Technical Workshop
2019 TPM Issues Paper

10 September 2019

COMPETITION • RELIABILITY • EFFICIENCY

Purpose

To assist stakeholders with their understanding of

the cost benefit analysis and charges modelling

to assist with preparing their submissions

Protocols

Respect

Ask relevant questions

Provide relevant answers

Park and move on

On time

Agenda

1 Introduction	09:00
2 Cost Benefit Analysis	09:15
3 Lunch	12:00
4 Modelling of indicative charges	12:30
5 Coffee and tea on departure	15:00

Cost Benefit Analysis

Cost Benefit Analysis

	Start
A. CBA – purpose and our approach	**9:15**
B. Grid use	
Basic set up	**9:30**
Consumers	**9:45**
Generators	**10:10**
Coffee break	**10:30**
Transmission investment	**10:45**
Investment in Batteries	**11:00**
Decomposition of benefits over time	**11:20**
C. Investment efficiencies	**11:40**

Significant long-term benefits for consumers

TPM proposal's estimated net benefit = $2.7b

- $2.36b: grid use efficiencies (net of increased costs)
- $200m: investment efficiencies (batteries)
- $145m: investment efficiencies (generation, large load, transmission, investment certainty)

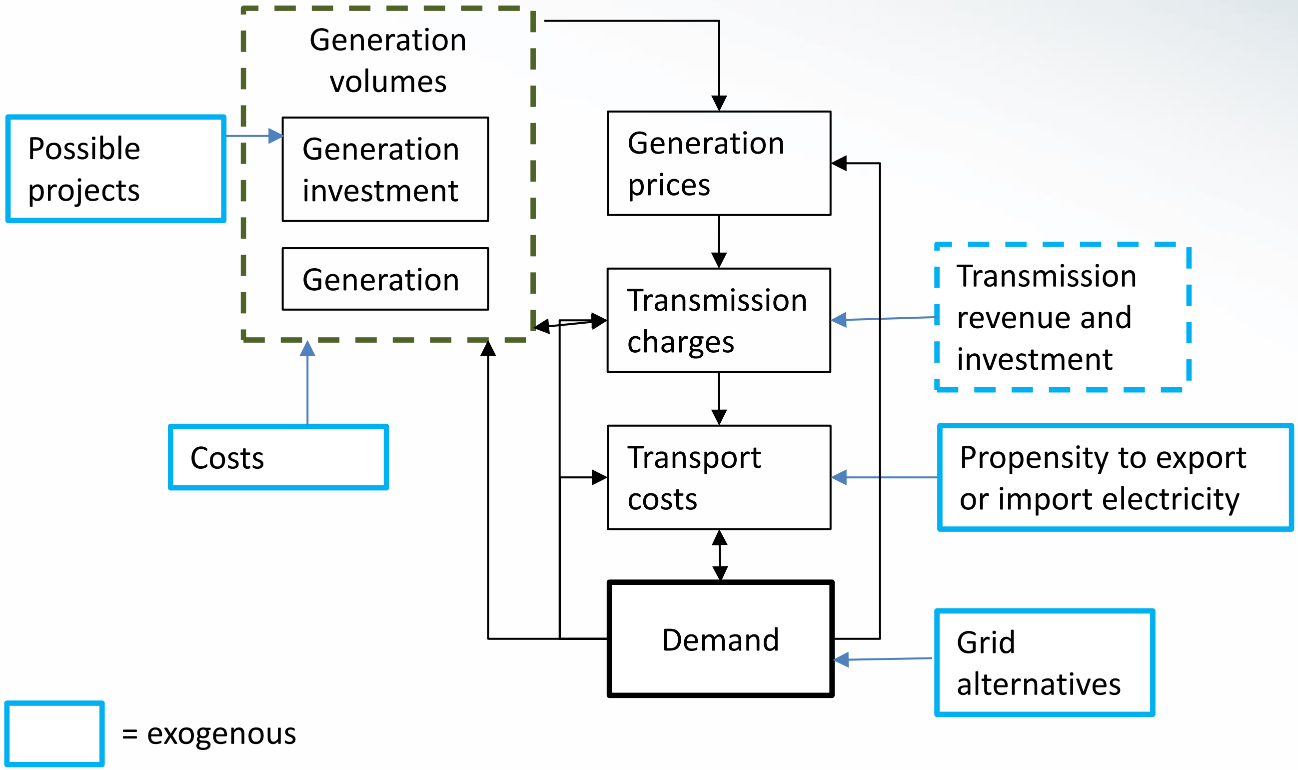
Quantified range: $0.2b – $6.4b

Some benefits not quantified, e.g. mass-market battery investment

CBA process: quantifying costs and benefits

Define the problem
Select options for addressing the problem that will be assessed
Specify the baseline to measure costs and benefits against
Identify the effects of the proposed options to address the problem
Assess the effects of the proposed options
Evaluate against decision criteria
Test the sensitivity of the results

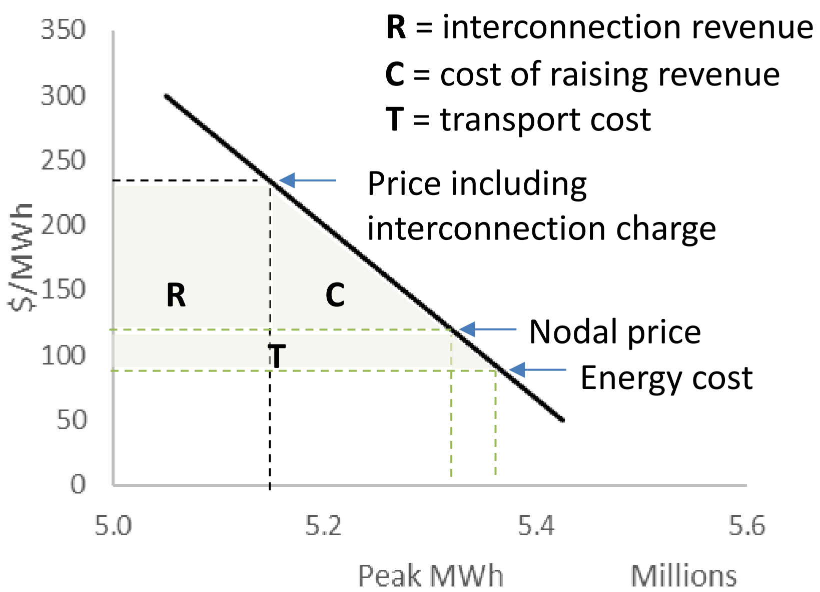
High level outline of grid use model

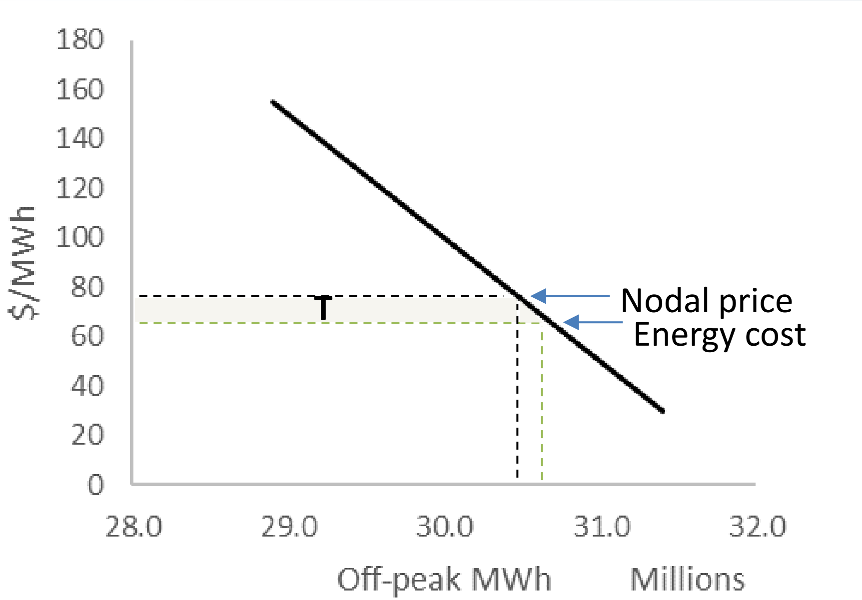


Time of use energy prices and consumer welfare

Consumer surplus under the baseline

Note: illustrative only, not to scale

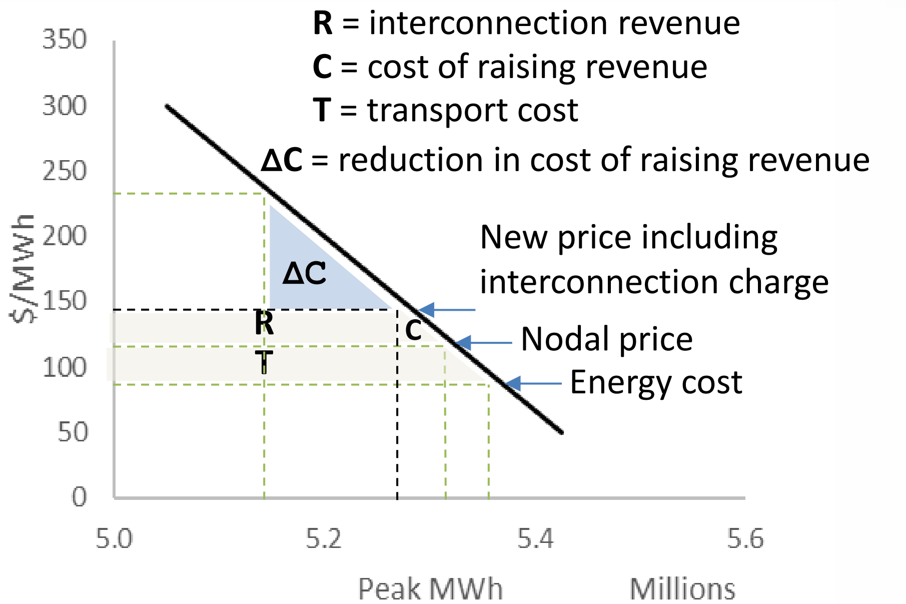


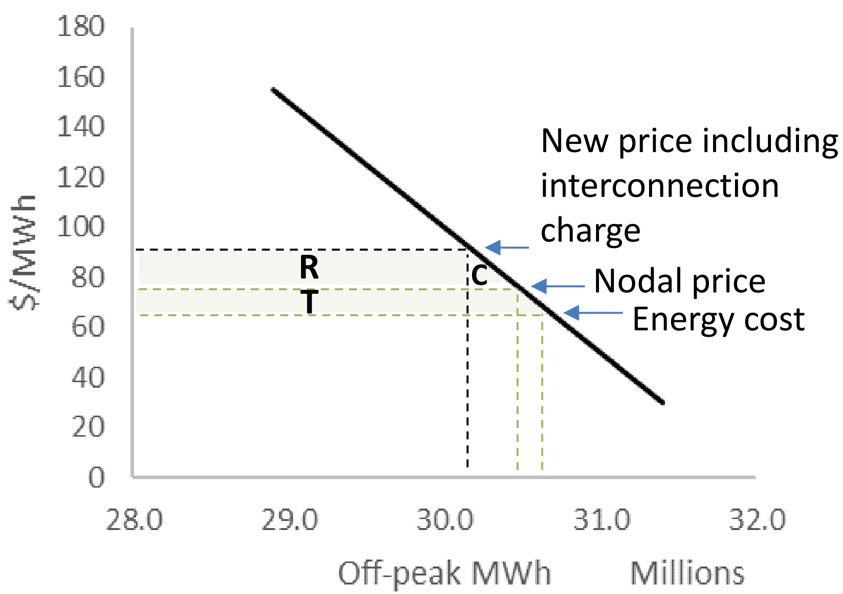


Time of use energy prices and consumer welfare

Consumer surplus under the proposal

Note: illustrative only, not to scale





Demand model(s) – elasticities

Distribution connected demand

Time of use elasticities, holding total expenditure constant

	Quantity			
Price	Peak	DG peak	Shoulder	Off peak
Peak	**-0.49**	0.03	-0.13	-0.43
DG peak	0.61	**-0.40**	-0.88	0.21
Shoulder	-0.18	-0.09	**-0.23**	-0.49
Off peak	-0.26	0.00	-0.21	**-0.55**
Expenditure	1.011	0.467	0.991	1.016

Adjusted for aggregate demand elasticity (-0.11 from dynamic panel)

	Quantity			
Price	Peak	DG peak	Shoulder	Off peak
Peak	**-0.05**	0.00	-0.01	-0.05
DG peak	0.07	**-0.04**	-0.10	0.02
Shoulder	-0.02	-0.01	**-0.03**	-0.05
Off peak	-0.03	0.00	-0.02	**-0.06**

Grid connected demand

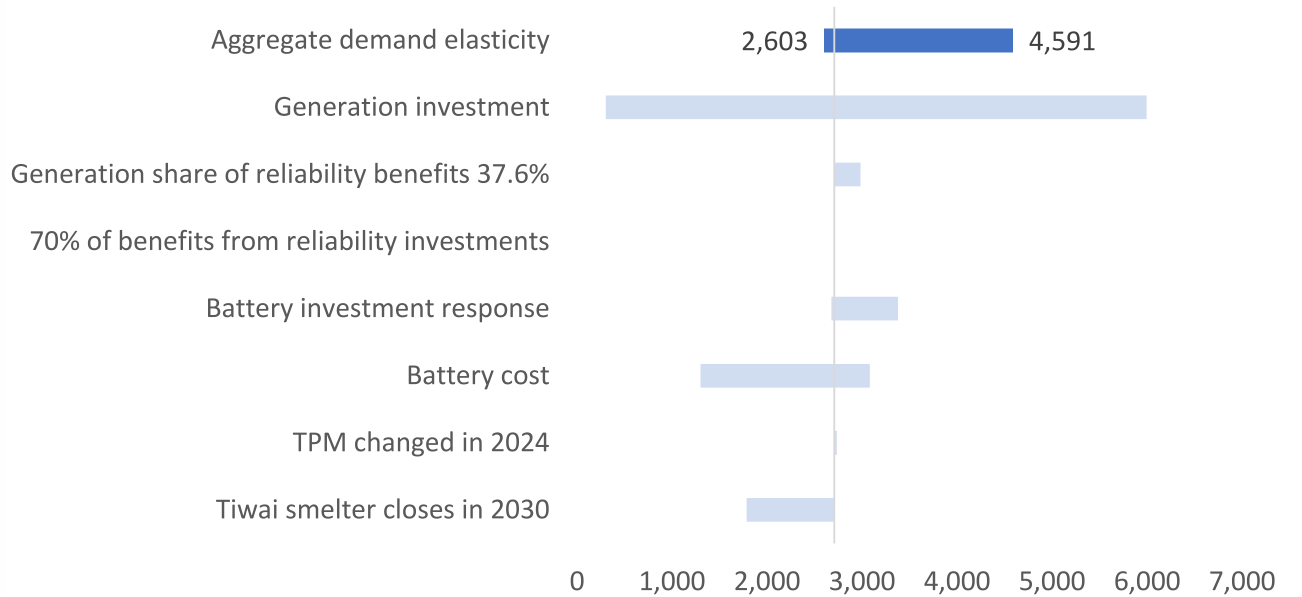
Time of use elasticities, holding total expenditure constant

	Quantity			
Price	Peak	DG peak	Shoulder	Off peak
Peak	**-0.13**	-1.08	-0.29	-0.25
DG peak	-0.02	**1.33**	-0.03	0.00
Shoulder	-0.20	-1.93	**-0.08**	-0.19
Off peak	-0.64	0.70	-0.60	**-0.57**
Expenditure	0.988	0.980	0.991	1.007

Adjusted for aggregate demand elasticity (-0.02 from cost model)

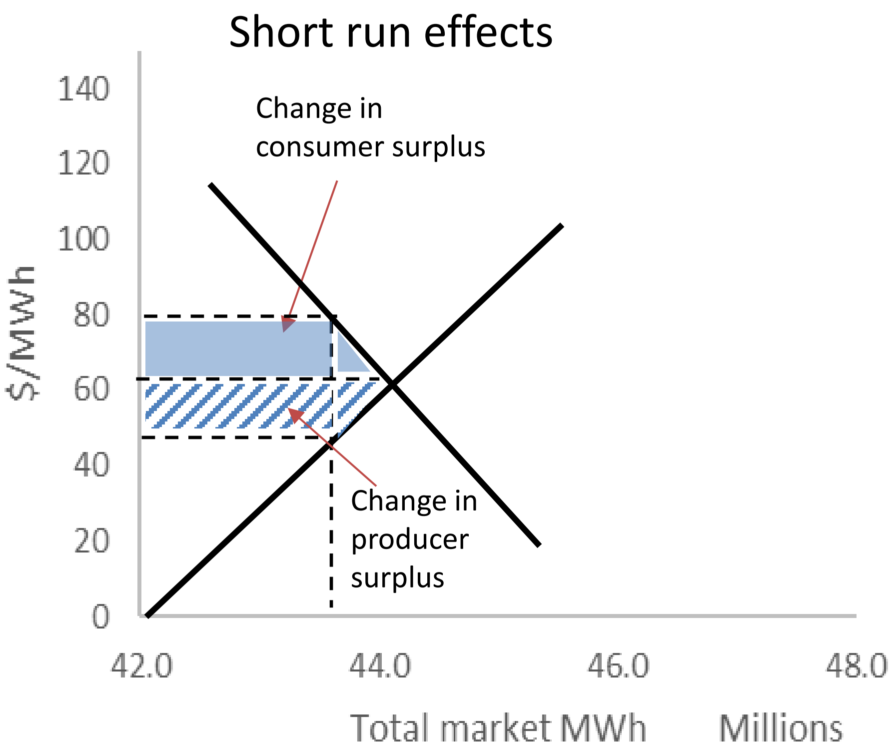
	Quantity			
Price	Peak	DG peak	Shoulder	Off peak
Peak	**-0.003**	-0.024	-0.006	-0.006
DG peak	0.000	**0.029**	-0.001	0.000
Shoulder	-0.004	-0.042	**-0.002**	-0.004
Off peak	-0.014	0.015	-0.013	**-0.012**

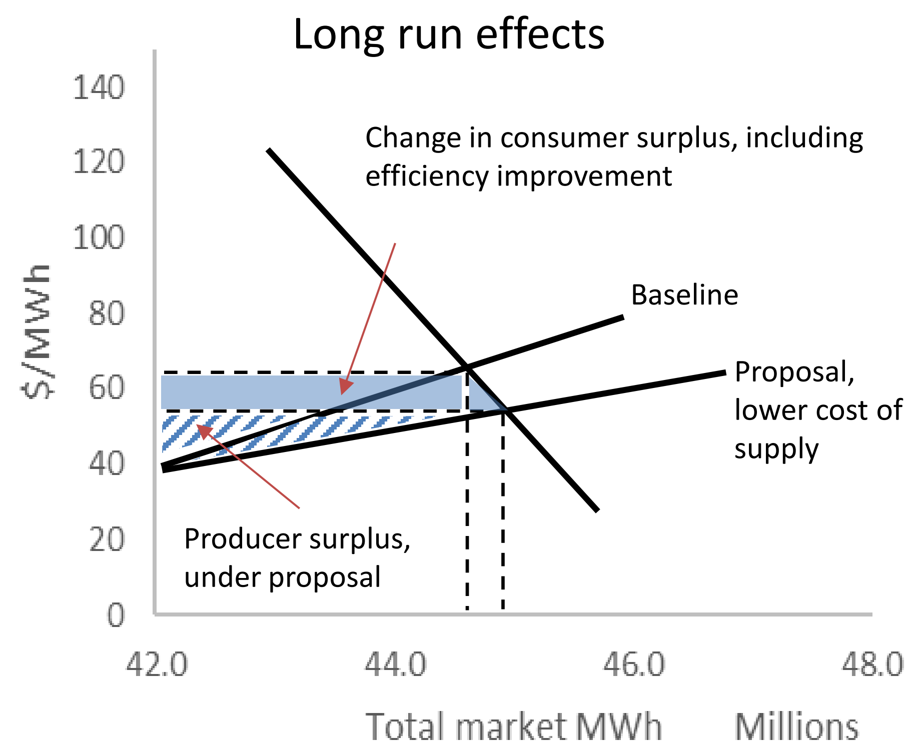
Summary of sensitivities results



Range of net benefits, relative to central scenario ($2018 millions, present value)

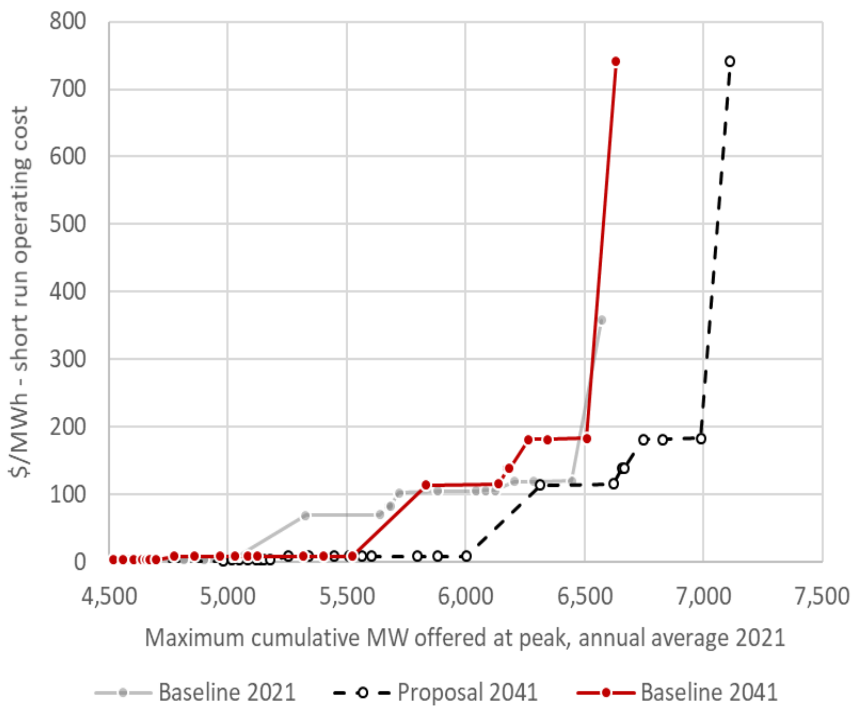
Energy costs and total surplus



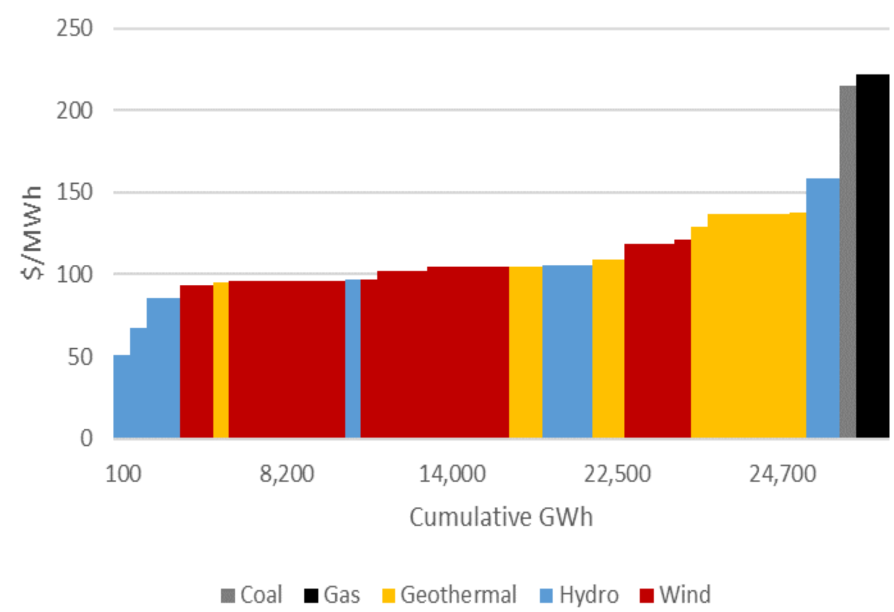


Supply modelling

Short-run costs/prices



Long-run costs, example



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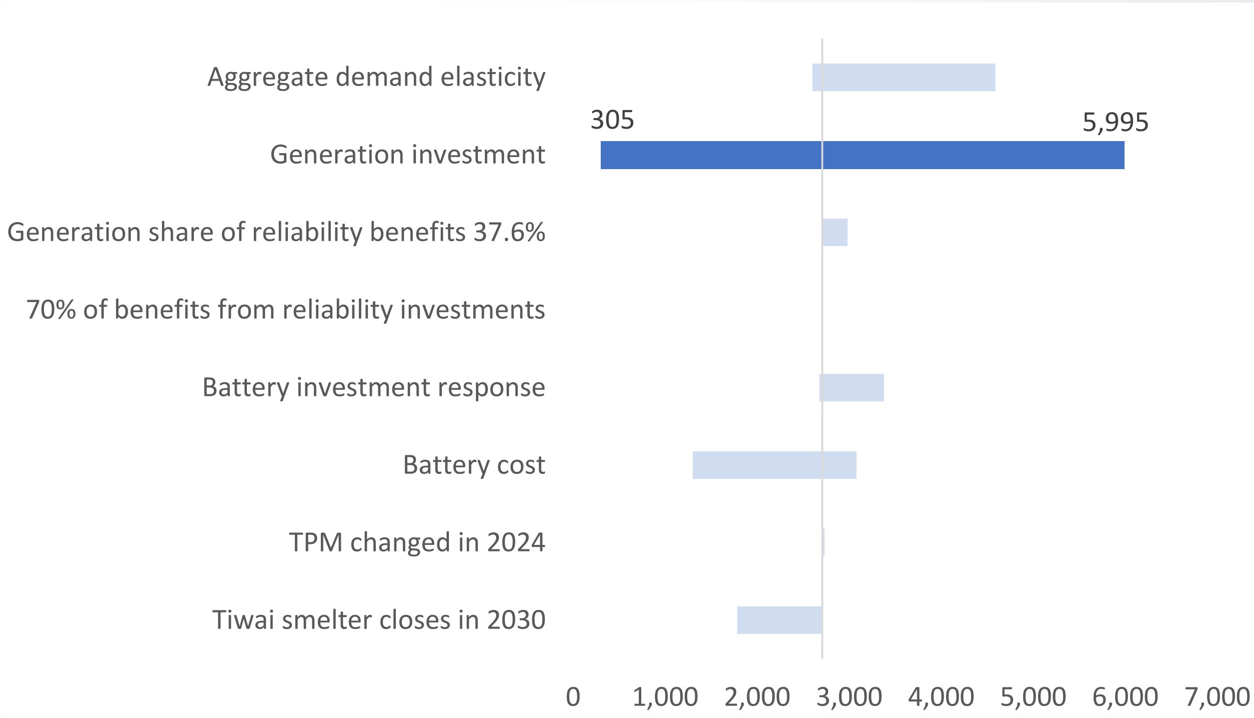


Range of net benefits, relative to central scenario ($2018 millions, present value)

Allocation of transmission revenue under proposal

7 historical transmission investments allocated to benefit-based charge

- Share of charges by backbone node determined externally to modelling

Remaining historical transmission investments allocated to residual charge

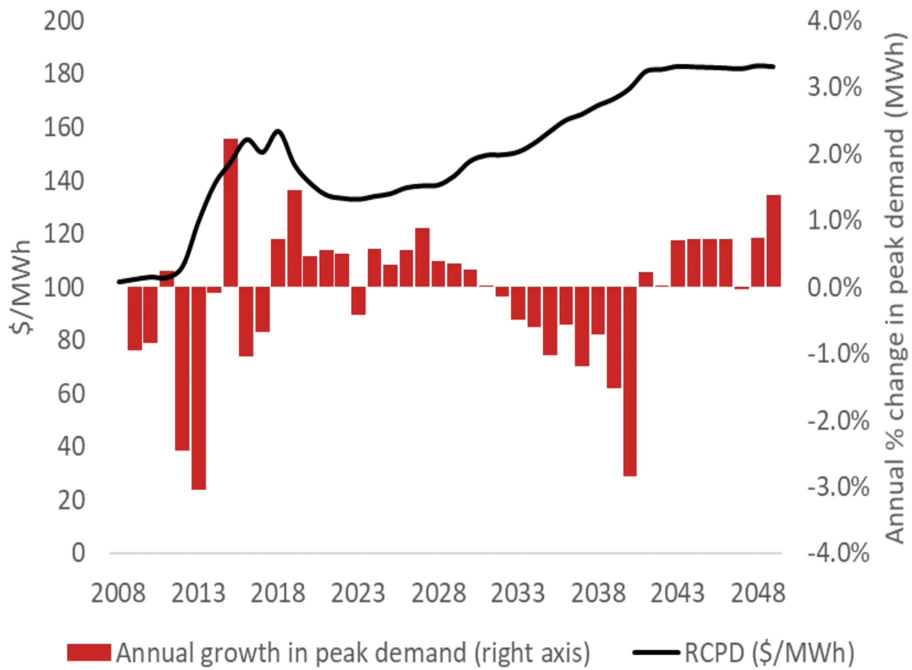
- Share of charges by backbone node determined by each backbone node's initial share, averaged over 5 years, of New Zealand historical peak demand

All future transmission expenditure allocated to benefit-based charge ex $160 million

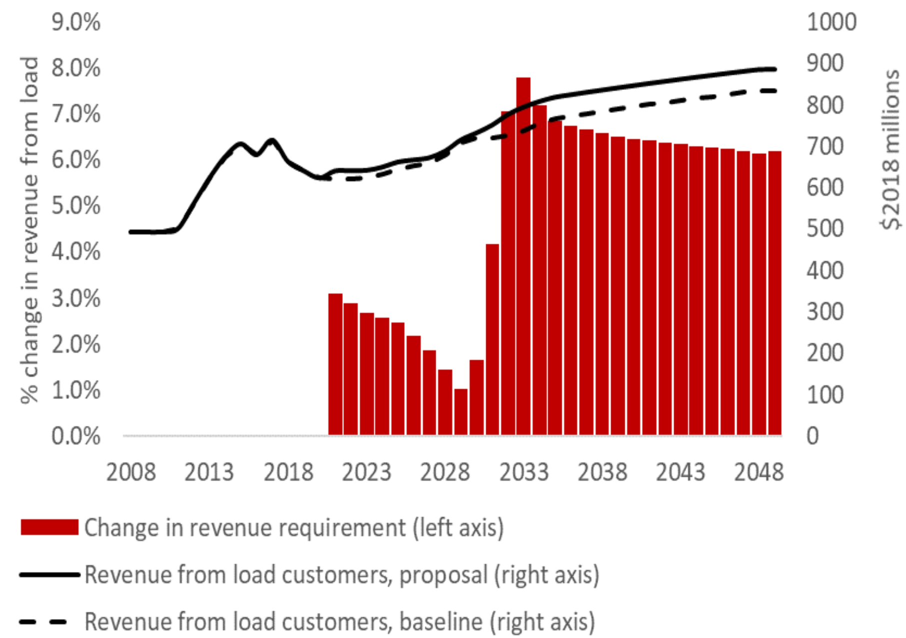
- 50% = economic – share of charges by backbone node determined by loss & constraint excess
- 50% = reliability – share of charges by backbone node determined by each backbone node's share, over previous 3 years, of average New Zealand peak MWh (demand + generation)

Transmission prices and revenue

Peak prices rise in the baseline, a battery investment effect



Transmission investment rises under the proposal, with lower battery investment



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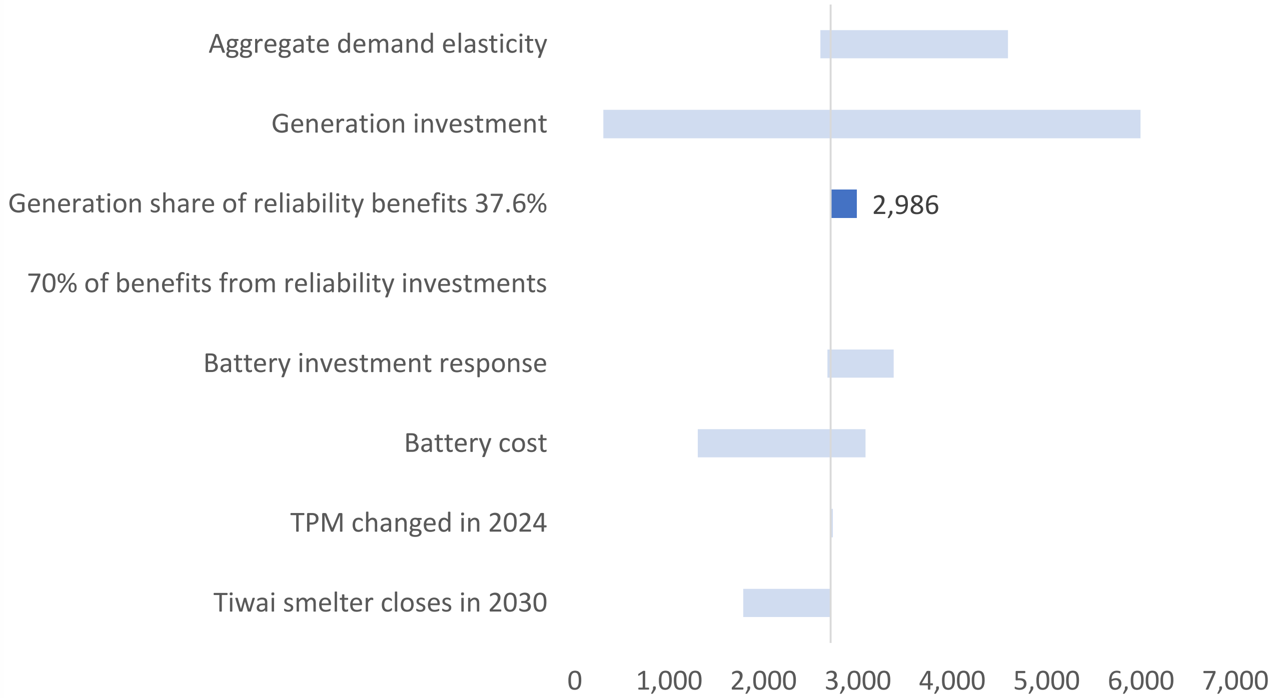


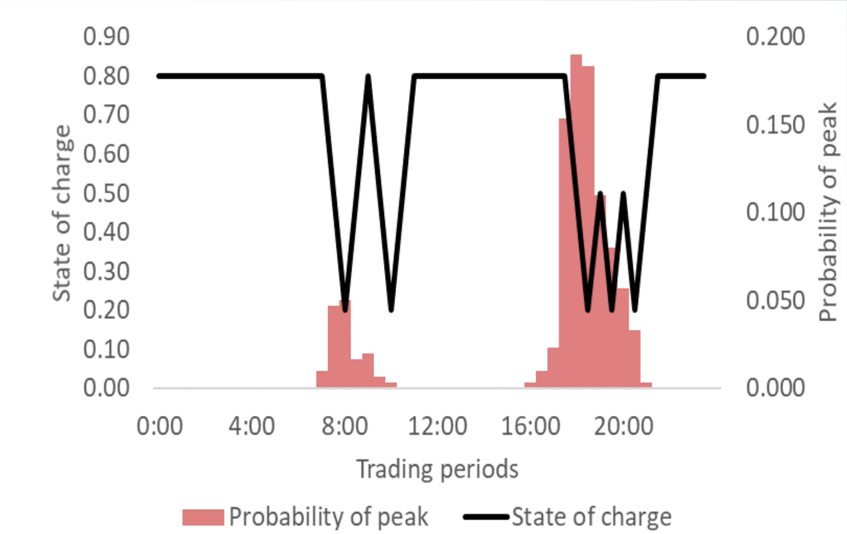
Range of net benefits, relative to central scenario ($2018 millions, present value)

Battery strategies

Probability of hitting peaks

	UNI	LNI	USI	LSI	Average
p(Peak|strategy)	0.59	0.70	0.55	0.71	0.64
Cycles/day	4	3.5	7	7	5.375
Charging at peak	0.90	0.90	0.90	0.90	0.90
Discharge at peak	1.5	1.8	1.8	1.8	1.73
Peak displacement (ratio)	0.4	0.5	0.5	0.5	0.48

E.g. Upper North Island peak avoidance



Battery cost/configuration assumptions

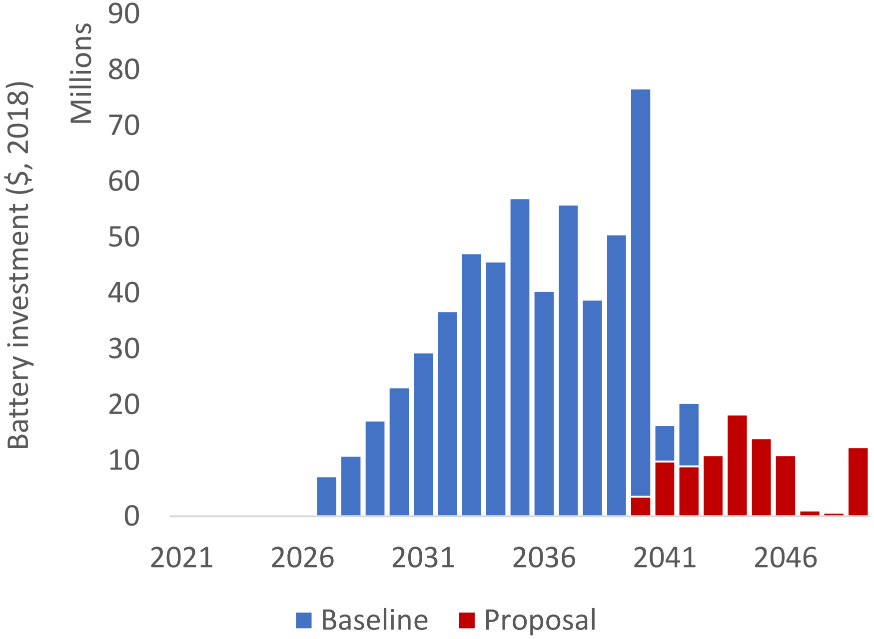
Single configuration modelled

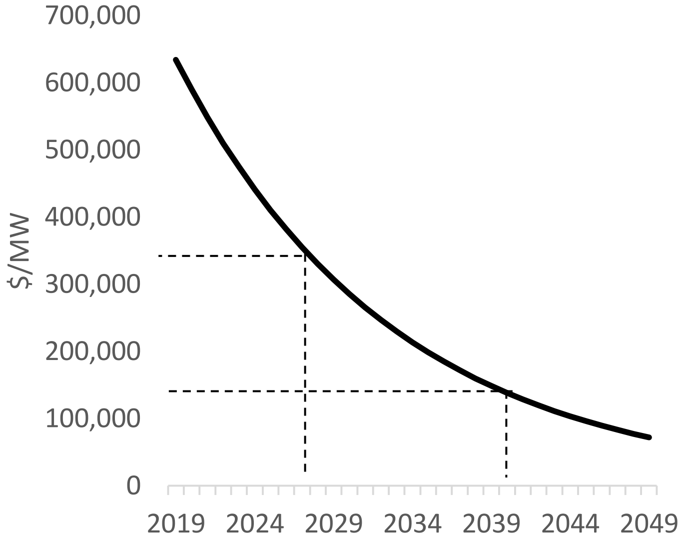
Assumed battery configuration (2017)	
Battery life (years)	15
Capacity (MW)	1
Capital cost ($/kW)	733
Fixed O&M (p.a., % capital cost)	1%
E/P ratio	1.29
Round trip efficiency	0.9
Discharge/Charge (h), constant power	1
Present value fixed O&M ($/MW)	62,741
Present value fixed cost ($/MW)	795,741

Assumptions about effects on system

Assumed effects of batteries on energy demand	MW
For each additional MW of DG	
1 MW DG/battery capacity means DG output increases by	0.80
of which peak grid demand declines by	0.38
with charging at peak of	0.41
while charging occurs at shoulder	0.19
and charging occurs during off-peak periods	0.20

Accelerated battery investment





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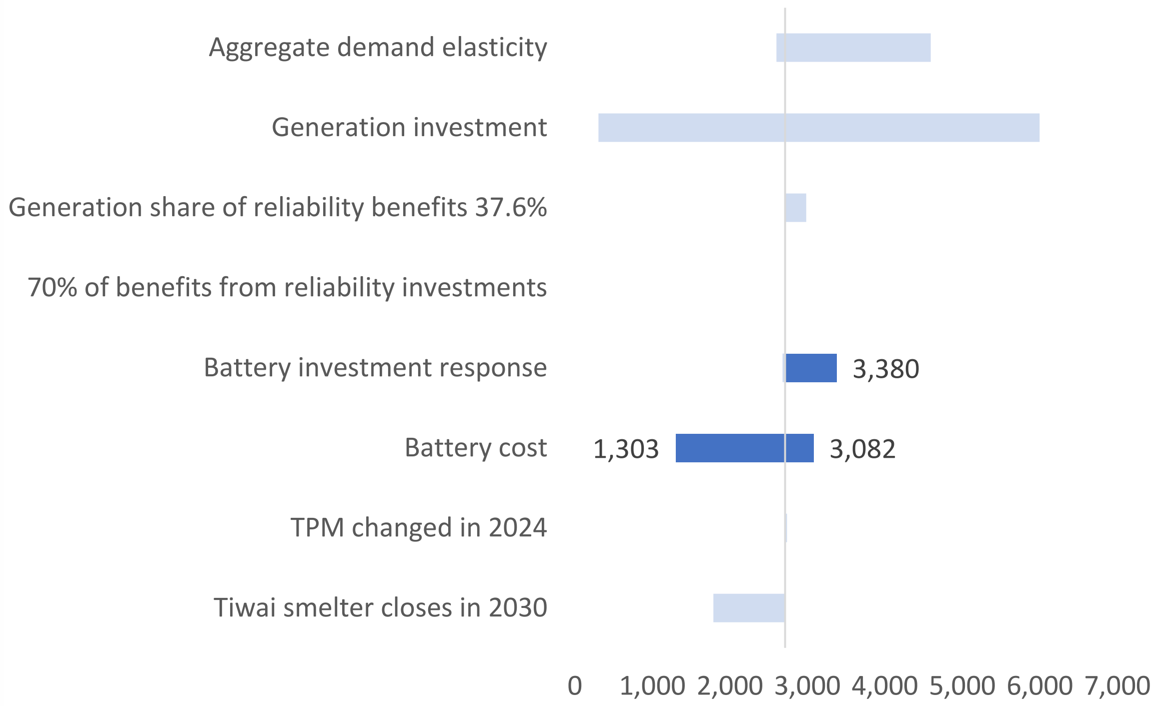
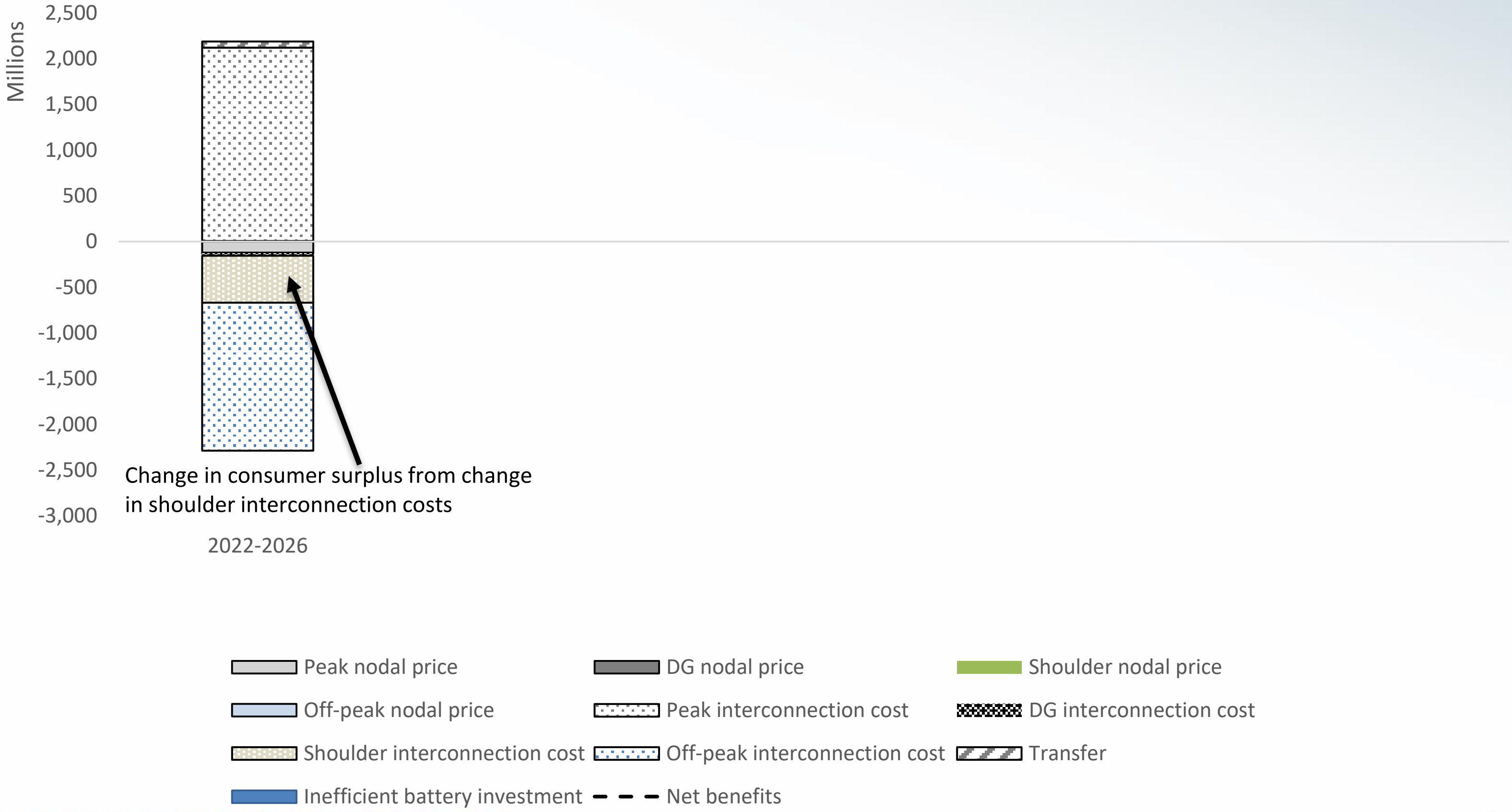
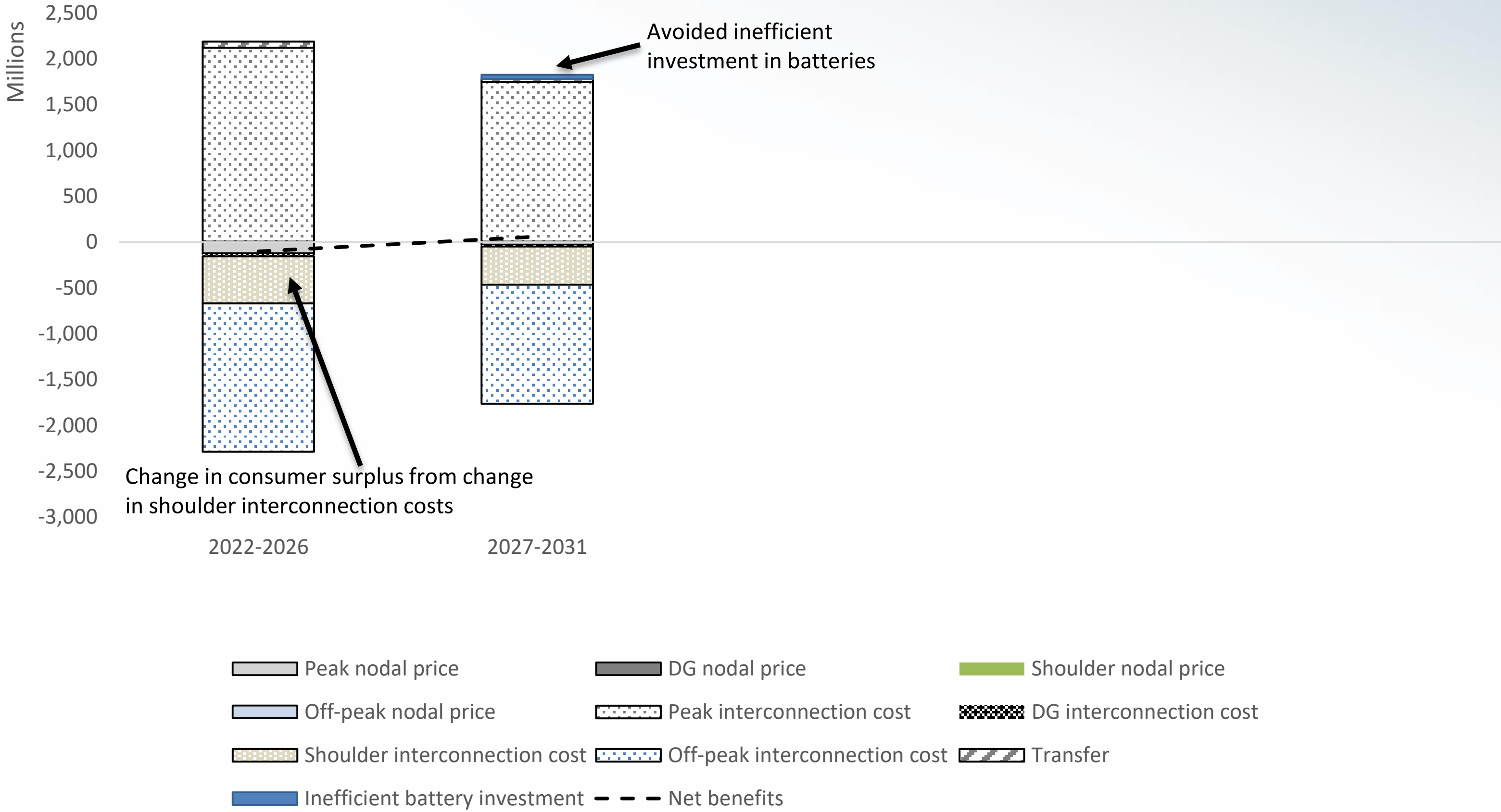


Range of net benefits, relative to central scenario ($2018 millions, present value)

Decomposition of grid use benefits (discounted)



Decomposition of grid use benefits (discounted)



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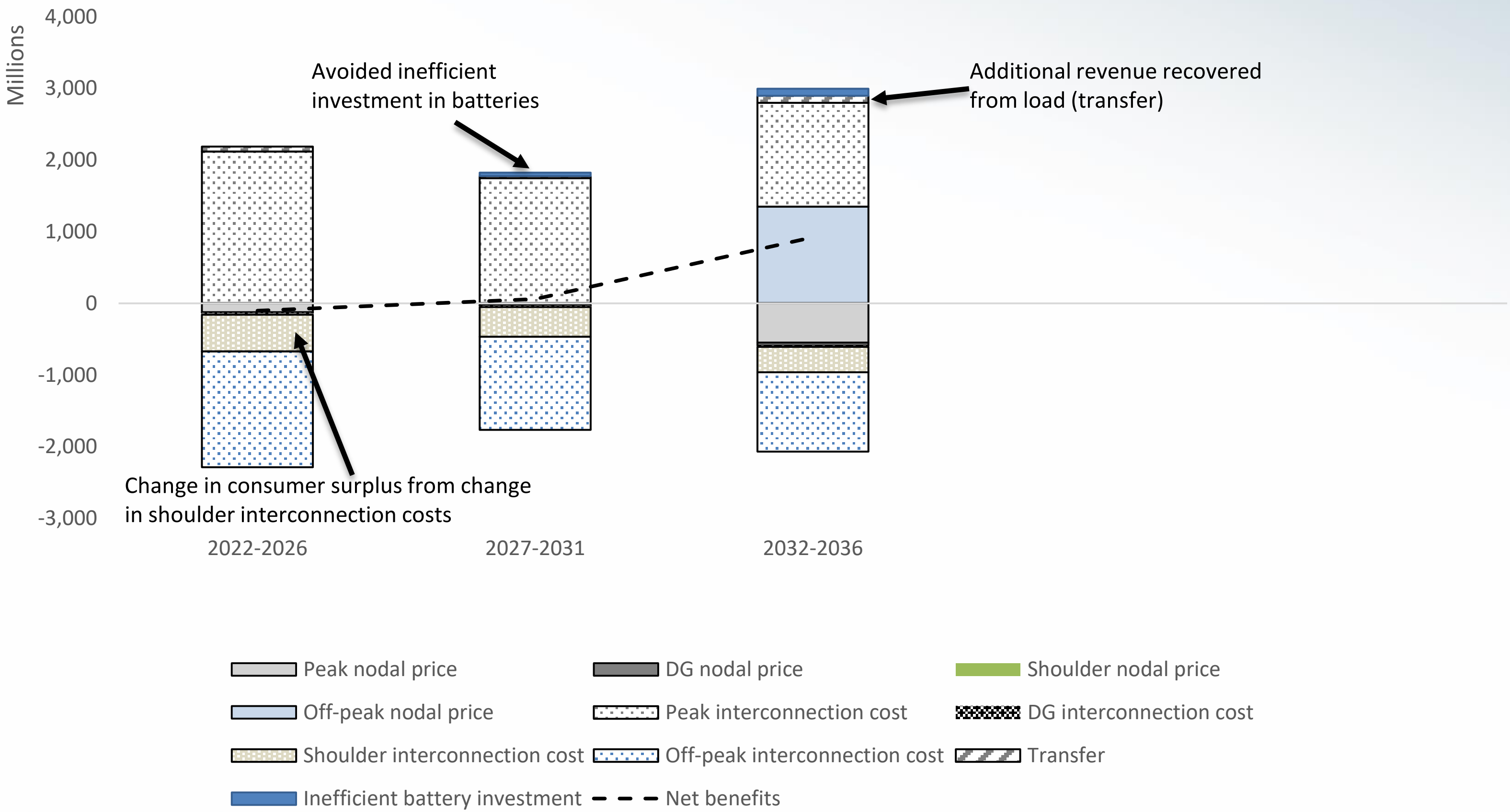

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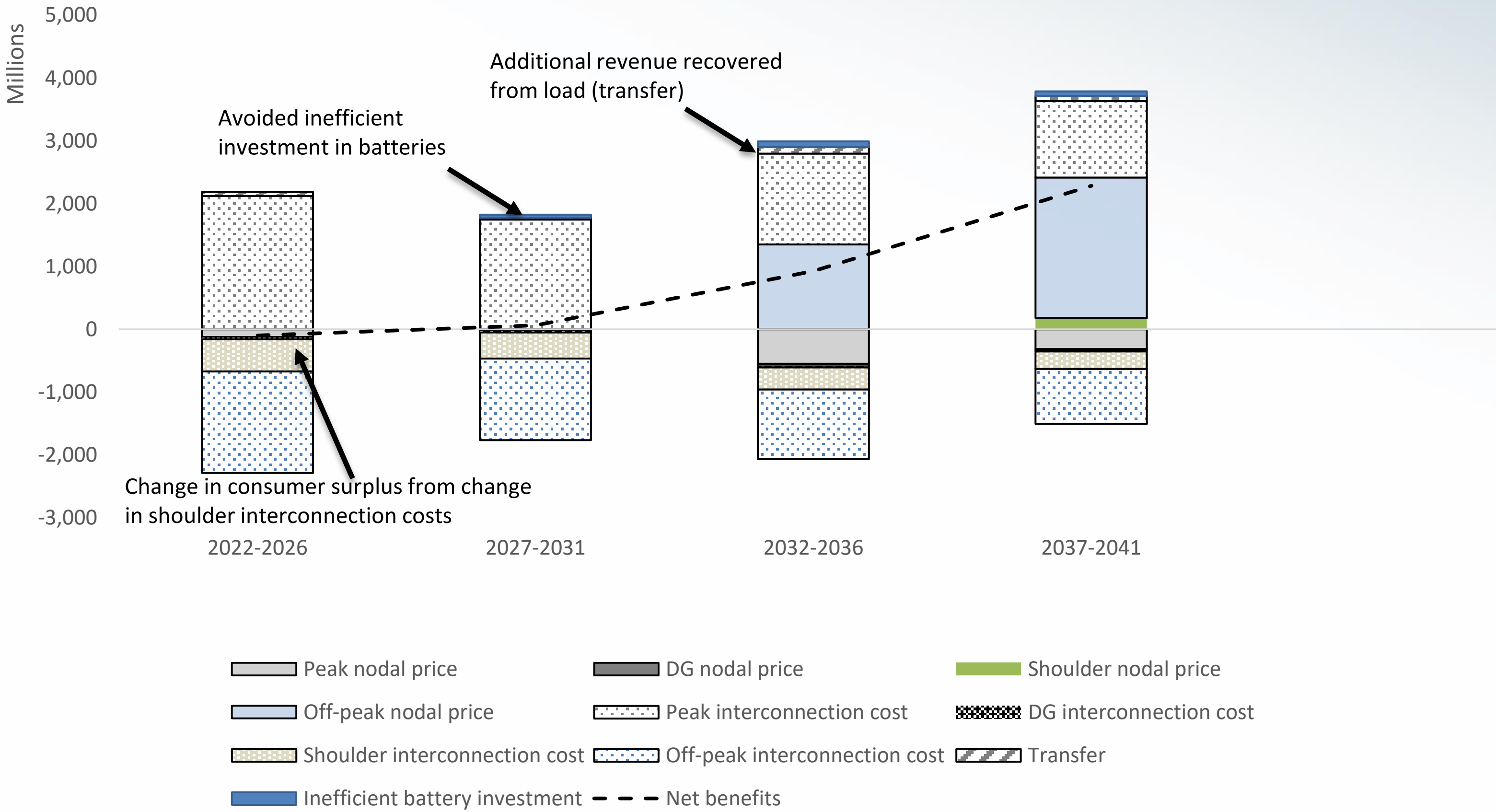

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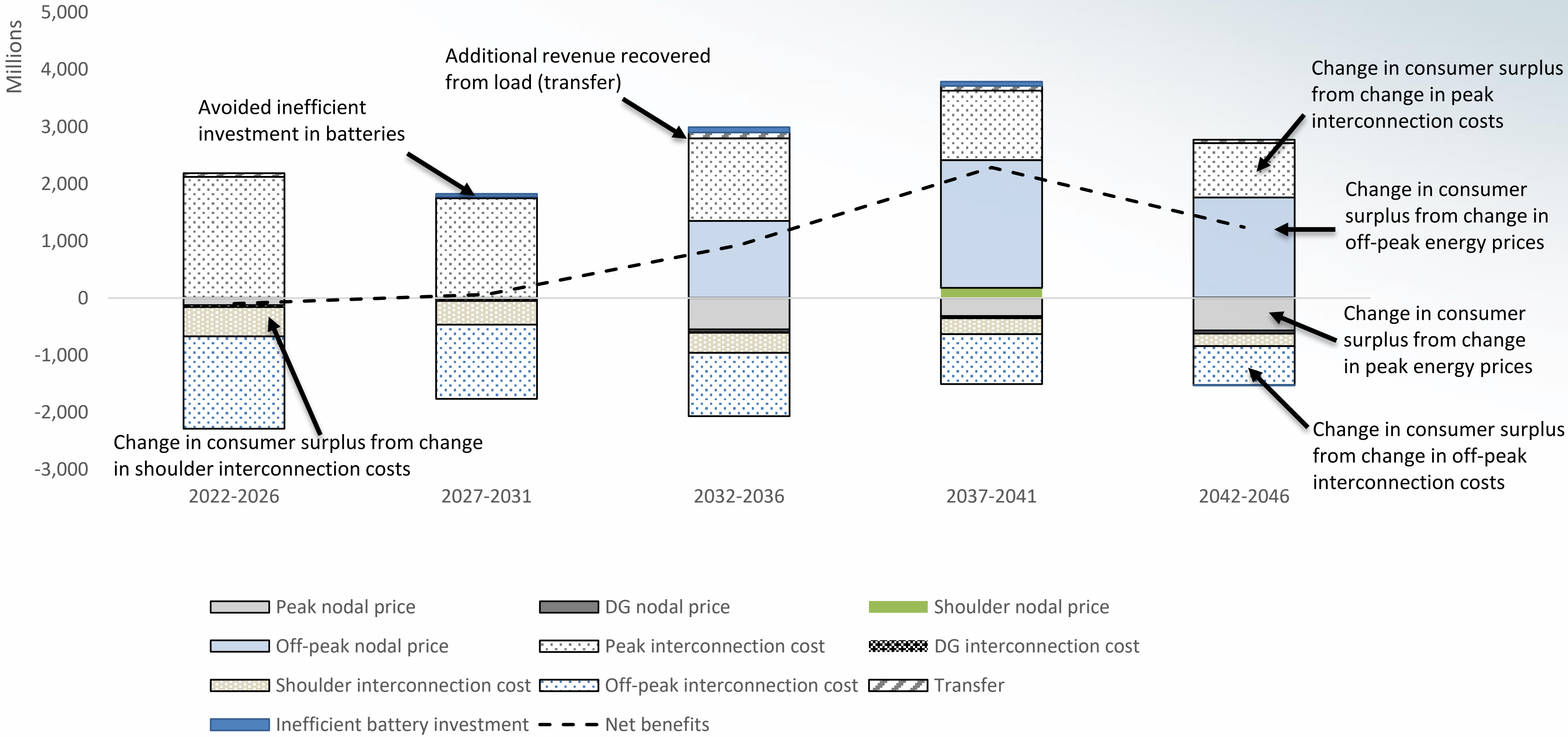


Non-battery investment benefits

	Central ($m)	Lower sensitivity ($m)	Upper sensitivity ($m)
More efficient investment in generation & load	42	8.9	110.7
Reduced uncertainty for investors	26	9.8	48.3
Scrutiny of major capex	46	22.8	68.4
Scrutiny of base capex	31	6.3	56.4
Total	**146**	48	284

Benefits from greater transmission investment scrutiny

Closer scrutiny modelled as productivity gain – depends on type of capex:

- 4% (sensitivities: 2% and 6%) for major capex reviewed by ComCom
- 4% (sensitivities: 2% and 6%) for E&D base capex not reviewed by ComCom
- 2% (sensitivities: 1% and 3%) for E&D base capex reviewed by ComCom
- 2% (sensitivities: 1% and 3%) for R&R base capex that could be covered by deeper connection charges and which has been reviewed by ComCom
- 1% (sensitivities: 0% and 2%) for R&R base capex that could not be covered by connection charges or deeper connection charges and which has been reviewed by ComCom

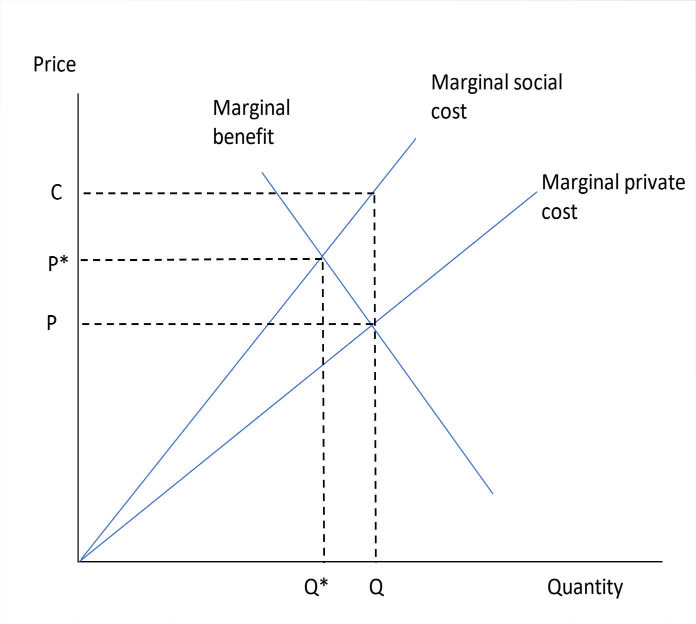
More efficient investment by generators and large consumers

Top-down analysis

Assessing net benefit from generator / consumer in a region not making investment / consumption decision requiring transmission investment

Externality framework used:

- marginal private cost < marginal social cost
- socially optimal quantity of transmission investment: Q*, not Q



Excess demand for electricity transmission when transmission price does not reflect marginal social cost

Benefits from increased certainty for investors

Uncertainty increases:

- Value of delaying investment
- Level of private benefits required to trigger an investment

We draw on findings from USA, UK and NZ studies

- Electricity
- Telecommunications
- Economy-wide

Case study: Undergrounding transmission in Auckland

Transpower's blueprint for Auckland includes undergrounding new 220 kV lines between 2030 and 2050

- Brownhill Road to Otahuhu (as part of North Island Grid Upgrade)
- Pakuranga to Albany

We are concerned about <u>change</u> in probability of economically inefficient investment in undergrounding Auckland's urban transmission lines

Assume 25% change in probability between baseline and proposal

Sensitivities: 0% and 50%

Costs

(pp35-40 were not able to be presented at workshop)

Costs

Quantified costs	Proposal ($m)	Alternative ($m)
TPM development / approval	8 (4 - 12)	6 (3 - 8)
TPM implementation costs	9 (4 - 13)	4 (2 - 5)
TPM operational costs	9 (5 - 14)	0.3 (0.2 - 0.5)
Grid investment brought forward	188 (51 - 324)	135 (6 - 264)
Load not locating in regions with recent grid investment	1 (0 - 2)	--
Efficiency costs of price cap	1	--
Total quantified costs	215 (65 - 366)	144 (11 - 278)

Cost to develop, implement, operate TPM

Have drawn on 2016 Transpower cost information

- 2019 proposal ≈ Transpower's "high complexity" solution to 2016 proposal
- 2019 alternative ≈ Transpower's "low complexity" solution to 2016 proposal

Have based estimated stakeholder submission costs on types of TPM submissions received since 2011 — wide range of estimated costs:

- Lengthy, with reports / supporting material from 3 or 4 subject matter experts
- Internally prepared with no external advice, including e-mail, social media post

Cost to develop, implement, operate TPM (cont)

Key changes to 2016 Transpower cost information

- From “high complexity” solution, remove our estimate of:
  - Transpower cost for additional components in 2016 proposal
  - Transpower cost to determine charges for 7 historical investments
- From “low complexity” solution:
  - Remove our estimate of Transpower cost to develop, implement and operate a benefit-based charge
  - Include our estimate of Transpower cost to develop, implement and operate MWh residual charge and proposed PDP

Cost to develop, implement, operate TPM (cont)

Key TPM development / implementation / operation assumptions:

- Continuation of same amount of sharing of expert resources by submitters seen since 2011
- Transpower does two rounds of formal/structured engagement with stakeholders during TPM development process
- Transpower does not establish TPM working group to assist in detailed design of proposed TPM
- 50% of distributors require IT changes
- A PDP assessment occurs once every 3 years
- 1/3 of transmission customers engage every 10 years in process for optimising a transmission investment

Cost of load not locating where recent transmission capacity investment

Demand may be displaced from a region with recent transmission investment

Inefficiency arises if:

- Displaced demand relocates to another region, and
- Speed and scale of transmission investment in other region exceeds need for incremental transmission investment in region with higher recent transmission investment and higher benefit-based charges

Cost of load not locating where recent transmission capacity investment (cont)

Model cost of bringing forward transmission investment in region to which displaced demand relocates – consider:

- Quantity of displaced demand that relocates to other region
  - NB: non-electricity factors in demand location decision
- How much sooner transmission investment in other region occurs

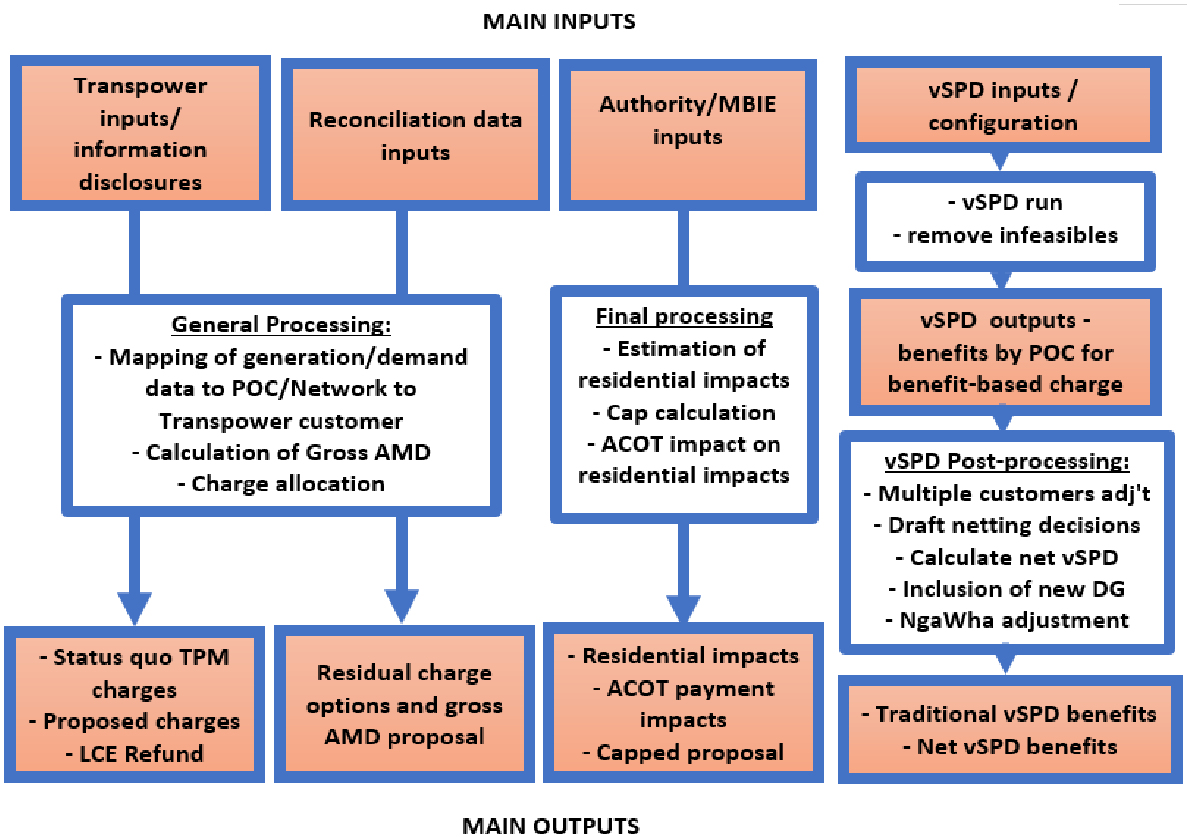
Modelling the transmission charges

Modelling of indicative charges

	Start
A. Indicative charges	**12:30**
B. Benefit based charges – allocators for historical assets	
vSPD modelling approach	12:45
Virtual price offers (VPO)	13:30
Netting approach	13:45
C. Residual charges	14:00
D. Cap	14:45
E. Afternoon tea on departure	**15:00**

Indicative charges introduction

EMI file structure – impacts modelling structure

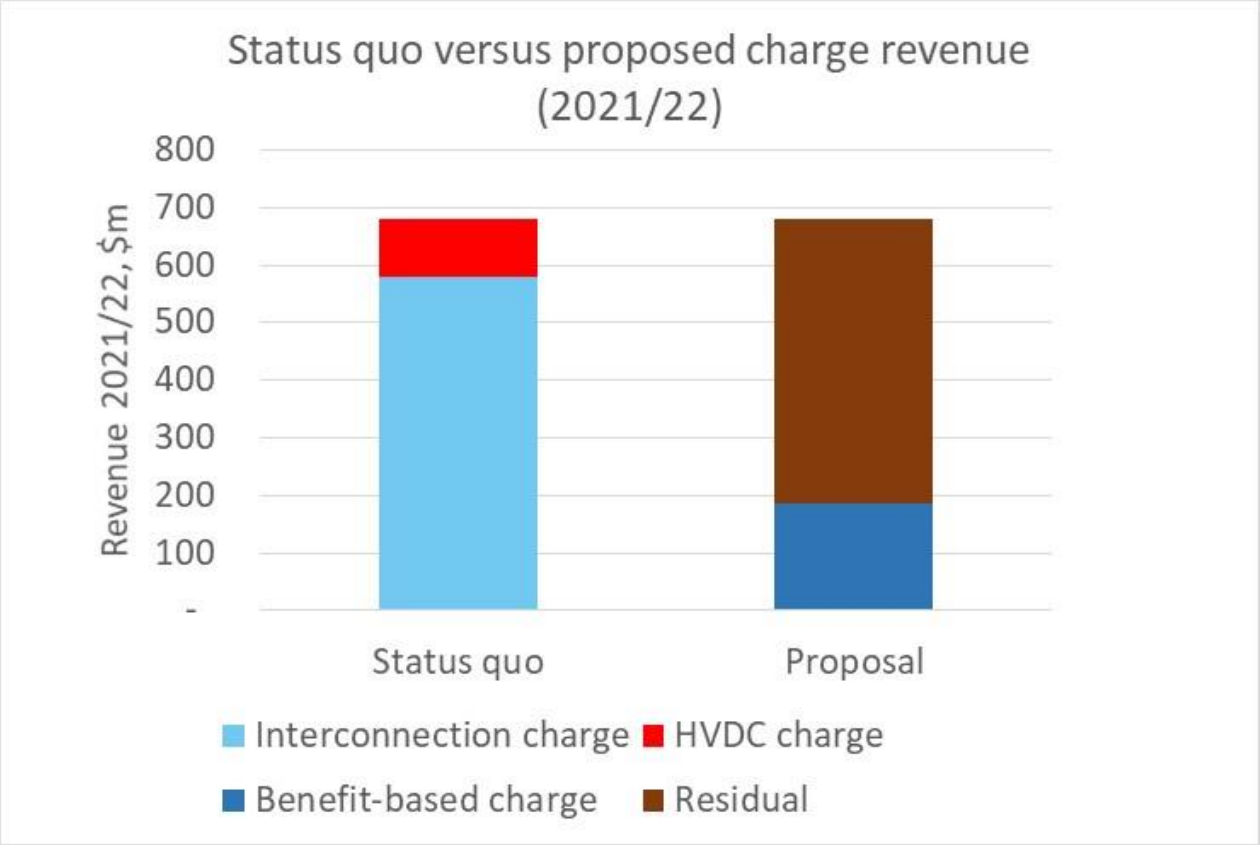


EMI files address: https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis
File name: README_GUIDE TO IMPACTS ANALYSIS FILES"

Indicative charges at implementation

TPM Revenue Draft determination 21/22	$848m
Less connection charge	-$111m
Less PDP	-$3m
Less LCE revenues	-$55m
Recover via Benefit-based and residual charge	**$679m**

Proposed charges, 2021/22 pricing year



EMI Ref: File "2019 Proposal impacts modelling" Sheet "Forecast TPM revenue.

Walkthrough of SQ charge

- EMI file “2019 Proposal impacts modelling”, Sheet “Results”, Column H.
- Also sheet “Current TP charges”.
- 2019-2020 TPM from disclosure = $926m ($129m connection, $797m IC + HVDC)

Data and adjustment process

- ***'Please review your quantities/reference data, and advise us in submissions if there are any issues'***
- Refer EMI File "2019 Proposal impacts modelling", sheet "Reconciliation maps 15042019"
  - **Column A: POC_Network**
  - **Column F: Transpower customer**
  - **Columns H to K: Gross Flow – 4 years in kWh**
- Ie. POC_Network (ie, BDE0111_RAYN … Brydone_Rayonier Limited) = Unique ref

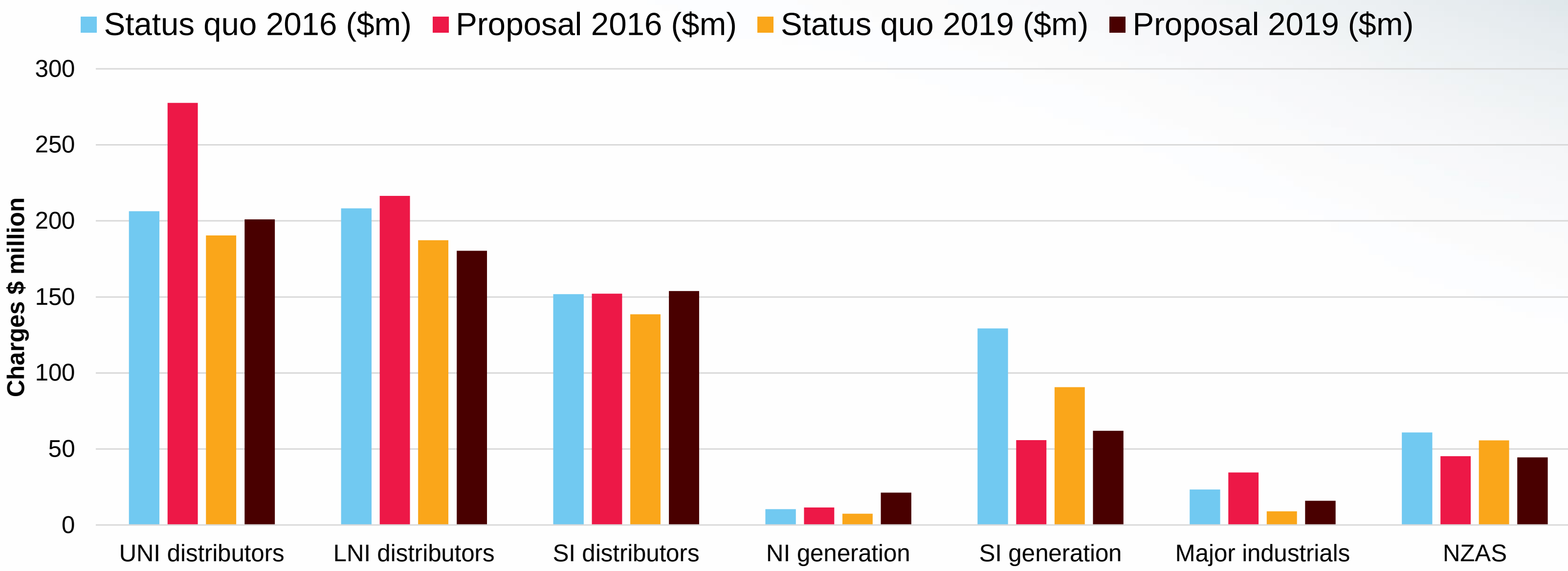
Schedule 1 is proposed, not indicative

- ***'Please review your quantities/reference data, and advise us in submissions if there are any issues'***

Schedule 1 Annual benefit-based charges for the benefit-based investments

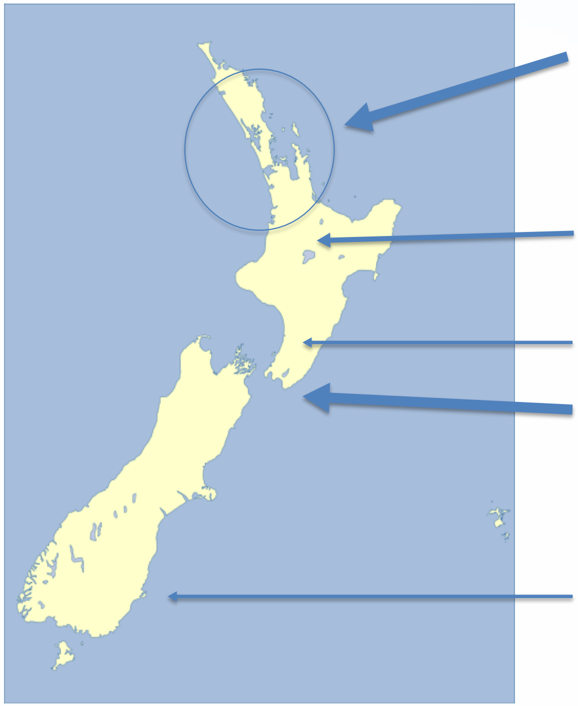
	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive
Alpine Energy	3.11%	0.85%	1.49%	2.98%	0.30%	0.24%	0.30%
Aurora Energy	5.71%	1.57%	0.90%	4.48%	0.30%	0.27%	0.30%
Beach Energy Resources (Kupe)	0.03%	0.07%	0.10%	0.08%	0.03%	0.04%	0.03%
Buller Electricity	0.27%	0.08%	0.12%	0.20%	0.03%	0.02%	0.03%
Centralines	0.07%	0.21%	0.24%	0.17%	0.05%	0.01%	0.05%
Contact Energy	2.11%	12.55%	23.98%	0.09%	5.96%	21.25%	5.96%
Counties Power	0.32%	1.06%	1.08%	0.85%	2.62%	1.41%	2.62%

Comparison of indicative charges: 2016 and 2019 proposals



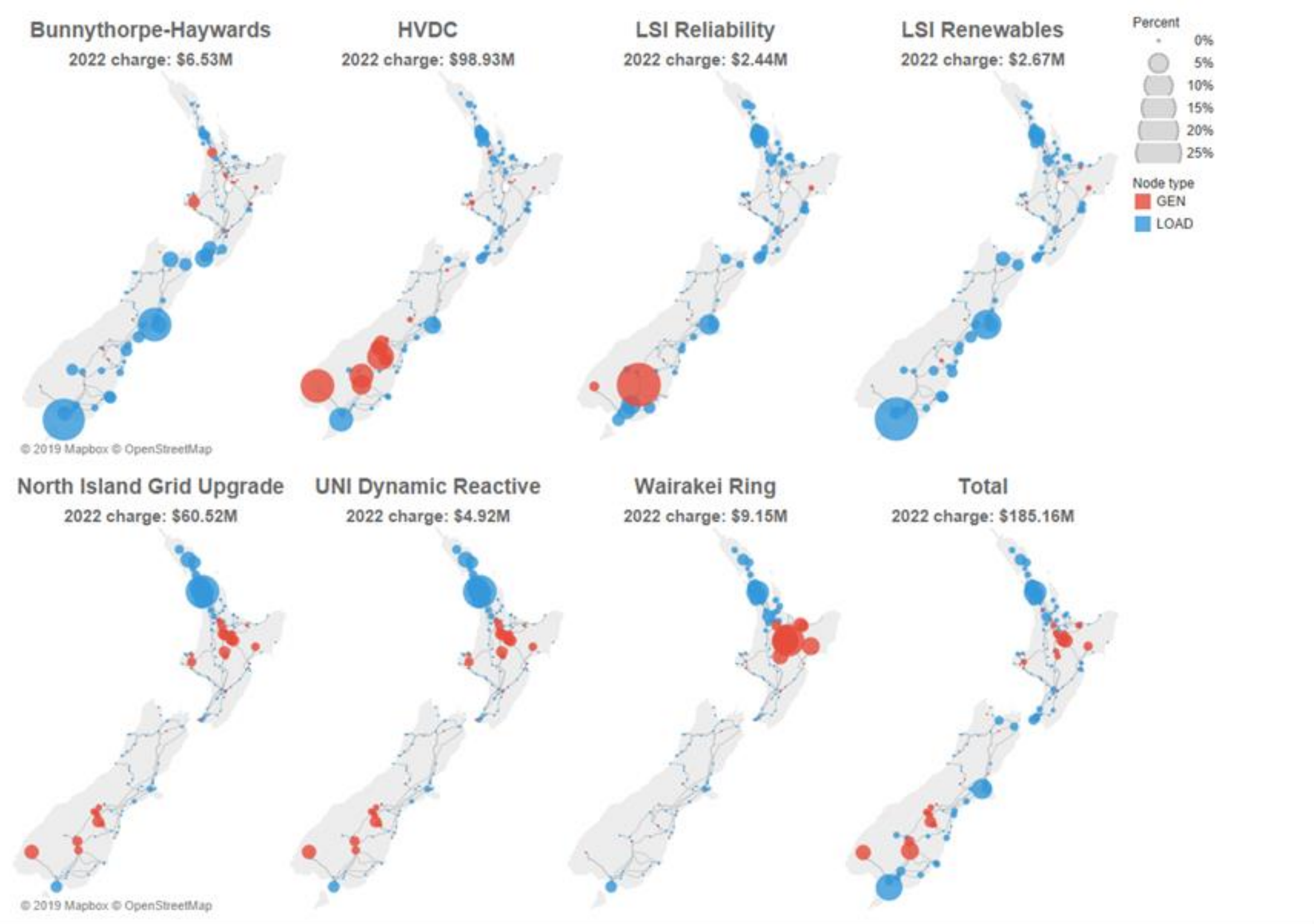
Benefit-based charge

Benefit-based charge for 7 historical investments



- NIGU ($876m)
- UNI reactive ($110m)
- Wairakei Ring ($141m)
- BPE-HAY reconductoring ($161m)
- HVDC Pole 2
- HVDC Pole 3 ($673m)
- LSI reliability ($62m)
- LSI renewables ($197m)

Investment	Modelled amount recovered ($m in 2022)
NIGU	60.50
UNI dynamic reactive support	4.90
Wairakei Ring	9.10
BPE-HAY reconductoring	6.50
HVDC (Poles 2 and 3 combined)	98.90
LSI Reliability	2.40
LSI Renewables	2.70



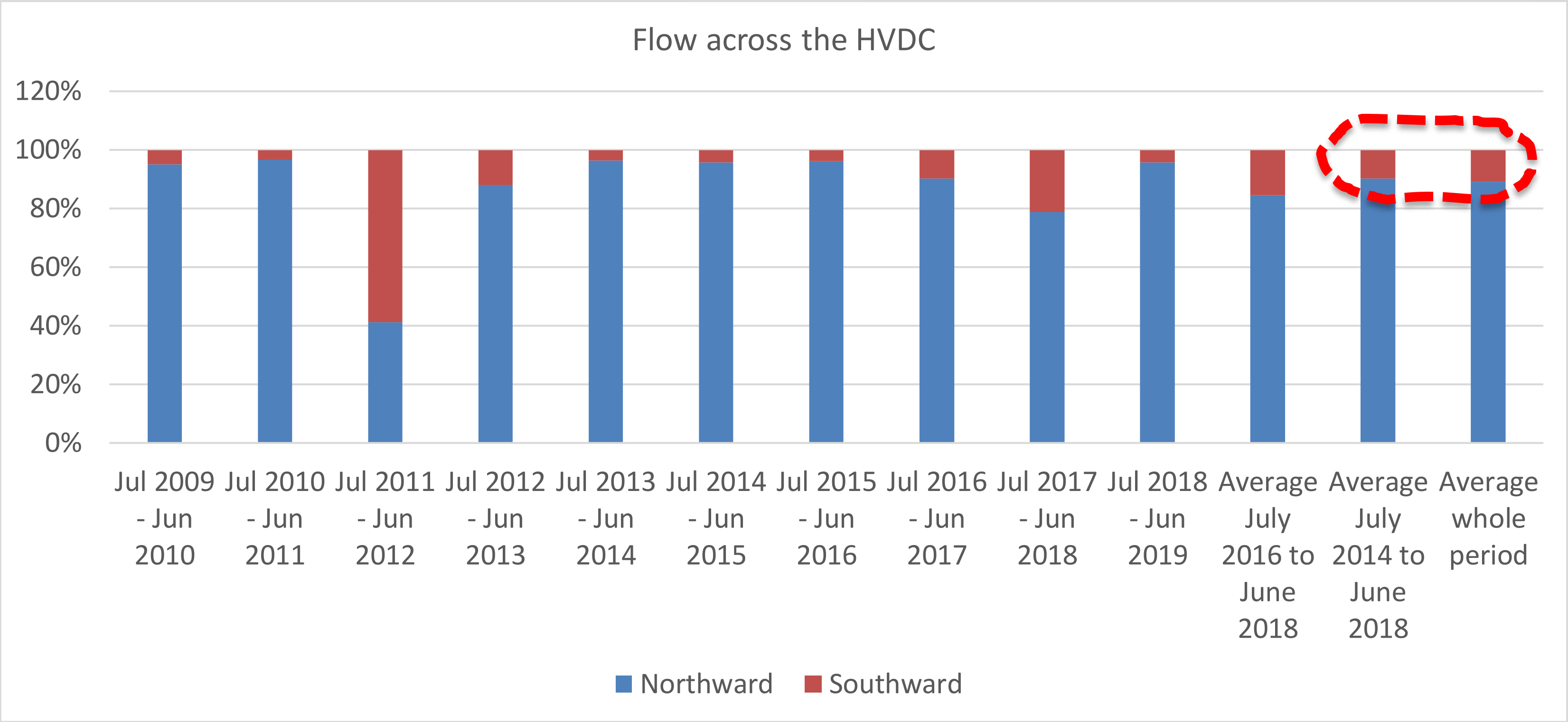
We used vSPD to estimate who benefits from each of seven recent major investments

vSPD modelling approach

Ex post vSPD versus forecast vSPD

- 2019 proposal – ex post vSPD as a proxy for future benefits
  - 4 recent past years selected

Datasets – a broadly representative time period



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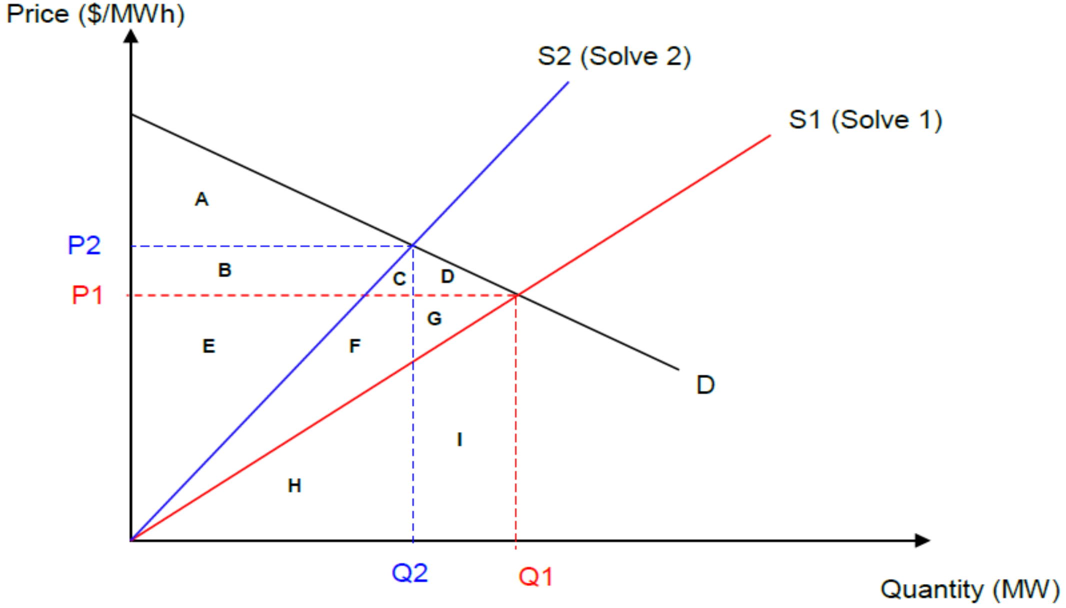
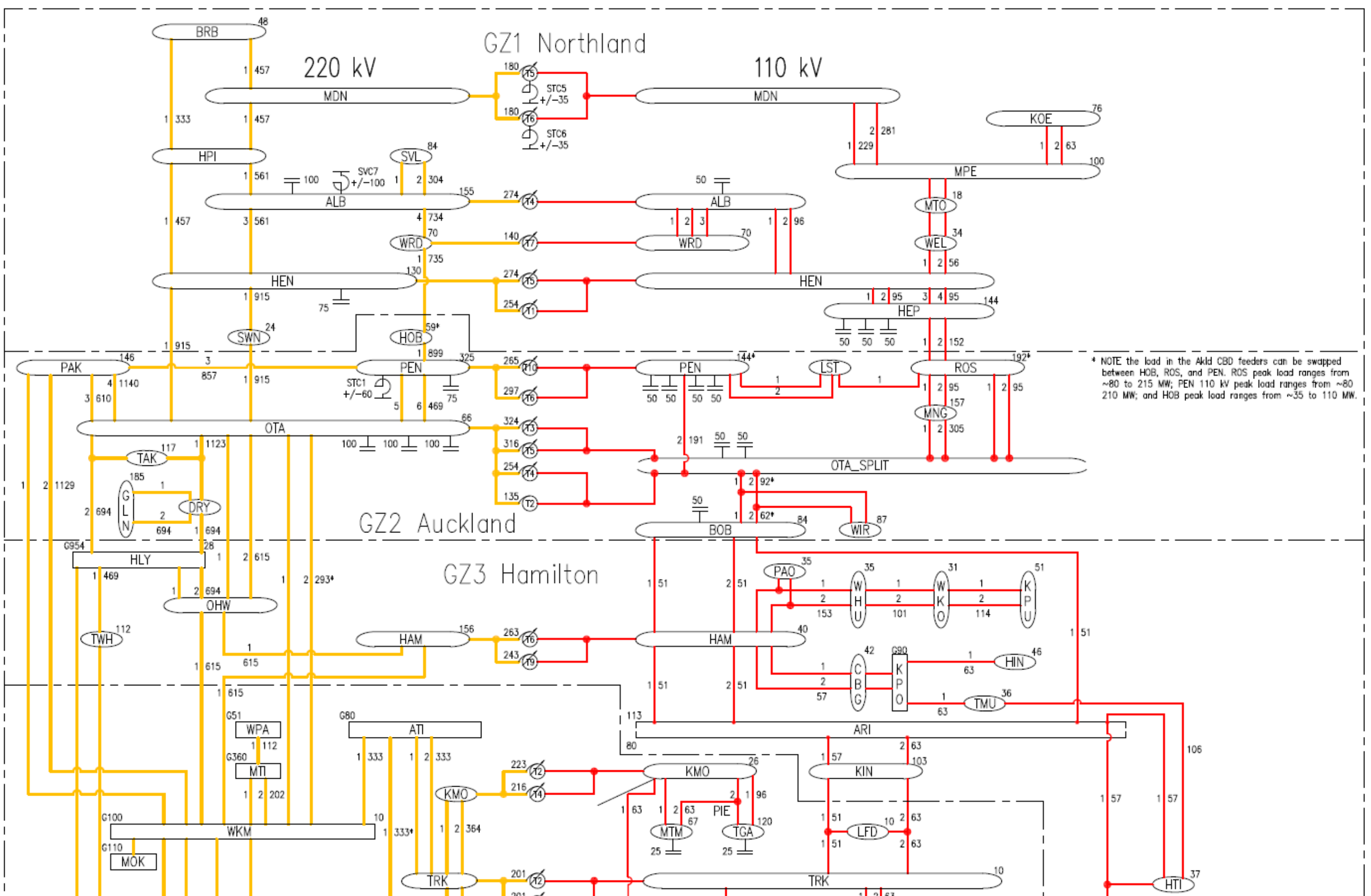
ELECTRICITY AUTHORITY TE MANA HIKO

Consumer and producer surplus calculation

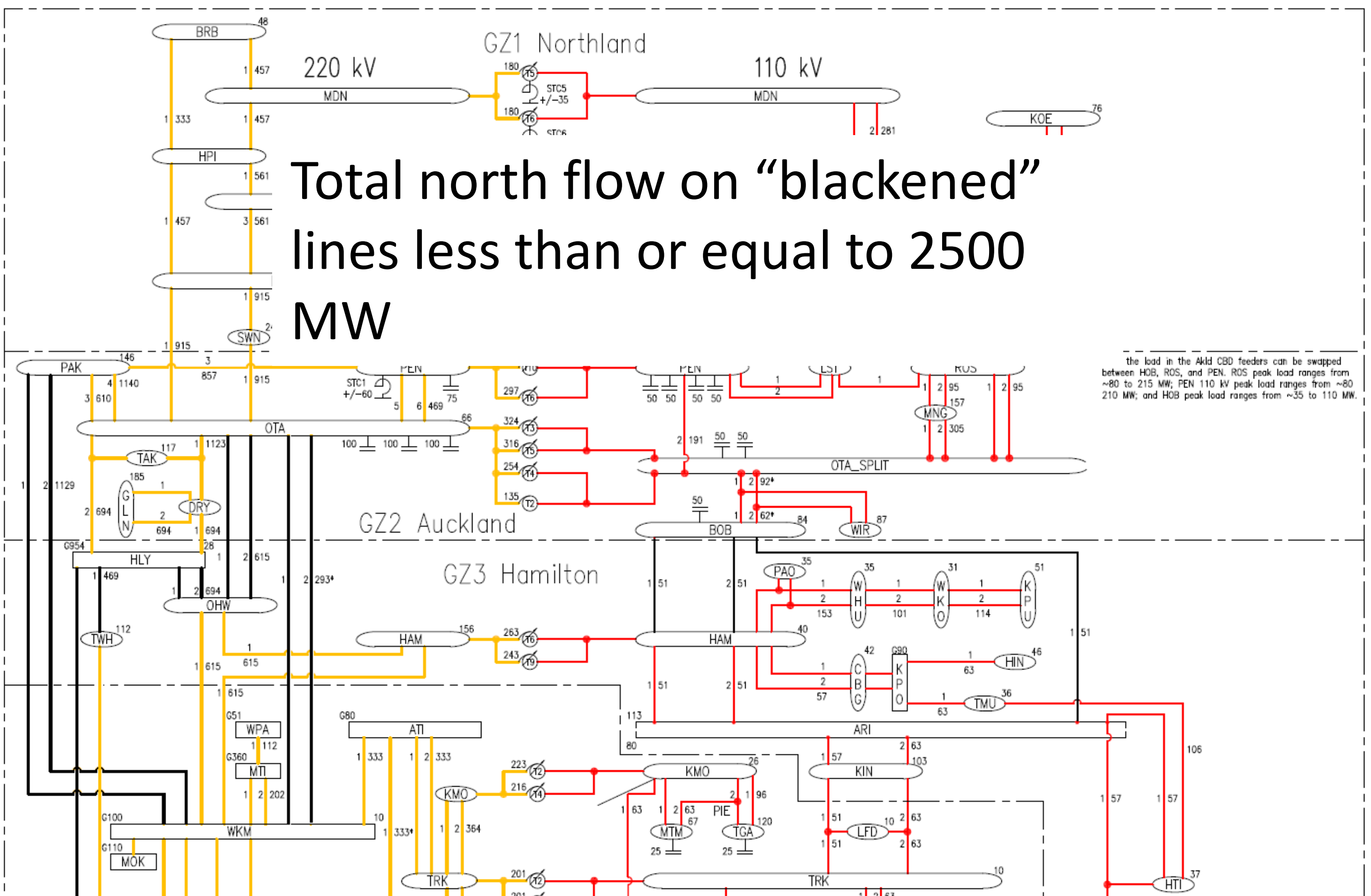


	Solve 1	Solve 2	Change
Demand (offtake)	A + B + C + D	A	B + C + D
Supply (injection)	E + F + G	B + E	F + G - B

With NIGUP

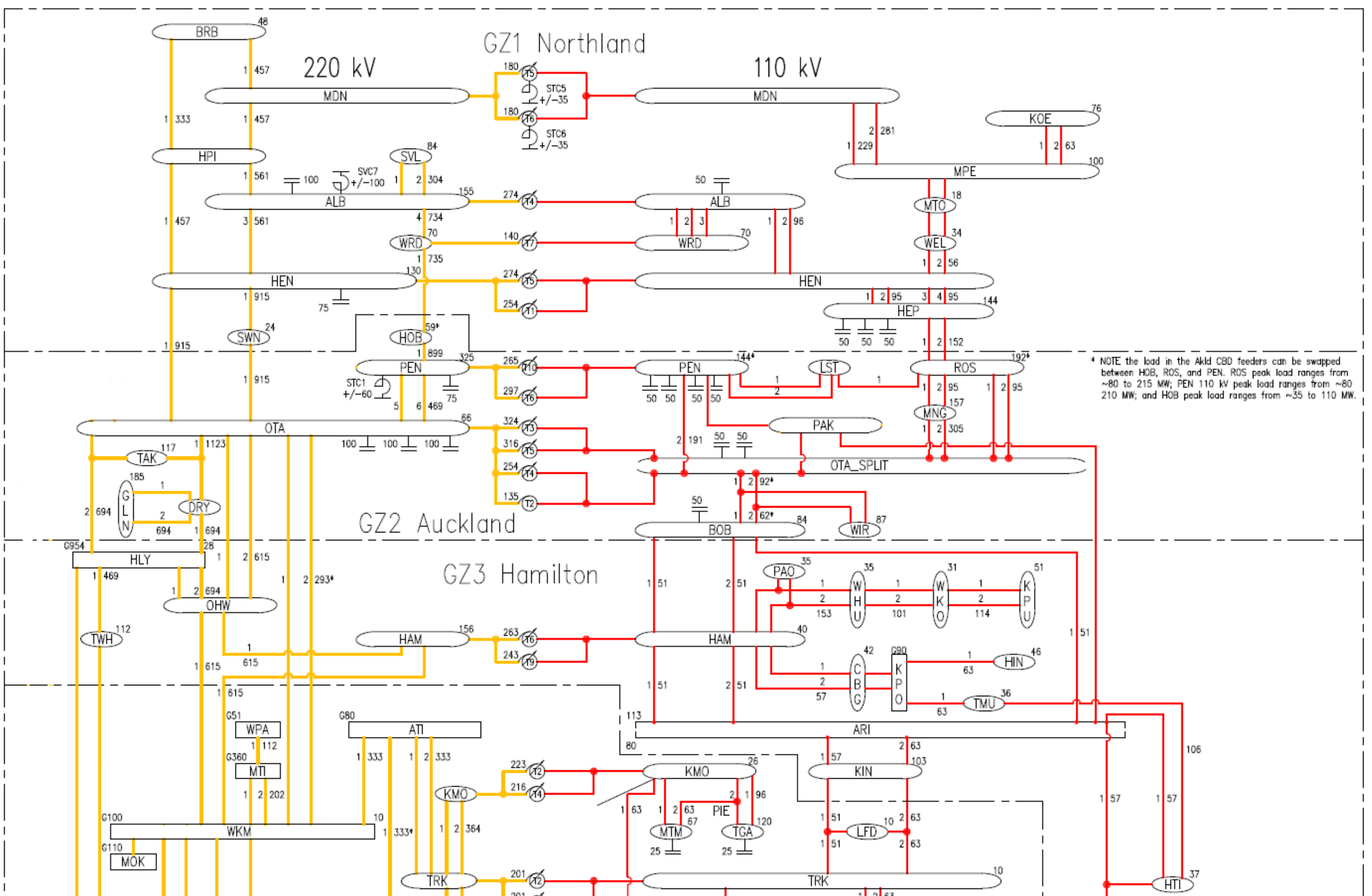

GZ1 Northland
220 kV
110 kV
GZ2 Auckland
GZ3 Hamilton
* NOTE the load in the Akld CBD feeders can be swapped between HOB, ROS, and PEN. ROS peak load ranges from ~80 to 215 MW; PEN 110 kV peak load ranges from ~80 210 MW; and HOB peak load ranges from ~35 to 110 MW.
BRB
MDN
HPI
SVL
ALB
WRD
HEN
SWN
HOB
PAK
PEN
OTA
TAK
GLN
DRY
HLY
OHW
TWH
HAM
WPA
MTI
ATI
WKM
MOK
KMO
TRK
KOE
MPE
MTO
WEL
HEP
LST
ROS
MNG
OTA_SPLIT
BOB
WIR
PAO
WHU
WKO
KPU
CBG
KPO
HIN
TMU
ARI
KIN
PIE
MTM
TGA
LFD
HTI
STC5 +/-35
STC6 +/-35
SVC7 +/-100
STC1 +/-60

With NIGUP constraint

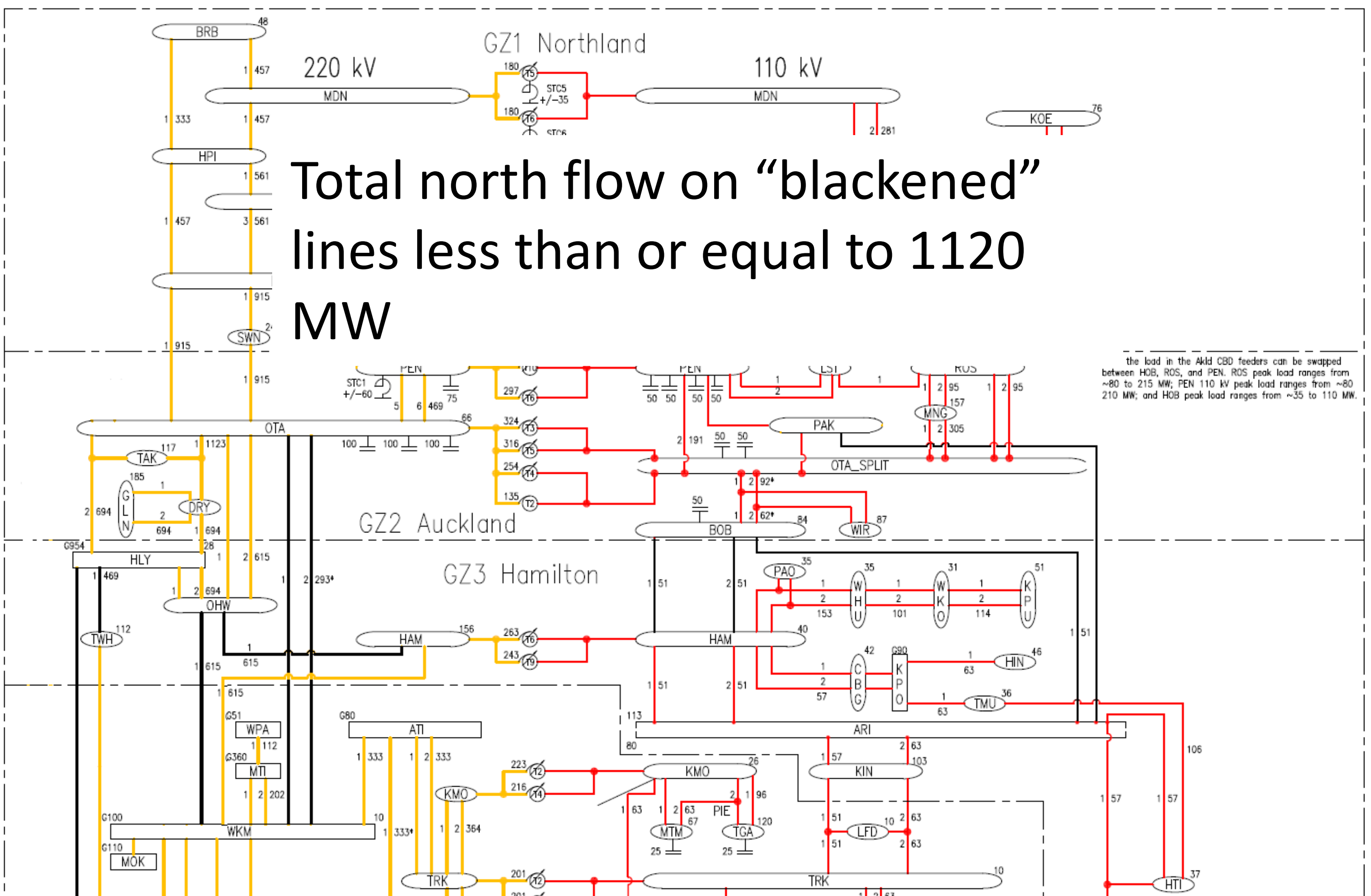


Total north flow on “blackened” lines less than or equal to 2500 MW

Without NIGUP



Without NIGUP constraint



Benefit calculation

datetime	node	generation	load	price	generation revenue	generation cost	Factual Load Benefit	Factual Generation Benefit
01/04/2015 0:00	BEN2202 BEN0	422	-	90.9	19,189	6	-	19,183
01/04/2015 0:00	CPK0331	-	53	90.8	-	-	24,123	-
01/04/2015 0:00	GLN0331	-	64	80.3	-	-	29,633	-
01/04/2015 0:00	GLN0332 GLN0	38	-	80.2	1,524	-	-	1,524
01/04/2015 0:00	HLY2201 HLY5	379	-	79.5	15,057	3,354	-	11,703
01/04/2015 0:00	MPE1101	-	52	81.7	-	-	23,912	-
01/04/2015 0:00	PEN0331	-	108	80.3	-	-	49,683	-
01/04/2015 0:00	TWI2201	-	574	103.5	-	-	257,433	-

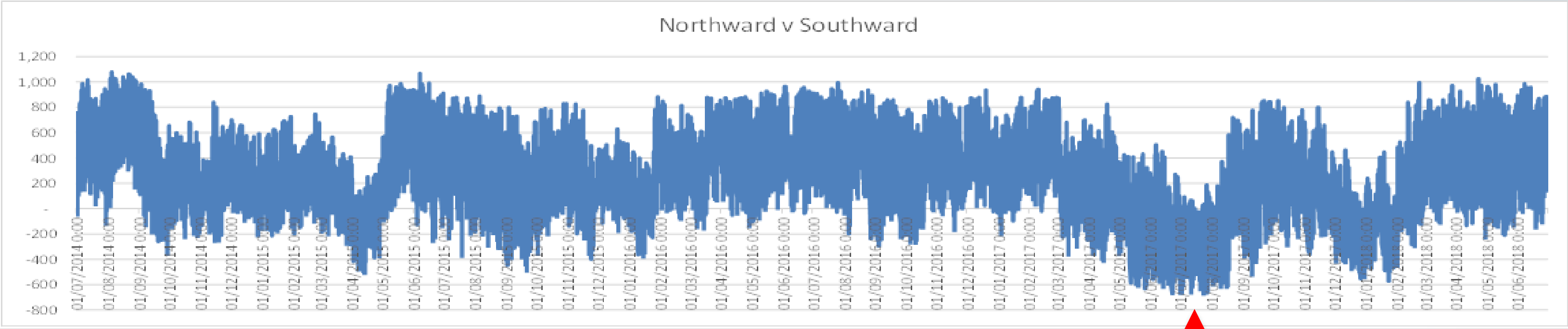
datetime	node	c_generation	c_load	c_price	c_generation revenue	c_generation cost	Counterfactual Load Benefit	Counterfactual Generation Benefit	Load Benefit	Generation Benefit	Total benefit
01/04/2015 0:00	BEN2202 BEN0	422	-	139.5	29,438	6	-	29,431	-	- 10,249	- 10,249
01/04/2015 0:00	CPK0331	-	53	64.7	-	-	24,817	-	- 693	-	- 693
01/04/2015 0:00	GLN0331	-	64	60.8	-	-	30,260	-	- 627	-	- 627
01/04/2015 0:00	GLN0332 GLN0	38	-	60.8	1,155	-	-	1,155	-	369	369
01/04/2015 0:00	HLY2201 HLY5	379	-	60.2	11,412	3,354	-	8,058	-	3,645	3,645
01/04/2015 0:00	MPE1101	-	52	61.9	-	-	24,428	-	- 516	-	- 516
01/04/2015 0:00	PEN0331	-	108	60.8	-	-	50,734	-	- 1,051	-	- 1,051
01/04/2015 0:00	TWI2201	-	574	158.6	-	-	241,630	-	15,803	-	15,803

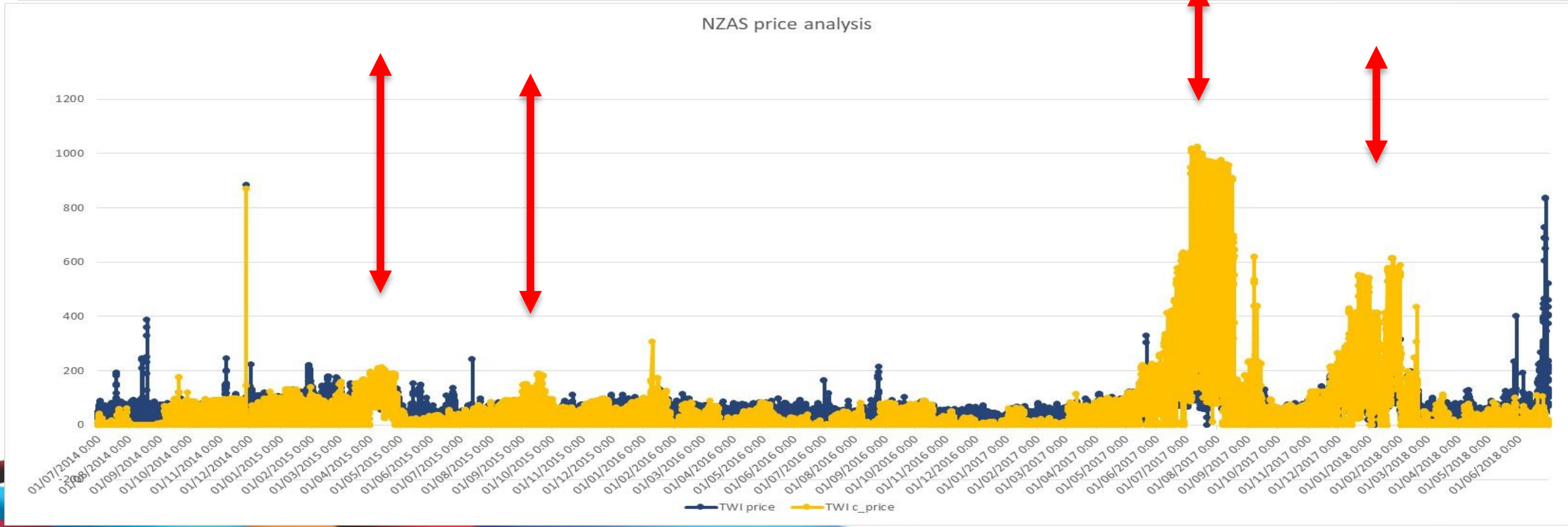
= (VOLL - Price) x Load / 2
= (1000-E19)*D19/2

Generation revenue - generation cost
=F16-G16

Load benefit = Factual benefit - CF benefit

Benefits linked to HVDC flow direction



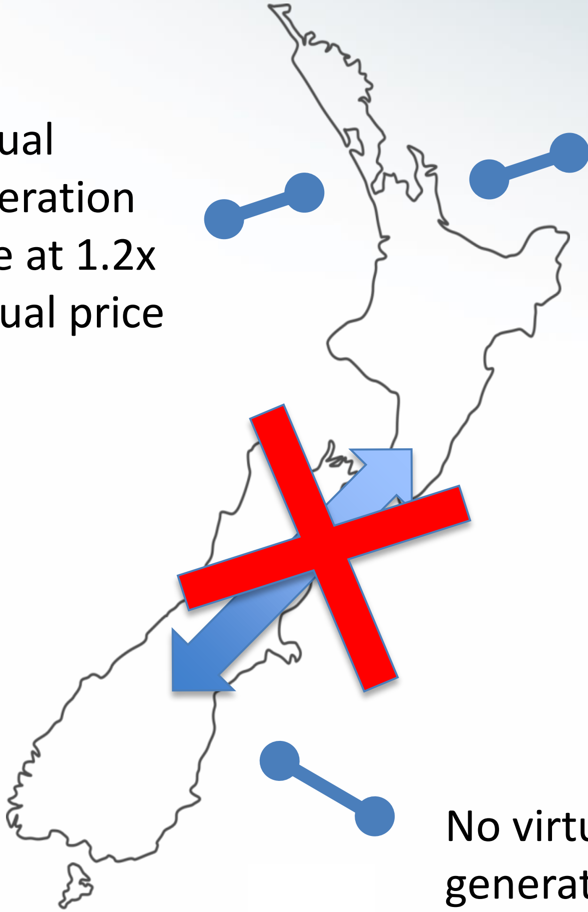


Virtual price offer (VPO)

No HVDC

Virtual generation here at 1.2x factual price

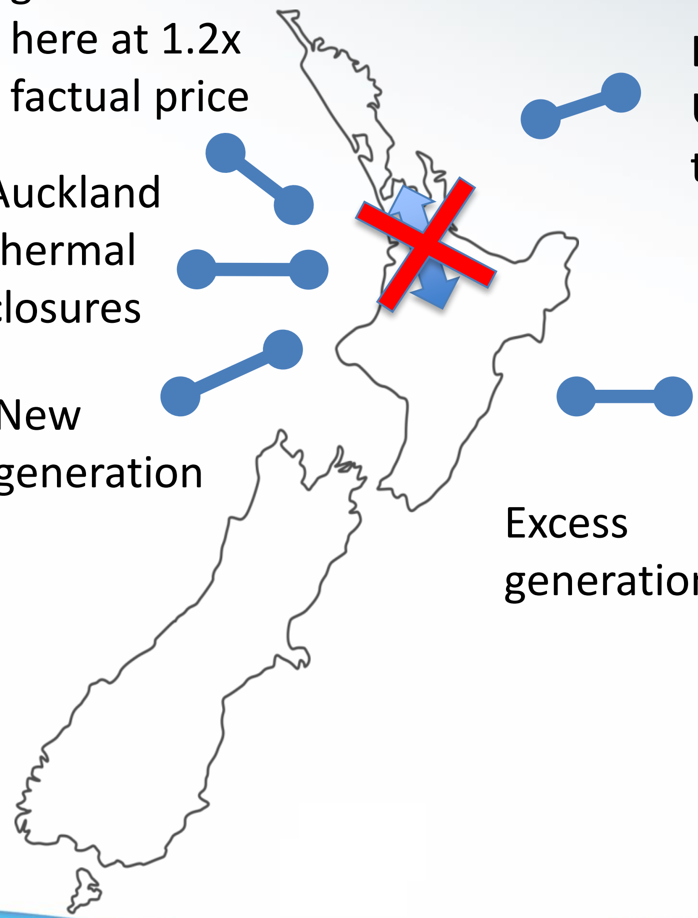
Lost load in the NI in many trading periods



Excess generation in the SI

No virtual generation in the SI

No NIGU



Virtual generation here at 1.2x factual price
Auckland thermal closures
New generation
Lost load in the UNI in many trading periods
New generation
Excess generation

Some projections for grid v alternatives

in $/kWh	2017	2025
Grid	0.04	0.04
Energy	0.17	0.17
Lines companies	0.09	0.09
Retail (G+E+L) *(Source: MBIE)*	0.30	0.30
Solar+Battery alternative	0.51	0.28
(Source: Transpower)		
Ratio: Grid connected cost v alternative cost	*1.71*	*0.94*

Variable v fixed VPO assumption

	Variable VPO	Fixed VPO
Customer group	Benefit-based ($m)	Benefit-based ($m)
NI generation	15.8	4.7
SI generation	57.2	15.5
UNI distributors	57.0	101.5
LNI distributors	21.8	42.2
SI distributors	18.7	9.1
Major industrials	14.7	12.2
Generation	73.0	20.1
Load	112.2	165.0
Load share of BBC	61%	89%
Load - BBC + residual	597.7	650.6
Total BBC + residual	679.1	679.1
Load share	88%	96%

See excel spreadsheet titled ‘2019 Proposal impacts modelling’, sheet titled ‘Results”, cell X3. Select 1 = Var VPO. Select 2 = Fixed VPO

Netting approach in vSPD

Default vSPD netting approach

- ‘Traditional’ vSPD treats generation as grid-connected if it ‘offers in’
- Otherwise, net of DG
- Some DG offers in

i_Offer
ARA2201 ARA0
ARG1101 BRR0
ARI1101 ARI0
ARI1102 ARI0
ASB0661 HBK0
ATI2201 ATI0
AVI2201 AVI0
BEN2202 BEN0
BOB1101
BPE0331 TWF0
BWK1101 WPI0
COL0661 COL0
CPK0331
CYD2201 CYD0

Manual netting approach for the benefit-based charge

- Rules to guide judgement of whether to net:
  - Partially embedded generation - netting permitted.
  - Notionally embedded generation - if it meets the definition of DG in the Code.
  - Grid-connected co-generation - only against the grid-connected industrial load it is co-located with.

EMI Ref: File "2019 Proposal impacts modelling"
Sheet "Reconciliation maps 15042019"
Column G has our judgement.

vSPD output check:
EMI Ref File:
Sheet "Draft netting rules" for list of adjustments.

Sheet "FINAL Net.vSPD" for netted benefits by POC.

Sheet: FINAL Adjusted Trad.vSPD for benefits before netting.

Example - manual netting approach

Load POC X

Generation	Load	Benefit	Ratio - benefit to load
-	500	1,000	2

Generation POC Y

Generation	Load	Benefit
250	-	-

Adjusted POC X

Generation	Load	Benefit
250	500	500

Adjusted annual benefit = 250 [net load] x 2 [Ratio - benefit to load] = 500

Generators treated as grid-connected in vSPD

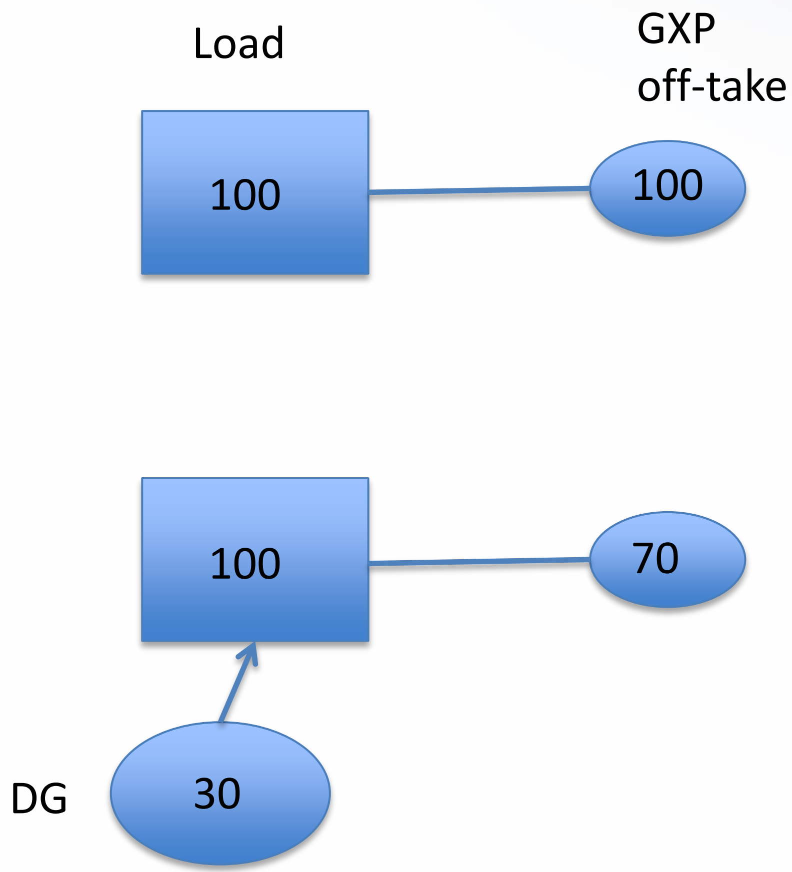
POC.GEN	Customer	POC.GEN	Customer	POC.GEN	Customer
ARA2201 ARA0	Mercury	MHO0331 MHO0	Nova	SWN2201 SWN5	Southdown Generation
ARG1101 BRR0	TrustPower	MKE1101 MKE1	Nova	THI2201 THI1	Contact Energy
ARI1101 ARI0	Mercury	MTI2201 MTI0	Mercury	THI2201 THI2	Contact Energy
ARI1102 ARI0	Mercury	NAP2201 NAP0	Nga Awa Purua JV	TKA0111 TKA1	Genesis Power
ATI2201 ATI0	Mercury	NAP2202 NTM0	Ngatamariki Geothermal	TKB2201 TKB1	Genesis Power
AVI2201 AVI0	Meridian	OHA2201 OHA0	Meridian	TKU0331	Genesis Power
BEN2202 BEN0	Meridian	OHB2201 OHB0	Meridian	TKU2201 TKU0	Genesis Power
COL0661 COL0	TrustPower	OHC2201 OHC0	Meridian	TUI1101 KTW0	Genesis Power
CYD2201 CYD0	Contact Energy	OHK2201 OHK0	Mercury	TUI1101 PRI0	Genesis Power
HLY2201 HLY1	Genesis Power	OKI2201 OKI0	Contact Energy	TUI1101 TUI0	Genesis Power
HLY2201 HLY2	Genesis Power	OTA2202 OTC0	Contact Energy	TWC2201	Tilt
HLY2201 HLY4	Genesis Power	PPI2201 PPI0	Contact Energy	WDV1101	Meridian
HLY2201 HLY5	Genesis Power	ROX1101 ROX0	Contact Energy	WHI2201 WHI0	Contact Energy
HLY2201 HLY6	Genesis Power	ROX2201 ROX0	Contact Energy	WKM2201 MOK0	Tuaropaki Power
HWA1102 WAA0	Nova	RPO2201 RPO0	Genesis Power	WKM2201 WKM0	Mercury
KPO1101 KPO0	Mercury	SFD2201 SFD21	Contact Energy	WPA2201 WPA0	Mercury
MAN2201 MAN0	Meridian	SFD2201 SFD22	Contact Energy	WRK2201 WRK0	Contact Energy
MAT1101	Southern Generation	SFD2201 SPL0	Contact Energy	WTK0111 WTK0	Meridian
MAT1101 ANI0	Southern Generation	SWN2201	Southdown Generation	WWD1102	Meridian
MAT1101 MAT0	TrustPower	SWN2201 SWN0	Southdown Generation	WWD1103	Meridian

Residual charge

Calculating the residual charge

- Allocated in proportion to historical anytime maximum demand
- Gross
- Load customers only
- Shares based on average AMD over:
  - at least two years prior to July 2019
  - or at least 10 years prior to date assessed
- Indicative charges: average of four annual peaks, not highest over 4 years

How to measure demand under net vs gross approach



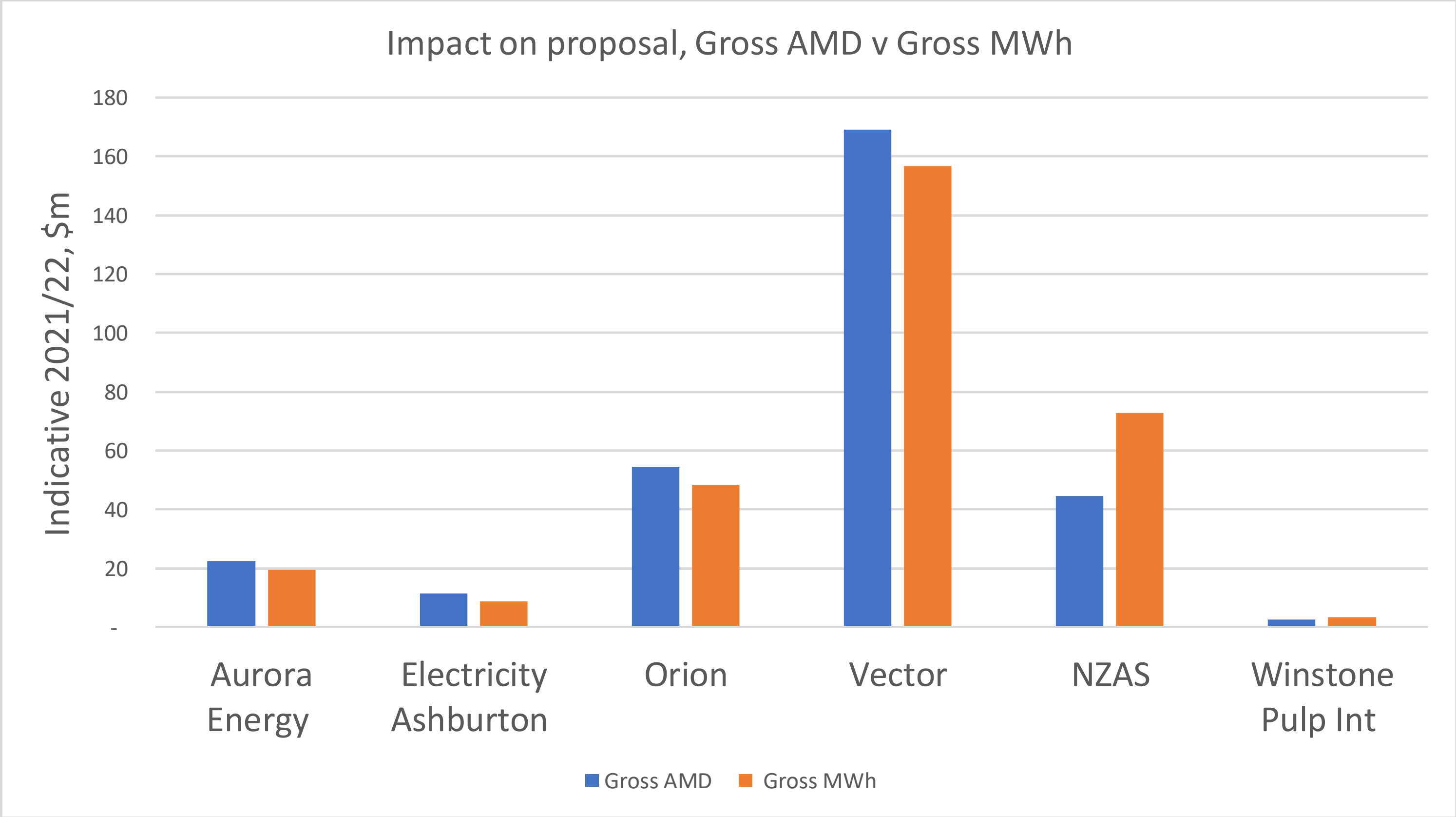
Net	Gross
100	100
70	100

Indicative modelling of the residual charge

- ***'Please review your quantities/reference data, and advise us in submissions if there are any issues'***
- Refer EMI File "2019 Proposal impacts modelling", sheet "Reconciliation maps 15042019"
  - **Column A: POC_Network**
  - **Column F: Transpower customer**
  - **Columns H to K: Gross Flow – 4 years in kWh**
- Ie. POC_Network (ie, BDE0111_RAYN … Brydone_Rayonier Limited) = Unique ref

EMI File: Residual charge options module for summary.

AMD v MWh



EMI File:
2019 proposal impacts modelling
Sheet: results
Cell X9.

Cap

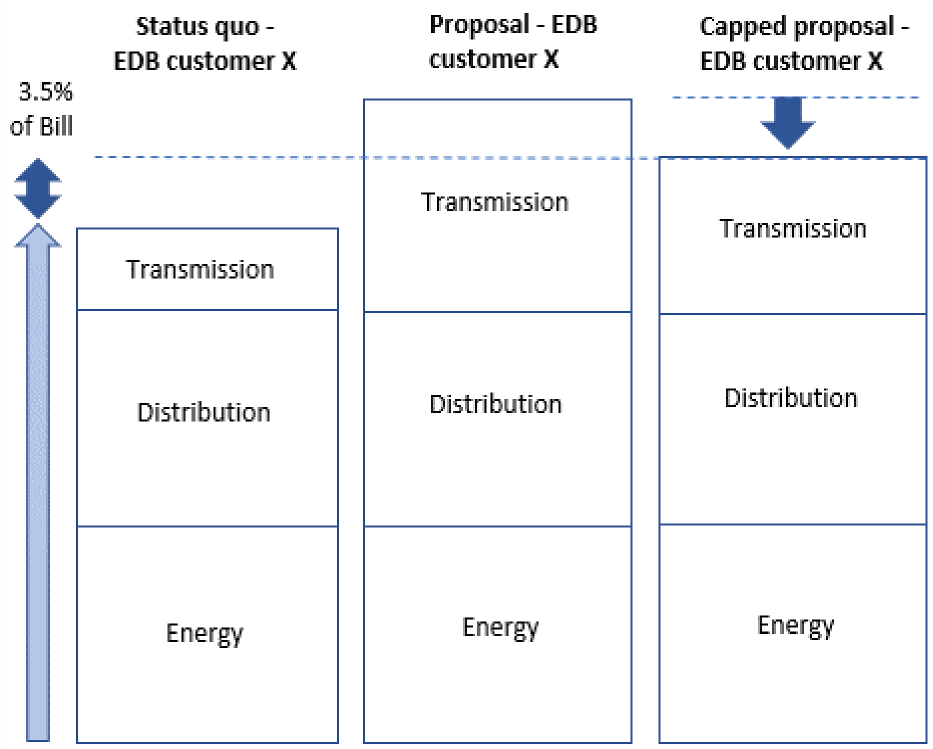
How the proposed cap works

- Distributors: 3.5% of estimated consumer electricity bills (2019/20)
  - capped amount increases annually by inflation and load growth
- Industrials: 3.5% cap rises by 2 percentage points per year, after first five years
- Guidelines give formula and data sources

Key Cap assumptions

- Load growth: 1% pa until 2021/22
- Cost of wholesale electricity: $75/MWh in 2021/22
- For networks, the total electricity bill: network charge + wholesale electricity costs

How the proposed cap works



Direct-connect example – NZ Steel

	2021/22
Electricity cost (2021/22)	90,696,472
Permitted increase (3.5%)	3,174,377
Status quo charge	2,660,778
Capped charge(SQ + permitted increase)	5,835,154
Proposal before cap	11,899,436

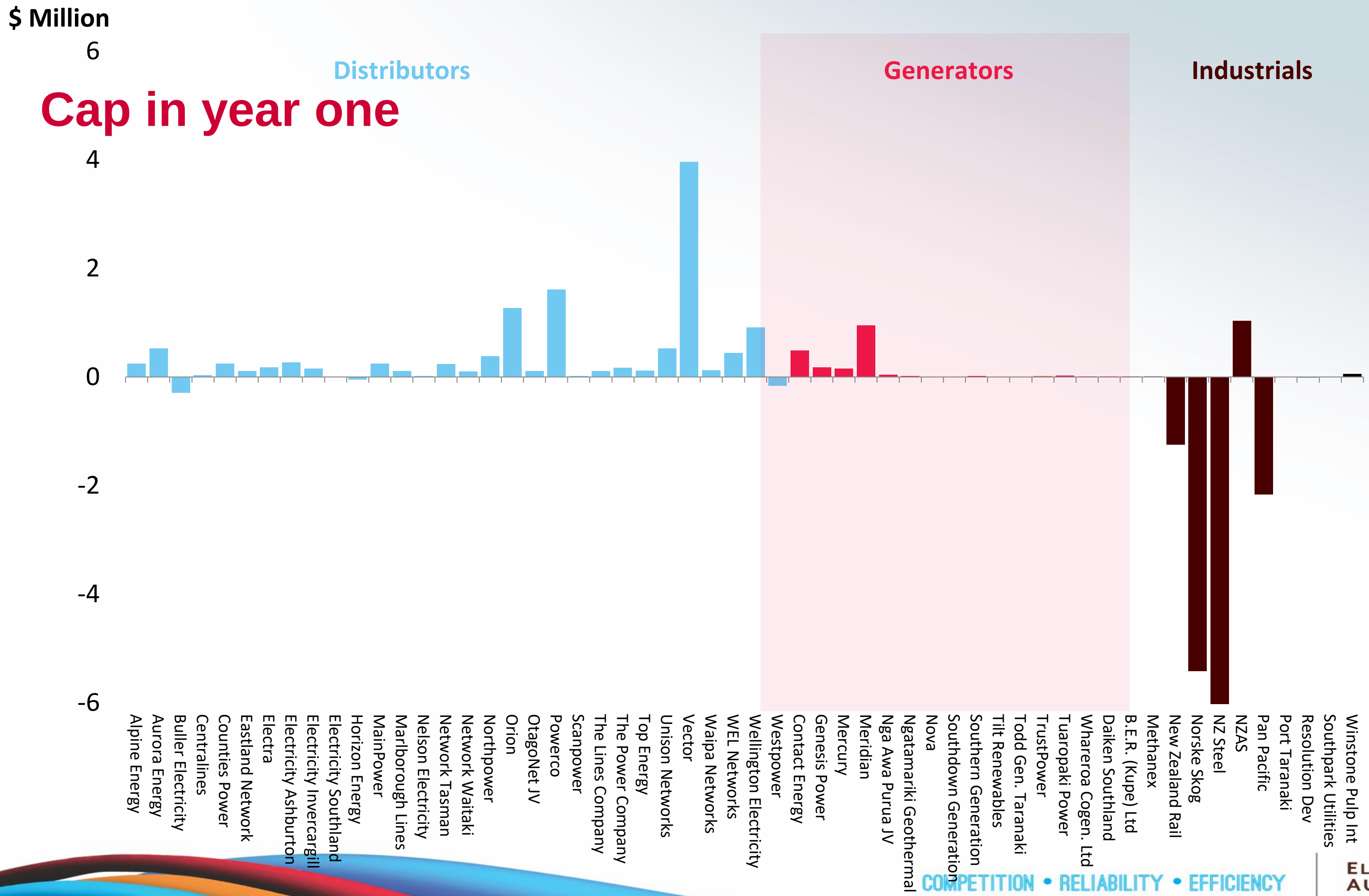
Refer EMI file: “2019 Proposal impacts modelling”, sheet “Direct connects”

Distributor cap methodology example – Buller

Buller Electricity	
Line charges (including TPM charge)*	7,711,111
Energy cost**	6,196,557
Total electricity cost	13,907,668
Permitted increase (3.5%)	486,768
Status quo charge	641,139
Capped charge(SQ + permitted increase)	1,127,907
Proposal before cap	1,419,784
* The lines charge is sourced from disclosures	
** The energy cost is calculated as volume x $75/MWh	

Refer EMI file: "2019 Proposal impacts modelling", sheet "EDBs capping"

Cap in year one



COMPETITION • RELIABILITY • EFFICIENCY

ELECTRICITY AUTHORITY
TE MANA HIKO

Transmission pricing methodology

www.ea.govt.nz

https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

tpm@ea.govt.nz