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Financial Transmission Rights – An Introduction

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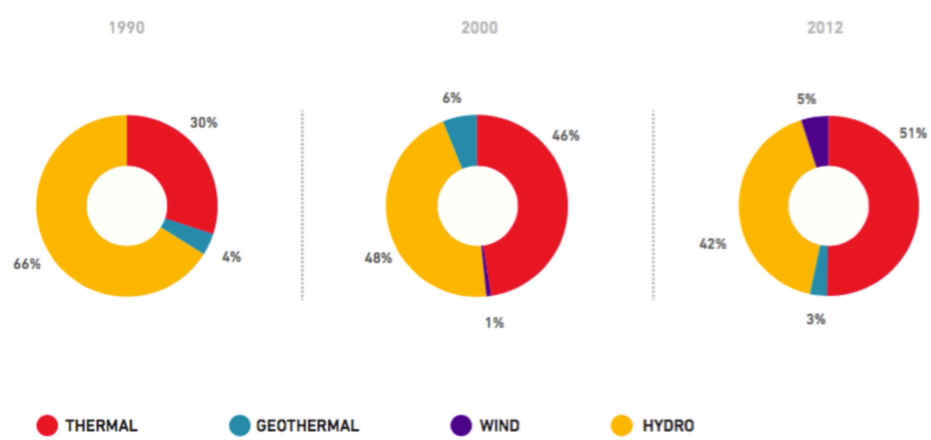
Objective

- It is my sincere pleasure to be here today.
- My objectives today are to:
  - Provide a shared understanding of the issues.
  - Provide a common vernacluar.
  - Provide a paradigm for solving the issues.
- I sincerely apologize if some of the information is redundant.

Quick overview

- 6 national markets (Guatemala, Honduras, El Salvador, Nicarauga, Costa Rica, and Panama).
- 1 regional market (MER) with SIEPAC as the transmission backbone of the regional market.
- Diverse levels of reform.
- Changing nature of generation mix…strong demand growth.

PERCENTAGE OF TOTAL GENERATION BY FUEL SOURCE IN CENTRAL AMERICA
REGIONAL INSTALLED CAPACITY



Transmission Rights – Introductory Comments

- Open access to the transmission system changes things.
- In particular what does it mean to have access to the transmission system?
  - Discussion with TransPower in 1995
- Must define a "transmission right:"
  - A Transmission Right is a "right" to use the transmission system.
    - What constitutes "use" of the transmission system?
      1. Access to transmission capacity.
      2. Access to the dispatch process.

Airport Analogy

- An airport as an analogy:
  - If an airline company wants to use the airport they need to have “landing strip capacity”, i.e., they need to own, rent, or lease, some amount of the physical capacity of the landing strip.
  - They also need the air traffic controller to allow them to take off and land.
- A user of the electricity grid has the same requirements.

Transmission Rights – Some Considerations

- In defining a transmission right, there are some fundamental issues or characteristics that need to be resolved:
  - What “rights” and “obligations” are attached to a transmission right?
  - Will either a buyer or seller be required to have a transmission right if they produce or consume power…what requirements must they meet?
- Will there be different levels of rights?
  - Will some transmission rights have a higher level of service, i.e., will they receive preferential treatment?
    - For example, suppose a constraint arises and not all capacity is available and some users are not able to use all of their transmission rights, is there some “ranking’ as to who gets cut or is it on a pro rata basis?

Transmission Rights – Some More Considerations

- Who will be responsible for determining the quantity of transmission rights that are available?
  - Will it be the transmission asset owner or
  - Will it be the system operator?
- What methodology will be used to determine the quantity of transmission rights?
  - Average or peak? How will outages be handled?
- What obligations, i.e., responsibilities and liabilities, are placed on the “creator” of the transmission rights?
  - What if they issue too many? Too few?
- Will there be regulatory oversight of the process and operation?
  - Will transmission customers be able to participate?

Transmission Rights – Some Final Considerations

- How will the transmission rights be priced?
  - Who receives the revenues?
- How will they be distributed?
  - Allocated to participants, auctioned or is there another way?
- What will be the term/duration of a transmission right?
  - If there is going to be more than one period, how will transmission capacity be allocated across the different periods?
  - Suppose we decide to create and offer a 1 year transmission right and a 3 year transmission right. How much transmission capacity do we make available for each potential category and how do we handle credit issues?
- Does an existing holder of a transmission right receive preferential rights for acquiring them in subsequent periods?
  - That is, are there "rollover rights?"

Avoidance of the issues…

- …is not an option. If competition is going to occur, then these, and many additional related, questions will have to be answered.
  - Not addressing these issues will result in inefficiency, poor investment choices, and ultimately the failure of open access….because the issues have to be solved in some manner.
  - How these questions are addressed provide the operational and commercial platform for the industry.
- Returning to the airport example: how would the airline or a customer purchase a ticket if they did not know when or how they could take off or land?
  - What language would the airline company use?
  - We will sell you a seat on the plane but we cannot guarantee there will be a plane available. Nor can we guarantee when the plane will be allowed to take off. Hence we cannot guarantee when, or even if, you will arrive at the destination you purchased the ticket for!

Avoidance of the issues…

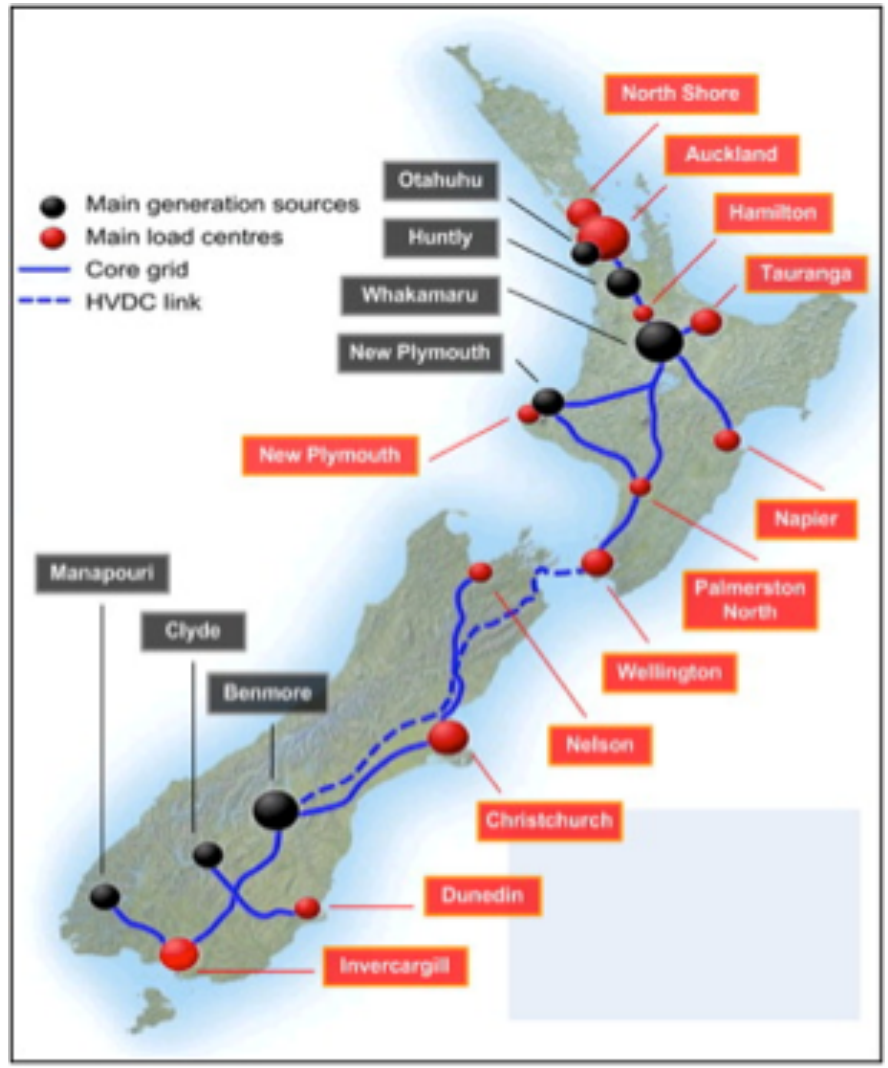
- Defining and determining transmission rights is a necessary step in implementing competition. As a result, this issue has been dealt with in other areas.
  - Two distinct methodologies have been developed.
  - The “physical rights model” whereby a transmission right has a physical interpretation…value comes from scheduling priority.
  - The “financial rights model” whereby a transmission right has no physical interpretation, rather it is purely a financial right to revenue streams (positive or negative) that arise from using the transmission system.
- While these are two very distinct approaches they are best thought of as evolutionary.
  - Physical transmission rights are best thought of as a “bridge” or intermediate step.
  - A mechanism to implement open access without implementing centralized dispatch, i.e., an electricity spot market.
- Financial transmission rights are consistent with the final step in creating an electricity market and they replace physical rights.

New Zealand – Case Study

- New Zealand represents an interesting case study.
  - Two islands connected by a DC tie. Majority of load on the North Island. Majority of generation capacity on the South Island. North Island generation was predominantly thermal and South Island was hydro (70% of total capacity was hydro). Dual peaking system – North Island in the summer, South Island in the winter.
- A single generator - Electricity Corporation of New Zealand (ECNZ) that was a State Owned Enterprise (SOE).
- The high voltage transmission assets and grid operation had been separated into Transpower, another SOE.
- There were a number of vertically integrated local distribution and retail companies.
- There were no explicit or defined "transmission right" - no need.

Case Study – New Zealand

- Contracts were in the form of an annual "hedge" whereby ECNZ and a customer would agree on a price and quantity.
- There were two possible delivery points – one in the North Island (Haywards) and the other in the South Island (Benmore).
- An hourly wholesale "spot" price was calculated weekly for both delivery points…single "Island" Marginal Cost" based on the cost of the "marginal" generator. Prices at the two points deviated whenever the DC tie was constrained (which was almost always).
- The hedges settled against this price…hedge was a swap (CfD).



New Zealand – Open Access

- In 1995 the New Zealand government announced that ECNZ would be separated into two competing companies – ECNZ and Contact Energy. Open access to the transmission system had to be implemented.

- The industry developed the (market) rules for non-discriminatory centralized dispatch.
  - Market was simply a derivative of the dispatch process

  .
- The rules specified that the dispatch for any interval would be least-cost based on the offers made by generators.
  - Access to the transmission system for individual generation facilities was based on the as offered price(s) of each individual unit.
  - Non-discriminatory access since the rules apply to all generation and each unit is free to offer at whatever price they want.

New Zealand – Open Access

- Dispatch was accomplished through centralized security constrained economic dispatch (SCED).
  - Prices were created every 15 minutes for approximately 240 different electrical locations (nodes) around the country.
  - Transmission constraints, reserves and losses all caused prices to deviate…no single Island price.
- Physical dispatch was mandatory and everybody either received or paid the 15 minute prices.
- Bilateral contracts were still written using Haywards and Benmore as the delivery points and were still in the form of hedge contracts that settled against the 15 minute prices.
  - Counterparties had to factor in their exposure to transmission constraints in their bilateral contracts, i.e., the delivery point for the bilateral contract was at Haywards but the physical load might be at Hamilton…if there were transmission constraints then prices at Hamilton were different than the Haywards price paid by customer.

New Zealand – Open Access Conclusions

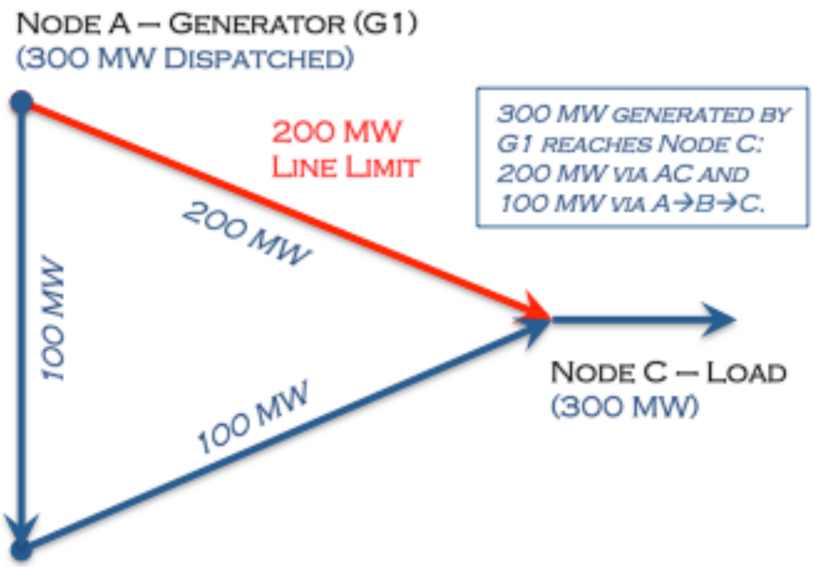
- Remember there are two aspects to the “issue” of transmission rights: (1) defining and acquiring the capacity on the transmission system and (2) ensuring the dispatch is non-discriminatory.
- New Zealand solved these two problems simultaneously by:
- Implementing security constrained economic dispatch based on generator offers. This solved the question of ensuring non-discriminatory access to the “air traffic controller” – every generating unit was treated the same.
- The issue of allocating transmission capacity was dealt with implicitly. When transmission capacity on the system or a line was scarce because of high demand or transmission constraints, prices across the system deviated and customers wore the financial risk.

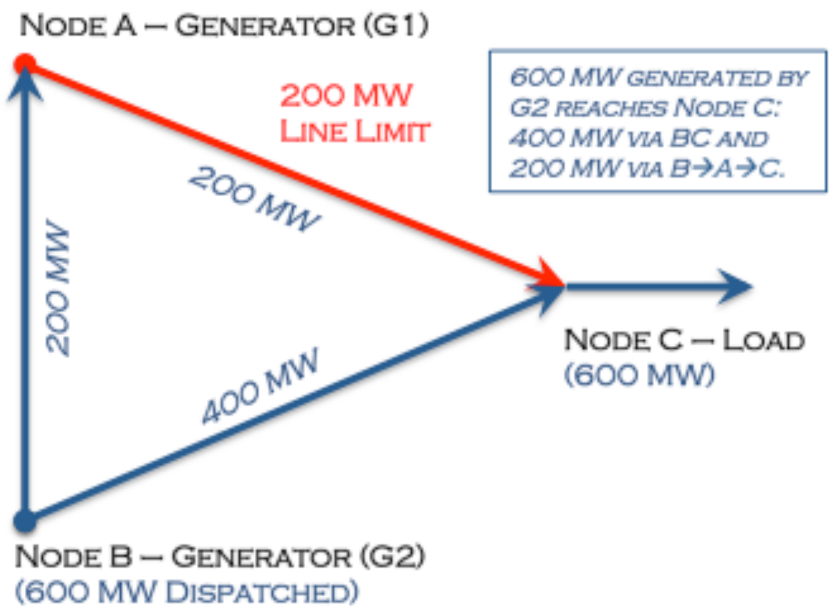
New Zealand – From Open Access to FTRs

- In the 20+years since the market started things have changed:
  - Government further spit generation into 2 more companies. The market is dominated by 4 “integrated” companies…very high market concentration. FTRs were introduced, in part, to “help” retail competition.
  - Generation has largely re-integrated with load.
    - Load is the physical hedge for generation and it makes commercial sense for this to happen as generators attempt to reduce the risk of their cpaital investment.
- Finanacial Transmission Rights were inroduced in June 2013.
  - Two locations Benmore and Otahuhu.
  - Two products – monthly options and obligations.
  - Two auctions per month.
- FTR market was Expanded in June 2014 to Haywards, Invercargill and Islington.

Defining Physical Transmission Rights

- There are two fundamental issues with physical transmission rights
  - First, how do you determine the capacity of the system?
  - Second, defining what the “right” provides to the holder.
  - We can use a 3 node model to demonstrate the difficulty in determining transmission capacity.
- This example highlights the central issue of non-discriminatory open access based on physical rights…deciding how many rights to allocate.
- Two examples – Load =300 MW and Load = 600 MW
  - Two different measures of capacity…how many do you sell?





Defining Physical Transmission Rights

- In order to have true non-discriminatory open access every generator must have an equal opportunity to sell their power…and the system must be operated reliably!
  - Using the results from the previous examples, suppose we issue 300 MWs of physical transmission capacity rights. Transmission rights would be necessary in order for a generator to run, i.e., a generator must have the transmission rights for the power they are producing. In order for a generator to run, they must use transmission rights to schedule power from their generation facility (source) to the load (sink).
  - Now assume that for whatever reason, G1 ends up with all the rights.
  - On any given day, G1 uses their physical transmission rights to schedule power from their plant at Node A to load at Node C. As long as the load is ≤ 300 MW everything is fine. But what happens if load is more than 300 MW? With only 300 MW of physical transmission rights available, no additional generation can be scheduled…nobody would own the right.
- If the dispatcher forced somebody to generate…they would simultaneously violate G1's rights. As was shown, if G1 produces 300 MW, there is no way for G2 to produce anything. The only thing the dispatcher can do in this situation is to mandate that G1 reduce their output and allow G2 to produce, and this would violate G1's transmission rights.

Defining Financial Transmission Rights

- Nearly every issue associated with defining physical transmission rights is present with financial transmission rights with one very important exception that financial transmission rights have no physical interpretation. That is, a financial transmission right does not "map" to the physical dispatch or flow of energy.
  - No need to have an FTR to schedule energy
  - No rights are violated from re-dispatch.
- As a result, FTR's as compared to physical transmission rights allow more efficient market outcomes.
- MER faces a number of unique issues because of the interface with the 6 National Markets which necessarily means there is coordinated dispatch and alternative definitions of transmission rights.