2008 Grid Planning Assumptions: Consultation material on draft generation scenarios

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Purpose

1. As part of the development of the next Statement of Opportunities (**SOO**), the Commission has developed five draft generation scenarios.

2. The purpose of this paper is to present the draft scenarios, and the input assumptions and methodology used to develop them, so that stakeholders can comment on the scenarios and methodology.

3. Parties who wish to provide feedback should refer to the Commission's website for instructions. In brief, the Commission has not posed specific consultation questions, but welcomes written feedback in any format. Respondents should include data and/or analysis to support their feedback.

4. The Commission is also holding a technical workshop, which will include presentations on the GPA material and a question-and-answer session. The Commission considers this to be an important aspect of the feedback process and encourages stakeholders to attend.

Introduction and background

5. The Commission is required to publish a SOO, as part of its duties in overseeing aspects of transmission investment (Rule 9 of section III of Part F of the Electricity Governance Rules 2003 (**Rules**)).

6. Rule 9.1.2 states that the purpose of the SOO is to enable identification of potential opportunities for efficient management of the grid, including investment in upgrades and transmission alternatives. In practice, the SOO also has a wider role to play in informing stakeholders about the Commission's views of possible future developments in the power system.

7. Under Rule 9.1.1.2, the SOO must include the Grid Planning Assumptions (**GPAs**). The GPAs must include 'a reasonable range of credible future, high-level generation scenarios' (Rule 10.3.1.3).

8. These scenarios are integrated with the demand forecasts and the power systems analysis (**PSA**) to form the Market Development Scenarios (**MDS**).

9. The Initial Statement of Opportunities was published in 2005.[1]

10. In September 2006, the Commission developed draft GPAs as an initial step towards releasing a new SOO (originally anticipated to be released in 2007). This included the preparation and publication of demand forecasts and four generation scenarios for consultation with interested parties.

11. In May 2007, the Commission decided to delay the publication of the SOO until the New Zealand Energy Strategy was finalised. However, at the same time, the Commission released the then-current drafts of the demand forecasts and generation scenarios that had been developed and consulted on in late 2006.[2]

12. Once the Government's climate change policies had been developed further and the New Zealand Energy Strategy was finalised, the Commission recommenced work on preparing the next SOO. As an initial step, the Commission revised the GPAs and released the revised drafts in October 2007.[3]

13. The Commission now intends to publish a SOO in 2008. A new set of draft GPAs have been developed. The Commission is seeking feedback from participants on these draft GPAs in advance of publishing the SOO, so that feedback can be taken into account before the PSA commences.

14. In parallel with the feedback process, the Commission will continue to develop the generation scenarios. The planned work programme is described in this paper.

15. A further set of scenarios will be produced by 3 April 2008, taking into account feedback on the draft GPAs. The scenarios will then be integrated with the PSA, as described in paragraph 8 above.

Analysis

16. This section describes:

[1] http://www.electricitycommission.govt.nz/opdev/transmis/soo/initial2005
[2] http://www.electricitycommission.govt.nz/opdev/modelling/gpas/May2007/index.html
[3] http://www.electricitycommission.govt.nz/opdev/modelling/gpas/Oct2007/Generation/index.html

(a) the scenario development process;

(b) the Generation Expansion Model (**GEM**) used to produce the scenarios;

(c) the ‘stories’ of the five scenarios;

(d) selected input parameters;

(e) draft scenario results;

(f) in-development price projection methodologies (for testing revenue adequacy); and

(g) other ongoing work.

The scenario development process

17. The scenario development process includes three key steps:

(a) assembling input data, including information on existing generation projects, possible future generation projects, fuel price projections, carbon charges, etc, etc;

(b) developing the scenario 'stories' – i.e., identifying the key drivers which guide the future development paths in the scenarios and determining which combination of drivers will apply in each scenario; and

(c) running GEM to develop each generation scenario, based on the input assumptions determined in the previous steps.

18. These steps are repeated, in a process of iterative refinement, until the scenarios are satisfactory (i.e. that they are reasonable, credible, technically feasible, suitable for power systems analysis, and accurately reflect the stories that they are intended to depict).

19. The last set of generation scenarios published by the Commission were included in the version of the GPAs published in October 2007 (**October 2007 draft GPAs**). This set included five scenarios, of varying degrees of renewableness and with different mixtures of generation types and modelled projects.

20. Since then, the Commission has:

(a) continued to update input data in response to announcements by participants;

(b) drawn on data from reports commissioned for the Transmission to Enable Renewables (**TTER**) project;

(c) commissioned a review of the GEM model from EGR Consulting and begun to implement EGR's suggestions for further improvement;

(d) identified and corrected shortcomings in data and models where possible;

(e) produced new electricity demand forecasts for use in GEM;

(f) developed a set of five new scenario 'stories', and

(g) applied the GEM model to develop these scenarios.

The Generation Expansion Model (GEM)

21. GEM is a long range capacity planning model. The key purpose of the model is to create “build schedules” for new generation plant. In other words, when given a large list of possible generation options, the model selects which ones to commission and the year in which to commission them.

22. The primary purpose of GEM is to allow evaluation of the economic benefits associated with transmission investment. It can also be used to evaluate the benefits and costs of other policies relating to the electricity sector. It is not intended to be used as a tool to centrally plan the electricity system.

23. When choosing investment options, GEM seeks to minimise the discounted capital expenditure and ongoing operating and maintenance costs over the entire time horizon for which the model is run (typically 20-40 years), while at the same time ensuring that economic, physical, and technical constraints are satisfied.

24. The heart of GEM is the canonical capacity expansion problem formulated as a mixed integer programming (**MIP**) problem. The computer code is written using the GAMS optimisation software and the model is solved with CPLEX, a commercial MIP solver accessed via the GAMS/CPLEX interface. The model’s input data is compiled as a series of thematic worksheets in an Excel spreadsheet. Model outputs are written to spreadsheet-compatible files, allowing further processing and/or plotting using software such as Matlab or Excel.

25. In order that a transparent and open model development process is maintained by the Commission, GEM has been peer-reviewed and industry participants

have been invited to critique it. The model code, data files, documentation, reviews and critiques are all published by the Commission. The publication of models and code allows stakeholders to reproduce the Commission's analysis and test the effects of modifying input assumptions.

26. GEM is formulated as a cost minimisation problem. The cost categories to be minimised include the capital expenditure required to build new generation plant, fixed and variable operating and maintenance costs, and HVDC charges. All costs enter the objective function on an after-tax basis and are converted to present values using an estimate of generator weighted average cost of capital (**WACC**). Capital expenditure is modelled as an annualised capital charge.

27. Each potential new plant is characterised by a set of parameters describing specific attributes such as location, technology, fuel type, capacity, capital cost, and operating costs.

28. Total electricity demand data are typically drawn from the GPA demand forecasts. Total energy demand in GEM is generally non-price responsive, though an expensive 'shortage generator' representing demand-side response can run in very dry sequences.

29. In addition to demand for energy, the model is also required to satisfy peak load constraints. These constraints are also based on GPA demand forecasts, but are modified according to the level of system security that the user specifies. The presence of peak load constraints biases the model away from excessive construction of baseload and intermittent plant, towards flexible generation including thermal peakers and storage hydro. Demand-side response at peak times is modelled in GEM as if it were a form of generation.

30. Some changes have been made to the GEM modelling approach (as opposed to the input data) since the publication of the October 2007 draft GPAs. The changes that have had the most significant impact on model results have been:

    (a) previously GEM produced scenarios which were least-cost under conditions of slightly below average hydrological inflows, then 'reoptimised' these scenarios by adding or bringing forward thermal peakers to meet dry-year needs. GEM is now optimised over a selection of hydro scenarios, ranging from very dry (1992 flows) to very wet: there is now no reoptimisation phase. This approach is more computationally intensive but is thought to give better results;

(b) the treatment of existing hydro schemes has become somewhat more detailed;

(c) previously the most renewable scenario used a 'renewable energy constraint' which imposed an external requirement of 90% renewable energy by 2025. This constraint is now not used, and the renewable percentage is now brought about by drivers such as carbon prices and plant retirements, if at all;

(d) the model now has additional flexibility – to give one example, the user can now make a given technology (e.g., wind) more expensive in some scenarios than others.

Five new 'stories'

31. The five new scenarios are roughly evenly spaced along a continuum of renewableness:

    (a) the first ('Sustainable Path') is 90% renewable by 2025;

    (b) the second ('South Island Surplus') is about 85% renewable by 2025, with a bias towards South Island wind and hydro;

    (c) the third ('Medium Renewables') is about 80% renewable by 2025, with more generation located in the North Island;

    (d) the fourth ('Demand Side Participation') is about 75% renewable by 2025, with extensive demand side involvement and high electric vehicle uptake;

    (e) the last ('High Gas Discovery') is approximately 70% renewable by 2025, with low gas prices due to indigenous gas finds.

32. In applying the Grid Investment Test (**GIT**) to a proposed investment, the Commission assigns weightings to each generation scenario. The weightings of each generation scenario are in practice also the weightings (probability of occurrence) of each MDS,[4] which are used when calculating the expected net market benefit of a proposed investment (clauses 6 and 26 of schedule F4 of part F). At this stage, the Commission's view is that these five scenarios could all be assigned equal weight.

33. A brief description of each scenario is included in Table 1.

34. The scenarios are described in Table 2 in 'key driver' format. These drivers are passed to GEM as inputs; they have a major influence on the pattern of new generation investment in the scenarios, especially after 2012.

[4] Clause 6 of the GIT provides that the MDS must be the possible future scenarios outlined in the SOO unless the Board determines that the MDS proposed by Transpower, the proponent of a transmission alternative or the Board are more appropriate. If the Board determines that MDS other than the MDS in the SOO are more appropriate, then weightings for those other MDS will also have to be determined.

Table 1: Scenario descriptions.

#	Scenario	Renewable by 2025	Features (beyond 2012)
1	Sustainable Path	~ 90%	New Zealand embarks on a path of sustainable electricity development and sector emissions reduction. Major existing thermal power stations close down and are replaced by renewable generation, including hydro, wind and geothermal backed by thermal peakers for security of supply. Electric vehicle uptake is relatively rapid after 2020, though the effect on electricity demand is countered to some extent by the closure of the Tiwai smelter. New energy sources are brought onstream in the late 2020s and 2030s, including biomass, marine, and CCS.
2	South Island Surplus	~ 85%	Renewable development proceeds at a slightly more moderate pace, with all existing gas-fired power stations remaining in operation until after 2030, though taking a more mid-order role as gas prices increase. The coal-fired units at Huntly Power Station are shifted into a reserve role and eventually removed from service. Wind and hydro generation increase considerably, particularly in the lower SI. Relatively little geothermal energy is utilised. Thermal peakers supplement renewables. Electric vehicle uptake is low. Tiwai remains in operation.
3	Medium Renewables	~ 80%	A 'middle-of-the-road' scenario. Renewables are developed in both islands, with North Island geothermal development playing an important role. As above, thermal generation takes a back seat and the coal-fired units at Huntly transition through dry-year reserve to total closure. Thermal peakers supplement renewable development. Electric vehicle uptake is low.
4	Demand Side Participation	~ 75%	Demand-side participation becomes a more important feature of the market, driven by a desire from consumers of all types to become more involved. Electric vehicle uptake is high, and vehicle-to-grid technology is used to manage peaks and provide ancillary services. On the generation side, CCGTs are built after 2020, fueled with imported LNG, and new wind and geothermal resources are developed. Little new hydro can be consented, however, and some existing hydro schemes have to reduce their output (due to difficulty in securing water rights). Huntly Power Station remains in full operation until 2030.
5	High Gas Discovery	~ 70%	Major new indigenous gas discoveries keep gas prices low to 2030 and beyond. Some existing thermal power stations are replaced by new, more efficient gas-fired plants. New CCGTs and gas-fired peakers are built to meet the country's power needs; the most cost-effective renewables are also developed. The demand side remains relatively uninvolved. Electric vehicle uptake is low.

These features are brought about by applying the key drivers described in Table 2 in the GEM model.

Table 2: Key drivers of the draft generation scenarios.

#	Scenario	Eventual carbon price (\$/t CO_2e)	Moratorium on baseload thermal	Gas price	Renewables available	Fate of coal-fired Huntly units	Fate of HVDC Pole 1	Demand side
1	Sustainable Path	\$50 (rising to this level by 2018)	Continues indefinitely	Baseline, rising sharply after 2010	Extensive hydro, wind and geothermal available. Biomass, marine and CCS available later	Closed by 2020 (Tiwai smelter and Stratford Power Station and also close in 2020s)	Half pole on standby until replacement in 2012	Baseline participation. High electric vehicles uptake
2	South Island Surplus	\$40	Extends to 2028, then efficient gas-fired plant permitted	Baseline	Extensive hydro and wind available, especially lower SI. Geothermal less aggressively developed. CCS appears later	By 2020, two units out and two in dry-year reserve mode. (Tiwai remains in operation)	Half pole fully available until replacement in 2012	Baseline participation. No significant electric vehicles uptake
3	Medium Renewables	\$35	Lapses 2019	Baseline	Extensive wind and geothermal, and some hydro available	As above	Half pole on standby until replacement in 2012	Baseline participation. No significant electric vehicles uptake
4	Demand Side Participation	\$30	Lapses 2019	Baseline. Imported LNG available after 2020	Extensive wind and geothermal available. Little new hydro can be consented; some existing hydro must reduce output from 2020	Coal-fired units remain in operation until 2030	Half pole on standby until replacement in 2012	Extensive participation. High electric vehicles uptake, with vehicle-to-grid
5	High Gas Discovery	\$20	Lapses 2019; CCGTs can be built to replace coal in the 2010s	Low	Moderate amounts of wind, geothermal and hydro available	Two units replaced by a new CCGT in 2015; the remaining two units displaced by CCGTs in the 2020s	Removed from service until replacement in 2012	Minimal participation. No significant electric vehicles uptake

These drivers are inputs to the GEM model and affect the modelled pattern of future generation investment.

Selected input parameters

35. This section briefly describes some of the GEM data inputs, focusing on those which have a high degree of influence on the scenarios and have changed significantly since the 2007 GPAs.

36. The following Figures show the electricity demand to be met in the draft scenarios. Figure 1 shows total electricity demand in GWh; Figure 2 shows peak national demand in MW. In both cases, demand is based on GXP-level forecasts (which are inclusive of local line losses and net of embedded generation), but also includes an allowance for double-counting of embedded generation.

Figure 1: Total electricity demand (GWh) in the draft scenarios.

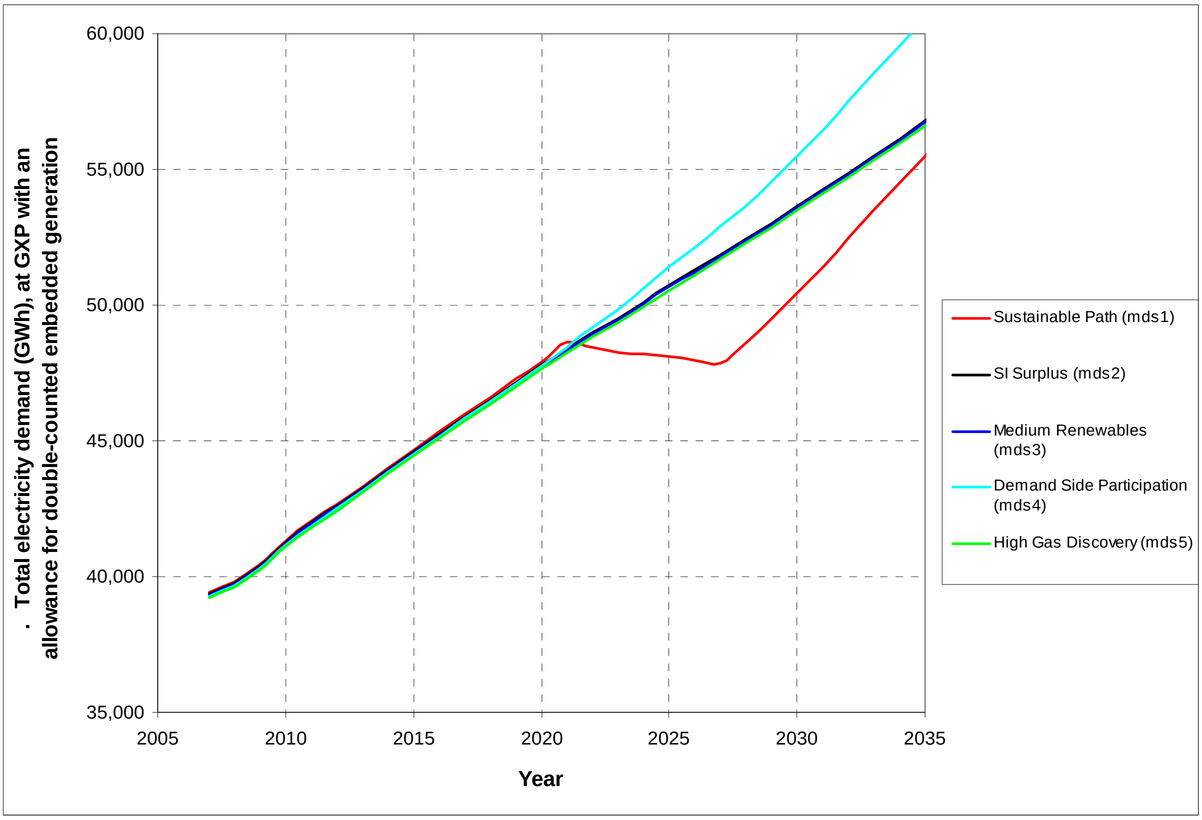
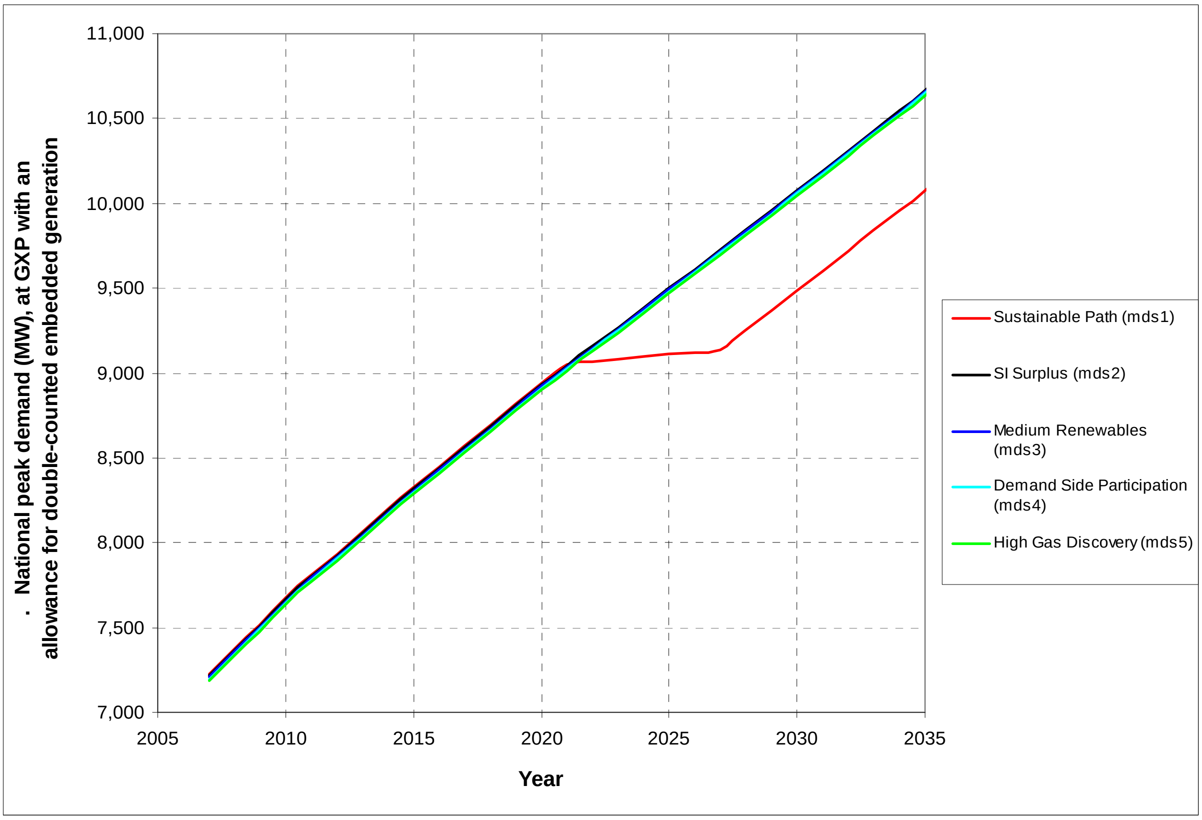


Figure 2: Peak national electricity demand (MW) in the draft scenarios.



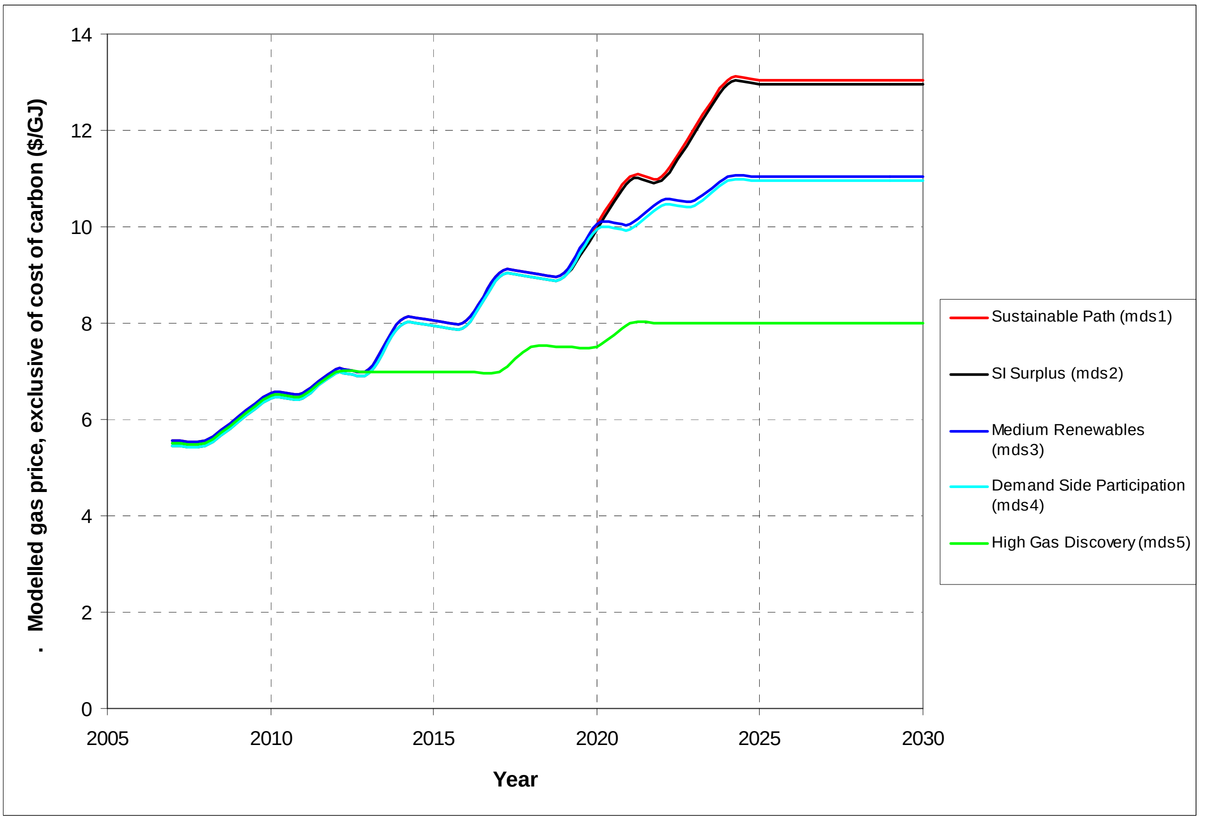
37. Both total and peak demand drop steeply in the 2020s in the Sustainable Path scenario to model the phased decommissioning of the Tiwai aluminium smelter.

38. Total energy demand increases towards the end of the Sustainable Path and Demand Side Participation scenarios to allow for the consumption of consumer electric vehicles. It has been assumed that most vehicle charging would be off-peak, so peak demand has not been adjusted upwards in these scenarios.

39. The Commission has recently received information from another Government agency which indicates that the electric vehicle demand forecasts shown here may be overstated. These assumptions will be revisited when better data becomes available.

40. Figure 3 shows the gas price paths in the draft scenarios. Prices are as paid by electricity generators, at Huntly rather than at wellhead (but exclusive of delivery costs north of Huntly, which are factored in separately in GEM). Carbon costs are not included.

Figure 3: Assumed gas prices in the draft scenarios.



41. Delivered prices of $4/GJ for coal and $25/GJ for diesel are assumed, again exclusive of carbon costs.

42. In terms of transmission, special focus is given to the HVDC link. It is assumed that the HVDC will be a 1200 MW bipole from 2012, rising to 1400 MW with the addition of a fourth cable in 2018. The HVDC configuration between now and 2012 is still uncertain at the time of preparation of this paper, and several possibilities have been modelled:

(a) the link could remain a monopole (assumed in MDS 2);

(b) half of Pole 1 could be used intermittently when required for security in the North Island (assumed in MDS 1, 3, and 4); or

(c) half of Pole 1 could return to full service (assumed in MDS 5).

43. It is currently assumed, for the purpose of producing generation scenarios, that the AC transmission grid will be upgraded as required to connect generation and demand.

44. The Commission is currently developing a methodology for co-optimisation of generation and transmission – i.e. finding the most optimal build schedule from lists of both generation and transmission projects. This approach will potentially be able to be used for the final SOO scenarios, but it was not available in time for use in these draft scenarios.

45. A wide selection of future generation projects are offered to the model, which will choose the most economic subset, subject to security of supply requirements and various other constraints. Not all the projects are available in all scenarios (for example, coal plants may only be built in MDS 5). These projects include:

    (a) nine conventional coal and lignite plants;

    (b) integrated gasification coal plants with carbon capture and sequestration (**IGCC** with **CCS**);

    (c) seven combined cycle gas turbine (**CCGT**) options;

    (d) diesel- and gas-fired peakers;

    (e) interruptible load, demand-side response, and electric vehicle to grid (these technologies are clearly not generation, but are modelled as if they were generation in GEM);

    (f) fourteen geothermal projects;

    (g) fifty-seven hydro projects, including run-of-river, storage-backed, enhancements to existing schemes and pumped storage;

    (h) forty-one wind farms;

    (i) six marine generation projects;

    (j) gas- and biomass-fuelled cogeneration; and

    (k) one coal seam gas plant.

46. A key aspect of the generation input data is the relative economics of the various types of generation. The following tables describe the costs of the modelled generation technologies, in terms of long-run marginal cost (**LRMC**) and short-run marginal cost (**SRMC**).

47. SRMC is defined as the marginal cost (at the relevant grid injection point (**GIP**)) of producing the next unit of electricity (in this context, including carbon costs, fuel costs and variable O&M, but excluding capex, fixed O&M, transmission charges and network losses).

48. LRMC is defined as the mean price (at the relevant GIP) that is sufficient to cover all plant costs (in this context, including capital financing costs, carbon costs, fuel costs, O&M and transmission charges but excluding network losses). A real pre-tax discount rate of 8% has been assumed in the calculation of LRMC. Assumed depreciation rates vary between technologies. LRMCs depend on load factor and have been calculated for several different load factors, where applicable.

49. Readers should be cautious in comparing the LRMCs shown here with those published in other documents. Differences in assumed project life, depreciation rate, treatment of tax, discount rate, load factor and/or types of cost considered can make a very substantial difference to calculated LRMCs (easily $20/MWh or more). If cost assumptions are to be compared, then the comparison is best carried out on raw cost components (capital cost per kW, variable O&M cost per MWh, etc).

50. The Commission's assumptions about LRMCs for thermal technologies are shown in Table 3. Prices depend on carbon costs, and, for gas-fired plant, on gas prices. Three sets of prices are shown, to indicate the range of values: an LRMC with cheap gas ($7/GJ) and no carbon charge, an LRMC with more expensive gas ($10/GJ) and a moderate carbon charge of $30/t CO_2-equiv, and an LRMC with very expensive gas ($13/GJ) and a high carbon charge of $50/t CO_2-equiv. All prices shown are for North Island plant.

51. It can be seen that thermal LRMCs depend strongly on the assumed load factor. A plant operating as mid-order (load factor in the ballpark of 50%) faces a higher LRMC per unit output than a similar plant operating as baseload. On the other hand, the mid-order plant has the flexibility to run when prices are higher, so will earn more revenue per unit output. Plants running in a peaking capacity have extremely high LRMCs (much higher than their SRMCs). GEM will determine the load factor of each plant in each simulated year on a least cost basis, within the limits imposed by the technology.

52. Carbon prices and fuel prices also have a very significant impact on thermal SRMCs and LRMCs.

Table 3: Assumed LRMCs of thermal generation.

Category	Assumed load factor	LRMC ($/MWh) – gas at $7/GJ, no carbon charge	LRMC ($/MWh) – gas at $10/GJ, carbon at $30/t	LRMC ($/MWh) – gas at $13/GJ, carbon at $50/t
Combined cycle gas turbine	50%	95	127	155
	70%	83	115	144
Diesel-fired peaker	5%	613	634	648
Gas-fired peaker	5%	523	569	609
Conventional coal plant	30%	167	193	210
	50%	119	145	163
	70%	98	125	142
	90%	87	113	130
IGCC coal plant with CCS	70%	139	143	145
	90%	121	124	126

53. Assumed SRMCs for thermal technologies are shown in Table 4.

Table 4: Assumed SRMCs of thermal generation.

Plant (example)	LRMC ($/MWh) – gas at $7/GJ, no carbon charge	LRMC ($/MWh) – gas at $10/GJ, carbon at $30/t	LRMC ($/MWh) – gas at $13/GJ, carbon at $50/t
Taranaki CC	56	90	119
Whirinaki	183	198	208
Huntly units 1-4 on coal	52	81	100

54. Assumed LRMCs for renewable technologies are shown in Table 5. Each technology is divided into three tranches – the most economic resources, the next most economic projects, and finally the least economic (which are unlikely to be built in most scenarios). For each tranche, the table shows a range of LRMCs and the amount of capacity available at that price.

55. These assumptions indicate that the best available resources of wind, hydro and geothermal are each around the $80/MWh mark.

Table 5: Assumed LRMCs of renewable generation.

Category	Island	Assumed load factor	Best resources – LRMC ($/MWh)	Capacity at this price (MW)	Next resources – LRMC ($/MWh)	Capacity at this price (MW)	Lower-grade resources – LRMC ($/MWh)
Wind (*)	NI	(intermittent)	80-85	~500	Ballpark of 95	Over 2000	Over 100
	SI	(intermittent)	Same + ~$5 for HVDC	~300	Same + ~$5 for HVDC	Over 1000	Over 100
Geothermal (**) (+)	NI	90%	80	250-300	Ballpark of 85	~400	As much as 100
Hydro backed by storage (+)	NI	50%	75-80	~200	90-110	~600	N/A
Run-of-river hydro	NI	(intermittent)	80-95	~100	95-120	~200	Very high
	SI	(intermittent)	Same + ~$5 for HVDC	~100	Same + ~$5 for HVDC	~200	Very high
Biomass cogeneration	Mostly NI	70%	130	150			
Marine	Both	(intermittent)	125	400			

These LRMCs are calculated based on GEM data inputs. See the explanation in the main text.

(*) Wind costs are increased in MDS 5, indicating new sources of cost (either technical or regulatory)

(**) Carbon costs are not included – this might put geothermal LRMCs up by $5 or more

(+) Some of the best hydro and geothermal resources are assumed to be unavailable in some scenarios

Draft scenario results

56. The scenarios are expressed as build schedules – i.e. lists of projects to be constructed, by commissioning year. These schedules are reproduced in full in Appendix 1. Generator decommissionings are also included in the schedules.

57. These build schedules are all that is needed for the PSA. However, for ease of interpretation, some summaries of the scenario results are provided in this section.

58. Table 6 (overleaf) presents the scenarios in timeline format, showing the major events projected to occur in each five-year period until 2030.

59. Appendix 2 summarises the amount and breakdown of new generation. The 'capacity stackplots' in this Appendix show the projected nameplate capacity of each generation technology, in each future year, for each scenario. They include both existing and new capacity, and are adjusted for the effects of projected plant retirements.

60. Appendix 3 shows the same information in a different way. Each of these 'technology lineplots' shows the total projected capacity of a given generation technology, in each future year, for all scenarios. Again, these lineplots include both existing and new capacity, and are adjusted for retirements.

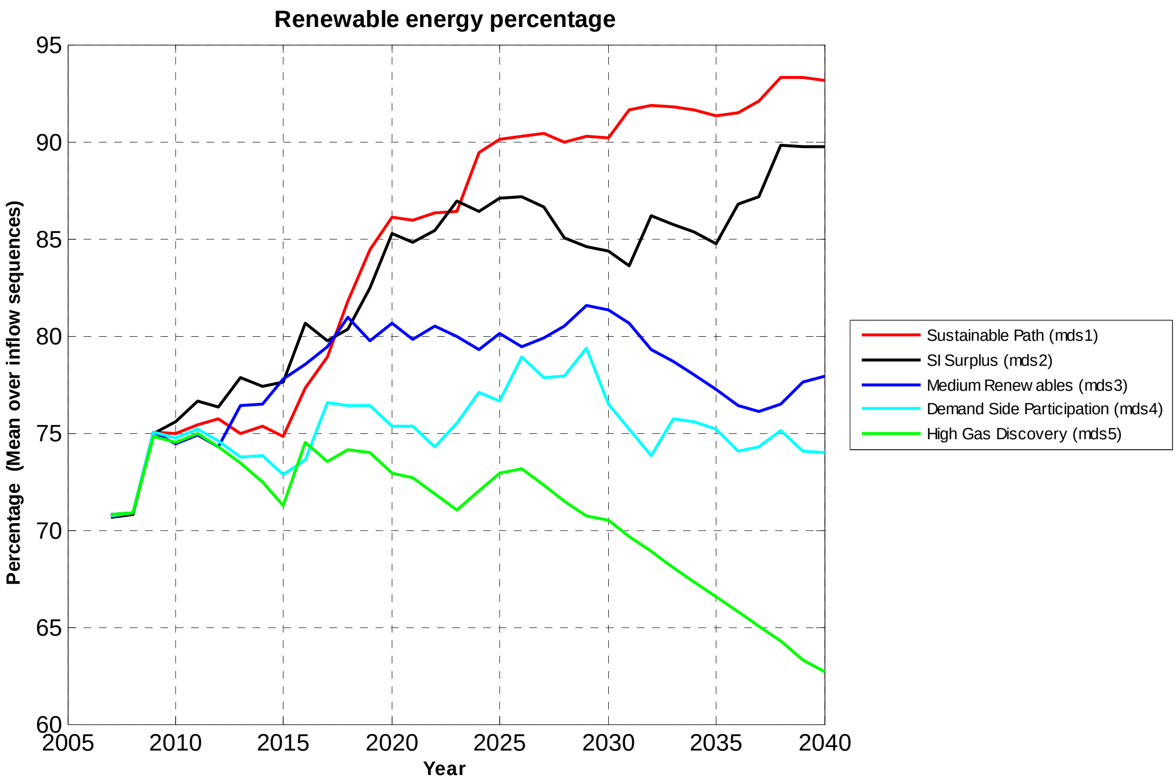
61. The scenario modelling includes forecasts of the amount of electricity produced by each generation technology in each future year. The breakdown is dependent on hydrological inflows, but can be averaged over flow sequences for summary purposes. The resulting 'energy stackplots' in Appendix 4 show the breakdown of total electricity generation by fuel type (e.g. gas, coal, hydro, wind, etc).

Table 6: Timelines to 2030 for the draft scenarios (based on summarised GEM output).

Scenario	2008 - 2010	2011 - 2015	2016 - 2020	2021 - 2025	2026 - 2030
Sustainable Path	New wind and geothermal developments, possibly with diesel- or gas-fired peakers to provide security of supply at North Island peak. Status of HVDC Pole 1 not yet known.	New HVDC Pole 1. Hydro and geothermal development backed by thermal peakers.	Coal-fired units at Huntly close down. Hydro, geothermal and wind development backed by demand-side response.	Stratford Power Station decommissions. Tiwai smelter begins to close down. Hydro and wind development backed by thermal peakers.	Tiwai smelter closed. Consumer electric vehicles becoming widespread. Renewable development continues, marine energy developed.
SI Surplus		New HVDC Pole 1. Hydro, geothermal and major South Island wind developments, backed by thermal peakers.	Coal-fired units at Huntly shift to dry-year reserve status. Major south island hydro developments.	Coal-fired units at Huntly close down. Wind development backed by more thermal peakers.	More hydro and wind development. Coal with carbon storage on the horizon.
Medium Renewables		New HVDC Pole 1. Mixed renewable development backed by thermal peakers.	Coal-fired units at Huntly shift to dry-year reserve. New CCGT built when moratorium lapses. Demand-side backs renewables.	Coal-fired units at Huntly close down. Renewable development continues. More gas plant built, taking a mid-order role.	Renewable development continues, backed by CCGTs and thermal peakers.
Demand Side Participation		New HVDC Pole 1. Mixed renewable development backed by thermal peakers.	Geothermal and hydro development. Demand-side takes an important role with advanced metering widespread.	New CCGTs built after thermal moratorium lapses. Demand side continues to develop.	Coal-fired units at Huntly close. Consumer electric vehicles widespread. Vehicle-to-grid technology used to back extensive wind development.
High Gas Discovery		New HVDC Pole 1. Two Huntly units replaced by Rodney CCGT. Demand side has little involvement; thermal peakers used instead	Relatively little generation development.	Coal-fired units at Huntly close down. More CCGTs built, operating in a semi-baseload role. Some geothermal development.	New conventional coal-fired plants being built.

62. A key statistic is the projected proportion of electricity which would be produced by renewable generation. Renewable generation fuels are deemed to include hydro, geothermal, wind, biomass, and marine, but not gas, coal or diesel. The exception is that coal with carbon sequestration is considered to be renewable (because the greenhouse emissions would be relatively low). The renewable generation percentage is plotted in Figure 4.

Figure 4: Renewable energy percentage in the draft scenarios.

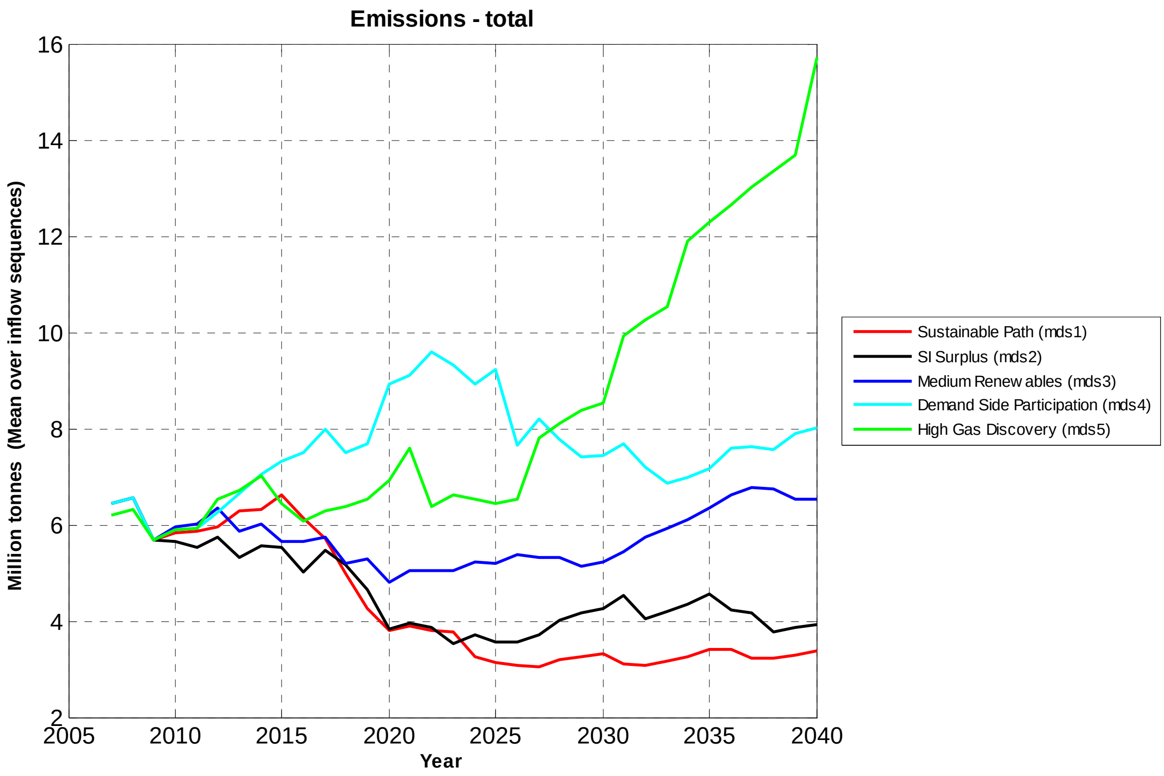


63. It should be noted that these renewable generation percentages represent averages over inflow sequences. The actual percentage would be higher in a dry year, but lower in a wet year.

64. The Commission observes that all five scenarios include wind, geothermal and hydro projects and thermal peakers. The Commission considers that each of these generation technologies is an important contributor to a renewable future.

65. Projections of sector greenhouse emissions are plotted in Figure 5. Again, these are averages over inflow sequences.

Figure 5: Sector greenhouse emissions in the draft scenarios.



66. The Sustainable Path and SI Surplus scenarios predict significant reductions in sector greenhouse emissions by 2020. The Medium Renewables scenario projects emissions remaining roughly constant at 2005 levels. The Demand Side Participation scenario shows increased emissions (not *because of* the demand side participation, but as a result of increased use of gas for electricity generation in the 2020s).

67. The High Gas Discovery scenario shows an increase in sector emissions to more than twice their 2005 level by 2035 (again, not so much *because of* the gas discoveries, but as a result of the construction of new coal-fired plant after 2025). Although this increase in emissions is dramatic, it could well be offset by emission reductions in other sectors. If, post-2030, New Zealand had a target for total onshore greenhouse gas emissions, then increases in electricity-sector emissions would need to be countered by decreases in other sectors (transport, agriculture, or industry). One possible mechanism would be through increased uptake of electric vehicles.

Price projections

68. The Commission is currently developing capability to forecast wholesale electricity market prices. This will allow the GEM generation scenarios to be checked for revenue adequacy – i.e. to determine whether they would lead to wholesale prices that would be high enough for generators to recoup their investments. Revenue adequacy is not an absolute requirement, but if it can be demonstrated, this will support the credibility of the scenarios.

69. It should be noted that wholesale market prices are notoriously hard to predict over any time frame longer than a few hours. Any analysis on this issue must be considered highly speculative.

70. Several different analyses are under consideration:

    (a) a 'statistical projection' of wholesale price, based on observed relationships between the wholesale price, the New Zealand winter energy margin (**WEM**), and the short-run marginal cost (**SRMC**) of thermal generation;

    (b) a calculation of the 'revenue adequate price path', which would first seek to determine the price levels that would be necessary for revenue adequacy; and

    (c) a 'shadow price' produced internally by GEM.

71. The revenue adequate price path and the shadow price are still in early development.

72. The statistical price projection approach seeks to determine how high prices would be in a given future year, given the demand forecast and the generation build schedule. The key element of this approach is the strong relationship that has been observed in recent years between spot prices and WEMs. In this context, the WEM is defined as the excess of the maximum possible generation in a given winter (Apr-Sep) over the expected demand, expressed as a percentage. A WEM of 20% means that the maximum possible generation exceeds expected demand by 20%. *For the purpose of this calculation only;*

    (a) thermal baseload or mid-order stations and geothermal stations are assumed to run constantly, except during forced outages,

    (b) wind plants are assumed to run as wind allows;

(c) Whirinaki is assumed to run constantly, except during forced outages; any new thermal peaking stations are assumed to be run up to a load factor of 50% (for various reasons it seems unlikely that they could be relied on to run as baseload even in a very dry sequence);

(d) hydro output is calculated based on hydrology – leading to a single WEM figure for each historical year, or a distribution of figures depending on inflows for each future year.

73. The resultant WEM has been shown to be very closely correlated with annual mean Haywards prices since 2000. Values of WEM below 12% have been associated with mean prices above $70; WEMs above 15% have been associated with prices below $40.

74. The 'statistical projections' of wholesale price are based on this relationship. Prices are high for years and hydrological flow sequences where:

(a) projected WEM is low (i.e. dry-year security is relatively poor);

(b) projected SRMCs of thermal plant are high; and/or

(c) projected utilisation of thermal peakers is high.

75. Conversely, prices are low where:

(a) projected WEM is high (i.e. there is ample supply in dry years);

(b) projected SRMCs of thermal plant are low; and/or

(c) the market is saturated by baseload and intermittent renewable generation.

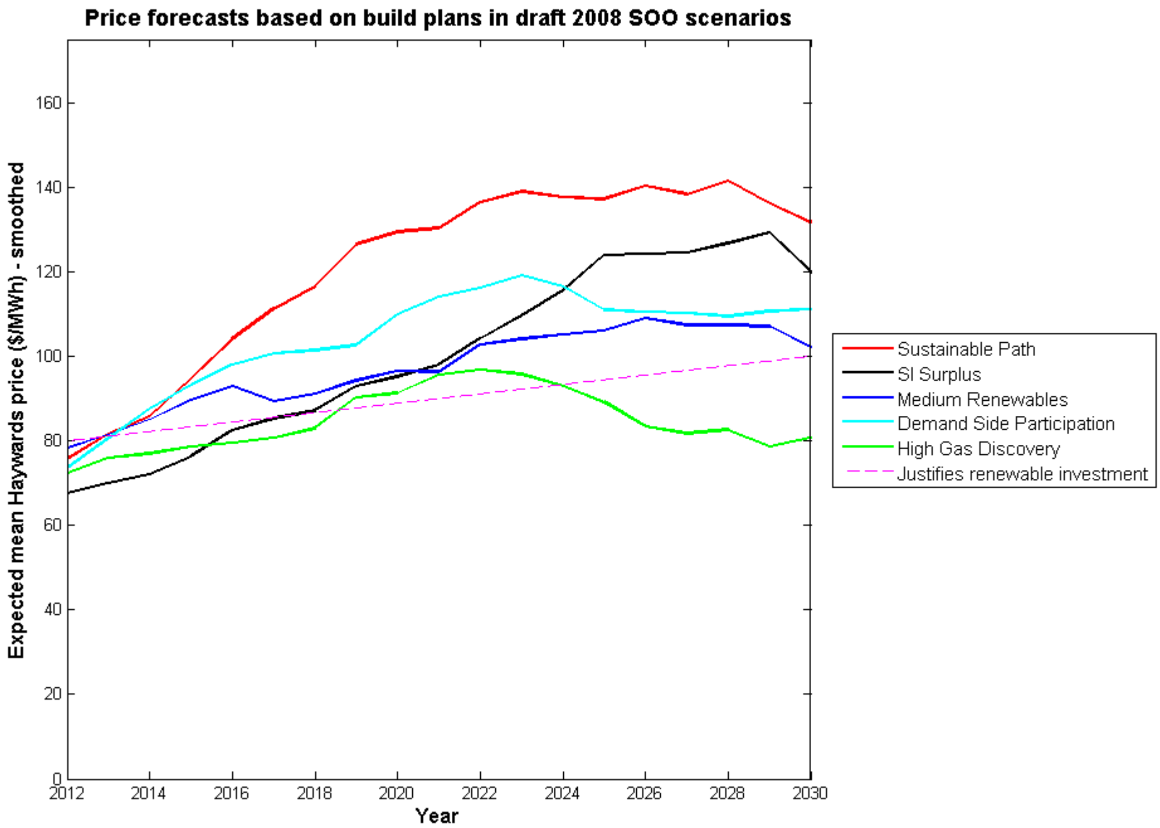
76. On this basis, Figure 6 shows projections of mean wholesale price at the Haywards node.

77. Prices at other nodes are not modelled, and hedge positions are not considered. Note that, although the graphs are smooth, prices would actually vary significantly over time. The graphs are smooth because of averaging effects – each point represents a mean over the 12 months of the year, over trading periods, and over 74 historical flow sequences.[5]

[5] These data can also be used to produce a price duration curve (**PDC**) – i.e. a plot showing the expected amount of time for which the price would reach each level from $0 to $20,000, in each future year. Price duration curve forecasts have been produced but are not included in this paper.

78. Prices prior to 2012 have not been predicted, in large part because of the uncertainty about the future state of the HVDC inter-island link.

Figure 6: 'Statistical' wholesale price projections for the draft scenarios.



79. The indications are that the draft scenarios appear revenue-adequate to 2030 in terms of baseload plant – with the exception of the 'High Gas Discovery' scenario, which may include more generation than would be revenue-adequate from 2025 onwards. The Commission will consider whether there is a need to modify this scenario.

80. The high price path shown for the 'Sustainable Path' scenario should not be interpreted as a prediction that, under a 90% renewable future, prices would rise to the level shown. There is no reason to believe that renewable development would lead to such high prices. In practice, rather than allowing average prices to rise so far above LRMC, either the supply side would build more generation, or the demand side would reduce consumption; in either case, mean prices would fall. What this projection *does* suggest is that the 'Sustainable Path' scenario may not include enough generation. Adding more