

ISO Net Surplus Extraction in Restructured Wholesale Power Markets

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Abstract—This study uses dynamic 5-bus and 30-bus test cases to explore the social efficiency implications of the net surplus (congestion rents) collected and redistributed by ISOs in restructured wholesale power markets with grid congestion managed by locational marginal pricing (LMP). Demand price sensitivity and generator learning capabilities are taken as treatment factors. A key finding is that ISO net surplus substantially increases as the price-sensitivity of demand is reduced and the learning capabilities of generators are increased, conditions resulting in greater economic capacity withholding and a possible wastage of resources. A practical implication is that a more transparent public oversight of all net surplus extractions and uses in wholesale power markets operating under LMP would be publicly prudent because these extractions are not structurally well-aligned with social efficiency objectives.

Index Terms—Restructured wholesale power markets, locational marginal pricing, ISO net surplus (congestion rents), social efficiency, learning, demand-bid price sensitivity, AMES Test Bed

I. INTRODUCTION

AS elaborated in [1], over 50% of electric power generation in the U.S. is now traded at wholesale using locational marginal prices (LMPs). Under this pricing scheme, the solutions of suitably formulated optimal power flow problems at successive time intervals are used to price electric power in accordance with the location of its injection into or withdrawal from the transmission grid [2].

More precisely, an LMP at a particular grid location is the least cost to the system of providing an additional increment of power at that location. Congestion arising on any grid branch necessarily results in separation between the LMPs at two or more pricing locations. Ideally, as explained in [3], this LMP separation should encourage transmission enhancements that relieve grid congestion, encourage new generation to locate where it has the greatest value, and encourage load to locate where it can be serviced most cheaply.

As is well-known, however, given branch and generation capacity limits, the physical laws regulating the flow of power on non-radial transmission grids can result in counter-intuitive LMP separation outcomes [4],[5, Chp. 6]. For example, LMPs at the two ends of a branch can separate without the branch being congested, power can flow from higher to lower price

locations, and the price at a load-only location can be strictly higher or strictly lower than the marginal cost of all marginal (non-capacity-constrained) generation.

Another important LMP separation outcome is the creation of a net earnings stream whose use is discretionary to the independent system operator (ISO). When LMPs separate across the grid, the prices paid by load-serving entities (LSEs) can diverge from the prices paid to generation companies (GenCos). The difference between total LSE payments and total GenCo receipts, referred to below as *ISO net surplus*,¹ is collected and redistributed by the ISO.

Previous research has shown that ISO net surplus is necessarily non-negative under standard DC OPF formulations; see [7, Prop. 2.1]. Simulation findings in [4, Fig. 11] demonstrate the strong sensitivity of ISO net surplus to variations in line flow limit specifications. To date, however, the social efficiency² implications of ISO net surplus extractions and uses do not appear to have been systematically examined.

Standard market efficiency analysis, entailing the maximization of the total net surplus extracted in a single market, is increasingly being applied to the study of power markets (e.g., [8],[9]). However, this standard analysis focuses on seller and buyer net surplus extractions. It does not consider the possibility that an agency tasked with clearing the market, here the ISO, is able to extract net surplus along with sellers and buyers, a feature that appears to raise conflict of interest issues. Moreover, it does not consider the more comprehensive issue of *social* efficiency.

This study uses the AMES Wholesale Power Market Test Bed ([10],[11]) to investigate ISO net surplus extractions in relation to social efficiency for dynamic 5-bus and 30-bus test cases under systematically varied settings for demand-bid price sensitivity and the learning capabilities of GenCos. Developed by H. Li, J. Sun, and L. Tesfatsion, AMES (Agent-based Modeling of Electricity Systems) captures key aspects of the two-settlement LMP market system as implemented in the Midwest ISO [12] and other U.S. restructured wholesale power markets.

Our key finding is that ISO net surplus is enhanced in circumstances *unfavorable* to social efficiency. Specifically,

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¹When grids are modeled as lossless, LMP separation only arises in the presence of congestion and the net surplus extracted by the ISO is then sometimes referred to as *congestion rent*. In economics, however, “rent” has the precise meaning of a payment received by a resource in excess of the amount needed to retain the resource in its current productive use.

²Economists standardly measure *social efficiency* in terms of the current and future non-wastage of resources in either physical or value terms [6]. In contrast, *social welfare* is measured in terms of the current and future “utility” (well-being) of people in their roles as consumers of final goods and services.

ISO net surplus substantially increases with increased congestion, with decreased price-sensitivity of demand, and with increased GenCo learning capabilities that lead to increased economic capacity withholding. Indeed, if regulated rates for LSEs are adjusted in step with wholesale power prices, the net surplus of the ISO, GenCos, and LSEs all increase in these same circumstances; resulting net surplus losses are borne by retail consumers and/or taxpayers. The transfer of ISO net surplus to FTR holders or load does not necessarily rectify any overall loss of net surplus that ensues from these net surplus redistributions. These findings strongly suggest that a more transparent public oversight of net surplus extractions and uses in wholesale power markets operating under LMP would be publicly prudent.

II. AMES TEST BED: SUMMARY OVERVIEW

The AMES(V2.03) wholesale power market operates over an AC transmission grid starting with hour 00 of day 1 and continuing through hour 23 of a user-specified maximum day. AMES includes an *Independent System Operator (ISO)* and a collection of energy traders consisting of *Load-Serving Entities (LSEs)* $j = 1, \dots, J$ and *Generation Companies (GenCos)* $i = 1, \dots, I$ distributed across the buses of the transmission grid.

As explained more carefully in Section III, the objective of the not-for-profit ISO is the maximization of “total net surplus” subject to transmission constraints and GenCo operating capacity limits. In an attempt to attain this objective, the ISO operates a day-ahead market settled by means of LMP.

The objective of each LSE j is to secure for itself the highest possible net earnings each day through the purchase of power in the day-ahead market and the resale of this power to downstream (retail) consumers. During the morning of each day D , each LSE j reports a *demand bid* to the ISO for the day-ahead market for day $D+1$. Each demand bid consists of two parts: fixed demand (i.e., a 24-hour load profile) that can be sold downstream at a per-unit regulated rate r ; and 24 price-sensitive inverse demand functions (one for each hour) representing downstream price-sensitive retail-consumer demand. LSEs have no learning capabilities; LSE demand bids are user-specified at the beginning of each simulation run.

The objective of each GenCo i is to secure for itself the highest possible net earnings each day through the sale of power in the day-ahead market. During the morning of each day D , each GenCo i uses its current action choice probabilities to choose a supply offer from its action domain AD_i to report to the ISO for use in all 24 hours of the day-ahead market for day $D+1$. This *reported supply offer* consists of a marginal cost function defined over an operating capacity interval. GenCo i 's ability to vary its choice of a reported supply offer from AD_i permits it to adjust the ordinate/slope of its reported marginal cost function in an attempt to increase its daily net earnings.

After receiving demand bids from LSEs and reported supply offers from GenCos during the morning of day D , the ISO determines and publicly posts hourly LMP and dispatch levels for the day-ahead market for day $D+1$ as the solution to hourly bid/offer-based DC optimal power flow (DC-OPF) problems.

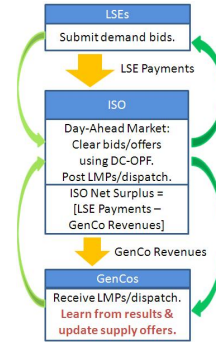


Fig. 1. AMES day-ahead market activities during a typical day D .

Grid congestion is managed by the inclusion of congestion cost components in LMPs. At the end of each day D the ISO settles the day-ahead market for day $D+1$ by collecting all purchase payments from LSEs and making all sale payments to GenCos based on the LMPs for the day-ahead market for day $D+1$, retaining the difference as *ISO net surplus*.

At the end of each day D , each GenCo i uses stochastic reinforcement learning to update the action choice probabilities currently assigned to the supply offers in its action domain AD_i , taking into account its day- D settlement payment (“reward”). In particular, if GenCo i 's reported supply offer on day D results in a relatively good reward, GenCo i increases the probability it will choose to report this same supply offer on day $D+1$, and conversely.

There are no system disturbances (e.g., weather changes) or shocks (e.g., line outages). Consequently, the dispatch levels determined on each day D for the day-ahead market for day $D+1$ are carried out as planned without need for settlement of differences in the real-time market.

Fig. 1 provides a schematic depiction of AMES day-ahead market activities during a typical day D .

III. LSE, GENCO, AND ISO NET SURPLUS

For each day D , LSE j 's *demand bid* for hour H of the day-ahead market in day $D+1$ consists of a fixed demand for power, $p_{Lj}^F(H,D)$, to be sold downstream at a regulated rate r , and a price-sensitive inverse demand function

$$D_{jH}(p_{Lj}^S) = c_j(H) - 2d_j(H)p_{Lj}^S \quad (\$/MWh) \quad (1)$$

defined over a *power purchase interval*

$$0 \leq p_{Lj}^S \leq SLMax_j(H) \quad (MW) \quad (2)$$

The expression $D_{jH}(p_{Lj}^S)$ denotes LSE j 's *purchase reservation value* for energy evaluated at p_{Lj}^S , i.e., the maximum dollar amount it is truly willing to pay per MWh.

Suppose LSE j , located at bus $k(j)$, is cleared at a load level $p_{Lj}(H,D) = [p_{Lj}^F(H,D) + p_{Lj}^S(H,D)]$ at price $LMP_{k(j)}(H,D)$ for hour H of the day-ahead market for day $D+1$. The *payments* of LSE j over all 24 hours of day $D+1$, incurred at the end of day D , are

$$Pay_j(D) = \sum_{H=00}^{23} LMP_{k(j)}(H,D) \cdot p_{Lj}(H,D) \quad (\$/h) \quad (3)$$

Using standard market efficiency analysis for buyers [6], the gross surplus $GS_j(D)$ for LSE j for day $D+1$, incurred on day D , is then given by the revenue amount

$$\sum_{H=00}^{23} \left[r \cdot p_{Lj}^F(H, D) + \int_0^{p_{Lj}^S(H, D)} D_{jH}(p) dp \right] \quad (4)$$

and the *LSE net surplus* for day $D+1$, incurred on day D , is

$$LSENetSur(D) = \sum_{j=1}^J [GS_j(D) - Pay_j(D)] \quad (5)$$

For each day D , the *reported supply offer* chosen by GenCo i to submit to the ISO for use in each hour H of the day-ahead market for day $D+1$ consists of a *reported marginal cost function*

$$MC_i^R(p_{Gi}) = a_i^R + 2b_i^R p_{Gi} \quad (\$/MWh) \quad (6)$$

defined over an *operating capacity interval*

$$Cap_i^L \leq p_{Gi} \leq Cap_i^U \quad (MW) \quad (7)$$

for the generation of power p_{Gi} . The expression $MC_i^R(p_{Gi})$ denotes GenCo i 's *reported sale reservation value* for energy evaluated at p_{Gi} , i.e., the minimum dollar amount it reports it is willing to accept per MWh. The reported marginal cost functions (6) can lie either on or above GenCo i 's *true marginal cost function*

$$MC_i(p_{Gi}) = a_i + 2b_i p_{Gi} \quad (\$/MWh) \quad (8)$$

At the beginning of any planning period, the *avoidable costs* of a GenCo refer to the production costs it can avoid during the period by shutting down and possibly taking additional actions (e.g., resale of purchased assets). Here it is assumed the *true avoidable cost function* for each GenCo i for any hour H is the integral of its true marginal cost function:

$$VC_i(p_{Gi}) = \int_0^{p_{Gi}} MC_i(p) dp = a_i p_{Gi} + b_i [p_{Gi}]^2 \quad (\$/h) \quad (9)$$

where p_{Gi} satisfies (7).

Suppose GenCo i , located at bus $k(i)$, is dispatched at level $p_{Gi}(H, D)$ at price $LMP_{k(i)}(H, D)$ for hour H of the day-ahead market for day $D+1$. The *revenues* of GenCo i over all 24 hours of day $D+1$, received on day D , are

$$Rev_i(D) = \sum_{H=00}^{23} LMP_{k(i)}(H, D) \cdot p_{Gi}(H, D) \quad (\$/h) \quad (10)$$

Net earnings are defined as revenues minus avoidable costs. Let the true avoidable costs incurred by GenCo i for any hour H of day $D+1$ based on its actual day- D dispatch $p_{Gi}(H, D)$ be denoted by $VC_i(H, D)$. Then the net earnings of GenCo i over all 24 hours of day $D+1$, incurred on day D , are

$$NE_i(D) = Rev_i(D) - \sum_{H=00}^{23} VC_i(H, D) \quad (\$/h) \quad (11)$$

Using standard market efficiency analysis for sellers [6], the *GenCo net surplus* for day $D+1$, incurred on day D , is then

$$GenNetSur(D) = \sum_{i=1}^I NE_i(D) \quad (12)$$

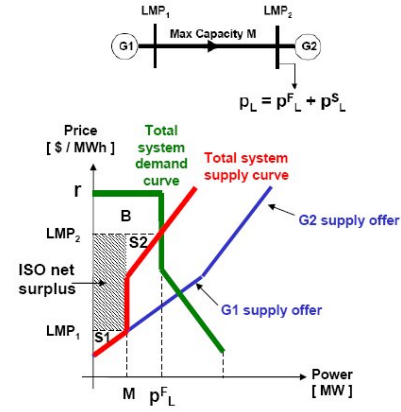


Fig. 2. Illustration of ISO net surplus extraction for a simple 2-bus system with a thermal branch limit M restricting power flow from the cheaper GenCo $G1$ at bus 1 to the load p_L at bus 2. (Figure adapted from [13].)

Finally, the *ISO net surplus* extracted by the ISO during any given day D is the difference between LSE payments and GenCo revenues for the day-ahead market for day $D+1$:

$$ISONetSur(D) = \sum_{j=1}^J Pay_j(D) - \sum_{i=1}^I Rev_i(D) \quad (\$/h) \quad (13)$$

An illustration of ISO net surplus extraction for a simple 2-bus system is depicted in Fig. 2. The LSE at bus 2 pays $LMP_2 > LMP_1$ for each unit of the cleared load p_L^F . However, M units of this cleared load are supplied by GenCo $G1$ at bus 1, who receives only LMP_1 per unit. The ISO net surplus extraction is then given by $M \times [LMP_2 - LMP_1]$.

The standard ISO DC-OPF objective used on day D for deriving LMP and dispatch solutions for day $D+1$ is the maximization of *total net surplus*, measured by the area $TotNetSur(D)$ between the total system demand and supply curves for day $D+1$. As carefully shown in [14], $TotNetSur(D)$ can be expressed as the following sum of component surpluses:

$$LSENetSur(D) + GenNetSur(D) + ISONetSur(D) \quad (14)$$

For example, $TotNetSur$ in Fig. 2 is the sum of the LSE net surplus B , the GenCo net surpluses $S1$ and $S2$ extracted by $G1$ and $G2$, and the ISO net surplus. When GenCos are learners, the ISO constructs $GenNetSur(D)$ in (14) using GenCo *reported* marginal costs (6) rather than *true* marginal costs (8).

IV. EXPERIMENTAL DESIGN

The experimental designs for our 5-bus and 30-bus experiments are based on the *benchmark dynamic 5-bus and 30-bus test cases* included as default test cases in the download of the AMES(V2.03) test bed [10].

As detailed in Li et al. [15], the benchmark dynamic 5-bus test case is characterized by the following structural, institutional, and behavioral conditions:

- The wholesale power market operates over a 5-bus transmission grid as depicted in Fig. 3, with branch reactances, locations of LSEs and GenCos, and initial hour-0 LSE fixed demand levels adopted from Lally [16].

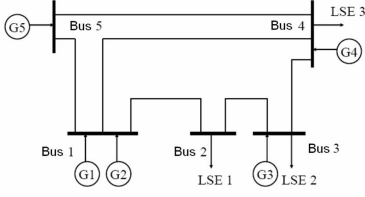


Fig. 3. Transmission grid for the benchmark dynamic 5-bus test case.

- True GenCo cost and capacity attributes are as depicted in Figure 4. GenCos range from GenCo 5, a relatively large coal-fired baseload unit with low marginal operating costs, to GenCo 4, a relatively small gas-fired peaking unit with relatively high marginal operating costs.

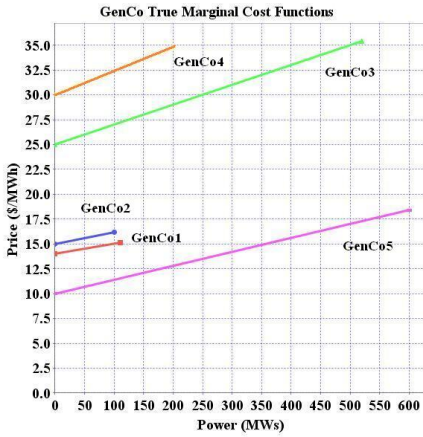


Fig. 4. GenCo true marginal cost functions and true capacity attributes for the benchmark dynamic 5-bus test case.

- Demand is 100% fixed (no price sensitivity) with LSE daily fixed demand profiles adopted from a case study presented in Shahidehpour et al. [17, p. 296-297]. Hourly load varies from light (hour 4:00) to peak (hour 17:00).
- GenCos are non-learners, meaning they report supply offers to the ISO that convey their true marginal cost functions and true operating capacity limits.

A complete input data file for this benchmark dynamic 5-bus test case is included as a default test case in the data directory of the AMES(V2.03) download [10].

The benchmark dynamic 30-bus test case used in this study is a modified version of the IEEE 30-bus system presented in [17, App. D.4, 477-478]. This 30-bus system has 9 GenCos, 21 LSEs, and 41 transmission grid branches. A complete input data file for this 30-bus system is included as a default test case in the data directory of the AMES(V2.03) download [10].

Two learning treatments are investigated in the experiments reported below: (a) As in the benchmark case, GenCos are non-learners; and (b) as detailed in Li et al. [15], each GenCo i is a learning entity that makes daily use of a stochastic reinforcement learning algorithm to adjust the ordinate and slope parameters $\{a_i^R, b_i^R\}$ of its reported marginal cost functions (6) in pursuit of increased net earnings.

To control for random effects when GenCos are learners, we use thirty pseudo-random number seed values to initialize thirty distinct runs, each 1000 (5-bus) or 500 (30-bus) simulated days in length. See Li et al. [15, Table III] for a listing of these seed values.

To investigate LSE demand-bid price sensitivity, we systematically vary the ratio R of maximum potential price-sensitive demand to maximum potential total demand in each hour H , starting from $R=0.0$ (100% fixed demand) and ending with $R=1.0$ (100% price-sensitive demand). A positive R value indicates that the LSEs are able to exercise at least some degree of price resistance. Figure 5 illustrates the construction of R for the special cases $R=0.0$, $R=0.5$, and $R=1.0$.

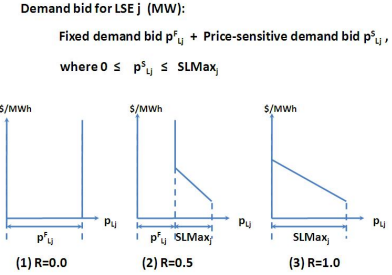


Fig. 5. Illustration of the R ratio construction for the experimental control of relative demand-bid price sensitivity in each hour H .

V. KEY FINDINGS

A. 5-Bus Benchmark-Case Findings

As detailed in Li et al. [15], during a typical day D for the benchmark dynamic 5-bus test case the branch 1-2 connecting bus 1 to bus 2 is persistently congested. As a result, in each hour there is complete LMP separation across the grid.

TABLE I
HOURLY GENCO NET EARNINGS DURING A TYPICAL 24-HOUR DAY D FOR THE BENCHMARK DYNAMIC 5-BUS TEST CASE.

Hour	GenCo 1	GenCo 2	GenCo 3	GenCo 4	GenCo 5
00	67.81	1.15	1,105.79	0.00	1,377.42
01	67.24	1.08	725.83	0.00	1,340.07
02	66.87	1.04	518.48	0.00	1,315.68
03	66.68	1.02	427.08	0.00	1,303.45
04	66.49	0.99	345.93	0.00	1,291.50
05	66.59	1.01	385.44	0.00	1,297.48
06	66.68	1.02	427.08	0.00	1,303.45
07	67.06	1.06	618.74	0.00	1,327.95
08	68.00	1.18	1,247.51	0.00	1,389.76
09	68.75	1.28	1,909.70	0.00	1,440.36
10	68.94	1.30	2,097.94	0.00	1,453.20
11	69.03	1.31	2,193.68	0.00	1,459.54
12	68.94	1.30	2,097.94	0.00	1,453.20
13	68.75	1.28	1,909.70	0.00	1,440.36
14	68.66	1.26	1,820.44	0.00	1,434.06
15	68.66	1.26	1,820.44	0.00	1,434.06
16	69.03	1.31	2,193.68	0.00	1,459.54
17	0.02	0.00	18,654.46	142.27	1,912.03
18	57.62	0.22	4,980.40	0.00	1,573.60
19	69.41	1.37	2,601.82	0.00	1,485.24
20	69.31	1.35	2,497.56	0.00	1,478.84
21	69.13	1.33	2,291.68	0.00	1,465.89
22	68.66	1.26	1,820.44	0.00	1,434.06
23	68.09	1.19	1,324.32	0.00	1,396.18
Total	1,556.41	26.58	56,016.09	142.27	34,266.94

As depicted in Table I, GenCos 1 and 2 have relatively small net earnings in all hours and particularly in the peak-demand

hour 17. This occurs for two reasons. First, as depicted in Fig. 3, these two GenCos are located at bus 1, hence they are semi-islanded away from the “load pocket” at buses 2 through 4 due to the persistent congestion on branch 1-2. Second, as seen in Fig. 4, these two GenCos have relatively small operating capacities.

In contrast, GenCo 3 located at the load-pocket bus 3 has relatively large net earnings in every hour, particularly in the peak-demand hour 17. This occurs because GenCo 3 is a pivotal supplier in most hours, meaning its relatively large capacity is needed to meet fixed demand. Moreover, during hour 17, GenCo 3 is dispatched at its maximum capacity and GenCo 5 is semi-islanded from bus 3 due to the congestion on branch 1-2. Consequently, to meet demand at bus 3 during hour 17, the ISO needs to call upon the expensive peaker unit, GenCo 4. This substantially spikes the LMP at bus 3 in hour 17, and hence the net earnings of GenCo 3.

GenCo 5 is essentially a base-load generator with large capacity and low marginal cost that is never dispatched at its maximum capacity. Consequently, although it is a pivotal supplier in most hours, its net earnings remain relatively flat.

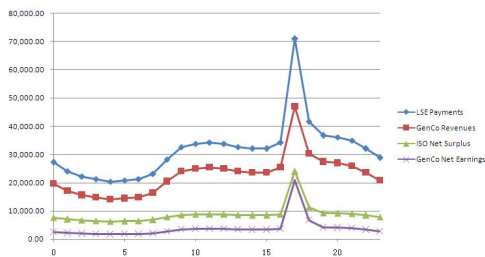


Fig. 6. LSE payments, GenCo revenues, ISO net surplus, and GenCo net earnings during a typical 24-hour day D for the benchmark dynamic 5-bus test case.

Fig. 6 presents benchmark-case hourly financial flows during a typical day D. Note that LSE payments are persistently higher than GenCo revenues, particularly during the peak-demand hour 17. Consequently, ISO net surplus is persistently positive with a spike during hour 17.

Indeed, as will be seen below in Table II, for a typical day D for the benchmark case ($R=0.0$), LSE payments are \$754,919.61 and GenCo revenues are \$545,508.54. Consequently, ISO net surplus is \$209,411.07, which is about 2.3 times the amount \$92,008.30 of GenCo net earnings.

B. 5-Bus Findings with Learning & Price-Sensitive Demand

For each R treatment, both with and without GenCo learning, congestion persistently occurs on branch 1-2. As seen in Fig. 7, however, the extension of the benchmark 5-bus test case to include GenCo learning and price-sensitive demand results in a substantial increase in mean LMP outcomes, particularly for small values of R . As more carefully explained in Li et al. [15], this substantial LMP increase arises because each GenCo i learns over time to exercise *economic capacity withholding*, i.e., to submit to the ISO reported marginal cost functions (6) that lie strictly above its true marginal cost function (8).

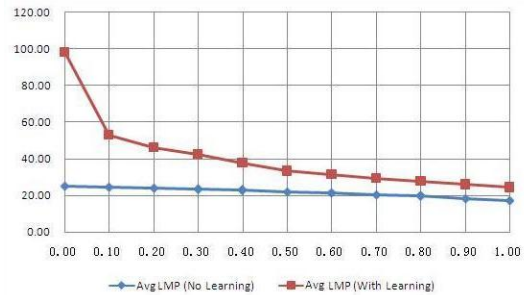


Fig. 7. Mean outcomes for average hourly LMP values on day 1000 for the benchmark dynamic 5-bus test case extended to include GenCo learning and demand varying from $R=0.0$ (100% fixed) to $R=1.0$ (100% price sensitive).

This economic capacity withholding by the learning GenCos also has dramatic effects on ISO net surplus extraction. These dramatic effects are graphically depicted in Figs. 8 and 9 and numerically reported in Tables II and III.

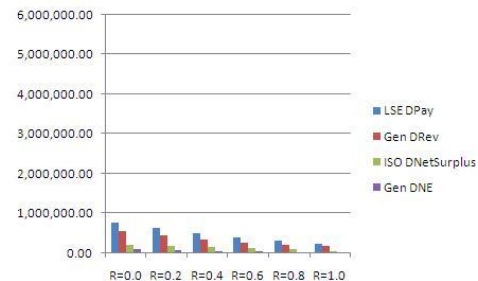


Fig. 8. LSE payments, GenCo revenues, ISO net surplus, and GenCo net earnings during a typical day D for the benchmark dynamic 5-bus test case extended to permit demand to vary from $R=0.0$ (100% fixed) to $R=1.0$ (100% price sensitive)

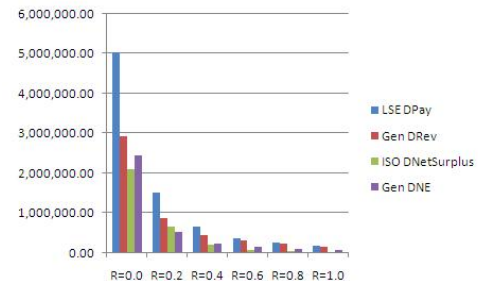


Fig. 9. Mean outcomes for LSE payments, GenCo revenues, ISO net surplus, and GenCo net earnings during day 1000 for the benchmark dynamic 5-bus test case extended to include GenCo learning and demand varying from $R=0.0$ (100% fixed) to $R=1.0$ (100% price sensitive)

Specifically, Fig. 8 and Table II present financial flows on a typical day D for the benchmark dynamic 5-bus test case extended to permit demand to vary from $R=0.0$ (100% fixed) to $R=1.0$ (100% price sensitive). As in the benchmark case, the GenCos submit supply offers to the ISO that reflect their true cost and capacity attributes. In contrast, Fig. 9 and Table III present corresponding financial flows on day 1000 for the case in which all five GenCos have learning capabilities. In particular, each GenCo applies stochastic reinforcement

TABLE II

GENCO NET EARNINGS, GENCO REVENUES, LSE PAYMENTS, AND ISO NET SURPLUS ON A TYPICAL DAY D FOR THE BENCHMARK DYNAMIC 5-BUS TEST CASE EXTENDED TO PERMIT DEMAND TO VARY FROM R=0.0 (100% FIXED) TO R=1.0 (100% PRICE SENSITIVE).

	R=0.0	R=0.2	R=0.4	R=0.6	R=0.8	R=1.0
GenCo 1 DNE	1,556.41	1,412.41	1,316.90	1,239.14	1,193.74	1,145.06
GenCo 2 DNE	26.58	10.93	4.30	1.42	1.21	0.43
GenCo 3 DNE	56,016.09	35,651.85	21,354.23	11,479.86	2,874.96	2,493.13
GenCo 4 DNE	142.27	13.91	0.00	0.00	0.00	0.00
GenCo 5 DNE	34,266.94	32,253.34	30,460.22	28,531.08	26,246.37	23,364.36
Total GenCo DNE	92,008.30	69,342.45	53,135.65	41,251.49	30,316.28	27,002.99
GenCo 1 DRev	38,356.90	38,599.53	37,574.43	36,411.03	35,826.48	34,932.06
GenCo 2 DRev	4,801.54	3,082.31	1,912.43	990.22	617.12	303.06
GenCo 3 DRev	321,967.71	229,151.51	144,201.72	74,559.64	24,303.90	17,528.99
GenCo 4 DRev	3,551.07	1,049.37	0.00	0.00	0.00	0.00
GenCo 5 DRev	176,831.32	169,568.69	163,032.42	155,905.91	147,307.23	136,178.18
Total GenCo DRev	545,508.54	441,451.41	346,721.00	267,866.80	208,054.73	188,942.29
Total LSE DPay	754,919.61	625,704.76	506,698.47	399,806.50	301,537.97	231,945.71
ISO DNetSurplus	209,411.07	184,253.35	159,977.47	131,939.70	93,483.24	43,003.42

learning to its past net earnings outcomes in an attempt to determine which supply offer it should report to achieve the highest daily net earnings.

Consider, for example, the R=0.0 (100% fixed demand) daily data presented for the benchmark no-learning case in Fig. 8 and Table II and for the learning case in Fig. 9 and Table III. Mean LSE payments on day 1000 for the learning case are \$5,040,530.89, an approximately 6.7-fold increase relative to the benchmark no-learning case. Also, mean GenCo revenues on day 1000 for the learning case are \$2,942,909.93, an approximately 5.4-fold increase relative to the benchmark no-learning case. Note, however, that mean ISO net surplus on day 1000 for the learning case is then \$2,097,620.96, an almost ten-fold increase relative to the benchmark no-learning case. Indeed, ISO net surplus under learning is similar in magnitude to GenCo net earnings (\$2,441,646.71).

Since total demand for R=0.0 is the same under learning and no learning, the ten-fold increase in mean ISO net surplus extraction under learning implies that the mean LMP paid by the LSEs is substantially higher than the mean LMP received by the GenCos. As suggested by Fig. 7, and more carefully detailed in Li et al. [15], this is due to the approximately six-fold increase under learning in the mean LMP for bus 2, which has the largest load (LSE 1) and no generation, and to the much smaller increases under learning in the mean LMPs for buses 1 and 5, which have generation but no load.

Another regularity observed in Figs. 8 and 9, as well as in Tables II and III, is that GenCo net earnings, GenCo revenues, LSE payments, and ISO net surplus all undergo marked monotonic declines as R increases from R=0.0 (100% fixed demand) to R=1.0 (100% price-sensitive demand). The explanation for these monotonic declines is as follows.

Consider, first, the benchmark no-learning case. Given low R values, the LSEs have very little price resistance; they are willing to pay any price to satisfy their fixed demands, and their fixed demands constitute the bulk of their total demands. Around the peak-demand hour 17, due in part to congestion on branch 1-2, the ISO must dispatch the most expensive GenCos 3, 4, and 5 to meet the large LSE fixed demand, i.e., these GenCos are pivotal suppliers for hour 17.

This results in relatively high LMPs. As R increases,

however, the LSEs are increasingly able to resist high prices through demand withholding. As carefully reported in Li et al. [15], this results in lower LMPs, lower total demand, and lower avoidable costs of production. GenCo revenues and LSE payments are thus lower, and GenCo net earnings are also lower because the decline in GenCo avoidable costs is more than offset by the decline in GenCo revenues. Similarly, ISO net surplus is lower because the decline in GenCo revenues is more than offset by the decline in LSE payments.

Next consider the day-1000 data for the learning case. For R=0.0 the mean outcomes for LSE payments, GenCo revenues, and ISO daily net surplus under learning are all substantially higher than their corresponding values under no learning. As R increases, however, the mean outcomes for LSE payments, GenCo revenues, and ISO net surplus under learning eventually drop below their corresponding values under no learning. For mean GenCo revenues the switch point is at R=1.0, whereas for mean LSE payments and mean ISO net surplus the switch point is at R=0.6.

The explanation for these switch points can be deduced from the detailed LMP and total demand findings for the no-learning and learning cases presented in Li et al. [15]. When GenCos are learners, low R values (implying large fixed demands) provide pivotal suppliers with a substantial opportunity to engage in profitable economic withholding. This dramatically increases LMPs relative to the no-learning case, particularly at the load-only bus 2. Since total demand for the learning case is only modestly lower than for the no-learning case for low R values, the end result is substantially higher LSE payments, GenCo revenues, and ISO net surplus.

On the other hand, as R increases and the LSEs acquire an increasing ability to resist high prices through demand withdrawal, the learning GenCos are increasingly forced to compete with each other for dispatch by lowering their reported marginal costs. This competitive process results in lower LMPs. However, the LMPs resulting under learning remain higher than under no learning for all R values, which in turn induces the LSEs to engage in greater demand withholding under learning.

The end result is that mean LSE payments, mean GenCo revenues, and mean ISO net surplus under learning all fall

TABLE III

MEAN OUTCOMES (WITH STANDARD DEVIATIONS) FOR GENCO NET EARNINGS, GENCO REVENUES, LSE PAYMENTS, AND ISO NET SURPLUS ON DAY 1000 FOR THE BENCHMARK DYNAMIC 5-BUS TEST CASE EXTENDED TO INCLUDE GENCO LEARNING AND DEMAND VARYING FROM R=0.0 (100% FIXED) TO R=1.0 (100% PRICE SENSITIVE).

	R=0.0	R=0.2	R=0.4	R=0.6	R=0.8	R=1.0
GenCo 1 \overline{DNE}	69,219.61 (64,055.42)	21,950.82 (32,888.20)	18,028.37 (20,401.49)	15,317.64 (17,342.48)	11,460.38 (13,341.31)	6,075.72 (8,585.60)
GenCo 2 \overline{DNE}	54,548.72 (57,868.92)	18,919.31 (30,102.78)	13,271.49 (19,648.72)	11,141.69 (15,916.37)	8,368.95 (13,528.49)	5,061.87 (9,487.15)
GenCo 3 \overline{DNE}	1,725,216.72 (389,906.14)	293,743.16 (269,901.79)	41,122.50 (20,776.25)	8,213.84 (7,847.69)	4,059.61 (3,343.84)	2,316.01 (1,775.20)
GenCo 4 \overline{DNE}	321,907.08 (153,782.17)	38,678.95 (73,333.88)	5,589.68 (14,969.93)	66.32 (161.70)	14.11 (51.51)	3.38 (18.22)
GenCo 5 \overline{DNE}	270,754.58 (124,835.20)	167,938.19 (113,128.59)	149,920.04 (85,701.22)	118,535.14 (50,853.37)	83,774.92 (32,392.38)	54,920.77 (20,700.86)
Total GenCo \overline{DNE}	2,441,646.71 (153,782.17)	541,230.41 (73,333.88)	227,932.07 (14,969.93)	153,274.62 (161.70)	107,677.99 (51.51)	68,377.76 (18.22)
GenCo 1 \overline{DRev}	93,976.61 (78,884.69)	39,069.66 (46,553.23)	34,172.46 (35,411.75)	30,876.22 (31,825.48)	25,992.32 (27,100.83)	16,407.69 (20,871.22)
GenCo 2 \overline{DRev}	74,751.32 (72,682.55)	32,167.61 (44,047.41)	25,385.25 (34,607.65)	22,521.81 (30,244.82)	18,284.43 (27,425.88)	12,934.50 (22,709.95)
GenCo 3 \overline{DRev}	1,952,910.84 (386,964.13)	432,137.00 (257,439.64)	97,834.40 (37,540.80)	27,830.78 (27,309.84)	13,671.15 (14,680.47)	7,337.80 (6,473.61)
GenCo 4 \overline{DRev}	449,051.68 (195,313.53)	70,968.73 (122,983.56)	14,705.64 (36,263.17)	296.48 (575.30)	77.98 (231.84)	16.88 (90.88)
GenCo 5 \overline{DRev}	372,219.49 (102,726.38)	305,520.62 (106,382.80)	285,483.62 (79,412.59)	238,548.54 (44,763.65)	181,354.58 (47,182.98)	131,542.33 (46,882.23)
Total GenCo \overline{DRev}	2,942,909.93 (558,938.79)	879,863.63 (385,241.09)	457,581.36 (113,573.45)	320,073.84 (52,131.79)	239,380.46 (24,347.08)	168,239.20 (25,679.71)
Total LSE \overline{DPay}	5,040,530.89 (1,043,543.03)	1,526,994.60 (975,375.28)	663,801.01 (209,686.70)	377,524.06 (11,366.32)	271,061.40 (26,241.77)	183,118.99 (33,324.23)
ISO $\overline{DNetSurplus}$	2,097,620.96 (632,303.71)	647,130.97 (633,129.12)	206,219.65 (197,896.93)	57,450.22 (48,696.64)	31,680.94 (30,789.07)	14,879.79 (11,016.23)

below their corresponding no-learning values as R approaches 1.0 due to the relatively strong contraction in total demand under learning. As can be verified from the GenCo net earnings data provided in Table III, the most expensive GenCo 4 is at the greatest disadvantage in this competitive process while the least expensive GenCo 5 is most advantaged.

TABLE IV

MEAN OUTCOMES (WITH STANDARD DEVIATIONS) FOR GENCO NET EARNINGS, GENCO REVENUES, LSE PAYMENTS, AND ISO NET SURPLUS ON DAY 500 FOR THE BENCHMARK DYNAMIC 30-BUS TEST WITH R=0.0 (100% FIXED DEMAND), BOTH WITH AND WITHOUT GENCO LEARNING.

	No GenCo Learning	With GenCo Learning
Total GenCo \overline{DNE}	14,210.01	142,866.39 (67,530.19)
Total GenCo \overline{DRev}	82,265.01	231,663.41 (68,839.94)
Total LSE \overline{DPay}	110,853.01	285,531.70 (74,214.33)
ISO $\overline{DNetSurplus}$	28,588.00	53,868.30 (32,322.68)

C. 30-Bus Findings

Due to space limitations, we report only a sampling of results for the 30-bus test case with R=0.0 (100% fixed demand), both with and without GenCo learning.

As seen in Table IV, for the no-learning case the typical ISO daily net surplus extraction is \$28,588, and for the learning case the mean ISO net surplus extraction on day 500 is \$53,868.30, nearly double the amount for the no-learning case. This increase in ISO net surplus under learning is qualitatively similar to the findings for the 5-bus test case. However, the size of this increase under learning (an approximate doubling) is not as large as for the 5-bus test case, a reflection of the increased rivalry among the more numerous GenCos in the 30-bus test case that results in a more difficult learning environment and less economic capacity withholding.

VI. EMPIRICAL COMPARISONS

Comparisons of empirical ISO/RTO day-ahead market net surplus (congestion rent) extractions with our simulation findings are not straightforward. For example, the “congestion costs,” “congestion charges,” and “net congestion revenues” data presented in the ISO/RTO state-of-the-market and market monitoring reports [18], [19], [20], [21] are in highly aggregated dollar form, and in some cases the explanation of calculation procedures is not fully given. In addition, these dollar amounts should ideally be normalized in some consistent fashion across ISO/RTOs to correct for the size differences among ISO/RTO market footprints. It does not

appear to be possible to do this in a completely satisfactory manner based on current publicly released ISO/RTO data.

The most complete reporting appears to be provided by PJM. In [18, Table 2-47, p. 48], the 2008 average cleared fixed plus price-sensitive load in the PJM day-ahead market is given as 76,961 MWh whereas the average cleared price-sensitive load in the PJM day-ahead market is given as only 1,846 MWh. This implies an R-ratio equal to $R=0.02$, which is close to $R=0.0$ (100% fixed demand). In Section 7 (pp. 342) the “total congestion cost” is said to “represent the overall charge or credit to a zone,” which we interpret to mean the difference between load payments to the ISO and generation credits (revenues) received from the ISO, i.e., ISO net surplus. On page 339 the 2008 day-ahead congestion costs for PJM are given as \$2.66 billion. This is approximately 7% of 2008 total PJM billings, listed as \$34.3 billion.

In comparison, consider the simulation findings reported in Table IV for our 30-bus test case with $R=0.0$. For the no-learning case, the ratio of ISO daily net surplus to *total daily billings*, measured as [GenCo daily revenues + LSE daily payments], is about 15%. For the learning case, the ratio of ISO daily net surplus to total daily billings is about 10%. The latter learning-case findings are in line with the 7% empirical findings for PJM, particularly since total PJM billings include settlements for black start, ancillary services, reactive services, FTR payouts, ARR credits, and transmission charges in addition to settlements for load and generation day-ahead energy trades.

In [19, Section 5, p. 5.3(103)], the CAISO “inter-zonal congestion charges” for the day-ahead and hour-ahead markets in year 2008 are listed as \$176 million. However, these charges are calculated as the product of the “congestion price” (branch shadow price) and the power flow on the branches connecting variously specified zones rather than the difference between load payments and generator revenues as used in this study. In [20, Section 3.4, p. 70], the combined 2008 Net Congestion Revenue for the ISO-NE real-time and day-ahead markets is listed as \$121 million, where “net congestion revenue” is calculated as the product of branch flows and branch shadow prices. In Figure 46 (p. 68) of [21, Section V], the 2007 congestion cost for the MISO day-ahead market is listed as approximately \$633 million and the 2007 total congestion cost combining both day-ahead and real-time markets is listed as approximately \$713 million. “Congestion cost” for the MISO is defined (p. 67) as “the difference in LMP prices between the locations multiplied by the amount of the transfer.”

VII. CONCLUDING REMARKS

ISOs for restructured wholesale power markets are typically organized as independent not-for-profit entities with a fiduciary responsibility for ensuring the efficiency as well as reliability of market operations. Maximization of ISO net surplus is certainly not the intended objective of ISOs. Nevertheless, ISO net surplus represents a net earnings stream whose use is discretionary to the ISO.

The findings presented in Section V demonstrate that ISO net surplus can be substantial in the presence of grid congestion. ISO net surplus was found to be particularly large

when demand was predominately fixed (insensitive to price) and GenCos were able to learn over time to strategically report supply offers with higher-than-true marginal costs. Congestion and strategic reporting (encouraged by the presence of fixed demand) reduce market efficiency to the extent they result in the dispatch of more expensive generation in place of cheaper generation (out-of-merit-order dispatch) and/or a failure to meet serviceable price-sensitive demand; cf. Fig. 2.

In [22] the authors note that “under the current ISO practice, the congestion revenue gathered by the ISO is largely returned to the load and transmission owners, resembling the government surplus as part of the social surplus in welfare economics.” However, welfare economists do not assert the *unqualified* desirability of assigning government tax revenue dollars the same weight as private trader net surplus dollars in market objective functions, as is done in the ISO day-ahead market objective function (14). An equal weighting is especially problematic if the government redistributes tax revenues to third parties with high entry barriers (e.g., transmission owners) and this redistribution effectively rewards these third parties for maintaining social costs (e.g., congestion) that the government hopes to alleviate.

A key social welfare issue for the ISO day-ahead market objective function (14) is whether a dollar flowing to the ISO is properly treated as having the same social benefit as a dollar flowing to a private energy buyer or seller. The answer surely depends on social opportunity costs, i.e., on the net social benefits of alternative uses to which such dollars could be put. This issue would seem to require further serious study.

For example, in some regions the ISO net surplus is used in part to encourage new transmission investment through the subsidization of financial transmission rights (FTRs) for those who invest in new transmission capacity. This practice could lead to a reduction of ISO net surplus to the extent that congestion is alleviated.³ Nevertheless, transmission investment needs can arise for reasons other than congestion (e.g., the need to reach distributed energy resources), and congestion might better be alleviated by more local generation rather than by more transmission capacity. Consequently, the administrative subsidization of transmission investment through the distribution of ISO net surplus to FTR holders could inadvertently create additional sources of social inefficiency.

In addition, ISO net surplus is also used in part to compensate load. Here, however, it is important to keep in mind the intended market efficiency rationale for LMP pricing in relation to load: namely, to encourage load to locate where it can be serviced most cheaply. To the extent that redistribution of ISO net surplus to load dampens this incentive, it can be an unintended source of social inefficiency viewed from a dynamic vantage point.

Another troubling issue also arises. As seen in Section V, ISO and GenCo net surplus extractions dramatically increase when the price-sensitivity of demand is low and the GenCos

³The extent to which ISO net surplus payouts to FTR holders have actually resulted in new transmission investment is unclear. For example, the CAISO report [23, p. ES-3] reaches the following conclusion: “...the reality has been that the LMP differences have not provided enough incentives to upgrade key facilities even after many types of FTRs and CRRs are provided.”

have learning capabilities enabling them to exercise capacity withholding. On the other hand, LSE payments also dramatically increase. This would appear to give pure LSEs (those without generation ownership) an incentive to support congestion reduction measures, increased price-sensitivity of demand, and increased oversight to curtail GenCo capacity withholding.

However, if LSE payments in the wholesale power market are fully reimbursed through the receipt of regulated rates for sale of downstream (retail) electric power, and the LSEs are able to secure timely increases in these regulated rates in step with increases in wholesale power prices, then no direct participant in the wholesale power market suffers a loss of net surplus when LMPs increase due to congestion, fixed demand, and/or GenCo capacity withholding. Rather, to the extent that retail consumers are protected against high wholesale prices by locally regulated retail prices, losses in net surplus are in effect borne by taxpayers. Moreover, barriers to entry into transmission, generation, and load servicing could then lead to the persistence over time of socially inefficient *rents*, i.e., net surplus extractions in excess of the amounts needed to maintain resources in their current productive uses.

Power market researchers recognize that an important goal of market design is to ensure the structural alignment of participant objectives with socially desirable outcomes, thus reducing the need for oversight of participant behaviors [24]. The main conclusion drawn from the findings in this study is that net surplus extractions are not structurally well-aligned with social efficiency objectives in ISO-managed wholesale power markets operating under LMP. The immediate practical import is the desirability of encouraging more transparent public reporting and oversight of net surplus extractions and uses to maintain the confidence of both market participants and the public at large.

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