| # | Comment/Question | Party | Draft Response |
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| **Fuels Forecast** | | | |
| **General Comments/Questions** | | | |
| 1 | Slide 52 shows percentages of likelihood (PIRA) for the Base, High, and Low case natural gas scenarios of 45%, 25%, and 30%, respectively. The further slides do not refer to these percentages and PHP assumes that there is no specific weighting given to the probability of occurrence of the three separate cases in the proposed analysis. PHP would appreciate confirmation, or an explanation of why and how these percentage figures are to be utilized in the analysis. | PHP | Correct. The percentage likelihood figures by PIRA are quoted by NS Power for information purposes only. |
| 2 | Slide 55 shows that for the natural gas Base Case (Expected), there is no premium for the periods 2018-2030 or 2030-2040. This appears to assume as a Base Case that the U.S. Northeast and Atlantic Canadian gas market structural issues are fully mitigated by 2018 for the entire Planning Horizon. What level of confidence does NSPI place on this assumption to the extent that it can utilize it as the Base Case, considering the occurrence of the current unexpected natural gas pricing conditions, the capital works required to address this issue, and the increasing upward pressure on natural gas demand in New England? | PHP | NS Power relies on PIRA who expect pipeline capacity additions in the NE US in the 2017 timeframe. By extending this timeframe to 2018 (in the Base Case) and employing two additional cases for fuel price development (High and Low), the Company is comfortable that market uncertainty with regard to pipeline capacity additions in the NE US is captured. |
| 3 | Slide 65 states that for domestic coal, the price source is NSPI current contracts. For the analysis, what constraints, if any, are placed on the amount/volume of domestic coal and its source (i.e. will the modeling be able to choose Donkin coal, for example, or only coal from the coal fields currently supplying NSPI)? If the model is constrained in this regard, PHP believes it will be important to do sensitivities around the utilization of other indigenous resources to the greatest extent possible. | PHP | With respect to domestic coal, NS Power assumptions reflect current supply contracts only (for the duration of the current contracts). NS Power will evaluate alternative scenarios by performing sensitivities. |
| 4 | Please provide the updated Slide 66 (Solid Fuel Pricing Assumptions) as soon as possible on the basis of the revised underlying fuel forecast. Please note any significant assumption changes in the revision. | PHP | Please refer to slides 66 to 70 in the final assumptions. |

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| 5 | In order to better understand the impact of different fuel forecast assumptions, it would be helpful if NSPI would provide a graph comparing historic and forecast fuel costs over the planning horizon (in $/mmbtu) on a single graph. Where there are relative price differentials that diverge from historic differentials, it would be appropriate for NSPI to comment on the market (or other) assumptions that influence the change. | Industrial | Please refer to Figure D. |
| 6 | NSPI should consider using other fuel forecasts. | Industrial | NS Power considered the use of the EIA price forecasts but elected to rely on existing commercial relationships (such as PIRA and EVA) considering ready access to professional insight, support and visibility to underlying assumptions.<br><br>NS Power's preferred third party providers' forecasts are in-line with EIA's expectations according to Annual Energy Outlook 2014 Early Release, Reference Case. Please refer to Figures B and C. |
| 6a | In the 2014 US Energy Information Administration (EIA) forecast, the low oil price case projects flat oil prices to 2040 (flat in real terms – adjusted for inflation). Has NSPI considered a low coal forecast that holds coal prices flat, apart from inflation adjustment, for a significant portion of the IRP period? | Industrial | NS Power relies on EVA who have provided a range of potential outcomes for world coal prices (including a case of low (in real terms relatively "flat") prices). Further consideration will be given to lower coal prices during sensitivity analysis |
| 6b | What coal market trends has NSPI observed recently that support coal forecasts included in the IRP assumptions? | Industrial | EVA's projections for a general "softening" of the market are consistent with NSPI's own observations or recent market trends. |
| 7 | Has NSPI considered the IRP impact if the assumptions regarding the installation of new natural gas pipelines are not met? What are the costs and risks associated with delay? | Industrial | NS Power is proposing to consider three distinct cases for natural gas price development in the NE US and is reasonably comfortable that market uncertainty will be adequately captured across scenarios. The high gas price case considers later implementation of additional pipeline capacity and the low earlier implementation. Please refer to item 2 for discussion on risk. |
| 8 | For the Solid Fuel Price Assumptions, can NSPI provide prices in real and nominal terms? | Industrial | Please refer to slides 66 to 70 in the final assumptions deck. |

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| 9 | NSPI should examine whether capacity exists on the TCPL system to get gas from Wright to Maritimes & Northeast at firm tariff rates. | CA | The Company has examined this and understands that firm transport capacity is not currently available on the TCPL system from Wright to M&NP. TCPL has suggested that an expansion is possible, at Tariff Rates comparable to the current open season rates for Spectra and Tennessee Gas. |
| 10 | NSPI should provide more detail on the conversion of pipeline tariff rates into $/MMBtu used at Tufts Cove, given the fixed tariff charges and scheduling requirements. | CA | NS Power has used indicative $/MMBtu rates as quoted by pipeline project sponsors for new pipeline projects and historical costs (escalated where appropriate) for existing pipelines assuming similar volumes and scheduling requirements continuing in the future. |
| 11 | Scotian WindFields has the below comments regarding the Draft Assumptions for Fuel Price Forecast Assumptions, particularly for the long-term price forecasting for Natural Gas, Petroleum-based fuels and solid fuels.<br><br>a. The Average Annual Increase of fuel pricing for Natural Gas between years 2015 and 2040, as presented in the Draft Assumptions (Slide 58) is between 2.4% and 3.1%. This is exceedingly optimistic consider that the Average Annual Increase of Natural Gas pricing between years 1991 and 2013/2014 was calculated at 5.5%.[5]<br>b. The Average Annual Increase of fuel pricing for HFO and LFO between years 2015 and 2040, as presented in the Draft Assumptions (Slide 72) is between 2.3% and 3.59%. This seems exceedingly conservative as the Average Annual Increase of WTI crude pricing between years 1990 and 2013/2014 was calculated at 6.1%[6] and the Average Annual Increase of Heating Oil was calculated at 6.3%.[7]<br>c. Based on the above presented historical data, we recommend that NS Power consider more appropriate energy inflation figures in the IRP Model. | Scotian WindFields | Further consideration will be given to lower and higher prices during sensitivity analysis. For its basic starting point, NS Power relies on the opinion of PIRA and EVA for the development of long term fundamental price forecasts including assumptions about price growth rates across a range of potential outcomes. |
| 12 | There appears to be an inconsistency among the natural gas forecasts, emissions costs and import price assumptions over the study period. | SBA | NSPI is not aware of any significant inconsistencies across fuel price assumptions. |

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| 13 | The fuel cost assumptions should take into account the possibility of gas storage in the Province.<br>There should be a scenario where we can avoid the winter spikes as we will have storage in the area to fill up during the summer months and withdraw in the winter months. Heritage Gas is already considering such an investment. | Natural Forces | The pricing impact of natural gas storage is expected to evolve within the range of the IRP fuel price assumptions and sensitivities. Storage is not currently available in NS but projects have been announced or are being pursued. These projects are uncertain and NSPI may procure natural gas storage subject to availability and extensive review by the Company and others, based in part on the results of the IRP study and NSPI's long term fuel source mix expectations. |
| | **Carbon Pricing in Fuel/Import Prices** | | |
| 14 | Carbon costs should be counted and not only for U.S. imports so as to quantify the potential carbon price risk associated with the candidate resource plans. | ENE | All fuel price forecasts embed a cost of carbon as assumed by PIRA and EVA. These assumptions appear reasonable and within generally accepted market expectations. Nova Scotia carbon pricing is assumed to be incorporated as the costs required for the Company to meet the GHG cap. |
| 15 | High carbon pricing cases should explore prices well above 50$ a tonne by the end of the IRP timeframe and should be consistent with similar planning activities across North America. | EAC | NS Power relies on PIRA and EVA with respect to assumptions about the price of carbon, which appear reasonable and within generally accepted market expectations including those published by Synapse Energy Economics Inc. Please refer to Figure A. |
| 16 | Why is the assumption made that there is CO2 emissions limits or costs established for the reference natural gas forecast and not in either of the high and low forecasts? | SBA | The assumption regarding the cost of carbon (by PIRA) is common to the three cases for natural gas prices. |
| 17 | Scotian WindFields has the below comments regarding the Draft Assumptions for Carbon Pricing. Under the Case Development (Power) on Slide 60, it is stated that the assumed cost of Carbon is US$15/Ton CO2 in 2020, escalating to US$37/Ton CO2 in 2030.<br>The values for cost of carbon provided in the Draft Assumptions are associated with imported power. If and how carbon pricing is applied within Nova Scotia is a very significant variable as well.<br>a. The IRP model should consider the potential for NS Power to be required to pay a price on carbon emissions. Regarding the cost of carbon emissions specifically, we have drawn our analysis from a report commissioned by Synapse Energy Economics Inc. on November 1, 2013 - “2013 Carbon Dioxide Price Forecast”. This study considered the carbon price information from the most recent IRP efforts of 28 utilities. With the Canadian | Scotian WindFields | Please refer to items 47 and 52. |

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| | federal government's stated intention to harmonize carbon policy with the US and our economic interdependence, we feel it is reasonable to use US projections for Canadian pricing scenarios. We would request that the costs from this study for long-term carbon pricing be considered. The three key scenarios are itemized below:<br>b. The Low Case forecasts a cost of Carbon at US$10/Ton CO2 in 2020, escalating to US$40/Ton CO2 in 2030.2<br>c. The Mid Case forecasts a cost of Carbon at US$15/Ton CO2 in 2020, escalating to US$60/Ton CO2 in 2030.3<br>d. The High Case forecasts a cost of Carbon at US$25/Ton CO2 in 2020, escalating to US$90/Ton CO2 in 2030.4 | | |
| **Load Forecast** | | | |
| 18 | The Department appreciates the need for an accurate model to define the base case load forecast, however the Department respectfully suggests that the proposed scenarios do not show the levels of variance required to ensure that all reasonable futures will be included in the modeling. The proposed residential forecast in particular is extremely narrow in scope and the department believes that a much wider range should be considered; ideally at least +/- 15% of the base case for each customer class. | Dept. of Energy | The proposed scenarios are based on assumptions similar to those used historically to create a range of possible load requirements for the province. When DSM is added to the various load scenarios a cone of load variability emerges with enough scope to sufficiently cover a broad range of reasonable future load scenarios, please refer to the final Load Forecast assumptions. |
| 19 | The low forecast should assume flat or declining industrial load. | SBA | The large industrial class is where most of the loss of industrial load has come from in recent history. The forecast for this class is decreased by 40 GWh in 2016 and held flat throughout the rest of the forecast. Additionally the requirement to serve some of the municipalities' industrial load is decreased by the integration of the Ellerhouse wind farm into the forecast. The industrial load growth is being driven by the small and medium industrial classes. These are derived from the Conference Board of Canada's forecasts for provincial GDP and Manufacturing related GDP, both of which show an increasing trend. |

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| 20 | It would be helpful if further details were provided on the assumptions that go into developing the end use model base case load forecast. | Dept. of Energy | Further details on the end use model are included on slides 85 to 93 in the Final Assumptions slide deck. |
| 21 | Can NSPI explain how the total industrial forecast is so closely aligned to the medium and small industrial forecast? Wouldn't the flat large industrial forecast impact the overall industrial load projections? | Industrial | Because the large industrial forecast is held flat the only year over year change to the industrial sector load is from the small and medium industrial classes. Currently approximately 50% of industrial load comes from the small and medium industrial classes and 50% is from the large industrial class. Since small and medium industrial load is forecasted to grow, while load is forecasted flat for the large industrial class, small and medium industrial load as a percentage of total industrial load will grow for the duration of the forecast. As a result, year over year change in the industrial load forecast is closely aligned with the small and medium load forecast. |
| 22 | Can NSPI speak to what changes had occurred in the past year such that the ML base load case is included in the IRP assumptions as the High Scenario? | Industrial | There has not been any change in the past year to cause the Company to significantly alter its load assumptions. The naming of the load scenarios was a point of debate during the Maritime Link hearing and NS Power has adjusted the naming of its load assumptions to reflect the positions taken by stakeholders in the Maritime Link hearing. This change is not philosophical in nature but rather meant to provide clarity. |
| 23 | Will NSPI provide a scenario in which PHP is not on the Load Retention Tariff for the duration of the IRP period? | Industrial | In the base and high load scenarios where PHP remains in operation beyond 2019 it is assumed that PHP will transition from the load retention rate to an industrial rate in 2020. The Company assumes that PHP load will remain interruptible and that the load considered in the high case could be PHP or other interruptible load(s). |
| 24 | In terms of load growth, the possibility of the LNG plant should be viewed in this study. This would represent a step up in load growth which should be considered for electricity demand. | Natural Forces | Recent announcements have indicated the development of a LNG plant in Goldboro will include up to 180 MW of natural gas fired generation. Based on this information it appears the LNG plant will meet most or all of their load requirements with their own generation. |
| 25 | Sensitivity on load growth due to electric cars would be of interest to see | Natural Forces | The potential uptake of electric cars is considered in the high load scenario. |

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| **DSM** | | | |
| **Amount of DSM to be Modelled** | | | |
| 26 | ENE supports modeling the High and Low scenarios from the Navigant potential study. ENE strongly recommends that the Mid scenario be included as the third DSM scenario. | ENE | NS Power understands from ENSC that the High DSM scenario represents the DSM Administrator's view of the highest amounts achievable in Nova Scotia. The Company will also model the Base scenario. |
| 27 | DSM and supply-side resources should be assessed on an even playing field. Only those costs and benefits incurred by the utility should be included in the IRP. DSM should not be assessed from a total resource cost perspective, but rather from a utility cost perspective.<br><br>April 7, 2014: ENE again strongly recommends that NSPI consider DSM resources from a utility cost perspective. | ENE | The TRC test has been used for DSM screening in Nova Scotia since 2007 and remains the predominant primary-screening test used in North America. Based on the EERAM model, use of the TRC does not appear to significantly alter the DSM achievable potential. Consideration of the DSM potential assuming a PAC test would therefore not produce materially different results and would not have an effect on this IRP. NS Power has also indicated that it will provide revenue requirement information with and without the customer cost component of DSM for stakeholder information. This will provide the information needed for discussion of the selection of the Preferred Resource Plan. |

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| 28 | The IRP should include cost effectives DSM programming from any available source, including the utility's own incentive and infrastructure plans such as intelligent metering, conservation voltage reduction and other smart-grid based technologies. | Dept. of Energy | With respect to NS Power's infrastructure, the company continuously investigates and evaluates projects which could assist in improving the energy efficiency of its overall operations. These projects are either OM&G investments or are approved by the UARB as part of the capital program, assuming they have a strong business case.<br><br>The DSM energy efficiency assumptions to be used in the IRP are substantial enough to encompass a range of future programs, regardless of source.<br><br>NS Power has proposed Demand Response assumptions for modelling. Demand Response using direct load control has been shown to provide effective and reliable peak mitigation in other jurisdictions. The IRP will also consider whether using this approach can also provide ancillary services of benefit to the system. If this option forms part of the IRP action plan, the utility would have a role in developing it into a program for future consideration by the UARB and other stakeholders. |
| | **Avoided Costs** | | |
| 29 | In terms of avoided costs, NSP should provide stakeholders with justification for using a value other than $135/MWh | ENE | The IRP will provide new avoided cost information. Discussion about which components and methods to be used for calculating the avoided costs of DSM will be part of the IRP process. |
| 30 | The IRP offers an opportunity for NSP to engage stakeholders in the development of the avoided cost. The process should be transparent, and generate a breakdown of the avoided cost value by its components. | ENE | Please refer to item 29. |
| | **General DSM Questions/Comments** | | |
| 31 | If NSP runs a sensitivity analysis on the results of Navigant's DSM potential study, then it is necessary for stakeholders to have access to this methodology and assumptions prior to commenting on proposed DSM scenarios. | ENE | Please refer to item 26. Since the IRP is intended to provide direction rather than an explicit and detailed plan, NS Power has accepted ENSC's recommendation to base IRP DSM input assumptions on their DSM Potential scenarios. There is no need to review or revise EERAM in detail at this time. |

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| 32 | NSP should explain and support its contention that DSM potential is affected by the electric rate. | CA | In reviewing ENSC's EERAM model, it was discovered that the model includes electricity prices as input and it seemed appropriate to ensure these were up to date. NS Power recommended that EERAM's forecast of electricity prices be adjusted to reflect a historical average rather than a single year's increase. Please refer to DR-10 (Industrial Group). While it is unclear to NSPI how EERAM specifically utilizes the electricity price forecast, electric prices are generally a consideration in determining the expected bill savings and payback period of proposed DSM measures and could affect the uptake of certain programs. |
| 33 | ENE recommends using a discount rate that is equal to a recent average of the historic yields from a ten-year government bond. | ENE | NS Power's WACC has been used for DSM screening in Nova Scotia since 2007. Use of utility WACC is a common approach to setting the DSM discount rate in North America. Based on the EERAM model, use of the WACC does not appear to significantly alter the DSM achievable potential. Consideration of the DSM potential using a different rate would therefore not produce materially different results and would not have an effect on this IRP. Discussion regarding which discount rate should be used for DSM calculations is best conducted in a future ENSC DSM proceeding before the UARB. In the IRP, DSM is a capital or operating cost as are all other NS Power costs and should be subject to the same discount rate as all other expenses. |
| 34 | While Demand Response is mentioned it is not clear if it will be modeled as a separate process or only as an effect of Energy Efficiency DSM. The Department would suggest that as emerging technologies (such as smart-grid) will make Demand Response increasingly effective and relevant, it would be useful for the IRP to model these specific effects on peak load system demand. | Dept. of Energy | Yes, NSPI will be including four demand response programs in its IRP analysis. Please refer to the DR assumptions. |
| 35 | ENSC requests clarification on whether the IRP will include costs associated with increased spinning and planning reserve associated with new supply alternatives. Additionally ENSC requests clarification on whether the IRP will credit DSM activities (Demand Response and Energy Efficiency) commensurate with the associated reductions in reserve requirements. | ENSC | The model will include any reductions in firm peak associated with DSM effects and the corresponding reductions in planning reserve requirements. The contribution of any new supply option to the planning reserve requirements will be included in the Strategist modeling. Operating reserve requirements will be considered in Plexos. |

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| 36 | ENSC requests that NSPI share all relevant assumptions and supporting research for demand response alternatives included in this IRP. | ENSC | NS Power provided IRP Demand Response assumptions to all stakeholders on March 28th. Additional information can be found in the Demand Response Section of the Final Assumptions deck (slides 101 to 111). |
| | **Treatment of DSM** | | |
| 37 | DSM should be evaluated as a resource option alongside supply-side resources. | ENE | The ENSC DSM quantities to be used in the IRP have passed the TRC test based on ENSC's assumptions and at the cost levels presented by ENSC are generally anticipated to be competitive with supply side options. As a result, NS Power believes that the use of the scenarios as load modifiers is a reasonable and appropriate method for DSM analysis in this IRP. |
| 38 | Treat DSM as a resource alongside generation options. | EAC | Please refer to item 37. |
| 39 | Program Administrator Costs for incremental levels of DSM should be optimized along with supply side options so that the level of utility cost effective DSM is an output of the process, not an input. | EAC | Please refer to item 37. |
| 40 | Clarify what is meant by "layers" of DSM in the IRP process description. Indicate how the model will settle on the amount of DSM programming. | Dept. of Energy | Please refer to slides 78 to 82 and 94 to 100 in the Final Assumptions deck. |
| 41 | ENSC requests that the IRP Assumptions state that demand-side resources will be considered as an alternative to both existing and future supply resources as the IRP seeks to minimize the cumulative present worth of the annual revenue requirements over the planning period. For existing thermal plants, the IRP should consider reduced operations and earlier retirement. | ENSC | NS Power will consider the amounts of DSM proposed in ENSC's potential study. Please refer to item 26. |

| Financial | | | |
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| 42 | The cost of capital stated by NSPI should not be a single number; there should be a sensitivity to see what could be possible if the cost of capital for NSPI was 100 basis points lower. | Natural Forces | Please refer to item 43. |
| 43 | Request clarification on whether or not the IRP will include the costs of financing associated with candidate IRP alternatives. ENSC also requests clarification on whether sensitivities in future borrowing rates will be explored. | Scotian WindFields | Only one WACC is possible in the modelling and as the same WACC is used across all assumptions there is no benefit in using a range for WACC. |
| 44 | With respect to the Financial Assumptions, can NSPI confirm whether the revenue requirement profiles are appropriate for the IRP? Has NSPI considered levelized cost profiles? Have risk adjusted discount rates been considered? | Industrial | Revenue Requirement profiles closely match the actual annual spend of the Company and allow for other analysis. Levelized cost profiles were not considered because of the advantages of the revenue requirement profiles. Risk adjusted discount rates were not considered because there is only one rate allowed in the modelling. |
| 45 | It is suggested that the Canadian vs US currency values track closely to global oil prices. As global oil prices (and hence other commodity prices) increase in a sustained way, the value of the Canadian dollar rises. A high oil price case would be aligned with a strong Canadian dollar, while a low oil price case would see a weaker Canadian dollar. Does the exchange rate in the IRP reflect this trend and if not, why not? | Industrial | The forecasted exchange rates in the IRP are averages of the forecasted exchange rates provided by the economic departments of a number of major banks. It is believed that one of their many considerations in developing these rate forecasts would be commodity prices. |

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| **Environmental & Emissions** | | | |
| **Emissions Scenarios** | | | |
| 46 | ENE recommends assessing a GHG emissions reduction scenario with a trajectory that achieves science-based targets in 2050 as a high environmental constraint. This would translate into an emissions level of approximately 5.14 Mt in 2020 and 2.60 Mt in 2040. | ENE | NS Power is aware of The Climate Change Accountability Act Bill C-311. Since Bill C-311 was defeated in 2010, the Government of Canada has released regulations for coal fired generators to come into force in 2015. Currently, the Nova Scotia Greenhouse Gas Emission Regulations outline hard caps for 2010 to 2030. In September 2012, the Provincial and Federal governments released a draft equivalency agreement which, once finalized, will ensure the provincial regulations will apply in Nova Scotia. It has been determined that the Nova Scotia regulatory regime will meet or exceed the Federal GHG reductions in a less costly manner. NS Power must follow future regulations implemented by the Provincial and Federal Government, which at this time, are most likely those standards set out in the draft equivalency agreement and reflected as Scenario A. The Company will consider deeper emissions cuts than Scenario A, please refer to item 47. |
| 47 | EAC proposes that a third GHG scenario that approaches zero electricity GHG emissions to be added: Scenario C: Emission limits as per An Agreement on the Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia (Sept. 2012)<br>Limit declines to 2.25 in 2040, 0 in 2050.<br>The downward path of the GHG constraint in Scenario C is consistent with the established medium term goals and long-term commitments consistent with the Federal government's signature to the Copenhagen Accord. | EAC | The Company will model GHG emission cuts to 2.25MT in 2040 as a Scenario C (and associated co-benefits for other air emissions and RES targets); however, the Company will not extend the modelling exercise past the 2040 window during this IRP. |
| 48 | This would suggest that the current assumption set only includes one probable scenario, making it prudent for the IRP to include a third, more aggressive, scenario for these pollutants as well as for CO2 to illustrate the relative costs of achieving such reductions. | ENSC | Please refer to item 47. |

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| 49 | Should IRP study emissions reduction targets that go beyond compliance in order to establish the impact of policy changes that might ratchet down emissions? What would these targets be? Would it be valuable to test targets desired by individual stakeholder groups? | SBA | Please refer to item 47. |
| 50 | Given scenario B is outside the reasonable range of possible air pollution trajectories, NSE suggests replacing it with a more realistic scenario similar to the approach taken with the GHG emission assumptions. NSE recommends that Scenario B reflects the air pollution reduction trajectory as depicted in "the Paper" (Scenario A) until 2030, then assumes no continual reduction after 2030. | NSE | Scenario B for SO2, NOx and Hg, was included to demonstrate the cost of achieving emissions reductions beyond what is currently in legislation (to 2020). Not all emissions reductions for these air pollutants are achieved through co-benefits of GHG reductions, so it is important to demonstrate the costs associated with the proposed post-2020 emissions reductions. |
| 51 | A sensitivity of more and less stringent emissions reductions strategies than Scenario A for the GHG and various Air Pollutants assumptions in order to fully assess the impact of policy changes in the Federal and Provincial governments should be carried out. | Industrial | NS Power agrees that assessing the cost of policy change is important. Scenario B provides the emission targets currently legislated. Scenario A is meant to provide more stringent targets, and is based on direction from Nova Scotia Environment through their Discussion Paper (June 2013) and their long term goal of continuous emissions reductions. NS Power agrees that a less stringent scenario should also be examined to assess the relative costs of current and proposed future policy. |
| 52 | The IRP model should consider the potential for NS Power to be required to pay a price on carbon emissions. | Scotian WindFields | NS regulations have hard caps which impose an implied price on carbon emissions. |
| 53 | Are there different scenarios of constraints? How will NSPI incorporate the A&B scenarios for emissions constraints? Is it the best use of limited time/resources to study both? Why not plan for the more stringent resources since there will be many IRPs prior to reaching the point where the Scenarios A & B diverge? | SBA | See items 47, 50 and 51. |

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| 54 | The stated GHG emission targets for the period between 2015 & 2035 have been drafted on the basis of the existing Federal legislation. With global developments as described above we believe that more discussion and thought is required as to what the appropriate GHG 'book-end' cases would look like. A suggestion would be to look at the British and German 2050 targets and perhaps applying standards similar to these to Nova Scotia as a 'book-end'.<br><br>NSPI's Case A and B show what a base case (current government standards) is and a lower standard (less reduction) of reducing GHGs, NOX, SOX and Hg. We believe it would be important to also show an increased standard (more reduction) than what the current government policies mandate. | Natural Forces | Please refer to items 46, 47, and 49. |
| 55 | In many jurisdictions carrying out resource planning, it is now common to include scenarios which seek to understand what the cost to the rate payer would be with varying costs allocated to carbon and other GHG emissions. Perhaps allocating a payment for non compliance in terms of GHG emissions or a saving by selling over compliance to another jurisdiction. | Natural Forces | Please refer to items 47 and 52. |
| | **RES Requirements** | | |
| 56 | The Province of Nova Scotia has no current plans to change the requirements of the Renewable Electricity Standards (RES), as defined under the Renewable Electricity Regulations. However, the government continues to support the development of renewables and expects that the percentage of renewable electricity supply is likely to increase beyond levels currently mandated by the RES Regulations. | Dept. of Energy | Increased renewables will be considered during the development of candidate resource plans. In addition, the company may need to examine renewables above 40% in order to meet Scenario C emissions scenarios. |

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| 57 | Include within the RES assumptions an additional scenario where:<br>Electricity Supply consists of 100% Renewable Energy Sources by 2040<br>Electricity Supply consists of 80% Renewable Energy Sources by 2030 | EAC | Please refer to Item 47, NS Power will model increased RES requirement associated with achieving GHG reductions to 2.25 MT by 2040. |
| 58 | Are the existing RES requirements the only future to be analyzed? Should the IRP evaluate renewable energy strategy targets beyond RES compliance? | SBA | Please refer to items 56 and 57. |
| 59 | While NSPI believes this is taken care of by the differing level of environmental standards, it would be of interest to us to see what an increased renewable energy standard would cost or save. | Natural Forces | Refer to items 56 and 57. |
| **Analysis Plan** | | | |
| 60 | The Industrial Group requests that NSPI provide a clearer articulation of the basis for evaluation and selection of the Preferred Plan and a means for resolving competing objectives. | Industrial | NS Power is working with Synapse to establish the preferred resource plan selection criteria - they are along the lines of previous IRPs and IRP best practices. They include robustness across a range of futures, relative revenue requirements, technology, fuel availability etc. NS Power will provide periodic reports to all stakeholders during the Analysis Plan stage. Please also refer to item 64. |
| 61 | The Industrial Group requests that NSPI circulate the proposed evaluation criteria for the high-level screening and to select the Preferred Resource Plan with commentary on how the other IRP objectives identified in the TOR have been defined, measured, and weighted in establishing the criteria. | Industrial | Please refer to item 60. |
| 62 | The SBA believes that it is important for stakeholders to come to agreements first and foremost on the objectives of the IRP. This includes establishing metrics NS Power intends to look at to determine the best resource plan or even the good resource plans. | SBA | Please refer to item 60. |

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| 63 | The objectives should be made up of three areas, goals, metrics, and key questions that should be answered. | SBA | These concerns will be addressed during the evaluation of the Candidate Resource Plans – please refer to item 60. |
| 64 | The Terms of Reference provide specifically for a Stakeholder Engagement Process. "Stakeholder input is an integral part of the process". With this in mind the SBA is concerned that the process is not more interactive. | SBA | The Company is committed to meeting with stakeholders throughout the IRP process to ensure engagement and information sharing to the level required. NS Power is committed to meet the timelines established with the UARB for the completion of the IRP. |
| 65 | What are the plans that will be tested? What are the metrics? Will stakeholders get to comment on the plans before the analysis?<br><br>What is the process to choose or design these "Worlds"? Will these be established using primarily a consultant or forecasting organization's scenarios? How will the optimization process work? Will Plans be allowed to recognize the alternative scenario at some point in time?<br><br>Risk Analysis – how is this going to be evaluated? What risks? | SBA | Please refer to item 60. |
| 66 | It would be helpful if the Analysis Plan included a schedule (or perhaps an outline of the sequencing and work flow) for several tasks required for near-term planning. | CA | NS Power is working on an analysis schedule with Synapse and will make it available when it is finalized. |
| 67 | If NSP will be assessing and potentially reporting rate impacts, then the company should also assess and report bill impacts. | ENE | Consistent with past IRPs, NS Power only plans to compare the relative revenue requirements of the various plans as the test of cost effectiveness, not the rate impacts. |
| 68 | Will each supply option provided be separate options in the IRP analysis or will NSP establish certain generation options to each represent a group of similar supply options? | SBA | Candidate resource plans will consist of a variety of resource options |

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| 69 | Resource Plans for consideration provided on pg. 5 of submission | SBA | NS Power and Synapse are working to establish candidate resource plans that encompass a broad range of futures that will screen out or encompass those suggested. Please refer to item 60. |
| 70 | Candidate Resource Plans suggested on pg. 5 of submission | Scotian WindFields | Please refer to item 69. |
| **Future Supply Options** | | | |
| **Wind & Solar** | | | |
| 71 | Since wind costs, both in Nova Scotia and globally, have tended to trend downward (from $2,600 for Nuttby and Digby and over $2,300/kW for Point Tupper), future wind costs should be even less than the South Canoe cost. | CA | South Canoe is favorably priced taking advantage of market conditions and technology development. In the future, inflation effects on construction and less favorable sites could offset reductions if any on machine costs. Please refer to item 77. |
| 72 | NSPI's estimate of the cost of photovoltaic solar ($5,600/kW) is also overstated. Taking into account currency exchange rates, the NSPI estimate is at the high end of US costs for 2012, and probably even more overstated for the future. Considering the amount of PV solar installed in North America and Europe, the readiness level of PV seems as high as wind. | CA | The Company has modified solar cost estimates down to $3500 / kW. |
| 73 | The CAES option requires greater detail on the operating cost of the plant (especially the cost of gas necessary to warm the compressed air as it is expanded). | CA | The operating cost in reference to natural gas is reflected in the round trip efficiency of 55% shown in the heat rate column. |
| 74 | This method [the capacity value of wind calculated based on statistical probabilities of wind generation being available at peak load] should be modified to estimate the contribution of wind at times of NSPI's tightest capacity conditions; that may be higher or lower than the contribution at peak load. | CA | The capacity value of wind is a parameter which determines the contribution of nameplate wind capacity to help meet the firm system peak. The Company will model a capacity value range of 12% low case to 27% high case. |

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| 75 | No support is cited for the presumption that "additional firm capacity will have to be built in order to securely integrate more intermittent generation in the future," and "The study may show that integration costs are in line with the estimates used in Regulatory proceedings." Available support should be identified. | CA | More information will follow on this matter in the release of the full integration cost assumptions. Additional time will be provided to stakeholders to comment on these assumptions. |
| 76 | In light of the agile transmission link available to Newfoundland and Labrador in the near term and the potential for near equal cost interconnection through New Brunswick to Quebec, the IRP should thoroughly examine the capacity for inter-regional power pooling to maximize the value of zero emission wind resources across the Atlantic region. | EAC | This type of study is outside of the scope of the IRP. |
| 77 | a. Wind energy supply in excess of an additional 100MW should be considered as a Supply-Side Option<br>b. Additional distribution-connected wind energy should be considered as a Supply-Side Option, with specific capital costs and integration costs considered.<br>c. We would recommend that COMFIT-scale development and along with future distribution connected wind energy has a capital range of $2500-$2800/kW. | Scotian WindFields | The Company has adjusted the capital cost of distribution connected wind to $2500. |
| 78 | a. We recommend that large amounts (>10MW) of distribution-connected, individual and commercial-scale (1-100kW) solar photovoltaic energy be considered as a Supply-Side Option.<br>b. We recommend that large amounts (>10MW) of individual and commercial-scale (1-100kW) solar thermal energy be considered as a Supply-Side offset.<br>c. We recommend that the capital costs for solar photovoltaic and individual-scale development be considered with a capital range as low as $3,500/kW.<br>d. We recommend that the capital costs for solar photovoltaic and utility-scale development be considered with a capital range as low as $3,000/kW.<br>e. We recommend that the costs for solar thermal for individual and commercial-scale development at $2,000/kW. | Scotian WindFields | Please refer to item 72. |

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| 79 | Welcome further discussion on the capacity factors of the various types of solar energy. | Scotian WindFields | More details will accompany the assumptions on variable integration costs. Stakeholders will be given the opportunity to comment on these assumptions. |
| 80 | The SBA wants to get specific assumptions on how NSPI intends to evaluate any potential strategic and cost advantages to wind procurement through PPAs versus NSPI ownership | SBA | NS Power would expect the most cost competitive option of a given resource alternative to be employed. That is currently assumed to be NS Power owned wind based on the South Canoe regulatory application. |
| | **COMFIT** | | |
| 81 | The Department suggests that a range of approximately 110 - 120 MW of COMFIT projects will be in-service by 2016. | Dept. of Energy | The Company will consider this recommendation as part of the candidate resource plan phase of analysis. |
| 82 | EAC strongly urges that the RES assumptions bring COMFIT projects to the full 200MW level by 2016 and include an extension of the program ongoing at 20 - 30 MW per year. | EAC | Please refer to item 81. |
| | **Hydro** | | |
| 83 | The value of the Mersey Incremental Upgrade option depends on the energy production and the dependable capacity, as well as the installed cost per kW. Additional information on this option will be necessary. | CA | The Mersey incremental upgrade assumes a 30MW increase in firm capacity and an incremental 40 GWh of energy production. The additional energy results from re-engineering and restructuring of power houses. |
| 84 | NSPI should provide a breakdown of the $500M in sustaining capital by facility, to test whether the investments are small compared to the value of the hydro plants. NSPI should examine the cost-effectiveness in greater detail. | CA | The majority of the sustaining capital is for the Mersey, Wreck Cove and Annapolis systems. For the purposes of the IRP, it will be assumed that these legacy assets will continue to run providing value as flexible system assets. Any capital expenditures required to sustain the hydro systems will be studied on an individual basis outside the IRP and will require UARB approval. |

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| 85 | The Industrial Group queries the underlying assumptions for sustaining capital projects for existing hydro systems. Is this an economic option given the generation capacity of existing hydro systems? | Industrial | The assumption is common across all plans and will not impact the relative economics across plans. Project economics will be determined on a case by case basis as projects are reviewed by the UARB |
| 86 | Why is the 500M$ hydro assumption made? | SBA | The $500M figure is immaterial in the IRP analysis as the assumption is that the preservation of the valuable hydro assets is common across all of the cases to be considered. Incremental hydro developments will be added to the resource option list of the IRP. |
| 87 | Cost associated with the incremental capacity increased in hydro should be the total cost of the refurbishment not just the difference between maintenance and total capital cost, unless the maintenance is due that year. | Natural Forces | Please refer to item 84. |
| | **Import Options** | | |
| 88 | What are the risks, costs, and benefits of the firm and non-firm options proposed? | Industrial | Costs, risks and benefits will be considered in the IRP candidate resource plan development process. |
| 89 | Can NSPI confirm that the Mass Hub Forecast that will be used to price import power is consistent with the natural gas assumptions? | Industrial | Confirmed. |
| | **Supply Alternatives** | | |
| 90 | Burnside 4 is included with 33 MW of net demonstrated capacity. That capacity is not currently available and NSPI should review the cost and appropriate timing of reactivation of that unit. | CA | Burnside 4 provides capacity at the load centre and other services such as operating reserve, VAR support in Metro Halifax and black start capability. For these reasons the IRP will assume the unit is available. Any capital expenditure to return the unit to service will require UARB approval. This is currently the most economic option. |
| 91 | NSPI's assumptions about the feasibility of continued operations of steam plants, especially the gas-fire units, should be tested. Tufts Cove (especially the more flexible units 2 and 3) should be compared to replacement peakers. | CA | NS Power anticipates steam unit retirement alternatives will be explored. |

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| 92 | For the steam plants, NSPI should consider whether costs would be minimized by retiring Lingan 2 (and possibly 1) or by converting multiple coal units to cycling operation, as suggested by a recent NREL study… | CA | Coal unit cycling will be considered in the integrated resource plan modeling. |
| 93 | As all parties are aware, the IRP terms of reference were explicitly revised to consider the potential utilization of load as a resource. The current version of the Draft Assumptions does not specifically refer to consideration of this possibility. | PHP | NS Power is meeting with PHP to assess the options for demand response. |
| 94 | It is unclear to PHP if the modeling will have a constraint on the amount of non-dispatchable renewables that can be backed-up by Nova Scotia resources. If there is such a constraint, how will the modeling deal with the non-dispatchable renewables excess to this constraint? | PHP | This information will be provided with the wind integration assumptions. |
| 95 | NSE believes the environmental control technology assumptions as outlined on page 21 of the Assumptions are limited in scope. NSE suggests that a broader look at a diversity of options for various types of abatement equipment would make for a more robust analysis. | NSE | The IRP will identify the need for environmental control technologies. Further study following the IRP will determine the detailed specifications and location for each control technology identified in the IRP. |
| 96 | NSE would also like to have additional context around "municipal solid waste" supply scenario. It should be noted that any such projects are subject to environmental regulations and the appropriate environmental approvals. | NSE | The configuration used includes a dry flue gas scrubber with a baghouse with NOx control and activated carbon injection. This should meet compliance with environmental regulations including dioxin /furans and particulate emission limits that have been a concern for these facilities. |
| 97 | The Supply Side Options (19) list several options for coal-fired plants; these are presented as if each are equally established and viable options. The Industrial Group questions whether NSPI has evaluated the technical risk and associated costs that are linked to these generation options. An evaluation of the costs and risks should be part of the modeling exercise. | Industrial | These aspects have been addressed in the associated costs of each coal option as well as the lead times and readiness levels. |
| 98 | It is noted that fluidized bed combustion (FBC) units have not been included in the supply-side options for coal-fired plants. An FBC plant equipped to burn petcoke may be an economically attractive generation option and should be evaluated. | Industrial | Although an FBC solution is not identified, the single unit advanced PC holds this placeholder for modelling purposes, as does the advanced PC with CCS. The current front runner would be an oxy fired CFB but it is assumed it would have to be price competitive with an advanced PC Unit. Any premium price to accommodate Pet coke would need to offset by a long term fuel contract. This would require detailed engineering beyond the scope of the IRP and would be |

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| | | | studied at the time of project conception to make the correct decision. |
| 99 | The Industrial Group urges NSPI to explore storage options more closely, particularly given the need to integrate significant amounts of intermittent renewable into the system. | Industrial | Various storage options have been considered including batteries, fly wheel storage, etc. In order to meet the IRP requirements at utility level we have chosen both pumped storage and CAES. Other solutions need to become cost competitive with these technologies and we continue to monitor their development. |
| 100 | What are the costs to maintain each existing generating resource? | SBA | Capital investment profiles reflect unit utilization intensity. O&M costs are included in the unit profiles within the model. |
| 101 | How much will certain generating units operate under various ML energy delivery scenarios? | SBA | The model will determine the ML surplus energy purchases and the generation from the existing units based on the input assumptions such as fuel costs and power costs. |
| 102 | The cost/MW for the various technologies is stated but there is no comment on the cost per MWh | Natural Forces | In order to provide the capital cost on a $/MWh basis a capacity factor would have to be assumed. Depending on the technology this could vary with location of resource, unit dispatch, etc. Rather make an assumption for capacity factor, costs have been provided on a $/kW basis. |
| 103 | There are a variety of battery storage options on the market now which should also be considered. | Natural Forces | Please refer to item 99. |
| **DSM Comments Received on March 28, 2014 DSM Assumptions Deck** | | | |
| 104 | DSM is screened solely on economics versus avoided costs, when in fact, 'avoided costs' is an output parameter of the new resource plan. | SBA | Please refer to ENSC's IRP submission on March 24 in which ENSC explains its rationale for the Achievable Potential presented in its potential study. NSPI provides the following excerpt:<br><br>"Achievable potential is an amount of DSM that, given such constraints as the existing capacity of the administrator, the willingness and awareness of Nova Scotians to engage in DSM activities, the incentive levels provided, the amount of free-ridership that is measured, and other factors, can reasonably be expected to be obtained in Nova Scotia over the period. The Achievable potential presented in the study has been calculated to include a calibration to these factors and prior years' DSM achievements. Achievable potential does not need to be economic, and not all economic potential is achievable. To be conservative, ENSC presented Achievable DSM that was determined to be economic; however, even if the economic potential was determined to be lower, the achievable potential, particularly in the near term, would not materially change." |

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| 105 | The IRP process should use substantial information from the DSM potential study. | SBA | NS Power's proposal is based on the DSM potential study. |
| 106 | A DSM supply curve should be created as an output of the DSM potential study. | SBA | NS Power anticipates that its modelling approach will illustrate the levels of DSM beneficial for customers over the planning horizon. |
| 107 | Requests confirmation that NS Power will consider potential opportunities for industrial-type DR programs that may be different than what is proposed to be modelled. | PHP | The DR programs being investigated for peak reduction in the IRP are to mitigate Firm Peak, not NS Power's Total System Peak. Most of NS Power's large industrial load is on an interruptible tariff, meaning that it is not counted in the Firm Peak. There is no further peak reduction benefit to be derived from customers under these tariffs, though it is possible that large industrial load may be capable of providing ancillary services.<br><br>Consideration will also be given in the IRP (outside the specific modeling) to identifying potential opportunities where a different DR option (including ones that can provide ancillary services) may be of interest. |
| 108 | Recommend that ENSC's Base Case DSM should be included in IRP analysis. | NSDoE, Industrial Group, ENSC | NS Power accepts this recommendation and will replace Case 2 (ENSC's Low DSM Case) with ENSC's Base DSM Case. |
| 109 | Recommends that revenue requirements be prepared from IRP analysis showing both a) total DSM costs and b) program administrator costs only. ENSC and ENE state that only Program Administrator Costs should be considered. | NSDoE, ENE, ENSC | NS Power will provide information for both DSM costing approaches. |
| 110 | Request more detailed information on the DR options NS Power has outlined. Industrial Group requested that NS Power outline all demand reduction options in use or that might be used in NS. | Industrial Group, CA, ENSC | As requested, NS Power has released the details underlying the Demand Response assumptions to be modelled in the IRP. NS Power is at this time proposing to model direct load control options rather than pricing options due to the predictable responsiveness associated with direct load control. Please refer to NS Power's response to PHP re: DSM for further information. It is important to remember that for IRP purposes, both EE and DR DSM levels are intended to represent possibilities for the purpose of determining direction. |
| 111 | Disagree with the use of an NSPI-constructed DSM case (Case 1, which is 50% of ENSC's Low Case and costed at the same $/MWh as ENSC's Low Case). | ENSC, ENE, EAC | The IRP is intended to provide direction rather than explicit plans. Assumptions should represent a range of possible scenarios. ENSC indicated that it believes its Base Case is most appropriate for use and its High Case represented the highest practically achievable level. NS Power has agreed to use both these cases. NS |

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| | | | Power considered it appropriate to also include a lower (total) cost DSM scenario in its range of possible DSM options and chose to base this on a portion of ENSC's Low DSM case. |
| 112 | Reiterating desire to be involved in discussions regarding the method to be used to calculate avoided costs for DSM evaluation purposes. | ENSC, CA | NS Power has committed to involving stakeholders in these discussions during the IRP process and has indicated that this will be a subject of discussion at the June technical conference. |
| 113 | A Long Term Government Bond rate should be used as the DSM discount rate. | ENE | The selection of a DSM discount rate is best addressed in a future DSM proceeding. This view is also shared by ENSC as stated in their April 7 comments. Please refer to item 33. |
| 114 | We share the concerns expressed by the Small Business Advocate that the assumptions do not minimize the cumulative present worth of the annual revenue requirement, the central objective of the IRP. | EAC | Please refer to item 104. |
| 115 | Here again, the proposed assumptions are in conflict with the terms of reference by including non-utility costs for DSM and thereby masking potential DSM benefits. | EAC | Please refer to item 27. |
| 116 | The DSM study provides sufficient information to model DSM as a resource, with a variable cost curve, or at least multiple discrete levels. Only by integrating DSM within the resource selection process will the IRP fully inform the Preferred Resource Plan. | EAC | Please refer to item 37. |
| 117 | Use of NSPI's WACC as the discount rate for DSM exaggerates the risk associated with DSM. Compared to the long life associated with capital assets (for generation assets see slide 41 – 50 plus years), DSM programs on a 1 to 3 year planning cycle are far more nimble and able to respond to variations in their performance. As such their risks are lower as should be their discount rates. | EAC | Please refer to items 33 and 113. |

**Figure A**

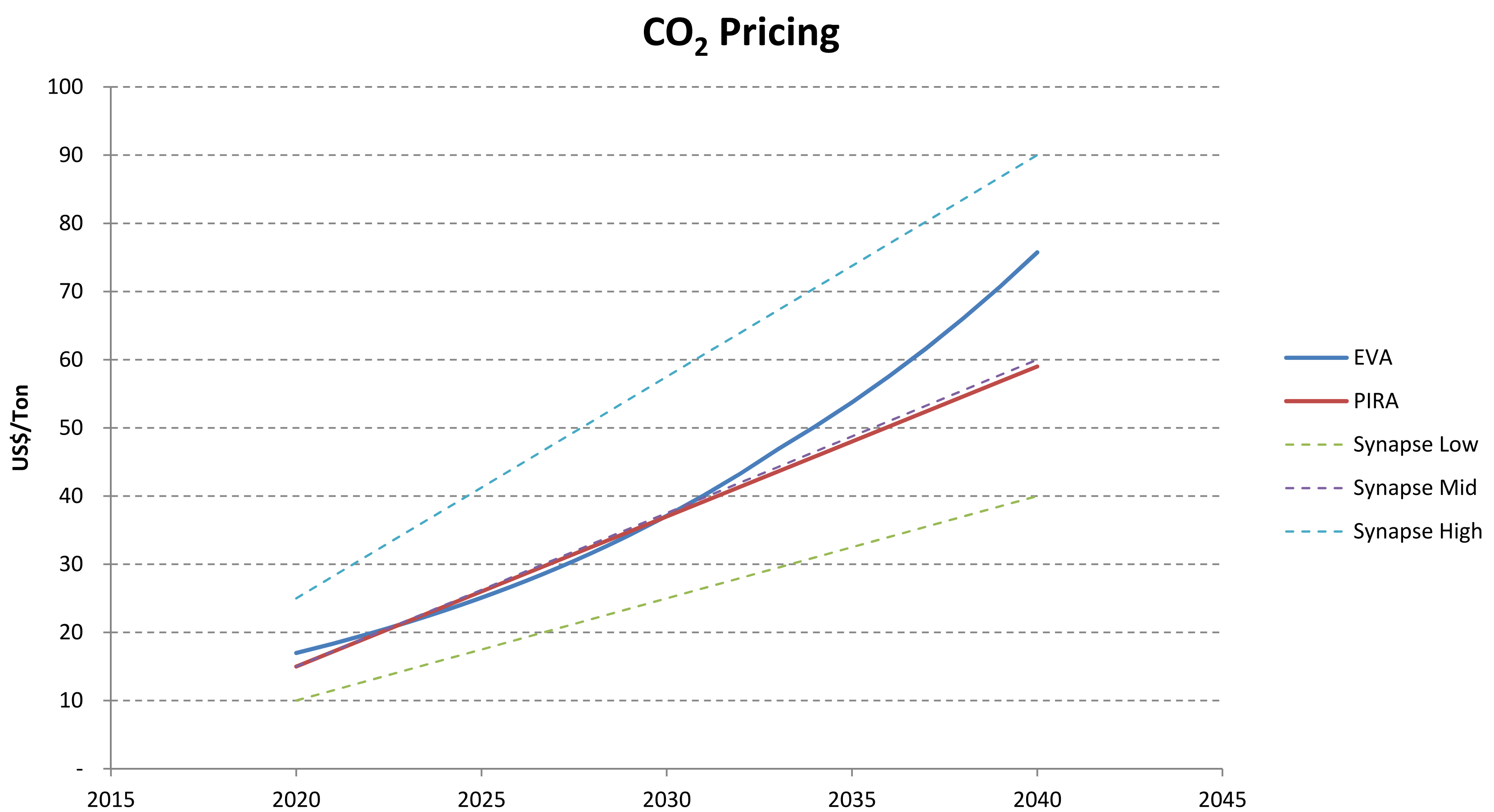

$CO_2$ Pricing
US$/Ton
100
90
80
70
60
50
40
30
20
10
-
2015
2020
2025
2030
2035
2040
2045
EVA
PIRA
Synapse Low
Synapse Mid
Synapse High

**Figure B**

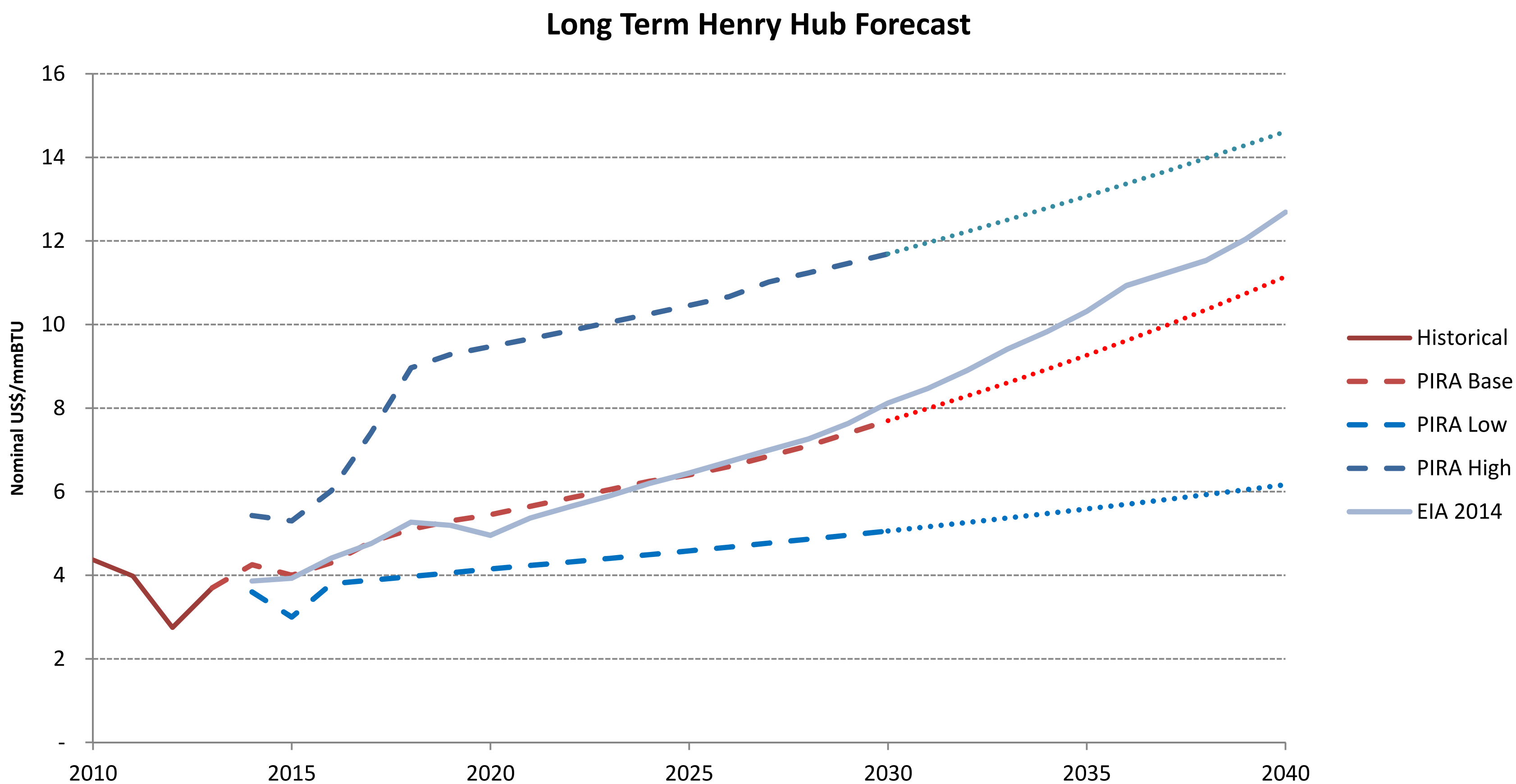

Long Term Henry Hub Forecast
Nominal US$/mmBTU
16
14
12
10
8
6
4
2
-
2010
2015
2020
2025
2030
2035
2040
Historical
PIRA Base
PIRA Low
PIRA High
EIA 2014

**Figure C**

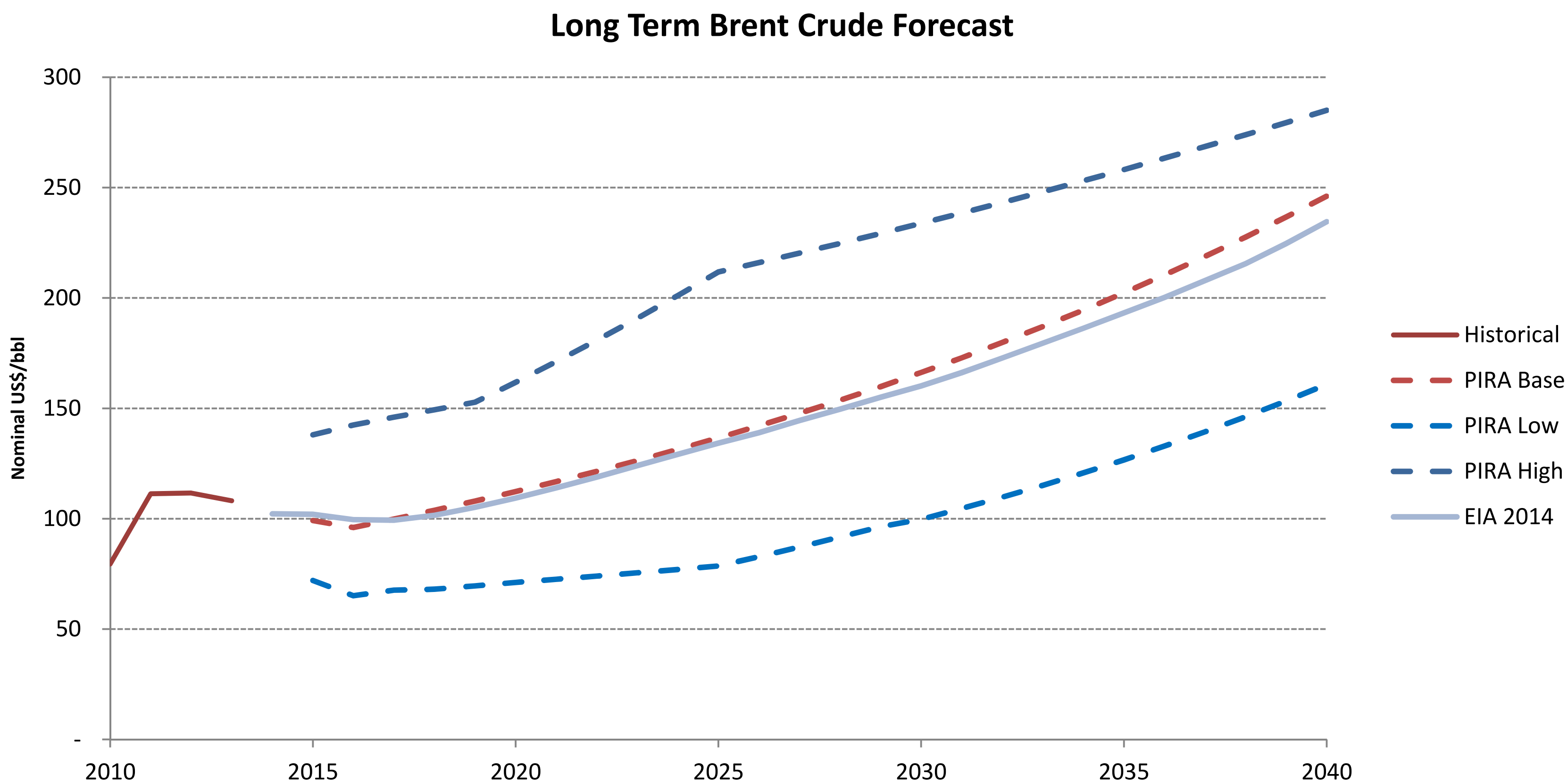
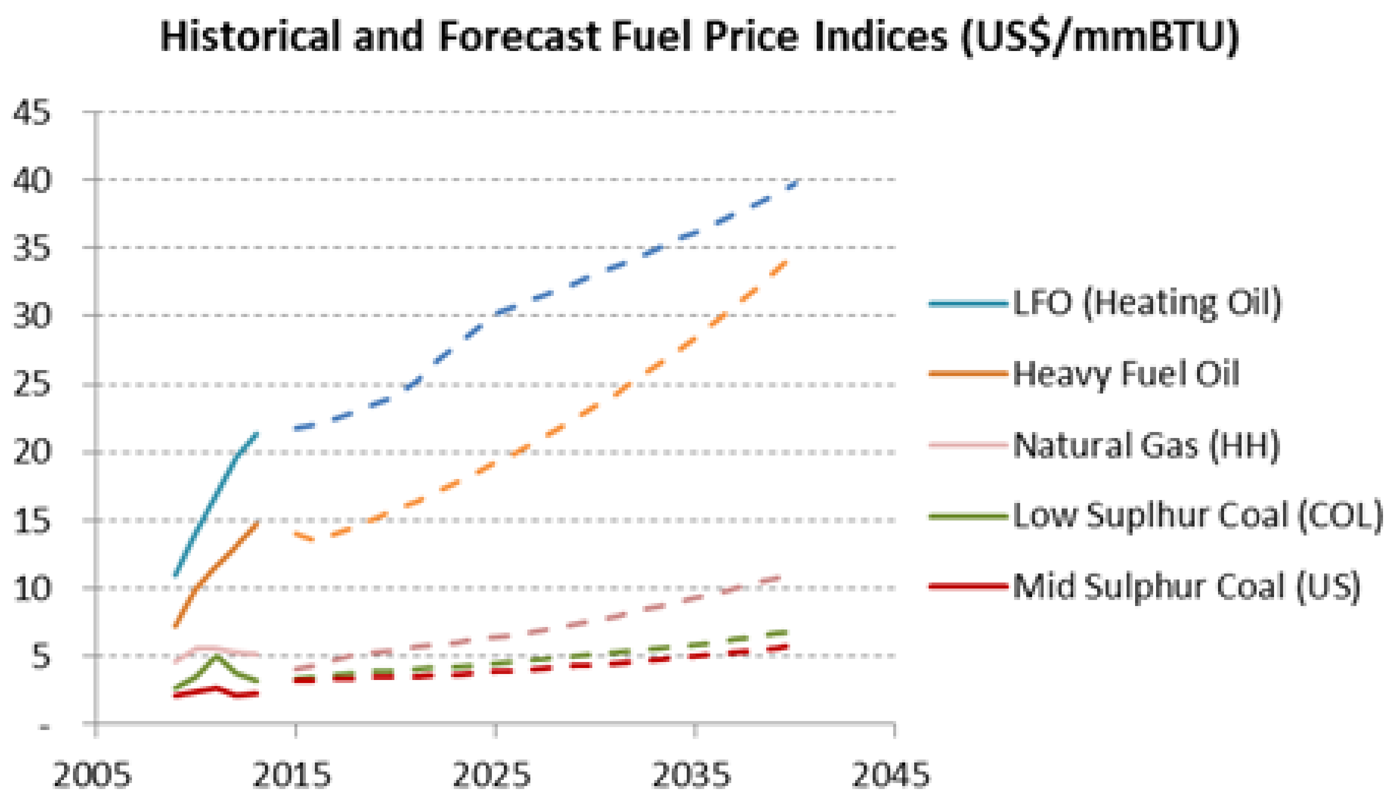

Long Term Brent Crude Forecast
Nominal US$/bbl
300
250
200
150
100
50
-
2010
2015
2020
2025
2030
2035
2040
Historical
PIRA Base
PIRA Low
PIRA High
EIA 2014

**Figure D**


Historical and Forecast Fuel Price Indices (US$/mmBTU)
45
40
35
30
25
20
15
10
5
-
2005
2015
2025
2035
2045
LFO (Heating Oil)
Heavy Fuel Oil
Natural Gas (HH)
Low Suplhur Coal (COL)
Mid Sulphur Coal (US)