STAFF EXHIBIT 1

STATE OF NEWHAMPSHIRE

PUBLIC UTILITIES COMMISSION

DE 10-195

In the Matter of:
Public Service Company of New Hampshire
Petition for Approval of Proposed
Power Purchase Agreement with Laidlaw
Berlin Biopower, LLC.

Direct Testimony

of

George R. McCluskey

December 17, 2010

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OF
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BEFORE THE
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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is George McCluskey and my business address is the New Hampshire Public Utilities Commission ("Commission"), 21 South Fruit Street, Suite 10, Concord, NH 03301.

Q. WHAT IS YOUR POSITION WITH THE COMMISSION?

A. I am an analyst within the Electric Division.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I am a utility ratemaking specialist with over 30 years experience in utility economics. I rejoined the Commission in March 2005 after working as an energy consultant for La Capra Associates for five years. Before joining La Capra Associates, I directed the Commission's electric utility restructuring division and before that I was manager of least cost planning, directing and supervising the review and implementation of electric utility least cost plans and demand-side management programs. I have participated in restructuring-related activities in New Hampshire, Arkansas, Pennsylvania, California and Ohio and have presented or filed testimony before state regulatory authorities in New Hampshire, Maine, Ohio and Arkansas and before the FERC. I have also testified on a variety of cost-of-service, rate design and power procurement topics. A copy of my resume is included as Exhibit GRM-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony will address the Power Purchase Agreement ("PPA") entered into by Public Service Company of New Hampshire ("PSNH") and Laidlaw Berlin Biopower, LLC ("Laidlaw") which was filed with the Commission on July 26, 2010. The PPA governs the purchase by PSNH of all of the electrical energy, capacity and renewable energy certificates ("RECs") produced by the Laidlaw wood-fired electric generating facility during its 20-year term. I provide an analysis of whether the PPA is in the public interest pursuant to the public interest criteria set forth in RSA 362-F:9. A focal point of that analysis is whether the PPA prices reflect the lowest prices necessary for the facility to receive financing and earn a reasonable return. A related issue, which is also examined, is whether PSNH is required to purchase more of the facility's output than is necessary for Laidlaw to receive financing and earn a reasonable return.

Q. DOES YOUR TESTIMONY ALSO ADDRESS THE LOCAL ECONOMIC BENEFITS ATTRIBUTED TO THE LAIDLAW PROJECT?

A. No, that issue will be addressed in the testimony of Thomas Frantz.

Q. WHO IS LAIDLAW BERLIN BIOPOWER?

A. Laidlaw is the developer of the project and will be responsible for the day-to-day operations and management of the facility. Laidlaw is 100% owned by NewCo Energy, LLC ("NewCo"), a single purpose entity formed solely for the purposes of constructing and operating the facility.[1] The plant and the land on which it will be located will not, however, be owned by Laidlaw. The real property and assets will be owned by PJPD Holdings, LLC ("PJPD"), an affiliate of Laidlaw. PJPD, like Laidlaw, is 100% owned by NewCo. PJPD will lease the use of the land and its assets to Laidlaw, pursuant to a long-term lease agreement. Under the lease agreement, all operating expenses of any nature will be the responsibility of Laidlaw.

Q. YOU SAID THAT PSNH HAS COMMITTED TO PURCHASE ALL OF THE ENERGY, CAPACITY AND RECs PRODUCED BY THE FACILITY DURING THE FIRST 20 YEARS. DOES PSNH HAVE A NEED FOR THAT OUTPUT?

A. PSNH needs to purchase sufficient energy and capacity to reliably supply the loads of its retail customers. It also needs to purchase specific quantities of RECs to satisfy the requirements of RSA 362-F, New Hampshire's Renewable Portfolio Standard ("RPS"). Since each of these products can be purchased in existing organized markets, PSNH does not have a "need" for the output of the facility in

[1] NewCo's owners include both the former and current managing partners of the consulting firm Accenture Utilities Practice, as well as other individuals associated with Accenture.

the sense that if the agreement was not approved it would fail to supply the loads of its customers and fail to meet its RPS obligations. That said, PSNH is generally able to use energy, capacity or RECs that is priced below what it would otherwise pay in the market. The question of need should, therefore, begin with the question of whether the products are priced competitively. If the answer is yes, the next question should be whether PSNH is physically able to utilize all that is offered to it. If the answer to that question is no, then PSNH's need for the output is constrained.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Section II, I provide a description of the Laidlaw project and summarize the key price and non-price terms in the PPA. Section III comprises five subsections, each addressing a different aspect of the PPA. The first subsection addresses PSNH's obligation to purchase all of the output of the facility. The second addresses PSNH's need for Class I RECs. The third addresses the proposed Wood Price Adjustment (WPA). The fourth addresses the cost-effectiveness of the PPA. The fifth and last subsection addresses the provisions dealing with the Purchase Option and the Right of First Refusal. Using the criteria set forth in RSA 362-F:9(II), I provide in Section IV an analysis of whether the PPA is in the public interest. Finally, in Section V, I provide my recommendations.

II. SUMMARY OF KEY PRICE AND NON-PRICE TERMS IN PPA

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE LAIDLAW PROJECT.

A. Laidlaw has proposed to develop a 70 MW (gross) wood-fired electric generating facility that produces electrical energy, capacity and RECs. The facility is to be located in Berlin, New Hampshire, on the site of the former Fraser Paper Pulp mill. While most of the building and equipment from the pulp mill operation have been removed from the site; a black liquor recovery boiler and its associated facilities were retained. This recovery boiler will be converted to a bubbling fluidized bed boiler, which will supply steam to an existing turbine generator to produce electricity. Homeland Renewable Energy, Inc. will operate the facility under contract with Laidlaw.

According to Laidlaw's application to New Hampshire's Site Evaluation Committee ("SEC"),[2] the facility has been designed to incorporate advanced emissions control technologies and monitoring systems which will allow it to meet the definition of "eligible biomass technologies" under New Hampshire's RPS and hence qualify it for New Hampshire Class I REC status.

The capital cost of the project is currently estimated at $167 million, which is to be financed with $137 million of debt and $30 million of equity.[3] The debt financing will be provided by various institutional investors and will be secured by the property owned by PJPD. The term of the debt is expected match the term of the PPA, which is 20 years beginning June 1, 2014. The equity capital will be provided by a combination of NewCo investors and a grant from the federal government.

Q. HOW WILL THE FACILITY BE CONNECTED TO PSNH'S TRANSMISSION SYSTEM?

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[2] SEC Docket No. 2009-02.

[3] See Laidlaw Response to Staff 3-3 attached as Exhibit GRM-2.

A. A new switchyard will be built and connected to the existing East Side Substation 300 operated by PSNH. A new 115kV transmission line will be installed for this purpose. Portions of the transmission line will run both underground and overhead. The underground portion will run for an estimated length of 3,200 feet and the overhead portion is estimated to be 800 feet.

Q. PLEASE PROVIDE A SUMMARY OF THE KEY PRICE AND NON-PRICE TERMS IN THE PPA.

A. During the 20-year term of the PPA, PSNH is obligated to purchase 100% of the products produced by the facility, which include energy, capacity and renewable energy attributes. Although each product is priced separately under the PPA, the starting bundled price is estimated at $143.5 per megawatt-hour (MWh) in 2014 rising to $183.6 per MWh in the last year of the agreement.[4] Over the term of the agreement the contract prices are equivalent to a levelized bundled price of about $162 per MWh. This is approximately twice the level of PSNH's current energy service rate when expressed on a MWh basis.

The projected energy prices recover, among other things, the cost of wood fuel consumed in the facility, which is assumed to start at $34/ton in 2014 and rise at an annual rate of 2.5%.[5] If the price of wood fuel deviates from these

[4] See Exhibit GRM-3. Note that the bundled energy prices differ slightly from the bundled prices contained in Attachment RCL-1 to Mr. Labrecque's testimony. The difference is attributable to the use in my analysis of Laidlaw's claimed capacity factor for the facility of 87.5% instead of the 85% used by Mr. Labrecque.

[5] More accurately, the energy prices reflect the projected cost of wood fuel consumed by Schiller Unit 5 rather than by the Laidlaw facility.

assumptions, the difference will be charged or credited to PSNH through a Wood Price Adjustment ("WPA") to the contract energy price.

Over the 20-year term, PSNH will pay approximately $1.6 billion to Laidlaw for the products produced by the facility. About one-third of this total payment will be for the production and delivery of RECs to PSNH, a huge sum for a relatively small project. Energy payments will account for most of the remaining $1 billion.

Q. WHAT IS THE ENERGY PRICE UNDER THE PPA?

A. Energy prices will vary over the term of the agreement, starting in 2014 at $83 plus the WPA for every MWh delivered to the designated delivery point. The $83/MWh price is referred to as the base energy price and comprises two components. One component, equal to $61.2/MWh, is the product of the base fuel price of $34/ton and a conversion factor of 1.8 tons/MWh. As noted, PSNH assumes in its analyses that the base fuel price will increase at an annual rate of 2.5%. The other component, equal to $21.8/MWh, does not change over the term and appears to represent the levelized charge that will collect over the 20-year term the estimated O&M costs for the facility. These costs were also assumed to increase annually at a rate of 2.5%. In summary, the energy prices in the PPA are designed to recover: (i) the cost of wood fuel on a reconciled basis; and (ii) the estimated costs of O&M.

Q. YOU INDICATED THAT THE WPA COULD BE POSITIVE OR NEGATIVE. HOW IS THAT ADJUSTMENT CALCULATED?

A. The WPA is simply the product of a factor that converts tons of fuel to MWh and the difference in dollars per ton between the unit cost of fuel consumed at Schiller Unit 5 and the base fuel price of $34/ton. The actual conversion factor is 1.8 tons/MWh, the same factor used to convert the base fuel price to $/MWh.

Q. WHAT IS THE CAPACITY PRICE UNDER THE PPA?

A. The capacity price also varies over the 20-year term. Over the first five years, PSNH will pay $4.25 per kW-month of capacity. For each subsequent year, the payment will increase by $0.15 per kW-month. Thus, capacity prices are fixed by the terms of the PPA whereas energy prices depend on the cost of fuel consumed at Schiller Unit 5, which is currently unknown.

Q. HOW ARE THE REC PRICES DEVELOPED IN THE PPA?

A. Over the first five years, the REC price is 80% of the "Renewables Products Payment" applicable to the period during which the RECs were produced. During the next five years, the REC price is 75% of the applicable Renewable Products Payment. During the subsequent five years, the REC price is 70% of the applicable Renewables Products Payment. Finally, during the remaining five years of the term, the REC price is 50% of the applicable Renewable Products Payment.

The Renewable Products Payment is defined in the PPA as the alternative compliance payment (ACP) schedule set forth under RSA 362-F for RECs produced by NH Class I renewable facilities, as adjusted by the Commission.

Although RSA 362-F does not contain a "schedule" of Class I ACPs, it does contain an initial Class I ACP that will be adjusted each year by the Commission using the Consumer Price Index. Thus, assuming the initial Class I ACP plus the annual adjustments comprise the schedule referenced in the PPA, it is reasonable to view the REC prices as essentially fixed.

Q. YOU SAID THAT PSNH WOULD PAY APPROXIMATELY $1.6 BILLION TO LAIDLAW OVER THE 20-YEAR TERM OF THE PPA. COULD THE FINAL PRICE TAG BE HIGHER?

A. It could. My estimate is based on the capacity factor claimed by Laidlaw before the SEC. That figure, however, is considerably lower than the capacity factors achieved by some of the wood-fired generators selling to PSNH in recent years.[6] Thus, if the Laidlaw facility achieves the level of performance achieved by the high performers, the total power bill will increase because PSNH is obligated to purchase 100% of the products produced by the facility during the term.

Q. YOU ALSO SAID THAT PSNH WOULD PAY ABOUT $500 MILLION OVER THE 20-YEAR TERM FOR RECs. DOES THE MAGNITUDE OF THOSE PAYMENTS RAISE A RED FLAG?

A. It does. The stated purpose of RSA 362-F, New Hampshire's RPS, is to stimulate investment in low emission renewable generation technologies. To achieve this purpose, the statute mandates that a certain percentage of each electricity provider's end-use load be supplied with eligible renewable resources. This

[6] See Exhibit GRM-4. Prior to November 2008, the Indeck plant was mothballed.

requirement, along with the issuance of RECs to eligible resources for each MWh generated, has the effect of providing an additional revenue stream for the developers of those resources. The expectation was that this additional revenue stream would make it economically feasible for renewable resources to compete with conventional generating units.

If the REC market price is insufficient for this purpose, renewable resources would not be built and the resulting supply shortage would force prices to rise to a level that stimulated investment. Similarly, if the REC market price is too high, the resulting supply excess would force prices to fall until investment was slowed. Thus, in an efficient market, the REC price would always approach the uneconomic variable cost of renewable generation. In this proceeding, however, the REC payments total approximately three-quarters the total cost of wood fuel, which suggests that wood is either a very uneconomic fuel for electricity generation or the negotiated prices are too high and would over stimulate biomass investment if they were made generally available.

III PPA PROVISIONS OF INTEREST

A. PSNH's Obligation to Purchase All of the Output of the Facility

Q. ARTICLE 5.1 TO THE PPA STATES THAT PSNH SHALL PURCHASE 100% OF THE PRODUCTS PRODUCED BY THE FACILITY. WHAT IS YOUR CONCERN WITH THIS PROVISION?

A. My concern is that the provision does not place an absolute limit on the amount of products that PSNH must purchase under the PPA. As a result, the above-market prices under the PPA may encourage Laidlaw to increase the output of the facility resulting in PSNH paying for the incremental products at the PPA prices.

Q. DOES LAIDLAW HAVE THE ABILITY UNDER THE PPA TO INCREASE THE OUTPUT OF THE FACILITY?

A. According to PSNH, the PPA is silent on Laidlaw's right to expand the facility. One interpretation of this response is that the PPA does not prohibit Laidlaw from increasing the facility's output. In fact, Laidlaw has already filed papers informing ISO-NE of its intention to increase the output to 75 MW gross and 67.5 MW net. Laidlaw projects that this expansion will increase the annual net output to approximately 504,711 MWh from the 482,895 MWh referenced in the SEC proceeding.[7]

Q. DOES PSNH BELIEVE THAT IT IS OBLIGATED TO PURCHASE THE INCREMENTAL PRODUCTS IF LAIDLAW INCREASES THE OUTPUT OF THE FACILITY?

A. PSNH states that Article 1.18 of the PPA defines the "Facility" as the generating plant in Appendix A. It goes on to say that if and when the Facility is expanded such that the description in Appendix A is no longer valid, "it will determine the appropriate course of action consistent with the PPA terms and conditions."

[7] See Exhibit GRM-5.

Q. IS THIS A SATISFACTORY RESPONSE, IN YOUR OPINION?

A. No, it is not. Given the high above-market cost of the products purchased under the PPA, I believe that the public interest demands that PSNH purchase no more than it is absolutely obligated to purchase. To remove any uncertainty as to what that level might be, I recommend the Commission establish a specific output level expressed in MW above which PSNH would have no purchase obligation.

Q. DOESN'T THE LANGUAGE IN APPENDIX A ESTABLISH THAT LIMIT?

A. Appendix A states that the facility will be designed to have a net electrical output at standard conditions of approximately 64 MW (winter) and 61 MW (summer). However, the undefined terms winter, summer, and standard conditions, as well as the vagueness of the word "approximately," plus Laidlaw's claim that the net output of the facility is 63 MW, create significant opportunities for future disagreements.

B. PSNH's Need for Class I Renewable Energy Certificates.

Q. ARTICLE 5.1 TO THE PPA REQUIRES PSNH TO PURCHASE ALL OF THE RECs PRODUCED BY THE FACILITY. IS THIS OBLIGATION CONSISTENT WITH PSNH'S CLASS I OBLIGATION UNDER THE RPS?

A. No, for two reasons. First, RSA 362-F:3 requires each provider of electricity to obtain and retire RECs sufficient in number and class type to meet or exceed specified percentages of "total megawatt-hours of electricity supplied by the provider to its end-use customers." For example, in 2014 PSNH must acquire sufficient Class I RECs to meet 5% of its retail energy service load. Stated differently, suppliers of RECs will be paid for energy delivered to PSNH's end-use customers rather than to PSNH's distribution system. The cost associated with the difference (i.e., distribution system losses) is to be shouldered by the REC supplier. Under the PPA, however, PSNH's REC payment obligation is based on the number RECs delivered to its distribution system, which means that the cost of the lost RECs will be shouldered by PSNH customers. The net result is that PSNH retail customers will face REC prices that are higher than indicted in the PPA.[8]

Second, when account is taken of the Class I RECs already under contract to PSNH and the Class I RECs produced by Schiller Unit 5, PSNH does not have a need to acquire additional Class I RECs until 2016. The PPA, however, obligates PSNH to purchase all of the RECs produced by the Laidlaw facility as early as 2014. Even after 2016, the RECs delivered by Laidlaw will exceed PSNH's estimated need through 2023 based on an assumed migration rate of 31%.[9] These facts appear to be in conflict with the plain meaning of RSA 362-F:9(I), which envisions approval of multi-year purchase agreements for RECs "to meet reasonably projected renewable portfolio requirements." Given that over the first 10 years of the PPA, PSNH will be required to purchase from Laidlaw over 3 million RECs[10] that it does not expect to need, representing approximately one-

[8] For example, in 2014 retail customers will actually pay $57.50 per MWh consumed instead of the $53.80 price shown in Mr. Labrecque's Attachment RCL-1.
[9] See Exhibit GRM-6. Note that during this period, 2016 to 2023, other suppliers will effectively be shut out of PSNH's portion of the New Hampshire Class I REC market and will have to compete with PSNH in the non-PSNH markets.
[10] Ibid.

third of the total RECs produced by the facility, it is difficult to envision how this obligation can be consistent with meeting "reasonably projected" needs.

Finally on this issue, the Wood-Fired IPPs have argued that there is no requirement for the purchase of REC after 2005 in the RPS. If this is correct, all of the RECs scheduled to be purchased during the 2026-2033 period will be in excess of need absent modification of the RPS by the legislature. In other words, PSNH will have taken on the very significant cost risk that the legislature will not extend the RPS beyond 2025.[11]

Q. IS IT LIKELY THAT PSNH WILL BE ABLE TO SELL THE EXCESS RECs TO OTHER BUYERS IN NEW HAMPSHIRE OR ELSEWHERE?

A. Yes, but not at the price it paid for them. The REC prices under the PPA are substantially above current and expected future market prices for Class I RECs. Using the current market price as a benchmark, PSNH would only recoup about $50 million of the $175 million excess cost. The above-market cost of $125 million would have to be collected from the declining number of energy service customers, thus increasing energy service prices and adding to the pressure for further migration.

Q. YOUR ESTIMATE OF THE EXCESS RECs TO BE PURCHASED BY PSNH IS BASED ON PSNH'S DEMAND FORECAST AND AN ASSUMED 31%

[11] This statement assumes that the Commission has the authority to approve cost recovery for a non-existent REC obligation.

MIGRATION RATE. IS THERE A SIGNIFICANT RISK THAT MIGRATION IN THE FUTURE COULD EXCEED THAT RATE?

A. Yes, because the 31% figure used by PSNH to determine its need for RECs does not represent a forecast for the future but simply the current level of migration. Moreover, that rate has already been exceeded in three out of last twelve months.[12] Thus, if the current migration rate is exceeded, the first year that PSNH can use all of the RECs produced by the Laidlaw will be pushed out beyond 2023.

Q. WHAT ARE YOUR CONCLUSIONS?

A. I conclude that PSNH has committed to purchase more RECs from Laidlaw than it is likely to need during the term of the PPA resulting in unnecessary additional costs for PSNH customers.

C. Proposed Wood Price Adjustment

Q. EARLIER YOU SAID THAT IF THE PRICE OF WOOD CONSUMED AT SCHILLER DEVIATES FROM THE BASE WOOD PRICE OF $34/TON THE DIFFERENCE WILL BE CHARGED OR CREDITED TO PSNH THROUGH A WOOD PRICE ADJUSTMENT TO THE ENERGY BASE PRICE. YOU ALSO SAID THAT THE AMOUNT CHARGED OR CREDITED WILL EQUAL THE PRODUCT OF THE WPA AND A CONVERSION FACTOR. DO YOU HAVE ANY CONCERNS WITH THE CONVERSION FACTOR INCLUDED IN THE PPA?

[12] See PSNH Response to Staff 5-2 attached as Exhibit GRM-7.

A. I do. My initial reading of the PPA and Mr. Labrecque's testimony left the impression that the WPA was simply a dollar-for-dollar pass-through of any increase or decrease in the price of wood relative to the base wood price. That, however, is not the case. In order to have a dollar-for-dollar pass-through of the cost associated with a change in the price of wood, the conversion factor would have to be 1.55 tons per MWh for an electric generating plant of the size and operating characteristics claimed by Laidlaw. Because the factor in the PPA is not 1.55 but 1.8 tons per MWh, Laidlaw will actually collect through the WPA mechanism more than the actual incremental cost if wood prices rise above $34/ton. In other words, the WPA is potentially another source of income for Laidlaw.

Q. WHAT IS THE MAGNTUDE OF THIS ADDITIONAL INCOME?

A. For every dollar increase in the price of wood, I estimate Laidlaw will collect an additional $113,000 per year.

Q. WAS PSNH AWARE OF THIS WHEN IT ENTERED INTO THE AGREEMENT?

A. Yes, PSNH has stated that agreement on the 1.8 tons per MWh factor was part of the overall contract negotiation.[13]

Q. DOES PSNH EXPECT WOOD FUEL PRICES TO INCREASE?

[13] See PSNH response to Staff 3-19 attached as Exhibit GRM-8.

A. Yes, its base case assumption is that wood fuel prices will increase at an annual rate of 2.5%.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE APPROPRIATE CONVERSION FACTOR FOR THIS FACILITY IS 1.55 TONS PER MWH.

A. In testimony before the SEC, Laidlaw witnesses stated that the facility would consume 750,000 tons annually when operating at its planned capacity factor of 87.5%. The witnesses also state that the net output of the facility will be 63 MW. Since 750,000 tons per year equates to 97.84 tons per hour at a capacity factor of 87.5%, the equivalent quantity on a MW basis is 1.55 tons per MW per hour.

Q. USING THE 1.55 TONS/MWH FACTOR TO CONVERT THE BASE WOOD PRICE OF $34/TON TO $/MWH PRODUCES A FIGURE OF $52.7/MWH. WHY IS THE PPA ENERGY PRICE SO MUCH HIGHER THAN THIS FIGURE?

A. The difference amounts to $30.3/MWh. Most of this difference, equal to $21.8/MWh, is the levelized charge negotiated by the parties that recovers over the 20-year term the estimated O&M costs for the facility. The remaining amount is attributable to using a conversion factor of 1.8 instead of 1.55 tons/MWh.

D. The Purchase Option and Right of First Refusal

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE PURCHASE OPTION.

A. The proposed PPA provides PSNH with the option to purchase the facility and the site on which it is located at the end of the 20-year term. The purchase price will equal the fair market value of the facility at the end of the term less the balance in the so-called Cumulative Reduction account, provided that the net of the two values is not less than zero. The Cumulative Reduction account tracks and aggregates the amount by which the adjusted base energy price[14] in each hour differs from the ISO-NE's energy price in the hour multiplied by the MWhs delivered. These positive or negative amounts will be aggregated over the term of the PPA to determine the cumulative net positive or negative adjustment to the fair market value. A cumulative net negative adjustment will serve to reduce the purchase price of the facility. A cumulative net positive adjustment will have no impact on the purchase price.

PSNH can also acquire the facility prior to the end of the 20-year term under its Right of First Refusal. Under this provision, if Laidlaw elects to sell the facility to a third-party PSNH has the right to match the third-party offer and purchase the facility. Because Article 7.1.2 requires that a third-party owner of the facility assume all rights and obligations of the Laidlaw, including those with respect to the Cumulative Reduction account, the purchase price under the Right of First Refusal will also reflect the value in this account.

Q. MR. LABRECQUE DESCRIBES THE CUMULATIVE REDUCTION ACCOUNT AS A MECHANISM THAT PROTECTS CUSTOMERS FROM

[14] The adjusted base energy price is defined as the base energy price plus the WPA.

PAYING PPA PRICES THAT EXCEED THE MARKET PRICE. DO YOU AGREE?

A. Not at all. First, PSNH is obligated to pay the PPA energy prices regardless of whether those prices are above or below market energy prices. Second, because there is no provision in the PPA for above-market payments to accumulate interest, the balance in the cumulative reduction account at the end of the 20-year term is likely to be far less than if customers had paid only market energy prices and deposited the difference in an interest bearing bank savings account or invested it in stocks.[15] The magnitude of the benefit that customers forego by not receiving interest on their above-market payments can be estimated using the results of an analysis performed by PSNH in 2008. In that analysis, PSNH compared the proposed PPA prices to a forecast of market energy prices and calculated that Laidlaw would receive more than $144 million in above-market payments over the 20-year term without paying a penny in interest. If PSNH had insisted on Laidlaw treating the above-market payments as loans requiring interest to be accumulated at, say, 5% annually, the cumulative reduction balance would have been about $77 million higher at $221 million. Not accumulating interest is a detriment to customers, and a benefit to PSNH, because it requires PSNH to make a larger investment to acquire the facility and a consequent higher return on rate base.

[15] My argument assumes for simplicity that the PPA energy prices always exceed market energy prices.

Q. YOU SAID THAT THE PPA DOES NOT PROVIDE FOR INTEREST TO BE PAID ON THE PRINCIPAL. IS REPAYMENT OF THE PRINCIPAL GUARANTEED?

A. No.[16] In the answer to the first question in this subsection, I noted that the purchase price will equal the fair market value of the facility at the end of the term less the balance in the cumulative reduction account, *provided that the net of the two values is not less than zero.* The italicized phrase is important. If the fair market value is low compared to the balance in the cumulative reduction account, then customers will not receive the full value of their above-market payments. In fact, it is possible that very little of the above-market payments is returned to customers.

Q. IS THAT OUTCOME REALISTIC IN YOUR OPINION?

A. I think there is a good chance that the facility will have little value after the PPA ends. Once the lucrative prices in the PPA terminate, the value in the facility will depend on: (i) whether the Laidlaw wood-fired facility can compete head-to-head with the marginal generating units in the region, which typically are fired with natural gas; and (ii) whether New Hampshire's RPS continues to exist and, if so, whether the REC market prices will be high or low. If the Laidlaw facility cannot compete directly with gas-fired units, which is very likely given the historic relationship between natural gas and wood prices and the projected downward pressure on the future price of natural gas caused by US shale gas production, its market value will depend almost exclusively on the level of Class I REC prices

[16] In the example above, the principal corresponds to the $144 million.

during the remaining life of the plant.[17] Based on Synapse's supply/demand study for Class I RECs, the facility's market value will be low and unable to support payment of the Cumulative Reduction balance.

Q. IS THERE A MORE FUNDAMENTAL PROBLEM WITH THE PROPOSED CUMULATIVE REDUCTION ACCOUNT?

A. Yes. The Cumulative Reduction account effectively tracks and aggregates above-market energy payments since it is unlikely that market energy prices will exceed the energy prices in the PPA for extended periods of time. At the end of the 20-year term, the cumulative amount of these payments will be applied against an agreed purchase price for the facility with PSNH paying the seller a one-time payment to cover any shortfall.[18] Once acquired, PSNH's investment in the facility will presumably be added to its generation rate base. The recovery of such above-market payments through rates before the acquisition is complete is, however, contrary to a long-standing ratemaking principle that prevents utilities from collecting through rates costs for investments that are not yet included in rate base. Although the facility will have been operating for 20 years by the time PSNH acquires it under the Purchase Option, the investment will not be providing useful service at the time the payments are made and collected through rates because those payments relate to acquiring the rights to the output of the facility over its remaining life, not the first 20 years. Interestingly, the Commission as recently as June of this year denied a request by Unitil Energy Services to collect

[17] This value in turn depends on an extension of the New Hampshire RPS beyond 2025. If the RPS is not extended, the facility is unlikely to have much value.
[18] Assuming PSNH elects to purchase the facility under the Purchase Option.

in advance the cost of distributed energy resource investments that had been found to be in the public interest but had yet to be completed, citing the used and useful standard as the basis for its decision.[19]

E. Cost-Effectiveness Tests

Q. DID PSNH ISSUE A COMPETITIVE SOLICITATION FOR THE PRODUCTS THAT IT IS PROPOSING TO PURCHASE FROM LAIDLAW?

A. No, it did not. PSNH apparently believes that it can achieve better results for customers through bilateral negotiations.

Q. ABSENT BIDS FROM A COMPETITIVE SOLICITATION, WHAT OPTIONS DID PSNH HAVE TO DETERMINE WHETHER THE PRICES NEGOTIATED WITH LAIDLAW REPRESENT THE BEST POSSIBLE OUTCOME FOR CUSTOMERS?

A. One option was to compare the negotiated product prices with the pricing for other comparable projects that offer the same products. Another was to compare the negotiated prices with market price projections for the products to be purchased. Still another option was to perform a financial analysis of the proposed project to determine whether the negotiated product prices result in a reasonable return on investment for investors. If the results of those analyses indicated that the negotiated prices do not represent the best possible outcome for customers (i.e., they are high relative to either market price projections or the

[19] See Order No. 25,111, page 38.

prices accepted by developers of comparable projects or they result in an unreasonably high rates of return for investors), PSNH could either have demanded lower prices for the products or withdrawn from the negotiations.

Q. REGARDING THE THIRD OPTION, WHY SHOULD THE COMMISSION CARE ABOUT THE RETURN EARNED BY NEWCO ON ITS INVESTMENT?

A. In most circumstances it would not care because the products would be purchased through a competitive solicitation where potential suppliers are required to compete on price and quality for the business. This is almost always the case when the purchase involves large dollar expenditures, although the present transaction is clearly at odds with this guiding principle.[20] The theory is that in competitive markets, profit margins are driven down by the actions of competitors to levels that are neither too high nor too low. Unfortunately, this outcome cannot be assumed in this instance. The very fact that PSNH elected not to bring other potential suppliers into the negotiations to compete with Laidlaw raises serious doubts about the efficacy of the process. In other words, can the Commission be sure that the process lead to the most competitive economic outcome? Whenever doubt exists, the Commission can and should use every tool at its disposal, including financial analysis, to ensure the public interest has been protected.

[20] Personally, I am not aware of any utility expenditure in excess of $1 billion dollars that what was not put out to bid.

PSNH apparently shares, or shared, this view because it conducted a financial analysis of the project back in 2008 without any prodding from interested parties.

(i) **Pricing for Comparable Renewable Energy Projects**

Q. DID PSNH REVIEW OR CONSIDER THE PRICE OF OTHER RENEWABLE RESOURCE PROJECTS WHEN IT NEGOTIATED THE PRICING IN THE PPA?

A. PSNH has said that the process of negotiating the pricing provisions in the PPA was not directly influenced by the price of other renewable projects.[21] This response, when considered in isolation, suggests that cost minimization was not high on the Company's list of objectives for the PPA. I say this because the list of comparable renewable energy projects should include a project that recently received from PSNH a long term PPA – the Lempster wind project. PSNH negotiated an agreement with Lempster in 2009 that involves the purchase of energy, capacity and Class I RECs, the same products that PSNH is proposing to purchase from Laidlaw. Although the Lempster project is smaller and produces fewer RECs than Laidlaw, the primary difference between the two PPAs relates to pricing. The levelized bundled price under the Laidlaw PPA is approximately \$162/MWh over the first 15 years. The same products can be purchased under the Lempster PPA at about half that price, indicating substantial cost savings for customers. See Exhibit GRM-10.

[21] See PSNH response to Staff 1-10 attached as Exhibit GRM-9.

Q. DID PSNH ALSO RECIEVE UNSOLICTED OFFERS FOR ENERGY, CAPACITY AND RECS?

A. Yes, in 2008 PSNH received unsolicited long-term offers from two proposed biomass projects, Clean Power Development ("CPD") and Concord Steam ("Concord"), and four existing biomass facilities. Both proposed biomass projects and one of the four existing facilities offered to supply PSNH the same products that Laidlaw is proposing to supply. Although all four submitted prices that in bundled form undercut the Laidlaw bundled prices, the discounts do not come close to bridging the gap between the PPA prices and today's market projections. It is also apparent from the structure of the offers that all four suppliers had detailed knowledge of the PPA, which in my opinion substantially reduces their value as an independent measure of the reasonableness of the PPA prices. At most they provide support for the view that PSNH could have achieved a much better outcome for its customers had it issued a properly structured competitive solicitation or involved itself in a multi-party negotiation.

(ii) Market Price Projections

Q. DID PSNH COMPARE THE NEGOTIATED PRICES WITH MARKET PRICE PROJECTIONS FOR THE PRODUCTS IN QUESTION? IF SO, WHAT DID THAT COMPARISON SHOW?

A. Yes, but most of the market prices or price projections used in those comparisons were prepared in 2008, in some cases two years before the PPA was filed. As a result, those comparisons do not reflect current market conditions or the conditions at the time of the filing. Even so, the comparisons generally show that the negotiated product prices are significantly above-market. For example, in an analysis performed in 2008 for the purpose of evaluating the Purchase Option, PSNH used the long-term market energy price forecast shown in Exhibit GRM-11. Alongside that forecast are the proposed energy prices as well as the difference between the two. The exhibit shows that on average over the 20-year term the PPA energy prices were expected to be about 18% higher than the market energy prices.

Since that time, however, natural gas prices, the primary driver of wholesale market energy prices, have fallen to the point where the energy prices under the PPA are now about 30% above the market energy price forecast. See Exhibit GRM-12. From a financial standpoint this indicates PSNH would pay Laidlaw approximately $285 million in above-market energy costs over the 20-year term of the agreement.

Q. HOW DO THE REC PRICES IN THE PPA COMPARE TO LONG TERM MARKET PRICE PROJECTIONS?

A. It appears PSNH did not prepare or obtain a long-term REC price projection to benchmark the negotiated REC prices. Instead, PSNH used broker quotes for 2009 and 2010 for several New England states. These data indicated an average

2010 price in the region of $37. More recent information, however, points to Class I market prices for 2010 and 2011 less than half that price.

Q. ARE YOU FAMILIAR WITH A LONG TERM REC PRICE FORECAST THAT COULD BE USED TO BENCHMARK THE REC PRICES IN THE PPA?

A. Yes, Synapse Energy Economics, Inc. ("Synapse") was selected by a group of New England electric and gas utilities (including PSNH) to provide projections of energy supply costs avoided by the use of energy efficiency programs in the electricity, natural gas, and heating oil sectors. One of the avoided electric supply costs investigated by Synapse was the cost to purchase RECs. Synapse's original 2007 report was updated in 2009 and included for each New England state a projection of Class I REC prices covering the full term of the Laidlaw PPA. However, because Synapse defined the cost to purchase RECs as the premium over wholesale energy market prices that a purchaser would have to pay to acquire renewable energy, it appears that Synapse's REC price forecast is tied to its forecast of wholesale energy market prices. That is, if energy market prices are expected to increase, the premium required to purchase renewable energy will be expected to decrease and vise versa. Because my analysis of above-market energy costs was based on an energy market price forecast that is approximately 30% lower than the energy price forecast used by Synapse to calculate in premiums, I have increased the Synapse REC price forecast for New Hampshire by the same percentage.

A comparison of the adjusted REC price forecast for New Hampshire and the REC prices in the PPA is shown in Exhibit GRM-13. It shows Synapse prices in nominal dollars starting at over $40 in 2014, climbing to about $53 in 2018, and falling to below $5 in 2026.[22] In contrast, the PPA prices vary from a low of $49 to a high of $67. Over the full 20-year term, the PPA will require PSNH to pay Laidlaw approximately $280 million more in REC payments than under Synapse's view of the market. However, as noted above, a substantial portion of this above-market cost would be avoided if PSNH purchased only the RECs it needs to meet its RPS obligations.

Q. HOW DO THE CAPACITY PRICES IN THE PPA COMPARE TO LONG TERM MARKET PRICE PROJECTIONS?

A. During the negotiations on the PPA, PSNH had available a long-term projection of FCM prices developed by Errichetti and Levitan. That projection had prices starting at $2.95/kW-month in 2014 and ending at around $12.5/kW-month in 2031. Exhibit GRM-14 shows that over the 20-year term the capacity prices in the PPA are about 55% lower than Levitan's projection of FCM prices. In other words, PSNH believes the PPA capacity prices are below-market. Because I have had insufficient time to review the Levitan price projection, I am unable to comment on this claim.

[22] Given that current market prices for NH Class I RECs are below $20, the near term adjusted Synapse prices could reasonably be described as being too high.

Q. WHAT DO YOU CONCLUDE FROM THESE MARKET COMPARISONS?

A. I conclude that the proposed prices for the energy and REC products have been set at levels that are substantially above current market expectations. As for the capacity product, the analysis is not conclusive.

(iii) Financial Analysis

Q. DID PSNH PERFORM A FINANCIAL ANALYSIS OF THE PROJECT AS PART OF ITS ASSESSMENT OF THE REASONABLENESS OF THE PROPOSED PRICES?

A. Yes, the Company conducted several cash flow analyses which were provided in response to discovery request Staff 1-15. The first was performed in July 2008 during the early stages of the negotiations. This analysis used internal PSNH estimates of the cost to construct and operate the facility plus a set of product prices that the Company initially claimed "ultimately became what was presented in the final PPA." PSNH modeled the project as having a 2010 start date. Two additional cash flow analyses were performed, each with different pricing assumptions. One allegedly incorporated the pricing in the proposed PPA. The other included so-called interim prices but in reality the prices differ from the proposed prices only in regard to the REC prices in years 2026 through 2029.[23]

Q. WHAT WERE THE RESULTS OF THE COMPANY'S FIRST FINANCIAL ANALYSIS?

[23] Specifically, the REC prices in 2026 through 2029 were set to zero. This model run would appear to be consistent with a scenario in which PSNH has no RPS obligation beyond 2005.

A. Using an initial set of product prices, PSNH calculated the cash flows for Laidlaw, the lessee, and PJPD, the lessor. For Laidlaw, it determined that after tax net income would increase from about \$2.6 million in 2010 to \$26 million in 2029 for a total of \$275 million. For PJPD, it determined that after tax net income would fall from about \$20 million in 2010 to \$11.3 million in 2029 for a total of \$316 million. Since both Laidlaw and PJPD are 100% owned by NewCo, the end result of PSNH's initial analysis was net income from the project totaling \$590 million. This compares to the capital cost for the facility of just \$96 million. Clearly, this initial set of product prices was very lucrative for NewCo.

Q. THE COMISSION COULD BE EXCUSED FOR QUESTIONING THE VALIDITY OF AN ANALYSIS THAT PRODUCES AN AFTER TAX NET INCOME TOTALING \$590 MILLION ON A \$96 MILLION INVESTMENT. IS IT POSSIBLE TO INDEPENDENTLY TEST THE LEGITIMACY OF THE RESULT WITHOUT EXAMINING EVERY ASSUMPTION AND CALCULATION?

A. Yes, it is. Leaving aside for the moment the fact that the net income figure is the sum of annual cash flows expressed in nominal dollars,[24] the legitimacy of the result can be assessed once it is understood that two of the three major cost components of the biomass project (i.e., fuel and O&M) are effectively collected on a dollar-for-dollar basis through the energy prices in the PPA.[25] As a result, the energy prices, which account for about \$1 billion of the \$1.6 billion total

[24] That is, the cash flows have not been adjusted for the time value of money.
[25] As noted earlier, the energy prices contribute in a small way to net income by the inclusion in the pricing formula of a conversion factor that is not supported by the plant assumptions.

revenue, contribute very little to net income. The third major cost component is the capital cost for the facility, which in this analysis was assumed to be $96 million. Almost all of this cost is covered by the capacity payments, leaving a small residual amount to be covered by the REC payments. Since there is no cost associated with the production of RECs, almost all of the $550 million REC revenues must go to NewCo's bottom line. In summary, a financial analysis of the Laidlaw project that does not produce net income of the order of $500 million should be suspected of containing errors and/or inaccuracies.

Q. WHAT IS THE PRESENT VALUE OF THE ABOVE CASH FLOWS?

A. To calculate present value, PSNH used a discount rate of 11.6% that was based on a 70/30 debt to equity ratio, a debt cost of 8% and an equity cost of 20%.[26] Using this rate, the present value of NewCo's cash flows is approximately $114 million after taking into account the capital cost of $96 million (i.e., the net present value or NPV).

Q. WHAT DOES THIS RESULT MEAN?

A. An NPV equal to zero means that NewCo would recover its capital investment and earn a return on investment equal to the discount rate. The fact that the NPV is greater than zero means that the initial set of product prices produces a higher return on investment than the discount rate. This can be observed in Table 1 below which shows the return on equity, after annual interest and loan repayment,

[26] See PSNH response to Staff 3-7 attached as Exhibit GRM-15

for NewCo in each year of the contract. Clearly, these ROEs are far higher than the 20% assumed by PSNH for the project.

					Table 2					
					Return on Equity After Interest					
					and Loan Repayment					
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
NewCo ROE	49%	53%	57%	61%	66%	70%	75%	80%	84%	89%
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
NewCo ROE	73%	78%	83%	87%	92%	97%	102%	107%	112%	117%

Q. YOU SAID THAT THE COST OF EQUITY FOR THE LAIDLAW PROJECT WAS ASSUMED BY PSNH TO BE 20%. DO YOU AGREE WITH THAT ASSUMPTION?

A. No, a 20% ROE is equivalent to assuming the project carries a risk similar to a merchant power plant. Unlike merchant power plants, the Laidlaw project carries relatively little risk for its investors. Merchant power plants by definition do not have long-term power purchase contracts. As a result, the output from such plants is fully exposed to price volatility in power markets and hence the investment carries the risk that future income will not be paid resulting in lower than expected profits. This can arise when a merchant power plant is not dispatched because its variable cost exceeds the market price. These plants are also exposed to price volatility in fuel markets. Thus, an unexpected rise in fuel prices could render the merchant power plant uncompetitive, further increasing the probability of lower than expected profits.

In contrast, the PPA fully protects Laidlaw from the risk of not finding a buyer for its output and from price volatility in both fuel and power markets. This is because the PPA obligates PSNH to purchase 100% of the products produced by the facility at prices that are either fixed, as with capacity and RECs, or track changes in wood fuel prices, as is the case with the energy product. In addition, the risk of Laidlaw not recovering its O&M expenses is low because the energy price includes a component that is designed to collect the estimated O&M costs over the 20-year term. Laidlaw, however, is subject to the risk of capital cost overruns, higher than expected inflation on O&M, and catastrophic failure of the plant.

Q. IN ADDITION TO FUEL MARKET AND POWER MARKET RISKS, A PRIMARY RISK FOR MERCHANT POWER PLANTS IS REGULATORY RISK. IS REGULATORY RISK A MAJOR CONCERN FOR LAIDLAW?

A. Not if the PPA is approved. Although a significant component of Laidlaw's total revenue is projected to come from the fixed REC prices in the PPA, Laidlaw appears to have insulated itself from the risk that the RPS statute could be repealed or amended in a way that substantially reduces that revenue stream. This was done by the inclusion in the PPA of a provision that provides for REC prices to be tied to the alternative compliance payments under the current version of the statute rather than some future version. In other words, PSNH may be required under the PPA to make REC payments even if the existing statute were amended or repealed.

In addition, by imposing a contractual obligation on PSNH to purchase all of the RECs produced after 2025, Laidlaw appears to have shifted to PSNH the regulatory risk that the legislature will not extend the RPS beyond that year.

Q. ARE THERE OTHER INDICATORS THAT THE PROJECT CARRIES A LOW RISK?

A. Yes, the proposed capital structure. Although PSNH assumed in its analyses a 70/30 debt to equity ratio, Laidlaw has since stated that it will employ a capital structure comprising 82% debt and 18% equity. In comparison, equity investments for merchant power plants are typically much higher. The decision to proceed with such a highly leveraged capital structure suggests that Laidlaw's project is considered by institutional investors to be a low risk venture.

Q. GIVEN THESE ARGUMENTS, WHAT IS AN APPROPRIATE DISCOUNT RATE FOR THE LAIDLAW PROJECT?

A. A more appropriate cost of equity for this project would be somewhat higher than the 9.81% ROE authorized for PSNH's generation investments, say 11%. This cost combined with the 70/30 debt to equity ratio assumed by PSNH results in a discount rate of 8.9%. Using this discount rate, the present value of cash flows from PSNH's initial analysis is $160 million.

Q. YOU HAVE TESTIFIED THAT THE RISKS UNDR THE PPA ARE NOT SUBSTANTIALLY DIFFERENT TO THE RISKS THAT PSNH FACES WITH ITS OWN GENERATING FACILITIES. WHAT WOULD THE PRESENT VALUE OF THE CASH FLOWS BE IF PSNH RATHER THAN LAIDLAW

CONSTRUCTED AND OPERATED THE FACILITY AND INCLUDED THE INVESTMENT IN ITS RATE BASE?

A. Assuming the facility has the exact same size and operating characteristics as the facility modeled by PSNH and that it receives the same ratemaking treatment received by PSNH's Schiller Unit 5, the present value of the after tax net cash flows over an assumed 30 year facility life would be negative $1.5 million. In short, customers will pay approximately $160 million more in present value terms to have Laidlaw host the facility under the terms of the PPA than to have PSNH include it in its rate base.

Q. HOW DID PSNH UTILIZE THE RESULTS OF ITS INITIAL FINANCIAL ANALYSIS?

A. How PSNH responded to the results of its analysis is not known because it was not required to disclose the offers and counter offers made by each party. I do know, however, that PSNH ultimately agreed to a set of product prices that produce about 10% less revenue for Laidlaw than the initial set. Using these prices while retaining the other assumptions in the initial analysis, the total cash flow is lower at $496 million. However, the NPV remains high at around $132 million.

Q. YOU NOTE IN YOUR ANSWER THAT THE UPDATED NPV WAS BASED ON THE INPUT ASSUMPTIONS USED BY PSNH IN ITS INITIAL CASH FLOW ANALYSIS. DO YOU AGREE WITH THOSE ASSUMPTIONS?

A. Not completely. My main concerns are the assumptions relating to: (i) the size of the facility; (ii) the capital cost and capital structure of the project; (iii) the tax credits available from the federal government; and (iv) the fuel cost estimates for the facility. Concerning the first issue, PSNH modeled the facility as having a net capacity of 58 MW and a capacity factor of 85%. Laidlaw, however, designed the facility to have a net capacity of 63 MW and a capacity factor of 87.5%.[27] Concerning the second issue, PSNH assumed the cost would be $96 million and be financed with 70% debt and 30% equity. Laidlaw, in contrast, estimates the capital cost to be $167 million financed with 82% debt and 18% equity.[28] As to the third issue, while PSNH assumed that PJPD would receive approximately $5 million per year for 10 years in federal Production Tax Credits ("PTC"), Laidlaw has stated that it intends to forego those credits in favor of a cash grant under the American Recovery and Reinvestment Act ("ARRA") that is equivalent in value to what would otherwise be available under the federal Investment Tax Credit ("ITC"). This is consistent with a study by the Lawrence Berkeley National Laboratory that found that the ITC is financially more attractive than the PTC in every combination of capital cost and capacity factor for open-loop biomass generation facilities.[29] That said, for ease of modeling I have assumed that PJPD will receive tax credits under the federal PTC program. In addition, PJPD expects to receive $12 million in upfront equity capital in the form of proceeds from the

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[27] See SEC Docket 2009-02, Transcript, Day 1, Afternoon Session. At page 94, Laidlaw witness Strickler states that the planned capacity factor for the facility is 87.5%. At page 90, Laidlaw witness Bravakis states that the net output of the facility is 63 MW.

[28] See Exhibit GRM-2. The document allegedly supporting this cost estimate was not made available to the parties in this proceeding.

[29] PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States, Lawrence Berkeley National Laboratory, LBNL-1642E, March 2009.

federal New Market Tax Credit Program.[30] Finally, although energy revenues were modeled by PSNH as rising over time to reflect the expectation that fuel costs would increase, the fuel cost line item in PSNH's analysis was not escalated because PSNH stated that it was unable to reconcile the aggregate of the cost components to match the estimate of total operating expenses that Laidlaw provided. In my analysis, the O&M expenses are lower than the expenses used by PSNH but fuel costs increase consistent with the assumed increase in energy revenue.

Q. WHAT EFFECT DO THESE CHANGES HAVE ON PROJECT CASH FLOWS?

A. Some of the changes increase the project cash flows while others decrease them. Overall, total cash flow increases to $527 million but the NPV decreases to $94.5 million due in large part to the substantial increase in the capital cost of the facility.[31] Consistent with this decrease in NPV, the equity returns for NewCo (net of annual interest and loan repayment) shown in Table 2 are lower than under the initial analysis but continue to be well outside of the range of returns that developers of merchant power plants located in the US could reasonably expect.

[30] See Laidlaw response to Staff 2-2 attached as Exhibit GRM-16. This reduces the required equity contribution from NewCo investors from $30 million to $18 million.
[31] See Exhibit GRM-17.

Table 3
Return on Equity After Interest and Loan Repayment

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
NewCo ROE	61%	66%	71%	77%	82%	82%	88%	94%	100%	106%
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
NewCo ROE	66%	71%	76%	81%	86%	60%	65%	69%	74%	77%

Q. NEITHER PSNH'S INITIAL CASH FLOW ANALYSIS NOR YOUR ADJUSTMENTS TO IT TAKE INTO ACCOUNT LAIDLAW'S OBLIGATION TO PAY PSNH AT THE END OF THE 20-YEAR TERM THE BALANCE IN THE CUMULATIVE REDUCTION ACCOUNT. DOES THIS MEAN THAT THE ABOVE REFERENCED CASH FLOWS OVERSTATE THE TRUE VALUE OF THE PROJECT TO NEWCO?

A. No. Although the PPA provides for Laidlaw to reduce the purchase price for the facility by the balance in the Cumulative Reduction account at the end of the 20-year term, the actual amount of the reduction also depends on the market value of the plant. If the market value of the plant is greater than the balance in the Cumulative Reduction account, the purchase price will be reduced by the full amount of the balance. If the market value of the plant is less than the balance in the Cumulative Reduction account, the reduction in the purchase price is capped at the market value. Under the first scenario, NewCo would be left with a positive post-PPA net income equal to the difference between the market value and the Cumulative Reduction balance. Under the second scenario, NewCo would have zero post-PPA net income. In either case, the project cash flows would not be overstated.[32]

Q. ARE THERE FACTORS THAT COULD INCREASE THE PROJECT'S CASH FLOWS?

A. Yes. The most obvious is the capacity factor of the Laidlaw facility. As I have stated, PSNH used an 85% capacity factor in its analyses whereas Laidlaw used 87.5%. Both, however, are substantially below the level of performance achieved by two New Hampshire wood-fired generating facilities, Bethlehem and Tamworth, which sell to PSNH. Since January 2008, Bethlehem's capacity factor has averaged 92% while Tamworth's was a little lower at 90%. If the Laidlaw facility achieves even the Tamworth level of performance, which is very likely given the tremendous incentive to maximize output in the proposed prices, the NPV could increase by over $7 million.

Another factor is the size of the facility. If Laidlaw increases the output of the facility and is able to sell the incremental output at PPA prices, the NPV for the project after accounting for the cost of the expansion could be even higher.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR FINANCIAL ANALYSIS?

A. I have concluded that the equity returns for NewCo shareholders are likely to be well outside of the range that developers of merchant power plants located in the

[32] Any market value remaining after payment of the Cumulative Reduction balance would add to the value of the project as would the addition of salvage at the end of the facility's life.

US could reasonably expect. Since the Laidlaw facility will experience less rather than more risk under the PPA than merchant power plants, this conclusion indicates that the prices in the PPA are too high and should be lowered.

IV. PUBLIC INTEREST ANALYSIS

Q. RSA 362-F:9(I) AUTHORIZES THE COMMISSION TO APPROVE LONG-TERM AGREEMENTS BETWEEN DISTRIBUTION COMPANIES AND RENEWABLE ENERGY GENERATORS FOR THE PURCHASE OF RECs, WITH OR WITHOUT THE POWER, TO MEET REASONABLY PROJECTED RENEWABLE PORTFOLIO REQUIREMENTS AND DEFAULT SERVICE NEEDS. IN YOUR OPINION, DOES THE LAIDLAW PPA SATISFY THIS CONDITION?

A. No. For the reasons detailed in Section III above, the PPA does not satisfy this condition because it obligates the Company to purchase substantially more RECs than it needs to "meet reasonable projected renewable portfolio requirements." Thus, the PPA falls at the very first hurdle.

Q. IF THE COMMISSION DISAGREES WITH YOUR INTERPRETATION OF RSA 362-F:9(I), IS THE PPA SUBSTANTIALLY CONSISTENT WITH THE PUBLIC INTEREST CRITERIA SET FORTH IN RSA 362-F:9(II)?

A. I do not believe so.

A. Efficiency and Cost-Effectiveness

Q. ADDRESSING EACH CRITERION IN TURN, PLEASE EXPLAIN YOUR PREVIOUS ANSWER.

A. The first criterion is the efficient and cost-effective realization of the purposes and goals of RSA 362-F, which in summary are to stimulate investment in low emission renewable energy generation technologies located in New England. The PPA fails on both counts. Regarding efficiency, which I understand to mean the process used to produce the PPA since the terms economic efficiency and cost-effective are synonymous, there can be no dispute that the parties took an unusually long time to come to agreement on the terms and conditions. As a result, the scheduled start date for the project is now two years later than originally planned. Further, despite the inordinate amount of time spent negotiating the agreement, many unanswered questions remain about the meaning of certain provisions as well as what rights and obligations PSNH has under different scenarios. For example, if the Commission approved the PPA, could the Company purchase the facility under the Right of First Refusal or the Purchase Option without Commission review of either the purchase decision or the price to be paid? Another unanswered question is whether the Commission has any jurisdiction over the PPA after it is approved.

Other unanswered questions include but are not limited to the following:

(i) Whether PSNH's Right of First Refusal is triggered as a result of a proposed sale of NewCo.'s stock as opposed to the proposed sale of the facility.

(ii) The implications for PSNH's Right of First Refusal and its Purchase Option of the fact that the "Seller" under the PPA does not own either the facility or the facility site.

(iii) Whether upon completion of the purchase under PSNH's Right of First Refusal the PPA terminates and, if so, whether PSNH's investment in the facility will be added to its generation rate base.

(iv) If the Commission approved the PPA, would it be barred from ordering any revisions inclusive of pricing terms?

(v) Whether PSNH would continue to be required to make REC payments under the PPA if: (i) the legislature were to repeal RSA 362-F; or (ii) the RPS eligibility requirements for NH Class I RECs were to change such that the facility were to become ineligible for such certificates.

(vi) Whether under Article 8.1, PSNH is seeking pre-approval to recover any capital expenditure made or expense incurred by Laidlaw or PJPD in order to continue to produce RECs if a change in law occurs.

Regarding cost-effectiveness, I have already demonstrated in considerable detail in Section III that the PPA is uneconomic based on all of the standard cost-effectiveness tests. In fact, the term uneconomic does not do justice to the extent to which PSNH's energy service customers would be overcharged if the PPA is approved as filed.

B. Restructuring Policy Principles

Q. THE SECOND CRITERION IS CONSISTENCY WITH THE RESTRUCTURING POLICY PRINCIPLES OF RSA 374-F:3. WHAT IS YOUR OPINION?

A. I believe the PPA is consistent with some provisions but inconsistent with others. Regarding the latter, the PPA is clearly inconsistent with the requirement that generation services be subject to market competition and minimal economic regulation. See RSA 374-F:3(III). As already noted, the terms of the PPA will shield Laidlaw from the market price and fuel price risks that are the defining characteristics of merchant power plants. Consequently, competition within those two markets will be harmed. As for minimal economic regulation, despite being owned and operated by an independent (i.e., unregulated) power producer, the Laidlaw facility will be subject to a form of cost plus rate regulation that produces for its investors a return on equity that vertically integrated utilities could only dream about. This is so because the energy prices are designed to track and collect changes in wood-fuel costs, the single largest and most volatile cost component for a biomass facility. The energy prices also include a component that collects, on a levelized basis, the estimated O&M costs over the life of the facility. Furthermore, the capacity and REC prices have been set at levels that provide for the return of the initial investment plus an abnormally high return on that investment.

In addition, because PSNH is proposing to collect the costs of the PPA from default service customers, it becomes subject to the principle that default service be procured from the competitive market. The Company, however, has acknowledged that it did not issue a competitive solicitation for the products it proposes to purchase from Laidlaw. Nor is it able to claim that the prices for energy and capacity are based on market prices for those products, as is the case with the Lempster wind power project. For these reasons, I contend that the PPA is not consistent with RSA 374-F:3(V)(c).

Finally, the PPA is not consistent with the principle that default service be designed to minimize customer risk, not unduly harm the development of competitive markets, and mitigate against price volatility without creating new deferred costs. See RSA 374-F:3(V)(e). This is so for the following reasons:

First, the use of fixed energy, capacity and REC prices in the PPA shifts the market price risk for all three products from Laidlaw to PSNH's customers. The inclusion in the PPA of a WPA also shifts fuel price risk from Laidlaw to PSNH's customers. Finally, basing the REC prices in the PPA on the existing RPS legislation rather than potential future legislation shifts to PSNH customers the regulatory risk that the existing legislation will be repealed or amended in a way that reduces the benefits paid to eligible resources. In other words, PSNH customers may in the future over pay for the renewable attributes received from the Laidlaw facility.

Second, the PPA is harmful to the development of competitive markets because it unfairly protects Laidlaw from the risks of market competition. Because of the cost-based energy pricing in the PPA, the Laidlaw facility will have an incentive to bid into the New England spot market at or near zero instead of its short-run variable cost to be assured of being dispatched by ISO-NE. As a result, Laidlaw has less incentive to cut its operating costs so as to maximize its profits, which undermines the competitiveness of the wholesale power market. The primary example of this reduced incentive to minimize costs is the WPA. Because any increase in fuel costs is covered by an increase in revenues through the WPA mechanism, Laidlaw has less incentive to bargain hard with wood suppliers for lower wood prices or to change fuel suppliers.

Third, while the pricing in the PPA will reduce the level of price volatility experienced by PSNH's energy service customers, it does so by requiring those same customers to shoulder significant above-market costs. Furthermore, because the number of customers to absorb those costs is continually declining, the remaining captive customers will experience higher and higher prices. In short, the cost of reduced price volatility is too great.

C. Least Cost Integrated Resource Planning

Q. THE THIRD CRITERION IS CONSISTENCY WITH THE LEAST COST ENERGY PLANNING REQUIREMENTS AS SET FORTH IN RSA 378:37. IS THE PPA CONSISTENT WITH THOSE REQUIREMENTS?

A. The statute provides in effect that the energy needs of New Hampshire's customers shall be met at the lowest reasonable cost while maintaining reliability, diversity, and the physical environment of the state. In my opinion, this mandate, which I interpret broadly to relate to the energy, capacity and REC needs of customers, cannot be met if each product is priced well above its market level, as is the case with the Laidlaw PPA. The reason is simple: purchasing products at above-market prices involves the displacement of purchases priced at market levels, resulting in cost increases and higher rates for customers. Even if PSNH were mandated to purchase the energy and capacity produced by a renewable energy facility that is supplying it with RECs, it would be contrary to the "lowest reasonable cost" requirement to pay above-market prices for those products if they could be purchased at market prices. Paying above-market prices for energy and capacity when the purchases are discretionary, as is the case here, is clearly contrary to the plain meaning of the statute.

D. Administrative Efficiency and Market-Driven Competitive Solutions

Q. THE FOURTH CRITERION IS CONSISTENCY WITH ADMINISTRATIVE EFFICIENCY AND THE PROMOTION OF MARKET-DRIVEN COMPETITIVE INNOVATIONS AND SOLUTIONS. WHAT IS YOUR OPINION?

A. My opinion on whether the negotiation of the PPA was conducted in an administratively efficient manner was presented above in Subsection A: Efficiency and Cost-Effectiveness.

Whether the second goal, promotion of market-driven competitive innovations, has been met depends on one's interpretation of the phrase. I interpret market-driven to mean a non-utility project and competitive innovations to mean a procurement process that promotes competition between prospective suppliers of novel solutions. Since the developer of the Laidlaw project can reasonably be described as an IPP, I consider the market-driven requirement to be met. I do not, however, consider the sole source procurement process used by PSNH as promoting competition between prospective suppliers. For this reason, I believe the PPA is at odds with this particular criterion.

E. Economic Development and Environmental Benefits

Q. THE FIFTH AND FINAL CRITERION IS CONSISTENCY WITH THE GOALS OF ECONOMIC DEVELOPMENT AND ENVIRONMENTAL IMPROVEMENT. WHAT DID MR. FRANTZ CONCLUDE?

A. As to economic development, Mr. Frantz concluded that the economic harm to New Hampshire caused by the PPA's over-market costs more than offsets any economic benefit derived from the project. Regarding environmental impact, Mr. Frantz recommended that the Commission take administrative notice of the Laidlaw proceeding before the SEC.

V. RECOMMENDATIONS

Q. PLEASE PROVIDE YOUR RECOMMENDATIONS.

A. For the reasons set forth in Section IV, I conclude that on balance the proposed PPA does not satisfy the public interest criteria in RSA 362-F:9(II). That said, and assuming the Commission decides that the RPS does not terminate in 2025 as argued by the Wood-Fired IPPs, I believe the PPA can be amended in ways that address the concerns expressed in this testimony. Accordingly, I recommend that the Commission condition its approval of the PPA on the parties agreeing to the following changes:

(i) Eliminate the Cumulative Reduction provision and make the Purchase Option conditional on PSNH having the legal authority to acquire new generation;
(ii) Base the PPA energy prices on hourly ISO-NE spot market energy prices with a floor price to address volatility and financing concerns;
(iii) Base the PPA capacity prices on actual prices realized in ISO-NE's FCM;
(iv) Adjust the PPA REC prices such that NewCo is provided a reasonable opportunity to earn a reasonable return on its documented investment taking into account the risks under the amended PPA;
(v) Amend the PPA such that PSNH is obligated to purchase no more RECs than it needs to meet its RPS obligations;
(vi) Establish a specific output level for the facility expressed in MW above which PSNH would have no obligation to purchase.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

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

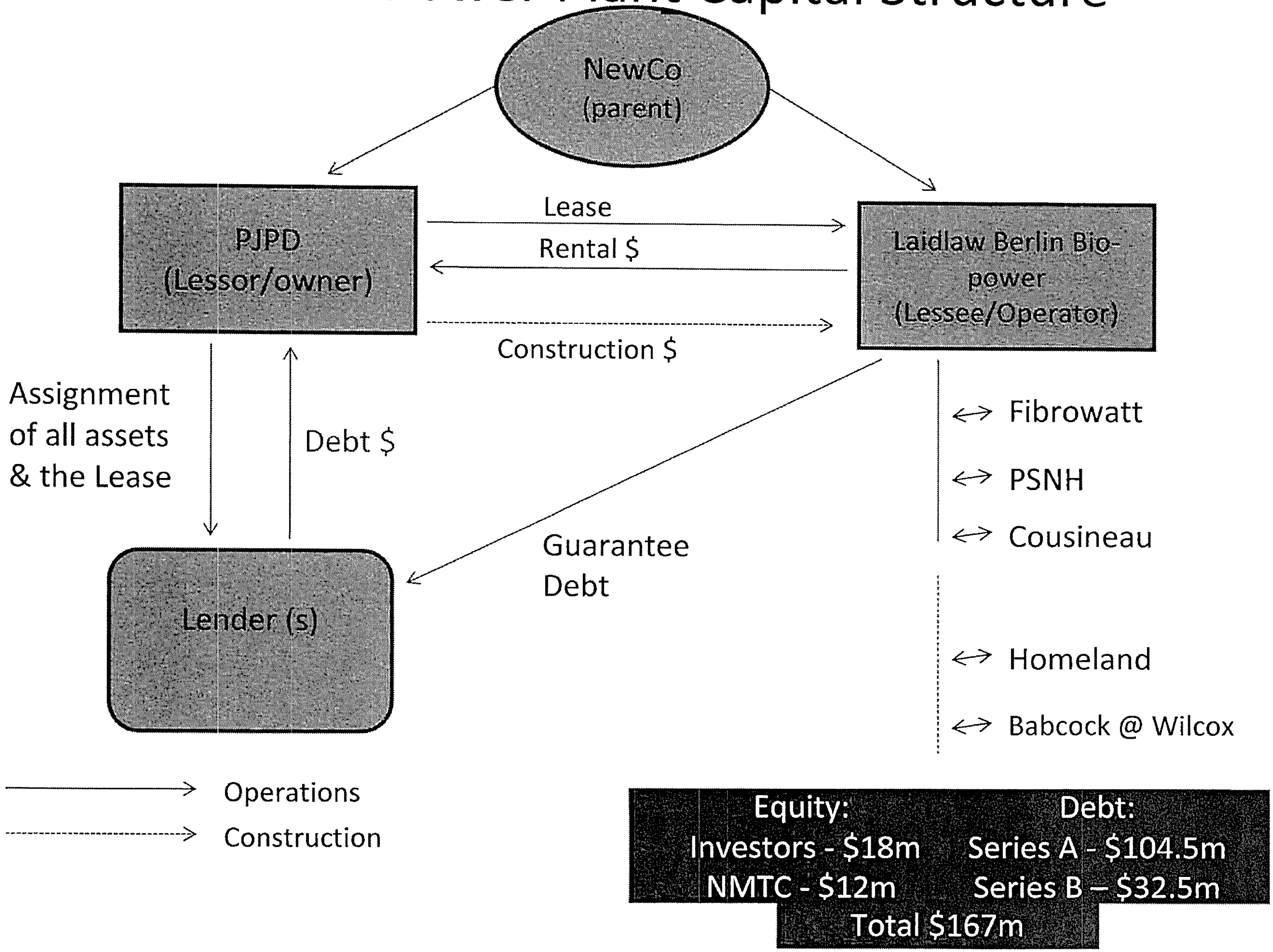
EDUCATION:

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:________________________________

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

<u>Assumptions</u>

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	

Exhibit GRM-12

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	

Exhibit GRM-13

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.

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	$6,501,651	$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