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Subject Text Writes about Bonneville Power Administration reducing rates to approximately \$30/megawatt and encloses report, "Policy Analysis, Rethinking Electricity Restructuring"	Date Received 2/24/2005
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February 11, 2005

Samuel Bodman
Secretary of Energy
U.S. Department of Energy
1000 Independence Ave., SW
Washington, D.C. 20585

Dear Mr. Bodman:

Our company was certainly glad to see Bonneville Power Administration reduce rates to approximately \$30/megawatt. This reduced the cost of Bonneville power to both public and private utilities by a total of about \$123 million per year.

At \$30/megawatt, the BPA rate approximates market rates. You might imagine my surprise that the Bush Administration budget presumed that by charging BPA power at "market rates" that there would be more revenue from Bonneville Power.

The difficulty with hydropower on the Columbia River is that the system of dams has very limited ability to store the flow of the river. Consequently, during periods of high flow, open market sales of electricity fall around \$20/megawatt. During periods of low flow, BPA sells little on the open market and the price of electricity climbs to about \$50/megawatt, or sometimes more.

If BPA power is truly charged at open market prices, prices will fluctuate dramatically year to year, as well as season to season. It was not long ago that BPA worked to keep the aluminum companies on the system because open market rates were very low. We seem to forget the market swings when we look at current market rates. Although the current system is cost based, the current pricing reflects an average market. I am sure that it would be foolish to have price be totally open market so that the regional bill for power fluctuated radically, either floating or sinking the whole regional economy depending on river flows. That would be a counterproductive system.

Finally, since BPA controls the wholesale market, the U.S. government can't simply turn BPA loose to charge whatever the market will or will not bear at any given time. Some system is needed so that rates on average meet the needs of BPA and the ratepayers, but do not allow excessive profits for BPA as the largest power producer in the region.

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300 Fibre Way • P.O. Box 639, Longview, WA 98632
Phone (360) 425-1550 • Fax (360) 575-5934 • www.longviewfibre.com

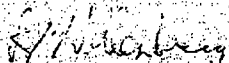
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I am also enclosing two interesting analyses from the Cato Institute on Electricity restructuring and the "hydrogen economy" which I thought you would find interesting.

In closing, I appreciate the keen intellect and analytical approach you bring to evaluating U.S. energy policy and setting a good path forward.

Very truly yours,



R. H. Wollenberg
President, Chief Executive Officer
and Chairman of the Board

dmv

Enclosures

Policy Analysis

No. 530

November 30, 2004

Routing

Rethinking Electricity Restructuring

by Peter Van Doren and Jerry Taylor

Executive Summary

Electric utility restructuring was initiated in the 1990s to remedy the problem of relatively high electricity costs in the Northeast and California. While politicians hoped that reform would allow low-cost electricity to flow to high-cost states and that competition would reduce prices, economists wanted reform to eliminate regulatory incentives to overbuild generating capacity and spur the introduction of real-time prices for electricity.

Unfortunately, high-cost states have seen little price relief, and competition has had a negligible impact on prices. Meanwhile, the California crisis of 2000–2001 has led many states to adopt policies that would once again encourage excess capacity. Finally, real-time pricing, although the subject of experiments, has yet to emerge.

Most arresting, however, is the fact that struc-

turing contributed to the severity of the 2000–2001 California electricity crisis and (some scholars also argue) the August 2003 blackout in the Northeast, without delivering many efficiency gains.

The poor track record of restructuring stems from systemic problems inherent in the reforms themselves. We recommend total abandonment of restructuring and a more thoroughgoing embrace of markets than contemplated in current restructuring initiatives. But we recognize that such reforms are politically difficult to achieve. A second-best alternative would be for those states that have already embraced restructuring to return to an updated version of the old, vertically integrated, regulated status quo. It's likely that such an arrangement would not be that different from the arrangements that would have developed under *laissez faire*.

Peter Van Doren is editor of Regulation magazine and Jerry Taylor is director of natural resource studies at the Cato Institute.

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Electric utility restructuring was a political answer to the problem of high rates in the Northeast and California.

Introduction

Throughout most of the 20th century, the electricity sector in the United States was characterized by balkanized regional and state supply systems with significant barriers to trade between them. Those supply systems were vertically integrated (that is, the same company owned the power generation facility, the transmission lines that delivered the power to local transfer stations, and the neighborhood power lines that brought electricity from transfer stations to the home), unchallenged by competitors, and regulated every step of the way by state public utility commissions. By the early 1990s, however, those systems (hereinafter the "old regime") produced large discrepancies in both prices and costs between states. Large consumers of electricity located in high-cost states demanded policy changes to reduce electricity prices.¹

The policy response has been the national deregulation of the interstate wholesale market to allow generators access to transmission systems owned by others. Some high-cost states went further and encouraged vertical disintegration to separate ownership of generators from ownership of transmission and distribution systems. Some states have also implemented retail choice programs to allow consumers and generators to contract directly using transmission and distribution systems owned by others to transmit the electricity.²

States with low-cost electricity have responded by resisting those policy changes and attempting to maintain the old regime for two reasons.³ First, while costs could conceivably be lower if market forces were introduced, the costs in "traditional" states have been acceptable to consumers even without the use of market forces, largely because the low-cost states avoided two high-cost strategies undertaken by other states: nuclear power and expensive long-term contracts undertaken at the behest of the Public Utilities Regulatory Policy Act of 1978.⁴

Second, the California meltdown and the Northeast blackout have drastically reduced

politicians' appetite for electricity regulatory reform. To average voters and the politicians who listen to them, change away from the old regime is associated with bad outcomes because the states that introduced the most wide-ranging regulatory changes also experienced the most problems over the last several years.

Accordingly, restructuring has been an uneven process. Although competition was introduced on interstate electricity systems, the old regime still exists in most states. And those states that have restructured their regulatory systems have also suffered embarrassing adverse outcomes.

The Case for Restructuring

Electric utility restructuring was a political answer to the problem of high rates in the Northeast and California. Firms threatened to leave high-cost states, so those states attempted to bring the low-cost electricity to the firms. Under restructuring, local electricity generators would no longer have a monopoly over local customers. In theory, distant (lower-cost) generators could compete for business and rates would go down.

Academic arguments for generation competition were somewhat different. First, because investment in capital received a guaranteed return, total generation investment was excessive and skewed toward capital-intensive facilities. The enthusiasm in the 1960s for nuclear power was the product of excessive optimism about costs (progressives regarded nuclear as an energy source that would be "too cheap to meter"), the growing hostility to coal-fired generation for environmental reasons, and the guaranteed rate-of-return regime that encouraged capital intensity. But nuclear power costs, for the most part, were much higher than anticipated.⁵ According to economists, introduction of market forces into the generation side of electricity markets would eliminate the bias toward capital-intensive projects by introducing uncertainty about returns.

Second, prices for electricity did not serve their usual role of signaling to consumers the marginal costs of additional consumption, which vary by time of day and season. Instead, the commonly used fixed rates served solely as a device to recover costs. Thus electricity prices were wrong all the time. They were too low on peak and too high off peak. Market forces, it was hoped, would introduce marginal-cost pricing and as a result reduce peak demand, increase off-peak demand, and reduce the needless political fighting (most notably, the eternal fight over more supply versus less demand) that inevitably arises in electricity markets because of the absence of prices as a signaling device.

Thus, for economists competition between generators was supposed to discipline the cost of generation and introduce the use of price signals to allocate electricity rather than just recover costs.

The deregulation of interstate wholesale electricity markets in 1992 and the restructuring of state-level regulation, where it has occurred, have induced owners of generators to think about costs and risk. Catherine Wolfram reports that owners of generators in states that have restructured have reduced their fixed costs. And if investors were not aware of risk, they certainly are now. In the 1992-2002 period investors added too much capacity resulting in low wholesale prices and widespread bankruptcy in the electric generation sector.⁸

Prices to retail customers have been affected by restructuring in two ways. First, to the extent that state public service commissions now solicit bids from generators to serve so-called default customers (those who do not chose their own generator through retail choice), consumers presumably benefit from the competition. Yet the lower prices secured through such programs are largely due to the glut of generation capacity added over the last several years, meaning that restructuring is playing less of a role in those cost savings than might appear to be the case.⁹ Lower wholesale prices are also passed on to consumers in

those states that retain traditional regulation. The original objective of economists, however—real-time pricing—has not been implemented on a large scale anywhere.¹⁰

Restructuring has delivered some of its promised benefits, but most Americans associate markets in electricity with bad outcomes because of California and the 2003 Northeast summer blackout. Accordingly, anyone who believes market forces ought to play a larger role in electricity has to argue convincingly that

- the California meltdown and the Northeast blackout were not the result of market forces;
- the low costs of the states still under the old regulatory regime are not the result of regulation;
- gains to trade (efficiency improvements) not possible in the regulated status quo would take place in a truly deregulated world; and
- the "commons" nature of the alternating current (AC) transmission system can be managed in a deregulated world.

Unfortunately, we would be lying if we claimed that would be easy.

The California Story

During 2000-2001 a large supply reduction in hydropower together with weather-related demand increases (a hot summer and very cold winter) raised electricity and natural gas prices in California.¹¹ Those price increases were exacerbated by the regulation of nitrogen oxide emissions in the Los Angeles basin, some design features of the California auction bidding system, and retail price controls.

The retail price controls were particularly harmful in that they encouraged generators to price high in the wholesale market because there would be no reduction in demand at the retail level as a consequence of their pricing behavior. In addition, because retail price controls prevented utilities from passing on their higher costs to consumers, the utilities

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Restructuring plus ICAP requirements returns us to the world before restructuring, the main economic defect of which was excess generation capacity and price signals that did not convey the price of peak supply.

suffered a financial meltdown. Generators, in turn, increased prices because of the possibility they would not be paid. From November 2000 on, the California story is a financial meltdown story: wholesale prices had a large credit-risk component.¹²

Those who believe in markets often argue that an important lesson from California is that true markets were never tried. In most of the state that was true; wholesale deregulation was combined with rigid retail prices.¹³ But market retail prices were used in San Diego for a little more than a year, which proved to be politically unstable. Prices in San Diego were free of all controls from July 1999 through August 2000.¹⁴ The doubling of rates that occurred during 2000 triggered a consumer rebellion and the reenactment of price controls by the California legislature.

Bushnell and Mansur estimate that after controlling for weather and other sources of non-price-related demand variation, a doubling of prices resulted in a demand reduction of 2.3 percent, an extremely disappointing response.¹⁵ Peter Reiss and Matthew White, on the other hand, found that after controlling for trend and weather, consumption went down a more robust 12-13 percent.¹⁶

Even though demand *does* respond to price, many observers have concluded that demand-responsiveness is too low and, therefore, price spikes would be too high for too long in a truly deregulated environment that experienced tight supplies. If we switched from flat rate to time-varying prices, there would be additional efficiency gains, but there would also be redistribution from large consumers whose use varies more than that of the average customer (and who, thus, benefit the most from flat rates) to large customers whose use is relatively constant across the daily and seasonal cycles (and thus currently subsidize those whose use varies a lot).¹⁷

The response of regulators to the San Diego experiment has been a return to the fixed-price system and the procurement of extra capacity through nonmarket forces (so-called installed capacity [ICAP] requirements) rather than peak prices, which cause

customers (voters) to revolt. Restructuring plus ICAP requirements essentially returns us to the world before restructuring, the main economic defect of which was excess generation capacity and price signals that did not convey the price of (otherwise underutilized) peak supply.¹⁸

The Blackout Story

The blackout of August 14, 2003, illustrates the difficulty of managing externalities on the grid. Although markets per se were not responsible for the blackout, the shift over the last 30 years from balkanized, vertically integrated utilities to independent power producers and vertically disintegrated power service providers has increased the number of players whose behavior has to be coordinated to maintain satisfactory operation of the North American Transmission System.¹⁹

The final report of the U.S.-Canada Power System Outage Task Force concludes that poor tree maintenance along transmission lines in the First Energy (Ohio) service area, combined with inoperative computer software and operator errors, was the proximate cause of the blackout.²⁰ Although the blackout was not *caused* by market forces, the task force did state that "it is likely that the increased loads and flows across a transmission grid that has experienced little new investment is causing greater stress upon the hardware, software, and human beings that are critical components of the system."²¹

Transmission investment is problematic for two reasons. First, transmission projects are considered, approved, and paid for at the state level even though they have benefits that cross state lines. Accordingly, there is a mismatch between the decisionmaking and regulatory frameworks that govern transmission investment and the real geographic impact of those investments.²² State decisionmakers understandably resist using ratepayer dollars to pay for investments that will primarily help parties outside the state.

Second, incumbent utilities and state politicians in the low-cost states actively

resist improving the grid. Vertically integrated companies in those states fear that a more robust transmission system will primarily advantage the competition—merchant generators. Politicians in those states oppose grid improvements because the benefits of cheaper generation technologies—particularly old coal-fired plants—would then flow to the highest bidder rather than exclusively to ratepayers within their states.

Of course, blackouts were not unheard of in the days of the old regime, and little can be intelligently said about the risks of blackouts today versus the risks of blackouts two decades ago. But to the extent that electric utility restructuring has placed added stress on the transmission system, it has made coping with unexpected events like blackouts more difficult.

About Those Low-Cost States

Political support for restructuring had little to do with the promotion of real-time pricing or with reducing the incentives to overbuild or to overcontract for power. Instead, it stemmed from the possibility of transmitting low-cost power from states like Kentucky (4.3 cents per kWh in 2002) to states like New York (11.3 cents per kWh in 2002).²⁵ Few recognize, however, that states like Kentucky have low electricity costs because they have not changed very much from the nonmarket status quo of 1965. Most importantly, most of the low-cost states never abandoned the use of coal in the production of electricity, and some of those states had continued access to cheap hydropower. None of those states aggressively implemented long-term fixed-price PURPA independent power contracts. Those states also retained rate regulation, which transfers resources from producers to consumers through the use of weighted-average pricing for electricity.²⁶

An understanding of why weighted-average pricing transfers wealth from producers to consumers requires a quick review of some economic fundamentals. In a free market, the prices of commodities are determined by the most expensive source of supply necessary to

meet demand.²⁵ In markets in which increasing output is available at *constant* marginal cost, the price of new supply does not differ from the price of existing supply. But in some markets, increasing output is available only at *increasing* marginal cost.

In electricity markets nuclear and coal-fired electricity plants have high fixed but low marginal costs, while natural-gas-fired units have lower fixed but higher marginal costs. Because nuclear and coal plants are large, incremental increases in electricity supply come from smaller natural-gas-fired units. Increased electric output is thus available only at increasing marginal cost. In markets where aggregate supply consists of producers with differing marginal costs, the market price must be high enough to cover the marginal costs of the last producer (whose output is necessary to meet demand) plus a normal return.

In an unregulated electricity market, then, marginal sources of electricity—such as high-cost generators typically in operation only during the peak-demand periods—would need to earn at least a normal return. That implies that those facilities with lower marginal costs whose supply is limited (such as old coal-fired units exempt from plant-specific emission controls under the 1970 and 1977 Clean Air Act amendments and hydropower facilities whose supply can't be expanded) would receive payments in excess of marginal cost (and a normal return) in an unregulated market.

Rate regulation by the states, however, suppresses that process. Consumers are charged a weighted average of generator costs rather than the market price, which would be at least the marginal cost of the most costly unit necessary to meet demand.

In a free market, the proportion of electricity produced by coal or hydropower *would not* affect prices if neither is the marginal source of power (and both are not). But in regulated electricity markets, cheap infra-marginal power does lower electricity prices to consumers because prices are weighted averages of producer costs rather than marginal

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Because Kentucky's low prices reflect average rather than marginal costs, the efficiency gains that might occur from connecting Kentucky with New York may be largely illusory.

costs of the most expensive producer. Thus regulation plays a role in the low prices of electricity in those states that maintain the old regulatory regime.

Because Kentucky's low prices reflect average rather than marginal costs, the efficiency gains that might occur from connecting Kentucky with New York via improved transmission may be largely illusory. The expanded Kentucky output would probably have costs greater than 4.3 cents per kWh because the main source of low prices is cheap infra-marginal coal generation whose supply can't be expanded because it is the result of old sources (under the Clean Air Act) whose supply cannot be expanded by definition.²⁰ Because the supply of that cheap power is fixed, if consumers outside of Kentucky were allowed access to that power, its price would be bid up to just below the price of the expensive power it was supposed to replace.

If natural gas is the fuel source for increases in electricity output everywhere and coal is infra-marginal, then prices would not vary across states in an unregulated market because the price of gas-fired output would set the market price everywhere and be largely the same. If we are correct, this implies that gains to trade not occurring under the current balkanized system are much smaller than many observers believe.

Accordingly, *the fight between the old regime and a restructured regime* (that is, the case for a transmission-intense versus balkanized system) *is a fight about wealth rather than efficiency.* This is why low-cost states vigorously resist a national integrated electricity market—it would allow their electricity to go to the highest bidders rather than to those who happen to reside within an electric utility's current service territory. Because there is a relatively fixed supply of this low-cost electricity, mandatory open access involves wealth redistribution as much as, and maybe even more than, efficiency gains.

AC Transmission System Is a Commons

In regulated markets, it is usually quite easy for economists to demonstrate that con-

sumers do not benefit from regulation. To be sure, weighted-average pricing under regulation redistributes from off-peak users to on-peak, but unlike many other markets, electricity markets have characteristics that are difficult to manage through property rights and contracts. Accordingly, regulation has at least the possibility of a plausible rationale.

For example, the alternating current (AC) grid is a "commons." That is, the physical reality of the grid does not coincide with current private property rights or the 50-state regulatory schemes that govern the grid. Power added by any generator on an AC transmission system follows all paths but favors those with least resistance rather than the shortest distance between generator and customer. Thus bilateral contracts between any willing seller and buyer of electricity affect all other buyers and sellers within each interconnected system in ways that are not captured by prices—the textbook definition of externality. The proper way to manage those externalities is a subject of great dispute.

Moreover, transmission additions confer benefits across all generators and consumers on the grid and thus have public good characteristics. The development of property rights and prices that internalize those characteristics is very difficult.

Traditionally, the commons problem was addressed through monopoly-franchise vertical integration. Trade between vertically integrated utilities was never very large and was governed by barter arrangements rather than markets. Where trade was extensive, voluntary arrangements such as the Pennsylvania-New Jersey-Maryland transmission pool (PJM) arose to manage the flows across separately owned transmission systems through contract. Thus, historically, the "commons" characteristics of the grid did not create large externality issues.

The Energy Policy Act of 1992 and orders 888 and 889 from the Federal Energy Regulatory Commission, however, facilitated the development of widespread trading on the grid—particularly by nonvertically integrated merchant generators. The mismatch

between the physical reality of the grid and its current governance structure has since become an important problem.

The Verdict on Markets

In light of our discussion of the California electricity crisis, the 2003 blackout, the low electricity prices found in heavily regulated states, and the physical nature of the electricity grid, can one defend the case for increased reliance on market forces in the electricity sector? Yes—but it is unclear exactly what kind of market is best suited for this industry and how much could be gained through reform. Until now, restructuring has imposed a particular vision of what an efficient electricity market would look like, but that model has traded one set of economic problems for another. The main hurdle that proponents of deregulation must surmount is the problematic nature of the transmission grid, the subject of the next section.

Solving the Public Goods Problem

What are the possible solutions to the public good nature of the transmission system? The most commonly discussed possibility is aggressive regulation by the Federal Energy Regulatory Commission through mandatory utility participation in regional transmission organizations, which would be responsible for long-term management of the electricity grid. The FERC also favors a standard market design for the industry (including provisions to ensure that adequate generation capacity is available) to eliminate the discrepancy between the commons nature of the transmission system and the current fragmented system that governs it.²⁷

The problem with that answer isn't so much that it involves regulation per se. In fact, many of the standard market design rules would be adopted by utilities that *voluntarily* wanted to engage in interstate trade. The problem is that many utilities are happy with the state-based cartels that now exist. They

don't want to facilitate trade because it would mean facilitating competitors coming into their service territories. And they don't want to be responsible for investment in transmission if they don't receive all the benefits.

Moreover, why bother implementing the federal solution if it leaves state-level regulation intact, with its impediments to electricity trade and lack of recognition of the regional spillover effects of transmission investment? The federal solution also confuses rather than clarifies incentives in the governance of transmission by separating ownership from control.²⁸

Nobel laureate economist Vernon Smith believes that private solutions are possible.²⁹ He argues that new transmission is a "club good" that facilitates the ability of generators to get their product to market. Consortia of generators could fund new investment and, in turn, get rights to inject or take power from the system in proportion to their financial contributions. MIT economist Paul Joskow is skeptical, however:

Transmission investment decisions do not immediately strike me as being ideally suited to relying entirely on the invisible hand. Transmission investments are lumpy, characterized by economies of scale and can have physical impacts throughout the network. The combination of imperfectly defined property rights, economies of scale and long-lived sunk costs for transmission investments, and imperfect competition in the supply of generating services can lead to either underinvestment or overinvestment at particular points on the network if we rely entirely on market forces.³⁰

In short, the weakness of the private solution is the inability of investors to capture the full benefits of their investment.

An institution drawn from petroleum economics—the unitization contract—illustrates one possible solution to the problems raised by Joskow as well as the difficulty of its implementation. In many cases, petroleum

The mismatch between the physical reality of the grid and its current governance structure has become an important problem.

**One could
implement
real-time pricing
without
deregulation.**

producers find that surface property rights do not coincide with the geological characteristics of petroleum reservoirs. This discrepancy creates incentives to drill and pump fast before other surface owners do the same, because no one represents the interests of the entire oil field.

A unitization contract is a set of payoffs to all existing surface owners that induces them to give up their production autonomy. In theory, surface owners consent to such a contract if operation of the reservoir by one operator produces enough excess revenue that the distribution of the excess induces all existing owners to give up their rights and still leaves a surplus.³¹

In the electricity context, the use of the unitization contract analogy leads to the following questions:

- Is there a set of payoffs to all existing players in electricity transmission (including state regulatory regimes and incumbent utilities) that would induce them to turn over operation of their systems to a welfare-maximizing operator in return for a contractually determined share of the increased profits?
- What plan would the welfare-optimizing operator implement?
- Is the plan achievable through private action or are transaction costs prohibitively high?
- And, if they are high, is coercion by FERC likely to achieve the same outcome?

The most pertinent question is the first. Are the unexploited gains to trade large enough to allow payoffs to all existing players in electricity transmission and still leave a surplus?

Doug Hale and his colleagues suggest that the unexploited gains from trade may be high in the eastern part of the United States. They found that several small transmission investments better linking New England with New York would reduce peak power prices considerably in the summer across several states.³² It would appear that the gains to

consumers far exceed the costs of the investments—the textbook definition of unexploited gains to trade—and yet the links have not been built because no one represents the beneficiaries across numerous state and utility boundaries.

But the gains from trade are true efficiency gains rather than wealth transfers only if there is underutilized capacity in existing coal-fired plants that is priced at marginal cost. Once that underutilized capacity is gone and the marginal sources of electricity—both local and long distance—are natural gas, gains from trade exist only if the transmission costs are less than the higher fixed costs (land and labor) of locating generation near urban consumers. And to the extent that the price differences across states represent weighted-average rather than marginal-cost differences, potential gains to trade may be zero.

The other important source of efficiency gains is real-time pricing. According to Maloney, McCormick, and Sauer, the potential gains are large because peak uses would respond to high peak prices by shifting use to other times of day and reducing off-peak underutilization of generation facilities. They report that full utilization of conventional steam-electric “baseload” facilities would result in a 25.5 percent increase in power production and a similar percentage decrease in price to an average 5.1 cents per kwh for the country.³³ Unfortunately, mandatory open access and restructuring have not involved the use of real-time pricing. Regardless, one could implement real-time pricing without deregulation.

Our analysis to this point has considered only the static efficiency gains possible through increased reliance on market forces. We find that those potential gains may be rather small, especially in the absence of price incentives to shift consumption from peak to off peak.

Yet the pursuit of innovation and *dynamic* efficiency (how to organize a business) is as important—if not more so—than the pursuit of *static* efficiency (how best to deliver a ser-

vice within a set organizational structure). Market agents are simply far better at discovering innovative organizational structures, manufacturing practices, product lines, pricing regimes, and retail service arrangements than are state regulatory officials or the incumbent monopolies they regulate.³⁴ Economists Arthur De Vany and W. David Walls, in the course of a similar discussion about the merits of deregulating the natural gas sector, go so far as to argue that policy analysts ought to "forget about static efficiency; no one knows where the industry is headed or how it will need to adapt to future circumstances."³⁵

Industry design by policy makers founders on the complexity of the design problem; it is a search for local optima only. Regulatory policy that aims at a social optimum is too vague. Yet policy that aims at a specific goal is too narrow. The attempt to optimize policy for a given goal produces a narrow optimum that lacks robustness and may be far from optimal when circumstances change.

Successful innovations in industry institutions and organizations are more likely to produce gains in efficiency than are changes in how a firm prices a particular product. These innovations are more likely to come from the interactions of the participants in the process; in other words, effective products and organizations are more likely to be self-organized rather than handed down from above.³⁶

Given the resistance of many traditional utilities to the FERC's standard market design proposal, however, it seems clear that the industry would return to vertical integration and balkanized service territories if given the chance.³⁷ How the industry might evolve in the future—or what new modes of operation the industry would pursue in the near term if freed from government regulation—we cannot predict.

Back to the Future?

A central implication of our analysis is that vertical integration may be the most efficient organizational structure for the electricity industry. In the name of advancing competition in the generation sector, however, mandatory open access requires much additional regulation to govern the interaction of independent generators and the AC grid "commons." And with the revival of installed capacity requirements, we recreate the costs of excess capacity that led to the call for generation competition in the first place.

If the static efficiency gains from mandatory open access are smaller than advertised and the costs created by the regulatory apparatus necessary to achieve them are large, what should we do? Traditional vertically integrated utilities are often low cost, but they restrict trade and seem to prefer state-based cartels. If they were totally deregulated (including transmission and distribution) they probably wouldn't change their behavior very much because entry and rivalry are difficult as long as they control the "highways" over which electricity trade takes place. The only competition they would face is from large customers who generate their own power from natural gas cogeneration, but that threat has been considerably weakened by the doubling of natural gas prices.

Such a realization led many well-meaning people to support mandatory open access in order to "force" competition and rivalry to occur. But that has required the substitution of legal orders for vertical integration to manage transmission externalities, and that has not been successful.

Our sense is that we should go either forward with true deregulation or backward to the old regime but not stay in mandatory open-access limbo, which is more regulatory than the old status quo, with few if any benefits. We should either deregulate generation, transmission, and distribution; allow all arrangements to be determined by contract; and introduce the possibility of gains

Vertical integration may be the most efficient organizational structure for the electricity industry.

The differences between a regulated and an unregulated market may not be as great in the electricity sector as they are in other markets.

through dynamic efficiency,³⁸ or we should go backwards to a world of vertical integration and incentivised rate regulation.

To execute the forward transition, Congress would simply declare that state regulation of the electricity business is an unconstitutional interference with interstate commerce—a precedent established when Congress preempted state trucking regulation.³⁹ Congress would then remove any legal barriers to vertical reintegration of the industry and any requirement that grid owners open their wires to parties under regulated terms and conditions. Service territories, however, would no longer be protected, and politically created barriers to entry would be eliminated.

Such a proposal would be politically unpopular because of the widespread fear that unrestrained local power monopolies would “gouge” both commercial and residential consumers, even though the evidence does not suggest that regulation has constrained prices below monopoly levels.⁴⁰ State legislators and public service commissions, moreover, would resist a congressional move to eliminate their roles.

True deregulation would be an easier sell if one could be certain of the gains to trade that would occur if it were not for the current ownership and governance system. The reason that this is so difficult is probably the same as the reason that the political obstacles described by the unitization analogy have been so hard to overcome.

Accordingly, a second-best solution might be to go backwards: to accept the regulatory oversight of electric power companies (oversight that would include utility prices and investment decisions) in return for management of the transmission commons through vertical integration.

The differences between a regulated and an unregulated market may not be as great in the electricity sector as they are in other markets. That’s because, in an unregulated world, the relations between electric firms and consumers would likely be governed by long-term contracts because the dedicated nature of electricity assets implies that each side can

“hold up” the other.⁴¹ That is, once assets are in place, consumers might refuse to pay anything above a plant’s marginal costs and firms could well be forced to accept such demands because the plant’s assets cannot be dedicated to other uses and the plant itself cannot move to more lucrative service territories. And, conversely, customers would likely not agree to spot-market relationships with electric firms because entry and rivalry from other firms is difficult, thus reducing consumers’ ability to avoid extortion from firms under spot prices.

Accordingly, the relationship between firms and consumers in a totally unregulated world might very well include some guaranteed return for firms and fixed prices for consumers. The only question then is how different the specifics of regulation would be from such hypothetical contracts.

Fortunately, the problems associated with regulation are fewer today than they were 30 or 40 years ago because incentive-based (IB) regulation has replaced traditional rate-of-return (ROR) regulation.⁴² Under IB regulation, owners have an incentive to reduce rather than increase costs and thus would not have the same incentive to have an excessively large generation investment (i.e. nuclear power plants).

One way to reap the advantages of the old regime while still allowing more electricity trade between service territories would be to promote the more extensive use of direct current DC transmission links between AC systems that have one owner and thus no externalities. DC links end the commons problem because the electricity flows would not affect third parties on the grid.⁴³

Smaller AC systems with DC connections between them cost more, but such a design reduces externalities and management requirements. George Loehr, a member of the New York State Reliability Council, estimates that it would cost \$7-8 billion to break up the eastern interconnection into 10 smaller interconnections linked by DC lines.⁴⁴

Finally, a regulated system could introduce real-time pricing for large commercial

and industrial users. Such prices would provide very effective incentives for innovation by both electricity suppliers and consumers.

Conclusion

Electricity restructuring was originally embraced by many economists because they believed that reforms would reduce the incentive to build excess generating capacity, eliminate the incentive to build capital-intensive generating facilities, and lead to an introduction of real-time pricing. Many investors in electricity generation are now responsible for their own fate, but the drastic overbuilding of generation has left most of them in bankruptcy.⁴⁵

While restructuring does not have quite as bad a record as the anti-market faction would maintain, it has created problems previously unknown in the electricity sector. Those problems generally arose because electricity restructuring

- focused on generation competition and ignored the pricing and incentive issues involved in managing the transmission system and its public commons characteristics;
- grafted a relatively free wholesale market onto a still heavily regulated retail market; and
- established artificial market institutions that invited manipulation and abuse. The end result has proven far from satisfactory.

There is little reason to think that the restructuring experiment will produce improved results in the future. The problems with the current regime are systematic. Ironically, the ICAP regime essentially returns us to the old status quo without saying so.

We do not expect full, genuine deregulation to happen in the foreseeable future. But we do expect the case for restructuring as it is currently conceived to come under increasing political and economic stress.

Notes

1. For an overview of the old regulatory regime and the events that prompted consideration of wide-ranging reforms, see Peter Van Doren, "The Deregulation of the Electricity Industry: A Primer," *Caro Policy Analysis* no. 320, October 6, 1998. www.caro.org/pubs/pas/pa-320.pdf.

2. For a review of state policies relating to electricity regulation, see U.S. Energy Information Administration, "Status of State Electric Industry Restructuring Activity—as of February 2003," www.eia.doe.gov/cneaf/electricity/chg_str/regmia.p.html.

3. Of the 34 states that have either refused to move ahead with restructuring or retreated from previous restructuring initiatives, all have below-average electricity costs. Kenneth Rose, "The State of Retail Electricity Markets in the U.S.," *Electricity Journal* 17, no. 1 (January/February 2004): 26.

4. The Public Utilities Regulatory Policy Act of 1978 in part required electric utility companies to purchase power generated by independent producers at a price equal to "avoided costs," defined as the cost that the regulated utility would have had to incur if it had generated the same amount of electricity. The purpose of that provision was to stimulate the development of alternatives to fossil fuels, which were expected to become terribly expensive in the decades to come. The details of the legislation implementation were left to the 50 states given that they were the political entities that actually regulated electricity rates. Each state set a price to reflect its regulators' best estimate of what "avoided costs" would be in the future and required utilities to sign contracts with any/all independent electricity producers who offered power at that price. The upshot is that states that established high prices for avoided costs under the act (most notably, California and New York) saddled utilities with costly obligations that served to increase retail prices relative to the states that established lower avoided-cost estimates.

5. It is not clear whether nuclear power was imprudent from the start or was made excessively costly by federal safety regulation (in the form of the Nuclear Regulatory Commission). In 1975, Resources for the Future projected that the total costs of nuclear plants in 1985-88 would be less than the total costs of equivalent coal plants. See William Spangar Peirce, *Economics of the Energy Industries* (Westport, CT: Praeger, 1996), pp. 216-17. A set of costly nuclear plants came online during the early 1980s and electricity rates rose 60 percent from 1978 to 1982. See Caleb Solomon, "As Competition Roids Electric Utilities, They Look to

- New Mexico," *Wall Street Journal*, May 9, 1994, p. A1. By 1990 nuclear plants had total costs that were about double those for coal plants (Peirce, p. 216). Not all nuclear plants are more expensive than coal-fired plants. Peirce reports (pp. 217-18) that the least expensive nuclear plants have total costs lower than the cheapest coal plants but that at every other point in their respective distributions, nuclear plants are more expensive.
6. In 1996, if implemented, full utilization of conventional steam-electric "baseload" facilities off peak would have resulted in a 25.5 percent increase in power production and a similar percentage decrease in price. See Michael T. Maloney, Robert E. McCormick, and Raymond D. Sauer, "Customer Choice. Consumer Value: An Analysis of Retail Competition in America's Electric Industry," Citizens for a Sound Economy Foundation, May 1996, p. 32.
 7. Catherine Wolfram, "The Efficiency of Electricity Generation in the U.S. after Restructuring," Center for the Study of Energy Markets, University of California Energy Institute Working Paper no. 111, June 2003, p. 25, www.ucei.berkeley.edu/pubs-cse/mwp.html.
 8. Leonard Hyman, "A Financial Postmortem: Ten Years of Electricity Restructuring," *Public Utilities Fortnightly*, November 15, 2003, pp. 10-15.
 9. Peter Behr, "Electricity Bills Likely to Jump When Price Caps Expire," *Washington Post*, March 5, 2004, p. E1.
 10. Ahmad Faruqi and Stephen S. George, "Dynamic Pricing for the Mass Market," *Public Utilities Fortnightly*, July 1, 2003, pp. 33-35.
 11. Hydroelectric output in California went from 40,350,453 MWh in 1999 (21.4 percent of California production) to 25,192,087 MWh in 2001 (12.7 percent of production), a decrease of 38 percent. Natural gas electric production during the same period went from 85,098,862 MWh (45 percent of production) to 111,932,271 (an increase of 32 percent to 56 percent of production).
 12. For a more thorough discussion of the crisis, see Jerry Taylor and Peter Van Doren, "California's Electricity Crisis: What's Going On, Who's to Blame, and What to Do," *Caro Institute Policy Analysis* no. 406, July 3, 2001.
 13. Other lessons are (1) that the separation of the real time and day-ahead electricity markets adds to the complexity of arbitrage calculation in which sellers of electricity must engage and (2) multipart bidding in a tight market leads to bad incentives. The California PX employed an auction in which generators could bid in "supply curves" with up to 16 price-quantity pairs. Everyone would be paid the amount needed to get supply sufficient to meet demand. In theory, generators would have little reason to act strategically because each gets the market-clearing price. In practice, each might have an incentive to bid in a little bit of power at a very high price. If such a bid is not taken, the generator does not lose much—only the profits from the small amount of sales. If the bid is taken, however, the generator could reap a windfall in that it receives that high price on all of its output, not just the amount bid in at the high price. See Tim Brennan, "Questioning the Conventional Wisdom," *Regulation* 24, no. 3 (Fall 2001): 65.
 14. James Bushnell and Erin Mansur, "The Impact of Retail Rate Deregulation on Electricity Consumption in San Diego," Program on Workable Energy Regulation Working Paper no. PWP-082, p. 4, www.ucei.berkeley.edu/PDF/pwp082.pdf.
 15. Bushnell and Mansur, p. 17. Steven Braichwait and Ahmad Faruqi, "The Choice Not to Buy: Energy Savings and Policy Alternatives for Demand Response," *Public Utilities Fortnightly*, March 15, 2001, p. 60, report elasticity estimates of .07 to .135 (a reduction in demand of 7 to 13 percent for a doubling of prices).
 16. Peter C. Reiss and Matthew W. White, "Demand and Pricing in Electricity Markets: Evidence from San Diego During California's Energy Crisis," NBER Working Paper no. 9986, September 2003, pp. 20-21.
 17. Severin Borenstein, "The Long-Run Effects of Real-Time Electricity Pricing," University of California Energy Institute, Center for the Study of Energy Markets Working Paper no. 133, June 2004, p. 15.
 18. Janet Gail Besser, John G. Fair, and Susan Tierney, "The Political Economy of Long-Term Generation Adequacy: Why an ICAP Mechanism Is Needed as a Part of Standard Market Design," *Electricity Journal* 15, no. 7 (August/September 2002): 53-62. Bruce Radford, "New York Throws a Curve," *Public Utilities Fortnightly*, May 15, 2003, pp. 25-27.
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 20. U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, p. 17, <https://reports.energy.gov/>.
 21. *Ibid.* p. 32.

22. Douglas Hale, Thomas Overbye, and Thomas Leckey, "Competition Requires Transmission Capacity: The Case of the U.S. Northeast," *Regulation* 23, no. 2 (Summer 2000): 40-45. The authors use optimal power flow analysis to demonstrate that small additions to the grid in the Northeast would lower prices for consumers across several states.
23. U.S. Department of Energy, Energy Information Administration, *Electric Power Annual 2002*, figure 7.4, p. 43.
24. Weighted-average pricing entails adding up the cost of each unit of electricity from all generators in a service area and charging consumers the average cost of power from those generators.
25. Simply restated, when a supply curve is upward sloping and the corresponding demand curve is downward sloping (as it is in the electricity market), the intersection of the two curves establishes the price. Suppliers to the left of the intersection point on that curve (that is, lower-cost suppliers) will charge what the market will bear, not the sum of their production costs plus a normal profit.
26. This argument does not apply to claims about efficiency gains from underutilized off-peak coal capacity made by Maloney, McCormick, and Sauer.
27. For an explanation of the particulars envisioned, see Thomas Lenard, "FERC's New Regulatory Agenda," *Regulation* 25, no. 3 (Fall 2002): 36-41.
28. Robert J. Michaels, "Can Nonprofit Transmission Be Independent?" *Regulation* 23, no. 3 (Fall 2000): 61-66.
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30. Paul L. Joskow, "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector," in Chao and Huntington, p. 24.
31. Gary D. Libecap and James L. Smith, "Regulatory Remedies to the Common Pool: The Limits to Oil Field Unitization," *The Energy Journal* 22, no. 1 (January 2001): 1-26.
32. See Hale, Overbye, and Leckey.
33. Maloney, McCormick, and Sauer, p. 32. Full utilization would require an off-peak price for power lower than current prices, which, in general, are time-invariant "average-cost" prices. Lower off-peak prices would induce customers to shift use so as to fully utilize generating capacity.
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35. Arthur De Vanev and W. David Walls, *The Emerging New Order in Natural Gas Markets: Markets versus Regulation* (Westport, CT: Quorum Books, 1995), p. 113.
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42. Shimon Awerbuch, Leonard Hyman, and Andrew Vesey, *Unlocking the Benefits of Restructuring: A Blueprint for Transmission* (Vienna, VA: Public Utilities Reports Incorporated, 1999).

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Hydrogen's Empty Environmental Promise

by Donald Anthrop

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Executive Summary

Politicians on both the Left and the Right have increasingly embraced subsidies for hydrogen-powered fuel cells as a promising way to move America away from reliance on petroleum. Although advocates concede that such technologies are at least several decades away from penetrating the market in any significant manner because of cost considerations, less attention has been paid to the environmental implications of such a transition.

Given current technology, switching from gasoline to hydrogen-powered fuel cells would greatly increase energy consumption even if the hydrogen were extracted from water rather than from fossil fuels. That's because it takes a tremendous amount of electricity to harvest hydrogen and to deliver it to consumers. Moreover, a transition from gasoline to hydrogen would nearly double net greenhouse gas emissions attributable to passenger vehicles, given the current fuel mix in the electricity sector.

Donald Anthrop is professor emeritus of environmental studies at San Jose State University and the author of more than 60 papers and articles on energy and water resources.

Separating hydrogen atoms from other atoms on an industrial scale is a technologically challenging and energy-intensive undertaking.

Introduction

Hydrogen energy is all the rage among American politicians at the moment. A \$1.8 billion, 10-year federal program to underwrite research in hydrogen-powered fuel cells—termed the “FreedomCar initiative” by the Bush administration—is a popular component of energy legislation passed by both the House and the Senate in 2003. In his campaign for the White House, Sen. John F. Kerry (D-MA) put forth an even more ambitious, \$5 billion hydrogen fuel-cell initiative. And even though all observers agree that economically viable hydrogen-powered vehicles will not be available for at least a couple of decades (if then),¹ California governor Arnold Schwarzenegger is promoting the use of state funds to help start building a statewide network of hydrogen refueling stations in the here and now.² If hydrogen refueling stations are available, the theory goes, automakers will build vehicles powered by fuel cells and people will buy them.

Before any more taxpayer money is spent pursuing the dream of a “hydrogen economy,” however, policymakers need to get out their calculators and seriously consider the environmental costs of bringing this dream to reality. If they do, they’ll find that harnessing hydrogen for widespread use in the energy sector will consume more energy than it will save, and it will worsen, not better, environmental quality.

The Challenge

Advocates of a hydrogen economy do not envision that hydrogen will be burned directly to create energy; instead, they envision using hydrogen primarily as an input for fuel cells. A fuel cell is basically a gas battery, although fuel cells come in a variety of types and employ a range of different materials.³ Because fuel cells emit only water vapor and heat, environmentalists tout them as a source of pollution-free energy.

That characterization is grossly misleading, however, because it fails to consider the

issue of hydrogen production. After all, hydrogen does not exist in subterranean pockets waiting to be tapped by drilling equipment. Hydrogen is an atom fused with other atoms that together constitute molecules of various chemical substances. Separating hydrogen atoms from other atoms on an industrial scale is a technologically challenging and energy-intensive undertaking.

There are basically two ways to produce hydrogen. The first method (called “electrolysis”) is to send through water an electric current that separates the water’s hydrogen atoms from its oxygen atoms. The second method is to mix steam with some sort of fossil fuel (usually natural gas) in a superheated chamber. The ensuing chemical reaction produces hydrogen.

The Electrolysis Calculation

Environmentalists and other advocates of fuel cells often cite the electrolysis route as a viable and attractive way to reduce fossil fuel consumption and greenhouse gas emissions. But is it? Let’s take a look at the numbers.

It takes 39.4 kilowatt-hours of energy to extract a kilogram of hydrogen from water. But the energy efficiency of the electrolysis process is only about 70 percent (that is, 30 percent of the energy used in the course of electrolysis is wasted).⁴

Let’s suppose the electrical energy for the electrolysis process is provided by a coal-fired power plant with an overall conversion efficiency of 40 percent (that is, 40 percent of the thermal energy input to the plant is converted into electrical energy—a typical figure).⁵ Accordingly, the energy input to the boiler of the power plant required to produce the kilogram of hydrogen is 140.8 kilowatt-hours.

Now, let’s look at the fuel cell. Because the reaction that occurs in the fuel cell produces water vapor, the most energy we could produce from the fuel cell is 33.4 kilowatt-hours per kilogram of hydrogen. Given that the best fuel cells operate at about 70 percent efficiency,⁶ the energy actually obtained from the reaction of a kilogram of hydrogen in the fuel cell is 23.3 kilowatt-hours.

There is one final matter to consider. If hydrogen is to be used as a transportation fuel, it must be compressed to at least 4,000 pounds per square inch, and that compression requires energy. After subtracting the energy needed for compression, we find the net output from the kilogram of hydrogen in the fuel cell is only about 17.4 kilowatt-hours.⁷

In sum, one must put 140.8 kilowatt-hours of energy into the front end of a power plant to produce 17.4 kilowatt-hours of electricity from a hydrogen-powered fuel cell in an automobile. The overall conversion efficiency of the whole process is a dismal 12 percent.

Now, let's estimate the electrical output from fuel cells that would be needed to power the U.S. vehicle fleet. According to data from the Bureau of Transportation Statistics, the total vehicle-miles traveled by passenger cars, pickup trucks, vans, and SUVs in the United States in 2000 was 2,526 billion.⁸ Extensive tests performed by Southern California Edison Company suggest that it would take an average of at least 0.46 kilowatt-hour of electricity to drive a passenger vehicle a mile down the road.⁹ Applying that figure to the total 2,526 billion vehicle-miles traveled in 2000, we find that fuel cells would need to produce 1.16 trillion kilowatt-hours to power the U.S. vehicle fleet. Given the ratios discovered above, that implies the need for 9.38 trillion kilowatt-hours of energy to feed into coal-fired power plants (the equivalent of 32 quadrillion British Thermal Units, or "32 quads" in engineering jargon).

It is interesting to compare that number with the energy content of the U.S. gasoline supply. In 2000 U.S. motor gasoline consumption averaged 8.472 million barrels per day.¹⁰ Since reformulated gasoline has an energy content of 5.150 million BTU per barrel, we find that the energy content of the gasoline consumed in 2000 equals 16 quads, or exactly half the energy required for the fuel-cell route using coal to generate the electricity for electrolysis.¹¹

The environmental implications of moving vehicles with hydrogen-powered fuel cells rather than with gasoline are bracing. Replac-

ing 16 quads of gasoline-fired energy with 32 quads of coal-fired energy to produce electrolysis hydrogen would result in a 2.7-fold increase in carbon emissions.¹² Replacing gasoline with electricity fired by the fuel mix currently employed in the generation sector would increase net carbon emissions from 309 million metric tons to 610 million metric tons.¹³

Renewables to the Rescue?

Environmentalists argue that renewable energy sources could in theory supply the needed electrical energy and thereby reduce use of fossil fuel and, relatedly, net carbon emissions. The calculations, however, are daunting. Hydroelectric power, for instance, dwarfs all other renewable energy production in the United States, yet the 3.75 trillion kilowatt-hours of electricity necessary to deliver hydrogen from water to fuel cells¹⁴ is almost 15 times the total hydroelectric energy produced in the United States last year.¹⁵ Given the mounting public pressure to remove existing dams, it's unlikely that the construction of any significant new hydroelectric generating capacity will occur in the foreseeable future.

Photovoltaic (PV) cells, which are used to produce solar power, are an even worse choice. Doing an input-output analysis of the energy obtained from a PV array vs. the energy required to produce it is extremely difficult, but some analysts have performed those calculations and found that it would take about eight years for a PV panel to produce as much energy as was used to produce the panel in the first place.¹⁶ A modern PV panel operating over a period of 25 years can probably be expected to convert no more than about 12 percent of the incident solar radiation striking the cell into electrical energy.¹⁷ Since we need 56.3 kilowatt-hours of electricity to power the electrolyzer in order to obtain an output of 17.4 kilowatt-hours from the fuel cells, if PV cells are used to provide that electrical energy, the efficiency of the whole process is a minuscule 4 percent (that is, 4 percent of the energy in the incident solar radiation captured by the PV cells appears as electrical output from the fuel cells).¹⁸

One must put 140.8 kilowatt-hours of energy into the front end of a power plant to produce 17.4 kilowatt-hours of electricity from a hydrogen-powered fuel cell in an automobile.

Powering the domestic vehicle fleet with hydrogen derived from natural gas would increase natural gas consumption by about 66 percent.

That dismal conversion efficiency has two consequences. First, the energy required to make the PV panel will exceed the energy produced by the fuel cells. Second, the cost of that energy will be prohibitively expensive.

Using wind power rather than solar power requires a different set of calculations. Unfortunately, the data for those calculations are not readily available. Like solar power facilities, however, wind power facilities are quite capital intensive, and the power from those facilities is only intermittently available. Accordingly, the calculations for wind-generated electricity are unlikely to be much different from the calculations for solar-generated electricity.¹⁹

The "Steam Reforming" Calculation

Virtually all of the hydrogen produced in the world today is derived from natural gas in a process called "steam reforming." In that process, natural gas is mixed with steam and heated in a reformer tank. Once again, however, the chemical reactions that produce hydrogen require the input of energy. Additional energy inputs are required to generate steam, heat the reformer tank, and separate the products. The overall efficiency of the whole process is only about 30 percent—much less than if the natural gas were simply burned in an electrical power generating plant.²⁰

In order to provide the 1.16 trillion kilowatt-hours of fuel-cell output needed to power the U.S. vehicle fleet, 66.7 billion kilograms of hydrogen would be needed. Accordingly, about 15 trillion cubic feet of natural gas would be required to produce that hydrogen by the steam reforming process.²¹

In 2002, the last year for which we have data, domestic natural gas consumption was about 22.6 trillion cubic feet.²² Thus, powering the domestic vehicle fleet with hydrogen derived from natural gas would increase natural gas consumption by about 66 percent.

That figure is particularly striking given that domestic production and imports of Canadian gas are declining while demand is rapidly increasing, a combination of events that has sent natural gas prices skyrocketing.

Preliminary data indicate that the average wellhead price in 2003 was about \$5.10 per thousand cubic feet (mcf) compared with \$2.95 per mcf in 2002.²³

Furthermore, there is growing concern that natural gas prices are destined to remain high and that the imbalance between supply and demand can be satisfied only with imports of liquefied natural gas (LNG).²⁴ Accordingly, most if not all of the 15 trillion cubic feet of natural gas needed to produce hydrogen for fuel cells would have to come from LNG imported primarily from the Middle East. That would do little to reduce energy costs or enhance the security of our energy supplies.

Conclusion

The economic problems involved in delivering hydrogen to fuel cells are difficult to remedy because they stem from fundamental thermodynamics. Although technological improvement may well increase the efficiency with which energy is used along some if not all of the production chain, the challenges are so immense that the confident predictions of imminent economic breakthroughs heard from the political class are hard to take seriously.²⁵

Decisions about the relative merits of various emerging technologies are best left to the marketplace, where private investors have every incentive to make the soundest bets. If hydrogen-powered fuel cells hold economic promise, investors will have every incentive to promote their development. If they do not, then investors will rightly put their money elsewhere. Subsidies simply impose politically inspired judgments on market actors, and there is no reason to think that those judgments are better informed than the ones that reign in the marketplace.

Notes

1. According to the U.S. Department of Energy, a hydrogen-powered car costs about \$1 million to manufacture today, and its range is limited to about 200 miles before refueling—much less than

the range of a gasoline-powered car. Hydrogen fuel made from natural gas costs about \$4 per gallon and hydrogen fuel made from water costs three times that amount. Miguel Bustrillo and Gary Polakovic, "Governor Pushes for 'Hydrogen Highways,'" *Los Angeles Times*, January 20, 2004, p. B1. For a more thorough discussion of the steep economic hurdles faced by hydrogen-powered fuel cells, see Joseph Romm, *The Hype about Hydrogen* (Washington: Island Press, 2004).

2. Termed the "Hydrogen Highways" initiative, the plan is intended to locate a hydrogen refueling station every 20 miles along major highways in California by 2010. That would mean 150-200 hydrogen refueling stations at a cost of \$250,000-\$300,000 per station, the full cost of which would be split between the public and private sectors. The Hydrogen Highways initiative is not unlike a similar initiative undertaken years ago in California that used state funds to help build electric-charging stations along major state roadways—facilities that today go largely unused. See Bustrillo and Polakovic.

3. In a fuel cell, two electrodes are separated by some type of electrolyte or proton exchange membrane. Hydrogen under pressure is introduced at the anode and oxygen from air is introduced at the cathode. At the anode, the hydrogen dissociates into electrons, which travel through an external circuit to produce an electrical current, and protons, which travel through the electrolyte to the cathode. At the cathode, the protons combine with oxygen and the electrons that have traveled through an external circuit to produce water vapor. H. Petroski, "Fuel Cells," *American Scientist* 91 (September-October, 2003): 398-402.

4. M. Wang, "Hydrogen a Transportation Fuel," *Oil & Gas Journal* 101, no. 33 (August 25, 2003): 10-12.

5. Harold Schobert, *Energy & Society* (New York: Taylor & Francis, 2002), p. 253.

6. T. Standing, "Making Hydrogen," *Oil & Gas Journal* 101, no. 15 (April 14, 2003): 10-12.

7. *Ibid.*

8. U.S. Department of Transportation, Bureau of Transportation Statistics, "National Transportation Statistics 2002," Table 1-32.

9. Southern California Edison undertook comprehensive tests of various electric vehicles on the Pomona Loop in Southern California. The test loop, which included city streets, highways, and hilly terrain, was designed to simulate real-world driving conditions. The test vehicles included small electric vehicles (Toyota's RAV4, GM's EV1, and

Honda's EV Plus) as well as some larger electric vehicles (the Ford Ranger, Chevy's S10, Nissan's Altra, and the Chrysler EPIC). The average energy consumption for all electric vehicles tested was 0.422 kilowatt-hour per mile traveled, while the average for the larger electric vehicles was 0.46 kilowatt-hour per mile traveled. It's worth noting, however, that even the larger electric vehicles included in the test were smaller and lighter than the full-sized pickup trucks, vans, and SUVs on the road today. Of course, the vehicles tested were electric vehicles, not vehicles powered by fuel cells. In order for a vehicle powered by fuel cells to achieve the results found in the study, it would have to carry a large battery pack (in addition to the steel tank carrying the compressed hydrogen) that could store the energy generated in braking—an economic cost and weight penalty not usually considered in fuel-cell vehicles. California Energy Commission, Southern California Edison Co., "Pomona Loop Test Data," Sacramento, 2001. Unpublished document available from the author.

10. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2003/07), July 2003, Table 3.4.

11. *Ibid.*, Table A1.

12. Author's calculation based on data found in EIA, *Emission of Greenhouse Gases in the U.S., 1987-1994*, DOE/EIA-0573(87-94), October 1995, Table B1.

13. Author's calculation based on data found in EIA, *Monthly Energy Review*, DOE/EIA-0035 (2004/02), February 2004, Tables 2.6, 7.2a. In calculating carbon emissions, we used a carbon emission coefficient of 14.9 million metric tons of carbon/quad for the wood and waste. We assumed there were no carbon emissions for the hydro, nuclear, and the other nonhydro renewable energy sources. Since residual fuel oil was 65 percent of the petroleum used for electrical power generation, we used a carbon emission coefficient of 21.49 million metric tons of carbon per quad of energy (the value for residual fuel oil) for the petroleum.

14. Earlier we found that with an electrolyzer operating at an efficiency of 70 percent, an input of 56.3 kilowatt-hours of electricity is needed to produce one kilogram of hydrogen from water. After subtracting the energy loss for compressing the hydrogen, we found that a fuel cell operating at an efficiency of 70 percent produced 17.4 kilowatt-hours from that kilogram of hydrogen. Thus, we need an electrical energy input of 56.3 kilowatt-hours to the electrolyzer to obtain an output of 17.4 kilowatt-hours from fuel cells. Accordingly, 3.75 trillion kilowatt-hours of electricity would be needed to produce the 1.16 trillion kilowatt-hours of output

from fuel cells that would be required to power the domestic vehicle fleet.

15. EIA, *Monthly Energy Review*, February 2004, Table 7.2A.

16. C. Yoder, *Alternative Energy FAQ2*, <http://www.ibiblio.org/ecolandtech/alternativeenergy/faqs/AlternativeEnergyFAQ2>; E. A. Alsema, P. Frankel, and K. Kato, "Energy Pay-Back Time of Photovoltaic Energy Systems: Present Status and Prospects,"

any calculations that have taken all of those things into account. Moreover, because wind power is intermittent, either several large installations would have to be constructed in various regions of the country—resulting in a large overcapacity—or hydrogen would have to be stored for periods when hydrogen production was inadequate to meet demand, which would require even greater energy inputs. For a more thorough discussion of the economics of wind power, see Jerry Taylor and Peter Van Doren, "Evaluating the Case