Transpower NZ Ltd
System Operator Industry Seminar
13/15 September 2006

Pricing of the 17:30 Trading Period 19th June 2006

TRANSPOWER

Introduction

System Operator Industry Seminar

Kevin Small
System Operations Manager
13/15 September 2006

Agenda

1. Introduction
2. Description of Schedules
3. Standby Residual Checks and Comparison of Schedules
4. Final Pricing – how prices are derived
5. Questions (afternoon tea)
6. Net Free Reserves
7. Dispatch of Reserves
8. Development proposals
9. Discussion

June 19 a significant day for many reasons

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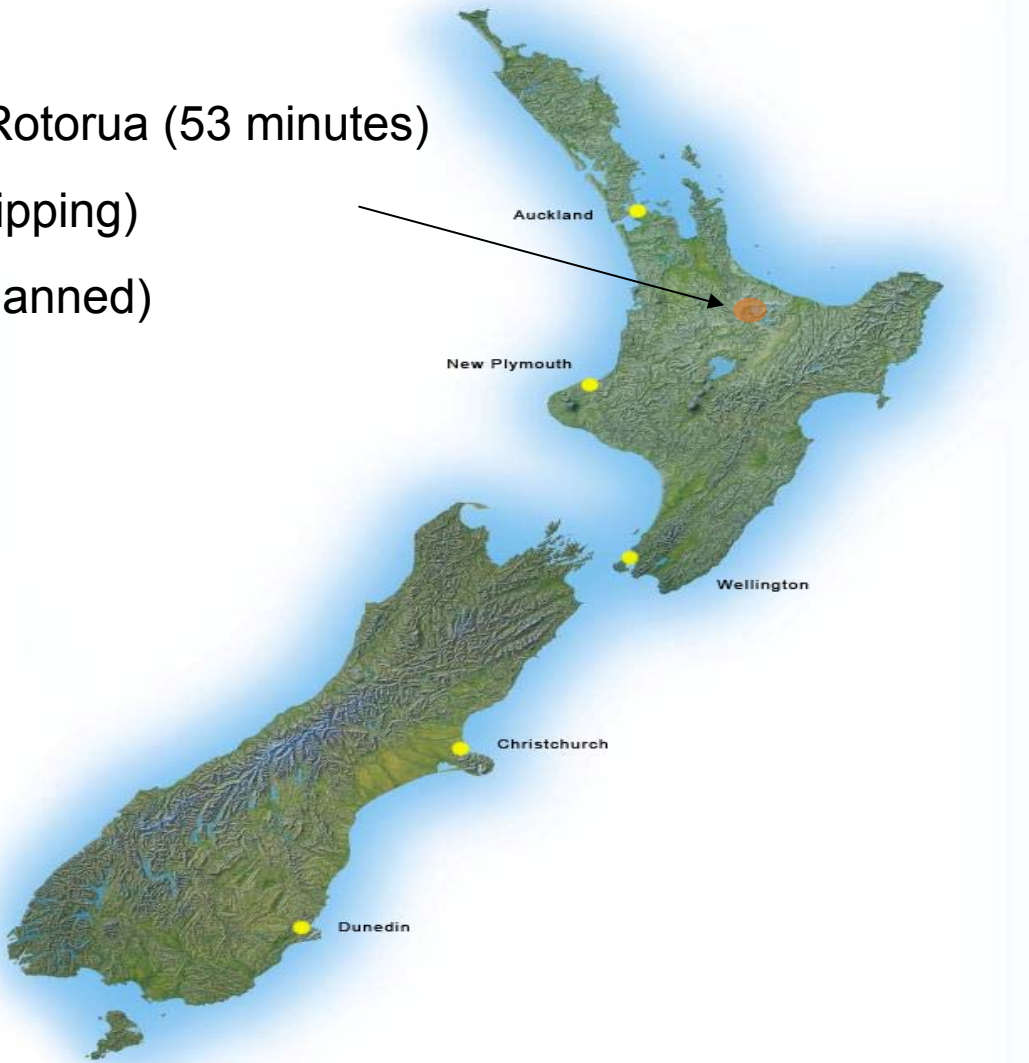
Loss of supply: Rotorua (53 minutes)

- ROT-TRK 1 (tripping)
- ROT-TRK 2 (planned)



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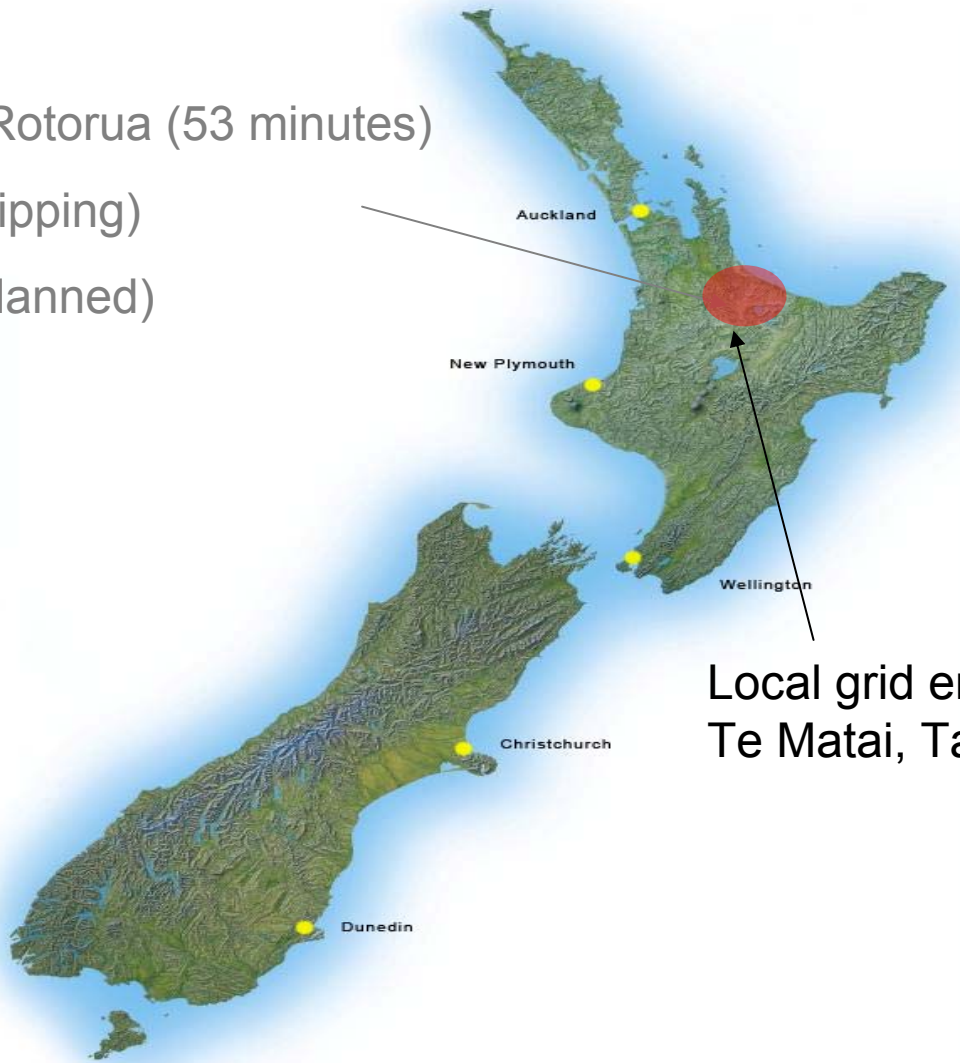

Local grid emergency 1330 to 2000
Te Matai, Tauranga, Mt Maunganui

June 19 a significant day for many reasons

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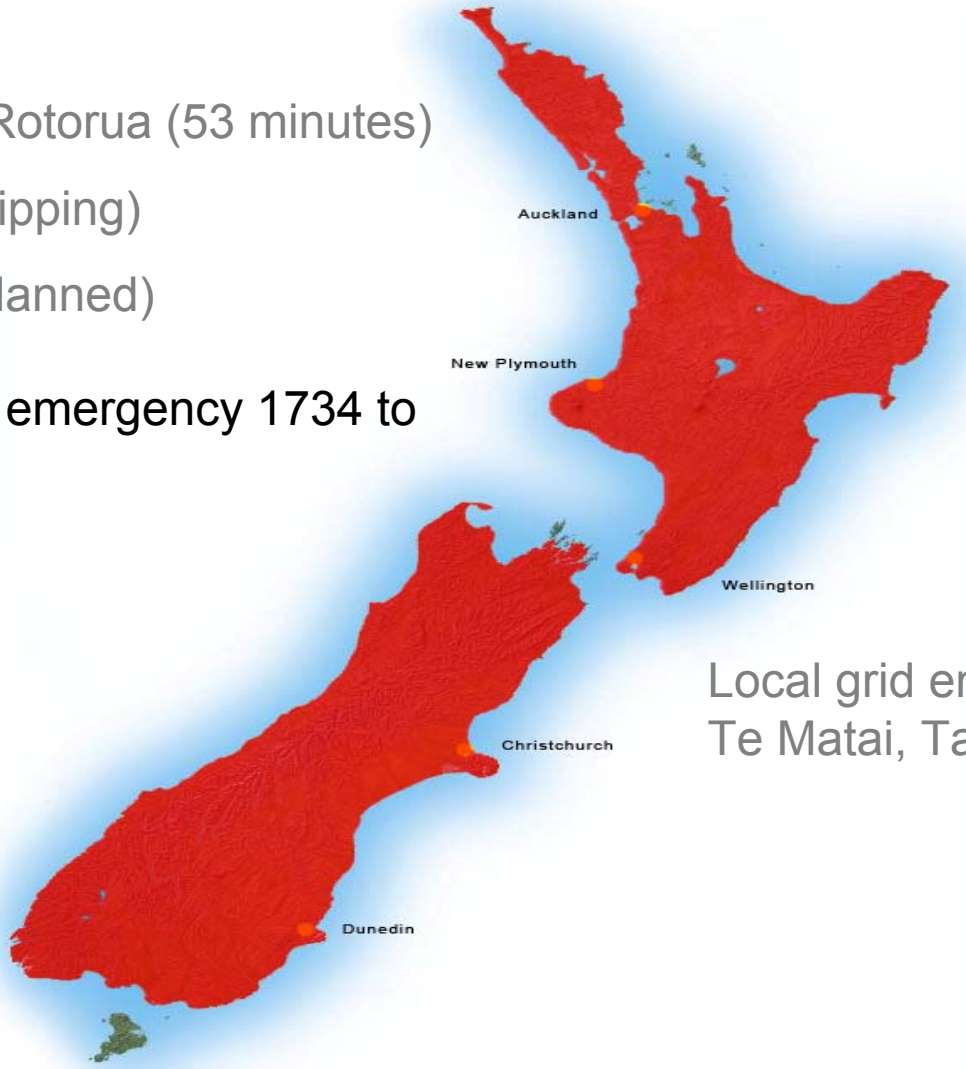
Nation wide grid emergency 1734 to 2000

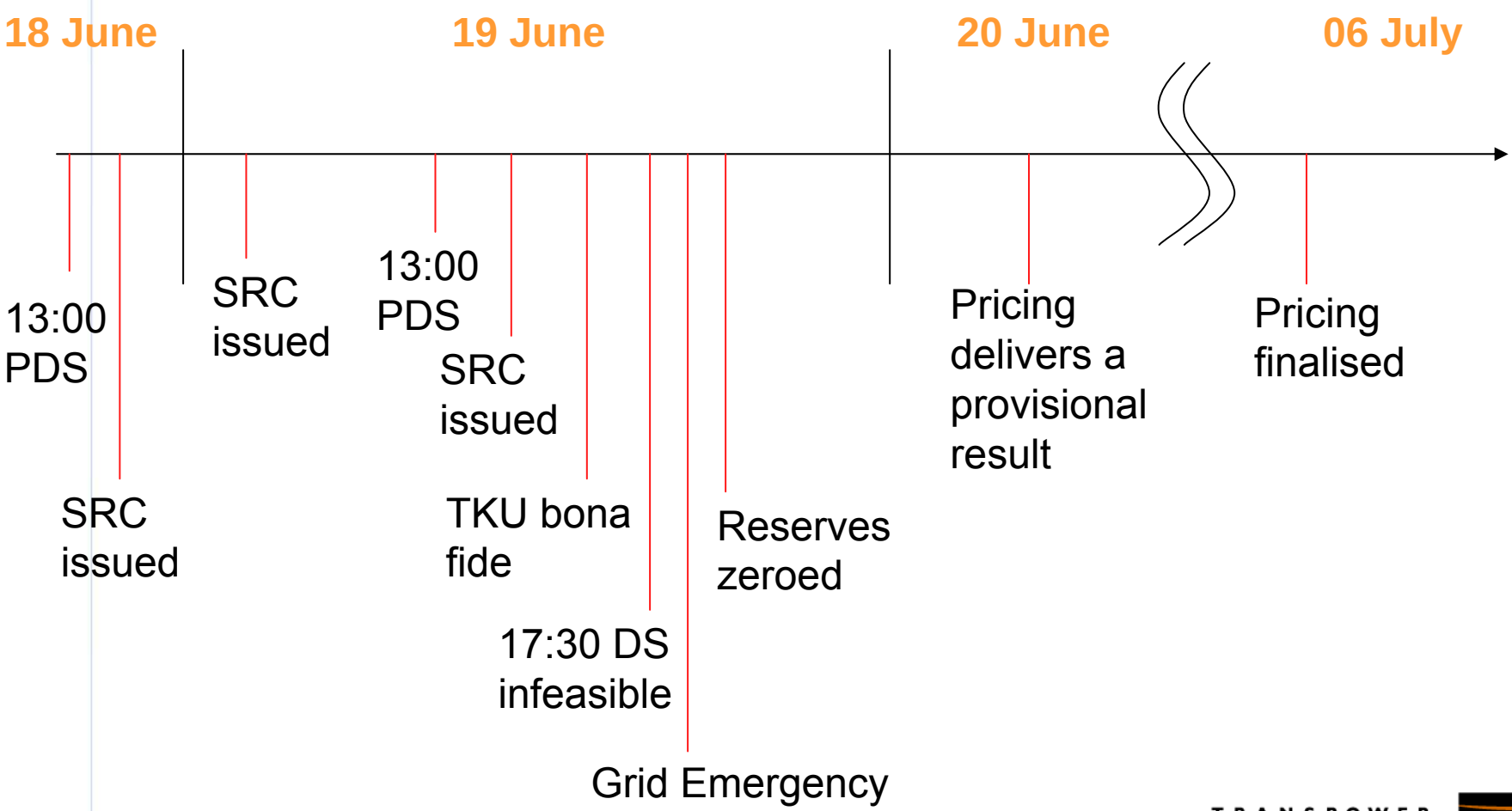


Local grid emergency 1330 to 2000
Te Matai, Tauranga, Mt Maunganui

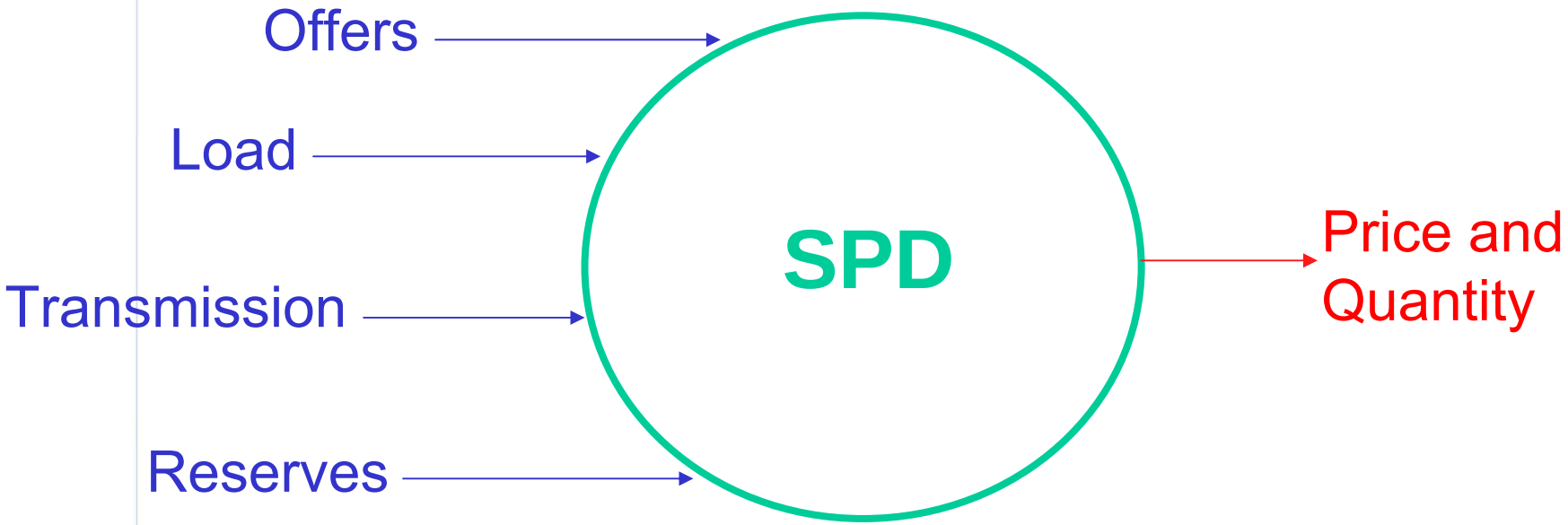
Seminar Objectives

- to focus on pricing issues arising from nation wide grid emergency
- provide an understanding of how the price was determined.
- provide an opportunity for relevant pricing questions to be considered

Time Line of Events



Scheduling Pricing and Dispatch (SPD)



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Description of Schedules

System Operator Industry Seminar

Andrew Twaddle

13/15 September 2006

Schedules Produced

Six schedules produced by the Scheduling, Pricing & Dispatch (SPD) software

1. Pre-Dispatch Schedule (PDS)
2. Security Dispatch Schedule (SDS)
3. Schedule of Dispatch Prices and Quantities (SDPQ)
4. Dispatch Schedule (a.k.a. Real Time Dispatch RTD)
5. Real Time Pricing (RTP)
6. Provision/Final Pricing (FP)

Pre-Dispatch Schedule (PDS)

PDS: is the 'ideal' supply and demand schedule

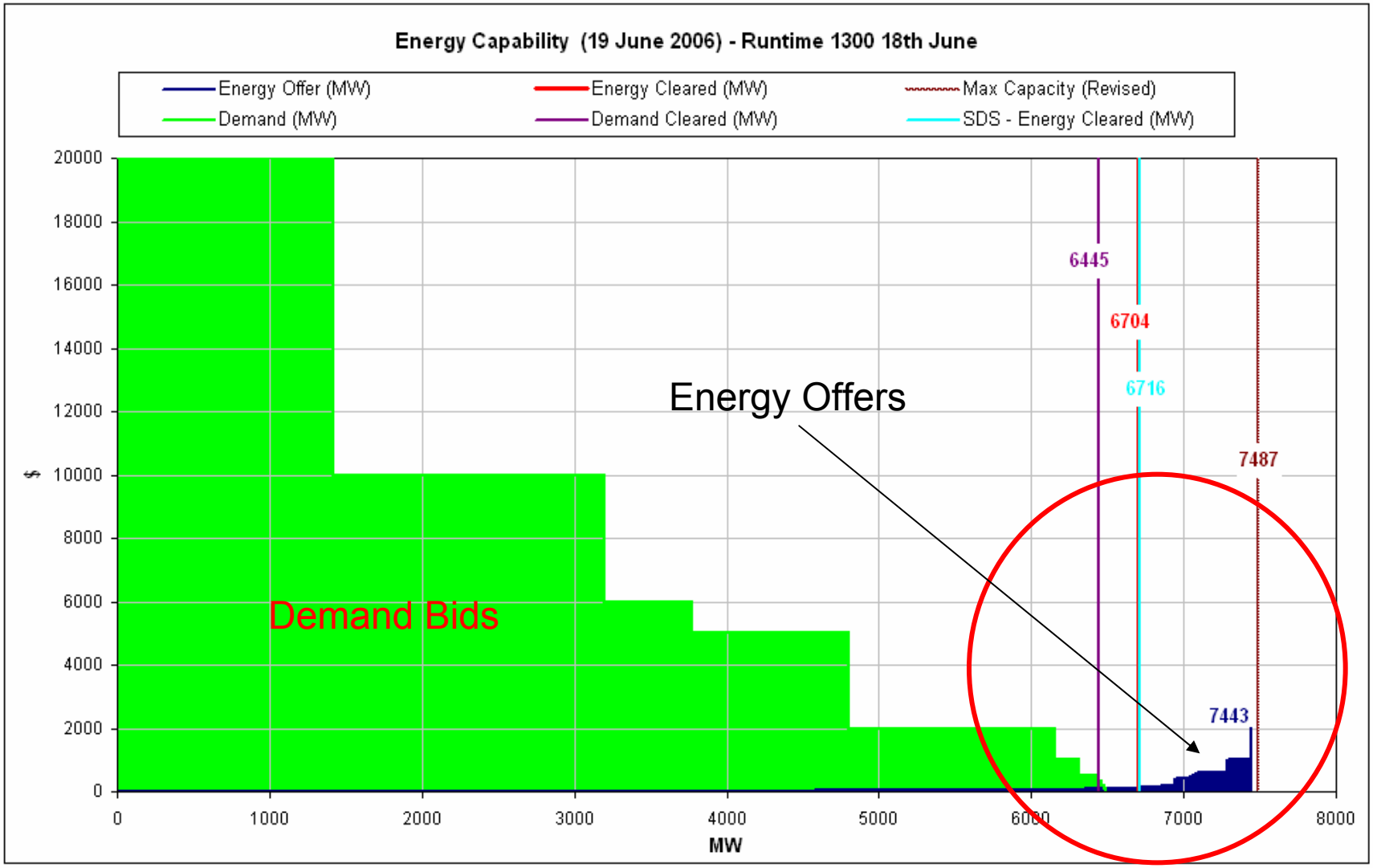
- demand bids supplied by purchasers; the price they will pay for demand
- generation and reserve offers: the prices at which suppliers are willing to provide generation and/or reserve

Security Dispatch Schedule (SDS)

SDS: an internal SO schedule used to assess security

- demand based on:
  - area load forecast from Transpower Energy Management System (EMS)
  - linear regression model
  - updates half hourly based on real time data
- total demand quantity bid provided by 10 large industrials (no price attached)
- generation and reserve offers: prices at which suppliers are willing to provide generation and/or reserve
- SDS exactly the same as the Schedule of Dispatch Prices and Quantities (SDPQ). Solving for different time periods.

18 June 2006 13:00 PDS/SDS



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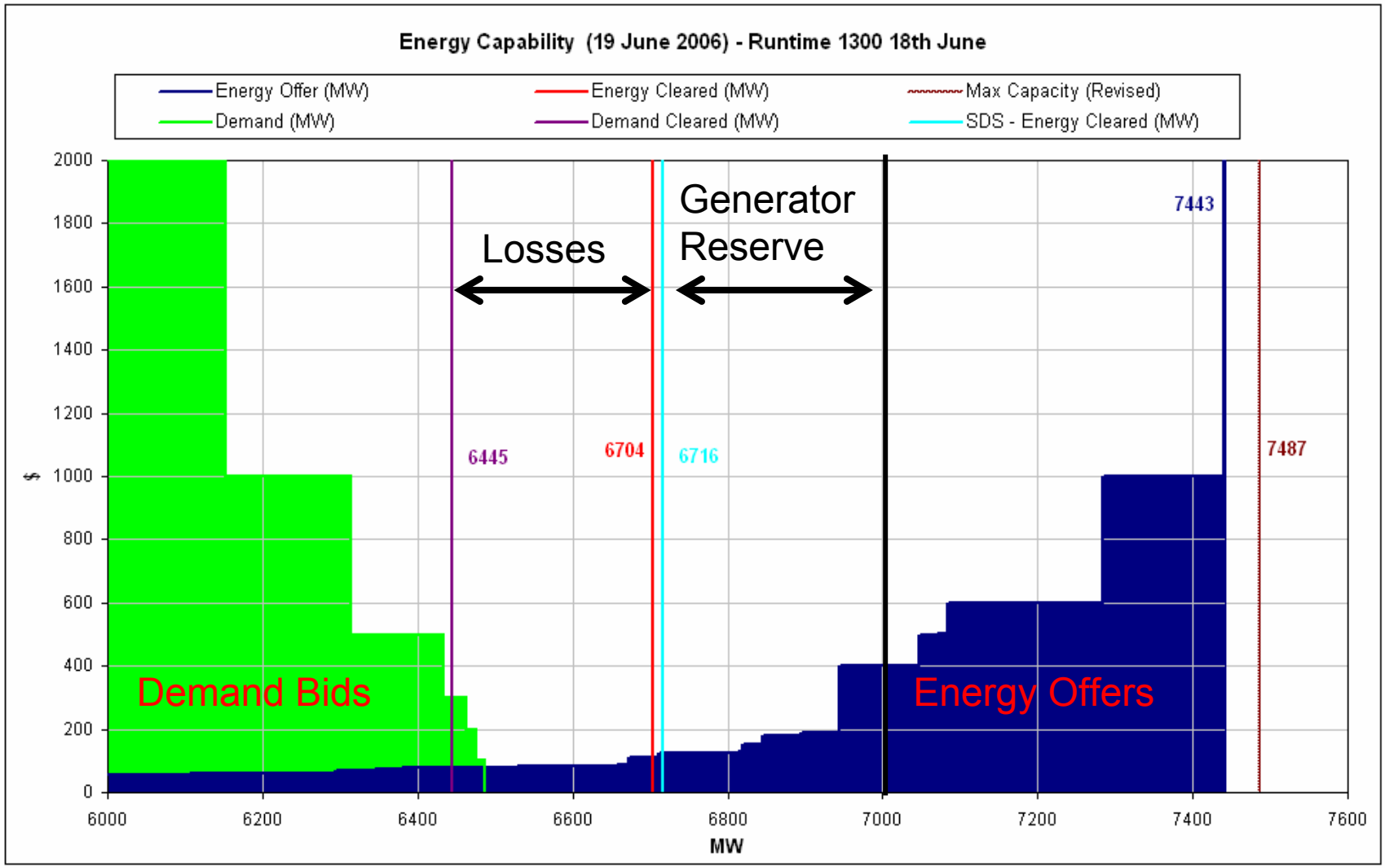
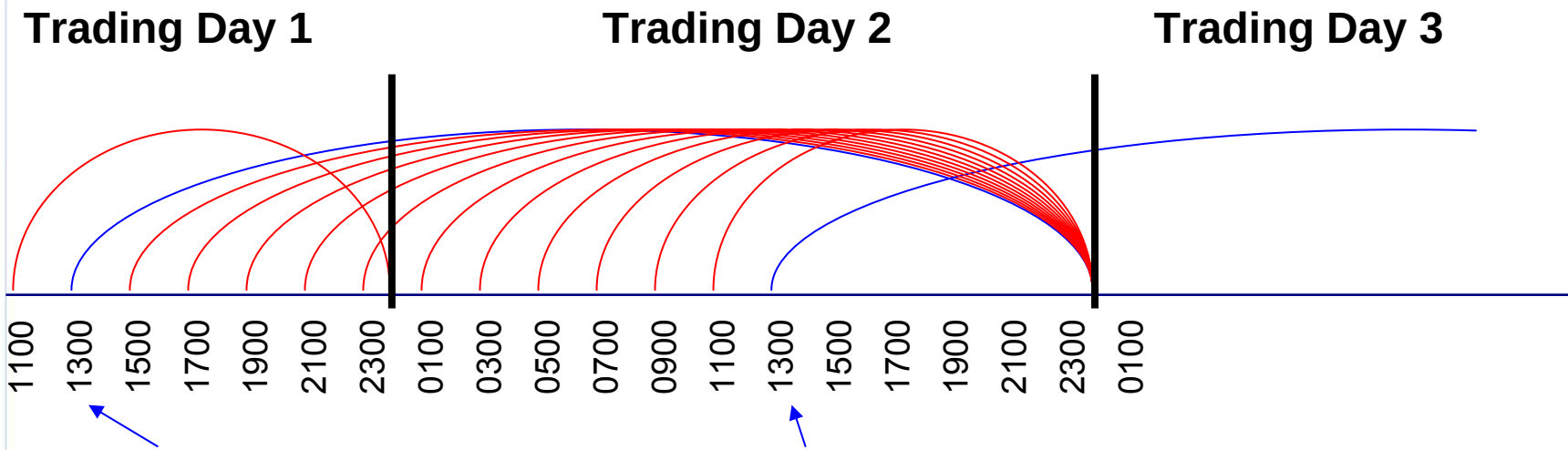


Time Line SPD Outputs – PDS/SDS

- runs every 2 hours
- provides solution for every trading period during current scheduling period



Trading Day 2 PDS
Solved from 13:00 on
Trading Day 1

Trading Day 3 PDS
Solved from 13:00 on
Trading Day 2

Dispatch Schedule (RTD)

RTD: schedule uses 5-minute load forecast provided by the coordinator to optimally dispatch system every 5-minutes

- demand based on:
  - actual bus load figures from SCADA/EMS for previous 5-minutes
  - the EMS LF area forecast
  - coordinator forecast at the island level

- generation and reserve offers: the prices at which suppliers are willing to provide generation and/or reserve

Real Time Pricing (RTP)

RTP: schedule of five-minute prices based on system as it existed for the preceding five-minute period

- demand is based on actual load figures from SCADA/EMS for previous 5-minutes
- generation and reserve offers are prices at which suppliers are willing to provide generation and/or reserve

Provisional and Final Pricing (FP)

FP: schedule of thirty-minute prices based on system as it existed for each trading period:

- demand based on actual load figures (from MV90) for each trading period
- generation and reserve offers: prices at which suppliers are willing to provide generation and/or reserve

FP is what should have ideally happened:

- given actual load, but
- ignoring actual energy produced (other than initial conditions)

Summary

- SDS & SDPQ– *Average MWh* forecast
  - Deficit CVP's possible
- PDS – *Average MWh* load bids
  - Deficit CVP's less likely, as bids may not be cleared
- RTD – Average 5-minute forecast
  - Deficit CVP's possible
- RTP Average 5-minute actual
  - Deficit CVP's possible
- FP – *Average Actual MWh*
  - Deficit CVP's possible

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Schedules Comparison and the Standby Residual Check Notices

System Operator Industry Seminar
Derrick Westenra
Market Services Manager
13/15 September 2006

Contents

1. Standby Residual Check and 18 June 13:47 SRC notice
2. Schedule comparisons to Final Pricing
3. Offer changes from 18 June 13:00 through to 19 June 17:29
4. Actual Generation dispatched

SRC Calculations

To determine whether enough:

- generation and reserves offers available after taking off:
  - largest MWMAX offer (assumes largest risk has occurred)
  - frequency keeping bands
  - and including HVDC constraints

- may be short of energy/reserve post event
- demand shedding post event if not enough energy

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Why is a second risk considered for reserves?

System Operator has the requirement to get the system back to normal state within 30 minutes following an event….

…..provided sufficient assets are offered by participants

SRC notices issued for 17:30 period on 19th June 2006

- Three notices issued:

  notice **1** issued at 13:37 on 18th June 2006

  notice **2** issued at 03:05 on 19th June 2006

  notice **3** issued at 14:47 on 19th June 2006

SRC notice 1 for 17:30 period on 19th June 2006

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Telephone : 0800 488 500
Facsimile : 07 843 7176

To: CAN Energy Traders

Date: 18 Jun 2006, 13:36

From: System Operator

Standby Reserve (CAN) for Insufficient dispatch proposals on 19-Jun-2006 from 17:30 to 18:30

The System Operator advises participants that there are insufficient standby reserves available for the following trading periods:

Following a contingent event:
- There may be insufficient generation reserve available for the System Operator to re-dispatch the system to a secure state (i.e. manage a subsequent contingent event).
- Demand management may be required

Market Day	Time	Period	North Island	South Island	New Zealand
19-Jun-2006	17:30	36	63.606		5.757
19-Jun-2006	18:00	37	96.723		29.044
19-Jun-2006	18:30	38	50.636		

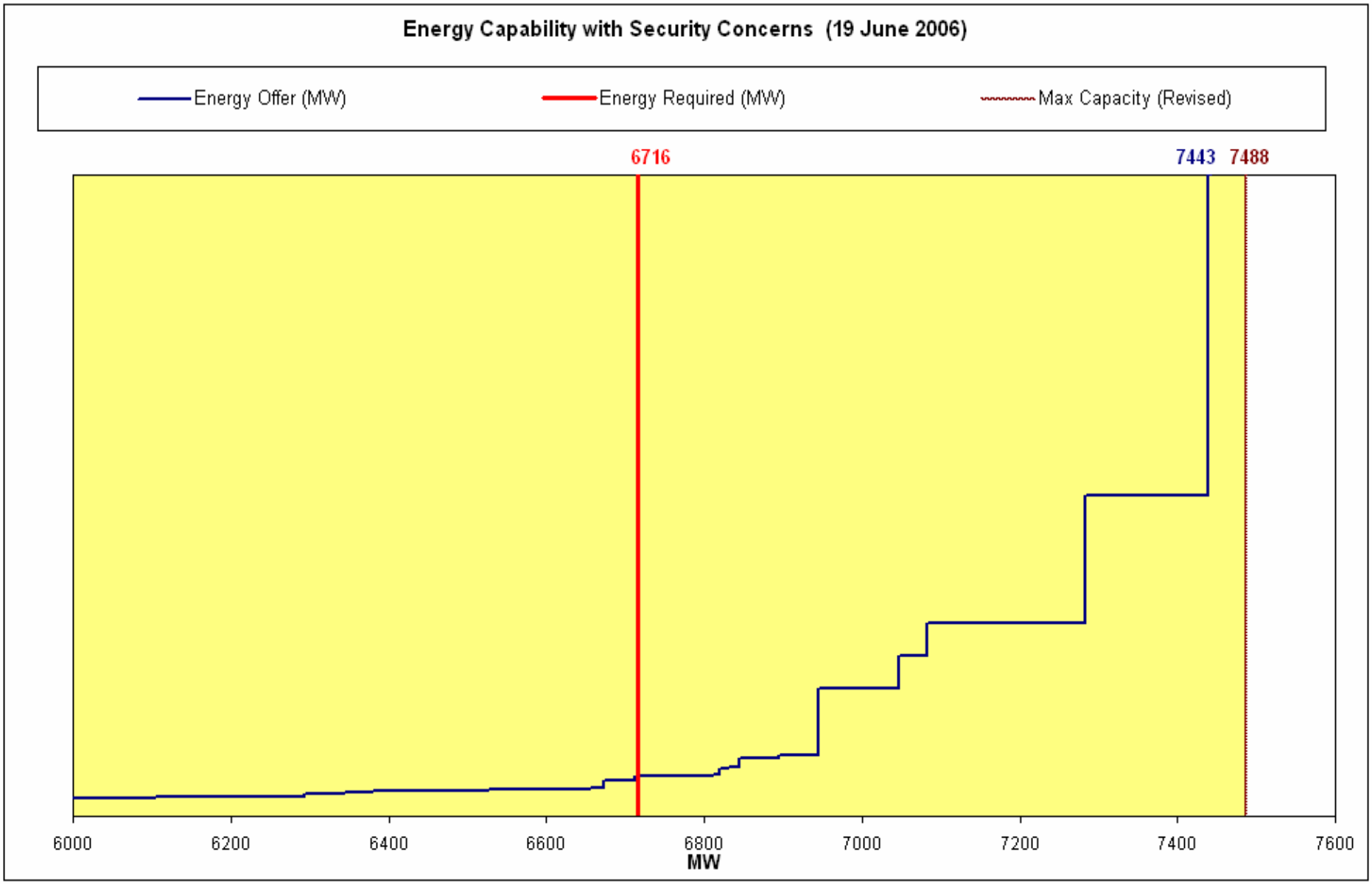
This situation can be alleviated by participants revising their demand and generation offers for those trading periods.

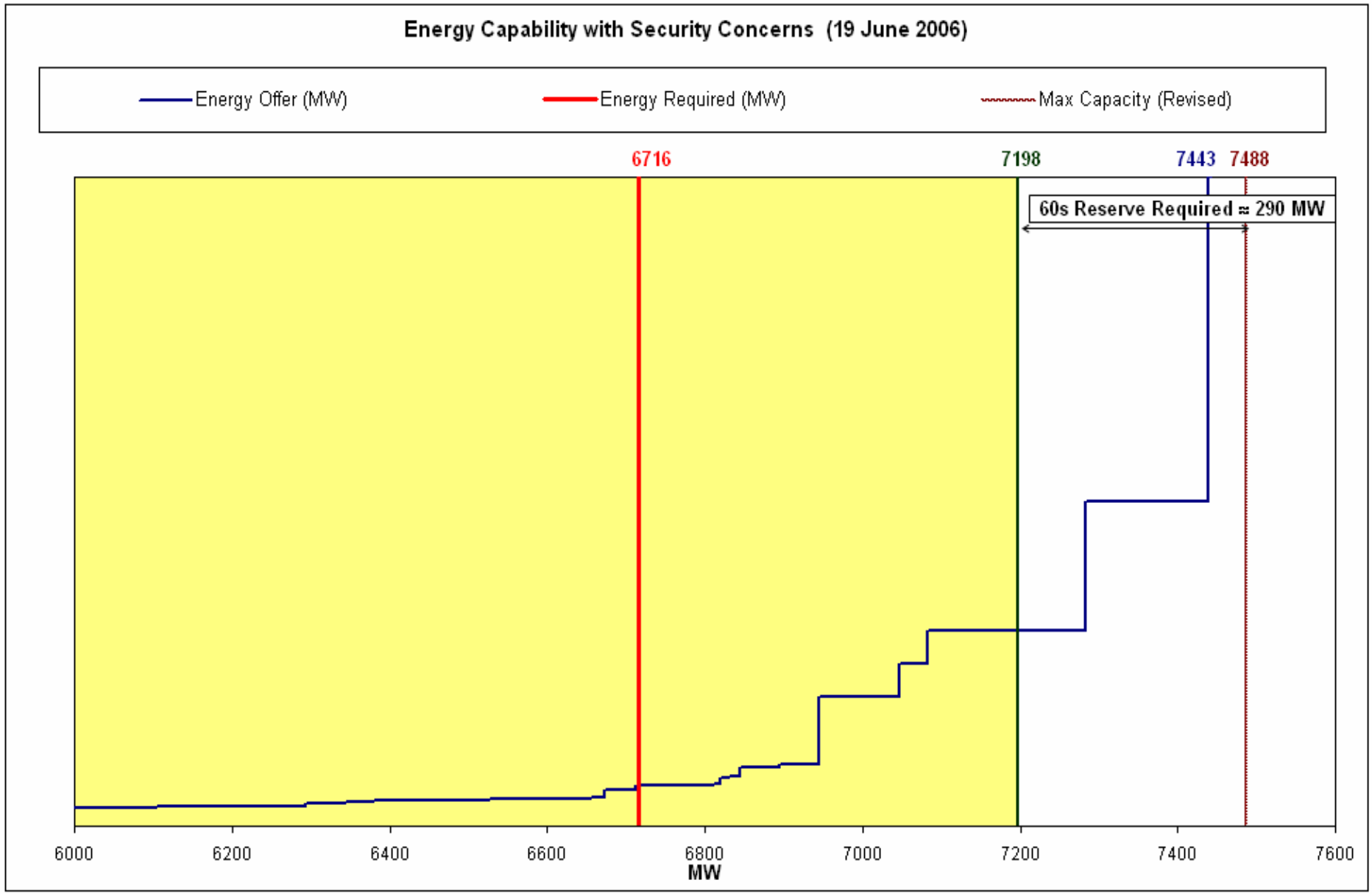
A revision of this notice will be issued if there is any change to the situation advised above.

- demand management may be required if short of energy offers following a CE
- SPD may have infeasible solutions for energy and/or reserve following a CE if short of capacity

Things to note about SRC

- SRC a simple set of calculations derived from SPD solutions
- does not consider transmission constraints that may affect generation
- HVDC only transmission event included in calculations


Energy Capability with Security Concerns (19 June 2006)
Energy Offer (MW)
Energy Required (MW)
Max Capacity (Revised)
6716
7443
7488
6000
6200
6400
6600
6800
7000
7200
7400
7600
MW


Energy Capability with Security Concerns (19 June 2006)
Energy Offer (MW)
Energy Required (MW)
Max Capacity (Revised)
6716
7198
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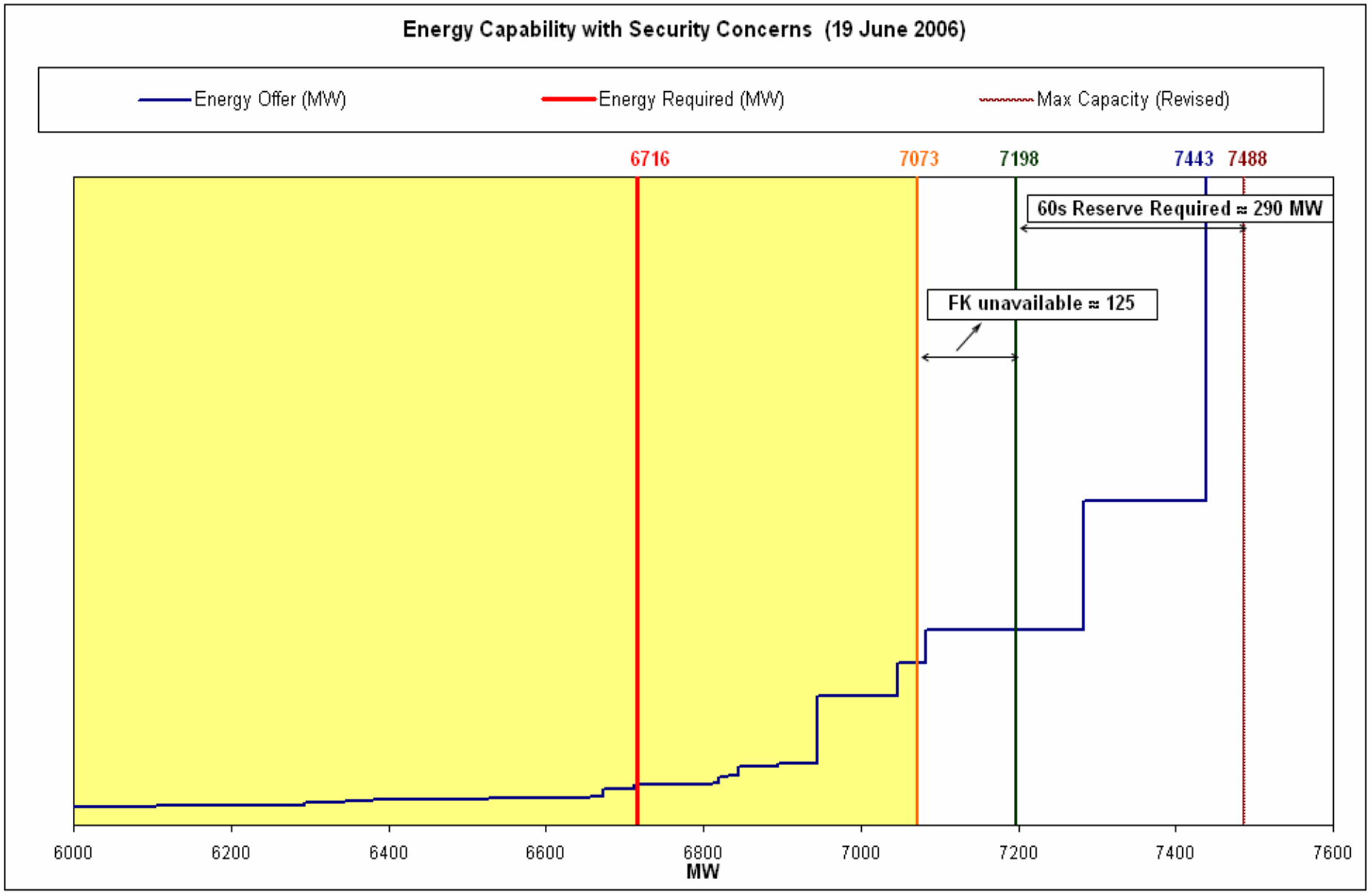
7488
60s Reserve Required ≈ 290 MW
6000
6200
6400
6600
6800
7000
7200
7400
7600
MW


Energy Capability with Security Concerns (19 June 2006)
Energy Offer (MW)
Energy Required (MW)
Max Capacity (Revised)
6716
7073
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60s Reserve Required ≈ 290 MW
FK unavailable ≈ 125
6000
6200
6400
6600
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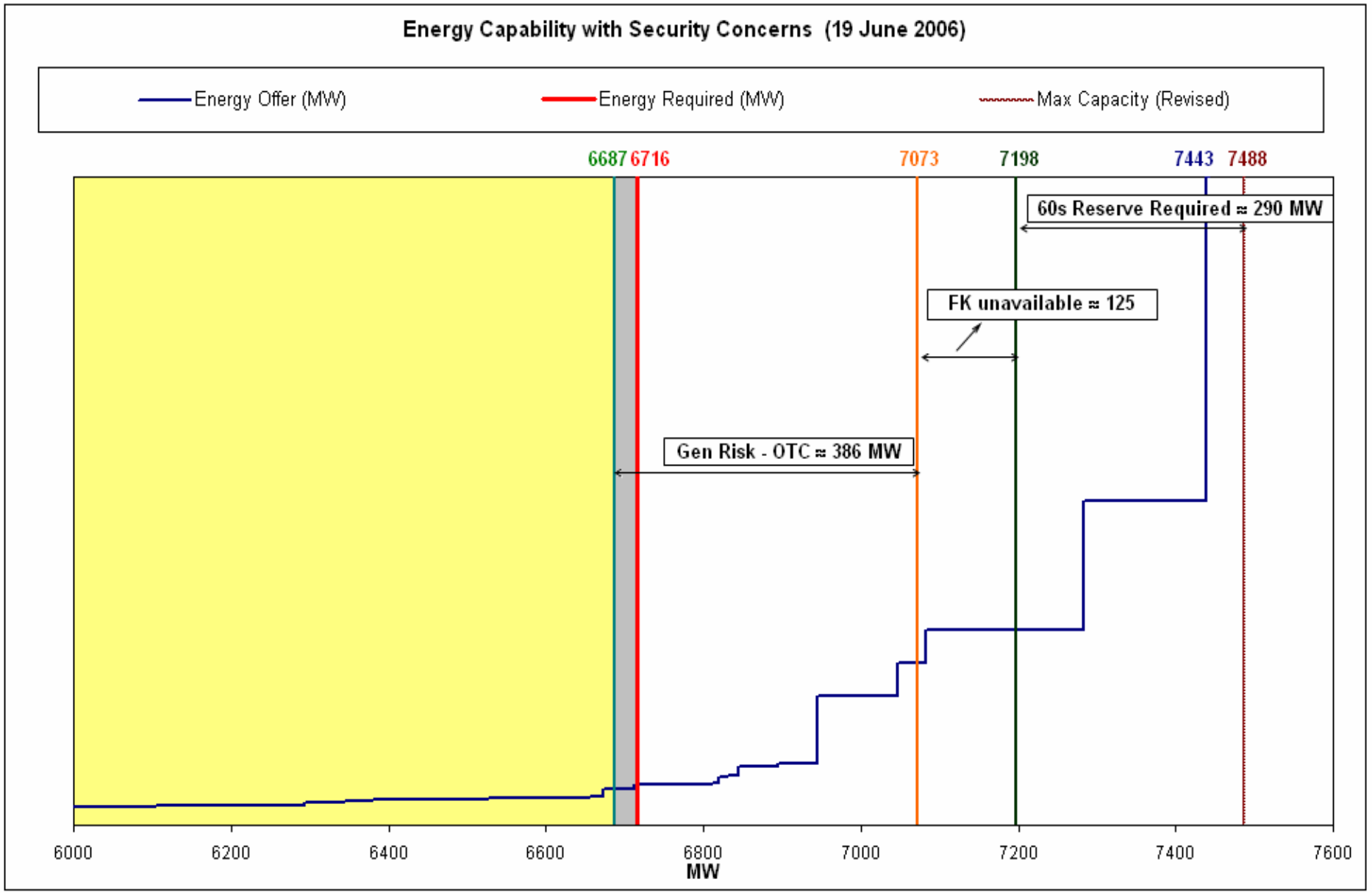
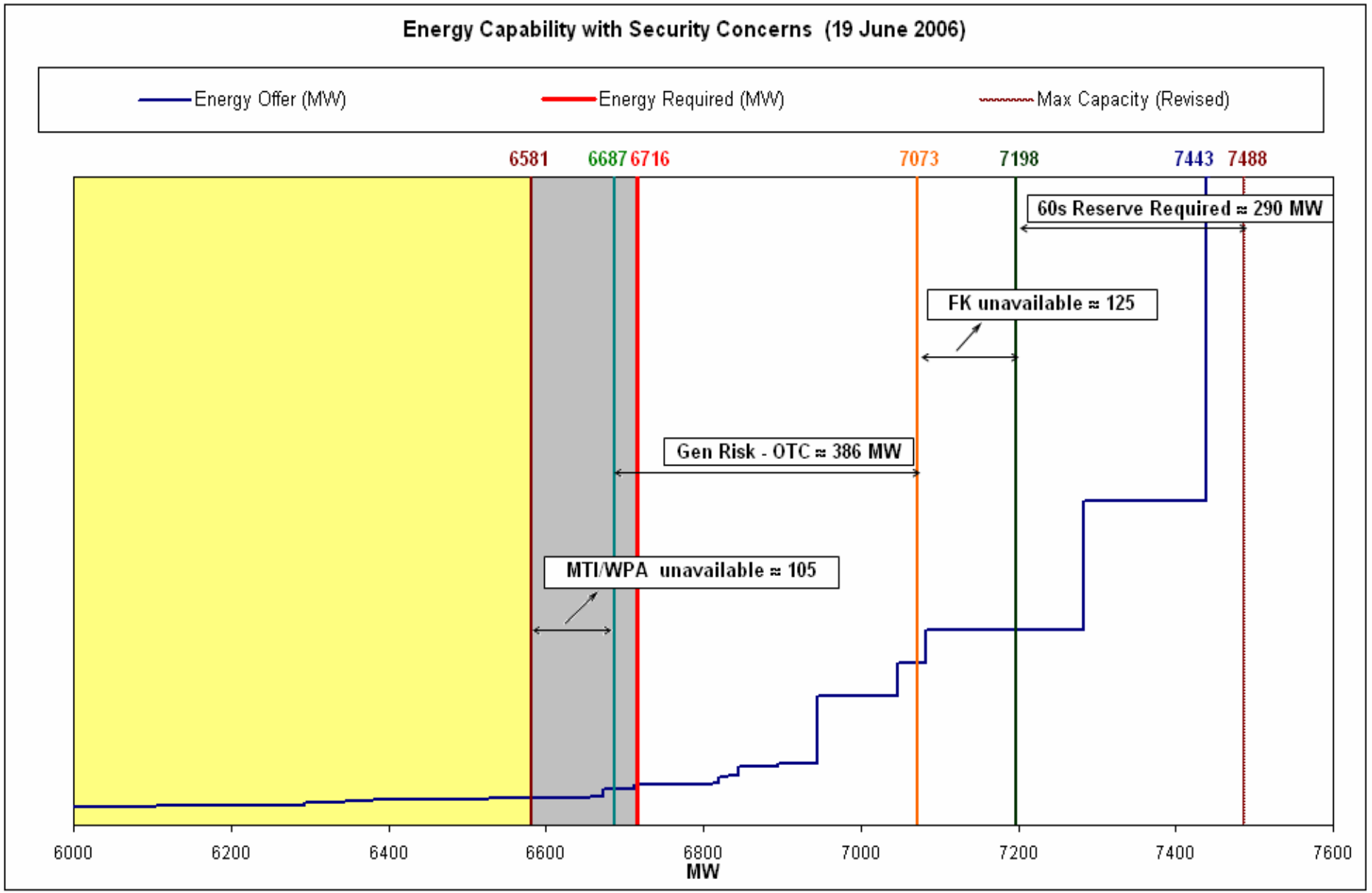
7000
7200
7400
7600
MW


Energy Capability with Security Concerns (19 June 2006)
Energy Offer (MW)
Energy Required (MW)
Max Capacity (Revised)
6687
6716
7073
7198
7443
7488
60s Reserve Required ≈ 290 MW
FK unavailable ≈ 125
Gen Risk - OTC ≈ 386 MW
6000
6200
6400
6600
6800
7000
7200
7400
7600
MW


Energy Capability with Security Concerns (19 June 2006)
Energy Offer (MW)
Energy Required (MW)
Max Capacity (Revised)
6581
6687
6716
7073
7198
7443
7488
60s Reserve Required ≈ 290 MW
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MTI/WPA unavailable ≈ 105
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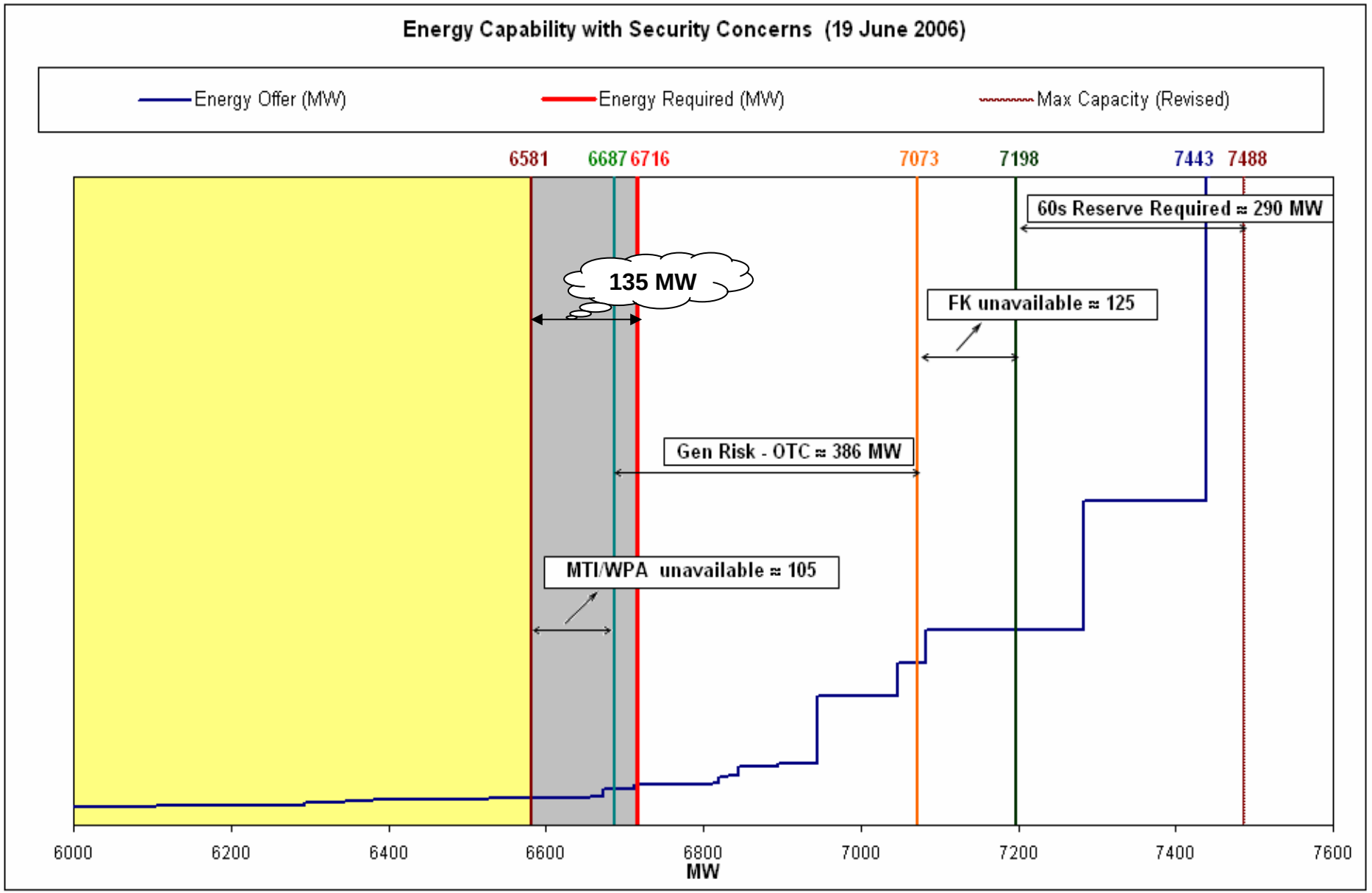
6200
6400
6600
6800
7000
7200
7400
7600
MW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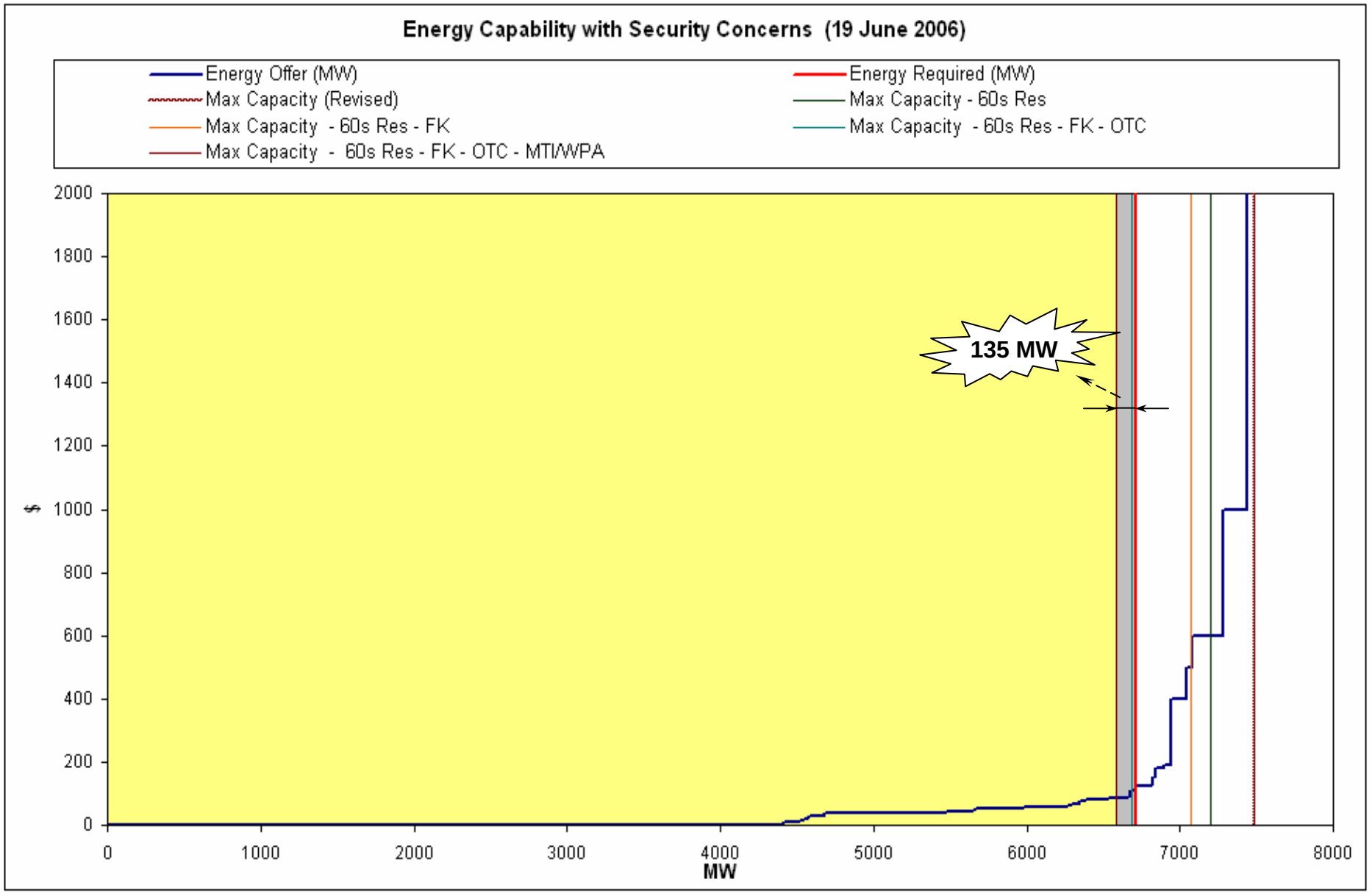
7600
MW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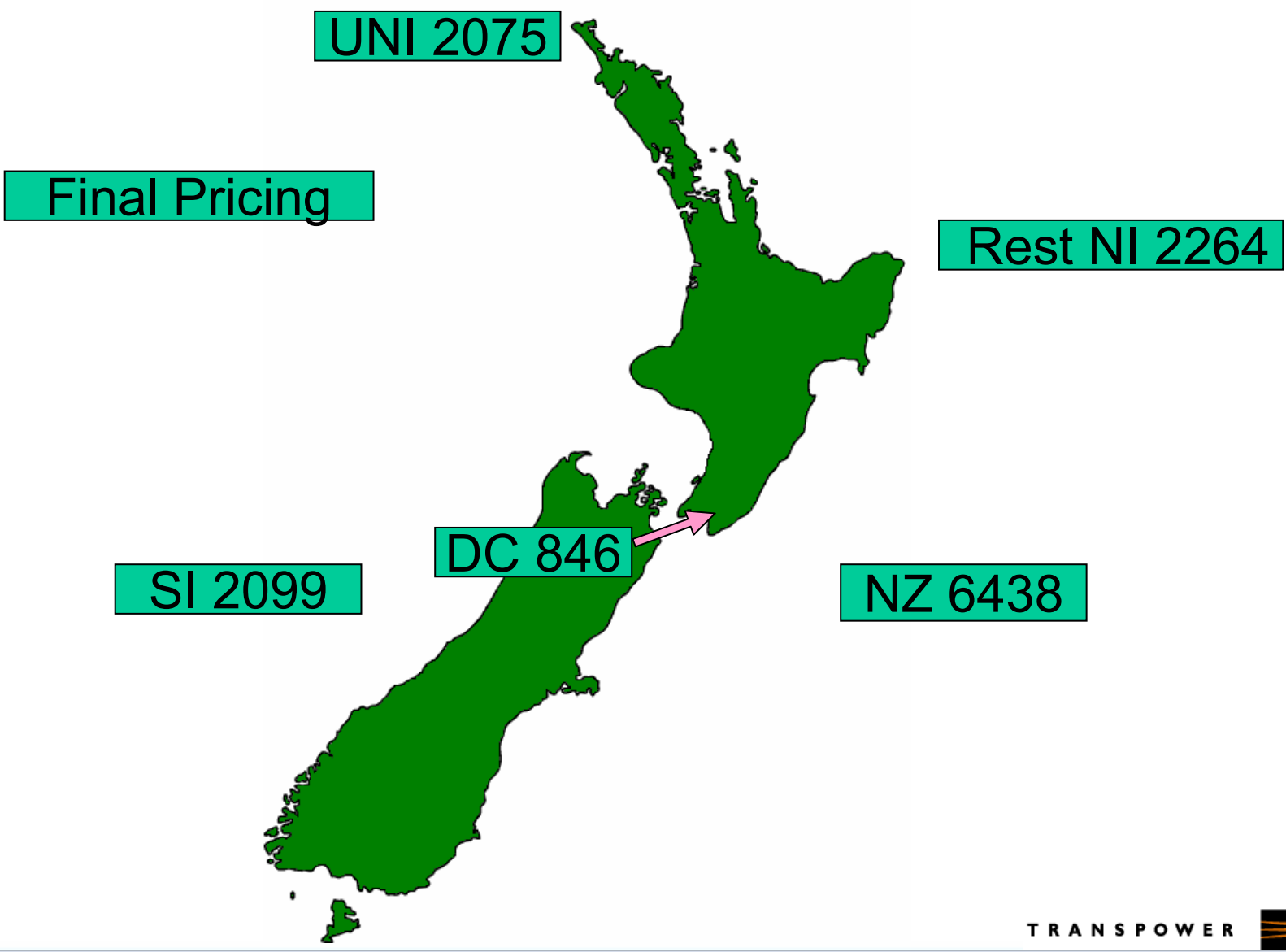
Energy Offer (MW)
Energy Required (MW)
Max Capacity (Revised)
Max Capacity - 60s Res
Max Capacity - 60s Res - FK
Max Capacity - 60s Res - FK - OTC
Max Capacity - 60s Res - FK - OTC - MTI/WPA
135 MW
$
2000
1800
1600
1400
1200
1000
800
600
400
200
0
0
1000
2000
3000
4000
5000
6000
7000
8000
MW

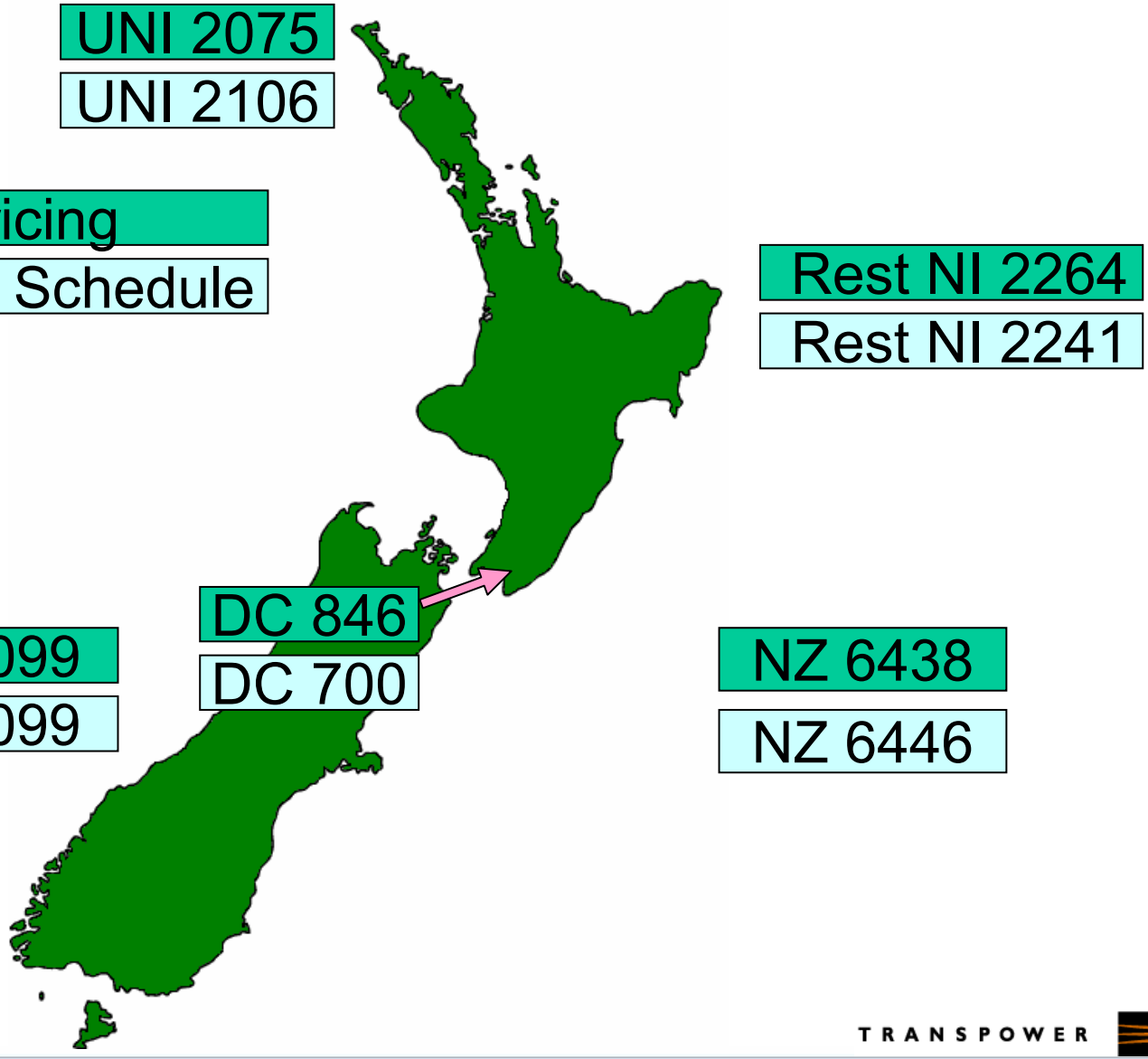
LOAD

18 June 2006 13:00 FP



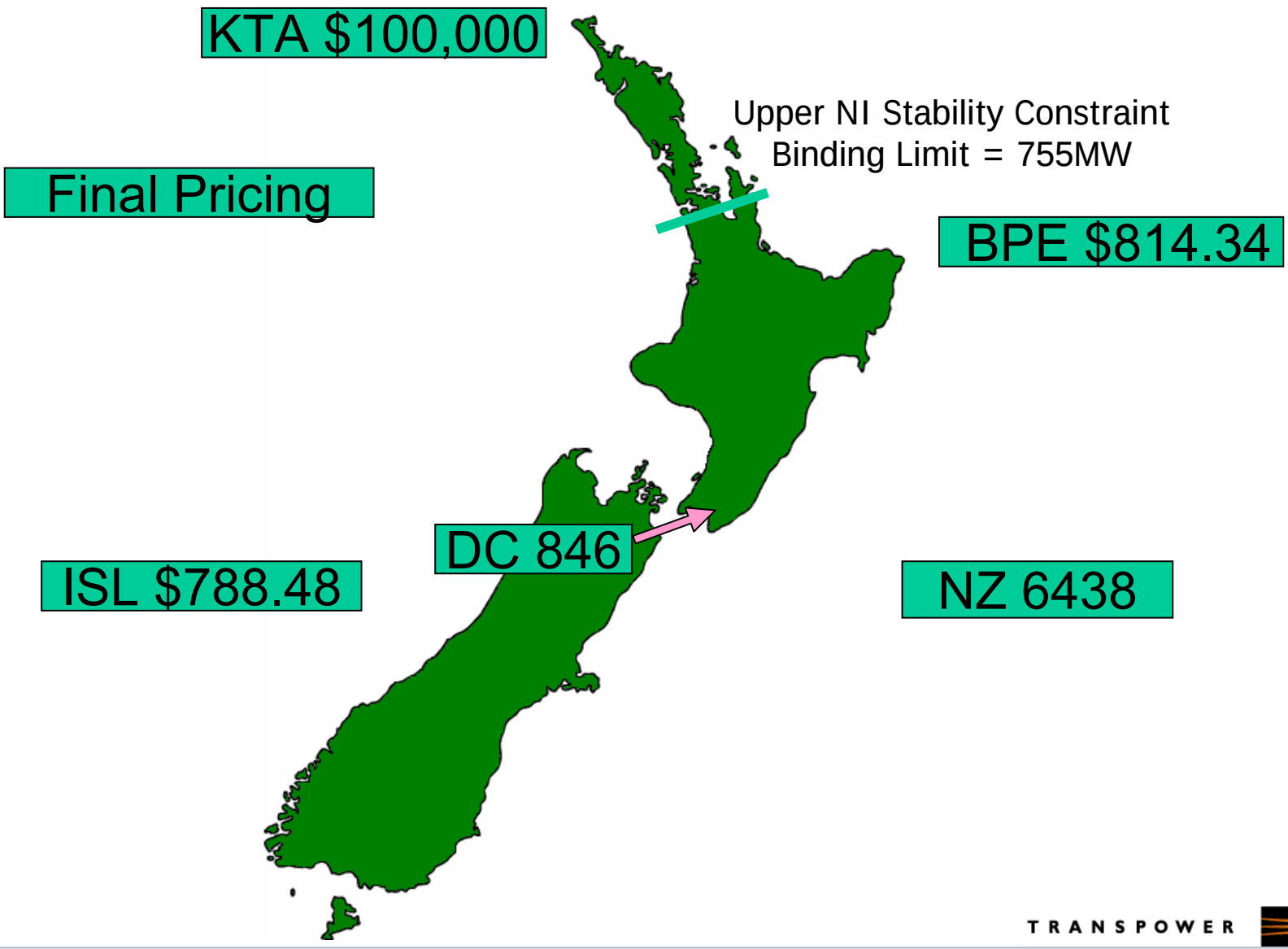
LOAD

18 June 2006 13:00 PDS/FP



PRICE

18 June 2006 13:00 FP



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PRICE

18 June 2006 13:00 PDS/FP

KTA $100,000

KTA $475.86

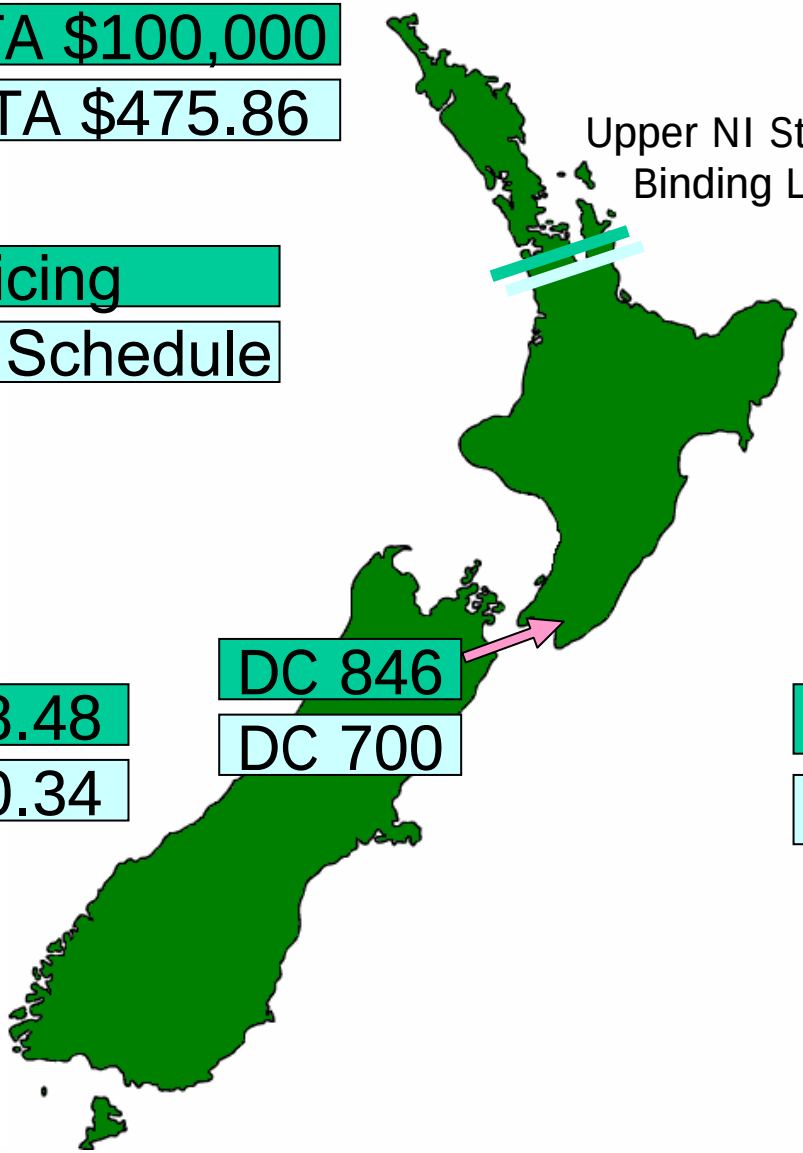
Upper NI Stability Constraint
Binding Limit = 755MW

Final Pricing

Pre Dispatch Schedule

BPE $814.34

BPE $287.82



DC 846

DC 700

ISL $788.48

ISL $280.34

NZ 6438

NZ 6446

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18 June 13:00 summary

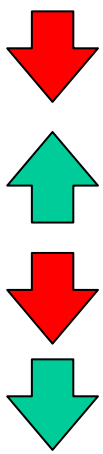
	18 June 13:00 SDS
Total ENOF	7443MW
Wind Forecast	54MW
NI 60s Offered	548MW
Load	6445MW

19 June 17:00 summary

	18 June 13:00 SDS		19 June 17:00 SDPQ
Total ENOF	7443MW	-116 ↓	7300MW
Wind Forecast	54MW	+48 ↑	102MW
NI 60s Offered	548MW	-181 ↓	367MW
Load	6445MW	-7 ↓	6438MW

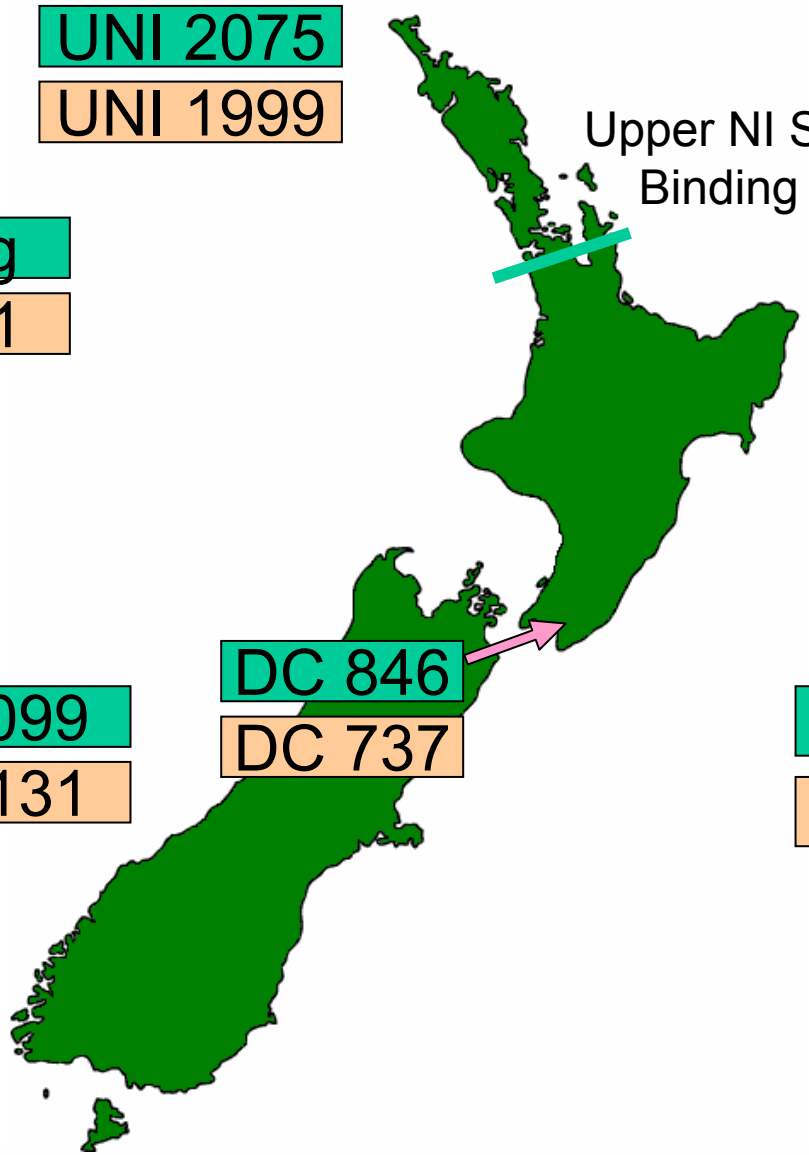
19 June 17:29 summary

	18 June 13:00 SDS		Final total
Total ENOF	7443MW	-152	7291MW
Wind Forecast	54MW	+57	111MW
NI 60s Offered	548MW	-181	367MW
Load	6445MW	-5	6440MW



LOAD

17:00 - 17:29 19th



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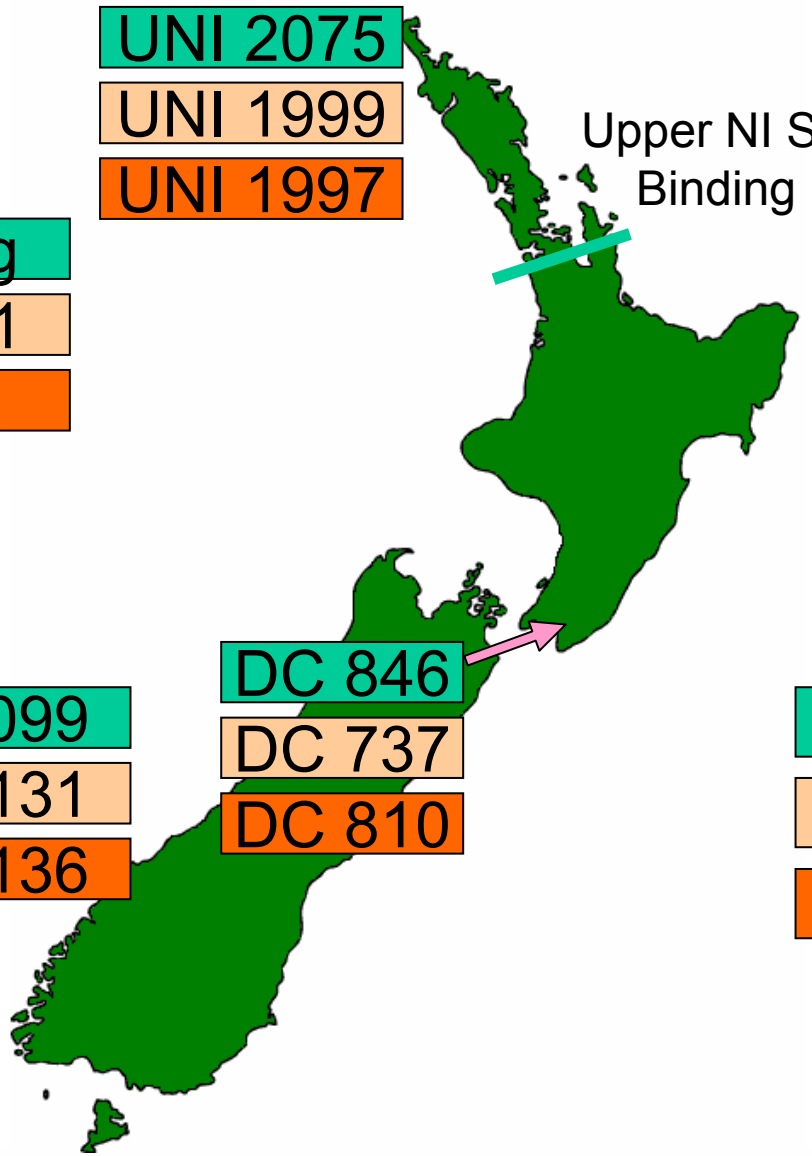
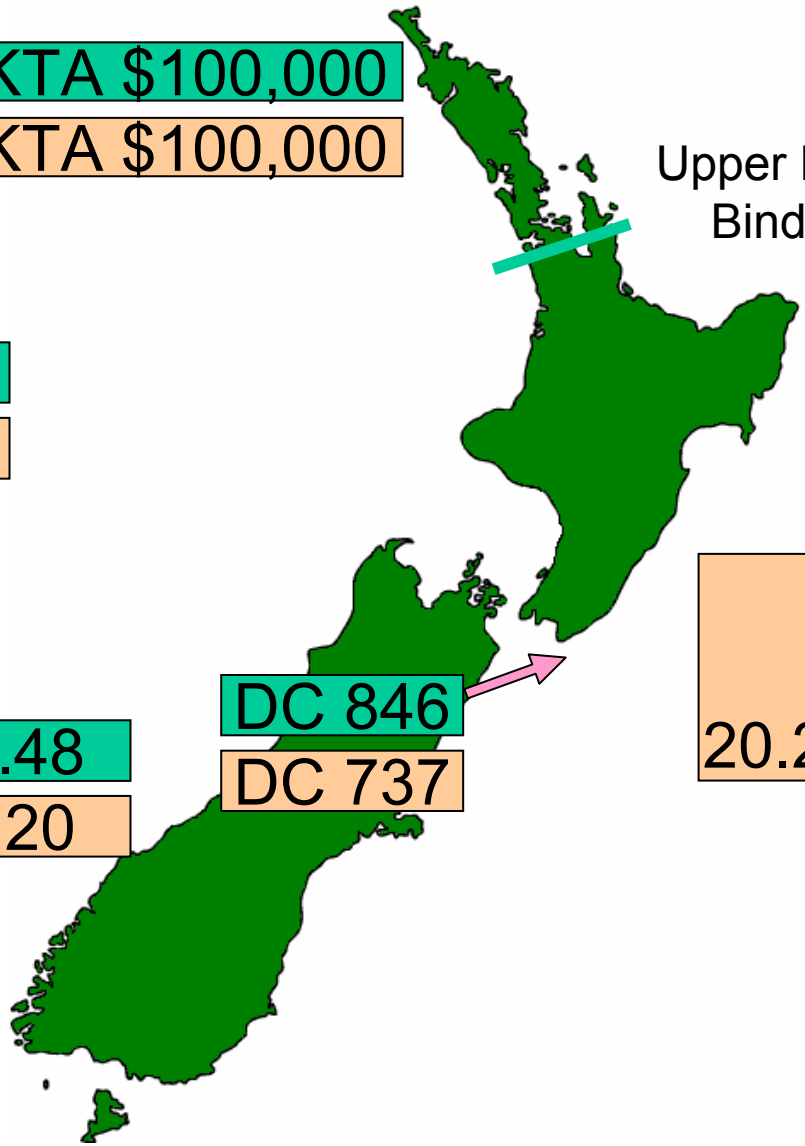
17:00 - 17:29 19th



PRICES

17:00 - 17:29 19th



KTA $100,000

KTA $100,000

Upper NI Stability Constraint
Binding Limit = 755MW

BPE $814.34

BPE $83,354.12

Final Pricing

SDPQ 17:11

7:11 SDPQ
19.82 Def Gen
20.27 Def NI 60s Res

DC 846

DC 737

ISL $788.48

ISL $362.20

TRANSPOWER

PRICES

17:00 - 17:29 19th

KTA $100,000
KTA $100,000
KTA $100,000

Upper NI Stability Constraint
Binding Limit = 755MW

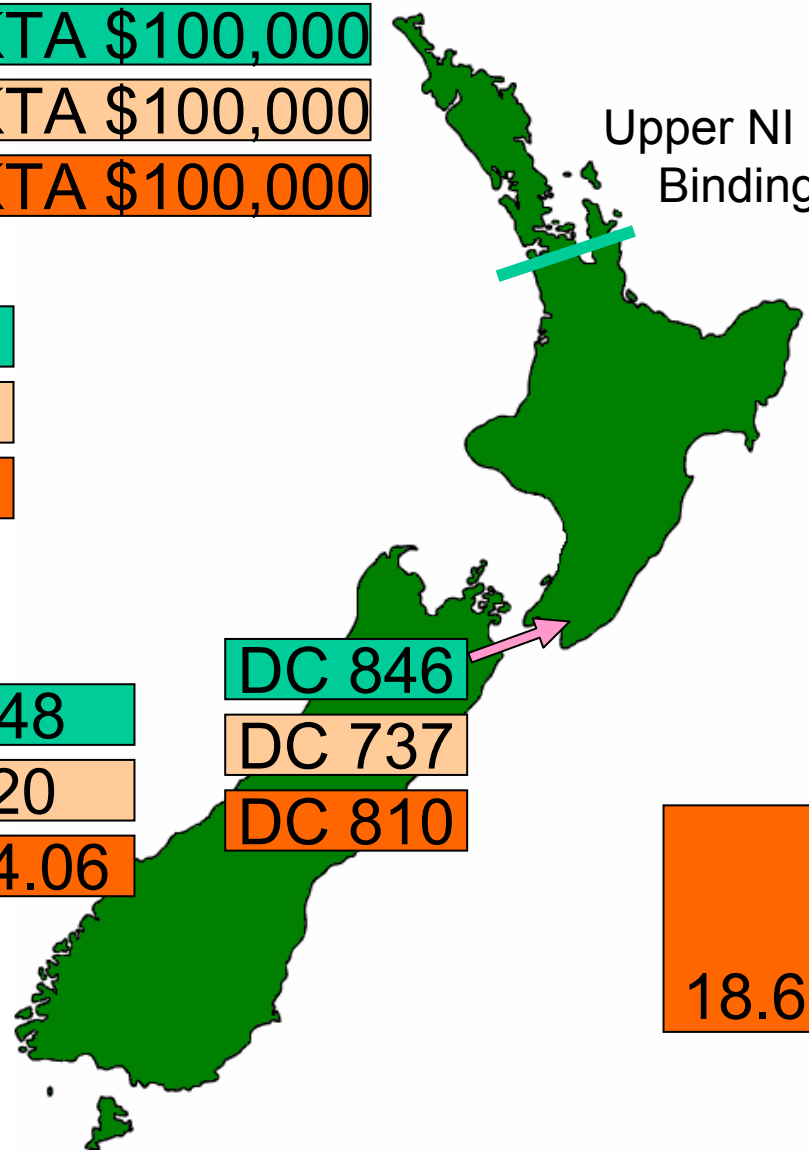
BPE $814.34
BPE $83,354.12
BPE $83,781.96

Final Pricing
SDPQ 17:11
RTD 17:29

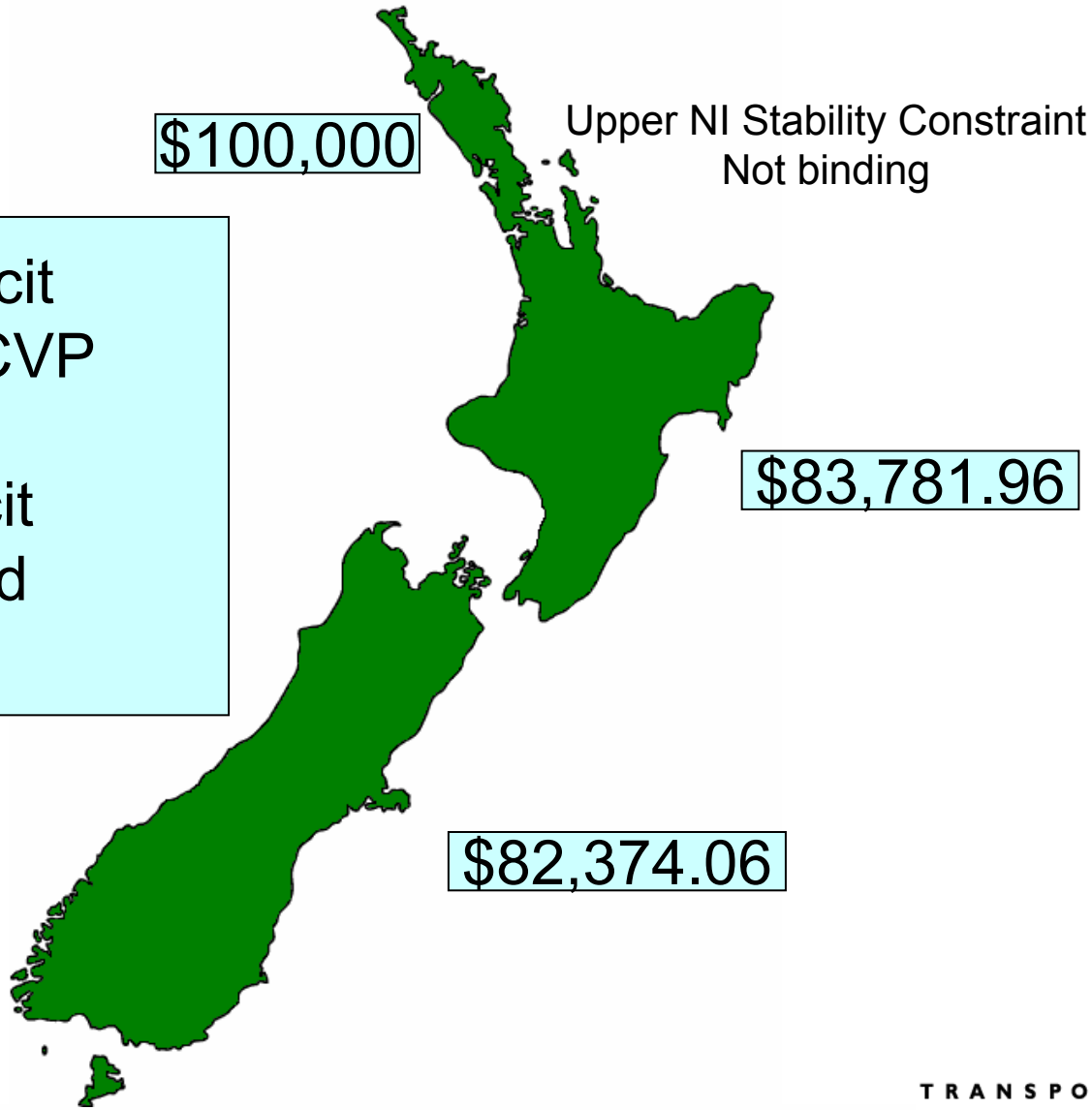
DC 846
DC 737
DC 810

ISL $788.48
ISL $362.20
ISL $ 82,374.06

17:29 RTD
42 Def Gen
18.63 Def NI 60s Res

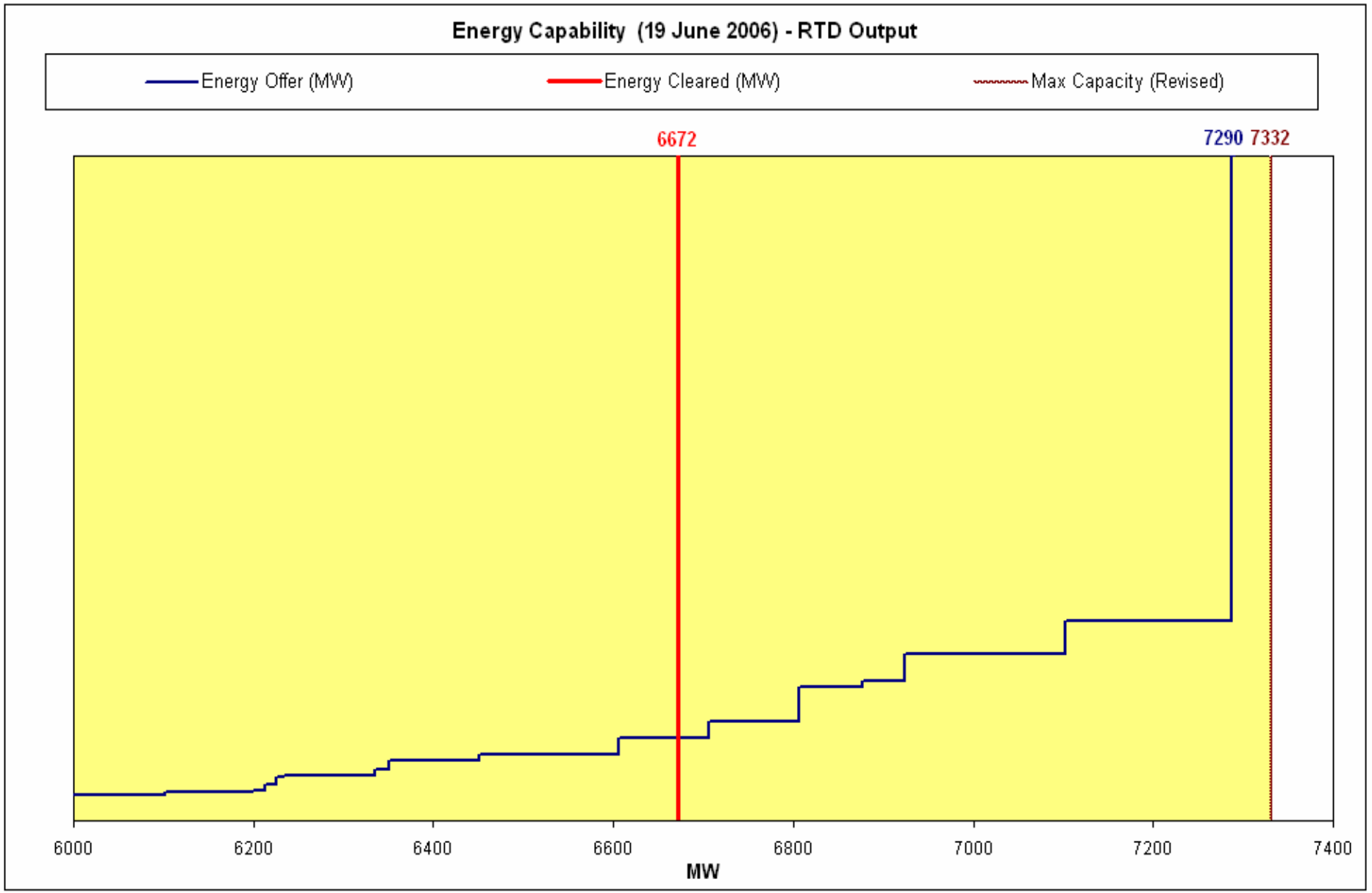


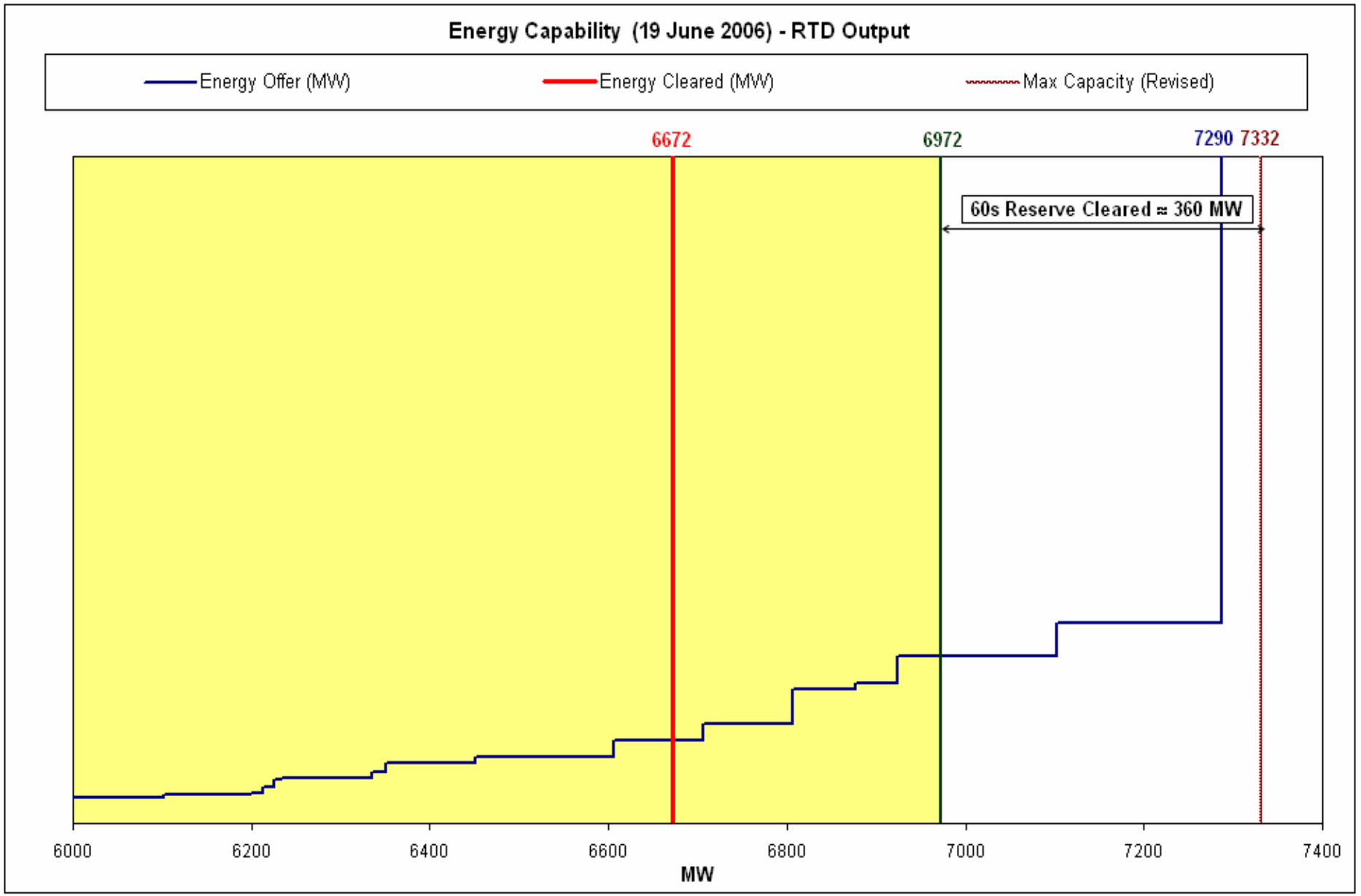
17:29 Real Time Dispatch

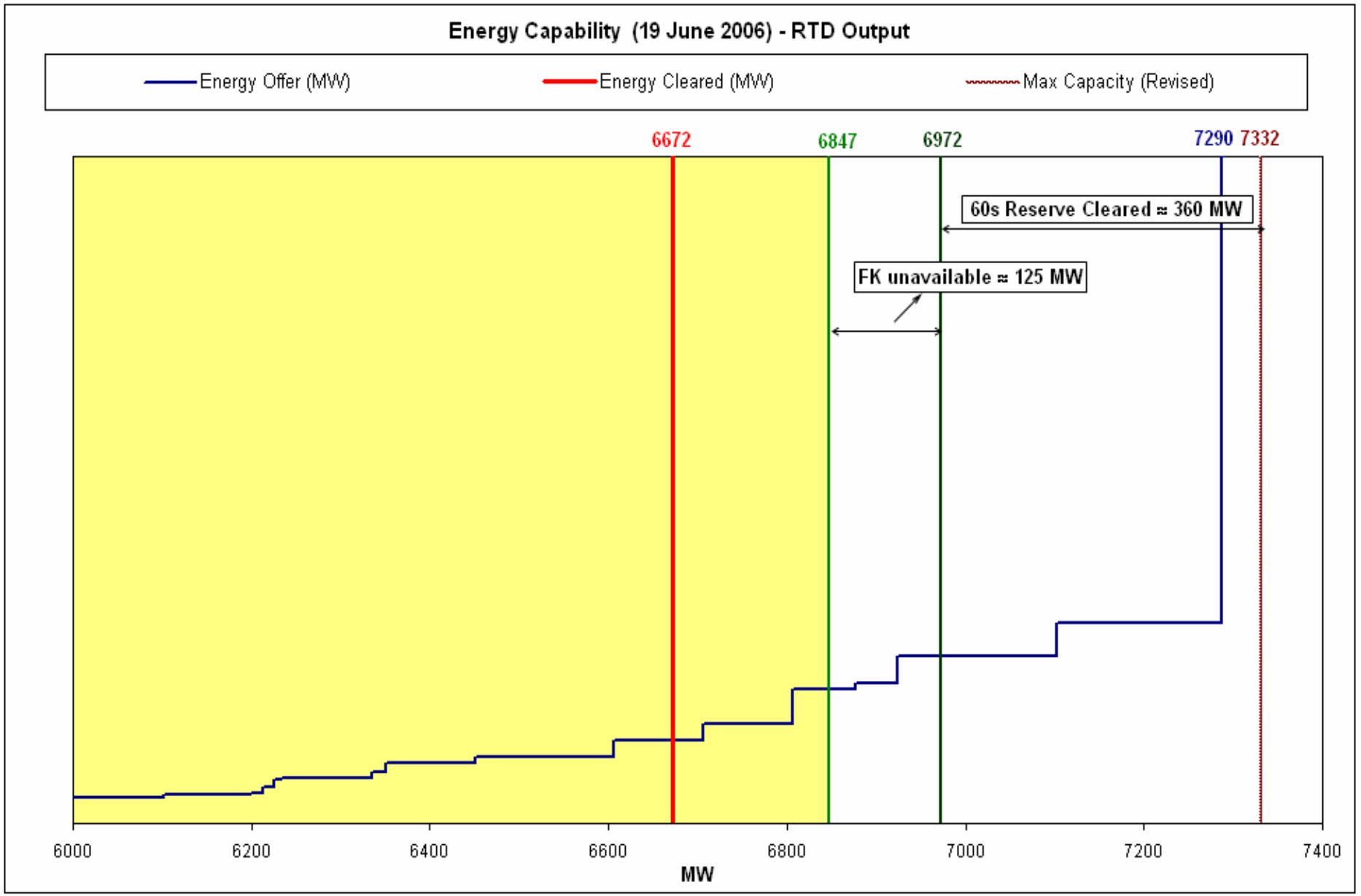


42 MW Deficit
Generation CVP

18.63 Deficit
North Island
SIR CVP


Energy Capability (19 June 2006) - RTD Output
Energy Offer (MW)
Energy Cleared (MW)
Max Capacity (Revised)
6672
7290
7332
6000
6200
6400
6600
6800
7000
7200
7400
MW


Energy Capability (19 June 2006) - RTD Output
Energy Offer (MW)
Energy Cleared (MW)
Max Capacity (Revised)
6672
6972
7290
7332
60s Reserve Cleared = 360 MW
6000
6200
6400
6600
6800
7000
7200
7400
MW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FK unavailable ≈ 125 MW
6000
6200
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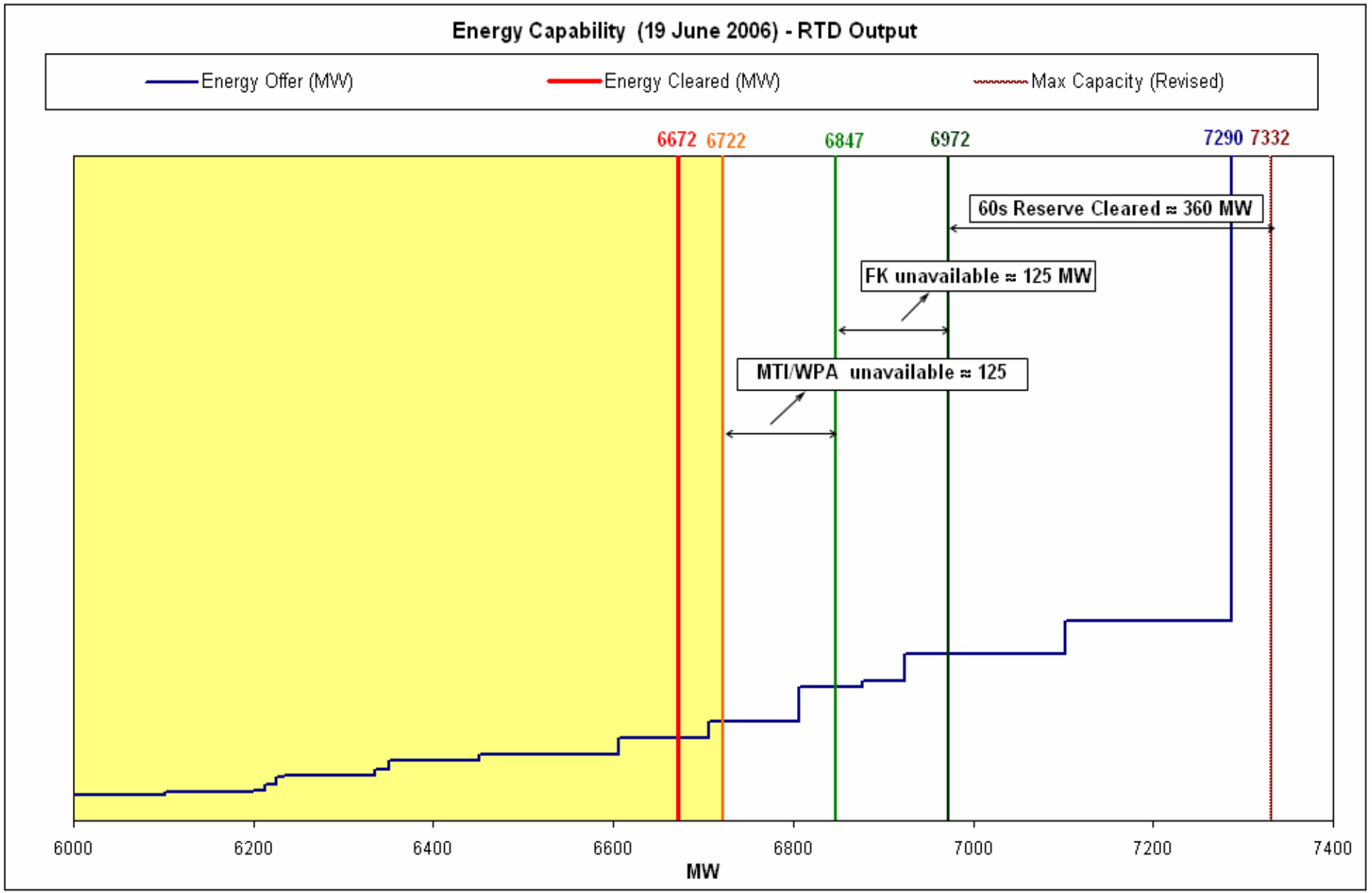
6600
6800
7000
7200
7400
MW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7000
7200
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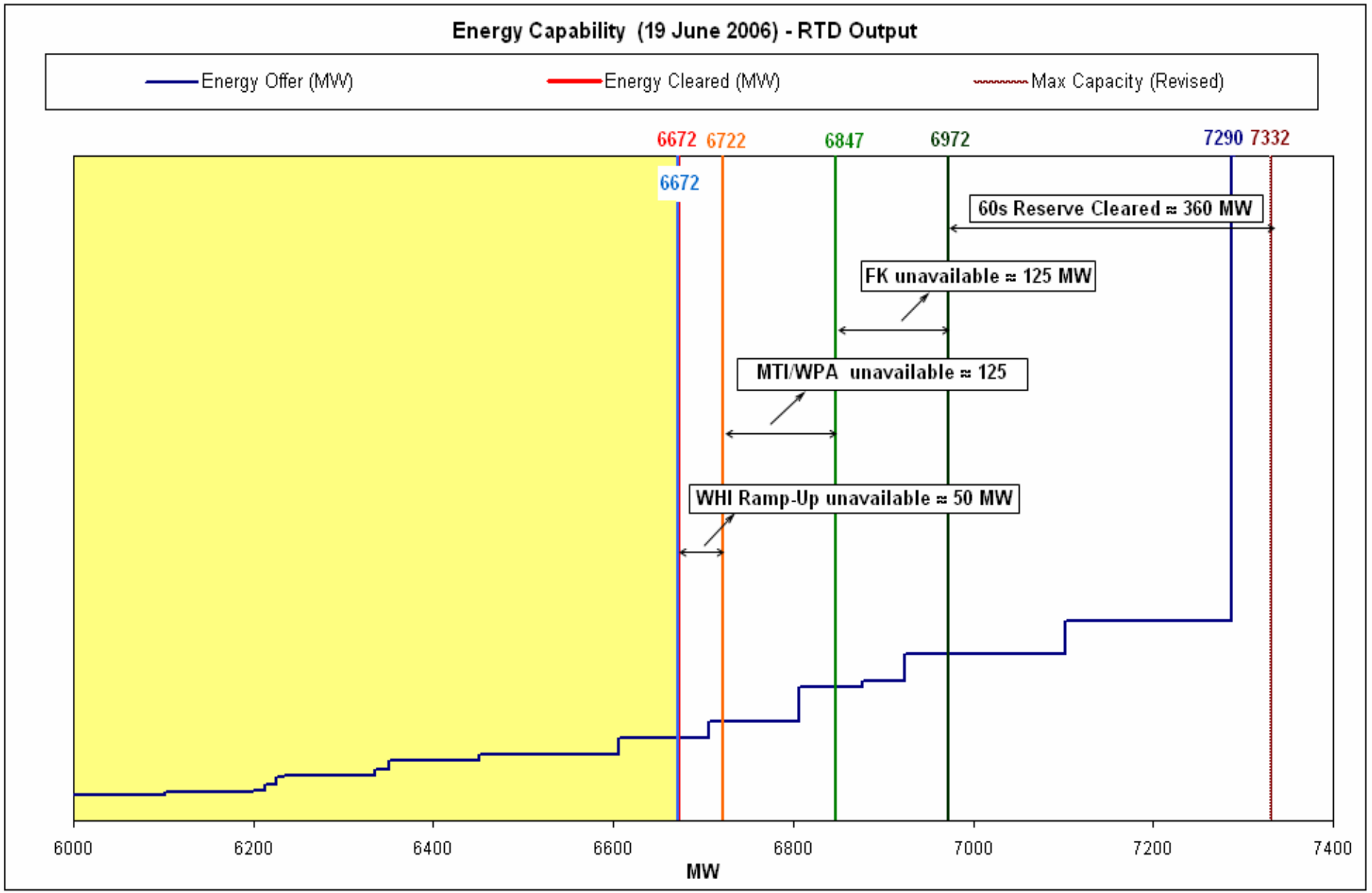
MW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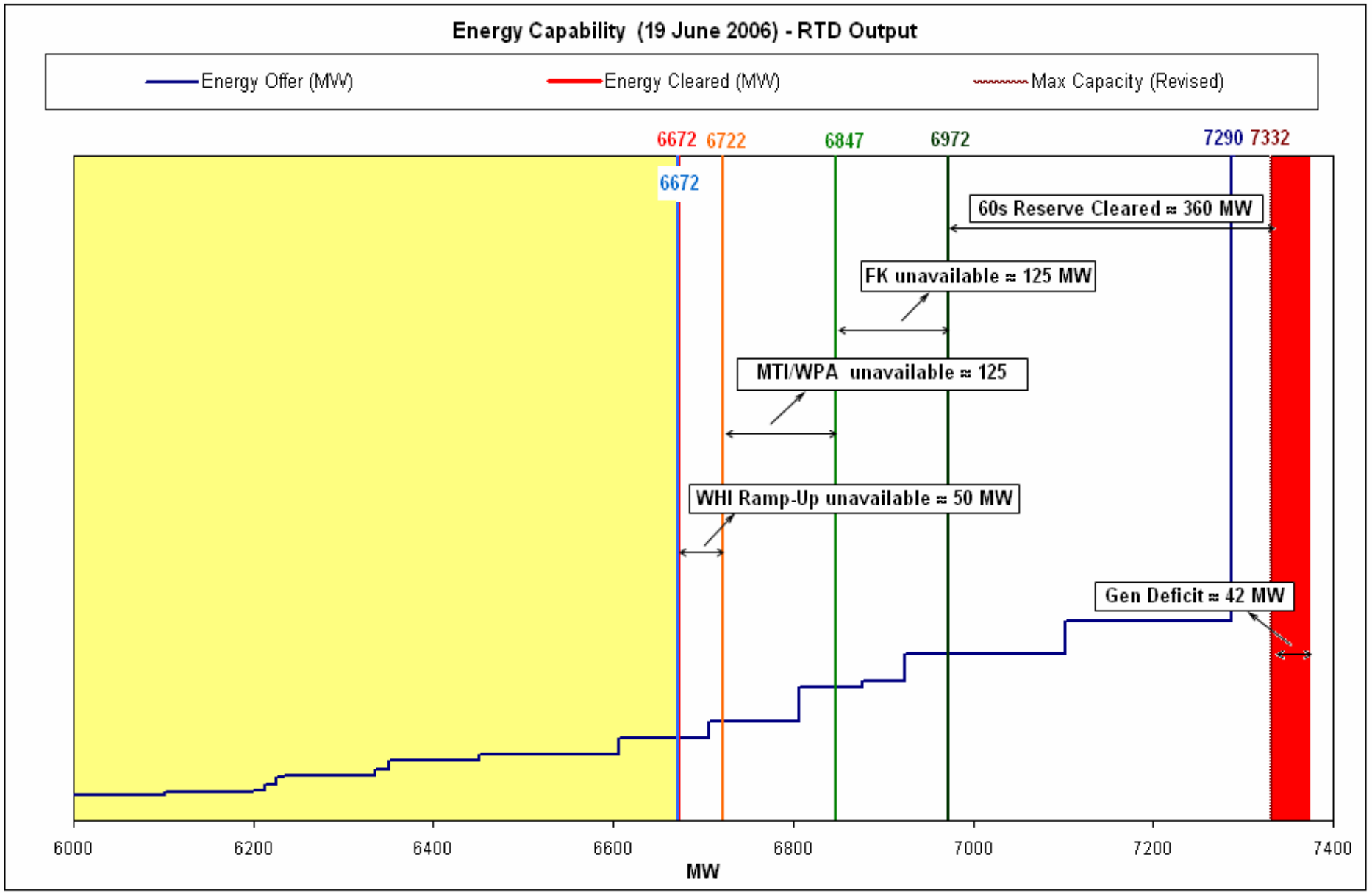
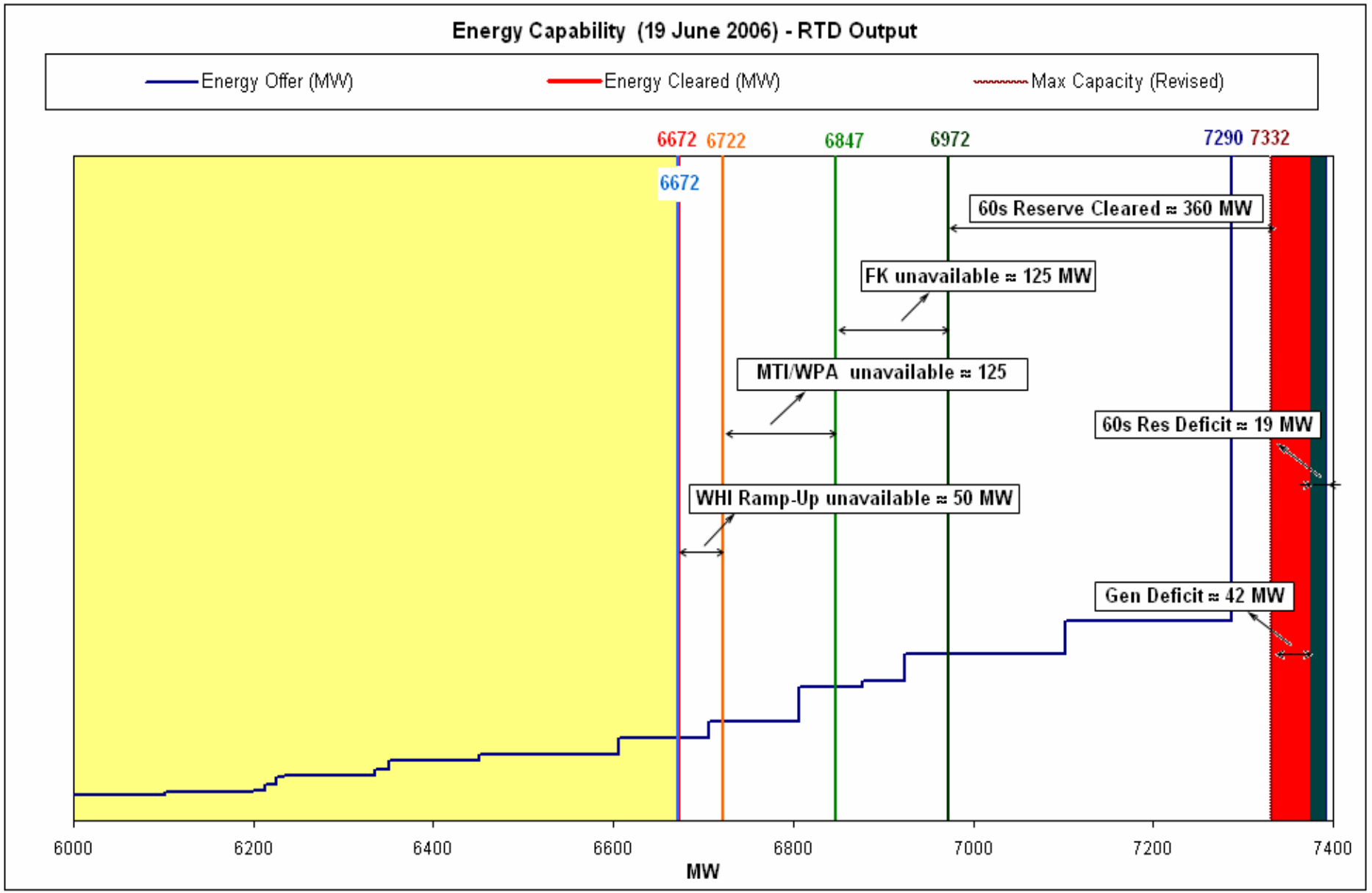
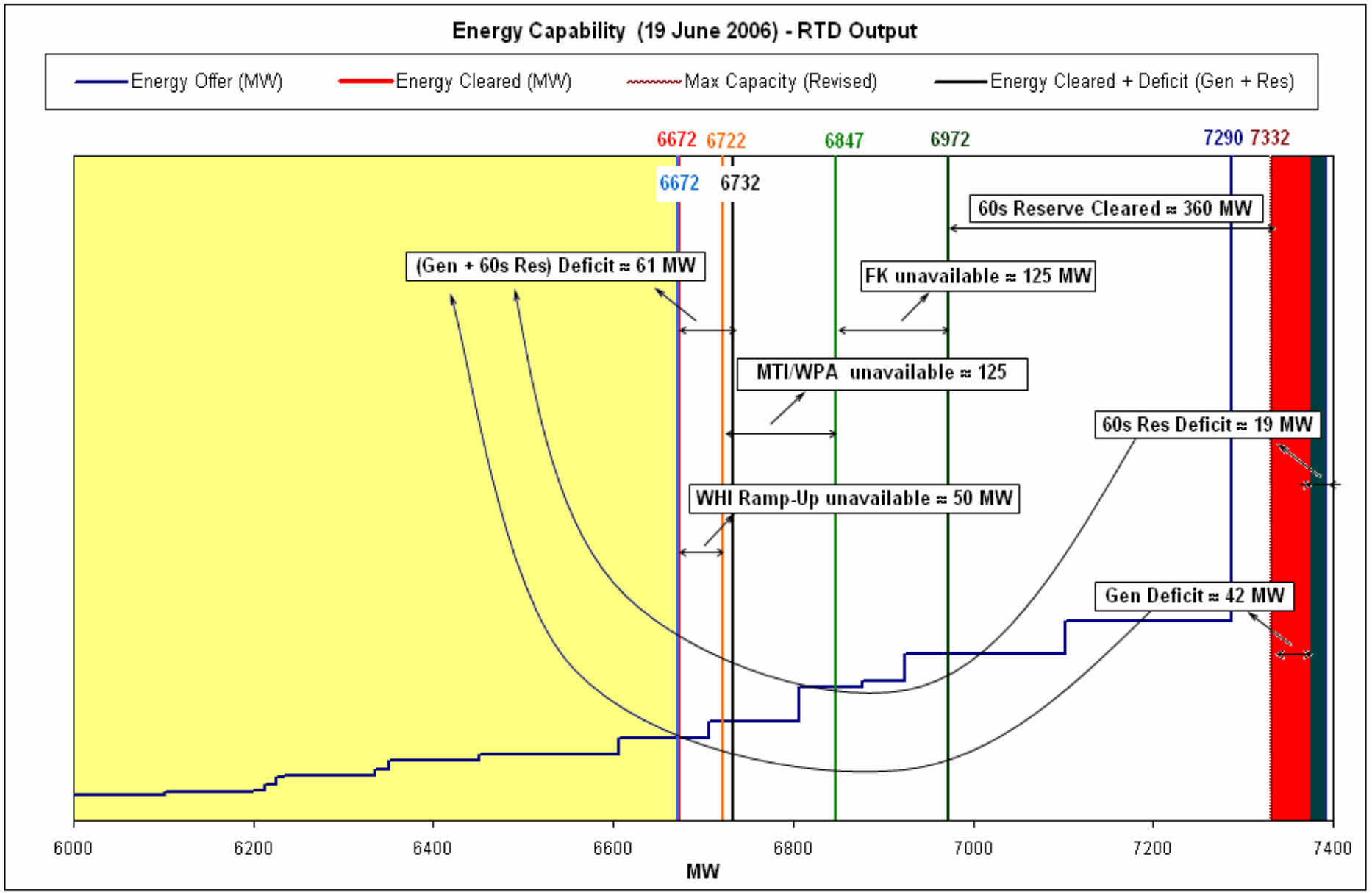
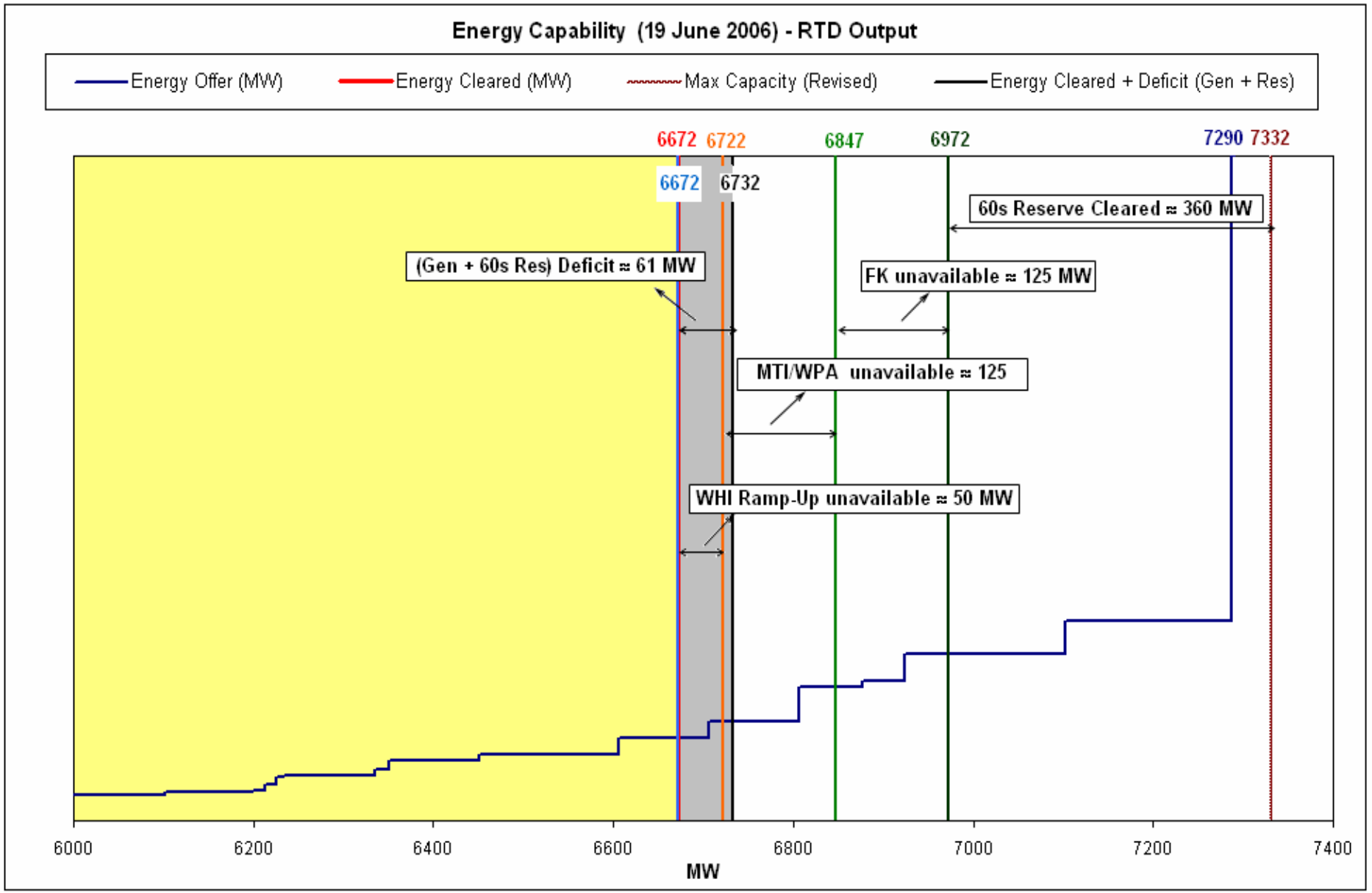
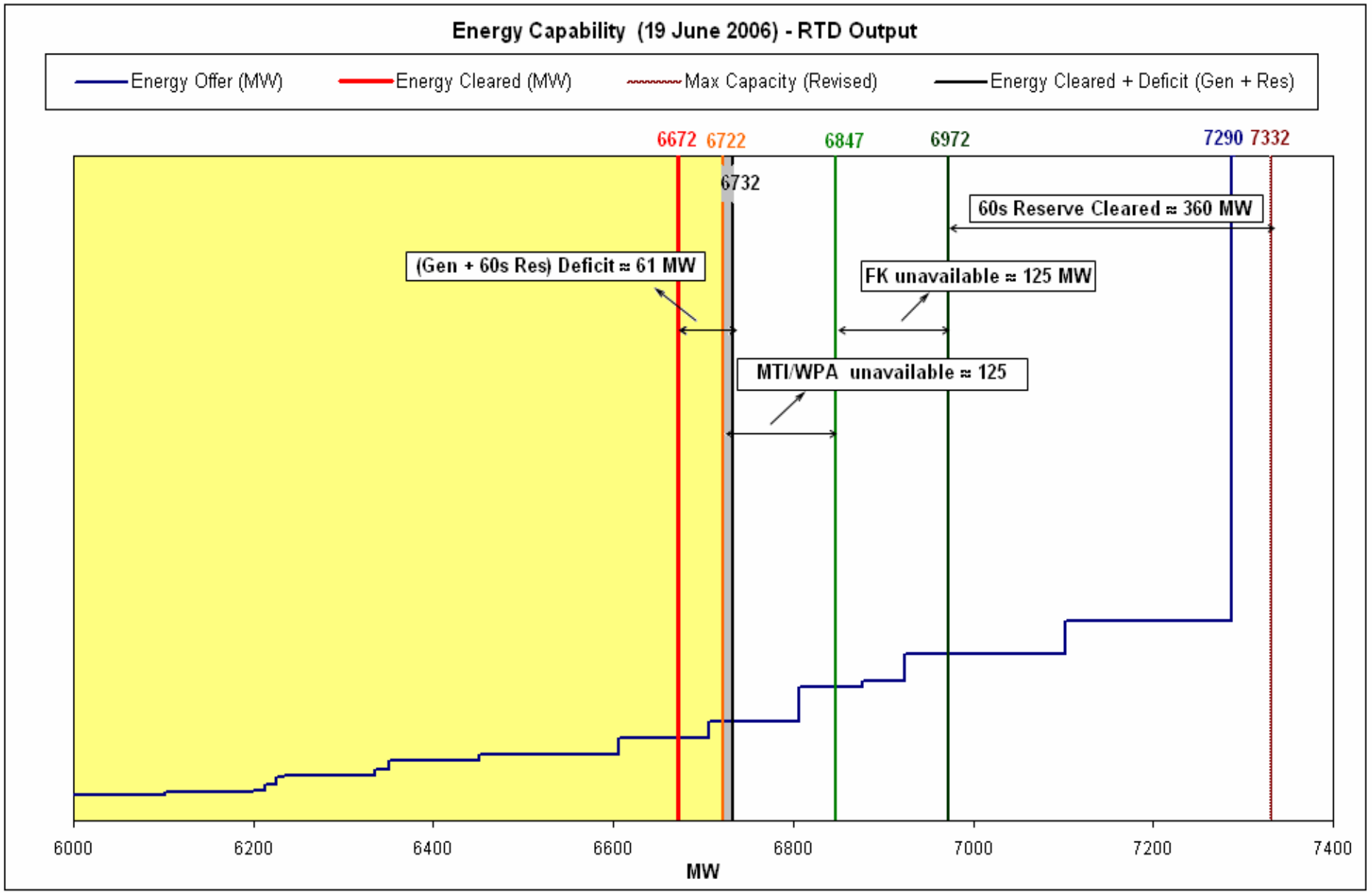
6847
6972
7290
7332
6672
60s Reserve Cleared ≈ 360 MW
FK unavailable ≈ 125 MW
MTI/WPA unavailable ≈ 125
WHI Ramp-Up unavailable ≈ 50 MW
6000
6200
6400
6600
6800
7000
7200
7400
MW

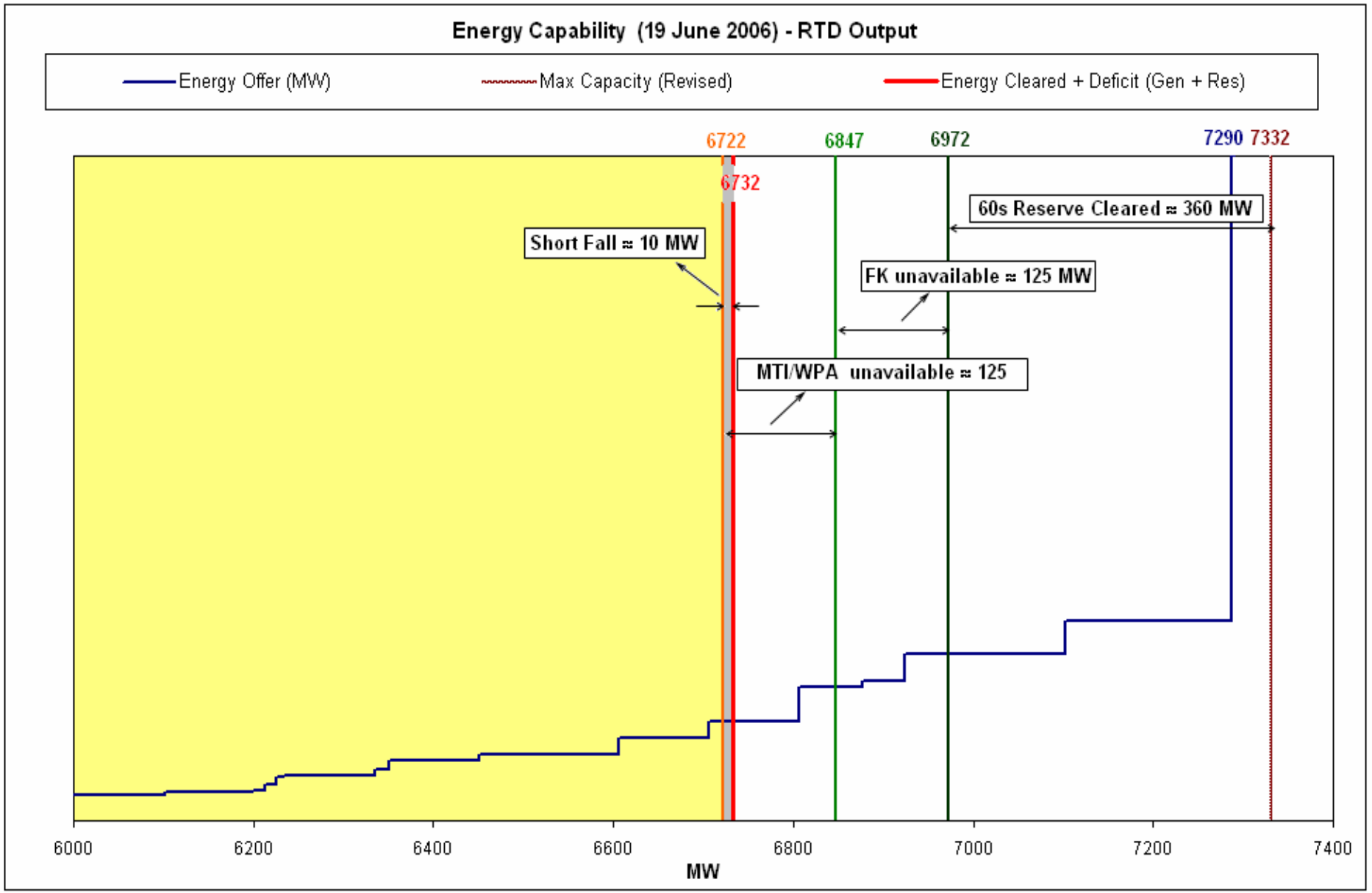

Energy Capability (19 June 2006) - RTD Output
Energy Offer (MW)
Energy Cleared (MW)
Max Capacity (Revised)
6672
6722
6847
6972
7290
7332
6672
60s Reserve Cleared ≈ 360 MW
FK unavailable ≈ 125 MW
MTI/WPA unavailable ≈ 125
WHI Ramp-Up unavailable ≈ 50 MW
Gen Deficit ≈ 42 MW
6000
6200
6400
6600
6800
7000
7200
7400
MW


Energy Capability (19 June 2006) - RTD Output
Energy Offer (MW)
Energy Cleared (MW)
Max Capacity (Revised)
6672
6722
6847
6972
7290
7332
6672
60s Reserve Cleared ≈ 360 MW
FK unavailable ≈ 125 MW
MTI/WPA unavailable ≈ 125
60s Res Deficit ≈ 19 MW
WHI Ramp-Up unavailable ≈ 50 MW
Gen Deficit ≈ 42 MW
6000
6200
6400
6600
6800
7000
7200
7400
MW

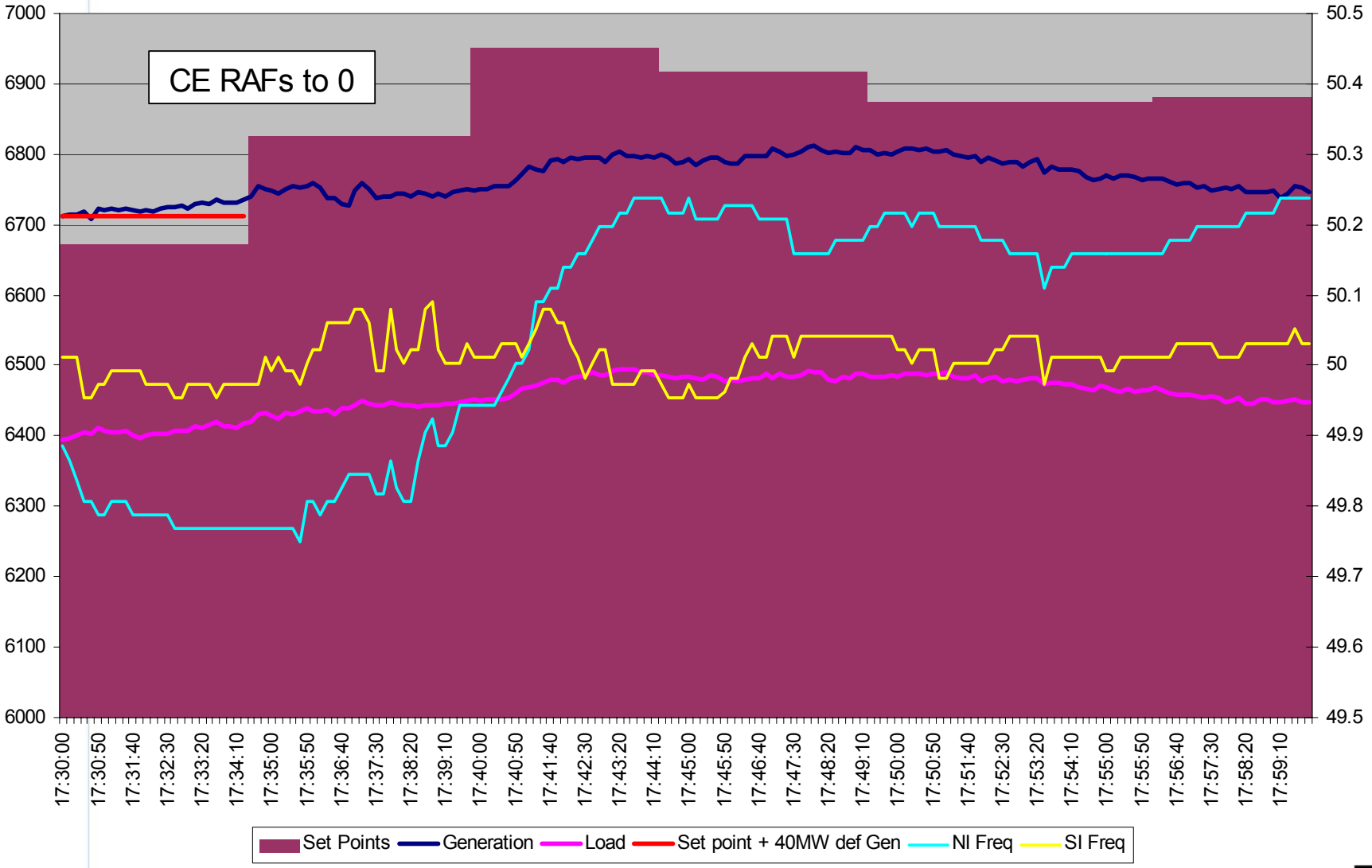

Energy Capability (19 June 2006) - RTD Output
Energy Offer (MW)
Energy Cleared (MW)
Max Capacity (Revised)
Energy Cleared + Deficit (Gen + Res)
6672
6722
6847
6972
7290
7332
6672
6732
60s Reserve Cleared ≈ 360 MW
(Gen + 60s Res) Deficit ≈ 61 MW
FK unavailable ≈ 125 MW
MTI/WPA unavailable ≈ 125
60s Res Deficit ≈ 19 MW
WHI Ramp-Up unavailable ≈ 50 MW
Gen Deficit ≈ 42 MW
6000
6200
6400
6600
6800
7000
7200
7400
MW


Energy Capability (19 June 2006) - RTD Output
Energy Offer (MW)
Energy Cleared (MW)
Max Capacity (Revised)
Energy Cleared + Deficit (Gen + Res)
6672
6722
6847
6972
7290
7332
6672
6732
60s Reserve Cleared ≈ 360 MW
(Gen + 60s Res) Deficit ≈ 61 MW
FK unavailable ≈ 125 MW
MTI/WPA unavailable ≈ 125
WHI Ramp-Up unavailable ≈ 50 MW
6000
6200
6400
6600
6800
7000
7200
7400
MW

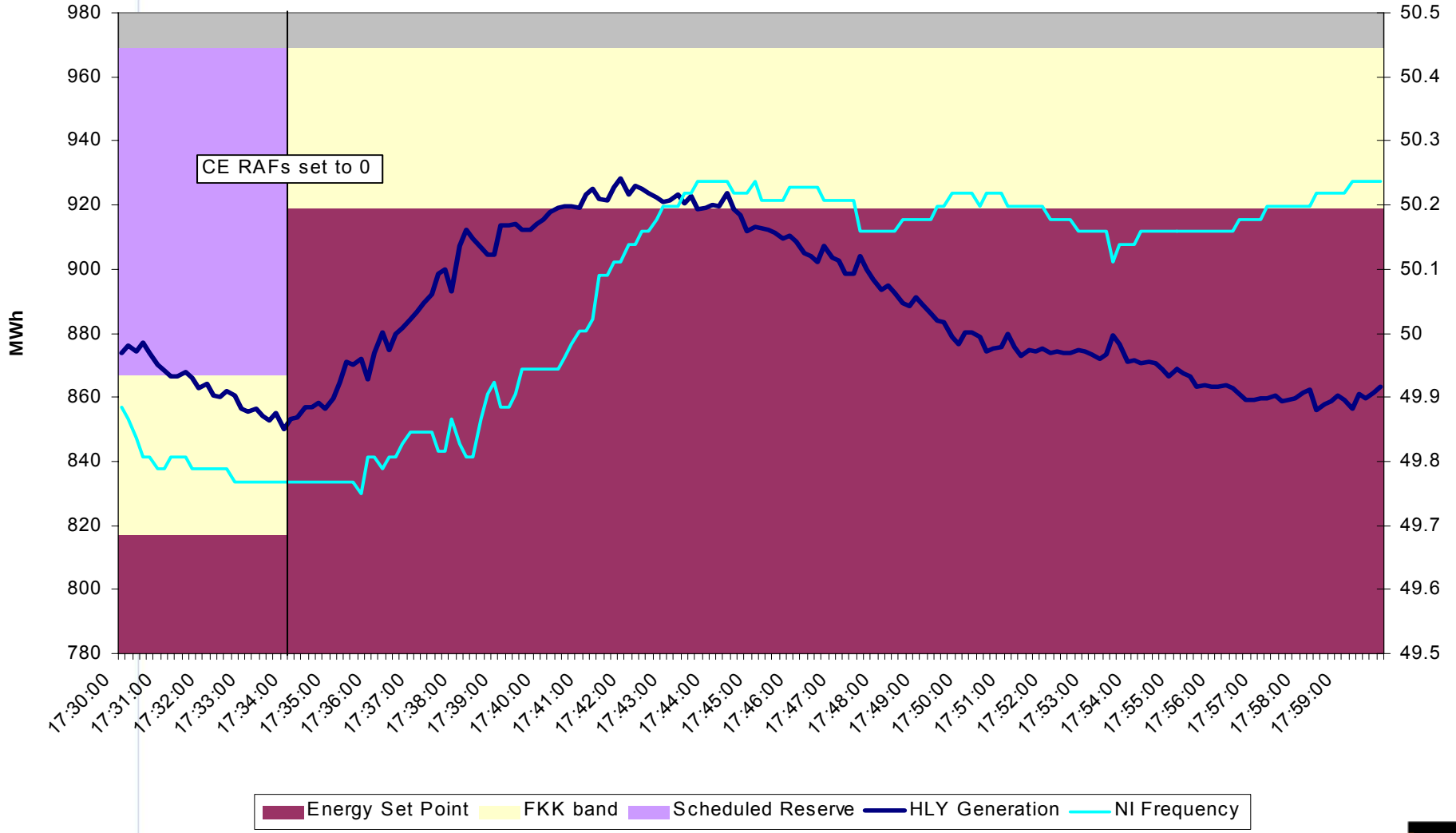

Energy Capability (19 June 2006) - RTD Output
Energy Offer (MW)
Energy Cleared (MW)
Max Capacity (Revised)
Energy Cleared + Deficit (Gen + Res)
6672
6722
6732
6847
6972
7290
7332
60s Reserve Cleared ≈ 360 MW
(Gen + 60s Res) Deficit ≈ 61 MW
FK unavailable ≈ 125 MW
MTI/WPA unavailable ≈ 125
6000
6200
6400
6600
6800
7000
7200
7400
MW


Energy Capability (19 June 2006) - RTD Output
Energy Offer (MW)
Max Capacity (Revised)
Energy Cleared + Deficit (Gen + Res)
6722
6732
6847
6972
7290
7332
Short Fall = 10 MW
60s Reserve Cleared = 360 MW
FK unavailable = 125 MW
MTI/WPA unavailable = 125
6000
6200
6400
6600
6800
7000
7200
7400
MW

Dispatch and actual energy



Huntly versus dispatch instructions and frequency



TRANSPOWER

Agenda

1. Introduction
2. Description of Schedules
3. Standby Residual Checks and Comparison of Schedules
4. Final Pricing – how prices are derived
5. Questions (afternoon tea)
6. Net Free Reserves
7. Dispatch of Reserves
8. Development proposals
9. Discussion

19 June 2006 – Pricing

System Operator Industry Seminar
Murray Henderson and Derrick Westenra
Market Services
13/15 September 2006

The objective function

SPD solves to the lowest total cost possible to meet **Physical network requirements** for each trading period.

= Minimum (Offer $'s x Quantities cleared)

Energy Offers

Reserve Offers – IL, PLSR, TWD

The objective function

- the physical solution is the primary problem being solved by SPD at least cost
- physical network requirements include:
  - transmission network limits
  - risk reserve requirements
  - plant capability
- SPD will rearrange generation to achieve a physical outcome

Marginal prices (nodal prices)

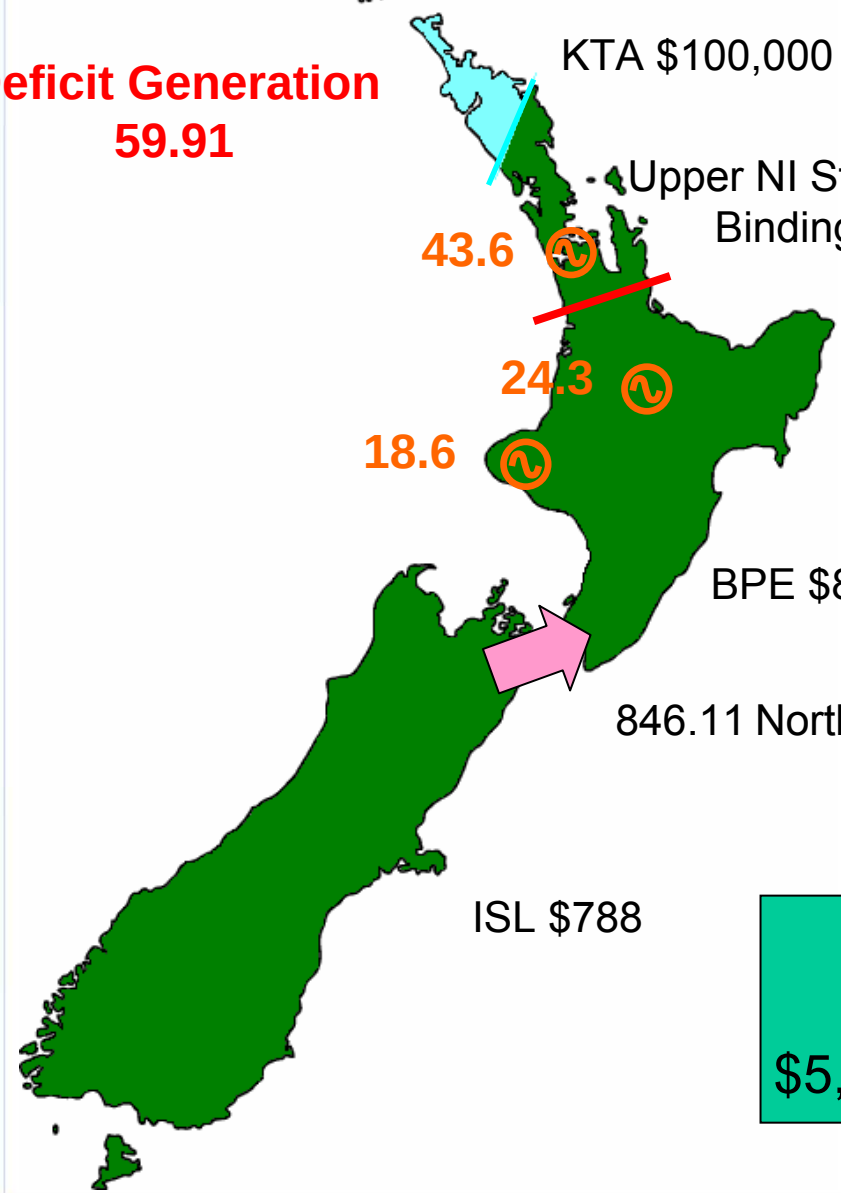
- marginal prices are the outcome to the primary physical SPD solution.
- primary problem solved at least cost, then outcome will be least cost marginal prices
- marginal prices are increment/decrement cost of unit at each bus

Resolution of infeasibilities - process

- Two primary principles are used to resolve infeasibilities:
  - according to actual network operation as far reasonably possible, subject to the EGR's Part G
  - in 1 MW increments until feasible
    - No **Discretion** in resolution approach

The 17:30 infeasible solution - I

Deficit Generation
59.91



North Island

- Uncleared ENOF
  ARI 24.3
  OTC 43.6
  TCC 18.6
- Losses 135.2

South Island

- Uncleared ENOF
  0
- Losses 99.1

Objective Function Cost
$6,226,896
$5,990,709 CVP + $236,187 physical

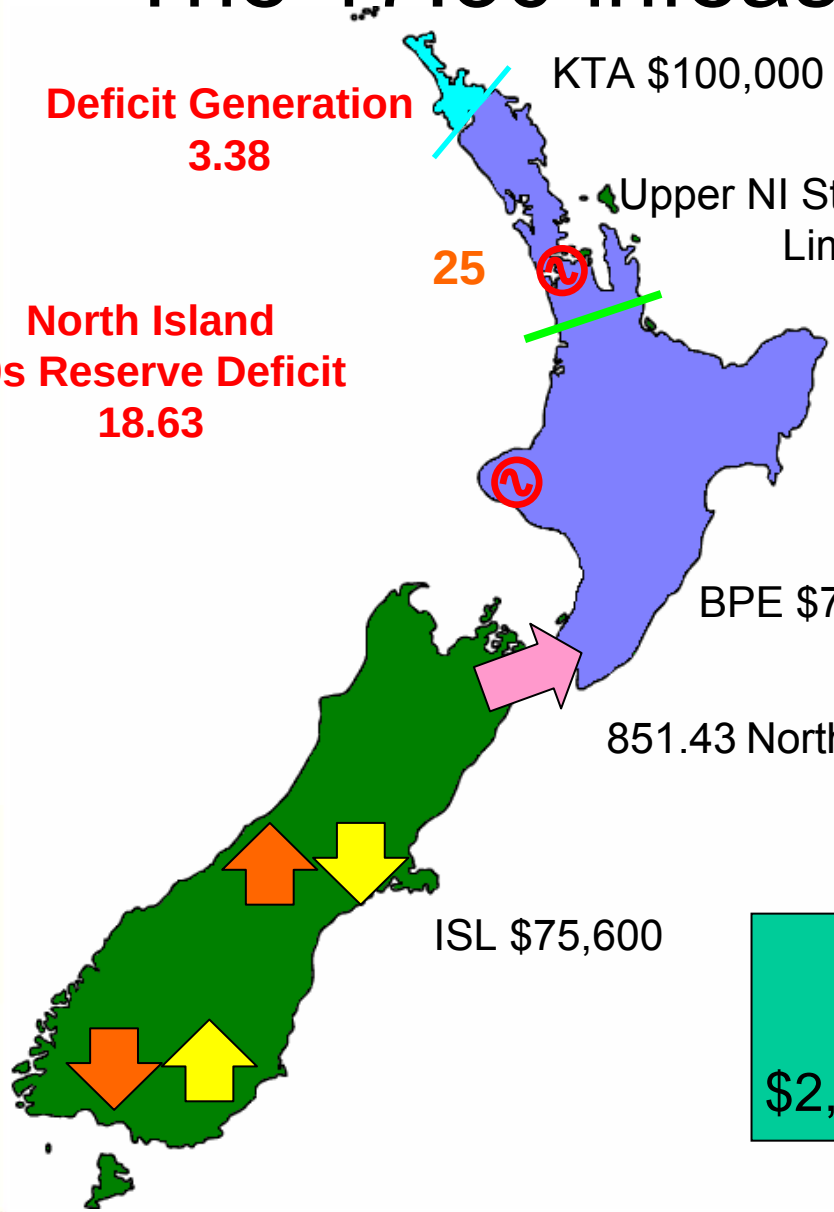
Grid Owner response – infeasibility resolution

- resolution via constraint relaxation:

  increase constraint limit in 1MWh increments, stopping once feasible solution achieved or null point achieved.

- UNI Stability Constraint Limit not binding in dispatch/actual and infeasible in final pricing

The 17:30 infeasible solution - II



North Island

- Uncleared ENOF
  OTC 25
- Losses 145

South Island

- Uncleared ENOF
  0
- Losses 93.8

Objective Function Cost
$3,224,796
$2,945,983 CVP + $278,813 physical

TRANSPOWER

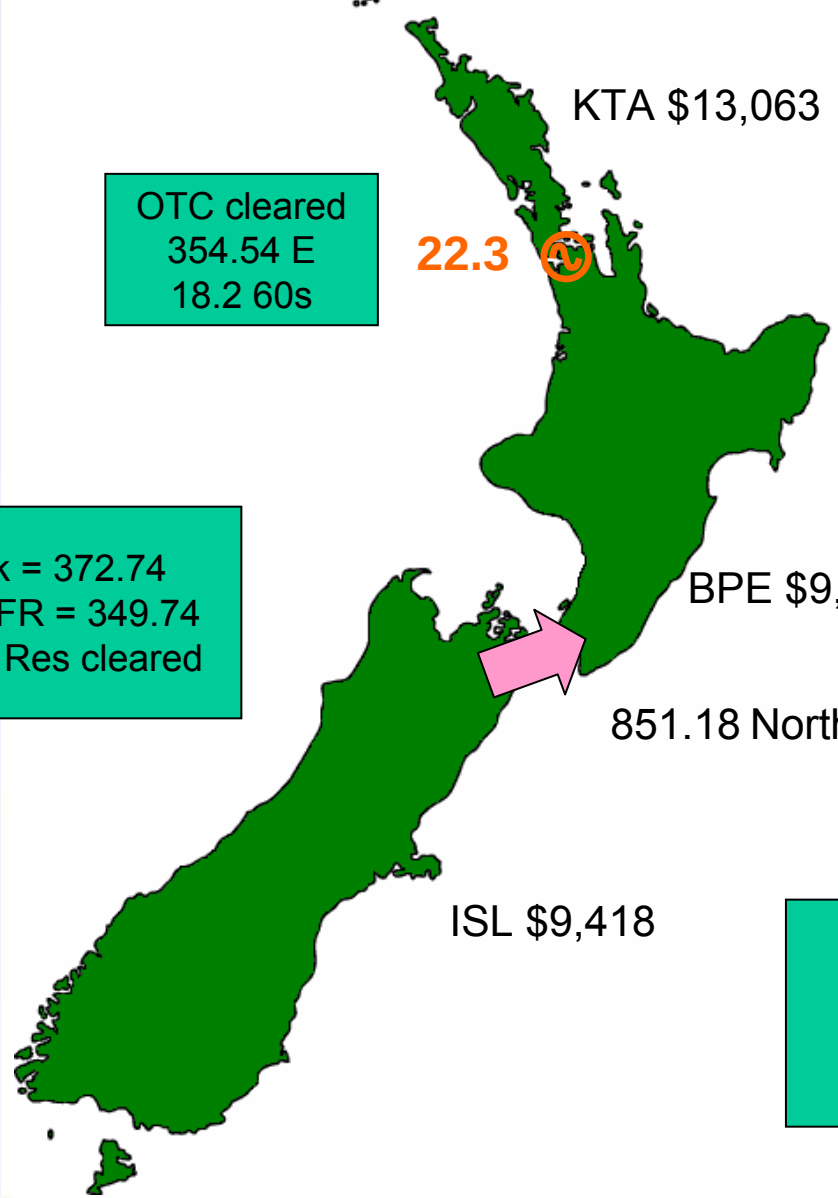
Grid Owner response – infeasibility resolution

- resolution via addition of North Island 60s Net Free Reserve:

  increase 60s Net Free Reserve in 1MWh increments stopping once feasible solution achieved or null position reached.

- only resolution approach possible to obtain a feasible Final Price

The 17:30 **feasible** solution = final prices



OTC cleared
354.54 E
18.2 60s

Risk = 372.74
-23 NFR = 349.74
= 60s Res cleared

North Island

- Uncleared ENOF
  OTC 22.3
- Losses 145.82

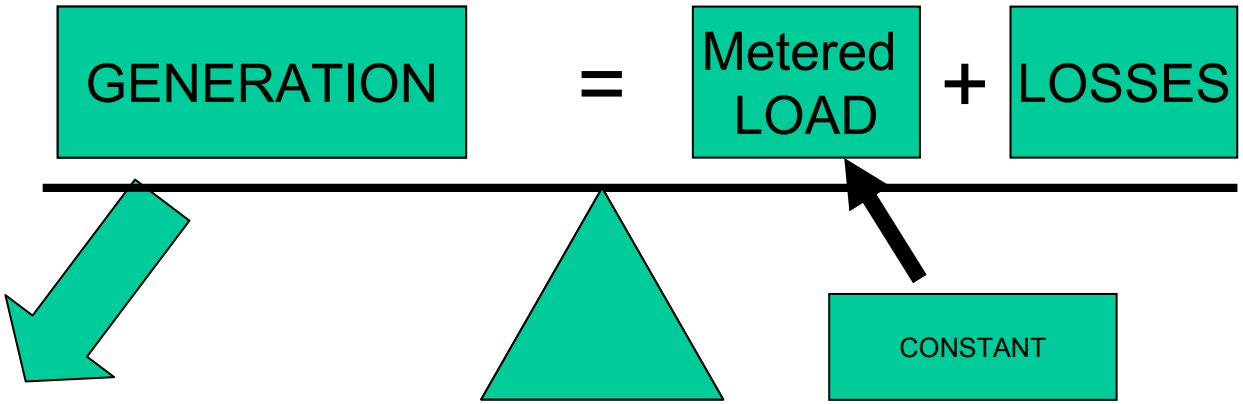
South Island

- Uncleared ENOF
  0
- Losses 94.1

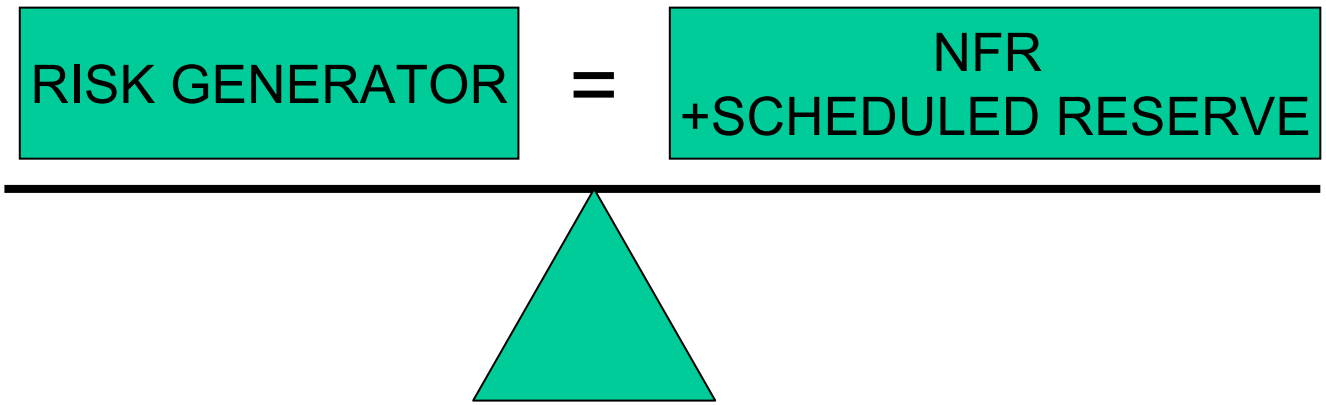
Objective Function Cost
$275,597 physical

The network energy balance

- The balance equations can be represented thus:



- Subject to:



The 17:30 price sensitivity – marginal prices

GENERATION = Metered LOAD + LOSSES

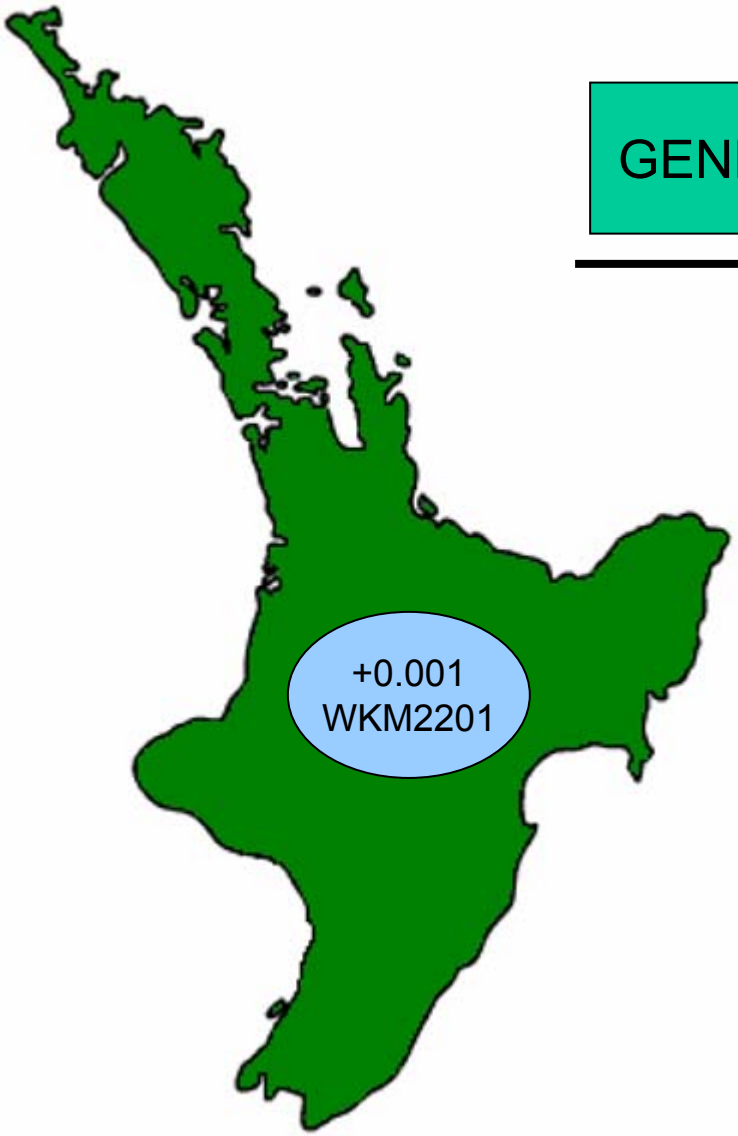
RISK = RESERVE

The 17:30 price sensitivity – marginal prices

GENERATION = Metered LOAD + LOSSES

RISK = RESERVE

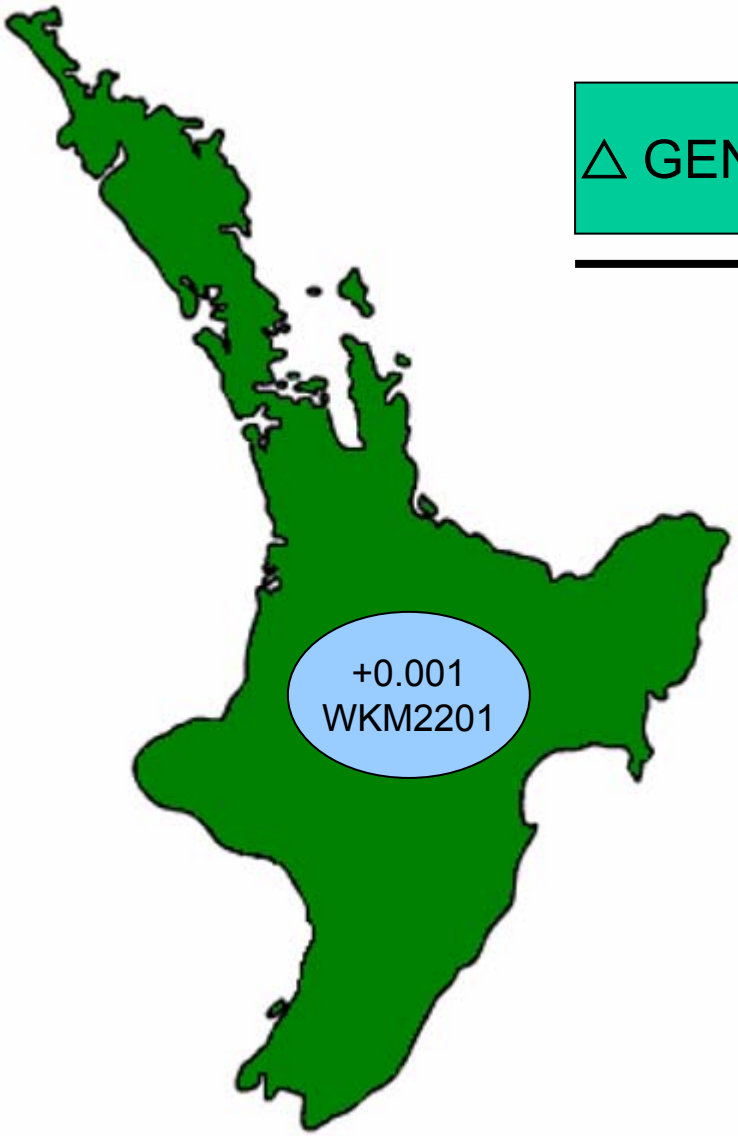
The 17:30 price sensitivity – marginal prices



GENERATION = +0.001 WKM2201 + LOSSES

RISK = RESERVE

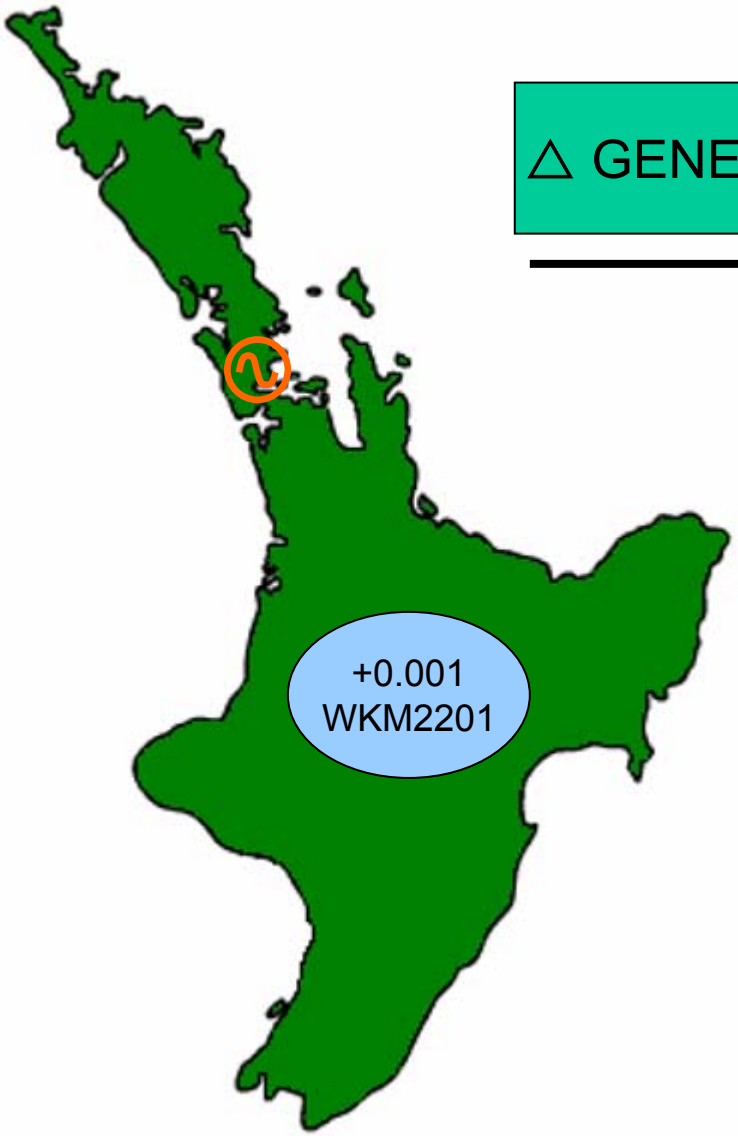
The 17:30 price sensitivity – marginal prices



△ GENERATION = +0.001 WKM2201 + LOSSES

RISK = RESERVE

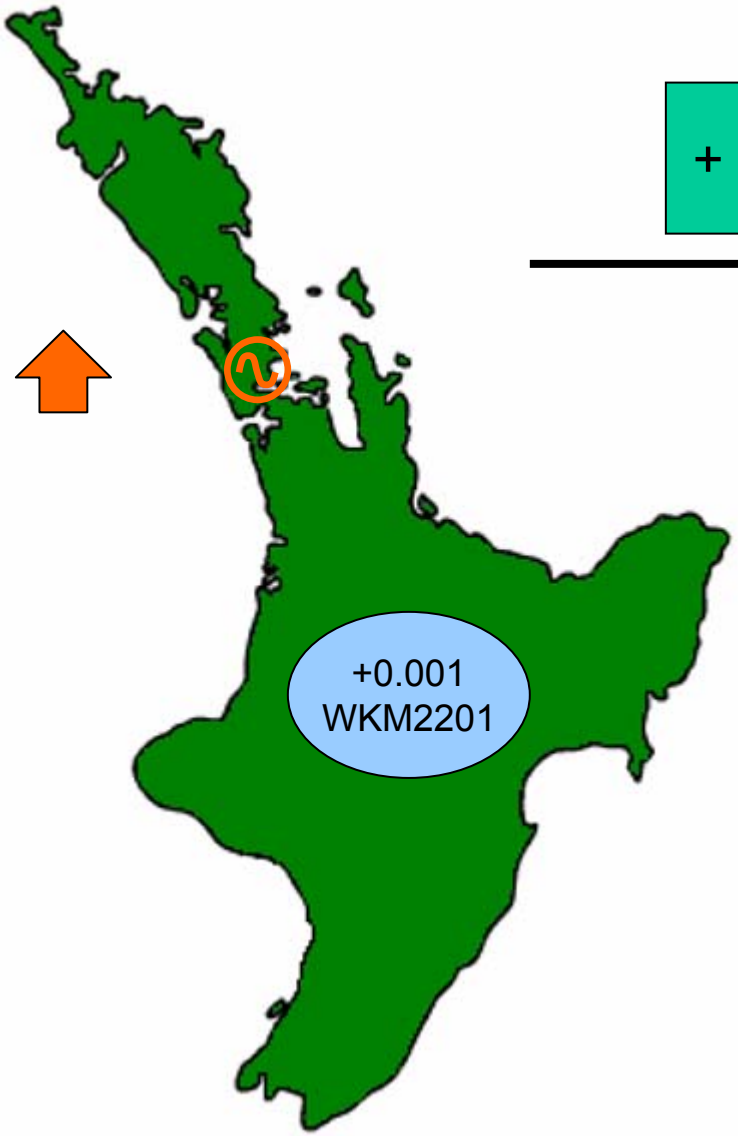
The 17:30 price sensitivity – marginal prices

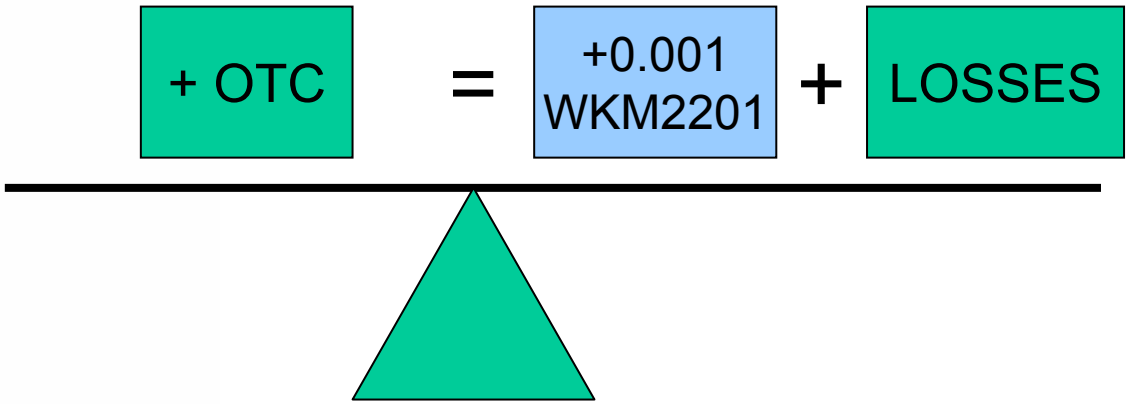


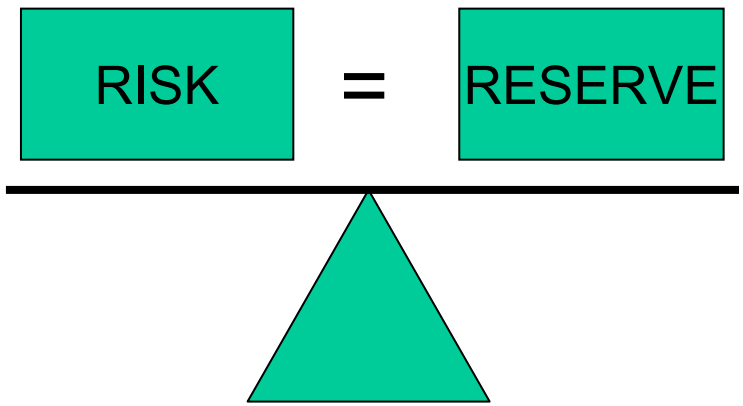
△ GENERATION = +0.001 WKM2201 + LOSSES

RISK = RESERVE

The 17:30 price sensitivity – marginal prices







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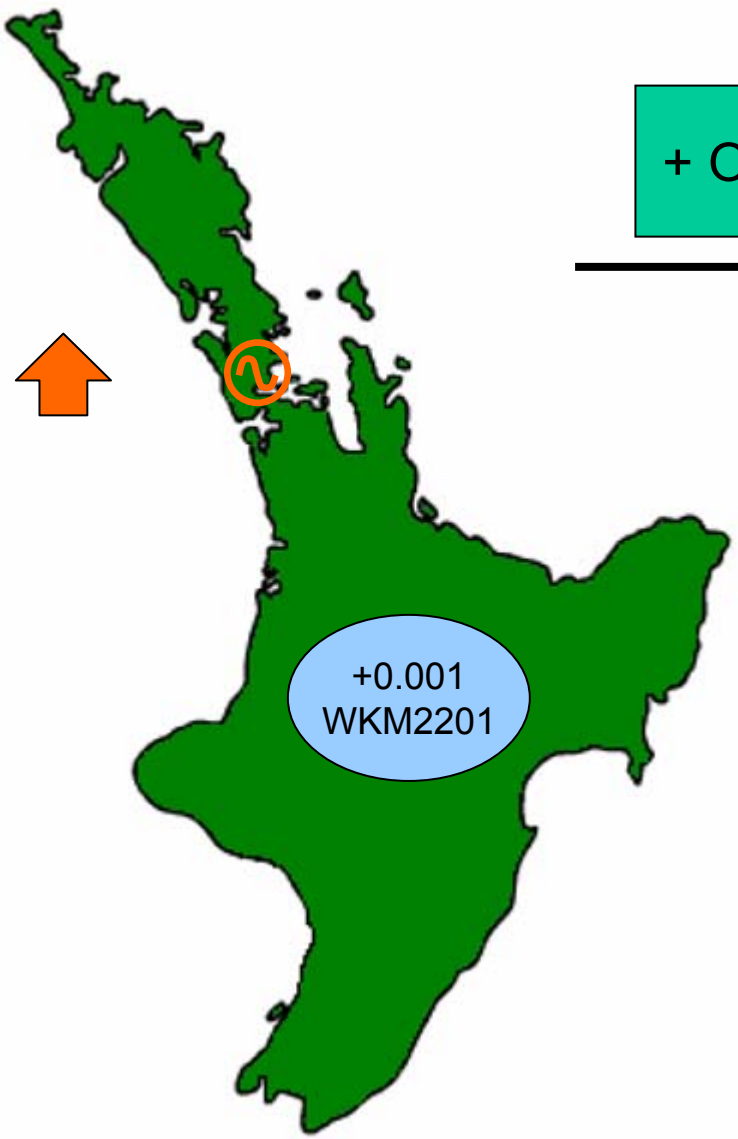
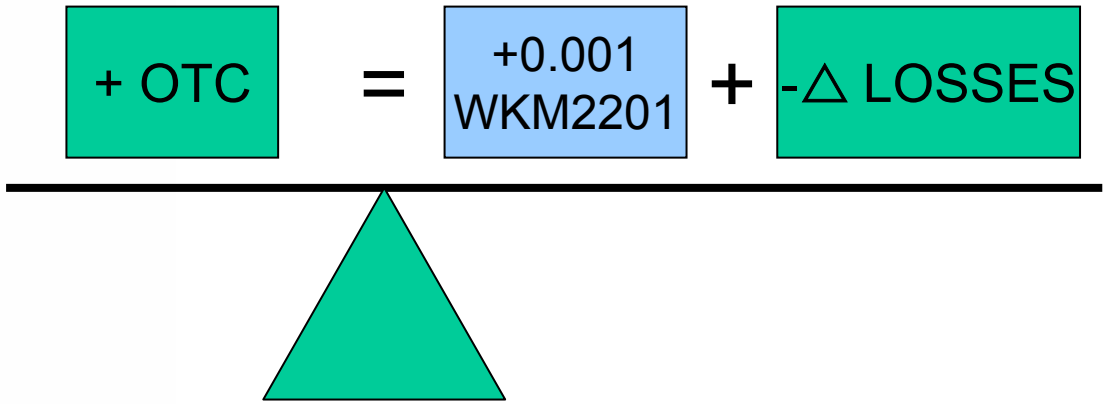
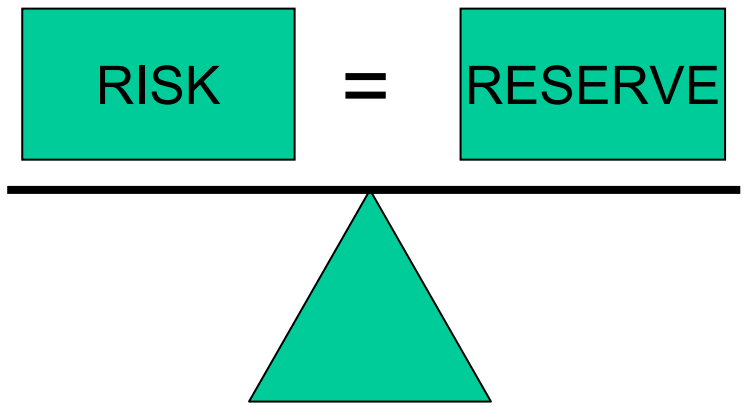
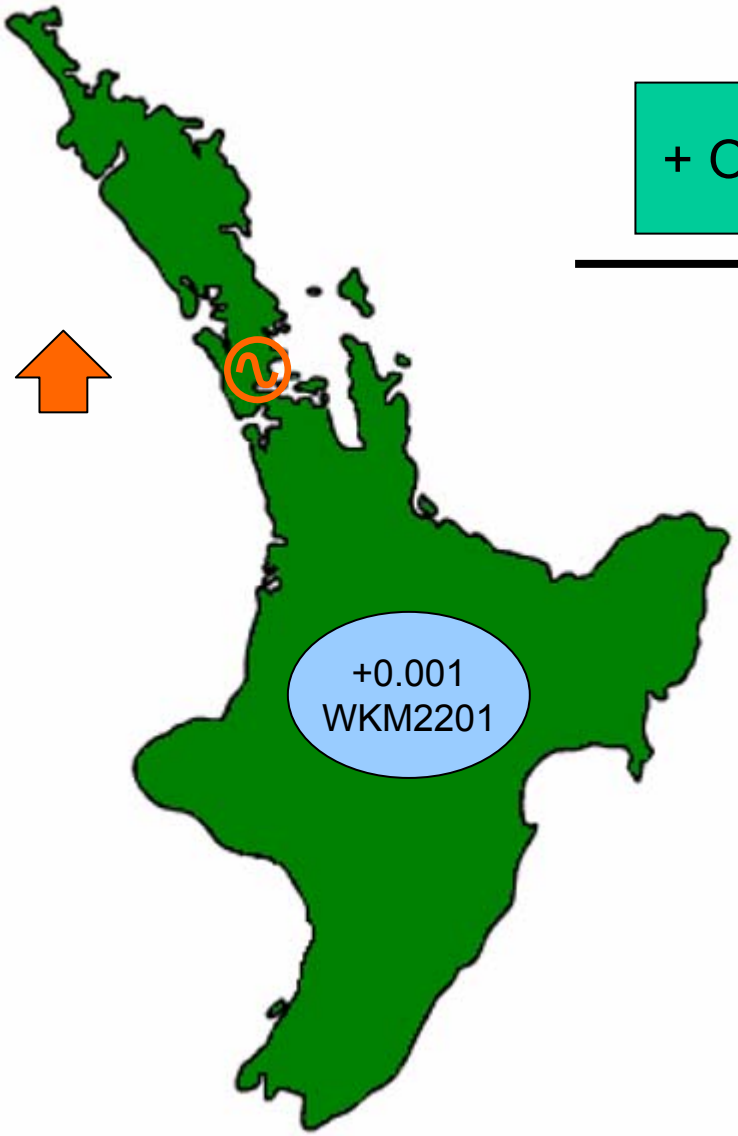
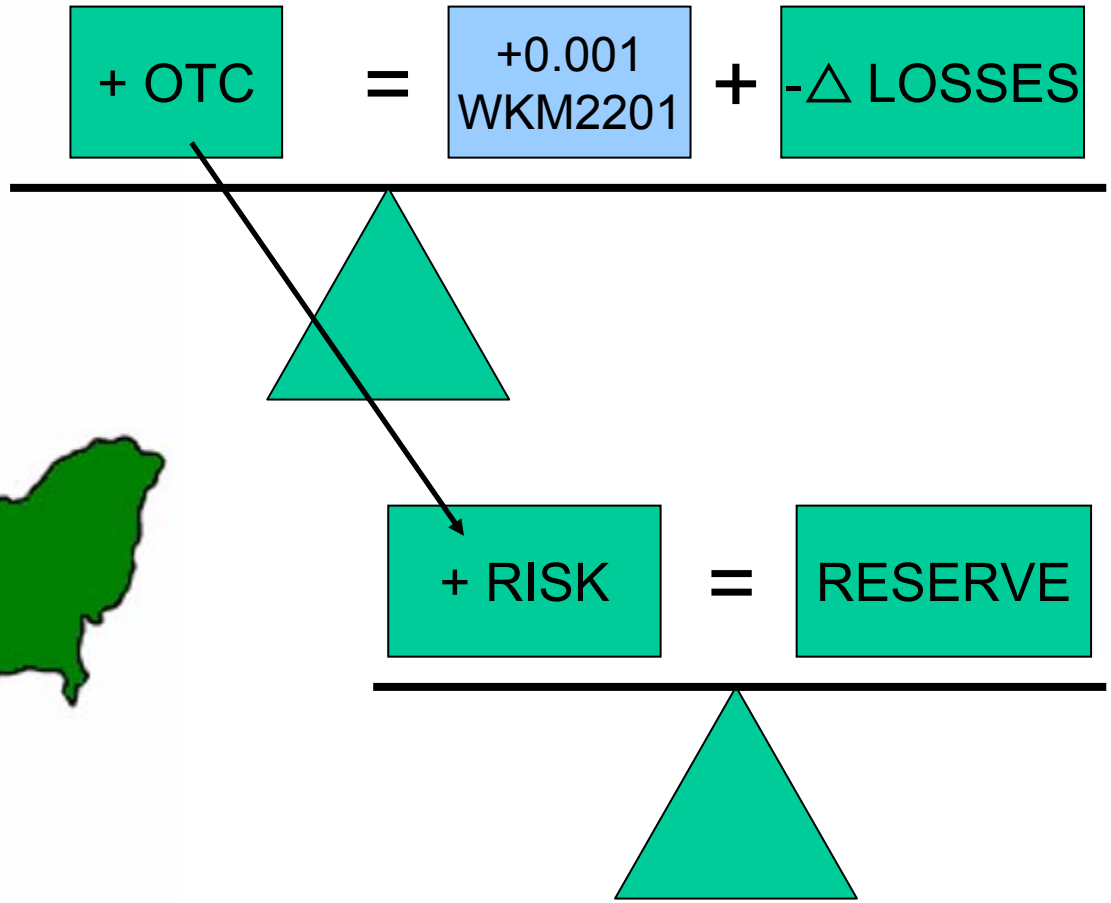






The 17:30 price sensitivity – marginal prices





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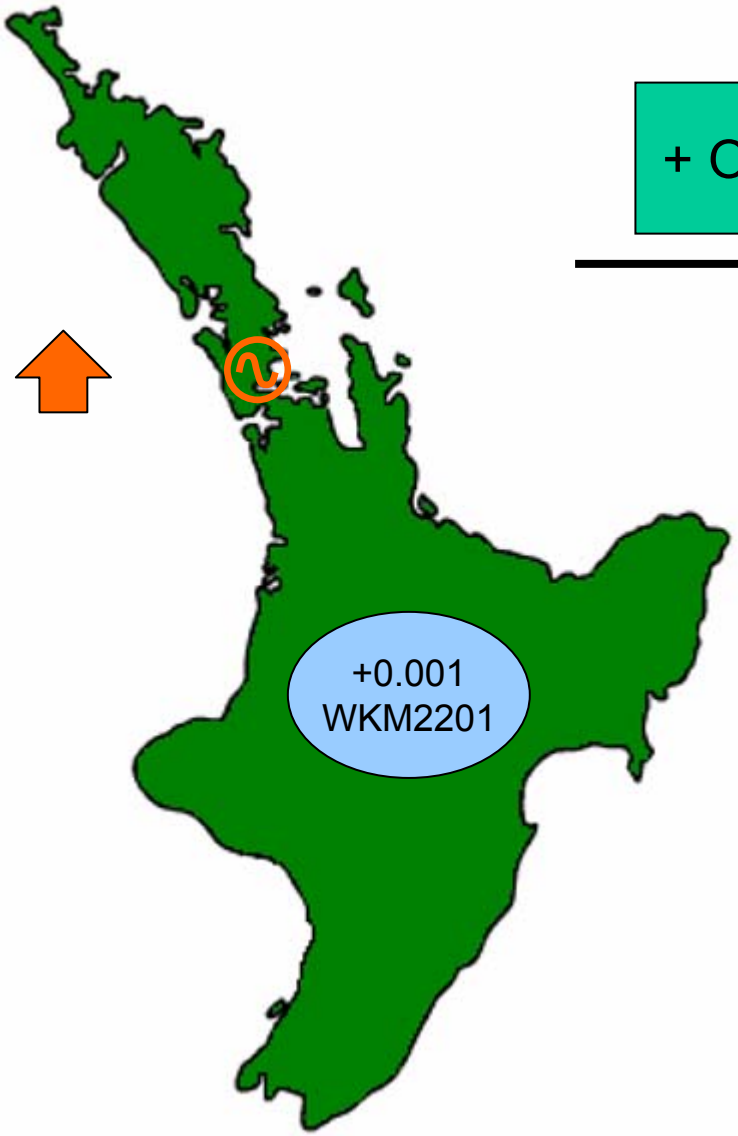

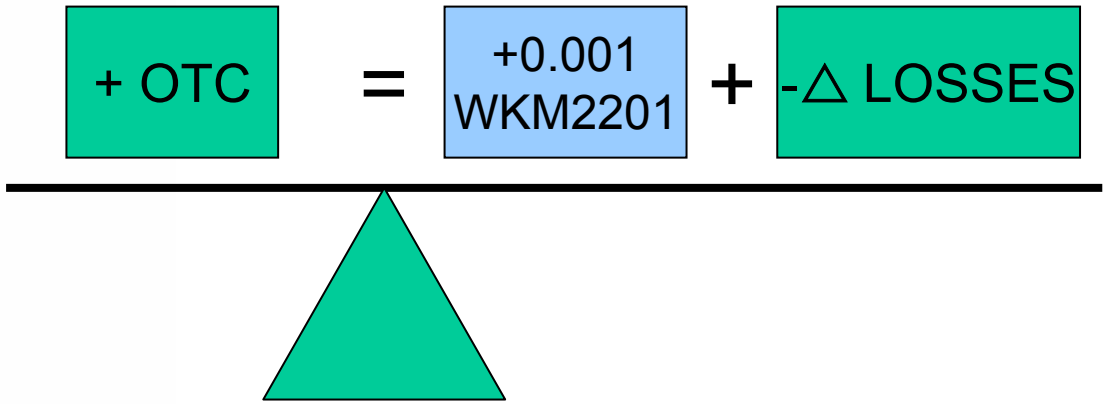

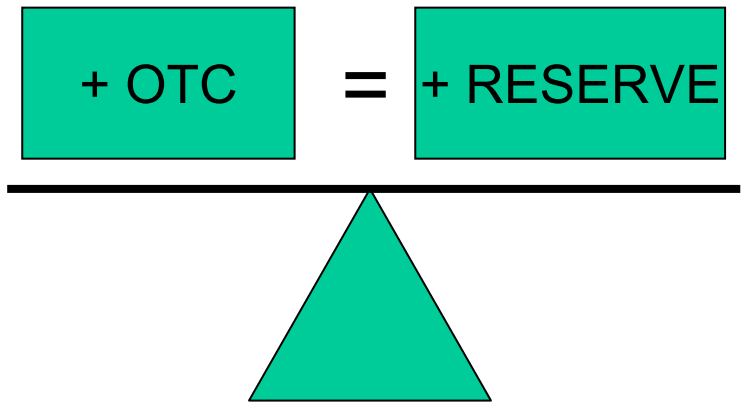

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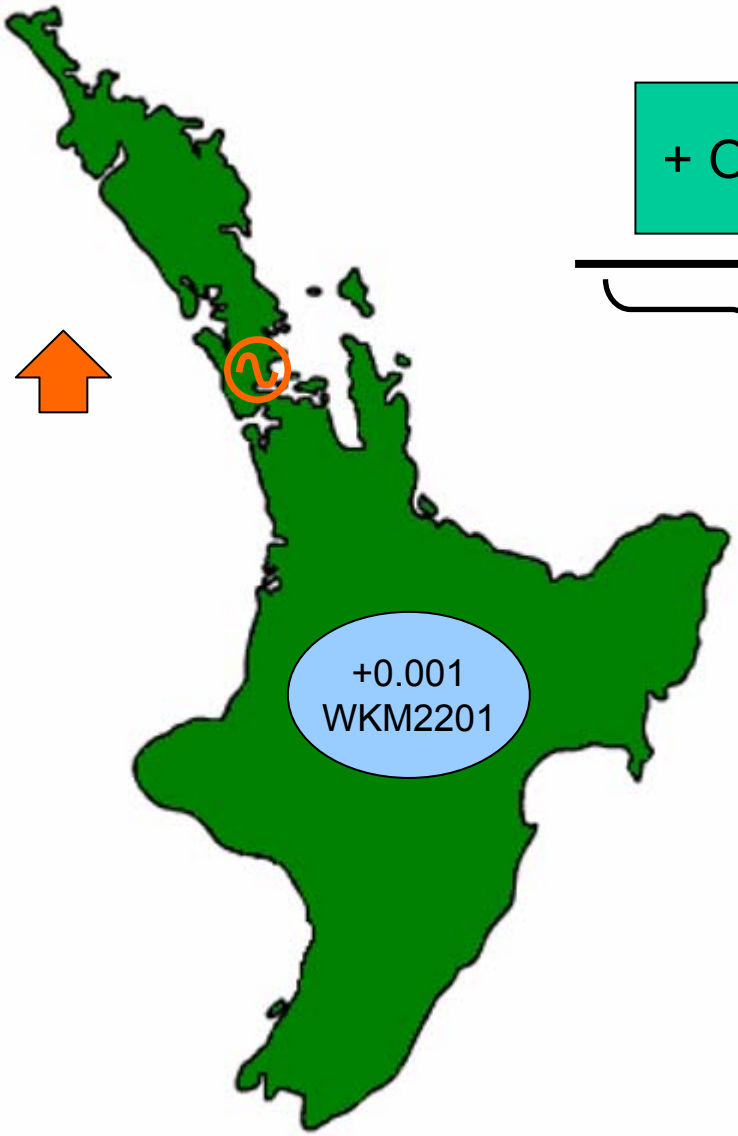

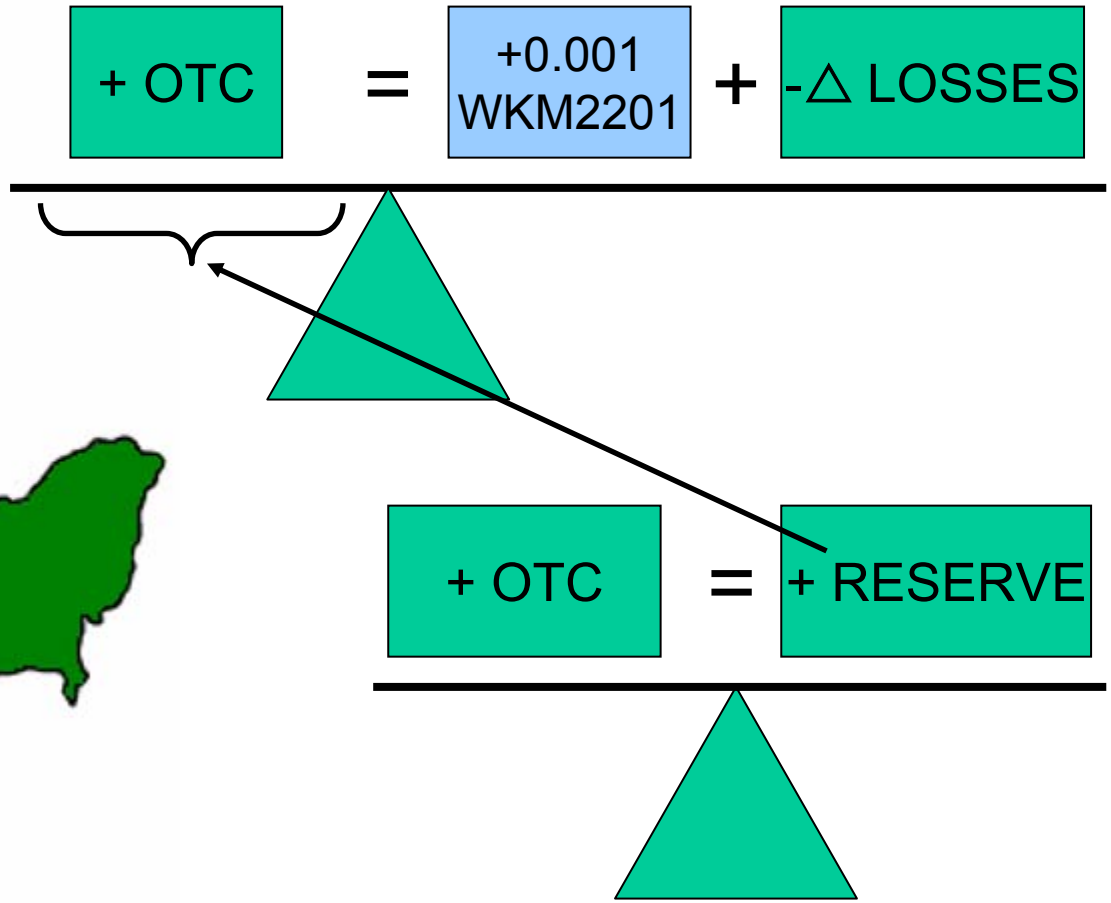

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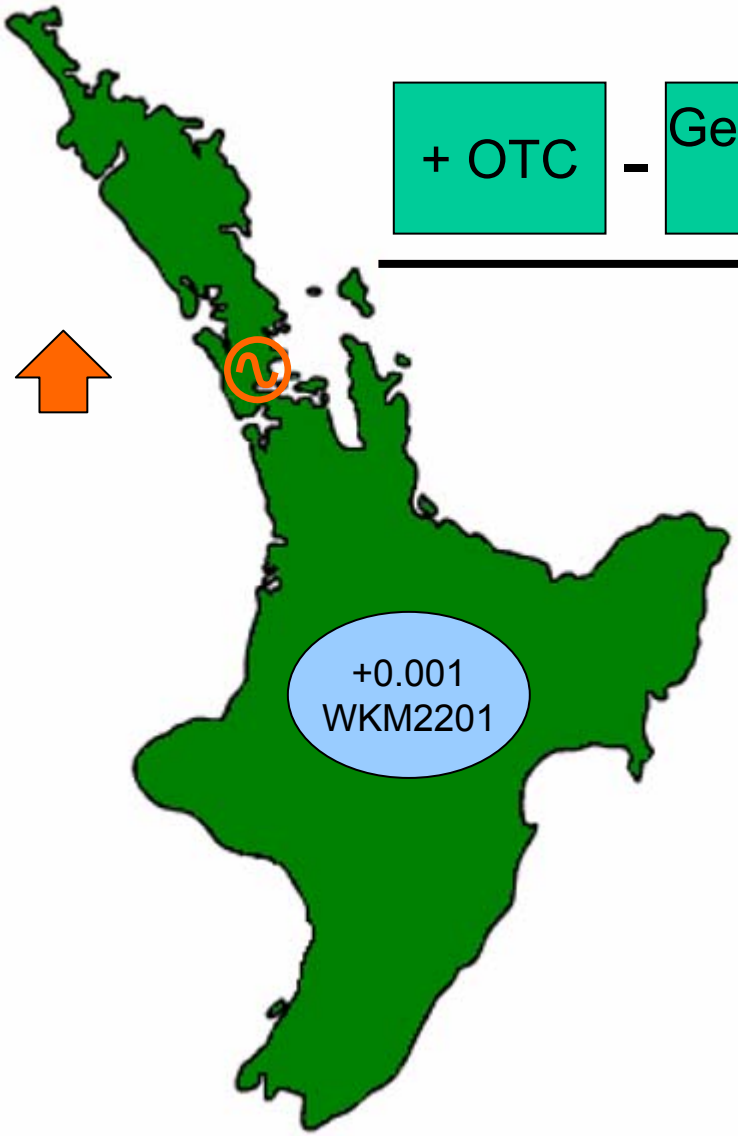
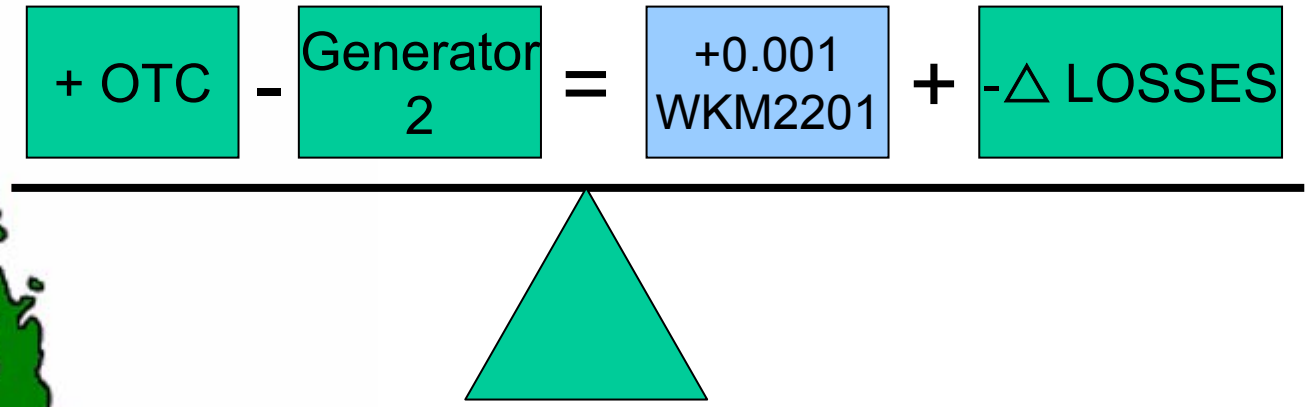
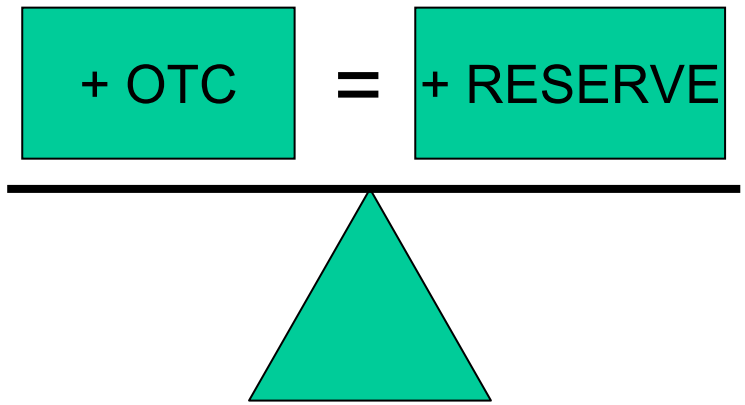
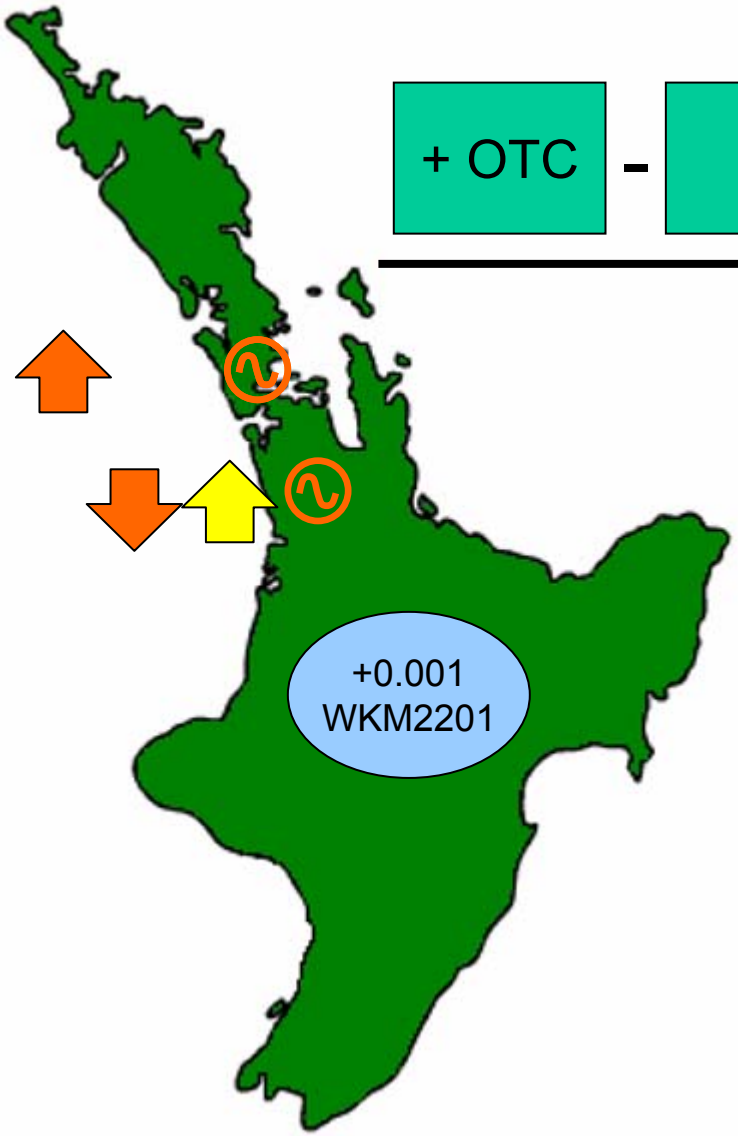






The 17:30 price sensitivity – marginal prices

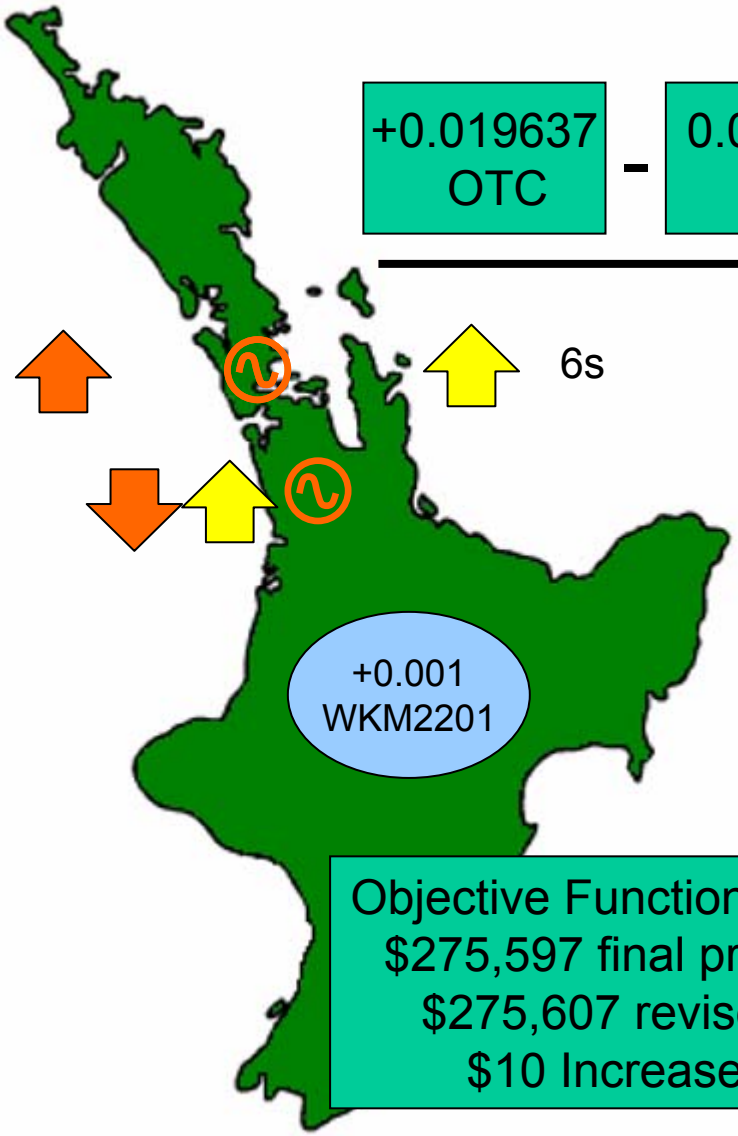


+ OTC - HLY = +0.001 WKM2201 + -△ LOSSES

60s Reserve

+ OTC = + HLY

The 17:30 price sensitivity – marginal prices



+0.019637 OTC - 0.019637 HLY = +0.001 WKM2201 + -0.001

6s

60s Reserve

+0.019637 OTC = +0.019637 HLY

Objective Function Cost
$275,597 final prices
$275,607 revised
$10 Increase

The marginal price calculation

- change in Energy costs

OTC	+(0.019637 x 1,000) x $420.00	$8,247.74
HLY	-(0.019637 x 1,000) x $55.04	-$1,080.85

- change in Reserve costs

IL	6s	+(0.019637 x 1,000) x $130.00	$2,552.87
HLY	60s	+(0.019637 x 1,000) x $0.24	$4.71

- change in Total costs $9,724.47

  = Change in Objective Function (x 1,000)

  = Nodal Price @ WKM2201

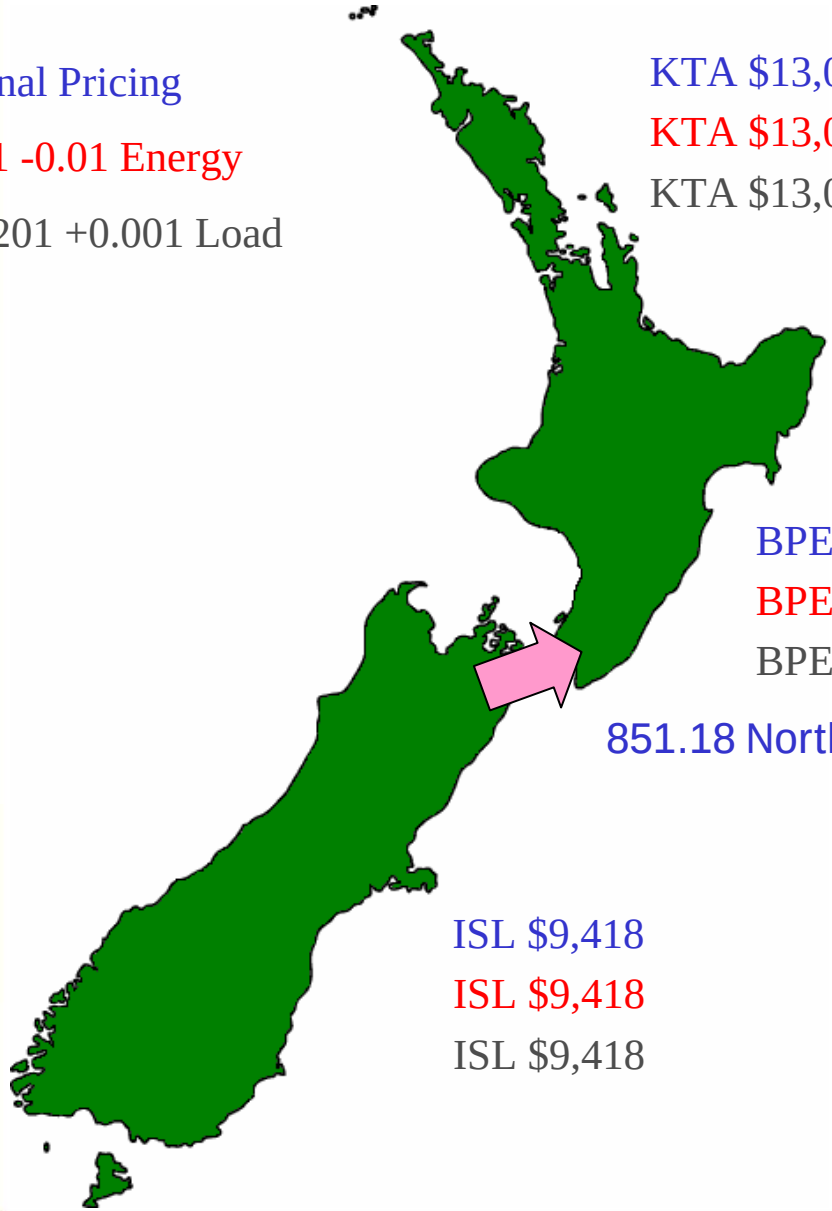
Summary

Final Pricing

HLY1 -0.01 Energy

WKM2201 +0.001 Load

KTA $13,063
KTA $13,063
KTA $13,063



BPE $9,636
BPE $9,636
BPE $9,636

851.18 North

ISL $9,418
ISL $9,418
ISL $9,418

Objective Function Costs

$275,597
$275,698
$275,607

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1. Introduction
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Reserve Management
Net Free Reserves (NFR)

System Operator Industry Seminar
Derrick Westenra
Market Services Manager
13/15 September 2006

Contents

- Sources of Net Free Reserves (NFR's)
- How Scheduling Pricing & Dispatch (SPD) and Reserve Management Tool (RMT) interact

Sources of Net Free Reserve (NFR)

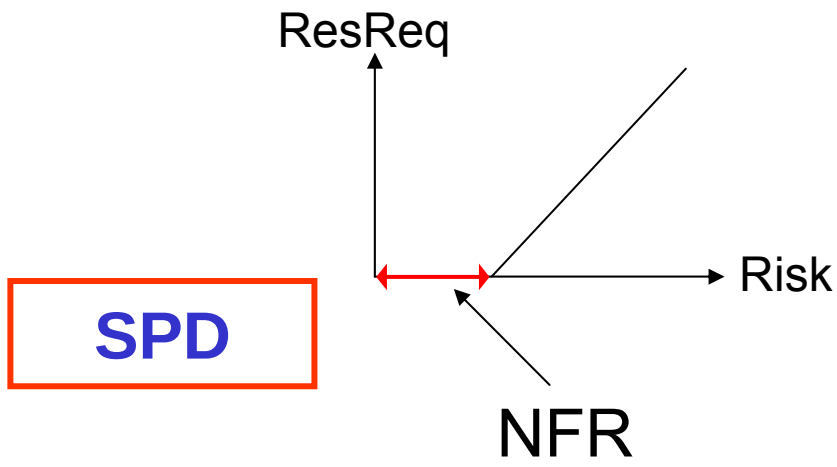
- NFR accounts for undispatched reserves available in the system (increases NFR)
  - AUFLS
  - Load damping
  - Free hydro reserve in the North Island
  - HVDC reserve sharing
- it also accounts for non-compliant generation (decreases NFR)

How SPD and RMT interact

- SPD SDS produced at 07:00 each day includes next (new) trading day

- schedule has rolled over NFR's from current day applied to next (new) trading day

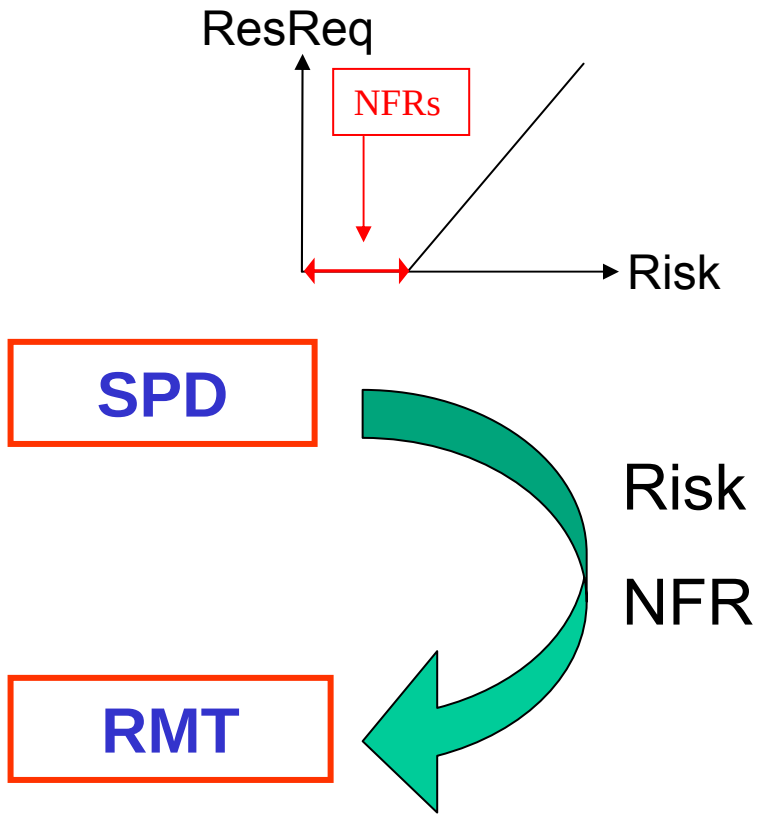
How SPD and RMT interact



- cleared risk energy above the NFR must be covered by reserve
- SPD co-optimised risk energy against reserve procured given NFR's

How SPD and RMT interact

- SPD output goes to RMT
  - risk
    - AC CE
    - DC CE
    - DC ECE
  - all energy and reserve cleared
  - NFR values already in SPD



How SPD and RMT interact

- RMT simulates frequency fall for each contingency based on:
  - all energy and reserve cleared
  - risk energy and reserve cleared
  - NFR's from SPD
  - non-compliant plant

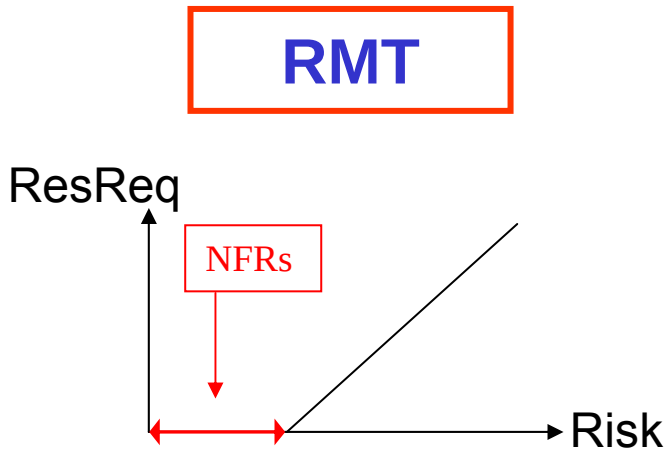
- determines if enough reserve available

RMT

How SPD and RMT interact

- dependent on solution outcomes:
  - can decrease NFR's as not enough reserve cleared in SPD
  - can increase NFR's as too much reserve cleared in SPD
  - can remain unchanged as adequate reserve cleared in SPD

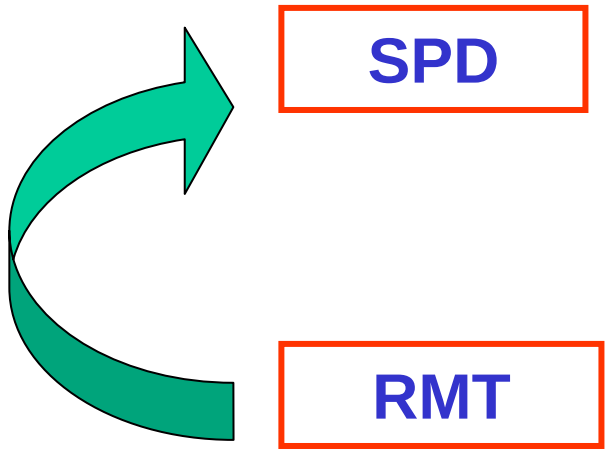
- RMT models reserve as that required above system reserve



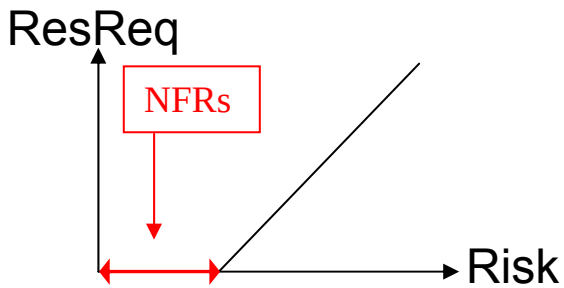
How SPD and RMT interact

RAF

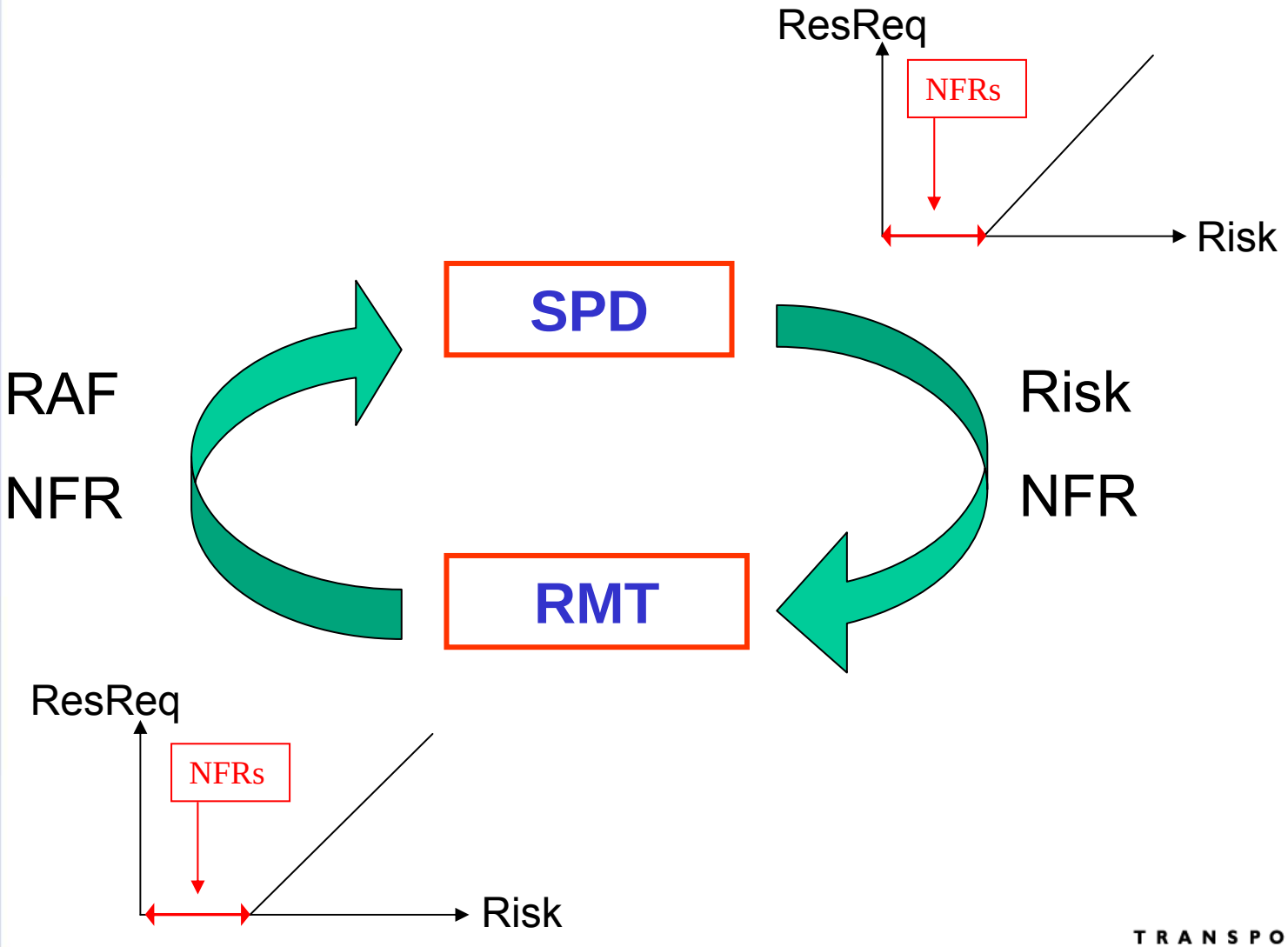
NFR



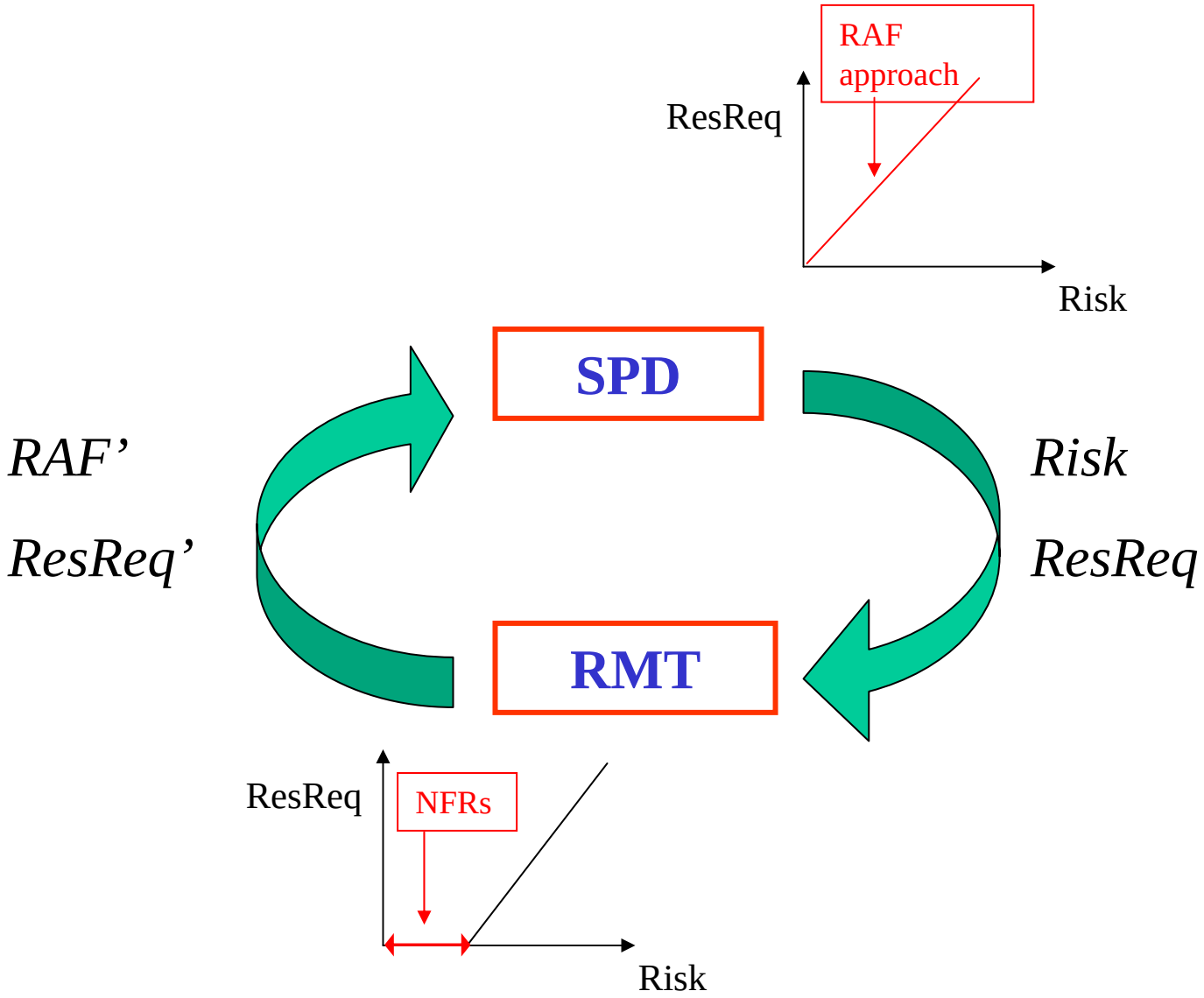
- RMT outputs revised numbers to SPD for:
  - CE HVDC NFR
  - ECE HVDC NFR
  - CE AC NFR
- RAF's can only be 0 or 1



How SPD and RMT interact



How SPD and RMT interact – pre-2004



Agenda

1. Introduction
2. Description of Schedules
3. Standby Residual Checks and Comparison of Schedules
4. Final Pricing – how prices are derived
5. Questions (afternoon tea)
6. Net Free Reserves
7. Dispatch of Reserves
8. Development proposals
9. Discussion

Reserve Management Outcomes
19th June 2006 17:30

System Operator Industry Seminar

John Clarke
Investigations and Planning Manager

13/15 September 2006

Reserve outcomes for 17:30

- purpose
  - explain why up to 90 MW of reserves still dispatched after reserve dispatch for contingent event ceased at 17:34
- to recap
  - NFR's in RMT are calculation of net free reserve
  - SPD and RMT iterate in successive SPD solves to optimise reserve requirements for dispatch
  - assumption in reserve calculation process - system conditions do not change markedly between last schedule and dispatch

System Reserve cover CE 17:30 on 19 June

NFR Components	FIR NFR	SIR NFR
Non-compliant generation	0	0
AUFLS	0	0
Load Damping	41	0
Free Hydro Reserve	103	0
HVDC Sharing	25	0
Factor	0	0
Total (MW)	169	0

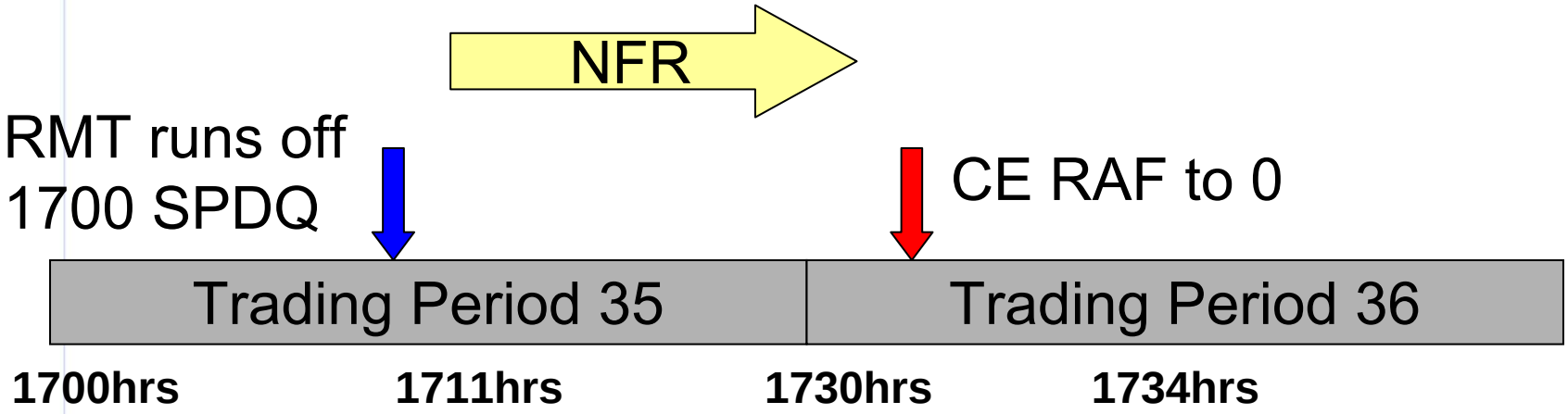
- **Input into RMT is 17:11 SDPQ on 19th June 2006**
- **Load damping applies for load remaining after FIR IL has tripped**
- **HVDC reserve sharing for AC CE risk only, not DC CE risk**

System Reserve cover ECE 17:30 on 19 June

NFR Components	FIR NFR	SIR NFR
Non-compliant generation	-105	-29
AUFLS	1141	1141
Load Damping	44	0
Free Hydro Reserve	111	0
HVDC Sharing	0	0
factor	-11	0
Total (MW)	1180	1112

- **Input into RMT is 17:11 SDPQ on 19th June 2006**
- **Load damping applies for load remaining after AUFLS has tripped**
- **No HVDC sharing as this is the risk**

Reserves for 17:30 on 19 June



- **HVDC binding CE risk**
- **AC CE risk very close**
- **ECE risk (HVDC) not binding**

- **ECE RAF not zeroed (risk always covered)**
- **ECE NFR set to ECE risk - 701MW**
- **Reserve dispatch up to 90MW FIR and SIR**

Why is ECE risk covered

- PPO's require System Operator to avoid cascade failure
  - ie must ensure frequency does not fall outside envelope where NI generators required to remain connected
  - with CE RAF's set to zero SO must still ensure ECE risk is still covered
  - ECE risk not always covered by AUFLS alone
  - significant amount of generating plant with dispensations to trip before ECE limit of 47 Hz

Observations

- If RMT had been run on 1730 dispatch AUFLS would have been sufficient for ECE risk
- Processes and RMT spec do not include rerunning RMT in dispatch
- Current mitigation is for SPD to cover any increase in risk between last SDPQ and dispatch
- With full reserve dispatch to cover CE risk, ECE risk only binds with very high HVDC transfer

Conclusion

- difference in HVDC transfer between RMT solve and actual conditions in dispatch resulted in reserve requirement for ECE in dispatch

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Development Proposals

System Operator Industry Seminar

Doug Goodwin

System Operator Development Manager

13/15 September 2006

Development Proposals

- Rule change proposals
- Provision of participant information
- Future development

Publication of SRC information

- Standby Residual Check Notices via Comit
  - publication of the Capacity Residual
- will provide the energy and reserve margins
- all trading periods in scheduling period

Variable Reserves rule change

- increases absolute value and relativities of SPD's constraint violation penalties (CVP's)
- ensures SPD will breach reserve constraint before breaching deficit energy constraint
- this will dispatch all available reserves
- ensures a non zero price for cleared reserve offers
- would not have changed 19th June price outcome

Spring Washer rule change

- a ratio test for High Spring Washer prices
- in final pricing, if ratio of highest nodal price to maximum cleared unconstrained energy offer price is ≥5
  - declare spring washer pricing event
  - relieve binding transmission constraint by greater of 1MW or 1%
- would have changed 19th June price outcome by a small amount
  - (MTI WKM constraint)

Demand Side Bidding & Forecasting

- proposed rule change
  - demand bidding replaced with:
    - central demand forecast + non conforming load bids
    - optional dispatchable demand bids
  - 2 schedules linking participant bids and offers directly to security and dispatch schedules and prices
  - improved pricing information
  - improved demand response signals

- benefits
  - enabler for demand response
  - basis of co-ordinated response in shortage of supply
  - basis for providing payment for dispatched demand

Frequency keeping selection

- frequency Keeping (CQAG)
  - improve frequency keeper selection
  - additional/better information to provide transparency
  - better information to understand possible price impact
  - no large gain in schedule information until co-optimised within SPD

Automatic frequency control

- supposed advantages in wholesale energy and ancillary services markets must be investigated
- problems not technical (AFC systems exist in other markets)
- AFC rules
- integration of ancillary and energy markets frameworks

Additional information

- The following slides contain further information and examples that were not presented in the seminars.

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

- the following price sensitivity analysis demonstrates the change in the objective function if you remove 0.01MW of offered energy from Huntly 1.

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

GENERATION = Metered LOAD + LOSSES

RISK = RESERVE

TRANSPOWER

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

GENERATION = Metered LOAD + LOSSES

RISK = RESERVE

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

GENERATION = Metered LOAD + LOSSES

RISK = RESERVE

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

△GENERATION = △ LOSSES

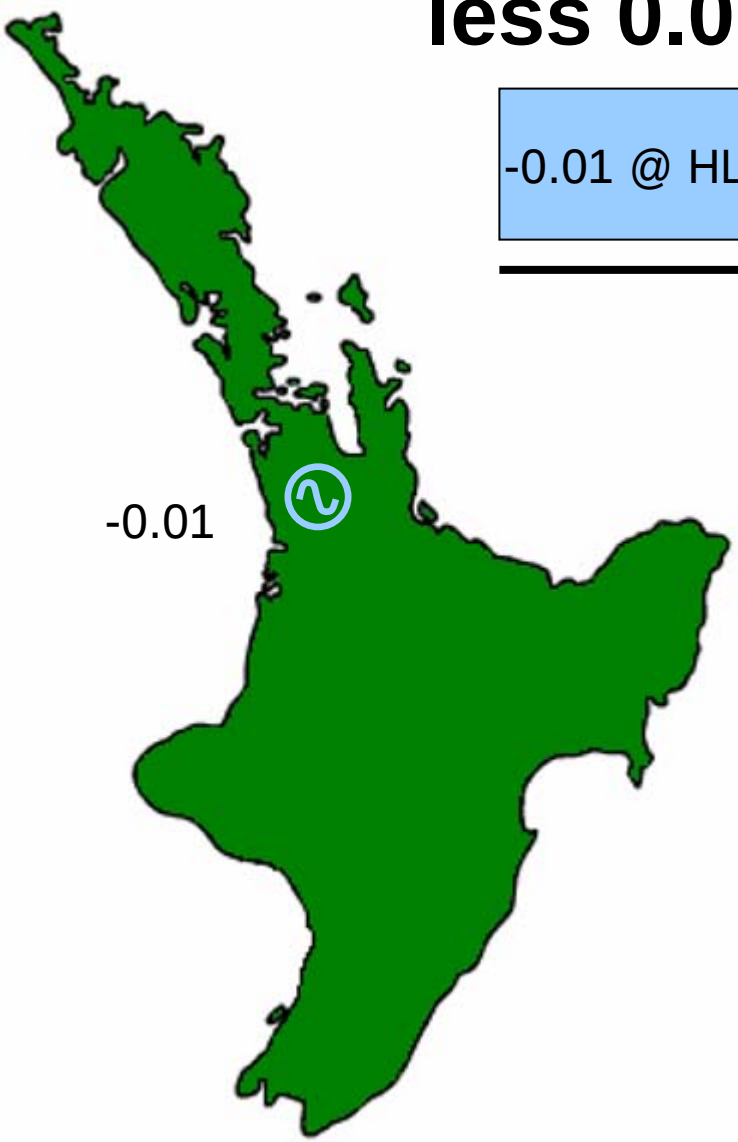
RISK = RESERVE

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

△GENERATOR 1 △GENERATOR 2 = △ LOSSES

RISK = RESERVE

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF



-0.01 @ HLY1 + △ GENERATION = △ LOSSES

60s Reserve

RISK = RESERVE

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

-0.01 @ HLY1 + △ GENERATION = △ LOSSES

60s Reserve

RISK = RESERVE

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

-0.01 @ HLY1 + +@ OTC = -△ LOSSES

60s Reserve

RISK = RESERVE

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

-0.01 @ HLY1 + +@ OTC = -△ LOSSES

60s Reserve

+ RISK = RESERVE

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

-0.01 @ HLY1 + +@ OTC = -△ LOSSES

60s Reserve

+ OTC = + RESERVE

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

-0.01 @ HLY1 + +@ OTC = -△ LOSSES

60s Reserve

+ OTC = + RESERVE

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF

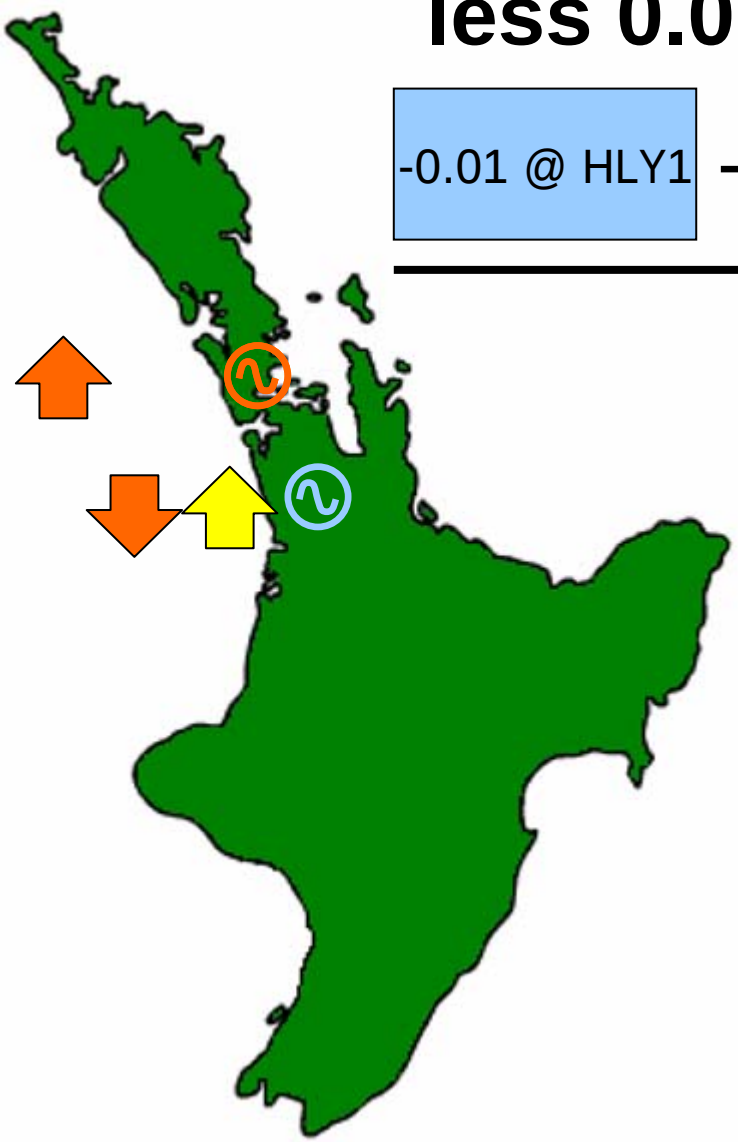
-0.01 @ HLY1 + @ OTC - Generator 3 = -△ LOSSES

60s Reserve

+ OTC = + RESERVE

TRANSPOWER

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF



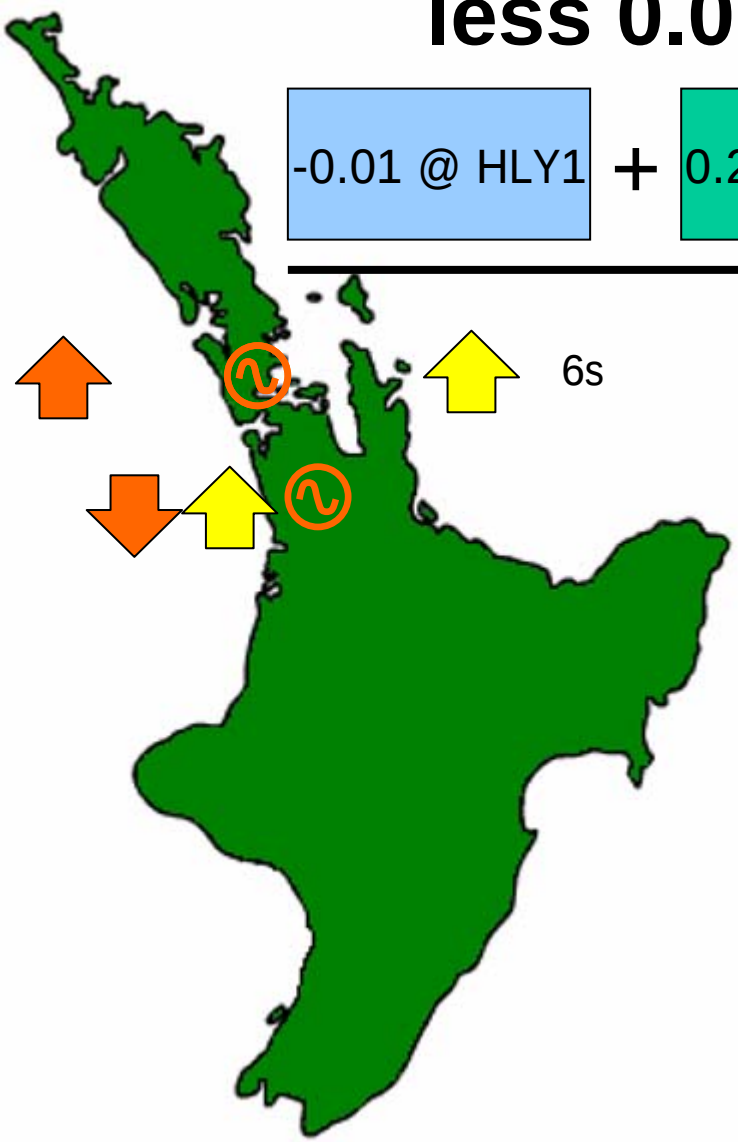
-0.01 @ HLY1 + @ OTC - HLY = -△ LOSSES

60s Reserve

+ OTC = + HLY

TRANSPOWER

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF



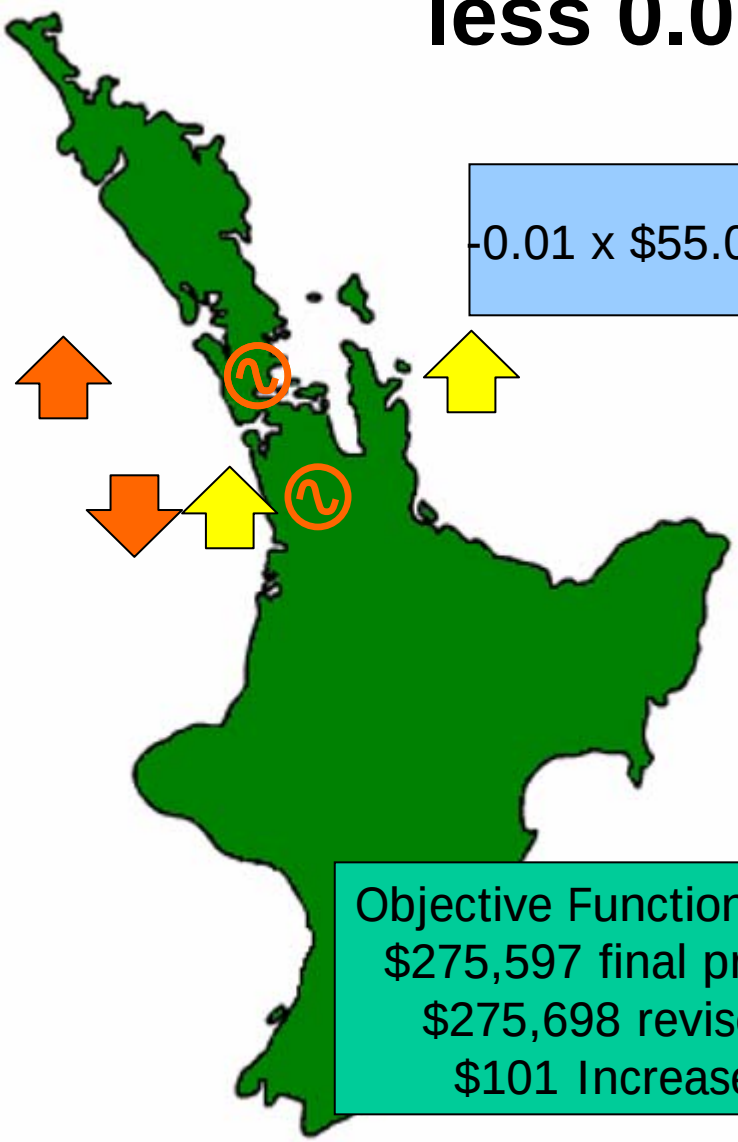
-0.01 @ HLY1 + 0.2051 @ OTC - 0.2051 @ HLY = -0.01

6s

60s Reserve

+0.2051 @ OTC = +0.2051 @ HLY

The 17:30 price sensitivity – Huntly 1 less 0.01MW ENOF



Energy

-0.01 x $55.01 + +0.2051 x $420 -0.2051 x $55.04 = $74.30

60s Reserve

+0.2051 x $0.24 = $0.05

6s Reserve

+0.2051 x $130 = $26.66

$101.01

Objective Function Cost
$275,597 final prices
$275,698 revised
$101 Increase

TRANSPOWER

1700

System Operator Industry Seminar

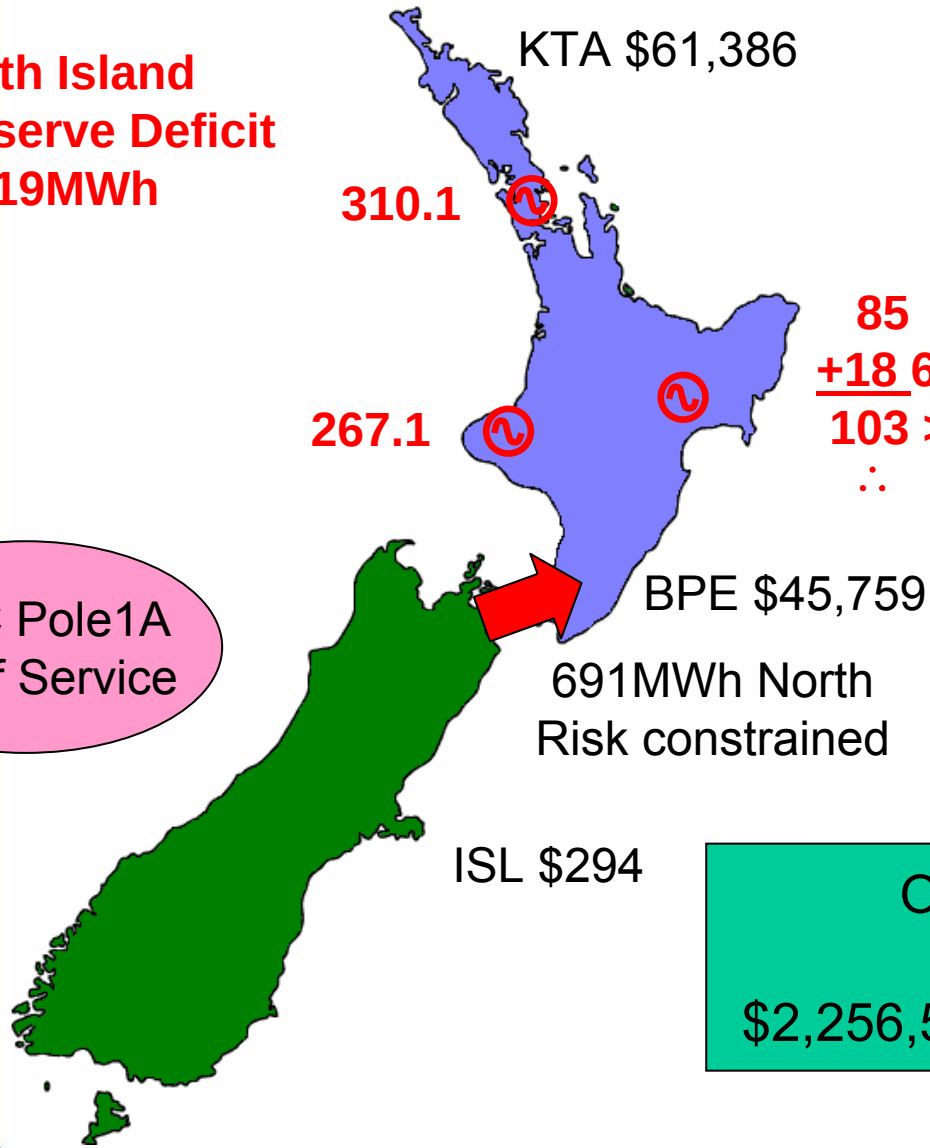
Murray Henderson

Market Services

13/15 September 2006

The 17:00 infeasible solution

North Island
60s Reserve Deficit
2.19MWh



HVDC Pole1A
Out of Service

85
+18 60s
103 > 88 FKK limit
∴ 15MWh FKK + 60s violation

North Island

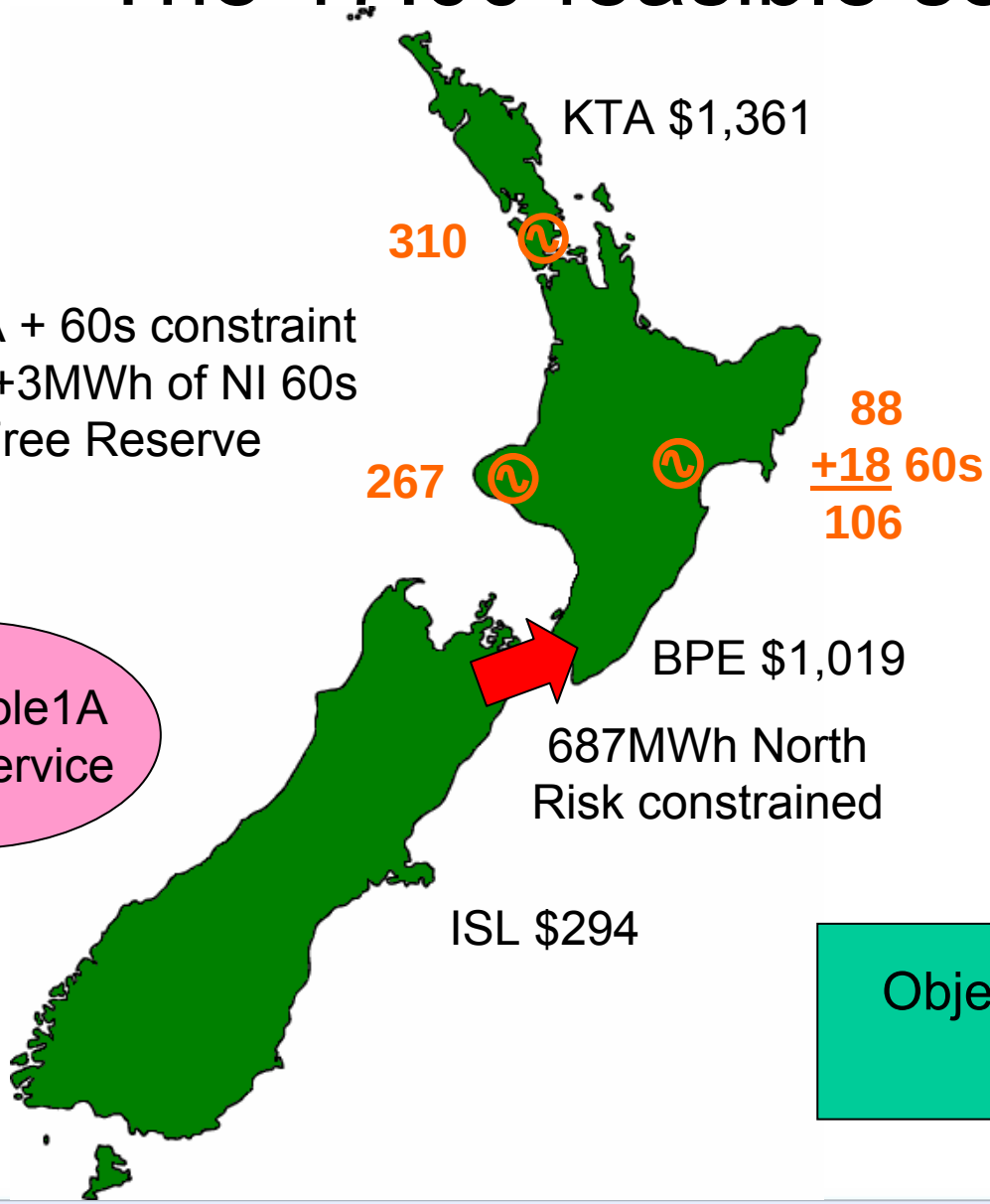
- Uncleared ENOF
  OTC 67MWh
  TCC 42MWh
  WHI 5MWh

South Island

- Uncleared ENOF
  270MWh

Objective Function Cost
$2,545,520
$2,256,514 CVP + $289,006 physical

The 17:00 feasible solution



North Island

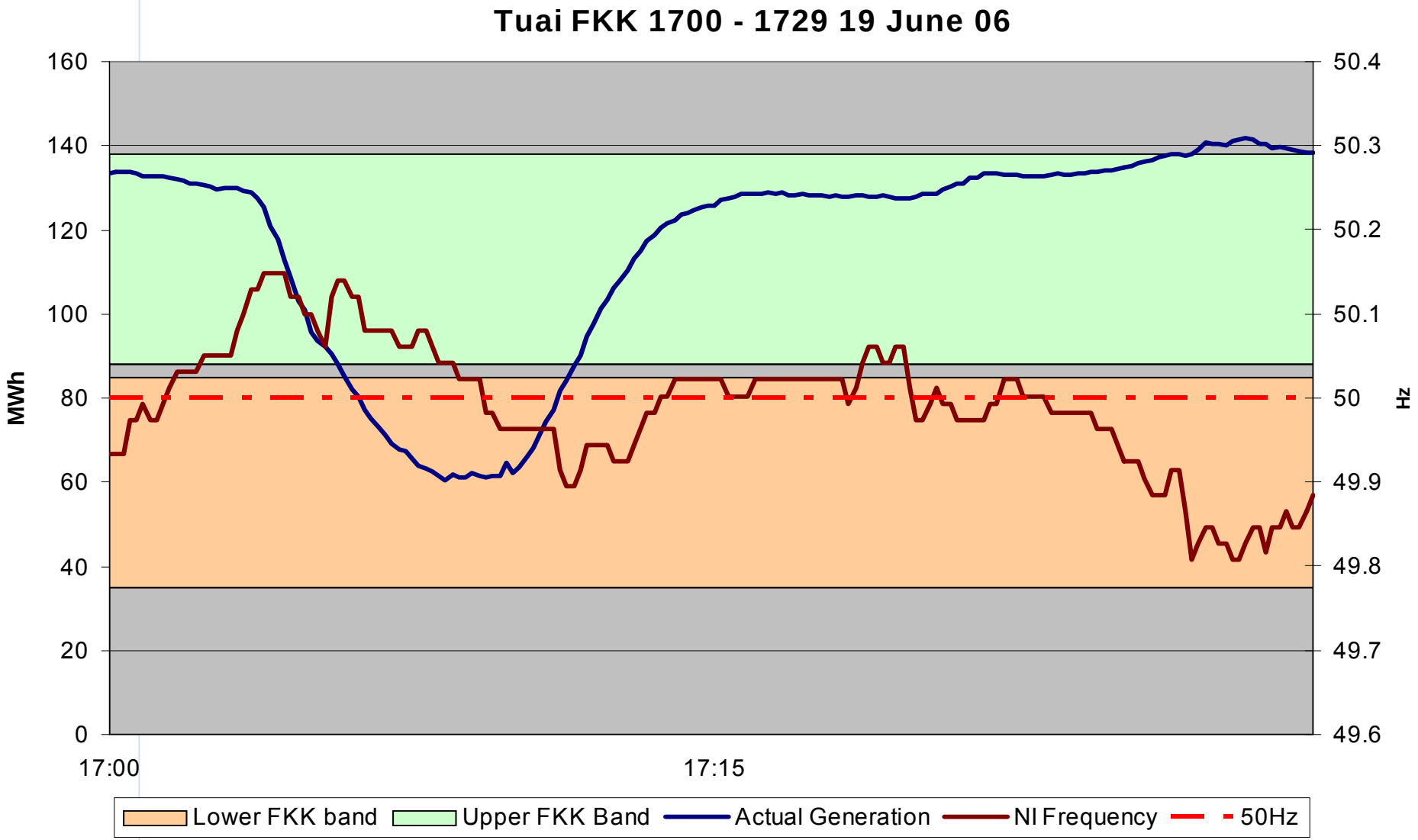
- Uncleared ENOF
  OTC 67MWh
  TCC 42MWh
  WHI 5MWh

South Island

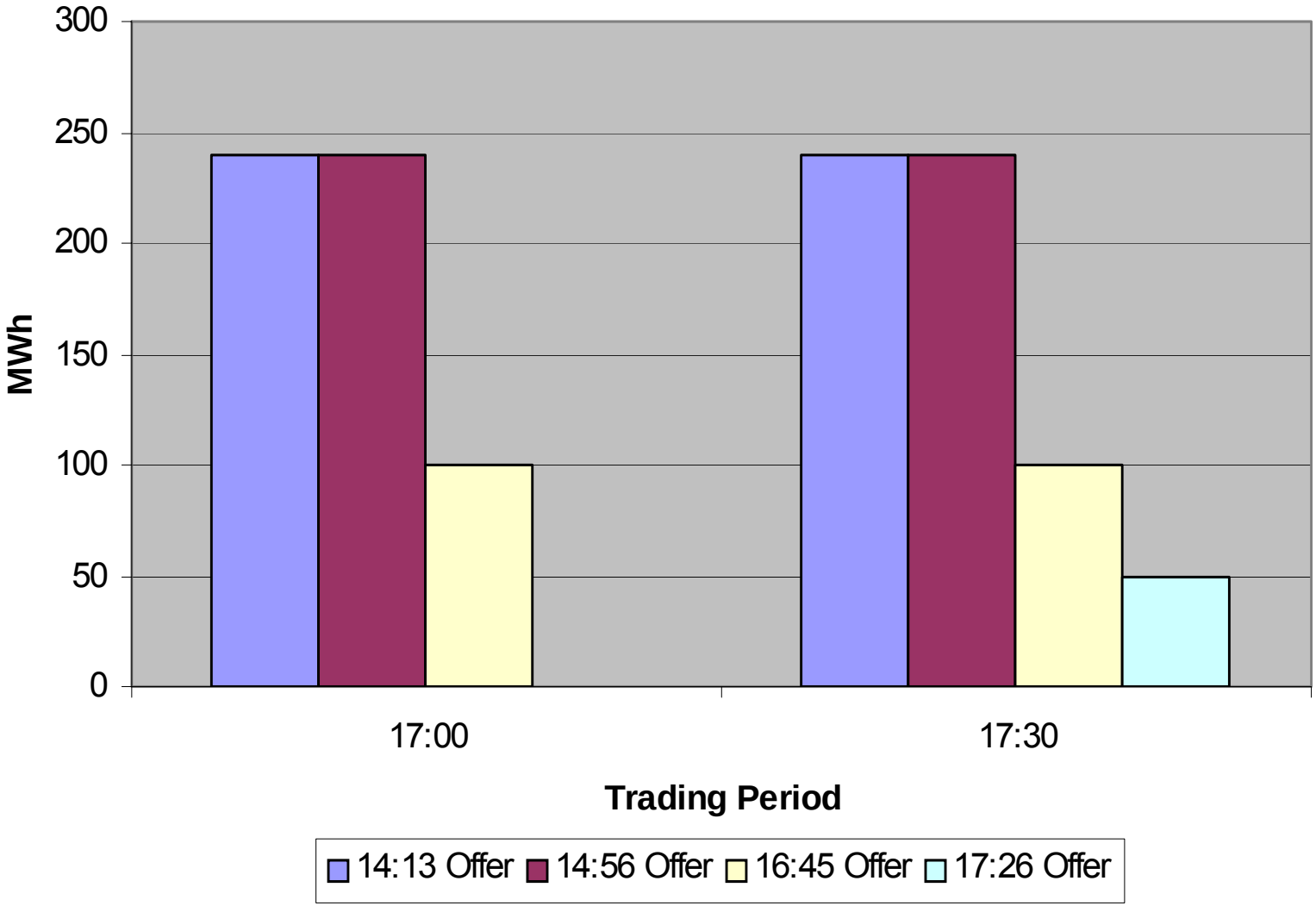
- Uncleared ENOF
  270MWh

Objective Function Cost
$287,877

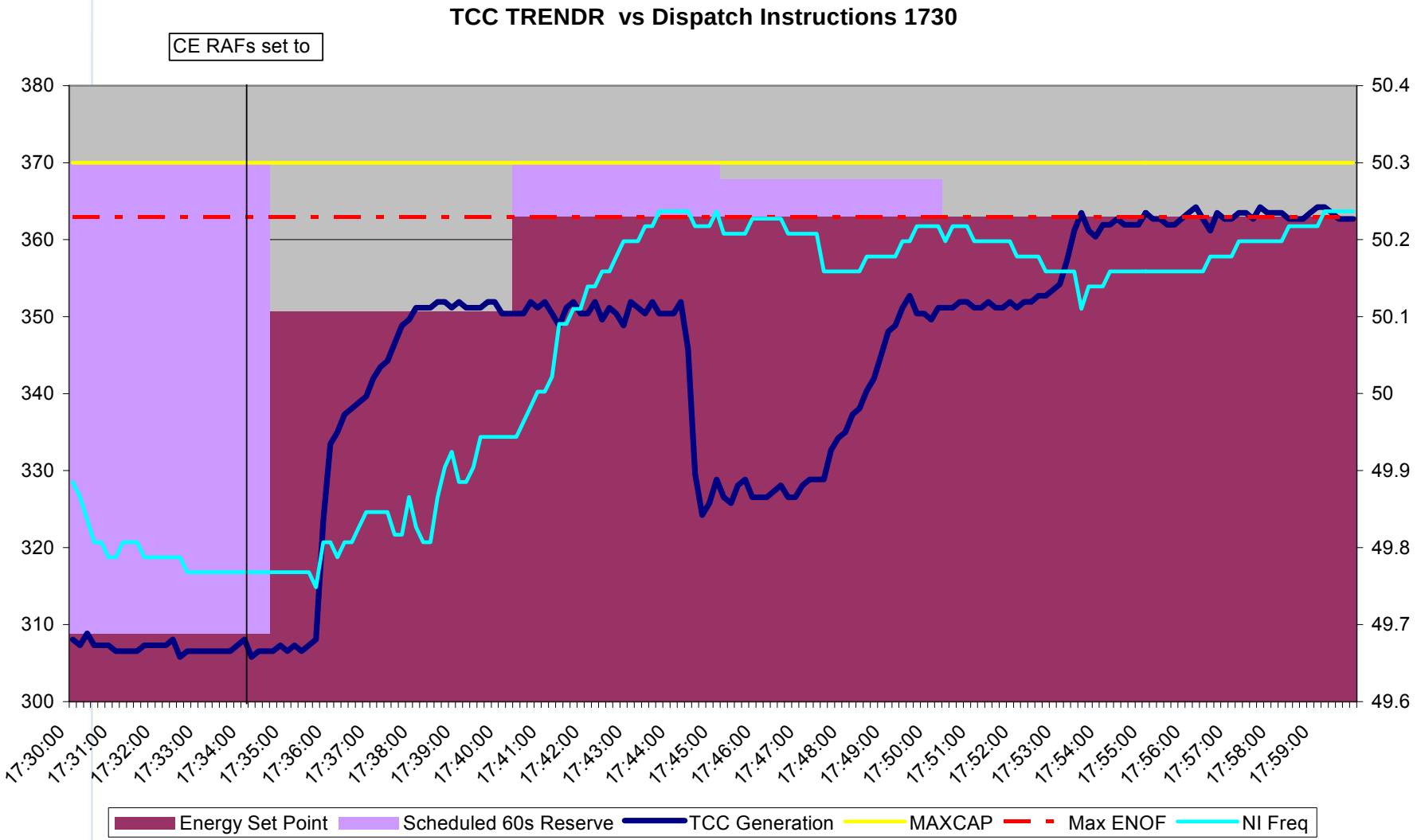
Tuai actual generation vs FKK limits



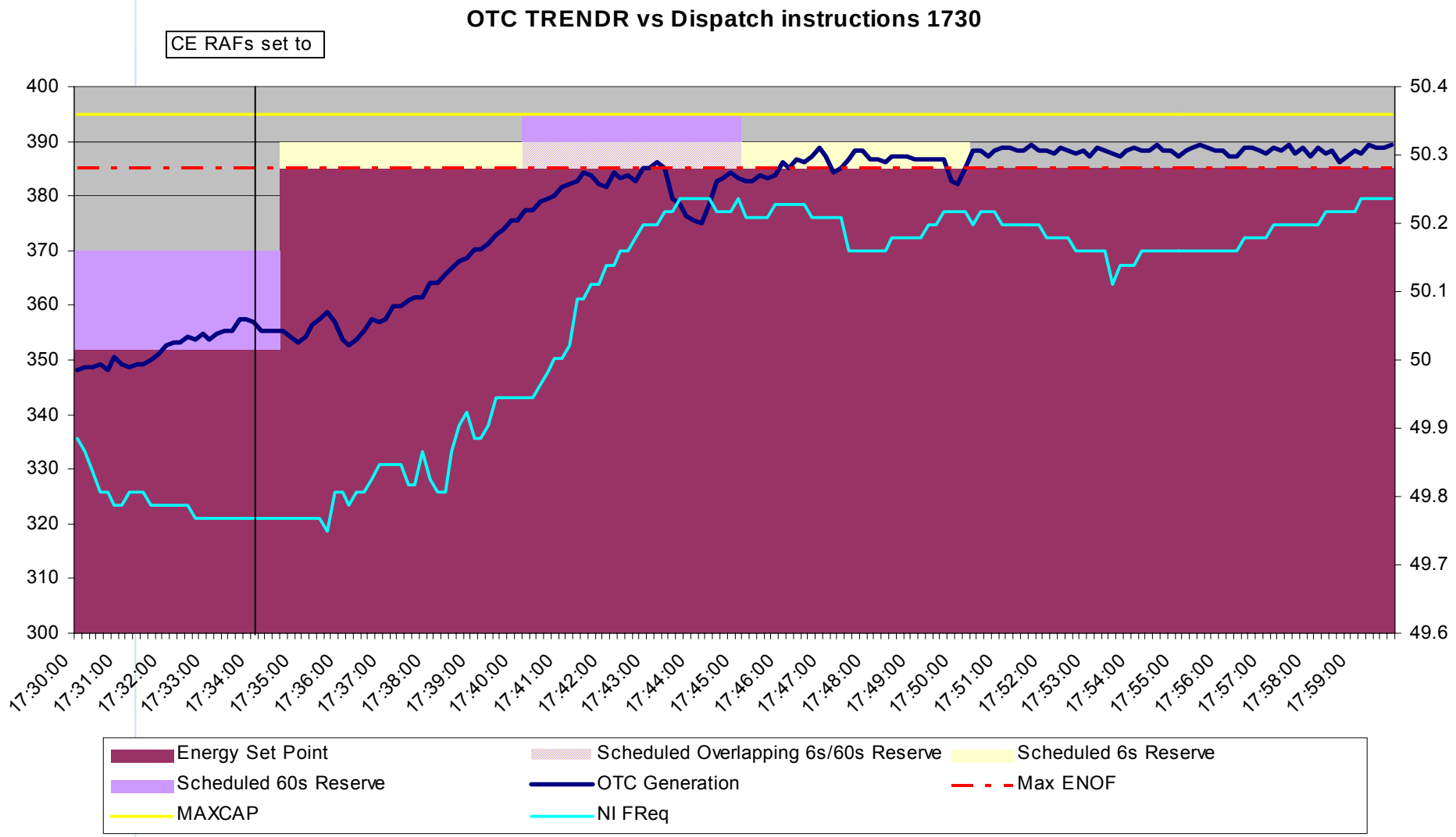
Tokaanu's bona fide reduction



TCC dispatch versus actual



OTC dispatch versus actual



17:30 Trading Period

Why 23MW of North Island 60s NFR?

- Existing 60s Deficit 18.63
- Deficit Generation KTA0331 3.38
- Increase in losses 0.99
- Total 23

How SPD and RMT interact

- DC Contingent Event Risk Model

  $Risk_{CE} \geq RAF_{CE}(HVDCflow - RiskOffset_{CE})$

- Generator Contingency Risk Model

  $Risk_{Gen} \geq RAF_{Gen}(Gen - RiskOffset_{Gen})$

- Manual Risk

  $Risk_{Man} \geq RAF_{Man}(ManualRisk - RiskOffset_{Man})$

- DC Extended Contingent Event Risk Model

  $Risk_{ECE} \geq RAF_{ECE}(HVDCflow - RiskOffset_{ECE})$