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A Zonal Capacity Market Model With Energy Storage for Transmission and Distribution

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ABSTRACT Traditional generation and transmission expansion planning has served electric utilities well for several decades to procure the least costing set of assets to meet forecasted demand. Unfortunately, it does not consider a demand curve, in which case it procures generation and transmission assets that do not ensure maximum societal value. An Incremental Capacity Auction (ICA) enables a power system to competitively procure additional generation capacity that maximizes social welfare while satisfying numerous constraints. However, typical ICA designs, zonal or otherwise, do not consider new inter-zonal transmission lines and distributed energy resources (DERs) embedded in distribution systems, promoting suboptimal solutions. To address these shortcomings, this work presents a new comprehensive ICA model that considers intra-zonal and inter-zonal constraints with provision to add new inter-zonal transmission lines and distribution system embedded DERs, while accommodating non-monotonically increasing generator capacity price bids. The proposed zonal ICA model is applied to two systems: (1) a synthetic test system with two zones; and (2) Ontario, Canada's provincial power system with six zones. The Ontario system study considers a realistic demand growth and demonstrates that the proposed zonal ICA model achieves 5.7% higher social welfare considering new inter-zonal transmission enhancements and DERs over existing single-zone methods.

INDEX TERMS Energy storage, optimization, power system economics, capacity market, zonal constrained.

I. NOMENCLATURE

A. INDICES

i, j, k	Index for conventional generators', intermittent generators' and energy storage's capacity bids	-
m	Index for load increments	-
n	Index for power increments	-
$z, z1, z2$	Index for transmission zones	-

B. PARAMETERS

AF	Availability factor	-
BD	Base power demand of the daily chronological load curve	MW
BG	Price of capacity offers	\$/MW-day
BT	Price of building a new inter-connection	\$/MW-day
C_1, C_2, C_3	Constants of the approximated linear LOLP curve	MW^{-1}
C_4	The maximum percentage of demand that can be supplied by a capacity supplier	%
FPC	Full power plant capacity	MW
FU	Forced outage rate	-
$ICAP$	Installed capacity of a CG, IG, ES or line	MW
$\underline{LOLP}_z$	Maximum intra-zonal loss of load probability	-
M	Total number of load increments	-
N	Total number of power increments	-
NH	Length of the commitment period	hours

NL	Number of possible new inter-zonal transmission connections	-
OL	Number of old inter-zonal transmission connections	-
OCG, NCG	Number of old and new conventional generators' capacity bids	-
OES, NES	Number of old and new energy storage's capacity bids	-
OIG, NIG	Number of old and new intermittent generators' capacity bids	-
p	Price of a demand increment	\$/MW-day
p_0	Ceiling price of base demand	\$/MW-day
$\underline{PD}_z$	The minimum value of the sloped demand curve MW	
PF	Power capacity generated available for frequency regulation	MW
PFR	The total capacity required to fulfill the frequency regulation requirements in a zone z	MW
PLF	Plant load factor of capacity offers	%
$\underline{PG}$	Unforced capacity-based power capacity offers from generators	MW
$\underline{PG}$	Must run capacity of supply offers, if they are selected (output of some generators cannot be zero, for others this is zero)	MW
$PGmin$	Minimum amount of capacity of a generator	MW
$PGmax$	Amount of increment capacity of a generator	MW
$\overline{PT}$, $\underline{PT}$	The maximum and minimum value of the capacity flowing in an inter-zonal interconnection	MW
RMP	Ramp power contribution from generating sources	% per minute
RMR	System ramp power requirement	% per minute
SLF	System load factor	%
$Zones$	Number of all zones into the system	-
ΔPD	Small increment in the demand	MW

C. VARIABLES

$LOLP_z$	Loss of load probability of selected capacities and demand	-
PTP, PTB	Power capacity flowing through new and old lines connections on peak and base demand	MW
UD	Binary variable for selecting demand increments	-
UG	Binary variable for selecting capacity offers	-
UT	Binary variable for selecting capacity offers using new interconnections	-

D. OTHER

CG	Conventional generator	-
ES	Energy storage	-
IG	Intermittent generator	-

II. INTRODUCTION

THE traditional model of generation and transmission (G&T) system planning is designed to meet fixed, inelastic load forecasts. However, this does not account for the price-sensitive, elastic nature of demand. Therefore, this approximation of price-sensitive demand as fixed means that traditional G&T planning does not truly maximize social welfare [1], [2], [3]. Furthermore, G&T planning has been traditionally done in isolation by two separate entities with no co-optimization, as shown in Table 1.

TABLE 1. **Comparison of electricity planning models.**

	Traditional	Present-Day	Proposed
Generation	Generation Supply Planning ↓	Single-Zone Incremental Capacity Auction ↓	Multi-Zonal Incremental Capacity Auction with Transmission System Expansion
Transmission	Transmission System Planning	Transmission System Planning	
	Fixed, inelastic demand	Price-sensitive, elastic demand	Price-sensitive, elastic demand
	Two steps implemented by two separate entities	Two steps implemented by two separate entities	One step implemented by a single entity

Presently, system operators around the world are turning to incremental capacity auctions (ICAs) to introduce market-based approaches to long-term generation planning. Capacity markets are in operation around the world, including in the United States in New York Independent System Operator (NYISO), the Independent System Operator of New England (ISO-NE), the Independent System Operator of Pennsylvania, New Jersey and Maryland (PJM), and Mid-continent ISO (MISO) [4]. The United Kingdom expects its electricity market reforms, including capacity markets, to reduce household electricity bills by 6% [5]. One of the main challenges that face capacity markets where ICA models are useful is the volatile and uncertain nature of capacity prices [6]. Thanks to new emerging ICA models, average capacity prices in several jurisdictions have cleared below the cost of new entry (CONE) [7]. While ICAs can account for demand elasticity, they do not co-optimize generation and transmission planning.

In this context, this work creates a new capacity market formulation that includes distribution system embedded distributed energy resources (DERs) and inter-zonal transmission system upgrades. The proposed ICA streamlines generation and transmission planning processes into a single integrated step while considering demand elasticity. Therefore, its design allows generation planning and transmission planning to be co-optimized, while recognizing distribution embedded DERs, leading to even greater economic efficiency.

A. LITERATURE REVIEW

Traditionally, generation planning and transmission planning take place independently and are based on fixed, inelastic load forecasts [1], [2], [3]. Later, capacity markets for electricity were first established to use a market-based approach to ensure reliability and adequacy [1], [2]. Capacity markets compensate generators that are unable to fully recoup their fixed and/or operating costs from energy markets alone. Since these generators were still providing a necessary service for consumers in ensuring generation adequacy, additional incentives through capacity markets were offered so that these essential generators would be built.

Efficient settlement of capacity markets requires accurate supply and demand curves. In theory, market participants declare their demand price and quantity bid pairs. Capacity bids are adjusted to account for availability factors such as forced outage rates and capacity factors [1], [10]. One of the most comprehensive ICA models to date contains a single zone for a transmission system [11] and enables the participation of energy storage units. It uses the bids from suppliers, including energy storage, to create the supply curve. It then considers a stepped demand curve.

In addition to efforts in improving the design and performance of ICA models such as [4], analyses were conducted to evaluate the implementation of ICAs. For example, [12] and [13] present surveys of the impacts of ICAs in the long run and on end-user customers in the European Union. As a result, the capacity market assists in the development of renewable energy resources.

While ICAs have been explored in literature and implemented in some jurisdictions in practice, none of the existing capacity market models includes zonal capacity pricing or new inter-zonal transmission upgrades.

The most efficient market result is when social welfare is maximized. However, the lack of zonal characterization of a multi-zone power system, with limiting inter-zonal constraints wrongly assumes an uncongested market. This may lead to ICA outcomes that are not technically feasible due to limiting inter-zonal constraints and would require out of market interventions to overcome these limiting inter-zonal constraints, rendering these ICA outcomes suboptimal. To address these shortcomings, this work presents a new comprehensive ICA model that considers intra-zonal and inter-zonal constraints with the provision to add new inter-zonal transmission lines and distribution system embedded DERs. Therefore, the proposed model optimizes transmission systems leveraging DER capacities in distribution systems.

Challenges arising from separate but interconnected capacity markets has been identified, leading to inefficient and sub-optimal outcomes [4]. However, there is very limited published research on zonal implementations of capacity markets. One early study proposed a locational capacity price at each bus using the same, simple, continuous formulation as an energy-only market [14]. [15] proposes a capacity expansion model in zonal pricing markets based on flow-based market coupling (FBMC). This work considers zonal transmission constraints and private firms' investments. The formulation is used to evaluate the European market. However, it does not consider ancillary service constraints. Similar work is presented in [16]. In this case, an available-transfer-capacity market coupling is considered. Both formulations do not account for renewable resources, such as energy storage. Our work proposes a more sophisticated and realistic mixed-integer formulation specifically for capacity (rather than energy) and examines systems on a zonal (rather than bus) level. This allows for analyses of much larger regional systems and can include DER capacities in distribution systems. It also includes the complexities unique to capacity markets.

B. DRAWBACKS OF TRADITIONAL G&T PLANNING AND EXISTING ICA METHODS

Traditional G&T planning does not consider the flexibility of price-sensitive, elastic demand and therefore does not maximize social welfare. Some present-day capacity market formulations improve the economic efficiency of traditional G&T planning through their ability to consider elastic demand through demand bids and aggregate demand curves [11]. However, past capacity market formulations have been for a single, uncongested market. This can lead to sub-optimal results when supply units cannot reach demand due to congestion or line limits. We are not aware of any published model that considers transmission lines. In the current practice, the regional transmission organizations (RTOs) have identified zones, where the capacity of transmission lines to transmit electricity into or out of the zone is limited [17]. In certain Independent System Operators (ISOs), zonal models are used, but inter-zonal transmission system upgrades are not considered, as in PJM [20].

Further, the rise of distribution system embedded DERs is gradually altering the generation profile. Drivers for pervasive adoption of DERs in the distribution sector include economic opportunity and a lower greenhouse gas footprint [22], [23]. One significant example of such a phenomenon is California's duck curve [24]. Between 2015 and 2020, the total installed photovoltaic energy capacity in the world increased by more than 325%, reaching 707.50 GW in 2020 and 1 TW in 2022 [18]. The global battery energy market is expected to grow 243.18% from 2022 to 2027, representing an increase from \$4.4 billion USD to

$15.1 billion USD [19]. Recognition of distribution embedded DERs in capacity market designs is imperative going forward and the lack of such cognizance will significantly impact the efficiency of ICA outcomes. The zonal model, proposed in this paper, allows large distribution systems to be modeled as zones and aggregate DERs within them, thus creating indirect DER representations.

C. MAIN CONTRIBUTIONS

ICA models enhance traditional G&T planning by accounting for price-sensitive demand. However, typical ICA designs, zonal or otherwise, do not consider the provision of new inter-zonal transmission lines and distributed energy resources embedded in distribution systems. These severely limits the efficiency of ICA outcomes and requires out-of-market interventions, which render the ICA outcomes suboptimal. Therefore, the next major developmental iteration for the ICA mechanism is to allow inter-zonal asset upgrades (e.g., lines, transformer stations, etc.) and enable participation of distribution embedded DERs. This ICA enhancement can further reduce consumer costs and encourage greater participation from distribution embedded DERs into the bulk electricity markets via aggregation.

Our main contribution is a zonal capacity market formulation, which enhances existing methods by considering:

- Price-sensitive demand;
- Power flow between zones, thereby allowing for new lines, transformers, and distribution systems embedded DERs;
- DERs such as renewable generation and energy storage;
- Services such as frequency regulation, ramping, and reliability; and
- Suppliers' non-monotonically increasing-price bids.

D. ORGANIZATION OF THIS PAPER

This paper is organized as follows. Section III introduces the new zonal capacity market model. Section IV shows the case studies. Section V raises the conclusions.

III. ZONAL CAPACITY MARKET MODEL

This new zonal capacity market model is based on the most comprehensive capacity model to our knowledge in literature [11], and we expand it to include zonal line capabilities, considering inter-zonal upgrades and distribution embedded DERs. The new set of line flow constraints is in Section III.III-F.

This optimization challenge has an objective function subject to a series of constraints.

A. OBJECTIVE FUNCTION

The objective function as in (1), shown at the bottom of the page, maximizes social welfare. The first term represents the downward sloping demand, and the second term represents the stacked costs of selected supply bids together with the costs of selected new lines between zones. The costs for the new lines are halved to avoid double-counting; each new line will appear in the two zones to which it connects, but its costs are incurred only once.

B. QUALIFYING CAPACITY

Consistent with industry practice [25], the installed, nameplate capacities of suppliers and transmission lines are de-rated for the purposes of the capacity market to account for forced outages and availability factors. This helps to procure capacity past the required amount, considering outages. Hence, the procured generation capacity would be able to meet scheduled and reserve capacity requirements during operations. In addition, the demand curve may be bolstered should additional, system-specific reserve requirements need to be included.

Conventional generators are de-rated in accordance with their forced outage rates. This accounts for their technical availability and reflects the amount of capacity we expect to be offered for the purposes of capacity planning.

$$\overline{PG}_{iz} = ICAP_{iz} \times (1 - FU_{iz}) \qquad \forall i \in \{OCG, NCG\}, \quad z \in \{Zones\} \tag{2.1}$$

Intermittent generators are de-rated according to their availability factor. The availability factor is based on the generator's historic availability rates during system peaks.

$$\overline{PG}_{jz} = ICAP_{jz} \times AF_{jz} \qquad \forall j \in \{OIG, NIG\}, \quad z \in \{Zones\} \tag{2.2}$$

ES units are de-rated using both their forced outage rates and their availability factor:

$$\overline{PG}_{kz} = ICAP_{kz} \times (1 - FU_{kz}) \times AF_{kz} \qquad \forall k \in \{OES, NES\}, \quad z \in \{Zones\} \tag{2.3}$$

where

$$AF_{kz} = \frac{\begin{bmatrix} Agreed\ Energy\ Supply \\ -Agreed\ Energy\ Consumption \end{bmatrix}}{[ES\ rated\ power\ \times Number\ of\ peak\ hours]} \tag{2.4}$$

ES units should be available to supply for the assigned hours. The equation aims to decide the maximum output that the energy storage can afford over a specified period.

$$Maximize \sum_{\forall z} \left[\underline{PD}_z \cdot p_{0z} + \sum_{m=1}^{M} UD_{mz}.p_{mz}.\Delta PD \right] - \sum_{\forall z} \left[\begin{matrix} \left(\sum_{n \in N} \sum_{i \in \{NCG,NIG,NES\}} BG_{izn} \cdot ICAP_{izn} \right) \\ + \left(\sum_{i \in \{NL,z\}} \frac{1}{2} BT_i \cdot \overline{PT}_i \cdot UT_i \right) \end{matrix} \right] \qquad \forall z \in \{Zones\} \tag{1}$$

Furthermore, transmission lines are de-rated according to their forced outage rates. This represents the availability of the line that connects different zones.

$$\overline{PT}_{iz} = ICAP_{Iz} \times (1 - FU_{iz}) \quad \forall i \in \{OL, NL\}, \quad z \in \{Zones\} \tag{2.5}$$

C. EQUIPMENT POWER LIMITS

The minimum and maximum power capacity of supplier units must be respected to ensure the safe operation of the equipment. The must-run capacity of supply offers $\underline{PG}$, if selected, must be $PGmin$ for the first power increment or bid. The unforced capacity-based power capacity offers from generators $\overline{PG}$ increases according to the incremental capacity of each selected bid segment defined for the generator.

$$\underline{PG}_{iz} = UG_{in=0z} \cdot PGmin_{iz} \;\; \forall i \in \{NCG, NIG, NES\}, \quad z \in \{Zones\} \tag{3.1}$$

$$\overline{PG}_{iz} = \left[\sum_{n}^{N} UG_{inz} \cdot PGmax_{inz}\right] \forall i \in \{NCG, NIG, NES\}, \quad z \in \{Zones\} \tag{3.2}$$

Furthermore, constraint (3.3) permits a non-monotonic cost curve – a new development we introduce here which gives an additional functionality for more realistic modeling. This can allow for situations where the first bid step includes high capital costs (e.g., for facility space), and subsequent bid steps can leverage the investments included in the earlier segments.

$$UG_{inz} \geq UG_{in+1z} \forall i \in \{NCG, NIG, NES\}, \quad z \in \{Zones\} \tag{3.3}$$

For the existing old generators, $\underline{PG}_{iz}$ and $\overline{PG}_{iz}$ values are given.

D. ZONE PEAK DEMAND REQUIREMENT

The peak demand must be satisfied for every zone; it is an intra-zonal requirement. This ensures the amount of intra-zonal generation capacity and the import/export capacity together can meet zonal demand.

$$\sum_{i \in \left\{\begin{array}{l} OCG, NCG, \\ OIG, NIG, \\ OES, NES \end{array}\right\}} \overline{PG}_{iz} + \sum_{i \in \{z\}} PTP_i \geq \underline{PD}_z + \sum_{m=1}^{M} UD_{mz}.\Delta PD \quad \forall z \in \{Zones\} \tag{4}$$

E. ZONE BASE DEMAND REQUIREMENT

The intra-zonal capacity selected must have the ability to reduce supply in case the load required is reduced to the base demand. To fulfill this requirement, the minimum limit that can be produced by this capacity should be less than zonal based demand. For generators that may be curtailed to zero, their minimum demand would be set to zero.

$$\sum_{i \in \left\{\begin{array}{l} OCG, NCG, \\ OIG, NIG, \\ OES, NES \end{array}\right\}} \underline{PG}_{iz} + \sum_{i \in \{z\}} PTB_i \leq BD_z \quad \forall z \in \{Zones\} \tag{5}$$

F. POWER FLOW LIMITS BETWEEN ZONES

This set of inter-zonal power flow constraints are introduced here for the first time. Under peak demand conditions, the power flow between zones must respect line and equipment limits. This applies to both existing lines and new lines. Constraints on new inter-zonal transmission upgrades, during peak demand period:

$$UT_i \cdot \underline{PT}_i \leq PTP_{iz1} \leq UT_i \cdot \overline{PT}_i \quad \forall i \in \{NL\}, \quad z \in \{Zones\} \tag{6.1}$$

$$UT_i \cdot \underline{PT}_i \leq PTP_{iz2} \leq UT_i \cdot \overline{PT}_i \quad \forall i \in \{NL\}, \quad z \in \{Zones\} \tag{6.2}$$

Constraints on existing inter-zonal transmission upgrades, during peak demand period:

$$\underline{PT}_i \leq PTP_{iz1} \leq \overline{PT}_i \quad \forall i \in \{OL\}, \quad z \in \{Zones\} \tag{6.3}$$

$$\underline{PT}_i \leq PTP_{iz2} \leq \overline{PT}_i \quad \forall i \in \{OL\}, \quad z \in \{Zones\} \tag{6.4}$$

Constraints to ensure that net power from inter-zonal transmission element is zero, during peak demand period:

$$PTP_{iz1} + PTP_{iz2} = 0 \quad \forall i \in \{OL, NL\}, \quad z \in \{Zones\} \tag{6.5}$$

Likewise, the power flows in the base demand scenario must also respect line and equipment limits. Therefore, constraints to ensure that net power from all inter-zonal transmission elements is zero, during the off-peak demand period:

$$PTB_{iz1} + PTB_{iz2} = 0 \quad \forall i \in \{OL, NL\}, \quad z \in \{Zones\} \tag{6.6}$$

Constraints on new inter-zonal transmission upgrades, during off-peak demand period:

$$UT_i \cdot \underline{PT}_i \leq PTB_{iz1} \leq UT_i \cdot \overline{PT}_i \quad \forall i \in \{NL\}, \quad z \in \{Zones\} \tag{6.7}$$

$$UT_i \cdot \underline{PT}_i \leq PTB_{iz2} \leq UT_i \cdot \overline{PT}_i \quad \forall i \in \{NL\}, \quad z \in \{Zones\} \tag{6.8}$$

Constraints on existing inter-zonal transmission upgrades, during off-peak demand period:

$$\underline{PT}_i \leq PTB_{iz1} \leq \overline{PT}_i \quad \forall i \in \{OL\}, \quad z \in \{Zones\} \tag{6.9}$$

$$\underline{PT}_i \leq PTB_{iz2} \leq \overline{PT}_i \quad \forall i \in \{OL\}, \quad z \in \{Zones\} \tag{6.10}$$

G. RAMPING REQUIREMENT

The ramping capability of suppliers must be able to meet the ramping requirements of the system. Ramping requirements are a function of load ramping rates, further accentuated by ramping of intermittent generators. Together, they influence the demand and generation balance, requiring ramping capability to manage those variations. Ramp power requirements from the loads and intermittent generators need to be satisfied by the intra-zonal conventional generators and energy storage systems.

$$\begin{aligned}\sum_{\forall z} \sum_{i\in\left\{\begin{matrix} OCG, NCG, \\ OES, NES \end{matrix}\right\}} \overline{PG}_{iz} \cdot RMP_{iz} &\\ \geq \sum_{\forall z}\left(\underline{PD}_z + \sum_{m=1}^{M} UD_{mz}.\Delta PD\right).RMR_z &\\ + \sum_{\forall z} \sum_{j\in\{OIG,NIG\}} \overline{PG}_{jz} \cdot RMP_j \quad \forall z \in \{Zones\} & \quad (7)\end{aligned}$$

H. ENERGY REQUIREMENT

The suppliers must be able to satisfy the energy requirements of the system:

$$\begin{aligned}\sum_{\substack{i \in \left\{\begin{matrix} OCG, NCG, \\ OIG, NIG \end{matrix}\right\}, \\ z\in\{Zones\}}} \overline{PG}_{iz} \cdot PLF_{iz} \cdot NH_{iz} &\\ \geq \sum_{z\in\{Zones\}}\left(\underline{PD}_z + \sum_{m=1}^{M} UD_{mz}.\Delta PD\right) \cdot SLF_z \cdot NH_z & \quad (8)\end{aligned}$$

This constraint is particularly important in power systems where a significant portion of the peak demand is met via renewables, energy storage units, and other DERs.

I. RELIABILITY CONSTRAINT

The resulting system must satisfy the linear approximation for the Loss of Load Probability (LOLP) constraint [11]. This constraint ensures that each zone has adequate supply capacity such that LOLP is below a threshold value. To consider the inter-zonal effect, the term *PTP* is included as in (9.1), shown at the bottom of the page.

J. SUPPLIERS' RESOURCE TYPE CAPACITY LIMITS

Each resource type could have a limit on the total permitted on the system, for instance, due to government policy objectives. An example of this is the coal phase-out campaign in Ontario [26] or Illinois' mandate to have renewable energy comprise 25% of the supply by 2025 [27]. Such constraints ensure that a certain type of resource does not exceed a portion of the total supply capacity.

$$\sum_{i\in\{OCG,NCG\}} \overline{PG}_{iz} \leq FPC_z^{CG} \quad \forall z \in \{Zones\} \quad (10.1)$$

$$\sum_{j\in\{OIG,NIG\}} \overline{PG}_{jz} \leq FPC_z^{IG} \quad \forall z \in \{Zones\} \quad (10.2)$$

$$\sum_{k\in\{OES,NES\}} \overline{PG}_{kz} \leq FPC_z^{ES} \quad \forall z \in \{Zones\} \quad (10.3)$$

K. FREQUENCY REGULATION CONSTRAINT

This is an intra-zonal constraint as frequency regulation service in one zone is unable to satisfy needs in other zones. Hence, sources procured for frequency regulation must be within that zone, as identified by the system operator [21].

$$\begin{aligned}\sum_{i\in\left\{\begin{matrix} OCG, \\ OIG, \\ OES \end{matrix}\right\}} PF_{iz} + \sum_{i\in\left\{\begin{matrix} NCG, \\ NIG, \\ NES \end{matrix}\right\}} &\\ \times \sum_{n} UG_{inz} \cdot PF_{inz} \geq PFR_z \quad \forall z \in \{Zones\} & \quad (11)\end{aligned}$$

This formulation (1) – (11) is a mixed-integer optimization challenge. It was solved using MOSEK within the MATLAB programming environment.

IV. CASE STUDIES

The proposed zonal ICA model is applied to two systems: (1) a synthetic test system with two zones; and (2) Ontario, Canada's provincial power system with six zones. The synthetic system demonstrates the benefits of the proposed zonal ICA model where simultaneous consideration of new inter-zonal transmission lines and distribution system embedded DERs leads to a lower-cost solution. The Ontario system study considers a realistic demand growth and demonstrates that the proposed zonal ICA model achieves 5.7% higher

$$LOLP_z = C_{1z} - C_{2z}\left(\sum_{i\in\left\{\begin{matrix} OCG, NCG, \\ OIG, NIG, \\ OES, NES \end{matrix}\right\}} ICAP_{iz} + \sum_{i\in\{OL,NL\}} PTP_{iz}\right) + C_{3z}\left(\sum_{m=1}^{M} x_{mz}.\Delta PD\right) \quad (9.1)$$

$$LOLP_z \leq \overline{LOLP_z} \quad \forall z \in \{Zones\} \quad (9.2)$$

social welfare considering new inter-zonal transmission enhancements and DERs over existing single-zone methods.

A. SHOWCASING FEATURES OF CAPACITY MARKET MODEL

1) CASE A1: TWO ZONES WITH MARGINAL DEMAND

In order to demonstrate the flow of power between zones, a test case with two zones with marginal demand was analyzed. This test system is shown in Fig. 1. Both zones have the same demand bids, consisting of a base demand of 150 MW at \$110/MW-day with 10 steps of 20 MW each with a \$10/MW-day decrement per step. The supplier bids for both zones are shown in Table 2. There is an existing line connecting the two zones with a power flow limit of 100 MW. A new 100 MW line can be built at \$60/MW-day.

TABLE 2. Supplier bids for two zones with marginal demand.

		CG1	CG2	IG1	ES1
Generator Type		Conventional Generator	Conventional Generator	Intermittent Generator	Energy Storage
Zone 1	Segment 1	80 MW at \$20/MW-day	120 MW at \$32/MW-day	70 MW at \$70/MW-day	50 MW at \$50/MW-day
	Segment 2	20 MW at \$30/MW-day	-	-	-
Zone 2	Segment 1	100 MW at \$32/MW-day	80 MW at \$52/MW-day	50 MW at \$85/MW-day	30 MW at \$90/MW-day
	Segment 2	50 MW at \$40/MW-day	-	-	-

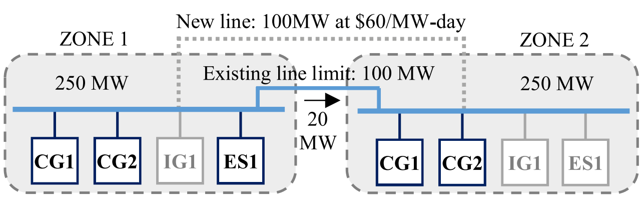

FIGURE 1. Case A1: Results for test system with two zones with marginal demand.

The resulting chosen supply units are shown in Fig. 1, with 20 MW of power flowing from Zone 1 to Zone 2 across the existing line to satisfy 250 MW of demand in each zone. Construction of the new line is not triggered. The cost of a new 100 MW line is \$60/MW-day. This is more expensive than CG2 (segment 1) priced at \$52/MW-day. Hence, the line is not built and CG2 (segment 1) is chosen. The total social welfare is \$31,100.

TABLE 3. Social welfare comparison with existing methods for Cases A1& A2.

Method	Case A1	Case A2
Traditional G&T [14]	\$24,650	\$24,650
Single Zone ICA [11]	\$31,100	\$26,850
Proposed Zonal ICA	**\$31,100**	**\$30,900**

Segments of a generator are included, as presented in Table 2, to allow flexibility where a generator wishes to offer a multi-part generation facility, with non-monotonically increasing individual offer prices. The constraint in (3.3) represents this behavior.

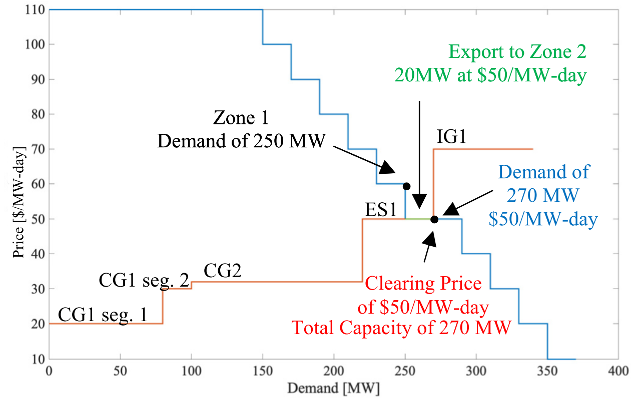

FIGURE 2. Case A1: Electricity market settlement graph for Zone 1. For bids and offers, refer to Table 2.

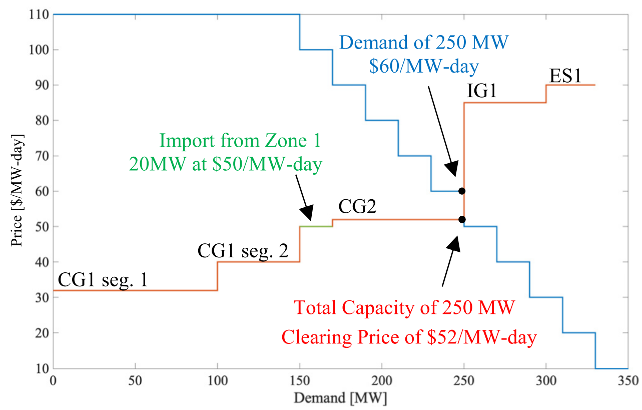

FIGURE 3. Case A1: Electricity market settlement graph for Zone 2. For bids and offers, refer to Table 2.

Fig. 2 and Fig. 3 show the electricity market settlement graphs for Zones 1 and 2 respectively. In Fig. 2, the export of 20 MW from Zone 1 to Zone 2 is reflected as additional demand. In Fig. 3, the import of 20 MW from Zone 1 to Zone 2 is shown as additional supply. Furthermore, there are different prices in the two zones: the clearing price in Zone 1 is \$50/MW-day, while the clearing price in Zone 2 is \$52/MW-day.

2) CASE A2: TWO ZONES WITH MARGINAL DEMAND AND CONGESTION

The same system in Case A1 was used with the line limit of the existing line connecting the two zones reduced to 10 MW, forcing congestion between the two zones. As the price of the 100 MW new line is quite high at \$60/MW-day, generators and energy storage are chosen instead of the new line.

The results are shown in Fig. 4, and the total social welfare is reduced to \$30,900 (as compared to \$31,100 without congestion). While the same supply units are selected, more demand is dispatched in Zone 1 and less in Zone 2. This accounts for the difference in social welfare as demand

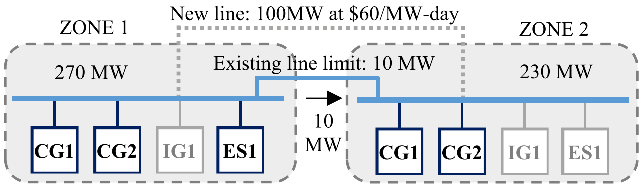

FIGURE 4. **Case A2: Results for test system with two zones with congestion.**

that "wanted" the capacity less (i.e., bid at a lower price) was dispatched in Zone 1 instead of Zone 2's higher-value demand.

A comparison of results with existing methods is in IV-A.3, which shows our proposed model yielding the highest social welfare for both Case A1 and A2. Traditional generation and transmission planning would have procured all the supply units due to high inelastic demand; however, this would have overbuilt the system, and the excess supply would have a detrimental effect on social welfare. In Case A1, the single zone ICA produces identical social welfare as the proposed zonal ICA at $31,100 because there is no congestion in the connecting line. That means the full complement of supply units in both zones are freely available to satisfy the demand in both zones. However, in Case A2, the line limit of 10 MW forces an additional unit in Zone 2 to be procured out-of-market for the single zone ICA, reducing the social welfare from $31,100 (no congestion) to $26,850 (with congestion). Our proposed ICA further improves the social welfare from $26,850 (existing single zone ICA) to $30,900 (proposed zonal ICA) by optimally selecting demand bids in each zone as explained above.

3) CASE A3: TWO ZONES WITH BINDING RELIABILITY CONSTRAINT

The same system in Case A1 was used with two modifications: a reliability constraint was imposed on Zone 1, requiring LOLP to be less than 0.000263; and the existing line limit connecting the two zones was raised to 1000 MW. It is worth noting that the reliability constraint is intra-zonal and must be satisfied within a certain zone.

The resulting electricity market settlement graphs for Zones 1 and 2 are shown in Fig. 5 and Fig. 6 respectively. All the supply units are dispatched in Zone 1 in order to satisfy the LOLP constraint. Furthermore, additional demand is *not* selected even though the capacity is available because their selection would cause the LOLP to be greater than its upper limit. Instead, 20 MW is exported from Zone 1 to Zone 2. This is why the export to Zone 2 is shown before the other demand bids in Fig. 5. The total social welfare for this test system is $18,200.

For comparison, modeling this system as a single zone with the reliability constraint applied to the entire system will yield a falsely rosy social welfare of $28,700. However, this allows any supply unit to contribute towards reliability, when in fact

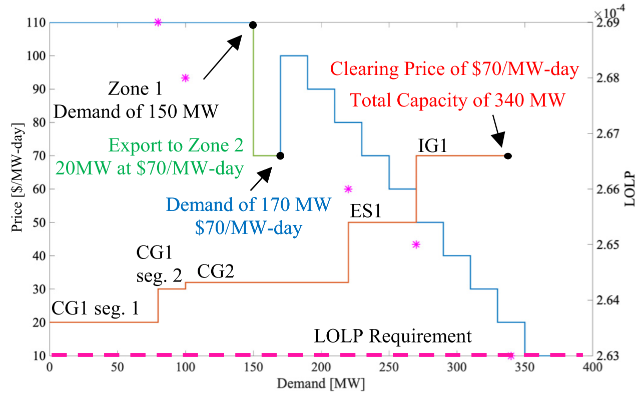

FIGURE 5. **Case A3: Electricity market settlement graph for Zone 1. For bids and offers, refer to Table 2.**

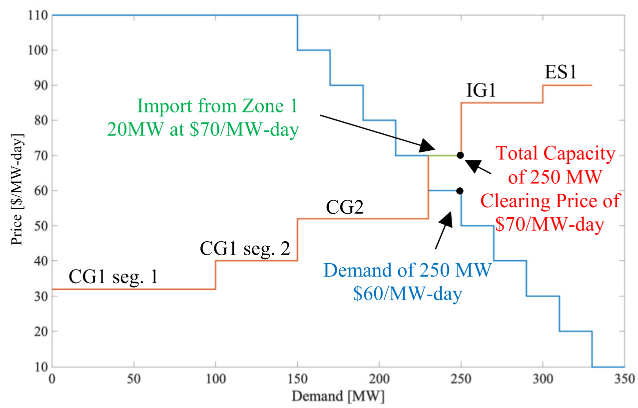

FIGURE 6. **Case A3: Electricity market settlement graph for Zone 2. For bids and offers, refer to Table 2.**

reliability can be satisfied only by supply units in the local zone. This nuance is captured in our model and missing from previously published ones.

B. TORONTO, ONTARIO, CANADA

The proposed method is applied here to help solve the real-world challenge of load growth in Toronto, Canada. The Independent Electricity System Operator (IESO) of Ontario has defined ten internal transmission zones for the Canadian province of Ontario [28]. Ontario's power system representation used in this paper is a simplification of this ten-zone representation for the purpose of better illustrating the proposed zonal ICA model. Based on generator capability [29], existing transmission zones [28], and zonal demand data [30] from the IESO, the transmission system in Ontario was approximated into four transmission zones: two zones for the City of Toronto (Manby and Leaside, named after the Transmission Stations at which electricity enters each zone); one zone for the province to the west of Toronto; and one zone for the province to the east of Toronto. Additionally, two distribution zones, one in each of the City of Toronto zones, are modeled (these can be considered feeders emanating from the low-voltage bus at one transformer station). The system model for Toronto, as shown in Fig. 7 and Fig. 8, enables us to focus the study on the Toronto area and its key issues. The same data will be used in the two case studies (B1 and B2) for Toronto.

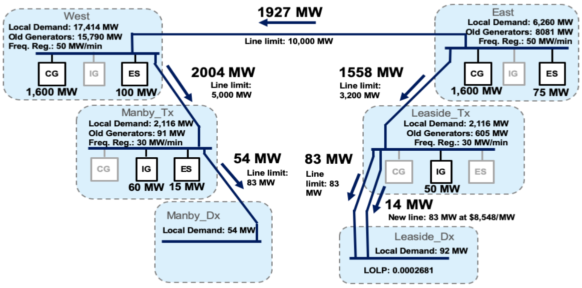

FIGURE 7. **Case B1: Results for simplified model of Toronto for energy only.**

TABLE 4. **Zonal interconnections: Toronto model (cases B1 & B2).**

Interconnection Status	From Zone	To Zone	Capacity (MW)	Price Bid ($/MW-day)
Existing	West	East	10,000	-
Existing	West	Manby_Tx	5,000	-
Existing	East	Leaside_Tx	3,200	-
Existing	Manby_Tx	Manby_Dx	83	-
Existing	Leaside_Tx	Leaside_Dx	83	-
New	Leaside_Tx	Leaside_Dx	83	$8,548

Table 4 shows the zonal interconnection limits for all existing interconnections as well as the limit and price for the potential new interconnection between Leaside_Tx and Leaside_Dx, which is the annualized unit cost of a new $10 million transformer at a discount rate of 5% and expected to last 25 years. New supply bids are summarized in Table 5 and are consistent with those found in the published literature [11]. The existing supply is noted in Fig. 7 and Fig. 8.

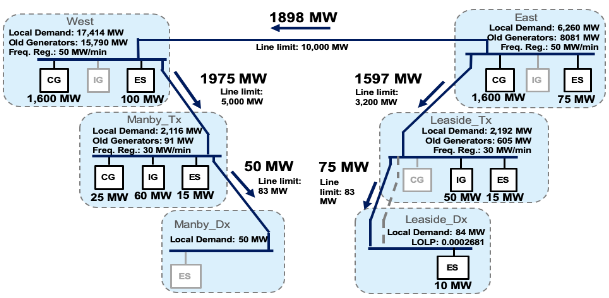

FIGURE 8. **Case B2: Results for simplified model of Toronto for energy & services.**

These cases can represent load growth in Toronto, Canada. In fact, the population in the Greater Toronto Area is projected to increase by more than 40.9% from 2020 to 2046 [31]. Peak demand in the Leaside_Dx zone is set at 84 MW, which is just above the transformer capacity of 83 MW between Leaside_Tx and Leaside_Dx. This situation considers demand growth in the Leaside_Dx zone, and this growth is exceeding the interconnection (i.e., transformer) capacity limits between Leaside_Tx and Leaside_Dx. This demand can be satisfied by building a new interconnection (i.e., transformer) or by sourcing local DERs (i.e., energy storage). Traditional planning would necessitate upgrading the transformer to accommodate the load growth – a very expensive option. Our transmission-distribution capacity market model enables new, cheaper, distribution-connected non-wires alternatives to meet the increased demand at a lower cost.

1) CASE B1: TRANSMISSION AND DISTRIBUTION SYSTEMS WITHOUT DISTRIBUTION CONNECTED DERs

The proposed capacity auction was run for the Toronto model described above, procuring both energy and services (i.e., constraints for services such as frequency regulation were enabled). Furthermore, a certain level of reliability was required in the Leaside_Dx zone (LOLP of 0.0002681). However, supply units were not available on the distribution system (Leaside_Dx and Manby_Dx). This is consistent with existing published ICA models since they lack the capability for including DERs.

The resulting power flows between zones and the amount of unforced capacity of each generator chosen during the auction period are shown in Fig. 7. Load growth in Leaside_Dx triggers the construction of a new interconnection – in this case, a transformer represented as a new line of 83 MW at $8,548/MW-day in Fig. 7–between this zone and the transmission system (Leaside_Tx), thereby dramatically increasing the zonal price in Leaside_Dx to $8,778/MW-day. The clearing price for each zone is in Table 6. The total social welfare of Case B1 is $6,182,221.

2) CASE B2: TRANSMISSION AND DISTRIBUTION SYSTEMS WITH DISTRIBUTION CONNECTED DERs

The proposed capacity auction was run for the same Toronto model as in Case B1, however, DERs connected to the distribution zones were included.

The resulting power flows between zones and the amount of unforced capacity of each generator chosen during the auction period are shown in Fig. 8.

The construction of new interconnections is expensive ($8,778/MW-day), and the interconnection is congested between the Leaside distribution and transmission zones. The energy storage unit at Leaside_Dx is therefore dispatched. Even though the local storage unit is more expensive at $250/MW-day than supply units available in other zones, the cost of upgrading the interconnection would make those units from other zones more expensive than the local one. Table 6 presents the clearing price for each zone for this case.

This case demonstrates the value of our zonal model in allowing distribution-connected resources to meet system energy needs at a lower cost than existing single-zone capacity auctions. With the inclusion of distribution-connected

TABLE 5. Supply bids for Toronto model (cases B1 & B2).

Zone	Supply Type	Fuel	Number of units	Number of Offers	Price Range of Bids ($/MW-day)	ICAP (MW)	Technical Availability (%)	Power Range for Frequency Regulation (MW/min)
West	Conventional Generators	Gas	2	2	50-80	1,242.48	96-97	5
		Hydro	1	1	30	421.06	95	5
	Intermittent Generators	Solar	2	2	130-225	928.57	30-35	10
		Wind	2	2	300-320	1,892.86	35-40	10
	Energy Storage	-	1	1	200	115.83	86	30
East	Conventional Generators	Gas	2	2	60-100	1,036.30	96-97	5
		Hydro	1	1	80	652.17	92	5
		Nuclear	1	1	350	2,551.02	98	5
	Intermittent Generators	Solar	2	2	170-200	591.52	28-32	10
		Wind	2	2	250-280	781.71	35-42	10
	Energy Storage	-	1	1	230	83.22	90	30
Manby_Tx	Conventional Generators	Gas	1	1	130	26.32	95	5
	Intermittent Generators	Solar	1	1	190	150	40	20
	Energy Storage		1	1	80	18.3	82	10
Leaside_Tx	Conventional Generators	Gas	1	1	150	53.2	94	5
	Intermittent Generators	Solar	1	1	200	131.58	38	30
	Energy Storage	-	1	1	120	15.96	94	10
Manby_Dx	Energy Storage	-	1	1	150	17.54	86	-
Leaside_Dx	Energy Storage	-	1	1	250	11.36	88	-

TABLE 6. Zonal clearing prices for Toronto models.

Zone	Case B1	Case B2
West	$230/MW-day	$230/MW-day
East	$230/MW-day	$230/MW-day
Manby_Tx	$230/MW-day	$230/MW-day
Leaside_Tx	$230/MW-day	$230/MW-day
Manby_Dx	$230/MW-day	$230/MW-day
Leaside_Dx	$8,778/MW-day	$250/MW-day

TABLE 7. Social welfare for Toronto models.

Case B1	Case B2	Improvement
$6,182,221	$6,535,498	5.7%

resources in our new multi-zonal system, social welfare has increased by 5.7% as shown in Table 7.

V. CONCLUSION

Only market models that include both buyer and seller information can truly maximize social welfare. This was absent in the traditional G&T model. As a way forward, a single zone ICA was developed [11]. However, the lack of line flow models resulted in incomplete solutions. This paper presents a zonal ICA model offering single-shot optimal planning while including buyer bids to ensure maximum social welfare. Our new model allows for more efficient and accurate outcomes because: (a) inter-zonal transmission limits can be considered; (b) DERs connected to distribution systems can also participate in the ICA market; and (c) price-sensitive demand is modeled.

In this context, a new zonal capacity market model with the mathematical formulation is proposed. The proposed zonal ICA model is applied to two systems: (a) a synthetic test system with two zones; and (b) Ontario, Canada's provincial power system with six zones. In fact, social welfare increased by 5.7% using our model for Toronto when distribution-connected DERs are permitted to participate.

The proposed single-zone energy-only incremental capacity market in Ontario, Canada is already expected to save consumers $290-$610 million annually [25]; augmenting it to include the zonal features in our model would bring even greater benefits to consumers. The main contributions to zonal capacity market formulations include the following features:

- Price-sensitive demand;
- Power flow between zones, thereby allowing for new lines, transformers, and distribution systems;
- DERs such as renewable generation and energy storage;
- Services such as frequency regulation, ramping, and reliability; and
- Suppliers' non-monotonically increasing-price bids.

The proposed zonal ICA model is particularly useful for solving real problems now facing growing urban centers like Toronto, where population growth in older neighborhoods is straining existing equipment limits. Traditional system expansions (e.g., new transformers and lines) are very expensive and sometimes not even feasible in these highly built environments. Our model incorporates these constraints to identify the most economically efficient solution, which could include new features such as DERs and inter-zonal transmission upgrades.

This new zonal capacity market formulation can enable a more comprehensive and competitive approach to both supply and asset planning. All suppliers compete on equal footing to meet energy and service needs, while risk can be transferred from the public (i.e., the central planning authority on behalf of consumers) to the private sector (i.e., third-party market participants). Asset upgrades are then performed only when the improvements lead to the most economically efficient outcomes, thereby lessening the probability of stranded assets.

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