NSUARB P-887(16)

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF A HEARING INTO NOVA SCOTIA POWER INCORPORATED'S 2017-2019 FUEL STABILITY PLAN AND BASE COST OF FUEL RESET UNDER THE FUEL ADJUSTMENT MECHANISM (FAM) AS REQUIRED UNDER THE *ELECTRICITY PLAN IMPLEMENTATION (2015) ACT*

DIRECT EVIDENCE OF JONATHAN WALLACH ON BEHALF OF THE CONSUMER ADVOCATE

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THE CONSUMER ADVOCATE

Resource Insight, Inc.

MAY 2, 2016

I. Introduction

Q: Please state your name, occupation, and business address.

A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Please summarize your professional experience.

A: I have worked as a consultant to the electric-power industry since 1981. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the past thirty years, I have advised clients on a wide range of economic, planning, and policy issues including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and management; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Exhibit JFW-1.

Q: Have you testified previously in utility regulatory proceedings?

A: Yes. I have sponsored expert testimony in 75 federal, provincial, or state proceedings in the U.S. and Canada, including in Nova Scotia in NSUARB P-887(2), P-887(6), and P-887(7). Exhibit JFW-1 provides a detailed listing of my previous testimony.

Q: Please summarize your experience with regard to the Fuel Adjustment Mechanism (FAM).

A: I have assisted the Nova Scotia Consumer Advocate in its oversight of the FAM process since full implementation of the FAM on January 1, 2009. During that time, I have participated in FAM technical conferences and meetings of the FAM Small Working Group (SWG) on the Consumer Advocate's behalf, reviewed and evaluated all FAM reports and FAM-related filings, reviewed material filed in the FAM data room located in the offices of Nova Scotia Power Inc. (NS Power or "the Company"), and assisted the Consumer Advocate in its interventions in various General Rate Application, Base Cost of Fuel (BCF), and FAM proceedings. Finally, I provided direct evidence in NSUARB P-887(2) regarding the FAM incentive mechanism, in NSUARB P-887(6) regarding the allocation of demand-related purchased power costs to the residential class, and in NSUARB P-887(7) regarding the process for deriving the 2017 Actual Adjustment (AA) and Balancing Adjustment (BA).

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Nova Scotia Consumer Advocate (CA).

Q: What is the purpose of your testimony?

A: On March 7, 2016, NS Power filed an application for approval of a plan to stabilize fuel costs ("Fuel Stability Plan Application" or "Application") over the three-year period from 2017 through 2019 ("Rate Stability Period"). In accordance with the provisions of the *Electricity Plan Implementation (2015) Act* (EPIA), the Fuel Stability Plan:

- Forecasts the annual Base Cost of Fuel, including the estimated annual recovery of the Maritime Link assessment, over the Rate Stability Period.[1]
- Proposes to increase base rates in each year of the Rate Stability Period by a constant percentage amount in order to recover the projected increase in the Base Cost of Fuel from 2016 through 2019.
- Proposes a plan to hedge the costs of forecasted fuel requirements over the Rate Stability Period ("Fuel Hedging Plan").

The Consumer Advocate has asked me to comment on NS Power's request for approval of its proposed Fuel Stability Plan. Specifically, my testimony addresses the following aspects of the Fuel Stability Plan:

- The forecast of natural gas prices for the years 2017 through 2020.
- The proposed allocation of the Maritime Link assessment to customer classes.
- The proposed annual increase in the BCF rate for the residential class.
- The proposal for a Fuel Hedging Plan.

Q: Do you have any preliminary comments regarding the proposed Fuel Stability Plan?

A: Yes. According to recent press reports, Nalcor Energy's chief executive officer and entire board of directors abruptly resigned on April 20, 2016. During a press conference the following day, the new CEO announced that he will initiate a full review of the Muskrat Falls hydroelectric project and the associated agreements related to the Nova Scotia Block. These developments raise the concern that deliveries of Nova Scotia Block power might not commence in April of 2018, as

[1] The Application also provides the Company's forecast of the Base Cost of Fuel for 2020.

currently anticipated by NS Power, or perhaps at any time during the Rate Stability Period.

On May 27, 2016, NS Power will file an update to its Fuel Stability Plan ("Update Filing"), including a refreshed forecast of the Base Cost of Fuel during the Rate Stability Period using current market prices.[2] The Company should include in the Update Filing an assessment of the potential implications of a delay in Nova Scotia Block deliveries, along with an alternative forecast of the Base Cost of Fuel based on a sensitivity case which assumes that the start of Nova Scotia Block deliveries is delayed to 2020.

II. Natural Gas Price Forecast

Q: How did NS Power forecast the price of natural gas during the Rate Stability Period and in 2020?

A: In general, NS Power relied on the fuel forecasting methodology set forth in the FAM Plan of Administration (POA) to forecast natural gas prices for the years 2017 through 2020.[3] Specifically, the Company forecasted natural gas prices based on contract prices for any gas supply contracts in place between 2017 and 2020 and on a forecast of market prices for open gas requirements in excess of contract supply. The forecast market price of gas for open volumes, in turn, was estimated based on prevailing forward prices for the Henry Hub and basis components of the natural gas price, with an adjustment to the basis price based on NS Power's estimate of market premiums or discounts.

[2] According to NS Power's response to Industrial Group IR-18(e), the updated BCF forecast will also reflect the impact of the Province's removal of the must-run requirement for the Port Hawkesbury Biomass Plant.

[3] The FAM fuel forecasting methodology is described in Appendix B of the FAM POA.

Q: Do you have any comments regarding the Company's forecast of the market price for natural gas?

A: Yes. First, with respect to the market premium / discount adjustment, I note that NS Power has not documented how the price adjustment was derived in each year between 2017 and 2020.

According to the FAM POA:

> As there is no published information which can be used as the reason for forecasting the premium or discount that Maritimes consumers pay relative to market basis indices, NS Power will use the historical premium/discount. <u>Given the variability in the natural gas market, the prior year's premium/discount historical information will be most relevant.</u> NS Power will provide the rationale for any deviation from the prior year's premium/discount.[4]

As there was no available historical information for the year immediately prior to 2017 (or thereafter) at the time that the Company forecast the market premium / discount, it is not clear the extent to which NS Power relied on information from previous years or what adjustments were made to such historical data for forecasting purposes. The Company should therefore include in the Update Filing a detailed description of the assumptions and calculations relied on to derive the market premium / discount price adjustment.

Second, New England basis forward prices for the winter months of 2017 and 2018 have dropped sharply since NS Power developed its BCF forecast for the Fuel Stability Plan Application. Consequently, we can expect that the natural gas price forecast in the Update Filing will reflect lower basis prices than in the current forecast.[5] Moreover, if these forward pricing trends continue, actual

[4] FAM Plan of Administration, Appendix B, June 12, 2015, p. 11. Emphasis added.

[5] According to NS Power's response to Liberty IR-3, the Fuel Stability Plan Application used forward basis prices from November of 2015 to forecast natural gas market prices, whereas the Update Filing will use forward basis prices from March of 2016.

natural gas prices during the Rate Stability Period could fall well below levels forecast in the Update Filing.

Q: Would ratepayers benefit in the event actual prices are below forecast?

A: Not necessarily. As I discuss in Section V, the primary objective of the proposed Fuel Hedging Plan is to minimize expected deviations between forecasted and realized fuel prices. Thus, the Fuel Hedging Plan would protect ratepayers when actual prices exceed forecast levels, but would deny ratepayers the opportunity to benefit when actual prices fall below forecast levels. In addition, the proposed Fuel Hedging Plan would expose ratepayers to the risk of economic loss when excess hedges are unwound in a falling-price environment.

III. Maritime Link Cost Allocation

Q: How does NS Power propose to allocate to FAM customer classes the revenue requirements associated with the Maritime Link assessment?

A: The Company proposes to allocate Maritime Link revenue requirements in the same manner as revenue requirements for hydro generation owned by the Company. Specifically, NS Power proposes to classify a portion of Maritime Link revenue requirements equal to the system load factor as energy-related and to classify the remainder as demand-related. According to Appendix G of the Fuel Stability Plan Application, under NS Power's approach, about 56% of Maritime Link revenue requirements would classified as energy-related and allocated in proportion to each customer class's contribution to annual system energy requirements. The remaining 44% would be classified as demand-related and allocated in proportion to the average of peak demands for the three winter months.

Q: Is NS Power's proposal a departure from past practice?

A: Yes. As NS Power explains:

> Deliveries of energy and capacity under the Nova Scotia Block represent out-of-province long-term firm imports. The Board's decision in the 2013 COS proceeding did not specifically address treatment of firm imports as capacity constraints on the New Brunswick tie have put a limit on utilization of firm contracts for the last several years. Therefore, imports are currently treated as 100% energy under the assumption that the majority of them fall into an interruptible category.[6]

Q: What is NS Power's rationale for classifying and allocating Maritime Link revenue requirements in the same fashion as for Company-owned hydro plant costs?

A: The Company explains that:

> Given that purchases under the Nova Scotia Block provide for delivery of both energy and capacity and their costs do not vary with the amount of energy delivered to NS Power, they are proposed to be treated in the same manner as NS Power-owned hydro generation…. This approach is consistent with the treatment of purchases from wind and biomass generation sources, which are also being treated in the same manner as similar generation owned by NS Power.[7]

Q: Is this a reasonable argument for the Company's proposed approach?

A: No. The justification for NS Power's commitment to the Maritime Link is very different from the justifications for NS Power's construction and purchase of domestic hydro. The Company had adequate capacity to serve projected system loads indefinitely when it committed to the Maritime Link. Instead, the Maritime Link investment was justified on the basis of a number of economic benefits, including:

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[6] NS Power response to Industrial Group IR-29(a).

[7] Nova Scotia Power Inc., *2017-2019 Fuel Stability Plan Application*, March 7, 2016, pp. 91-92.

- Avoiding fuel costs by displacing generation from NS Power's thermal plants.
- Reducing import costs by procuring Surplus Energy at prices lower than conventional economy imports through New Brunswick.
- Reducing spending on fixed O&M by allowing for the retirement of Lingan 2.
- Starting in 2020, avoiding investments in or purchases from new wind plants for the purposes of meeting the 40% Renewable Energy Standard in 2020.

Q: How would these costs be classified if they were not avoided by the investment in Maritime Link?

A: Avoided fuel costs and lower costs of economy imports would be classified as 100% energy-related. Any reduction in fixed costs of the Lingan plant due to the retirement of Lingan 2 would be classified based on the system load factor (56% energy-related; 44% demand-related). Finally, avoided wind costs would be classified as either 100% energy-related for ERIS resources or 83% energy-related for NRIS resources.

Q: Has NS Power derived a classification scheme based on the economic benefits from the Maritime Link investment?

A: Yes. In Attachment 1 to its response to Industrial Group IR-29(b), the Company outlined an approach that would classify Maritime Link revenue requirements in the same fashion as "fossil fuel generation displaced by deliveries under the Nova Scotia Block." Under this scheme, 93% of Maritime Link revenue requirements would be classified as energy-related and the remaining 7% would be classified as demand-related.[8]

As noted by the Company in Attachment 1 to its response to Industrial Group IR-29(b): "This is the least rate disruptive approach from a cost methodological standpoint as it would treat Nova Scotia Block costs in exactly the same manner as displaced fossil fuel generation costs."

Q: Does NS Power express any concern about classifying and allocating Maritime Link revenue requirements commensurate with the economic benefits from the investment?

A: Yes. In Attachment 1 to its response to Industrial Group IR-29(b), the Company expresses two concerns. First, NS Power asserts that "this approach would not reflect cost causation as Nova Scotia Block provides both energy and capacity." This claim is inconsistent with the fact that 7% of Maritime Link revenue requirements would be classified as demand-related under this benefits-driven classification scheme.[9]

Second, NS Power asserts that its benefits-based approach "would not be consistent with the Company's position on treatment of purchases and imports in the 2013 COS proceeding and the approved COS methodology." In fact, the Board did not accept the Company's position on treatment of purchases. Instead, the Board-approved classification of both in-province purchases (about 80%

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[8] While NS Power does not explain the nature of the 7% of displaced fossil generation costs that are classified as demand-related, it may include fixed generation costs that would be avoided by the investment in Maritime Link.

[9] In fact, a 7% demand-related classification implies that 16% of the costs avoided by Maritime Link are capacity-related. Such capacity costs would be classified based on system load factor as 56% energy-related and 44% demand-related. Thus, if 16% of total avoided costs were avoided capacity costs, then 7% of total avoided costs (16% x 44%) would be classified as demand-related.

energy-related in aggregate) and imports (100% energy-related) is more like NS Power's estimate of the benefit-based classification (93% energy-related) than the Company's proposed classification (56% energy-related).

Q: What would be the impact on the allocation of Maritime Link revenue requirements to the residential class if such costs were classified as 93% energy-related?

A: Compared to the allocation under the Company's proposed classification, classifying 93% of Maritime Link revenue requirements as energy-related would reduce the allocation to the residential class by about \$8.4 million in 2018, \$8.6 million in 2019, and \$8.7 million in 2020.

Q: What do you recommend with regard to the classification and allocation of Maritime Link revenue requirements for 2018 and 2019.

A: Maritime Link revenue requirements should be classified and allocated to customer classes in proportion to the benefits to customer classes from the Maritime Link investment. Accordingly, the Board should reject NS Power's proposal to classify Maritime Link revenue requirements in the same fashion as Company-owned hydro plant costs. Instead, Maritime Link revenue requirements should be classified as 93% energy-related and 7% demand-related based on the Company's classification of Maritime Link benefits. Consistent with the treatment of other non-biomass purchases, the energy-related portion of Maritime Link revenue requirements should be allocated in proportion to each class's contribution to annual system energy requirements and the demand-related portion should be allocated in proportion to the average of peak demands for the three winter months.

IV. Annual BCF Rate Increase

Q: Please summarize the Company's forecast of BCF and total base rates.

A: Table 1 shows the Company's forecast for 2016 through 2020 of BCF rates on average for all FAM customer classes and for the residential class.[10] I derived Table 1 based on data provided in NS Power's response to CA IR-2.

Table 1: Forecast of BCF Rates

`	FAM Class Average Rate ($/kWh)	Percent Change	Residential Rate ($/kWh)	Percent Change
2016	0.054		0.055	
2017	0.049	-8.2%	0.051	-8.1%
2018	0.066	32.6%	0.069	36.9%
2019	0.066	1.2%	0.070	0.9%
2020	0.069	4.6%	0.073	4.1%

As indicated in Table 1, NS Power is currently forecasting about an 8% drop in the residential BCF rate from 2016 to 2017, followed by a steep 37% increase from 2017 to 2018.

Q: Does NS Power's rate forecast for the years 2017 through 2020 reflect any recovery of FAM over- or under-recoveries in 2016?

A: No. The Company assumes that the AA and BA riders are reset to zero in the years 2017 through 2020 for the purposes of forecasting rates. However, according to the Company's response to CA IR-4, NS Power will file in November of 2016 a request for recovery or reimbursement of 2016 AA and BA amounts during the Rate Stability Period.

[10] The BCF rates shown for 2016 reflect recovery of the 2016 AA and BA riders.

Q: What is NS Power's proposal for recovering forecasted increases in the Base Cost of Fuel over the Rate Stability Period?

A: Tables 2 and 3 provide the BCF and base rates, respectively, proposed by NS Power in order to comply with the Section 6 of the EPIA mandating that the forecasted increase in the Base Cost of Fuel over the Rate Stability Period be recovered in equal annual increments. As indicated in Table 2, NS Power proposes to increase the residential BCF rate by around 4% annually from 2016 to 2019. This percentage increase in the residential BCF rate is equivalent to a 1.5% annual increase in the total base rate for the residential class.

Table 2: Smoothed BCF Rates

`	FAM Class Average Rate ($/kWh)	Percent Change	Residential Rate ($/kWh)	Percent Change
2016	0.054		0.055	
2017	0.056	3.3%	0.058	4.3%
2018	0.058	3.3%	0.060	4.2%
2019	0.059	3.3%	0.062	4.1%
2020	0.069	16.7%	0.073	16.9%

Table3: Smoothed Base Rates

`	FAM Class Average Rate ($/kWh)	Percent Change	Residential Rate ($/kWh)	Percent Change
2016	0.140		0.158	
2017	0.142	1.3%	0.161	1.5%
2018	0.144	1.3%	0.163	1.5%
2019	0.146	1.3%	0.165	1.5%
2020	0.156	6.8%	0.176	6.4%

Q: Do you have any concerns regarding the Company's proposal for smoothing residential BCF rates over the Rate Stability Period?

A: Yes. I am concerned about the magnitude of the rate increase in 2020 under the Company's proposal. As forecasted by NS Power, the residential BCF rate would jump by about 17% and the residential base rate would increase by more than 6% from 2019 to 2020. Thus, three years of comparative rate stability would be followed by a steep increase in residential rates.

Q: Are you recommending an alternative to the Company's proposal for smoothing residential rates during the Rate Stability Period?

A: Not at this time. I understand that the Consumer Advocate intends to pursue this issue further with NS Power once the Company files its refresh of the BCF forecast and revised proposal for smoothing BCF rates on May 27, 2016.

V. Fuel Hedging Plan

Q: What is the primary objective of the Fuel Hedging Plan proposed by NS Power?

A: As stated in the Fuel Stability Plan Application, the proposed Fuel Hedging Plan is designed "to provide rate stability for customers."[11] However, the primary focus is not on rate stability during the Rate Stability Period, when rates will be perfectly stable by design, but on rate stability when the Rate Stability Period ends. Consequently, the primary objective is to minimize the probability of substantial under-recovery of fuel and purchased-power (F&PP) costs during the Rate Stability Period in order to minimize the risk of rate shock in 2020 due to the recovery of deferred F&PP under-recoveries.

[11] Application, p. 81.

Q: How does NS Power plan to achieve its primary objective?

A: According to the Company's response to Liberty IR-9(a), NS Power intends to hedge 75-100% of individual fuel requirements with a combination of financial and physical contracts in order to minimize the risk that actual fuel costs will exceed forecasted amounts for the portfolio as a whole:

> For each fuel type, NS Power will target hedging 75-100% of forecast consumption during the Rate Stability Period. The actual amount hedged will vary depending on the availability of suitable cost-effective hedges.

Q: What precisely does NS Power mean when it states that it will hedge 75-100% of F&PP requirements "during the Rate Stability Period"?

A: That is not clear. The Company does not specify how far in advance it proposes to reach the 75-100% target range (which could range from one day to three years in advance) or whether it will seek to achieve the target range every day, every month on average, or every year on average.

Q: How did NS Power determine its hedge target of 75-100% of forecasted fuel requirements?

A: The Fuel Hedging Plan does not describe specifically how it was determined that a hedge target of 75-100% of forecasted fuel requirements provides an appropriate level of risk mitigation for ratepayers. Presumably, the hedge target would have been determined based on an assessment of ratepayers' tolerance for the risk of F&PP cost deferrals. In this case, it appears that NS Power assumed that ratepayers have effectively zero tolerance for deferral risk and therefore that the appropriate strategy would be to hedge as much of expected fuel requirements as feasible and cost-effective:

> Maximum price stability is achieved when the proportion of fuel costs hedged reaches 75-100% of forecast fuel requirements…. Maximizing the level of fuel cost stability through hedging 75-100% of forecast fuel requirements will provide the greatest degree of fuel cost stability to customers.[12]

In response to CA IR-29(a), NS Power offers one other justification for maximizing hedge amounts:

> Presently, the forward curves for many fuels exhibit a very low amount of contango during the Rate Stability Period, i.e. there is only a small amount of escalation in forward prices. This will allow NS Power to hedge commodity costs for the entire period without paying a significant premium for longer dated futures, providing further stability for customers.

However, it is not clear why NS Power makes this claim. Contango refers to the situation where the forward price of a commodity is higher than the expected spot price at the maturity of the contract. The Company has not provided any basis for estimating future spot prices or provided any evidence that current forward prices are not much higher than estimates of future spot prices.

Instead, NS Power appears to use the term "contango" to refer to a situation where there is little escalation in forward prices, and therefore little difference between current spot prices and market prices for long-dated forward contracts. However, it is not clear why this situation provides an opportunity for maximizing hedge amounts.[13]

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[12] NS Power response to CA IR-29(a).

[13] If future spot prices were not expected to decline from current levels, then a situation of "contango" in the Company's sense would provide NS Power the opportunity to purchase forward contracts without paying a significant premium over future spot prices. However, as noted above, NS Power has not provided any basis for expecting future spot prices to be about the same as current spot prices.

Q: Is there any potential downside to hedging 75-100% of forecast fuel requirements?

A: Yes. If fuel requirements are lower than forecast, NS Power may have excess fuel (or financial hedges) to sell back into the market. If the market price for these hedges had dropped between the time that NS Power purchased them and the time it liquidated them, there would be a net cost from unwinding excess hedges that would be deferred to 2020.[14]

The risk of disposing of hedges at a loss is not academic. For example, forward prices for winter 2015/16 Algonquin basis contracts declined dramatically from 2014 to 2016.[15] In this case, if NS Power had hedged most or all of its expected gas needs for the winter of 2015/16 one or two years in advance and actual requirements were less than expected, the Company would have had to unwind excess hedges at a loss.

Q: How will the Company measure a particular hedge instrument's effectiveness at reducing the risk of deviations from forecasted fuel costs?

A: According to NS Power's response to CA IR-30(b), hedge effectiveness will be measured in terms of the reduction to the portfolio-wide Value at Risk (VaR) from entering into the hedge.

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[14] Customers would also have foregone the negative deferral that would have resulted from the lower price for a later purchase. It may be reasonable to forego this opportunity to benefit from lower prices in order to hedge against the risk of higher prices. However, care must be taken when hedging price risk not to increase the risk of losses when actual requirements deviate from forecasted levels.

[15] This decline in basis expectation may have been due to increases in gas transportation capacity during this period, changing expectations for gas demand from electric generators, or other factors.

Q: How will NS Power determine the cost-effectiveness of a particular hedge purchase?

A: Again, this is not clear. According to NS Power's response to CA IR-30(c), the Company will determine the cost-effectiveness of a hedge by comparing the increase in costs expected to result from executing the hedge against the reduction in fuel cost variability (expressed as VaR) expected to result from executing the hedge:

> The expected direct increase in the total fuel and purchase power will be estimated, as well as the expected reduction in portfolio level VaR. Should an increase in fuel costs be expected as a result of executing the hedge, it would only be entered if there is a commensurate decrease in VaR resulting from the hedge.

However, NS Power has not specified how it intends to trade off increased cost against reduced VaR. In particular, the Fuel Hedging Plan does not specify how an increase in direct costs (e.g., a direct hedge cost of $1 million) would be compared against a reduction in potential under-recoveries at a specified probability level (e.g., a $1 million reduction in VaR at 10% probability.) Instead, in response to Liberty IR-64(a), NS Power offers the general statement that it "will weigh the balance between the benefit of the reduction in fuel cost variability and the costs of entering these hedges."

Q: What is NS Power's request to the Board with respect to the proposed Fuel Hedging Plan?

A: As stated in the Company's response to Liberty IR-6(a):

> NS Power is seeking approval of the Fuel Hedging Plan, which contains the key strategies and mechanisms expected to be used. This includes, but is not limited to, the strategy to hedge 75-100% of the forecast fuel requirements during the Rate Stability Period, the periodic rebalancing of hedge portfolio, and the products listed in Appendix C to the Fuel Hedging Plan.

Q: Should the Board approve the proposed Fuel Hedging Plan?

A: Not at this time. As discussed above, NS Power has not provided a reasonable basis for approving a hedge target of 75-100% of F&PP requirements, or even adequately described what it means by hedging "75-100% of the forecast fuel requirements during the Rate Stability Period." Nor has the Company explained in any detail how it will measure hedge cost-effectiveness.

Instead, the Board should direct NS Power to meet with the FAM Small Working Group in order to provide members with further details on its hedge target and strategy and to solicit member feedback.[16] The Board should further direct NS Power to re-file a Fuel Hedging Plan after due consideration of feedback from members of the FAM Small Working Group.

Q: Does this conclude your direct evidence?

A: Yes.

[16] The proposed Fuel Hedging Plan has been discussed at prior meetings of the FAM Small Working Group. However, NS Power's presentations during those discussions did not offer any more details than provided in the Application regarding the selection of the 75-100% hedge target, the specifics of how that target would be implemented, or how hedge cost-effectiveness would be measured.

Exhibit JFW-1

Qualifications of

JONATHAN F. WALLACH

Resource Insight, Inc.
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SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

“The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities” (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities" (with Paul Chernick), *1996 Summer Study on Energy Efficiency in Buildings* 7(7.47–7.55). Washington: American Council for an Energy-Efficient Economy, 1996.

"Retrofit Economics 201: Correcting Common Errors in Demand-Side-Management Cost-Benefit Analysis" (with John Plunkett and Rachael Brailove). In proceedings of "Energy Modeling: Adapting to the New Competitive Operating Environment," conference sponsored by the Institute for Gas Technology in Atlanta in April of 1995. Des Plaines, Ill.: IGT, 1995.

"The Transfer Loss is All Transfer, No Loss" (with Paul Chernick), *Electricity Journal* 6:6 (July, 1993).

"Benefit-Cost Ratios Ignore Interclass Equity" (with Paul Chernick et al.), *DSM Quarterly*, Spring 1992.

"Consider Plant Heat Rate Fluctuations," *Independent Energy*, July/August 1991.

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"New Tools on the Block: Evaluating Non-Utility Supply Opportunities With *The Power Analyst*, (with John Plunkett), *Proceedings of the Fourth National Conference on Micro-computer Applications in Energy*, April 1990.

REPORTS

"Economic Benefits from Early Retirement of Reid Gardner" (with Paul Chernick) prepared for and filed by the Sierra Club in PUC of Nevada Docket No. 11-08019.

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"Risk Analysis of Procurement Strategies for Residential Standard Offer Service" (with Paul Chernick, David White, and Rick Hornby) report to Maryland Office of People's Counsel. 2008. Baltimore: Maryland Office of People's Counsel.

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"First Year of SOS Procurement." 2004. Prepared for the Maryland Office of People's Counsel.

"Energy Plan for the City of New York" (with Paul Chernick, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

"Peak-Shaving–Demand-Response Analysis: Load Shifting by Residential Customers" (with Brian Tracey). 2003. Barnstable, Mass.: Cape Light Compact.

"Electricity Market Design: Incentives for Efficient Bidding; Opportunities for Gaming." 2002. Silver Spring, Maryland: National Association of State Consumer Advocates.

"Best Practices in Market Monitoring: A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets" (with Paul Peterson, Bruce Biewald, Lucy Johnston, and Etienne Gonin). 2001. Prepared for the Maryland Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Delaware Division of the Public Advocate, New Jersey Division of the Ratepayer Advocate, Office of the People's Counsel of the District of Columbia.

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