PUB/CAC & GAC 1 Reference: Figure 1 Benchmarking

a) Please provide a schedule of supporting calculations for MH's and other Canadian jurisdictions' position on the chart with references to supporting documents.

Please see accompanying Excel file.

In reviewing the file, we noticed an error (incorrect cell link) that resulted in an understatement of Hydro-Quebec's 2010 savings. Listed as 0.40%, the correct value is 0.55%. We apologize for the error.

b) Please explain why Mr. Dunsky did not include jurisdictional comparisons with Ontario, Saskatchewan and Alberta and what factors warranted their exclusion?

The benchmarking exercise used readily-available data covering all U.S. states. In order to include a Canadian perspective, we supplemented that with data from the Canadian provinces that were the focus of the more detailed, forward-looking benchmarking exercise we were already undertaking. This allowed us to cover some 90% of North American regions while minimizing the time and cost of the exercise. I do not believe that the inclusion of Ontario, Saskatchewan and Alberta would have materially changed the results.

c) Please comment on MH's relative position to Canadian peers?

Note to reader: the value for Hydro-Quebec was based on an incorrect cell link and has been corrected to 0.55% (see above).

In 2010, the energy savings generated by Hydro-Québec's programs were somewhat greater (27%) than Manitoba Hydro's, while savings generated in B.C. and Nova Scotia were nearly double those of Manitoba Hydro (92% and 96% higher, respectively). While one should use a single year comparison with caution, none of these values are anomalies: reported 2010 savings in the provinces with a history of DSM (B.C., Manitoba, and Québec) all fell roughly at the mid-point between their 2008 and (expected) 2012 savings. In Nova Scotia's case, annual savings are growing rapidly, and 2010 reported savings are far below those of both 2011 and 2012.

d) Please explain what additional annual expenditures MH will be required to make given current levels to achieve the top quartile position. Identify programs to be targeted.

Assuming the top quartile of performance in 2010 remains the same going forward, at least in the aggregate, Manitoba Hydro would need to achieve a minimum of approximately 1% of savings / sales to enter the top quartile. Based on current load, this would require incremental annual savings of 220 GWh.

At a typical yield of $0.30/kwh (first year)[1], the annual budgetary requirement for Manitoba

[1] Manitoba Hydro's current planned cost is $0.28/kWh (first year).

Hydro would be about $65 million.

I have not undertaken a complete assessment of Manitoba Hydro's planned portfolio of programs, though I identified in my testimony some examples of opportunities that do not seem to be targeted. Broadly speaking, each program would need to be revisited with a view to maximizing both depth of savings and participation rates.

PUB/CAC & GAC 2 Reference: Dunsky Rpt Page 6

a) Please provide a comparison between the savings over sales versus share of forecast growth approaches for MH

See response to (b) below.

b) Please explain what factors have led to the share of forecast growth not being used as a metric.

There are two primary factors:

First, savings / sales has evolved to become the industry standard benchmarking metric.

Second, the alternative "share of forecast growth" metric would have been uniquely unfair to Manitoba Hydro in the current North American economic context. As economic growth – and with it demand growth – has temporary slowed or halted in many US states, this indicator would likely have pointed to much higher ratios for states with the most affected economies, compared with Manitoba that has largely weathered the storm. The resulting values for these US states would have appeared artificially impressive, but would have been the result of a temporary economic anomaly.

c) Given MH's planned investments in new Generation and Transmission please explain which metric is most appropriate in measuring DSM efforts.

It depends on the purpose of the metric. If the purpose is to compare DSM goals and performance against other regions, the savings/sales metric is more appropriate for the reasons noted above. If the purpose is to set internal targets, both can be of value. For example, Manitoba might wish to adopt a target or requirement for DSM to cover X% of projected load growth; the resulting planned savings could then be benchmarked against other regions using a % of sales metric.

PUB/CAC & GAC 3 Reference: Dunsky Report Page 8

Please describe how rate structure changes have been utilized in other jurisdictions and comment on the applicability of these rate structures in the context of MH. Provide specific examples.

BC Hydro recently adopted a relatively aggressive revamping of its rate structures to encourage energy efficiency, and others are considering similar changes. Simply put, the rate structures include two tiers: a less expensive rate for the first tier of consumption, and a more expensive rate for the second tier.

For example, for residential customers, the utility adopted a "Conservation Rate" structure by which the first block of energy is sold at 6.8¢/kWh, and the second at 10.2¢/kWh. For business users (large and medium), a more complex structure leads to the same results: a lower-priced first block of energy (determined as 80% of the client's monthly rolling three-year historical average consumption) is less expensive, followed by a higher-priced second block (to achieve this result, a system of credits and charges is used). The higher rate is based on the long-run marginal cost of supply. Some exceptions apply.

In other regions, time-of-use (TOU) rates are increasingly adopted. This is the case in Ontario and Nova Scotia, and is likely to be adopted elsewhere in the coming years. In Ontario, customers of regulated entities can choose between tiered rates (as per B.C. above) and TOU rates. In Nova Scotia, a voluntary TOU rate is available to residential customers through which power rates vary between 6.5¢/kWh and 16.4¢/kWh. The utility also offers real-time pricing based on short-run marginal costs to its largest customers.

I have not examined Manitoba Hydro's rate and load structures, and therefore cannot recommend a given approach at this time. However, I am not aware of any reason for which the BC model could not be adapted for Manitoba Hydro. Doing so can certainly help to align rate structures with cost structures and/or with broader policy goals.

PUB/CAC & GAC 4 Reference: Page 10 Figure 4

a) Mr. Dunsky has indicated a continued decline in MH's Saving Ratios, relative to other jurisdictions. Please provide an updated comparison showing the Savings Ratio changes reflecting the evolving plans for Minnesota, Massachusetts, BC, Nova Scotia and Vermont relative to MH.

Please see the table below. Note that four of the cohort plans do not extend to 2020 and beyond. These values are also provided in Figure 5 (page 13) of my testimony.

	2010	2015	2020	2025
Minnesota	1.1%	1.4%		
Massachusetts	1.3%	2.6%		
British Columbia	0.8%	1.0%	1.1%	
Nova Scotia	0.8%	1.3%		
Vermont	2.0%	2.1%*		
Manitoba	0.4%	0.3%	0.2%	0.1%

* Data is for 2014.

b) Please provide the composition of generation resources in the jurisdictions in part (a).

See the table below.

Generation Mix – 2010 (sum may not add up to 100% due to rounding)						
	MA	**MN**	**VT**	**BC**	**NS**[a]	**MB**
Natural gas	60%	8%	0%	4%	20%	0%
Coal	19%	52%	0%	0%	57%[b]	0%
Nuclear	14%	25%	72%	0%	0%	0%
Wind	0%	9%	0%	1%	7%	1%
Biomass	3%	3%	7%	3%	0%	0%
Hydroelectric	2%	2%	20%	61%	10%[c]	98%
Others	2%	1%	0%	32%[d]	6%	1%

[a] 2011 data. [b] includes petcoke. [c] includes tidal. [d] primarily short-term purchases from hydro installations.

As the reader will note, every region's generation mix is different. We are not aware of any relationship between generation mix and energy efficiency.

PUB/CAC & GAC 5 Reference: Page 12. Comparison to Cohort

a) How does MH's new Major Generation Plans impact the future value of the Utility's energy conservation efforts?

The economic value of DSM *to the utility* is typically its long-run deferral value, i.e. its ability to defer investments in additional generation, transmission and distribution assets, and/or to defer purchases of new power from independent suppliers. Other elements of the value proposition to utilities may include risk minimization, avoided purchase of ancillary services, and avoided costs related to revenue collection (arrearages, others). This is the same framework that applies to utilities throughout North America. Manitoba Hydro's historic focus on export revenue, while not necessarily wrong, was largely an anomaly on the continent.

b) Explain whether there is a similar issue at play within the other Cohort jurisdictions?

Each of the cohort regions, to the best of my knowledge, has plans to either build new assets and/or purchase additional power, and uses the deferral value of DSM as the prime determinant of avoided costs.

PUB/CAC & GAC 6 Reference: Page 14 Exogenous Factors

a) Please indicate how MH's energy efficiency and conservation efforts are influenced by the in-service dates of Bipole III HVDC Transmission, Keeyask G.S. and Conawapa G.S.

I would not want to speculate as to the extent to which MH's energy efficiency efforts are influenced by specific capital projects. However, the anticipated need for large-scale capital investments *should* normally act as an impetus for pursuing the maximum achievable savings, to the extent that their benefit (including the capital deferral value) is greater than their cost.

b) Does MH's advancement of these in-service dates to support export sales suggest an overbuilding of hydro resources?

The answer depends on the *projected* value of the exports and the risk associated with those projections (this can be significant). This assessment is outside the scope of my current mandate.

c) Please indicate the impact of low export prices on MH's conservation efforts, given that domestic load growth achieves higher prices than export sales.

I cannot speak to whether – or how – low export prices may currently affect MH's conservation efforts. I do caution, however, that the value of DSM *to the utility* is best understood from a long-run marginal cost perspective, not one of short-term revenue collection. I also not that *if the decision to reduce the DSM effort were based on the opportunity for added revenue through increased domestic sales,* as the question suggests, such a decision would be clearly contrary to the interests of ratepayers. If followed to its logical conclusion, this would argue for a campaign in favour of energy waste, to the extent such waste results in greater revenue.

PUB/CAC & GAC 7 Reference: Page 17, Benchmarking against BC Hydro

Please provide further details on MH's plans to benchmark against BC Hydro and please comment on the applicability of BC Hydro as a model for MH to emulate.

To the first part of the question, I would not want to speculate about MH's plans to benchmark against BC Hydro. However, to the second part of the question, I am quite familiar with BC Hydro's Power Smart plan and can comment on the value of using it as a benchmark.

BC Hydro is a strong utility when it comes to DSM, and as such offers a lot of value in terms of learning lessons and achieving success in certain areas. Nonetheless, it is important to recognize that each region operates under a different set of market, weather and other sometimes unique characteristics and dynamics. For this reason, it is ill-advised to focus on a single utility.

Indeed, as much as BC Hydro does excellent work in a variety of areas, it faces unique challenges that Manitoba Hydro does not share. For example, because most of the province's homes and buildings are in a relatively temperate climate, the same dollar invested in the very same measures (e.g. insulating attics, or promoting ground source heat pumps) may generate half the savings in Vancouver as in Winnipeg. So both savings and cost-effectiveness will be significantly higher for Manitoba Hydro than for BC Hydro. As a result, BC Hydro's programs and strategies in that particular market segment may not be an appropriate "model" or benchmark for Manitoba Hydro (and vice versa). Another example: while new, inverter-driven ductless heat pumps may offer an important opportunity for savings in new multi-family buildings in Manitoba, technical barriers make it exceedingly difficult for much of BC's new multifamily units (where exterior shells are increasingly nearly-100% window).

This is why, in my benchmarking exercises, I always use a group of regions chosen to reflect a variety of critical market characteristics that may influence results. I would encourage a similar approach for Manitoba.

PUB/CAC & GAC 8 Reference: Page 19 Heating & Cooling needs.

a) Please discuss differences between available energy savings opportunities in Manitoba versus BC given the higher insulation levels at initial construction in Manitoba due to building to meet a more extreme climate.

On one hand, higher baseline insulation levels would reduce the available savings (or increase associated incremental costs), all else being equal. On the other hand, however, colder weather increases the available savings for a given investment, all else being equal. As a result, it is difficult to determine which way, on the whole, climate may impact the potential for cost-effective DSM.

This is borne out in the analysis of the cohort regions and Manitoba, presented on page 18 of my testimony. As I noted there, we do not find a relationship between heating degree days and energy savings. For example, the savings ratio in relatively cold Minnesota or Nova Scotia (upward of 3,000 HDD) is substantially higher than the ratio in much more temperate BC (1,761 HDD), yet substantially lower than in Massachusetts with its nearly as temperate weather (2,060 HDD).

b) Please confirm that the GWh sold used for determining the comparative sales ratio represents only domestic revenue sales. (Note: 1/3 of total energy sold by MH is exported)

Confirmed.

c) Please discuss the relationship between HDD and GWh sales in Manitoba and BC.

On space heating loads, HDD has a strong influence, although relative fuel prices and resulting electricity market shares within the space heating market are more important factors.

In other loads, the relationship is either weaker or non-existent. For example, industrial loads have nearly no relationship to HDDs. Water heating loads are slightly impacted, but market shares of electricity, natural gas and oil is a far more important factor. Lighting loads are unrelated to HDD (though they are related to distance from the equator, which in Manitoba and BC's case is very similar). Neither are most appliances and electronics.

On the whole, there may be a small relationship between HDD and total, economy-wide consumption, but it is speculative. This is borne out in the table provided in response to part (a) of the question below, in which we see that the average residential GWh load in Minnesota is slightly lower than that in BC, despite Minnesota being nearly twice as cold as BC (3,274 HDD in MN vs. 1,761 in BC).

d) Please indicate notionally the savings ratio for MH if the HDD were equal to that of BC.

As noted in my testimony, cold climate can work both ways in terms of DSM potentials. On one hand, a larger heating load can hinder DSM efforts because baseline building envelopes may be more efficient, or because some measures like appliances and lighting create stronger (negative) interactive effects through reduced heat losses. On the other hand, the colder the climate, the larger the savings for a given heating-related measure, thus making savings both larger and more cost-effective. Given this, it would be speculative to indicate, even notionally, the impact that a lower HDD might have, if any, on the savings potential in BC.

PUB/CAC & GAC 9 Reference: Page 19 Residential Load

a) Please indicate the average annual residential electricity load/customer in Manitoba, B.C. and Minnesota?

	MB	MN	BC
	2010-2011	*2010*	*2011*
Total residential load (GWh)	7 060	22 465	17 797
Residential customers	469 635	2 300 291	1 654 079
Average load per customer (kWh)	**15 033**	**9 766**	**10 759**

b) Please indicate the average annual DSM savings targeting residential load in (a) by jurisdiction.

See table in c) below.

c) Please provide the savings ratio from part (a) & (b).

	MB	BC	MN
	2010-11	*2011*	*2010*
Residential DSM (GWh from programs)	17.1	67.0	83.9
Residential savings/load ratio	**0.24%**	**0.38%**	**0.37%**

As we can see, the residential savings ratio is more than 50% higher in both BC and MN than in Manitoba. Given that the *overall (plan-wide)* deltas between the three regions are much larger (BC and MN's ratios are 96% and 163% higher, respectively), as indicated in the testimony, this suggests that there may be far greater room for improvement in the C&I sectors.

PUB/CAC & GAC 10 Reference: Page. 24 Baseline Efficiency

"Lower baseline efficiency should translate to larger savings, all else being equal"

a) Please provide an explanation of Baseline Efficiency.

Baseline efficiency refers to the typical level of efficiency with which energy is used for a given end-use, *in the absence* of a DSM program. For example, the baseline for window replacements may be a 2-pane low-e argon-filled window; the baseline for existing windows may be a 2-pane with no fill. Baseline efficiency of specialty lighting may be an incandescent bulb emitting 12 lumens/watt, whereas the baseline for general lighting may be a combination of incandescent and compact fluorescent bulbs, with an average 30 l/w. At a more aggregate scale, the average (baseline) consumption of existing office buildings may be 30 kWh/sf/yr. in one region, but 40 kWh/sf/yr in another.

Baseline efficiencies are different for each end-use and, within end-use can differ by market segment and/or housing type. Some are quite common across regions, but many vary by region. The purpose of energy efficiency programs is to transform markets such that in the long-run, baselines evolve toward higher efficiencies.

b) Please provide the relative Baseline from which DSM is measured for each in the cohort group.

As noted above, baseline efficiencies are measured on an end-use basis. Assessing comparative baselines across every end-use, market segment and housing type would be a very costly exercise.

PUB/CAC & GAC 11 Reference: Figure 12 Electricity Rate Comparison

Please indicate why Mr. Dunsky excluded comparisons to Quebec, Ontario, Saskatchewan and Alberta.

As indicated in the testimony, in order to broaden the scope of the analysis, we chose to include all the regions from Figure 1 that fell above the lowest of the cohort regions (Nova Scotia) in terms of 2010 performance. The provinces noted above either were not included in figure 1, or fell below the threshold.

PUB/CAC & GAC 12 Reference: Page 27. Plans vs. Real Savings

a) Please indicate what impact if any does MH's self reporting have on its DSM efforts.

Without independent evaluations, the extent to which Manitoba Hydro's self-reporting may or may not be accurate would be speculative at best. I do note that MH's "2010-2011 Power Smart Annual Review", while providing summary results, provides no indication as to how free ridership and other net-to-gross factors were determined (billing analysis, participant and non-participant surveys, measurement and verification activities, etc.), nor does it provide any of that information (these would normally be provided, on either a program or measure-level basis, in typical independent evaluations, along with a complete description of the methodology).

In my experience, independent evaluations can be extremely valuable, not only in determining actual savings, but as or more importantly, in identifying program strengths *and weaknesses* with a view to continuously improving performance by modifying program strategies accordingly.

b) How effective is the reputational incentive to succeed in DSM achievements.

Reputational incentives *may* be effective, but the degree to which they are can vary tremendously from case to case. On the other hand, legally binding requirements and financial incentives/penalties are almost always very effective.

c) Please indicate how MH's reporting and evaluation should change and explain why.

In preparing my testimony, I did not seek to examine MH's internal evaluation processes in detail. As a result, I would not want to comment on specific evaluation methodologies. However, I can certainly comment on the process.

There are many ways to approach evaluation, but they should all begin with an evaluation plan. The plan should specify which programs should undergo which types of evaluation (e.g. process, impact), at which times, and should also specify the nature of the information that should be reported. For example, the evaluation plan may be spread over 3 years; within those 3 years, some programs would undergo annual impact evaluations, while others (where impact evaluations are deemed less important) might be evaluated only once in that timeframe. The board could specify that reported results should include net and gross savings, a delineation of the factors that led from gross to net (e.g. free ridership, spillover, market effects), areas of uncertainty, costs by major category (e.g. incentives, customer support, administration), benefit/cost results, and other important variables. In all cases, the full evaluation report with detailed results and methodological descriptions should be provided as an appendix.

The board's role in the process should be an equally important consideration. For example, in some regions the utility is allowed to hire the evaluators, oversee the work, and merely submit the results to the regulator. In other regions, a committee comprised of representatives of the utility, the regulator and stakeholders oversees the scope of work and the resulting RFP, selects the evaluators, and jointly determines the information to be reported back. In another model, the regulator approves the evaluation plan, allows the utility to hire the evaluator and report their findings, but then hires an expert to independently review the evaluator's work. It is important to keep in mind that the independence of the evaluator is critical to the value of the process. From that perspective, I would urge the board to consider the two latter options.

PUB/CAC & GAC 13 Reference: Page 28 DSM Risk

a) Please explain how MH's DSM could become a dispatchable product [i.e. biddable into the MISO market]

This falls outside the scope of my testimony.

b) Please explain how DSM has less risk than:

i. New CCCT natural gas

Assuming the question refers to the option of Manitoba Hydro building its own CCCT plant, the major risks are fourfold: (1) construction cost overruns (cost risk), (2) construction schedule delays (cost and availability risk), (3) gas price forecast accuracy (cost risk), and (4) future environmental regulations related to greenhouse gas or other air emissions (cost risk). Each of these risks can be significant.

Were the CCCT to be built instead by a third party under a long-term PPA, it would depend on the terms of the contract. For example, in many PPA contracts, fuel price risk is passed on to the purchasing utility, but construction cost overruns or delays may be assumed by the IPP and built into their costing.

ii. New Hydro

The major risks associated with new hydro are the same as (1) and (2) above. In addition, if the hydro is large-scale and therefore involves a long planning and construction lead time, there is a very important risk related to (3) the accuracy of demand forecasts (for example, if in the intervening years demand grows at a slower pace than expected, the value of the asset upon coming into service may be severely depleted for many years). This should be considered a substantial cost risk. A fourth risk relates to (4) the accuracy of rainfall forecast models, especially in the context of significant climactic changes currently underway (this is both an availability and a cost risk). A final risk relates to (5) the possibility of heightened environmental regulations in the future (e.g related to fish and wildlife protection).

In contrast, the risks associated with energy efficiency are far smaller, primarily for the reasons noted in my testimony: program offerings can be ramped up or down – as well as shifted between measures, programs and sectors – as needed to ensure performance objectives are met. Furthermore, the most important exogenous factors tend to be *positive* risk factors for DSM. For example, savings opportunities are greater when economic activity is strong, which is also when loads grow fastest and DSM is most valuable. Similarly, *DSM program* savings may be at risk when governments adopt tighter codes and standards; in this case, overall energy efficiency improves for the very reason that program performance may be hindered.

PUB/CAC & GAC 14 Reference: Page 32, DSM Impact on Ratepayers

"As a reduction in DSM spending invariably – mathematically in fact – involves increases in net costs for the province's ratepayers as a whole, and further deprives consumers in the short-run of a solution to offset the effect of such increases."

a) Please provide a schedule illustrating how a reduction in DSM spending will increase net costs to ratepayers.

Using the residential sector as an example, Manitoba Hydro currently spends 1.5¢ for every kWh saved (lifetime levelized).[2] Each kWh thus saved helps Manitoba Hydro to avoid costs, according to the utility, of 8.5¢/kWh.[3] Therefore each kWh saved under Manitoba Hydro's current plan results in 7¢ of net benefit.[4]

Put differently, if Manitoba Hydro were to *not* spend the 1.5¢ it plans on spending to help residential customers reduce their bills, residential ratepayers would have to pay 8.5¢/kWh instead, as the cost necessary to either expedite construction of the next power plant (and associated T&D costs), or make up for lost export revenue. **Put in the aggregate, if Manitoba Hydro *did not* spend the $5.2 million it plans on spending in the current fiscal year, ratepayers would instead have to pay $29.5 million to support the utility's additional costs.**

b) Please provide a schedule demonstrating how a reduction in DSM spending equivalent to 100 GWh of energy savings in one year will increase net costs to ratepayers.

Using the same approach as above, let us take Manitoba Hydro's current plan. In Appendix A, we see that incremental savings of nearly that amount (92.8 GWh) are expected from the plan's first year (2011-12). To achieve those savings, Manitoba Hydro budgeted $19.9 million in that same year.[5] On page 14 of the plan, we see that the total levelized cost of kWhs produced in this plan is 1.8¢/kWh (note: this covers all sectors, whereas the example I gave previously was specific to residential). From the utility's answers to certain IRs, we understand that the avoided cost is close to 8.5¢/kWh, or a ratio of 5:1.

Assuming that the levelized cost of savings applies to savings generated in year 1, we can surmise that, had Manitoba Hydro eliminated its DSM budget for the first year of the plan, the net result would be:

	Unit Cost	**Absolute Cost**
DSM Spending	(1.8 ¢/kWh)	($19.9 M)
Utility-wide Cost (lost opportunity cost)	8.5 ¢/kWh	$94.0 M
Net Cost to Ratepayers of reducing DSM spending	**6.7 ¢/kWh**	**$74.1 M**

PUB/CAC & GAC 15 Reference: Page 33 Economic Screening RIM

[2] Manitoba Hydro, 2011 Power Smart Plan, October 2011, page 14.
[3] Manitoba Hydro, response to CAC-GAC/MH I-4(b).
[4] This comparison includes a minor simplification, in that the stated avoided costs are for a kWh levelized over a 30-yr timeframe, which may be different from the average life of residential measures. However I would not anticipate that a closer matching would significantly alter the comparison.
[5] Manitoba Hydro, 2011 Power Smart Plan, October 2011, Appendix A.

a) Is MH's financial well-being best served by increasing domestic electricity consumption which provides higher revenue rates than exports?

If choosing between selling to export or to domestic customers, and if ignoring the interests of said customers, then yes MH's financial interest is best served as described.

If choosing between increasing sales – to export *or* domestically – and not increasing sales, the answer depends on the associated costs and revenues. In the current case, Manitoba Hydro's long-run marginal cost of increasing sales to domestic customers appears to be 8.5¢/kWh[6], while the current plan's cost to reduce sales growth is pegged at 1.8¢/kWh. Arguably, this suggests that the long-run financial well-being of MH is best served by efforts at reducing sales growth. If accounting for lost revenues, then all depends on which customer categories are involved: residential at 6.9¢/kWh, general service at between 2.8-3.3¢ (last block, not counting demand changes, depending on customer size).

In practice, the financial impact of any scenario depends on how rates adjust to costs.

Of course, the financial well-being of MH's domestic customers - whose bills would increase to ensure the greater domestic sales - is another matter altogether.

b) Please comment on the MH's marginal cost employed in RIM, TRC and other tests.

My scope of work did not include an assessment of Manitoba Hydro's marginal cost methodology.

PUB/CAC & GAC 16 Reference: Page 33 Economic Screening

a) Please provide a description of each of the screening methods and the relative strengths and weaknesses related to each approach for determining the level of DSM investments.

Screening methods are both valuable (for providing guidance) and subject to misuse (when miscalculated, or when used in ratio form to optimize portfolios).

Currently in North America, there are three types of tests:

- **TRC:** The TRC is meant to account for the sum of utility and participant perspectives. A variant of the TRC, the SCT, further accounts for societal benefits. The TRC is increasingly controversial, as a growing number of studies are finding that it is being used incorrectly. In so doing, the TRC as commonly applied misses significant benefits – primarily but not exclusively participant benefits –, while overstating costs. A number of regions, especially those that lead on DSM, are now moving to either substantively modify the TRC, or move to the Program Administrator Cost test (PACT, previously known as the Utility Cost Test).

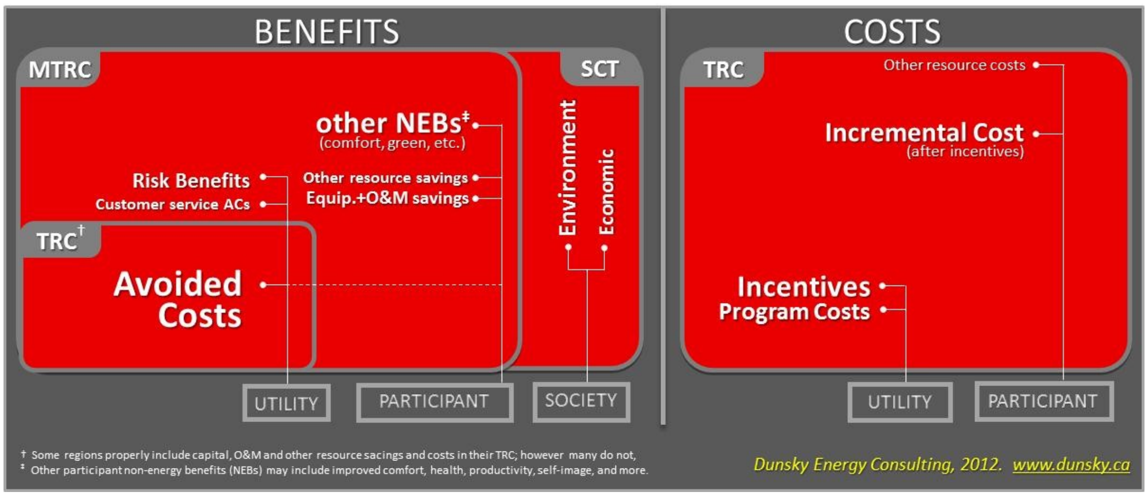
[6] Manitoba Hydro, response to CAC-GAC/MH I-4(b). Note that this applies to residential and most commercial/institutional customers; the cost to transmission-linked large industrial customers may be somewhat lower.

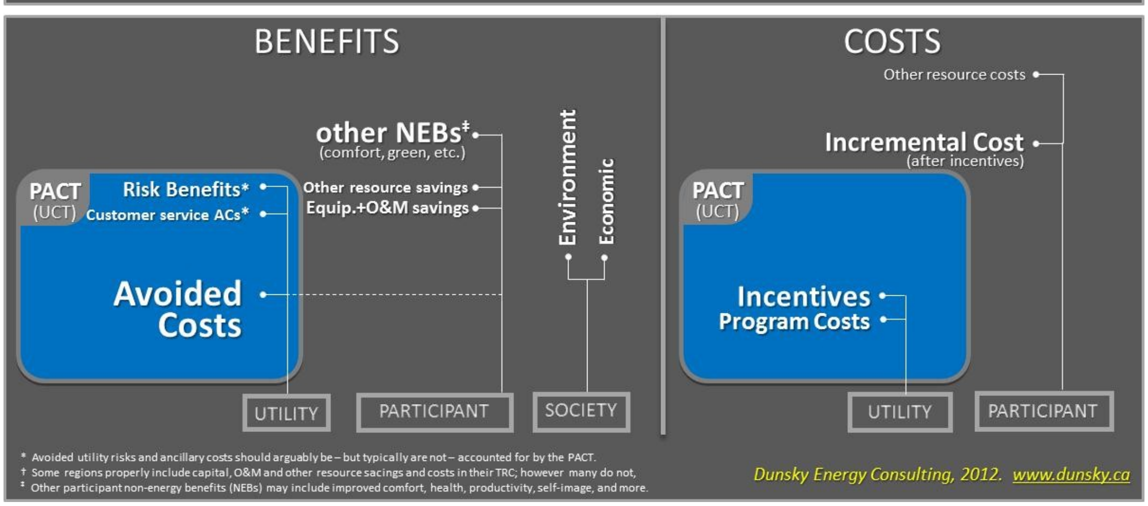
- **PACT:** The PACT treats DSM on the same footing as new supply, i.e. it accounts for the utility's cost, and the utility's benefit (avoided costs). It is a simpler, more straightforward approach. It is considered both less comprehensive, and fairer.

- **Others:** I understand that Manitoba Hydro continues to use the RIM test (though it is not clear to what extent). I note that in North America today, the RIM is rarely if ever used as a primary screening test.

Across our cohort regions, two (Vermont and Minnesota) use the SCT, two (B.C. and Massachusetts) use a substantively Modified TRC, and one (N.S. uses a classic TRC, though this is currently under review).

The following charts illustrate the boundaries of the various tests *as they are commonly applied*.





As important as the choice of tests may be, equally critical is how they are used. For example, while the tests may provide guidance, they should only be used as hard screens at either the portfolio (plan) or sector level. It is entirely normal for plans to contain individual measures or programs that do not pass the primary test, to the extent they serve other purposes that are hard to quantify (e.g. reinforcing a brand, taking the role of "loss leader" in a retail strategy, or ensuring equity within a given rate class).

Finally, it is also critically important to choose appropriate metrics. Most tests can be expressed in one of three ways: absolute terms (NPV), ratios (B/C), or unit terms ($/kWh). While a B/C ratio is important to understand *whether* a DSM plan screens positively, it is not appropriate when examining different strategic options for a specific program. For example, a program administrator may be considering two different options regarding incentive levels for a given program. Under option A, the utility would provide very low incentives, which would generate both low participation and high free ridership among participants. Under option B, the utility would provide high incentives, which would generate high participation but (arguably) cost the utility more money for every kWh saved. If the program manager used the simple PACT test (aka Utility Cost Test), option A would show a much better B/C ratio, even though option B might maximize the net present value of the program.

Finally, I should note that beyond the choice of tests and their application context, users ought take care in determining appropriate inputs. Recent work, including by my firm and others, has found important errors in the inputs used to determine costs and benefits.

b) Please indicate the implications on DSM spending behind Mr. Dunsky's suspicion related to MH's screening practices.

To clarify, I did not point to a "suspicion" as much as addressed a variety of reasons that *may* explain Manitoba Hydro's DSM plan. Screening practices may or may not be among them.

If Manitoba Hydro were either placing too much emphasis on the RIM, or using a flawed version of the TRC, the impact could be to underestimate the net value of DSM options and, as a result, not pursue certain options. More importantly, if the tests are being used to optimize program designs, but NPV is not used as the metric, then there is a real risk that programs are being designed to produce minimal effect.

For example, I understand that the Levelized Utility Cost (LUC) is a critical consideration for Manitoba Hydro in screening DSM opportunities. The LUC effectively provides valuable information, and in many cases may be entirely appropriate to gage the value proposition of the plan as a whole (if the LUC is less than the avoided costs, which MH has determined as 8.5¢ for most end-uses, we know it is positive). However, if the LUC is used to compare program design *options*, then it will systematically bias toward weak programs that do not maximize utility or ratepayer interests.

The table below provides an example. Here the program manager is examining three different levels of incentives – 10%, 40%, or 70% – that she could offer to promote home energy retrofits. The retrofits themselves are expected to cost $5,000 on average, and generate 4,000 kWh of savings with an estimated useful life of 25 years. We assume an avoided cost of 8.5¢/kWh and a 6% discount rate.

Options	Incentive		Participation		Utility Results			
	% of Cost	$/part.	Homes	% Free Riders	**M$ Cost**	**LUC**	**M$ Benefit**	**NPV**
A	**10%**	$500	100	60%	$50,000	**$0.02**	$173,854	$123,854
B	**40%**	$2,000	1000	20%	$2,000,000	$0.05	$3,477,073	**$1,477,073**
C	**70%**	$3,500	2000	10%	$7,000,000	$0.08	$7,823,414	$823,414

As we can see, if the program manager were asked to determine the appropriate option based on the LUC, she would choose option A, the cheapest one. This looks very good on a per-unit basis. However, the LUC ignores the # of units produced. As we can see, option B actually maximizes the utility's net present value, i.e. it is the least cost option for Manitoba Hydro's ratepayers. By focusing on the LUC, the manager would have forfeited more than $1.3M in net benefits (not to mention 3.2 GWh of incremental annual savings).

It is worth reiterating that I am not privy to how Manitoba Hydro uses its screening tools, and am only speculating as to *possible* approaches that may help to explain the surprisingly low planned savings.

PUB/CAC & GAC 17 Reference: Page 36 DHPs

a) Please file the referenced study prepared by Mr. Dunsky's firm.

To clarify, we referred to an analysis conducted by my firm for purposes of this testimony. For purposes of this analysis, we used an algorithm calculation using the median Heating Seasonal Performance Factor (HSPF) of Mitsubishi Mr. Slim models. Nameplate HSPF value was adjusted to account for colder Canadian climate, and we further assumed that the heat pump would only supply heat to part of the home. In real life, mini-split systems can have multiple heads and/or multiple compressors to supply heat to a larger portion of the home (and savings can represent a larger share of heating loads). On the other hand, Winnipeg is colder than average Canadian cities, so we supplemented this initial estimate with other references.

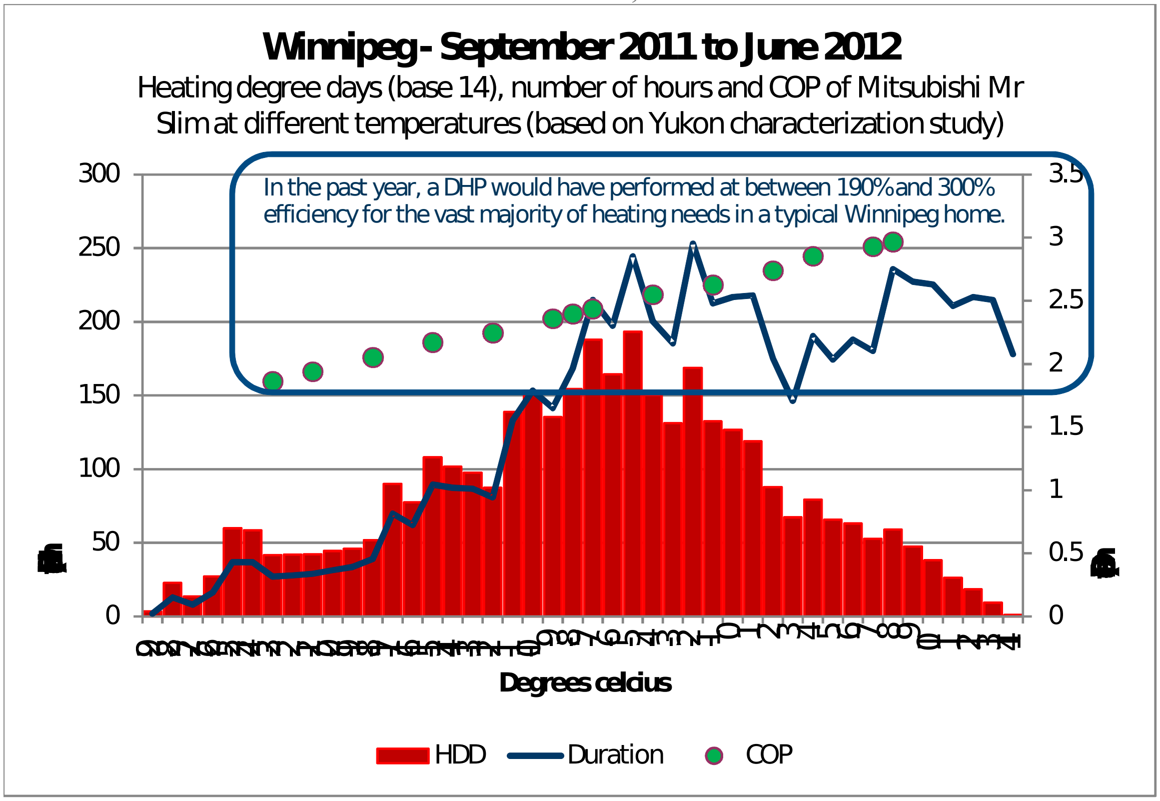
A heat pump characterization study, conducted in Yukon and published in March 2010, has shown that cold climate heat pumps can supply a large portion of heating while maintaining good performance at low temperature. The study recommends that a heat pump be sized to supply 25% to 35% of the house heating load at -18 °C. A heat pump of this size will supply 60% to 75% of the annual heating load. As cold climate heat pumps maintain a COP of 2 and above at low temperatures , this would translate roughly into 30% to 40% savings on the annual heating load in the much colder climate of Whitehorse.

A heat pump energy efficiency reference guide, funded in part by Manitoba Hydro, also give an estimate of 30% to 45% savings from air source heat pumps over electric resistance heating for most of Manitoba including Winnipeg. This estimate is for all air source heat pumps and does not specifically refer to high efficiency, inverter-driven mini-split systems.

Finally, a very large pilot program launched in the Northwest US (a total of 16,000 units have now been installed in Idaho, Oregon, Montana and Washington states) confirmed ductless heat pump real-life performance with metering of a sample of installations (95 homes), including billing analysis and in-situ COP measurement, and with detailed laboratory testing . Results of the laboratory tests were compared to in-situ field monitoring data, and were found “surprisingly consistent”.

The initial assumption was that the DHP would provide up to 60% of the space heat and result in a 30% to 40% reduction in space heating energy requirements. The actual fraction of house heated by the DHP was, on average, higher than excepted (67%), but lower (45%) for the coldest region. This is explained by the fact that the pilot’s general approach was to market the system as a “displacement” technology— a technology that would partially offset the existing space heating. The systems were thought to be optimized with a single outdoor compressor and one or two indoor air handlers. It is also important to note that systems with more than two indoor units or one outdoor unit that actually entered the pilot program were not metered during the subsequent impact analysis. The “one head – one compressor” configuration represents a relatively low-cost way to supply the needs of a major portion of the heating load, but is less efficient in colder climate. In colder regions, the effect of multiple heads is to offset the load more effectively and reduce the time that the electric resistance operates (the effect of multiple heads is much smaller in warmer regions). Optimizing the configuration for Manitoba’s climate would necessarily improve this result.

As can be seen on the following graph, the Mitsubishi Mr Slim maintains a COP value above 2 up to -18 °C, meaning the heat provided at this low temperature is still twice as efficient as electric resistance heating (or takes half the quantity of kWh for the same output). Temperatures colder than -18 °C represent a very small proportion of the Winnipeg winter, both in terms of duration and heating requirements (HDDs). Heating needs peak at about 5 °C, where the COP is near 2.5.



Finally, my firm conducted an analysis for the present IR round using the Hot2000 modeling software and a single-family detached house located in Winnipeg with an annual heating load of 60 GJ. Electric savings due to the installation of a DHP represented 36% of the heating load. This result is again consistent with our earlier estimate, as with the literature review. Please refer to MH/CAC/GAC (Dunsky)-3 for more information.

b) Please indicate the source of the information that supports the claim that there are 13,750 new electrically heated homes built in Manitoba annually.

The correct value should read “approximately 2,750”. This is from Manitoba Hydro’s response to CAC-GAC/MH II-4(a), in which 13,750 was provided as the value for new housing starts that use electric heat. I failed to notice that this value was not annual but covered the five-year period from 2005-2009.

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Please indicate to what extent increased DSM spending could defer the current need for new Generation in MH’s current plans.

To answer this question, we examine two scenarios:

In the first scenario, program-related savings are increased such that, when combined with MH's anticipated *other* savings (codes, standards, self-gen), total savings achieve and maintain a 1% savings/sales ratio. This implies that Manitoba Hydro's programs alone achieve a ratio of approximately 0.6% every year on average.

In the second scenario, program savings are increased such that, combined with other savings sources, the total achieves 1.5%/year on average. For comparison purposes, we note that over the next ten years (2012-2021), B.C.'s *average* equivalent total savings ratio is 1.7%.

Under the 1% scenario (0.6% from programs), additional savings of 637 GWh are generated by the time the Keeyask project is supposed to be commissioned (in-service date 2019/20). This allows Manitoba Hydro to defer this project by three years (assuming that exports do not change). The Conawapa project, scheduled to be commissioned in 2024/25, would be deferred by 7 years (to 2031/32). I note that this analysis is based on energy needs; I have not had the time to conduct the analysis of capacity needs needed to confirm these values.

Under the 1.5% scenario, additional savings of 1,385 GWh/yr by 2019/20 would allow for Keeyask to be deferred by 12 years (to 2031/32). I did not calculate the expected in-service date for the Conawapa project under this scenario as this would be too speculative.

On the cost side, the reader will recall (see Fig. 16 of my testimony) that Manitoba Hydro's current savings cost some 28¢/$kWh_{1st\text{-}YR}$ (this is not to be confused with levelized lifetime savings). This is slightly below the costs incurred by BC Hydro, Efficiency Nova Scotia, and Vermont (30¢/kWh). Assuming that Manitoba Hydro's unit costs increase to 30¢/kWh, Manitoba Hydro would have to spend an additional $191 million (cumulative) by 2019/20 for the 1% scenario, or $416 million (cumulative) for the 1.5% scenario. Of course, other DSM options like codes & standards, and rate structures, are a lot cheaper from the utility's point of view, and would decrease the amount of additional spending required.

	Business as usual	**1% DSM target***	**1.5% DSM target***
Additional savings by 2019/20	---	637 GWh	1 385 GWh
Additional spending by 2019/20	---	$191 M or less	$416 M or less
Keeyask in-service date	2019/20	**2022/23**	**2031/32**
Conawapa in-service date	2024/25	**2031/32**	**?**

* *Includes all of Manitoba Hydro's anticipated savings from codes, standards, and self-generation. The implied MH program-related savings ratios are 0.6% and 1.1%/year, the latter being approximately the same as BC Hydro's.*