NYISO Installed Capacity Working Group

Suggestions for Improvement of Energy Net Operating Revenue Modeling

on behalf of New York City Generators

Overview

Levitan & Associates, Inc. (LAI) presents this response to the New York Independent System Operator (NYISO) sponsored draft report by NERA, *Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator*, of May 21, 2010. The comments provided herein are presented on behalf of US Power Generating Co., TransCanada Power, and NRG Energy, Inc., owners and operators of power plants in New York City (NYC).

This response is limited to a set of issues surrounding the calculation of annual energy net operating revenues from the sale of energy over the range of reserve margins used in the demand curve model. In addition to information contained in the NERA draft report and the Excel "Demand Curve" model file posted by NYISO on July 2, this response also considers information contained in the three Stata model files posted July 9, and in oral comments by Mr. Jonathan Falk of NERA at the July 16th Installed Capacity Working Group (ICAPWG) meeting in response to the presentation by Dr. Richard Carlson of LAI. At the July 16th meeting, Dr. Carlson addressed seven of the ten issues identified in these comments.[1]

LAI has evaluated the reasonableness of the data and modeling methods used in NERA's statistical analysis presented in the draft report of July 1, 2010. Emphasis has been placed on the identification of significant data and modeling deficiencies that have the potential to cause material bias in the quantification of energy profits associated with the postulated addition of the LMS100 peaker unit in NYC.

Executive Summary

Upon inspection of NERA's data and Stata scripts, LAI has determined that there were significant data deficiencies and modeling biases which skewed profits from energy sales above what may be reasonably expected when statistical analysis is performed in strict accord with standards of professional excellence. LAI notes the existence of ten issues that have impacts on the determination of net operating revenue. The problems and LAI's recommended solutions are summarized in the table below.

[1] Dr. Carlson had earlier raised two of the other issues (forward gas prices and Special Case Resource, or "SCR," call price adjustment) in comments during NERA's April 1, May 21, and June 17 ICAPWG meeting presentations.

List of Issues and their Proposed Solutions

ID	Issue	Solution
1	Emission allowance costs not included	Include RGGI and NO_x allowance costs that the proxy units will undoubtedly face
2	Fuel transport costs and tax rates underestimated for NYC zone, and intraday price premium not included	• Include the current commodity tax rates applicable to proxy units in NYC • Use reasonable estimates of local transport charges that proxy units in NYC will undoubtedly face • Include a reasonable estimate of the intraday premium cost
3	Daily temperature impacts on capacity and heat rate not included	Include appropriate capacity and heat rate adjustments to the seasonal values based on daily temperature variation
4	NYC adjustment to LBMP for units connected to 345kV node under-estimated	Revise the 345kV basis spread method to include separate summer, winter, and shoulder season values based on the average spreads over the past four years
5	One LBMP regression model inconsistently applied to produce two sets of LBMP forecasts	Estimate one set of LBMP regression equation parameters and one LBMP forecast using the appropriate gas price index for each zone, in accordance with established standards of professional excellence for statistical methods
6	Insufficient length of historic data period for reliable estimation of the parameters of the LBMP prediction model	Use more historical data to estimate accurate, robust LBMP regression equation parameters, in accordance with established standards of professional excellence for statistical methods
7	LBMP regression model can be improved to be more accurate and robust	Use an alternative LBMP regression equation specification that minimizes statistical parameter estimation problems, in accordance with established standards of professional excellence for statistical methods
8	LBMP regression model is not estimated with an appropriate statistical method to correct for patterns in the residuals	Use statistical diagnostic tests and alternative model specification and/or estimation method that corrects any statistical problems in the regression residuals, in accordance with established standards of professional excellence for statistical methods
9	SCR call price adder method is biased	• Provide empirical support for assuming that the top 500 price hours should be the benchmark for simulating SCR call price adders, or provide an alternative supportable estimate • Correct the bias in the SCR call price adjustment method by also including the indirect price decrease impacts of SCR calls that do not result in an administrative price increase
10	Energy net operating revenue not adjusted for lower expected future natural gas prices	Contingent upon development of a more accurate and robust LBMP prediction model, use market forward prices for natural gas instead of historic spot prices

At the July 16, 2010 ICAPWG meeting, Mr. Jonathan Falk defended the statistical regression model. At the meeting, Mr. Falk indicated he was "not sanguine" about implementing further model changes on the basis of four modeling procedure issues raised in the meeting presentation by Dr. Richard Carlson, including discussions among NYISO, NERA and LAI on July 15th. In contrast, Mr. Falk appeared willing to incorporate further adjustments in the final report based on a more accurate representation of operating costs. The body of this report specifies the nature of the problem areas and also outlines specific solutions that can be implemented to facilitate a fair and efficient simulation of net operating revenue associated with the postulated LMS100 unit in NYC.

Highlights of the ten issues are presented in this summary.

Issue 1: Emissions Allowance Costs Not Included

Regional Greenhouse Gas Initiative (RGGI) allowance costs were a variable production cost starting in January 2009, and have been reflected in the LBMPs after that date. Neither actual historic RGGI costs were deducted in the dispatch simulation for the 10 months RGGI allowances were required, nor forward prices for the November 1, 2006 to December 31, 2008 historic data segment of the forecast period. As well, NO_x emission allowance costs have been omitted.

The solution consistent with the NERA approach of only modifying historic costs when necessary is to use the actual 2009 spot RGGI prices for the last 10 months of the three year prediction period and include current forward RGGI 2011 and 2012 prices for the other 26 months. RGGI (and NO_x) allowance costs should be added to the delivered gas price used in the regression model and the dispatch simulation model.

Issue 2: Fuel Transport Costs and Tax Rates Underestimated for NYC Zone, and Intraday Price Premium Not Included

The LBMP regression model and the dispatch model use a $0.202/MMBtu gas adder for the NYC. The dispatch model also includes a 4% fuel commodity tax rate in unit operating costs, but not in the LBMP regression model. No intraday premium cost is charged for gas used in the Real Time Market (RTM) dispatch. These charges are too low compared to actual costs borne by generators in NYC.

The solution is to use reasonable higher values for transportation charges on the New York Facilities System (NYFS) consistent with the New York Public Service Commission (NYPSC) approved tariff for interruptible transportation and actual experience. The reasonable higher value for Day-Ahead (DA) gas should be about $0.50/MMBtu. For gas used in RTM dispatch, it is appropriate to add another $0.45/MMBtu for the intraday price premium, for a total of $0.95/MMBtu. These reasonable higher values incorporate an allowance for imbalance resolution costs on the NYFS or penalty incurrence, and lost and unaccounted for gas. In addition, the Commodity Sales Tax (CST) was recently raised to 4.5% and the Gross Receipts Tax (GRT) is 2.4066%, so 6.9066% is the correct going forward tax rate. The reasonable higher values proposed above do not explicitly account for the 50% minimum bill requirement set forth in the NYPSC tariff, a cost component that NERA has acknowledged, but has not incorporated in the determination of the adder. If accounted for, this cost would be higher.

Issue 3: Energy Net Operating Revenue Not Adjusted for Impacts of Daily Ambient Temperature Differences from Seasonal Average Temperature

Net energy revenues are scaled from the per MW value coming from the Stata dispatch model to the Excel demand curve model by using seasonal Unforced Capacity (UCAP), which includes the average impact of different summer and winter temperatures. But daily effects are not modeled, which causes net energy revenue to be overestimated since peakers realize a disproportionate share of their net operating revenue on the hottest days. On the hottest days, peakers cannot generate as much energy as the summer UCAP (with 83º F basis in NYC). Secondly, heat rate degrades when operating capacity is constrained, thereby increasing operating cost.

The solution is to account for the change in capacity and heat rate as a function of temperature in the Stata dispatch model, and then for consistency sake incorporate the same maximum daily temperature data in the regression model.

Issue 4: NYC Adjustment to LBMP for Units Connected to 345kV Node Under-Estimated

NERA assumes that the LMS100 in NYC would be located on the 345kV system. LBMPs on the 345 kV system tend to be significantly lower than the regression model's prediction of LBMPs for the NYC load zone as a whole. NERA uses a $1.54/MWh deduction based on the 2006 all-hours spread between the zonal LBMP and the Poletti bus LBMP. LAI suggests that a somewhat larger spread, based on the seasonal average spreads for the three peak summer months, three peak winter months, and the remaining six shoulder months would constitute a more reasonable proxy deduct. This is because peakers tend to operate mostly during the summer season when the spread is larger than the annual average.

Issue 5: One LBMP Regression Model Inconsistently Applied to Produce Two Sets of LBMP Forecasts

The documentation of the regression model says one equation with a single reserve margin (RM) coefficient shared by all regions is used to predict LBMPs for all zones. But the analysis actually ran two models, one using only Transco Z6 (TZ6NY) prices, and the other using only Tetco M3 (M3) prices, resulting in two conflicting sets of model coefficients. The RM coefficient estimates were -1.30 for the TZ6NY model and -1.00 for the M3 model. The TZ6NY model is then used to predict prices for the net operating revenue simulation of NYC (and Long Island, or "LI") units while the M3 model is used to predict prices for the simulation of net operating revenue for units in Rest of State (ROS). The difference in the RM (and other) coefficients between the two models has a large negative impact on profitability for the NYC and LI units.

The solution is to merge the TZ6NY and M3 prices into one gas price vector, with TZ6NY prices for Zones J and K, and M3 prices for ROS. Doing so results in a single RM coefficient close to that estimated with M3 prices only, and it slightly corrects gas price and other coefficients that are also shared across zones. The impacts are that the model works as described, and does not disadvantage NYC and LI region units by using a much steeper RM coefficient.

Issue 6: Insufficient Length of Historic Data Period for Reliable Estimation of the Parameters of the LBMP Prediction Model

RM data has not varied much over the past three years, and part of its variation is an artifact of a trailing adjustment to EFORd changes and seasonal temperature-based changes in UCAP. Much of its variation is correlated with the gas price, load, and temperature variables in the regression model, which makes it extremely difficult to properly estimate its parameter value. Statisticians refer to this as a “multicollinearity” problem in the data. This parameter estimation problem is exacerbated because the model is used to extrapolate prices with RM predictions that are far outside the historic range. As NERA notes, some coefficient estimates, such as most November gas price coefficients, and the two temperature coefficients, are small and insignificant, or have the wrong sign yet are significant. LAI’s tests with different data sets indicate a serious multicollinearity problem.

The solution is to use more data. LAI has run the NERA model with six years of data rather than three. The RM coefficient becomes much smaller, indicating that net operating revenues will be lower than otherwise over the same three-year prediction period. The other coefficients also appear more reasonable in size and significance.

Issue 7: LBMP Regression Model can be Improved to be More Accurate and Robust

Even using more data does not mitigate the multicollinearity problem or other data and statistical problems sufficiently. All of the independent variables currently in the regression equation, RM, load, gas price, and temperature, have causal multicollinearity with one another at the monthly or seasonal level. These seasonal patterns cause multicollinearity which is not entirely eliminated by using more data.

The solution is to reformulate the regression equation while still using the same data and underlying variables. The first modification is to substitute a regional demand-supply ratio (DSR) variable and a New York Control Area (NYCA)-wide DSR variable in the model (both in log form) for the RM variable, and to omit the zonal load and aggregate load variables because they are now the numerator of the log DSR variables. A second modification is to put the DSR variable in logarithmic form, which allows for omission of the various zonal and aggregate load variables as separate explanatory variables. A third change is to use either average or maximum daily temperature instead of minimum and maximum temperature variables since they are very highly correlated with one another, and cause multicollinearity problems with other variables.

Issue 8: LBMP Regression Model Is Not Estimated with an Appropriate Statistical Method to Correct for Patterns in the Residuals

Various methods should be used to test for two related violations of the suitability of estimating the regression model with Ordinary Least Squares (OLS) regression. These requirements are that the residuals should not be correlated ("serial correlation" problem) and the size of the residuals should not have a pattern ("heteroskedasticity" problem). One alternative available in Stata is use of the Generalized Least Squares (GLS) estimation procedure, which corrects for both technical problems, allowing parameter estimates to be more accurate. The larger issue is that there appears to have been insufficient diagnostic testing and reporting of likely model specification and estimation issues.

Issue 9: Special Case Resource Call Price Adder Method is Biased

The method for overriding the Real-Time (RT) LBMP predictions of the regression model to account for the number of hours that SCRs are called as the reserve margin varies has not had the empirical basis for determining the size of the price increases revealed. In addition, the logic of using the procedure appears to be biased. Price increases are simulated for some SCR call events, but for other SCR events, there is not a corresponding decrease in the predicted RT LBMP to account for SCRs being activated, which pushes the supply of market-based resources to the right, tending to reduce prices from what they would have been without the SCR activation.

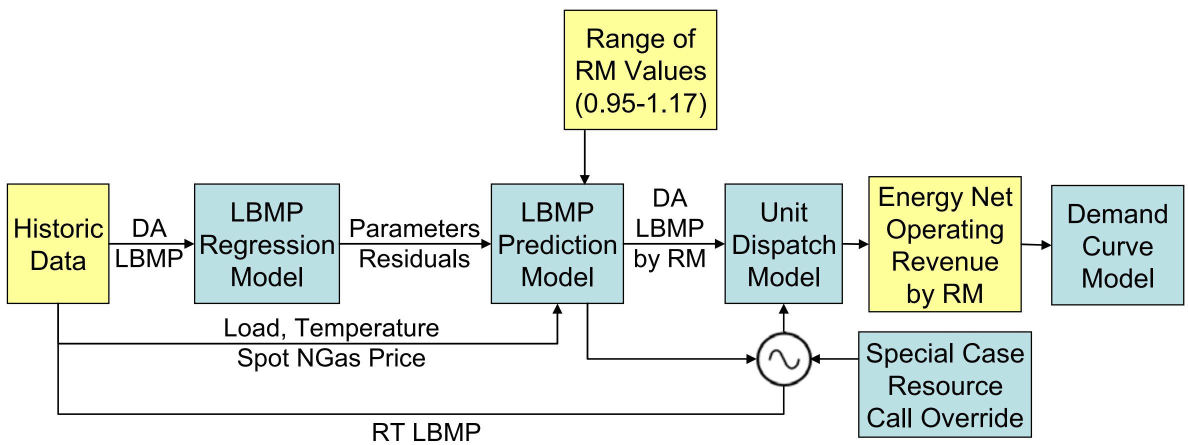
Issue 10: Energy Net Operating Revenue Not Adjusted for Lower Expected Future Natural Gas Prices

NERA has rejected consideration of the use of the current lower gas futures prices to drive the forecast of LBMPs. NERA claims that the decision to use the higher historic spot prices results in somewhat lower energy net operating revenues. LAI's testing indicates that this conclusion is model sensitive, at least for some zones. We advise reconsideration of this issue in light of any modifications that may be made to the forecast model, stemming from several of the data and statistical issues raised here.

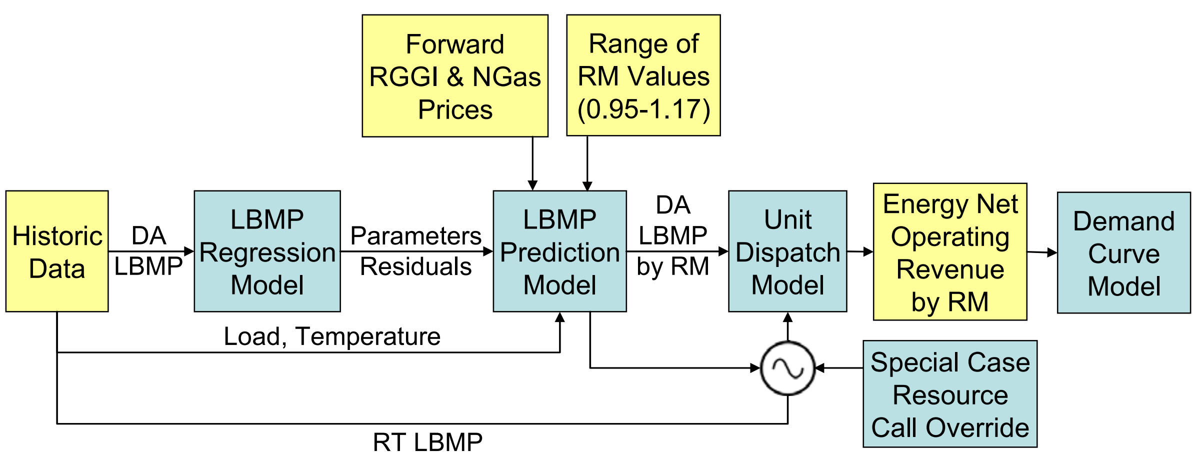
Report

The scope of the NERA analysis investigated by LAI can be visualized in the following data flow diagram which indicates key data inputs (yellow boxes) and model components (blue boxes) that result in the energy net operating revenues evaluated by the Demand Curve Model (in Excel). The upstream model components and data transfers all use the scripting language and statistical functions of the commercial Stata software application. LAI has inspected and run the NERA-provided data set and Stata scripts in order to fully understand the LBMP price forecasting and unit economic commitment and dispatch logic. The recommendations of LAI, among other items not shown here, would slightly modify the data flow diagram as indicated in the second diagram.

Current NERA Modeling System for Simulation of Energy Net Operating Revenue



LAI Proposed Modeling System for Simulation of Energy Net Operating Revenue



A more detailed discussion of each of the aforementioned issues is presented in this section. To redress problems associated with the data deficiencies and specification bias, subsequent to issuance of NERA's most recent draft report on July 1^{st} LAI implemented each of the recommended solutions delineated in the comments that follow.

Issue 1: Emission Allowance Costs Not Included

NERA omitted consideration of RGGI allowance costs and NO_x allowance costs, which would appropriately be included as a burner-tip adder to the gas price in the LBMP regression model and the dispatch model.

Currently, RGGI futures for 2011 and 2012 are slightly below \$2 per short ton on the Chicago Climate Futures Exchange. The CO_2 emission rate for natural gas combustion is 116.97 lb/MMBtu.[2] Even at the low current RGGI prices, the cost burden for an efficient LMS100 PA with a 9,156 Btu/kWh net plant heat rate in NYC is about \$1.07/MWh.

To follow NERA's approach of minimizing forecast period differences from historical period values, LAI recommends the simple strategy of using actual RGGI spot allowance prices from January 1 to October 31, 2009 together with historical data for the other variables in the regression and dispatch models. But since we know from current RGGI futures prices that RGGI costs will be the equivalent of about \$0.12/MMBtu in the first two years of the forecast period, LAI recommends that current futures prices for 2011 and 2012, respectively, be used with historic data for the November 1, 2006 to December 31, 2008 period.

Because the LMS100 unit incorporates state of the art selective catalytic reduction equipment, it is reasonable to expect NO_x allowance costs for the postulated gas turbine (GT) unit in Zone J to be small. While outside LAI's technical review to support these comments, we note that NO_x allowance costs may be significant for GE Frame 7 units that have been postulated for ROS. For consistency across different peaker technology types that vary with respect to emission rates and NO_x control technology, LAI recommends that NO_x allowance costs be included in the analysis. However, it is appropriate to use a different method for each type of emission. CO_2 emissions are a function of fuel type; hence, we recommend that RGGI costs be included in the delivered fuel costs used in the LBMP regression model and in the dispatch simulation model. NO_x emissions are a function of combustion conditions, control technology, and operating regime; hence, a more accurate simulation of NO_x allowance costs would model NO_x emissions in a more complex manner than CO_2 allowance costs. However, since NO_x emissions are relatively small, even for GE Frame 7 units, and NO_x allowance prices are presently at an all-time low, for simplicity sake LAI recommends that NO_x costs be modeled as a fuel cost adder.

---

[2] Energy Information Administration, *Electric Power Annual 2004*, DOE/EIA-0348(2004) November 2005, Table A1.

Issue 2: Fuel Transport Costs and Tax Rates Underestimated for NYC Region, and Intraday Price Premium Not Included

The defects in the definition of local transportation costs include the following: (i) no inclusion of a significant intra-day premium for gas purchased to enable dispatch in the RTM; (ii) no inclusion of the GRT; (iii) use of the obsolete 4% CST; (iv) uncertain treatment of the 50% minimum take (min-take) requirement set forth in the interruptible transportation tariff; (v) underestimation of Value Added Charge; (vi) no inclusion of gross-up allowance for Lost & Unaccounted gas associated with losses on the NYFS.

The following fuel transportation charges and commodity tax rates by region were modeled by NERA in Stata:

	NYC	LI	ROS
Fuel transportation charges ($/MMBtu)	$0.202	$0.253	$0.402
Commodity tax rate (%)	4.0%		
Intraday premium ($/MMBtu)	NA	NA	NA

NERA added the local fuel transportation charges to the commodity price of gas in forming the delivered fuel price used in the LBMP regression model. Both the fuel transportation cost adder and the NYC commodity tax rate were included in the simulation of energy net operating revenue in the dispatch model. No reason was presented for omitting the commodity tax rate from the fuel price used in the regression model. Likewise, the Stata scripts indicate that NERA has not included any intraday premium for gas purchases to enable dispatch in the RTM. The incurrence of such intraday premium reflects the higher cost of obtaining "swing" gas supply relative to Mid-Point pricing in *Gas Daily* after the North American Energy Standards Board nomination / confirmation scheduling protocols have been concluded for each gas day.

The components of the fuel transportation charges, in 2010 dollars, in the NERA 2010 draft report (Table II-7, p. 35) are identical to the 2007 dollar costs shown in the NERA 2007 final report (Table II-7, p. 41) for NYC and LI. For ROS the cost in the 2010 draft report is $0.270/MMBtu relative to $0.402/MMBtu in the 2007 final report. The ROS value used in the 2010 Stata regression and dispatch models matches the 2007 final report value instead of 2010 draft report value.

NERA has assumed that the NYC gas price adder for all local transportation costs is $0.202/MMBtu. NERA has incorporated a price multiplier for applicable taxes equal to 4%. The adjustment for tax effects is significantly below the applicable tax rate borne by generators in NYC. NERA's local cost assumptions result in a significant overestimation of net operating revenue by failing to account for certain significant local costs that in-city generators incur. Moreover, certain of the included cost components are lower than actual. For example, NERA notes that representatives from Con Edison and Grid have indicated that imbalance charges are minimal in the DAM, but they do not comment on whether such imbalance charges are minimal in the RTM. Consistent with the NYPSC authorized interruptible transportation tariffs applicable to local delivery services on the NYFS, both

Con Edison and Grid are permitted, *if not required,* to levy imbalance charges when a generator's daily gas use does not conform to the nomination and confirmation quantities required under the tariff. Imbalance resolution charges can be incurred for daily gas used in both the DAM and RTM. Imbalance charges levied by Con Edison and/or Grid may or may not be *as* significant for steam turbine generators (STGs) or GTs scheduled in the DAM, but they are nevertheless highly likely to be material for the postulated quick-start LMS 100 unit which operates from a cold start in the RTM. In actuality, STGs and GTs in NYC do incur significant imbalance resolution charges. Therefore, NYPSC tariff provisions which allow for the recovery of costs for the incurrence of penalties for unauthorized gas use cannot be ignored. NYISO's Market Monitor has the ability to review the frequency and magnitude of such imbalance resolution costs, as well as other cost components incurred by generators on the NYFS.

The actual current CST is 4.5% and the GRT is another 2.4066%, for a combined tax rate of 6.9066%. To account for the missing components or underestimated components in NERA's total local adder, LAI estimates local transport costs of $0.50/MMBtu, applicable to both day-ahead and intraday purchases. To account for the intra-day premium associated with gas procured in the RTM, LAI estimates the intraday gas cost adder to average about $0.45/MMBtu. LAI did not assess whether GTs in ROS and/or LI would likely incur a gas cost premium in the intra-day gas market.

From a conceptual standpoint and consistency of treatment in the regression model and the dispatch model, it would be preferable to include the commodity tax in the delivered gas price data used in the regression model for predicting LBMPs since a single set of gas price coefficients are used with gas prices across all 11 zones. Including emission costs, the DAM burner-tip gas price ($/MMBtu) formula for both the regression model and the dispatch model should be:

$$\text{DAGasPrice} = (1 + \text{TaxRate}) * \text{CommodityPrice} + \text{TransportCharge} + \text{EmissCost}$$

The RTM burner-tip gas price formula in the dispatch model may for modeling simplicity be expressed as:

$$\text{RTGasPrice} = \text{DAGasPrice} + \text{IntradayPremium}$$

However, the intraday premium for NYC also includes the CST and GRT, so this formulation of the RTM delivered gas price assumes that those taxes are appropriately included in the intraday premium adder.

Issue 3: Energy Net Operating Revenue Not Adjusted for Impacts of Daily Ambient Temperature Differences from Seasonal Average Temperature

NERA's RM variable is calculated as the ratio of the NYISO's "committed" capacity (Committed) variable divided by the NYISO's "minimum required" capacity (MinReq) variable. Committed capacity properly reflects the seasonal impact of ambient temperature differences between winter and summer, so the seasonal difference in average daily temperature is also reflected in the RM variable.

NERA's Stata regression model for predicting LBMP includes two ambient temperature variables based on data for Central Park in NYC: daily minimum temperature and daily maximum temperature. These two variables are used as control variables in the regression equation to reflect the impact on LBMP of daily changes in generation capability and heat rate as a function of ambient temperature fluctuations between days within each season. Hence, the issue of daily ambient temperature fluctuations not being reflected in the simulation of energy net operating revenue pertains only to the Stata dispatch model.

For each GT technology evaluated, Appendix 1 of the NERA draft report provides graphs of capacity degradation as a function of ambient temperature, and of heat rate degradation as a function of unit loading for three ambient temperatures. The capability or net capacity function of temperature graph and the heat rate function of net capacity by ambient temperature graph for the LMS100 unit modeled for Zone J are reproduced on the following page to illustrate the magnitude of the impacts. For the LMS100 unit, the net capacity curve has an inverted "U" shape, falling slightly at low temperatures and falling much more at high temperatures. For NYC, NERA has specified in the draft report summer, winter, and spring-fall temperatures of 83ºF, 28ºF, and 59ºF, respectively, with slightly different relative humidity values.[3]

[3] See Appendix 1, p. 74.

Figure A-1 — LMS100 PA: Net kW vs. Ambient Temperature

Average Degradation, 60% Relative Humidity

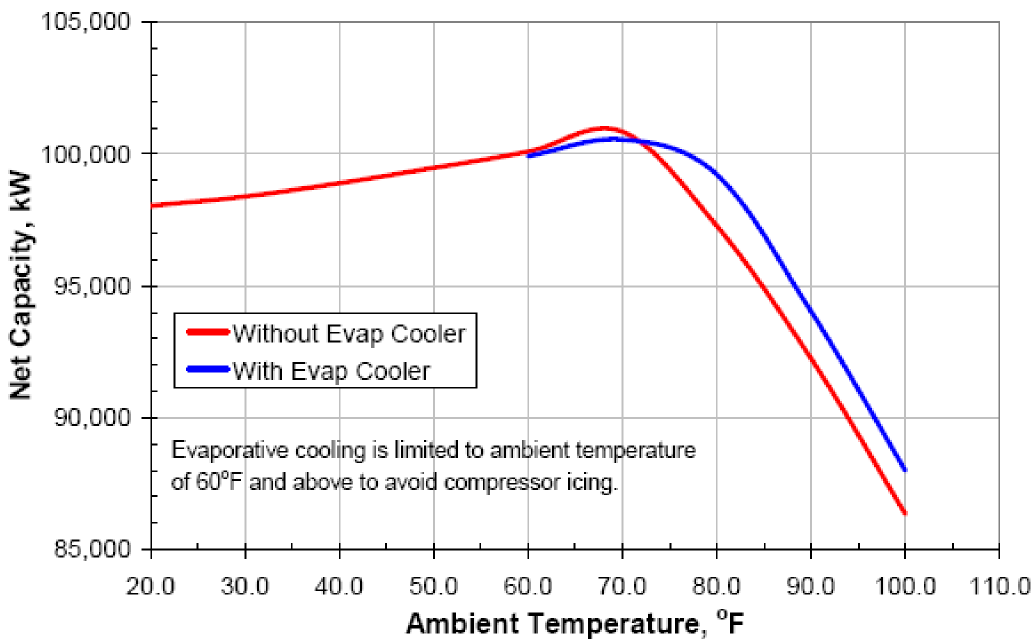
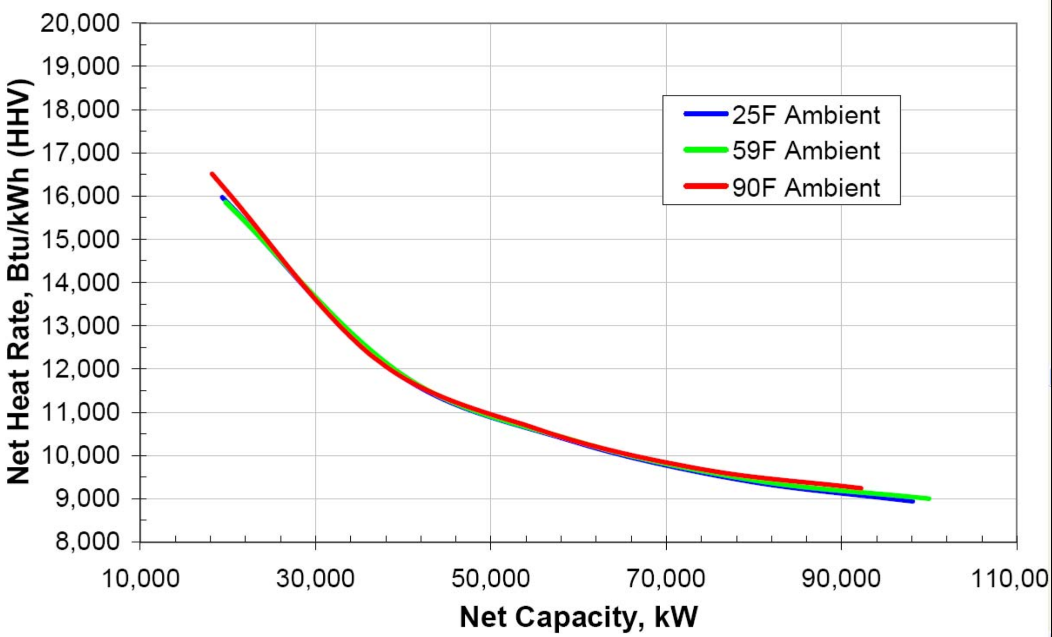


Figure A-2 — LMS100 PA: Net Capacity vs. Net Heat Rate

Average Degradation



Since the NERA analysis assumed that daily temperature impacts were important enough to include in the LBMP prediction model, for consistency those impacts should also be included in the dispatch simulation model. Moreover, inclusion of daily ambient temperature fluctuations is of much greater importance for evaluation of net operating revenues in the dispatch simulation model than for the LBMP prediction model.[4]

While the measurement error of not including the ambient temperature impacts on net capacity and heat rate tends to cancel out for hotter or colder temperature conditions than seasonal average temperatures, the net impact remains positively skewed toward the over-estimation of net operating revenue. This is because electricity load and prices are positively correlated to cooling degree days and heating degree days. LBMPs will tend to be higher on hotter than average summer days and on colder than average winter days. Similarly, LBMPs will tend to be lower on cooler than average summer days and on warmer than average winter days. By not capturing net capacity degradation on those days, energy revenue is over-estimated by more than it is under-estimated on cooler than average summer days and warmer than average winter days due to the asymmetric shape of the capacity function of temperature. The heat rate degradation impact also increases dispatch cost on hotter than average summer days and colder than average winter days more than the opposite impact on heat rate for the reversed daily temperature conditions. The impacts of daily temperature fluctuations on net capacity and heat rate are compounded in their net impact on net operating revenue.

Fortunately, inclusion of the daily temperature fluctuation impacts on net capacity and heat rate is easily modeled in the model, which already uses daily temperature data in predicting LBMPs. Since issuance of the draft report, LAI has constructed an enhanced dispatch simulation model as a proof-of-concept prototype. As the data were not tabulated in NERA's draft report, LAI relied on a visual lookup of pairs of points on the net capacity graph for the relatively linear negative slope in the high temperature range, and the relatively linear positive slope in the low temperature range to estimate summer and winter linear coefficients to adjust the respective seasonal UCAP values included in the Excel Demand Curve Model.[5] LAI also relied on visual lookup of the relatively linear upper ends of the three heat rate functions of net capacity to estimate a linear coefficient for the impact of net capacity on heat rate. These two effects modify the energy revenues, dispatch costs, and net operating revenue per MW of seasonal UCAP simulated for the unit.

---

[4] If the LBMP prediction model had omitted the daily temperature fluctuation effect, the larger "unexplained" residuals from the regression model would still be included in the LBMP prediction used by the dispatch model since the final prices are the sum of predicted prices and the residuals. However, without the daily temperature fluctuation effect, the dispatch model overestimates (underestimates) net capacity on summer days when temperature is higher (lower) than the summer UCAP rating for the location modeled. For the LMS100 technology, the reverse impacts occur in the winter because that portion of the net capacity function of temperature has a positive slope, while at higher summer temperatures the slope is negative.

[5] The Stata dispatch model does not include capacity (other than to calculate the per MW start cost), since it only transfers net operating revenue per MW of capacity to the Excel Demand Curve Model. Instead of directly modeling the daily net capacity value, the approach implemented by LAI calculates the ratio of the daily net capacity to the seasonal UCAP.

In order to capture the impacts of daily changes in temperature on both operable capacity and heat rate (at full load output), LAI estimated the linear slopes of the LMS100 capacity graph for each end of the curve, and the linear slope of the heat rate function of capacity graph. To be conservative and to ignore the complication of the inverted U-shape at mid range temperatures, the dispatch model was enhanced to calculate daily capacity and heat rate for just the peak three winter months (Dec. to Feb.) and peak three summer months (June to Aug.), based on the daily deviation of daily maximum temperature from the respective peak season average daily maximum temperature.

Issue 4: NYC Adjustment to LBMP for Units Connected to 345kV Node Under-Estimated

The 2010 NERA draft report assumes that the LMS100 will be connected to a 345kV bus. To account for the lower LBMPs at 345kV nodes in NYC than the NYC Load Zone LBMP, NERA effectively reduced the LBMPs received by the modeled LMS100 unit by $1.54/MWh from the zonal LBMPs predicted by the regression model, using Poletti as a benchmark 345 kV generator price node.[6]

The form of the adjustment is certainly appropriate. However, it appears that NERA has underestimated the appropriate 345kV price basis spread for two reasons. First, the same Poletti basis of $1.54/MWh appeared in the 2007 NERA final report (p. 54), so the value is outdated as a proxy for any 345kV location. LAI has determined that the $1.54/MWh value matches the annual average price spread for calendar year 2006. While the all-hours average price for the 2007 to 2009 period is slightly higher ($1.71/MWh), as shown in the table below, the spread is consistently higher than the annual average during the three peak summer months when most net operating revenue is earned.

NYC DA Average Spread, 345kV LBMP (at Poletti) Minus NYC Load Zone LBMP ($/MWh)

Cal. Year	All Hours	June, July, Aug.	Jan., Feb., Dec.	Shoulder Months
2006	-1.54	-3.92	-0.80	-0.70
2007	-1.72	-2.01	-1.76	-1.56
2008	-2.16	-5.97	-1.09	-0.78
2009	-1.23	-2.46	-0.91	-0.72
4-yr Ave.	-1.66	-3.59	-1.14	-0.94

LAI recommends that separate summer (3-month), winter (3-month), and shoulder (6-month) price spreads be deducted from the NYC Load Zone LBMPs. Specifically, LAI recommends that the four-year average spreads by season in the table above be used. Within each season, there is little difference by time-of-day, so it appears reasonable not to further differentiate the spreads by time-of-day.

[6] See NERA 2010 draft report, p. 51.

Issue 5: One LBMP Regression Model Inconsistently Applied to Produce Two Sets of LBMP Forecasts

The ICAPWG presentations by Mr. Falk represented the LBMP regression modeling method as being a single equation model for simultaneously predicting hourly DA LBMPs for all 11 load zones. In the discussion of whether TZ6NY or M3 prices would be used, the only issue was whether NERA planned to use TZ6NY only, M3 only, or use both price indexes according to which gas price index is more appropriate for each zone. The NERA draft report says M3 price data was used "for all but New York City and Long Island" and TZ6NY for NYC and LI (p. 43). The only other documentation in the draft report of which gas price index was used is implicit in the Stata regression output log file in Appendix 3.

LAI confirmed that the coefficients produced by this regression analysis were based on use of M3 gas prices only. However, the topmost lines in the Stata script files that NERA posted indicated a toggle for using either Tetco or Transco prices. This ambiguity led to LAI's request for NERA to provide the Stata script and output files that produced the net operating revenue results for the units modeled in the NYC zone. LAI confirmed that the units modeled in NYC had used a different set of Zone J LBMPs than those produced by the regression model included in the draft report. The LBMPs used to evaluate units in the NYC and LI zones resulted from a second run of the regression equation, driven by using only TZ6NY prices for the entire state. At the July 16 ICAPWG meeting, Mr. Falk acknowledged that two different models had been used. One model used M3 prices for all 11 zones and the other model used TZ6NY prices for all 11 zones.

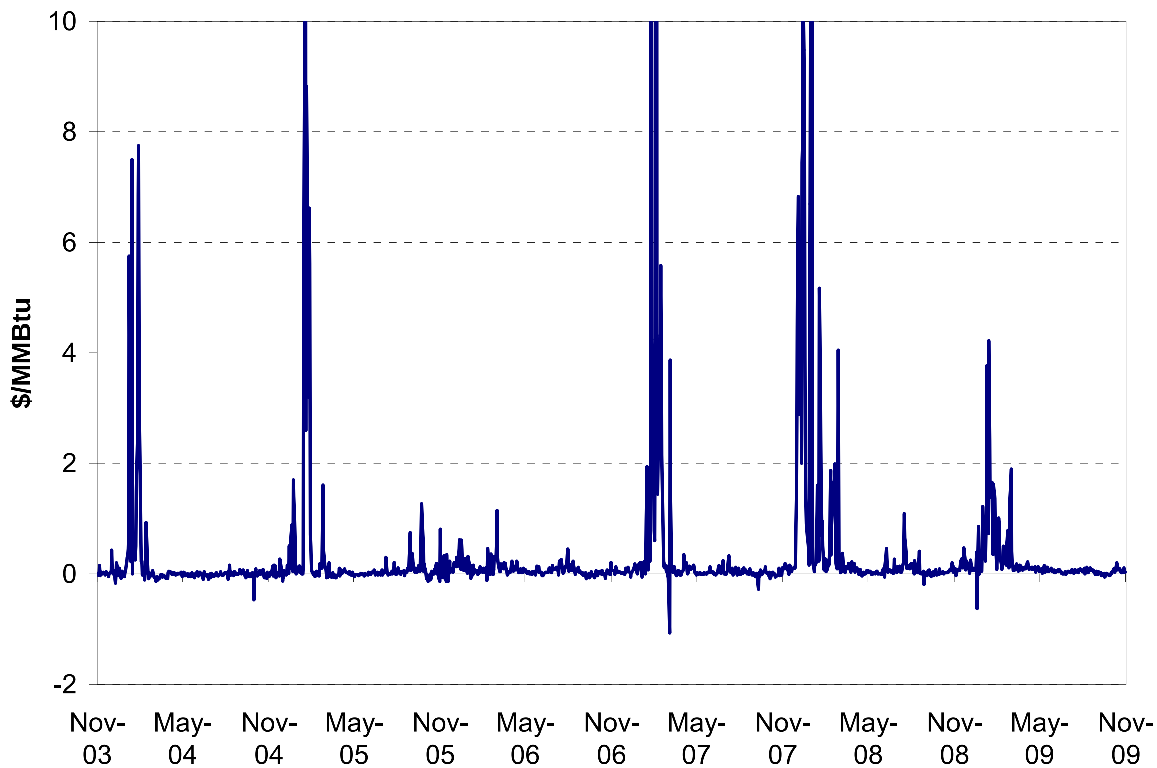
The issue is that two different sets of identical gas commodity prices for all 11 zones produced two different sets of regression equation coefficients, which resulted in two different competing sets of predicted LBMPs. This dual regression equation "fitting" and forecasting procedure is unnecessary and inconsistent for several reasons. There is no reason in either economic theory or statistical theory to support use of this approach. The single equation model simultaneously predicts hourly LBMPs for all 11 zones. Hence, the OLS parameter estimation method of minimizing the sum of the squared residuals over all 288,002 observations (11 zones times 8760 or 8784 hours in each of three years) weights the fit of the model to the sample data equally for all 11 zones. If the model had been intended to be applied to only the NYC and LI zones in one analysis, and nine ROS zones in another analysis, then predictions for the other zones would not only have been unnecessary, but also harmful to the estimation of regression equation coefficients. If the objective was to predict prices more accurately based only on local conditions, then the same equation could be run separately for each zone or region.

On the other hand, if the objective was to make use of gas price data most relevant to generation in each zone, then the equation could have been fitted with a set of gas prices that represent TZ6NY prices in the NYC and LI zones, and M3 prices in the ROS zones. In fact, the regionally distinct gas transportation charges ($0.202 in NYC, $0.253 in LI, and $0.402 in ROS) were added to whichever gas commodity price data was used for each of the two regression equation fit and price prediction cases. So, delivered gas prices were different by region, but only by the amount of the region-specific adders to the same commodity price.

Using Stata, it is straightforward to merge each commodity price index by region or zone. It is also trivial to change the equation specification to allow the coefficients on the gas price variable to be distinct by energy price region or zone.

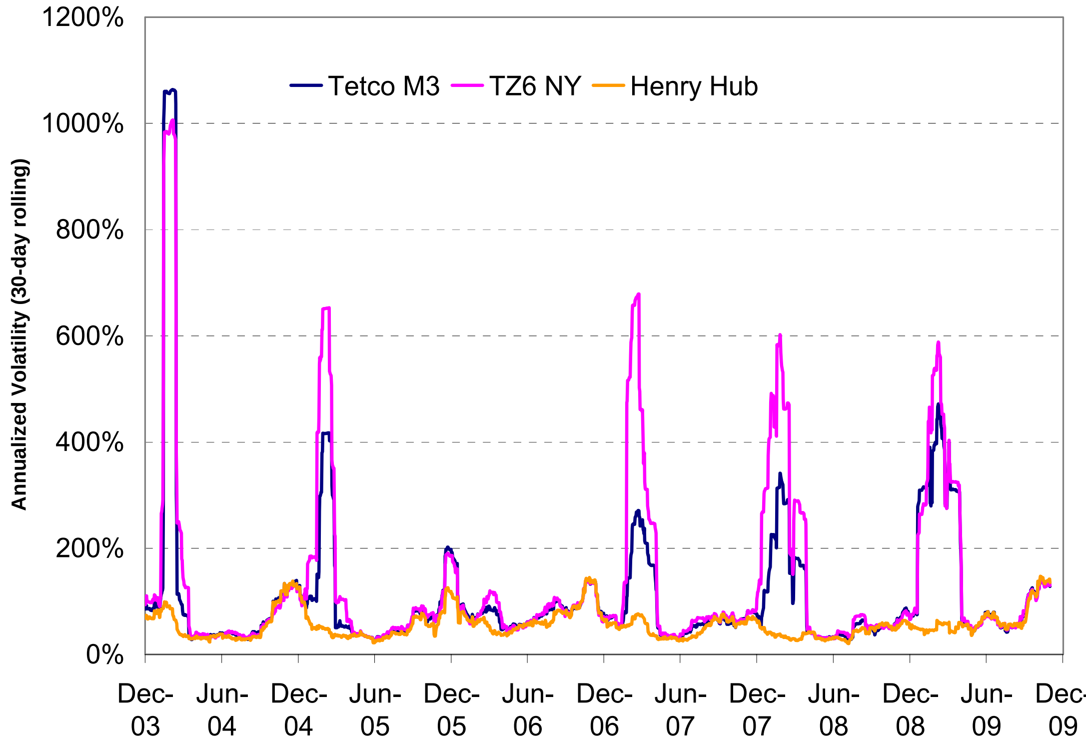
While TZ6NY and M3 prices are highly correlated (about 0.90 for the three years of daily spot price data) and have a small basis spread in most months, during winter months TZ6NY prices are higher on average and have greater volatility and larger upward price spikes than M3 prices. The difference in the two price indexes is substantial enough that it causes the regression model to estimate substantially different coefficient values, not just for the gas price coefficients, but all coefficients. In particular, the estimate of the key RM coefficient is markedly different between the two cases.

TZ6NY Minus M3 Basis Spread[7]



[7] High positive values were truncated in the chart.

Historical Volatility, TZ6NY, M3, and Henry Hub Daily Spot Prices



This inconsistent and inappropriate application of the regression equation resulted in an estimate of the RM coefficient of -1.30 in the regression with TZ6NY prices, and a smaller (in absolute size) RM of -1.00 in the regression with M3 prices, a 30% difference. The sizeable difference in the key RM coefficient, as well as other coefficients, translates into a large difference in net operating revenue for units located in all locations. The heart of this issue is not the question of which gas price index is "better" (or an "optimal" weighted average of the two) to represent LBMP formation in each zone and for inclusion as the fuel cost index in the unit dispatch model. By following NERA's documentation of using TZ6NY prices in the LI and NYC zones and M3 prices in the other nine zones, the regression equation estimates the RM coefficient to be -1.03. This RM value is much closer to the M3 only data case estimate of the RM coefficient (-1.00) since nine of the 11 zones are assigned the M3 price, and all zones have equal weight in the model estimation procedure.

At the July 16 ICAPWG meeting, Mr. Falk claimed that the newly acknowledged two models approach is not inconsistent because the same regression equation is just being applied to each region, but makes use of explanatory data from nearby regions. However, for that rationale to be valid, each of the regional models should only predict prices in their own region. The regression equation still allows the only non-local explanatory variable data, the NYCA-wide "aggload" variable, to be used to predict LBMPs for a single region. To test Mr. Falk's claim, after the July 16 meeting we ran a proper sub-state regression with the NERA equation that only predicts prices in NYC and LI when run with TZ6NY gas price data. It resulted in an RM coefficient of -0.95, lower than when running either M3 gas prices only or both gas price indexes for all 11 zones. The net operating revenue for an LMS100 unit located in NYC is reduced substantially compared to the NERA case of running the regression equation with TZ6NY gas prices for all zones.

Issue 6: Insufficient Length of Historic Data Period for Reliable Estimation of the Parameters of the LBMP Prediction Model

In reviewing NERA's econometric modeling procedures, we endeavored to minimize the deviations from the methods used by NERA, and therefore we have formulated suggested improvements the procedures employed by NERA. Initially, LAI focused on trying to make better use of the three year historical data set provided by NERA, as well as to limit regression model improvements to possible alternative regression model structures (see Issue 7), or estimation procedures (see Issue 8). In LAI's opinion, while the chronology of NERA's model formulations favorably evolved over the last three months, none of the three proposed NERA regression equations appeared to be satisfactory with respect to producing sensible coefficient estimates.[8] Likewise, while LAI feels certain changes to the regression model (Issue 7) or estimation procedures (Issue 8) would be improvements, all of the alternative model specifications, and alternative estimation procedures appeared to show limited improvement in terms of sensible, robust outcomes.

Based on a priori knowledge of the typical patterns of correlation among the variables used in the NERA regression model, LAI suspected that the problem of linear, or near-linear relationships among the "independent" variables, referred to in statistics as a multicollinearity problem, would be a significant impediment to estimating robust, accurate parameters, useful for LBMP prediction.

These relationships include the following seasonal (or monthly) patterns:[9]

- Gas prices are generally higher in winter than summer, so they have a positive correlation with RM through its higher winter UCAP in its numerator than its summer UCAP.
- Hourly load is positively correlated with RM through its annually-updated peak load forecast (MinReq) in its denominator.
- Gas prices are negatively correlated with temperature
- Load is positively correlated with temperature
- Daily minimum temperature is highly correlated with daily maximum temperature

These monthly or seasonal correlations will remain in the regression model despite the use of monthly, day-of-week, and hourly indicator variables since their only role in the regression equation is to shift the LBMP dependent variable intercept up or down. The

[8] The sequence of equations was proposed at the April 1, May 21, and June 16 ICAPWG meetings.
[9] Correlations at the daily or hourly level do not matter much for estimation of the key RM parameter since its data is only available at monthly granularity.

definition of RM makes their values highly correlated, so the three-year data set is actually quite small for its intended purpose. This concept of independent information will be explored more in the discussion of Issue 7.

One very strong indication of a serious multicollinearity problem is that simply using either TZ6NY prices only or M3 prices resulted in a large (30%) change in the estimated RM coefficient. Such a material change in the value of the RM coefficient when only the data for another, supposedly independent, regression variable is changed is very troubling. The fragility of the RM coefficient means that the estimation method is inadequate to the purpose of varying RM over an even wider range of predicted values than in the historic data set used for parameter estimation in order to predict the impact on LBMP as the capacity market tightens.

It appears that NERA decided to roll the previous 36 parameters (12 months by 3 regions) for the RM variable into just one coefficient due to the serious problem of estimating coefficients with the wrong sign, and the instability of the estimates when the data set is slightly changed. But forcing all months and all regions to share one coefficient, while allowing for the use of more RM values per estimated coefficient, may run counter to the previous intuition that there may be structural locational or seasonal differences in the RM relationship to LBMP. In addition, there is the additional peculiar problem in the data structure that two of the three regions (NYC and LI) are nested within the third region (NYCA).

A second indication of the extent of multicollinearity was a test regression that omitted the two temperature variables since, according to NERA, their purpose was only to account for capacity and heat rate degradation impacts of ambient temperature changes on a daily basis (the major seasonal difference already being accounted for in RM). As "independent" variables, their omission should simply reduce the R2 measure of goodness-of-fit in predicting LBMP, but not change the value of other independent variables, such as RM. But in this reduced regression equation, the RM estimate fell to -0.66, which is indicative of severe multicollinearity between RM and temperature, and perhaps indirectly with load and gas price.

Based on the a priori assumptions that the independent variables would not be independent, and the lack of robust and sensible parameter estimates, LAI decided that the extra effort to develop and test a longer time-series of data should be undertaken. The natural choice was to double the data set to six years, by extending the same regression variables back to November 2003. This allows for twice as much data to be used for estimation of the LBMP prediction model parameters. The first solution recommended in statistics when facing a multicollinearity challenge is to use more data.[10] Because multicollinearity is not a model

[10] At heart, multicollinearity stems from lack of variance in the available data. It is indistinguishable from the problem of an insufficient number of observations for making valid statistical inferences concerning true parameter values. With more observations, it is easier to statistically compartmentalize among correlated explanatory variables the true contribution of each variable in explaining the dependent variable (LBMP).

equation specification problem or a statistical estimation procedure problem, there are also no good tests for the existence or degree of multicollinearity.

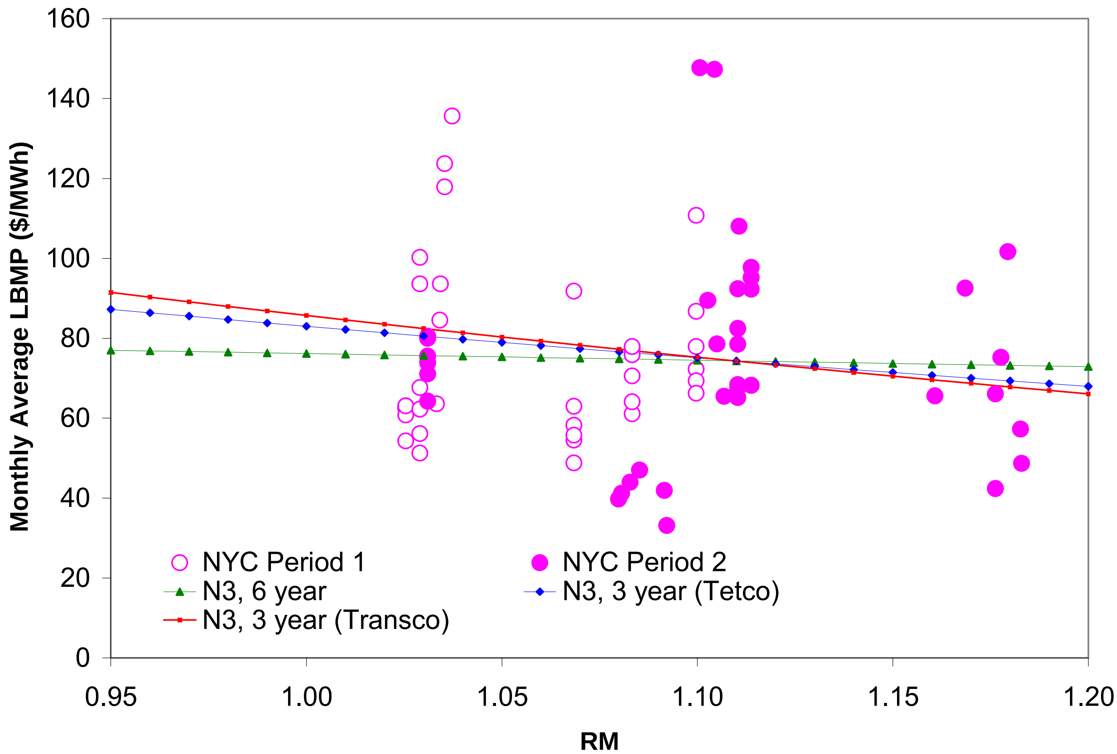
Other sources of multicollinearity are the structural relationships among temperature, gas prices, load, and RM. Since RM only varies by month – and some of its variation is the seasonal change between summer and winter UCAP ratings – estimation of the RM coefficient will be influenced by its monthly correlation with other variables. Lower winter temperatures are negatively correlated with RM, lower winter loads are negatively correlated with RM, and typically higher winter gas prices are negatively correlated with RM. While multicollinearity exists among the temperature, load and gas price variables, the focus here is the impact on the RM coefficient. As NERA states, the temperature variables had a "slightly anomalous effect," with the minimum temperature variable having the wrong sign, and the maximum temperature variable being "small and insignificant" (p. 45).

The first response when multicollinearity problems are suspected is to use more data. To test the stability of NERA's model with more data, we estimated a regression with six years of data (Nov. 1, 2003 to Oct. 31, 2009). NERA used only three years (Nov. 1, 2006 to Oct. 31, 2009). Before January 31, 2005, data for the LI and NYC zones were not reported separately. Like NERA's 2007 report, we assumed that the split of the combined NYC and LI load before then was at the same ratio (about 71% NYC) as the experience after that date.

The prediction of LBMPs and simulation of profits was still performed by using only the same most recent three years of data to drive the "forecast." Using both gas price indexes and six years of data resulted in an RM coefficient of only -0.22, a much more realistic value. Using six years of data overcame both regression fit shortcomings NERA noted in regard to their coefficient estimates. First, the November hourly coefficients for gas price were no longer "odd" (draft report, p. 50). Using three years of data, in some hours the sign was negative and significant while in other hours it was small and the majority insignificant. Running OLS with six years of data, the signs were all positive, and the values were all significant and close to those estimated for October and December. Second, the daily temperature coefficient that appeared significant switched to the correct negative sign. The day-of-week indicator variables also appeared to have a more reasonable pattern across days, and the zone indicator variables had a more reasonable pattern across locations.

A graphical summary of the impact on the NYC zone LBMP function of varying RM values in the dispatch simulation from using either the TZ6NY or M3 gas price data in a regression with three years of data, or both price indexes using 6 years of data is shown in the chart below. The chart also shows the historical monthly RM values for the NYC region plotted against the corresponding monthly average LBMPs. The hollow circles represent the first three years of RM and LBMP data, and the solid circles the latter three years of data. Notice that while there is no apparent upward or downward trend in LBMPs between the two 3-year periods, the RM values are clustered closer to the left side of the RM range. This means that estimation of the regression equation's ln(LBMP)/RM slope coefficient is easier with about the same number of RM observations at each end of the range over the six years. However, also note that none of the NYC region RM observations is below about 1.03. This means that one must trust that the estimated RM coefficient can reliably be extrapolated beyond the available data range to tighter RM values than have been experienced over the past six years.[11]

Comparison of RM Coefficients Estimated with Three Data Sets



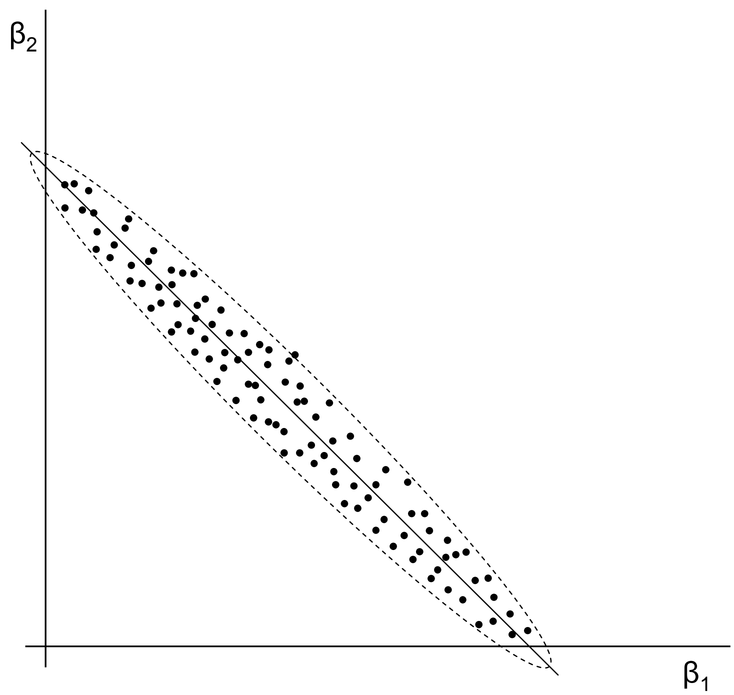
At the July 16 ICAPWG meeting, Mr. Falk claimed that multicollinearity is not a problem without citing any diagnostic information. He asserted that the NERA regression equation is similar to a two-step procedure of first running a regression that omits the RM variable, and then running a second regression of the residuals from the first regression on the RM variable. That "stepwise" regression procedure would only be valid if there was no multicollinearity between the RM data and the other explanatory variables. Since our prior investigation indicated extremely strong support for multicollinearity, we ran the stepwise regression procedure suggested by Mr. Falk. *In conducting this exercise we found more evidence of multicollinearity.* Without the RM variable, the R^2 of the first regression equation estimated with TZ6NY gas prices barely dropped (0.8814 to 0.8802), and the R^2 of the second regression equation was tiny (0.0096), as was its estimated RM coefficient (+0.0053), which even had the wrong sign. If RM does not exhibit multicollinearity with the other explanatory variables, then the only alternative explanation is that its true value is not significantly different from zero, so it need not be included in the LBMP price prediction model. The reason this stepwise regression procedure did not support Mr. Falk's thesis is

[11] However, it should be noted that the other two regions' RM values also play a role in estimating the statewide RM coefficient, and some of their RM values were slightly lower than shown here for the NYC region.

that the existence of multicollinearity between two (or more) explanatory variables means that whichever variable is omitted will not diminish R^2 very much.

But keeping RM and its multicollinear variables in the regression means that their parameter estimates will not be robust, and can basically be quite arbitrary. Small changes in the data for estimation can result in dramatic changes in coefficient estimates and their standard errors (confidence intervals). This linear relationship is illustrated in the following diagram. Due to their linear dependency, small changes in data can lead to dramatic changes in the size (and sign) of the estimated coefficients, β_1 and β_2. But the R^2 measure of overall regression "fit" will barely change because the dependent variable is explained by the linear relationship between the two explanatory (but not independent) variables. However, in such a case, the data for these two variables used for making predication cannot change (much) because then a much different pair of coefficients would be more appropriate. That is the multicollinearity problem when varying the prediction value of the RM variable to predict its impact on LBMP.

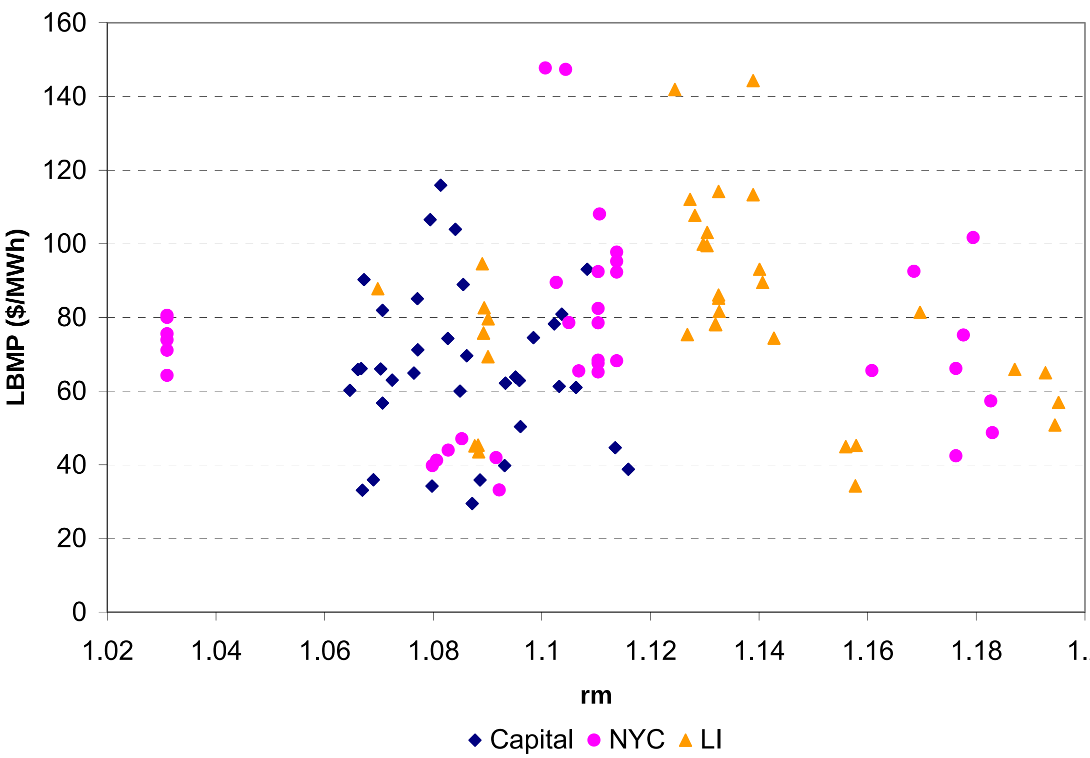
Illustration of High Collinearity between Two Independent Variables



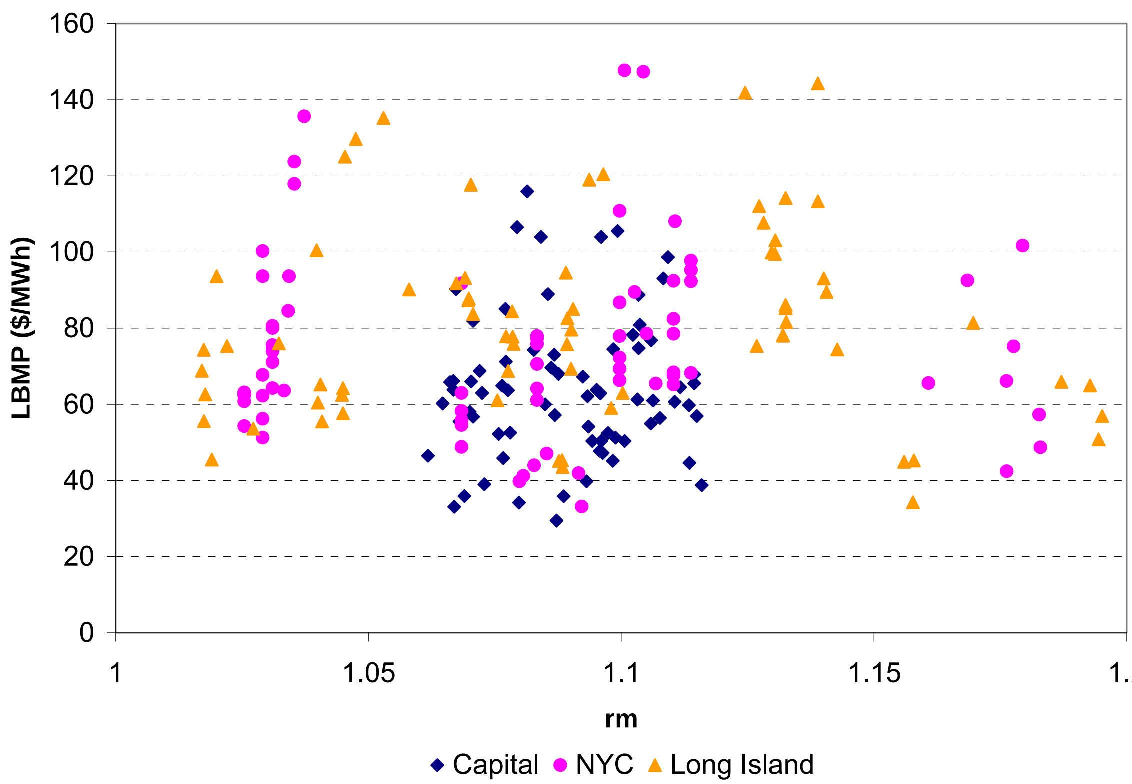
Mr. Falk also asserted that using six years of data is not a good solution because of an "attenuation" problem. We understand that the attenuation problem to which he referred means that data more than three years old is not relevant enough to include in the estimation of model parameters. In LAI's view, this argument contradicts the standard practice in econometric model-building. Models are only good tools because reality evolves slowly enough over time that their structural parameters are robust when re-estimated with different data periods. In fact, for a bid markup parameter, such as the RM coefficient, which is based on the excess of installed capacity relative to demand, having data that spans at least one full business cycle ("boom-bust") of investment in generation capacity, is a great benefit to estimating a robust parameter. From year-to-year, or even month-to-month, current market imbalance data values will change, but good predictions will still be made by running the new data through the same, stable parameter estimates to predict LBMPs. If there is a tradeoff between using older, somewhat less relevant data for parameter estimation, and otherwise not having sufficient data variability to robustly estimate the parameters, then the choice is easy. Because the forecast data set is independent of the parameter estimation data set, forecasts can still make use of just the more recent, more applicable data.

The benefit of relying on six rather than three years of data can be seen in the following plots of monthly RM values and average LBMPs across all three regions. The six year data set includes many more observations at lower RM values, so there is less uncertainty about the slope of the relationship showing the LBMP change impact of a change in RM.

Three Year Period (Nov. 2006 to Oct. 2009)



Six Year Period (Nov. 2003 to Oct. 2009)



A reality check also throws doubt on the adoption of the large RM coefficient (-1.30) for the NYC and LI regions based on three years of data using only TZ6NY gas prices. The table below compares the energy net operating revenue of a backcast of the NERA dispatch model using NERA's current LMS100 cost and operating characteristics against actual TZ6NY gas prices and DA and RT LBMPs over each three-year period. There is very little change in energy net operating revenue between the two periods, despite the fact that the NYC region has grown "longer" in its excess capacity in the past three years, as indicated by the above two graphs.

Backcast of LMS100 Operation in NYC Zone for Two 3-Year Periods

3-Year Period	Gas Price (TZ6NY) ($/MMBtu)	LBMP ($/MWh)	DA Profit ($/MW-yr)	RT Profit ($/MW-yr)	Total Profit ($/MW-yr)	Capacity Factor	Average Margin when Running ($/MW)
2003-06	8.20	74.95	53,827	18,224	72,052	45.3%	18.14
2006-09	8.26	74.61	56,103	20,722	76,825	47.9%	18.29
Increase	0.7%	-0.5%	4.2%	13.7%	6.6%	5.7%	0.9%

Issue 7: LBMP Regression Model Can be Improved to be More Accurate and Robust

While multicollinearity stems from lack of data variability, in addition to using more data sometimes there are ways to modify the specification of the regression model in order to decrease the number of collinear variables or change the functional form to mitigate the multicollinearity. As well, there may also be other reasons based on economic theory or knowledge of the particular problem for preferring an alternative regression model specification. Without departing from reliance on the variables utilized by NERA, a number of modifications to the regression equation structure may help both in reducing the non-robustness of parameter estimates caused by multicollinearity, and improve predictability. While the more technical or statistical aspects of regression model specification involve how the model is estimated, the use of lagged variables in a time-series model, or correction for violation of the assumptions of the OLS or other parameter estimation procedure, those concerns are dealt with in Issue 8. Here, the focus is on how to make best use of the information available in the data from the perspective of economic modeling. This thrust leads to three suggested modest improvements to the NERA model:

First, substitution of a DSR variable in the model for the RM variable, it is possible to eliminate the structural multicollinearity between seasonal (monthly) changes in load and RM. The supply-demand tightness is more naturally an interplay between installed or "committed" UCAP and hourly load than with peak load. Eliminating the peak load information aspect of the RM variable eliminates a source of multicollinearity across years, due to the strong structural relationship between annual peak load and hourly load. Peak load data also has the further problem of only changing once per year, preventing the RM data series from exhibiting much variation from the load side. Separate DSR variables can be used to represent the regional and NYCA-wide impacts for the NYC and LI regions, and separate regional coefficients can robustly be used, provided six years of data are used for estimation.

Second, by also transforming the DSR variable into logarithmic form, its natural relationship to LBMP is simpler to represent, since that relative scarcity bid markup effect is generally thought to be an exponential function, rising ever more rapidly as the reserve margin shrinks. This allows the model to be less cluttered, by being able to eliminate the separate zone-by-load variables, the polynomial terms of the NYCA-wide ("aggload") variable, and the zonal load times NYCA load interaction variable.

Third, while Mr. Falk has accepted LAI's advice to eliminate one of the three daily temperature variables that caused perfect multicollinearity among the set of three variables, there is still very high multicollinearity between daily minimum temperature and daily maximum temperature. LAI recommends using just daily average temperature or daily maximum temperature. Furthermore, as seen in Issue 3, the degradation impact of temperature on capacity and heat rate may vary by season. It would be preferable to use the two degrees of freedom to estimate separate winter and summer coefficients on a single temperature variable.

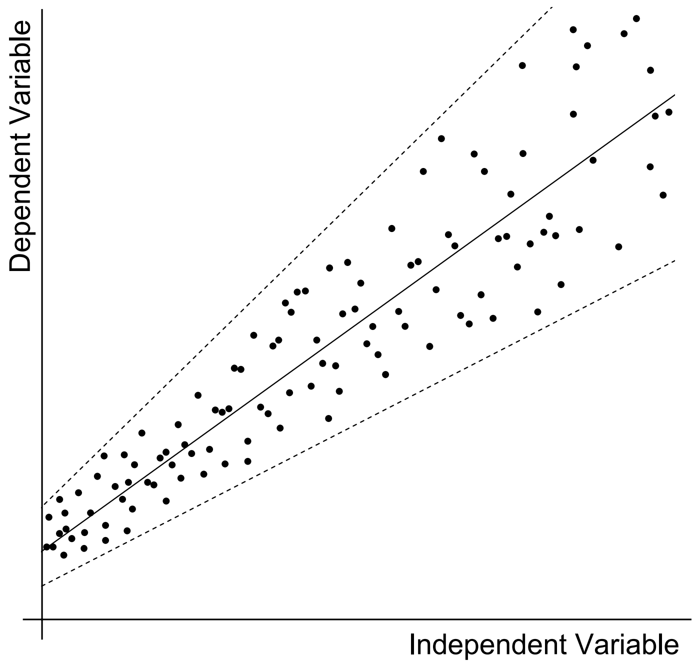
Issue 8: LBMP Regression Model Is Not Estimated with an Appropriate Cross-Section, Time-Series Method to Correct for Patterns in the Residuals

The LBMP regression problem is to consistently predict hourly LBMPs for all NYISO load zones for a three-year period. This statistical problem has a structure in two dimensions: time and space. These aspects present what may be considered two "nuisance" factors when attempting to estimate the model parameters of interest (those with economic meaning, such as price elasticities). The statistical theory behind using OLS regression to make valid parameter estimates includes, among other rules, the related concepts that the residuals (unexplained portion of the dependent variable) should not be correlated with one another, and that the residuals all originate from the same normally-distributed population of error values, with the same variance. These two properties are summed up in the shorthand of "independent, identically distributed" errors. In practice, however, both of these problems are difficult to avoid.

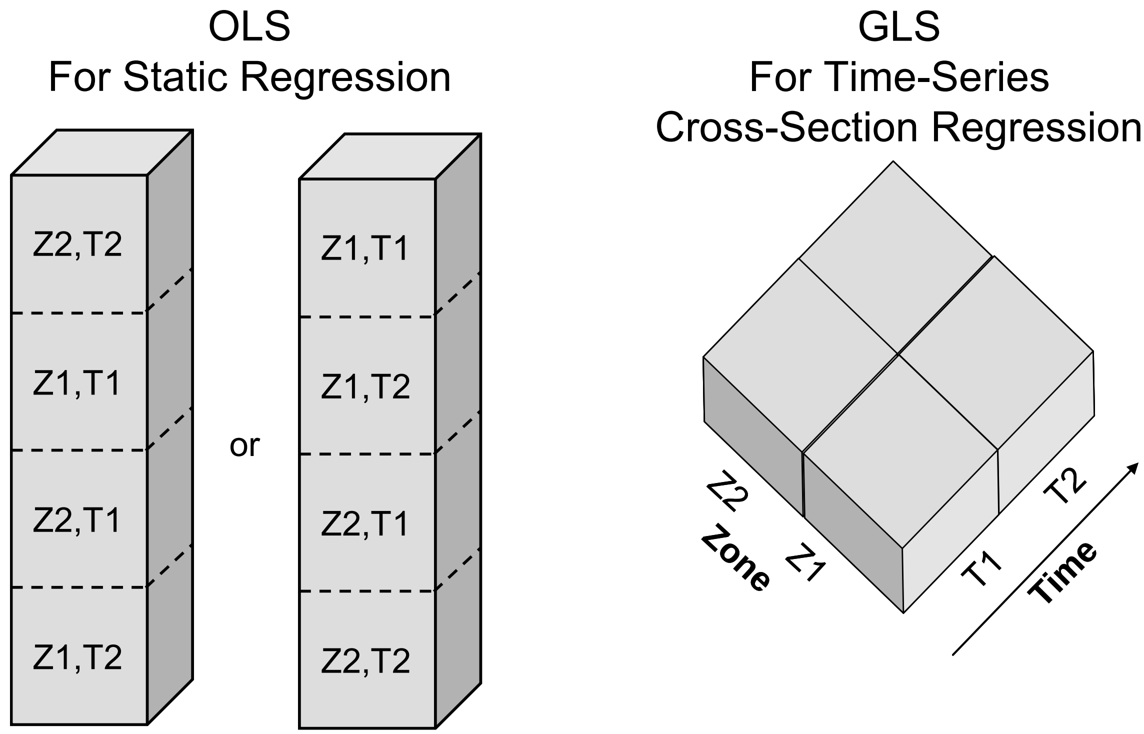
A structural economic model of a commodity market usually has errors that are serially-correlated across time, and across any spatial dimension. For example, due to random weather events, such as a rainstorm or heat wave, or a generator outage, LBMPs over adjacent hours at one location will tend to have positive (unexplained by the model) residuals. And due to network interdependencies the contemporaneous residuals across nearby locations will also tend to have positive correlations for spatially nearby observations. The correlations among residuals tend to decay and die out for observations farther removed in time, and in distance. Significant violation of the assumption of OLS regression that there is no serial correlation causes problems in estimation of parameters.

A second problem is that the residuals across observations may not be of the same size, and there may be a pattern to their sizes. This problem goes by the name "heteroskedasticity" which basically means residuals of different sizes that have a predictable pattern. An illustration of this concept is shown below. Mr. Falk has pointed out that heteroskedasticity is less of a problem now that the latest version of his model uses log LBMP instead of level LBMP as the dependent variable. This logarithmic transformation is usually desired for commodity prices because the positive errors are often much larger than the downward errors. In logs of prices, the distribution will have much closer to the desired normal or symmetric distribution. However, if some time periods (summer months, on-peak hours) have much higher prices, their residuals may also be larger, even after transforming the data into log form. And in a spatial model, prices in more tightly-constrained import zones, such as NYC and LI, will tend to exhibit larger upward deviations than in other zones.

Illustration of Heteroskedasticity



Several possible methods can be utilized to correct or largely mitigate these statistical problems that are endemic to cross-section, time-series market data. One widely-applied statistical method for automatically "correcting" for both the serial correlation and heteroskedasticity violations of the assumptions of uniform, independent disturbances required by the OLS estimation method is known as GLS. Basically, it allows the observations to be weighted in a manner that results in the OLS assumptions regarding the distribution of residuals. To use this method, the static data set used by NERA simply needs to be transformed into a structured data set along both the time dimension and the spatial dimension. This structuring is illustrated in the following diagram. In OLS regression, the data have no structure in the time dimension or the spatial dimension. All observations are treated as independent of one another, rather than ordered. GLS regression (as well as some other methods) allows the data set to have a time indicator and a "panel" indicator, which for the present purpose can be used to define different zones. The data observations in this two period (T1, T2) and two zone (Z1, Z2) illustration can then be organize in a way that allows the GLS technique to correct for serial correlation across panels or time, and to optionally also correct for any heteroskedasticity.



In one test of using Stata's GLS estimation procedure, with both serial correlation and heteroskedasticity correction, the RM coefficient fell from -1.03 to -0.26, similar to the test that used six years of data instead of three. Rather than enumerate a range of alternative estimation procedures, and diagnostic tests, our general advice is for NERA to investigate the applicability of estimation techniques other than OLS, and to perform and report on various diagnostic tests that ensure that the regression model's parameter estimates are unbiased and efficient (have small errors).

Issue 9: Special Case Resource Call RTM Price Increase Method is Biased

The May 21 NERA presentation regarding the new method for increasing RT LBMPs to \$500/MWh when SCRs are called is more detailed than the description of the method in NERA's draft report. Because there were no SCR calls that triggered an administrative price increase in the Nov. 2006 through Oct. 2009 period that NERA used for its data on the spread between DAM and RTM prices, NERA decided to add a mechanism to override the RT LBMPs that would otherwise be predicted based on the regression model's prediction of DA LBMPs and the actual spreads between DA and RT LBMPs over the past three years. The mechanism uses an exponential curve of the number of annual hours that SCR calls resulting in administered price increases would be made, based on a report that used GE MAPS reliability modeling. The call hours are anchored at 110.4 hours when the reserve margin is at equilibrium (RM = 1.0), and an exponent of 0.3 to decrease (increase) the number of hours when there is excess (deficit) capacity. The adjustment mechanism increases RT LBMPs based on the average price for the top 500 RT price hours when the reserve margin is at equilibrium, and the same (500/110) relative number of hours in comparison with the SCR call hours at higher or lower RM values.

LAI has raised two issues in regard to this procedure; one conceptual and the other empirical. There are two conceptual weaknesses to the use of an SCR call RTM price adjustment mechanism; one statistical and the other based in economic theory. The statistical issue is addressed first. The coefficient on the reserve margin variable in the DA LBMP prediction model is supposed to capture the increase in prices when reserve margins are lower than the recent history. The confidence interval on any LBMP prediction for RM values below the average value in the historic period increasingly widens towards the minimum (and maximum) end of the historic RM range. And extrapolating at RM values lower than those encountered in the past three years is not supported by statistical theory. So, adding a price override mechanism to the RTM price calculated on the basis of its historic spread to the regression model's prediction of the DAM price is quite bold, piling assumption on top of assumption, on top of assumption.

The theoretical economic argument is that the administrative activation of SCR resources will tend to result in *lower* RTM prices than otherwise except when scarcity pricing is triggered and the RTM price would otherwise be less than the $500/MWh administrative price. This can be seen in the following table which constructs four possible states, depending on whether the regular RTM price would be less than $500 or not, and whether SCR activation triggered the scarcity pricing rule or not. The rule is not triggered for the local reliability need. Only one of the four types of SCR calls results in replacement of the RTM's clearing price with an administered $500 price. In the other three cases, SCR resources are added to the supply of resources in the RTM, which has the effect of shifting the supply curve to the right, reducing the RTM price.

RTM Price Impacts of Four Types of SCR Calls

<table>
<tr><td colspan="2" rowspan="2"></td><td colspan="2">Econometric RTM Price Prediction</td></tr>
<tr><td>< $500/MWh</td><td>≥ $500/MWh</td></tr>
<tr><td rowspan="2">SCR Activation Type</td><td>Scarcity Pricing Triggered</td><td>Price increases to $500</td><td>Price lower than without activation</td></tr>
<tr><td>Scarcity Pricing Not Triggered</td><td>Price lower than without activation</td><td>Price lower than without activation</td></tr>
</table>

For consistency, if it is supposed that the impact on RTM price from extrapolation of RM to lower than recent values does not capture the impact of calling on SCR resources, then the negative as well as positive impacts of those calls on the prices predicted by the econometric model should be included in any SCR adjustment.

Issue 10: Energy Net Operating Revenue Not Adjusted for Lower Expected Future Natural Gas Prices

NERA had considered using natural gas futures prices to drive the forecast of LBMPs, but in the draft report historic spot prices were used instead; the same approach as in the 2007

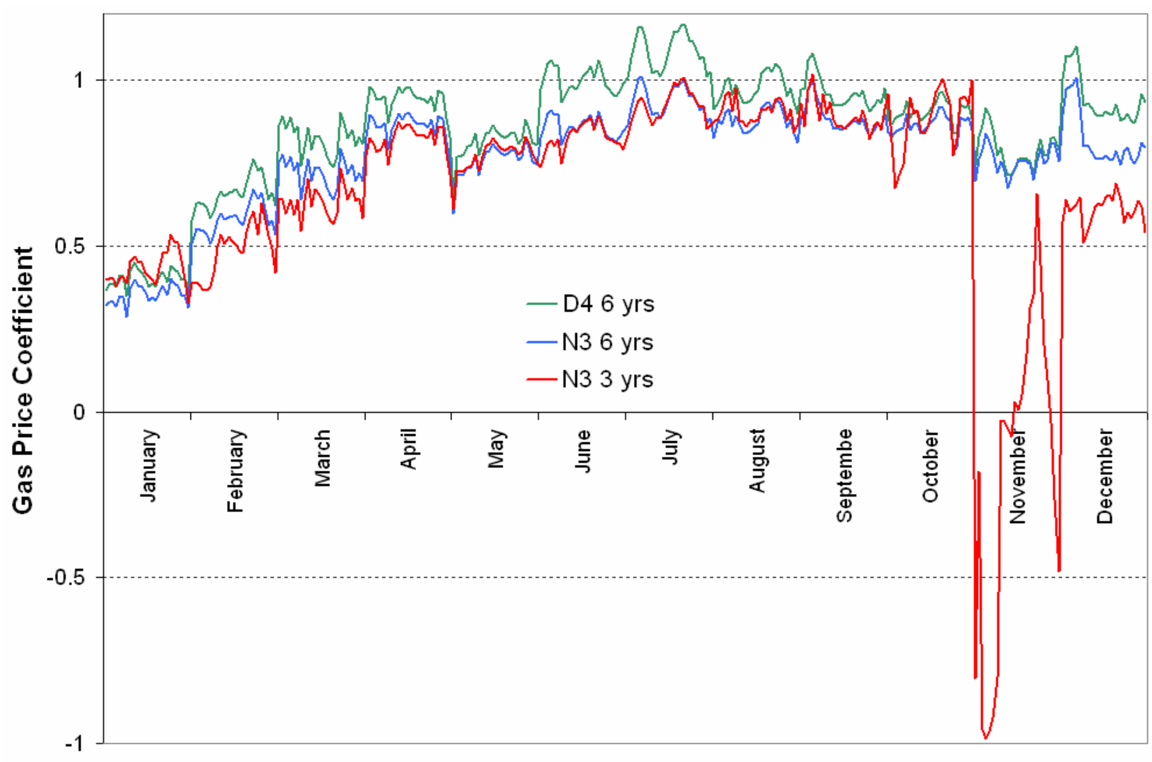
NERA study. Some stakeholders had commented at ICAPWG meetings that the current lower natural gas forward curve should be used compared to the historic spot natural gas prices for the November 2006 through October 2009 period used in the draft report as the "forecast" prices. Mr. Falk had commented that net operating revenue would rise rather than fall if LBMPs were predicted on the basis of lower natural gas prices.

However, the correct answer to the question of whether the spark spread rises or falls is "It depends." With the NERA regression model, which uses the log of LBMP and the log of gas prices, the regression equation coefficients for the hour-by-month gas price coefficients are easy-to-interpret unitless elasticities. These elasticities may be interpreted as the percent change in LBMP for an X percent change in gas price.[12] The answer to the question of whether net operating revenue increases or decreases when natural gas prices decline revolves around the question of whether the coefficients during the hours when the unit is in-the-money or near-the-money are mostly above or below 1.0. The size of the coefficients in off-peak or off-season hours does not matter as much as the coefficients during the on-peak summer and winter month hours.

The NERA model estimated with three years of data results in generally lower gas price coefficients, and November hour coefficients that are unreasonably small or even negative (and sometimes at supposedly significant confidence levels), than when the model is estimated with six years of data. Alternatively, the gas price coefficients of an LAI model using the alternative DSR variable in place of the RM variable also has higher and more robust coefficients, close to those of the NERA model estimated with six years of data. A graphical comparison of the coefficients for these three cases is shown below. The coefficients curves labeled "N3" is the third NERA model, estimated with three or six years of historic data. The "D4" model is an alternative regression equation specification based on the DSR variable. It is readily apparent from the red line for the N3, 3-year model that attempting to estimate a valid, robust LBMP prediction model based on only three years of data is ill advised. The large negative coefficients in some November hours mean that a one percent decrease in natural gas prices would cause LBMP to *increase* by up to nearly one percent.

[12] For coefficient values greater than 1.0, LBMP changes proportionately more than the change in natural gas price. Thus, the market heat rate increases in hours in which the coefficient is greater than 1.0, and decreases when the coefficient is less than 1.0.

Comparison of LBMP Regression Equation Coefficients for Three Models



LAI recommends that the issue of whether to adjust natural gas prices based on the current lower forward curve be reexamined once a more robust price prediction model is developed, so that more informed decisions can be made about the direction and magnitude or significance of any predicted change in net operating revenue stemming from a change in gas prices.