REGIONAL INTEGRATION PARADIGM AND REGIONAL TRADE AGREEMENT MODEL

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COMPETITION • RELIABILITY • EFFICIENCY

New Zealand and regional integration of electricity

- New Zealand is geographically isolated from other countries and its electricity system serves only New Zealand for good technical and economic reasons
- New Zealand has two main islands and there are important regional imbalances between generation and consumption between the two islands and within the two islands
- In 2014:
  - 63.1% of New Zealand's 42,200 GWh of electricity was consumed in the North Island, but only 55.7% was produced there
  - 36.9% of consumption was in the South Island, of which one-third was consumed by one aluminium smelter at Bluff. 44.3% of production was in the South Island
  - 29.1% of North Island electricty was produced by geothermal generators with other sizeable contributions from gas (28.2%) and hydro (24.3%). Less significant contributions came from wind (8.0%) and coal (7.8%) with a range of other sources making very small contributions
  - 98.3% of South Island electricity was hydro with wind contributing only 1.6% and very small contributions from other sources

Requirements for regional integration

- New Zealand's high dependence on renewables (84%) which have to be located near the resource requires very significant regional flows on the transmission grid. There is an HVDC link to transport power between the two main islands and AC grids in the North and South Islands
- A number of things are required to successfully and efficiently integrate dispersed electricity generation and consumers connected to a grid using a market
- Three important requirements are:
  - Rules to determine what generators will be run and how much each will run at every point in time to meet demand
  - Rules about what the generators at various locations will be paid and what the consumers at various locations will be charged
  - Rules setting out from whom and how the costs of the grid linking the regionally dispersed generators and consumers will be recovered
- These requirements need to be satisfied whether the market is operating within one country or across countries
- Of course, the problems of getting agreement and enforcing rules are more complicated when trading is across political boundaries but many of the same challenges occur when trading is within the one country

Matching demand and supply #1

- New Zealand has used a wholesale electricity market since October 1996 to determine what generators will be run, and how much electricity each will produce, at every point in time to meet demand
- Generators (including despatchable demand) make offers to provide various quantities of electricity at the locations at which they can inject into the grid. Each generator specifies for each tranch of electricity it offers the price it will be willing to sell at
- Offers are made for every half hour of every day from two days in advance until "gate-closure". Generators not directly connected to the grid with capacity less than 10MW generally do not have to make offers. Negative price offers are not permitted
- "Gate-closure" for most generators is two hours before the start of the half hour to which an offer relates. A standard generator cannot alter its offer price after "gate closure" and can only alter its offer quantities for a genuine physical reason
- For "intermittent generators" (i.e. wind and potentially grid connected solar) there is no effective "gate closure" but there are rules around how they must offer to prevent them gaming the market
- These rules include a requirement for intermittent generators to offer at no more than $0.01/MWh and so be a price-taker in the market. These simple rules allow wind (and solar) to be very effectively integrated into the wholesale electricity market

Matching demand and supply #2

- The system operator uses an optimisation program (SPD = Scheduling Pricing Dispatch) to determine what offers will be accepted to meet forecast demand i.e. which generation plant (or despatchable load) will be utilised and for what quantities
- The optimisation program minimises the delivered total cost of energy (and reserves) to consumers, subject to the despatched sources of generation not violating transmission constraints and security requirements
- SPD takes into account transmission losses and the price of reserves required to support dispatch. The offers to provide energy and reserves are chosen to minimise the overall cost to consumers of energy, reserves and transmission losses
- Reserves can be provided by either generators or interruptible load and the two sources of reserves compete directly with one another. In practice, interruptible load is an important source of reserves
- New Zealand also has markets for the provision of black start capacity and frequency keeping. It is introducing market arrangements to support the provision of extended reserves to deal with major grid emergencies

Price setting #1

- The optimisation program SPD also detemines the “locational marginal price” (LMP) at each injection and off-take point of the grid
- The price at each node reflects the marginal cost or benefit of providing an extra MWh of energy at that node, given the available offers and the transmission losses and constraints that will be incurred at that node
- There are approximately 250 nodes at which prices are determined. These are spread cross the two main islands of New Zealand
- In general, the more northerly and the more remote from major generation a node is, the higher the market price at the node.
- Average daily prices at the various nodes typically differ over a range of about 10-20% from lowest to highest but can be much more when constraints bind
- A generator is paid on the basis of the LMP at the location at which it injects electricity into the grid. Offtake customers pay on the basis of the LMP at the location at which they take electricity from the grid
- New Zealand’s wholesale market is an energy only market. There are no capacity payments to generators as there are in many electricity markets. Generators only get paid for the energy (or ancillary services) they provide to the market and do not get paid anything for having capacity available, but unused

Energy only, no capacity payments

- The need for capacity payments in wholesale electricity markets arises for two reasons:
  - the imposition of a cap on wholesale prices that discourages investors from providing plant that will be used only occasionally to cover capacity shortages
  - a desire to promote the construction of particular types of generation, usually renewables for climate change mitigation purposes
- New Zealand’s wholesale market has no mandated price cap, except in the very unlikely situation of the need for island-wide power cuts due to insufficient supply
- New Zealand’s electricity law requires the independent regulator to promote competition and an efficient electricity industry. Promoting one type of generation plant over others would be difficult to justify relative to these objectives
- 84% of New Zealand’s electricity is currently produced by renewables. This percentage has risen from 65% in the mid 2000’s
- New Zealand has had an emissions trading scheme since 2008. It applies to the electricity sector and ties the price of carbon emissions by generators to the world price.
- Investors have been replacing higher emitting generators with efficient lower emitting renewable generators and will continue to do so
- The reasons for having capacity payments do not apply in New Zealand

Full nodal pricing

- The use of a nodal pricing approach in the wholesale market has been contentious in the past
- Some parties have argued using nodal pricing with about 250 separate nodes inhibited competition by limiting the extent to which parties would seek customers outside the regions in which they had generation plants to avoid the risks of inter-nodal price differences
- These parties favoured New Zealand to shift to zonal pricing with only a few zones
- The counter argument is that differences in nodal prices reflect real economic cost differences between nodes caused by losses and constraints and it is more efficient for buyers and sellers of electricity to see these differences than mask them by averaging
- New Zealand has a long and stringy grid reflecting the nature of the country and geographic spread of generation and consumption. Transmission constraints and losses are important and having market participants respond to these is beneficial.
- The introduction in 2013 of financial transmission rights (FTRs), which allow parties to hedge inter-nodal price differences, has largely silenced calls for zonal pricing to replace full nodal pricing

Efficiency of market prices

- Complaints that major generators used their market power to manipulate wholesale and hedge prices to their advantage, especially in dry years, used to be very common
- A number of steps taken by the Electricity Authority have contributed to a decline in these complaints:
  - the facilitation of an active electricity futures market for hedging with the four major generators acting as market makers
  - the introduction of good behaviour requirements on offerors in the market when they may be in a position where their output is required to meet demand
  - active monitoring of market performance and publication of reports on unusual events
  - the introduction of measures to reduce the impact of dry years on the supply of electricity
- In addition, in 2011 the Government required two generators to transfer ownership and management of some very important hydro-generation plants which improved the management of hydro storage and reduced the risks of dry years

Paying for transmission #1

- Charges for the transmission grid have been highly contentious in New Zealand since charges for transmission were separated from charges for electricity in the early 1990s. New Zealand is not unique in transmission charges being contentious; they are contentious in many jurisdictions
- There is usually debate about the total revenue the grid owner should be permitted because of disagreements about the efficient operating cost of providing the grid and the opportunity cost of the capital utilised in doing so
- Even if the total revenue can be agreed, the allocation of this among parties gives ample scope for more debate. There are several reasons for this:
  - the economics of setting efficient charges is not easy because:
    - the large economies of scale means marginal cost is generally below average cost, so marginal cost pricing will not fully recover the costs of providing grid assets
    - estimating the long run marginal cost (LRMC) of expanding the grid is also challenging and requires judgements, which can be disputed
    - linking grid charges to electricity consumption reduces the allocative eficiency of the consumption of electricity. Similar issues arise if grid charges are linked to production

Paying for transmission #2

  - estimating the elasticity of demand of the various groups consumers for grid services is diffiult and so using Ramsey pricing to minimise allocative inefficiency requires judgements that can be debated
  - network effects make it challenging to identify who is using what grid assets and the extent to which they are benefiting from using them
  - the lumpy nature of the optimal scale of investment means that assets are often built ahead of demand. Who should pay for this extra grid capacity and how?
- the services provided by transmission assets are often not well defined; there is a focus by grid owners on the provision of assets rather than the provision of services. Consumers don’t care about assets; they just want low cost electricity to be delivered to them. People debate charges when what they are reciving is not well matched with what they want; transmission is no different
- transmission is a natural monopoly and the grid is often provided by a government-owned entity or a regulated company. This has several effects:
  - the charges set are often heavily influenced by political decisions and potentially open to effective lobbying. If parties think lobbying may work for them, expect lobbying

Paying for transmission #3

- those paying for the grid suspect the provider is not cost efficient because it is a natural monopoly. They are concened about paying for inefficient operations
- customers fear grid investments will be larger and occur earlier than economically optimal because of the risk aversion of politically controlled entities and grid investment regulators. They are concerned about paying for inefficient investment

Lessons about transmission pricing from New Zealand #1

- New Zealand's experience debating transmission charges almost continuously for over 20 years offers a number of lessons and suggestions:
  - requiring those parties directly connected to the grid to pay the capital and operating costs of the connection is usually not contentious, especially if the grid owner potentially faces competition in the provision of connection assets
  - if the wholesale market has nodal pricing, the prices reflect the marginal costs of transmission losses and constraints but, in aggregate, only average losses and constraint costs are incurred. There is, therefore, a loss and constaint excess (LCE) in market settlements. Using this to partially offset transmission costs is not very contentious although there can be debate about how this is done
  - a couple of ways to identify the beneficiaries of specific transmission assets are:
    - using the SPD optimisation program to run market solutions with and without the specific grid assets and comparing the prices and quantities under the two scenarios
    - using the allocation of costs and benefits in the cost benefit analysis undertaken to justify investment in the specific grid assets
  - converting estimates of benefits into charges is not without challenge, however

Lessons about transmission pricing from New Zealand #2

- the simple approach of smearing evenly the costs of the interconnected grid can run into major efficiency problems when significant new investment is required in specific parts of the grid
- once an allocation approach has been in place for some time, parties will make investments in load and generation in response. Attempts to change the allocation that adversely effect these groups will be contentious. It is better to develop a durable approach from the outset than start with a simple approach with the view to improving it later