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Is Real-time Pricing Good for the Environment?

Real-time pricing (RTP) — retail pricing that changes hourly to reflect changing wholesale prices — may be the answer to many problems, according to economists who study electricity, but can it reduce pollution? One might think that since RTP lowers demand peaks, thereby reducing the need for peak fossil-fired generation, RTP would have a positive environmental impact. It's not such a simple relationship, as it turns out. Erin Mansur (Yale University) and Stephen Holland (University of North Carolina-Greensboro) have examined the interactions between the introduction of RTP and the level of emissions in different regions across the United States and found that the answer depends on market characteristics.

IN THIS ISSUE

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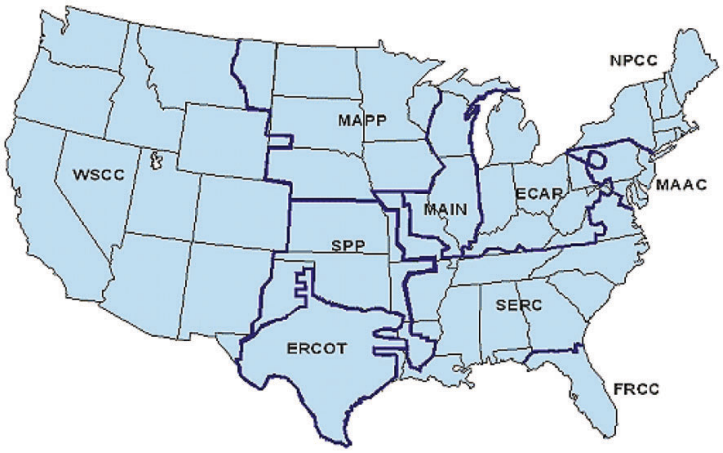
In Mansur and Holland's CSEM Working Paper, "Is Real-Time Pricing Green?: The Environmental Impacts of Electricity Demand Variance," (CSEMWP-136), they explore the short-run impacts of introducing RTP on sulfur dioxide, nitrogen oxides, and carbon dioxide emissions across the ten North American Electric Reliability Council (NERC) regions of the U.S. They look at the impacts on emissions from reducing both within-day and across-day demand variations.

MAP OF NERC REGIONS (SOURCE:WWW.NERC.COM)



Mansur and Holland build a model that represents the existing relationship between the demand patterns and emissions within a region. Using Federal Energy Regulatory Commission (FERC) data from January 1997 to December 2000, they then estimate the effect of a change in the demand pattern on the emissions levels of these three pollutants. Since RTP is expected to shift demand from peak periods to off-peak periods, RTP's overall impact would be to reduce demand fluctuations. Holland and Mansur analyze whether a reduction in demand variation within a region significantly affects the emissions levels.

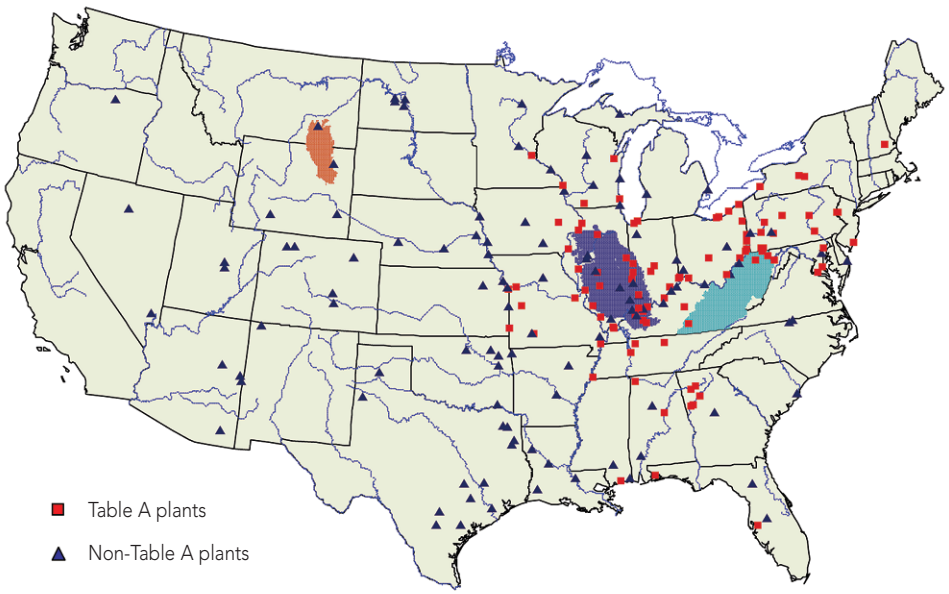
CONTINUED ON PAGE 3

Coal Emissions Regulation a Windfall for Railroads

Unintended consequences can be positive or negative — or both — as in the case of coal emissions regulation. The introduction of cap-and-trade emissions regulation of coal plants in 1995 altered the demand relationship between "clean" and "dirty" coal in such a way that the railroad companies that transport the clean coal gained financially. Although the railroad companies gained, their pricing actions may have made complying with the regulation less costly for many coal plants.

In their CSEM Working Paper, "Market Effects of Environmental Regulation: Coal, Railroads, and the 1990 Clean Air Act" (CSEMWP-137), Meghan Busse (UC Berkeley and UCEI), and Nathaniel Keohane (Yale University) analyze the effect of Title IV of the 1990 Clean Air Act Amendments ("Title IV") on the prices charged by two railroads to transport low-sulfur (i.e., clean) coal. Title IV introduced tradeable permits to control the emission of sulfur dioxide from existing coal-fired electric generating units. Phase I of Title IV began in 1995 and applied to the 263 largest and dirtiest coal units (Table A plants). In 2000 Phase II extended this regulation to all coal-fired units of any significant size. Each coal unit receives an allotment of permits, which allow it to emit a certain amount of sulfur dioxide in a given year. The permits are tradeable so that a unit that emits more sulfur dioxide than was provided for in its allotment can buy another unit's permit. Similarly, a unit that chooses to reduce its emissions - through using a cleaner coal or investing in new technology - can sell its surplus permits or bank them for future use.

GEOGRAPHIC DISTRIBUTION OF REGULATED POWER PLANTS AND MAJOR COAL DEPOSITS OF THE UNITED STATES



Powder River Basin
0.38 - 0.98 lbs SO2/mmbtus
8600 btus/lb

Illinois Basin
2.1 - 7.5 lbs SO2/mmbtus
11250 btus/lb

Central Appalachia
0.95 - 3.1 lbs SO2/mmbtus
12300 btus/lb

The largest deposit of clean, low-sulfur coal is in Wyoming's Powder River Basin ("PRB"), and only two railroads serve that area. The establishment of Title IV regulation increased the demand for low sulfur coal, which has significantly lower emissions levels. While the presence of many mines in the PRB makes production of coal competitive, only two railroads are able to transport the coal out of the region, which provides the railroads with an opportunity to exercise market power on the delivered price of coal. Busse and Keohane theorize that after implementation of Title IV the delivered price of PRB coal would increase for those plants closest to the PRB and decrease for plants further away. They point out that plants relatively close to the PRB are willing to pay more because they are the farthest from alternative sources of coal. However, plants much further away from the PRB are closer to alternative sources of coal, so the price of PRB coal would have to drop in order to encourage the distant plants to adopt it.

To evaluate the impact of the emission regulation on coal prices, Busse and Keohane compared the prices that affected coal units paid before and after Title IV implementation, and they also compared those prices with the prices paid by coal units not subject to Phase I implementation (Non-Table A plants). Controlling for other considerations that affect the price (such as distance, railroad costs, and coal characteristics), Busse and Keohane find evidence that the railroads took advantage of differences among coal plants in their willingness to pay for low-sulfur coal, charging some plants higher rates and others lower rates than before the implementation of the regulation.

CONTINUED ON PAGE 5

IS REAL-TIME PRICING GOOD FOR THE ENVIRONMENT?

CONTINUED FROM FRONT PAGE

The ten regions have different generation profiles *(see Table 1)*. Some regions, such as ECAR, are very "dirty" in that a large share of their electricity generation comes from fossil fuels, which have high emission rates, while other regions, such as WSCC, get the largest share of their electricity from non-fossil fuels, which have no emissions. Each region tends to use its lowest cost fuel source for its baseload generation, although in some regions hydroelectric power, with a very low marginal cost, is used to meet peak demand. Coal has low operating costs but high emissions levels; oil has high operating costs and emissions levels; natural gas has intermediate costs and emissions levels; and, nuclear and hydroelectric have the lowest operating costs and no emissions.

Holland and Mansur find that reductions in load variance have different environmental impacts in different regions. For example, a reduction in within-day demand variance decreases emissions of some of the pollutants in three of the ten regions (FRCC, MAAC, and MAIN). Yet the same reduction is likely to yield an increase in emissions in most of the other regions. In fact, emissions of all three pollutants would increase in ECAR and SERC and emissions of two of the three pollutants would increase in ERCOT, MAPP, and WSCC.

Holland and Mansur also discovered that a reduction in across-day load variance can lead to an emissions reduction in some regions (MAAC, MAIN, NPCC, and SPP) but is likely to lead to an increase in emissions in other regions (ECAR, MAPP, SERC, and WSCC). In their results, they see that a marginal change in the across-day variation has a larger effect, nearly twice as large, than a marginal change on within-day variation. This means that if RTP were to smooth demand variation across days, the impact on the changes in emissions would be much greater than if RTP led to a smoothing of demand within the same day.

Mansur and Holland note that RTP's impact on emissions is analogous to its impact on fossil generation. If a reduction in demand variance leads to an increase in use of fossil generation, then it also leads to an increase in emissions. This finding is consistent with the comparison of the generation profile of each region. Regions that have more oil-fired capacity experience a decrease in emissions as demand variance lessens. Regions using hydroelectric to meet their peak demand see an increase in emissions as RTP is introduced. This supports their hypothesis that the environmental benefits of RTP come from reducing peak demand, but only if peak capacity is served by a high emissions fuel source.

So, in response to the question of does RTP have positive environmental effects, the answer is – it depends. It depends on the fuel source used to meet peak demand. In a region that uses a high emissions fuel source, such as oil, to meet its peak demand, RTP will likely reduce emissions as less of the polluting fuel source is used. If, however, a region relies on a clean fuel source to meet its peak demand, then RTP will likely lead to higher emissions as less of the clean fuel will be used. Although there are other aspects to this question that still need to be explored, it is clear that predicting the environmental impacts of market changes requires a detailed understanding of the complex adjustments that follow.

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TABLE 1: SHARES OF INSTALLED CAPACITY AND GENERATION BY FUEL TYPE

PANEL A: INSTALLED CAPACITY (MW)

		SHARES				
NERC Region	Total	Coal	Gas	Hydro	Nuclear	Oil
ECAR	123,381	79%	9%	3%	7%	1%
ERCOT	72,583	24%	67%	1%	7%	0%
FRCC	43,880	29%	26%	0%	4%	38%
MAAC	64,512	44%	17%	4%	21%	13%
MAIN	64,238	54%	17%	2%	23%	3%
MAPP	36,244	63%	10%	10%	8%	5%
NPCC	67,841	13%	32%	14%	15%	23%
SERC	195,989	47%	21%	10%	18%	2%
SPP	47,440	48%	41%	5%	3%	2%
WSCC	144,046	22%	30%	36%	7%	1%

PANEL B: NET GENERATION (GWH)

		SHARES				
NERC Region	Total	Coal	Gas	Hydro	Nuclear	Oil
ECAR	590,666	87%	3%	0%	8%	1%
ERCOT	313,659	35%	51%	0%	12%	1%
FRCC	181,322	36%	23%	0%	18%	19%
MAAC	264,901	45%	9%	1%	40%	3%
MAIN	294,155	56%	3%	1%	39%	0%
MAPP	178,980	76%	1%	9%	12%	0%
NPCC	254,617	17%	25%	13%	26%	13%
SERC	861,033	55%	10%	2%	29%	1%
SPP	186,976	68%	23%	2%	5%	0%
WSCC	667,187	32%	23%	28%	11%	1%

Notes:
a) Source: EPA eGRID for 2000 *(http://www.epa.gov/cleanenergy/egrid/index.htm)*.
b) Shares are of total capacity or total generation for utilities and non-utilities. Renewables are the missing share.
c) Net generation equals electricity produced excluding that which is used internally at power plants.
d) GWh are gigawatt-hours, or 1000 MWh.

Do Competitive Energy Markets Make Rising Energy Prices Worse for Poor Consumers?

Britain was one of the first countries to introduce competition into retail energy markets, a process helped by falling world energy prices, and a gas incumbent handicapped by long term contracts struck below the prevailing spot price. Now that energy prices are rising again, will the competitive market make things worse for low-income households? Will the vulnerable suffer more, now that price regulation has been removed? We look at evidence, which suggests that the main issue may be the general competitiveness of the market, rather than the relative prices charged to different consumers, often the focus of previous concern.

BILL PAYMENT OPTIONS FOR UK RESIDENTIAL END USERS

Type of Bill Payment	Description
Quarterly Bill	*End user receives a quarterly bill for the previous quarter's usage.*
Prepayment	*An end user must make a pre-payment onto a fuel card that the electricity company then charges against. As the card gets low, an end user must add funds.*
Direct Debit	*Monthly direct debit from an end user's checking account based on estimated annual consumption.*

When competition first threatened, the incumbent suppliers' immediate response was to rebalance prices in favour of higher income direct debit payers. They maintained that other prices did not adequately reflect the costs; they needed to lower prices to direct debit customers to meet the better deals which they expected entrants to offer in these markets. The result was to reduce the bills of these consumers relative to others - by over £14 per year in gas and £4 a year in electricity between privatisation and 1996 when the markets opened[1]. Commentators were particularly worried about households using prepayment meters, whose income was well below the average, and who saw their relative prices rise even before any entrants came into the market.

When electricity competition started in 1999, companies entered each others' regional markets. Here their prices were not regulated and they could choose a price structure which reflected the relative costs of serving consumers using different payment methods. A company entering any market had to offer all payment schemes. Companies offered much deeper discounts for direct debit payers, compared with the prepayment tariffs, as entrants than they did in their home markets, where the regulator controlled prices. This did not augur well for pre-payment customers once the price caps were removed, and there was widespread concern from the consumer watchdog and others that prepayment consumers served by incumbents would see their prices rise once ex ante regulation was withdrawn.

Despite these fears, five years later, two and a half years after all price caps were removed, we find that prices are rising no faster for prepayment meter users than for others; indeed if anything they are rising more slowly. One of the five major consolidated electricity companies has lowered the price for prepayment relative to direct debit in its home areas, where it still retains about 60% of the market, and the other four have not changed the differential. The companies seem to have changed their behaviour as entrants, too. Between 1999 and 2004 three of the six[2] major suppliers have reduced the relative cost of prepayment, one has increased it and the other two have made no change. In November 2004 Powergen announced that it was cutting the prepayment premium across the board, while raising the general level of its prices. Perhaps these changes are because suppliers are very sensitive to comments and potential adverse publicity from regulator, consumer watchdog and media[3]. This may be acting as a 'surrogate cap' on the relative prices charged for tariffs used mainly by lower income groups, particularly in the region where the supplier is still dominant.

Even though low income consumers have not suffered as much as was feared from tariff rebalancing in the competitive market, they are more vulnerable to increases in general energy price levels because they devote a higher proportion of their income to energy expenditure. In 2002 the average expenditure by the poorest tenth of households was nearly 6% of their income, while that of the richest tenth was less than 2%[4]. Energywatch[5] estimates that 3 million people are in fuel poverty (spend or need to spend more than 10% of their income on energy), and Help the Aged maintains that another half million are added for every 10% rise in fuel bills[6]. If removing regulatory constraints means that prices might rise more than they otherwise would have done, the poor will suffer most.

There are some worrying signs that considerable market power does remain two and a half years after the last price caps were removed. Incumbents are still able to charge a considerable premium over other companies. Their incumbent power would be constrained if consumers actively switched to cheaper suppliers, but many believed that the incumbent would match the lower entrants' prices[7], and many of those who did switch chose more expensive suppliers[8] (see CSEM WP-112 and CSEM WP-123). These results do not suggest a vigorously competitive market. Of course rising energy bills may galvanise consumers to seek better deals, contributing directly to more effective competition.

However even if more active consumers succeed in preventing incumbents from charging more than entrants, they may not be able to prevent a concerted raising

CONTINUED ON PAGE 5

DO COMPETITIVE ENERGY MARKETS MAKE RISING ENERGY PRICES WORSE FOR POOR CONSUMERS?

CONTINUED FROM PAGE 4

of prices in the market. There are now only 6 significant players, and three market leaders. They share an interest in keeping prices well above costs, and market conditions make this feasible, without any need for explicit collusion. This small number of companies interacts repeatedly in 14 regional electricity and one national gas market; the product is homogeneous and the companies of a similar size; they are required to publish their tariffs to facilitate informed consumer switching, and the regulator regularly publishes assessments of the market to assess the health of competition, making it easy for companies to keep an eye on each other. Rising world energy prices provide a perfect excuse for companies to raise their own prices, and they frequently signal their intention to do so through public statements about rising costs. We have seen that any increase in fuel prices has the most severe impact on the lowest income groups, and seriously threatens the Government's target of reducing fuel poverty. The regulator is right to examine these issues in its latest market review[9] as prices continue to rise across the Board. Controlling market dominance will yield benefits for all consumers, but especially for the poorest who have to spend more of their income to heat, light and power their homes.

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Author: **Catherine Waddams.** *Adapted from CCP Newsletter, Issue Number 7, Centre for Competition Policy, University of East Anglia, Norwich, November 2004, p. 4 - 5. www.ccp.uea.ac.uk*

1 Distributional Effects of Liberalising UK Residential Utility Markets by Catherine Waddams Price and Ruth Hancock, Fiscal Studies, Vol. 19, Number 3, 1998.
2 British Gas is an entrant to the electricity market, but not an incumbent in that market.
3 Social Obligations and Economic Regulation; Coincidence or Conflict – A Report on the UK Energy Supply Industry by Diane Sharratt, 2003.
4 A Report on the 2002-03 Expenditure and Food Survey, ONS (2004).
5 Press Release 2nd November 2004.
6 Reported in *The Guardian*, 3rd November 2004.
7 This was also released as Consumer Choice and Industrial Policy: A Study of UK Energy Markets by Monica Giulietti, Catherine Waddams Price and Michael Waterson, Revised Version of CCR Working Paper 01-5, 2003.
8 This was also released as Spoilt for Choice by Catherine Waddams Price, CCR Working Paper 04-1, 2004.
9 Domestic Competitive Market Review, Ofgem (2004).

COAL EMISSIONS REGULATION A WINDFALL FOR RAILROADS

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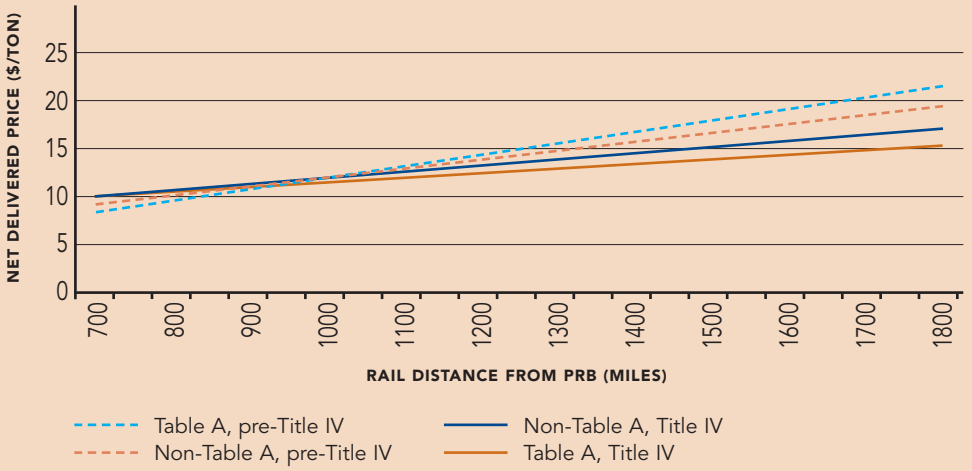
GRAPH 1: PREDICTED "CONSTANT-COST" NET DELIVERED PRICE SCHEDULES FOR BOTH TABLE A AND NON-TABLE A PLANTS, BEFORE AND AFTER THE ADVENT OF THE ALLOWANCE MARKET



For example, Busse and Keohane's results suggest that an unregulated plant located 750 miles from the PBR paid 3.3% more for delivery of coal with average characteristics after Title IV took effect than before. A plant in the same location that was regulated by Title IV, however, paid 7.5% more than before the regulation. Contrast this with the prediction for a plant located 1500 miles from the PRB. Such a plant would likely have more attractive options for compliance with Title IV, either because it is located closer to alternate sources of low-sulfur coal, or because it is close to sources of high sulfur coal, which would make using permits or using a flue gas desulfurization device (a "scrubber") a potentially attractive means for compliance. Busse and Keohane's results indicate that an unregulated plant located 1500 miles from the PRB paid 7.1% less after Title IV than before. A regulated plant, however, paid 16.2% less. *(See Graph 1.)* These numbers suggest that railroads are able to set rates differentially among power plants based both on the plant's location and on its regulatory status.

Busse and Keohane's research indicates that the introduction of tradeable permits for reducing emissions increased the demand for low sulfur coal and created conditions in which the only two railroads able to deliver the low sulfur coal could price discriminate among coal plants. Those coal plants that most needed the low sulfur coal and therefore were the most willing to pay a high price were charged more, surely not what the drafters of Title IV regulation intended. The railroads' pricing structure lowered the cost of low sulfur coal for those plants farther away from the PRB and thereby induced those plants to purchase more of the PRB coal than they did prior to Title IV. The net impact of Title IV on these two railroads was an increase in their revenues, both from the higher prices they charged to the plants close by and from the increased volume of coal sold to those further away. The silver lining in this market power scenario is that for those coal plants paying the lower prices, their cost of compliance with the emission regulation was lower than it otherwise would have been. Yet another unintended consequence.

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