Analysis of the TRCA Surplus Allocation Methodology

PREPARED FOR

The Ontario Independent Electricity System Operator (IESO)

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Executive Summary

This report is designed to assist the Ontario Independent Electricity System Operator (IESO) with a review of its Transmission Rights Clearing Account (TRCA) surplus disbursement methodology, and complements the IESO "Backgrounder" concerning its *Review of the Transmission Rights Market*. The report examines Ontario's and other jurisdictions' treatment of transmission rights to identify alternative objectives and best practices for managing congestion accounts. From these, we derive three alternative disbursement options and discuss their relative merits to ensure that the resulting outcome is *efficient* (meaning that it derives the optimal least-cost solutions to delivering power while maintaining the physical requirements of the system) and *equitable* (meaning that it follows cost-causation principles leading to a "non-discriminatory" rate design that does not unduly subsidize market participants).

In Ontario, internal load pays for the long term cost of the transmission system (including the cost of the interties) through regulated Provincial Transmission Service (PTS) charges, while exporters pay for transmission service on the interties through an Export Transmission Service (ETS) charge. In addition to these physical transmission charges, the IESO imposes congestion charges on market participants for the competitive use of constrained transmission paths to deliver power. To protect against such charges on its interties, Ontario auctions financial transmission rights (TRs) to market participants, the proceeds from which go into the TRCA. Importers and exporters pay for intertie congestion into the TRCA, while TR holders are then paid from the TRCA.

In 2015, the IESO Board authorized a reserve threshold of $20 million for the TRCA, and formalized a schedule to disburse TRCA surplus funds on a semi-annual basis when the surplus funds exceed the reserve threshold by at least $5 million. Under current market rules, TRCA balances above the reserve threshold are distributed to internal load within Ontario and market participants exporting power from Ontario, based on load shares. In 2017, the Market Surveillance Panel determined that the existing TRCA disbursement methodology disproportionately benefits exporters over native Ontario transmission customers in a way that is inconsistent with the stated purpose of the disbursements. The IESO elected to review the methodology, and continue with the existing system of semi-annual disbursements until the review is completed. The review prompted this report, and the three options it proposes.

A comparison of Ontario's treatment of congestion to the systems used by other electricity system operators in Australia, the European Union and United States provides insight as to four objectives that Ontario might consider when adopting best practices relevant to a revised TRCA disbursement methodology: 1) *manage congestion risk for internal load,* because it is responsible for paying for the long term costs of the transmission system; 2) *lower transaction charges,* thus maximizing the potential for efficient power trades to the benefit of the broader market; 3) *increase transmission investment*, potentially increasing system reliability and reducing congestion in the long run; and

4) *improve the efficiency of the TR market,* thus promoting efficient price signals and maximizing the value of the TRs as a congestion hedge.

Seeking to improve the liquidity of the TR market would serve no purpose in Ontario because the current system already supports full payments to TR holders. Similarly, the current system already addresses transmission buildout through a separate mechanism. The current TRCA disbursement methodology also effectively reduces transaction charges to market participants by distributing funds to transmission customers (internal load and exporters), but does so based on load shares and not based on cost of service principles. However, from the perspective of efficiency and equity, the "best" practice for managing congestion risk is to transfer surplus TRCA funds to the market participants that pay for the long term costs of transmission service. To the extent that the current system over-allocates TRCA surplus funds to exporters, this provides a subsidy for their use of the transmission system and provides the inefficient incentive for more exports from the system.

These objectives suggest three options concerning how future TRCA surpluses are distributed. The first option would shift future surpluses to internal load. This would the give the revenues to the market participant responsible for paying the long-term costs of the transmission system through regulated rates. The second option would split the surpluses between exporters and internal load, given that both continue to pay transmission service charges through the ETS and PTS, respectively. The third would allocate the entire surplus to reduce the charges paid by exporters, thus encouraging the trading of power across Ontario's interties. It is likely, however, that payments to exporters that are not tied to the long term cost of transmission service will reflect a subsidy that could encourage inefficient trading across the interties, resulting in inefficient price signals and artificially-high levels of congestion over time.

Ontario should be mindful of how its decisions concerning its TRCA disbursement methodology could impact and be impacted by its adoption of a new day-ahead/real time ("Day 2") market to be implemented post-MRP. While the essence of the TRCA—including the auctioning of TRs and the distribution of any resulting surpluses—will not necessarily change as a result of MRP, the ability to measure congestion on a nodal basis and in day-ahead and real time markets may present new considerations for Ontario to consider. While the system operators in the U.S. have addressed many issues related to congestion in their Day 2 markets, significant differences between Ontario's future market design and those of the U.S. markets belie why the U.S. market operator's experience might be less relevant to Ontario's future market design. These are considerations that the IESO should consider studying in the next phase of its TRCA Review.

I. Introduction

The Ontario Independent Electricity System Operator (IESO) is reviewing its Transmission Rights Clearing Account (TRCA) surplus disbursement methodology to ensure that it is efficient and equitable to the contributors to the transmission system and to support the development and evaluation of potential alternative disbursement options. The Brattle Group (Brattle) was retained to support the IESO in the development and evaluation of the current disbursement methodology and potential alternative disbursement methods. This report is a first step in that process, and is drafted in anticipation of the engagement of the IESO with market stakeholders to discuss their perspectives concerning the alternatives posed.

At the outset, we observe that there are four distinct categories of Market Participants (MPs) in the Ontario competitive electricity market who, at least in theory, could claim part or all of the intertie-based TRCA surplus:

- Internal load, which includes demand internal to Ontario (*i.e.,* excluding exports);
- Importers/Exporters (IEs), which include all users of the interties (imports or exports);
- Transmission Owners (TOs), including Hydro One and other private shareholders; and
- Transmission Right (TR) Holders, who acquired financial import or export transmission rights from the IESO's auctions.

The TRCA surplus currently is paid semi-annually and allocated to internal load and exporters based on load shares.[1] However, system operators in other jurisdictions allocate surplus congestion rents to TOs and/or TR Holders as well as load and IEs. When considering these alternative allocation methodologies, how should the IESO evaluate the relative costs and benefits of each as they relate to the current and future market design in Ontario? For its review of the current and future TRCA surplus disbursement methodology, we suggest that the IESO should consider two key questions:

- Does the allocation of the surplus to one MP versus another improve the *efficiency* of the current or future market?
- Is the allocation chosen *equitable* given the role which each MP plays (or will play) in the current (or future) market design?

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1 Presently, disbursements are made to the same MPs that are charged for transmission service, in amounts proportional to their allocated quantities of energy withdrawn from wholesale meters and scheduled quantities of energy withdrawn from intertie metering points respectively. IESO, "Market Rules, Chapter 9: Settlements and Billing," December 5, 2018, Section 4.7.1.

As to the first question, "efficiency" within the context of electricity markets typically refers to the process of deriving the optimal least-cost solutions to delivering power while maintaining the physical requirements of the system (*e.g.,* reliability, power quality, and voltage support). To the extent that MPs reduce the costs of delivering power on the system, such as by relieving constrained transmission paths by ramping up generation or trading power from a low-cost source to higher-cost delivery point, the MP is rewarded with profits while the efficiency of the system is enhanced. Likewise, MPs that increase system costs should bear the economic burden of the inefficiencies (or, in the case of congestion, externalities) that they create.

Regarding the second question, based on general ratemaking principles used in Canada (and elsewhere), an "equitable" distribution of rates follows cost-causation principles to lead to a rate design that is "non-discriminatory"—*i.e.,* MPs with roughly the same cost of service are charged roughly equivalent rates, with higher rates to MPs then justified by higher costs of service. The overall rate design must provide sufficient revenues to allow the TOs who invested in the transmission system to recover their costs incurred plus a reasonable rate of return. The result should not cause unwarranted wealth transfers between MPs, as such cross-subsidizations are both inequitable and may prompt long-term inefficiencies. Although competitive market constructs have replaced some regulatory mechanisms to incentivize cost-minimization and efficiency, these broader regulatory principles still apply, particularly for transmission and distribution assets that remain supported by regulated rates.

Important to addressing both of these questions is the avoidance of unwarranted subsidizations of one class of MPs over another given the allocation chosen—*i.e.,* the inequitable allocation of the TRCA surplus in a manner that ignores cost-causation principles or which incentivizes inefficient behavior that is inconsistent with providing least-cost solutions for the provision of power, such as by distorting price signals away from competitive levels. To better understand these issues, it is helpful to examine the broader economic principles that surround the objectives and best practices employed by other jurisdictions in managing congestion costs and payments and for allocating surplus congestion funds amongst MP.

In the remainder of this report, we first provide background concerning transmission congestion, the role of financial transmission rights, and the operation of the TRCA under the current and planned market designs for Ontario. This is designed to complement the information provided in the IESO's "Backgrounder" released attendant with this report. Next, we discuss the economics surrounding transmission congestion, and discuss how system operators in other countries allocate congestion rents amongst their market participants. We then synthesize these jurisdictions' experience to identify four objectives that are generally followed and the best practices associated with each. These are then applied to Ontario and used to assess whether the current TRCA disbursement methodology is efficient and equitable, and discuss how alternative allocations would affect those factors. We conclude by discussing how planned future changes to the Ontario market design might affect these allocations and the equity/efficiency thereof.

II. Background: The Ontario Power Market

The information in this section is designed to supplement the information provided by the IESO in its "Backgrounder" concerning its *Review of the Transmission Rights Market*. Understanding the purpose of the TRCA requires knowledge of what transmission congestion is and how market participants protect themselves against it. For this reason, we first provide a brief discussion of congestion and the difference between physical and financial transmission rights. We then turn to a description of the operation of the TRCA under the current market design, followed by a discussion of how the account might operate differently after market reforms.

A. Physical vs. Financial Transmission Rights

MPs pay for physical transmission service through regulated, cost-based rates which are designed to allow the TOs the ability to recover their costs and earn a regulated rate of return on their invested capital.[2] In Ontario, all physical transmission service is scheduled through the IESO. Internal load pays for the long term cost of the transmission system (including the cost of the interties) through regulated Provincial Transmission Service (PTS) charges, whereas exporters pay for transmission service over the interties through an Export Transmission Service (ETS) charge.[3]

By comparison, financial transmission rights (in the case of Ontario, "TRs") do not allow any use of the physical transmission system, and do not entitle the purchasers of the rights to utilize the transmission assets in any way. Rather, TRs are financial contracts that entitle their holders to *congestion revenues* on the path specified in the contract, which in Ontario is limited to specific interties. Transmission congestion can arise on a transmission path if the prices on either side of the path are allowed to fluctuate independently (*i.e.,* between nodes or zones within a market or at external interties between markets). When the cost to produce or procure power is cheaper on one side of the path than the other, economics dictates that power should flow from the low-cost side to the high-cost side, with the prices equilibrating (adjusted for losses) at both locations if the transmission path is unconstrained.

However, if the thermal limits of the transmission path prevent the transmission of sufficient power from the low-cost side to meet the demand at the high-cost side, higher cost generation must be dispatched to meet that demand, thus raising the price at that location. When this happens, load at the higher-cost side of the transmission path must pay the difference between the higher and lower prices as a congestion cost (excluding the portion of the differential that is attributable to losses). In Ontario, congestion revenues in the interties are collected by the IESO, similar to the transmission system operators in other electricity markets (*e.g.,* Independent System Operators [ISOs], Regional Transmission Operators [RTOs] or Transmission System Operators [TSOs]).

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2 By comparison, in jurisdictions where merchant transmission assets are allowed, these do not charge regulated rates for the use of their facilities and are not guaranteed cost recovery.

3 *See, e.g.,* Ontario Energy Board, Decision and Interim Rate Order EB-2018-0326—2019 Uniform Transmission Rates (December 20, 2018).

In Ontario, the costs of internal congestion are combined with system reliability costs and charged to load (sourced both internally and from exporters) on an hourly basis as Congestion Management Settlement Credits (CMSCs). By comparison, congestion on Ontario's interties is priced separately and based on the difference of the price at the intertie border and the Hourly Ontario Energy Price (HOEP). As we discuss below, IEs pay the cost of intertie congestion into the TRCA, which is combined with the revenues from the TR auctions; TR Holders and the recipients of the TRCA surplus allocation are then paid from this account.

B. Description of the TRCA under the Current and Future Market Design

The IESO has a uniform price throughout the market and there are no explicit congestion rents incurred or collected on internal transactions. Rather, internal congestion on the IESO system is managed through CMSCs, which pay for adjustments to market dispatch as needed for congestion management.

The price of energy on the IESO interties, known as the Intertie Zonal Price (IZP), may deviate from the uniform Ontario Market Clearing Price (MCP)[4] in cases of intertie congestion. IEs are exposed to intertie congestion risk based on the difference between the IZP and MCP (equal to the Intertie Congestion Price, or ICP), and the IESO collects intertie congestion rents into the TRCA when congestion arises. Since May 2002, the IESO has operated a TR market to allow intertie traders to hedge against congestion risk.[5] After conducting a confidence level analysis, the IESO auctions off injection (import) and withdrawal (export) TRs, with the associated revenues accumulating in the TRCA.[6] These TRs are "options" in the sense that the *target allocation* (*i.e.,* the expected value of the TR given actual congestion) cannot be less than zero in a given hour. Actual import and export congestion rents that are collected over the interties by the IESO are credited to the TRCA[7] and then paid out to the respective injection and withdrawal TR Holders.

TR holders are paid their target allocations out of the TRCA, regardless of whether the congestion revenues collected are sufficient to pay out their full values.[8] In other words, in the event that

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4 The MCP is a sub-hourly price set every 5 minutes. The HOEP is the average of the 12 MCPs set within each hour.

5 Ontario Energy Board Market Surveillance Panel, "Monitoring Report on the IMO-Administered Electricity Markets for the First Four Months, May – August 2002," October 7, 2002, p. 45, available at: https://www.oeb.ca/documents/msp/panel_mspreport_imoadministered_071002.pdf.

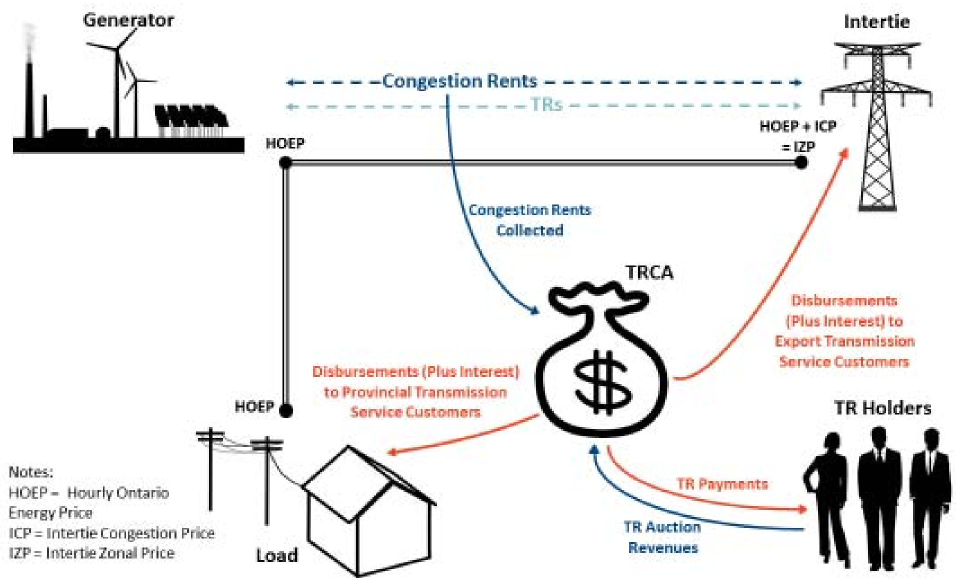
6 IESO, "Market Rules, Chapter 8: Physical Bilateral Contracts and Financial Markets," June 1, 2016, Sections 4.6.1 and 4.18.1, available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/586603f319a04df9a08fcea9f8705b32.ashx.

7 *Id.,* Section 4.18.1.

8 *Id.,* Sections 4.4.1-2 and 4.18.1.3.

congestion revenues on an intertie are less than the total target allocations for that intertie, the shortfall is covered by the fund of auction revenues and any accrued interest. After all TR holders are paid, the remaining funds in the TRCA may, at the discretion of the IESO Board, be disbursed to the MPs who pay transmission service charges in the market,[9] provided that the TRCA balance is $5 million above the TR reserve threshold of $20 million.[10] Presently, disbursements are made to the same MPs that are charged for transmission service, in amounts that are proportional to their allocated quantities of energy withdrawn from wholesale meters and scheduled quantities of energy withdrawn from intertie metering points respectively.[11] This process is depicted below in Figure 1.

Figure 1
Existing IESO Transmission Rights Market



9 Two types of transmission service charges are paid in Ontario. The Provincial Transmission Service (PTS) applies to all transmission customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system. These charges are paid by internal load to support the long term cost of the transmission system. By comparison, the Export Transmission Service (ETS) charge applies for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario. These charges are therefore paid by exporters only for the short term use of the transmission system. See Ontario Energy Board, "EB-2017-0359: 2018 Uniform Transmission Rates," Appendix B: 2018 Uniform Transmission Rate Schedules, February 1, 2018, pp. 5-6.

10 See IESO, "Market Rules, Chapter 4: Market Operations," Section 4.4, p. 4 (March 1, 2017) and "Market Rules, Chapter 5: Settlements," Section 5.5, p. 56 (March 1, 2017).

11 IESO, "Market Rules, Chapter 9: Settlements and Billing," December 5, 2018, Section 4.7.1.

Until 2015 the payments to TR Holders consistently exceeded the congestion revenue collected by the IESO, due in part to deliberate over-allocation of TRs.[12] This over-allocation started in 2003 when the IESO implemented a mechanism to gradually increase the number of TRs allocated to exceed what was simultaneously feasible.[13] The Market Surveillance Panel (MSP) states that this decision was made in order to foster liquidity in the TR market.[14] However, the revenue inadequacy caused by the over-allocation of TRs led to a continual depletion of revenues in the TRCA, leaving very few funds eligible for disbursement to transmission customers.[15]

In 2013 the MSP issued two recommendations to remedy this situation.[16] First, it recommended that the IESO stop over-allocating TRs so that the congestion rent collected would approximately equal the TR payments.[17] Second, it recommended that the IESO disburse the balance of the TRCA above the reserve threshold and establish a more regular system of semi-annual disbursements to transmission customers.[18] The IESO implemented both recommendations in 2013, increasing the disbursements made to transmission service customers given surpluses in the TRCA.[19]

In 2017, the MSP opined that the existing TRCA disbursement methodology disproportionately benefits exporters over native Ontario transmission customers in a way that is inconsistent with the stated purpose of the disbursements.[20] The IESO Market Rules state that the purpose of disbursements is to offset transmission services charges, but the disbursements are allocated based on the share of load withdrawn or scheduled, not share of transmission charges paid.[21] Further,

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12 Ontario Energy Board Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2011 – April 2012," January 2013, pp. 152-153, available at: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf.

13 IESO, "MR-00242-R00 Market Rule Amendment Proposal," November 11, 2003, p. 2, available at: http://www.ieso.ca/en/Sector-Participants/Change-Management/-/media/files/ieso/document-library/mr-amendments/archive/mr_00242-R00-R04_BS.pdf.

14 Ontario Energy Board Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2015 – April 2016," May 2017, p. 91.

15 *Id.,* pp. 91-93.

16 Ontario Energy Board Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2011 – April 2012," January 2013, pp. 152-161.

17 *Id.,* p. 157.

18 *Id.,* pp. 160-161.

19 Ontario Energy Board Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2012 – April 2013," January 2014, p. 185, available at: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf.

20 Ontario Energy Board Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2015 – April 2016," May 2017, pp. 94-96.

21 *Id.,* p. 95. See also IESO, "Market Rules, Chapter 8: Physical Bilateral Contracts and Financial Markets," June 1, 2016, Section 4.18.2.

because the ETS charges paid by exporters are significantly lower than the PTS charges paid by Ontario transmission customers, the MSP found that exporters receive a disproportionately large share of the disbursements.[22] The MSP recommended that the IESO revise its methodology to better align the allocations with their intended purpose and to delay any disbursements until the issue has been remedied.[23]

The IESO elected to review the disbursement methodology and continue with the existing system of semi-annual disbursements until that review is completed.[24] The IESO will assure the TRCA is consistent with its forthcoming Market Renewal Program (MRP), in which the IESO will convert the existing market design to a single schedule market (SSM). Instead of establishing a uniform system energy price (the HOEP), transmission constraints will be taken into account so that energy prices at different locations within Ontario will settle independently of each other based on locational marginal prices (LMPs).[25] This will eliminate the need for using CMSCs for tracking internal congestion, but will not significantly alter the need for continuing to track intertie congestion through a separate process.[26]

Ontario will combine a financially binding day-ahead market with the real time SSM to create a "Day 2" market design. In anticipation that the vast majority of transactions will occur in the day-ahead, Ontario's post-MRP TRs will become day-ahead instruments, with the TRCA then funded by the auction of those instruments and payments for day-ahead intertie congestion.[27] To the extent that these changes alter how MPs pay for transmission service, the result may change the arithmetic for how future TRCA surpluses are allocated between exporters and internal load given the MSP's interpretation of the existing market rules.

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22 Exporters pay $1.85 per MWh in transmission charges. By comparison, Ontario transmission customers paid $8.97 per MWh in transmission charges by a 2016 estimate. See Ontario Energy Board Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2015 – April 2016," May 2017, p. 96.

23 *Id.*

24 Ontario Energy Board Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets for the Period from May 2016 – October 2016," February 2018, pp. 12-13.

25 IESO, "Single Schedule Market High-Level Design, Executive Summary," September 2018, p. 5.

26 Specifically, the internal reference price used to calculate intertie congestion will shift from the HOEP to the internal LMP calculated at the intertie.

27 We will address the question of whether real-time congestion revenues should be included in the TRCA later in Section V(B), below.

III. Economic Principles and Best Practices Concerning the Treatment of Congestion

Below, we discuss the economic background behind the treatment of congestion in competitive electricity markets and will discuss the efficient operation of a TR market. We next discuss how regulators in Australia, the European Union (EU) and United States (U.S.) have treated congestion payments through the allocation and auctioning of different types of TRs. From these examples, we will identify four broad objectives that are or have been pursued in these other jurisdictions. These successful (and sometimes unsuccessful) efforts inform best practices that the IESO might apply to its evaluation of its own TR market and the associated TRCA surplus that will arise under its current and future market designs.

A. The Economic Motivation for TRs

TRs in other jurisdictions are typically offered to provide internal load with the ability to manage congestion costs. For example, in most U.S. jurisdictions where TRs are offered, their motivation ties back to how electric systems operated before competition. Vertically integrated load-serving entities built out the capacity of the transmission system to deliver generated power to internal load. Internal load paid for the cost of power generation and the cost of transmitting and delivering the power, and were not exposed to any congestion costs under that system. However, the transition to competition exposed internal load to congestion costs, an externality caused by competitive bidding for access to constrained transmission paths. Absent a mechanism to hedge against such costs, internal load is inefficiently forced to absorb the cost of this externality, an expense that it neither created nor anticipated given its continuing responsibility to pay for the transmission system through regulated rates.

In contrast, Ontario manages congestion costs through CMSC allocations for internal congestion and through the TR market for intertie congestion. TRs in Ontario are offered solely on the interties to promote and facilitate intertie trading by providing a mechanism to traders to hedge intertie congestion costs. Internal load is not exposed to the risk of intertie congestion costs, but the fundamental principle is consistent across jurisdictions: the party responsible for paying for the costs of the transmission system receives the benefits generated from the transmission system (*e.g.,* congestion rent), either through the TR market or other mechanisms. This approach respects the legacy of how the transmission system was originally funded and recognizes that internal load continues to have, in the regulated context, the ultimate responsibility to pay for the system.

For a TR market to function efficiently, the prices of TRs must settle at their target allocations, equal to their expected congestion rents. Payments above this amount reflect a subsidy to the TR holder, allowing it to earn profits above those expected from congestion alone. However, such gains are necessarily ephemeral given the repetitive nature of competitive auctions, since higher profits earned in one period will incentivize higher TR bids (and as a result, higher prices) in later auctions. Inflated TR prices can deter IEs seeking to hedge their exposure to congestion, making them less likely to execute (otherwise efficient) energy trades over the interties. Contrary to an efficient outcome, the distortion from the subsidy skews the market to an outcome that in the long run benefits no one. This is of high importance to Ontario, which should avoid distribution of the TRCA surplus in ways that provide unwarranted subsidies to one or more classes of MPs.

B. Ontario Compared to Other Jurisdictions

A comparison of the treatment of congestion and import/export fees in Ontario, Australia, the EU and the various U.S. markets is provided in the Appendix.[28] Other than in the EU (wherein all TRs are traded bilaterally), all organized competitive electricity markets have some form of auction that allows market participants to acquire the rights to receive congestion revenues collected by the system operator. Unlike in Ontario, U.S. markets give certain MPs (internal load or TOs) rights to financial transmission rights ("FTR") auction revenues directly through the allocation of Auction Revenue Rights (ARRs—see ISO New England [ISO-NE], the Midcontinent ISO [MISO], PJM Interconnection [PJM} and the Southwest Power Pool [SPP]) or through the sale of allocated FTRs (see the California ISO [CAISO], the Electric Reliability Council of Texas [ERCOT] and the New York ISO [NYISO]). Alternatively, these MPs can obtain actual congestion revenues by converting ARRs into FTRs, as can other MPs who choose to buy or hold FTRs allocated to them or otherwise purchased from the auctions or bilaterally.

While TR holders are entitled to some share of the congestion revenues over the applicable paths, jurisdictions differ significantly concerning the risk associated with those rights. For example, the "fully funded" TRs in Ontario and the CAISO essentially guarantee that TR holders receive payments equal to their target allocations. Three markets (ERCOT, ISO-NE and PJM) cap upside gains for TR holders to the instruments' target allocations, but apply *pro rata* "haircuts" to TR holders if the congestion accounts are underfunded; these RTOs also track any such deficiencies and compensate them when later surpluses arise. Australia, MISO and the NYISO place all risk on TR holders, allowing them to profit from congestion above expectations but incur reductions in revenues when congestion is below expectations. By comparison, the SPP allows underfunding of TRs in the event of a congestion account deficit, with no commensurate upside to the TR holder.

Ontario's decision concerning which MPs should receive the TRCA surplus also can be informed by the choices made by other jurisdictions. Generally speaking, in U.S. jurisdictions, internal load, TOs and transmission customers with long-term firm transmission service contracts have rights to congestion rent, because they ultimately pay for the long-term costs of the transmission system. After payments to the FTR holders, three U.S. markets (CAISO, ERCOT and ISO-NE) give any remaining surplus to internal load. Similarly, PJM and the SPP allocate congestion account surpluses to ARR holders. In EU markets, intertie congestion is first allocated to optimize and improve the intertie transmission system, or otherwise used to lower transmission rates. In either case, internal loads and IEs are the resulting beneficiaries.

[28] The information in the Appendix and discussed in this section was compiled in early 2019 and may not reflect recent market evolutions that have occurred since the time when the research was completed.

C. Objectives Pursued in Other Jurisdictions

The comparison of other jurisdictions' treatment of their congestion accounts and associated revenue surpluses provided above and in the Appendix suggests that there are many approaches as to how to disburse these funds across MPs. These approaches broadly can be grouped into four objectives, which can be associated with best practices given these other jurisdictions' experiences:

- **Manage Congestion Risk for Internal Load.** This objective prioritizes recognition that internal load is ultimately responsible for paying for the long term costs of the transmission system, and so should receive all congestion revenues to cover the cost of this externality produced from competitive use of that system. The best practices for this objective would assure that internal load receives all congestion surplus remaining after TR Holders receive their target allocations.
- **Lower Transaction Charges.** Focus on this objective would reduce the service charges of all transmission customers, thus maximizing the potential for efficient power trades benefitting internal load, IEs, TOs and the broader market. The best practices for this objective require assuring that the reductions track the long-term cost of transmission service after TR Holders receive their target allocations.
- **Increase Transmission Investment and Reliability.** Optimization of existing transmission systems and/or the buildout of additional transmission capacity could benefit TOs through increases to their rate base while potentially benefitting both internal load and IEs through reduced congestion. Best practices for this objective would assure that such investments work equitably across MPs and be cognizant that efficient transmission buildouts could allow for some (efficient) level of congestion to remain in the long run.
- **Improve the Efficiency and Liquidity of the TR Market.** This would drive TR prices toward expected levels of congestion through eliminating subsidies, promoting efficient price signals and maximizing the value of the TRs as a congestion hedge. Best practices for this objective require assuring both that TR Holders receive their target allocations over time and that TRs are not oversold (thus avoiding chronic deficiencies).

Given these options, the question then turns to which of them are most appropriate for Ontario to consider when assessing the optimal allocation of the TRCA surplus.

IV. Identification of Key Objectives and Best Practices Most Relevant to Ontario

This section will draw from the prior discussions to evaluate the objectives and best practices that are most relevant to Ontario's decision concerning how to allocate future TRCA surpluses. We first discuss concepts relevant to assisting the IESO in its determination of what an "efficient" or "equitable" allocation of the TRCA surplus funds might be. We then address each of the four objectives listed above and will discuss the implications of each on the efficiency of the Ontario power market and the equitable distribution of the TRCA surplus amongst its MPs. We conclude by evaluating which of these four objectives are most compatible with the Ontario market design and its TRCA disbursement methodology.

A. What Constitutes an Efficient or Equitable Allocation of the TRCA Surplus?

We defined broadly the concepts of efficiency and equity as they apply to organized competitive electricity markets above. Below, we apply these concepts to the Ontario market generally and to the allocation of the TRCA surplus amongst MPs specifically.

1. What is "Efficient" in the Context of the TRCA Surplus Allocation?

Efficient electricity markets provide optimal least-cost solutions to delivering power while maintaining the physical requirements of the system. Efficient markets promote price convergence based on cost-causation principles, such as by rewarding transactions that flow power from lower-cost to higher cost markets. This concept applies directly to the use of Ontario's interties, over which low cost power sourced from the Province often is exported to higher cost markets in the U.S., or through which Ontario can benefit from importing cheaper power from adjacent markets at times when the HOEP is relatively high.

Transmission congestion results from competitive bidding by IEs for the use of a scarce economic resource—capacity over the interties. The addition of congestion therefore favors power trades expected to be more profitable (and, thus, bid or offered at higher or lower prices, respectively) to clear the market over those expected to be less profitable. If the bidding process is itself efficient, the resulting congestion therefore represents a competitive equilibrium for use of the intertie that maximizes its value to generation and load in Ontario and its interconnected regions.

IEs willingly accept the risk of real-time congestion when placing bids or offers over the interties, which should constrain their bids or offers to those expected to be profitable if congestion arises. Given risk aversion, some potentially profitable bids and offers will not be made for fear that the real-time HOEP might exceed expectations. This also will deter uneconomic bids, which increase market inefficiency by causing the divergence of true (cost-based) market prices and can be used intentionally for manipulative purposes.[29] The resulting market equilibrium prices are therefore efficient, as they lead to appropriate price convergence given the actual costs of congestion.

By comparison, subsidizing MPs for trades—such as by giving IEs a portion of the TRCA surplus when they are not obligated to contribute to the long-term costs of the transmission system—can encourage inefficient bids and offers over time. For example, by refunding some of the congestion that the IEs create through their competition to use the interties, this subsidy would remove part of a key market signal that disincentivizes uneconomic trades (whether placed intentionally or not). This encourages the placement of riskier bids that are more likely to reduce efficiency by diverging prices from competitive levels. Such trades also can artificially increase congestion, thus temporarily increasing payouts to current TR holders. This can cause upward price distortions in the prices paid for TRs in later auctions due to (artificially) higher expected congestion payments.

If the TRCA surplus subsidy is denied to IEs, one source of such inefficiencies will be eliminated. Fewer—but more likely to be economically efficient—trades will occur, resulting in appropriate price convergence across markets given the actual costs of congestion. Fewer trades may also cause less congestion than anticipated to the detriment of current TR holders, which can reduce the prices of TRs sold in future auctions. However, assuming that the number of TRs offered for sale at auction preserves their target allocations, this is a one-time adjustment that will improve the efficiency of the TR market. Internal load may be better, worse, or equally well off as a result of these changes, depending on the size of the reduction of ETS charges collected that benefit internal load relative to internal load's gains obtained from more efficient energy and congestion pricing and any greater share it receives from the TRCA surplus.

2. Defining an "Equitable" Disbursement of the TRCA Funds to the Various MPs

An "equitable" distribution of rates follows cost-causation principles that lead to a rate design that is non-discriminatory, such that MPs with roughly the same cost of transmission service are charged roughly equivalent rates, with higher rates to MPs then justified by higher costs of service. These cost-causation principles are not followed by the current TRCA disbursement methodology. Under the present market rules, the TRCA surplus is allocated based on load shares as a percentage of total load consumed. Thus, for example, if load consumed 6,000 MWh and IEs (specifically, exporters) consumed another 4,000 MWh over the period, 60 percent of the TRCA surplus would be allocated to load and the remaining 40 percent to exporters.

A better basis for this allocation would tie to the question of which parties are obligated to pay for the *long-term* costs of the transmission system. Within the context of Ontario's entire transmission network (of which the interties are a component), the two MPs that are relevant to this calculus are: (1) TOs, which have invested in the transmission system and are owed cost recovery and a

29 This is why the FERC and EU prohibit such transactions as manipulative. See Gary Taylor, Shaun Ledgerwood, Romkaew Broehm and Peter Fox-Penner, *Market Power and Market Manipulation in Energy Markets: From the California Crisis to the Present*, PUR Inc. (April 2015), Part III.

reasonable rate of return; and (2) internal load, which is bound to pay TOs for those costs through regulated rates over time. An equitable distribution of the TRCA surplus theoretically could be accomplished several ways, through direct payments to internal load, reduction of transmission rates generally, or through the buildout of more transmission to relieve congestion.

In the context of competitive use of the interties, Ontario's exporters may claim that they too pay toward the costs of the transmission system through payment of the ETS charge. However, whereas load is obliged to pay the PTS for such costs whether the system is used or not over time,[30] exporters only pay this charge for actual use of the system on an hourly basis. Much like the regional through and out rates (RTOR) charged for exports between U.S. RTOs, these charges are for use of the transmission system for exports and should not be viewed as either investments in (made by TOs) or obligated payments for (made by internal load) the transmission system. As further evidence of this, the $1.85/MWh ETS charge was noted by the Ontario Energy Board's Market Surveillance Panel as always being well below the PTS paid by other transmission customers in Ontario,[31] which were estimated at $8.97/MWh by a 2016 estimate.[32]

Based on traditional ratemaking principles, TR Holders should have no claim to the TRCA surplus funds. TR Holders do not contribute to the costs of the transmission system, but rather pay into the TR auctions to acquire the rights to congestion payments (either as a hedge or a speculative investment). These payments are (or should be) sufficient to make the TR Holders whole, assuming that actual congestion equals that anticipated when the bids into the auction were made. Actual congestion above (or below) that expected would then provide the only gain (or loss) which the TR Holder should expect.

B. Efficiency and Equity Applied to Potential Objectives for TRCA Disbursement

In Section III(C), we identified objectives and associated best practices from other jurisdictions. We now evaluate the applicability of the objectives and best practices observed in other regions to Ontario by applying the principles of equity and efficiency described above.

30 Whereas the ETS is an energy charge measured on a $MWh basis, the PTS is a demand charge based on a $/kW basis. *See* Decision and Interim Rate Order EB-2018-0326—2019 Uniform Transmission Rates, *supra* n. 3, p. 3.

31 See Ontario Energy Board, Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2015 to April 2016" (May 2017), p. 96, n. 75, available at: https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf.

32 *See supra,* n. 22.

Manage Congestion Risk for Internal Load

As discussed above, the justification for protecting internal load from congestion cost risk stems from the fact that load is ultimately responsible for paying for the transmission system. This applies in Ontario for the same reason; since internal Ontario load is ultimately responsible for the cost of the system, it should have first claim to any excess revenues generated by the transmission assets it pays for, including the congestion surpluses that accrue in the TRCA.

No other market participant has a similar claim to the surplus TRCA funds because they do not bear the ultimate responsibility and risk of paying for the transmission system. Exporters do not; even though they pay a share of the CMSCs, they are free to exit the market and thus avoid paying for the transmission system. Nor do TOs, because they are already compensated with a guaranteed rate of return on their investments, which significantly reduces the risks they face for supplying the transmission assets. TR Holders likewise have no basis to claim a share of the TRCA surplus above that necessary to receive their target allocations, as best practices would confirm.

Lower Transaction Charges

A way to facilitate efficient, competitive transactions is to reduce the transactions costs associated with making such trades.[33] The current TRCA disbursement method approximates this outcome by returning surplus funds to both internal load and exporters, which make up the transmission customers in Ontario. However, it does not do so according to the amount of transmission charges paid by each MP, but instead uses load shares to allocate surplus funds. An efficient allocation of TRCA funds would only incentivize trades that should exist under competitive conditions. Further, the principle of equity would suggest that the MPs that are responsible for the long-term costs of the transmission system are entitled to have their transmission charges lowered, not the entities that are paying a short-term transmission usage fee. Allocating funds to Ontario exporters to lower their transmission service charges would likely result in inefficient exports, particularly so because the ETS charge is already below the PTS charge paid by internal Ontario load for transmission service.

Increase Transmission Investment and Reliability

In theory, TRCA surplus funds could be used to subsidize the buildout of new transmission assets to reduce (or eliminate) congestion on the interties, or to support the operation and maintenance of the existing transmission system, thus supporting reliability. However, Ontario already has an existing process to identify and construct needed transmission investments through the IESO Regional Planning Process.[34] Moreover, there is concern about how this allocation would achieve

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33 Coase, R. H. *The Problem of Social Cost.* October 1960.

34 After needs are identified, Hydro One works with the IESO to develop a case to explain those needs, identify alternatives, explain the rationale for selecting the transmission option (the most cost-effective and reliable option), and provide cost breakdowns and supporting evidence. Hydro One then submits a Leave to Construct application to the OEB to get the project and costs approved. Once approved, Hydro One proceeds with the construction and tracks all costs in a deferred account during the

efficient and equitable outcomes. The prospect of blindly allocating funds to transmission projects purely in the interest of eliminating congestion without properly weighting the long term costs and benefits of those projects risks inefficient capital investments. Likewise, internal transmission investments may benefit some MPs disproportionately and others not at all, which would violate equity principles.

Improve the Efficiency and Liquidity of the TR Market

The TR market provides the most effective congestion hedge when it is liquid, competitive, and free of subsidies so as to minimize the TRs' cost. Robust market participation in the TR auctions is desirable as it maximizes the amount of money available to fund payouts to TR holders for actual congestion experienced on the interties. Therefore, supporting robust participation in the TR market is, in theory, a valid objective for the use of surplus TRCA funds. The current system in Ontario allocates TR auction revenues to the TRCA and pays TR holders the target allocation of their TRs prior to allocating surplus funds to other MPs. The IESO also follows best practices by assuring that the amount of TRs offered at auction are not oversold. Therefore, the current system already sufficiently supports the efficiency and liquidity of the TR market, as well as ensuring the equitable treatment of TR holders.

C. Compatibility of the Four Objectives with the TRCA Disbursement Methodology

The current TRCA surplus disbursement methodology essentially allocates funds to two types of MPs—internal load and exporters—that pay transmission charges, but it does not necessarily do so in an efficient and equitable manner. An efficient TRCA disbursement methodology would distribute surplus funds in a way that does not distort MPs' economic incentives or provide the motivation to deviate from the competitive outcome (*i.e.,* the outcome that minimizes total system costs). Similarly, an equitable disbursement methodology would direct surplus TRCA funds to those MPs that are responsible for paying for the transmission system.

The four objectives must be analyzed differently for Ontario than in other jurisdictions due to the unique construction of its current market design and TR auctions. It is useful to consider each objective independently, starting from the last objective and working backwards. The fourth objective, improving liquidity in the TR market, would serve little purpose in Ontario because, unlike in the U.S. markets, the TR auction revenues do not go directly to internal load. Instead, the TR auction revenues go into the TRCA account, which is first paid out to TR holders and then disbursed, presently to internal load and exporters. The current system already supports liquidity in the TR market by using the auction revenues as a backstop to pay TR holders if congestion rents are not sufficient (because the auction revenues are already in the TRCA). Additional payments

construction period. When the construction is completed and the project is in service, Hydro One incorporates the incurred and on-going costs into its rate application to the OEB, which is included in a single set of Uniform Transmission Rates (UTRs) that apply province-wide. The incurred and on-going costs of the transmission projects are recovered after the fact through the UTRs.

to TR holders from the TRCA would only serve to distort the TR market by creating artificially high prices, which would make it harder for physical traders to hedge against the cost of export congestion. This would represent an inefficient outcome.

Similarly, the current system in place in Ontario already addresses transmission buildout (the third objective) through a separate mechanism. Ontario has a process in place to approve and implement transmission investments to improve system reliability, which has its own independent funding mechanism to ensure that projects get built. Moreover, Ontario has its own process in place for funding the necessary investments to support system reliability. The IESO is not responsible for this process, and cannot fund it through TRCA disbursements. These factors imply that the third option on the list is not a relevant objective for TRCA disbursement, and could actually contribute to inefficient outcomes if it were to lead to unnecessary transmission investments.

This leaves managing congestion risk for internal load and lowering transaction charges as the relevant objectives in the Ontario context. As to the latter, some jurisdictions would lower charges by providing surplus congestion funds directly to TOs in the region. This does not make sense in Ontario, in which Uniform Transmission Rates (UTRs) are set by the OEB and would not include a process for including TRCA surplus funds. By comparison, the current TRCA disbursement methodology effectively meets this objective by transferring funds to transmission customers (internal load and exporters) to lower their cost of using the transmission system. The IESO cannot directly influence transmission rates through TOs, but can achieve the same end through direct transfers of surplus TRCA funds to partly offset the PTS charges paid by internal load and ETS charges paid by exporters.

The best practice for managing congestion risk for internal load is to transfer surplus TRCA funds to those MPs that pay for the long term costs of transmission service yet face congestion costs due to competitive use of the transmission system. Instead, the current system allocates money to internal load and exporters semi-annually based on their aggregate load shares. To the extent that this over-allocates TRCA surplus funds to exporters, this provides a subsidy for their use of the transmission system and provides the inefficient incentive for more exports from the system (*i.e.,* this incentive may result in additional exports above what would be profitable absent the subsidy). This can result in a higher amount of exports from Ontario than would otherwise occur in a competitive market, which represents an inefficient outcome due to divergence of cross-market prices and higher HOEPs. Therefore, while the current TRCA disbursement methodology partly aligns with this objective, it does not accomplish it in an efficient, non-discriminatory manner.

V. Alternate Allocations of the TRCA Surplus

Given the potential to opt either for managing the congestion risk for internal load or reducing transaction charges for internal load and exporters, it is important to recall that the MSP stressed that IESO Market Rules require the TRCA surplus funds be used to offset transmission services charges. This would suggest that the second objective is a mandate. Considerations of efficiency and equity would require that these costs be reduced in proportion to transmission cost of service principles. The present use of load shares as an allocation mechanism for the TRCA surplus funds therefore is unlikely to produce an efficient or equitable outcome, particularly for internal load. This is consistent with the findings of the MSP (discussed above).

But what allocation would be preferable between internal load and exporters? Below, we discuss three options that the IESO might consider.

A. Option One: Allocate All TRCA Surpluses to Internal Load

As discussed above, the key efficiency and equity-based argument for Ontario's internal load to receive the entirety of the TRCA surplus rests in its responsibility to pay for the long-term costs of the transmission system through regulated rates. By definition, these are the costs of the *physical assets* needed to deliver energy to the Ontario customers, for whose benefit those assets were built. By comparison, exporters' claim to the payment of transmission costs ties only to the payment of the ETS charges for exports over the interties. However, as we discussed previously, (1) this charge is well below the transmission rates paid by other transmission customers in Ontario, and (2) the charge is only for short-term use of the intertie portion of the transmission system, with no payment made for use of internal transmission resources. Indeed, if exporters chose not to export a single MW of power over time, they would pay no ETS charges, and, in fact, would have no load share. By comparison, internal load would be forced to pay for the transmission system and the costs of the interties irrespective of their use.

Exporters might argue that giving the entire TRCA surplus to internal load is inequitable because they share in the costs of internal congestion through the payment of CMSCs and they alone pay the costs of intertie congestion on their trades. However, these are not costs that are associated with the physical transmission system, but instead are costs of the *energy* that is sent through the system. Again, if exporters chose not to export a single MW of power over time, they would pay no intertie congestion charges and pay no CMSCs. By comparison, internal load would be forced to pay for the transmission system costs of the interties irrespective of their use. Put differently, if there was no load (either internally or from exports), no one would pay CMSCs, but internal load would still be required to pay for the costs of the transmission system. This supports the key efficiency argument that internal load should be entitled to the entirety of the TRCA surplus.

B. Option Two: Split the TRCA Surpluses between Exporters and Internal Load

The current methodology for allocating the TRCA surplus based on load shares is an imprecise basis for lowering transmission rates for all transmission customers in Ontario. While the approach follows the same principles that comprise best practices in some U.S. RTOs and the EU (assuming no transmission upgrades are warranted), in those jurisdictions the actual cost of transmission service associated with serving each class is known and informs the rate reductions provided to internal load versus external transactions. Without the benefit of knowing the actual proportion of transmission costs paid by exporters through the ETS,[35] Ontario's current allocation of the TRCA surplus therefore has greater risk of subsidizing exporters to the detriment of internal load.

As compared to the status quo (which inefficiently splits the surplus based on load shares), the IESO could adopt the MSP's suggestion to use the percentages of the total TSCs paid by each group. This would tend to allocate a greater share of the TRCA surplus funds to internal load, which would provide an improvement over the status quo given the various efficiency-based and equity-based considerations discussed previously. However, to the extent that the portion of the surplus that exporters receive exceeds their contribution to the long term costs of the transmission system, the outcome would continue to over-subsidize exporters to the detriment of market efficiency.

Exporters may cite reduced TRCA surplus payments as a reason for them to withdraw a significant volume of trades from the market. This is unlikely because trading decisions are (or should be) made based on hourly margins and generally should not be influenced by TRCA surplus payments made on a semiannual basis. Internal load may or may not benefit from this re-equilibration immediately, but should benefit from the efficiencies brought by correct price signals over time.

C. Option Three: Allocate All TRCA Surpluses to Exporters

Exporters may make efficiency-based or equity-based arguments based on the value that their transactions can bring to the market. As discussed above, traders improve the efficiency of the market by equilibrating prices in pursuit of profits—*i.e.,* flowing low-priced power to higher-priced regions at a cost that allows the trader to profit overall from the trade. Competition amongst traders then reduces expected profit margins to the lowest spreads possible that cover the traders' expected costs. By this logic, anything that lowers the traders' costs allows even lower spreads to be profitable, potentially providing even greater price convergence. While this can result in higher prices paid by Ontario energy customers via the HOEP, generators benefit while cross-market

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35 A study was performed in an attempt to make this link, but it is unclear whether the study failed or succeeded in linking the ETS charge to actual transmission costs. *See* Ontario Energy Board, *Decision and Order: Hydro One Networks Inc.,* EB-2016-0160 (September 28, 2017), p. 109.

efficiency is improved. This can be particularly attractive at off-peak times when surplus energy is available, as the generation capacity (already paid for by ratepayers) is otherwise wasted.

However, this logic only follows if the cost reduction does not subsidize trades in a manner that promotes inefficient transaction—as would occur if a MP received a share of the TRCA surplus greater than its cost of transmission service would require. For exporters, this is likely in Ontario given that ETS charges are already low (and not well tied to costs) and actual internal transmission costs are not ascertainable given the current market design. Such over-allocations can incentivize transactions that would be uneconomic but-for the subsidy, potentially resulting in prices that over-converge—*i.e.,* diverge beyond that needed to create an equilibrium spread—when true costs are considered, thus providing inefficient price signals. Too much congestion also can result from the artificially-increased competition incentivized from such trades, harming Ontario internal loads through higher HOEPs and increased CMSC payments.

Irrespective of whether the current TRCA surplus payments to exporters reflect an unwarranted subsidy, discontinuation of those payments will result in fewer export transactions competing for use of the interties (and, simultaneously, internal transmission resources). Note that this does not mean that fewer MW will necessarily flow over heavily congested interties in some hours (*i.e.,* a less congested intertie is still fully subscribed), but the overall effect will be to reduce the quantity of trades scheduled—and the amount of ETS charges collected—overall.[36] However, the trades that are scheduled would reflect and reinforce price signals that are more efficient, as well as more efficient levels of congestion.

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[36] For example, because the Ontario-Michigan intertie is heavily congested in many hours, removing some exports during those hours will only reduce the congestion without affecting the size of the exports equal to the maximum transmission capacity of the intertie. That said, in less congested hours (or on less congested interties), the overall flow of MWs traded should decline.

VI. The Future of the TRCA Surplus Post-MRP

The new day-ahead/real time ("Day 2") market design to be implemented post-MRP will provide significant and needed improvements to Ontario's power markets. By adding a financially-binding day-ahead market, the IESO will provide to risk-averse MPs a cash-settled futures market within which to transact with greater price certainty and stability. A real time market will remain and function as a physical/balancing energy market much as the current market design provides. Both markets will benefit from the transition to LMPs, within which congestion costs will be identified and tracked as separate marginal congestion components (MCCs). This will separate congestion from other reliability-based charges, a key drawback of the present (CMSC-based) market design.

Rather than forcing exporters to transact in real time based on the HOEP and ICP, the new Day 2 structure will allow exporters to trade in either market paying the intertie LMP plus the ICP plus any applicable uplift charges. The TRCA would continue to be funded by congestion tied to LMPs at the interties instead of the HOEP. Thus, the essence of the TRCA—including the auctioning of TRs and the distribution of any resulting surpluses—will not necessarily change as a result of MRP. But this belies the key question: *should it change?* Specifically, should the TRCA include day-ahead intertie congestion, real time intertie congestion, or both? Further, given that internal transmission congestion will be separable from transmission costs, will it still make sense to distribute any future TRCA surpluses based on the reasoning described above as it relates to the current market design?

Regarding the first question, the U.S. RTOs provide suggestions for best practices (albeit imperfect ones). For all U.S. markets of Day 2 design, FTRs are limited to day-ahead congestion only, valued based on the MCCs at each FTR's source and sink. Initial FTR allocations (in whatever form) and subsequent auctions generally are designed to maximize the payments to load and MPs who choose to sell their rights. Congestion is then paid into the system operator's congestion account from internal transactions based on MCCs, and is paid to existing FTR Holders. Any surplus funds remaining in the congestion account are then used to fund the market's specific objectives. Note that congestion incurred on trades between RTOs are not included in these processes.

Real time congestion also has been included in some RTOs' congestion accounts (*e.g.,* see Figures A2 and A3 in the Appendix for PJM and ISO-NE, respectively). Real time congestion is addressed through LMPs, in addition to various uplift charges attributable to specific MPs or socialized across all MPs (*e.g.,* operating reserves and other ancillary services charges).[37] Traditionally, FTRs are day-ahead instruments only and do not hedge the risk of real time transmission congestion.

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[37] See, *e.g., PJM Manual 11: Energy & Ancillary Services Market Operations,* § 2.13, "Using and Calculating Locational Marginal Prices," Revision 104 (February 7, 2019), available at: https://www.pjm.com/directory/manuals/m11/index.html#Sections/213%20Using%20and%20Calculating%20Locational%20Marginal%20Prices.html.

Ontario might note a recent decision by PJM on point. Before June 1, 2017, balancing congestion cost in PJM was allocated to FTR holders. However in a January 31, 2017 FERC order, the Commission determined that allocating balancing congestion to FTR holders contributes to a cost shift between ARR holders and FTR holders, is inconsistent with cost causation principles, reduces the efficacy of FTRs as a hedge, and leads to chronic underfunding of FTRs.[38] As a result, the Commission ordered that PJM allocate balancing congestion costs on a pro-rata basis to real-time load and exports.[39] This decision to segregate real time and day-ahead congestion therefore followed cost-causation principles identified separately for the day-ahead and real time markets.

There are some parallels but also key differences between the U.S. RTOs' experience and the future Day 2 Ontario market that are worth noting. The IESO's TRs will become a hedge for day-ahead congestion only, similar to FTRs in the U.S. Likewise, the TRCA could—but does not necessarily have to—include real-time congestion in its collections. But the IESO's future TRs differ from their U.S. counterparts in two important ways. First, Ontario TRs are expected to be valued based not on the difference between internal MCCs, but instead on the ICP relative to the LMP at the intertie. Second, the proceeds of Ontario's TR auctions do not inherently belong to internal load, except to the extent that the TRCA surplus allocation process allows. These differences belie why U.S. market's experience might be less relevant to Ontario's future market design.

Given the discussion above concerning the efficiency and equity-based reasons for distributing the TRCA surplus to internal load, there may be little reason why the IESO would not wish to disburse real time congestion within the balancing account unless there are aspects of the future market design that would make such inclusions risky to the fund's integrity. This is a consideration that the IESO should evaluate in the next phase of its TRCA Review.

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[38] PJM Interconnection, L.L.C., *Order on Rehearing and Compliance*, 158 FERC ¶ 61,093 (January 31, 2017), P 54.

[39] *Id.,* P 124.

VII. Conclusion

Given the current and future market design of the Ontario power market, changes to the TRCA surplus disbursement methodology should be mindful of the principles of efficiency and equity that are discussed herein. While the benefits of a successful competitive market design can benefit all market participants in the long run, constant adjustments will need to be made that in the short term can benefit one or more groups of participants over others. Such changes are consistent with the underlying principles of rate design as long as they are non-discriminatory in their application. This may necessarily mean that (at times) improvements in market design will appear to advantage one group over another, when in fact the movement reflects a change to a more equitable and efficient outcome for the market as a whole.

Given the three options presented above, the IESO and its stakeholders should keep in mind the distinction in the character or payments made by different market participants—in particular, the difference between payments required to support the long-term cost of the transmission system (such as the PTS charges paid by internal load) and payment required as a transaction cost for flowing energy over the system (such as congestion charges). At first blush, the ETS charges paid by exporters seem like a hybrid of these two types—*i.e.,* they pay the cost of transmission service, but do so on a per MWh basis as a transaction cost for flowing power over the interties. However, an important distinction is that exporter *chooses* to pay ETS charges as a function of seeking to export power in pursuit of profits, whereas internal load *must* pay the PTC irrespective of whether any power flows on the system at all. Equitable considerations suggest that any revenues earned from use of the system should therefore flow to internal load—including any TRCA surpluses.

Should the determination be made that exporters should continue to receive a portion of the TRCA surplus because they pay transmission service charges through the ETS, ratemaking principles dictate that the portion of the surplus they receive should be scaled to match their contribution to the long term costs of the transmission system. Continual overpayments from the TRCA surplus (which the present system has been found to encourage) serve only to over-subsidize exporters, to the inequitable detriment of internal load and to the encouragement inefficient power exports.

Appendix: Congestion in Other Markets

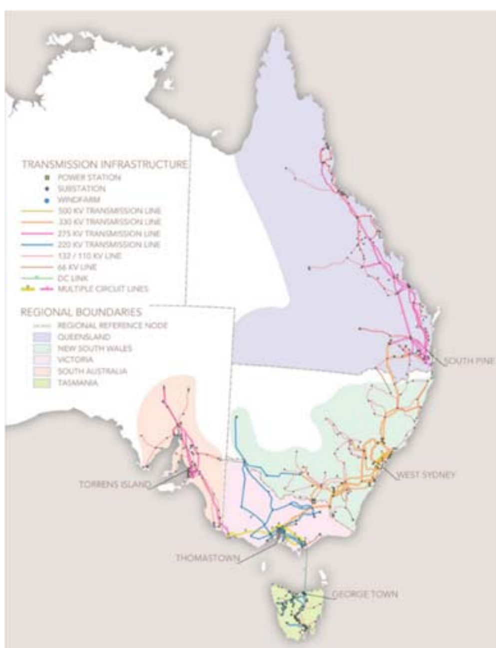
In this appendix, we present a survey of how organized competitive electricity markets in other jurisdictions treat congestion revenues and payments. We begin by discussing the Australian and EU approaches to the problem which have aspects that are similar to the current market design used in Ontario. Next, we discuss the treatment of congestion in organized U.S. electricity markets, which will provide examples that are relevant to the "Day 2" market design that the IESO will administer post-MRP. While structured somewhat differently than how the Ontario market will be designed post-MRP (particularly with respect to an anticipated lack of internal TRs in Ontario), these examples provide insight as to how other system operators allocate congestion surpluses amongst various MPs. We then conclude by providing a table that summarizes key aspects of these systems and compares them with the system of TRs used in Ontario.

The reader should note that much of the information provided in this Appendix was compiled in early 2019 and may not reflect the most recent market evolutions that have occurred since the time when the research was completed.

A. The Australian National Energy Market

The National Electricity Market (NEM) in Australia covers the eastern half of the country. The NEM is not a nodal market; rather prices are set at a zonal level where each state makes up its own price zone, shown below in Figure A1. Therefore, MPs do not face congestion risk when trading within a price zone (*i.e.,* within each state), as all generators receive and all loads pay the same price within each price zone.

Figure A1
Map of the Australian National Electricity Market



Source: AEMC (2018), "National Electricity Market", January 2018.

However, MPs do face congestion risk when trading between states. These congestion rents are calculated and settled as part of the Inter-Regional Settlement Residue (IRSR). Rights to a share of the IRSR are auctioned off to allow MPs to hedge their price differential risk between zones. Revenues from the auctioning of IRSR shares are distributed back to TOs for the corresponding interconnection between the states (price zones). The auction winners are entitled to a share of the IRSR over a specified time period. The size of the shares varies depending on how much is purchased at auction. Since the IRSR is made up of the collected congestion rents between price zones, the IRSR shares are effectively similar to TRs sold in other jurisdictions in that they entitle their holders to a portion of the associated congestion rents. If any shares of the IRSR are not sold in the auction, they are given to the TOs who then collect that share of the IRSR.

Since IRSR shares only entitle their holder to a *share* of the congestion rents collected, shortfalls and surpluses in the fund do not occur. If congestion is higher than expected in a certain period, the IRSR shares for that period receive a higher than expected payout. Similarly, if congestion is lower than expected in that period, the share receives a smaller than expected payout. IRSRs also can be negative in the event of counter-flows,[40] meaning the instruments mimic TR obligations, not options like those used on the Ontario interties. Negative IRSRs are recovered from internal load as part of network charges.[41]

B. European Markets

The EU also shares characteristics that are similar to the current Ontario market design. Each EU member country has (or, once the EU market design is fully implemented, will have) a single Transmission System Operator (TSO) with a single zonal price. Price differentials occur at the borders between countries along interties (referred to as "interconnectors"). The TSOs own all of the interconnectors and there are no financial products sold by the TSOs for hedging thereon. The price differentials between countries allow for the TSOs to collect congestion rents based on the physical system, while market participants are left to trade TRs obtained from the bilateral market or to trade swaps tied to the zonal prices of the TSOs (*i.e.,* as a "dirty" hedge against congestion).

The European Union Commission Regulation directs revenue generated from congestion rents obtained from the interconnectors to be used for two primary purposes: the first is to guarantee that allocated capacity at the interconnectors is actually available (*i.e.,* system optimization); the second is to increase the interconnection capacity by maintaining current lines and investing in the network by funding new interconnectors (*i.e.,* transmission buildout).

To prevent the subsidization of inefficient transmission investments, a caveat in the tariff states that if the revenues in the congestion fund "cannot be efficiently used for the purposes set out" in

40 See for example, AEMC (2014), "Management of negative inter-regional settlements residues", February 2014.

41 *Id., p. i.* Negative IRSRs are managed by the market operator, by restricting counter-price flow, so that they do not exceed $100,000.

the points above, then they can be used as "income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs and/or fixing network tariffs."[42] This suggests that if all beneficial transmission optimizations and upgrades as determined by each TSO (and approved by the EU Commission) have been performed, the congestion rents can be used to reduce the cost of transmission service, to the ultimate benefit of the users of the TSO network system—*i.e.,* IEs and the loads that benefit from competitive trading across markets.

C. U.S. RTO/ISO Markets

1. Congestion in U.S. Markets

All organized U.S. markets have some type of financial transmission rights (FTRs) and congestion accounts in place. As a broad matter, these programs share several common aspects. Some rights (either to auction revenues or the congestion revenues themselves) initially are allocated to internal load and/or TOs, while others are retained by the Regional Transmission Operators (RTOs). The allocated rights sold by their holders and RTO rights are then made available to physical and financial MPs through one or more competitive auctions. FTR payments are funded by actual congestion rents collected from the day-ahead market and auction proceeds. All system operators maintain a congestion account, through which all auction and congestion rents are deposited and from which all FTR (or, if applicable, ARR) payments flow. RTOs allow FTRs to be acquired at auction by any registered entity or through bilateral transactions between a FTR holder and a buyer so as to maximize liquidity in the instruments.

However, some differences exist across markets with respect to the tenors of FTRs made available (*e.g.,* multi-year, annual, seasonal or monthly), the nature of the rights allocated in advance of the auctions (as either FTRs or Auction Revenue Rights [ARRs]), and the treatment of congestion account overfunding or underfunding once actual congestion payments are realized. As to the latter, there are differences between jurisdictions on which MPs are eligible to receive excess congestion rents after all ARR and/or FTR holders have been paid, or are responsible for any deficits owed to ARR and/or FTR holders in the event that congestion rents are inadequate to cover the outstanding obligations.

42 *Id.*

a. ARR/FTR Markets

i. PJM

I. Description of the Market

PJM maintains a two-tiered system of financial transmission rights tied to congestion in the Day-ahead market. The first is through the allocation of ARRs, which are entitlements allocated to Firm Transmission Service Customers that entitle their holders to receive an allocation of the revenues from PJM's annual and monthly FTR Auctions.[43] The second is through the auction of FTRs, which occurs annually for the upcoming three planning periods ("annual" FTRs for year 1 and "long-term" FTRs for years 2 and 3) and on a monthly basis. Parties seeking to hedge congestion costs that are not allocated ARRs must therefore procure FTRs either from these auctions or bilaterally.[44]

From an ARR holder's perspective, there are three ways to receive payments from this system. First, the ARR holder can keep the ARRs and receive payments from the FTR auctions. Second, the ARR holder can "self-schedule" the ARRs to convert them on a MW-for-MW basis into FTRs, which then entitles the holder to receive a share of the actual congestion payments collected by the RTO over the associated transmission path. Third, the ARR holder can convert the ARRs into FTRs and sell them in the PJM FTR auctions or bilaterally.[45]

To maximize the value received from FTRs sold into PJM's auctions, it is necessary to maximize the number of market participants that are willing to bid on the offered paths. For this reason, financial market participants are allowed to participate in PJM's FTR auctions and acquire FTRs as speculative investments. Rationally, this should allow an ARR holder to receive compensation from the auction in an amount equal to the maximum congestion expected over the path, reflected by the highest bid(s) offered by the auction's winner. ARR holders who self-schedule and sell their FTRs likewise benefit.

However, because actual congestion experienced over a path can exceed the congestion anticipated in the auction, load-serving entities opting to keep their ARRs (or sell their self-scheduled FTRs) risk under-hedging, with the difference in actual congestion payments benefitting the FTR

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43 ARRs are allocated in a two-step process. The first stage allocates ARRs to protect native load's utilization of the transmission system with the goal of providing long-term certainty (*i.e.*, customers who historically served load in each area). The second stage allows for reassignment of the ARRs on a proportional basis within a zone as load switches between LSEs within the planning period. See PJM State & Member Training Dept, "PJM ARR and FTR Market", January 2016, slides 31-34.

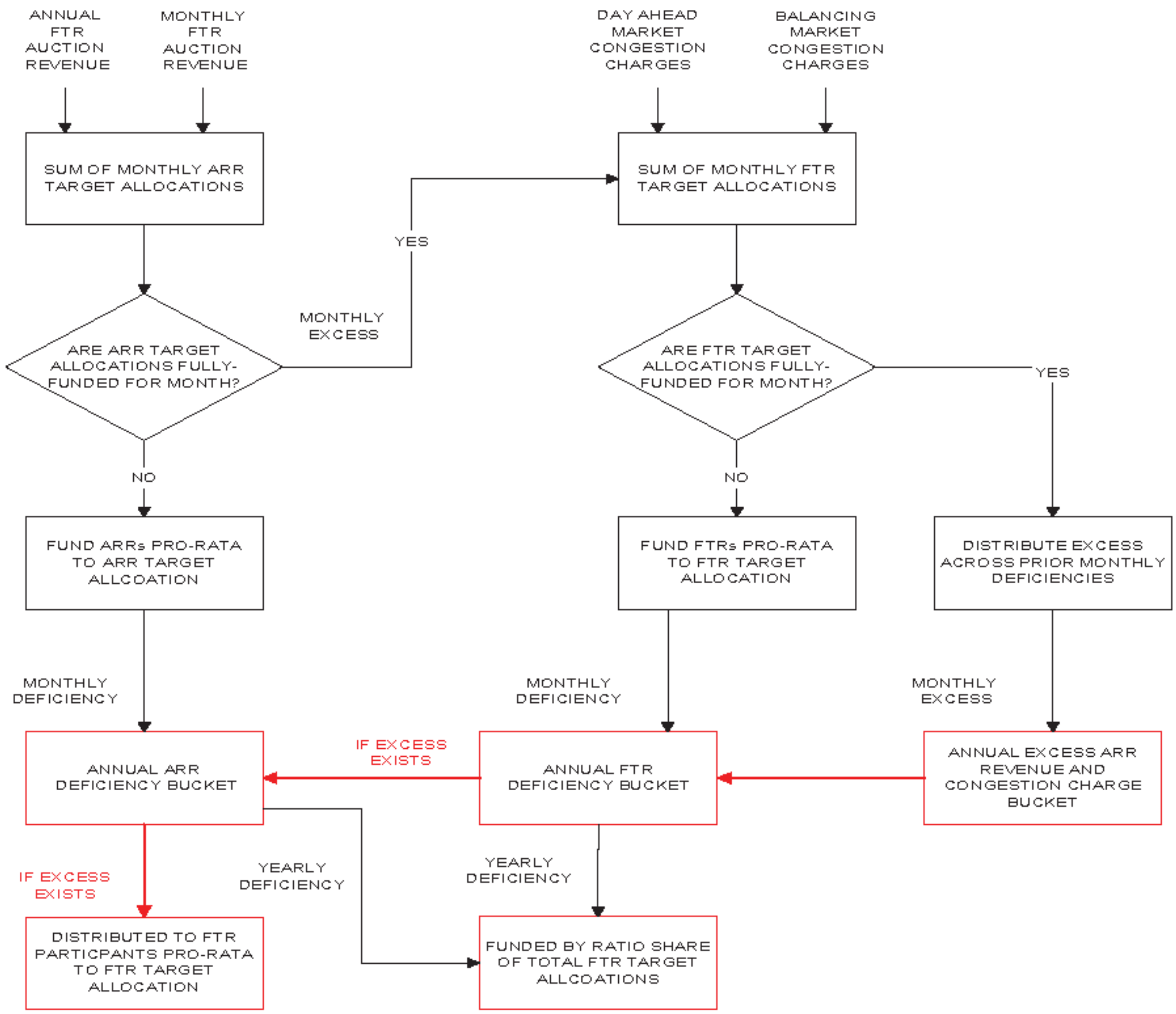
44 *Id.,* slide 86, discussing PJM's Secondary Market. Market participants can also procure FTR-equivalent hedges bilaterally outside of PJM through Nodal Exchange. See http://www.nodalexchange.com/.

45 *Id.,* slides 35, 77-85.

purchaser. This can result in perceived wealth transfers that are viewed negatively by the public, particularly if the FTR holder is a financial market participant.[46]

PJM's process of funding ARRs and FTRs is somewhat complex, described as of 2016 in Figure A2:

Figure A2
PJM's Process of Funding ARRs/FTRs[47]



46 See, *e.g.*, Julie Creswell and Robert Gebeloff, " Traders Profit as Power Grid Is Overworked," *New York Times*, Aug. 14, 2014, available at: https://www.nytimes.com/2014/08/15/business/energy-environment/traders-profit-as-power-grid-is-overworked.html.

47 PJM State & Member Training Dept, "PJM ARR and FTR Market", January 2016, slide 115. Note that real time balancing market congestion charges no longer are paid into the congestion account and excess distributions are now paid to ARR holders (not FTR holders) on a *pro rata* basis.

As described by PJM in 2016,[48] long-term, annual and monthly FTR auction revenues are distributed to ARR holders in proportion to (but not to exceed) the economic value of the ARRs when compared to the Annual FTR Auction clearing prices for FTR Obligations from each round proportionately. Long-term FTR auction revenues associated with FTRs that cover multiple planning years are distributed equally across each planning period in the effective term of the FTR. Excess revenues after distribution to ARR holders are used to fund any shortfall in FTR target allocations over the Planning Period. These funds are accounted for on a monthly basis, with any deficiencies tracked cumulatively.

FTR holders are compensated monthly using the actual Transmission Congestion Charges (TCCs) derived from the Day-ahead and (prior to 2017)[49] balancing energy markets, with deficiencies tracked cumulatively. If there is an excess in the TCCs recovered, PJM allocated it using a five-stage process:

1. Stage One - PJM distributes excess TCCs accumulated during the month to each holder of FTRs in proportion to, but not greater than, any deficiency in the share of TCCs received by the holder during that month.
2. Stage Two - Any remaining excess after the stage one distribution is used to satisfy any FTR deficiency from previous months within the planning period on a pro-rata basis up to the full FTR Target Allocation value.
3. Stage Three – Any remaining excess after the Stage Two distribution is carried forward to the next month as Excess Congestion Charges.
4. Stage Four - At the end of the planning period, any remaining Excess Congestion Charges are first used to satisfy any ARR deficiency that may exist. If insufficient funds exist to honor all ARR revenue shortfalls, then the funds would be distributed by ratio of the ARR deficiency.
5. Stage Five - PJM distributes any excess TCCs remaining after the Stage Four distribution to all FTR holders on a pro-rata basis according to their net FTR target allocation position for all FTRs held at any time during the relevant Planning Period. An entity with a net negative FTR target allocation position is not subject to this excess distribution.

Any revenue-deficient transmission rights (ARRs or FTRs) remaining at the end of the planning period are satisfied through a transmission rights uplift credit, the costs of which are allocated as charges to FTR holders on a pro-rata basis according to their net FTR target allocation position, relative to the total net FTR target allocation positions of all FTR holders in the PJM Interchange Energy Market. An entity with a net negative FTR target allocation position is not subject to transmission rights uplift allocation charges and is excluded from the uplift charge calculations.

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48 *Cf.* PJM, "PJM Manual 6: Financial Transmission Rights, Revision 20", June 2018, pp. 51 and 54, which now show that Stage Five excesses are paid to ARR holders.

49 See PJM Interconnection, L.L.C., 156 FERC ¶ 61,180 (2016); PJM Interconnection, L.L.C., *Order on Rehearing and Compliance*, 158 FERC ¶ 61,093 (January 31, 2017), P 54.

II. *Issues with PJM's ARR/FTR Protocols*

Because any excess TCCs under this system ultimately are paid to FTR holders—many of whom are financial market participants—PJM undertook changes to their treatment of ARR/FTR surplus funds to divert more of these revenues to protect load. In addition to allocating balancing energy congestion charges to load, PJM undertook a proposal to assure that all surpluses in excess of those needed to fully fund FTR target allocations would be allocated to ARR holders on a pro-rata basis.[50] PJM's Independent Market Monitor (IMM) went further, observing that flaws in the existing system are caused by the archaic nature of how it was created when PJM was first created:

> The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with rights to all the potential congestion revenues… One of the reasons for this inefficiency is the link, established by PJM member companies in their initial FTR filings prior to the opening of the PJM market, between congestion revenues and specific generation to load transmission paths. The original filings, made before PJM members had any experience with LMP markets, retained the contract path based view of congestion rooted in physical transmission rights. In an effort to protect themselves, the PJM utilities linked the payment of FTRs to specific, physical contract paths from specific generating units to specific load zones. That linkage was inconsistent with the appropriate functioning of FTRs in a nodal, network system with locational marginal pricing but it served as a reasonable approximation in the early years, although that is no longer true. The ARR allocation in 2015 continued to be based on those original physical generation to load paths, an illustration of the inadequacy of that approach and a source of the issues with the FTR model in 2015.[51]

The IMM used this observation to justify the scrapping of PJM's present system, arguing:

> If the original PJM FTR design had been designed to return congestion revenues to load without use of the generation to load paths, many of the subsequent issues with the FTR design would have been avoided. The design should simply have provided for the return of all congestion revenues to load…This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.[52]

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50 See PJM, "Day Ahead Surplus Congestion and FTR Auction Revenue Surplus Funds," January 25, 2018, available at: https://www.pjm.com/-/media/committees-groups/committees/mc/20180125/20180125-item-01c-ftrmps-day-ahead-surplus-congestion-and-ftr-auction-revenue-solution-presentation.ashx.

51 Marketing Analytics, "2017 State of the Market Report: Section 13: FTRs and ARRs", Dec, 2018, pp. 1-2, available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017-som-pjm-sec13.pdf.

52 *Id.,* p. 2.

While not allowing this drastic change, PJM applied for and the FERC approved the future ability of PJM to allocate revenues greater than 100 percent of those necessary to fully fund the FTR target values to ARR holders on a *pro rata* basis.[53]

ii. *MISO*

MISO allocates ARRs based on firm historical usage of the transmission network. This includes (1) Firm PTP transmission service reservations of annual duration or longer, valid during the previous year, (2) Network Integration Transmission Service for network load from qualifying reserved source points valid during the previous reference year, and (3) grandfathered agreements as defined in the tariff.[54] Incremental ARRs may be allocated for network upgrades and for new and replacement network resources.[55] All ARR allocation is subject to simultaneous feasibility tests, and the ARRs allocated are obligations, not options.[56]

As with PJM, MISO allows ARR holders to self-schedule their ARRs on a MW-for-MW basis into FTRs, which can then be sold at auction with other FTRs made available by the RTO. MISO holds an annual FTR auction in which peak and off-peak FTRs are available for each season in the coming planning year, and multi-period monthly auctions (MPMAs) in which monthly and seasonal FTRs are auctioned off.[57] MISO also allows trading of existing FTRs through a secondary market.[58]

MISO's process for funding its FTRs generally is consistent with the historical (pre-2018) process described above in Figure A2 for PJM. MISO FTR holders therefore directly bear the benefits and burdens of the funding levels achieved by the MISO through the collection of balancing charges and congestion revenues, with overfunding resulting in FTR holders receiving a premium above their target allocations and underfunding resulting in a concomitant "haircut." However, the MISO IMM observed that "[a] large share of the value of these rights is allocated to participants,"[59] suggesting that overpayments should ultimately benefit load if auction values reflect actual congestion (thus benefitting ARRs) or if load retains self-scheduled FTRs.

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53 Order Accepting Proposed Tariff and Operating Agreement Revisions, 163 FERC ¶ 61,165, May 31, 2018, available at: https://www.ferc.gov/CalendarFiles/20180531160639-ER18-1245-000.pdf.

54 MISO, "Level 200 - Auction Revenue Rights and Financial Transmission Rights," slide 28, available at: https://cdn.misoenergy.org/Level%20200%20-%20ARRs%20and%20FTRs119130.pdf.

55 MISO, "MUI User Manual," March 1, 2017, page 6, available at: https://cdn.misoenergy.org/FTR%20MUI%20User%20Manual104860.pdf.

56 *Id*.

57 Potomac Economics, "2017 State of the Market Report for the Miso Electricity Markets," June 2018, p. 59, available at: https://www.potomaceconomics.com/wp-content/uploads/2018/07/2017-MISO-SOM_Report_6-26_Final.pdf.

58 MISO, "Level 200 - Auction Revenue Rights and Financial Transmission Rights," slide 63.

59 Potomac Economics, "2017 State of the Market Report for the Miso Electricity Markets," p. 55.

This assumes that (1) the MISO accurately models its system constraints and (2) that auction values provide a good approximation of actual congestion.[60] Concerning the first point, the IMM noted that transmission outages and loop flows resulted in significant underfunding of the FTR account, as did export constraints into the SPP.[61] The IMM suggested improving coordination of marked-to-market settlements with PJM and the SPP, as opposed to relying on TLRs or other congestion management protocols.[62] The IMM observed that while FTRs sold in the annual auction generally performed well, those sold in the MPMAs tended to underperform.[63] The IMM suggested that this problem was due to lack of liquidity in the MPMA.[64]

iii. SPP

In March 2014, SPP converted to a "Day 2" design, including the introduction of a FTR product it refers to as Transmission Congestion Rights (TCRs). According to the SPP tariff, the TCR process includes an annual Long-term Congestion Right (LTCR) allocation, an annual ARR allocation, annual and monthly TCR auctions and a monthly ARR allocation.[65] Eligible participants with firm transmission service through Network Integration Transmission Service (NITS), point-to-point transmission or Grandfathered Agreements (GFAs) can opt for either LTCRs or ARRs under the tariff, but must nominate them to be in effect.[66] The SPP allocates ARRs based on transmission service sufficient to meet up to 103 percent of each network transmission owner's annual peak load and all point-to-point service.[67] All LTCRs, ARRs, and TCRs are subject to a simultaneous feasibility test.[68]

Like PJM and MISO, SPP allows market participants to convert ARRs into TCRs. SPP holds TCR auctions annually "for all months and seasons" of the next year,[69] and monthly thereafter based on

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60 "If the FTRs issued by MISO are physically feasible, meaning that flows over the network sold as FTRs do not exceed limits in the day-ahead market, MISO will always collect enough congestion revenue through its day-ahead market to "fully fund" the FTRs (*i.e.,* to pay them 100 percent of the FTR entitlements)." *Id.*

61 *Id.,* pp. 56-59.

62 *Id.,* pp. 63-65.

63 *Id.,* pp. 59-62.

64 *Id.,* pp. 61-62.

65 Southwest Power Pool, "Open Access Transmission Tariff, Sixth Revised Volume No. 1," Attachment AE Integrated Marketplace, February 27, 2018, p. 199.

66 *Id.,* pp. 209-211 and 214-219.

67 *Id.,* pp. 212-213; SPP Market Monitoring Unit, "2016 Annual State of the Market Report," August 10, 2017, p. 126, available at: https://www.spp.org/documents/53549/spp_mmu_asom_2016.pdf.

68 Southwest Power Pool, "Open Access Transmission Tariff," pp. 216-217, 220, 224, 227, 229 and 235.

69 *Id.,* p. 225.

subsequent simultaneous feasibility tests.[70] TCRs are then paid from the day-ahead congestion charge differential of the relevant sink/source pair. To the extent that the day-ahead market does not provide sufficient congestion revenues to support the full value of all payments to TCR holders for a given day, SPP charges each TCR holder a share of the underfunding proportional to the absolute value of its TCR portfolio for that day.[71]

SPP has had persistent problems with the overselling of TCRs in excess of what was required to fund ARR payments, resulting in a surplus of funds that was allocated proportionately to ARR holders.[72] This system has been faulted by the SPP market monitor as resulting in the persistent underfunding of TCRs (94% in 2017) and overfunding of ARRs (164% in 2017).[73] As a result, it noted that TCR owners "may have paid too much for their transmission congestion rights, but instead of receiving a refund, the over-payment was allocated to the auction revenue right holders."[74] This is seen as evidence of a potentially inequitable shift of funding from TCR customers to the subset of SPP customers with long-term firm transmission service (and thus eligible for ARRs).[75] Further, within groups of LSEs holding ARRs, some were found to have been under-hedged while others were over-hedged, but the market monitor found this to be the result of under-nominations of ARRs.[76]

iv. *ISO-NE*

ISO-NE operates a FTR/ARR market on both an annual and monthly basis. The ISO allocates ARRs to congestion-paying LSEs and incremental ARRs to entities paying for transmission upgrades.[77] The ARRs are allocated during a four-stage process that includes a simultaneous feasibility test.[78] FTRs in ISO-NE are directional and structured as obligations.[79] FTRs are sold at auction at the

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70 *Id.,* pp. 231 and 235.

71 SPP Market Monitoring Unit, "2016 Annual State of the Market Report," pp. 125-126.

72 *Id.,* p. 126.

73 SPP Market Monitoring Unit, "2017 Annual State of the Market Report," May 8, 2018, p. 160, available at: https://www.spp.org/documents/57928/spp_mmu_asom_2017.pdf.

74 *Id.,* p. 164.

75 *Id.,* pp. 164-165.

76 *Id.,* pp. 156-157.

77 Grandfathered agreements may also receive ARR allocations.

ISO-NE, "ISO New England Manual for Financial Transmission Rights, Manual M-06," October 4, 2018, p. 7-2, available at: https://www.iso-ne.com/static-assets/documents/2018/10/manual_06_financial_transmission_rights_rev11_20181004.pdf.

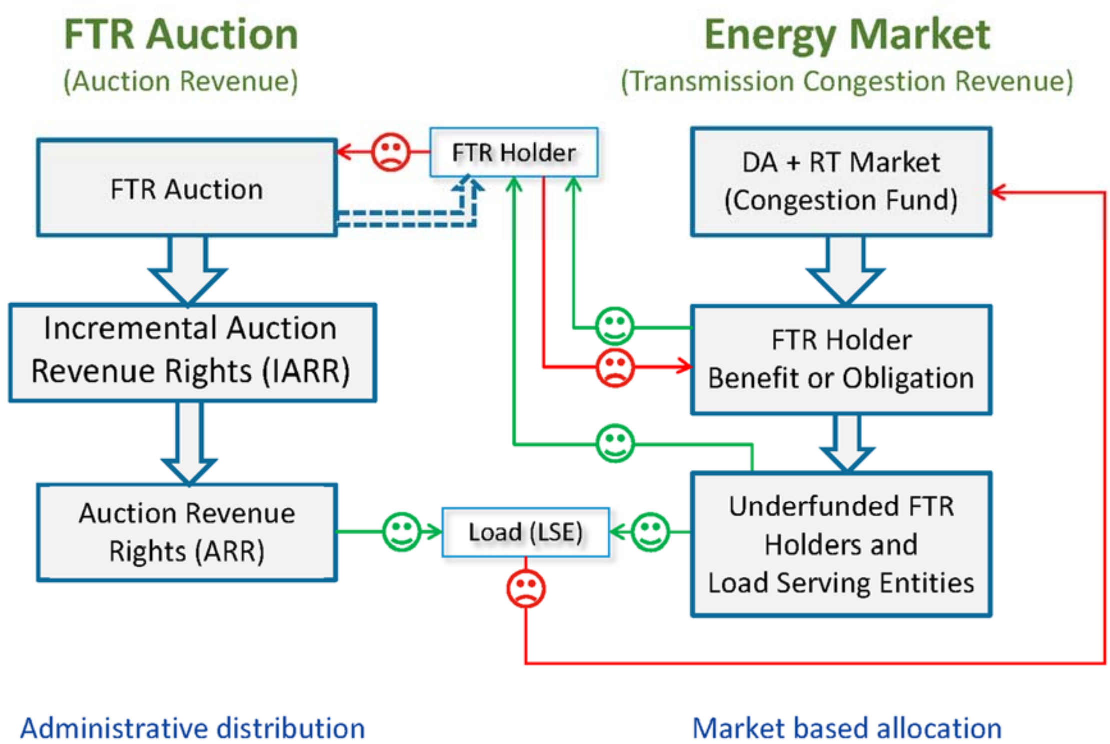
78 ISO-NE, "Transmission, Markets, and Services Tariff," Section III: Market Rule 1, Appendix C, January 1, 2013, Section III.C.2-II.C.5, available at: https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_c.pdf.

79 ISO-NE, "ISO New England Manual for Financial Transmission Rights, Manual M-06," p. 1-1.

market-clearing price, equal to the bid value of the marginal FTR which could not be sold.[80] Any FTR holders may also offer previously acquired FTRs into the FTR auctions, optionally specifying a reservation price below which they refuse to sell.[81] Up to 50% of system capacity may be offered in annual auctions, and up to 95% of system capacity may be offered in monthly auctions.[82]

ISO-NE's process of funding ARRs and FTRs is shown below in Figure A3, with payments shown in red and revenues shown in green:

Figure A3
ISO-NE ARR and FTR Revenue Stream[83]



In the event of a congestion revenue deficiency, payments to FTR holders are reduced in proportion to the magnitude of the target allocations for each FTR holder.[84] Any congestion revenues surpluses are held until the end of the calendar year, at which time they are paid out first to FTR holders who were paid less than their due allocations during revenue deficient months,

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80 ISO-NE, "Transmission, Markets, and Services Tariff," Section III.7.3.6.c.

81 *Id.,* Section III.7.3.5.b.

82 ISO-NE, "Financial Transmission Rights (FTRs)," presented at the ISO-NE Introduction to Wholesale Electricity Markets Orientation Course held September 24-28, 2018, p. 21, available at: https://www.iso-ne.com/static-assets/documents/2018/10/20180924-11-wem101-financial-transmission-rights.pdf.

83 ISO-NE, "Financial Transmission Rights (FTRs)," slide. 30.

84 ISO-NE, "ISO New England Manual for Financial Transmission Rights, Manual M-06," pp. 6-4 - 6-5.

plus interest.[85] After all deficiencies have been compensated, any remaining revenue excess is allocated to transmission customers *pro rata* with total yearly net congestion costs.[86] If excess transmission congestion revenues are insufficient to reimburse all of the target allocation deficiencies plus interest, all surplus revenues are paid out proportionally to the deficiencies that each participant holds relative to the total.[87]

b. *FTR Markets*

i. *The CAISO*

I. *Description of the Market*

The California ISO (CAISO) offers a single FTR product it refers to as Congestion Revenue Rights (CRRs). The CAISO offers CRR obligations or options in several tenors, including monthly, seasonal, and long term annual products out to ten years, including for peak and off peak periods.[88] The number of CRRs made available to the market is determined by Simultaneous Feasibility Tests, with a portion of the available long-term annual and seasonal CRRs are allocated to load or eligible merchant transmission.[89] The CRR process removes other types of contracts ["Transmission Ownership Rights" (TORs) and "Existing Transmission Contracts" (ETCs)] from the model, as these are viewed by the system as perfectly hedged against congestion.[90]

A portion of the available long-term annual and seasonal CRRs are allocated to Load-Serving Entities (LSEs), Out of Balancing Authority Area Load Serving Entities (OBAALSEs), or eligible merchant transmission, based on a four-tiered system.[91] The annual CRR auction is performed after these allocations are complete. After adjusting for load migration,[92] monthly CRRs are allocated to LSEs and OBAALSEs based on a two-tiered system.[93] The annual and monthly CRR auctions are performed after these allocations are complete.

Whether allocated or procured by auction, all CAISO CRRs pay their holders the difference between the actual day-ahead congestion components of the LMPs at the CRR's sink and source. Thus, the process for funding is (at least in theory) relatively simple, shown below in Figure A4.

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85 *Id.,* p. 6-5.

86 *Id.*

87 *Id.*

88 CAISO, "Congestion Revenue Rights (CRR): CRR Basics Overview Training Course," May 15, 2014, slides 11-13, available at: http://www.caiso.com/Documents/CongestionRevenueRightsOverviewPresentation_Printable.pdf.

89 *Id.,* slides 76-77 and 85-92.

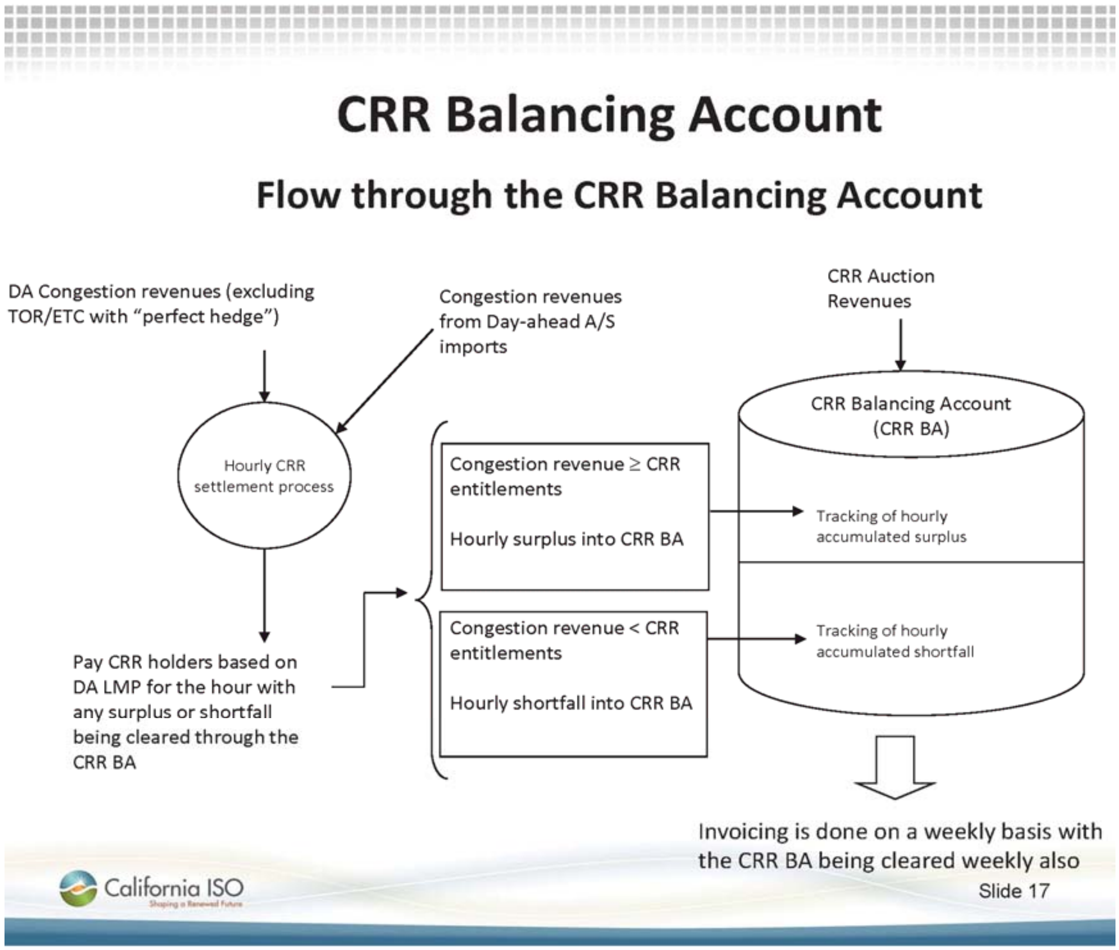
90 *Id.,* slides 98-100.

91 *Id.,* slides 76-77 and 85-92.

92 *Id.,* slides 101-112.

93 *Id.,* slides 93-97.

Figure A4
CAISO's Process of Funding CRRs[94]



The CRR balancing account is funded initially through auction revenues and then through revenues from congestion payments. As congestion occurs on an hourly basis, load pays congestion while CRR holders are paid congestion rents. Because the size (in MW) of the CRR positions auctioned by the CAISO can differ from the size of the load at the CRR's source and sink, the net revenue can be either positive or negative, thus adding to or drawing down the account. CAISO CRRs are "fully funded," meaning that their holders are guaranteed payment of the CRRs' target allocations. Negative balances must be paid by load, while surpluses are allocated to load. The account is cleared weekly, with load invoiced and CRR holders compensated.

94 *Id.,* slide 17.

II. *Issues with the CAISO's CRR Protocols*

In 2016, the CAISO Department of Market Monitoring (DMM) issued a whitepaper that described problems with its CRR market design.[95] Therein, it noted that "[r]atepayers lost $520 million in the CRR auction from 2012 through 2015. Ratepayers paid $970 million to non-LSE CRR holders but received only $450 million in auction revenues. For every dollar paid to non-LSE CRR holders, ratepayers received just 46 cents."[96] The DMM blamed the chronic shortfalls on its inability to accurately model constraints in the auctions relative to actual Day-ahead outcomes.[97] This would effectively cause the CAISO to auction off more MW of CRRs than actual Day-ahead loads could support through congestion payments, thus causing chronic underfunding that would profit CRR holders (often financial market participants) at the expense of CAISO ratepayers.

As discussed above with respect to the efficiency of FTR market auctions, this should be a self-correcting problem. The lure of profits should incentivize auction market participants to bid more for profitable paths and incentivize LSEs and other holders of allocated CRRs to raise their offer prices, which should increase auction revenues sufficiently to abate the underfunding problem. Further, the ratepayers could acquire the CRRs themselves, thus giving them the ability to hedge (or over-hedge) against uplift charges due to CRR balancing account deficiencies.

However, the DMM noted that the CAISO's CRR market has features that inhibit these responses. Allocated CRR holders are required to offer those CRRs into the auction as price takers ($0/MW), preventing their ability to set auction prices higher.[98] Likewise, "[r]atepayers face significant economic, regulatory and technical hurdles restricting them from effectively bidding in the CRR auction." The DMM was less certain as to reasons why competition has not driven auction prices higher, although it speculated that high entry costs (due to a need for specialized experience, high collateral costs and risk) could be deterring entry.[99]

Given these problems, the DMM recommended in its whitepaper replacing the CAISO CRR auction process with a bilateral CRR auction, such that willing counterparties would assume the risk of excessive congestion payments with no risk to CAISO ratepayers.[100] In later filings before the FERC, the CAISO instead applied to (1) improve the efficiency of its CRR auctions by correcting its models to better account for transmission outages and accurately reflect CRR source-

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95 CAISO DMM, "Shortcomings in the congestion revenue right auction design," November 28, 2016, available at: https://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf

96 *Id.,* p. 8.

97 *Id.,* pp. 11-13.

98 *Id.,* pp. 13-14.

99 *Id.,* pp. 14-15.

100 *Id.,* pp. 15-16.

sink pairs,[101] and (2) allow the CAISO to no longer fully-fund CRRs, instead addressing underfunding by applying pro rata haircuts to the affected CRR holders.[102] The FERC approved the CAISO's first request,[103] while the second is under consideration by the Commission at the time of this writing.

ii. NYISO

The NYISO offers a single FTR product referred to as Transmission Congestion Contracts (TCCs). These are auctioned to market participants twice annually in centralized auctions or monthly in "reconfiguration" auctions, or can be purchased bilaterally through sales from transmission owners or through the NYISO's secondary market.[104] The annual auctions include the sale of two-year, one-year and six-month TCCs, while the reconfiguration auctions are "Balance-of-Period" auctions that allow the sale of a single month TCCs or a combination of months remaining in the period.[105] TCCs can be bought and sold as "bundled" (combined) or unbundled products, which can include intra-zonal point-to-point and/or inter-zonal TCCs.[106]

The NYISO determines the amounts of TCCs to be auctioned through an Optimal Power Flow model (*i.e.,* simultaneous feasibility test) after accounting for (and allocating TCCs to) Existing Transmission Agreements (ETAs) that pre-existed the formation of the NYISO.[107] TCCs also are allocated to LSEs with grandfathered transmission rights or market participants that increase the transfer capability of the system by constructing new, or improving existing, transmission facilities ("incremental TCCs").[108] All NYISO TCCs are sold as obligations. Auction revenues are allocated to transmission owners (thus reducing charges to ratepayers) or the sellers of the TCCs.[109]

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101 CAISO, "Tariff Amendments to Increase Efficiency of Congestion Revenue Rights Auctions," filed April 11, 2018, available at: https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14884955.

102 CAISO, "Tariff Amendment to Eliminate Full Funding of Congestion Revenue Rights," filed October 1, 2018, available at: http://www.caiso.com/Documents/Oct1-2018-TariffAmendment-CRRAuctionEfficiencyTrack1BModification-ER19-26.pdf.

103 *Order Accepting Tariff Revision*, 163 FERC ¶ 61,237, June 29, 2018, available at: https://www.caiso.com/Documents/Jun29_2018_OrderAcceptingTariffAmendment-CRRAuctionEfficiencyTrack1A_ER18-1344.pdf.

104 NYISO, "Transmission Congestion Contacts," presented at the New York Market Orientation Course held October 16-19, 2018, slides 17 and 48, available at: https://www.nyiso.com/documents/20142/3037451/Transmission_Congestion_Contracts.pdf/c3d147f1-13eb-4c3a-2514-b50c7a7f18e4.

105 *Id.,* slides 28-36.

106 *Id.,* slides 37-39.

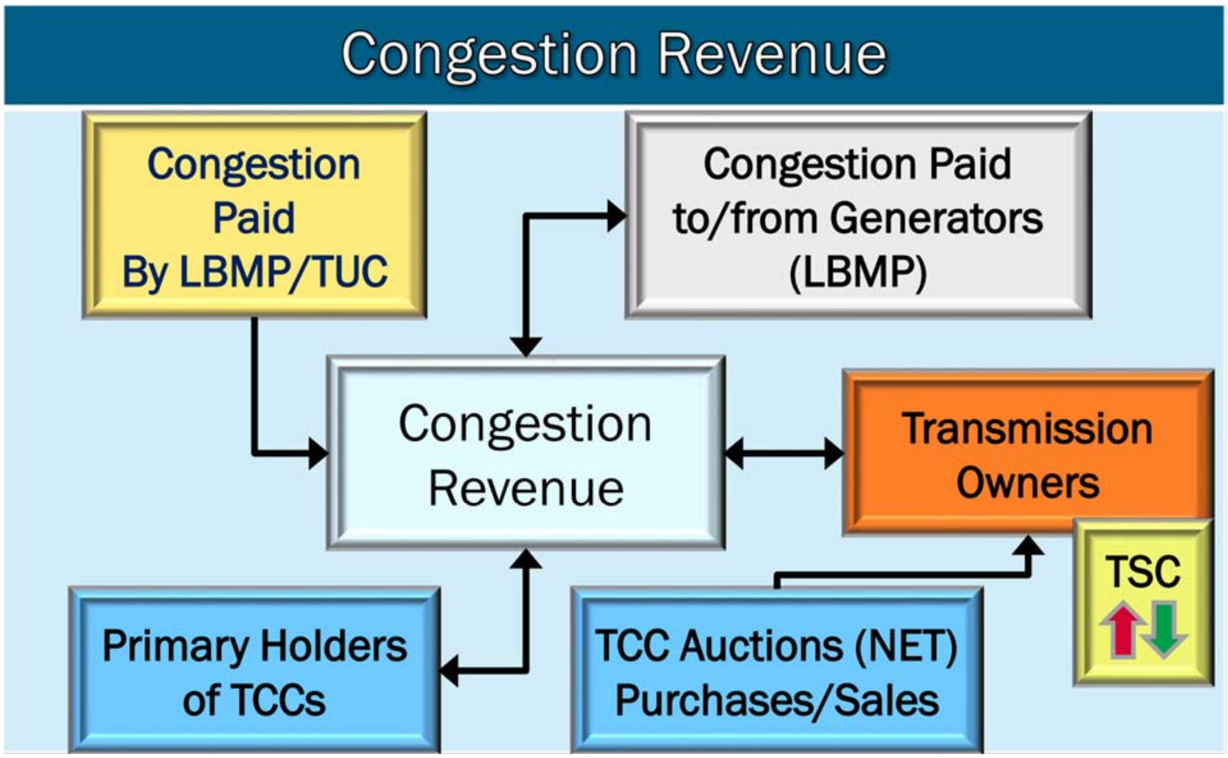
107 *Id.,* slides 20-24.

108 *Id.,* slide 49.

109 NYISO, "Transmission Congestion Contracts Manual," August 2017, p. 4-10, available at: https://www.nyiso.com/documents/20142/2923301/tcc_mnl.pdf/cc3f4273-3e2f-b969-550a-01c2587a70d6.

Like other types of FTRs, NYISO TCC holders are paid the difference between the actual day-ahead congestion components of the LMPs at the TCC's sink and source. The process is described below in Figure A5:

Figure A5
NYISO Congestion Revenue Collection and Disbursement[110]



NYISO TCCs are "fully funded," meaning that any congestion revenue shortfalls are covered by transmission owners and any excess congestion rents are paid to the transmission owners. These charges are applied to the transmission owners' irrespective of other charges, including the Transmission Service Charge (TSC) or NYPA Transmission Adjustment Charge (NTAC).[111] As a result, the benefits and burdens ultimately flow through to ratepayers.

The NYISO IMM noted that:

> In general, the TCC prices reflected the anticipated levels of congestion at the time of auctions. The profits and losses that TCC buyers netted on most transmission paths have been generally consistent with changes in day-ahead congestion patterns from previous like periods. In addition, the past TCC auction results generally show that the level of congestion was increasingly recognized by the markets from the annual auction to the six-month auction and from the six-month

110 NYISO, "Transmission Congestion Contacts," slide 62.

111 NYISO, "Transmission Congestion Contracts Manual," p. 2-1.

> auction to the monthly auction. This is expected since more accurate information is available about the state of the transmission system and likely market conditions in the auctions that occur closer to the actual operating period.[112]

However, the NYISO plans to change its Centralized TCC Auction format to an end-state (or "a multi-durational") auction format at some point in the future.[113]

iii. *ERCOT*

Like the CAISO, ERCOT calls its FTR product a Congestion Revenue Right (CRR). ERCOT auctions CRRs semi-annually for the next six successive six-month periods and on a monthly basis.[114] The set of CRRs to be auctioned is determined by a simultaneous feasibility test.[115] Some CRRs are pre-allocated to certain market participants (PCRRs) at a discount, with the rest made available to the broader market at auction prices.[116] Monthly CRRs cover 24 hours of the day, while others can cover certain time-of-use blocks.[117]

Revenues from the CRR auctions are distributed to ERCOT's load monthly. There are two settlement methods based on congestion zones that ERCOT set up in 2003 (North, West, South, and Houston). Revenues from CRRs that cover transmission paths within the same congestion zone are distributed to loads within that zone. Revenues from CRRs that cover transmission paths that cross congestion zone boundaries are distributed to all loads in ERCOT. ERCOT's IMM makes the point that, "[a]llocating CRR auction revenues in this manner reduces the net cost for load purchases in heavily-congested areas, but it does so whether the congestion had raised prices in the area or lowered prices in the area."[118] Discounts to PCRRs holders were $50 million in 2017, the last study year we examined.[119]

Like other RTOs, hourly congestion rents are accumulated based on sink/source price differentials in the day-ahead market and paid to CRR holders on a monthly basis. If congestion revenues over

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[112] Potomac Economics, "2017 State of the Market Report for the New York ISO Markets," May 2018, p. 34, available at: https://www.nyiso.com/documents/20142/2223763/2017-State-Of-The-Market-Report.pdf/cd4ee8a0-1989-dfa0-b53e-2d642c65e46d.

[113] NYISO, "Transmission Congestion Contracts Manual," p. 2-2.

[114] ERCOT, "ERCOT Market Education: Congestion Revenue Rights," May 2017, slide 48, available at: http://www.ercot.com/content/wcm/training_courses/109553/CRR_2017_May.pdf. Note that ERCOT expanded its forward CRR auction from two years to three years in 2018.

[115] *Id.,* slide 55.

[116] *Id.,* slides 53-57.

[117] *Id.,* slide 60.

[118] Potomac Economics, "2017 State of the Market Report for the ERCOT Markets", May 2018, p. 63, available at: https://www.potomaceconomics.com/wp-content/uploads/2018/05/2017-State-of-the-Market-Report.pdf.

[119] *Id.,* pp. 63-64.

a path are insufficient to cover CRR obligations for a month, the CRR holders are "short-paid" for that month with their shortfalls tracked. Any excess revenues are placed into ERCOT's CRR Balancing Fund, a rolling account with a $10 million fund cap.[120] Excess revenues are first paid to any short-paid CRR holders from the prior month(s); money left after that accumulates in the CRR Balancing Fund up to the cap, beyond which it is distributed to LSEs based on each entity's Load Ratio Share in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for that month.[121]

2. Imports and Exports between U.S. RTOs

Transactions between markets in the U.S. have some relevance to Ontario as well. For example, the CAISO has similarities to Ontario in that it too imports and exports power over interties with the rest of the Western Interconnection, with CRRs tied to hourly intertie congestion prices. Specifically, if an exporter holds a CRR from an internal price point (where they are sourcing their power) to an intertie price point (where they plan to wheel their power out of the market), they would be entitled to collect the value of the CRR as described above. This is conceptually similar to the system currently in place in the IESO, where a MP can hold TRs between the HOEP and the price at the intertie (albeit not yet from an internal resource). This does not provide a hedge against price differentials with the neighboring (importing) market, which may differ from the price in the exporting market due to congestion over the intertie and would not be reflected in the value of the CRR from the internal source to the sink at the border.

In addition to paying these congestion charges, IEs in U.S. markets also contribute to offsetting the costs of the transmission system in other ways. In the U.S., any market participant that wishes to move power out of an RTO's footprint to export to another jurisdiction must pay a regulated rate for transmission service out of the footprint, which is typically referred to as the regional through and out rate (RTOR) or "wheel-out" rate.[122] The wheel-out rates typical in U.S. markets are similar to the Export Transmission Service (ETS) charge paid by exporters in Ontario to move power out of the IESO footprint. However, while they are designed to recover the cost of the transmission system, including variable, fixed, and capital cost recovery, their payment does not shield the IE from the payment of congestion up to the interface, nor does it entitle the IE to any portion of the congestion rents collected over the path. Revenues collected by the RTOs from sale of this transmission service are given back to TOs in the market and is used to offset the revenue requirements that each TO collects from internal transmission customers (mostly load) to pay for building and maintaining the transmission system.

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120 *Id.,* p. 67.

121 *Id.,* p. 67. See also ERCOT, "ERCOT Nodal Protocols," September 14, 2017, p. 7-37, available at: http://www.ercot.com/content/wcm/libraries/135899/September_14__2017_Nodal_Protocols.pdf.

122 In non-RTO areas of the U.S. market participants would buy transmission service from the incumbent utility in order to export power onto a neighboring utility's transmission system. Therefore, a third party exporter in a non-RTO area would similarly be offsetting the cost of the transmission system.

D. Comparison of Ontario and Other Global Electricity Markets Concerning Treatment of Congestion and Import/Export Fees

The experiences of these other jurisdictions inform several questions relevant for consideration by Ontario as it evaluates its TRCA surplus distribution methodology. Who has the right to auction revenues? How are congestion rents allocated? What happens in the event of a revenue shortfall? What happens if there is a revenue surplus? Do transmission service charges paid by exporters affect congestion payments? Each jurisdiction's response to these questions is summarized below in Table A1 and serves to inform best practices for consideration by Ontario and its stakeholders as they address the TRCA surplus.

Table A1
Jurisdictional Comparison of Ontario to Other Power Markets

Jurisdiction (Instrument)	Who has the right to auction revenues?	How are congestion rents allocated?	What happens in a revenue shortfall?	What happens to revenue surplus or other funds?	Do exporters contribute to the transmission system?
Ontario (TRs)	• TR Holders • MPs that pay Transmission Service Charges (TSCs) (IEs and internal load)	• To TR holders, based on fully funded target allocations	• Surplus funds in TRCA account used to pay TR holders	• Surplus is presently allocated on the basis of load shares • MSP recommends this be changed to shares of TSCs	• Exporters pay ETS charges, which are hourly payments made on a $/MWh basis
Australia NEM (IRSR Shares)	• IRSR shareholders (shares won at auction) • TOs (residual shares)	• IRSR shareholders • TOs (receive shares not purchased)	• No shortfall (shares total to 100% of actual congestion)	• No surplus (shares total to 100% of actual congestion)	• No explicit export or import charges are included in the rate design
European Markets (FTRs)	• There are no auctions. FTRs are arranged in the bilateral market	• Optimization of the interconnectors • Interconnection capacity buildout	• No guaranteed payments so there can be no shortfalls	• Revenues above that needed for efficient transmission buildout used to reduce the cost of transmission service	• Exporters pay transmission service charges which offset the revenues collected from native load
CAISO (CRRs)	• CRRs allocated to LSEs, OBAALSEs, or eligible merchant transmission • Remaining CRR auction revenues go directly to the balancing account	• To CRR holders, based on fully funded target allocations	• Currently allocated to load • Proposed change would reduce CRR payments on a pro rata basis	• Currently allocated to load • Proposed change would allocate surpluses in each month to cover shortfalls, with residual surplus allocated to load	• Exporters pay a wheeling fee, offsetting revenues collected from native load

Jurisdiction (Instrument)	Who has the right to auction revenues?	How are congestion rents allocated?	What happens in a revenue shortfall?	What happens to revenue surplus or other funds?	Do exporters contribute to the transmission system?
ERCOT (CRRs)	• Native load in the zone where CRR is located • Cross-zone CRRs allocated to all load	• To CRR owners • Excess goes into the CRR Balancing Account	• "Haircuts" to CRR holders on pro rata basis, but these are tracked over time	• Compensate CRR holders previously given haircuts • Balancing Account surplus above cap paid to LSEs	• Exporters pay a wheeling fee, offsetting revenues collected from LSEs
ISONE (FTRs)	• ARRs allocated to LSEs based on load share • Incremental ARRs allocated to new transmission	• To FTR holders, but only up to the FTR's target values	• FTR payments are reduced on a pro rata basis	• Surplus is distributed first to FTR and ARR holders that received less than their target allocations • Remaining surplus allocated to internal load	• Exporters pay wheeling fees that offset revenues needed from native load • Some interties have fees that do not offset costs • The NY-NE seam does not have a wheel-out fee
MISO (FTRs)	• ARRs allocated to LSEs and long-term firm transmission buyers based on historical use and load forecasts • Incremental ARRs may be allocated to new transmission	• To FTR holders, even if the congestion is greater than FTR's target allocation	• Shortfalls allocated to FTR holders on a pro rata basis	• Surpluses are allocated to FTR holders	• Exporters pay a wheeling fee, offsetting revenues collected from load • The PJM-MISO seam does not have a wheel-out fee
NYISO (TCCs)	• TCCs allocated to TOs • Various legacy TCCs (or equivalent products) allocated to other MPs	• To TCC holders, even if congestion is greater than TCC's target allocation	• Shortfalls paid for by TOs	• Distributed to TOs to lower transmission charges paid by transmission customers	• Exporters pay a wheeling fee, offsetting revenues collected from load • The NY-NE seam does not have a wheel-out fee

Jurisdiction (Instrument)	Who has the right to auction revenues?	How are congestion rents allocated?	What happens in a revenue shortfall?	What happens to revenue surplus or other funds?	Do exporters contribute to the transmission system?
PJM (FTR)	• ARRs allocated to LSEs and long-term firm transmission buyers • Exporters may receive ARRs if they buy long-term firm transmission	• To FTR holders, up to the FTR's target allocation • To ARR holders, if they receive less than their target allocations	• Shortfalls allocated to FTR holders on a pro rata basis	• Surplus first allocated to FTR holders up to receive their target allocations • Additional surplus used to fund ARR deficiencies up to their target allocations • Any remaining surplus is paid pro rata to ARR holders	• Exporters pay a wheeling fee, offsetting revenues collected from load • The PJM-MISO seam does not have a wheel-out fee
SPP (TCR)	• ARRs allocated to long-term firm transmission customers	• To TCR holders, up to their fully funded target allocations	• Shortfalls allocated to each TCR holder proportional to the absolute value of its TCR portfolio held on that day	• Any excess TCR congestion rents gets allocated to ARR holders	• Exporters pay a wheeling fee, offsetting revenues collected from load

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