SUBJECT: DSM

REFERENCE: Page 6

PREAMBLE:

Your report states that "DSM cannot be addressed only with uncertainty analysis, once the die is cast and supply options have been chosen; rather, they must be an integral part of the options considered at the outset. Failure to do so will result in an exaggerated focus on supply solutions."

QUESTION:

Please comment on how, as a practical matter, approaching DSM as a resource in an integrated resource plan leads to a different outcome than using DSM to reduce the load forecast.

RESPONSE:

When DSM is treated as a resource in an IRP, the process looks for the highest-value and/or lowest cost option among all resources. Since DSM tends to cost significantly less than other resource options, as a practical matter this usually means that all or most available DSM is first selected. Only once that lowest-cost resource is selected are other, supply-side options examined, either to meet the remaining growth in demand, to compete against continued operation of existing plants, and/or to replace planned retirements.

Inversely, when DSM is treated as a sensitivity analysis, the process focuses first and foremost on new supply options. Once the initial set of options (or bundles thereof) are selected for further analysis, they are compared on a number of parameters, including their ability to adjust to lower-than-anticipated demand (in effect, a DSM sensitivity is little more than a demand sensitivity analysis). As a practical matter, this tells us which supply resources are most

flexible to adjust to an unexpected change in demand, but does not tell us whether the resource is needed or of value in the first place. Worse, this leads to commitments -- or in the very least, organizational focus -- on these supply options coming on line, which can then lead to a neglect, as a practical matter, of (lower-cost) DSM options.

SUBJECT: DSM

REFERENCE: Page 6

PREAMBLE:

Your report states that "DSM cannot be addressed only with uncertainty analysis, once the die is cast and supply options have been chosen; rather, they must be an integral part of the options considered at the outset. Failure to do so will result in an exaggerated focus on supply solutions."

QUESTION:

Please confirm that as a resource, DSM would be evaluated against the marginal cost of new generation alternatives. If not, please explain.

RESPONSE:

Generally this is the case, with some caveats. In practice, DSM should compete with the marginal cost of all alternatives, which typically includes new generation as well as any related T&D costs that DSM can avoid. In some regions, DSM may also compete against continued operation of existing plants, though this is not relevant to a hydropower region where the marginal cost of operations is for all intents and purposes nil. It is also worth noting that "marginal cost" itself can include different components, including energy and capacity, and can also account for air emissions and risk factors (this is done in some regions by incorporating a proxy adder to the marginal cost of supply or, in others, by reducing the cost of DSM by a similar factor).

SUBJECT: DSM

REFERENCE: Page 6

PREAMBLE:

Your report states that "DSM cannot be addressed only with uncertainty analysis, once the die is cast and supply options have been chosen; rather, they must be an integral part of the options considered at the outset. Failure to do so will result in an exaggerated focus on supply solutions."

QUESTION:

Please comment on how one would reconcile least-cost resource planning with other parameters applied to DSM, such as the societal cost test.

RESPONSE:

Least-cost planning is designed to choose the lowest cost (and risk) resources to balance supply and demand. The "cost" in question can be narrow or broad in scope. For example, it can be focused solely on minimizing the utility's costs, or more broadly on minimizing society's costs. If the goal is the former, then the Program Administrator Cost (PAC) test is the most consistent way to screen DSM; if the latter, then the Societal Cost Test is most consistent.

SUBJECT: DSM

REFERENCE: Page 6

PREAMBLE:

For IRP purposes, DSM resources must be characterized at a relatively high level; for example a "potential study" may define different DSM scenarios. MH has completed a DSM potential study and Dunsky has critiqued the study and results.

QUESTION:

Are the IRP process DSM "potential study" and the DSM potential study completed for MH the same concept and is the approach the same?

RESPONSE:

Yes, the potential study normally identifies a Maximum Achievable Cost Effective (MACE) potential. That potential can be used to characterize the DSM resource that is then included in the IRP and allowed to compete against other options. When the potential study is being conducted specifically to feed an IRP, it can also examine multiple scenarios. While MH's potential study has shortcomings that impact its results, conceptually it can and should be used to characterize the DSM resource.

SUBJECT: DSM

REFERENCE: Page 6

PREAMBLE:

For IRP purposes, DSM resources must be characterized at a relatively high level; for example a "potential study" may define different DSM scenarios. MH has completed a DSM potential study and Dunsky has critiqued the study and results.

QUESTION:

How do Dunsky's proposed Scenario A and Scenario B targets fit conceptually into an IRP in this NFAT process? Are different DSM target assumptions required for the proper IRP approach? Explain.

RESPONSE:

If this were an IRP process, I would recommend developing 2-3 DSM scenarios that could "compete" against other (supply-side) resources. Each DSM resource would be characterized with different anticipated energy and capacity outputs (e.g. our two scenarios), costs, lifespans, and levels of risk. I note that the number of DSM scenarios is not fixed in stone -- for example, Nova Scotia Power's previous IRP included only one DSM scenario, while BC Hydro's examined several DSM scenarios. Nonetheless, the development of multiple scenarios can be helpful, for example to compare a "maximum achievable" scenario with a more limited one, or to compare portfolios that put more or less emphasis on peak vs. energy savings.

SUBJECT: DSM

REFERENCE: Page 9

PREAMBLE:

Figure 4 depicts NERC DSM Peak Demand Offset Forecast in GW to the Year 2022.

QUESTION:

Provide the MISO region data from the NERC forecast and graphically display the MISO region data for DSM Peak Demand Offset to 2022.

RESPONSE:

The data required to plot the MISO region separately is not available within the body of the report. We sent a request to the authors requesting the required data. No response was received by the time of the writing of this response.

SUBJECT: DSM

REFERENCE: Page 9

PREAMBLE:

Figure 4 depicts NERC DSM Peak Demand Offset Forecast in GW to the Year 2022.

QUESTION:

How does the U.S. DSM peak demand offset impact U.S. demand and long term pricing for MH's power?

RESPONSE:

I included the chart referred to in the preamble to illustrate the ability of demand response and other DSM programs to be used as a resource to meet needs without new generation assets. In terms of MH's exports specifically, I assume that demand-side peak resources are already accounted for by those States with which MH has entered into discussions for power exports.

SUBJECT: DSM

REFERENCE: Pages 8-9, 40

PREAMBLE:

Your report states that "As noted previously, DSM can help to meet energy as well as capacity needs (figure 3). Depending on the targeted end-uses and technologies, DSM and its various components can meet baseload, peak or "needle peak" needs, much the same way traditional supply does."

QUESTION:

Have you considered which of Manitoba Hydro's existing DSM initiatives would be dependable or dispatchable? If so, please elaborate.

RESPONSE:

The terms dependable and dispatchable are not standardized. The definitions we use here are :

- **Dependable: energy that can be counted on for planning purposes (e.g. over one or several years)**
- **Dispatchable: loads that may be curtailed or shifted to meet system needs within a reasonably short timeframe (e.g. minutes)**

Using these definitions, Manitoba Hydro's Load Management Curtailable Rates program is the only dispatchable program. The remaining initiatives, taken together, provide dependable power.

SUBJECT: DSM Potential Study - Benchmark

REFERENCE: Page 8-9

PREAMBLE:

Your report states that "As noted previously, DSM can help to meet energy as well as capacity needs (figure 3). Depending on the targeted end-uses and technologies, DSM and its various components can meet baseload, peak or "needle peak" needs, much the same way traditional supply does."

QUESTION:

Please advise whether in your view, all of the DSM categories shown in Figure 3 are dependable or dispatchable. Please explain your reasons.

RESPONSE:

See CAC_GAC-004a for relevant definitions of dependable and dispatchable.

The table below provides a indication as to the dispatchabiltiy and/or dependability of each resource listed in figure 3. The comments apply to the general case with the particular case dependant on the type of measure installed. Different measures within the same resource can have different characteristics, so the classification is meant to provide a high level grouping.

Also the resource categories below are not disjoint. For example since direct load control is listed as a separate resource, all resources that can be enrolled in DLC programs (advanced thermostats, HVAC systems, etc) have that feature covered by the

DLC entry.

Resource	Dependable/ Dispatchable	Notes
Interruptible Loads	**Dispatchable**	**Can be called on utility request**
Direct Load Control	**Dispatchable**	**Can be called on utility request**
TOU Rates	**Both**	**Dependable: "static" TOU rates designed around time periods in the day encourage long term behavior change and would be considered dependable** **Dispatchable: real-time pricing or critical-peak pricing programs create predictable responses (customers shed loads) to price signals and can be considered dispatchable**[1]
Progressive Rate Structures	**Dependable**	**Encourages long term behavior change**
Fuel Switching	**Both**	**Dependable: Programs that replace original equipment with altenative non-electric equipment would be dependable.** **Dispatchable: Programs that supplement orginal equipment with alternative non-electric equipment (e.g. bi-energy programs) can be designed to provide dispatchable capacity.**[2]

1 Dispatchability in this case is subject to debate. For example, in California, TOU rates are considered dispatchable; in other regions they may not be. Ultimately their dispatchability increases with experience (as the accuracy of response predictions increases).

2 This is the case in Quebec, for example, where a long history of dual energy ("bi-énergie") provides Hydro-Québec with capacity while maintaining its baseload of electric heat.

Demand-side Renewables	**Partly Dependable**	**When aggregating power output across a diverse set of technologies (eg. Solar and wind) and sites (in various regions of a province), combined with ongoing improvements in weather forecasting, *a portion of* renewable output can be considered dependable on an annual or pluriannual basis.**
Building Envelope	**Dependable**	**Lowers power consumption**
Advanced Thermostats	**Dependable**	**Lowers power consumption**
HVAC Systems	**Dependable**	**Lowers power consumption**
Hot Water Systems	**Dependable**	**Lowers power consumption**
Lighting (incl Controls)	**Dependable**	**Lowers power consumption**
Appliances	**Dependable**	**Lowers power consumption**
Industrial Processess	**Dependable**	**Lowers power consumption**
Motors	**Dependable**	**Lowers power consumption**

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SUBJECT: DSM

REFERENCE: Dunsky report, Pages 8-9

PREAMBLE:

Your report states that "As noted previously, DSM can help to meet energy as well as capacity needs (figure 3). Depending on the targeted end-uses and technologies, DSM and its various components can meet baseload, peak or “needle peak” needs, much the same way traditional supply does."

QUESTION:

Is the concept of "biddable" DSM referred to on page 9 the same as dispatchable DSM? If not, please explain the difference.

RESPONSE:

No. "Biddable" refers to a resource that can be offered through a competitive bid process, while "dispatcheable" resources are those that can be ramped up or shut down in a short period of time.

SUBJECT: DSM

REFERENCE: Page 11

PREAMBLE:

Your report states that "A critical but oft-neglected resource planning risk is the risk inherent in demand forecasting, i.e. the risk that we invest to meet a need that fails to materialize (or inversely, that we fail to invest on time to meet a real need). DSM addresses this risk in two important ways: first, investment in DSM can be ramped up or down as needed to match needs as they evolve, and second, DSM potential itself is strongly correlated with demand, such that as demand grows, DSM “auto-adjusts” by increasing production (and inversely, as demand shrinks or grows more slowly, so too do DSM savings)."

QUESTION:

How is this statement impacted by the timeframes required to implement different types of DSM? Is the timing of new generation as a resource easier to predict then the timing of successful DSM measures?

RESPONSE:

I am not aware of any empirical studies that compare the accuracy of predictions for bringing demand vs. supply resources on-line. From my experience, each resource type incurs different types of timing-related risks:

- **Supply resources may suffer delays due to siting approvals, labour disruptions (e.g. strikes), and technical problems (e.g. structural deficiencies in dams discovered during testing). Their risk of occurence is relatively limited, but their occurence will typically delay 100% of output.**
- **Demand resources, meanwhile, may suffer delays due to lower-**

than-anticipated initial uptake or installation, both of which require adjustments in program design and implementation. Their risk of occurence is greater, but their occurence will typically delay only a fraction of output.

From my experience, these risks are both lower than the risk associated with load forecasts, which is purely a function of each resource’s lead time (i.e. the length of the forecast required – the longer the timeframe, the greater the risk of over- or under-estimating demand). In this regard, I note that DSM's lead time is significantly shorter than those of most supply resources.

SUBJECT: DSM

REFERENCE: Dunsky report, page 12

PREAMBLE:

Figure 6 sets out a chart prepared by Binz et al. that plots the risk and resource costs of different resources.

QUESTION:

Please provide the reasoning behind the risk allocation.

RESPONSE:

The relative risk displayed in the graph is a composite risk evaluated according to seven main categories: Construction Cost Risk, Fuel and Operating Cost Risk, New Regulation Risk, Carbon Price Risk, Water Constraint Risk, Capital Shock Risk, and Planning Risk.

The complete reference is: Binz, Ronald et al. 2012. "Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know, CERES. We file the report as part of our response. Please refer to section 2 of the report for more details.

SUBJECT: DSM

REFERENCE: Dunsky report, page 12

PREAMBLE:

Figure 6 sets out a chart prepared by Binz et al. that plots the risk and resource costs of different resources.

QUESTION:

Please confirm whether the costs are financial costs only or include societal costs.

RESPONSE:

The costs in the chart refer to the LCOE and "indicates the cost per megawatt-hour for electricity over the life of the plant, encompassing all expected costs (e.g., capital, operations and maintenance, and fuel)." (Binz, p. 7) It is my understanding that societal costs are not included.

SUBJECT: DSM

REFERENCE: Page 15

PREAMBLE:

Your report states that "Ultimately, Manitoba Hydro's assertion that there are "typically" benefits from advancing generation and losses from deferring generation is an oversimplification. The more valid question is: will additional generation-driven exports "crowd out" the potential for additional, higher-return DSM-driven exports? If this is the case, then DSM must be understood to be "competing" against new generation."

This example appears to assume contract sales.

QUESTION:

In your experience, do utilities show a sufficient willingness to contract for firm power based on energy freed up through DSM, or do they assess the risk of their counterparty being unable to meet the supply obligations differently depending on whether those obligations are backstopped by new generation or an assurance of DSM?

RESPONSE:

While some electricity sales contracts are linked to specific resources, others are rather based on the pool of resources available to the seller. For example, to my knowledge none of Hydro-Quebec's long-term sales contracts are tied to a specific power plant; the buyer is rather relying on the HQ system's ability to deliver the power over time. HQ's system is comprised of a variety of power plants, diverse and evolving domestic loads, and DSM resources meant to reduce those loads and, to some extent, free up supply to enable exports.

Of course, each client is different, and ultimately they will assess the risk of contracted power not being available based on a variety of factors, including the robustness of the exporting utility's plans to adjust to a broad array of risks, be they of supply disruptions, DSM underperformance, or unanticipated growth in domestic "serve first" loads.

SUBJECT: DSM

REFERENCE: Page 15

PREAMBLE:

The report notes that a number of provinces and states now forecast essentially flat demand for electricity despite continued growth. These regions are planning no new generation resources (beyond internal replacements).

QUESTION:

Provide source reports and / or source data for the provinces and states cited in the report that show the projected flat demand based on DSM.

RESPONSE:

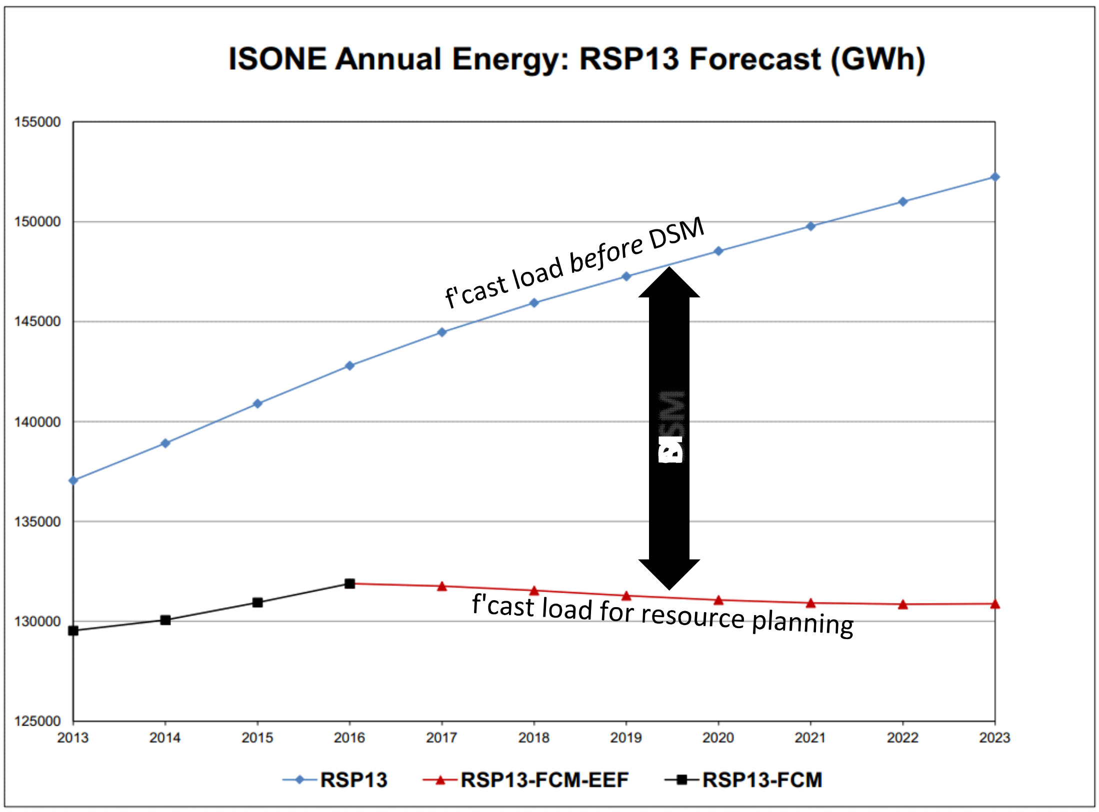
Below we provide charts and references for the following regions:

- New England: **Latest Independent System Operator (NE-ISO) forecast projects flattening of energy needs over 10-year forecast period for the region as a whole, due to DSM. Below we provide charts for the region as a whole, as well as for individual states. Note that <u>DSM forecasts were developed by the ISO</u> based on extensive analysis of historical savings and consultation of parties, and are <u>used for planning purposes</u> (to ensure resource adequacy across the region and in each state individually).**
- California: **Recent agreement between Independent System Operator (CalISO), regulator (CPUC), and energy agency (CEC) establishes amounts of DSM to be counted on for planning purposes. Based on this, demand is held nearly flat over the planning horizon.**
- Nova Scotia: **Most recent Nova Scotia Power Inc. update (July**

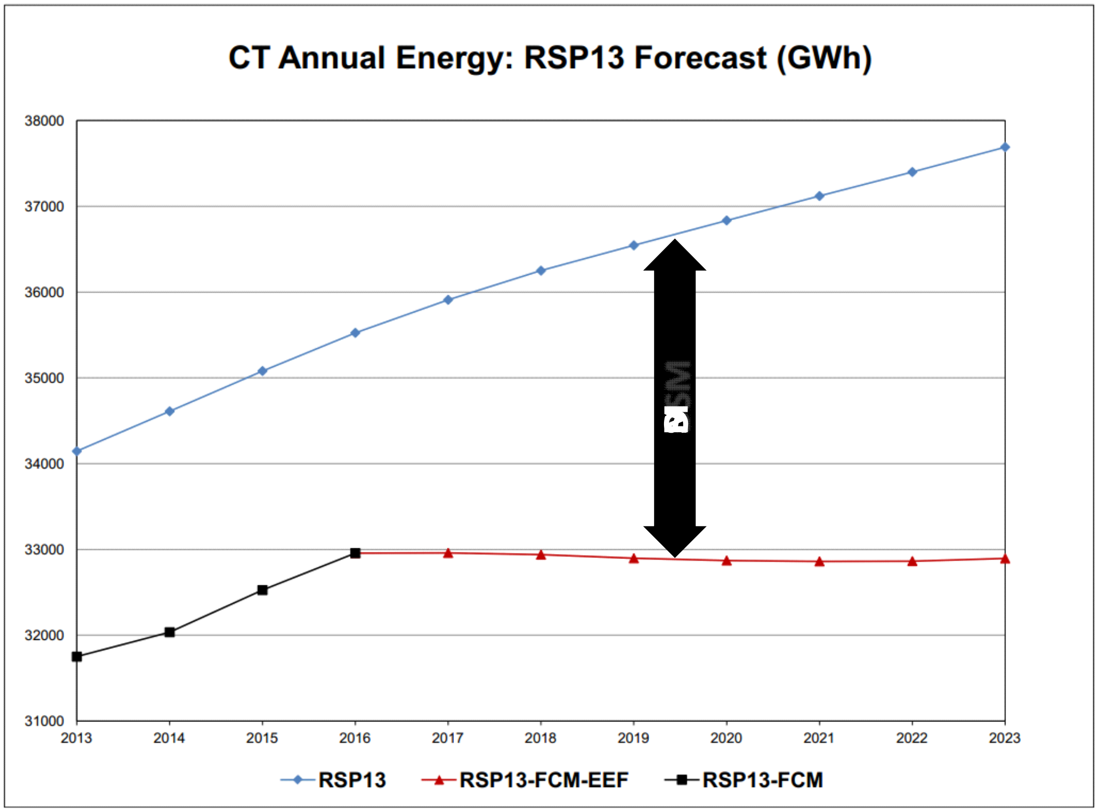
2013) forecasts energy needs after firm DSM to *decline* by 4% over the 10-year planning horizon (capacity needs remain flat).

- Ontario: **recent Long-Term Energy Plan update (LTEP 2013) plans on capacity needs slightly *declining* over coming 20 years due to mix of conservation and demand response. (*note: demand response to meet 10% of total peak needs by 2025)***

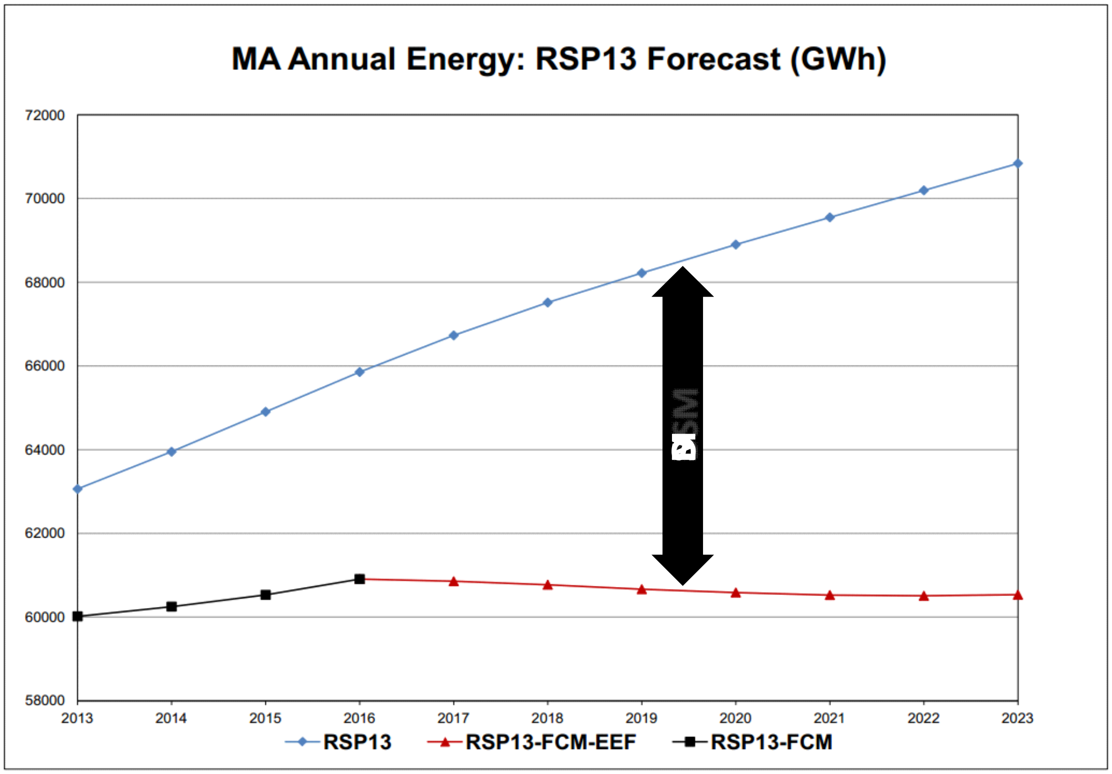
New England (flat demand across entire region):



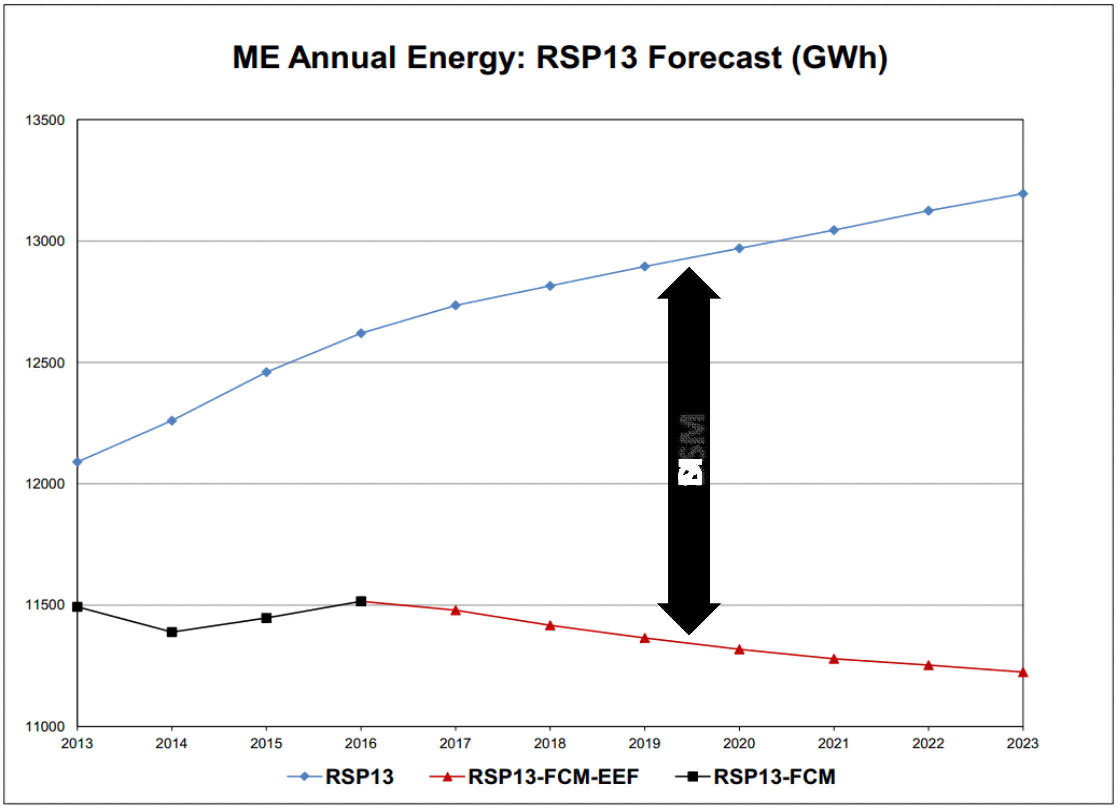
Connecticut: flat demand



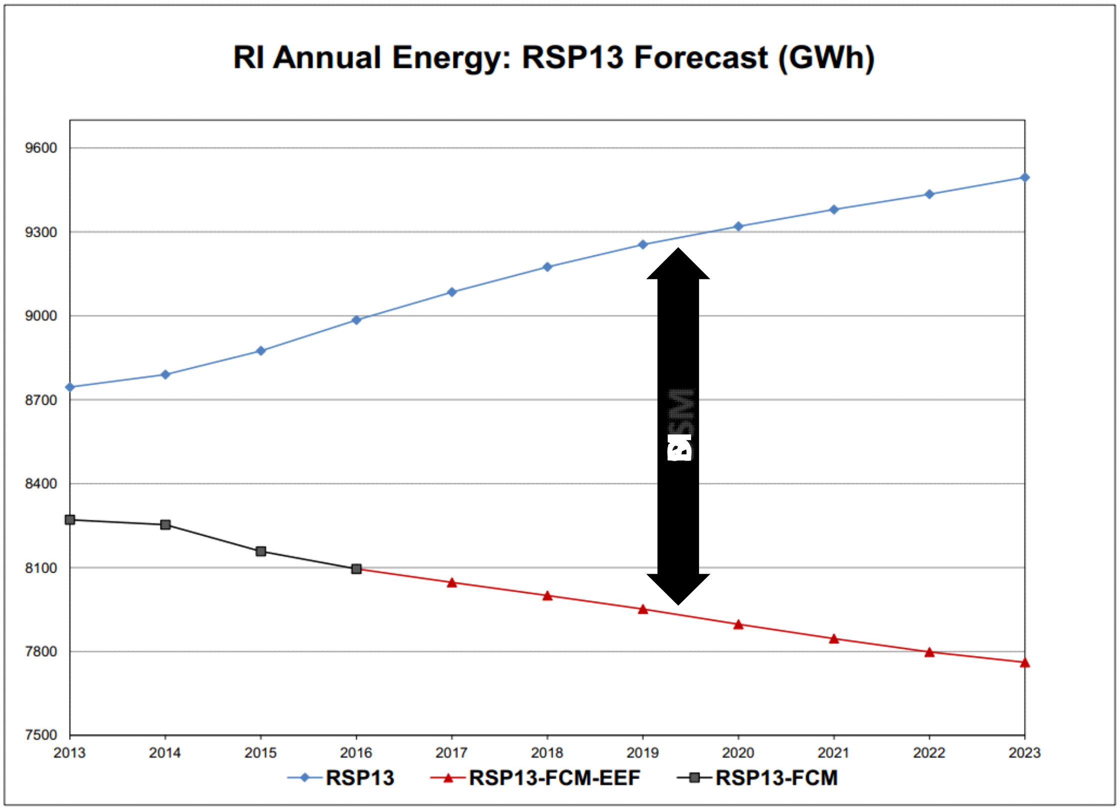
Massachusetts: flat demand



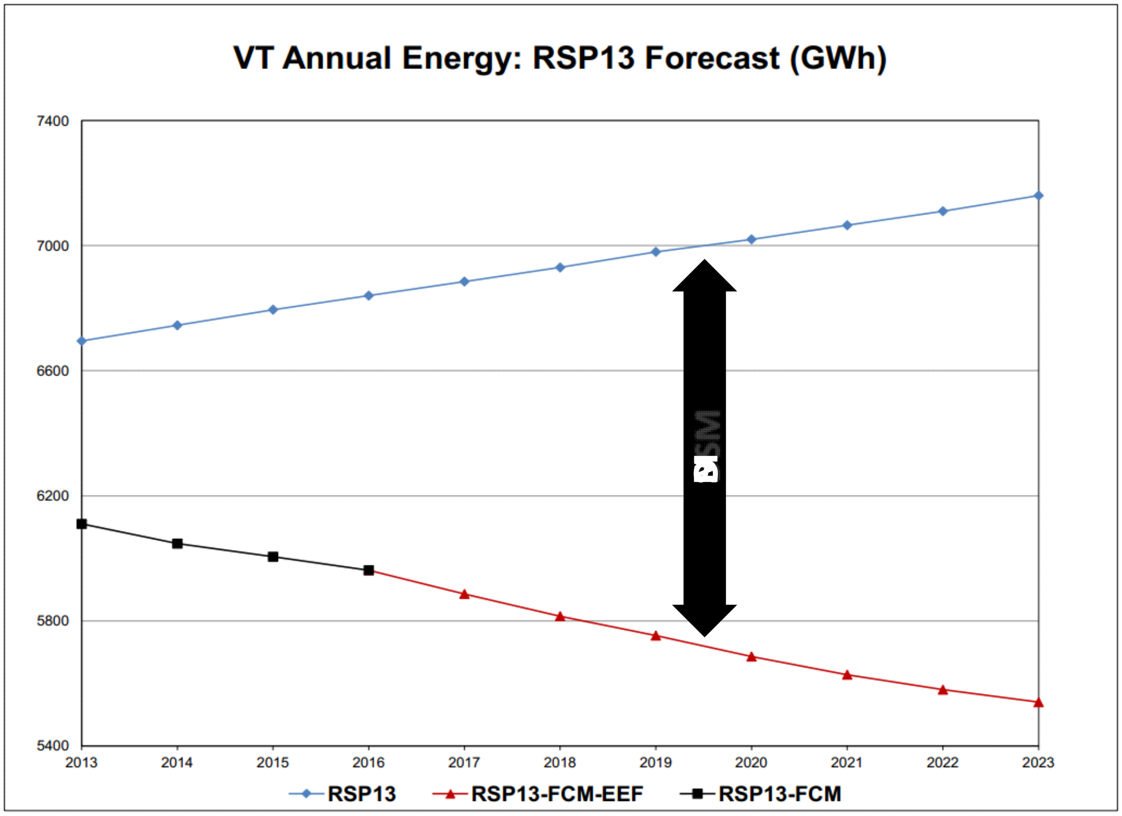
Maine: declining demand



Rhode Island: declining demand



Vermont: declining demand



California: flat demand*

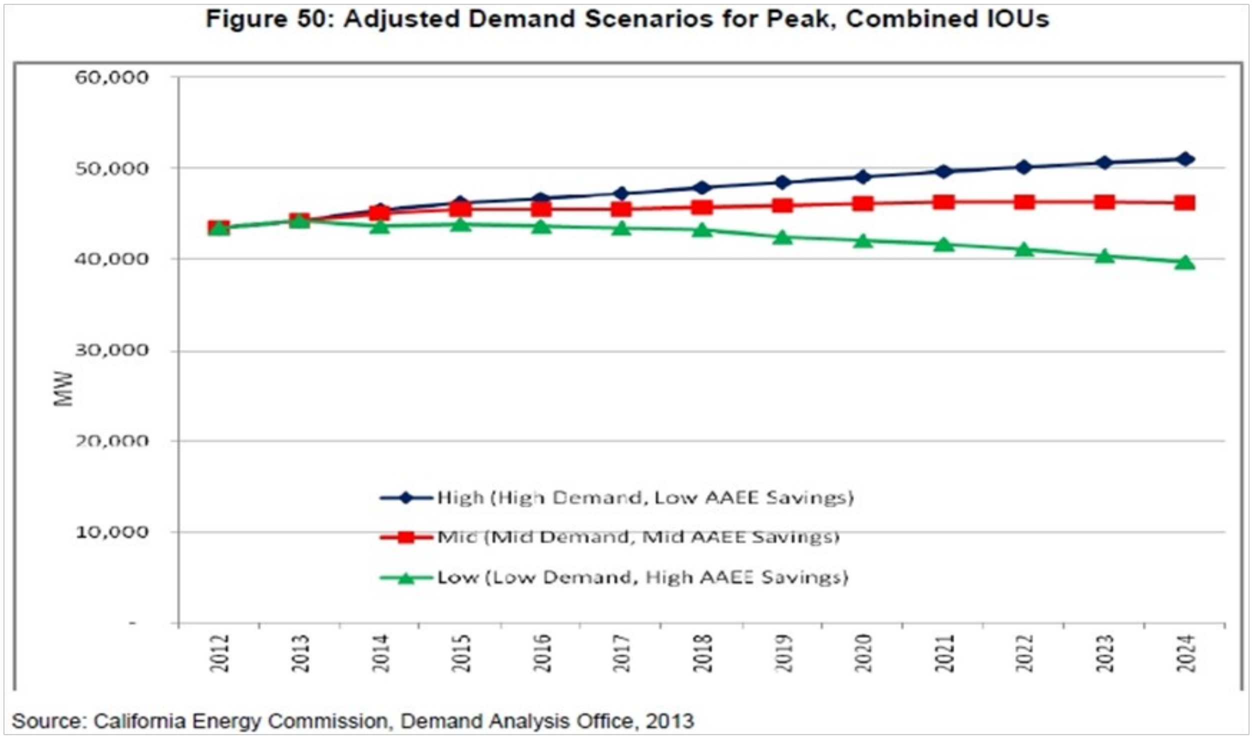


Figure 50: Adjusted Demand Scenarios for Peak, Combined IOUs

Source: California Energy Commission, Demand Analysis Office, 2013

**** Note: this forecast encompasses the four large investor-owned utilities in the State; municipal utilities are not included.***

Nova Scotia: declining demand

Table 1 – Total Energy Requirement with Future DSM Program Effects[2]

Year	Net System Requirement (GWh)	Annual Change (%)
2003	12,009.1	4.4
2004	12,387.7	3.2
2005	12,338.2	-0.4
2006	10,946.2	-11.3
2007	12,638.9	15.5
2008*	12,538.3	-0.8
2009*	12,073.1	-3.7
2010*	12,157.7	0.7
2011*	11,906.8	-2.1
2012*	10,475.4	-12.0
2013F	11,003.3	5.0
2014F	10,917.2	-0.8
2015F	10,919.9	0.0
2016F	10,853.2	-0.6
2017F	10,776.8	-0.7
2018F	10,707.4	-0.6
2019F	10,733.1	0.2
2020F**	10,710.1 [9,569.1]	-0.2 [-10.8]
2021F**	10,663.1 [9,522.1]	-0.4 [-0.5]
2022F**	10,595.8 [9,454.8]	-0.6 [-0.7]
2023F**	10,563.8 [9,422.8]	-0.3 [-0.3]

* Results for the years 2008 to 2012 contain the effects of past DSM programs
** Bracketed numbers represent the low load scenario without Port Hawkesbury Paper load.

Ontario: flat demand*

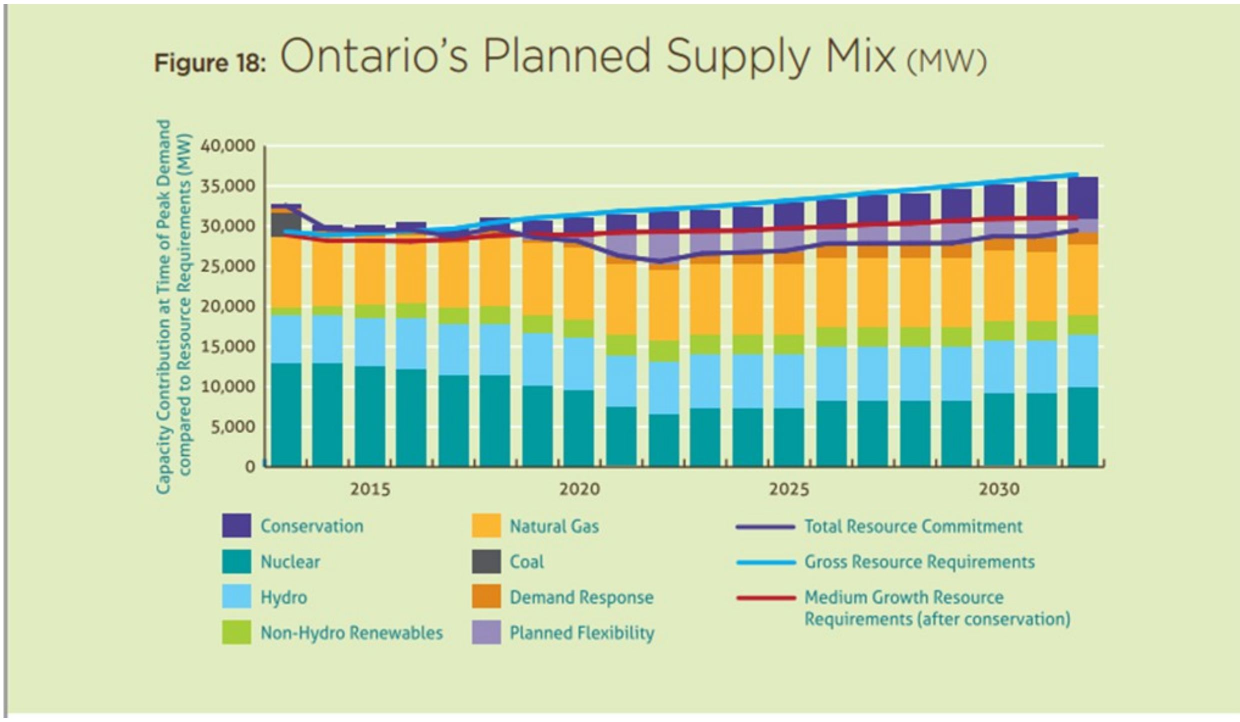


Figure 18: Ontario's Planned Supply Mix (MW)

*** Note: net demand includes all resources *except* dark purple bar (primarily energy efficiency), an undefined part of the light purple bar (a mix of energy efficiency, demand response, and non-utility generation), and dark yellow bar (demand response).**

Jurisdiction	Source
New England region + Each individual State	**ISO New England, *Initial 2014 Energy Efficiency Forecast 2017-2023*. February 11, 2014.**
California	http://www.energyefficiencymarkets.com/california-energy-agencies-adopt-historic-agreement-energy-efficiency-saves-customers-paying-unnecessary-polluting-power-plants-2/
Nova Scotia	**http://oasis.nspower.ca/site/media/oasis/20130702 NSPI to UARB 10 Year System Outlook Report FILED.pdf**
Ontario	http://www.energy.gov.on.ca/docs/LTEP_2013_English_WEB.pdf

SUBJECT:

REFERENCE: Page 15

PREAMBLE:

The report notes that a number of provinces and states now forecast essentially flat demand for electricity despite continued growth. These regions are planning no new generation resources (beyond internal replacements)

QUESTION:

Which of the cited jurisdictions, planning flat demand, are comparable to Manitoba when considering DSM? Explain.

RESPONSE:

Intuitively, Manitoba is probably most similar to Minnesota, Nova Scotia, Ontario, and to a lesser extent Vermont and Massachusetts. However, in practice no two regions are perfectly comparable, nor are any two regions entirely different from a DSM perspective.

As noted in my evidence last year, after examining a variety of factors including climate, industrial structures, market size and rates, I found no strong correlation between *any of these* factors and the regions' ability to exploit its DSM resource.

SUBJECT: DSM Potential Study - Benchmark

REFERENCE: Page 19

PREAMBLE:

Figure 7 shows Manitoba Hydro's "achievable potential" to be the lowest of nine DSM studies compared.

QUESTION:

Please advise how the comparison studies were chosen.

RESPONSE:

The studies were chosen based on three criteria:

1. **The study had to be relatively recent (we excluded anything earlier than 2007);**
2. **The study had to be focused on a similar timeframe (we excluded anything shorter than 5 and longer than 15 years); and**
3. **The study had to have included a “max achievable” (or comparable) potential (we excluded potentials based on self-imposed constraints other than technical, economic, and achievable screens).**

SUBJECT: DSM Potential Study - Benchmark

REFERENCE: Page 19

PREAMBLE:

Figure 7 shows Manitoba Hydro's "achievable potential" to be the lowest of nine DSM studies compared.

QUESTION:

Did you come across any other North American DSM studies that showed lower achievable, economic or technical potential that were rejected as comparisons? If so, please advise why they were rejected.

RESPONSE:

See PUB/CAC_GAC-009a for a description of how the studies were chosen as a comparison. All studies found that met the requirements were included.

SUBJECT:

REFERENCE: Page 34

PREAMBLE:

You set out 14 methodological concerns with the ENERNOC study.

QUESTION:

How do the exclusions compare to the other DSM studies against which you compared the ENERNOC study?

RESPONSE:

The scope of any potential study may be limited in a number of ways as pointed out in my testimony. The set of potential studies cited also contain some of methodological limitations which might serve to underestimate the potential. While an exhaustive analysis of each study's methodology is beyond the scope of my mandate, I do note the following:

- **Many of the studies limit the available measures to what is currently available in the marketplace today, thereby leaving unaccounted technological improvements and/or innovations. However, the Connecticut, B.C., and California studies do address future improvements and emerging technologies.**
- **Many studies do not include fuel switching measures and demand side renewables. The Wisconsin, British Columbia and New Hampshire studies all include at least one fuel switching measure, however, and Florida and Wisconsin also include demand-side renewables with their scopes.**
- **Four studies included demand response measures: Minnesota, Illinois, British Columbia and Florida. Of these, pricing measures were modeled in the Minnesota, Illinois, and Florida studies.**

For more information on preparing potential studies, I am attaching two reports:

- **Bonneville Power Administration's *Guidebook for Potential Studies in the Northwest* (2010), and**
- **U.S. EPA's *Guide for Conducting Energy Efficiency Potential Studies* (2007).**

SUBJECT:

REFERENCE: Page 20

PREAMBLE:

You set out 14 methodological concerns with the ENERNOC study.

QUESTION:

What should the applicable discount rate be, and how should be determined?

RESPONSE:

There is no generic "right" answer to the discount rate question. Regions typically use either a weighted average cost of capital (WACC) as a simple proxy to facilitate comparisons, or a societal rate (typically a long-term government bond rate) to reflect either the lower risk associated with DSM, or the public benefits perspective that often drives DSM.

For example, in the U.S., Vermont and Massachusetts use a societal rate, while California and Oregon use the WACC (although California is currently reconsidering this choice, and is leaning toward use of a societal rate as well). While some argue for a rate of zero, or even a negative rate to account for the intergenerational benefits of DSM, these options have thus far remained in the realm of academic debate.

The use of the WACC is increasingly subject to criticism, in that the WACC reflects the utility's existing capital structure and cost, not the marginal effect of a new investment option. As a result, the WACC may be a reasonable proxy to the extent that the utility is considering "like" investment options, e.g. large hydro following on a history of large hydro – in this case, the current WACC may reflect the risk of a generation portfolio that may be similar to the generation option being considered at the margin. However, the

marginal impact of DSM on a utility’s cost of capital is likely very different.

I have not examined Manitoba Hydro's structure enough to conclude on this topic. However, I do note that use of a societal rate, an increasingly common practice elsewhere in North America, would likely imply a rate equivalent to a long-term bond issuance. For practical purposes, I usually recommend using a 3-year rolling average of 10-20 year bond rates; for Government of Canada bonds, this would currently be on the order of 2 to 2.5% (nominal), though it is noteworthy that these reflect historical lows.

SUBJECT: DSM

REFERENCE: Page 27

PREAMBLE:

Your report criticizes Manitoba Hydro's use of the rate impact measure (RIM) and levelized utility cost (LUC) tests.

QUESTION:

What screening test do you recommend and why?

RESPONSE:

There are fundamentally two appropriate tests, depending on the perspective sought: the societal cost test (SCT), a variant of the TRC, and the program administrator cost (PAC) test.

The SCT is an appropriate measure of society's perspective; however, its application (and that of its 'sister' TRC) can be inaccurate and, more importantly, biased. The primary concern when applying the SCT or TRC is that they are designed to account for all costs and all benefits, irrespective of who bears/receives them; however, because many of the benefits are difficult to quantify, they are often neglected. The result is an inconsistent application of the test that reflects all costs, but only a limited set of benefits.

As a result of this (unintentional) bias, I only recommend using the SCT (or the TRC) if sufficient effort is made to account for the full array of benefits that accrue to society.

The PAC test is an appropriate measure of the utility's perspective, or put differently, of the perspective of ratepayers as a whole. It lends itself to much greater accuracy than the TRC or SCT, but of

course reflects a narrower perspective. If a comprehensive assessment of non-energy benefits (or a reasonable proxy thereof) is not feasible when applying the SCT or TRC, then I recommend using the PAC, with some caveats.

SUBJECT: DSM

REFERENCE: Page 34

PREAMBLE:

Figure 13 shows first-year DSM program costs in different jurisdictions.

You assume an average useful life of 15 years, and calculate an annualized cost on that basis.

QUESTION:

Please state the basis for your 15-year assumption.

RESPONSE:

Based on my experience, most DSM portfolios' average effective useful lives are approximately 15 years. Moreover, there is very little variation; across the variety of states and provinces in which I have worked over more than 20 years, I have never seen a marked difference in average, plan-wide EULs.

If memory serves me well, I believe that Manitoba Hydro's current Power Smart portfolio has an EUL of 14 years.

SUBJECT: DSM

REFERENCE: Dunsky report, page 34

PREAMBLE:

You set out 14 methodological concerns with the ENERNOC study.

QUESTION:

Does this assumption hold true for the other jurisdictions referred to in Figure 13? Please explain.

RESPONSE:

Figure 13 of my report presents achieved savings. Therefore, methodological issues related to potential studies do not apply to these results.

SUBJECT: Solar

REFERENCE: Page 37

PREAMBLE: **Your report provides solar PV generation as a case study for a relatively expensive technology possibly reaching grid parity through technological advances. Your calculations are based on cost on installation and Manitoba sunshine intensity.**

QUESTION:

Would your calculation be significantly affected by snow load and possible snow cover of PV units in Manitoba during the winter months? Why/why not?

RESPONSE:

The effects of snow accumulation on PV systems are still being researched, and field data from systems installed in snowy climates does not exhibit a clear relationship between system losses and snowfall (Rob W. Andrews 2012). In fact, literature suggests that snowfall affects the performance of a solar array both positively and negatively: while decreasing the amount of light that can reach the system, snow increases PV performance by increasing the reflection coefficient of the available light. It has also been demonstrated that cold weather can significantly increase the electrical yield of a system (Swapnil Dubey 2012).

In practice, snow usually melts or slides quickly off roof-mounted solar panels (we have assumed a 30 degree roof tilt for all customers). As a result, we have chosen to rely on the system performance data supplied for each region without including the

effects of snowfall, which at the moment are difficult to evaluate precisely.

Sources:

Rob W. Andrews, Joshua M. Pearce. 2012. *Prediction of Energy Effects on Photovoltaic Systems due to Snowfall Events.* Paper, Michigan Technological University.

Swapnil Dubey, Jatin Narotam Sarvaiya, Bharath Seshadri. 2012. *Temperature Dependent Photovoltaic (PV) Efficiency and Its Effect on PV Production in the World - A Review .* Singapore: Energy Research Institute.

SUBJECT: Solar

REFERENCE: Page 37

PREAMBLE: **Your report provides solar PV generation as a case study for a relatively expensive technology possibly reaching grid parity through technological advances.Your calculations are based on cost on installation and Manitoba sunshine intensity.**

QUESTION:
How is your analysis impacted if solar PV technology would have to be backstopped by conventional generation?

RESPONSE:

Although solar power is an intermittent source of power, it can generate quite predictable quantities of energy on an annual or seasonal basis. Annual values can be estimated with considerable precision based on the yearly solar irradiation statistics at the specific location of the panel (data publicly available through RETScreen) as well as documented system performance.

SUBJECT: Solar

REFERENCE: Page 37

PREAMBLE: **Your report provides solar PV generation as a case study for a relatively expensive technology possibly reaching grid parity through technological advances.Your calculations are based on cost on installation and Manitoba sunshine intensity.**

QUESTION:
How is your analysis impacted if solar PV technology would have to be backstopped by conventional generation?

RESPONSE:

Our analysis assumes that solar PV adopters continue to be tied to the grid, and continue to pay utility fixed fees. As such, these scenarios already assume that solar PV is backstopped by conventional generation.

SUBJECT: Solar

REFERENCE: Page 39

PREAMBLE: **Figure 15 depicts residential solar PV system grid parity.**

QUESTION:

What specific electricity price assumptions are used to create the projected residential utility rates for each of the jurisdictions displayed?

RESPONSE:

A summary of the residential prices used in the model is provided in the table below, followed by the numbered list of sources.

2013 DATA	RESIDENTIAL RATE	SOURC E	ANNUAL INCREASE	SOURCE
MANITOBA HYDRO	$0.08	1	4.30%	4
SASK POWER	$0.13	1	5.00%	5
ONTARIO (OPA)	$0.12	1	3.50%	3
MINNESOTA (XCEL)	$0.12	2	4.34%	Average of past 5 years' (EIA data)
NORTH DAKOTA (XCEL)	$0.09	2	4.44%	Average of past 5 years' (EIA data)

Sources:

1. Comparison of Electricity Prices in Major North American Cities, Hydro Quebec, April 2013
2. Average Annual Retail Price of Electricity dataset, U.S. Energy Information Administration, Electricity Data Browser
3. Ontario Economic Outlook and Fiscal Review (Chapter 1), The Ontario Ministry

of Finance, 2013

4. Financial Evaluation of Development Plans – Customer Rates, Manitoba Hydro, August 2013

5. Interviews with Nathan Ziegler, Sustainable Electricity Engineer at Saskatoon Light and Power by Dunsky Energy Consulting, December 2013

SUBJECT: Solar

REFERENCE: Page 39

PREAMBLE: **Figure 15 depicts residential solar PV system grid parity.**

QUESTION:

Do residential users of Solar PV continue to require connection to the electric grid system to guarantee a reliable power supply? If so, how does the need for residential electricity infrastructure impact consideration of the cost calculations when considering parity?

RESPONSE:

We have assumed that residential users of Solar PV indeed will continue to require connection to the electric grid. We have also assumed that users continue to pay fixed charges to Hydro (in addition to charges for any net energy consumption). To the extent that solar adoption grows considerably, the fixed charge portion of Hydro's rates may need to evolve to account for an evolving mix of fixed and variable pricing.

SUBJECT: DSM

REFERENCE: Dunsky report, page 41

PREAMBLE:

Your report states that "Based on our two scenarios for more aggressive DSM in Manitoba, and using Manitoba Hydro's current Power Smart ratio of capacity to energy savings, I estimate the peak load reduction of our scenarios at approximately 1,000 MW by 2025 (specifically 1,045 MW for scenario A, and 957 MW for scenario B)."

QUESTION:

Please show how you arrived at these numbers.

RESPONSE:

The 2013-2016 Power Smart Plan is planning to achieve savings of 1,370 GWh (at meter) and 490 MW (at generator) by 2027/28. Included in the capacity savings are 162 MW (at generator) planned for the Curtailable Rates Program.

The MW/GWh ratio of the 2013-2016 Power Smart plan is calculated as follows:

(490-162)1,370=0.239

This result means that the Power Smart Plan will produce on average 0.239 MW of capacity savings (at generator) for each GWh of energy savings (at meter), excluding the Curtailable Rates Program.

This ratio has then been applied to the energy savings of the respective DSM scenarios to estimate capacity savings of these scenarios.

SUBJECT: DSM

REFERENCE: Dunsky report, page 42

PREAMBLE:

Your report further states that "To provide an initial estimate of the resource available to Manitoba Hydro, I leveraged two demand response potential studies that my firm led or was involved with in the past two years. It is worth noting that these studies were conducted for Canadian utility clients – specifically for two provinces that share many common characteristics with Manitoba, including climate, prevalence of electric space heating, and large industrial loads."

Based on these studies, I estimated the achievable DR potential in Manitoba at between 6.2% and 12.7% by 2025. I note that these estimates fall within the range of results from two important U.S.-based potential studies (they found savings opportunities to range between 4.6% and 15.1%).

Using this range as a reasonable proxy of achievable DR in Manitoba by 2025, I calculated the capacity savings potential after adjusting for our DSM-driven load reduction scenarios, as well as the existing curtailable rates."

QUESTION:

Please show how you arrived at these numbers.

RESPONSE:

The range represents the adjusted results of two studies that we led or participated in, conducted for Canadian regions with strong similarities to Manitoba, the full reports of which are, however, confidential. Each study assessed the technical potential for demand response throughout the region's market, and proceeded to screen that potential to include only the economic (cost-effective) portion.

To generate a high-level range for Manitoba, we took those results (economic potential), and proceeded to apply a reduction factor of 30% to 50% to account for the portion of the cost-effective potentials that could be reasonably secured (“achievable potential”). This resulted in the high-level range of 6.2% to 12.7%. Interestingly, I note that Ontario recently adopted a target of meeting 10% of its own peak demand needs through demand response (the Ontario Power Authority is currently preparing plans in this regard).

In terms of how the studies themselves were conducted, we used a micro-analytical approach for the residential and commercial sectors, and a macro-analytical approach for the industrial sector, as described below.

Residential & Commercial Sectors: For the micro-analytical approach, the targeted market is broken down into representative cases. For the building stock, this translates into a number of building archetypes defined as representative of the entire stock. In some instances, it is more reliable to define representative cases in terms of typical equipment since demand response measures, as well as attributable markets, can then be more precisely defined. Once the aggregated model of the targeted market segment is calibrated with demand, demand response measures can be evaluated using the various archetypes and typical equipment/appliances defined in the base case. This approach ensures that the peak savings associated with the measures are also based on a representative aggregated model of the entire market. A significant benefit of the micro-analytical approach is that it allows for easily defining the various savings, cost, useful life and other characteristics of the measures, since they are applied to well-defined archetypes or equipment/appliances.

Industrial Sector: Due to the heterogeneity of the industrial sector, using a micro-analytical approach is not manageable as it would require a large number of archetypes and typical equipment, each with only a very small associated market. For this sector, a macro-analytical approach is best suited. Under this approach, the market is segmented based on its main sectors and subdivided by sub-sectors. The electricity usage is then split among each of the subsectors and by all major end uses. This break-down is based on available sector data as well as from building audits performed in the various sectors. The procedure automatically ensures calibration of the segmented model as the initial source is always the reference-year total electricity usage.

Once the energy and peak usage breakdown is completed, the typical peak savings of the various measures for each end-use is evaluated either based on literature data, past implementations or analytical calculations.