The potential impact of HVDC cost allocation on SI and NI Generation Investment

TPAG Secretariat

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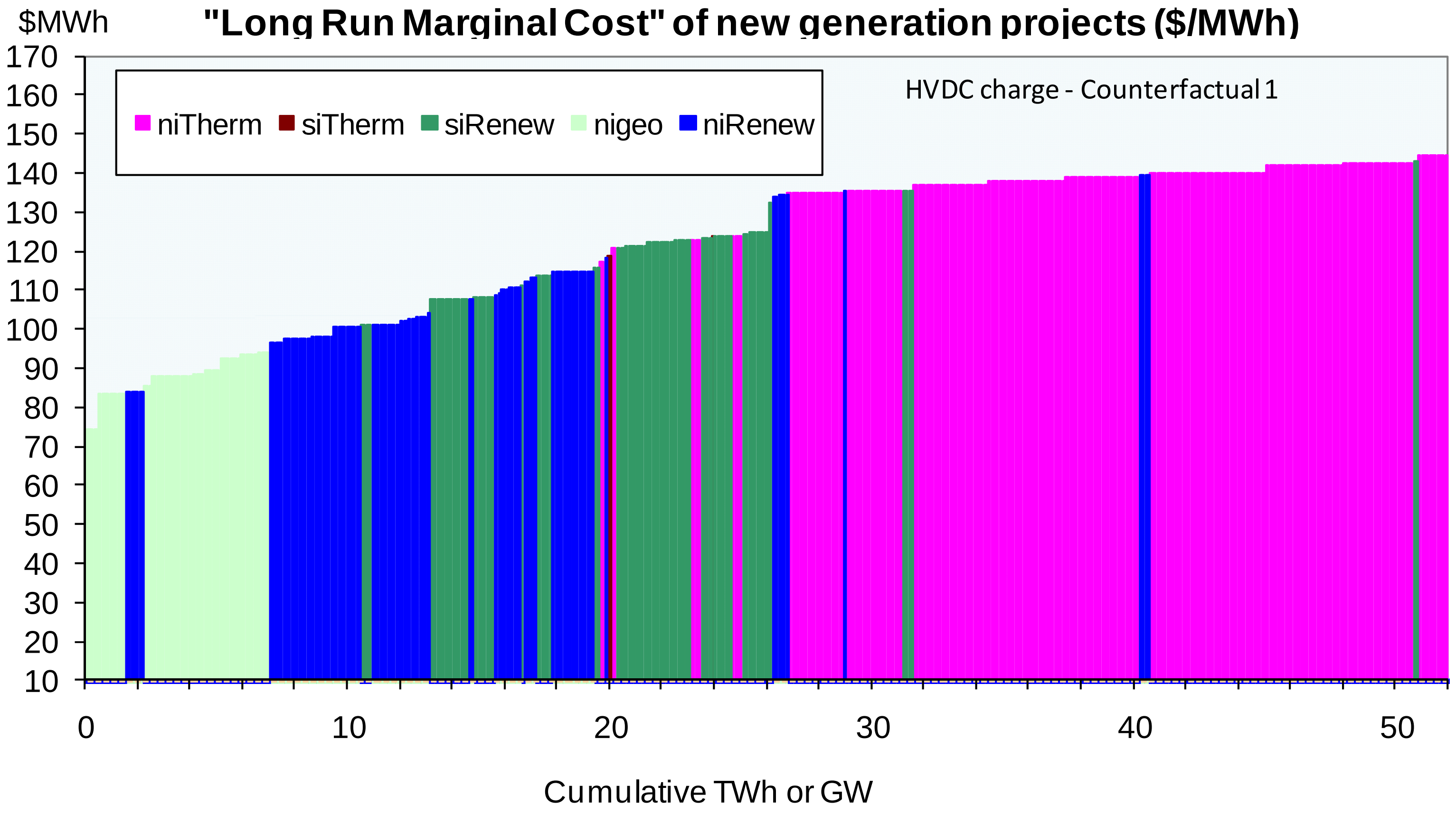
Introduction

- **These slides**
  - **Attempt to establish whether there is a potential cost arising from delaying cheaper SI projects ahead of NI projects as a result of allocating HVDC charges to SI generators, and to quantify the extent of those costs.**
  - **The analysis is simplified so as to explore the impact of:**
    - Different underlying cost assumptions: capital costs, exchange rates, fuel prices and availability, exchange rates, carbon prices, limits on resources and the different effective costs facing the dominant generator in the South Island.
  - **The potential costs of moving to a postage stamp allocation of HVDC costs are also analysed:**
    - These include the implementation costs, the deadweight loss reduction from any increase in delivered prices to customers and any potential loss from this changed HVDC pricing policy (eg increased lobbying incentives as a result of wealth transfers, impact on future HVDC link investment decisions.
  - **Transitional mechanisms are explored that could mitigate the wealth transfer and incentive impacts of moving to a postage stamp allocation, if these are believed to be significant.**
  - **An alternative option that retains the allocation of HVDC costs to SI generators via a MWh allocation is also considered.**

Methodology

- **A simple merit order of new generation investment is constructed:**
  - **As a cross check this uses modified but equally plausible assumptions to those used in the GEM analysis.**
    - This includes modified CCGT, hydro and geothermal capex costs, CCGT heat rates and a simplified treatment of investment constraints.
  - **The investments are ranked on the basis of a simple LRMC measure:**
    - This includes capital recovery, fixed and variable operating cost, fuel and carbon cost, and an approximate location factor (reflecting marginal losses) and cost of backup for intermittent generators (wind and run of river hydro).
  - **The merit order without an HVDC charge is constructed:**
    - This is used to derive the LRMC to meet an increment of demand (to cover demand growth and plant retirements) each year out to 2050.
  - **The merit order with an assumed HVDC charge is then constructed:**
    - This accounts for the impact of the HVDC charge on new investment in the NI and SI and on projects in the SI with different “owners” with differing HVDC cost shares.
  - **The potential economic cost of this is estimated**
    - It is equal to the increase in the present value cost of the new investments accounting for the merit-order impact of the HVDC charges.

Illustrative Merit Order

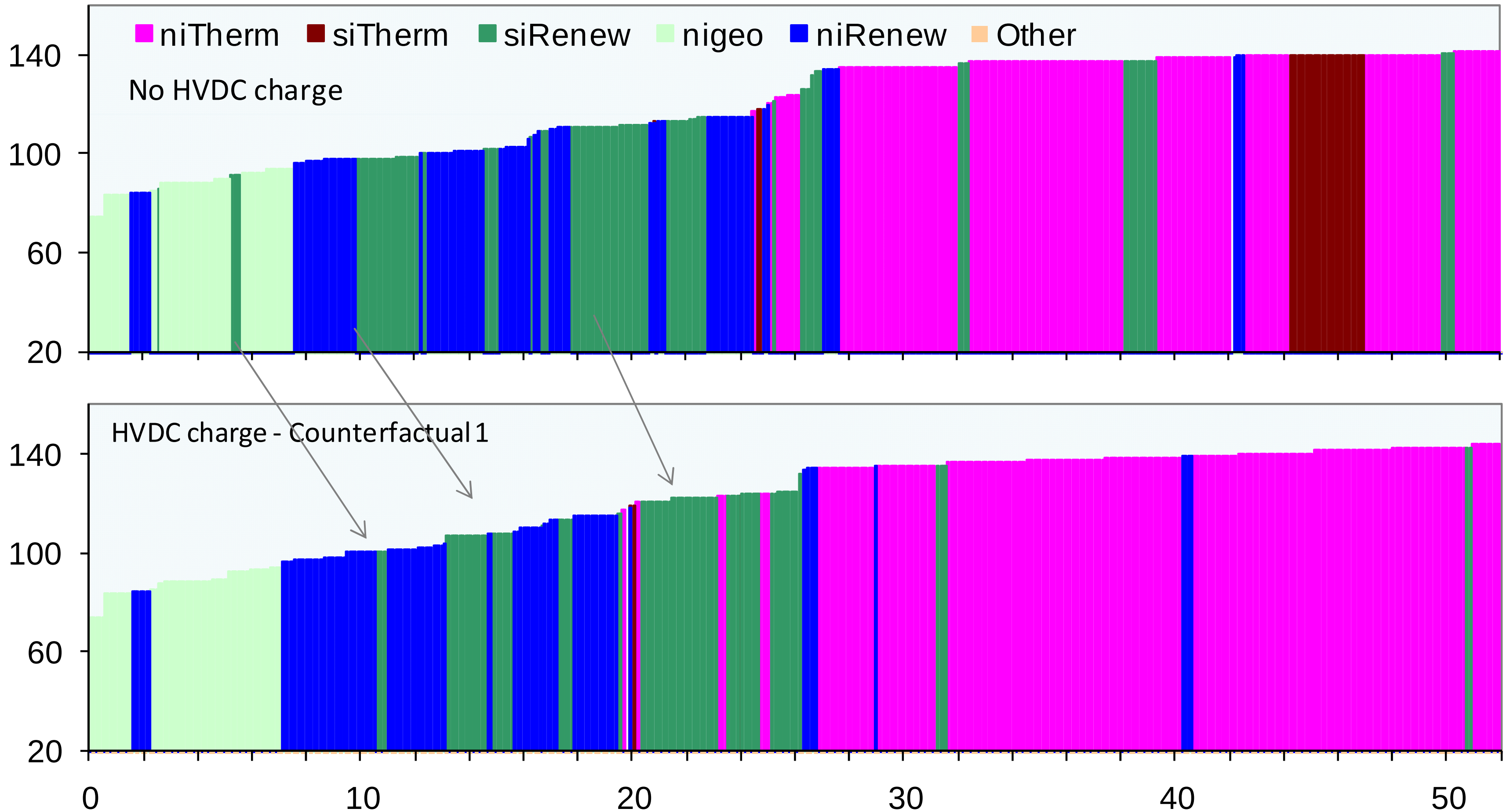


Assumptions: - similar to GEM scenarios 1 to 4

$40/t Carbon price, $13/GJ gas , $4.5/GJ coal, 8% cost of backup for wind

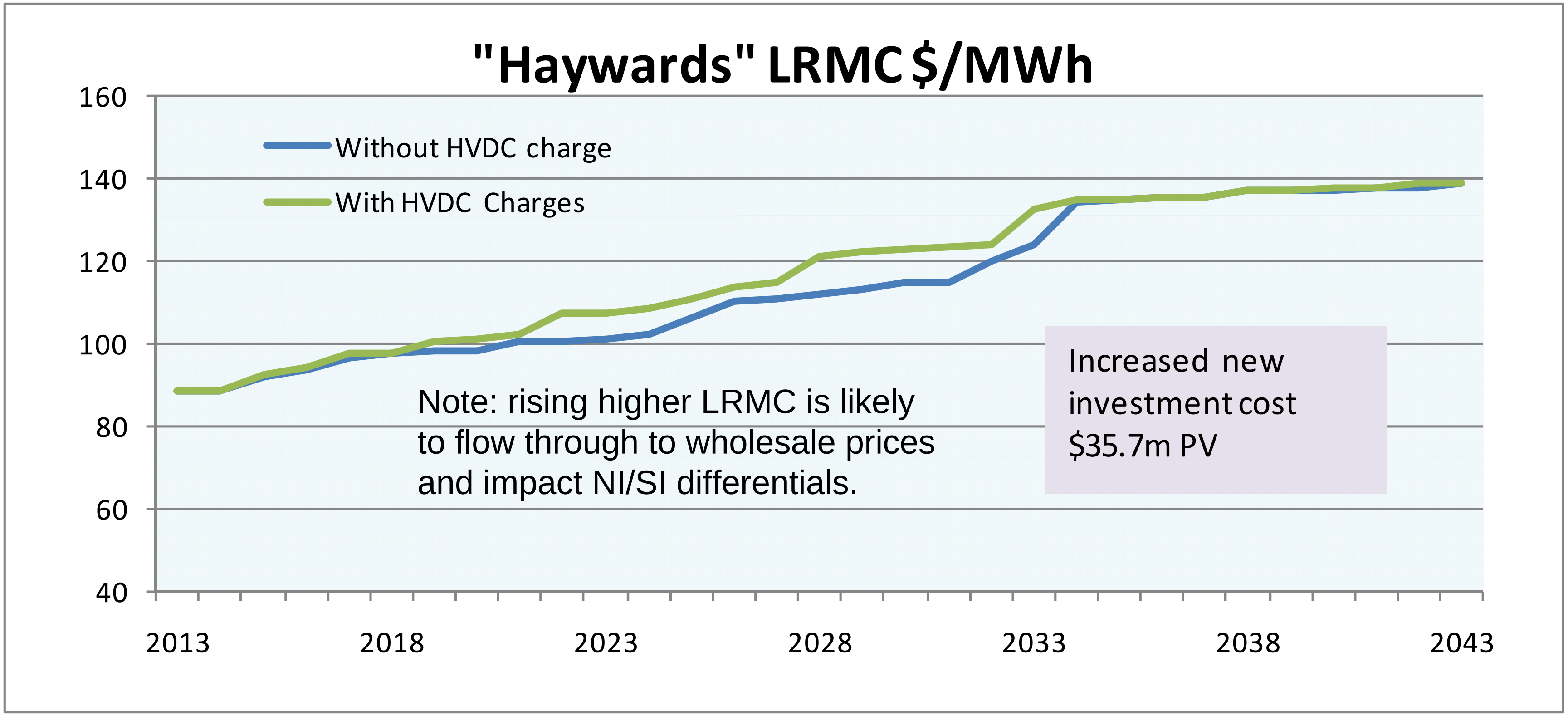
Exchange rates revert to long run US = 0.6, Euro = 0.5, very limited gas

Impact of HVDC charge



Cheaper SI options are delayed as a result of HVDC charge

Impact on the LRMC Curve

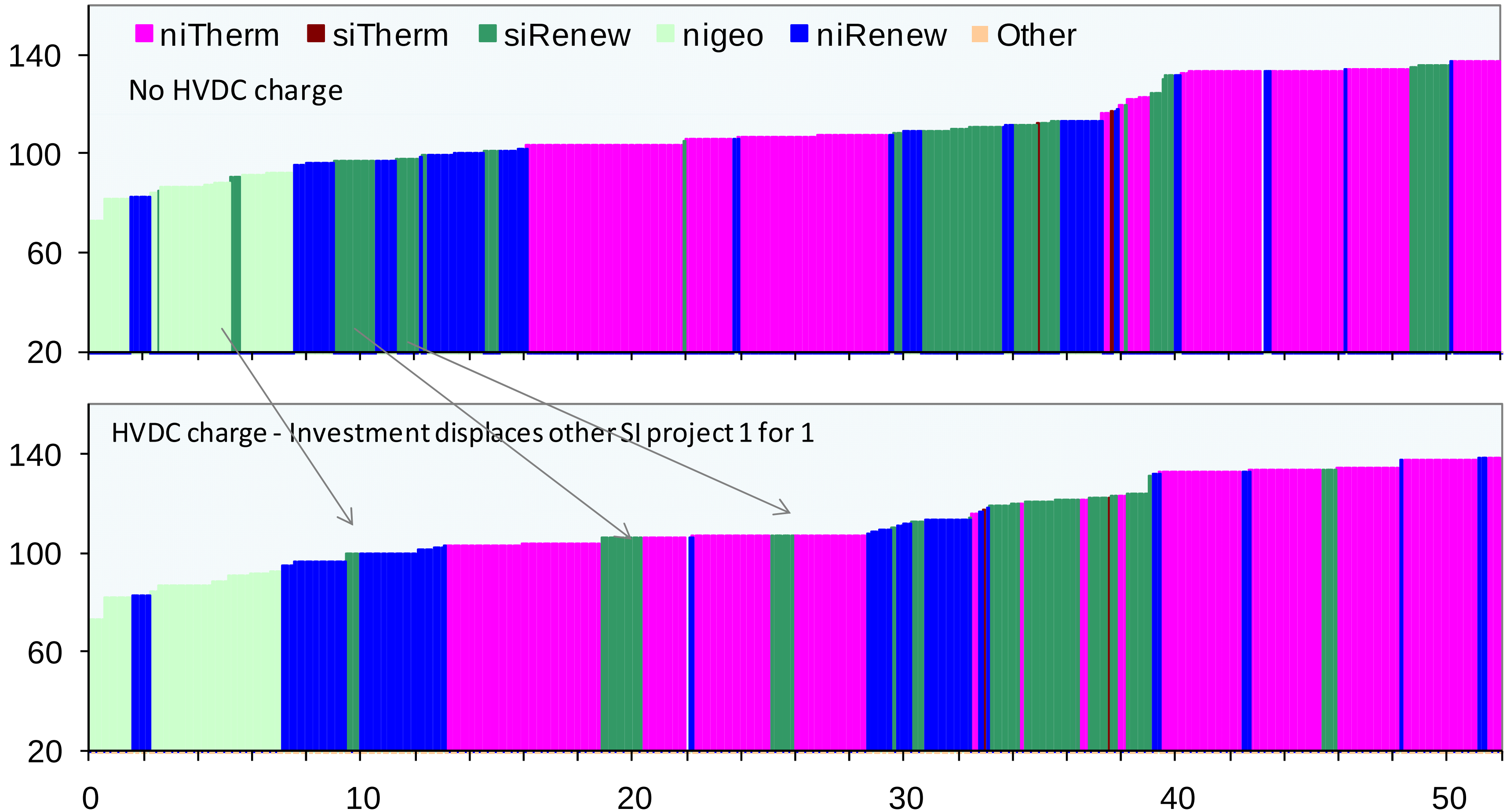


Assumes

1.9% pa demand growth, Huntly is progressively retired, no new gas CCGTs

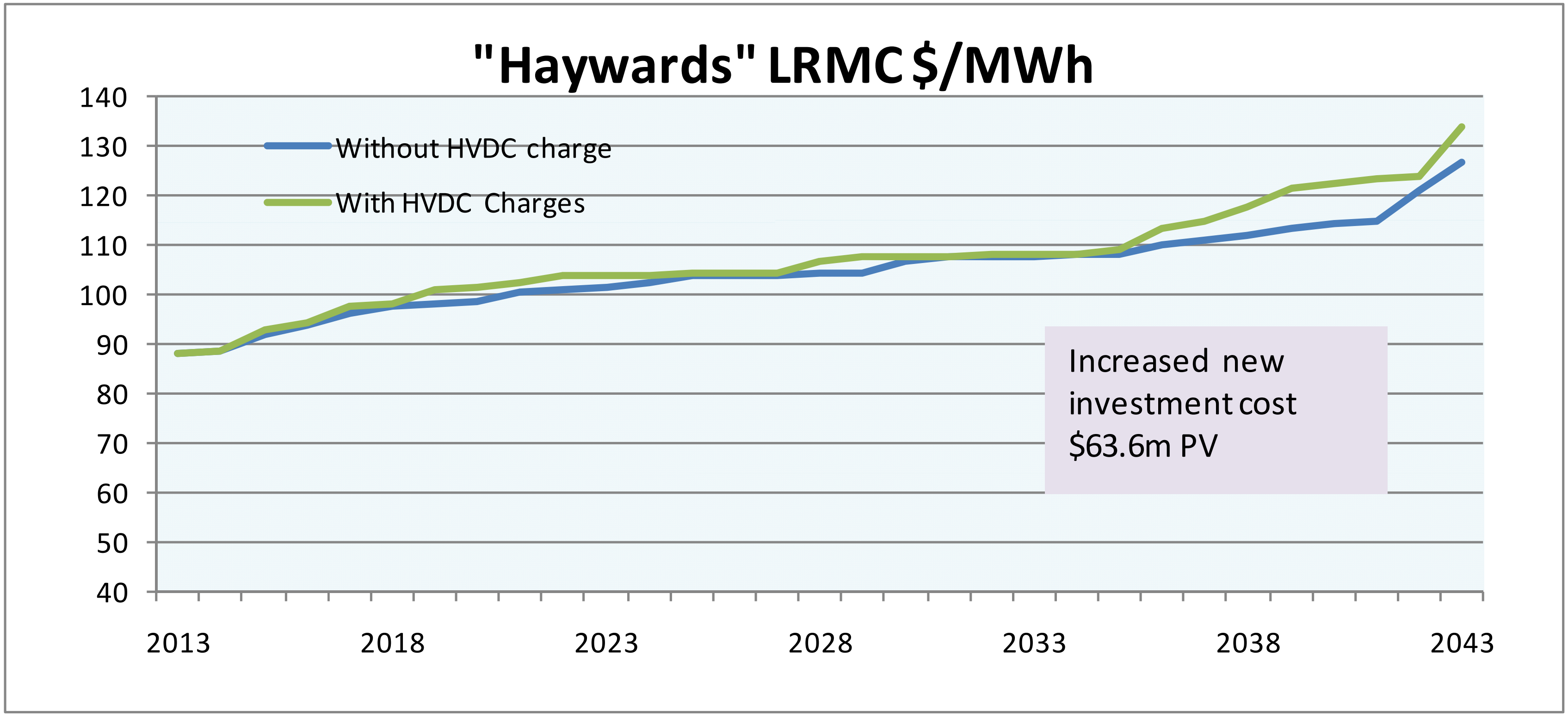
Estimate of economic loss = Change in NPV of new investment LRMC (excluding HVDC charges) over 40 years at 8% real pre tax discount rate.

Low gas cost scenario ($8/GJ)



Cheaper SI options are delayed even more in this scenario.

Low gas cost scenario



The NPV cost is higher in this case as there is greater volume of more expensive (NI thermal) advanced ahead of cheaper SI options, which are hence delayed for more years.

Investment "counterfactuals"

- **Meridian's effective HVDC cost is impacted by the "counterfactual" it faces;**
  - **This refers to the impact that its investment in a new SI generation plant has on other generation investment in New Zealand:**
  - **Counterfactual 1:**
    - If Meridian is confident that its SI investment will simply displace a competitor's investment <u>in the SI</u> then its effective HVDC cost is $40/kW/yr = the full HVDC charge.
  - **Counterfactual 3:**
    - If Meridian is certain that its SI investment will <u>delay a NI</u> option and will have no impact on competitors' investment in the SI then its effective HVDC cost = $12/KW/yr (=$40 *(1 - 0.7)).
  - **Counterfactual 2:**
    - In reality Meridian won't be sure, so the effective HVDC cost will be between these extremes. For this analysis we use Counterfactual 2 to represent this situation. This has an expected HVDC cost of $26/kW/yr based on a 50:50 probability.

The impact of the "counterfactual"

Impact of Counterfactual			
	MEL Effective	Economic Cost $m PV	
Counterfacual	HVDC Cost $/kW	Base Case	Low Gas
1. Displaces other SI generation	$40	$35.7	$63.6
2. Intermediate	$26	$29.8	$46.2
3. Displaces NI generation	$12	$26.5	$42.4

This shows that under all cases considered, and regardless of the counterfactual, there is a material inefficiency associated with the HVDC charge to SI generators.

Counterfactual 3 appears to provide the lowest cost because Meridian's SI projects face a much lower effective HVDC cost and hence its projects won't be delayed as much as they would be under counterfactual 1.

However in this case Meridian has up to a $28/kW advantage relative to other SI generators or new entrants. Hence it is likely to increase its dominance in the SI market. This reduction in competition may lead to additional efficiency losses not included in this analysis. We have not attempted to quantify the additional cost but it could be significant. Therefore we focus on the results for counterfactual 1 in the following slides.

Sensitivity to other factors

Sensitivity Analysis			
HVDC Charge $40/kW	Economic Cost $m PV		
Sensitivity	Base Case	Limited geothermal	Low Gas cost
Current Exchange rates	$51	$48	$46
Long run Exchange Rates	$36	$41	$64
Random Capex 1	$35	$32	$61
Random Capex 2	$36	$41	$62
Random Capex 3	$34	$38	$54
Random Capex 4	$34	$34	$59
Random Capex 5	$37	$33	$48
Random Capex 6	$36	$32	$50
Random Capex 7	$36	$39	$57
Random Capex 8	$37	$40	$56
Random Capex 9	$36	$40	$43
Random Capex 10	$36	$39	$54
Average	$37	$38	$54

Current ER : US =.75, Euro=0.56
Long run ER: US=0.6, Euro=0.5

Capital cost estimates are subject to significant variation:

The random capex cases include a random +/-20% adjustment to all projects.

The table shows the impact of altering other assumptions such as the total quantity of cheap geothermal available, the exchange rates and the relative capital costs of individual new investment options.

The estimated investment inefficiency is within a band of $32-$64m allowing for variations in the underlying capital costs, exchange rates and scenario assumptions.

Impact of MWh cost allocation

Impact of Other factors						
HVDC Charge $7.9/MWh	Economic Cost $m PV			Difference from HAMI		
Sensitivity	Base Case	Limited geothermal	Low Gas	Base Case	Limited geothermal	Low Gas cost
Current Exchange rates	$37	$36	$36	-$14	-$11	-$10
Long run Exchange Rates	$25	$28	$43	-$11	-$14	-$20
Random Capex 1	$25	$22	$47	-$10	-$10	-$14
Random Capex 2	$24	$27	$42	-$12	-$14	-$20
Random Capex 3	$27	$27	$45	-$7	-$11	-$9
Random Capex 4	$25	$22	$41	-$10	-$12	-$17
Random Capex 5	$27	$21	$40	-$10	-$11	-$7
Random Capex 6	$27	$22	$45	-$9	-$11	-$6
Random Capex 7	$26	$28	$45	-$10	-$10	-$12
Random Capex 8	$27	$28	$49	-$11	-$11	-$6
Random Capex 9	$28	$31	$31	-$8	-$9	-$12
Random Capex 10	$27	$30	$29	-$8	-$9	-$25
Average	$27	$27	$41	-$10	-$11	-$13

The table shows the impact of going from a $40/kW HAMI charge to a $7.9/MWh HVDC charge which would recover the same revenue over all SI generation (16,400 GWh). As can be seen, moving to a MWh allocation reduced the investment inefficiency by around $10-13m on average.

Interim Conclusions

- **Charging HVDC costs to SI generators causes investment inefficiencies of the order of $32-64m PV as a result of delaying cheaper SI new investments in favour of NI options.**
  - **The $32-64m loss is small compared with the total value of electricity but is consistently positive and relatively easily avoided.**
  - **This cost would be around $10-15m lower if Meridian faced counterfactual 3 or 2, however in these cases Meridian would increase its dominance in the South Island which is likely to result in other economic losses.**
  - **Moving to a MWh allocation to SI generators would probably reduce the size of the investment inefficiency by around $10-18m to $24-47m, but it would still leave a significant and easily avoided inefficiency.**
- **This investment inefficiency can be avoided by:**
  - **Recovering HVDC costs from all customers or all generators (or some mix between), rather than from SI generators, via some form of postage stamp charge.**

The costs of implementing a change

- **The costs of implementing and administering a change**
  - **These should be relatively insignificant as existing cost allocation procedures could be used.**
- **The potential deadweight efficiency impacts of any flow-through of a change in transmission and wholesale electricity prices.**
  - **Recovering HVDC revenue from customers will increase peak interconnection charges by around $24/kW ($3.5/MWh).**
  - **Reductions in SI new entry costs of $4-10/MWh should flow into wholesale prices at least in the medium term.**
  - **Recovery of HVDC charges from a uniform charge on all generators ($3.5MWh charge) would avoid the rise in interconnection charges but will flow immediately through into wholesale prices.**
    - All existing and new generators face the same charge and hence competitive offers to the market will reflect the additional cost. This will have the same impact as a recovery from customers except it would be via a $/MWh energy price increase rather than an increased $/kW peak interconnection charge.

Estimating the deadweight loss

- **Recovering HVDC revenue from all customers would increase interconnection charges by $24/kW or average delivered prices $3.5/MWh.**
  - This will result in a short term $3.5/MWh price cost to customers, assuming that the reduction in new entry costs does not flow through to wholesale prices for a number of years.
- **The deadweight loss associated with this price increase is estimated to be approximately $0.4m/yr.**
    - $3.5MWh represents a 2% increase in the national average electricity price of $170/MWh (MeD 2009), which would reduce demand by 0.4% or 200GWh assuming a -0.25 elasticity. The deadweight loss = $3.5*200/2 = $400k
  - In the medium term the $4-11/MWh reduction in new entry costs for SI generation options should flow through to wholesale prices at least in the South Island, and probably into the North Island.
    - In the long term wholesale prices may decline $4-11/MWh if South Island options are marginal for New Zealand or $0/MWh if North Island options are marginal for NZ (see earlier charts)
  - The net impact on consumer delivered prices is likely to be:
    - Up to +$3.5/MWh in short run
    - Zero or maybe negative in the medium term
    - Uncertain in the long run – could be either slightly up or down
- **The total deadweight loss PV = -$0.8 to -1.6m (at 8% real pre tax discount rate).**
  - The deadweight loss would be similar if HVDC charges were recovered from all generators or a mix of generators and customers.
  - There may be additional efficiency gains/loss if there is a shift from peak to MWh recovery from customers.
    - The size will depend on the level of the peak charges compared with the potential value of deferred reliability investments (a split between MWh and peak maybe better if peak charges get too high).

Potential "additional costs"

- **There may be a potential loss from changing from a SI generator to a postage stamp cost recovery for the HVDC.**
  - **See separate discussion on the principles, application and value of attempting a beneficiary pays approach to the HVDC for future link investments.**
- **The value transfer may result in future lobbying costs.**
  - **It is inevitable that there will be some value transfers.**
    - The extent and even direction is difficult to estimate as there are combinations of transmission and wholesale pricing impacts – the net impact may be:
      - a small value gain for SI generators (reduced transmission charges offset by lower medium term wholesale SI prices) and a small loss to NI generators.
      - a small loss to NI customers (increased transmission charges not fully offset by in medium term NI wholesale prices) and a small (or zero) net gain to SI customers.
    - However the net impact is likely to be in the range of a few $/MWh
      - Much less than many other regulatory and market changes – carbon pricing, market structure, spot market pricing rules, etc.
- **We don't believe these additional costs are particularly significant but we have not attempted to quantify them and would welcome comments and feedback from the TPAG.**

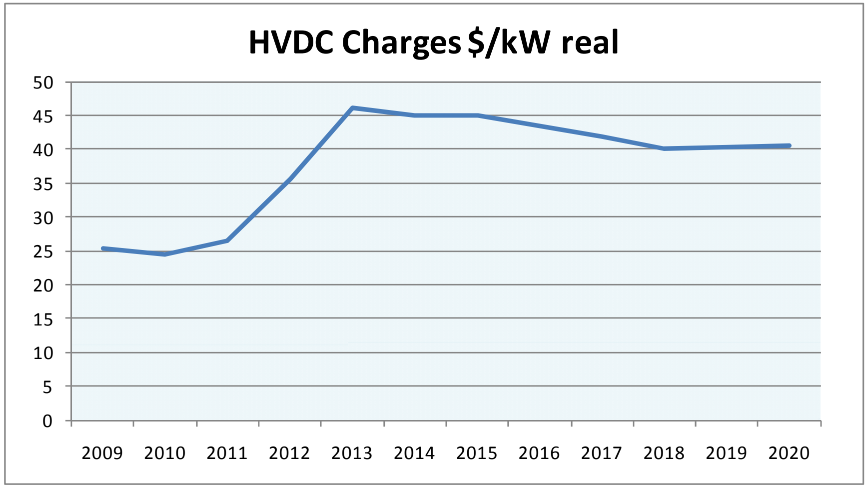
Possible transitional mechanisms

- **If the "additional costs" are believed to be material then:**
  - **It may be possible to devise a transitional cost allocation mechanism which avoids significantly deterring new SI generation, while still recovering a portion of HVDC costs from existing generators.**
    - This could involve a "grand-fathering" approach whereby existing SI generators continue to pay for the existing HVDC link, but that the cost of the replacement investment is recovered from either all generators or all customers or a mix.
    - Ideally the allocation to existing generators should be via an incentive free approach such as:
      - Historical HVDC charge shares (say over 5 years?)
      - Historical average GWh
      - Nameplate MW for existing generators
    - If it was not possible to find a practical incentive free approach then maybe costs could be shared on the basis of either HAMI or MWh for existing generators.
      - This is not very satisfactory since it will lead to arguments over future upgrades and retirement.
    - Ideally the grand-fathering should be as simple as possible:
      - It should avoid creating complexities relating the definition of new and old HVDC assets, sharing of common overheads. A simple pragmatic guide path formula would be best.

Alternative option

- **If TPAG considers that moving to a postage stamp allocation of HVDC costs is not preferred, an alternative option is moving from a HAMI to a MWh allocation to SI generators:**
  - **This could reduce investment inefficiencies by around $10m PV.**
  - **This would also avoid other potential inefficiencies:**
    - Incentivising SI generators to mothball or retire existing peaking capacity.
    - Deterring incremental SI peaking capacity (enhancements of existing or new peaking).
    - Distorting the choice between capacity and energy for new SI generation (for example in the design of new wind and hydro schemes).
  - **This change would avoid a price shock to customers but would still probably involve some value shifts between SI generators.**
    - However it is unlikely to give rise to significant "additional costs" as there is no change in the level of the cost allocation and the wealth transfers should be small;
    - and the implementation costs would be very low.

Appendix



Estimated HVDC revenue requirement as supplied by Transpower (Mar2011).

For this analysis $40/kW/yr is used to represent average charge for 10-15 years post Pole 3 commissioning.

Note that $40/kW/yr = $11.4/MWh for a 40% capacity factor wind generator.

SI Generation Shares	GWh	MW
Meridian	69.3%	70.8%
Genesis	6.0%	5.6%
Contact	22.3%	21.4%
TPW	2.5%	2.2%

The SI generation and MW shares are estimates based on publically available historical data.

Note that the cost allocation on a GWh basis appears to be similar to MW.