Levelized Cost of Energy: Expanding the Menu to Include Direct Use of Natural Gas

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August 2017

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Executive Summary

Many analysts and advocates have published levelized cost comparisons over the years to compare the going forward costs of various energy technology choices, often to encourage public policy that favors one technology over another. Levelized costs are the stream of costs in discounted net present value terms that attempts to put fixed costs and future variable costs on an equal footing. Levelized costs analysis has historically and typically been limited to electric generation technologies, thus precluding the fair consideration of other technologies, like the direct use of natural gas for such end uses as space and water heating. While natural gas has become the fuel of choice for many electrical generation plants, the direct use of natural gas may provide greater economic, reliability and emissions benefits compared to first converting natural gas to electricity and then using that electricity in resistance heaters for the same end use.

The United States has undergone a transformational shift in the perceived role of natural gas. Once viewed as a scarce resource, and constrained by statute, North American natural gas is now recognized as an abundant low-cost fuel that serves as an essential component of a clean and secure energy portfolio. Today more than 70 million households and businesses in the U.S. utilize natural gas served by an infrastructure network that is unrivaled. Local distribution and interstate pipeline companies in collaboration with policy makers are investing billions of dollars each year to modernize the nation's natural gas delivery infrastructure, making it safer and more reliable. At the same time, many states are pursuing expansion efforts to connect unserved and underserved households and businesses. These investments are predicated on a recognition that access to natural gas enables economic and environmental benefits. But the full potential of natural gas as an important tool for balancing economic growth and greenhouse gas emissions reduction remains unrealized.

This report provides levelized cost comparisons of electricity generation options and direct use of natural gas, recognizing that not all end uses can use natural gas directly. Nevertheless, public policies that call for 'electrify everything' ignore the efficiency, cost and emission benefits of the direct use of natural gas compared to using electricity for 'everything.' Importantly, this report only provides reconnaissance level analysis; more detailed analysis is warranted, but the bottom line is the direct use of natural gas provides significant economic, energy and environmental benefits and should not be discarded in public policy deliberations.

We find that the direct use of natural gas, for appropriate end uses has significantly lower levelized costs than any of the electric generation technologies. Further it avoids the potential for stranding capital investments, making them uneconomic, and provides flexibility and diversity while providing emission reductions (compared to status quo) at lower costs than electric generation technologies. Table ES1 provides our estimates in constant 2017 dollars, per million btu, and including losses in transmission. Capacity costs and greenhouse gas reduction costs are provided later in the report.

- Direct use of natural gas can reduce the cost of GHG emission reductions by as much as 80% compared to electricity options.

- While distributions are wide, most likely LCOE values for direct use of NG options are well below the most likely values for electric options. This means that policies should encourage the direct use of natural gas where it works, over electrification, to provide consumer cost savings while simultaneously providing reliability benefits, by reducing demands on an already stressed grid.
- Costs are widely divergent and highly dependent on future fuel forecast and dramatically impacted by discount rate assumptions.
- Many end-uses for electricity are not amenable to service with natural gas as expected.
- Cost of capacity (power plant and natural gas pipelines) differ by over two orders of magnitude. The results are not surprising, as levelized costs include annual fixed charges (e.g. financing of large capital investments) which are largely avoided by using natural gas. Drilling and pipeline costs are rolled into commodity costs and, even so, futures markets provide evidence of continuing low natural gas prices as shown in Figure ES-1.

Figure ES-1

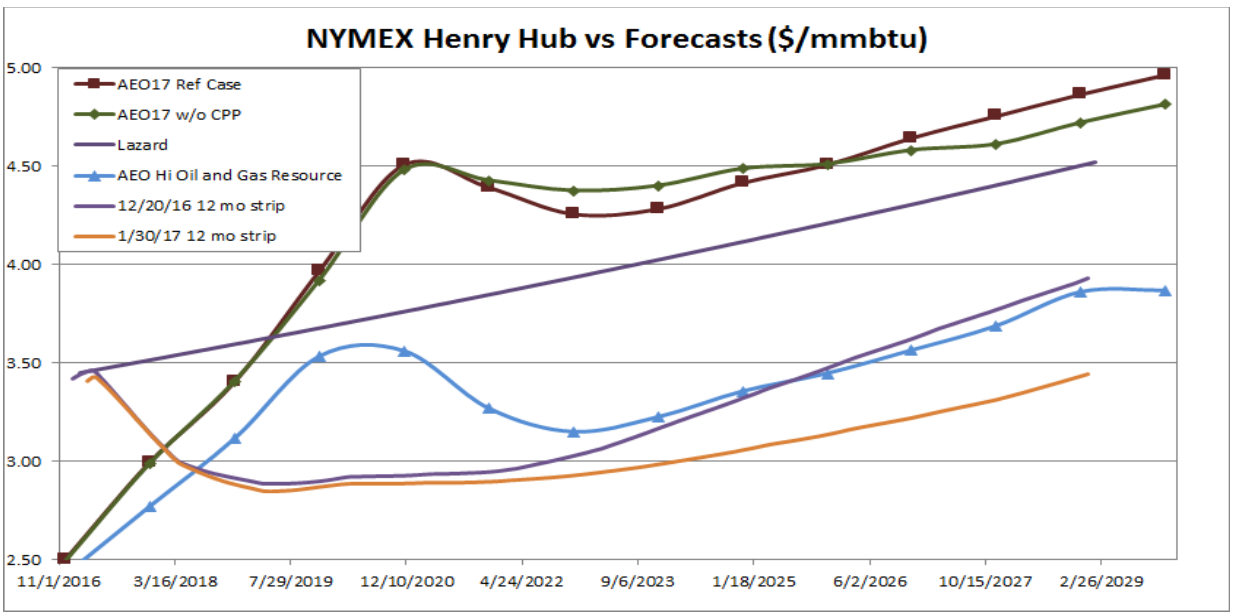


Chart courtesy of Jim Moore with Spire Energy[1]

Table ES1

[1] Jim Moore, Spire Energy, private communications February 9, 2017. NYMEX prices off the settlement prices here: http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_settlements_futures.html#tradeDate=02/03/2017

Levelized Cost of Energy Technologies, Including Transmission Losses

Technology	$/mmbtu
Wind/onshore	32.29
Solar PV	31.05
Nat Gas Comb Cycle	17.70
Coal new	43.47
Coal Existing	19.56
Nuclear	31.98
Geothermal	13.04
Gas Furnace NC	13.83
Gas Furnace Condensing	13.70
Gas Water Heater NC	13.83
Gas Water Heater Condensing	13.70
Gas Boiler NC	13.83
Gas Boiler Condensing	13.70

Notes: Readers should not directly compare levelized costs, which reflect net present value of future prices, with wholesale or city gate prices today. Second, load factors of end use appliances do not affect LCOE at city gate, as LCOE are per unit (MMBtu) prices.

Major assumptions used in this report include:

- Electric Transmission Losses of 6%, natural gas of 1.5%
- Discount Rate of 2% (real)
- No continuation of PTC (federal production tax credit) nor implementation of the Clean Power Plan, at least at the Federal level
- Capital Expenditures for Natural gas supply are reflected in future commodity prices
- Did not include "environmental externality"
- Did not include options values, which would make direct use even more attractive by avoiding current large Capital Expenses (CapEx) for power plants.
- KWh/MWh converted to MMBtu for comparison
- Levelized capacity costs do not account for contribution to capital from energy sales. In other words, it reflects only the fixed charges associated with carrying debt on capital costs.

Prices paid by end use consumers are the result of rate making proceedings and likely different and higher than levelized cost; and only somewhat reflect wholesale costs. Our results, however, are generally consistent with national average consumer prices which show electricity about three times as costly at natural gas. We recommend that analysts, especially those at EIA and state level analysts, include the direct use of natural gas as an option when undertaking levelized cost analysis. EIA has made a significant step forward in differentiating between dispatchable and non-dispatchable electricity options; now it's time to expand the options considered. We further recommend that policies aimed at "electrifying every end use" cease and broader recognition of the life cycle energy use and costs be included as policy is refined. Finally, we recommend that free market principles and performance be fairly considered and not relegated to the dust bin of 'doing nothing' as policy and programs are made consistent with the new administration's goals.

Introduction

Why Even Compare the Levelized Cost of Direct Use?

When used directly in homes or buildings for space conditioning, cooking and water heating applications, natural gas can and should play a valuable role in achieving greater energy efficiency, reducing pollution, and lowering greenhouse gas emissions, all while reducing consumer utility bills. As states and the federal government pursue ways to expand energy supplies, reduce costs, improve reliability and lower carbon dioxide emissions, the *direct use* of natural gas can and should be considered as a long-term solution, not just a so-called bridge fuel. One metric to compare across technologies is the 'levelized cost' of delivered energy. Unfortunately, most levelized cost analysis have been limited to electricity technologies: this paper seeks to correct that.

Background on Current Trends

In November 2015, Richard Meyer of the American Gas Association (AGA) reported on trends in energy consumption and emissions on a full fuel cycle basis for the residential and commercial sectors, including the direct use of natural gas[2]. This section and the following two sections summarize parts of that report.

Buildings are a core driver of US energy use. The residential and commercial sector, which are comprised almost entirely of buildings, account for 40 percent of US primary energy consumption and 39 percent of carbon dioxide emissions.

Primary energy consumption has grown steadily as the US population has expanded, home sizes have increased, and consumers adopt more energy using devices and appliances. A new home today is more than 60 percent bigger than forty years ago. New appliances and devices are available for use. Cooling requirements have increased as households have migrated southward into warmer geographies. The United States, in general, is just using more energy. Important to this view is not only end use energy, but also the requirements to deliver that energy to end users. Within this view, electricity has played a disproportionate role in shaping building energy usage during the past four decades.

When consumption is broken down by energy type, nearly all of the increase is in electricity usage and, importantly, the electric system *losses* associated with those sales. Losses include the energy lost during the conversion of primary fuel to electric energy (i.e. power plant efficiency), as well as transmission and distribution losses on the system as electric energy passes from generators to end

[2] *Dispatching Direct Use: Achieving Greenhouse Gas Reductions With Natural Gas In Homes And Businesses,* Richard Meyer, Manager Energy Analysis & Standards, American Gas Association, November 16, 2015

user. Electric system *losses* account for an astounding *half* of the primary energy consumed in the residential sector.

By contrast, natural gas use during the past forty years has been relatively flat, even though the natural gas market has grown substantially during this time. Since 1970, more than 30 million more customers have been added onto the natural gas system. While the system has grown, the use of natural gas by individual customers has declined. The result is that the average household today uses 50 percent less natural gas than in 1970. This decline in use per customer results from steady improvements to appliance efficiencies, tighter building shells, behavioral changes in gas consumption, and the effectiveness of gas utility efficiency programs.

This efficiency of the gas system and its users has led to no material increase in annual CO_2 emissions from residential and commercial natural gas use during this time. However, during this same time carbon dioxide emissions associated with electricity use have risen dramatically. Residential CO_2 emissions have increased 23 percent since 1973, mostly associated with growth in residential electric power, which increased 78 percent during this time. By contrast, residential carbon dioxide emissions from natural gas *direct use* have remained relatively flat.

Direct Use Technologies Use Less Primary Energy Than Their Electric Counterparts

The primary method for estimating the likely impacts of fuel and equipment choices is the use of full-fuel-cycle measures of energy use and emissions. This is in contrast to site energy measurements, which only include energy consumed at the point of use. Full-fuel-cycle measures of energy use and greenhouse gas emissions can be used for impact analyses, environmental assessments, and rulemakings for energy conservation standards.

Full-fuel cycle energy used in this report can be defined as "the energy consumed by an appliance, system, or building as measured at the building site plus the energy consumed in the extraction, processing, and transport of primary fuels such as coal, oil, and natural gas; energy losses in thermal combustion in power-generation plants; and energy losses in transmission and distribution to the building site[3].

[3] *Full-Fuel-Cycle energy and Emissions Factors for Building Energy Consumption – 2013 Update*. Gas Technology Institute. January 2014. https://www.aga.org/full-fuel-cycle-energy-and-emission-factors-building-energy-consumption-20node3-update-jan-20node4

Table 1

National average full-fuel-cycle energy factors for electricity generated with different fuel types and for direct use fuels

Energy Type	Process energy efficiency (percent)						
	Extraction	Processing	Transportation	Conversion	Distribution	Cumulative Efficiency	FFC Energy Conversion Factor
Electricity							
Coal	98.0	98.6	99.0	32.9	93.5	29.4	3.40
Oil	96.3	93.8	98.8	32.0	93.5	26.7	3.75
Natural Gas	96.2	97.0	99.3	43.2	93.5	37.4	2.67
Nuclear	99.0	96.2	99.9	32.6	93.5	29.0	3.45
Hydro	100.0	100.0	100.0	90.0	93.5	84.2	1.19
Biomass	99.4	95.0	97.5	24.4	93.5	21.0	4.76
Wind	100.0	100.0	100.0	26.0	93.5	24.3	4.11
Solar	100.0	100.0	100.0	12.0	93.5	11.2	8.91
Geothermal	100.0	100.0	100.0	16.0	93.5	15.0	6.68
U.S. Average	98.0	97.8	99.3	35.7	93.5	31.8	3.15
Direct Use Fuels Used in Buildings							
Natural Gas	96.2	97.0	99.0	100.0	99.0	91.5	1.09
Heating Oil	94.9	89.1	99.7	100.0	99.6	84.0	1.19
Propane/LPG	94.6	93.6	99.2	100.0	99.2	87.1	1.15

Source: *Full-Fuel-Cycle energy and Emissions Factors for Building Energy Consumption – 2013 Update*. Gas Technology Institute.[4]

This important methodology has been sporadically incorporated into governmental policy and proceedings. The Department of Energy in a 2011 Statement of Policy declared its intent to use full-fuel-cycle measures of energy use and emissions in national impact analyses and environmental assessments included in future energy conservation standards rulemakings.[5]

Most of the energy associated with the delivery and utilization of *direct use* fuels is associated with consumption on site. By contrast, site electricity use is only about one third of the total primary energy associated with electric end use.

The energy required in the extraction, processing, and transport of natural gas, including losses, has a *source-to-site* efficiency of 92 percent. Electricity use on average has a *source-to-site* efficiency of 32 percent, according to EPA's "Energy Star" program. In other words, only one third of primary energy associated with energy generated and transmitted along the electric system is associated with final

[4] Emissions factors used in the calculation of full-fuel-cycle emissions comes from several different sources. The ANL GREET Model v1 2012 rev2 and the US EPA Inventory of US Greenhouse Gas Emissions and Sinks (2013) were sources of information on pre-combustion air emissions. Combustion emissions for conversion to electricity are calculated using EPA eGRID2012 v1.0.

[5] "Energy Conservation Program for Consumer Products and Certain Commercial and Industrial Equipment: Statement of Policy for Adopting Full-Fuel-Cycle Analyses into Energy Conservation Standards Programs." Department of Energy. 10 CFR Part 431 Docket No. EERE-2010-BT-NOA-0028. https://www.federalregister.gov/articles/2011/08/18/2011-21078/energy-conservation-program-for-consumer-products-and-certain-commercial-and-industrial-equipment

useful energy delivered to the consumer[6].

Proper accounting of cost, energy implications and emissions from electric appliances must take into account the composition of regional generation fleets. Even in the least carbon-intensive grid mix, the Northeast Power Coordinating Council (including portions of northeast Canada), which has a higher-than-average share of hydroelectric and nuclear electricity generation, a natural gas fired water heater system is still more efficient and produces less carbon dioxide than an electric storage water heater. Regional considerations also impact the levelized cost of natural gas options as the demand and load profile for heating end uses vary from region to region.

Direct Use Technologies Emit Less than Their Electric Counterparts

The emissions reduction potential of *direct use* gas applications will vary depending on the fuel used in the electric grid. The use of regional values can improve the accuracy of a full- fuel-cycle calculation.

Average emissions rates will typically under-predict emissions reductions achieved through efficiency improvements. Inclusion of baseload generators such as nuclear and hydropower brings down the overall rate of electric system emissions. However, these baseload generators are unlikely to be affected by energy efficiency improvements.

Importantly, energy efficiency will affect *marginal* generators, which are almost always fueled with natural gas or coal: Marginal generation represents the generation plant used next as demand changes, and can be complicated to determine precisely. It can vary depending on time of year, loads and available resources. Marginal and average FFC energy and carbon dioxide-equivalent (CO2e) emission results can be significantly different, especially in regions dominated by hydropower generation. In addition, displacing coal plants has a higher impact on CO2e emissions and FFC energy use than displacing natural gas plants.

Marginal generation methodologies vary, but EPA recognizes several valid and established approaches to quantify emissions reductions using the non-baseload or fossil fuel electricity mix. Use of eGRID sub-region non-baseload emission factors are recommended as a simple, low-cost method to estimate emissions reduction potential and to demonstrate emissions benefits. More information on these methodologies can be found in the Appendix to *Dispatching Direct Use*[7].

Intangibles

In addition to 'hard costs' there are important intangibles that affect consumer experience and satisfaction. "Gas ovens have a longer life," … "They have way less components to them, so they tend to breakdown less." Many cooking experts also prefer gas ovens over electric, because they heat faster, and provide more specific temperature control. The main advantage of an electric oven is that most

[6] https://portfoliomanager.zendesk.com/hc/en-us/articles/216670148-What-are-the-Site-to-Source-Conversion-Factors-

[7] Dispatching Direct Use: Achieving Greenhouse Gas Reductions With Natural Gas In Homes And Businesses, Richard Meyer, Manager Energy Analysis & Standards, American Gas Association, November 16, 2015.

people consider them easier to use[8]. While the longer lifetime of gas over electric appliances could be accounted for using levelized cost analysis, we chose not to, just for simplicity.

In addition, how your house is set up will dictate what type of fuel to use. Changing the connection in any room will be very costly, as would changing the venting for condensing gas appliances versus non-condensing appliances.

Salesmen at two major supply chains told Consumer Affairs[9] that gas dryers typically dry clothes faster, as they heat up much quicker. And although gas dryers, along with gas stoves, do use some electricity, it's minimal compared to electric models.

With respect to infrastructure costs, natural gas provides an additional value not available with electric alternatives. Natural gas avoids the billion-dollar investments in power plants. IF natural gas prices, for example, end up rising to unacceptable levels, the option of building electric plants is still open. If, however large capital investments are made in electric generation facilities and gas prices remain low (as evidenced by futures market) the capital investment made in electric plant becomes stranded and no longer cost effective nor competitive (without government intervention), 'wasting' that capital. In other words, there is a value to the option of committing now versus committing later: there is a 'time value' or 'real' options value[10]. This value can be estimated as with trading financial options (puts and calls) using such techniques as Black Sholes[11], but we leave that to future work. Suffice it to say that maintaining flexibility and avoiding premature commitments has value in public policy deliberations, but is generally not accounted for.

Policy Mechanisms Should Also Be Expanded

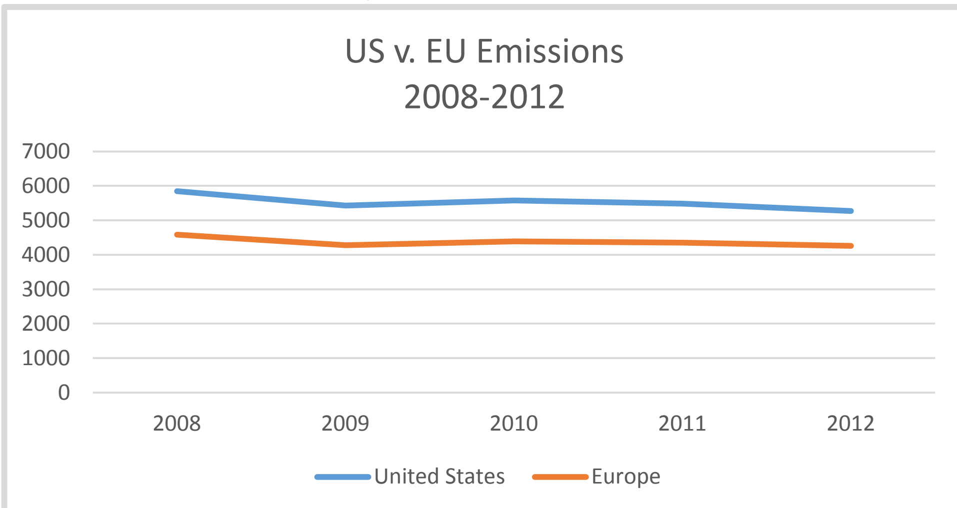
Using levelized cost to compare one technology or fuel to another is only one part of public policy. Also crucial is selecting appropriate policy mechanisms. In this regard, evidence suggests that government policies that encourage, or incentivize, or mandate, certain technologies or fuels, such as the idea of electrifying everything, are misplaced and counterproductive, even when "justified" by comparative costs. For example, U.S. energy-related carbon dioxide emissions (CO_2) have declined in five of the past eight years. This trend has been led by emissions reductions in the electric power sector. Electricity demand growth has been lower than in the past and at the same time the power sector has become less carbon-intensive (measured as CO_2 emitted per kilowatt hour of generation) due largely as a result of increased reliance on natural gas. Total emissions from the electric power sector in 2013 totaled 2,053 million metric tons (Mmt), about 15% below its 2005 level.[12] A modest increase in intensity occurred in 2013 (mostly due to weather, which drove up energy demand). According to the Energy Information Administration, the U.S.'s intensity now compares favorably with most other countries. [13] Similarly, the

[8] *Electric or Gas Appliances: Which Is Better*? Consumer Affairs, June 6, 2012 https://www.consumeraffairs.com/news04/2012/06/electric-or-gas-appliances-which-is-better.html
[9] Ibid.
[10] A real option is a choice made available with business investment opportunities, referred to as "real" because it typically references a tangible asset instead of financial instrument.
[11] Black Scholes is a model of price variation over time of financial instruments such as stocks that can, among other things, be used to determine the price of a call option.
[12] Energy Information Administration at http://www.eia.gov/todayinenergy/detail.cfm?id=18511
[13] Energy Information Administration at http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=91&pid=46&aid=31&cid=regions&syid=2011&eyid=2011&unit=MTCDPUSD

carbon (equivalent) intensity of the U.S. has declined between 2000 and 2013.[14] While the U.S.'s *total* emissions rank high, its intensity ranks better than most other countries, especially some of the large industrializing developed countries, such as China. Policy focus should be on intensity and productivity improvements, not artificial reductions in btu consumed.

Further, from 2008 through 2012, U.S. emissions dropped ten percentage points, while Europe dropped only seven, despite no national carbon control (other than the relatively free market) regulation being in place in the U.S., and a near European-wide emission trading scheme there. The same better performance is illustrated on a state by state basis as shown in the second figure, looking at electric power sector in the various states. While many of the states exhibiting greater percentage reductions started at higher overall emission rates, it is stunning the difference in emission reductions between states like California with the most stringent and interventionist laws on the books compared to, say, Georgia with a relatively freer market for electrical generation.

Figure 1
US versus European Union Emissions 2008-2012

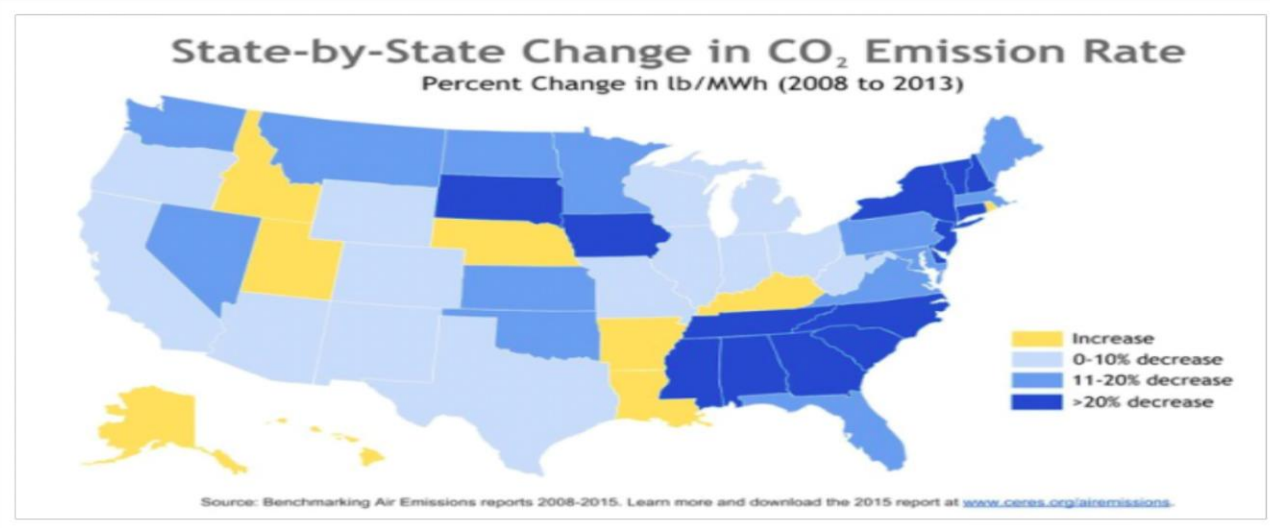


Source:

http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=90&pid=44&aid=8&cid=r1,r3,&syid=2008&eyid=2012&unit=MMTCD

[14] Thomas Tanton, "Key Investments in Greenhouse Gas Mitigation Technologies from 2000 Through 2012 by Energy Firms, Other Industry and the Federal Government," American Petroleum Institute, Washington, D.C., September 2013, and http://www.eia.gov/todayinenergy/detail.cfm?id=10191

Figure 2
State By State Emissions Trends

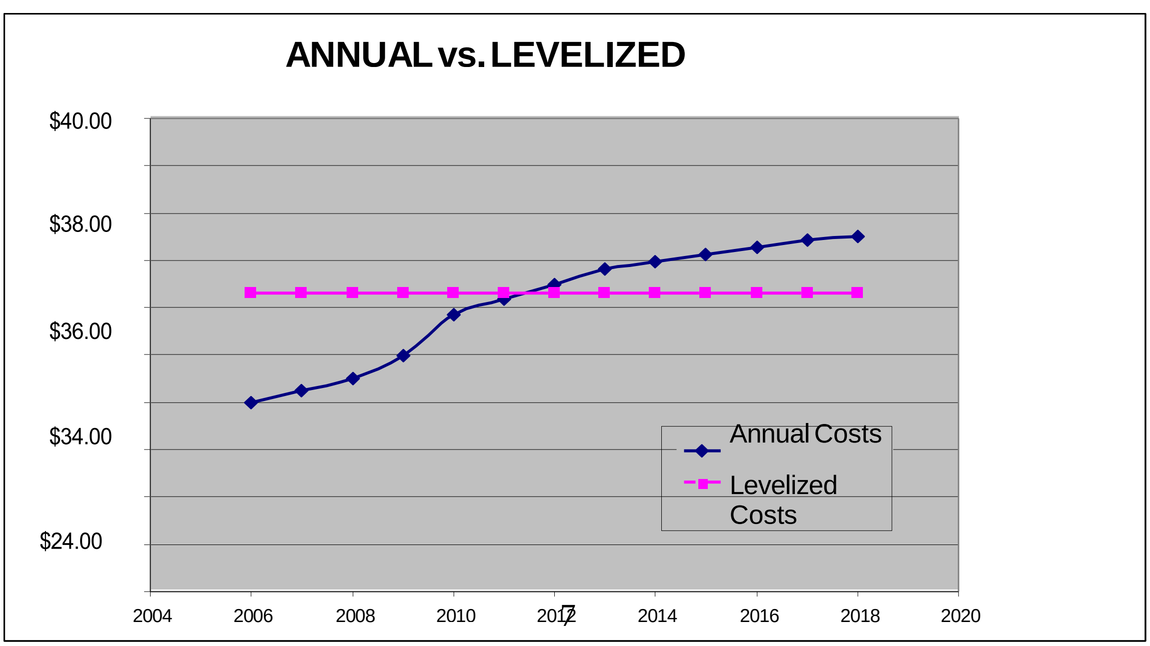


Source: http://www.ceres.org/press/press-releases/new-report-u.s.-power-sector-continues-to-reduce-air-pollution-emissions-in-advance-of-epa2019s-clean-power-plan

Levelized Cost Comparison

Levelized cost is the constant (flat or level) annual cost that is equivalent on a present value basis to the actual annual costs, which are themselves variable. Figure 3 is a fictitious illustration of this relationship, which is defined by the fact that the present worth of the annualized levelized cost values is exactly equal to the present worth of the actual annual costs. This annualized cost value allows for the comparison of one technology against the other, whereas the differing annual costs are not easily compared.

Figure 3: One Illustration of Levelized Cost



Levelized Cost Components

Levelized costs are estimated for fixed and variable cost components as shown in Table 2 and in more detail in Appendix A.

Table 2: Summary of Levelized Cost Components

Fixed Cost
Capital and Financing – The total cost of construction including financing Insurance – The cost of insuring the power plant
Ad Valorem – Property taxes
Fixed O&M – Staffing and other costs that are independent of operating hours
Variable Costs
Fuel Cost – The cost of the fuel used
Variable O&M – Operation and maintenance costs, which are a function of operating hours

Costs are often reported in dollars per megawatt-hour ($/MWh) or dollars per kilowatt-year ($/kW-Yr). The $/MWh form is the more common one and is useful since it allocates costs to the expected hours of operation. The $/kW-Yr is useful for tracking annual costs where hours of operation are not a concern or when calculating capacity only cost[15]. In this report, we provide estimates in terms of million btu (MMbtu), converting kilowatt-hours to btu by multiplying by 3412 to get btu then converting to MMbtu.

These costs vary depending on whether the project is a merchant facility, an investor owned utility (IOU) or a publicly owned utility. In addition, the costs can vary with location due to differing land costs, projected future fuel costs, construction costs, operational costs and environmental licensing costs, as well as financial parameters. Finally, these costs vary by year. Later we provide examples of the wide range of component costs and hence levelized costs as estimated by several credible sources.

Background on Levelized Costs: Approach and Caveats

Determining the levelized cost of energy technologies and comparing one source against the other, involves a multitude of estimates and forecasts and assumptions. As it is an attempt to determine a constant level of revenue necessary to recover all expenses for each type of power

[15] Most electricity technologies present a joint production problem; they produce both energy and capacity and there is no rational way to allocate cost to each product, any more than there is a way to allocate a farm's cost of growing cotton to the products of cotton seed oil and cotton fiber. Any such allocation is arbitrary at best. In later estimates of levelized capacity costs, we assume there is no associated energy sale.

plant, it not only includes forecasting the cost of construction in future years but also the cost of capital to finance that construction, forecasting the future price of fuel and governmental policies such as tax treatment and preferences as specific as depreciation schedules that may differ from one technology to another. There are several factors which go into total "cost": capital, operating and maintenance (O&M), and fuel. Each of these factors change over time due to inflation and real escalation. Capital costs change prior to a plant beginning operation but are fixed once the plant is completed, although financing may not be at a fixed rate. Fuel and O&M charges, however, continue to change throughout the life of the plant, due to both market and government actions. Each technology and fuel type has a different ratio of capital, fuel and O&M costs associated with it. Because of varying escalation rates on fuel and capital, a technology with high capital costs but low fuel cost may, in total, cost the same, less than, or more than a technology with low capital costs but with a rapidly escalating fuel cost.

In addition to the myriad estimates and forecasts and assumptions, the 'comprehensiveness' of costs included have a dramatic effect on the comparability of levelized costs estimates from different sources. For example, the cost of the second most rapidly-growing choice -- wind electricity – has been vastly understated in most reports, even official EIA estimates[16]. The levelized costs of some technologies can be nearly twice as expensive as suggested by Lazard[17], as one example, if only the six most obvious missing factors are taken into account:

1. A significant subsidy unique to wind turbines and solar, the Production Tax Credit,
2. An overly optimistic assumption about the operating life of wind facilities and solar facilities essentially assuming they last twice as long as history suggests,
3. The capital, operations and maintenance costs imposed on traditional plants required to balance wind and solar fluctuations and to keep the grid in perfect harmony
4. Increased fuel consumption in primary plants due to the volatile output of wind and solar facilities, akin to your car mileage when stuck in stop and go traffic
5. Increased capital cost to build transmission lines to access remote wind and solar facilities with low capacity factors
6. Cost of additional transmission lines losses due to increased distances

These missing costs are not difficult to understand. They have been discussed and quantified in previous reports, including *The Myth Of Grid Parity –Why The Cost Of Wind Electricity Is Unlikely To Match The Cost Of Natural Gas, Coal Or Nuclear Electricity*[18] by Tanton and Taylor. They just have not been counted because wind electricity is so different from traditional sources, in that it provides energy only and is not dispatchable capacity. Further some costs allocable to wind have been offloaded by the wind developers onto other market participants. Lazard notes other costs are not included in their analysis, but makes no attempt to quantify them. As a result, their levelized cost estimates are misleading when used directly for public policy purposes.

[16] Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017, US Dept. Of Energy, Energy Information Administration, Jan. 5, 2017, https://www.eia.gov/outlooks/aeo/electricity_generation.cfm
[17] Lazard, *Levelized Cost of Energy Analysis 10.0* Dec.15 2016, https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/
[18] Thomas Tanton, George Taylor, *The Myth Of Grid Parity –Why The Cost Of Wind Electricity Is Unlikely To Match The Cost Of Natural Gas, Coal Or Nuclear Electricity,* December 2012, https://eelegal.org/wp-content/uploads/2013/09/Hidden-Cost.pdf

Most levelized cost analysis, suffers from the common problems of:

- Hidden assumptions and reliance on unrealistic assumptions or forecasts of future fuel price
- Lack of comprehensive cost inclusion
- Lack of Comprehensive Options
- Comparison of costs for incomparable energy options
- Lack of consideration of Free market approaches to achieving a sustainable energy future

Special Considerations

Discount Rate and Fixed Charge Rate

Discount Rate. Money held today will be worth more in the future because it may be invested to generate earnings during the intervening period. Thus, at an interest rate of 5 percent, $100 at the present time will be worth $105 one year from now. Conversely, at the same interest rate, the value of $105 in the future is equivalent to $100 now. In this case, the $100 may be referred to as the present value of the $105 discounted at 5 percent. Discounting is used to reflect the value that investors, including society, put today on money that will be available in the future. The larger the discount rate, the more investors value money today versus money tomorrow. Benefit over time mirror costs in terms of relative importance now and in the future. A larger discount rate produces a lower present value for the same future stream of cash flows and consequently a lower levelized cost over that time frame.

In addition to the positive return that an invested resource will earn, there are two additional rationales for discounting future values:

- Postponed benefits also have a cost because people generally prefer present to future consumption. They are said to have positive time preference.
- If consumption continues to increase over time, as it has for most of U.S. history, an increment of consumption will be less valuable in the future than it would be today.

Whereas interest rates are determined exogenously (rates paid by various banks, bonds, commercial paper, and so forth), the discount rate is chosen by the analyst. Since not investing means forgoing the income that could be earned in the meantime and incurring a cost in the form of a lost opportunity (opportunity cost), the discount rate to determine the present value of a project is frequently the return that would otherwise be earned on the funds that would be used for the project. If the net present value of all costs and benefits of a project is negative, then the return realized by the alternative use for those funds would be superior, and the proposed project should not be undertaken.

In general, higher discount rates, such as those generally derived from the cost of capital or market costs in the private sector, favor projects with lower initial costs and higher future costs, since future costs are discounted more heavily relative to costs incurred nearer to the present, even without considering inflation. Thus, future generations may bear a disproportionate share of project costs if those costs are delayed. Lower discount rates, such as those associated with the public-sector cost of capital, increase the present net worth of projects with early costs and later benefits. The discount rate assumed by analysts have a profound impact on the levelized cost, and consequently technology rankings, especially given the long lives of plants under consideration. The choice of 3 percent versus 7 percent can change the net present value of future cost stream (and benefit stream) by a factor of 3 or more. OMB has recommended that for regulatory analysis, both 3 and 7 percent (real) discount rates be used.[19] Use of a 2 percent discount rate here is conservative, perhaps overly so. It has the overall effect of increasing the present value of future natural gas prices as part of the levelization process.

The fixed charge rate represents the percentage of total generating plant capital costs which must be received annually by a utility over the life of the plant for the utility to recoup its investment and earn a return. The FCR reflects all accumulated and yearly costs associated with a capital investment such as the cost of financing, return on and of capital, income and property taxes (for investor-owned utilities), insurance, and administrative costs. The calculation of an FCR for private utilities also considers various tax treatments such as the investment tax credit and accelerated depreciation schedules (municipal utilities are not affected by any of the tax provisions since they pay no taxes).

The reader should note that the fixed charge rate is actually an economic device which enables comparisons among either generic technologies or individual plants (or non-generation alternatives as long as their investment cost is known). In reality, utilities do not normally raise capital for specific power plants. Instead, capital is raised by the sale of bonds or common stock (or taken from retained earnings) to support an overall construction program during a specific time period. Similarly, income taxes are not associated with particular units but with the company as a whole. Nevertheless, the FCR is a valuable tool and facilitates economic comparisons among various technologies.

FCR Derivation. The annual revenue requirement is defined as the sum of the following components: book depreciation, interest on debt, return on preferred and common equity, federal and state income taxes, property taxes, insurance, and general administrative costs. The revenue requirements technique calculates the total revenue which must be collected from customers during each year of plant book life to pay all expenses associated with the capital investment of the plant. This amount varies from year to year due to the effects of plant depreciation (which may vary depending on the technology) and the manner in which the investment tax credit is applied. Revenue requirements are calculated separately for the portion of plant costs due to finance charges (AFUDC-allowance for funds used during construction; or the utility cost of capital) and the cash (non-AFUDC) plant costs.

Weighted average revenue requirements are then calculated for each year based on the ratio of AFUDC to non-AFUDC costs. Finally, an annual fixed charge rate is derived by applying a capital recovery factor to the sum of the discounted present values of the stream of annual weighted average revenue requirements.

Service Provided

Not all technologies provide the same service. Some, like coal fired and natural gas fired combined cycle power plants provide electricity to the grid upon demand. Others like wind and solar provide fuel displacement but require backup and balancing, typically from fast response fossil or hydroelectric, which increases their costs and reduces their functionality. Others, like the direct use of natural gas provide comparable service but perhaps in niche or limited application. They can however provide important diversity of supply choice to customers and provide supply security in the event of electric grid outages from natural or other causes. The direct use of natural gas can provide heat and important

[19] White House Office of Management and Budget, Regulatory Analysis, Circular No. A-4, September 17, 2003.

sanitation (hot water) services in the event of a disaster even while providing lower cost energy for certain uses.

'Type' of Dollar

The purpose of this section is to describe three methods to express levelized cost: then-current, base-year, and constant dollar. Each of these three methods is often used by energy analysts to express the cost of energy production. This often leads to confusion or inappropriate conclusions regarding the relative cost between technologies when costs are expressed by more than one method. More importantly, however, the conversion of levelized cost from one method of expression to another is not as simple a task as, say, discounting future dollar estimates to present value. There is no single factor (like a discount factor) which converts one method to another.

A. Current-Year

The current dollar method of analysis computes as its figure- of merit the levelized cost of energy in average dollars throughout the service life of the project. This mode includes the impact of general inflation and of variable cost escalation. The current dollar figure is a strong function of the project service life as well as the specific time during which the service life occurs. The current dollar method internalizes effects of inflation on the energy technology.

B. Base Year Dollar

This calculational method ultimately provides the dollar figures for levelized costs as the current year dollar method, but separates technology from general economy issues. Further, the method reduces the importance of future escalation which occurs after construction is complete. The base year dollar mode projects cost results to a base year (say the time of decision or plant start date). This method reduces the dependency of the levelized cost on time variables (e.g the year in which plant operation begins, construction time. etc.). The method externalizes the estimated effects of general inflation on the estimated cost by applying inflation after the calculation of cost.

C. Constant Dollar

The constant dollar is used to mean the dollar if there were no inflation whatsoever. Net escalation (positive or negative) is still allowed for specific commodities. In this context, the dollar has the same purchasing power in each year. When applied to levelized costs, this method ignores the effect of inflation on the relative cost of energy technologies.

We use constant dollars (2017) throughout this report, except when directly reporting estimates by others.

Data Sources and Examples of Levelized Cost

One of the most often cited sources of levelized cost is the Energy Information Administration, EIA. They publish almost annually, their best estimates based upon an extensive data base and thoughtful assumptions along with their forecast of such things as future fuel prices and impacts of various government policy. Their most recent report was released in April 2017[20]. The following table, from their 2016 report, continues a feature included just a few cycles ago: differentiate between dispatchable and non-dispatchable technologies and specific call out of the effect of favorable tax treatment for certain renewables. Historically, LCOE for all generation types, by other analysts have not distinguished between dispatchable and non-dispatchable technologies. This is somewhat an artifact of the cost of service regulatory paradigm and does not recognize the shift, at least in part, to a value based assessment of options.

Importantly EIA indicates:

> *It is important to note that actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other factors not reflected in LCOE values. The projected utilization rate, which depends on the load shape and the existing resource mix in an area where additional capacity is needed, is one such factor. The existing resource mix in a region can directly impact the economic viability of a new investment through its effect on the economics surrounding the displacement of existing resources. For example, a wind resource that would primarily displace existing natural gas generation will usually have a different economic value than one that would displace existing coal generation.*
>
> *A related factor is the capacity value, which depends on both the existing capacity mix and load characteristics in a region. Since load must be balanced on a continuous basis, units whose output can be varied to follow demand (dispatchable technologies) generally have more value to a system than less flexible units (non-dispatchable technologies), or those whose operation is tied to the availability of an intermittent resource. The LCOE values for dispatchable and nondispatchable technologies are listed separately in the tables, because caution should be used when comparing them to one another.*

Table 3

[20] https://www.eia.gov/outlooks/aeo/electricity_generation.cfm

EIA's Levelized Cost Estimates

U.S. Average LCOE (2015 $/MWh) for Plants Entering Service in 2022

Plant Type	Capacity Factor (%)	Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System LCOE	Levelized Tax Credit	Total LCOE including Tax Credit[1]
Dispatchable Technologies								
Advanced Coal with CCS[2]	85	97.2	9.2	31.9	1.2	139.5	N/A	139.5
Natural Gas-fired								
Conventional Combined Cycle	87	13.9	1.4	41.5	1.2	58.1	N/A	58.1
Advanced Combined Cycle	87	15.8	1.3	38.9	1.2	57.2	N/A	57.2
Advanced CC with CCS	87	29.2	4.3	50.1	1.2	84.8	N/A	84.8
Conventional Combustion Turbine	30	40.9	6.5	59.9	3.4	110.8	N/A	110.8
Advanced Combustion Turbine	30	25.8	2.5	63.0	3.4	94.7	N/A	94.7
Advanced Nuclear	90	78.0	12.4	11.3	1.1	102.8	N/A	102.8
Geothermal	91	30.9	12.6	0.0	1.4	45.0	-3.1	41.9
Biomass	83	44.9	14.9	35.0	1.2	96.1	N/A	96.1
Non-Dispatchable Technologies								
Wind	40	48.5	13.2	0.0	2.8	64.5	-7.6	56.9
Wind – Offshore	45	134.0	19.3	0.0	4.8	158.1	-11.4	146.7
Solar PV[3]	25	70.7	9.9	0.0	4.1	84.7	-18.4	66.3
Solar Thermal	20	186.6	43.3	0.0	6.0	235.9	-56.0	179.9
Hydroelectric[4]	58	57.5	3.6	4.9	1.9	67.8	N/A	67.8

Note: dollar figures are shown in terms of cost per kilowatt-hour for plants beginning operation in 2022.

Adding to EIA's differentiation of generation technology additions by dispatchability, Stacy and Taylor, for the Institute for Energy Research (IER)[21], evaluated the relative costs of new versus existing power plants. In situations where supplies are adequate, continued use of existing plants may be more economical than premature replacement. As the authors note:

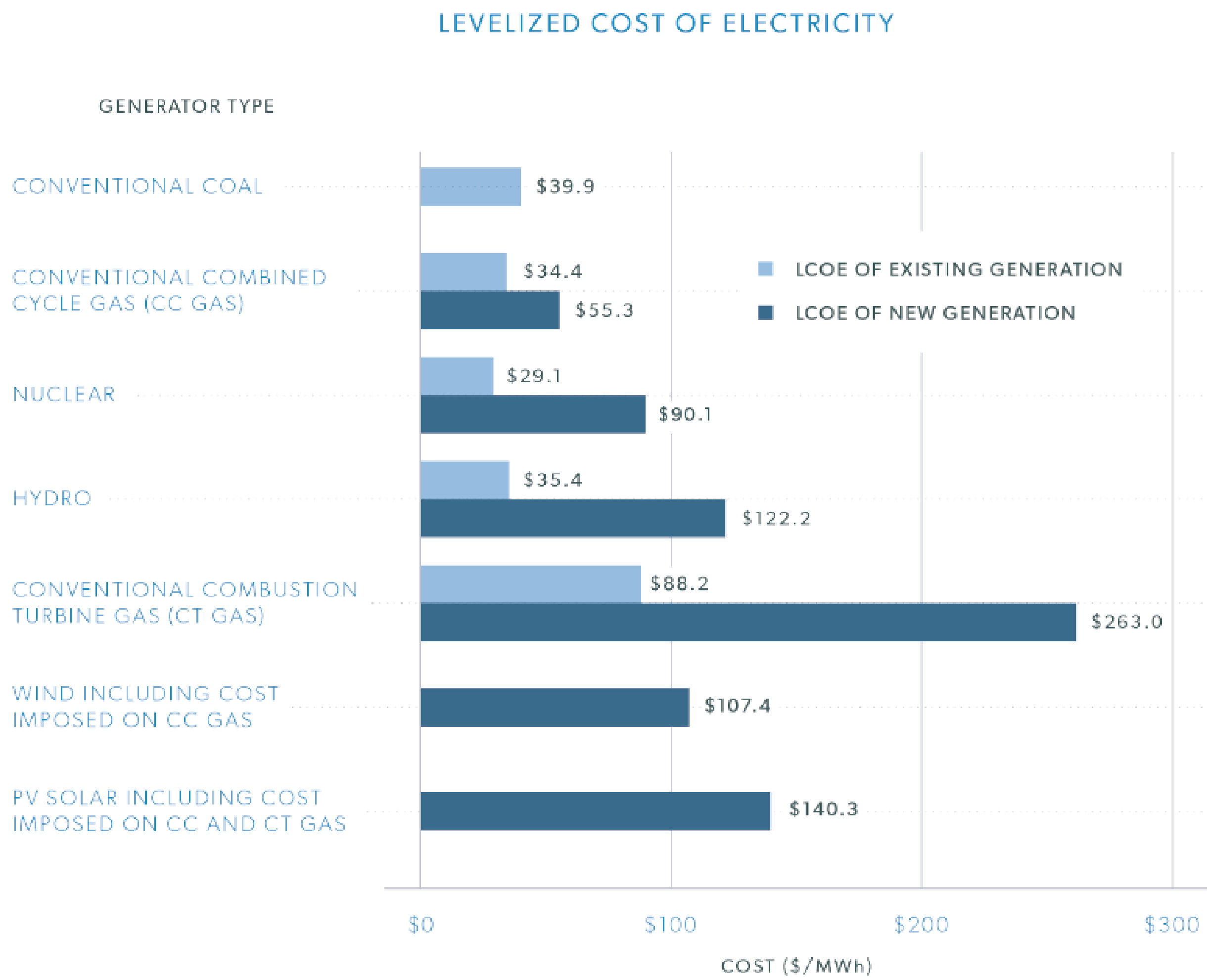
> *What is the levelized cost of electricity? The approach taken by the federal Energy Information Administration (EIA) to answer that question is exclusively forward-looking. That is, EIA publishes LCOE calculations for new generation resources only. If no existing generation sources were closed before the end of their economic life, EIA's approach would provide sufficient information to policymakers on the costs of different electricity policies.*
>
> *However, in the current context of sweeping environmental regulations on conventional generators—coupled with mandates and subsidies for intermittent resources—policies are indeed forcing existing generation sources to close early. Federal policies alone threaten to shutter 110 gigawatts of coal and nuclear generation capacity. The LCOE-E we introduce in this paper allows for much-needed cost comparisons between existing resources that face early closure and the new resources favored by current policy to replace them.*

This new treatment of levelized cost adds considerably to the debate about what is preferable: add additional capacity at higher costs or rely on existing, and largely paid for, power plants provided they meet existing environmental standards. It sets a threshold of cost competitiveness for new additions to meet: can they beat existing facilities in price?

21 http://instituteforenergyresearch.org/wp-content/uploads/2015/06/ier_lcoe_2015.pdf

Figure 4

IER's Levelized Cost Estimates



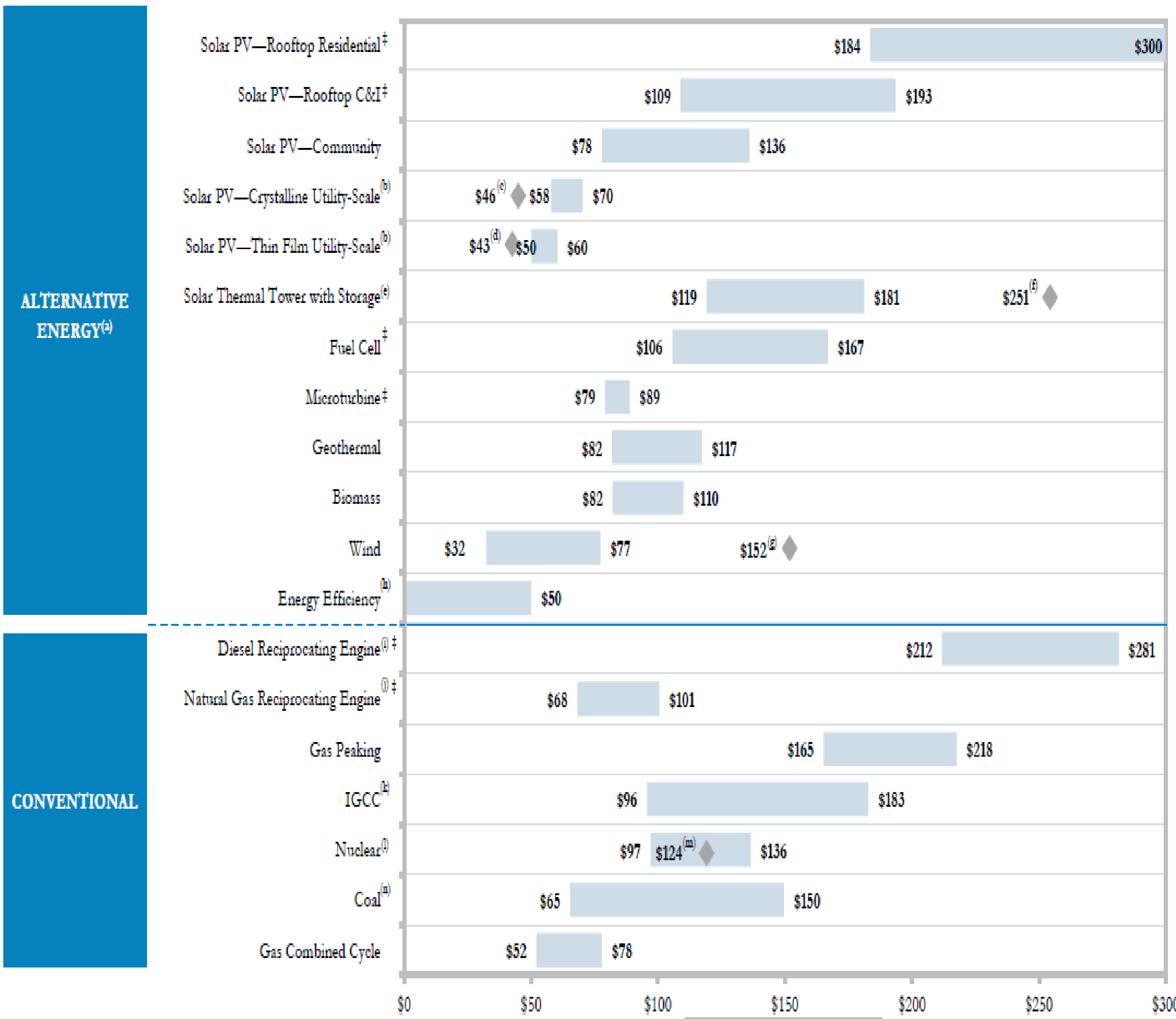
In December 2016, Lazard[22] published their latest in a series of Reports describing the 'levelized cost' of various electric generating technologies. The December report is "Version 10." In the report, Lazard compared the cost of 'alternative' generating technologies to the cost of select conventional electric technologies. They compared the net present value of lifetime costs in dollars per MWh including sensitivities on fuel cost and tax treatment.

Lazard found that the cost of generating energy from solar photovoltaic (PV) technology continues to decline: The median levelized cost of energy from utility-scale PV technologies is down approximately 11% from last year (2015), and rooftop residential PV technology is down about 26%, although the latter is still not cost competitive without significant subsidies and other policy support.

Figure 5

[22] https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/

Lazard's Levelized Cost Estimates



It is beyond the scope of this reconnaissance level analysis to attempt to reconcile or refute these three reports. They each have merit, and illustrate the wide disparity in levelized cost estimates from different analysts. Part of the reason for such disparity is the assumptions made by the analyst (such as plant start date, discount rate etc.) and part is due to the intermediate input data such as the capital cost of new construction. Table 4 provides estimated capital costs from a variety of sources illustrating the wide range of just one input data point, most vary by factors of 4 or 5. No wonder the resulting LCOE exhibits such wide-ranging results. The same is true for other input data such as capacity factor and fuel price trajectory as shown earlier in Table 1 and Figure ES-1.

Table 4: Range of Capital Costs for Generation Technologies, in $/kW

Technology	Capital cost $/kW	Source[23]
Onshore Wind	$1200-4000	IPCC 2011/Hubbell et.al. 2012
Offshore Wind	$3100-8000	Lazard 2014/E3 2010
Photovoltaic	$1500-8347	Lazard 2014/LBNL 2014
Solar Thermal	$1830-11000	Hubbell et al. 2012/ Turchi and Heath 2013
Hydrothermal	$1160-11522	Mai et al. 2014/ DOE 2011
Small Hydropower	$945-11070	Klein et al. 2010/ Mai et al. 2014
Biopower	$140-8000	IRENA Biomass 2012/ Hubbell et al. 2012
Distributed Generation	$500-9800	Lazard 2014/ IPCC 2011
Fuel Cell	$3800-7500	Lazard 2010/ Lazard 2014
Combined Cycle	$753-1683	Klein et al. 2010/ AEO 2009
Combustion Turbine	$500-1609	IEA 2012/McCann and Walters 2013
Coal fired	$1923-8400	AEO 2009/ Lazard 2014
IGCC	2120-11000	IIASA 2014/E3 2010
Nuclear	2873-8199	AEO 2009/ Lazard 2014

Natural Gas Cost Estimates

Table 5 provides two critical input parameters for direct use of natural gas options along with their source.

Table 5: Input Parameters for Direct Use Options

Parameter	Capital Cost	Utilization

[23] See appendix B for source citations

Value/Range	$1.83/ bcfd	70-95%
Source(s)	Kinder Morgan[24]	EIA[25]

Fuel Price Scenarios

Naturally, the forecast, or assumed, future price of fuel also impacts the levelized cost of fuel dependent technologies and their relative competitiveness. Technologies that have high capital cost as a percent of their total are less affected by future changes in fuel price; those with low capital cost as a percent of total more so. In addition to using the EIA natural gas future price scenario (Annual Energy Outlook 2017 Reference Case[26]) which we believe represents one reasonable forecast for natural gas, we also believe lower future prices (lower than that estimated by EIA) would also be reasonable. The prices shown in Figure ES-1 reflect actual market prices, at least in the forward market through 2029. Therefore, we also assume a scenario where prices continue to drop (relative to inflation) through 2020, and then escalate at approximately the same rate as EIA's High Resource case. This however, results in prices in 2029 being considerably lower than EIA reference case, but close to EIA "High Oil and Gas Resource" scenario. Note in EIA's High Resources case, prices fall below inflationary growth and drop in constant 2016 dollars. They emphasize the scenario "[In] the High Oil and Gas Resource and Technology case, lower costs and higher resource availability than in the Reference case allow for higher production at lower prices." Table 6 compares the low, medium and high natural gas prices used in this study. Fuel prices for other fuels were left as estimated by the source documents. Note in the out year of 2047, only the reference case has prices that are higher in constant 2016 dollars than today, reflecting in large measure the continued success of expanded resource and technological advancement.

Table 6: Natural Gas Price Scenarios

Estimated Price in 2029 $/MMbtu, 2016 dollars

Scenario	2029 Price $/MMbtu at Henry Hub	2047 Price $/MMbtu at Henry Hub	Growth 2016-2050
Low: Futures Market	$3.50	$3.25	1%*
EIA: High Oil and Gas Resources, No CPP	$3.90	$3.43	1%
EIA Reference Case	$4.75	$5.69	2.5%

*Note: after 2020

Conversions and Adjustments

In order to compare the levelized costs of electricity to the levelized cost of direct use, the first step was to convert estimates to a common unit. We chose $/MMbtu, although we could just as easily have chosen $/MWh. In any event, we first converted electricity estimates to $/MMbtu.

We then added costs to each type of delivery, electricity or gas, to account for energy losses in transmission. We added a 'penalty' to electricity of 6% based on national average losses in

[24] http://ir.kindermorgan.com/press-release/all/kinder-morgan-confirms-anchor-shippers-northeast-energy-direct-project
[25] EIA
[26] https://www.eia.gov/outlooks/aeo/

transmission.[27] We also added a penalty of 2% to natural gas also based on national average transmission loss.[28]

Finally, we adjusted estimates for wind and solar to account for added cost of backup and balancing as described in *The Hidden Cost of Wind Electricity*.[29] This effectively doubled the busbar levelized cost of wind, and increased the cost of solar by 50 percent.

For natural gas direct use options, we calculated levelized cost using the method described in Appendix A. It is important to realize that there are important boundary conditions that define the cost estimates. Levelized cost of electricity estimates as posited by EIA and others, refer to 'busbar' costs, not delivered cost. Thus, they represent the cost at the first point of interconnection to the grid, not as delivered to or used by the end use customer, nor even to the local distribution company. For consistency with this boundary condition, we estimated direct use of natural gas at the city gate.[30] Future analysis should consider these additional costs to make a more complete comparison; they will also affect the levelized cost of electricity options. While we estimated and considered different fuel price scenarios (as described above) we did not adjust natural gas fired electric generation options. Lower future fuel prices would affect natural gas fired combined cycle for example, by reducing the levelized fuel component, but not the capital cost component.

Conclusions

Levelized Cost of Energy

Table 7 provides our adjusted and calculated estimates of the levelized cost of energy at the busbar/city gate. Figure 6 provides the same estimates in graphical form.

Table 7: Levelized Cost of Energy

Technology	Median LCOE $/MMBtu	Low LCOE $/MMBtu	High LCOE $/MMBtu
Wind/onshore	32.3	23.6	41.0
Solar PV	31.1	23.3	38.8
Nat Gas Comb Cycle	17.7	15.9	19.5

[27] Estimates of transmission losses in electricity vary from about 5% (https://www.eia.gov/tools/faqs/faq.php?id=105&t=3) to over 10% depending on region (http://insideenergy.org/2015/11/06/lost-in-transmission-how-much-electricity-disappears-between-a-power-plant-and-your-plug/)

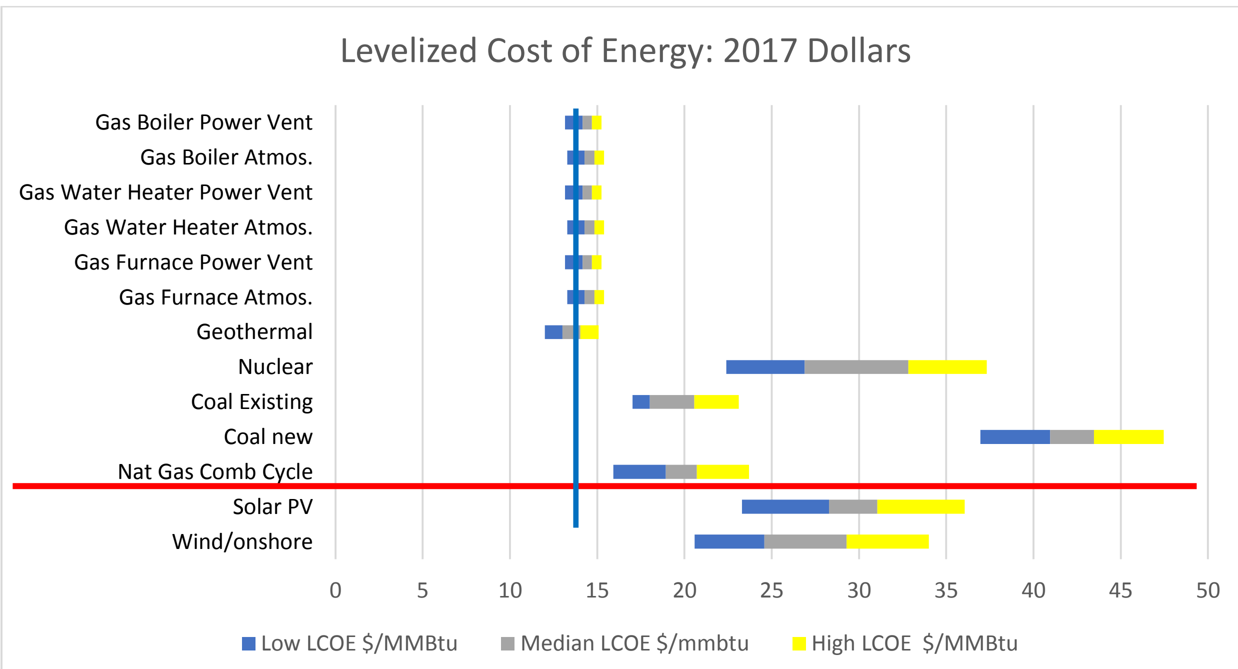
[28] https://www.energyvortex.com/energydictionary/energy_loss__transmission_loss.html

[29] https://eelegal.org/wp-content/uploads/2013/09/Hidden-Cost.pdf

[30] This explains, for example why the natural gas options have similar results: the capital cost difference across end use types is not considered.

Coal new	43.5	36.9	50.0
Coal Existing	19.6	17.0	22.1
Nuke	31.9	22.4	41.6
Geothermal	13.0	12.0	14.1
Gas Furnace Atmospheric Vent	13.8	13.3	14.4
Gas Furnace Power Vent	13.7	13.1	14.2
Gas Water Heater Atmospheric Vent	13.8	13.3	14.4
Gas Water Heater Power Vent	13.7	13.1	14.2
Gas Boiler Atmospheric Vent	13.8	13.3	14.4
Gas Boiler Power Vent	13.7	13.1	14.3

Figure 6



Notes: Options above red line are dispatchable. Natural Gas direct use is less costly than most electric options, where usable, as shown by median value vertical blue line. The ranges shown are wide for electric generation technologies simply because we took estimates from multiple analysts.

Levelized Cost of Capacity (LCOC)

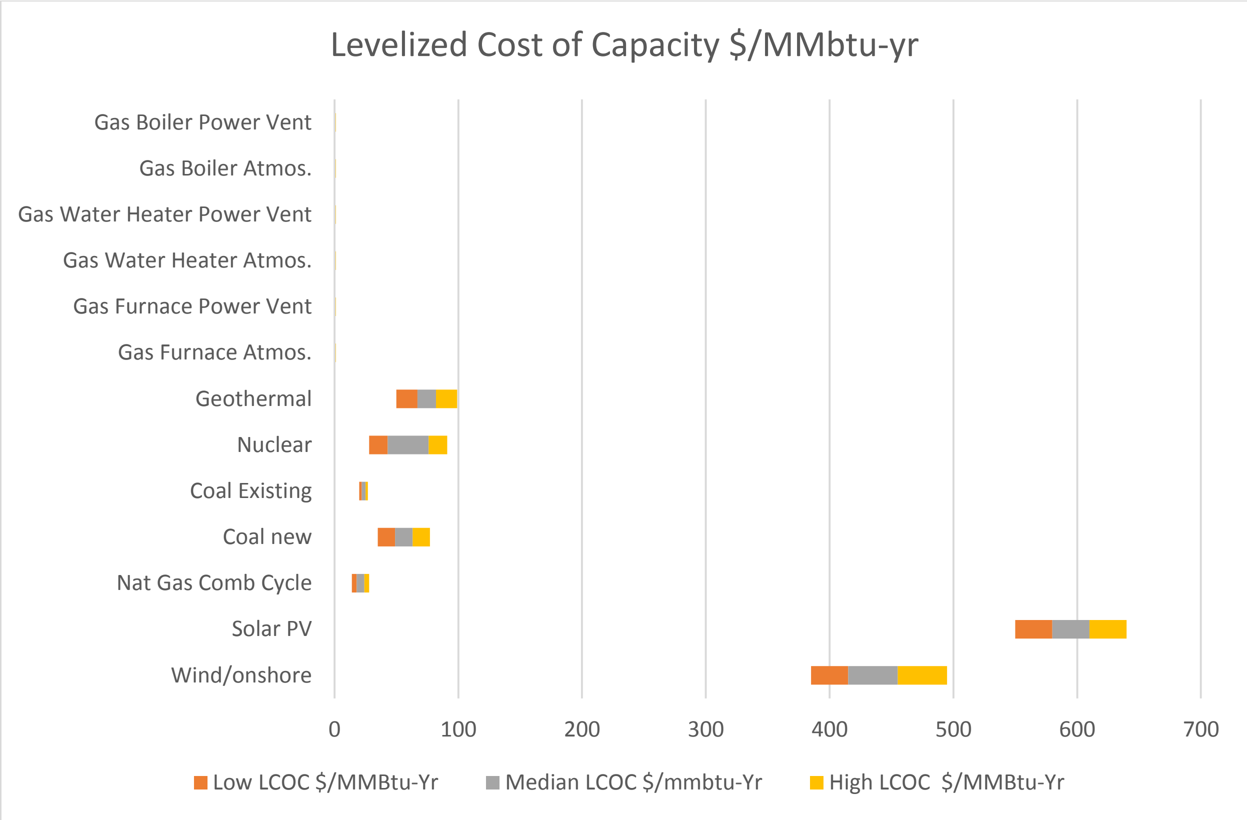
The levelized cost of capacity was calculated by multiplying a fixed charge rate (see Appendix A) by the installed or capital cost, including for electricity options. Estimated levelized cost of capacity from elsewhere do not adequately account for joint production problem[31] and consequently allocate part of the cost to energy and part to capacity, but with little justification. We chose not to artificially allocate. This problem will be resolved at some point once value pricing overtakes cost-of-service regulation.

Table 8

Technology	Low LCOC $/MMBtu-Yr	Median LCOC $/MMbtu-Yr	High LCOC $/MMBtu-Yr
Wind/onshore	390	395	500
Solar PV	570	580	650
Nat Gas Comb Cycle	16	20	24
Coal new	40	59	73
Coal Existing	22	23	24
Nuclear	35	63	83
Geothermal	55	72	85
Gas Furnace Atmos.	0.15	0.35	0.55
Gas Furnace Power Vent	0.15	0.35	0.55
Gas Water Heater Atmos.	0.15	0.35	0.55
Gas Water Heater Power Vent	0.15	0.35	0.55
Gas Boiler Atmos.	0.15	0.35	0.55
Gas Boiler Power Vent	0.15	0.35	0.55

Figure 7

[31] The simultaneous production of two or more goods from the same resource. For example, the production of beef also results in the production of leather and the production of lumber also results in the production of sawdust. Joint production can be beneficial, but complicates cost allocation. In the situation we have here, a power plant or pipeline provides two, simultaneous goods: energy and capacity. There is no basis to allocate the total cost among the two products. See http://glossary.econguru.com/economic-term/joint+production



Notes: Wind and solar provide essentially zero dependable capacity on peak, but are here assumed to provide 10% capacity value
NG capacity cost based on K.M. withdrawn Northeast Energy Direct Project/pipeline capacity of 1.8bcfd and $3B cost.

Levelized Cost of GHG Emission Reduction

For levelized cost of GHG emission reduction from electricity options we took the estimates of the Midwest Independent System Operator comments regarding the Clean Power Plan.[32] For natural gas we compared the per million btu emissions with the marginal emissions of electricity generation, corrected for non-dispatchable technologies (which therefore cannot be considered 'marginal') approximately half way between the emissions of existing fleet of coal fired facilities and natural gas fired facilities, and divided the cost by that emission rate.

Table 9
Levelized Cost of Emission Reduction

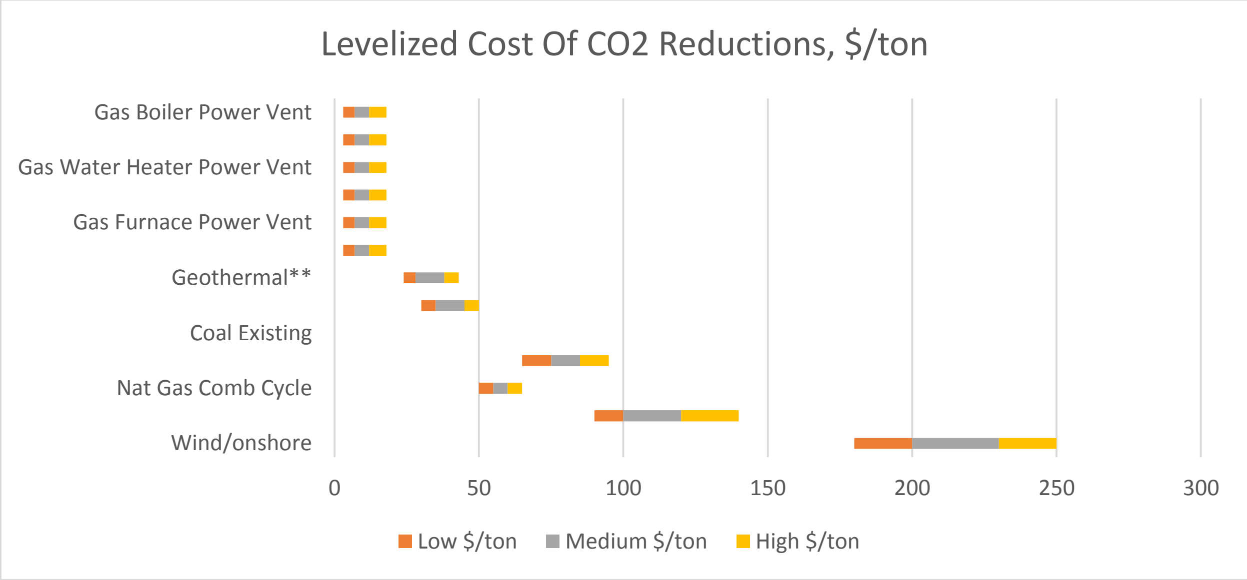
	Low $/ton	Medium $/ton	High $/ton

32 https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20140917/20140917%20PAC%20Item%2002%20GHG%20Regulation%20Impact%20Analysis%20-%20Study%20Results.pdf

Wind/onshore	180	210	250
Solar PV	90	110	140
Nat Gas Comb Cycle	50	55	60
Coal new	65	75	90
Coal Existing		NA	
Nuclear	30	40	50
Geothermal**	4	10	5
Gas Furnace Atmos.	4	5	6
Gas Furnace Power Vent	3	5	7
Gas Water Heater Atmos.	3	5	7
Gas Water Heater Power Vent	3	5	7
Gas Boiler Atmos.	3	5	7
Gas Boiler Power Vent	3	5	7

* compared to existing fleet
** assumes zero CO2/GHG in non-condensable off gasses; electric generation, not heat pumps
***generally consistent with McKinsey's global supply curve analysis[33]

Figure 8



Direct use of natural gas can reduce the cost of GHG emission reductions by as much as 80% compared to electricity options.
While distributions are wide, most likely LCOE values for most direct use of NG options are well below the most likely values for electric options.

[33] http://www.mckinsey.com/business-functions/sustainability-and-resource-productivity/our-insights/a-cost-curve-for-greenhouse-gas-reduction

Many end-uses for electricity are not amenable to service with natural gas as expected, but many are poorly made by service with electricity, such as heating. Heating applications waste the quality of electricity, better serving computers and motors and digital applications where it's needed.

Cost of capacity (power plant and natural gas pipelines) differ by over two orders of magnitude. The results are not surprising, as levelized capacity costs include annual fixed charges (e.g. financing of large capital investments in power plant) which are largely avoided by using natural gas.

Recommendations

Levelized cost estimates here and elsewhere are basic comparisons that ignore other important features of energy choices. Other important factors include operating flexibility, risk (like stranding investments) avoidance, diversity in both sources and delivery, and others, that should be evaluated and monetized where possible. Such analysis should differentiate based on regional considerations such as existing building stock and structure of economy. Perhaps most importantly, levelized cost comparisons should take a customer and end use perspective and account for local distribution and relative capital cost and efficiency of end use appliances and equipment.

This was a reconnaissance level effort, but clearly illustrates the potential cost and environmental benefit of the direct use of natural gas. Analysts supporting national and state level policy makers should undertake more comprehensive comparisons and evaluations including the option of direct use. This should include more reasonable forecast of future fuel prices in 'official forecasts' based on market realities. In the meantime, government agencies, especially the National Labs, should stop pushing the false narrative that electrifying 'everything' is in the public's interest.

The direct use of natural gas in water and space heating offers significant value in all four "E": energy, environmental, (customer) experience and economics.

EIA and state level agencies should be encouraged to include direct use of natural gas in publications of "levelized cost" and "levelized avoided cost" (i.e. value based) to better inform policy makers charged with designing and implementation energy policy.

Glossary

Capital and Financing Costs

The capital cost includes the total costs of construction, including land purchase, land development, permitting, interconnection, environmental control equipment and component costs. The financing costs are those incurred through debt and equity financing and are incurred by the developer on an annual basis, similar in structure to financing a home. These annual costs, therefore, are essentially levelized by this cost structure.

Insurance Cost

Insurance is the cost of insuring the power plant, similar to the insuring of a home. The annual costs are based on an estimated first year cost and are then escalated by nominal inflation throughout the book life period. The first year cost is estimated as a percentage of the installed cost per kilowatt for a merchant facility and publicly owned plant. For an IOU plant, the first year cost is a percentage of the book value.

Ad Valorem

Ad valorem costs are annual property tax payments that are paid as a percent of the assessed value and usually transferred to local governments. Publicly owned power plants are generally exempt from these taxes, but may pay in-lieu fees. The assessed values for power plants are set by the State Board of Equalization as a percent of book value for an IOU and as depreciation factored value for a merchant facility.

Fixed Operating and Maintenance

Fixed operating and maintenance (O&M) costs are depicted as costs that occur regardless of how much the plant operates. These are not uniformly defined by all interested parties, but generally include staffing, overhead and equipment (including leasing), regulatory filings and miscellaneous direct costs.

Corporate Taxes

Corporate taxes are state and federal taxes, which are not applicable to a publicly owned utility. The calculation of these taxes is different for a merchant facility or an IOU. Neither lends itself to a simple explanation, but in general the taxes depend on depreciated values and are adjusted for interest on debt payments. The federal taxes are adjusted for the state taxes similar to adjustment rates for a home owner.

Fuel Cost

Fuel cost is the cost of fuel, most commonly expressed in dollars per megawatt hour. For a thermal power plant, it is the heat rate (Btu/kWh) multiplied by the cost of the fuel ($/MMBtu). This includes start up fuel costs as well as the online operating fuel usage. Allowance must be made for the degradation of the heat rate over time.

Variable Operations and Maintenance

Variable operation and maintenance costs are a function of the operation of the power plant. Most importantly, this includes yearly maintenance and overhauls. However, this also includes repairs for forced outages, consumables, water supply and annual environmental costs.

Appendix A: Calculation of Levelized cost.

A technology's levelized cost is calculated as the sum of levelized capital, levelized fuel and levelized operations and maintenance as shown in equation 1.

$LC=CC+LFC+LOM+VOM$ eq. 1

1. The capital cost component is calculated according to equation 2.

$CC = (IC \times FCR \times 100)/(8766 \times CF)$ eq.2

Where:

CC= fixed charges (capital component of levelized cost; ¢/kWh)

IC = in-service cost ($/kW)

FCR = fixed charge rate

CF = capacity factor

2. The levelized fuel component is calculated using equation 3.

$LFC = (FC \times LF \times HR \times 100)/10^6$ eq.3

Where:

LFC =levelized fuel cost (¢/kWh)

FC = fuel cost, first year of operation ($/$10^6$ BTU)

LF = fuel levelization factor

HR = heat rate (Btu/kWh)

The fuel levelization factor is the product of the capital recovery factor and the present worth value factor. This factor is then applied to the initial year fuel cost, including expected life time price escalation (positive or negative), to determine the equivalent levelized fuel cost over the life of the project.

3. The levelized fixed O&M is calculated according to equation 4.

$LOM = (FM \times LM \times 100)/(8766 \times CF)$ eq.4

where:

LOM =levelized fixed O&M ($/kW-yr)

FM =first year fixed O&M ($/kW-yr)

LM =O&M levelization factor

C F= Capacity Factor

4. The levelized variable O&M is calculated by equation 5.

VOM =OM x LM eq.5

where:

VOM =levelized variable O&M (¢/kWh)

OM =first year variable O&M (¢/kWh)

LM =O&M levelization factor

The O&M levelization factor is calculated the same as the fuel levelization factor. The difference between the fuel levelization and O&M levelization factors is due to the different escalation rate for fuel and for O&M; therefore, the present worth value factor is different.

Appendix B: Capital Cost Estimate Sources for Electric Generation Technologies

Publication Year	Report Author(s)	Dataset name	Dataset web source
2011	IPCC	IPCC Annex 3	http://srren.ipcc-wg3.de/report/
2012	Hubbell et al.	Renewable Energy Finance Tracking Initiative	http://financere.nrel.gov/finance/webfm_send/ 47/REFTI_Aggregate_Q309thruQ310_27March 2011_External.xlsx
2014	Lazard	Lazard Levelized Cost of Energy Analysis, version 8.0	http://www.lazard.com/PDF/ Levelized%20Cost%20of%20Energy%20-%20 Version%208.0.pdf
2010	E3	Capital Cost Recommendations for 2009 TEPPC Study.	http://www.wecc.biz/ committees/BOD/TEPPC/ Versions/100106_TEPPC_E3_ CapitalCosts.ppt_2.0.ppt
2014	Galen Barbose, Samantha Weaver, Naim Darghouth	Tracking the Sun VII	http://emp.lbl.gov/publications/ tracking-sun-vii-historical-summary -installed-price-photovoltaics-united-states-1998-20
2013	Turchi and Heath	Molten Salt Power Tower Cost Model for the System Advisor Model (SAM)	http://www.nrel.gov/docs/fy13osti/57625.pdf
2014	Mai et al.	Envisioning a renewable electricty future for the United States	http://www.sciencedirect.com/ science/article/pii/S0360544213009912#
2011	McCalley et al.	A Wider Horizon. IEEE Power & Energy Magazine. May/June 2011	http://www.ieee.org/ organizations/pes/public/2011/may/index.html
2010	Klein et al.	Comparative Costs of California Central Station Electricity Generation. Final Staff Report	http://www.energy.ca.gov/ 2009publications/CEC-200-2009-017/ CEC-200-2009-017-SF.PDF
2011	DOE		Program Estimate
2012	IRENA	IRENA Biomass 2012	http://www.irena.org/ DocumentDownloads/ Publications/RE_Technologies_Cost_Analysis-BIOMA
2010	Lazard	Lazard Levelized Cost of Energy Analysis, version 4.0	http://www.dpuc.state.ct.us/ DEEPEnergy.nsf/ c6c6d525f7cdd1168525797d0047c5bf/ 8525797c00471adb852579ea00731d74/ $FILE/Ex%2013%20-%20 Lazard%202010%20Levelized%20Cost%20of%20Energ
2009	AEO	Annual Energy Outlook 2009	http://www.eia.gov/oiaf/ archive/aeo09/pdf/0383(2009).pdf
2012	IEA	Energy Technology Perspectives 2012	http://www.iea.org/ publications/freepublications/

		Pathways to a Clean Energy System	publication/ETP2012_free.pdf
2013	McCann and Walters 2013	Cost of Generation Workshop: Natural Gas Technologies	http://www.energy.ca.gov/ 2013_energypolicy/documents/ 2013-03-07_workshop/ presentations/Gas-Fired_Plants_Costs_ Survey_Section_for_CEC_Workshop_2013-03-05.pdf
2009	AEO	Annual Energy Outlook 2009	http://www.eia.gov/ oiaf/archive/aeo09/pdf/0383(2009).pdf
2014	IIASA	AMPERE DB	https://secure.iiasa.ac.at/web-apps/ene/AMPEREDB

About The Author

Mr. Tanton is President of T^2 & Associates, a firm providing consulting services to the energy and technology industries. T^2 & Associates are active primarily in the area of renewable energy and interconnected infrastructures, analyzing and providing advice on their impacts on energy prices, environmental quality and regional economic development. Mr. Tanton is also Director of Science and Technology at Energy and Environment Legal Institute a 501(c) 3 nonprofit involved in strategic litigation in the public interest. Mr. Tanton is a strong proponent of free market environmentalism and consumer choice, and frequently publishes and speaks against alarmist and reactionary policies and government failures.

Most recently, Mr. Tanton presented invited testimony to the House Energy and Commerce Committee, regarding energy technology focused Federal policies, provided expert testimony to various state legislatures, and provided Hill briefings on the critical nature of Rare Earths markets.

Mr. Tanton has 45 years direct and responsible experience in energy technology and legislative interface, having been central to many of the critical legislative changes that enable technology choice and economic development at the state and federal level.

As the General Manager at Electric Power Research Institute, from 2000 to 2003, Mr. Tanton was responsible for the overall management and direction of collaborative research and development programs in electric generation technologies, integrating technology, market infrastructure, and public policy. From 2003 through 2007, Mr. Tanton was Senior Fellow and Vice President of the Houston based Institute for Energy Research. Until 2000, Mr. Tanton was Principal Policy Advisor at the California Energy Commission, including serving on the Governor's Task force on Critical Infrastructure for the 21st Century.