# Energy-only electricity markets: fundamentals, fallacies and flaws

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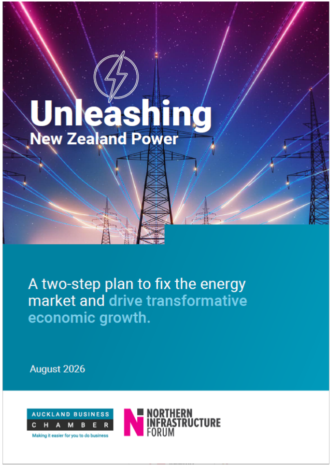
(The theoretical paper is available for download from www.epoc.org.nz)

GEEC Seminar, August 26, 2026.

# Electricity markets in the news


Consumer report, July 2026
https://www.datocms-assets.com/58051/1784769601-cnz-electricity-report-3-full-report-web.pdf




ABC Report, August 2026
https://cdn.freemanmedia.co.nz/sites/default/files/d10/article/2026/08/04/unleashing_nz_power_final.pdf

# The solution according to Consumer

contact
genesis
Mercury
Meridian.

**DRIVER 1**

## Four big power companies dominate the market

### The issue

Contact, Genesis, Mercury and Meridian together control around 85% of the retail market. The remaining 15% is shared among around 20 smaller retailers.

The four dominant companies are "gentailers", both generating and selling electricity. This structure (called "vertical integration") gives them a built-in advantage over smaller, independent retailers and shapes how competition functions across the market.

A key part of this advantage lies in how electricity is bought and sold. Smaller retailers typically rely

Independent retailers don't have this option. They must buy electricity from the wholesale market – often from the gentailers themselves – and are therefore more exposed to risk and price swings.

An NZIER analysis found that most wholesale electricity trading between 2012 and 2021 occurred within gentailer businesses, rather than between competing firms. In practice, this means relatively little electricity is traded in an open, competitive market.

The result is a structural imbalance. Gentailers face lower risks and have more control over pricing, and independent retailers operate under tighter margins and greater uncertainty. While gentailers are able to absorb or manage changes in generation costs, independent retailers are more likely to pass these costs on to consumers.

**DRIVER 2**

## Power prices don't reflect real costs

### The issue

In New Zealand, our power comes from a range of sources, both renewable (e.g. hydro dams and wind farms) and non-renewable (thermal energy such as coal and gas).

Transpower, a state-owned enterprise, is responsible for making sure there's enough power supplied when New Zealanders need it. Every half hour, generators tell Transpower how much power they can offer and at what price. Transpower accepts offers, starting with cheaper renewable energy and progressing to more expensive non-renewable energy if necessary to meet demand.

However, because we have what's known as a "spot market", the price paid to generators is not actually the offer price. Instead, all dispatched generators are paid the spot price for their location, which is set by the highest-cost generation needed to meet demand. This means that when there's not enough renewable energy, expensive fossil fuels – not cheaper renewable energy – are setting the price for electricity.

It also means renewable generators profit when non-renewables are used. Critics of the spot market argue that this pricing system allows gentailers to profit at consumers' expense.

A NZ Council of Trade Unions report put it bluntly: "For the gentailers, keeping coal and gas as part of our energy mix is a crucial part of the business

### The response

The 2025 Frontier Economics review found the spot market was operating as expected and recommended no changes, arguing that the market revealed problems, rather than causing them. One author emphasised that "keeping the pricing mechanism stable over time gives people confidence in the pricing mechanism".

The OECD concurred with Frontier in so far as the electricity market was "textbook best practice", yet it noted the dominance of the gentailers and lack of dry-year cover, which limited competition on the spot market.

The Electricity Authority has noted increased spot market volatility since 2018, when the Pohokura gas field declined. It reviewed wholesale spot pricing in 2023 and again after high prices in winter 2024. Its conclusion was that the market should be proactively monitored, not fundamentally redesigned.

The OECD noted that the Electricity Authority was trying to make changes but that its success was limited, because it was looking for solutions within the current market, which wouldn't change the structural issues.

### Our recommendation

**Make power prices reflect real costs.** Sort out the market so we stop paying high fossil fuel prices

# I asked Google AI about New Zealand gentailer profits

AI Overview

In Aotearoa New Zealand, "gentailers" (vertically integrated generator-retailers like Contact, Genesis, Mercury, and Meridian) face intense scrutiny over "excess profits". Critics argue these firms exploit their market dominance to keep retail power bills high, while often paying out dividends to shareholders that exceed their net profits. * NZCTU +3

## The Core Issues and Arguments

- **Excess Dividends vs. Reinvestment:** Unions and advocacy groups like 350 Aotearoa have reported that gentailers distributed billions of dollars more in shareholder dividends than they earned in net profits over the past decade. Critics claim this diverts vital capital away from building new renewable energy infrastructure.
- **High Wholesale Prices:** The spot price for electricity is often set by the highest-cost generator dispatched—which is frequently coal or gas. Because gentailers own the cheaper renewable generation (hydro, wind, solar) as well, they effectively reap massive margins.

# Outline

# Outline

Fundamentals: thermal-only systems

Fallacies: Part I

The New Zealand market

Modelling renewables and storage

Fallacies: Part II

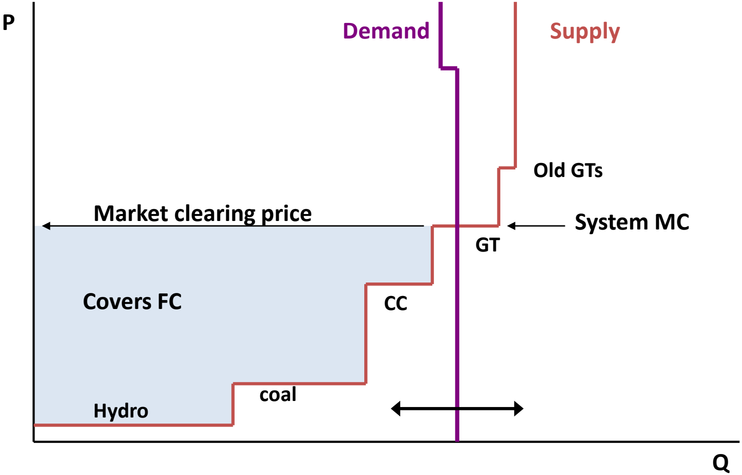
Flaws (or features?)

## Assumptions for energy-only markets

- perfect competition (price-taking participants)
- complete markets (all instruments are priced in market)
- linear capacity cost for technology $j$ $a_j x_j$
- linear production cost for technology $j$ $c_j y_j$
- known value of lost load $V$
- risk-neutral market participants
- complete information including probabilities

In practice, short-run marginal cost (SRMC) increases with output, capacity is lumpy, competition is "workable", markets are incomplete, and agents are risk averse with different forward views.

# Economic Dispatch & Pricing at a Single Node




In perfect competition, the supply curve is the SRMC of each plant. The market dispatches plant in merit order. The clearing price is set by the most expensive dispatched plant. The grey area is Ricardian rent.

# Classical screening curve ranks plant

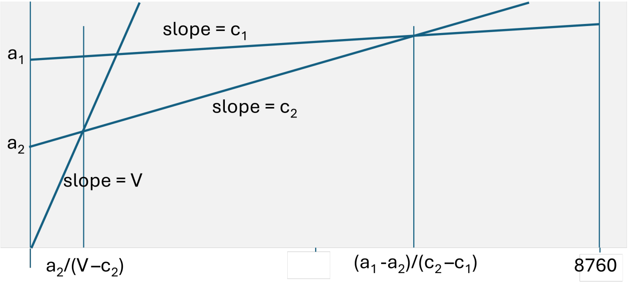
[Boiteaux, 1960, Stoft, 2002]

Base load (SRMC=$\$c_1$/MWh, annual capacity cost =$\$a_1$/MW).

Peaker (SRMC=$\$c_2$/MWh, annual capacity cost =$\$a_2$/MW).

Load shed (SRMC=$V$)

Peaker runs for $= \frac{a_1 - a_2}{c_2 - c_1}$ hours. Load shed for $\frac{a_2}{V - c_2}$ hours.



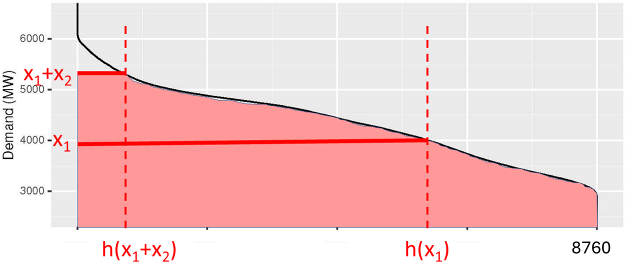

Screening curve showing most economical plant for different durations.

# Screening curve capacity choices

Base load (SRMC=$c_1$) on for 8760 hours in year.

Peaker (SRMC=$c_2$) on for $h(x_1) = \frac{a_1 - a_2}{c_2 - c_1}$ hours.

Load shed (SRMC=$V$) for $h(x_1 + x_2) = \frac{a_2}{V - c_2}$ hours.




Load duration curve with base load capacity $x_1$ and peaker capacity $x_2$.

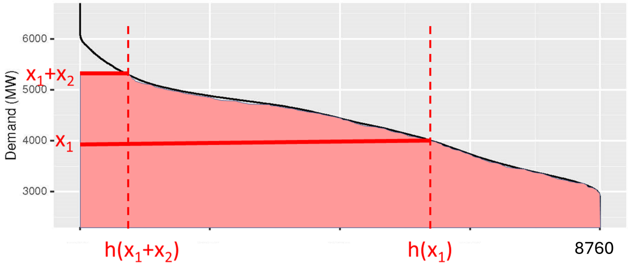
# Rents pay for capacity choices

Annual rent for peaker $= h(x_1 + x_2)(V - c_2)x_2 = a_2 x_2$ .

Annual rent for base load

$$= h(x_1 + x_2)(V - c_1)x_1 + (h(x_1) - h(x_1 + x_2))(c_2 - c_1)x_1$$

$$= (a_2 + h(x_1)(c_2 - c_1))x_1 = a_1 x_1.$$




All plants make zero profit at social optimum capacities.

# Outline

Fundamentals: thermal-only systems

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## Fallacies in energy-only electricity markets: Part I

- Fallacy: Peak generators need to offer energy above their SRMC to recover fixed costs.
- Why? The scarcity price $V$ gives the correct rent to peakers.
- Fallacy: If you cap prices below $V$ then welfare will improve.
- Why? A low scarcity price $V$ reduces capacity of all plants below their socially optimal level. Lost load probability will increase.
- Fallacy: Wholesale price should be the average cost of generation, not the cost of the most expensive dispatched plant.
- Why? Possible change in merit order gives short-run efficiency loss. Lower rents reduce capacity of all plants below their socially optimal level. Lost load probability will increase.

# Outline

## How does this work in New Zealand?

- Generators submit offers of energy to Transpower who aggregates them and solves an optimization model called SPD.
- With demand-side bidding, $V$ can be replaced by a utility function for demand $U(d)$.
- Every five minutes, SPD returns the optimal dispatch and locational marginal prices at each grid exit point.
- Prices $\pi$ are marginal utility, so $\pi = U'(d)$.
- The dispatch and prices satisfy the optimality conditions of the optimization problem.
- Henceforth, we consider a simple model with a single node.

## SPD basic model: single node

Let $n$ be a trading period, and $\mathcal{J}$ the set of generators, each with capacity $x_j$ and SRMC $c_j(n)$.

Choose $y_j(n)$ and $d(n)$ to solve:

$$
\begin{aligned}
\text{SPD: } \min \; & \sum_{j \in \mathcal{J}} c_j(n) y_j(n) - U_n(d(n)) \\
\text{s.t.} \quad & \sum_{j \in \mathcal{J}} y_j(n) = d(n), \\
& 0 \leq y_j(n) \leq x_j, \quad \text{for all } j \in \mathcal{J},
\end{aligned}
$$

## What are the optimality conditions?

Suppose that $(y_j^*(n), d^*(n))$ is an optimal solution to SPD. Then there exists $\pi(n)$ and $\rho_j(n) \geq 0$ satisfying

$$\pi(n) = U'(d^*(n))$$

$$\sum_{j \in \mathcal{J}} y_j^*(n) = d^*(n)$$

$$0 \leq c_j(n) + \rho_j(n) - \pi(n) \perp y_j^*(n) \geq 0$$

$$0 \leq x_j - y_j^*(n) \perp \rho_j(n) \geq 0$$

Here $0 \leq a \perp b \geq 0$ means $a \geq 0$, $b \geq 0$, and both cannot be strictly positive.

# SPD gives system investment optimization model SMP

Let $\mathcal{N} = \{\text{trading periods in a year}\}$. Choose $x_j$, $y_j(n)$ and $d(n)$ to solve:

$$
\begin{aligned}
\text{SMP: min} \quad & \sum_{j \in \mathcal{J}} a_j x_j + \sum_{n \in \mathcal{N}} \left( \sum_{j \in \mathcal{J}} c_j(n) y_j(n) - U_n(d(n)) \right) \\
\text{s.t.} \quad & \sum_{j \in \mathcal{J}} y_j(n) = d(n), \quad \text{for all } n \in \mathcal{N} \\
& 0 \le y_j(n) \le x_j, \quad \text{for all } j \in \mathcal{J}.
\end{aligned}
$$

## Fix optimal capacities at $x^*$, and solve dispatch problems

Let $\mathcal{N} = \{\text{trading periods in a year}\}$.

$$\begin{aligned} \text{SPD}(x_j^*)\colon \min \quad & \sum_{j\in\mathcal{J}} a_j x_j^* + \sum_{n\in\mathcal{N}} \left( \sum_{j\in\mathcal{J}} c_j(n) y_j(n) - U_n(d(n)) \right) \\ \text{s.t.} \quad & \sum_{j\in\mathcal{J}} y_j(n) = d(n), \quad \text{for all } n \in \mathcal{N} \\ & 0 \le y_j(n) \le x_j^*, \quad \text{for all } j \in \mathcal{J}. \end{aligned}$$

This decouples into $|\mathcal{N}|$ dispatch problems, where plant $j$ offers $x_j^*$ at marginal cost $c_j(n)$, and demand bids marginal utility $U_n'(d)$.

SPD has same dispatch and prices as SMP.

## Optimality conditions for SMP imply SPD rents cover costs

$$\pi(n) = U'(d(n))$$

$$0 \leq c_j(n) + \rho_j(n) - \pi(n) \perp y_j(n) \geq 0$$

$$0 \leq x_j - y_j(n) \perp \rho_j(n) \geq 0$$

$$0 \leq a_j - \sum_{n \in \mathcal{N}} \rho_j(n) \perp x_j \geq 0$$

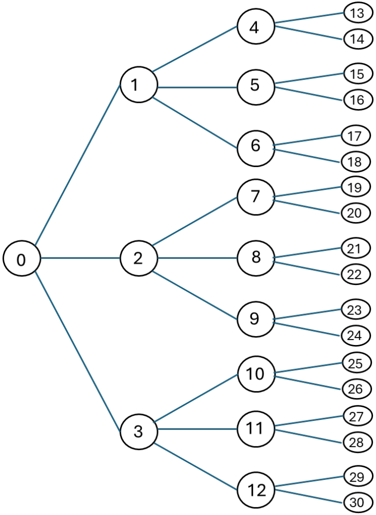
$$\begin{aligned} \text{Annual rent } (R_j) \text{ for technology } j &= \sum_{n \in \mathcal{N}} (\pi(n) - c_j(n)) y_j(n) \\ &= \sum_{n \in \mathcal{N}} \rho_j(n) y_j(n) \\ &= \sum_{n \in \mathcal{N}} \rho_j(n) x_j = a_j x_j \end{aligned}$$

## The story so far...

- Assume
  - perfect competition
  - complete markets
  - linear capacity cost $a_j x_j$
  - linear production cost $c_j(n) y_j(n)$
  - concave differentiable utility $U(d)$
- Solve investment problem SMP to give optimal capacities for each technology.
- With capacities fixed, solve dispatch problem SPD in each hour to give system marginal prices.
- The total annual Ricardian rent $(R_j)$ earned by each technology $j$ exactly covers its annual capital cost $a_j x_j$.
- SMP solution is a competitive equilibrium.

# Outline

# Uncertain supply: $n$ is a node in a scenario tree.




A scenario tree with 30 nodes and 18 scenarios. Node $n$ has probability $p(n)$.

## Wind/solar generator with uncertain supply $\omega(n)$

$$
\begin{array}{llcll}
\text{SMP:} & \min & \theta x & + & \sum_{n\in\mathcal{N}} p(n)(C(g(n)) - U_n(d(n))) & \\
& \text{s.t.} & z(n) & = & d(n) - g(n) & [p(n)\pi(n)] \\
& & z(n) & \leq & x\omega(n) & [p(n)\phi(n)]
\end{array}
$$

$$0 \leq \pi(n) - \phi(n) \perp z(n) \geq 0$$

$$0 \leq x\omega(n) - z(n) \perp \phi(n) \geq 0$$

$$0 \leq \theta - \sum_{n\in\mathcal{N}} p(n)\omega(n)\phi(n) \perp x \geq 0$$

$$
\begin{aligned}
\mathbb{E}[R] \text{ (rent)} &= \sum_{n\in\mathcal{N}} p(n)\pi(n)z(n) = \sum_{n\in\mathcal{N}} p(n)\phi(n)z(n) \\
&= \sum_{n\in\mathcal{N}} p(n)\phi(n)\omega(n)x = \theta x
\end{aligned}
$$

## Run-of-river plant with inflow $\omega(n)$

**(inflow measured in MW)**

$$
\begin{array}{llcll}
\text{SMP:} & \min & \theta x & + & \sum_{n\in\mathcal{N}} p(n)\big(C(g(n)) - U_n(d(n))\big) & \\
& \text{s.t.} & z(n) & \geq & d(n) - g(n) & [p(n)\pi(n)] \\
& & z(n) & \leq & \omega(n) & [p(n)\lambda(n)] \\
& & z(n) & \leq & x & [p(n)\phi(n)]
\end{array}
$$

$$0 \leq \pi(n) - \lambda(n) - \phi(n) \perp z(n) \geq 0$$

$$0 \leq x - z(n) \perp \phi(n) \geq 0$$

$$0 \leq \omega(n) - z(n) \perp \lambda(n) \geq 0$$

$$0 \leq \theta - \sum_{n\in\mathcal{N}} p(n)\phi(n) \perp x \geq 0$$

# Run-of-river plant optimality conditions

$$0 \le \pi(n) - \lambda(n) - \phi(n) \perp z(n) \ge 0$$

$$0 \le x - z(n) \perp \phi(n) \ge 0$$

$$0 \le \omega(n) - z(n) \perp \lambda(n) \ge 0$$

$$0 \le \theta - \sum_{n \in \mathcal{N}} p(n)\phi(n) \perp x \ge 0$$

$$\begin{aligned}
\mathbb{E}[R] = \sum_{n \in \mathcal{N}} p(n)\pi(n)z(n) &= \sum_{n \in \mathcal{N}} p(n)(\phi(n) + \lambda(n))z(n) \\
&= \sum_{n \in \mathcal{N}} p(n)\phi(n)x + \sum_{n \in \mathcal{N}} p(n)\lambda(n)\omega(n) \\
&= \theta x + \sum_{n \in \mathcal{N}} p(n)\lambda(n)\omega(n)
\end{aligned}$$

# Hydro storage reservoir with uncertain inflows
**(inflow measured in MW)**

- The reservoir capacity is $h$ and the station capacity is $x$.
- Inflow in node $n$ is $\omega(n)$.
- Reservoir cost is $\psi h$. Station cost is $\theta x$.
- Can calculate expected rent $\mathbb{E}[R]$ for each station from solution to dispatch problem as a stochastic program giving optimal generation $z(n)$ and marginal water value $\lambda(n)$.

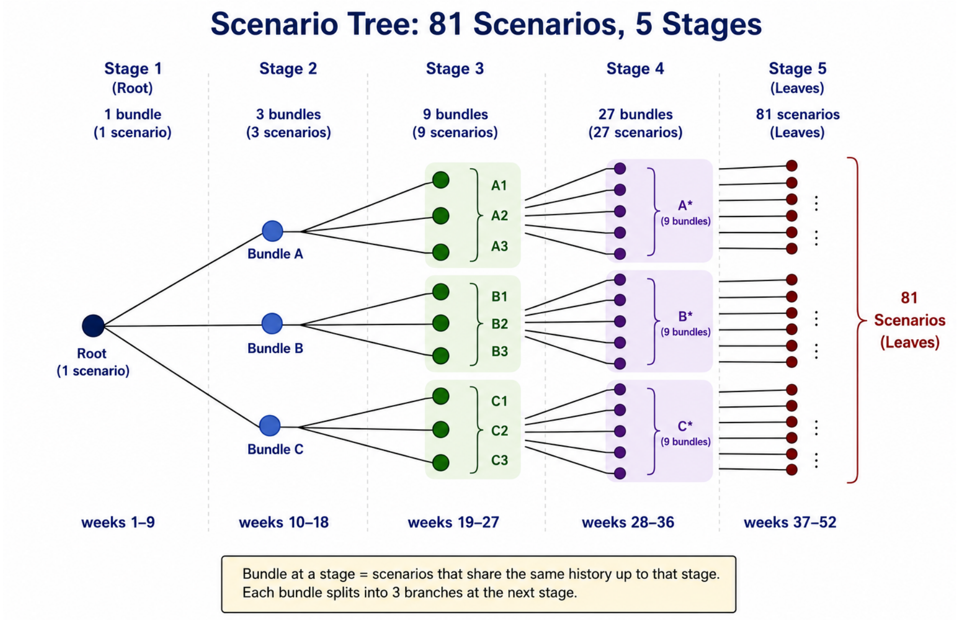
$$\mathbb{E}[R] = \sum_{n \in \mathcal{N}} p(n)\pi(n)z(n) = \psi h + \theta x + \sum_{n \in \mathcal{N}} p(n)\lambda(n)\omega(n).$$

## What have we learnt?

- Run-of-river hydro plant with inflow $\omega(n)$ makes surplus rent $\sum_{n \in \mathcal{N}} p(n)\lambda(n)\omega(n)$.
- Reservoir hydro plant with inflow $\omega(n)$ makes surplus rent $\sum_{n \in \mathcal{N}} p(n)\lambda(n)\omega(n)$.
- These surplus inflow rents occur in energy-only markets under perfect competition.
- The size of the hydro plants is socially optimal given the SMP model. Paying dividends instead of capacity expansion is economically rational...
- ...but if there were more river chains with unused inflows to exploit then the SMP capacity outcomes would be suboptimal; entry would be profitable.

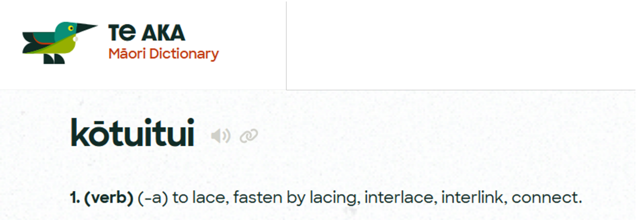
## Estimation of inflow rent in NZ system

- JADE.jl (SDDP.jl inside) is EPOC's NZ hydrothermal model.
- We can run a version of JADE.jl to optimize investments in first stage and operations over an infinite horizon with discounting (see Hole, P., Dowson, 2025).
- JADE.jl gives approximately optimal investments as it approximates expected operating cost well ...
- ... but JADE.jl can have poor approximations of optimal actions in improbable future states of the world...
- ... and JADE.jl can have poor approximations of future prices and Ricardian rents.
- Our screening curve analysis is not verifiable in JADE.jl so to verify we revert to a scenario tree built from 81 years of inflows.


Scenario Tree: 81 Scenarios, 5 Stages
Stage 1
(Root)
1 bundle
(1 scenario)
Stage 2
3 bundles
(3 scenarios)
Stage 3
9 bundles
(9 scenarios)
Stage 4
27 bundles
(27 scenarios)
Stage 5
(Leaves)
81 scenarios
(Leaves)
Root
(1 scenario)
Bundle A
Bundle B
Bundle C
A1
A2
A3
B1
B2
B3
C1
C2
C3
A*
(9 bundles)
B*
(9 bundles)
C*
(9 bundles)
81
Scenarios
(Leaves)
weeks 1–9
weeks 10–18
weeks 19–27
weeks 28–36
weeks 37–52
Bundle at a stage = scenarios that share the same history up to that stage.
Each bundle splits into 3 branches at the next stage.

# KOTUITUI

[Robinson, 2026]


Te AKA
Māori Dictionary

kōtuitui

1. (verb) (-a) to lace, fasten by lacing, interlace, interlink, connect.

- Key Optimization Tool for Utility Investment with Tree-based Uncertain Inflows.
- Kotuitui.jl and JADE.jl yield the same optimal investments.
- Kotuitui.jl gives system marginal prices and water values at each stage.
- Kotuitui.jl computes the rent from energy prices and the inflow rent which is sum of inflows times marginal water value.

# KOTUITUI results

Cobb dam and 32-36 MW power station [https://www.manawaenergy.co.nz/generation-images]

- Optimize investment in Cobb power station using Kotuitui.jl
- When capital cost/MW/year = $150K, optimal capacity is 33.1 MW
- Annual capital cost = $5M.
- Annual present value of energy price rents = $19.3 M.
- Annual present value of inflow rent = $14.3 M.
- PV($5M) = $48.7 M (20 years at discount rate 7.8%)
- According to Chat GPT ...

> So if your question is "**what value did Contact effectively put on Cobb when it bought Manawa?**", I would use **approximately $160 million (2025 NZ dollars)**.

# Outline

Fundamentals: thermal-only systems

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Fallacies: Part II

Flaws (or features?)

## Fallacies in energy-only electricity markets: Part II

- Fallacy: Positive profits of gentailers should be used to pay for expansion of wind and solar instead of paying dividends to shareholders.
- Why? Rents accrue to technologies not agents. Free entry makes wind and solar already optimal.
- Fallacy: Splitting up gentailers/level playing field measures will lead to acceptable wholesale rents.
- Why? Rents from barriers to entry accrue to hydro generators in perfect competition. Even very small hydros make inflow rent.
- Fallacy: Taxing inflow rent changes short-term incentives.
- Why? Inflows are uncontrolled so cannot be changed.

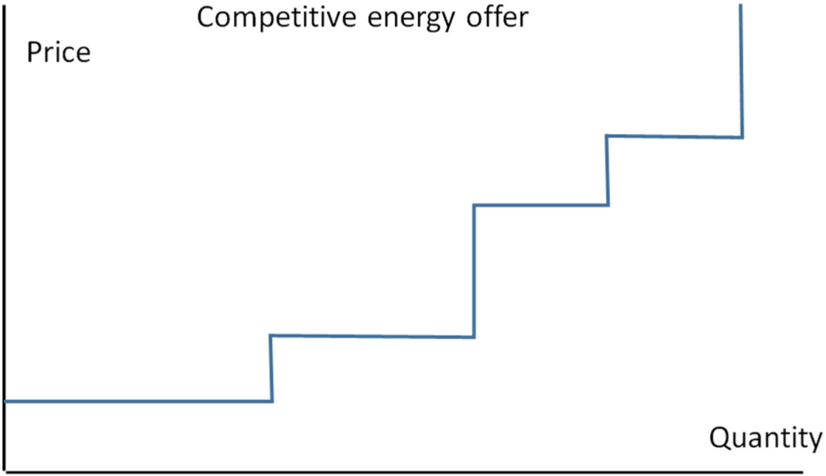
# Outline

# Energy-only markets and hydro

- In theoretical energy-only markets, hydro plants sized at their socially optimal capacity make surplus inflow rent.
- Regulation to curb generator market power will not resolve this.
- Breaking up gentailers will not resolve this.
- The inflow rent is a feature of the energy-only market model that arises from physical and political barriers to entry.
- Does this need to be fixed?
  - Do nothing?
  - Capacity market and cap on prices?
  - Retain energy-only market and levy inflows?
  - Retain energy-only market and nationalize hydro assets?

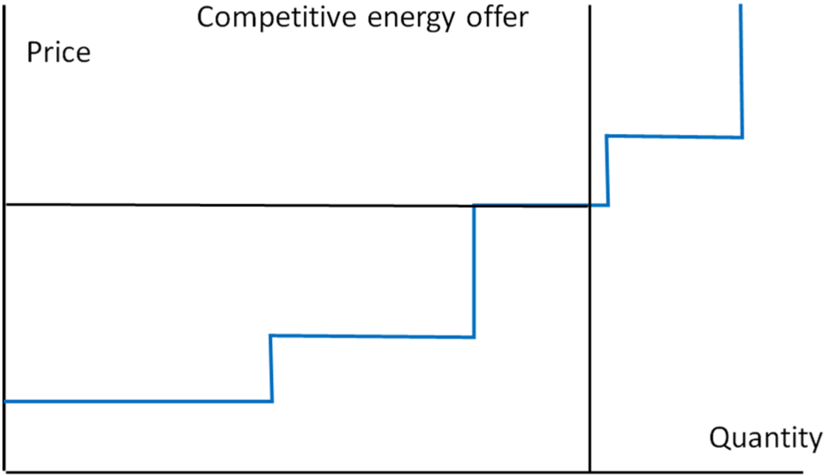
**The end**

# Perfect competition in a deterministic setting



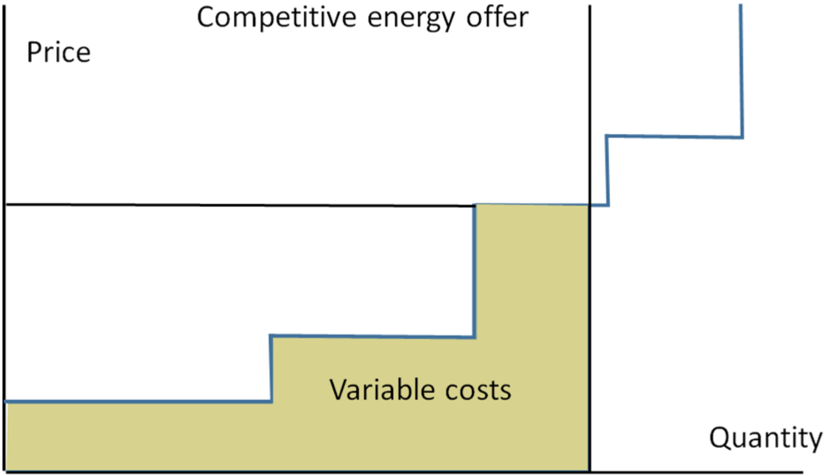

The perfectly competitive offer curve follows the true short-run marginal cost of generation.

# Perfect competition in a deterministic setting



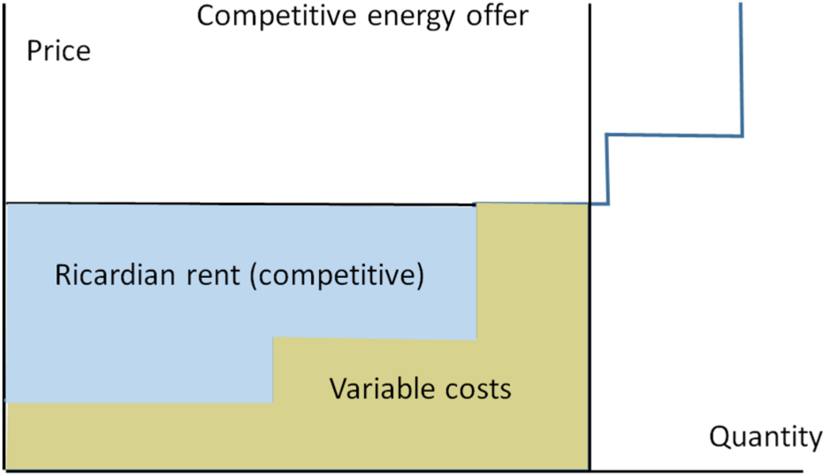

The perfectly competitive offer curve follows the true short-run marginal cost of generation.

# Perfect competition in a deterministic setting



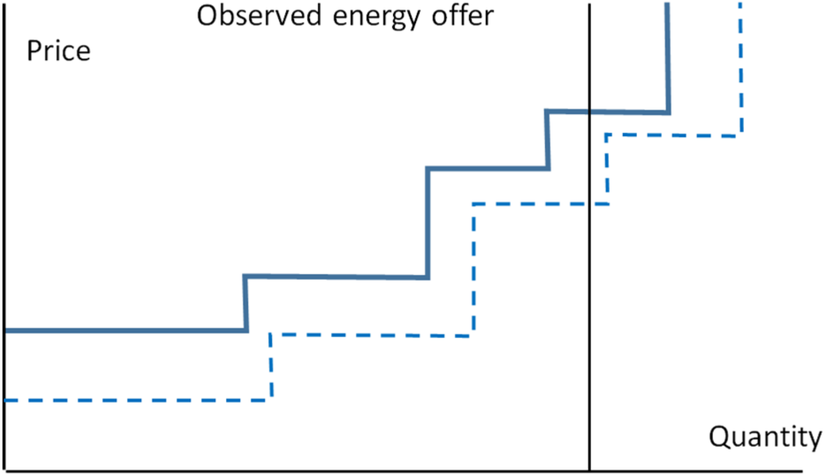

The cost of the perfectly competitive offer when dispatched is the light brown area.

# Perfect competition in a deterministic setting



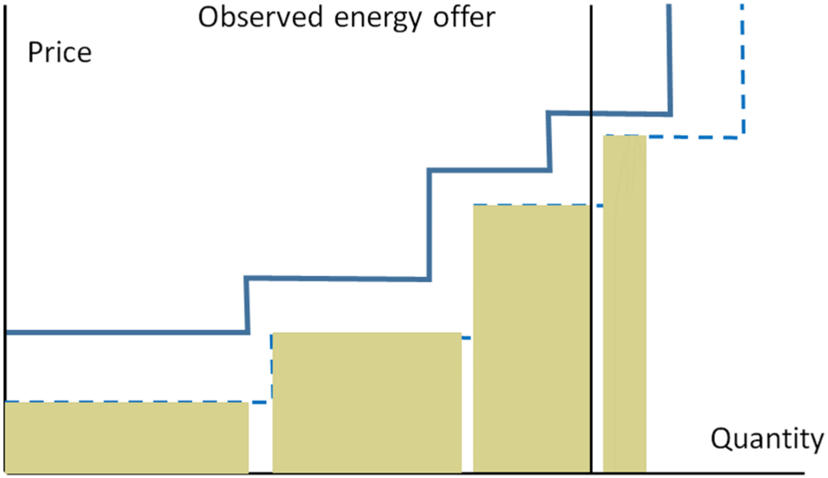

The operating surplus (or Ricardian rent) from the perfectly competitive offer curve is the blue area.

# Analysing market power in a deterministic setting



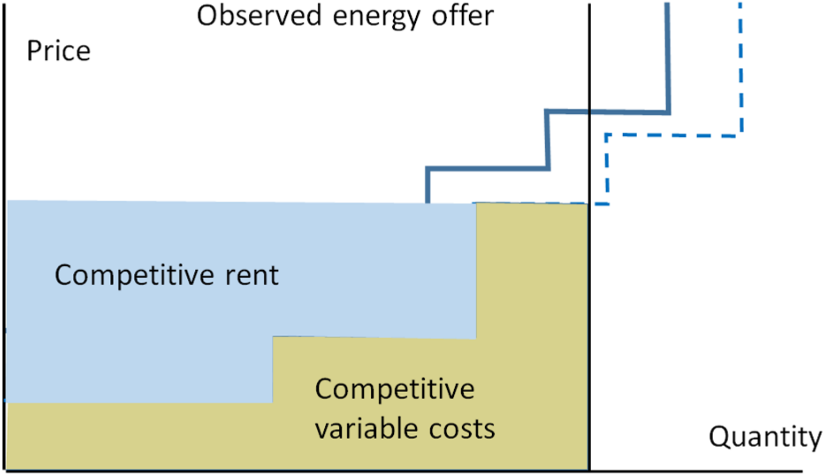

An observed energy offer may mark up prices and/or withhold capacity as shown in the solid blue curve.

# Productive inefficiency in a deterministic setting



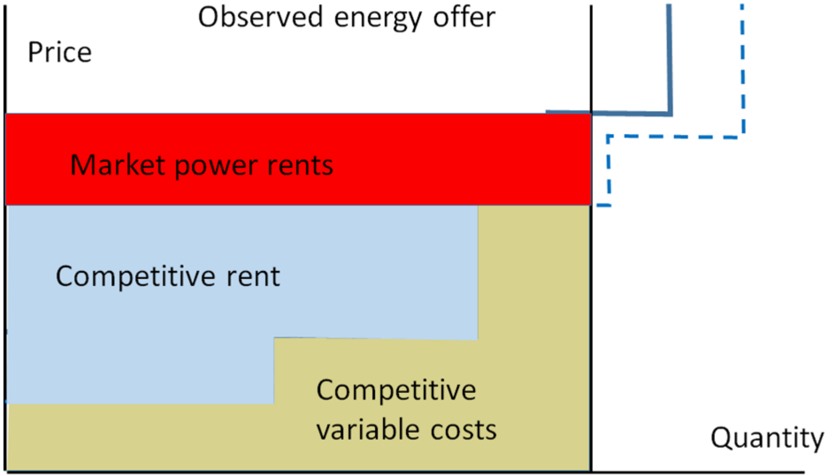

The area of the light brown region is the actual cost of the dispatch from the observed solid blue offer stack.

# Allocative inefficiency in a deterministic setting



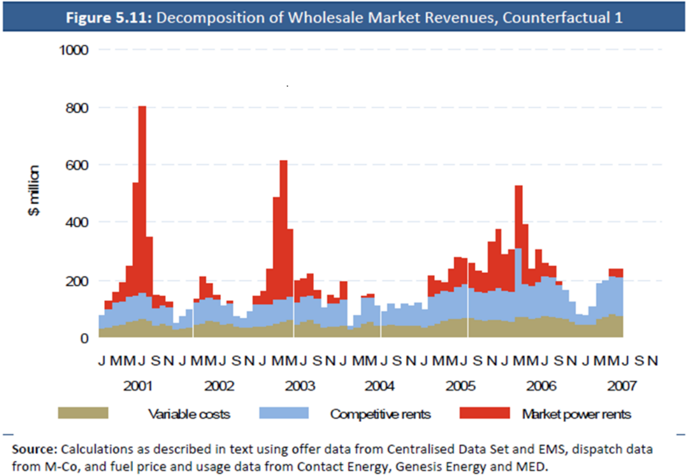

We can compare perfectly competitive counterfactual Ricardian rents with historical Ricardian rents.

# Allocative inefficiency in a deterministic setting




The Ricardian rent earned by the observed offer is greater than the rent earned by the perfectly competitive offer. Frank Wolak termed this the "market power rent".

# Analysing market power in a stochastic setting?




Source: F.A. Wolak, An assessment of the performance of the New Zealand wholesale electricity market, May 19, 2009.

## Battery with capacity $h$ and charge $y(n)$

$$
\begin{array}{llcll}
\text{P: min} & \psi h & - & \sum_{n\in\mathcal{N}} p(n) U_n(d(n)) & \\
\text{s.t.} & \bar{y}(n) & = & y(n) - u_D(n) + u_C(n) & [p(n)\lambda(n)] \\
 & y(0) & = & 0 & [\lambda(0)] \\
 & y(n) & = & \bar{y}(n-) & [p(n)\tau(n)],\ n \notin \{0\} \\
 & \bar{y}(n) & = & 0 & n \in \mathcal{L} \\
 & g(n) & \geq & d(n) - u_D(n) + \beta u_C(n) & [p(n)\pi(n)] \\
 & u_D(n) & \leq & \alpha_D h & [p(n)\rho(n)] \\
 & u_C(n) & \leq & \alpha_C h & [p(n)\sigma(n)] \\
 & y(n) & \leq & h,\ \ n \notin \{0\} & [p(n)\mu(n)]
\end{array}
$$

$$
\text{Rent} = \sum_{n\in\mathcal{N}} p(n)\pi(n)(u_D(n) - \beta u_C(n)) = \psi h
$$

## Pumped hydro with storage capacity $h$, turbine capacity $x$

$$
\begin{array}{llcll}
\text{SMP: } \min & \psi h + \theta x & - & \sum_{n \in \mathcal{N}} p(n) U_n(d(n)) & \\
\text{s.t.} & \bar{y}(n) & = & y(n) - u_D(n) + u_C(n) & [p(n)\lambda(n)] \\
& y(0) & = & 0 & [\lambda(0)] \\
& y(n) & = & \bar{y}(n-) & [p(n)\tau(n)],\ n \notin \{0\} \\
& \bar{y}(n) & = & 0 & n \in \mathcal{L} \\
& g(n) & \geq & d(n) - u_D(n) + \beta u_C(n) & [p(n)\pi(n)] \\
& u_D(n) & \leq & x & [p(n)\rho(n)] \\
& u_C(n) & \leq & \delta x & [p(n)\sigma(n)] \\
& y(n) & \leq & h,\ n \notin \{0\} & [p(n)\mu(n)]
\end{array}
$$

$$
\mathbb{E}[R] = \sum_{n \in \mathcal{N}} p(n)\pi(n)(u_D(n) - \beta u_C(n)) = \psi h + \theta x
$$