Manitoba Hydro 2023/24 & 2024/25
General Rate Application

Consumers Coalition Aid to Cross Examination

Exhibit CC-28

Tab	Reference
1.	PUB Order 43/13 at 4-5
2.	Excerpt from MIPUG-15 (Manitoba Hydro 2017/18 & 2018/19 General Rate Application)
3.	Excerpt from MIPUG-13 (Manitoba Hydro 2017/18 & 2018/19 General Rate Application)
4.	Excerpt from Lazar, J., Chernick, P., Marcus, W., Lebel, M. (Ed.) “Electric Cost Allocation for a New Era: A Manual” (2020), available online: https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf

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2.0.0 IT IS ORDERED:

1. That the 1% rate deferral and associated revenues, which formed part of interim rates granted in Order 30/11 and 40/11 to be included in Manitoba Hydro's revenue and base rates effective April, 2012 **BE AND IS HEREBY APPROVED AS FINAL**.

2. That the interim rate increases of 2% granted April 1, 2012 and 2.4% granted September 1, 2012 **BE AND ARE HEREBY APPROVED AS FINAL**.

3. That a 3.5 % overall increase in billed rates for the basic monthly charge, the demand charge, and the energy charge for all rate categories to take effect May 1, 2013, with revenues from a 1.5% portion of the rate increase accruing in a deferral account to be utilized to mitigate the required rate increases when Bipole III is placed in-service, **BE AND IS HEREBY APPROVED**.

4. That Manitoba Hydro recalculate and refile, for Board approval, a schedule of rates reflecting a 3.5% increase to the basic monthly charge, demand charge and energy charge across all consumer classes, effective May 1, 2013, together with all supporting schedules including proof of revenue and customer impacts.

5. That Manitoba Hydro file with the Board, as part of any future interim application for rate increases, the following information on a monthly basis for the previous three months, and on an on-going basis until a rate Order in respect of the Application is issued:

   (a) Hydraulic generation monthly data (GWh) for the Winnipeg River System, Grand Rapids, Upper Nelson River Generating Station(s), Lower Nelson River Generating Station(s), and Wuskwatim Generating Station;

   (b) Monthly adjusted system energy-in-storage curves and Lake Winnipeg water levels;

   (c) Average monthly flow data for the Winnipeg River, Saskatchewan River, and Upper Nelson River (Kelsey Generating Station) and Lower Nelson River (Kettle Generating Station);

   (d) Monthly extra-provincial energy exchange data (volumes and prices) for National Energy Board-filed sales and purchases (by permit / license number), Midwest Independent System Operator day-ahead and real-time sales and purchases, and Canadian sales and purchases; and

   (e) Monthly updates to Manitoba Hydro's financial results relative to its forecast.

6. That Manitoba Hydro file with the Board an International Financial Reporting Standards status update report prior to the next General Rate Application that will provide the Board options available for rate-setting purposes.

7. That Manitoba Hydro complete and file with the Board an Asset Condition Assessment Study no later than the filing of the next updated depreciation study with the Board.

8. That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.

9. That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.

10. That Manitoba Hydro file, with its next General Rate Application, a detailed quantitative and probabilistic risk assessment and review of all of its operating and financial risks in order to allow the Board to assess the adequacy of the reserves. Commercially sensitive information in the report is to be redacted from the public version and filed in confidence with the Board.

11. That Manitoba Hydro file with the Board any negotiated agreements or changes with respect to the Wuskwatim Power Limited Partnership when finalized, and detail the impacts on Manitoba Hydro's operating results and rates.

12. That Manitoba Hydro's revenue requirements are determined based on the level of Demand-Side Management spending as set out in Manitoba Hydro's 2011 Power Smart report, i.e., $34 million for 2012/13 and $35 million for 2013/14, for a total of $69 million. To the extent Manitoba Hydro's spending on Demand-Side Management in the test years, including the Affordable Energy Fund and the Lower Income Energy Efficiency Program, falls below $69 million, Manitoba Hydro shall establish a deferral account for the discrepancy, the disposition of which the Board will consider at the next General Rate Application.

13. That Manitoba Hydro's proposed changes to the Curtailable Rate Program **BE AND ARE HEREBY APPROVED ON AN INTERIM BASIS**, to be reviewed by the Board at a General Rate Application to follow the Needs For And Alternatives To (NFAT) hearing with respect to Manitoba Hydro's Preferred Development Plan.

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BACKGROUND PAPER C:

UNCERTAINTY ANALYSIS AND RISK SCENARIOS

BACKGROUND PAPER C: UNCERTAINTY ANALYSIS AND RISK SCENARIOS

The current Hydro GRA includes, for the first time, a major new area of analysis based on quantifying risks that had been requested by the PUB since at least 2008 (Order 116/08)[1]. The new analytical product, termed the "uncertainty analysis", was first made available to the PUB and intervenors in the 2016 Interim Rate review, but has not been fully reviewed or tested in a GRA to date.

At its heart, the uncertainty analysis is different than previous Hydro analyses in the following ways:

1. **Multiple overlapping risks:** The analysis looks at not just the effect of single risks, but also combinations of risks (e.g., a bad drought combined with adverse interest rate movements). The three most variable risks faced by Hydro are included – export prices, water flows and interest rates. Discrete but unquantifiable risks (e.g., positive or adverse policy changes outside of those already included in export price forecasts, infrastructure failure) are not included.

2. **Full probabilistic range:** The analysis considers not just a single given scenario (such as the worst case) but a combination of future scenarios to give a portrayal of the probability of a given outcome, rather than just the implications of the worst possible outcome.

3. **Integrated modelling:** The analysis permits scenarios to be considered in their entirety, rather than just a single effect. For example, previous risk analyses had tended to indicate that a 5 year drought would reduce retained earnings by a given dollar impact compared to what would have occurred without the drought. But this portrayal fails to indicate that absent the drought, there would likely have been a positive net income over this 5 year period. For example, if a 5 year drought "cost" $1.5 billion, but over this five year period the IFF had forecast $1 billion in net income at normal water, then the adverse effect on Hydro's retained earnings from the drought is only $0.5 billion over those 5 years. In this manner, the previous system tended to give results that appeared excessively pessimistic by focusing on the value like $1.5 billion – the new uncertainty analysis helps improve on the information presented.

Despite these advances, the modelling still fails to include a mechanism for rate response – where each scenario run by the computer does not rely on a fixed rate increase path, but instead on annual increases that are adaptive and responsive to the ongoing conditions (e.g., raises rates more than average, but with a constrained set of bounds, if poor conditions require, less than average if good conditions permit).

[1] Directive 12.

This background paper addresses two aspects of the new uncertainty analysis:

1) What does the results of the analysis tell us?
2) How can it be improved?

Each of these items is addressed below relying on the materials filed in the current GRA.

For reference, the uncertainty analysis for the current IFF16 is provided in Tab 4, particularly Section 4.5. Earlier uncertainty analysis conducted on IFF15 is contained in Appendix 4.2. Significant additional material is contained in MIPUG/MH I-1a (Tab 4 figures extended to 20 years) and MIPUG/MH I-3c (Tab 4 charts with alternative scenario weightings). KPMG also reviewed and commented on the IFF16 uncertainty analysis in Appendix 4.5. Finally, the uncertainty analysis was updated for MH16 Update with Interim in PUB/MH II-41a-b.

1. WHAT DOES THE UNCERTAINTY ANALYSIS TELL US?

The uncertainty analysis focuses on a large range of future scenarios, which permits an assessment of not just the potential for a given outcome to occur, but also the likelihood of that outcome. The probability ranges charted focus on 50^{th} percentile (the middle scenario – with an equal number of scenarios that are better than this outcome and an equal number that are worse than this outcome). Around this value, a box and whisker plot shows the 20^{th} and 80^{th} percentile as the "box" (the 20^{th} being the value where 1 in 5 scenarios are worse than this value, and 4 in 5 are better; the 80^{th} vice versa) and the 5^{th} and 95^{th} as the "whiskers" (the 5^{th} being a value that has 1 in 20 scenarios worse than this value, and 19 out of 20 better; the 95^{th} vice versa). An example is reproduced in Figure C-1 below.

Figure C-1: Comparison of the Annual Net Income Variability[2]

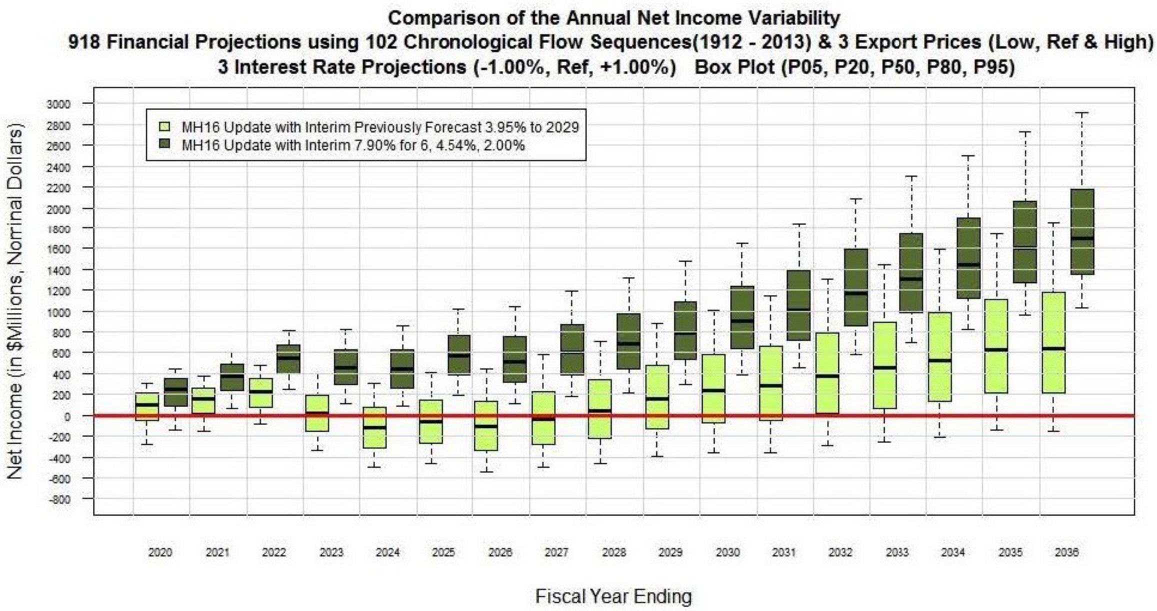


Figure C-1 shows the net income, by year, generated by the uncertainty model. It shows the box and whisker plot for two scenarios – one with 3.95%/year rate increases to 2029, followed by 2%/year (the light green), and one with the 7.9%/year rate increases for 6 years followed by 4.54%, and then 2%/year (the dark green).

The box and whisker plots read as follows, using an **example year of 2022:[3]**

- Looking to the **7.9% scenario** as proposed by Hydro (the dark green box-and-whisker plot) shows the 50th percentile outcome to be $546 million net income in that year.
- The 20th and 80th percentiles range from $402 million net income to $673 million net income (6 out of 10 times net income would be expected to fall within this range).
- Looking to the more extreme "whiskers", the results show that the 5th percentile (19 times out of 20) net income would exceed $244 million, but the 95th percentile would be $811 million (only 1 time in 20 would this be exceeded). Note that results anywhere within this range can be compared to Hydro's previous record high net income of $415 million in 2006.
- Comparing to the **3.95% scenario** (light green), the 2022 values show a 50th percentile net income of $221 million.
- The 80th and 20th percentile values are $351 million and $76 million (6 out of 10 times the net income would be within this range).

[2] PUB/MH II 41a-b, page 7 of 16.
[3] All values per PUB/MH II 41a-b page 8.

- The 5th percentile shows a net loss of $80 million, with the 95th at well above $483 million.

In reviewing Figure C-1 above, it is important to note that the 5th percentile line in any given year is not necessarily the same scenario that leads to the 5th percentile line in the subsequent years. In other words, looking to the light green line, there is not a 1 in 20 chance that net income will be negative $80 million in 2022 followed by negative $335 million in 2023 followed by negative $497 million 2024 etc. as would be shown by tracking the 5th percentile through the years – these 5th percentile values are not driven by the same underlying scenarios (i.e., the same worst drought does not repeat itself for each year of a 20 year horizon).

The 5th percentile line is also informative regarding droughts. Under the 3.95%/year scenario, the 5th percentile values show the adverse effects in any given year from experiencing a very serious drought combined with other adverse effects. At its worst (2026) the resulting net income is negative $539 million. The interesting part of characterizing the exposure in this manner is that it is highly correlated with the risks Hydro has been exposed to for the last few decades – in particular consider that in 2003/04 a very serious drought led to negative $436 million in Net Income. What is important to understand is that in the 2003/04 case, the drought was not noted to be correlated with adverse moves on interest rates or export prices, which the uncertainty modelling is assuming. It is also important to note that the 2003/04 drought occurred at a time when Hydro's retained earnings were only $1.2 billion and domestic revenues (on which rate increases could be granted) were only $918 million.[4] In today's context, retained earnings are approaching $3 billion and domestic revenue is near $1.6 billion.

In short, the risk exposure characterized by the 3.95%/year case (light green), which shows $539 million in losses in a severe drought in only the worst year (2026), and significantly less in each other year of the sequence, is not uncharacteristically poor for Hydro, if anything it is uncharacteristically good. It is clearly less risk exposure than existed for likely much of the last 20 years or longer.

Figure C-1 emphasizes the effects arising from Hydro's targeting 7.9%/year rate increases for the next number of years (dark green scenario). In particular, the chart shows that Hydro would be seeking to achieve net income that has at most a very small chance of being negative - even in the worst years of the scenario (2020), with compounding adverse effects occurring (e.g., drought combined with unexpectedly adverse interest rate moves and poor export conditions). Outside of a few years that are particularly susceptible to adverse outcomes (e.g., 2023 to 2026) the path is designed to make it more likely than not that each given year of the forecast will be above the existing record net income for Hydro, with many years having a likely 80-90 percent chance that the existing record of $415 million will be exceeded, year-after-year.

[4] Hydro Annual Report 2007, page 100 (Appendix 15 to the 2008 GRA).

Turning to the level of retained earnings, a similar figure is produced for the level of retained earnings in each future year, as shown in Figure C-2 below:

Figure C-2: Comparison of the Annual Retained Earnings Variability[5]

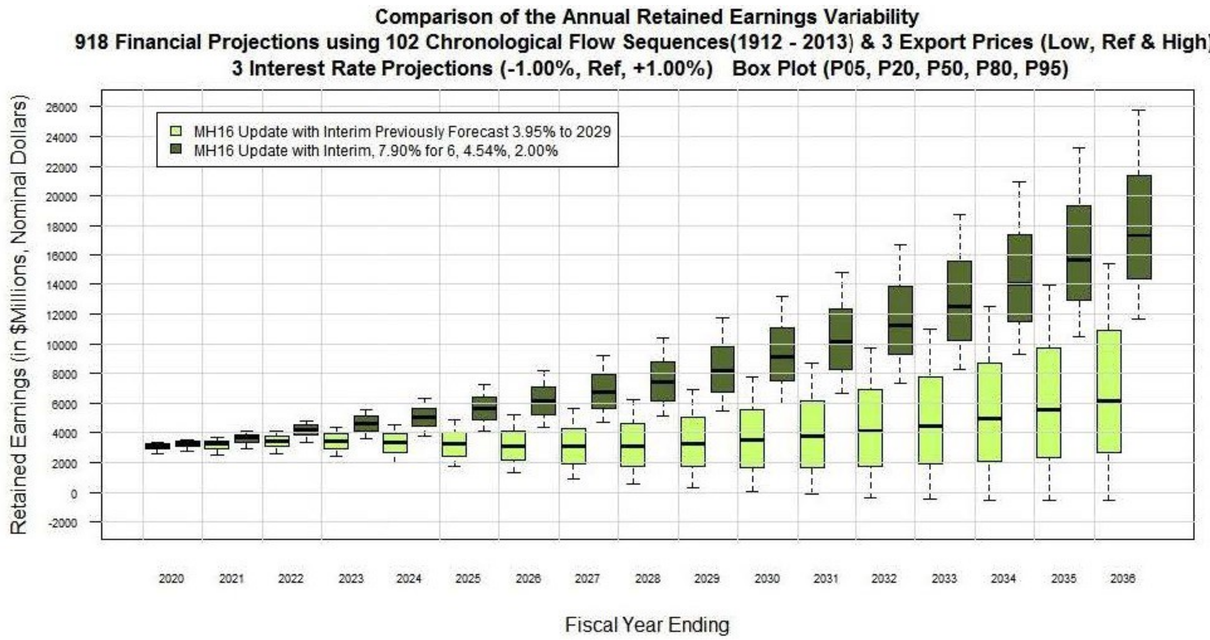


Figure C-2 highlights the retained earnings scenarios, in dollars, for Hydro's two main rate increase scenarios modelled – again, dark green for 7.9%/4.54%/2% and light green for 3.95%. The 50th percentiles emphasize that starting with the approximately $3 billion retained earnings at present, the 3.95%/year rate increase median sustains this over the next decade. After 2027, as the effects of ongoing inflation and rate increases take effect, the retained earnings 50th percentile shows growth to over $6 billion within 20 years. The retained earnings scenarios highlight a further important aspect that over the period to 2024, there is only a 5th percentile outcome that has retained earnings decreasing to $2 billion.

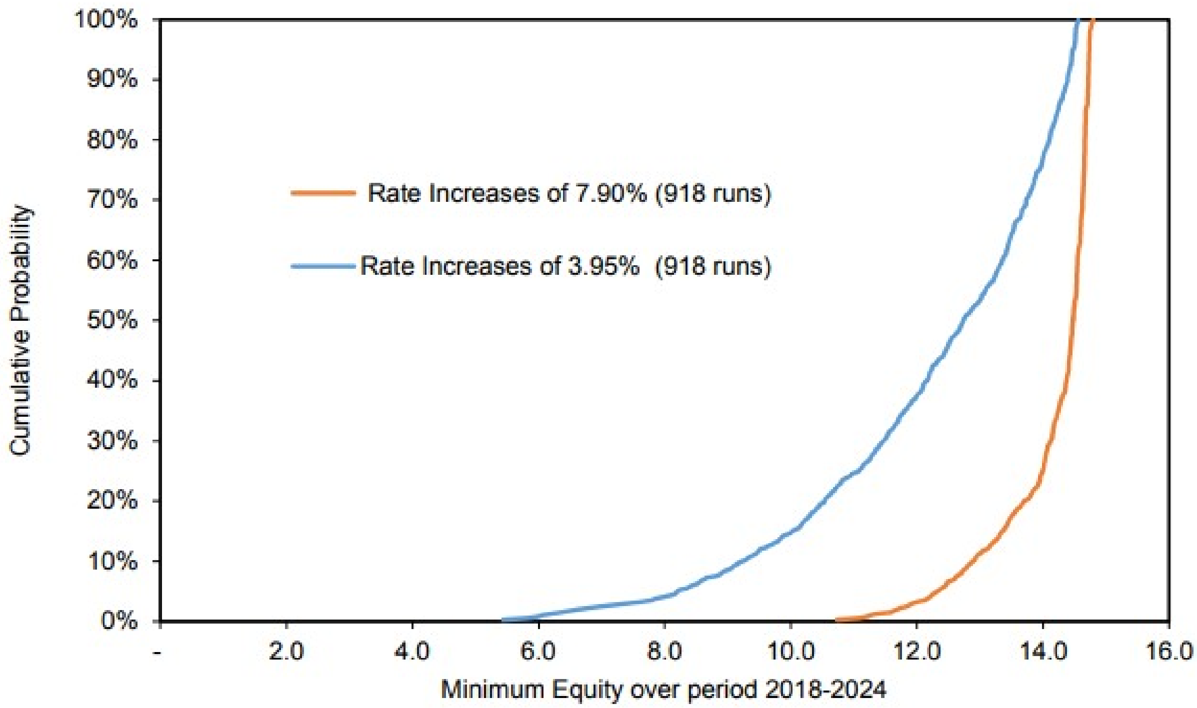
An aspect of the retained earnings scenarios in Figure C-2 is the compounding nature of the range of outcomes (the heighted of the bars and whiskers) given the model applies no rate response, but only a fixed unyielding rate increase scenario. As discussed below, this inability to have rates react to the scenarios as they unfold is a major limitation with the model as developed by Hydro that should be addressed in future. Since this feature does not exist, the fixed unyielding rate increase scenarios mean that if a scenario is knocked off course earlier in the model run (e.g. years 3-8), whether positive or negative, the failure of the rate scenario to react leads to an ever widening cone that is not a reasonable portrayal of the actions that would be expected to be taken. For example, the 20 year range of negative $0.5 billion to positive $15.5 billion for the 5th to 95th percentiles under the 3.95%/year rate increase reflects a failure of the model to adjust rate increases to, say, 4.95% when needed for adverse

[5] PUB/MH II 41a-b, page 11.

conditions, or 2.95% when possible for exceeding financial expectations. Nonetheless, the 50th percentile values should remain reasonably accurate, but the outer edges of the cone would be expected to be narrowed with rate response.

KPMG has provided a different approach to portraying the same analysis approach in Appendix 4.5, KPMG Figure 6-15 (reproduced below as Figure C-3) though this appears to be based on the original MH16 conditions.

Figure C-3: Minimum Equity Value Observed 2018 through 2024 Alternative Scenarios[6]



In Figure C-3 above, KPMG provides a snapshot assessment for the 2018-2024 period of the lowest level of Hydro retained earnings for each run (as a percentage of capital) that can be expected given the scenarios modelled. The orange line portrays the scenarios tied to 7.9%/year rate increases and the blue line to 3.95%/year rate increases. The form of the chart shows that if 7.9%/year rate increases are adopted, there is effectively no risk (considering the variables modelled) that Hydro would hit, at any time during the 2018-2024 period, a retained earnings level that is below about 11% of capital. With 3.95%/year increases, there is a small risk that Hydro could hit retained earnings levels between 5 and 6% of capital in at least one year, but not below. The 50th percentile retained earnings ratio is about 14% for the 7.9%/year rate increases and just over 12% for the 3.95%/year rate increases. Under best cases, both

[6] KPMG LLP. 2017. Manitoba hydro Financial Targets Review Supplementary Update. Appendix 4.5 of the Manitoba Hydro 2017/18 & 2018/19 GRA. August 2017. Figure 6-15, pg. 75.

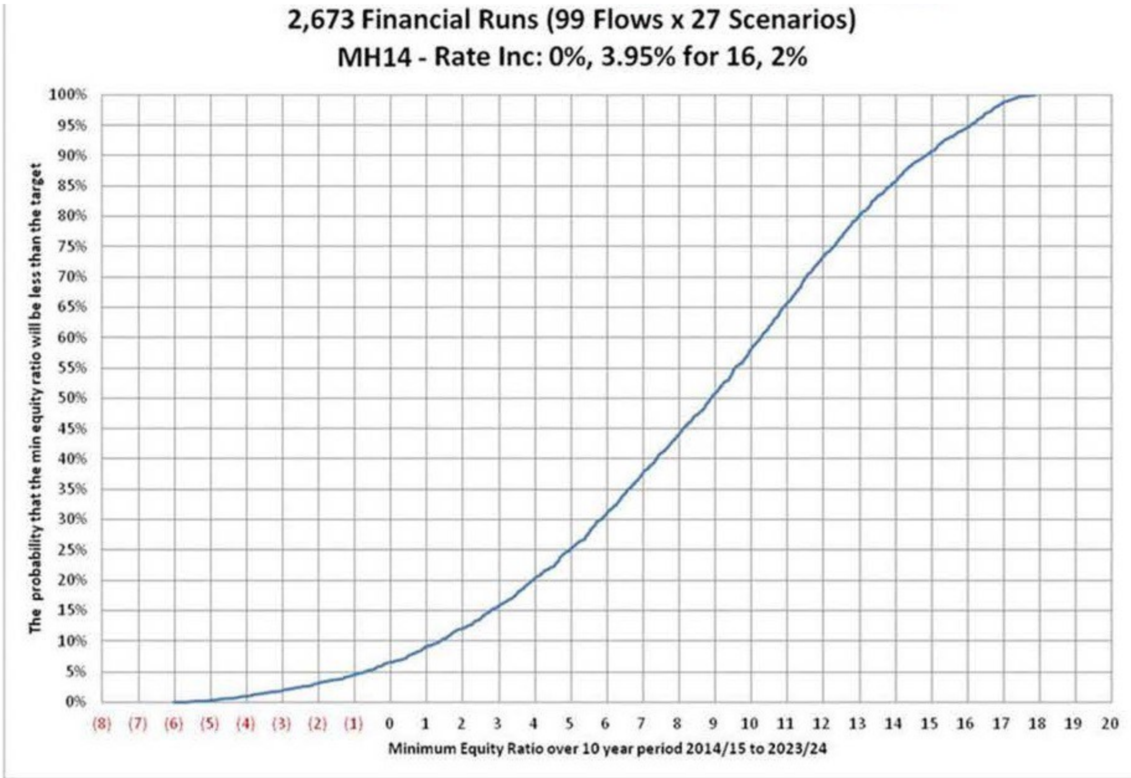
scenarios have a minimum retained earnings at 14% (which is approximately the 2018 ratio, so neither scenario can avoid this minimum retained earnings value).

Note that neither scenario above applies any rate response – even in the worst conditions, each approach sticks to the 3.95%/year or 7.9%/year rate increases characterizing the scenario. Also note that due to this lack of rate response, neither scenario comes close to the situation KPMG highlighted as being where Hydro would no longer be self-supporting, i.e., "…a position of near zero retained earnings and rates have increased in real terms such that Manitoba can no longer be considered a cost competitive jurisdiction with respect to electricity rates"[7] (emphasis in original). Under the above scenarios, particularly the 3.95%/year scenario, retained earnings under the worst cases would hit between 5 and 6 percent of capital (slightly below $1.5 billion)[8] for a time and rates would remain among the lowest in Canada[9]. For this reason, Figure C-3 above suggests that if the worst situation were to arise, some level of rate response (higher than 3.95%/year increases) could be applied to further bolster the retained earnings above the $1.5 billion level.

A further benefit of the KPMG presentation format is a high degree of information provided about the range of outcomes (to 2023/24) comparing IFF14 to IFF16. Figure C-3 above provides, in the blue line, the minimum retained earnings percentages arising under IFF16 inputs but using a rate increase scenario similar to IFF14. The same graph based on the IFF14 inputs is provided below in Figure C-4:

[7] Appendix 4.1, page 7.
[8] In 2023/24, per PUB MFR-17, total capital (debt+equity) approximates $27.8 billion, at 5% this totals $1.4 billion.
[9] At 3.95%/year increases the real rate of increase is approximately 2%/year for the 7 years to 2023/24. Other than Quebec, Hydro's application Figure 2.33 highlights that Manitoba's rates are below the other lowest jurisdiction in Canada – BC. Even with 7 years of increases Manitoba's rates would remain competitive.

Figure C-4: Cumulative Probability Graph
Minimum Equity Ratio Over 10-Year Period 2015-2024[10]



Comparing Figure C-3 to Figure C-4 (blue line), it is clear that under effectively the same rate increase scenario, IFF16 has materially reduced the risk of adverse outcomes. In particular, at the time of IFF14, a rigid adherence to 3.95%/year rate increases over the period to 2024 would have provided a 25% chance that retained earnings levels would drop below 5%, and a 6% chance that they would drop below $0 (potentially as low as negative 6% of total capital). These scenarios, though highly unlikely, would be a significantly problematic outcome. Of course, had such conditions arisen after IFF14 was prepared, rate response (e.g., higher than projected rate increases) would have become required.

By IFF16, these extreme results are no longer within the range of modelled outcomes. While IFF14 showed a 1 in 4 chance that retained earnings could drop below 5%, this outcome is no longer shown at even the 1 in 100 level. IFF14 exhibited a 6% chance that retained earnings could drop below $0, this outcome is no longer within the range of outcomes at any probability threshold.

[10] KPMG LLP. 2017. Manitoba Hydro Financial Targets Review. Appendix 4.1 of the Manitoba Hydro 2017/18 & 2018/19 GRA. May 2015. Figure 7-7, pg. 116 (original source: Manitoba Hydro).

At the 50th percentile, IFF14 had showed a minimum retained earnings at 9% of capital. This outcome is now at the 10th percentile (only a 1 in 10 chance of this low an outcome occurring). The new IFF16 50th percentile exceeds 12 percent of capital.

The reason for the narrowing of potential outcomes to 2024 for IFF16 versus IFF14 are twofold:

1) IFF16 shows improvement in a number of critical input conditions, such as interest rates and water levels.
2) More importantly, IFF16 shows the benefits of 2 years of actual known conditions at the outset of the sequence. The IFF16 probability set is all those outcomes that may arise within 8 years to 2024, while the IFF14 was all scenarios that could arise within 10 years to 2024. This is a very important distinction that underlines the critical importance of timing and sequence of risk. In the intervening 2 years from IFF14 to IFF16, a significant reduction in risk has occurred leading to a narrowing of the 5th/95th range. This is due to the normal evolution of facts as major capital projects (and associated borrowing) proceeds. The trend would be expected to continue as Keeyask and Bipole III progress towards completion. This feature is highly informative to the need for attentive, but measured, responses during the critical years to 2022/23 as risks are carefully monitored and resolved.

2. HOW CAN THE UNCERTAINTY MODELLING BE IMPROVED?

Hydro's uncertainty modelling is a significant improvement on the ability to assess and analyze future potential events. Three potential improvements have been identified, but two of the potential improvements are not likely to materially change the results.

Improvements that are important to the next evolution of the modelling:

1) Include rate response.

Improvements that are possible, but unlikely to materially affect the modelling results for IFF16:

1) Determine if additional risks should be included in addition to the main three risks already included (interest rates, export prices and water flows).
2) Consider alternative weighting for input values (e.g., are low/high prices just as likely as the expected prices, or are they somewhat less likely).

Each is addressed in the sections below.

2.1 Rate Response

The most notable omission from Hydro's uncertainty analysis is the failure to include any mechanism for automated rate response in the analysis. This means that the scenarios show excessive divergence from targeted financial performance as rate increases continue to be enforced by the model in situations where they are nonsensical. For example, the model may show that there is a risk, if a 3.95%/year rate regime is implemented, that equity will turn negative and continue eroding, or at 7.9%/year that Hydro will exceed 50% equity and $1 billion in net income yet continue to raise rates. The result is that the projected cones are much wider than can reasonably be expected.

The same issue was present to some degree in the NFAT hearing, where multiple scenarios were similarly being examined. In that case Hydro developed a simplified rate response regime that could be applied by the computer within the modelling (targeted to interest coverage each year). Hydro's approach was better than using an unresponsive fixed rate regime, but was coarse. In particular, Hydro's scenarios forced a specific rate increase for 20 years (tied to the specific development plan), but then let the rate increases respond to the measured Interest Coverage ratio without constraint after year 20. The result was an overly rigid rate increase regime in the first 20 years, and an overly frenetic rate scenario in the years after year 21 (e.g., sometimes with double digit rate increases in one year followed by double digit decreases the next).

Morrison Park Advisors, as an Independent Expert Consultant retained by the PUB, provided modelling that was more sophisticated in terms of rate responsiveness. The Morrison Park modelling implemented a given rate level for each year, and then adjusted the rates the next year to reflect the evolution of conditions so as to either achieve or proceed towards a given financial target – but the rate changes were constrained to a reasonable range (the maximum increase or decrease was fixed at two times inflation).[11]

In the case of Hydro's current uncertainty analysis, this could be implemented by modelling a rate regime based around a given starting baseline percentage increase, but if conditions trended adverse, an increase somewhat higher than this level could be used (e.g., 2% higher than baseline)[12] and if conditions were better than expected, a lower than baseline increase could be assumed (e.g., 2% below baseline). In each scenario, for each year of the model, the calculation would start with assessing which rate increase would be implemented.

The specific financial criteria to be met to trigger each respective rate increase level would need further development, but would likely be able to be based generally around Hydro's financial targets. For example, in assessing the rate increase to be applied to a given year, if the Interest Coverage Target was being missed to the downside then the higher rate increase may be used in that year, while if the debt-to-capital pathway that leads to a given debt percentage within a given number of years was being materially exceeded, then the lower rate increase would be used in that year.

[11] MH/MPA I-007 from the 2013 NFAT proceeding.

[12] In the last major drought – 2004 – the PUB decided to implement a 5% rate increase, compared to a 3% sought by Hydro. A reasonable inference could be that 2% above baseline is an accepted response to adverse conditions occurring.

The results of such modelling would yield two beneficial results:

1) The modelling would permit answering critical questions – including whether a 3.95%/year pathway (recognizing the potential for a 5.95% increase if conditions are significantly poor, and 1.95% if conditions are above expectations) would provide sufficient or potentially even excessive risk protection. This could be compared, for example, to scenarios with a 3%/year baseline and a +/-3% boundary or other alternatives, offering a lower initial rate increase to customers but perhaps a slightly higher risk of instability in rates.

2) The modelling would allow the PUB to signal endorsement of not only a current rate increase, but a possible future pathway (including pre-assessed rate responses) to address Hydro's known risks should they arise. This has the potential to provide an added degree of comfort and clarity to lenders and credit ratings agencies about the regulatory responses that are able to be brought to bear to deal with future adverse conditions, though such signalling would not be intended to in any way fetter the Board's discretion to act according to the best evidence at the time each future rate increase is sought.

It is expected that rate response would permit a much more accurate portrayal of the financial scenarios that is representative of a given pathway available. The tool would permit scenario evaluation that informs whether a specific rate increase in the first 1-2 years exposes the company to potentially needing rate shock increases in future years under reasonably foreseeable adverse conditions. If such risk was not exhibited, then it could provide comfort that the specified rate increase was reasonable and appropriate in the first years under review.

2.2 Modelling of Additional Risks

The uncertainty model incorporates risks for export prices (which also affects fuel used during low flow scenarios), interest rates and water flows. Hydro's traditional deterministic risk register from the IFF includes a number of additional variables. In the case of IFF16, the measured impacts to retained earnings over the 10 years to 2026/27 for uncontrollable risks[13] are as follows (in terms of adverse impact in retained earnings)[14]:

- Drought (5 year impact) - $1.367 billion;
- +1% interest rates - $0.930 billion;
- Low export prices - $0.777 billion;
- Canadian US dollar exchange rate down $0.10 (C$ strengthening) - $0.220 billion; and

[13] Two other scenarios are also modelled related to Hydro adding to capital expenditures, but these are not uncontrollable risks and do not fit the profile for inclusion in an uncertainty analysis so are not included above.
[14] IFF16, page 44.

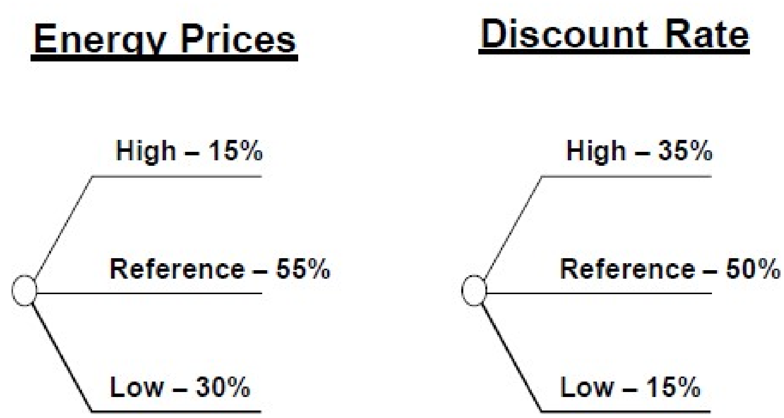
- Low domestic load growth - $0.179 billion.

As can be seen from the above list, the uncertainty analysis already includes by far the biggest 3 risks that dominate Hydro's future exposure to adverse outcomes, and as such it is unlikely there would be significant benefit from adding to the analysis scenarios with varying exchange rates and domestic load growth.

2.3 Alternative Weightings

A final area of potential improvement is to explore the impacts of using alternative weightings for the respective reference, low and high input values (interest rates and export prices). Hydro's uncertainty modelling uses equal weights of 1/3 to each[15] value. During NFAT, Hydro had a more refined weighting system as shown in Figure C-5 below (reproduced Figure 2.15 from NFAT Appendix 9.3):

Figure C-5: Probabilities for Highest Impact Factors[16]

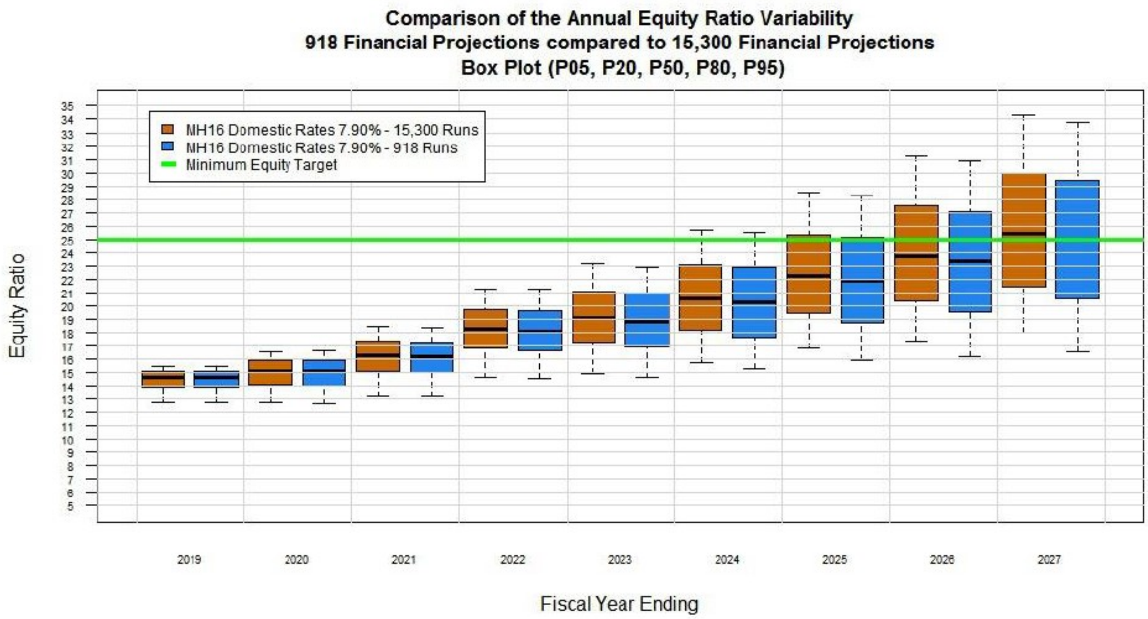


The above Figure C-5 shows that at the time of NFAT, Hydro had placed considered and unequal weightings that prioritized the likelihood of the reference case for Energy Prices and for interest rates (represented by the Discount Rate). MIPUG/MH I-3a in the current proceeding reviews the rationale and impact for now using equal weightings. Hydro specifically notes that in the absence of retaining additional outside expertise regarding the energy cost forecasts (as was done with NFAT), "Manitoba Hydro assumed equal weightings to avoid introducing any subjectivity or bias." With respect to interest rates, Tab 4 sets out that interest rates can be modelled using a sample of 50 interest rates from a stochastic interest rate generator[17] but that Hydro elected to use the 3 state model, equally weighted, as it gave relatively similar results with considerably less computing requirements. Figure 4.16 from Hydro's Tab 4 (reproduced

[15] MIPUG/MH I-3a
[16] Manitoba Hydro. 2013. Economic Evaluation Document. Appendix 9.3 of the Needs For and Alternatives To Proceeding. August 2013. Figure 2.15, pg. 60
[17] Tab 4, Manitoba Hydro 2017/18 & 2018/19 GRA, page 20.

below as Figure C-6) sets out a comparison of the two methods to confirm the reasonableness of using the 3 state model rather than the 50 state.

Figure C-6: Projected Equity Ratios from Uncertainty Analyses[18]

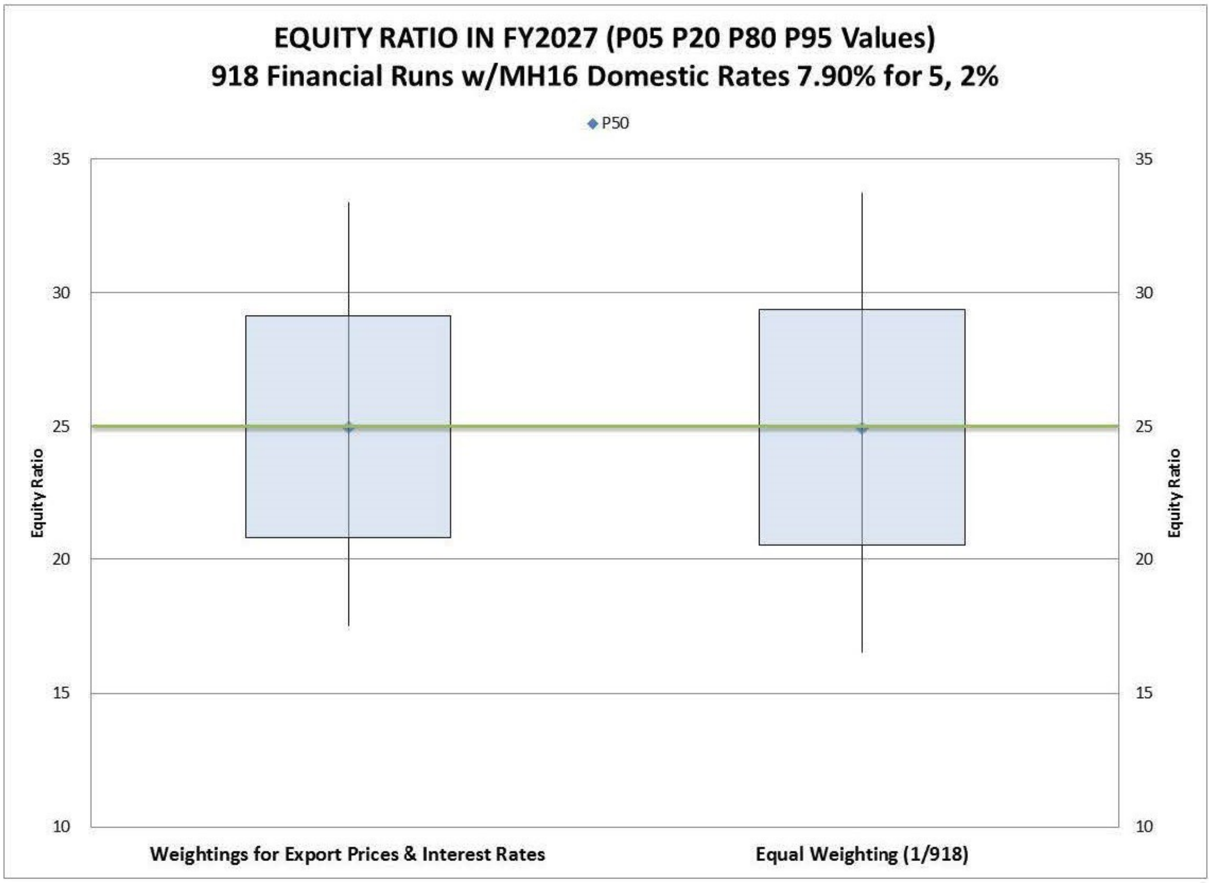


As shown in Figure C-6, the 3 state model (the blue case) does reasonably track the same outcomes as the 50 state model (the brown case), but with a somewhat more pessimistic lean (blue bars and whiskers are lower than brown).

Looking to MIPUG/MH I-3a regarding the combined effect of interest rates and export prices, the figure shown at page 3 of that response illustrates the impact on one sample year and scenario from using a 25%/50%/25% weighting as opposed to a 33%/33%/33% weighting, as reproduced below as Figure C-7.

[18] Tab 4, Manitoba Hydro 2017/18 & 2018/19 GRA, page 21.

Figure C-7: Equity Ratio in FY 2027 (P05 P20 P80 P95 Values)[19]



The above Figure C-7 highlights that little of the box component (the 80th and 20th percentile ranges) is affected by the altered weightings, but that the more extreme ranges (particularly the 5th percentile) is drawn into a notably more constrained range.

Combining the above information, it is likely that Hydro's approach to modelling, using only 3 interest rate projections from the stochastic model rather than 50, and using 3 equally weighted export prices rather than a weighting more similar to the NFAT scenarios, likely results in a small tendency of the cones to be wider (i.e., exhibit more sensitivity) than would otherwise be the case, and the extreme low 5th percentile values in particular to be lower than might otherwise be the case. While the effect is likely measurable, it is unlikely to be materially skewing the output of the uncertainty analysis in a manner that requires immediate action.

Further future improvements to the uncertainty modelling may plan to investigate more refinement in the weightings used, as an incremental improvement.

[19] MUIPUG/MH I-3a, Manitoba Hydro 2017/18 & 2018/19 GRA, page 3 of 9.

3

PRE-FILED TESTIMONY OF
PATRICK BOWMAN
IN REGARD TO MANITOBA HYDRO 2017/18 & 2018/19
GENERAL RATE APPLICATION

Submitted to:

The Manitoba Public Utilities Board

on behalf of

Manitoba Industrial Power Users Group

Prepared by:

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October 31, 2017

3.0 PRINCIPLES OF RATE REGULATION

This testimony has been prepared taking into account regulatory and rate making principles appropriate to Manitoba Hydro as a Crown-owned and hydroelectric generation dominated utility. This section reviews the key principles relied upon in this testimony and supporting rationale.

3.1 BACKGROUND

The premise of rate regulation is that customers generally, or a class of customers specifically, require protection from a monopoly supplier who could, in the absence of competition or a principled decision on the fairness of rates, charge prices that are unreasonable. Principles of Public Utility Rates, by James C. Bonbright (1966)[10] is generally accepted as a relatively comprehensive source for regulatory and ratemaking principles and processes. It describes the primary functions of reasonable public utility rates, with "reasonableness" in this context generally representing a number of different considerations, including:

- The price for service to customers overall reflects the costs of providing that service[11] ("Revenue Requirement");
- The costs are measured based on the assets that are used and useful in the period in question, and at a level that reflects prudency in the costs of acquiring the asset (the "Used and Useful" and "Prudent Investment" tests);[12] and
- The costs are allocated on a principled basis to the various classes of customers that share in receiving service from a single system ("Cost of Service").
- The rates ultimately charged should yield the appropriate revenues to Hydro under varying conditions and meet a series of important rate objectives ("Rate Design").

As a general principle, prices for electricity throughout Canada are set based on one of the following three basic approaches:

1) Based on markets such as bulk power costs in Alberta or Ontario (with government subsidies or rebates at times being provided to certain groups);

[10] Principles of Utility Regulation, Bonbright, J. 1966. Page 49
[11] See, for example, Bonbright, J.C., 1960, "Chapter IV – Cost of Service as the Basic Standard of Reasonableness".
[12] Also see Charles F. Phillips, The Regulation of Public Utilities (3rd. ed,) at pp. 340.

2) By government, based on political considerations, such as in Quebec for bulk power, in Nunavut, and in Manitoba prior to the *Crown Corporations Public Review and Accountability Act* of the late 1980s;[13] or

3) Based on regulated cost-of-service approaches, such as in British Columbia, Yukon, Northwest Territories, Newfoundland and Labrador, or Nova Scotia[14].

Manitoba Hydro fits into this last category, of regulation on the basis of costs to serve the customer.

3.2 REVENUE REQUIREMENT AND THE USED AND USEFUL TEST

Hydro's revenue requirement is reviewed by the PUB and is to include reasonable costs required to run the utility. The PUB makes the final determination regarding what costs are reasonable and recoverable by Manitoba Hydro from domestic ratepayers. The PUB's concern must reside with determining what amounts of Hydro's spending (all, or potentially not all) is ultimately recovered from ratepayers, and when.

In making this determination, the PUB must look to the years in question (the "test years")[15], and to a lesser degree, to relevant subsequent periods to the extent needed to take into account the critical concepts of rate stability. For example, Bonbright notes that pricing methods should not "deprive consumers of those expectations of reasonable continuity of rates on which they must rely in order to make rational advance preparations for the use of services"[16].

3.3 COST OF SERVICE AND RATE DESIGN

In order to fulfill normal ratemaking principles, the relative levels of rates charged to various customer classes by Manitoba Hydro are to be developed based on principles of "cost of service", or determining a fair allocation of Hydro's costs to the various rate classes based on a consistent set of principles. This retains the concept of used and useful – for example, if a customer class does not use a component of the system (e.g., distribution), its rates are not to include the costs of that component of the system; likewise if only one class uses assets (such as streetlights) all costs related to those assets are to be assigned to the relevant class.

[13] This approach is also similar to that used by other non-electric utilities such as many Canadian water and sewer services.

[14] In some cases, only a portion of the respective utility's rates or tolls are regulated based on cost-of-service principles.

[15] For example, as far back as 1922, the New York Public Service Commission noted: "Consumers should not pay in rates for property not presently concerned in the service rendered, unless- (1) Conditions exist pointing to its immediate future use; or (2) Unless the property is such that it should be maintained for reasonable emergency or substitute service; and in studying these two exceptions the economic factor should be carefully considered." Elmira Water, Light & R.R., 1922D Pub. Util. Rep. (PUR) 231, 238.

[16] Bonbright, J.C., 1960, Page 396-397.

Based on these allocated costs, a rate design can be developed to recover the appropriate level of costs from the various customer classes, as well as achieve key objectives such as stability, economic efficiency, etc.

An analysis of a Cost of Service Study is required in order to ensure that the various utility rates, which collectively result in generating sufficient revenue for Hydro, are individually just and reasonable to each class of ratepayer.

3.4 RESOURCE PLANNING

Within the context of Canadian public utility ratemaking, there is a notable difference in practice between jurisdictions as to whether a utility's capital development plans are reviewed prospectively by the regulator, or only following the implementation of the plan when the related costs are proposed to be included in rates. Some utilities require approvals such as a "Certificate of Public Convenience and Necessity"[17] prior to constructing major assets (e.g., BC Hydro) while for others there is no similar standing requirement for capital spending to be reviewed before construction, such as Manitoba Hydro.

In practice, Manitoba Hydro has been required to have capital resource plans reviewed when major new hydraulic generation is being proposed, such as 1990 in regards to Conawapa, the mid 2000s in regard to Wuskwatim,[18] or the 2013-2014 Needs For and Alternatives To (NFAT) proceeding related to Keeyask and Conawapa.

Underlying these reviews are many public policy elements, among them the premise that the assets will be devoted to public service, and ultimately costs will likely be recovered from ratepayers. As a result, the utility benefits from informed input before it commits to construction regarding the likelihood of being able to recover the costs it incurs, and the regulator (and ratepayers) have the opportunity to review and test the plans and expectations regarding their likely impact on rates or other variables, such as reliability. This is consistent with Bonbright's concept that regulation and ratemaking, and utility service in general, can be heavily tied to customers' "expectations of reasonable continuity of rates on which they must rely in order to make rational advance preparations for the use of services."[19]

[17] BC Utilities Commission Act, section 45(1), available online: http://www.bclaws.ca/civix/document/id/complete/statreg/96473_01
[18] This review was held by a panel of the Clean Environment Commission who had members of the PUB cross-appointed for the review.
[19] Bonbright, J.C., 1960, Page 396-397.

3.5 "HERITAGE RESOURCES" AND HYDRAULIC GENERATION

The above principles and excerpts from the literature highlight normal utility regulation and ratemaking principles as they apply to the power utility industry generally and in particular to private utilities. A unique additional consideration is at work in jurisdictions such as Manitoba (and similarly in systems such as Quebec) where the development of power systems has not been pursued on a private investor/equity return basis but instead as a government enterprise. This is a common feature of hydro dominated systems, given the unique nature of hydro projects:

- **Capital Required:** Hydro projects require massive commitments of capital. If this capital is to be sourced from investors (equity) it requires a considerable return to attract sufficient investment to complete a large project. Also the nature of very capital-intensive projects is that there is a very high "fixed" annual cost related to the investment, and low operating costs. For example, a typical investment by Hydro today in each $1 billion project likely requires 1%-2.5% of the capital cost (on average) for depreciation and a further amount for interest cost, for a minimum net cost in the first year of $50-$75 million (if not offset by new revenue, this would mean a 3.5%-5% impact on rates).[20]
- **Low Initial Returns:** Hydro projects would normally be expected have extremely low (or zero, or slightly negative) economic returns in the near-term, but are highly likely to have positive returns over the medium to very long-term. Government entities, relying on a debt guarantee of the citizenry, can find this economic profile attractive. This pattern of economic returns however, is not generally attractive to private sector investors needing to pay annual dividends to investors. Government entities can also be attentive to social benefits (like local and northern investment) or Government revenues from taxation of construction work when the project is first constructed, which would not be relevant to private investors.
- **Annual Risk:** Hydro projects have no assurance of economic returns in any single given year, or even in any multi-year period, due to water flow variation. It is possible to calculate a very favourable return statistically over any longer-term period, but the duration of drought risk, with its attendant cost and cash flow challenges, would be unattractive to private investors, or would demand excessive risk premiums on equity returns.

In short, hydro projects are exceedingly challenging economic projects to develop, and are exceedingly risky from year to year due to water flows, but have a reasonable expectation of being among the lowest risk power projects available over any longer-term horizon. While a comparable generation asset (in terms of annual GW.h generating capability) of thermal plant would cost a fraction of the cost of hydro plants,

[20] At approximately $15 million per percentage point of rate increase.

and bring a far more stable annual revenue and cost profile year-to-year over the short-term (outside of fuel costs which are typically a flow through to customers and not to the investor), the intense long-term risk to customers with respect to fuel prices, and almost certain higher life cycle cost over the full plant life cycle, make such plants more attractive to investors, and much less attractive to ratepayers.

For a jurisdiction with a good hydro potential, there exists a potentially attractive development opportunity, but a very challenging investment opportunity. If the returns are permitted to be very high, this development can attract private capital. More typically, jurisdictions in Canada with this resource profile elect to use a more patient capital that is more characteristic of provincial governments (or aboriginal governments) including low-cost borrowings that can be available to provincial governments (even on a highly leveraged basis) when backed by the full faith and credit of the citizenry. This latter government entity approach leads to far more advantageous rates, particularly for a cost-based Crown utility like Manitoba Hydro.

Against this backdrop, an overriding principle that must be brought to bear in regulation is ensuring that the costs of these very large developments (e.g., costs to develop new projects, costs to depreciate existing projects) are recognized in the appropriate time period, and in particular not in advance of when the bulk of the economic benefits of the plant arise. With exceptional long-term economics that, in general, get better with time, one role for regulation is to ensure that today's ratepayers are not being burdened with costs that are appropriately collected from ratepayers later in a hydro plant's life when the economic prospects are vastly improved. Balancing this principle is front-and-centre in the current GRA.

It is also important to acknowledge the fundamental tenets underlying electricity pricing and policy existing in Manitoba since at least the 1970s[21]. Manitoba electricity prices are based on the costs required to operate the public power electricity system put in place in past years. These prices reflect the underlying "heritage resources" developed and paid for by Manitoba electricity consumers[22] who took on the costs and risks related to major generation and transmission developments (both one-time investment risks, as well as ongoing risks related to water flows, plant performance, etc.). In this regard, the generation and transmission resources currently in place (the "bulk power" system) represent the entitlements of ratepayers to attractive and stable electricity prices. Export revenues have been integral to this policy approach, in that the ability to export power enables development (and in some cases allows advancement of development) of large northern hydro stations, in excess of what would be required for solely domestic

[21] This basic set of principles is set out in numerous documents from the 1970's through the present, including reports of Manitoba Hydro, the provincial government, the PUB, as well as previous agencies such as the Manitoba Energy Authority.

[22] In the case of the HVDC system, there was financing from the Government of Canada, provided for the benefit of Manitoba electricity consumers.

requirements at any given point in time[23]. Absent the export markets, the Manitoba power marketplace would likely more closely resemble the non-interconnected jurisdictions in Canada, designed for only a portion of the generation to be hydraulic with a substantial (and more costly) fossil fuel component being part of the supply mix[24]. The access to the export market (for exports and imports as needed) allows larger scale and more economic hydro plants to be developed, and allows rates to be lower than they would otherwise be (were some portion of the major hydro developments not otherwise possible) and more stable (since fluctuations and risks related to Manitoba load levels can be offset in part by complementary changes to quantity of power exported, and since the ongoing costs of hydraulic generation are not subject to fuel price fluctuations).

Similarly, these same basic tenets have been the basis for the current Manitoba initiatives to develop new renewable hydro. These plans are founded on the ability to construct generation projects sooner than they would otherwise be triggered for solely domestic use, and to use the intervening "advancement" period to make sales to export markets. As such, Hydro's supply is bolstered, giving the utility increased flexibility to address such situations as unexpected load growth. Also, the new hydro plants are constructed earlier, and at a lower cost than would otherwise arise (due to inflation) and to have the investment partially "paid down" by early years export sales (whether the early years are in fact cash flow positive or not). In each case, the premise put forward by Hydro is that these generation investments are aimed at maintaining stable and low cost electricity for Manitobans, along with all the associated advantages for cost-of-living, jobs and investments, and development of renewable public resources (and in the current hydro developments, opportunities for northern community investment).

Up until the recent filings, and in particular at the NFAT proceeding, Manitoba Hydro continued to indicate that its intent is to develop new generation such that there are long-term beneficial impacts on Manitoba ratepayers, but at most limited near-term adverse impacts.

3.6 THE ROLE OF RESERVES

With the above noted cost profile for hydro developments, the final component of the regulatory framework becomes determining an appropriate level of reserves. A Crown utility has no investor or shareholder "equity" *per se*. While there is a simple mathematical benefit to paying down the utility's debt (lower future interest payments), there is no absolute guidance from stock markets, or lenders, or business theory for Hydro to have a specific precisely calculated balance of debt. The assets are paid for by ratepayers as they

[23] This basic relationship is set out in detail in the PUB's Report to the Minister regarding Manitoba Hydro's 1990 Capital Plan, Section 3 and Page 5-4.
[24] Examples include the island of Newfoundland, the Snare-Yellowknife system in NWT, or the system in place in Yukon.

are being used by ratepayers, and the debt financing of the existing assets can be retired commensurate with depreciation.

The absolute value of "equity" in Hydro as reported on the balance sheet is at best a notional concept, as it is simply the difference between the sum of assets (mostly property, plant and equipment) less liabilities (mostly debt) where the assets are recorded at original cost less depreciation. Consider an example of Grand Rapids Generating Station – it is included in the assets side of the ledger based on original cost from the 1960s ($117 million[25], plus any focused reinvestment since that time) despite a capacity that is a full 70% of Keeyask's[26], and with a role that is far more significant to Hydro's overall system than the lower Nelson plants[27].

Further, lenders do not appear to explicitly require an equity cushion to know they will be repaid, though it can be one factor in support of ratings. Evidence indicates that lenders moreso require a principled and independent rate regulator, a rate regime that appears able to absorb some degree of higher costs in the event adverse events arise, and a provincial government guarantee[28]. Many Crown utilities (both electrical and other) have operated for long periods with little to no "equity".

Despite this lack of clear guidance, it is clear that Hydro requires relatively substantial "reserves" to be able to absorb adverse events, such as drought (which, though of far less dollar impact than in past years, remains Hydro's largest single risk[29]). Hydro's chart at Tab 7 (page 26) is reproduced below as Figure 3-1 to illustrate the degree of water flow variability inherent in its system.

[25] Manitoba Hydro's profile of Grand Rapids Generating Station, https://digitalcollection.gov.mb.ca/awweb/pdfopener?smd=1&did=20775&md=1

[26] 479 MW versus 695 MW

[27] Grand Rapids is a more flexible resource than the lower Nelson plants, due to storage, location, and can play a cornerstone role in terms of frequency control for the entire system and voltage support for the northern regions.

[28] Each of these criteria exist in Manitoba, with a longstanding PUB, relatively low power rates, and the guarantee of the Government of Manitoba on Hydro's debt.

[29] The Corporate Risk Management Report (PUB MFR-9 (Revised)), at section 2 lists three high consequence risks, drought, plus two others (generic catastrophic infrastructure failure, and a general market access risk related to United States exports and imports) neither of which are items that are appropriately defined in dollar/reserve terms, and each of which are underpinned by substantial actions by Manitoba Hydro to reduce exposure. As a result, neither of the other 2 risks shown under Section 2 Significant and Emerging Risks appear in the Corporation Risk Map (page 21) as a High Likelihood (which is where drought is mapped).

Figure 3-1: Historical Water Supply - System Inflows[30]

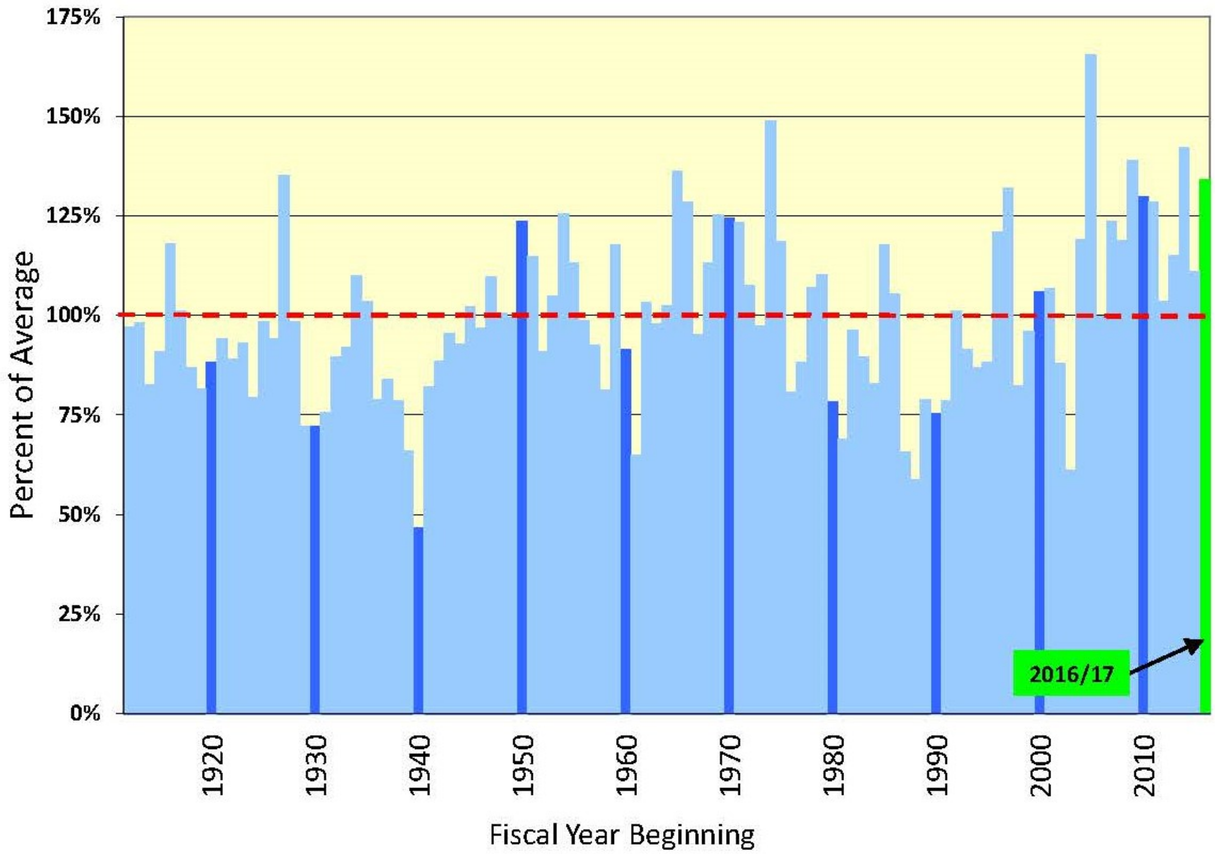

Figure 3-1 shows the extent to which water flows can vary from year to year and drive large swings in financial returns in any given year (or longer), even if the long-term trend is mean-reverting. The financial implications of this water flow variability is shown in Table 3-1 below, based on the underlying financial characteristics of the 2019/20 year.[31]

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[30] Figure 7.12. Historical Water Supply from Tab 7: Energy Supply from Hydro's 2017/18 & 2018/19 GRA, page 26.
[31] PUB/MH I-153d

Table 3-1: Financial Implications of Flow Variability, Fiscal Year 2019/20[32]

Flow Year Begin	Annual System Inflow (Kcfs)	MH Hydraulic Energy (TWh/yr)	Net Revenue (M $Cdn)	Variation of Net Revenue from Average (M $Cdn)	Flow Year Begin	Annual System Inflow (Kcfs)	MH Hydraulic Energy (TWh/yr)	Net Revenue (M $Cdn)	Variation of Net Revenue from Average (M $Cdn)
1912	112	32.3	243	83	1963	110	30.2	192	33
1913	119	32.1	235	76	1964	113	30.5	202	43
1914	98	28.0	126	-33	1965	156	37.5	358	198
1915	105	27.8	120	-40	1966	151	36.3	328	168
1916	136	35.2	315	156	1967	114	32.2	237	77
1917	119	33.9	281	121	1968	133	33.4	269	110
1918	105	29.3	163	3	1969	148	37.6	359	199
1919	98	25.6	56	-104	1970	145	36.7	341	181
1920	103	26.4	77	-83	1971	139	35.7	323	163
1921	113	29.8	179	20	1972	125	34.7	288	128
1922	106	28.9	154	-6	1973	115	31.4	219	60
1923	111	29.4	166	7	1974	163	37.0	339	180
1924	99	25.9	63	-97	1975	139	36.2	323	164
1925	120	30.0	186	26	1976	91	25.0	31	-128
1926	111	31.0	211	52	1977	99	23.3	-32	-192
1927	155	37.8	355	195	1978	122	30.8	207	48
1928	114	33.5	269	110	1979	135	34.0	266	106
1929	87	24.1	3	-157	1980	93	24.3	13	-146
1930	89	21.3	-165	-325	1981	85	20.4	-240	-400
1931	87	21.1	-184	-344	1982	115	28.8	152	-8
1932	95	22.9	-52	-211	1983	110	29.5	169	10
1933	101	25.3	46	-113	1984	101	26.3	74	-86
1934	119	30.6	201	41	1985	136	33.1	258	98
1935	118	32.5	245	86	1986	124	34.0	272	112
1936	96	26.2	73	-87	1987	82	21.7	-141	-300
1937	99	25.0	36	-124	1988	72	20.4	-239	-399
1938	89	23.3	-28	-187	1989	91	23.0	-43	-203
1939	79	20.3	-245	-405	1990	85	22.0	-107	-267
1940	55	18.6	-253	-412	1991	91	23.4	-26	-185
1941	92	22.4	-77	-236	1992	114	28.9	152	-7
1942	101	26.4	76	-84	1993	106	29.2	158	-2
1943	108	29.1	158	-2	1994	101	28.0	122	-37
1944	107	29.9	178	18	1995	102	28.4	136	-24
1945	119	31.8	228	68	1996	141	34.7	295	135
1946	113	31.9	232	72	1997	151	36.5	334	174
1947	126	33.5	273	113	1998	106	29.6	158	-2
1948	113	32.3	237	77	1999	110	28.7	146	-14
1949	116	29.7	176	17	2000	126	32.9	255	95
1950	144	35.1	305	145	2001	126	32.5	228	68
1951	132	35.9	331	172	2002	104	26.9	91	-69
1952	107	31.4	220	60	2003	72	19.9	-272	-432
1953	124	32.8	255	95	2004	140	32.9	261	101
1954	143	37.0	354	194	2005	175	38.7	385	225
1955	133	35.7	310	150	2006	113	31.9	210	50
1956	119	32.7	252	93	2007	150	36.0	331	171
1957	111	30.8	202	43	2008	141	36.5	337	177
1958	96	25.4	49	-110	2009	151	36.0	321	161
1959	137	33.3	266	106	2010	162	38.5	377	218
1960	102	29.1	152	-7	2011	153	35.9	308	149
1961	75	20.6	-232	-391	2012	121	33.2	262	102
1962	119	29.2	159	0	2013	134	35.8	315	156
					Average	115	30.05	160	0

Table 3-1 above is based on a concept of "Net Revenue" which is a subset of the items that make up net income. The full net income in the year shown (2019/20, under Appendix 3.8 assumptions) is $205 million.[33] For an assessment of the impact of a given water condition on the 2019/20 year, it is necessary to add this $205 million to the values shown in the column entitled "Variation of Net Revenue from Average" – for example, for the worst single water year in Hydro's hydrologic record look to 2003, which shows negative $432 million in net revenue worse than the average condition. Adding $205 million to this value makes this flow year equal to a $205 million net loss. Comparing to the actual financial outcome of the 2003/04 year (net loss of $436 million) shows the significantly reduced exposure to drought in the current forecast compared to earlier periods.

32 PUB/MH I-153d
33 Appendix 3.8

4

Electric Cost Allocation for a New Era

A Manual

By Jim Lazar, Paul Chernick and William Marcus

Edited by Mark LeBel

JANUARY 2020

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Contents

Part III: Embedded Cost of Service Studies

Introduction and Overview

> Charting a new path on cost allocation is an important part of creating the fair, efficient and clean electric system of the future.

The purpose of this manual is to provide a comprehensive reference on electric utility **cost allocation** for a wide range of practitioners, including utilities, intervenors, utility regulators and other policymakers. Cost allocation is one of the major steps in the traditional regulatory process for setting utility rates. In this step, the regulators are primarily determining how to equitably divide a set amount of costs, typically referred to as the **revenue requirement**, among several broadly defined classes of ratepayers. The predominant impact of different cost allocation techniques is which group of customers pays for which costs. In many cases, this is the share of costs paid by residential customers, commercial customers and industrial customers.

In addition, the data and analytical methods used to inform cost allocation are often relevant to the final step of the traditional regulatory process, known as **rate design**. In this final step, the types of charges for each class of ratepayers are determined — which can include a per-month charge; charges per **kilowatt-hour** (kWh), which can vary by season and time of day; and different charges based on measurements of **kilowatt** (kW) **demand** — as well as the price for each type of charge. As a result, cost allocation decisions and analytical techniques can have additional efficiency implications.

Cost allocation has been addressed in several important books and manuals on utility regulation over the past 60 years, but much has changed since the last comprehensive publication on the topic — the 1992 *Electric Utility Cost Allocation Manual* from the **National Association of Regulatory Utility Commissioners** (NARUC). Although these works and historic best practices are foundational, the legacy methods of cost allocation from the 20th century are no more suited to the new realities of the 21st century than the engineering of internal combustion engines is to the design of new electric motors. New electric vehicles (EVs) may look similar on the outside, but the design under the hood is completely different. This handbook both describes the current best practices that have been developed over the past several decades and points toward needed innovations. The authors of this manual believe strongly that charting a new path forward on cost allocation is an important part of creating the fair, efficient and clean electric system of the future.

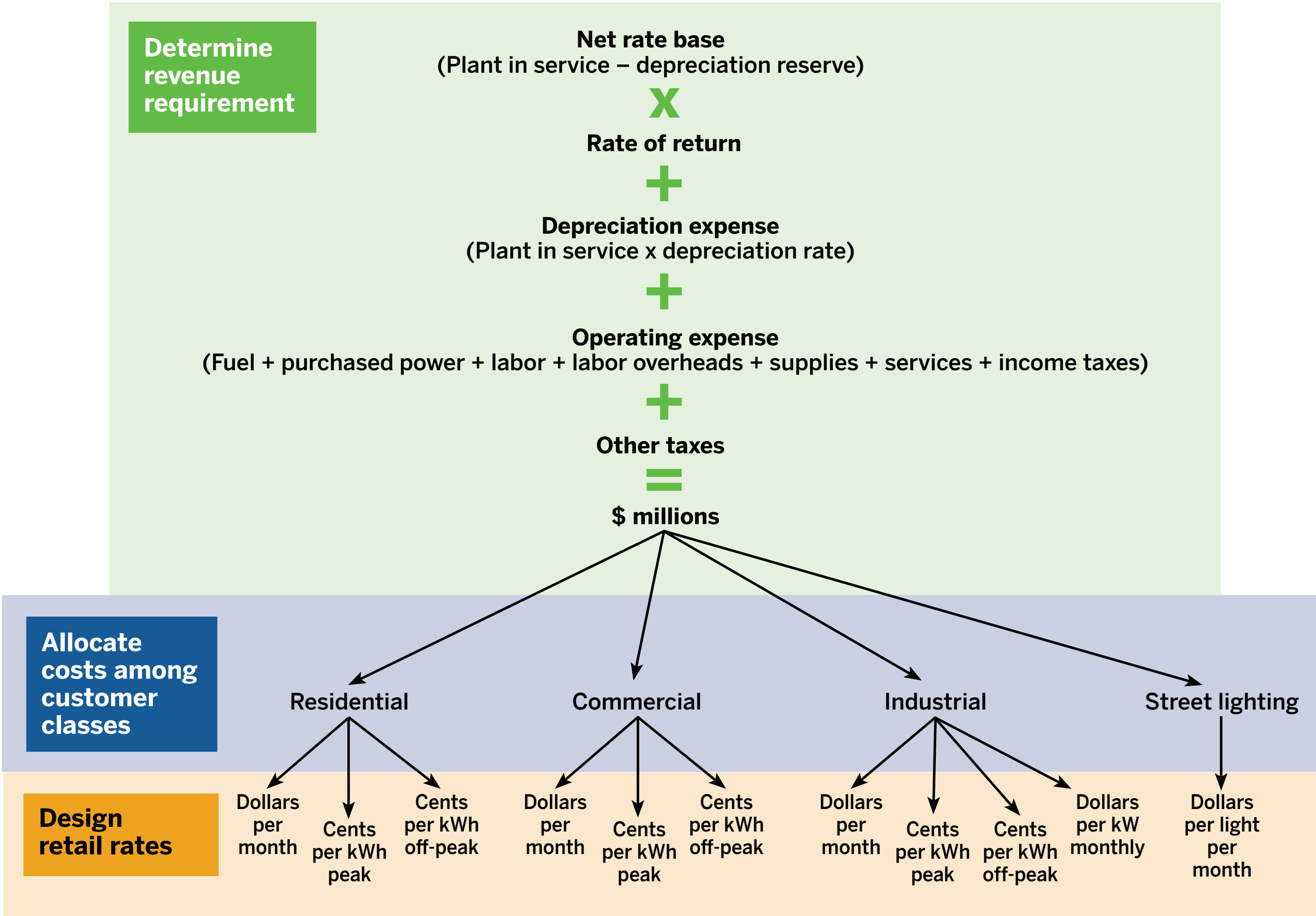
Scope and Context of This Manual

This manual focuses on cost allocation practices for electric utilities in the United States and their implications. Our goal is to serve as both a practical and theoretical guide to the analytical techniques involved in the equitable distribution of electricity costs. This includes background on regulatory processes, purposes of regulation, the development of the electricity system in the United States, current best practices for cost allocation and the direction that cost allocation processes should move. Most of the elements of this manual will be applicable elsewhere in the Americas, as well as in Europe, Asia and other regions.

The rate-making process for **investor-owned utilities** (IOUs) has three steps: (1) determining the annual revenue requirement, (2) allocating the costs of the revenue requirement among the defined rate classes and (3) designing the rates each customer ultimately will pay. Figure 1 on the next page presents a highly simplified version of these steps.

In the cost allocation step, there are two major quantitative frameworks used around the United States: **embedded cost of service studies** and **marginal cost of service studies**. Embedded cost studies typically are based on a single year-long period, using the embedded cost revenue requirement and customer usage patterns in that year to divide up costs.

Figure 1. Simplified rate-making process



Marginal cost of service studies, in contrast, look at how costs are changing over time in response to changes in customer usage.

Regardless of which framework will be used, an enormous amount of data is typically collected first, starting with the costs that make up the revenue requirement, **energy** usage by **customer class** and measurements of demand at various times and often extending to data on **generation** patterns. Furthermore, when the quantitative **cost of service study** is completed, regulators typically don't take the results as the final word, often making adjustments for a wide range of policy considerations after the fact.

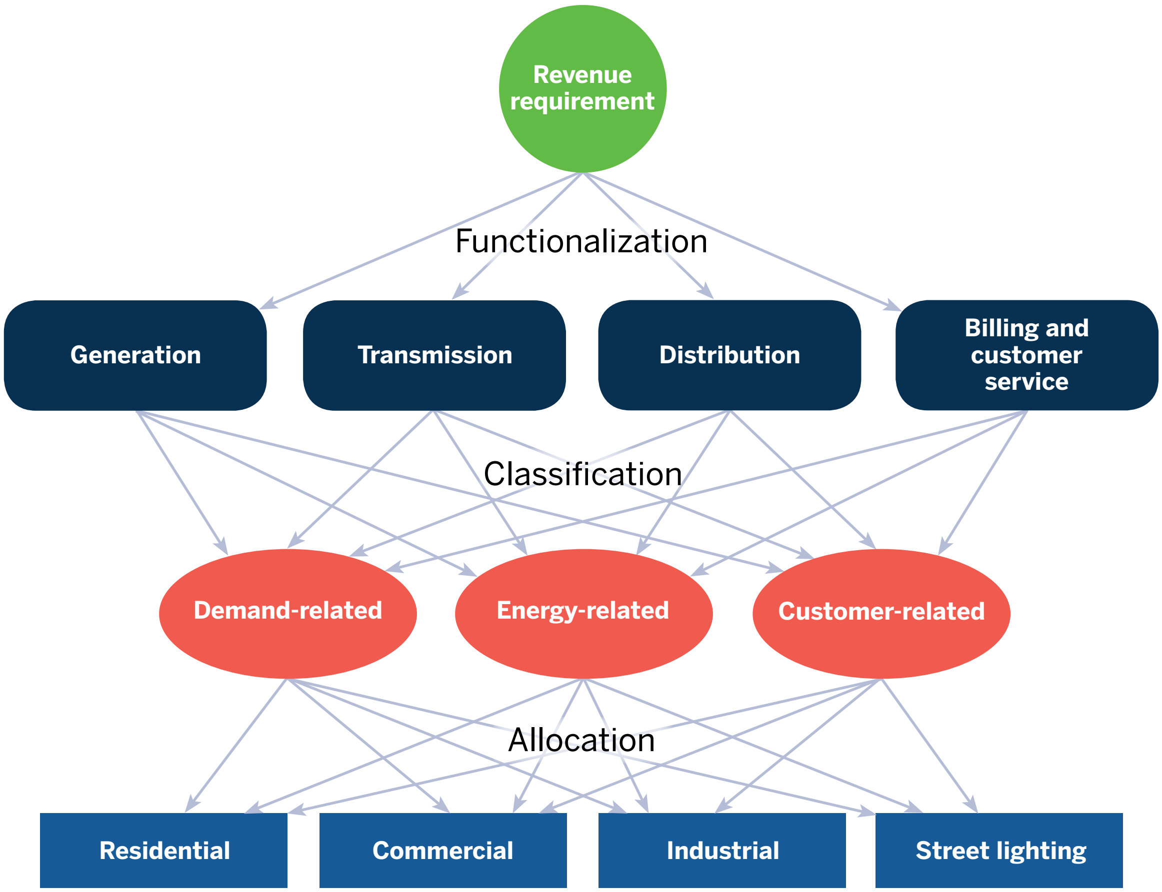
Traditionally, the analysis for an embedded cost of service study is itself divided into three parts: **functionalization**, **classification** and **allocation**. Figure 2 on the next page shows the traditional flowchart for this process.

The analysis for a marginal cost of service study starts with a similar functionalization step, but that is followed by estimation of marginal unit costs for each element of the system, calculation of a **marginal cost revenue requirement** (MCRR) for each class as well as for the system as a whole, and then **reconciliation** with the annual embedded cost revenue requirement.

This cost allocation manual is intended to build upon previous works on the topic and to illuminate several areas where the authors of this manual disagree with the approaches of the previous publications. Important works include:

- *Principles of Public Utility Rates* by James C. Bonbright (first edition, 1961; second edition, 1988).
- *Public Utility Economics* by Paul J. Garfield and Wallace F. Lovejoy (1964).

Figure 2. Traditional embedded cost of service study flowchart



- *The Economics of Regulation: Principles and Institutions* by Alfred E. Kahn (first edition Volume 1, 1970, and Volume 2, 1971; second edition, 1988).
- *The Regulation of Public Utilities* by Charles F. Phillips (1984).
- The 1992 NARUC *Electric Utility Cost Allocation Manual.*

Of course, cost allocation has been touched upon in other works, including RAP's publication *Electricity Regulation in the United States: A Guide* by Jim Lazar (second edition, 2016). However, since the 1990s, there has been neither a comprehensive treatment of cost allocation nor one that addresses the emerging issues of the 21st century. This manual incorporates the elements of these previous works that remain relevant, while adding new cost centers, new operating regimes and new technologies that today's cost analysts must address.

Continuing Evolution of the Electric System

Since the establishment of electric utility regulation in the United States in the early 20th century, the electric system has undergone periods of great change every several decades. Initial provision of electricity service in densely populated areas was followed by widespread rural electrification in the 1930s and 1940s. In the 1950s and 1960s, **vertically integrated utilities**, owning generation, **transmission** and **distribution** simultaneously, were the overwhelmingly dominant form of electricity service across the entire country.

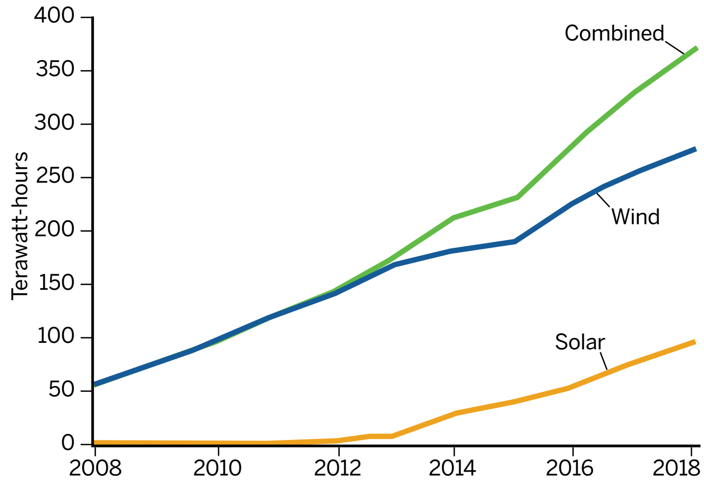
However, the oil crisis in the 1970s sparked a chain reaction in the electric industry. That included a new focus by utilities on **baseload generation** plants, typically using coal or nuclear power. At the same time, the federal government began to open up competition in the electric system with the passage of the **Public Utilities Regulatory Policy Act** (PURPA) of 1978. PURPA dictated that each state utility commission consider a series of standards to reform rate-making practices, including **cost of service**.[1] Nearly every state adopted the recommendation that rates should be based on the cost of service, but neither PURPA nor state regulators were clear about what that should mean. This has led to a fertile legal and policy discussion about the cost of service, how to calculate it and how to use it. PURPA also required that utilities pay for power from **independent power producers** on set terms.

In the 1970s and early 1980s, major increases in oil prices, the completion of expensive capital investments in coal and nuclear generation facilities and general inflation all led to significantly higher electricity prices across the board. These higher prices, in combination with PURPA's requirement for set compensation to independent power producers, led to demands by major consumers to become wholesale purchasers of electricity. This in turn led to the Energy Policy Act of 1992, which enabled the broader restructuring of the electric industry in much of the country around the turn of the 20th century.

The key texts and most of the analytical principles currently used for cost allocation were developed between the 1960s and early 1990s. Since that time, the electric system in the United States has been undergoing another period of dramatic change. That includes a wide range of interrelated advancements in technology, policy and economics:

- Major advances in data collection and analytical capabilities.
- Restructuring of the industry in many parts of the country, including new wholesale electricity markets, new retail markets and new market participants.
- New consumer interests and technologies that can be deployed **behind the meter**, including clean **distributed generation**, **energy efficiency**, **demand response**, storage and other energy management technologies.
- Dramatic shifts in the relative cost of technologies and fuels, including massive declines in the price of **variable renewable resources** like wind and solar and sharp declines in the cost of energy storage technologies.
- The potential for beneficial electrification of end uses that currently run directly on fossil fuels — for example, electric vehicles in place of vehicles with internal combustion engines.

Figure 3. Increase in US wind and solar generation from 2008 to 2018



Data source: U.S. Energy Information Administration. (2019, February). *Electric Power Monthly.* Table 1.1.A. Retrieved from https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01_a

Many, if not all, of these changes have quantifiable elements that can and should be incorporated directly into the regulatory process, including cost allocation. The increased development of renewable energy and the proliferation of more sophisticated meters provide two examples.

Figure 3 illustrates the dramatic increase in wind and solar generation in the United States in the last decade, based on data from the U.S. Energy Information Administration.

Traditional cost allocation techniques classify all utility costs as **energy-related**, **demand-related** or **customer-related**. These categories were always simplifications, but they must be reevaluated given new developments. Some legacy cost allocation methods would have treated wind and solar generation entirely as a demand-related cost simply because they are capital investments without any variable **fuel costs**. However, wind and solar generation does not necessarily provide firm **capacity** at peak times as envisioned by the legacy frameworks, and it displaces the need for fuel supply, so it doesn't fit as a demand-related cost.

1 The PURPA rate-making standards are set forth in 16 U.S.C. § 2621. Congress in 2005 adopted a specific requirement that cost of service studies take time of usage into account; this is set forth in 16 U.S.C. § 2625.

Table 1. Types of meters and percentage of customers with each in 2017

	Residential	Commercial	Industrial
Advanced metering infrastructure	52.2%	50.0%	44.5%
Automated meter reading	29.5%	26.5%	28.0%
Older systems	18.3%	23.5%	27.5%

Data source: U.S. Energy Information Administration. *Annual Electric Power Industry Report, Form EIA-861: 2017* [Data file]. Retrieved from https://www.eia.gov/electricity/data/eia861/

In addition, many utilities now collect much more granular data than was possible in the past, due to the widespread installation of **advanced metering infrastructure** (AMI) in many parts of the country and other advancements in the monitoring of the electric system. As a result, utility analysts often have access to historical hourly usage data for the entire utility system, each distribution **circuit**, each customer class and, increasingly, each customer. Some **automated meter reading** (AMR) systems also allow the collection of hourly data, typically read once per billing cycle. Table 1 shows the recent distribution of meter types across the country, based on data from the U.S. Energy Information Administration. Improved data collection allows for a wide range of new cost allocation techniques.

In addition, meters have been primarily treated as a customer-related cost in older methods because their main purpose was customer billing. However, advanced meters serve a broader range of functions, including demand management, which in turn provides system capacity benefits, and **line loss** reduction, which provides a system energy benefit. This means the benefits of these meters flow beyond individual customers, and logically so should responsibility for the costs.

These are just two examples of how recent technological advances affect appropriate cost allocation. In subsequent chapters, this manual will address each major cost area for electric utilities, the changes that have occurred in how costs are incurred and how assets are used, and the best methods for cost allocation.

Principles and Best Practices

There is general agreement that the overarching goal of cost allocation is equitable division of costs among customers. Unfortunately, that is where the agreement ends and the arguments begin. Two primary conceptual principles help guide the way to the right answers:

1. Cost causation: Why were the costs incurred?
2. Costs follow benefits: Who benefits?

In some cases these two frameworks point to the same answer, but in other cases they conflict. The authors of this manual believe that "costs follow benefits" is usually, but not always, the superior principle. Other helpful questions can be asked to illuminate the details of particularly difficult questions, such as:

- If certain resources were not available, which services would not be provided, and what different resources would be needed to provide those services at least cost?
- If we did not serve this need in this way, how would costs change?

In the end, cost allocation may be more of an art than a science, since fairness and equity are often in the eye of the beholder. In most situations, cost allocation is a zero-sum process where lower costs for any one group of customers lead to higher costs for another group. However, the techniques used in cost allocation have been designed to mediate these disputes between competing sets of interests. Similarly, the data and analysis produced for the cost allocation process can also provide meaningful information to assist in rate design, such as the seasons and hours when costs are highest and lowest, categorized by system component as well as by customer class.

In that spirit, we would like to highlight the following current best practices discussed at more length in the later chapters of this manual. To begin, there are best practices that apply to both embedded and marginal cost of service studies:

- Treat as customer-related only those costs that actually vary with the number of customers, generally known as the **basic customer method**.
- Apportion all shared generation, transmission and distribution assets and the associated operating expenses

15. Revenues and Offsets in Embedded Cost of Service Studies

15.1 Off-System Sales Revenues

Some retail cost of service studies treat wholesale sales as a separate class and allocate costs to the off-system customers. The cost of service study does not necessarily lead to any change in the off-system customers' charges (which are typically set by contracts, markets or FERC) but does help the regulator determine what share of the revenue requirement not recovered by FERC-regulated sales should be borne by each retail class. Alternatively, many utilities allocate all their costs to the retail classes and credit the export revenues back to the retail classes.[190]

In the latter approach, utilities sometimes allocate wholesale revenues to classes in proportion to their allocation of generation costs. Under this type of allocator, the greater the rate class's demand and usage, the greater its share of the off-system sales revenue. The problem with this approach is that some classes (e.g., industrials) use most of the generation capacity allocated to them throughout the year, while other classes typically pay for capacity they use in their peak season but which is available for sale in other seasons. Off-system sales revenues depend not only on the retail customers' financial support of the resources (including generating capacity) from which off-system sales are made but also on the extent to which class load shapes leave resources available to make those sales.

A more appropriate allocator would reward a class for having lower demand and usage, perhaps on a monthly basis, thereby leaving generation (and transmission) capacity available to support the off-system sales. In other words, the revenue from off-system sales should reflect classes' contribution to the availability of capacity to make the sales.[191]

15.2 Customer Advances and Contributions in Aid of Construction

As discussed in Section 11.2, most utilities charge new customers or new major loads for expansion of the delivery system, at least in some circumstances. Utilities frequently require customer advances for construction costs when they are asked to build a facility to accommodate subsequent load growth (e.g., to connect a subdivision or commercial development before some or perhaps any of the units are built and sold). The utility requires the advance to transfer to the developer the risk that the load will never materialize, or that load will grow more slowly than expected. As the load materializes, the advances are refunded to the developer. Those advances provide capital to the utility and generally are treated as a reduction of rate base; that cost reduction should be directly assigned to the customer classes for whom the advances were made.

Contributions in aid of construction are similar to customer advances but are applied in situations in which the utility does not expect the incremental net revenues from the load to cover the entire cost of the expansion. The contributions are thus a permanent payment to the utility, offsetting part of the capital cost. Contributions in aid of construction should be treated similarly to customer advances, allocated as

190 The same approach is possible with retail customers whose rates are fixed under multiyear contracts. Off-system sales revenues may vary considerably, based on market conditions, and are therefore often included in a fuel adjustment clause or similar rider between rate cases, while the base allocation is typically established in a general rate case.

191 MidAmerican Energy in Iowa proposed an hourly cost allocation method for capacity and energy in a recent case but also argued that if the Iowa Utilities Board were to use its traditional "average and excess demand" method instead, off-system sales margins should be allocated by excess demand, not by energy. "MidAmerican believes it is more appropriate to allocate wholesale margins (revenues less fuel costs) based on the excess demand component of the [average and excess] allocator, as it is from excess generation capacity that wholesale sales can be made" (Rea, 2013, p. 19).

resources are equitably allocated to the customers for whom the New York Power Authority provides the power and that all customers share the cost of incremental resources needed to serve demand in excess of incremental usage.[201]

Northwest Power Act — New Large Single Loads

The Pacific Northwest Electric Power Planning and Conservation Act of 1980 provided, among other things, for division of the economic benefits of the federal Columbia River power system among various customer groups and rate pools (Pub. L. No. 96-501; 16 U.S.C. § 839 et seq.). The act set forth a specific mechanism for the Bonneville Power Administration to charge a price based on new resources to "new large single loads" (discrete load increments of 10 average MWs or 87,600 MWhs per year, such as might be experienced if a new oil refinery were built). This provision was intended to protect existing consumers from rate increases that could result from new very large loads attracted by the low average generation costs in the region, in a period in which new resources were very expensive. Table 38 shows average rates for Bonneville Power Administration by category for recent years, including a higher rate for new resources (Bonneville Power Administration, n.d.).[202]

Table 38. Bonneville Power Administration rate summary, October 2017 to September 2019

Rate category	Average rates per MWh
Priority firm public utility average	$36.96
Priority firm public utility Tier 1	$35.57
Priority firm – IOU residential load	$61.86
Industrial power	$43.51
New resources	$78.95

Source: Bonneville Power Administration. *Current Power Rates*

Nova Scotia Power Load Retention and Economic Development Rates

In 2011, falling global demand for paper resulted in the bankruptcy and shutdown of two paper mills that were Nova Scotia Power's largest customers, which accounted for about 20% of its sales and 12% of its revenues. The mills had been major employers, both directly and as purchasers of wood harvested from forests in the province. A buyer emerged for the larger of those facilities, contingent on a variety of supportive policies from the provincial and federal governments, including favorable tax treatment and rates.

Nova Scotia Power proposed and the Nova Scotia Utility and Review Board approved (with modifications) a load retention rate that would charge the mill hourly marginal fuel and purchased power costs (including opportunity costs from lost exports), plus administrative charges and mill rates to cover variable O&M, variable capital expenditures and a contribution to capital investments and long-term O&M. The load would be entirely interruptible, and the utility committed to excluding the mill's load from its planning and commitment decisions (Nova Scotia Utility and Review Board, 2012).

The determination of Nova Scotia Power's hourly marginal costs proved to be more difficult than expected.[203] Nonetheless, the rate design succeeded in attracting the investment necessary to restart and retain the mill as an employer while producing some contribution to Nova Scotia Power's embedded costs. The load retention tariff expires in 2020, at which time the mill may switch to a firm rate or negotiate a new load retention tariff.[204]

Chelan County Public Utility District Bitcoin Rate

The creation of bitcoin cryptocurrency units requires energy-intensive mathematical computations called mining. To limit the cost of their operations, bitcoin "miners" have sought locations with low-priced electricity. Those operations

201 This same concept has been the foundation of inclining block rates in Washington state and Indonesia.

202 The average rates subsume a variety of fixed and variable charges.

203 Nova Scotia Power was not part of an energy market and had limited connections to its only neighboring utility (NB Power, which is also not part of an energy market), and its marginal generation resources are coal plants with long commitment horizons (Rudkevich, Hornby and Luckow, 2014).

204 The Nova Scotia Power system will operate differently after 2020, when it is expected to have access to large amounts of Newfoundland hydro energy and operate under stricter carbon emissions standards. Any new load retention tariff would need to reflect those changes.

typically require very large amounts of power but have few on-site employees and little local economic benefit. One of these locations is Chelan County in Washington state, where the local public utility district owns two very large dams on the Columbia River and has industrial rates about one-fourth of the national average.[205]

Chelan County Public Utility District's existing low-cost resource is fully obligated to a combination of local retail use and long-term contract sales. The contract sales prices are above the average retail rates, bringing significant revenue to fund public infrastructure in the county, including a world-class parks network. When the district received applications for service from bitcoin miners, it decided that this high-density load growth would not be in the public interest, declared a moratorium on new connections and developed a tariff designed to ensure that any growth of this type of load would not adversely affect other consumers or the local economy (Chelan County Public Utility District, 2018). This tariff is geographically differentiated, to recognize areas where transmission and distribution capacity are available, and includes:

- Payment in a one-time charge of transmission and distribution system costs to serve large new loads.
- A price for electricity, tied to (generally higher) regional wholesale market prices, not Chelan County Public Utility District system costs.
- Severe penalties for excess usage that could threaten system reliability.

205 The Chelan County Public Utility District rate for primary industrial customers up to 5 MWs with an 80% load factor is 1.91 cents per kWh (Chelan County Public Utility District, n.d.). The average U.S. industrial price was 6.88 cents per kWh in 2017 (U.S. Energy Information Administration, 2018, Table 5.c).