# Managing locational price risk

**Proposed amendments to Code**

**19 April 2011**

# Agenda

- Background
- Problem definition
- Proposals to address problems
- Design issues
- Cost-benefit analysis
- Next steps

# Requirements of Act: s.42

Authority must have, by 1 November 2011:

- Amended the Code to include "*mechanisms to help wholesale market participants manage price risks caused by constraints on the national grid*" (s.42(2)(c)); or
- to extent the Code does not include this matter, delivered a report to the Minister that:
  - explains why the Authority has not amended the Code to include it;
  - suggests alternative methods by which it is or may be provided for; and
  - sets out if, when, and how the Authority proposes to provide for it (section 42(2)(c) of the Act).

ELECTRICITY AUTHORITY
TE MANA HIKO

# Consultation

**2009**

- LRA
- Zonal pricing
- FTR
- hybrid

**Mid 2010**

Supplementary evaluation

**Sep 2010**

- Inter-island FTR
- Augmented FTR
- Extended FTR

**Apr 2011**

- Confirm inter-island FTR
- Evaluate intra-island LPR later

# Project objective

- "To promote competition in the electricity industry for the long-term benefit of consumers"
  - Consistent with Authority's statutory objective

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# 2010 problem definition still applies:

- LPR has resulted in a lack of:
  - retail competition; and
  - hedge market liquidity
- LPR primarily managed through vertical integration
  - Most retailers concentrated in one island
    - Key motivation for asset swaps

# Submissions raised two key issues:

- Need for inter-island LPR solution given availability of swaps?
- Does solution reflect likely future LPR?

# Will swaps solve problem?

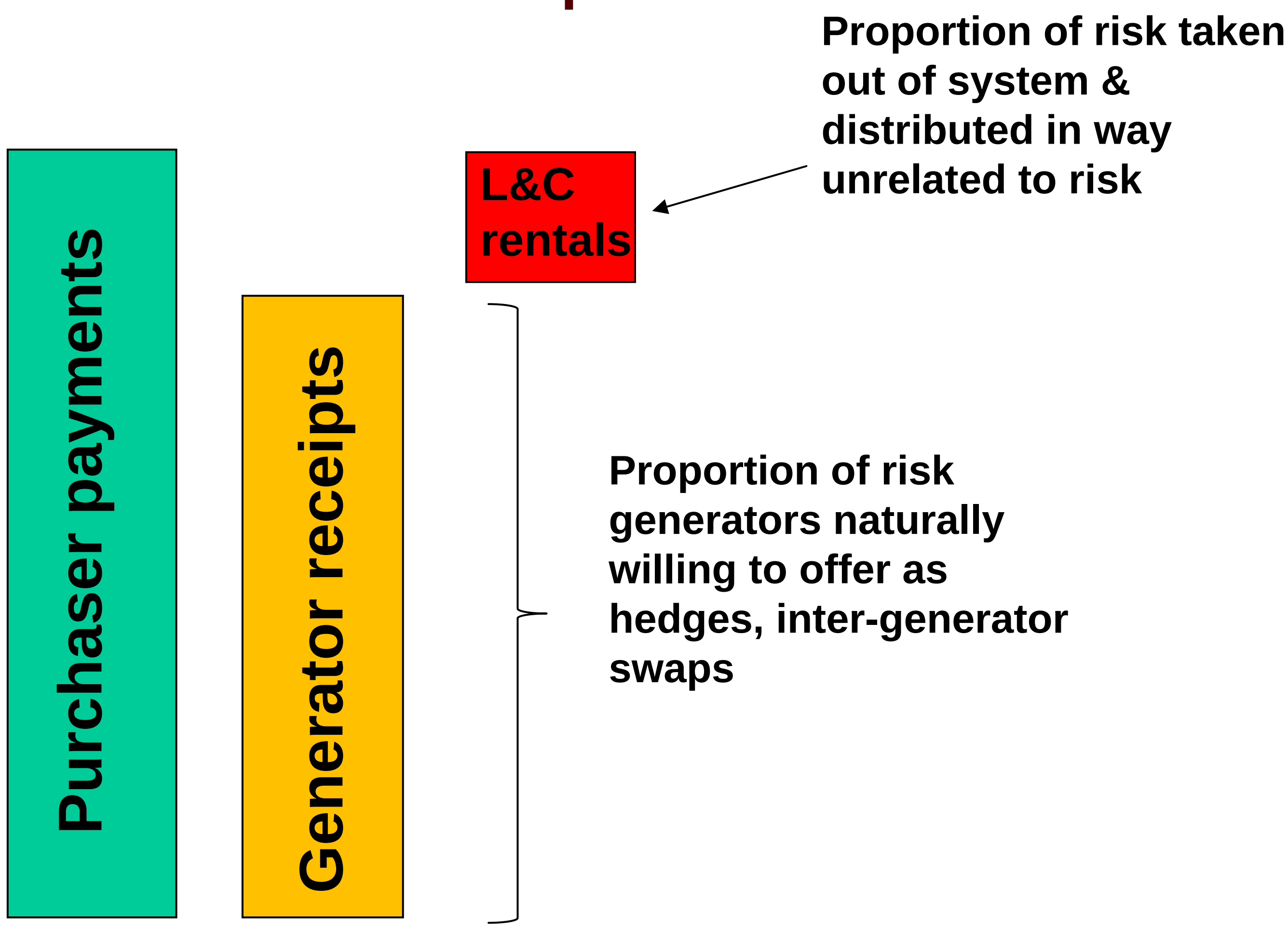
- Providers of LPR products could construct swaps using OTA, BEN futures; but
- No natural party is available to match swap (next slide)
- Must charge a high premium as exposed to actions of parties facing weak competitive pressure

→ participants manage LPR through:

  - balancing local generation and load
  - not entering retail where don’t have generation

- ***Net effect: reduced competition***

# Volume of hedges with and without settlement surplus



# Future LPR: Updated Energy Link analysis

- LPR likely significant problem in future
  - Would increase with scarcity pricing
- Over time AC higher proportion of LPR than HVDC
  - Primarily because of losses
- 67% of all modelled constraints to 2025/26 caused by HVDC or Bunneythorpe-Haywards equation constraint
  - Covered by inter-island FTR

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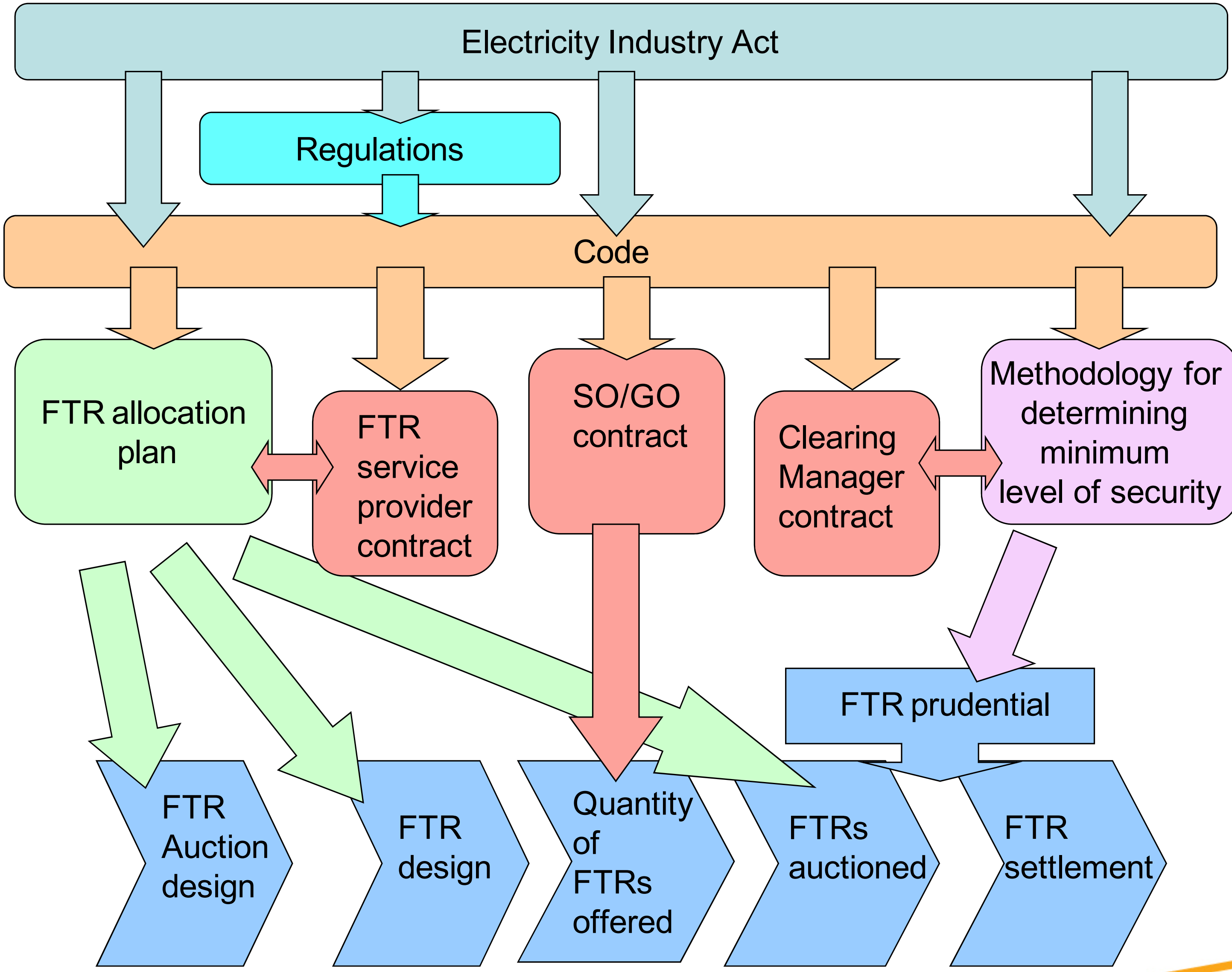
# Inter-island FTR: Overview

- Price difference between Otahuhu and Benmore
- monthly auctions
- available 1 year out initially, 2 years out after 3rd year of operation
- one month duration
- 0.1MW
- One-way (option) and two-way (obligation)
- Funded by rentals between Otahuhu and Benmore
- Secondary trading
- Allocation of residual: Method and recipients to be determined
- Amendments to Parts 1, 13 and 14 of Code

# Regulatory and operational framework



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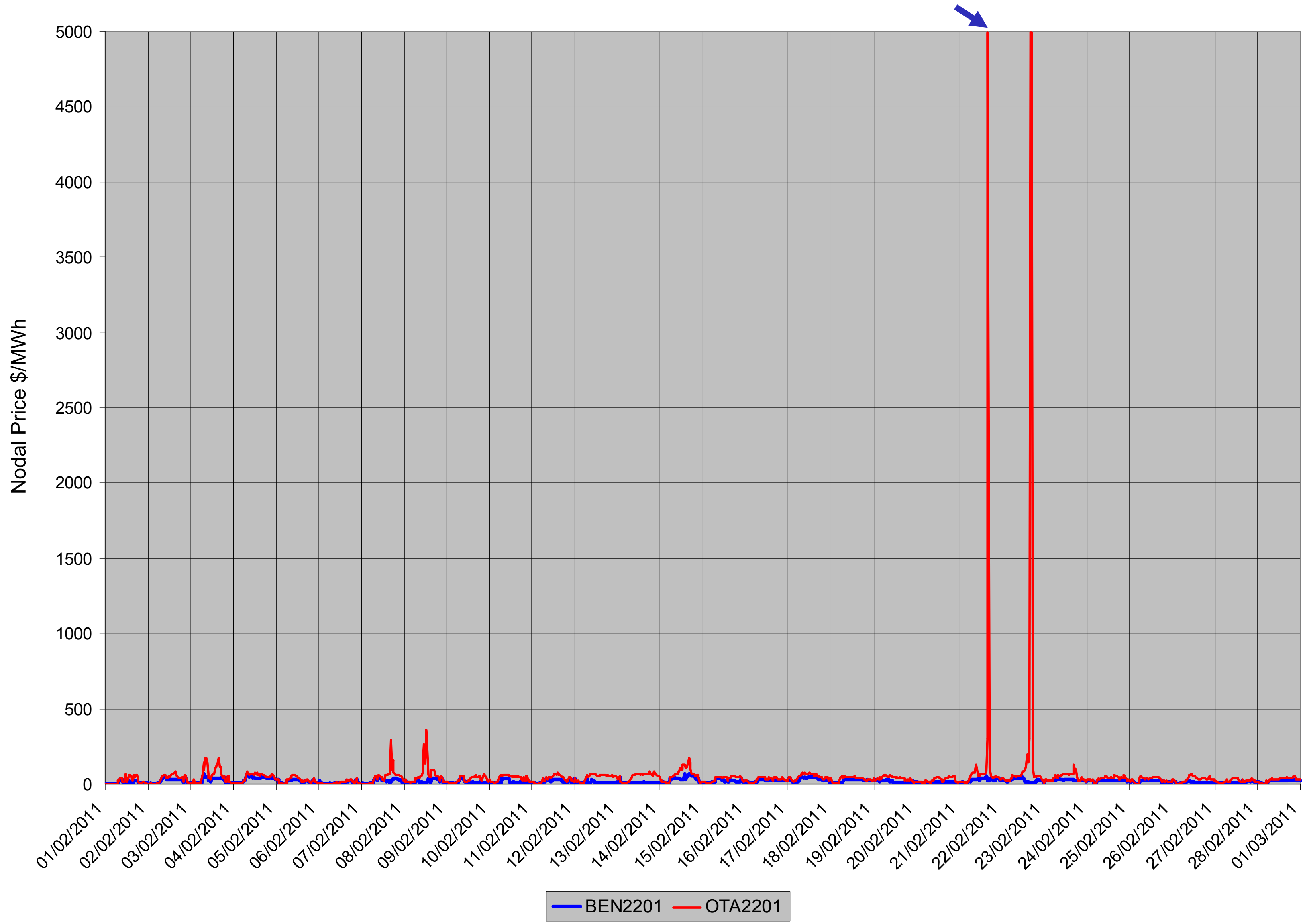
# Nodes and hubs

- For the purpose of establishing:
  - FTR reference prices: Otahuhu and Benmore grid reference points
    - Prices used for ASX futures
  - FTR quantity: hubs at Otahuhu and Benmore

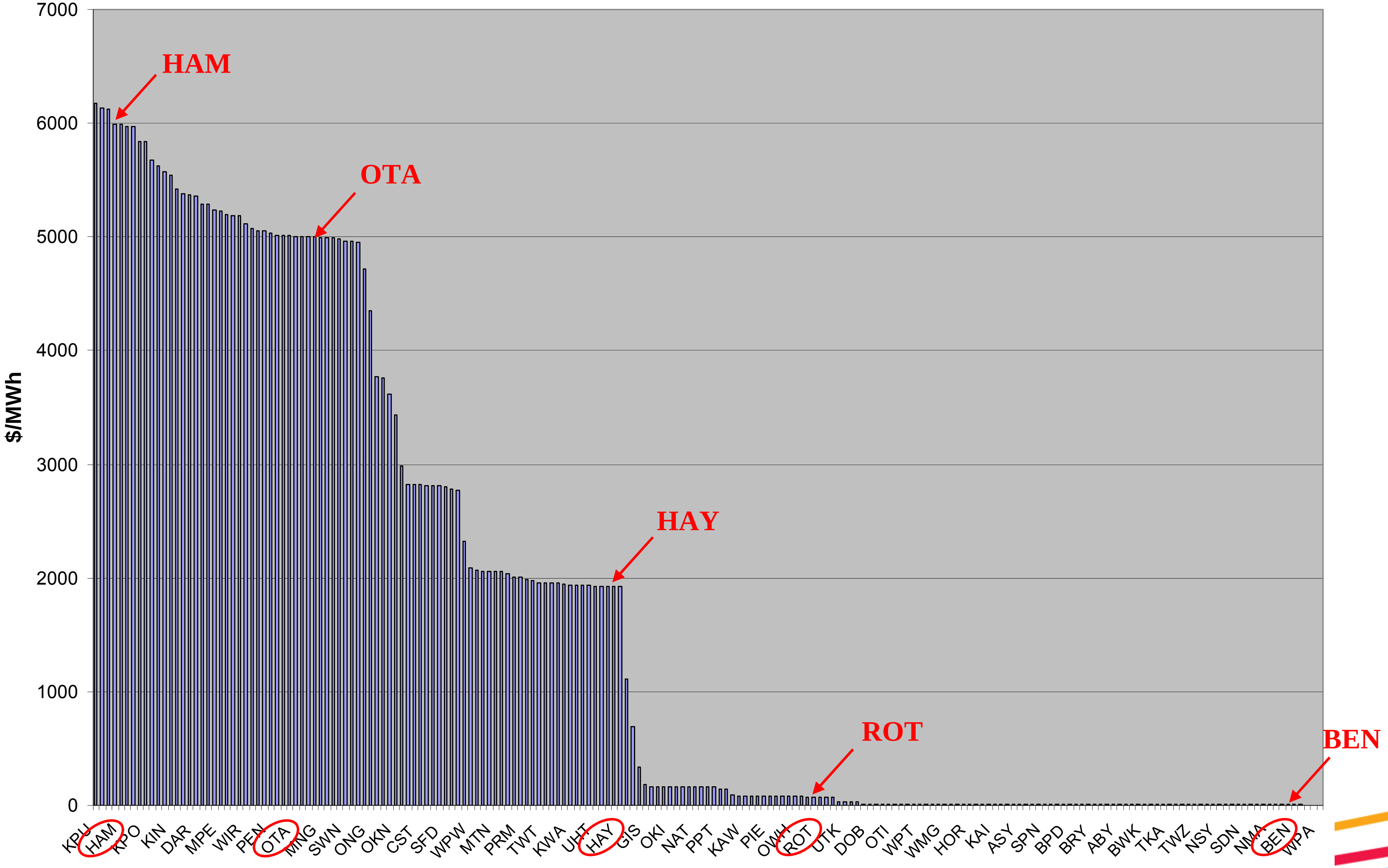
# Products

- Obligation FTRs:
  - Payout if price at receiving node > price at sending node
  - Must pay if price at receiving node < price at sending node
- Option FTRs:
  - Payout if price at receiving node > price at sending node
  - No requirement to pay for opposite

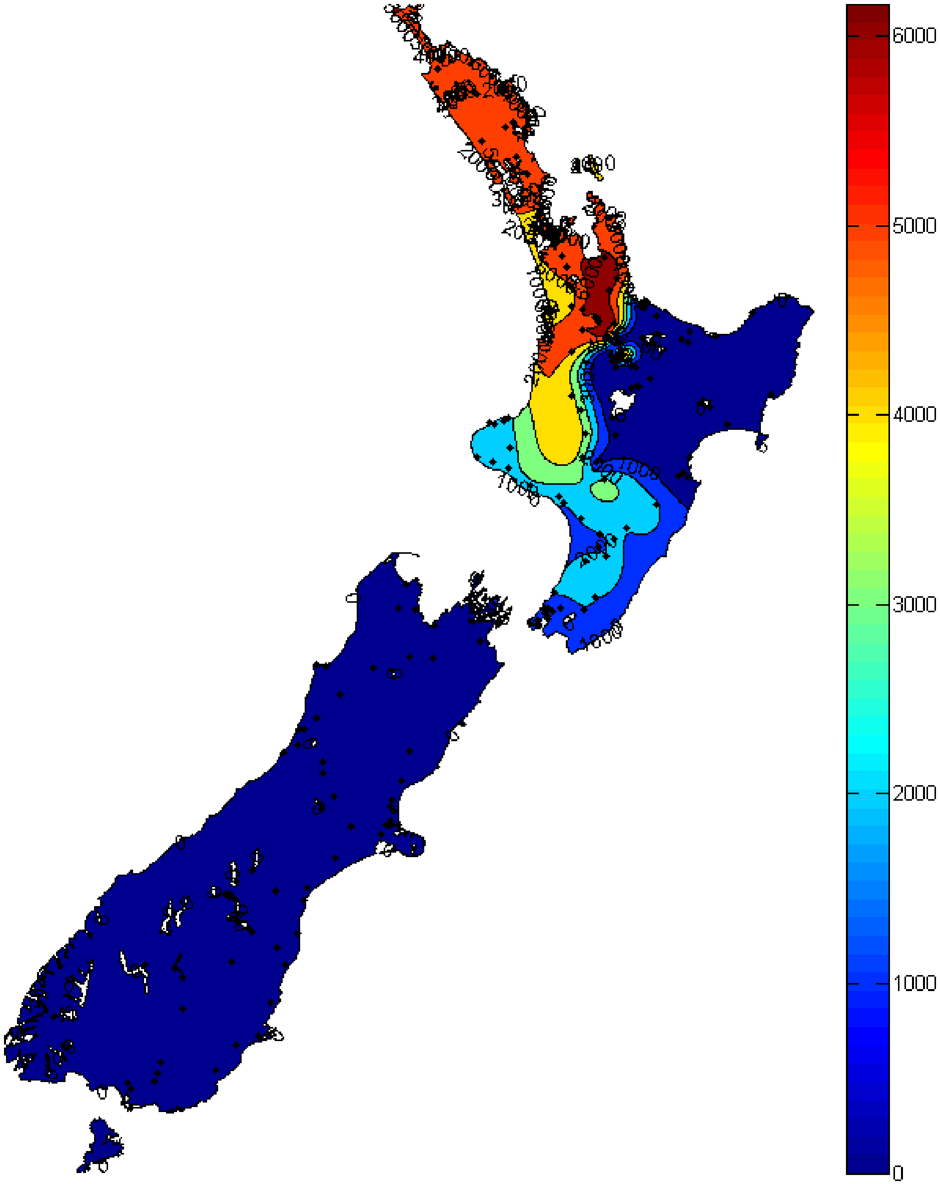
# Example: BEN, OTA Prices – Feb 2011



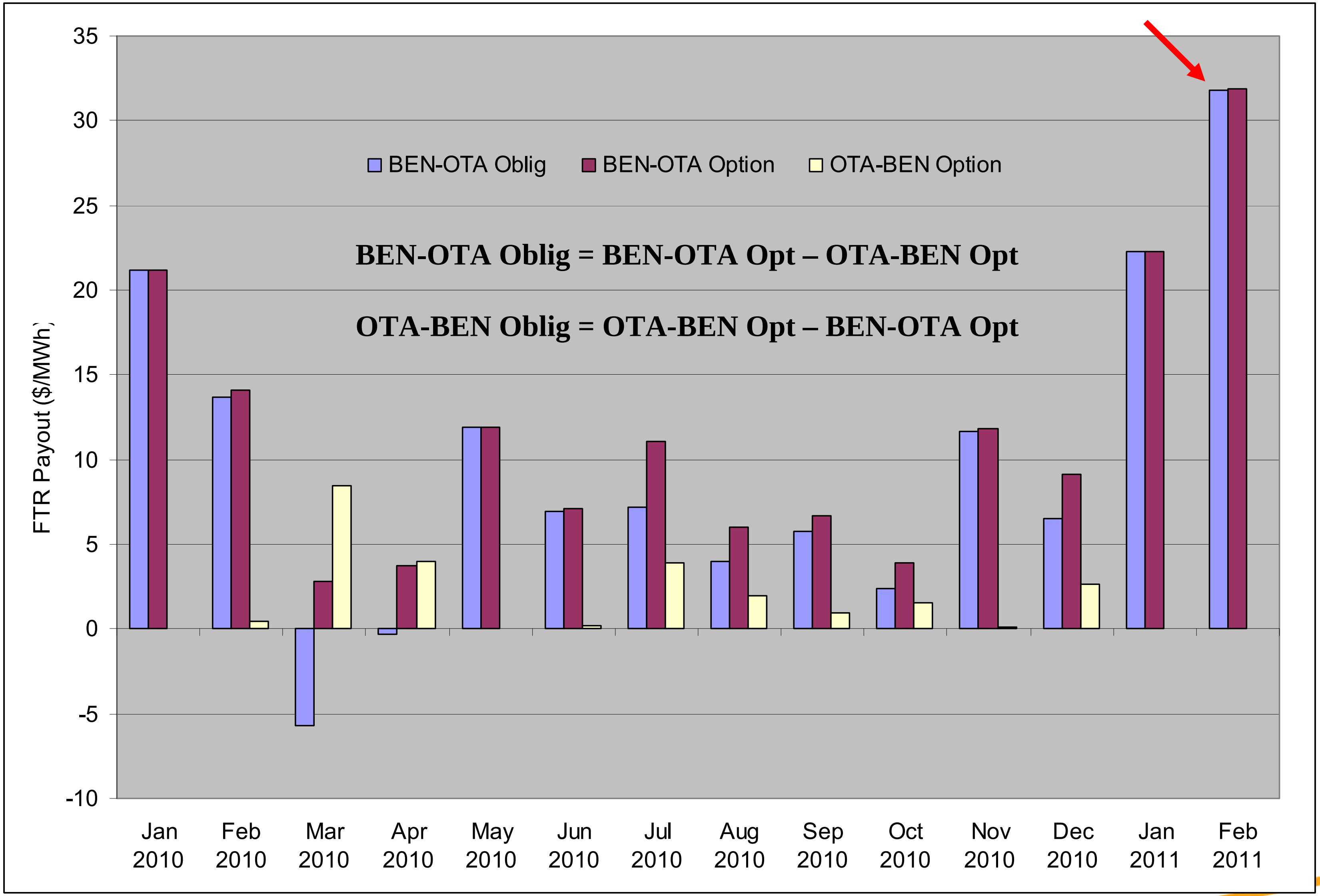
# Nodal Prices – 16:00 on 22 Feb 2011



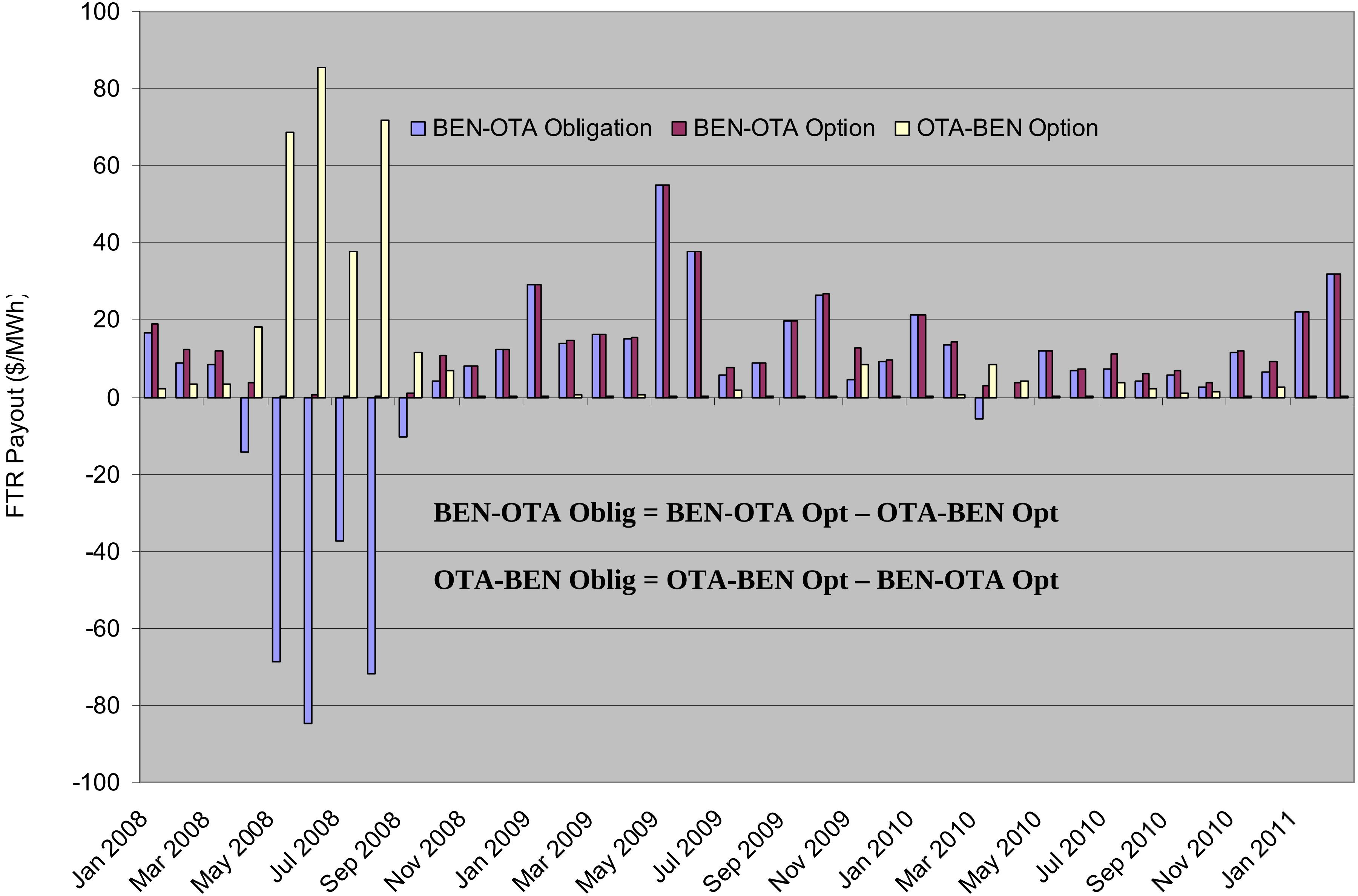
# Nodal Prices – 16:00 on 22 Feb 2011



# Obligation and Option FTR Payouts



# Obligation and Option FTR Payouts



# Auction design

- Responsibility of FTR service provider
- Standard design similar to wholesale electricity market
- Requirements:
  - FTRs offered based on estimate of grid
  - Designed to:
    - Maximise auction value
    - Maximise competition in auction
    - Minimise participation costs
  - Two options for determining quantity offered:
    - System operator
    - FTR service provider

# Managing credit and default risk

- Clearing manager has management role initially
  - Must determine methodology for minimum level of security
- To participate parties must meet prudential requirements
- Trading limit would set maximum participant can bid
- Minimum level of security = total cost of FTRs purchased less forecast FTR value
  - Margin calls (weekly?) if necessary
- Security combined with security for wholesale market
  - FTR payouts can offset wholesale market security requirements
- Risk of default shared proportionately between all parties

# FTR settlement

- Settlement amount/MW =
  a) ½∑price differences for trading periods in FTR period; less
  b) Any scaling of (a); less
  c) Per MW FTR auction price
- Provision for “netting” approach, which would allow secondary trading
- Same timeframe as energy market settlement

# Illustration of netting approach

| Month | 1 | 2 | 3 | 4 | Settlement | Total |
|---|---|---|---|---|---|---|
| | Auction price | | Sale price | | | |
| FTR value | $10 | $7 | $5 | $2 | | |
| Payment required | | $3 | $2 | $3 | $2 | $10 |
| Payment required by party 1 (seller) | | $3 | $2 | | | $5 |
| Payment required by party 2 (buyer) | | | | $3 | $2 | $5 |

# Managing revenue adequacy

- Ability to pay out full price difference
- Theory: FTR grid = actual grid → revenue adequacy
- Unexpected events may result in FTRs issued > actual grid
- Manage by:
  - Seeking FTR grid = actual grid;
  - Limiting quantity issued;
  - Access to rentals: HVDC rentals plus share of North Island rentals based on maximum inter-hub flows;
  - Accrue surplus rentals & auction revenue in “FTR account” for six months; and if necessary
  - Scaling
  - Attempt to “make whole” scaled FTRs from FTR account surplus over following year

# Allocation of residual FTR revenue

- Residual FTR revenue = auction proceeds plus unallocated inter-hub rentals
- Possible competition issues with allocation to FTR auction participants
- Propose assessing options according to project objective
- Options should avoid distortions to efficient price signals — inconsistent with statutory objective

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# Methodology and assumptions

- Top-down analysis
- Baseline scenario includes:
  - Authority has more focussed statutory objective
  - Development of hedge market
  - Physical and virtual SOE asset swaps
  - Approved transmission investment
  - Ability of lines companies to be retailers
  - More active demand-side participation
- Assumed that 67% of total LPR addressed by inter-island FTR
- Discount rate of 8%

# Costs

- Development, implementation, set-up and operating costs, participation costs

# Benefits

- Greater use of locational hedging (transfer)
- Lower search and transaction costs
- **Improved retail and generator competition**
- Improved price signals
- Option value provided by inter-island FTR
- Dynamic efficiency benefits (not estimated) – innovation from enhanced competition, investment

# Net present value (NPV)

| Costs | Benefits | 10-year NPV | 30-year NPV |
|---|---|---|---|
| Low | High | $40.3m | $100.0m |
| High | High | $24.9m | $72.3m |
| Low | Low | $13.7m | $38.1m |
| High | Low | $0.5m | $14.3m |

# Qualitative evaluation of inter-island FTR

- Addresses main source of LPR in NZ
- Relatively simple
- Fits well with other industry developments
- Matches major energy trading points so promotes hedge market liquidity
- Avoids distortions to nodal price signals
- Flexible to changes in market design and conditions

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# Indicative timeline

| | | Develop Code | Procure FTR Service Provider | Implementation | | |
|---|---|---|---|---|---|---|
| 2011 | Jan | Final proposal design and drafting of Code amendments | | | Jan | 2011 |
| | Feb | | | | Feb | |
| | Mar | | | | Mar | |
| | Apr | Consultation | Preparations for tender for FTR service provider | | Apr | |
| | May | Consider submissions | | | May | |
| | Jun | | | | Jun | |
| | Jul | **Code provisions made** | Tender for FTR service provider | | Jul | |
| | Aug | | | | Aug | |
| | Sep | | Selection of FTR service provider | | Sep | |
| | Oct | | | FTR market development | Oct | |
| | Nov | | | | Nov | |
| | Dec | | | | Dec | |
| 2012 | Jan | | | | Jan | 2012 |
| | Feb | | | | Feb | |
| | Mar | | | | Mar | |
| | Apr | | | **Go Live** | Apr | |

# Key dates

- Consultation (Code changes) closes 12 May 2011
- Targeting implementation prior to winter 2012

Questions?