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A nice electricity market design

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ABSTRACT

This paper proposes a nice electricity market design that is efficient and practical, meaningfully satisfying the wants of a market design's stakeholders. Hence, this new design should be considered by countries that have reformed their electricity sectors or are in the process of doing so.

1. Introduction

The global trend of electricity market reform (Sioshansi, 2013) has resulted in wholesale markets that house independent power producers (IPPs) and load serving entities (LSEs) and retail markets that house LSEs and end-use customers (Woo et al., 2003a). Fig. 1 is a stylized model of a restructured electricity sector in which end-use customers obtain energy and services from LSEs, which include local distribution companies (LDCs) that own and operate distribution networks and retailers that do not. To serve electricity needs unmet by the resources already owned or for which they have rights, LDCs and retailers buy from wholesale markets differentiated by structure (pool vs. bilateral). Large end-users (e.g., industrial firms) may do the same in a region like the Pacific Northwest in the U.S. or the Canadian province of Ontario. These market participants may use financial contracts (e.g., electricity futures and options) to manage their electricity risk exposure (Eydeland and Wolyniec, 2003; Deng and Oren, 2006).

Though not explicitly shown in Fig. 1, open transmission access enables electricity wholesale competition through active trading among market participants (Lusztig et al., 2006). Under the pool structure, an independent system operator (ISO) like those shown in Fig. 2 performs least-cost dispatch of heterogeneous generation units with diverse fuel types and heat rates, maintains real-time load-resource balances required by safe and reliable grid operation, and implements locational marginal pricing based on real-time marginal energy costs by electric node (Stoft, 2002). Under the bilateral structure, a buyer and a seller transact directly via bilateral negotiation under a regulated transmission company's open access transmission tariff. A good case in point is the day-ahead electricity trading in the Western Interconnection of the U.S (Woo et al., 2013), made possible by the U.S. Federal Energy Regulatory Commission's Order 888 *pro forma* tariff (Woo et al., 1998).

Market experience in the early 1990s indicates reforms can fail, unable to deliver reliable service to meet end-use consumption at competitive prices (Woo et al., 2003a, 2006). Over two decades later, two market design problems of missing money and price manipulation persist, as exemplified by Alberta's wholesale electricity market with an energy-only design (Brown and Olmstead, 2017).

The missing money problem occurs when a wholesale electricity market cannot provide adequate investment incentives for conventional generation units, including combined cycle gas turbines (CCGTs) and combustion turbines (CTs) (Joskow, 2013). The price manipulation problem occurs when IPPs exercise their market power that can, even in the absence of a generation capacity shortage or transmission constraints, cause abnormally high wholesale market prices (Wolfram, 1999; Borenstein et al., 2002).

Exacerbating the missing money problem is the price reduction (*aka* merit order) effect of renewable energy (RE) like wind and solar that has zero fuel cost and displaces thermal generation (Woo et al., 2016a, 2017a, 2017b, 2018; Zarnikau et al., 2019).[1] Essential for deep decarbonization (Williams et al., 2012), the world's large-scale RE development is attributable to resource abundance (Hoogwijk et al., 2004; Marini et al., 2014) and such government policies as easy and low-cost

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[1] A dramatic case in point is an electric grid's occasional inability to fully absorb the non-dispatchable generation from solar and wind resources. Consequently, negative prices are used to induce dispatchable generation (e.g., CCGT) owners to curtail their output so as to maintain the grid's real-time load-resource balance (https://energyathaas.wordpress.com/2017/04/24/is-the-duck-sinking/).

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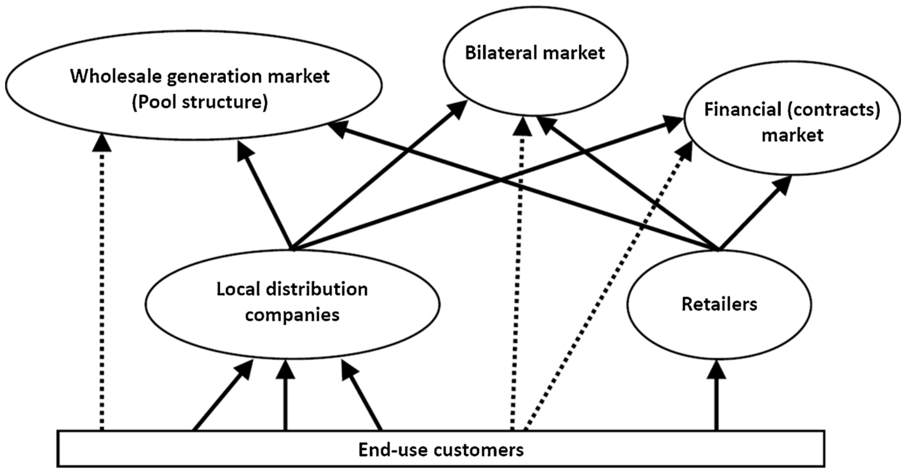

Fig. 1. A restructured electricity sector's stylized model.

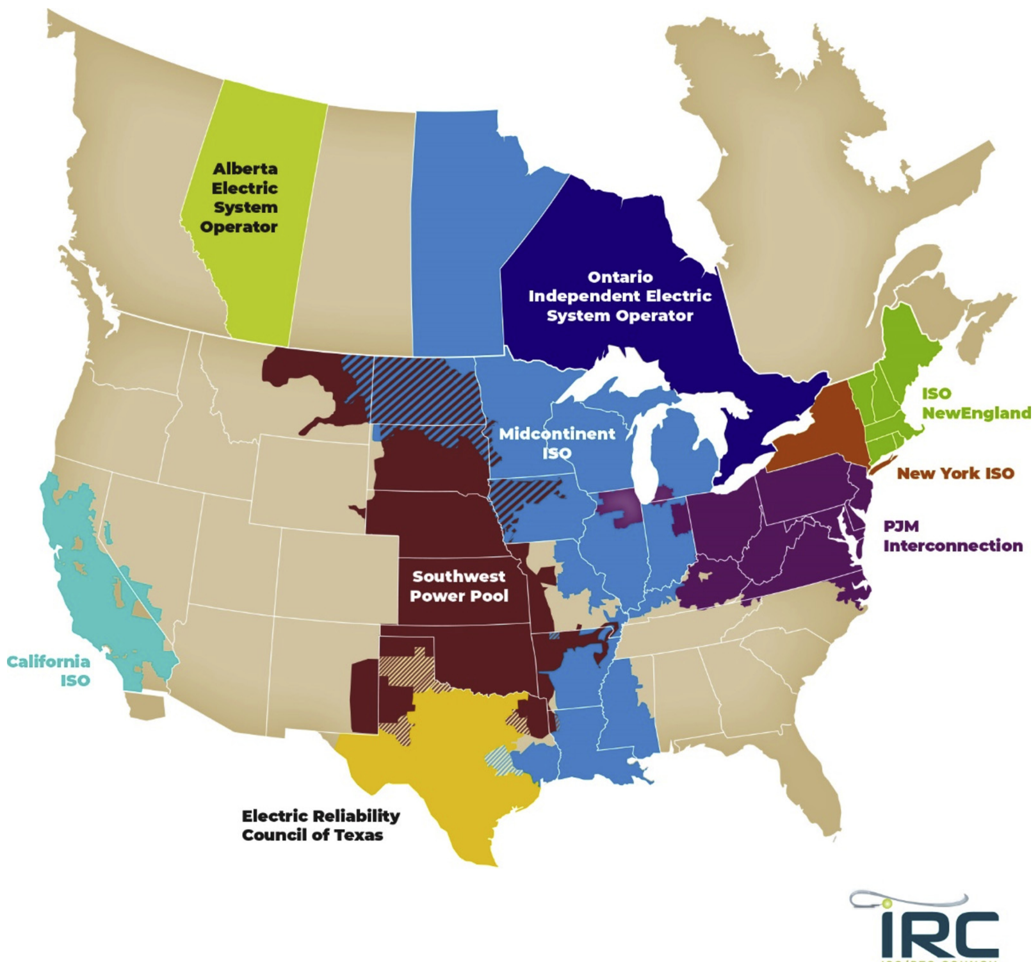

Fig. 2. ISOs in North America (Source: ISO/RTO Council).

transmission access, financial incentives (e.g., feed-in-tariffs, government loans and grants, and tax credits), and quota programs (e.g., renewable portfolio standards, cap-and-trade programs for carbon emissions certificates, and renewable-energy credits) (Alagappan et al., 2011; Zarnikau, 2011; Green and Yatchew, 2012).

Motivated by the two aforementioned problems, this paper proposes a new market design to achieve electricity reliability, market competition and RE development. It informs the ongoing market design debate documented by several recent studies (Spees et al., 2013; Cramton, 2017; Coester et al., 2018; Conejo and Sioshansi, 2018; Newbery et al., 2018; Bublitz et al., 2019).

Our newly proposed design uses an ISO's existing practice of least-cost dispatch of heterogeneous generation units, real-time market (RTM) price determination, and capacity rationing during a shortage.[2]

[2] A description of California's plan of emergency actions is available at https://www.caiso.com/Documents/

It mirrors LSEs in states like California and Texas that procure RE contracts to meet their load obligations. It solely relies on market forces to provide adequate incentives for generation investments. It does not use such remedies as capacity payments and price caps (Milstein and Tishler, 2019), subsidized market entry (Brown, 2018a), centralized capacity auctions (Brown, 2018b), and cost auditing of generation units (Munoz et al., 2018).

Section 2 shows that our proposed design is efficient and practical. Section 3 concludes that this design is nice, thus meaningfully satisfying the wants of a market design's stakeholders. Hence, it deserves consideration by countries that have implemented electricity market competition (e.g., the U.S. and Canada in North America; Chile and Brazil in South America; the European Union; Australia, New Zealand and Singapore in Asia Pacific) or are in the process of doing so (e.g., China, Japan, India and Korea in Asia).

2. Materials and methods

2.1. What do an electricity market design's stakeholders want?

Our search for a nice design begins with a simple question: what do an electricity market design's stakeholders want? By no means exhaustive, these stakeholders are listed below.

First, electricity economists aim for a market-based outcome of economic efficiency (Stoft, 2002), implementing the rules of efficient pricing, planning and operation for social welfare maximization (Chao, 1983). Unfortunately, a textbook model of perfect competition exemplified by an energy-only market design used by Texas, Alberta and Ontario can cause the problems of missing money and price manipulation. Adopted remedies for the missing money problem include: (a) centralized capacity auctions to provide additional revenues to IPPs (e.g., New England, New York and PJM); (b) resource adequacy requirements (RAR) (e.g., California, Midcontinent and Pacific Northwest); and (c) administratively set price adders based on the concept of an operating reserve demand curve (e.g., Texas) (Spees et al., 2013; Cramton, 2017). To counter IPPs' potential of price manipulation, North American ISOs use market surveillance to identify abnormal price spikes and sanction against the offending IPPs. Similar to cost auditing of generation units used in South America (Munoz et al., 2018), an ISO like the California Independent System Operator (CAISO) may use a market power test to exclude generation supply bids with price quotes exceeding its preset price limits (Woo et al., 2018). While these reasonable remedies are effective, they may be seen as *ad hoc* and piecemeal, offering room for improvement via a new design proposed below.

Second, electrical engineers plan and operate an electricity grid (Wood and Wollenberg, 2012). Obeying the laws of physics and appreciating a grid's complexities, they worry about load-resource balance and resource adequacy that are essential for the grid's safe and reliable operation, which has become increasingly challenging because of large-scale development of intermittent solar and wind resources (Zarnikau et al., 2019). As a result, North American electricity grids are subject to generation planning and operating reserve requirements.[3] Underscoring California's RAR (Woo et al., 2016b), a planning reserve requirement is the reserve margin of ~15% of a grid's annual peak forecast, which is often based on the administratively set reliability criterion of loss-of-load-expectation of one-day-in-ten-years. To be met by an ISO's procurement of ancillary services (Zarnikau et al., 2019), the operating reserve requirement is ~6% of a grid's daily peak forecast.[4] As generation capacities are costly, reducing these reserve requirements without compromising a grid's reliability performance can yield large capacity cost savings. Our new design achieves such savings through reliability differentiation that implements efficient capacity rationing during a generation shortage (Chao and Wilson, 1987; Woo, 1990).

Third, industry practitioners (e.g., electricity analysts, plant operators and traders) are practical folks. When considering a new market design, they responsibly ask the critical question: how may a new design work in practice? If the design entails significant changes that are hard to understand and implement, its acceptance by practitioners is doubtful. Hence, the new design should preferably adopt, as much as possible, a grid's existing operating rules and practices; otherwise, it is a dead-on-arrival proposition.

Fourth, IPPs prefers a market environment of adequate and stable revenue streams that are critical for project financing at reasonable terms (Stern, 1998). They eschew fuel cost risks, as evidenced by a forward contract's risk premium of up to 10% of the spot price expectation (DeBenedictis et al., 2011). To encourage investments in CTs and CCGTs whose flexible capacity is necessary for a grid's RE integration, a nice market design should provide IPPs with stable revenues and minimal fuel cost risks.

Fifth, LSEs aim to best serve their retail end-users. A privately owned LDC (e.g., Pacific Gas and Electric Company in California) is subject to regulatory oversight that ensures reliable and environmentally friendly service at just and reasonable rates. A publicly owned LDC (e.g., Sacramento Municipal Utility District in California) has a public mandate similar to a privately owned LDC's regulatory goal. Like those in Texas (Distributed Energy Financial Group, 2015), a retailer offers competitive service plans differentiated by price level and design (e.g., flat vs. time-varying) and non-price term (e.g., reliability level, plan duration and renewable energy content). A nice market design should encourage LSEs' optimal procurement of generation resources that can match the preferences of their retail end-users.

Sixth, retail end-users prefer price reasonableness, price stability, customer choice, and clean electricity. A market design's retail pricing is deemed reasonable if it is based on a LSE's least-cost procurement of generation resources at competitively determined capacity prices and an ISO's least-cost dispatch that sets a grid's RTM prices for energy. As RTM prices are highly volatile, retail price stability may occur through price averaging (e.g., an end-user's monthly energy price is the equally-weighted average of RTM prices). An alternative is to make RTM prices strictly based on a grid's marginal fuel costs that are far less volatile than those reported in California, Texas and other parts of North America. Availability of customer choices allows a retail end-user to self-select its service reliability and preferred LSE. Clean electricity may come from a retail end-user's behind-the-meter RE installation (e.g., roof-top solar PV) and a LSE's RE procurement. A nice market design should encourage economically rational development of solar and wind resources that are now cost competitive relative to conventional generation resources (Islam et al., 2013; Jones-Albertus et al., 2018).[5]

Seventh, environmentalists prefer a clean and sustainable electricity future. Such a future may occur through RTM prices that fully pass through a cap-and-trade program's carbon prices (Woo et al., 2018). Along with RE's trend of declining capacity prices and rising capacity factors (Islam et al., 2013; Jones-Albertus et al., 2018), these RTM prices encourage a retail-end user's RE investment and a LSE's RE

(*footnote continued*)
SystemAlertsWarningsandEmergenciesFactSheet.pdf.

[3] Reliability standards of the North American Reliability Council (NERC) are available at https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

[4] tp://ftp2.cpuc.ca.gov/PG&E20150130ResponseToA1312012Ruling/2012/08/SB_GT&S_0560665.pdf

[5] "Onshore wind is one of the most competitive sources of new generation capacity. Recent auctions in Brazil, Canada, Germany, India, Mexico and Morocco have resulted in onshore wind power (costs) as low as USD 0.03/kWh" (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018.pdf, p.14).

procurement despite diminishing government support for RE development.

Finally, when gauging a market design's merit, regulators and policy makers use such criteria as reliable service at competitive prices, customer choice, practicality and environmental friendliness. These criteria requires a market design be incentive compatible (Laffont and Tirole, 1993), yielding a desirable outcome primarily driven by market participants' decentralized decisions based on maximizing self-interests.

2.2. A new market design

Our proposed design assumes a pool structure, comprising a wholesale market containing an ISO, IPPs and LSEs and a retail market with LSEs serving diverse end-use customers. To introduce wholesale reliability differentiation now absent in North America's pool market designs, it assumes that the ISO requires all LSEs under its jurisdiction to buy tolling agreements for thermal generation units. The ISO's must-buy requirement is unrestrictive in practice because a LSE preferring higher reliability can procure more MWs. Further, a LSE can choose to procure between zero MW and the peak MW load unmet by the resources already in place.[6]

Our proposed design's operation has a time sequence mimicking that of a North American ISO (e.g., CAISO). We use a 3-step process to demonstrate our design's merit. Step 1 assumes that each LSE optimally procures RE contracts and tolling agreements before the realization of RTM prices and weather conditions. Step 2 assumes that each LSE informs the ISO of its real-time net demand (= retail load – RE) curve under the realized weather condition. Step 3 assumes that the ISO uses all LSEs' procured tolling agreements and real-time net demand curves for least-cost dispatch, RTM price determination and capacity rationing. We analyze these steps recursively, aided by an explanation of the important role played by tolling agreements in our proposed design.

2.3. Why tolling agreements?

A tolling agreement is often based on a thermal generation unit fueled by natural gas (Eydeland and Wolyniec, 2003; Deng and Oren, 2006). After paying the agreement's upfront capacity price D (\$/MW-year), a buying LSE has the right, but not the obligation, to obtain electricity from a selling IPP at the strike price (= per MWh fuel cost) defined below:[7]

$$\$C/\text{MWh} = \text{Heat rate } HR \text{ (MMBtu/MWh)} \times \text{Fuel price } F \text{ (\$/MMBtu)} + CO_2 \text{ emissions cost } EC \text{ (\$/MWh)}. \quad (1)$$

The presumably cost-minimizing LSE exercises the right when the hourly spot market price P (\$/MWh) exceeds C, earning an *ex post* per MWh variable profit of max(P – C, 0) that measures the LSE's per MWh cost saving from not buying spot electricity at high RTM prices (Woo et al., 2016b).

Eq. (1) includes EC to fully pass through a carbon cap-and-trade program's impact to a grid's market prices (Woo et al., 2017a, 2017b, 2018). As $EC = HR$ (MMBtu/MWh) $\times$ CO_2 emissions from burning fossil fuel (metric ton/MMBtu) $\times$ CO_2 price (\$/metric ton),[8] it is higher for units with higher HR than those with lower HR.

Tolling agreements play an important role in our proposed design for the following reasons. First, they are used by a LSE to comply with the ISO's must-buy requirement. Second, they signal what a LSE should buy. For example, rising CO_2 prices tend to encourage a LSE's procurement of agreements for fuel-efficient units with relatively low CO_2 emissions. Finally, a LSE's procured tolling agreements enable the ISO's efficient capacity rationing and RTM price determination, as explained in the next subsection below.

2.4. Step 3: the ISO's efficient capacity rationing and RTM price determination

The ISO's capacity rationing scheme operates as follows. When the grid has a capacity surplus, ***all*** LSEs' net loads (= retail MWh loads – RE MWh output) are fully met, thus precluding the inefficient outcome of load curtailment for ***some*** LSEs when the grid has a capacity surplus. When the grid has a capacity shortage, each LSE receives its procured tolling agreements' total capacity available during the shortage. The resulting allocation of the grid's limited capacity in a shortage hour is *ex post* efficient under the assumption that LSEs' net loads exhibit similar time and weather dependence (Woo, 1990). This assumption is empirically reasonable, as evidenced by California's and Texas's summer peaking LDCs that all see high air conditioning loads on hot afternoons and the Pacific Northwest's winter peaking LDCs that all face high space heating loads on cold evenings.

With reliability differentiation in place, Fig. 3 illustrates the ISO's RTM price determination based on a least-cost dispatch of the generation units underlying the LSEs' procured tolling agreements. The ISO's real-time dispatch implicitly assumes: (a) the LSEs have delegated their rights to the ISO for obtaining electricity at the per MWh fuel costs defined by Eq. (1); and (b) the ISO knows the per MWh fuel costs of these units based on the contractual terms of the LSEs' procured agreements submitted to comply with the ISO's must-buy requirement.

The solid green line in Fig. 3 portrays a hypothetical grid's generation stack of K_{1h} MW of CCGTs and K_{2h} MW of CTs available in hour $h = 1, \ldots, H$ (= 8760 for an annual analysis assumed herein).[9] The per MWh fuel costs for the CCGTs and CTs are C_{1h} and C_{2h} respectively. The red dashed lines are the grid's strictly positive net demands.[10] The grid's RTM price is $P_h = C_{1h}$ under mild weather and $P_h = C_{2h}$ under extreme weather. Rather than allowing P_h to rise above C_{2h}, the ISO uses capacity rationing in the shortage hour to resolve the difference between the grid's aggregate Q_h at $P_h = C_{2h}$ and total available capacity at $K_h = K_{1h} + K_{2h}$. As these RTM prices are solely driven by the per MWh fuel costs, they are far less volatile than the RTM prices actually observed in North America. Importantly, these RTM prices are free from IPPs' manipulation because they are set *sans* IPPs' supply bidding, which is currently used in a North American ISO's RTM operation (Woo et al., 2018; Zarnikau et al., 2019).

Our design's financial settlement is as follows. Each LSE pays P_h for each MWh bought from the ISO's RTM. The ISO's total RTM revenue is the sum of the energy payments made by all LSEs. The ISO uses the total RTM revenue to pay the fuel costs incurred by the dispatched generation units. Unless $P_h = C_{1h}$ = minimum RTM price for all hours, the ISO's total RTM revenue exceeds total fuel cost payment, resulting in a strictly positive operating surplus. As the ISO refunds the surplus according to its actual dispatch of each LSE's contracted generation units, its RTM operation breaks even with certainty unless some LSEs fail to make their RTM payments to the ISO.

[6] If a LDC owns generation capacity in excess its retail load obligations, it profitably sells its surplus power into the ISO's RTM market.

[7] For expositional simplicity, Eq. (1) intentionally ignores the per MWh costs for variable O&M, startup and ramping. Including these additional cost terms arithmetically complicates our market design analysis *sans* the benefit of additional insights.

[8] Without any loss of generality, the market-based CO_2 price used here may be replaced by an administratively set CO_2 tax.

[9] Without any loss of generality H can be readily changed by modifying the time-scale (e.g., from 60-minute to 5-minute) and H's size (e.g., from 8760 to 12 $\times$ 8,760 = 105,120 for the 5-minute time scale or from 8760 to 10 $\times$ 8,760 = 87, 600 for a 10-year analysis based on the 60-minute time scale).

[10] While negative net demands are possible and can cause negative RTM prices, they are relatively rare events even in states like California and Texas with large scale RE development and therefore not considered herein.

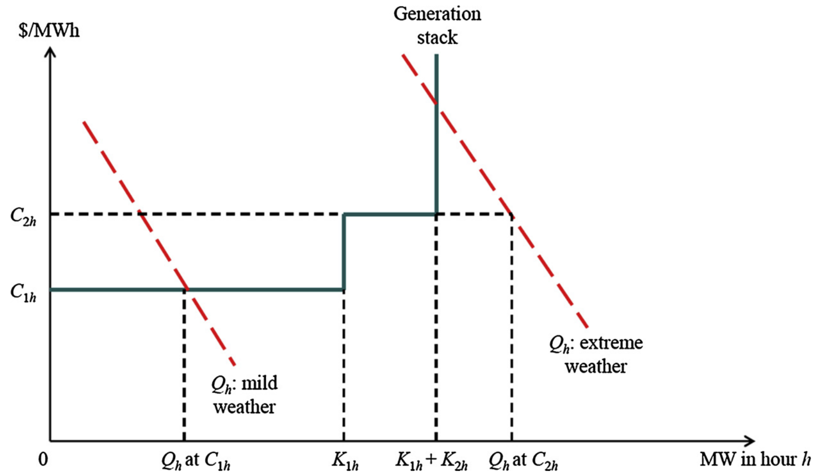

Fig. 3. The ISO's least-cost dispatch, RTM price determination and capacity rationing.

2.5. Step 2: LSEs' submission of net demand curves to the ISO

Submitted to the ISO shortly (e.g., within 30 min) before the real-time dispatch, a LSE's net demand curve states the MWh quantities demanded at different RTM prices. Each quantity demanded is the aggregate of the LSE's retail end-users' net loads less the output from the LSE's RE contracts. Each end-user's net load is the end-user's gross load less behind-the-meter generation.

Using an accurate 30-minute-ahead weather forecast, the LSE estimates its net demand curve based on the assumption that each retail end-user maximizes its net benefit of electricity consumption. This net benefit is the gross benefit from consuming X MWh, less the sum of (a) the energy bill for buying (X – Y) MWh from the LSE at the RTM price; (b) the procurement cost of Y MWh of behind-the-meter generation; and (c) the LSE's pass through of the ISO's surplus refund via a customer rebate that reduces the retail end-user's customer charge.

A retail end-user achieves net benefit maximization when its marginal benefit of electricity consumption equals the RTM price (Woo et al., 2008), which also equals its marginal procurement cost of behind-the-meter generation (Woo and Zarnikau, 2017). In the era of prosumers (Parag and Sovacool, 2016), this market-based outcome yielded by retail end-users' decentralized decisions affirm efficient pricing of retail kWh consumption based on the ISO's RTM prices. The next subsection shows how to price a retail end-user's kW demand, leading to an efficient Hopkinson tariff design comprising real-time per kWh energy charges and a per kW demand charge for firm power (Woo, 1990; Seeto et al., 1997).

2.6. Step 1: a LSE's optimal procurement

A LSE's optimal procurement answers the questions of "what to buy?" and "how to buy?" We bypass the question of "when to buy?" by simply assuming that all LSEs complete their procurement plans near the end of year t-1 and conduct procurement auctions at the end of year t-1 before actual consumption takes place in year t. While a further exploration of the "when to buy?" question is important and fruitful, it is well beyond the intent and scope of this paper.

2.6.1. What to buy?

A LSE's optimal procurement plan states what the LSE should buy as a result of integrated resource planning (Sreedharan et al., 2012). The LSE's choice variables are the MW amounts of RE contracts and tolling agreements and the plan's total MW size.

To develop its optimal procurement plan, the LSE uses the decision rule that the marginal benefit of a chosen MW amount should equal the capacity price. To see this point, consider hour h's per MW capacity benefit of a RE contract. As the LSE uses the RE contract's output to meet its retail loads, this benefit is:

$$W_h = P_h \times S_h \tag{2}$$

where S_h = capacity factor of renewable generation.

Eq. (2) makes sense because one MW of renewable capacity expansion that yields an additional MWh of RE reduces the LSE's RTM procurement cost by an amount equal to the RTM price P_h. But renewable generation is time- and weather-dependent, with a random capacity factor between 0% and 100%. For example, solar generation is at full capacity in a sunny daytime hour, diminishes with cloudiness and is zero in a nighttime hour. Similarly, wind generation is at full capacity at a high wind speed, diminishes with declining wind speed and becomes zero in a windless hour. Hence, Eq. (2) uses S_h to scale P_h to obtain the per MW benefit of RE capacity in hour h.

The expected annual per MW benefit of RE capacity is

$$W = \Sigma_h \mathrm{E}(W_h). \tag{3}$$

The LSE should sign a RE contract, up the MW level at which the contract's capacity price equals the expected benefit W given by Eq. (3). As a result, large-scale RE development can naturally occur *sans* government intervention under one or more of the following three conditions: (1) the grid's marginal fuel costs are expected to rise due to escalating prices for fuel and CO_2 emissions; (2) RE's capacity factors are projected to improve due to technological advancements; and (3) RE's capacity prices are forecast to decline because of cost reductions in the manufacturing of solar panels and wind turbines.

Suppose there are J heterogeneous tolling agreements available for a LSE's procurement consideration. Tolling agreement j's per MW capacity benefit in hour h has two parts. Part 1 is the agreement's operating profit (Woo et al., 2016b):

$$A_{jh} = \max(P_h - C_{jh}, 0) \times \alpha_{jh}, \tag{4}$$

where C_{jh} = strike price in hour h based on Eq. (3); and α_{jh} = availability factor of agreement j's underlying generation unit in hour h. The presence of α_{jh} in Eq. (4) recognizes that the underlying generation unit may be unavailable due to planned and forced outages. Part 2 is the agreement's reliability benefit (Woo et al., 2019):

$$B_{jh} = LOLP_h \times VOLL_h \times \alpha_{jh}, \tag{5}$$

where $LOLP_h$ = loss of load probability in hour h; and $VOLL_h$ = value of loss load in hour h.

Tolling agreement j's expected annual per MW capacity benefit is:

$$Z_j = \Sigma_h \mathrm{E}(A_{jh} + B_{jh}). \tag{6}$$

The LSE should sign tolling agreement *j* up to the MW level at which $Z_j = D_j$ = toll agreement *j*'s capacity price.

Eq. (6) enables the LSE to compare the financial merits of two tolling agreements. When the underlying generation units have similar availability, their capacity price difference should approximately equal their expected annual operating profit difference, chiefly because these generation units offer similar expected annual reliability benefits.

Eq. (6) indicates Σ_h E(A_{jh}) < D_j for all $j = 1, \ldots J$, implying that the LSE's procured tolling agreements do not break even. Hence, the LSE implements retail reliability differentiation by mandating demand subscription service (DSS) (Woo, 1990; Seeto et al., 1997).

Using a Hopkinson tariff design, DSS has a monthly demand charge ($/kW-month) applicable to an end-use customer's mandatory subscription of firm service level (FSL), the kW amount that the LSE is obligated to provide in a grid's generation capacity shortage hour. It enables the LSE's efficient capacity allocation because retail end-users preferring higher reliability can subscribe bigger FSLs (Woo, 1990).

The LSE's DSS implementation uses an opt-in approach under which a retail end-user's default FSL subscription is the end-user's historic peak kW demand. The end-user can then self-select a lower FSL to obtain a bill discount because non-firm kW demand (= historic peak kW – self-selected FSL) is not subject to the kW demand charge (Seeto et al., 1997). Hence, DSS encompasses the commonly used demand response programs of interruptible and curtailable rate options offered by a LDC (Woo et al., 2008).

Under DSS, the LSE's demand charge is based on the tolling agreements' capacity prices (Woo et al., 2019). Illustrating this point is the example of a tolling agreement for a 50-MW CT that is assumed to have the highest per MWh fuel cost and lowest capacity price. As the maximum RTM price is capped by this agreement's per MWh fuel cost, the agreement's expected operating profit is zero and as a result, the annual per MW capacity benefit can be estimated using this agreement's capacity price. Along with the LSE's hourly energy charges set at RTM prices for kWh actually consumed by a retail end-user, DSS meaningfully links a grid's wholesale and retail markets.

Using its retail end-users' total FSL subscription, the LSE determines the MW size of its procurement plan based on the thermal generation units' annual availability factors (Woo et al., 2019), yielding an optimal reserve margin that is likely less than what has been adopted in North America. To see this point, consider the LSE's maximum retail MW demand in a grid's shortage hour: M = sum of retail FLS subscriptions that are known with certainty before actual consumption takes place. Because M eliminates the LSE's coincident peak demand uncertainty, an estimate for the procurement plan's MW size is (M / α), where α = average availability factor based on the forced outage rates of the thermal generation units during hours of a likely shortage.[11] Hence, the LSE's planning reserve margin is $R \equiv$ planned MW capacity ÷ peak MW demand = $(1/\alpha) - 1$.

At $\alpha \approx 0.95$ for new CCGTs and CTs, $R \approx 5.3\%$ that matches the operating reserve requirement of ~6% for an American grid but is well below California's adopted planning reserve margin of 15% and Texas's 13.75%. To be sure, the R value of 5.3% is likely too low because it does not account for an ISO's transmission constraints. It nevertheless highlights the potential benefit from implementing DSS at the retail level.

2.6.2. How to buy?

Absent an active market for RE contracts and tolling agreements, a LSE uses a procurement auction. The auction process has three steps (Woo et al., 2004, 2016b): (1) the LSE issues a request for proposal (RFP) to announce its total MW target (e.g., 1000 MW) and eligibility criteria for auction participation by IPPs; (2) interested IPPs then respond to the RFP by making offers of RE contracts and tolling agreements; and (3) subject to cost benchmarking (Orans et al., 2004), the LSE selects the winning offers to execute its optimal procurement plan. Thanks to the selected IPPs' revealed preference, the winning offers necessarily embody sufficient investment incentives for generation investments. Importantly, these IPPs do not face fuel cost risks because their revenues solely come from the LSE's capacity payments.

Aided by cost benchmarking, the LSE's procurement auction is expected to yield competitively determined capacity prices (Klemperer, 2004) that track the per MW-year capacity costs of new generation units. Successful procurement auctions (Woo et al., 2003b, 2004) allay concerns of non-competitive prices that may arise in a Cournot market for generation capacity (Munoz et al., 2018).

[11] As the ISO has control over the LSE's tolling agreements, it can order scheduled maintenance in the mild-weather spring months of April and May when the grid has surplus capacity because of low hourly system demands.

3. Conclusion

We conclude by first recapping our proposed design's meritorious attributes. First, our proposed design facilitates large-scale RE development *sans* government intervention. Second, it is practical because it adopts an ISO's current practice of least-cost dispatch, the RTM price determination and capacity rationing. Third, it uses market forces to determine a grid's optimal reserve margin with adequate investment incentives. Fourth, it does ***not*** use such *ad hoc* remedies as capacity payments, RTM price caps, subsidized market entry, centralized capacity auctions, administratively determined price adders, and cost auditing of generation units. Fifth, it uses DSS to meaningfully link a grid's wholesale and retail markets. Finally, it responds to the wants of an electricity market design's stakeholders.

Underscoring the final attribute are the following remarks. First, our proposed design is economically efficient, thus achieving energy economists' main design goal. Second, it ensures resource adequacy and real-time resource balance, thus addressing the primary concerns of electrical engineers. Third, it is practical because of its readily implementable components. Forth, it creates a financially stable market environment with adequate incentives for IPPs' investments. Fifth, it is consistent with LSEs' objectives of best serving their end-use customers. Sixth, it matches retail end-users' preferences for customer choice, price stability, price reasonableness, and clean electricity. Seventh, it encourages large-scale RE development that pleases environmentalists. Finally, it furthers the goals of regulators and policy makers. To conclude, these remarks affirm that our proposed design is nice, leading to our recommendation that the design be considered in the ongoing debate of electricity reliability, market competition and RE development.

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