Category	Participant	Assumption Comment	NS Power Response
1. Financial	CanWEA/SIA	Ensure sensitivities reflect variability of assumptions and recognize how modular nature and experience w/ some technologies reduce underlying risks and potential variability of costs	Low and High capital cost sensitivities for wind and storage will allow for a broad range of potential costs to be considered. Assumptions set was updated to reflect more sharply declining cost estimates over time using recent 2019 industry cost data.
2. Load	CA (Chernick & Wilson)	Effects of ideal EV load shape should be reflected in capacity expansion model and not just as a sensitivity in production cost modelling	As part of the developing the IRP load shapes, NS Power has included the effect of EV peak shifting capability.
2. Load	CA (Chernick & Wilson)	No indication of how potential uncertainty in load viewed How much could load vary from baseline forecast [and why] Could load shape change over time due to changes in load mix (industry shifts, changes in space/water heating technology, increased large commercial air conditioning load, etc.)	Range of load curves was presented at Stakeholder Conference on February 27; a broad range is being considered, informed by the Pathways study and E1 DSM Potential Study. NS Power will work with E3 on potential impact of changes to load shape and how to model, in particular for scenarios where the monthly peak and energy requirements are significantly different from what our 2018 actual 8760 load shape would reflect.
2. Load	Heritage Gas	Incorporate contribution of electrification technologies in calculation to peak (system build-out and emissions contributions) Understood E3 developing assumptions and alternative options for electrification scenario modelling to be provided to stakeholders for review & comment	NS Power's load forecast assumptions consider the impacts of electrification on peak loads, under several different scenarios. These were reviewed at the February 27 stakeholder meeting and have been provided with the final assumptions set.

Category	Participant	Assumption Comment	NS Power Response
2. Load	Natural Forces	DSM scenarios of 17% reduction in low case to 30% in max achievable case appear ambitious Consider demand growth from electrification Include a wider spread of demand projections, potentially retaining some demand regression scenarios but adding scenarios w/ significant demand growth	NS Power's DSM assumptions are informed by the E1 Potential Study; a range of Load and DSM forecasts will be tested on the main scenarios. The load forecast assumptions were informed by the PATHWAYS work, which considers several electrification scenarios for the Nova Scotia economy that produce a wide range of long-term outcomes in terms of both peak and energy requirements.
2. Load	Verschuren Centre	Need to consider appropriate amount of electrification, which is most cost-effective pathway to zero emissions Reasonable to assume 80-100% of transportation electric (direct, fuel cell or other derived source) by 2050 Reasonable to assume 80-100% of space heating via heat pump by 2050 Space heating load aligned with demand peaks and electrification of space heating presents capacity concerns	The load forecast assumptions were informed by the PATHWAYS work, which considers several electrification scenarios for the Nova Scotia economy that produce a wide range of long-term outcomes in terms of both peak and energy requirements.
2. Load	E1 (March 6)	Request confirmation that - Load Forecast to be modified by Pathways by removing 40% of future EE and DR from "before DSM" scenario from 2019 Load Forecast while retaining lasting impacts of previously delivered programs. NS Power will look to Pathways report to ascertain level of incremental electrification w/ high & mod electrification. NS Power will then adopt consistent inputs to produce modified 2019 Load Forecast accounting for electrification before EE and DR; no data from Pathways model to be used directly in IRP model.	The 2019 System Outlook future DSM amounts have a coefficient applied that accounts for embedded DSM and the "before DSM" in the System Outlook only adds back this adjusted amount rather than the full DSM. For the IRP scenarios, the No DSM forecast includes the full future DSM added back in so that the basis for comparison is the same when the various E1 DSM scenarios are subtracted out. Please refer to NS Power's Final Assumptions and Scenarios and Modeling Plan.

Category	Participant	Assumption Comment	NS Power Response
3. Environmental Assumptions	AREA	NSP should consider modelling decarbonization efforts in each scenario and at what price other sectors would need to pay NSP to effect such decarbonization [NSP should model exceeding environmental targets and selling surplus attributes to various markets/sectors]	The load forecast assumptions were informed by the PATHWAYS work, which considers several electrification scenarios for the Nova Scotia economy that produce a wide range of long-term outcomes in terms of both peak and energy requirements. NS Power will consider the option to sell surplus GHG emissions into the Nova Scotia Cap and Trade Market in the initial screening work, to determine if it warrants inclusion in the Plexos LT models (i.e. if it changes the optimal resource buildout plan).
3. Environmental Assumptions	Dalhousie	How to model for organizations w/ climate change goals and targets which exceed existing regulatory targets Need a more aggressive carbon scenario beyond regulatory targets and which models net zero	The load forecast assumptions were informed by the PATHWAYS work, which considers several electrification scenarios for the Nova Scotia economy that produce a wide range of long-term outcomes in terms of both peak and energy requirements. The Final Scenario and Modeling Plan contains GHG trajectories more stringent than current regulatory requirements.
3. Environmental Assumptions	E1 (February 14)	Does NSP expect to sell excess credits from lower emissions; if so, how will carbon cost be captured and will revenues from carbon credits be accounted for in revenue requirement for each scenario?	NS Power will incorporate cap and trade market revenue from sales of excess GHG allowances during the screening phase of the modeling work for some key scenarios. If market revenue is found to affect the preferred resource plan selection, then a determination will be made as to how to incorporate the cap and trade market in the full IRP modeling phase.
3. Environmental Assumptions	E1 (February 14)	Considering C02 caps business as usual? Will SDGA be considered in business as usual scenario? [comparator scenarios?]	The Comparator scenario is not consistent with the SDGA and is intended to be informational in nature only.

Category	Participant	Assumption Comment	NS Power Response
3. Environmental Assumptions	E1 (February 14)	Air quality regs to 2030; what causes drop in hard caps for SO2 and Hg in 2035	The drops post 2030 are assumptions by NS Power that further SO_2 and Hg emissions limit reductions are likely post-2030. These assumptions are consistent with what was modeled as "Scenario B" in the 2014 IRP.
3. Environmental Assumptions	EAC	Consider more ambition in GHG reductions (increased because of SDGA) because reductions to come from electricity sector Fed government may require further reductions in cap & trade jurisdictions	The Final Scenario and Modeling Plan contains GHG trajectories more stringent than current regulatory requirements.
3. Environmental Assumptions	EAC	Consider further Renewable Energy targets and RES requirements Consider need to comply w/ federal green building standards	A sensitivity to analyze an increased RES standard has been proposed as part of the Modeling Plan.
3. Environmental Assumptions	EAC	Consider enhanced / extended equivalency agreement w/ feds and associated emissions reductions (2025 forward) and need for new equivalency agreement 2030-2040 Hard caps on p. 17 of Assumptions should be the lowest / least aggressive level for consideration in IRP	The proposed scenarios incorporate a range of GHG emissions profiles, which are designed to be compliant with the SDGA and provide a range of potential rates of emissions reduction including GHG trajectories more stringent than current regulatory requirements.
3. Environmental Assumptions	EAC	NSP should propose emissions pathway compliant with federal regs of 3.0 MT /C02 for 2030-2040	In the final Modeling Plan NS Power has included a GHG Scenario with limits below 3.0MT CO_2e after 2030 ("Accelerated Net Zero 2045" case), please see the Scenarios and Modeling Plan for details.

Category	Participant	Assumption Comment	NS Power Response
Environmental Assumptions	EAC	CO_2 pre 2030; 0 by 2040 4.5 MT 2030 vs 3.0 – Is equivalency the reason for this?	In the final Modeling Plan NS Power has included a GHG Scenario with limits below 3.0MT CO_2e after 2030 ("Accelerated Net Zero 2045" case); this case also includes emissions reductions that start pre-2030 as suggested. Please see the Scenarios and Modeling Plan for details.
3. Environmental Assumptions	Envigour (Bruce Cameron)	Need to assume net-zero is ≥ 85-90% carbon-free (using existing pipelines with carbon-free fuels ie hydrogen, renewable natural gas and carbon offsets) by 2050	The scenarios incorporate a range of GHG emissions profiles, which are designed to be compliant with the SDGA and provide a range of potential rates of emissions reduction and GHG trajectories more stringent than current regulatory requirements.
3. Environmental Assumptions	EAC	At least one scenario should examine portfolio where all units retired by end of 2029 in accordance with 2018-19 federal regs	NS Power has included a key driver on coal closure dates including scenarios where all coal units are retired by Dec. 31, 2029.
3. Environmental Assumptions	Natural Forces	Emissions modelling relates to meeting limits rather than ascribing value to further reductions; reductions not monetized and strategic benefits not recognized Need additional emissions savings w/in alternative scenarios – capture as benefit and monetize	NS Power will incorporate cap and trade market revenue from sales of excess GHG allowances during the screening phase of the modeling work for some key scenarios. If market revenue is found to affect the preferred resource plan selection, then a determination will be made as to how to incorporate the cap and trade market in the full IRP modeling phase.
4. Supply Side Options	AREA	Will support NSP proposal if NSP will clearly state in future reports that developers believe "low cost of renewables" scenario prices are easily achievable NSP should indicate at what project size the costing is associated	NS Power's capital cost estimates for wind are based on a facility of 50MW to 100MW installed capacity.

Category	Participant	Assumption Comment	NS Power Response
4. Supply Side Options	AREA	Need to consider alternative non-NSP lower costs of capital	The proposed sensitivities on capital costs (e.g. low/high wind cost, low/high storage cost, etc.) are representative for modeling purposes of potential alternative capital structures.
4. Supply Side Options	CA (Chernick & Wilson)	Should include allowance for decommissioning Evaluate resources on an equivalent full-cost basis	NS Power confirms that decommissioning costs are not included in the capital cost estimates for any of the new resources presented in the supply option assumptions. Decommissioning costs are difficult to estimate due to the potential for further life extensions, salvage value, re-powering, etc. of any new asset built during the IRP Planning Horizon. For these reasons, the present value of the future decommissioning costs for new assets is assumed to be immaterial to the IRP analysis.
4. Supply Side Options	CA (Chernick & Wilson)	Supply side capacity options should include flexible solar (for dispatch control for ancillary services) and hybrid (renewable + storage) resources. Need to list flexible solar and hybrid resources from projected levelized cost of capacity resources	The model will be free to select combinations of renewable generators and energy storage when optimal to meet system needs; post-modeling analysis of the model runs could indicate whether there are good candidates for hybrid sites with similar build times and capacities.

Category	Participant	Assumption Comment	NS Power Response
4. Supply Side Options	CA (Chernick & Wilson)	Request more information about how NSP supply-side cost assumptions were developed and supported [NSP showing higher renewable and storage costs and lower gas-fired and nuclear] Solar PV costs have come down in last 2 years; CC natural [and CT] gas costs should be 20% lower per NREL ATB Storage technologies O&M should be variable and not fixed; should include charging cost and charging cost escalator unless values calculated w/in system planning models	Details are available in the NS Power Resource Options Study by E3, completed in July 2019 as part of the Pre-IRP work, and finalized following stakeholder comments in October 2019. Additional detail is available in the full report document including comparisons of various source data available. Certain of these assumptions were updated early in 2020 based on 2019 actual data that became available after the original study was completed. Charging cost for storage is calculated by the dispatch model and applied as an incremental production cost.
4. Supply Side Options	CanWEA/SIA	Capex and Opex for technologies should be combined with assumptions (financing, useful life, cap factors) and may yield revenue requirement profiles unsupported by market data Explicitly identify LCOE values from E3 Resource Options Study	LCOEs were provided in the E3 supply options study but were not included in the NS Power Assumptions slides as this is not an input to the modeling tool.
4. Supply Side Options	Dalhousie	Scenarios w/ more grid sharing from provinces w/ hydro and micro-grid structures	NS Power has added a Regional Integration resource strategy to explicitly analyze the value of additional integration with neighbouring jurisdictions. Microgrids are not being modeled in the IRP as the distribution system is not considered by the model.
4. Supply Side Options	Heritage Gas	Final assumptions to include coal-to-gas conversion, and despite base loaded gas price assumption of 100,000 MMBtu/day, no supply constraint on natural gas in the model	Confirmed.

Category	Participant	Assumption Comment	NS Power Response
4. Supply Side Options	Heritage Gas	New nat gas-fired CTs to be included in the supply options, and 25-year IRP study period to consider reliability of existing CTs from fuel security, general reliability and start-up perspective (in reliability screening phase or earlier)	The sustaining capital assumptions being used in the IRP model represent NS Power's estimate of the capital required to maintain current levels of reliability from the diesel CT units.
4. Supply Side Options	JFS Hydrostor	Consider compressed air energy storage (stored in underground caverns and released to surface turbine to generate electricity); consider a lower price or sensitivity for compressed air storage.	The IRP will consider sensitivities on both Low and High Capital Cost of Storage which will encompass the range of costs submitted by Hydrostor.
4. Supply Side Options	Envigour (Bruce Cameron)	Consider in-stream tidal as supply side option. Costs to decline as technology deploys. NSP assumption is too high for instream tidal (vs bottom turbine).	Industry experience in tidal generation is so far limited and unlike wind and solar, costs appear to be site specific and tied to construction costs with limited opportunities for economies of scale. Technological and commercial readiness level in Nova Scotia is still uncertain.
4. Supply Side Options	Envigour (Bruce Cameron)	No issue with assumption of wind capex declining, but need to consider offshore wind which has a capacity factor of 63%. Need assurance that modelling will capture the value (incl. decrease in levelized cost of energy) of such a high capacity factor.	E3 used CanWEA data to generate offshore wind capacity factors of 37%-45% as part of the Supply Options Study; these capacity factors drive the capital cost assumptions for offshore wind being used in the IRP.
4. Supply Side Options	Natural Forces	The cost of wind $2100 is 15% higher than Natural Forces experience on slide 35.	The low wind sensitivity included in the final assumption set is $1500/kW which is in line with the 2019 Lazard low costs.
4. Supply Side Options	Digby	Energy storage and smart grid technologies could assist w/ controlling voltage and redirecting power flows; important for areas like Digby w/ inadequate transmission (69kV line).	The DER resource strategy will consider options such as behind the meter energy storage and distributed solar.

Category	Participant	Assumption Comment	NS Power Response
4. Supply Side Options	Digby	Introduce EVs as means to create demand at Conway substation. EV charging supports renewable energy integration in capacity-constrained grid.	The IRP does not consider the specific programs that could be used to incent electrification; the effect of electrification on load is assumed to be exogenous to the NS Power system (e.g. policy driven)
4. Supply Side Options	Digby	Tidal energy will require management of generation and load; creation of micro grid and load balancing will create background for energy storage. Installation of solar garden suggested.	Microgrids are not considered in the IRP as it does not model NS Power's distribution system. NS Power has included costs for solar generation in our supply options based on the E3 Supply Options Study.
4. Supply Side Options	Verschuren Centre	Consider updated capex and opex costs of lithium ion battery systems Value of storage is in ability to respond quickly w/ no ramp rates and provide flexibility as load and generator Model should consider all potential value streams for energy storage systems and how can be stacked; provide detail re how this accounted for in PLEXOS	NS Power updated capital and FO&M cost estimates for Li Ion storage with 2019 data in early 2020; these appear to be slightly higher than, but in the general range of, the data supplied by the Verschuren Centre in their written comments. NS Power will work with stakeholders through the IRP process to develop a methodology for Avoided T&D Costs which could be associated with substation level or distributed storage resources; if applicable this approach could be added outside of the model in the Distributed Resources Promoted scenario which NS Power has included in the Modeling Plan. Storage in PLEXOS allows these resources to provide capacity, energy, and operating reserves. Charging cost is calculated in the production model dynamically. Battery Storage contributions to essential grid services will be considered both inside of and outside the PLEXOS model during the Reliability and Operability screening phases of the IRP.

Category	Participant	Assumption Comment	NS Power Response
4. Supply Side Options	E1 (February 14)	Re Pathways (E3 Resource Options Study) - Provide details on assumption re access to firm capacity via new transmission up to 800 MW – basis and costs?	Under the Regional Integration resource strategy the model will have access to transmission via HVDC to the Quebec / New Brunswick border. The assumptions consider a 1000MW bi-pole design, which would allow 450MW firm capacity to be considered towards the NS PRM requirements. The capital cost estimates are NS Power internal and represent the total capital cost of the new transmission facilities.
4. Supply Side Options	Bates White	Consider transmission alternatives to supply resource options in IRP.	Detailed transmission planning is not considered in the IRP model; however we are presenting the model with transmission options to enable additional wind integration and also to provide access to additional capacity and energy markets.
5. DER (Distributed Energy Resources)	CA (Chernick & Wilson)	DER should include full cost of resources (and not just portion paid by NSP incentives) and reduce gross costs to reflect T&D and NEBs (incl. backup and other customer values). If NS Power can't estimate NEBs, DER should be just NS Power costs reduced by T&D benefits (line losses, avoided investment).	The IRP evaluates the costs and benefits of utility resources to derive revenue requirement and utility benefits. DER costs evaluated would be NS Power costs. The IRP does not consider Non-Energy Benefits. Current assumptions do not include utility-funded DER. Methodology for estimating avoided T&D costs will be developed through this IRP process.
5. DER (Distributed Energy Resources)	Envigour (Bruce Cameron)	Changes in pricing decrease costs of DER; technology prices declining as production and deployments more widespread.	NS Power agrees that DERs will have a declining cost trajectory. The DER resource strategy assumes widespread penetration of DER installations that would be consistent with declining prices.

Category	Participant	Assumption Comment	NS Power Response
5. DER (Distributed Energy Resources)	SBA	Behind the meter (BTM) is not included as an option because won't be selected by model due to cost is a shortcoming. Needs to be recognition of existence of Renewable to Retail sales recognizing different economic signals. BTM generation installed based on customer economics related to retail rates, not just generation savings; credit savings against rates. Need to test solar ratemaking and net metering policies. Need to confirm what analysis to be used to vary DER penetration across scenarios & portfolios.	The Distributed Resources scenario will provide information as to the potential impacts of these technologies will have on how NS Power serves peak and energy requirements.
5. DER (Distributed Energy Resources)	Verschuren Centre	IRP should consider BTM thermal energy storage (to address need for flexibility and increased demand) vs utility scale battery (cheaper and longer duration) Cost competitive w/ other capacity sources ($520/kW; $83/kWh), and ETS can provide 12 hours of storage	The Distributed Resources Promoted scenario will consider BTM approaches as a load modifier.
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Use longer averaging period for TUC DAFOR (7 years vs 3)	To avoid subjectivity, NS Power selected a three year average for all units in order to compare them on an even footing. Upon review of the initial modeling results, should there be any outliers that require further examination, we may consider this recommendation again.

Category	Participant	Assumption Comment	NS Power Response
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Re Table 17: since ELCC used for rating variable generation, other types of generation (non-thermal) should be de-rated using methods that are identical/produce identical results Thermal treatment (ELCC/ UCAP) with DAFOR Adjustments; ICAP method results in a PRM of 20%; UCAP method results in a PRM of 7%to 9%. Dynamic under capacity expansion with incremental build; circle back to PRM.	NS Power will use the ELCC calculation for thermal units contribution to PRM in the capacity expansion portion of the model. Once resource portfolios are identified, NS Power and E3 will evaluate against an ELCC PRM with an ICAP PRM consistent with NS Power's PRM calculation approach and confirm that reliability obligations (i.e. 0.1 days/year LOLE) are maintained in all years of the plan; will iterate if required.
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Revisit hydro ELCC assumptions, looking at storage capacity by system (hours of full-load generation), time to recharge from inflow (Nov-Mar), capacity factors during winter peak hours x last several years, effect of 2016 drought or other events on effective hydro capacity over long winter peaks, historical frequency of droughts.	This suggestion requires extensive evaluation. For the purpose of the IRP, we do not believe it will significantly impact the ELCC of hydro units.
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Make visible numerical values behind Figure 27 (LOLP by month and hour).	Please refer to Attachment 1.
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Consider whether feeder circuit outages could significantly affect DAFOR for any generation units.	Distribution Feeder outage events do not affect the capacity value of any NS Power thermal or hydro generation units; in the example cited of Wreck Cove / 85S, outages to the distribution feeders supplied from the 85S substation do not impact the ability of the Wreck Cove Hydro units to provide energy or capacity to the NS Power system. Multiple transmission circuits, separated from the Distribution Feeders, connect that station to the provincial transmission system.

Category	Participant	Assumption Comment	NS Power Response
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	If EE program load shape is different from load shape in forecast, then overall scale of EE resource investment could shift load shape, particularly if EV resources affecting load shape	NS Power will work with E3 to assess any modifications required to load shapes, particularly in scenarios where peak and energy assumptions are significantly different than the 2018 actuals on which the load shape is based.
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Forecast marginal ELCC values may be missing diversity benefits from resource mix and could result in selection of too many resources with high ELCC values and too little of other resources	The diversity benefit to ELCC will be computed as part of the Reliability and Operability phases of the IRP analysis; this will address any over- or under-build of capacity resources that could be caused by the ELCC curves being considered in isolation.
6. Planning Reserve Margin (Load)	CA (Chernick & Wilson)	Want more details regarding methods and key diagnostic outputs for capacity value study: • How are hourly loads related to weather data / what assumptions not in last 5-10 years / provide methods and data outputs (scatter plot re actual & modeled vs load) • Weather conditions considered in relationship b/w weather & load (temp, wind, humidity, precipitation) • What consideration of long-term weather trends (> wind, what about precipitation) • Weather conditions (temp) correlated with outages, efficiency (heat rate) or capacity?	The Capacity Study was issued to stakeholder in July 2019 and finalized following stakeholder comment in October 2019. This is an extensive request and NS Power will follow up directly to discuss these comments.
7. ELCC (Wind, Solar, Battery and DR – Effective Load Carrying Capability)	Verschuren Centre	ETS should be considered separately from other forms of energy storage and demand control. ETS has more potential and higher ELCC than other technologies. Could be best solution for balancing wind energy.	NS Power's ETS program participation is considered in the 2019 Load Forecast. The load modifications assoc with the DR strategy, while not included in the current set of DR assumptions, could be viewed as incorporating a portion of ETS the specific program which would be determined. The DR assumptions presented can be viewed as a proxy for other DR programs that may be pursued in the future, dependent on technical capabilities and cost.

Category	Participant	Assumption Comment	NS Power Response
7. ELCC Batteries	Synapse	Use a 2-hour battery resource (+ 1 & 4) in all PLEXOS runs to provide flexibility for short and long-duration attributes.	The resource screening phase will consider several durations for storage options. This will inform the number of storage options to be offered in the Plexos LT capacity expansion model.
7. ELCC Batteries	Synapse	4-hour 2019 battery costs higher than mid-range NREL 2019 and (imputed) 2019 Lazard 5.0 costs; use the lower value $1800-1900/kW vs $2125/kW	The low sensitivity for four-hour battery cost in the Final Assumption set is $1,835 kW.
7. ELCC Batteries	Synapse	Confirm year-over-year cost trajectory for batteries 2020-30 (linear or otherwise). 2018 Lazard 4.0 suggests non-linear 28% CAGR decline to 2025.	The assumed cost trajectory for batteries declines sharply in the early years with an approx. 40% decline 2019-2025 (in real dollar terms).
7. ELCC Wind	Synapse	Wind costs align w/ 2019 NREL data, but cost values ($2100/kW) are higher than 2019 Lazard high costs ($1980/kW). Cost updates may not reflect potential for lower costs ie repowering old sites	The low wind sensitivity included in the final assumption set is $1500/kW which is in line with the 2019 Lazard low costs.
7. ELCC Wind	Synapse	NB Burchill wind farm project shows costs aligned w/ low Lazard costs rather than $2100/kW benchmark. NSP and E3 to explore extent to which cost reduction reasonable. At least one wind cost scenario/sensitivity to be explored if retaining $2100/kW benchmark.	The low wind sensitivity included in the final assumption set is $1500/kW which is in line with the 2019 Lazard low costs.
8. DSM	E1 (February 14)	Confirm avoided DSM costs: • Avoided energy & capacity will be output • Avoided T&D costs will be input, using values based on historical growth-related spending • Avoided environmental compliance costs included in avoided energy, as carbon credit $ included as fuel-related costs	• Confirmed that avoided energy and capacity will be output • Avoided T&D costs will not be an input to the IRP model; methodology for estimating avoided T&D costs will be developed through this IRP process. • Confirmed that environmental avoided costs will be included with fuel

Category	Participant	Assumption Comment	NS Power Response
8. DSM	E1 (February 14)	For 2021-2022, use DSM amounts in the 2020-2022 DSM supply agreement and hold remaining years constant on an incremental basis	Confirmed.
8. DSM	E1 (March 6)	Confirm levels of achievable cost-effective EE and DR in Potential Study are estimated for electrification scenarios considered in IRP because Potential Study levels based on 2019 Load Forecast	NS Power used the cost-effective EE and DR from the Potential Study as described in the Scenario Modeling Plan.
8. DSM	E1 (February 14)	Confirm or explain behaviour, codes, other agency initiatives, and market developments are part of the before DSM load forecast	Energy efficiency and demand response may come from a variety of sources. The IRP is agnostic as to the provider. The DSM Potential Study is being used for EE and DR potential assumptions; however actual delivery may come from a variety of sources as noted in the Assumptions.
8. DSM	E1 (February 14)	Confirm whether NSP using 2019 “Before DSM” load forecast which does not exclude all DSM	Confirmed.

Category	Participant	Assumption Comment	NS Power Response
8. DSM	E1 (February 14)	What modifications were made to 2019 load forecast for use in IRP; clarify whether embedded DSM removed from "Before DSM" scenario. Have potential study scenarios been modified other than shift for DSM activity 2021-2022? Provide Excel version of base load forecast and peak demand forecast including DSM scenarios.	Please refer to the Load Assumptions Overview in the final Assumptions set. The 2019 System Outlook future DSM amounts have a coefficient applied that accounts for embedded DSM and the "before DSM" in the System Outlook only adds back this adjusted amount rather than the full DSM. For the IRP scenarios, the No New DSM forecast includes the full future DSM added back in so that the basis for comparison is the same when the various E1 DSM scenarios are subtracted out. The Potential study scenarios have not been modified other than shift for DSM activity 2021-2022 and the above noted modification. These details have now been included in the Load Assumptions.
8. DSM	E1 (February 14)	Exclude DSM variability from supply-side risk sensitivity runs; may be beneficial to explore DSM risk mitigation effects by examining supply-side risk with and without DSM.	NS Power will follow up with E1 to better understand this suggestion.

Category	Participant	Assumption Comment	NS Power Response
8. DSM	SBA	Treating DSM as load modifier and only considering low, base, mid, max scenarios treats it as exogenous factor rather than integrated resource option. Suggests selection of DSM program implementation efforts will not be output of IRP optimization, but DSM scenarios that change load will be used as model inputs. Concerns with this approach: • Economics of different DSM amounts not tested • Doesn't look at potential focus differences (peak reduction vs energy reduction [which affects emissions] or summer vs winter peaking) • Doesn't capture dynamic effects between DSM penetration and avoided cost	NS Power acknowledges these points. The data provided through the Potential Study warrants treating DSM as a load modifier.
8. DSM	SBA	If DSM adoption depends on comparison of program cost to avoided cost, using DSM as input does not recognize that avoided cost changes with supply-side resource buildout.	Treating DSM as a load modifier does enable the quantification of avoided costs. Altering the level of DSM programming will result in different capacity expansion plans with different fuel and power purchase costs and distinct avoided DSM costs.
8. DSM	SBA	Some EE measures encourage electrification and could increase load – not clear whether captured in NS Power methodology.	NS Power agrees. Efficient electrification is captured within the Pathways Analysis.
8. DSM	SBA	Need specificity re how revenue requirements to be determined for annual DSM expenditures. i.e. multi-year amortization period. A question that arises is whether it is a variable.	Current annual program spending for DSM programs is treated as an expense in the IRP modeling. NS Power is open to alternative considerations as to how DSM recovery is matched to the benefits profile.

Category	Participant	Assumption Comment	NS Power Response
9. Demand Response	E1 (February 14)	Each market potential case for DR should be treated as one trajectory for spending and savings. Model the 3 DR Potential Study cases as load modifiers, potentially as drivers within Analysis Plan context.	Based on conversations with E1, NS Power has aggregated E1's DR programs into one trajectory for spending and savings for each case. NS Power will model the DR Potential Study cases as resource options.
10. Imports	CA (Chernick & Wilson)	Reflect correlation of temperature & load (NL, NS & NB) and availability /cost of imports.	This type of granularity is not included in NS Power's long term planning model.
10. Imports	CA (Chernick & Wilson)	Potential cost of new transmission or how impact analysis	This information has been provided in the final Assumptions.
10. Imports	CA (Chernick & Wilson)	Impact of 800 MW tie line becoming largest contingency w/ associated reserve requirements	Many factors in the design of a tie line would contribute to the ability of the line to provide firm peak capacity, and what its contribution to reserve requirements would be as a result of contingency modeling. Reliability considerations for candidate resource plans of interest will be considered during the Reliability and Operability Screening phase of the modeling.
10. Imports	CA (Chernick & Wilson)	Assuming imports clean understates emissions from NB coal or NE gas (and cost of meeting emission limits) or ignore economic imports of fossil generation	The model will be provided with pricing for both emitting (with REC / carbon price) and non-emitting sourced imports
11. Fuel Pricing	Bates White	Forecast fuel prices (biomass, coal) appear low.	The referenced data set was developed as a pre-IRP deliverable and does not form the basis of the final fuel Assumptions.

Category	Participant	Assumption Comment	NS Power Response
12. Fuel Pricing (Gas)	CA (Chernick & Wilson)	Confirm if model selects new gas units, supply per option 3; alternatives would be potential substitutes to be evaluated post-IRP; alternative options not necessary for feasibility of gas units in IRP since option 3 feasible & sufficient	Confirmed for builds with a high capacity factor (i.e. combined cycle units)
12. Fuel Pricing (Gas)	CanWEA/SIA	Consider natural gas constraints through NE Will role of Canaport LNG in addressing peak change w/ proliferation of LNG in US	The 3 tiers of gas pricing based on incremental volumes and adjusted for seasonality are designed to capture the effects of natural gas pipeline constraints and reliance on LNG in some periods at some volumes.
13. Sustaining Capital	CA (Chernick & Wilson)	Please confirm or correct our understanding of the discussion about the utilization factor. We understand that the base forecast assumes capital investments that would occur if each unit operated at what NS Power considers to be a high utilization factor for that unit. We think you are defining "high" utilization as the most demanding experience of the unit in some recent historical period, as opposed defining "high" by the same metric for all units (e.g., 80% capacity factor). Thus, if the IRP results forecast relatively low utilization factors for some units, compared to the historical base, NS Power would expect future capital investments to be lower than the base assumptions included in the IRP.	Confirmed. The high utilization does generally imply the most demanding experience of the unit, however not necessarily indicative of a high capacity factor. NS Power agrees that if units are utilized at a lower utilization factor, NS Power would expect to see lower sustaining capital costs on those units.

Category	Participant	Assumption Comment	NS Power Response
13. Sustaining Capital	CA (Chernick & Wilson)	Are IRP and 2020 ACE sustaining capital forecasts based on different UF? Does sustaining capital for each unit reflect historical experience + inflation or is it increased to reflect age of the plant?	Yes. The ACE Plan is based on the annual bottom-up view and projected utilization, whereas in the IRP the high UF method puts all the units on an equal basis in terms of their operation in order to appropriately compare economics. As described in the Assumptions set, High and Low (or other iterative ranges) will be evaluated. The sustaining capital estimates in the final Assumptions set are presented in real 2020 dollars. For modeling inflation is included.
13. Sustaining Capital	Heritage Gas	NSP to review sustaining capital costs from slide 95 (Feb 3) against original (Jan 20) assumptions set; explain changes, esp. in light of revisions to vertical axis.	As discussed in the February 27 workshop, the change reflects basis of presentation (nominal to real dollars)
13. Sustaining Capital	SBA	Revised assumptions included significant changes to sustaining capital forecast for coal, CTs and small hydro.	The more significant change in basis of presentation was associated with the change from nominal to real dollars for the CTs. The other revisions reflect updated forecasts from June 2019 to January 2020.
13. Sustaining Capital	Bates White	Bates White requested clarification about how historical sustaining capital corresponds with projected IRP estimates and/or requests further detail respecting sustaining costs development.	Historical maintenance cycles are considered in development of sustaining capital cost forecasts but are not directly comparable. NS Power has agreed with Bates White, and as noted in the final Assumptions set, the way to approach the issues raised is to run high cost sensitivity tests in the model.

Category	Participant	Assumption Comment	NS Power Response
13. Sustaining Capital Thermal Fleet	Bates White	**CTs** – forecast 28% reduction in sustaining cap vs. historical data.	CTs – fleet undergoing LEM modernization activities now and approximately 70% of the way through. Some major component replacement has occurred and is not expected to be repeated during the next 25 years – 40-year life extension. Victoria Junction capital item currently before the UARB.
14. Renewable Integration	CA (Chernick & Wilson)	What technology options will model have to meet minimum requirements for essential grid services such as hybrid resources or flexible solar? Suggest NSP host tech conference to explain and solicit feedback	Options available to the model to enable various levels of wind integration include a second 345kV AC tie line between Onslow, NS and Salisbury, NB or a 200 MVA Synchronous Condenser and 200 MW Battery located in Nova Scotia.
14. Renewable Integration	CanWEA/SIA	Need realistic assumptions re wind and solar integration strategies and costs: • Use expanded balancing footprint and joint system operations (NS/NB); better integration w/ NE market; sub-hourly scheduling and dispatch; real-time forecasts to reflect best practices • Use DR strategies to facilitate wind/solar energy integration (incl. space/H20 heating as storage w/ switching devices) • Curtail surplus wind / solar generation; electrolysis (if not enough export capacity to produce H) as element of solar integration • Flexible ML hydro imports to offset generation/load imbalances	Wind and Solar integration are being considered in the IRP, informed by the PSC Stability Study Pre-IRP deliverable.

Category	Participant	Assumption Comment	NS Power Response
14. Renewable Integration	Natural Forces	Reconsider inclusion of VAR support as key operational parameter (constraint could be resolved by easier cheaper solutions – installation of SVCs or synchronous condensers)	Synchronous Condensers are being considered as one method of integrating additional wind on the NS Power system; additional analysis on VAR and other essential grid services will be conducted during the Reliability and Operability phase of the IRP modeling process.
14. Renewable Integration	Natural Forces	Setting required minimum levels for remaining requirements important - synchronous inertia requirement will depend on largest system infeed/outfeed; Not likely able to model this degree of sophistication in IRP – will adopt single static values.	NS Power agrees that these more detailed wind integration requirements are important but are difficult to include in the capacity expansion portion of the model; these items will be examined during the Reliability and Operability assessment phases of the IRP Modeling Plan.
14. Renewable Integration	Natural Forces	Although there may be learnings from the PSC Renewable Integration study, have to take care as scenarios modelled in it don't reflect normal system conditions and grid service requirements.	The intent of the PSC Stability study was to model via transient analysis particular contingencies which the system must be able to survive in order to reliably service customers. Additional analyses on the integration of high levels of variable generation will be completed during the Reliability and Operability assessment phases of the IRP modeling plan.
14. Renewable Integration	Natural Forces	Proposed grid service level limits should be low rather than high, but don't want to exclude economic portfolio options, but this will be picked up in operability screening.	NS Power agrees; resource portfolios with high levels of variable generation will be analyzed during the Reliability and Operability assessment phases of the IRP modeling plan.

Category	Participant	Assumption Comment	NS Power Response
14. Renewable Integration	Natural Forces	Don't default to assumed existing levels of performance for capability of portfolio of resources to contribute to grid services. Considerations from elsewhere: • Generation units can improve flexibility and contribution to system services (ramping, min stable output, start times, reserves) • New generation can be configured to provide grid services optimally • Renewable plants are also important source of grid services • Widening supply base successful (demand side contribution to s/t operating reserves)	NS Power is interested to examine how variable generators can provide additional ancillary services during the Operability and Reliability screening phases; additional information and discussion on this front would be helpful.
15. Interconnection & T&D	Natural Forces	Treatment of interconnectors critical. Firm imports could support transition to lower GHG emissions, but fixed import schedules can reduce wind output/capacity as it squeezes space available for RES and local thermal/synchronous plants. Intertie to NB can be the most severe contingency on the system, determining grid services requirements. Request further description of proposed modelling of interconnector flows.	NS Power agrees that additional transmission interconnections are an enabler of further wind integration. Additional assumptions supporting renewable integrations have been included in the final Assumptions set.
15. Interconnection & T&D	Digby	Risk that distribution interconnection may not be available, which limits Digby's ability to introduce new generation capacity from renewable energy projects.	The capacity expansion modeling of the IRP is, in general, not location or project specific; therefore candidate locations for new generation resources would be considered as part of specific project planning post-IRP.

Category	Participant	Assumption Comment	NS Power Response
15. Interconnection & T&D	Verschuren Centre	IRP should take into account substation level capacity considerations (some of which have Transmission restraints as well). Most electrification will take place at end of line and place additional load on substations. Consider suite of distribution scale energy and capacity assumptions (1-10MW).	The IRP model does not consider the Distribution system explicitly however NS Power will be considering a methodology for avoided T&D costs as part of the IRP process. Once developed, this could be applied outside of the model to understand its impact.

Average of lolp	Column Labels													
Row Labels	0	1	2	3	4	5	6	7	8	9	10	11	12	13
1	0.0001	0.0001	0.0000	0.0000	0.0000	0.0001	0.0009	0.0011	0.0014	0.0016	0.0014	0.0016	0.0016	0.0011
2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0004	0.0006	0.0006	0.0006	0.0008	0.0006	0.0005
3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001
4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
7	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
9	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
12	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0001	0.0002	0.0002	0.0003	0.0003	0.0002

Average of lolp Row Labels	14	15	16	17	18	19	20	21	22	23
1	0.0009	0.0010	0.0015	0.0022	0.0022	0.0018	0.0012	0.0012	0.0002	0.0007
2	0.0003	0.0002	0.0006	0.0009	0.0012	0.0008	0.0008	0.0004	0.0000	0.0001
3	0.0000	0.0000	0.0000	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001
4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
7	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
9	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11	0.0000	0.0000	0.0001	0.0001	0.0003	0.0002	0.0001	0.0001	0.0000	0.0000
12	0.0002	0.0002	0.0003	0.0015	0.0012	0.0004	0.0004	0.0002	0.0000	0.0002