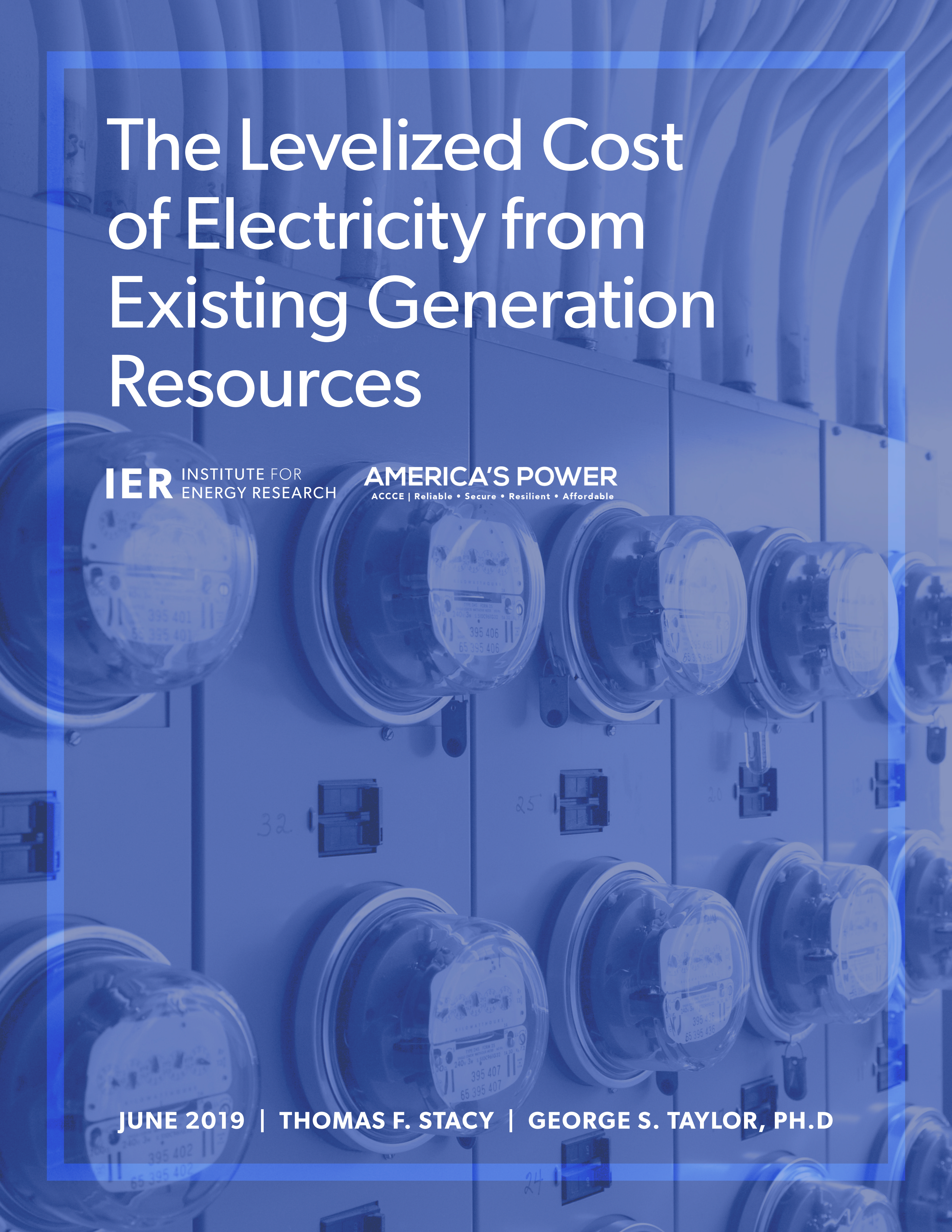

The Levelized Cost of Electricity from Existing Generation Resources

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JUNE 2019 | THOMAS F. STACY | GEORGE S. TAYLOR, PH.D

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Introduction

In this report, we analyze publicly available data to estimate the average levelized cost of electricity from existing generation resources (LCOE-Existing), as compared to the levelized cost of electricity from new generation resources (LCOE-New) that might replace them. The additional information provided by LCOE-Existing presents a more complete picture of the generation choices available to the electric utility industry, policymakers, regulators and consumers.

What is the levelized cost of electricity? The Energy Information Administration (EIA) defines it as "the cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle." But EIA's Annual Energy Outlook and similar LCOE reports focus only on new generation resources, while ignoring the cost of electricity from existing generation resources. If the economic lives of all generation resources matched their assumed financial lives, and no resource ever closed before the end of its economic life, then EIA's approach would provide enough information to compare the costs of the available options.

Contrary to that assumption, the economic lives of existing generation resources exceed EIA's assumed 30-year financial life. And environmental regulations on conventional generators—combined with the wholesale price suppression effect of mandates and subsidies for wind and solar resources and persistent low fuel prices for natural gas—have indeed forced existing coal and nuclear plants to close early. About 70 gigawatts of coal and nuclear generation capacity that could have been called upon on demand have retired since 2011.[1]

Our report has two principal findings:

First: that, on average, continuing to operate existing natural gas, coal, nuclear and hydroelectric resources is far less costly than building and operating new plants to replace them. Existing coal-fired power plants, for example, can generate electricity at an average LCOE of $41 per megawatt-hour, whereas we project the LCOE of a new coal plant operating at a similar duty cycle to be $71 per MWh. Similarly, we estimate existing combined-cycle (CC) gas power plants can generate electricity at an average LCOE of $36 per MWh, whereas we project the LCOE of a new CC gas plant to be $50 per MWh.

Second: is a calculation of the costs that non-dispatchable wind and solar generation resources impose on the dispatchable generation resources which are required to remain in service but are forced to generate less in combination with them. Non-dispatchable means that the level of output from wind and solar resources depends on factors beyond our control and cannot be relied upon to follow load fluctuations nor consistently perform during peak loads. Wind and solar resources increase the LCOE of dispatchable resources they cannot replace by reducing their utilization rates without reducing their fixed costs, resulting in a levelized fixed cost increase.

Our calculations estimate that the "imposed cost" of wind generation is about $24 per MWh (of wind generation) when we model the cost against new CC gas generation it might displace, and the imposed cost of solar generation is about $21 per MWh (of solar generation) when we model the CC and combustion turbine (CT) gas generation it might displace. The average LCOEs from existing coal ($41), CC gas ($36), nuclear ($33) and hydro ($38) resources are less than half the cost of new wind resources ($90) or new PV solar resources ($88.7) with imposed costs included.

FOOTNOTES: INTRODUCTION

[1] *EIA, Today in Energy, U.S. Utility-scale Electric Generating Capacity Retirements (2008—2020) in "Almost All Power Plants that Retired in the Past Decade Were Powered by Fossil Fuels"*, *www.eia.gov/todayinenergy/detail.php?id=34452*

About the Authors

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Tom Stacy has dedicated the past ten years to education and research on electricity generation, wholesale market design and public policy with a focus on the dynamics of grid-scale wind electricity; has served on the American Society of Mechanical Engineers Energy Policy Committee; and testified before energy policy committees of the Ohio legislature. He continues to help state lawmakers come to terms with the electricity system's complex economic and technical issues, in order to base the state's electricity-related laws and regulations on sound economic, engineering, and land-use principles. He holds a B.A. in Industrial Marketing from Ohio State University's Fisher College of Business.

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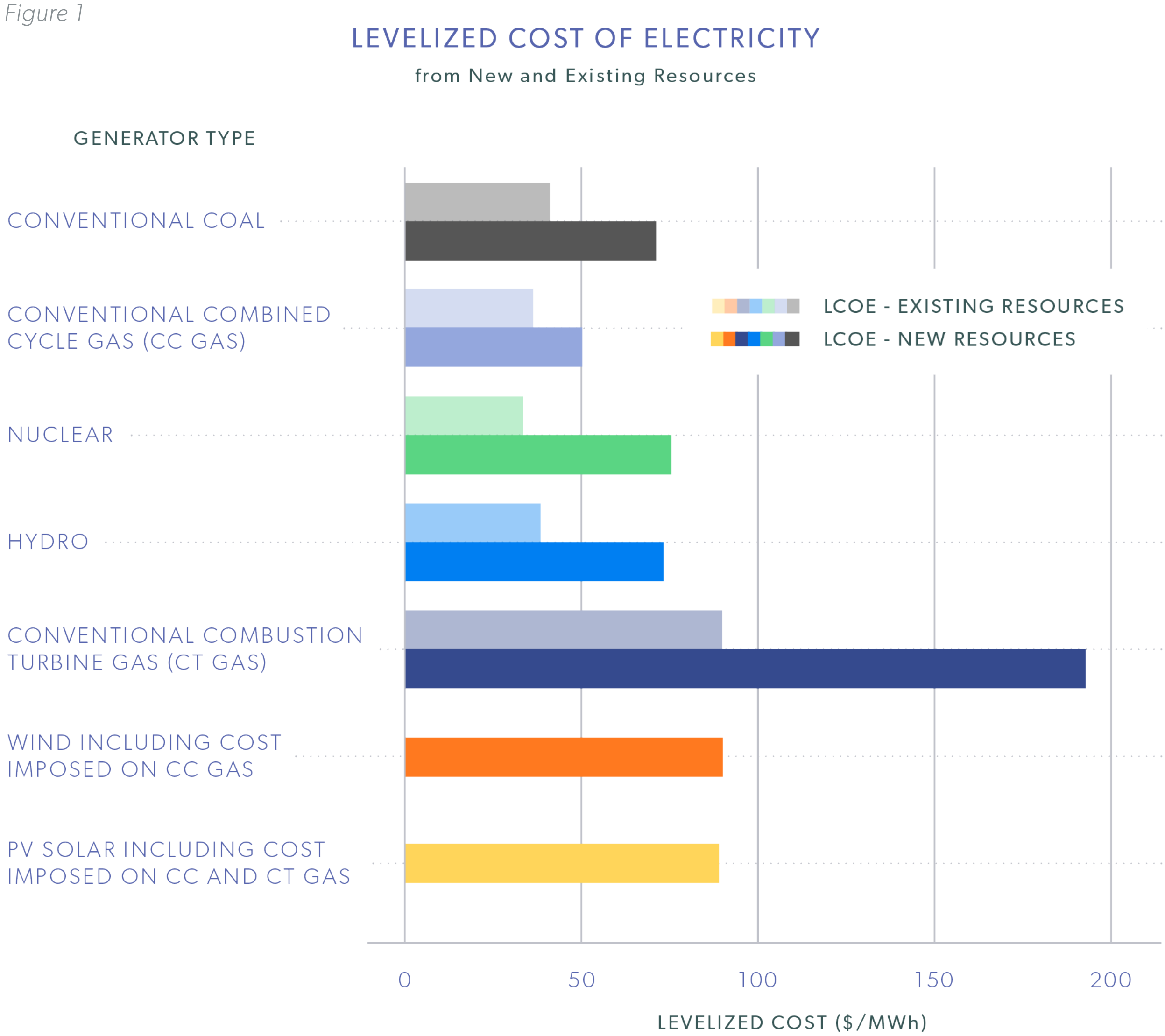
Executive Summary

This report estimates the levelized cost of electricity (LCOE) from existing generation resources (LCOE-Existing) and compares them to the estimated LCOE of new resources (LCOE-New) that might be built to replace them. We use the most recently available public data collected by the Federal Energy Regulatory Commission (FERC) in its Form 1 database to estimate LCOE-Existing, then compare our estimates to the Department of Energy, Energy Information Administration's (EIA's) most recent estimates of LCOE-New, adjusted for today's fuel prices and utilization rates (capacity factors). **Our conclusion is that for all major full-time-capable generation resources (coal, combined-cycle gas, and nuclear), the levelized cost of electricity from new plants would be higher, on average, than the levelized cost of electricity from existing resources. (See Figure 1).**

Figure 1



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."[i] LCOE is a useful metric to compare different electricity generating resources of similar operating characteristics, but few analyses compare LCOE-New to LCOE-Existing.

The data we analyzed indicate that on average, existing power plants have lower fixed costs, yet similar variable costs, compared to their most likely replacements. The reason new plants have higher fixed costs is that they begin their operational lives with a full burden of construction cost to recover. Conversely, the ongoing fixed costs of existing power plants are lower because they have already paid for some or all of their original construction costs. In other words, to the extent power plants outlive their "mortgages," they enjoy lower fixed costs of operation, and thus are likely to be capable of supplying electricity at a lower cost overall.

Wind and solar have become popular choices for new energy generation but they are not replacements for required dispatchable capacity on the system, making fair levelized cost comparisons between them more difficult. In order to facilitate appropriate comparison of wind and solar with new and existing dispatchable resources, we explain and calculate an estimate of "imposed costs" and allocate them to the LCOE of wind and solar which create them. Table 1 and Figure 1 summarize our estimates for LCOE-Existing and LCOE-New for the seven leading generation technologies, grouped into three categories of practical functionality.

Column 2 of Table 1 shows the fleet-average LCOE-Existing. Column 3 shows EIA's projected LCOE-New which could be brought online in 2023 at highest achievable single-plant capacity factors.[ii] Column 4 show the estimates for LCOE-New after adjustments to Column 3 using current year data for levels of operation and the price of fuels. We draw our conclusions by comparing Column 2 to Column 4. However, even without adjustments, the estimated LCOE-Existing for dispatchable technologies (coal, gas, nuclear, and hydro) is less than the LCOE-New for all new electric generating technologies.

As summarized in Table 1, we can state the conclusions numerically in two ways:

1. The added cost of electricity from new resources of the same type would on average range from 40% more for combined-cycle natural gas (CC gas) to 75% more for coal, 90% more for hydro and over 100% more for nuclear.

2. The additional cost of electricity from the lowest-cost new resource (CC gas) would range from 25% more than average existing coal, 40% more than average existing CC gas and 50% more than average existing nuclear.

Existing resources supply all our electricity today and most could continue to do so – at comparatively low cost – for years and decades into the future. On the other hand, if laws, regulations and the design of specific wholesale markets lead existing power plants to retire earlier than they would have otherwise, ratepayers will ultimately bear the burden of higher electricity system producer-costs which contribute to retail electricity rates.

Our findings could have been different. The fuel savings from the higher efficiency of new plants might have more than paid for new capital investment. Or the cost of replacement modules purchased one at a time could have been higher than the cost of building an entire new plant. But according to the data we analyzed, neither is the case. Efficiency gains due to new technology are small, and economies of scale for large construction projects do not enjoy the same economies of scale as mass-produced goods. The data suggest the cost of replacement modules purchased one at a time for an existing power plant is not much higher than the cost of purchasing those modules as a package in a new plant. Furthermore, many parts of existing plants have almost unlimited

TABLE 1

LCOE-EXISTING vs LCOE-NEW (2018 $/MWh)[5]:	LCOE-Existing (FERC FORM 1 2008 - 2017)[1]	LCOE-New (EIA/AEO 2019)	LCOE New (adjusted by this report)
Capacity Factors (CFs):	FORM 1 Average CFs	EIA LCOE 2019 Best Case CFs	2014 - 2018 EIA fleet avg CFs[11]
Heat Rates:	EIA 2017 Heat Rates for Existing[13]	that EIA used in AEO 2019[7]	that EIA used in AEO 2019[7]
Fuel Prices:	2018 EIA Fuel Prices[10]	used in EIA LCOE 2019 [2, 8, 12]	2018 EIA Fuel Prices[10]
DISPATCHABLE FULL-TIME-RESOURCES			
Conventional Coal	40.9	[3] 58.6	[6] 70.9
CC Gas	35.9	46.3	50.0
Nuclear	33.3	77.5	75.2
Hydro (seasonal)	[14] 38.2	39.1	73.1
DISPATCHABLE PEAKING RESOURCE			
CT Gas	89.9	89.3	192.9
INTERMITTENT RESOURCES – AS USED IN PRACTICE			
EIA New Wind including cost imposed on CC gas	[4] (N/A)	55.9	90.0 + other costs[9]
EIA New PV Solar including cost imposed on CC and CT	[4] (N/A)	60.0	88.7 + other costs[9]

1 Derived from the FERC Form 1 (https://www.ferc.gov/docs-filing/forms/form-1/data.asp)
2 Based on EIA's Annual Energy Outlook levelized cost report (https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf)
3 Interpolated using ratios between the levelized cost of conventional coal and coal with 90% CCS for capital and O&M from EIA's Annual Energy Outlook 2015 levelized cost report (https://www.eia.gov/outlooks/archive/aeo15/pdf/electricity_generation_2015.pdf) and those ratios applied to the components of the levelized cost of coal with 90% CCS from AEO 2019 levelized cost report (https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf).
4 No value for wind or PV solar was computed because the authors did not have access to FERC Form 1 data for these resources.
5 https://www.bls.gov/data/inflation_calculator.htm
6 Levelized cost components for new conventional coal LCOE estimate interpolated from the ratio of costs and heat rates between conventional coal and coal with 90 percent CCS published in EIA's levelized cost report for 2015 and AEO 2015 Assumptions Report with 2018 fuels costs and average heat rates for 2014 to 2018 applied. AEO 2015 was the most recent AEO that contained financial data for conventional coal. See (3), above.
7 https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf
8 Levelized fuel costs for new resources was derived by subtracting Variable O&M in https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf Table 2 from Levelized Variable O&M Including Fuel in AEO 2019 Levelized Cost Report https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf Table 1b.
9 Includes imposed costs based on low firm capacity contribution relative to energy contribution. For solar, $21.0/MWh based on 25% capacity value at 3% energy market share and 25.7% capacity factor.
10 https://www.eia.gov/totalenergy/data/monthly/pdf/sec9_13.pdf
11 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a
https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b
12 https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf
13 https://www.eia.gov/electricity/annual/html/epa_08_02.html
14 LCOE-Existing Hydro calculated for 2016 LCOE-E Report, inflated to 2018$/MWh.

lifetimes. Thus, any replacements in new power plants for functioning modules in existing ones are redundant, and on average, paying for a new power plant instead of maintaining an existing one increases the overall cost of the system.

Longevity of the Existing Fleet

Form 1 data indicate that, on average, existing coal, natural gas, nuclear and hydro generation resources could continue generating electricity for years to come at lower cost than their likely replacements. At a typical fossil fuel-fired power plant, for example, when a component wears out, only the component need be replaced, rather than the entire plant. And such replacement could continue indefinitely. The same is true for nuclear plants, until they reach their regulatory end of life, currently defined to be 60 years, but which may be extended to 80 years.[iii]

Under current laws and regulations, and low natural gas prices, about 70 GW of coal and nuclear capacity have retired since 2011.[iv]

Existing resources, on average, remain a lower cost option than their likely replacements. But, regulatory compliance costs and "wholesale price suppression" brought about by subsidies and mandates for higher-cost technologies (such as the wind production tax credit, the solar investment tax credit, and state-level wind and solar mandates) have contributed to some existing dispatchable resources operating at a financial loss. These external influences are inconsistent with minimizing costs to consumers over the long term because some existing resources may be forced to retire even though their likely replacements would generate electricity or provide required firm capacity to the system at an even higher cost.[v] The lowest electricity rates can only be achieved over the long-term by keeping existing generating resources in operation until their product becomes uneconomic– not relative to suppressed wholesale market clearing prices, but because the savings from replacing them over an assumed operating lifetime would outweigh the costs.

LCOE addresses electricity generation costs contributing to system cost optimization, but does not address how generators are compensated, or whether power markets place explicit or appropriate value on all of the services each technology provides. Each generation resource (technology and fuel combination) has characteristics that distinguish it from others, making both LCOE comparisons and wholesale market designs problematic. We indicate this by the three category sections in Table 1. Resource attributes are contrasted further in the "Analysis" section.

In other words, to the extent power plants outlive their "mortgages," they enjoy lower fixed costs of operation, and thus are likely to be capable of supplying electricity at a lower cost overall.

Conclusion

Low natural gas prices and subsidies, mandates and private purchase agreements for wind and solar generation (not additional demand or strictly cost considerations) have become the driving forces for most new construction, and for the premature retirement of existing dispatchable resources which are crucial for maintaining dispatchable generating capacity sufficient to meet system peak demand. This makes it particularly important to understand the fundamental value of new generating capacity as well as the existing dispatchable capacity it might replace. We find that, in general, absent external non-economic pressures, the most cost-effective generating option is not to replace existing resources.

FOOTNOTES: EXECUTIVE SUMMARY

[i] *EIA, Levelized Cost of New Generation Resources, in Annual Energy Outlook 2019, January 24, 2019, https://www.eia.gov/outlooks/aeo/pdf/electricity generation.pdf*

[ii] EIA does not estimate the LCOE-New for coal without carbon capture and sequestration (CCS) technology in AEO 2019. Therefore, we provide an estimated LCOE-New for coal without CCS technology using several relevant EIA assumptions.

[iii] *U.S. Nuclear Regulatory Commission, Status of Subsequent License Renewal Applications, www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html*

[iv] *EIA, Today in Energy, www.eia.gov/todayinenergy/detail.php?id=34452, January 9, 2018.*

[v] *Monitoring Analytics, https://www.monitoringanalytics.com/Filings/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf*
Section 1.B, Page 4, paragraphs 1, 2.

Data Sources And Methodology

Determination of LCOE-Existing

To calculate the levelized cost of electricity from existing generation resources, we utilized information from two federal databases:

Federal Energy Regulatory Commission (FERC) Form 1 — "a comprehensive financial and operating report submitted for Electric Rate regulation and financial audit,"[i] which includes annual net electricity generation, fuel consumption and other costs for all non-government-owned power plants for the past 24 years.

Energy Information Administration (EIA) Form 860 — which "collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants with 1 megawatt or greater combined nameplate capacity." [ii] The EIA 860 includes some of the same information as FERC Form 1 including technology employed in each plant, the types of fuel consumed and the capacities of individual units in multi-unit plants.

To produce this report, we collected, sorted and evaluated data from each year of Form 1 filings available online (1994-2017). Specifically: nameplate capacity, net generation (in kilowatt-hours), capital expenditures, fuel expense, and operations and maintenance expense. Capital expenditures are reported each year as a cumulative value from the year of startup, whereas O&M and fuel expenses are entered as annual expenditures.

A limitation of the Form 1 data is that it allows free-form responses for facility and unit names, technology and fuel type. FERC collects separate forms from each owner of shared-ownership plants. These remain unreconciled and separate in the public database. In contrast, Form 860 limits respondents' entries for plant name, unit name, fuel type and generator technology to specific ID numbers and codes. In addition to serving as a cross reference for these important fields, EIA 860 contains other generator attributes such as physical address, nameplate capacity, grid control region and Regional Transmission Operator / Independent System Operator interconnection. For these reasons we cross-reference Form 1 data with EIA 860 as a filtering step before analyzing Form 1 data.

Insufficient Wind and Solar Data

We could not extract sufficient, complete and consistent wind and solar facility data from the Form 1 public database so the LCOE-Existing for wind and solar generation resources could not be estimated. We publish no number for the levelized cost of existing wind or PV Solar.

FERC Form 1 Data

FERC Form 1 is maintained and offered to the public as annual databases—one for each of the past twenty-four years. To calculate LCOE-Existing this report, we used only Form 1 data over the past 10 years to better reflect recent trends in the resource mixes and economic dispatch orders across the U.S.

All thermal plants (gas, coal, nuclear and dual fuel) report as steam plants, and the steam database from FERC was accessible. CT Gas unit records appear in the stream unit data set even though CT Gas by definition does not employ a steam cycle. Hydro plants report under a separate category. Due to the obsolescence of the "Visual FoxPro" database format FERC uses to offer data to the public, and lack of conversion tools for that system, we were unable to access recent-year data for existing hydro for this analysis. Instead we substituted our calculations for the levelized cost for existing hydro made the cost for our 2016 study and restated in 2018$. The Form 1 fields used to calculate LCOE-Existing are listed in Figure 2.

Filtering Incomplete/Invalid Form 1 Records

Data fields critical to an LCOE calculation are annual net generation, annual capital expense and annual operations expense. If these data were absent or were out of

Figure 2

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)

reasonable range, that year's data was omitted and we kept the more recent years from that year in our sample. In cases of missing data, if at least two consecutive years of complete data from 2008-2017 was available prior to or following a year with missing data, we included as many consecutive years with complete data as possible up to ten years.

We always excluded data from the first year of operation and the year of retirement whenever these years surfaced in a record because these are often partial years of operation that we could not confidently reconcile to annualized figures.

Form 1 suggests categories and names for respondents to use in the "plant kind" field, but still allows respondents to enter open-ended text. This occurred across units as well as from year to year for the same units. This necessitated cross-referencing Form 1 "plant kind" data with Form 860 generator- level and plant-level information, where applicable, as indicated in Figure 3.

"Data out of range" also triggered plants to be removed from our sample. It seemed plausible in some cases that respondent personnel had skipped or added a digit, or reported in the wrong units for generation (such as MWh/yr instead of the requested kWhs per year). Because we could not be certain in most cases, we had no choice but to eliminate such years or units entirely from our sample in some cases. Data out of range was the single largest reason for omitting records from the samples.

Large negative values were reported for capital expense by some plants in some years, some large enough to negate up to twenty years of reported ongoing capital reinvestment expense. We polled several generation managers to inquire how this happens and how we might salvage such records for our sample. We concluded that plants reporting such amounts had to be eliminated from our sample.

Sorting Resource Category Data by Capacity Factors and Eliminating Outliers

We kept only units reporting in a reasonable range for their generator technology. For nuclear we kept units reporting in a range from 40% to 100%, for coal we kept records reporting a capacity factor range from 25% to 85%. For CC Gas category we kept units reporting from 20% to 90% capacity factor. For CT we kept units reporting between 0.5% and 50%.

Sample Years Limited to Reflect Recent Year Trends

Since our 2016 LCOE-Existing report[iii], substantial new natural gas, wind and PV Solar capacity have been installed, which has led to changes in capacity factors and energy market shares of all major generating technologies. 24-year-old cost and performance data for existing resources may not reflect current and future circumstances. Therefore, we truncated records of more than ten years in length and eliminated records whose sample period was longer than 10 years but ended before 2017. For samples more than ten years in length we used the two most recent years of data – if neither year was prior to 2008. We used the most recent two years in each sample of over ten years in length because it better reflects recent trends in reinvestments, expenses and dispatch order. Applying the screens to remove units with incomplete and otherwise unusable data left us with a much smaller but still significant data set: 8% of coal capacity, 74% of nuclear capacity, 7% of CC gas capacity, and 9% of CT gas capacity. Once collected, each facility's annual data were sorted and merged into a single record.

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

Because future natural gas and coal prices will impact the LCOE for both new and existing plants similarly, we applied 2018 fuel prices in both cases to put them on more equal terms. It would have represented a bias in favor of existing resources had we used the 2018 average fuel prices collected by EIA for existing resources and EIA's

Figure 3

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

projected fuel prices for new resources. EIA publishes average delivered fuel prices by state for each month and year, and a weighted-average national annual price for each fuel. [iv] Using a Levelized Variable Operations and Maintenance value published in the AEO 2019 Assumptions document for the Electricity Market Model[v], we determined the levelized fuel cost projection in EIA's most recent LCOE estimates. We subtracted that derived fuel cost and added back the 2018 fuel prices we used for LCOE-Existing.

Retaining Heat Rate Differences Between Existing and New Resources of the Same Type

EIA's LCOE calculations for new resources impute a projected heat rate in order to estimate "levelized variable O&M including fuel in $/MWh rather than the initial fuel cost in terms of $/Btu or a volumetric (natural gas) or gravimetric (coal) price." The heat rates EIA used are found in the AEO 2019 assumptions document. For existing resources we used EIA's "Tested Heat Rates" in 2017[vi], the most recently available published figures. The application of same fuel costs in terms of $/fuel unit for new and existing, but improved (projected) heat rates for new resources, resulted in a levelized fuel cost advantage for new resources of $2.6/MWh for coal, $3.7/MWh for CC Gas and $4.7/MWh for CT Gas over existing resources. Using most recently available fuel cost figures for new resources rather than projected fuel prices resulted in a reduced adjusted LCOE-New of $6.0/MWh for new coal, $7.4/MWh for new CC Gas and $12.0/MWh for new CT Gas.

Including Remaining Unrecovered Construction Costs

Stranded cost is not a factor in our LCOE-Existing estimates because we assume units in our sample will operate to at least age sixty and that their construction costs are fully recovered over the first 30 years of their operation. We assume full cost recovery by considering an estimated unrecovered capital cost estimate at each facility's first sample year. Because Form 1 reports capital investment cumulatively year over year and because some pants in our sample are older than 24 years, construction cost is not apparent from ongoing capital expense for all plants in our sample. For plants aged 25 to 30, we amortized the estimated remaining reported construction cost assuming a 30-year recovery period and a 5% real interest rate on debt and equity. We pro-rated those figures for each relevant plant across an additional 30 years of life as an adder to ongoing capital expense.

Calculating Fleet-Weighted-Average LCOE-Existing for Each Resource

We converted annual capital and O&M values for existing resources in our sample to 2018 dollars for every year within each record in the sample. We then divided annual average capital and operations expense in 2018$ by average annual net generation to arrive at levelized ongoing capital expense and levelized O&M for each plant in our sample.

To calculate the weighted fleet-average levelized capital and O&M expense excluding fuel for each resource, we weighted each plant's levelized capital expense and levelized O&M values by its generation across its sample window prior to making the fleet average calculation. This prevents over-weighting plants with fewer years in their samples or with lower average annual generation.

The average of the remaining years' (to age 60) capital, O&M and the addition of 2018 levelized fuel costs at 2017 tested heat rates ($/MWh) sum to the final LCOE-Existing figure for each resource.

FOOTNOTES: DATA SOURCES AND METHODOLOGY

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

[ii] *Energy Information Administration, Form EIA-860,* *https://www.eia.gov/electricity/data/eia860/*

[iii] IER, *http://instituteforenergyresearch.org/wp-content/uploads/2016/07/IER_LCOE_2016-2.pdf*

[iv] *EIA, https://www.eia.gov/totalenergy/data/monthly/pdf/sec9_13.pdf*

[v] *EIA, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf*

[vi] *EIA, https://www.eia.gov/electricity/annual/html/epa_08_01.html*

Findings

Tables 1-4 and Figure 1 summarize our principal findings, which are that for the four leading dispatchable generation technologies – combined-cycle natural gas (CC gas), coal, nuclear and hydro—the projected average levelized cost of electricity from new plants of the same type (or any competing type) is higher than the average levelized cost of electricity from existing plants:

1. The additional average LCOE from new resources of the same type ranges from 40% more for CC gas to 75% more for coal, 90% more for hydro and over 100% more for nuclear;

2. The projected LCOE of the lowest-cost full-time-capable new resource (CC gas) is 25% higher than the LCOE of existing coal, 30% higher than the LCOE of existing hydro, 40% higher than the LCOE existing CC gas and 50% higher than the LCOE for existing nuclear.

Definition of LCOE

EIA defines the levelized cost of electricity as "the per-megawatt-hour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle."[i] The components of LCOE include:

1. Construction cost, typically paid using a combination of equity and debt, for which EIA assumes a financial life of 30 years for all technologies
2. Ongoing capital expenditures
3. Fixed and variable operations and maintenance
4. Fuel
5. New transmission investment

Understanding Table 1

Table 1 summarizes LCOE-Existing versus LCOE-New for the seven leading generation technologies, grouped by the three segments of the demand curve which they address:

1. Dispatchable long-duration: CC gas, coal, nuclear and hydro
2. Dispatchable peak-load: CT gas
3. Non-dispatchable intermittent: wind and solar

Column 2 shows the LCOE-Existings we calculated based on:

1. Annual level of generation and costs reported to FERC for each resource from 2008-2017
2. The capacity factors[ii] (CFs) achieved by our sample of plants in FERC Form 1 from 2008-2017
3. Fleet-average fuel efficiencies (tested heat rates) reported by EIA for 2017[iii] and
4. Fuel prices (per Btu) reported by EIA for 2018[iv].

TABLE 1

LCOE-EXISTING vs LCOE-NEW (2018 $/MWh)[5]:	LCOE-Existing (FERC FORM 1 2008 - 2017)[1]	LCOE-New (EIA/AEO 2019)	LCOE New (adjusted by this report)
Capacity Factors (CFs):	FORM 1 Average CFs	EIA LCOE 2019 Best Case CFs	2014 - 2018 EIA fleet avg CFs[11]
Heat Rates:	EIA 2017 Heat Rates for Existing[13]	that EIA used in AEO 2019[7]	that EIA used in AEO 2019[7]
Fuel Prices:	2018 EIA Fuel Prices[10]	used in EIA LCOE 2019 [2, 8, 12]	2018 EIA Fuel Prices[10]
DISPATCHABLE FULL-TIME-RESOURCES			
Conventional Coal	40.9	[3] 58.6	[6] 70.9
CC Gas	35.9	46.3	50.0
Nuclear	33.3	77.5	75.2
Hydro (seasonal)	[14] 38.2	39.1	73.1
DISPATCHABLE PEAKING RESOURCE			
CT Gas	89.9	89.3	192.9
INTERMITTENT RESOURCES – AS USED IN PRACTICE			
EIA New Wind including cost imposed on CC gas	[4] (N/A)	55.9	90.0 + other costs[9]
EIA New PV Solar including cost imposed on CC and CT	[4] (N/A)	60.0	88.7 + other costs[9]

1 Derived from the FERC Form 1 (https://www.ferc.gov/docs-filing/forms/form-1/data.asp)
2 Based on EIA's Annual Energy Outlook levelized cost report (https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf)
3 Interpolated using ratios between the levelized cost of conventional coal and coal with 90% CCS for capital and O&M from EIA's Annual Energy Outlook 2015 levelized cost report (https://www.eia.gov/outlooks/archive/aeo15/pdf/electricity_generation_2015.pdf) and those ratios applied to the components of the levelized cost of coal with 90% CCS from AEO 2019 levelized cost report (https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf).
4 No value for wind or PV solar was computed because the authors did not have access to FERC Form 1 data for these resources.
5 https://www.bls.gov/data/inflation_calculator.htm
6 Levelized cost components for new conventional coal LCOE estimate interpolated from the ratio of costs and heat rates between conventional coal and coal with 90 percent CCS published in EIA's levelized cost report for 2015 and AEO 2015 Assumptions Report with 2018 fuels costs and average heat rates for 2014 to 2018 applied. AEO 2015 was the most recent AEO that contained financial data for conventional coal. See (3), above.
7 https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf
8 Levelized fuel costs for new resources was derived by subtracting Variable O&M in https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf Table 2 from Levelized Variable O&M Including Fuel in AEO 2019 Levelized Cost Report https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf Table 1b.
9 Includes imposed costs based on low firm capacity contribution relative to energy contribution. For solar, $21.0/MWh based on 25% capacity value at 3% energy market share and 25.7% capacity factor.
10 https://www.eia.gov/totalenergy/data/monthly/pdf/sec9_13.pdf
11 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a
https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b
12 https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf
13 https://www.eia.gov/electricity/annual/html/epa_08_02.html
14 LCOE-Existing Hydro calculated for 2016 LCOE-E Report, inflated to 2018$/MWh.

Column 3, other than for coal, shows EIA's LCOE-New for resources that could be brought online in 2023, based on:

1. EIA's projected capital costs and operating expenses
2. EIA's specified best-case single-plant capacity factorsi (higher than actual fleet averages for all but nuclear)
3. EIA's projected heat rates for those new resources, and
4. EIA's projected fuel prices for 30 years into the future.

To estimate LCOE for new conventional coal we:

1. Began with LCOE for new conventional coal and coal-with-CO2-capture-and-storage (CCS) in 2015, the most recent year when EIA published an LCOE of conventional coal
2. Backed out a 3% capital cost adder for conventional coal meant to signify an expected future "carbon tax"
3. Used the levelized cost ratio between the two technologies for each category of levelized cost, and
4. Applied those ratios to coal with 90% CCS in the 2019 AEO.

Column 4 is Column 3 adjusted to use:

1. The same fixed costs
2. EIA's measured 2014-2018 fleet-average capacity factorsv (which alter levelized capital and other fixed costs)
3. Heat rates EIA reported in its Electricity Market Module Assumptions Report[vi], and
4. The same prices per unit of fuel (Btu) as in Column 2.

Using actual 2014-2018 fleet-average capacity factors (as opposed to best-case single-plant capacity factors) raises the levelized fixed costs of existing coal, CC gas, CT gas, hydro, PV solar and wind; but lowers the levelized fixed costs of existing nuclear, and changes all LCOEs accordingly.

Replacing EIA's fuel price projections with actual 2018 prices reduces the adjusted LCOEs of coal, CC gas and CT gas and facilitates more direct comparison between new and existing resources.

For wind and solar, Column 4 adds the imposed costs which those technologies force onto the dispatchable generation resources which must sacrifice energy market share to them yet remain operational, as described in the next section..

Table 2 calculates the factor by which the fixed costs included in EIA's LCOE report (Column 3 of Table 1) must be multiplied in order to levelize the fixed costs over the generation like resources achieve in the real world – a condition to which we hold both new and existing resources. To do so, we divided EIA's best-case single-plant CFs for new resources by the historical annual fleet-average CFs in EIA's report on Capacity Factors for Utility-scale Generators (See footnote 1 of Table 2.)

Table 3 is a component of the calculation of Column 4 of Table 1 (the adjusted LCOE of new generation resources), by adjusting the Levelized Fixed Cost of Electricity for new resources to fleet-average capacity factors (using the fixed cost multipliers from Table 2) and adding it to the variable costs in column 5.

Table 4 shows the ratio of LCOE-New (as adjusted) to LCOE-Existing for each technology.
Figure 1 displays the LCOEs of new and existing generation resources from Columns 2 and 4 of Table 1.

TABLE 2

Generator Type	Fleet Average Capacity Factors For Existing Resources (EIA 2014 - 2018)[1]	Best Case Single-Plant Capacity Factors From EIA LCOE (2019)	Fixed Cost Multiplier
DISPATCHABLE FULL-TIME-RESOURCES			
Conventional Coal	55.4%	85%	1.54
CC Gas	53.7%	87%	1.62
Nuclear	92.2%	90%	0.98
Hydro (seasonal – not fully dispatchable)	39.4%	75%	1.90
DISPATCHABLE PEAKING RESOURCE			
CT Gas	7.8%	30%	3.86
INTERMITTENT RESOURCES – AS USED IN PRACTICE			
Wind including cost imposed on CC gas	34.5%	41%	1.19
PV Solar including cost imposed on CC and CT gas	25.7%	29%	1.13

1 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a and https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b

TABLE 3

Generator Type	Sum of Levelized Fixed Costs of LCOE-New as reported by EIA (2018 $/MWh)	Fixed Cost Multiplier	Adjusted Levelized Fixed Cost (2018 $/MWh)	Levelized Variable Costs including fuel (2018 fuel price)	**LCOE-New Adjusted by This Report**
DISPATCHABLE FULL-TIME-RESOURCES		x	=	+	=
Conventional Coal	29.3	1.54	45.0	25.9	70.9
CC Gas	11.9	1.62	19.3	30.8	50.0
Nuclear	67.9	0.98	66.3	9.0	75.2
Hydro (seasonal – not fully dispatchable)	37.7	1.90	71.7	1.4	73.1
DISPATCHABLE PEAKING RESOURCE					
CT Gas	38.8	3.86	149.6	43.3	192.9
INTERMITTENT RESOURCES – AS USED IN PRACTICE					
Wind including cost imposed on CC gas	55.9	1.19	66.4	—	90.0
PV Solar including cost imposed on CC and CT gas	60.0	1.13	67.7	—	88.7

TABLE 4

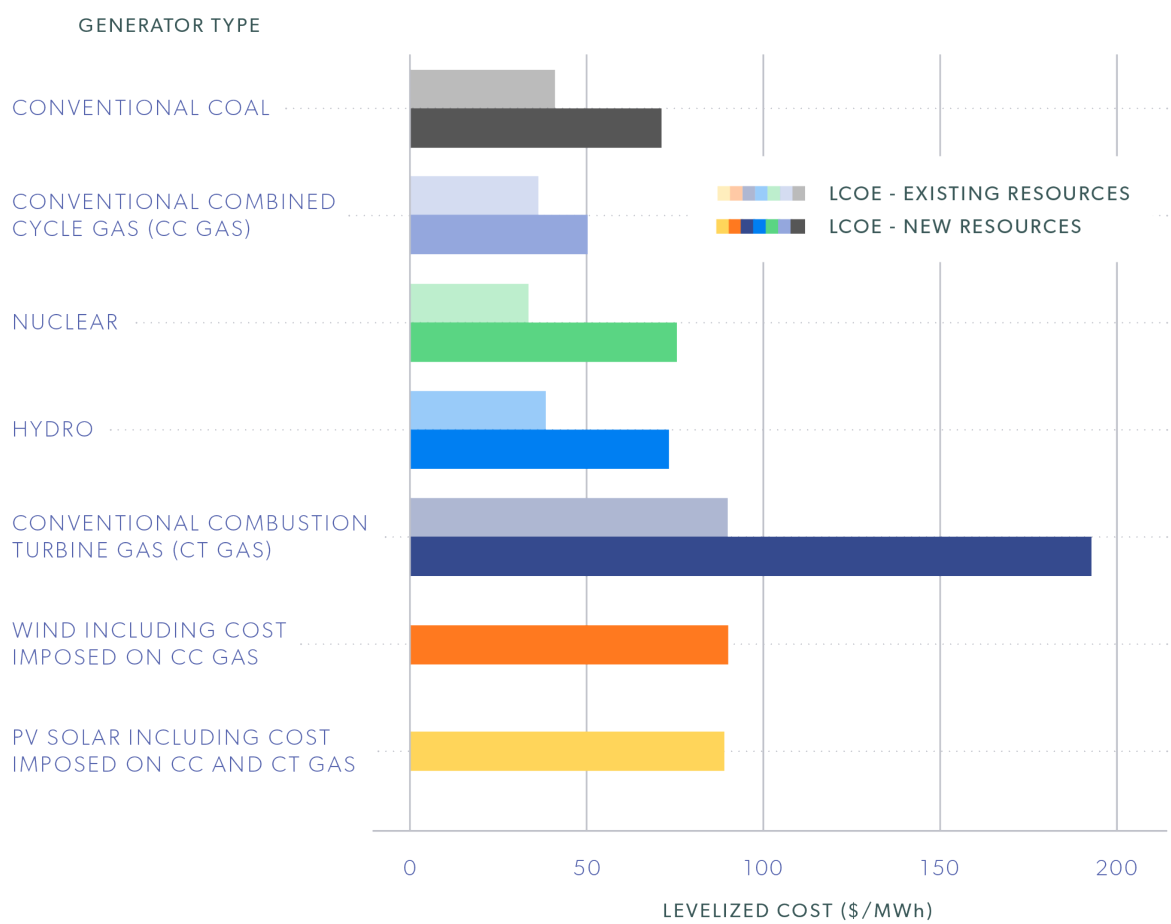
Generator Type	LCOE Existing at Real World Capacity Factors (as found in FERC Form 1 sample) (2018 $/MWh)	EIA LCOE-New at EIA 2014 - 2018 Real-World Average Capacity Factors	Levelized Cost Premium for New over Same Resource Existing
DISPATCHABLE FULL-TIME-RESOURCES			
Conventional Coal	40.9	70.9	74%
CC Gas	35.9	50	39%
Nuclear	33.3	75.2	126%
Hydro (seasonal – not fully dispatchable)	38.2	73.1	91%
DISPATCHABLE PEAKING RESOURCE			
CT Gas	89.9	192.9	115%
INTERMITTENT RESOURCES – AS USED IN PRACTICE			
Wind including cost imposed on CC gas	[1] (N/A)	90.0	(N/A)
PV Solar including cost imposed on CC and CT gas	[1] (N/A)	87.5	(N/A)

[1] No value for wind or PV solar was computed because the authors did not have access to FERC Form 1 data for these resources.

Figure 1

LEVELIZED COST OF ELECTRICITY

from New and Existing Resources



Analysis

This purpose of this study was to estimate the levelized costs of electricity from existing generation resources (LCOE-Existing) and compare them with EIA's projections for the Levelized Costs of Electricity from new generation resources (LCOE-New) that might be constructed to replace them, after adjusting LCOE-New to use comparable fleet-average capacity factors and the same prices for fuel. We applied the same LCOE categories to existing generation resources that EIA applied to new generation resources.

We endeavored to compare generating resources on an apples-to-apples basis. However, as the three parts of Table 1 indicate, each generation technology has characteristics that distinguish it from the others. Over and above "megawatt-hours," the various generation technologies are not direct substitutes for each other in terms of the attributes they bring to the electricity system, attributes which may have significant consequences for system cost and reliability. For example, baseload-capable CC gas units have greater ramping flexibility than other full-time capable resources considered in this report, allowing them to follow steeper load changes than coal or nuclear units. On the other hand, coal and nuclear units have lower risk of fuel supply disruption and have demonstrated long-term price stability per unit of fuel (per Btu).

While LCOE addresses electricity generation costs at a high level, it does not address how generation resources are compensated, or whether power markets place the correct values on the range of services each technology provides. We defer such questions to a different report.

Comparisons Between Generation Resources with Similar Capabilities

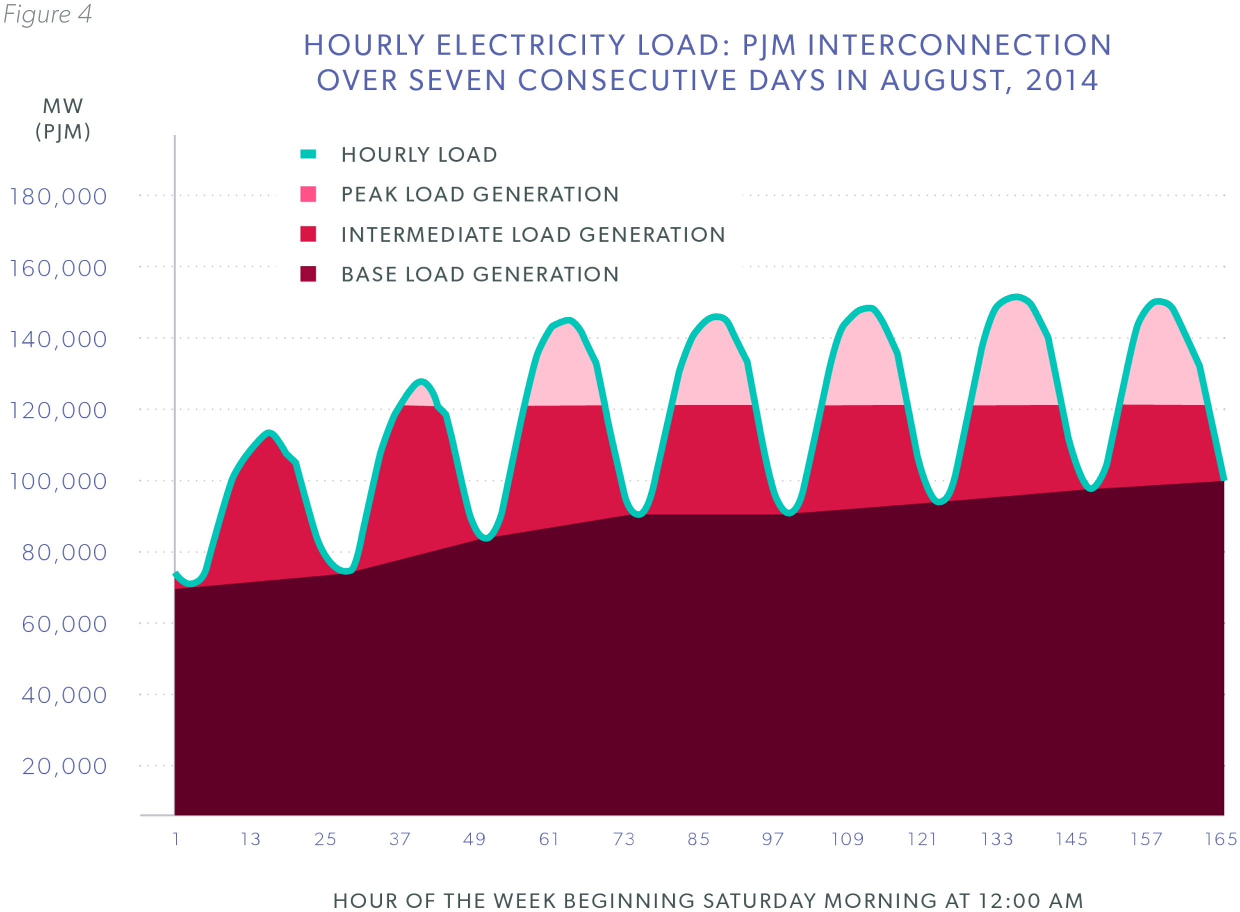
Aggregate electricity demand varies not only on a small scale from moment to moment, but on larger scales from hour to hour and day to day, as illustrated in Figure 4.

As a result, we can segment the demand curve into three horizontal stripes:

1. Full-time — baseload
2. Time-varying — load-following
3. Short duration — peak load

We call the generation resources which serve them: baseload, load-following and peak load, respectively. These resources play different roles in meeting aggregate demand, while keeping the grid in balance. Some are designed to run full-time at a steady level (baseload) while others are designed to run part-time or to vary their output as demand varies (load-following.) Still others run only for short intervals, but can adapt quickly to changes in demand or supply (peak load).

Figure 4



LCOE of Existing CC Gas, Coal and Nuclear by Plant Age and Cost Component

Figures 5-7 show the average LCOEs by plant age that we found for existing coal, nuclear and CC gas. Different but appropriate age spans are indicated on the X axis of each graph. In each case, the LCOE-Existing is markedly less over the full range of plant ages than the adjusted LCOEs that we calculated for new CC gas, coal and nuclear plants.

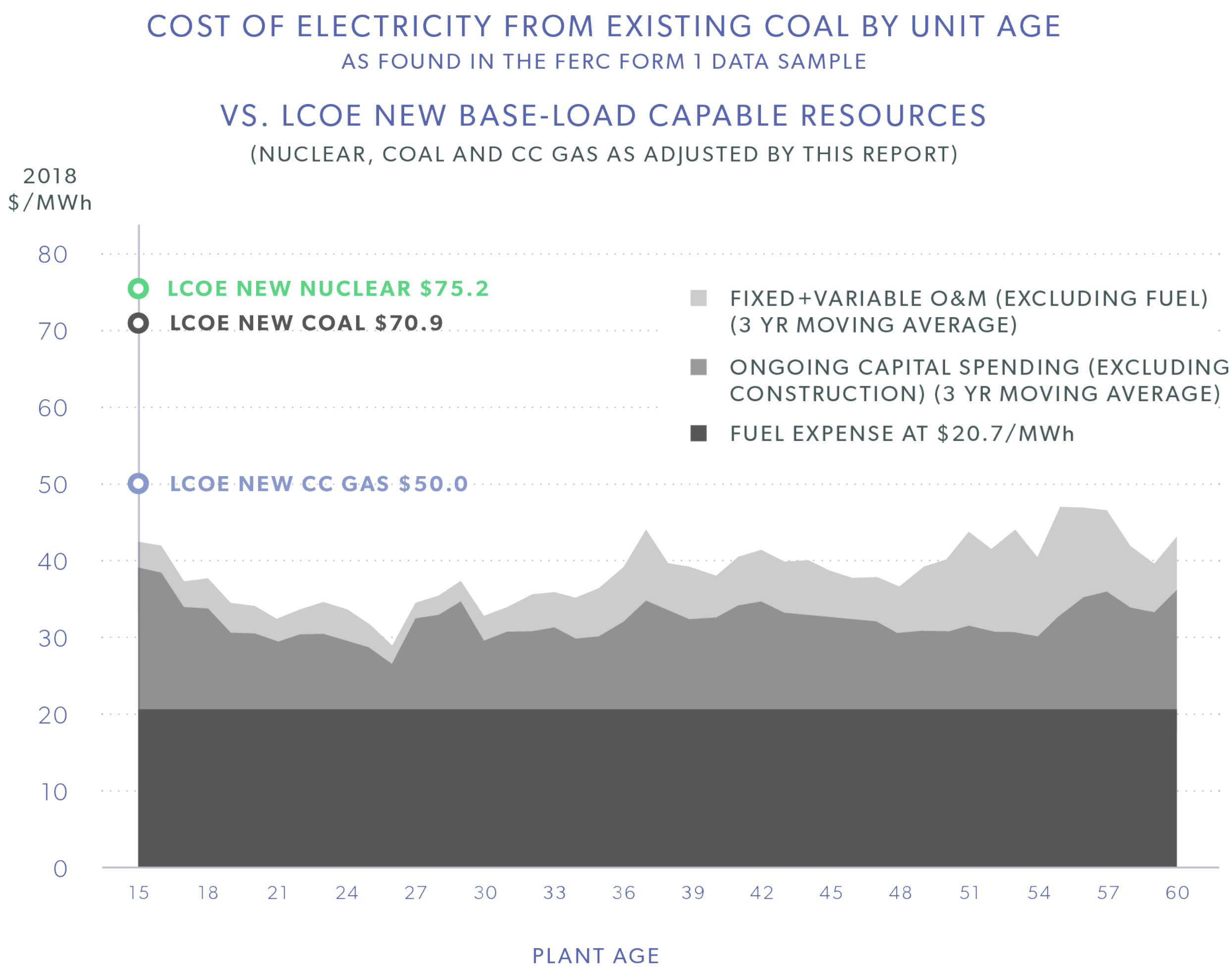
Each figure divides LCOE-Existing into three components:

1. Fixed plus variable operations and maintenance
2. Ongoing capital expenditures
3. Fuel

For coal in Figure 5, the total LCOE is under $40/MWh through age 36, about $40/MWh through age 50 and in the low to mid-$40s/MWh through age 60. Fuel cost is shown at $20.7/MWh consistent with our intent to use most recent year U.S. average annual delivered fuel costs. Ongoing capital expenditure is approximately $10/MWh through age 54, then higher by $2-3 through age 60. Fixed + variable O&M is $6-7/MWh for ages 35-50, then somewhat higher until age 58, at which point it returned to $7/MWh.

Figure 6 presents similar information for existing nuclear considered in our analysis. Here the cost of fuel is $6.6/MWh. Ongoing capital spending rises to as much as $9/MWh from ages 28-42, but drops to $6/MWh for ages 43-45. Fixed

Figure 5



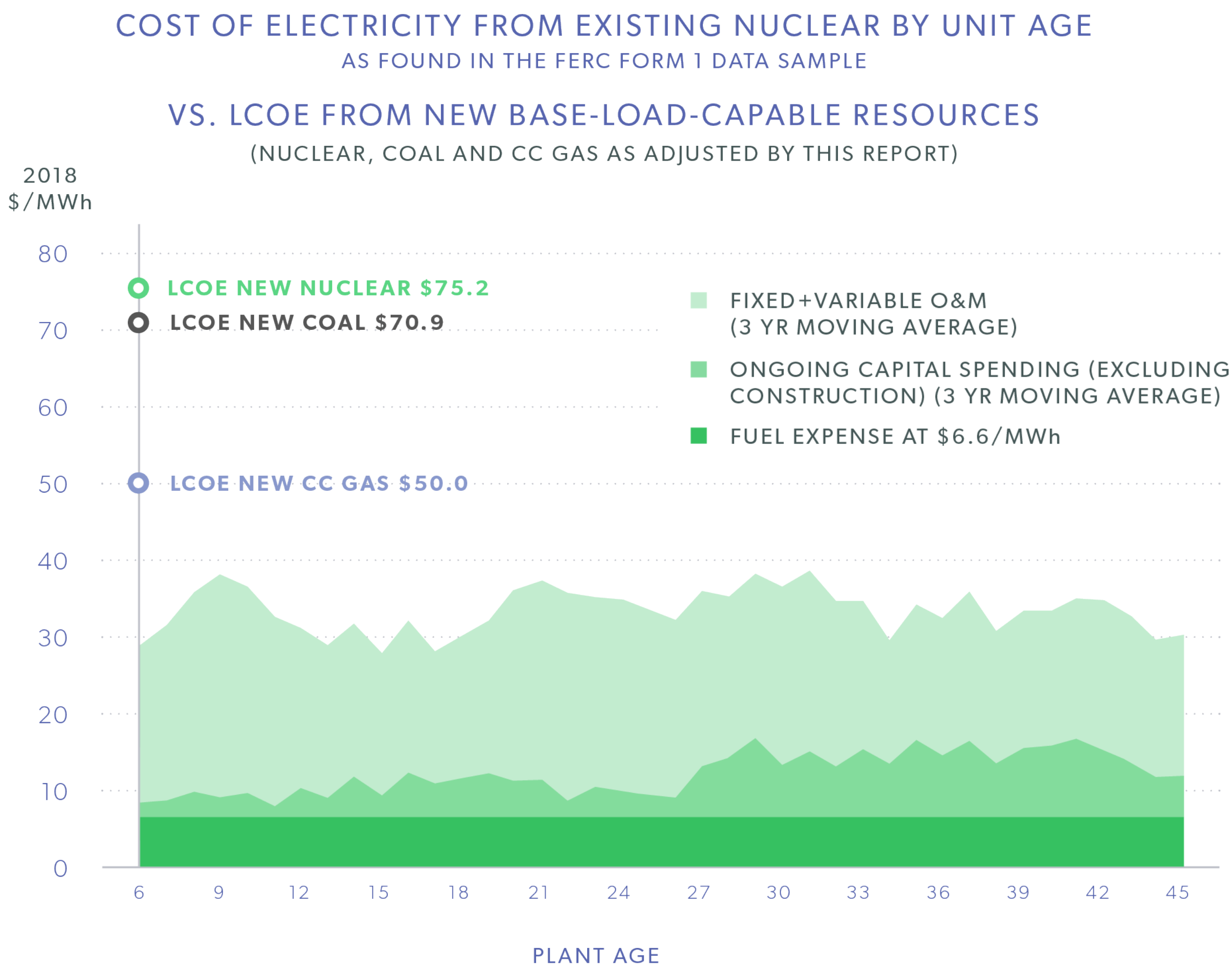
plus variable O&M is over $20/MWh from ages 20-31, but remains under $20/MWh for ages 32-45. The typical LCOE at any age being about one-third lower than the LCOE of new CC gas, with no uptrend across the final 12 years.

Figure 7 covers existing CC gas, whose costs are dominated by fuel at $27.2/MWh. Capital expenditure of almost $5/MWh begins at age 23. O&M is $6-10/MWh for the first 10 years, but declines to $4-6/MWh after age 10, until a small temporary increase from ages 25 to 28 which is not observed for ages 29 and 30. Overall existing CC Gas in our sample displays a steady LCOE that's about 25% lower than the LCOE of new CC gas.

Figures 5-7 show no evidence that, on average, existing CC gas, coal or nuclear generation resources are under economic pressure to retire, and some may remain viable to age 60 or beyond.

In contrast, although some wind generation facilities may retire before the 30 years of financial life that EIA assumed, we did not include the effect of shorter lifespan in our adjustments to the LCOE-New for wind. Nor did we count higher-than-average transmission costs even though regions with the best wind resources are farther from centers of demand than conventional generation resources and EIA's model does not take transmission distances into account.

Figure 6



Historical Capacity Factors by Plant Age

Figure 8 shows that older members of the CC gas, coal and CT gas fleets operate at somewhat lower capacity factors than newer members. This may be due to higher efficiency of newer plants causing them to be preferentially dispatched. The nuclear fleet's trend is different, although we offer no plausible reason why it would trend upward instead of level. If it were level, that could be explained by the fact that nuclear plants of any age supply baseload generation for long intervals of time at constant output near or at rated capacity.

The four technologies' capacity factors are negatively correlated with their capital costs per unit of capacity and reflect the segments of the demand curve to which they are applied – from full-time baseload for nuclear to load-following for CC gas and coal to peak-load for CT gas.

Figure 7

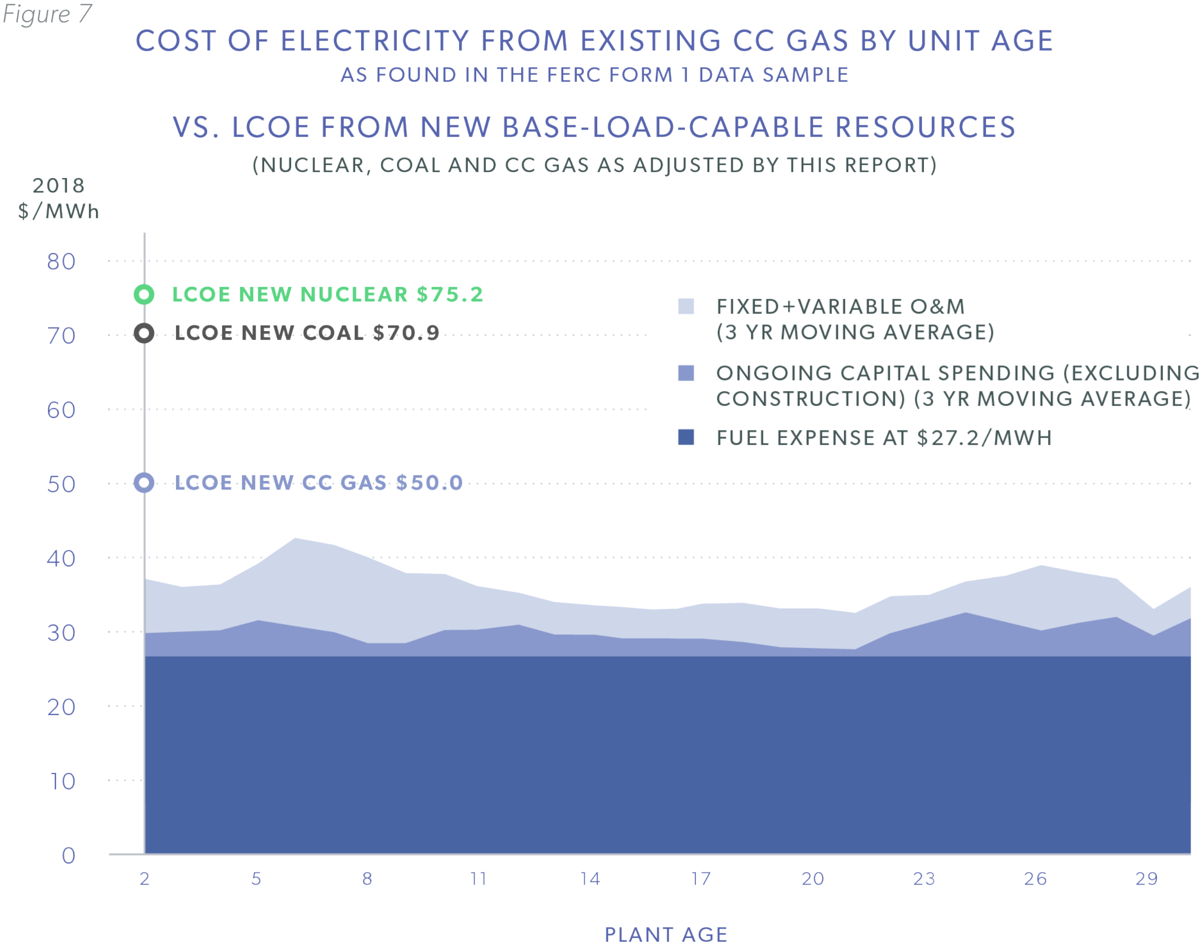
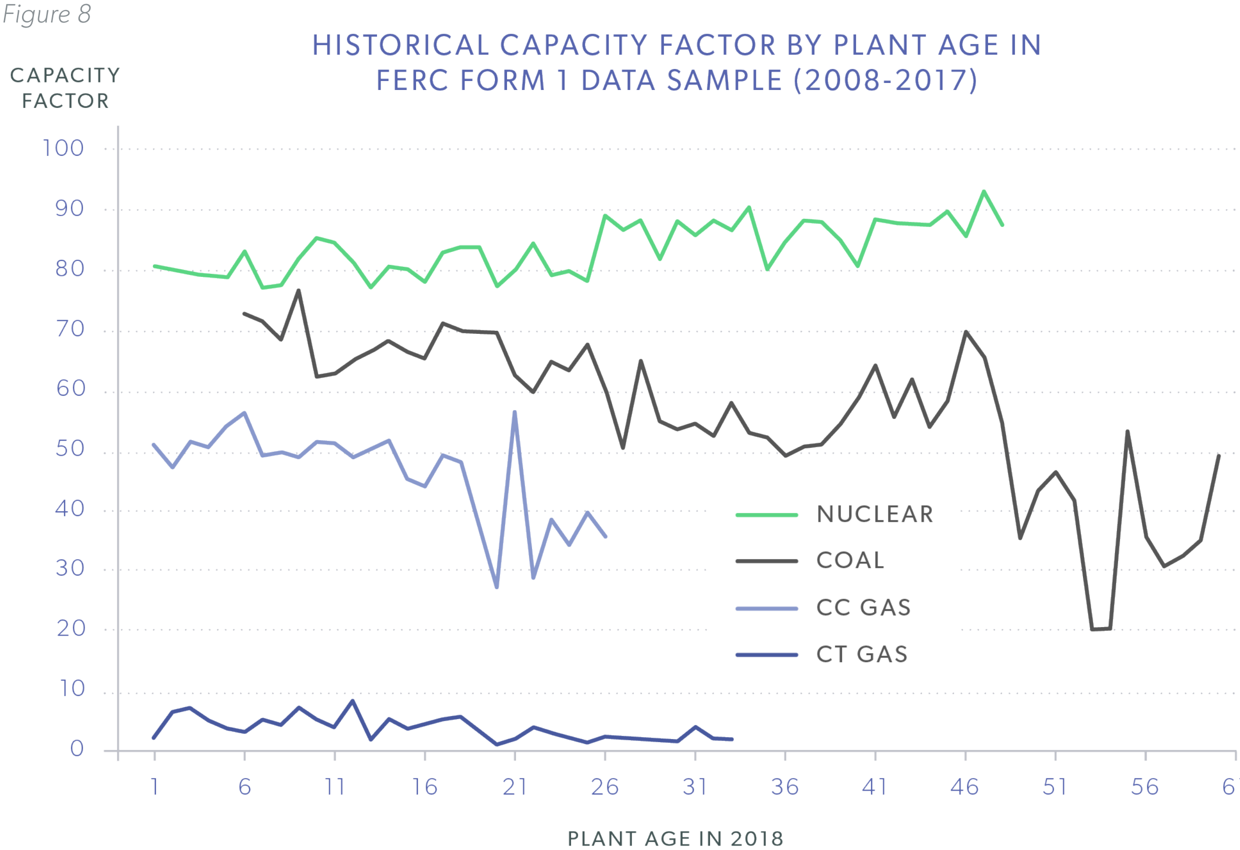


Figure 8



Nameplate Capacity by Technology and Plant Age

Figures 9a and 9b show the nameplate capacities by plant age (from EIA Form 860) of the seven leading generation technologies using the same vertical scale to facilitate comparison.

Figure 9a

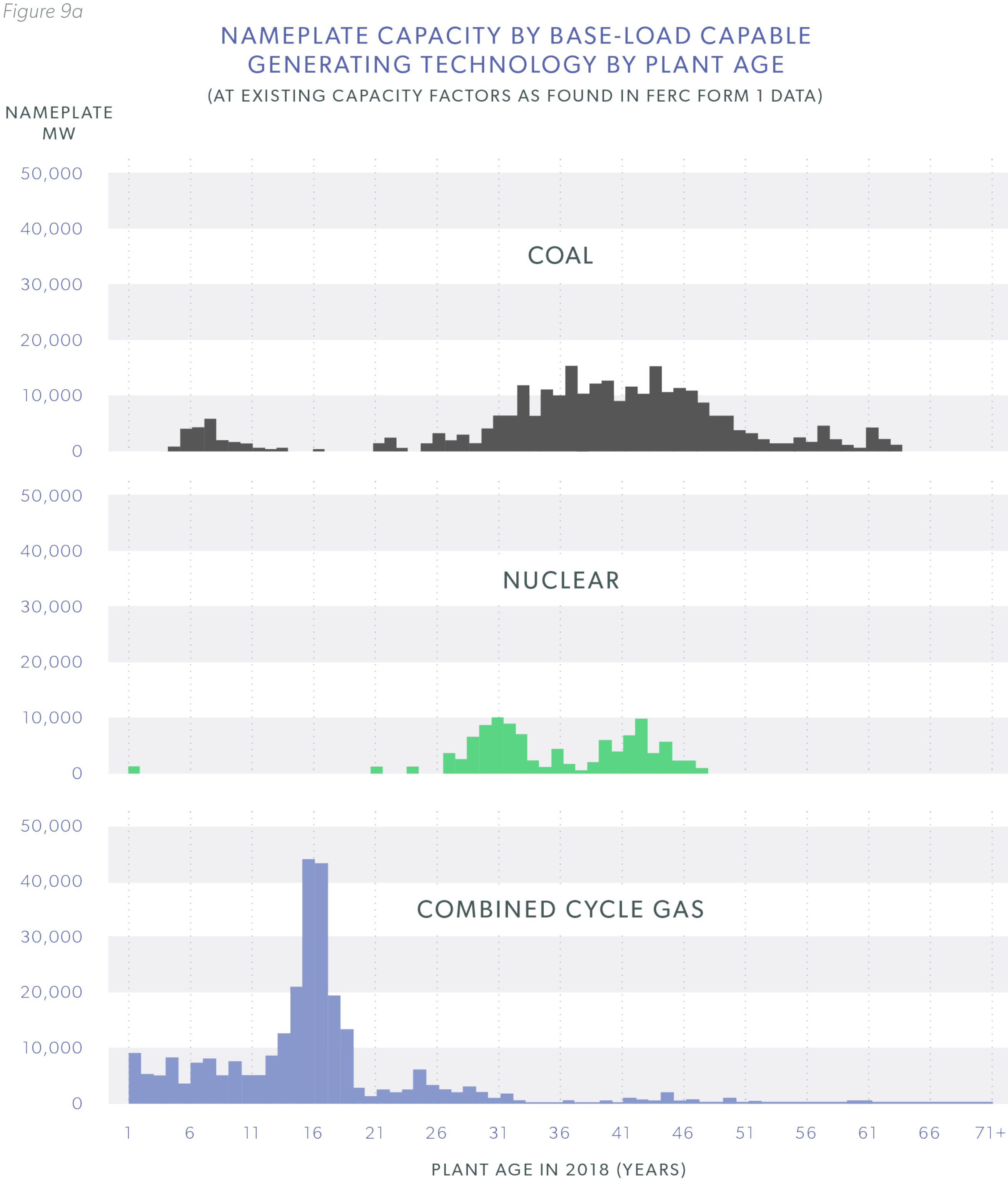
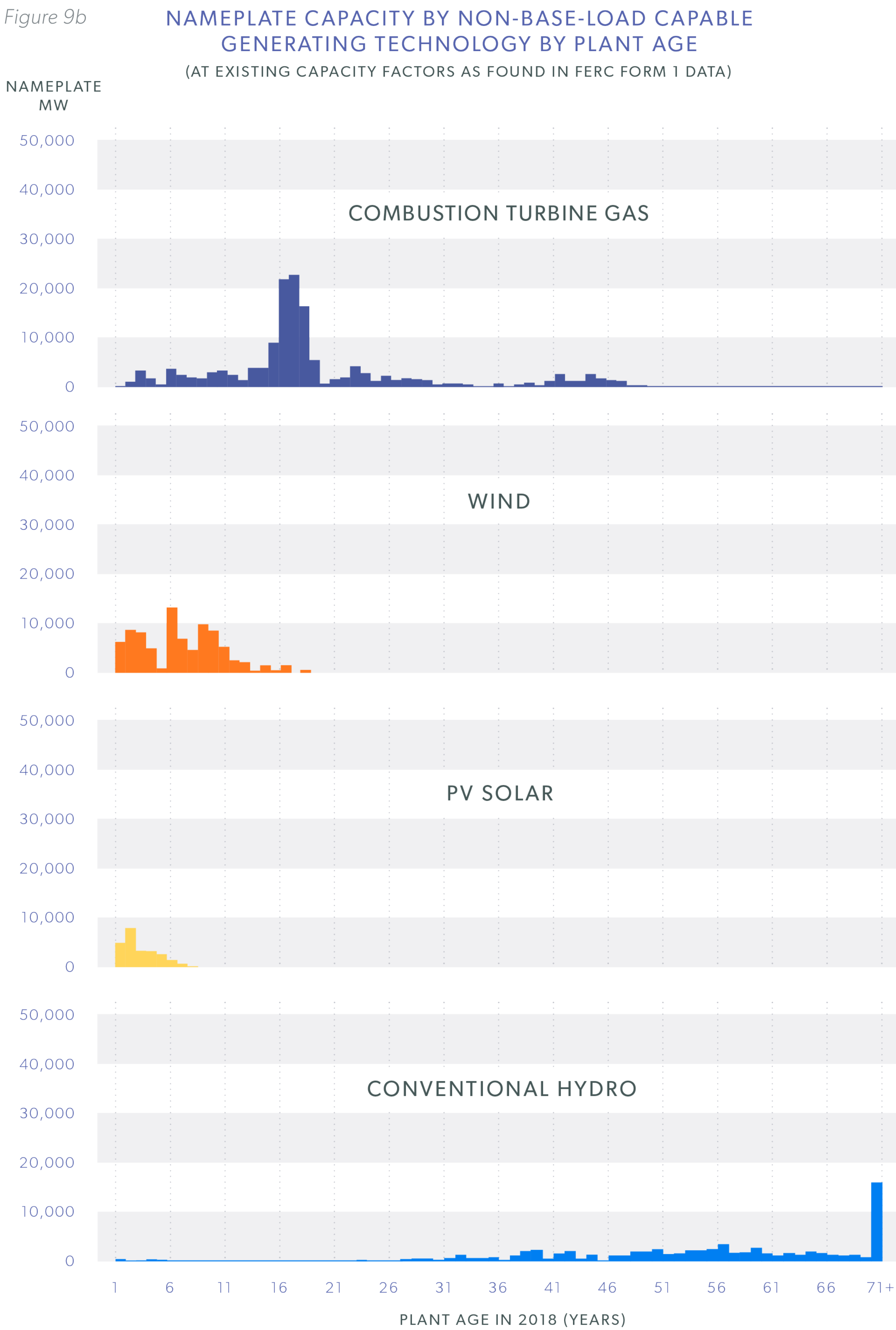


Figure 9b


NAMEPLATE CAPACITY BY NON-BASE-LOAD CAPABLE
GENERATING TECHNOLOGY BY PLANT AGE
(AT EXISTING CAPACITY FACTORS AS FOUND IN FERC FORM 1 DATA)
NAMEPLATE MW
50,000
40,000
30,000
20,000
10,000
0
COMBUSTION TURBINE GAS
WIND
PV SOLAR
CONVENTIONAL HYDRO
1
6
11
16
21
26
31
36
41
46
51
56
61
66
71+
PLANT AGE IN 2018 (YEARS)

Generation and Dispatchable Capacity by Technology

Nameplate capacity by itself doesn't tell us how many power plants are necessary to meet ongoing demand plus reserve margin, or at what total or levelized capital cost. Nor is it an indicator of how much we must utilize the required levels of firm capacity to meet electricity demand. However, using nameplate capacity as a starting point we can calculate:

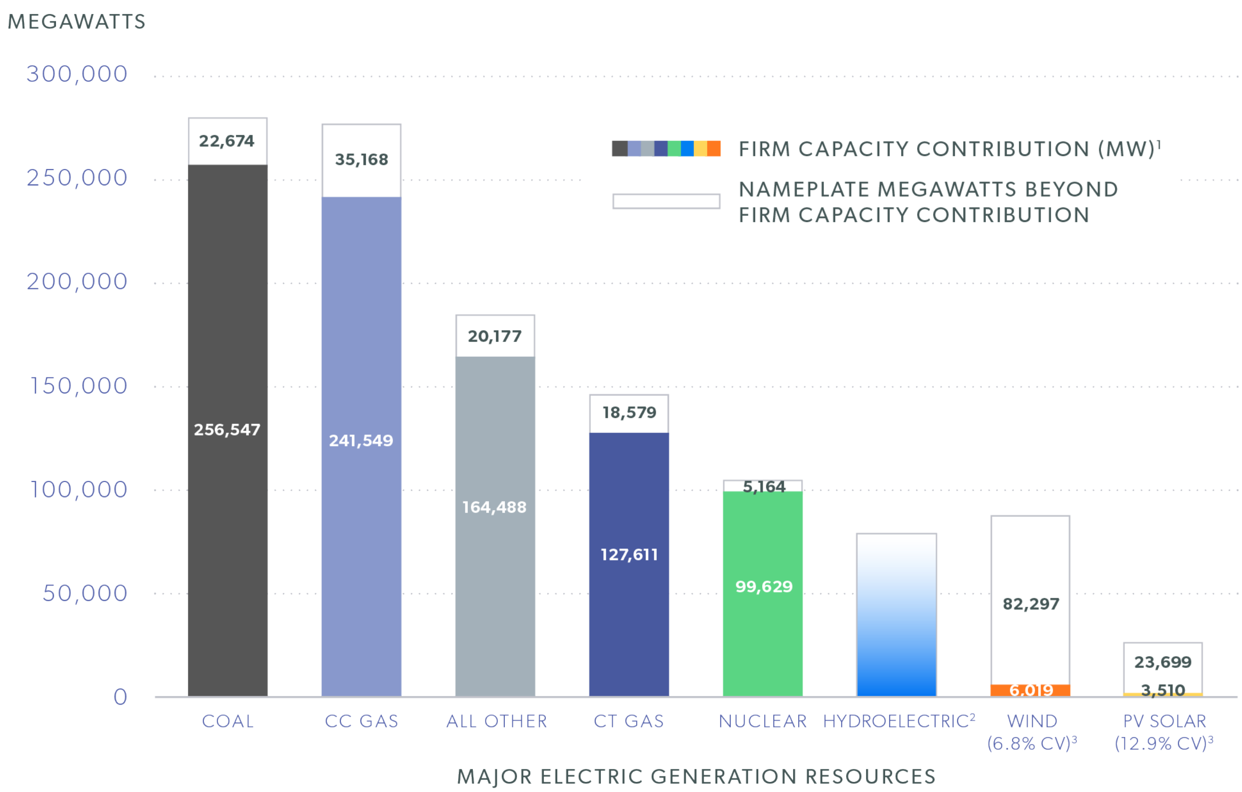
1. 2018 actual and potential generation by technology (using capacity factors from Table 2, Column 2)
2. 2018 firm capacity by technology (Figures 10 and 11)

For generation CC and CT Gas (35%) are the leading resources, followed by coal (27%), nuclear (19%), hydro (7%), wind (7%) and solar (2%).[vii]

For firm capacity CC and CT Gas (40%) are the leading resources, followed by coal at (27%), nuclear (11%) and wind plus PV solar (1%). A firm capacity estimate for hydro is not listed because it varies by facility depending on impoundment capacity, water resource origin, annual rain/snowfall variability and other factors beyond the scope of this report. Of all the attributes resources offer other than energy, firm capacity is the most vital to system adequacy.

Figure 10

FIRM CAPACITY CONTRIBUTION AND NAMEPLATE (MW) OF MAJOR US GENERATION RESOURCES IN 2018



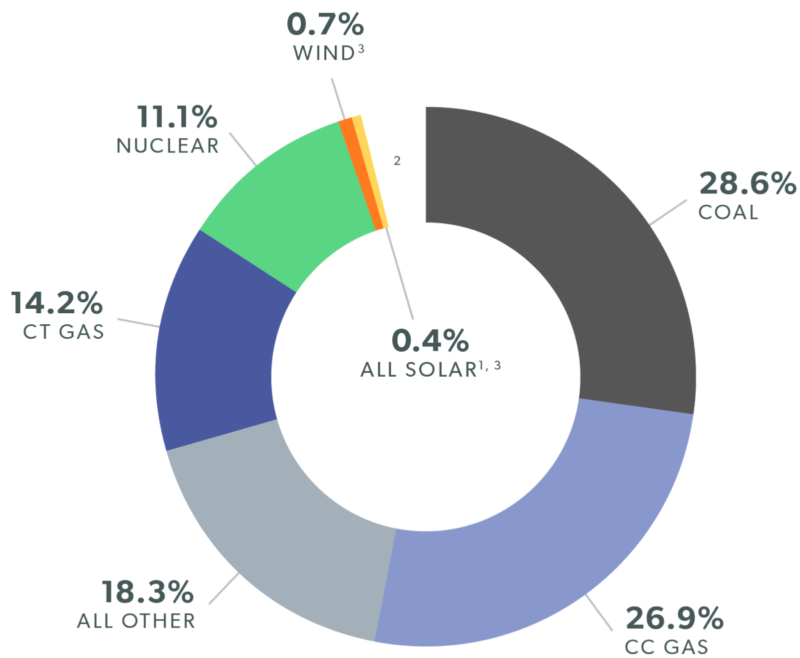
1 https://www.eia.gov/electricity/data/eia860/xls/eia8602017.zip
- 3_1_Generator_Y2017, "Operable" tab,Column R "Summer Capacity" used as capacity value for thermal and "all other" resources. For wind and solar capacity value estimates using MLQ methodologies are used

2 Because water resources are a variable resource, firm capacity contribution is likely less than for conventional thermal resources, but varies for each facility. No fleet-average capacity value was available.

3 Wind and solar capacity value calculations detailed in this chapter.

Figure 11

FIRM CAPACITY CONTRIBUTION TO US ELECTRIC GENERATING FLEET BY RESOURCE CATEGORY



[1] Includes EIA's estimate for behind-the-meter solar.

[2] Because water resources are a variable resource, firm capacity contribution is likely less than for conventional thermal resources, but varies for each facility. No fleet-average capacity value was available.

[3] Wind and solar capacity value calculations detailed in this chapter.

Overnight Capital Cost of New Generation Resources, Per Watt of Firm Capacity

Figure 12 compares the overnight capital cost of new construction per watt of firm capacity for the major generation technologies—CT and CC gas are the lowest, coal 2.5X higher, nuclear 5.5X higher, solar 13X higher and wind 20X higher. Hydro is omitted from this figure because its firm capacity contribution varies widely across the U.S. due to many contributing factors.

"Mean of Lowest Quartile Generation" Method (MLQ) for Calculating Capacity Value Across Peak Load Hours of a Year

We observed that RTOs and ISOs have used methods to estimate the firm capacity contribution (capacity value) of wind and solar generation resources that are different from those applied to dispatchable resources. For example, PJM calculates capacity value for wind and solar only across the hours from 2PM to 6PM during June, July and August, then counts the average capacity factor of wind or solar across those hours as their potential firm capacity contribution which can be bid into the RTO's capacity auctions.

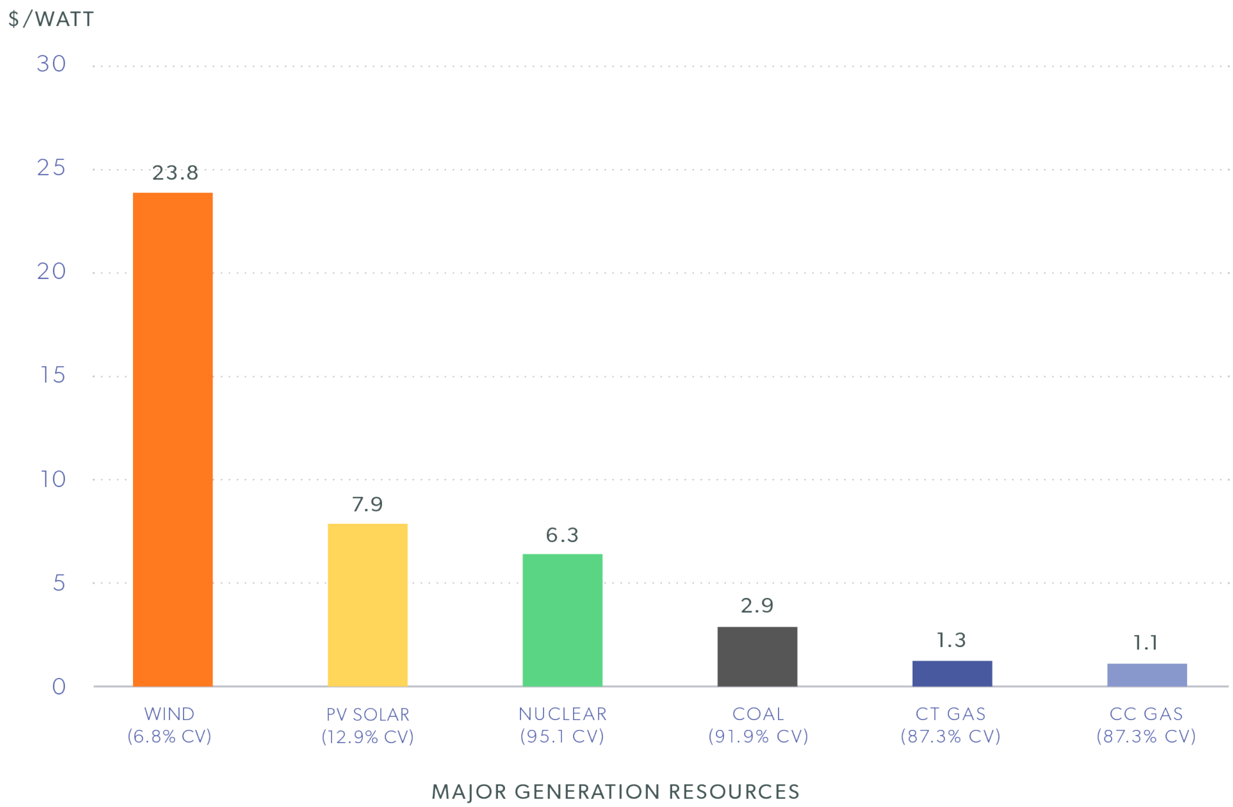
This results in a generous firm capacity valuation of intermittent over dispatchable resources in 3 respects:

1. Many peak load hours occur after 6 PM or in other months.
2. Over-generation during peak-load hours is valued as highly as the avoidance of shortfall.
3. Wind and solar fall short of their firm capacity allowance during about half of peak-load hours.

Figure 12

TOTAL OVERNIGHT CAPITAL COST FOR NEW MAJOR GENERATION RESOURCES (2018 $/WATT OF **FIRM CAPACITY CONTRIBUTION**)

USING OUR MLQ CAPACITY VALUES FOR WIND (6.8%) AND PV SOLAR (25%)



Consequently, we adopted the method for computing firm capacity recommended by Potomac Economics, Midcontinent ISO's market monitor, in its 2012 State of the Market Report[viii] and applied it across the combined PJM and MISO regions:

1. Consider the highest load hours, regardless of month or hour of the day.
2. Sort the levels of generation across those hours, from lowest to highest.
3. Then take the mean of the lowest 25%, in which case the resource will meet or exceed its firm capacity estimate approximately 87% of peak hours.

The result of this calculation differs depending on the number of peak load hours chosen. For wind generation, we took the average of three sample sizes:

1. The 191 highest peak load hours.
2. The 368 highest peak load hours.
3. The 720 highest peak load hours.

The sample size of 191 was selected based on the ratio of annual peak load to wind's installed capacity. The sample size of 368 hours matches the number of hours PJM uses in its "likely peak load windows." The sample size of 720 was selected because it is roughly double the number of hours of the 368-hour figure PJM uses. [ix]

For PV Solar we averaged in a fourth capacity value indicator – the single hour reduction in annual peak load. For 2018, this hour was in the daytime, so including it increased solar's MLQ capacity value.

The resulting average MLQ capacity values across PJM and MISO using 2018 data were 6.8% of nameplate capacity for wind and 12.9% of nameplate capacity for solar (at the third percent of energy market share it is increasing to).

Wind's capacity value by the MLQ method remains nearly constant across energy market shares. PV solar's capacity value by the MLQ method, on the other hand, decreases with increasing energy market share because peak load hours net of solar generation shift to twilight and dark hours.

Imposed Cost

Once a capacity value is calculated, it can be used to determine the "imposed cost" of a resource within a system consisting of high-capacity-value and low-capacity-value resources. By including the costs imposed on the system to "firm" the output of intermittent generators, those generators can be compared more directly with dispatchable resources.

Imposed cost occurs when a resource's firm capacity contribution is less than its average energy contribution. A cost is imposed because dispatchable resource generation must decrease by the amount the lower-firm-capacity resource's generation increases yet cannot retire at the same rate the low capacity value resource is added (because its capacity is still required to maintain the same level of reserve margin on the system).

By adding imposed costs to wind and solar levelized capital, fuel and operating costs, we arrive at LCOEs which can be meaningfully compared to the LCOEs of dispatchable resources. Cost comparisons are only meaningful if the products being delivered are similar in dispatchability, particularly dispatchability in response to peak loads. In the case of electricity generation, the products can be made similar if we add the cost of the appropriate amount of firm capacity to the cost of each unit of energy delivered. The energy to firm capacity ratio needs to be the same for all resources being compared.

Of course, results will vary based on differences in economic dispatch order. Imposed costs could be more accurately estimated if grid operators would run dispatch with and without intermittent generation to determine which dispatchable generation resources wind and solar generation displace and in what proportions.

Load Variations Alone Create Imposed Costs

If electricity demand across the system never varied, the capacity factor of the generation fleet would be high. Assuming a 15% reserve margin and the 91% capacity value typical for conventional thermal generators, the fleet-average capacity factor would come out to 0.91 / 1.15, or 79%.

> *Cost comparisons are only meaningful if the products being delivered are similar in dispatchability, particularly dispatchability in response to peak loads.*

In the real world, variations in demand create an imposed cost (relative to the case of a flat load curve) by reducing the average capacity factor of the fleet from 79% to about 50% (if we take the 2018 combined hourly load from PJM and MISO as an example).

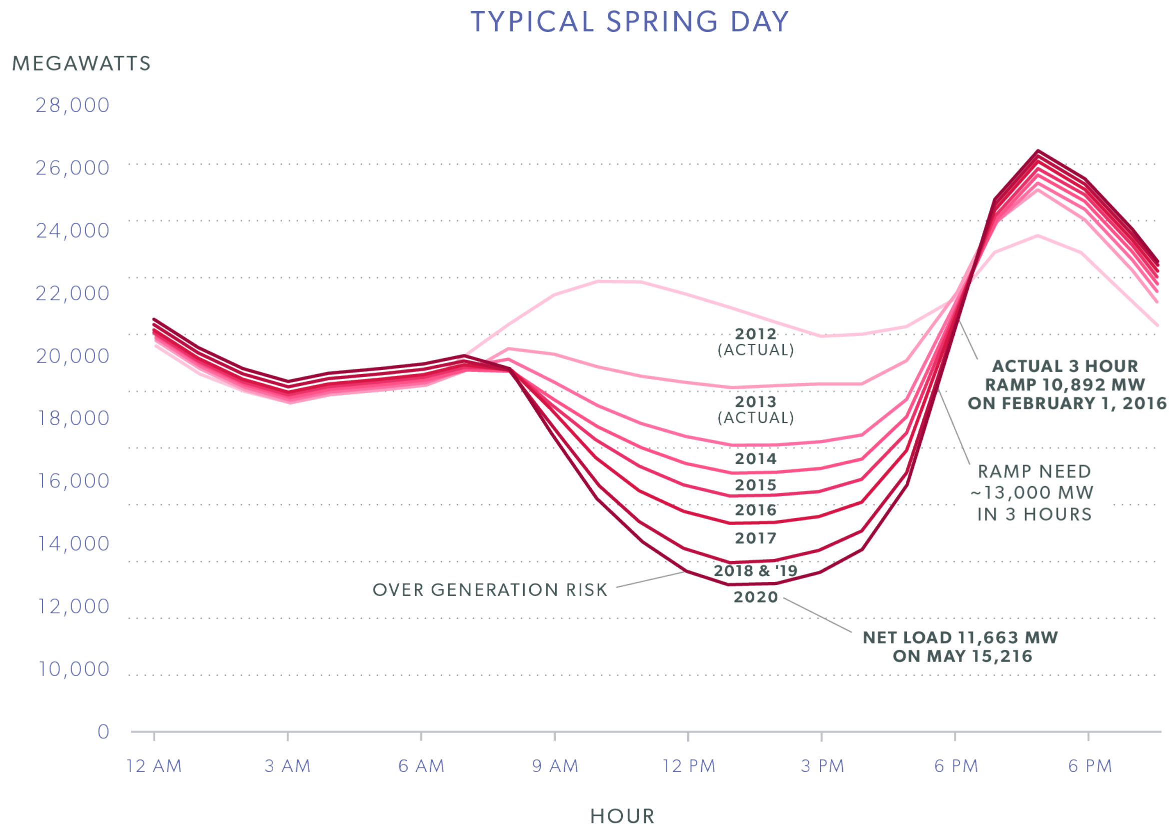
Wind and Solar Generation Exacerbate Load Variations and Create Additional (Chosen) Imposed Costs

Wind and solar generation exacerbate the variations in the load curve that dispatchable resources are called upon to fill, by lowering the average capacity factor of the combined fleet.

One illustration of this effect is evident in Figure 13, a reproduction of the California Independent System Operator's "Duck Curve" published in 2012.[X] Over the time period represented in Figure 13 – showing the time period in years over which solar generation has been added to California's electricity grid, peak load has increased (requiring additional dispatchable generator capacity to meet it) but the area under the net load curve has decreased. That area when summed for each hour of the year instead of just for a "typical spring day", is directly proportional to the combined average capacity factor of the required dispatchable fleet as a single coordinated system.

This is not a competitive situation because the displaced dispatchable resources must generate less electricity over time, yet are required to remain in service to maintain capacity reserve margins.

Figure 13



Source: https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

Example of Our Method for Estimating Wind Generation's Imposed Cost

We estimated imposed costs because we lack the hourly marginal resource reports, and levelized fixed costs and capacity factors for those marginal resources (prior to their displacement) that would be required for a more accurate determination. If we had those, we could determine exactly which resources wind generation displaced each hour, the number of megawatt-hours displaced, and the costs imposed on the displaced resources. Grid operators could make these calculations by rerunning the economic dispatch order with and without the wind or solar resources in question. We urge them to do so, but in the meantime, our simple methodology is adequate to demonstrate that wind and solar imposed costs are significant.

Note: We chose to displace dispatchable resources which would result in the lowest imposed costs—CC gas for wind, and a combination of CT gas and CC gas for solar.

Step by Step Explanation

Assumptions:

1. Wind displaces only new CC Gas's energy market share.
2. Firm capacity is chosen to meet reserve margin requirement of 15% and no more. As wind is added CC Gas retires so that the firm capacity of wind (6.8% of nameplate) plus CC Gas (91% of nameplate) continues to match annual peak load plus 15%.
3. Stranded cost recovery is not included. In jurisdictions where stranded cost recovery is permitted, the unrecovered capital costs of the capacity displaced would increase the imposed cost.

Calculation, as diagrammed in Figure 14:

For purposes of illustration, assume 1150 MW of firm capacity is required.

Based on PJM's and MISO's 2018 demand curves, the average load would equal 506.5 MW (40.1% capacity factor.)

Using a 91% capacity value for CC gas, 1264 MW of CC gas capacity is required.

This is more than enough to meet the generation requirement at the same time.

CC gas's levelized fixed cost = $11.90/MWh @ EIA's best-case CF of 87%

= $25.83/MWh @ 40.1% CF ($11.90 * (0.87 / 0.401))

Assume wind generation supplies 10% of the energy and CC gas supplies 90%.

The result of the calculation is independent of this percentage.

Then 147 MW of wind capacity is required, which contributes 10 MW of firm capacity (147 * 6.8%)

Therefore, CC gas's capacity factor decreases by 9.2% and its levelized fixed cost increases by 10.14%.

(10% less energy produced by 1253/1264 as much capacity)

Imposed cost = $2.62/MWh of CC gas generation (10.14% * $25.83/MWh)

Since wind generation equals 1/9th of CC gas generation,

Imposed cost = $23.6/MWh of wind generation (9 * $2.62)

Figure 14

LEVELIZED IMPOSED COST OF WIND ELECTRICITY EXAMPLE	
System Annual Peak Load	1,000 MW
Reserve margin percentage requirement	15% (above expected annual peak load)
SYSTEM FIRM CAPACITY REQUIRED	1,150 MW FIRM
Average annual energy requirement	506.5 Avg. MW (using PJM + MISO 2018 hourly load data)
ANNUAL ENERGY REQUIRED	4,436,940 MWh
BASELINE: SYSTEM SUPPLIED BY 100% CC GAS	
CC Gas Capacity Value	91% (of nameplate capacity)
CC Gas Maximum Capacity Factor (EIA)	87% (of theoretical maximum)
Nameplate MW of CC Gas to meet capacity requirement	1,264
Nameplate MW of CC Gas to meet energy requirement	1,149
Minimum Nameplate MW of CC Gas to meet both requirements	1,264
Capacity factor of CC Gas at required annual energy (no wind)	40.1%
ADD WIND:	
Wind energy Capacity Factor	34.5% (average last 5 years EIA 923)
Wind Energy Capacity Value	6.8% (of nameplate capacity - mean of three methods)
Desired wind energy market share	10% (energy market share) (does not effect outcome)
Annual energy represented by desired market share	443,694 MWh
Nameplate of wind at stated capacity factor required	147 Nameplate MW
Firm Capacity Contribution of Wind	10.01 MW FIRM
Remaining Firm Capacity Requirement for CC Gas	1,140
Nameplate Capacity of CC Gas required to meet system capacity requirement	1,253
Remaining Energy for CC Gas	3,993,246
Resulting CC Gas Capacity Factor	36.4%
IMPOSED COST CALCULATION:	
EIA CC Gas Capacity Factor	87%
Initial Levelized Fixed Cost of CC Gas (at EIA LCOE Best-Case Capacity Factor)	11.9
Levelized Fixed Cost of CC Gas at Capacity Factor resulting from wind addition	28.45
Levelized Fixed Cost of CC Gas at initial Real World Capacity Factor	25.83
Cost imposed on CCGT per MWh of CC Gas on the system	2.62
For every one MWh of wind energy on the system there are...	9 parts CC Gas energy (at 10% wind market share)
Cost imposed on new CC Gas per MWh of Wind on the system:	**23.6 (2018 $/MWh)**

Two ratios effect the imposed cost: 1) The ratio of CC Gas to wind capacity value.
2) The ratio of CC Gas to wind capacity factor.

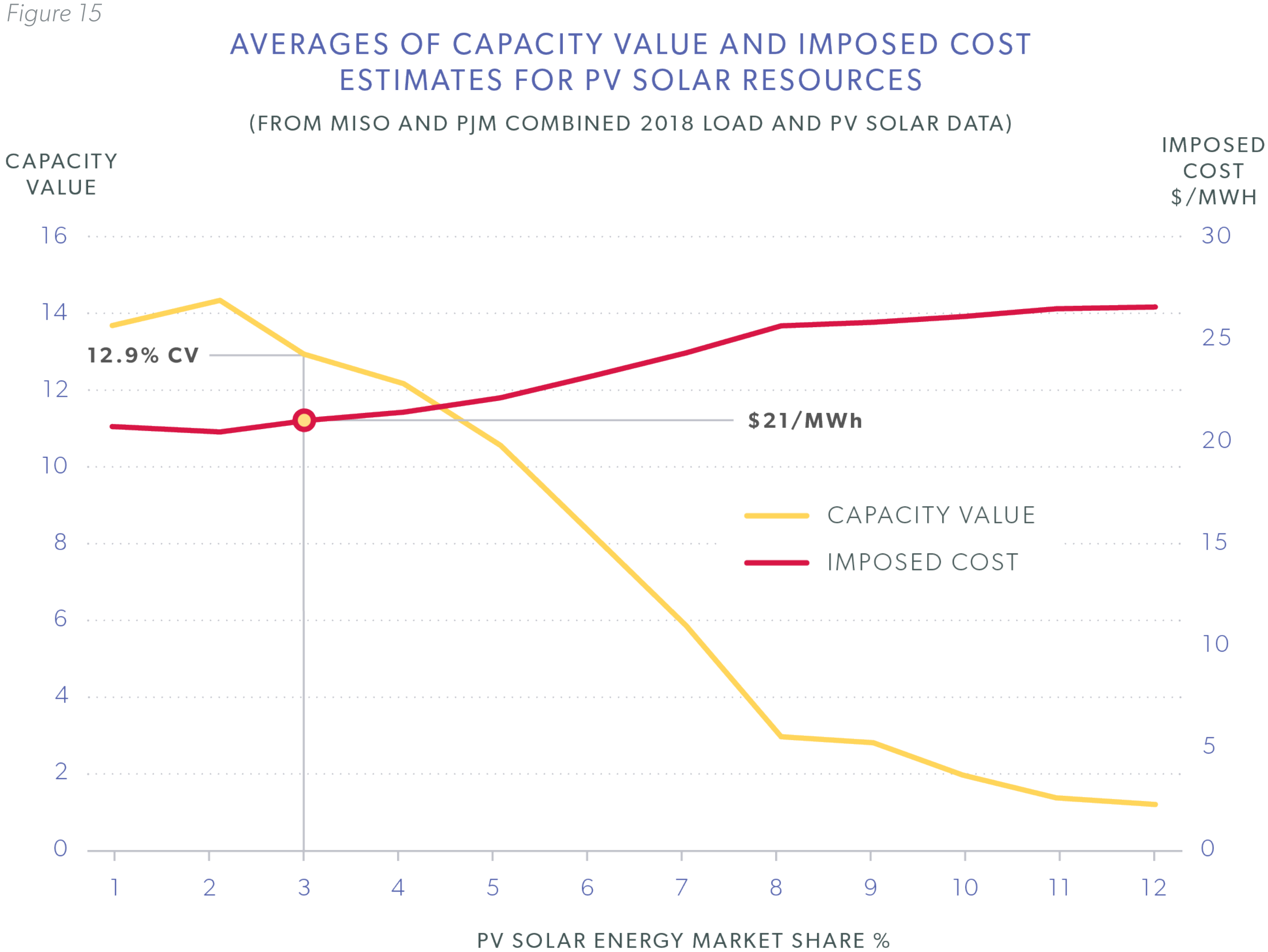
The third influence is initial Levelized Fixed Cost of CC Gas, which increases as its capacity factor falls.

Solar Capacity Value and Imposed Cost as a Function of Energy Market Share

For PV solar generation, we calculated independent capacity values for each energy market share from 1% to 12%, using the full hourly load for the first percent, and the load net of previously modeled solar generation for each additional percent. Because on average the U.S. receives about 2% of total electricity from PV solar now, we used the third percent capacity value (12.9%) to calculate PV Solar's imposed cost. This assumption results in a lower imposed cost than would apply to regions with higher solar penetration (for instance, 10% of total consumption in California).

Decreasing average MLQ capacity value estimates for PV Solar across PJM and MISO result in increasing imposed costs, as shown Figure 15. Imposed costs fall in the range of $20-26/MWh across modeled energy market penetrations of 1% to 12%.

Figure 15



Assumptions:

1. Solar displaces new CC and CT gas energy market share, because solar generates at peak-load hours (displacing CT gas) as well as non-peak load hours (displacing CC gas).
2. The ratios of CC gas to CT gas capacity and energy remain the same as incremental solar capacity is added.
3. As solar firm capacity is added CC and CT gas retire at same ratio as they existed in the base case (with no PV solar). Because CC and CT gas have capacity values of about 90% of nameplate, while PV Solar has an MLQ average capacity value of 12.9% at 3% market share, for every seven nameplate MWs of PV solar added to the system, approximately one nameplate MW of gas-fired capacity may retire.
4. Stranded cost recovery is not included.

Calculation, as diagrammed in Figure 16, is as follows:

For purposes of illustration, assume 1150 MW of firm capacity is required.
Based on PJM's and MISO's 2018 demand curve, the average load would equal 506.5 MW (40.1% capacity factor.)
Using a 91% capacity value for CC and CT gas, 1264 MW of gas nameplate capacity is required (1150/0.91)

Assume 818 MW of CC gas, 446 MW of CT gas.

This is more than enough to meet the generation requirement at the same time.

Capacity factors 57.2% for CC gas, 8.7% for CT gas.

CC gas's levelized fixed cost = \$11.9 / MWh @ EIA's best-case capacity factor of 87%
= \$18.1 / MWh @ 57.2% capacity factor (\$11.9 * (0.87 / 0.572))

CT gas's levelized fixed cost = \$38.8 / MWh @ EIA's best-case capacity factor of 30%
= \$133.3 / MWh @ 8.7% capacity factor (\$38.8 * (0.30 / 0.087))

Assume solar generation supplies 3% of the energy and gas supplies 97%.

The result of the calculation is independent of this percentage.

Then 59.08 MW of solar capacity is required, which contributes 7.6 MW of firm capacity.

Therefore, CC and CT gas's capacity factors will decrease by 2.4% (1.4/57.2 and 0.2/8.7)

CC gas's levelized fixed cost will increase by \$0.436 / MWh (2.4% * \$18.1)

CT gas's levelized fixed cost will increase by \$3.211 / MWh (2.4% * \$133.3)

Since solar generation equals 3.35% of CC gas generation and 40% of CT gas generation
Cost imposed on CC gas = \$12.9 / MWh of solar generation (\$0.436 / 0.0335)
Cost imposed on CT gas = \$8.0 / MWh of solar generation (\$3.211 / 0.40)

Total imposed cost = \$21.0/MWh of PV solar generation

Figure 16

LEVELIZED IMPOSED COST OF SOLAR ELECTRICITY EXAMPLE	
System Annual Peak Load	1,000 MW
Reserve margin percentage requirement	15% (above expected annual peak load)
SYSTEM FIRM CAPACITY REQUIRED	1,150 MW FIRM
Average annual energy requirement	506.5 Avg. MW (using PJM + MISO 2018 hourly load data)
ANNUAL ENERGY REQUIRED	4,436,940 MWh
BASELINE: SYSTEM SUPPLIED BY 92.3% CC GAS AND 7.7% CT GAS	
CC and CT Gas Capacity Value	91% (of nameplate capacity)
System Capacity Requirement	1,150 MW FIRM
CC and CT Gas Average Maximum Capacity Factor at assumed installed capacity ratio	83% (of theoretical maximum)
Nameplate MW of CC and CT Gas to meet capacity requirement	1,264
Nameplate MW of CC and CT Gas to meet energy requirement	613
Minimum Nameplate MW of CC and CT Gas to meet both requirements	1,264
Minimum Nameplate MW of CC Gas to meet both requirements	818
Minimum Nameplate MW of CT Gas to meet both requirements	446
Average combined Capacity factor of CC and CT Gas at required annual energy (no PV Solar)	40.1%
Capacity factor of CC Gas at required annual energy (no PV Solar) (12:1 E assumption)	57.2%
Capacity factor of CT Gas at required annual energy (no PV Solar) (1:12 E assumption)	8.7%
ADD PV SOLAR:	
PV Solar energy Capacity Factor (EIA real world CF 5 year average)	25.72% (average last 5 years EIA 923)
PV Solar Energy Capacity Value	12.9% (of nameplate capacity - mean of four methods)
Desired PV Solar energy market share	3% (energy market share) (does not effect outcome)
Annual energy represented by desired market share	133,108 MWh
Nameplate of PV Solar at stated capacity factor required	59.08 Nameplate MW
Firm Capacity Contribution of PV Solar	6.7 MW FIRM
Remaining Capacity to meet Energy Requirement for CC and CT Gas	1,142
Nameplate Capacity of CC and CT Gas required to meet system capacity requirement	1,255
Nameplate Capacity of CC Gas required to meet system capacity requirement	812
Nameplate Capacity of CT Gas required to meet system capacity requirement	443
Remaining Energy for CC and CT Gas	4,303,832
Resulting CC and CT Gas Average Capacity Factor	39.1%
Resulting CC Gas Capacity Factor (12:1 Energy ratio assumption)	55.8%
Resulting CT Gas Capacity Factor (1:12 Energy ratio assumption)	8.5%
IMPOSED COST CALCULATION:	
EIA CC Gas Best-Case Capacity Factor	87%
EIA CT Gas Best-Case Capacity Factor	30%
Initial Levelized Fixed Cost of CC Gas (at EIA LCOE Best-Case Capacity Factor)	11.9
Initial Levelized Fixed Cost of CT Gas (at EIA LCOE Best-Case Capacity Factor)	38.8
Levelized Fixed Cost of CC Gas at Capacity Factor resulting from PV Solar addition	18.5
Levelized Fixed Cost of CT Gas at Capacity Factor resulting from PV Solar addition	136.5
Levelized Fixed Cost of CC Gas at initial Real World Capacity Factor	18.1
Levelized Fixed Cost of CT Gas at initial Real World Capacity Factor	133.3
Cost imposed on CC Gas per MWh of CC Gas on the system	0.436
Cost imposed on CT Gas per MWh of CC Gas on the system	3.211
For every one MWh of PV Solar energy on the system there are...	29.8 parts CC Gas energy (at 3% PV Solar market share)
For every one MWh of PV Solar energy on the system there are...	2.5 parts CT Gas energy (at 3% PV Solar market share)
Cost imposed on new CC and CT Gas per MWh of PV Solar on the system:	**21.0 (2018 $/MWh)**

[i] *EIA, Levelized Cost of New Generation Resources, in Annual Energy Outlook 2019, January 24, 2019 https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf*

[ii] Capacity factor is the average output of a plant or fleet of plants over time divided by the maximum potential output of that plant or fleet. For example, EIA's best-case capacity factor for CC gas is 87%, while the actual capacity factor for the CC gas fleet in 2018 was 57.6%.

[iii] EIA, *https://www.eia.gov/electricity/annual/html/epa_08_01.html*

[iv] *EIA, https://www.eia.gov/totalenergy/data/monthly/pdf/sec9_13.pdf*

[v] *EIA, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a and https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b*

[vi] *EIA, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf*

[vii] *EIA, Electric Power Monthly, Table 1.17.B, www.eia.gov/electricity/monthly/*

[viii] Potomac Economics, 2012 State of the Market Report for the Midcontinent Independent System Operator Electricity Markets, Analytical Appendix, June 2013, *https://www.potomaceconomics.com/wp-content/uploads/2017/02/2012-State-of-the-Market-Analytical-Appendix.pdf*, pages A-26 and A-27.

[ix] *Ibid.*

[x] *California Independent System Operator, "What the duck curve tells us about managing a green grid", https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf*