Using Coal Gasification to Generate Electricity: A Multibillion-Dollar Failure

Kemper and Edwardsport: Painful Case Studies for Ratepayers and Investors Alike

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Executive Summary

Efforts to gasify coal for power generation have been major failures, technologically and financially.

Only two of the 25 coal-gasification electricity generating plants proposed in the U.S. since 2000 have ever come on line: Southern Company's Kemper plant in Mississippi and Duke Energy's Edwardsport plant in Indiana.

Both Kemper and Edwardsport have been economic disasters for consumers and investors alike.

Under pressure from the Mississippi Public Service Commission for having logged billions of dollars in cost overruns at Kemper, the Southern Company affiliate Mississippi Power announced in July 2017 that it will halt coal burning at Kemper. Henceforth the plant will run only on natural gas.

That leaves Edwardsport as the sole remaining plant built in the U.S. in the last decade burning gasified coal to produce power. It is the only modern plant built around "clean coal" gasification technology that continues to be promoted as a viable way to generate electricity but in fact is not.

Edwardsport has been plagued by technological problems, and four years after opening is still not running properly. Because of its operational problems and its huge construction cost overruns, Edwardsport's electricity is wildly expensive. Power from the plant costs more than five times what electricity sells for in wholesale energy markets in Indiana.

Some in the electric utility and coal industries continue to push for new coal-gasification projects, even though natural gas plants are much less expensive to build and are more reliable, and wind- and solar-generated electricity is cheaper.

The technology used in coal gasification plants—known as Integrated Gasification Combined Cycle (IGCC)—poses major risks to ratepayers and investors alike as the technology remains both unreliable and expensive.

Sources: Edwardsport costs from Duke Energy Indiana FERC Form 1 filings for the years 2013 through 2016. Market prices for MISO's Indiana Zone from SNL Financial.

A number of important and painful lessons have emerged from Kemper and Edwardsport:

- Modern IGCC plants are far more expensive to build than proponents have been willing to publicly acknowledge.
- Such plants take much longer to construct than proponents typically assert.
- IGCC plants are very expensive to operate.
- IGCC plants have proven unreliable due to problems with modern coal-gasification technology.
- The high costs of building and operating IGCC plants, and their unreliable operations, mean that the technology is not an economically feasible option for capturing and sequestering carbon dioxide emissions from coal plants.
- IGCC plants cannot compete with wholesale market power prices or with falling prices for wind- and solar-generated electricity.

In sum, Kemper and Edwardsport prove the high cost and unreliability of IGCC technology and serve as a stark warning against investing in such projects.

What Is Coal Gasification and Why Has It Been Promoted?

Traditional coal-fired power plants produce electricity by burning crushed coal in a boiler to produce steam. The steam then flows into a turbine-generator to generate electricity.

Coal gasification adds several steps to this straightforward, time-tested process. It still uses coal as its base fuel, but converts it—typically in one or two gasifiers—to create "syngas," a synthetic energy product that resembles natural gas. The syngas is then used to fuel a conventional combined cycle electricity generating power plant—a facility using gas-fired turbines to produce electricity *and* that captures the excess heat to power steam-driven turbines to produce additional electricity.
Such generating facilities are known as Integrated Gasification Combined Cycle (IGCC) plants.

IGCCs—which are often promoted as "clean coal" plants—are purportedly designed to reduce air pollution emissions while burning coal as the primary fuel. The origins of these plants stem from a time in which natural gas and renewables were not as abundant and cheap as they are today.
The concept of coal gasification is not new: Well over a century ago, coal was commonly converted into "town gas," a term for gaseous fuel produced from coal before the widespread use of natural gas. Town gas was sold to municipalities and

piped to customers for light, heating and cooking. Like coal-fired electricity generation, town gas production was a relatively simple process.

However, applying and implementing coal gasification in large electric power plants has proven to be technologically tricky and extremely expensive.
In the first decade of this century, more than 25 utility companies in the U.S., under pressure to reduce emissions and wanting at the time to continue to burn coal for fuel considered building new IGCC plants. (Natural gas and renewable energy prices were still comparatively high). In 2000, the U.S. had two small demonstration projects up and running, but there were no IGCC plants in operation anywhere in the world that were comparable in size to the proposed IGCC projects under consideration or that used the new technologies that were under consideration. All these projects carried a "first mover risk" as the first-of-their-kind commercial power plants.[1]

Many utilities and independent power plant developers around the U.S. (and two state regulatory commissions) rejected IGCC projects because the technology was untested and involved higher financial risk than conventional coal-fired power plants.

In June 2007, the Tondu Corp. in Houston announced that it was suspending plans to build a planned 600-megawatt (MW) IGCC facility in Texas, citing high costs and other issues related to technology and construction risks.[2] Similarly, Xcel Energy announced in October 2007 that it was deferring indefinitely its plans to build an IGCC plant in Colorado because the development costs were higher than the utility originally expected.[3]

At about the same time, the federal government pulled the plug on the marquee FutureGen project, an undertaking in which the U.S. Department of Energy had agreed to provide 74 percent of the funding, with private investors putting up the balance. This was to be a test project combining IGCC technology with carbon capture and sequestration (CCS). In early 2008, the Bush administration cancelled FutureGen, citing cost overruns. The proposal was revived under the Obama administration with the support of Congress. The U.S. Department of Energy cancelled it again in 2015 "in order to best protect taxpayer interests."[4]

Some state regulatory commissions also refused to make ratepayers bear the risks of new IGCC project. In August 2007, the Minnesota Public Utilities Commission rejected a contract under which Xcel Energy would have purchased power from a proposed

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1 Duke Energy Indiana claimed during construction that the Edwardsport IGCC project merely merged two mature technologies or represented the scaling-up of the technology used at the two existing demonstration projects in the U.S. This claim is analogous to saying that a new Boeing 747 did not represent a new airplane design in 1970 because the concepts of wind, lift and aircraft propulsion had been around since the Wright Brothers' first biplane flew at the turn of the 20th Century.

2 http://www.reuters.com/article/companyNewsAndPR/idUSN1526955320070615

3 "Xcel Delays IGCC Power Plant." Denver Business Journal, October 30, 2007, https://www.bizjournals.com/denver/stories/2007/10/29/daily26.html

4 http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead

IGCC facility in northern Minnesota. The commission cited uncertainties in construction and operating costs as well as operational and financial risks.[5]

In 2008, the Virginia State Corporation Commission refused to make the Virginia ratepayers of Appalachian Power Company (APCO) bear any of the costs of APCO's proposed IGCC plant, citing uncertainties on costs, technology and unknown federal mandates:

> "The record in this case indicates there is no proven track record for the development and implementation of large-scale IGCC generation plants like the one proposed by APCO. Evidence in this case also raises concerns whether large-scale IGCC generation plants are characterized by, among other things, (1) complexities attendant to a technology for which there is no proven track record for power plants of this size, (2) high initial capital costs compared to other coal-fired units, and (3) uncertainty surrounding performance and operating costs."[6]

The Virginia Commission found also that the project represented "an extraordinary risk that it could not allow the ratepayers of Virginia in APCO's service territory to assume." The commission said would not grant the "blank check" the company sought and concluded, "We cannot ask Virginia ratepayers to bear the enormous costs—and potentially huge costs" of the uncertainties associated with the IGCC project.[7]
Such skepticism was common across the utility industry, and is even greater today. For example, an article in Power Magazine in late 2006 noted that IGCC technology was unproven and "still in its infancy."[8]

A July 1, 2007, editorial "IGCC Sticker Shock" by the editor in chief of Power Magazine framed commonly held industry doubts:

> "Former Illinois Senator Everett Dirksen once observed, 'A billion here and a billion there, and pretty soon you're talking real money.' The same can be said about skyrocketing estimated costs of integrated gasification combined cycle (IGCC) plants as their designs are fleshed out. The higher price tags shouldn't be a surprise—the more you learn about the complexity of a project, the higher your guess about its cost will go…
> "It seems to me that ratepayers should not assume any additional cost, performance, or scheduling risks over those presented by other, less-expensive and more-mature generation technologies. In balancing those risks, regulators should give IGCC-enamored utilities the opportunity to earn a higher than usual return on their investment – after the project has proven successful.

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5 Minnesota Public Utility Commission Final Order in Case E-6472/GS-06-668, available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={B05A0CFF-E2FA-4D4D-9EE8-FE89D2ADCA48}&documentTitle=5520555
6 Virginia State Corporation Commission Final Order in Case No. PUE-2007-00068, April 14, 2008. Available at http://www.scc.virginia.gov/docketsearch/DOCS/1_xm01!.PDF
7 Ibid.
8 http://www.powermag.com/speaking-of-coal-power-igcc-sticker-shock/

> "Fair allocation of the incremental costs and rewards of IGCC should be the goal of every state public service commission, as its ratepayers' eyes and ears. At the end of the day, the shareholders who elected the management team to make wise technology decisions should pay the freight if those decisions go south. "Corporate management teams come and go, but a bad project lives forever."[9]

Plans for all but two of the more than 25 proposed IGCC plants in the U.S. were cancelled because of customer and/or investor risks associated with high costs related to technology and construction.
As noted, those two IGCC plants were Southern Company's Kemper Plant in Mississippi and Duke Energy Indiana's Edwardsport Project.

Southern Company / Mississippi Power's Kemper Plant: A $7.5 Billion Failure

When Southern Company subsidiary Mississippi Power first requested approval from the Mississippi Public Service Commission to build the Kemper plant, in late 2009, it put the project's cost at slightly below $2.9 billion, and said the 824MW-rated plant would be in full operation by May 2014. Kemper was supposed to burn lignite coal in its gasification process—one of the lowest-quality forms of coal—from the Red Hills Mine in Mississippi. The Sierra Club and the Public Service Commission's independent consultant warned that the cost of the project would be much higher than Southern Company estimating and that it would take much longer to build.[10] Nonetheless, the project was approved in early 2010.

Southern Company sought successfully to shift much of the project risk to ratepayers. While the company argued against having to bear such risks, it refused to agree to share any profits it stood to earn had the project succeeded and if it were able to sell the technology in other countries.[11]

The costs to build Kemper steadily increased as construction proceeded, as shown in Figure 1, below, and its scheduled commercial in-service date was repeatedly delayed. The "cost cap" in Figure 1 represents the cap adopted by the Mississippi Public Service Commission and was based on Southern Company's original cost estimate.

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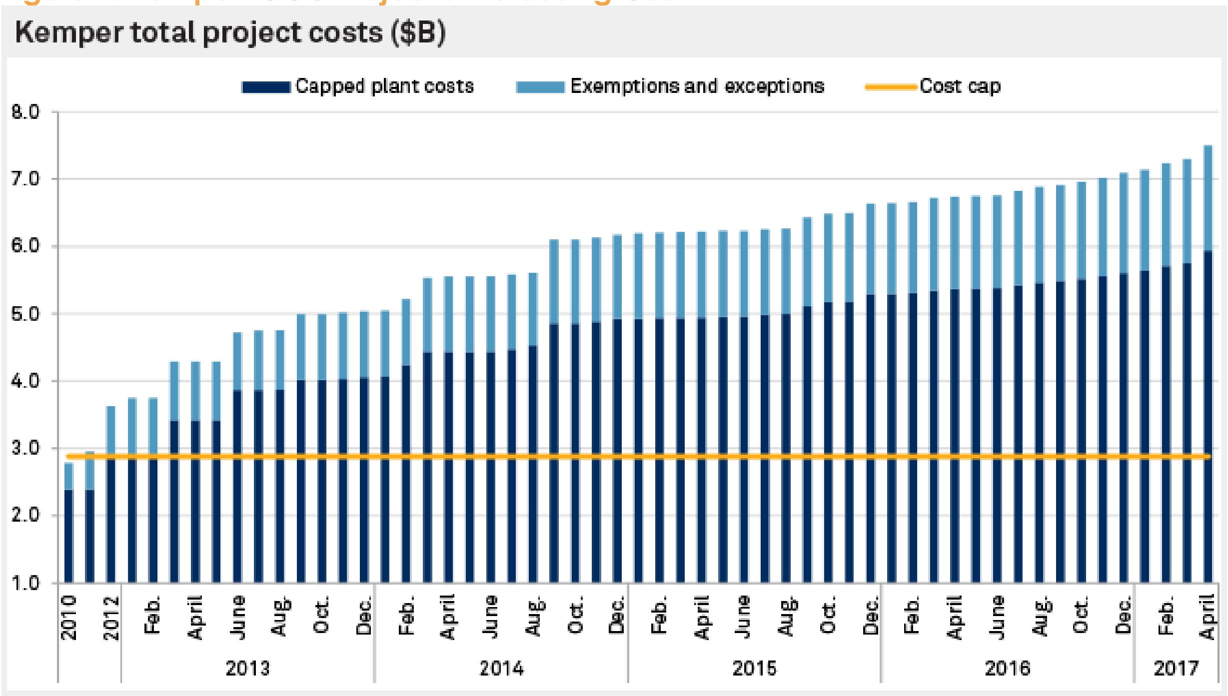
9 Ibid.
10 See the Direct Testimony of David A. Schlissel on Behalf of the Sierra Club in Mississippi Public Service Commission Docket No. 2009-UA-014, available at http://schlissel-technical.com/docs/testimony/testimony_21.pdf and *Kemper Update*, Mississippi Business Journal, February 2, 2010, http://msbusiness.com/2010/02/kemper-update-psc-resource-hearings-on-kemper-county-coal-plant/
11 Ibid.

Figure 1: Kemper IGCC Project's Increasing Cost[12]



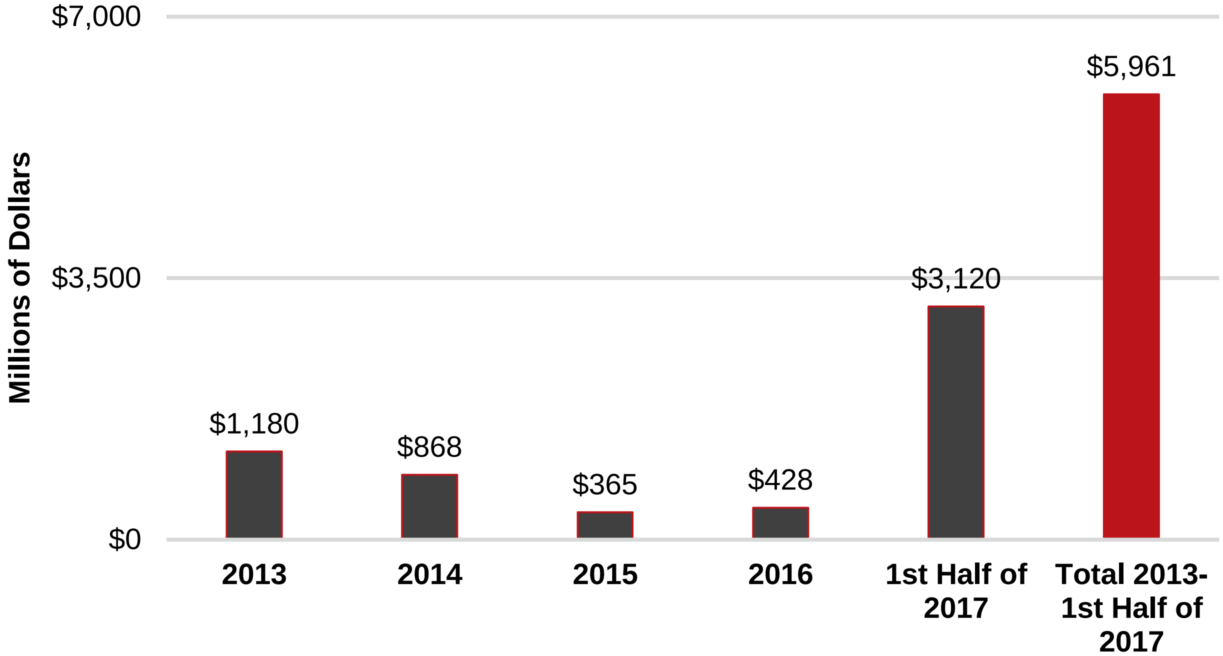
Data as of June 26, 2017.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Although Kemper began producing electricity in mid-2014 *as a conventional combined cycle power plant burning natural gas*, problems with the operation of its unproven gasification systems—which were to have come online that same year—led to further cost increases and schedule delays. By June 2017, Kemper's estimated cost had jumped to $7.5 billion, and construction and startup testing of its gasifiers was still incomplete.

As the cost of building Kemper has skyrocketed, Southern Company has taken nearly $6 billion in pre-tax charges for its estimated losses on the project.

[12] Source: SNL Financial, a unit of S&P Global Market Intelligence.

Figure 2: Southern Company's Estimated Losses on Kemper From 2013 to June 2017.[13]



As its construction costs rose, Mississippi Power's estimates for how much it would cost to operate the project as an IGCC plant for its first five years also jumped from its $205 million estimate in 2010 to $730 million, an increase of more than 250 percent. The total capital expenditures that Mississippi Power said would be needed during the plant's first five years of operations skyrocketed from $52 million to more than $270 million.[14]

In a late concession to market realities, Mississippi Power released a study in February 2017 that suggested that low natural gas prices and the true costs of operating Kemper meant that the plant was far more viable running just on natural gas.[15] This was essentially the same point made in a Sierra Club affidavit to the Mississippi Public Service Commission filed in early 2012.[16] As that affidavit noted, the very decline in natural gas prices that has undermined the viability of the Kemper IGCC project was foreseeable.

As a result of the rising costs and continuing problems with the gasification system at Kemper, the Mississippi Public Service Commission expressed its intention on June 21, 2017, to order that Southern Company, in the interest of ratepayers, cease burning coal

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13 Southern Company's Quarterly Earnings Reports and SEC Form 10-K filings for calendar years 2013, 2014, 2015, and 2016 and its SEC Form Q filing for the first half of 2017.
14 Direct Testimony of Bruce C. Harrington on behalf of Mississippi Power Company, Mississippi Public Service Commission Docket No. 2016-AD-0161, October 13, 2016.
15 http://mississippipowernews.com/2017/02/22/mississippi-power-issues-statement-regarding-kemper-county-energy-facility-progress-and-schedule-2/
16 Sierra Club "Motion for Status Conference Pending Remand," Mississippi Public Service Commission Docket No. 2009-UA-014, March 19, 2012.

at Kemper and use only natural gas to run the plant.[17] The commission also expressed its belief that Kemper's gasifier technology was not and will not become "used and useful" in serving Mississippi customers and that Kemper's gasification technology has not operated reliably and is not likely do so in the near future.

In response, Southern Company announced on June 28, 2017, that it would stop burning coal at the plant, and the commission finalized its directive in an order issued on July 6.[18] Consequently, Kemper is now operating what is undoubtedly the world's most expensive natural-gas fired power plant—and it will not burn syngas made from gasified coal. The only outstanding question is how much of the costs of the Kemper debacle will be borne by Mississippi Power customers.

Duke Energy's Edwardsport Plant: Unreliable Power at Five Times Market Prices

When Duke Energy Indiana asked the Indiana Utility Regulatory Commission (IURC) in October 2006 for approval to build an IGCC plant in Edwardsport, it estimated the project's construction cost at just under $2 billion. By the time the 618 MW-rated plant officially went online in June 2013, construction costs had ballooned to $3.5 billion—a number that did not include some $600 million Duke's Indiana customers were charged before June 2013.[19]

Since being declared operational in June 2013, Edwardsport has not operated reliably and has now cost Duke Energy Indiana customers over than $1 billion more than what they would have paid to buy the same amount of power from the competitive wholesale market.

There are many ways to measure a power plant's operational effectiveness, and Edwardsport performs poorly by all of them.

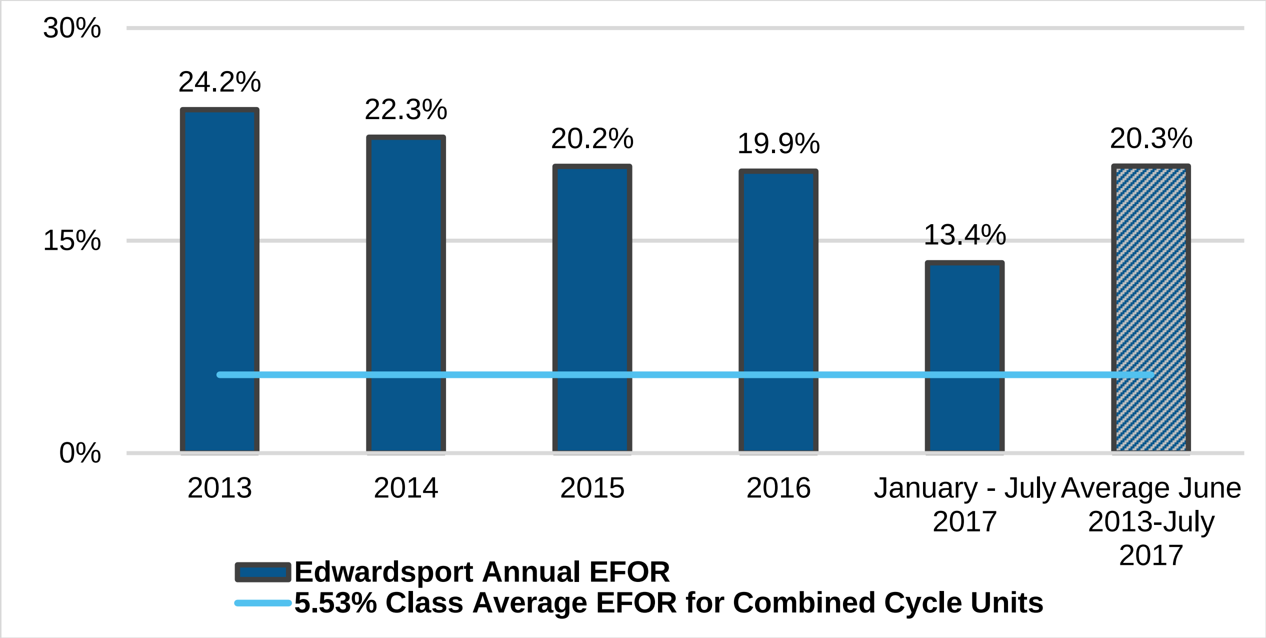
For example, a power plant's equivalent forced outage rate (EFOR) measures how much a plant is out of service as a result of unplanned outages or reductions in output ("derates"). The higher the EFOR, the worse a plant is performing. As shown below, Edwardsport's EFOR is more than 3.5 times higher than the typical combined cycle plant that burns natural gas—that is, a plant that does not include gasifiers/gasification technology.

[17] http://www.psc.state.ms.us/mpsc/press%20releases/2017/Joint%20Press%20Kemper%20Stipulation%20Docket%206.21.17.pdf

[18] http://www.southerncompany.com/newsroom/2017/june-2017/0628-kemper.html

[19] In addition, Duke Energy Indiana recorded pretax charges of approximately $897 million on its earnings through 2014 as a result of cost overruns at Edwardsport. See Duke Energy's SEC Form 10-K for the Year Ending December 31, 2014.

Figure 3: Edwardsport's Equivalent Forced Outage Rate (EFOR) vs. Industry Average[20]



Thus, Edwardsport was out of service for unplanned outages, on average, more than 3.5 times as often as a typical natural gas-fired combined cycle unit.
In addition to unplanned outages, Edwardsport has been shut down every year for extended planned maintenance and was off line for planned spring and fall maintenance in 2014, 2015, 2016 and 2017. Each of those outages led to at least one of Edwardsport's two gasifiers being out of service for days or weeks.

Another measure of a plant's operating performance is its heat rate which measures how efficiently the plant burns fuel. The higher the heat rate, the less efficiently the plant burns fuel. The lower the heat rate, the more efficient the plant is. In other words, the higher the plant's heat rate, the more fuel it must burn to generate the same amount of power. This makes the plant less economic for consumers and less competitive with other plants in the wholesale market.

While Edwardsport was being built, Duke and General Electric, the plant's designer, claimed that it would achieve an average annual heat rate of less than 9,000 BTUs per KWh of generation.[21] Edwardsport's actual annual heat rates have ranged between a high of 13,882 BTU/KWh in 2013 and a low of 11,102 BTU/KWh in 2015. As shown in Figure 4, this means that Edwardsport's actual heat rate has been significantly higher than promised and far above the heat rates of other coal and gas-fired combined cycle units.

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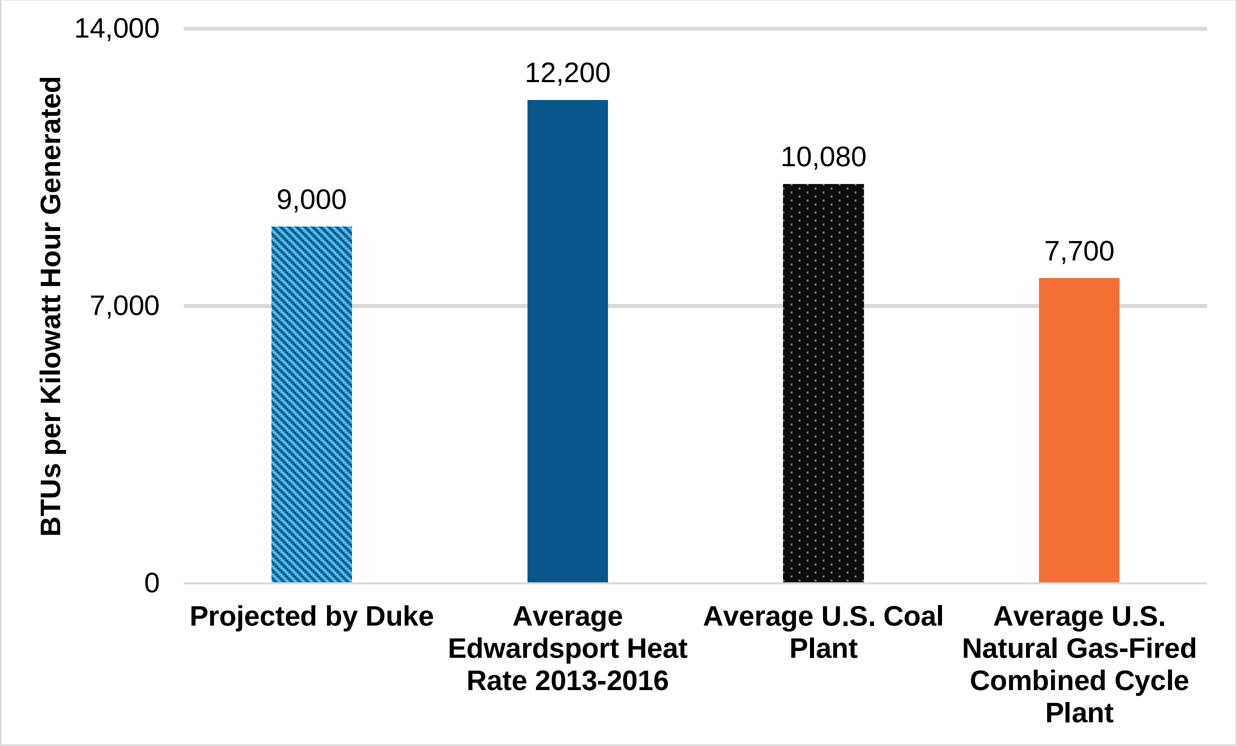
[20] Edwardsport data provided by Duke Energy Indiana in Indiana Utility Regulatory Commission Cause 43114, Sub-Dockets IGCC-12/13, IGCC-15 and IGCC-16. Industry data from the Generating Availability Data System of the North American Electric Reliability Corp., or NERC.

[21] See http://www.purdue.edu/discoverypark/energy/assets/pdfs/cctr/presentations/EdwardsportIGCC-041609.pdf

Figure 4: Edwardsport's Actual vs. Projected Heat Rate and the Average Heat Rates of Other Coal and Gas-Fired Plants[22]

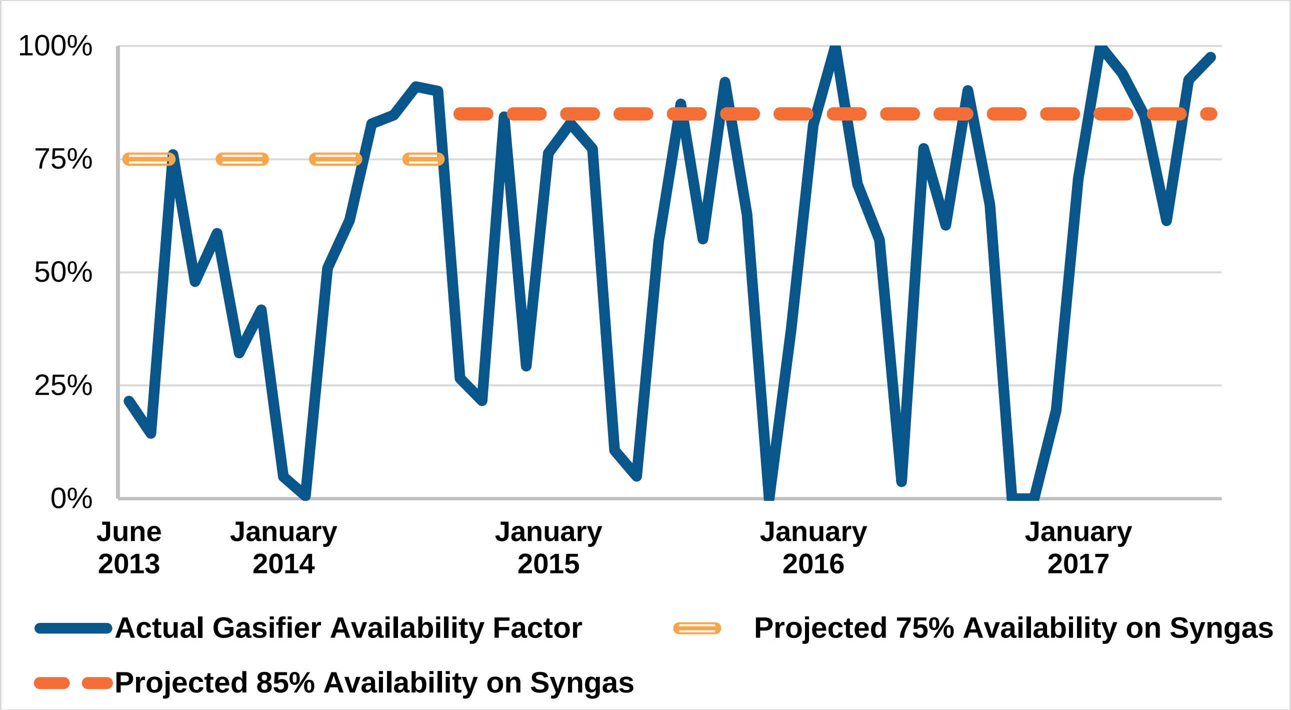


Duke marketed Edwardsport to the public and the Indiana Utility Regulatory Commission as a plant that would generate power from syngas that had been produced in its gasifiers from coal mined in Indiana.[23] Indiana. However, Figure 5, below, shows that Edwardsport's gasifiers have been available only about 55 percent of the time since the plant was declared operational in June 2013, well below the levels Duke Energy Indiana said to expect.

[22] Edwardsport heat rates from data in EIA Form 923, downloaded from SNL Financial on August 29, 2017.

[23] Starting as early as its original filing in IURC Cause 43114 in 2006, Duke Energy Indiana claimed that Edwardsport would operate at an 85 percent availability factor and, in its resource modeling analyses assumed (1) that the plant would operate this well starting immediately after it began commercial operations and (2) that all of this generation would be on SNG. The company later presented a revised projection that the plant would operate at a 75 percent availability factor for its first 15 months and at an 85 percent availability factor after that. However, its modeling analyses, which the company presented to support its claim that finishing Edwardsport was the most economic option, continued to assume that the plant would operate on SNG.

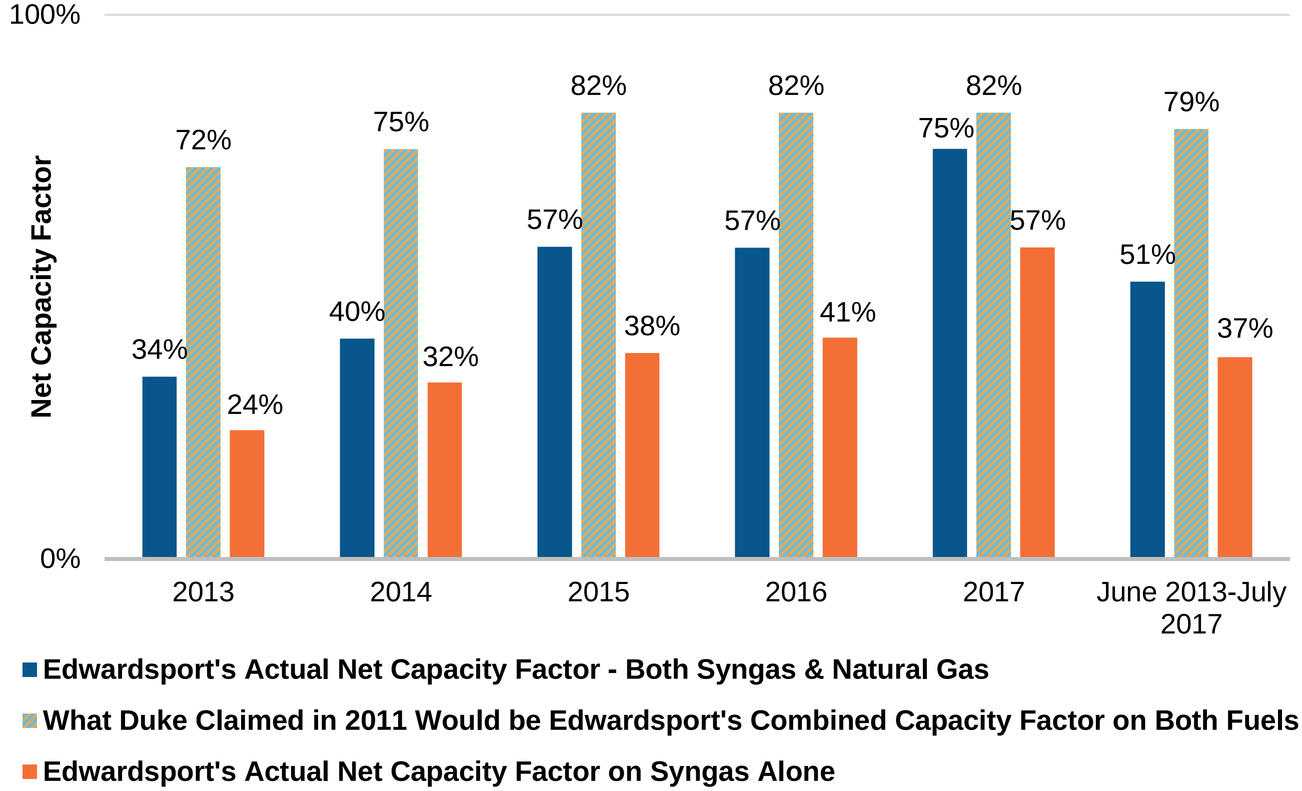
Figure 5: Edwardsport's Actual vs. Projected Gasifier Availability[24]



Because of its unreliable gasification systems, Edwardsport has generated far less power than Duke Energy Indiana said it would when Duke was arguing to the Indiana Utility Regulatory Commission that the plant should be built. We know this because the plant's actual capacity factors have been significantly below what Duke Energy said they would be. Capacity factor is a measure of how much power a plant actually produces in a month or a year compared to how much it would have produced had it operated at full power in that month or year.

[24] Ibid.

Figure 6: Edwardsport's Actual vs. Projected Capacity Factors[25] [26]



Edwardsport has averaged only a 51 percent capacity factor since it began commercial operations, far below the nearly 80 percent capacity factor Duke told the IURC it would. The plant's average capacity factor while running on syngas has been even lower, averaging only 37 percent through May 2017.

While Figures 3, 5 and 6 show that while Edwardsport's operating performance improved during the first seven months of 2017, it did not reach the levels the company promised when it was seeking to build the plant. Nor does this improved performance make the plant economic for consumers.

Another contributor to Edwardsport's poor operating performance is the fact that running the equipment for the gasification portion of the plant consumes a lot of power. A power plant's gross generation is the total amount of energy that it generates. Its net generation is the amount of power it sends out onto the electric grid. The difference between gross and net power is the "parasitic" load—the amount of power

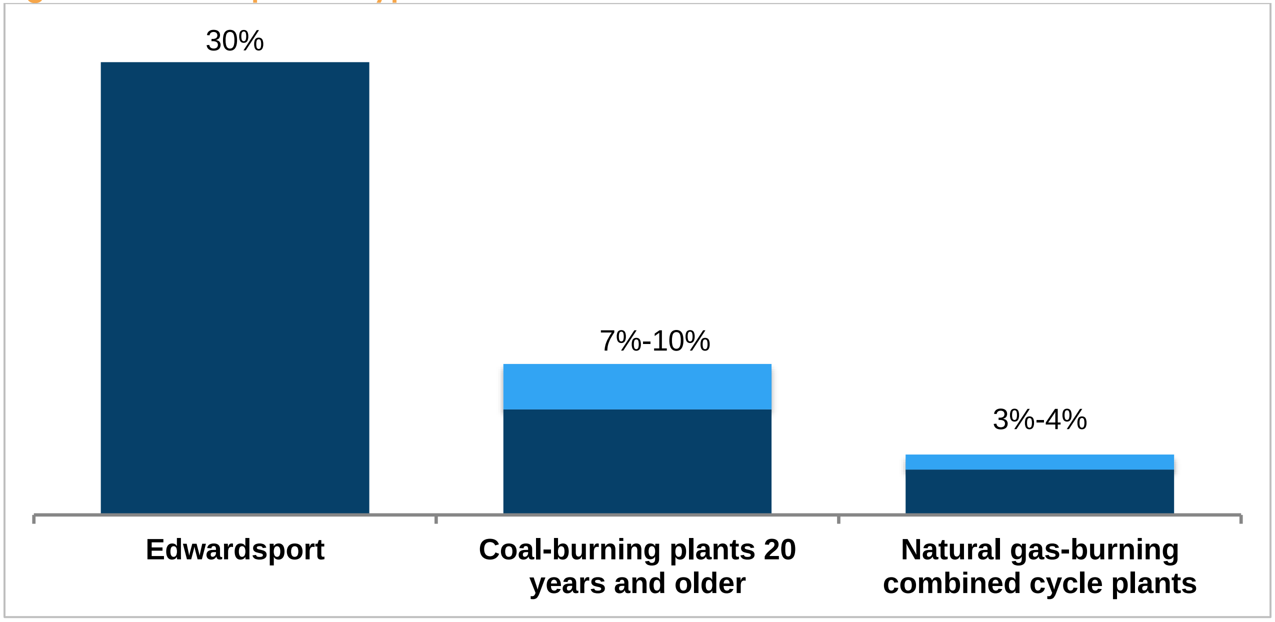
[25] Projected Edwardsport capacity factors from data provided by Duke Energy Indiana in IURC Cause 43114. Actual Edwardsport capacity factors on syngasl and natural gas from data submitted by the company in Form 923 of the Energy Information Administration (EIA).

[26] The Edwardsport actual capacity factor for 2017 in Figure 6 on both natural gas and syngas is for the months of January thru July. The capacity factor for the year on syngas alone is just for the months of January thru May 2017.

needed to operate onsite auxiliary equipment. When Edwardsport is operating on syngas, approximately 30 percent of its gross generation is lost to parasitic load.[27]

Thus, when it is operating on syngas, Edwardsport could be using as much as 190 MW of its 618 MW of capacity just to run internal equipment including gasifiers and other components of the gasification portion of the plant. As shown in Figure 7, below, this is much higher than the parasitic loads for natural gas-fired combined cycle plants; this on-site consumption of power adversely affects Edwardsport's economics.

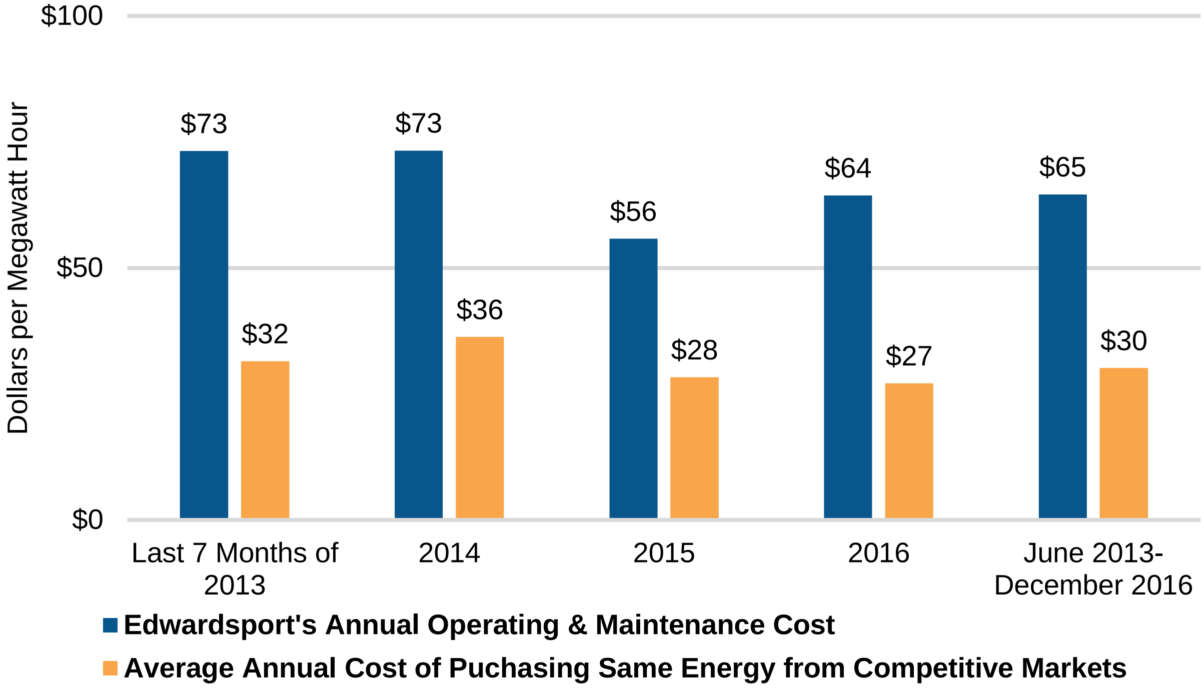
Figure 7: Edwardsport vs. Typical Power Plant Annual Parasitic Loads



Beyond having been very expensive to build and operating unreliably, Edwardsport is very costly to run. Figure 8, below, compares the annual cost of operating and maintaining Edwardsport with the average cost of buying power (both energy and capacity) from the competitive wholesale market in the Midwest.

[27] Based on a comparison of Edwardsport's gross generation on syngas provided in monthly compliance reports to the Lt. Governor of Indiana and the IURC and the plant's net generation reported in EIA Form 923.

Figure 8: Edwardsport's Annual Operating & Maintenance Costs (O&M) per MWh[28]

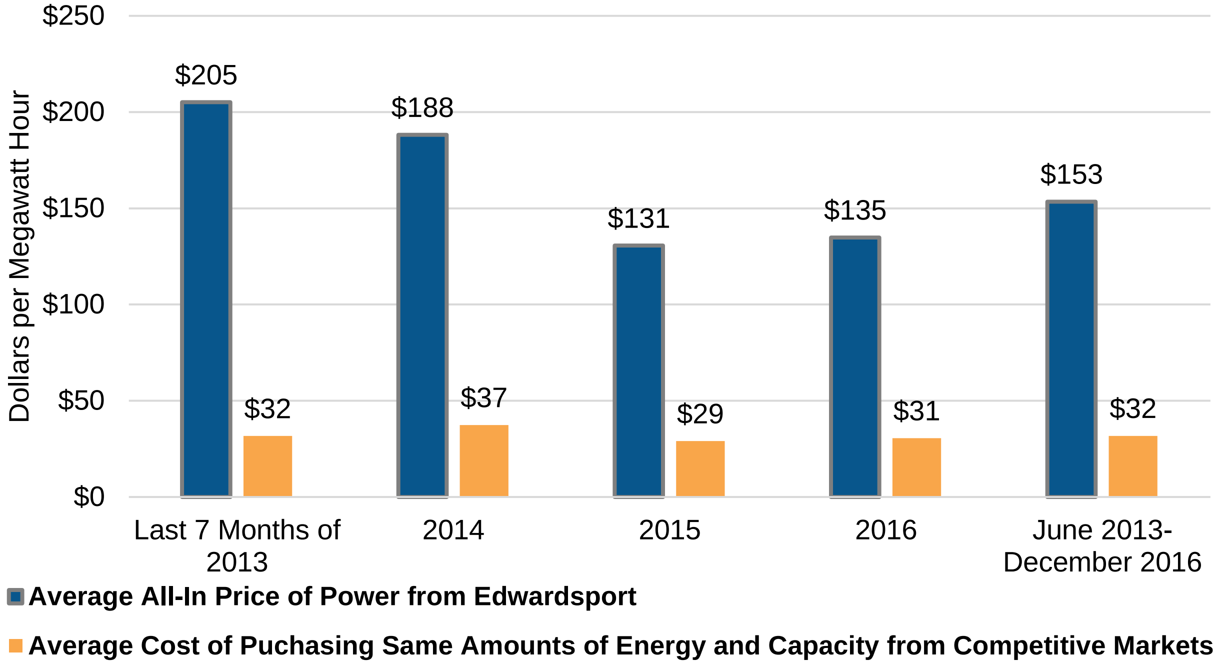


Customers don't pay just for the cost of operating and maintaining the Edwardsport IGCC plant. They also ultimately pay interest on the funds borrowed to build the plant, they pay for returns (profits) to Duke Energy Indiana, they pay the plant's property taxes and they absorb depreciation of plant costs. Customers pay as well for annual capital expenditures ("capex") to keep the plant operating and to keep it in compliance with environmental regulations.

All of these add up to the "All-In" cost of power from Edwardsport and represent all of the costs that customers must pay for the plant. Figure 9, below, shows that Edwardsport's "All-In" cost has been significantly more expensive than the cost of power in competitive wholesale markets.

[28] Edwardsport costs from Duke Energy Indiana FERC Form 1 filings for the years 2013 through 2016. Market prices for MISO's Indiana Zone downloaded from SNL Financial.

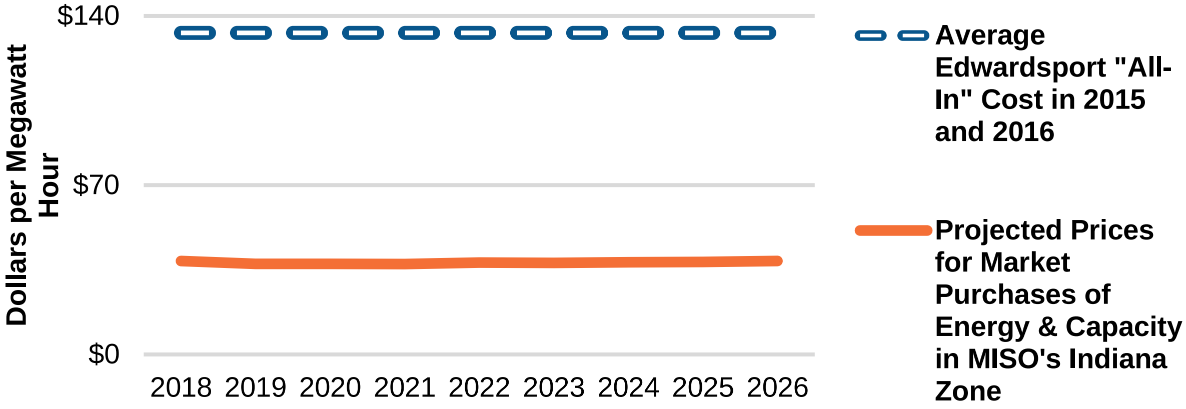
Figure 9: Edwardsport "All-In" Cost vs. Cost of Buying Same Amounts of Energy and Capacity from Competitive Wholesale Markets.



As a result, in the 43 months from June 2013 through December 2016, Duke Energy Indiana's customers paid almost five times as much, or around $1 billion more, for power from Edwardsport than they would have paid had Duke simply bought the same amounts of electricity and capacity from competitive wholesale markets.

Given Edwardsport's very high "All-In" costs, as shown in Figure 9, above—and given that the general expectation that future prices in the competitive wholesale markets will grow slowly for at least the next decade—it is extremely unlikely that the cost of buying capacity and energy from the competitive wholesale markets will ever equal, let alone exceed, the cost of the power produced by Edwardsport. This is true even if the company manages to maintain the improved plant performance reported during the first seven months of 2017.

Figure 10: Edwardsport's All-In Cost vs. the Market's Expectation for Future Energy Market Prices in Indiana[29]



Meanwhile—as Edwardsport has struggled to perform and as its costs have mounted—prices for wind- and solar-generated power have declined so far and so fast that wind and solar power now cost a fraction of the electricity produced at Edwardsport. And the prices for wind- and solar-generated power are expected to decline even further in coming years.

Table 1: Edwardsport's Annual Operating & Maintenance and All-In Costs vs. the Costs of Wind and Solar Resources

	Cost per MWh
Edwardsport Average Operating & Maintenance Costs 2013-2016	$65
Edwardsport Average All-In Costs 2013-2016	$153
Average of Recent U.S. Wind Long-Term PPA Prices[30]	$22
Average of Recent U.S. Solar Long-Term PPA Prices[31]	$40
Market Expectations for Future Long-Term Wind PPA Prices in Early 2020s, Without Any Wind Production Tax Credit[32]	$20-$30
Market Expectations for Future Long-Term Solar PPA Prices in Early 2020s, Without Any Solar Investment Tax Credit[33]	$20-40

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29 The projected market prices in Figure 10 reflect (i) forward energy market prices as of August 7, 2017 and (ii) the conservative assumption that capacity prices in MISO will jump back up to $72 per MW-day from their current level of $1.50 per MW-day and, on average, will remain at the level through 2026.

30 Moody's Investors Service, *Rate-Basing Wind Generation Adds Momentum to Renewables*, March 15, 2017, and U.S. Department of Energy, *2016 Wind Technologies Market Report*, available at https://emp.lbl.gov/sites/default/files/2016_wind_technologies_market_report_final_optimized.pdf

31 Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance and Pricing Trends in the United States, Lawrence Berkeley National Laboratory. Available at https://emp.lbl.gov/sites/all/files/lbnl-1006037_report.pdf

32 UBS Global Research, *The Renewable Cost Deflation Trends Continue*, February 16, 2017, https://neo.ubs.com/shared/d1X1OBuc7TKNdeG/

33 Ibid.

Edwardsport Cancelled Plans for Carbon Capture Technology

When Duke Energy Indiana filed its petition in 2006 for a certificate to build Edwardsport, the company said that carbon capture technology would become a "strong potential benefit of IGCC plants"[34]:

> "Although capture and storage or sequestration techniques have not yet been commercially proven, IGCC technology offers the potential for relatively easier and less energy-intensive means of capturing CO_2 than [pulverized coal] plants."[35]

The company also cited a U.S. Department of Energy study that estimated that the costs of outfitting an IGCC plant with carbon capture equipment would increase the cost of producing electricity by about 30 percent, whereas the impact of adding carbon capture equipment to a supercritical pulverized coal plant would have an impact of around 68 percent on the plant's cost of producing electricity.[36]

Duke Energy Indiana decided not to pursue carbon capture after the Indiana Utility Regulatory Commission refused to approve the company's recovery of costs associated with the technology. As a result, Edwardsport now emits millions of tons of CO_2 into the atmosphere each year. In fact, Edwardsport today emits more CO_2, on a pounds per MMBTU basis, than any of Duke Energy Indiana's other coal-fired generators.[37]

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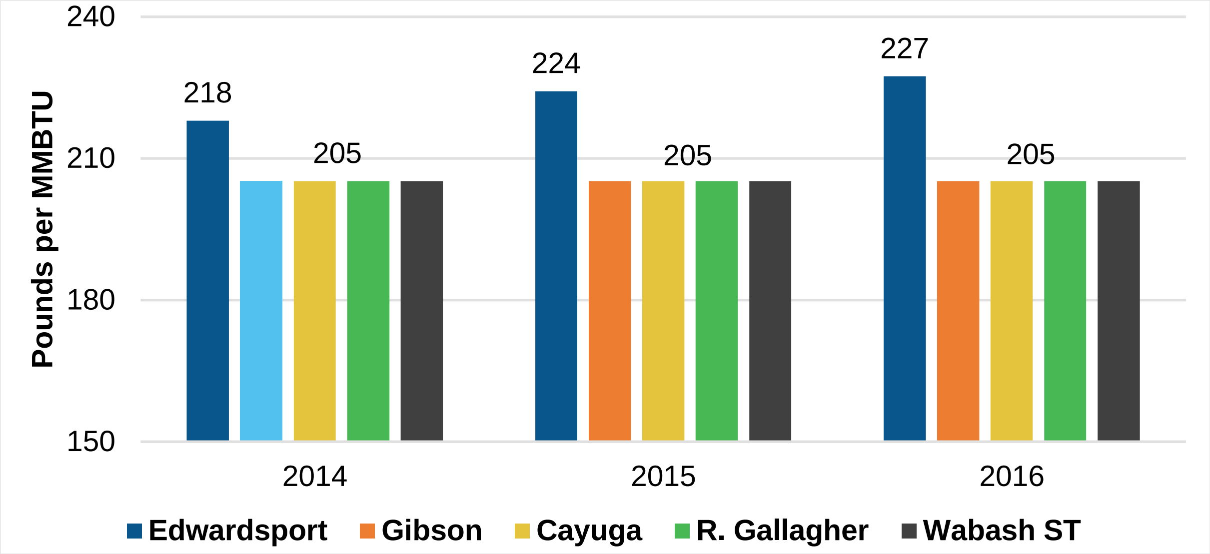
[34] Testimony of James E. Rogers, IURC Cause No. 43114, October 24, 2006, page 11, line 21, through page 12, line 3.
[35] Ibid.
[36] Ibid., page 12, line 22, through page 13, line 3.
[37] Mississippi Power planned to capture 65 percent of the CO2 from Kemper and sell it for enhanced oil recovery in a nearby oil field. However, this plan does not appear to be viable given the switch from coal gasification to burning natural gas.

Figure 11: Annual CO2 Emission Rates, Edwardsport and Duke Energy Indiana's Other Coal-Fired Generators[38]



Demonstration IGCC Plants Built in the U.S. During the 1990s Have Shown Similar Results

Two demonstration projects using IGCC technology to generate electricity from coal were built during the 1990s: The Wabash Valley Power IGCC plant in Indiana and the Polk IGCC plant near Tampa, Fla.

Wabash Valley Power IGCC plant began operations in November 1995 but was retired after 20 years in operation, a relatively short life span for a power plant. With about 150 MW of net summer capacity, the plant was less than one-quarter the size of either Edwardsport or Kemper.

The plant did not operate reliably, achieving only an average 31 percent capacity factor over its operating life, which included a three-year period (2008-2010) when it did

[38] Emissions data downloaded from the EIA CEMS program through SNL Financial.

not generate any power at all. The cost of producing power at the plant was high, averaging from $40 per MWh to $60 per MWh in its last five years of operation.

The Polk IGCC plant is also substantially smaller than Edwardsport or Kemper, with only 294 MW of operating capacity versus Edwardsport's 618 MW and Kemper's 824 MW. Although it operated more often than Wabash Valley (achieving an average 58 percent capacity factor from 1996 to 2016), much of its generation was produced by burning natural gas, not syngas, especially in recent years.

Power from Polk IGCC has been expensive, reaching $60 per MWh in 2011 and 2012. The cost of producing power at the plant started to decline in 2013 when it began to burn more natural gas. The average price of power from the plant dropped to $36.21 per MWh in 2016, from $60.41 in 2012. The owner of Polk IGCC, Tampa Electric, received a permit from the Florida Department of Environmental Protection in October 2016 to burn natural gas only for 3,000 hours each year, up from a previous limit of 876 hours. Given the low price of natural gas, this will almost certainly lead to far more generation from natural gas and less from syngas.

Conclusion

The Kemper and Edwardsport experiments, the only two coal gasification plants built in the U.S. in the past decade, show that Integrated Gasification Combined Cycle (IGCC) technology does not operate as advertised. Further, they demonstrate how high construction costs, unreliable performance, and high operating costs keep such plants from being financially viable or from effectively reducing carbon-dioxide emissions. Coal-gasification technology for the purposes of electricity generation is not feasible, especially given the declining costs of solar and wind resources and the expectation that natural gas prices will remain low for the foreseeable future.

Institute for Energy Economics and Financial Analysis

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David Schlissel, director of resource planning analysis for IEEFA, has been a regulatory attorney and a consultant on electric utility rate and resource planning issues since 1974. He has testified as an expert witness before regulatory commissions in more than 35 states and before the U.S. Federal Energy Regulatory Commission and Nuclear Regulatory Commission. He also has testified as an expert witness in state and federal court proceedings concerning electric utilities. His clients have included state regulatory commissions in Arkansas, Kansas, Arizona, New Mexico and California. He has also consulted for publicly owned utilities, state governments and attorneys general, state consumer advocates, city governments, and national and local environmental organizations.

Schlissel testified as an expert witness in state regulatory commission cases in Mississippi and Indiana involving the Kemper and Edwardsport IGCC plants. In his testimony, he noted that because the projects involved first-of-their-kind technologies, the plants would cost far more and take much longer to build than the developers acknowledged. Schlissel testified also that future natural gas and energy market prices would be substantially lower than the developers projected.

Schlissel has undergraduate and graduate engineering degrees from the Massachusetts Institute of Technology and Stanford University. He has a Juris Doctor degree from Stanford University School of Law.

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