SUBJECT: DSM Potential Study - Benchmark

REFERENCE: Pages 19, 23

PREAMBLE:

Mr. Dunsky's report provides a chart in Figure 7 with an update of the benchmarking exercise prepared for last year's GRA that compares recent savings across many states and a few provinces.

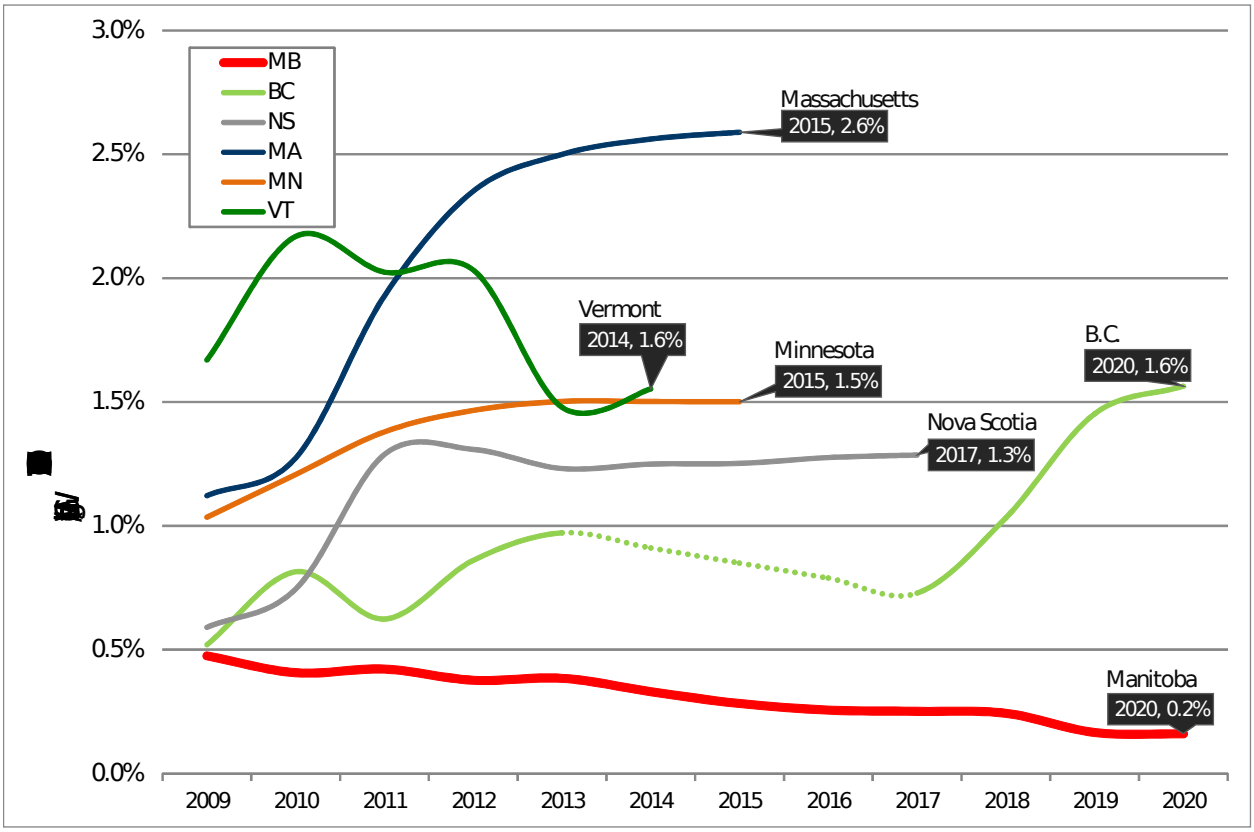
QUESTION:

Please provide an update of the benchmarking of the forward-looking DSM goals of the 5 "cohort" regions considered previously for the GRA, or if this cannot be provided, please explain why.

RESPONSE:

Below is an update of last year's cohort analysis. Please note that to facilitate comparisons, the chart below is limited to DSM programs only, and therefore does not include additional savings from codes and standards, nor from conservation-inducing rate structure changes.

22 Planned Energy Efficiency: Manitoba and Five Cohort Regions



23

SUBJECT: Demand-side management

REFERENCE: Dunsky report, page 25

PREAMBLE:

Electricity Targets. The x-axis on Figure 10 is not labelled.

QUESTION:

Please indicate the x-axis in Figure 10.

RESPONSE:

The X-axis represents the specific jurisdiction. Jurisdictions are sorted first by country, then by alphabetical order. The label appears next to each plot in the graph.

SUBJECT: Demand-side management

REFERENCE: Dunsky report, page 34

PREAMBLE:

DSM Program Costs. It is unclear whether Figure 13 of Mr. Dunsky's report reflects gross total resource costs (TRC), or TRC net of benefits, or something else.

The numbers used by Manitoba Hydro in the NFAT filing for DSM program costs appear to reflect gross TRC for DSM and not TRC net of benefits (i.e. gas benefits, capacity benefits, non-energy benefits, etc.). Though many of these other benefits would accrue to the customer and not the utility, it is not clear that none of them would accrue to the utility.

To illustrate the role that these other benefits can play in determining the net TRC for DSM, I am attaching a copy of BC Hydro's Figure 6-10 from its Draft 2012 IRP. The graph shows the DSM TRC Average for the 5 DSM resource options considered by BC Hydro in its IRP. The difference between the "pre" and "post" columns illustrates the effect of amended DSM regulation. As BC Hydro rightly points out, "including these additional benefits drastically decreases the cost of DSM..."

QUESTION:

In determining the cost of DSM savings, please indicate whether the reported cost proposed for planning purposes of 3.5 cents/kWh is net of benefits that might acrrue to the utility, net of benefits that might accrue to both the utility and the ratepayer, is equivalent to gross TRC, or is something else.

RESPONSE:

The cost of 3.5 cents/kWh refers to the levelized utility cost of energy. This metric looks only at the costs side of the equation, allowing for a direct comparison with the levelized costs of supply options. It is true, as the MMF notes in its question, that DSM also brings additional benefits, on top of energy savings, that are not captured here, and that the BC Hydro approach would result in reducing the 3.5 ¢/kWh considerably.

SUBJECT: Solar

REFERENCE: Page 37

PREAMBLE: **Future solar prices. We agree that Hydro's projections for cost declines in solar PV may be overstated. Nonetheless, the potential error may not be in the price of hardware (i.e. panels, inverters, etc.) but in the price of "soft" costs (installation, permitting, etc.). To use some rough numbers, a typical 4kW residential system costed about $30,000 to install in Ontario in 2009, of which about $18,000 was hardware and $12,000 was soft costs. In 2014, the same system costs about $18,000 installed, of which about $6,000-$7,000 is hardware and $11,000 to $12,000 is soft costs. In other words, the soft costs have declined only marginally.**

Other jurisdictions (e.g. Germany, California) have seen greater declines in soft costs with 4 kW residential systems now being installed for $8000-$10,000 in soft costs, or even less. In any case, soft costs have not fallen nearly as quickly as hardware costs.

As a result, in Figure 14, we would have expected more of a levelling off of the system cost lines as hardware costs become a decreasing part of total installed costs and soft costs decline more modestly.

QUESTION:

Please explain and justify the use of a 5% annual decline in total costs for installed PV, explain the role that "soft costs" play in overall installed PV costs, and discuss how those soft costs could

decline in Manitoba or more generally in the future.

RESPONSE:

Although definitions vary throughout the literature, “soft” costs of a solar PV system generally encompass solar PV installation costs, permitting costs, and financing costs.

Our model looks at most of those costs separately. Solar PV permitting costs are assumed to be negligible for residential systems below 10 kW, as most regions neighbouring Manitoba only require an electrical permit for small installations, representing less than 1% of total system cost. Financing costs are represented by the discount rate applied to the customer’s revenue stream. Finally, installation costs are included in the rate of decrease of installed system prices, which have been estimated at an average of 5% for the Manitoba region based on several sources (CanSIA 2013) (Pye 2013).

Sources:

Barbose, Galen. 2013. *Tracking the Sun VI.* Lawrence Berkeley National Laboratory.

CanSIA. 2013. *Revising Ontario's Long-Term Energy Plan.* Canadian Solar Industries Association.

Pye, Andrew. 2013. *Solar Photovoltaics: Grid Parity in British Columbia.* Victoria: BC Sustainable Energy Association.

SUBJECT: Solar

REFERENCE: Page 37

PREAMBLE: **Residential Solar PV System Grid Parity. The dates for grid parity were determined inclusive of incentives (i.e. the fee-in-tariff in Ontario, and tax incentives in the US).**

QUESTIONS:

a) **Please provide the grid parity dates assuming no feed-in tariff in Ontario.**

b) **Please provide the grid parity dates for all jurisdictions in Figure 15 with no tax incentives or feed in tariffs.**

RESPONSE:

The parity dates assuming no incentives for each jurisdiction, including Ontario, is provided in the table below.

JURISDICTION	PARITY YEAR AT LOW LCOE SCENARIO	PARITY YEAR AT HIGH LCOE SCENARIO
MANITOBA	2018	2026
SASKATCHEWAN	2014	2019
ONTARIO	2016	2022
MINNESOTA	2013	2018
NORTH DAKOTA	2017	2023

SUBJECT:

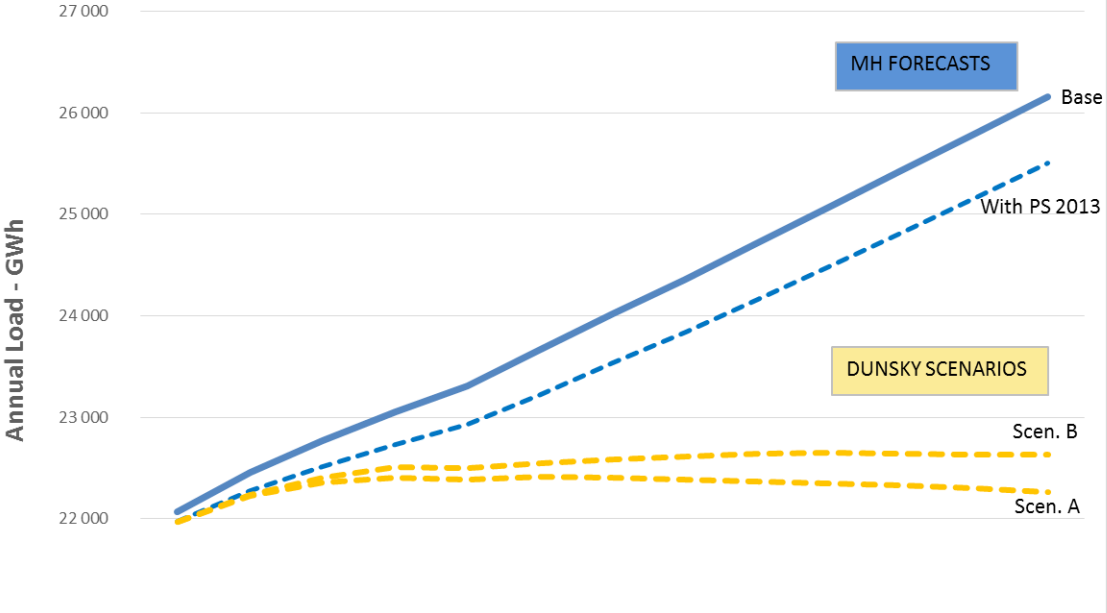
REFERENCE: Dunsky Report

QUESTION:

What are the implications of your evidence for the load forecast of Manitoba Hydro and the timing of projected need for additional generation for the purposes of addressing energy constraints and for the purposes of addressing capacity constraints.

RESPONSE:

The ability of DSM to play a much greater role in lowering demand implies that, if Manitoba Hydro were to focus greater effort on DSM, the forecast would be revised downward significantly. Specifically, the following chart illustrates the impact of our two scenarios:



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base Load Forecast (2013)	22 070	22 455	22 768	23 053	23 313	23 670	24 019	24 363	24 722	25 081	25 440	25 797	26 152
Load Forecast with PS 2013	21 974	22 275	22 513	22 732	22 929	23 225	23 533	23 842	24 165	24 489	24 822	25 165	25 506
Dunsky Scenario A	21 974	22 224	22 355	22 410	22 390	22 415	22 404	22 383	22 371	22 354	22 331	22 301	22 264
Dunsky Scenario B	21 974	22 237	22 402	22 506	22 499	22 551	22 587	22 614	22 647	22 655	22 645	22 636	22 629

As a practical matter, this would obviate the need for Keeyask, assuming Keeyask is built to meet internal needs. To the extent that Keeyask is built instead to respond to near-term export opportunities, with a view to eventually transitioning to meeting local needs, then the lower projected demands would imply that the business case for Keeyask should depend indefinitely on the anticipated revenue from export sales. As a practical matter, this would imply that new generation is built essentially as a "pure export play", and its value proposition would depend on projected export revenues generating sufficient margins, over the long term and accounting for risk, over the cost of building and operating the generation assets.

I note that the demand curve above is similar to the “flattened” curves that many other states and provinces are now planning for, in large part due to accelerated DSM efforts. See my response to PUB-CAC_GAC-008a for examples.