FORTNIGHTLY'S

SPARK

Letter #53
May 2008

THE ON-LINE GATEWAY FOR READERS OF PUBLIC UTILITIES FORTNIGHTLY MAGAZINE.

An outdated electric regulatory model is a challenge to those who want to build generating plants. Sean Casten, however, believes the challenge is not insurmountable as he investigates what happens as the U.S. works on weaning itself off coal as one way to deal with climate-change issues. He takes a look at the interplay among the four significant fuel sources used in this nation—hydro, nuclear, coal and natural gas. The coming prick shocks in energy will not be so easily reversed as they are driven by the global economy and desire for a better environment.

L. A. Burkhart
Editor

What disclosure requirements are utility companies facing regarding climate-change risks?

You would know if you read Fortnightly magazine. ***Click here*** *for the answer.*

BEYOND COAL

No Longer Cheap – So What Next?

By Sean Casten

When it comes to power generation, coal isn't cheap. Both power plant and fuel costs are up by nearly 300%, and projected to rise further.[1] Even before factoring in the risks of future greenhouse-gas legislation, this situation has conspired to make a bet on coal-fired central-station power equivalent to a bet on massive retail power price increases. Increasingly, this is a bet that neither equity nor debt providers are willing to take.

And yet we continue to operate under the assumption that coal is cheap — to the extent that we largely have framed our greenhouse-gas policy conversation as a tradeoff between environmental stewardship and the fantasy of cheap coal.

On balance, this is good news, because it means that the perceived conflict at the heart of our current climate-change debate is false. We need not quibble about whether or not we can afford to address global warming; indeed, we can lower greenhouse gases and grow the economy. But first, we have to get beyond coal.

The Electric Sector's GHG Role

In the United States, coal is primarily a power plant fuel, and the electricity sector is the single biggest source of greenhouse-gas (GHG) emissions. As a result, any discussion of GHG reduction must confront coal-based electricity.

The U.S. Environmental Protection Agency (EPA) in 2005 investigated U.S. GHG emissions by sector, finding 42% came from electricity generation, 33% from transportation and 25% from thermal energy generation. The EPA published a chart showing historically how the electric sector has steadily increased its share of GHG emissions (*see Figure 1*).

The trends reflect our nation's steady and inexorable electrification — first as the nation switched from candles to electric light, then »

PRINT

shifted away from mechanical power, then later as waves of computerization and air conditioning enabled great leaps in our national standard of living. As the United States now shifts from a manufacturing- to a service-intensive economy, this trend undoubtedly will continue — and so the nation increasingly will find that efforts to curtail GHG emissions must focus on the electric sector.

For rather perverse reasons, this is good news. The U.S. electric sector today is only half as fuel efficient as it was in 1910, implying that the nation could cut CO_2 emissions from the electric sector in half and lower electricity costs simply by deploying century-old technologies and regulatory models.

How did this happen?

Thomas Edison's first power plant was much less efficient than any of today at converting fuel to electricity, but Edison wasn't in business to make electricity: He was in business to make money. Therefore, he recovered as much of his waste energy as possible in the form of thermal energy and sold that to neighboring commercial and industrial facilities. This combined heat and power generation continued as the standard approach during the early part of the 20th century when, to speed electrification, governments created electric monopoly franchises. The monopoly model sped up electrification but removed the free-market impulse that drove the first three decades of the industry. In place of competition, the industry was ceded to protected monopolies, wherein profits were earned not by controlling costs and increasing revenues, but rather by deploying commission-approved capital to earn a commission-approved return. Under these rules, operating costs are simply passed along to customers, on the theory that monopolies should not be rewarded for spending money. As a practical matter, this eliminated the incentive to reduce operating costs. Since power plant operating costs are dominated by fuel, this has both economic and environmental consequences.

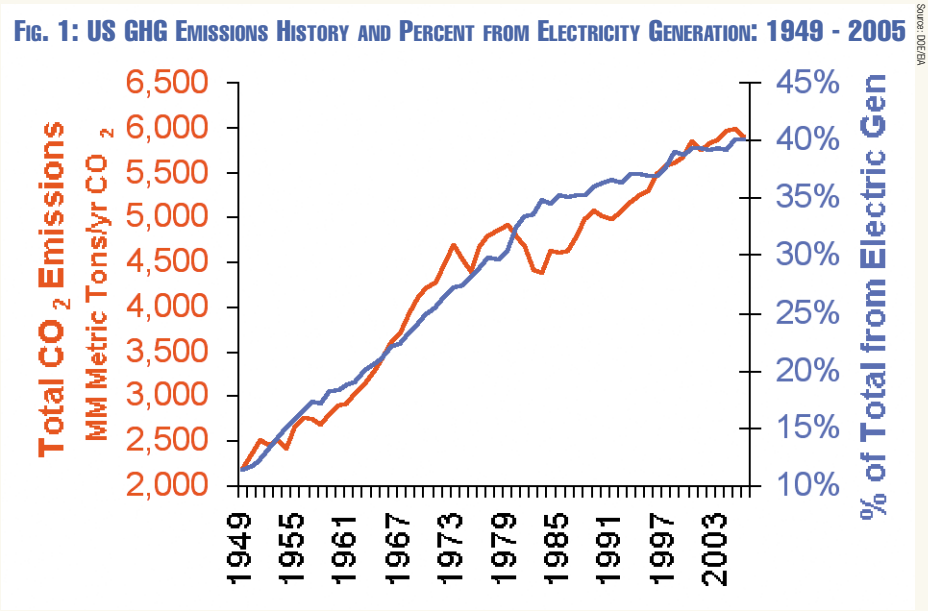
This regulatory flaw is the elephant in the room. Fix the regulation, and good things will happen. But until that is done, one cannot assume that GHG mitigation is incompatible with economic growth.

The conventional wisdom that "coal is cheap" is at odds with reality.

The Coal Truth

Coal is a cheap fuel. Relative to natural gas, oil and even biomass, coal remains quite cheap, even after 200% price increases in spot coal since 1999. But who cares? An iPod can't be run with coal. And *(Cont. on p. 7)*

Fig. 1: US GHG Emissions History and Percent from Electricity Generation: 1949 - 2005



Source: DOE/EIA

FORTNIGHTLY'S SPARK

Public Utilities Reports, Inc.
8229 Boone Blvd., Suite 400
Vienna, VA 22182
Phone: 703–847–7720
800–368–5001
Fax: 703–847–0683
http://www.pur.com

Bruce Radford, Publisher
radford@pur.com
Lori A. Burkhart, Editor
lab@pur.com
Horia Stefanescu, Designer
ahstephen@pur.com

E-mailed to all *Fortnightly* subscribers.
Call: 800–368–5001

For e–mail address changes or other information, contact jcole@pur.com or 800–368–5001.

MEMO TO THE CEO

Increasing the Perceived Value of Our Service

TO: BILL BIGWIG, CEO, LOCAL UTILITY POWER & LIGHT CORP. (LUP&L)

FROM: SAM SOUNDBITE, VP, CORPORATE COMMUNICATIONS, LUP&L

Bill, I know you spend a lot of time with the financial community, which is keenly interested in our P/E ratio—the ratio of our stock price to our earnings. In my group, we spend a lot of time working on a less commonly known but no less important ratio—our P/V ratio, that is, our price/value ratio, or the amount of value our customers say they receive for the amount of money they send us each month.

Our customers give us a below-average P/V ratio—they know they are paying us more money each month, but feel they are receiving less and less value from us. We know that our most recent price increase widened that gap between our price and our value, and the near-annual price increases we are planning over the next 10 years likely will widen it even further.

Our P/V ratio is a qualitative reflection of our standing with our customers and other stakeholders. Ultimately, our P/V ratio will affect our P/E ratio, for better or worse. There are a number of ways we could improve our P/V ratio, which should bolster our P/E ratio as well. Increasing the value we provide to customers can head off negative events at the PUC and among our employees and investors.

But we can't increase the perceived value of our service just by rolling out a new set of ads or launching a new communications campaign that is all "spin" but no substance. We need to start by asking ourselves harder, more basic, strategic questions about our vision, mission, and goals, such as: Why are we in business? What is our purpose? What unique role do we fill? How could we provide greater value to customers?

Yes, I know—it sounds like a full employment act for consultants. And yes, I've had more than my fair share of those guys! And no, I'm definitely not proposing we put all of our various operations and projects on "hold" so we can spend a lot of time sitting in rooms trading platitudes.

We can do a lot of the heavy lifting ourselves, without the help of high-priced consultants. And the good news is our employees want to do that heavy lifting. Our price increases have demoralized them; they're tired of being unable to answer their friends and neighbors who ask, "What? Another price increase?" Our employees want to restore our good name in the community. They want to feel good about working for LUP&L, the way they used to.

Having a robust internal conversation about our vision, mission, and goals is the first step forward. Other utilities that have had these internal conversations are the ones with higher P/V scores, fewer problems with customers, more engaged employees, and less-troubled relations with their regulators. Knowing what they are about and why they exist has helped guide these utilities' efforts to achieve better alignment with their various stakeholder groups. That alignment makes a variety of other good things possible.

Once those critical internal discussions are under way, we can move to the issue of whether we should change our approach to communicating with our customers about our price increases. All utilities face the same sets of problems: large construction programs, soaring fuel and capital costs, new environmental regulations, and an aging workforce. Yet some utilities clearly are doing a better job than others in managing these issues without damaging their customer satisfaction scores.

Our Problem

We can't get out of our predicament just by making some tactical changes to our communications. Periodically, we do need to make tactical adjustments to our communications, but we face deeper problems. Here's what our market research tells us:

- customers don't trust us the way they once did;
- customers no longer see us as a positive force in the local community;
- customers are not hearing (or believing) our messages;
- customers don't understand why we're trying to raise prices when our stock price is so high and we've reported record earnings; and
- customers feel it is unfair for LUP&L executives (including you and me) to get big bonuses when we are reducing staff, unemployment is rising, and the local economy is in recession. »

As we have discussed, our continued ability to run our business more or less as we see fit depends on the support, or at least acquiescence, of customers, communities, elected officials, and employees. Regulators won't get deeply involved in our business if we don't give them a reason to get deeply involved. Regulators are getting very antsy these days; some have tried to impose "command and control" decisions on utilities that sharply limit operational flexibility.

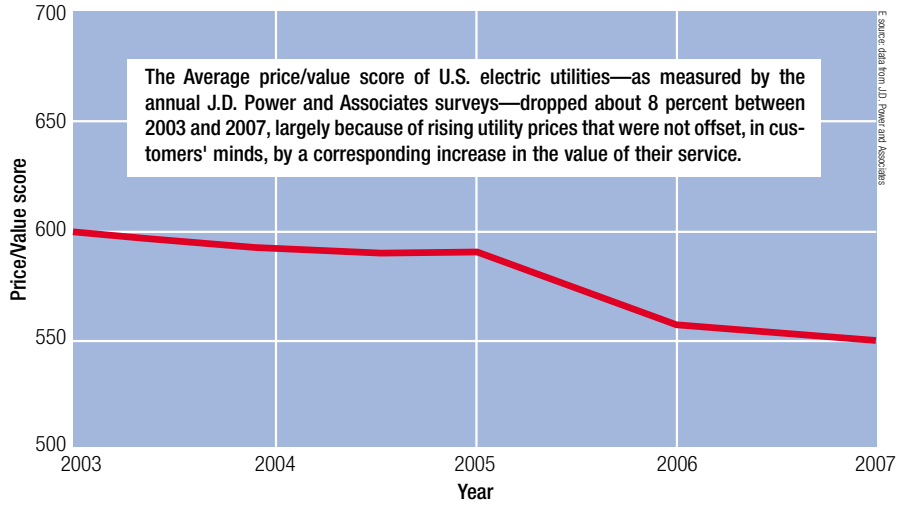
Every time we go in for a rate case, we give regulators and our distracters an opportunity to take potshots at us. Every person who shows up at a PUC hearing should be seen as a potential threat to our organizational independence. LUP&L needs to keep as many people as possible out of that PUC hearing room. We can do that by increasing the value we provide to our customers.

We need to care about what our customers and communities think about us. Everyone understands this is true for investors, but less well recognized is how the views of other stakeholders affect our business. Look what happened in Texas when TXU announced plans to build a dozen new coal-fired power plants, ignoring public opinion and the views of local elected officials. That public-relations flap knocked several billion dollars off TXU's market capitalization. In Missouri, Aquila bought endless grief upon itself when it decided to build a power plant without engaging the public or its regulators in a discussion about whether it was needed and where it should be sited. In recent years, several IOUs have had to defend parts of their service area from threats of municipalization that were driven by years of high rates, low reliability, poor service, or customer conflict.

It is noteworthy that U.S. residential utility customers in general perceive a steady decline in the value of service provided by their electric utilities over the last five years (*see Fig. 1, below*). This is a harbinger of future trouble. The industry's declining P/V scores are mostly the result of repeated price increases that have not been offset, in the customer's mind, by increases to the value of electric utility service. Unfortunately, our P/V scores have declined along with the industry average.

Despite this generalized industry downturn on Price/Value perceptions, a select few utilities have actually increased their P/V scores in recent years. What's their secret? In general, they have had an open and ongoing conversation with their customers, captured with market research, which kept the utilities informed about the dynamic needs and expectations of their customers. And then those utilities developed, delivered, and positioned programs, products, and services that responded to those needs. It's not magic, nor is it a coincidence.

FIG. 1 U.S. ELECTRIC UTILITY AVERAGE "PRICE/VALUE" SCORES DROP STEADILY



Our Solution

We need to work harder to show our customers that we are providing them with greater value. We need to make "value" a rallying cry for the entire organization. Utilities that successfully have positioned themselves as their customer's trusted energy advisor have been able to offset the negative effects of price increases. Our customers and communities, by contrast, don't see us as a partner or trusted advisor. At best we are seen as a large, far-removed, faceless institution, rather like the U.S. Postal Service.

Next year, when we expect to file another rate case, I'd like your support to change some of the ways we have been communicating with customers. It's pretty clear that our last price increase communication campaign was a mixed success: We scored a few victories and dodged a few bullets, but on the whole we could have done better.

Here's how I'd like to revamp our »

approach to communications in advance of next year's rate case:

- Increase our market research and message-testing efforts. Some utilities have found that customers don't object as much to price increases if they can be tied to things they care about, like improving reliability or reducing our impact on the environment.
- More consistently use everyday terms that customers understand, like "prices," and stop distinguishing between "base rates" and "fuel costs" in our external communications.
- Develop a new message to show customers that we are good stewards of their money. We have tried to convey that with the phrase, "We haven't raised rates since 1992," but that message doesn't resonate. We also will stop comparing changes in our prices over time to changes in the Consumer Price Index, or the price of select consumer goods like gasoline, tomatoes, and movie tickets. That doesn't resonate with customers either.
- Focus our communications on ways customers can lower their monthly energy bills and steps they can take to offset our planned price increases. Customers want to be empowered.
- Feature more people and more art in our ads; scale back the amount of copy and detail.
- Emphasize the non-price features of our service, like bill-payment options, energy-efficiency programs, demand-response pilots, pricing options, CFL discounts, customer assistance programs, renewable power, and our employee volunteerism.
- Begin our communications campaign earlier. In fact, given our capital construction plans we should be talking to customers on a monthly basis about ways they could use energy more efficiently and lower their bills.
- Focus our messaging: Let's pick one horse and ride it. I think "value" should be our rallying cry, but we need to hear that from customers.
- More effectively use our Speaker's Bureau and our employees' social networks to communicate with the community.
- Make our customer programs more readily visible on our website. Conduct usability testing with our customers before we go public with any web site redesign.
- Improve the quality of our energy information graphics and calculators translating the kWh and therm consumption of various household appliances into dollars and cents. We need to speak to customers in language they understand. I recommend we model our efforts on what Ameren has done with its interactive energy house graphic: *http://www.ameren.com/Residential/ADC_EnergyHouse.asp*

I know we don't get a "do over" for the decisions leading up to our last communications campaign. In retrospect I think we let our internal concerns about factual accuracy, context, costs, or our own preferences override what our customers expect from us, or in some cases are telling us directly.

As part of your executive team, I share responsibility for those past decisions. But our capital program is such that we will be raising prices on a near-annual basis for the next 10 years. Implementing the changes I recommend should allow us to maintain our customer satisfaction scores, position us more favorably with our major stakeholders, and potentially head off future problems at the PUC. It's a comparatively small investment in strategic risk management. I hope you and the Board agree. ■

John Egan is a research director at E SOURCE, an independent utility-industry research firm based in Boulder, Colorado. This article is based on E SOURCE's work with utilities on how to more effectively communicate price increases. John can be reached at 303-345-9110 or john_egan@esource.

UTILITY BILLING COSTS

Improving the Odds and the Bottom Line

By Harry Stephens

In May, utility business mailers were hit by yet another increase in postal costs. At a time when utilities are trying to lower operating costs while still meeting consumer demand, there are continual challenges arising from annual print mail rate increases. Even though there has been some relief with the Postal Reform, which mandates the United States Postal Service (USPS) replace the previous and somewhat erratic system of setting rates for business mailers with something more predictable, utilities still are facing higher and unexpected postage costs.

Based on the new law enacted in December 2006, the CPI Rate Cap is 2.9 percent. For all classes of mail the average rate increase is not supposed to exceed this percentage. On May 12 of this year, the single-piece stamp rate rose from to 41 to 42 cents, setting prices up 2.44 percent, which is .46 percent under the CPI Cap. However, for business mailers who provide the largest volume of automated bar-coded three- and five-digit mail, the rates will increase by 3.59 and 3.85 percent—which is .69 percent and .95 percent more than the CPI. This turns a "minor" rate increase to a major one for utilities.

The fact is that for utilities mailing high volumes of bills, the financial impact will be significant, making it critical to explore and use every avenue possible to offset these costs. Here are some immediate actions a business can take:

- **Follow USPS pre-sort rules:** Properly preparing and pre-sorting mail will earn significant USPS discounts. Leverage these discounts aggressively by making sure mail is segmented to reach the critical volumes per zip code needed to qualify for the highest discount rates. To qualify for these rates a delivery point barcode must be printed on each mail piece and the mail commingled for concentrated volume to geographical areas.
- **Verify addresses:** Nearly one-fourth of all mail that goes through the USPS contains some simple error such as misspelled street names and improper abbreviations, which can result in significant postage cost increases. If a mail piece cannot be delivered (*e.g.*, "undeliverable-as-addressed" or UAA), the cost to correct the piece can be up to 70 cents. A number of tools in the marketplace are designed to identify undeliverable addresses and link old addresses to new move addresses, including Coding Accuracy Support System (CASS) software to validate, correct, and standardize addresses. If CASS does not recognize a mail piece, it will not qualify for presort discounts and will instead be mailed at full rate (42 cents instead of the approximate automated discount rate of 33 cents).
- **Double-check those addresses:** According to the USPS, there are 145 million confirmed mail delivery points in the United States today. "Cycle L," which began on August 1, 2007, requires mailing lists to be run through DPV (Delivery Point Verification) processing. DPV takes the CASS™ system one step further by comparing the utility's mailing list to the USPS's own list of known addresses and verifying whether or not a CASS™-certified Zip+4 address is one of these confirmed delivery points. For example, a Zip+4 Code might cover an area with addresses from 100 Main Street to 300 Main Street. Typically, addresses would run 100 Main Street, 102 Main Street, 104 Main Street, and so on. However, if 104 Main Street is an empty lot, this is not a valid delivery point and DPV would mark it "N" for "invalid"—and a First-Class rate then would apply. DPV confirms all primary number addresses, so addresses missing a secondary number—like a suite or apartment number—remain acceptable, along with addresses that have a secondary number that hasn't yet been confirmed by the USPS. While DPV can't correct an invalid address, by identifying these addresses it can be eliminated.
- **Keep mailings letter-size:** Automation is key for achieving postal savings. While First Class Mail letters containing odd-shaped items are mailable, they will be charged the "non-machinable surcharge"—$0.055 for pieces mailed at presorted and automation rates—in addition to postage if they weigh one ounce or less. What's more, »

the non-machinable surcharge also will apply to flat and parcel mail weighing one ounce or less. Converting flat mail to folded will help save money.

■ **Explore electronic options:** Electronic-bill presentment is another way to sidestep the postal rate increases. Though reports by the USPS show that more than 70 percent of people still prefer to receive their statements through the mail, converting just 10 to 20 percent of existing customers to electronic-bill receipt corresponds to a significant cost savings and is worth the effort.

Opportunity to Improve

Over the last few years, the cost of postage has been rising gradually and this trend shows no sign of slowing. While no one likes to see a rate increase at any time, the silver lining may be an increased focus on print/mail production within the utility company and better efficiencies within the USPS. By keeping current with changing regulations and available technology that supports them, utilities can take advantage of savings that go straight to the bottom line. ■

Harry Stephens is President/CEO, and founder of DATAMATX, one of the nation's largest privately held, full-service providers of printed and electronic billing solutions. For more information about DATAMATX, visit www.datamatx.com.

Beyond Coal

(Cont. from p. 2)

if it was only the variable costs of fuel that mattered, the nation would be full of solar and wind-powered generation, which have zero fuel cost. The economic number that matters is not the price of fuel, but the delivered cost of electricity, including fuel cost, capital recovery, pollution-control costs, maintenance expense, transmission and distribution capital recovery and line losses.

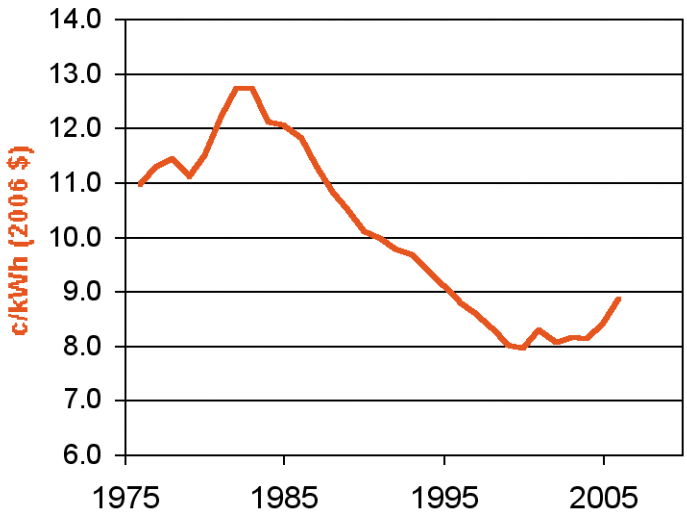
So look at how investors — who have good reasons to factor all capital and operating costs into their calculus — have allocated their capital amongst generation technologies.

From a generation perspective, the U.S. power grid has only four significant fuel sources: hydro, nuclear, coal and natural gas. Of the four, hydro has the lowest marginal costs and runs whenever the water flows. However, the U.S. hasn't built any hydropower of any significance in 50 years, largely because the biggest potential sources already have been tapped.[2] As a result, even while the total generation from hydropower stays relatively consistent from year to year at 200 – 300 billion kWh, it has become an ever smaller percent of the U.S. total mix due to load growth, from 32% in 1949 to just 6% today.

Nuclear has the next cheapest variable costs, but has the highest capital costs. As such, it has only been built when governments have agreed to subsidize plant capital cost and insurance risks. However, with variable costs in the range of 1 cent/kWh, nuclear plants tend to run as often as they can once they are built.

Coal historically has been next on the marginal price curve, at 2 – 4 cents per kWh marginal operating costs at the generator buss bar, followed »

Fig. 2: U.S. Average Retail Electric Price (2006 $)



Source: DOE/EIA

by natural gas at 6 – 8 cents/kWh (at current fuel prices).

This "dispatch order" explains how marginal electric pricing works, but says nothing about the investment thesis for any given generation technology. After all, no investor wants to build a power plant that only earns marginal pricing. The resulting total cost inference comes from looking at which technologies were built in response to variable electric prices. Given the long time horizon for power-plant investment and operation, start by looking back over the past 30 years, going back to the beginning of the OPEC energy price run-up in the late 1970s.

The increase in electricity price in the late 1970s was based in large part on a global increase in all energy costs as a result of OPEC price shocks (*see Figure* 2). But what accounts for the current increase?

First, recall that that United States can't build the really cheap stuff (hydro) anymore — which means that everything we have built since then has tended to increase the average price of electricity. However, the cessation of hydro investments occurred decades ago — far too long to explain the 2000 price inversion.

Things get a bit more interesting by examining the nuclear fleet. The United States has not added any new nuclear capacity since 1990. (While the 1979 accident at Three Mile Island turned public opinion against new nuclear plants, those plants that already were "in the pipeline" were built over the subsequent decade.)

At first glance, the slowdown in nuclear plant construction doesn't appear to explain the 2000 up tick in power costs. But a generator doesn't have any impact on power prices unless it runs. Thus, it is not only the capacity of the generator that matters, but also the number of hours the generator operates (*see Figure 3*).

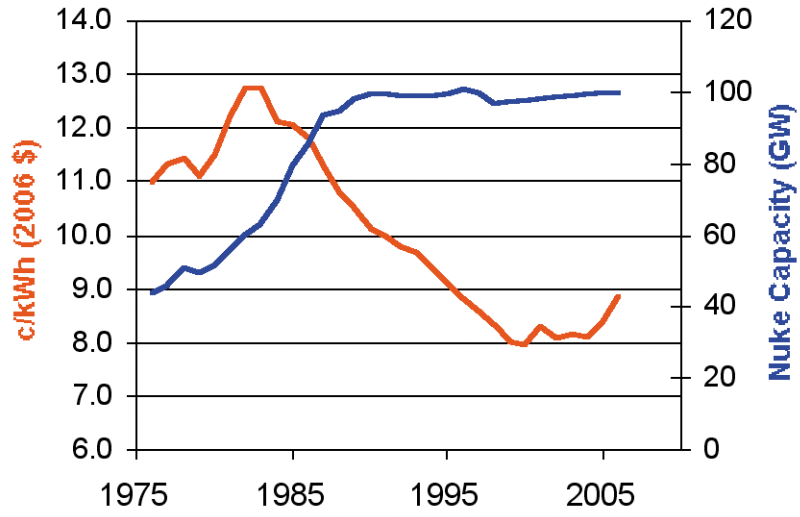
But look at the nuclear fleet's capacity factor over the same period, calculated as the number of GWh generated from the entire fleet relative to the maximum it could have generated if it ran at full rated power output for 24 hours/day, 365 days/year.

A cause for the recent price increases now comes into focus. While the United States stopped building new nuclear capacity in 1990, the fleet had a lot of "spare" room, running at only 60% of its potential. But by 2003, the nuclear fleet capacity factor had saturated at 90%, about as high as it can go given maintenance constraints.[4] As the nuclear fleet capacity factor leveled off, power prices rise; after all, with no more increases of marginal nuclear generation available, load growth had to be served by higher-priced alternatives.

Now, shift the focus to coal. The coal fleet also sees a leveling off of generation additions in about 1990, just about concurrent with the curtailment of new nuclear capacity additions.

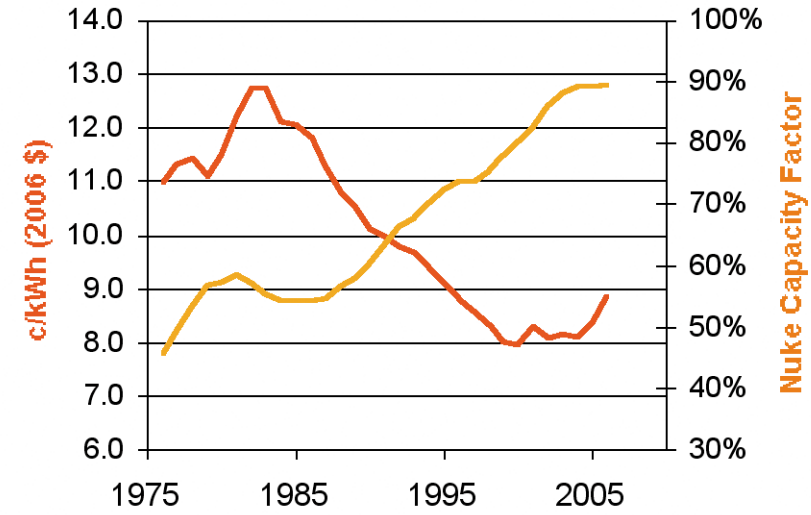
Like the nuclear slow-down, the causes of the coal slowdown »

Fig. 3: U.S. Retail Electric Rate History and Nuclear Capacity History



Source: DOE/EIA/Recycled Energy Development, LLC

Fig. 4: U.S. Retail Electric Rate History and Nuclear Capacity Factor History[3]



Source: DOE/EIA/Recycled Energy Development, LLC

are — in hindsight — understandable. The 1976 Clean Air Act (CAA) dramatically raised the cost of new coal plants, but grandfathered the existing coal plants out of compliance obligations. This essentially eliminated the economic logic for new coal plant construction — and explains the absence of coal fleet growth over the past two decades.[5]

And what about coal plant capacity factor? Today's fleet has a 72% capacity factor, suggesting that it still has room to grow. This figure is deceptive though. In many regions of the country, the total generation capacity represented by the combined nuclear, hydro and coal fleets exceeds the off-peak demand. As the most expensive of these three sources, central coal plants are the first source curtailed during low demand periods, and it is thus not possible to run the coal fleet at the capacity factors seen in the nuclear industry until the base power demand grows. Thus, the relevant question for coal is how the total fleet MWh output has grown relative to the growth in overall retail electricity purchases.[6] (*See Figure 6.*)

Note that since 1990, coal growth relative to retail sales growth essentially has been zero. In other words, the coal fleet is already running as hard as it can, subject to the limits of demand. As demand has risen, the coal fleet has been able to increase its capacity factor to keep up, but it has essentially been a non-factor in the provision of peak loads since 1990. In other words, since the nuclear fleet capacity factor saturated in 2003, peak load has had to come from sources other than old hydro, old nuclear and old coal.

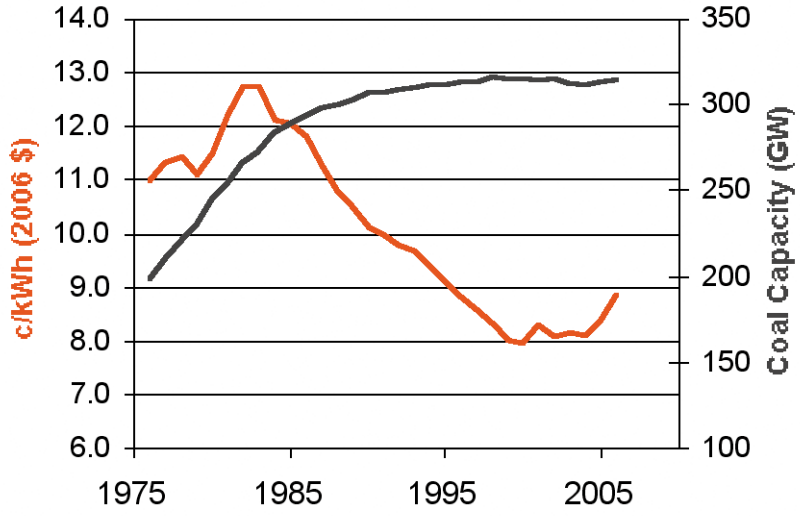
That creates a question: If coal is cheap, why isn't anyone building coal plants? And more broadly, if nuclear, coal, and hydro are not being built… what is being built?

That brings us to natural gas.

Unlike nuclear and coal, natural gas is a relatively low-risk fuel from an environmental perspective: Clean Air Act compliance is (comparatively) minor, and the siting challenges are orders of magnitude lower than either nuclear or coal-based assets. In addition, the cessation of nuclear and coal construction in 1990 was followed shortly thereafter by the 1992 Energy Policy Act and FERC Order 888 which — for the first time — allowed private capital to meaningfully participate in wholesale power markets. This combination of environmental considerations and market liberalization persuaded many independent power producers to invest in new natural gas plants. The power industry added nearly 200 GW of natural gas-fired capacity in just five years — starting in the late 1990s — a growth rate that was unprecedented in the history of the U.S. electricity industry, for any fuel type.

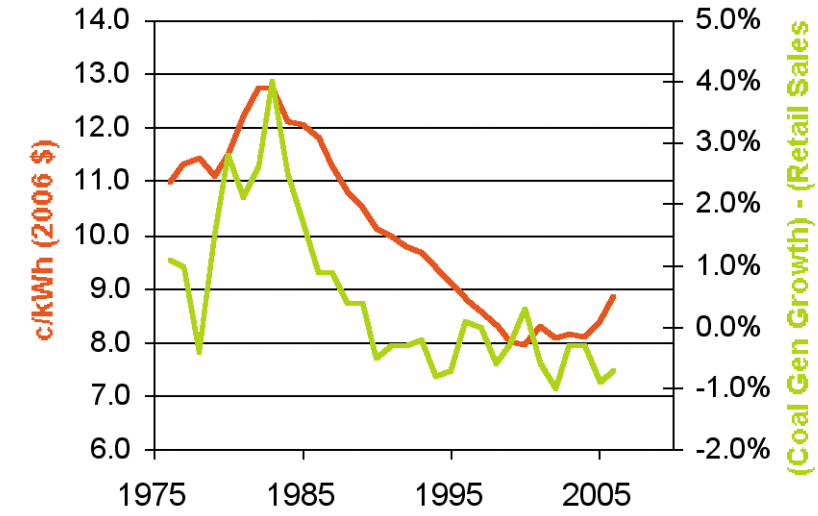
Note that even before the 1992 wholesale market liberalization, the gas fleet was growing, albeit more slowly. However, the rate of gas fleet growth »

Fig. 5: U.S. Retail Electric Rate History and Coal Capacity History



Source: DOE/EIA/Recycled Energy Development, LLC

Fig. 6: U.S. Retail Electric Rate History and Coal MWh Growth Relative to Load[7]



Source: DOE/EIA/Recycled Energy Development, LLC

slowed dramatically in the wake of rising fuel costs at the beginning of this decade.

The impact of rising natural gas costs on the investment thesis for natural gas-fired generation is readily apparent. (*See Figure 7*). As higher costs forced these plants to curtail production, equity investors lost their appetite for new gas plant construction (among other things).

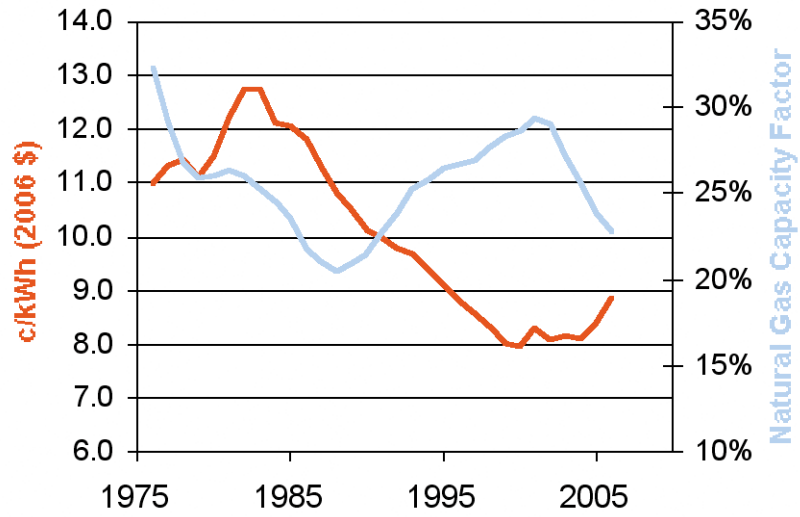
And thus the United States experienced a wave of bankruptcies in the merchant-power industry: Equity capital that was deployed in anticipation of 30% utilization simply evaporated. The largest publicly-traded IPPs lost over $200 billion of shareholder value between June 2000 and the end of 2001. This lesson is not lost on today's would-be coal plant investors as they try to figure out whether their investments also will be driven down to run at their marginal generation costs and sacrifice capital recovery.

And so the retail electric price increases that began in 2000 were the result of the cessation of nuclear and coal plant construction ten years earlier (and due to causes that occurred 10 – 15 years prior), coupled with an increase in natural gas price. This more or less comports with conventional wisdom.

But now we return to the main question. If coal is so cheap, why have investors exclusively invested in natural gas plants? Even after the spike in gas prices and collapse in capacity factor, gas-fired plants remain the only technology that is still increasing generating capacity. Moreover, natural gas-fired generation has comprised more than 100%[8] of all our capacity additions since 1996 (*see Figure 8*). This would imply that no one thought it was a good idea to build coal-fired plants prior to the recent increase in electricity costs — which is hardly consistent with the thesis that coal is inherently cheap.

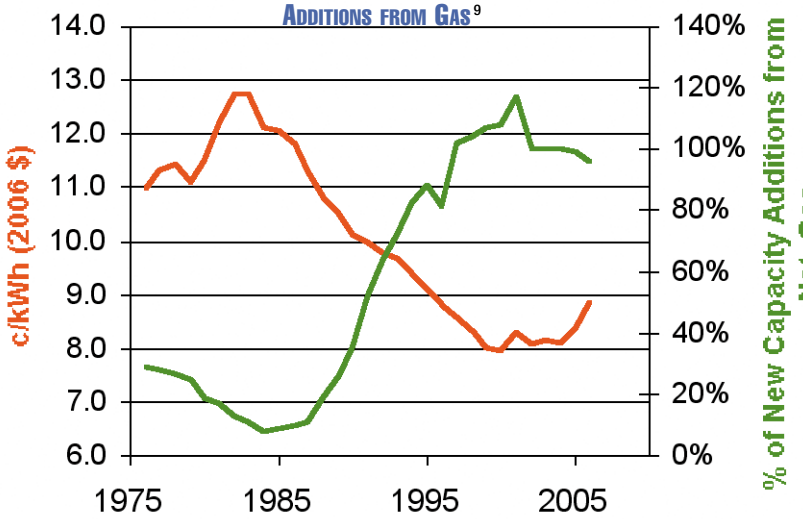
That's because coal isn't cheap. Clearly, the fuel is cheap — and if society is willing to tolerate pre-Clean Air

Figure 7: U.S. Retail Electric Rate History and Natural Gas Capacity Factor History



Source: DOE/EIA/Rockyard Energy Development, LLC

Fig. 8: U.S. Retail Electric Price History and Percent of Total Capacity Additions from Gas[9]



Source: DOE/EIA/Rockyard Energy Development, LLC

Act levels of SOx, NOx, particulate and mercury emissions, a relatively cheap coal plant can be built. But society will no longer tolerate dirty coal — and investors will not tolerate an investment that doesn't pay off its equity. Taken together, this has made central-station coal a lousy investment.

Consider these recent estimates of the capital costs for modern coal-fired power plants, remembering that old dirty coal plants cost about $800 to $1,000 per kilowatt of capacity to construct:

- "…well north of $2,500 per kilowatt for supercritical coal plants…"[10]
- "Duke said it would cost $1.83 billion [for an 800 MW power plant in North Carolina]."[11] ($2,300/kW)
- "GE… company executives Monday gave figures… of $2,000 to $3,000 [per kilowatt for new coal-fired power plants]."[12]
- "Indiana utility regulators approved Duke Energy's proposed $2 billion coal-fired… 630-MW »

power plant."[13] ($3,174/kW)

- "West Virginia regulators have approved American Electric Power's plan to build a $2.3 billion [629 MW] clean coal plant"[14] ($3,700/kW)

It is worth noting that none of the plants cited above include any provision for CO_2 recovery or sequestration which — if FutureGen is any indication — would roughly double total capital costs and reduce net generation efficiency.[15] But even these "conventional" coal plants are averaging over $2,500/kW, and increasing dramatically with each subsequent commission-approved facility.

Even with no further increases in coal-plant construction costs, the economics stink. Consider a coal plant with a total installed cost of $2,500/kW and assume no cost overruns. At the low costs of capital that ratepayer-guarantees provide for regulated utilities, $2,500/kW and 70% capacity factor requires 5 cents/kWh *just to recover the capital costs associated with generation.*[16] Fuel and operating costs add 3 – 4 cents, and transmission and distribution add another 2 – 3 cents. Add it all together and one quickly concludes that the investment in these coal plants simply doesn't pencil below anticipated retail prices of 10 – 12 cents/kWh. Even after the recent run-up in electricity rates, this would represent a 17% increase in average retail electric prices — and even more in the coal-belt, where these plants would likely be built.

Here, then is the question facing prospective coal plant investors: Will you put billions of dollars at risk, in order to return below-market (*e.g.*, utility-level) returns in exchange for assuming the risk that (a) retail prices will spike and (b) you will never have to pay for greenhouse gas emissions?

Not surprisingly, no one is making that bet without first getting utility commissions or state legislatures to guarantee equity returns. Consequently, much of the "cheap coal" thesis is »

emanating from what are essentially public relations efforts directed at utility commissions and state legislators. But the PR cannot hide the fact that coal isn't cheap, or that no one is building coal without public guarantees.

Environmentally, this is good news — because if cheap coal doesn't exist, then there is no conflict between GHG mitigation and power from cheap coal. But — and here's the catch — while we have massive opportunities for clean and cheap power, our current regulatory model stands in direct opposition to deployment. The 200 GW of gas-fired generation deployed after the 1992 EPACT shows just how quickly the private sector can act once the regulatory shackles are removed — and that was in response to very modest reform, which applied only to wholesale power. Comparable reform today could unleash a comparable flood of low-cost, low-carbon generation. But we must first reform.

Better Options

Understanding our better options first requires that we confront one final piece of flawed conventional wisdom: That the U.S. energy industry optimally allocates capital. Per this conventional wisdom, there can be no better options than the current mix of power on the grid, because markets would have seen to it to allocate capital more efficiently if such options existed. Ergo, reducing fuel consumption must impose unacceptable costs, since otherwise the changes would have already been made.

This conventional wisdom is refuted by fuel efficiency history. Fuel is the single biggest variable cost associated with power generation. Why did the industry shift capital allocation to electric-only plants that could not recycle byproduct thermal energy to displace boiler fuel? Why did industry double its fuel consumption per kilowatt-hour of delivered electricity over the last century? The answer, at its core, is that the power industry does not allocate capital efficiently. This is not to say that the industry does not behave rationally with its capital: Rather, it is responding rationally to regulation-enforced incentives for inefficient capital allocation.

So what to do? The political appetite for full deregulation of the electricity industry remains weak — but the need to mitigate climate »

change and lower energy costs grows more urgent by the day.

Fortunately, within past failures lie the seeds of economically and environmentally beneficial reform. After all, the sign-error that is innate to the present GHG conversation means that carbon can be lowered while simultaneously spurring economic growth. Addressing the flaws of the present regulatory model will allow the accessing of a huge volume of low-hanging fruit. Just as the Soviet bread-regulation model did not facilitate the creation of vibrant boulangeries, the current U.S. system does not encourage cheap, clean power. Thus, the failure to deploy cheaper power must be understood as a failure of the system, not as the economic impossibility of a decent bakery.

Consider: According to the U.S. Department of Energy, there are 135,000 megawatts of feasible cogeneration projects that could be deployed in the U.S., all of which would be at least twice as efficient as the U.S. average.[17] An EPA study identified a further 65,000 megawatts of electric-generation capacity that would recycle industrial waste energy (exhaust heat, flare gas, pressure drop, *etc.*) and burn no incremental fossil fuel.[18] In aggregate, this 200 GW of power could provide 40% of U.S. electricity needs and reduce total U.S. greenhouse gas emissions by 20%.[19] It would also generate attractive returns on equity even while lowering power costs and GHG emissions.

So why aren't they being built? As noted previously, there is no incentive for a regulated utility to build cheap generation. And even if there were, regulated utilities simply don't have the skills. The 200-GW opportunity identified above requires very close integration with industrial hosts in design, contracting, construction and operation. This integration is necessary to procure waste energy from those facilities and/or to provide thermal energy to same. But it also introduces a set of design and operational dependencies (not to mention a suite of thermal and industrial engineering skills) that are not native to electric utilities, which are best at building and dispatching big, power-only assets.

And it is therefore again appropriate to revisit the Soviet bread example. The same challenges that face the deployment of cheap, clean power in the United States today faced a developer who wanted to put an Au Bon Pain in Moscow in 1985. The problem is the paradigm. As the U.S. begins to enter a build-cycle in the power fleet, it is urgently important to modernize our regulatory model so that generation will be brought on line based on least-cost considerations — as opposed to the "least cost within the present paradigm" model that currently prevails. Failure to modernize compels us to build expensive central coal or expensive central gas, which will be disastrous for both the economy and the environment.

Conclusions

The United States is about to enter an unprecedented era of energy price increases, as a flock of thirty year old chickens — from Three Mile Island to the Clean Air Act— come home to roost. The U.S. experienced price increases of a similar scale after the OPEC supply disruptions in the late 1970s, and has direct experience with the massive economic dislocation that can result. But as bad as those price shocks were, they were at least transitory. The coming price shocks are driven by structural shifts in the global economy and environment that will not be so easily reversed.

However, unlike the OPEC shocks of the 1970s, these can be seen coming, and we can plan accordingly. Moreover, the challenges soon to be faced have, at their core, a single, and largely fixable cause: An outdated electricity regulatory model. This model can be fixed, but only if we are willing to confront the *status quo* and take off the blinders »

Next Month's FORTNIGHTLY

The June issue of *Fortnightly* magazine takes a multi-faceted look at energy conservation and efficiencies, starting with the *CEO FORUM 2008: Conservation Compact*. As the industry is struggling to reconcile legacy business models with emerging green priorities, Editor-in-Chief Michael T. Burr interview CEOs at Green Mountain Power, Progress Energy, IDACORP, Pepco Holdings, and Reliant Energy. They explain their perspectives on financing investments in conservation and efficiency.

Here is more of what you will find:

Policies Get Smart

State and federal incentives provide the carrot for utilities to invest in grid intelligence. But regulatory and technological incentives are not enough without customer participation. Smart-grid policies will succeed only by focusing on customer needs and benefits.

PLUS: Revenue Decoupling in the States

SPECIAL REPORT: Demonstrating the Smart Grid

Pilot projects are bringing the future vision of the grid to life. Whether leveraging existing systems or rebuilding entire networks in a Big Bang rollout, new technology applications suggest an intuitive electrical network may not be far off.

The Politics of Carbon

The outcome of the 2008 elections will determine how the nation deals with greenhouse gas emissions. With the presumptive nominees for president for both parties supporting mandatory GHG regulation, a cap-and-trade system likely will become U.S. law. How soon and how tough depends on the choices voters will make in November.

imposed by a century of central electric system planning. And when that happens, the nation will play to its national strengths, deploying our prodigious creative and financial talents to address the greatest global problems of the day. We will lower GHG emissions. We will lower energy costs. We will create new industries and entrepreneurial success stories.

But first, the nation must get beyond the model of monopoly-only capital allocation. It must get beyond the false premise that economic growth is incompatible with greenhouse gas mitigation. It must get beyond coal. ■

Sean Casten is president and CEO of Recycled Energy Development, LLC. Contact him at: scasten@recycled-energy.com.

ENDNOTES

1 On March 7, 2008, Merrill Lynch announced it expects thermal coal prices to rise 200% by the end of the year (*Greenwire*, 3/7/08).

2 And of course, the public has lost its appetite for the environmental consequences of massive hydroelectric dams.

3 Capacity factors shown are calculated as 5-year trailing averages.

4 Nuclear fleet capacity factors before and after deregulation – and between presently regulated and presently restructured states – provide compelling evidence of the ways in which our current regulatory model prevents utilities from preferentially deploying their lowest cost generation options. For details, see Casten, Sean, "Deregulation, Phase II", *Public Utilities Fortnightly*, November 2007, pp 48 – 54.

5 This is not to suggest that pollution control is incompatible with low-cost generation – simply that CAA-compliance is incompatible with low-cost generation. Other regulatory approaches, like output-based standards that incentivize energy efficiency deliver equivalent or greater environmental benefit without the CAA's economic pain.

6 In truth, one would like to compare coal MWh growth to growth in the "troughs" of demand – *e.g.*, during winter nights, when electricity demand is at a minimum – but this is not readily available in the data, and we use total retail sales as a surrogate.

7 Coal growth data shown is as a 5-year trailing average.

8 This ratio is calculated as total year-on-year natural gas capacity additions, divided by total fleet capacity growth during the same period. Since both values also include capacity retirements, this ratio can sometimes exceed 100%.

9 Gas capacity values shown are a 5-year trailing average, comparing total natural-gas fired capacity additions in a given year to total capacity growth. In some years, this value exceeds 100% due to fleet retirements.

10 *Energy Biz Insider*, 7/6/07

11 *New York Times*, 7/10/07

12 Ibid.

13 *E&E News*, 11/27/07

14 *Greenwire*, 3/7/08

15 FutureGen is the (recently abandoned) plant slated for construction in Illinois that would have separated CO_2 from the exhaust to sequester underground. DOE estimated costs of $1.8 billion for this 275-MW plant, or $6,500/kW. (*Greenwire*, 11/12/07).

16 Calculated at 11%, 20-year level amortization.

17 Hedman, Bruce, *Combined Heat & Power and Heat Recovery as Energy Efficiency Options*, Briefing to Senate Renewable Energy Caucus, Sept. 10 2007; Energy and Environmental Analysis/USCHPA, Washington, D.C.. This work was done under contract to the U.S. DOE, in support of their goal to deploy 90 GW of CHP by 2010.

18 Bailey, Owen and Ernst Worrell, *Clean Energy Technologies: A Preliminary Inventory of the Potential for Electricity Generation*, Lawrence Berkeley National Laboratory (under contract to U.S. EPA under U.S. DOE contract number DE-AC02-05CH11231), April 2005. Note that this report identifies 96 GW of total potential, but some of this total includes fueled CHP applications that are redundant with the DOE-identified 135-GW total.

19 There is approximately 1000 GW of total generation in the U.S. today, but much of this base runs only during system peaks. The 200 GW of clean generation opportunity – by virtue of being so much cheaper than the rest of the grid – tends to run closer to baseload, as is the case for the existing 83 GW of already-installed assets. Thus, 20% of the total GW base can provide 40% of total GWh use.