impact due to the highest value of undepreciated plant, absent any rate-smoothing initiatives, the impact on energy service rates is estimated to be approximately one-half cent per kWh (1/2¢/kWh).

D. Sensitivity analyses were conducted to test the impact of changes to each of the key assumptions (capital cost, coal cost and equivalent CO2 allowance cost) on the overall bus bar cost of Merrimack Station. These sensitivity analyses indicated the economics of the project are most sensitive to variations in the future price of coal, and far less sensitive to variations in the capital cost or equivalent CO2 allowance cost.

IV. EFFECT ON ENERGY SERVICE RATES IF MERRIMACK STATION IS RETIRED

A. The Commission's Secretarial Letter requires "an analysis of the effect on energy service rates if Merrimack Station were not in the mix of fossil and hydro facilities operated by PSNH." Three alternatives were chosen for this analysis. These comparison cases included analyses over the time frame of 2012 through 2027 of the following options:

1. Purchase of energy and capacity to replace the equivalent of Merrimack Station through a "Cost of Service" contract with new base load coal fired generating station;

2. Purchase of energy and capacity to replace the equivalent of Merrimack Station through a "Cost of Service" contract with a new combined cycle natural gas fired generating station; and

3. Purchase of energy and capacity to replace the equivalent of Merrimack Station through market purchases.

B. The 2012 through 2027 analysis period was chosen to coincide with the anticipated 15 year depreciable life of the scrubber, as defined in the base case. Cost of service style contracts, though not routinely in place in ISO-New England at this time, provided a presumed floor for total operating costs for a new coal or natural gas fired unit, employing a presumed "regulated return" and debt/equity ratio consistent with the PSNH values used in the base case, of operating with the scrubber.

C. PSNH undertook a data review of energy trade press and publications to determine current estimates of newly proposed coal and natural gas combined cycle generating stations.

1. For recently proposed coal plants, PSNH found references to the Virginia City Hybrid facility (Attachment 5). This is a 585 MW fluidized bed facility with a currently reported capital cost of $1.8 billion. A net present value of revenue requirements model was created that employed this capital cost, the PSNH capital structure and anticipated ROE, and for the sake of consistency, coal price and equivalent CO2 allowance cost assumptions consistent with those used in the scrubber analysis. FERC has estimated significantly higher costs for construction of new coal generation, as set forth in Attachment 2.

2. For recently proposed combined cycle natural gas plants, PSNH found references to the Middletown Kleen plant, a 620 MW plant with a currently reported financing of $985 Million (Attachment 6). This cost is consistent with the FERC estimated cost of new generation contained in Attachment 2.

D. For future market conditions, PSNH examined the forward market for natural gas delivered to New England and applied a "heat rate" factor to translate the raw delivered fuel cost to electrical energy. To the energy cost derived from these calculations, an adder was applied for ISO-NE capacity value, which would be required to replace the lost capacity value existing with the operation of Merrimack Station.

E. In the market purchase and combined cycle natural gas scenarios, a year 2012 price of $11 per MMbtu was used as the first year price of natural gas. This value was escalated at a rate 2.5% per year for future years of the analysis.

F. The results of these analyses indicated that the new coal and new combined cycle natural gas plants would have bus bar costs of about $135 per MWhr. For the market purchase alternative the sum of the energy and capacity costs resulted in a total cost per MWhr value of $107.10. To this amount, PSNH calculated and added a recovery of the estimated $63 Million of stranded assets (undepreciated plant and inventories) that would exist at Merrimack Station over a period of five years (as required by RSA 369-B:3-a). The overall cost of a market purchase plus retirement scenario produced a levelized bus bar cost of $107.83/MWhr, which is nearly 15% higher than the cost calculated to operate Merrimack Station in the first year after completion of the Clean Air Project.

G. From these results, PSNH has computed that the average net effect on energy service rates if Merrimack Station is retired and replaced by market purchases would be 0.73 cents/kWh of additional costs to customers over the period of 2012 through 2027.

H. Comparison and sensitivity analyses were conducted using the scrubber and market purchase plus retirement scenarios. Under the base case assumptions the scrubber scenario produced a nominal benefit to customers of $583 Million; $132 Million benefit on a net present value basis, over the depreciable life of the scrubber. Additional net present value benefit of $34.2 Million is attributable to customers associated with the scrubber, as the charges for stranded assets are avoided in the scenario where the scrubber is installed and the station continues to operate.

I. As a result of these analyses, PSNH has concluded that installation of the scrubber, and continued operation of Merrimack Station is the best economic alternative for the benefit of its customers.

CONCLUSION

PSNH has historically provided Clean Air Project status reports to the Legislature and the committees having oversight responsibilities for this project, NHDES, Office of Consumer Advocate, and this Commission; we continue to be ready and willing to meet with the Commission Staff and OCA to discuss the Clean Air Project whenever requested.

PSNH urges the Commission to act promptly in this docket so that the project work can resume without further delay. PSNH is at a critical juncture in the project since some contract work is on hold, while other contracts are not being executed pending the outcome of the Commission's inquiry. Any delay to the project will increase its cost and therefore result in higher costs to customers once the project is in service.

Attachment 1

The Wall Street Journal

Costs to Build Power Plants Pressure Rates

By REBECCA SMITH

May 27, 2008; Page B3

Construction costs for power plants have more than doubled since 2000, according to new index data to be released Tuesday, and inflationary pressures will continue to put the squeeze on electricity prices.

The findings are bad news for consumers and utilities alike, and help explain why power-plant development has become something of a quagmire in the U.S. -- with no type of plant emerging as a reasonably priced option that can meet rising demand for electricity.

The analysis comes in the form of a price index from Cambridge Energy Research Associates Inc., a research and consulting firm in Massachusetts that is a unit of IHS Co. Similar to the consumer-price index, it calculates the cost of building new power plants based on the cost of materials and other factors.

"Costs for labor, materials, equipment and design and engineering -- all are up," said Candida Scott, senior director of cost and technology for CERA. As a result, the cost of building new plants is up 19% from a year ago and up 69% from 2005.

The skyrocketing price tag comes as the world is roiled by surging electricity demand and as it weathers various supply disruptions, some caused by what appear to be changing weather patterns.

In all, CERA says, the construction of new generating capacity that would have cost $1 billion in 2000 would cost $2.31 billion if construction began today.

According to the index, all types of power plants are feeling the pinch. Components and construction materials for nuclear power plants scored the biggest run-up in costs, up 173% -- nearly tripled -- since 2000. Most of that increase has taken place since 2005. Costs for turbines used to generate wind power more than doubled, at 108%, and natural gas-fueled and coal-fired plants saw their capital costs nearly double, up 92% and 78%, respectively.

If anything, the index likely minimizes the rising cost of building power plants, because it doesn't factor in financing costs, and it doesn't include fuel costs. But as prices for coal, natural gas and uranium have risen, they have put added pressure on the operating costs of many companies, and those increases are pushing up electricity prices, too.

The upshot, Ms. Scott said, is that prudent utility regulators should make sure they are basing future decisions on data that are updated frequently, because even calculations less than a year old can be dangerously out of date.

One practical consequence of the inflationary pressures is that they make it harder for plant developers, such as utilities, to lock in prices as part of big projects. The longer the time period involved in construction, the bigger the risks inherent in any fixed-price contracts. Instead of paying for "time and materials," many firms are seeking contracts in which prices are tied to various indexes.

In some states, utilities are rolling out big programs to install millions of "smart" electric meters in the belief they will help cut electricity consumption and reduce the need for new power plants. Oncor, a big utility in Texas, last week said it plans to install three million advanced meters on homes and small businesses, giving consumers a tool to help get a handle on electricity use.

The CERA report underscores the tough choices facing utilities and regulators. Both are interested in finding the technology that will be most affordable.

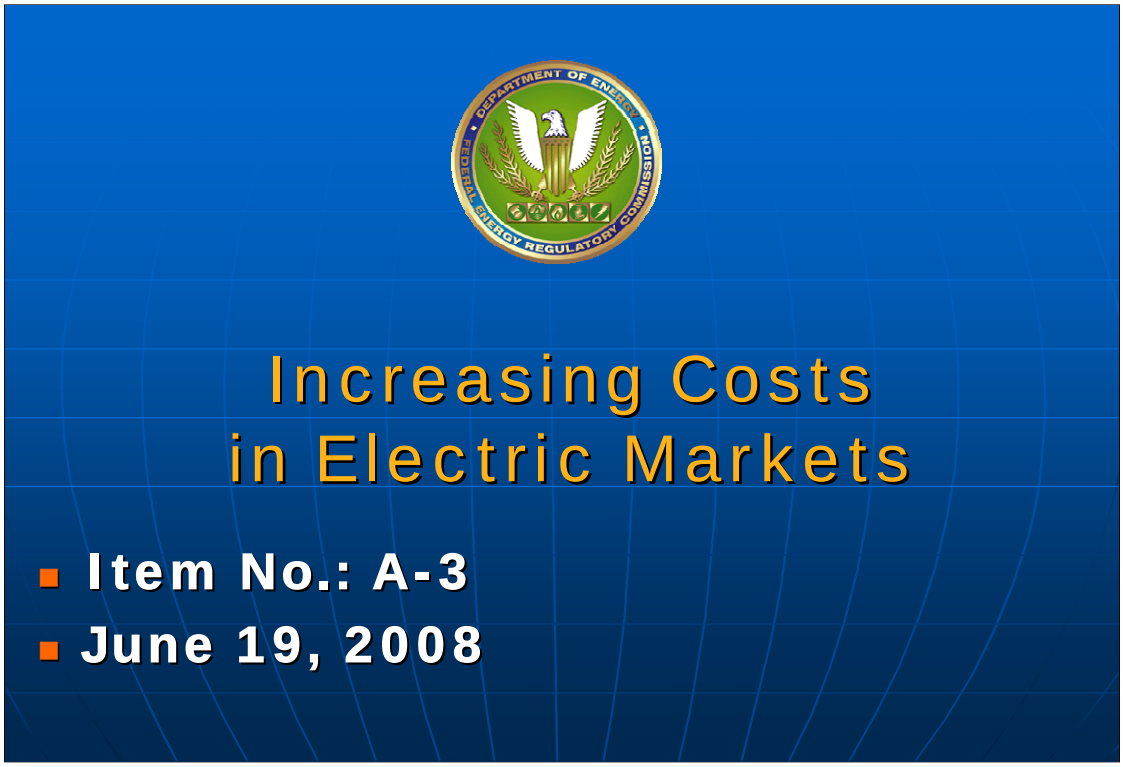
That is especially difficult, since big power plants often remain in service 40 to 60 years.
One commodity whose cost has risen markedly is steel, a important material for building both power-plant structures and power-generating equipment. The cost of iron ore, needed to make steel, rose about 10% in 2007 but has surged 65% in recent months. Shortages of coking coal, also needed to make steel, have been another problem in Australia, a big export country. CERA said steel costs could rise 40% to 60% this year.

A weak dollar also is a factor, since roughly 30% of equipment needed by the U.S. power industry comes from outside the U.S.

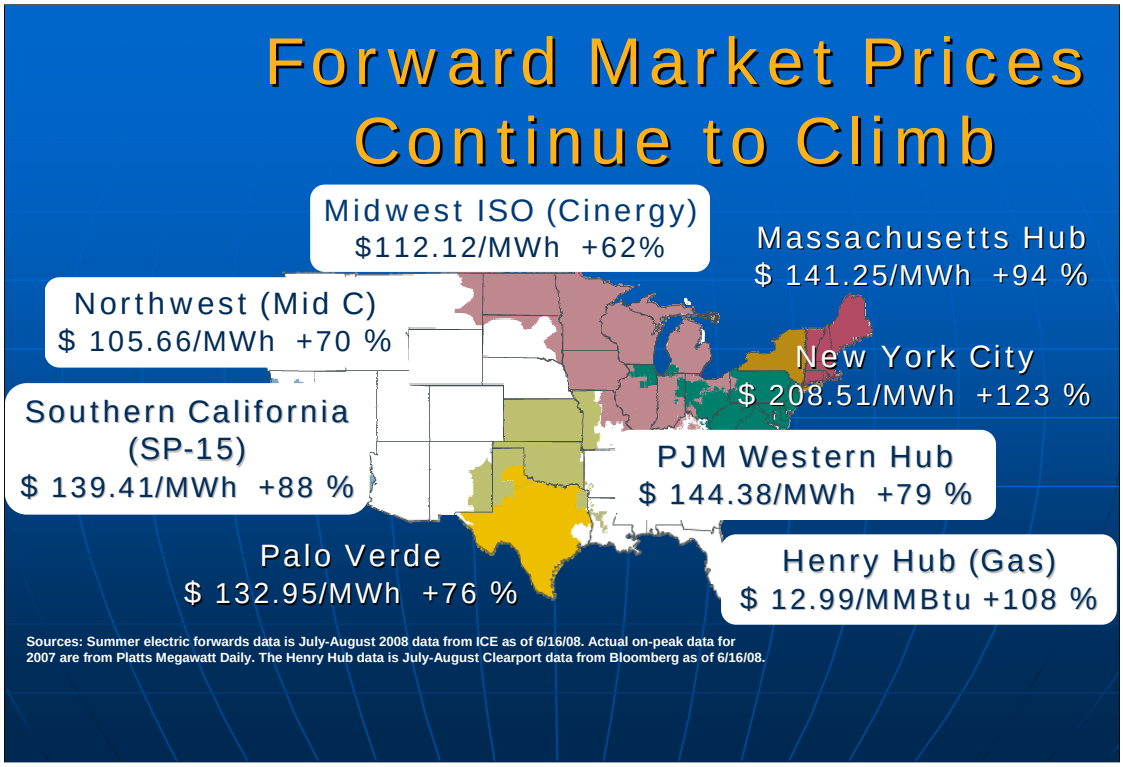
The analysis is of interest because it is difficult to get solid cost data until after plants have been built. Even then, data aren't always available.

Attachment 2

FERC's Office of Enforcement's Report to the FERC Commissioners on Increasing Costs in Electric Markets, presented on June 19, 2008

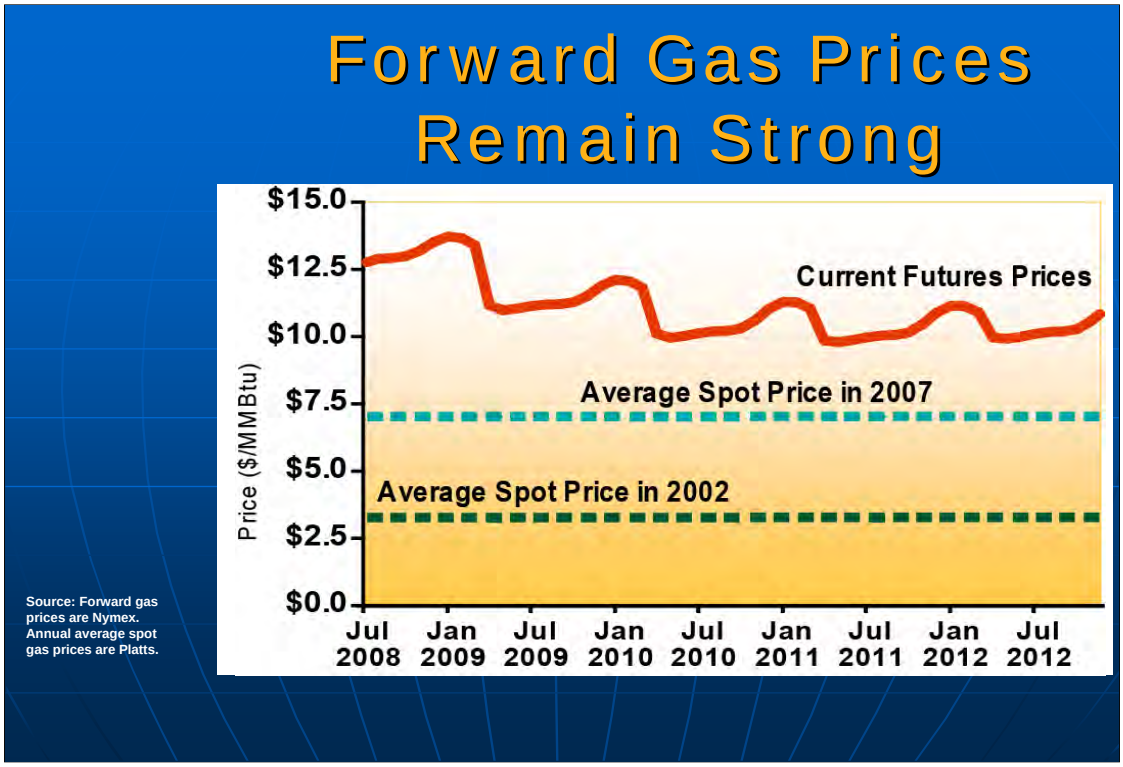


Mr. Chairman and Commissioners, good morning. I am here to present the Office of Enforcement's assessment of likely electricity costs in coming years. This presentation will be posted on the Commission's Web site today.

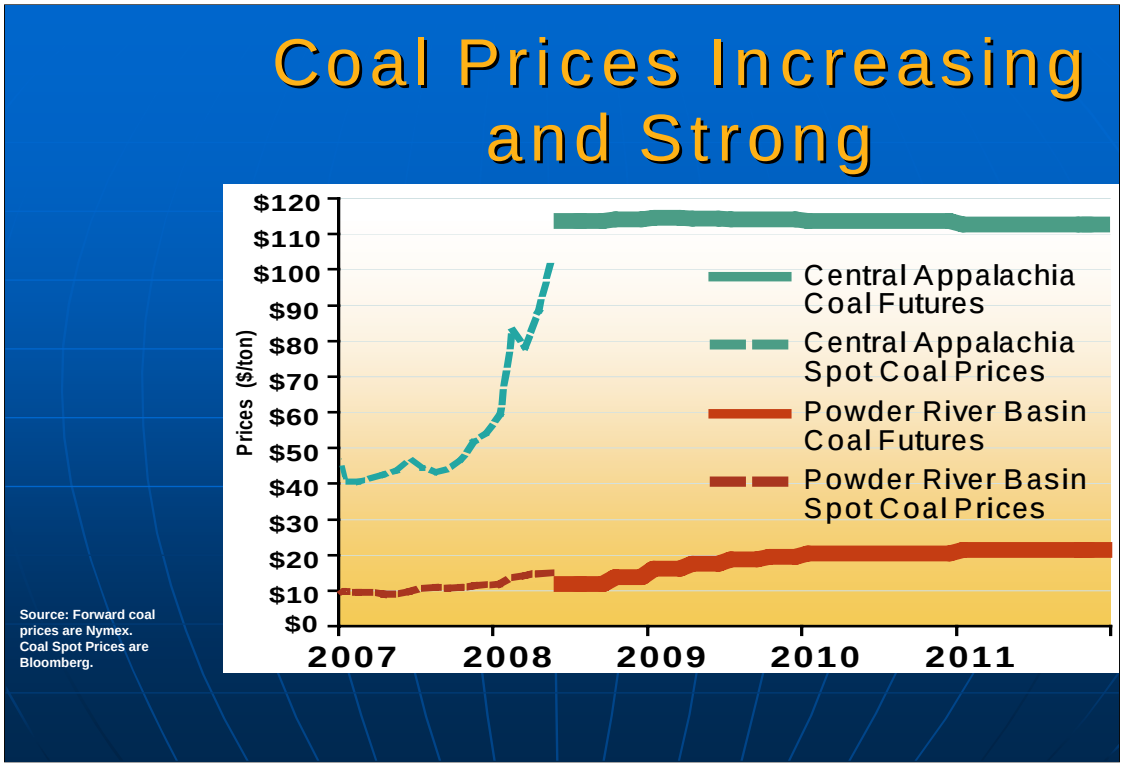


At last month's meeting, we reported that forward market prices for electric power are much higher than the prices we actually experienced last year. This trend is universal around the country. The slide shows the increases in forward prices for July and August as of this week. They have risen further during the last month as natural gas prices have continued to rise.

There is little reason to believe that this summer is unusual. Rather, it may be the beginning of significantly higher power prices that will last for years. The purpose of this presentation is to explain why that is so. The two major factors pushing the costs of electric generation higher are increased fuel costs and increased cost for new construction. These factors affect all parts of the country. That is, higher future prices are likely to affect all regions.



The primary reason for the electric power price increases this year is high fuel prices. All current market indications suggest that they will remain high. Let's look at natural gas, which often determines prices because it is so frequently on the margin. The slide shows futures prices for the next few years. The futures prices are somewhat lower for 2009 than for 2008. Even so, they are a good deal higher for all years than the prices people actually paid last year, and they are much higher than the prices many of us remember from earlier in the decade. The implication is that markets anticipate continuing high prices, even though they know that the United States has seen a significant increase in domestic natural gas production over the last year and a half. The anticipation of further high prices makes more sense when one considers the likely increase in gas demand for generation and the global nature of competition for LNG.



Natural gas is not the only important fuel in setting electric power prices. Coal still powers half of all power produced in the U.S. In some markets – the Midwest and the Southeast, for example – coal is often on the margin and plays a major role in setting average prices over time. The slide shows that the price of one key form of coal – Central Appalachian coal - has risen rapidly over the last year. Forward markets show continuing high prices for Central Appalachian coal for the next three years. This reflects, in part, the growing global market for coal and the relatively weak US dollar. Coal imports are becoming more costly and coal exports more profitable, both of which contribute to higher prices in the United States.

I should mention that other coal prices behave somewhat differently from Central Appalachian coal. For example, a majority of the overall cost for Powder River Basin coal comes from transportation rates and can be more difficult to see. Nonetheless, the implication of the prices we can see is that electric power prices are likely to increase even where coal is on the margin. This may take place somewhat differently from the way natural gas price increases flow through into power prices. Generally, companies buy coal under fairly long term contracts, so there may be a lag before the higher prices show their full effects. But the effects are coming.

Net Natural Gas Generation by Region
(TWh)

Region	2000	2007	Difference
Northeast	66.3	103.9	37.6
RFC	41.0	64.5	23.5
SERC	86.9	150.5	63.6
FRCC	42.0	96.7	54.7
ERCOT	155.9	163.3	7.4
Midwest	44.2	62.8	18.5
WECC-Rockies and SW	28.1	77.6	49.5
WECC-CA and NW	115.4	129.7	14.4

Source: Derived from Energy Velocity (differences due to rounding).

While both natural gas and coal prices have increased rapidly, natural gas is increasingly important in every region of the country. The slide shows that even in regions where coal has historically dominated – most noticeably in SERC– natural gas usage has grown substantially since 2000, up 63.6 TWh in 2007, more than in any other region. Noticeable increases also occurred in FRCC, which has flexibility to burn either gas or oil at many facilities, and also in the Rockies and Southwest where demand continues to grow considerably.

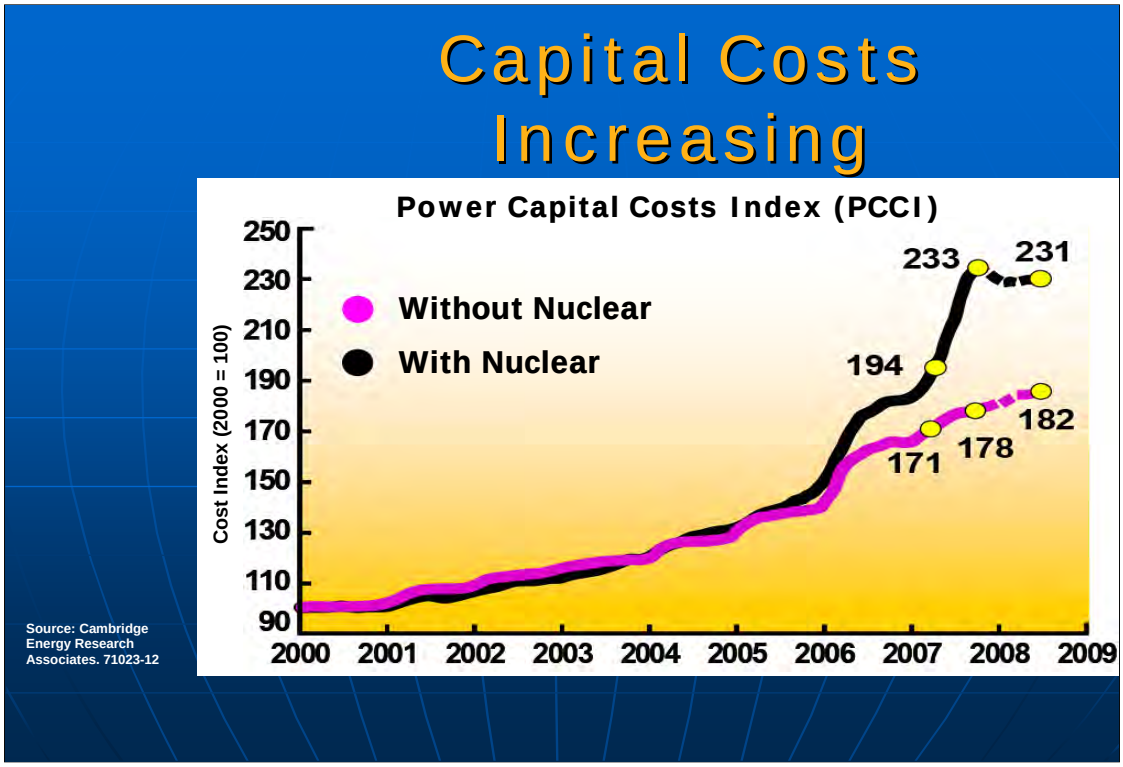
NERC Net Load Projections through 2016

Region	Total Difference (GW)	Percent Change
Northeast	9.7	17
RFC	23.2	13
SERC	28.2	14
FRCC	7.1	15
ERCOT	14.7	24
Midwest	17.2	21
WECC-Rockies and SW	7.6	25
WECC-CA and NW	10.9	10
Total	108.8	14

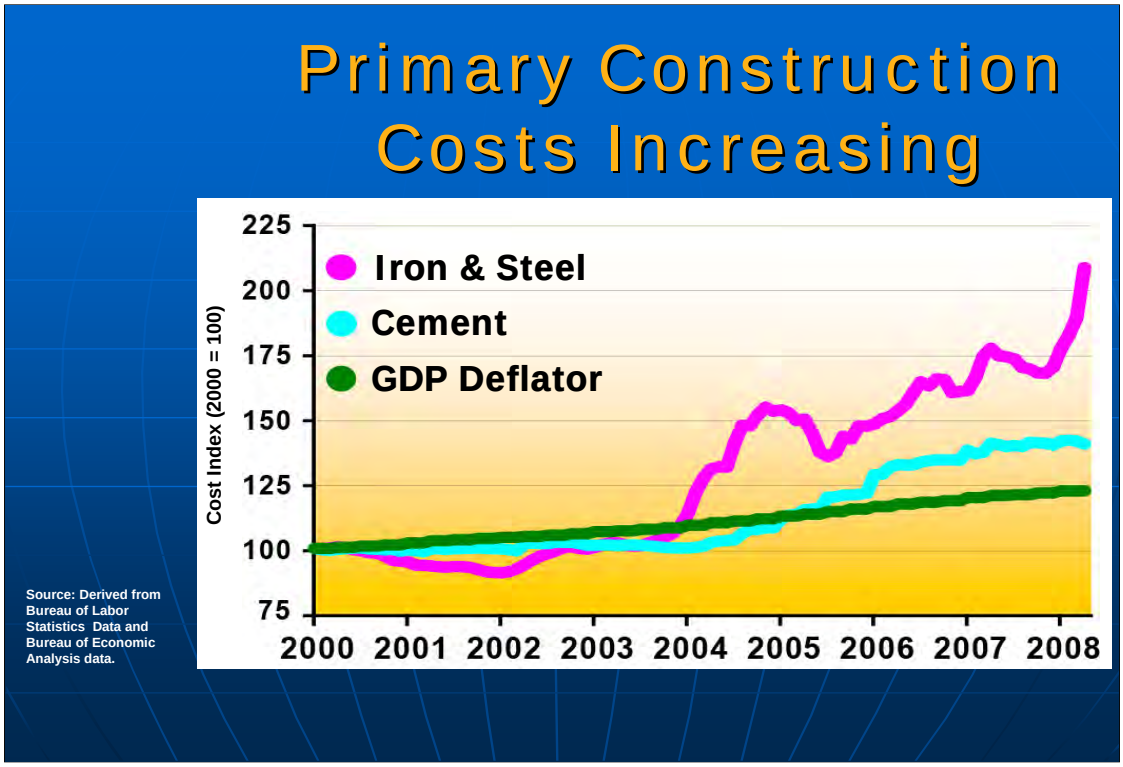
Source: Derived from NERC 2007 Long Term Reliability Assessment, Oct. 2007 and NERC data request, June 2008.

The second major factor that will put upward pressure on electric power prices is the increasing cost of new construction. This effect is particularly important because the country is entering a period when we will need to make substantial new investments, especially in generation.

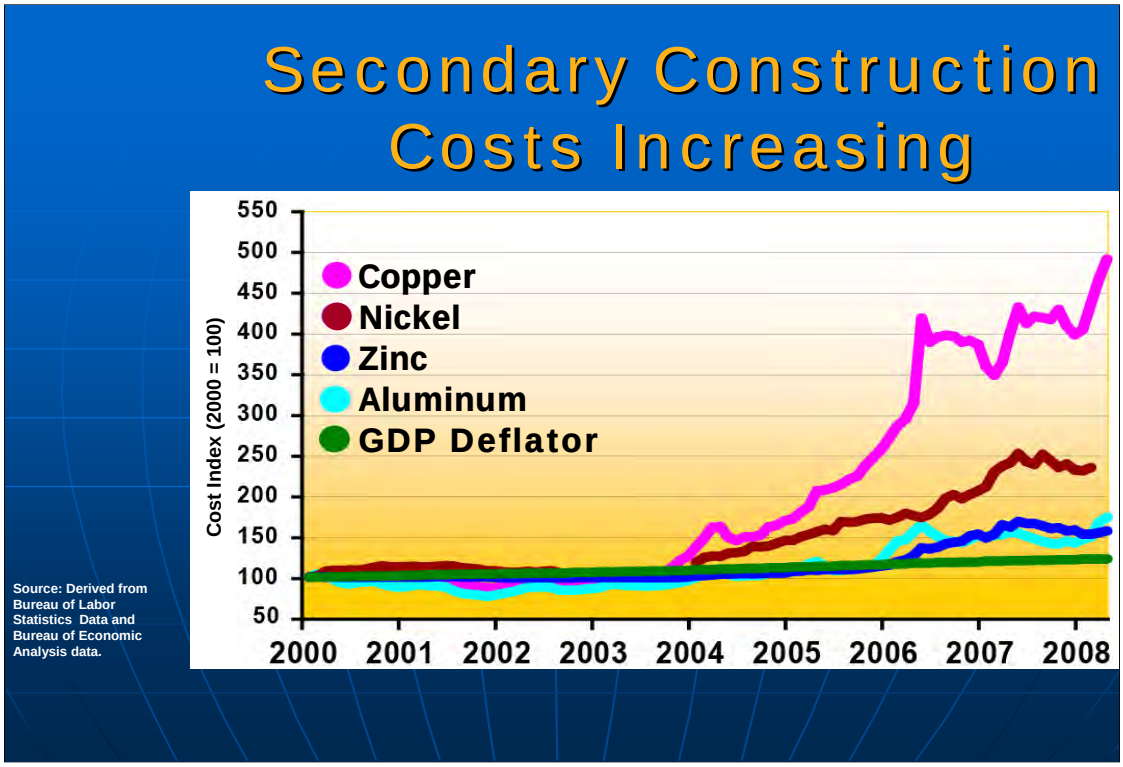
Natural gas fueled most of the last great wave of generation investment, which occurred between 1995 and 2004. In recent years, demand in most regions has gradually caught up with the capacity built around 2000. Looking forward, demand will continue to grow, and the need for new capacity will become ever more acute and ever more widespread. The slide shows NERC's expectation of peak net load growth in different regions for the next 10 years. We at the Commission are not in the business of forecasting, so I would just say this: There are legitimate reasons to be unsure about exactly how much new generation the country will need in the coming years. For one thing, higher prices will themselves discourage some power demand. Nonetheless, a significant level of demand increase seems virtually inevitable. So will be the need to build more capacity.



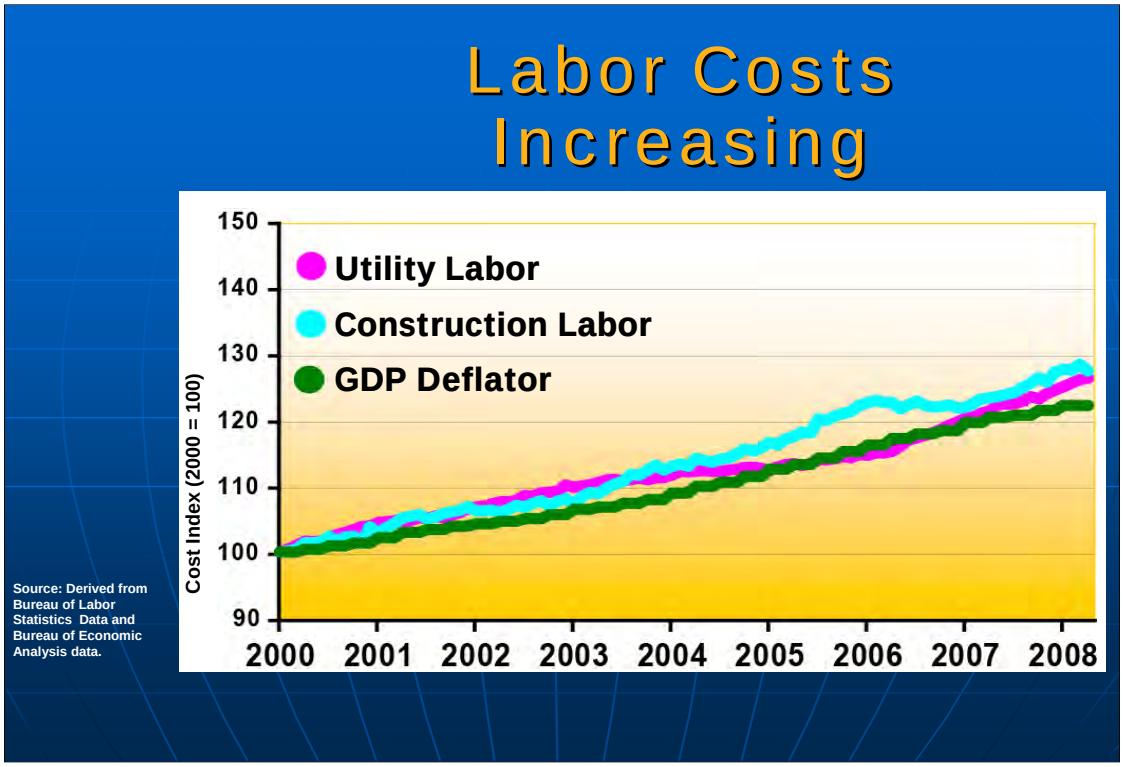
The need for new generation is important because new construction is becoming more expensive – quite aside from fuel price increases. Cambridge Energy Research Associates – CERA – produces an index of costs for the main inputs that go into building new generating plants. The slide shows how that index has almost doubled since 2003. The increase in nuclear plant inputs has risen even faster. Much of this cost increase results from rising global demand for basic materials. Part of it also comes from shortages of people to do key engineering and construction jobs. In any case, the implication is that, we will pay more, not less, for the next round of construction.



Let's look at some of the reasons that CERA's index is rising so rapidly. The slide shows two of the primary construction materials for electric generating plants – concrete is on the blue line and iron and steel on the red line. As you can see, the prices of both have been rising recently – especially steel, which is now more than twice as expensive as it was four years ago. Rising costs for iron and steel will also affect fuel prices for the power industry. For example, natural gas wells and pipelines both use substantial amounts of steel, so natural gas costs will also reflect rising iron and steel prices.

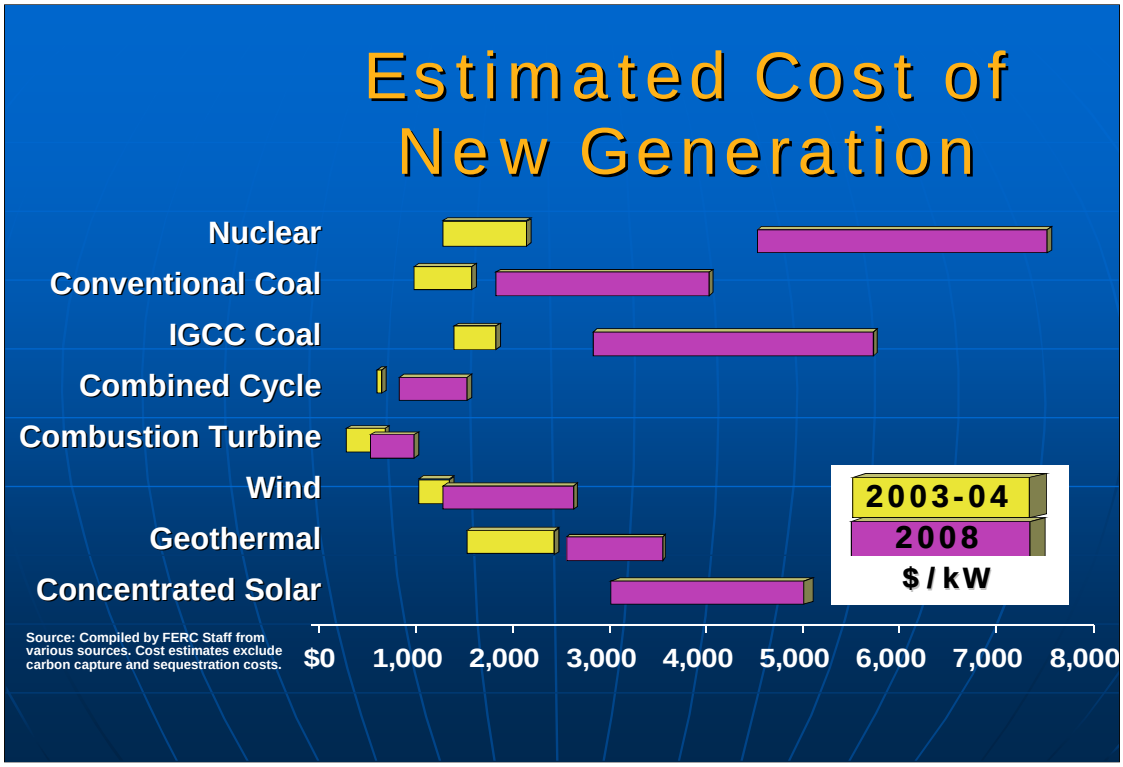


Of course, new generating plants require many other basic commodities. The slide shows the pricing for four key metals that go into generators. As you can see, all of these metals are increasing in price. The one that stands out is copper, up more than five times over the past four years. Indeed, copper is now so valuable there are reports of copper thieves cutting live cables to steal the metal.



Labor costs are also increasing. Perhaps the most frequently cited labor shortage is that for nuclear engineers. It has been a full generation since the nation built its last nuclear plant. Most of the engineers who worked on those plants are near retirement – and many have moved on to other occupations. In fact, the labor shortages are more widespread than just nuclear engineers. The slide shows that there has been about a 27% nominal change in average hourly earnings for both construction labor generally and for non-construction utility labor since 2000, outpacing inflation by over 4% for the same period.

In practice, the American labor market is quite responsive to market forces, so short-term labor shortages tend to be self-correcting over the mid-term. Still, there is no quick way to force several years of education into six months, or decades of experience into a year or two.



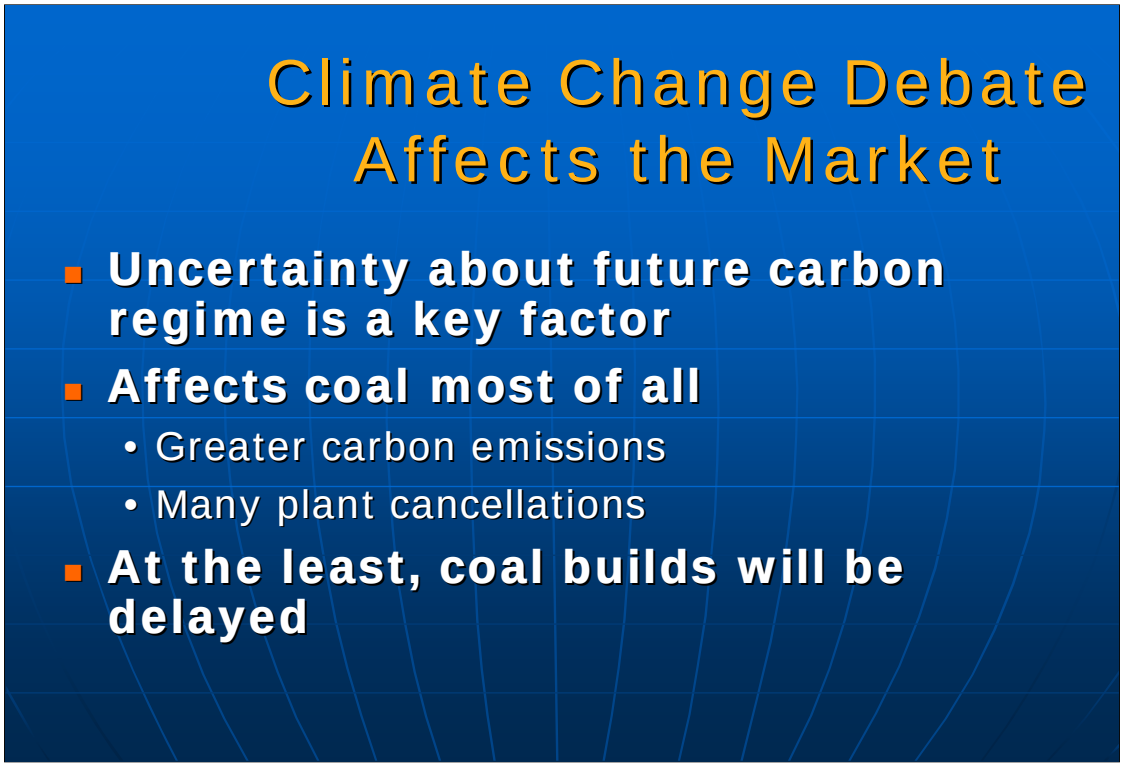
What do all these cost increases mean for the cost of building a new generating plant?

No one knows precisely. It's difficult to get consistent and trustworthy numbers about plant costs, both because they are commercially sensitive and because the assumptions behind them vary greatly. The numbers reflected on the slide come from a variety of sources and include different assumptions about, for example, location or exactly what facilities are included in the estimate. To take one example: Two recent nuclear procurements in South Carolina and Georgia produced cost estimates of $5,100 and $6,400 per kW, respectively, for the same technology. We have been told that most of the difference may be due to different uses of Allowances for Funds Used during Construction – AFUDC.

Despite the difficulties in being precise, the slide represents a good general indication of how capital costs have been changing. If anything, the cost estimates may be lower than the final costs of projects, if input costs continue to rise.

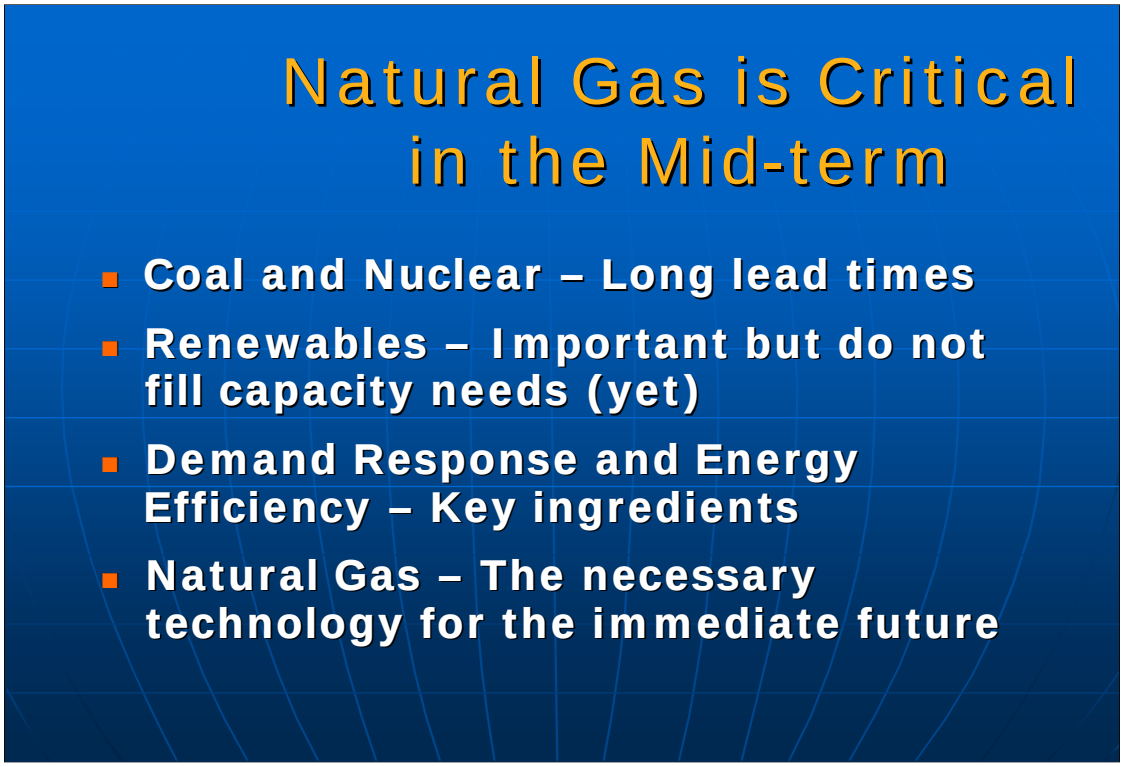
It's also important to remember that these cost estimates cover only capital costs. They do not include fuel costs, which as we've seen earlier will be a large factor for both natural gas and coal-fired plants. To the extent that plants do not have major fuel costs - they may be more competitive over their life cycles than would be suggested just looking at the capital costs. That would affect renewables and, to a degree, nuclear plants.

Similarly, these estimates generally do not include a full accounting of major risk factors, especially those affecting coal and nuclear plants. Both of these technologies have long lead times. That increases the chance that market conditions will change before they are complete and adds to the financial risk of building them. Nuclear plants also have risks associated with both decommissioning and waste fuel disposal. And coal plants have risks associated with the future treatment of greenhouse gases. Of course, relatively new technologies like wind and the new approaches to nuclear also have some risks, simply because they do not have the same track record of more mature technologies.



Climate change has become an increasingly urgent national issue. The debate over how to address carbon dioxide emissions is lively and has already affected how companies think about investments. Until recently, rising natural gas prices made coal plants attractive. However, the national uncertainty about carbon policy has made investing in coal plants more risky. Without carbon capture or sequestration, coal unit emit about four times as much carbon as natural gas combined cycle units per MWh. Since January 2007, 50 coal plants have been canceled or postponed. Only 26 remain under construction.

Whatever the eventual result of the climate change debate, costs of producing power from both coal and natural gas are likely to increase. Moreover, as long as future climate change policy is unclear, market participants will have a considerable disincentive to invest in coal plants. Even when the issues are resolved, it remains an open question how competitive coal-fired generation will be, and it would take another four to eight years to build new coal-fired capacity.



Over the long run, the nation can meet its increasing need for generation in several ways. But for the next few years, the options are more limited, and natural gas will be crucial.

The lead times for both nuclear and coal units mean that they will not supply a significant amount of new capacity for nearly a decade.

Most people expect renewables to supply an increasing proportion of the nation's power. For the next few years, wind will almost certainly account for a large share of generation investment and will account for a growing share of overall generation. Wind power has no fuel costs, and so will generally operate when available. However, wind is a variable, weather-dependent resource. As a result, it will not make up as strong a share of the Nation's capacity needs over the next few years. Other renewables are becoming more competitive. Geothermal power is already an important resource in the west, and concentrated solar is becoming economically attractive in desert areas like the Southwest. But these sources are likely to remain relatively small in the national picture over the next few years.

Both demand response and energy efficiency will be important – I'll talk more about them on the next slide – but they are unlikely to eliminate the need for new capacity.

Overall, the most likely outcome is that natural gas will continue to be the leading fuel for new capacity over the next half decade. For example, the consulting firm, Wood Mackenzie estimates that in a carbon constrained environment, gas consumption for power will increase by 69 % by 2017. That's in addition to the 55% increase we've seen since 2000.

Over the years, we have learned repeatedly that people respond to prices. In the case of electric power, this is likely to take several forms.

First, there is likely to be more demand response. In the simplest terms, high prices at peak will lead some customers – both businesses and others – to prefer to save their money rather than use power. In fact, the first round of demand response may be both the cheapest and fastest way to improve capacity margins on many systems. The best cost estimates for the first rounds of demand response suggest that it should be available for about $165/kW, far less than any generation side options. The results of ISO-NE's first Forward Capacity Market auction last year corroborates the economic importance of demand response - 7.4 % of the accepted bids were for demand response. However, there are impediments that limit the full use of demand response. For example, most customers do not have the option to respond directly to real-time prices. As a result, they are unlikely to reduce peak consumption as much as they might prefer to if they could take advantage of the price.

Second, customers are likely to be more energy efficient. While few customers see real-time prices, most get an average price over a month. As a result, high prices give them considerable incentive to reduce their overall consumption of power – though no more at peak than at other times. That is, energy efficiency is essentially a substitute for baseload capacity, while demand response is a substitute for peaking capacity. Energy efficiency is also likely to be economically important. Cost estimates show that the first round of energy efficiency may be available for about 3 cents/kWh. At

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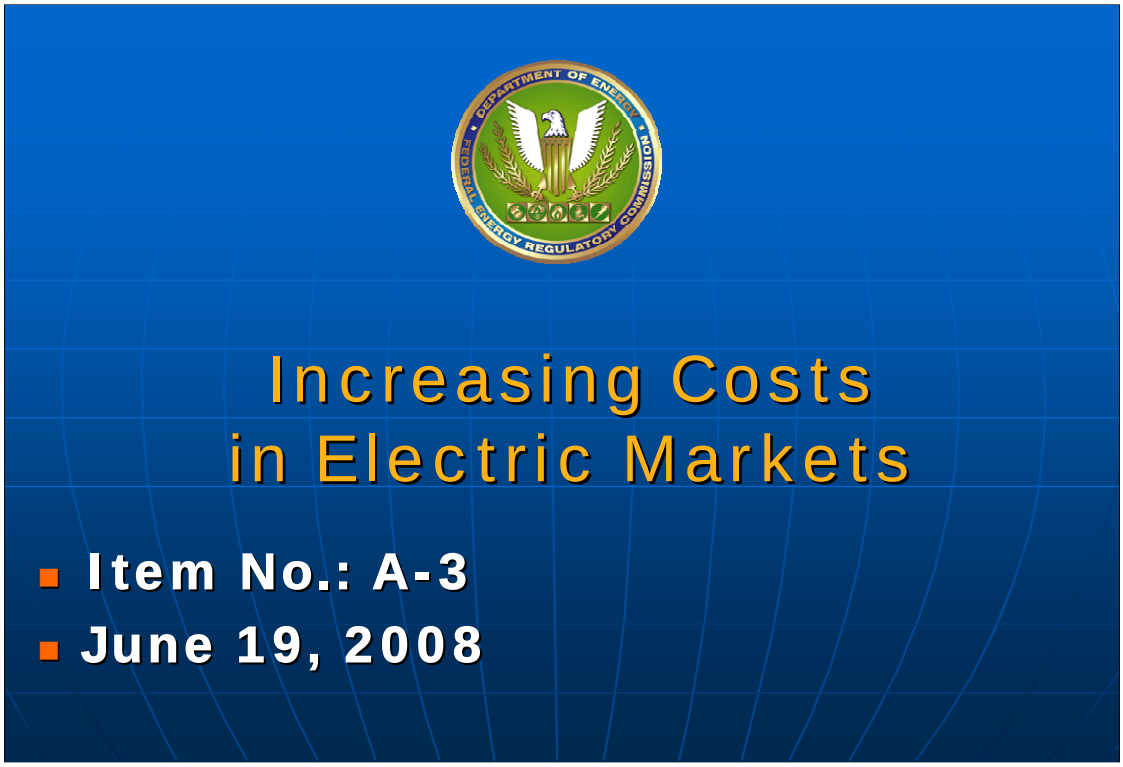
current prices, supplying that same kWh from a combined cycle gas plant would cost 9 cents just for the fuel. Adding to the likelihood of greater energy efficiency is that many states have adopted fairly strong energy efficiency standards.

Third, innovators see higher prices as an opportunity. By the nature of things, it's hard to predict what innovations will succeed. The electric industry has a number of technologies that might take off – including concentrating solar power, hydrokinetic power, and vehicle to grid technologies. In addition, distributed generation is becoming more important, and may continue to do so for both cost and emissions reasons In other newly competitive industries, such as telecoms and natural gas, innovations have produced large changes, sometimes quickly. Given continuing high electric prices, the electric power industry may see similar results.



That concludes our presentation. We welcome comments and questions.

Confidential Attachment 3

Detailed Project Cost Breakdown

Confidential attachment filed pursuant to "Motion for Protective Order" pursuant to the Commission's August 22, 2008 Secretarial Letter

Attachment 4

DETAILED NET PRESENT VALUE OF REVENUE REQUIREMENTS

Detailed Net Present Value of Revenue Requirements

Rate Base Calculation																														
			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scrubber Only Incremental Costs																									
RateBase Build																									
Cumulative Capital		$	871,913	$ 2,734,966	$ 44,061,397	$ 145,377,133	$ 310,955,865	$ 407,418,024	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069
Accumulated Book Depr		$	-	$ -	$ -	$ -	$ -	$ -	$ 15,240,702	$ 45,722,107	$ 76,203,512	$ 106,684,916	$ 137,166,321	$ 167,647,725	$ 198,129,130	$ 228,610,535	$ 259,091,939	$ 289,573,344	$ 320,054,748	$ 350,536,153	$ 381,017,558	$ 411,498,962	$ 441,980,367	$ 457,221,069	$ 457,221,069
Net Book Value		$	871,913	$ 2,734,966	$ 44,061,397	$ 145,377,133	$ 310,955,865	$ 407,418,024	$ 441,980,367	$ 411,498,962	$ 381,017,558	$ 350,536,153	$ 320,054,748	$ 289,573,344	$ 259,091,939	$ 228,610,535	$ 198,129,130	$ 167,647,725	$ 137,166,321	$ 106,684,916	$ 76,203,512	$ 45,722,107	$ 15,240,702	$ -	$ -
Working Capital									$ 366,918	$ 731,914	$ 750,314	$ 769,178	$ 788,516	$ 808,340	$ 828,664	$ 849,499	$ 870,859	$ 892,756	$ 915,205	$ 938,219	$ 961,812	$ 985,999	$ 1,010,794	$ 1,036,214	$ -
Month end Fuel Inventory									$ (71,563)	$ (293,407)	$ (300,742)	$ (308,260)	$ (315,967)	$ (323,866)	$ (331,963)	$ (340,262)	$ (348,768)	$ (357,488)	$ (366,425)	$ (375,585)	$ (384,975)	$ (394,599)	$ (404,464)	$ (414,576)	$ (424,940)
Nox/Sox									$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
M&S inventory									$ 6,693,835	$ 5,850,483	$ 5,007,132	$ 4,163,781	$ 3,320,429	$ 2,477,078	$ 2,069,326	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	
ADIT		$	-	$ -	$ -	$ -	$ -	$ -	$ 24,537,531	$ 44,247,660	$ 63,759,539	$ 83,088,529	$ 102,247,799	$ 91,988,368	$ 81,583,723	$ 71,045,204	$ 60,484,739	$ 49,923,908	$ 39,363,442	$ 28,802,611	$ 18,242,145	$ 7,681,314	$ (2,879,152)	$ (7,343,702)	$ (5,711,606)
RateBase End of Year		$	871,913	$ 1,803,439	$ 23,398,181	$ 94,719,265	$ 228,166,499	$ 359,186,944	$ 424,432,026	$ 373,540,293	$ 322,714,723	$ 272,072,322	$ 221,599,927	$ 200,546,528	$ 180,074,244	$ 159,856,568	$ 139,948,482	$ 120,041,087	$ 100,133,659	$ 80,226,939	$ 60,320,203	$ 40,414,192	$ 20,508,184	$ 9,747,340	$ 5,286,665
Average Rate Base		$	871,913	$ 1,803,439	$ 23,398,181	$ 94,719,265	$ 228,166,499	$ 359,186,944	$ 440,826,548	$ 398,986,160	$ 348,127,508	$ 297,393,522	$ 246,836,125	$ 211,073,228	$ 190,310,386	$ 169,965,406	$ 149,902,525	$ 129,994,784	$ 110,087,373	$ 90,180,299	$ 70,273,571	$ 50,367,197	$ 30,461,188	$ 15,127,762	$ 7,517,003
Revenue Requirements																									
Pre-tax Capital Return		$	-	$ -	$ -	$ -	$ -	$ -	$ 23,952,745	$ 43,358,612	$ 37,831,702	$ 32,318,340	$ 26,824,168	$ 22,937,743	$ 20,681,405	$ 18,470,475	$ 16,290,203	$ 14,126,789	$ 11,963,412	$ 9,800,071	$ 7,636,767	$ 5,473,503	$ 3,310,277	$ 821,982	$ -
Depreciation		$	-	$ -	$ -	$ -	$ -	$ -	$ 15,240,702	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 15,240,702	$ -
O&M		$	-	$ -	$ -	$ -	$ -	$ -	$ 2,976,112	$ 5,936,638	$ 6,085,884	$ 6,238,886	$ 6,395,739	$ 6,556,539	$ 6,721,387	$ 6,890,384	$ 7,063,635	$ 7,241,246	$ 7,423,329	$ 7,609,995	$ 7,801,360	$ 7,997,543	$ 8,198,665	$ 8,404,851	$ -
Fuel				$ -	$ -	$ -	$ -	$ -	$ (397,570)	$ (1,630,037)	$ (1,670,788)	$ (1,712,558)	$ (1,755,372)	$ (1,799,256)	$ (1,844,237)	$ (1,890,343)	$ (1,937,602)	$ (1,986,042)	$ (2,035,693)	$ (2,086,585)	$ (2,138,750)	$ (2,192,219)	$ (2,247,024)	$ (2,303,200)	$ (2,360,780)
Emmisions Costs		$	-	$ -	$ -	$ -	$ -	$ -	$ (8,867,412)	$ (29,775,129)	$ (30,519,507)	$ (28,647,698)	$ (22,838,582)	$ (20,065,325)	$ (20,566,958)	$ (21,081,132)	$ (21,608,161)	$ (22,148,365)	$ (22,702,074)	$ (23,269,626)	$ (23,851,366)	$ (24,447,650)	$ (25,058,842)	$ (25,685,313)	$ (26,327,446)
Property Tax		$	-	$ -	$ -	$ -	$ -	$ -	$ -	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subotal Revenue Requirements		$	-	$ -	$ -	$ -	$ -	$ -	$ 32,904,577	$ 48,371,489	$ 42,208,696	$ 38,678,375	$ 39,107,358	$ 38,111,106	$ 35,473,000	$ 32,870,788	$ 30,289,479	$ 27,715,034	$ 25,130,378	$ 22,535,260	$ 19,929,416	$ 17,312,581	$ 14,684,481	$ (3,520,977)	$ (28,688,225)
Percentage of Year In-Service		$	-	$ -	$ -	$ -	$ -	$ -	50%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	50%	0%
Existing Plant With Capital Adds																									
RateBase Build																									
Cumulative Capital				$ 188,935,000	$ 232,935,000	$ 241,935,000	$ 250,935,000	$ 259,935,000	$ 268,935,000	$ 277,935,000	$ 286,935,000	$ 295,935,000	$ 304,935,000	$ 313,935,000	$ 322,935,000	$ 331,935,000	$ 340,935,000	$ 349,935,000	$ 358,935,000	$ 367,935,000	$ 376,935,000	$ 385,935,000	$ 394,935,000	$ 403,935,000	$ 412,935,000
Accumulated Book Depr				$ 140,727,000	$ 149,245,701	$ 159,564,403	$ 171,683,104	$ 185,601,805	$ 201,320,507	$ 218,839,208	$ 236,357,909	$ 253,876,611	$ 271,395,312	$ 288,914,014	$ 302,032,715	$ 313,935,000	$ 322,935,000	$ 331,935,000	$ 340,935,000	$ 349,935,000	$ 358,935,000	$ 367,935,000	$ 376,935,000	$ 385,935,000	$ 393,135,000
Net Book Value				$ 48,208,000	$ 83,689,299	$ 82,370,597	$ 79,251,896	$ 74,333,195	$ 67,614,493	$ 59,095,792	$ 50,577,091	$ 42,058,389	$ 33,539,688	$ 25,020,986	$ 20,902,285	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 19,800,000
Working Capital				$ 3,457,356	$ 3,543,790	$ 3,632,385	$ 3,723,194	$ 3,816,274	$ 3,911,681	$ 4,009,473	$ 4,109,710	$ 4,212,453	$ 4,317,764	$ 4,425,708	$ 4,536,351	$ 4,649,760	$ 4,766,004	$ 4,885,154	$ 5,007,283	$ 5,132,465	$ 5,260,776	$ 5,392,296	$ 5,527,103	$ 5,665,281	$ 5,806,913
Month end Fuel Inventory				$ 19,159,000	$ 28,112,102	$ 28,112,102	$ 28,112,102	$ 28,112,102	$ 28,112,102	$ 28,814,904	$ 29,535,277	$ 30,273,659	$ 31,030,500	$ 31,806,263	$ 32,601,419	$ 33,416,455	$ 34,251,866	$ 35,108,163	$ 35,985,867	$ 36,885,513	$ 37,807,651	$ 38,752,843	$ 39,721,664	$ 40,714,705	$ 41,732,573
Nox/Sox				$ 22,920,000	$ 18,336,000	$ 13,752,000	$ 9,168,000	$ 4,584,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
M&S inventory				$ 3,181,728	$ 5,523,494	$ 5,436,459	$ 5,230,625	$ 4,905,991	$ 4,462,557	$ 3,900,322	$ 3,338,088	$ 2,775,854	$ 2,213,619	$ 1,651,385	$ 1,379,551	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,306,800
ADIT				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RateBase End of Year				$ 96,926,084	$ 139,204,684	$ 133,303,543	$ 125,485,817	$ 115,751,561	$ 104,100,833	$ 95,820,492	$ 87,560,165	$ 79,320,354	$ 71,101,571	$ 62,904,342	$ 59,419,606	$ 57,254,214	$ 58,205,870	$ 59,181,316	$ 60,181,149	$ 61,205,978	$ 62,256,428	$ 63,333,138	$ 64,436,767	$ 65,567,986	$ 68,646,286
Average Rate Base				$ 96,926,084	$ 118,065,384	$ 136,254,114	$ 129,394,680	$ 120,618,689	$ 109,926,197	$ 99,960,662	$ 91,690,328	$ 83,440,260	$ 71,101,571	$ 62,904,342	$ 59,419,606	$ 57,254,214	$ 58,205,870	$ 59,181,316	$ 60,181,149	$ 61,205,978	$ 62,256,428	$ 63,333,138	$ 64,436,767	$ 65,567,986	$ 68,646,286
Revenue Requirements																									
Pre-tax Capital Return		$	-	$ 10,533,149	$ 12,830,398	$ 14,807,003	$ 14,061,575	$ 13,107,871	$ 11,945,896	$ 10,862,922	$ 9,964,169	$ 9,067,617	$ 7,726,748	$ 6,835,939	$ 6,457,246	$ 6,221,928	$ 6,325,347	$ 6,431,350	$ 6,540,004	$ 6,651,374	$ 6,765,529	$ 6,882,537	$ 7,002,470	$ 7,125,402	$ 7,459,927
Depreciation		$	-	$ 10,599,000	$ 8,518,701	$ 10,318,701	$ 12,118,701	$ 13,918,701	$ 15,718,701	$ 17,518,701	$ 17,518,701	$ 17,518,701	$ 17,518,701	$ 17,518,701	$ 17,518,701	$ 13,118,701	$ 11,902,285	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 7,200,000
O&M		$	-	$ 28,043,000	$ 28,744,075	$ 29,462,677	$ 30,199,244	$ 30,954,225	$ 31,728,081	$ 32,521,283	$ 33,334,315	$ 34,167,672	$ 35,021,864	$ 35,897,411	$ 36,794,846	$ 37,714,717	$ 38,657,585	$ 39,624,025	$ 40,614,625	$ 41,629,991	$ 42,670,741	$ 43,737,509	$ 44,830,947	$ 45,951,721	$ 47,100,514
Fuel		$	-	$ 118,776,109	$ 159,028,012	$ 159,028,012	$ 159,028,012	$ 159,028,012	$ 159,028,012	$ 163,003,713	$ 167,078,805	$ 171,255,775	$ 175,537,170	$ 179,925,599	$ 184,423,739	$ 189,034,333	$ 193,760,191	$ 198,604,196	$ 203,569,301	$ 208,658,533	$ 213,874,996	$ 219,221,871	$ 224,702,418	$ 230,319,979	$ 236,077,978
Emmisions Costs				$ -	$ -	$ -	$ -	$ -	$ 31,624,387	$ 32,414,996	$ 33,225,371	$ 45,363,357	$ 46,497,441	$ 47,659,877	$ 48,851,374	$ 50,072,658	$ 51,324,475	$ 52,607,587	$ 53,922,776	$ 55,270,846	$ 56,652,617	$ 58,068,932	$ 59,520,656	$ 61,008,672	$ 62,533,889
Property Tax		$	-	$ 3,304,000	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600
Subotal Revenue Requirements		$	-	$ 171,255,257	$ 212,507,786	$ 217,002,993	$ 218,794,132	$ 220,395,409	$ 253,431,677	$ 259,708,215	$ 264,507,961	$ 280,759,724	$ 285,688,524	$ 291,224,127	$ 293,032,506	$ 298,332,522	$ 302,454,198	$ 309,653,757	$ 317,033,306	$ 324,597,344	$ 332,350,483	$ 340,297,450	$ 348,443,091	$ 356,792,374	$ 363,758,908
Total New Plant With Scrubber																									
Revenue Requirements																									
Pre-tax Capital Return		$	-	$ 10,533,149	$ 12,830,398	$ 14,807,003	$ 14,061,575	$ 13,107,871	$ 35,898,641	$ 54,221,534	$ 47,795,871	$ 41,385,957	$ 34,550,916	$ 29,773,682	$ 27,138,650	$ 24,692,404	$ 22,615,549	$ 20,558,140	$ 18,503,416	$ 16,451,445	$ 14,402,296	$ 12,356,039	$ 10,312,748	$ 7,947,384	$ 7,459,927
Depreciation		$	-	$ 10,599,000	$ 8,518,701	$ 10,318,701	$ 12,118,701	$ 13,918,701	$ 30,959,404	$ 48,000,106	$ 48,000,106	$ 48,000,106	$ 48,000,106	$ 48,000,106	$ 43,600,106	$ 42,383,690	$ 39,481,405	$ 39,481,405	$ 39,481,405	$ 39,481,405	$ 39,481,405	$ 39,481,405	$ 39,481,405	$ 24,240,702	$ 7,200,000
O&M		$	-	$ 28,043,000	$ 28,744,075	$ 29,462,677	$ 30,199,244	$ 30,954,225	$ 34,704,192	$ 38,457,921	$ 39,420,199	$ 40,406,659	$ 41,417,603	$ 42,453,950	$ 43,516,233	$ 44,605,101	$ 45,721,220	$ 46,865,271	$ 48,037,954	$ 49,239,986	$ 50,472,101	$ 51,735,053	$ 53,029,613	$ 54,356,572	$ 47,100,514
Fuel		$	-	$ 118,776,109	$ 159,028,012	$ 159,028,012	$ 159,028,012	$ 159,028,012	$ 158,630,442	$ 161,373,675	$ 165,408,017	$ 169,543,218	$ 173,781,798	$ 178,126,343	$ 182,579,502	$ 187,143,989	$ 191,822,589	$ 196,618,154	$ 201,533,608	$ 206,571,948	$ 211,736,246	$ 217,029,653	$ 222,455,394	$ 228,016,779	$ 233,717,198
Emmisions Costs		$	-	$ -	$ -	$ -	$ -	$ -	$ 22,756,975	$ 2,639,868	$ 2,705,865	$ 16,715,659	$ 23,658,860	$ 27,594,552	$ 28,284,416	$ 28,991,526	$ 29,716,314	$ 30,459,222	$ 31,220,703	$ 32,001,220	$ 32,801,251	$ 33,621,282	$ 34,461,814	$ 35,323,359	$ 36,206,443
Property Tax		$	-	$ 3,304,000	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600
Subotal Revenue Requirements	**Levelized-2012-2027**	**NPV**		$ 171,255,257	$ 212,507,786	$ 217,002,993	$ 218,794,132	$ 220,395,409	$ 286,336,254	$ 308,079,704	$ 306,716,657	$ 319,438,099	$ 324,795,883	$ 329,335,234	$ 328,505,507	$ 331,203,310	$ 332,743,677	$ 337,368,791	$ 342,163,685	$ 347,132,604	$ 352,279,899	$ 357,610,031	$ 363,127,573	$ 353,271,396	$ 335,070,683
NPV Gross Revenue Requirements	$323,475,945	$2,405,312,572							1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	
Less Market Energy	$325,874,918	$2,423,150,928			$273,109,197	$273,109,197	$273,109,197	$273,109,197	$283,537,003	$290,625,428	$297,891,064	$305,338,340	$312,971,799	$320,796,094	$328,815,996	$337,036,396	$345,462,306	$354,098,864	$362,951,335	$372,025,119	$381,325,747	$390,858,890	$400,630,362	$410,646,122	$420,912,275
Less Market Capacity	$23,089,319	$171,688,284			$17,957,400	$20,500,500	$21,746,100	$20,085,300	$18,891,600	$19,151,100	$19,566,300	$20,085,300	$20,656,200	$21,175,200	$21,694,200	$22,887,900	$24,600,600	$26,313,300	$27,974,100	$29,686,800	$31,399,500	$33,060,300	$34,773,000	$36,485,700	$38,146,500
NPV Net Revenue Requirements	($25,488,292)	($189,526,641)	2012		$ (78,558,811)	$ (76,606,704)	$ (76,061,165)	$ (72,799,088)	$ (16,092,349)	$ (1,696,824)	$ (10,740,706)	$ (5,985,542)	$ (8,832,116)	$ (12,636,060)	$ (22,004,689)	$ (28,720,986)	$ (37,319,229)	$ (43,043,372)	$ (48,761,750)	$ (54,579,315)	$ (60,445,347)	$ (66,309,159)	$ (72,275,790)	$ (93,860,425)	$ (123,988,092)
	($17,763,560)	($132,086,833)	2008																						
Busbar Cost, Prior	$88.99			52.56	65.22	66.60	67.15	67.64	77.78	79.71	81.18	86.17	87.68	89.38	89.93	91.56	92.83	95.04	97.30	99.62	102.00	104.44	106.94	109.50	111.64
Busbar Cost, Scrubber	$10.29			0.00	0.00	0.00	0.00	-67.64	10.10	14.85	12.95	11.87	12.00	11.70	10.89	10.09	9.30	8.51	7.71	6.92	6.12	5.31	4.51	-1.08	-8.80
Busbar Cost, Total	$99.28			52.56	65.22	66.60	67.15		87.88	94.55	94.13	98.04	99.68	101.08	100.82	101.65	102.12	103.54	105.01	106.54	108.12	109.75	111.45	108.42	102.84
cents				0.000	0.000	0.000	0.000	-6.764	1.010	1.485	1.295	1.187	1.200	1.170	1.089	1.009	0.930	0.851	0.771	0.692	0.612	0.531	0.451	-0.108	-0.880

Attachment 5

SNLi article, July 1, 2008

SNLi

SNLFinancial

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Power & Coal - Infrastructure Development

Dominion starts construction on Virginia clean coal plant

July 01, 2008 8:14 AM ET

By Adnan Munawar

Dominion Virginia Power said June 30 it began construction on the 585-MW Virginia City Hybrid clean coal plant in Wise County, Va.

Construction of the plant is scheduled to take four years, Dominion said.

The plant is part of Dominion Virginia Power's response to a projected growth in demand for electricity of 4,000 MW from its customers by 2017.

The Virginia Department of Environmental Quality issued the necessary air permits following the unanimous approval June 25 by the State Air Pollution Control Board. The Virginia State Corporation Commission approved the $1.8 billion project on March 31.

The circulating fluidized bed unit will use coal and up to 20% biomass for its fuel. The station will provide nearly 1,000 jobs during construction and require a permanent staff of more than 75 people once it begins operating, the company said.

Dominion Virginia Power is the trade name of Virginia Electric and Power Co., a subsidiary of Dominion Resources Inc.

Attachment 6

SNLi article, June 26, 2008

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Power & Natural Gas - Operations and Strategy

EIF raises financing to build 620-MW Kleen plant in Connecticut

June 26, 2008 2:16 PM ET

By Jay Hodgkins

Energy Investors Funds Group on June 26 said its United States Power Fund II LP and United States Power Fund III LP have raised construction financing for the Kleen Energy Systems LLC power plant in Middletown, Conn., known as Middletown Kleen.

The financing totaled $985 million of senior secured bank loans and a revolving credit facility, the company said. EIF said it is the majority owner of the project, with the balance owned by White Rock Holdings Associates LLC.

Goldman Sachs & Co. acted as joint lead arranger and sole book runner for senior secured loans raised to help finance the construction of the project. The bank loans were rated as investment grade at BBB- by Fitch Ratings, EIF said.

"With this construction financing in place, we're able to build a first-class power plant to serve the people of Connecticut," said William Corvo of Kleen Energy Systems. "This plant will provide clean, economical power to an area in need of new power generation."

Construction of the project began in February and is expected to be completed in mid-2010, EIF said. The project will be operated by Itochu Corp. subsidiary North American Energy Services and will be managed by Power Plant Management Services.

The Kleen plant will be a 620-MW, combined-cycle natural gas-fired facility. The project won a competitive request for proposals process run by the state of Connecticut and has entered into a 15-year capacity agreement with Northeast Utilities subsidiary Connecticut Light and Power Co. for the electricity produced by the plant.

The project has also finalized a multiyear tolling agreement, EIF said.

THE STATE OF NEW HAMPSHIRE
before the
PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire
Merrimack Station Scrubber Project
Request for Information

Docket No. DE 08-103

MEMORANDUM OF LAW

Pursuant to the Commission's Secretarial Letter dated August 22, 2008, Public Service Company of New Hampshire ("PSNH" or the "Company") provides this Memorandum of Law concerning the legal mandate placed on the Company by the General Court to install a wet flue gas desulphurization system ("scrubber technology") at PSNH's Merrimack Station in Bow.

On June 8, 2006, "AN ACT relative to the reduction of mercury emissions," 2006 N.H. Laws Chapter 105 (the "Scrubber Law") took effect. By that law, the General Court imposed an unmistakable legislative mandate for PSNH to install and have operational scrubber technology to control mercury emissions at Merrimack Units 1 and 2 no later than July 1, 2013. RSA 125-O:13, I. Three years earlier, in 2003 N.H. Laws, Chapter 21, the legislature had enacted RSA 369-B:3-a. RSA 369-B:3-a authorizes PSNH to modify its generation assets upon a finding that such modifications are "in the public interest of retail customers of PSNH to do so." In its Secretarial Letter, the Commission requested this Memorandum of Law to address "the nature and extent of the Commission's authority relative to the Merrimack Station scrubber project" in light of the statutory requirements contained in RSA 125-O:11, *et seq.*, and RSA 369-B:3-a.

Subject to acknowledged constitutional limitations, the regulation of utilities and the setting of appropriate rates to be charged for public utility products and services is the unique province of the legislature. *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 313 (1989); *The Minnesota Rate Cases*, 230 U.S. 352, 433 (1913); *LUCC v. Public Serv. Co. of N.H.*, 119 N.H. 332, 340 (1979). The Public Utilities Commission ("PUC") derives its authority from powers delegated by the legislature. *Appeal of Richards*, 134 N.H. 148, 158 (1991).

The "nature and extent of the Commission's authority" has been clearly set forth in numerous New Hampshire Supreme Court decisions. *Petition of Boston & Maine Railroad*, 82 N.H. 116 (1925); *State of New Hampshire v. New Hampshire Gas & Electric Co.*, 86 N.H. 16 (1932); *H.P. Welch Co. v. State*, 89 N.H. 428 (1938); *Blair and Savoie v. Manchester Water Works*, 103 N.H. 505 (1961); *State v. New England Telephone & Telegraph Co.*, 103 N.H. 394 (1961); *Appeal of Public Service Co.*, 122 N.H. 1062 (1982). *See also, The Manchester Press Club v. State Liquor Comm'n*, 89 N.H. 442 (1938).

As early as 1925, the Court held:

> ***The public service commission is an agency of limited powers and authority.*** While the legislature may delegate to such an agency certain of its own powers and authority, ***the exercise of such delegation does not extend beyond expressed enactment or its fairly implied inferences.*** The establishment of such an agency is of a special rather than general character, and ***power and authority not granted are withheld***.

Boston & Maine Railroad, *id.* at 116 (emphases added).

The Court, citing to this 1925 precedent, re-affirmed the limited authority of the PUC in *Appeal of Public Service Co.*:

> The PUC is a creation of the legislature and as such is endowed with ***only*** the powers and authority which are ***expressly granted or fairly implied by statute***. *Petition of Boston & Maine Railroad*, 82 N.H. 116, 116, 129 A. 880, 880 (1925). ***Consequently, the authority of the PUC…is limited to that specifically delegated or fairly implied by the legislature and may not be derived from other generalized powers of supervision.***

Appeal of Public Service Co., *id.* at 1066 (emphases added).

Recently, the Commission itself noted these restrictions on its power and authority. In *Re RCC Minnesota, Inc.*, 88 NH PUC 611 (2003), discussing the Commission's authority to regulate cellular carriers, the Commission found:

> The New Hampshire Supreme Court has held that "[t]he PUC is a creation of the legislature and as such is endowed with only the powers and authority which are expressly granted or fairly implied by statute." *Appeal of Public Service Company of New Hampshire*, 122 NH 1062, 1066 (1982). Consequently, ***the Commission must look to its statutory authority to determine whether it has jurisdiction*** over cellular providers. RSA 362:6 expressly states that it does not. A cellular provider is not a public utility, and its "services shall not be subject to the jurisdiction of the public utilities commission pursuant to this title." RSA 362:6. ***We therefore must conclude that the Commission does not have jurisdiction over any cellular carrier because the New Hampshire legislature specifically removed cellular carriers from the jurisdiction of this Commission***.

Re RCC Minnesota, Inc., at 615 (emphases added). *See also, Re Congestion on the Telephone Network Caused by Internet Traffic*, 89 NH PUC 173, 175 (2004) ("It is a well-established principle that this Commission possesses only those powers that are granted to it by the legislature.")

These precedents clearly and consistently note that "the regulation of utilities…is the unique province of the legislature"; the Commission "derives its authority from powers delegated by the legislature"; "[t]he…commission is an agency of limited powers and authority"; and, "the authority of the PUC…is limited

to that specifically delegated or fairly implied by the legislature and may not be derived from other generalized powers of supervision." These holdings detail the limits of the Commission's authority and form the bases for any discussion concerning the nature and extent of the Commission's authority relative to the Merrimack Station scrubber project.

The Scrubber Law, codified at RSA 125-O:11 through 125-O:18, is clear, straightforward, and unambiguous in its mandate, as set forth in the first words of the statute:

> ***Statement of Purpose and Findings. The general court finds that:***
>
> ***I. It is in the public interest to achieve significant reductions in mercury emissions at the coal-burning electric power plants in the state as soon as possible.*** The requirements of this subdivision will prevent, at a minimum, 80 percent of the aggregated mercury content of the coal burned at these plants from being emitted into the air by no later than the year 2013. ***To accomplish this objective, the best known commercially available technology shall be installed at Merrimack Station no later than July 1, 2013.***

RSA 125-O:11, I (emphases added).

The General Court provided unequivocal notice of the Scrubber Law's intent in eight such findings in the law's ***Statement of Purpose and Findings***:

> I. ***It is in the public interest to achieve significant reductions in mercury emissions at the coal-burning electric power plants in the state as soon as possible.*** The requirements of this subdivision will prevent, at a minimum, 80 percent of the aggregated mercury content of the coal burned at these plants from being emitted into the air by no later than the year 2013. ***To accomplish this objective, the best known commercially available technology shall be installed at Merrimack Station no later than July 1, 2013.***
>
> II. ***The department of environmental services has determined that the best known commercially available technology is a wet flue gas desulphurization system, hereafter "scrubber***

technology," as it best balances the procurement, installation, operation, and plant efficiency costs with the projected reductions in mercury and other pollutants from the flue gas streams of Merrimack Units 1 and 2. Scrubber technology achieves significant emissions reduction benefits, including but not limited to, cost effective reductions in sulfur dioxide, sulfur trioxide, small particulate matter, and improved visibility (regional haze).

III. ***After scrubber technology is installed at Merrimack Station,*** and after a period of operation has reliably established a consistent level of mercury removal at or greater than 80 percent, the department will ensure through monitoring that that level of mercury removal is sustained, consistent with the proven operational capability of the system at Merrimack Station.

IV. To ensure that an ongoing and steadfast effort is made to implement practicable technological or operational solutions to achieve significant mercury reductions prior to the construction and operation of the scrubber technology at Merrimack Station, the owner of the affected coal-burning sources shall work to bring about such early reductions and shall be provided incentives to do so.

V. ***The installation of scrubber technology will not only reduce mercury emissions significantly but will do so without jeopardizing electric reliability and with reasonable costs to consumers.***

VI. ***The installation of such technology is in the public interest of the citizens of New Hampshire and the customers of the affected sources.***

VII. Notwithstanding the provisions of RSA 125-O:1, VI, the purchase of mercury credits or allowances to comply with the mercury reduction requirements of this subdivision or the sale of mercury credits or allowances earned under this subdivision is not in the public interest.

VIII. ***The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of cost, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components.***

RSA 125-O:11 (emphases added).

The Scrubber Law's mandate that a scrubber shall be installed at Merrimack Station is detailed in the statutory provisions contained in its "Statement of Purpose

and Findings." In RSA 125-O:13, I, the General Court unequivocally requires PSNH to install a scrubber at Merrimack Station within a set timeframe:

> I. ***The owner [PSNH] shall install and have operational scrubber technology to control mercury emissions at Merrimack Units 1 and 2 no later than July 1, 2013. The achievement of this requirement is contingent upon obtaining all necessary permits and approvals from federal, state, and local regulatory agencies and bodies; however, all such regulatory agencies and bodies are encouraged to give due consideration to the general court's finding that the installation and operation of scrubber technology at Merrimack Station is in the public interest.*** The owner shall make appropriate initial filings with the department and the public utilities commission, if applicable, within one year of the effective date of this section, and with any other applicable regulatory agency or body in a timely manner.

(Emphasis added).

The General Court could not be clearer regarding the purpose and intent of the Scrubber Law. ***PSNH shall install a scrubber at Merrimack Station as soon as possible***. This mandate is binding not just on PSNH, but also on the Commission. As noted earlier, "the authority of the PUC…is limited to that specifically delegated or fairly implied by the legislature and may not be derived from other generalized powers of supervision." *Appeal of Public Service Co., supra,* 122 N.H. at 1066. In the Scrubber Law, the General Court has:

I. Found that "It is in the public interest to achieve significant reductions in mercury emissions at the coal-burning electric power plants in the state as soon as possible."

II. Mandated that scrubber "technology shall be installed at Merrimack Station no later than July 1, 2013."

III. Found that "the best known commercially available technology is a wet flue gas desulphurization system, hereafter 'scrubber technology,' as it best balances the procurement, installation, operation, and plant efficiency costs with the projected reductions in mercury and other pollutants from the flue gas streams of Merrimack Units 1 and 2."

IV. Found that "Scrubber technology achieves significant emissions reduction benefits, including but not limited to, cost effective reductions in sulfur dioxide, sulfur trioxide, small particulate matter, and improved visibility (regional haze)."

V. Found that "The installation of scrubber technology will not only reduce mercury emissions significantly but will do so without jeopardizing electric reliability and with reasonable costs to consumers."

VI. Found that "The installation of such technology is in the public interest of the citizens of New Hampshire and the customers of the affected sources."

VII. And declared that "The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of cost, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components."

The Scrubber Law does not delegate authority to the Commission to second-guess the mandates and findings of the General Court. There is absolutely no implication within the Scrubber Law that the mandate to install a scrubber at Merrimack Station as soon as possible can be delayed, conditioned, or eliminated in its entirety, by the Commission.

Interpretation of the Scrubber Law is not difficult. Just a few days ago, the Supreme Court issued its most recent holdings on statutory interpretation:

> We are the final arbiters of the legislative intent as expressed in the words of the statute considered as a whole. *State v. Langill*, 157 N.H. ___, ___ (decided April 4, 2008). We begin by examining the language of the statute, *State v. Whittey*, 149 N.H. 463, 467 (2003), and ascribe the plain and ordinary meaning to the words used, *Langill*, 157 N.H. at ___. We interpret legislative intent from the statute as written and will not consider what the legislature might have said or add language that the legislature did not see fit to include. *Id.* We also interpret a statute in the context of the overall statutory scheme and not in isolation. *Id.* If a statute is ambiguous, however, we consider legislative history to aid our analysis. *Whittey*, 149 N.H. at 467. Our goal is to apply statutes in light of the legislature's intent in enacting

> them, and in light of the policy sought to be advanced by the entire statutory scheme. *Id*.

State v. Dansereau, ___ N.H. ___ (August 15, 2008, *slip op.* at 2); *See also, Oulette v. Town of Kingston,* ___ N.H. ___ (August 15, 2008, *slip op.).*

In the case of the Scrubber Law, the overall statutory scheme includes not just the contents of 2006 N.H. Laws 105, but the entirety of RSA Chapter 125-O, the state's Multiple Pollution Reduction Program. Enacted during the 2002 legislative session as "AN ACT relative to additional emissions reductions from existing fossil fuel burning steam electric power plants," (2002 N.H. Laws, Chapter 130), RSA 125-O:1 contains additional findings by the General Court that are part of the overall statutory scheme leading to the Scrubber Law. The Legislature's findings include: a finding that "scientific advances have demonstrated that adequate protection of public health, environmental quality, and economic well-being - the 3 cornerstones of New Hampshire's quality of life - requires additional, concerted reductions in air pollutant emissions." RSA 125-O:1, I; a finding "that protecting New Hampshire's high quality-of-life environment by reducing air pollutant emissions returns substantial economic benefit to the state through avoided health care costs; greater tourism resulting from healthier lakes and improved vistas; more visits by fishermen, hunters, and wildlife viewers to wildlife ecosystems, and a more productive forest and agricultural sector." RSA 125-O:1, IV; a finding "that aggressive further reductions in emissions of sulfur dioxide (SO2), oxides of nitrogen (NOx), mercury, and carbon dioxide (CO2) must be pursued." RSA 125-O:1, III; and, a finding "that substantial additional reductions in emissions of SO2, NOx, mercury, and CO2 must be required of New Hampshire's existing fossil fuel burning steam electric power plants.." RSA 125-O:1, V.

When viewed with the Supreme Court's stated goal of applying statutes in light of the legislature's intent in enacting them, and in light of the policy sought to be advanced by the entire statutory scheme, there is no doubt what was intended by passage of the Scrubber Law. The public interest findings of the General Court in RSA 125-O:1 overwhelmingly dictate the policy objectives; the Scrubber Law was intended to expeditiously implement these objectives via installation of the scrubber as quickly as possible.

The language of the Scrubber Law is clear. Ascribing the "plain and ordinary meaning to the words used" in the Scrubber Law leaves no doubt that the General Court has mandated installation of a scrubber at Merrimack Station as soon as possible. The intent of the Scrubber Law is obvious and apparent from the statute as written. The overall statutory scheme and the policy sought to be advanced is obvious and unwaivering: "The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of cost, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components."

The Supreme Court has also discussed the importance of the General Court's use of the word "shall," as used in the Scrubber Law. (A scrubber "***shall*** be installed at Merrimack Station no later than July 1, 2013." RSA 125-O:11, I. The requirements of the Scrubber Law "***shall*** be viewed as an integrated strategy of non-severable components." RSA 125-O:11, VIII. "The owner ***shall*** install and have operational scrubber technology to control mercury emissions at Merrimack Units 1 and 2 no later than July 1, 2013." RSA 125-O:13, I. "Total mercury emissions from the affected sources ***shall*** be at least 80 percent less on an annual basis than the

baseline mercury input, as defined in RSA 125-O:12, III, beginning on July 1, 2013."

RSA 125-O:13, II. In *State v. Johanson*, 156 N.H. 148, 151 (2007), the Court noted:

> "The use of the word 'shall' is generally regarded as a command; although not controlling, it is significant as indicating the intent that the statute is mandatory. This is especially so where the purpose of the statute is to protect private rights." *McCarthy v. Wheeler*, 152 N.H. 643, 645, 886 A.2d 972 (2005).

Similarly, in *City of Rochester v. Corpening*, 153 N.H. 571, 574 (2006) the Court held:

> "The intention of the Legislature as to the mandatory or directory nature of a particular statutory provision is determined primarily from the language thereof." *Appeal of Rowan*, 142 N.H. 67, 71, 694 A.2d 1002 (1997) (quotation and citation omitted). The general rule of statutory construction is that "the word 'may' makes enforcement of a statute permissive and that the word 'shall' requires mandatory enforcement." *Town of Nottingham v. Harvey*, 120 N.H. 889, 895, 424 A.2d 1125 (1980).

As recently as July 25th of this year, the Supreme Court reiterated this principle of statutory construction. Discussing the Legislature's use of the word "shall" in RSA 402-C:34, the Court cited to *Rowan, supra,* and held that "having used the word 'shall,' the legislature is presumed to have intended setoff under RSA 402-C:34 to be mandatory rather than discretionary." *In the Matter of the Liquidation of The Home Insurance Company*, ___ N.H. ___, *slip op. at* 10 (July 25, 2008).

The use of the word "shall" in the Scrubber Law emphasizes the Legislature's intent that installation of a scrubber at Merrimack Station is "commanded" and is "mandatory." Indeed, within the Scrubber Law, the General Court used the word "shall" sixty times! There can be no doubt of the mandatory and unequivocal direction expressed in the Scrubber Law.

When the Scrubber Law is analyzed using the Supreme Court's statutory interpretation rules, the General Court's meaning, intent, and command is clear. If there was any ambiguity, which there is not, the Court has indicated that legislative history would be used to aid in the statute's analysis. The Scrubber Law's legislative history is equally clear and unambiguous:

> **SCIENCE, TECHNOLOGY AND ENERGY**
>
> HB 1673-FN, relative to the reduction of mercury emissions.
>
> MAJORITY: OUGHT TO PASS WITH AMENDMENT. MINORITY: OUGHT TO PASS WITH AMENDMENT.
>
> Rep. Roy D. Maxfield for the Majority of Science, Technology and Energy: ***This bill provides for at least an 80% reduction of mercury emissions from coal-fired power plants by requiring the installation of a scrubber technology no later than July 1, 2013 and provides economic incentives for earlier installation timeframes and greater reduction in emissions.*** The committee amendment provides for annual progress reports from Public Service of New Hampshire (PSNH) and also cost recovery language. ***This legislation is a result of months of collaborative work by PSNH, the Department of Environmental Services, the Governor's office, multiple environmental groups, members of the committee and other stakeholders.*** The scrubber technology not only will reduce mercury by at least 80%, it will dramatically reduce SO2 emissions. ***Our committee held multiple work sessions and all had an opportunity to present their views.*** A comprehensive review of the timeframe was conducted by two members of the committee who concluded that the 2013 date is appropriate. ***It is in the best interests of PSNH to achieve early reductions for mercury*** and they are proceeding with a US Department of Energy (DOE) grant to accomplish this objective. ***This bill has consensus support from the Governor and stakeholders, and has wide bipartisan support in the General Court. The bill achieves the primary objectives of reasonable reductions, in a reasonable timeframe, at a reasonable cost to electricity users.*** Vote 13-2.
>
> Rep. Gene F. Andersen for the Minority of Science, Technology and Energy: ***The bill provides for significant mercury reductions from facilities operated by Public Service of New Hampshire (PSNH) by 2013.*** Some testimony indicated that an optimal permit

> and construction schedule could provide a 2011 completion for mercury removal equipment; thereby providing the necessary and desired reductions of mercury and other pollutants during that two year period. ***The minority felt the 2011 date should be utilized for implementation of the mercury reduction requirement*** and provide for extensions beyond that date if and only if PSNH was unable to complete by 2011 due to circumstance beyond its control.

House Calendar, Vol. 28, No. 22, February 17, 2008, p. 1280 (emphases added).

Moreover, the Analysis accompanying the Scrubber Law reads:

> **ANALYSIS**
>
> This bill provides for an 80 percent reduction of mercury emissions from coal-burning power plants by requiring the installation of scrubber technology no later than July 1, 2013 and provides economic incentives for earlier installation and greater reductions in emissions.

2006 N.H. Laws, Chapter 105.

The Scrubber Law's legislative history and Analysis echo the mandates found in the plain language of the law itself - - the bill requires the installation of scrubber technology no later than July 1, 2013. The only difference of opinion between the legislative majority and minority was on the schedule for the mandated installation of the scrubber - - the minority wanted the scrubber installed earlier - - a goal that is being materially hindered by the Commission's creation of this docket.

The Secretarial Letter states that there is "a potential conflict between" the Scrubber Law and RSA 369-B:3-a. PSNH finds no such conflict. The Scrubber Law uses plain and ordinary words which mandate that a scrubber "shall be installed at Merrimack Station no later than July 1, 2013." RSA 369-B:3-a, enacted during the 2003 legislative session, reads:

> 369-B:3-a Divestiture of PSNH Generation Assets. The sale of PSNH fossil and hydro generation assets shall not take place before April 30, 2006. Notwithstanding RSA 374:30, subsequent to April 30, 2006, PSNH may divest its generation assets if the commission finds that it is in the economic interest of retail customers of PSNH to do so, and

> provides for the cost recovery of such divestiture. ***Prior to any divestiture of its generation assets, PSNH may modify or retire such generation assets if the commission finds that it is in the public interest of retail customers of PSNH to do so***, and provides for the cost recovery of such modification or retirement.

(Emphasis added).

The "potential conflict" noted in the Secretarial Letter appears to be whether PSNH is required to obtain a Commission finding under RSA 369-B:3-a that the modification of Merrimack Station by the installation of a scrubber "is in the public interest of retail customers of PSNH" before such installation may proceed. As noted in *Appeal of Pinetree Power, Inc.*, 152 N.H. 92, 97 (2005), "By the plain language of the statute [RSA 369-B:3-a], the public interest standard for modification is broader than just economic interests." The General Court has weighed and ruled on the broader public interest and found that the Scrubber Law's requirements "represent a careful, thoughtful balancing of cost, benefits, and technological feasibility…." RSA 125-O:11, VIII.

Due to the mandatory language and express findings of the General Court contained in the Scrubber Law, there is no need nor authority for the Commission to render an additional and duplicative public interest finding under RSA 369-B:3-a prior to the installation of the scrubber. Any such proceeding under RSA 369-B:3-a would be held to determine only one thing - - whether it is "in the public interest of retail customers of PSNH" to modify Merrimack Station by installation of a scrubber. ***That precise finding has already been made by the General Court*** - - "The installation of [scrubber] technology is in the public interest of the citizens of New Hampshire and the customers of the affected sources." RSA 125-O:11, VI. As the General Court has already made the requisite RSA 369-B:3-a finding, the

Commission lacks authority to contravene this Legislative finding and there is no need for a separate and redundant Commission finding. Such a reading of the law is consistent with General Court's express statements of purpose and findings contained in the Scrubber Law. Statutes are to be interpreted "not in isolation, but in the context of the overall statutory scheme." *State v. Farrow,* 140 N.H. 473, 475 (1995); *Appeal of Ashland Elec. Dept*., 141 N.H. 336, 340 (1996); *Pinetree Power, id.* at 96.

By finding that "The installation of [scrubber] technology is in the public interest of…the customers of [PSNH]," the General Court has removed from the Commission any authority to reach a contrary finding. Recall, "the authority of the PUC…is limited to that specifically delegated or fairly implied by the legislature and may not be derived from other generalized powers of supervision." *Appeal of Public Service Co., id*. The General Court has not delegated authority to the Commission to determine whether installing a scrubber at Merrimack Station is in the public interest, nor is such authority fairly implied. That public interest finding has been made, and is clearly and definitively embodied in the law.

It should be noted that two of the sponsors of the Scrubber Law were also sponsors of 2003 N.H. Laws, Chapter 21, the law creating RSA 369-B:3-a. Senators Green and Odell both sponsored Senate Bill 170 during the 2003 legislative session and House Bill 1673-FN during the 2006 legislative session. It is inconceivable that these two Senators would sponsor legislation in 2006 finding that installation of scrubber technology at Merrimack Station is in the public interest of PSNH's customers (the precise finding required in their earlier 2003 law), yet would delegate to the Commission the authority and duty to make (or contradict) that same finding.

Any other reading of the interplay between the Scrubber Law and RSA 369-B:3-a would create the very conflict implied in the Secretarial Letter. In the event that there was a conflict between two statutes, the Supreme Court has held:

> When a conflict exists between two statutes, the later statute will control, especially when the later statute deals with a subject in a specific way and the earlier enactment treats that subject in a general fashion. 2A C. D. Sands, Sutherland Statutes and Statutory Construction § 51.05 (4th ed. 1973). However, as we noted in *Ingersoll v. Williams*, 118 N.H. 135, 138, 383 A.2d 1119, 1121 (1978), decided this day, implied repeal of former statutes is a disfavored doctrine in this State. *See also State v. Miller*, 115 N.H. 662, 348 A.2d 345 (1975); *Opinion of the Justices*, 107 N.H. 325, 221 A.2d 255 (1966). The party arguing a repeal by implication must demonstrate it by evidence of convincing force. *Opinion of the Justices, id.* at 328, 221 A.2d at 257. If any reasonable construction of the two statutes taken together can be found, this court will not find that there has been an implied repeal. *State v. Miller supra; Public Serv. Co. v. Lovejoy Granite Co.*, 114 N.H. 630, 325 A.2d 785 (1974).

Board of Selectmen of Merrimack v. Planning Board of Merrimack, 118 N.H. 150 (1978).

> More recently the Court re-affirmed this principle:
>
> "It is a well-recognized rule of statutory construction that where one statute deals with a subject in general terms, and another deals with a part of the same subject in a more detailed way, the latter will be regarded as an exception to the general enactment where the two conflict." *State v. Bell*, 125 N.H. 425, 432, 480 A.2d 906 (1984). We also note that RSA 161:4, VI was enacted in 1991, while RSA chapter 151-E was enacted in 1998. "When a conflict exists between two statutes, the later statute will control, especially when the later statute deals with a subject in a specific way and the earlier enactment treats that subject in a general fashion." *Petition of Public Serv. Co. of N.H.*, 130 N.H. 265, 283, 539 A.2d 263 (1988) (quotations omitted), appeal dismissed, 488 U.S. 1035, 109 S. Ct. 858, 102 L. Ed. 2d 983 (1989).

Bel Air Associates v. Dept. of Health and Human Services, 154 N.H. 228, 233 (2006).

Of the two laws in question, the Scrubber Law is the later statute, enacted during the 2006 legislative session versus the 2003 enactment for RSA 369-B:3-a. In addition, RSA 369-B:3-a deals with undefined, potential modifications of PSNH's

generation assets in a general way. The Scrubber Law contains specific findings and mandates. In accordance with the Court's holding in *Bel Air Associates*, the explicit directions provided in the Scrubber Law must be regarded as controlling over the general RSA 369-B:3-a enactment.

The instant situation is similar to the facts facing the Supreme Court in *Petition of Public Service Co. of N.H.,* 130 N.H. 265 (1988), cited in *Bel Air*, *supra.* In *Petition of Public Service Co. of N.H.*, the Court dealt with the power of the Commission to grant PSNH an emergency rate increase per RSA 378:9 during the construction of the Seabrook nuclear plant despite the enactment of the so-called "anti-CWIP" law, RSA 378:30-a. The Court noted that the emergency rate statute "grants the commission broad discretionary powers." *Petition of PSNH* at 283. "The anti-CWIP statute, on the other hand, restricts the commission's discretionary powers in the ratemaking process." *Id.* The Court then held:

> The one statute grants the commission general ratemaking powers under emergencies, and the other, enacted after the first, restricts the commission's discretion when determining rates. "When a conflict exists between two statutes, the later statute will control, especially when the later statute deals with a subject in a specific way and the earlier enactment treats that subject in a general fashion." *Board of Selectmen v. Planning Bd.*, 118 N.H. 150, 152, 383 A.2d 1122, 1124 (1978). RSA 378:30-a was enacted after the emergency statute. The anti-CWIP statute is unconditional in its prohibition, and makes no exceptions for emergencies.

Id.

Once again, PSNH faces a situation involving the enactment of a more recent, specific statute and an older statute of general application. Like the anti-CWIP law, the Scrubber Law, enacted after RSA 369-B:3-a, restricts the Commission's discretion. It also deals with the subject of modifying Merrimack

Station by the installation of a scrubber in a specific way, versus the general supervisory authority found in the earlier statute. Under the Court's holding in *Petition of PSNH*, the Scrubber Law's mandate for the installation of a scrubber at Merrimack Station and finding of such action to be in the public interest are controlling and binding upon the Commission.

The legislative mandates contained in the Scrubber Law are made even more apparent when the Scrubber Law is compared to the language in RSA Chapter 362-C, "Reorganization of Public Service Company of New Hampshire." As in the Scrubber Law, RSA Chapter 362-C begins with a legislative "Declaration of Purpose and Findings." RSA 362-C:1. Notably, the RSA 362-C:1 findings include a grant of authority to the Commission:

> …the public utilities commission should be authorized to determine whether a proposed agreement relating to the reorganization of Public Service Company of New Hampshire and, upon receipt of required regulatory approvals, the acquisition of Public Service Company of New Hampshire by Northeast Utilities, would be consistent with the public good and whether the rates for electric service to be established in connection with the reorganization are just and reasonable and should be approved.

RSA 362-C:1, IV. In RSA Chapter 362-C, the General Court specifically delegated authority to the Commission to make a determination whether the cited agreement "would be consistent with the public good." RSA 362-C:3. In the Scrubber Law, no such delegation of authority to the Commission is included; the General Court itself has determined that installation of a scrubber "is in the public interest of the citizens of New Hampshire and the customers of the affected sources." Had the Legislature intended to delegate such authority to the Commission, it certainly knew how to do so, as it had done in the past in RSA Chapter 362-C for another

matter involving the Commission's regulatory authority concerning PSNH. *See also*, *Cannata v. Town of Deerfield*, 132 N.H. 235, 243 (1989) (…the legislature knew how to include real property in a definition when it intended to do so.); *Barry v. Amherst*, 121 N.H. 335, 339 (1981) (The express language of RSA 36:23 (Supp. 1979) demonstrates that the legislature knew how to provide for automatic approval when that was its intention.).

PSNH notes that in a recent e-mail, the Commission's former general counsel, citing to RSA 125-O:13, I, indicated that the General Court's findings in the Scrubber Law were not binding upon the Commission, but were only to be afforded "due consideration." The complete wording of RSA 125-O:13, I, reads:

> I. The owner shall install and have operational scrubber technology to control mercury emissions at Merrimack Units 1 and 2 no later than July 1, 2013. The achievement of this requirement is contingent upon obtaining ***all necessary permits and approvals*** from federal, state, and local regulatory agencies and bodies; however, ***all such regulatory agencies and bodies are encouraged to give due consideration to the general court's finding that the installation and operation of scrubber technology at Merrimack Station is in the public interest. The owner shall make appropriate initial filings with the department and the public utilities commission, if applicable***, within one year of the effective date of this section, and with any other applicable regulatory agency or body in a timely manner.

For all the reasons set forth earlier, the Scrubber Law eliminates any need for a Commission determination under RSA 369-B:3-a; it is just not applicable and is not a necessary approval. Indeed, the creation of any such proceeding before the Commission (including the instant proceeding) would frustrate the General Court's specific finding that "It is in the public interest to achieve significant reductions in mercury emissions at the coal-burning electric power plants in the state as soon as possible." RSA 125-O:13, I. Any delays in the project will cause increases in the

ultimate price tag to be borne by PSNH's customers as costs of materials and labor continue to escalate, AFUDC continues to accrue, and the possibility to achieve early emissions reduction credits under RSA 125-O:16 evaporates. In the only other proceeding held under RSA 369-B:3-a, a total of 16 months elapsed between PSNH's initial filing and the achievement of a final, unappealable decision. NHPUC Docket No. DE 03-166, *PSNH Petition for Authority to Modify Schiller Station; Pinetree Power, id.* It is inconceivable that the General Court intended to subject the scrubber project to delays arising from a similar proceeding, given the "significant emissions reduction benefits, including but not limited to, cost effective reductions in sulfur dioxide, sulfur trioxide, small particulate matter, and improved visibility (regional haze)" (RSA 125-O:11, II) and incentives (that would benefit PSNH's retail customers) provided for early completion of the scrubber (RSA 125-O:16).

Notwithstanding the clarity of the mandate and intent of the Scrubber Law, if any ambiguity in the meaning of RSA 125-O:13, I, remained, the principles of statutory construction established by the Supreme Court, *supra*, would be applied. Recall the Court's direction in *Dansereau, supra*:

> We also interpret a statute in the context of the overall statutory scheme and not in isolation. If a statute is ambiguous, however, we consider legislative history to aid our analysis. Our goal is to apply statutes in light of the legislature's intent in enacting them, and in light of the policy sought to be advanced by the entire statutory scheme.

(Internal citations omitted).

The "overall statutory scheme" set forth in RSA 125-O:13, "Compliance," is clear, when these remaining provisions of that section are considered:

I. ***The owner shall install and have operational scrubber technology*** to control mercury emissions at Merrimack Units 1 and 2 ***no later than July 1, 2013.***

II. ***Total mercury emissions from the affected sources shall be at least 80 percent less*** on an annual basis than the baseline mercury input, as defined in RSA 125-O:12, III, beginning on July 1, 2013.

IV. If the net power output (as measured in megawatts) from Merrimack Station is reduced, ***due to the power consumption requirements or operational inefficiencies of the installed scrubber technology***, the owner may invest in capital improvements at Merrimack Station that increase its net capability…

V. Mercury reductions achieved ***through the operation of the scrubber technology*** greater than 80 percent shall be sustained insofar as the proven operational capability of the system, as installed, allows.

VI. The purchase of mercury emissions allowances or credits from any established emissions allowance or credit program shall not be allowed for compliance with ***the mercury reduction requirements of this chapter***.

VII. If the mercury reduction requirement of paragraph II is not achieved in any year after the July 1, 2013 implementation date, and ***after full operation of the scrubber technology***,….

VIII. If the mercury reduction requirement of paragraph II is not achieved by the owner in any year after the July 1, 2013 implementation date ***despite the owner's installation and full operation of scrubber technology***….

IX. The owner shall report by June 30, 2007 and annually thereafter, to the legislative oversight committee on electric utility restructuring, established under RSA 374-F:5, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee, on ***the progress and status of complying with the requirements of paragraphs I and III, relative to achieving early reductions in mercury emissions and also installing and operating the scrubber technology including any updated cost information.*** The last report required shall be after the department has made a determination, under paragraph V, on the maximum sustainable rate of mercury emissions reductions ***by the scrubber technology.***

RSA 125-O:13 (emphases added).

There can be no mistake that in enacting the Scrubber Law the Legislature intended that scrubber technology ***shall*** be installed at Merrimack Station. Without installation of the scrubber, the entirety of RSA 125-O:13 is made ineffective, as the provisions contained therein all anticipate and are based upon the mandated scrubber installation. Since the "goal is to apply statutes in light of the legislature's intent in enacting them, and in light of the policy sought to be advanced by the entire statutory scheme," (*Dansereau, id.*), there can be no doubt regarding the meaning of the Scrubber Law.

The "necessary permits and approvals" referenced in RSA 125-O:13, I, do not include a proceeding under RSA 369-B:3-a. Examples of such "necessary permits and approvals" include zoning laws, building permits, Federal Aviation Administration approvals, environmental permits, and the like, all of which PSNH is in the process of obtaining in a timely manner. The mandate to install a scrubber, and the General Court's finding that such installation is in the public interest of PSNH's retail customers, does not dictate ***how*** the scrubber is installed, just that it ***must*** be installed. PSNH is still required to ensure that the scrubber design meets traditional safety, environmental, and other building standards. *Cf.*, RSA 674:30, which provides that a public utility "may petition the public utilities commission to be exempted from the operation of any local ordinance, code, or regulation enacted under this title [LXIV]." RSA 674:30, III. This statute continues "The public utilities commission, following a public hearing, ***may*** grant such an exemption if it decides that the present or proposed situation of the structure in question is reasonably necessary for the convenience or welfare of the public…." *Id.* Note that

the Legislature made such a grant of exemption permissive, by use of the word "may" instead of "shall" - - it is such determinations to which "regulatory agencies and bodies are encouraged to give due consideration to the general court's finding that the installation and operation of scrubber technology at Merrimack Station is in the public interest."

The nature and extent of the Commission's authority concerning the scrubber project is set forth in the Scrubber Law itself. RSA 125-O:18, "Cost Recovery" states in part, "If the owner is a regulated utility, the owner shall be allowed to recover all prudent costs of complying with the requirements of this subdivision in a manner approved by the public utilities commission." The section continues by specifying that during ownership and operation of Merrimack Station by PSNH, "such costs shall be recovered via the utility's default service charge." By this section, the General Court has clearly established the Commission's role and authority regarding the scrubber project. When the scrubber project is completed, the Commission has the authority to review the prudence of PSNH's design and installation of the scrubber. The Commission does not have the authority to second-guess the General Court's decision mandating the installation of the scrubber.

Until the scrubber project is finished, the General Court has reserved to itself the power and authority to oversee the project. This reservation of authority is found in RSA 125-O-13, IX:

> The owner shall report by June 30, 2007 and annually thereafter, to the legislative oversight committee on electric utility restructuring, established under RSA 374-F:5, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee, on the progress and status of complying with the requirements of paragraphs I and III, relative to achieving early reductions in mercury emissions and also installing

> and operating the scrubber technology including any updated cost information. The last report required shall be after the department has made a determination, under paragraph V, on the maximum sustainable rate of mercury emissions reductions by the scrubber technology.

Such a reservation of authority by the General Court concerning the progress, status, and cost of complying with the Scrubber Law is yet another clear indication of the law's intent to negate the need for a RSA 369-B:3-a proceeding in this matter.

PSNH is confident that up to the initiation of the instant proceeding, it was diligently pursuing and complying with the legal mandates contained in 2006 N.H. Laws, Chapter 105, the Scrubber Law, by moving forward rapidly with the installation of scrubber technology at Merrimack Station. The legal mandates and requirements of the statute are set forth in plain and ordinary language, clearly expressing the legislature's intent and the policy sought to be advanced by the entire statutory scheme. This statutory scheme limits the powers and authority of the Commission concerning the installation of scrubber technology at Merrimack Station to a determination of the manner for the recovery of all prudent costs of complying with the requirements of this law.

PSNH urges the Commission to expeditiously act in this inquiry so that the Company may resume the commitment of capital and manpower necessary to install a wet flue gas desulphurization system ("scrubber technology," RSA 125-O:12, V) at its Merrimack Station as mandated by law.

Respectfully submitted this 2nd day of September, 2008.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

By:_____

Robert A. Bersak
Assistant Secretary and Assistant General Counsel
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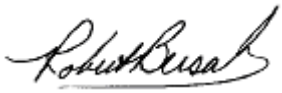
CERTIFICATE OF SERVICE

I certify that on this date I caused the attached Memorandum of Law to be served pursuant to N.H. Code Admin. Rule Puc 203.11.

September 2, 2008 

THE STATE OF NEW HAMPSHIRE
before the
PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire
Merrimack Station Scrubber Project
Request for Information

Docket No. DE 08-103

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE'S
MOTION FOR PROTECTIVE ORDER
RE: BID AND CONTRACT INFORMATION

Pursuant to RSA 91-A:5,(IV)(Supp.) and N.H. Code Admin. Rules Puc § 203.08, Public Service Company of New Hampshire ("PSNH" or the "Company") hereby requests protective treatment for certain information requested in the Commission's Secretarial Letter of August 22, 2008. In that letter the Commission requested that PSNH supply, *inter alia,* "a comprehensive status report on its installation plans, a detailed cost estimate for the project, and an analysis of the effect on energy service rates if Merrimack Station were not in the mix of fossil and hydro facilities operated by PSNH." A portion of this information is confidential, commercial, or financial information exempted from public disclosure under RSA 91-A:5.

In support of its Motion for Protective Order, PSNH says the following:

1. In order to prepare a comprehensive status report and a detailed cost estimate for the project, PSNH must rely on the results of progress made to date in preparing the different portions of the scrubber project for the commencement of construction efforts. There are several "islands" of work which are being negotiated with bidders before a final contract is executed for each portion of the project. These areas of the project are still in various stages of bidding or negotiations with bidders, contractors and subcontractors. The bids offered have all been made under a strictly confidential request for proposal process in order to protect the information from public disclosure. Even final contract terms and designs have been designated by the bidders and contractors as proprietary and subject to confidentiality terms to be included in the final agreements. Conclusions and summaries of data can be

made publicly available; however, the specific data contains information that is confidential, commercial, or financial information which the Commission may protect from public disclosure under RSA 91-A:5, IV.

2. If this information were to be made public, the contractors' proprietary information would be available to their competitors damaging their future ability to bid competitively on other contracts. Many vendors may withdraw from this project altogether if they cannot rely on customary business practices which include maintaining the confidentiality of contract terms. PSNH may have difficulty in attracting potential contractors in the future if there is a perception that their bids or confidential contract terms will be publicly disclosed.

3. The Commission must use a balancing test in order to weigh the importance of creating an open record of this proceeding with the harm from disclosure of confidential, financial or competitive information. "Under administrative rule Puc 204.06, the Commission considers whether the information, if made public, would likely create a competitive disadvantage for the petitioner; whether the customer information is financially or commercially sensitive, or if released, would likely constitute an invasion of privacy for the customer; and whether the information is not general public knowledge and the company takes measures to prevent its' dissemination." *Re Northern Utilities*, *Inc.,* 87 NH PUC 321, 322, Docket No. DG 01-182, Order No. 23,970 (May 10, 2002). Contracts with suppliers and confidential bidding information are routinely granted confidential treatment by the Commission. *Unitil Energy Systems,* 91 NH PUC 145, 150 (2006).

4. The limited benefits of publicly disclosing the information requested in the status report on the project's detailed cost estimate do not outweigh the harm done by disclosing the information. The ability to finalize contracts with vendors for this project and future projects may be jeopardized.

WHEREFORE, PSNH respectfully requests the Commission to issue an order preventing the public disclosure of the detailed cost estimate for the project, and to order such further relief as may be just and equitable.

Respectfully submitted this 2nd day of September, 2008.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

By:_____

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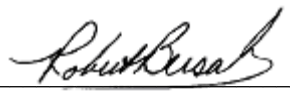
CERTIFICATE OF SERVICE

I certify that on this date I caused the attached Motion for Protective Order to be served pursuant to N.H. Code Admin. Rule Puc 203.11.

September 2, 2008



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Docket #: 08-103-1 Printed: September 02, 2008

FILING INSTRUCTIONS: **PURSUANT TO N.H. ADMIN RULE PUC 203.02(a)(1)**

WITH THE EXCEPTION OF DISCOVERY, FILE 7 COPIES (INCLUDING COVER LETTER) WITH:

DEBRA A HOWLAND
EXEC DIRECTOR & SECRETARY
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

PURSUANT TO N.H. ADMIN RULE 203.09 (d), FILE DISCOVERY

DIRECTLY WITH THE FOLLOWING STAFF

RATHER THAN WITH THE EXECUTIVE DIRECTOR

LIBRARIAN
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

BULK MATERIALS:

Upon request, Staff may waive receipt of some of its multiple copies of bulk materials filed as data responses. Staff cannot waive other parties' right to receive bulk materials.

NHPUC
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Docket #:
Printed: 9/2/2008

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-03
Dated: 08/24/2012
Q-TC-003
Page 1 of 3

Witness: **Terrance J. Large**
Request from: **TransCanada**

Question:

Reference the September 2, 2008 report by PSNH to the Commission in DE 08-103, page 14, Section III.C, please explain the basis for the statements about the effect that the Clean Air Project would have on energy service rates and provide any and all documents in PSNH's possession or the possession of any of its agents that related to such statements or the analysis done to support such statements.

Response:

Attached is an exhibit with the calculations to support the statements made about the effect that the Clean Air Project would have on energy service rates. In the attached exhibit, page 2, cell B5 lists the 2012-2017 average impact on energy service rates as 0.31 cents/kWh. This is calculated by taking the annual revenue requirement shown on page 3, line 23 of the attached exhibit and dividing by the annual kWh sales shown on page 2, line 46 of the attached exhibit and averaging the annual rate impacts over the 2012-2027 time period.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W
1	Filing Numbers																						
2																							
3	Slide 1																						
4																							
5	Scrubber 2012 to 2027 avg rate impact	0.31	cents per KwH																				
6	Scrubber 2013 rate impact	0.55	cents per KwH																				
7																							
8	5-year scrubber impact	0.18	cents per KwH																				
9																							
10	2012-2027 Avg Market Energy Cost	10.540	cents per KwH																				
11	2012-2027 Avg Capacity Cost	4.918	dollars per KW-Month																				
12	Busbar Cost, Scrubber	1.029	cents per KwH																				
13	Busbar Cost, Total	9.928	cents per KwH																				
14																							
15																							
16	Slide 2-table	Merrimack w/Scrubber	Market Purchase plus Retirement																				
17	Cost per KW	$ 1,057	-																				
18	2012-2027 Levelized busbar	$99.28	$109.13																				
19	2012 to 2027 Avg Energy Impact	0.0031	0.0389																				
20	Year 1 energy rate (2013 for scrubber and 2	0.0055	0.0379																				
21								10															
22																							
23																							
24	Year	Levelized Cost (2012-2027)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
25	Energy $/mwh	$100.01	$83.82	$83.82	$83.82	$83.82	$87.02	$89.20	$91.43	$93.71	$96.05	$98.46	$100.92	$103.44	$106.03	$108.68	$111.39	$114.18	$117.03	$119.96	$122.96	$126.03	
31	Capacity Converted to MWHs	$7.09	$5.51	$6.29	$6.67	$6.16	$5.80	$5.88	$6.01	$6.16	$6.34	$6.50	$6.66	$7.02	$7.55	$8.08	$8.59	$9.11	$9.64	$10.15	$10.67	$11.20	
32	Retirement per MWhs	$2.03	$0.00	0	0	0	0	0	5.76	5.34	4.92	4.50	4.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
33	Total levelized Market Cost	$109.13																					
34									5.76														
35																							
36																							
37																							
38																							
39																							
40	**Market Energy, Capacity, and Retirement Costs**																						
41			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
42	Energy		$ 273,109,197	$ 273,109,197	$ 273,109,197	$ 273,109,197	$ 283,537,003	$ 290,625,428	$ 297,891,064	$ 305,338,340	$ 312,971,799	$ 320,796,094	$ 328,815,996	$ 337,036,396	$ 345,462,306	$ 354,098,864	$ 362,951,335	$ 372,025,119	$ 381,325,747	$ 390,858,890	$ 400,630,362	$ 410,646,122	
43	Capacity		$ 17,957,400	$ 20,500,500	$ 21,746,100	$ 20,085,300	$ 18,891,600	$ 19,151,100	$ 19,566,300	$ 20,085,300	$ 20,656,200	$ 21,175,200	$ 21,694,200	$ 22,887,900	$ 24,600,600	$ 26,313,300	$ 27,974,100	$ 29,686,800	$ 31,399,500	$ 33,060,300	$ 34,773,000	$ 36,485,700	
44	Retirement Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ 18,760,543	$ 17,391,361	$ 16,022,179	$ 14,652,996	$ 13,283,814	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
45	Total		$ 291,066,597	$ 293,609,697	$ 294,855,297	$ 293,194,497	$ 302,428,603	$ 309,776,528	$ 336,217,907	$ 342,815,001	$ 349,650,178	$ 356,624,290	$ 363,794,010	$ 359,924,296	$ 370,062,906	$ 380,412,164	$ 390,925,435	$ 401,711,919	$ 412,725,247	$ 423,919,190	$ 435,403,362	$ 447,131,822	
46	Sales		8,208,482	8,276,709	8,361,350	8,527,730	8,681,138	8,757,261	8,876,549	8,988,206	9,120,460	9,224,176	9,349,758	9,463,333	9,605,283	9,749,362	9,895,603	10,044,037	10,194,697	10,347,618	10,502,832	10,660,374	
47	$/KWH		0.0355	0.0355	0.0353	0.0344	0.0348	0.0354	0.0379	0.0381	0.0383	0.0387	0.0389	0.0380	0.0385	0.0390	0.0395	0.0400	0.0405	0.0410	0.0415	0.0419	
48																							
49																							
50																							
51	**Retirement only rate impact**		0	0	0	0	0	0	0.21	0.19	0.18	0.16	0.14										
52																							
53																							
54	**Scrubber only Rate Impact**		0	-	-	-	0.0038	0.0055	0.0048	0.0043	0.0043	0.0041	0.0038	0.0035	0.0032	0.0028	0.0025	0.0022	0.0020	0.0017	0.0014	(0.0003)	
55																							
56																							
57	**Shutdown Ratebase buildup**																						
58				2014	2015	2016	2017	2018															
59			Reg Asset BB	$ 62,996,114	$ 50,396,891	$ 37,797,668	$ 25,198,446	$ 12,599,223															
60	Stranded Cost	$ 62,996,114	Reg Asset EB	$ 50,396,891	$ 37,797,668	$ 25,198,446	$ 12,599,223	$ -															
61	Number of Years to Recover	5	Avg Reg Asset	$ 56,696,503	$ 44,097,280	$ 31,498,057	$ 18,898,834	$ 6,299,611															
62			Amort	$ 12,599,223	$ 12,599,223	$ 12,599,223	$ 12,599,223	$ 12,599,223															
63			Pre-tax Return	$ 6,161,321	$ 4,792,138	$ 3,422,956	$ 2,053,774	$ 684,591															
64			Total RR	$ 18,760,543	$ 17,391,361	$ 16,022,179	$ 14,652,996	$ 13,283,814															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
1	**Rate Base Calculation**																											
2				2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028		
3	**Scrubber Only Incremental Costs**																											
4		**RateBase Build**																										
5		Cumulative Capital		$ 871,913	$ 2,734,966	$ 44,061,397	$ 145,377,133	$ 310,955,865	$ 407,418,024	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069	$ 457,221,069		
6		Accumulated Book Depr		$ -	$ -	$ -	$ -	$ -	$ -	$ 15,240,702	$ 45,722,107	$ 76,203,512	$ 106,684,916	$ 137,166,321	$ 167,647,725	$ 198,129,130	$ 228,610,535	$ 259,091,939	$ 289,573,344	$ 320,054,748	$ 350,536,153	$ 381,017,558	$ 411,498,962	$ 441,980,367	$ 457,221,069	$ 457,221,069		
7		Net Book Value		$ 871,913	$ 2,734,966	$ 44,061,397	$ 145,377,133	$ 310,955,865	$ 407,418,024	$ 441,980,367	$ 411,498,962	$ 381,017,558	$ 350,536,153	$ 320,054,748	$ 289,573,344	$ 259,091,939	$ 228,610,535	$ 198,129,130	$ 167,647,725	$ 137,166,321	$ 106,684,916	$ 76,203,512	$ 45,722,107	$ 15,240,702	$ -	$ -		
8		Working Capital								$ 366,918	$ 731,914	$ 750,314	$ 769,178	$ 788,516	$ 808,340	$ 828,664	$ 849,499	$ 870,859	$ 892,756	$ 915,205	$ 938,219	$ 961,812	$ 985,999	$ 1,010,794	$ 1,036,214	$ -		
9		Month end Fuel Inventory								$ (71,563)	$ (293,407)	$ (300,742)	$ (308,260)	$ (315,967)	$ (323,866)	$ (331,963)	$ (340,262)	$ (348,768)	$ (357,488)	$ (366,425)	$ (375,585)	$ (384,975)	$ (394,599)	$ (404,464)	$ (414,576)	$ (424,940)		
10		Nox/Sox								$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
11		M&S inventory								$ 6,693,835	$ 5,850,483	$ 5,007,132	$ 4,163,781	$ 3,320,429	$ 2,477,078	$ 2,069,326	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000	$ 1,782,000		
12		ADIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,537,531	$ 44,247,660	$ 63,759,539	$ 83,088,529	$ 102,247,799	$ 91,988,368	$ 81,583,723	$ 71,045,204	$ 60,484,739	$ 49,923,908	$ 39,363,442	$ 28,802,611	$ 18,242,145	$ 7,681,314	$ (2,879,152)	$ (7,343,702)	$ (5,711,606)		
13		RateBase End of Year	$ 871,913	$ 1,803,439	$ 23,398,181	$ 94,719,265	$ 228,166,499	$ 359,186,944	$ 424,432,026	$ 373,540,293	$ 322,714,723	$ 272,072,322	$ 221,599,927	$ 200,546,528	$ 180,074,244	$ 159,856,568	$ 139,948,482	$ 120,041,087	$ 100,133,659	$ 80,226,939	$ 60,320,203	$ 40,414,192	$ 20,508,184	$ 9,747,340	$ 5,286,665		
14		Average Rate Base	$ 871,913	$ 1,803,439	$ 23,398,181	$ 94,719,265	$ 228,166,499	$ 359,186,944	$ 440,826,548	$ 398,986,160	$ 348,127,508	$ 297,393,522	$ 246,836,125	$ 211,073,228	$ 190,310,386	$ 169,965,406	$ 149,902,525	$ 129,994,784	$ 110,087,373	$ 90,180,299	$ 70,273,571	$ 50,367,197	$ 30,461,188	$ 15,127,762	$ 7,517,003		
15																												
16		**Revenue Requirements**																										
17		Pre-tax Capital Return		$ -	$ -	$ -	$ -	$ -	$ -	$ 23,952,745	$ 43,358,612	$ 37,831,702	$ 32,318,340	$ 26,824,168	$ 22,937,743	$ 20,681,405	$ 18,470,475	$ 16,290,203	$ 14,126,789	$ 11,963,412	$ 9,800,071	$ 7,636,767	$ 5,473,503	$ 3,310,277	$ 821,982	$ -		
18		Depreciation		$ -	$ -	$ -	$ -	$ -	$ -	$ 15,240,702	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 15,240,702	$ -		
19		O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,976,112	$ 5,936,638	$ 6,085,884	$ 6,238,886	$ 6,395,739	$ 6,556,539	$ 6,721,387	$ 6,890,384	$ 7,063,635	$ 7,241,246	$ 7,423,329	$ 7,609,995	$ 7,801,360	$ 7,997,543	$ 8,198,665	$ 8,404,851	$ -		
20		Fuel				$ -	$ -	$ -	$ -	$ (397,570)	$ (1,630,037)	$ (1,670,788)	$ (1,712,558)	$ (1,755,372)	$ (1,799,256)	$ (1,844,237)	$ (1,890,343)	$ (1,937,602)	$ (1,986,042)	$ (2,035,693)	$ (2,086,585)	$ (2,138,750)	$ (2,192,219)	$ (2,247,024)	$ (2,303,200)	$ (2,360,780)		
21		Emmisions Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,867,412)	$ (29,775,129)	$ (30,519,507)	$ (28,647,698)	$ (22,838,582)	$ (20,065,325)	$ (20,566,958)	$ (21,081,132)	$ (21,608,161)	$ (22,148,365)	$ (22,702,074)	$ (23,269,626)	$ (23,851,366)	$ (24,447,650)	$ (25,058,842)	$ (25,685,313)	$ (26,327,446)		
22		Property Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
23		Subotal Revenue Requirements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 32,904,577	$ 48,371,489	$ 42,208,696	$ 38,678,375	$ 39,107,358	$ 38,111,106	$ 35,473,000	$ 32,870,788	$ 30,289,479	$ 27,715,034	$ 25,130,378	$ 22,535,260	$ 19,929,416	$ 17,312,581	$ 14,684,481	$ (3,520,977)	$ (28,688,225)		
24																												
25		Percentage of Year In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	50%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	50%	0%		
26																												
27	**Existing Plant With Capital Adds**																											
28		**RateBase Build**																										
29		Cumulative Capital			$ 188,935,000	$ 232,935,000	$ 241,935,000	$ 250,935,000	$ 259,935,000	$ 268,935,000	$ 277,935,000	$ 286,935,000	$ 295,935,000	$ 304,935,000	$ 313,935,000	$ 322,935,000	$ 331,935,000	$ 340,935,000	$ 349,935,000	$ 358,935,000	$ 367,935,000	$ 376,935,000	$ 385,935,000	$ 394,935,000	$ 403,935,000	$ 412,935,000		
30		Accumulated Book Depr			$ 140,727,000	$ 149,245,701	$ 159,564,403	$ 171,683,104	$ 185,601,805	$ 201,320,507	$ 218,839,208	$ 236,357,909	$ 253,876,611	$ 271,395,312	$ 288,914,014	$ 302,032,715	$ 313,935,000	$ 322,935,000	$ 331,935,000	$ 340,935,000	$ 349,935,000	$ 358,935,000	$ 367,935,000	$ 376,935,000	$ 385,935,000	$ 393,135,000		
31		Net Book Value			$ 48,208,000	$ 83,689,299	$ 82,370,597	$ 79,251,896	$ 74,333,195	$ 67,614,493	$ 59,095,792	$ 50,577,091	$ 42,058,389	$ 33,539,688	$ 25,020,986	$ 20,902,285	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 18,000,000	$ 19,800,000		
32		Working Capital			$ 3,457,356	$ 3,543,790	$ 3,632,385	$ 3,723,194	$ 3,816,274	$ 3,911,681	$ 4,009,473	$ 4,109,710	$ 4,212,453	$ 4,317,764	$ 4,425,708	$ 4,536,351	$ 4,649,760	$ 4,766,004	$ 4,885,154	$ 5,007,283	$ 5,132,465	$ 5,260,776	$ 5,392,296	$ 5,527,103	$ 5,665,281	$ 5,806,913		
33		Month end Fuel Inventory			$ 19,159,000	$ 28,112,102	$ 28,112,102	$ 28,112,102	$ 28,112,102	$ 28,112,102	$ 28,814,904	$ 29,535,277	$ 30,273,659	$ 31,030,500	$ 31,806,263	$ 32,601,419	$ 33,416,455	$ 34,251,866	$ 35,108,163	$ 35,985,867	$ 36,885,513	$ 37,807,651	$ 38,752,843	$ 39,721,664	$ 40,714,705	$ 41,732,573		
34		Nox/Sox			$ 22,920,000	$ 18,336,000	$ 13,752,000	$ 9,168,000	$ 4,584,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
35		M&S inventory			$ 3,181,728	$ 5,523,494	$ 5,436,459	$ 5,230,625	$ 4,905,991	$ 4,462,557	$ 3,900,322	$ 3,338,088	$ 2,775,854	$ 2,213,619	$ 1,651,385	$ 1,379,551	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,188,000	$ 1,306,800		
36		ADIT				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
37		RateBase End of Year			$ 96,926,084	$ 139,204,684	$ 133,303,543	$ 125,485,817	$ 115,751,561	$ 104,100,833	$ 95,820,492	$ 87,560,165	$ 79,320,354	$ 71,101,571	$ 62,904,342	$ 59,419,606	$ 57,254,214	$ 58,205,870	$ 59,181,316	$ 60,181,149	$ 61,205,978	$ 62,256,428	$ 63,333,138	$ 64,436,767	$ 65,567,986	$ 68,646,286		
38		Average Rate Base			$ 96,926,084	$ 118,065,384	$ 136,254,114	$ 129,394,680	$ 120,618,689	$ 109,926,197	$ 99,960,662	$ 91,690,328	$ 83,440,260	$ 71,101,571	$ 62,904,342	$ 59,419,606	$ 57,254,214	$ 58,205,870	$ 59,181,316	$ 60,181,149	$ 61,205,978	$ 62,256,428	$ 63,333,138	$ 64,436,767	$ 65,567,986	$ 68,646,286		
39																												
40		**Revenue Requirements**																										
41		Pre-tax Capital Return		$ -	$ 10,533,149	$ 12,830,398	$ 14,807,003	$ 14,061,575	$ 13,107,871	$ 11,945,896	$ 10,862,922	$ 9,964,169	$ 9,067,617	$ 7,726,748	$ 6,835,939	$ 6,457,246	$ 6,221,928	$ 6,325,347	$ 6,431,350	$ 6,540,004	$ 6,651,374	$ 6,765,529	$ 6,882,537	$ 7,002,470	$ 7,125,402	$ 7,459,927		
42		Depreciation		$ -	$ 10,599,000	$ 8,518,701	$ 10,318,701	$ 12,118,701	$ 13,918,701	$ 15,718,701	$ 17,518,701	$ 17,518,701	$ 17,518,701	$ 17,518,701	$ 17,518,701	$ 13,118,701	$ 11,902,285	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 7,200,000		
43		O&M	$ -	$ -	$ 28,043,000	$ 28,744,075	$ 29,462,677	$ 30,199,244	$ 30,954,225	$ 31,728,081	$ 32,521,283	$ 33,334,315	$ 34,167,672	$ 35,021,864	$ 35,897,411	$ 36,794,846	$ 37,714,717	$ 38,657,585	$ 39,624,025	$ 40,614,625	$ 41,629,991	$ 42,670,741	$ 43,737,509	$ 44,830,947	$ 45,951,721	$ 47,100,514		
44		Fuel	$ -	$ -	$ 118,776,109	$ 159,028,012	$ 159,028,012	$ 159,028,012	$ 159,028,012	$ 159,028,012	$ 163,003,713	$ 167,078,805	$ 171,255,775	$ 175,537,170	$ 179,925,599	$ 184,423,739	$ 189,034,333	$ 193,760,191	$ 198,604,196	$ 203,569,301	$ 208,658,533	$ 213,874,996	$ 219,221,871	$ 224,702,418	$ 230,319,979	$ 236,077,978		
45		Emmisions Costs			$ -	$ -	$ -	$ -	$ -	$ -	$ 31,624,387	$ 32,414,996	$ 33,225,371	$ 45,363,357	$ 46,497,441	$ 47,659,877	$ 48,851,374	$ 50,072,658	$ 51,324,475	$ 52,607,587	$ 53,922,776	$ 55,270,846	$ 56,652,617	$ 58,068,932	$ 59,520,656	$ 61,008,672	$ 62,533,889		
46		Property Tax	$ -	$ -	$ 3,304,000	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600		
47		Subotal Revenue Requirements	$ -	$ -	$ 171,255,257	$ 212,507,786	$ 217,002,993	$ 218,794,132	$ 220,395,409	$ 253,431,677	$ 259,708,215	$ 264,507,961	$ 280,759,724	$ 285,688,524	$ 291,224,127	$ 293,032,506	$ 298,332,522	$ 302,454,198	$ 309,653,757	$ 317,033,306	$ 324,597,344	$ 332,350,483	$ 340,297,450	$ 348,443,091	$ 356,792,374	$ 363,758,908		
48																												
49																												
50	**Total New Plant With Scrubber**																											
51		**Revenue Requirements**																										
52		Pre-tax Capital Return		$ -	$ 10,533,149	$ 12,830,398	$ 14,807,003	$ 14,061,575	$ 13,107,871	$ 35,898,641	$ 54,221,534	$ 47,795,871	$ 41,385,957	$ 34,550,916	$ 29,773,682	$ 27,138,650	$ 24,692,404	$ 22,615,549	$ 20,558,140	$ 18,503,416	$ 16,451,445	$ 14,402,296	$ 12,356,039	$ 10,312,748	$ 7,947,384	$ 7,459,927		
53		Depreciation		$ -	$ 10,599,000	$ 8,518,701	$ 10,318,701	$ 12,118,701	$ 13,918,701	$ 30,959,404	$ 48,000,106	$ 48,000,106	$ 48,000,106	$ 48,000,106	$ 48,000,106	$ 43,600,106	$ 42,383,690	$ 39,481,405	$ 39,481,405	$ 39,481,405	$ 39,481,405	$ 39,481,405	$ 39,481,405	$ 39,481,405	$ 39,481,405	$ 24,240,702	$ 7,200,000		
54		O&M	$ -	$ -	$ 28,043,000	$ 28,744,075	$ 29,462,677	$ 30,199,244	$ 30,954,225	$ 34,704,192	$ 38,457,921	$ 39,420,199	$ 40,406,559	$ 41,417,603	$ 42,453,950	$ 43,516,233	$ 44,605,101	$ 45,721,220	$ 46,865,271	$ 48,037,954	$ 49,239,986	$ 50,472,101	$ 51,735,053	$ 53,029,613	$ 54,356,572	$ 47,100,514		
55		Fuel	$ -	$ -	$ 118,776,109	$ 159,028,012	$ 159,028,012	$ 159,028,012	$ 159,028,012	$ 158,630,442	$ 161,373,675	$ 165,408,017	$ 169,543,218	$ 173,781,798	$ 178,126,343	$ 182,579,502	$ 187,143,989	$ 191,822,589	$ 196,618,154	$ 201,533,608	$ 206,571,948	$ 211,736,246	$ 217,029,653	$ 222,455,394	$ 228,016,779	$ 233,717,198		
56		Emmisions Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,756,975	$ 2,639,868	$ 2,705,865	$ 16,715,659	$ 23,658,860	$ 27,594,552	$ 28,284,416	$ 28,991,526	$ 29,716,314	$ 30,459,222	$ 31,220,703	$ 32,001,220	$ 32,801,251	$ 33,621,282	$ 34,461,814	$ 35,323,359	$ 36,206,443		
57		Property Tax	$ -	$ -	$ 3,304,000	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600	$ 3,386,600		
58		Subotal Revenue Requirements	**Levelized-2012-2027**	**NPV**	$ 171,255,257	$ 212,507,786	$ 217,002,993	$ 218,794,132	$ 220,395,409	$ 286,336,254	$ 308,079,704	$ 306,716,657	$ 319,438,099	$ 324,795,883	$ 329,335,234	$ 328,505,507	$ 331,203,310	$ 332,743,677	$ 337,368,791	$ 342,163,685	$ 347,132,604	$ 352,279,899	$ 357,610,031	$ 363,127,573	$ 353,271,396	$ 335,070,683		
59																												
60		NPV Gross Revenue Requirements	$323,475,945	$2,405,312,572						1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16			
61																												
62		Less Market Energy	$325,874,918	$2,423,150,928		$273,109,197	$273,109,197	$273,109,197	$273,109,197	$283,537,003	$290,625,428	$297,891,064	$305,338,340	$312,971,799	$320,796,094	$328,815,996	$337,036,396	$345,462,306	$354,098,864	$362,951,335	$372,025,119	$381,325,747	$390,858,890	$400,630,362	$410,646,122	$420,912,275		
63		Less Market Capacity	$23,089,319	$171,688,284		$17,957,400	$20,500,500	$21,746,100	$20,085,300	$18,891,600	$19,151,100	$19,566,300	$20,085,300	$20,656,200	$21,175,200	$21,694,200	$22,887,900	$24,600,600	$26,313,300	$27,974,100	$29,686,800	$31,399,500	$33,060,300	$34,773,000	$36,485,700	$38,146,500		
64																												
65		NPV Net Revenue Requirements	($25,488,292)	($189,526,641)	2012	$ (78,558,811)	$ (76,606,704)	$ (76,061,165)	$ (72,799,088)	$ (16,092,349)	$ (1,696,824)	$ (10,740,706)	$ (5,985,542)	$ (8,832,116)	$ (12,636,060)	$ (22,004,689)	$ (28,720,986)	$ (37,319,229)	$ (43,043,372)	$ (48,761,750)	$ (54,579,315)	$ (60,445,347)	$ (66,309,159)	$ (72,275,790)	$ (93,860,425)	$ (123,988,092)		
66			($17,763,560)	($132,086,833)	2008																							
67																												
68		Busbar Cost, Prior	$88.99		52.56	65.22	66.60	67.15	67.64	77.78	79.71	81.18	86.17	87.68	89.38	89.93	91.56	92.83	95.04	97.30	99.62	102.00	104.44	106.94	109.50	111.64		
69		Busbar Cost, Scrubber	$10.29		0.00	0.00	0.00	0.00	-67.64	10.10	14.85	12.95	11.87	12.00	11.70	10.89	10.09	9.30	8.51	7.71	6.92	6.12	5.31	4.51	-1.08	-8.80		
70		Busbar Cost, Total	$99.28		52.56	65.22	66.60	67.15		87.88	94.55	94.13	98.04	99.68	101.08	100.82	101.65	102.12	103.54	105.01	106.54	108.12	109.75	111.45	108.42	102.84		
71																												
72		cents			0.000	0.000	0.000	0.000	-6.764	1.010	1.485	1.295	1.187	1.200	1.170	1.089	1.009	0.930	0.851	0.771	0.692	0.612	0.531	0.451	-0.108	-0.880		
73			$ 0.010																									

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-03
Dated: 08/24/2012
Q-TC-004
Page 1 of 4

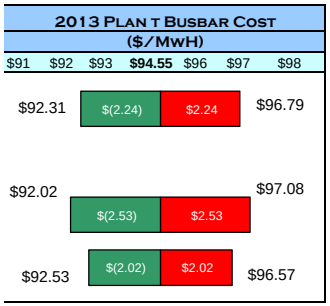
Witness: **Terrance J. Large**
Request from: **TransCanada**

Question:
Reference the September 2, 2008 report by PSNH to the Commission in DE 08-103, page 14, please provide copies of any and all documents in PSNH's possession or the possession of any of its agents related to the sensitivity analyses described in Section III.D on this page. Please explain when and why these analyses were done.

Response:
Please reference the attached exhibit for the supporting documents describing the sensitivity analyses referenced on page 14, section III.D. These sensitivity analyses were developed in the summer of 2008 to assess the risks and sensitivities impacting energy service rates as a result of the Clean Air Project.

PSNH Clean Air Project Sensitivities

Assumption Category	Assumptions			2008 PV of Net Customer Cost[1] 2012-2027 ($Mil)	Net Customer Cost Break-Even Rates
	Downside	Base	Upside	($300) ($180) **($132)** ($50) $40	
Capital Cost	+10%	$457 mil	-10%	$(159) $(27) $(7) $(105)	$684 mil
2012 gas prices, MMBTU[2]	-10%	$11.00	+10%	$(295) $(163) $163 $31	$10.10
2012 coal prices, MMBTU[2]	+10%	$4.82	-10%	$(228) $(96) $96 $(36)	$5.49
Implied Gas/coal Spread	$4.60	$6.18	$7.76		$5.29[4]
2012 Carbon Costs[2,3]	+50%	$7	-50%	$(167) $(35) $35 $(97)	$30.13



9.9
$5.30
$4.60

	Low	Middle	High
Carbon	$ 35.30	$ -	$ (35.30)
	$ -		$ -
Coal	$ 95.64	$ -	$ (95.64)
Gas	$ 162.67	$ -	$ (162.67)
Capital	$ 26.62	$ -	$ (26.62)

Carbon	$ (167)	$ (132)	$ (97)
Coal	$ (228)	$ (132)	$ (36)
Gas	$ (295)	$ (132)	$ 31
Capital	$ (159)	$ (132)	$ (105)

	Low	Middle	High
Carbon	$ 2.02	$ -	$ (2.02)
Coal	$ 2.53	$ -	$ (2.53)
Gas	$ 2.75	$ -	$ (2.75)
Capital	$ 2.24	$ -	$ (2.24)

Carbon	$ 96.57	$ 94.55	$ 92.53
Coal	$ 97.08	$ 94.55	$ 92.02
Gas	$ 97.30	$ 94.55	$ 91.80
Capital	$ 96.79	$ 94.55	$ 92.31

Sensitivity and Scenario Cases

	Sensitivities and Scenarios	Capital	Capital Increase	Gas	Coal	Carbon	
1	Sensitivity 1	457221069	10.0%	$ 11.0	$ 4.8	$ 7.0	
2	Sensitivity 2	457221069	-10.0%	$ 11.0	$ 4.8	$ 7.0	
3	Sensitivity 3	457221069	0.0%	$ 12.1	$ 4.8	$ 7.0	
4	Sensitivity 4	457221069	0.0%	$ 9.9	$ 4.8	$ 7.0	
5	Sensitivity 5	457221069	0.0%	$ 11.0	$ 5.3	$ 7.0	
6	Sensitivity 6	457221069	0.0%	$ 11.0	$ 4.3	$ 7.0	
7	Sensitivity 7	457221069	0.0%	$ 11.0	$ 4.8	$ 10.5	
8	Sensitivity 8	457221069	0.0%	$ 11.0	$ 4.8	$ 3.5	
9	Scenario 1	532000000	16.4%	$ 8.8	$ 5.8	$ 30.0	
10	Scenario 2	497000000	8.7%	$ 9.9	$ 5.3	$ 20.0	
11	Scenario 3	457221069	0.0%	$ 11.0	$ 4.8	$ 7.0	Base Case
12	Scenario 4	447000000	-2.2%	$ 12.1	$ 4.3	$ 5.0	
13	Scenario 5	437000000	-4.4%	$ 13.2	$ 3.9	$ -	

Scenario Assumption Inputs

Scenario Used	Capital Increase	Gas	Coal	Carbon
11	0.0%	$ 11.00	$ 4.82	$ 7.00

Scenario Results

Scenario	Number	RR NPV	Monthly Cost Impact	2013 Busbar Costs	2013 Net Income
Sensitivity 1	1	$ (105.47)	1 $ (0.81)	1 $ 96.80	1 $ 20.30
Sensitivity 2	2	$ (158.71)	2 $ (1.22)	2 $ 92.31	2 $ 16.67
Sensitivity 3	3	$ (294.75)	3 $ (2.26)	3 $ 94.55	3 $ 18.49
Sensitivity 4	4	$ 30.58	4 $ 0.23	4 $ 94.55	4 $ 18.49
Sensitivity 5	5	$ (36.44)	5 $ (0.28)	5 $ 99.60	5 $ 18.49
Sensitivity 6	6	$ (227.73)	6 $ (1.75)	6 $ 89.51	6 $ 18.49
Sensitivity 7	7	$ (105.95)	7 $ (0.81)	7 $ 96.57	7 $ 18.49
Sensitivity 8	8	$ (161.36)	8 $ (1.24)	8 $ 92.53	8 $ 18.49
Scenario 1	9	$ 481.10	9 $ 3.69	9 $ 102.40	9 $ 21.46
Scenario 2	10	$ 193.58	10 $ 1.49	10 $ 100.36	10 $ 20.07
Scenario 3	11	$ (132.09)	11 $ (1.01)	11 $ 94.55	11 $ 18.49
Scenario 4	12	$ (413.08)	12 $ (3.17)	12 $ 87.85	12 $ 18.08
Scenario 5	13	$ (719.03)	13 $ (5.52)	13 $ 79.43	13 $ 17.68

Risk Scenarios - PSNH Clean Air Project

	Unlikely Low	Possible Low	Base	Possible High	Unlikely High
NPV - net Customer Cost [1]	$481 mil	$194 mil	($132 mil)	($413 mil)	($719 mil)
Monthly Residential Customer Cost Impact [2]	$3.70	$1.49	($1.01)	($3.17)	($5.52)
2013 Plant Busbar Cost ($/MwH)	$102.41	$100.37	$94.55	$87.86	$79.44
Net Inc - 2013 (First full Year In-Service)	$21.5 mil	$20.1 mil	$18.5 mil	$18.1 mil	$17.7 mil
Assumed probability	*5%*	*25%*	-	*25%*	*5%*
Parameters					
Capital Costs, Millions	$532	$497	$457	$447	$437
2012 Gas Prices, MMBTU[3]	$8.80	$9.90	$11.00	$12.10	$13.20
2012 Coal Prices, MMBTU[3]	$5.78	$5.30	$4.82	$4.34	$3.86
2012 Carbon Costs, Ton[3,4]	$30	$20	$7	$5	$0

CASE LEGEND

- **Unlikely Low** — case reflects project in-service delayed one year and cost overun ($45M), cooling tower addition ($30M), minimal Gas/coal Spread
- **Possible Low** — case reflects project in-service on-time with cost overun ($10M), cooling tower addition ($30M), decreased Gas/coal Spread
- **Base** — Current assumptions
- **Possible High** — case reflects project in-service 6 months early ($10M), project costs as expected, benign carbon legislation, increased gas/coal spread
- **Unlikely High** — case reflects project in-service 6 months early ($10M) with lower than expected costs ($10M), no carbon legislation, maximum gas/coal spread

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-03
Dated: 08/24/2012
Q-TC-006
Page 1 of 2

Witness: **Terrance J. Large**
Request from: **TransCanada**

Question:
Reference the September 2, 2008 report by PSNH to the Commission in DE 08-103, page 15, Section IV.D, please provide the heat rate factor that PSNH applied and provide any and all documentation in PSNH 's possession or the possession of any of its agents related to the analysis described in this section. Please explain when and why this analysis was done.

Response:
The heat rate factor applied was 7.62 MMBtu/MWh. This is a 2008-2011 average implied heat rate calculated from NYMEX gas prices. The attached exhibit provides the supporting detail for the 7.62 number. This analysis was done in the summer of 2008 to support the update filing to the NHPUC.

						avg implied Ht rt >>		**7.62**		
	APB Peak	APB Offpk	24 hr	NYMEX Hub Gas	NE Gas Basis	NE Gas (NYMEX plus basis)	NE Gas (EVA)	Implied Ht Rate	Power Price	
Cal 08	129.74	101.15	114.38	12.91	1.71	14.62	8.37	7.82	114.38	apb
Cal 09	117.75	92.25	104.24	11.72	2.18	13.90	8.81	7.50	104.24	apb
Cal 10	107.00	83.63	94.61	10.60	1.92	12.51	8.82	7.56	94.61	apb
Cal 11	103.63	81.25	91.77	10.28	1.80	12.08	9.04	7.60	91.77	apb
Cal 12				10.34	1.70	12.04	9.53		91.76	nymex
Cal 13				10.55	1.73	12.28	8.97		68.38	eva
Cal 14				10.77	1.77	12.54	9.24		70.37	eva
Cal 15				10.99	1.81	12.80	9.50		72.43	eva
Cal 16				11.22	1.84	13.07	9.78		74.52	eva
Cal 17				11.46	1.88	13.34	10.06		76.67	eva
Cal 18				11.70	1.92	13.63	10.35		78.87	eva
Cal 19				11.96	1.97	13.93	10.65		81.14	eva esc.
Cal 20				12.22	2.01	14.22	10.95		83.47	eva esc.

Nominal dollars

Used TZ6 Basis swap from NYMEX Jun 11th for 2008- 2012 basis
Used EVA (Feb 2008 forecast) for 2013 - 2018 delivered gas
Used EVA growth rate to derive 2019 - 2020 delivered gas (Boston citygate)

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-03
Dated: 08/24/2012
Q-TC-008
Page 1 of 2

Witness: **Terrance J. Large**
Request from: **TransCanada**

Question:

Reference the September 2, 2008 report by PSNH to the Commission in DE 08-103, page 15, Section IV.D, please describe the adder applied for ISO-NE capacity value and please provide copies of any and all documentation in PSNH's possession or the possession of any of its agents related to this adder.

Response:

The adder referenced in section IV.D on page 15 of the September 8, 2008 report was intended to calculate the ISO-NE capacity costs that PSNH would need to purchase from the market to replace the capacity provided by Merrimack Station. The attached exhibit provides the support for the calculation of the capacity value associated with Merrimack Station.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W
1	**Forecasted Energy Rates**																						
2																							
3	Year	Levelized Cost (2014-2023)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
4	Energy $/mwh	$100.01	$83.82	$83.82	$83.82	$83.82	$87.02	$89.20	$91.43	$93.71	$96.05	$98.46	$100.92	$103.44	$106.03	$108.68	$111.39	$114.18	$117.03	$119.96	$122.96	$126.03	$129.18
5																							
6																							
7	Capacity Price		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
8	($/kW-mo)	$4.45	$ 3.46	$ 3.95	$ 4.19	$ 3.87	$ 3.64	$ 3.69	$ 3.77	$ 3.87	$ 3.98	$ 4.08	$ 4.18	$ 4.41	$ 4.74	$ 5.07	$ 5.39	$ 5.72	$ 6.05	$ 6.37	$ 6.70	$ 7.03	$ 7.35
9																							
10	Capacity Converted to MWHs	$7.09	$5.51	$6.29	$6.67	$6.16	$5.80	$5.88	$6.01	$6.16	$6.34	$6.50	$6.66	$7.02	$7.55	$8.08	$8.59	$9.11	$9.64	$10.15	$10.67	$11.20	$11.71
11																							
12	Total Market Cost	$107.10																					
13																							
14	**Market Energy Costs**																						
15																							
16	Energy		$273,109,197	$273,109,197	$273,109,197	$273,109,197	$283,537,003	$290,625,428	$297,891,064	$305,338,340	$312,971,799	$320,796,094	$328,815,996	$337,036,396	$345,462,306	$354,098,864	$362,951,335	$372,025,119	$381,325,747	$390,858,890	$400,630,362	$410,646,122	$420,912,275
17	Capacity		$17,957,400	$20,500,500	$21,746,100	$20,085,300	$18,891,600	$19,151,100	$19,566,300	$20,085,300	$20,656,200	$21,175,200	$21,694,200	$22,887,900	$24,600,600	$26,313,300	$27,974,100	$29,686,800	$31,399,500	$33,060,300	$34,773,000	$36,485,700	$38,146,500

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-03
Dated: 08/24/2012
Q-TC-010
Page 1 of 2

Witness: **Terrance J. Large**
Request from: **TransCanada**

Question:

Reference the September 2, 2008 report by PSNH to the Commission in DE 08-103, page 16, Section IV.F, please describe how PSNH calculated the estimated $63 Million of stranded assets referenced in this section and provide any and all documentation in PSNH's possession or the possession of any of its agents related to this estimate. Please explain when and why this estimate was prepared.

Response:

The $63 Million represents an estimate of the year ending 2013 undepreciated plant balance of $59,095,792 (shown in cell K7 of the attached exhibit) and inventories of $3,900,322 (shown in cell K11 of the attached exhibit) that would become a stranded cost if the plant were to shut down at the end of 2013. This estimate was prepared in the summer of 2008 to calculate the cost associated with the option to retire Merrimack Station and purchase replacement energy and capacity from the market.

	A	B	C	D	E	F	G	H	I	J	K
1	**Rate Base Calculation**										Shutdown at YE
2				2006	2007	2008	2009	2010	2011	2012	2013
3	**Existing Plant With Capital Adds**										
4		**RateBase Build**									
5		Cumulative Capital			$ 188,935,000	$ 232,935,000	$ 241,935,000	$ 250,935,000	$ 259,935,000	$ 268,935,000	$ 277,935,000
6		Accumulated Book Depr			$ 140,727,000	$ 149,245,701	$ 159,564,403	$ 171,683,104	$ 185,601,805	$ 201,320,507	$ 218,839,208
7		Net Book Value			$ 48,208,000	$ 83,689,299	$ 82,370,597	$ 79,251,896	$ 74,333,195	$ 67,614,493	$ 59,095,792
8		Working Capital			$ 3,457,356	$ 3,543,790	$ 3,632,385	$ 3,723,194	$ 3,816,274	$ 3,911,681	$ 4,009,473
9		Month end Fuel Inventory			$ 19,159,000	$ 28,112,102	$ 28,112,102	$ 28,112,102	$ 28,112,102	$ 28,112,102	$ 28,814,904
10		Nox/Sox			$ 22,920,000	$ 18,336,000	$ 13,752,000	$ 9,168,000	$ 4,584,000	$ -	$ -
11		M&S inventory			$ 3,181,728	$ 5,523,494	$ 5,436,459	$ 5,230,625	$ 4,905,991	$ 4,462,557	$ 3,900,322
12		ADIT				$ -	$ -	$ -	$ -	$ -	$ -
13		RateBase End of Year			$ 96,926,084	$ 139,204,684	$ 133,303,543	$ 125,485,817	$ 115,751,561	$ 104,100,833	$ 95,820,492
14		Average Rate Base			$ 96,926,084	$ 118,065,384	$ 136,254,114	$ 129,394,680	$ 120,618,689	$ 109,926,197	$ 99,960,662

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-03
Dated: 08/24/2012
Q-TC-011
Page 1 of 21

Witness: **Terrance J. Large**
Request from: **TransCanada**

Question:

Reference the September 2, 2008 report by PSNH to the Commission in DE 08-103, page 16, Section IV.F, please explain how PSNH arrived at the bus bar costs of $135 per MWhr and provide any and all documentation in PSNH's possession or the possession of any of its agents related to this estimate. Please explain when and why this estimate was prepared.

Response:

The attached exhibits provide support for the statement that the bus bar costs of a new coal or natural gas combined cycle plant would be about $135/MWh. PSNH conducted this analysis in the summer of 2008 in support of this filing.

Summary

New Regulated Natural Gas Combined Cycle Plant

In-service date	2012 (January 1, 2012)
Total capital cost	$ 758,587,130
Size (MW net)	432.5
Annual Capacity Factor	86%
Annual MWH output	3,258,282

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Revenue Requirements	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Total Revenue Requirements w/o Fuel	165,473,561	163,203,730	159,352,977	155,687,498	152,195,639	148,866,699	145,690,772	142,658,753	139,718,503	136,813,519	133,934,896	131,083,293	128,259,385	125,463,865	122,697,443	119,960,846	117,254,820	114,580,128	111,937,555	109,327,903	107,101,200	105,607,338	104,498,133	103,425,267	102,389,648	101,392,208	100,433,901	99,515,705	98,638,624	97,803,684
Fuel Costs	241,862,273	247,908,830	254,106,550	260,459,214	266,970,695	273,644,962	280,486,086	287,498,238	294,685,694	302,052,836	309,604,157	317,344,261	325,277,868	333,409,814	341,745,060	350,288,686	359,045,903	368,022,051	377,222,602	386,653,167	396,319,497	406,227,484	416,383,171	426,792,750	437,462,569	448,399,133	459,609,112	471,099,340	482,876,823	494,948,744
Total Revenue Requirements w/ Fuel	407,335,833	411,112,559	413,459,527	416,146,712	419,166,333	422,511,661	426,176,858	430,156,991	434,404,197	438,866,355	443,539,053	448,427,554	453,537,253	458,873,680	464,442,503	470,249,533	476,300,723	482,602,179	489,160,157	495,981,070	503,420,696	511,834,822	520,881,304	530,218,017	539,852,217	549,791,341	560,043,013	570,615,045	581,515,447	592,752,427
Forward Capacity Market Revenue	18,891,600	19,151,100	19,566,300	20,085,300	20,656,200	21,175,200	21,694,200	22,887,900	24,600,600	26,313,300	27,974,100	29,686,800	31,399,500	33,060,300	34,773,000	36,485,700	38,146,500	39,100,163	40,077,667	41,079,608	42,106,598	43,159,263	44,238,245	45,344,201	46,477,806	47,639,751	48,830,745	50,051,514	51,302,802	52,585,372
Energy Market Revenue	283,537,003	290,625,428	297,891,064	305,338,340	312,971,799	320,796,094	328,815,996	337,036,396	345,462,306	354,098,864	362,951,335	372,025,119	381,325,747	390,858,890	400,630,362	410,646,122	420,912,275	431,435,081	442,220,958	453,276,482	464,608,394	476,223,604	488,129,194	500,332,424	512,840,735	525,661,753	538,803,297	552,273,380	566,080,214	580,232,219
Total Net Revenue Requirements w/fuel	104,907,231	101,336,031	96,002,163	90,723,072	85,538,335	80,540,367	75,666,662	70,232,695	64,341,291	58,454,191	52,613,618	46,715,635	40,812,006	34,954,490	29,039,141	23,117,711	17,241,949	12,066,935	6,861,532	1,624,980	(3,294,296)	(7,548,046)	(11,486,135)	(15,458,608)	(19,466,324)	(23,510,163)	(27,591,029)	(31,709,849)	(35,867,569)	(40,065,164)
Earnings Impact																														
Earnings (equity ratio *cost of equity)	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%
Average Rate Base	748,423,247	717,057,148	681,628,535	647,675,083	615,086,564	583,761,234	553,604,417	524,528,512	496,057,115	467,674,239	439,293,698	410,915,550	382,539,856	354,166,676	325,796,074	297,428,114	269,062,862	240,700,385	212,340,754	183,984,038	158,784,537	139,895,137	124,163,102	108,434,286	92,708,769	76,986,635	61,267,967	45,552,852	29,841,378	14,133,638
Earnings Impact to NU Shareholders	35,241,754	33,764,787	32,096,524	30,497,724	28,963,196	27,488,149	26,068,125	24,698,999	23,358,337	22,021,845	20,685,462	19,349,191	18,013,037	16,677,000	15,341,086	14,005,295	12,669,632	11,334,100	9,998,701	8,663,440	7,476,846	6,587,382	5,846,592	5,105,954	4,365,471	3,625,147	2,884,986	2,144,993	1,405,171	665,525
Customer Impact																														
Customer ES Requirement Forecast (MWh)	8,681,138	8,757,261	8,876,549	8,988,206	9,120,460	9,224,176	9,349,758	9,463,333	9,605,283	9,749,362	9,895,603	10,044,037	10,194,697	10,347,618	10,502,832	10,660,374	10,820,280	10,982,584	11,147,323	11,314,533	11,484,251	11,656,515	11,831,362	12,008,833	12,188,965	12,371,800	12,557,377	12,745,737	12,936,923	13,130,977
ES Rate Impact ($/kWh)	$0.01208	$0.01157	$0.01082	$0.01009	$0.00938	$0.00873	$0.00809	$0.00742	$0.00670	$0.00600	$0.00532	$0.00465	$0.00400	$0.00338	$0.00276	$0.00217	$0.00159	$0.00110	$0.00062	$0.00014	-$0.00029	-$0.00065	-$0.00097	-$0.00129	-$0.00160	-$0.00190	-$0.00220	-$0.00249	-$0.00277	-$0.00305
Annual Customer Impact ($/Yr)	$72.507	$69.430	$64.892	$60.561	$56.272	$52.389	$48.557	$44.529	$40.191	$35.974	$31.901	$27.906	$24.020	$20.268	$16.589	$13.011	$9.561	$6.592	$3.693	$0.862	-$1.721	-$3.885	-$5.825	-$7.724	-$9.582	-$11.402	-$13.183	-$14.927	-$16.635	-$18.307
Replacement Power Cost	$0.03220	$0.03110	$0.02946	$0.02784	$0.02625	$0.02472	$0.02322	$0.02156	$0.01975	$0.01794	$0.01615	$0.01434	$0.01253	$0.01073	$0.00891	$0.00710	$0.00529	$0.00370	$0.00211	$0.00050	-$0.00101	-$0.00232	-$0.00353	-$0.00474	-$0.00597	-$0.00722	-$0.00847	-$0.00973	-$0.01101	-$0.01230
15 Year Average ES Rate Impact ($/kWh)	$0.00740																													
Busbar Costs																														
Busbar Cost ($/MWh)	$125.02	$126.17	$126.89	$127.72	$128.65	$129.67	$130.80	$132.02	$133.32	$134.69	$136.13	$137.63	$139.20	$140.83	$142.54	$144.32	$146.18	$148.12	$150.13	$152.22	$154.50	$157.09	$159.86	$162.73	$165.69	$168.74	$171.88	$175.13	$178.47	$181.92
Busbar Cost ($/kWh)	$0.12502	$0.12617	$0.12689	$0.12772	$0.12865	$0.12967	$0.13080	$0.13202	$0.13332	$0.13469	$0.13613	$0.13763	$0.13920	$0.14083	$0.14254	$0.14432	$0.14618	$0.14812	$0.15013	$0.15222	$0.15450	$0.15709	$0.15986	$0.16273	$0.16569	$0.16874	$0.17188	$0.17513	$0.17847	$0.18192
Busbar Cost (cents/kWh)	12.502	12.617	12.689	12.772	12.865	12.967	13.080	13.202	13.332	13.469	13.613	13.763	13.920	14.083	14.254	14.432	14.618	14.812	15.013	15.222	15.450	15.709	15.986	16.273	16.569	16.874	17.188	17.513	17.847	18.192
Capacity Costs																														
Cost per kW including fuel ($/kW)	$941.82	$950.55	$955.98	$962.19	$969.17	$976.91	$985.38	$994.58	$1,004.40	$1,014.72	$1,025.52	$1,036.83	$1,048.64	$1,060.98	$1,073.86	$1,087.28	$1,101.27	$1,115.84	$1,131.01	$1,146.78	$1,163.98	$1,183.43	$1,204.35	$1,225.94	$1,248.21	$1,271.19	$1,294.90	$1,319.34	$1,344.54	$1,370.53
Cost per kW including fuel and revenue offsets ($/kW)	$242.56	$234.30	$221.97	$209.76	$197.78	$186.22	$174.95	$162.39	$148.77	$135.15	$121.65	$108.01	$94.36	$80.82	$67.14	$53.45	$39.87	$27.90	$15.86	$3.76	($7.62)	($17.45)	($26.56)	($35.74)	($45.01)	($54.36)	($63.79)	($73.32)	($82.93)	($92.64)
Fixed and Variable Costs																														
Variable Cost ($/MWh)	$79.04	$81.02	$83.04	$85.12	$87.25	$89.43	$91.66	$93.96	$96.31	$98.71	$101.18	$103.71	$106.30	$108.96	$111.68	$114.48	$117.34	$120.27	$123.28	$126.36	$129.52	$132.76	$136.08	$139.48	$142.97	$146.54	$150.20	$153.96	$157.81	$161.75
Fixed Cost ($/kW)	$346.34	$340.19	$330.36	$320.93	$311.88	$303.18	$294.81	$286.75	$278.88	$271.05	$263.27	$255.51	$247.80	$240.11	$232.47	$224.86	$217.29	$209.76	$202.27	$194.82	$188.23	$183.29	$179.20	$175.16	$171.16	$167.22	$163.32	$159.48	$155.68	$151.94

Levelized Values:	**Levelized 2012-20**	**NPV**	**Cost per kW**	**Cost per kWh**
2012 Gross Revenue Requirement (including fuel, no offsets)	$439,462,684	$3,799,385,317	$1,016.10	$0.0506
2012 Net Revenue Requirement (including fuel and revenue offsets)	$65,147,486	$563,234,175	$150.63	$0.0075
Busbar $/MWh (gross revenue requirements including fuel)	$134.88	$1,166.07		

Chart 1

Net Revenue Requirements vs Market Energy Purchases

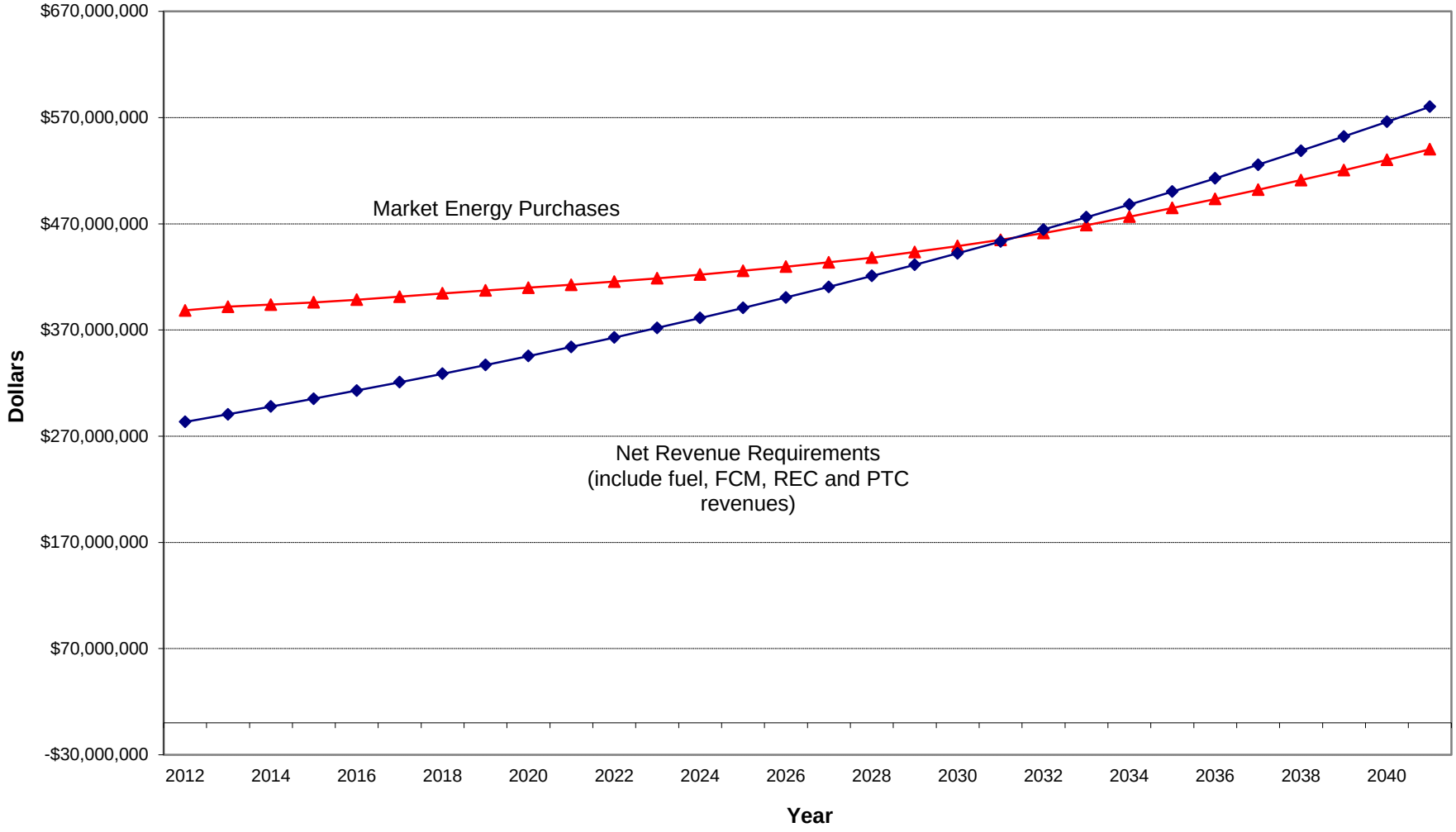
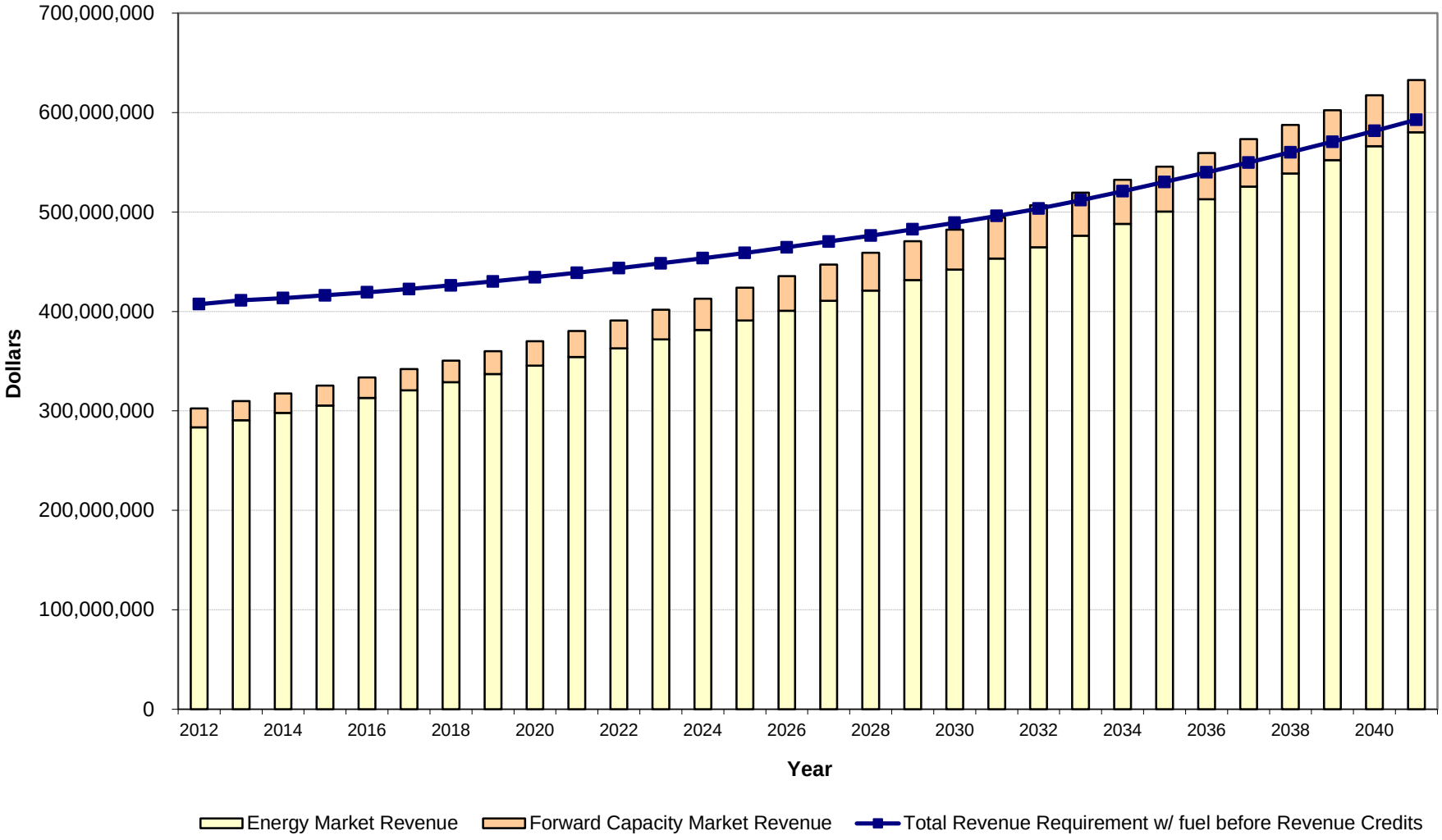


Chart 2

Revenue Requirements and Revenue Sources



Natural Gas Combined Cycle Owner Dispatch Costs

Heat Rate (Btu/kWh)	6,500	<- per ISO-NE Scenario Analysis NGCC pg. 24
Size (MW)	432.5	<- assumes same as Merrimack
Equipment Availability (%)	86%	<- assumes same as Merrimack
SO_2 Emissions (lbs/mmBtu)	0.0006	<- per ISO-NE Scenario Analysis NGCC pg. 29
NOx Emissions (lbs/mmBtu)	0.0100	<- per ISO-NE Scenario Analysis NGCC pg. 29
CO_2 Emissions (lbs/mmBtu)	120.0	<- per ISO-NE Scenario Analysis NGCC pg. 29
Output (MWh)	3,258,282	<- assumes same as Merrimack

		1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026	16 2027	17 2028	18 2029	19 2030	20 2031	21 2032	22 2033	23 2034	24 2035	25 2036	26 2037	27 2038	28 2039	29 2040	30 2041	31 2042
Variable O&M ($/MWh)	1.830	2.12	2.18	2.23	2.29	2.34	2.40	2.46	2.52	2.59	2.65	2.72	2.78	2.85	2.93	3.00	3.07	3.15	3.23	3.31	3.39	3.48	3.56	3.65	3.74	3.84	3.93	4.03	4.13	4.24	4.34	4.45
Fuel ($/mmbtu)		11.42	11.71	12.00	12.30	12.61	12.92	13.24	13.57	13.91	14.26	14.62	14.98	15.36	15.74	16.14	16.54	16.95	17.38	17.81	18.26	18.71	19.18	19.66	20.15	20.66	21.17	21.70	22.24	22.80	23.37	23.95
Fuel ($/MWh)		74.23	76.09	77.99	79.94	81.94	83.98	86.08	88.24	90.44	92.70	95.02	97.40	99.83	102.33	104.89	107.51	110.19	112.95	115.77	118.67	121.63	124.68	127.79	130.99	134.26	137.62	141.06	144.59	148.20	151.90	155.70
Fuel Cost		241,862,273	247,908,830	254,106,550	260,459,214	266,970,695	273,644,962	280,486,086	287,498,238	294,685,694	302,052,836	309,604,157	317,344,261	325,277,868	333,409,814	341,745,060	350,288,686	359,045,903	368,022,051	377,222,602	386,653,167	396,319,497	406,227,484	416,383,171	426,792,750	437,462,569	448,399,133	459,609,112	471,099,340	482,876,823	494,948,744	507,322,462
SO_2 ($/ton)		565.70	579.85	594.34	609.20	624.43	640.04	656.04	672.44	689.26	706.49	724.15	742.25	760.81	779.83	799.33	819.31	839.79	860.79	882.31	904.36	926.97	950.15	973.90	998.25	1,023.20	1,048.78	1,075.00	1,101.88	1,129.43	1,157.66	1,186.60
SO_2 ($/MWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO_2 Cost		3,594	3,684	3,776	3,871	3,967	4,067	4,168	4,272	4,379	4,489	4,601	4,716	4,834	4,955	5,079	5,206	5,336	5,469	5,606	5,746	5,890	6,037	6,188	6,343	6,501	6,664	6,830	7,001	7,176	7,355	7,539
NOx ($/ton)		1,886.06	1,933.21	1,981.54	2,031.08	2,081.85	2,133.90	2,187.25	2,241.93	2,297.98	2,355.43	2,414.31	2,474.67	2,536.54	2,599.95	2,664.95	2,731.57	2,799.86	2,869.86	2,941.61	3,015.15	3,090.52	3,167.79	3,246.98	3,328.16	3,411.36	3,496.65	3,584.06	3,673.66	3,765.50	3,859.64	3,956.13
NOx ($/MWh)		0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13
NOx Cost		199,722	204,716	209,833	215,079	220,456	225,968	231,617	237,407	243,342	249,426	255,662	262,053	268,605	275,320	282,203	289,258	296,489	303,901	311,499	319,286	327,269	335,450	343,837	352,432	361,243	370,274	379,531	389,019	398,745	408,714	418,931
CO_2 ($/ton)		7.00	7.18	7.35	7.54	7.73	7.92	8.12	8.32	8.53	8.74	8.96	9.18	9.41	9.65	9.89	10.14	10.39	10.65	10.92	11.19	11.47	11.76	12.05	12.35	12.66	12.98	13.30	13.63	13.98	14.32	14.68
CO_2 ($/MWh)		2.73	2.80	2.87	2.94	3.01	3.09	3.17	3.25	3.33	3.41	3.49	3.58	3.67	3.76	3.86	3.95	4.05	4.15	4.26	4.36	4.47	4.59	4.70	4.82	4.94	5.06	5.19	5.32	5.45	5.59	5.73
CO_2 Cost		8,895,110	9,117,488	9,345,425	9,579,060	9,818,537	10,064,000	10,315,600	10,573,490	10,837,828	11,108,773	11,386,493	11,671,155	11,962,934	12,262,007	12,568,557	12,882,771	13,204,841	13,534,962	13,873,336	14,220,169	14,575,673	14,940,065	15,313,567	15,696,406	16,088,816	16,491,036	16,903,312	17,325,895	17,759,043	18,203,019	18,658,094
Total Emissions Cost		9,098,427	9,325,887	9,559,034	9,798,010	10,042,961	10,294,035	10,551,385	10,815,170	11,085,549	11,362,688	11,646,755	11,937,924	12,236,372	12,542,282	12,855,839	13,177,235	13,506,665	13,844,332	14,190,440	14,545,201	14,908,831	15,281,552	15,663,591	16,055,181	16,456,560	16,867,974	17,289,674	17,721,916	18,164,963	18,619,088	19,084,565

Inputs

New Regulated Natural Gas Combined Cycle Plant

Assumptions (Inputs)

		(in service date)	
	2008	2012	
Capital Cost	$ 687,242,500	$ 758,587,130	
Size (MW net)		432.5	
Winter Claimed Capability (WCC) (MW)		432.5	
Summer Claimed Capability (SCC) (MW)		432.5	<- same size as Merrimack Station
Unforced Outage Rate		0.0%	
Annual Capacity Factor		86%	
Annual MWH output		3,258,282	
Full Load Avg Heat Rate (MMBtu/MWh)		6.5	
Variable O&M ($/MWh)	$ 1.83	$ 2.12	
Annual Variable O&M	$ 5,962,656	$ 6,581,657	
Fixed O&M ($/kW)		$ 43.00	e assumption as Merrimack Station
Annual Fixed O&M		$ 18,597,500	
Book Life of Plant (in years)		30	
Property Taxes on net beginning plant (per $1,000)	2.50%	3.04%	
Materials Inventory	$ -	$ -	

Average annual escalation rates:		
Capital	2.50%	
O&M	2.50%	
Property Tax annual inflator	5.00%	
Price Inflator	2.50%	Used to inflate FCM
Fuel	2.50%	
SO2/Nox Emissions	2.50%	

Revenue Requirements

New Regulated Natural Gas Combined Cycle Plant
Revenue Requirements Analysis
Assumed in-service date of **2012**

	0	1	2	3	4	5	6	7	8	9	10
Annual O&M Costs:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Variable O&M		6,581,657	6,746,198	6,914,853	7,087,724	7,264,917	7,446,540	7,632,704	7,823,521	8,019,109	8,219,587
Fixed O&M		18,597,500	19,062,438	19,538,998	20,027,473	20,528,160	21,041,364	21,567,398	22,106,583	22,659,248	23,225,729
Depreciation		25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238
Property Taxes		23,051,685	23,397,460	22,590,651	21,783,842	20,977,033	20,170,224	19,363,415	18,556,606	17,749,797	16,942,988
SO_2 Emissions		3,594	3,684	3,776	3,871	3,967	4,067	4,168	4,272	4,379	4,489
NOx Emissions		199,722	204,716	209,833	215,079	220,456	225,968	231,617	237,407	243,342	249,426
CO_2 Emissions		8,895,110	9,117,488	9,345,425	9,579,060	9,818,537	10,064,000	10,315,600	10,573,490	10,837,828	11,108,773
TOTAL		82,615,506	83,818,221	83,889,775	83,983,288	84,099,309	84,238,401	84,401,141	84,588,119	84,799,942	85,037,231
Return on Rate Base:											
Plant in Service		758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130
Accumulated Depreciation		25,286,238	50,572,475	75,858,713	101,144,951	126,431,188	151,717,426	177,003,664	202,289,901	227,576,139	252,862,377
Net Plant in Service	758,587,130	733,300,893	708,014,655	682,728,417	657,442,180	632,155,942	606,869,704	581,583,467	556,297,229	531,010,991	505,724,754
Working capital for 45 days based on Incremental O&M	3,104,280	3,104,280	3,181,887	3,261,434	3,342,970	3,426,544	3,512,207	3,600,013	3,690,013	3,782,263	3,876,820
Accumulated Deferred Taxes		(1,250,088)	(12,237,330)	(21,691,994)	(29,732,841)	(36,461,666)	(41,980,264)	(46,376,292)	(49,737,406)	(52,928,861)	(56,117,489)
Materials Inventory	-	-	-	-	-	-	-	-	-	-	-
Rate Base end of the period	761,691,410	735,155,084	698,959,212	664,297,857	631,052,308	599,120,820	568,401,648	538,807,187	510,249,836	481,864,393	453,484,084
Average Rate Base		748,423,247	717,057,148	681,628,535	647,675,083	615,086,564	583,761,234	553,604,417	524,528,512	496,057,115	467,674,239
Cost of capital		11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%
Return on Rate Base		82,858,055	79,385,509	75,463,202	71,704,210	68,096,330	64,628,297	61,289,632	58,070,634	54,918,561	51,776,288
Total Revenue Requirement (w/o fuel before revenue offsets)		**165,473,561**	**163,203,730**	**159,352,977**	**155,687,498**	**152,195,639**	**148,866,699**	**145,690,772**	**142,658,753**	**139,718,503**	**136,813,519**
Annual MWH output		3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282
Fuel Cost		241,862,273	247,908,830	254,106,550	260,459,214	266,970,695	273,644,962	280,486,086	287,498,238	294,685,694	302,052,836
Offsetting Revenue:											
Energy Market Benefit											
All-Hours Mkt Price ($/Mwh)		$87.02	$89.20	$91.43	$93.71	$96.05	$98.46	$100.92	$103.44	$106.03	$108.68
Energy Market Revenues		283,537,003	290,625,428	297,891,064	305,338,340	312,971,799	320,796,094	328,815,996	337,036,396	345,462,306	354,098,864
Fuel Costs		241,862,273	247,908,830	254,106,550	260,459,214	266,970,695	273,644,962	280,486,086	287,498,238	294,685,694	302,052,836
Variable O&M		6,581,657	6,746,198	6,914,853	7,087,724	7,264,917	7,446,540	7,632,704	7,823,521	8,019,109	8,219,587
Energy Market Benefit		35,093,073	35,970,400	36,869,660	37,791,402	38,736,187	39,704,592	40,697,206	41,714,636	42,757,502	43,826,440
ISO-NE Market											
Forward Capacity Market Rate ($/KW-Mo)		3.64	3.69	3.77	3.87	3.98	4.08	4.18	4.41	4.74	5.07
Forward Capacity Market Revenue		18,891,600	19,151,100	19,566,300	20,085,300	20,656,200	21,175,200	21,694,200	22,887,900	24,600,600	26,313,300
Total ISO-NE Market Revenue		18,891,600	19,151,100	19,566,300	20,085,300	20,656,200	21,175,200	21,694,200	22,887,900	24,600,600	26,313,300
Total Revenue Requirement (w/o fuel before revenue offsets)		**165,473,561**	**163,203,730**	**159,352,977**	**155,687,498**	**152,195,639**	**148,866,699**	**145,690,772**	**142,658,753**	**139,718,503**	**136,813,519**
Fuel Cost		241,862,273	247,908,830	254,106,550	260,459,214	266,970,695	273,644,962	280,486,086	287,498,238	294,685,694	302,052,836
Total Revenue Requirement (w/fuel)		407,335,833	411,112,559	413,459,527	416,146,712	419,166,333	422,511,661	426,176,858	430,156,991	434,404,197	438,866,355
Energy Market Revenue		283,537,003	290,625,428	297,891,064	305,338,340	312,971,799	320,796,094	328,815,996	337,036,396	345,462,306	354,098,864
ISO FCM Credits		18,891,600	19,151,100	19,566,300	20,085,300	20,656,200	21,175,200	21,694,200	22,887,900	24,600,600	26,313,300
Total Net Revenue Requirement (w/fuel and Energy Revenue and ISO credits)		104,907,231	101,336,031	96,002,163	90,723,072	85,538,335	80,540,367	75,666,662	70,232,695	64,341,291	58,454,191
2012 Net Present Value of Revenue Requirements	$563,234,175										
Variable Costs ($/MWh)		79.04	81.02	83.04	85.12	87.25	89.43	91.66	93.96	96.31	98.71
Fixed Costs ($/kW)		346.34	340.19	330.36	320.93	311.88	303.18	294.81	286.75	278.88	271.05
Fixed Costs ($/kW-Mo)		28.86	28.35	27.53	26.74	25.99	25.27	24.57	23.90	23.24	22.59

	11	12	13	14	15	16	17	18	19	20	21
Annual O&M Costs:	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Variable O&M	8,425,077	8,635,704	8,851,596	9,072,886	9,299,709	9,532,201	9,770,506	10,014,769	10,265,138	10,521,767	10,784,811
Fixed O&M	23,806,372	24,401,532	25,011,570	25,636,859	26,277,781	26,934,725	27,608,093	28,298,296	29,005,753	29,730,897	30,474,169
Depreciation	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238
Property Taxes	16,136,179	15,329,370	14,522,562	13,715,753	12,908,944	12,102,135	11,295,326	10,488,517	9,681,708	8,874,899	8,068,090
SO_2 Emissions	4,601	4,716	4,834	4,955	5,079	5,206	5,336	5,469	5,606	5,746	5,890
NOx Emissions	255,662	262,053	268,605	275,320	282,203	289,258	296,489	303,901	311,499	319,286	327,269
CO_2 Emissions	11,386,493	11,671,155	11,962,934	12,262,007	12,568,557	12,882,771	13,204,841	13,534,962	13,873,336	14,220,169	14,575,673
TOTAL	85,300,622	85,590,768	85,908,338	86,254,017	86,628,509	87,032,533	87,466,828	87,932,151	88,429,277	88,959,001	89,522,139
Return on Rate Base:											
Plant in Service	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130
Accumulated Depreciation	278,148,615	303,434,852	328,721,090	354,007,328	379,293,565	404,579,803	429,866,041	455,152,278	480,438,516	505,724,754	531,010,991
Net Plant in Service	480,438,516	455,152,278	429,866,041	404,579,803	379,293,565	354,007,328	328,721,090	303,434,852	278,148,615	252,862,377	227,576,139
Working capital for 45 days based on Incremental O&M	3,973,740	4,073,084	4,174,911	4,279,284	4,386,266	4,495,922	4,608,320	4,723,529	4,841,617	4,962,657	5,086,724
Accumulated Deferred Taxes	(59,308,945)	(62,497,573)	(65,689,029)	(68,877,657)	(72,069,113)	(75,257,741)	(78,449,196)	(81,637,825)	(84,829,280)	(88,017,908)	(84,900,914)
Materials Inventory	-	-	-	-	-	-	-	-	-	-	-
Rate Base end of the period	425,103,311	396,727,789	368,351,923	339,981,430	311,610,718	283,245,509	254,880,214	226,520,556	198,160,951	169,807,126	147,761,949
Average Rate Base	439,293,698	410,915,550	382,539,856	354,166,676	325,796,074	297,428,114	269,062,862	240,700,385	212,340,754	183,984,038	158,784,537
Cost of capital	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%
Return on Rate Base	48,634,274	45,492,525	42,351,047	39,209,848	36,068,934	32,928,313	29,787,991	26,647,977	23,508,278	20,368,902	17,579,061
Total Revenue Requirement (w/o fuel before revenue offsets)	**133,934,896**	**131,083,293**	**128,259,385**	**125,463,865**	**122,697,443**	**119,960,846**	**117,254,820**	**114,580,128**	**111,937,555**	**109,327,903**	**107,101,200**
Annual MWH output	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282
Fuel Cost	309,604,157	317,344,261	325,277,868	333,409,814	341,745,060	350,288,686	359,045,903	368,022,051	377,222,602	386,653,167	396,319,497
Offsetting Revenue:											
Energy Market Benefit											
All-Hours Mkt Price ($/Mwh)	$111.39	$114.18	$117.03	$119.96	$122.96	$126.03	$129.18	$132.41	$135.72	$139.12	$142.59
Energy Market Revenues	362,951,335	372,025,119	381,325,747	390,858,890	400,630,362	410,646,122	420,912,275	431,435,081	442,220,958	453,276,482	464,608,394
Fuel Costs	309,604,157	317,344,261	325,277,868	333,409,814	341,745,060	350,288,686	359,045,903	368,022,051	377,222,602	386,653,167	396,319,497
Variable O&M	8,425,077	8,635,704	8,851,596	9,072,886	9,299,709	9,532,201	9,770,506	10,014,769	10,265,138	10,521,767	10,784,811
Energy Market Benefit	44,922,101	46,045,153	47,196,282	48,376,189	49,585,594	50,825,234	52,095,865	53,398,261	54,733,218	56,101,548	57,504,087
ISO-NE Market											
Forward Capacity Market Rate ($/KW-Mo)	5.39	5.72	6.05	6.37	6.70	7.03	7.35	7.53	7.72	7.92	8.11
Forward Capacity Market Revenue	27,974,100	29,686,800	31,399,500	33,060,300	34,773,000	36,485,700	38,146,500	39,100,163	40,077,667	41,079,608	42,106,598
Total ISO-NE Market Revenue	27,974,100	29,686,800	31,399,500	33,060,300	34,773,000	36,485,700	38,146,500	39,100,163	40,077,667	41,079,608	42,106,598
Total Revenue Requirement (w/o fuel before revenue offsets)	**133,934,896**	**131,083,293**	**128,259,385**	**125,463,865**	**122,697,443**	**119,960,846**	**117,254,820**	**114,580,128**	**111,937,555**	**109,327,903**	**107,101,200**
Fuel Cost	309,604,157	317,344,261	325,277,868	333,409,814	341,745,060	350,288,686	359,045,903	368,022,051	377,222,602	386,653,167	396,319,497
Total Revenue Requirement (w/fuel)	443,539,053	448,427,554	453,537,253	458,873,680	464,442,503	470,249,533	476,300,723	482,602,179	489,160,157	495,981,070	503,420,696
Energy Market Revenue	362,951,335	372,025,119	381,325,747	390,858,890	400,630,362	410,646,122	420,912,275	431,435,081	442,220,958	453,276,482	464,608,394
ISO FCM Credits	27,974,100	29,686,800	31,399,500	33,060,300	34,773,000	36,485,700	38,146,500	39,100,163	40,077,667	41,079,608	42,106,598
Total Net Revenue Requirement (w/fuel and Energy Revenue and ISO credits)	52,613,618	46,715,635	40,812,006	34,954,490	29,039,141	23,117,711	17,241,949	12,066,935	6,861,532	1,624,980	(3,294,296)
Variable Costs ($/MWh)	101.18	103.71	106.30	108.96	111.68	114.48	117.34	120.27	123.28	126.36	129.52
Fixed Costs ($/kW)	263.27	255.51	247.80	240.11	232.47	224.86	217.29	209.76	202.27	194.82	188.23
Fixed Costs ($/kW-Mo)	21.94	21.29	20.65	20.01	19.37	18.74	18.11	17.48	16.86	16.24	15.69

	22	23	24	25	26	27	28	29	30	31
Annual O&M Costs:	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Variable O&M	11,054,431	11,330,792	11,614,062	11,904,413	12,202,023	12,507,074	12,819,751	13,140,245	13,468,751	13,805,470
Fixed O&M	31,236,023	32,016,924	32,817,347	33,637,781	34,478,725	35,340,694	36,224,211	37,129,816	38,058,062	39,009,513
Depreciation	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	-
Property Taxes	7,261,281	6,454,472	5,647,663	4,840,854	4,034,045	3,227,236	2,420,427	1,613,618	806,809	-
SO_2 Emissions	6,037	6,188	6,343	6,501	6,664	6,830	7,001	7,176	7,355	7,539
NOx Emissions	335,450	343,837	352,432	361,243	370,274	379,531	389,019	398,745	408,714	418,931
CO_2 Emissions	14,940,065	15,313,567	15,696,406	16,088,816	16,491,036	16,903,312	17,325,895	17,759,043	18,203,019	18,658,094
TOTAL	90,119,525	90,752,016	91,420,490	92,125,846	92,869,006	93,650,915	94,472,542	95,334,880	96,238,946	71,899,547
Return on Rate Base:										
Plant in Service	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	-
Accumulated Depreciation	556,297,229	581,583,467	606,869,704	632,155,942	657,442,180	682,728,417	708,014,655	733,300,893	758,587,130	-
Net Plant in Service	202,289,901	177,003,664	151,717,426	126,431,188	101,144,951	75,858,713	50,572,475	25,286,238	-	-
Working capital for 45 days based on Incremental O&M	5,213,892	5,344,239	5,477,845	5,614,791	5,755,161	5,899,040	6,046,516	6,197,679	6,352,621	6,511,436
Accumulated Deferred Taxes	(75,475,469)	(66,050,023)	(56,624,578)	(47,199,133)	(37,773,688)	(28,348,243)	(18,922,798)	(9,497,353)	(71,908)	(71,908)
Materials Inventory	-	-	-	-	-	-	-	-	-	-
Rate Base end of the period	132,028,325	116,297,879	100,570,693	84,846,846	69,126,423	53,409,510	37,696,193	21,986,564	6,280,713	6,439,528
Average Rate Base	139,895,137	124,163,102	108,434,286	92,708,769	76,986,635	61,267,967	45,552,852	29,841,378	14,133,638	6,360,121
Cost of capital	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%
Return on Rate Base	15,487,812	13,746,116	12,004,777	10,263,802	8,523,202	6,782,986	5,043,163	3,303,744	1,564,737	704,130
Total Revenue Requirement (w/o fuel before revenue offsets)	**105,607,338**	**104,498,133**	**103,425,267**	**102,389,648**	**101,392,208**	**100,433,901**	**99,515,705**	**98,638,624**	**97,803,684**	**72,603,677**
Annual MWH output	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282
Fuel Cost	406,227,484	416,383,171	426,792,750	437,462,569	448,399,133	459,609,112	471,099,340	482,876,823	494,948,744	507,322,462
Offsetting Revenue:										
Energy Market Benefit										
All-Hours Mkt Price ($/Mwh)	$146.16	$149.81	$153.56	$157.40	$161.33	$165.36	$169.50	$173.74	$178.08	$182.53
Energy Market Revenues	476,223,604	488,129,194	500,332,424	512,840,735	525,661,753	538,803,297	552,273,380	566,080,214	580,232,219	594,738,025
Fuel Costs	406,227,484	416,383,171	426,792,750	437,462,569	448,399,133	459,609,112	471,099,340	482,876,823	494,948,744	507,322,462
Variable O&M	11,054,431	11,330,792	11,614,062	11,904,413	12,202,023	12,507,074	12,819,751	13,140,245	13,468,751	13,805,470
Energy Market Benefit	58,941,689	60,415,232	61,925,612	63,473,753	65,060,596	66,687,111	68,354,289	70,063,146	71,814,725	73,610,093
ISO-NE Market										
Forward Capacity Market Rate ($/KW-Mo)	8.32	8.52	8.74	8.96	9.18	9.41	9.64	9.88	10.13	10.39
Forward Capacity Market Revenue	43,159,263	44,238,245	45,344,201	46,477,806	47,639,751	48,830,745	50,051,514	51,302,802	52,585,372	53,900,006
Total ISO-NE Market Revenue	43,159,263	44,238,245	45,344,201	46,477,806	47,639,751	48,830,745	50,051,514	51,302,802	52,585,372	53,900,006
Total Revenue Requirement (w/o fuel before revenue offsets)	**105,607,338**	**104,498,133**	**103,425,267**	**102,389,648**	**101,392,208**	**100,433,901**	**99,515,705**	**98,638,624**	**97,803,684**	**72,603,677**
Fuel Cost	406,227,484	416,383,171	426,792,750	437,462,569	448,399,133	459,609,112	471,099,340	482,876,823	494,948,744	507,322,462
Total Revenue Requirement (w/fuel)	511,834,822	520,881,304	530,218,017	539,852,217	549,791,341	560,043,013	570,615,045	581,515,447	592,752,427	579,926,139
Energy Market Revenue	476,223,604	488,129,194	500,332,424	512,840,735	525,661,753	538,803,297	552,273,380	566,080,214	580,232,219	594,738,025
ISO FCM Credits	43,159,263	44,238,245	45,344,201	46,477,806	47,639,751	48,830,745	50,051,514	51,302,802	52,585,372	53,900,006
Total Net Revenue Requirement (w/fuel and Energy Revenue and ISO credits)	(7,548,046)	(11,486,135)	(15,458,608)	(19,466,324)	(23,510,163)	(27,591,029)	(31,709,849)	(35,867,569)	(40,065,164)	(68,711,891)
Variable Costs ($/MWh)	132.76	136.08	139.48	142.97	146.54	150.20	153.96	157.81	161.75	165.80
Fixed Costs ($/kW)	183.29	179.20	175.16	171.16	167.22	163.32	159.48	155.68	151.94	91.82
Fixed Costs ($/kW-Mo)	15.27	14.93	14.60	14.26	13.93	13.61	13.29	12.97	12.66	7.65

Depreciation - Book

New Regulated Natural Gas Combined Cycle Plant
Revenue Requirements Analysis
Assumed in-service date of 2012

	1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026	16 2027	17 2028	18 2029	19 2030	20 2031	21 2032	22 2033	23 2034	24 2035	25 2036	26 2037	27 2038	28 2039	29 2040	30 2041	31 2042	TOTAL
New Project:																																
GROSS PLANT	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	
ACCUMULATED DEPRECIATION	25,286,238	50,572,475	75,858,713	101,144,951	126,431,188	151,717,426	177,003,664	202,289,901	227,576,139	252,862,377	278,148,615	303,434,852	328,721,090	354,007,328	379,293,565	404,579,803	429,866,041	455,152,278	480,438,516	505,724,754	531,010,991	556,297,229	581,583,467	606,869,704	632,155,942	657,442,180	682,728,417	708,014,655	733,300,893	758,587,130	783,873,368	
NET GROSS PLANT	733,300,893	708,014,655	682,728,417	657,442,180	632,155,942	606,869,704	581,583,467	556,297,229	531,010,991	505,724,754	480,438,516	455,152,278	429,866,041	404,579,803	379,293,565	354,007,328	328,721,090	303,434,852	278,148,615	252,862,377	227,576,139	202,289,901	177,003,664	151,717,426	126,431,188	101,144,951	75,858,713	50,572,475	25,286,238	-	(25,286,238)	
PROJECT BOOK LIFE	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
PROJECT BOOK DEPRECIATION RATE	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	
ANNUAL DEPRECIATION	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	
Capital Additions																																
Remaining station life (in years)		29	28	27	26	25	24	23	22	21	20	19	18	17	16	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1		
DEPRECIATION RATE FOR ADDITION - based on station remaining life	0.000%	3.448%	3.571%	3.704%	3.846%	4.000%	4.167%	4.348%	4.545%	4.762%	5.000%	5.263%	5.556%	5.882%	6.250%	6.667%	7.143%	7.692%	8.333%	9.091%	10.000%	11.111%	12.500%	14.286%	16.667%	20.000%	25.000%	33.333%	50.000%	100.000%		
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9								-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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12											-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13												-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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16															-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17																-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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23																						-	-	-	-	-	-	-	-	-	-	-
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25																								-	-	-	-	-	-	-	-	-
26																									-	-	-	-	-	-	-	-
27																										-	-	-	-	-	-	-
28																											-	-	-	-	-	-
29																												-	-	-	-	-
30																													-	-	-	-
Total Book Depreciation for capital additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cumulative Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			-																													
SUMMARY FOR PLANT:																																
GROSS PLANT																																
Initial Investment	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	21,999,026,784
Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gross Plant	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	758,587,130	21,999,026,784
ACCUMULATED DEPRECIATION																																
Initial Investment	25,286,238	50,572,475	75,858,713	101,144,951	126,431,188	151,717,426	177,003,664	202,289,901	227,576,139	252,862,377	278,148,615	303,434,852	328,721,090	354,007,328	379,293,565	404,579,803	429,866,041	455,152,278	480,438,516	505,724,754	531,010,991	556,297,229	581,583,467	606,869,704	632,155,942	657,442,180	682,728,417	708,014,655	733,300,893	758,587,130	11,732,814,285	
Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Accumulated Depreciation	25,286,238	50,572,475	75,858,713	101,144,951	126,431,188	151,717,426	177,003,664	202,289,901	227,576,139	252,862,377	278,148,615	303,434,852	328,721,090	354,007,328	379,293,565	404,579,803	429,866,041	455,152,278	480,438,516	505,724,754	531,010,991	556,297,229	581,583,467	606,869,704	632,155,942	657,442,180	682,728,417	708,014,655	733,300,893	758,587,130	11,732,814,285	
NET PLANT																																
Initial Investment	733,300,893	708,014,655	682,728,417	657,442,180	632,155,942	606,869,704	581,583,467	556,297,229	531,010,991	505,724,754	480,438,516	455,152,278	429,866,041	404,579,803	379,293,565	354,007,328	328,721,090	303,434,852	278,148,615	252,862,377	227,576,139	202,289,901	177,003,664	151,717,426	126,431,188	101,144,951	75,858,713	50,572,475	25,286,238	-	10,266,212,499	
Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Plant	733,300,893	708,014,655	682,728,417	657,442,180	632,155,942	606,869,704	581,583,467	556,297,229	531,010,991	505,724,754	480,438,516	455,152,278	429,866,041	404,579,803	379,293,565	354,007,328	328,721,090	303,434,852	278,148,615	252,862,377	227,576,139	202,289,901	177,003,664	151,717,426	126,431,188	101,144,951	75,858,713	50,572,475	25,286,238	-	10,266,212,499	
Total Depreciation Expense for the year (book)	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	733,300,893	

Inputs

Depreciation - Tax

New Regulated Natural Gas Combined Cycle Plant
Revenue Requirements Analysis

	Project Costs	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Project Costs	$758,587,130																															
Year		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Tax Depreciation		$ 28,447,017	$ 54,762,405	$ 50,650,863	$ 46,857,927	$ 43,338,083	$ 40,091,330	$ 37,079,739	$ 34,303,310	$ 33,848,158	$ 33,840,572	$ 33,848,158	$ 33,840,572	$ 33,848,158	$ 33,840,572	$ 33,848,158	$ 33,840,572	$ 33,848,158	$ 33,840,572	$ 33,848,158	$ 33,840,572	$ 33,848,158	$ 33,840,572	$ 16,924,079	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Book Depr.		25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	25,286,238	-
Deferred Tax Difference		3,160,780	29,476,167	25,364,625	21,571,689	18,051,845	14,805,092	11,793,501	9,017,072	8,561,920	8,554,334	8,561,920	8,554,334	8,561,920	8,554,334	8,561,920	8,554,334	8,561,920	8,554,334	8,561,920	8,554,334	8,561,920	8,554,334	(8,362,159)	(25,286,238)	(25,286,238)	(25,286,238)	(25,286,238)	(25,286,238)	(25,286,238)	(25,286,238)	(25,286,238)	(25,286,238)	-
Tax Rate		39.550%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%
Deferred Tax Expense		1,250,088	10,987,241	9,454,664	8,040,847	6,728,825	5,518,598	4,396,028	3,361,114	3,191,456	3,188,628	3,191,456	3,188,628	3,191,456	3,188,628	3,191,456	3,188,628	3,191,456	3,188,628	3,191,456	3,188,628	3,191,456	3,188,628	(3,116,995)	(9,425,445)	(9,425,445)	(9,425,445)	(9,425,445)	(9,425,445)	(9,425,445)	(9,425,445)	(9,425,445)	(9,425,445)	-
Accum. Deferred Tax Expense		1,250,088	12,237,330	21,691,994	29,732,841	36,461,666	41,980,264	46,376,292	49,737,406	52,928,861	56,117,489	59,308,945	62,497,573	65,689,029	68,877,657	72,069,113	75,257,741	78,449,196	81,637,825	84,829,280	88,017,908	84,900,914	75,475,469	66,050,023	56,624,578	47,199,133	37,773,688	28,348,243	18,922,798	9,497,353	71,908	71,908
Tax Depreciation on Plant		28,447,017	54,762,405	50,650,863	46,857,927	43,338,083	40,091,330	37,079,739	34,303,310	33,848,158	33,840,572	33,848,158	33,840,572	33,848,158	33,840,572	33,848,158	33,840,572	33,848,158	33,840,572	33,848,158	33,840,572	16,924,079	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation on Capital Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Tax depreciation		28,447,017	54,762,405	50,650,863	46,857,927	43,338,083	40,091,330	37,079,739	34,303,310	33,848,158	33,840,572	33,848,158	33,840,572	33,848,158	33,840,572	33,848,158	33,840,572	33,848,158	33,840,572	33,848,158	33,840,572	16,924,079	-	-	-	-	-	-	-	-	-	-	-
20 year MACRS		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%										
Plant balance for tax purposes, end of period		$ 730,140,113	$ 675,377,708	$ 624,726,845	$ 577,868,918	$ 534,530,836	$ 494,439,506	$ 457,359,767	$ 423,056,457	$ 389,208,299	$ 355,367,727	$ 321,519,569	$ 287,678,997	$ 253,830,840	$ 219,990,268	$ 186,142,110	$ 152,301,538	$ 118,453,380	$ 84,612,809	$ 50,764,651	$ 16,924,079	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Capital Additions for Plant		0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20 year MACRS		0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%									
DEPRECIATION RATE FOR ADDITION - based on station remaining life																																
2			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0									
3			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0								
4				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0							
5					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0						
6						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
7							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
8								0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
9									0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
10										0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
11											0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12												0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13													0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14														0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15															0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16																0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17																	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18																		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19																			0	0	0	0	0	0	0	0	0	0	0	0	0	0
20																				0	0	0	0	0	0	0	0	0	0	0	0	0
21																					0	0	0	0	0	0	0	0	0	0	0	0
22																						0	0	0	0	0	0	0	0	0	0	0
23																							0	0	0	0	0	0	0	0	0	0
24																								0	0	0	0	0	0	0	0	0
25																									0	0	0	0	0	0	0	0
26																										0	0	0	0	0	0	0
27																											0	0	0	0	0	0
28																												0	0	0	0	0
29																													0	0	0	0
30																														0	0	0
Total Tax Depreciation for capital additions		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Capital Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Tax Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Additions for tax purposes		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Inputs

Cost of capital

Public Service of New Hampshire
Calculation of weighted Generation cost of capital

Year	2008	2009	2010	2011	2012	2013
1) Capitalization Ratios:						
Common Equity	47.2%	48.0%	48.0%	48.0%	48.0%	48.0%
Long-term Debt	52.8%	52.0%	52.0%	52.0%	52.0%	52.0%
Total Capitalization	100.00%	100.00%	100.0%	100.0%	100.0%	100.0%
2) Cost of capitalization:						
Common Equity (net of tax)	9.81%	9.81%	9.81%	9.81%	9.81%	9.81%
Cost of Long-term debt (pre-tax)	5.96%	6.06%	6.06%	6.06%	6.06%	6.06%
Effective Tax Rate	40.525%	40.525%	40.525%	40.525%	40.525%	40.525%
Cost of Equity (pre-tax)	16.49%	16.49%	16.49%	16.49%	16.49%	16.49%
3) Weighted Cost of Capital (pre-tax)						
Cost of Equity	7.79%	7.92%	7.92%	7.92%	7.92%	7.92%
Cost of Long-term debt	3.15%	3.15%	3.15%	3.15%	3.15%	3.15%
Total	10.94%	11.07%	11.07%	11.07%	11.07%	11.07%
4) AFUDC Rates						
PSNH Transmission						
AFUDC Debt Rate %	3.25%	4.16%	4.31%	4.13%	3.95%	3.95%
AFUDC Equity Rate %	4.70%	2.82%	3.15%	3.79%	4.44%	4.44%
Total	7.95%	6.98%	7.46%	7.92%	8.39%	8.39%
PSNH Other than Transmission						
AFUDC Debt Rate %	3.67%	4.41%	4.69%	4.05%	3.78%	3.78%
AFUDC Equity Rate %	3.00%	1.76%	1.69%	2.92%	3.50%	3.50%
Total	6.67%	6.17%	6.38%	6.97%	7.28%	7.28%

2008 and 2009 Equity and Debt capitalization rates per the 2008 Budget (Mei Yang)
2008 and 2009 Cost of Long-term debt (pre-tax) per the 2008 Budget (Mei Yang).
AFUDC rates per the 2008 Budget (Mei Yang).

Graph information

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Chart 1:	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Total Revenue Requirement w/fuel and revenue credits, no energy benefit	388,444,233	391,961,459	393,893,227	396,061,412	398,510,133	401,336,461	404,482,658	407,269,091	409,803,597	412,553,055	415,564,953	418,740,754	422,137,753	425,813,380	429,669,503	433,763,833	438,154,223	443,502,017	449,082,491	454,901,462	461,314,098	468,675,558	476,643,059	484,873,816	493,374,411	502,151,590	511,212,268	520,563,531	530,212,645	540,167,056
Total Market Purchases	283,537,003	290,625,428	297,891,064	305,338,340	312,971,799	320,796,094	328,815,996	337,036,396	345,462,306	354,098,864	362,951,335	372,025,119	381,325,747	390,858,890	400,630,362	410,646,122	420,912,275	431,435,081	442,220,958	453,276,482	464,608,394	476,223,604	488,129,194	500,332,424	512,840,735	525,661,753	538,803,297	552,273,380	566,080,214	580,232,219

Chart 2:	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Total Revenue Requirement w/ fuel before Revenue Credits	407,335,833	411,112,559	413,459,527	416,146,712	419,166,333	422,511,661	426,176,858	430,156,991	434,404,197	438,866,355	443,539,053	448,427,554	453,537,253	458,873,680	464,442,503	470,249,533	476,300,723	482,602,179	489,160,157	495,981,070	503,420,696	511,834,822	520,881,304	530,218,017	539,852,217	549,791,341	560,043,013	570,615,045	581,515,447	592,752,427
Forward Capacity Market Revenue	18,891,600	19,151,100	19,566,300	20,085,300	20,656,200	21,175,200	21,694,200	22,887,900	24,600,600	26,313,300	27,974,100	29,686,800	31,399,500	33,060,300	34,773,000	36,485,700	38,146,500	39,100,163	40,077,667	41,079,608	42,106,598	43,159,263	44,238,245	45,344,201	46,477,806	47,639,751	48,830,745	50,051,514	51,302,802	52,585,372
Energy Market Revenue	283,537,003	290,625,428	297,891,064	305,338,340	312,971,799	320,796,094	328,815,996	337,036,396	345,462,306	354,098,864	362,951,335	372,025,119	381,325,747	390,858,890	400,630,362	410,646,122	420,912,275	431,435,081	442,220,958	453,276,482	464,608,394	476,223,604	488,129,194	500,332,424	512,840,735	525,661,753	538,803,297	552,273,380	566,080,214	580,232,219

Fixed Costs Only	149,793,477	147,131,644	142,879,089	138,801,763	134,887,761	131,126,124	127,506,683	124,020,061	120,613,844	117,231,243	113,863,063	110,509,665	107,171,416	103,848,697	100,541,896	97,251,410	93,977,648	90,721,027	87,481,976	84,260,935	81,407,558	79,271,354	77,503,750	75,756,024	74,028,675	72,322,210	70,637,153	68,974,039	67,333,415	65,715,845
$/kW-Mo	28.86	28.35	27.53	26.74	25.99	25.27	24.57	23.90	23.24	22.59	21.94	21.29	20.65	20.01	19.37	18.74	18.11	17.48	16.86	16.24	15.69	15.27	14.93	14.60	14.26	13.93	13.61	13.29	12.97	12.66

New Regulated Fluidized Bed Coal Plant

In-service date	2012	(January 1, 2012)
Total capital cost	$ 1,468,956,954	
Size (MW net)	432.5	
Annual Capacity Factor	86%	
Annual MWH output	3,258,282	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Revenue Requirements	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Total Revenue Requirements w/o Fuel	301,915,015	297,061,103	289,130,038	281,545,888	274,285,787	267,328,710	260,655,165	254,247,197	248,003,519	241,814,380	235,662,192	229,547,879	223,472,387	217,436,688	211,441,775	205,488,669	199,578,415	193,712,083	187,890,773	182,115,610	177,063,960	173,412,916	170,487,781	167,613,583	164,791,596	162,023,125	159,309,508	156,652,116	154,052,354	151,511,665
Fuel Costs	157,437,732	161,373,675	165,408,017	169,543,218	173,781,798	178,126,343	182,579,502	187,143,989	191,822,589	196,618,154	201,533,608	206,571,948	211,736,246	217,029,653	222,455,394	228,016,779	233,717,198	239,560,128	245,549,131	251,687,860	257,980,056	264,429,558	271,040,296	277,816,304	284,761,711	291,880,754	299,177,773	306,657,217	314,323,648	322,181,739
Total Revenue Requirements w/ Fuel	459,352,747	458,434,779	454,538,055	451,089,105	448,067,585	445,455,053	443,234,666	441,391,186	439,826,108	438,432,534	437,195,800	436,119,827	435,208,634	434,466,340	433,897,169	433,505,448	433,295,613	433,272,212	433,439,905	433,803,469	435,044,016	437,842,474	441,528,078	445,429,887	449,553,308	453,903,879	458,487,281	463,309,333	468,376,002	473,693,404
Forward Capacity Market Revenue	18,891,600	19,151,100	19,566,300	20,085,300	20,656,200	21,175,200	21,694,200	22,887,900	24,600,600	26,313,300	27,974,100	29,686,800	31,399,500	33,060,300	34,773,000	36,485,700	38,146,500	39,100,163	40,077,667	41,079,608	42,106,598	43,159,263	44,238,245	45,344,201	46,477,806	47,639,751	48,830,745	50,051,514	51,302,802	52,585,372
Energy Market Revenue	283,537,003	290,625,428	297,891,064	305,338,340	312,971,799	320,796,094	328,815,996	337,036,396	345,462,306	354,098,864	362,951,335	372,025,119	381,325,747	390,858,890	400,630,362	410,646,122	420,912,275	431,435,081	442,220,958	453,276,482	464,608,394	476,223,604	488,129,194	500,332,424	512,840,735	525,661,753	538,803,297	552,273,380	566,080,214	580,232,219
Total Net Revenue Requirements w/fuel	156,924,144	148,658,250	137,080,692	125,665,465	114,439,586	103,483,759	92,724,470	81,466,890	69,763,202	58,020,370	46,270,365	34,407,908	22,483,387	10,547,150	(1,506,194)	(13,626,374)	(25,763,162)	(37,263,032)	(48,858,720)	(60,552,621)	(71,670,977)	(81,540,394)	(90,839,362)	(100,246,738)	(109,765,233)	(119,397,625)	(129,146,761)	(139,015,560)	(149,007,013)	(159,124,187)
Earnings Impact																														
Earnings (equity ratio *cost of equity)	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%
Average Rate Base	1,446,144,900	1,385,367,265	1,316,682,715	1,250,852,743	1,187,663,849	1,126,918,959	1,068,434,692	1,012,041,355	956,816,369	901,760,502	846,706,802	791,655,323	736,606,121	681,559,252	626,514,776	571,472,751	516,433,240	461,396,304	406,362,009	351,330,420	302,409,567	265,704,743	235,110,794	204,519,833	173,931,934	143,347,174	112,765,631	82,187,385	51,612,519	21,041,117
Earnings Impact to NU Shareholders	68,096,071	65,234,174	61,999,956	58,900,154	55,924,715	53,064,360	50,310,453	47,655,003	45,054,569	42,462,099	39,869,730	37,277,466	34,685,309	32,093,262	29,501,328	26,909,509	24,317,808	21,726,229	19,134,774	16,543,447	14,239,862	12,511,505	11,070,897	9,630,430	8,190,107	6,749,932	5,309,908	3,870,040	2,430,330	990,784
Customer Impact																														
Customer ES Requirement Forecast (MWh)	8,681,138	8,757,261	8,876,549	8,988,206	9,120,460	9,224,176	9,349,758	9,463,333	9,605,283	9,749,362	9,895,603	10,044,037	10,194,697	10,347,618	10,502,832	10,660,374	10,820,280	10,982,584	11,147,323	11,314,533	11,484,251	11,656,515	11,831,362	12,008,833	12,188,965	12,371,800	12,557,377	12,745,737	12,936,923	13,130,977
ES Rate Impact ($/kWh)	$0.01808	$0.01698	$0.01544	$0.01398	$0.01255	$0.01122	$0.00992	$0.00861	$0.00726	$0.00595	$0.00468	$0.00343	$0.00221	$0.00102	-$0.00014	-$0.00128	-$0.00238	-$0.00339	-$0.00438	-$0.00535	-$0.00624	-$0.00700	-$0.00768	-$0.00835	-$0.00901	-$0.00965	-$0.01028	-$0.01091	-$0.01152	-$0.01212
Annual Customer Impact ($/Yr)	$108.459	$101.853	$92.658	$83.887	$75.285	$67.313	$59.504	$51.652	$43.578	$35.707	$28.055	$20.554	$13.232	$6.116	-$0.860	-$7.669	-$14.286	-$20.358	-$26.298	-$32.111	-$37.445	-$41.972	-$46.067	-$50.087	-$54.032	-$57.905	-$61.707	-$65.441	-$69.108	-$72.709
Replacement Power Cost	$0.04816	$0.04562	$0.04207	$0.03857	$0.03512	$0.03176	$0.02846	$0.02500	$0.02141	$0.01781	$0.01420	$0.01056	$0.00690	$0.00324	-$0.00046	-$0.00418	-$0.00791	-$0.01144	-$0.01500	-$0.01858	-$0.02200	-$0.02503	-$0.02788	-$0.03077	-$0.03369	-$0.03664	-$0.03964	-$0.04267	-$0.04573	-$0.04884
15 Year Average ES Rate Impact ($/kWh)	$0.00874																													
Busbar Costs																														
Busbar Cost ($/MWh)	$140.98	$140.70	$139.50	$138.44	$137.52	$136.71	$136.03	$135.47	$134.99	$134.56	$134.18	$133.85	$133.57	$133.34	$133.17	$133.05	$132.98	$132.98	$133.03	$133.14	$133.52	$134.38	$135.51	$136.71	$137.97	$139.31	$140.71	$142.19	$143.75	$145.38
Busbar Cost ($/kWh)	$0.14098	$0.14070	$0.13950	$0.13844	$0.13752	$0.13671	$0.13603	$0.13547	$0.13499	$0.13456	$0.13418	$0.13385	$0.13357	$0.13334	$0.13317	$0.13305	$0.13298	$0.13298	$0.13303	$0.13314	$0.13352	$0.13438	$0.13551	$0.13671	$0.13797	$0.13931	$0.14071	$0.14219	$0.14375	$0.14538
Busbar Cost (cents/kWh)	14.098	14.070	13.950	13.844	13.752	13.671	13.603	13.547	13.499	13.456	13.418	13.385	13.357	13.334	13.317	13.305	13.298	13.298	13.303	13.314	13.352	13.438	13.551	13.671	13.797	13.931	14.071	14.219	14.375	14.538
Capacity Costs																														
Cost per kW including fuel ($/kW)	$1,062.09	$1,059.96	$1,050.96	$1,042.98	$1,035.99	$1,029.95	$1,024.82	$1,020.56	$1,016.94	$1,013.72	$1,010.86	$1,008.37	$1,006.26	$1,004.55	$1,003.23	$1,002.32	$1,001.84	$1,001.79	$1,002.17	$1,003.01	$1,005.88	$1,012.35	$1,020.87	$1,029.90	$1,039.43	$1,049.49	$1,060.09	$1,071.24	$1,082.95	$1,095.24
Cost per kW including fuel and revenue offsets ($/kW)	$362.83	$343.72	$316.95	$290.56	$264.60	$239.27	$214.39	$188.36	$161.30	$134.15	$106.98	$79.56	$51.98	$24.39	($3.48)	($31.51)	($59.57)	($86.16)	($112.97)	($140.01)	($165.71)	($188.53)	($210.03)	($231.78)	($253.79)	($276.06)	($298.61)	($321.42)	($344.52)	($367.92)
Fixed and Variable Costs																														
Variable Cost ($/MWh)	$57.16	$58.59	$60.06	$61.56	$63.10	$64.67	$66.29	$67.95	$69.65	$71.39	$73.17	$75.00	$76.88	$78.80	$80.77	$82.79	$84.86	$86.98	$89.15	$91.38	$93.67	$96.01	$98.41	$100.87	$103.39	$105.98	$108.63	$111.34	$114.13	$116.98
Fixed Cost ($/kW)	$631.44	$618.56	$598.51	$579.23	$560.65	$542.72	$525.41	$508.66	$492.24	$475.90	$459.60	$443.33	$427.10	$410.90	$394.74	$378.63	$362.55	$346.51	$330.52	$314.57	$300.22	$289.05	$279.49	$269.98	$260.51	$251.10	$241.74	$232.43	$223.17	$213.97

Levelized Values:	**Levelized 2012-2041**	**NPV**	**Cost per kW**	**Cost per kWh**
2012 Gross Revenue Requirement (including fuel, no offsets)	$446,390,999	$3,859,284,231	$1,032.12	$0.0514
2012 Net Revenue Requirement (including fuel and revenue offsets)	$72,075,801	$623,133,089	$166.65	$0.0083
Busbar $/MWh (gross revenue requirements including fuel)	$137.00	$1,184.45		

Chart 1

Net Revenue Requirements vs Market Energy Purchases

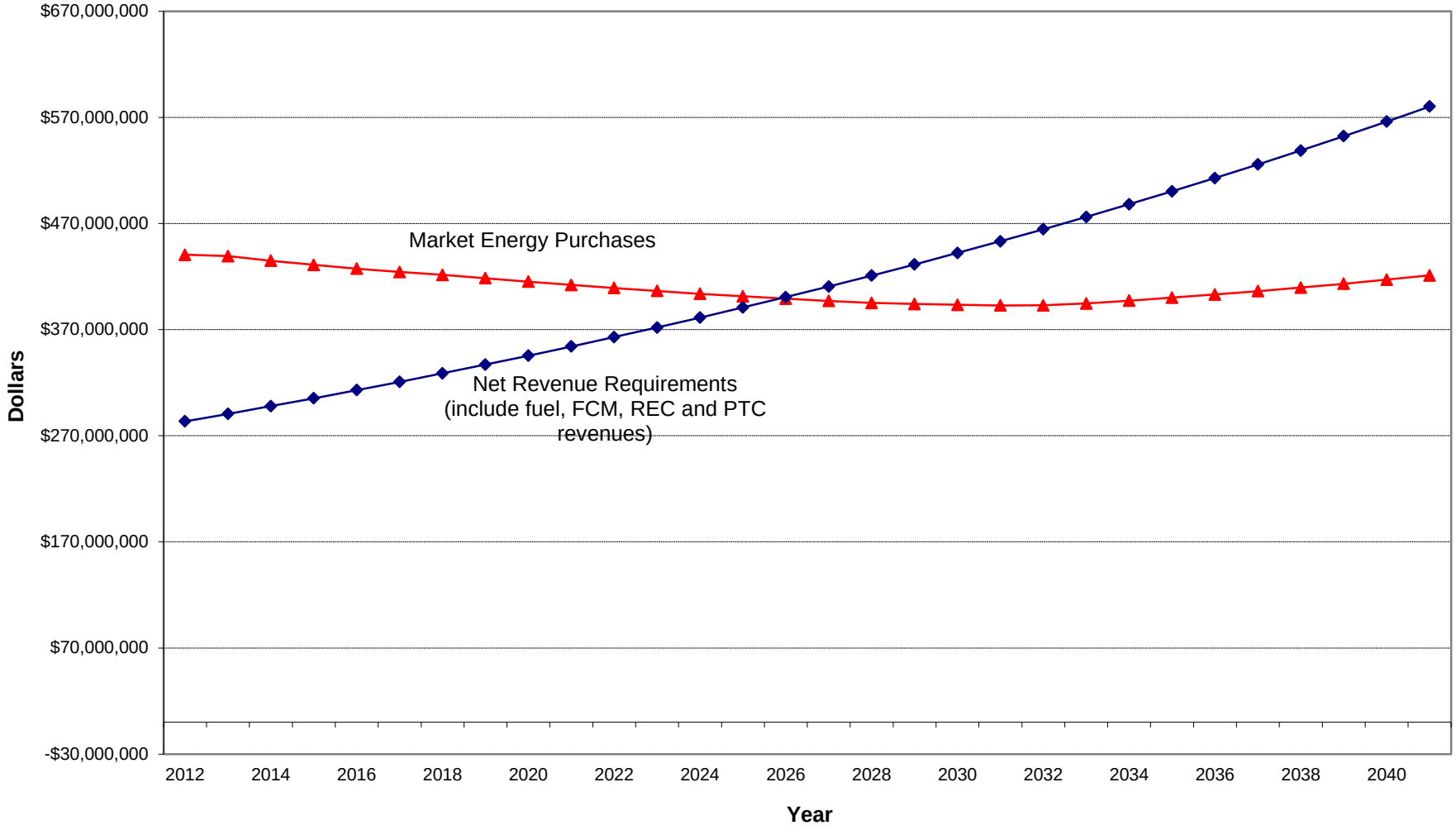
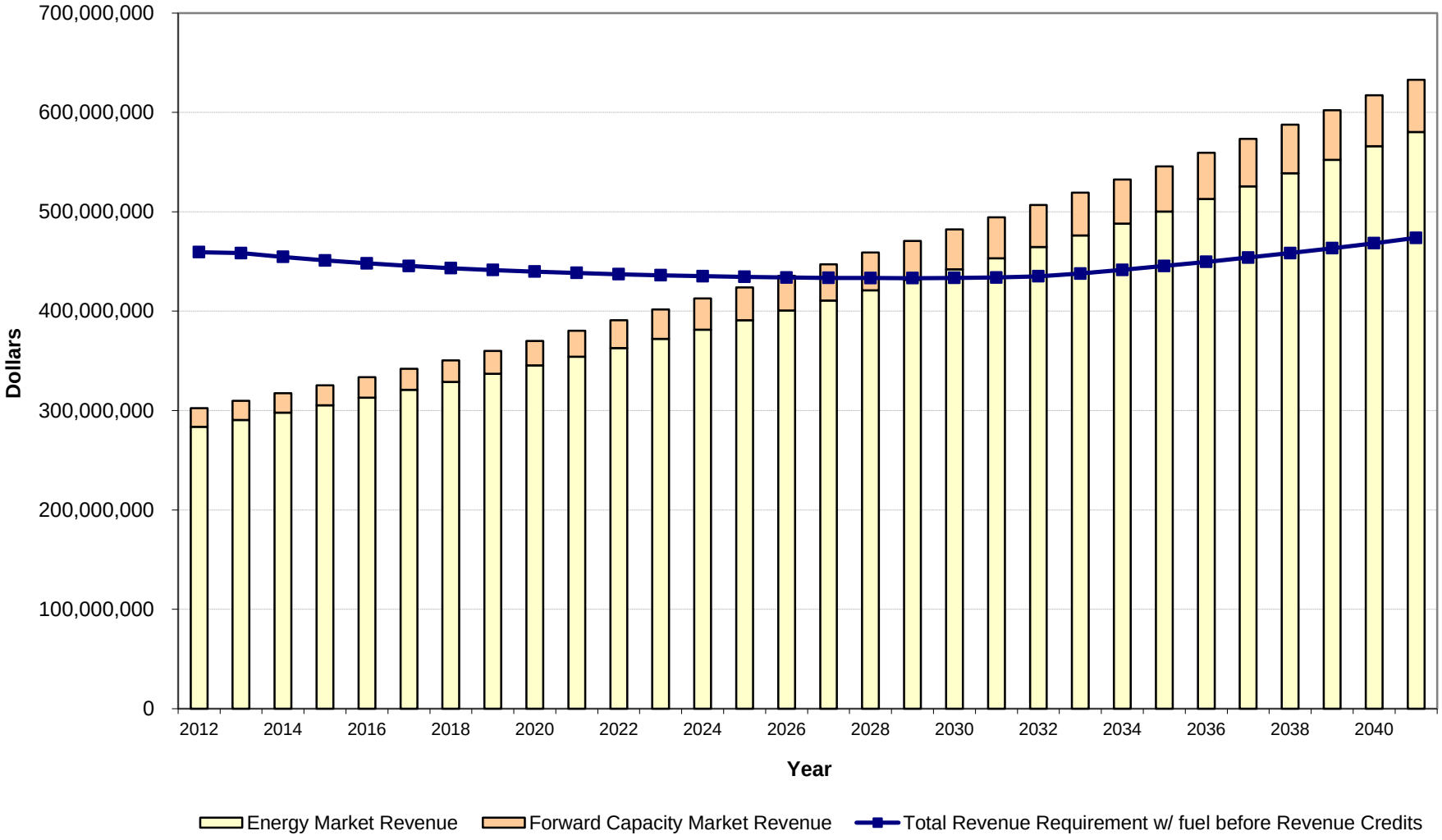


Chart 2

Revenue Requirements and Revenue Sources



Fluidized Bed Coal Owner Dispatch Costs

Heat Rate (Btu/kWh)	10,126	<- assumes same as Merrimack
Size (MW)	432.5	<- assumes same as Merrimack
Equipment Availability (%)	86%	<- assumes same as Merrimack
SO_2 Emissions (lbs/mmBtu)	0.0300	<- per ISO-NE Scenario Analysis Coal IGCC pg. 29
NOx Emissions (lbs/mmBtu)	0.0100	<- per ISO-NE Scenario Analysis Coal IGCC pg. 29
CO_2 Emissions (lbs/mmBtu)	210.0	<- per ISO-NE Scenario Analysis Coal IGCC pg. 29
Output (MWh)	3,258,282	<- assumes same as Merrimack

		1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026	16 2027	17 2028	18 2029	19 2030	20 2031	21 2032	22 2033	23 2034	24 2035	25 2036	26 2037	27 2038	28 2039	29 2040	30 2041	31 2042
Variable O&M ($/MWh)	1.105	1.22	1.25	1.28	1.31	1.35	1.38	1.41	1.45	1.49	1.52	1.56	1.60	1.64	1.68	1.72	1.77	1.81	1.86	1.90	1.95	2.00	2.05	2.10	2.15	2.21	2.26	2.32	2.38	2.44	2.50	2.56
Fuel ($/mmbtu)		4.77	4.89	5.01	5.14	5.27	5.40	5.53	5.67	5.81	5.96	6.11	6.26	6.42	6.58	6.74	6.91	7.08	7.26	7.44	7.63	7.82	8.01	8.21	8.42	8.63	8.85	9.07	9.29	9.53	9.77	10.01
Fuel ($/MWh)		48.32	49.53	50.77	52.03	53.34	54.67	56.04	57.44	58.87	60.34	61.85	63.40	64.98	66.61	68.27	69.98	71.73	73.52	75.36	77.25	79.18	81.16	83.19	85.26	87.40	89.58	91.82	94.12	96.47	98.88	101.35
Fuel Cost		157,437,732	161,373,675	165,408,017	169,543,218	173,781,798	178,126,343	182,579,502	187,143,989	191,822,589	196,618,154	201,533,608	206,571,948	211,736,246	217,029,653	222,455,394	228,016,779	233,717,198	239,560,128	245,549,131	251,687,860	257,980,056	264,429,558	271,040,296	277,816,304	284,761,711	291,880,754	299,177,773	306,657,217	314,323,648	322,181,739	330,236,283
SO_2 ($/ton)		565.70	579.85	594.34	609.20	624.43	640.04	656.04	672.44	689.26	706.49	724.15	742.25	760.81	779.83	799.33	819.31	839.79	860.79	882.31	904.36	926.97	950.15	973.90	998.25	1,023.20	1,048.78	1,075.00	1,101.88	1,129.43	1,157.66	1,186.60
SO_2 ($/MWh)		0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.18	0.18
SO_2 Cost		279,967	286,966	294,141	301,494	309,031	316,757	324,676	332,793	341,113	349,641	358,382	367,341	376,525	385,938	395,586	405,476	415,613	426,003	436,653	447,570	458,759	470,228	481,984	494,033	506,384	519,044	532,020	545,320	558,953	572,927	587,250
NOx ($/ton)		1,886.06	1,933.21	1,981.54	2,031.08	2,081.85	2,133.90	2,187.25	2,241.93	2,297.98	2,355.43	2,414.31	2,474.67	2,536.54	2,599.95	2,664.95	2,731.57	2,799.86	2,869.86	2,941.61	3,015.15	3,090.52	3,167.79	3,246.98	3,328.16	3,411.36	3,496.65	3,584.06	3,673.66	3,765.50	3,859.64	3,956.13
NOx ($/MWh)		0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.20
NOx Cost		311,137	318,915	326,888	335,060	343,437	352,023	360,823	369,844	379,090	388,567	398,282	408,239	418,445	428,906	439,628	450,619	461,884	473,432	485,267	497,399	509,834	522,580	535,644	549,036	562,761	576,830	591,251	606,032	621,183	636,713	652,631
CO_2 ($/ton)		7.00	7.18	7.35	7.54	7.73	7.92	8.12	8.32	8.53	8.74	8.96	9.18	9.41	9.65	9.89	10.14	10.39	10.65	10.92	11.19	11.47	11.76	12.05	12.35	12.66	12.98	13.30	13.63	13.98	14.32	14.68
CO_2 ($/MWh)		7.44	7.63	7.82	8.01	8.22	8.42	8.63	8.85	9.07	9.29	9.53	9.77	10.01	10.26	10.52	10.78	11.05	11.32	11.61	11.90	12.20	12.50	12.81	13.13	13.46	13.80	14.14	14.50	14.86	15.23	15.61
CO_2 Cost		24,250,122	24,856,375	25,477,785	26,114,729	26,767,597	27,436,787	28,122,707	28,825,775	29,546,419	30,285,080	31,042,207	31,818,262	32,613,718	33,429,061	34,264,788	35,121,408	35,999,443	36,899,429	37,821,914	38,767,462	39,736,649	40,730,065	41,748,317	42,792,025	43,861,825	44,958,371	46,082,330	47,234,388	48,415,248	49,625,629	50,866,270
Total Emissions Cost		24,841,226	25,462,257	26,098,813	26,751,284	27,420,066	28,105,567	28,808,207	29,528,412	30,266,622	31,023,288	31,798,870	32,593,842	33,408,688	34,243,905	35,100,002	35,977,503	36,876,940	37,798,864	38,743,835	39,712,431	40,705,242	41,722,873	42,765,945	43,835,093	44,930,971	46,054,245	47,205,601	48,385,741	49,595,385	50,835,269	52,106,151

New Regulated Fluidized Bed Coal Plant

Assumptions (Inputs)

		(in service date)	
	2008	2012	
Capital Cost	$ 1,330,802,500	$ 1,468,956,954	
Size (MW net)		432.5	
Winter Claimed Capability (WCC) (MW)		432.5	
Summer Claimed Capability (SCC) (MW)		432.5	<- same size as Merrimack Station
Unforced Outage Rate		0.0%	
Annual Capacity Factor		86%	
Annual MWH output		3,258,282	
Full Load Avg Heat Rate (MMBtu/MWh)		10.1	
Variable O&M ($/MWh)	$ 1.105	$ 1.22	
Annual Variable O&M	$ 3,600,402	$ 3,974,170	
Fixed O&M ($/kW)		$ 44.84	<- per EPRI Technical Gas Assessment Guide, pg. 5-19
Annual Fixed O&M		$ 19,393,300	
Book Life of Plant (in years)		30	
Property Taxes on net beginning plant (per $1,000)	2.50%	3.04%	
Materials Inventory	$ -	$ -	

Average annual escalation rates:		
Capital	2.50%	
O&M	2.50%	
Property Tax annual inflator	5.00%	
Price Inflator	2.50%	Used to inflate FCM
Fuel	2.50%	
SO2/Nox Emissions	2.50%	

New Regulated Fluidized Bed Coal Plant
Revenue Requirements Analysis
Assumed in-service date of 2012

		0 2011	1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018	8 2019
Annual O&M Costs:										
Variable O&M			$ 3,974,170	$ 4,073,524	$ 4,175,362	$ 4,279,746	$ 4,386,740	$ 4,496,408	$ 4,608,818	$ 4,724,039
Fixed O&M			$ 19,393,300	$ 19,878,133	$ 20,375,086	$ 20,884,463	$ 21,406,575	$ 21,941,739	$ 22,490,282	$ 23,052,539
Depreciation			$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232
Property Taxes			$ 44,638,159	$ 45,307,731	$ 43,745,396	$ 42,183,060	$ 40,620,725	$ 39,058,389	$ 37,496,054	$ 35,933,718
SO_2 Emissions			$ 279,967	$ 286,966	$ 294,141	$ 301,494	$ 309,031	$ 316,757	$ 324,676	$ 332,793
NOx Emissions			$ 311,137	$ 318,915	$ 326,888	$ 335,060	$ 343,437	$ 352,023	$ 360,823	$ 369,844
CO_2 Emissions			$ 24,250,122	$ 24,856,375	$ 25,477,785	$ 26,114,729	$ 26,767,597	$ 27,436,787	$ 28,122,707	$ 28,825,775
TOTAL			$ 141,812,087	$ 143,686,877	$ 143,359,889	$ 143,063,785	$ 142,799,337	$ 142,567,336	$ 142,368,593	$ 142,203,940
Return on Rate Base:										
Plant in Service			$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954
Accumulated Depreciation			$ 48,965,232	$ 97,930,464	$ 146,895,695	$ 195,860,927	$ 244,826,159	$ 293,791,391	$ 342,756,623	$ 391,721,855
Net Plant in Service	$ 1,468,956,954		$ 1,419,991,723	$ 1,371,026,491	$ 1,322,061,259	$ 1,273,096,027	$ 1,224,130,795	$ 1,175,165,564	$ 1,126,200,332	$ 1,077,235,100
Working capital for 45 days based on Incremental O&M	$ 2,880,921		$ 2,880,921	$ 2,952,944	$ 3,026,768	$ 3,102,437	$ 3,179,998	$ 3,259,498	$ 3,340,985	$ 3,424,510
Accumulated Deferred Taxes			$ (2,420,719)	$ (23,696,830)	$ (42,005,201)	$ (57,575,803)	$ (70,605,756)	$ (81,292,179)	$ (89,804,814)	$ (96,313,403)
Materials Inventory	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base end of the period	$ 1,471,837,875		$ 1,420,451,925	$ 1,350,282,604	$ 1,283,082,825	$ 1,218,622,661	$ 1,156,705,037	$ 1,097,132,882	$ 1,039,736,502	$ 984,346,207
Average Rate Base			$ 1,446,144,900	$ 1,385,367,265	$ 1,316,682,715	$ 1,250,852,743	$ 1,187,663,849	$ 1,126,918,959	$ 1,068,434,692	$ 1,012,041,355
Cost of capital			11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%
Return on Rate Base			$ 160,102,928	$ 153,374,227	$ 145,770,149	$ 138,482,103	$ 131,486,450	$ 124,761,374	$ 118,286,572	$ 112,043,257
Total Revenue Requirement (w/o fuel before revenue offsets)			**$ 301,915,015**	**$ 297,061,103**	**$ 289,130,038**	**$ 281,545,888**	**$ 274,285,787**	**$ 267,328,710**	**$ 260,655,165**	**$ 254,247,197**
Annual MWH output			3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282
Fuel Cost			157,437,732	161,373,675	165,408,017	169,543,218	173,781,798	178,126,343	182,579,502	187,143,989
Offsetting Revenue:										
Energy Market Benefit										
All-Hours Mkt Price ($/Mwh)			$87.02	$89.20	$91.43	$93.71	$96.05	$98.46	$100.92	$103.44
Energy Market Revenues			$ 283,537,003	$ 290,625,428	$ 297,891,064	$ 305,338,340	$ 312,971,799	$ 320,796,094	$ 328,815,996	$ 337,036,396
Fuel Costs			$ 157,437,732	$ 161,373,675	$ 165,408,017	$ 169,543,218	$ 173,781,798	$ 178,126,343	$ 182,579,502	$ 187,143,989
Variable O&M			$ 3,974,170	$ 4,073,524	$ 4,175,362	$ 4,279,746	$ 4,386,740	$ 4,496,408	$ 4,608,818	$ 4,724,039
Energy Market Benefit			$ 122,125,101	$ 125,178,229	$ 128,307,684	$ 131,515,376	$ 134,803,261	$ 138,173,342	$ 141,627,676	$ 145,168,368
ISO-NE Market										
Forward Capacity Market Rate ($/KW-Mo)			$ 3.64	$ 3.69	$ 3.77	$ 3.87	$ 3.98	$ 4.08	$ 4.18	$ 4.41
Forward Capacity Market Revenue			$ 18,891,600	$ 19,151,100	$ 19,566,300	$ 20,085,300	$ 20,656,200	$ 21,175,200	$ 21,694,200	$ 22,887,900
Total ISO-NE Market Revenue			$ 18,891,600	$ 19,151,100	$ 19,566,300	$ 20,085,300	$ 20,656,200	$ 21,175,200	$ 21,694,200	$ 22,887,900
Total Revenue Requirement (w/o fuel before revenue offsets)			**$ 301,915,015**	**$ 297,061,103**	**$ 289,130,038**	**$ 281,545,888**	**$ 274,285,787**	**$ 267,328,710**	**$ 260,655,165**	**$ 254,247,197**
Fuel Cost			$ 157,437,732	$ 161,373,675	$ 165,408,017	$ 169,543,218	$ 173,781,798	$ 178,126,343	$ 182,579,502	$ 187,143,989
Total Revenue Requirement (w/fuel)			$ 459,352,747	$ 458,434,779	$ 454,538,055	$ 451,089,105	$ 448,067,585	$ 445,455,053	$ 443,234,666	$ 441,391,186
Energy Market Revenue			$ 283,537,003	$ 290,625,428	$ 297,891,064	$ 305,338,340	$ 312,971,799	$ 320,796,094	$ 328,815,996	$ 337,036,396
ISO FCM Credits			$ 18,891,600	$ 19,151,100	$ 19,566,300	$ 20,085,300	$ 20,656,200	$ 21,175,200	$ 21,694,200	$ 22,887,900
Total Net Revenue Requirement (w/fuel and Energy Revenue and ISO credits)			$ 156,924,144	$ 148,658,250	$ 137,080,692	$ 125,665,465	$ 114,439,586	$ 103,483,759	$ 92,724,470	$ 81,466,890
2012 Net Present Value of Revenue Requirements	$623,133,089									
Variable Costs ($/MWh)			$ 57.16	$ 58.59	$ 60.06	$ 61.56	$ 63.10	$ 64.67	$ 66.29	$ 67.95
Fixed Costs ($/kW)			$ 631.44	$ 618.56	$ 598.51	$ 579.23	$ 560.65	$ 542.72	$ 525.41	$ 508.66
Fixed Costs ($/kW-Mo)			$ 52.62	$ 51.55	$ 49.88	$ 48.27	$ 46.72	$ 45.23	$ 43.78	$ 42.39

	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026	16 2027	17 2028	18 2029	19 2030	20 2031
Annual O&M Costs:												
Variable O&M	$ 4,842,140	$ 4,963,193	$ 5,087,273	$ 5,214,455	$ 5,344,816	$ 5,478,437	$ 5,615,398	$ 5,755,783	$ 5,899,677	$ 6,047,169	$ 6,198,348	$ 6,353,307
Fixed O&M	$ 23,628,853	$ 24,219,574	$ 24,825,064	$ 25,445,690	$ 26,081,832	$ 26,733,878	$ 27,402,225	$ 28,087,281	$ 28,789,463	$ 29,509,199	$ 30,246,929	$ 31,003,103
Depreciation	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232
Property Taxes	$ 34,371,382	$ 32,809,047	$ 31,246,711	$ 29,684,376	$ 28,122,040	$ 26,559,705	$ 24,997,369	$ 23,435,033	$ 21,872,698	$ 20,310,362	$ 18,748,027	$ 17,185,691
SO_2 Emissions	$ 341,113	$ 349,641	$ 358,382	$ 367,341	$ 376,525	$ 385,938	$ 395,586	$ 405,476	$ 415,613	$ 426,003	$ 436,653	$ 447,570
NOx Emissions	$ 379,090	$ 388,567	$ 398,282	$ 408,239	$ 418,445	$ 428,906	$ 439,628	$ 450,619	$ 461,884	$ 473,432	$ 485,267	$ 497,399
CO_2 Emissions	$ 29,546,419	$ 30,285,080	$ 31,042,207	$ 31,818,262	$ 32,613,718	$ 33,429,061	$ 34,264,788	$ 35,121,408	$ 35,999,443	$ 36,899,429	$ 37,821,914	$ 38,767,462
TOTAL	$ 142,074,229	$ 141,980,334	$ 141,923,150	$ 141,903,594	$ 141,922,608	$ 141,981,156	$ 142,080,226	$ 142,220,831	$ 142,404,010	$ 142,630,826	$ 142,902,372	$ 143,219,764
Return on Rate Base:												
Plant in Service	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954
Accumulated Depreciation	$ 440,687,086	$ 489,652,318	$ 538,617,550	$ 587,582,782	$ 636,548,014	$ 685,513,245	$ 734,478,477	$ 783,443,709	$ 832,408,941	$ 881,374,173	$ 930,339,404	$ 979,304,636
Net Plant in Service	$ 1,028,269,868	$ 979,304,636	$ 930,339,404	$ 881,374,173	$ 832,408,941	$ 783,443,709	$ 734,478,477	$ 685,513,245	$ 636,548,014	$ 587,582,782	$ 538,617,550	$ 489,652,318
Working capital for 45 days based on Incremental O&M	$ 3,510,122	$ 3,597,875	$ 3,687,822	$ 3,780,018	$ 3,874,518	$ 3,971,381	$ 4,070,666	$ 4,172,432	$ 4,276,743	$ 4,383,662	$ 4,493,253	$ 4,605,585
Accumulated Deferred Taxes	$ (102,493,459)	$ (108,668,040)	$ (114,848,096)	$ (121,022,676)	$ (127,202,732)	$ (133,377,313)	$ (139,557,369)	$ (145,731,950)	$ (151,912,006)	$ (158,086,587)	$ (164,266,643)	$ (170,441,223)
Materials Inventory	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base end of the period	$ 929,286,532	$ 874,234,472	$ 819,179,131	$ 764,131,514	$ 709,080,727	$ 654,037,777	$ 598,991,774	$ 543,953,728	$ 488,912,751	$ 433,879,857	$ 378,844,161	$ 323,816,680
Average Rate Base	$ 956,816,369	$ 901,760,502	$ 846,706,802	$ 791,655,323	$ 736,606,121	$ 681,559,252	$ 626,514,776	$ 571,472,751	$ 516,433,240	$ 461,396,304	$ 406,362,009	$ 351,330,420
Cost of capital	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%
Return on Rate Base	$ 105,929,290	$ 99,834,046	$ 93,739,042	$ 87,644,285	$ 81,549,779	$ 75,455,531	$ 69,361,549	$ 63,267,838	$ 57,174,405	$ 51,081,257	$ 44,988,402	$ 38,895,846
Total Revenue Requirement (w/o fuel before revenue offsets)	**$ 248,003,519**	**$ 241,814,380**	**$ 235,662,192**	**$ 229,547,879**	**$ 223,472,387**	**$ 217,436,688**	**$ 211,441,775**	**$ 205,488,669**	**$ 199,578,415**	**$ 193,712,083**	**$ 187,890,773**	**$ 182,115,610**
Annual MWH output	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282
Fuel Cost	191,822,589	196,618,154	201,533,608	206,571,948	211,736,246	217,029,653	222,455,394	228,016,779	233,717,198	239,560,128	245,549,131	251,687,860
Offsetting Revenue:												
Energy Market Benefit												
All-Hours Mkt Price ($/Mwh)	$106.03	$108.68	$111.39	$114.18	$117.03	$119.96	$122.96	$126.03	$129.18	$132.41	$135.72	$139.12
Energy Market Revenues	$ 345,462,306	$ 354,098,864	$ 362,951,335	$ 372,025,119	$ 381,325,747	$ 390,858,890	$ 400,630,362	$ 410,646,122	$ 420,912,275	$ 431,435,081	$ 442,220,958	$ 453,276,482
Fuel Costs	$ 191,822,589	$ 196,618,154	$ 201,533,608	$ 206,571,948	$ 211,736,246	$ 217,029,653	$ 222,455,394	$ 228,016,779	$ 233,717,198	$ 239,560,128	$ 245,549,131	$ 251,687,860
Variable O&M	$ 4,842,140	$ 4,963,193	$ 5,087,273	$ 5,214,455	$ 5,344,816	$ 5,478,437	$ 5,615,398	$ 5,755,783	$ 5,899,677	$ 6,047,169	$ 6,198,348	$ 6,353,307
Energy Market Benefit	$ 148,797,577	$ 152,517,517	$ 156,330,454	$ 160,238,716	$ 164,244,684	$ 168,350,801	$ 172,559,571	$ 176,873,560	$ 181,295,399	$ 185,827,784	$ 190,473,479	$ 195,235,316
ISO-NE Market												
Forward Capacity Market Rate ($/KW-Mo)	$ 4.74	$ 5.07	$ 5.39	$ 5.72	$ 6.05	$ 6.37	$ 6.70	$ 7.03	$ 7.35	$ 7.53	$ 7.72	$ 7.92
Forward Capacity Market Revenue	$ 24,600,600	$ 26,313,300	$ 27,974,100	$ 29,686,800	$ 31,399,500	$ 33,060,300	$ 34,773,000	$ 36,485,700	$ 38,146,500	$ 39,100,163	$ 40,077,667	$ 41,079,608
Total ISO-NE Market Revenue	$ 24,600,600	$ 26,313,300	$ 27,974,100	$ 29,686,800	$ 31,399,500	$ 33,060,300	$ 34,773,000	$ 36,485,700	$ 38,146,500	$ 39,100,163	$ 40,077,667	$ 41,079,608
Total Revenue Requirement (w/o fuel before revenue offsets)	**$ 248,003,519**	**$ 241,814,380**	**$ 235,662,192**	**$ 229,547,879**	**$ 223,472,387**	**$ 217,436,688**	**$ 211,441,775**	**$ 205,488,669**	**$ 199,578,415**	**$ 193,712,083**	**$ 187,890,773**	**$ 182,115,610**
Fuel Cost	$ 191,822,589	$ 196,618,154	$ 201,533,608	$ 206,571,948	$ 211,736,246	$ 217,029,653	$ 222,455,394	$ 228,016,779	$ 233,717,198	$ 239,560,128	$ 245,549,131	$ 251,687,860
Total Revenue Requirement (w/fuel)	$ 439,826,108	$ 438,432,534	$ 437,195,800	$ 436,119,827	$ 435,208,634	$ 434,466,340	$ 433,897,169	$ 433,505,448	$ 433,295,613	$ 433,272,212	$ 433,439,905	$ 433,803,469
Energy Market Revenue	$ 345,462,306	$ 354,098,864	$ 362,951,335	$ 372,025,119	$ 381,325,747	$ 390,858,890	$ 400,630,362	$ 410,646,122	$ 420,912,275	$ 431,435,081	$ 442,220,958	$ 453,276,482
ISO FCM Credits	$ 24,600,600	$ 26,313,300	$ 27,974,100	$ 29,686,800	$ 31,399,500	$ 33,060,300	$ 34,773,000	$ 36,485,700	$ 38,146,500	$ 39,100,163	$ 40,077,667	$ 41,079,608
Total Net Revenue Requirement (w/fuel and Energy Revenue and ISO credits)	$ 69,763,202	$ 58,020,370	$ 46,270,365	$ 34,407,908	$ 22,483,387	$ 10,547,150	$ (1,506,194)	$ (13,626,374)	$ (25,763,162)	$ (37,263,032)	$ (48,858,720)	$ (60,552,621)
Variable Costs ($/MWh)	$ 69.65	$ 71.39	$ 73.17	$ 75.00	$ 76.88	$ 78.80	$ 80.77	$ 82.79	$ 84.86	$ 86.98	$ 89.15	$ 91.38
Fixed Costs ($/kW)	$ 492.24	$ 475.90	$ 459.60	$ 443.33	$ 427.10	$ 410.90	$ 394.74	$ 378.63	$ 362.55	$ 346.51	$ 330.52	$ 314.57
Fixed Costs ($/kW-Mo)	$ 41.02	$ 39.66	$ 38.30	$ 36.94	$ 35.59	$ 34.24	$ 32.90	$ 31.55	$ 30.21	$ 28.88	$ 27.54	$ 26.21

	21 2032	22 2033	23 2034	24 2035	25 2036	26 2037	27 2038	28 2039	29 2040	30 2041	31 2042
Annual O&M Costs:											
Variable O&M	$ 6,512,140	$ 6,674,943	$ 6,841,817	$ 7,012,862	$ 7,188,184	$ 7,367,888	$ 7,552,086	$ 7,740,888	$ 7,934,410	$ 8,132,770	$ 8,336,090
Fixed O&M	$ 31,778,180	$ 32,572,635	$ 33,386,951	$ 34,221,624	$ 35,077,165	$ 35,954,094	$ 36,852,946	$ 37,774,270	$ 38,718,627	$ 39,686,593	$ 40,678,757
Depreciation	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ 48,965,232	$ -
Property Taxes	$ 15,623,356	$ 14,061,020	$ 12,498,685	$ 10,936,349	$ 9,374,013	$ 7,811,678	$ 6,249,342	$ 4,687,007	$ 3,124,671	$ 1,562,336	$ -
SO_2 Emissions	$ 458,759	$ 470,228	$ 481,984	$ 494,033	$ 506,384	$ 519,044	$ 532,020	$ 545,320	$ 558,953	$ 572,927	$ 587,250
NOx Emissions	$ 509,834	$ 522,580	$ 535,644	$ 549,036	$ 562,761	$ 576,830	$ 591,251	$ 606,032	$ 621,183	$ 636,713	$ 652,631
CO_2 Emissions	$ 39,736,649	$ 40,730,065	$ 41,748,317	$ 42,792,025	$ 43,861,825	$ 44,958,371	$ 46,082,330	$ 47,234,388	$ 48,415,248	$ 49,625,629	$ 50,866,270
TOTAL	$ 143,584,149	$ 143,996,703	$ 144,458,629	$ 144,971,161	$ 145,535,565	$ 146,153,137	$ 146,825,207	$ 147,553,138	$ 148,338,324	$ 149,182,199	$ 101,120,998
Return on Rate Base:											
Plant in Service	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ 1,468,956,954	$ -
Accumulated Depreciation	$ 1,028,269,868	$ 1,077,235,100	$ 1,126,200,332	$ 1,175,165,564	$ 1,224,130,795	$ 1,273,096,027	$ 1,322,061,259	$ 1,371,026,491	$ 1,419,991,723	$ 1,468,956,954	$ -
Net Plant in Service	$ 440,687,086	$ 391,721,855	$ 342,756,623	$ 293,791,391	$ 244,826,159	$ 195,860,927	$ 146,895,695	$ 97,930,464	$ 48,965,232	$ -	$ -
Working capital for 45 days based on Incremental O&M	$ 4,720,724	$ 4,838,742	$ 4,959,711	$ 5,083,704	$ 5,210,796	$ 5,341,066	$ 5,474,593	$ 5,611,458	$ 5,751,744	$ 5,895,538	$ 6,042,926
Accumulated Deferred Taxes	$ (164,405,356)	$ (146,153,566)	$ (127,901,776)	$ (109,649,986)	$ (91,398,196)	$ (73,146,406)	$ (54,894,615)	$ (36,642,825)	$ (18,391,035)	$ (139,245)	$ (139,245)
Materials Inventory	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base end of the period	$ 281,002,454	$ 250,407,031	$ 219,814,558	$ 189,225,109	$ 158,638,760	$ 128,055,588	$ 97,475,673	$ 66,899,096	$ 36,325,941	$ 5,756,293	$ 5,903,681
Average Rate Base	$ 302,409,567	$ 265,704,743	$ 235,110,794	$ 204,519,833	$ 173,931,934	$ 143,347,174	$ 112,765,631	$ 82,187,385	$ 51,612,519	$ 21,041,117	$ 5,829,987
Cost of capital	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%	11.07%
Return on Rate Base	$ 33,479,810	$ 29,416,214	$ 26,029,153	$ 22,642,423	$ 19,256,032	$ 15,869,988	$ 12,484,301	$ 9,098,978	$ 5,714,030	$ 2,329,465	$ 645,439
Total Revenue Requirement (w/o fuel before revenue offsets)	**$ 177,063,960**	**$ 173,412,916**	**$ 170,487,781**	**$ 167,613,583**	**$ 164,791,596**	**$ 162,023,125**	**$ 159,309,508**	**$ 156,652,116**	**$ 154,052,354**	**$ 151,511,665**	**$ 101,766,437**
Annual MWH output	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282
Fuel Cost	257,980,056	264,429,558	271,040,296	277,816,304	284,761,711	291,880,754	299,177,773	306,657,217	314,323,648	322,181,739	330,236,283
Offsetting Revenue:											
Energy Market Benefit											
All-Hours Mkt Price ($/Mwh)	$142.59	$146.16	$149.81	$153.56	$157.40	$161.33	$165.36	$169.50	$173.74	$178.08	$182.53
Energy Market Revenues	$ 464,608,394	$ 476,223,604	$ 488,129,194	$ 500,332,424	$ 512,840,735	$ 525,661,753	$ 538,803,297	$ 552,273,380	$ 566,080,214	$ 580,232,219	$ 594,738,025
Fuel Costs	$ 257,980,056	$ 264,429,558	$ 271,040,296	$ 277,816,304	$ 284,761,711	$ 291,880,754	$ 299,177,773	$ 306,657,217	$ 314,323,648	$ 322,181,739	$ 330,236,283
Variable O&M	$ 6,512,140	$ 6,674,943	$ 6,841,817	$ 7,012,862	$ 7,188,184	$ 7,367,888	$ 7,552,086	$ 7,740,888	$ 7,934,410	$ 8,132,770	$ 8,336,090
Energy Market Benefit	$ 200,116,199	$ 205,119,103	$ 210,247,081	$ 215,503,258	$ 220,890,840	$ 226,413,111	$ 232,073,438	$ 237,875,274	$ 243,822,156	$ 249,917,710	$ 256,165,653
ISO-NE Market											
Forward Capacity Market Rate ($/KW-Mo)	$ 8.11	$ 8.32	$ 8.52	$ 8.74	$ 8.96	$ 9.18	$ 9.41	$ 9.64	$ 9.88	$ 10.13	$ 10.39
Forward Capacity Market Revenue	$ 42,106,598	$ 43,159,263	$ 44,238,245	$ 45,344,201	$ 46,477,806	$ 47,639,751	$ 48,830,745	$ 50,051,514	$ 51,302,802	$ 52,585,372	$ 53,900,006
Total ISO-NE Market Revenue	$ 42,106,598	$ 43,159,263	$ 44,238,245	$ 45,344,201	$ 46,477,806	$ 47,639,751	$ 48,830,745	$ 50,051,514	$ 51,302,802	$ 52,585,372	$ 53,900,006
Total Revenue Requirement (w/o fuel before revenue offsets)	**$ 177,063,960**	**$ 173,412,916**	**$ 170,487,781**	**$ 167,613,583**	**$ 164,791,596**	**$ 162,023,125**	**$ 159,309,508**	**$ 156,652,116**	**$ 154,052,354**	**$ 151,511,665**	**$ 101,766,437**
Fuel Cost	$ 257,980,056	$ 264,429,558	$ 271,040,296	$ 277,816,304	$ 284,761,711	$ 291,880,754	$ 299,177,773	$ 306,657,217	$ 314,323,648	$ 322,181,739	$ 330,236,283
Total Revenue Requirement (w/fuel)	$ 435,044,016	$ 437,842,474	$ 441,528,078	$ 445,429,887	$ 449,553,308	$ 453,903,879	$ 458,487,281	$ 463,309,333	$ 468,376,002	$ 473,693,404	$ 432,002,719
Energy Market Revenue	$ 464,608,394	$ 476,223,604	$ 488,129,194	$ 500,332,424	$ 512,840,735	$ 525,661,753	$ 538,803,297	$ 552,273,380	$ 566,080,214	$ 580,232,219	$ 594,738,025
ISO FCM Credits	$ 42,106,598	$ 43,159,263	$ 44,238,245	$ 45,344,201	$ 46,477,806	$ 47,639,751	$ 48,830,745	$ 50,051,514	$ 51,302,802	$ 52,585,372	$ 53,900,006
Total Net Revenue Requirement (w/fuel and Energy Revenue and ISO credits)	$ (71,670,977)	$ (81,540,394)	$ (90,839,362)	$ (100,246,738)	$ (109,765,233)	$ (119,397,625)	$ (129,146,761)	$ (139,015,560)	$ (149,007,013)	$ (159,124,187)	$ (216,635,312)
Variable Costs ($/MWh)	$ 93.67	$ 96.01	$ 98.41	$ 100.87	$ 103.39	$ 105.98	$ 108.63	$ 111.34	$ 114.13	$ 116.98	$ 119.90
Fixed Costs ($/kW)	$ 300.22	$ 289.05	$ 279.49	$ 269.98	$ 260.51	$ 251.10	$ 241.74	$ 232.43	$ 223.17	$ 213.97	$ 95.55
Fixed Costs ($/kW-Mo)	$ 25.02	$ 24.09	$ 23.29	$ 22.50	$ 21.71	$ 20.93	$ 20.14	$ 19.37	$ 18.60	$ 17.83	$ 7.96

New Regulated Fluidized Bed Coal Plant
Revenue Requirements Analysis
Assumed in-service date of 2012

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
New Project:															
GROSS PLANT	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954
ACCUMULATED DEPRECIATION	48,965,232	97,930,464	146,895,695	195,860,927	244,826,159	293,791,391	342,756,623	391,721,855	440,687,086	489,652,318	538,617,550	587,582,782	636,548,014	685,513,245	734,478,477
NET GROSS PLANT	1,419,991,723	1,371,026,491	1,322,061,259	1,273,096,027	1,224,130,795	1,175,165,564	1,126,200,332	1,077,235,100	1,028,269,868	979,304,636	930,339,404	881,374,173	832,408,941	783,443,709	734,478,477
PROJECT BOOK LIFE	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
PROJECT BOOK DEPRECIATION RATE	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%
ANNUAL DEPRECIATION	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232
Capital Additions															
Remaining station life (in years)		29	28	27	26	25	24	23	22	21	20	19	18	17	16
DEPRECIATION RATE FOR ADDITION - based on station remaining life	0.000%	3.448%	3.571%	3.704%	3.846%	4.000%	4.167%	4.348%	4.545%	4.762%	5.000%	5.263%	5.556%	5.882%	6.250%
2		-	-	-	-	-	-	-	-	-	-	-	-	-	-
3			-	-	-	-	-	-	-	-	-	-	-	-	-
4				-	-	-	-	-	-	-	-	-	-	-	-
5					-	-	-	-	-	-	-	-	-	-	-
6						-	-	-	-	-	-	-	-	-	-
7							-	-	-	-	-	-	-	-	-
8								-	-	-	-	-	-	-	-
9									-	-	-	-	-	-	-
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28															
29															
30															
Total Book Depreciation for capital additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cumulative Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			-												
SUMMARY FOR PLANT:															
GROSS PLANT															
Initial Investment	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954
Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gross Plant	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954
ACCUMULATED DEPRECIATION															
Initial Investment	48,965,232	97,930,464	146,895,695	195,860,927	244,826,159	293,791,391	342,756,623	391,721,855	440,687,086	489,652,318	538,617,550	587,582,782	636,548,014	685,513,245	734,478,477
Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Accumulated Depreciation	48,965,232	97,930,464	146,895,695	195,860,927	244,826,159	293,791,391	342,756,623	391,721,855	440,687,086	489,652,318	538,617,550	587,582,782	636,548,014	685,513,245	734,478,477
NET PLANT															
Initial Investment	1,419,991,723	1,371,026,491	1,322,061,259	1,273,096,027	1,224,130,795	1,175,165,564	1,126,200,332	1,077,235,100	1,028,269,868	979,304,636	930,339,404	881,374,173	832,408,941	783,443,709	734,478,477
Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Plant	1,419,991,723	1,371,026,491	1,322,061,259	1,273,096,027	1,224,130,795	1,175,165,564	1,126,200,332	1,077,235,100	1,028,269,868	979,304,636	930,339,404	881,374,173	832,408,941	783,443,709	734,478,477
Total Depreciation Expense for the year (book)	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	TOTAL
New Project:																	
GROSS PLANT	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	
ACCUMULATED DEPRECIATION	783,443,709	832,408,941	881,374,173	930,339,404	979,304,636	1,028,269,868	1,077,235,100	1,126,200,332	1,175,165,564	1,224,130,795	1,273,096,027	1,322,061,259	1,371,026,491	1,419,991,723	1,468,956,954	1,517,922,186	
NET GROSS PLANT	685,513,245	636,548,014	587,582,782	538,617,550	489,652,318	440,687,086	391,721,855	342,756,623	293,791,391	244,826,159	195,860,927	146,895,695	97,930,464	48,965,232	-	(48,965,232)	
PROJECT BOOK LIFE	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
PROJECT BOOK DEPRECIATION RATE	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	
ANNUAL DEPRECIATION	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	
Capital Additions																	
Remaining station life (in years)	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1		
DEPRECIATION RATE FOR ADDITION - based on station remaining life	6.667%	7.143%	7.692%	8.333%	9.091%	10.000%	11.111%	12.500%	14.286%	16.667%	20.000%	25.000%	33.333%	50.000%	100.000%		
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
17		-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
18			-	-	-	-	-	-	-	-	-	-	-	-	-		-
19				-	-	-	-	-	-	-	-	-	-	-	-		-
20					-	-	-	-	-	-	-	-	-	-	-		-
21						-	-	-	-	-	-	-	-	-	-		-
22							-	-	-	-	-	-	-	-	-		-
23								-	-	-	-	-	-	-	-		-
24									-	-	-	-	-	-	-		-
25										-	-	-	-	-	-		-
26											-	-	-	-	-		-
27												-	-	-	-		-
28													-	-	-		-
29														-	-		-
30															-		-
Total Book Depreciation for capital additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Cumulative Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Net Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
SUMMARY FOR PLANT:																	
GROSS PLANT																	
Initial Investment	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954		42,599,751,677
Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Total Gross Plant	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954	1,468,956,954		42,599,751,677
ACCUMULATED DEPRECIATION																	
Initial Investment	783,443,709	832,408,941	881,374,173	930,339,404	979,304,636	1,028,269,868	1,077,235,100	1,126,200,332	1,175,165,564	1,224,130,795	1,273,096,027	1,322,061,259	1,371,026,491	1,419,991,723	1,468,956,954		22,719,867,561
Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Total Accumulated Depreciation	783,443,709	832,408,941	881,374,173	930,339,404	979,304,636	1,028,269,868	1,077,235,100	1,126,200,332	1,175,165,564	1,224,130,795	1,273,096,027	1,322,061,259	1,371,026,491	1,419,991,723	1,468,956,954		22,719,867,561
NET PLANT																	
Initial Investment	685,513,245	636,548,014	587,582,782	538,617,550	489,652,318	440,687,086	391,721,855	342,756,623	293,791,391	244,826,159	195,860,927	146,895,695	97,930,464	48,965,232	-		19,879,884,116
Capital Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Total Net Plant	685,513,245	636,548,014	587,582,782	538,617,550	489,652,318	440,687,086	391,721,855	342,756,623	293,791,391	244,826,159	195,860,927	146,895,695	97,930,464	48,965,232	-		19,879,884,116
Total Depreciation Expense for the year (book)	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232		1,419,991,723

Inputs

New Regulated Fluidized Bed Coal Plant
Revenue Requirements Analysis

	Project Costs																																
Project Costs	$1,468,956,954																																
Year		1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026	16 2027	17 2028	18 2029	19 2030	20 2031	21 2032	22 2033	23 2034	24 2035	25 2036	26 2037	27 2038	28 2039	29 2040	30 2041	31 2042
Tax Depreciation		$ 55,085,886	$ 106,044,003	$ 98,082,256	$ 90,737,471	$ 83,921,511	$ 77,634,375	$ 71,802,616	$ 66,426,233	$ 65,544,859	$ 65,530,170	$ 65,544,859	$ 65,530,170	$ 65,544,859	$ 65,530,170	$ 65,544,859	$ 65,530,170	$ 65,544,859	$ 65,530,170	$ 65,544,859	$ 65,530,170	$ 32,772,430	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Book Depr.		48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	(16,192,802)	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	48,965,232	-
Deferred Tax Difference		6,120,654	57,078,771	49,117,024	41,772,239	34,956,279	28,669,143	22,837,384	17,461,002	16,579,627	16,564,938	16,579,627	16,564,938	16,579,627	16,564,938	16,579,627	16,564,938	16,579,627	16,564,938	16,579,627	16,564,938	16,579,627	16,564,938	(16,192,802)	(48,965,232)	(48,965,232)	(48,965,232)	(48,965,232)	(48,965,232)	(48,965,232)	(48,965,232)	(48,965,232)	-
Tax Rate		39.550%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%	37.275%
Deferred Tax Expense		2,420,719	21,276,112	18,308,371	15,570,602	13,029,953	10,686,423	8,512,635	6,508,588	6,180,056	6,174,581	6,180,056	6,174,581	6,180,056	6,174,581	6,180,056	6,174,581	6,180,056	6,174,581	6,180,056	6,174,581	(6,035,867)	(18,251,790)	(18,251,790)	(18,251,790)	(18,251,790)	(18,251,790)	(18,251,790)	(18,251,790)	(18,251,790)	(18,251,790)	(18,251,790)	-
Accum. Deferred Tax Expense		2,420,719	23,696,830	42,005,201	57,575,803	70,605,756	81,292,179	89,804,814	96,313,403	102,493,459	108,668,040	114,848,096	121,022,676	127,202,732	133,377,313	139,557,369	145,731,950	151,912,006	158,086,587	164,266,643	170,441,223	164,405,356	146,153,566	127,901,776	109,649,986	91,398,196	73,146,406	54,894,615	36,642,825	18,391,035	139,245	139,245
Tax Depreciation on Plant		55,085,886	106,044,003	98,082,256	90,737,471	83,921,511	77,634,375	71,802,616	66,426,233	65,544,859	65,530,170	65,544,859	65,530,170	65,544,859	65,530,170	65,544,859	65,530,170	65,544,859	65,530,170	65,544,859	65,530,170	32,772,430	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation on Capital Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Tax depreciation		55,085,886	106,044,003	98,082,256	90,737,471	83,921,511	77,634,375	71,802,616	66,426,233	65,544,859	65,530,170	65,544,859	65,530,170	65,544,859	65,530,170	65,544,859	65,530,170	65,544,859	65,530,170	65,544,859	65,530,170	32,772,430	-	-	-	-	-	-	-	-	-	-	-
20 year MACRS		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%											
Plant balance for tax purposes, end of period		$ 1,413,871,069	$ 1,307,827,066	$ 1,209,744,810	$ 1,119,007,339	$ 1,035,085,828	$ 957,451,453	$ 885,648,837	$ 819,222,604	$ 753,677,745	$ 688,147,575	$ 622,602,716	$ 557,072,546	$ 491,527,687	$ 425,997,517	$ 360,452,657	$ 294,922,488	$ 229,377,628	$ 163,847,459	$ 98,302,599	$ 32,772,430	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
Capital Additions for Plant		0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20 year MACRS		0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%										
DEPRECIATION RATE FOR ADDITION - based on station remaining life																																	
	2			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
	3				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0									
	4					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0								
	5						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0							
	6							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0						
	7								0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
	8									0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
	9										0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
	10											0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
	11												0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	12													0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	13														0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	14															0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	15																0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	16																	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	17																		0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	18																			0	0	0	0	0	0	0	0	0	0	0	0	0	
	19																				0	0	0	0	0	0	0	0	0	0	0	0	
	20																					0	0	0	0	0	0	0	0	0	0	0	
	21																					0	0	0	0	0	0	0	0	0	0	0	
	22																						0	0	0	0	0	0	0	0	0	0	
	23																						0	0	0	0	0	0	0	0	0	0	
	24																							0	0	0	0	0	0	0	0	0	
	25																								0	0	0	0	0	0	0	0	
	26																									0	0	0	0	0	0	0	
	27																										0	0	0	0	0	0	
	28																											0	0	0	0	0	
	29																												0	0	0	0	
	30																													0	0	0	
Total Tax Depreciation for capital additions		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Capital Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Tax Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Additions for tax purposes		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Inputs

Public Service of New Hampshire
Calculation of weighted Generation cost of capital

Year	2008	2009	2010	2011	2012	2013
1) Capitalization Ratios:						
Common Equity	47.2%	48.0%	48.0%	48.0%	48.0%	48.0%
Long-term Debt	52.8%	52.0%	52.0%	52.0%	52.0%	52.0%
Total Capitalization	100.00%	100.00%	100.0%	100.0%	100.0%	100.0%
2) Cost of capitalization:						
Common Equity (net of tax)	9.81%	9.81%	9.81%	9.81%	9.81%	9.81%
Cost of Long-term debt (pre-tax)	5.96%	6.06%	6.06%	6.06%	6.06%	6.06%
Effective Tax Rate	40.525%	40.525%	40.525%	40.525%	40.525%	40.525%
Cost of Equity (pre-tax)	16.49%	16.49%	16.49%	16.49%	16.49%	16.49%
3) Weighted Cost of Capital (pre-tax)						
Cost of Equity	7.79%	7.92%	7.92%	7.92%	7.92%	7.92%
Cost of Long-term debt	3.15%	3.15%	3.15%	3.15%	3.15%	3.15%
Total	10.94%	11.07%	11.07%	11.07%	11.07%	11.07%
4) AFUDC Rates						
PSNH Transmission						
AFUDC Debt Rate %	3.25%	4.16%	4.31%	4.13%	3.95%	3.95%
AFUDC Equity Rate %	4.70%	2.82%	3.15%	3.79%	4.44%	4.44%
Total	7.95%	6.98%	7.46%	7.92%	8.39%	8.39%
PSNH Other than Transmission						
AFUDC Debt Rate %	3.67%	4.41%	4.69%	4.05%	3.78%	3.78%
AFUDC Equity Rate %	3.00%	1.76%	1.69%	2.92%	3.50%	3.50%
Total	6.67%	6.17%	6.38%	6.97%	7.28%	7.28%

2008 and 2009 Equity and Debt capitalization rates per the 2008 Budget (Mei Yang)
2008 and 2009 Cost of Long-term debt (pre-tax) per the 2008 Budget (Mei Yang).
AFUDC rates per the 2008 Budget (Mei Yang).

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Chart 1:	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Total Revenue Requirement w/fuel and revenue credits, no energy benefit	440,461,147	439,283,679	434,971,755	431,003,805	427,411,385	424,279,853	421,540,466	418,503,286	415,225,508	412,119,234	409,221,700	406,433,027	403,809,134	401,406,040	399,124,169	397,019,748	395,149,113	394,172,049	393,362,238	392,723,861	392,937,417	394,683,211	397,289,833	400,085,686	403,075,502	406,264,128	409,656,536	413,257,819	417,073,201	421,108,032
Total Market Purchases	283,537,003	290,625,428	297,891,064	305,338,340	312,971,799	320,796,094	328,815,996	337,036,396	345,462,306	354,098,864	362,951,335	372,025,119	381,325,747	390,858,890	400,630,362	410,646,122	420,912,275	431,435,081	442,220,958	453,276,482	464,608,394	476,223,604	488,129,194	500,332,424	512,840,735	525,661,753	538,803,297	552,273,380	566,080,214	580,232,219

Chart 2:	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Total Revenue Requirement w/ fuel before Revenue Credits	459,352,747	458,434,779	454,538,055	451,089,105	448,067,585	445,455,053	443,234,666	441,391,186	439,826,108	438,432,534	437,195,800	436,119,827	435,208,634	434,466,340	433,897,169	433,505,448	433,295,613	433,272,212	433,439,905	433,803,469	435,044,016	437,842,474	441,528,078	445,429,887	449,553,308	453,903,879	458,487,281	463,309,333	468,376,002	473,693,404
Forward Capacity Market Revenue	18,891,600	19,151,100	19,566,300	20,085,300	20,656,200	21,175,200	21,694,200	22,887,900	24,600,600	26,313,300	27,974,100	29,686,800	31,399,500	33,060,300	34,773,000	36,485,700	38,146,500	39,100,163	40,077,667	41,079,608	42,106,598	43,159,263	44,238,245	45,344,201	46,477,806	47,639,751	48,830,745	50,051,514	51,302,802	52,585,372
Energy Market Revenue	283,537,003	290,625,428	297,891,064	305,338,340	312,971,799	320,796,094	328,815,996	337,036,396	345,462,306	354,098,864	362,951,335	372,025,119	381,325,747	390,858,890	400,630,362	410,646,122	420,912,275	431,435,081	442,220,958	453,276,482	464,608,394	476,223,604	488,129,194	500,332,424	512,840,735	525,661,753	538,803,297	552,273,380	566,080,214	580,232,219

Fixed Costs Only	273,099,619	267,525,322	258,855,863	250,514,858	242,478,981	234,726,734	227,238,140	219,994,746	212,894,757	205,827,899	198,776,049	191,739,582	184,718,883	177,714,346	170,726,375	163,755,384	156,801,797	149,866,051	142,948,590	136,049,871	129,846,578	125,015,100	120,880,020	116,765,628	112,672,442	108,600,992	104,551,821	100,525,487	96,522,560	92,543,625
$/kW-Mo	52.62	51.55	49.88	48.27	46.72	45.23	43.78	42.39	41.02	39.66	38.30	36.94	35.59	34.24	32.90	31.55	30.21	28.88	27.54	26.21	25.02	24.09	23.29	22.50	21.71	20.93	20.14	19.37	18.60	17.83

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-01
Dated: 06/04/2012
Q-TC-002-SP01
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Witness: **Frederick White, Jody J. TenBrock, Terrance J. Large**
Request from: **TransCanada**

Question:
(Originally numbered TC-01, Q-TC-002 in the Temporary Rates portion of this docket) Please provide all fuel price forecasts available to PSNH at the time of its initial decision to construct the flue gas scrubber at Merrimack Station.

Response:
ORIGINAL RESPONSE: PSNH objects to this question as it is based upon a faulty premise. Moreover, the information requested is irrelevant to the subject of this proceeding. Notwithstanding this objection, PSNH responds as follows:

See the response to TC-01, Q-TC-001.

SUPPLEMENTAL RESPONSE: The initial round of contracts for construction of the scrubber were signed in October, 2008. The fuel price forecasts available to PSNH at that time are provided in the attached; which includes NYMEX (natural gas) and broker (coal) forward fuel price quotations from June, 2008, and fuel price forecasts (various) received from industry consultants in February, March, July, and August, 2008. In the scrubber analyses prepared by PSNH, in advance of October, 2008, the company examined a range of values for various cost items, including fuel prices, and did not rely on a singular fuel price forecast.

NYMEX Closing Prices - June 11, 2008

$/MMBtu

Year	Natural Gas at Henry Hub	Transportation Basis from Henry Hub	
		Transco Zone 6	Tetco M-3
2008 (Jul-Dec)	12.909	1.714	1.216
2009	11.718	2.178	1.393
2010	10.596	1.919	1.325
2011	10.278	1.801	1.233
2012	10.342	1.700	1.150
2013	10.548		
2014	10.767		
2015	10.992		
2016	11.223		
2017	11.459		

ICAP United, Inc - Coal

10-Jun-08

www.upicoal.com
Dan Vaughn @ 417-336-5582

www.icapenergy.com
Ian Tapsall, Manzar Iqbal @ 203-762-8493

Matt Keck @ 502-327-1417

Nymex look-alike

Delivery	Bid - Ask Range		Last	Date
Jul	107.50	108.50	*110.00*	10-Jun
Aug	107.50	108.50	*107.75*	06-Jun
Q3 08	107.50	108.50	*110.00*	10-Jun
Q4 08	109.00	110.00	*110.25*	10-Jun
Q1 09	110.25	111.25	*111.00*	06-Jun
Q2 09	110.25	111.25	*110.75*	06-Jun
Q3 09	110.50	111.50	*112.20*	09-Jun
Q4 09	110.50	111.50	*112.50*	09-Jun
Q1 10	109.75	110.75		
CY 09	110.38	111.38	*111.00*	06-Jun
CY 10	109.25	110.25	*105.50*	05-Jun
CY 11	108.25	109.25	*est*	

CSX-BSK < 1% physical market

Bid - Ask Range		Last	Date
124.50	126.50	*120.00*	04-Jun
123.50	124.50		
123.50	124.50	*124.00 est*	10-Jun
119.50	120.50	*122.00 fin*	09-Jun
116.50	117.50	*114.00 fin*	06-Jun
115.00	116.00		
114.00	115.00		
113.50	114.50	*83.75 est*	28-Feb
112.75	113.75		
114.75	115.75	*115.00 est*	10-Jun
112.50	113.50	*108.50 fin*	29-May
108.00	109.00	*est*	

PRB 8800 - physical market

Bid - Ask Range		Last	Date
11.25	12.25	*12.00*	04-Jun
11.25	12.25		
11.25	12.25	*11.75 fin*	10-Jun
13.00	14.00	*13.50 est*	10-Jun
15.60	16.10		
16.80	17.30		
17.80	18.30		
18.80	19.30		
19.15	19.65		
17.25	17.75	*17.50*	09-Jun
19.65	20.15	*20.45*	27-May
20.15	20.65	*19.75*	03-Jun

Other Markets - Most Recent Trades

Delivery	Origin	Btu	#SO2	Last	Date
Jul	CSX	12500	1.2	*118.00*	05-Jun
Aug-Sep	NS	12500	1.2	*140.00*	06-Jun
Q3Q4	NS	12500	1.6	*121.00*	22-May
CY 09	NS	12500	1.6	*102.00*	06-May
Q1 09	NAPP rc	13000	3.0	*103.00*	15-May
CY 10	NAPP rc	13000	3.0	*103.00*	21-May
May-Aug	Mon Rvr	13000	4.5 / 5.0	*97.50*	22-Apr
May-Jul	ILB bg	11500	3.5	*74.00*	15-May
CY 09	PRB xCC	8400	0.8	*13.70*	09-Jun

Additional Market Activity

Delivery	Origin	Btu	#SO2	Bid	Ask

SO2

	Bid	Ask
2008	320	330
2009	319	329
2010	177	182
2011	167	173

Seasonal NOx

Bank	600	675
2008	750	775
2009	600	675
2010	550	700

Annual NOx

2009	4500	5000
2010	2100	2600
2011	1850	2350

SO2
2008 trades 11x, 315 -330

The Daily Scoreboard

Nymex
Jun-Jul trades 110
Q3 trades 110
Q4 trades 112 (10), 111 (2x), 110.25

CSX fin / Nym
CY 09 trades 4.25

CSX 1% phys
Aug-Sep over Oct-Nov trades 4.00

PRB 8800 fin
Q4 / Q3 trades 1.75
CY 09 17.50 (10k), 17.75 (10k), 17.50 (10k)

Vaughn's View of the U.S. Coal Markets - a perspective provided by Dan Vaughn to assist in marking coals to market

PRB Coal

10-Jun-08			Prompt	PM + 1	PQ	PQ + 1	PQ + 2	PQ + 3	PQ + 4	PY	PY + 1	PY + 2
Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
BNSF / UP	8800	0.8	11.75	11.75	11.75	13.50	#REF!	#REF!	#REF!	17.50	19.90	20.40
BNSF / UP	8400	0.8	10.00	10.15	10.15	10.50	#REF!	#REF!	#REF!	13.40	15.50	16.00

CAPP Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
BS Rvr	12000	1.2	111.67	111.50	111.50	113.00	114.25	114.25	114.50	114.38	112.75	111.75
Nymex	12000	1.7	108.00	108.00	108.00	109.50	110.75	110.75	111.00	110.88	109.75	108.75
BS Rvr	11500	1.8	101.76	102.00	102.00	103.50	105.00	105.00	105.25	105.13	104.50	103.75
CSX-BSK	12500	1.2	128.35	126.75	126.75	122.75	120.00	118.50	117.50	118.25	116.00	111.50
CSX-BSK	12500	1.6	125.50	124.00	124.00	120.00	117.00	115.50	114.50	115.25	113.00	108.50
NS-T/K	12500	1.2	145.00	142.50	142.50	141.50	131.50	130.00	129.00	129.75	126.00	120.00
NS-T/K	12500	1.6	127.00	126.50	126.50	125.50	122.50	121.00	120.00	120.75	118.50	114.00

NAPP Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
MGA	13000	3.0 / 3.4	107.00	107.00	107.00	107.00	106.00	105.00	105.00	105.25	103.00	98.50
MGA	13000	4.0 / 4.5	100.25	100.50	100.50	100.50	99.50	98.50	98.50	98.75	96.50	92.00
Mon Rvr	13000	4.5 - 5.0	102.50	102.50	102.50	102.50	101.50	100.50	100.50	100.75	98.50	94.00
U. OH Rvr	12200	6.5	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.75

ILB Barge Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
L. OH Rvr	12000	2.0	84.00	84.00	84.00	84.00	83.00	83.00	83.00	83.00	83.00	83.00
L. OH Rvr	12000	5.0	74.00	74.00	74.00	74.00	73.00	73.00	73.00	73.00	73.00	73.00

Colorado Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
UP	11800	1.0	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00
UP	11300	1.0	63.00	63.00	63.00	63.00	63.00	63.00	63.00	63.00	63.00	63.00

International API Markets ($/tonne)

Origin	kCal	# SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
API 2	6000	1.7	176.00	176.00	176.00	176.00	174.00	170.25	166.25	169.00	166.00	163.25
API 4	6000	1.7	137.00	138.25	139.00	140.00	140.50	140.50	140.50	140.50	140.50	141.75

PETROLEUM PRODUCT PRICES FORECAST

No. 2 Fuel Oil (0.2% Sulfur)

$/MMBtu (Connecticut)

	Current $				Percent Change			
Year	Residential	Commercial	Industrial	Electric	Residential	Commercial	Industrial	Electric
1970	$1.48	$1.09	$0.73	$0.37				
1971	$1.56	$1.16	$0.77	$0.54	5.4%	6.4%	5.5%	45.9%
1972	$1.56	$1.16	$0.77	$0.91	0.0%	0.0%	0.0%	68.5%
1973	$1.77	$1.38	$0.99	$1.29	13.5%	19.0%	28.6%	41.8%
1974	$2.88	$2.46	$2.24	$2.28	62.7%	78.3%	126.3%	76.7%
1975	$2.84	$2.44	$2.41	$2.36	-1.4%	-0.8%	7.6%	3.5%
1976	$3.04	$2.62	$2.52	$2.40	7.0%	7.4%	4.6%	1.7%
1977	$3.40	$2.96	$2.78	$2.38	11.8%	13.0%	10.3%	-0.8%
1978	$3.61	$3.12	$2.88	$2.00	6.2%	5.4%	3.6%	-16.0%
1979	$5.19	$4.59	$4.01	$3.64	43.8%	47.1%	39.2%	82.0%
1980	$7.07	$6.37	$5.75	$6.13	36.2%	38.8%	43.4%	68.4%
1981	$8.77	$8.04	$6.93	$7.78	24.0%	26.2%	20.5%	26.9%
1982	$8.53	$7.80	$7.74	$7.31	-2.7%	-3.0%	11.7%	-6.0%
1983	$8.46	$7.46	$7.42	$6.28	-0.8%	-4.4%	-4.1%	-14.1%
1984	$8.69	$7.41	$6.95	$6.21	2.7%	-0.7%	-6.3%	-1.1%
1985	$8.37	$7.07	$6.75	$5.88	-3.7%	-4.6%	-2.9%	-5.3%
1986	$6.90	$4.97	$4.43	$3.59	-17.6%	-29.7%	-34.4%	-38.9%
1987	$6.46	$4.88	$4.88	$4.01	-6.4%	-1.8%	10.2%	11.7%
1988	$6.61	$4.65	$4.67	$3.64	2.3%	-4.7%	-4.3%	-9.2%
1989	$7.23	$5.51	$5.54	$4.26	9.4%	18.5%	18.6%	17.0%
1990	$8.55	$6.80	$6.77	$5.67	18.3%	23.4%	22.2%	33.1%
1991	$8.27	$6.09	$5.93	$4.92	-3.3%	-10.4%	-12.4%	-13.2%
1992	$7.24	$5.45	$5.11	$4.82	-12.5%	-10.5%	-13.8%	-2.0%
1993	$7.02	$5.22	$5.06	$4.12	-3.0%	-4.2%	-1.0%	-14.5%
1994	$6.80	$5.01	$4.78	$3.82	-3.1%	-4.0%	-5.5%	-7.3%
1995	$6.60	$4.94	$4.77	$3.82	-2.9%	-1.4%	-0.2%	0.0%
1996	$7.54	$5.77	$5.91	$4.76	14.2%	16.8%	23.9%	24.6%
1997	$7.36	$5.54	$5.49	$4.88	-2.4%	-4.0%	-7.1%	2.5%
1998	$6.35	$4.48	$4.52	$3.28	-13.7%	-19.1%	-17.7%	-32.8%
1999	$6.51	$4.86	$4.86	$4.03	2.5%	8.5%	7.5%	22.9%
2000	$9.87	$7.73	$7.71	$6.81	51.6%	59.1%	58.6%	69.0%
2001	$9.47	$7.32	$6.69	$5.79	-4.1%	-5.3%	-13.2%	-15.0%
2002	$8.54	$6.87	$6.31	$5.29	-9.8%	-6.1%	-5.7%	-8.6%
2003	$10.36	$8.12	$7.58	$6.85	21.3%	18.2%	20.1%	29.5%
2004	$11.60	$9.87	$9.58	$6.43	12.0%	21.6%	26.4%	-6.1%
2005	$15.80	$13.64	$13.25	$12.29	36.2%	38.2%	38.3%	91.2%
2006	$17.20	$14.99	$14.60	$13.62	8.9%	10.0%	10.2%	10.8%
2007	$18.93	$16.68	$16.28	$15.28	10.0%	11.2%	11.5%	12.2%
2008	$22.22	$19.93	$19.53	$18.51	17.4%	19.5%	20.0%	21.2%
2009	$21.66	$19.34	$18.93	$17.90	-2.5%	-3.0%	-3.1%	-3.3%
2010	$21.50	$19.14	$18.72	$17.68	-0.8%	-1.0%	-1.1%	-1.2%
2011	$21.77	$19.38	$18.96	$17.90	1.3%	1.3%	1.3%	1.2%
2012	$22.37	$19.95	$19.52	$18.45	2.8%	2.9%	3.0%	3.1%
2013	$22.98	$20.53	$20.09	$19.00	2.7%	2.9%	2.9%	3.0%
2014	$23.60	$21.12	$20.68	$19.57	2.7%	2.9%	2.9%	3.0%
2015	$24.24	$21.73	$21.28	$20.16	2.7%	2.9%	2.9%	3.0%
2016	$24.89	$22.34	$21.89	$20.75	2.7%	2.8%	2.9%	2.9%
2017	$25.82	$23.24	$22.78	$21.63	3.7%	4.0%	4.1%	4.2%
2018	$26.79	$24.17	$23.71	$22.54	3.8%	4.0%	4.1%	4.2%

Note: 1989-1998 data was updated using the latest figures from the Master Oil and Gas Database
Basis differences for 1989-1995 were taken from actual data

PETROLEUM PRODUCT PRICES FORECAST

Residual Fuel Oil (1.0% Sulfur) - Annual

$/MMBtu (Connecticut)

	Current $			Percent Change		
Year	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1970	$0.42	$0.43	$0.38			
1971	$0.59	$0.61	$0.54	40.5%	41.9%	42.1%
1972	$0.70	$0.66	$0.65	18.6%	8.2%	20.4%
1973	$0.83	$0.79	$0.85	18.6%	19.7%	30.8%
1974	$2.00	$2.02	$2.06	141.0%	155.7%	142.4%
1975	$1.97	$2.12	$2.02	-1.5%	5.0%	-1.9%
1976	$1.87	$2.08	$1.94	-5.1%	-1.9%	-4.0%
1977	$2.22	$2.31	$2.24	18.7%	11.1%	15.5%
1978	$2.11	$2.34	$2.13	-5.0%	1.3%	-4.9%
1979	$3.35	$3.41	$3.32	58.8%	45.7%	55.9%
1980	$4.59	$4.55	$4.70	37.0%	33.4%	41.6%
1981	$5.49	$5.74	$5.56	19.6%	26.2%	18.3%
1982	$4.67	$4.88	$4.75	-14.9%	-15.0%	-14.6%
1983	$4.51	$4.67	$4.54	-3.4%	-4.3%	-4.4%
1984	$5.25	$5.25	$4.84	16.4%	12.4%	6.6%
1985	$4.68	$4.68	$4.24	-10.9%	-10.9%	-12.4%
1986	$2.79	$2.79	$2.51	-40.4%	-40.4%	-40.8%
1987	$3.12	$3.12	$2.93	11.8%	11.8%	16.7%
1988	$2.57	$2.57	$2.40	-17.6%	-17.6%	-18.1%
1989	$3.04	$3.04	$2.85	18.3%	18.3%	18.8%
1990	$3.25	$3.25	$3.01	6.9%	6.9%	5.6%
1991	$2.69	$2.69	$2.47	-17.2%	-17.2%	-17.9%
1992	$2.53	$2.53	$2.40	-5.9%	-5.9%	-2.8%
1993	$2.66	$2.66	$2.39	5.1%	5.1%	-0.4%
1994	$3.16	$3.16	$2.52	18.8%	18.8%	5.4%
1995	$3.38	$3.38	$2.63	7.0%	7.0%	4.4%
1996	$3.90	$3.90	$3.21	15.4%	15.4%	22.1%
1997	$3.15	$3.15	$2.92	-19.2%	-19.2%	-9.0%
1998	$2.46	$2.46	$2.18	-21.9%	-21.9%	-25.3%
1999	$2.55	$2.55	$2.23	3.7%	3.7%	2.3%
2000	$4.36	$4.36	$3.27	71.0%	71.0%	--
2001	$4.04	$4.04	$3.37	-7.3%	-7.3%	--
2002	$4.67	$4.67	$3.67	15.6%	15.6%	8.9%
2003	$5.40	$5.40	$3.74	15.6%	15.6%	1.9%
2004	$5.64	$5.64	$3.96	4.4%	4.4%	5.9%
2005	$7.42	$7.42	$6.62	31.5%	31.5%	67.3%
2006	$8.31	$8.31	$7.50	12.1%	12.1%	13.2%
2007	$9.47	$9.47	$8.64	13.9%	13.9%	15.2%
2008	$11.41	$11.41	$10.57	20.5%	20.5%	22.3%
2009	$10.94	$10.94	$10.09	-4.1%	-4.1%	-4.5%
2010	$10.71	$10.71	$9.85	-2.1%	-2.1%	-2.4%
2011	$11.26	$11.26	$10.38	5.1%	5.1%	5.4%
2012	$11.59	$11.59	$10.70	3.0%	3.0%	3.1%
2013	$11.93	$11.93	$11.03	2.9%	2.9%	3.1%
2014	$12.28	$12.28	$11.37	2.9%	2.9%	3.0%
2015	$12.63	$12.63	$11.71	2.9%	2.9%	3.0%
2016	$12.99	$12.99	$12.06	2.9%	2.9%	3.0%
2017	$13.52	$13.52	$12.58	4.1%	4.1%	4.3%
2018	$14.08	$14.08	$13.12	4.1%	4.1%	4.3%

PETROLEUM PRODUCT PRICES FORECAST

Residual Fuel Oil (1.0% Sulfur) - Annual

$/MMBtu (Connecticut)

	Current $			Percent Change		
Year	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1993	$2.66	$2.66	$2.39			
1994	$3.16	$3.16	$2.52	18.8%	18.8%	5.4%
1995	$3.38	$3.38	$2.63	7.0%	7.0%	4.4%
1996	$3.90	$3.90	$3.24	15.4%	15.4%	23.2%
1997	$3.15	$3.15	$2.92	-19.2%	-19.2%	-9.9%
1998	$2.46	$2.46	$2.18	-21.9%	-21.9%	-25.3%
1999	$2.55	$2.55	$2.23	3.7%	3.7%	2.3%
2000	$4.36	$4.36	$3.27	71.0%	71.0%	--
2001	$4.04	$4.04	$3.37	-7.3%	-7.3%	--
2002	$4.67	$4.67	$3.67	15.6%	15.6%	8.9%
2003	$5.40	$5.40	$3.74	15.6%	15.6%	1.9%
2004	$5.64	$5.64	$3.96	4.4%	4.4%	5.9%
2005	$7.42	$7.42	$6.62	31.5%	31.5%	67.3%
2006	$8.31	$8.31	$7.50	12.1%	12.1%	13.2%
2007	$9.47	$9.47	$8.64	13.9%	13.9%	15.2%
2008	$11.41	$11.41	$10.57	20.5%	20.5%	22.3%
2009	$10.94	$10.94	$10.09	-4.1%	-4.1%	-4.5%
2010	$10.71	$10.71	$9.85	-2.1%	-2.1%	-2.4%
2011	$11.26	$11.26	$10.38	5.1%	5.1%	5.4%
2012	$11.59	$11.59	$10.70	3.0%	3.0%	3.1%
2013	$11.93	$11.93	$11.03	2.9%	2.9%	3.1%
2014	$12.28	$12.28	$11.37	2.9%	2.9%	3.0%
2015	$12.63	$12.63	$11.71	2.9%	2.9%	3.0%
2016	$12.99	$12.99	$12.06	2.9%	2.9%	3.0%
2017	$13.52	$13.52	$12.58	4.1%	4.1%	4.3%
2018	$14.08	$14.08	$13.12	4.1%	4.1%	4.3%

PETROLEUM PRODUCT PRICES FORECAST

Residual Fuel Oil (1.0% Sulfur) - Summer

$/MMBtu (Connecticut)

	Current $			Percent Change		
Year	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1993	$2.74	$2.74	$2.47			
1994	$3.12	$3.12	$2.48	14.0%	14.0%	0.5%
1995	$3.35	$3.35	$2.60	7.5%	7.5%	5.0%
1996	$3.78	$3.78	$3.12	12.8%	12.8%	20.0%
1997	$3.06	$3.06	$2.83	-19.1%	-19.1%	-9.4%
1998	$2.53	$2.53	$2.25	-17.5%	-17.5%	-20.7%
1999	$2.72	$2.72	$2.40	7.7%	7.7%	6.8%
2000	$4.47	$4.47	--	64.6%	64.6%	--
2001	$4.01	$4.01	$3.34	-10.4%	-10.4%	--
2002	$4.93	$4.93	$3.93	23.0%	23.0%	17.7%
2003	$5.11	$5.11	$3.45	3.6%	3.6%	-12.3%
2004	$5.74	$5.74	$4.06	12.4%	12.4%	17.7%
2005	$7.76	$7.76	$6.97	35.2%	35.2%	71.6%
2006	$8.43	$8.43	$7.62	8.6%	8.6%	9.3%
2007	$10.60	$10.60	$9.77	25.7%	25.7%	28.2%
2008	$10.95	$10.95	$10.11	3.3%	3.3%	3.5%
2009	$10.60	$10.60	$9.75	-3.2%	-3.2%	-3.6%
2010	$10.50	$10.50	$9.64	-1.0%	-1.0%	-1.2%
2011	$11.03	$11.03	$10.16	5.1%	5.1%	5.4%
2012	$11.71	$11.71	$10.82	6.2%	6.2%	6.6%
2013	$12.05	$12.05	$11.15	2.9%	2.9%	3.0%
2014	$12.40	$12.40	$11.49	2.9%	2.9%	3.0%
2015	$12.75	$12.75	$11.83	2.9%	2.9%	3.0%
2016	$13.12	$13.12	$12.18	2.8%	2.8%	2.9%
2017	$13.64	$13.64	$12.70	4.0%	4.0%	4.2%
2018	$14.20	$14.20	$13.24	4.0%	4.0%	4.2%

PETROLEUM PRODUCT PRICES FORECAST

Residual Fuel Oil (1.0% Sulfur) - Winter

$/MMBtu (Connecticut)

	Current $			Percent Change		
Year	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1993	$2.55	$2.55	$2.28			
1994	$3.22	$3.22	$2.58	26.0%	26.0%	12.9%
1995	$3.42	$3.42	$2.67	6.2%	6.2%	3.5%
1996	$4.06	$4.06	$3.40	18.9%	18.9%	27.6%
1997	$3.27	$3.27	$3.04	-19.4%	-19.4%	-10.5%
1998	$2.37	$2.37	$2.09	-27.7%	-27.7%	-31.4%
1999	$2.31	$2.31	$1.99	-2.3%	-2.3%	-4.5%
2000	$4.20	$4.20	--	81.5%	81.5%	--
2001	$4.08	$4.08	$3.41	-2.8%	-2.8%	--
2002	$4.30	$4.30	$3.30	5.4%	5.4%	-3.2%
2003	$5.80	$5.80	$4.14	34.9%	34.9%	25.5%
2004	$5.50	$5.50	$3.82	-5.3%	-5.3%	-7.9%
2005	$6.91	$6.91	$6.12	25.8%	25.8%	60.4%
2006	$8.14	$8.14	$7.33	17.8%	17.8%	19.8%
2007	$10.67	$10.67	$9.84	31.0%	31.0%	34.2%
2008	$12.05	$12.05	$11.22	13.0%	13.0%	13.9%
2009	$11.42	$11.42	$10.57	-5.3%	-5.3%	-5.8%
2010	$11.01	$11.01	$10.15	-3.6%	-3.6%	-4.0%
2011	$11.57	$11.57	$10.70	5.1%	5.1%	5.4%
2012	$11.42	$11.42	$10.54	-1.3%	-1.3%	-1.5%
2013	$11.76	$11.76	$10.86	3.0%	3.0%	3.1%
2014	$12.11	$12.11	$11.20	2.9%	2.9%	3.1%
2015	$12.46	$12.46	$11.54	2.9%	2.9%	3.1%
2016	$12.83	$12.83	$11.89	2.9%	2.9%	3.0%
2017	$13.36	$13.36	$12.41	4.1%	4.1%	4.3%
2018	$13.91	$13.91	$12.95	4.1%	4.1%	4.3%

DELIVERED NATURAL GAS PRICES FORECAST

$/MMBtu (Connecticut)

	Current $				Percent Change			
Year	Residential	Commercial	Industrial	Electric	Residential	Commercial	Industrial	Electric
1970	$1.88	$1.45	$1.03	$0.34				
1971	$2.04	$1.53	$1.14	$0.38	8.5%	5.5%	10.7%	11.8%
1972	$2.06	$1.59	$1.15	$0.43	1.0%	3.9%	0.9%	13.2%
1973	$2.21	$1.79	$1.24	$0.53	7.3%	12.6%	7.8%	23.3%
1974	$2.76	$2.20	$1.71	$0.63	24.9%	22.9%	37.9%	18.9%
1975	$3.28	$2.64	$2.24	$1.36	18.8%	20.0%	31.0%	115.9%
1976	$3.38	$3.20	$2.65	$1.65	3.0%	21.2%	18.3%	21.3%
1977	$4.30	$3.53	$2.94		27.2%	10.3%	10.9%	
1978	$4.42	$3.72	$3.04		2.8%	5.4%	3.4%	
1979	$4.69	$3.90	$3.25		6.1%	4.8%	6.9%	
1980	$5.72	$4.67	$4.08		22.0%	19.7%	25.5%	
1981	$6.68	$5.46	$4.97		16.8%	16.9%	21.8%	
1982	$8.29	$6.78	$5.86		24.1%	24.2%	17.9%	
1983	$9.43	$7.24	$5.76		13.8%	6.8%	-1.7%	
1984	$8.56	$6.49	$5.47	$3.71	-9.2%	-10.4%	-5.0%	
1985	$8.88	$6.59	$5.38	$3.39	3.7%	1.5%	-1.6%	-8.6%
1986	$8.57	$6.24	$4.53	$2.09	-3.5%	-5.3%	-15.8%	-38.3%
1987	$7.96	$5.59	$4.08	$2.37	-7.1%	-10.4%	-9.9%	13.4%
1988	$7.63	$5.45	$3.92	$2.17	-4.1%	-2.5%	-3.9%	-8.4%
1989	$7.98	$5.88	$4.36	$2.51	4.6%	7.9%	11.2%	15.7%
1990	$8.58	$6.30	$4.80	$2.81	7.5%	7.1%	10.2%	12.0%
1991	$8.74	$6.90	$4.84	$2.16	2.0%	9.6%	0.6%	-23.1%
1992	$8.96	$7.20	$4.92	$2.74	2.5%	4.3%	1.7%	26.9%
1993	$9.16	$6.81	$4.63	$3.79	2.2%	-5.4%	-5.8%	38.2%
1994	$9.84	$7.18	$4.36	$1.93	7.5%	5.3%	-5.9%	-49.0%
1995	$9.70	$7.34	$4.26	$1.95	-1.4%	2.3%	-2.3%	1.0%
1996	$9.79	$7.19	$4.66	$2.68	0.8%	-2.1%	9.4%	37.3%
1997	$10.03	$7.02	$4.59	$2.40	2.5%	-2.4%	-1.4%	-10.5%
1998	$10.29	$6.69	$4.21	$2.37	2.6%	-4.7%	-8.2%	-1.2%
1999	$10.23	$6.34	$4.03	$2.66	-0.6%	-5.2%	-4.4%	12.3%
2000	$11.10	$6.43	$5.78	$3.97	8.4%	1.4%	43.4%	49.4%
2001	$11.84	$7.46	$6.57	$3.09	6.7%	16.0%	13.8%	-22.2%
2002	$10.83	$6.97	$4.83	$3.51	-8.6%	-6.5%	-26.6%	13.4%
2003	$12.40	$10.17	$7.30	$6.20	14.5%	45.8%	51.3%	76.6%
2004	$13.65	$10.98	$9.05	$6.70	10.1%	8.0%	23.9%	8.1%
2005	$15.79	$12.70	$11.36	$9.61	15.6%	15.6%	25.5%	43.5%
2006	$17.10	$13.20	$10.56	$7.30	8.3%	4.0%	-7.0%	-24.0%
2007	$15.20	$11.92	$9.31	$7.77	-11.1%	-9.7%	-11.8%	6.4%
2008	$15.55	$12.23	$9.58	$8.02	2.3%	2.6%	2.9%	3.2%
2009	$15.34	$11.96	$9.28	$7.69	-1.4%	-2.2%	-3.2%	-4.1%
2010	$15.47	$12.05	$9.32	$7.72	0.9%	0.7%	0.5%	0.3%
2011	$15.81	$12.34	$9.58	$7.95	2.2%	2.4%	2.7%	3.0%
2012	$16.43	$12.91	$10.11	$8.46	3.9%	4.6%	5.5%	6.4%
2013	$16.96	$13.39	$10.56	$8.88	3.3%	3.8%	4.4%	5.0%
2014	$17.33	$13.71	$10.84	$9.14	2.2%	2.4%	2.7%	2.9%
2015	$17.71	$14.04	$11.13	$9.41	2.2%	2.4%	2.7%	2.9%
2016	$18.09	$14.38	$11.43	$9.68	2.2%	2.4%	2.7%	2.9%
2017	$18.48	$14.72	$11.73	$9.96	2.1%	2.4%	2.6%	2.9%
2018	$18.88	$15.07	$12.04	$10.25	2.2%	2.4%	2.6%	2.9%

Note: Beginning in 2000, delivered natural gas prices for the electric sector are estimated.

DELIVERED PROPANE PRICES FORECAST

Cents/Gallon (Selkirk)

Winter

Year	Current $	Percent Change
1989	--	
1990	--	
1991	45.3	
1992	39.1	-13.8%
1993	40.2	3.0%
1994	40.8	1.3%
1995	42.6	4.4%
1996	59.8	40.4%
1997	51.8	-13.3%
1998	37.1	-28.4%
1999	40.7	9.6%
2000	72.3	77.8%
2001	61.7	-14.7%
2002	50.3	-18.4%
2003	74.3	47.6%
2004	84.5	13.7%
2005	99.4	17.7%
2006	104.9	5.5%
2007	137.8	31.3%
2008	178.8	29.8%
2009	169.6	-5.1%
2010	152.0	-10.4%
2011	154.5	1.6%
2012	160.6	4.0%
2013	167.0	3.9%
2014	173.4	3.9%
2015	180.0	3.8%
2016	186.7	3.7%
2017	196.7	5.3%
2018	207.1	5.3%

Annual

Year	Current $	Percent Change
1989	--	
1990	--	
1991	42.6	
1992	40.9	-4.1%
1993	40.8	-0.1%
1994	40.6	-0.6%
1995	41.9	3.3%
1996	56.9	35.7%
1997	48.9	-14.0%
1998	36.5	-25.3%
1999	44.2	21.0%
2000	69.1	56.3%
2001	62.3	-9.9%
2002	52.3	-15.9%
2003	74.0	41.3%
2004	95.7	29.4%
2005	100.5	5.0%
2006	109.8	9.3%
2007	137.5	25.2%
2008	176.3	28.3%
2009	168.0	-4.7%
2010	155.9	-7.1%
2011	158.4	1.6%
2012	164.8	4.0%
2013	171.3	3.9%
2014	178.0	3.9%
2015	184.8	3.8%
2016	191.7	3.7%
2017	202.0	5.4%
2018	212.7	5.3%

Summer

Year	Current $	Percent Change
1989	--	
1990	--	
1991	40.7	
1992	42.1	3.6%
1993	41.3	-2.1%
1994	40.5	-1.9%
1995	41.5	2.6%
1996	54.9	32.2%
1997	46.9	-14.6%
1998	36.1	-22.9%
1999	46.7	29.3%
2000	66.7	43.0%
2001	55.0	-17.6%
2002	52.5	-4.5%
2003	64.4	22.6%
2004	85.8	33.2%
2005	101.3	18.0%
2006	113.3	11.9%
2007	137.2	21.1%
2008	174.5	27.1%
2009	166.8	-4.4%
2010	158.8	-4.8%
2011	161.3	1.6%
2012	167.8	4.0%
2013	174.5	4.0%
2014	181.2	3.9%
2015	188.2	3.8%
2016	195.3	3.8%
2017	205.8	5.4%
2018	216.7	5.3%

HENRY HUB NATURAL GAS PRICE FORECAST

$/MMBtu

	Current $			Percent Change		
Year	Annual	Summer	Winter	Annual	Summer	Winter
1989	$1.70	$1.61	$1.82			
1990	$1.70	$1.48	$2.01	0.1%	-8.1%	10.2%
1991	$1.49	$1.39	$1.62	-12.5%	-5.7%	-19.4%
1992	$1.77	$1.87	$1.63	19.2%	34.4%	0.9%
1993	$2.12	$2.16	$2.07	19.7%	15.4%	26.7%
1994	$1.92	$1.78	$2.11	-9.5%	-17.4%	2.0%
1995	$1.69	$1.61	$1.79	-12.2%	-9.7%	-15.1%
1996	$2.76	$2.31	$3.39	63.4%	43.3%	88.7%
1997	$2.53	$2.40	$2.70	-8.4%	4.0%	-20.3%
1998	$2.08	$2.11	$2.05	-17.5%	-12.1%	-24.1%
1999	$2.27	$2.41	$2.06	8.7%	14.3%	0.7%
2000	$4.23	$4.19	$4.28	86.6%	73.9%	107.2%
2001	$4.07	$3.44	$4.96	-3.7%	-18.0%	15.9%
2002	$3.33	$3.40	$3.23	-18.2%	-1.0%	-34.9%
2003	$5.63	$5.17	$6.26	68.9%	51.9%	94.0%
2004	$5.84	$5.83	$5.86	3.9%	12.8%	-6.4%
2005	$8.81	$8.97	$8.59	50.8%	53.7%	46.6%
2006	$6.76	$6.21	$7.54	-23.3%	-30.8%	-12.3%
2007	$6.95	$6.82	$7.12	2.7%	9.9%	-5.5%
2008	$7.17	$6.92	$7.52	3.2%	1.5%	5.5%
2009	$6.83	$6.74	$6.95	-4.8%	-2.6%	-7.6%
2010	$6.84	$6.38	$7.48	0.1%	-5.4%	7.6%
2011	$7.06	$6.59	$7.72	3.2%	3.2%	3.2%
2012	$7.55	$7.05	$8.26	7.0%	7.0%	7.0%
2013	$7.97	$7.44	$8.71	5.5%	5.5%	5.5%
2014	$8.21	$7.67	$8.98	3.1%	3.1%	3.1%
2015	$8.47	$7.90	$9.26	3.1%	3.1%	3.1%
2016	$8.73	$8.15	$9.55	3.1%	3.1%	3.1%
2017	$9.00	$8.40	$9.84	3.1%	3.1%	3.1%
2018	$9.27	$8.65	$10.14	3.1%	3.1%	3.1%

TX-LA ONSHORE WELLHEAD NATURAL GAS PRICE FORECAST

$/MMBtu

	Current $			Percent Change		
Year	Annual	Summer	Winter	Annual	Summer	Winter
1989	$1.63	$1.55	$1.76			
1990	$1.61	$1.42	$1.87	-1.6%	-8.1%	6.5%
1991	$1.39	$1.30	$1.52	-13.3%	-8.2%	-18.8%
1992	$1.65	$1.74	$1.52	18.4%	33.9%	-0.2%
1993	$2.00	$2.04	$1.94	21.2%	17.1%	27.9%
1994	$1.78	$1.68	$1.93	-11.0%	-17.9%	-0.7%
1995	$1.55	$1.49	$1.65	-12.7%	-11.4%	-14.3%
1996	$2.45	$2.13	$2.90	57.6%	43.1%	75.8%
1997	$2.39	$2.27	$2.56	-2.4%	6.9%	-11.9%
1998	$1.98	$2.01	$1.94	-17.0%	-11.4%	-24.0%
1999	$2.15	$2.30	$1.94	8.3%	14.1%	0.0%
2000	$4.09	$4.05	$4.13	90.1%	76.5%	112.8%
2001	$3.93	$3.32	$4.78	-3.8%	-18.0%	15.6%
2002	$3.21	$3.28	$3.10	-18.4%	-1.1%	-35.2%
2003	$5.39	$5.00	$5.92	68.0%	52.4%	91.2%
2004	$5.72	$5.66	$5.80	6.1%	13.1%	-2.1%
2005	$8.25	$8.56	$7.82	44.4%	51.3%	34.9%
2006	$6.48	$6.05	$7.10	-21.4%	-29.4%	-9.2%
2007	$6.69	$6.63	$6.78	3.2%	9.6%	-4.5%
2008	$6.90	$6.65	$7.25	3.2%	0.4%	7.0%
2009	$6.56	$6.47	$6.68	-4.9%	-2.7%	-7.8%
2010	$6.57	$6.11	$7.21	0.1%	-5.6%	7.9%
2011	$6.79	$6.32	$7.45	3.4%	3.4%	3.4%
2012	$7.28	$6.78	$7.99	7.3%	7.3%	7.3%
2013	$7.82	$7.68	$8.11	7.4%	13.3%	1.5%
2014	$8.07	$7.93	$8.36	3.1%	3.2%	3.1%
2015	$8.32	$8.18	$8.61	3.1%	3.2%	3.1%
2016	$8.58	$8.44	$8.88	3.1%	3.1%	3.0%
2017	$8.84	$8.70	$9.14	3.1%	3.1%	3.0%
2018	$9.12	$8.97	$9.42	3.1%	3.1%	3.0%

LA GULF COAST ONSHORE GAS PRICE FORECAST

$/MMBtu

	Current $			Percent Change		
Year	Annual	Summer	Winter	Annual	Summer	Winter
1989	$1.69	$1.60	$1.81			
1990	$1.69	$1.48	$1.98	0.0%	-7.5%	9.4%
1991	$1.48	$1.37	$1.62	-12.4%	-7.1%	-17.9%
1992	$1.74	$1.86	$1.57	17.8%	35.8%	-3.6%
1993	$2.10	$2.16	$2.02	20.8%	15.9%	29.0%
1994	$1.89	$1.77	$2.06	-10.2%	-18.2%	1.8%
1995	$1.60	$1.54	$1.69	-15.1%	-13.0%	-17.6%
1996	$2.62	$2.18	$3.25	63.7%	41.5%	91.9%
1997	$2.45	$2.31	$2.65	-6.6%	6.2%	-18.6%
1998	$2.04	$2.05	$2.02	-16.8%	-11.1%	-23.7%
1999	$2.21	$2.34	$2.02	8.3%	14.1%	0.0%
2000	$4.16	$4.12	$4.22	88.6%	75.8%	109.3%
2001	$3.98	$3.37	$4.85	-4.3%	-18.3%	14.8%
2002	$3.26	$3.33	$3.16	-18.2%	-1.2%	-34.8%
2003	$5.39	$5.04	$5.88	65.5%	51.5%	86.0%
2004	$5.69	$5.56	$5.86	5.5%	10.4%	-0.4%
2005	$8.63	$8.92	$8.23	51.8%	60.3%	40.4%
2006	$6.72	$6.26	$7.35	-22.2%	-29.8%	-10.7%
2007	$6.94	$6.79	$7.16	3.4%	8.4%	-2.6%
2008	$7.12	$6.87	$7.47	2.5%	1.2%	4.3%
2009	$6.78	$6.69	$6.90	-4.8%	-2.6%	-7.6%
2010	$6.79	$6.33	$7.43	0.1%	-5.4%	7.6%
2011	$7.01	$6.54	$7.67	3.3%	3.3%	3.3%
2012	$7.50	$7.00	$8.21	7.1%	7.1%	7.1%
2013	$7.84	$7.76	$7.83	4.5%	10.8%	-4.6%
2014	$8.09	$8.00	$8.08	3.1%	3.1%	3.1%
2015	$8.34	$8.25	$8.33	3.1%	3.2%	3.1%
2016	$8.60	$8.51	$8.59	3.1%	3.1%	3.1%
2017	$8.87	$8.77	$8.86	3.1%	3.1%	3.1%
2018	$9.14	$9.05	$9.13	3.1%	3.1%	3.1%

Boston City Gate Natural Gas Price
$/MMBtu

	Current $			Percent Change		
Year	Annual	Summer	Winter	Annual	Summer	Winter
1992	$2.28	$2.30	$2.26			
1993	$2.57	$2.53	$2.64	12.8%	10.1%	16.6%
1994	$2.44	$2.10	$2.92	-5.3%	-17.2%	10.7%
1995	$2.25	$1.89	$2.76	-7.5%	-9.8%	-5.3%
1996	$3.60	$2.60	$4.99	59.6%	37.5%	80.8%
1997	$2.94	$2.72	$3.25	-18.4%	4.4%	-35.0%
1998	$2.42	$2.37	$2.48	-17.7%	-12.7%	-23.6%
1999	$2.57	$2.64	$2.48	6.3%	11.2%	-0.2%
2000	$5.18	$4.50	$6.13	101.6%	70.7%	147.7%
2001	$4.42	$3.78	$5.32	-14.6%	-16.0%	-13.2%
2002	$3.52	$3.52	$3.52	-20.4%	-6.8%	-33.8%
2003	$6.35	$5.41	$7.01	80.2%	53.6%	98.9%
2004	$7.29	$6.35	$8.60	14.8%	17.4%	22.7%
2005	$9.85	$9.13	$10.87	35.3%	43.7%	26.5%
2006	$8.23	$6.88	$10.11	-16.5%	-24.6%	-7.0%
2007	$7.88	$7.43	$8.52	-4.2%	7.9%	-15.8%
2008	$8.37	$7.56	$9.50	6.2%	1.8%	11.5%
2009	$8.81	$8.72	$8.93	5.3%	15.4%	-6.0%
2010	$8.82	$8.36	$9.46	0.1%	-4.1%	5.9%
2011	$9.04	$8.57	$9.70	2.5%	2.5%	2.6%
2012	$9.53	$9.03	$10.24	5.5%	5.4%	5.6%
2013	$8.97	$8.07	$10.69	-5.9%	-10.6%	4.4%
2014	$9.24	$8.30	$10.96	2.9%	2.9%	2.5%
2015	$9.50	$8.54	$11.24	2.9%	2.9%	2.5%
2016	$9.78	$8.79	$11.53	2.9%	2.8%	2.5%
2017	$10.06	$9.04	$11.82	2.9%	2.8%	2.5%
2018	$10.35	$9.29	$12.12	2.9%	2.8%	2.5%

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia																				
-1.6%, 13000 BTU	$25.59	$26.41	$24.85	$24.45	$26.34	$26.04	$24.94	$23.65	$24.09	$40.52	$30.37	$31.04	$50.27	$54.42	$45.82	$46.61	$78.98	$50.48	$41.14	$37.42
-1.8%, 13000 BTU	$25.06	$25.55	$23.49	$22.21	$22.51	$22.89	$23.59	$22.12	$23.07	$39.46	$29.38	$29.83	$48.89	$52.23	$43.41	$45.85	$77.43	$49.13	$40.29	$36.70
-2.3%, 13000 BTU	$22.40	$21.72	$21.48	$20.71	$21.26	$21.79	$22.54	$20.65	$22.05	$35.99	$27.51	$28.67	$47.91	$48.94	$39.80	$44.71	$75.10	$47.10	$39.00	$35.63
Central Appalachia																				
-.7%, 12500 BTU	$24.31	$26.02	$26.75	$24.86	$26.01	$25.45	$25.97	$24.50	$24.90	$47.09	$29.20	$34.27	$58.62	$61.97	$55.91	$46.46	$80.25	$57.87	$54.38	$54.87
-.7%, 13000 BTU	$26.08	$27.58	$28.31	$26.60	$25.80	$25.25	$25.77	$25.15	$26.42	$50.06	$31.07	$36.49	$62.42	$66.01	$59.56	$49.50	$85.52	$61.68	$57.99	$58.62
-1.0%, 12500 BTU	$21.94	$24.01	$24.22	$22.84	$24.41	$24.02	$24.24	$23.29	$23.45	$44.09	$27.25	$32.04	$55.03	$57.49	$50.71	$44.33	$76.94	$54.65	$50.03	$46.34
-1.5%, 12500 BTU	$21.54	$22.92	$22.70	$21.72	$22.73	$23.05	$23.33	$22.07	$21.72	$38.50	$24.19	$29.19	$49.92	$53.18	$45.49	$40.72	$59.26	$39.79	$39.91	$42.00
Ohio																				
-4%, 12500 BTU	$19.79	$21.50	$20.83	$18.38	$18.25	$18.34	$18.05	$18.41	$18.89	$26.44	$20.72	$23.01	$33.25	$35.88	$32.55	$39.19	$69.01	$42.54	$35.36	$32.34
Illinois Basin																				
-3%, 11000 BTU (IL)	$18.93	$21.68	$19.85	$16.96	$17.71	$18.10	$18.25	$17.44	$16.83	$24.63	$19.71	$19.61	$26.12	$27.54	$27.01	$27.01	$35.91	$32.47	$33.37	$33.43
-3%, 11000 BTU (KY)	$20.03	$22.78	$20.95	$18.10	$19.29	$20.25	$19.90	$18.81	$17.51	$29.93	$23.34	$22.09	$29.18	$29.82	$29.06	$28.91	$37.81	$34.28	$35.18	$35.27
Powder River Basin																				
-.33%, 8400 BTU	$3.58	$3.26	$4.34	$3.60	$3.09	$3.13	$3.35	$3.45	$3.43	$7.58	$4.74	$5.13	$5.23	$7.96	$10.17	$8.36	$12.91	$10.88	$10.08	$10.22
-.35%, 8800 BTU	$4.58	$4.64	$5.08	$4.68	$4.11	$4.29	$4.45	$4.42	$4.38	$9.34	$5.85	$6.21	$6.26	$10.09	$12.74	$9.85	$15.56	$12.30	$11.49	$12.09
Uinta Basin																				
-.5%, 11500 BTU	$19.79	$19.35	$13.64	$14.05	$13.58	$15.18	$15.09	$14.16	$13.35	$20.06	$16.95	$17.13	$26.82	$33.11	$36.76	$29.93	$38.15	$28.99	$25.54	$24.86
Foreign Coal																				
-.7%, 12000 BTU	$28.74	$26.45	$28.05	$34.31	$32.76	$31.71	$29.31	$26.35	$27.89	$35.37	$27.70	$33.43	$59.18	$50.12	$50.53	$62.03	$105.40	$65.52	$56.25	$52.13
-.8%, 11600 BTU						$29.61	$26.70	$24.09	$25.79	$32.94	$26.04	$31.41	$55.40	$46.90	$47.22	$57.85	$98.30	$61.13	$52.57	$48.81
Petroleum Coke																				
-6%/30 HGI, 14000 BTU			$15.42	$12.55	$18.22	$19.39	$3.52	$1.71	$9.98	$12.73	$8.57	$13.03	$11.27	$17.50	$34.76	$44.90	$59.59	$48.09	$46.66	$39.99

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON

BASE CASE

Year:	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia																				
-1.6%, 13000 BTU	$35.40	$35.72	$32.91	$31.73	$33.55	$32.62	$30.91	$28.89	$28.79	$47.30	$34.85	$34.87	$54.91	$57.58	$46.99	$46.61	$77.70	$48.83	$39.03	$34.80
-1.8%, 13000 BTU	$34.68	$34.55	$31.11	$28.83	$28.68	$28.67	$29.23	$27.02	$27.58	$46.06	$33.71	$33.51	$53.40	$55.26	$44.52	$45.85	$76.17	$47.52	$38.22	$34.14
-2.3%, 13000 BTU	$31.00	$29.37	$28.44	$26.88	$27.08	$27.31	$27.93	$25.23	$26.37	$42.02	$31.56	$32.21	$52.32	$51.77	$40.82	$44.71	$73.88	$45.55	$37.01	$33.14
Central Appalachia																				
-.7%, 12500 BTU	$33.63	$35.19	$35.43	$32.27	$33.13	$31.89	$32.19	$29.92	$29.77	$54.97	$33.50	$38.51	$64.02	$65.56	$57.34	$46.46	$78.95	$55.98	$51.60	$51.04
-.7%, 13000 BTU	$36.08	$37.29	$37.49	$34.52	$32.86	$31.64	$31.93	$30.72	$31.59	$58.44	$35.65	$41.00	$68.17	$69.84	$61.09	$49.50	$84.14	$59.66	$55.02	$54.52
-1.0%, 12500 BTU	$30.36	$32.48	$32.07	$29.64	$31.10	$30.10	$30.04	$28.45	$28.03	$51.47	$31.27	$36.00	$60.10	$60.82	$52.00	$44.33	$75.69	$52.86	$47.47	$43.10
-1.5%, 12500 BTU	$29.80	$31.00	$30.06	$28.19	$28.96	$28.88	$28.91	$26.96	$25.96	$44.95	$27.76	$32.80	$54.53	$56.27	$46.65	$40.72	$58.30	$38.48	$37.87	$39.06
Ohio																				
-4%, 12500 BTU	$27.38	$29.08	$27.58	$23.85	$23.25	$22.98	$22.37	$22.49	$22.58	$30.86	$23.78	$25.86	$36.32	$37.96	$33.38	$39.19	$67.89	$41.15	$33.55	$30.08
Illinois Basin																				
-3%, 11000 BTU (IL)	$26.18	$29.31	$26.29	$22.02	$22.56	$22.68	$22.62	$21.30	$20.11	$28.75	$22.62	$22.04	$28.52	$29.14	$27.70	$27.01	$35.33	$31.40	$31.66	$31.10
-3%, 11000 BTU (KY)	$27.71	$30.80	$27.74	$23.49	$24.57	$25.37	$24.66	$22.98	$20.94	$34.93	$26.78	$24.82	$31.86	$31.54	$29.80	$28.91	$37.20	$33.15	$33.38	$32.81
Powder River Basin																				
-.33%, 8400 BTU	$4.95	$4.41	$5.74	$4.67	$3.93	$3.92	$4.15	$4.21	$4.09	$8.84	$5.44	$5.76	$5.71	$8.42	$10.43	$8.36	$12.70	$10.53	$9.56	$9.50
-.35%, 8800 BTU	$6.33	$6.27	$6.72	$6.07	$5.24	$5.37	$5.51	$5.40	$5.23	$10.90	$6.71	$6.98	$6.84	$10.67	$13.06	$9.85	$15.31	$11.89	$10.90	$11.24
Uinta Basin																				
-.5%, 11500 BTU	$27.38	$26.17	$18.06	$18.24	$17.29	$19.01	$18.70	$17.30	$15.96	$23.42	$19.45	$19.24	$29.29	$35.02	$37.70	$29.93	$37.54	$28.04	$24.23	$23.12
Foreign Coal: Colombia																				
-.7%, 12000 BTU	$39.76	$35.77	$37.15	$44.53	$41.73	$39.73	$36.32	$32.19	$33.34	$41.29	$31.78	$37.56	$64.64	$53.02	$51.82	$62.03	$103.69	$63.38	$53.37	$48.48
-.8%, 11600 BTU						$37.10	$33.09	$29.42	$30.83	$38.45	$29.87	$35.29	$60.50	$49.62	$48.43	$57.85	$96.71	$59.13	$49.88	$45.39
Petroleum Coke																				
-6%/30 HGI, 14000 BTU			$20.42	$16.29	$23.21	$24.30	$4.36	$2.09	$11.93	$14.86	$9.83	$14.64	$12.31	$18.52	$35.65	$44.90	$58.62	$46.51	$44.27	$37.19
IMPLICIT PRICE DEFLATOR (GDP)	86.40	88.39	90.27	92.10	93.85	95.41	96.47	97.86	100.00	102.40	104.19	106.40	109.45	112.99	116.56	119.54	121.51	123.59	126.00	128.53
% Change	2.77%	2.30%	2.12%	2.04%	1.89%	1.67%	1.11%	1.44%	2.18%	2.40%	1.74%	2.12%	2.87%	3.23%	3.16%	2.56%	1.65%	1.71%	1.95%	2.01%

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

	1995		1996		1996	1996	1997		1997		1998		1998		1999				2000	
Year: / Quarter:	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Northern Appalachia																				
-1.6%, 13000 BTU	$24.73	$24.68	$26.27	$24.93	$26.76	$27.41	$26.76	$25.67	$25.77	$25.94	$25.72	$24.63	$24.63	$24.78	$24.43	$23.54	$23.29	$23.34	$22.90	$22.95
-1.8%, 13000 BTU	$22.15	$22.10	$23.29	$22.10	$22.35	$22.30	$22.40	$22.30	$23.05	$23.79	$23.79	$23.29	$23.84	$23.44	$22.80	$21.66	$21.41	$22.60	$22.03	$22.00
-2.3%, 13000 BTU	$20.96	$20.87	$21.81	$20.91	$21.21	$21.11	$21.21	$21.16	$22.01	$22.80	$22.80	$22.25	$22.80	$22.30	$21.51	$19.73	$19.92	$21.46	$21.11	$20.96
Central Appalachia																				
-.7%, 12500 BTU	$24.95	$24.70	$25.71	$24.50	$26.86	$26.97	$27.17	$24.55	$24.50	$25.60	$25.64	$25.27	$26.28	$26.71	$25.91	$24.14	$23.89	$24.04	$23.54	$23.39
-.7%, 13000 BTU	$26.49	$26.23	$25.50	$24.30	$26.65	$26.75	$26.95	$24.35	$24.30	$25.40	$25.43	$25.07	$26.07	$26.50	$25.70	$23.95	$25.46	$25.50	$24.96	$24.78
-1.0%, 12500 BTU	$22.92	$22.81	$24.11	$23.54	$24.90	$25.10	$25.21	$23.59	$23.33	$23.96	$24.06	$23.33	$24.48	$25.10	$24.32	$23.13	$22.92	$22.81	$22.34	$22.19
-1.5%, 12500 BTU	$21.61	$21.46	$22.50	$21.56	$23.44	$23.44	$23.54	$23.13	$22.40	$23.13	$23.18	$22.81	$23.33	$24.01	$23.13	$22.03	$21.82	$21.30	$20.73	$20.63
Ohio																				
-4%, 12500 BTU	$18.35	$18.25	$18.25	$18.20	$18.30	$18.25	$18.40	$18.30	$18.35	$18.30	$18.30	$18.10	$18.10	$17.70	$18.35	$18.00	$18.40	$18.90	$19.00	$18.25
Illinois Basin																				
-3%, 11000 BTU (IL)	$16.70	$ 16.85	$ 17.50	$ 17.35	$ 18.00	$ 18.00	$18.00	$18.00	$18.15	$18.25	$18.25	$17.95	$ 18.20	$ 18.60	$18.10	$17.50	$17.15	$17.00	$16.75	$16.70
-3%, 11000 BTU (KY)	$17.80	$ 18.10	$ 18.75	$ 18.50	$ 19.90	$ 20.00	$21.00	$20.05	$20.00	$19.95	$20.05	$19.35	$ 20.00	$ 20.20	$19.75	$19.00	$18.45	$18.05	$17.20	$16.95
Powder River Basin																				
-.33%, 8400 BTU	$3.40	$3.30	$3.20	$3.15	$3.00	$3.00	$3.00	$3.00	$3.20	$3.30	$3.62	$3.35	$3.15	$3.27	$3.38	$3.45	$3.47	$3.50	$3.40	$3.20
-.35%, 8800 BTU	$4.45	$4.40	$4.25	$4.20	$4.00	$4.00	$4.00	$4.05	$4.50	$4.60	$4.80	$4.45	$4.20	$4.34	$4.38	$4.45	$4.40	$4.45	$4.40	$4.20
Uinta Basin																				
-.5%, 11500 BTU	$14.20	$14.00	$13.50	$13.20	$13.60	$14.00	$14.40	$15.05	$15.65	$15.60	$15.25	$15.20	$ 15.10	$ 14.80	$14.65	$14.40	$14.10	$13.50	$12.75	$12.80
Foreign Coal																				
-.7%, 12000 BTU	$34.20	$34.50	$33.65	$32.15	$32.00	$33.25	$33.50	$32.40	$30.95	$30.00	$29.20	$29.00	$30.15	$28.90	$28.40	$28.00	$24.60	$24.40	$26.00	$27.25
-.8%, 11600 BTU							$31.54	$30.51	$28.69	$27.71	$26.61	$26.08	$27.99	$26.13	$25.63	$24.63	$23.34	$22.75	$24.13	$25.21
Petroleum Coke																				
-6%/30 HGI, 14000 BTU	$10.28	$11.79	$15.88	$17.24	$19.35	$20.41	$21.47	$21.02	$19.81	$15.27	$7.41	$3.93	$1.36	$1.36	$1.36	$1.36	$1.36	$2.75	$5.58	$5.73

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

ANNUAL AVERAGE SPOT

BASE CASE

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia																			
-1.6%, 13000 BTU	$35.74	$34.76	$34.75	$35.09	$35.54	$36.06	$36.54	$37.02	$37.53	$39.24	$39.84	$40.46	$41.09	$41.75	$42.41	$43.07	$43.72	$44.38	$45.08
-1.8%, 13000 BTU	$35.12	$34.22	$34.33	$34.68	$35.15	$35.67	$36.17	$36.67	$37.21	$38.89	$39.49	$40.11	$40.74	$41.39	$42.04	$42.70	$43.34	$43.99	$44.69
-2.3%, 13000 BTU	$34.18	$33.40	$33.68	$34.07	$34.56	$35.08	$35.61	$36.14	$36.73	$38.38	$38.97	$39.58	$40.20	$40.85	$41.49	$42.14	$42.77	$43.41	$44.10
Central Appalachia																			
-.7%, 12500 BTU	$54.93	$55.89	$56.32	$57.10	$58.07	$59.24	$60.63	$62.10	$63.62	$65.95	$68.34	$70.14	$71.93	$73.84	$75.83	$77.84	$79.91	$81.97	$84.09
-.7%, 13000 BTU	$58.64	$59.66	$60.12	$60.95	$61.98	$63.24	$64.71	$66.28	$67.91	$70.40	$72.96	$74.89	$76.81	$78.85	$80.99	$83.14	$85.36	$87.57	$89.84
-1.0%, 12500 BTU	$44.52	$42.80	$42.61	$42.98	$43.60	$44.39	$45.26	$46.09	$47.07	$48.58	$50.16	$51.25	$52.35	$53.50	$54.65	$55.82	$57.00	$58.19	$59.46
-1.5%, 12500 BTU	$41.26	$41.31	$41.48	$42.20	$42.99	$43.79	$44.66	$45.54	$46.53	$48.04	$49.63	$50.72	$51.83	$52.98	$54.14	$55.31	$56.50	$57.69	$58.96
Ohio																			
-4%, 12500 BTU	$31.04	$30.34	$30.61	$30.98	$31.44	$31.93	$32.42	$32.92	$33.47	$35.00	$35.55	$36.13	$36.71	$37.32	$37.92	$38.53	$39.13	$39.74	$40.38
Illinois Basin																			
-3%, 11000 BTU (IL)	$33.52	$33.62	$33.70	$33.91	$34.20	$34.53	$34.84	$35.19	$35.48	$35.87	$36.25	$36.63	$36.96	$37.33	$37.77	$38.23	$38.67	$39.11	$39.58
-3%, 11000 BTU (KY)	$35.37	$35.52	$35.66	$35.92	$36.27	$36.65	$37.02	$37.42	$37.78	$38.23	$38.66	$39.10	$39.50	$39.92	$40.44	$40.96	$41.47	$41.97	$42.51
Powder River Basin																			
-.33%, 8400 BTU	$10.01	$9.86	$9.75	$9.80	$9.89	$10.12	$10.35	$10.56	$10.81	$11.16	$11.52	$11.72	$11.90	$12.10	$12.26	$12.45	$12.63	$12.80	$13.01
-.35%, 8800 BTU	$12.01	$12.03	$12.03	$12.17	$12.37	$12.63	$12.91	$13.21	$13.59	$14.04	$14.49	$14.78	$15.06	$15.36	$15.63	$15.92	$16.22	$16.50	$16.84
Uinta Basin																			
-.5%, 11500 BTU	$24.00	$24.26	$24.59	$24.93	$25.31	$25.68	$26.05	$26.43	$26.85	$27.26	$27.67	$28.10	$28.53	$28.98	$29.43	$29.88	$30.33	$30.78	$31.26
Foreign Coal																			
-.7%, 12000 BTU	$49.89	$49.93	$50.47	$51.00	$51.55	$52.23	$52.93	$53.60	$54.27	$55.01	$55.80	$56.62	$57.49	$58.40	$59.38	$60.40	$61.44	$62.52	$63.57
-.8%, 11600 BTU	$46.84	$47.02	$47.62	$48.25	$48.91	$49.57	$50.27	$50.96	$51.69	$52.44	$53.20	$54.00	$54.84	$55.73	$56.67	$57.64	$58.63	$59.66	$60.67
Petroleum Coke																			
-6%/30 HGI, 14000 BTU	$37.26	$37.14	$37.52	$37.92	$38.35	$38.78	$39.25	$39.72	$40.21	$40.73	$41.28	$41.86	$42.48	$43.14	$43.85	$44.60	$45.37	$46.19	$46.97

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

ANNUAL AVERAGE SPOT
BASE CASE

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia																			
-1.6%, 13000 BTU	$32.59	$31.11	$30.51	$30.22	$30.02	$29.88	$29.71	$29.53	$29.39	$30.16	$30.07	$29.99	$29.90	$29.82	$29.73	$29.64	$29.54	$29.44	$29.37
-1.8%, 13000 BTU	$32.02	$30.62	$30.13	$29.86	$29.68	$29.56	$29.40	$29.25	$29.14	$29.90	$29.81	$29.73	$29.64	$29.56	$29.47	$29.38	$29.28	$29.19	$29.11
-2.3%, 13000 BTU	$31.17	$29.89	$29.57	$29.34	$29.19	$29.07	$28.95	$28.83	$28.76	$29.50	$29.42	$29.34	$29.25	$29.18	$29.09	$28.99	$28.90	$28.80	$28.73
Central Appalachia																			
-.7%, 12500 BTU	$50.09	$50.01	$49.45	$49.16	$49.04	$49.09	$49.29	$49.54	$49.82	$50.69	$51.58	$51.98	$52.34	$52.74	$53.16	$53.56	$53.99	$54.38	$54.78
-.7%, 13000 BTU	$53.48	$53.39	$52.78	$52.48	$52.35	$52.41	$52.61	$52.89	$53.18	$54.12	$55.07	$55.51	$55.89	$56.32	$56.77	$57.21	$57.67	$58.10	$58.53
-1.0%, 12500 BTU	$40.60	$38.30	$37.41	$37.01	$36.83	$36.79	$36.79	$36.78	$36.86	$37.34	$37.86	$37.98	$38.09	$38.21	$38.31	$38.41	$38.51	$38.60	$38.74
-1.5%, 12500 BTU	$37.63	$36.97	$36.42	$36.34	$36.31	$36.29	$36.30	$36.34	$36.44	$36.93	$37.46	$37.59	$37.71	$37.84	$37.95	$38.06	$38.17	$38.27	$38.41
Ohio																			
-4%, 12500 BTU	$28.30	$27.15	$26.87	$26.67	$26.55	$26.46	$26.36	$26.27	$26.21	$26.90	$26.84	$26.78	$26.71	$26.65	$26.58	$26.51	$26.44	$26.36	$26.31
Illinois Basin																			
-3%, 11000 BTU (IL)	$30.57	$30.08	$29.58	$29.20	$28.89	$28.61	$28.33	$28.07	$27.78	$27.58	$27.36	$27.15	$26.89	$26.66	$26.48	$26.30	$26.13	$25.95	$25.79
-3%, 11000 BTU (KY)	$32.26	$31.79	$31.30	$30.93	$30.63	$30.37	$30.10	$29.86	$29.58	$29.38	$29.18	$28.98	$28.74	$28.52	$28.35	$28.18	$28.02	$27.85	$27.70
Powder River Basin																			
-.33%, 8400 BTU	$9.13	$8.82	$8.56	$8.44	$8.36	$8.39	$8.41	$8.43	$8.47	$8.58	$8.69	$8.68	$8.66	$8.64	$8.60	$8.57	$8.54	$8.49	$8.48
-.35%, 8800 BTU	$10.96	$10.76	$10.56	$10.48	$10.45	$10.47	$10.49	$10.54	$10.64	$10.79	$10.93	$10.95	$10.96	$10.97	$10.96	$10.96	$10.96	$10.95	$10.97
Uinta Basin																			
-.5%, 11500 BTU	$21.89	$21.71	$21.59	$21.47	$21.38	$21.28	$21.17	$21.09	$21.03	$20.96	$20.89	$20.82	$20.76	$20.70	$20.63	$20.56	$20.49	$20.42	$20.36
Foreign Coal: Colombia																			
-.7%, 12000 BTU	$45.49	$44.69	$44.31	$43.92	$43.54	$43.28	$43.03	$42.77	$42.50	$42.29	$42.12	$41.96	$41.83	$41.72	$41.63	$41.56	$41.51	$41.48	$41.41
-.8%, 11600 BTU	$42.71	$42.08	$41.80	$41.55	$41.31	$41.08	$40.87	$40.66	$40.48	$40.31	$40.16	$40.02	$39.91	$39.81	$39.73	$39.66	$39.61	$39.58	$39.52
Petroleum Coke																			
-6%/30 HGI, 14000 BTU	$33.98	$33.24	$32.93	$32.65	$32.39	$32.14	$31.91	$31.69	$31.49	$31.31	$31.16	$31.02	$30.91	$30.81	$30.74	$30.69	$30.66	$30.64	$30.60
IMPLICIT PRICE																			
DEFLATOR (GDP)	131.09	133.58	136.17	138.84	141.54	144.25	147.05	149.83	152.66	155.51	158.37	161.30	164.29	167.36	170.52	173.73	176.94	180.18	183.49
% Change	1.99%	1.90%	1.93%	1.96%	1.95%	1.91%	1.94%	1.89%	1.89%	1.87%	1.84%	1.85%	1.85%	1.87%	1.89%	1.88%	1.85%	1.83%	1.84%

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

QUARTERLY SPOT PRICES

BASE CASE

Year:			2001				2002				2003				2004				2005			
Quarter:	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia																						
-1.6%, 13000 BTU	$24.38	$26.12	$32.86	$42.38	$43.91	$42.92	$35.34	$29.34	$29.09	$27.70	$28.20	$30.88	$31.57	$33.50	$41.24	$45.53	$52.70	$61.62	$56.60	$54.24	$53.91	$52.95
-1.8%, 13000 BTU	$23.59	$24.65	$31.91	$41.26	$42.81	$41.85	$34.32	$28.36	$28.09	$26.73	$27.01	$29.66	$30.41	$32.23	$40.04	$44.46	$51.30	$59.78	$55.15	$52.33	$51.52	$49.91
-2.3%, 13000 BTU	$22.55	$23.59	$29.39	$37.07	$39.40	$38.11	$31.57	$26.61	$26.66	$25.18	$25.82	$28.50	$29.34	$31.03	$39.12	$43.84	$50.32	$58.33	$52.98	$49.48	$47.94	$45.35
Central Appalachia																						
-.7%, 12500 BTU	$24.65	$28.02	$46.72	$51.11	$49.19	$41.33	$30.14	$27.67	$29.23	$29.74	$32.36	$34.02	$33.87	$36.84	$49.62	$56.75	$62.95	$65.15	$62.35	$63.07	$60.38	$62.08
-.7%, 13000 BTU	$26.17	$29.77	$49.66	$54.33	$52.31	$43.93	$32.07	$29.43	$31.12	$31.65	$34.44	$36.21	$36.07	$39.24	$52.84	$60.43	$67.05	$69.37	$66.41	$67.18	$64.33	$66.12
-1.0%, 12500 BTU	$22.92	$26.35	$43.07	$48.65	$45.89	$38.75	$28.18	$25.94	$27.24	$27.66	$29.43	$31.77	$31.93	$35.05	$47.99	$54.08	$58.30	$59.75	$57.71	$59.20	$56.23	$56.81
-1.5%, 12500 BTU	$21.04	$24.48	$34.69	$43.65	$41.15	$34.53	$24.22	$22.86	$24.53	$25.16	$26.93	$28.85	$28.96	$32.03	$44.34	$49.69	$53.05	$52.61	$53.50	$54.86	$52.78	$51.59
Ohio																						
-4%, 12500 BTU	$18.75	$19.55	$23.95	$26.85	$27.85	$27.10	$22.34	$20.15	$20.45	$19.95	$21.40	$22.95	$23.35	$24.35	$28.09	$28.78	$35.38	$40.77	$36.73	$35.18	$35.75	$35.85
Illinois Basin																						
-3%, 11000 BTU (IL)	$16.80	$17.05	$22.05	$25.35	$25.65	$25.45	$21.90	$19.80	$18.50	$18.65	$18.80	$19.55	$19.60	$20.50	$22.55	$25.07	$26.80	$30.05	$27.32	$27.22	$27.75	$27.88
-3%, 11000 BTU (KY)	$17.45	$18.45	$24.30	$31.45	$32.10	$31.85	$27.80	$22.60	$21.50	$21.45	$21.45	$21.95	$22.10	$22.85	$24.95	$28.05	$30.50	$33.20	$30.03	$29.25	$29.83	$30.15
Powder River Basin																						
-.33%, 8400 BTU	$3.40	$3.70	$6.25	$10.65	$7.05	$6.35	$4.65	$4.70	$4.65	$4.95	$5.00	$4.80	$5.25	$5.45	$5.55	$5.43	$5.00	$4.93	$5.18	$6.35	$7.72	$12.57
-.35%, 8800 BTU	$4.35	$4.55	$7.90	$12.75	$8.70	$8.00	$5.85	$5.75	$5.75	$6.05	$6.00	$5.90	$6.30	$6.65	$6.58	$6.43	$6.02	$6.02	$6.33	$7.98	$10.03	$16.00
Uinta Basin																						
-.5%, 11500 BTU	$13.30	$14.55	$19.05	$19.85	$20.55	$20.80	$18.40	$16.30	$16.45	$16.65	$16.15	$16.90	$17.15	$18.30	$22.42	$25.95	$29.42	$29.50	$28.98	$31.12	$34.82	$37.50
Foreign Coal																						
-.7%, 12000 BTU	$27.85	$30.45	$35.10	$36.90	$36.85	$32.62	$29.81	$27.54	$25.06	$28.38	$28.55	$28.04	$35.00	$42.12	$46.23	$54.39	$68.50	$67.62	$57.64	$49.06	$51.92	$41.84
-.8%, 11600 BTU	$25.63	$28.20	$32.60	$34.32	$34.31	$30.52	$27.99	$25.95	$23.57	$26.63	$26.83	$26.40	$32.86	$39.55	$43.28	$50.97	$64.08	$63.25	$53.92	$45.94	$48.57	$39.17
Petroleum Coke																						
-6%/30 HGI, 14000 BTU	$8.83	$19.78	$18.11	$14.62	$9.95	$8.24	$7.44	$5.79	$7.97	$13.08	$20.35	$14.53	$8.52	$8.71	$6.60	$6.46	$14.71	$20.46	$22.76	$13.25	$12.02	$21.98

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

QUARTERLY SPOT PRICES

BASE CASE

	2006				2007				2008				2009				2010			
Year: / Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia																				
-1.6%, 13000 BTU	$49.63	$46.60	$44.14	$42.90	$44.00	$44.75	$46.60	$51.10	$73.95	$88.05	$82.50	$71.42	$58.77	$49.90	$48.48	$44.78	$42.93	$41.18	$41.03	$39.42
-1.8%, 13000 BTU	$46.48	$43.85	$41.92	$41.40	$43.09	$44.02	$45.83	$50.46	$72.73	$86.53	$80.85	$69.60	$57.15	$48.43	$47.20	$43.74	$42.01	$40.22	$40.24	$38.68
-2.3%, 13000 BTU	$41.76	$39.72	$38.58	$39.14	$41.73	$42.93	$44.67	$49.50	$70.90	$84.25	$78.37	$66.88	$54.73	$46.22	$45.27	$42.17	$40.63	$38.77	$39.05	$37.57
Central Appalachia																				
-.7%, 12500 BTU	$61.21	$59.39	$54.23	$48.82	$41.92	$44.73	$45.65	$53.55	$74.38	$89.33	$85.03	$72.27	$61.70	$57.33	$57.10	$55.35	$54.95	$54.08	$54.77	$53.73
-.7%, 13000 BTU	$65.20	$63.26	$57.79	$52.01	$44.66	$47.65	$48.65	$57.06	$79.26	$95.18	$90.63	$77.01	$65.76	$61.10	$60.87	$59.00	$58.58	$57.65	$58.40	$57.28
-1.0%, 12500 BTU	$55.10	$51.81	$49.69	$46.23	$39.55	$42.53	$43.65	$51.60	$71.43	$85.48	$81.50	$69.35	$58.85	$54.25	$53.77	$51.75	$51.05	$49.88	$50.27	$48.93
-1.5%, 12500 BTU	$48.97	$46.25	$44.09	$42.62	$35.52	$39.22	$40.17	$47.98	$63.05	$67.21	$59.57	$47.20	$41.20	$38.95	$39.65	$39.35	$39.67	$39.35	$40.38	$40.25
Ohio																				
-4%, 12500 BTU	$34.63	$32.63	$30.67	$32.24	$35.45	$37.43	$38.63	$45.23	$65.86	$78.04	$71.70	$60.44	$49.28	$41.73	$40.95	$38.21	$36.86	$35.13	$35.42	$34.05
Illinois Basin																				
-3%, 11000 BTU (IL)	$27.27	$26.53	$26.63	$27.60	$26.85	$26.53	$26.93	$27.73	$32.13	$39.42	$38.23	$33.85	$32.07	$32.27	$32.83	$32.70	$32.98	$32.98	$33.93	$33.58
-3%, 11000 BTU (KY)	$29.37	$28.57	$28.72	$29.58	$28.77	$28.52	$28.77	$29.60	$34.05	$41.40	$40.07	$35.72	$33.88	$34.13	$34.60	$34.48	$34.80	$34.85	$35.70	$35.37
Powder River Basin																				
-.33%, 8400 BTU	$14.20	$10.63	$8.20	$7.63	$7.18	$7.48	$8.92	$9.85	$11.97	$13.85	$13.15	$12.68	$12.22	$11.50	$10.48	$9.33	$9.83	$9.70	$10.50	$10.28
-.35%, 8800 BTU	$17.68	$13.62	$10.18	$9.47	$8.80	$8.93	$10.47	$11.20	$14.42	$17.25	$15.97	$14.62	$13.65	$12.92	$11.82	$10.80	$11.27	$11.12	$11.83	$11.75
Uinta Basin																				
-.5%, 11500 BTU	$38.45	$37.62	$35.83	$35.13	$33.75	$32.50	$27.02	$26.43	$34.83	$42.40	$39.70	$35.68	$32.52	$29.07	$27.90	$26.47	$25.80	$25.40	$25.63	$25.32
Foreign Coal																				
-.7%, 12000 BTU	$48.83	$52.74	$50.93	$49.61	$51.13	$52.48	$59.37	$85.13	$111.06	$123.68	$105.18	$81.68	$70.69	$66.43	$63.52	$61.45	$59.55	$55.20	$56.82	$53.44
-.8%, 11600 BTU	$45.68	$49.24	$47.65	$46.32	$47.70	$48.95	$55.37	$79.38	$103.60	$115.38	$98.07	$76.17	$65.93	$61.96	$59.27	$57.35	$55.62	$51.57	$53.12	$49.98
Petroleum Coke																				
-6%/30 HGI, 14000 BTU	$24.99	$36.75	$39.32	$37.98	$44.03	$47.68	$44.98	$42.90	$55.19	$70.38	$60.30	$52.48	$49.98	$47.62	$47.55	$47.20	$46.93	$46.63	$47.30	$45.78

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

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ANNUAL AVERAGE CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$72.15	$49.33	$40.12	$37.51	$36.31	$35.86	$36.05	$36.46	$36.96	$37.47	$37.97	$38.68	$39.64
-1.8%, 13000 BTU	$70.51	$48.28	$39.38	$36.83	$35.73	$35.36	$35.62	$36.05	$36.56	$37.08	$37.60	$38.34	$39.30
-2.3%, 13000 BTU	$68.06	$46.70	$38.27	$35.82	$34.85	$34.61	$34.98	$35.43	$35.95	$36.50	$37.05	$37.81	$38.78
Central Appalachia													
-.7%, 12500 BTU	$73.85	$57.43	$55.24	$56.71	$57.15	$57.92	$58.58	$59.51	$60.65	$61.98	$63.46	$65.14	$67.14
-.7%, 13000 BTU	$78.72	$61.23	$58.93	$60.57	$61.01	$61.83	$62.53	$63.53	$64.74	$66.17	$67.74	$69.54	$71.67
-1.0%, 12500 BTU	$69.14	$52.38	$49.31	$46.50	$44.94	$44.05	$44.19	$44.73	$45.47	$46.31	$47.21	$48.24	$49.53
-1.5%, 12500 BTU	$55.50	$40.86	$41.23	$42.89	$42.56	$42.76	$43.23	$44.01	$44.84	$45.70	$46.62	$47.68	$48.98
Ohio													
-4%, 12500 BTU	$61.80	$42.50	$34.64	$32.52	$31.66	$31.45	$31.80	$32.23	$32.72	$33.23	$33.75	$34.46	$35.36
Illinois Basin													
-3%, 11000 BTU (IL)	$34.94	$33.31	$34.42	$34.50	$34.59	$34.70	$34.87	$35.13	$35.45	$35.79	$36.12	$36.46	$36.81
-3%, 11000 BTU (KY)	$36.83	$35.13	$36.30	$36.41	$36.53	$36.70	$36.92	$37.25	$37.62	$38.01	$38.40	$38.81	$39.22
Powder River Basin													
-.33%, 8400 BTU	$12.69	$10.74	$10.42	$10.39	$10.21	$10.11	$10.08	$10.18	$10.35	$10.58	$10.81	$11.07	$11.38
-.35%, 8800 BTU	$14.65	$12.46	$12.13	$12.42	$12.38	$12.41	$12.49	$12.68	$12.92	$13.21	$13.52	$13.88	$14.30
Uinta Basin													
-.5%, 11500 BTU	$33.60	$27.60	$25.81	$25.21	$24.91	$25.22	$25.57	$25.94	$26.32	$26.70	$27.10	$27.51	$27.94
Foreign Coal													
-.7%, 12000 BTU	$81.21	$60.35	$55.43	$52.54	$51.50	$51.80	$52.36	$52.93	$53.57	$54.27	$54.98	$55.68	$56.42
-.8%, 11600 BTU	$75.81	$56.44	$51.87	$49.29	$48.44	$48.85	$49.49	$50.15	$50.84	$51.54	$52.26	$53.00	$53.76
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$53.71	$47.54	$44.16	$39.76	$38.38	$38.52	$38.92	$39.36	$39.80	$40.27	$40.75	$41.25	$41.78

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

ANNUAL AVERAGE CONTRACT PRICES - REAL 2007 DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$70.98	$47.71	$38.07	$34.88	$33.11	$32.09	$31.65	$31.40	$31.21	$31.05	$30.87	$30.87	$31.04
-1.8%, 13000 BTU	$69.37	$46.69	$37.37	$34.26	$32.58	$31.64	$31.27	$31.04	$30.87	$30.73	$30.57	$30.59	$30.77
-2.3%, 13000 BTU	$66.95	$45.17	$36.31	$33.31	$31.78	$30.98	$30.71	$30.51	$30.37	$30.24	$30.12	$30.17	$30.37
Central Appalachia													
-.7%, 12500 BTU	$72.65	$55.55	$52.41	$52.75	$52.11	$51.83	$51.43	$51.24	$51.22	$51.37	$51.59	$51.98	$52.57
-.7%, 13000 BTU	$77.44	$59.23	$55.91	$56.33	$55.63	$55.33	$54.89	$54.70	$54.68	$54.83	$55.07	$55.48	$56.12
-1.0%, 12500 BTU	$68.02	$50.66	$46.78	$43.25	$40.98	$39.42	$38.79	$38.51	$38.40	$38.38	$38.38	$38.49	$38.78
-1.5%, 12500 BTU	$54.60	$39.52	$39.11	$39.89	$38.81	$38.27	$37.96	$37.90	$37.87	$37.87	$37.90	$38.04	$38.35
Ohio													
-4%, 12500 BTU	$60.80	$41.11	$32.87	$30.24	$28.87	$28.15	$27.92	$27.75	$27.63	$27.53	$27.43	$27.49	$27.69
Illinois Basin													
-3%, 11000 BTU (IL)	$34.37	$32.21	$32.66	$32.09	$31.54	$31.06	$30.61	$30.25	$29.94	$29.66	$29.36	$29.09	$28.83
-3%, 11000 BTU (KY)	$36.24	$33.98	$34.44	$33.86	$33.31	$32.84	$32.41	$32.07	$31.77	$31.50	$31.22	$30.96	$30.71
Powder River Basin													
-.33%, 8400 BTU	$12.48	$10.39	$9.88	$9.66	$9.31	$9.04	$8.85	$8.76	$8.74	$8.77	$8.79	$8.83	$8.91
-.35%, 8800 BTU	$14.41	$12.06	$11.51	$11.55	$11.29	$11.11	$10.97	$10.92	$10.91	$10.94	$10.99	$11.07	$11.20
Uinta Basin													
-.5%, 11500 BTU	$33.05	$26.70	$24.48	$23.44	$22.72	$22.57	$22.45	$22.34	$22.23	$22.13	$22.03	$21.95	$21.88
Foreign Coal: Colombia													
-.7%, 12000 BTU	$79.89	$58.38	$52.59	$48.87	$46.96	$46.36	$45.96	$45.58	$45.24	$44.98	$44.70	$44.43	$44.18
-.8%, 11600 BTU	$74.58	$54.59	$49.22	$45.84	$44.17	$43.71	$43.44	$43.18	$42.94	$42.71	$42.48	$42.28	$42.09
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$52.84	$45.98	$41.89	$36.98	$35.00	$34.47	$34.17	$33.89	$33.62	$33.37	$33.13	$32.91	$32.72

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

QUARTERLY CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	*2008*				*2009*				*2010*			
Quarter:	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*
Northern Appalachia												
-1.6%, 13000 BTU	$72.06	$78.83	$72.78	$64.93	$56.49	$48.00	$47.43	$45.39	$41.81	$40.00	$39.81	$38.87
-1.8%, 13000 BTU	$70.47	$77.05	$71.10	$63.42	$55.21	$46.96	$46.44	$44.49	$41.01	$39.25	$39.09	$38.18
-2.3%, 13000 BTU	$68.09	$74.39	$68.59	$61.15	$53.29	$45.39	$44.97	$43.14	$39.80	$38.13	$38.01	$37.15
Central Appalachia												
-.7%, 12500 BTU	$75.06	$79.18	$75.47	$65.68	$58.53	$57.43	$57.25	$56.50	$55.80	$55.29	$54.85	$55.00
-.7%, 13000 BTU	$80.00	$84.40	$80.45	$70.01	$62.40	$61.23	$61.04	$60.25	$59.52	$58.99	$58.53	$58.69
-1.0%, 12500 BTU	$70.81	$74.35	$70.50	$60.90	$53.88	$52.52	$52.05	$51.07	$50.18	$49.46	$48.85	$48.75
-1.5%, 12500 BTU	$60.95	$61.57	$53.60	$45.87	$40.65	$40.73	$41.00	$41.06	$41.07	$41.16	$41.28	$41.40
Ohio												
-4%, 12500 BTU	$62.05	$67.63	$62.17	$55.36	$48.26	$41.22	$40.94	$39.57	$36.78	$35.50	$35.66	$35.12
Illinois Basin												
-3%, 11000 BTU (IL)	$34.05	$36.49	$35.95	$33.26	$33.16	$33.27	$33.36	$33.43	$33.45	$33.50	$33.55	$33.53
-3%, 11000 BTU (KY)	$35.90	$38.45	$37.90	$35.09	$34.98	$35.10	$35.18	$35.26	$35.28	$35.34	$35.38	$35.38
Powder River Basin												
-.33%, 8400 BTU	$12.11	$13.58	$12.68	$12.39	$11.73	$10.74	$10.42	$10.07	$10.10	$10.11	$10.12	$10.07
-.35%, 8800 BTU	$14.06	$15.73	$14.58	$14.22	$13.49	$12.43	$12.13	$11.80	$11.87	$11.93	$11.99	$12.02
Uinta Basin												
-.5%, 11500 BTU	$33.12	$35.19	$34.05	$32.03	$29.60	$28.09	$26.67	$26.06	$25.53	$25.37	$25.24	$25.15
Foreign Coal												
-.7%, 12000 BTU	$88.57	$86.35	$79.15	$70.75	$63.16	$60.25	$59.91	$58.08	$56.35	$55.45	$54.93	$53.38
-.8%, 11600 BTU	$82.66	$80.60	$73.90	$66.09	$59.02	$56.33	$56.04	$54.36	$52.78	$51.97	$51.51	$50.09
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$56.16	$56.54	$52.59	$49.55	$48.06	$47.76	$47.21	$47.11	$46.13	$45.24	$45.14	$43.03

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

ANNUAL AVERAGE CONTR

BASE CASE

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$40.83	$41.46	$42.12	$42.78	$43.46	$44.14	$44.81	$45.49	$46.19	$46.89
-1.8%, 13000 BTU	$40.48	$41.10	$41.75	$42.41	$43.08	$43.75	$44.42	$45.10	$45.78	$46.48
-2.3%, 13000 BTU	$39.94	$40.56	$41.20	$41.85	$42.51	$43.18	$43.84	$44.50	$45.18	$45.87
Central Appalachia										
-.7%, 12500 BTU	$69.47	$71.62	$73.49	$75.41	$77.42	$79.49	$81.59	$83.73	$85.89	$88.08
-.7%, 13000 BTU	$74.16	$76.47	$78.48	$80.53	$82.69	$84.91	$87.16	$89.45	$91.76	$94.12
-1.0%, 12500 BTU	$51.04	$52.41	$53.55	$54.71	$55.90	$57.10	$58.31	$59.54	$60.80	$62.11
-1.5%, 12500 BTU	$50.49	$51.87	$53.01	$54.18	$55.37	$56.57	$57.79	$59.02	$60.29	$61.59
Ohio										
-4%, 12500 BTU	$36.43	$37.02	$37.62	$38.23	$38.85	$39.48	$40.10	$40.73	$41.37	$42.01
Illinois Basin										
-3%, 11000 BTU (IL)	$37.21	$37.59	$37.96	$38.33	$38.75	$39.22	$39.68	$40.14	$40.60	$41.08
-3%, 11000 BTU (KY)	$39.67	$40.12	$40.55	$40.99	$41.47	$42.00	$42.54	$43.07	$43.60	$44.14
Powder River Basin										
-.33%, 8400 BTU	$11.71	$12.00	$12.20	$12.39	$12.58	$12.76	$12.94	$13.13	$13.33	$13.54
-.35%, 8800 BTU	$14.74	$15.12	$15.42	$15.71	$16.01	$16.30	$16.60	$16.91	$17.23	$17.59
Uinta Basin										
-.5%, 11500 BTU	$28.36	$28.79	$29.24	$29.69	$30.16	$30.62	$31.09	$31.55	$32.03	$32.50
Foreign Coal										
-.7%, 12000 BTU	$57.21	$58.05	$58.92	$59.85	$60.83	$61.87	$62.93	$64.02	$65.11	$66.18
-.8%, 11600 BTU	$54.54	$55.35	$56.21	$57.11	$58.05	$59.04	$60.06	$61.09	$62.14	$63.15
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$42.33	$42.92	$43.54	$44.21	$44.93	$45.68	$46.48	$47.29	$48.10	$48.88

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

ANNUAL AVERAGE CONTR

BASE CASE

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$31.39	$31.30	$31.21	$31.13	$31.04	$30.94	$30.84	$30.74	$30.64	$30.55
-1.8%, 13000 BTU	$31.11	$31.03	$30.94	$30.86	$30.77	$30.67	$30.57	$30.47	$30.37	$30.28
-2.3%, 13000 BTU	$30.70	$30.62	$30.54	$30.45	$30.37	$30.27	$30.17	$30.07	$29.98	$29.88
Central Appalachia										
-.7%, 12500 BTU	$53.40	$54.06	$54.47	$54.87	$55.30	$55.73	$56.15	$56.57	$56.98	$57.38
-.7%, 13000 BTU	$57.01	$57.72	$58.16	$58.60	$59.06	$59.52	$59.97	$60.43	$60.88	$61.31
-1.0%, 12500 BTU	$39.23	$39.56	$39.69	$39.81	$39.93	$40.03	$40.12	$40.23	$40.34	$40.46
-1.5%, 12500 BTU	$38.81	$39.15	$39.29	$39.42	$39.55	$39.66	$39.76	$39.88	$40.00	$40.12
Ohio										
-4%, 12500 BTU	$28.01	$27.94	$27.88	$27.82	$27.75	$27.67	$27.59	$27.52	$27.44	$27.37
Illinois Basin										
-3%, 11000 BTU (IL)	$28.60	$28.37	$28.13	$27.89	$27.68	$27.49	$27.30	$27.12	$26.94	$26.76
-3%, 11000 BTU (KY)	$30.50	$30.28	$30.05	$29.83	$29.62	$29.45	$29.27	$29.10	$28.92	$28.76
Powder River Basin										
-.33%, 8400 BTU	$9.00	$9.05	$9.04	$9.01	$8.98	$8.94	$8.91	$8.87	$8.84	$8.82
-.35%, 8800 BTU	$11.33	$11.41	$11.43	$11.43	$11.44	$11.43	$11.42	$11.42	$11.43	$11.46
Uinta Basin										
-.5%, 11500 BTU	$21.80	$21.73	$21.67	$21.61	$21.54	$21.47	$21.39	$21.32	$21.25	$21.18
Foreign Coal: Colombia										
-.7%, 12000 BTU	$43.98	$43.82	$43.67	$43.55	$43.45	$43.37	$43.30	$43.25	$43.20	$43.11
-.8%, 11600 BTU	$41.93	$41.78	$41.66	$41.55	$41.47	$41.39	$41.32	$41.28	$41.22	$41.14
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$32.54	$32.40	$32.27	$32.17	$32.09	$32.03	$31.98	$31.95	$31.91	$31.85

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

HIGH CASE

March 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

HIGH CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$100.66	$105.96	$77.01	$62.96	$62.98	$63.45	$63.67	$64.41	$65.15	$65.97	$66.70	$67.38
-1.8%, 13000 BTU	$45.85	$98.64	$103.11	$75.40	$61.75	$61.88	$62.46	$62.89	$63.66	$64.43	$65.25	$66.02	$66.75
-2.3%, 13000 BTU	$44.71	$95.60	$98.85	$73.00	$59.95	$60.24	$60.96	$61.71	$62.53	$63.35	$64.18	$65.00	$65.79
Central Appalachia													
-.7%, 12500 BTU	$46.46	$78.41	$104.96	$88.47	$79.60	$70.39	$71.54	$72.66	$73.56	$75.07	$76.90	$78.74	$80.62
-.7%, 13000 BTU	$49.50	$83.56	$111.87	$94.34	$85.03	$75.15	$76.37	$77.57	$78.52	$80.14	$82.09	$84.05	$86.05
-1.0%, 12500 BTU	$44.33	$75.18	$99.12	$81.39	$67.22	$57.05	$54.78	$54.97	$55.37	$56.37	$57.62	$58.78	$59.84
-1.5%, 12500 BTU	$40.72	$57.90	$72.16	$64.93	$60.92	$52.88	$52.88	$53.52	$54.37	$55.58	$56.84	$58.00	$59.12
Ohio													
-4%, 12500 BTU	$39.19	$87.71	$89.29	$66.19	$51.87	$50.95	$50.22	$51.04	$51.96	$53.06	$54.18	$55.28	$56.31
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$43.75	$47.01	$41.11	$39.22	$39.76	$40.32	$40.86	$41.56	$42.37	$43.23	$44.08	$44.98
-3%, 11000 BTU (KY)	$28.91	$46.06	$49.63	$43.34	$41.37	$41.96	$42.60	$43.23	$44.03	$44.93	$45.89	$46.84	$47.84
Powder River Basin													
-.33%, 8400 BTU	$8.36	$15.29	$16.34	$13.55	$11.45	$11.46	$11.52	$11.62	$11.90	$12.27	$12.81	$13.37	$13.92
-.35%, 8800 BTU	$9.85	$16.87	$17.72	$15.13	$13.55	$13.76	$14.06	$14.33	$14.78	$15.33	$15.99	$16.68	$17.42
Uinta Basin													
-.5%, 11500 BTU	$29.93	$48.95	$50.65	$47.38	$44.44	$43.05	$43.10	$42.89	$43.02	$43.15	$42.49	$41.70	$40.18
Foreign Coal													
-.7%, 12000 BTU	$62.03	$136.25	$145.03	$108.60	$93.31	$81.37	$74.60	$70.07	$68.76	$70.07	$71.47	$72.81	$73.94
-.8%, 11600 BTU	$57.85	$127.07	$135.30	$101.49	$87.36	$76.41	$70.24	$66.11	$65.05	$66.48	$67.83	$69.14	$70.30
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$78.30	$106.44	$89.90	$71.58	$60.79	$55.49	$52.08	$51.12	$52.13	$53.07	$53.99	$54.78

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

HIGH CASE

March 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON

HIGH CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$99.03	$102.49	$73.07	$58.55	$57.43	$56.78	$55.90	$55.46	$55.03	$54.67	$54.23	$53.76
-1.8%, 13000 BTU	$45.85	$97.04	$99.74	$71.54	$57.44	$56.43	$55.89	$55.21	$54.81	$54.42	$54.07	$53.67	$53.25
-2.3%, 13000 BTU	$44.71	$94.05	$95.61	$69.26	$55.76	$54.93	$54.56	$54.17	$53.84	$53.50	$53.18	$52.84	$52.49
Central Appalachia													
-.7%, 12500 BTU	$46.46	$77.14	$101.52	$83.93	$74.03	$64.19	$64.02	$63.79	$63.33	$63.40	$63.73	$64.01	$64.32
-.7%, 13000 BTU	$49.50	$82.21	$108.21	$89.51	$79.08	$68.53	$68.34	$68.10	$67.60	$67.68	$68.02	$68.33	$68.66
-1.0%, 12500 BTU	$44.33	$73.96	$95.88	$77.22	$62.52	$52.03	$49.02	$48.26	$47.68	$47.61	$47.75	$47.79	$47.74
-1.5%, 12500 BTU	$40.72	$56.96	$69.80	$61.60	$56.66	$48.22	$47.32	$46.98	$46.81	$46.94	$47.10	$47.15	$47.17
Ohio													
-4%, 12500 BTU	$39.19	$86.29	$86.37	$62.80	$48.24	$46.46	$44.94	$44.81	$44.74	$44.81	$44.90	$44.94	$44.93
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$43.04	$45.47	$39.01	$36.48	$36.26	$36.08	$35.87	$35.79	$35.78	$35.82	$35.84	$35.88
-3%, 11000 BTU (KY)	$28.91	$45.31	$48.01	$41.12	$38.48	$38.26	$38.12	$37.95	$37.91	$37.95	$38.03	$38.08	$38.17
Powder River Basin													
-.33%, 8400 BTU	$8.36	$15.04	$15.80	$12.86	$10.65	$10.45	$10.31	$10.20	$10.25	$10.36	$10.62	$10.87	$11.11
-.35%, 8800 BTU	$9.85	$16.59	$17.14	$14.35	$12.60	$12.54	$12.58	$12.58	$12.73	$12.95	$13.25	$13.56	$13.90
Uinta Basin													
-.5%, 11500 BTU	$29.93	$48.15	$48.99	$44.95	$41.33	$39.26	$38.57	$37.65	$37.04	$36.44	$35.21	$33.90	$32.06
Foreign Coal: Colombia													
-.7%, 12000 BTU	$62.03	$134.05	$140.28	$103.03	$86.78	$74.20	$66.76	$61.52	$59.20	$59.18	$59.22	$59.19	$58.99
-.8%, 11600 BTU	$57.85	$125.02	$130.87	$96.29	$81.26	$69.68	$62.86	$58.03	$56.01	$56.15	$56.21	$56.21	$56.09
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$77.03	$102.96	$85.30	$66.57	$55.43	$49.66	$45.72	$44.02	$44.03	$43.98	$43.89	$43.71

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

HIGH CASE

March 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

HIGH CASE

Year:	*2008*				*2009*				*2010*			
Quarter:	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*
Northern Appalachia												
-1.6%, 13000 BTU	$79.50	$101.35	$109.65	$112.15	$115.60	$109.75	$103.70	$94.80	$86.50	$78.55	$72.90	$70.10
-1.8%, 13000 BTU	$78.19	$99.60	$107.45	$109.30	$112.43	$106.51	$100.95	$92.58	$84.65	$76.71	$71.49	$68.78
-2.3%, 13000 BTU	$76.22	$96.98	$104.16	$105.03	$107.67	$101.65	$96.82	$89.26	$81.87	$73.94	$69.38	$66.81
Central Appalachia												
-.7%, 12500 BTU	$85.30	$107.60	$109.55	$11.20	$109.82	$106.54	$102.59	$100.87	$96.25	$92.58	$85.60	$79.44
-.7%, 13000 BTU	$90.90	$114.64	$116.77	$11.94	$117.05	$113.54	$109.37	$107.51	$102.61	$98.68	$91.27	$84.69
-1.0%, 12500 BTU	$81.92	$102.96	$105.00	$10.75	$104.75	$100.81	$96.60	$94.31	$89.42	$85.39	$78.57	$72.34
-1.5%, 12500 BTU	$72.31	$80.95	$76.75	$7.32	$73.33	$72.38	$71.24	$71.71	$69.48	$67.36	$63.12	$59.51
Ohio												
-4%, 12500 BTU	$70.80	$89.83	$95.29	$94.92	$96.93	$91.77	$87.58	$80.89	$74.26	$67.01	$62.93	$60.55
Illinois Basin												
-3%, 11000 BTU (IL)	$35.40	$44.00	$47.40	$48.20	$49.00	$48.70	$46.00	$44.35	$43.00	$41.35	$40.50	$39.60
-3%, 11000 BTU (KY)	$37.49	$46.21	$49.67	$50.86	$51.78	$51.52	$48.48	$46.77	$45.46	$43.72	$42.60	$41.59
Powder River Basin												
-.33%, 8400 BTU	$13.20	$15.50	$16.10	$16.35	$16.50	$16.50	$16.35	$16.00	$15.00	$14.00	$13.20	$12.00
-.35%, 8800 BTU	$14.85	$17.07	$17.58	$17.97	$17.82	$17.92	$17.68	$17.47	$16.50	$15.55	$14.80	$13.65
Uinta Basin												
-.5%, 11500 BTU	$44.10	$48.54	$51.15	$52.00	$52.00	$51.35	$50.15	$49.10	$48.50	$48.00	$47.00	$46.00
Foreign Coal												
-.7%, 12000 BTU	$119.59	$131.88	$142.88	$150.66	$153.17	$150.04	$141.48	$135.41	$127.86	$112.61	$100.94	$93.01
-.8%, 11600 BTU	$111.56	$123.02	$133.22	$140.49	$142.85	$139.96	$132.02	$126.39	$119.41	$105.21	$94.36	$86.98
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$59.43	$75.05	$81.92	$96.80	$108.30	$107.55	$105.91	$104.02	$100.77	$95.13	$84.03	$79.68

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ANNUAL AVERAGE SPOT PR
HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$68.03	$68.88	$69.69	$70.53	$71.37	$72.25	$73.14	$74.04	$74.92	$75.81	$76.71
-1.8%, 13000 BTU	$67.45	$68.28	$69.09	$69.91	$70.75	$71.62	$72.50	$73.39	$74.27	$75.15	$76.04
-2.3%, 13000 BTU	$66.57	$67.38	$68.18	$68.99	$69.82	$70.67	$71.55	$72.43	$73.29	$74.16	$75.04
Central Appalachia											
-.7%, 12500 BTU	$82.55	$84.44	$86.39	$88.40	$90.45	$92.57	$94.32	$96.09	$97.87	$99.66	$101.49
-.7%, 13000 BTU	$88.12	$90.14	$92.24	$94.38	$96.59	$98.86	$100.74	$102.64	$104.55	$106.47	$108.44
-1.0%, 12500 BTU	$61.08	$62.20	$63.41	$64.59	$65.83	$67.07	$67.98	$68.91	$69.81	$70.75	$71.77
-1.5%, 12500 BTU	$60.38	$61.51	$62.74	$63.92	$65.17	$66.43	$67.34	$68.28	$69.20	$70.14	$71.17
Ohio											
-4%, 12500 BTU	$57.53	$60.27	$61.38	$62.57	$63.85	$65.14	$66.32	$67.50	$68.66	$69.86	$71.08
Illinois Basin											
-3%, 11000 BTU (IL)	$45.82	$46.80	$47.77	$48.75	$49.68	$50.66	$51.76	$52.89	$54.02	$55.14	$56.32
-3%, 11000 BTU (KY)	$48.79	$49.87	$50.95	$52.04	$53.09	$54.19	$55.41	$56.67	$57.92	$59.17	$60.49
Powder River Basin											
-.33%, 8400 BTU	$14.56	$15.34	$16.22	$16.93	$17.61	$18.36	$19.04	$19.80	$20.62	$21.38	$22.34
-.35%, 8800 BTU	$18.30	$19.30	$20.41	$21.35	$22.28	$23.32	$24.28	$25.34	$26.47	$27.56	$28.91
Uinta Basin											
-.5%, 11500 BTU	$39.42	$41.10	$42.85	$44.70	$46.63	$48.67	$50.80	$53.02	$55.31	$57.71	$60.25
Foreign Coal											
-.7%, 12000 BTU	$74.94	$76.02	$77.14	$78.28	$79.46	$80.67	$81.94	$83.24	$84.53	$85.85	$87.19
-.8%, 11600 BTU	$71.38	$72.46	$73.55	$74.66	$75.80	$76.98	$78.20	$79.43	$80.67	$81.92	$83.20
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$55.53	$56.29	$57.06	$57.87	$58.71	$59.59	$60.51	$61.46	$62.43	$63.42	$64.42

QCF (QUARTERLY
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ANNUAL AVERAGE SPOT PR
HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$53.27	$52.95	$52.61	$52.27	$51.94	$51.60	$51.27	$50.94	$50.62	$50.29	$49.97
-1.8%, 13000 BTU	$52.81	$52.48	$52.15	$51.81	$51.48	$51.15	$50.83	$50.50	$50.18	$49.86	$49.54
-2.3%, 13000 BTU	$52.13	$51.79	$51.46	$51.13	$50.81	$50.48	$50.16	$49.84	$49.52	$49.20	$48.89
Central Appalachia											
-.7%, 12500 BTU	$64.64	$64.91	$65.21	$65.51	$65.82	$66.12	$66.12	$66.12	$66.12	$66.12	$66.12
-.7%, 13000 BTU	$69.00	$69.29	$69.62	$69.95	$70.28	$70.61	$70.62	$70.63	$70.63	$70.64	$70.65
-1.0%, 12500 BTU	$47.82	$47.81	$47.86	$47.87	$47.90	$47.91	$47.65	$47.42	$47.17	$46.94	$46.76
-1.5%, 12500 BTU	$47.28	$47.29	$47.36	$47.38	$47.42	$47.45	$47.21	$46.99	$46.75	$46.54	$46.36
Ohio											
-4%, 12500 BTU	$45.05	$46.33	$46.33	$46.38	$46.46	$46.53	$46.49	$46.44	$46.39	$46.35	$46.31
Illinois Basin											
-3%, 11000 BTU (IL)	$35.88	$35.97	$36.06	$36.13	$36.15	$36.18	$36.29	$36.39	$36.49	$36.58	$36.69
-3%, 11000 BTU (KY)	$38.20	$38.33	$38.46	$38.57	$38.63	$38.70	$38.84	$38.99	$39.13	$39.26	$39.41
Powder River Basin											
-.33%, 8400 BTU	$11.40	$11.79	$12.25	$12.54	$12.81	$13.12	$13.35	$13.63	$13.93	$14.18	$14.55
-.35%, 8800 BTU	$14.33	$14.84	$15.40	$15.82	$16.22	$16.65	$17.02	$17.43	$17.89	$18.29	$18.83
Uinta Basin											
-.5%, 11500 BTU	$30.87	$31.59	$32.34	$33.13	$33.93	$34.76	$35.61	$36.48	$37.37	$38.28	$39.25
Foreign Coal: Colombia											
-.7%, 12000 BTU	$58.68	$58.43	$58.23	$58.02	$57.82	$57.62	$57.45	$57.28	$57.11	$56.95	$56.80
-.8%, 11600 BTU	$55.89	$55.70	$55.51	$55.33	$55.16	$54.99	$54.82	$54.66	$54.50	$54.35	$54.20
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$43.48	$43.27	$43.07	$42.89	$42.72	$42.56	$42.42	$42.29	$42.18	$42.08	$41.96

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

LOW CASE

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	Cell
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QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON	A121

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

LOW CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$59.64	$38.26	$28.06	$27.35	$27.21	$26.90	$26.50	$26.29	$26.12	$25.97	$27.08	$26.85
-1.8%, 13000 BTU	$45.85	$58.49	$37.23	$27.47	$26.82	$26.73	$26.47	$26.17	$25.98	$25.83	$25.69	$26.80	$26.60
-2.3%, 13000 BTU	$44.71	$56.76	$35.69	$26.60	$26.04	$26.02	$25.84	$25.68	$25.52	$25.39	$25.26	$26.39	$26.21
Central Appalachia													
-.7%, 12500 BTU	$46.46	$61.48	$45.93	$42.86	$39.58	$39.23	$39.75	$40.31	$40.77	$41.30	$41.88	$42.50	$43.13
-.7%, 13000 BTU	$49.50	$65.52	$48.95	$45.71	$42.28	$41.88	$42.43	$43.02	$43.52	$44.09	$44.70	$45.37	$46.03
-1.0%, 12500 BTU	$44.33	$58.94	$43.37	$39.43	$33.43	$31.79	$30.44	$30.49	$30.69	$31.02	$31.38	$31.73	$32.01
-1.5%, 12500 BTU	$40.72	$45.40	$31.57	$31.46	$30.29	$29.47	$29.38	$29.69	$30.13	$30.58	$30.96	$31.31	$31.63
Ohio													
-4%, 12500 BTU	$39.19	$52.22	$32.24	$24.12	$22.56	$21.35	$20.65	$20.60	$20.57	$20.63	$20.69	$21.77	$21.77
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$28.94	$26.46	$26.50	$26.88	$26.72	$26.57	$26.40	$26.34	$26.33	$26.34	$26.35	$26.36
-3%, 11000 BTU (KY)	$28.91	$30.48	$27.94	$27.94	$28.36	$28.20	$28.07	$27.93	$27.90	$27.92	$27.96	$27.99	$28.04
Powder River Basin													
-.33%, 8400 BTU	$8.36	$10.21	$8.83	$8.71	$9.02	$8.65	$8.36	$8.11	$8.01	$7.96	$8.00	$8.05	$8.10
-.35%, 8800 BTU	$9.85	$11.79	$10.21	$10.29	$10.68	$10.39	$10.19	$10.01	$9.95	$9.94	$9.98	$10.04	$10.13
Uinta Basin													
-.5%, 11500 BTU	$29.93	$29.25	$23.59	$21.23	$20.72	$20.86	$20.61	$20.41	$20.23	$20.07	$19.91	$19.74	$19.60
Foreign Coal													
-.7%, 12000 BTU	$62.03	$82.97	$39.13	$33.57	$32.58	$32.87	$33.13	$33.43	$33.70	$33.97	$34.31	$34.65	$34.95
-.8%, 11600 BTU	$57.85	$77.39	$36.50	$31.38	$30.51	$30.87	$31.19	$31.53	$31.88	$32.23	$32.56	$32.90	$33.23
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$46.38	$28.66	$27.88	$25.00	$24.56	$24.64	$24.84	$25.06	$25.27	$25.48	$25.69	$25.90

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

LOW CASE

March 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON

LOW CASE

Year:	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$58.67	$37.01	$26.63	$25.43	$24.81	$24.07	$23.26	$22.63	$22.06	$21.52	$22.01	$21.42
-1.8%, 13000 BTU	$45.85	$57.54	$36.01	$26.07	$24.95	$24.38	$23.69	$22.98	$22.37	$21.81	$21.29	$21.79	$21.22
-2.3%, 13000 BTU	$44.71	$55.84	$34.52	$25.24	$24.22	$23.73	$23.13	$22.55	$21.97	$21.45	$20.94	$21.45	$20.92
Central Appalachia													
-.7%, 12500 BTU	$46.46	$60.49	$44.42	$40.67	$36.81	$35.77	$35.57	$35.38	$35.10	$34.88	$34.71	$34.55	$34.41
-.7%, 13000 BTU	$49.50	$64.46	$47.35	$43.37	$39.32	$38.19	$37.97	$37.77	$37.47	$37.24	$37.05	$36.88	$36.73
-1.0%, 12500 BTU	$44.33	$57.99	$41.95	$37.41	$31.09	$28.99	$27.24	$26.77	$26.42	$26.20	$26.01	$25.79	$25.54
-1.5%, 12500 BTU	$40.72	$44.66	$30.54	$29.85	$28.17	$26.87	$26.29	$26.06	$25.95	$25.83	$25.65	$25.45	$25.23
Ohio													
-4%, 12500 BTU	$39.19	$51.38	$31.18	$22.88	$20.98	$19.47	$18.48	$18.09	$17.71	$17.42	$17.14	$17.69	$17.37
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$28.47	$25.60	$25.14	$25.00	$24.37	$23.77	$23.18	$22.68	$22.24	$21.83	$21.42	$21.03
-3%, 11000 BTU (KY)	$28.91	$29.98	$27.02	$26.50	$26.38	$25.71	$25.12	$24.52	$24.02	$23.58	$23.17	$22.76	$22.37
Powder River Basin													
-.33%, 8400 BTU	$8.36	$10.05	$8.54	$8.27	$8.39	$7.89	$7.48	$7.12	$6.90	$6.72	$6.63	$6.54	$6.46
-.35%, 8800 BTU	$9.85	$11.60	$9.87	$9.76	$9.93	$9.47	$9.12	$8.78	$8.57	$8.40	$8.27	$8.16	$8.08
Uinta Basin													
-.5%, 11500 BTU	$29.93	$28.78	$22.82	$20.14	$19.27	$19.02	$18.44	$17.92	$17.41	$16.95	$16.50	$16.05	$15.64
Foreign Coal: Colombia													
-.7%, 12000 BTU	$62.03	$81.63	$37.84	$31.85	$30.31	$29.98	$29.65	$29.35	$29.02	$28.69	$28.43	$28.17	$27.89
-.8%, 11600 BTU	$57.85	$76.13	$35.31	$29.77	$28.38	$28.15	$27.92	$27.68	$27.45	$27.22	$26.98	$26.75	$26.51
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$45.63	$27.72	$26.45	$23.25	$22.39	$22.05	$21.81	$21.57	$21.34	$21.11	$20.89	$20.66

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

LOW CASE

March 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

LOW CASE

Year:	*2008*				*2009*				*2010*			
Quarter:	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*
Northern Appalachia												
-1.6%, 13000 BTU	$71.34	$65.16	$54.32	$47.73	$42.73	$40.60	$36.63	$33.08	$30.64	$29.11	$26.85	$25.65
-1.8%, 13000 BTU	$70.17	$64.04	$53.23	$46.52	$41.56	$39.40	$35.66	$32.31	$29.98	$28.42	$26.33	$25.17
-2.3%, 13000 BTU	$68.40	$62.35	$51.60	$44.70	$39.80	$37.60	$34.20	$31.15	$29.00	$27.40	$25.55	$24.45
Central Appalachia												
-.7%, 12500 BTU	$71.15	$63.22	$57.46	$54.10	$48.35	$46.20	$45.00	$44.15	$43.50	$43.00	$42.75	$42.20
-.7%, 13000 BTU	$75.82	$67.36	$61.24	$57.65	$51.53	$49.23	$47.97	$47.06	$46.37	$45.83	$45.58	$44.99
-1.0%, 12500 BTU	$68.33	$60.50	$55.07	$51.92	$46.12	$43.72	$42.37	$41.28	$40.41	$39.66	$39.24	$38.43
-1.5%, 12500 BTU	$60.31	$47.56	$40.26	$35.33	$32.29	$31.39	$31.25	$31.39	$31.40	$31.29	$31.52	$31.61
Ohio												
-4%, 12500 BTU	$63.54	$57.76	$47.21	$40.40	$35.83	$33.95	$30.94	$28.23	$26.31	$24.83	$23.18	$22.16
Illinois Basin												
-3%, 11000 BTU (IL)	$31.10	$29.65	$28.15	$26.85	$26.50	$26.40	$26.60	$26.35	$26.50	$26.40	$26.60	$26.50
-3%, 11000 BTU (KY)	$32.93	$31.14	$29.50	$28.33	$28.00	$27.93	$28.03	$27.79	$28.02	$27.91	$27.98	$27.83
Powder River Basin												
-.33%, 8400 BTU	$11.35	$10.90	$9.40	$9.20	$9.20	$9.10	$8.60	$8.40	$8.50	$8.40	$9.00	$8.95
-.35%, 8800 BTU	$13.00	$12.47	$10.88	$10.82	$10.52	$10.52	$9.93	$9.87	$10.00	$9.95	$10.60	$10.60
Uinta Basin												
-.5%, 11500 BTU	$33.25	$31.10	$27.40	$25.25	$24.70	$24.00	$23.20	$22.45	$21.70	$21.15	$21.20	$20.85
Foreign Coal												
-.7%, 12000 BTU	$108.53	$92.65	$73.93	$56.78	$46.73	$39.35	$36.28	$34.14	$33.73	$33.50	$33.65	$33.41
-.8%, 11600 BTU	$101.24	$86.43	$68.94	$52.94	$43.58	$36.70	$33.85	$31.87	$31.51	$31.30	$31.45	$31.25
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$53.93	$52.72	$42.39	$36.48	$33.04	$28.21	$27.16	$26.23	$26.59	$28.30	$28.01	$28.62

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
LOW CASE
March 2008

ANNUAL AVERAGE SPOT PI
LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$26.62	$26.44	$26.25	$26.06	$25.87	$25.69	$25.52	$25.34	$25.16	$24.98	$24.80
-1.8%, 13000 BTU	$26.39	$26.21	$26.02	$25.83	$25.65	$25.47	$25.30	$25.12	$24.94	$24.76	$24.58
-2.3%, 13000 BTU	$26.05	$25.87	$25.68	$25.49	$25.31	$25.14	$24.96	$24.79	$24.61	$24.43	$24.26
Central Appalachia											
-.7%, 12500 BTU	$43.75	$44.35	$44.96	$45.58	$46.22	$46.87	$47.75	$48.65	$49.55	$50.46	$51.38
-.7%, 13000 BTU	$46.70	$47.34	$48.00	$48.67	$49.35	$50.05	$51.00	$51.96	$52.93	$53.91	$54.90
-1.0%, 12500 BTU	$32.37	$32.67	$33.00	$33.30	$33.64	$33.96	$34.42	$34.89	$35.34	$35.82	$36.33
-1.5%, 12500 BTU	$32.00	$32.31	$32.65	$32.96	$33.30	$33.63	$34.09	$34.57	$35.03	$35.51	$36.03
Ohio											
-4%, 12500 BTU	$21.83	$22.44	$22.42	$22.43	$22.45	$22.47	$22.45	$22.41	$22.37	$22.33	$22.29
Illinois Basin											
-3%, 11000 BTU (IL)	$26.34	$26.39	$26.42	$26.44	$26.43	$26.43	$26.49	$26.55	$26.60	$26.63	$26.68
-3%, 11000 BTU (KY)	$28.05	$28.12	$28.17	$28.23	$28.24	$28.27	$28.36	$28.45	$28.52	$28.58	$28.65
Powder River Basin											
-.33%, 8400 BTU	$8.16	$8.30	$8.43	$8.43	$8.43	$8.44	$8.44	$8.45	$8.45	$8.45	$8.47
-.35%, 8800 BTU	$10.26	$10.44	$10.60	$10.64	$10.67	$10.72	$10.76	$10.81	$10.85	$10.90	$10.96
Uinta Basin											
-.5%, 11500 BTU	$19.49	$19.37	$19.25	$19.14	$19.04	$18.95	$18.87	$18.78	$18.69	$18.61	$18.54
Foreign Coal											
-.7%, 12000 BTU	$35.23	$35.54	$35.86	$36.17	$36.49	$36.81	$37.15	$37.48	$37.81	$38.12	$38.44
-.8%, 11600 BTU	$33.56	$33.88	$34.19	$34.50	$34.81	$35.13	$35.45	$35.77	$36.08	$36.38	$36.68
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$26.11	$26.32	$26.52	$26.74	$26.96	$27.19	$27.43	$27.68	$27.92	$28.17	$28.40

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
LOW CASE
March 2008

ANNUAL AVERAGE SPOT PI
LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$20.84	$20.33	$19.81	$19.31	$18.83	$18.35	$17.89	$17.44	$17.00	$16.57	$16.15
-1.8%, 13000 BTU	$20.66	$20.15	$19.64	$19.15	$18.66	$18.19	$17.73	$17.29	$16.85	$16.43	$16.01
-2.3%, 13000 BTU	$20.39	$19.88	$19.38	$18.89	$18.42	$17.95	$17.50	$17.06	$16.63	$16.21	$15.80
Central Appalachia											
-.7%, 12500 BTU	$34.26	$34.09	$33.93	$33.78	$33.63	$33.48	$33.48	$33.48	$33.48	$33.48	$33.48
-.7%, 13000 BTU	$36.57	$36.39	$36.23	$36.07	$35.91	$35.75	$35.75	$35.76	$35.76	$35.76	$35.77
-1.0%, 12500 BTU	$25.34	$25.11	$24.91	$24.68	$24.47	$24.26	$24.13	$24.01	$23.88	$23.76	$23.67
-1.5%, 12500 BTU	$25.06	$24.84	$24.64	$24.43	$24.23	$24.02	$23.90	$23.79	$23.67	$23.56	$23.47
Ohio											
-4%, 12500 BTU	$17.10	$17.25	$16.93	$16.62	$16.34	$16.05	$15.74	$15.42	$15.11	$14.81	$14.52
Illinois Basin											
-3%, 11000 BTU (IL)	$20.63	$20.28	$19.94	$19.60	$19.23	$18.88	$18.57	$18.27	$17.97	$17.67	$17.38
-3%, 11000 BTU (KY)	$21.96	$21.61	$21.27	$20.92	$20.55	$20.20	$19.88	$19.57	$19.27	$18.96	$18.67
Powder River Basin											
-.33%, 8400 BTU	$6.39	$6.38	$6.36	$6.25	$6.14	$6.03	$5.92	$5.81	$5.71	$5.61	$5.52
-.35%, 8800 BTU	$8.03	$8.03	$8.00	$7.88	$7.76	$7.66	$7.54	$7.44	$7.33	$7.23	$7.14
Uinta Basin											
-.5%, 11500 BTU	$15.26	$14.89	$14.53	$14.19	$13.85	$13.54	$13.23	$12.92	$12.63	$12.35	$12.08
Foreign Coal: Colombia											
-.7%, 12000 BTU	$27.59	$27.32	$27.07	$26.81	$26.55	$26.29	$26.04	$25.79	$25.54	$25.29	$25.04
-.8%, 11600 BTU	$26.28	$26.04	$25.80	$25.57	$25.33	$25.09	$24.85	$24.61	$24.38	$24.14	$23.90
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$20.44	$20.23	$20.02	$19.82	$19.62	$19.42	$19.23	$19.05	$18.86	$18.69	$18.50

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
BUSINESS-AS-USUAL CASE
March 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BUSINESS-AS-USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$78.93	$50.48	$41.14	$37.42	$37.73	$37.85	$37.96	$38.34	$38.78	$39.25	$39.67	$40.09
-1.8%, 13000 BTU	$45.85	$77.37	$49.13	$40.29	$36.70	$37.11	$37.30	$37.54	$37.93	$38.39	$38.86	$39.30	$39.74
-2.3%, 13000 BTU	$44.71	$75.05	$47.10	$39.00	$35.63	$36.17	$36.49	$36.89	$37.32	$37.80	$38.27	$38.74	$39.21
Central Appalachia													
-.7%, 12500 BTU	$46.46	$80.24	$57.87	$54.38	$53.33	$54.89	$56.50	$57.62	$58.45	$59.48	$60.69	$62.06	$63.50
-.7%, 13000 BTU	$49.50	$85.51	$61.68	$57.99	$56.97	$58.60	$60.32	$61.50	$62.39	$63.50	$64.78	$66.25	$67.78
-1.0%, 12500 BTU	$44.33	$76.93	$54.65	$50.03	$46.04	$44.76	$44.18	$44.05	$43.98	$44.65	$45.46	$46.32	$47.12
-1.5%, 12500 BTU	$40.72	$59.21	$39.79	$39.91	$40.82	$41.23	$41.77	$42.44	$43.20	$44.04	$44.86	$45.71	$46.57
Ohio													
-4%, 12500 BTU	$39.19	$69.01	$42.54	$35.36	$32.34	$32.85	$33.14	$33.53	$33.93	$34.39	$34.83	$35.27	$35.72
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$35.91	$32.47	$33.37	$35.44	$35.53	$35.73	$36.05	$36.39	$36.77	$37.13	$37.51	$37.90
-3%, 11000 BTU (KY)	$28.91	$37.81	$34.28	$35.18	$37.15	$37.22	$37.43	$37.77	$38.13	$38.52	$38.89	$39.28	$39.68
Powder River Basin													
-.33%, 8400 BTU	$8.36	$12.91	$10.88	$10.08	$9.98	$10.07	$10.06	$10.06	$10.11	$10.20	$10.40	$10.59	$10.76
-.35%, 8800 BTU	$9.85	$15.56	$12.30	$11.49	$11.85	$12.08	$12.22	$12.33	$12.48	$12.67	$12.91	$13.15	$13.41
Uinta Basin													
-.5%, 11500 BTU	$29.93	$38.15	$28.99	$25.54	$24.86	$24.00	$24.26	$24.59	$24.93	$25.31	$25.68	$26.05	$26.43
Foreign Coal													
-.7%, 12000 BTU	$62.03	$105.40	$65.52	$56.25	$52.13	$49.89	$49.93	$50.47	$51.00	$51.55	$52.23	$52.93	$53.60
-.8%, 11600 BTU	$57.85	$98.30	$61.13	$52.57	$48.81	$46.84	$47.02	$47.62	$48.25	$48.91	$49.57	$50.27	$50.96
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$59.59	$48.09	$46.66	$39.99	$37.26	$37.14	$37.52	$37.92	$38.35	$38.78	$39.25	$39.72

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
BUSINESS-AS-USUAL CASE
March 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON

BUSINESS-AS-USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$77.65	$48.83	$39.03	$34.80	$34.41	$33.87	$33.33	$33.01	$32.75	$32.52	$32.25	$31.99
-1.8%, 13000 BTU	$45.85	$76.12	$47.52	$38.22	$34.14	$33.84	$33.38	$32.95	$32.66	$32.42	$32.20	$31.95	$31.71
-2.3%, 13000 BTU	$44.71	$73.83	$45.55	$37.01	$33.14	$32.99	$32.65	$32.39	$32.13	$31.92	$31.71	$31.49	$31.29
Central Appalachia													
-.7%, 12500 BTU	$46.46	$78.94	$55.98	$51.60	$49.60	$50.05	$50.57	$50.58	$50.33	$50.24	$50.29	$50.45	$50.66
-.7%, 13000 BTU	$49.50	$84.12	$59.66	$55.02	$52.99	$53.44	$53.98	$53.99	$53.72	$53.63	$53.69	$53.86	$54.08
-1.0%, 12500 BTU	$44.33	$75.68	$52.86	$47.47	$42.82	$40.82	$39.54	$38.67	$37.87	$37.71	$37.67	$37.65	$37.60
-1.5%, 12500 BTU	$40.72	$58.25	$38.48	$37.87	$37.97	$37.60	$37.38	$37.25	$37.20	$37.19	$37.17	$37.16	$37.16
Ohio													
-4%, 12500 BTU	$39.19	$67.89	$41.15	$33.55	$30.07	$29.95	$29.66	$29.44	$29.22	$29.04	$28.86	$28.68	$28.50
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$35.33	$31.40	$31.66	$32.96	$32.40	$31.97	$31.65	$31.34	$31.05	$30.77	$30.49	$30.24
-3%, 11000 BTU (KY)	$28.91	$37.20	$33.15	$33.38	$34.55	$33.94	$33.50	$33.16	$32.83	$32.53	$32.23	$31.93	$31.66
Powder River Basin													
-.33%, 8400 BTU	$8.36	$12.70	$10.53	$9.56	$9.28	$9.18	$9.00	$8.83	$8.70	$8.61	$8.62	$8.61	$8.59
-.35%, 8800 BTU	$9.85	$15.31	$11.89	$10.90	$11.02	$11.01	$10.94	$10.83	$10.74	$10.70	$10.70	$10.69	$10.70
Uinta Basin													
-.5%, 11500 BTU	$29.93	$37.54	$28.04	$24.23	$23.12	$21.89	$21.71	$21.59	$21.47	$21.38	$21.28	$21.17	$21.09
Foreign Coal: Colombia													
-.7%, 12000 BTU	$62.03	$103.69	$63.38	$53.37	$48.48	$45.49	$44.69	$44.31	$43.92	$43.54	$43.28	$43.03	$42.77
-.8%, 11600 BTU	$57.85	$96.71	$59.13	$49.88	$45.39	$42.71	$42.08	$41.80	$41.55	$41.31	$41.08	$40.87	$40.66
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$58.62	$46.51	$44.27	$37.19	$33.98	$33.24	$32.93	$32.65	$32.39	$32.14	$31.91	$31.69

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
BUSINESS-AS-USUAL CASE
March 2008

ANNUAL AVERAGE SPOT P
BUSINESS-AS-USUAL CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$40.55	$41.14	$41.66	$42.20	$42.75	$43.32	$43.89	$44.46	$45.02	$45.58	$46.17
-1.8%, 13000 BTU	$40.23	$40.78	$41.30	$41.84	$42.38	$42.94	$43.51	$44.07	$44.63	$45.18	$45.77
-2.3%, 13000 BTU	$39.74	$40.24	$40.75	$41.29	$41.82	$42.38	$42.93	$43.49	$44.04	$44.58	$45.17
Central Appalachia											
-.7%, 12500 BTU	$64.96	$66.46	$67.96	$69.60	$71.22	$72.95	$74.75	$76.56	$78.41	$80.25	$82.15
-.7%, 13000 BTU	$69.34	$70.95	$72.56	$74.32	$76.05	$77.90	$79.83	$81.77	$83.76	$85.74	$87.77
-1.0%, 12500 BTU	$48.05	$48.95	$49.89	$50.86	$51.84	$52.86	$53.88	$54.91	$55.94	$56.98	$58.10
-1.5%, 12500 BTU	$47.51	$48.41	$49.36	$50.33	$51.32	$52.34	$53.36	$54.40	$55.44	$56.48	$57.60
Ohio											
-4%, 12500 BTU	$36.22	$36.70	$37.18	$37.68	$38.19	$38.72	$39.24	$39.77	$40.29	$40.81	$41.37
Illinois Basin											
-3%, 11000 BTU (IL)	$38.32	$38.74	$39.16	$39.59	$40.02	$40.47	$40.92	$41.37	$41.81	$42.24	$42.71
-3%, 11000 BTU (KY)	$40.12	$40.55	$40.98	$41.42	$41.87	$42.33	$42.79	$43.25	$43.70	$44.14	$44.62
Powder River Basin											
-.33%, 8400 BTU	$10.97	$11.11	$11.25	$11.39	$11.51	$11.65	$11.75	$11.87	$11.99	$12.09	$12.24
-.35%, 8800 BTU	$13.74	$13.99	$14.22	$14.45	$14.67	$14.91	$15.12	$15.35	$15.58	$15.80	$16.06
Uinta Basin											
-.5%, 11500 BTU	$26.85	$27.26	$27.67	$28.10	$28.53	$28.98	$29.43	$29.88	$30.33	$30.78	$31.26
Foreign Coal											
-.7%, 12000 BTU	$54.27	$55.01	$55.80	$56.62	$57.49	$58.40	$59.38	$60.40	$61.44	$62.52	$63.57
-.8%, 11600 BTU	$51.69	$52.44	$53.20	$54.00	$54.84	$55.73	$56.67	$57.64	$58.63	$59.66	$60.67
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$40.21	$40.73	$41.28	$41.86	$42.48	$43.14	$43.85	$44.60	$45.37	$46.19	$46.97

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
BUSINESS-AS-USUAL CASE
March 2008

ANNUAL AVERAGE SPOT P
BUSINESS-AS-USUAL CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$31.75	$31.62	$31.44	$31.28	$31.11	$30.94	$30.77	$30.59	$30.41	$30.24	$30.08
-1.8%, 13000 BTU	$31.50	$31.35	$31.17	$31.01	$30.84	$30.67	$30.50	$30.33	$30.15	$29.97	$29.82
-2.3%, 13000 BTU	$31.12	$30.94	$30.76	$30.60	$30.43	$30.27	$30.10	$29.93	$29.75	$29.58	$29.43
Central Appalachia											
-.7%, 12500 BTU	$50.87	$51.09	$51.30	$51.59	$51.82	$52.10	$52.40	$52.68	$52.98	$53.24	$53.52
-.7%, 13000 BTU	$54.30	$54.54	$54.77	$55.08	$55.34	$55.64	$55.96	$56.27	$56.59	$56.88	$57.18
-1.0%, 12500 BTU	$37.62	$37.63	$37.66	$37.69	$37.72	$37.76	$37.77	$37.78	$37.80	$37.80	$37.85
-1.5%, 12500 BTU	$37.20	$37.22	$37.26	$37.30	$37.34	$37.39	$37.41	$37.43	$37.46	$37.47	$37.52
Ohio											
-4%, 12500 BTU	$28.36	$28.21	$28.06	$27.93	$27.79	$27.65	$27.51	$27.37	$27.22	$27.07	$26.95
Illinois Basin											
-3%, 11000 BTU (IL)	$30.01	$29.78	$29.56	$29.34	$29.12	$28.91	$28.69	$28.47	$28.25	$28.02	$27.82
-3%, 11000 BTU (KY)	$31.42	$31.17	$30.93	$30.70	$30.46	$30.23	$30.00	$29.76	$29.52	$29.28	$29.07
Powder River Basin											
-.33%, 8400 BTU	$8.59	$8.54	$8.49	$8.44	$8.38	$8.32	$8.24	$8.17	$8.10	$8.02	$7.97
-.35%, 8800 BTU	$10.76	$10.75	$10.74	$10.71	$10.67	$10.65	$10.60	$10.56	$10.53	$10.48	$10.46
Uinta Basin											
-.5%, 11500 BTU	$21.03	$20.96	$20.89	$20.82	$20.76	$20.70	$20.63	$20.56	$20.49	$20.42	$20.36
Foreign Coal: Colombia											
-.7%, 12000 BTU	$42.50	$42.29	$42.12	$41.96	$41.83	$41.72	$41.63	$41.56	$41.51	$41.48	$41.41
-.8%, 11600 BTU	$40.48	$40.31	$40.16	$40.02	$39.91	$39.81	$39.73	$39.66	$39.61	$39.58	$39.52
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$31.49	$31.31	$31.16	$31.02	$30.91	$30.81	$30.74	$30.69	$30.66	$30.64	$30.60

COAL MONTHLY SPREADSHEET
JD Energy, Inc.
July 2nd, 2008

DIRECTORY

All prices are displayed in nominal $/short ton

Region:	Central Appalachia	Central Appalachia	Central Appalachia	Central Appalachia	Northern Appalachia	Northern Appalachia	Illinois Basin (IL)	Illinois Basin (WKY)	Powder River Basin	Powder River Basin	Uinta Basin (CO)	Petcoke (Gulf)	Petcoke (Gulf)	Petcoke (West Coast)	Colombia Basin (CO)
Market:	Physical	Physical	Physical	NYMEX	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical
SO2 / mmBTU	1.2	1.6	2.3	1.6	2.5	3.0-4.0	5.45	5.45	0.8	0.8	0.9	8.6	5.7	5.7	1.4
Sulfur:	0.75%	1.00%	1.40%	1.00%	1.60%	2.30%	3.00%	3.00%	0.33%	0.35%	0.50%	6.00%	4.00%	4.00%	0.80%
BTU / lb:	12,500	12,500	12,500	12,000	13,000	13,000	11,000	11,000	8,400	8,800	11,500	14,000	14,000	14,000	11,300
Mode:	FOB Mine (CSX)	FOB Mine (CSX)	FOB Mine (CSX)	Barge-Big Sandy	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOBT	FOBT	FOBT	FOB Mine
Jan 2006	$61.79	$55.52	$49.23	$55.80	$51.05	$43.32	$27.60	$29.75	$16.00	$20.00	$38.45	$19.87	$27.67	$31.30	$41.41
Feb	$61.09	$55.52	$48.65	$55.95	$49.96	$42.23	$27.35	$29.45	$14.10	$18.15	$38.55	$24.83	$28.12	$32.66	$44.83
Mar	$60.74	$54.27	$49.03	$53.88	$47.88	$39.75	$26.85	$28.90	$12.50	$14.90	$38.35	$30.28	$30.39	$32.66	$49.84
Apr	$60.38	$52.86	$47.32	$52.89	$47.63	$40.14	$26.75	$28.75	$11.15	$14.25	$38.25	$34.25	$33.57	$34.25	$50.09
May	$58.97	$51.82	$46.46	$51.19	$46.59	$39.70	$26.40	$28.45	$10.75	$13.75	$37.90	$36.30	$37.83	$36.38	$47.72
Jun	$58.82	$50.73	$44.98	$49.75	$45.60	$39.30	$26.45	$28.50	$10.00	$12.85	$36.70	$39.70	$43.77	$36.74	$48.64
Jul	$56.55	$49.79	$44.21	$46.63	$44.36	$38.06	$26.10	$28.20	$8.95	$11.45	$36.00	$41.30	$44.45	$40.82	$47.67
Aug	$53.83	$49.95	$44.11	$47.51	$43.81	$38.31	$26.70	$28.80	$8.25	$10.45	$35.45	$38.10	$43.09	$43.09	$49.73
Sep	$52.32	$49.32	$43.96	$45.35	$44.26	$39.35	$27.10	$29.15	$7.40	$8.65	$36.05	$38.55	$43.32	$44.45	$44.68
Oct	$50.86	$47.81	$43.75	$43.12	$43.81	$39.75	$27.45	$29.45	$7.80	$9.45	$36.00	$39.35	$43.91	$41.64	$45.13
Nov	$49.45	$46.77	$43.19	$40.82	$42.92	$39.50	$27.70	$29.70	$7.80	$9.80	$34.95	$36.05	$38.78	$38.78	$45.93
Dec	$46.17	$44.11	$40.93	$41.89	$41.98	$38.16	$27.65	$29.60	$7.30	$9.15	$34.45	$38.55	$43.09	$40.37	$46.44
Jan 2007	$42.90	$40.55	$36.90	$39.55	$44.05	$41.10	$26.60	$28.50	$7.15	$8.85	$34.20	$43.18	$51.35	$46.09	$46.16
Feb	$40.90	$38.20	$34.00	$40.72	$44.25	$42.15	$26.90	$28.80	$7.35	$8.95	$33.55	$44.00	$52.45	$47.63	$47.57
Mar	$41.95	$39.90	$35.65	$41.07	$43.70	$41.95	$27.05	$29.00	$7.05	$8.60	$33.50	$44.91	$52.63	$48.76	$48.22
Apr	$43.90	$41.70	$38.00	$41.88	$45.05	$43.40	$26.85	$28.85	$7.00	$8.45	$33.55	$46.38	$52.80	$49.10	$46.89
May	$45.00	$43.00	$39.90	$43.97	$44.35	$42.35	$26.55	$28.55	$7.45	$8.85	$33.50	$48.13	$53.13	$49.94	$46.22
Jun	$45.30	$42.90	$39.75	$46.93	$44.85	$43.05	$26.20	$28.15	$8.00	$9.50	$30.45	$48.53	$53.18	$50.58	$51.96
Jul	$45.55	$43.50	$40.20	$43.86	$46.35	$44.35	$26.65	$28.50	$8.50	$10.05	$27.95	$48.53	$53.18	$51.14	$53.19
Aug	$45.60	$43.55	$40.05	$43.08	$46.65	$44.70	$27.10	$28.90	$9.05	$10.65	$26.45	$44.79	$48.28	$51.44	$54.78
Sep	$45.80	$43.90	$40.25	$44.13	$46.80	$44.95	$27.05	$28.90	$9.20	$10.70	$26.65	$41.62	$46.55	$51.65	$56.53
Oct	$50.55	$48.55	$44.70	$46.87	$48.75	$46.95	$27.65	$29.55	$9.45	$10.90	$26.90	$42.07	$46.38	$51.26	$66.68
Nov	$53.95	$52.15	$48.10	$51.82	$49.50	$48.00	$27.95	$29.80	$9.80	$11.05	$26.10	$42.07	$46.55	$56.02	$82.33
Dec	$56.15	$54.10	$51.15	$53.65	$55.05	$53.55	$27.60	$29.45	$10.30	$11.65	$26.30	$44.57	$48.42	$60.33	$86.75
Jan 2008	$60.70	$58.65	$55.75	$62.96	$62.60	$60.30	$28.05	$29.95	$10.65	$12.40	$28.85	$46.95	$51.48	$62.78	$92.19
Feb	$77.75	$74.45	$65.95	$82.50	$74.30	$71.20	$31.95	$33.85	$11.95	$14.30	$35.50	$55.11	$59.99	$65.09	$105.60
Mar	$82.75	$79.30	$73.45	$76.85	$82.45	$79.60	$35.15	$37.10	$12.10	$14.50	$38.75	$56.98	$66.40	$71.56	$102.17
Apr	$87.40	$84.25	$78.55	$89.95	$102.10	$96.20	$43.10	$45.10	$11.85	$14.40	$43.35	$59.10	$70.99	$74.84	$100.33
May	$102.40	$99.40	$91.30	$104.95	$105.25	$101.60	$49.25	$51.25	$11.60	$14.10	$51.90	$64.86	$79.29	$100.92	$112.38
Jun	$118.40	$115.00	$106.25	$119.54	$113.15	$108.40	$53.00	$54.95	$11.15	$13.25	$56.65	$74.16	$84.82	$113.67	$130.07
Jul	$161.45	$158.45	$148.95	$167.36	$158.78	$152.83	$59.00	$60.85	$10.60	$12.40	$61.40	$96.79	$113.04	$135.64	$173.45
Aug	$167.08	$164.08	$153.13	$172.80	$164.73	$158.68	$59.65	$61.45	$11.05	$12.75	$62.10	$103.69	$120.04	$142.59	$179.08
Sep	$171.34	$168.34	$157.24	$178.67	$169.09	$163.09	$60.05	$61.90	$11.60	$13.20	$62.55	$108.36	$124.86	$147.46	$183.34
Oct	$173.52	$170.52	$159.22	$179.08	$171.37	$165.42	$60.20	$62.10	$11.80	$13.55	$63.40	$110.57	$127.32	$149.72	$185.52
Nov	$171.97	$169.02	$157.57	$177.25	$169.67	$163.87	$60.50	$62.35	$11.90	$13.80	$62.90	$111.33	$128.18	$150.53	$184.02
Dec	$169.78	$167.03	$155.43	$172.96	$167.53	$161.88	$60.75	$62.60	$12.05	$13.80	$61.25	$111.58	$128.08	$150.88	$182.03
Jan 2009	$167.79	$164.99	$153.19	$168.58	$165.19	$159.79	$60.75	$62.55	$12.35	$13.90	$61.00	$111.95	$127.85	$151.30	$179.99
Feb	$165.43	$162.58	$150.43	$164.57	$162.58	$157.33	$60.25	$62.05	$12.30	$13.70	$59.85	$112.76	$128.76	$152.16	$177.58
Mar	$162.40	$159.50	$147.05	$160.55	$159.40	$154.20	$59.80	$61.65	$12.00	$13.35	$56.45	$105.75	$121.85	$145.25	$174.50
Apr	$155.78	$152.83	$140.08	$152.44	$152.53	$147.48	$58.85	$60.70	$11.80	$13.20	$52.70	$94.99	$111.19	$134.54	$167.83
May	$140.01	$136.91	$123.91	$134.47	$136.51	$131.51	$56.60	$58.50	$11.50	$12.95	$49.75	$79.60	$96.00	$119.50	$151.91
Jun	$117.84	$114.64	$101.44	$111.67	$114.19	$109.24	$53.70	$55.55	$11.20	$12.60	$46.95	$65.73	$81.53	$105.73	$129.64
Jul	$107.73	$104.48	$91.38	$102.71	$103.88	$99.03	$50.45	$52.25	$10.85	$12.20	$47.30	$59.62	$75.02	$99.77	$119.48
Aug	$102.66	$99.31	$86.26	$97.84	$98.56	$93.81	$48.20	$49.95	$10.55	$11.85	$45.65	$59.41	$74.31	$99.76	$114.31
Sep	$99.71	$96.31	$83.46	$94.17	$95.41	$90.76	$44.65	$46.40	$10.05	$11.40	$42.80	$60.15	$74.55	$100.35	$111.31
Oct	$96.27	$92.77	$80.27	$91.45	$91.72	$87.12	$42.10	$43.90	$9.30	$10.80	$39.90	$60.47	$74.27	$100.57	$107.77
Nov	$92.20	$88.60	$76.40	$89.24	$87.25	$82.90	$39.95	$41.75	$9.15	$10.65	$36.35	$60.28	$73.38	$100.28	$103.60
Dec	$86.99	$83.29	$71.49	$84.05	$81.64	$77.54	$37.30	$39.05	$9.55	$10.95	$33.45	$59.22	$71.82	$96.62	$98.29
Jan 2010	$82.15	$78.35	$66.75	$79.35	$76.40	$72.55	$35.50	$37.30	$9.75	$11.30	$31.80	$58.18	$70.28	$92.28	$93.35
Feb	$78.39	$74.49	$62.94	$74.83	$72.19	$68.59	$35.20	$37.00	$9.90	$11.30	$31.50	$57.63	$69.33	$88.79	$89.49
Mar	$73.73	$69.73	$58.63	$69.33	$66.93	$63.73	$34.45	$36.30	$9.85	$11.20	$29.50	$56.32	$67.32	$84.87	$84.73
Apr	$68.61	$64.51	$53.86	$63.46	$61.31	$58.36	$33.40	$35.25	$9.70	$11.10	$27.85	$54.50	$64.90	$80.05	$79.51
May	$63.59	$59.39	$49.34	$57.85	$55.74	$53.04	$32.85	$34.75	$9.55	$11.00	$26.00	$52.52	$62.32	$75.07	$74.39
Jun	$59.74	$55.44	$45.54	$55.52	$51.19	$48.79	$33.20	$35.05	$9.85	$11.25	$25.40	$51.20	$59.80	$70.75	$70.44
Jul	$59.50	$55.10	$44.80	$55.64	$50.40	$48.20	$33.60	$35.40	$10.20	$11.55	$25.60	$49.37	$57.17	$65.92	$66.04
Aug	$60.40	$55.90	$45.90	$56.65	$50.60	$48.70	$34.20	$35.95	$10.80	$12.10	$25.80	$48.05	$54.90	$63.25	$62.55
Sep	$58.35	$53.75	$44.40	$53.70	$48.20	$46.35	$34.00	$35.75	$10.50	$11.85	$25.50	$46.09	$53.09	$61.04	$58.42
Oct	$56.20	$51.50	$42.25	$50.44	$45.75	$43.85	$33.75	$35.55	$10.20	$11.70	$25.30	$44.07	$51.32	$58.67	$54.43
Nov	$54.10	$49.30	$40.85	$49.24	$43.25	$41.40	$33.60	$35.40	$10.25	$11.75	$25.30	$42.18	$49.48	$54.98	$50.80
Dec	$53.55	$48.65	$40.30	$49.01	$42.30	$40.50	$33.40	$35.15	$10.40	$11.80	$25.35	$40.14	$47.39	$51.34	$47.17

COAL MONTHLY SPREADSHEET
JD Energy, Inc.
July 2nd, 2008

PRODUCTION

TOTAL PRODUCTION (Millions of Tons)

	Q1	Q2	Q3	Q4	Total	% Change
2006	289.1	292.4	289.8	291.4	1,162.7	2.76%
2007	285.9	285.6	285.8	288.3	1,145.6	-1.48%
2008	289.1	288.5	295.1	290.9	1,163.6	1.58%
2009	291.5	285.6	289.9	291.0	1,158.7	-0.42%

APPALACHIAN PRODUCTION

	Q1	Q2	Q3	Q4	Total	% Change
2006	103.5	100.3	94.3	93.8	391.9	-1.38%
2007	99.5	95.5	91.4	91.4	377.8	-3.59%
2008	97.8	99.2	98.6	95.8	391.4	3.60%
2009	95.6	93.5	94.3	95.2	379.4	-3.09%

INTERIOR PRODUCTION

	Q1	Q2	Q3	Q4	Total	% Change
2006	37.6	36.8	38.8	38.2	151.4	1.50%
2007	38.0	36.3	36.9	35.5	146.7	-3.10%
2008	35.5	39.4	39.2	38.9	153.0	4.29%
2009	38.6	37.9	38.6	38.7	153.8	0.48%

WESTERN PRODUCTION

	Q1	Q2	Q3	Q4	Total	% Change
2006	148.0	155.3	156.8	159.4	619.4	5.89%
2007	148.4	153.8	157.4	161.4	621.0	0.25%
2008	155.8	149.8	157.3	156.2	619.2	-0.30%
2009	157.3	154.1	157.0	157.1	625.6	1.04%

DEMAND

Millions of Tons	2004	2005	2006	2007	2008	2009
Elec Power	1013.5	1030.8	1021.2	1039.2	1045.4	1044.2
Industrial	53.0	52.7	51.5	50.3	52.5	52.5
Coke Plants	23.7	23.4	23.0	22.7	22.7	23.4
Resident/Com.	4.1	3.7	3.7	3.9	4.1	4.1
Total Domestic	1,094.3	1,110.6	1,099.4	1,116.1	1,124.7	1,124.2
+Exports	48.0	49.9	49.6	59.2	85.1	70.1
-Imports	27.3	30.5	36.2	36.3	31.7	32.8
Stock Change	-11.5	-9.7	42.6	2.5	-14.4	-2.8
Production	1,112.1	1,131.5	1,162.7	1,145.6	1,163.6	1,158.7
Discrepancy	-8.5	-11.1	-7.3	-4.1	0.0	0.0

NOTE: Both Production and Demand numbers exclude waste coal; Electric Power consumption data includes electricty generation from all sectors including the electric, industrial and commerical sectors. Non-electricity output from both the electricity and industrial sectors are included under the Industrial category.

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia																				
-1.6%, 13000 BTU	$25.59	$26.41	$24.85	$24.45	$26.34	$26.04	$24.94	$23.65	$24.09	$40.52	$30.37	$31.04	$50.27	$54.42	$45.82	$46.61	$109.29	$100.38	$56.06	$41.01
-1.8%, 13000 BTU	$25.06	$25.55	$23.49	$22.21	$22.51	$22.89	$23.59	$22.12	$23.07	$39.46	$29.38	$29.83	$48.89	$52.23	$43.41	$45.85	$107.07	$98.45	$55.05	$40.30
-2.3%, 13000 BTU	$22.40	$21.72	$21.48	$20.71	$21.26	$21.79	$22.54	$20.65	$22.05	$35.99	$27.51	$28.67	$47.91	$48.94	$39.80	$44.71	$103.75	$95.54	$53.54	$39.25
Central Appalachia																				
-.7%, 12500 BTU	$24.31	$26.02	$26.75	$24.86	$26.01	$25.45	$25.97	$24.50	$24.90	$47.09	$29.20	$34.27	$58.62	$61.97	$55.91	$46.46	$108.30	$105.04	$64.73	$56.86
-.7%, 13000 BTU	$26.08	$27.58	$28.31	$26.60	$25.80	$25.25	$25.77	$25.15	$26.42	$50.06	$31.07	$36.49	$62.42	$66.01	$59.56	$49.50	$115.41	$111.96	$69.02	$60.74
-1.0%, 12500 BTU	$21.94	$24.01	$24.22	$22.84	$24.41	$24.02	$24.24	$23.29	$23.45	$44.09	$27.25	$32.04	$55.03	$57.49	$50.71	$44.33	$105.29	$101.83	$60.38	$48.01
-1.5%, 12500 BTU	$21.54	$22.92	$22.70	$21.72	$22.73	$23.05	$23.33	$22.07	$21.72	$38.50	$24.19	$29.19	$49.92	$53.18	$45.49	$40.72	$93.27	$88.15	$50.33	$43.51
Ohio																				
-4%, 12500 BTU	$19.79	$21.50	$20.83	$18.38	$18.25	$18.34	$18.05	$18.41	$18.89	$26.44	$20.72	$23.01	$33.25	$35.88	$32.55	$39.19	$81.14	$78.23	$48.35	$35.60
Illinois Basin																				
-3%, 11000 BTU (IL)	$18.93	$21.68	$19.85	$16.96	$17.71	$18.10	$18.25	$17.44	$16.83	$24.63	$19.71	$19.61	$26.12	$27.54	$27.01	$27.01	$50.75	$54.48	$38.12	$34.89
-3%, 11000 BTU (KY)	$20.03	$22.78	$20.95	$18.10	$19.29	$20.25	$19.90	$18.81	$17.51	$29.93	$23.34	$22.09	$29.18	$29.82	$29.06	$28.91	$52.65	$56.29	$39.93	$36.70
Powder River Basin																				
-.33%, 8400 BTU	$3.58	$3.26	$4.34	$3.60	$3.09	$3.13	$3.35	$3.45	$3.43	$7.58	$4.74	$5.13	$5.23	$7.96	$10.17	$8.36	$11.77	$11.99	$11.08	$11.13
-.35%, 8800 BTU	$4.58	$4.64	$5.08	$4.68	$4.11	$4.29	$4.45	$4.42	$4.38	$9.34	$5.85	$6.21	$6.26	$10.09	$12.74	$9.85	$13.78	$13.40	$12.50	$12.97
Uinta Basin																				
-.5%, 11500 BTU	$19.79	$19.35	$13.64	$14.05	$13.58	$15.18	$15.09	$14.16	$13.35	$20.06	$16.95	$17.13	$26.82	$33.11	$36.76	$29.93	$59.78	$54.61	$27.08	$25.68
Foreign Coal																				
-.7%, 12000 BTU	$28.74	$26.45	$28.05	$34.31	$32.76	$31.71	$29.31	$26.35	$27.89	$35.37	$27.70	$33.43	$59.18	$50.12	$50.53	$62.03	$125.45	$115.01	$76.58	$54.42
-.8%, 11600 BTU						$29.61	$26.70	$24.09	$25.79	$32.94	$26.04	$31.41	$55.40	$46.90	$47.22	$57.85	$117.00	$107.30	$71.56	$50.95
Petroleum Coke																				
-6%/30 HGI, 14000 BTU			$15.42	$12.55	$18.22	$19.39	$3.52	$1.71	$9.98	$12.73	$8.57	$13.03	$11.27	$17.50	$34.76	$44.90	$66.62	$58.65	$50.02	$40.71

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BASE CASE
August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON
BASE CASE

Year:	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia																				
-1.6%, 13000 BTU	$36.16	$36.49	$33.62	$32.42	$34.28	$33.32	$31.57	$29.51	$29.41	$48.32	$35.59	$35.62	$56.08	$58.81	$48.00	$47.57	$109.29	$98.34	$53.89	$38.64
-1.8%, 13000 BTU	$35.42	$35.29	$31.77	$29.45	$29.29	$29.29	$29.86	$27.60	$28.17	$47.05	$34.43	$34.23	$54.54	$56.44	$45.48	$46.79	$107.07	$96.44	$52.92	$37.98
-2.3%, 13000 BTU	$31.66	$30.00	$29.05	$27.46	$27.67	$27.89	$28.53	$25.77	$26.93	$42.92	$32.24	$32.90	$53.44	$52.88	$41.69	$45.62	$103.75	$93.59	$51.47	$36.98
Central Appalachia																				
-.7%, 12500 BTU	$34.35	$35.95	$36.19	$32.96	$33.84	$32.58	$32.88	$30.57	$30.40	$56.15	$34.22	$39.33	$65.39	$66.97	$58.57	$47.41	$108.30	$102.90	$62.23	$53.57
-.7%, 13000 BTU	$36.85	$38.09	$38.30	$35.26	$33.57	$32.32	$32.61	$31.38	$32.26	$59.69	$36.41	$41.88	$69.63	$71.33	$62.40	$50.52	$115.41	$109.68	$66.36	$57.23
-1.0%, 12500 BTU	$31.01	$33.17	$32.76	$30.28	$31.77	$30.75	$30.69	$29.07	$28.64	$52.58	$31.94	$36.77	$61.39	$62.12	$53.12	$45.24	$105.29	$99.75	$58.05	$45.24
-1.5%, 12500 BTU	$30.44	$31.67	$30.70	$28.79	$29.58	$29.50	$29.54	$27.54	$26.52	$45.91	$28.35	$33.50	$55.69	$57.47	$47.65	$41.55	$93.27	$86.35	$48.39	$41.00
Ohio																				
-4%, 12500 BTU	$27.97	$29.70	$28.17	$24.36	$23.75	$23.47	$22.85	$22.97	$23.06	$31.53	$24.29	$26.41	$37.10	$38.77	$34.09	$39.99	$81.14	$76.63	$46.49	$33.55
Illinois Basin																				
-3%, 11000 BTU (IL)	$26.75	$29.94	$26.85	$22.49	$23.05	$23.17	$23.10	$21.76	$20.55	$29.37	$23.10	$22.51	$29.14	$29.76	$28.29	$27.56	$50.75	$53.37	$36.65	$32.87
-3%, 11000 BTU (KY)	$28.30	$31.46	$28.34	$24.00	$25.10	$25.92	$25.19	$23.47	$21.38	$35.69	$27.35	$25.35	$32.55	$32.22	$30.44	$29.50	$52.65	$55.14	$38.38	$34.58
Powder River Basin																				
-.33%, 8400 BTU	$5.06	$4.51	$5.87	$4.77	$4.02	$4.00	$4.24	$4.30	$4.18	$9.03	$5.55	$5.88	$5.83	$8.60	$10.65	$8.53	$11.77	$11.75	$10.66	$10.48
-.35%, 8800 BTU	$6.47	$6.41	$6.87	$6.20	$5.35	$5.49	$5.63	$5.52	$5.34	$11.13	$6.86	$7.13	$6.99	$10.90	$13.34	$10.05	$13.78	$13.12	$12.01	$12.22
Uinta Basin																				
-.5%, 11500 BTU	$27.97	$26.73	$18.45	$18.63	$17.66	$19.42	$19.10	$17.67	$16.30	$23.92	$19.87	$19.65	$29.92	$35.77	$38.51	$30.54	$59.78	$53.50	$26.03	$24.20
Foreign Coal: Colombia																				
-.7%, 12000 BTU	$40.61	$36.54	$37.95	$45.49	$42.63	$40.59	$37.10	$32.88	$34.05	$42.18	$32.46	$38.36	$66.02	$54.16	$52.93	$63.30	$125.45	$112.67	$73.63	$51.27
-.8%, 11600 BTU						$37.90	$33.80	$30.06	$31.49	$39.28	$30.51	$36.05	$61.80	$50.68	$49.47	$59.03	$117.00	$105.11	$68.80	$48.01
Petroleum Coke																				
-6%/30 HGI, 14000 BTU			$20.86	$16.64	$23.71	$24.82	$4.45	$2.13	$12.19	$15.18	$10.04	$14.95	$12.58	$18.91	$36.41	$45.82	$66.62	$57.46	$48.09	$38.35
IMPLICIT PRICE DEFLATOR (GDP)	86.40	88.39	90.27	92.10	93.85	95.41	96.47	97.86	100.00	102.40	104.19	106.40	109.46	113.00	116.57	119.66	122.11	124.65	127.01	129.59
% Change	2.77%	2.30%	2.12%	2.04%	1.89%	1.67%	1.11%	1.44%	2.18%	2.40%	1.75%	2.13%	2.87%	3.23%	3.16%	2.66%	2.04%	2.08%	1.89%	2.03%

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BASE CASE
August 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	1995		1996		1996	1996	1997		1997		1998		1998		1999				2000	
Quarter:	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Northern Appalachia																				
-1.6%, 13000 BTU	$24.73	$24.68	$26.27	$24.93	$26.76	$27.41	$26.76	$25.67	$25.77	$25.94	$25.72	$24.63	$24.63	$24.78	$24.43	$23.54	$23.29	$23.34	$22.90	$22.95
-1.8%, 13000 BTU	$22.15	$22.10	$23.29	$22.10	$22.35	$22.30	$22.40	$22.30	$23.05	$23.79	$23.79	$23.29	$23.84	$23.44	$22.80	$21.66	$21.41	$22.60	$22.03	$22.00
-2.3%, 13000 BTU	$20.96	$20.87	$21.81	$20.91	$21.21	$21.11	$21.21	$21.16	$22.01	$22.80	$22.80	$22.25	$22.80	$22.30	$21.51	$19.73	$19.92	$21.46	$21.11	$20.96
Central Appalachia																				
-.7%, 12500 BTU	$24.95	$24.70	$25.71	$24.50	$26.86	$26.97	$27.17	$24.55	$24.50	$25.60	$25.64	$25.27	$26.28	$26.71	$25.91	$24.14	$23.89	$24.04	$23.54	$23.39
-.7%, 13000 BTU	$26.49	$26.23	$25.50	$24.30	$26.65	$26.75	$26.95	$24.35	$24.30	$25.40	$25.43	$25.07	$26.07	$26.50	$25.70	$23.95	$25.46	$25.50	$24.96	$24.78
-1.0%, 12500 BTU	$22.92	$22.81	$24.11	$23.54	$24.90	$25.10	$25.21	$23.59	$23.33	$23.96	$24.06	$23.33	$24.48	$25.10	$24.32	$23.13	$22.92	$22.81	$22.34	$22.19
-1.5%, 12500 BTU	$21.61	$21.46	$22.50	$21.56	$23.44	$23.44	$23.54	$23.13	$22.40	$23.13	$23.18	$22.81	$23.33	$24.01	$23.13	$22.03	$21.82	$21.30	$20.73	$20.63
Ohio																				
-4%, 12500 BTU	$18.35	$18.25	$18.25	$18.20	$18.30	$18.25	$18.40	$18.30	$18.35	$18.30	$18.30	$18.10	$18.10	$17.70	$18.35	$18.00	$18.40	$18.90	$19.00	$18.25
Illinois Basin																				
-3%, 11000 BTU (IL)	$16.70	$ 16.85	$ 17.50	$ 17.35	$ 18.00	$ 18.00	$18.00	$18.00	$18.15	$18.25	$18.25	$17.95	$ 18.20	$ 18.60	$18.10	$17.50	$17.15	$17.00	$16.75	$16.70
-3%, 11000 BTU (KY)	$17.80	$ 18.10	$ 18.75	$ 18.50	$ 19.90	$ 20.00	$21.00	$20.05	$20.00	$19.95	$20.05	$19.35	$ 20.00	$ 20.20	$19.75	$19.00	$18.45	$18.05	$17.20	$16.95
Powder River Basin																				
-.33%, 8400 BTU	$3.40	$3.30	$3.20	$3.15	$3.00	$3.00	$3.00	$3.00	$3.20	$3.30	$3.62	$3.35	$3.15	$3.27	$3.38	$3.45	$3.47	$3.50	$3.40	$3.20
-.35%, 8800 BTU	$4.45	$4.40	$4.25	$4.20	$4.00	$4.00	$4.00	$4.05	$4.50	$4.60	$4.80	$4.45	$4.20	$4.34	$4.38	$4.45	$4.40	$4.45	$4.40	$4.20
Uinta Basin																				
-.5%, 11500 BTU	$14.20	$14.00	$13.50	$13.20	$13.60	$14.00	$14.40	$15.05	$15.65	$15.60	$15.25	$15.20	$ 15.10	$ 14.80	$14.65	$14.40	$14.10	$13.50	$12.75	$12.80
Foreign Coal																				
-.7%, 12000 BTU	$34.20	$34.50	$33.65	$32.15	$32.00	$33.25	$33.50	$32.40	$30.95	$30.00	$29.20	$29.00	$30.15	$28.90	$28.40	$28.00	$24.60	$24.40	$26.00	$27.25
-.8%, 11600 BTU							$31.54	$30.51	$28.69	$27.71	$26.61	$26.08	$27.99	$26.13	$25.63	$24.63	$23.34	$22.75	$24.13	$25.21
Petroleum Coke																				
-6%/30 HGI, 14000 BTU	$10.28	$11.79	$15.88	$17.24	$19.35	$20.41	$21.47	$21.02	$19.81	$15.27	$7.41	$3.93	$1.36	$1.36	$1.36	$1.36	$1.36	$2.75	$5.58	$5.73

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

ANNUAL AVERAGE SPOT

BASE CASE

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia																			
-1.6%, 13000 BTU	$40.45	$40.62	$40.76	$41.25	$41.81	$42.47	$43.15	$43.90	$44.70	$45.69	$46.51	$47.37	$48.20	$49.01	$49.86	$50.76	$51.64	$52.51	$53.40
-1.8%, 13000 BTU	$39.84	$40.08	$40.34	$40.84	$41.42	$42.09	$42.78	$43.56	$44.38	$45.29	$46.10	$46.96	$47.78	$48.58	$49.42	$50.32	$51.19	$52.05	$52.94
-2.3%, 13000 BTU	$38.91	$39.27	$39.70	$40.24	$40.84	$41.51	$42.22	$43.04	$43.90	$44.69	$45.50	$46.34	$47.15	$47.94	$48.77	$49.66	$50.52	$51.37	$52.24
Central Appalachia																			
-.7%, 12500 BTU	$59.48	$60.96	$62.60	$64.03	$63.36	$63.77	$64.55	$66.30	$68.03	$69.88	$71.77	$73.91	$76.11	$79.24	$82.59	$85.18	$87.81	$90.43	$93.05
-.7%, 13000 BTU	$63.50	$65.08	$66.83	$68.34	$67.63	$68.08	$68.90	$70.77	$72.62	$74.60	$76.62	$78.91	$81.28	$84.63	$88.20	$90.98	$93.81	$96.61	$99.42
-1.0%, 12500 BTU	$48.21	$47.70	$47.36	$48.20	$47.58	$47.80	$48.18	$49.22	$50.34	$51.48	$52.68	$54.00	$55.39	$57.41	$59.52	$61.09	$62.64	$64.19	$65.80
-1.5%, 12500 BTU	$44.68	$45.39	$46.11	$47.33	$46.91	$47.15	$47.54	$48.63	$49.76	$50.91	$52.12	$53.45	$54.84	$56.86	$58.96	$60.53	$62.08	$63.64	$65.24
Ohio																			
-4%, 12500 BTU	$35.32	$35.66	$36.07	$36.57	$37.13	$37.76	$38.43	$39.19	$39.99	$40.74	$41.49	$42.28	$43.04	$43.78	$44.56	$45.39	$46.20	$47.00	$47.82
Illinois Basin																			
-3%, 11000 BTU (IL)	$35.09	$35.32	$35.67	$36.02	$36.40	$36.79	$37.22	$37.74	$38.31	$38.80	$39.29	$39.79	$40.26	$40.70	$41.16	$41.67	$42.14	$42.60	$43.07
-3%, 11000 BTU (KY)	$36.91	$37.20	$37.61	$38.02	$38.45	$38.89	$39.38	$39.96	$40.58	$41.14	$41.68	$42.25	$42.77	$43.28	$43.81	$44.38	$44.92	$45.44	$45.97
Powder River Basin																			
-.33%, 8400 BTU	$10.78	$10.61	$10.52	$10.60	$10.69	$10.93	$11.14	$11.38	$11.63	$12.02	$12.39	$12.62	$12.82	$13.02	$13.22	$13.45	$13.66	$13.87	$14.08
-.35%, 8800 BTU	$12.77	$12.75	$12.78	$12.95	$13.14	$13.41	$13.67	$14.01	$14.38	$14.88	$15.33	$15.66	$15.96	$16.26	$16.57	$16.89	$17.22	$17.54	$17.87
Uinta Basin																			
-.5%, 11500 BTU	$24.64	$25.00	$25.40	$25.79	$26.20	$26.61	$27.05	$27.57	$28.11	$28.62	$29.12	$29.65	$30.16	$30.66	$31.18	$31.73	$32.27	$32.80	$33.34
Foreign Coal																			
-.7%, 12000 BTU	$50.48	$49.17	$49.72	$50.23	$50.75	$51.41	$52.10	$52.82	$53.55	$54.31	$55.12	$55.96	$56.82	$57.70	$58.63	$59.63	$60.67	$61.73	$62.77
-.8%, 11600 BTU	$47.40	$46.30	$46.91	$47.52	$48.15	$48.79	$49.48	$50.22	$51.00	$51.77	$52.55	$53.37	$54.21	$55.06	$55.95	$56.91	$57.90	$58.91	$59.90
Petroleum Coke																			
-6%/30 HGI, 14000 BTU	$36.37	$34.69	$35.07	$35.47	$35.89	$36.33	$36.82	$37.35	$37.92	$38.49	$39.03	$39.64	$40.29	$40.96	$41.68	$42.46	$43.28	$44.13	$44.95

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

ANNUAL AVERAGE SPOT

BASE CASE

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia																			
-1.6%, 13000 BTU	$37.33	$36.74	$36.17	$35.90	$35.71	$35.60	$35.48	$35.39	$35.31	$35.41	$35.38	$35.37	$35.33	$35.28	$35.24	$35.22	$35.18	$35.12	$35.08
-1.8%, 13000 BTU	$36.76	$36.26	$35.79	$35.55	$35.38	$35.28	$35.17	$35.11	$35.06	$35.11	$35.07	$35.06	$35.02	$34.97	$34.93	$34.91	$34.87	$34.82	$34.77
-2.3%, 13000 BTU	$35.91	$35.52	$35.23	$35.02	$34.88	$34.79	$34.72	$34.69	$34.68	$34.64	$34.61	$34.60	$34.56	$34.51	$34.48	$34.45	$34.41	$34.36	$34.31
Central Appalachia																			
-.7%, 12500 BTU	$54.88	$55.15	$55.54	$55.73	$54.11	$53.46	$53.08	$53.45	$53.75	$54.17	$54.60	$55.18	$55.79	$57.04	$58.37	$59.10	$59.81	$60.48	$61.12
-.7%, 13000 BTU	$58.59	$58.87	$59.29	$59.49	$57.76	$57.06	$56.65	$57.05	$57.38	$57.82	$58.29	$58.92	$59.57	$60.91	$62.35	$63.13	$63.89	$64.62	$65.30
-1.0%, 12500 BTU	$44.48	$43.15	$42.02	$41.95	$40.64	$40.06	$39.62	$39.68	$39.77	$39.90	$40.07	$40.32	$40.60	$41.32	$42.07	$42.38	$42.66	$42.93	$43.22
-1.5%, 12500 BTU	$41.23	$41.06	$40.91	$41.19	$40.07	$39.52	$39.09	$39.21	$39.32	$39.46	$39.65	$39.90	$40.19	$40.92	$41.67	$42.00	$42.29	$42.57	$42.86
Ohio																			
-4%, 12500 BTU	$32.59	$32.26	$32.00	$31.83	$31.72	$31.65	$31.60	$31.59	$31.60	$31.58	$31.56	$31.56	$31.54	$31.51	$31.50	$31.49	$31.47	$31.44	$31.41
Illinois Basin																			
-3%, 11000 BTU (IL)	$32.37	$31.95	$31.65	$31.36	$31.09	$30.84	$30.61	$30.43	$30.27	$30.07	$29.89	$29.71	$29.50	$29.29	$29.10	$28.91	$28.70	$28.49	$28.29
-3%, 11000 BTU (KY)	$34.06	$33.66	$33.37	$33.09	$32.84	$32.60	$32.38	$32.21	$32.06	$31.88	$31.71	$31.54	$31.35	$31.15	$30.96	$30.79	$30.59	$30.39	$30.20
Powder River Basin																			
-.33%, 8400 BTU	$9.95	$9.59	$9.34	$9.23	$9.13	$9.16	$9.16	$9.18	$9.19	$9.32	$9.42	$9.42	$9.40	$9.37	$9.35	$9.33	$9.30	$9.27	$9.25
-.35%, 8800 BTU	$11.78	$11.53	$11.34	$11.27	$11.22	$11.24	$11.24	$11.29	$11.36	$11.53	$11.66	$11.69	$11.70	$11.70	$11.71	$11.72	$11.73	$11.73	$11.74
Uinta Basin																			
-.5%, 11500 BTU	$22.74	$22.62	$22.54	$22.45	$22.38	$22.30	$22.24	$22.22	$22.21	$22.18	$22.15	$22.14	$22.10	$22.07	$22.04	$22.01	$21.98	$21.94	$21.90
Foreign Coal: Colombia																			
-.7%, 12000 BTU	$46.58	$44.49	$44.11	$43.72	$43.34	$43.09	$42.84	$42.58	$42.31	$42.10	$41.93	$41.78	$41.64	$41.53	$41.44	$41.38	$41.33	$41.29	$41.23
-.8%, 11600 BTU	$43.74	$41.89	$41.62	$41.36	$41.12	$40.90	$40.68	$40.48	$40.30	$40.13	$39.98	$39.85	$39.73	$39.63	$39.55	$39.48	$39.44	$39.40	$39.35
Petroleum Coke																			
-6%/30 HGI, 14000 BTU	$33.56	$31.39	$31.12	$30.87	$30.65	$30.45	$30.27	$30.11	$29.96	$29.83	$29.69	$29.59	$29.53	$29.48	$29.46	$29.46	$29.48	$29.52	$29.52
IMPLICIT PRICE DEFLATOR (GDP)	132.33	134.98	137.63	140.29	142.97	145.68	148.51	151.47	154.55	157.54	160.52	163.56	166.61	169.65	172.76	176.00	179.27	182.56	185.90
% Change	2.11%	2.00%	1.97%	1.93%	1.91%	1.90%	1.94%	1.99%	2.03%	1.93%	1.89%	1.89%	1.87%	1.83%	1.83%	1.87%	1.86%	1.83%	1.83%

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

QUARTERLY SPOT PRICE

BASE CASE

Year:			2001				2002				2003				2004				2005			
Quarter:	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia																						
-1.6%, 13000 BTU	$24.38	$26.12	$32.86	$42.38	$43.91	$42.92	$35.34	$29.34	$29.09	$27.70	$28.20	$30.88	$31.57	$33.50	$41.24	$45.53	$52.70	$61.62	$56.60	$54.24	$53.91	$52.95
-1.8%, 13000 BTU	$23.59	$24.65	$31.91	$41.26	$42.81	$41.85	$34.32	$28.36	$28.09	$26.73	$27.01	$29.66	$30.41	$32.23	$40.04	$44.46	$51.30	$59.78	$55.15	$52.33	$51.52	$49.91
-2.3%, 13000 BTU	$22.55	$23.59	$29.39	$37.07	$39.40	$38.11	$31.57	$26.61	$26.66	$25.18	$25.82	$28.50	$29.34	$31.03	$39.12	$43.84	$50.32	$58.33	$52.98	$49.48	$47.94	$45.35
Central Appalachia																						
-.7%, 12500 BTU	$24.65	$28.02	$46.72	$51.11	$49.19	$41.33	$30.14	$27.67	$29.23	$29.74	$32.36	$34.02	$33.87	$36.84	$49.62	$56.75	$62.95	$65.15	$62.35	$63.07	$60.38	$62.08
-.7%, 13000 BTU	$26.17	$29.77	$49.66	$54.33	$52.31	$43.93	$32.07	$29.43	$31.12	$31.65	$34.44	$36.21	$36.07	$39.24	$52.84	$60.43	$67.05	$69.37	$66.41	$67.18	$64.33	$66.12
-1.0%, 12500 BTU	$22.92	$26.35	$43.07	$48.65	$45.89	$38.75	$28.18	$25.94	$27.24	$27.66	$29.43	$31.77	$31.93	$35.05	$47.99	$54.08	$58.30	$59.75	$57.71	$59.20	$56.23	$56.81
-1.5%, 12500 BTU	$21.04	$24.48	$34.69	$43.65	$41.15	$34.53	$24.22	$22.86	$24.53	$25.16	$26.93	$28.85	$28.96	$32.03	$44.34	$49.69	$53.05	$52.61	$53.50	$54.86	$52.78	$51.59
Ohio																						
-4%, 12500 BTU	$18.75	$19.55	$23.95	$26.85	$27.85	$27.10	$22.34	$20.15	$20.45	$19.95	$21.40	$22.95	$23.35	$24.35	$28.09	$28.78	$35.38	$40.77	$36.73	$35.18	$35.75	$35.85
Illinois Basin																						
-3%, 11000 BTU (IL)	$16.80	$17.05	$22.05	$25.35	$25.65	$25.45	$21.90	$19.80	$18.50	$18.65	$18.80	$19.55	$19.60	$20.50	$22.55	$25.07	$26.80	$30.05	$27.32	$27.22	$27.75	$27.88
-3%, 11000 BTU (KY)	$17.45	$18.45	$24.30	$31.45	$32.10	$31.85	$27.80	$22.60	$21.50	$21.45	$21.45	$21.95	$22.10	$22.85	$24.95	$28.05	$30.50	$33.20	$30.03	$29.25	$29.83	$30.15
Powder River Basin																						
-.33%, 8400 BTU	$3.40	$3.70	$6.25	$10.65	$7.05	$6.35	$4.65	$4.70	$4.65	$4.95	$5.00	$4.80	$5.25	$5.45	$5.55	$5.43	$5.00	$4.93	$5.18	$6.35	$7.72	$12.57
-.35%, 8800 BTU	$4.35	$4.55	$7.90	$12.75	$8.70	$8.00	$5.85	$5.75	$5.75	$6.05	$6.00	$5.90	$6.30	$6.65	$6.58	$6.43	$6.02	$6.02	$6.33	$7.98	$10.03	$16.00
Uinta Basin																						
-.5%, 11500 BTU	$13.30	$14.55	$19.05	$19.85	$20.55	$20.80	$18.40	$16.30	$16.45	$16.65	$16.15	$16.90	$17.15	$18.30	$22.42	$25.95	$29.42	$29.50	$28.98	$31.12	$34.82	$37.50
Foreign Coal																						
-.7%, 12000 BTU	$27.85	$30.45	$35.10	$36.90	$36.85	$32.62	$29.81	$27.54	$25.06	$28.38	$28.55	$28.04	$35.00	$42.12	$46.23	$54.39	$68.50	$67.62	$57.64	$49.06	$51.92	$41.84
-.8%, 11600 BTU	$25.63	$28.20	$32.60	$34.32	$34.31	$30.52	$27.99	$25.95	$23.57	$26.63	$26.83	$26.40	$32.86	$39.55	$43.28	$50.97	$64.08	$63.25	$53.92	$45.94	$48.57	$39.17
Petroleum Coke																						
-6%/30 HGI, 14000 BTU	$8.83	$19.78	$18.11	$14.62	$9.95	$8.24	$7.44	$5.79	$7.97	$13.08	$20.35	$14.53	$8.52	$8.71	$6.60	$6.46	$14.71	$20.46	$22.76	$13.25	$12.02	$21.98

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

QUARTERLY SPOT PRICE

BASE CASE

Year:	2006				2007				2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia																				
-1.6%, 13000 BTU	$49.63	$46.60	$44.14	$42.90	$44.00	$44.75	$46.60	$51.10	$73.12	$106.83	$135.23	$121.97	$117.50	$108.58	$92.97	$82.49	$71.84	$56.08	$49.73	$46.57
-1.8%, 13000 BTU	$46.48	$43.85	$41.92	$41.40	$43.09	$44.02	$45.83	$50.46	$72.02	$104.93	$131.75	$119.59	$115.39	$106.58	$91.07	$80.75	$70.42	$55.01	$48.94	$45.83
-2.3%, 13000 BTU	$41.76	$39.72	$38.58	$39.14	$41.73	$42.93	$44.67	$49.50	$70.37	$102.07	$126.52	$116.03	$112.22	$103.58	$88.22	$78.14	$68.29	$53.40	$47.75	$44.72
Central Appalachia																				
-.7%, 12500 BTU	$61.21	$59.39	$54.23	$48.82	$41.92	$44.73	$45.65	$53.55	$73.73	$102.73	$132.65	$124.07	$120.32	$112.05	$97.05	$90.76	$78.09	$63.98	$59.42	$57.42
-.7%, 13000 BTU	$65.20	$63.26	$57.79	$52.01	$44.66	$47.65	$48.65	$57.06	$78.58	$109.46	$141.39	$132.21	$128.24	$119.40	$103.46	$96.74	$83.25	$68.20	$63.35	$61.21
-1.0%, 12500 BTU	$55.10	$51.81	$49.69	$46.23	$39.55	$42.53	$43.65	$51.60	$70.80	$99.55	$129.65	$121.17	$117.47	$108.96	$93.72	$87.16	$74.19	$59.78	$54.92	$52.62
-1.5%, 12500 BTU	$48.97	$46.25	$44.09	$42.62	$35.52	$39.22	$40.17	$47.98	$65.05	$92.03	$111.25	$104.73	$102.12	$94.76	$80.72	$75.00	$62.77	$49.58	$45.03	$43.93
Ohio																				
-4%, 12500 BTU	$34.63	$32.63	$30.67	$32.24	$35.45	$37.43	$38.63	$45.23	$65.68	$80.68	$90.76	$87.44	$86.32	$80.97	$73.76	$71.86	$61.37	$48.21	$43.31	$40.52
Illinois Basin																				
-3%, 11000 BTU (IL)	$27.27	$26.53	$26.63	$27.60	$26.85	$26.53	$26.93	$27.73	$31.72	$48.45	$60.67	$62.15	$62.03	$57.87	$52.52	$45.52	$41.00	$37.82	$37.17	$36.48
-3%, 11000 BTU (KY)	$29.37	$28.57	$28.72	$29.58	$28.77	$28.52	$28.77	$29.60	$33.63	$50.43	$62.50	$64.02	$63.85	$59.73	$54.28	$47.30	$42.82	$39.68	$38.93	$38.27
Powder River Basin																				
-.33%, 8400 BTU	$14.20	$10.63	$8.20	$7.63	$7.18	$7.48	$8.92	$9.85	$11.57	$11.53	$11.62	$12.37	$13.12	$12.50	$11.48	$10.87	$10.85	$10.70	$11.50	$11.28
-.35%, 8800 BTU	$17.68	$13.62	$10.18	$9.47	$8.80	$8.93	$10.47	$11.20	$13.73	$13.92	$13.52	$13.97	$14.52	$13.92	$12.82	$12.33	$12.28	$12.12	$12.83	$12.75
Uinta Basin																				
-.5%, 11500 BTU	$38.45	$37.62	$35.83	$35.13	$33.75	$32.50	$27.02	$26.43	$34.37	$50.63	$75.12	$78.98	$73.72	$60.23	$47.93	$36.57	$30.93	$26.42	$25.63	$25.32
Foreign Coal																				
-.7%, 12000 BTU	$48.83	$52.74	$50.93	$49.61	$51.13	$52.48	$59.37	$85.13	$107.74	$124.32	$144.00	$125.74	$123.07	$117.18	$112.62	$107.20	$98.65	$82.68	$68.88	$56.12
-.8%, 11600 BTU	$45.68	$49.24	$47.65	$46.32	$47.70	$48.95	$55.37	$79.38	$100.50	$115.97	$134.27	$117.25	$114.77	$109.31	$105.08	$100.05	$92.13	$77.25	$64.40	$52.48
Petroleum Coke																				
-6%/30 HGI, 14000 BTU	$24.99	$36.75	$39.32	$37.98	$44.03	$47.68	$44.98	$42.90	$53.01	$66.04	$76.59	$70.85	$68.94	$56.49	$52.85	$56.33	$57.37	$52.74	$47.83	$42.13

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

	Cell
ANNUAL AVERAGE CONTRACT PRICES - NOMINAL DOLLARS PE	A14
ANNUAL AVERAGE CONTRACT PRICES - REAL 2008 DOLLARS P	A67
QUARTERLY CONTRACT PRICES - NOMINAL DOLLARS PER TON	A121

ANNUAL AVERAGE CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$102.89	$89.58	$50.24	$41.98	$41.78	$41.99	$42.33	$42.89	$43.52	$44.22	$44.97	$45.80	$46.69
-1.8%, 13000 BTU	$100.86	$87.94	$49.43	$41.31	$41.20	$41.50	$41.91	$42.48	$43.12	$43.84	$44.60	$45.44	$46.32
-2.3%, 13000 BTU	$97.81	$85.48	$48.21	$40.31	$40.34	$40.76	$41.27	$41.87	$42.53	$43.26	$44.06	$44.91	$45.76
Central Appalachia													
-.7%, 12500 BTU	$105.62	$96.98	$61.76	$60.17	$62.31	$63.88	$65.10	$65.67	$65.61	$66.39	$67.69	$69.50	$71.35
-.7%, 13000 BTU	$112.58	$103.39	$65.89	$64.25	$66.52	$68.19	$69.49	$70.10	$70.03	$70.87	$72.25	$74.19	$76.17
-1.0%, 12500 BTU	$101.17	$90.77	$55.18	$49.47	$49.33	$49.10	$49.11	$49.37	$49.19	$49.61	$50.35	$51.47	$52.64
-1.5%, 12500 BTU	$87.03	$79.85	$47.59	$45.54	$46.51	$47.33	$48.05	$48.57	$48.51	$48.95	$49.72	$50.87	$52.06
Ohio													
-4%, 12500 BTU	$79.10	$69.43	$43.19	$36.58	$36.62	$37.02	$37.51	$38.07	$38.69	$39.37	$40.11	$40.91	$41.71
Illinois Basin													
-3%, 11000 BTU (IL)	$51.42	$51.57	$37.63	$36.08	$36.32	$36.62	$36.99	$37.37	$37.77	$38.21	$38.70	$39.25	$39.79
-3%, 11000 BTU (KY)	$53.56	$53.93	$39.50	$37.96	$38.24	$38.60	$39.02	$39.45	$39.91	$40.41	$40.97	$41.57	$42.18
Powder River Basin													
-.33%, 8400 BTU	$12.48	$11.88	$11.38	$11.25	$11.00	$10.90	$10.90	$11.01	$11.17	$11.41	$11.64	$11.92	$12.24
-.35%, 8800 BTU	$14.22	$13.61	$13.08	$13.25	$13.15	$13.18	$13.28	$13.48	$13.72	$14.00	$14.32	$14.71	$15.15
Uinta Basin													
-.5%, 11500 BTU	$54.94	$48.85	$26.99	$25.98	$25.64	$26.02	$26.43	$26.85	$27.27	$27.72	$28.22	$28.76	$29.30
Foreign Coal													
-.7%, 12000 BTU	$106.24	$79.42	$66.79	$53.80	$51.41	$51.02	$51.56	$52.12	$52.73	$53.43	$54.16	$54.91	$55.69
-.8%, 11600 BTU	$109.29	$97.37	$62.49	$50.46	$48.36	$48.11	$48.74	$49.38	$50.04	$50.74	$51.48	$52.26	$53.06
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$64.74	$56.44	$45.98	$39.40	$36.66	$36.00	$36.40	$36.83	$37.28	$37.76	$38.30	$38.86	$39.44

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

ANNUAL AVERAGE CONTRACT PRICES - REAL 2008 DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$102.89	$87.76	$48.30	$39.56	$38.55	$37.99	$37.56	$37.33	$37.17	$37.07	$36.97	$36.92	$36.89
-1.8%, 13000 BTU	$100.86	$86.15	$47.52	$38.93	$38.02	$37.54	$37.18	$36.97	$36.83	$36.75	$36.67	$36.63	$36.60
-2.3%, 13000 BTU	$97.81	$83.74	$46.35	$37.99	$37.22	$36.88	$36.62	$36.44	$36.32	$36.26	$36.22	$36.20	$36.16
Central Appalachia													
-.7%, 12500 BTU	$105.62	$95.00	$59.38	$56.69	$57.49	$57.79	$57.76	$57.16	$56.03	$55.65	$55.65	$56.03	$56.37
-.7%, 13000 BTU	$112.58	$101.28	$63.35	$60.54	$61.38	$61.69	$61.65	$61.02	$59.81	$59.40	$59.41	$59.81	$60.18
-1.0%, 12500 BTU	$101.17	$88.92	$53.05	$46.61	$45.52	$44.42	$43.57	$42.97	$42.01	$41.58	$41.40	$41.49	$41.59
-1.5%, 12500 BTU	$87.03	$78.23	$45.76	$42.91	$42.92	$42.82	$42.63	$42.28	$41.43	$41.03	$40.88	$41.01	$41.13
Ohio													
-4%, 12500 BTU	$79.10	$68.01	$41.52	$34.47	$33.79	$33.49	$33.28	$33.13	$33.04	$33.00	$32.98	$32.98	$32.95
Illinois Basin													
-3%, 11000 BTU (IL)	$51.42	$50.52	$36.18	$33.99	$33.51	$33.13	$32.82	$32.52	$32.26	$32.02	$31.82	$31.64	$31.44
-3%, 11000 BTU (KY)	$53.56	$52.83	$37.97	$35.77	$35.29	$34.92	$34.62	$34.34	$34.09	$33.87	$33.68	$33.51	$33.32
Powder River Basin													
-.33%, 8400 BTU	$12.48	$11.64	$10.94	$10.60	$10.15	$9.86	$9.67	$9.58	$9.54	$9.56	$9.57	$9.61	$9.67
-.35%, 8800 BTU	$14.22	$13.33	$12.58	$12.49	$12.13	$11.92	$11.78	$11.73	$11.72	$11.74	$11.77	$11.85	$11.97
Uinta Basin													
-.5%, 11500 BTU	$54.94	$47.85	$25.95	$24.48	$23.65	$23.54	$23.45	$23.37	$23.29	$23.24	$23.20	$23.19	$23.15
Foreign Coal: Colombia													
-.7%, 12000 BTU	$106.24	$77.80	$64.21	$50.69	$47.44	$46.16	$45.75	$45.36	$45.04	$44.79	$44.53	$44.26	$44.00
-.8%, 11600 BTU	$109.29	$95.39	$60.07	$47.55	$44.62	$43.52	$43.24	$42.98	$42.74	$42.53	$42.33	$42.13	$41.92
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$64.74	$55.29	$44.20	$37.13	$33.83	$32.57	$32.30	$32.05	$31.84	$31.65	$31.49	$31.33	$31.16

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

QUARTERLY CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	*2008*				*2009*				*2010*			
Quarter:	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*
Northern Appalachia												
-1.6%, 13000 BTU	$72.06	$108.68	$117.78	$113.06	$108.62	$94.96	$83.07	$71.68	$62.31	$50.44	$46.95	$41.25
-1.8%, 13000 BTU	$70.47	$106.55	$115.46	$110.95	$106.61	$93.20	$81.54	$70.41	$61.26	$49.62	$46.22	$40.61
-2.3%, 13000 BTU	$68.09	$103.36	$111.99	$107.79	$103.60	$90.57	$79.25	$68.51	$59.68	$48.39	$45.11	$39.65
Central Appalachia												
-.7%, 12500 BTU	$75.06	$101.89	$127.37	$118.15	$113.67	$102.43	$89.46	$82.34	$70.32	$59.22	$58.69	$58.81
-.7%, 13000 BTU	$80.00	$108.61	$135.77	$125.94	$121.18	$109.20	$95.39	$87.81	$75.01	$63.18	$62.62	$62.76
-1.0%, 12500 BTU	$70.81	$97.62	$121.38	$114.88	$105.44	$96.57	$85.90	$75.19	$63.36	$55.92	$51.56	$49.89
-1.5%, 12500 BTU	$60.95	$84.22	$103.99	$98.94	$94.23	$83.99	$75.10	$66.10	$53.80	$47.77	$44.38	$44.41
Ohio												
-4%, 12500 BTU	$62.05	$81.22	$89.24	$83.89	$78.73	$72.37	$64.44	$62.17	$54.05	$43.88	$40.93	$36.68
Illinois Basin												
-3%, 11000 BTU (IL)	$34.05	$51.36	$59.36	$60.92	$58.58	$54.64	$50.12	$42.93	$38.48	$36.27	$35.38	$35.21
-3%, 11000 BTU (KY)	$35.90	$53.32	$61.65	$63.38	$61.08	$57.10	$52.49	$45.04	$40.42	$38.12	$37.20	$37.05
Powder River Basin												
-.33%, 8400 BTU	$12.11	$12.65	$12.61	$12.56	$12.84	$12.25	$11.41	$11.01	$11.00	$10.98	$10.97	$10.90
-.35%, 8800 BTU	$14.06	$14.36	$14.26	$14.22	$14.59	$14.01	$13.11	$12.72	$12.75	$12.78	$12.82	$12.82
Uinta Basin												
-.5%, 11500 BTU	$33.12	$49.54	$68.80	$68.29	$64.28	$52.41	$44.81	$33.89	$27.56	$26.00	$25.34	$25.09
Foreign Coal												
-.7%, 12000 BTU	$88.57	$117.98	$115.91	$102.50	$89.16	$81.26	$76.83	$70.43	$64.61	$60.19	$57.18	$54.44
-.8%, 11600 BTU	$82.66	$114.70	$128.11	$111.67	$104.12	$100.11	$96.22	$89.05	$78.09	$66.65	$54.59	$50.14
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$56.16	$64.14	$72.60	$66.06	$59.46	$55.04	$55.49	$55.77	$55.53	$49.11	$43.48	$40.44

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

ANNUAL AVERAGE CONTRA

BASE CASE

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$47.63	$48.49	$49.36	$50.21	$51.07	$51.97	$52.89	$53.79	$54.71	$55.63
-1.8%, 13000 BTU	$47.21	$48.07	$48.93	$49.77	$50.63	$51.52	$52.43	$53.32	$54.23	$55.15
-2.3%, 13000 BTU	$46.59	$47.44	$48.28	$49.12	$49.96	$50.84	$51.74	$52.62	$53.52	$54.42
Central Appalachia										
-.7%, 12500 BTU	$73.32	$75.40	$77.80	$80.58	$83.79	$86.85	$89.54	$92.24	$94.97	$97.76
-.7%, 13000 BTU	$78.27	$80.51	$83.07	$86.06	$89.49	$92.77	$95.65	$98.55	$101.47	$104.46
-1.0%, 12500 BTU	$53.87	$55.18	$56.68	$58.46	$60.49	$62.38	$63.98	$65.59	$67.24	$68.94
-1.5%, 12500 BTU	$53.29	$54.61	$56.11	$57.88	$59.91	$61.80	$63.41	$65.02	$66.66	$68.35
Ohio										
-4%, 12500 BTU	$42.48	$43.27	$44.06	$44.85	$45.64	$46.46	$47.31	$48.14	$48.98	$49.82
Illinois Basin										
-3%, 11000 BTU (IL)	$40.30	$40.81	$41.30	$41.77	$42.25	$42.74	$43.24	$43.72	$44.20	$44.69
-3%, 11000 BTU (KY)	$42.75	$43.31	$43.87	$44.41	$44.95	$45.51	$46.07	$46.62	$47.17	$47.72
Powder River Basin										
-.33%, 8400 BTU	$12.61	$12.91	$13.14	$13.34	$13.55	$13.77	$13.99	$14.21	$14.43	$14.65
-.35%, 8800 BTU	$15.61	$16.01	$16.33	$16.64	$16.96	$17.29	$17.62	$17.96	$18.30	$18.67
Uinta Basin										
-.5%, 11500 BTU	$29.83	$30.36	$30.89	$31.41	$31.94	$32.49	$33.05	$33.60	$34.16	$34.73
Foreign Coal										
-.7%, 12000 BTU	$56.50	$57.35	$58.23	$59.14	$60.08	$61.09	$62.14	$63.22	$64.30	$65.36
-.8%, 11600 BTU	$53.87	$54.69	$55.55	$56.43	$57.34	$58.29	$59.30	$60.33	$61.36	$62.38
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$40.02	$40.62	$41.28	$41.96	$42.69	$43.47	$44.30	$45.15	$46.01	$46.85

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

ANNUAL AVERAGE CONTRA

BASE CASE

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$36.92	$36.89	$36.85	$36.80	$36.76	$36.73	$36.70	$36.64	$36.59	$36.54
-1.8%, 13000 BTU	$36.60	$36.57	$36.53	$36.48	$36.44	$36.42	$36.38	$36.32	$36.27	$36.22
-2.3%, 13000 BTU	$36.11	$36.09	$36.05	$36.00	$35.96	$35.94	$35.90	$35.84	$35.79	$35.75
Central Appalachia										
-.7%, 12500 BTU	$56.83	$57.36	$58.08	$59.06	$60.31	$61.39	$62.12	$62.83	$63.52	$64.21
-.7%, 13000 BTU	$60.67	$61.24	$62.02	$63.07	$64.41	$65.57	$66.36	$67.12	$67.87	$68.61
-1.0%, 12500 BTU	$41.75	$41.98	$42.32	$42.84	$43.54	$44.09	$44.39	$44.68	$44.97	$45.28
-1.5%, 12500 BTU	$41.31	$41.54	$41.89	$42.42	$43.12	$43.68	$44.00	$44.29	$44.59	$44.90
Ohio										
-4%, 12500 BTU	$32.93	$32.92	$32.90	$32.87	$32.85	$32.84	$32.82	$32.79	$32.76	$32.73
Illinois Basin										
-3%, 11000 BTU (IL)	$31.24	$31.04	$30.83	$30.62	$30.41	$30.21	$30.00	$29.78	$29.57	$29.35
-3%, 11000 BTU (KY)	$33.13	$32.95	$32.75	$32.55	$32.35	$32.17	$31.97	$31.76	$31.55	$31.35
Powder River Basin										
-.33%, 8400 BTU	$9.77	$9.82	$9.81	$9.78	$9.75	$9.73	$9.71	$9.68	$9.65	$9.62
-.35%, 8800 BTU	$12.10	$12.18	$12.20	$12.20	$12.21	$12.22	$12.23	$12.23	$12.24	$12.26
Uinta Basin										
-.5%, 11500 BTU	$23.12	$23.09	$23.06	$23.02	$22.99	$22.96	$22.93	$22.89	$22.85	$22.81
Foreign Coal: Colombia										
-.7%, 12000 BTU	$43.80	$43.63	$43.48	$43.34	$43.25	$43.18	$43.11	$43.06	$43.01	$42.93
-.8%, 11600 BTU	$41.75	$41.61	$41.47	$41.36	$41.27	$41.20	$41.14	$41.09	$41.04	$40.97
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$31.02	$30.90	$30.82	$30.76	$30.73	$30.73	$30.74	$30.76	$30.78	$30.77

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

HIGH CASE

August 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

HIGH CASE

Year:	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$130.75	$186.80	$166.74	$137.86	$108.77	$96.29	$87.55	$82.29	$82.01	$82.72	$83.69	$84.86
-1.8%, 13000 BTU	$45.85	$128.06	$183.10	$163.80	$135.49	$107.12	$95.01	$86.64	$81.48	$81.25	$81.97	$82.97	$84.19
-2.3%, 13000 BTU	$44.71	$124.03	$177.69	$159.31	$131.94	$104.63	$93.10	$85.28	$80.27	$80.11	$80.84	$81.90	$83.19
Central Appalachia													
-.7%, 12500 BTU	$46.46	$128.57	$185.30	$163.85	$131.26	$102.12	$92.96	$94.89	$96.99	$99.23	$101.63	$104.07	$106.65
-.7%, 13000 BTU	$49.50	$137.01	$197.50	$174.73	$140.22	$109.03	$99.24	$101.29	$103.53	$105.92	$108.48	$111.08	$113.84
-1.0%, 12500 BTU	$44.33	$125.00	$179.62	$152.84	$110.84	$82.77	$72.73	$71.79	$73.02	$74.52	$76.16	$77.67	$79.18
-1.5%, 12500 BTU	$40.72	$110.72	$155.49	$127.41	$100.45	$76.72	$69.21	$69.89	$71.70	$73.47	$75.13	$76.64	$78.23
Ohio													
-4%, 12500 BTU	$39.19	$96.15	$146.94	$143.94	$119.69	$94.96	$84.53	$77.47	$72.96	$72.84	$73.54	$74.54	$75.75
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$57.55	$83.28	$84.89	$71.53	$70.82	$70.19	$69.75	$69.30	$68.88	$68.45	$68.06	$67.80
-3%, 11000 BTU (KY)	$28.91	$59.65	$86.08	$88.92	$75.29	$74.55	$73.96	$73.58	$73.17	$72.79	$72.40	$72.06	$71.84
Powder River Basin													
-.33%, 8400 BTU	$8.36	$12.43	$15.78	$14.43	$13.89	$14.26	$14.55	$14.99	$15.46	$15.95	$16.66	$17.34	$18.08
-.35%, 8800 BTU	$9.85	$14.44	$17.18	$15.84	$16.19	$16.88	$17.49	$18.20	$18.88	$19.59	$20.45	$21.28	$22.25
Uinta Basin													
-.5%, 11500 BTU	$29.93	$65.15	$101.65	$92.01	$81.10	$74.45	$69.14	$64.37	$59.71	$55.52	$56.49	$57.50	$58.55
Foreign Coal													
-.7%, 12000 BTU	$62.03	$148.93	$202.88	$193.86	$125.62	$86.67	$74.99	$75.37	$76.09	$79.48	$81.92	$84.00	$84.96
-.8%, 11600 BTU	$57.85	$138.90	$189.28	$181.16	$117.62	$81.38	$70.61	$71.10	$71.99	$75.41	$77.75	$79.77	$80.78
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$78.25	$103.85	$126.98	$93.97	$62.44	$52.90	$53.16	$53.74	$56.21	$57.90	$59.36	$60.08

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

HIGH CASE

August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON

HIGH CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$47.57	$130.75	$182.99	$160.30	$129.90	$100.37	$87.11	$77.68	$71.63	$70.05	$69.33	$68.81	$68.41
-1.8%, 13000 BTU	$46.79	$128.06	$179.37	$157.48	$127.67	$98.84	$85.96	$76.87	$70.92	$69.40	$68.70	$68.22	$67.87
-2.3%, 13000 BTU	$45.62	$124.03	$174.07	$153.16	$124.32	$96.55	$84.22	$75.66	$69.87	$68.42	$67.76	$67.34	$67.06
Central Appalachia													
-.7%, 12500 BTU	$47.41	$128.57	$181.52	$157.52	$123.68	$94.23	$84.10	$84.19	$84.42	$84.75	$85.18	$85.56	$85.98
-.7%, 13000 BTU	$50.52	$137.01	$193.47	$167.98	$132.12	$100.60	$89.78	$89.87	$90.11	$90.46	$90.93	$91.34	$91.77
-1.0%, 12500 BTU	$45.24	$125.00	$175.96	$146.94	$104.44	$76.38	$65.80	$63.69	$63.56	$63.65	$63.84	$63.87	$63.83
-1.5%, 12500 BTU	$41.55	$110.72	$152.32	$122.49	$94.65	$70.79	$62.61	$62.01	$62.40	$62.75	$62.97	$63.01	$63.07
Ohio													
-4%, 12500 BTU	$39.99	$96.15	$143.94	$138.38	$112.78	$87.63	$76.47	$68.73	$63.50	$62.21	$61.64	$61.29	$61.06
Illinois Basin													
-3%, 11000 BTU (IL)	$27.56	$57.55	$81.58	$81.61	$67.40	$65.35	$63.49	$61.89	$60.32	$58.83	$57.37	$55.96	$54.66
-3%, 11000 BTU (KY)	$29.50	$59.65	$84.32	$85.49	$70.94	$68.79	$66.91	$65.28	$63.69	$62.17	$60.68	$59.24	$57.91
Powder River Basin													
-.33%, 8400 BTU	$8.53	$12.43	$15.45	$13.87	$13.08	$13.16	$13.16	$13.30	$13.46	$13.62	$13.97	$14.26	$14.58
-.35%, 8800 BTU	$10.05	$14.44	$16.83	$15.23	$15.26	$15.58	$15.82	$16.15	$16.43	$16.73	$17.14	$17.50	$17.94
Uinta Basin													
-.5%, 11500 BTU	$30.54	$65.15	$99.58	$88.46	$76.42	$68.70	$62.55	$57.11	$51.97	$47.42	$47.35	$47.28	$47.20
Foreign Coal: Colombia													
-.7%, 12000 BTU	$63.30	$148.93	$198.75	$186.38	$118.37	$79.97	$67.84	$66.87	$66.23	$67.88	$68.66	$69.07	$68.49
-.8%, 11600 BTU	$59.03	$138.90	$185.42	$174.17	$110.83	$75.09	$63.88	$63.08	$62.66	$64.41	$65.17	$65.59	$65.12
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$45.82	$78.25	$101.73	$122.08	$88.54	$57.61	$47.86	$47.16	$46.77	$48.01	$48.53	$48.81	$48.43

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

HIGH CASE

August 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

HIGH CASE

Year:	*2008*				*2009*				*2010*			
Quarter:	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*
Northern Appalachia												
-1.6%, 13000 BTU	$73.12	$106.83	$168.45	$174.60	$183.25	$186.15	$190.45	$187.35	$182.45	$175.00	$161.15	$148.35
-1.8%, 13000 BTU	$72.02	$104.93	$164.11	$171.20	$179.95	$182.72	$186.56	$183.40	$178.84	$171.65	$158.58	$145.99
-2.3%, 13000 BTU	$70.37	$102.07	$157.59	$166.11	$175.01	$177.58	$180.72	$177.47	$173.43	$166.63	$154.72	$142.46
Central Appalachia												
-.7%, 12500 BTU	$73.73	$102.73	$164.85	$172.95	$181.44	$185.00	$189.40	$185.35	$179.20	$171.10	$159.15	$145.95
-.7%, 13000 BTU	$78.58	$109.46	$175.71	$184.31	$193.39	$197.15	$201.91	$197.56	$191.04	$182.37	$169.70	$155.59
-1.0%, 12500 BTU	$70.80	$99.55	$161.12	$168.91	$177.14	$179.91	$182.89	$178.00	$170.25	$159.87	$147.10	$133.75
-1.5%, 12500 BTU	$65.05	$92.03	$138.26	$146.00	$153.99	$156.46	$157.52	$153.15	$144.05	$132.59	$120.62	$111.68
Ohio												
-4%, 12500 BTU	$65.68	$80.68	$113.06	$125.17	$134.62	$138.82	$151.10	$163.22	$155.85	$150.44	$140.35	$129.10
Illinois Basin												
-3%, 11000 BTU (IL)	$31.72	$48.45	$72.55	$77.50	$80.20	$82.50	$85.75	$84.65	$85.00	$84.40	$86.00	$84.15
-3%, 11000 BTU (KY)	$33.63	$50.43	$74.72	$79.83	$82.55	$85.16	$88.63	$87.97	$88.77	$88.57	$90.09	$88.26
Powder River Basin												
-.33%, 8400 BTU	$11.57	$11.53	$13.10	$13.50	$14.85	$15.90	$16.35	$16.00	$15.50	$14.40	$14.00	$13.80
-.35%, 8800 BTU	$13.73	$13.92	$15.00	$15.10	$16.25	$17.32	$17.68	$17.47	$16.93	$15.82	$15.33	$15.27
Uinta Basin												
-.5%, 11500 BTU	$34.37	$50.63	$84.25	$91.35	$98.65	$100.45	$104.55	$102.95	$98.30	$94.45	$89.70	$85.60
Foreign Coal												
-.7%, 12000 BTU	$107.74	$124.32	$178.95	$175.28	$185.59	$193.47	$219.78	$218.91	$226.37	$221.10	$184.51	$142.64
-.8%, 11600 BTU	$100.50	$115.97	$166.86	$163.45	$173.07	$180.48	$205.08	$204.32	$211.43	$206.58	$172.49	$133.40
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$53.01	$66.04	$95.18	$98.76	$103.96	$93.27	$103.15	$115.03	$131.66	$141.03	$128.13	$107.09

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

HIGH CASE

August 2008

ANNUAL AVERAGE SPOT P

HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$86.22	$88.06	$89.57	$91.14	$92.74	$94.36	$96.04	$97.82	$99.65	$101.52	$103.45
-1.8%, 13000 BTU	$85.60	$87.30	$88.79	$90.35	$91.93	$93.54	$95.20	$96.97	$98.78	$100.63	$102.55
-2.3%, 13000 BTU	$84.68	$86.15	$87.62	$89.16	$90.72	$92.31	$93.95	$95.69	$97.48	$99.31	$101.20
Central Appalachia											
-.7%, 12500 BTU	$109.36	$112.00	$114.66	$117.39	$120.15	$122.93	$125.78	$128.75	$131.78	$134.84	$137.96
-.7%, 13000 BTU	$116.74	$119.56	$122.42	$125.34	$128.30	$131.29	$134.34	$137.53	$140.77	$144.05	$147.41
-1.0%, 12500 BTU	$80.91	$82.50	$84.16	$85.77	$87.44	$89.07	$90.65	$92.33	$94.00	$95.71	$97.57
-1.5%, 12500 BTU	$79.99	$81.59	$83.27	$84.89	$86.57	$88.20	$89.79	$91.49	$93.17	$94.89	$96.74
Ohio											
-4%, 12500 BTU	$77.15	$78.52	$79.90	$81.34	$82.81	$84.29	$85.83	$87.47	$89.15	$90.86	$92.63
Illinois Basin											
-3%, 11000 BTU (IL)	$67.57	$67.22	$66.84	$66.44	$65.96	$65.43	$64.90	$64.40	$63.83	$63.20	$62.57
-3%, 11000 BTU (KY)	$71.64	$71.33	$70.97	$70.61	$70.16	$69.65	$69.14	$68.66	$68.10	$67.50	$66.88
Powder River Basin											
-.33%, 8400 BTU	$18.87	$19.71	$20.52	$21.48	$22.40	$23.34	$24.33	$25.37	$26.46	$27.59	$28.78
-.35%, 8800 BTU	$23.33	$24.40	$25.40	$26.65	$27.87	$29.15	$30.47	$31.88	$33.35	$34.90	$36.53
Uinta Basin											
-.5%, 11500 BTU	$59.65	$60.71	$61.76	$62.84	$63.91	$64.98	$66.06	$67.20	$68.34	$69.49	$70.65
Foreign Coal											
-.7%, 12000 BTU	$86.07	$87.04	$88.07	$88.88	$89.70	$89.51	$89.30	$90.14	$91.05	$92.05	$93.07
-.8%, 11600 BTU	$81.98	$82.97	$83.96	$84.77	$85.57	$85.42	$85.22	$86.02	$86.89	$87.85	$88.81
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$60.96	$61.68	$62.35	$62.96	$63.59	$63.54	$63.48	$64.18	$64.94	$65.80	$66.64

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

HIGH CASE

August 2008

ANNUAL AVERAGE SPOT P

HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$68.12	$68.26	$68.14	$68.05	$67.97	$67.92	$67.88	$67.87	$67.88	$67.90	$67.95
-1.8%, 13000 BTU	$67.64	$67.66	$67.55	$67.45	$67.38	$67.33	$67.29	$67.28	$67.28	$67.31	$67.36
-2.3%, 13000 BTU	$66.91	$66.77	$66.66	$66.57	$66.49	$66.44	$66.41	$66.39	$66.40	$66.43	$66.47
Central Appalachia											
-.7%, 12500 BTU	$86.41	$86.81	$87.23	$87.64	$88.06	$88.48	$88.91	$89.33	$89.76	$90.19	$90.62
-.7%, 13000 BTU	$92.23	$92.67	$93.13	$93.58	$94.04	$94.50	$94.96	$95.42	$95.88	$96.35	$96.82
-1.0%, 12500 BTU	$63.93	$63.95	$64.02	$64.04	$64.09	$64.11	$64.07	$64.06	$64.02	$64.02	$64.09
-1.5%, 12500 BTU	$63.20	$63.24	$63.35	$63.38	$63.45	$63.49	$63.47	$63.48	$63.46	$63.47	$63.54
Ohio											
-4%, 12500 BTU	$60.95	$60.86	$60.79	$60.73	$60.69	$60.67	$60.67	$60.69	$60.72	$60.77	$60.85
Illinois Basin											
-3%, 11000 BTU (IL)	$53.39	$52.11	$50.84	$49.60	$48.34	$47.09	$45.87	$44.68	$43.47	$42.27	$41.10
-3%, 11000 BTU (KY)	$56.60	$55.29	$53.99	$52.72	$51.42	$50.13	$48.87	$47.64	$46.39	$45.15	$43.93
Powder River Basin											
-.33%, 8400 BTU	$14.91	$15.28	$15.61	$16.04	$16.41	$16.80	$17.19	$17.60	$18.02	$18.45	$18.90
-.35%, 8800 BTU	$18.43	$18.91	$19.32	$19.90	$20.43	$20.98	$21.54	$22.12	$22.72	$23.34	$24.00
Uinta Basin											
-.5%, 11500 BTU	$47.13	$47.06	$46.99	$46.91	$46.84	$46.77	$46.70	$46.62	$46.55	$46.48	$46.41
Foreign Coal: Colombia											
-.7%, 12000 BTU	$68.01	$67.47	$66.99	$66.36	$65.74	$64.43	$63.12	$62.54	$62.02	$61.57	$61.13
-.8%, 11600 BTU	$64.77	$64.31	$63.87	$63.29	$62.72	$61.48	$60.24	$59.68	$59.18	$58.76	$58.34
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$48.16	$47.81	$47.43	$47.00	$46.61	$45.74	$44.87	$44.53	$44.24	$44.01	$43.77

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

LOW CASE

August 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

LOW CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$95.68	$49.48	$30.24	$29.04	$28.91	$28.59	$28.21	$27.99	$27.80	$27.64	$28.83	$28.62
-1.8%, 13000 BTU	$45.85	$93.75	$48.52	$29.70	$28.54	$28.47	$28.21	$27.92	$27.71	$27.54	$27.39	$28.58	$28.40
-2.3%, 13000 BTU	$44.71	$90.87	$47.09	$28.89	$27.80	$27.81	$27.64	$27.48	$27.30	$27.15	$27.01	$28.21	$28.06
Central Appalachia													
-.7%, 12500 BTU	$46.46	$93.12	$50.49	$40.76	$39.64	$39.97	$40.54	$41.12	$41.58	$42.11	$42.69	$43.33	$44.01
-.7%, 13000 BTU	$49.50	$99.23	$53.81	$43.47	$42.34	$42.67	$43.28	$43.89	$44.38	$44.95	$45.57	$46.25	$46.97
-1.0%, 12500 BTU	$44.33	$90.53	$48.94	$38.02	$33.47	$32.40	$31.72	$31.11	$31.30	$31.63	$31.99	$32.34	$32.67
-1.5%, 12500 BTU	$40.72	$80.19	$42.37	$31.70	$30.34	$30.03	$30.18	$30.28	$30.74	$31.18	$31.56	$31.91	$32.28
Ohio													
-4%, 12500 BTU	$39.19	$71.60	$38.49	$26.10	$25.21	$25.24	$25.10	$24.96	$24.81	$24.69	$24.57	$25.68	$25.55
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$46.30	$38.53	$29.13	$25.54	$25.47	$25.42	$25.45	$25.48	$25.52	$25.57	$25.63	$25.75
-3%, 11000 BTU (KY)	$28.91	$48.07	$39.81	$30.51	$26.88	$26.81	$26.79	$26.85	$26.90	$26.97	$27.04	$27.14	$27.28
Powder River Basin													
-.33%, 8400 BTU	$8.36	$10.60	$8.68	$8.71	$9.05	$8.82	$8.59	$8.42	$8.32	$8.24	$8.27	$8.30	$8.35
-.35%, 8800 BTU	$9.85	$12.51	$10.06	$10.29	$10.55	$10.44	$10.32	$10.23	$10.16	$10.13	$10.15	$10.19	$10.28
Uinta Basin													
-.5%, 11500 BTU	$29.93	$54.25	$40.67	$21.69	$19.51	$18.97	$18.46	$17.96	$17.49	$17.03	$16.60	$16.18	$15.78
Foreign Coal													
-.7%, 12000 BTU	$62.03	$107.87	$55.28	$48.23	$37.94	$33.92	$32.70	$32.66	$32.62	$33.73	$34.41	$34.97	$35.06
-.8%, 11600 BTU	$57.85	$100.60	$51.57	$45.07	$35.52	$31.85	$30.79	$30.81	$30.86	$32.00	$32.66	$33.21	$33.33
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$57.93	$28.18	$31.56	$28.38	$24.44	$23.07	$23.04	$23.04	$23.85	$24.32	$24.72	$24.79

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

LOW CASE

August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON

LOW CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$47.57	$95.68	$48.47	$29.07	$27.37	$26.68	$25.87	$25.03	$24.36	$23.74	$23.17	$23.70	$23.07
-1.8%, 13000 BTU	$46.79	$93.75	$47.54	$28.56	$26.90	$26.27	$25.52	$24.77	$24.12	$23.52	$22.96	$23.50	$22.89
-2.3%, 13000 BTU	$45.62	$90.87	$46.13	$27.77	$26.19	$25.66	$25.01	$24.38	$23.76	$23.19	$22.64	$23.19	$22.62
Central Appalachia													
-.7%, 12500 BTU	$47.41	$93.12	$49.46	$39.19	$37.35	$36.88	$36.67	$36.48	$36.19	$35.97	$35.78	$35.63	$35.48
-.7%, 13000 BTU	$50.52	$99.23	$52.72	$41.79	$39.90	$39.37	$39.15	$38.94	$38.63	$38.39	$38.20	$38.03	$37.87
-1.0%, 12500 BTU	$45.24	$90.53	$47.94	$36.56	$31.54	$29.89	$28.69	$27.60	$27.25	$27.01	$26.82	$26.59	$26.34
-1.5%, 12500 BTU	$41.55	$80.19	$41.50	$30.47	$28.58	$27.71	$27.30	$26.87	$26.75	$26.63	$26.45	$26.24	$26.02
Ohio													
-4%, 12500 BTU	$39.99	$71.60	$37.71	$25.09	$23.76	$23.29	$22.71	$22.15	$21.60	$21.09	$20.60	$21.11	$20.59
Illinois Basin													
-3%, 11000 BTU (IL)	$27.56	$46.30	$37.74	$28.00	$24.07	$23.50	$23.00	$22.58	$22.18	$21.80	$21.43	$21.08	$20.76
-3%, 11000 BTU (KY)	$29.50	$48.07	$39.00	$29.33	$25.33	$24.73	$24.24	$23.82	$23.42	$23.04	$22.67	$22.31	$21.99
Powder River Basin													
-.33%, 8400 BTU	$8.53	$10.60	$8.50	$8.38	$8.52	$8.14	$7.77	$7.47	$7.24	$7.04	$6.93	$6.83	$6.73
-.35%, 8800 BTU	$10.05	$12.51	$9.85	$9.89	$9.94	$9.63	$9.34	$9.08	$8.85	$8.65	$8.51	$8.38	$8.28
Uinta Basin													
-.5%, 11500 BTU	$30.54	$54.25	$39.84	$20.85	$18.38	$17.51	$16.70	$15.94	$15.22	$14.55	$13.91	$13.30	$12.72
Foreign Coal: Colombia													
-.7%, 12000 BTU	$63.30	$107.87	$54.15	$46.37	$35.75	$31.30	$29.58	$28.97	$28.39	$28.81	$28.84	$28.76	$28.26
-.8%, 11600 BTU	$59.03	$100.60	$50.52	$43.33	$33.47	$29.39	$27.86	$27.33	$26.86	$27.33	$27.38	$27.31	$26.87
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$45.82	$57.93	$27.61	$30.35	$26.74	$22.55	$20.87	$20.44	$20.05	$20.37	$20.39	$20.32	$19.99

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

LOW CASE

August 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

LOW CASE

	Year:	2008				2009				2010			
	Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia													
-1.6%, 13000 BTU		$73.12	$106.83	$116.20	$86.55	$62.40	$51.70	$44.15	$39.65	$34.20	$31.05	$28.70	$27.00
-1.8%, 13000 BTU		$72.02	$104.93	$113.20	$84.87	$61.28	$50.75	$43.25	$38.81	$33.52	$30.46	$28.24	$26.57
-2.3%, 13000 BTU		$70.37	$102.07	$108.71	$82.34	$59.59	$49.32	$41.89	$37.56	$32.51	$29.56	$27.56	$25.93
Central Appalachia													
-.7%, 12500 BTU		$73.73	$102.73	$113.55	$82.45	$59.95	$53.65	$46.15	$42.20	$41.00	$40.40	$41.00	$40.65
-.7%, 13000 BTU		$78.58	$109.46	$121.03	$87.86	$63.90	$57.17	$49.20	$44.98	$43.71	$43.06	$43.72	$43.34
-1.0%, 12500 BTU		$70.80	$99.55	$110.98	$80.52	$58.53	$52.17	$44.56	$40.53	$38.95	$37.75	$37.89	$37.25
-1.5%, 12500 BTU		$65.05	$92.03	$95.23	$69.60	$50.88	$45.37	$38.38	$34.87	$32.96	$31.31	$31.07	$31.10
Ohio													
-4%, 12500 BTU		$65.68	$80.68	$77.99	$62.05	$45.84	$38.55	$35.03	$34.54	$29.21	$26.69	$25.00	$23.50
Illinois Basin													
-3%, 11000 BTU (IL)		$31.72	$48.45	$55.70	$49.35	$42.80	$38.80	$37.50	$35.00	$32.00	$30.00	$28.00	$26.50
-3%, 11000 BTU (KY)		$33.63	$50.43	$57.37	$50.83	$44.05	$40.05	$38.76	$36.37	$33.42	$31.48	$29.33	$27.80
Powder River Basin													
-.33%, 8400 BTU		$11.57	$11.53	$10.10	$9.20	$8.90	$8.80	$8.60	$8.40	$8.50	$8.40	$9.00	$8.95
-.35%, 8800 BTU		$13.73	$13.92	$11.58	$10.82	$10.22	$10.22	$9.93	$9.87	$10.00	$9.95	$10.60	$10.60
Uinta Basin													
-.5%, 11500 BTU		$34.37	$50.63	$69.40	$62.60	$55.35	$46.55	$35.70	$28.45	$24.95	$22.45	$21.85	$21.00
Foreign Coal													
-.7%, 12000 BTU		$107.74	$124.32	$123.27	$83.56	$61.32	$56.11	$53.55	$49.84	$51.79	$52.21	$47.53	$39.73
-.8%, 11600 BTU		$100.50	$115.97	$114.93	$77.92	$57.19	$52.34	$49.97	$46.52	$48.37	$48.78	$44.44	$37.15
Petroleum Coke													
-6%/30 HGI, 14000 BTU		$53.01	$66.04	$65.56	$47.08	$34.35	$27.05	$25.13	$26.19	$30.12	$33.30	$33.01	$29.83

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

LOW CASE

August 2008

ANNUAL AVERAGE SPOT PRI

LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$28.42	$28.36	$28.16	$27.97	$27.78	$27.57	$27.37	$27.18	$26.99	$26.79	$26.59
-1.8%, 13000 BTU	$28.22	$28.11	$27.92	$27.73	$27.54	$27.33	$27.13	$26.94	$26.75	$26.56	$26.36
-2.3%, 13000 BTU	$27.91	$27.74	$27.55	$27.36	$27.17	$26.97	$26.77	$26.59	$26.40	$26.21	$26.01
Central Appalachia											
-.7%, 12500 BTU	$44.70	$45.35	$45.99	$46.65	$47.31	$47.95	$48.83	$49.75	$50.67	$51.60	$52.55
-.7%, 13000 BTU	$47.72	$48.41	$49.10	$49.81	$50.52	$51.21	$52.15	$53.13	$54.13	$55.13	$56.14
-1.0%, 12500 BTU	$33.07	$33.40	$33.76	$34.09	$34.43	$34.74	$35.19	$35.67	$36.14	$36.63	$37.16
-1.5%, 12500 BTU	$32.70	$33.04	$33.40	$33.74	$34.08	$34.40	$34.86	$35.35	$35.82	$36.31	$36.84
Ohio											
-4%, 12500 BTU	$25.43	$25.28	$25.12	$24.97	$24.80	$24.63	$24.46	$24.30	$24.14	$23.98	$23.81
Illinois Basin											
-3%, 11000 BTU (IL)	$25.88	$25.98	$26.06	$26.15	$26.21	$26.26	$26.31	$26.38	$26.42	$26.46	$26.49
-3%, 11000 BTU (KY)	$27.44	$27.56	$27.68	$27.79	$27.88	$27.95	$28.03	$28.12	$28.20	$28.25	$28.31
Powder River Basin											
-.33%, 8400 BTU	$8.42	$8.49	$8.53	$8.54	$8.54	$8.54	$8.54	$8.54	$8.55	$8.55	$8.56
-.35%, 8800 BTU	$10.41	$10.50	$10.56	$10.60	$10.63	$10.66	$10.69	$10.73	$10.77	$10.82	$10.87
Uinta Basin											
-.5%, 11500 BTU	$15.39	$15.02	$14.67	$14.33	$14.00	$13.69	$13.39	$13.10	$12.82	$12.55	$12.30
Foreign Coal											
-.7%, 12000 BTU	$35.18	$35.24	$35.32	$35.32	$35.32	$34.91	$34.67	$34.83	$35.01	$35.23	$35.45
-.8%, 11600 BTU	$33.51	$33.59	$33.68	$33.69	$33.69	$33.32	$33.08	$33.24	$33.41	$33.62	$33.83
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$24.92	$24.97	$25.01	$25.02	$25.04	$24.79	$24.64	$24.80	$24.97	$25.18	$25.38

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

LOW CASE

August 2008

ANNUAL AVERAGE SPOT PRI

LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$22.45	$21.98	$21.42	$20.88	$20.36	$19.85	$19.35	$18.86	$18.38	$17.92	$17.47
-1.8%, 13000 BTU	$22.29	$21.79	$21.24	$20.70	$20.18	$19.67	$19.18	$18.69	$18.22	$17.76	$17.32
-2.3%, 13000 BTU	$22.05	$21.50	$20.96	$20.43	$19.92	$19.41	$18.92	$18.45	$17.98	$17.53	$17.09
Central Appalachia											
-.7%, 12500 BTU	$35.32	$35.15	$34.99	$34.83	$34.67	$34.51	$34.51	$34.51	$34.51	$34.51	$34.51
-.7%, 13000 BTU	$37.70	$37.52	$37.35	$37.19	$37.02	$36.86	$36.86	$36.87	$36.87	$36.87	$36.88
-1.0%, 12500 BTU	$26.13	$25.89	$25.68	$25.45	$25.23	$25.01	$24.87	$24.75	$24.62	$24.50	$24.41
-1.5%, 12500 BTU	$25.83	$25.61	$25.41	$25.19	$24.98	$24.76	$24.64	$24.53	$24.40	$24.29	$24.20
Ohio											
-4%, 12500 BTU	$20.09	$19.60	$19.11	$18.64	$18.18	$17.73	$17.29	$16.86	$16.44	$16.04	$15.64
Illinois Basin											
-3%, 11000 BTU (IL)	$20.45	$20.14	$19.83	$19.52	$19.21	$18.90	$18.60	$18.30	$18.00	$17.70	$17.40
-3%, 11000 BTU (KY)	$21.68	$21.37	$21.05	$20.75	$20.43	$20.12	$19.81	$19.51	$19.21	$18.90	$18.60
Powder River Basin											
-.33%, 8400 BTU	$6.65	$6.58	$6.49	$6.38	$6.26	$6.15	$6.03	$5.93	$5.82	$5.72	$5.62
-.35%, 8800 BTU	$8.22	$8.14	$8.04	$7.91	$7.79	$7.68	$7.56	$7.45	$7.34	$7.23	$7.14
Uinta Basin											
-.5%, 11500 BTU	$12.16	$11.64	$11.16	$10.70	$10.26	$9.85	$9.46	$9.09	$8.73	$8.40	$8.08
Foreign Coal: Colombia											
-.7%, 12000 BTU	$27.80	$27.32	$26.87	$26.37	$25.88	$25.13	$24.50	$24.16	$23.85	$23.56	$23.28
-.8%, 11600 BTU	$26.48	$26.04	$25.62	$25.15	$24.69	$23.98	$23.38	$23.06	$22.76	$22.49	$22.22
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$19.69	$19.36	$19.03	$18.68	$18.35	$17.84	$17.42	$17.20	$17.01	$16.84	$16.67

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BUSINESS-AS-USUAL CASE

August 2008

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ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TC	A67

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BUSINESS-AS-USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$109.29	$100.38	$56.06	$41.01	$42.71	$44.22	$44.53	$45.07	$45.62	$46.23	$46.84	$47.55
-1.8%, 13000 BTU	$45.85	$107.07	$98.45	$55.05	$40.30	$42.10	$43.69	$44.11	$44.67	$45.24	$45.85	$46.48	$47.21
-2.3%, 13000 BTU	$44.71	$103.75	$95.54	$53.54	$39.25	$41.18	$42.90	$43.49	$44.07	$44.67	$45.28	$45.94	$46.70
Central Appalachia													
-.7%, 12500 BTU	$46.46	$108.30	$105.04	$64.73	$55.26	$59.43	$61.64	$64.04	$65.55	$64.91	$65.34	$66.08	$67.80
-.7%, 13000 BTU	$49.50	$115.41	$111.96	$69.02	$59.03	$63.45	$61.64	$68.36	$69.97	$69.28	$69.75	$70.53	$72.38
-1.0%, 12500 BTU	$44.33	$105.29	$101.83	$60.38	$47.70	$48.47	$50.82	$48.96	$49.32	$48.72	$48.94	$49.31	$50.32
-1.5%, 12500 BTU	$40.72	$93.27	$88.15	$50.33	$42.29	$44.65	$45.89	$47.17	$48.45	$48.05	$48.30	$48.67	$49.73
Ohio													
-4%, 12500 BTU	$39.19	$81.14	$78.23	$48.35	$35.60	$37.37	$38.95	$39.51	$40.06	$40.62	$41.19	$41.81	$42.52
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$50.75	$54.48	$38.12	$34.09	$34.16	$34.32	$34.61	$34.92	$35.26	$35.59	$35.93	$36.28
-3%, 11000 BTU (KY)	$28.91	$52.65	$56.29	$39.93	$35.87	$35.94	$36.15	$36.49	$36.85	$37.25	$37.62	$38.01	$38.41
Powder River Basin													
-.33%, 8400 BTU	$8.36	$11.77	$11.99	$11.08	$10.99	$11.00	$10.96	$11.00	$11.09	$11.17	$11.37	$11.54	$11.74
-.35%, 8800 BTU	$9.85	$13.78	$13.40	$12.50	$12.84	$12.98	$13.11	$13.26	$13.43	$13.61	$13.85	$14.07	$14.36
Uinta Basin													
-.5%, 11500 BTU	$29.93	$59.78	$54.61	$27.08	$25.68	$24.64	$25.00	$25.40	$25.79	$26.20	$26.61	$27.05	$27.57
Foreign Coal													
-.7%, 12000 BTU	$62.03	$125.45	$115.01	$76.58	$54.06	$50.75	$52.40	$51.40	$51.40	$51.96	$52.64	$53.33	$53.99
-.8%, 11600 BTU	$57.85	$117.00	$107.30	$71.56	$50.62	$47.66	$49.34	$48.49	$48.63	$49.30	$49.97	$50.64	$51.33
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$66.62	$58.65	$50.02	$40.44	$36.56	$36.96	$36.26	$36.30	$36.75	$37.21	$37.68	$38.18

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
BUSINESS-AS-USUAL CASE
August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON

BUSINESS-AS-USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$47.57	$109.29	$98.34	$53.89	$38.64	$39.41	$40.01	$39.51	$39.22	$38.97	$38.75	$38.52	$38.33
-1.8%, 13000 BTU	$46.79	$107.07	$96.44	$52.92	$37.98	$38.84	$39.53	$39.14	$38.88	$38.64	$38.43	$38.22	$38.06
-2.3%, 13000 BTU	$45.62	$103.75	$93.59	$51.47	$36.98	$38.00	$38.81	$38.58	$38.36	$38.15	$37.95	$37.77	$37.64
Central Appalachia													
-.7%, 12500 BTU	$47.41	$108.30	$102.90	$62.23	$52.07	$54.84	$55.76	$56.82	$57.05	$55.44	$54.77	$54.33	$54.66
-.7%, 13000 BTU	$50.52	$115.41	$109.68	$66.36	$55.62	$58.55	$55.76	$60.65	$60.90	$59.17	$58.46	$57.99	$58.35
-1.0%, 12500 BTU	$45.24	$105.29	$99.75	$58.05	$44.94	$44.73	$45.98	$43.44	$42.93	$41.61	$41.03	$40.54	$40.56
-1.5%, 12500 BTU	$41.55	$93.27	$86.35	$48.39	$39.85	$41.20	$41.51	$41.85	$42.17	$41.04	$40.48	$40.02	$40.09
Ohio													
-4%, 12500 BTU	$39.99	$81.14	$76.63	$46.49	$33.55	$34.49	$35.24	$35.05	$34.86	$34.69	$34.53	$34.38	$34.28
Illinois Basin													
-3%, 11000 BTU (IL)	$27.56	$50.75	$53.37	$36.65	$32.13	$31.52	$31.05	$30.71	$30.40	$30.12	$29.83	$29.54	$29.25
-3%, 11000 BTU (KY)	$29.50	$52.65	$55.14	$38.38	$33.80	$33.17	$32.70	$32.38	$32.07	$31.81	$31.53	$31.25	$30.96
Powder River Basin													
-.33%, 8400 BTU	$8.53	$11.77	$11.75	$10.66	$10.36	$10.15	$9.92	$9.76	$9.65	$9.54	$9.53	$9.49	$9.46
-.35%, 8800 BTU	$10.05	$13.78	$13.12	$12.01	$12.10	$11.98	$11.86	$11.76	$11.69	$11.63	$11.61	$11.57	$11.58
Uinta Basin													
-.5%, 11500 BTU	$30.54	$59.78	$53.50	$26.03	$24.20	$22.74	$22.62	$22.54	$22.45	$22.38	$22.30	$22.24	$22.22
Foreign Coal: Colombia													
-.7%, 12000 BTU	$63.30	$125.45	$112.67	$73.63	$50.94	$46.83	$47.40	$45.61	$44.74	$44.38	$44.13	$43.85	$43.52
-.8%, 11600 BTU	$59.03	$117.00	$105.11	$68.80	$47.69	$43.97	$44.63	$43.02	$42.32	$42.11	$41.88	$41.64	$41.38
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$45.82	$66.62	$57.46	$48.09	$38.10	$33.74	$33.44	$32.17	$31.59	$31.39	$31.19	$30.98	$30.78

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
BUSINESS-AS-USUAL CASE
August 2008

ANNUAL AVERAGE SPOT P

BUSINESS-AS-USUAL CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$48.29	$47.90	$48.63	$49.41	$50.14	$50.85	$51.60	$52.40	$53.17	$53.93	$54.70
-1.8%, 13000 BTU	$47.98	$47.49	$48.21	$48.98	$49.70	$50.41	$51.15	$51.94	$52.71	$53.46	$54.23
-2.3%, 13000 BTU	$47.51	$46.86	$47.58	$48.33	$49.05	$49.74	$50.47	$51.26	$52.01	$52.75	$53.51
Central Appalachia											
-.7%, 12500 BTU	$69.46	$70.43	$71.38	$73.35	$75.37	$78.29	$81.40	$83.78	$86.17	$88.54	$90.90
-.7%, 13000 BTU	$74.15	$75.18	$76.21	$78.31	$80.48	$83.61	$86.94	$89.49	$92.05	$94.59	$97.13
-1.0%, 12500 BTU	$51.38	$51.87	$52.39	$53.60	$54.86	$56.73	$58.68	$60.09	$61.47	$62.86	$64.29
-1.5%, 12500 BTU	$50.81	$51.31	$51.84	$53.04	$54.30	$56.18	$58.12	$59.53	$60.92	$62.31	$63.74
Ohio											
-4%, 12500 BTU	$43.28	$42.71	$43.38	$44.09	$44.77	$45.42	$46.11	$46.85	$47.57	$48.27	$48.98
Illinois Basin											
-3%, 11000 BTU (IL)	$36.68	$37.04	$37.42	$37.81	$38.19	$38.60	$39.00	$39.40	$39.78	$40.17	$40.58
-3%, 11000 BTU (KY)	$38.85	$39.27	$39.70	$40.14	$40.58	$41.04	$41.50	$41.96	$42.40	$42.84	$43.32
Powder River Basin											
-.33%, 8400 BTU	$11.94	$12.11	$12.24	$12.41	$12.54	$12.67	$12.81	$12.96	$13.10	$13.23	$13.38
-.35%, 8800 BTU	$14.69	$14.97	$15.19	$15.45	$15.68	$15.91	$16.15	$16.41	$16.66	$16.91	$17.17
Uinta Basin											
-.5%, 11500 BTU	$28.11	$28.62	$29.12	$29.65	$30.16	$30.66	$31.18	$31.73	$32.27	$32.80	$33.34
Foreign Coal											
-.7%, 12000 BTU	$54.66	$54.73	$54.82	$55.54	$56.27	$57.02	$57.81	$58.66	$59.55	$60.46	$61.33
-.8%, 11600 BTU	$52.06	$52.17	$52.27	$52.97	$53.68	$54.41	$55.17	$55.98	$56.83	$57.70	$58.52
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$38.71	$38.78	$38.81	$39.34	$39.90	$40.48	$41.09	$41.77	$42.48	$43.22	$43.91

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
BUSINESS-AS-USUAL CASE
August 2008

ANNUAL AVERAGE SPOT F

BUSINESS-AS-USUAL CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$38.15	$37.13	$37.00	$36.89	$36.75	$36.60	$36.47	$36.35	$36.22	$36.07	$35.93
-1.8%, 13000 BTU	$37.91	$36.81	$36.68	$36.57	$36.43	$36.28	$36.15	$36.04	$35.90	$35.76	$35.62
-2.3%, 13000 BTU	$37.53	$36.32	$36.19	$36.08	$35.95	$35.80	$35.68	$35.56	$35.43	$35.29	$35.15
Central Appalachia											
-.7%, 12500 BTU	$54.88	$54.59	$54.30	$54.76	$55.24	$56.35	$57.54	$58.13	$58.69	$59.22	$59.71
-.7%, 13000 BTU	$58.58	$58.28	$57.97	$58.47	$58.98	$60.18	$61.45	$62.09	$62.70	$63.27	$63.80
-1.0%, 12500 BTU	$40.59	$40.21	$39.86	$40.01	$40.20	$40.83	$41.47	$41.69	$41.87	$42.05	$42.23
-1.5%, 12500 BTU	$40.14	$39.77	$39.43	$39.60	$39.80	$40.43	$41.08	$41.31	$41.50	$41.68	$41.87
Ohio											
-4%, 12500 BTU	$34.19	$33.11	$33.00	$32.92	$32.81	$32.70	$32.59	$32.51	$32.40	$32.28	$32.18
Illinois Basin											
-3%, 11000 BTU (IL)	$28.98	$28.71	$28.46	$28.23	$27.99	$27.78	$27.57	$27.34	$27.10	$26.87	$26.65
-3%, 11000 BTU (KY)	$30.70	$30.44	$30.20	$29.97	$29.74	$29.54	$29.33	$29.11	$28.88	$28.66	$28.45
Powder River Basin											
-.33%, 8400 BTU	$9.43	$9.39	$9.31	$9.26	$9.19	$9.12	$9.05	$8.99	$8.92	$8.85	$8.79
-.35%, 8800 BTU	$11.61	$11.60	$11.55	$11.53	$11.49	$11.45	$11.41	$11.38	$11.35	$11.31	$11.28
Uinta Basin											
-.5%, 11500 BTU	$22.21	$22.18	$22.15	$22.14	$22.10	$22.07	$22.04	$22.01	$21.98	$21.94	$21.90
Foreign Coal: Colombia											
-.7%, 12000 BTU	$43.18	$42.42	$41.71	$41.46	$41.24	$41.04	$40.86	$40.70	$40.56	$40.44	$40.28
-.8%, 11600 BTU	$41.13	$40.44	$39.76	$39.55	$39.35	$39.16	$38.99	$38.84	$38.71	$38.59	$38.44
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$30.58	$30.06	$29.53	$29.37	$29.24	$29.13	$29.04	$28.98	$28.93	$28.91	$28.84

THE STATE OF NEW HAMPSHIRE
before the
PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire
Merrimack Station Scrubber Project
Request for Information

Docket No. DE 08-103

Report

October 15, 2010

By Secretarial Letter dated September 29, 2010, the Commission directed Public Service Company of New Hampshire ("PSNH" or the "Company") to file updated information concerning the status of the "Clean Air Project" - - the legislatively mandated installation of wet flue gas desulphurization ("FGD") technology ("scrubber" technology) by PSNH at Merrimack Station. In particular, the Commission directed PSNH to address:

I. A comprehensive status report on its installation progress;

II. A detailed cost estimate for the Project (including costs incurred and committed);

III. An analysis of the anticipated effect of the Project on the energy service rates;

IV. An analysis of the effect on energy service rates if Merrimack Station were not in the mix of fossil and hydro facilities operated by PSNH; and

V. The current state of the electric power markets, PSNH's forecast of power market prices, and how the scrubber Project conforms to PSNH's Least Cost Integrated Resource Plan.

This Report is intended to comply with the Commission's directive.

I. SCRUBBER INSTALLATION PROGRESS

This report provides an update to the Company's September 2, 2008, report on the Clean Air Project. It focuses on certain key actions which will provide appropriate guide posts for the progress of the Project.

Since responding to the Commission's original 2008 information request, PSNH has made extraordinary progress in the construction of the Project in accordance with the legislative mandate to put the scrubber into operation "as soon as possible" (RSA 125-O:11,I), with the

support and assistance of the New Hampshire Department of Environmental Services ("NHDES"). NHDES issued Temporary Permit TP-0008 for the Project on March 9, 2009. That permit was the primary prerequisite for construction activities on the site. All major contracts had been executed prior to that time, enabling PSNH to begin construction immediately upon issuance of the permit. Since that time, with safety always the top priority, PSNH staff and URS, PSNH's program manager, have succeeded in orchestrating the work of many contracts and hundreds of workers. Through September 2010, over 700,000 Project contractor man-hours have been dedicated to this work, *with no lost time accidents on the site*. At this time, Project construction is approximately 75% complete, well ahead of the statutory schedule that the legislature determined to be in the public interest.

Overall the Project has progressed extremely well with timely execution beginning with design, engineering, and procurement, and transitioning to field engineering and construction activities over the two-year period from October 2008 to date. Field engineering and construction work is now in full swing with approximately 480 people working on the Project, of which over 350 are building trades craftsmen.

In this report, we will continue with the chronology of major actions from where the 2008 Report ended (September 2008).

A. Activities Performed in the Fourth Quarter, 2008

Quarter 4: Contracts for the four major islands--the scrubber, chimney, waste water treatment facility, and material handling system--were finalized, executed, and released for engineering during this period. A number of smaller contracts were also executed, such as those for the installation of an FGD construction substation and site preparation work. Other critical contracts for the Project were either out for bid or in negotiations. A substantial amount of engineering work was completed by URS. Also, many permits were applied for and obtained from the Town of Bow, NHDES and other regulatory bodies. These permits authorized a number of planned activities, including the demolition of small buildings and preparation for future foundations, contractor parking, temporary office trailers, and material lay down areas. Site preparatory work was planned in order to proceed expeditiously with actual construction upon receipt of the Temporary Air Permit from NHDES and other necessary permits. As with any complex construction project, the permitting effort would be an ongoing one, requiring frequent communications with various agencies.

A variety of other approvals were sought and obtained from the Town of Bow relating to site work. Area towns were notified and adjacent towns were fully briefed on the Project. Public outreach and information sessions were held with a number of organizations such as the Southern New Hampshire Planning Commission and towns including the Town of Pembroke and the Town of Hooksett, among others.

B. Activities Performed During 2009

Quarter 1: Significant engineering activity continued in early 2009 with URS providing a high volume of design and technical support for the Project. This information was critically

needed in order to provide the Town of Bow and other local and State agencies with sufficient technical information required by various approval processes for authorization to proceed with work. The most significant permit was received on March 9 when the Temporary Air Permit (TP-0008) was received from the NHDES Air Resources Division. This permit provided the authorization for actual construction of the Project to proceed.

Additional contracts were executed for activities such as smaller foundations, third party quality control, and inspection and testing. Site traffic patterns and construction strategies were finalized which identified the best locations for things such as Project office trailers, work force gates, work force parking, and material lay down areas. This work was essential to accommodate the large number of contractors who would be employed in Project construction, and to ensure a safe environment, amid the anticipated multi-pronged construction effort that would be fully underway later in the year.

Numerous contractors mobilized and established site office trailers and began the hiring of local supervisors and building trades craftsmen.

Quarter 2: Engineering procurement and contract work continued with the issuance of additional purchase orders for items such as booster fans and motors, electrical switch gear and substation equipment.

Numerous meetings were held with the Town of Bow Planning Board in order to receive approvals to construct various buildings and ensure that the plans complied with town ordinance and building code requirements. Major equipment suppliers prepared for initiation of heavier construction later in the year with foundation work and site preparation continuing as the major areas of emphasis. This site work included the installation of numerous underground electrical and piping systems in order to ensure clear access paths by late spring to the work zone for vehicles and heavy equipment. Permits were received from the NHDES Water Division for additional Alteration of Terrain activity as well as from the Air Resources Division for fabrication on-site of large fiberglass reinforced plastic piping for the chimney liner.

Construction work force on-site rose to approximately 150 people during this period.

Large spread-mat foundations were completed for the Scrubber Island. These 8-foot thick foundations were built in a timely fashion to support the critical path schedule.

On June 30, PSNH provided an update on the Project to the Legislative Oversight Committee on Electric Utility Restructuring as well as the chairpersons of the House Science, Technology, and Energy Committee and the Senate Energy and Economic Development Committee. This update included a review of the status of the Clean Air Project engineering, contracts, permits and approvals, site work, schedule, and costs, as well as the U.S. Department of Energy Carbon-Injection Test Program.

Quarter 3: Procurement efforts continued in the summer with a focus on items such as motor control centers, continuous emission monitors, structural steel procurement, duct work

fabrication, uninterruptible power source, expansion joints, cable bus, and many other relatively small contracts.

The engineering staff with URS began to decrease as the peak engineering periods were completed. Construction activities continued to grow with the work force exceeding 175.

Periodic discussions were held with the building trades representatives, URS, and PSNH in order to ensure that there was an open line of communication to discuss work and safety practices, work scope, and staffing plans. This open exchange provided a good forum for questions and answers and open discussions on any issues of interest to the parties present. Building trades generally were represented by one or more personnel from their unions. Contractors were also present in order to provide prompt answers to any questions raised. These meetings consolidated positive relations and provided clarity of work assignments with resulting good productivity from the building trades craftsmen.

The Scrubber contractor had prepared work zones for fabrication of the large absorber vessel. This vessel, which is approximately 50 feet wide and 110 feet tall, is the project component in which boiler exit gasses react with the prescribed water/limestone mixture to remove mercury and sulfur. This large vessel was to be built in place in segments and took approximately one year to complete.

Quarter 4: Numerous contracts were issued during the latter part of 2009 including duct work and steel erection, project distributed control system, and gas duct isolation dampers, among other things.

Engineering activities continued to be brisk although ramping down as construction work and field staffing ramped up. Subsurface and foundation work continued in support of various aspects of the Project, while construction began on the Scrubber building steel framing with work continuing on the absorber vessel rings for eventual installation on the Scrubber absorber.

The internal chimney liner installation was completed as required for future connection to the flue gas absorber vessel.

All major contractors were active on-site with preparation and construction work occurring in the Scrubber area, chimney area, fabrication, and limestone conveyor towers. Numerous other contractors were on-site to support the balance of the Project work.

C. Activities Performed During 2010

Quarter 1: Contract bidding activity continued with issuance of additional contracts.

Various additional building permits were received from the Town of Bow for items such as structural and architectural design of various buildings and conveyor systems, foundations, and building electrical work.

The limestone conveyor system and support towers were structurally and mechanically completed.

Contract work force on-site grew to more than 200 with approximately 200,000 man-hours expended on the Project through this period.

Approximately 50 purchase orders and contracts were active with values totaling more than $275 million.

The overall Project schedule continued to be on track or slightly ahead of schedule which confirmed our confidence in achieving Project completion one year early. Cost management of the Project remained positive, with no projected overruns envisioned.

On March 31, per the Commission's directive, PSNH provided an information update to the New Hampshire Public Utilities Commission staff, Office of Consumer Advocate representatives, and other interested parties. This presentation reviewed PSNH's legal obligation to construct and operate the Scrubber system, and the Legislature's public interest determination, under RSA 125-O:11-18, the Project construction and contract status, overall budget by year, schedule, jobs provided by the Project, and substantial economic value to New Hampshire during an economic recession, as well as the significant environmental benefits of early completion.

Quarter 2: A variety of smaller contracts were awarded in mid-2010 for items such as painting and coatings and balance of plant electrical work. Various equipment tests in factories and at fabrication facilities were successfully carried out as a critical part of URS's overall quality control management program, allowing equipment delivery to the job site to proceed smoothly.

Various local permits were obtained as necessary for activities such as mechanical erection, electrical, structural and architectural design of remaining buildings.

Site work continued for various underground utility installations needed for ongoing work by the Phase II site preparation contractor. The 115 KV yard expansion work began to tie into the permanent new substation to power the Project with testing projected in quarter 3.

Continued erection of the absorber rings proceeded while other rings were being fabricated in adjacent areas to expedite the overall construction schedule. URS's engineering activities and associated work force were reduced to approximately 20% of peak staffing in 2009. Remaining personnel worked on small new assignments as well as design modifications, typical scope requirements, ensuring proper documentation and filing of all information and construction as-built drawing recordings.

The new Unit 1 and Unit 2 combined chimney was completed, and is awaiting testing. Completion of the chimney was critical in that adjacent site work could now proceed without the necessary safety precautions that were in place during chimney construction.

On June 29, PSNH provided its annual update on the Project to the Legislative Oversight Committee on Electric Utility Restructuring, the chairpersons of the House Science, Technology and Energy Committee, and the Senate Energy and Economic Development Committee. This update included a review of the status of the Clean Air Project engineering, contracts, permits and approvals, site work, schedule, and costs.

Quarter 3: The Project's three booster fans were installed on foundations so that duct work could proceed. These fans are in a congested construction zone adjacent to the absorber vessel scrubber structural building and chimney.

The Project celebrated a 500,000 man-hour achievement with no lost time accidents. A safety luncheon was held for the work force to congratulate them on this remarkable achievement. As with all PSNH Generation activities, worker safety has been, and will continue to be, a top priority.

Contracts were awarded for site clean-up and for finalization, start-up electrical testing.

Large construction activities continued with erection of the absorber vessel and its tie-in to the chimney, structural completion of the Scrubber island, and material handling enclosure to make the overall Project weather-tight for indoor piping, electrical, and other work during the winter period. Similar objectives were achieved for the Wastewater Treatment Building, the Gypsum Stackout Building, and other work zones where significant interior work will proceed during the upcoming winter weather period.

The 115KV substation and the station high-yard expansion were completed and were made available for testing.

The two limestone storage silos were structurally completed allowing for internal equipment installation.

The Scrubber absorber vessel shell was completed in preparation for final connection to the chimney and inlet flue gas duct work.

The work force on-site as of the date of this report totals approximately 480 people, over 350 of whom are building trades craft people. At this point of the Project, all necessary construction permits from State, Federal, and local agencies have been received.

II. COST ESTIMATE

PSNH recently announced that the Clean Air Project cost estimate has been reduced from $457 million to $430 million based on current and projected costs. This cost reduction is based primarily on better than planned work force productivity and work quality which was further enhanced due to excellent weather for most of 2010. Also, certain global market based commodities, such as steel alloy materials, have dropped in price. This new cost projection is based on a detailed analysis of work completed and work remaining; contract

commercial, technical and field status; and current knowledge of all remaining activities. With some engineering and procurement risks eliminated at this stage of the work, coupled with good project management which has avoided added expenditures, PSNH is highly confident of this new estimate.

To date, purchase orders and contracts have been issued with values totaling $317.2 million. Approximately 46 additional, comparatively small purchase orders and contracts are currently envisioned to be released over the next few months with total values of about $6-8 million.

The remaining effort for 2010, 2011, and 2012 will focus on critical schedule supporting tasks. The expenditure level for 2010 is currently projected to be approximately $151.5 million and $77.8 million is currently estimated for 2011.

III. ENERGY SERVICE RATE CHANGE

PSNH anticipates that the Clean Air Project will be operational in mid-2012. That initial year of operation, 2012, will see the ES rate increase effective July 1, 2012, reflecting the Project being used and useful in providing utility service to PSNH's retail customers. (See RSA 378:30-a).

Based upon our best estimates of project cost, timing, accounting and regulatory matters, and the assumptions set forth below, we forecast the overall average impact on ES rates from the Project for the first full 12 months of service to be $0.011/kWh. The first year of operation will see the highest cost impact as the book value of the project will be at its highest level, and will decline over the depreciated life of the project. The overall comparative average increase to ES rates for the three years following the initial year of service are as noted below:

Year 1	July 2012 – June 2013	$0.011 per kWh (initial year of service)
Year 2	July 2013 – June 2014	0.011
Year 3	July 2014 – June 2015	0.010
Year 4	July 2015 – June 2016	0.009

The primary assumptions used as inputs to the revenue requirements analysis include:

Capital costs: $430 million

Capital structure: approximately 48%/52% debt to equity ratio.

Assumed Return on Equity: 9.81% (PSNH's currently allowed ROE on generation)

In-service date: July 1, 2012

Deferred taxes: PSNH has assumed that 100% of the project costs would be eligible for liberalized (accelerated) tax depreciation, creating deferred taxes. These deferred taxes were applied against the rate base value of the project, as an overall reduction to rate base, and therefore have reduced the overall return in these calculations.

Forecasted data: PSNH's most recent 5 year forecast (2011 – 2015) was used as a starting point for our analysis. This forecast deck was updated to reflect the most recent costs associated with all of the products embedded in providing full requirements service as well as use of the latest sales data. The following assumptions were also used:

	2012	2013	2014	2015
Peak Energy* ($/MWh)				
NYMEX	54.46	56.70	58.93	61.70
EVA	64.73	67.31	70.28	73.83
Off-Peak Energy* ($/MWh)				
NYMEX	42.06	43.58	46.57	48.57
EVA	50.08	51.88	55.70	58.28
New England Delivered Natural Gas* ($/MMbtu)				
NYMEX	5.50	5.69	5.85	6.03
EVA	6.56	6.77	6.99	7.22
Capacity ($/kW-month)**	3.00	2.73	2.78	2.84
MA Class I REC Prices ($/MWh)	20.00	20.51	21.02	21.56
SO_2 ($/ton)	215.00	110.00	110.00	110.00
No_x ($/ton year round)	50.00	25.00	25.00	25.00
RGGI ($/MWh)	2.00	2.00	2.00	2.00

Notes:
* ES model uses a blend NYMEX and EVA
** Includes a peak energy rent of $0.22/kw-month

These estimates reflect recent changes in the energy and environmental marketplace and are higher than those forecasted by PSNH two years ago. There are two primary drivers for this increase. First, ES sales levels have dropped significantly over the past two years, from an

annual level of over 8 million MWh to 5½ million MWh, due to the weakened economy, conservation efforts, and customer migration to competitive suppliers. This drop in sales accounts for at least $0.003 per kWh of the increase. Secondly, the avoided costs associated with SO_2 emissions reductions have decreased significantly over the past 2 years, consistent with the decrease in the price of SO_2 allowances. The avoided costs value of reduced SO_2 emissions was approximately $30 million per year two years ago and is now approximately $3 million per year. This change in SO_2 emissions reduction value also accounts for at least $0.003 per kWh of the increase.

IV. ENERGY SERVICE RATE CHANGE WITHOUT MERRIMACK STATION

Two ES financial scenarios were run comparing Base Case (with Merrimack Station) to Change Case (without Merrimack Station). The comparison values are through the year 2015.

BASE CASE

Summary of Forecasted Energy Service Cost	2011 (Note 1)	2012	2013	2014	2015
Fossil energy costs	$ 145,689	$ 168,553	$ 150,070	$ 161,564	$ 170,333
F/H O&M, depreciation & taxes	152,339	163,884	170,294	178,565	170,072
Return on rate base	43,187	69,468	92,983	92,317	90,908
ISO-NE ancillary	6,624	25	(1,065)	(1,067)	(1,123)
Capacity	13,806	12,803	11,886	11,686	10,807
NH RPS	10,808	12,248	13,764	15,828	17,349
RGGI costs	3,707	7,744	6,680	7,207	7,560
Vermont Yankee	7,602	1,837	-	-	-
IPP costs	28,836	31,354	33,254	34,999	34,392
Purchases and sales (Note 2)	56,830	37,172	72,105	67,124	68,366
2009 ES Over/Under Recovery	(1,482)	(70)	(1)	-	-
Total Forecasted Energy Service Cost	$ 467,946	$ 505,018	$ 549,970	$ 568,223	$ 568,664
Forecasted Retail MWH Sales	5,389,252	5,449,842	5,481,127	5,544,882	5,616,530
Forecasted Energy Service Rate - cents Per KWH	8.68	9.27	10.03	10.25	10.12

Note 1 - As filed 9/21/10 Docket DE No. 10-257
Note 2 - Purchases and Sales reflect credit adjustments for Rental Revenue, HQ Revenue, and Domestic Manufacturing Deduction Credits.

CHANGE CASE
Summary of Forecasted Energy Service Cost

	2011 (Note 1)	2012	2013	2014	2015
Fossil energy costs	$ 145,689	$ 98,218	$ 35,532	$ 35,375	$ 37,374
F/H O&M, depreciation & taxes	152,339	159,749	139,569	145,883	142,105
Return on rate base	43,187	69,158	91,290	88,838	85,912
ISO-NE ancillary	6,624	(2,874)	(6,574)	(7,455)	(8,123)
Capacity	13,806	20,455	24,946	25,462	25,680
NH RPS	10,808	12,248	13,764	15,828	17,349
RGGI costs	3,707	4,483	1,178	1,166	1,243
Vermont Yankee	7,602	1,837	-	-	-
IPP costs	28,836	31,354	33,254	34,999	34,392
Purchases and sales (Note 2)	56,830	119,031	225,078	242,098	259,049
2009 ES Over/Under Recovery	(1,482)	(70)	(1)	-	-
Total Forecasted Energy Service Cost	$ 467,946	$ 513,589	$ 558,036	$ 582,194	$ 594,981
Forecasted Retail MWH Sales	5,389,252	5,449,842	5,481,127	5,544,882	5,616,530
Forecasted Energy Service Rate - cents Per KWH	8.68	9.42	10.18	10.50	10.59
BASE CASE cents per KWH	8.68	9.27	10.03	10.25	10.12
Change from Base Case cents per KWH	-	0.15	0.15	0.25	0.47

Note 1 - As filed 9/21/10 Docket DE No. 10-257
Note 2 - Purchases and Sales reflect credit adjustments for Rental Revenue, HQ Revenue, and Domestic Manufacturing Deduction Credits.

The primary assumptions used as inputs to this analysis include:

Forecasted data: consistent with the assumptions noted in Section III, above.

Capital costs: all embedded capital costs and the related depreciation and property taxes are contained in both the Base Case and Change Case. These costs would be recoverable from customers regardless of the hypothetical assumptions applied to the without Merrimack Station Change Case.

This analysis indicates that if Merrimack Station was not in the mix of fossil and hydro facilities operated by PSNH, energy service rates would be higher.

V. THE CURRENT STATE OF THE ELECTRIC POWER MARKETS, PSNH'S FORECAST OF POWER MARKET PRICES, AND HOW THE SCRUBBER PROJECT CONFORMS TO PSNH'S LEAST COST INTEGRATED RESOURCE PLAN.

A. The Current State of the Electric Power Markets

To comply with requirements of the Federal Energy Regulatory Commission, ISO-New England prepares periodic reports regarding key statistics for the region's wholesale electric power markets. Its quarterly reports for 2010 are publically available from the ISO-NE website at:

http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/

Each year, ISO-NE also reviews the performance, competitiveness and efficiency of the region's wholesale electricity markets. ISO-NE's May, 2010, report is available at:

http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html

B. PSNH's Forecast of Power Market Prices

PSNH does not forecast market prices for power. However, the assumptions PSNH used in its analyses of Energy Service rates in Sections III and IV, were detailed in Section III.

C. How the Scrubber Project Conforms to PSNH's Least Cost Integrated Resource Plan

PSNH must comply with applicable laws, regulations, and administrative orders. RSA 374:41 allows the Commission to direct the Attorney General to immediately begin an action in the name of the state praying for appropriate relief whenever a public utility is failing or omitting, or about to fail or omit, to do anything required of it by law. The mandate to install scrubber technology imposed by law in RSA Chapter 125-O is express and unequivocal, and PSNH has a duty to comply. Hence, as a matter of law, the Company's Clean Air Project must be deemed consistent with the energy policy set forth in RSA 378:37, which forms the basis for each utility's biennial least cost plan.

The Clean Air Project's installation of scrubber technology was in fact included in PSNH's most recently approved Least Cost Integrated Resource Plan, which was reviewed and accepted by the Commission in Docket No. DE 07-108. Indeed, the scrubber was the first matter highlighted in that Plan, appearing as the first bulleted paragraph on the first page of that Plan's Executive Summary. The scrubber was discussed at length in that Plan's Section XII, "Assessment of the Plan's Long- and Short-Term Environmental, Economic, Energy Price, and Energy Supply Impact on the State."

On September 30, 2010, PSNH submitted an updated Least Cost Integrated Resource Plan. Discussion of the scrubber installation mandate was similarly discussed therein. In addition to its inclusion in the Plan's Executive Summary, the Clean Air Project was included in the Plan's "Assessment of Supply Resources," "Fuel Procurement Strategies," "Assessment of Plan Integration and Impact on State Compliance with the Clean Air Act Amendments of 1990," and "Assessment of the Plan's Long- and Short-Term Environmental, Economic, Energy Price, and Energy Supply Impact on the State."

Concord Steam Corporation

DG 08-107

Response to Record Request

Date of Request: February 25, 2009 Date of Response: March 4, 2009
Exhibit No.: Exhibit 6 Witness: Peter Bloomfield

REQUEST: What would the cost of natural gas need to be in February 2011 such that gas would be more economic than steam as a fuel source under the rates for the first year of the Steam Purchase Agreement?

RESPONSE:

Cost of wood fired steam vs gas fired steam

Projected cost of steam from Concord Power		$/MMBtu	$9.96
Boiler efficiency	80%		

Cost of natural gas delivered to the plant to be able to match wood fired steam price

$/mcf **$7.97**

Existing natural gas pricing
$/mcf

Delivery		$ 1.60
LDAC		$ 0.10
Basis		$ 2.50
Gas price		$ 5.95
	Total	$10.15 mcf

						avg implied Ht rt >>		**7.62**		
	APB Peak	APB Offpk	24 hr	NYMEX Hub Gas	NE Gas Basis	NE Gas (NYMEX plus basis)	NE Gas (EVA)	Implied Ht Rate	Power Price	
Cal 08	129.74	101.15	114.38	12.91	1.71	14.62	8.37	7.82	114.38	apb
Cal 09	117.75	92.25	104.24	11.72	2.18	13.90	8.81	7.50	104.24	apb
Cal 10	107.00	83.63	94.61	10.60	1.92	12.51	8.82	7.56	94.61	apb
Cal 11	103.63	81.25	91.77	10.28	1.80	12.08	9.04	7.60	91.77	apb
Cal 12				10.34	1.70	12.04	9.53		91.76	nymex
Cal 13				10.55	1.73	12.28	8.97		68.38	eva
Cal 14				10.77	1.77	12.54	9.24		70.37	eva
Cal 15				10.99	1.81	12.80	9.50		72.43	eva
Cal 16				11.22	1.84	13.07	9.78		74.52	eva
Cal 17				11.46	1.88	13.34	10.06		76.67	eva
Cal 18				11.70	1.92	13.63	10.35		78.87	eva
Cal 19				11.96	1.97	13.93	10.65		81.14	eva esc.
Cal 20				12.22	2.01	14.22	10.95		83.47	eva esc.

Nominal dollars

Used TZ6 Basis swap from NYMEX Jun 11th for 2008- 2012 basis
Used EVA (Feb 2008 forecast) for 2013 - 2018 delivered gas
Used EVA growth rate to derive 2019 - 2020 delivered gas (Boston citygate)