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sCO_2 Brayton System Market Analysis

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ABSTRACT

Supercritical CO_2 Brayton cycle systems (sCO_2) offer potential benefits over traditional steam plants. The changing economics of the electricity sector favors solar photovoltaic (PV), wind, and natural gas combined cycle (NGCC). Ultimately, the ability of sCO_2 systems to compete depends on the economics and ability to offer additional benefits to the market, such as the ability for dry cooling and their compact size. Updated results show that the projected LCOE for Brayton systems in the 100 to 300 MWe size range are between $44.8 and $56.1/MWh (4.48 and 5.61 cents/kWh). This report presents screening tools for assessing the potential market size and concludes that while at these LCOE estimates sCO_2 systems can compete directly against NGCC, there are many hurdles to commercialization, including the need to demonstrate long-term operations at low-cost and ability to quickly ramp for integration with intermittent resources. Additional customer discovery is necessary to fully understand the ability of this technology to solve customer problems that other technologies cannot.

ACKNOWLEDGEMENTS

The author acknowledge support from several Sandia experts, including Matt Carlson, Peter Kobos, Blake Lance, and Gary Rochau.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

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EXECUTIVE SUMMARY (ES)

Researchers at Sandia National Laboratories and elsewhere are developing supercritical CO_2 Brayton cycle systems for use in a wide-range of power systems. In these advanced cycles, supercritical carbon dioxide is held at or above its critical temperature and pressure, meaning that the working fluid is closer to a liquid than a gas, allowing for significantly reduced volumetric flow, which translates into substantially reduced size for key components, including the turbines and heat exchangers, and reduces the pumping requirements for compressors. These properties of sCO2 systems offer several potential benefits compared to traditional steam plants, including higher plant efficiency, reduced fuel use, lowered greenhouse gas emissions, and suitability for dry cooling in arid climates, where water resources might be scarce.

ES – 1. Market Trends

Section 2 discusses current market trends in the electricity sector. Electricity markets are rapidly evolving, creating both challenges and opportunities for new technologies. In general, the trend in the electricity sector is towards smaller, less carbon-intensive, decentralized power plants. Whereas prior to 2006, electricity demand grew at more than two percent per year, growth has been relatively stagnant since and most sources project only modest growth in the near term. Improved economics for solar, wind, and natural gas, and concerns about climate change, have led to shifts away from our long-term reliance on coal for power generation. Industry forecasts in the U.S. all point to a future of increased renewables and natural gas and ongoing retirements of existing coal and nuclear power plants. For example, Figure ES -1 shows the Energy Information Administration's (EIA) projected capacity additions and retirements in the U.S. through 2050. While these trends provide opportunities for new technologies, they also create challenges. Power producers will not buy new technologies just because they are more efficient. They must either compete economically with existing options or provide benefits that others cannot, such as ability to ramp quickly to balance intermittent resources, ability to utilize dry cooling, or for opportunities where smaller system size is required.

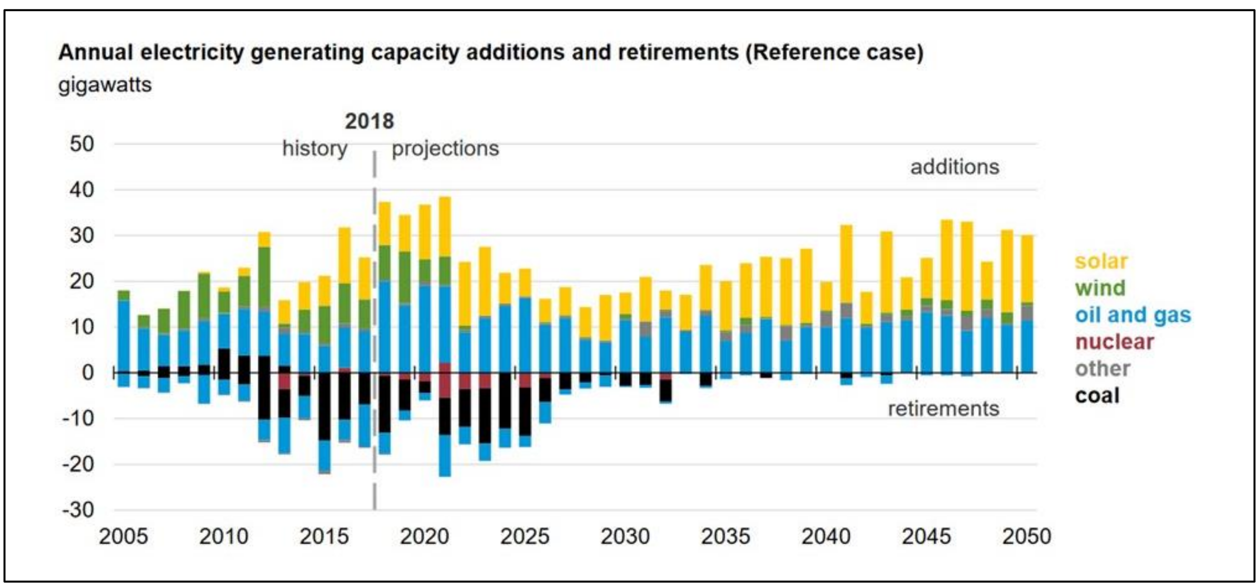

Figure ES 1. EIA (2019a) projected capacity additions and retirements in the U.S. through 2050.

ES – 2. Evaluating the Economics of Various Technologies

Section 3 discusses the two main metrics used for determining the economic competitiveness of new technologies. The most common economic metric for comparing technologies is the levelized cost of energy (LCOE). LCOE calculations estimate the per unit ($/kWh) cost of production over the economic lifetime of the technology. Specifically, this calculation takes the capital cost, associated financing costs, taxes, O&M, and fuel costs and calculates per unit production costs.

The EIA projects the technologies with the lowest LCOE in 2023 will be NGCC (40.2$/MWh), solar PV (48.8 $/MWh), and wind (42.8 $/MWh). Including tax credits, the LCOE in 2023 are NGCC (40.2 $/MWh), solar PV (37.8 $/MWh), and wind (36.6 $/MWh), EIA (2019b). The EIA estimates are largely consistent with estimates from other industry sources. For example, Lazard – a widely quoted consulting firm – estimates unsubsidized onshore wind costs range from 28 to 54 $/MWh, utility scale solar PV range from 32 to 44 $/MWh (below EIA), and NGCC range from 44 to 68 $/MWh (higher than EIA).

Based solely on the LCOE metric, the lowest cost options for new generating plants, on average, are utility scale PV and onshore wind.

The levelized avoided cost of energy (LACE) is increasingly used in conjunction with LCOE as it better quantifies a power plant's value to the grid. For example, power delivered to the grid during peak demand times is more valued than power delivered during non-peak times. Hence, solar PV will often have a higher LACE than LCOE. Projects are considered economically viable if the LACE is greater than the LCOE of alternative options, whether from an existing facility or a new build. EIA's projections of future capacity additions and retirements rely on this principle of LACE compared to LCOE. Specifically, if the LACE-to-LCOE ratio is greater than one, then that technology is attractive to build.

ES – 3. Economic Viability of Brayton Systems

The supercritical Brayton Economic Tool (sBET) calculates key system performance and LCOE based on user-defined input on key variables such as system size, recuperator effectiveness, and turbine inlet temperatures. The goal for this integrated tool is to allow system designers to understand the tradeoffs associated with various key design decisions. For example, increasing turbine inlet temperatures results in higher system efficiencies, but also requires components made from higher-cost alloys that raise the overall system cost. sBET allows one to analyze whether this increase in system efficiency is economically justified.

The sBET tool integrates the basic LCOE methodology with an existing Brayton cycle evaluation tool developed at Sandia – the RCBC Evaluation and Trade Studies Tool (RETS) (Pasch, 2016). RETS is a sCO_2 recompression closed Brayton cycle (RCBC) modeling tool that calculates key system performance characteristics based on user-defined inputs. A previous report (Drennen and Lance, 2019) documented sBET's structure, assumptions, and preliminary results. That report noted the importance of additional refinement of the costing methodology in order to increase the confidence in the estimates. An interlaboratory effort in 2018 and 2019 led to updated component estimations (Weiland et al., 2019) that were used to update and refine sBET for this report.

Based on these updated component costing relationships, the estimated LCOE for a 100 MWe system operating at 550 °C is 5.5 cents/kWh and 5.2 cents/kWh for a first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) plant, respectively. Figure ES-2 shows the relationship between system size, turbine inlet temperatures, and LCOE. Estimated LCOE falls significantly as system size increases, with the sharpest declines coming as system size increases from 10 to 50 MWe. For this range of plants and these operating assumptions, increasing system temperatures does not lead to lowered LCOE. For 10 MWe units, the higher operating temperature adds about 1.5 cents/kWh to the estimated cost.

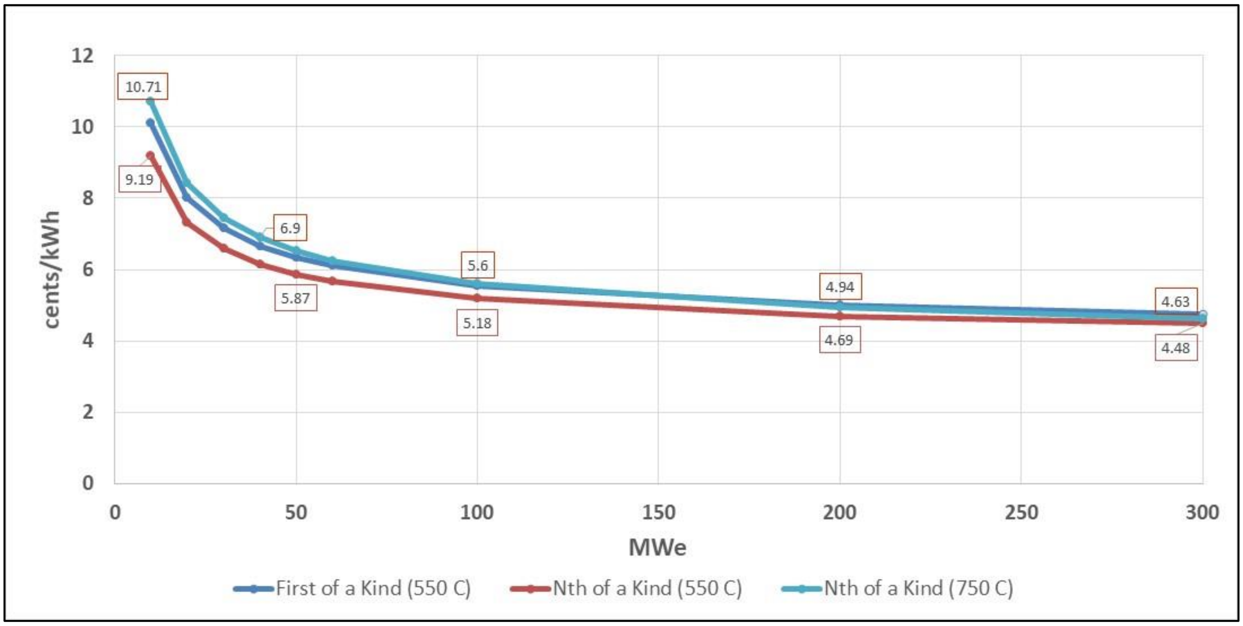

Figure ES-2. LCOE as a function of system size and turbine inlet temperature.

Additional sensitivity analysis demonstrates the value of sBET for doing parameter studies to understand key sensitivities and local optima for cycle parameters. Results show:

- Optimal recuperator design is dependent on natural gas prices. At lower natural gas prices ($3.00 - $5.00/MBtu), LCOE is minimized for a recuperator effectiveness around 91%. As natural gas prices increase, the optimal recuperator effectiveness increases.
- Each one percent improvement in turbine efficiency translates into a 0.4% increase in overall system efficiency and a 1% decrease in estimated LCOE.

ES – 4. Market Opportunities and Challenges

The changing economics of the electricity sector favors solar PV, wind, and NGCC plants. Rapidly dropping costs for battery storage are challenging the role of NGCC as the favored base-load option. It is in this changing landscape that the new Brayton systems will have to compete. This report documents that the projected LCOE for Brayton systems in the 100 to 300 MWe size range are between $44.8 and $56.1/MWh. At these costs, Brayton systems can compete directly for the same markets as NGCC. However, it is always difficult for a new, largely unproven technology to compete for the same markets as a technology with substantial market share. Comparable cost profiles are not sufficient; the new technology must be able to deliver a product that provides benefits that are not delivered by the existing technology. This is the challenge for Brayton systems.

There are several possible benefits Brayton systems can offer. First, the compact size of turbomachinery may provide a competitive edge in situations where size matters, such as integration with concentrated solar power (CSP) applications or with advanced small-scale, modular nuclear reactors. Their size also makes them suitable for onboard shipboard propulsion. Second, the thermodynamic properties of CO_2 as a working fluid make sCO_2 systems suitable for dry cooling, giving these systems a competitive advantage in regions lacking access to water.

To assess possible market opportunities for the Brayton system, we developed a market screening tool that allows the user to search out market opportunities using a broad range of screening criteria, such as identifying existing plants in the United States for which the estimated operating costs likely exceed the cost of building a new sCO_2 Brayton system. For example, the tool identifies 1,225 MWe of installed natural gas and 10,481 MWe of installed coal-fired capacity with current operating costs greater than \$0.05/kWh, section 5.1.1. This tool can also identify individual plants that meet user defined criteria, such as small-scale remote plants in Alaska with low capacity factors and high operating costs.

Section 5.2 discusses another useful screening tool from the Energy Institute at the University of Texas at Austin. The Energy Institute's tool uses the LCOE framework to determine the least cost option for new facilities in the U.S. Perhaps most useful for this market analysis, this tool includes the option to consider "availability zones" derived from work at Oak Ridge National Laboratory; these zones consider factors such as regulatory considerations, water availability, and access to fuel sources, such as natural gas pipelines. The tool also includes the option of including externality costs, including mercury, PM 2.5, SOx, NOx, and CO_2.

The updated LCOE estimates show that sCO_2 Brayton systems can compete directly for the same markets as new NGCC plants, including as a replacement for older, inefficient plants with high operating costs. The screening tools provide a way to quantify the potential markets. The largest hurdle, however, is that sCO_2 Brayton systems are still in the fairly early stages of development. Commercial customers are not going to be willing to invest in this technology until they are convinced of the commercial viability of the technology. For many, this translates into demonstrating the system can operate for several thousand hours (5,000 – 10,000 hours). Others note that the systems must not only be able to run for long-periods of time but must demonstrate the ability to rapidly cycle to meet load demands to allow for integration with intermittent resources, which are projected to continue to gain market share.

Alleviating these concerns will require multiple pilot projects of differing configurations and operating conditions. Equally important is an ongoing effort to truly understand potential customer needs. Claiming that this, or any technology, is superior because of system efficiency, for example, misses the mark. Going deeper into market analysis requires taking this next step of customer discovery. The expected outcome will be a list of problems the industry currently faces. The goal for the Brayton team then will be to explain and then demonstrate how and when sCO_2 technologies can solve these problems at an affordable cost. This report demonstrates that the technology will likely be economically competitive; the next step is to show that this technology can solve problems that the other technologies cannot.

ACRONYMS AND DEFINITIONS

Abbreviation	Definition
BNEF	Bloomberg New Energy Finance
CSP	concentrated solar power
CT	combustion turbine
EIA	Energy Information Administration
EPC	engineering and procurement costs
GE	General Electric
GWe	gigawatts electric
HTR	high temperature recuperator
kWe	kilowatt electric
FOAK	first-of-a-kind
LACE	levelized avoided cost of energy
IEA	International Energy Agency
LCOE	levelized cost of energy
LTR	low temperature recuperator
MMBtu	million btu
MWe	megawatt electric
MWh	megawatt hour
MWsh	MW shaft power
MWth	megawatt thermal
NEMS	National Energy Modeling System
NGCC	natural gas combined cycle
NOAK	nth-of-a-kind
O&M	operation and maintenance
PTT	Peregrine Turbine Technologies
PV	photovoltaic
RCBC	recompression closed Brayton cycle
RETS	RCBC Evaluation and Trade Studies Tool
sBET	sCO_2 Brayton Economic Tool
sCO_2	supercritical CO_2
SFR	sodium-cooled fast reactor
STEP	Supercritical Transformational Electric Power
UA	conductance area variable

1. INTRODUCTION

Researchers at Sandia National Laboratories and elsewhere are developing supercritical CO_2 Brayton cycle systems for use in a wide-range of power systems. In these advanced cycles, supercritical carbon dioxide is held at or above its critical temperature and pressure, meaning that the working fluid is closer to a liquid than a gas, allowing for significantly reduced volumetric flow, which translates into significantly reduced size for key components, including the turbines and heat exchangers, and reduces the pumping requirements for compressors. These properties of sCO_2 systems offer several potential benefits compared to traditional steam plants, including: higher plant efficiency, reduced fuel use, lowered greenhouse gas emissions, and suitability for dry cooling in arid climates, where water resources might be scarce.

Electricity markets are rapidly evolving, creating both challenges and opportunities for new technologies. In general, the trend in the electricity sector is towards smaller, less carbon-intensive, decentralized power plants. Whereas prior to 2006, electricity demand grew at more than two percent per year, growth has been relatively stagnant since and most sources project only modest growth in the near term. Improved economics for solar, wind, and natural gas, and concerns about climate change, have led to shifts away from our long-term reliance on coal for power generation. Industry forecasts in the U.S. all point to a future of increased renewables and natural gas and ongoing retirements of existing coal and nuclear power plants. While these trends provide opportunities for new technologies, they also create challenges. Power producers won't buy new technologies just because they are more efficient. They must either compete economically with existing options or provide benefits that others can't, such as the ability to ramp quickly to balance intermittent resources, ability to utilize dry cooling, or for opportunities where smaller system size is required.

This report is organized as follows. The next section discusses current market drivers and trends, and industry and government forecasts to 2050. Section 3 explains the economic metrics for evaluating technology choices. Section 4 provides updated estimates of the economic viability of Brayton systems, using updated relationships since our 2018 report (Drennen and Lance, 2019). Section 5 focuses on potential market opportunities for the sCO2 Brayton system, including a focus on two screening tools useful for evaluating market opportunities.

2. MARKET TRENDS

Electricity markets are rapidly evolving, creating both challenges and opportunities for new technologies. Prior to 2006, electricity demand grew at an average rate of 2.1%, Figure 2-1. Since 2008, demand has decreased by 2.1%, and per capita consumption has fallen 8.7% (EIA, 2019a). Over this time, there have been significant changes in market share, Figure 2-2. Electricity production from coal dropped 39%, while natural gas production increased 47%. Production from nuclear has been relatively stable.

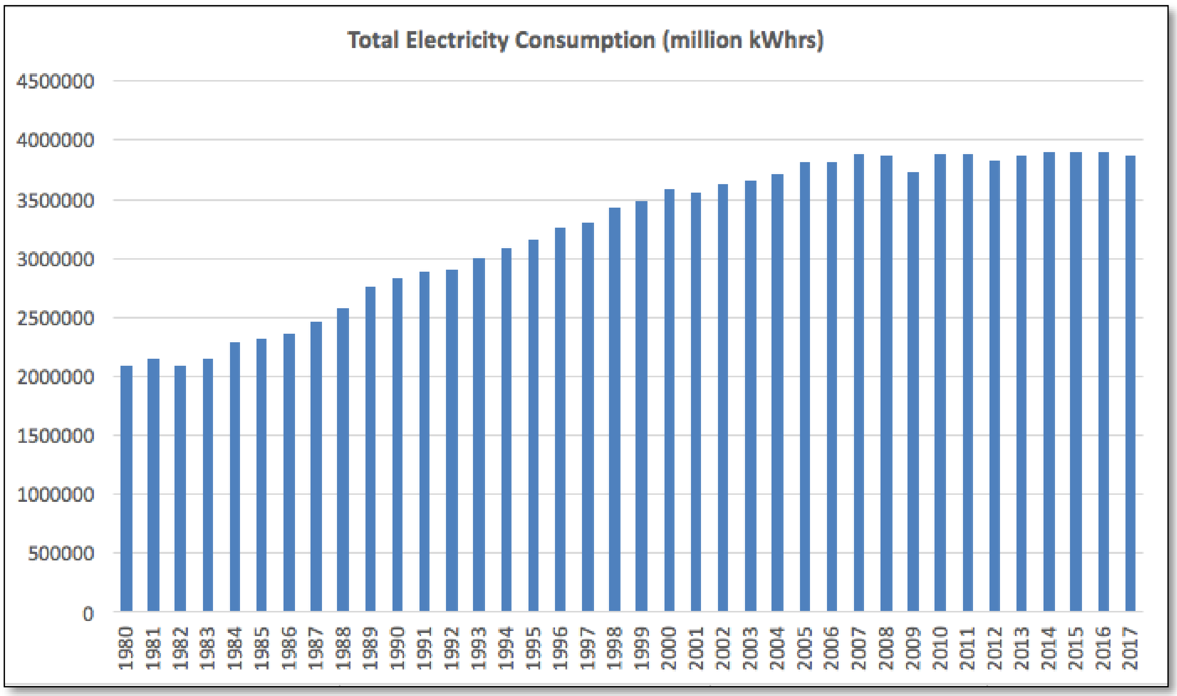

Figure 2-1. Total electricity consumption in the U.S., 1980 - 2017 (EIA, 2019a)

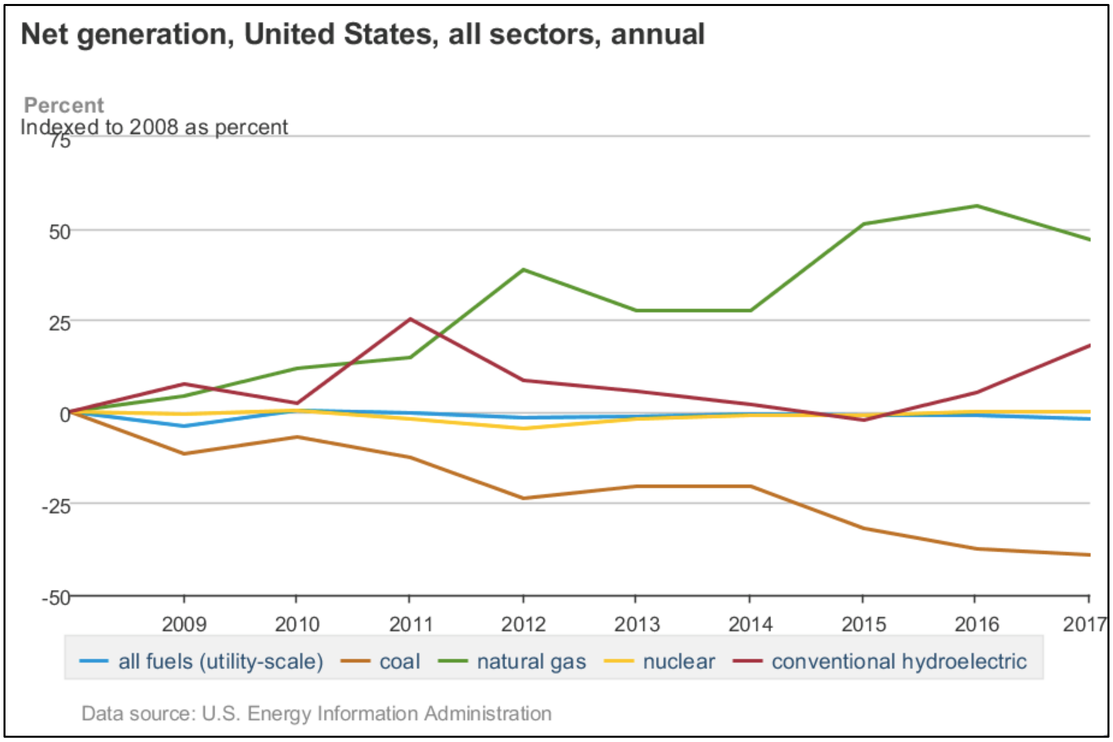

Figure 2-2. Changing generation patterns in U.S. since 2008 (EIA, 2019a).

Forecasts from EIA (2019a) and others (IEA, BNEF, BP, GE) suggest most new generating capacity in the U.S. and elsewhere will come from solar, wind, and natural gas. For example, EIA's 2019 forecast (*Annual Energy Outlook 2019*), Figure 2-3, has solar and natural gas technologies as the two dominant technologies after 2021. The same forecast shows retirements of coal and nuclear continuing. Key drivers of this forecast are recent steep declines in solar module costs and projected steep declines in storage technologies, such as Lithium-Ion batteries.

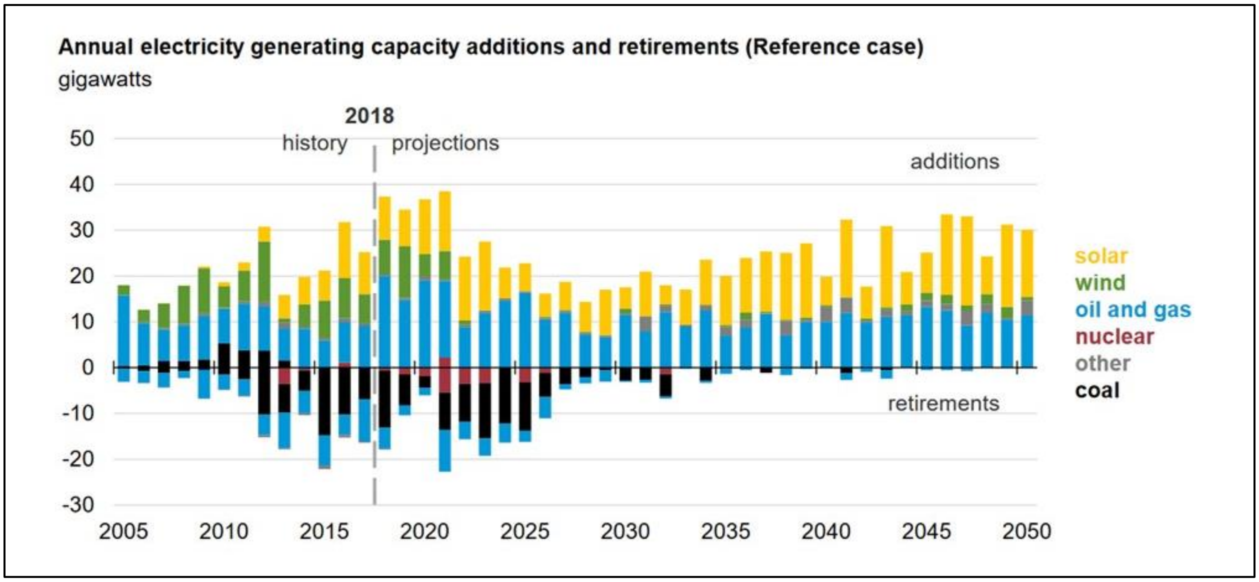

Figure 2-3. Forecasted capacity additions and retirements in the U.S. through 2050 (EIA, 2019a)

Some sources, such as Bloomberg New Energy Finance (BNEF) are even more bullish on the prospect for growth in renewables; their 2019 outlook projects that solar and wind will account for 35% of the U.S. electricity production by 2050 and 50% of the world's (BNEF, 2019). The International Energy Agency projects that shares of renewables will account for almost 50% of total electricity generation by 2040, 10 years earlier than the BNEF forecast (IEA, 2019). **Error! Reference source not found.** BP expects shares of renewables (not including hydro) to reach just under 30% of market share by 2040 (Dale, 2019).

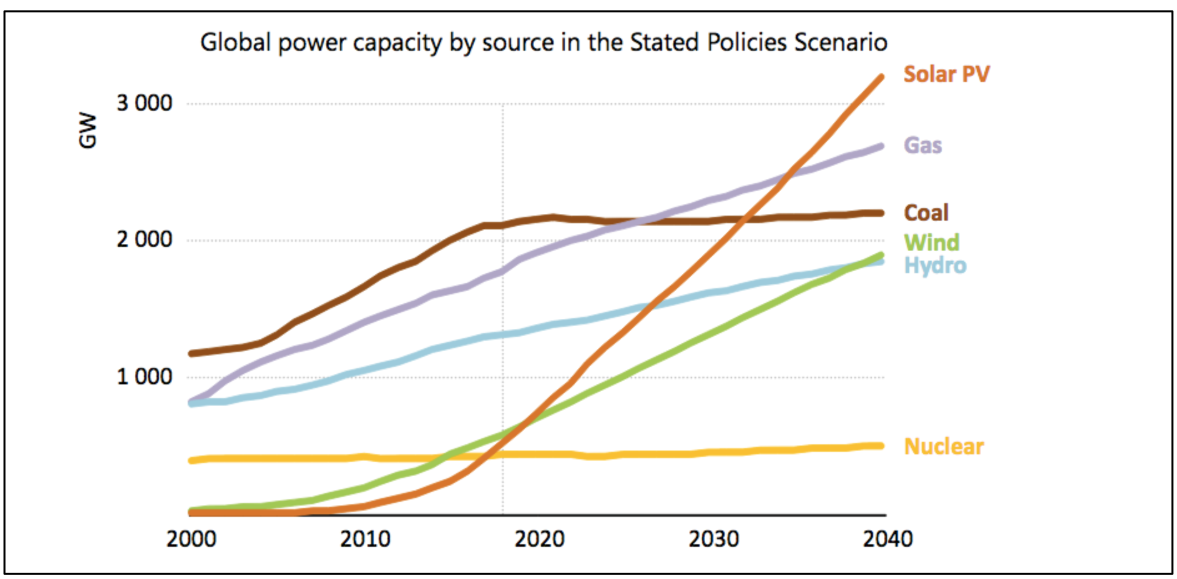

Figure 2-4. IEA forecast shows renewable capturing just under 50% of electricity generation worldwide by 2040 (IEA, 2019).

General Electric (GE), one of the leading suppliers of natural gas combined cycle systems, expects demand for new natural gas plants to be on the low side of the EIA estimates. DeLeonardo (2019) notes that orders for new natural gas combined cycle plants dropped from 55 GWe in 2015 to just 29 GWe in 2017. GE projects U.S. capacity additions of 27.5 GWe per year for the next decade but expects two-thirds of that to be renewables, leaving approximately 9.0 GWe per year for new NGCC or other technologies (DeLeonardo, 2019). GE's plan for staying competitive in the evolving marketplace is to focus on decarbonization, decentralization, and digitization (the three D's). As DeLeonardo (2019) puts it, today's power customers want plants that will minimize CO_2 emissions, are low cost, can ramp up in five minutes or less, and can operate for five years at 90% capacity factor with minimal maintenance. According to DeLeonardo (2019), GE's marketing strategy is to continue increasing the system efficiency for new plants and marketing these plants by targeting older, less efficient coal and natural gas plants.

Basic economics and concerns about changing climate are the key drivers of this evolving electricity sector landscape. As Deloitte's *2018 Outlook on Power and Utilities* states, "When it comes to new build, almost all planned generation capacity for the next five years is renewable or natural gas fired. Why? Because wind, solar, and natural gas are often the lower cost resources, and both experience and research have shown they're what utility customers want" (Deloitte, 2018).

Several recent announcements from utilities highlight the trend towards renewables. In 2018, Xcel Energy announced plans to prematurely retire two coal-fired units (Comanche 1 and 2) and to offset the capacity with 1131 MW of wind and 707 MW of solar, both coupled to 275 MW of battery storage (Pyper, 2018). An open solicitation for renewables resulted in median price bids for wind with storage of $21/MWh and solar with storage of $36/MWh (Pyper, 2018), below the cost of operating the existing coal units. Likewise, the Central Arizona Project signed a 20-year commitment to purchase power from a solar plant in 2020 for $24.99/MWh; the power will replace power from the Navajo coal-fired generating station (Merchant, 2018). BNEF (2018) estimates that levelized cost of energy (LCOE) for new wind projects in Texas averaged $29/MWh in 2018 and expects average costs will fall to $35/MWh for wind projects nationwide by 2030. BNEF attributes these cost drops to a trend towards larger turbines which can achieve higher capacity factors; they expect average capacity factors for new turbines will reach 62% by 2040 (BNEF, 2018).

These few examples highlight the trend towards large-scale renewable projects, coupled with energy storage to ease the concerns about the intermittency issue. The sharply reduced prices have also made it easier for companies, cities, and states to adopt ambitious clean energy plans. To date, nine states and the District of Columbia and Puerto Rico have adopted plans for 100% clean energy by 2050 or earlier. As examples, Hawaii adopted legislation requiring 100% renewable energy by 2045; NY passed legislation requiring 100% carbon-free electricity by 2040; and NM passed legislation in March 2019 requiring 80% renewables by 2040.[1]

The sharply reduced costs for solar PV and wind technologies, coupled with the availability of cheap natural gas, translate into forecasts where natural gas and renewables dominate the electricity sector. And in many states, the availability of cheaper renewables and promise of similar cost trends in storage technologies, are translating into 100% clean energy plans as a response to concerns about climate change. The next section focuses on the two most common methods for evaluating economic viability of new and existing electricity options.

[1] A complete list of city and state goals is available from the Center for American Progress (Podesta et al., 2019).

3. EVALUATING THE ECONOMICS OF NEW TECHNOLOGIES

The most common economic metric for comparing technologies is the levelized cost of energy (LCOE). LCOE calculations estimate the per unit ($/kWh) cost of production over the economic lifetime of the technology. Specifically, this calculation takes the capital cost, associated financing costs, taxes, O&M, and fuel costs and calculates per unit production costs.

The levelized avoided cost of energy (LACE) is increasingly used in conjunction with LCOE as it better quantifies a power plant's value to the grid. For example, power delivered to the grid during peak demand times is more valued than power delivered during non-peak times. Hence, solar PV will often have a higher LACE than LCOE, and wind in certain regions may have a lower LACE than LCOE if the power is delivered to grid in non-peak times. If comparing two technologies, the project with the higher LACE to LCOE ratio will be more attractive.

In terms of LCOE, the EIA projects by 2023 the technologies with the lowest LCOE are NGCC (40.2$/MWh), solar PV (48.8 $/MWh), and wind (42.8 $/MWh). Including tax credits, the LCOE in 2023 are NGCC (40.2 $/MWh), solar PV (37.8 $/MWh), and wind (36.6 $/MWh), EIA (2019b). As the EIA notes, there are huge regional differences in estimated LCOEs; for example, the LCOE for new onshore wind capacity ranges from 38.9 $/MWh in the region with the best available wind resource to 72.9 $/MWh for the region with either low-quality wind or higher estimated capital costs.

The EIA estimates are largely consistent with estimates from other industry sources. For example, Lazard – a widely quoted consulting firm – estimates unsubsidized onshore wind costs ranging from 28 to 54 $/MWh, utility scale solar PV range from 32 to 44 $/MWh (below EIA), and NGCC range from 44 to 68 $/MWh (higher than EIA), Figure 3-1. Lazard also documents how quickly the LCOE for solar and wind have changed over the past decade. In 2009, the lowest cost option was NGCC ($83/MWh). Solar PV was more than 4X higher - $359/MWh. By 2019, the estimated LCOE for utility-scale solar PV had dropped to 41 $/MWh, below NGCC (56 $/MWh), and comparable to onshore wind ($40/MWh), Figure 3-2. Based on these estimates, costs for new coal-fired plants have remained fairly constant ($109/MWh in 2019). Estimates for new nuclear plants have increased, likely due to the actual experience in constructing the Vogtle plants in Georgia ($155/MWh in 2019).

Based solely on the LCOE metric, the lowest cost options for new generating plants, on average, are utility scale PV and onshore wind.

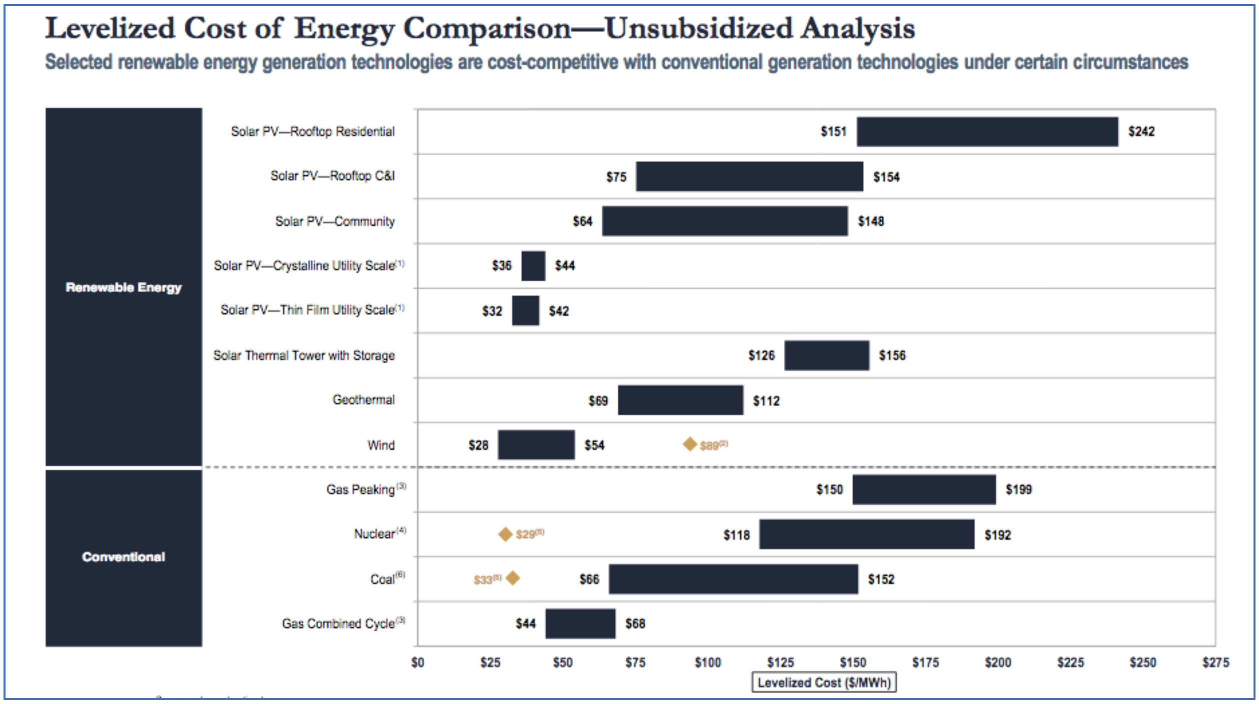

Figure 3-1. Lazard's estimated LCOE (Source: Lazard, 2019).

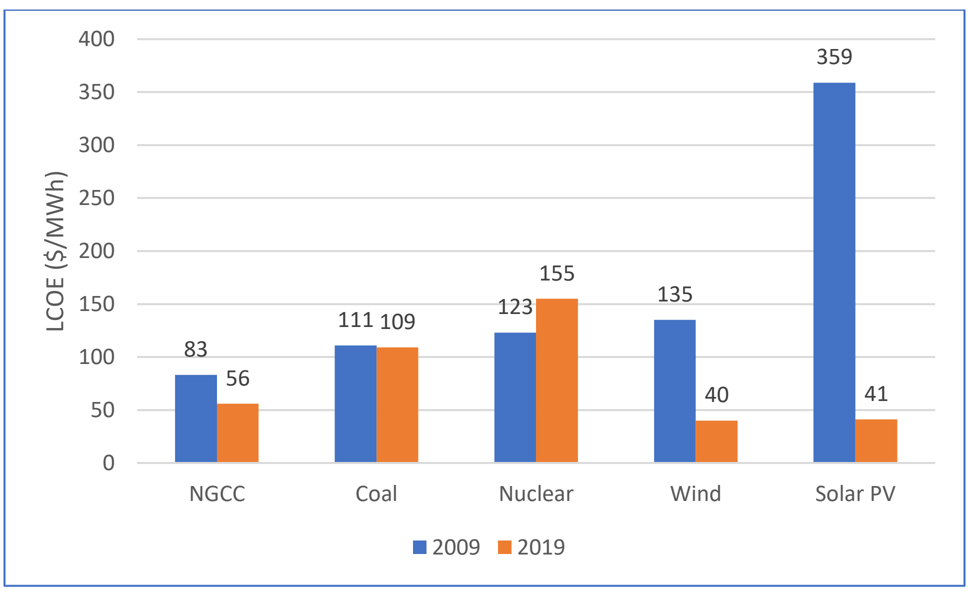

Figure 3-2. Lazard's LCOE estimates 2009 - 2019 (Lazard, 2019).

EIA's projections of future capacity additions and retirements, Figure 2-3, relies on this principle of LACE compared to LCOE. Specifically, if the LACE-to-LCOE ratio is greater than one, then that technology is attractive to build. Figure 3-4 shows the estimated LACE to LCOE ratio for NGCC, onshore wind, and solar PV coming online in 2023. The dashed line separates the economically attractive projects from the economically unattractive options. Each circle represents a specific region; solid circles represent regions with planned builds for that technology. These estimates suggest that most NGCC plants planned for 2023 are economically viable. Most of the onshore wind plants are not economically attractive, whereas most of the planned solar builds are economically attractive. The main takeaway from this figure is that solar PV has a higher LACE-to-LCOE ratio than onshore wind because of the time the power is delivered to the grid.

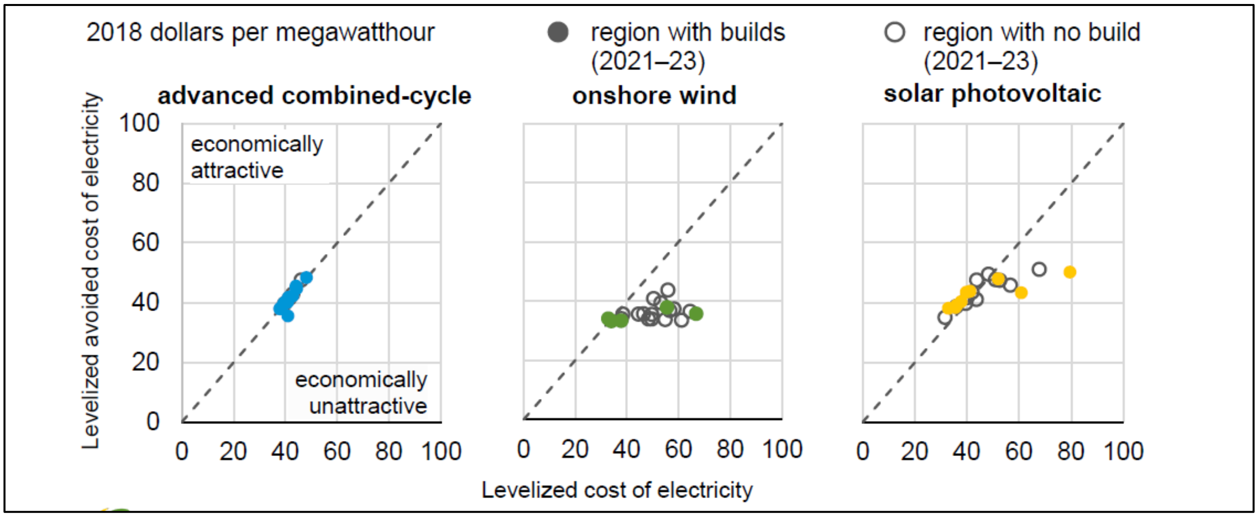

Figure 3-3. EIA's estimated LACE values for new generating technologies entering service in 2023 (Source: EIA, 2019b).

Figure 3-4 shows the regional variation in estimated LACE for new generating technologies coming online in 2023 (EIA, 2019b). For example, estimated LACE for solar PV range from a low of 35.1 $/MWh to 51.1 $/MWh.

Plant type	Minimum	Simple average	Capacity-weighted average[1]	Maximum
Dispatchable technologies				
Coal with 30% CCS[2]	35.6	40.8	NB	48.6
Coal with 90% CCS[2]	35.6	40.8	NB	48.6
Conventional CC	35.5	41.1	38.3	48.4
Advanced CC	35.5	41.1	40.4	48.4
Advanced CC with CCS	35.5	41.1	NB	48.4
Advanced nuclear	35.7	40.3	NB	47.7
Geothermal	41.4	44.6	45.8	48.1
Biomass	35.5	41.3	41.7	48.7
Non-dispatchable technologies				
Wind, onshore	33.3	36.1	33.7	43.7
Wind, offshore	36.4	40.5	39.9	52.2
Solar PV[3]	35.1	43.4	40.3	51.1
Solar thermal	39.8	44.0	NB	51.2
Hydroelectric[4]	41.6	41.6	41.6	41.6

Figure 3-4. LACE to LCOE comparisons by region for selected generating technologies coming online in 2023 (Source: EIA, 2019b).

Figure 3-5 shows EIA's projected LACE to LCOE ratios for NGCC, solar, and onshore wind through 2050. The EIA's modeling methodology selects those technologies with the greatest LACE/LCOE ratio. Onshore wind and solar PV become economically unattractive as tax credits expire but rebound in about a decade as the overall economics improve. This figure highlights the rationale behind the EIA's projections for solar, wind and NGCC over time.

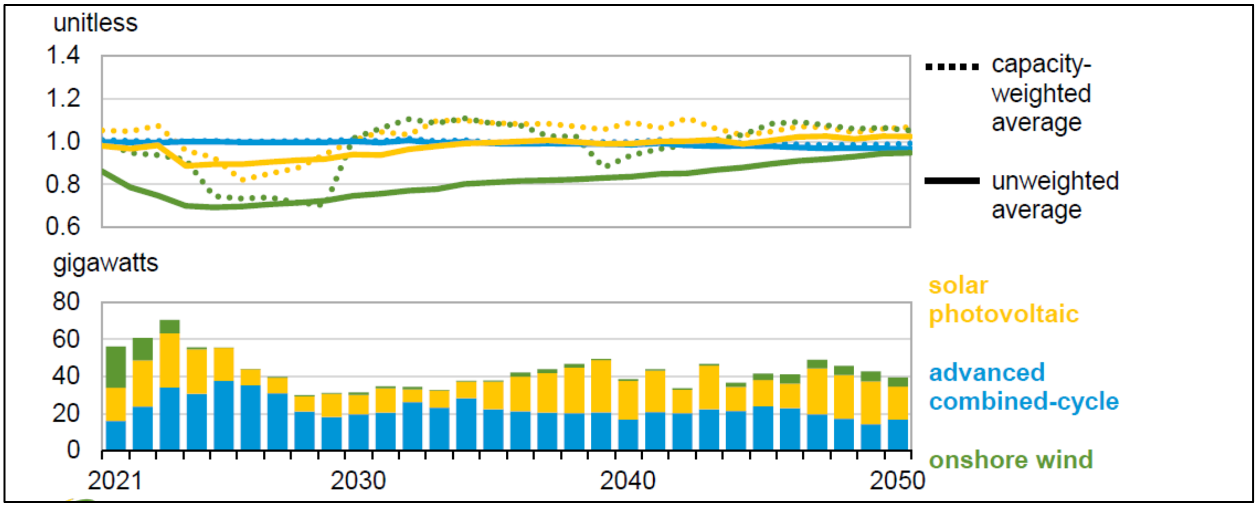

Figure 3-5. LACE to LCOE value and projected capacity additions (Source: EIA, 2019b).

The next section provides updated estimates of the LCOE for sCO_2 Brayton systems.

4. UPDATED ECONOMIC VIABILITY OF BRAYTON SYSTEMS

Sandia researchers developed a techno-economic modeling tool to evaluate and optimize Brayton system configurations. The supercritical Brayton Economic Tool (sBET) calculates key system performance and levelized cost of energy (LCOE) based on user-defined input on key variables such as system size, recuperator effectiveness, and turbine inlet temperatures. The goal for this integrated tool is to allow system designers to understand the tradeoffs associated with various key design decisions. For example, increasing turbine inlet temperatures results in higher system efficiencies, but also requires components made from higher-cost alloys that raise the overall system cost. sBET allows one to analyze whether this increase in system efficiency is economically justified.

The sBET tool integrates the basic LCOE methodology with an existing Brayton cycle evaluation tool developed at Sandia – the RCBC Evaluation and Trade Studies Tool (RETS) (Pasch, 2016). RETS is a sCO_2 recompression closed Brayton cycle (RCBC) modeling tool that calculates key system performance characteristics based on user-defined inputs.

A previous report (Drennen and Lance, 2019) documented sBET's structure, assumptions, and preliminary results. That report noted the importance of additional refinement of the costing methodology in order to increase the confidence in the estimates. An interlaboratory effort in 2018 and 2019 led to updated component estimations (Weiland et al., 2019) that were used to update and refine sBET for this report. Weiland et al. (2019) builds on initial work of Carlson et al. (2017), which focused largely on component costing for 1 – 100 MWe Brayton systems integrated with concentrated solar power (CSP) systems. As Weiland et al. (2019) notes, the new study "expands upon this work by leveraging the collective resources of the U.S. Department of Energy (DOE) national laboratories with sCO_2 component vendor costs spanning multiple applications (nuclear, fossil, solar) and size ranges (5 – 750 MWe)." The updated study provides new cost formulas (power law form) and cost scaling factors based on a total of 129 vendor estimates. The authors' approach included weighting of vendor estimates to take account of such factors as commercial availability and estimate details.

sBET was updated to include these new cost algorithms wherever possible. For those components included in the Weiland et al. (2019) study, the estimated cost for each system component is given by:

$$C = aSP^b * f_T \qquad (1)$$

Where: SP is the scaling parameter and f_T is the temperature scaling factor. For temperatures less than 550 °C, f_T is equal to 1. For temperatures above 550 °C, f_T is:

$$F_T = 1 + c(T_{max} - T_{bp}) + d(T_{max} - T_{bp})^2 \qquad (2)$$

Table 4-1 summarizes the component-specific coefficients from Weiland et al. (2019).

Table 4-1. Summary of Cost Algorithms used in sBET (adapted from Weiland et al., 2019)

Component	Scaling Parameter (units)	Coefficients				Database Range	Uncertainty Range
		a	*b*	*c*	*d*		
Coal-fired heaters	*Q* (MW_{th})	820,800	0.7327	0	5.4e-5	187 to 1,450 MW_{th}	-23% to +26%
Natural-gas fired heaters	*Q* (MW_{th})	632,900	0.6	0	5.4e-5	10 to 50 MW_{th}	-25% to 33%
Recuperators	*UA* (W/K)	49.45	0.7544	0.02141	0	1.6e5 to 2.2e8 W/K	-31% to 38%
Direct air coolers	*UA* (W/K)	32.88	0.75	0	0	8.6e5 to 7.5e7 W/K	-25% to 28%
Axial turbines	W_{sh} (MW_{sh})	182,600	0.5561	0	1.106e-4	10 to 750 MW_{sh}	-25% to 30%
Compressors	W_{sh} (MW_{sh})	1,230,000	0.3992	0	0	1.5 to 200 MW_{sh}	-40% to 48%
Gearboxes	W_{sh} (MW_{sh})	177,200	0.2434	0	0	4 to 10 MW_{sh}	-15% to 20%
Generators	W_e(MW_e)	108,900	0.5463	0	0	4 to 750 MW_e	-19% to 23%

4.1. Estimated costs for a 100 MWe Brayton system

Table 4-2 summarizes the key operating assumptions for a 100 MWe system with a natural gas-fired heater.[2] Based on these assumptions, the estimated system efficiency is 40.0%, Figure 4-1. The estimated LCOE is 5.5 cents/kWh and 5.2 cents/kWh for a first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) plant, respectively, Figure 4-2.

Table 4-2. Operating assumptions for 100 MWe reference case.

Turbine inlet temperature (°C)	550
Cooling outlet temperature (°C)	33
Compressor input pressure (MPa)	8.45
Compressor discharge pressure (MPa)	25.0
Recuperator approach temperatures (°C)	10
Turbine efficiency (%)	85
Main compressor efficiency (%)	82
Secondary compressor efficiency (%)	78
Power output (MWe)	100

[2] sBET includes three options for the heat source: Natural gas (default), concentrated solar power (CSP), and a sodium-cooled fast reactor (SFR). Additional costing details about these sources are discussed in Drennen and Lance (2018).

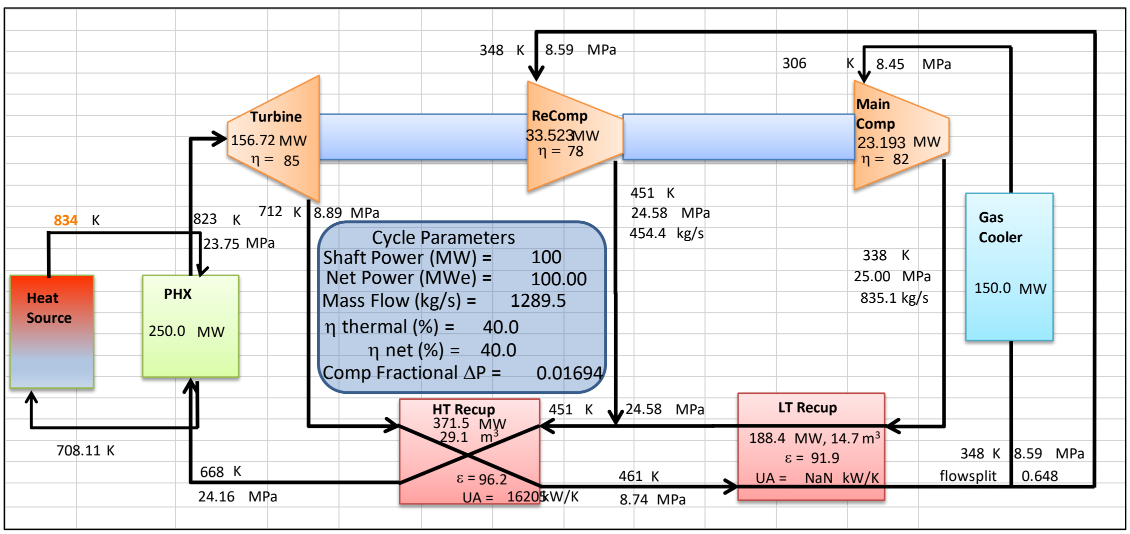

Figure 4-1. Estimated system configuration and efficiency from RETs.

Figure 4-2 also shows the detailed component cost breakdown for the 100 MWe Brayton system. The estimated system cost for a nth-of-a-kind facility is 1,308 $/kWe. Of that total, the recuperators account for 19% of the component costs. In terms of total LCOE, fuel costs account for 49% of the total, Figure 4-3. The actual system costs account for just 28% of the final LCOE costs. In addition to the fuel costs, other major cost components include the operating and maintenance (O&M) costs (7%), contingency and owner's fees (11%), and project indirects (8%).[3]

[3] sBET utilizes an EIA (2013) plant-costing methodology for new generating plants. Project indirects include engineering, labor, and construction management costs. Owner's costs include development costs, feasibility and engineering studies, legal fees, insurance, and electrical interconnection. sBET assumes indirect costs are a fixed 28.8% of total mechanical and electrical costs. Owner's costs are 20% of the engineering procurement costs (EPC), which include mechanicals, electrical, project indirects, and the civil and construction costs. More detail about this methodology is included in Drennen and Lance (2019).

Levelized Cost of Energy Calculator					
	Subsystem Cost ($1000)	$/kWe Net (FOAK)	% Total Cost	R-Value	$/kWe Net (NOAK)
Heat Source	**17,382**	173.82	11%	0.06	133
Heat Exchangers					
High temp recuperator	13,587	135.87	9%	0.06	104
Low temp recuperator	14,539	145.39	10%	0.06	111
Primary Heat Exchanger	-	0.00	0%	0.04	0.00
Heat rejection (Air Coolers/Condensers)	6,518	65.18	4%	0.04	55
Turbomachinery					
Turbine	3,035	30.35	2%	0.06	23
Compressors	9,313	93.13	6%	0.06	71
Turbine stop valve	4,600	46.00	3%	0.06	35
Turbine governor valve	4,700	47	3%	0.06	36
Gear box	606	6	0%	0.06	5
Turbomachinery control	791	8	1%	0.06	6
Other instrumentation	396	4	0%	0.06	3
Inventory control	375	4	0%	0.06	3
Generator	1,723	17	1%	0.06	13
Total Mechanical	**77,565**	**776**			**598**
Electrical, Instrumentation, Control	4,776	47.76	3%	0.02	44
Facilities (includes major infrastructure)	10,787	108	7%	0.01	103
Project indirects	23,714	237	16%	0.01	227
Total EPS	116,842	1,168			973
Contingency	11,684	117	8%	0.01	112
Owner's Costs	23,368	233.68	15%	0.01	224
Total Project Costs	**151,895**	**1,519**	100%		**1,308**
Levelized Cost of Energy ($/kWh$_e$)	**FOAK**	**$ 0.055**		**NOAK**	**$ 0.052**
Calculated Fuel Cost ($/kWh)		**$ 0.026**			**$ 0.026**

Figure 4-2. Estimated LCOE for 100 MWe Brayton system operating at 550 degrees C.

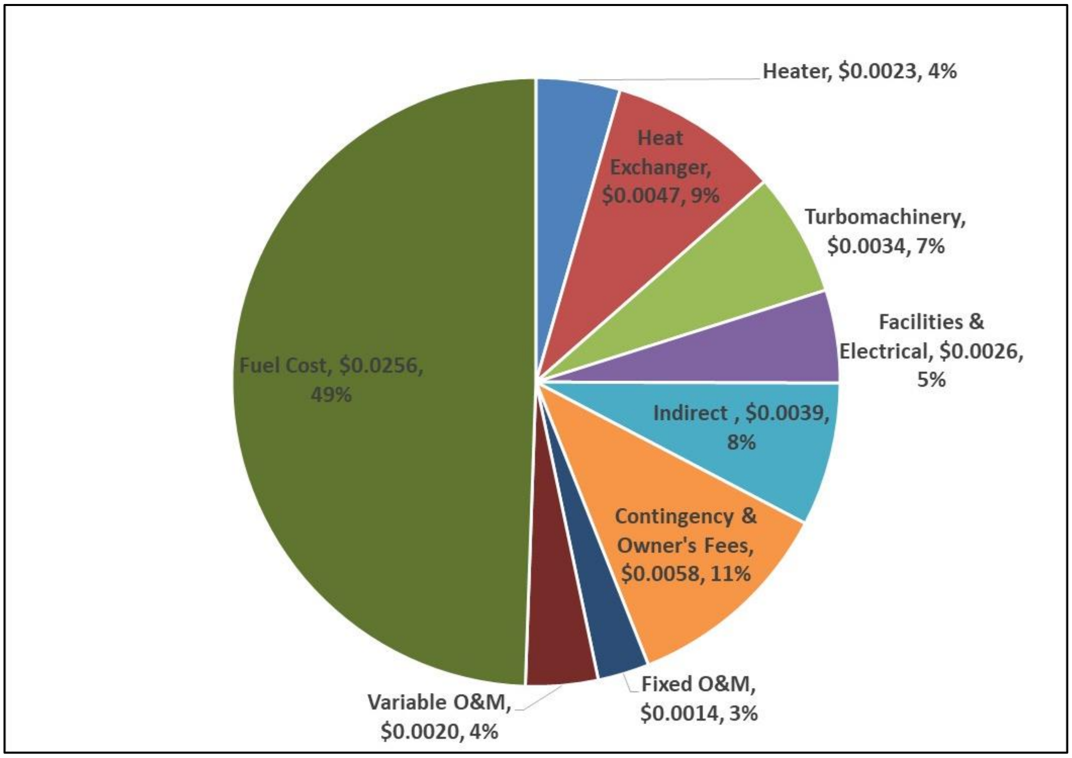

Figure 4-3. LCOE cost breakdown for 100 MWe Brayton system.

4.2. Sensitivity Analysis

Figure 4-4 shows the relationship between system size, turbine inlet temperatures, and LCOE. Estimated LCOE falls significantly as system size increases, with the sharpest declines coming as system size increases from 10 to 50 MWe. For this range of plants and these operating assumptions, increasing system temperatures does not lead to lowered LCOE. For 10 MWe units, the higher operating temperature adds about 1.5 cents/kWh to the estimated cost.

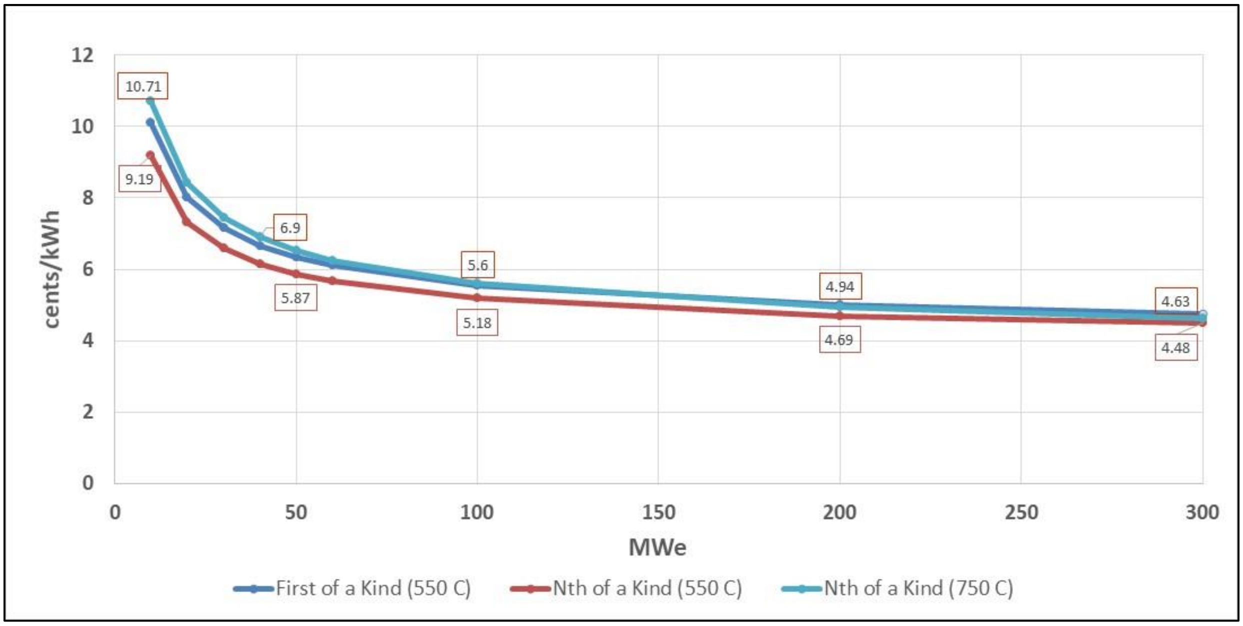

Figure 4-4. LCOE as a function of system size and turbine inlet temperature.

Figure 4-5 shows the relationship between turbine inlet temperature, fuel cost, and system efficiency. Increasing the turbine inlet temperature increases system efficiency; going from 550 to 700 °C improves overall system efficiency by 6.8 %. However, for natural gas at 3.00 $/MMBtu, estimated LCOE is minimized at a turbine inlet temperature of 600 °C. For natural gas prices of 7.00 $/MMBtu, the LCOE is minimized for a turbine inlet temperature of 650 °C. These results suggest that despite higher efficiencies achieved at higher operating temperatures, the added system component costs do not offset the increased efficiency.

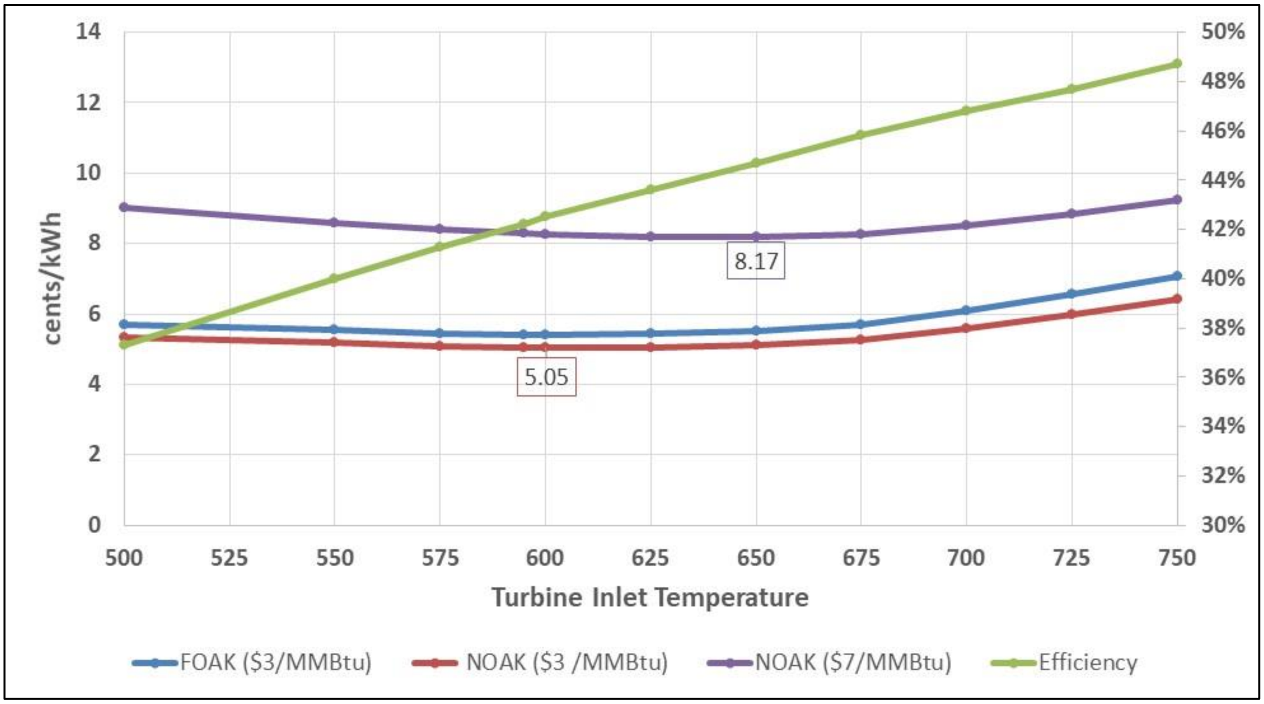

Figure 4-5. LCOE and system efficiency as a function of turbine inlet temperatures and fuel costs.

Drennen and Lance (2019) details additional sensitivity results, highlighting the value of sBET for doing detailed parameter studies to understand key sensitivities and local optima for cycle parameters. Several of these key sensitivities were re-evaluated for this report.

Figure 4-6 demonstrates the relationship between assumed recuperator effectiveness and system efficiency and LCOE for a 100 MWe Brayton system operating at 700 °C. The results show that the optimal design for the recuperators is dependent on natural gas prices. At lower natural gas prices (3.00 – 5.00 $/MMBtu), the LCOE is minimized for recuperator effectiveness around 91%. Beyond that the LCOE begins increasing. For more expensive natural gas (7.00 $/MMBtu), LCOE is minimized for a recuperator effectiveness of 93%.

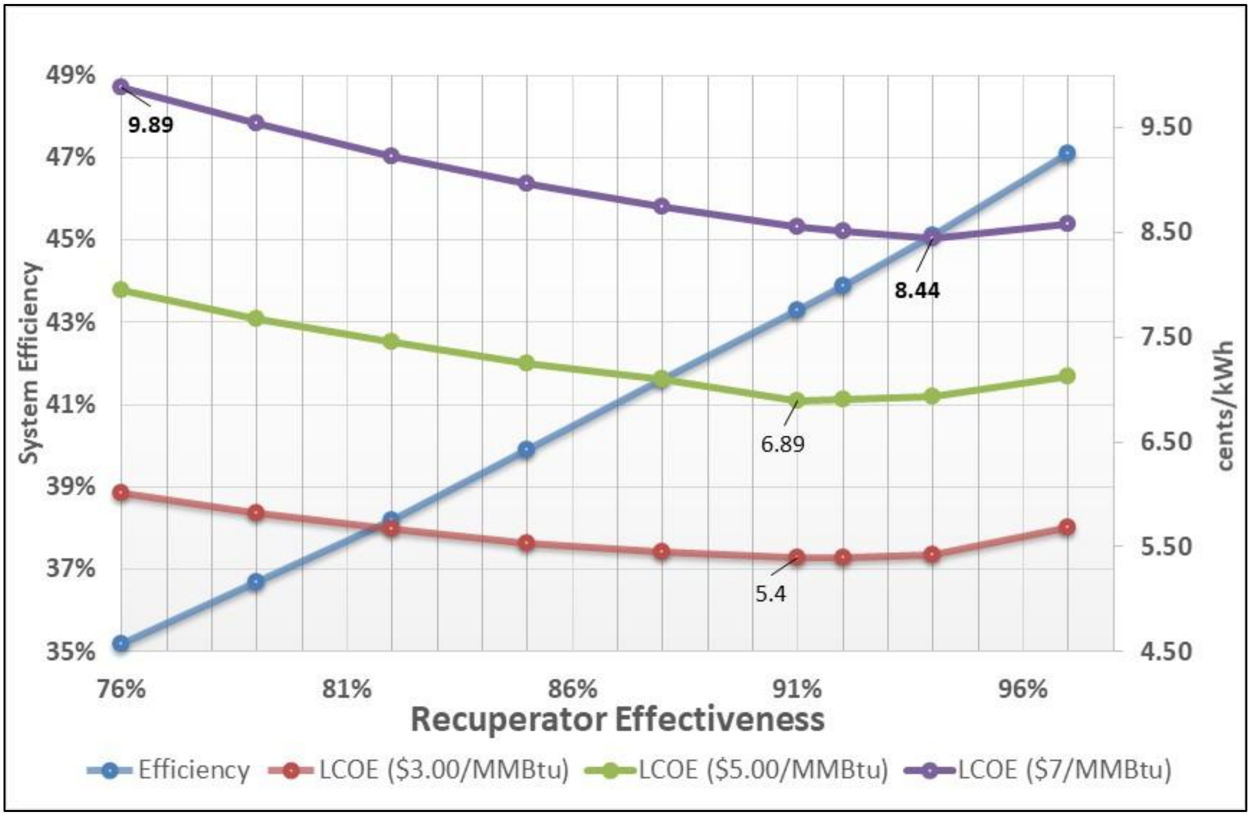

Figure 4-6. Sensitivity analysis on recuperator effectiveness and fuel cost (100 MWe, 700°C)

Figure 4-7 shows the relationship between the turbine efficiency, system efficiency, and LCOE for a 100 MWe Brayton system operating at 700 °C and with natural gas at $3.00/MMBtu. Each one percent improvement in turbine efficiency translates into a 0.4% increase in overall system efficiency and a 1% decrease in estimated LCOE[4].

[4] This analysis assumes the cost estimation for turbomachinery is valid over this efficiency range; whether this is a valid assumption requires additional vendor discussions and estimates.

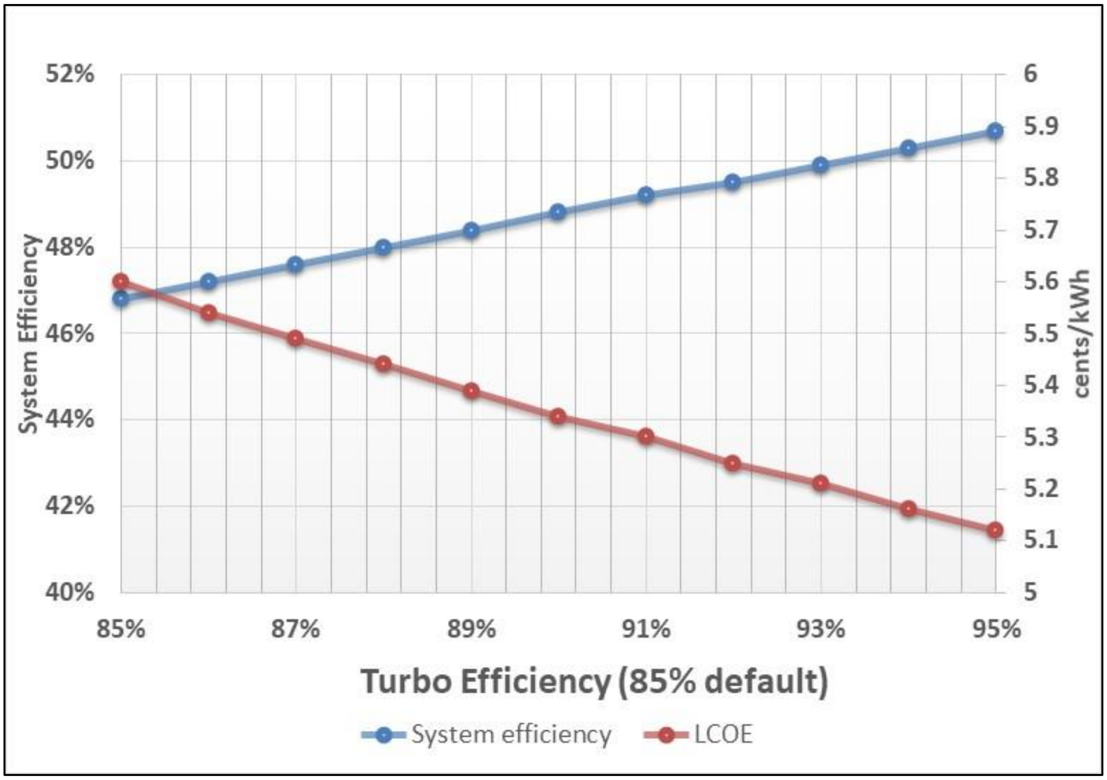

Figure 4-7. Sensitivity analysis on turbine efficiency (100 MWe, 700 °C)

Based on the updated economic assumptions for various system components, sCO_2 systems are economically competitive with new NGCC systems. The next section discusses the potential market opportunities and challenges for Brayton systems.

5. MARKET OPPORTUNITIES AND CHALLENGES

As discussed in previous sections, the changing economics of the electricity sector favors solar PV, wind, and NGCC plants. Rapidly dropping costs for battery storage are challenging the role of NGCC as the favored base-load option. As noted in section 2, General Electric, one of the major suppliers of NGCC plants, projects that approximately two thirds of new capacity additions will be renewables, leaving just about 9.0 GWe per year for new NGCC or other technologies (DeLeonardo, 2019). GE's strategy for remaining competitive is to focus on ever more efficient systems and target older, less efficient coal and natural gas plants. The newest LCOE estimates from Lazard (2019) estimated the LCOE for new NGCC plants ranging from \$44 to \$68/MWh. Estimates for utility-scale solar and onshore wind are \$32 to \$44/MWh and \$28 to \$54/MWh, respectively. Evidence from the marketplace, such as the Xcel and Central Arizona Project examples (Section 5) shows aggressive low-cost bids from renewables coupled with storage are challenging NGCC. By coupling the systems with storage, these systems can more closely match load demand, further eroding a unique marketing characteristic of NGCC.

It is in this changing landscape that the new Brayton systems will have to compete. This report documents that the projected LCOE for Brayton systems in the 100 to 300 MWe size range are between \$44.8 and \$56.1/MWh, Figure 4-4. At these costs, Brayton systems can compete directly for the same markets as NGCC. However, it is always difficult for a new, largely unproven technology to compete for the same markets as a technology with substantial market share. Comparable cost profiles are not sufficient; the new technology must be able to deliver a product that provides benefits that are not delivered by the existing technology. This is the challenge for Brayton systems.

There are several possible benefits Brayton systems can offer. First, the compact size of turbomachinery may provide a competitive edge in situations where size matters, such as integration with concentrated solar power (CSP) applications or with advanced small-scale, modular nuclear reactors. Their size also makes them suitable for onboard shipboard propulsion. Second, the thermodynamic properties of CO_2 as a working fluid make sCO_2 systems suitable for dry cooling, giving these systems a competitive advantage in regions lacking access to water.

To assess possible market opportunities for the Brayton system, we developed a market screening tool. This tool allows the user to search out market opportunities using a broad range of screening criteria. This tool is demonstrated in section 5.1. Another useful screening tool, developed by the Energy Institute, at the University of Texas is discussed in section 5.2

5.1. Screening Tool

This market screening tool was developed specifically for this market analysis. The tool relies on data from the EIA for all U.S. power plants in 2018, as reported on forms EIA-860 and EIA-923 (EIA, 2018a and 2018b). Using individual plant characteristics, the tool estimates the projected operating cost for each plant, based on average delivered fuel costs for plants in the U.S., average fixed operating and maintenance costs for new electricity plants as estimated by the EIA, and average incremental costs for existing plants using econometric relations used in EIA's Energy Modeling System (NEMs) (EIA, 2018c). The tool allows users to easily tailor any of these assumptions, such as changing delivered fuel costs for states with much higher delivered fuel costs, e.g. Alaska.

The following examples demonstrates the wide range of possible uses of this economic screening tool.

5.1.1. Example 1: Estimating total market size.

A primary use of this tool is in identifying near term market opportunities for Brayton systems by identifying plants where the estimated operating costs likely exceed the cost of building a new Brayton system, Figure 5-1. This example shows all NGCC (left) and coal-fired steam plants (right) with estimated operating costs above $0.05/kWh. The results show there are 1,225 MWe of installed natural gas and 10,481 MWe of installed coal-fired capacity that meet these criteria.

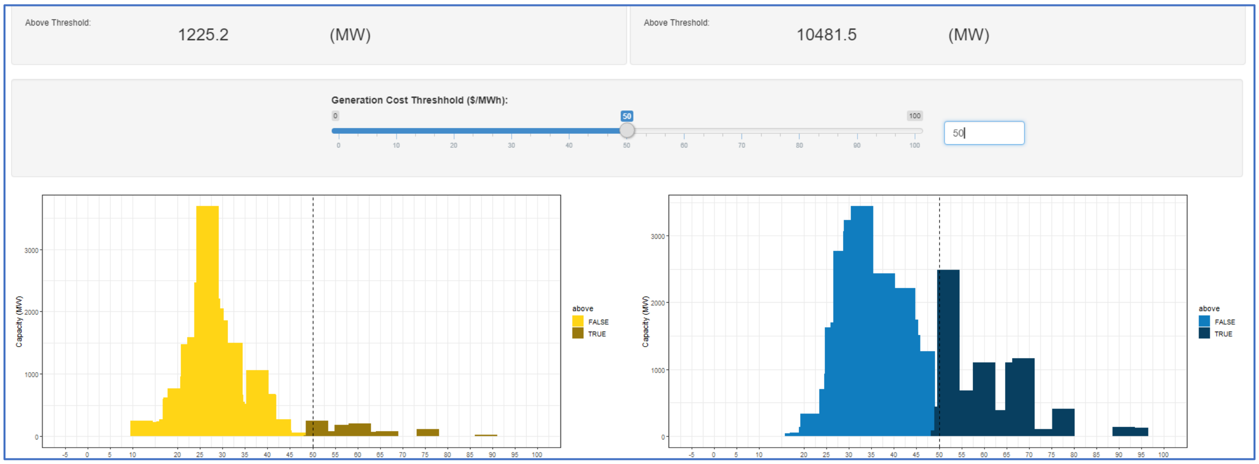

Figure 5-1. Market opportunities for Brayton systems where LACE of older plants exceeds the LCOE of new Brayton systems.

The screening tool also allows for identification of specific plants that meet the screening criteria, as shown with the next two examples.

5.1.2. Example 2: Identifying remote power applications.

For many remote areas in Alaska, electricity can cost in excess of 50 cents/kWh. These remote locations include both civilian and military installations, where resiliency and energy security may be more important than cost. While the military installations could be a potential market for Brayton systems, the screening tool can only identify civilian opportunities at this point.[5] Many of the highest cost units run on fuel-oil.

This example shows all operating oil-fired units in Alaska smaller than 20 MWe, with capacity factors less than 30%, and operating costs (incremental capital, fuel, and other O&M) above 20 cents/kWh, Figure 5-2. The tool shows there are five operating plants in Alaska meeting those criteria. For each location, the tool shows the estimated operating cost. For example, the NSB Atqasuk location on the North Slope, has an estimated operating cost of 22.3 cents/kWh.

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[5] Specifically, Senator Lisa Murkowski (Chair, Senate Energy and Natural Resources Committee) secured support for determining the feasibility of secure power generation and distribution on remote military facilities in 2018.

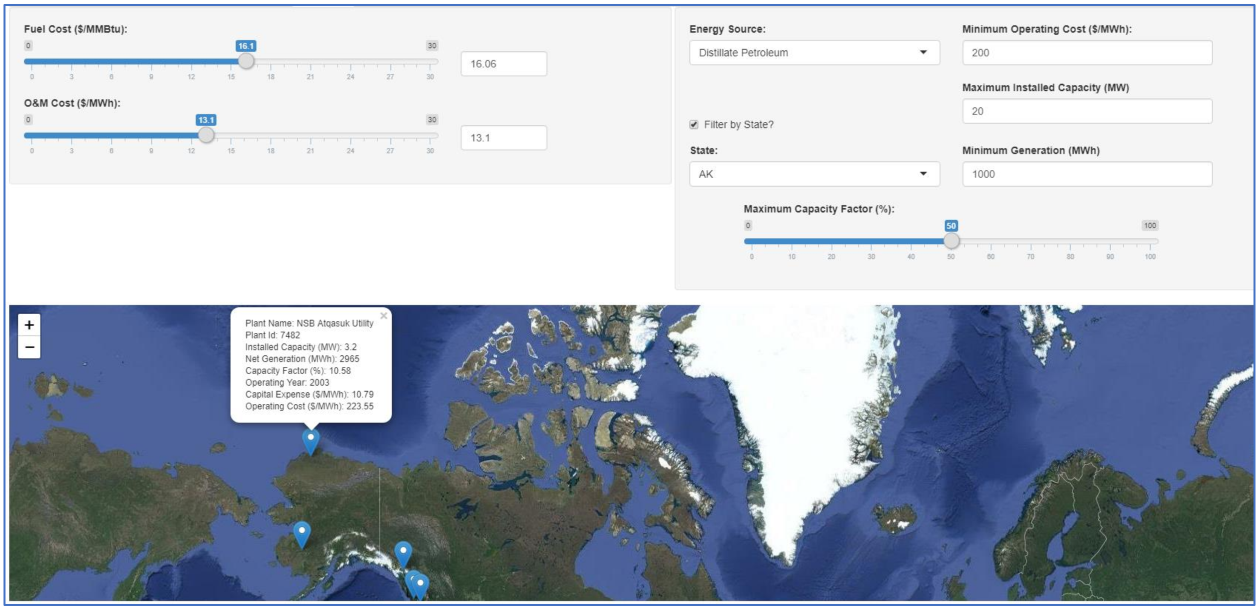

Figure 5-2. Identifying small-scale remote opportunities in Alaska

This example is meant to show the capabilities of the screening tool only. There are many reasons why this location might not be suitable for the installation of a Brayton system, including fuel source, access, and low capacity factor (just 4.76% in 2018). The next example illustrates identification of more likely options.

5.1.3. Example 3: Identifying small, expensive coal-fired plants across the United States

This example shows use of the tool to identify specific opportunities within the U.S. where the estimated operating cost for older plants is greater than the estimated LCOE for new Brayton systems. Specifically, this example identifies all coal-fired plants in the U.S. operating in 2018 that are smaller than 50 MWe and have estimated operating costs greater than 5 cents/kWh, Figure 5-3. The highlighted plant, the Manitowoc Power Plant, in Manitowoc, Wisconsin has an installed capacity of 44 MW and opened in 1955. The estimated operating costs in 2018 were $.102/kWh and had a very low capacity factor (4.76%).

Figure 5-3. Small coal-fired plants with operating cost above $0.05/kWh.

5.2. The Energy Institute at University of Texas at Austin Screening Tool

The Energy Institute at the University of Texas at Austin has developed an interactive tool that allows one to visually identify the lowest cost power option for new power plants (Energy Institute, 2018b). Unlike the screening tool discussed above, their tool does not focus on the estimated operating costs of existing plants that might be suitable for replacement. The Energy Institute's tool uses the LCOE framework to determine the least cost option for new facilities in the U.S. Perhaps most useful for this market analysis, this tool includes the option to consider "availability zones" derived from work at Oak Ridge National LaboratoryAvailability zones for new generating plants (Energy Institute, 2018a). These zones consider factors such as regulations, water availability, and access to fuel sources, such as natural gas pipelines. For example, Figure 5-4 shows the regions suitable for siting various types of new generating facilities, including renewable options, nuclear, coal, and natural gas (combined cycle or combustion turbine). Digging into the specific reasons why certain areas aren't suitable for NGCC, for example, can provide additional insight into possible opportunities for sCO_2 Brayton systems. The tool also offers the option of including externality costs, including mercury, PM 2.5, SOx, NOx, and CO_2. The tool does not consider the intermittency of renewables as a possible hurdle, but rather just seeks the lowest LCOE at the county level.

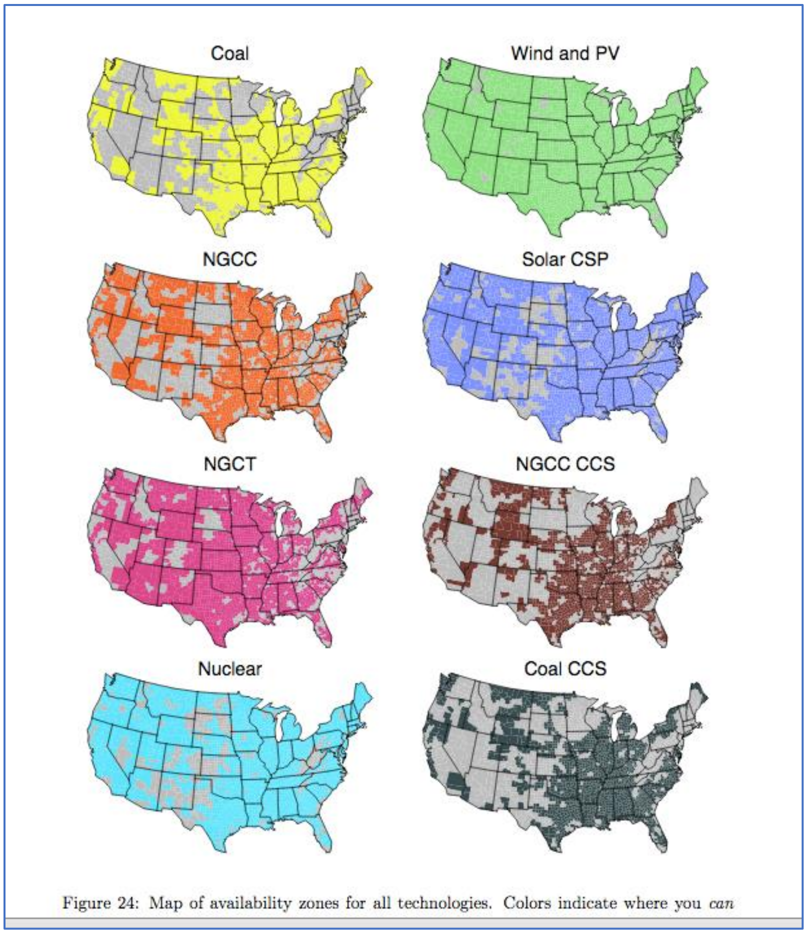

Figure 5-4. Availability zones for new generating plants (Energy Institute, 2018a).

The following three examples show how this tool can be used to screen for the lowest-cost generating options at the county level. The first example assumes no consideration of externalities or of siting ability. The second example includes consideration of siting ability. The final example includes full costing of externalities, including a $62/tCO_2$ cost.

5.2.1. Example 1: Least cost screening for new technologies

This first example considers the least cost generating technology for each county. It does not consider either siting restrictions or externalities. For the base case assumptions used by the Energy Institute, the lowest cost option in most of the eastern and western portions of the United States is NGCC. New York is a clear exception to this result; this tool shows that onshore wind is the low-cost option for much of NY. For much of the Midwest, onshore wind is the low-cost option. Utility scale solar PV is the low-cost option in parts of the upper Midwest and the Southwest.

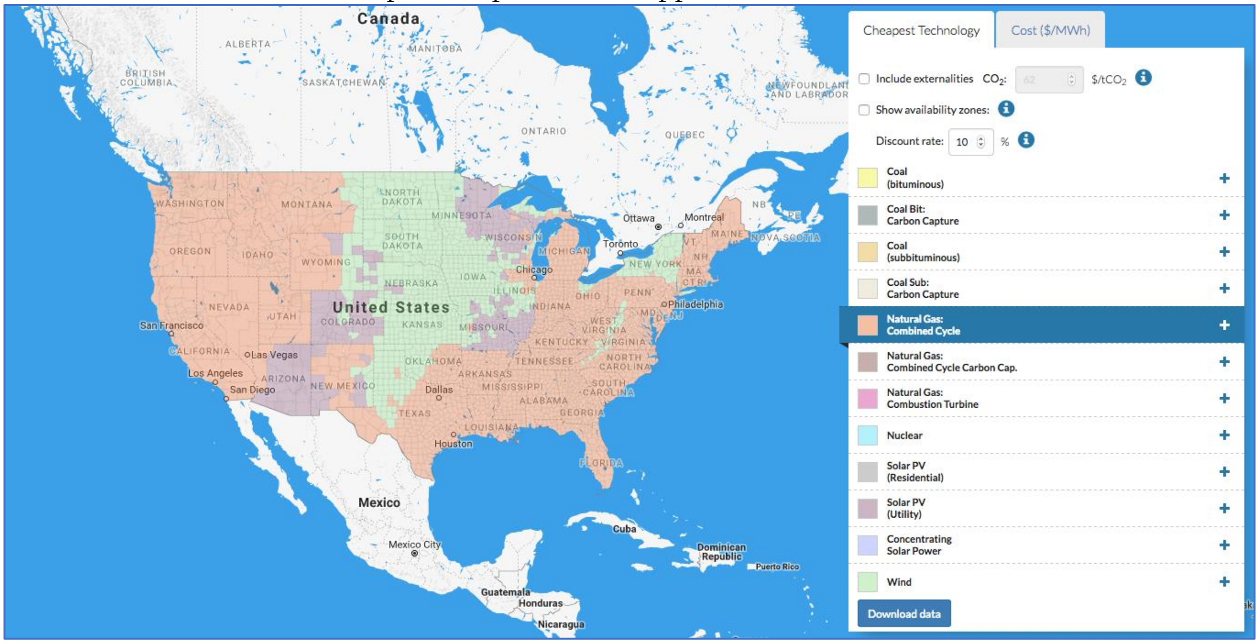

Figure 5-5. Least cost options by county (Energy Institute, 2018b).

5.2.2. Example 2: Least cost considering the ability to site

The second example considers the ability to site plants, based on the work done by Argonne, Figure 5-4. The main difference with the first scenario is that solar PV captures a large part of the NGCC market share. Siting considerations include access to fuel (natural gas pipelines), regulatory limits (can't site on federal lands), and lack of available water for cooling.

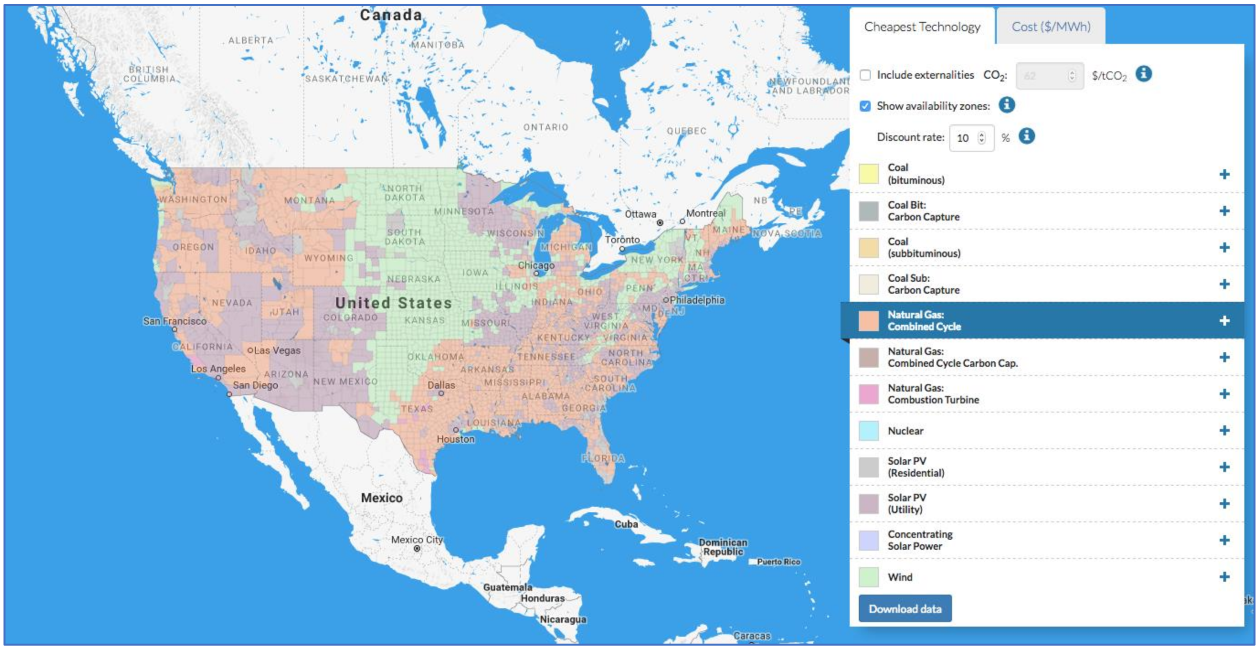

Figure 5-6. Least cost options that consider the ability to site (Energy Institute, 2018b).

5.2.3. *Example 3: Least cost considering the ability to site and externality costs*

This third example adds in the estimated costs of several pollutants, including a $62/ton carbon tax. These added costs further limit the potential market for NGCC to just areas in the Northwest and along the north east coastline.

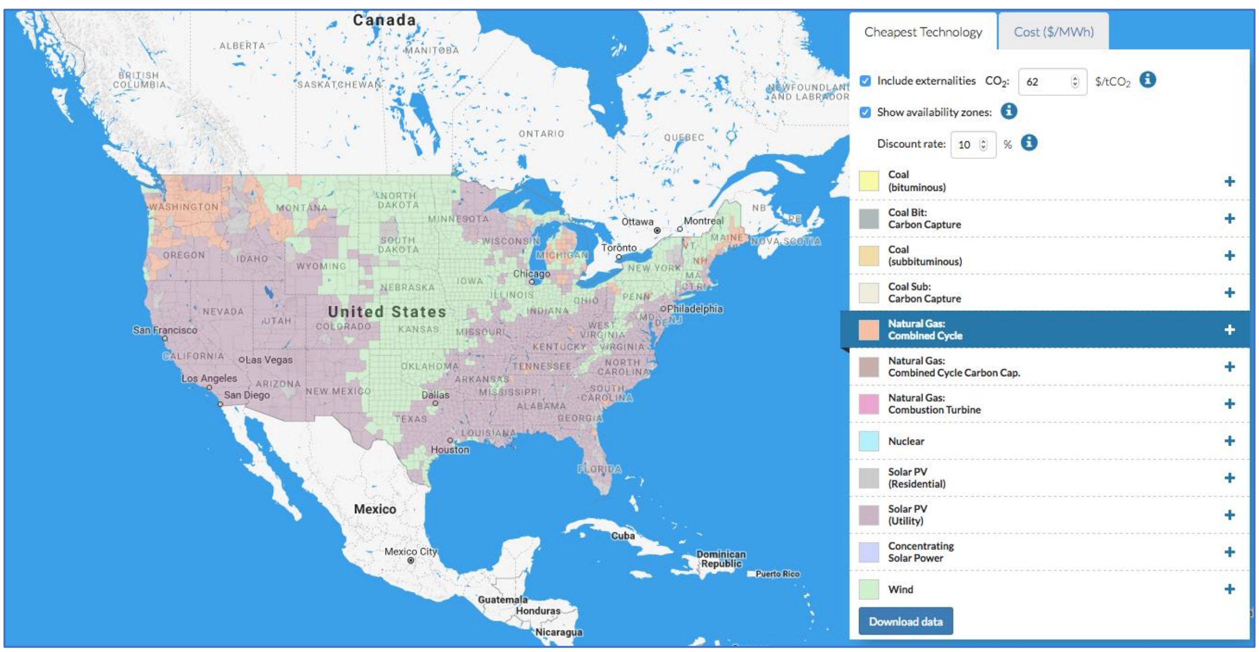

Figure 5-7. Least cost options that consider the ability to site and full externalities (Energy Institute, 2018b)

5.2.4. *Applicability of the Tool for Assessing sCO_2 Brayton System Market Potential*

While the examples above show the potential market opportunities for systems other than sCO_2 Brayton, the tool can also be used to show the estimated LCOE by county, which allows one to identify possible opportunities for sCO_2 systems. For example, Figure 5-8 shows the LCOE by county for example 2 above (includes siting restrictions but not externalities). This shows many areas in the upper Midwest and Mid-Atlantic with estimated LCOEs above $0.10/kWh. The results show pockets in the upper half of the country where projected LCOEs are greater than $0.15/kWh. Of course, the variation in LCOEs for any technology will vary widely by region as they reflect differences in land and labor costs. Each of these sites could be further analyzed to identify opportunities for sCO_2 Brayton systems.

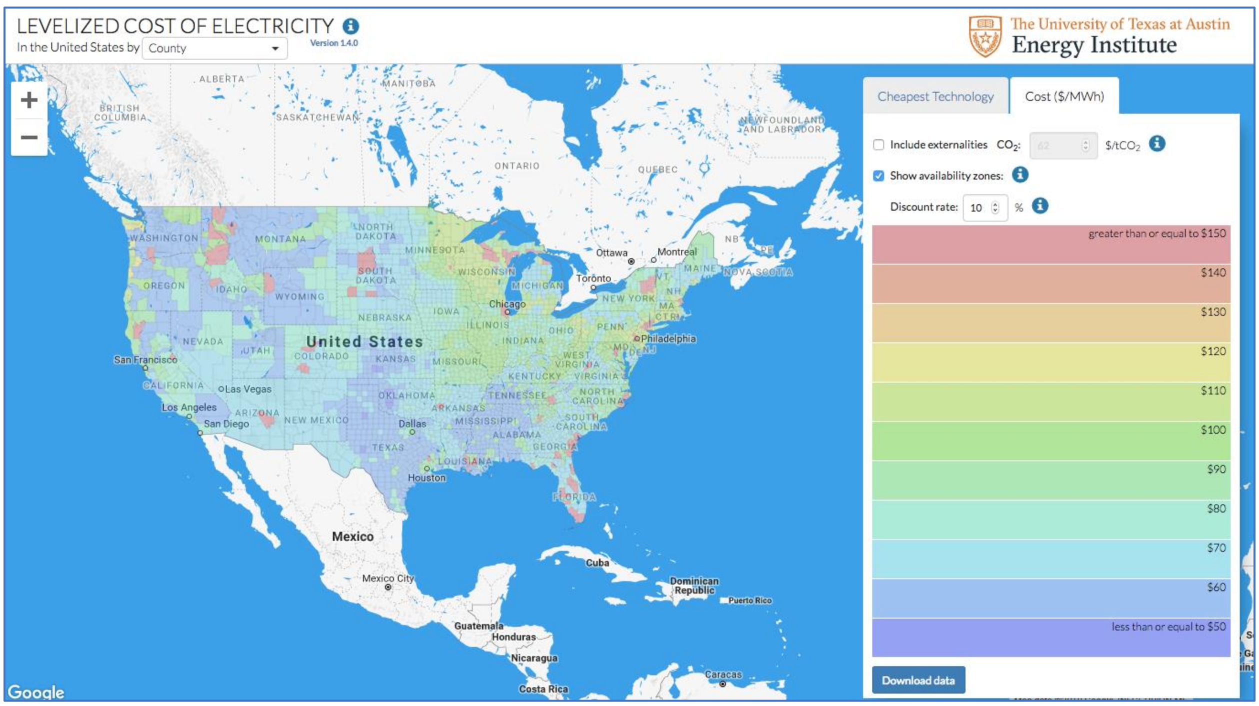

Figure 5-8. Estimated lowest cost LCOE by county for example that includes siting constraints but not externalities (Energy Institute, 2018b).

5.3. Next Steps towards Commercialization

The updated LCOE estimates for sCO_2 systems presented here indicate that Brayton systems can compete directly for the same markets as new NGCC plants, including as a replacement for older, inefficient plants with high operating costs. The screening tool developed for this analysis provides a way to measure the potential market size and specific opportunities. The Energy Institute's LCOE tool provides additional insight into specific regions to target. The largest hurdle, however, is that sCO_2 Brayton systems are still in the fairly early stages of development. As industry representatives repeatedly note, commercial customers are not going to be willing to invest in this technology until it is vetted for commercial viability. For many, this translates into demonstrating that the system can operate for several thousand hours (5,000 – 10,000 hours). Others note that the systems must not only be able to run for long periods of time but must demonstrate the ability to rapidly cycle to meet load demands to allow for integration with intermittent resources, which are projected to continue to gain market share.

Alleviating these concerns will require multiple pilot projects of differing configurations and operating conditions. The Supercritical Transformational Electric Power (STEP) 10 MWe pilot project in San Antonio is a good first step. Sandia's partnership with Peregrine Turbine Technologies (PTT) on their proprietary technology will also demonstrate the potential viability. As discussed in Sandia's sCO2 Brayton Roadmap (Mendez and Rochau, 2018), this partnership with PTT supports commercial readiness for a variety of products and applications. Further, the roadmap lays out a series of projects aimed at achieving the milestones necessary before commercialization of this technology is an option. In particular, the proposed Kirtland First initiative, which would see the coupling of a 1 MWe sCO_2 power cycle, using PTT technologies, to a SMART microgrid on Kirtland Air Force Base with renewables integration, would effectively demonstrate the commercial relevance of this technology.[6]

Perhaps equally important is an ongoing effort to truly understand potential customer needs. Claiming that this, or any technology, is superior because of system efficiency, for example, misses the mark. From talking and listening to industry representatives, we know that customers don't necessarily want higher efficiency; they want low-cost, reliable systems that can quickly ramp up or down to integrate with systems with increasing intermittent resources.

The process of conducting effective customer discovery is well documented[7]. Many new products fail because they fail to answer the most basic question: What problem does this technological solution solve and for whom? As Bizari (2019) notes, many new ideas fail because the developers are "looking inward instead of outward."

To date, this project has relied largely on a form of "indirect customer discovery", which relies on analyzing market reports and industry news and participating in relevant conferences and workshops. However, at some point, true market analysis requires moving beyond these methods and conducting interviews with a wide range of potential customers. This type of customer discovery will be key to determining which markets might ultimately want sCO_2 Brayton systems. Furthermore, effective customer discovery does not start with presenting the new technology, but rather requires conversations with a wide range of representative industry colleagues about the problems they are trying to solve. For example, we know that renewable integration is a problem many system operators are facing. We also know they are worried about such things as cost, availability of water, meeting stricter pollution requirements, etc.

Going deeper into market analysis requires taking this next step of customer discovery. The expected outcome will be a list of problems the industry currently faces. The goal for the Brayton team then will be to explain and then demonstrate how and when sCO_2 technologies can solve these problems at an affordable cost. This report demonstrates that the technology will likely be economically competitive; the next step is to show that this technology can solve problems that the other technologies can't.

[6] See Mendez and Rochau (2018) for a more detailed roadmap towards commercialization.
[7] See for example Osterwalder, 2014.

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