Transmission Pricing Review

Issues arising from HVDC Analysis Submissions

August 2011

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Summary - 1

Issue		Response	Action?
Should use CF3 = $13/kW/yr for all projects.	Sub NZIER	TPAG estimated $32m with CF1. NZIER $6m estimate assumes CF3 for all new projects – not realistic. Investment inefficiency with CF2 is around $20-29m depending on which projects could be developed by MEL. The additional cost arising from anticompetitive effects (higher SI wholesale prices, less w/s competition) is estimated to be $2-15m.	Redo with CF2 + add competition impact?
$0m loss from withholding peaking	Sub NZIER	Not likely to be an issue for fully controlled hydro MW, but remains an issue for relatively uncontrolled MW (eg run of river, within chain MW) which can cause extra spill. Could be 50 -100MW affected - 1-2% loss from additional spill could cause $1-5m NPV inefficiency.	Revise estimate to $0-5m?. More likely to be at lower end.
$0-3m loss from peaking investment	Sub NZIER	This applies to upgrade options – MEL can't upgrade others' plant. Even if 50% of the assumed 200MW upgrade capacity was MEL's plant then the loss would be $0 to $22m. Note HAMI can influence design trade off with "spill" and hence cost of all new SI wind/hydro.	Revise estimates to $0-22m? More likely to be at lower end.
Use of heuristics	IR	The merit order uses heuristics for capacity factor, renewables peaking factors, region loss factors etc. which may influence results.	Not significant – except for low demand?
Wind output too conservative	NZEA, TPW	Increasing wind CFs by 2% - increases inefficiency by around $1m NPV	Not significant
Geothermal uncertain	Sub NZEA	A new scenario with more limited and expensive geothermal is $3m higher cost.	Include extra scenario?

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Summary - 2

Issue		Response	Action?
Probability weightings	Sub NZIER	It would be possible to approximate the 5 SOO scenarios (gas price, carbon price, gas availability, geothermal availability) and derive an average (the SOO scenarios have equal weights.)	Redo with 5 SOO scenarios?
SI prices may already reflect HVDC costs to a degree	Sub TPW	If SI incumbent generators are already pricing up to SI new entry then forward contract prices could fall $5-10/MWh under the PST. The net allocative gain in this case would be $1-7m.	Review calculations of allocative loss/gain?
HVDC charges create incentives to embed with an efficiency loss	Sub	Yes – there could be inefficiency if there are additional costs to embed new generation without compensating benefits.	Attempt to estimate potential cost?
Transmission grid capital costs triggered by stations ignored	Sub	The capital costs include connection costs but exclude committed additional SI investments. May need to include additional <u>uncommitted</u> grid investments in the NI?	Check connection costs in GEM data and fix if necessary?
Modelling ignores the possibility of further HVDC expansion	Sub	The modelling only considered options that could be accommodated within the committed HVDC capacity limits. The impact on HVDC replacement approved under GIT (if any) is accounted for separately .	This is clearly noted in the report paras D.2.3 , 6.4.27
Incentive free allocation should be more fully considered.	Sub	This is a variation on PS transition with very long transition. Should look at acceptability, practicality and stability of alternatives.	Include incentive free option?

Summary - 3

Issue		Response	Action?
Simplified HVDC analysis is inadequate.	Sub	Check simplified HVDC analysis with GEM optimisation using SOO scenarios and similar random capex adjustments.	Phil will set up, [partly done]
“Central planning” approach to simplistico	Sub	The simplified HVDC analysis was an attempt to model generator behaviour, but it is difficult to factor all things into account. Maybe model uncertainty in the ranking of projects btw companies as a proxy for “other” factors?	Feedback from TPAG?
A stochastic approach is required.	Sub	There would have to be different “option values” in each island to have a significant influence (NI options face gas/CO2 risk, SI options face Tiwai closure risk?).	Feedback from TPAG?
Market behaviour modelling is required.	Sub/IR	This would be useful to explore market price scenarios and as a cross check on the impact on generation investment timing. However it is complex, requires assumptions on bidding behaviour (which can vary with supply/demand balance).	Feedback from TPAG?
Prices are set by thermal station offer prices which are not affected by HVDC.	Sub	Spot prices depend on offers and the balance between supply and demand. Small changes in investment -> large changes in spot prices. Investment adjusts to be revenue adequate – i.e. so expected market prices = LRMC in medium term.	Additional explanation?
Capacity rights cost too high.	Sub	The NPV cost in TPAG was based on the FTR proposal, includes implementation ($3.4-7.8m) and operating costs ($2.3-3.9m/yr) - for central bodies and participants for 20 years.	Explain

NZIER Criticism of Counterfactual

- TPAG used counterfactual 1 for analysing the increased generation investment costs.
  - TPAG stated that the most likely CF was 2 (between 1 and 3), but used CF1 on the grounds that this did not provide Meridian with a competitive advantage and hence avoided the need to explicitly estimate the cost of MEL increasing its dominance <u>in the SI</u>.
    - [Note that if the cost of giving MEL a competitive advantage was sufficiently high then the TPM could be changed from a cost allocation to a common SI generation charge]
- In their submission NZIER state that:
  - we should use the counter-factual 3 Meridian opportunity cost for <u>all potential new projects</u> in the SI, and asserted that the cost of Meridian increasing its dominance is “small”.

NZIER – Choice of Counterfactual

- The NZIER analysis implicitly assumes:
    - That Meridian alone can procure any new development option and develop it as cheaply as a group of potential competitive SI generation developers.
    - That any SI project that Meridian does develop will not displace any competitor's SI project over the project life time.
- However:
    - Meridian will not have the opportunity to develop options such as Mahinerangi, Arnold, Wairau expansions, additional Clutha developments etc.
    - Meridian may not be the lowest cost developer and may not identify the cheapest options compared to a group of competitive developers.
    - If Meridian builds new SI generation it can't be sure that it won't crowd out or displace other SI options at some time over its life – hence it is likely to use an intermediate counterfactual in its commercial decision to proceed – thus the hurdle HVDC charge it is likely to use is that based on counterfactual 2 rather than 3.
- The following slides attempt to replicate the NZIER approach by estimating the generation investment inefficiency based on an "expected" counterfactual (i.e. CF2) and a separate estimate of the efficiency impact of Meridian having a competitive advantage for marginal projects which are up to $35/kW/yr lower cost than North Island options.

Alternative Status Quo Assumptions

- To assess the generation investment inefficiency with Counterfactual 2 and Counterfactual 3 it is necessary to make assumptions concerning which projects Meridian could potentially develop.
- The following assumptions could apply:
  - A: MEL can only develop its “own” projects without extra cost.
  - B: MEL can develop 50% of “other” generic projects not “owned” by competitors without extra cost.
  - C: MEL can develop 100% of “other” generic projects not “owned” by competitors without extra cost.
  - D: MEL can develop 100% of all SI projects without extra cost (NZIER assumption).

Increased Investment Cost $m NPV

Additional Baseload investment cost $m NPV

Assumption		A: MEL is limited to "ow n" projects			B: MEL can do 50% of generic			C: MEL can do all generic projects			D: MEL can do all projects		
		Avg	Min	Max	Avg	Min	Max	Avg	Min	Max	Avg	Min	Max
CF1	Base	29	14	45									
	Cheap gas	35	20	51									
CF 2	Base	22.8	11.1	35.4	22.4	11.0	35.1	19.7	8.9	32.8	13.9	7.6	18.4
	Cheap Gas	29.3	18.2	39.5	28.9	17.5	39.5	25.3	15.2	37.2	18.4	10.7	24.6
CF 3	Base	20	11	32	19	10	32	14	5	30	4	2	11
	Cheap Gas	25	17	36	24	16	36	17	10	33	5	2	11
CF1	Total	31.8	14	51	31.8	14	51	32	14	51	32	14	51
CF2	Total	26.1	11.1	39.5	25.7	11.0	39.5	22.5	8.9	37.2	16.2	7.6	24.6
CF3	Total	22.1	11	36	21.2	10	36	16	5	33	5	2	11

Note: values here are the average , min and max over 11 random capex samples for each scenario.

The additional average generation investment cost is $20-$29m with the expected Counterfactual 2 and assumptions A, B or C. This is around $6-9m lower than the results for CF 1.

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Competitive Advantage

- With Counterfactual 2 Meridian has around a $10-12/kW/yr advantage relative to other incumbents and new entrants.
- This equates to a $3 to $4/MWh advantage for typical wind and hydro projects.
- This advantage will result in:
  - Meridian undertaking more SI projects and hence will have a higher market share than otherwise.
  - Meridian facing less competitive pressure, with potential implications for contract prices in the SI and for productive and investment execution efficiency.
- The extent of this increased market share will vary by scenario and status quo assumptions as shown in the following slide.

Impact on Market Share

- Without the HVDC charge there will be full competition for new SI projects and Meridian's SI market share during 2020 to 2029 is expected to fall to 63% (Base scenario).
- The table below shows the expected market shares for Meridian under the Status Quo with the different "Counterfactuals" and "Assumptions"

Assumption		A: MEL is limited to "own" projects			C: MEL can do all generic projects		D: MEL can do all projects	
		No HVDC	SQ	Delta	SQ	Delta	SQ	Delta
CF1	Base	63%	66%	3%				
	Cheap gas	63%	67%	4%				
CF 2	Base		66%	3%	68%	5%	72%	9%
	Cheap gas		66%	4%	68%	5%	72%	9%
CF 3	Base		67%	4%	69%	6%	73%	10%
	Cheap Gas		67%	4%	69%	6%	73%	10%

Note: values here are the average over 11 random capex samples.

This shows that the potential reduction in Meridian market share is 3% to 10% depending on the assumptions used to describe the status quo.

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Impact on SI Prices

- Removal of the HVDC charge lowers new entrant prices in the South Island by $35/kW/yr (approx $8-11/MWh for typical wind or hydro options).
- The impact on forward contract prices will depend on the strength of competition in the region and the extent of North -> South transmission constraints.
  - Meridian is still dominant in the SI (69% market share) and can be pivotal at times when North South flows are constrained.
  - If competition is weak or if the risks of NS flow constraints are high then SI contract prices are likely to reflect the cost of Meridian's competitors' new entry in the SI (not its own cost).
  - If competition is strong or if the risk of NS flow constraint is low then contract prices are likely to reflect NZ new entry costs – i.e. NI options or SI options which ever are the lowest (this was the conservative assumption used in earlier analysis).
  - There is some evidence to suggest that SI contract prices in 2013/14 may already be approaching SI new entry costs (see Appendix).
  - This indicates that the Postage Stamp Transition may result in a much earlier reduction in South Island contract prices.

Allocative efficiency impacts

- TPAG's earlier analysis took a conservative approach to the assessment of the pass through of lower marginal new entry costs through to consumers.
    - This assumed a high level of national competition with NZ wholesale contract and retail prices reflecting the lowest NZ new entry cost (Haywards equivalent base-load). Under this assumption prices did not fall for 5-10 years (after the development of cheaper NI resources such as geothermal).
    - The alternative assumption is that SI contract prices are already approaching SI new entry costs (with HVDC charges) and hence there may be a much earlier reduction in SI wholesale prices than assumed in the earlier analysis.
    - A market behavioural model including hydro management would be required to assess the risks and extent of North South constraint with rising SI demand and no significant SI generation. It is not feasible to undertake this modelling, however it is possible to assess the allocative efficiency impact for illustrative scenarios to assess the impact of this.
- The following slide calculates the allocative efficiency effect from the 10 year Postage Stamp Transition taking into account the different illustrative impacts in each island.

Allocative gain if SI wholesale prices reflect SI new entry.

- Calculate the net allocative gain assuming:
  - All HVDC Rentals go to customers, and existing generators continue to pay HVDC charges starting at $30/kW with 10 yr transition.
  - NI wholesale contract prices reflect the lowest Haywards equivalent base load option (North or South) as in the earlier analysis.
  - SI wholesale prices reflect SI new entry costs until 2025 (either from weak competition or North->South constraints in dry years) and then reflect national new entry costs.
  - Demand elasticity = -0.26, average delivered prices are around $153/MWh (MED 2010).

Allocative Gain from Delivered Price Reductions						
SI Wholesale Price Impact <2025	$/MWh	-$10.0	-$8.0	-$6.0	-$4.0	-$2.0
NZ Wholesale Price Impact > 2025	$/MWh	-$3.1	-$3.1	-$3.1	-$3.1	-$3.1
Allocative Gain NPV	$m	$8.8	$5.3	$2.7	$1.1	$0.9

Transition: initial charge to existing SI gen = $30/kW - term =10 yrs

Conclusions with Counterfactual 2

- Under more realistic CF2 assumptions the generation investment inefficiency is estimated to be $29-$20m (average) around $6-9m lower than the results for CF 1.
- Meridian has a $3-4/MWh advantage compared with other competitors and increases its SI market share 3-5% compared with the Postage Stamp Transition.
  - The benefits of increased competition are difficult to estimate, but:
    - Anticipated gain from increased competition resulting from the transfer of Tekapo (which reduced Meridian's SI capacity share by 5-6%) must have exceeded the estimated cost of $4-30m* (including potential loss of efficiency of water use). A 3-5% reduction in share could provide half of this gain = $2-15m.
      - E.g. $9m NPV gains could be obtained from a $0.09/MWh reduction in Meridian's operating costs , or from a 5% improvement in investment execution efficiency for 130MW in 2020 as a result of greater wholesale competition and greater competition for new investment options.
- The Postage Stamp Transition removes the competitive advantage to Meridian and reduces SI new entrant costs by around $10/MWh.
  - The allocative gains from price reductions (with a 10 year transition starting at $30/kW/yr) could be in the range $1-9m NPV depending on the strength of competition in the South Island and the risks of North->South constraints in dry years.

Note: * "Improving electricity market performance Summary note on recommendations taking account of submissions" Med Oct 2009 page 73.

Use of "Heuristics"

- The simplified merit order approach uses a number of heuristics in the calculation of the base load equivalent LRMCs for each option.
  - Growth in demand for "base load" supply.
    - Equal to the growth in energy demand + estimated retirement of Huntly, but could be higher (2.2%) or lower depending on contribution from existing and new mid-merit plant.
  - Choice of reference capacity factors:
    - Thermals at derated maximum generation (random and planned outages) = 80-85% (could be 85%-95%). (Thermals may operate less but would have higher peaking factors)
    - Renewables use expected capacity factors – 90% geo, 35-45% wind, 50% for hydro (could be individualised)
  - Use of "Peaking factors" to account for intermittency, flexibility and correlations. PF = Avg gen rev / time weighted price.
    - 100% for genuine base load – thermal and geothermal at reference CF
    - 92% for wind - depends on "capacity value" of wind (could be 85% to 96%)
    - 90% for hydro – depends on volatility of inflows, storage, correlation with total NZ inflows etc – (could be 90% to 100%)
  - Use of average "regional" MLF factors – referenced to Haywards
    - These were based on averaged MLF values from earlier GEM runs.

Impact of Heuristic Adjustments

Additional Baseload investment cost $m NPV		A: MEL is limited to "own" projects				C: MEL can do all of generic			
		Avg	Min	Max	Std	Avg	Min	Max	Std
CF1	Base	29	14	45	10				
	Low Demand	21	9	34	9				
	High Demand	32	16	47	10				
	Indiv hydro CF/PF	29	16	44	10				
	Low Wind PF	26	15	33	7				
	High Wind PF	33	19	46	11				
	High Therm CF	29	16	44	10				
	Old regional MLF	28	15	44	9				
CF 2	Base	23	11	35	7	20	9	33	7
	Low Demand	16	8	26	7	14	6	24	6
	High Demand	24	13	37	7	21	10	37	7
	Indiv hydro CF/PF	23	13	41	8	21	10	40	8
	Low Wind PF	20	13	28	6	18	11	28	6
	High Wind PF	26	14	36	8	22	13	35	7
	High Therm CF	23	14	41	8	21	11	40	8
	Old regional MLF	23	13	41	8	19	13	24	5

	Wind PF	CCGT CF	HydPk CF	HydPk PF	HydRR CF	HydRR PF	Init %pa
Base	92%	85%	50%	90%	50%	90%	2.0%
Low Demand	92%	85%	50%	90%	50%	90%	1.5%
Indiv hydro CF/PF	92%	85%	Var	95%	Var	90%	2.0%
Low Wind PF	85%	85%	50%	90%	50%	90%	2.0%
High Thermal CF	92%	90%	50%	90%	50%	90%	2.0%

The table shows the impact on the estimated generation investment inefficiency NPV $m) of choices for the heuristic parameters used.

The results are reasonably robust to reasonable variations in the heuristic parameters. It is most sensitive to the demand for base load generation.

This depends on the contribution from existing/new mid merit plant – Huntly, CCGTs, gas peakers. The analysis assumes a conservative contribution from existing plant closures.

Additional Scenarios

- NZIER queried if the scenarios used in the analysis were equally weighted and other submitters wanted more scenarios.
- The original approach attempted to account for the average features of the 3 renewable SOO scenarios and a separate “low gas price” scenario to illustrate the impact of HVDC charges on new generation investment costs.
- It is possible to approximate all 5 SOO scenarios:
    1. Sustainable path - high gas and CO2 price, high availability of renewables
    2. SI wind – relatively high gas and CO2 price, limited geothermal
    3. Medium renewables – medium gas and CO2 price, limited SI hydro
    4. Coal – low CO2 price, limited renewables
    5. High gas discovery – low gas price, high availability, limited geothermal and hydro
- The following slide provides results for these.
    - Note that not all features of these SOO scenarios are modelled in the simplified approach, heat rates and capital costs used in the SOO have been updated and pre-determined project timing has not been included. The phasing out of Tiwai has not been modelled in scenario 3.

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SOO Scenarios - indicative

Additional Baseload investment cost $m NPV		A: MEL is limited to "own" projects				C: MEL can do all of generic			
		Avg	Min	Max	Std	Avg	Min	Max	Std
CF1	Med Renewables	30	15	52	10				
	High Gas Discovery	37	22	49	10				
	SI Wind	30	16	45	8				
	Coal	32	19	51	11				
	Sustainable Path	28	11	45	11				
CF 2	Med Renewables	25	10	47	10	22	11	45	9
	High Gas Discovery	31	18	44	8	27	13	43	8
	SI Wind	23	11	30	5	19	10	27	5
	Coal	25	14	39	9	23	14	38	8
	Sustainable Path	22	8	38	9	16	13	18	2
CF1	Average	32	11	52	8	32	11	52	8
CF2	Total	**25**	8	47	8	**21**	10	45	6

		$/GJ	$/t	MW Limits				PF	PF
SOO	Scenario	Gas	CO2	Geo	HydPk	HydRR	Wind	Wind	HydRR
3	Med Renewables	13	30	750	830	440	4,000	0.90	0.95
5	High Gas Discovery	8	40	500	820	440	4,000	0.92	0.95
2	SI Wind	18	50	500	1,020	1,150	4,000	0.90	0.95
4	Coal	13	20	750	500	120	4,000	0.92	0.95
1	Sustainable Path	23	60	750	1,170	1,310	4,000	0.90	0.95

Medium renewables does not include the phasing out of Tiwai. This would probably reduce the estimated investment inefficiency.

Note: These are SOO Scenarios may be further refined and assessed using the GEM model.

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APPENDIX

MWh HVDC charge with CF2

Additional Baseload investment cost $m NPV							
Assumption		A: MEL is limited to "ow n" projects			C: MEL can do all generic projects		
		Avg	Min	Max	Avg	Min	Max
CF1	Base	19	9	28			
	Cheap gas	23	14	32			
CF 2	Base	15	9	22	13	6	21
	Cheap Gas	20	14	24	17	10	22
CF1	Total	21	9	32	21	9	32
CF2	Total	17	9	24	15	6	22

MWh allocation

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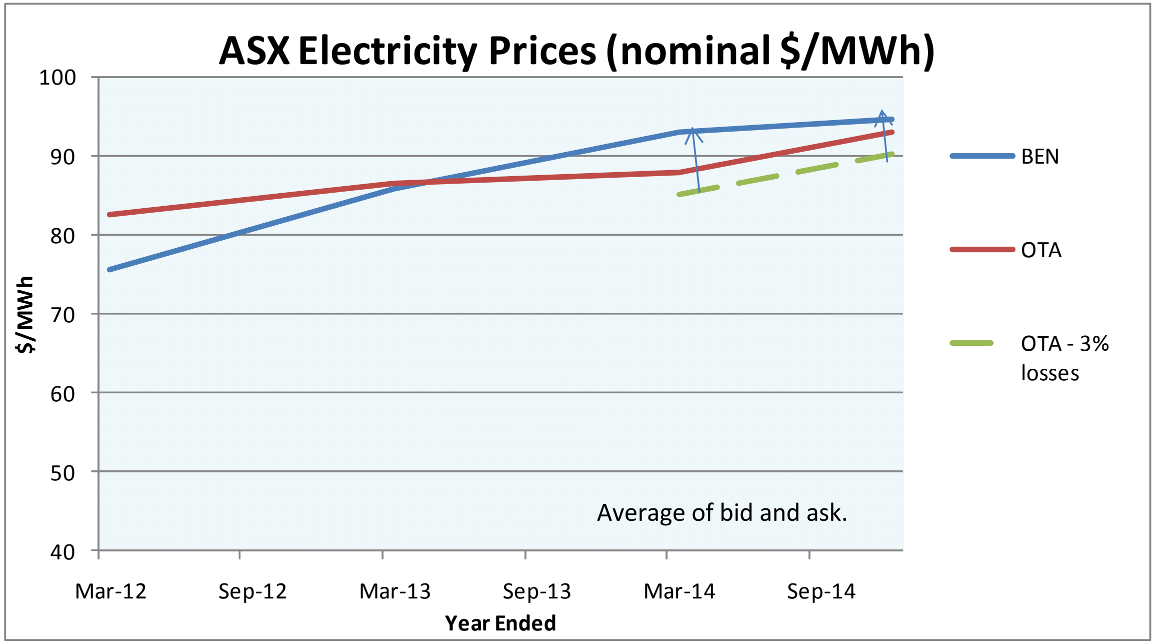
Do SI prices already include HVDC charges?



The avg OTA/BEN MLF was 106% over 10 years, and 105% over the last 5 years.

The difference post pole 3 should be lower - given lower losses on the HVDC and higher SI demand implying lower net flows.

ASX forward contract prices show SI prices at a $5-8/MWh premium above loss adjusted Otahuhu in 2013 and 2014 after pole 3 is commissioned. This may just reflect risks of SI hydro shortages given limited level of new SI investments. Prices may still not be high enough to justify new investment in wind and hydro with HVDC charges, but it does indicate that the impact of lowered new entry costs in the SI could be earlier than assumed in the previous analysis.

There is limited liquidity (last trades in Feb/June for 2013-14) but this provides some evidence that SI contract prices may already at least partly reflect the HVDC charges in SI new entrant costs and so there could be a reduction earlier than assumed in the previous analysis.

Allocative impact of Price Reductions

- The table below shows the allocative gain from wholesale price reductions in the South Island.

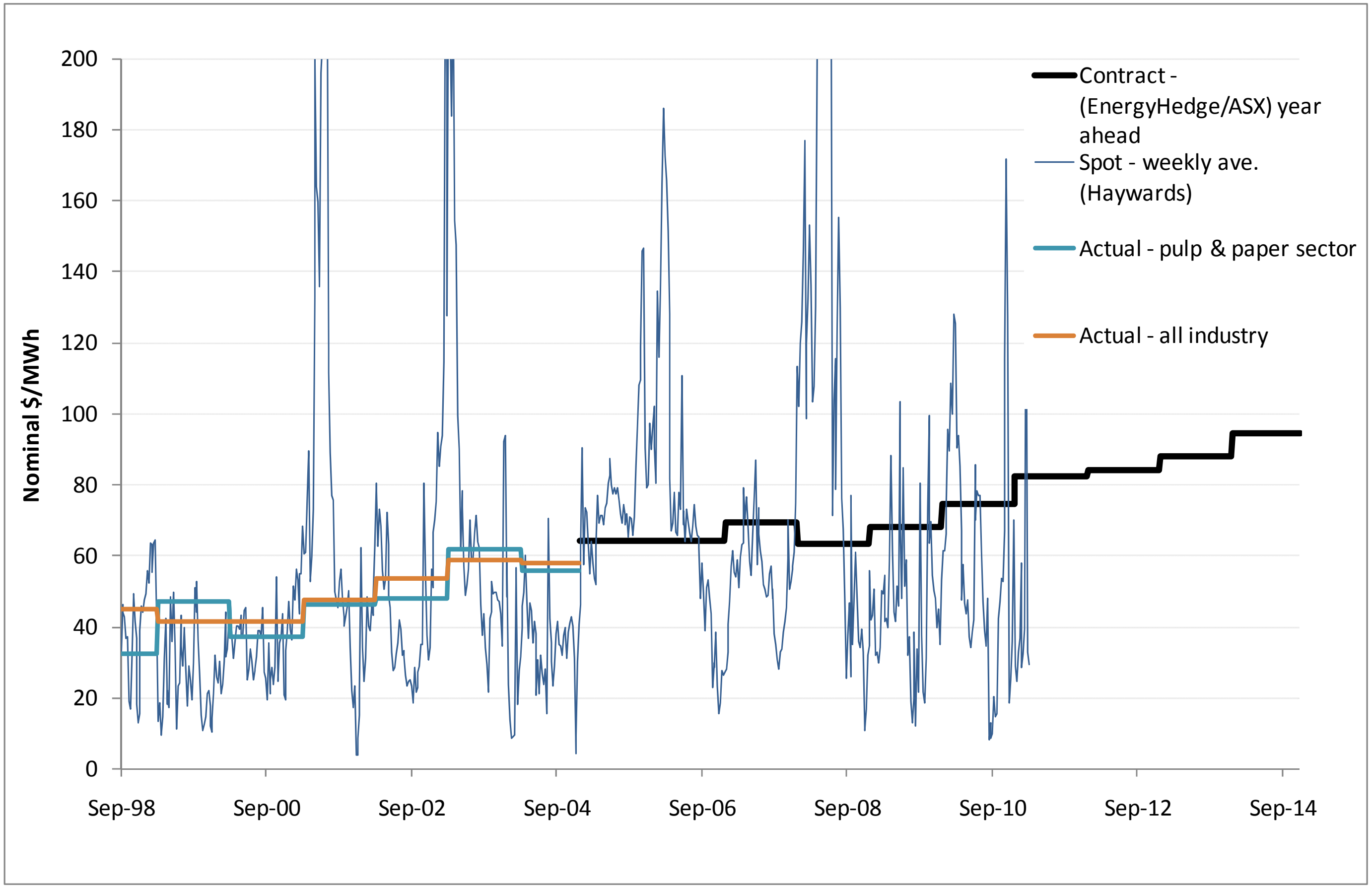
Allocative gain from Wholesale Price reductions in the South Island					
Wholesale Price Reduction $/MWh	$3.0	$5.0	$7.0	$9.0	$11.0
SI Demand GWh/yr in (2013)	15,865	15,865	15,865	15,865	15,865
Average Delivered cost $/MWh (1)	$153.0	$153.0	$153.0	$153.0	$153.0
Price Elasticity	-0.26	-0.26	-0.26	-0.26	-0.26
Pct Reduction in Price	2.0%	3.3%	4.6%	5.9%	7.2%
Pct increase in demand	0.5%	0.8%	1.2%	1.5%	1.9%
GWh increase in demand	81	135	189	243	297
Allocative Gain $m/yr	$0.1	$0.3	$0.7	$1.1	$1.6
NPV Allocative Gain 30 yr $m	$1.2	$3.5	$6.8	$11.2	$16.8

Source: (1) Table G.6a: Electricity Market Snapshot - 2010 March Year MED Data File

Impact of competition and new supply on prices

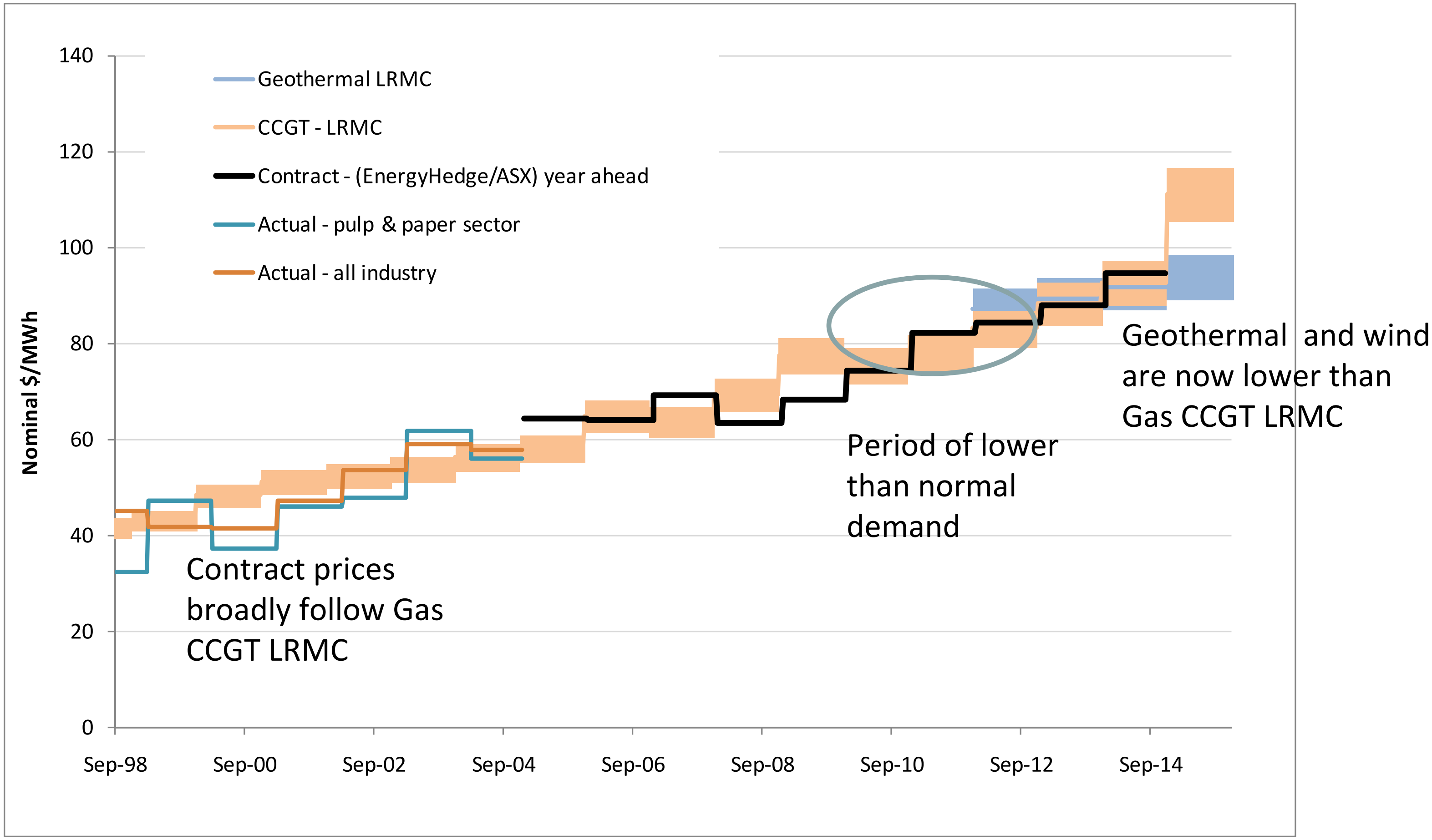
- If there is weak competitive pressure wholesale spot prices can be higher, particularly at times of tight supply.
- However, even with weak competitive pressure in the short run, forward contract prices can't be held above the cost of new entry for long.
  - If they are higher, then competitors can profitably build new plant and incumbents are likely to suffer low prices (if excess capacity flows through to spot prices), or volume loss (if incumbents "price up" or withhold capacity to avoid lowering spot prices).
  - This discipline is imposed by new entry of all technology types and limits the level of prices over the whole price duration curve (base load, intermediate and peaking).
  - Although there is uncertainty about the cost and timing of new entry of different technologies in general, the reduction in SI new entry costs is certain under the PST option.

Spot and Contract Prices



Spot prices are dominated by short run factors including hydro inflows. Contracts priced a year ahead reflect expected inflows, medium term supply and demand balance and LRMCs.

Do contract prices reflect LRMC?



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