Exhibit GRM-1

GEORGE R. McCLUSKEY

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Analyst

George McCluskey is a ratemaking specialist with over 30 years experience in utility economics. Since rejoining the New Hampshire Public Utilities Commission ("NHPUC.") in 2005, he has worked on default service and standby rate issues in the electric sector and cost allocation issues in the gas sector. While at La Capra Associates, a Boston-based consulting firm specializing in electric industry restructuring, wholesale and retail power procurement, market price and risk analysis, and power systems models and planning methods, he provided strategic advice to numerous clients on a variety of issues. Prior to joining La Capra Associates, Mr. McCluskey directed the electric utility restructuring division of the NHPUC and before that was manager of least cost planning, directing and supervising the review and implementation of electric and gas utility least cost plans and demand-side management programs. He has testified as an expert witness in numerous electric and gas cases before state and federal regulatory agencies.

ACCOMPLISHMENTS

Recent project experience includes:

Staff of the New Hampshire Public Utilities Commission – Expert testimony before NHPUC regarding default service design and pricing issues in case involving Unitil Energy Systems.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before Maine Public Utilities Commission regarding interstate allocation of natural gas capacity costs in case involving Northern Utilities.

Staff of the Arkansas Public Service Commission – Analysis and case support regarding Entergy Arkansas Inc.'s application to transfer ownership and control of its transmission assets to a Transco. Also analyzed Entergy Arkansas Inc.'s stranded generation cost claims.

Massachusetts Technology Collaborative – Evaluated proposals by renewable resource developers to sell Renewable Energy Credits to MTC in reponse to 2003 RFP.

Pennsylvania Office of the Consumer Advocate – Analysis and case support regarding horizontal and vertical market power related issues in the PECO/Unicom merger proceeding. Also advised on cost-of-service, cost allocation and rate design issues in FERC base rate case for interstate natural gas pipeline company.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before the NHPUC regarding stranded cost issues in Restructuring Settlement Agreement submitted by Public Service Company of New Hampshire and various settling parties. Testimony presents an analysis of PSNH's stranded costs and makes recommendations regarding the recoverability of such costs.

Town of Waterford, CT – Advisory and expert witness services in litigation to determine property tax assessment of for nuclear power plant.

Washington Electric Cooperative, Vt – Prepared report on external obsolescence in rural distribution systems in property tax case.

New Hampshire Public Utilities Commission - Expert testimony on behalf of the NHPUC before the Federal Energy Regulatory Commission regarding the Order 888 calculation of wholesale stranded costs for utilities receiving partial requirements power supply service.

Ohio Consumer Council - Expert testimony regarding the transition cost recovery requests submitted by the AEP companies, including a critique of the DCF and revenues lost approaches to generation asset valuation.

EXPERIENCE

New Hampshire Public Utilities Commission (2005 to Present)
Analyst, Electric Division

La Capra Associates (1999 to 2005)
Senior Consultant

New Hampshire Public Utilities Commission (1987 – 1999)
Director, Electric Utilities Restructuring Division

Manager, Least Cost Planning
Analyst, Economics Department

Electricity Council, London, England (1977-1984)
Pricing Specialist, Commercial Department
Information Officer, Secretary's Office

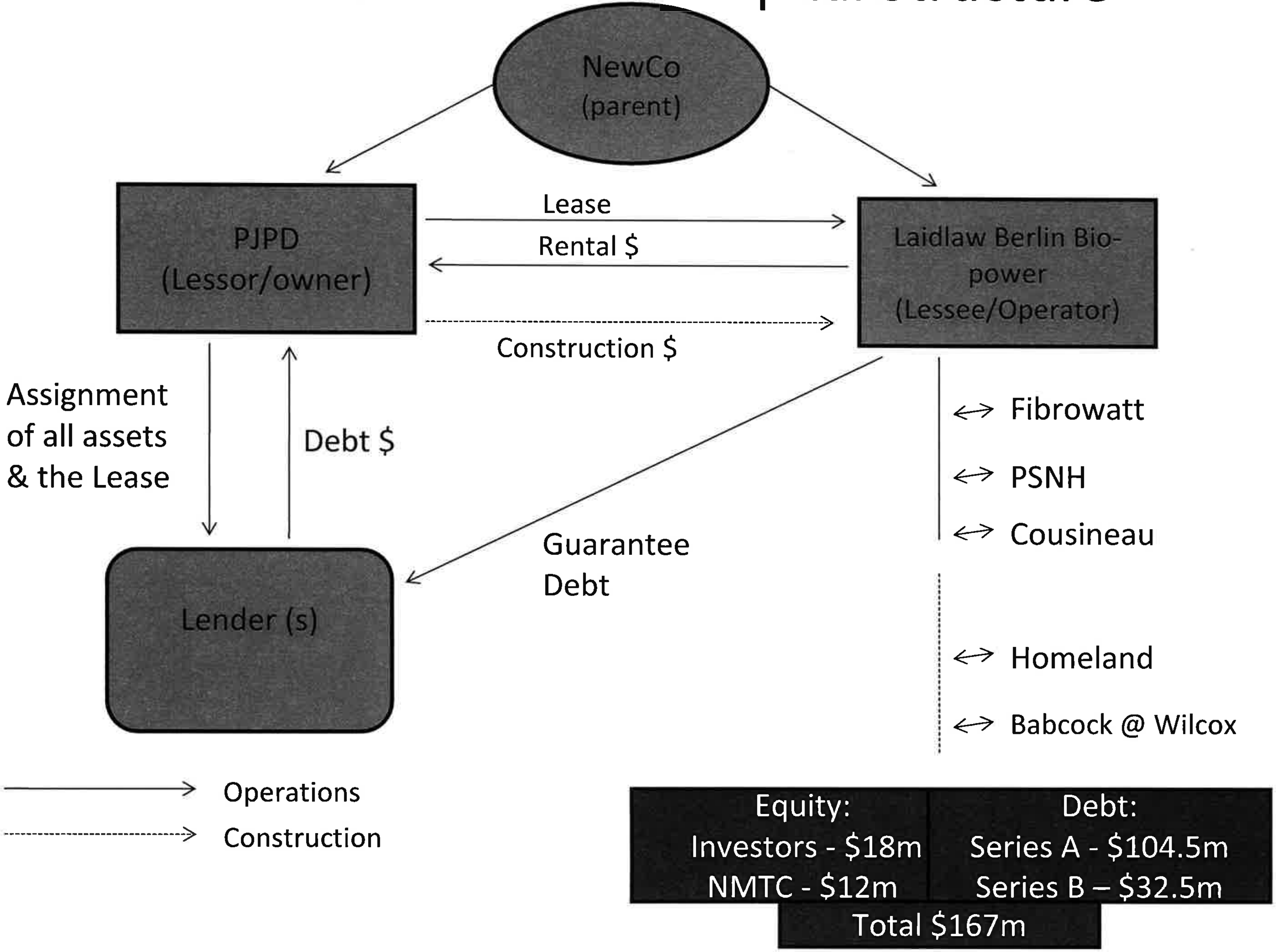
EDUCATION:

Ph.D. candidate in Theoretical Plasma Physics, University of Sussex Space Physics Laboratory.
Withdrew in 1997 to accept position with the Electricity Council.

B.S., University of Sussex, England, 1975.
Theoretical Physics

Exhibit GRM-2

Berlin Power Plant Capital Structure



Assumptions	
Gross Capacity (MW)	70.00
Net Capacity (MW)	63.00
Capacity Factor (%)	87.50%
Contract Term (Years)	20.00
Annual Net Production (MWh)	482,895
Base Fuel Cost ($/Ton)	$ 34.00
Inflation Rate (%)	2.50%

Laidlaw Power Purchase Agreement
Estimated Product Prices

Year	Energy ($/MWh)	Capacity ($/kW-mo)	Capacity ($/MWh)	REC ($/MWh)	Total ($/MWh)
2014	$83.00	$4.25	$6.65	$53.80	$143.46
2015	$84.53	$4.25	$6.65	$55.15	$146.33
2016	$86.10	$4.25	$6.65	$56.53	$149.28
2017	$87.71	$4.25	$6.65	$57.94	$152.30
2018	$89.35	$4.25	$6.65	$59.39	$155.40
2019	$91.04	$4.40	$6.89	$57.07	$155.00
2020	$92.77	$4.55	$7.12	$58.50	$158.39
2021	$94.55	$4.70	$7.36	$59.96	$161.86
2022	$96.37	$4.85	$7.59	$61.46	$165.42
2023	$98.23	$5.00	$7.83	$62.99	$169.05
2024	$100.14	$5.15	$8.06	$60.26	$168.47
2025	$ 102.10	$5.30	$8.30	$61.77	$172.17
2026	$104.11	$5.45	$8.53	$63.32	$175.96
2027	$106.16	$5.60	$8.77	$64.90	$179.83
2028	$108.27	$5.75	$9.00	$66.52	$183.80
2029	$110.44	$5.90	$9.24	$48.70	$168.38
2030	$112.65	$6.05	$9.47	$49.92	$172.04
2031	$114.92	$6.20	$9.71	$51.17	$175.80
2032	$117.25	$6.35	$9.94	$52.45	$179.64
2033	$119.64	$6.50	$10.18	$53.76	$183.57

Biomass IPPs Selling to PSNH
Capacity Factors

Mo-Yr	Bethlehem	Tamworth	Indeck Alexandria
Jan-08'	97%	104%	
Feb-08'	93%	100%	
Mar-08'	61%	104%	
Apr-08'	97%	47%	
May-08'	88%	84%	
Jun-08'	86%	89%	
Jul-08'	90%	84%	
Aug-08'	77%	94%	
Sep-08'	89%	97%	
Oct-08'	96%	92%	
Nov-08'	82%	89%	0%
Dec-08'	82%	84%	13%
Jan-09'	98%	84%	34%
Feb-09'	99%	88%	20%
Mar-09'	99%	80%	57%
Apr-09'	79%	76%	36%
May-09'	90%	87%	5%
Jun-09'	90%	100%	0%
Jul-09'	97%	99%	45%
Aug-09'	99%	100%	27%
Sep-09'	97%	100%	72%
Oct-09'	98%	99%	32%
Nov-09'	97%	86%	61%
Dec-09'	97%	92%	84%
Jan-10'	98%	95%	89%
Feb-10'	98%	97%	55%
Mar-10'	99%	95%	70%
Apr-10'	89%	72%	69%
May-10'	85%	65%	72%
Jun-10'	98%	88%	86%
Jul-10'	99%	98%	103%
Aug-10'	100%	100%	104%
Sep-10'	98%	101%	65%
Simple Avg	92%	90%	52%

APPENDIX 1

INTERCONNECTION REQUEST

The undersigned Interconnection Customer submits this request to interconnect its Large Generating Facility to the Administered Transmission System under Schedule 22 - Large Generator Interconnection Procedures ("LGIP") of the ISO New England Inc. Open Access Transmission Tariff (the "Tariff"). Capitalized terms have the meanings specified in the Tariff.

PROJECT INFORMATION

Proposed Project Name:__________Laidlaw Berlin Biomass Energy Plant__________________

This request is for the purpose of adding incremental increase in MW output for Project Queue Position 251.

1. This Interconnection Request is for (check one):

__________ **A proposed new Large Generating Facility**

____X_____ **An increase in the generating capacity or a modification that has the potential to be a Material Modification of an existing Generating Facility**

__________ **Commencement of participation in the wholesale markets by an existing Generating Facility**

__________ **A change from Network Resource Interconnection Service to Capacity Network Resource Interconnection Service**

2. The types of Interconnection Service requested:

__________ **Network Resource Interconnection Service (energy capability only)**

_____X____ **Capacity Network Resource Interconnection Service (energy capability and capacity capability)**

If Capacity Network Resource Interconnection Service, does Interconnection Customer request Long Lead Facility treatment? Check: ____Yes or _X__ No

If yes, provide, together with this Interconnection Request, the Long Lead Facility deposit and other required information as specified in Section 3.2.3 of the LGIP,

including (if the Large Generating Facility will be less than 100 MW) a justification for Long Lead Facility treatment.

3. This Interconnection Customer requests (check one, selection is not required as part of the initial Interconnection Request):

__________ A Feasibility Study to be completed as a separate and distinct study

____X_____ A System Impact Study with the Feasibility Study to be performed as the first step of the study

(The Interconnection Customer shall select either option and may revise any earlier selection up to within five (5) Business Days following the Scoping Meeting.)

4. The Interconnection Customer shall provide the following information:

Address or Location of the Facility (including Town/City, County and State):

Former Fraser Pulp Mill Property (bordered by Androscoggin River on the west, Community Street to the south and Hutchins Street on the east)
City of Berlin
Coos County
New Hampshire

Approximate location of the proposed Point of Interconnection (information is not required as part of the initial Interconnection Request):

PSNH East Side Substation 300, Goebel Street, Berlin, NH

Type of Generating Facility to be Constructed:________ST______________________

Generating Facility Fuel Type:__WDS____

Generating Facility Capacity (MW): **Present Q-251 Interconnection Request**

	Maximum Net MW Electrical Output	Maximum Gross MW Electrical Output
At or above 90 degrees F	58.7	65.9
At or above 50 degrees F	58.7	65.9
At or above 20 degrees F	58.7	65.9
At or above 0 degrees F	58.7	65.9

Generating Facility Capacity (MW): **Incremental Generation to be added to Q-251**

	Maximum Net MW Electrical Output	Maximum Gross MW Electrical Output
At or above 90 degrees F	8.8	9.1
At or above 50 degrees F	8.8	9.1
At or above 20 degrees F	8.8	9.1
At or above 0 degrees F	8.8	9.1

Generating Facility Capacity (MW): **Total Revised Q-251 Capacity**

	Maximum Net MW Electrical Output	Maximum Gross MW Electrical Output
At or above 90 degrees F	67.5	75.0
At or above 50 degrees F	67.5	75.0
At or above 20 degrees F	67.5	75.0
At or above 0 degrees F	67.5	75.0

General description of the equipment configuration (# of units and GSUs):

One straight condensing single flow steam turbine, water cooled
One synchronous generator

Projected Commercial Operations Date: **October 01, 2012**

Projected Initial Synchronization Date: **August 01, 2012**

Evidence of Site Control (check one):

____X_____ If for Capacity Network Resource Interconnection Service, Site Control is provided herewith, as required.

__________ If for Network Resource Interconnection Service: (Check one)

___ Is provided herewith

___ In lieu of evidence of Site Control, a $10,000 deposit is provided herewith (refundable within the cure period as described in Section 3.3.3 of the LGIP).

The technical data specified within the applicable attachment to this form (check one):

__________ Is included with the submittal of this Interconnection Request form

____X_____ Will be provided on or before the execution and return of the Feasibility Study Agreement (Attachment B) or the System Impact Study Agreement (Attachment A), as applicable

The ISO will post the Project Information on the ISO web site under "New Interconnections" and OASIS.

CUSTOMER INFORMATION

Company Name: Laidlaw Berlin Biopower, LLC (Interconnection Customer)

Company Address: Laidlaw Berlin Biopower, LLC
c/o NewCo Energy, LLC
One Cate Street, Suite 100
Portsmouth, NH 03801

Company Representative: Name: Robert Desrosiers
Title: Manager

Company Representative's Company and Address (if different from above): same as above

Phone: 603 319-4400 FAX: 603 584-1315 email: rdesrosiers@catecapital.com

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This Interconnection Request is submitted by:

Authorized Signature: RSKusche

Name (type or print): Raymond S. Kusche

Title: Vice President, Laidlaw Berlin Biopower, LLC

Date: September 24, 2010

PSNH Class 1 REC Obligation

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Delivery Service Forecast			7,788,024	7,877,125	7,903,333	7,995,366	8,064,644	8,141,016	8,199,342	8,271,759	8,329,217	8,432,844
Growth(%)				1.14%	0.33%	1.16%	0.87%	0.95%	0.72%	0.88%	0.69%	1.24%
Energy Service (31% migration)			5,373,737	5,435,216	5,453,300	5,516,803	5,564,604	5,617,301	5,657,546	5,707,514	5,747,160	5,818,662
Class 1 REC Obligation (%)			2%	3%	4%	5%	6%	7%	8%	9%	10%	11%
Class 1 REC Obligation (MWh)			107,475	163,056	218,132	275,840	333,876	393,211	452,604	513,676	574,716	640,053
RECs Under Contract (MWh)			102,684	94,625	67,638	67,638	67,638	67,638	67,638	67,638	67,638	67,638
Schiller Unit 5 RECs Produced (Mwh)	318,945	313,932	316,439	316,439	316,439	316,439	316,439	316,439	316,439	316,439	316,439	316,439
RECs Needed (MWh)			(311,648)	(248,007)	(165,945)	(108,236)	(50,200)	9,135	68,527	129,600	190,639	255,976
LBB RECs Produced(i) (MWh)			0	0	203,232	471,064	471,064	471,064	471,064	471,064	471,064	471,064
Excess(Shortfall) (MWh)			311,648	248,007	369,177	579,300	521,264	461,929	402,537	341,464	280,425	215,088
Cumulative Excess (MWh)					369,177	948,477	1,469,741	1,931,671	2,334,207	2,675,672	2,956,096	3,171,184
Unit Cost ($/REC)						53.8	55.1	56.5	57.9	59.4	57.07	58.50
Annual cost ($)						$ 31,166,360	$ 28,745,116	$ 26,109,926	$ 23,321,661	$ 20,277,901	$ 16,003,828	$ 12,581,928
Cumulative Cost ($)						$ 31,166,360	$ 59,911,476	$ 86,021,402	$ 109,343,064	$ 129,620,965	$ 145,624,792	$ 158,206,720
Revenue @ Current Mkt Price ($)						$ 9,558,456	$ 8,600,860	$ 7,621,836	$ 6,641,858	$ 5,634,160	$ 4,627,005	$ 3,548,946
Cumulative Revenue ($)						$ 9,558,456	$ 18,159,316	$ 25,781,152	$ 32,423,009	$ 38,057,170	$ 42,684,174	$ 46,233,120

(i) See PSNH response to Staff 1-19

PSNH Class 1 REC Obligation

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Delivery Service Forecast	8,477,761	8,520,150	8,562,751	8,605,564	8,648,592	8,691,835	8,735,294	8,778,971	8,822,866	8,866,981	8,911,316	8,955,873	9,000,652	
Growth(%)	0.53%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	
Energy Service (31% migration)	5,849,655	5,878,904	5,908,298	5,937,839	5,967,528	5,997,366	6,027,353	6,057,490	6,087,778	6,118,217	6,148,808	6,179,552	6,210,450	
Class 1 REC Obligation (%)	12%	13%	14%	15%	16%	16%	16%	16%	16%	16%	16%	16%	16%	
Class 1 REC Obligation (MWh)	701,959	764,257	827,162	890,676	954,805	959,579	964,377	969,198	974,044	978,915	983,809	988,728	993,672	
RECs Under Contract (MWh)	67,638	67,638	67,638	67,638	67,638	67,638	67,638	67,638	67,638	67,638	67,638	67,638	67,638	
Schiller Unit 5 RECs Produced (Mwh)	316,439	316,439	316,439	316,439	316,439	316,439	316,439	316,439	316,439	316,439	316,439	316,439	316,439	
RECs Needed (MWh)	317,882	380,181	443,085	506,599	570,728	575,502	580,300	585,122	589,968	594,838	599,733	604,652	609,595	
LBB RECs Produced(i) (MWh)	471,064	471,064	471,064	471,064	471,064	471,064	471,064	471,064	471,064	471,064	471,064	471,064	471,064	9,624,512
Excess(Shortfall) (MWh)	153,182	90,883	27,979	(35,535)	(99,664)	(104,438)	(109,236)	(114,058)	(118,904)	(123,774)	(128,669)	(133,588)	(138,531)	
Cumulative Excess (MWh)	3,324,366	3,415,249	3,443,227											36%
Unit Cost ($/REC)	59.96	61.46	62.99											
Annual cost ($)	$ 9,184,659	$ 5,585,504	$ 1,762,510											
Cumulative Cost ($)	$ 167,391,379	$ 172,976,883	$ 174,739,393											
Revenue @ Current Mkt Price ($)	$ 2,527,501	$ 1,499,570	$ 461,649											
Cumulative Revenue ($)	$ 48,760,622	$ 50,260,192	$ 50,721,841											
			$ 124,017,552											

(i) See PSNH response to Staff 1-19

Public Service Company of New Hampshire
Docket No. DE 10-195

Data Request STAFF-05

Dated: 11/01/2010
Q-STAFF-002
Page 1 of 1

Witness: **Richard C. Labrecque**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Ref. PSNH Response to Staff 1-19. Please provide for the period October 2008 through September 2010 the percentage of PSNH's monthly retail load met by competitive suppliers.

Response:
The percentage of PSNH's total retail load served by competitive suppliers for October 2008 through September 2010 is as follows:

Oct-08	2.9%
Nov-08	6.0%
Dec-08	7.4%
Jan-09	7.5%
Feb-09	10.4%
Mar-09	12.1%
Apr-09	13.5%
May-09	15.7%
Jun-09	17.8%
Jul-09	18.8%
Aug-09	19.7%
Sep-09	22.6%
Oct-09	25.7%
Nov-09	26.2%
Dec-09	26.8%
Jan-10	24.7%
Feb-10	26.4%
Mar-10	28.5%
Apr-10	30.6%
May-10	31.9%
Jun-10	31.8%
Jul-10	30.1%
Aug-10	30.6%
Sep-10	33.0%

Public Service Company of New Hampshire
Docket No. DE 10-195

Data Request STAFF-03

Dated: 10/25/2010
Q-STAFF-019
Page 1 of 1

Witness: **Richard C. Labrecque**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Ref. SEC Transcript, Day 1, Afternoon Session. At page 107, Laidlaw witness Bravakis states that the Facility will consume 750,000 tons of biomass fuel annually. At page 94, Laidlaw witness Strickler states that the planned capacity factor for the Facility is 87.5%. At page 90, witness Bravakis states that the net output of the Facility is 63 MW. Given that 750,000 tons per year equates to 97.84 tons per hour at a capacity factor of 87.5% or 1.55 tons per net MW per hour, please explain why the factor in Article 6.1.2 (a)(ii) of the PPA for converting $/ton to $/MWh was selected instead of 1.55 tons/MWh.

Response:
The factor in Article 6.1.2 (a)(ii) of the PPA was an estimated value that was part of the overall contract negotiation.

Public Service Company of New Hampshire
Docket No. DE 10-195

Data Request STAFF-01

Dated: 10/08/2010
Q-STAFF-010
Page 1 of 1

Witness: **Terrance J. Large**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Please provide all information on the price of other renewable resource projects which PSNH reviewed or considered in the process of negotiating the pricing provisions in the proposed PPA. Include in this response all evaluations, studies, reports, spreadsheets, correspondence, notes, presentation materials, and work papers related to the pricing of other renewable resource projects.

Response:
The process of negotiating the pricing provisions in the PPA was not directly influenced by the price of other renewable projects. See the response to Q-STAFF-017 for related information.

REDACTED Exhibit GRM-10

Laidlaw Revenue-Lempster Prices

Assumptions	
Net Capacity (MW)	63.00
Capacity Factor (%)	87.50%
Contract Term (Years)	20.00
Annual Net Production (MWh)	482,895
Discount Rate	7.59%

Year	Energy ($/MWh)	Capacity ($/kW-mo)	REC ($/MWh)	Delivered Energy (MWh)	Annual Power Revenue ($)
2014				$482,895	
2015				$482,895	
2016				$482,895	
2017				$482,895	
2018				$482,895	
2019				$482,895	
2020				$482,895	
2021				$482,895	
2022				$482,895	
2023				$482,895	
2024				$482,895	
2025				$482,895	
2026				$482,895	
2027				$482,895	
2028				$482,895	

15-Year Cost-Lempster Prices	
15-Year Cost-PPA Prices	$ 1,176,678,186
Percent Change	
Difference	

Exhibit GRM-11

Energy Price Comparison

	PPA Energy Prices ($/MWh)	Market Energy Price Proj. ($/MWh)	Difference ($/MWh)	Levelized Difference ($/MWh)	Levelized PPA Energy Prices ($/MWh)	
2014	$83.00	$ 66.63	$16.37	16.88	$95.51	17.68%
2015	$84.53	$ 66.60	$17.93	16.88	$95.51	
2016	$86.10	$ 68.32	$17.78	16.88	$95.51	
2017	$87.71	$ 70.06	$17.65	16.88	$95.51	
2018	$89.35	$ 71.92	$17.43	16.88	$95.51	
2019	$91.04	$ 73.80	$17.24	16.88	$95.51	
2020	$92.77	$ 75.67	$17.10	16.88	$95.51	
2021	$94.55	$ 77.53	$17.02	16.88	$95.51	
2022	$96.37	$ 79.37	$17.00	16.88	$95.51	
2023	$98.23	$ 81.38	$16.85	16.88	$95.51	
2024	$100.14	$ 83.43	$16.71	16.88	$95.51	
2025	$102.10	$ 85.54	$16.56	16.88	$95.51	
2026	$104.11	$ 87.70	$16.41	16.88	$95.51	
2027	$106.16	$ 89.92	$16.24	16.88	$95.51	
2028	$108.27	$ 92.19	$16.08	16.88	$95.51	
2029	$110.44	$ 94.52	$15.92	16.88	$95.51	
2030	$112.65	$ 96.91	$15.74	16.88	$95.51	
2031	$114.92	$ 99.33	$15.59	16.88	$95.51	
2032	$117.25	$ 101.82	$15.43	16.88	$95.51	
2033	$119.64	$ 104.36	$15.28	16.88	$95.51	
NPV	$967.25		$170.96	$170.97	$967.25	

Adj. Energy Price Comparison

	PPA Energy Prices ($/MWh)	Adjusted Market Energy Price Proj. ($/MWh)	Difference ($/MWh)	Levelized Difference ($/MWh)	Levelized PPA Energy Prices ($/MWh)	
2014	$83.00	$ 53.12	$29.88	29.55	$95.51	30.94%
2015	$84.53	$ 55.50	$29.03	29.55	$95.51	
2016	$86.10	$ 55.80	$30.30	29.55	$95.51	
2017	$87.71	$ 57.02	$30.69	29.55	$95.51	
2018	$89.35	$ 58.44	$30.91	29.55	$95.51	
2019	$91.04	$ 59.86	$31.18	29.55	$95.51	
2020	$92.77	$ 61.29	$31.48	29.55	$95.51	
2021	$94.55	$ 62.81	$31.74	29.55	$95.51	
2022	$96.37	$ 66.40	$29.97	29.55	$95.51	
2023	$98.23	$ 68.56	$29.67	29.55	$95.51	
2024	$100.14	$ 70.79	$29.35	29.55	$95.51	
2025	$102.10	$ 73.10	$29.00	29.55	$95.51	
2026	$104.11	$ 75.48	$28.63	29.55	$95.51	
2027	$106.16	$ 77.94	$28.22	29.55	$95.51	
2028	$108.27	$ 80.47	$27.80	29.55	$95.51	
2029	$110.44	$ 83.09	$27.35	29.55	$95.51	
2030	$112.65	$ 85.80	$26.85	29.55	$95.51	
2031	$114.92	$ 88.59	$26.33	29.55	$95.51	
2032	$117.25	$ 91.47	$25.78	29.55	$95.51	
2033	$119.64	$ 94.45	$25.19	29.55	$95.51	
NPV	$967.25		$299.22	$299.23	$967.25	

REC Price Comparison

	PPA REC Prices ($/MWh)	Synapse Market REC Price Proj. (2009 $/MWh)	Synapse Market REC Price Proj. ($/MWh)	Adj. Synapse Market REC Price Proj. ($/MWh)	Difference ($/MWh)	Levelized Difference ($/MWh)	Levelized PPA REC Price ($/MWh)	
2014	$53.80	$ 28.62	$ 32.38	$ 42.10	$11.71	28.89	$57.89	49.91%
2015	$55.15	$ 26.73	$ 31.00	$ 40.30	$14.85	28.89	$57.89	
2016	$56.53	$ 26.90	$ 31.98	$ 41.57	$14.96	28.89	$57.89	
2017	$57.94	$ 32.26	$ 39.31	$ 51.10	$6.84	28.89	$57.89	
2018	$59.39	$ 32.55	$ 40.65	$ 52.85	$6.54	28.89	$57.89	
2019	$57.07	$ 26.91	$ 34.45	$ 44.78	$12.29	28.89	$57.89	
2020	$58.50	$ 23.97	$ 31.45	$ 40.89	$17.61	28.89	$57.89	
2021	$59.96	$ 18.69	$ 25.14	$ 32.68	$27.28	28.89	$57.89	
2022	$61.46	$ 15.62	$ 21.53	$ 27.99	$33.47	28.89	$57.89	
2023	$62.99	$ 10.99	$ 15.53	$ 20.19	$42.81	28.89	$57.89	
2024	$60.26	$ 3.27	$ 4.74	$ 6.16	$54.11	28.89	$57.89	
2025	$61.77	$ 2.81	$ 4.17	$ 5.42	$56.35	28.89	$57.89	
2026	$63.32	$ 2.41	$ 3.67	$ 4.77	$58.55	28.89	$57.89	
2027	$64.90	$ 2.08	$ 3.24	$ 4.22	$60.68	28.89	$57.89	
2028	$66.52	$ 2.00	$ 3.20	$ 4.16	$62.36	28.89	$57.89	
2029	$48.70	$ 2.00	$ 3.28	$ 4.26	$44.44	28.89	$57.89	
2030	$49.92	$ 2.00	$ 3.36	$ 4.37	$45.55	28.89	$57.89	
2031	$51.17	$ 2.00	$ 3.44	$ 4.48	$46.69	28.89	$57.89	
2032	$52.45	$ 2.00	$ 3.53	$ 4.59	$47.86	28.89	$57.89	
2033	$53.76	$ 2.00	$ 3.62	$ 4.70	$49.06	28.89	$57.89	
NPV	$586.32				$292.62	$292.62	$586.32	

Annual production (MWh)	482,895
Nominal Cost ($)	$279,045,705

Exhibit GRM-14

Capacity Price Comparison

	PPA Capacity Prices ($/kW-mo)	Levitan Capacity Market Price Proj. ($/kW-mo)	Difference ($/kW-mo)	Levelized Difference ($/kW-mo)	Levelized PPA Capacity Price ($/kW-mo)	
2014	$4.25	$ 2.95	$1.30	-2.66	$4.85	-54.74%
2015	$4.25	$ 2.95	$1.30	-2.66	$4.85	
2016	$4.25	$ 3.43	$0.82	-2.66	$4.85	
2017	$4.25	$ 4.30	-$0.05	-2.66	$4.85	
2018	$4.25	$ 5.24	-$0.99	-2.66	$4.85	
2019	$4.40	$ 6.23	-$1.83	-2.66	$4.85	
2020	$4.55	$ 7.27	-$2.72	-2.66	$4.85	
2021	$4.70	$ 8.37	-$3.67	-2.66	$4.85	
2022	$4.85	$ 9.53	-$4.68	-2.66	$4.85	
2023	$5.00	$ 10.35	-$5.35	-2.66	$4.85	
2024	$5.15	$ 10.76	-$5.61	-2.66	$4.85	
2025	$5.30	$ 10.97	-$5.67	-2.66	$4.85	
2026	$5.45	$ 10.84	-$5.39	-2.66	$4.85	
2027	$5.60	$ 11.24	-$5.64	-2.66	$4.85	
2028	$5.75	$ 11.78	-$6.03	-2.66	$4.85	
2029	$5.90	$ 12.10	-$6.20	-2.66	$4.85	
2030	$6.05	$ 12.42	-$6.37	-2.66	$4.85	
2031	$6.20	$ 12.42	-$6.22	-2.66	$4.85	
2032	$6.35	$ 12.42	-$6.07	-2.66	$4.85	
2033	$6.50	$ 12.42	-$5.92	-2.66	$4.85	
NPV	$49.13		-$26.89	-$26.89	$49.12	
		Nominal Saving ($)		$ (40,143,600)		

Public Service Company of New Hampshire
Docket No. DE 10-195

Data Request STAFF-03
Dated: 10/25/2010
Q-STAFF-007
Page 1 of 2

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Ref. PSNH Confidential Response to Staff 1-15. Regarding page 2, please respond to the following:

(i) Provide the formula and inputs supporting the capacity revenue for 2011.

(ii) Explain the apparent contradiction between fixed annual fuel costs and annual energy revenue that increases at a rate equal to the CPI.

(iii) Describe the purpose of the percentage rent factor and state the source of the percentage.

(iv) Explain the rationale for a PTC that increases in value with time.

(v) Regarding the section headed Economics to Lessor, provide the discount rate used to present value the stream of annual net cash flows.

(vi) Justify the selected discount rate.

(vii) Regarding the section headed Economics to Lessor, specify the amount and timing of each cost that was subtracted from the cash flows to produce the net cash flows that resulted in the NPV shown.

(viii) Provide support for the costs provided in response to (vii).

Response:

(i) The page 2 capacity revenue for 2011 is the product of the "Capacity Price ($/kw-mo)" shown at the bottom of the page and the "Net MW" provided on page 3, and further multiplied by 12 months.

(ii) Energy revenues were modeled according to terms discussed during negotiations. Cost estimates were made for specific cost components (lease payments, O&M, and fuel) based on conversations with Laidlaw. However, PSNH was unable to reconcile the aggregate of the cost components to match the estimate of total ongoing expenses that Laidlaw provided. In order to arrive at total costs closer to the provided estimate, the fuel cost line item was not escalated.

(iii) This is a term negotiated between Laidlaw and its investor, with the assumption being that it is a form of additional profit sharing for Laidlaw's investor beyond the base lease costs. The percentage is based on terms discussed during negotiations. PSNH is not a party to Laidlaw's financing arrangement and therefore does not know the specifics of the final arrangements.

(iv) The Production Tax Credit was assumed to increase each year with inflation.

(v) The discount rate used was 11.6%.

(vi) The discount rate used was the after-tax weighted average cost of capital based on an assumed 70/30 debt/equity ratio, an 8% cost of debt and a 20% return on equity. These assumptions were used to simulate the capital structure of a merchant facility.

(vii) The assumed initial investment was subtracted from the annual cash flows to calculate the NPV shown.

The total annual cash flow to investors was calculated as Fixed lease payment (after tax) + Percentage rent (after tax) + Depreciation tax benefit + Production tax credit.

Fixed lease payment (after tax) = Amortization (as shown starting on pg. 4) + Interest (as shown starting on pg. 4) x Lease Rent Factor (shown on pg. 2) x Tax adjustment factor of 60%

Percentage rent (after tax) = Noted Rent percentage x net profit (shown on pg. 1) x Tax adjustment factor of 60%

Depreciation tax benefit = initial investment amortized over 20 years x Taxes of 40%

Production tax credit = 1% (in 2007, adjusted for 2.5% inflation) x MWh output

(viii) The costs developed for this analysis were based on prevailing price assumptions at the time of the analysis and discussions with Laidlaw.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
PETITION FOR APPROVAL OF POWER PURCHASE AGREEMENT
WITH LAIDLAW BERLIN BIOPOWER, LLC

DE 10-195

Laidlaw Berlin Biopower LLC's Responses to
Staff's Data Requests – Set #2

Date Received: October 14, 2010 Date of Response: October 21, 2010
Request No.: Staff LBB 2-2

REQUEST: Ref. SEC Docket 2009-02, Transcript August 25, 2010, Afternoon Session. At page 16, Mr. Bartoszek states that "The New Market Tax Credit is a seven-year program, but it's effectively monetized so that there's an upfront contribution to the project. So we're projecting a gross contribution from New Market Tax Credits of approximately 12 million." Please provide all calculations, workpapers and supporting documentation for the $12 million tax credit estimate.

RESPONSE: Laidlaw objects to this data request on the basis that it is vague and overbroad and is not reasonably calculated to lead to the discovery of information that is relevant to this proceeding. Notwithstanding and without waiving its objection, Laidlaw provides the following response.

Laidlaw is very fortunate to have obtained $44.5 million in NMTC allocation, which will provide approximately $12,000,000 in actual upfront gross equity capital to the Project, the balance of which is $32,500,000 in leverage debt financing (i.e. 12M + 32.5M = 44.5M). Essentially the $44.5M creates $17,355,000 in tax credits (i.e. $44.5M x 39% = $17,355,000 in NMTCs). These 39% in NMTCs are realized over seven years: 5% + 5% + 5% + 6% + 6% + 6% + 6% = 39%. The $17,355,000 is then sold to a tax credit investor that monetizes the 7-year stream of tax credits and provides an upfront cash equity contribution to the Project. The current market pricing for the NMTCs is $0.69 per $1.00 of NMTC. This means that a tax credit investor may be willing to pay approximately $12,000,000 upfront to receive the stream of NMTCs that amount to $17,355,000 over the seven years. ($17,355,000 x 69% = $11,974,950, rounded to $12,000,000).

The actual amount of net NMTC equity subsidy that is available to the Project is less than the full $12,000,000 amount as the gross amount is reduced by multiple NMTC related fees and transaction costs. In addition, Laidlaw, in consultation with the NMTC CDEs, has voluntarily elected to use, $2,750,000 as special set aside funds to be allocated for specific direct community benefits.

As indicated in 2-1(iii) above, timing is critical for the NMTC allocatees and NMTC equity investor who will be monetizing the seven-year stream of NMTCs with an upfront "NMTC equity" payment. The current NMTC pricing of $0.69 is very attractive, but that rate could go down if the Project is not able to meet its 2010 goals and commitments to the NMTc participants. If the year-end 2010 commitments cannot be met, the Project's NMTC allocation could be reduced or, more likely, potentially lost completely. While the Project will still go forward without NMTC funding, the costs, the timing, and certainly the funding available for the targeted community benefits would be negatively impacted.

Exhibit GRM-17
Page 1

PSNH Financial Analysis
Laidlaw Facility
Lease Scenario + PPA Prices + Changed Inputs

Revenue	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capacity		$ 3,213,000	$ 3,213,000	$ 3,213,000	$ 3,213,000	$ 3,213,000	$ 3,326,400	$ 3,439,800	$ 3,553,200	$ 3,666,600
Energy		$ 40,080,285	$ 40,819,114	$ 41,576,414	$ 42,352,647	$ 43,148,285	$ 43,963,815	$ 44,799,732	$ 45,656,548	$ 46,534,784
RECs		$ 25,981,806	$ 26,631,351	$ 27,297,135	$ 27,979,563	$ 28,679,052	$ 27,558,777	$ 28,247,746	$ 28,953,940	$ 29,677,788
Total Revenue		$ 69,275,091	$ 70,663,465	$ 72,086,549	$ 73,545,210	$ 75,040,338	$ 74,848,992	$ 76,487,279	$ 78,163,688	$ 79,879,172
Expenses										
Lease Payment		$25,050,000	$24,215,000	$23,380,000	$22,545,000	$21,710,000	$20,875,000	$20,040,000	$19,205,000	$18,370,000
Fixed and Variable O&M		$7,421,000	$7,651,525	$7,842,563	$8,039,227	$8,239,633	$8,445,899	$8,657,146	$8,873,500	$9,095,087
Fuel Costs		$29,300,573	$30,033,088	$30,783,915	$31,553,513	$32,342,351	$33,150,909	$33,979,682	$34,829,174	$35,699,904
Total expenses		$61,771,573	$61,899,613	$62,006,478	$62,137,740	$62,291,984	$62,471,808	$62,676,828	$62,907,674	$63,164,991
Net Profit		$7,503,518	$8,763,853	$10,080,071	$11,407,470	$12,748,354	$12,377,184	$13,810,450	$15,256,014	$16,714,181
Percentage Rent at 15%		$1,125,528	$1,314,578	$1,512,011	$1,711,121	$1,912,253	$1,856,578	$2,071,568	$2,288,402	$2,507,127
Pre-Tax Profit		$6,377,990	$7,449,275	$8,568,061	$9,696,350	$10,836,101	$10,520,606	$11,738,883	$12,967,612	$14,207,054
Calculated Tax at 40%		$2,551,196	$2,979,710	$3,427,224	$3,878,540	$4,334,440	$4,208,242	$4,695,553	$5,187,045	$5,682,822
Net Income		$3,826,794	$4,469,565	$5,140,836	$5,817,810	$6,501,661	$6,312,364	$7,043,330	$7,780,567	$8,524,233
Economics to Lessor										
Lease Payment (After Tax)		$ 15,030,000	$ 14,529,000	$ 14,028,000	$ 13,527,000	$ 13,026,000	$ 12,525,000	$ 12,024,000	$ 11,523,000	$ 11,022,000
Percentage Rent (After Tax)		$ 675,317	$ 788,747	$ 907,206	$ 1,026,672	$ 1,147,352	$ 1,113,947	$ 1,242,941	$ 1,373,041	$ 1,504,276
Depreciation Tax Benefit		$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000
PTC Credit		$ 5,600,102	$ 5,740,104	$ 5,883,607	$ 6,030,697	$ 6,181,464	$ 6,336,001	$ 6,494,401	$ 6,656,761	$ 6,823,180
Total Cash Flow		$ 24,645,418	$ 24,397,851	$ 24,158,813	$ 23,924,369	$ 23,694,816	$ 23,314,947	$ 23,101,341	$ 22,892,802	$ 22,689,456
Capital Cost	$ (167,000,000)									
Net Cash Flow	$ (167,000,000)	$ 24,645,418	$ 24,397,851	$ 24,158,813	$ 23,924,369	$ 23,694,816	$ 23,314,947	$ 23,101,341	$ 22,892,802	$ 22,689,456
NPV		$26,236,979								
Economics to Lessee										
Net Income (After Tax)		$3,826,794	$4,469,565	$5,140,836	$5,817,810	$6,501,661	$6,312,364	$7,043,330	$7,780,567	$8,524,233
NPV		$ 68,316,121								
Economics of Project										
Total Net Cash Flow	$ (167,000,000)	$ 28,472,212	$ 28,867,416	$ 29,299,649	$ 29,742,179	$ 30,196,477	$ 29,627,311	$ 30,144,671	$ 30,673,369	$ 31,213,689
NPV		$ 94,553,100								
ROE (After Interest and Loan Repayment)		61%	66%	71%	77%	82%	82%	88%	94%	100%

PSNH Financial Analysis
Laidlaw Facility
Lease Scenario + PPA Prices + Changed Inputs

Revenue	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Capacity	$ 3,780,000	$ 3,893,400	$ 4,006,800	$ 4,120,200	$ 4,233,600	$ 4,347,000	$ 4,460,400	$ 4,573,800	$ 4,687,200	$ 4,800,600	$ 4,914,000	$ 77,868,000
Energy	$ 47,434,976	$ 48,357,672	$ 49,303,436	$ 50,272,844	$ 51,266,488	$ 52,284,972	$ 53,328,919	$ 54,398,964	$ 55,495,760	$ 56,619,976	$ 57,772,298	$ 965,467,931
RECs	$ 30,419,733	$ 29,101,545	$ 29,829,083	$ 30,574,810	$ 31,339,181	$ 32,122,660	$ 23,518,376	$ 24,106,336	$ 24,708,994	$ 25,326,719	$ 25,959,887	$ 558,014,483
Total Revenue	$ 81,634,709	$ 81,352,617	$ 83,139,320	$ 84,967,855	$ 86,839,268	$ 88,754,632	$ 81,307,695	$ 83,079,100	$ 84,891,954	$ 86,747,295	$ 88,646,185	$ 1,601,350,415
Expenses												
Lease Payment	$17,535,000	$16,700,000	$15,865,000	$15,030,000	$14,195,000	$13,360,000	$12,525,000	$11,690,000	$10,855,000	$10,020,000	$9,185,000	
Fixed and Variable O&M	$9,323,040	$9,555,490	$9,794,578	$10,039,442	$10,290,228	$10,548,084	$10,811,161	$11,081,615	$11,358,605	$11,642,296	$11,933,853	
Fuel Costs	$36,592,401	$37,507,211	$38,444,891	$39,406,014	$40,391,164	$41,400,943	$42,435,967	$43,496,866	$44,584,288	$45,698,895	$46,841,367	$ 748,473,116
Total expenses	$63,450,441	$63,762,702	$64,104,469	$64,475,456	$64,876,392	$65,309,027	$65,772,128	$66,268,481	$66,797,893	$67,361,190	$67,960,220	
Net Profit	$18,184,268	$17,589,915	$19,034,850	$20,492,399	$21,962,876	$23,445,605	$15,535,567	$16,810,619	$18,094,061	$19,386,105	$20,685,965	
Percentage Rent at 15%	$2,727,640	$2,638,487	$2,855,228	$3,073,860	$3,294,431	$3,516,841	$2,330,335	$2,521,593	$2,714,109	$2,907,916	$3,102,895	
Pre-Tax Profit	$15,456,628	$14,951,428	$16,179,623	$17,418,539	$18,668,445	$19,928,764	$13,205,232	$14,289,026	$15,379,952	$16,478,189	$17,583,070	
Calculated Tax at 40%	$6,182,651	$5,980,571	$6,471,849	$6,967,416	$7,467,378	$7,971,506	$5,282,093	$5,715,610	$6,151,981	$6,591,276	$7,033,228	
Net Income	$9,273,977	$8,970,857	$9,707,774	$10,451,123	$11,201,067	$11,957,259	$7,923,139	$8,573,415	$9,227,971	$9,886,914	$10,549,842	
Economics to Lessor												
Lease Payment (After Tax)	$ 10,521,000	$ 10,020,000	$ 9,519,000	$ 9,018,000	$ 8,517,000	$ 8,016,000	$ 7,515,000	$ 7,014,000	$ 6,513,000	$ 6,012,000	$ 5,511,000	
Percentage Rent (After Tax)	$ 1,636,584	$ 1,583,092	$ 1,713,137	$ 1,844,316	$ 1,976,659	$ 2,110,104	$ 1,398,201	$ 1,512,956	$ 1,628,466	$ 1,744,749	$ 1,861,737	
Depreciation Tax Benefit	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	$ 3,340,000	
PTC Credit	$ 6,993,759	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,740,075
Total Cash Flow	$ 22,491,344	$ 14,943,092	$ 14,572,137	$ 14,202,316	$ 13,833,659	$ 13,466,104	$ 12,253,201	$ 11,866,956	$ 11,481,466	$ 11,096,749	$ 10,712,737	$ 363,739,575
Capital Cost												
Net Cash Flow	$ 22,491,344	$ 14,943,092	$ 14,572,137	$ 14,202,316	$ 13,833,659	$ 13,466,104	$ 12,253,201	$ 11,866,956	$ 11,481,466	$ 11,096,749	$ 10,712,737	$363,739,575
NPV												
Economics to Lessee												
Net Income (After Tax)	$9,273,977	$8,970,857	$9,707,774	$10,451,123	$11,201,067	$11,957,259	$7,923,139	$8,573,415	$9,227,971	$9,886,914	$10,549,842	$163,140,496
NPV												
Economics of Project												
Total Net Cash Flow	$ 31,765,320	$ 23,913,949	$ 24,279,910	$ 24,653,439	$ 25,034,726	$ 25,423,363	$ 20,176,340	$ 20,440,371	$ 20,709,437	$ 20,983,663	$ 21,262,579	$526,880,071
NPV												
ROE (After Interest and Loan Repayment)	106%	66%	71%	76%	81%	86%	60%	65%	69%	74%	77%	
Capital structure												