IER INSTITUTE FOR ENERGY RESEARCH

The Levelized Cost of Electricity from Existing Generation Resources

JUNE 2015 | THOMAS F. STACY | GEORGE S. TAYLOR, PH.D.

Table of Contents

Introduction

In this paper, we analyze publicly available data to establish the average levelized cost of electricity from existing generation sources, or "LCOE-E." This new measure is a crucial piece of information that has been missing from the electricity policy discussion. The LCOE-E data and framework we introduce in this report offer policymakers a powerful tool as they make decisions that affect the cost of electricity in the U.S.

What is the levelized cost of electricity? The approach taken by the federal Energy Information Administration (EIA) to answer that question is exclusively forward-looking. That is, EIA publishes LCOE calculations for new generation resources only. If no existing generation sources were closed before the end of their economic life, EIA's approach would provide sufficient information to policymakers on the costs of different electricity policies.

However, in the current context of sweeping environmental regulations on conventional generators—coupled with mandates and subsidies for intermittent resources—policies are indeed forcing existing generation sources to close early. Federal policies alone threaten to shutter 110 gigawatts of coal and nuclear generation capacity. The LCOE-E we introduce in this paper allows for much-needed cost comparisons between existing resources that face early closure and the new resources favored by current policy to replace them.

Our findings show the sharp contrast between the high cost of electricity from new generation resources and the average low cost from the existing fleet. Existing coal-fired power plants, for example, generate reliable electricity at an LCOE-E of $38.4 per megawatt-hour on average. Compare that to the LCOE of a new coal plant, which ranges from $80.0 to $97.7 per megawatt-hour depending on how frequently the plant operates. The analysis shows the same for existing natural gas, nuclear, and hydroelectric resources—each produces electricity at a substantially lower levelized cost than its forward-looking LCOE (as estimated by EIA) would indicate.

A secondary contribution we offer in this paper is to adjust the LCOE estimates provided by EIA to reflect the real-world operating characteristics of different generation resources on the power grid. We find that EIA's estimates of the LCOE for new generation resources are too low, because EIA assumes these resources will operate at the highest levels possible rather than at historical levels. We also find that intermittent resources increase the LCOE for conventional resources through a similar mechanism, that is, by reducing their run time without reducing their fixed costs. We refer to these as "imposed costs," and we estimate them to be as high as $29.94 per megawatt-hour of intermittent generation when we model combined cycle natural gas energy displaced by wind.

The LCOE-E framework allows for cost comparisons that are relevant for today's energy policymakers. For example, when all known costs are accurately included in the LCOE calculations, we find that existing coal ($38.4), nuclear ($29.6), and hydroelectric resources ($34.2) are about one-third of the cost of new wind resources ($112.8) on average. By increasing the transparency of the costs associated with policies favoring new resources over existing conventional resources, we hope to inform policymakers with the best available data and raise the level of the electricity policy debate.

About the Authors

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Tom Stacy has dedicated the past eight years to education and research in electricity generation, wholesale market design and public policy with a focus is on the dynamics of grid-scale wind electricity; has served on the ASME Energy Policy Committee; has testified before Ohio energy policy related legislative committees numerous times, many by invitation from their chairpersons. He continues to help state lawmakers come to terms with the electricity system's complex economic and technical issues and base the state's electricity related laws and regulations on conservative economic, sound engineering, and prudent land use principles. He holds a B.A. in Industrial Marketing from the Ohio State University's Fisher College of Business.

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George Taylor is a former Silicon Valley engineer and executive; the director of Palmetto Energy Research, an educational non-profit devoted to the future of electricity generation; the author of a report on "The Hidden Costs of Wind Electricity" released by the Energy and Environment Legal Foundation; and a participant in Energy Information Administration workshops on the cost of (and costs avoided by) new generation options. He received a Ph.D. in Computer Architecture from U.C. Berkeley.

Executive Summary

The purpose of this report is to compare the cost of electricity from existing generation resources with the cost from new generation resources that might be constructed to replace them. To date, the Levelized Cost of Electricity from New generation resources (LCOE-New) has been the primary focus of "cost of electricity" comparison studies and debates. Our new calculation of levelized cost from existing resources (LCOE-E) offers policymakers a more accurate depiction of the tradeoffs involved in decisions affecting the electricity industry. LCOE-E is based on data from two government sources – Federal Energy Regulatory Commission (FERC) Form 1 and Energy Information Administration (EIA) 860.

Decision makers often compare levelized cost of electricity from various types of new power plants that might be built to serve society in the future. One such comparison, a part of the EIA's Annual Energy Outlook (AEO) 2014 (& 2015), includes a projection for the LCOE from new generation facilities that could be brought online in 2019. EIA defines LCOE as "the per-megawatt-hour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle."[1] EIA's estimates of LCOE are the most widely accepted and commonly used version of the LCOE-New methodology.

LCOE-New comparisons can be quite useful if they encompass a wide range of likely alternatives. However, one of the clear deficiencies of most LCOE-New reports has been the absence of any information about cost of electricity from existing generation resources, even though those resources supply all of our electricity today and most of them could continue to supply reliable electricity at the lowest cost for years – even decades to come.

On the other hand, if regulators or lawmakers induce power plants to retire earlier than they would have otherwise, the price of electricity must increase to pay for the incremental cost of replacement capacity. Because electricity is an essential input to nearly all goods and services, replacement of operationally sound, least cost electricity producing power plants with new ones that produce electricity at a higher levelized cost comes at a cost which must be borne and allocated across the domestic economy.

This report on the cost of electricity from existing generation resources provides a baseline from which policymakers can assess the cost of replacing existing plants with new ones.

Our analysis is based on data reported to federal government agencies, EIA and FERC. The data suggest that almost all existing power plants have lower fixed costs than and similar variable costs to their most likely replacements. The primary reason new power plants have higher LCOE is because they begin their operational lives with a full burden of construction debt and equity investment to repay. Since existing power plants have already repaid some or all of those obligations, their fixed costs going forward are lower. To the extent power plants of the same type outlive their "mortgages," they enjoy far lower fixed costs of operation and thus are likely to be capable of supplying electricity at a lower cost overall.

Data sources mined for this report indicate that for all major generation resources, the fleet-average cost of electricity from existing power plants is less than the fleet-average cost of electricity from new power plants of the same type. We also examine a best-case scenario for new plants using a hypothetically achievable capacity factor that is higher than observed data.

Table 1 summarizes these findings. At 2014 fuel prices, the lowest cost new resource is combined-cycle natural gas (CC gas). Because the replacement of existing coal with new CC gas capacity is the most common real world scenario today, the fleet average costs of electricity from these two resources are highlighted yellow in Table 1. All figures are shown in 2012 $/MWh.

GENERATOR TYPE	LCOE Existing as found in FERC Form 1 (EIA fleet avg CF) 2012 $/MWh	LCOE New (EIA) as adjusted by the Report (EIA best case CF) 2012 $/MWh	LCOE New (EIA) as adjusted by the Report (EIA fleet avg CF) 2012 $/MWh
DISPATCHABLE FULL-TIME-CAPABLE RESOURCES			
Conventional Coal[2, 3]	38.4	80.0	97.7
Conventional Combined Cycle Gas (CC gas)[3]	48.9	66.3	73.4
Nuclear[3]	29.6	96.1	92.7
Hydro (seasonal)	34.2	84.5	116.8
DISPATCHABLE PEAKING RESOURCES			
Conventional Combustion Turbine Gas (CT gas)	142.8	128.4	362.1
INTERMITTENT RESOURCES - AS USED IN PRACTICE			
Wind including cost imposed on CC gas	N/A	96.2 +other costs*	112.8 +other costs*

"Other costs" could add $25 - $50 per MWh and include transmission costs and subsidies not considered by EIA in their calculation of LCOE-New. Furthermore, EIA apparently made no distinction between the 20 - 25 year expected lifespans of wind and solar facilities vs. the 50+ year lifespans of most other technologies. See the following publications: http://www.nrel.gov/docs/fy11osti/47078.pdf, http://eelegal.org/?page_id=1734.

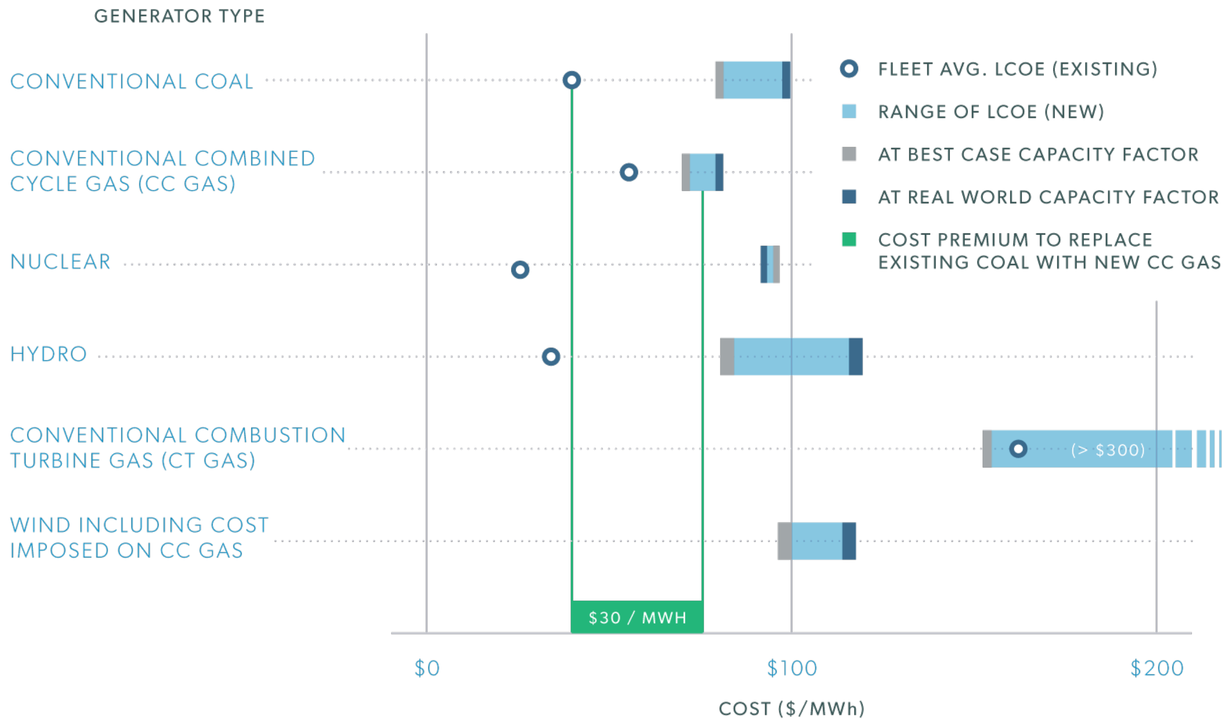
Table 1 shows levelized cost of electricity from existing resources (LCOE-E) in column 1, as derived using the FERC Form 1 database. EIA's estimate of the levelized cost of electricity from new generation resources for units becoming operational in 2019 (LCOE-New) is shown in Columns 2 and 3 and broken down in two ways. Column 2 reflects fixed costs per MWh as EIA calculates them (using "best case single plant" and "simple average of marginal units" capacity factors for dispatchable and non-dispatchable resources, respectively) and Column 3 uses actual (observed) fleet average capacity factors substituted for best case capacity factors.[4] Capacity factor is the average output of a plant or fleet over time divided by the theoretical maximum output of that plant or fleet, and is listed as a percentage. For example, the measured fleet average capacity factor for existing conventional coal plants in 2014 was 60.9 percent[5].

As Table 1 makes clear, the cost advantage of existing resources over new sources is pronounced. These cost advantages are most evident when comparing existing sources against: 1) new sources with high capital costs, such as coal, nuclear, wind, and hydro; or 2) new sources with low capacity factors, such as simple-cycle Combustion Turbine natural gas "peaker" plants (CT gas) and wind.

Environmental Regulations + Subsidies and Mandates for Renewables are Driving Most New Generating Capacity Construction, Not New Electricity Demand

The reason the cost of generation from existing sources is so important is that government mandates, regulations and subsidies (not additional demand) are driving the construction of new generation resources.

LEVELIZED COST OF ELECTRICITY



FERC Form 1 and EIA 860 show that, in the absence of mandates, subsidies and regulatory compliance costs, the cost of electricity from almost all existing generation resources will remain less than the cost of electricity from their likely replacements for at least the next 10 to 20 years.

In fact, in their 2014 State of the Market report to FERC, grid operator PJM's Independent Market Monitor stated that: "[S] ubsidies in the form of additional out of market revenue is not consistent with the PJM market design. The result would be to artificially depress prices in the PJM capacity market. This would negatively affect the incentives to build new generation and would likely result in a situation where only subsidized units would ever be built."[6]

From 2004 through 2014, electricity demand in the United States increased by an average of 0.3% percent per year.[7] Absent mandates for new generation and the onset of new federal environmental regulations forcing some coal fired generating capacity to retire, almost no new generation capacity would have been necessary over that ten year period.

Longevity of the Existing Fleet

Forms 1 and 860 data indicate that most existing power plants could remain economically viable for years or decades beyond their current age. While existing resources remain our lowest cost option, regulatory compliance costs and artificial "wholesale price suppression" brought about by subsidizing and mandating higher cost and lower value technologies causes low-cost existing dispatchable resources to operate at a financial loss. These external influences are not consistent with market design. The result is that some existing resources may be operating at a net financial loss even while their likely replacements would produce electricity at a substantially higher cost.[8] The lowest possible electricity rates will only be achieved by keeping existing generating resources in operation until their product becomes uneconomic relative to the levelized cost of electricity from new sources that would replace them.

Low-cost natural gas is another factor influencing the retirement of coal (and even some nuclear) capacity. Competitive marginal prices for CC gas energy place downward pressure on clearing prices, which in turn reduce the revenues accruing to all technologies. A properly valued and functioning capacity market should result in capacity market clearing prices sufficient to carry existing capacity contributors (in this case coal and nuclear) through any short-term reduction in gross margin and/or capacity factor. To date, however, even our most sophisticated grid operators such as PJM are struggling to arrive at appropriate capacity market rules.

Of course, substitutions of natural gas for coal could work for only some fraction of existing coal electricity before substantial and expensive increases in natural gas infrastructure would be required. Even then, the system would be more vulnerable to natural gas supply shortages and price increases.

Conclusion

Most existing coal, natural gas, nuclear, and hydroelectric generation resources could continue producing electricity for decades at a far lower cost than could any potential new generation resources. At a coal-fired power plant, for example, when a component wears out, only the component must be replaced, not the entire plant. The same is true for nuclear plants, until they reach their regulatory end of life, which is currently defined to be 60 years but could be extended to 80.[9]

Under current laws, rules, and regulations, large amounts of generating capacity is slated to retire and will be replaced with new generating capacity which will produce electricity at a far higher average levelized cost. The Institute for Energy Research recently identified more than 110 GW of coal and nuclear generation capacity set to close as a direct result of federal regulations. [10]

When electricity from an existing electric generating plant costs less to produce than the electricity from the new plant technology expected to be constructed to replace it—and yet we retire and replace the existing plant despite the higher costs—ratepayers must expect the cost of future electricity to rise faster than it would have if we had instead kept existing power plants in service.

An unprecedented amount of generating capacity is set to close due to ongoing renewables policies, undervalued capacity markets, currently low natural gas prices, and additional environmental regulations. In the absence of even some of these factors, most existing power plants would remain operational, helping keep electricity costs low for many years or decades into the future.

[1] *Energy Information Administration, Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014, Apr. 17, 2014, http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[2] *After backing out $15.6/MWh (3%) adder to the cost of capital representing EIA's anticipation of a future CO2 emissions "surcharge"*

[3] *Fuel costs derived by subtracting variable cost reported in " Updated Capital Cost Estimates for Electricity Generation Plants, November 2010" produced by R.W. Beck, Inc. for U. S. Energy Information Administration Office of Energy Analysis, U.S. Department of Energy (Page 7, Table 1) from EIA LCOE 2019 variable O&M including fuel.*

Coal: EIA modeled fuel cost was $26.1=/MWh.At 2014's delivered fuel price and heat rate, the fuel cost is $23.9/MWh

CC Gas: EIA modeled fuel cost was $45.7/MWh. At 2014's delivered fuel price and heat rate, the fuel cost is $38.7/MWh

CT Gas: EIA modeled fuel cost was $67.3/MWh. At 2014's delivered fuel price and heat rate, the fuel cost is $57.4/MWh

Uranium: EIA modeled fuel cost was $9.8/MWh. At 2014's delivered fuel price and heat rate, the fuel cost is $7.9/MWh

[4] *Real-world capacity factors today are lower than those EIA used to calculate LCOE in all cases except for nuclear and solar, and substantially lower for CC gas and CT gas.*

[5] *Energy Information Administration, Electric Power Monthly, Table 6.7.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, May 2015, http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a.*

[6] *Testimony of Monitoring Analytics, Dr. Joe Bowring, to the Ohio Electricity Mandate Costs Legislative Study Committee, April 16th, 2015 available through the office of the committee chairman, 131st Ohio General Assembly Senator Troy Balderson.*

[7] *Energy Information Administration, www.eia.gov/electricity/monthly Monthly Energy Review, Table 7.2a Electricity Net Generation: Total (All Sectors), February 2015, http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf.*

[8] *http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf Section 1 B, page 5*

[9] *Katherine Tweed, APS Argues to Extend Lifespan of Nuclear Reactors to 80 Years, IEEE Spectrum, Dec. 12, 2013, http://spectrum.ieee.org/energywise/energy/nuclear/aps-argues-to-extend-lifespan-of-nuclear-reactors-to-80-years. The American Physical Society argues that there are no technical barriers to run nuclear power plants for up to 80 years—20 years beyond the current maximum 60-year life of nuclear power plants.*

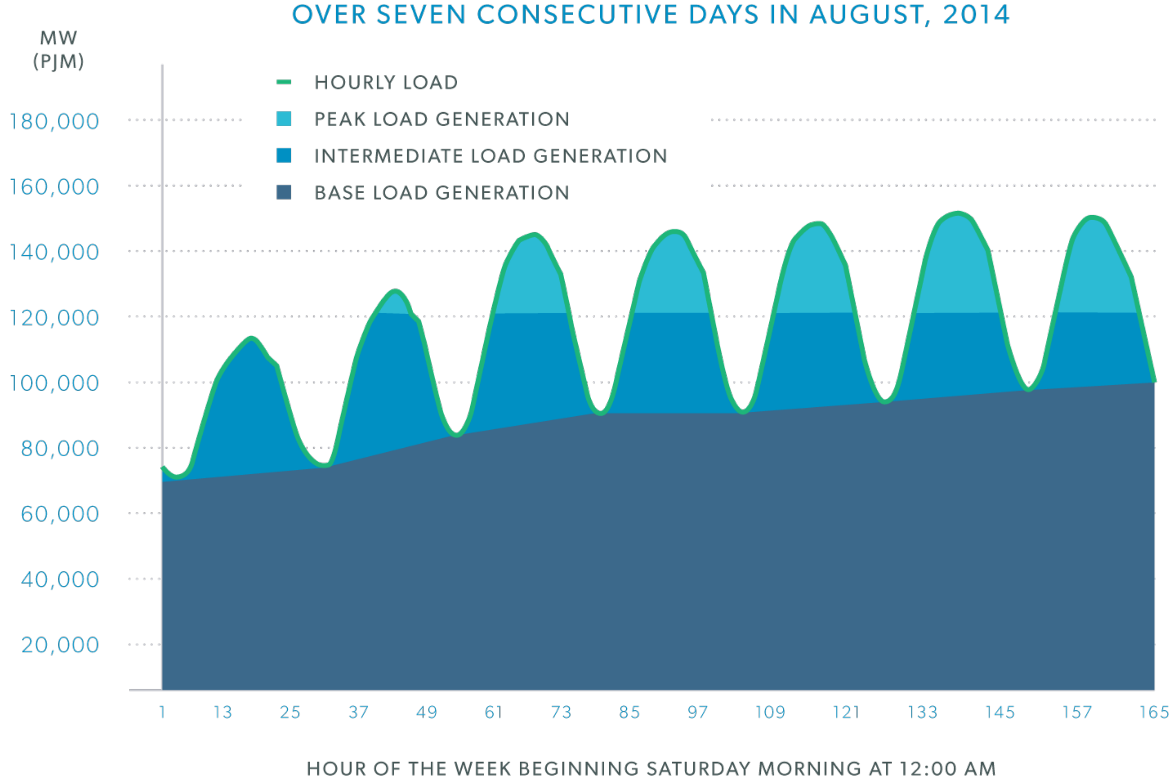
[10] *Travis Fisher, Assessing Emerging Policy Threats to the U.S. Power Grid, Institute for Energy Research, Feb. 24, 2015, http://instituteforenergyresearch.org/greatest-threat-power-grid-govt/.*

I. IDENTIFYING VALUE-COMPARABLE GENERATION RESOURCE CATEGORIES

Valid LCOE Comparison Must Be Limited to Generation Resources with Similar Performance Capabilities/Characteristics

One of the most commonly overlooked aspects of comparing the cost of electricity from different sources is that different generating resources play different roles in keeping the electricity grid in balance. Some are designed to run almost all the time at a fairly steady level (base load) while others run part of the time (load following). Still others are designed to run only a few hours per day or year, and must adapt quickly to changes in demand or supply (peaking resources). For this reason, peaking resources should not be electricity-cost compared with nuclear designed for base load operation, or with coal or CC gas units designed for base load and load following. That is why this report lists peaking resources in a separate section from base load generators, in the same way EIA lists non-dispatchable resources in a separate section of its LCOE Table 1.

HOURLY ELECTRICITY LOAD: PJM INTERCONNECTION OVER SEVEN CONSECUTIVE DAYS IN AUGUST, 2014



While it would be convenient for cost comparison if all types of electricity generators could serve the entire demand market, that is not realistic. Electricity has no shelf life. It is instantaneously perishable, so it cannot be produced now and used several hours, days, weeks or months later without large scale "batteries" or other mass electricity storage devices that convert the electricity to some other form of energy (such as chemical or kinetic potential), store it, and then convert it back into consumable electricity.

Because most bulk electricity storage options add more cost than the potential savings, fuel storage (where possible) remains the most prudent choice. For technologies whose fuel cannot be stored and will not always be available in accordance with electricity demand, the cost of necessary storage capacity to bring it to the same dispatchability standards as conventional generators must be counted as part of the cost of those technologies.

Another option is to force dispatchable generators to "back down" relative to their previous levels whenever non-dispatchable generators produce electricity. As with electricity storage, there are both potential costs and savings in doing so. The savings are in the form of lower variable costs (including some fuel savings) of the dispatchable fleet. The costs are more complicated and stem from the unchanged fixed costs of dispatchable generators having to be recovered through the sale of less electricity long-term (because the dispatchable generators are backing down to accommodate non-dispatchable resources). In this report we refer to these costs as "imposed costs."

If we could build fewer dispatchable resources as we add non-dispatchables, these imposed costs would not exist. Unfortunately the "replacement value" of some non-dispatchable resources for dispatchable resources is very low–close to zero–as measured by their guaranteed performance across the hours of the year society requires the greatest amount of electricity.

We are fortunate to have the means to store electricity-generating fuels and deliver them to the generators in the amounts and at the times electricity is needed. These fuels—primarily coal, natural gas and uranium—provide prompt and consistent generation of electricity in accordance with electricity demand, which is integral to electricity's value proposition. For that reason, LCOE comparisons are valid only between resources with similar performance characteristics: that is, between technologies that are able to consistently and reliably serve the same segments of electricity demand.

EIA partially represents this by listing non-dispatchable technologies such as wind and solar in a separate section of their LCOE Table 1, making special note just prior to its summary tables: "The duty cycle for intermittent renewable resources, wind and solar, is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset) and so will not necessarily correspond to operator dispatched duty cycles. As a result, their LCOE values are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar) and therefore are shown in separate sections within each of the tables." [11]

Table 1 of EIA's LCOE-New lists the highest achievable annual capacity factors for each technology for dispatchable resources and a simple estimate of average capacity factors expected for the next non-dispatchable resources to be built in each region of the U.S.. The latter seems optimistic for wind, given some of the 22 regions have extraordinarily weak wind resources. An exploration of estimated capacity factors for marginal wind and solar resources is beyond the scope of this report, but merits further study. Nevertheless, these mixed best-base and estimated-marginal-average capacity factors may have been displayed in EIA Table 1 to assist readers in further distinguishing between the capabilities of different dispatchable technologies in order to avoid an invalid LCOE comparison between full-time-capable and part-time-capable dispatchable resources which serve different market segments. EIA says: "In Table 1 and Table 2, the LCOE for each technology is evaluated based on the capacity factor indicated, which generally corresponds to the high end of its likely utilization range."

But natural gas and coal resources tend to operate at capacity factors significantly lower than "the high end of their utilization range" as shown in Table 2 of this report. Capacity factors directly impact levelized cost calculations because the present value of fixed costs over a unit's cost recovery period is converted to fixed cost per MWh when calculating LCOE.

Therefore, EIA's LCOE-New estimate is biased in favor of those technologies for which EIA's assumed capacity factor is higher than the actual capacity factor.

As discussed, this report makes a further distinction within EIA's category "Dispatchable Technologies," dividing them into two separate categories: "Dispatchable Full Time Capable Resources," and a "Dispatchable Peaking Resource," Combustion Turbine (CT) gas, which is expected to be called on and to run reliably, primarily at times of high electricity demand.

Base Load (Full-Time-Capable) Resources:

Nuclear, coal, and CC gas electricity are commonly deployed through facilities designed to produce:

- at or near full nameplate capability
- for sustained periods of time from several days to several months

Many hydroelectric resources operate the same way, although their capacity may vary from one time of the year to another. These operating characteristics promote the highest fuel efficiencies and lowest variable costs, as well as the lowest emissions intensities.

Peak Demand Resources:

CT gas facilities are designed to minimize fixed costs in anticipation of the low utilization rate associated with serving peak demand. The trade-off is lower fuel efficiency, higher variable costs and higher emissions intensity. Because CT gas units produce relatively small amounts of energy on an annual basis, low fixed costs take precedence over low fuel cost and emissions. While EIA lists a possible 30 percent capacity factor for CT gas, FERC Form 1 and EIA 923 data indicates that CT gas units typically have capacity factors in the mid to high single digits. A report prepared under contract to EIA assumes a 10 percent capacity factor for CT gas units in its calculation of fixed costs per MWh while Electric Power Monthly shows real world capacity factors for CT gas units average below 5 percent.[12] Since CTs were not intended to be full time resources, they are not direct replacements for nuclear, coal or CC gas units.

Intermittent Fuel Resources:

EIA refers to hydroelectric, wind and solar as "Non-Dispatchable Resources" because they consume fuels whose availability is not under human command. Such units can be turned down or off, ("downward dispatchable") but they cannot produce more electricity than their fuel streams permit. Wind generation is particularly problematic because across most of the U.S. its season of lowest production corresponds with the season of highest demand (summer).

Solar photovoltaic (PV) has the advantage of producing during daytime hours when demand is high. However, electricity demand remains high for several hours after solar radiation has declined in late afternoon. Therefore, even though solar generation's correlation with demand is higher than wind generation's, solar still has limited value as a replacement for "peaker" power plants whose fuel can be consumed precisely and only at peak demand times. Because combustion turbines (peaker plants) are less fuel-efficient than other dispatchables, solar PV saves more fuel per MWh of generation than wind. Neither solar PV nor wind, however, are good substitutes for base or intermediate load power plants.

The range of different hydroelectric facility capabilities means hydro does not fit neatly in any particular segment of a LCOE table. "Run of river" hydroelectric power could be shown in the intermittent or dispatchable category depending on the water resource feeding any given hydroelectric facility. Many current hydro facility locations and designs offer some fuel supply certainty over time (or "storage") in the form of regular precipitation, melting snow pack and/or ground saturation over a facility's feedstock watershed, or through impoundment capability (deep water stored behind tall dams), which allows them to operate much like dispatchable generators for weeks or even months at a time. Periodic shortages of water for hydro develop gradually and are far more foreseeable than shortages in wind velocity

Due to untimely changes and low availability of their fuels during hours of peak demand, wind and solar resources are not direct or complete substitutes for dispatchable resources. They are instead "supplemental" options that reduce the fuel consumption and utilization rates of "dispatchable" units without replacing the need to build and maintain those units. Wind and solar therefore can be thought of as "energy only" resources that save a portion of the variable costs (fuel and variable operations and maintenance or O&M) but little or no fixed costs.

To make it possible for policymakers to compare the cost of electricity from all available technologies, the body of this report examines each intermittent resource as part of a full-time-capable "combination" of resources composed of the intermittent resource and a full-time-capable dispatchable resource, the combination of which can deliver approximately the same levels of capacity and energy as the dispatchable resource by itself. Namely, we examine CC gas plus wind and CC gas plus PV solar. The LCOE of these two combinations is derived from the costs of the two components.

FOOTNOTES: IDENTIFYING VALUE-COMPARABLE GENERATION RESOURCE CATEGORIES

[11] *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm*

[12] *"..assumed 10 percent annual capacity factor and an operating profile of approximately 8 hours of operation per CT start." http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf (8-5)*

Actual class average CT capacity factor across the system in 2014 was 4.8% http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a

II. LCOE-E DATA SOURCES AND METHODOLOGY

Determination of LCOE from Existing Resources

This report uses data from two federal databases to calculate the levelized cost of electricity from existing power plants (LCOE-E). The first is the Federal Energy Regulatory Commission's (FERC's) Form 1 database.[13] Form 1 filings include annual fuel consumption, electricity generation and cost data from all non-government-owned power plants. Data for the past twenty years' filings are available to the public with some exceptions. The second data source is EIA's Form 860. Form 860 contains much of the same information as Form 1 (except cost and generation data, but also identifies the technology employed at each power plant, the types of fuel consumed, and unit capacity ratings.

All commercial electricity generators are required to file Form 1 annually. This form is "a comprehensive financial and operating report submitted for Electric Rate regulation and financial audits."[14] To produce this report, we collected, sorted and evaluated data from each of the 20 years of FERC Form 1 filings available on line. Specifically, nameplate capacity (MW), annual generation (KWh/yr), ongoing capital expense (nominal $ since inception), annual operating expense including fuel (nominal $/YR) and fuel expense (nominal $/YR).

EIA Form 860 "collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants with 1 megawatt or greater of combined nameplate capacity."[15] While Form 1 is the only public source of financial data from commercial power plants, it allows open text responses in some fields such as unit name, generator technology and fuel type. Form 860 limits respondents' entries regarding plant name, unit name, fuel type and generator technology (prime mover) to specific ID numbers and codes, restrictions which facilitate sorting and disambiguation. Form 860 also serves as a cross reference for other generator attributes and facts such as physical address, nameplate capacity, grid control region and RTO/ISO interconnection.

Most wind and solar facilities have either not submitted Form 1, have been permitted to complete the form only partially, or have requested their entries be redacted from the public record. Of those that did report, more than half were incomplete or unusable. This resulted in a sample that could not be used to estimate levelized cost. As a result the cost of existing sources of wind and solar versus the other sources of electricity generation could not be calculated under consistent methodology. For these reasons, this report does not estimate LCOE-E for wind or solar.

FERC Form 1 Data

Form 1 maintains 20 databases, one for each of the past twenty years. For this report we collected data for each plant for all twenty years. All thermal sources (Coal, CT Gas, CC Gas, nuclear and dual fuel and dual output plants) report as steam plants. Hydro plants report on a separate page. The fields used to calculate LCOE from existing sources are highlighted in the following figure.

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report End of ______

STEAM-ELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS)

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility
4. If net peak demand for 60 minutes is not available, give data which is available, specify period.
5. If any employees attend more than one plant, report on line11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct.
7. Quantities of fuel burned (Line38) and average cost per unit of fuel burned (Line41) must be consistent with charges to expense accounts 501/507 (Line42) as shown on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		
6	Net Peak Demand on Plant - MW (60 Minutes)		
7	Plant Hours Connected to Load		
8	Net Continuous Plant Capability (Megawatts)		
9	When Not Limited by Condenser Water		
10	When Limited by Condenser Water		
11	Average Number of Employees		
12	Net Generation, Exclusive of Plant Use - KWh		
13	Cost of Plant: Land and Land Rights		
14	Structures and Improvements		
15	Equipment Costs		
16	Asset Retirement Costs		
17	Total Cost *Reported as an aggregate figure since inception		
18	Cost per KW of Installed Capacity (line 17/5) Including		
19	Production Expenses: Oper, Supv & Engr		
20	Fuel * Reported as an annual expense		
21	Coolants and Water (Nuclear Plants Only)		
22	Steam Expenses		
23	Steam From Other Sources		
24	Steam Transferred (Cr)		
25	Electric Expenses		
26	Misc Steam (or Nuclear) Power Expenses		
27	Rents		
28	Allowances		
29	Maintenance Supervision and Engineering		
30	Maintenance of Structures		
31	Maintenance of Boiler (or reactor) Plant		
32	Maintenance of Electric Plant		
33	Maintenance of Misc Steam (or Nuclear) Plant		
34	Total Production Expenses * Annual		
35	Expenses per Net KWh		
36	Fuel: Kind (Coal, Gas, Oil or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned * Annual		
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)		
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year		
41	Average Cost of Fuel per Unit Burned		
42	Average Cost of Fuel Burned per Million BTU		
43	Average Cost of Fuel Burned per KWh Net Gen		
44	Average BTU Per KWh Net Generation		

FERC Form 1 Field Name Visual FoxPro Databases	Reason Field Collected
RESPONDENT_ID	Sorting field used to aggregate each plant's 20 years of data
REPORT_YEAR	Sorting field for chronological arrangement of values for each plant. To establish each plant's sample vintage and number of contiguous years in final sample.
PLANT_NAME	Name of plant. Used to sort polled database by plant. used to cross reference Form 1 data with EIA Form 860
PLANT_KIND	Used to preliminarily distinguish between nuclear, coal, and other types of primary units at each plant
YR_CONST	Used to track the age of the plant
YR_INSTALLED	Indicates the most recent year units were added
TOT_CAPACITY	Nameplate capacity of reported unit or entire plant. Used to calculate plant capacity factor.
PEAK_DEMAND	Not used in this report
PLNT_CAPABILITY	Not used in this report
NET_GENERATION	Annual generation figure. Used to convert annual expenses figures to $/MWh for each year for each round
COST_OF_PLANT_TO	Cumulative Capital Cost since inception reported annually. Includes construction cost. Subtracting each year's figure from the following year's reported figure yields annual capital expense.
EXPNS_FUEL	Annual fuel expense. Used to calculate the cost of fuel per MWh for each year in a plant record. Subtracting this from the tot_prdctn_expns yields Fixed + Variable O&M excluding fuel.
TOT_PRDCTN_EXPNS	Annual production expenses (includes fuel)(includes both fixed & variable operations expense)

Eliminating Plants and/or Years with Flawed or Incomplete Fields:

The Form 1 database included some records in which fields were missing or contained erratic values. Records with data missing in fields required to calculate LCOE were discarded, as were records with erratic or unintelligible numbers and records where the plant name or specific unit in the plant could not be reconciled with the 2012 EIA 860 database.

For example, if a plant reported cumulative production expense figures that implied large negative values for some specific years, these might represent the correction of a previous error, but it is impossible to know which previous year or years were corrected. In this case calculation of capital expense per MWh for any year would not be reliable. So for the plant in question, all years of and prior to any negative result(s) were omitted from the chronological plant record.

Discrimination of Useful from Incomplete/ Invalid Form 1 Records

In cases of missing data: if at least three consecutive years of complete data were available in the years prior to or following the missing data, we included as many consecutive years with complete data as possible—and in some cases, included more than one (but not more than two), sample windows for the same plant. Dual windows for the same plant were treated as two separate samples.

When a plant record reported a change in nameplate capacity of 5% or more, we divided the chronological data for the plant into two independent samples where three or more years of data were available before and after the nameplate capacity change. Because such uprates were optional, and historical learning might incorporate such uprates for new plants, the year(s) of the uprate were omitted from the former and latter samples for that plant. In that sense we calculate LCOE-E under the assumption no additional downtime and capital expense will occur over the remaining lifespan of that plant.

The year of a plant's retirement was often marked by a steep reduction in annual capacity factor. Where these reductions were significant, we omitted the final year from a plant's sample window. Assuming a thirty year lifespan, omitting the final year of operations created at most a 3.3% opportunity for error and on average about half that. Since very few plants retired during the Form 1 data window, the average error due to omitting the final year of operation over our entire sample was even less. Furthermore, since the final year could have been a partial year of operation, but the month of retirement was not often reported, inclusion of the final year would also represented an opportunity for error. The same reasoning applies to omission of initial year data for plants which began operation within the 20-year span of the database.

Form 1 suggests categories and names for respondents to use in the "plant_kind" field found on page 402, but then allows respondents to enter open-ended text responses in the field. As a result, our confidence in the accuracy of data was low. Misspellings, multiple names for the same technology, and inaccurate information were entered into this field. Inconsistencies appeared not only from one plant to another, but sometimes from year to year at the same plant. This lack of data certainty and sortability necessitated cross referencing Form 1 "plant_kind" data for each plant with the more reliable EIA 860 generator level and plant level databases, as explained in the EIA 860 section below.

EIA 860 Data

As indicated above, in the Form 1 filings FERC allowed open ended text for the "plant_kind" field. We found that in the EIA 860 generator level database, the fields "prime mover" and "fuel type" were consistently filled out. The public database contained complete, reliable annual records for all power plant facilities, and for the generators or units within those facilities. The following table shows fields collected from the 2012 plant level and generator level EIA 860 databases.

Field Retrieved	EIA Plant Data	EIA Generator Data	FERC Form 1 Data
Utility ID	x	x	
Utility Name	x	x	
Plant Code	x	x	
Plant Name	x	x	INCS
Plant/Unit Ownership			x
County	x		
State	x	x	x
ISO RTO	x		
Prime Mover (generator technology)		x	INCS
Energy Source 1		x	INCS
Energy Source 2		x	
Operational Status		x	x
Nameplate Capacity	x	x	x
Summer Capacity	x	x	x
Unit Initial Operating Year	x		x
Annual Generation			RDCT
Annual Fuel Expense			RDCT
Annual Total Operations Expense			x
Annual Aggregated Plant Capital Spending			x

x	Reported Consistently
INCS	Reported Inconsistently
RDCT	Partially Redacted

Once data were collected from both plant level and generator level 860 data sets, each facility's data were sorted and merged into a single row/record, similar to the procedure used with the Form 1 data.

Cross-Referencing Form 1 and 860 Records

Form 1 records for each plant were cross-referenced with 2012 EIA 860 plant and unit records, ascertaining/verifying the generating technology and fuel used at each plant. Plants and units we could not cross reference between Form 1 and 860 data sets were searched individually on the internet for utility industry and general news stories in an effort to create as complete and fully cross referenced Form 1 / EIA 860 data set as possible. Plants whose prime mover and/or fuel were still ambiguous were omitted from the sample.

Applying a Uniform Fuel Price to LCOE-E and LCOE-New

EIA publishes average delivered fuel prices by state for each month and year and a weighted average national annual figure for each fuel. In our calculations, we applied 2014 delivered fuel prices for natural gas to both existing and new generation resources. Because future fuel price fluctuations will impact LCOE from both new and existing plants similarly, 2014 fuel prices were applied to both.

FOOTNOTES: LCOE-E DATA SOURCES AND METHODOLOGY

[13] *http://www.ferc.gov/docs-filing/forms/form-1/data.asp*

[14] *Federal Energy Regulatory Commission, Form 1 – Electric Utility Annual Report, Dec. 18, 2014, http://www.ferc.gov/docs-filing/forms/form-1/data.asp.*

[15] *Energy Information Administration, Form EIA-860 detailed data, Feb. 17, 2015, http://www.eia.gov/electricity/data/eia860/*

III. DATA ANALYSIS

According to EIA, LCOE is "- the per-megawatt-hour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle."[16] Components of LCOE include:

- **Construction cost, typically paid using a blend of debt and owner equity with a repayment term for all technologies over the first 30 years of operation.**
- **Ongoing capital expenditures for upgrades and major overhauls**
- **Operations and maintenance expenses, which have fixed and variable components**
- **Fuel**
- **New transmission investment. Note that EIA's number for transmission investment does not take into account the likely physical location of any of the technologies examined in their report. Instead, EIA treats all technologies the same with regard to transmission investment.**

Because of the running total reported for cost of plant, construction cost is not independently reported in Form 1 records, except where the facility was constructed within the past 20 years. For the younger plants, we used the reported costs. For older plants, we used EIA's 2019 capital cost value for new plants of the same or similar technology, deflated from the 2012 dollar value to the year of the existing plant's construction as a proxy for actual construction cost.

Ongoing capital cost is reported as "Cost of Plant Total" in Form 1. This is a cumulative figure beginning with the year construction was commenced. For plants older than 20 years, the first year of available data for cost of plant total is a blended value of construction cost and ongoing annual capital expenditures through 1994.

An estimated adder for taxes, insurance and real cost of borrowing of 34 percent has been added to all capital costs per tables received from particular power plant financial officers.

Form 1 records show a total figure for operations and maintenance in each year's forms, showing both fixed and variable operations and maintenance expense and fuel. Fuel expense is reported in a separate field, allowing the derivation of total O&M excluding fuel. Fuel expense is then added back using 2014 delivered fuel prices. This was done because current fuel price is a better indicator of future fuel price than its historical fuel price.

Initial transmission costs for existing power plants were excluded because these costs are either fully repaid (in the case of older facilities) or are likely to be recovered through the rate base—even if the associated power plant retires prematurely. [17]

Next we converted historical year annual capital and O&M figures to 2014 dollars for every record[18] in the sample. We then divided annual capital and operations spending by annual net generation for each plant for each year to convert published figures into 2014 $/MWh.

U.S. average delivered cost of fuel per MWh was added at an assumed standard heat rate for each technology.

The remaining construction debt was calculated based on 30-year term from date of construction over the coming 30 years. Remaining debt and expected return on equity obligations make up a small fraction of levelized cost for existing resources.

The average of the coming thirty years' capital, O&M and fuel costs per MWh sum to the final levelized cost figure in 2014 dollars.

Present Value and Other Cost Adjustments

We applied an annual average rate of inflation to historical year reported data for O&M, construction cost and ongoing capital spending.[19] Only real rate of interest is implicit in the addition to capital cost described in the following section.

Applying Cost of Capital Adjustment to Ongoing Capital Expense per MWh

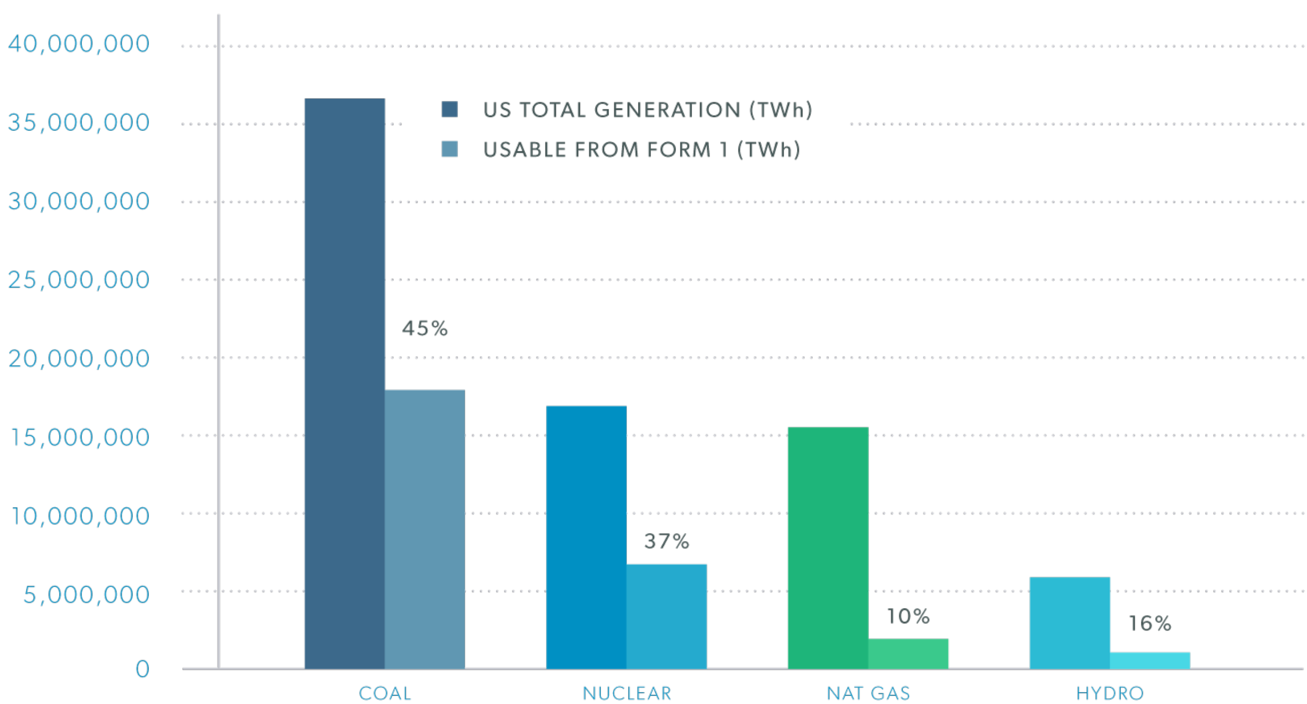
In the initial calculations of LCOE, we applied several factors:

– Inflation/present value factor: Using a table of historical inflation rates, we applied a present value calculation based on the mean age of each plant's sampled time window to bring all the figures to 2012 equivalent dollars.

– Real Cost of Capital, Insurance and Property Tax Multiplier: Based on recommendations from industry officials, we applied a fixed 34 percent adder to reported annual capital expense. While this may not be accurate for all plants or across technologies, using this average figure does not represent a significant error in the final results.

LCOE-E Form 1 Sample Size

The FERC Form 1 public database includes only data from non-government owned power plants. This represents a considerable limitation of our sample size compared to the entire grid-connected power plant fleet in the entire U.S.. The Form 1 database allows respondents open text entry of the name of the type of generating unit or units the respondents refer to in each form. For this reason this report cross-referenced Form 1 records with the most recently available EIA Form 860 records (2012). The Form 860 records require respondents to choose from a specific list of fuel and prime mover (technology) codes. The EIA maintains form 860 data for facilities generating units in separate files, with common fields across files so merging can be automated. Additionally, the 860 records make clear the nameplate capacity and age of each unit within each facility as well as the physical address, FERC market region and ISO/RTO (where applicable) of each plant. While the Form 1 data provided the necessary financial and electricity generation data, the 860 data provided a well-organized cross-check as to what was actually being reported in FERC Form 1. The following figure shows the usable sample size in the Form 1 database over the years 1994 – 2013 vs. the installed capacity in the U.S. by generating technology.

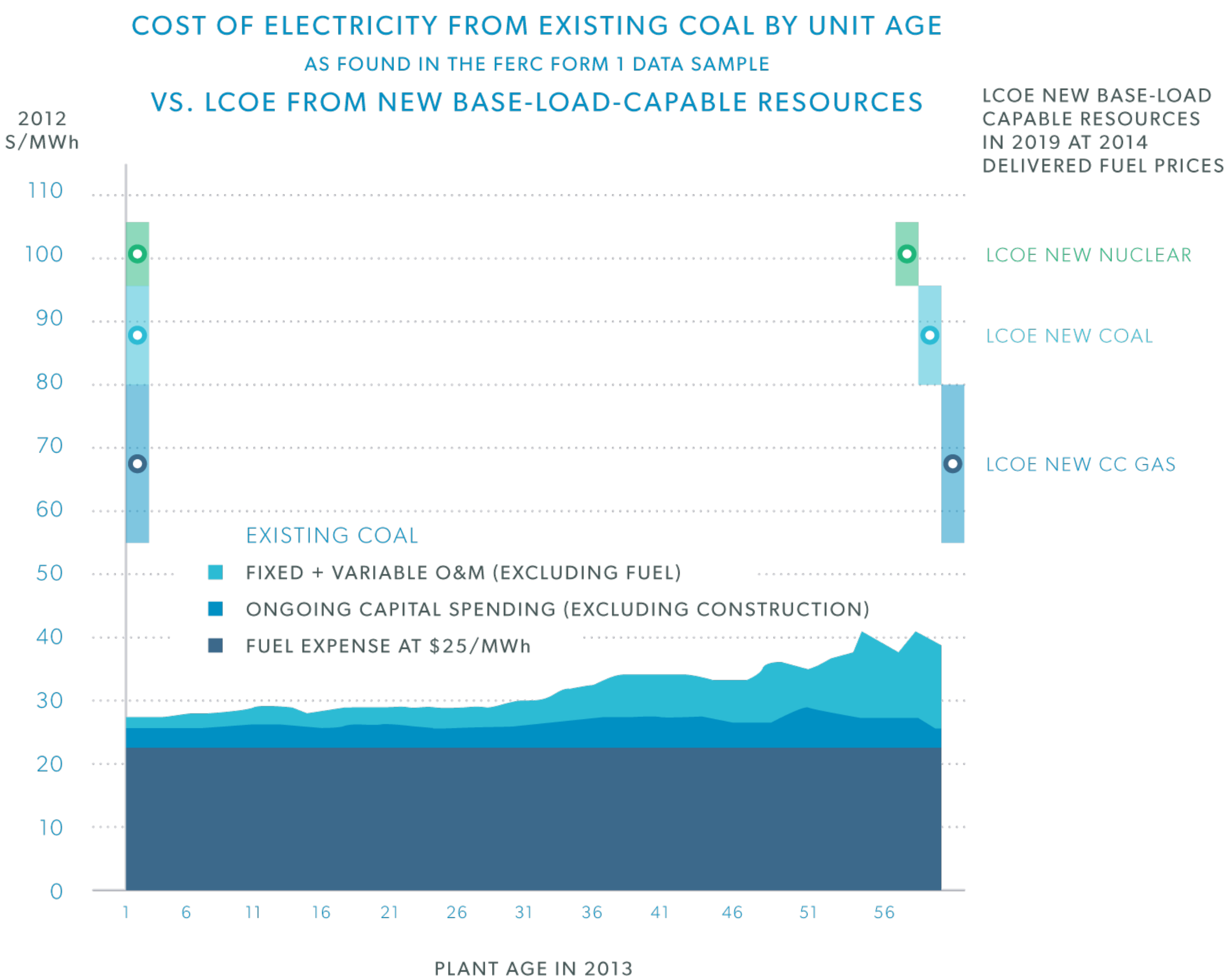


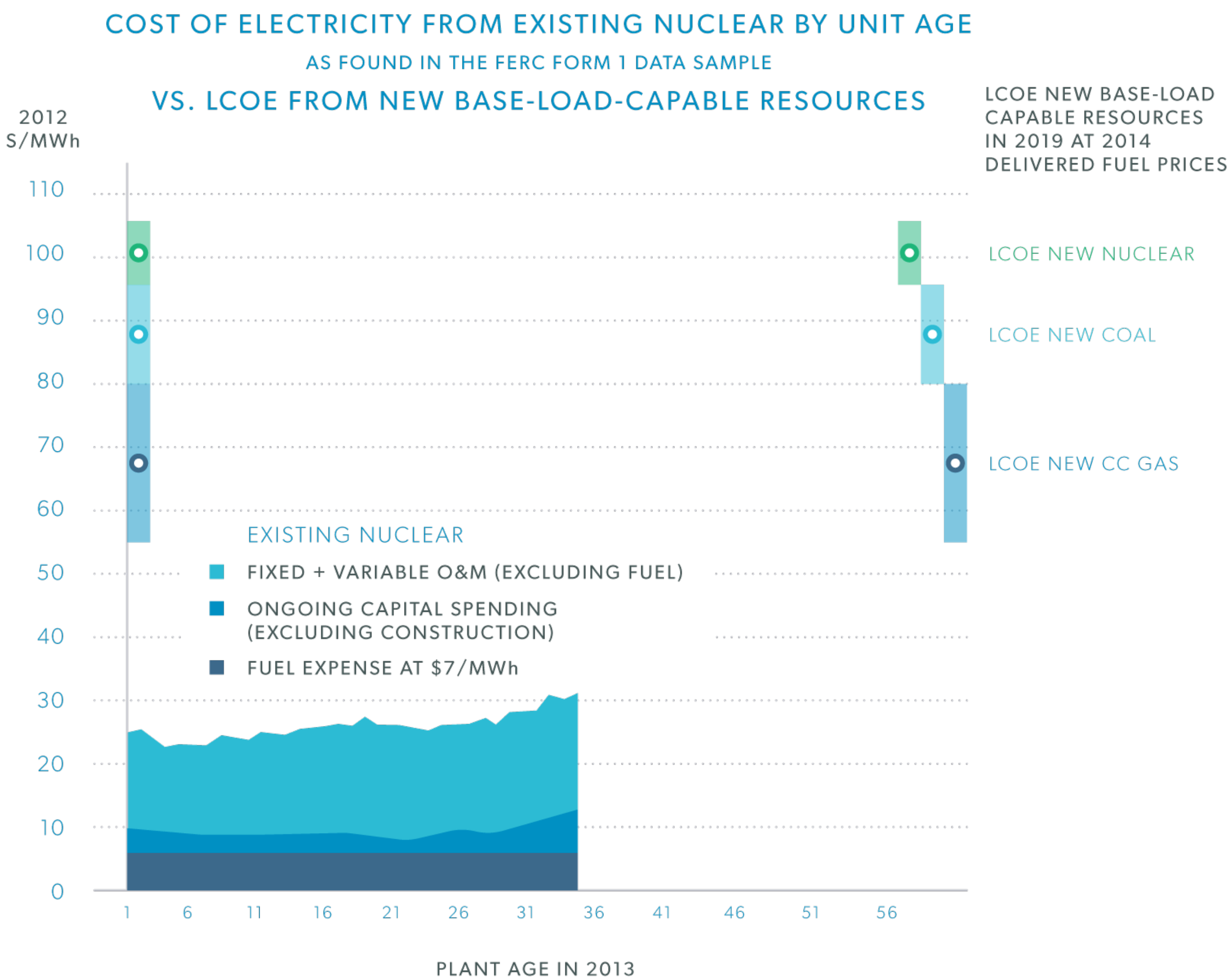
Capital Reinvestment and Operations Expense Trends by Technology by Plant Age

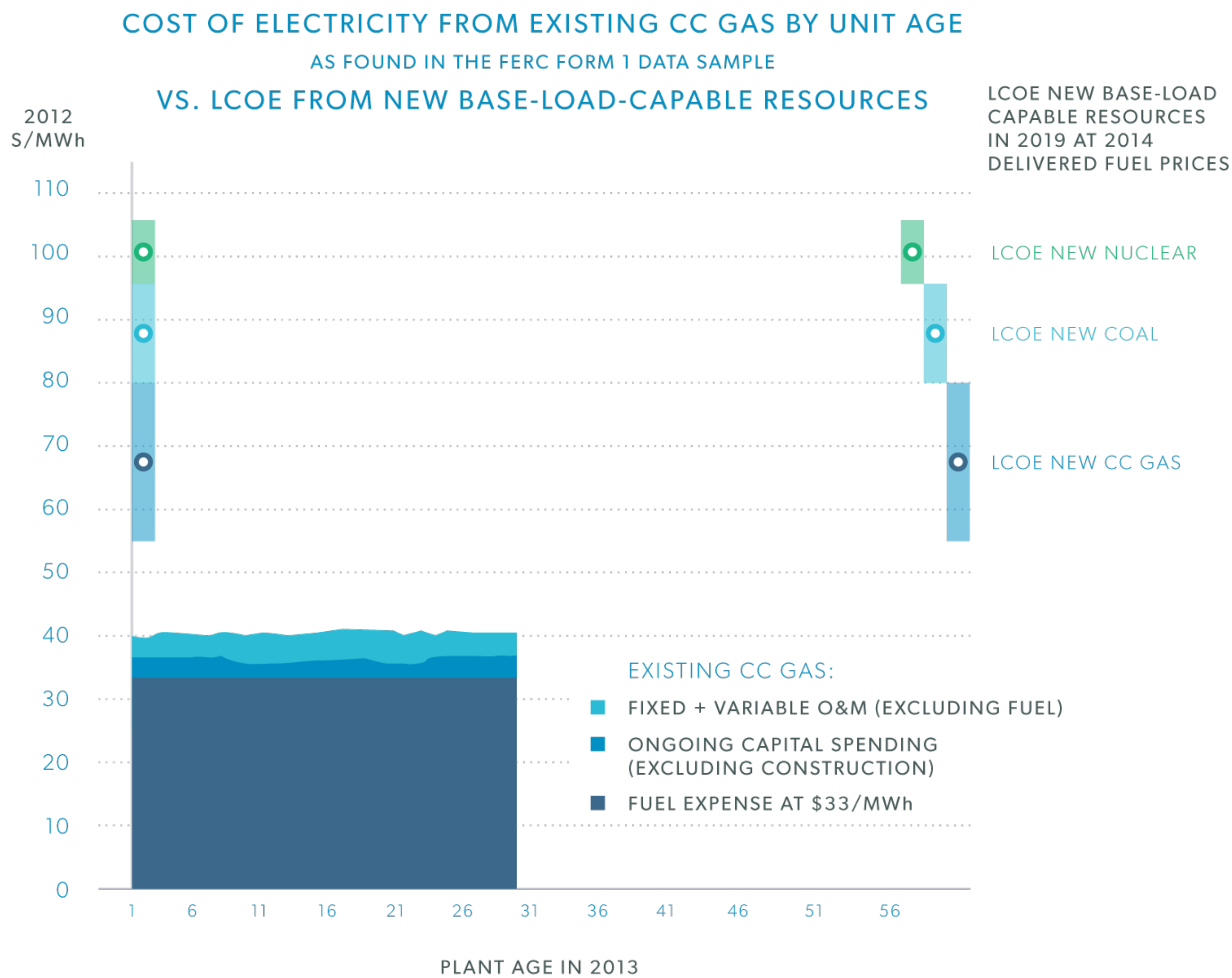
In addition to the "static" cost comparisons between various electricity resource choices, it is helpful to illustrate trends by plant age. The FERC Form 1 sample offers a cross section of plants by plant age in two ways:

1. **It considers each plant's annual generation costs for up to the past twenty years.**
2. **It considers operating plants constructed over the entire history of the electricity sector.**

We illustrate these plant age trends by vintage within each major technology below. The shaded areas of the three graphs illustrate the average levelized cost of electricity from existing full-time-capable resources by generating technology by plant age, excluding outstanding construction debt repayment obligation and at 2014 delivered fuel prices. These values are derived from the usable FERC Form 1 sample. The horizontal stripes above each shaded area represent LCOE from new resources at their inception in 2019, at the same delivered fuel price used for existing resources. The vertical distance between the shaded area and any horizontal line above represents opportunity cost of replacing the existing resource with the corresponding new resource; assuming new resources achieve the best case scenario capacity factors.




COST OF ELECTRICITY FROM EXISTING NUCLEAR BY UNIT AGE
AS FOUND IN THE FERC FORM 1 DATA SAMPLE
VS. LCOE FROM NEW BASE-LOAD-CAPABLE RESOURCES
2012 $/MWh
LCOE NEW BASE-LOAD CAPABLE RESOURCES IN 2019 AT 2014 DELIVERED FUEL PRICES
110
100
90
80
70
60
50
40
30
20
10
0
LCOE NEW NUCLEAR
LCOE NEW COAL
LCOE NEW CC GAS
EXISTING NUCLEAR
FIXED + VARIABLE O&M (EXCLUDING FUEL)
ONGOING CAPITAL SPENDING (EXCLUDING CONSTRUCTION)
FUEL EXPENSE AT $7/MWh
1
6
11
16
21
26
31
36
41
46
51
56
PLANT AGE IN 2013



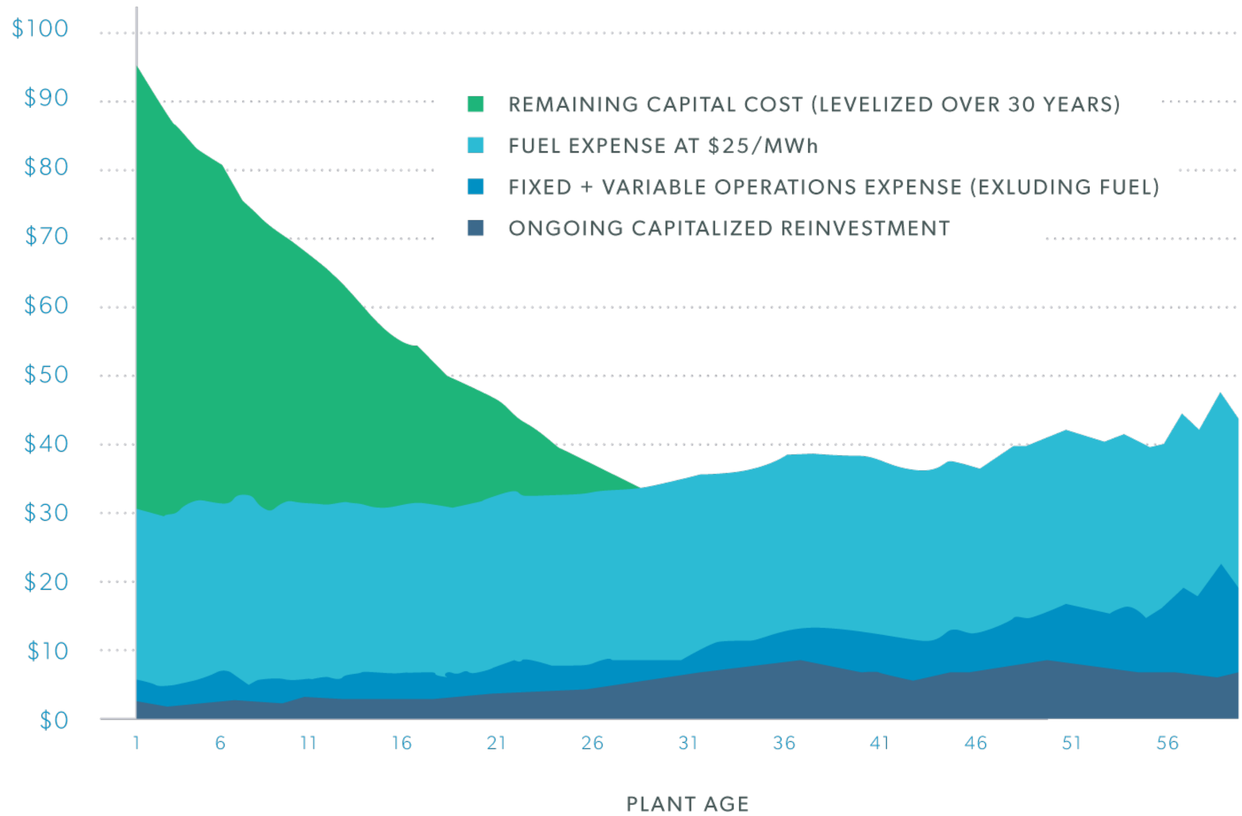
The shaded blocks for new full-time-capable technologies in the previous graphs show the range of expected LCOE based on the range of fleet-average capacity factors between actual (as reported by EIA in Electric Power Monthly) and "best case" (which were used by EIA to calculate LCOE-New).

These graphs indicate that, on average, existing full-time-capable plants of any age will have a lower LCOE than their likely replacements for the foreseeable future—even at "best case" capacity factors. Of course some existing units do not achieve their same-age technology's average LCOE. Some of those may be approaching or have reached the end of their competitive lifespans.

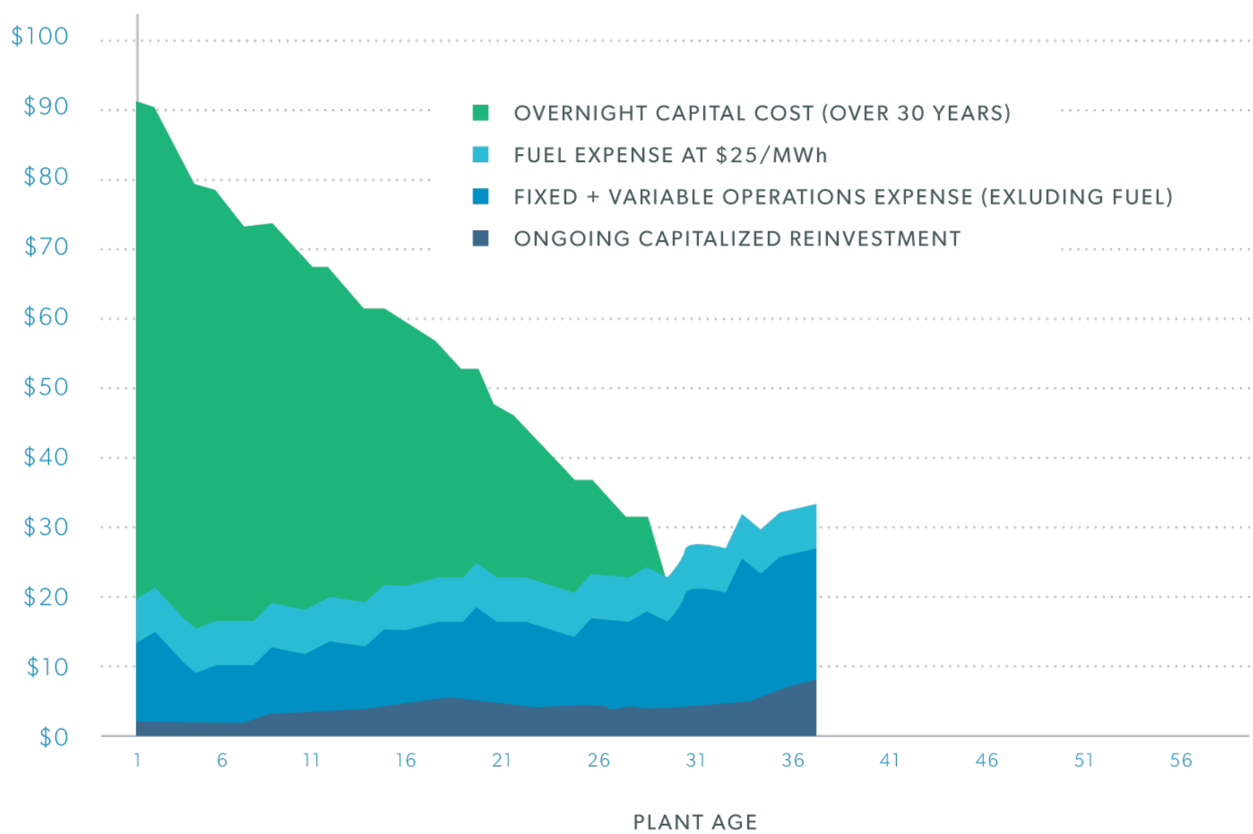
Reinvestment and Operations Expense by Unit Age vs. Remaining Fixed Costs Recovery for Base Load Capable Resources

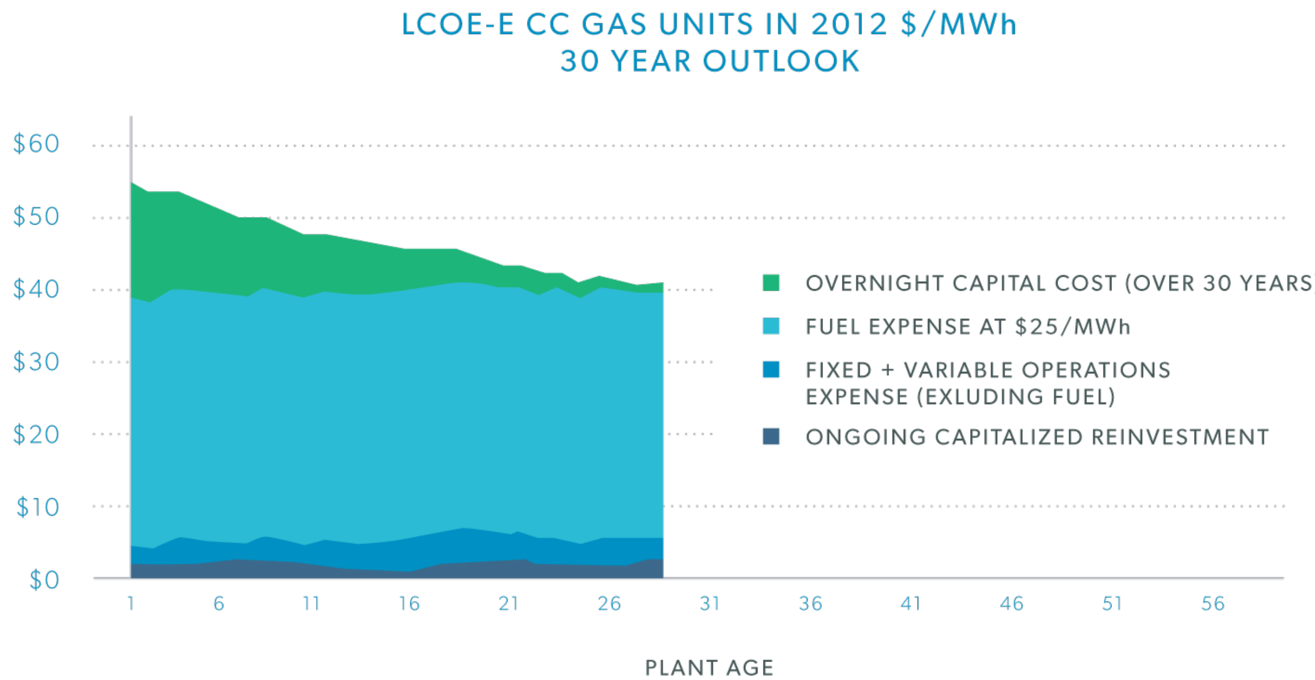
Data from Form 1 show ongoing expenses rise gradually over time as plants age. From a second perspective similar to that shown in the graphs above, some outstanding debt repayment and return on equity obligations do exist for all new and some existing units, but decline over an assumed 30-year financial repayment term. The purple shaded areas on the following charts represent the decline of remaining construction cost repayment obligation and the rising operations expense across their current lifespans. The height of the entire shaded area at any year represents the "going forward" LCOE for the next 30 years.

LCOE FROM COAL IN 2012 $/MWh BY PLANT AGE 30 YEAR OUTLOOK



LCOE FROM NUCLEAR IN 2012 $/MWh BY PLANT AGE 30 YEAR OUTLOOK





Observation: Going forward LCOE is at its lowest for plants which have just retired construction debt and equity obligations (at 30 years of age).

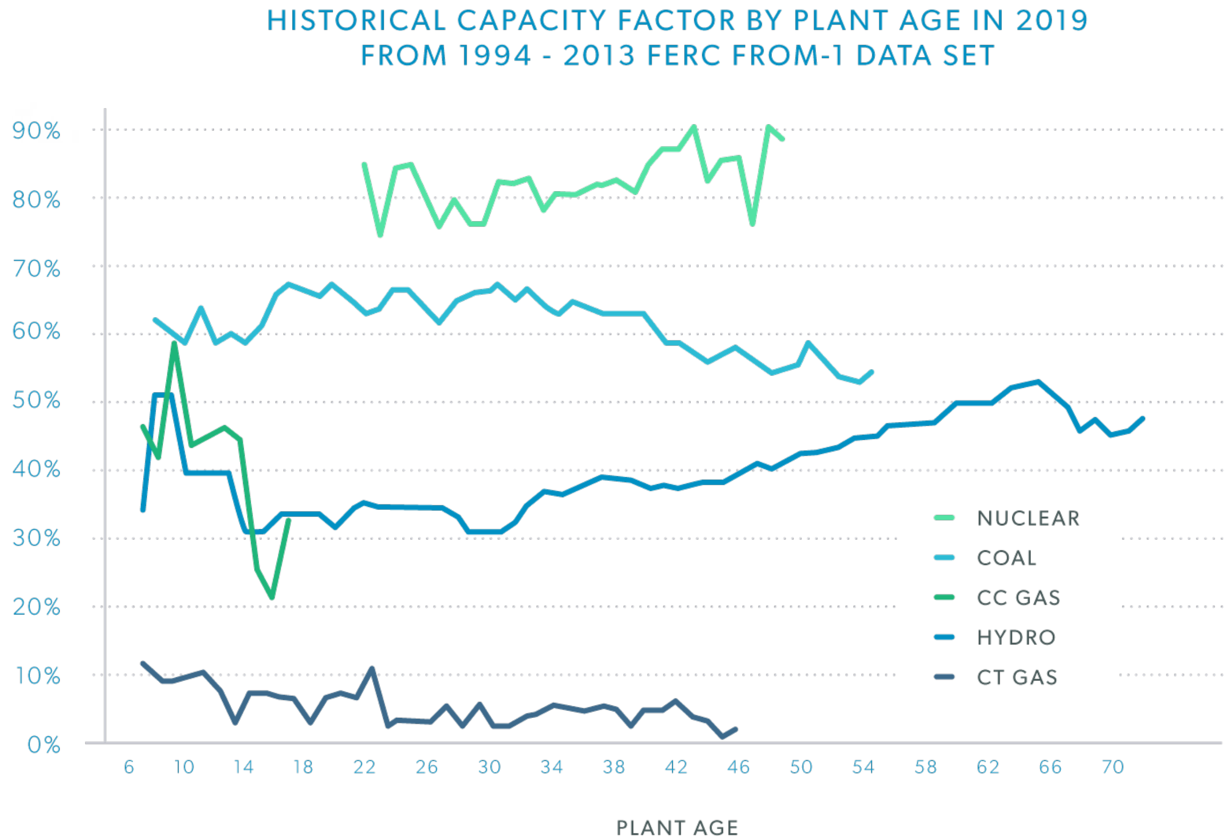
Observation: For plants within any generation resource category, per-MWh operations expenses rise gradually over their lifespans, but do not exceed the rate of decline in construction repayment obligations over a 30-year repayment term. On average, therefore, going-forward LCOE-E falls steadily until plants reach age 30, then rises gradually as operations and capital expenditures accrue due to facility and component age. Regulatory changes imposed on existing generators after they are constructed and in operation also force new capital expenditures.

On average, even for the oldest plants of each generation resource category sampled, rising operations capital reinvestment expenses do not appear to force LCOE-E to the level of LCOE from new resources for several years to several decades. This suggests the US could enjoy lower cost electricity for the foreseeable future by continuing to operate existing power plants with levelized costs lower than their possible replacements.

Observation: Older power plants with lower fixed costs and lower LCOE are of the highest value to electricity consumers.

Capacity Factor by Generating Technology by Plant Age

Capacity factor, listed as a percent, is the measured historical (or assumed future) utilization rate of a unit or technology over an average calendar year relative to theoretical maximum (running at nameplate capacity for all hours). The following graph indicates that capacity factors for older plants are not markedly lower than those for younger plants of the same type (except for hydroelectric).



Applying Real-World Capacity Factors to EIA LCOE-New

For new resources, EIA lists "best case scenario" capacity factors for each technology, based on an absence of market competition throughout a year. Capacity factors are de-rated based only on manufacturer suggested maintenance down time (all resources) seasonal fuel efficiency derates (nuclear and combustion technologies) and estimated average annual fuel source unavailability (wind, solar and hydro).

Historical capacity factors for fossil fueled resources are considerably lower than best case scenario levels for most technologies. As such, EIA's calculation of fixed costs per MWh likely underestimates actual fixed costs per MWh in competitive markets and fluctuating load conditions from day to night, weekday to weekend and season to season.

Table 2 lists real capacity factor ranges vs. the capacity factors used by EIA to calculate LCOE for new resources. The product of the sum of fixed cost components of LCOE-New and the adjustment multiplier for each resource yields LCOE-New under the assumption that average utilization rates for new resources would match average utilization rates of existing generators in the real world.

Generator Type	Fleet Average Capacity Factors For Existing Resources[20]	Best-Case Capacity Factor From EIA LCOE	Fixed Cost Adjustment Factor
DISPATCHABLE FULL-TIME-CAPABLE RESOURCES			
Conventional Coal	60.9%	85%	1.40
CC Gas	47.8%	87%	1.82
Nuclear	91.7%	90%	0.98
Hydro (seasonal – not fully dispatchable)	37.5%	53%	1.41
DISPATCHABLE PEAKING RESOURCE			
CT Gas	4.8%	30%	6.2
INTERMITTENT RESOURCES – AS USED IN PRACTICE			
Wind including cost imposed on CC gas	33.9%	35%	1.03

Table 3 shows the sum of per-MWh fixed cost components of LCOE-New and applies the real world adjustment multiplier. The right hand column shows LCOE-New at real world capacity factors.

New Generator Type	Sum of Fixed Costs of LCOE-New as reported by EIA ($/MWh)	×	Adjustment Factor	=	Adjusted Fixed Cost per MWh	+	Variable Costs inluding fuel at 2014 delivered price	=	EIA LCOE-New at Real-World Capacity Factors
Dispatchable Full-Time-Capable Resources									
Conventional Coal	49.8		1.40		69.5		28.2		97.7
CC Gas	17.2		1.82		31.3		42.1		73.4
Nuclear	84.3		0.98		82.7		9.9		92.7
Hydro (seasonal – not fully dispatchable)	78.1		1.41		110.4		6.4		116.8
Dispatchable Peaking Resource									
CT Gas	46.4		6.2		290.0		72.1		362.1
Intermittent Resources – as used in practice									
Wind including cost imposed on CC gas	80.3		1.03		82.9		+ $29.9 Imposed on new CC gas		112.8

As in previous tables, variable costs of natural gas include fuel at average 2014 delivered prices

Table 4 compares LCOE-E to LCOE-New at equivalent capacity factors.

Generator Type	LCOE Existing at Real World Capacity Factors (2012 $/MWh)	LCOE New (EIA) at Real-World Capacity Factors (2012 $/MWh)	Premium for Replacing Existing with Same Resource New
DISPATCHABLE FULL-TIME-CAPABLE RESOURCES			
Conventional Coal	38.4	97.7	154%
CC Gas	48.9	73.4	50%
Nuclear	29.6	92.7	213%
Hydro (seasonal – not fully dispatchable)	34.2	116.8	242%
DISPATCHABLE PEAKING RESOURCE			
CT Gas	142.8	362.1	154%
INTERMITTENT RESOURCES – AS USED IN PRACTICE			
Wind including cost imposed on CC gas*	––	112.8	––

Table 4 compares LCOE-E to LCOE-New at equivalent capacity factors.

The most common and likely near-term replacement taking place is new CC gas for existing coal, In this case, using the figures in Table 4, the premium would be (73.4 – 38.4) / 38.4 = 91%

Because the real world capacity factor adjustment for CC gas is substantially larger than for coal and the capacity factor adjustment for coal is substantially larger than for nuclear, the LCOEs for all three resources are closer to each other than in previous tables and in the AEO. If we applied the future natural gas price estimated in the AEO numbers, the difference would be even less.

Moreover, the comparison between LCOE-E and adjusted LCOE-New is even greater than it appeared using "ideal" capacity factors for the new resources. If future competitive forces, load shape and reserve margins remain similar to the existing markets, the cost premium consumers must pay when replacing existing active resources with same-technology new resources is substantially higher than indicated in Table 1 of this report. The most prevalent capacity replacement of comparable resources today is the replacement of existing coal capacity with new CC gas capacity. At 2014 delivered fuel prices that substitution imposes an energy cost premium of $(73.4 – 38.4), or $35/MWh, which is a 91% cost increase.

Calculation of Cost Imposed by Non-Dispatchable Resources on Fixed Cost per MWh From Base Load Capable Resources

As we discussed on page 9 above, non-dispatchable resources impose costs on dispatchable resources by causing them to run fewer hours without substantially reducing their fixed costs. Thus, with an increase in non-dispatchable generation, the fixed costs of dispatchable resources are levelized over fewer units of production. In this section, we detail our calculation finding that each additional MWh of wind imposes a cost of $15.87 per MWh under best-case capacity factors, and a cost of $29.94 per MWh under real-world capacity factors.

Intermittent resources do not always displace natural gas generation. In practice, they also displace generation from coal and perhaps nuclear power plants, among others. But for simplicity and purposes of this report we make the following assumptions about how intermittent resources are integrated onto the electricity grid:

- We compare two scenarios in a snapshot in time (load growth and fuel prices are held constant).
- The base line scenario assumes no intermittent generation. In this simple baseline scenario, CC gas provides all needed electricity.
- The alternate scenario includes an intermittent resource combined with CC gas, where the two resources combine to produce the same constant output as in the baseline scenario.
- CC gas as a fleet offers 87% of its nameplate capacity as summer peak demand capacity credit[21] regardless of capacity factor.
- CC gas as a fleet offers base load capacity. That is, at whatever capacity factor it operates, it operates at the same level all the time.
- Intermittent resources are "paired" with CC gas to create the same flat generation profile, capacity factor and capacity value in the pairing as achieved by CC gas alone in the base line scenario.
- Capacity values for intermittent resources are determined using the "mean of lowest quartile output across summer peak hours" method recommended by Midcontinent ISO's market monitor, Potomac Economics[22] and using hourly wind data from MISO and PJM[23] for calendar year 2013.
- Installed capacity of CC gas in the pairing is equal to installed capacity of CC gas prior to the pairing minus the capacity value of the intermittent resource in the pairing.
- Installed capacity of the intermittent resource is equal to the nameplate of the CC gas prior to the addition of the intermittent resource times the CC gas capacity factor prior to the pairing.
- The annual energy from the new CC gas capacity in the pairing is the remainder of CC gas energy prior to the intermittent resource minus the energy that can be produced at the best-case capacity factor of the installed capacity of the intermittent resource.
- The new capacity factor of the new installed capacity of CC gas in the pairing is the new CC gas energy divided by the new CC gas capacity required to meet the capacity and energy levels of CC gas prior to the pairing.
- Fixed costs per MWh of CC gas are altered by multiplying the prior fixed costs per MWh by the prior capacity factor of CC gas divided by the new capacity factor of CC gas.
- The imposed cost per MWh of the intermittent resource is the increase in fixed cost per MWh of CC gas times the percentage of CC gas in the pairing divided by the percentage of the intermittent energy in the pairing.

Example 1: Base Load CC Gas + Wind at Best-Case Capacity Factors:

In this example the CC gas fleet runs at an 87% annual capacity factor. For simplicity, we assume the CC gas fleet runs at a steady state 24/7/365.

1 MW of CC gas on the system works to provide 0.870 MWs of constant power 24/7/365. Its capacity factor is: 0.870MW / 1MW= 87%.

0.870 MW of wind is then "installed" and operates at a 35% capacity factor with no curtailment. Its output ranges from a minimum of 2.7% of nameplate (using the mean of lowest quartile output across peak hours calculation method) to 100% of nameplate.[24]

To create the identical generation and capacity profile as the 1 MW of CC gas, we will require slightly less CC gas summer capacity by the amount of summer capacity offered by the 0.870 MW of wind. Specifically: 0.870 MW x 2.7% = 23.49 KW. 0.870 MW CC gas summer capacity – 0.02349 MW = 0.84651 MW of CC Gas summer capacity required. To achieve that level of summer capacity we must divide by the capacity value of the CC Gas facility: 0.84651 / 87% = 0.973 MW.

We have now established that the pairing includes 0.870 MW of wind nameplate capacity and 0.973 MW of CC gas nameplate capacity.

The CC gas system will back down in synchronously as wind generation increases so that the pairing produces 0.870 MWs continuously throughout the year.

The wind energy produces an average of 0.870 MWs x 35% capacity factor = 0.3045 average MWs of power. The CC gas produces 0.8700 MW – 0.3045MW = 0.5655 MWs from its installed 9,730MWs.

The new CC gas capacity factor in the pairing is: 5,655MW / 9,730MW = 58.1%

The fixed cost per MWh from the CC gas was $17.20/MWh at an 87% capacity factor. The new fixed cost per MWh is $17.20 x 87%/58.1% = $25.75/MWh.

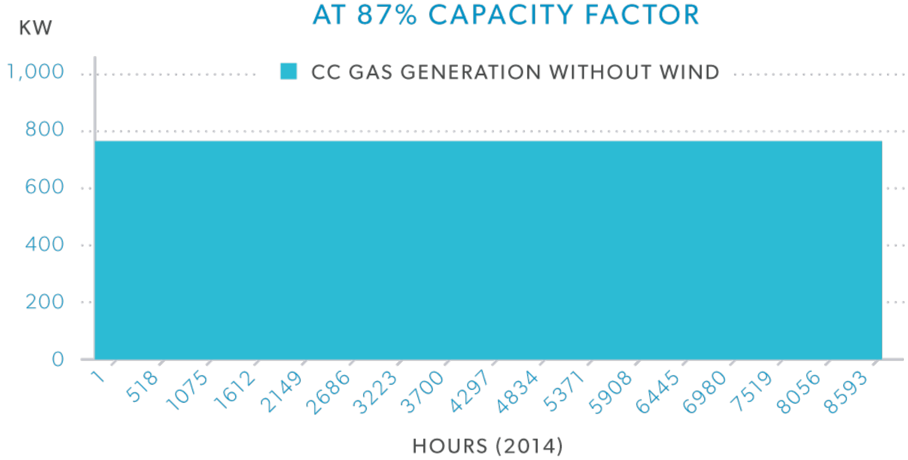
Each unit of gas in the pairing costs $25.75 - $17.20 = $8.55/MWh more than it used to.

Every MWh of wind energy in the pairing requires: 65% / 35% = 1.86 units of CC gas energy.

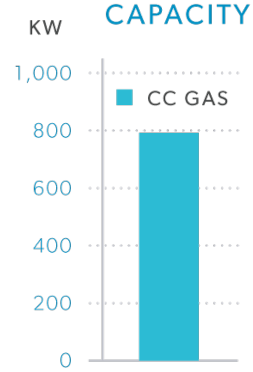
The imposed cost of wind on CC gas in the pairing is $8.55 x 65%/35% = **$15.87** per MWh of wind in the pairing. The natural gas fuel and capital cost savings in the pairing are integral to these figures. The figures in the following spreadsheet table reflect the example above. All Excel worksheets are available on request.[25]

Model to serve a full time slice of 870KW demand and 870KW of UCAP	
CC GAS SERVING MODEL REQUEST BY ITSELF	
Fixed Cost ($/MWh) of CC Gas at 87% CF	$17.2
Variable Cost ($/MWh) of CC Gas	$42.1
Capacity Factor of CC Gas	87.0%
Capacity Value (UCAP) of CC Gas	87.0%
ADD MAXIMUM WIND CAPACITY TO REPLICATE MODEL SCENARIO (WITHOUT CURTAILMENT)	
KIND OF INTERMITTENT	WIND
Nameplate Capacity of wind to build (MW)	0.870
Summer Capacity From wind (KW)	23.49
Average energy from 0.87MW of wind at 35% CP (KW)	304.50
Residual energy to be generated from CC Gas (KW)	565.50
Residual Summer Capacity Required from CC Gas (KW)	845.51
Nameplate Capacity of CC Gas required to meet new summer capacity requirement (KW)	973.00
Fixed Cost ($/MWh) of Intermittent	$80.3
Variable Cost ($/MWh) of Intermittent	$ --
Capacity Factor of Intermittent	35.0%
Capacity Value of Intermittent	2.7%
RESULTING RATIOS AND COSTS WHEN PAIRING WIND WITH CC GAS	
LCOE CC Gas Alone	$59.3
LCOE Intermittent Alone (Invalid Choice)	$80.3
CC Gas nameplate required to meet 870KW of summer capacity and 870KW of energy (KW)	1,000.0
Gas nameplate required to meet 0.65% of PREVIOUS energy and 846.51KW of summer capacity	973.0
Energy from 973 KW of CC gas in combination with wind	565.50
Old CC Gas capacity factor	87.0%
New CC Gas Capacity Factor After Backing Down for Intermittent	58.1%
Fixed Cost ($/MWh) of CC Gas in Combination with Intermittent	$25.75
LCOE CC Gas in Combination with Intermittent	$67.85
Percent of Energy from CC Gas	65.0%
Percent of Energy from Wind	35.0%
LCOE of combination new CC Gas + new wind	$72.21
Imposed cost on new CC Gas per unit of new wind	$15.87
LCOE new wind including imposed cost	$96.17
Imposed cost on CC Gas per unit of CC Gas in Pairing	$8.55

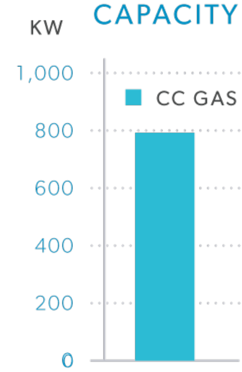
CC GAS ENERGY AS BASE LOAD (WITHOUT WIND) AT 87% CAPACITY FACTOR



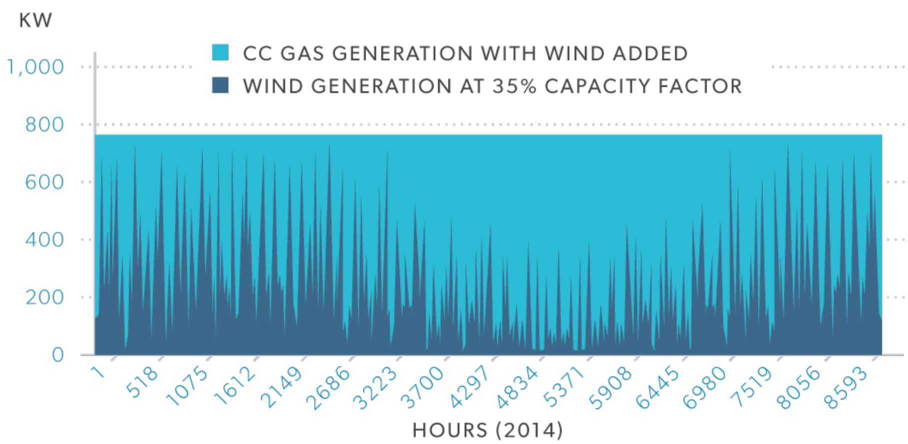
SUMMER CAPACITY



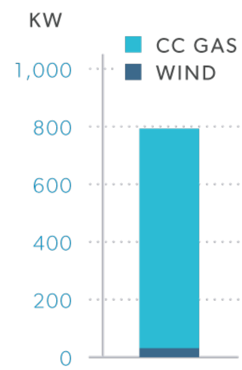
NAMEPLATE CAPACITY



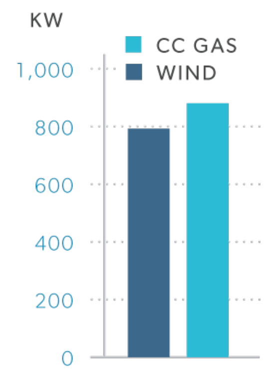
CC GAS ENERGY AT 87% CF + WIND ENERGY AT 35% CF AS BASE LOAD



SUMMER CAPACITY



NAMEPLATE CAPACITY



Example 2: "Base Load" CC Gas + Wind at Real-World Capacity Factors:

In this example the CC gas fleet runs at a 47.8% annual capacity factor. For simplicity, we assume the CC gas fleet runs at a steady state 24/7/365.

1 MW of CC gas on the system works to provide 0.478 MWs of constant power 24/7/365. Its capacity factor is: 0.478MW / 1MW= 47.8%.

0.478 MW of wind is then "installed" and operates at a 33.9% capacity factor with no curtailment. Its output ranges from a minimum of 2.7% of nameplate (using the mean of lowest quartile output across peak hours calculation method) to 100% of nameplate.

To create the identical generation and capacity profile as the 1 MW of CC gas, we will require slightly less CC gas summer capacity by the amount of summer capacity offered by the 1 MW of wind. Specifically: 0.478 MW wind nameplate x 2.7% = 12.91 KW of summer capacity from wind. 0.870 MW CC gas summer capacity – 0.01291 MW = 0.85709 MW of CC Gas summer capacity required. To achieve that level of summer capacity we must divide by the capacity value of the CC Gas facility: 0.85709 / 87% = 0.98517 MW.

We have now established that the pairing includes 0.478 MW of wind nameplate capacity and 0.98517 MW of CC gas nameplate capacity.

The CC gas system will back down in synchronously as wind generation increases so that the pairing produces 0.478 MWs continuously throughout the year.

The wind energy produces an average of 0.478 MWs x 33.9% capacity factor = 0.16204 average MWs of power. The CC gas is left to produce 0.478 MW – 0.16204MW = 0.31596 MWs from its installed 0.98517 MWs.

The new CC gas capacity factor in the pairing is: 0.31596 MW / 0.98517 MW = 32.07%

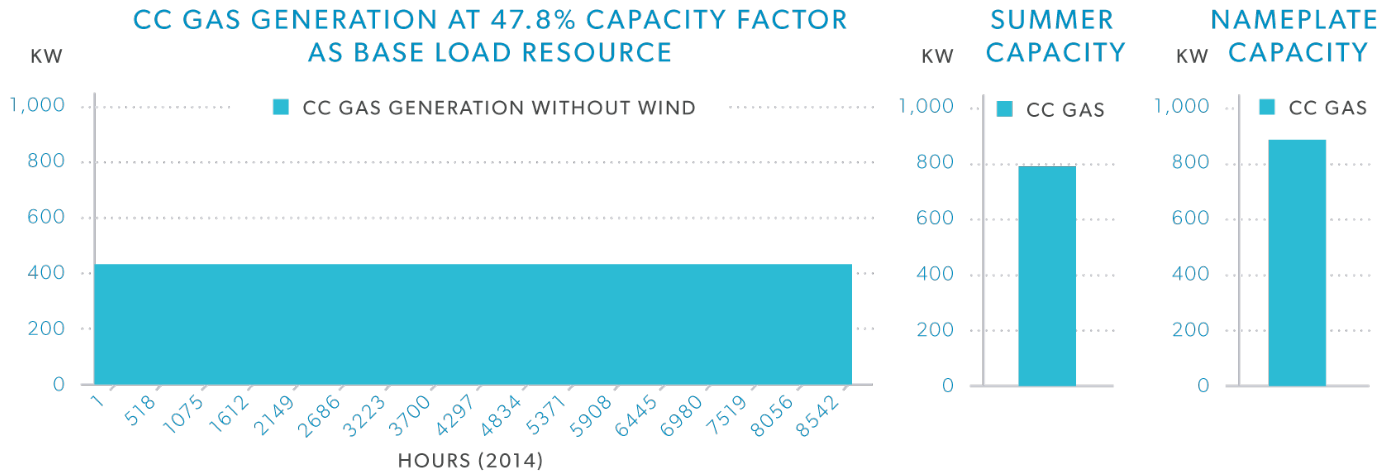
The fixed cost per MWh from the CC gas was $31.31/MWh at a 47.8% capacity factor. The new fixed cost per MWh is $31.31 x 47.8%/32.07% = $46.67/MWh.

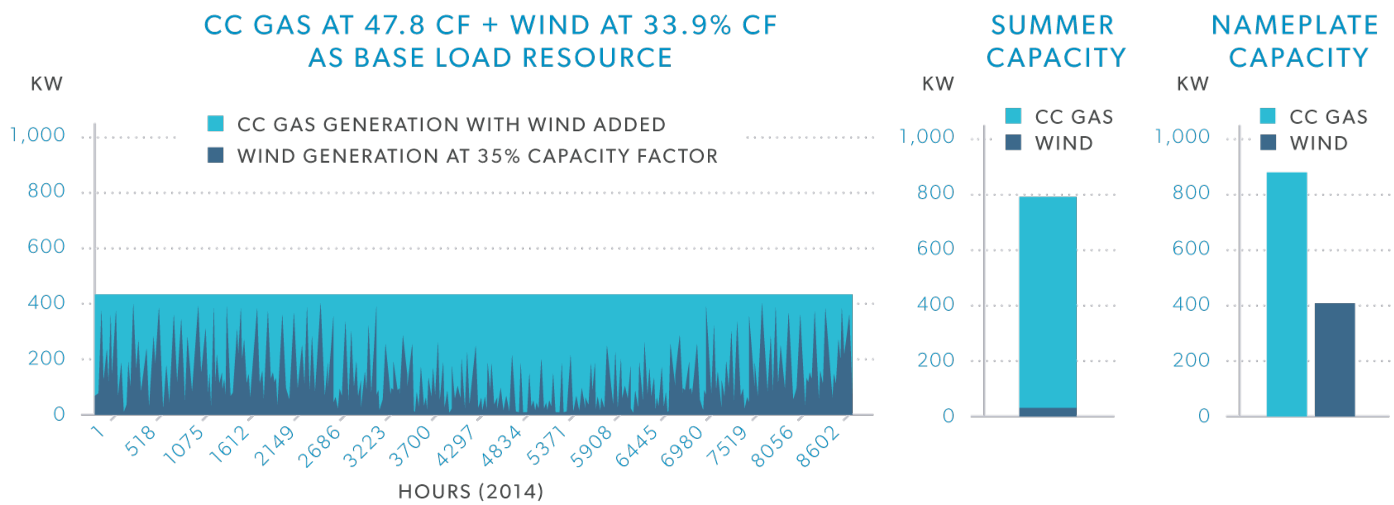
Each unit of gas in the pairing costs $46.67 - $31.31 = $15.35/MWh more than it used to.

Every MWh of wind energy in the pairing requires: 66.1% / 33.9% = 1.95 units of CC gas energy.

The imposed cost of wind on CC gas in the pairing is $15.35 x 66.1%/33.9% = **$29.94** per MWh of wind in the pairing. The natural gas fuel and capital cost savings in the pairing are integral to these figures. The figures in the following spreadsheet table reflect the example above. All Excel worksheets are available on request.[26]

Model to serve a full time slice of 478KW demand and 870KW of UCAP	
CC GAS SERVING MODEL REQUEST BY ITSELF	
Fixed Cost ($/MWh) of CC Gas at 47.8% CF	$31.31
Variable Cost ($/MWh) of CC Gas	$42.10
Capacity Factor of CC Gas	47.8%
Capacity Value (UCAP) of CC Gas	87.0%
ADD MAXIMUM WIND CAPACITY TO REPLICATE MODEL SCENARIO (WITHOUT CURTAILMENT)	
KIND OF INTERMITTENT	WIND
Nameplate Capacity of wind to build (MW)	0.478
Summer Capacity From wind (KW)	12.91
Average energy from 0.498MW of wind at 33.9% CF (KW)	162.04
Residual energy to be generated from CC Gas (KW)	315.96
Residual Summer Capacity Required from CC Gas (KW)	857.09
Nameplate Capacity of CC Gas required to meet new summer capacity requirement (KW)	985.17
Fixed Cost ($/MWh) of Intermittent	$82.91
Variable Cost ($/MWh) of Intermittent	$ --
Capacity Factor of Intermittent	33.9%
Capacity Value of Intermittent	2.7%
RESULTING RATIOS AND COSTS WHEN PAIRING WIND WITH CC GAS	
LCOE CC Gas Alone	$73.41
LCOE Intermittent Alone (Invalid Choice)	$82.91
CC Gas nameplate required to meet 870KW of summer capacity and 478KW of energy (KW)	1,000.0
Gas nameplate required to meet 0.661% of PREVIOUS energy and 857.09KW of summer capacity	985.17
Energy from 985.2 KW of CC gas in combination with wind	315.96
Old CC Gas capacity factor	47.8%
New CC Gas Capacity Factor After Backing Down for Intermittent	32.1%
Fixed Cost ($/MWh) of CC Gas in Combination with Intermittent	$46.7
LCOE CC Gas in Combination with Intermittent	$88.8
Percent of Energy from CC Gas	66.1%
Percent of Energy from Wind	33.9%
LCOE of combination new CC Gas + new wind	$86.77
Imposed cost on new CC Gas per unit of new wind	$29.94
LCOE new wind including imposed cost	$112.84
Imposed cost on CC Gas per unit of CC Gas in Pairing	$15.35





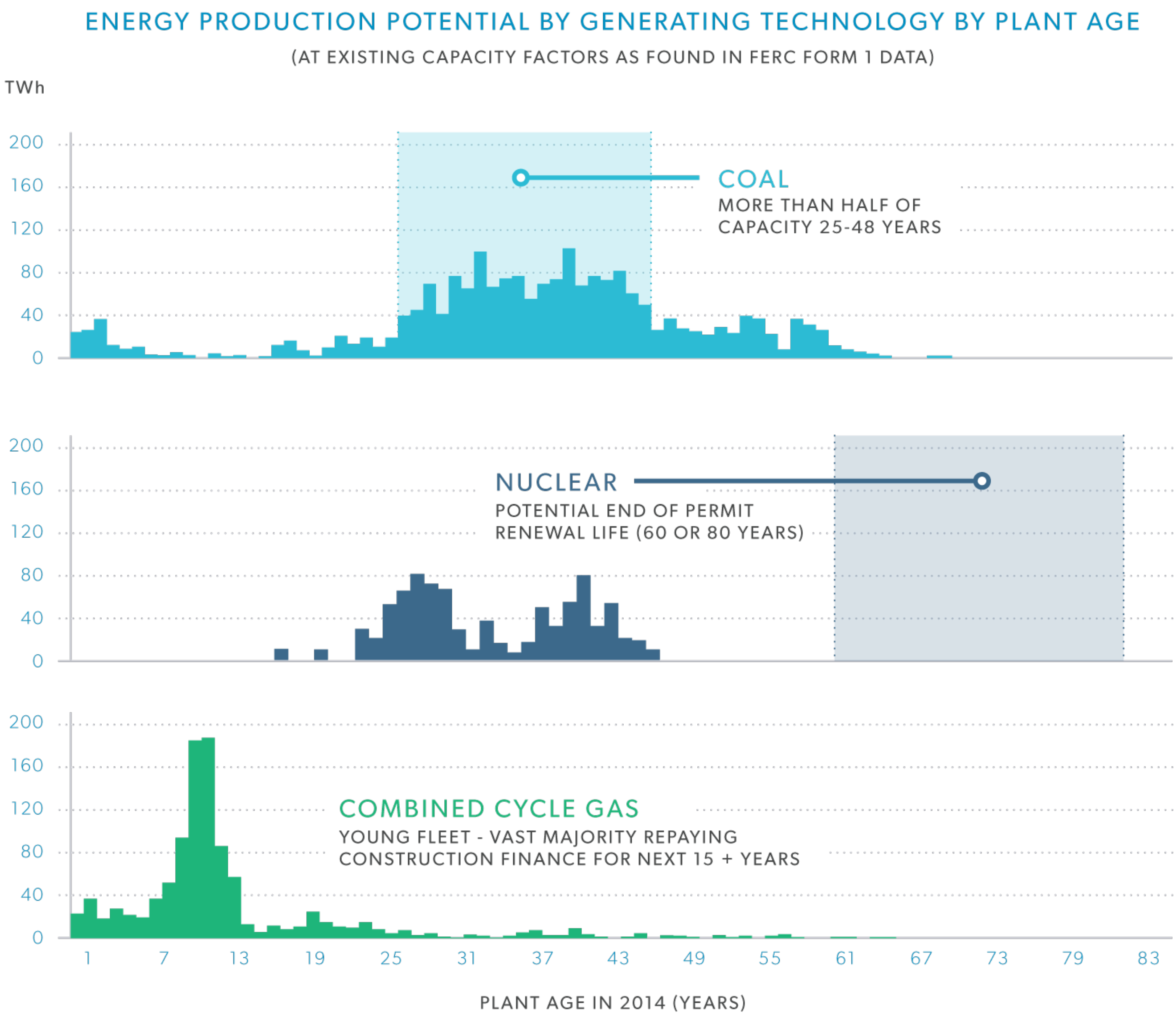
U.S. Generating Capability by Generating Technology by Unit Age

The following bar chart shows installed capacity times 8,760 hours (the number of hours in one year) times the highest capacity factors achievable for each respective technology as reported in EIA LCOE Table 1, herein referred to as "generating capability." The figure is shown for all US plants from newly commissioned through 83 years of age as reported in EIA Form 860.

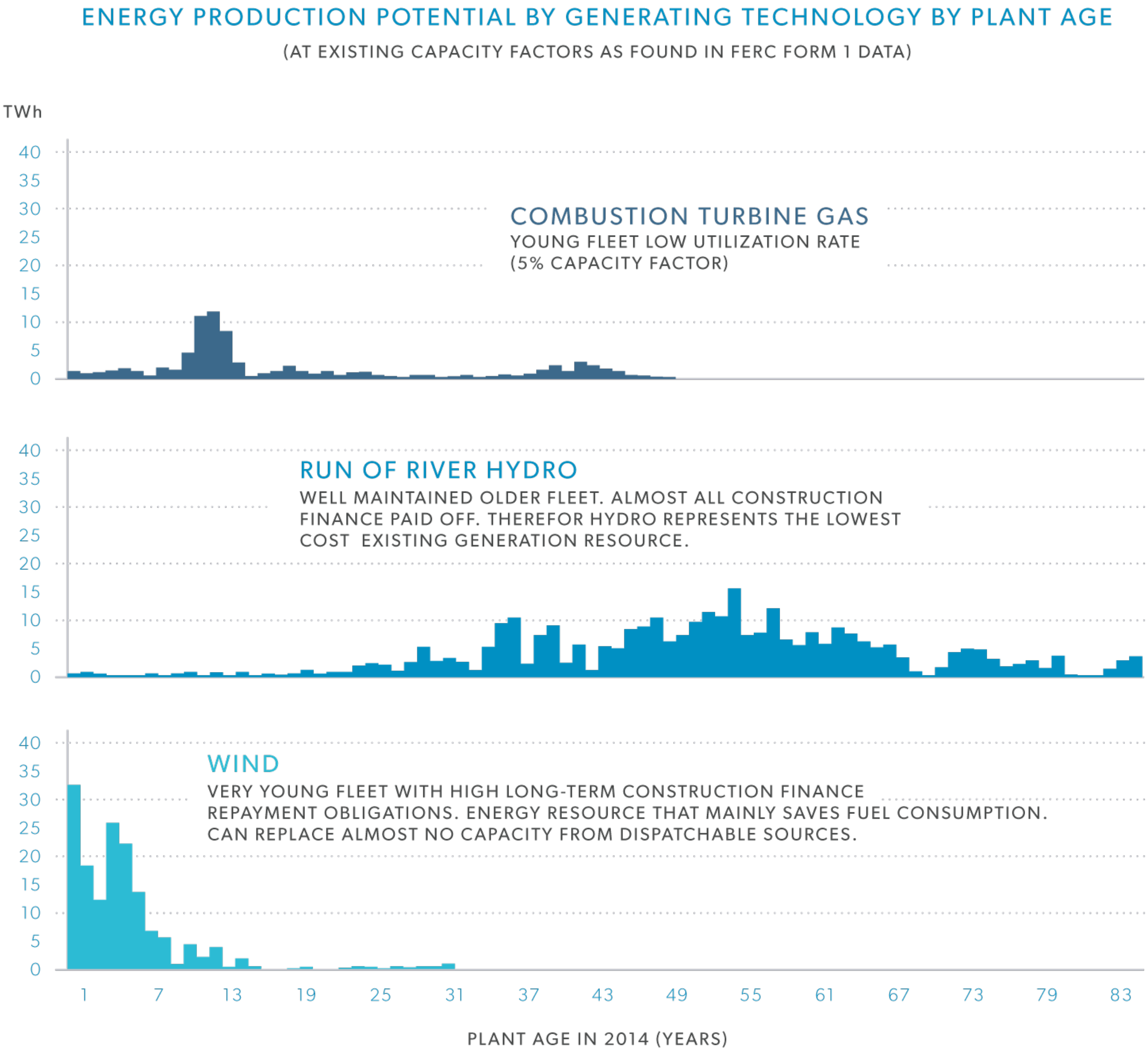
The three technologies shown in the first chart are full-time-capable resources that make them reasonable substitutes for each other. The technologies shown in the second group of three charts include sources that are not substitutes for one another or for any of the full-time-capable resources.

The vertical scale is different between the first and second set of charts—specifically, the scale is five times greater for the first compared with the second.

U.S. Generating Capability for Each Major Full-Time-Capable Resource by Unit Age



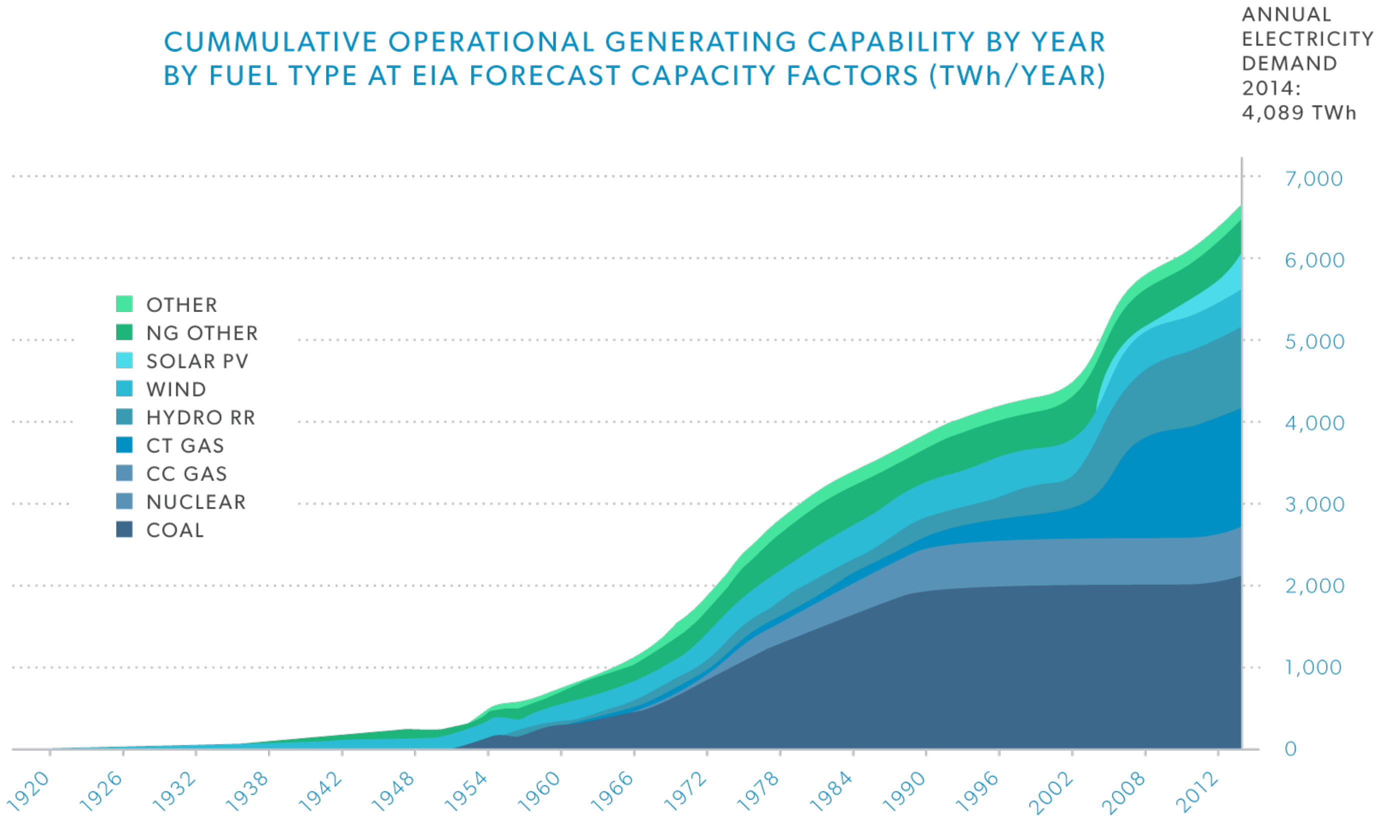
U.S. Generating Capability for Each Major Non-Full-Time-Capable Generator Type by Unit Age



The histograms above indicate that almost the entire existing fleet would have a decade or more remaining economic life relative to their likely replacements if not for the impacts imposed by new existing source environmental regulations coupled with the profit and market share erosion associated with subsidies and mandates for non-dispatchable (renewable) generation.

The following illustration shows the generating capability of the existing fleet by year at best-case capacity factors. Generating capability exceeds total demand by almost 65% and capacity was sufficient to meet peak demand (peak demand and summer capacity not shown).

CUMMULATIVE OPERATIONAL GENERATING CAPABILITY BY YEAR BY FUEL TYPE AT EIA FORECAST CAPACITY FACTORS (TWh/YEAR)

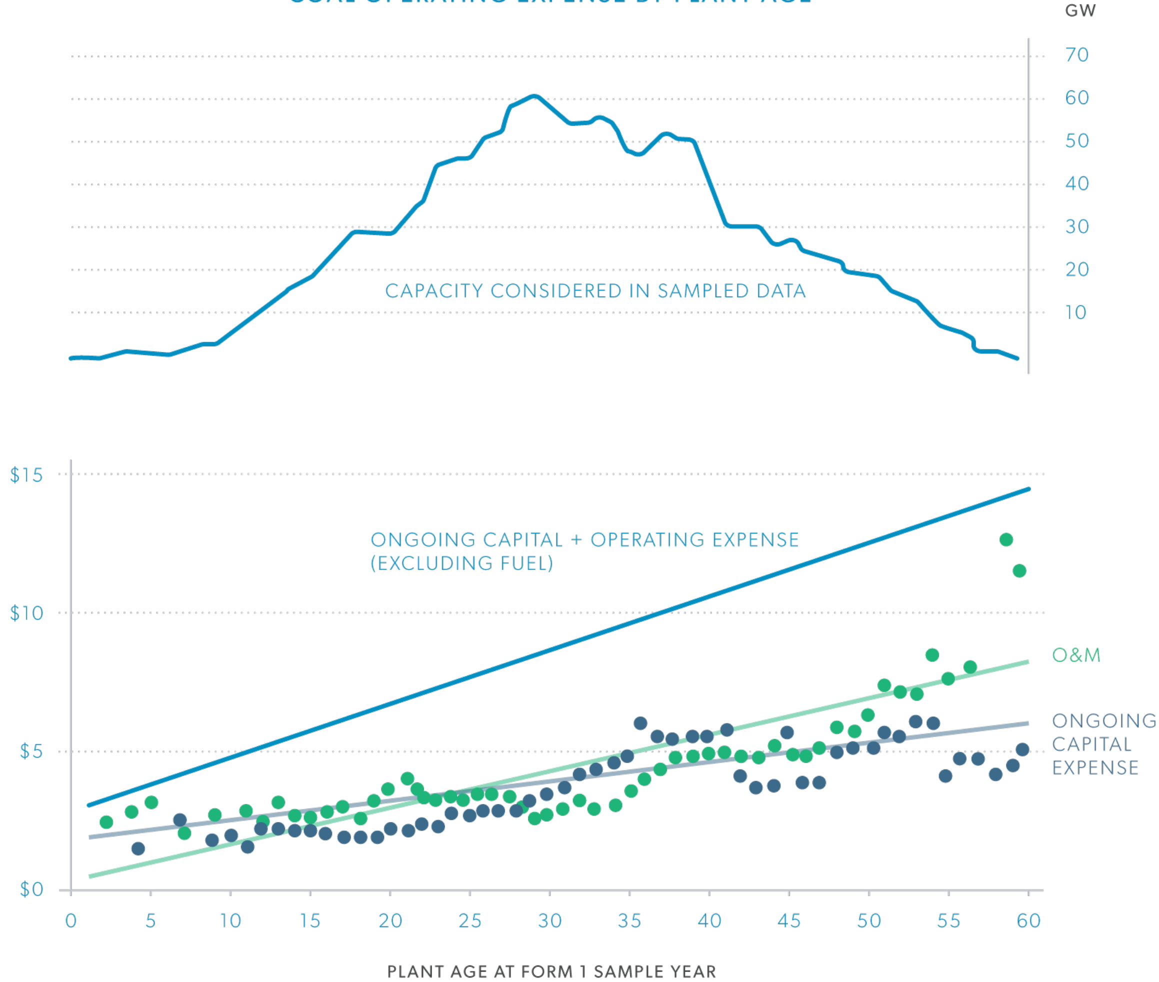


Source Data EIA 860, 2013 [27] *and AEO 2015* [28]

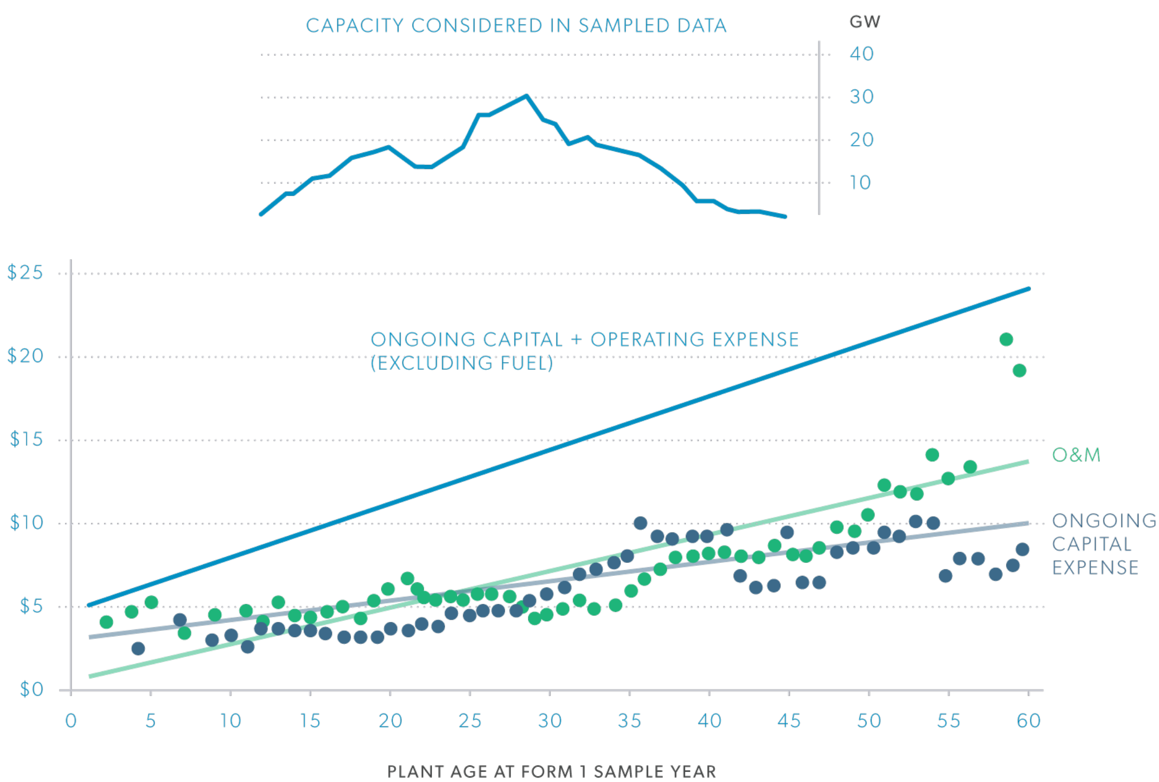
Sample Size by Plant Age by Major Generating Technology

The following bubble charts show fleet-average operations and ongoing capital reinvestment expenses by plant age for each considered technology. Bubble size as well as the line graph above each bubble chart represent the FERC Form 1 sample size by technology by plant age.

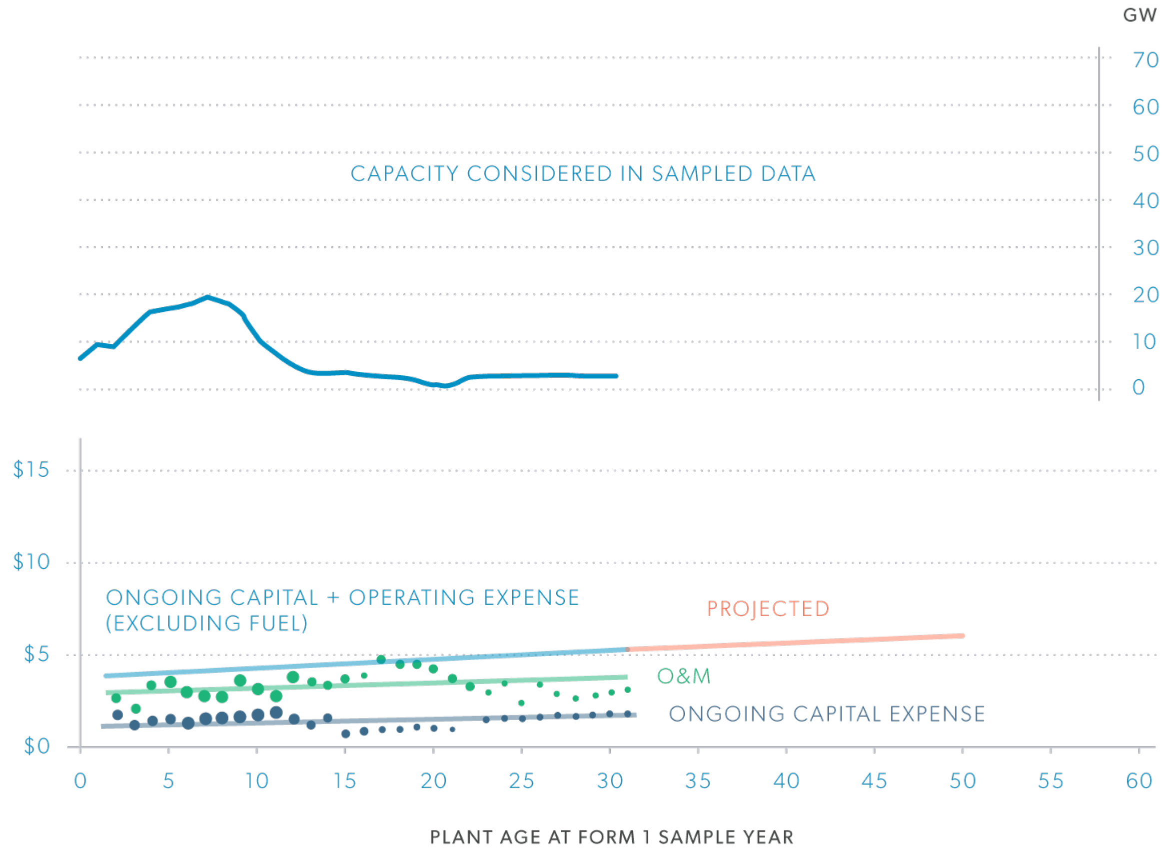
COAL OPERATING EXPENSE BY PLANT AGE



NUCLEAR OPERATING EXPENSE (2013 $/MWh) BY PLANT AGE



CC GAS OPERATING EXPENSE BY PLANT AGE



EIA's Calculation of the Components of LCOE

There are important limitations to the application of EIA's LCOE figures when evaluating the costs of electricity from and between new resources:

– EIA applies "best case" capacity factors in calculating fixed cost per MWh. As a result fixed costs per MWh and LCOE are understated for technologies whose capacity factors in real world application fall short of "best case." For example, EIA applies a 30% capacity factor to fixed costs of combustion turbines, while those resources realize only a 5% capacity factor in application today. This means fixed costs per MWh for CT are underestimated by six fold, driving LCOE up from $125/MWh to over $300/MWh.

– EIA assumes a 30-year lifespan for all technologies in their LCOE report for new generation resources, giving no credit to the value of the electricity produced by new units surviving beyond that age, and applying no penalty for technologies with operational lives of less than 30 years.

– EIA transmission investment figures do not recognize the additional cost of transmission associated with onshore wind, which must be sited near the best fuel availability locations. These locations are many hundreds of miles from primary load centers of the continental US. Therefore EIA either sharply underestimates transmission expense for wind or grossly overstates its achievable capacity factor. In either case, LCOE for new onshore wind is underestimated by EIA.

– Special accelerated depreciation available to wind and solar is not considered a "cost" in EIA's calculation of those technologies' LCOEs. It should be, however, because it represents advanced cash flows to wind developers and postponed cash flows to the treasury, which is funded primarily by all taxpayers.

– EIA divides its LCOE Table 1 into two sections attempting to separate resources which are not performance (and cost) comparable. In practice, combustion turbines are not performance comparable to full-time-equivalent resources and should be separated into their own section of the table to avoid confusion.

[16] *Energy Information Administration, Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014, Apr. 17, 2014,* *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm*

[17] *However, when an existing power plant is induced to retire and is replaced with a new one constructed at a a different site, the existing transmission serving the retiring generation unit may become underutilized, while new transmission must be constructed for the new generator. These circumstances add additional cost to the system that would otherwise be unnecessary. That would clearly be the case when wind energy capacity is added to the system because of the remote siting requirement for that technology. But in addition, some new natural gas fired power plants would also require either new gas or electricity transmission. While we maintain EIA's direct transmission cost estimates for new generation resources, estimates of imposed transmission cost are beyond the scope of this report.*

[18] *The number of records in the sample is equal to the number of "plant years" collected. This is the number of power plants reporting to Form 1 times the average number of years of complete data across all power plants). Due to some missing data and significant nameplate capacity changes at some plants, the average sample period was approximately 11 years.*

[19] *http://data.bls.gov/pdq/SurveyOutputServlet*

[20] *http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a and http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_b*

[21] *EIA Tables 4.7.C. Net Summer Capacity and 4.3 Nameplate Capacity*

[22] *https://www.potomaceconomics.com/uploads/reports/2012_SOM_Report_final_6-10-13.pdf Section II C, page 16*

[23] *ftp://ftp.pjm.com/operations/wind-web-posting/2013-hourly-wind.xls & https://www.misoenergy.org/Library/Repository/Market%20Reports/20131231_hwd_HIST.csv*

[24] *https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/Markets%20Committee/2013/20130724/20130724%20Markets%20Committee%20of%20the%20BOD%20Item%2005%202012%20SOM%20Report.pdf (Page 16)*

[25] *Contact Tom Stacy at (937) 407-6258 or tfstacy@gmail.com*

[26] *Contact Tom Stacy at (937) 407-6258 or tfstacy@gmail.com*

[27] *http://www.eia.gov/electricity/data/eia860/ (Generator/Unit level data set)*

[28] *http://www.eia.gov/forecasts/aeo/MT_electric.cfm*

IV. SUMMARY & RECOMMENDATIONS

Electricity from the existing generating fleet is less expensive than from its available new replacements, and existing generators whose construction costs repayment and recovery obligations have been substantially or entirely met are often the least-cost producers in their resource fleet. Cost trends extracted from Form 1 indicate the fleet average cost of electricity from existing resources is on track to remain a lower cost option than new generation resources for at least a decade—and possibly far longer.

However, wholesale energy and capacity market price suppression caused by external subsidies can drive lowest-cost generators toward earlier retirement than otherwise. This negative incentive is compounded as units face capital reinvestment decisions to comply with additional environmental or other regulations.

When low-cost electricity generators retire, they must be replaced with capacity sources whose electricity may be substantially more expensive. Recognizing these costs now could help avert poor policy and regulatory decisions in the near term.

A combination of current public policies drive the current retire/replace trend including:

- Subsidies; making the construction and operation of energy-only "renewable" generation resources the least-cost entry even though they may offer a significantly lower capacity value than the sources they displace.
- Mandates; requiring significant increases in the market share of renewable electricity over several years. Increases in market share for renewable energy erodes the market share and capacity factor of marginal high capacity value resources.
- Environmental and other regulations, both pending and finalized, add new fixed costs to existing units.

The levelized cost of electricity from existing resources (LCOE-E) is a vital piece of information that has been missing from the public policy discussion. The framework we introduce in this report offers policymakers a powerful tool as they make decisions that affect not only the cost structure of the U.S. electricity industry but, by extension, a large sector of the domestic economy and a fundamental part of Americans' well-being.