ENERGY edits to IESO's draft 2017 LTEP Modules
IESO responses are in green – November 29, 2017
Additional ministry questions in red

Module 1: Demand

- By End-Use – Res tab
  - Cell A2 should just read "Residential Net Energy Demand by End-Use" no (TWh) needed at the end because it is duplicative. Updated and renamed worksheet.
  - Regarding cell A21, is "Space Heating Room" intended to refer to "Space Heating"?
- By End-Use – Comm tab
  - Spell out Cooling DX Updated and renamed worksheet.
- "Energy Demand" tab and "Peak demand" tab: Suggest a note be added to clarify that the demand presented is at the generator level. Note added.
- We suggest the level of detail included be similar to what was included in the 2013 LTEP modules and the OPO. Currently, Module 1 is missing the following
  - Residential intensity (kWh per household, see slide 12 OPO Demand Module), commercial intensity (kWh per sq ft, see slide 21 of OPO Demand Module) and industrial intensity (kWh/GDP, see slide 32 of OPO Demand Module) Added worksheets "Residential Intensity", "Commercial Intensity" and "Industrial Intensity".
  - "Residential Intensity" – Consider noting that HH refers to "household".
  - Housing stock and new housing stats (see slide 15 of OPO Demand Module) Added "Housing Stock" worksheet.
  - Residential demand by building type (see slide 13 of 2013 LTEP Module 1), Commercial demand by sub sector (see slides 27, 28 of OPO Demand Module) and Industrial demand by sub sector (see slide 35 of OPO Demand Module) Added "Res Demand by Building" and "Comm Demand by Building" tab. Industrial demand by sub sector was already there from before ("Ind Demand by Subsector"); title for this tab is changed.
  - "Comm Demand by Building" – Does "Warehouse Wholesale" refer to "Warehouses and Wholesale" or "Wholesale Warehouses"?
  - Transportation demand forecast split, between EVs and transit (see slide 39 of OPO Demand Module) Added worksheet "Electric Vehicle and Transit".
  - Contribution to peak from different end-uses (see slide 47 of OPO Demand Module) Added worksheet "Peak Contribution".

Module 2: Conservation

- Achievable Potential tab

- It's unclear what the difference between market achievable and unconstrained achievable is. Suggest including a reference to the APS study and addendum in the footnotes so the reader can access further details if needed A link to the APS reports was added.

- 2006-2015 CDM Savings Tab
  - Could "Energy Efficiency Programs" be retitled to "Energy Efficiency Programs (2006-2015)". This edit is consistent with the 2016 OPO modules. Title changed
  - Could "Codes and Standards" be retitled to "Codes and Standards (implemented by 2015)". This edit is consistent with the 2016 OPO modules. Title changed
- Demand Response Tab
  - Could the following clarification footnotes be added
    - *Demand response programs introduced prior to 2015 included DR2 and DR3 for business customers* Note added
    - *Beginning in 2015, the DR2 and DR3 programs were transitioned to the Capacity-Based Demand Response (CBDR) program.* Note added
- CDM Cost Effectiveness Tab
  - Could IESO staff please reconfirm the stats for 2016. These are significantly different from those reported in previous years! (LUEC in 2016 is reported at 1.8 cents per kWh, whereas in previous years it has been consistently over 3.5 cents per kWh)) To be confirmed; response forthcoming.

Module 3: Supply

- Total Capacity Reqt – Consider noting that the total is the same as the "Demand Outlook" shown in Figure 8 of the LTEP document which reflects the net demand capacity requirement. Note added
- Energy Imports and Exports tab
  - Consider adding a net line? Added
- General – Why is this file 8 MB? There may be some legacy data embedded. It needs to be smaller for easy download Fixed
- There are a number of references to Demand Response in this module. Please add a footnote to the first Demand Response reference explaining what is included in this (DR auction, DR pilots). We understand this does not include ICI and TOU. Added to worksheet "Installed MW by Fuel"
- In footnotes, please explain the difference between the DR resources listed under the "Installed MW of Existing" tab and the "Installed MW of Directed" tab. For the "installed MW of Directed" tab please clarify through a footnote that the government has not directed a future amount for DR, but rather these are capacity assumptions for the purpose of modelling. DR contracts that expire in the "Installed MW of Existing" and "Installed MW of Directed" are now reallocated

as capacity that is expired in the worksheet “Installed MW of Expired” – similar to the treatment of other supply resources. Other worksheets including “Installed MW by Commitment” and “MW at Summer by Commitment” affected by this reallocation were also updated. Thank you for the DR related edits to the supply module. DR capacity has now been moved to expire beyond 2019 (supply module). Given the change, does the DR cost forecast in the cost module (CBDR and DR auction tab and Wholesale Market Service Cost tab) need to be adjusted? Also given that there is now a DR footnote in the Wholesale Market Service cost tab (cost module), it would be best to delete the specific tab on CBDR and DR Auction costs in the cost module.

- On tabs 3 (installed MW by fuel), 8 (MW at summer by commitment), and 9 (MW at summer by fuel) add a line for “planned flexibility/identified needs” that indicates the gap between identified supply sources and anticipated demand. Indicate the MW expected procurement in the future (e.g. through an ICA). The order in which the worksheets are sequenced does not lend itself to having the “planned flexibility” amounts in the tabs noted by ENERGY. As an alternative, the incremental capacity needs that are required over and above existing resources are indicated once we know what is available and what is our capacity requirement - this is shown in a new worksheet, “Incremental Needs”. That incremental capacity need can be acquired through a number of mechanisms. While it appears that the Ministry requested more explicit references to Planned Flexibility, IESO’s addition of “Incremental Needs” seems duplicative given that the preceding tab (i.e., “Capacity Above Below Reqt”) shows exactly the same numbers. Suggest removing this “Incremental Needs” tab.

- Installed MW of Directed Tab
  - The 50 MW in 2017 and the additional 150 MW in 2019 in the ‘Installed MW Directed’ tab appear to be from the 2017 mFIT procurement target, and the FIT 5 procurement. This raises a potential question of how the IESO is counting the 50 MW 2017 mFIT procurement target as directed until such time as everything is contracted? And, at the time the modules were produced, was FIT 5 un-contracted (i.e. still directed)? If the answer to both of those questions is yes, then the table is fine from an accounting perspective.
  - However, we may have an interest in accounting for the 50 MW from mFIT and the 150 MW from FIT 5 as ‘committed’ rather than ‘directed’ in order to provide a clear message that there are no further renewables procurements planned. 200 MW of Directed MW from 2017 to 2019 appears confusing considering both of the procurements have been run and are closed.

Module 4: Transmission

- For the Hawthorne to Merivale line the module includes an in-service date of 2021 but the recent H1 Transmission Rate Application used early 2020. Is there a rationale for using a different date? The Hawthorne to Merivale project requires 3 years of lead-time before putting into service. The timing in the H1 Transmission Rate Application assumed the approval process for this project was initiative by 2017. Given that the process has not yet been initiated at this time and the required lead time for this project, it is reasonable to assume that the project can be put in-service as early as 2021.

Module 5: Cost

- For the Transmission Delivery Costs, can you provide the underlying assumptions for both the base and incremental costs? Notes added. Regarding transmission, IESO notes on the Module 5 Transmission Delivery Costs tab that "Base Transmission is based on the Hydro One Revenue Requirement Application EB-2016-0160, plus the revenue requirement of the other transmitters obtained from the 2016 Uniform Transmission Rates" and "Incremental Transmission cost is based the list of transmission projects shown in the Transmission Module 4" however Module 4 notes that "Other regional planning projects were also assumed throughout the planning period" in addition to the specific projects listed. Can you provide the assumptions used for these regional planning projects (i.e. cost profile over the planning period, specific projects, etc.)? Or if these assumptions were from the Hydro One Rate application can we modify the Module 4 notes to say "Other regional planning projects listed in the Hydro One Revenue Requirement Application EB-2016-0160, plus the revenue requirement of the other transmitters obtained from the 2016 Uniform Transmission Rates" to close the loop?
- For the wholesale market service cost, what is the assumption for the RRRP rate going forward? Did IESO assume some portion of the remote connection project costs will be included in this charge? Yes. In 2017, the Rural/Remote Rate is $0.76/MWh based on an average of the EB-2016-0362 OEB Decision of $0.0021/KWh for 6 months and $0.3/MWh for another 6 months based on the EB-2017-0234 Decision. From 2018 to 2035, the RRRP rate assumed is the EB-2017-0234 rate of $0.3/MWh or 0.03 cents/KWh ($2017 Real) - this rate is held constant in real dollars. Can IESO describe how capital and operating cost assumptions for the Remote Connection Project were applied to determine RRRP amounts? E.G. a description of cost inputs for the project over the period?
- DRC – DRC is expected to end before April 1, 2018. Why is DRC about the same amount in 2018 ($0.61B) when compared to 2017 ($0.62B)? The expected expiry date of April 1, 2018 was not used; rather it was assumed in the modelling that the DRC is in place for the full calendar year. A note is included in the "Debt

Retirement Charge" tab. Flagging IESO's assumption regarding DRC is inconsistent with MOF's public statements.

- "Conservation Cost" tab: Through a footnote could the IESO clarify which row includes Conservation Fund costs. Titles are changed for greater clarity.
- In an appropriate tab, please also include costs related to Demand Response. Demand Response is recovered through the wholesale market charge. A note was added to the "Wholesale Market Service Cost" tab. CBDR and DR auction costs that are embedded in the wholesale market service costs are indicated in a new tab "CBDR and DR Auction Costs".
- On tabs 1 (cost of electricity service) and 8 (debt retirement charge), why is the DRC expected to be $600M in both 2017 and 2018 despite the charge being removed from bills as of March 31, 2018? The expected expiry date of April 1, 2018 was not used; rather it was assumed in the modelling that the DRC is there for the full calendar year, as noted in the response above. Flagging IESO's assumptions regarding DRC are inconsistent with MoF's public statements.
- Don't use "pre-FHP" amounts in tab 10 (global adjustment costs) and tab 11 (residential bill forecast). Fair hydro plan is legislated government policy and should be included in the cost forecasts. Given that IESO did not develop the FHP forecasts we leave that up to the discretion of ENERGY to replace these tabs with information they are more comfortable with, as discussed earlier with ENERGY. For the GA tab, full GA pre-OFHP must be shown since it represents the costs being paid to generators. The full GA pre-OFHP to be depicted in the total system cost line. Row 6 is the forecast total system cost to all consumers. Removed the text ("prior to Ontario Fair Hydro Plan") from the title of the table. For the residential bill tab, as noted by the yellow highlighted rows and blue tab, the residential bill has been replaced by the Ministry.
- Include the 2017 price curve, broken down by line item. ENERGY is to provide clarity on this request, as discussed with ENERGY ESPD staff. In response to IESO's comments in green, ENERGY has updated the module – see yellow highlighted rows and blue tabs. The Ministry has replaced:
    1) Residential bill forecast;
    2) Class A and Class B commodity cost; and
    3) Large industrial indicative cost.
- Additional ENERGY comment on nuclear costs. In the FAO's report on nuclear refurbishments, released a couple weeks ago, the unit cost of nuclear was calculated differently in order to respect the confidentiality of Bruce Power's contract price. Given the prices in Module 5, one could back out the Bruce contract price by subtracting OPG's regulated rate and production which are available in OEB rate filings. We ask that IESO reconsider its presentation of the unit cost of nuclear. From the FAO report:

… in each year, the FAO calculated the production weighted average of the FAO's estimate of the actual OPG nuclear price and the average Bruce Nuclear Price of $80.6/MWh. The FAO is unable to include the actual Bruce Price estimate in the Base Case Nuclear Price trend due to disclosure restrictions under s.13 of the Financial Accountability Officer Act, 2013.