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Analysis of Locational Marginal Prices in Look-ahead Economic Dispatch

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***Abstract*—This paper studies the impact of introducing look-ahead dispatch on locational marginal prices in real-time electricity markets. Due to the high forecast error and inter-temporal variability of renewable resources (e.g., wind and solar), many system operators are in the process of upgrading their market clearing engine from static economic dispatch-based ones to dynamic look-ahead economic dispatch-based ones. Compared with conventional static dispatch that calculates the optimal dispatch for the current operating interval, look-ahead dispatch calculates the optimal dispatch solution over multiple future time intervals. Look-ahead dispatch can obtain cost saving by pre-ramping some of the dispatched generators so that the system can more economically match forecast changes in net load (i.e., system load - renewable power output). In addition to the cost saving benefit, system operators in RTOs claim that look-ahead dispatch results in lower price volatility than static dispatch. In this paper, we attempt to demystify this industry claim and provide counter-examples to this claim. Specifically, we investigate the relationship between price volatility and some key factors such as system-wide ramping capability, the number of time intervals in look-ahead dispatch horizon, load pattern and forecast uncertainty. The simulation results are illustrated with numerical examples in the IEEE 14-bus system.**

***Index Terms*—Electricity market, look-ahead economic dispatch, locational marginal price**

I. INTRODUCTION

THE increasing penetration of generation from variable renewable sources such as wind and solar poses challenges to the reliable operation of electricity grids. In order to deal with the increased uncertainty associated with renewables some Regional Transmission Organizations (RTOs)/Independent System Operators (ISOs) are planning to move from their current static economic dispatch model to a time-coupled look-ahead economic dispatch model [1]–[3].

The major difference between conventional static security constrained economic dispatch and look-ahead security constrained economic dispatch is that multiple time intervals are considered in the latter model. By incorporating a prediction horizon of system load and renewable output, look-ahead dispatch is capable of providing more cost-effective generation dispatch orders. There has been industry feedback and empirical assessment of the benefit of a time-coupled look-ahead dispatch model. The benefits include (a) reduced generation dispatch cost, (b) improved social welfare; and (c) reduced system security risk [4]. However, the impact of look-ahead dispatch on locational marginal prices (LMPs) is still an open question. Given that the price of electricity is a major market signal as well as a measure of competitiveness, the behavior of the wholesale market clearing price under the look-ahead dispatch approach is an important issue. The industry belief on this issue is that price might be more smoothed with look-ahead dispatch as compared to static dispatch [3].

This paper aims to systematically assess the impact of time-coupled look-ahead dispatch on price behavior and compare it to the static dispatch model. The contributions of this paper are suggested as follows:

- We attempt to demystify the industry claim on electricity wholesale market price behavior and provide counter-examples.
- We show the relationship between price behavior and some key factors such as system-wide ramping capability, the number of time intervals in look-ahead dispatch horizon, load pattern and forecast uncertainty.
- We present numerical examples on the IEEE 14-bus system using Monte Carlo simulation as well as real load data.

The remainder of this paper is organized as follows. Section II provides the literature review of previous work done on the look-ahead economic dispatch problem. In Section III the formulation of static and look ahead economic dispatch is reviewed. Also the mathematical definitions of LMPs for both static and look ahead dispatch models are presented. Section IV contains a numerical example on the IEEE 14 bus system. The price behavior for different ramp rates of generators, number of intervals in look-ahead horizon, and load variation is illustrated through numerical examples, assuming perfect forecast of net load. Section V presents results of Monte Carlo simulations for cases without and with net load forecast error. Also simulations are shown which use real load data from New York ISO (NYISO) for one year.

II. LITERATURE REVIEW

Look ahead economic dispatch, also known as dynamic economic dispatch (DED), has been recognized as an important problem in power system operations for many years. Ross and Kim [5] used dynamic programming to solve the DED problem. Travers and Kaye [6] presented an approach to dynamic dispatch based on constructive dynamic programming, which avoids the discretization of state space which is usually required in dynamic programming. Barcelo and Rastgoufard [7] included network security constraints in the formulation for a two interval dynamic dispatch. Han et al. [8]

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TABLE I
NOTATION

i	Index for generators i
n	Index for buses n
l	Index for transmission line l
K	Total number of time intervals in look-ahead horizon
N	Total number of buses
L	Total number of transmission lines
G	Set of generation units
$\hat{D}_n[k]$	nth bus forecast net demand at time k
$P_{g_i}[k]$	Scheduled ith generator power at time k
$F_l[k]$	Transmission flow at line l at time k
R_i	Ramp rate of generator i
ΔT	Dispatch interval duration
$\lambda[k]$	Shadow price of the system energy balance equation at time k
$\tau_i[k]$	Shadow price of the capacity constraint for generator i at time k
$\omega_i[k]$	Shadow price of the ramp constraint for generator i at time k
$\mu_l[k]$	Shadow price of the transmission line constraint for transmission line l at time k
$P_{g_i}^{\min}$, $P_{g_i}^{\max}$	Min, max generation limits for generator i
$F_l^{\min}$, $F_l^{\max}$	Min, max flow limits for line l

considered both energy balance and spinning reserve in their formulation. They also presented two heuristic methods: the first to preserve the feasibility of solutions, and the second to obtain the optimal solution through an efficient technique. Xia et al. [9] presented a model predictive control (MPC) approach to the DED problem. Xia and Elaiw [10] presented a thorough review of papers on the DED problem, which shows that over the years many different methods have been used, from the categories of mathematical programming, artificial intelligence and hybrid approaches. Recently, some independent system operators (ISOs) have also expressed interest in look ahead dispatch [1]. This is due to increased uncertainty in the net load forecast, arising from the increase in renewable generation and demand response. Gu and Xie [4] present an algorithm for detecting and correcting power system insecurity issues in look-ahead dispatch.

III. FORMULATION OF LOOK-AHEAD AND STATIC DISPATCH

Look-ahead dispatch differs from conventional static dispatch in that it uses the predicted net load over multiple future time steps to determine the optimal economic dispatch allocation of generators. In time-coupled look-ahead dispatch the ramping capability of generators over the look-ahead time horizon is taken into account in the optimization model. Thus, look-ahead dispatch can obtain cost saving by pre-ramping some of the dispatched generators so that the system can more economically match forecast changes in *net load* (i.e., system load - renewable power output).

In this section the formulation of the look-ahead dispatch model, conventional static dispatch model and associated locational marginal prices (LMPs) are presented. The notations used in this paper are summarized in Table I. Bold symbols represent vectors.

For $\forall k = 1, \ldots, K$ and $\forall l = 1, \ldots, L$, look-ahead dispatch is formulated as the following multi-interval optimization problem [11],

$$\min_{P_{g_i}[k]} \sum_{k=1}^{K} \sum_{i \in G} C_i(P_{g_i}[k]) \tag{1}$$

s.t.

$$\lambda[k] : \sum_{i \in G} P_{g_i}[k] = \sum_{n=1}^{N} \hat{D}_n[k] \tag{2}$$

$$\boldsymbol{\omega}[k] : |P_{g_i}[k] - P_{g_i}[k-1]| \leq R_i \Delta T \, \forall i \tag{3}$$

$$\boldsymbol{\tau}[k] : P_{g_i}^{\min} \leq P_{g_i}[k] \leq P_{g_i}^{\max} \, \forall i \tag{4}$$

$$\boldsymbol{\mu}[k] : F_l^{\min} \leq F_l[k] \leq F_l^{\max} \, \forall l \tag{5}$$

In this formulation, the objective function is to minimize the total generation costs (1). (2) is the system-wide energy balance equation. (3) are the ramp constraints of each generator in multiple future time intervals. (4) are the physical capacity constraints of each generator. (5) are the transmission line constraints. In the above formulation when $K = 1$ then we get the formulation for *static* dispatch, which we denote in this paper using the abbreviation ST. The Lagrangian function of the aforementioned look-ahead dispatch is written as

$$\begin{aligned}
\mathcal{L} = & \sum_{k=1}^{K} \sum_{i \in G} C_i(P_{g_i}[k]) - \sum_{k=1}^{K} \lambda[k] \left[\sum_{i \in G} P_{g_i}[k] - \sum_{n=1}^{N} \hat{D}_n[k] \right] \\
& + \sum_{k=1}^{K} \sum_{i \in G} \left[\omega_{i,\max}[k] (P_{g_i}[k] - P_{g_i}[k-1] - R_i \Delta T) \right] \\
& + \sum_{k=1}^{K} \sum_{i \in G} \left[\omega_{i,\min}[k] (P_{g_i}[k-1] - P_{g_i}[k] - R_i \Delta T) \right] \\
& + \sum_{k=1}^{K} \sum_{i \in G} \left[\tau_{i,\max}[k] (P_{g_i}[k] - P_{g_i}^{\max}) \right] \\
& + \sum_{k=1}^{K} \sum_{i \in G} \left[\tau_{i,\min}[k] (P_{g_i}^{\min} - P_{g_i}[k]) \right] \\
& + \sum_{k=1}^{K} \sum_{l=1}^{L} \left[\mu_{l,\max}[k] (F_l[k] - F_l^{\max}) \right] \\
& + \sum_{k=1}^{K} \sum_{l=1}^{L} \left[\mu_{l,\min}[k] (F_l^{\min} - F_l[k]) \right]
\end{aligned} \tag{6}$$

where all the Lagrangian multipliers at time k ($\lambda[k]$, $\omega_{i,\max}[k]$, $\omega_{i,\min}[k]$, $\tau_{i,\max}[k]$, $\tau_{i,\min}[k]$, $\mu_{l,\max}[k]$, and $\mu_{l,\min}[k]$) are positive.

According to the definition of the nodal price [12], and assuming that bus 1 is the slack bus, the locational marginal price (LMP) for each bus n ($n = 2, \ldots, N$) at time k is given by

$$\text{LMP}_n[k] = \lambda[k] - \mathbf{H_{d_n}}^T (\boldsymbol{\mu}_{\max}[k] - \boldsymbol{\mu}_{\min}[k]) \tag{7}$$

where $\lambda[k]$ is the LMP for the slack bus 1 at time k, $\mathbf{H_{d_n}} = [\frac{\partial F_1}{\partial \hat{D}_n}, \ldots, \frac{\partial F_L}{\partial \hat{D}_n}]^T$, $\boldsymbol{\mu}_{\max}[k] = [\mu_{1,\max}[k], \ldots, \mu_{L,\max}[k]]^T$, and $\boldsymbol{\mu}_{\min}[k] = [\mu_{1,\min}[k], \ldots, \mu_{L,\min}[k]]^T$. However, equation (7) does not differentiate look-ahead and static LMPs explicitly.

On the other hand, using the first-order KKT condition of look-ahead dispatch formulation ($\partial \mathcal{L} / \partial P_{g_i}[k] = 0$), the look-ahead and static LMP associated with each generator

TABLE II
GENERATOR BASE PARAMETERS OF THE IEEE 14-BUS TEST SYSTEM.

Unit Type (Bus)	$\mathbf{P_{min}}$ (MW)	$\mathbf{P_{max}}$ (MW)	**Ramp Rate** (MW/5min)	**MC** ($/MWh)
Wind(1)	0	300	$R_1 = 150$	5
Nuclear(2)	0	100	$R_2 = 3$	10
Coal(3)	0	100	$R_3 = 5$	30
Natural Gas(6)	50	200	$R_4 = 60$	70
Oil(8)	60	200	$R_5 = 60$	100

i connected to bus n can be expressed in the following alternative forms:

$$\mathrm{LMP}_i^{\mathrm{LA}}[k] = \frac{\partial C_i(P_{g_i}[k])}{\partial P_{g_i}[k]} + (\tau_{i,\max}[k] - \tau_{i,\min}[k]) + (\omega_{i,\max}[k] - \omega_{i,\max}[k+1]) + (\omega_{i,\min}[k+1] - \omega_{i,\min}[k]) \tag{8}$$

$$\mathrm{LMP}_i^{\mathrm{ST}}[k] = \frac{\partial C_i(P_{g_i}[k])}{\partial P_{g_i}[k]} + (\tau_{i,\max}[k] - \tau_{i,\min}[k]) + (\omega_{i,\max}[k] - \omega_{i,\min}[k]) \,. \tag{9}$$

Different from (7), the above LMP formulations allow us to have the knowledge of the binding status of each generator at a certain dispatch interval. In comparison with the static LMP formulation (9), it should be noted that the look-ahead LMP formulation (8) includes two additional lagrangian multipliers, $\omega_{i,\max}[k+1]$ and $\omega_{i,\min}[k+1]$, corresponding to the ramp constraints at the future time $k+1$. Thus in look-ahead dispatch future interval binding ramping constraints have an impact on the current interval LMP.

IV. LMP VOLATILITY UNDER PERFECT LOAD FORECAST

In this section, the volatility of real-time price in look-ahead and static dispatch methods is examined and compared with each other in the IEEE 14-bus system as shown in Fig. 1. Table II shows the five generators' operating characteristics, including unit type (generation bus number), physical capacity limit, ramp rate and marginal cost (MC). Wind in this study is treated as a dispatchable resource rather than a negative load. Given the increase in penetration of wind, grid operators are beginning to treat wind at par with other generators in the market, and consider it to be a dispatchable generator. The minimum power outputs of the nuclear and coal units are assumed to be zero in this paper, but can be generalized to any positive number. Changing their P_{min} values does not affect the fundamental observations of this case study.

The price volatilities in both dispatch methods are evaluated using the one day (7 Aug 2013) net load profile with a 5-min resolution shown in Fig. 2, which is a scaled-down version of New York ISO real load data [13]. In this simulation we assume that there is no transmission line congestion. Therefore, since $\boldsymbol{\mu}_{\max}[k]$ and $\boldsymbol{\mu}_{\min}[k]$ equal to zero in (7), LMPs at all buses become uniform. Studying the impact of transmission line congestion on look-ahead dispatch LMPs will be part of our future work.

We first investigate the impact of generator ramp rates on the LMPs. Specifically, we change the ramp rates of the

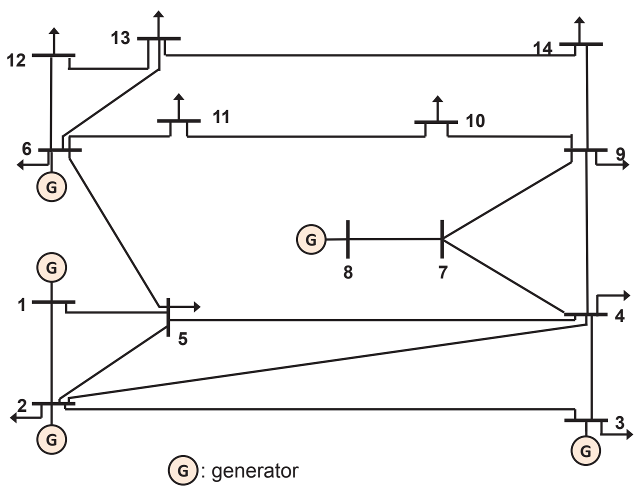


Fig. 1. IEEE 14-bus system.

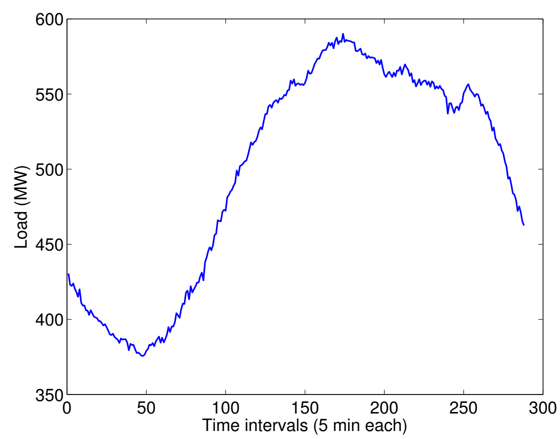
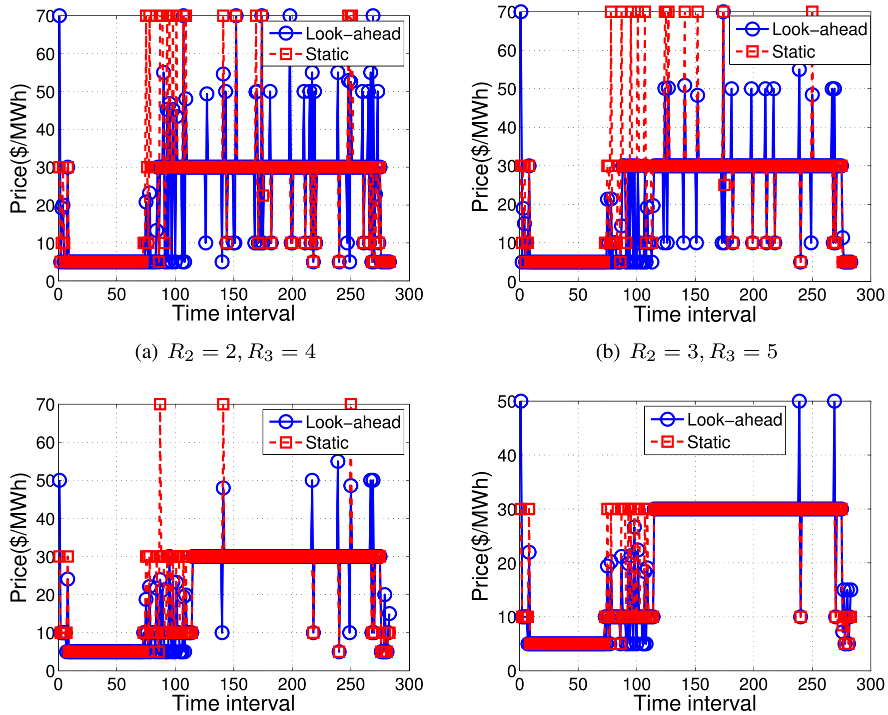


Fig. 2. Base net load profile.

nuclear (R_2) and the coal (R_3) units, with all other parameters remaining the same as shown in Table II. Fig. 3 shows the impact of the ramp rate of generators for look-ahead ($K = 6$) and static ($K = 1$) dispatch on LMPs given the load profile in Fig. 2. The LMP results in these figures are obtained using four different pairs of ramp rates with an increasing 1 MW step size, corresponding to ($R_2 = 2, R_3 = 4$), ($R_2 = 3, R_3 = 5$), ($R_2 = 4, R_3 = 6$) and ($R_2 = 5, R_3 = 7$), respectively. We observe from these figures that the number of price spikes and their magnitudes in both dispatch methods decrease as system-wide ramping capability increases. This observation holds true until their ramp rates increase to ($R_2 = 11, R_3 = 13$). Given more relaxed ramp constraints, LMPs in both dispatch methods become consistent with each other and hence the effect of ramp capability on LMP differences between both dispatch methods disappears.

Table III shows and compares the standard deviation (SD) of LMPs in both dispatch methods for different pairs of ramp rates and load variabilities. Here the standard deviation of the LMP vector comprising of all five minute dispatch intervals in



(a) $R_2 = 2, R_3 = 4$ (b) $R_2 = 3, R_3 = 5$

(c) $R_2 = 4, R_3 = 6$ (d) $R_2 = 5, R_3 = 7$

Fig. 3. Comparison of LMPs in look-ahead ($K = 6$) and static ($K = 1$) dispatch with varying ramp rate.

TABLE III
STANDARD DEVIATION OF LMP WITH VARYING RAMP RATE AND LOAD VARIATION.

Ramp Rate	Dispatch	$L_g = 2.6$	$L_g = 5.7$	$L_g = 11.8$
$R_2 = 1, R_3 = 3$	LA	19.22	24.51	25.90
	ST	**20.62**	**26.56**	**29.11**
$R_2 = 3, R_3 = 5$	LA	13.87	20.06	23.03
	ST	**14.82**	**21.81**	**25.33**
$R_2 = 5, R_3 = 7$	LA	**11.78**	17.09	20.92
	ST	11.38	**18.03**	**23.03**
$R_2 = 7, R_3 = 9$	LA	**11.47**	15.30	19.36
	ST	11.34	**16.14**	**21.43**

the day is used as the index to quantify and compare the price volatility in look-ahead and static dispatch. In the first row of Table III, L_g represents the average of the absolute values of load deviations between pairs of consecutive time intervals, for the given day's load profile.

$$L_g = \frac{\sum_{t=1}^{T-1} |D[t+1] - D[t]|}{T-1} \quad (10)$$

where $D[t]$ is the total system demand at interval t, and T = 288 i.e., the number of real-time dispatch intervals in a day.

Three different load profiles are generated by adding independent identically distributed (i.i.d.) Gaussian random vectors with different variance to the base load vector. In this table, bolded numbers represent the greater SD between look-ahead and static dispatch for a given load profile and pair of ramp rates. From Table III, we have the following observations:

(O1) As system-wide ramping capability increases, the SD of LMPs for look-ahead and static dispatch decreases (i.e., LMPs become less volatile).

(O2) As the average load variation L_g increases, the SD of LMPs for look-ahead and static dispatch also increases (i.e., LMPs become more volatile).

(O3) More stringent system-wide ramping capability leads to lower SD in look-ahead dispatch than in static dispatch.

It is noted from (O1) and (O2) that the increase of ramp rate and load variation has an opposite effect on change in SD relative to each other. The results in this table provide a counter-example to industry claim that the price volatility in look-ahead dispatch is always less than that in static dispatch.

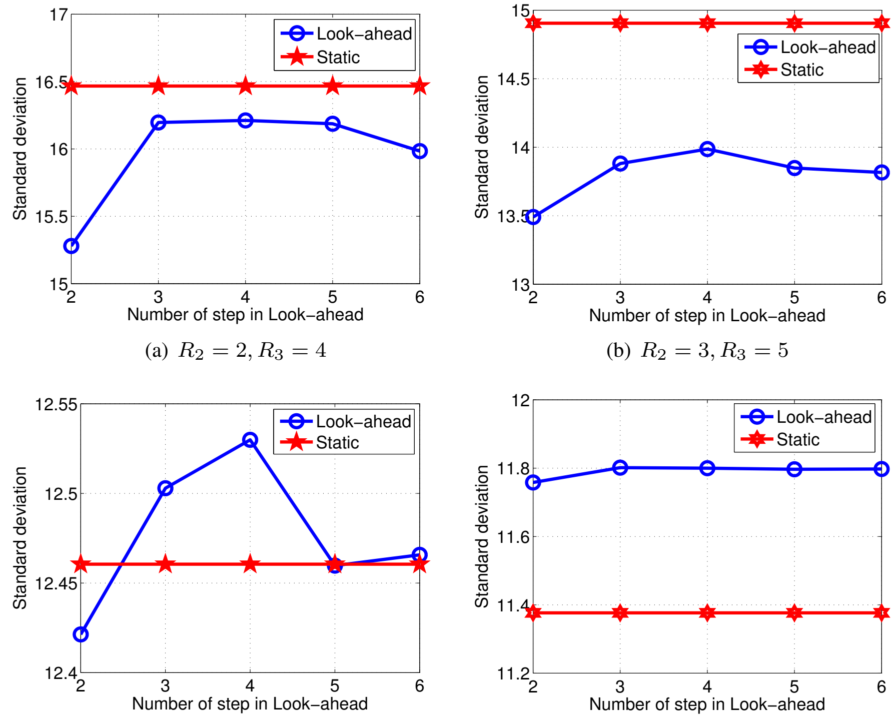
Fig. 4 shows the impact of the number of time steps K in look-ahead dispatch on the SD of LMP in look-ahead dispatch. In this figure, the value of K increases from 2 to 6. The plot in each subfigure illustrates such impact under different ramp rate conditions. From Fig. 4, we can obtain the following observations:

(O6) Price volatility of look-ahead dispatch does not monotonically increase or decrease as a function of dispatch horizon K.

(O7) Look-ahead dispatch with $K = 2$ has the lowest price volatility.

(O8) The relative price volatility between look-ahead and static dispatch changes with the value of K. For example, Fig. 4(c) shows that the price volatility of look-ahead dispatch compared to static dispatch is lower when $K = 2$, but greater when $K = 3$.

Table IV shows the total cost of look-ahead and static dispatch with varying number of steps in look-ahead dispatch. First, we can obtain from this table a well-known observation that the increase of K leads to the decrease of the total cost of



(a) $R_2 = 2, R_3 = 4$ (b) $R_2 = 3, R_3 = 5$ (c) $R_2 = 4, R_3 = 6$ (d) $R_2 = 5, R_3 = 7$

Fig. 4. Impact of the number of time intervals (K) in look-ahead dispatch on price volatility.

TABLE IV
TOTAL COST OF LOOK-AHEAD AND STATIC DISPATCH WITH VARYING NUMBER OF TIME STEPS IN LOOK-AHEAD DISPATCH.

Ramp Rate	Dispatch	$K = 2$	$K = 3$	$K = 4$	$K = 5$	$K = 6$
$R_2 = 2, R_3 = 4$	LA	3532471	3531945	3531893	3531793	3531730
	ST	3538129	3538129	3538129	3538129	3538129
$R_2 = 3, R_3 = 5$	LA	3521564	3520932	3520909	3520854	3520820
	ST	3524177	3524177	3524177	3524177	3524177
$R_2 = 4, R_3 = 6$	LA	3520247	3520177	3520173	3520173	3520173
	ST	3521147	3521147	3521147	3521147	3521147
$R_2 = 5, R_3 = 7$	LA	3519901	3519898	3519898	3519898	3519898
	ST	3520557	3520557	3520557	3520557	3520557

look-ahead dispatch as well as the increase of total cost saving compared to static dispatch. A more interesting observation related to look-ahead pricing is as follows:

(O9) From (O7) and Table IV, both the lowest price volatility and the largest total cost are obtained in look-ahead dispatch with $K = 2$. In other words, lower price volatility does not necessarily imply lower total cost.

V. LMP ANALYSIS UNDER UNCERTAIN LOAD FORECAST

In this section we conduct simulations on the same IEEE 14 bus test system using larger datasets for the load. First we conduct simulations for a large number of load scenarios generated by random perturbations around the base load profile. Next we investigate the impact of different seasonal load profiles by using real data for one year.

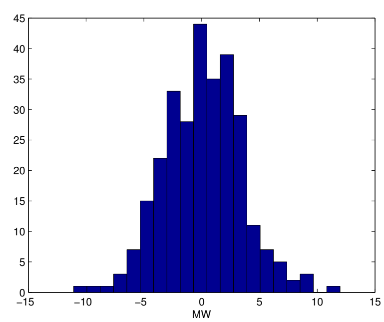


Fig. 5. Histogram of Scaled NYISO Real Time Load Deviations.

A. Monte Carlo Simulation

To generate scenarios for Monte Carlo simulation the base case considered is shown in Fig. 2. The mean of this load profile is 498.17 MW. Most of the load deviations are within ± 12 MW, i.e., $\pm 2.41\%$ of the mean (Fig. 5). Zero-mean Gaussian random noise with standard deviation SD = 4 is added to all data points of the day, to create 1000 load profiles. Both the static ($K = 1$) and look ahead ($K = 6$) economic dispatch are run for all 1000 load profiles.

To analyze the statistics of the resulting LMPs from the Monte Carlo simulation two indices are considered, namely (i) the standard deviation of LMPs, and (ii) the number of spikes in LMPs above a certain threshold price.

1) Standard deviation of LMP (for each scenario)
   - For a load profile if $SD(\lambda^{ST}) > SD(\lambda^{LA})$, then the counter ST^s is incremented by 1.

TABLE V
STATISTICS OF RESULTS OF MONTE-CARLO SIMULATION WITH NO ERROR IN FORECAST

Ramp Rates	ST^s	LA^s	ST^p	LA^p
$R_2 = 5$, $R_3 = 3$	853	147	60257	50817
$R_2 = 3$, $R_3 = 5$	144	856	40200	40072
$R_2 = 5$, $R_3 = 5$	241	759	37259	34667
$R_2 = 8$, $R_3 = 5$	177	823	34234	31594
$R_2 = 5$, $R_3 = 8$	30	970	17036	16955
$R_2 = 5$, $R_3 = 12$	17	983	4796	4659
$R_2 = 8$, $R_3 = 12$	22	978	4325	4300

TABLE VI
STATISTICS OF RESULTS OF MONTE-CARLO SIMULATION WITH STANDARD DEVIATION OF ERROR IN FORECAST

Ramp Rates	ST^s	LA^s	ST^p	LA^p
$R_2 = 5$, $R_3 = 3$	963	37	68615	55333
$R_2 = 3$, $R_3 = 5$	704	296	50722	45505
$R_2 = 5$, $R_3 = 5$	777	223	47322	40326
$R_2 = 8$, $R_3 = 5$	770	230	43770	36176
$R_2 = 5$, $R_3 = 8$	439	561	26442	23543
$R_2 = 5$, $R_3 = 12$	176	824	10999	10100
$R_2 = 8$, $R_3 = 12$	284	716	10510	8648

- Whereas if $SD(\lambda^{LA}) > SD(\lambda^{ST})$, then the counter LA^s is incremented by 1.

2) Price spikes above threshold = \$50/MWh
- ST^p = number of intervals in which Static dispatch LMP $> \$50$
- LA^p = number of intervals in which Look ahead dispatch LMP $> \$50$

In the first simulation it is assumed that there is no uncertainty in the load forecasts. Table V shows the statistics of the results obtained from the Monte Carlo simulation. The dispatch results and LMPs for different values of generator ramp rates are obtained. Specifically the ramp rates of the nuclear (R_2) and coal (R_3) units are varied, since these are most often the ramp constrained units in the system, under the given load profiles.

From Table V we see that static dispatch LMPs have greater standard deviation than look ahead dispatch LMPs in all cases when the ramp rates of the two critical generators are low. As the key ramp rates are increased we see more cases where look ahead LMPs have greater standard deviation. It is also observed that in all cases look ahead yields a smaller number of LMP spikes above \$50.

In the next simulation it is assumed that there is error in the load forecasts over the look ahead horizon. In the look ahead dispatch the current time step ($k = 1$) is assumed to have an accurate forecast of load, but the forecast for subsequent time steps is assume to have some error. Thus when the real time dispatch moves forward one step at a time, a new forecast must be done and the dispatch result updated accordingly.

Table VI shows the results of the simulations where there is an error in load forecast which has zero-mean and SD = 4. Again we observe that static LMPs usually have greater standard deviation than look ahead LMPs when the ramp rates of the critical generators are low. But as the system ramp rate increases the volatility of look-ahead LMPs also tends to increase. As compared to the case without uncertainty we see more price spikes in both the static and look-ahead LMPs. Further, the difference between the number of price spikes in static and look-ahead has increased compared to the previous simulation (Table V). This indicates that static dispatch is sensitive to load forecast error. Look-ahead despite using load forecasts from more time intervals still outperforms static when the forecast error is low.

TABLE VII
STATISTICS OF RESULTS OF MONTE-CARLO SIMULATION WITH INCREASING STANDARD DEVIATION OF ERROR IN FORECAST

Ramp Rates	ST^s	LA^s	ST^p	LA^p
$R_2 = 5$, $R_3 = 3$	981	19	71435	57020
$R_2 = 3$, $R_3 = 5$	766	234	52877	47321
$R_2 = 5$, $R_3 = 5$	931	69	51026	42002
$R_2 = 8$, $R_3 = 5$	970	30	47740	37014
$R_2 = 5$, $R_3 = 8$	764	236	29779	24977
$R_2 = 5$, $R_3 = 12$	476	524	13407	11347
$R_2 = 8$, $R_3 = 12$	534	466	12446	9646

TABLE VIII
PRICE SPIKES BY SEASON

Season	ST^p	$LA^p(1)$	$LA^p(2)$	$LA^p(3)$
Winter	724	3	3	5
Spring	412	1	0	0
Summer	5573	1132	1135	1142
Fall	566	16	14	17

Table VII shows the results of the simulations where the error in load forecast has increasing standard deviation over the look ahead horizon. The forecast error is assumed to be zero-mean but with standard deviation increasing from SD = 4 to SD = 6, evenly over the steps of the look-ahead horizon, where $K = 6$. The differences in price spikes between static and look ahead LMPs are higher relative to the differences in Table VI. This shows the advantage of look-ahead dispatch in reducing price spikes under a realistic setting where the forecast error is usually higher for time intervals further into the future from the current time. We also observe that for a given ramp rate the inclusion of forecast error in load leads to a reduction in the number of cases where look-ahead LMPs are more volatile than static LMPs.

B. Season-wise Simulation

In the simulations presented in this subsection, the scaled down real time load data for the entire year 2012 is considered. The year is divided into seasons as follows: (i) Winter: January, February, December; (ii) Spring: March, April, May; (iii) Summer: June, July, August; and (iv) Fall: September, October, November. The look ahead economic dispatch is run for 3 cases: (1) without error in forecast, (2) with constant standard deviation of error in forecast, and (3) with increasing standard deviation of error in forecast.

Table VIII shows that look ahead dispatch results in a significant reduction in the number of price spikes in winter, spring and fall. In summer also there is a reduction in the number of price spikes, but the factor of reduction is much smaller. This is due to greater loading on the system which requires the dispatch of the more expensive generators more often, as compared to other seasons. Further the inclusion of

TABLE IX
SPIKES IN LMPS BY LOAD PATTERN (FOR SUMMER AND FALL)

	Summer		Fall	
ΣD (MW)	ST^p	LA^p	ST^p	LA^p
≤ -10	1094	580	52	16
> -10 & ≤ -5	478	142	51	0
> -5 & < 5	1299	181	152	0
≥ 5 & < 10	807	25	117	0
≥ 10	1895	204	194	0

forecast error in the load forecast leads to an increase in the number of price spikes under look-ahead dispatch.

Next we look at the relationship between the number of LMP spikes and the load pattern for the corresponding time period. The operating day is divided into 30 minute blocks, where each block consists of six 5-minute intervals of real time dispatch. The cumulative load change in each 30 minute block is denoted by ΣD and the number of LMP spikes above the chosen threshold of \$50 corresponding to the time blocks are counted.

Table IX shows the division of the number of price spikes for changes in load over 30 minute blocks for summer and fall seasons. From these results we can see that larger cumulative load changes in both up and down directions coincide with greater number of price spikes. This indicates that LMPs tend to be higher when load ramps are more severe. This makes sense since more expensive generators with higher ramp capability would have to be dispatched when the ramps in load are more severe, in order to maintain system energy balance.

In Table IX it is seen that a large number of price spikes coincide with time blocks when the cumulative load change is less than ± 5 MW. This can be explained by the fact that these occur during peak load periods. Thus even though the load profile is relatively flat, since the system is heavily loaded it requires the system operator to dispatch more expensive generators to maintain the system energy balance.

VI. CONCLUSIONS

In this paper we study and compare locational marginal prices resulting from time-coupled look-ahead and conventional static dispatch. The observations are summarized as follows:

- The increase of system-wide ramp capability (or decrease of load variability) leads to lower price volatility in both look-ahead and static dispatch.
- The price in look-ahead dispatch is relatively less volatile than in static dispatch under more stringent system-wide ramping capability.
- It is evident that look-ahead dispatch obtains the benefit of the total cost saving with the increasing number of time intervals K. However, price volatility does not monotonically change in terms of K.
- In a realistic setting where the forecast error usually increases with the forecast horizon, look-ahead dispatch greatly reduces the number of price spikes as compared to the static dispatch.
- Look-ahead reduces the price spikes in summer when the system is heavily loaded. But the factor of reduction in number of price spikes is greater in other seasons when the system loading is lighter.

Future work will include much more in-depth theoretical analysis of time-coupled dynamic dispatch as a multi-stage dynamic programming problem. Also the impact of transmission line congestion on look-ahead dispatch LMPs will be studied in our future work. As a policy recommendation, the design of pricing signal in real-time power market needs to carefully consider behaviors as reported in this paper.

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