DECISION

IN THE MATTER OF an Application by New Brunswick Power Corporation pursuant to subsection 103(1) of the *Electricity Act*, S.N.B. 2013, c. 7, for approval of the schedules of rates for the fiscal year commencing April 1, 2019.

(Matter No. 430)

July 16, 2019

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

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NEW BRUNSWICK ENERGY AND UTILITIES BOARD:

Chairperson:	Raymond Gorman, Q.C.
Vice-Chairperson:	François Beaulieu
Members:	Michael Costello
	Patrick Ervin
	John Patrick Herron
Counsel:	Ellen Desmond, Q.C.
Chief Clerk:	Kathleen Mitchell

APPLICANT:

New Brunswick Power Corporation:	John Furey

INTERVENERS:

Gerald Bourque:	per se
Enbridge Gas New Brunswick:	Jeffery Callaghan
J.D. Irving, Limited:	Christopher Stewart
Dr. Roger Richard:	per se
Utilities Municipal:	Scott Stoll
PUBLIC INTERVENER:	Heather Black

A. Introduction

[1] The New Brunswick Power Corporation (NB Power or Utility) applied to the New Brunswick Energy and Utilities Board (Board) on January 8, 2019 (Application) for an Order approving its proposed rates for services for the fiscal year commencing April 1, 2019 (test year).

[2] Based on revenue requirements of $1,740.4 million, NB Power sought an average two and one half per cent (2.50%) increase in rates and proposed differential rate increases across various customer classes.

[3] NB Power also requested an Order approving the creation of a regulatory deferral account with respect to certain Demand-Side Management (DSM) expenses.

[4] A Notice of this Application was published both on the Board's website and in the daily newspapers in the province of New Brunswick. A pre-hearing conference was held on February 6, 2019, at which time a number of procedural issues were addressed, including the hearing dates. The commencement of the hearing was set for May 21.

[5] In addition, the Board scheduled afternoon and evening sessions on May 9 in Fredericton, to receive comments from the public in relation to the application. Eight oral presentations were made at the public sessions and the Board received a large number of written submissions. Staff members from NB Power were present at the public sessions which gave the Utility an opportunity to respond at the full hearing.

[6] In a letter dated May 15, NB Power advised the Board that, in accordance with an interrogatory (IR) response that had been provided to the Public Intervener, NB Power was now seeking revenue requirements of $1,742.3 million. The test year net earnings had been revised, which resulted in an increased amount of $1.9 million being attributed to net earnings. While no party took issue with the revised amount, seeking such an important amendment to the revenue requirements should be done, in the future, by amending its filing as soon as possible.

[7] In support of its Application, NB Power presented four witness panels. Two of its witnesses were declared as experts. Mr. Philippe Dunsky, President of Dunsky Energy

Consulting, was declared as an expert in demand-side management strategies and regulation, and Mr. John Todd, President of Elenchus Research Associates Inc., was declared an expert in the regulation of electric and gas utilities and specifically in the areas of class cost allocation and rate design.

[8] In addition, NB Power offered the evidence of Mr. Jamie O'Neil, a Partner at KPMG LLP, who was declared an expert in accounting, and in particular the interpretation of accounting standards including International Financial Reporting Standards. Mr. O'Neil however, was not required to attend the hearing in person as no party had cross-examination questions for him.

[9] One intervener submitted evidence in this matter. The Public Intervener presented the evidence of Mr. Robert Knecht, principal of Industrial Economics, Incorporated. He was qualified as an expert in the areas of regulatory economics and rate making.

B. Legislative Framework

[10] NB Power is required, under the *Electricity Act*, S.N.B. 2013, c.7 (Act), to apply to the Board for approval of its rates to take effect on April 1 of each fiscal year. The application must include NB Power's projection of its load and revenue, its revenue requirements and its proposed schedules of rates. If satisfied that the rates are just and reasonable, the Board will approve the rates, or it will fix other rates that it finds to be just and reasonable.

[11] Subsections 103(7) and 103(8) state as follows:

> **103**(7) In approving or fixing just and reasonable rates, the Board shall base its order or decision on the Corporation's revenue requirements, taking into consideration
>
> (a) the policy set out in section 68,
>
> (b) the most recent integrated resource plan approved or deemed to be approved by the Executive Council under section 100,
>
> (c) the most recent strategic, financial and capital investment plan filed with the Board under section 101,

(d) any requirements imposed by law on the Corporation that may be relevant to the application, including, without limitation, requirements regarding demand-side management and energy efficiency plans and renewable energy requirements,

(e) any directive issued by the Executive Council under section 69 that may be relevant to the application, and

(f) any policy established by a regulation made under paragraph 142(1)(f) that may be relevant to the application.

103(8) In approving or fixing just and reasonable rates, the Board may take into consideration

(a) accounting and financial policies of the Corporation,

(b) matters of cost allocation and rate design,

(c) customer service related charges,

(d) the Corporation's demand-side management and energy efficiency plans, and

(e) any other factors that the Board considers relevant.

[12] Section 68, as cited in paragraph 103(7)(a), states:

68 It is declared to be the policy of the Government of New Brunswick:

(a) that the rates charged by the Corporation for sales of electricity within the Province

(i) should be established on the basis of annually forecasted costs for the supply, transmission and distribution of the electricity, and

(ii) should provide sufficient revenue to the Corporation to permit it to earn a just and reasonable return, in the context of the Corporation's objective to earn sufficient income to achieve a capital structure of at least 20% equity,

(b) that all the Corporation's sources and facilities for the supply, transmission and distribution of electricity within the Province should be managed and operated in a manner that is consistent with reliable, safe and economically sustainable service and that will

(i) result in the most efficient supply, transmission and distribution of electricity,

(ii) result in consumers in the Province having equitable access to a secure supply of electricity, and

(iii) result in the lowest cost of service to consumers in the Province, and

(c) that, consistent with the policy objectives set out in paragraphs (a) and (b) and to the extent practicable, rates charged by the Corporation for sales of electricity within the Province shall be maintained as low as possible and changes in rates shall be stable and predictable from year to year.

C. Issues

[13] The issues to be determined by the Board in this decision will be addressed under the following categories:

1. Load Forecast and Revenue Requirements;
2. Proposed Regulatory Deferral Account for DSM expenses;
3. Cost Allocation;
4. Differential Rates; and
5. Other Issues.

D. Analysis

1. Load Forecast and Revenue Requirements

[14] The Act requires NB Power to apply annually for approval of the schedules of rates it proposes to charge. The application must include the Utility's projection of its load and revenue for the test year as well as its revenue requirements and proposed schedules of rates. These issues will be considered in the following paragraphs.

a. Load Forecast

[15] NB Power filed its load forecast for in-province customer requirements for the ten-year period from fiscal year 2019/20 to 2028/29. The load forecast is based on an analysis of past loads and trends, using data gathered through customer surveys and assessments of economic, demographic, technological and other factors affecting the utilization of electrical energy.

[16] The forecasted in-province energy load for the test year is 14,363 gigawatt hours, a slight increase from the estimated load for the previous year. Forecasted annual peak hour demand for the test year is 3,060 megawatts, which is no change from the estimate for 2018/19.

[17] The load forecast incorporates several key assumptions. In this hearing, two issues related to the load forecast were the subject of cross-examination.

[18] The first issue deals with the 30-year average temperature history that NB Power uses to define "normal weather" in its load forecast.

[19] Mr. Knecht states in his report that "While 30 years was the industry standard, some utilities have moved to a shorter time period, to better reflect more recent changes in weather patterns." His analysis of the Utility data led him to conclude that a 20-year average would produce a more accurate forecast.

[20] NB Power stated that 30 years is used by many utilities, although it acknowledges that a number of utilities also use a 20-year rolling average.

[21] NB Power committed, in final argument, to reviewing the 30-year heating degree day average to determine whether 20 years, or some other time period, would be more appropriate. The Board directs NB Power to provide the results of the evaluation at the next general rate application.

[22] The second issue relates to the methodology used to forecast the monthly residential load.

[23] In its load forecast, NB Power states that while there were no changes to the forecasting of annual energy volumes, there was a change to the monthly allocation of energy. Instead of using a 10-year rolling average of energy in each month, NB Power decided to

use a monthly spread, based on a 3-year regression, to better capture changing market trends.

[24] The change was not, in itself, contentious. This new approach, however, produced an anomalous result, effectively increasing the share of residential load occurring in the winter months, resulting in an increase in costs allocated to the residential class. This result was the subject of debate and cross-examination and will be addressed below.

[25] Except as provided above, the Board accepts the load forecast, as filed. However, for reasons set out later in this decision, the Board has concerns about the impact of the methodology changes on cost allocation.

b. Revenue Requirements

[26] NB Power submitted its budgeted revenue requirements, consisting of the following:

Component	Budgeted Revenue Requirements
(1) Fuel and purchased power expense	$615.3 million
(2) Operations, maintenance and administration	$516.5 million
(3) Depreciation and amortization	$300.7 million
(4) Taxes	$47.0 million
(5) Finance costs and other income	$232.6 million
(6) Net change in regulatory balances	$(3.7) million
(7) Net earnings	$33.8 million
Total revenue requirements	$1,742.3 million

Note: Financial tables reflect differences due to rounding

[27] No party took issue with the Fuel and purchased power expense, Depreciation and amortization, Taxes, Finance costs and other income, Net change in regulatory balances

or Net earnings. Each of these items was supported by evidence and the Board approves these components of the revenue requirements, as filed.

i. Operations, Maintenance and Administration

[28] Several parties did challenge certain aspects of the proposed Operations, maintenance and administration (OM&A) costs of $516.5 million, an increase of $24.8 million over the approved revenue requirements in 2018/19.

(a) Storm Costs

[29] Last year, the Board approved $2.7 million for storm costs. In this Application, the average budgeted storm costs are $16.8 million, an increase of $14.1 million.

[30] This increase is a result of a change in how NB Power proposes to budget for forecasted storm costs. NB Power has proposed, for the first time, a five-year rolling average of actual costs, when calculating its forecasted storm costs. It submits that the frequency of storms has increased, resulting in larger restoration costs in more recent years. As a result, the budgeted amount reflects the average storm costs that were incurred for the period April 1, 2013 to March 31, 2018.

[31] Mr. Christopher Stewart, counsel for J.D. Irving, Limited, submitted that a three-year average would result in a budgeted amount that would be more accurate and in keeping with the practice in other jurisdictions.

[32] Mr. Knecht testified that, although a ten-year average would be more stable, the five-year average may be more accurate and he would be comfortable with either one. He did not recommend a three-year average, as it may be less stable and accurate, given the high volatility in storm costs from year to year.

[33] Storm costs have been less predictable in the past few years and unexpected costs have had an impact on NB Power's net income. It is important that these costs be more accurately budgeted. At the same time, a slightly longer average does allow for stability and results in less volatility.

[34] The Board finds that a five-year rolling average will provide both a reflection of past experience while also providing a smoothing effect on the annual budget. The Board

approves this approach. Each year, forecasted storm costs will be adjusted to reflect the most recent actual results.

[35] There was concern expressed with respect to what expenses would be classified as a storm cost. To address this concern, NB Power is to provide, in each rate filing, details of what has been included as a storm cost to ensure these costs are being recorded in a transparent fashion.

(b) Energy Smart NB

[36] As part of its DSM plan, NB Power allocates funds towards enabling activities. This includes planning and designing the portfolio of DSM programs, the evaluation, measurement and verification of the programs and market-focused activities, such as building awareness of the programs.

[37] In Matter 375, NB Power explained that a DSM Potential Study (Potential Study) was underway, which would assist NB Power in assessing achievable DSM opportunities and marketing these programs. NB Power had planned to have this study completed by the end of 2018. The Board determined that while certain enabling activities should continue in the 2018/19 test year, the marketing-oriented activities should be deferred until after the Potential Study was completed. As a result, $0.3 million was disallowed from the test year budget.

[38] The Potential Study has not yet been completed. Although NB Power has budgeted $0.3 million for marketing activities for the test year, it remains the Board's determination that it would not be reasonable to spend these funds until the study is complete. As a result, the amount of $0.3 million is disallowed.

(c) Research Spending

[39] Three research projects were of particular interest for interveners in relation to OM&A.

[40] The first project involves exploring the feasibility of an iron production facility at Belledune in partnership with Maritime Iron. If successful, a new iron facility could produce an energy-rich process gas to be used as an alternative fuel at the Belledune Generating Station. This process gas could, potentially, reduce coal consumption at the

generating station and allow for the continued operation of the power plant beyond 2030, being the accelerated phase-out of conventional coal-fired electricity across Canada.

[41] NB Power has budgeted $250,000 for preliminary studies related to this project, but additional costs may also include internal labour and hired services.

[42] The second research project relates to small modular reactors. Mr. Michael Hare, Deputy Chief Nuclear Officer at NB Power, testified that to date, small modular reactors have never been commercially deployed. He noted that a nuclear research cluster has been established in Saint John to determine whether current technology can be scaled to a commercial range.

[43] Mr. Hare testified that NB Power has not yet made any investment, other than providing internal resources or in-kind support to this project. While no additional funding is requested in the revenue requirements, it is estimated that the cost of providing such support is approximately $700,000 in the test year, with similar support to be provided in the future.

[44] The third research project relates to a partnership between NB Power and Joi Scientific, based in Florida, to develop a new technology to commercialize a hydrogen production system that could be used in the world's first generating plant of its kind.

[45] This development phase follows an initial license agreement, signed in 2016, granting NB Power the rights to develop, manufacture, use, and sell hydrogen and hydrogen generation systems for large and small electric utility applications using Joi Scientific's "Hydrogen 2.0" technology.

[46] NB Power has not budgeted any costs in the test year related to this agreement. Mr. Darren Murphy, Chief Financial Officer and Senior Vice President, Corporate Services at NB Power, testified that there is a possibility that certain development milestones may be achieved in the test year which would, in turn, require NB Power to make additional payments.

[47] In support of all of the above projects, Mr. Murphy testified that NB Power is facing significant challenges. One challenge is the potential that the cost of carbon could grow "to be $80 to $90 million annually without any action being taken." It is in that context

that NB Power asserts that it is taking every opportunity to "mitigate and minimize this carbon impact on the ratepayers of New Brunswick."

[48] Mr. Murphy confirmed that there were no specific policies which determine when investments of this nature are permitted. He testified that while there were "…very specific and defined policies around capital expenditures that cover the majority of investments", strategic investments of this nature did not fall within such policies. In the absence of a specific policy, Mr. Murphy stated that strategic research investments, such as those discussed above, would be reviewed and considered at the senior executive and Board of Directors level.

[49] With respect to these projects, Mr. Knecht expressed the opinion that it becomes problematic to ask ratepayers to fund such research when it is apparent that the proposed rate trajectory must increase for NB Power to meet its legal obligations and achieve a sound financial position. He states that it is not unreasonable for the government to ask NB Power to contribute to the evaluation of the technologies, given NB Power's status as a government entity with specialized expertise. However, given the circumstances which NB Power's ratepayers are facing, he believes that these costs should be funded by government.

[50] The total costs associated with these projects are unknown. Much will depend on whether any of the technologies are actually developed. While Mr. Murphy described a "gating process" which guides NB Power's decision making, uncertainty does exist with respect to the costs and potential benefits of these projects. While alternatives may need to be explored, investments must balance both the need for alternatives and the impact on ratepayers.

[51] In the absence of a clear policy covering strategic investments of this nature, it is difficult for the Board to determine whether these projects meet a minimal threshold of acceptable risk to ratepayers, particularly in challenging financial circumstances.

[52] The only budgeted research funding for the above projects is $250,000 in relation to Maritime Iron. The Board approves that expense. This approval should not be construed as allowing future spending associated with these projects. Any spending on research and innovative projects in future test years will be subject to Board review.

(d) Trends in Operations, Maintenance and Administration

[53] NB Power has indicated in its recent filings that some large components of earnings are outside the control of management and can result in significant variances between approved revenue requirements and actual results. Fuel and purchased power, for example, is a cost item that is difficult to budget accurately, and can be subject to significant variability each year.

[54] One area where NB Power can generally control costs, however, is OM&A. During cross-examination, Mr. Jonathan Dobson, Director, Financial Risk & Treasury Management at NB Power, confirmed that these costs are forecasted to increase by over 20 percent in the four years ending in 2022.

[55] Each year, NB Power calculates its OM&A costs per megawatt-hour (MWh), which provides some insight as to how these costs are being managed. In 2017/18, the actual cost per MWh was $28.66. This cost is forecasted to increase to $31.25 for 2018/19 and to $33.39 for 2019/20.

[56] This trend illustrates the Board's concern about rising OM&A expenses. While there are particular issues and projects that impact the result in any given year, this trend cannot continue, given NB Power's current financial position. Cost control is critical if NB Power is to achieve its equity target and provide rates that reflect the lowest cost of service to consumers in the Province.

2. Proposed Regulatory Deferral Account for DSM Expenses

[57] NB Power seeks an Order approving the creation of a deferral account for its DSM expenses.

[58] DSM is aimed at deferring or eliminating fuel and energy purchase costs and future generation capacity costs. DSM spending has historically been expensed in-year by NB Power as OM&A. The Utility submits that it would now be appropriate to capitalize and amortize DSM expenses through the use of a deferral account.

[59] Under current International Financial Reporting Standards, new regulatory deferral accounts require the approval of the regulatory authority. DSM expenses therefore do not qualify to be capitalized without Board approval.

[60] NB Power submitted the report of Dunsky Energy Consulting, which provided three reasons as to why it would be appropriate to capitalize DSM costs: (a) it better aligns ratepayer costs with benefits; (b) it allows for smoothing of ratepayer costs as expenditures are ramped up; and (c) it is a common practice amongst peer Canadian utilities.

[61] NB Power's proposal includes the following specifics:

1. DSM costs incurred in one year would begin to be recovered in the following year, using an amortization period of 10 years on a straight-line basis;

2. No carrying costs will be applied to the deferral account;

3. Expenditures with a short benefit period and certain marketing and training costs will be expensed annually; and

4. Any outside funding of costs would be netted against costs that would otherwise be deferred.

[62] NB Power also provided a 25-year projection of proposed DSM spending, detailing the amounts to be amortized. In the next ten years, for example, DSM spending is estimated at $327 million, while payments from customers would total $122 million. At the end of year 10, a regulatory balance of over $200 million would exist and by year 25, the ending balance would be in excess of $293 million. This would be recorded as an asset by NB Power, to be recovered from future customers. Under cross-examination, Mr. Dobson confirmed that this balance does not reflect any carrying charges, which would be financed through debt.

[63] At the outset of Mr. Knecht's written evidence on this issue, he states that the proposed deferral of DSM expenses would have "no real impact on the basic financing of the utility" as the cash expenditures are the same, regardless of its accounting recognition.

Such expenditures "must be met by either revenues or more borrowing." He points out that a deferral of DSM expenses would, however, result in:

> … the appearance of an improvement in the Company's financial position, since both income and book equity increase, which serves to improve the equity to capital ratio. To the extent that this improved equity to capital ratio results in a reduction in revenue or a mitigation of rate increases, the Company will be financially worse off if this change is adopted.

[64] Later in his written evidence, Mr. Knecht states that although NB Power's rationale has significant merit, there are four reasons why the proposal "should not necessarily" be approved.

[65] First, he suggests that the matching principle is not a particularly strong argument to use in support of this proposal. By their nature, NB Power's DSM programs are inconsistent with the matching principle, "since the benefits flow (almost entirely) to participating customers, while costs are borne (almost entirely) by non-participating customers."

[66] Second, the programs offered by NB Power are economically similar to U.S. DSM programs, where DSM costs are expensed. Given the close parallels between utility ratemaking in Canada and the U.S., there is at least some credible precedent for retaining the existing method.

[67] Third, at least some portion of the expenditures for DSM program is associated with items that would generally not be capitalized, such as light bulbs and smaller lighting systems. It would be inconsistent, in his view, to capitalize such costs incurred in a DSM program if they would otherwise be expensed.

[68] Finally, allowing these expenses to be capitalized has the appearance of a systematic bias in favour of deferring the recognition of costs and shifting costs to future ratepayers.

[69] In conclusion, Mr. Knecht stated that "…neither approach is clearly superior, and that either approach is reasonable." In his judgment, he generally favoured continuing the existing practice of expensing, at least until a more systematic review of all capitalization and amortization issues can be undertaken.

[70] Most interveners commented on the proposed deferral of DSM costs and they neither fully supported nor opposed that proposal.

[71] Mr. Stewart stated that he understood the proposal but was concerned with the end result. He submitted that a deferral account has potential consequences, that is, the carrying of a large debt, which then begins to affect the operational capabilities of a utility in this province. He also submitted that if the Board was inclined to accept NB Power's recommendation, it was essential that the Board set out very specific parameters surrounding the operation and the progress of the deferral account. In his view, "…accepting such proposal will have ramifications immediately for the next decade and certainly year over year decades to come."

[72] Mr. Scott Stoll, counsel for the Utilities Municipal, stated that his clients understood the accounting difficulties presented by NB Power, and that the proposal was "not unreasonable in the circumstances." His clients were concerned that carrying costs were not reflected in the deferred amounts. He also stated that the amortized amounts will be in excess of over $200 million for approximately 15 of the next 25 years. In his view, those amounts should be tracked and accounted for in the deferral account. He submitted that not tracking the interest or carrying costs would depart further from the principle of cost causality and exacerbate the revenue to cost ratio problems that have been experienced.

[73] In her closing argument the Public Intervener, Ms. Heather Black, stated that either approach, whether to establish a DSM deferral account or not, can be in the public interest. She stated that if the Board approves the deferral account, then it may increase the burden on future ratepayers. She was unable to express a preference because, in her view, it depends on other elements of the decision in this matter, and in prior and future proceedings.

[74] Having considered the evidence, the Board is not satisfied that the creation of the proposed DSM deferral account is in the public interest, for the reasons set out below.

[75] As the Public Intervener pointed out, approving the deferral may increase the burden on future ratepayers. In this proceeding, there is no other element that would alleviate that burden.

[76] The proposed deferral account, if it was to be approved by the Board, would also need to include any associated carrying costs. These costs would aggregate over time and would represent a significant liability that would be shifted to future ratepayers.

[77] In the absence of other factors that would mitigate NB Power's annual revenue requirements in future years, the ongoing accumulation of deferred DSM costs and associated carrying costs would eventually need to be recovered through rates. While deferral might achieve some degree of rate smoothing in the short term, the recovery of such deferred costs in the long term would require higher rates than would otherwise be the case. As stated by Mr. Dunsky in his report:

> While rate smoothing will occur in the near term, over time the amortized costs can accumulate, resulting in higher nominal costs to ratepayers than DSM expenses in a given year.

[78] Continuing to recognize and recover annual DSM costs in-year, as has been the case in past years, would of course be reflected in annual revenue requirements, and therefore in annual customer rates. It would also be reflected in there being no increase in the debt burden.

[79] The proposed accounting change to defer recovery of DSM costs would postpone the necessary recovery of those costs, and would include the carrying costs that would not otherwise be incurred. Given NB Power's financial position, the Board does not consider this to be prudent.

[80] The fact that some provincial regulators in Canada have permitted regulatory deferral accounts for DSM spending is not seen by the Board as a persuasive reason. Although the establishment of such accounts may accomplish certain objectives in those jurisdictions, NB Power has its own unique set of circumstances, which the Board must consider.

[81] Accordingly, the Board rejects the proposal to establish a DSM deferral account.

3. Cost Allocation

[82] NB Power utilizes an embedded Class Cost Allocation Study (CCAS) methodology which allocates the total cost of providing service among rate classes and compares allocated costs to the revenue generated by each customer class. The result is expressed as a revenue-to-cost ratio (RCR) for each rate class and is used as the basis for rate adjustments.

[83] NB Power's current CCAS methodology was approved in Matter 271 and modified in subsequent general rate applications. In this filing, NB Power requested two methodological changes to the CCAS.

[84] One of the changes is related to the proposed DSM regulatory deferral. As indicated above, the Board does not approve the creation of the deferral account and as a result, the CCAS will not require modification in relation to this item.

[85] The second modification relates to a directive that had been provided to NB Power in Matter 375. At that time, the Board had considered the low-income, energy efficiency programs and determined that the revenues received from the Province of New Brunswick in relation to these programs were not being allocated properly. The Board stated at paragraph 197 of its decision:

> The Board agrees that the revenues received from the Province for low-income programs are not allocated appropriately. The Board finds that the most appropriate allocation is solely to the residential class. NB Power is therefore directed to make this adjustment to the CCAS model.

[86] NB Power submits that this adjustment has been made to the CCAS model and now proposes to assign all costs associated with these low-income energy efficiency programs to the residential class. This would, in effect, address a mismatch between program costs and revenues. The Board approves this adjustment to the methodology.

[87] Three other issues, in relation to the CCAS, will be addressed below.

a. Miscellaneous Revenue: Joint Use Pole Revenues

[88] In this proceeding, NB Power shows a material increase in joint use pole revenues over the previous test year. In rebuttal evidence, Mr. Todd explains the issue as follows:

> Joint use revenue ($7,049,929) - NB Power has a joint use agreement with a third party. The agreement recognizes the interdependencies between the two companies and provides for maximum economic advantages to both companies by sharing assets. The agreement is based on NB Power maintaining an ownership of 57% of the poles and the third party maintaining an ownership of 43% of the poles. The new revenue standard (IFRS 15) would have NB Power records a miscellaneous revenue for what

is owed to NB Power and an OM&A cost for what is owed to the third party. The two transactions offset on NB Power's books.

[89] In his review, Mr. Knecht noted that revenue from the joint use agreement is allocated to the customer classes proportional to the classes' shares of total utility costs. However, the costs are allocated based only on the shares of distribution costs. As a result, Mr. Knecht recommends that both costs and revenues for all miscellaneous revenues be allocated based on distribution costs.

[90] Mr. Todd, under cross-examination, agreed that allocating revenues and costs on this basis would be correct and would not be onerous.

[91] NB Power is ordered to allocate costs and revenues from those services related to miscellaneous revenues based on total distribution costs.

b. Market-Based Revenues: Water Heaters, Street Lights and Unmetered

[92] A second CCAS issue relates to market-based revenues.

[93] In the CCAS model, water heaters, street lights and unmetered services are treated as a "market-based" rate class. Currently, those services generate revenue in excess of costs. The issue is how to treat these revenues.

[94] Mr. Knecht submits that revenues in excess of allocated costs for water heaters and street lighting should be re-assigned to all of the other classes, in proportion to overall allocated costs. He prepared a summary table demonstrating his preferred approach and its impact to the overall allocated costs.

[95] In rebuttal testimony, Mr. Todd states that this issue is better dealt with as part of the rate design process that is ongoing with the Board. He believes that there are a number of options that exist with respect to the treatment of these revenues, and it is premature to adjust the CCAS at this time.

[96] Having considered the evidence of the Public Intervener and NB Power, the Board is satisfied that assigning these excess revenues proportionately to all other rate classes is appropriate. Certainly the rate design process may allow parties to explore new and other

alternatives, but until such time as Matter 357 is concluded, NB Power is directed to make this change.

[97] The Board orders NB Power to allocate excess revenue from the water heaters, street lights and unmetered classes to the remaining classes in proportion to overall allocated costs.

c. Load Data and Load Research

[98] The final issue relates to load data. Mr. Knecht aptly points out that the CCAS generally relies on two basic foundations, methodology and data. In this case, several interveners questioned the load data, particularly as it relates to the unmetered or distribution level rate classes.

[99] Mr. Todd, in his testimony, agreed that the load research used in the CCAS for unmetered distribution classes is "getting a little bit stale." The previous load research program has not been kept up to date and the data that is being used in the CCAS dates back to 2015/16. When this data is then applied in the CCAS, and in particular when using the 3 Coincident Peak demand (3CP) allocator, the result is "unusual".

[100] Mr. Todd does not advocate changing the methodology used in the CCAS, but states that the result may be an indicator that, in the future, NB Power should do more load research or look more closely at the drivers behind the coincident peak load factors. He suggests that it may be appropriate to "reinvigorate the load research program" which would improve the quality of the data that is being used in load forecasting and cost allocation.

[101] Mr. Knecht expressed serious concern about the use of this "stale" data. He summarized the issue as follows:

> Unfortunately, with respect to the data underlying some of the Company's key allocation factors, NB Power's CCAS is built on a foundation of sand. All cost allocation studies rely heavily on class forecasts of energy consumption and peak demands. Unfortunately, for distribution rate classes where interval metering is not available, the Company's peak demand estimates are only weakly supported. The Company's method for developing 1CP, 3CP and NCP allocators for distribution voltage classes rests substantially on some limited load research from FY 2015 and FY 2016, and rough relative load factors for the other rate classes based on historical practice.

[102] In Mr. Knecht's view, the stale data, combined with a load forecasting methodological change, create anomalous CCAS results and suggest that costs are over-allocated to the residential class. This calls into question the reliability of the CCAS results.

[103] The load data for the distribution classes is stale and should be refreshed. The Board directs NB Power to provide a detailed proposal as soon as practicable on how the load research program can be reinvigorated.

4. Differential Rates

[104] NB Power has requested that the Board approve an average two and one half per cent (2.50%) increase in rates and differential rate increases across rate categories.

[105] In particular, an average rate increase would be applied to all classes, with the exception of the Residential class, which would see a rate increase of 2.90%, with the General Service I, General Service II and Small Industrial classes receiving a rate increase of 1.70%. NB Power submits that differential rate increases are in keeping with recent efforts to move all rate classes to within a range of reasonableness of 0.95 to 1.05.

[106] The Board agrees that moving rate classes within a range of reasonableness is an appropriate objective. In recent proceedings, the Board has approved differential rates, given the information and evidence that was presented at that time. In this proceeding however, a combination of factors, when taken together, raise doubt as to whether differential rates will accomplish this objective.

[107] Changes to the treatment of both miscellaneous and market-based revenues, made earlier in this decision, would move the residential class closer to the range of reasonableness. This calls into question whether this rate class requires a higher than average rate increase. Given the stale load data currently being used as discussed above, the Board lacks confidence in the precision of the currently calculated RCRs.

[108] Finally, applying differential rates has not, to date, resulted in a resolution to the RCR issue. Both Mr. Todd and Mr. Stephen Russell, Senior Advisor, Regulatory and Rates at NB Power, acknowledge that there are several factors influencing the RCRs. As long as these factors continue to have an impact, there may be no realistic expectation that differential rate increases will move class RCRs to within a range of reasonableness.

[109] Considering the above, the Board is not satisfied that ordering differential rate increases in the current proceeding will result in bringing more customer classes closer to the range of reasonableness.

[110] The Board therefore concludes that approving a uniform rate increase is appropriate for this proceeding and will result in just and reasonable rates. As a result, all customer classes will receive the average rate increase for the test year.

5. Other Issues

a. Late Filing

[111] At the beginning of the hearing, and again during closing arguments, the Board advised NB Power that it was concerned with the delay in the filing of the annual rate applications. This current application was filed in January, which did not provide sufficient time to conduct all of the pre-hearing processes and for a decision to be issued by the Board before April 1.

[112] Mr. Knecht, in his evidence, states that late filings have contributed modestly to lower net income for the Utility. He estimates that year-end retained earnings would be almost $20 million higher at year-end 2019 if the rate increases had all been applied by April 1 of each year. In this test year, given the late filing of this Application, the impact is estimated to be in the range of $ 7.7 million.

[113] The Act requires NB Power to apply for approval of its schedules of rates for each fiscal year. To allow sufficient time for interveners to review the application and prepare for the hearing, the annual application must be filed in a timely fashion.

[114] As a result, NB Power is directed to file its annual rate application no later than the first Wednesday of October, each and every year. This should give sufficient time for the Board to hold a hearing in early February. It is anticipated that this fixed schedule will assist all parties in planning for the annual rate application and result in rates being approved in a timely fashion.

b. Confidentiality

[115] The Board is also concerned with the volume of materials that have been filed in this proceeding for which confidentiality has been claimed.

[116] In all matters before the Board, it is important that the public is able to review the evidence and information that has been filed. Transparency is critical to the process. The Board's *Rules of Procedure* (Rules) provide guidance on this issue and documents should not be marked confidential if, in fact, there are no grounds for such a claim.

[117] In this case, voluminous amounts of information were filed either as confidential or restricted, which limited the ability of the public and some interveners to consider the evidence. In addition, moving "confidential" documents to a new "confidential restricted" category, further limited access to the evidence.

[118] Although the Rules allow parties to challenge claims for confidentiality, the sheer volume of claims in this proceeding made it challenging to do so in a timely fashion. NB Power should carefully review documents for which they claim confidentiality to ensure that all information that should be public is placed on the public record.

c. Commitments by NB Power

[119] As stated above, NB Power has committed to reviewing the 30-year heating degree day average to determine whether 20 years, or some other period, is more appropriate.

[120] NB Power made two additional commitments during closing arguments, both of which relate to the Integrated Resource Plan (IRP). The Act requires NB Power to prepare an IRP at least once every three years and it is anticipated that the next IRP will be prepared in 2020.

[121] As a result of issues raised by interveners, NB Power committed, as part of its supply and demand side analysis, to evaluate the potential life extension of the Bayside Power Generating Station to 2036. In addition, the IRP will review and consider the impacts of "carbon and/or coal legislation", including any updates that exist at the time the IRP is conducted.

[122] The Board directs NB Power to file the results of these reviews and evaluations as they become available.

E. Approval of Rates

[123] NB Power proposed an average rate increase of 2.50% and differential rate increases for various rate classes. As indicated earlier, the Board does not approve the differential increases in this Application.

[124] Taking into consideration the disallowance for marketing costs at $0.3 million, the Board approves revenue requirements in the amount of $1,742 million.

[125] With these changes, NB Power is directed to provide the Board, for review, its calculation of a revised average rate increase for all customer classes, as well as its revised proposed schedules of rates.

[126] Subject to its review and validation of the information provided by NB Power, the Board will approve the revised schedules of rates and set the time at which the rates are to take effect.

Dated in Saint John, New Brunswick, this 16th day of July, 2019.

Raymond Gorman, Q.C.
Chairperson

François Beaulieu
Vice-Chairperson

Michael Costello
Member

Patrick Ervin
Member

DISSENTING OPINION OF MEMBER HERRON

I concur with the majority decision of the Board and with the reasons offered above, with the following exception.

- I am of the opinion that the creation of the proposed DSM Regulatory Deferral Account is the approach most in the public interest and represents the best regulatory practice for the benefit both ratepayers and NB Power. My reasons are set out below.

A. Proposed DSM Regulatory Deferral Account

[1] NB Power's request to defer and amortize specific Demand Side Management (DSM) costs through the creation of a regulatory account is consistent with the practice of other Canadian utilities, to better align the recovery of these investments with the benefit periods.

[2] NB Power's DSM programming include both energy efficiency and Demand Response expenditures that are incurred by utilities to reduce future fuel and purchased power costs and the deferral of future spending in generating capacity.

[3] Given that the majority of the financial benefits from such investments occur in the future, a mismatch occurs under NB Power's current accounting practice in the timing of when expenditures are included in the revenue requirement and when the benefits are being received by the company. NB Power states that as spending becomes more significant overtime the mismatch in timing of such investments and when the benefits are received will continue to expand overtime.

[4] NB Power conducted a review to assess if a change in current accounting practices is warranted for its DSM spending. The review focused on assessing the practices employed by peer Canadian utilities and found that other Canadian utilities are making similar investments and deferring/ amortizing such costs through a regulatory deferral account to better align recovery of the expenditures with the benefit periods of the investments.

[5] In its application to the Board, NB Power requests that the Board approve the establishment of a regulatory deferral account for specific DSM expenditures as such

investments do not qualify under current International Financial Reporting Standards (IFRS), absent of the approval of the Board to apply such regulatory accounting.

[6] NB Power's specific accounting recommendations related to the capitalization and amortization of its DSM expenditures are outlined in their evidence in NBP 9.01 as follows:

- Costs deferred in one year begin to be collected in the year subsequent to the expenditure on a straight-line basis
- No carrying costs to be applied to the regulatory account
- Expenditures with a short benefit period and certain marketing and training costs to continue to be expensed annually, as incurred
- Any funds received by government or from other outside sources to be netted against any costs that would otherwise be included in the deferral account
- An amortization period of 10 years to be utilized for cost recovery purposes

B. Evidence of the Expert Witnesses – Dunsky and Knecht

[7] Two reports were filed in evidence with the Board that provide observations and recommendations related to accounting for NB Power's DSM expenditures and the proposed DSM regulatory deferral account.

1. The Dunsky Report

[8] The rationale for the proposed specific recommendations as well as the appropriateness and reasonableness of proceeding with the regulatory deferral account was assessed by Mr. Philippe Dunsky, President of Dunsky Energy Consulting (the Dunsky Report, ex. NBP 1.78) Mr. Dunsky testified at the hearing and was declared as an expert in demand-side management strategies and regulation.

[9] NB Power engaged Dunsky Energy Consulting to review the fundamental principles behind DSM cost capitalization, review the practices of other Canadian crown corporations, and advise on an appropriate amortization period.

[10] The Dunsky Report included details on the role that DSM spending plays in different jurisdictions. It states that both Energy Efficiency and Demand Response are commonly recognized as energy and capacity resources which play a complementary role to supply side (generation) options. The report identifies over 26 U.S. states where utilities apply binding energy efficiency resource standards to procure a percentage of their future electric needs using energy efficiency measures. In addition, the Dunsky Report offered the example of ISO New England's Forward Capacity Market where DSM resources can bid into auction energy capacity.

[11] The Dunsky Report states that DSM investments provide value over the lifetime of the installed measures similar to how utility assets such as power plants and transmission and distribution infrastructure provide value over the lifetime of such assets. The Report states that by treating DSM investments as a utility asset allows for different cost recovery practices.

[12] The Dunsky Report concludes that it is appropriate to integrate the capitalization of DSM costs into a utility's cost recovery practice citing three primary observations.

1. It leads to a better alignment over time of ratepayer costs with benefits;

2. It allows for a smoothing of ratepayer costs as expenditures are ramped up; and

3. It is a common practice amongst peer Canadian utilities.

Better Alignment of Costs and Benefits

[13] The Dunsky Report states that the key reason NB Power should treat its DSM investments as a capital asset is to ensure consistent treatment between supply and demand options that lead to better alignment of customer costs with system benefits over time. The Report explains that given the expected useful life (EUL) of certain DSM measures that maintain benefits lasting for significant periods of time leads to a disconnect between when the investments occur and when the benefits are accrued. Deferring the timing of when the investment is carried by the ratepayer allows for better alignment of costs and benefits.

DSM Amortization Period

[14] The Dunsky Report states that the minimum average EUL for NB Power's portfolio of DSM measures is estimated to be 13 years, concluding that NB Power's proposal of a 10-year amortization period would represent a conservative approach in line with the practices at other Canadian crown corporations.

Capitalizing DSM costs allows for a smoothing of rate payer costs

[15] The Dunsky Report identifies that the amortization of DSM investments defer the collection of the costs help to tamper rate impacts of near term rate pressures that arise from:

- Significant new investments in DSM;
- Other rate pressures such as new capacity requirements; or
- Rate freezes that limit new investments.

Capitalizing DSM Cost is a common practice amongst peer Canadian Utilities

[16] The Dunsky Report finds that capitalizing DSM costs is a common practice amongst its peer Canadian utilities. To provide a better comparison to NB Power, the examination focused on four electric utilities that were also Crown corporations.

[17] The Dunsky Report concluded that in Canada:

- There is a long history of DSM cost recovery (> 10 years);
- The rate case is a preferred cost recovery mechanism; and
- Most DSM costs are typically treated as a regulated asset and amortized in a deferred account; however, some costs may be considered operating expenses.

[18] Table 2 from the Dunsky Report provides an overview of the treatment of DSM investments for all the examined utilities:

Source: Table 2 NBP 1.78 Dunsky Report P.7

Utility	Energy Type	DSM Treatment	Amortization
BC Hydro	Electric	Capital Asset & Operating Expense	15 years
Manitoba Hydro	Electric & Natural Gas	Capital Asset & Operating Expense	10 years
Hydro Quebec	Electric	Capital Asset & Operating Expense	10 years
NFLD & Labrador Hydro	Electric	Capital Asset & Operating Expense	7 years

[19] The Dunsky Report also provides a detailed analysis for the amortized treatment of DSM expenditures for each of these utilities.

[20] Although the Dunsky Report identified numerous U.S. states who have adopted DSM measures as part of their energy and capacity resources, it outlined the differences between the treatment of such expenses in the U.S. versus utilities in Canada, as follows:

- Many states use multiple cost recovery mechanisms (Canada = no provinces with multiple);
- The preferred cost recovery mechanism is a tariff rider (Canada = rate case); and
- When rate cases are used, DSM costs are primarily treated as operating expenses (Canada = capital assets).

[21] The Dunsky Report concludes that should NB Power capitalize its DSM spending; it should align the treatment of DSM investments with the treatment of other tangible utility assets for costs that create multi-year benefits.

[22] The Dunsky Report also concludes that 13 years should be considered a maximum amortization period for the current portfolio-wide DSM budget.

2. The Knecht Report

[23] The Public Intervener presented the evidence of Mr. Robert Knecht (the Knecht Report, ex. PI 1.01), Principal of Industrial Economics, Incorporated who was qualified as an expert in the areas of regulatory economics and rate making. The Public Intervener requested that Mr. Knecht review NB Power's general rate application to evaluate

whether the company's proposals in eight specific areas were reasonable. One of the areas within this scope of work included the proposed changes to NB Power's DSM plan, including the proposed Regulatory Deferral Account.

[24] Mr. Knecht's full analysis is found at section 6.3 of his report on pages 32-34.

[25] The Knecht Report's conclusion on the issue of whether the Board should approve the Regulatory Deferral Account as proposed by NB Power for its DSM expenditures versus maintaining the status quo of expensing such expenditures (in-year) is found at line 17-22 of page 34 of the Knecht Report.

> At the end of the day, focusing only on this specific issue, I conclude that neither approach is clearly superior, and that either approach is reasonable. As a matter of judgement, I generally favor continuing the existing practice, at least until a more systematic review of all capitalization/amortization issues can be undertaken (most specifically with respect to the reasonable lifetime of major generating assets).

[26] The Knecht Report states at line 17 of page 32, that the proposed change has no real impact on the basic financing of the utility. The report states that the changing in accounting results in the appearance of an improved financial position that results in an improved equity to capital ratio. The report also states that the "improved equity to capital ratio results in a reduction in revenue or a mitigation of rate increases, the Company will be financially worse off if this change is adopted" as the company proposes to capitalize $14.1 million of its DSM expenditures with no amortization for the test year. The report calculates that net income improves by $14.1 million, if the change is adopted as the test revenue would be $17.8 million rather than the $31.9 million without the change as NB Power proposed to amortize $14.1 million in the test year. [1]

The Knecht Report conclusions – "Review and Observations" on the issue are as follows:

[27] The report states that "The Company's rationale has significant merit." It also cites four reasons why the proposal "should not be necessarily be accepted".

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[1] In a letter dated May 15th, NB Power advised the Board that, in accordance with an interrogatory (IR) response that had been provided to the Public Intervener, NB Power was now seeking revenue requirements of $1,742.30 million. The test year net earnings had been revised, which resulted in an increased amount of $1.9 million being attributed.

1. The company is correct that amortizing costs overtime would better align when costs are recognized on the company's books with when benefits are recognized by participating customers. However, conceptually, the matching principle is not a particularly strong argument to use in support of this proposal. By their nature, NB Power's DSM programs are inconsistent with the matching principle, since the benefits flow (almost entirely) to participating customers, while costs are borne (almost entirely) by non-participating customers.

2. While Canadian utilities generally capitalize these expenditures, U.S. utilities do not. The programs offered by NB Power are economically similar to U.S. DSM programs, where costs are expensed. Given the close parallels between utility ratemaking in Canada and the US, there is at least some credible precedent for retaining the existing method.

3. At least some portion of the expenditures for DSM program is associated with items that would generally not be capitalized.

4. Finally, allowing these expenses to be capitalized has the appearance of a systematic bias in favor of deferring the recognition of costs and shifting costs to future ratepayers.

C. Positions of the parties on the establishment of the Regulatory Deferral Account to allow NB Power to amortize certain DSM expenditures

[28] In addition to the applicant, four interveners addressed the issue of the proposed DSM Deferral Account in their final arguments. A summary of each of the parties' arguments can be found below, including Transcript references.

[29] It is noteworthy that upon review of the Transcript, no intervener opposed NB Power's proposal to amortize DSM expenditures.

1. Mr. Furey on behalf of NB Power

[30] Mr. Furey's comments on behalf of NB Power on the DSM deferral in final argument can found at line 8 on page 849 through to line 22 of page 852 of the Transcript.

[31] Mr. Furey set out three reasons for the deferral/amortization of DSM expenditures as outlined in the Dunsky Report (ex. NBP 1.78 page 3).

1. Better matching of the associated benefits in terms of lower fuel and purchased power expenses and the deferral of capacity investments with the recognition of DSM expenditures.

2. Consistency with the approach taken by Canadian peer utilities and their regulators.

3. It allows for smoothing of ratepayer costs as expenditures are ramped up.

- Mr. Furey pointed out that Mr. Knecht did not take issue with the proposed amortization period nor the effectiveness of the EUL of NB Power's DSM programs as they are developed in accordance with industry standards.

- Mr. Furey argued since DSM programming has been mandated by the *Electricity Act* in subsection 117(1) and that programs are evaluated using the Program Administrator Cost Test (PACT) the DSM deferral account proposed by the company is not about the cost effectiveness of DSM programs it is about matching the recognition of DSM expenditures with the receipt of DSM benefits in reduced spending of fuel and purchased power and the deferral of capacity investments, which improves intergenerational equity and is consistent with the regulator approach of Canadian peer utilities.

- Mr. Furey pointed out that if the Board were to disallow the DSM regulatory deferral account in its entirety, net income would be reduced by $14.1 million.

- Mr. Furey also referred to concerns expressed by Mr. Knecht in Matter 375 and in testimony in this hearing where Mr. Knecht expressed concern that DSM programs put upward pressure on near term rates when expensed in the year they are incurred, while the benefits are received over a longer period of time. Mr. Furey stated that the DSM deferral account proposed is a solution to the problem.

- Mr. Furey also defended the company's rational for not including interest costs in the deferral as it is consistent with the accounting of other fixed assets, and it is

consistent with the approach of other Canadian utilities who also do not include such carrying costs in their respective regulatory deferral accounts.

- Mr. Furey also responded to a set of questions from the Panel which can be found from line 10 on page 855 to line 18 on page 867 of the Transcript.

2. Mr. Stewart on behalf of J.D. Irving, Limited

[32] Mr. Stewart's comments in his final argument on the DSM deferral account can be found at line 18 on page 875 through to line 9 of page 880 and again from line 22 of page 898 through to line 7 of page 902 of the Transcript.

- Mr. Stewart stated that he would leave the decision to the Board on whether to put into place the deferral account or not. He submitted though that it is essential to ensure that the parameters for DSM spending are well-defined, legitimized and that the process for the annual review is clear.

- However, in response to a question from the Panel on whether he was "for or against" the establishment of the regulatory deferral account, Mr. Stewart referenced Mr. Knecht's description that the approach was "not unreasonable". He further stated that he understood why the Utility was taking this approach for the accounting of its DSM expenditures and that he "did not think it to be wholly unreasonable" (Transcript line 21 page 901-line 7 page 902).

- Mr. Stewart emphasized the need to establish specific parameters on the operation and progress of the proposed deferral account. He urged the Board to put into place directions for a public process to annually track and review expenditures that are proposed to be added to the deferral account to ensure they provide multi-year benefits and measure the effectiveness of the programs that are already in place. Mr. Stewart raised the importance of such oversight given the consequences of carrying a large debt.

3. Mr. Stoll on behalf of Utilities Municipal (UM)

[33] Mr. Stoll's comments in his final argument on the DSM deferral account can found at line 22 on page 909 through to line 24 of page 911 of the Transcript.

- Mr. Stoll stated that UM understood the accounting difficulties presented by the company and its expert witness, and found that the company's proposal is "not unreasonable in the circumstances" (line 22 page 909- line 3 page 910).

- He stated that in his clients' view, carrying costs should be tracked and accounted for in the deferral account.

- Mr. Stoll referenced that NB Power's witness, Mr. John Todd testified that he recommended that carrying costs be included in the deferral account and that, with the program costs, be tracked and allocated to the appropriate rate class. Mr. Stoll submitted that in UM's view that not tracking the interest or carrying costs within the deferral account would depart from the principle of cost causality and potentially exacerbate existing customer class revenue to cost ratios.

4. Ms. Black, The Public Intervener

[34] Ms. Black's comments in her final argument on the DSM deferral account can be found at line 13 of page 941 through to line 8 of page 943 and line 6 of page 955 to line 24 of page 964 of the Transcript.

- Ms. Black stated that her view was that it is in the public interest to take either approach with respect to the financial accounting of NB Power's DSM expenditures. In her view she states at lines 14-15 of p. 964 of the Transcript that "based on Mr. Knecht's evidence, it is my view that either solution is in the public interest." Ms. Black cited from page 34 of the Knecht Report where he concluded that "neither approach is clearly superior and either approach is reasonable."

- Although she submitted that Mr. Knecht's preference on maintaining the status quo is largely based on his concern that the deferral account will have the effect of shifting costs to future ratepayers. She stated that there are reasonable grounds for the Board to make either choice, depending on where ultimately the Board

determines that the balance should be set between the Act's requirements for low and stable rates now and low and stable rates in the future.

- Ms. Black acknowledged that an argument can be made that in the case of the proposed deferral account the costs and benefits are intended to match and that costs are not pushed off into the future, but are moved to when the benefits occur. Ms. Black also pointed out Mr. Knecht's concerns that there is not perfect matching of costs and benefits as programming benefits accrue to only participants of DSM programming.

- Ms. Black further cited Mr. Knecht's evidence in response to questions from the Panel that the DSM program effectiveness was reasonable as they are based on industry standards and that the 10-year amortization period for the DSM portfolio was reasonable.

[35] Ms. Black agreed in part with Mr. Stewart that the reporting of the details and progress of the proposed DSM Regulatory Account needs to occur within a public process, but should be part of the GRA process (one of Mr. Stewarts options), opposed to a separate filing. She stated that there was already some "front door" vetting in place in terms of programming and their evaluation. Ms. Black, however, agreed with Mr. Stewart that there were areas that were still unclear such as carrying costs and the deferral of certain DSM marketing activities.

D. Analysis and Findings

[36] After reviewing the evidence and testimony of the parties' submissions and the expert evidence and testimony of Mr. Dunsky and Mr. Knecht, I find that the creation of the proposed DSM Regulatory Deferral Account is the approach most in the public interest and represents the best regulatory practice to benefit both ratepayers and NB Power.

[37] I find that the use of the regulatory financial instrument is the preferred approach for the accounting of NB Power DSM expenditures for the following reasons.

[38] I find that the evidence of the two experts, Mr. Dunsky and Mr. Knecht to be the best available evidence.

[39] I find that the concluding observations by Mr. Knecht's evidence and testimony to be balanced and helpful to the Board in identifying the issues it must consider in the decision to allow the proposed DSM Regulatory Deferral Account versus continuing the existing practice of expensing NB Power expenditures in year.

[40] Mr. Knecht concluded that neither approach is superior and either is reasonable. He, however, also states that he favours the existing practice, at least until a more systemic review of all of NB Power's capital assets are undertaken that will determine the reasonable lifetime of its major generation assets.

[41] I agree with Mr. Knecht that a systemic analysis and understanding of all of NB Power's supply and demand side requirements of the Utility is needed to fully understand the necessary magnitude of NB Power's DSM programming. Mr. Knecht's observation is helpful in that it connects the attributes of both DSM and supply side assets.

[42] Given scale of the NB Power's DSM programming, however, that is outlined in section 8 of the current IRP, (which the Board must consider in this application as per paragraph 103(7)(c) of the *Electricity Act*), as well as in responses to IR-49 and IR-50 of ex. NBP 12.03 and ex. NBP 12.28, the scale of the company's DSM programming warrants the establishment of the proposed DSM Regulatory Deferral Account. Accordingly, I find that it is unnecessary to delay the establishment of the deferral account.

[43] I also agree with the primary observations found in the Dunsky Report that indicate that it is appropriate to capitalize NB Power's DSM costs as listed below:

1. It leads to a better alignment over time of ratepayer costs with benefits;
2. It allows for a smoothing of ratepayer costs as expenditures are ramped up; and
3. It is a common practice amongst peer Canadian utilities.

Better Alignment of Costs and Benefits

[44] I agree with Mr. Dunsky and NB Power that the establishment of the proposed DSM Regulatory Deferral Account will better match benefits associated with lower fuel and purchase power spending and the deferral of future generating capacity investments with the recognition of DSM expenditures. NB Power's DSM programs are evaluated in

advance using industry standards and measured and evaluated after implementation to assess their effectiveness and in terms of their EUL. I agree that accounting for such investments through a deferral account improves intergenerational equity. Although much of the associated costs for the spending of these multi-year programs are paid by future ratepayers, the associated benefits are also realized in future system benefits and future ratepayers' benefits. A table that calculates future costs, benefits as well as the deferral account in terms of Net Present Value is provided in evidence in a response to IR-48 in ex. NBP 12.03.

Smoothing of Ratepayer Costs as Expenditures

[45] I agree with the findings of the Dunsky Report that the amortization of DSM investments allow for the smoothing of ratepayer costs as expenditures are ramped up is another benefit for capitalizing DSM expenditures. I agree with NB Power and Mr. Knecht that DSM programs put upward pressure on near term rates when expensed in the year that they are incurred, while the benefits are received over a longer period of time. I agree that the deferral account is a solution to the problem.

[46] Disallowing the deferral account has the potential to have an onerous impact on ratepayers in the near term through higher rates without receiving the benefits of the spending. The potential for rate shock is greatly mitigated with the smoothing effect of the deferral account. In the response to IR-49 found in ex. NBP 12.03 we learn that the rate increase for the test year would have needed to be 3.5% to cover the costs for the test year for the allowed $14.1 million of DSM spending that the company proposes to amortize. Given the increased level of spending that the company proposes to spend in future years, higher rate increases beyond 3.5% are apt to be required, absent of significant cost reductions in year and/or reductions in its DSM program.

[47] The rate smoothing effect of the deferral account approach also best meets the objectives set out in subsection 68(c) the Act that states that to the extent possible that rates charged shall be maintained as low as possible and changes in rates shall be stable and predictable.

Common Practice Amongst Peer Canadian Utilities

[48] The Dunsky Report states that the capitalization of DSM expenditures is a common practice amongst Canadian utilities. The Dunsky Report's examination of the four peer crown corporations does provide a valuable comparison. The Dunsky Report as well as Mr. Dunsky's testimony (Transcript page 540 - page 583) provides the Board with numerous references that compare the similarities of the four examined utilities with NB Power and their DSM programs.

[49] It is common practice for regulators and courts to rely on the expertise and precedent of peer regulators for such issues. Given the clear trend by all of the examined provincial regulators to establish such accounts for such programming, I find it to be the most reasonable best practice to allow NB Power to establish the proposed deferral account consistent with the approach taken by Canadian peer utilities and their regulators.

Perspective of the Intervenors

[50] It is noteworthy that upon review of the Transcript that no intervenor took a position in opposition of the proposal to allow NB Power to amortize its DSM expenditures. I find that their considered collective comments on the issue, despite expressing specific concerns on the details, aligns with a decision to approve the preferred deferral account.

E. Additional Related Observations

[51] There are a number of specific accounting recommendations and details that are appropriate to address in this decision related to the operationalization of the proposed deferral account. These issues were principally raised as concerns over details by intervenors.

1. I agree with Mr. Stewart and Ms. Black that the reporting of the details and progress of the proposed DSM Regulatory Account needs to occur within a public process annually and should be part of the GRA process.

2. I agree with NB Power and Mr. Dunsky that the proposed Amortization Method and Amortization Period should be 10 years. Mr. Dunsky confirms at lines 1-4 on page 576 of the Transcript that the EUL for NB Power's DSM portfolio is apt to

significantly go beyond 10 years particularly with NB Power having chosen to exclude related components as depicted in their proposal.

3. I agree with NB Power's proposal that no carrying costs be applied to the regulatory account. I agree that this recommendation can be seen as a conservative approach as it reduces the amount of costs being deferred in the account. It also follows Mr. Dunsky's recommendation that aligns DSM investments with the accounting treatment of other fixed assets such as generation and transmission assets. This practice is also used by other utilities identified with the exception of one.

[52] Although I prefer the proposed approach of NB Power, I note that Mr. Stoll, however submitted that in UM's view that not tracking the interest or carrying costs within the deferral account would depart from the principle of cost causality and potentially exacerbate existing customer class revenue to cost ratios. I find that it would be appropriate to consider this issue and potential change to NB Power's proposal as a part Rate Design and Matter 357.

F. Conclusions & Recommendations

[53] I find that the creation of the proposed DSM Regulatory Deferral Account is the approach that is most in the public interest and represents the best regulatory practice that is taken by Canadian peer utilities and their regulators.

[54] I note that the impact of disallowing the deferral account in its entirety has a significant impact on the company's proposed net earnings. The effect of disallowing the deferral account has the effect of reducing the proposed net earnings by $14.1 million.

[55] NB Power states that the deferral account is an integrated part of NB Power's revenue requirement and that a complete review of all costs would be required to determine the impact of not approving the DSM Deferral Account. It is my opinion based on the company's DSM plan outlined in the 10-year plan, the IRP and in responses to IR-49 and IR-50 of ex. NBP 12.03 and NBP 12.28 that the company's ability to fund its DSM program will be greatly impacted without the proposed deferral account.

[56] Disallowing the deferral account has the potential to have an onerous impact on ratepayers in the near term through higher rates if NB Power is required to fund its full DSM Program in-year. With this approach, ratepayers in the near term will be tasked with funding certain measures that will only benefit ratepayers in the future. The matching of ratepayer and system costs with ratepayer and system benefits is a primary rationale for the DSM deferral.

Dated in Saint John, New Brunswick, this 16th day of July, 2019.

John Patrick Herron
Member