NERA
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Review of Financial Transmission Rights and Comparison with the Proposed OFA Model

A Report for the Australian Energy Market Commission

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1. Introduction

This report has been prepared by NERA Economic Consulting (NERA) at the request of the Australian Energy Market Commission (AEMC). The AEMC has requested a review of existing Financial Transmission Rights (FTR) arrangements around the world and a comparison of their main design elements with the AEMC's proposed Open Firm Access (OFA) model.[1] The AEMC has also requested a discussion of alternative mechanisms adopted in other jurisdictions to provide financially firm transmission access for generators.

This report is structured as follows:

- Section 2 provides an overview of the existing FTR arrangements in the US and New Zealand, and compares them with the main elements of the proposed OFA model.
- Section 3 provides an overview of the mechanisms used in Ireland and Spain, as examples of other ways to provide financially firm access, and offers a discussion of the main implications of their designs.
- Annex 1 provides a more detailed description of the FTR designs in each of the US regions and New Zealand.

[1] For a more detailed description of the OFA model refer to: AEMC 2012, *Transmission Frameworks Review*, Technical Report: Optional Firm Access, 16 August 2012, Sydney.

2. Financial Transmission Rights in LMP Markets

2.1. Existing FTR Designs

To date, FTRs have only been implemented in the US and soon will be in New Zealand.[2] The PJM Regional Transmission Organization (PJM RTO) and the New York Independent System Operator (NYISO) were among the first US markets that adopted FTRs as an alternative to physical transmission rights, in the late 1990s.[3] California adopted an FTR scheme in 2000, followed by ERCOT, ISO-New England, and the Midwest ISO (MISO) in early to mid-2000s. In October 2012, FERC conditionally approved an FTR mechanism for Southwest Power Pool (SPP) with an effective date of March 1, 2014.[4]

The common denominator of the markets that have adopted FTRs is that they all use a nodal pricing system for energy, in day-ahead, and/or hour-ahead or real-time time frames. The nodal market price is defined as the marginal cost to deliver an incremental MWh to the transmission node concerned, based on bids submitted to the system operator by both generators and retailers or consumers. Generators receive the nodal market price or Locational Marginal Price (LMP) for their output at the node in the transmission system where they inject energy, while wholesale electricity customers and retail suppliers may either pay the nodal price at the location where they withdraw energy from the market, or, more often, a zonal market price computed as the load-weighted average of nodal prices over the zone. The difference between the LMPs at the injection location and the withdrawal location(s) reflects the marginal cost of losses and congestion associated with the flow of energy in a particular hour. In this context, holders of "point-to-point" FTRs will receive the stream of revenues associated with the value of congestion, as established by the locational price difference between specific injection and withdrawal locations for a specified MW quantity.

An FTR is normally structured as an obligation – meaning that the FTR payment to the FTR holder can be either positive or negative. An FTR obligation is positive (implying a benefit to the FTR holder) when the LMP at the delivery location designated in the FTR is higher than the LMP at the source location. The same FTR will have a negative value (implying a payment obligation for the FTR holder) when the LMP at the delivery location is lower than the LMP at the source. However, if a generator holding an FTR physically generates to match its FTR position, the FTR acts as a hedge so that their net effect is to always receive the price at the delivery location (excluding the effect of losses).

FTRs are sometimes alternatively configured as "options". An FTR option eliminates the downside risk of the obligation by constraining the economic value of the FTR to zero in scenarios where the obligation would exhibit a negative value. FTR options have revenue adequacy issues however, which FTR obligations do not, because with FTR options it cannot

[2] The first auction for inter-island FTRs will be held in May 2013.

[3] The term "Financial Transmission Rights" (FTRs) can receive different names: Financial Transmission Rights (FTRs) in PJM, New England ISO and MISO; Transmission Congestion Contracts (TCCs) in the New York ISO; Congestion Revenue Rights (CRRs) in California and ERCOT; Transmission Congestion Rights (TCRs) in SPP.

[4] In October 2012, the FERC conditionally accepted SPP's market-based congestion management proposal which implements ARRs, TCRs with an effective date of March 1, 2014. On February 15, 2013, SPP submitted a compliance filing with the FERC with the required Tariff revisions and requested Commission approval of these refinements.

always be guaranteed that the congestion rent from nodal pricing is sufficient to pay all the FTR option holders.

FTRs can also be defined on a "flowgate" basis, typically in markets where the system operator solves congestion on a zonal basis. This was the case of California prior to the implementation of a nodal market for example. Flowgate-type FTRs give their holder the right to collect payments based on the shadow price associated with a particular group of transmission constraints (a flowgate) between two pre-established transmission zones.

Table 1 below provides a summary of the key elements of the existing FTR designs across the US markets and New Zealand.[5]

[5] We note that other wholesale electricity markets such as those in Argentina, Chile, Singapore and Russia have adopted locational prices, yet they have not implemented an FTR system, for different reasons. In the case of Chile and Argentina, it has to do with the specific approach to set the locational market prices, which are not based on the marginal generator bids to the market but rather on administratively-determined nodal factors. In the case of Singapore, no transmission constraints are relevant to justify the use of FTRs. In Russia, it is largely a function of the fact that generators do not generally face basis risk with buyers in different locations. A high proportion of their output is sold either under regulatory-determined contracts, at the local spot price, or to their own local customers in the case of vertical integration.

Table 1. Characteristics of Existing FTR Markets

MARKET	PJM	NEW YORK	CALIFORNIA	TEXAS-ERCOT
Contract Type	Point-to-Point FTRs, no hedge against losses; both obligations and options.	Point-to-Point FTRs, no hedge against losses; obligations only.	Point-to-Point FTRs, no hedge against losses; obligations; options available for merchants only.	Point-to-Point FTRs and flowgate-based FTR; no flowgates currently defined. No hedge against losses. Obligations and Options.
Acquisition and Trading	Auctions, ARR Allocations, secondary market.	Auctions, FTR allocations, secondary market.	Auctions, FTR allocations, secondary market.	Auctions, FTR allocations, secondary market.
Auction Frequency	Annual multi-round and monthly.	Seasonal multi-round, monthly reconfiguration auctions and annual uniform-price auction.	Annual, multi-round and uniform-price auction.	Annual and monthly single-round simultaneous auctions.
Distribution of Auction Revenues	Distributed to Auction Revenue Rights (ARR) holders (firm transmission customers and merchant transmission).	Credited against the transmission owner's cost of service to reduce the transmission service charge.	Applied to IFM congestion fund in periods of revenue inadequacy.	For FTR in the same zone, distributed to customers on a zonal load ratio share. Distributed ERCOT-wide for revenue between zones.
FTR Duration	Annual or three-year FTRs	Monthly, 6 month, 1-year FTRs. Also, 2-year fixed price FTRs renewable up to 10 years. Longer term FTRs awarded for merchant transmission capacity.	Monthly, 6-month, and 10-year FTRs. Long-term FTRs for merchant investors, for the useful life of the facility up to 30-year duration.	1-month FTR strips for two off-peak and two peak segments, up to 2 years out.
Auction Revenue Right (ARR) Duration	Monthly, annual or 3-year ARRs for firm transmission customers, and up to 30-year ARRs for new merchant facilities or upgrades.	N/A	N/A	N/A
Congestion Rents	Excess congestion rents distributed to months with shortfall rents. End of year deficit rents reduce payments proportionally.	Excess congestion rents offset transmission system cost; deficit rents covered by the transmission owners.	Excess rents are placed in a FTR balancing account for use during periods of revenue inadequacy.	Collected in a FTR balancing account and allocated to FTR holders previously paid on a pro-rated basis. Any remaining balance is allocated to all qualified scheduling entities.
Liquidity (traded volume)	245 GW (2012/13) (excluding self-scheduled FTRs).	123 GW (2012).	13.4 GW (2012 Peak), 11.2GW (2012 Off-Peak).	326 GW of capacity (2014 rights).

Table 1 (cont.)

MARKET	NEW ENGLAND	MISO	NEW ZEALAND
Contract Type	Point-to-Point FTRs, no hedge against losses, obligations only.	Point-to-Point FTRs, no hedge against losses, obligations only. ARRs to transmission network customers.	Point-to-Point inter-island FTRs, no hedge against losses, both obligations and options.
Acquisition and Trading	Auctions, ARR Allocations, FTR secondary market.	FTR Auctions, ARR Allocations, secondary market.	Auctions and bilateral trading, secondary market left to market forces.
Auction Frequency	Annual and monthly FTR auctions for buying and selling FTRs.	Annual FTR auction (for peak and off-peak blocks, four seasons) and monthly auctions (peak and off-peak).	Monthly.
Distribution of Auction Revenues	Distributed to ARR holders.	Distributed to ARR holders. Market participants nominate ARRs.	FTR payouts from an FTR account to be funded by a proportion of losses, constraint excess and auction revenues.
FTR Duration	Monthly or yearly FTRs.	Seasonal and monthly FTRs.	Monthly FTRs.
Auction Revenue Right (ARR) Duration	Monthly, 1-year of long-term ARRs, allocated to firm transmission customers. Merchant transmission can be awarded long-term ARRs.	6-month and monthly ARR based on historical usage of the system. Long term (10-year) ARRs also available. Merchant transmission can be awarded long-term ARRs.	N/A
Congestion Rents	Placed in a Congestion Revenue Fund for future use.	Excess monthly rents applied to future months and end-of-year deficits.	FTRs largely funded from loss and constraint excess.
Liquidity (traded volume)	582 GW (2011).	650 GW (2011) not including self-scheduling of ARRs.	N/A - The first auction for inter-island FTRs will be held in May 2013, in units of 0.1 MW.

While the ISOs in the US competitive markets and New Zealand have adopted similar FTR designs, none of the arrangements are exactly the same. Below we highlight the main similarities and differences between the existing FTR arrangements:

- Most regions only offer the obligation-type FTRs, while a few regions, such as New Zealand, offer both FTR obligations and options. All of the surveyed markets utilize point-to-point FTRs to manage exposure to congestion charges, the difference in the congestion components of the LMPs at the source and delivery point, but no losses. Point-to-point FTRs can source or sink at a generation node, hub, load zone, or interface point. While ERCOT also theoretically allows "flowgate" type of FTRs, currently no designated flowgates exist in the Texas market. All FTRs are firm, i.e., the FTR holder has a contract for a fixed MW amount; this is not dependent on actual patterns of flow or congestion in a particular hour and is not subject to scaling.

- In all the surveyed regions, FTRs can be bought and sold through auctions. Since the configuration and pricing of the transmission system is constantly changing, allocations and auctions of FTRs allow market participants to reconfigure the bulk of their transmission right requests each year, or within the year, to reflect their changing needs. Auctions are held, at a minimum, annually and monthly, and in some cases, also seasonal auctions. In New Zealand, however, auctions will only be held monthly.

- Depending on the region, the incumbent retailers may receive an initial allocation of FTRs based on their firm historical usage of the transmission system, free of charge, and are then able sell the FTRs in subsequent primary auctions or secondary markets at prices they choose. For example, in NYISO, revenues from FTR auctions are credited back to offset the transmission owners' cost of service. Generators can also get awarded FTRs in return for funding transmission enhancements. The notion is that transmission upgrades that increase the transfer capability of the RTO transmission system make it possible to award additional FTRs during the FTR auctions.

- In PJM, New England and MISO, entities supplying electricity to retail customers get allocated "Auction Revenue Rights" (ARRs) on an annual basis, as opposed to FTRs, based on their customers' firm historical usage of the transmission network.[6] ARRs are financial obligations which entitle their holders to a share of the revenue (or charges) generated in the annual FTR auction. The annual ARR allocation process begins with market participants, typically electricity suppliers, requesting ARRs for a share of the peak load they are serving in a given zone. The RTOs run a feasibility test to increase the likelihood that the ARRs are fully funded by annual FTR auction revenue. The duration of each point-to-point ARR is the same as the associated FTR. ARR holders may decide to convert them into FTRs prior to the first round of the annual FTR auction, provided that they are on the same path as the ARR.[7]

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[6] Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs. Since then, all PJM members have been eligible to purchase FTRs in auctions.

[7] The source of an ARR may originate from a generation node, hub, load zone or interface. The sink is always associated with an ARR zone, which is a hub-type node. ARR zones are electrical areas defined for the purpose of allocating ARRs based upon locations where a market participant serves load.

- Following FERC Order 681,[8] RTOs were required to develop long term transmission rights. FERC's directive was implemented differently by each RTO. Currently RTOs allocate both long term FTRs/ARRs, ranging from 2 and 3 years (ERCOT and PJM) to 10 year FTRs (California and NYISO), in addition to short term (one year, one month) to firm transmission customers.

- The ISOs and RTOs have adopted similar arrangements in the case of providing FTRs or ARRs to merchant investors who fund or construct new transmission facilities (i.e., investments not financed via the standard open access transmission service rates). [9] In California for example, merchant transmission investors can be awarded long term FTRs for the useful life of the facility and up to a maximum of 30 years. In NYISO, merchant transmission FTRs may have between 20 and 50 years of duration, provided that they do not exceed the expected operating life of the enhanced facility. In PJM, ISO-NE and MISO, merchant transmission may request long term ARRs typically up to a limit or 20 or 30 years. In all cases it is only for investments not undertaken by the incumbent transmission owner.

- In the presence of electrical losses and congestion, the net revenues collected under nodal pricing are greater than the FTR payments to participants. This difference consists of excess congestion rent (over and above that paid to FTR holders) and losses rent. Most US markets use a similar approach to deal with the financial imbalances created when the funds collected to pay FTR holders do not match the FTR obligations. Excess rents are generally distributed to cover shortfalls ('deficiencies') in other periods using RTO balancing accounts, while deficit rents reduce payments to FTR holders on a pro-rated basis to be recovered later. In NYISO, excess rents are used to offset transmission owner system costs while deficits are recovered directly from transmission owners.

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[8] *Long-Term Firm Transmission Rights in Organized Electric Markets,* FERC Order No. 681. July 20, 2006.

[9] Merchant investors may qualify for incremental, long term ARRs for new transmission capacity provided that they directly finance these investments, either in the form of up-front payments or periodic instalments.

2.2. The experience with FTRs to date

The design features of FTRs in the US have evolved over time since they were first adopted, most notably in the case of regions where FTRs were designed as flowgate types to accommodate zonal markets that later evolved to nodal or LMP markets. The various revisions to point-to-point FTRs have generally involved providing more flexibility in the length of the FTR auctions and contracts, as well as replacing in some cases FTR allocations with ARR allocations[10], all of which contributed to further incentivize contracting and liquidity in the markets. The theory suggests that FTRs can also be instrumental to provide efficient incentives to build merchant transmission when it is efficient to do so. In 2007, many ISOs and RTOs began developing long-term firm transmission rights or long term ARRs to comply with FERC Order No. 681. The intention of the FERC rule was to provide stronger incentives to market participants to both make new investments in transmission and to enter into long-term power supply arrangements. As discussed in section 2.1., many of the RTOs opted for issuing long-term ARRs, as opposed to FTRs, which in theory would also provide stronger incentives than short term FTRs.

In practice, despite the additional flexibility in the design of transmission rights, long term FTRs or ARRs have been found to have no major impact on the way transmission investment takes place in the US, and a very limited number of merchant transmission investments have been awarded FTRs under this framework.[11] The reason for this outcome lies in a combination of structural and regulatory factors, which we highlight below.

- In the existing US markets, the expected revenues from FTRs, based on the congestion component of nodal price differences across the FTR path, are rarely sufficient to justify merchant investment. Current price caps in energy markets range from $1,000/MWh to $3,500/MWh, and are intended to limit market power of the local generators at times of scarcity; but by placing a cap on the LMP, the market fails to signal the true scarcity of supply when local system LOLP (the Loss of Load Probability) increases. In other words, the nodal price differentials between two zones or within a zone do not fully reflect the value of additional transmission investment.

- The return function on FTRs and ARRs remain uncertain for merchant investors, and further these potential investors are concerned about "free-riding" issues, including the fact that new investment in transmission could eliminate existing congestion and largely nullify the value of FTRs and ARRs in the near term.

- The economies of scale of transmission also play a role in terms of limiting incentives for merchant investment in transmission. Transmission investments are "lumpy" – i.e. it is impossible to precisely match transmission capacity with transmission requirements, and there are only a handful of possible configurations in which a transmission line can be built in a given situation. The result of this economy of scale is that transmission is commonly over-built – the cost of doing so is minimal, and it is generally less costly to use transmission solutions than rely on generation solutions to solve a range of system

[10] Allocating ARRs in some RTOs allowed any excess transmission capacity on the system to be made available to market participants other than retailers, who wish to use FTRs to speculate or to hedge positions.

[11] For example, to date, CAISO has not yet awarded CRRs to any entity through the complete merchant transmission process defined in its Tariff section 36.11.

problems.[12] As result, new investment in transmission may significantly reduce losses and congestion below the long run marginal cost of transmission.

- The independent system operators, in charge of transmission planning and coordination of transmission proposals submitted by different parties, tend to err on the side of caution when deciding on the level of required investments, often in order to ensure that high reliability standards imposed by federal regulators. This means that centrally-planned transmission investments often take place before locational market prices can signal to market participants the need for new transmission in a particular location. [13]

As a consequence of all these factors, FTRs have not been found to incentivize new merchant transmission investment in the US. Overall, the consensus from the experience of FTRs in the US energy industry is that FTRs have worked well as a hedging mechanism for congestion costs, which has facilitated bilateral contracting among market participants. This has proved to be the key benefit of FTRs.

[12] If regions A and B are interconnected and region A has sufficient generation reserve, it is likely to be cheaper to overbuild the transmission link between the two (given that transmission has large economies of scale) rather than duplicating the generating reserve in B.

[13] Further, ISOs or RTOs, when assessing planned reliability-triggered investments, typically evaluate whether those upgrades would also bring economic benefits to the system, i.e., savings in congestion costs. In PJM, for example, transmission upgrades may be considered in the central planning for economic reasons, even if no reliability-based need has yet been identified.

2.3. Comparison of FTRs with the proposed OFA model

There are important differences between the AEMC's proposed OFA model for Australia, and the FTR models surveyed. Under the OFA model, generators would be allowed to purchase a form of firm financial transmission rights at a Regional Reference Price (RRP) for both intraregional and interregional firm access. The proposed OFA model relies on the development of Long Run Incremental Cost (LRIC) estimates to establish the amount that a firm transmission customer (generator) must pay to the Transmission Network Service Provider (TNSP) for firm access.

A comparison of the main elements of the OFA design and the FTR designs is summarized below.

- **Contract type (point-to-point vs. flowgates)**:

  All FTRs in the US regions surveyed are currently for point-to-point transmission service. The value of the FTR depends on the on-going *market-based* cost of congestion between the source and delivery nodes of a given path. The OFA model is intended to determine the value of network access through "flowgates", referring to locations in the shared network where congestion may occur. However, in practice the OFA model, as described, would define flowgates in a different fashion as that followed in the US (the approach used by California and Texas prior to switching to point-to-point FTRs). The OFA model would describe every potential constraint in the transmission system as flowgate, and therefore it tends to be closer to a method that relies on "point to point" rights as currently used in the US and elsewhere.[15] In the US, flowgate-based rights were specifically associated with constraints at major interfaces, and a selection criterion was required to define 'commercially significant' flowgates. These flowgates did not intend to capture the entire extent of the congestion problem and so it was possible that a number of congested areas were not defined by flowgates.

- **Contract Duration:**

  Contract duration under OFA model will be determined by generator requests, but is envisaged to be 'long term' (with the exception of the short term access product, which would be of a quarterly frequency). In the surveyed markets, typical FTRs are relatively short term, with only California and NYISO offering up to 10 year FTRs to retailers for their customers' firm transmission usage. Longer term ARRs are available to merchant investors generally for the useful life of the upgrade.

- **Financial firmness:**

  FTRs are financially firm for a specific pre-defined MW quantity under all subsequent (actual) system conditions. Typically, a set of FTRs defined by any feasible pattern of system usage is revenue-adequate for any subsequent (and potentially different) feasible pattern of system usage, and the FTRs need not be subject to scaling or other adjustment.[16] The OFA model, by way of contrast, can modify the MW quantity for which financial

[15] For more detail on the 'flowgate' approach contemplated by OFA model, refer to the explanation of the settlements in the 2012 AEMC report, which uses local prices at specific points on the transmission system.

[16] For example, if a 450 MW generator at node A has a FTR to move 450 MW of power to node B, the FTR will be financially firm for 450 MW regardless of system conditions.

firmness is provided as a function of system conditions – meaning that the OFA model does not provide full financial firmness.

FTRs can provide financial firmness between any locations in the transmission system. The OFA model provides firm access only with respect to a single location – the location of a RRP – and does not allow for the location of the RRP to change over time. A related point is that with FTRs there is no need to separately identify flowgate-support generators, or to treat them differently than other generators. Rather, all generators – whether in high value locations or low value locations – are paid under a consistent principle: the marginal cost of serving load at the location concerned. Finally, under LMP with FTRs, the price received by non-firm generators (generators without an FTR) is not a function of firm/non-firm decisions by other generators. LMP prices are based on the marginal cost of serving load. In the OFA model the price received is a blend of LMP and the RRP.

- **Acquisition and Trading:**

  In contrast with the surveyed regions that use FTRs, auctions would not be the primary means of allocating rights under the proposed OFA model. Rather, the OFA would predominately allocate capacity via bilateral contracts for long-term *intraregional* access. The exceptions would be the allocation of *inter-regional* firm access and for *short term* firm access, which would be subject to an auction.

- **Auction Frequency:**

  In the proposed OFA model, for *inter-regional* access, there would be quarterly auctions for quarterly blocks of transmission capacity. However, only the fourth (annual) auction would be used as a trigger for network expansion, while the other three auctions would be used to allocate existing capacity. There would also be quarterly auctions for short-term *intra-regional* firm access, with an option for quantity and price bids. In the case of the surveyed regions with FTRs, auctions are mostly annual, while quarterly and monthly auctions are mostly held for fine tuning within the year.

- **Distribution of Auction Revenues:**

  Under the OFA model, the auction revenues from short-term inter-regional firm access (above a 'baseline interconnector capacity'), would be retained by the transmission provider, in the same manner as intra-regional short term access. However, the revenue received from auctions for long-term inter-regional access rights would form part of the transmission provider's regulated revenue, and would indirectly lead to reduced transmission charges to electricity consumers. This would be broadly equivalent to the method typically used in the US, where FTR auction revenues in the majority of the regions are distributed to firm transmission customers and to a lower extent, merchant transmission investors holding ARRs.

- **Congestion Rents:**

  The proposed OFA model anticipates that firm generators will be compensated by non-firm generators when constrained, with any shortfalls in congestion rents being funded by both the transmission provider and the generators holding transmission rights (by scaling back these rights). In the US, any difference between congestion rents received by the RTO as part of the LMP settlement and the overall FTR payments paid to FTR holders in a given hour is accumulated in a central fund by the RTO concerned. A deficit in congestion rents with FTRs is possible under limited circumstances, for example resulting from some loop flow between the RTO concerned and an external RTO, or from transmission facility outages in excess of planned levels. Surplus of congestion rents are carried over from prior months to compensate those deficits, via RTO balancing accounts. In more exceptional cases, deficits may persist at the end of a planning period requiring an uplift charge collected from FTR holders on a pro-rated basis.[17]

[17] PJM has experienced under-funding of their FTR market in recent years. Congestion along the PJM borders, in combination with outages and reduced facility ratings, increased the differences in congestion rents between Day-Ahead and Real-Time markets.

3. Other Financial Arrangements for Firm Access

Outside of FTRs, other models exist internationally that make constrained-off and constrained-on payments to generators as a form of firm access. Examples of this approach can be found in markets that use either a zonal or system-wide single-market price, most notably in Europe. In this section we describe the Irish and Spanish mechanisms as a way of case studies.

3.1. Congestion Management in Ireland and Spain

The Irish and Spanish wholesale electricity markets have many similarities and specifically in the way transmission constraints are solved by the system operator. Both countries also have a single electricity market price for the entire country. However, there are differences in the way payments to constrained off generators are made. The main aspects of each market, beginning with Ireland, are highlighted below.

Ireland

On the island of Ireland, the Single Electricity Market (SEM) has the following key features:

- Electricity prices (System Marginal Prices, or SMPs) are determined for the island ex-post, based on a simulated dispatch of actual system load and actual generator offers and availability. Transmission constraints are ignored in the dispatch simulation[18] (and transmission losses are accounted for separately) meaning there is just a single SMP for the whole island in each half hour. The SMP is set equal to the shadow price (instantaneous system marginal cost) plus an uplift, if an uplift is necessary to recover no-load and start-up costs for each generator over the course of the day. The cap on energy market prices is €1,000/MWh.

- Generator quantities scheduled in this simulation (known as Market Schedule Quantities, or MSQs) become firm entitlements for the generators concerned. MSQ is adjusted by a unique transmission losses factor for each generator.

- The actual system dispatch used to physically dispatch the system does (naturally) take transmission constraints into account and is a least-cost security-constrained dispatch like in Australia and elsewhere. As a result, the Dispatch Quantity (DQ) can differ from the MSQ for each generator.

- Generators are paid a Constraint Payment if DQ differs from MSQ. The Constraint Payment equals (DQ *minus* MSQ) * Offer Price.[19]

  - For a *constrained-on generator* (i.e. a generator whose DQ is greater than MSQ) the use of the Constraint Payment in the settlement arrangements ensures that each generator is paid at least its offer price if it is instructed to run. An expensive generator in an import-constrained sub-region could therefore be paid its offer price for some or all of its output.

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18 This simulation is known as Ex-Post Unconstrained Dispatch, or EPUS.

19 For a full description of the settlement arrangements in the SEM, refer to the SEM Operator's website: http://www.sem-o.com/Publications/General/20070706_Settlements%20Invoicing%20Metering_MP_SMO.pdf

- For a *constrained-off generator* (i.e. a generator whose DQ is less than MSQ) the use of the Constraint Payment in the settlement arrangements has the effect of ensuring that generators have firm access to the SMP. *It is therefore this feature of the settlement arrangements in the SEM which is particularly relevant to the discussion in Australia*. In total a generator is paid [MSQ * SMP + (DQ *minus* MSQ) * Offer Price] – meaning that a constrained-off generator earns the same profit from SMP when constrained off as it would have if it had not been constrained off.

Consider a worked example: a 100 MW generator has an offer price of €20/MWh, a MSQ of 100 MW, and the SMP is €50/MWh. It would expect to make revenue of €50 * 100 = €5,000, and incur costs of €20 * 100 = €2,000, for a profit of €3,000. Now, suppose that the generator is instead constrained off, down to 50 MW, because of transmission constraints that affect its ability to export. Under the SEM settlement rules its settlement revenue is adjusted by (DQ *minus* MSQ) * Offer Price = (50 *minus* 100) * 20 = -€1,000. So it receives revenue of €5,000 *minus* €1,000 = €4,000. It incurs costs of €20 * 50 = €1,000. Its profit is therefore €4,000 minus €1,000 = €3,000, i.e. the same as if it had not been constrained off. [20]

Spain

The Spanish electricity market has the following key features:[21]

- The hourly wholesale energy market produces a single energy price for the entire country. Prices are calculated in a day-ahead market, in each of six possible intra-day hourly markets and, on an ex-post basis, in a ‘balancing market’. The day-ahead market price for each hour of the following day is equal to the last generation offer accepted for dispatch in that hour.[22] Generators can specify a minimum level of revenues in their bid as a binding condition. The energy market price is capped at €180/MWh, although Spain provides an explicit regulated capacity payment outside of the energy market.

- The methodology used to dispatch the system is a least-cost security-constrained dispatch. Once the day-ahead market has closed, the Spanish Market Operator provides the quantities that have been scheduled for every hour in the day-ahead energy market to the Spanish system operator (Red Eléctrica, REE). REE then performs a grid analysis to evaluate possible congestion or voltage problems associated with the schedule.

- If transmission constraints are detected, REE modifies the results of the daily market schedule, by displacing some generator units (constrained off units) and increasing the output of other units (constrained-on units). Before 2005, REE selected the constrained-on generators and constrained off generators based on their day-ahead offer prices. Constrained on generators were paid the price specified in their day-ahead offer, just like in the Irish market. The constrained-off generators received no

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20 In practice, constraint payments are a relatively small component of the SEM revenues (between 3.8% and 5.5%), mostly because the island of Ireland is, itself, geographically small.

21 For a full description of the wholesale energy market operations, refer to the market operator’s website: www.omie.es

22 All generators of at least 50 MWs of capacity that are not subject to a physical bilateral contract must submit offers into the day-ahead energy market. The expected energy associated with physical bilateral contracts, as well as the output of must-run renewable resources, is taken into account before determining the need to solve transmission constraints.

compensation, effectively foregoing the profit from their cancelled sales in the day-ahead market. Under this scheme, there were concerns that generators that could expected to be constrained off at the time of system constraints, would submit artificially low offer prices into the day-ahead market, in order to ensure that they remained dispatched when transmission constraints took place. The mechanism was later revised.[23] Currently, once the REE has identified transmission constraints that require a modification to the day-ahead market schedule, REE invites generating units to submit offers specifically to increase or reduce output, within 30 minutes upon the identification of such constraints. Generators are selected based on those offers and the constrained on generators will receive their offer price. There continues to be no compensation to generators that reduce their generation as a result of congestion management.

- If additional constraints appear in real time, the system operator can resort to emergency procedures. The extra-cost incurred in removing all grid constraints is added to the charges for other ancillary services and recovered through an uplift on the energy price in each hour.

3.2. Implications of the Irish and Spanish approaches

The arrangements adopted in the SEM and Spain have a number of implications in terms of financial firmness of transmission access, the nature of incentives for locational decisions and transmission availability, as summarized below.

1. A system like the one implemented in the SEM provides dispatch certainty with a least-cost security-constrained dispatch, like other markets. It provides firm access by using the constraint payment settlement mechanism. The process followed in Spain does not provide all generators with firm access, given the lack of compensation for constrained-off output.

2. Both the SEM and the Spanish wholesale energy market use a single system-wide price, which substantially nullifies any locational signal for generators.

3. The way the Irish market corrects for the lack of locational signals in market prices is by incorporating locational signals in the Transmission Use of System (TUoS) charges.[24] A study of transmission system conditions is conducted on a periodic basis to determine the relative long-term costs and benefits of additional new generation on different parts of the network and generator TUoS charges are scaled accordingly. This methodology has functioned without too much difficulty to date, in part, again, because of the small geographic size of the island of Ireland. The idea in the SEM is that TUoS charges signal where new transmission is most valuable. However, like LMP the SEM approach does not truly co-optimise generation and transmission planning. True co-optimisation is only possible in a vertically-integrated structure.

4. The Spanish system does not use locational transmission access charges. All transmission charges are levied on load, not on generation.

[23] A detailed description of current procedures can be found in Secretary of Energy's Resolution of July 24, 2012, posted to REE's website (www.ree.es).

[24] Most markets do not apply transmission usage charges to generators, but Ireland does, partly for this reason.

5. Finally, neither the SEM system nor the Spanish system operators provide incentives for the transmission operator to maximize availability. If they were to do so, the likely mechanism would be for the transmission operator to share constraint costs if they exceeded some predefined level.[25]

[25] National Grid in the United Kingdom may be a more relevant example in this respect.

Annex: Details of FTR Implementation

1. California ISO

The CAISO is one of the few ISOs in the US that initially adopted a "flowgate" system for FTRs in lieu of a point-to-point system. In this context transmission rights were defined for "commercially significant" constraints across pre-established zones, at major interfaces.[26] Limiting transmission rights to a handful of interfaces where congestion was a major problem was considered to promote simplicity and transparency, thus helping to promote a more liquid and robust competitive environment for generation. However participants delivering to uncongested areas subsidized deliveries made by others across undefined paths via socialized uplift payments until such time as a flowgate was defined. The flowgate-type of transmission rights were replaced with point-to-point Congestion Revenue Rights (CRRs) under a nodal system when CAISO transitioned to a nodal pricing and intra-zonal management of congestion in 2009.

CRRs may take the form of obligation or options. Options are only provided to merchant transmission facilities. Unlike the FTRs under the initial flowgate system, point-to-point CRRs are designated from a single source to a single sink[27] and do not entitle the holder to physical delivery of power.

CRRs are first allocated during an annual, then monthly, process before they are auctioned in annual, then monthly auctions. The annual auction does not include the auction of any Long-Term (LT) CRRs. CRRs may also be obtained through a secondary registration system where CRRs are bi-laterally traded. With the exception of the Tier LT, the CAISO makes available seventy-five percent (75%) of Seasonal Available CRR Capacity for the annual CRR allocation and CRR auction processes, and one hundred percent (100%) of Monthly Available CRR Capacity for the monthly CRR Allocation and CRR Auction processes. The CAISO makes available sixty percent (60%) of Seasonal Available CRR Capacity in the Tier LT.

CRRs are offered in multiple durations:

- *Monthly CRR* – A CRR acquired for one calendar month. Monthly CRRs are made available on a time-of-use basis.
- *Seasonal CRR* – A CRR acquired through the annual CRR allocation or CRR auction process that has a term of one season and either on or off peak. For the purpose of the CRR processes, a season is defined as follows: season 1 is January through March, season 2 is April through June, season 3 is July through September and season 4 is October through December.
- *Long Term CRR* – Long Term CRRs have a term of 10 years and are allocated on a seasonal/time-of-use basis.

[26] Initially flowgates were designated to only included interfaces at transmission owners' zones, but were later expanded to flowgates where congestion was deemed a major problem.

[27] See Section 36.2 of the CAISO Fifth Replacement Tariff

- *Merchant Transmission CRR* – The Merchant Transmission CRR has a term of 30 years or the pre-specified intended life of the facility, whichever is less. The acquisition of the Merchant Transmission CRR is performed through a separate process. Merchant projects are transmission upgrades and additions undertaken by parties other than PTOs. Once constructed, operational control of the transmission lines is turned over to CAISO and the developer will not receive rate-based recovery of the investment cost through the Transmission Access Charge (TAC). The merchant is eligible to receive an allocation of the 30-year option CRRs (merchant CRRs) in a quantity that reflects the incremental capacity the merchant project adds to the CAISO grid.

Long-term Congestion Revenue Right (CRR) feasibility projects include transmission upgrades identified by the CAISO during its annual transmission planning cycle (discussed in detail below) to ensure the feasibility of previously released long-term CRRs for their full ten-year term. If any such upgrades are found to be needed, their costs are recovered through the CAISO's Transmission Access Charge.

All CRRs held by CRR Holders are settled with revenue collected in what is called the IFM Congestion Fund. In the hourly settlement of CRRs, through the IFM Congestion Fund, all CRR Holders will be paid and charged fully for their CRR entitlements of outstanding CRRs. Revenues collected through auctions are used to offset scenarios of revenue inadequacy.

In 2010, CAISO experienced a CRR revenue deficiency of approximately $11.59 million. This shortfall was fully offset by the application of $44.85 million in auction revenues. [28]

2. ERCOT

The ERCOT Congestion Revenue Right (CRR) market is unique in that it contemplates both point-to-point obligations and options, and flowgate rights, albeit at the moment no flowgates are defined within the ERCOT system.[29] CRRs may be acquired in four ways:[30]

- Auctions – ERCOT conducts auctions to allow eligible CRR account holders to acquire CRRs and provides an opportunity for CRR owners to sell the CRRs that they hold. Auctions are held monthly, annually and a balance of the year auction occurs after six monthly auctions have been held.

- Pre-Assigned Congestion Revenue Rights (PCRRs) Allocations – ERCOT allocates PCRRs to eligible municipal-owned utilities and electric cooperatives.

- Bi-lateral Market - CRR account holders may trade Point-to-Point (PTP) options, PTP obligations, and flowgate rights bilaterally. PTP options with refund and PTP obligations with refund are not bilaterally tradable.

- Day-ahead Market (DAM) - Qualified Scheduling Entities (QSEs) may bid for point-to-point obligations in the DAM.

[28] Discussed in the CAISO: 2011 Annual Market Performance CRR Report

[29] See Section 7.3.1.2 *"Defined Flowgates"* of the ERCOT Nodal Protocols.

[30] See Section 7.1 *"Function of Congestion Revenue Rights"* of the ERCOT Nodal Protocols (10/1/2012)

CRRs obtained through auctions are awarded in time-of-use blocks consisting of two off-peak segments and separate peak weekend and weekday segments. Auction revenues from CRRs awarded on an intra-zonal basis are distributed based on a zonal load ratio share, while revenues from CRRs awarded on an inter-zonal basis are distributed throughout the ERCOT service territory based on an ERCOT-wide load ratio share. Excess rents are collected in a CRR balancing account and allocated as "make-whole" payments to CRR holders that were previously paid on a pro-rated basis. Any remaining balance is allocated to all qualified schedule entities.

3. MISO

MISO began operating a competitive wholesale electricity market on April 1, 2005. MISO offers tradable, point-to-point, financially settled rights as opposed to physical delivery, intended as hedges against congestion rents.[31] Market participants can be allocated ARRs, or acquire FTRs through a series of auctions and allocations, and through a secondary market. The key elements of MISO FTR and ARR allocation processes are described below.

- Annual ARR allocation – ARRs are initially allocated to market participants based on firm historical usage of the transmission network. Eligible market participants can nominate ARRs to be considered for allocation by MISO. MISO then evaluates all submitted ARR requests and runs a simultaneous feasibility test (SFT) to determine how many ARRs can be granted. ARRs are allocated once a year, for peak and off peak time periods and for four different seasons. Therefore the annual FTR auction consists of eight independent auctions for each of the periods.

- Monthly FTR auction – The monthly FTR auction consists of two independent auctions: one for the peak period and one for the off-peak period. All FTRs sold in monthly FTR auctions have a term of one month beginning on the first day of the month following the FTR auction and are associated with either the peak or the off-peak period.

- Secondary market - FTR holders may trade their FTRs in a secondary market outside MISO-administered allocations and auctions, subject to the caveat that the FTR holders of record retain full responsibility to MISO unless MISO agrees to change the FTR holder of record. There is a private section to the FTR secondary market (aside from the public bulletin board) where market participants can enter into private FTR transactions that have been pre-arranged.

MISO also allocates "long-term firm transmission rights" (LTTRs) which essentially represent incremental ARRs that may be allocated to parties financing network upgrades or new network resources, except when these are funded by the incumbent transmission owners. These LTTRs may be converted into FTRs at the discretion of the market participant. MISO will issue such LTTRs equal to the incremental capacity created by the network upgrade, as agreed upon by MISO and the market participant funding the upgrade, and consistent with the existence of FTRs previously issued.

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[31] See Section 4 "*Financial Transmission Rights (FTRs)*" of the MISO "FTR and ARR Business Practice Manual".

MISO allocates FTRs based on a percentage of capacity available during each auction round.[32] Only loop flows and FTRs awarded in previous rounds are considered as the base loading to calculate available transmission capacity. ARRs that are allocated from the annual ARR allocation are not considered as base loading in the annual FTR auction.

During each month, MISO attempts to fund FTRs by applying surplus revenues from overfunded hours to shortfalls in other hours. Monthly congestion revenue surpluses accumulate during the year and are prorated at year-end to compensate for any remaining FTR shortfall. The Independent Market Monitor (IMM) for MISO reported FTR annual revenue shortfalls between $43 and $62 million from 2008 to 2010.[33] Such shortfalls typically arise from a disconnect between the forecast transmission capability when the FTRs were bought or sold and the capability observed in the day-ahead market.[34]

4. ISO- New England

The ISO New England (ISO-NE) offers tradable, point-to-point, financially settled rights as opposed to physical delivery, and intended as hedges against congestion rents. FTRs are made available through monthly and yearly auctions as well as secondary markets and have durations of one month and one year. Twenty-five percent of the available network capacity is made available for the initial round of the annual FTR auction. The FTRs that remain feasible with fifty percent of the network capacity available and after deducting the network capability associated with FTRs sold in the initial round is made available during the second round. During monthly FTR auctions, all FTRs that remain feasible after accounting for all FTRs transacted in the annual FTR auctions will be made available. [35]

ISO-NE also uses ARRs to distribute auction revenues to rights holders. Incremental, long-term ARRs are made available to merchant transmission investors for the new capacity built or upgraded.

Congestion revenue from the settlement of the Day-Ahead Energy Market and Real-Time Energy Market is accumulated in a Congestion Revenue Fund for distribution to holders of congestion instruments. However, counter-flow congestion may require a holder to contribute to the fund. Excess funds are carried over for future use.

5. NYISO

The NYISO began operating a point-to-point FTR (known in NYISO as Transmission Congestion Contract -TCC) system in 2000, shortly after PJM introduced its FTR system. TCCs are made available through monthly and seasonal auctions as well as secondary markets and have durations of one, six and twelve months. Fixed-Price non-historic TCCs are available for an initial duration of two years with an option to renew after each year for a

[32] In round 1, one third of available transmission capacity is utilized. In round 2, half of available transmission capacity is utilized. All remaining transmission capacity is utilized in round 3. The available transmission capacity is equally distributed to all remaining rounds.

[33] See the “2011 State of the Market Report for the MISO Electricity Markets”.

[34] The Independent Market Monitor for MISO noted that a constraint relaxation algorithm employed in MISO’s day-ahead market modeling improperly relaxed flow constraints in some areas resulting in artificially suppressed congestion prices, thus contributing to FTR revenue inadequacy.

[35] See Section III.7 “*Financial Transmission Rights Auctions* “ of NEISO Market Rule 1: “Standard Market Design”

maximum cumulative duration of ten-years. FTR options have been studied for possible inclusion, but as of yet have not been implemented. NYISO also offers long term ARRs to firm transmission customers, of up to 10 years, in addition to long term ARRs to merchant transmission customers.

The NYISO sets the percentage of available transmission system capability to be offered to support the sale of TCCs of duration in an auction.[36] The NYISO then determines the percentage of transmission system capability for each round, considering 1) the percentage of transmission system capability to be offered for the product, and 2) the number of rounds over which that product will be sold. No less than 5% of the available transmission system capability is available in each round of an auction. NYISO does not make public the availability of specific TCC flows as bids and offers are analyzed round-by-round by a power flow model which produces new flows based on new bid/offer combinations. Revenues from TCC auctions are allocated and credited back to transmission owners' cost of service.

6. New Zealand

The Electricity Authority of New Zealand is introducing FTRs to manage inter-island price risk following more than a decade of industry and regulatory debate. In 2009, the Electricity Commission considered a pure locational rental allocation mechanism ("LRA") as opposed to an FTR model. An LRA is an allocation of rentals between spot market participants in a way that reduces or eliminates locational price differences and reduces participants' exposure to locational price risk. Additionally, since LRAs and FTRs are not mutually exclusive, hybrids of FTRs and LRAs were considered. In 2010, the Electricity Commission determined that an inter-island FTR model is preferable to the hybrid FTA/LRA model or an extended FTR model (which comprises of both inter- and intra-island FTRs), due to its simplicity, ability to capture most benefits, and flexibility in managing the with-in island basis risk.

The first auction for inter-island FTRs will be held in May 2013.[37] FTRs are to be based on the full difference between prices at the two locations, covering losses, constraints and all other causes of nodal price differences. An option and an obligation will both be offered in each direction (i.e. four products) and FTRs are to be available in units of 0.1 MW. The FTR contracts are to have a term of one month, with contracts initially being offered up to one year in advance and this advance period increasing as time goes on. FTR payouts in New Zealand will be sourced from an FTR account which will be funded by a proportion of rentals and auction revenues.

The Commission has not yet decided how residual revenues will be allocated to specific assets. The FTR manager (appointed by the Electricity Authority) determines the number and nature of FTRs to auction "supported by a reasonable estimate of the capacity of the grid for the relevant period, and set so as to achieve a reasonable balance between (a) ensuring there is revenue available that is sufficient to settle the FTRs and (b) ensuring that sufficient FTRs are available so that participants who wish to purchase FTRs are able to obtain them"[38] .

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[36] See Section 3 "*The Auction Process*" of the NYISO Transmission Congestion Contracts Manual.

[37] For more details on the New Zealand FTR arrangements, refer to "Energy Market Services, an Introduction to the New Zealand FTR Market v1.2", November 2012.

[38] Subpart 6 of Part 13 of the New Zealand Electricity Industry Participation Code 2010.

New Zealand has reviewed methods of making FTRs more 'firm' or 'resource adequate', including:

- placing limits on the combination of FTRs that may be sold, based on the capacity of the transmission grid;
- increasing the reliability of the physical transmission grid;
- requiring a party (such as the grid owner or FTR service provider) to underwrite the FTR product;
- funding shortfalls from FTR auction revenue;
- funding a shortfall in one time period from excess in other time periods;
- using 'non FTR' loss and constraint excess;
- making prudential arrangements;
- centrally procuring a suitable combination of energy and/or reserve hedges (which can help to manage some of the causes of revenue inadequacy); and
- scaling (i.e. paying out a reduced amount).[39]

7. PJM

PJM began operating a point-to-point auction for FTR obligations in May 1999. The initial annual allocation process allocated FTRs to Network and Firm point-to-point transmission service customers who paid the embedded cost of the transmission system, allowing them to trade their FTRs in a PJM administered secondary market using bi-lateral transactions. As the PJM market evolved, it became apparent that more flexible types of FTR products needed to be developed and to enhance the value of transmission rights. This realization led to the introduction of a new annual auction process effective June 1, 2003, which replaced the allocation of FTRs with the annual allocation of Auction Revenue Rights (ARRs), making FTR products in the auction available to all market participants.

Revenues from annual FTR auctions are allocated annually to firm transmission service customers holding ARR entitlements. FTRs are sold based on the system capability remaining after ARRs are allocated, in order to maximize grid usage and efficiency. ARRs allocated for the planning period are reassigned on a proportional basis within a zone as customers switch between retailers within the planning period.

ARR holders can "self-schedule" their ARR to become a FTR. Self-scheduling must be on the exact same path as the ARR and must be done prior to the first round of the FTR Auction. ARR holders can also bid into the annual auction to acquire a FTR on an alternative path, or may retain the allocated ARR and receive associated revenues from the auction.

[39] Locational Price Risk Technical Group, "Within-island basis risk: review of FTRs and LRAs, November 2012.

FTRs can be purchased as obligations or options and be acquired through four market mechanisms: the Long-term (LT) FTR auction, the annual FTR auction, the monthly FTR auction, or the FTR secondary market.[40]

- Long-Term (three-year planning horizon) auctions - PJM conducts a long term multi-round auction for FTRs for three consecutive annual planning periods immediately subsequent to the planning period during which the FTR auction is conducted. The capacity offered for sale is the residual system capability which assumes self-scheduling of all ARRs that have been allocated in the immediately prior annual ARR allocation process. The FTRs purchased in the long term auction can only be obligations, not options, and can have durations of one year (for each of the three planning years covered by the auction) or three years (for the entire three-year period covered by the auction).

- Annual FTR auctions - The annual FTR auction offers for sale the entire transmission entitlement that is available on the PJM system on an annual basis, meaning the entire FTR capability of the transmission system minus approved long-term FTRs. The clearing mechanism of the annual FTR auction maximizes the quote-based value of FTRs awarded in the auction. FTRs can be both obligations and options and have a duration of one year.

- Monthly FTR auctions - The monthly FTR auction offers for sale any residual transmission entitlement that is available after FTRs are awarded from the annual and long-term (three-year) FTR auctions. The auction also allows market participants an opportunity to sell FTRs that they are currently holding. FTRs purchased in the monthly auction can be both obligations and options, and have durations of one month or three months.

- Secondary market - The FTR secondary market facilitates bilateral trading of existing FTRs between PJM members through an internet application.

Transmission expansion projects associated with new generation interconnection and merchant transmission projects in PJM may also be awarded incremental long term ARRs, for the life of the facility and to a maximum of 30 years, in a three-round allocation process for three pairs of point-to-point combinations.

PJM has experienced an under-funding of their FTR market in recent years. This has been attributed to congestion along the PJM borders in combination with a more fully utilized system due to unplanned transmission outages and reduced facility capacity ratings. The negative balancing explicit congestion has increased as a result.[41] The balancing explicit congestion includes differences in congestion between the Day-Ahead and Real-Time energy markets from imports, exports and wheel-through PJM transactions flowing through the PJM balancing authority.

[40] See Section 7.1 "*Auctions of Financial Transmission Rights*" of the PJM Open Access Transmission Tariff.
[41] See Section 1 "*Overview*" in PJM Report: "*PJM Options to Address FTR Underfunding*" (4/30/2012)

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