2006

ORIGINAL

NSUARB-P-886

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

-AND-

IN THE MATTER OF an Application by Nova Scotia Power Incorporated for a Hearing for Approval of Certain Revisions to its Rates, Charges and Regulations

INFORMATION REQUEST RESPONSES

January 12, 2007

TO: Nova Scotia Power Incorporated

FROM: Dr. Alan Rosenberg

RECEIVED
JAN 15 2007
Nova Scotia
Utility and Review Board

Question No. IR-1:

Reference Exhibit AR-1, Schedule 1. Comparison of Electric Rates.

Please identify all utilities listed that are located in north-eastern North America.

Response:

If northeastern North America is intended to mean the Northeast Power Coordinating Council (NPCC), then Nova Scotia Power (#3), New Brunswick Power (#6), and Hydro-Quebec (#16) would qualify. However, utilities in ISO New England, the New York Independent System Operator and the Ontario Independent Electricity Market Operator were excluded, as the last unit on the margin (which for most hours is gas or oil) sets the prices in those markets. This market design (known as Locational Marginal Pricing or Standard Market Design) has been highly criticized as producing inordinately high prices that are not reflective of the average generation costs and, of course, is quite different than the situation for regulated utilities, whose rates are predicated on the basis of average generation costs. Consequently, Dr. Rosenberg felt that including those utilities would not provide a meaningful comparison.

Question No. IR-2:

For each individual company shown in this exhibit, please provide:

a. A copy of the actual tariff used to calculate the unit cost shown or the source of the information if a tariff has not been consulted.

b. All assumptions and determinants used to calculate the unit cost shown.

c. Identify whether the company utilizes a fuel adjustment clause.

d. For each utility that has an approved FAM, please provide the full text of the most recently approved FAM, together with a reference to the regulatory decision approving it.

e. Identify which companies are distribution utilities or transmission/distribution only.

f. Provide the revenue-to-cost ratio, or a comparable indicator, for each tariff listed. Please identify those with a R/C ratio of 0.95 or less.

g. Explain the differences between each rate and the ELI 2 P-RTP rate.

h. Provide all worksheets showing details of calculation of each rate (cents per kilowatt hour) referred to in the table.

i. Are all rates presented in your testimony expressed in Canadian dollars? If not, what foreign exchange rate was used?

j. Provide the date of approval of each rate.

k. Indicate which of the utilities you list has a rate case pending.

Response:

a. See Attachment SEB-NSPI-2a.

b. These are included in the worksheets which are provided in Attachment SEB-NSPI-2h.

c. See Attachment SEB-NSPI-2c.

d. See Attachment SEB-NSPI-2d for all the information that was readily available.

e. All utilities listed own their own generation and the rates are for bundled service.

Response to Question No. IR-2 (continued):

f. This information was not available to Dr. Rosenberg.

g. The actual tariffs of each rate are provided in response to part a. of this question. Since NSPI has its own ELI 2P RTP rate, it can easily ascertain any differences in applicability or interruption terms and conditions between these rates and ELI 2P RTP. In general, however, the other rates cited are more generally available and less interruptible or, in some cases, even firm.

h. See Attachment SEB-NSPI-2h.

i. The currency and exchange rate used was noted on the Schedule.

j. This information can be ascertained from the tariffs that are provided in response to part a. of this question.

k. This information was footnoted on the Schedule.

Question No. IR-3:

Reference Exhibit AR-1, Schedule 1. Comparison of Electric Rates.

Please prepare a revised and re-ordered table, using a 75% load factor in calculating each tariff, rather than 90%, and adjusting for the "pending increases" shown as footnotes at the bottom of the table.

Response:

The information requested is provided in Attachment SEB-NSPI-3. However, Dr. Rosenberg cannot agree that this Attachment is as relevant as Schedule 1 because the standard cost of ELIIR-2, that is the take-or-pay portion of the rate, is predicated on the CBL which exhibits a load factor *greater than*, not less than, 90 percent.

Question No. IR-4:

Please provide the following information for each of the utilities listed in Exhibit AR-1:

a. Mix of fuels in 2005 as measured by Btus purchased or generation.

b. Delivered prices of each fuel YTD 2006.

c. Average quality of coal purchased YTD 2006.

Response:

a. The attached pages show the primary sources of energy for each Canadian utility in petajoules. The source of this information was *Canada's Energy Future* published by the NEB. Similar data for U.S. utilities was unavailable. However, Attachment SEB-NSPI-4a also includes copies of Sources and Uses of Power from the FERC Form 1, where available.

b. Dr. Rosenberg does not know the prices of each fuel, but for the U.S. utilities the cost of fuel and purchased power is shown on the FERC Form 1 pages included in Attachment SEB-NSPI-4a.

c. This information was not available.

Question No. IR-5:

Reference Fuel Cost Evidence.

Please identify, in your qualifications, your experience as an expert witness with respect to fuel costs and fuel procurement.

Response:

Dr. Rosenberg is not offering testimony in this case on fuel procurement, but only on the calculation of fuel costs given more recent evidence on actual purchases and gas and oil price forwards, as well as the accuracy of previous forecasts by NSPI. In addition to his 25 years of experience and expert testimony in the field of energy and regulatory economics, Dr. Rosenberg has been certified by the Association of Energy Engineers as a Certified Energy Procurement Professional and acts as the principal advisor to the City of New York on its procurement and hedging (risk management) of electrical energy in the New York ISO market and its financial interest in 500 MW and 850 MW generating stations in New York that burn gas and heavy fuel oil.

Question No. IR-6:

Please list all investor owned electric utilities in North America of which you are aware that do not have fuel adjustment mechanisms. Please identify whether the utility provides any or all of generation, distribution and transmission.

Response:

Dr. Rosenberg is not proposing a fuel adjustment mechanism in this case. He is aware that states such as Missouri, Utah, Montana and Vermont, and provinces such as British Columbia, Alberta and New Brunswick do not currently have fuel adjustment clauses for electric utilities. (For Montana and Alberta the reference is to when electric utilities were vertically integrated and regulated.)

Question No. IR-7:

Please list all utilities that have a fuel adjustment mechanism similar to the one which you advocate for NSPI on pages 23 through 25 of your testimony. For each, please provide documentation as to each specific mechanism.

Response:

Dr. Rosenberg is not proposing a fuel adjustment mechanism in this case, but rather a fuel deferral mechanism. Utilities that have fuel adjustment mechanisms normally defer fuel costs to match their fuel recovery. Dr. Rosenberg is unaware of any utilities that do not have a fuel adjustment mechanism that normally defer their fuel costs. It should be noted that a fuel deferral mechanism is more advantageous to the utility than the absence of such a mechanism, all other things being equal.

Question No. IR-8:

a. Please provide copies of testimony by this consultant in other proceedings and jurisdictions, if any, in which:

   i. The consultant has suggested that a fuel forecast be reduced to account for "a tendency to overstate," and which has been adopted by the regulator; and/or

   ii. The consultant has suggested that a fuel forecast be reduced to account for global fuel cost trends, and which has been adopted by the regulator; and/or

   iii. The consultant has suggested a fuel forecast be reduced to normalize maintenance downtime, and which has been adopted by the regulator.

b. Please provide evidence to support the statement at lines 12-13, that normalization adjustments are "often done in ratemaking." If this statement is a matter of Dr. Rosenberg's opinion or judgment, please so state, and explain Dr. Rosenberg's basis for his opinion. Please also state any utilities where this applies and whether or not those utilities have fuel adjustment clauses.

c. Please provide examples of regulator decision in which a test year expense was reduced by a regulator because of possible reductions in that cost in years following the test year.

d. Does the concept of "normalization" of test year expenses apply when increases in expenses in years subsequent to the test year are foreseen? Please provide examples.

Response:

a.

   i. Dr. Rosenberg has not offered testimony, prior to this case, suggesting that a fuel forecast be reduced to account for a tendency to overstate or overestimate fuel costs. However, it should also be noted that: (1) in cases where utilities have FAMs, the accuracy of a fuel forecast is not relevant to the actual rates paid by customers; and (2) Dr. Rosenberg cannot recall any utilities that have exhibited this tendency to the extent that NSPI has. However, he is aware of regulatory precedent for adjusting an applicant's forecasts in view of past tendencies to misforecast. This is demonstrated in the following two excerpts.

      (a) *ATCO Electric Ltd. 2005-2006 General Tariff Application*, [2006] A.E.U.B.D. No. 25:

      ¶ 111 **The Board is of the view that the overall historic trend for the forecast to be overstated relative to the actual is indicative of an over**

Response to Question No. IR-8 (continued):

> **forecasting tendency in AE's forecast of Isolated Generation O&M costs.** The Board notes that the forecast in 2005 is 13.1% higher than 2004 actuals. The Board is not persuaded that AE has provided sufficient reasons for the increased forecast for 2005. Given this situation, the Board considers that it is reasonable to reduce the forecast by 10% as recommended by FIRM for the 2005 year. The Board considers that the 2006 year forecast appears reasonable compared to the 2003 and 2004 actuals. [emphasis added]
>
> ¶ 112 Accordingly, the Board directs AE, in its Refiling, to reduce its forecast of Isolated Generation O&M expenses in 2005 by 10% to $4,611,000. The Board approves the 2006 forecast at $4,653,000 as forecast.

(b) *ATCO Pipelines 2003/2004 General Rate Application, Phase I*, [2003] A.E.U.B.D. No. 94:

> ¶ 110 However, the Board agrees with the submission of the AUMA/EDM/CG that ATCO Pipelines has a history of over forecasting in this category. **The Board directs ATCO Pipelines to reduce its 2003 and 2004 transmission growth general forecast in the South by 15% as a result of its past record of over forecasting.** The Board also notes that this reduction is consistent with the downward trend of APS's actual growth related expenditures. [emphasis added]

ii. Dr. Rosenberg is not aware of offering such testimonies.

iii. Dr. Rosenberg is not aware of offering such testimonies. However, to the best of his knowledge and belief, such normalization is standard practice in states such as Missouri and Utah.

b. No, this statement is not simply a matter of Dr. Rosenberg's opinion or judgment. The evidence for the practice of the principle of "normalization" abounds in the lore of regulation. For example, in the text "Accounting for Public Utilities" by Robert Hahne and Gregory Aliff of Deloitte & Touche (published by Matthew Bender, 1992), it states:

> The operations and maintenance expenses of the test period are based upon *historical* test year data, as recorded or as annualized to levels at the end of the test period with *pro forma adjustments for known and measurable changes*, or upon forecasted test year results, depending upon the type of test year used.
>
> (Section 7.08, page 7-14, emphasis added)

Response to Question No. IR-8 (continued):

The term pro-forma adjustment is consonant with the expression "normalization" as Dr. Rosenberg uses that term of art on pages 12-13 of his testimony. Thus, the very concept of a future test year is a type of normalization that developed in those jurisdictions where regulators felt that historic test years were not representative of prospective conditions when the new rates would be in effect. Moreover, NSPI itself uses a form of "normalization" when it uses normalized weather for its sales forecasts for weather sensitive classes. The rationale for using normal weather to forecast sales for the test year is no different than the reasoning that Dr. Rosenberg is using for adjusting fuel costs in the test year – i.e., to have test year results that are neither biased high nor biased low on a prospective basis.

c. A prime and pertinent example of such a regulatory policy occurred here in Nova Scotia, as the following excerpt from the 2002 Nova Scotia Power rate case (NSPI-P-875) exemplifies:

[54] The Board agrees with the intervenors that the fuel costs for the 2002 test year are based on higher than normal coal costs. The expert witnesses all appear to agree that coal prices have begun to decline and, while costs may remain relatively high, the abnormally high prices seen during 2001 have dropped. Under these circumstances, the Board finds that the test year coal costs used by NSPI are not suitable for rate-making purposes. In this case, NSPI applied for a rate increase at the end of 2001 projecting coal costs which were higher than most experts anticipate to be the case during 2002-03. NSPI is not entitled to recover past expenses caused by high coal prices. It is an accepted principle, which the Board endorses, that rate-making should be prospective and not retroactive. NSPI lost the opportunity to mitigate the high cost of coal for a good part of 2002 when it waited to file an application until December of 2001. **Accordingly, the Board finds that the cost of fuel for the test year must be reduced in order to ensure that the costs are more representative of the period during which the rates will be in place (i.e., late 2002 and into 2003).** [emphasis added]

[55] As noted above, since the Board finds that NSPI's projected fuel costs for the test year are unusually high, it believes the fuel costs should be "normalized" by reducing the amount estimated by NSPI. In determining an appropriate reduction the Board notes that Dr. Stutz's recommended 10% reduction in imported coal costs moves the price of coal closer to the historic mean price as shown in Exhibit N-152, JS-5, while still acknowledging the increase in coal prices which did occur. The Board finds that to normalize these coal costs on a go-forward basis for the balance of this year and into 2003, a 10% reduction in the test year costs for imported coal is reasonable and balanced. The Board does note that, according to the information in the January 28, 2002 update, NSPI's actual imported coal costs were less than those originally estimated. In the Board's view, a reasonable reduction in test year costs is the 10% suggested by Dr. Stutz. This will result in a reduction of approximately $19.7 million in the test year revenue requirement. [emphasis added]

Response to Question No. IR-8 (continued):

Furthermore, he is generally aware from his experience that reductions, as well as increases, to test year expenses that are known and measurable have been reflected in the establishment of rates. He is also aware that Alberta and British Columbia have used multi-year test years on occasion.

d. Yes. See the response to part c. of this question.

Question No. IR-9:

Please provide complete copies of all testimony prepared by you in the last 10 years (redacted as appropriate) related to the adoption or rejection of a fuel adjustment mechanism.

Response:

With the exception of his testimony in NSPI's 2005 Rate Application, to the best of his recollection, Dr. Rosenberg has not testified on that topic in the last ten years, nor is he testifying on the adoption or rejection of a fuel adjustment mechanism in this case.

Question No. IR-10:

Reference pages 23 to 25 – "Deadband feature and sharing mechanism"

a. Please identify any jurisdiction and regulatory proceeding in which such an approach has been adopted by a regulator, with a copy of the decision of the regulator establishing the mechanism.

b. If this consultant was involved in the proceeding, please provide a complete copy of his evidence.

c. Please provide a complete copy of all evidence filed by this consultant in all other proceedings in which the consultant has made such a suggestion, identifying for each piece of testimony whether the consultant's evidence was adopted by the regulator.

Response:

a. Dr. Rosenberg recalls that before deregulation New York state for many years used fuel clauses with a sharing and/or a deadband. Dr. Rosenberg has not conducted research on all such utilities, as he is only addressing the situation in Nova Scotia. Moreover, Dr. Rosenberg would take note of the Report from Christensen Associates prepared for NSPI, and provided in response to UARB IR-185 (Attachment) (in the course of NSUARB-P-881) which states in part:

> "Efficient fuel cost adjustment mechanisms should have a performance based ratemaking component, which provides incentives to the utility to cost minimize and share the outcomes appropriate between the utility and its customers. This provides stronger incentives for efficient behavior of the utility than if the mechanism was simply an extension of the cost of service ratemaking process. When PBR is applied to the fuel price risk management problem, it translates into a set of rules and financial incentives that are referred to as incentive-based fuel adjustment mechanisms (or banded fuel adjustment mechanisms, BFAM). Unlike typical fuel adjustment mechanisms that operate as straight cost pass-throughs, these mechanisms share the fuel price risks between the utility and its customers."

b. Not applicable.

c. See Dr. Rosenberg's evidence in NSUARB-P-881. In that proceeding, Dr. Rosenberg recommended a deadband and sharing feature as a prerequisite for approval of a FAM. The regulator in that case declined to approve a FAM, thus making Dr. Rosenberg's suggestion moot.

Question No. IR-11:

Reference page 29, lines 9-15

On what date did the consultant become aware that his client, Stora Enso Port Hawkesbury, would be re-opening in 2006 and operating in 2007?

Response:

Dr. Rosenberg became aware of that fact when Mr. George Cooper sent him an e-mail containing or replicating (he cannot recall which) the public announcement made by Stora Enso to that effect. The date was shortly after the Board's decision last fall in the ELIIR-2 proceeding, but Dr. Rosenberg cannot recall the exact date.

Question No. IR-12:

Dr. Rosenberg is familiar with the Mersey Rate, which is based on the 1965 Mersey Agreement and with the fact. Please confirm that this rate utilizes a year-end "true-up" in the form of a 13th bill. Does Dr. Rosenberg consider the Mersey 13th bill "retro-active ratemaking," and if so why?

Response:

Yes, any provision that changes a customer's rate subsequent to the actual taking of the service is technically retro-active ratemaking, by definition. It should be duly noted, however, that: (a) the Mersey Rate is pursuant to a contract which I understand is essentially a "cost plus" operating agreement developed to deal with the specifics of that generating facility; and (b) the energy taken under governance by that rate is "first-through-the-meter" and so the retroactive aspects of that rate cannot, and do not, affect the hourly consumption decisions of the single customer on that rate.

Question No. IR-13:

a. Does the consultant's evidence on Cost of Service Methodology result in reduced costs to his clients if adopted by the Board?

b. If so, what is the dollar amount of those reductions based on NSPI's Application as filed?

c. If so, what customer classes will become responsible to pay those costs?

d. Please calculate the revenue responsibility change ($ millions) to each of the classes affected.

Response:

a. Yes.

b. Under the Board's policy for the ELIIR-2 rate, Dr. Rosenberg estimates the dollar amount would be $2.24 million dollars. However that figure is predicated on NSPI receiving the full amount of its rate request. If the Board reduces that request, that figure could, and most likely would, be similarly reduced as well.

c. It is impossible to say precisely which customer classes would become responsible to pay those costs as the Board does not have a set Revenue/Cost ratio for the other classes.

d. The requested quantities are not quantifiable at present because: (1) the reason cited in part c. of this question; and (2) the ultimate magnitude of NSPI's increase in 2007 has not yet been determined.