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To: McCullough Research Clients

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Subject: Is Existing Coal Actually Cost Effective in the Presence of Falling Renewable Prices?

Introduction:

The Institute for Energy Research (IER) and America's Power (ACCCE) recently published a report defending the cost effectiveness of aging thermal power plants.[1]

The report claims that installation of new alternative energy resources, such as wind turbines and photovoltaics (PV), are more costly than maintaining existing plants.[2] Industry standard studies claim the opposite.[3] Additionally, the rapid rate of economic closures of coal units makes this claim rather doubtful.[4]

At best, the report's methodology is dubious. It departs from the industry standard of calculating the Levelized Cost of Electricity (LCOE), instead replacing it with a method that seems inherently designed to cast doubt on the viability of the renewables industry.[5] Masked with seemingly legitimate justifications, data which doesn't fit the agenda is pruned, regulatory limitations are ignored, and alternative energy is saddled with extraneous costs. With questionable analytic practices such as these, it is no wonder IER's report has not been included in industry-wide analytics summaries.[6]

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[1] Stacy, Tom; Taylor, George. *The Levelized Cost of Electricity from Existing Generation Resources* IER, June 2019.
[2] Ibid., page 1.
[3] VCE – The Coal-Cost Crossover, 2019. https://energyinnovation.org/wp-content/uploads/2019/04/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL2.pdf
[4] Nearly all power plants that retired in the past decade were powered by fossil fuels. https://www.eia.gov/todayinenergy/detail.php?id=34452
[5] Stacy, Tom; Taylor, George. *The Levelized Cost of Electricity from Existing Generation Resources* IER, June 2019, Page 7.
[6] Transparent Cost Database. https://openei.org/apps/TCDB/

This response starts with a basic review of the data. We then proceed to a review of IER's methods and assertions. Its erroneous assumptions are discussed, as well as the industry standard solutions that are ignored, and missteps made while conducting the analysis, biasing the results.

Basic Data:

Older thermal units become more expensive and less reliable over time. It is normal for heat rates to increase, O&M expenses to rise, and forced outages to become more frequent. In the same way that the family car becomes more costly to operate as years pass, large thermal plants also do not age gracefully.

Figure 1 shows a comparison of real fuel and O&M costs from the FERC Form 1 database for coal units, compared to market prices:

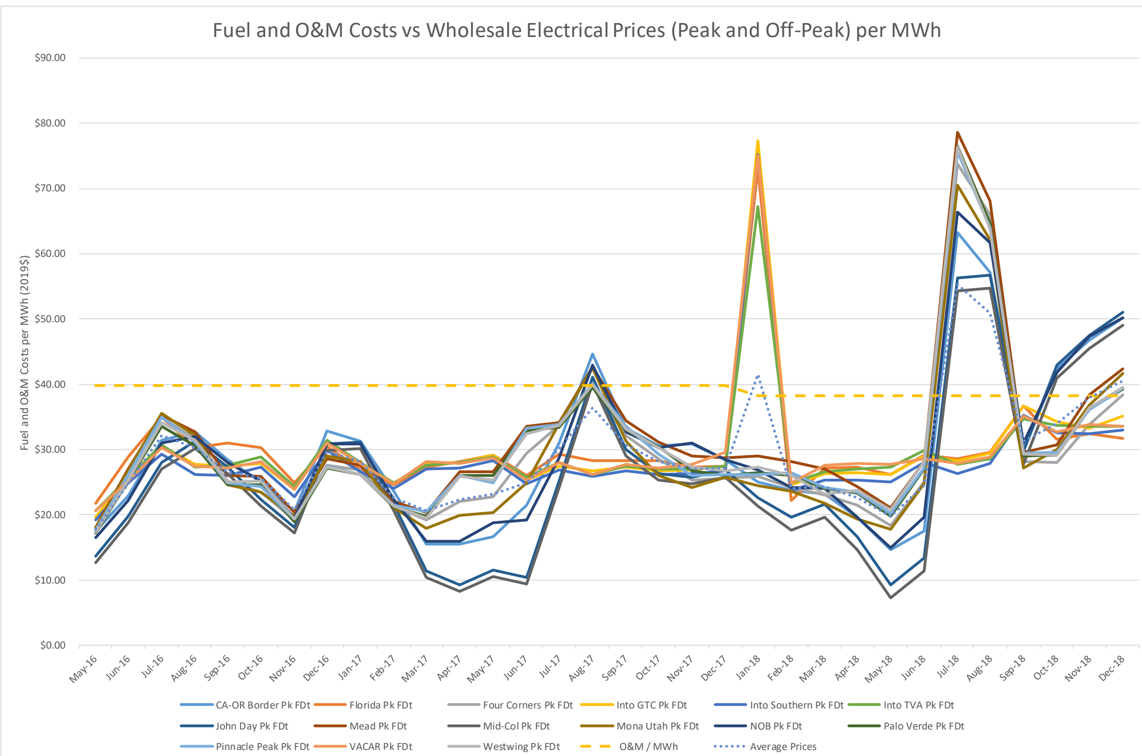

Figure 1: Coal Operating Cost vs. Market Prices [7]

Although it does not include all costs, this chart shows the basic problem. Existing coal units expend significant amounts on incremental capital for repairs and environmental

[7] Line 35 (expenses per net KWh) from FERC Form 1 pages 402 and following. Market prices are taken from Platt's Megawatt Daily.

upgrades. Moreover, aggregating all coal units gives a rosier picture of the plight of existing coal units than their owners actually experience.

Figure 2 shows fuel and O&M data for 2018 on a plant by plant basis:

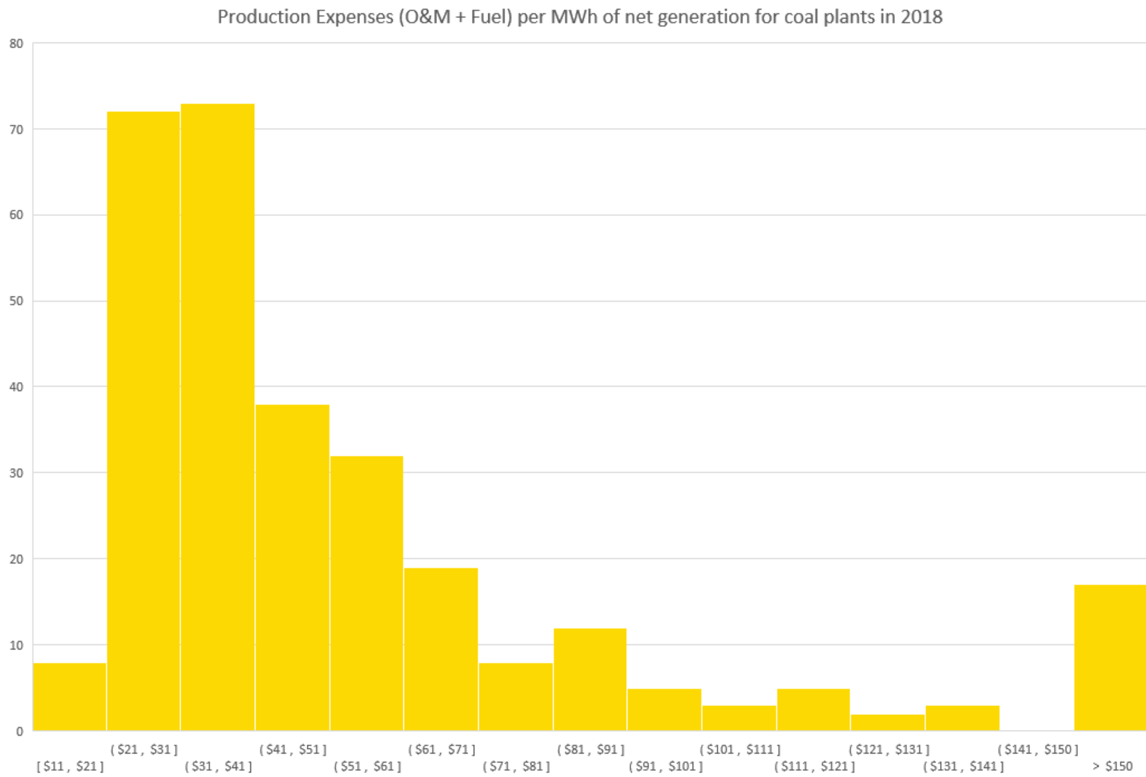

Figure 2 – O&M + Fuel $/MWh net generation [8]

Newer coal units have lower costs since they have better technology and less age-related heat rate degradation. Older coal units are not so lucky. A substantial proportion – just over one third – of total units have O&M and fuel costs above $50/MWh.

With bids on new renewable resources coming in at 40% of that, the economic life of older coal units is sharply reduced.

[8] FERC Form 1, 2018 - line 35 divided by line 12. https://www.ferc.gov/docs-filing/forms/form-1/data.asp

Overt Bias:

The industry standard for determining the cost-output ratio of energy production technology includes the sum total of each plant's lifetime of costs (capital expenditures plus operations and maintenance), divided by its sum total of energy produced. Taking a weighted average of all generation plants of a particular type allows different technologies to be compared and contrasted, assuming it is on an apples-to-apples basis. This method of LCOE calculation was used by IER, but they diverged from the apples-to-apples methodology.

- Questionable data cleaning practices that culled data in favor of fossil fuel units were used.
- Costs were imposed as an externality onto competing technologies when they should be associated with normal business expenses and risks for the technology that incurred them.
- Existing EIA figures were altered in ways that reduce costs for conventional coal without explanation.

The result is a subjective analysis with a strong bias against renewable energy, and in favor of existing facilities.

The sponsors of the IER report have clearly stated the objective of the study:

> *The 2019 LCOE Study was commissioned to evaluate whether it makes sense to continue operating existing power plants—coal, nuclear and natural gas combined cycle (NGCC)—rather than replace them with new electricity sources.*[9]

This is different than objectively comparing the costs of a ground-up installation and operation of each technology in that it assumes conventional generation is established and operational, only needing to be maintained and repaired.

Presumably, this metric for existing plants does not include construction costs, transmission costs, or externalities. If this is the case, this is closer to a calculation for the Marginal Cost of Electricity (MCOE), not the Levelized Cost of Electricity (LCOE). Labeling concerns aside, an apples-to-apples comparison would also use a similar metric for all other generation types, something that was not done in the report. Even if MCOE was calculated for all sources, this is a fundamentally flawed approach to comparing the total cost for each

[9] ACCCE Blog. http://www.americaspower.org/the-cost-of-existing-versus-new-sources-of-electricity/

technology. The industry standard is to use LCOE, not MCOE, for scoping level comparisons.

Resource comparisons are frequently used in scoping studies. Two highly respected sources are those of the U.S. Energy Information Administration (EIA) and the yearly report from Lazard Ltd.[10,11]

The authors of the IER study argue that the EIA assessment is flawed because it does not consider loss of revenue from premature closures:

> *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. environmental regulations on conventional generators…have indeed forced existing coal and nuclear plants to close early.*[12]

However, the report later backpedals on this by abstaining from assessing the lost revenues they were previously concerned about:

> *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.*[13]

If it is IER's position that the EIA approach is flawed, their aim should be to correct it, along with other industry leaders in LCOE calculations, such as Lazard. They do not make corrections to the underlying methodology, instead they use EIA estimates and build on them with questionable alterations.[14]

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[10] EIA Annual Energy Outlook. https://www.eia.gov/outlooks/aeo/

[11] Lazard – Levelized Cost of Electricity. https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2018/

[12] Stacy, Tom; Taylor, George. *The Levelized Cost of Electricity from Existing Generation Resources* IER, June 2019, Page 1.

[13] Ibid, Page 11.

[14] Ibid., Page 3.

Industry Standards:

A major business and investment analyst, Lazard, publishes a report that calculates LCOE for a variety of generation types.[15] This report is widely considered the industry standard for LCOE calculations and Lazard is widely considered the industry expert on the subject. According to Lazard, the levelized costs of newly installed renewable energy sources (including cost of installation) are considered to be on par with the marginal costs of existing coal facilities at about $30-40/MWh (Figure 3).

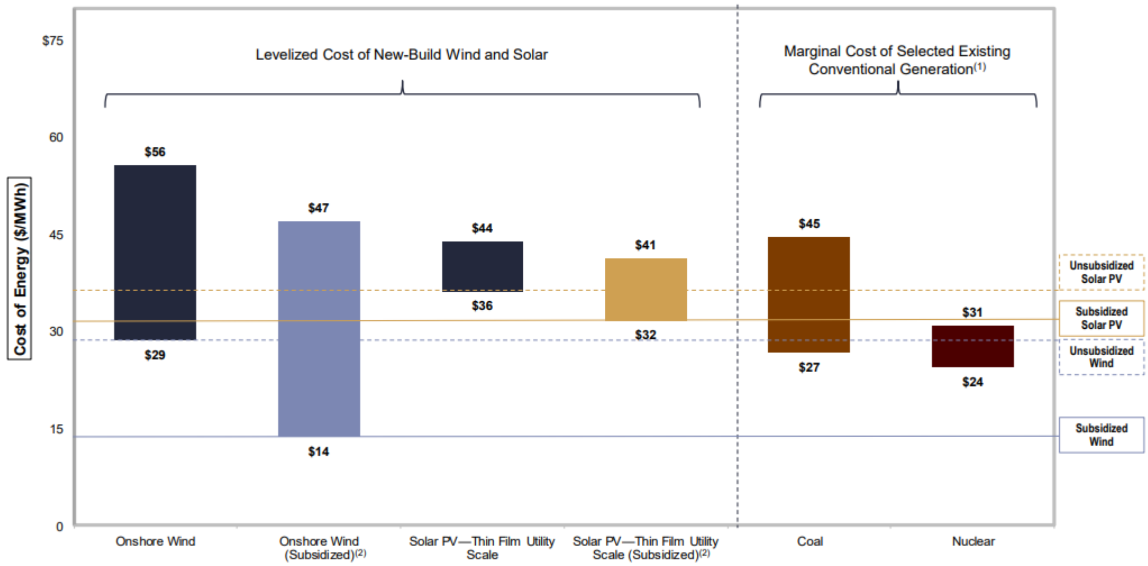

Figure 3 – Lazard LCOE, 2018 [16]

Lazard goes on to suggest that the prices for wind and PV solar are dropping fast.

> *Lazard's latest annual Levelized Cost of Energy Analysis (LCOE 12.0) shows a continued decline in the cost of generating electricity from alternative energy technologies, especially utility-scale solar and wind. In some scenarios, alternative energy costs have decreased to the point that they are now at or below the marginal cost of conventional generation.*[17]

The IER report does not mention Lazard or their calculations of LCOE, instead relying entirely on EIA for their figures. EIA is reputable, but when issuing a report on LCOE calculations, Lazard's methods and results are important to consider.

[15] Lazard – LCOE 12.0, 2018. https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf
[16] Lazard – LCOE 12.0, 2018. Page 6. https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf
[17] Lazard – LCOE/LACE, 2018. https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2018/

Methodology Concerns:

Substantial concerns about the methodology and transparency of the IER report abound. Conclusions are based on three (3) separate methods of determining LCOE, each with their own problems.

1. LCOE – Existing. IER's in house calculations, based on FERC data.
2. LCOE – New. Largely taken from EIA AEO 2019, with the exception of coal.
3. LCOE – New (Adjusted by This Report). Assessing "imposed costs" on less dispatchable generation, among other alterations to the conventional LCOE metric.

Concern #1 – FERC data

IER's calculations for existing power plants are compared to EIA estimates of new installations of each type. The same comparisons for wind and solar are not made because they claim no true comparison of existing facilities can be conducted.

> *…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.*[18]

This would be reasonable, if it were legitimate. Review of the FERC Form 1 database supports the notion that data can be difficult to obtain, as it requires use of vintage Visual FoxPro software. FoxPro can hardly be described as either user-friendly nor powerful. However, the data in question – costs for existing wind and PV solar – are in fact part of the same database as information on coal and natural gas plants. When filtering by "plant type" an analyst can clearly see the missing data.

The same claims are made for hydro plants, laying the blame for the inability to source data on the Visual FoxPro system:

> *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*

[18] Stacy, Tom; Taylor, George. *The Levelized Cost of Electricity from Existing Generation Resources* IER, June 2019, page 7.

> *analysis. Instead we substituted our calculations for the levelized cost for existing hydro made the cost for our 2016 study and restated in 2018.*[19]

Numerous conversion tools capable of translating the FoxPro data into .csv files exist.[20] These files are easily readable by Microsoft Excel, and the errant hydro data was quickly found. Additionally, while using previously generated results is not off-base, the exclusion of the most recent 3+ years of data in a world of rapidly changing technology raises significant questions about the accuracy of the analysis.

Another concern about the IER report is that a significant number of data points were discarded without explanation or justification:

> *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.*[21]

While FERC accounting standards are used in the creation of the FERC Form 1 database, it is not unusual to find differences between company submissions. As with any financial data, there is no easy shortcut. If specific companies are making filings that seem unusual, it is necessary to check with the company to make sure that the results are justified.

Whatever the cause of the discrepancy, IER's procedure was not standardized. All questionable values could be eliminated or what constitutes "large" could be disclosed. Instead, the data is simply culled without indicating any specific criteria. A true apples-to-apples comparison would either resolve the question of negative values, including those that were not obvious mistakes into the analysis, would eliminate them across the board, or would seek to estimate accurate values by other methods. Arbitrarily deciding a threshold for elimination is a questionable practice, especially when the threshold is undisclosed in the report.

Another questionable elimination of data occurs due to certain values that were too large or too small:

> *Data out of range was the single largest reason for omitting records from the samples…For nuclear we kept units reporting in a range from 40% to*

[19] Ibid, page 8.
[20] "Csv" stands for "comma separated values. This is a common format for transferring data between different computer programs.
[21] Ibid., Page 9.

> *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%.*[22]

As suggested above, challenging data can be difficult to reconcile, but simply eliminating an entire plant from the assessment because an arbitrarily determined threshold was reached one time is inappropriate. Regardless, there is a legitimate reason for a plant to have a capacity factor of 10-15%. Since capacity factor is simply production divided by nameplate capacity, if a plant was offline for significant portions of the year due to repair activities, it is entirely possible that it would have only generated 10-15% of its potential for that year. Moreover, for plants with high operating costs, it is entirely rational to reduce their operations to an absolute minimum.

To avoid the impression of bias, significant care must be taken not to eliminate valid observations, however incorrect they may appear. Inclusion of all relevant data gives a truer representation of the costs of deploying that technology. By eliminating it, the calculation sheds a heavy cost burden. Unsurprisingly, the IER results for conventional energy sources are substantially lower than industry averages. For an analyst seeking to bias the results, this data elimination can easily be masked from the non-scrutinous eye as a legitimate method of cleaning muddy data.

Concern #2 – Adjusting Plant Costs

LCOE – New values from the U.S. Energy Information Administration's Annual Energy Outlook report for 2019 (Figure 4, Figure 5) are used.

Table 1b. Estimated levelized cost of electricity (unweighted average) for new generation resources entering service in 2023 (2018 $/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmis-sion cost	Total system LCOE	Levelized tax credit[1]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[2]	85	61.3	9.7	32.2	1.1	104.3	NA	104.3
Coal with 90% CCS[2]	85	50.2	11.2	36.0	1.1	98.6	NA	98.6
Conventional CC	87	9.3	1.5	34.4	1.1	46.3	NA	46.3
Advanced CC	87	7.3	1.4	31.5	1.1	41.2	NA	41.2
Advanced CC with CCS	87	19.4	4.5	42.5	1.1	67.5	NA	67.5
Conventional CT	30	28.7	6.9	50.5	3.2	89.3	NA	89.3
Advanced CT	30	17.6	2.7	54.2	3.2	77.7	NA	77.7
Advanced nuclear	90	53.8	13.1	9.5	1.0	77.5	NA	77.5
Geothermal	90	26.7	12.9	0.0	1.4	41.0	-2.7	38.3
Biomass	83	36.3	15.7	39.0	1.2	92.2	NA	92.2
Non-dispatchable technologies								
Wind, onshore	41	39.8	13.7	0.0	2.5	55.9	-6.1	49.8
Wind, offshore	45	107.7	20.3	0.0	2.3	130.4	-12.9	117.5
Solar PV[3]	29	47.8	8.9	0.0	3.4	60.0	-14.3	45.7
Solar thermal	25	119.6	33.3	0.0	4.2	157.1	-35.9	121.2
Hydroelectric[4]	75	29.9	6.2	1.4	1.6	39.1	NA	39.1

Figure 4 - EIA Annual Energy Outlook 2019[23]

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[22] Ibid., Page 9.

[23] EIA Annual Energy Outlook, 2019. Page 8. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

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]

Figure 5 - IER LCOE 2019 [24]

> *Column 3* [Figure 5] *shows EIA's projected LCOE-New which could be brought online in 2023…*[25]

However, an adjustment is made,

> [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.*[26]

Footnote 3 is given as an explanation (Figure 6), but the calculation metric is somewhat less than transparent.

[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).

Figure 6 – IER LCOE 2019 [27]

Distilling Footnote 3, the tactic used was to calculate a percentage difference between conventional and carbon capture (CCS) coal facilities from the AEO 2015 report and then apply it to the figures from AEO 2019 in order to give an estimate of the cost to install new conventional coal.

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[24] Stacy, Tom; Taylor, George. *The Levelized Cost of Electricity from Existing Generation Resources* IER, June 2019, TABLE 1.
[25] Ibid., Page 4.
[26] Ibid., Page 6, footnote ii.
[27] Ibid., Table 1.

This raises numerous red flags. Attempts to replicate their methodology failed to verify the $58.6/MWh value. Moreover, technology costs change over time, suggesting these ratios would not be the same four years later.

More importantly, there is good reason for EIA to only calculate LCOE – New for CCS facilities, and not for new conventional coal facilities:

> *AEO2019 assumes new coal plants without CCS cannot be built because of emission standards for new plants. These technologies exist in the modeling framework, but they are not assumed to be available to be built in the projections.*[28]

EIA claims that regulatory standards make it unlikely there will be any new coal plants installed without CCS technology.

This bears repeating. Regulatory standards make it unlikely there will be any new coal plants installed without CCS technology, making calculations of LCOE - New for those plants unnecessary, calling into question the reasoning behind the use of this tactic. Even if this calculation was warranted and fully transparent, the values calculated are nearly half of the LCOE – New values for coal calculated by EIA in 2015 (Figure 7).

	U.S. Average Levelized Costs (2013 $/MWh) for Plants Entering Service in 2020[1]							
Plant Type	**Capacity Factor (%)**	**Levelized Capital Cost**	**Fixed O&M**	**Variable O&M (including fuel)**	**Transmission Investment**	**Total System LCOE**	**Subsidy[2]**	**Total LCOE including Subsidy**
Dispatchable Technologies								
Conventional Coal	85	60.4	4.2	29.4	1.2	95.1		
Advanced Coal	85	76.9	6.9	30.7	1.2	115.7		
Advanced Coal with CCS	85	97.3	9.8	36.1	1.2	144.4		

Figure 7 – EIA Annual Energy Outlook 2015 [29]

Whatever the metric, it is completely unreasonable to suggest that in only four years' time, efficiency gains in an obsolete technology amounted to a fifty percent cost reduction. If the coal industry could achieve such rapid cost reductions with existing equipment, such changes would have been observed in practice.

Unlike the stagnating or reducing efficiency of the coal industry, advances in wind generation are increasing its efficiency. Figure 8 shows an example of the increases in average wind capacity factor since 1998 as calculated by the U.S. DOE Berkley lab.

[28] EIA Assumptions. https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf
[29] EIA Annual Energy Outlook, 2019. Page 6. https://www.eia.gov/outlooks/archive/aeo15/pdf/electricity_generation_2015.pdf

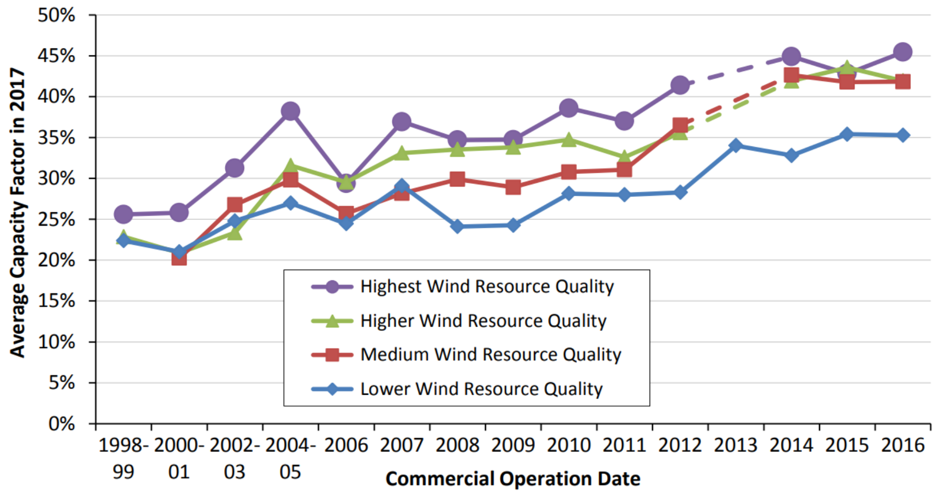

Figure 8 - U.S. DOE – Wind Technologies Market Report [30]

The technological improvements in recent years contradict the IER report's assumption that future wind will be less efficient.

In sum, values are assumed that cannot be replicated, using a metric that is not particularly transparent, for reasons that are invalid. Additionally, the coal value is unreasonably low when compared to calculations only 4 years old, as efficiency gains for obsolete technologies are unlikely to amount to such substantial reductions in cost. Wind and solar receive the opposite treatment – gains from new technology are removed from the calculations, though they are plainly increasing.

This may be an attempt at an apples-to-apples comparison, but falls well short of objective analysis.

Concern #3 - Imposed Costs:

The IER report claims that wind and solar PV provide erratic and un-dispatchable generation to a relatively fixed demand market, forcing base load generators to ramp-down during high output from wind and PV solar. The associated costs are considered unexpected in an existing balanced system and therefore an externality of the erratic source, which it must shoulder in its LCOE calculations.

> *In order to facilitate appropriate comparison of wind and solar with new and existing dispatchable resources, we explain and calculate an estimate*

[30] U.S. DOE, Wind Technologies Market Report, 2017. https://www.energy.gov/sites/prod/files/2018/08/f54/2017_wind_technologies_market_report_8.15.18.v2.pdf

> *of "imposed costs" and allocate them to the LCOE of wind and solar which create them.*[31]

The metric for IER's "LCOE – New (adjusted by this report)" takes this calculation of "imposed cost" into consideration, among other changes:

> *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*[32]

Differences in dispatchability are reasonable to consider, as they make LCOE comparisons difficult between sources with different dispatchability characteristics (noted by EIA in their AEO 2019 report).[33]

However, imposed costs such as this are not a component of industry standard LCOE calculations. They are an entirely new way of approaching LCOE. By "adjusting" EIA's figures with their own metric, particularly one that serves to increase costs for renewables but no other generation type, the results appear skewed in opposition to renewables. Using the industry standard moniker – LCOE – belies a certain authority and quality of analysis. But altering the methods and still calling it LCOE is disingenuous about the claims, giving them an unwarranted authoritative nature.

Core economic principles suggest that any investment project has associated risks, including advancing technology that increases efficiency, lowers costs and makes the investment obsolete, cutting short the viable lifetime of the project. However, this marketplace reality is ignored with the implication that existing equipment (most of which is already beyond its financial lifetime) will always take precedent because it is already established:

> *…many parts of existing plants have almost unlimited 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.*[34]

What is being suggested is that as long as legacy plants are functional or repairable, which is contended to be forever, any new plant is extraneous and impinges on established operations. This completely ignores industry reports which explicitly state that brand new

[31] Stacy, Tom; Taylor, George. *The Levelized Cost of Electricity from Existing Generation Resources* IER, June 2019, Page 4.
[32] Ibid., Page 14.
[33] Annual Energy Outlook, 2019. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf
[34] Stacy, Tom; Taylor, George. *The Levelized Cost of Electricity from Existing Generation Resources* IER, June 2019, Pages 4-5.

installations of renewable generators, including transmission lines and construction costs, are less expensive than repairing and maintaining old and obsolete thermal generators.[35]

The assumption implied by IER is that investors expect their existing projects to operate as forecasted to the end of their useful life. Any infringement on that predictable operation is treated as an additional cost that would not exist if the instigator of the unpredictability did not exist. Therefore, these costs are calculated and factored into LCOE for the new and usurping facility.

However, this method runs contrary to traditional ratemaking – which recovers invested capital regardless of the level of operations – and the expectations of most administered markets with separate energy and capacity markets.[36]
In addition to the dubious nature of adjusting the Levelized Cost of Energy for intermittent renewable generation, the assumptions that drove the imposition of costs were flawed. Dispatchability of wind and solar can indeed be a concern for grid managers, but there are a number of industry solutions that exist and are being developed and improved to address this issue. This method of addressing dispatchability is completely overlooked. Lazard publishes a Levelized Cost of Storage (LCOS) report to go with their LCOE report.

> *Combining energy storage with solar PV can create value through shared infrastructure (e.g., inverters, interconnection), reducing the need to curtail production by delaying the dispatch of electricity onto the grid and/or by capturing the value of "clipped" solar production (e.g., solar PV output that is in excess of the system inverter)*[37]

The first and foremost approach of generation "firming" for wind and solar is storage technology. Batteries, cement blocks, flywheels, compressed air and reservoirs of water can all provide cost effective storage solutions that provide during times of peak load demand, and replenish during times of over-abundant generation.

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[35] VCE – The Coal-Cost Crossover, 2019. https://energyinnovation.org/wp-content/uploads/2019/04/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL2.pdf
[36] Approximately half of the U.S. and Canada are served under the traditional regulatory formula. For these areas, revenue requirements are determined by the formula:

Revenue Requirements = Rate of Return x (Original Cost Depreciated) + O&M + Fuel.

Under traditional regulation, the level of generation does not affect the return to investors.

In administered markets (markets where market prices are set by a central independent system operator) separate auctions are held for energy and capacity (with the exception of California and Texas). Capacity prices vary, in part, due to supply and demand for capacity. They also do not reflect MWhs generated.
[37] Lazard - Levelized Cost of Storage (LCOS), 2018. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf

Grid managers have a variety of tactics at their disposal for both demand load shifting and peak generation shifting. A less discussed tactic is also to simply shut off generation, called "clipping". For individual plant owners, this may seem like an unreasonable expectation, but in highly vertically integrated generation markets, grid managers have the ability to pick and choose which generation types are more cost effective to run, and which can be clipped to maximize cost efficiency.

Simply the existence of options which firm load generation (such as storage), or address system diversity (such as LDC and Resource Planning models) should be enough to eliminate the justification of imposing costs. However, these existing solutions and any future advancements in storage and dispatching are completely overlooked by IER, instead suggesting that wind and solar are simply an untenable burden to the existing industry.

The reality of dispatchability concerns is on the verge of being entirely immaterial, as the costs for installation plus storage are dropping quickly. Though some storage technologies incur externality costs, such as lithium mining for batteries, similar environmental externalities are not assessed for conventional generation, so it would be improper to unilaterally impose these costs on renewables.

IER's attempts to adjust LCOE so as to approximate for changes needed in system planning are unique, and not according to industry standard.

System Planning Models:

For nearly as long as electricity infrastructure has existed, there have been guidelines on how to optimize between different types of generation sources. One almost universal model is found in engineering economics texts over the past one hundred years. See, for example, the Standard Handbook for Electrical Engineers, page 911, for an early exposition of the utility scoping model.[38]

A more recent authority, *The Handbook of Electric Power Calculations*, contains an 18-step algorithm that lays out the methodology to arrive at the most efficient mixture of available resources.[39]

One of the first steps is constructing a set of screening curves. These curves are linear with a y-intercept at construction costs, and have a slope of the marginal cost of operations (O&M + fuel). The scoping model equals the total cost divided by expected generation – basically the same as LCOE.

[38] *Standard Handbook for Electrical Engineers Fifth Edition*, Frank F. Fowle, Editor, 1922.
[39] *Handbook of Electric Power Calculations*, H. Wayne Beaty, 2001.

Figure 9 is an example of a screening model. It shows a comparison of various generation sources and their associated costs at different levels of generation. It is assumed that the sources with the lowest costs for the given range of capacity needs will be used. This effectively creates a convex hull of options depending on the load capacity that is being planned for.

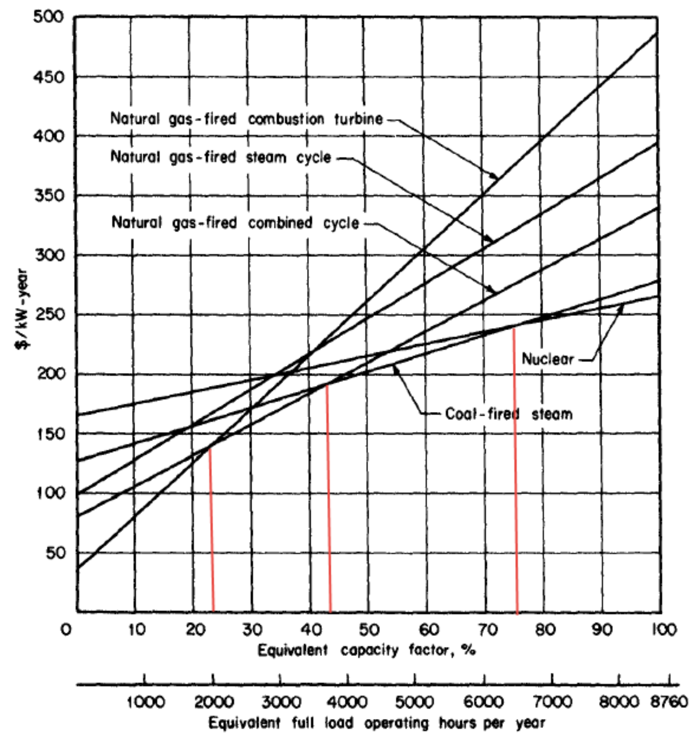

Figure 9 - Screening curves for electric-generation-system alternatives.[40]

Figure 9 shows that natural gas fired combustion turbines (CT) are the most cost-effective generation choice for under 2000 operating hours per year. Similarly, natural gas combined cycle (CC) is the most efficient if planned for use 24-43% of the year or about 2000-3800 operating hours. Coal-fired steam generation is most affordable if the planner is looking to run it 44-75% of the year or 3800-6500 operating hours. Nuclear is the most cost-effective way of producing electricity when operated for more than 75% of the year or over 6500 hours. Once the planner has determined how much of the year the facility is planned to run, and eliminated or "screened" the less cost-effective options, the ranges and break points are taken to a load duration curve (LDC – Figure 10). The point at which the vertical lines touch the LDC determines which generation type is to be used for which portion of the load.

[40] Ibid., Section 8.11.

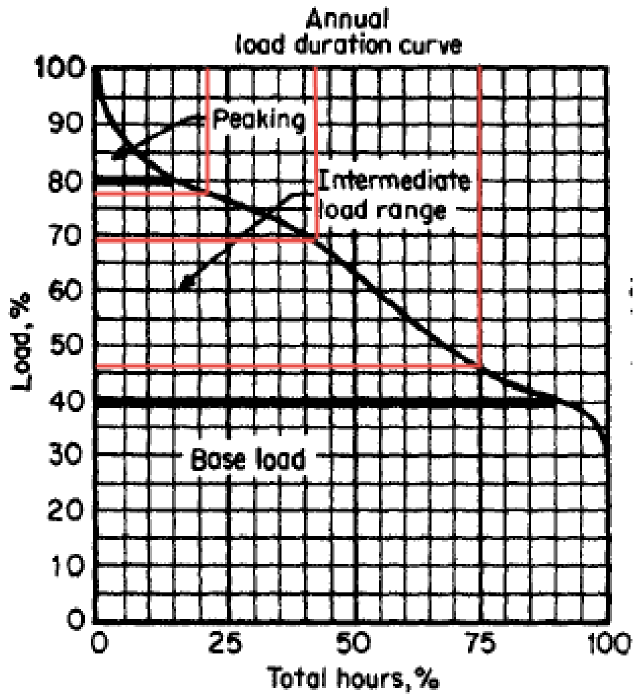

Figure 10 – Annual load duration curve [41]

In this example, nuclear is the best option for base load generation up to about 46% of the required capacity. About 22% of total load generation should be done by coal fired steam plants to stay cost-effective. For times of high demand, or "peaks", natural gas CC and CT will efficiently provide up to 9% and 22% of the grid generation, respectively, illustrating why CT and CC plants are considered "peaker" plants.

Obviously, this 2001 chart is without the inclusion of newer technologies such as wind and solar, and with costs reflective of those earlier times. Additionally, this method does not necessarily take certain other factors into account, such as environmental externalities, social or political goals, and other system characteristics. However, this format remains a known industry tool to screen inefficient technologies and determine the optimal long run mix of generation methods based on their operating costs.

To generate a screening curve for renewables is not difficult. Their marginal costs are relatively low since there are no fuel costs. However, most wind generators are not beyond their financial lifetime, so capital expenditures are often considered. System planners must also consider dispatchability when screening resources.

[41] Ibid., Section 8.7.

IER brings dispatchability up as a way of justifying their metric of "imposed costs", but fails to understand that system planners already take these limitations into account.

> *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.* [42]

For planning models, it may be reasonable to consider renewables in a different way, but the industry standard metric for penalizing renewables for their dispatchability concerns is to apply their peak load capacity factor, not to charge them for the amount needed to firm generation. The metric for this planning exercise is to consider capital costs per megawatt hour of expected capacity during peak load times. By calculating the percentage of the available nameplate capacity that can be expected to be online during peak hours, system planners are taking into account the dispatchability concerns and the reduced capacity availability of renewables.

Capacity credit by technology and pool that
TEPPC uses to meet the reserve margin criteria

Generation Type	AZ-NM-NV	Basin	Alberta	BC	CA-North	CA-South	NWPP	RMPA
Biomass RPS	100%	100%	100%	100%	66%	65%	100%	100%
Geothermal	100%	100%	100%	100%	72%	70%	100%	100%
Small Hydro RPS	35%	35%	35%	35%	35%	35%	35%	35%
Solar PV	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**
Solar CSP0	90%	95%	95%	95%	72%	72%	95%	95%
Solar CSP6	95%	95%	95%	95%	100%	100%	95%	95%
Wind	**10%**	**10%**	**10%**	**10%**	**16%**	**16%**	**5%**	**10%**
Hydro	70%	70%	90%	90%	70%	95%	70%	70%
Pumped Storage	100%	100%	100%	100%	100%	100%	100%	100%
Coal	100%	100%	100%	100%	100%	100%	100%	100%
Nuclear	100%	100%	100%	100%	100%	100%	100%	100%
Combined Cycle	95%	95%	100%	95%	95%	95%	95%	95%
Combustion Turbine	95%	95%	100%	95%	95%	95%	95%	95%
Other Steam	100%	100%	100%	100%	100%	100%	100%	100%
Other	100%	100%	100%	100%	100%	100%	100%	100%
Negative Bus Load	100%	100%	100%	100%	100%	100%	100%	100%
Dispatchable DSM	100%	100%	100%	100%	100%	100%	100%	100%

Figure 11 - WECC - Contribution to Resource Adequacy [43]

Figure 11 shows the rule of thumb capacity factors for various generation types at peak times, as determined by the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee (WECC TEPPC). This gives insight into how lower

[42] Stacy, Tom; Taylor, George. *The Levelized Cost of Electricity from Existing Generation Resources* IER, June 2019, Page 27.
[43] NREL, Capacity Value: Evaluation of WECC Rule of Thumb, 2015. https://www.nrel.gov/docs/fy15osti/64879.pdf

capacity factor is taken into consideration in system planning models. For system planners to consider wind as providing one mega-watt of generation in the NWPP market, they must budget 20 MW of nameplate capacity (5% * 20 MW = 1 MW). This would have the effect of generating a screening curve at 20 times the O&M costs. A similar calculation for solar would expect 1.66 MW of nameplate capacity to be budgeted per megawatt of expected solar generation. In this way, resources with different dispatchability and capacity can be compared apples to apples.

To be clear, the industry standard is to take into account the dispatchability characteristics of a plant for system planning purposes. It is not considered a reason to impose costs on LCOE.

The availability of modern information technology allows for vastly more sophisticated resource planning approaches. This includes stochastic modeling for intermittent resources such as wind and solar, as well as methods that can account for forced outages at thermal units.

Many studies are available that use more advanced methods than the simple example shown above. The NREL study "Implications of Model Structure and Detail for Utility Planning: Scenario Case Studies Using the Resource Planning Model" provides a good opportunity to see such an approach.[44] The results from such an advanced model for the west coast of the U.S. can be seen in Figure 12.

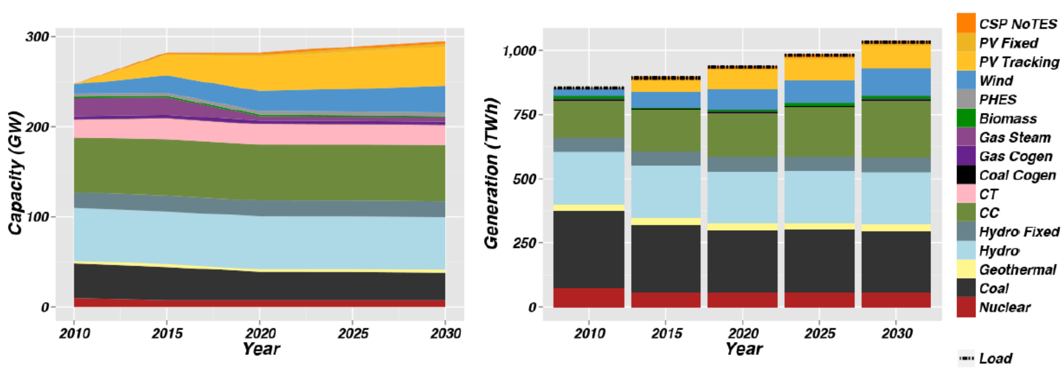

Figure 12 - NREL Resource Forecast [45]

There's nothing extraordinary about the results derived from this technique. The selection of renewables over continued operation of coal is a frequently observed result of utility Integrated Resource Plans across the United States.

[44] *Implications of Model Structure and Detail for Utility Planning: Scenario Case Studies Using the Resource Planning Model*, Trieu Mai, Clayton Barrows, Anthony Lopez, Elaine Hale, Mark Dyson, and Kelly Eurek, April 2015.
[45] Ibid., page 24.

Costs vs. Revenue:

So far, the debate has surrounded the supply side of the energy market, comparing the moving forward costs of conventional generation with the installed costs of wind and solar. The plant type that can generate for the least expense is assumed to be the preferred source. But this ignores a significant factor in investment decisions; market prices. A demand side analog would be an assessment of wholesale hub prices paid to producers with a comparison to their production costs. As mentioned above, the EIA publishes wholesale electricity and natural gas market prices sourced from International Exchange. Figure 13 shows a distribution of these weighted-average wholesale prices from 2019.

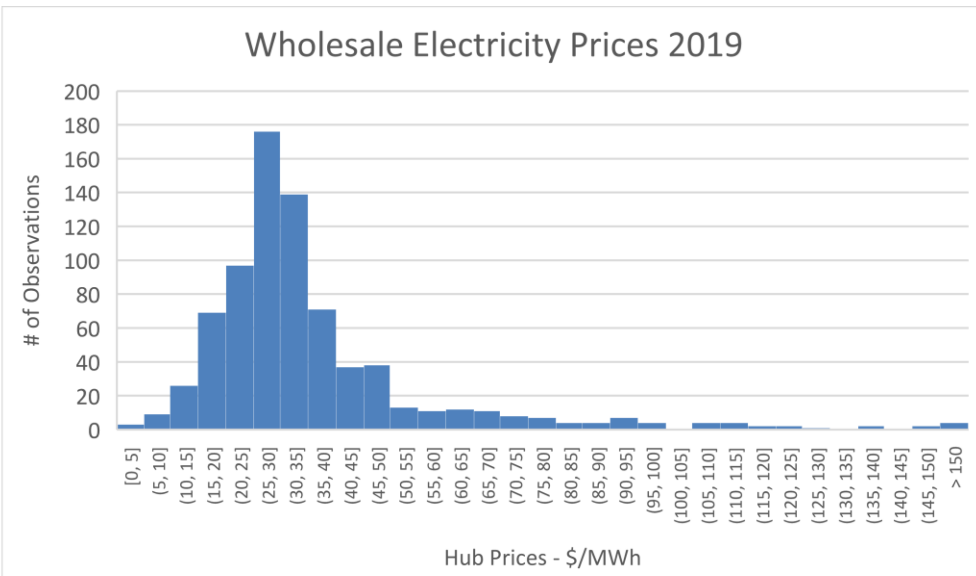

Figure 13 – Wholesale Electricity Prices, EIA 2019 [46]

The majority of the observed prices fall between $15/MWh and $40/MWh with a mode of $25-30/MWh. For existing plants that are operating at an MCOE of $40/MWh or greater, this serves as a wake-up call that the plant may be at the end of its economic lifetime.

Regardless of competition, if it is impossible for a plant to produce electricity for less than wholesale prices, then that plant is running in the red and is destined for shutdown if changes aren't made. Wholesale prices would need to increase, or facility costs reduce. But, rate-payers aren't looking to spend more, and it is unlikely that overhead and maintenance costs for conventional technologies will become much less expensive.

[46] Wholesale Electricity Prices, EIA, 2019. https://www.eia.gov/electricity/wholesale/

Fuel costs are also paramount in calculations of MCOE for conventional sources. If fuel prices are too high, no amount of O&M reduction will help.

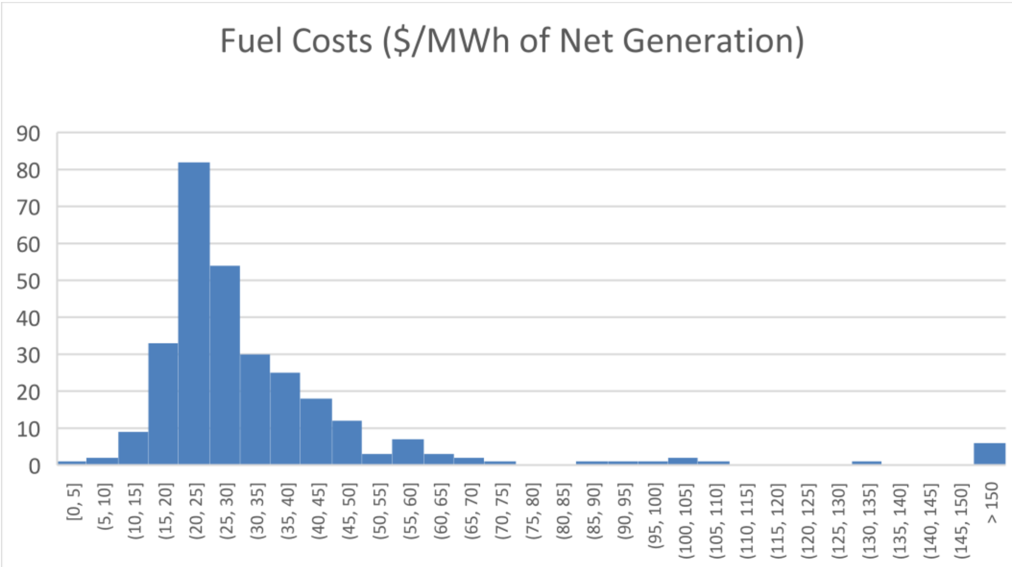

Figure 14 - FERC Form 1 Data [47]

Using FERC Form 1 data, Figure 14 shows the distribution of fuel cost per MWh of generation (for coal facilities). Most values fall within a range of $15-40/MWh with a mode of $20-30/MWh. If these numbers look familiar, it is because they are similar to the ranges of wholesale market prices. This suggests that firms have very little leeway, and their profitability is highly dependent on fuel prices.

Comparing these figures with wholesale prices suggests that a number of plants are only barely able to recover input costs, let alone overhead and repair costs.

Xcel Energy published a solicitation report which catalogs the over 400 bids placed by installers of electricity generators.[48] The report detailing the most recent bids is still being compiled, but the report for 2017 gives insight into the realities faced by investors. Figure 15 shows the median bids for each generation type.

[47] FERC Form 1 data set. https://www.ferc.gov/docs-filing/forms/form-1/data.asp

[48] Xcel Energy Solicitation Report, 2017. https://assets.documentcloud.org/documents/4340162/Xcel-Solicitation-Report.pdf

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	6.70	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	14.60	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	50.00	$/MWh
Waste Heat	2	21	1	11	55.40	$/MWh
Biomass	1	9	1	9	387.50	$/MWh
Total	430	111,963	238	58,283		

Figure 15 - Xcel Solicitation Report, 2017 [49]

The median bid for wind is $18.10/MWh without storage, $29.50/MWh for solar without storage.

When battery storage is included, the prices increase by small amounts. Wind goes up to $21.00/MWh, and solar increases to $36.00/MWh.

Values presented by Xcel fall in line with installed and subsidized estimates by Lazard (mentioned previously in this report). Lazard's unsubsidized estimates are not much more, beginning under $40/MWh. It should be noted that Xcel values are not estimated values, and they are not marginal costs, they are contract bids to install operational generators. Fuel costs would be in addition to these figures, which would be zero for wind and fuel.

Even including the cost of load firming storage solutions, wind and solar are able to generate for less expense than the operational costs of conventional sources. With the advancement of technology, those bids will only reduce further.

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[49] Ibid., Page 9.

Conclusions:

The conclusions arrived at by IER - conventional coal is cheaper than renewables - is both incorrect and ill-conceived. Even if the imposed costs levied on wind and PV solar were to be accepted, the approximately $90/MWh estimate for wind and PV solar is still lower than the LCOE – New figures calculated by U.S. Energy Information Administration for coal facilities with carbon capture technology (the only new coal facilities able to be built). To arrive at the conclusion that conventional coal is less expensive than renewables takes a significant departure from reality. To argue that marginal costs of coal-powered generators (the ability to continue operating existing plants) are cheaper than brand new installations of solar or wind is not only counter to industry expert analyst reports, it departs from the apples-to-apples comparison known as LCOE, sacrificing credibility and rendering the conclusions invalid.

Determining the cost for various facilities to generate a megawatt of power is a difficult task. Industry standards for calculating this value exist along with certain liberties that can be taken, as long as they are explained with clarity and transparency. IER has published a report that both took liberties with industry methods and lacked transparency. This gives a strong impression of bias.