May 21, 2022
Via Email

Jordan Munson
Wisconsin Department of Natural Resources
Bureau of Air Management
101 S. Webster St., Box 7921
Madison, WI 53707-7921

Re: Nemadji Trail Energy Center
Proposed Construction Permit (21-JAM-212)

Dear Mr. Munson,

Please accept these comments on behalf of the Sierra Club[1] regarding Wisconsin's Department of Natural Resources ("WDNR")'s proposed determination that the Nemadji Trail Energy Center's applications for air pollution control construction and operation permits (Permits No. 21-JAM-212 and 816127840, respectively) meet state and federal air pollution control requirements and approval of the draft permits. Nemadji Trail Energy Center (NTEC) proposes to build and operate a 625-MW combined-cycle methane-burning power plant. We urge WDNR not to approve the proposed permit unless and until it has addressed the serious flaws in its PSD modeling, BACT Analysis, and limits in the Draft Permit identified below.

[1] Sierra Club is the largest nonprofit grassroots environmental organization in the United States, with more than 19,000 members in Wisconsin. Sierra Club is dedicated to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. In keeping with our mission, Sierra Club seeks to accelerate climate mitigation measures, and ensure that those measures both achieve their stated outcomes and reduce harm to communities impacted by historic and contemporary environmental injustices.

As an initial matter, WDNR should not grant *any* permit until it has conducted PSD modeling that incorporates 2021 background emission levels. WDNR's PSD analysis shows a total impact of the proposed facility at 97.4% of the one-hour NAAQS for nitrogen dioxide, perilously close to moving Superior into nonattainment. This modeling was conducted with background concentrations from 2018-20—*i.e.* incorporating artificially low nitrogen oxide concentrations due to the COVID-19 global pandemic—and excluding emissions from the 1,490-hp diesel generator (which the permit would allow to operate up to 500 hours per year). WDNR has not shown that with the full facility emissions included and more realistic background values for the years in which the facility is intended to operate, nitrogen dioxide levels will remain under the 1-hour NAAQS, and thus cannot issue a permit.

If WDNR does grant a permit for the construction of the NTEC facility, that permit must adequately address the harmful pollutants produced by the use of methane for electricity generation. The proposed permit does not. The Draft Permit (1) lacks annual (or rolling 12-month) limits for total emissions of criteria pollutants and greenhouse gases; (2) adopts unjustifiably high limits for both the total number of hours for start-up and shutdown and the emission rates of nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compounds (VOCs) during start-up and shutdown; (3) incorporates (without justification, analysis, or explanation) purported Best Achievable Control Technologies ("BACTs") significantly in excess of those incorporated into permits for other combined cycle facilities for greenhouse gases, particulate matter, and sulfuric acid mist; (4) improperly rejects low-leaking valves as BACT for fugitive emissions; (5) incorporates unreasonably long averaging periods for CO and VOC limits; (6) fails to require adequate monitoring for sulfur dioxide and particulate matter emissions; (7) would allow excessive operation of putatively emergency equipment and use of diesel fuel oil; and (8) fails to consider alternatives to sulfur hexafluoride in 19kv circuit breakers. WDNR must address each of these issues before it can lawfully issue a permit to construct to NTEC.

In addition to the objections described below, Sierra Club is concerned about the permitting process. WDNR appears to have reissued a draft permit that is substantively identical to 18-MMC-168, which was issued on September 1, 2020—at least as to the BACT limits associated with the combined-cycle turbine. As NTEC acknowledges in its Application, the purpose of resubmission was to avoid expiration of the prior permit before construction of the proposed facility is complete. Under these circumstances, WDNR and NTEC are obligated to rigorously reevaluate the state of power plant technology. As the Environmental Appeals Board has observed:

> The need to base the permit determination on current information is fundamental to any determination of "best *available* control technology," for old technologies are constantly being replaced by newer and more advanced ones…whenever the original permit application is being updated at the behest of the permit applicant, it is only fair that the

applicant's new information be balanced with other contemporaneous information relevant to the BACT determination.[2]

NTEC claims to have updated its BACT analysis for each component and criteria pollutant in its Application. However, and as described in greater detail below, neither NTEC nor WDNR appears to have incorporated certain permits issued in 2020 or 2021 into its analysis which would support the imposition of lower limits in some cases. These lower limits include those set for particulate matter at the 744-MW combined cycle unit at Plant Barry in Alabama (RBLC ID[3] AL-0328, approved in November 2020) and for sulfuric acid mist limit at the 1275-MW Mountain State Clean Energy facility in West Virginia (RBLC ID WV-0033, approved in January 2022). Both NTEC and WDNR must conduct a BACT analysis that accounts for technological developments (most significantly, relating to carbon capture and sequestration) since the prior permit's issuance. Failure to do so effectively nullifies the time limit for initiating construction set by Wisconsin statute and is contrary to law.[4]

A. Background

1. The NTEC facility threatens to further burden already overburdened communities.

The proposed facility will be located in close proximity to environmental justice communities, both with respect to current air pollution burdens and as to economic vulnerability. According to EPA's EJScreen, Superior already includes multiple census tracts that are above the 90th percentile for diesel particulate matter emissions and above the 80th percentile for air toxics cancer risk.[5] Large sections of Duluth, just across the St. Louis River from the proposed site, are in the 95th percentile or above for percentage of the population that is low-income.

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[2] In the Matter of: Columbia Gulf Transmission Company Id No. 105-0640-0021, Applicant, 1990 WL 324099, at *2.

[3] RACT/BACT/LAER Clearinghouse ID No. Details for facilities identified by RBLC are available by searching at https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en.

[4] *See* Wisc. Stat. §285.66(a); *see also* NR 405.08(4) ("For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.")

[5] See https://ejscreen.epa.gov/mapper/

These communities already suffer from especially high pollution and corresponding health risk, and are more likely to lack access to regular health care, and the proposed facility (which NTEC projects will emit up to 269 tons of nitrogen oxides, 2,003 tons of carbon monoxide, 167 tons of fine particulate matter, and 43 tons of sulfur dioxide mist each year[6]) will cause them further disproportionate harm.

2. Accounting for upstream emissions, the climate impacts of a natural gas plant like NTEC will rival those of a coal-burning facility.

While power plant developers and utilities often tout "natural gas"—methane—as a climate-friendly alternative to coal, the climate impacts of "natural" gas are equally, if not more, severe when the full life-cycle of the fuel is considered. Although gas produces fewer carbon emissions than coal when burned, the production, processing, storage, transmission, and distribution of gas leaks into the atmosphere immense amounts of methane, which is a much more destructive pollutant for our climate than carbon dioxide. When accounting for methane leaks, gas has climate impacts that rival those of coal.[7]

While carbon dioxide remains in the atmosphere for longer than methane, methane has a much stronger climate warming effect. When methane is leaked directly into the atmosphere, it is 36 times more powerful at trapping heat than carbon dioxide when its impact is averaged over a 100-year period. Over a 20-year period, methane's heat-trapping impact is 87 times more powerful than that of carbon dioxide.[8] The proposed project would be an significant new source of climate-warming pollution. Including the upstream leakage of methane in the production and transportation of gas to the plant (which the permit does not account for), the plant would be responsible for an estimated 4.42 million metric tons of carbon-dioxide equivalent greenhouse gases per year.[9]

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[6] Application at 1-3.

[7] There is a large volume of academic literature and other research on this topic. *See, e.g.*, Robert W. Howarth, A bridge to nowhere: methane emissions and the greenhouse gas footprint of natural gas, Energy Science & Engineering (April 22, 2014), available online at http://www.research.howarthlab.org/publications/Howarth_2014_ESE_methane_emissions.pdf; Environmental Defense Fund, Methane Research: The 16 Study Series, available online at http://www.edf.org/sites/default/files/methane_studies_fact_sheet.pdf.

[8] EPA, Understanding Global Warming Potentials, available online at https://www.epa.gov/ghgemissions/understanding-global-warming-potentials.

[9] See Exhibit A, attached, documenting calculation of 1.94 million metric tons in upstream emissions.

Climate impacts are only some of the detrimental effects of reliance on methane for energy production. Two-thirds of all gas produced in the U.S. is fracked.[10] Fracking involves the high-pressure injection of "fracking fluid" into a wellbore to create cracks in the deep-rock formations through which natural gas will flow more freely. Along with the air pollution impacts in the communities where gas is burned, fracking directly impacts communities living on the frontlines where fracking occurs. The harmful impacts include (but are not limited to): contaminated groundwater from the chemicals contained in fracking fluid; earthquakes from fracking; and explosions due to leaking pipelines and storage facilities.

B. The permit application must be denied because WDNR and NTEC have not sufficiently demonstrated that the proposed facility will not cause an exceedance of the NAAQS for NOx.

1. The PSD modeling incorporates artificially low background concentrations by relying on 2020 data.

Under the Clean Air Act, a state permitting authority cannot issue a permit to a major stationary source unless it "will not cause, or contribute to, air pollution in excess of any" NAAQS.[11] WDNR's analysis showed that the total impact of the proposed facility (including background) will be 183.1 μ/m^3 for NO_2 over the 1-hour averaging period, or 97.4% of NAAQS.[12] The background data incorporated into WDNR's modeling to arrive at this result was derived from 2018-2020 at a monitoring station in Milwaukee that is used for all "high" concentration areas in Wisconsin, including Superior.[13]

During 2020, COVID-related restrictions drastically reduced emissions, including that of nitrogen dioxide. A NASA model indicated global concentrations may have been reduced by 20%.[14] Given the marginal attainment under WDNR's modeling, it is highly likely that, with

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[10] U.S. Energy Information Agency, Today in Energy: 'Hydraulically fractured wells provide two-thirds of U.S. natural gas production' (May 5, 2016).

[11] 42 U.S.C. §7475(a)(3).

[12] Preliminary Determination at 104.

[13] WDNR, Guidance Memorandum on Background Concentrations (October 15, 2021). Available online at https://dnr.wisconsin.gov/sites/default/files/topic/AirPermits/2021BackgroundConcentrations.pdf

[14] *See* Lara Streiff, "NASA Model Reveals How Much COVID-related Pollution Levels Deviated from the Norm" (Nov. 17, 202), at https://www.nasa.gov/feature/goddard/2020/nasa-model-reveals-how-much-covid-related-pollution-levels-deviated-from-the-norm.

background emissions restored to typical levels, the contribution of the proposed facility will cause nitrogen dioxide levels in Superior to exceed the NAAQS. WDNR cannot issue the permit unless it demonstrates, through new modeling that incorporates 2021 NO_2 levels, that the proposed facility will not cause exceedances in Superior, an area WDNR already acknowledges is highly burdened by nitrogen dioxide pollution.

2. WDNR must re-do its PSD analysis with a reasonable estimate of emissions from the 1,490-horsepower diesel generator and associated fire pump.

WDNR improperly excluded emission units P06 and P07 from its air quality review. The Preliminary Determination asserts that, because P07 (the 1,490 HP Emergency Diesel Generator) and P06 (the 282 HP Emergency Diesel Fire Pump) "do not have a set operating schedule" and generally operate "outside of the facilities' control," their emissions were not included as part of the dispersion modeling.[15] But the Draft Permit does not limit either stack to emergency situations. Rather, the two units can be operated up to 500 hours per consecutive 12-month period.[16] Nor does the Draft Permit set a limit on the total emissions from either unit, instead relying on a grams-per-horsepower-hour limit. WDNR must either impose absolute limits on emissions from these units (as discussed below), either in hours per year or total emissions that are consistent with their designation as "emergency," or incorporate the maximally permitted emissions into a new PSD analysis. Analysis with the "emergency" diesel operation is particularly important because, as discussed above, even under NTEC's own analysis the proposed facility is likely to bring NO_2 levels very close to the NAAQS.

C. WDNR must include annual limits on greenhouse gas and other emissions in any approved permit.

The Draft Permit lacks any annual limits on emissions. Before issuing a final permit, WDNR must impose meaningful annual limits on total emissions of criteria pollutants that ensure not just best combustion practices on an hourly basis, but operating protocols with respect to ramping and load that minimize the air pollution associated with the proposed project's electricity generation. Moreover, WDNR must provide for additional public comment on these limits, so that local residents and interested organizations can compare the proposed limits with similar facilities and raise any concerns about discrepancies or unwarranted leniency.

Not only does the Draft Permit lack annual emission limits, Sierra Club was unable to find any information in NTEC's Application or the Preliminary Determination as to the total generation or fuel usage anticipated at the proposed facility that would allow a reasonable

[15] Preliminary Determination at 100.

[16] Draft Permit at 69, 76.

determination of what those emissions might be. Although NTEC has proposed, and WDNR adopted, an annual limit on *diesel fuel oil*,[17] no analogous limit (or even estimate) of natural gas usage can be found in the materials. NTEC does not describe the anticipated capacity factor for the facility or propose a limit on fuel consumption on a 12-month rolling basis. For purposes of PSD modeling, NTEC does estimate a total amount of emissions for the facility (which in theory allows one to infer the total fuel consumption, based on permitted emission limits for carbon dioxide per MWh). However, this total (2,738,318 tons per year of carbon dioxide equivalents for the primary turbine) is well in excess of what would be anticipated even for non-stop full capacity operation of a 625-MW gas power plant.

At the same time, NTEC also proposes a limit of 1,525 hours of start-up and shutdown time. Not only is this limit unjustifiably high (as it would allow for considerably higher emissions on an hourly basis more than 15% of each year), it is inconsistent with NTEC's Application and the Preliminary Determination, which assume full operation 8,760 hours of the year.

NTEC must provide additional information sufficient for WDNR and the public to understand the anticipated capacity factor and use case of the proposed facility. WDNR should not issue a permit without consecutive-12-month emission limits for greenhouse gases and other pollutants.

D. The Draft Permit's secondary limits for start-up and shutdown are unreasonable and unjustified.

The Draft Permit would allow the proposed facility to emit at exceptionally high levels during start-up and shutdown and—compounding this error—operate in start-up or shutdown mode to a far greater extent than is permitted for other combined cycle plants.

The allotted emissions for each startup/shutdown cycle are well above secondary or alternative BACT limits for comparable plants. Specifically, the Draft Permit would allow twice as much carbon monoxide emissions per startup than allowed under the Fox Energy Center's current Title V permit (Permit No. 4451159110-P2), which includes two 183-MW combined cycle turbines, and *24 times* the amount of hourly carbon monoxide emissions associated with warm startup at CPV Three Rivers in Illinois (a 1,250-MW CCGT facility). As the chart below shows, DNR's proposed secondary limits for startup at the NTEC facility are far outside what both Wisconsin DNR and Illinois EPA have previously determined to be BACT for CCGT plants. These secondary limits are unacceptably high and must be dramatically lowered in the final permit.

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[17] Draft Permit at 8.

Pollutant	Fox Energy Center	Jackson Generating (RBLC ID IL-0130)[18]	CPV Three Rivers (RBLC ID IL-0129)	NTEC Draft
NOx	650 lb/hot start 385 lb/warm start 200 lb/cold start	180.3 lb/hr	228 lb/hr	335 lb/cold start (2 hours) 233 lb/warm start (80 min) 111 lb/hot start (45 min)
CO	4825 lb/cold start 810 lb/warm start 530 lb/hot start	483.5 lb/hr	204 lb/hr 1,522 lb/hr during extended startup	11,066 lb/cold start 6,495 lb/warm start 779 lb/hot start
VOC	67 lb/ cold start 38 lb/warm start 23 lb/hot start	94.1 lb/hr	12.6 lb/hr 150 lb/hr during extended startup	950 lb/cold start 558 lb/warm start 67 lb/hot start

The only control technology identified for start-up and shutdown is "limiting start-up and shutdown time."[19] But the proposed limits on total start-up and shutdown time are significantly *greater* than that of other commercially available turbines or permitted combined cycle plants. First, NTEC has not selected a turbine that minimizes start-up time. The Application estimates a cold start period of two hours, a warm start period of 80 minutes, and a cold start period of 45 minutes, and projects 900 hot starts, 150 warm starts, and 50 cold starts per year—that is, approximately three cycles per day. Other turbines (*e.g.* the Siemens SCC6-9000HL) have significantly shorter start-up or shut-down times (an hour for the SCC6-9000HL versus the two hours for cold start-up and 80 minutes for warm start-up specified by NTEC). Siemens represents that NTEC's chosen turbine, the SGT6-8000H, "can achieve combined cycle base load within 30 min[] for hot starts"—fifteen minutes less per start than what NTEC estimates.

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[18] Jackson Generating Station's Permit also includes lower alternative limits (33.9 lb/hr NOx, 20.6 lb/hr CO, and 8.3 lb/hr VOM) for periods of "very low load," *i.e.* at a level "far below the level at which the turbine would typically be dispatched by PJM" but during which operation is maintained to avoid shutdown. It may be that these limits are the more appropriate comparator for the "hot/fast start" described in the Draft Permit and associated documents.

[19] Preliminary Determination at 57.

Reducing the time for hot starts would reduce the total amount of time cycling by 225 hours per year based on the 900 hot-starts-per-year estimate.[20]

Second, the Draft Permit does not actually apply this control technology of "limiting start-up and shutdown time" to the turbine's operation. The permit does not contain any limits on how long each startup or shutdown will last or any explanation as to why the total hours per year for start-up and shutdown is the minimum achievable time consistent with the purpose of the proposed project. NTEC must explain why their turbine selection minimizes emissions from start-up and shutdown or otherwise justify the choice of turbine as BACT for startup and shutdown.

The permit does contain a limit on total start-up/shutdown time on a rolling 12-month basis, but this limit is unreasonably high. The Preliminary Determination states that, "combustion turbine emissions are based on 1,525 hours per each 12 consecutive calendar months for start-up and shutdown, combined, for natural gas operation."[21] This does not include an *additional* 42 start-ups and shutdowns per each 12 consecutive calendar months on diesel fuel oil.[22] This limit is not BACT. Michigan limited the start-up/shutdown time for the Indeck-Niles facility (RBLC ID MI-0445) (which includes combined cycle turbines and duct burners with a throughput of 4,161 MMBtu/h) to 500 hours per 12-month rolling period. Illinois EPA limited Jackson Generating Station (RBLC ID IL-0130), a natural gas-fired 1-GW CCGT with duct burners, to 560 hours per year. Under the permit as drafted, NTEC could operate the proposed facility in start-up or shutdown mode, with emissions up to ten times that of its normal operation, 17% of the year.

WDNR must reduce the secondary BACT for NOx, CO, and VOC. In addition, because startup and shutdown have inherently higher associated higher emissions in a combined cycle methane plant (even with reasonable secondary limits), WDNR should reduce the total allowable hours of startup/shutdown time to the fewest number of hours a on a rolling 12-month basis necessary to the proposed project and explain the basis of that determination, and no more than 500 hours per year.

Finally, WDNR must require NTEC to report *actual* emissions during the start-up and shutdown periods for all criteria pollutants, rather than relying on hypothetical emission rates for

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[20] *See* https://www.siemens-energy.com/global/en/offerings/power-generation/gas-turbines/sgt6-8000h.html.

[21] Preliminary Determination at 12-13.

[22] *Id.* at 13. Allowing 42 cycles on diesel fuel oil is also excessive given diesel fuel oil's higher emission levels and purported use as an emergency fuel; *see discussion in* Section G below.

some or all criteria pollutants. Indeed, as drafted, the Permit could be construed allow NTEC to report emissions based on assumed rates even for those criteria that NTEC is otherwise required to conduct continuous emissions monitoring. [23] Allowing NTEC to report "assum[ed] emissions" for start-up and shutdown events obviates the entire purpose of the permit, which is to ensure *actual* emissions stay within those limits.

E. NTEC's and WDNR's BACT analyses are flawed and lead to unjustifiably high limits for multiple criteria pollutants.

"BACT determinations are one of the most critical elements in the PSD permitting process, must reflect the considered judgment on the part of the permit issuer, and must be well documented in the administrative record."[24] Specifically, "when a technology has been considered a 'potentially available control technology' at otherwise seemingly similar facilities in previous permitting actions," the applicant or permitting authority must proffer "some explanation as to why the previously 'potentially available control technology' is no longer potentially available at the latest facility."[25] In other words, "the existence of a similar facility with a lower emissions level creates an obligation for the [permit applicant and state agency] to consider or document whether that same emissions limit can be achieved at [the] proposed facility."[26]

WDNR appears to have adopted NTEC's BACT analysis wholesale. Although the Preliminary Determination nominally conducts a "top-down" analysis (although that analysis is lacking with respect to at least greenhouse gas emissions and fugitive emissions, as described below), WDNR does not explain the basis for its numerical limits, identify comparator combined cycle units, or explain why the proposed BACT significantly exceeds emission limits determined to be BACT at those other facilities. As a result, the proposed BACT limits are well in excess of what other state regulators have found are reasonable to impose on similar combined-cycle facilities. WDNR cannot lawfully approve the Draft Permit without considering and documenting whether NTEC can achieve the same limits. Moreover, WDNR's BACT analysis for greenhouse gases fails to adequately consider concentrated solar or carbon capture

[23] *See* Draft Permit at 18 ("these emissions shall be calculated based on CEMS data and/or assuming emission rates for each pollutant shown in I.A.8.a. on the following page.")

[24] *In re: Mississippi Lime Company*, 15 E.A.D. 349, 2011 WL 3557194 at *11 (EAB 2011) (citing decisions).

[25] *In re Desert Rock Energy Company*, 14 E.A.D. 484, 2009 WL 5326323 at *39 (EPA 2009).

[26] *In re Indeck-Elwood, LLC*, 13 E.A.D. 126, 2006 WL 3073109, *37 (EPA 2006).

technologies, both of which have been installed and operated successfully and thus cannot be automatically ruled out as infeasible control technologies.

1. **WDNR's BACT analysis and limit for greenhouse gas emissions are flawed for failure to adequately consider comparable combined cycle units, alternatives to duct burners, and carbon capture and sequestration technologies.**

    a. **The BACT limit for the proposed turbines should be 775 lb/MWh-gross.**

WDNR has proposed an emission rate of 850 lb/MWh (gross) for the Siemens SGT6-8000H turbines to be employed at this project. Neither NTEC nor WDNR offers any explanation for its selection of 850 lb/MWh as BACT. This figure is arbitrary, unsupported by any technical analysis, and wrong. A relatively straightforward analysis demonstrates that the BACT limit should be 75 lb/MWh lower than that proposed by NTEC and WDNR.

As an initial matter, there is a discrepancy between the project description and publicly available information about NTEC's chosen turbine. The Preliminary Determination identifies the turbine as a Siemens SGT6-8000H and the project capacity as 625 MW. But Siemens's website states that the gross plant power output for a SGT6-8000H in a combined cycle configuration is 472 MW.[27] WDNR and NTEC must address this discrepancy and confirm the accuracy of the proffered information about the selected turbine and project size.

Sierra Club was also unable to determine, based on the Application, Preliminary Determination, and Draft Permit, the megawatt capacity of the duct burner component of the selected combined-cycle configuration. This information is crucial to assess the appropriateness of the various BACT determinations and limits (which are in most cases higher during duct burner firing) and whether alternatives (such as concentrated solar thermal, described below) could replace the duct burner. NTEC and WDNR must provide this information explain why the increased emissions associated with duct burner firing are necessary to serve the project's purpose.

Based on the information provided, however, lower carbon dioxide emissions per megawatt-hour are achievable. The published heat rate for the most efficient combined cycle unit in 2021 is 5,625 kJ/kW,[28] which converts to 0.314 mt/MWh emission rate. Assuming the

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[27] *See* https://www.siemens-energy.com/global/en/offerings/power-generation/gas-turbines/sgt6-8000h.html.

[28] These are the most efficient units reported. *See* Gas Turbine World, 2021 GTW Handbook, Pequot Publishing, Volume 36.

project indeed involves the Siemens SGT6-8000H, that turbine rated at a slightly lower numeric value, but the vendor asserts that it 61.9% net plant efficiency (5,815 kJ/kW or 5,512 Btu/kWh).[29] This converts to a CO_2 emission rate of 0.325 mt/MWh. However, each of these ratings are for "new and clean" units operated at or near maximum load at standard temperature, humidity and atmospheric pressure conditions. They provide useful comparisons between units at the same conditions but are not intended as guaranteed "in use" performance estimates.

Emission data reported to EPA[30] by the operators of nine of the most efficient U.S. units at three plants,[31] were reviewed to determine their actual in-use performance. Each of these units had a claimed net efficiency of 60 percent and so, would have a "theoretical" emission rate of 0.335 mt/MWh.[32] The average emission rate for these nine units was 0.372 mt/MWh, an 11 percent increase over the claimed "theoretical" rate for these units.[33]

If one applies this conversion factor to the most efficient "theoretical" rate claimed in 2021, the likely "in use" emission rate for the best units commercially available in 2021 would be 0.348 mt/MWh (net)—767 lb/MWh (net) or 744 lb/MWh (gross). For the Siemens unit the rating converts to a projected "in use" emission rate of 0.361 mt/MWh—796 lb/MWh (net). Adding a compliance margin over and above these figures suggests a long-term BACT limit of 800 lb/MWh (net) or 775 lb/MWh (gross). Note that these "in use" emission rates include startup and shutdown emissions for the units studied. In short: Beginning with the vendor's stated efficiency of the proposed turbine, adjusting upward to account for actual "in use" performance (based on units with similar off-the-shelf efficiencies in operation) still produces a BACT limit of 75 lb/MWh below that proposed in the Draft Permit.

The proposed excessively lenient emission rate adversely affects the environment by (1) permitting periods of operation of the combustion turbines (CTs) without employing the heat recovery steam generators; (2) reducing the operator's incentive to properly operate and maintain

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[29] *See* https://www.siemens-energy.com/global/en/offerings/power-generation/gas-turbines/sgt6-8000h.html.

[30] As reported to EPA, CO_2 emissions are per "gross generation, which includes the electricity the plant uses to operate." A correction of 3 percent is commonly used to convert gross generation to net generation at CCGTs and was applied here.

[31] Cape Canaveral Power Station, Brunswick County Power Station and Warren County Power Station.

[32] Using the standard figure for the specific CO_2 emission rate of natural gas (55.82 kg/GJ) and the heat rate of a plant with 60 percent efficiency (6000 kJ/kW).

[33] The best performance reported was 0.360 mt/MWh.

the equipment; and (3) diminishing the technology-forcing aspect of BACT for future projects in Wisconsin and elsewhere.

Moreover, and notably, the analysis put forth in the Project Summary does not attempt to explain why the proposed project cannot achieve the BACT limits adopted in Michigan for two combined-cycle facilities, Indeck-Niles (802 lb/MWh) and DTE Electric Belle River (794 lb/MWh).[34] (These permitted plants have 1,000 MW and 1,100 MW nameplate capacity, respectively.) The permit and associated documents do not set forth any rolling 12-month limits on fuel consumption or carbon dioxide emissions, as discussed above. However, WDNR's modeling assumes full-time operation. Assuming a 90% capacity factor, reducing the BACT limit for the turbines to 794 lb/MWh rather than the proposed 850 lb/MWh would reduce emissions of greenhouse gases by approximately 149,000 short tons *per year*, or the equivalent emissions produced annually by 29,000 cars. This is hardly a negligible difference, and WDNR must either reduce the BACT for greenhouse gases to 794 lb/MWh or less or explain why the proposed project cannot achieve that limit within its stated parameters.

b. The proposed permit documents also do not fully examine alternatives, including co-located renewable energy, that would reduce the overall carbon intensity of the project while maintaining net power output.

The BACT analysis for greenhouse gases does not consider integrated renewables as a means of reducing emissions. EPA has highlighted the potential of integrating renewables into natural gas power plants as a means of reducing emissions in a recent draft white paper, *Available and Emerging Technologies or Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units*, attached to these comments as Exhibit B.[35] "An efficient and cost-effective renewable pairing for a combined cycle EGU has been demonstrated to be concentrated solar thermal, particularly in terms of the capital costs of the technology and the cost of carbon abatement (Alqahtani and Patino-Echeverri, 2016)."[36] EPA cites as one currently commercially operating example the Martin Next Generation Solar Energy Center in Indiantown,

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[34] The Project Summary describes this facility (RBLC ID/Permit No. MI-0435 as "DTE Electric Belle River," but DTE has renamed the facility the "Blue Water Energy Center." *See* https://empoweringmichigan.com/bluewater/.

[35] EPA Office of Air and Radiation, *Available and Emerging Technologies or Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units*. Prepared by the Sector Policies and Programs Division of the Office of Air Quality Planning and Standards (April 21, 2022) ("Exhibit B").

[36] Exhibit B at 32.

Florida, where a 75-MW concentrated parabolic solar thermal array creates auxiliary heat integrated into the pre- and post- combustion steam cycle and "reduces fuel consumption by 1.3 billion cubic feet per year,…reducing CO2 emissions by 2.75 million tons over 30 years."[37]

c. Recent developments call into question WDNR's determination that CCS is technically infeasible.

In rejecting carbon capture and sequestration (CCS) as BACT for greenhouse gas emissions, WDNR relies on more than decade-old guidance (EPA's March 2011 PSD and Title V Permitting Guidance for Greenhouse Gases), the assertion that "[l]ow" carbon dioxide levels are expected in the exhaust stream from a combined-cycle gas unit, and the fact that the Department is "not aware of any commercially available systems currently in place for this type of application and considers this to be an undemonstrated technology."[38] Elsewhere (and somewhat contradictorily), WDNR states that, "[n]o commercially available post-combustion CO_2 capture systems are known to have been installed at a large power plant *other than* pilot-scale demonstration projects."[39]

As an initial matter, the fact that prior installations were classified as "pilot" does not excuse WDNR from conducting an analysis of their feasibility for *this* proposed facility. A "control technology [that] has been installed and operated successfully on the type of source under review [] is demonstrated and [] is technically feasible."[40] As of November 2021, a utility-scale natural gas facility has generated electricity for use on the ERCOT grid.[41] Indeed, as EPA has observed in a recent draft white paper, "[t]here are multiple demonstrations of the separation and capture, transport, and storage and utilization components of CCUS within the electric generating and industrial sectors."[42] From 1991 through 2005, a 40-MW combined cycle EGU in Bellingham, Massachusetts utilized CCS to capture 85 to 95 percent of the emitted carbon

[37] Exhibit B at 32.

[38] Analysis and Preliminary Determination at 68.

[39] Preliminary Determination at 56.

[40] NSR Manual at B.17.

[41] This facility has a nameplate capacity of 50MW and is located in LaPorte, Texas. *See* https://netpower.com/press-releases/.

[42] Exhibit B at 39.

dioxide.[43] A 900-MW combined cycle EGU with CCS is currently being planned in Scotland.[44] According to EPA, while second-generation carbon capture systems are still being tested (but are operational at those testing facilities), "amine-based solvent systems are currently in commercial use."

WDNR's undifferentiated rejection of carbon capture technologies also failed to consider use of the Allam-Fetvedt Cycle, which facilities the generation of high-pressure carbon dioxide that can be put directly into pipelines for other uses rather than emitted. One 50-MW Allam-Fetvedt Cycle plant is currently operational and synchronized to the grid, and at least two other 280-MW plants (according to EPA) are planned for commercial operation by 2025, the same time as the proposed NTEC facility is expected to come online.[45]

Before WDNR can assert that CCS is "infeasible" for the proposed NTEC facility, it must adequately consider whether and how the above-described technologies might be applied to some or all of the throughput at the proposed facility. Failure to do so renders WDNR's greenhouse gas BACT analysis arbitrary.

2. The proposed BACTs for PM and sulfuric acid mist are well in excess of analogous facilities.

Assuming the maximum heat efficiency of the proposed turbine of 4,571 MMBtu/hr, the proposed PM limit for operation with duct burners is 0.0078 lb/mmBtu (0.0047 lb/mmBtu without duct burners). This is considerably higher than BACT limits for other CCGT plants that have recently received permits. For example, Alabama Power Company's Barry Plant is limited to 0.0040 lb/MMBtu of particulate matter under *all* conditions. (That plant consists of two 744 MW combined cycle units.) Indeck-Niles in Michigan, a CCGT with duct burners, is limited to 0.0058 lb/mmBtu or 19.8 pounds per hour.

The Draft Permit also incorporates unreasonably high limits for sulfur dioxide and sulfuric acid mists. The proposed BACT is 9.9 lb/hr of sulfuric acid mist when firing natural gas, with ducts. But the Mountain State Clean Energy CCGT (a 2x1 CCGT with duct burners with combined nameplate capacity of 1275 MW, RBLC ID WV-0033) is limited to sulfuric acid mist emissions of 4.28 lb/hr (3-hour rolling average) and the Cogen Tech Linden facility (a 250 MW combined cycle turbine, RBLC ID NJ-0088) is limited to sulfuric acid mist emissions of 3.45 lb/hr. Neither WDNR nor NTEC acknowledges these lower emission limits or explains

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[43] Exhibit B at 39.

[44] *Id*.

[45] Exhibit B at 41.

why BACT for the proposed facility is nevertheless more than twice the limit at a comparable, but larger plant. NTEC has not demonstrated its proposed limits are BACT and the Draft Permit cannot be approved as written.

Neither WDNR nor NTEC appears to have considered these analogous facilities, nor explained why it cannot achieve these lower limits or why limits almost twice as high as analogous plants for *both* particulate matter and sulfuric acid mist can be justified as BACT. WDNR must re-do its PM BACT analysis, beginning from the presumption that 0.0040 lb/MMBtu is BACT for PM2.5 and 3.45 lb/hr is BACT for sulfuric acid mist.

3. WDNR improperly rejected low-leaking valves as BACT for greenhouse gas and VOC fugitive emissions.

WDNR identified, as a candidate control technology for fugitive emissions, "[c]ertified low-leaking valves," and finds that use of this technology is feasible.[46] However, the Preliminary Determination rejects low-leaking valves as economically infeasible.[47] This conclusion is unjustified, and contrary to at least one other state's BACT determination with respect to a similar project.

As an initial matter, WDNR does not cite or otherwise provide support for its assertion that low-leaking valves are only 80% effective and thus should be ranked beneath LDAR. Illinois EPA found, to the contrary, that "leakless" piping components are up to 99% effective.[48]

WDNR's rejection of low-leaking valves as economically infeasible is also unjustified. As the Environmental Appeals Board has observed, based on EPA's New Source Review Workshop Manual:

> In determining whether BACT for a pollutant should be based on a particular control technology, the permit issuer must consider the economic impacts of using the control technology. *See* 40 C.F.R. § 52.21(b)(12) (BACT definition). The determination of economic impacts focuses on whether the control option under consideration would be cost-effective, measured in terms of "the dollars per tons of pollutant emissions reduced." The "average cost-effectiveness" of a particular technology is calculated by dividing the

[46] Preliminary Determination at 96.

[47] *Id.* at 98.

[48] Illinois EPA, *Project Summary for a Construction Permit Application from Lincoln Land Energy Center, LLC, for an Electrical Generating Facility Near Pawnee, Illinois*, at 154. Available online at https://external.epa.illinois.gov/WebSiteApi/api/PublicNotices/GetAirPermitDocument/7738.

> average annualized cost of installing and operating the control technology by the tons per year of pollutant that the technology would remove. This cost-effectiveness figure is then compared with what other companies in the same industry have been required to pay in recent BACT determinations to remove a ton of the same pollutant. In most cases, a control option is determined to be economically achievable if its cost-effectiveness is within the range of costs being borne by other sources of the same type to control the pollutant…."In the absence of unusual circumstances, the presumption is that sources within the same source category are similar in nature, and that [they can bear the same] costs and other impacts."[49]

WDNR failed to engage in any comparative analysis to assess whether the cost-effectiveness figure it identified for low-leaking valves is "within the range of costs being borne by other sources of the same type." In fact, Illinois EPA has found that "leakless" valves are BACT for fugitive methane and VOC emissions and ordered their inclusion as a condition of permitting two CCGT facilities: Jackson Generation, RBLC ID IL-0130, and CPV Three Rivers, RBLC ID IL-0129. The final permit should require NTEC to install low-leaking valves to minimize methane emissions.

4. The carbon monoxide (CO) and volatile organic compound (VOC) emission limits for the primary turbine include unreasonably long averaging periods.

WDNR has proposed an unreasonably long averaging period for carbon monoxide emission limits for the primary turbine: 168 hours. This is well outside what other state agencies have required and contrary to past EPA decisions. "Emission limits should be based on concentration estimates for the averaging time that results in the most stringent control requirements."[50] Moreover, the carbon monoxide NAAQS uses an 8-hour and 1-hour averaging standard; the emission limit should accordingly protect against exceedances within this time frame.[51] Other permitting agencies have accordingly imposed carbon monoxide limits across averaging periods of 24 hours (Indeck-Niles, RBLC ID MI-0445) or 3 hours (Jackson Generating

[49] *In Re: Masonite Corporation Permittee*, 1994 WL 615380, at *8 (citations omitted).

[50] 40 C.F.R. Part 51, App. W, § 10.2.3.1.a.

[51] *See In Re: Mississippi Lime Company*, 15 E.A.D. 349, 2011 WL 3557194 at *26–27 (EAB 2011) ("[I]t is reasonable to infer that U.S. EPA expects 'PSD permit[s] [to] define a maximum allowable hour emission limitation' for NO_x to protect the one-hour NO_2 NAAQS.").

Station, IL-0130; Chickahominy, VA-0332[52]; Shady Hills Energy Center, FL-0371) on large combined-cycle EGUs.

Similarly, the Draft Permit limits VOC emissions on a 168-hour rolling average basis. This is well outside the standard for other EGUs; for example, the Indeck-Niles permit (RBLC ID MI-0445) uses an *hourly* averaging period. WDNR should adopt an hour averaging period as well in any approved permit.

F. The Draft Permit does not provide for adequate monitoring of particulate matter and sulfur dioxide emissions.

The Draft Permit does not include any continuous monitoring requirements for particulate matter or sulfur dioxide, instead relying on performance testing every five years particulate matter and fuel content sampling for sulfur dioxide. Given the close proximity of the proposed project to environmental justice communities (see above), and the well-documented adverse cardiovascular impacts to even hourly exposure to PM2.5 and sulfur dioxide,[53] continuous monitoring of emissions of both these pollutants is appropriate to protect the health of local residents. Even if continuous monitoring is not required, the proposed interval between testing would allow Duluth and Superior residents to suffer increased health risks for an unacceptably long period of time—up to five *years*—before exceedances are identified through testing. WDNR should require continuous emission monitoring of both sulfur dioxide and particulate matter and make results available to the public upon request.

G. Any final permit should impose limits on diesel fuel oil and the emergency diesel generator consistent with their putative use as emergency resources.

The primary emissions unit, the Siemens SGT6-8000H combined-cycle turbine, can be operated on both methane ("natural gas") and diesel fuel oil. When operating on diesel fuel oil the proposed turbine's emissions are considerably higher—for example, the Draft Permit proposes a limit of 54.5 lb/hr when firing diesel fuel oil with duct firing versus 36.3 lb/hr with natural gas, and 1,180 lb/MWh carbon dioxide for diesel fuel oil versus 850 lb/MWh for natural

[52] Chickahominy also has a lower emissions limit, 1 ppm rather than 1.5 ppm. (The Chickahominy facility uses three 310-MW CCGTs without duct burners).

[53] *See, e.g.*, Xu, D., Chen, Y., Wu, L. et al. Acute effects of ambient $PM_{2.5}$ on lung function among schoolchildren. Sci Rep 10**,** 4061 (2020). https://doi.org/10.1038/s41598-020-61003-4 (finding adverse impact on lung function of children with one day of elevated PM2.5 exposure and summarizing other studies with similar findings); EPA, *Sulfur Dioxide Basics*, at https://www.epa.gov/so2-pollution/sulfur-dioxide-basics ("Short-term exposures to SO_2 can harm the human respiratory system and make breathing difficult. People with asthma, particularly children, are sensitive to these effects of SO_2.")

gas.[54] Recognizing the considerably higher emissions associated with diesel fuel oil, the Preliminary Determination includes the use of "low-carbon fuel (e.g. natural gas)" as a control technology for carbon dioxide.[55]

Despite this, the Draft Permit does not limit the use of diesel fuel oil to emergency scenarios, *i.e.* when natural gas is unavailable and operation of the facility is required for grid stability. The Draft Permit limits use of diesel fuel oil (as a limitation on NOx emissions) to 11,025,196 gallons every 12 consecutive calendar months.[56] This works out to approximately 376 hours per year. Neither WDNR or NTEC offers an explanation as to why they anticipate such an extensive period of natural gas unavailability and need for generation on an annual basis.

The proposed limit is not BACT. Other permitting authorities have limited use of fuel oil both by situation and numerically. For example, NRG Canal 3, a 350-MW simple cycle combustion turbine in Massachusetts, is prohibited from utilizing fuel oil unless the relevant ISO declares an emergency or scarcity condition, natural gas in unavailable, for testing and maintenance, and 160 hours over a four-year rolling period to maintain fuel turnover.[57] Without either a stricter numerical limit or a qualitative limit restricting use of diesel fuel oil to defined emergencies, the Draft Permit allows NTEC to use diesel fuel oil to its economic advantage (*e.g.* in the case of natural gas or energy price spikes where natural gas is limited) at the expense of air quality. WDNR should limit use of diesel fuel oil to the circumstances set forth in the NRG Canal 3 permit (testing, maintenance, a MISO-declared emergency, or natural gas curtailment) and/or limit diesel fuel oil operation to 100 hours per year or fewer. Moreover, NTEC should be required to document all hours of diesel fuel operation and the basis for the operational decision to use diesel oil and whether and what designated emergency conditions applied.

Similarly, the 282-hp emergency diesel fire pump (S06/P06) and 1,490 horsepower diesel generator (S07/P07) are permitted to operate up to 500 hours per year.[58] This limit is inconsistent with their designation as "emergency" units and their exclusion, as discussed above,

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[54] Draft Permit at 6.

[55] Preliminary Determination at 56.

[56] Draft Permit at 8.

[57] See Massachusetts Department of Environmental Protection, Air Quality Plan Approval (August 4, 2017), pp. 23-24. Available online at https://www.nrg.com/assets/documents/legal/overview/canal-3-development-project-applications/080417-air-quality-plan-approval.pdf.

[58] Draft Permit at 64.

from PSD modeling calculations. WDNR must impose either a more stringent numerical limit or qualitative conditions for the use of these stacks.

H. NTEC should be required to replace SF_6 in the 19kV circuit breakers.

Finally, we urge DNR to require NTEC to replace the sulfur hexafluoride low-side generator circuit breakers with an alternative.[59] As the Preliminary Determination notes, sulfur hexafluoride is a potent greenhouse gas with a warming potential of 22,800 times carbon dioxide. In a recently published white paper, EPA observed that "alternatives to sulfur hexafluoride are readily available for low and medium (up to 72.5 kilovolt (kV)) voltage equipment."[60] The low-side generator circuit breakers are estimated to be 19 kV and thus need not use sulfur hexafluoride.

I. Conclusion

For at least the foregoing reasons, WDNR should decline to issue a Final Permit to the NTEC or, at a minimum, address the issues identified above in a substantially revised draft construction permit for additional public review and comment.

If you have any questions, please do not hesitate to contact the undersigned. Thank you for the opportunity to comment.

Sincerely,

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[59] *See* Draft Permit at 54.

[60] Exhibit B at 16.

Exhibit A

Calculation of Nemadji Trail Energy Center Upstream Emissions
May 20, 2022

To estimate the extent of upstream methane emissions from the use of gas, we estimate:
1) Leakage emissions
2) Gas lease and plant fuel emissions
3) Gas pipeline fuel emissions

Leakage Emissions
The production, processing, storage, transmission, and distribution of gas leaks immense amounts of a dangerous greenhouse gas into our atmosphere. Unburned gas consists primarily of methane, and while carbon dioxide remains in the atmosphere for longer than methane, methane has a much stronger climate warming effect. When its impact is averaged over a 20-year period, methane leaked directly into the atmosphere is 82.5 times more powerful at trapping heat than carbon dioxide.[1] Many researchers have calculated the national average gas leakage rate with a central estimate of about 3% of total production.[2,3,4,5,6,7,8,9] Based on that recent literature, we use a leakage rate of 2.9% from well to power plant end use.

Gas Lease and Plant Fuel Emissions
EIA defines lease and plant fuel as "gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in natural gas

[1] IPCC 6AR WG, Table 7.15, pp.7-125 https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Full_Report.pdf.
[2] Littlefield et. al., 2017, *Synthesis of recent ground-level methane emission measurements from the U.s. natural gas supply chain*, https://www.sciencedirect.com/science/article/pii/S0959652617301166.
[3] National Energy Technology Laboratory, 2016, *Life Cycle Analysis of Natural Gas Extraction and Power Generation*, https://www.netl.doe.gov/energy-analyses/temp/LifeCycleAnalysisofNaturalGasExtractionandPowerGeneration_083016.pdf.
[4] Environmental Protection Agency (EPA), 2018, *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.
[5] Howarth et. al., 2011, *Methane and the greenhouse-gas footprint of natural gas from shale formations*, https://link.springer.com/content/pdf/10.1007%2Fs10584-011-0061-5.pdf.
[6] Burnham et. al., 2011, *Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum*, https://pubs.acs.org/doi/pdf/10.1021/es201942m.
[7] Miller et. al., 2013, *Anthropogenic emissions of methane in the United States*, http://www.pnas.org/content/110/50/20018.
[8] Brandt et. al., 2014, *Methane Leaks from North American Natural Gas Systems*, http://science.sciencemag.org/content/sci/suppl/2014/02/12/343.6172.733.DC1/1247045.Brandt.SM.revision2.pdf.
[9] Alvarez et. al., 2018, *Assessment of methane emissions from the U.S. oil and gas supply chain*, https://science.sciencemag.org/content/361/6398/186.

processing plants."[10] We use a methane emissions rate for these sources from EPA's Greenhouse Gas Inventory.[11]

Gas Pipeline Fuel

EIA defines pipeline fuel as "gas consumed in the operation of pipelines, primarily in compressors.."[12] We use a methane emissions rate for these sources from EPA's Greenhouse Gas Inventory.[13]

Total Upstream Methane Emissions

The Application and Preliminary Determination do not identify any limits on the operation of Nemadji Trail Energy Center below its nameplate capacity. The Application states that the facility's potential to emit carbon dioxide is 2,738,317.8 tons per year. If the plant burned the max fuel oil it was allowed (11,096,125 gallons/year), using the average btu content of fuel oil[14] and CO_2 emissions coefficient,[15] that would mean the fuel oil burned would emit 113,018 metric tons CO_2/year. Based on the total annual emissions allowed (2,738,318 tons CO_2/year or 2,484,161 metric tons CO_2/year), that means gas burn could still emit up to 2,371,143 metric tons CO_2/year.

A 625-MW combined cycle unit running at 100% capacity is predicted to emit approximately 2,200,000 metric tons CO_2/year. NTEC's own proposed potential to emit is above what would be expected given current technology and nameplate technology. Assuming, then, that the proposed facility emits 2.2 million metric tons CO_2 per year through burning natural gas, we estimate it would create upstream emissions, before that gas is even burned, of 1.94 million metric tons of carbon dioxide equivalent per year.

Adding 1.94 million metric tons to the allowable stack emissions from burning natural gas (2.48 million metric tons), this plant could be responsible for 4.42 million metric tons of carbon dioxide equivalent each year.

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[10] EIA, Glossary, https://www.eia.gov/tools/glossary/index.php.

[11] EPA Greenhouse Gas Inventory, Table A-91, https://www.epa.gov/sites/default/files/2020-04/documents/us-ghg-inventory-2020-annexes.pdf. Using value for gas boilers.

[12] EIA, Glossary, https://www.eia.gov/tools/glossary/index.php.

[13] EPA Greenhouse Gas Inventory, Table A-91, https://www.epa.gov/sites/default/files/2020-04/documents/us-ghg-inventory-2020-annexes.pdf. Using value for gas-fired gas turbines >3 MW.

[14] EIA, Units and Calculators Explained, https://www.eia.gov/energyexplained/units-and-calculators/.

[15] EIA, Carbon Dioxide Emissions Coefficients, https://www.eia.gov/environment/emissions/co2_vol_mass.php.

Exhibit B

United States Environmental Protection Agency

Office of Air and Radiation **April 21, 2022**

AVAILABLE AND EMERGING TECHNOLOGIES FOR REDUCING GREENHOUSE GAS EMISSIONS FROM COMBUSTION TURBINE ELECTRIC GENERATING UNITS

Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units

Prepared by the

Sector Policies and Programs Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

April 21, 2022

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List of Exhibits

Acronyms and Abbreviations

BACT	Best Available Control Technology
BFG	blast furnace gas
Btu	British thermal unit
CAA	Clean Air Act
CCUS	carbon capture, utilization, and storage
CH_4	methane
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
DLE	dry low emissions
DLN	dry low-NO_X
DOE	Department of Energy
EGU	electric generating unit
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
g/kWh	grams per kilowatt-hour
GHG	greenhouse gas
GW	gigawatt
GWP	Global Warming Potential
HAP	hazardous air pollutant
HFC	hydrofluorocarbon
HHV	higher heating value
HRSG	heat recovery steam generator
IGCC	integrated gasification combined cycle
kg	kilogram
kJ	kilojoule
kW	kilowatt
kWe	kilowatt electrical
kWh	kilowatt-hour

KV	kilovolt
LCOE	levelized cost of electricity
LHV	lower heating value
Mg	megagram
MMBtu/hr	million British thermal units per hour
MPa	megapascal
MW	megawatt
MWe	megawatt electrical
MWh	megawatt-hour
MSW	municipal solid waste
N_2	nitrogen
N_2O	nitrous oxide
NETL	National Energy Technology Laboratory
NO_X	nitrogen oxides
NREL	National Renewable Energy Laboratory
NSR	New Source Review
O_2	oxygen
PFC	perfluorocarbon
ppmv	parts per million volume
PSD	prevention of significant deterioration
PV	photovoltaic
RICE	reciprocating internal combustion engine
SCR	selective catalytic reduction
SF_6	sulfur hexafluoride
SNCR	selective noncatalytic reduction
U.S.	United States
USDA	U.S. Department of Agriculture
WLE	wet low emissions
WLN	wet low-NO_X

1.0 Introduction

This white paper summarizes readily available information on control techniques and measures with the potential to mitigate greenhouse gas (GHG) emissions from stationary combustion turbines permitted to operate as electric utility generating units (EGUs).[1] A discussion of the basic types of available stationary combustion turbines is included as well as factors that influence GHG emission rates from these sources. The subsequent technology discussion includes information on an array of control technologies and potential reduction measures for GHG emissions.

The information in this white paper is intended to assist states and local air pollution control agencies, tribal authorities, and regulated entities in their consideration of technologies and measures that may be implemented to reduce GHG emissions from stationary combustion turbines. The discussion of technologies and measures in this paper may also provide context for permit development under the prevention of significant deterioration (PSD) program of the Clean Air Act (CAA), including in the assessment of the best available control technology (BACT) for GHG emissions from stationary combustion turbines. The range of technologies and measures included is comprehensive enough that this discussion may also inform state programs or initiatives to further reduce GHG emissions from stationary combustion turbines. Similarly, the information herein may also be useful to EPA in future development of new source performance standards (NSPS), which must be based on the "best system of emission reduction … adequately demonstrated."[2]

This white paper focuses on a review of technologies and measures that can reduce the GHG emissions associated with electricity generation from stationary combustion turbines. This white paper does not set policy or establish emissions or performance standards, or otherwise establish any binding requirements. Critically, the information presented in this document does not represent EPA endorsement of any particular control strategy for any particular purpose. While some developing technologies are noted as such, inclusion in this white paper generally represents that a technology or measure is sufficiently well-developed that it could be constructed and successfully operated to achieve its intended purpose in the identified applications but not necessarily that it meets the applicable standard for it to be required under any particular regulatory program, either as a general matter for a class or category of sources or for any particular application on a case-by-case basis. As such, it should not be construed as EPA approval of a particular control technology or measure, or of the emissions reductions that could be achieved by a class or category of sources or a particular unit or source. With regard to permitting decisions specifically, this white paper does not set forth any requirements for a permitting authority to consider a process or control technology within the scope of review for an application to approve a particular stationary combustion turbine project. Finally, this paper does not necessarily address all potentially available GHG reduction technologies or measures that may be considered for any given source.

[1] While this white paper focuses on GHG mitigation options for stationary combustion turbines that operate as EGUs, some of the technologies may also be available for GHG mitigation at stationary combustion turbines that operate in other industrial sectors.
[2] *See* Clean Air Act §111(a)(1).

2.0 Clean Air Act Requirements

Emissions from stationary combustion turbines are addressed under a variety of federal, state, and voluntary programs. This section presents a brief, non-exhaustive overview of several contexts in which the technical information contained in this white paper may be relevant.

2.1 Regulation of GHG Emissions from Combustion Turbines Under CAA Section 111

Under authority of CAA section 111, EPA establishes emissions requirements for categories of industrial facilities, also called stationary sources, that cause or contribute significantly to air pollution that may endanger public health or welfare. Under CAA section 111(b), EPA establishes NSPS for new, reconstructed, and modified stationary sources. To set the NSPS for a particular source category, EPA determines the best system of emission reduction (BSER) that has been "adequately demonstrated," taking into account costs and any non-air quality health and environmental impacts and energy requirements. Under CAA section 111(d), for certain pollutants EPA establishes emission guidelines for states to use in preparing plans establishing performance standards for existing sources. These emission guidelines likewise include the EPA's determination of BSER for the existing sources in the source category.

In 2015, EPA issued the final NSPS to limit emissions of GHG pollution manifested as carbon dioxide (CO_2) from stationary combustion turbines. These standards, codified in 40 CFR part 60, subpart TTTT, reflect the degree of emission limitation achievable through the application of BSER to three subcategories of stationary combustion turbines: base load EGUs, non-base load natural gas-fired EGUs, and non-base load multifuel-fired (*i.e.*, non-natural gas-fired) EGUs. The emissions standard for new and reconstructed base load combustion turbines is 1,000 pounds of CO_2 emitted per megawatt hour-gross of operation (lb CO_2/MWh-gross). The emissions standards for non-base load natural gas-fired and non-base load multifuel-fired EGUs are based on the use of natural gas and number 2 fuel oil, respectively.

2.2 Regulation of GHG Emissions from Combustion Turbines Under the CAA PSD Permitting Program

The CAA sets forth the requirements for a permitting program known as New Source Review (NSR), which governs the construction of stationary sources of air pollution. NSR requires such sources emitting above specified levels to obtain permits containing limitations on their air pollutant emissions before they are first constructed or before they engage in a modification of an existing facility. The NSR program is composed of the following three principal components: (1) the PSD program, which sets forth the permitting requirements for new major stationary sources and major modifications of such sources constructed in areas that meet the National Ambient Air Quality Standards (NAAQS), known as "attainment" areas, and in areas for which there is insufficient information to classify an area as either attainment or nonattainment ("unclassifiable" areas); (2) the nonattainment NSR program, which establishes permitting requirements for major stationary sources and major modifications of such sources in areas that do not meet the NAAQS; and (3) the minor NSR program, which applies to sources and modifications that do not emit or increase emissions above "major" levels as defined in the CAA and EPA regulations. The CAA directs states to implement these programs in the first instance, but EPA also implements these programs where states fail to do so or in areas of exclusive federal jurisdiction.

GHGs are regulated under the CAA's PSD program, but not the other components of the NSR program.[3] For PSD, section 165 of the CAA requires that the permitting authority establish emissions limitations based on BACT for each new source or modified emissions unit that is required to obtain a permit under this program. BACT must be assessed on a case-by-case basis, and the permitting authority, in its analysis of BACT for each pollutant, must evaluate the emissions reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic, and other costs associated with each technology or technique. The CAA also specifies that BACT cannot be less stringent than any applicable standard of performance under the NSPS.[4]

In determining BACT, many permitting authorities apply EPA's five-step "top-down" approach, which is most comprehensively described in EPA's NSR Workshop Manual (U.S. EPA, 1990 – Draft) and PSD and Title V Permitting Guidance for GHGs (U.S. EPA, 2011). This approach is not required but is a method that EPA uses to ensure that all the criteria in the CAA's definition of BACT are considered. The "top-down" approach begins with the permitting authority identifying all available control options that have the potential for practical application for the regulated NSR pollutant and emissions unit under evaluation. The analysis then evaluates each option and eliminates options that are technically infeasible, ranks the remaining options from most to least effective, evaluates the energy, environmental, economic impacts, and other costs of the options, eliminates options that are not achievable based on these considerations from the top of the list down, and ultimately selects the most effective remaining option as BACT. Given the CAA's direction that BACT be determined on a case-by-case basis, and the discretion afforded to individual permitting authorities under the applicable criteria, BACT determinations for similar types of projects can sometimes differ from one permit to another based on particular circumstances.

2.3 Reducing GHG Emissions Through Non-CAA Programs

Many states have enacted laws and other programs and initiatives that are aimed at reducing GHG emissions. These GHG reduction programs are independent of any applicable CAA requirements but may nevertheless influence decisions being made by industry and state authorities as they evaluate the overall GHG emissions outcomes of new combustion turbine projects. Such programs include New York's Climate Leadership and Community Protection Act, the California Global Warming Solutions Act of 2006 ("AB 32"), and a host of state-specific renewable fuel standards. Permitting and other authorities responsible for implementing these laws and programs may be subject to different and/or additional requirements and considerations for potential GHG reduction approaches for new combustion turbines than exist under the CAA. Examples of some of these potential GHG reduction approaches are contained in this white paper and are intended to share information that may be helpful under the full range of relevant contexts, whether under the CAA or not, when evaluating proposed combustion turbine projects.

In addition, some individual companies have established corporate goals and commitments to reduce GHG emissions within their own operations, independent of any regulatory or other

[3] The PSD program treats GHG as a single air pollutant defined as the aggregate group of the following six gases: CO_2, nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

[4] CAA 165(a)(4), 169(3).

requirement. These efforts may include onsite CO_2 reduction measures as well as offsite measures that consider the overall GHG emissions, including those associated with fuel production or procurement upstream of the facility (*e.g.*, entities committing to only purchase natural gas from suppliers that demonstrate they have minimized emissions in the production supply chain of the gas). As companies continue to make voluntary commitments to reduce GHG emissions[5] both onsite and offsite, EPA believes they may benefit from considering the GHG reduction strategies discussed in this white paper.

[5] See, *e.g.*, https://www.theclimatepledge.com/us/en; https://www.utilitydive.com/news/xcel-looks-to-gas-suppliers-with-lower-methane-emissions-in-colorado/600108/; https://www.bloomenergy.com/applications/certified-gas/; https://www.bloomenergy.com/applications/biogas/.

3.0 Combustion Turbine Technology

This section provides a description of the primary thermodynamic cycles used by combustion turbines and describes the types of combustion turbines used to generate electricity. Combustion turbine EGUs meet all types of electrical demand—baseload, intermediate, and peaking—and can be quickly dispatched (C2ES, n.d.). As solar, wind, and storage capacities increase, combustion turbines are expected to provide backup power and ancillary services that contribute to dynamic grid stability.

3.1 Electric Power Generation Using Combustion Turbines

Electricity is generated at most electric power plants using mechanical energy to rotate the shaft of electromechanical generators. Mechanical work is produced from thermal energy through the combustion of fossil fuels or nuclear fission; from the kinetic energy harnessed from flowing water, wind, or tides; or from the thermal energy from geothermal wells or concentrated solar arrays. Electricity also can be produced directly from sunlight using photovoltaic (PV) cells or by using a fuel cell to electrochemically convert chemical energy into an electric current.

The combustion of fossil fuel to generate electricity can occur either in a steam generating unit (*i.e.*, boiler) to feed a steam turbine that, in turn, spins an electric generator, or in a combustion turbine or reciprocating internal combustion engine (both spark ignition and compression ignition) that directly drives the generator. A power plant that uses a stationary combustion turbine to directly generate electricity is often referred to as a "simple cycle" plant. Some power plants use a "combined cycle" electric power generation process in which a gaseous or liquid fuel is burned in a combustion turbine that drives an electrical generator and provides heat to produce steam in a heat recovery steam generator (HRSG).[6] The steam produced by the HRSG is then fed to a steam turbine that drives a second electric generator. The combination of using the chemical energy released by burning a fuel to drive both a combustion turbine generator and a steam turbine generator significantly increases the overall efficiency of the electric power generation process. Combined cycle EGUs generally range in capacity from 40 megawatts (MW) up to 1.3 gigawatts (GW).[7] In the U.S. in 2019, approximately 38 percent of net electricity was produced using natural gas. Natural gas-fired combined cycle EGUs accounted for about 33 percent and simple cycle generators (all fuels) produced 3.3 percent of total net generation.[8] Exhibit 3-1 summarizes the differences in generating technologies used in 2010 compared to 2019 and shows how the use of combustion turbine technologies has increased during the past decade.

[6] As described in more detail in section 5.4.2, duct firing (sometimes referred to supplementary firing) adds additional thermal energy input to the HRSG.

[7] According to the specifications in Gas Turbine World (GTW), the largest combined cycle EGUs available in the U.S. are comprised of two turbine engines that are rated at 430 MW each combined with a single 440-MW steam turbine.

[8] EIA 923 data can be downloaded from https://www.eia.gov/electricity/data/eia923/.

Exhibit 3-1. Comparison of annual net generation (MWh) by technology 2010 vs. 2019.

Generating Technology	2010 Net MWh and Percentage of Total		2019 Net MWh and Percentage of Total	
Combined Cycle Natural Gas	813,117,886	20%	1,350,891,889	33%
Simple Cycle (all fuels)	92,575,530	2.1%	136,146,724	3.3%
Reciprocating Engine	8,863,272	0.21%	16,092,423	0.39%
Coal Steam Turbine	1,834,372,360	44%	958,047,858	23%
Nuclear	806,968,301	20%	809,409,262	20%
Fuel Cell	11,379	0.0%	1,645,022	0.04%
Hydro	260,203,069	6.3%	287,873,730	7.0%
Wind	94,652,246	2.3%	295,882,949	7.2%
Utility Solar	422,831	0.011%	68,718,894	1.7%
Small-Scale Photovoltaic[9]	1,281,000	-	34,957,000	-%

Source: U.S. Energy Information Administration (EIA) (2021b)

Among the technologies used as prime movers[10] for stationary and mobile energy conversion applications, combustion turbines can have high power-to-weight ratios with greater than 10 kilowatts (kW) per kilogram (kg). Designs can range from refrigerator-size "microturbines" with rated outputs as low as 30 kW to utility-scale "heavy frame" units that are more than 30 feet long and 10 feet in diameter and with rated outputs of approximately 400 MW. These various characteristics enable designers to incorporate combustion turbines into a wide range of mobile applications, including propulsion systems for ships, military vehicles, and aircraft. Stationary applications are also diverse and include mechanical drive systems for industrial compressors and pumps. This document focuses on control techniques and measures that are available to mitigate GHG emissions from stationary combustion turbines used as prime movers for EGUs.

3.2 Simple Cycle EGUs and the Brayton Cycle

Combustion turbines operate using the Brayton thermodynamic cycle. Exhibit 3-2 presents a simple schematic of the three primary components of combustion turbines: compressor (C), combustion chamber (*i.e.*, combustor), and turbine (T). In the Brayton cycle, a multistage compressor (1-2) is used to supply large volumes of high-pressure air to a combustion chamber. The combustion chamber (2-3) ignites fuel to heat and expand the compressed air. By heating the compressed air, the combustion chamber provides the turbine with a high volume of high-pressure, high-temperature gas that can be converted to shaft work as the hot gas expands through the multistage turbine blades. Expansion of the gases through the turbine causes the blades and shaft to rotate and produce shaft work (W_S). Most of the shaft work produced (55 to 65 percent) is used by the compressor with the remainder available for driving an electric generator or a mechanical drive system.

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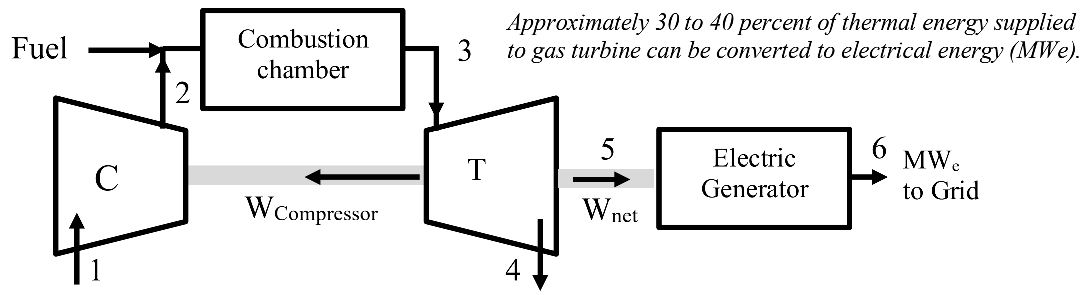
[9] Estimated using data from the U.S. Energy Information Administration's (EIA) State Energy Data Systems (SEDS) (https://www.eia.gov/state/seds/seds-data-complete.php?sid=US#CompleteDataFile), EIA Table 1.1.A, Net Generation from Renewable Sources, and the Solar Energy Industries Association (https://www.seia.org/solar-industry-research-data).

[10] A device that converts a non-electrical form of energy to electrical energy.

Exhibit 3-2. Simplified schematic of a simple cycle combustion turbine operating in the thermodynamic cycle known as the Brayton cycle.



1 – Ambient air enters the compressor.
2 – Compressed air [pre-mixed with fuel on dry low-nitrogen oxide (NOx) or DLN system] enters combustion chamber.
3 – High-pressure (up to 30 Bar) hot gases (900 to 1,400 °C) exit combustion chamber and enter gas turbine.
4 – Hot (450 to 650 °C) exhaust gases [including nitrogen (N_2), oxygen (O_2), CO_2, NO_X, and carbon monoxide (CO)] exit turbine:

a. In simple cycle units these gases are vented to the atmosphere through a stack.
b. In combined cycle EGUs these gases are sent through an HRSG before being exhausted to the atmosphere through a stack. See Exhibit 3-3.

5 – The net work (Wnet) available for turning an electric generator or mechanical drive system is the total energy extracted from the hot gases (4 minus 3) less the work necessary to operate the compressor.

Combustion turbines that vent the high-temperature exhaust gases directly to the atmosphere without recovering additional useful output are called simple cycle turbines. Simple cycle turbines have relatively low capital costs and can start and change load quickly. Therefore, they are often used to supply electricity during periods of high demand (*i.e.*, peaking EGUs) and act as backup for intermittent forms of generation such as wind and solar.[11]

3.3 Combined Cycle EGUs and the Rankine Cycle

As shown in Exhibit 3-2 at 4b, when the exhaust gas (*i.e.*, flue gas) from the Brayton cycle is routed to an HRSG operating in the Rankine cycle,[12] the resulting thermodynamic cycle is called a "combined cycle." Exhibit 3-3 provides a detailed schematic of a combined cycle EGU. Combined cycle installations are commonly called power blocks with two leading numbers that designate the number of combustion turbine generator sets and the number of steam turbine generator sets, respectively. For example, a "3-on-1 combined cycle power block" designates three combustion turbine generators and one steam turbine generator.

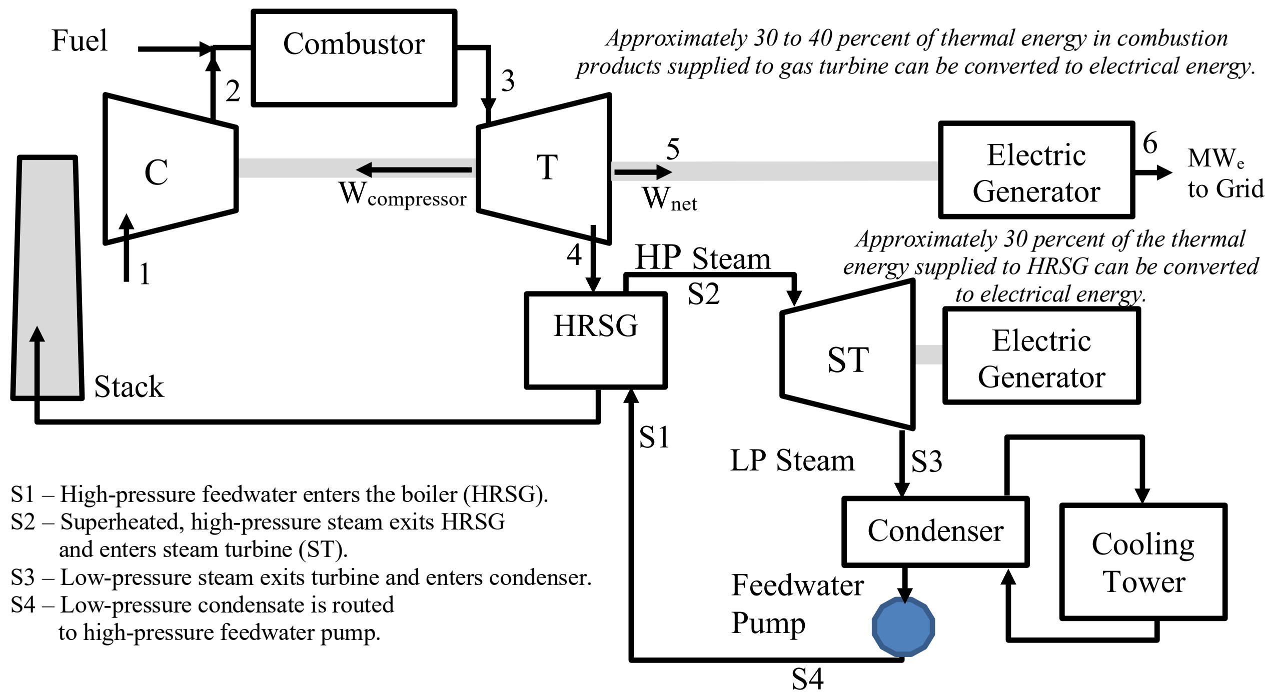
Combined cycle EGUs have higher capital costs and are more efficient, but not as flexible as simple cycle EGUs. Therefore, combined cycle EGUs have typically been used for base load and

[11] The generation from wind and solar EGUs is determined by atmospheric conditions that are not necessarily related to end user electric demand. As more electricity is generated from these intermittent sources, to continue to provide reliable power, utilities need to either invest in dispatchable forms of electric generation, energy storage, or demand-side programs where end users agree to curtail demand when generation is not able to keep up with demand.

[12] The Rankine cycle is a thermodynamic cycle that converts heat to mechanical energy—which is then often converted to electrical energy—using an evaporation and condensation cycle. It is widely used in coal-fired and nuclear power plants as well as the HRSG in a combined cycle EGU.

intermediate load generation. However, “flexible” and “fast-start” combined cycle EGUs can start more quickly than traditional combined cycle designs and are intended to be capable of supporting intermittent renewable generation. It should be noted that flexible and fast-start combined cycle EGUs typically have additional capital and operating expenses compared to combined cycle EGUs intended primarily for base load operation.

Exhibit 3-3. Simplified schematic of combustion turbine operating in the thermodynamic cycle known as the “combined cycle” that converts thermal energy to electrical energy using the Brayton cycle combined with the Rankine cycle.



4.0 GHG Emissions from Combustion Turbine EGUs

The principal GHGs that accumulate in the Earth's atmosphere above pre-industrial levels because of human activity are CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Of these, CO_2 is the most abundant, accounting for 80 percent of GHGs present in the atmosphere, largely due to the combustion of fossil fuels by the transportation, electricity, and industrial sectors (U.S. EPA, 2021c). The amount of CO_2 emitted from fossil fuel-fired EGUs depends on the carbon content of the fuel and the size and efficiency of the EGU.

Different fuels emit different amounts of CO_2 in relation to the energy they produce when combusted. The amount of CO_2 produced when a fuel is burned is a function of the carbon content of the fuel. The heat content, or the amount of energy produced when a fuel is burned, is mainly determined by the carbon and hydrogen content of the fuel. Exhibit 4-1 shows that, in terms of pounds of CO_2 emitted per million British thermal units of energy produced, when combusted, natural gas is the lowest compared to other fossil fuels.

Exhibit 4-1. Fossil fuels compared by lb CO_2 per MMBtu of energy produced.[13, 14]

Coal (anthracite)	228.6
Coal (lignite)	215.4
Coal (subbituminous)	214.3
Coal (bituminous)	205.7
Diesel fuel and heating oil	161.3
Gasoline (without ethanol)	157.2
Propane	139.0
Natural Gas	117.0

Significant CO_2 reductions have occurred in the power sector as generation has transitioned to less use of coal and greater use of natural gas. In Exhibit 4-2 below, data from the U.S. Energy Information Administration (EIA) illustrates this transition from 1990 to 2018 in terms of percent of net electric generation by source. Note the mirrored relationship of the coal (blue) and natural gas (green) generation trend lines.

[13] Values reflect the carbon content on a per unit of energy produced on a higher heating value (HHV) combustion basis and are not reflective of recovered useful energy from any particular technology.

[14] Natural gas is primarily methane (CH_4), which has a higher energy content relative to other fuels, and thus, has a relatively lower CO_2-to-energy content. Water and other compounds, such as sulfur and noncombustible elements in some fuels, reduce their heating values and increase their CO_2-to-heat contents.

Exhibit 4-2. Share of net electricity generation by source.

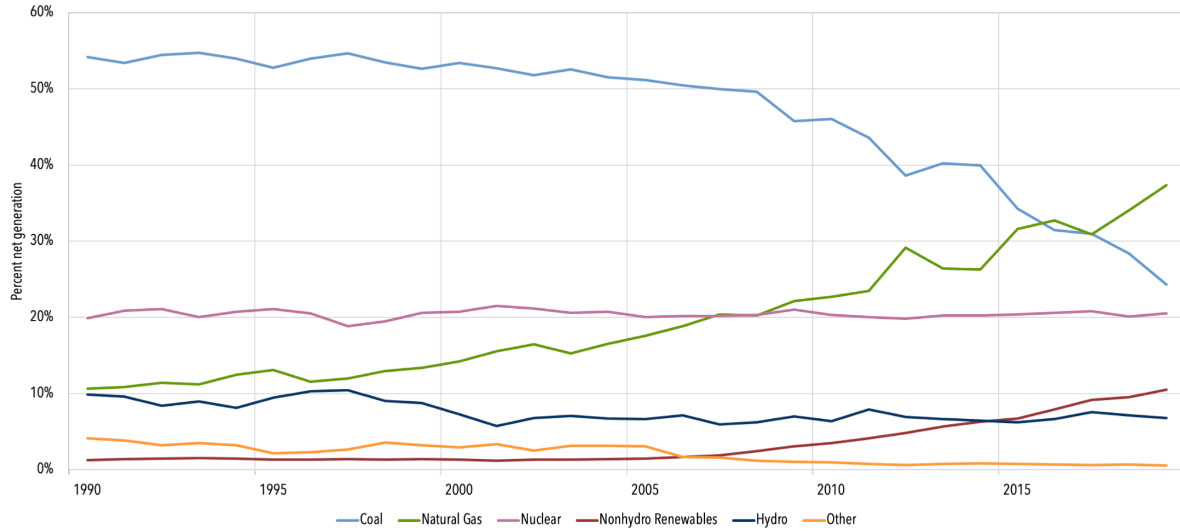
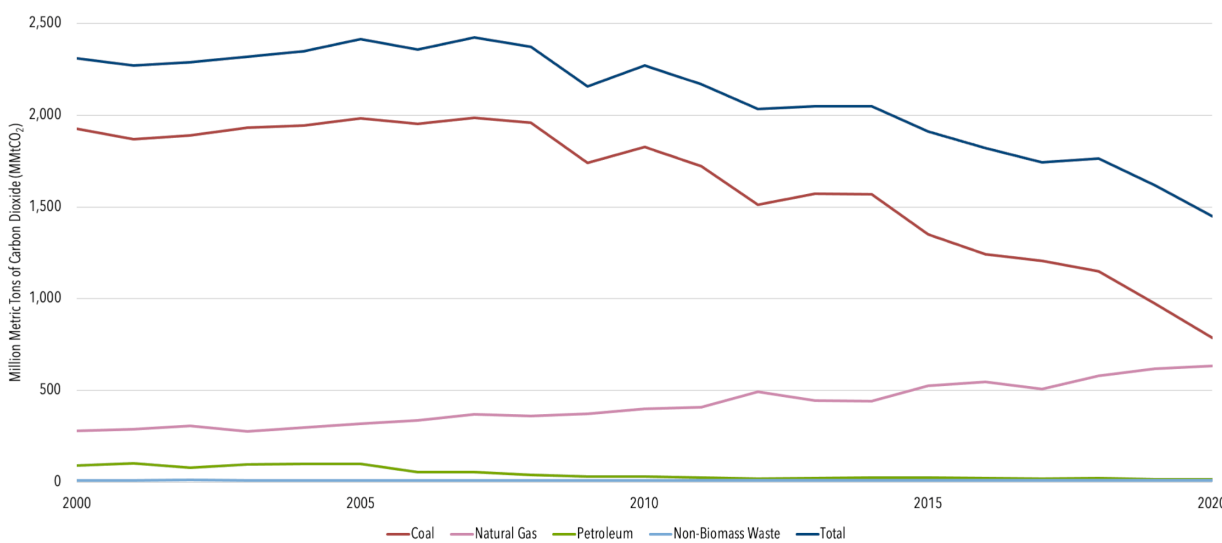


Exhibit 4-3 shows EIA power sector CO_2 emissions over time by fuel type. Note the gradual but steady increase in CO_2 emissions from natural gas (pink line) due to the expansion of combustion turbine capacity since the early 2000s. Power generation from natural gas-fired combustion turbines is projected to increase as more coal-fired EGUs retire and new combustion turbines are added to the electric grid—in many instances to respond to demand fluctuations caused by expanded generation from intermittent solar and wind (Lin, 2019).

Exhibit 4-3. CO_2 emissions by power sector fuel type.



The primary GHG emitted by combustion turbine EGUs is CO_2, and that pollutant is the focus of the onsite control technologies and measures presented in this white paper. Emissions of methane from the turbine exhaust are typically extremely low. However, during the production, transportation, and distribution of natural gas, methane can be emitted to the atmosphere. The Global Warming Potential (GWP) of methane is from 28 to 36 times stronger than that of CO_2

over 100 years.[15] While methane is relatively short-lived, with an atmosphere lifetime of about a dozen years, the increase in CO_2 concentrations due to CO_2 emissions can persist for centuries or more (U.S. EPA, 2020c).

Nitrous oxide may be formed during the combustion of fossil fuels from a series of reactions. However, nitrous oxide formation from the combustion of natural gas in a combustion turbine is generally less than 1 part per million (ppm) during steady state operation but can rise to several ppm during transient operation (Colorado *et al.*, 2017). Additional nitrous oxide can be formed by the selective catalytic reduction (SCR) systems that are often used to control emissions of smog-forming nitrogen oxides (*i.e.*, NO_X, which is a mixture of nitric oxide (NO) and nitrogen dioxide (NO_2)). SCR systems using vanadium and vanadium-tungsten catalysts that are designed for use in combined cycle EGUs typically operate between 260 and 400 degrees Celsius (°C) (500 to 750 degrees Fahrenheit (°F)). At these temperatures, formation of nitrous oxide is not expected to be significant; however, at temperatures above 400 °C (750 °F), the reaction kinetics for nitrous oxide formation become much more favorable, resulting in a potential increase in emissions. This is especially important for simple cycle EGUs, which can have exhaust temperatures of up to 600 °C (1,100 °F) and can use a high-temperature SCR operating at 470 to 580 °C (880 to 1,075 °F). Tempered air can be added to the turbine exhaust prior to the SCR to reduce exhaust gas temperatures. However, this can increase the cost of the SCR system.

Test data from commercial-scale operations are not readily available to confirm if additional nitrous oxide is formed in high-temperature SCR systems. It is plausible that other factors, such as the catalyst structure and the amount of ammonia slip[16] may also impact nitrous oxide formation. Companies may be able to provide additional information regarding their specific SCR system and its anticipated nitrous oxide formation to determine if emissions testing is required for nitrous oxide.

Hydrofluorocarbons and sulfur hexafluoride are not formed as a byproduct of combustion in a fossil fuel-fired turbine. However, as with all EGUs, sulfur hexafluoride might be used at a power plant switchyard to insulate equipment. Sulfur hexafluoride is a strong GHG, and a certain amount of sulfur hexafluoride used by an insulator is emitted to the atmosphere through leaks and servicing of the equipment. Several states have initiatives requiring that these GHG emissions be reduced by maintaining annual sulfur hexafluoride emission rates for new and existing equipment to 1 percent or less of the sulfur hexafluoride used on the insulating equipment. Furthermore, alternatives to sulfur hexafluoride are readily available for low and medium (up to 72.5 kilovolt (kV)) voltage equipment, and, while more limited, sulfur

[15] Two factors influence how different GHGs impact the climate: 1) their ability to absorb energy (*i.e.*, "radiative efficiency") and 2) how long they stay in the atmosphere (*i.e.*, "atmospheric lifetime"). The GWP is a measure of the global warming impacts of different gases. Specifically, it is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of CO_2. The larger the GWP, the more that a given gas warms the Earth compared to CO_2 over that time period. The United States primarily uses the 100-year GWP as a measure of the relative impact of different GHGs. However, GWP can also be based on different timeframes. See https://www.epa.gov/ghgemissions/understanding-global-warming-potentials.
[16] Ammonia slip is excess ammonia that passes through the SCR system unreacted.

hexafluoride-free options are available for equipment up to 145 kV. EPA's sulfur hexafluoride partnership programs and state requirements have expanded the use of these technologies.[17]

[17] See https://www.epa.gov/eps-partnership; California and Massachusetts also have regulatory programs to reduce emissions of sulfur hexafluoride. Assuming an insulating piece of equipment losses 1 lb of sulfur hexafluoride annually, this is equivalent to 11 tons of CO_2e. In 2019, the average combined cycle EGU emitted 600,000 tons of CO_2 and the average simple cycle emitted 30,000 tons of CO_2. However, while the atmospheric lifetime of CO_2 is hundreds of years, the atmospheric lifetime of sulfur hexafluoride in 3,200 years. In 2019, sulfur hexafluoride emissions from electrical power systems and electric equipment manufacturers were 4.2 million metric tons of carbon dioxide equivalents (MMT CO2e) (0.2 kilotons (kt) of sulfur hexafluoride). See Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019 (2021). (U.S. EPA, 2021i).

5.0 Combustion Turbine EGU GHG Control Approaches

The development of effective and commercially viable GHG emission control technologies[18] and other approaches for reducing GHG emissions from combustion turbine EGUs is receiving widespread attention from stakeholders including electric utilities, technology providers, nongovernmental organizations, and government agencies. Some GHG control technologies are available at present. Some are still in the research and development phase and are not ready for commercial application. Yet other GHG control technologies are being demonstrated at larger scales and are progressing toward commercial viability. This remains an active area of research and new projects, programs, and technology advances are reported routinely.

In this section, the discussions of direct/onsite GHG control technologies (and/or their development status) and other mitigation approaches for a given combustion turbine EGU are based on descriptions in publicly available information as of November 2021. For this white paper, these technologies and mitigation options are organized as follows and basically cover four broad topics.

1) Sections 5.1-5.6 discuss the reduction of GHG emissions rates by improving heat rates and reducing fuel usage (thereby limiting CO_2 formation) for both the combustion turbine engine (*i.e.*, the Brayton cycle) and the HRSG (*i.e.*, the Rankine cycle), combined heat and power (CHP), and the integration of non-emitting sources (*e.g.*, renewables) and/or energy storage.
2) Sections 5.7 and 5.8 discuss existing and emerging technologies that focus on the capture of CO_2.
3) Section 5.9 discusses the GHG benefits of the combustion of hydrogen (and ammonia).

5.1 Impact of EGU Efficiency on CO_2 Emissions

As the thermal efficiency of a combustion turbine EGU is increased, less fuel is burned per kilowatt-hour (kWh) generated, and there is a corresponding decrease in CO_2 and other air emissions. EPA's Clean Air Markets Division collects heat input and gross MW output data on an hourly basis for the majority of fossil fuel-fired EGUs.[19] The heat input is derived from standardized continuous emissions monitors or fuel flow monitors while the owner/operator of the EGU supplies gross MW output. The electric energy output as a fraction of the fuel energy input expressed as a percentage is a common practice for reporting the efficiency. The greater the output of electric energy for a given amount of fuel energy input, the higher the efficiency of the electric generation process. Heat rate is another common way to express how efficient an EGU is at converting input energy to electric energy. Heat rate is expressed as units of Btu or the kilojoules (kJ) required to generate one kWh of electricity. Lower heat rates are associated with more efficient power generating plants.

Heat rate can be calculated using the higher heating value (HHV) or the lower heating value (LHV) of the fuel. The HHV is the heating value directly determined by calorimetric measurement of the fuel in the laboratory. The LHV is calculated using a formula to account for

[18] When EPA refers to "GHG control technologies" the Agency is including both technologies that reduce onsite GHG emissions and other GHG control approaches that reduce offsite GHG emissions.
[19] CAMD Power Sector Emissions Data is collected from most fossil fuel-fired EGUs greater than 25 MW.

the moisture in the combustion gas (*i.e.*, subtracting the energy required to vaporize the water in the flue gas) and is a lower value than the HHV. Consequently, the HHV heat rate for a given EGU is always lower than the corresponding LHV heat rate because the reported heat input for the HHV is larger. For natural gas, the HHV heat rate is approximately 10 percent lower than the corresponding LHV heat rate.[20] Manufacturers typically use the LHV to express the heat rate of combustion turbines.

Similarly, the electric energy output for an EGU can be expressed as either of two measured values. One value relates to the amount of total electric power generated by the EGU, or *gross* output. However, a portion of this electricity must be used by the EGU facility to operate the unit, including compressors, pumps, fans, electric motors, and pollution control equipment. This within-facility electrical demand, often referred to as the parasitic load or auxiliary load, reduces the amount of power that can be delivered to the transmission grid for distribution and sale to customers. Consequently, electric energy output may also be expressed in terms of *net* output, which reflects the EGU gross output minus its parasitic load. It is important to note that this value represents the net output delivered to the electric grid and not the net output delivered to the end user. Electricity is lost as it is transmitted from the point of generation to the end user and these “line losses” increase the farther the power is transmitted.[21] Subpart TTTT of the NSPS currently provides a way to account for the environmental benefit of reduced line losses by crediting CHP EGUs—which are typically located close to large electric load centers.[22]

When using efficiency to compare the effectiveness of different combustion turbine EGU configurations and the applicable GHG emissions control technologies, it is important to ensure that all efficiencies are calculated using the same type of heating value (*i.e.*, HHV or LHV) and the same basis of electric energy output (*i.e.*, MWh-gross or MWh-net).

Although for a given fuel there is a direct inverse correlation between combustion turbine EGU efficiency and CO_2 emissions[23] (*i.e.*, as efficiency goes up, CO_2 emissions go down and vice versa), other factors must be considered when comparing the effectiveness of GHG control technologies to improve the efficiency of a given combustion turbine EGU. The actual overall efficiency that a given combustion turbine EGU achieves is determined by the interaction of a combination of site-specific factors that impact efficiency to varying degrees. These factors include:

- *EGU equipment and components:* The design specifications of major EGU components such as the combustion turbine engine, HRSG, steam turbine, electrical generators,

[20] The HHV of natural gas is 1.108 times the LHV of natural gas. Therefore, the HHV heat rate (or efficiency) is equal to the LHV heat rate (or efficiency) divided by 1.108. For example, an EGU with a LHV heat rate of 5,740 Btu/kWh (59.4 percent LHV efficiency) is equal to a HHV heat rate of 6,360 Btu/kWh (53.6 percent HHV efficiency).

[21] Line losses are the product of the square of the current that passes through the wires multiplied by the resistance of the wires. The resistance of the wire is the product of the conductivity of the wire (a property of the conductor used to construct the wire) and the length of the wire divided by the cross-sectional area of the wire. All else equal, a transmission line that is twice as long will have twice the line losses.

[22] The electric transmission and distribution factor (TDF) in subpart TTTT provides a 5 percent credit to account for the improved delivered net output for EGUs located close to electric load centers (See §60.5540(a)(5)(i) and the definitions of gross energy output and net energy output in §60.5580).

[23] The use of carbon capture technology is an exception. While capturing carbon emissions lowers GHG emissions, the energy required to run the equipment reduced both the gross and net efficiency of an EGU.

electric motors, etc., provided by equipment manufacturers can affect overall EGU efficiency.

- *EGU plant size*: Combustion turbine engines range from approximately 30 kilowatts of electrical power (kWe) microturbines to 440 megawatts of electrical power (MWe) frame units. Combustion turbine efficiency generally increases with size because the losses are lower for larger equipment. However, as equipment size increases, the differences in these losses start to taper off.
- *EGU pollution control systems*: The electricity and/or steam consumed by air pollution control equipment reduces the overall efficiency of the EGU.
- *EGU operating and maintenance practices*: The specific operating and equipment maintenance practices used by the owner/operator of an EGU can affect the overall efficiency of the source.
- *EGU cooling system*: The temperature of the cooling system impacts the steam turbine performance of a combined cycle EGU. Recirculating cooling systems (*e.g.*, cooling towers) have an efficiency advantage over dry cooling systems. While the use of once-through cooling systems results in the highest efficiencies, the relatively large water-related ecological concerns limit the use of open cooling system in the United States.
- *EGU geographic location*: The elevation and seasonal ambient temperatures at the facility location may have a measurable impact on EGU efficiency. At higher elevations, air pressure is lower, and less oxygen is available for combustion per unit volume of ambient air than at lower elevations, thereby reducing combustion turbine EGU output but not impacting other parameters. Cooler ambient temperatures increase the overall combustion turbine EGU efficiency and output by decreasing the air compressor workload, increasing the draft pressure of the HRSG flue gases and the condenser vacuum, and by increasing the efficiency of a condenser cooling system.
- *EGU load generation flexibility requirements*: Operating an EGU as a base load unit is more efficient than operating an EGU as a non-base load[24] (load cycling or peaking) unit to respond to fluctuations in customer electricity demand.

Because of these factors, combustion turbine EGUs that are identical in design but operated by different companies in different locations may have different efficiencies and corresponding GHG emission rates.

5.2 Efficiency Improvements

When the efficiency of the power generation process is increased, less fuel is burned to produce the same amount of electricity. All else equal, this provides the benefits of lower fuel costs and reduced air pollutant emissions (including CO_2). The EPA notes that this paper does not attempt to address the emissions impact of any potential rebound effect—that more efficient combustion turbines would be used more often. Many energy efficiency technologies are available for application to new combustion turbine EGU projects that can provide incremental improvements to the overall thermal efficiency. The energy efficiency technologies with the potential to achieve the greatest improvements in electric power generation efficiency involve EGU design,

[24] Base load EGUs operate at high loads most of the time. Peaking EGUs only operate a few hours a year during periods of high electric demand. Load cycling or intermediate load EGUs are dispatchable EGUs that are neither base load nor peaking units. There is not a universal definition for the different types of EGUs.

equipment selection, and cost decisions that are typically incorporated during the planning and engineering design phases for a new EGU project.

5.2.1 Selection of the Type of Combustion Turbine

An early design choice that impacts the emissions rate of a combustion turbine is the determination to build either a simple cycle EGU or a combined cycle EGU. While simple cycle EGUs have lower capital costs and generally provide more operational flexibility than combined cycle EGUs, they are less efficient and have higher fuel costs. Therefore, simple cycle EGUs are primarily used during periods of peak electric demand (*i.e.*, peaking EGUs that operate at lower capacity factors[25]). Due to their higher efficiencies, combined cycle EGUs often operate at higher capacity factors and can be considered base load EGUs. However, both simple cycle and combined cycle EGUs can be built with the intention to operate at intermediate capacity factors. One of the roles of these intermediate load EGUs is to provide backup to intermittent generating sources such as wind and solar. The decision of whether to build a simple cycle or a combined cycle EGU to serve intermediate load demand is determined on a case-by-case basis that incudes consideration of how it is anticipated the combustion turbine will be operated. Based strictly on the costs and performance for new EGUs included in EIA's Annual Energy Outlook (AEO) for 2021 (U.S. EIA, 2021a), combined cycle EGUs have lower levelized costs of electricity (LCOE) when annual capacity factors exceed 25 percent.

5.3 Simple Cycle Combustion Turbines

For a given fuel, a primary design choice that impacts the GHG emissions rate of a simple cycle turbine is selecting an efficient combustion turbine engine. For stationary sources, the most efficient simple cycle combustion turbines operate at pressure ratios greater than 40 (*i.e.*, the pressure exiting the compressor is more than 40 times atmospheric pressure) and have relatively low exhaust temperatures.[26] Combustion turbines are often divided into two categories—aeroderivative and frame turbine engines. Frame combustion turbines are designs that were always intended to operate in stationary applications while aeroderivative stationary combustion turbines are derived from designs that were originally intended for aviation. Aeroderivative combustion turbines typically are limited to approximately 100 MW in output, but start faster, are smaller, lighter, and have higher efficiencies than frame turbines of comparable size. However, turbine manufacturers have incorporated design elements of frame turbines into aeroderivative turbines and vice versa, narrowing any distinctive design or performance differences (Brooker, 2017).[27]

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[25] Capacity factor is the actual amount of fuel consumed divided by the amount of fuel that could theoretically be consumed if the EGU had operated at full load for the entire year. Capacity factor can also be expressed as the actual electrical output divided by the theoretical maximum electrical output.

[26] The most efficient simple cycle designs are relatively long to accommodate the additional compressor and turbine stages to optimize pressure ratio and energy extraction.

[27] Certain aeroderivative simple cycle combustion turbine designs have incorporated an intercooler between the low- and high-pressure compression stages and therefore requires a cooling system.

5.3.1 Maximum Theoretical Combustion Turbine Efficiency

The theoretical thermal efficiency[28] (η_B) for a combustion turbine that operates using the Brayton cycle is a function of the ratios of the atmospheric temperature (T_a) and the temperature at the exit of the compressor (T_b), expressed as:

$$\text{Ideal Brayton cycle efficiency: } \eta_B = 1 - T_a/T_b = 1 - T_{atmospheric}/T_{compressor\ exit}$$

Using thermodynamic relationships between temperature and pressure, efficiency can be expressed as:

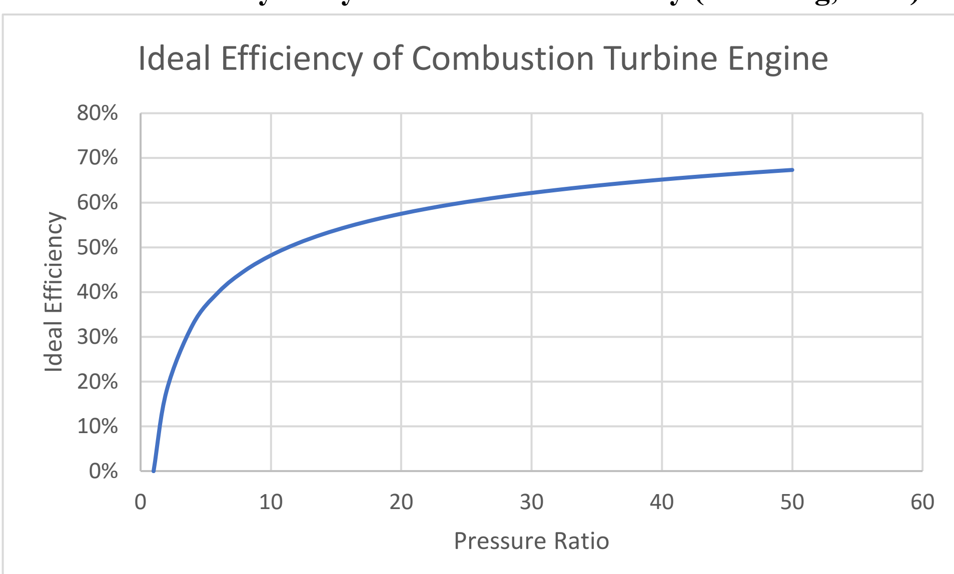
$$\eta_B = 1 - 1/TR = 1 - (1/PR)^{(\gamma-1)/\gamma}$$

Where:

TR =	temperature ratio of T_b/T_a
PR =	pressure ratio of compressor outlet pressure to inlet pressure
γ =	the ratio of the specific heat of air at a constant pressure to the specific heat capacity of air at a constant volume (1.4)

The theoretical operating efficiency of the Brayton cycle is most often plotted as a function of the pressure ratio (PR) and shown as follows:

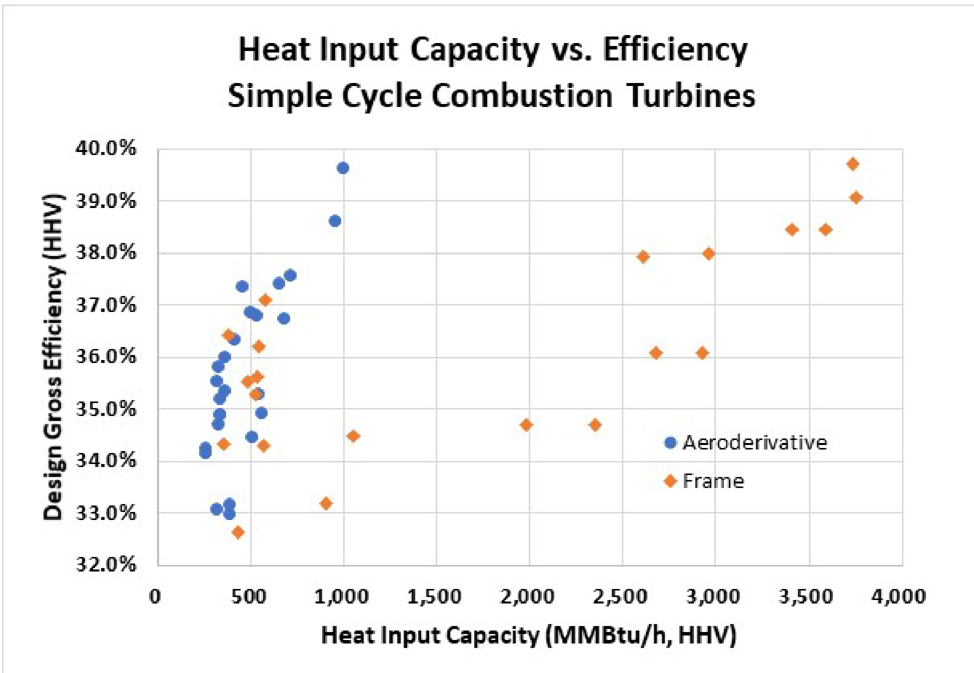
Exhibit 5-1. Brayton cycle theoretical efficiency (Ginsberg, 2016).



[28] The maximum theoretical efficiency of any heat engine is the Carnot efficiency.

The efficiency of the Brayton cycle is a function of the pressure ratio, the ambient air temperature, the turbine inlet air temperature, the efficiency of the compressor and turbine elements, the turbine blade cooling requirements, and any other performance enhancements (*e.g.*, recuperation, intercooling, inlet air cooling, and steam injection). Because combustion turbines reduce power output by reducing combustion temperature, efficiency at part load can be substantially below that of full-power efficiency (U.S. EPA, 2015). Exhibit 5-2 shows the design efficiency (as reported in Gas Turbine World (GTW) for multiple manufacturers) of 60 hertz simple cycle combustion turbines introduced after 2000. The trend is that efficiency generally increases with size, and that while certain aeroderivative designs have higher efficiencies than comparable-sized frame designs, on average comparable-sized aeroderivative and frame combustion turbines intended for simple cycle operation have similar design efficiencies.

Exhibit 5-2. Design efficiency of simple cycle combustion turbines.



The choice of NO_X emissions control technology can also impact the design efficiency and rated output of a combustion turbine. There are two primary types of combustion controls used with combustion turbines—the addition of water or steam, known as wet low-NO_X (WLN) or wet low emissions (WLE) technology, and staged air combustion systems, known as dry low-NO_X (DLN) or dry low emissions (DLE) technology. Both approaches reduce the peak flame temperature to reduce the formation of thermal NO_X. WLN can achieve NO_X emissions of approximately 25 parts per million volume (ppmv) for natural gas combustion and 42 ppmv for fuel oil combustion (NJ DEP, 2021; Schorr and Chalfin, n.d.). Various combustion turbine manufacturers have developed DLN combustion controls that can reduce NO_X emissions to single-digit ppm values when burning natural gas. However, DLN technology is more challenging for liquid fuels and WLN is generally used when fuel oils are combusted.

The use of WLN technology increases the power output of the combustion turbine due to increased mass flow, but the thermal energy required to vaporize the water increases the heat rate by approximately 3 percent (EPA, 1993). Efficiency and output can be improved if steam is produced using the thermal energy in the simple cycle turbine exhaust.[29] The output gain and efficiency loss will vary based on the specific turbine design. In Exhibit 5-3, GTW provides a direct comparison to determine the tradeoff on efficiency and output associated with WLN and DLN models of the same turbine. This is likely due to the distinct differences between the designs of combustion zones of engines in gas turbines, causing engine manufacturers to have different combustion technologies for different model turbines. Information was obtained for the Siemens Energy Trent 60, which is available in DLE and WLN combustion technologies. A comparison of key performance information for the Trent 60 is provided below:

Exhibit 5-3. Comparison of industrial Trent 60 WLN and DLE performance.

Model	Hz	ISO Base Load (kW)	Efficiency (%)	WLN Efficiency Impact (%)	WLN Power Impact (%)
SGT-A65 DLE ISI	60	64,900	43.3	-	-
SGT-A65 WLN ISI	60	78,500	42.5	-0.8	+20.9%

Source: Gas Turbine World (2020), p.16.

5.3.2 Impact of Ambient Conditions on Simple Cycle Combustion Turbines

While ambient conditions impact both combustion turbine engine maximum output and efficiency, there are strategies owners/operators can take to maximize efficiency, and decrease GHG emissions, under different ambient conditions. A combustion turbine operates on a fixed maximum input of air to the compressor. At higher temperatures and elevations, the density of the air entering the compressor is lower, reducing the mass flow through the turbine and consequently less air is available for combustion. Since the combustion turbine maximum heat input is reduced, the combustion turbine engine output is less than the rated output. In addition, as the air inlet temperature increases, more work is required to accomplish the specified pressure rise. The increased work is provided by the turbine and less is available to rotate the generator to produce electricity. At lower temperatures the opposite occurs—output and efficiency increases compared to design specifications. For every degree °C increase in ambient temperature, combustion turbine output is decreased 0.5 to 1 percent and the heat rate increases 0.15 to 0.4 percent (Farouk *et al.*, 2013). One approach owners/operators of combustion turbines can take to reduce the efficiency and capacity losses due to higher ambient temperatures is precooling the combustion air.[30]

5.4 Combined Cycle Combustion Turbines

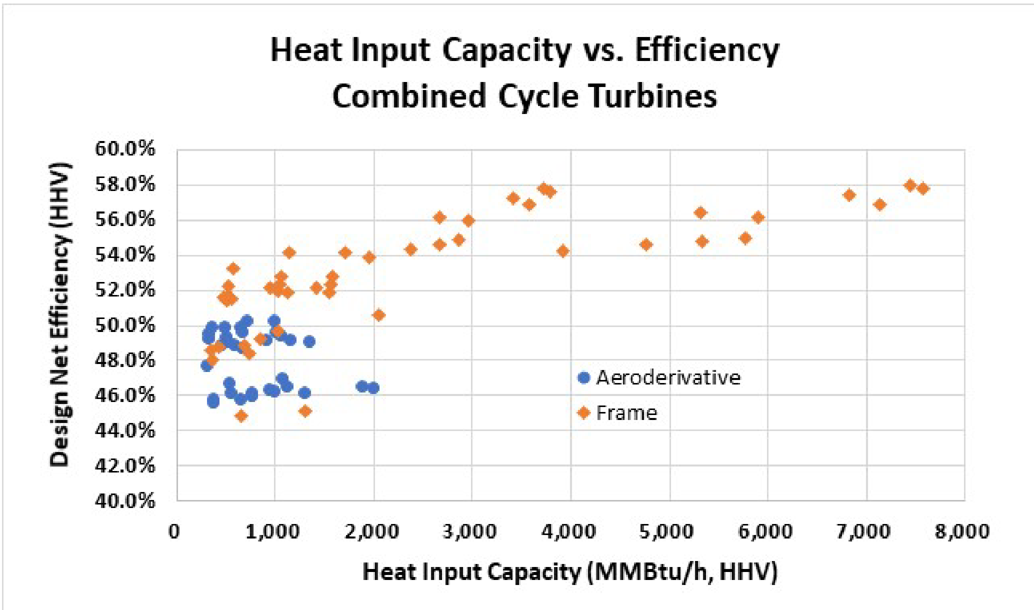
As opposed to the use of high pressure ratios that increase the efficiency of simple cycle EGUs, combined cycle EGUs often use turbine engines with lower pressure ratios to deliver higher mass flowrates and higher exhaust temperatures (Gas Turbine World, 2021) to maximize the overall

[29] Water/steam injection for NO_X control is different than a steam injected gas (STIG™) cycle or the Cheng Cycle®. These approaches use a HRSG to generate high-pressure, superheated steam and inject that steam into the combustion turbine to increase both the output and efficiency of the combustion turbine.

[30] Combustion air can either be cooled using an evaporative or a chilling system. Evaporative cooling adds liquid water to the combustion air and the air is cooled as the water evaporates. Evaporative cooling is limited by the wet bulb temperature and is most effective in areas with low humidity. Chilling systems use either mechanical or adsorption chillers to lower the temperature of the combustion air. Chilling systems can cool the air below the dew point temperature but can have significant auxiliary loads.

EGU efficiency (*i.e.*, using Brayton plus Rankine cycles). There are several variables that impact the theoretical efficiency of a given combined cycle EGU, and consequently, there is not a straightforward representation for the theoretical efficiency like there is for the Brayton cycle. Exhibit 5-4 shows that, like simple cycle EGUs, the efficiency of combined cycle EGUs increases with increasing size, and that combined cycle EGUs based on frame turbine engines are more efficient than similar-sized aeroderivative combined cycle EGUs.

Exhibit 5-4. Combined cycle efficiency.



Source: Gas Turbine World (2020)

State-of-the-art power blocks achieve design net thermal efficiencies greater than 58 percent on a HHV basis (64 percent on a LHV basis). The most efficient combined cycle EGUs utilize HRSGs with a steam reheat cycle and multi-pressure steam. A steam reheat cycle extracts and reheats steam that has been partially expanded in the steam turbine prior to expansion in the lower pressure portion of the turbine. A reheat module allows more efficient operation of the steam turbine and prevents formation of water droplets that can damage the steam turbine's lower pressure stages. The use of three discrete steam pressures (high pressure (HP), intermediate pressure (IP), and low pressure (LP)) maximizes efficiency. Each of these three sections contains separate superheater, evaporator, steam drum, and economizer modules. The HP steam section is located on the high-temperature end of the HRSG, closest to the combustion turbine exhaust duct. The LP steam section is located on the low-temperature end of the HRSG, just before the stack. This arrangement maximizes the degree of superheat (*i.e.*, the quantity of energy per pound of steam) delivered to the steam turbine. Simpler, low-cost, less-efficient HRSGs are also available in single-, double-, and triple-pressure designs and without a reheat cycle. Double-pressure and triple-pressure HRSG without a reheat cycle have efficiencies of approximately 20 and 26 percent, respectively. A triple-pressure HRSG with a reheat cycle improves the efficiency of thermal energy to electrical output to approximately 30 percent.[31] After the energy has been extracted for steam production, the flue gas enters an economizer, which preheats the condensed feedwater recycled back to the HRSG. The final heat recovery section is the fuel preheater, which preheats the fuel used for the combustion turbine. Integrated fuel gas heating results in higher turbine efficiency due to the reduced fuel flow required to raise the total gas temperature to firing temperature. Fuel heating reduces the output of the combustion turbine but improves the efficiency by approximately 0.6 percent.

5.4.1 Fast Start/Flexible Combined Cycle EGUs

Combined cycle EGUs built before the increase in generation from intermittent sources (*i.e.*, renewables) were often designed and intended to operate for extended periods of time at steady loads. Since combined cycle EGUs were not intended to start and stop on a regular basis, they have relatively long startup times. With increased generation from intermittent sources, more flexible combined cycle EGU designs were developed. These fast-start, combined cycle EGUs incorporate multiple techniques to allow the EGU to start and stop faster, cycle output faster, and maintain higher part load efficiencies than previous designs. These design features include an HRSG bypass stack that allows the combustion turbine engine to operate independent of the HRSG. This approach allows the turbine engine to come to full load quickly and operate in simple cycle mode. The HRSG can then be slowly brought to temperature while the combustion turbine engine operates at high load.[32]

Design features have also been incorporated to allow the HRSG to begin operation more rapidly. These features include the use of stack dampers, purge credits, and an auxiliary boiler. Stack dampers conserve heat in the HRSG by reducing airflow and the associated heat losses while the EGU is not operating. Purge credits involve purging the fuel systems during shutdown and adding isolation valves in the fuel supply system. Previous combined cycle EGUs were required to purge residual fuel from the combustion system with fresh, ambient air prior to commencing operation to remove any excess combustible fuels in the unit. However, this increased start times, reduced efficiency by decreasing the temperature of the HRSG, and increased thermal fatigue on the units. Generating purge credits during shutdown allows the EGU to start up without a purge. An auxiliary boiler may also be used to maintain the HRSG temperature, reducing the time required for an HRSG to begin producing steam.

The design of the HRSG can also impact how long it takes to start producing steam and generating power. While relatively inefficient, a dual-pressure HRSG without a reheat cycle has a simpler startup procedure and can start quicker than a more efficient triple-pressure HRSG with a steam reheat cycle. The use of a once-through HRSG[33] can also improve the ability of a combined cycle EGU to start quickly and maintain efficiency at part load. A once-through HRSG does not have a steam drum like a more traditional HRSG. Instead, the feedwater is

[31] According to Gas Turbine World, all aeroderivative and frame combined cycles with base load ratings of less than 500 MMBtu/h use double-pressure HRSG. Triple-pressure HRSG without a reheat cycle are used for frame combined cycle EGUs up to 2,000 MMBtu/h, and triple-pressure HRSG with a reheat cycle are used for frame combined cycle EGUs with base load ratings of greater than 2,000 MMBtu/h.

[32] Previous combined cycle designs had to operate the combustion turbine engine at low loads to slowly increase the HRSG temperature. Configurations with a stack bypass can slowly increase the percentage of the combustion turbine engine exhaust into the HRSG to increase the HRSG temperature without damage.

[33] Once-through HRSG are sometimes referred to as Benson® HRSG.

converted to steam in the HRSG furnace waterwalls and goes directly into the steam turbine. This allows for the use of higher-pressure steam, which improves design efficiencies, provides higher part-load efficiencies, allows reduced startup times, and results in more flexible operation.

5.4.2 Duct Burner/Supplemental Firing

The exhaust from combustion turbines contains significant amounts of excess oxygen that can support additional fuel combustion. Duct burners are optional supplemental burners located in the HRSG that are used to increase the flue gas temperature and generate additional steam.[34] In theory, heat input to duct burners could be twice that of the combustion turbine engine but are more often sized at 10 to 30 percent of the heat input to the combustion turbine engine. Duct burners are often used during periods of high electric demand to generate additional incremental electricity. While the efficiency of the incremental generation is less than the overall efficiency of a combined cycle EGU, it can be more efficient than a standalone Rankine cycle or a separate simple cycle EGU used for peaking applications. Duct burners that are relatively small and only designed to make up steam turbine capacity lost due to high ambient temperatures do not impact the efficiency of the combined cycle EGU when they are not operating. However, large duct burners that are designed to significantly increase the output of the steam turbine can negatively impact the efficiency of the combined cycle EGU when not operating. To accommodate the additional steam generated by the duct burners, the steam turbine may need to be oversized relative to operation without the duct burners. Since steam turbines are less efficient when operated at part load, this can decrease the overall efficiency of the combined cycle EGU. The efficiency impacts should be weighed against the anticipated displaced generation when determining the emissions standard for a new combined cycle EGU.

5.4.3 Cooling Technology for Rankine Cycle

Simple cycle turbines do not include a Rankine cycle and therefore do not require a cooling/condensing cycle. However, combined cycle EGUs include a Rankine cycle and need a cooling cycle to condense the generated steam back to liquid water and return it to the HRSG for reuse through high-pressure feed pumps. Heat from the condensing steam is rejected to the cooling technology. The lower the temperature that the cooling system can achieve the more efficient the Rankine cycle. The cooling system can either be a recirculating, hybrid, or dry cooling system.[35]

Recirculating cooling systems are closed systems in which the water extracted for cooling is evaporated in the cooling tower. Cooling towers reduce water impacts compared to once-through systems but still require water to operate. Dry cooling systems use air heat exchangers to provide cooling and minimize water impacts. Dry cooling systems eliminate the adverse environmental impacts caused by cooling tower intake structures. A drawback of dry cooling systems is that the

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[34] While the common approach is for the duct burners to burn the same fuel as the combustion turbine engine, any fuel could be used to provide supplemental heat. The Gerstein power plant, unit K, in Germany integrates a natural gas-fired combustion turbine engine that discharges the exhaust directly into the coal-fired boiler. This essentially creates a combined cycle EGU with a coal-fired heat recovery steam generator.

[35] Open (once-through) cooling systems use an open system that extracts cooling water directly from a waterbody and returns it to the same waterbody at a higher temperature. This type of cooling results in the lowest temperature and most efficient operation but has greater adverse environmental impacts. Therefore, new EGUs cannot use open cooling systems.

EGU is unable to reach as low of a condensing temperature and is, therefore, less efficient. A hybrid cooling system combines recirculating and dry systems in one integrated system. Depending on the specific design, the owner/operator can adjust the amount of cooling that is accomplished by dry and recirculating systems to reduce water use compared to a fully recirculating system. While the choice of cooling technology has less of an impact on overall efficiency of a combined cycle EGU than for a coal-fired EGU,[36] it is an important factor to consider when comparing efficiencies and GHG emission rates of EGUs. Approximately a quarter of combined cycle EGUs that have commenced operations since 2010 use hybrid or dry cooling.[37] A combined cycle EGU using an open cooling system would be expected to have an emissions rate 0.5 percent lower than a comparable combined cycle EGU with a recirculating cooling system. Combined cycle EGUs using hybrid and dry cooling systems would be expected to have emissions rates 0.8 percent and 1.6 percent higher than a comparable combined cycle EGU using a recirculating cooling system.[38]

5.4.4 Impact of Ambient Conditions on Combined Cycle EGUs

Like simple cycle EGUs, ambient conditions impact both output and efficiency of combined cycle EGUs. At higher temperatures, the efficiency and output of the turbine engine decreases and the temperature of the turbine engine exhaust increases. The higher exhaust temperature allows additional energy to be recovered in the HRSG and the resultant increase in generation from the steam turbine partially offsets some of the combustion turbine engine efficiency loss. In addition, as described in the cooling technology section, the efficiency of the Rankine cycle decreases with increased ambient temperatures. The overall effect of these parameters is shown in Exhibit 5-5.

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[36] A typical coal-fired EGU uses a Rankine cycle to generate all the electrical output, but only approximately one-third of the output from a combined cycle EGU is from the Rankine cycle.

[37] EIA 923 data can be downloaded from https://www.eia.gov/electricity/data/eia923/.

[38] Assumes one-third of the overall output is generated from the steam turbine and that a hybrid system has half the efficiency impact relative to a dry system. See Coal Industry Advisory Board to the International Energy Agency, "Power Generation from Coal," (Paris, 2010). (https://iea.blob.core.windows.net/assets/3dcfe688-35cf-46fe-9d80-27828a56fd80/power_generation_from_coal.pdf).

Exhibit 5-5. Impact of temperature on combined cycle performance.

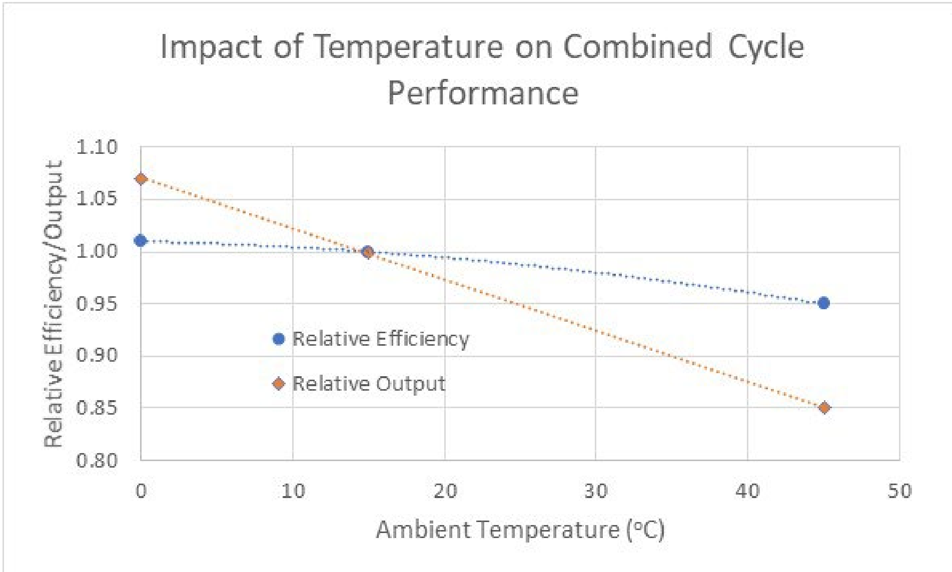

Exhibit 5-5 demonstrates that the impact of ambient temperature on annual emission rates is relatively minor compared to other factors that influence efficiency but should be accounted for when comparing emission rates of combined cycle EGUs.

5.4.5 Potential Efficiency Gains in the Bottoming Cycle

Combined cycle EGUs typically have HRSGs that operate at subcritical steam conditions with pressures of 2,400 pounds per square inch (psi), or 17 megapascal (MPa), and temperatures of 1,112 °F (600 °C). However, once-through HRSGs can be designed to operate using supercritical steam conditions. "Supercritical" is a thermodynamic term describing the state of a substance in which there is no clear distinction between the liquid and the gaseous phase (*i.e.*, they are a homogenous fluid). Supercritical EGUs can be designed to operate at steam pressures higher than 3,200 psi (22 MPa). A combined cycle EGU designed to use supercritical steam conditions in the high-pressure portion of the steam turbine would reduce fuel use by 2 percent (Marcin).

In addition, alternate working fluids (*i.e.*, the use of organic fluids or supercritical CO_2 rather than steam) also have the potential to increase the efficiency of combined cycle EGUs. Organic Rankine cycles are primarily applicable to temperatures lower than combustion turbine engine exhaust temperatures.[39] DOE's National Energy Technology Laboratory (NETL) is working on improvements to a supercritical CO_2 cycle power cycle.[40] While the use of supercritical CO_2 as the working fluid in a Rankine cycle (Patel, 2021b) is of most interest for nuclear and coal-fired EGUs, it also has the potential to improve the overall efficiency of combined cycle EGUs. The primary efficiency benefit would be for combined cycle EGUs using smaller frame or aeroderivative combustion turbine engines that typically use a double-pressure HRSG without a

[39] The Kalina Cycle® is another cycle that has the potential for efficiency gains compared to a water-based Rankine cycle. See http://www.kalinapower.com/technology/.
[40] See https://netl.doe.gov/project-information?p=FE0028979/.

reheat cycle (Huck *et al.*, 2016).[41] However, a HRSG using supercritical CO_2 has the potential to improve the efficiency of combined cycle EGUs compared to triple-pressure steam with a reheat cycle as well (Thanganadar *et al.*, 2019).

Combined cycle EGUs generate significant quantities of relatively low-temperature heat (*i.e.*, waste or byproduct heat) that cannot be used by the traditional Rankine cycle and is sent to the power plant cooling system (*i.e.*, cooling tower). If this energy could be recovered to produce additional electricity, it could reduce the environmental impact of power generation. Thermoelectric materials (*e.g.*, bismuth telluride (Bi_2Te_3), lead telluride (PbTe), silicon-germanium (SiGe, magnesium antimonide (Mg_3Sb_2), and magnesium bismuthide (Mg_3Bi_2)) can be used to generate electricity due to temperature differences across the material.[42] While still in development, this technology has the potential to recover useful energy from the waste heat from power plants. However, if a thermoelectric generator were able to convert 5 percent of combustion turbine waste heat to electric output, the CO_2 emissions rate for simple cycle EGUs would be reduced by approximately 10 percent and combined cycle EGUs by approximately 5 percent.

5.5 Combined Heat and Power (CHP) Plant

Combined cycle EGUs dedicated to electric power generation and using the latest commercially available advanced technologies can have net design efficiencies of greater than 60 percent on a LHV basis. Significant amounts of energy are lost during the steam condensation segment of the Rankine cycle due to heat transfer into the cooling water. CHP, also known as cogeneration, is the simultaneous production of electricity and/or mechanical energy and useful thermal output from a single fuel. CHP uses the energy lost during steam condensation of an electric-only EGU. The temperature of the cooling water is normally not high enough to meet the requirements for most industrial (*i.e.*, steam) or commercial process (*i.e.*, district heating) applications. Therefore, steam is often extracted at an elevated pressure and temperature from an intermediate stage of the steam turbine and then used for the industrial or commercial process. This results in a decrease in the total electric power generation from the EGU. However, the overall fuel efficiency of CHP can be 80 percent or higher and requires less fuel overall than if the electricity and steam were generated separately.[43]

Because electricity can be transmitted over long distances, EGUs are located in remote as well as populated areas. However, thermal energy cannot be effectively transported over extended distances. This limits the practicality of incorporating a CHP mode into many EGU designs. A CHP EGU needs to be in proximity to either an industrial or commercial facility with a significant and steady thermal demand. It can be challenging to locate a thermal host with sufficiently large thermal demands such that the useful thermal output would impact the

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[41] Using the design HRSG efficiencies listed in Gas Turbine World and the efficiency of the design efficiency of the Echogen supercritical EPS100 heat recovery system (24 percent net, https://www.echogen.com/our-solution/product-series/eps100/), the median decrease in design heat rates for replacing dual-pressure HRSG with supercritical CO_2 HRSG is 7 percent.

[42] Electricity can also be generated from electrochemical reactions at different temperatures and pressures, see https://jtecenergy.com/technology/. In addition, thermogalvanic cells use temperature differences to generate an electric current. See *e.g.*, Yuan (2014).

[43] According to form EIA-923, in 2019, CHP installations accounted for 10 percent of installed capacity and 15 percent of electricity generated in the U.S.

emissions rate. However, the refining, chemical manufacturing, pulp and paper, food processing, and district energy industries tend to have large thermal demands and there are several examples where co-located combustion turbine CHP EGUs are providing reliable, low-cost thermal energy to thermal hosts. To the extent that a proposed EGU is in proximity to a thermal host, it may be possible to investigate if it is economically feasible to design the EGU as a CHP facility.

5.6 Integrated Non-Emitting Generation

The co-location of two or more sources of electricity generation—known as a hybrid power plant—is another approach that can reduce the onsite output-based emissions rate.[44] There are multiple configurations for how these hybrid systems can be designed, but for the purposes of this discussion, examples have been categorized as either steam-cycle integrated (*i.e.*, contributes energy or heat to the steam cycle of a combustion turbine) or energy-output integrated (*i.e.*, contributes to the total energy output of the affected facility). There are limited examples of the co-location of a combustion turbine with integrated renewables, but as energy storage technology continues to advance, onsite storage is becoming a more common feature.

Hybrid power plants are not new technology. According to an analysis by the Lawrence Berkeley National Laboratory (LBNL) that mapped hybrid, co-located power plants in the U.S. based on EIA Form 860 data, there were 125 co-located projects in 2019 with a total output of almost 13.5 GW (Wiser *et al.*, 2020).

As the following LBNL graphic (Exhibit 5-6) indicates, there are many configurations of integrated sources of generation that could be considered; but, in terms of the number of projects, the combination of solar (*i.e.*, photovoltaic or PV) plus storage (40) is the most common followed by PV plus fossil-fired generation (26) (Wiser *et al.*, 2020). In terms of capacity, PV plus fossil is by far the largest (6,953 MW), ahead of fossil plus storage (2,414 MW), and wind plus storage (1,290 MW) (Wiser *et al.*, 2020).

[44] The definition of an affected facility in 40 CFR part 60, subpart TTTT includes "any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment."

Exhibit 5-6. Hybrid/co-located projects of various configuratons.

125 projects, 13.4 GW of generating capacity, 0.9 GW storage capacity

Installed at end of 2019	# projects	Gen 1 (MW)	Gen 2 (MW)	Gen 3 (MW)	Total Gen (MW)	Storage capacity (MW)	Storage energy (MWh)	Storage: generator ratio	Duration (hrs)
Wind+Storage	13	1,290	0	0	1,290	184	109	14%	0.6
Wind+PV+Storage	2	216	21	0	237	34	15	15%	0.4
Wind+Fossil+Storage	1	5	12	0	17	1	1	7%	0.8
Wind+PV+Fossil+Storage	1	0.1	0.1	1	1	0	1	25%	1.7
Wind+PV	6	535	212	0	747	0	0	0%	n/a
Wind+PV+Fossil	3	6	2	98	106	0	0	0%	n/a
Wind+Fossil	8	27	79	0	106	0	0	0%	n/a
PV+Storage	40	882	0	0	882	169	446	19%	2.6
PV+Fossil	26	77	6,876	0	6,953	0	0	0%	n/a
PV+Fossil+Storage	3	9	10	0	20	5	9	24%	1.9
PV+Biomass	3	4	15	0	19	0	0	0%	n/a
PV+Geothermal	2	18	85	0	103	0	0	0%	n/a
PV+Geothermal+CSP	1	22	47	2	71	0	0	0%	n/a
CSP+Storage	2	390	0	0	390	390	2,780	100%	7.1
Fossil+Storage	10	2,414	0	0	2,414	91	84	4%	0.9
Hydro+Storage	4	71	0	0	71	12	11	17%	0.9

Sources: EIA 860 2019 Early Release, Berkeley Lab

Note: **Pumped hydro** is not considered a hybrid resource for the purpose of this compilation. The hydro+storage plants noted in the table pair hydropower with batteries.

5

5.6.1 Steam-Cycle Integrated Renewables

The integration of renewable sources of energy into the operation of a combustion turbine in such a manner as to augment its performance, efficiency, and/or output is an option for reducing GHG emissions. An efficient and cost-effective renewable pairing for a combined cycle EGU has been demonstrated to be concentrated solar thermal, particularly in terms of the capital costs of the technology and the cost of carbon abatement (Alqahtani and Patino-Echeverri, 2016).

In the U.S., the best example of a steam-cycle integrated, large-scale operating system that increases combustion turbine efficiency is at the Martin Next Generation Solar Energy Center in Indiantown, Florida. According to permits made available online by the Florida Department of Environmental Protection (FDEP), the Florida Power & Light facility operates five EGUs, with Unit 8 being a 4-on-1 combined cycle EGU with a capacity of 1,150 MW and connected to a 75-MW concentrated parabolic solar thermal array (FDEP, 2021). In this system, called Integrated Solar Combined Cycle (ISCC), solar energy is concentrated by parabolic polished steel mirrors onto stainless steel tubes containing specialized heat transfer fluid, and after being heated, the fluid is pumped to a heat exchanger where the auxiliary heat is integrated into the pre- and post-combustion steam cycle for the turbine (Neville, 2011). The solar array at Martin, which is owned by NextEra Energy, came online in 2010 and utilizes a 500-acre area that was originally permitted to be a coal-fired facility in 1989. The energy from the solar thermal array does not increase the capacity of the EGU but rather reduces fuel consumption by 1.3 billion cubic feet per year, saving approximately $180 million in fuel costs and reducing CO_2 emissions by 2.75

million tons over 30 years (Neville, 2011). At the time of construction, Martin was eligible for a \$120 million federal investment tax credit that further reduced capital costs associated with the project (Neville, 2011).

It should be noted that the steam-cycle integration of non-emitting sources at Martin could not be achieved if combustion turbines did not operate as base load generators of electricity. As EPA noted in its 2018 proposed amendments to the NSPS, one of the primary benefits of ISCC is that by co-locating the solar system with a natural gas-fired combustion turbine, it creates incremental cost reductions for the solar thermal electricity (83 FR 65446).

Another example of an ISCC facility is the Archimede demonstration power plant in Sicily, Italy. The plant, which has been in operation since 2010, performs much like the Martin facility in that thermal energy from a concentrated solar array is integrated into the steam cycle of a combustion turbine to increase efficiency and achieve fuel and emissions reductions. But Archimede is unique because it is the first power plant in the world to use molten salt as the heat transfer fluid and for thermal energy storage (Maccari *et al.*, 2015). According to facility data listed online by the National Renewable Energy Laboratory (NREL, 2021), the molten salt heat transfer fluid that passes through the 5-MW, 27-acre parabolic solar array is fed to a "hot" storage tank, which can store up to 100 MWh of thermal energy for 8 hours. The molten salt transfer fluid (60 percent sodium nitrate, 40 percent potassium nitrate) can then be drawn into a heat exchanger to generate steam for the combined cycle system (Maccari *et al.*, 2015). The cooled salt transfer fluid is then sent to a "cold" tank prior to being recirculated through the concentrated solar array and reheated. This thermal energy storage system allows Archimede to continue utilizing solar energy regardless of time of day or weather conditions.

Examples of other power plants where natural gas-fired EGUs are integrated with concentrated solar thermal arrays include Kuraymat in Egypt, Yazd in Iran, Hassi R'mel in Algeria, and Ain Beni Mathar in Morocco. There are two recent instances in California of ISCC projects being canceled, but not due to any limitations of the technology. Those projects are the 570-MW gas and 50-MW solar plant in Palmdale and the 518-MW gas and 50-MW solar plant in Victorville. In both situations, following lengthy permitting processes, public opposition, and the inability to obtain power purchase agreements (PPAs) in California for fossil fuel-based electricity, the projects were canceled in 2019 and 2018, respectively (Gatlin, 2019; Johnson, 2018).

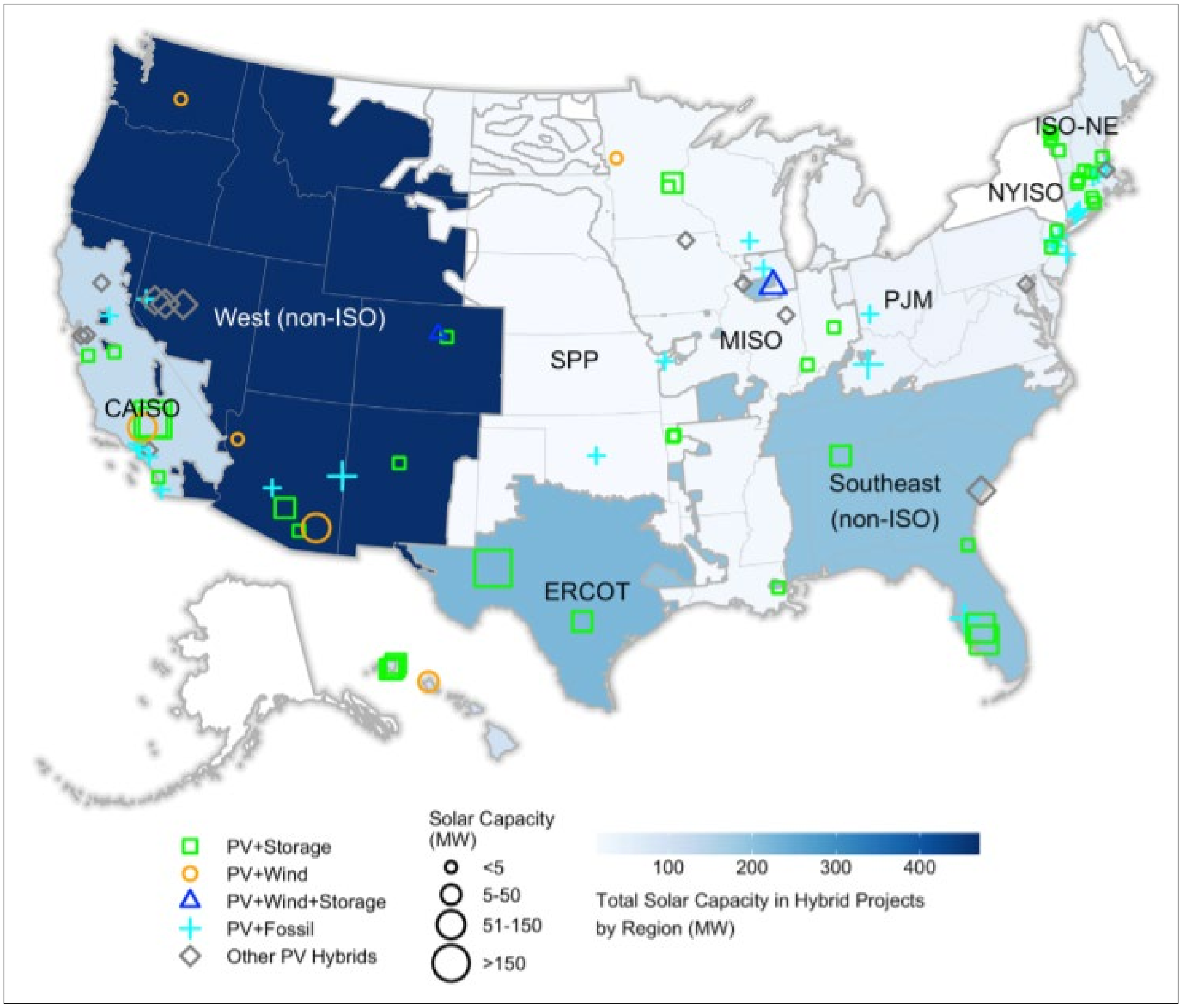
5.6.2 Energy-Output Integrated Renewables

There are also opportunities for a fossil fuel-fired power plant to add renewables to its onsite generation mix even though the system operates independently of the steam cycle. This may include onsite renewables that factor into the total electric output and reduce the total emissions rate of the fossil fuel EGU(s). Power plants with the physical space for a solar array, wind turbines, or hydroelectric (*i.e.*, co-located run of river or electric generation from the dam used to create the lake used for cooling), can achieve emissions reductions and environmental benefits (Dykes *et al.*, 2020).

One such facility with a diverse, integrated generation mix is the E.W. Brown Generating Station near Harrodsburg, Kentucky. Operated by Louisville Gas & Electric (LG&E) and Kentucky Utilities (KU), E.W. Brown operates one 457-MW coal-fired EGU and seven natural gas-fired combustion turbines with combined capacities of approximately 900 MW. According to information posted online by LG&E and KU (LG&E-KU, 2021), onsite renewable generation includes a 33-MW hydroelectric dam and a 10-MW solar array. The hydroelectric plant is located adjacent to the facility on Herrington Lake and the 44,000-panel solar array was added in 2016 and is located on 50 acres of plant property.

Exhibit 5-7 below was produced by LBNL and depicts the co-located hybrid projects as of 2019 within the structure of the regional grids in the U.S.

Exhibit 5-7. Co-located hybrid power plants.



Advantages of siting renewable projects at new (or existing or former fossil-fired facilities) are reduced grid interconnection costs and reduced environmental and social impacts. Often worth hundreds of millions of dollars, an interconnection point to enter a dispatch queue is critical (Tomich, 2021). For example, in the Midwest and Mid-Atlantic regions there are renewable projects with PPAs in place that are having to withdraw from interconnection queues because of market congestion, the cost of required transmission upgrades, and the added years it will take to get their energy to customers (Tomich, 2021). The transmission costs and the environmental and social impacts associated with transmission of intermittent renewable generation are higher than dispatchable generation. One reason is that dedicated lines for renewable generation can have relatively low capacity factors that increase the costs, and the environmental and social impacts of transmission per MWh of electricity transmitted to the end user.[45] Co-locating intermittent generating sources with dispatchable generation decreases these costs and associated environmental and social impacts.[46]

Co-location can also reduce the costs and environmental impacts of the land required for electric generation from renewable sources of power. Large solar arrays and wind farms can require thousands of acres to produce enough electricity to replace a single fossil fuel-fired plant and developers often must secure land-use agreements with facility neighbors in addition to the approval of local zoning boards and public utility commissions (Tomich, 2021). The land-use challenges of siting large solar and wind projects are considerable and can be controversial. The co-location of renewables with new combustion turbine EGUs generally can reduce any potential land use impacts because the renewable generation is located on land that would likely not otherwise be used for agriculture or wildlife habitat. For example, installing PV panels on the rooftop and over the parking lot of a new combined cycle facility could add 50 kW of renewable generation with essentially no land use implications. If that same 50 kW were built as a standalone facility, the land use impacts from disrupting former forested or agricultural land would be greater.[47] The land-use requirements of solar and wind can be tempered by the utilization of co-location with agricultural land,[48] offshore wind turbines, expanded solar on

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[45] Renewable generating sources located far from electric demand centers require longer transmission lines than generation located close to end users. The line losses associated with transmitting the power results in less efficient delivered net efficiency. Longer transmission lines also have higher costs and greater externalities (*i.e.,* land use impacts).

[46] The capacity factor for transmission lines dedicated for intermittent renewable generation can also be improved by co-locating energy storage with the intermittent generation. Existing wires can also be replaced with high-performance conductors capable of transmitting more electricity (See https://www.utilitydive.com/spons/5-reasons-utilities-are-switching-to-high-performance-overhead-conductors/568808/ and https://www.ctcglobal.com/efficiency/), reducing the land use and social impacts (*e.g.*, impact on property values, open space, and wildlife habitat) from new transmission lines. High voltage direct current (HVDC) transmission lines are also able to transmit more power than high voltage alternating current (HCAC) lines with reduced land use impacts, energy losses, material requirements (less embodied carbon), and noise (reducing audible impacts on residents) (See https://www.electricaltechnology.org/2020/06/difference-between-hvac-hvdc.html and https://www.electricaltechnology.org/2020/06/advantages-of-hvdc-over-hvac-power-transmission.html). Locating new transmission lines underground along existing rail lines has also been proposed and this approach would reduce the environmental and social impacts of new transmission lines (See https://www.soogreenrr.com/direct-connect-development-company/ and https://www.utilitydive.com/news/transmission-troubles-a-solution-could-be-lying-along-rail-lines-and-next/587703/).

[47] PV added to former agricultural or forested land reduces wildlife habit, can increase rainwater runoff, and increase local temperatures due to heat island impacts. The impacts of large scale solar can be reduced by planting native plants to create pollinator friendly habits and creating wildlife corridors. See https://www.renewableenergymagazine.com/emily-folk/how-solar-energy-can-coincide-with-crop-20201119; https://www.nature.org/content/dam/tnc/nature/en/documents/ED_TNCNCPrinciplesofSolarSitingandDesignJan2019.pdf; http://ncpollinatoralliance.org/wp-content/uploads/2018/10/NC-Solar-Technical-Guidance-Oct-2018.pdf; and https://www.nature.org/en-us/about-us/where-we-work/united-states/north-carolina/stories-in-north-carolina/making-solar-wildlife-friendly/

[48] Using land for the dual purpose of solar energy and crop and/or animal agriculture is referred to as agrivoltaics. The panels are elevated 7 to 9 feet and spaced apart to allow sunlight to reach the plants below. While the panels reduce the available energy for photosynthesis and the ability to use certain mechanized agricultural techniques, the shading effect can create cooler microclimates that increase the efficiency of the solar panels, reduce water losses

already disturbed (*e.g*., rooftops, parking lots), and degraded land (Merrill, 2021; U.S. EPA, 2021a). A disadvantage of integrated renewables is that the location might not be ideal and there may be limited physical space at a power plant, especially if located in a more urban or industrial area, that can constrain the size of a solar array or wind farm and thereby limit the potential of non-emissions generation (Gorman *et al.*, 2020).

5.6.3 Integrated Energy Storage

There are several energy storage options that can provide either short-term and/or long-term storage capacity. The type of energy storage technology used for a particular application is dependent upon many variables, such as intended goals, cost, safety, the process receiving energy, and space constraints. Generally, energy storage that discharges in less than 1 minute is used for grid support (*i.e*., voltage and frequency regulation) and short-term storage (2 to 4 hours) is ideal to provide peak power generation. Medium-term storage (4 to 10 hours) is ideal to normalize daily integrated plant output at renewable energy sources while long-term bulk energy storage can address seasonal variations in energy generation and demand.

The following table summarizes various integrated storage options, several of which are discussed in more detail later in this subsection.

Exhibit 5-9. Energy Storage Technologies

Power Quality	Typical Duration	Example Technologies
Ephemeral (power quality)	1 – 30 seconds	Flywheels, supercapacitors
Short term (peaking support)	0.5 – 4 hours	Lithium-ion battery
Medium term	1 –10 hours	Vanadium flow, sodium sulfur, and lead acid batteries
Long term (bulk storage)	1 – 100+ hours	Pumped hydroelectric, compressed air, and hydrogen

Co-location of energy storage with new combustion turbine EGUs offers multiple potential environmental benefits. Combustion turbines are dispatchable, reliable, and can operate on a continuous basis. However, while combustion turbines can start rapidly, they are not instantaneous and require power for initial startup. And although they can change load rapidly, they cannot take advantage of excess renewable generation and store the energy for later use. Energy storage integrated with combustion turbines can provide power within 1 second and increase the spinning reserve capacity of the EGU and allow the EGU to balance the grid and absorb excess grid power. Specifically, energy storage allows combustion turbines to minimize starts and stops and to operate more continuously at optimal efficiency, both of which reduce GHG emissions. Co-location of energy storage with power generation can also reduce transmission constraints by locating close to end users and charge during periods of low demand by the transmission grid. Like co-located renewables, co-located energy storage shares costs for

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that can, in certain circumstances, enhance agricultural productivity. Additional information on the benefits of low-impact solar is available from The National Renewable Energy Laboratory and the Department of Energy; see https://www.nrel.gov/news/features/2019/beneath-solar-panels-the-seeds-of-opportunity-sprout.html and https://www.energy.gov/eere/solar/farmers-guide-going-solar.

permitting, siting, infrastructure, and grid interconnections and associated transmission and distribution capabilities (Gorman *et al.*, 2020).

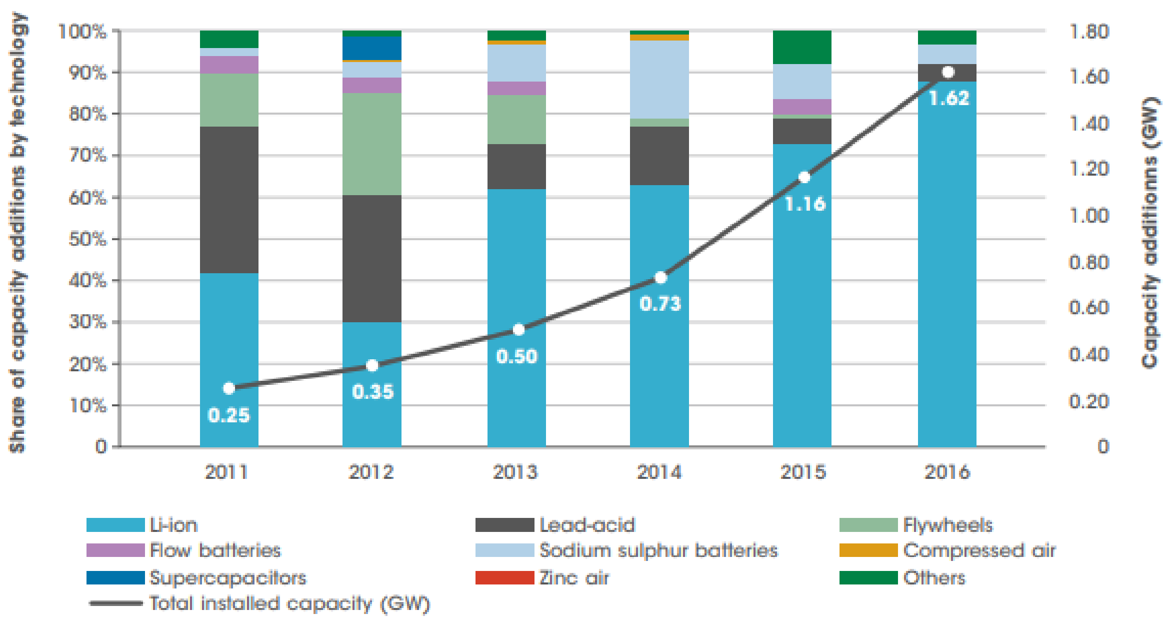
An example of the successful integration of short-term storage with natural gas-fired combustion turbines can be seen at two 50-MW peaking plants operated by Southern California Edison (SCE). In 2017, the utility's stations in Norwalk and Rancho Cucamonga began operating the world's first Hybrid Enhanced Gas Turbine systems, or Hybrid EGT (Aoyagi-Stom, 2017; Patel, 2017). The plants' energy storage comes from co-located 10-MW/4.3-MWh lithium-ion batteries that pull excess renewable energy from the grid and then provide energy during peak demand. The stored energy serves as spinning reserves, giving the turbines time to ramp up, if necessary. According to SCE and partner General Electric (GE), this system reduces operational and maintenance costs by reducing the number of starts and reduces onsite GHG emissions because the turbines no longer need to operate as often (Aoyagi-Stom, 2017; Patel, 2017).[49]

A significant increase in the number of studies of how battery storage might impact the dispatch of existing fossil fuel resources has occurred recently. Energy storage charging from dispatchable generation generally occurs when excess power can be generated more economically and stored during low demand periods when the cost of electricity is relatively inexpensive (Goteti *et al.*, 2021; McPherson *et al.*, 2020). Most studies suggest that in electrical grids where substantial coal and nuclear capacity are available, those technologies will be used to charge energy storage devices. However, in other markets, electricity to charge energy storage will likely be generated from combined cycle EGUs. The type of fossil generation displaced during battery discharge may be dependent on several regional grid variables; however, in regions dependent upon the use of standby natural gas peaking turbines, battery storage typically displaces peaking turbine dispatch despite batteries having a roughly 20 percent energy penalty resulting from charge/discharge and transmission losses.

The following graphic (IRENA, 2019) depicts the capacity share of different storage technologies over time:

[49] Standalone energy storage facilities can be much larger. In August 2021, Vistra Zero began operations at Phase II of its Moss Landing Energy Storage Facility in Monterey Bay, California. The project includes 100 MW/400 MWh of lithium-ion batteries that will capture excess energy from the grid during peak solar generation and then sell the energy during periods of peak demand (Herrera, 2021). This project is an addition to Phase I, completed in December 2020, and brings the total storage capacity of the Moss Landing facility to 400 MW/1,600 MWh, enough to power 300,000 homes (Herrera, 2021). The Moss Landing Energy Storage Facility is able to take advantage of the former plant's active transmission lines and infrastructure (Patel, 2021a).

Exhibit 5-10. Capacity share of different storage technologies.



Note: GW = gigawatt
Source: IEA (2018); Sandia Corporation (2018)

Lithium-ion technology, an outgrowth of technology for small electronics, mobile devices, and cars, currently dominates the energy storage market and provides energy for ancillary services, capacity reserve, and grid reliability (IRENA, 2019). A principal drawback of lithium-ion batteries is degradation. Depending on how frequently lithium-ion batteries are cycled between energy discharge/recharge, the battery will need to be replaced (Rapier, 2020).

Two of the primary competitors to lithium-ion technology are sodium sulfur and vanadium flow batteries. According to the Energy Storage Association ("Sodium Sulfur (NAS) Batteries," 2021), sodium sulfur batteries use molten sulfur as the positive electrode and molten sodium as the negative electrode and have been demonstrated to offer up to 6 hours of duration. The limitation to sodium sulfur batteries is that they need to be operated at high temperatures (572 °F) and can require independent heaters. Vanadium flow batteries (VFB) offer several potential advantages to lithium-ion.[50] According to one manufacturer, the batteries are safer and have no fire hazard, which in turn means they can be packed tighter in a smaller footprint (Rapier, 2020). VFBs also exceed the performance of lithium-ion batteries in long-term duration due to the fact the batteries do not degrade from repeated discharge/recharge cycles and can last for decades without needing to be replaced (Rapier, 2020). The drawback, however, is that, although vanadium is more plentiful than lithium, it is more expensive to extract. This impacts the cost per MWh compared to lithium-ion but tilts in favor of VFB in terms of the LCOE over time (Rapier, 2020).

[50] See https://www.invinity.com/vanadium-flow-batteries/

An emerging technology being developed by staff at the Massachusetts Institute of Technology has the potential to impact the storage market as well. The technology is a liquid metal battery that involves a combination of molten metals that operate as electrodes with a layer of molten salt in between that transfers charged ions between the layers (Stauffer, 2016). Low-cost production has already been demonstrated and the technology is to be field tested with small-scale grids that include intermittent wind and solar. The promise of these liquid metal batteries is that there is no degradation over time (Stauffer, 2016). One of the latest emerging technologies is a long-duration battery that utilizes ambient air and iron in a modular system to create a process called "reversible rusting."[51] The iron rusts during discharge and reverts to iron during recharge. These iron-air batteries can provide more than 100 hours of storage at a fraction of the cost of lithium-ion (Plautz, 2021). A 1-acre pilot project that will be the first commercial deployment of the iron-air technology was announced in June 2020.[52] The batteries will be sited adjacent to a natural gas peaking plant for connection to the grid and the project is scheduled to be completed in 2023.

5.7 Post-Combustion Carbon Capture, Utilization, and Storage (CCUS)

Carbon capture, utilization, and storage (CCUS) involves the separation and capture of CO_2 from flue gas, the pressurization and transportation via pipeline of the captured CO_2 (if necessary), and utilization or long-term geologic storage (also referred to as geologic sequestration). There are multiple demonstrations of the separation and capture, transport, and storage and utilization components of CCUS within the electric generating and industrial sectors. Examples of carbon capture installed on coal-fired power plants include the slip stream capture facilities AES Warrior Run in Maryland and AES Shady Point in Oklahoma. In both cases, the captured CO_2 is used in the food processing industry. In addition, the Southern Company and Mitsubishi Heavy Industries plant Barry in Alabama and AEP's Mountaineer in West Virginia are power plants that have demonstrated the viability of the capture component of CCUS. Furthermore, the Petra Nova Parish plant in Washington and Boundary Dam plant in Saskatchewan, Canada, are projects that have demonstrated the separation and capture, transport, and geologic storage components of post-combustion carbon capture. In terms of industrial projects, Searles Valley Minerals in Kansas uses post-combustion amine scrubbing to capture CO_2 from a coal-fired power plant for use in the production of soda ash.[53] Examples of CCUS on combined cycle EGUs include the Bellingham, Massachusetts, power plant and the proposed Peterhead CCUS Power Station in Scotland. The Bellingham plant used Fluor's Econamine FG PlusSM™ capture system and demonstrated the commercial viability of carbon capture using first-generation technology. The 40-MW slipstream capture facility operated from 1991 to 2005 and captured 85 to 95 percent of the CO_2 for use in the food industry. In Scotland, the proposed 900-MW combined cycle EGU with CCUS is in the planning stages of development. It is anticipated that the power plant will be completed by 2026, and, once operational, the CCUS system will have the potential to capture up to 1.5 million tons of CO_2 annually (Buli, 2021). A storage site being developed 62 miles off the Scottish North Sea coast might serve as a destination for the captured CO_2 (Buli, 2021). A potential constraint on the use of CCUS on combined cycle EGUs is that

[51] See https://www.formenergy.com/technology/battery-technology/

[52] See https://www.greatriverenergy.com/long-duration-battery-project-in-the-works/

[53] Several additional industrial sites (*e.g.*, ethanol production facilities and natural gas processing facilities) are also capturing CO_2. See https://www.c2es.org/content/carbon-capture/

regenerator preheating can lengthen startup times and limit the ability to operate at low loads (Domenichini, 2013).

While amine-based solvent systems are currently in commercial use, DOE, the utility industry, and other organizations are developing additional carbon capture technologies that can reduce the cost and auxiliary energy requirements. These processes typically use solvents, polymeric membranes, combination solvent/membranes, or solid sorbents for separating and capturing CO_2.[54] Fuel cells configured for emissions capture have also emerged as a viable CCUS technology. Specifically, the flue gas from and EGU is routed through a molten carbonate fuel cells that concentrates the CO_2 as a side reaction during the electric generation process in the fuel cell (FuelCell Energy, 2018).

A few second-generation systems have been tested in recent years at the National Carbon Capture Center (NCCC) funded by NETL. While most of the existing capture projects have focused on coal-fired EGUs, there is increased interest in CCUS for natural gas-fired EGUs. A natural gas boiler with the capability of simulating CO_2 flue gas concentrations[55] from combined cycle facilities was added to the NCCC's test facilities via an installation at Alabama Power's Plant Gaston, which became operational in January 2021 and will likely allow for more applicable studies of second-generation capture technologies for combined cycle facilities (NETL, 2021). Several other solvent capture technologies have reportedly been validated for potential commercial use on natural gas combustion flue gas at the Test Centre Mongstad facility in Norway (U.S. DOE, 2017).

5.8 Oxygen Combustion

Oxygen combustion (*i.e.*, oxy-combustion, oxy-firing, or oxy-fuel) is the use of a mixture of oxygen (or oxygen-enriched air) and recycled flue gas (containing mostly CO_2 with some water) in place of ambient air for combustion. An oxy-combustion power plant consists of an air separation unit (ASU), an EGU with O_2-blown combustion, and a CO_2 treatment unit. The most common ASU is a cryogenic process that has a significant energy requirement. However, alternative oxygen separation methods are being researched for possible commercial-scale development. These alternative methods include ion transport membranes (ITM), ceramic autothermal recovery, oxygen transport membranes, and chemical looping.[56] The benefits offered by this technology are its potential for higher efficiencies, reduced overall costs, reduced criteria and hazardous air pollutants, and advantages for CO_2 emissions control. Because the oxygen combustion produces a flue gas that contains primarily CO_2 and water vapor, minimal post-combustion cleanup (if necessary) is required prior to compression, transportation, and injection for use in geological storage, enhanced oil or gas recovery, or some other use. There are multiple pilot scale projects that have demonstrated the technology.[57] A potential constraint of oxygen combustion is the ability of the air separation unit to respond to variable loads. Air

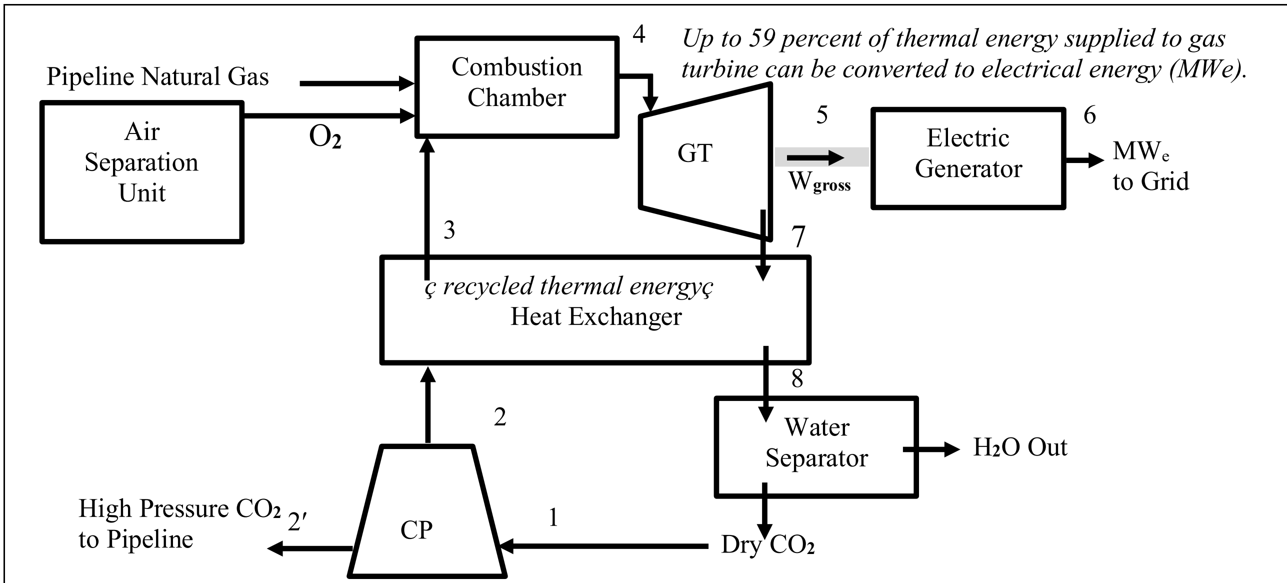
[54] Solid sorbents can be used to capture CO_2 through chemical adsorption, physical adsorption, or a combination of the two effects. Membrane-based capture uses permeable or semi-permeable materials that allow for the selective transport/separation of CO_2.
[55] Flue gas from a combined cycle facility is only approximately 4 percent CO_2 by volume compared to 12 to 15 percent CO_2 in the flue gas from a conventional coal plant (NETL, n.d.a).
[56] The energy required to operate a cryogenic ASU offsets at least a portion of the emissions and cost savings. Newer ASU designs offer the potential to improve the overall environmental benefits of oxygen combustion.
[57] See https://netl.doe.gov/node/7477 and https://sequestration.mit.edu/tools/projects/vattenfall_oxyfuel.html/

separation units can increase startup times, reduce the ability to operate at low loads, and reduce ramp rates relative to an air-fired combined cycle EGU (Domenichini, 2013).

5.8.1 The Allam-Fetvedt Cycle

The Allam-Fetvedt cycle,[58] presented in Exhibit 5-11, is a combustion turbine technology that incorporates an air separation unit to burn natural gas with pure oxygen. This “oxy-fuel” design feature precludes formation of NO_X compounds inherent in traditional air-fuel technologies. However, the flame temperature of natural gas burned with pure oxygen is greater than 2,800 °C (5,000 °F), which is above the melting point of conventional materials used to fabricate combustor components. To prevent overheating, the Allam-Fetvedt cycle uses recycled CO_2 as a diluent to control temperatures within the combustor. Like an air-fired combined cycle EGU, the Allam-Fetvedt cycle incorporates a heat exchanger to capture the heat in combustion turbine exhaust, but instead of transferring the heat to a steam cycle, the Allam-Fetvedt cycle transfers the heat to the high-pressure CO_2 stream that supplies diluent to the combustor. This cycle is designed to achieve thermal efficiencies of 59 percent (Yellen, 2020). An advantage of this cycle is the production of a stream of high-purity CO_2 that can be delivered by pipeline to a storage or sequestration site without extensive processing. A test facility with a heat input rating of 50 MW was completed in 2018 and was synchronized to the grid in 2021. There are several announced commercial projects proposing to use the Allam-Fetvedt cycle. These include the 280-MW Broadwing Clean Energy Complex in Illinois, the 280-MW Coyote Clean Power Project on the Southern Ute Indian Reservation in Colorado, and several international projects. Final investment decisions on the U.S. projects are expected in 2022 and commercial operations could commence by 2025.

Exhibit 5-11. Simplified schematic of a combustion turbine operating in the thermodynamic cycle known as the Allam-Fetvedt cycle.



1 – Low-pressure, low-temperature, dry CO_2 exits water separator and enters the compressor pump (CP).
2 – Recycled portion of high-pressure CO_2 routed to heat exchanger to use heat from turbine exhaust to preheat diluent.
2′– Excess portion of high-pressure CO_2 routed to pipeline for geologic sequestration.

[58] https://netpower.com/technology/

3 – High-pressure, pre-heated CO_2 routed to combustion chamber to serve as nitrogen-free diluent for combustion of pure oxygen and natural gas. 4 – High-pressure, high-temperature recycled CO_2 + [CO_2 & H_2O combustion products] to gas turbine (GT) to turn generator shaft. 5 – The gross work ($W_{\mathbf{gross}}$) available per Btu of fuel fired can be significantly higher than a conventional Brayton Cycle because of the increase in thermal energy at 4 gained from the recycled thermal energy from 7 to 3. 7 – Hot exhaust gases sent to heat exchanger to increase cycle efficiency using thermal energy in turbine exhaust to pre-heat diluent supplied to combustion chamber. 8 – Low-pressure, low-temperature CO_2 and H_2O exit the heat exchanger and are routed for water removal and delivery of dry CO_2 to compressor pump (CP).

5.9 Hydrogen

Hydrogen is often included as a component of broad decarbonization goals of the overall economy, and its potential as a low-GHG alternative to natural gas—especially as a fuel for combustion turbines—has received much attention of late. This section reviews the ability of combustion turbine technologies to utilize hydrogen as a fuel. It also provides a basic comparison of the different types of hydrogen production, notes the GHG emissions attributed to these different production methods, and highlights a few programs working to address some of the current challenges with the widespread availability of low-GHG hydrogen. This discussion of hydrogen as a low-carbon fuel alternative for EGUs and the GHG emissions associated with its production processes is for informational purposes and does not constitute EPA comment on whether or how upstream activities or offsite GHG emissions could be considered under any particular regulatory program.

Industrial combustion turbines have been burning byproduct fuels containing large percentages of hydrogen for decades, and combustion turbines have been developed to burn syngas from the gasification of coal in integrated gasification combined cycle EGUs (Goldmeer and Catillaz, 2021). Most combustion turbines currently used for electric generation can burn hydrogen blends of 5 to 10 percent by volume with blends as high as 20 or 30 percent by volume being utilized in certain situations. There are several recent examples of combustion turbine installations proposing to blend up to 30 percent hydrogen with natural gas—with 100 percent capabilities being developed.[59] The Long Ridge Energy Generation Project in southeast Ohio is an example of the potential to use hydrogen as fuel. Developers of the 485-MW project purchased H-class GE turbines and plan to combust a blend of 5 percent industrial byproduct hydrogen (McGraw, 2021). Eventually the facility will increase the blend to 15 to 20 percent hydrogen before a turbine modification is necessary for the plant to combust 100 percent hydrogen (Hering, 2021). The power plant utilizes only a portion of the 1,600-acre property and is offering other industries the opportunity to co-locate with eventual access to low-GHG energy as an incentive (McGraw, 2021). Another example is the Intermountain Power Authority (IPA) project in Utah. In March 2021, Siemens Energy announced a partnership with IPA to study the integration of large-scale hydrogen production and storage with a combustion turbine. IPA's goal is to successfully combust a blend of 30 percent hydrogen by 2025 to meet the emissions demands of customers of the California Water and Power Authority. According to IPA, the long-term goal of the converted 840-MW coal-fired plant is to combust 100 percent hydrogen by 2045 (Hering, 2021). Additional proposed projects in the U.S. include the Brentwood power plant and the Cricket Valley Energy Center in New York. The New York Power Authority is planning to demonstrate the use of blended hydrogen, between 5 and 30 percent, on a simple cycle turbine at the

[59] The use of large percentages of hydrogen can result in increased emissions of NO_X. For EGUs, investments could be needed in refinements of combustion controls and potentially in advanced SCRs (Goldmeer and Catillaz, 2021).

Brentwood station (Palmer & Nelson, 2021; Van Voorhis, 2021). Cricket Valley is planning to demonstrate a 5-percent blend of hydrogen at a combined cycle facility (GE, 2021). In addition to other projects in New York, the integration of hydrogen and combustion turbines is planned for sites in Virginia, Ohio, and Florida (MHI, 2020; Patel, 2020; Stromsta, 2020).

To fully evaluate the potential GHG reductions from using hydrogen as a fuel for combustion turbines, it is important to consider the different processes of hydrogen production and that each is associated with different amounts of GHG emissions.[60] The different processes and energy sources for producing hydrogen are listed below in Exhibit 5-12. For example, hydrogen can be produced from water through a process called electrolysis. The energy intensity of electrolysis is high, so potential overall GHG emission reductions from the use of hydrogen versus fossil fuels are dependent on the fuel used to power the production process. If that form of energy is renewable (*e.g.*, solar) or nuclear, then the overall GHG reductions associated with using hydrogen as a fuel could be significant.[61] To date, the production of hydrogen via electrolysis remains limited and expensive compared to other production technologies.

For the Long Ridge, IPA, Brentwood, and Cricket Valley projects mentioned above, the objective is for those facilities to eventually transition to hydrogen produced from renewable energy and electrolysis as it becomes available. In Europe, several projects have been announced that will utilize offshore wind energy to power onshore electrolysis. Hydrogen produced in this manner can be used to produce electricity and for other industries in the area and likely incorporated into their "low-GHG" products. For example, a Danish energy company has begun a project called "SeaH2Land" in which 2 gigawatts of offshore wind in the Dutch North Sea will power the electrolysis of hydrogen.[62] The hydrogen will then be utilized by industries in the North Sea Port areas of the Netherlands and Belgium—home to industries such as ArcelorMittal (steel), Yara (ammonia), Dow (material sciences), and the Zeeland Refinery (reformed methane) (Frangoul, 2021; Orsted, 2021).

At the National Wind Technology Center in Boulder, Colorado, NREL has partnered with Xcel Energy on a wind-to-hydrogen demonstration project. Powered by wind turbines and

[60] Hydrogen can be produced through any of several different processes that emit varying amounts of GHGs. When these varying levels of GHG emissions associated with hydrogen production, including upstream emissions, are accounted for in an overall system GHG emissions analysis, there is currently no zero-GHG hydrogen. For example, even electrolysis powered by solar or wind energy includes indirect upstream emissions of GHGs associated with building the system components and potential land use impacts. To attempt to recognize and differentiate between these varying levels of upstream emissions associated with hydrogen production, some organizations have developed a convention for labeling hydrogen according to a color scheme to characterize the production process (*e.g.*, gray, brown, blue, green, etc.).

[61] In addition to using electricity from nuclear energy in electrolysis, there are several other ways nuclear energy could lower the overall GHG emissions associated with the production of hydrogen. First, nuclear energy could provide steam for conventional steam methane reforming, replacing the natural gas-fired boilers typically used to provide the steam. In addition, thermal energy from nuclear reactors could be used for low- and high-temperature electrolysis, which is more efficient than cold electrolysis. Finally, high-temperature reactors could be used to decompose water directly to hydrogen (and byproduct oxygen) using a thermochemical process. See https://www.world-nuclear.org/information-library/energy-and-the-environment/hydrogen-production-and-uses.aspx.

[62] See https://orsted.com/en/media/newsroom/news/2021/04/451073134270788/.

photovoltaic arrays, hydrogen is produced via electrolysis and then stored[63] or converted to electricity by an internal combustion engine or fuel cell and fed to the grid at peak demand (NREL, n.d.). The goal of this "Wind2H2" project is to research pathways to improve system efficiencies, reduce costs, and increase competitiveness with traditional fossil fuels (NREL, n.d.). The U.S. government is also working to reduce the cost of low-GHG hydrogen. The goal of DOE's Hydrogen Shot initiative—known as "111"—is to reduce the cost of low-GHG hydrogen by 80 percent to $1 per 1 kg in one decade (equivalent to $7.40 per MMBtu, DOE, 2020).[64]

Most of the dedicated hydrogen produced today originates from natural gas using a process known as steam methane reforming (SMR). When this type of production occurs without CCUS, it emits relatively large amounts of CO_2 (EPRI, 2020). The second-largest source of dedicated hydrogen production is from the gasification of coal without CCUS. According to analysis by GE, current global demand for hydrogen is 70 million tons per year and 90 percent of that demand is met by reforming natural gas or coal. From an overall GHG emissions perspective, the use of hydrogen from steam methane reforming would increase emissions approximately 50 percent compared to using the natural gas directly to produce electricity from a combustion turbine (Goldmeer and Catillaz, 2021). With the addition of CCUS, hydrogen produced from steam methane reforming and coal gasification can have overall GHG emissions reduction benefits compared to the use of natural gas directly to produce electricity from a combustion turbine.[65]

Exhibit 5-12. Types of Hydrogen Production

Power Source	Production Process
Coal	Gasification
Natural Gas	Steam Methane Reforming
Natural Gas or Coal	Steam Methane Reforming/Gasification w/CCUS
Nuclear	Electrolysis, thermochemical, and thermal energy for steam methane reforming
Renewable	Electrolysis

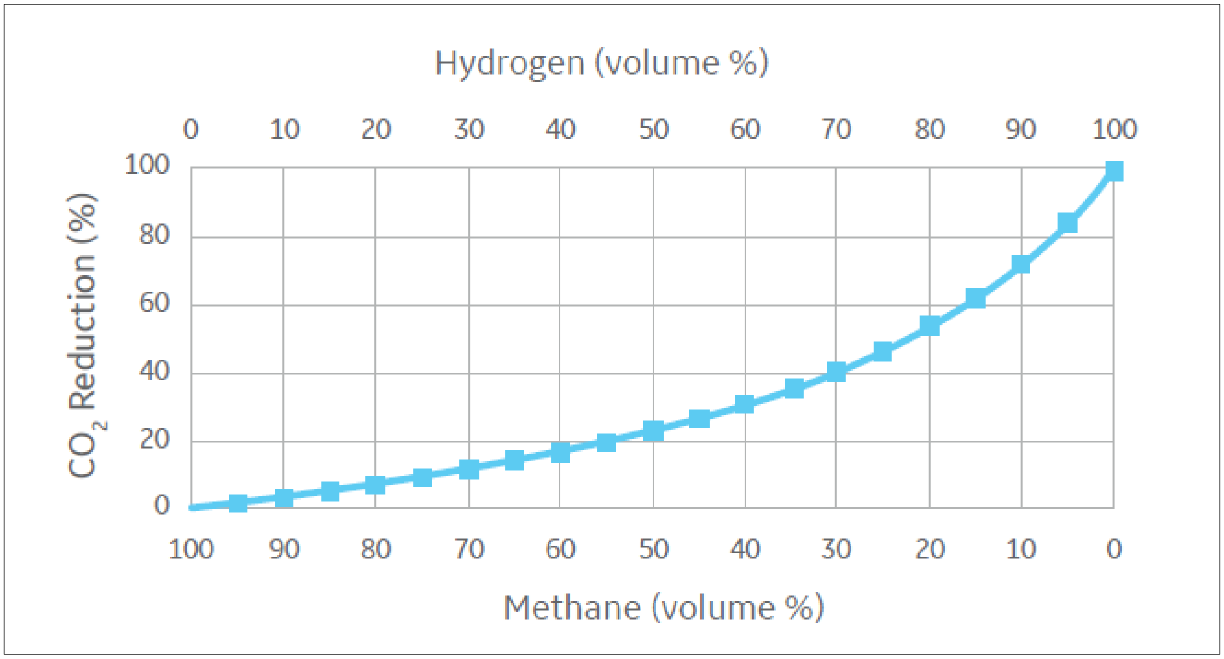
[63] Currently available utility batteries typically have 4 hours or less of storage and are not used for long-term storage. Longer-term storage is typically done using pumped hydro or compressed air. A potential use of hydrogen is to serve as long-term energy storage. Electricity generated from renewables or nuclear power during periods of low electric demand can be converted to hydrogen and stored onsite for long periods. In addition, if this hydrogen is injected into the existing natural gas distribution network, the distribution system itself can act as the storage device. Another advantage of injecting low-GHG hydrogen into the existing natural gas distribution network is that the energy from renewable generation can be transported to end users without using the electric grid—potentially reducing the need for additional transmission capacity and the associated negative environmental and societal impacts.

[64] Significant projects in the U.S. include the Green Hydrogen Coalition's HyDeal Los Angeles (https://www.ghcoalition.org/hydeal-la) and the HY STOR project in Mississippi (https://hystorenergy.com/).

[65] In the SMR process, CO_2 can be captured from the shifted syngas, the pressure swing adsorption tail gas, and the SMR flue gas. In addition, research is ongoing to develop processes that convert methane directly to hydrogen and carbon solids. See https://www.pnnl.gov/news-media/new-clean-energy-process-converts-methane-hydrogen-zero-carbon-dioxide-emissions.

A noteworthy characteristic of hydrogen used as a fuel and blended into natural gas is the volume of hydrogen necessary to achieve CO_2 reductions at the EGU stack. Since hydrogen and methane have different volume energy densities, when blending natural gas and hydrogen, the CO_2 emissions reduction is smaller than the volume percent of hydrogen in the mixture (Goldmeer and Catillaz, 2021). For example, as illustrated below by Exhibit 5-13, to achieve a 50 percent reduction in EGU stack emissions of CO_2 requires a fuel blend that is approximately 75 percent hydrogen; a 75 percent CO_2 reduction requires a blend of 90 percent hydrogen (Goldmeer and Catillaz, 2021).

Exhibit 5-13. Hydrogen to methane fuel blend volume ratios and CO_2 reductions.



Source: Goldmeer & Catillaz (2021)

5.9.1 Ammonia

While hydrogen is a stable and versatile fuel that could potentially reduce GHG emissions across all sectors of the economy, a disadvantage of hydrogen is the relatively low volume energy density. Storage of large amounts of hydrogen generally requires high pressures or cryogenic temperatures. To increase the energy density, hydrogen gas can be converted to ammonia.[66] Ammonia is a stable colorless gas that consists of nitrogen and hydrogen. It is a "drop-in ready" fuel capable of being added or blended directly into existing natural gas infrastructure and could be combusted in a combustion turbine. A drawback to ammonia is the energy required to convert hydrogen to ammonia (Boerner, 2019). Siemens has a set up a demonstration plant in the United Kingdom that utilizes wind power to produce the energy for hydrogen electrolysis, creating green[67] ammonia (Boerner, 2019).

[66] Combining hydrogen with CO_2 to produce methanol or dimethyl ether (DME) also increases the energy density.
[67] The production method of the hydrogen used to create ammonia impacts the carbon intensity of ammonia. Like hydrogen, ammonia has applications across multiple sectors of the economy.

6.0 Fuels Burned in Combustion Turbine EGUs and Overall GHG Considerations

This section provides an overview of the types of fuels that are burned in combustion turbines and the GHG emissions associated with these fuels, including consideration from an overall GHG emissions perspective. The discussion of each fuel includes a description of the production process and the fuel's potential to be burned in a combustion turbine based on existing turbine technology. The section also includes general discussion of the overall GHG emissions profile associated with each fuel's production process, including consideration of offsite (*i.e.*, upstream) emissions, and potential GHG mitigation measures associated with these upstream emissions.[68] In particular, this section highlights several regulations, policies, and programs to reduce GHG emissions, including overall GHG emissions.

The following discussion is intended to facilitate the sharing of information that may assist states and local air pollution control agencies, tribal authorities, and regulated entities considering and/or implementing similar technologies and measures as part of a broader GHG reduction strategy. As described in Section 2.3, many public and private stakeholders have enacted various programs to reduce GHG emissions. These programs include efforts to reduce onsite GHG emissions, as well as offsite measures and measures that consider the overall GHG emissions outcomes of their operations, including emissions that occur upstream of a facility. Although information and experience gleaned from such existing efforts may or may not be relevant under any particular CAA program,[69] they are nonetheless valuable to the broader discussion of potential strategies for reducing GHG emissions from new combustion turbines. Thus, we are sharing the following information for the benefit of a broad group of stakeholders, including industry and state authorities, as they explore options for addressing GHG emissions associated with new combustion turbine projects.

Determining the overall GHG emissions associated with the use of various fuels at combustion turbine EGUs can, where applicable, include emissions beyond just the stack exhaust and could include upstream GHG emissions associated with the production, processing, and transmission or transportation of different fuels that can be used to generate electricity. For the purposes of this discussion, consideration of the overall GHG emissions associated with the production and use of a fuel could encompass upstream emissions, including avoided emissions. Avoided emissions in this context generally represent GHG reductions that may result from upstream processes that are put in place to avoid the release of or to capture and utilize gases that would otherwise be released into the atmosphere. Examples include: (1) natural gas produced and delivered in a way that reduces methane emissions from supply chains versus business as usual and (2) the capture and utilization of certain GHGs by EGUs—such as biogas and industrial byproduct gases—that would otherwise be released regardless of their use in a combustion turbine to produce electricity. While use of these types of fuels in combustion turbine EGUs may

[68] As a general matter, the fuels that are burned in combustion turbines are produced via different processes that result in varying amounts of GHG emissions. Consideration of overall GHG emissions in an analysis of a specific fuel's use could entail recognition of emissions associated with not only the fuel's combustion, but also upstream activities and systems associated with the production, processing, transport, etc., of the fuel prior to use in a combustion turbine. The scope of GHGs considered in such an analysis may depend on the program, policy, or other defining parameter.

[69] EPA is providing this discussion for informational purposes only and is making no judgment about whether upstream or avoided emissions are relevant under any particular regulatory program or scheme.

not reduce direct CO_2 emissions at the stack, consideration of upstream GHG emissions, including those that are avoided during the fuel production process or utilization of emissions that would occur anyway and are not already used in a productive application, may contribute to overall GHG emissions reductions. Specifically, many of the fuels discussed in this section have the same (or higher) onsite (direct) GHG emissions as natural gas. However, when offsite (indirect) GHG emissions are considered (*e.g.*, avoided methane emissions) the overall GHG emissions of the fuel can be lower by virtue of the way in which the fuel or a portion of the fuel is produced or distributed.[70]

In this technical paper, the discussion of upstream GHG emissions considerations, including avoided emissions, is meant to generally acknowledge that there may be some indirect or offsite emissions that occur during fuel production, transmission, and use, and that approaches to mitigate some of these associated but indirect GHG emissions (*i.e.*, not emitted directly out the stack) could be considered under some programs. This document focuses on the potential technical merits of the fuels and approaches discussed; again, inclusion of upstream GHG emissions considerations in this white paper does not represent a determination that it is possible to consider offsite/upstream emissions or activities under any particular regulatory program. It should also be noted that some input fuels' GHG emissions from production and/or distribution processes may already or in the future be accounted for by other GHG reduction policies or programs, which could have the potential to be counted in more than one program.

6.1 Methane Emissions

The U.S. government tracks GHG emissions, including fugitive emissions, through complementary data collection programs. First, the Inventory of U.S. Greenhouse Gas Emissions and Sinks provides national-level estimates for all anthropogenic sources of emissions and provides annual estimates starting in 1990. Second, EPA implements the Greenhouse Gas Reporting Program under the CAA, in which facilities, including facilities in the oil and gas sector, that exceed program thresholds report their emissions and other data each year. Estimated methane emissions from these and other sources can provide an idea of the scale of historic and current methane emissions relative to overall GHG emissions from EGUs. Total emissions of methane and CO_2 from upstream and onsite sources can be summed as lb CO_2e/MMBtu, where "CO_2e" is a CO_2 equivalency that applies a value for the GWP of methane to the quantity of methane that is released to the atmosphere, and then adds the product to the CO_2 released when natural gas is burned (Simmons, 2020b).[71]

An example of where equivalency is useful is determining the relative importance of methane loss. Methane loss is the percent of delivered methane that is released upstream of the delivery point (Simmons, 2020a). There are multiple studies that estimate the upstream methane

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[70] Consideration of additionality may be relevant in some policy contexts. Such consideration could entail taking into account current uses and procurement pathways (*e.g.*, production, processing, and transmission or transportation) of methane that can potentially be used as fuel in combustion turbines to generate electricity, including evaluating the GHG emissions profile under current practices (*i.e.*, business as usual). Such an analysis may be useful in determining the extent to which new systems or utilization pathways, such as using methane to power combustion turbines in lieu of business-as-usual practices, would result in further GHG reductions relative to those current practices.

[71] In 2019, the electric power sector emitted 1,606 MMT CO_2e. See Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019 (2021). (U.S. EPA, 2021i)

emissions from the production and delivery of natural gas (*e.g.*, NW Council, 2021; Rai *et al.*, 2021), though it should be noted that comparisons of upstream GHG estimates are only possible if the same assumptions and assessment parameters are used when conducting the analysis (*e.g.*, same boundaries). As previously stated, when combusted, methane emits 117 lb CO_2/MMBtu. At an upstream methane emissions rate of 1.5 percent, assuming no other upstream GHGs are accounted for, the overall emissions rate of natural gas is 134 lb CO_2e/MMBtu.[72] If the methane emissions rate is lowered to 1 percent, the overall emissions rate would be 128 lb CO_2e/MMBtu, a GHG benefit that is equivalent to a reduction in fuel use of approximately 4 percent. This level of GHG reduction is similar to the incremental differences in efficiency between new combined cycle designs. Therefore, actions to avoid upstream methane emissions can be an important factor in efforts to reduce the overall GHG emissions from a new combustion turbine EGU.

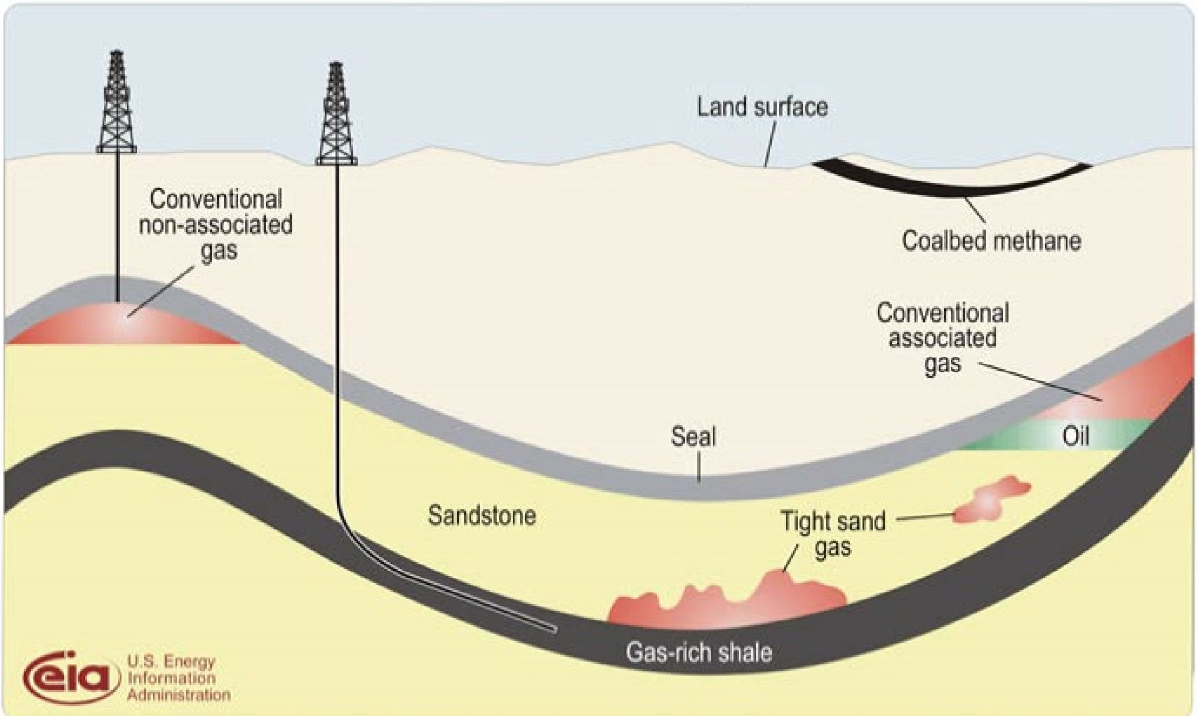
6.2 Conventional and Unconventional Natural Gas

In the lower 48 states, most combustion turbine EGUs burn natural gas with distillate oil backup for periods when natural gas is not available. Areas of the country without access to natural gas often use distillate oil or some other locally available fuel. Combustion turbines can burn either gaseous or liquid fossil fuels, including but not limited to kerosene, naptha, synthetic gas, biogases, and liquefied natural gas (LNG).

Natural gas consists of primarily methane and can be derived from multiple sources. These include conventional non-associated and associated natural gas and unconventional shale gas, tight gas, and coal bed methane. After the raw gas is extracted from the ground, the gas is processed to remove impurities and to separate methane from other natural gas liquids (NGLs) and other gases to produce "pipeline quality gas" (C2ES, n.d.). This gas is sent to intermediate storage facilities prior to being piped through transmission feeder lines to a distribution network on its path to storage facilities or end users.

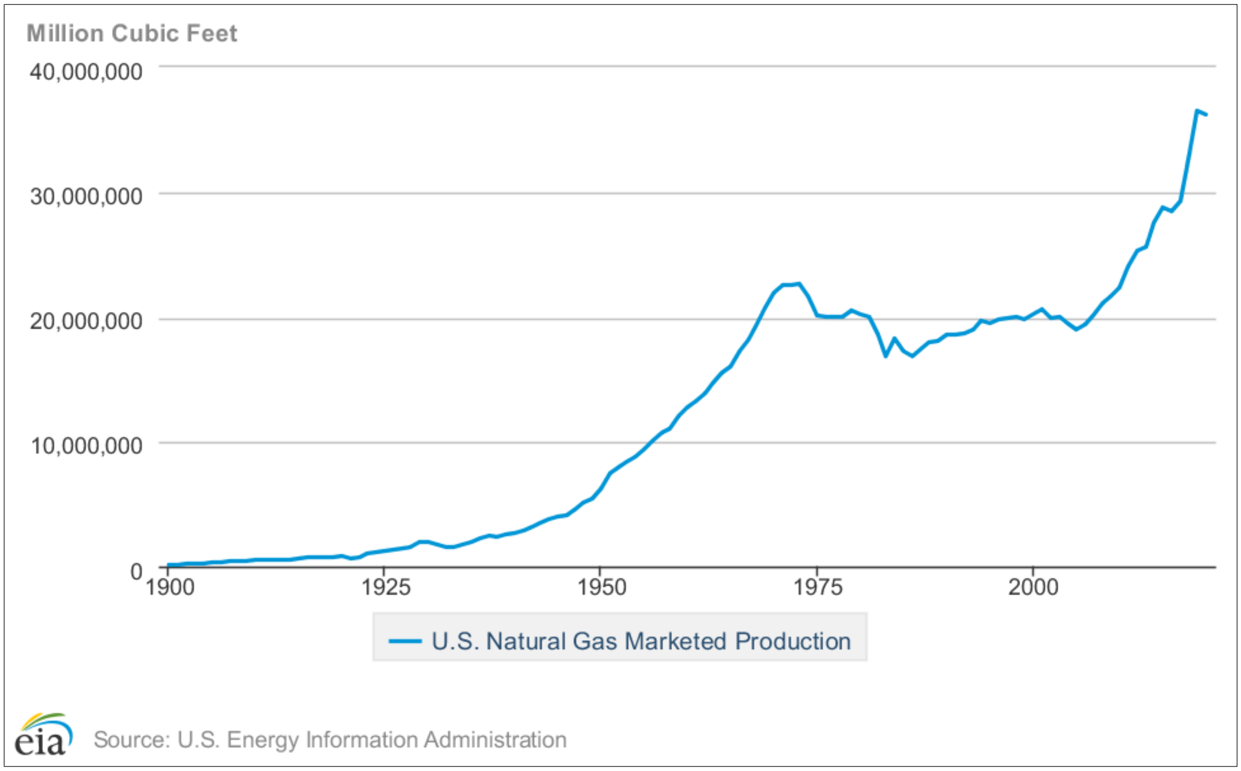
[72] The calculation uses a GWP of 25 for methane—the 100-year GWP.

Exhibit 6-1. Schematic geology of natural gas resources.



Non-associated natural gas describes natural gas that is the primary saleable product that results from drilling activity. Associated natural gas is natural gas that is a byproduct of oil extraction. During the past 20 years, advances in hydraulic fracturing (*i.e.*, fracking) and horizontal drilling techniques have opened new regions of the U.S. to gas exploration, such as unconventional shale and impermeable rock that produce what is known as tight natural gas. Coal bed methane is unconventional natural gas that is extracted by drilling into underground coal seams and pumping water out of the coal to release trapped natural gas. These techniques and rapid expansion have been accompanied by the construction of new infrastructure capable of processing and delivering reliable supplies of fuel to more customers in more markets. Exhibit 6-2 shows the increase in natural gas production in the U.S. over time. Note the sharp increase that begins around 2010.

Exhibit 6-2. U.S. natural gas marketed production.



6.2.1 Avoided Methane Emissions Associated with Natural Gas

This section describes GHG emissions associated with natural gas extraction and distribution. It also discusses example practices and programs that can assist with mitigating (*i.e.*, avoiding) GHG emissions from these upstream activities. The following discussion sets forth a range of different approaches, examples, and estimates of GHG emissions; inclusion here does not constitute endorsement of any particular approach or estimate in any particular context.

When natural gas is the only fuel produced by a drilling activity (non-associated gas), the primary sources of upstream GHG emissions (*i.e.*, emissions other than those from ultimate combustion), are methane emissions that result from recovery and processing activities, unintentional methane leaks, and co-produced CO_2 that is often vented to the atmosphere. Reductions in intentional methane emissions and leaks and the utilization or sequestration of the co-produced CO_2 reduce the overall GHG emissions from the natural gas production. When associated natural gas is co-produced during oil extraction, the natural gas can be vented or flared instead of being used productively either onsite or by being transmitted offsite. Using associated gas productively, or otherwise limiting flaring and venting, can also reduce overall GHG emissions from associated gas. Many stakeholders, including federal, state, and local regulators as well as electricity and oil and gas industry groups, are working on policies and programs to reduce upstream GHG emissions associated with natural gas production.

On November 15, 2021, EPA published proposed rules, titled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," to address emissions of methane from the oil and gas sector. The rulemaking proposed to strengthen current national standards for methane emissions from new, reconstructed, and modified sources involved in the production and processing of natural gas. The Agency also proposed new guidelines to address emissions from existing sources.[73]

In addition, there are other programs that complement EPA regulations. One such effort is EPA's Natural Gas STAR Methane Challenge Program. This Agency collaboration with the oil and gas industry recognizes companies that make specific and transparent commitments to reduce methane emissions. More than 60 companies are program Partners and share the goal of transparently reporting systematic and comprehensive voluntary actions to reduce methane emissions. The program requires a partnership agreement with EPA, an implementation plan, and the collection and submittal of data annually. Partners can participate in one, or both, of the program's two commitment options: 1) the Best Management Practice commitment option in which Partners commit to company-wide implementation of best management practices to reduce methane emissions from key sources, and 2) the ONE Future Commitment Option in which Partner's commit to achieving a specified emissions intensity rate by a future target date.

Partners in Methane Challenge's ONE Future Commitment Option are also members of the ONE Future Coalition, a group of more than 45 natural gas companies working to reduce emissions—specifically methane intensity—across the natural gas supply chain. ONE Future Coalition members agree to measure their emissions and track their progress using EPA-approved reporting protocols (ONE Future, 2021). ONE Future Coalition members can choose to also join the Methane Challenge ONE Future Commitment Option but are not required to do so.

Companies in the oil and gas industry are also collaborating and working toward reductions through the voluntary Oil and Gas Climate Initiative (OGCI). Comprised of 12 CEOs from some of the world's largest oil and gas producers, OGCI has stated objectives of achieving net-zero carbon emissions by taking direct action to reduce upstream, systemwide methane and carbon intensities, developing low-carbon alternatives, and investing in technologies such as CCUS (OGCI, n.d.). OGCI supports bringing an end to routine flaring and venting by 2030. In addition, multiple organizations are working on certification programs for natural gas produced with lower methane emissions.[74]

6.3 Methane Emissions from Abandoned Oil and Gas Wells

Unplugged and abandoned (including orphaned) oil and gas wells can emit significant quantities of methane into the air in addition to leaching toxic substances into the soil and water. The numbers of these wells are increasing rapidly and pose a serious environmental and health challenge to many state, tribal, and federal agencies. If these methane emissions were captured, the release of methane to the atmosphere could be avoided and instead be used productively as fuel. Alternatively, funding the remediation of wells (*e.g.*, by plugging currently unplugged and abandoned wells) provides an opportunity to reduce overall GHG emissions associated with natural gas production (Ehli 2021).

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[73] See https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.
[74] See *e.g.*, https://www.rff.org/events/rff-live/greening-gas-creating-market-low-methane-natural-gas/; https://miq.org/; https://marcellusdrilling.com/2021/01/new-methane-certification-scheme-for-green-natural-gas/; https://marcellusdrilling.com/2018/09/southwestern-sells-1st-certified-responsible-gas-to-nj-resources/; and http://www.sustainableshale.org/performance-standards/

According to EPA estimates, there are approximately 3 million abandoned (including orphaned) wells in the U.S., and in 2019 these wells emitted more than 6.6 million metric tons carbon dioxide equivalent (MMT CO_2e).[75] Many of these wells date back to drilling operations from more than 100 years ago when recordkeeping and reporting were not as accurate. In many instances, these historical wells have been buried; nevertheless, they continue to emit significant amounts of methane and leach toxic substances, such as arsenic, benzene, hydrogen sulfide, and chloride into the surrounding soil and water (Groom, 2020). Each year more wells are being abandoned or orphaned, which occurs when a previous operator or owner cannot be identified or held liable for remediation and associated costs (Wolf, 2021). The 2021 Infrastructure Investment and Jobs Act included $4.7 billion in state grants for plugging and remediating abandoned and orphaned gas wells.[76]

6.4 Coal Mine Methane (CMM)

Coal mine methane (CMM) is the methane released from coal and the surrounding coal seam due to mining activities (EPA, 2021). It is primarily generated from underground mines and is emitted from active mines through degasification systems (*i.e.*, drained methane or drainage system methane (DSM)) and ventilation systems (*i.e.*, ventilation air methane (VAM)) as well as from closed (or "abandoned") mines (*i.e.*, abandoned mine methane (AMM)) and from surface mines (*i.e.*, surface mine methane (SMM). In active mines, degasification systems consisting of boreholes,[77] pipelines to the surface, and a surface pump station, are installed in the coal seam before or during mining to remove some of the methane and relieve the demand on the ventilation systems to maintain a safe air quality in the mines. The ventilation systems in underground mines release VAM emissions, which are typically dilute, consisting of less than 1 percent methane. Abandoned mines release AMM, even though active mining no longer occurs. SMM emissions are released from surface mining activities. When coal ore is broken up and transported, the resulting methane emissions are referred to as post-mining emissions. According to EPA estimates, in 2019, total CMM emissions in the U.S. were 53.3 MMT CO_2e.[78]

EPA's Coalbed Methane Outreach Program (CMOP) is a voluntary program that promotes the profitable recovery, utilization, and mitigation of CMM (U.S. EPA, 2021b). CMM can be destroyed,[79] used to generate useful thermal output and electricity, or upgraded for injection into the natural gas distribution network. Destruction of CMM can be accomplished through combustion/flaring or catalytic combustion of VAM. CMM can also be recovered and processed to produce pipeline quality natural gas for use as a fuel.

6.5 Biogas and Biomethane

Biogas is produced by the anaerobic microbial digestion of organic material from a variety of sources. Anaerobic digestion occurs or is otherwise deployed at landfills, wastewater treatment

[75] 264 kiloton (kt) of methane and 6 kt of CO_2. See Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019 (2021). (U.S. EPA, 2021i)
[76] See https://www.doi.gov/sites/doi.gov/files/orphan-well-mou-01-13-2022.pdf/
[77] Degasification systems can also include a network of pipelines. See https://www.globalmethane.org/training/CMM_module5/story.html.
[78] 47.4 MMT CO_2e from coal mining and 5.9 MMT CO_2e from abandoned underground mines. 1,895 kt of methane from coal mining and 237 kt of methane from abandoned underground mines. See Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019 (2021). (U.S. EPA, 2021i)
[79] Depending on the concentration, CMM can be destroyed through catalytic oxidation or by flaring.

facilities, and in the agricultural sector. The resulting captured biogas primarily consists of a mixture of methane and CO_2, plus other trace gases, and is often used directly for electricity generation, process heat, or CHP (EPRI, 2020). As a general matter, any form of biomass (*e.g.*, wastewater treatment residues; livestock byproducts; food, forest, and crop materials or residues; yard trimmings) can be anaerobically digested and produce bio-based gases.

In addition to direct onsite use, biogases can be refined/upgraded to remove non-methane elements to produce biomethane, sometimes called renewable natural gas (RNG), which can be injected into the natural gas distribution network (DOE, n.d.). Currently, upgrading biogas to biomethane is energy intensive[80] and connecting to a pipeline network is often not economically viable for small biogas producers (EPRI, 2020). However, more centralized upgrade facilities with natural gas interconnections can reduce costs.

6.5.1 Upstream Biogas GHG Emissions

To the extent that biogas from any of these sources would be generated anyway (*e.g*., as a byproduct) and emitted to the atmosphere, capturing it for use in a combustion turbine to displace use of fossil-based fuels may result in a lower overall GHG emissions profile of that turbine. It is important to note that CO_2 emissions from the stack resulting from combustion of biogas in a combustion turbine would not be reduced relative to the use of natural gas. However, in certain contexts, the overall GHG emissions profile associated with the use of biogas could potentially be lower than the natural gas profile if avoided emissions are considered (noting that the upstream overall GHG emissions outcomes depend on a range of factors including business-as-usual practice applied to the biogas[81]).

The federal government and state governments have several regulatory and voluntary initiatives that reduce methane emissions from landfills, the agricultural sector, and wastewater management. Federal regulatory requirements include subpart XXX of 40 CFR part 60 (Standards of Performance for Municipal Solid Waste Landfills That Commenced Construction, Reconstruction, or Modification After July 17, 2014) that establishes requirements to collect and treat landfill gas from certain new municipal solid waste (MSW) landfills and subpart Cf of 40 CFR part 60 (Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills) that requires states to establish requirements for certain existing MSW landfills to collect and treat landfill gas. In 2019, methane emissions from U.S. landfills were 114.5 MMT CO_2e or approximately 17% of the national total emissions of methane.[82] In addition to regulatory efforts, EPA's Landfill Methane Outreach Program (LMOP) is a voluntary program that works cooperatively with industry stakeholders and waste officials to reduce or avoid methane emissions from landfills. LMOP encourages the recovery and beneficial use of biogas generated from MSW (U.S. EPA, 2021d). The LMOP Landfill and Landfill Gas Energy Database is a data repository for most MSW landfills in the U.S. that are either accepting MSW or closed in the past few decades. As of September 2021, approximately 20 percent of MSW landfills provide

[80] The additional processing necessary to convert biogas to biomethane can reduce the GHG benefits of the use of the biofuel.
[81] Consideration of current biogas production and biogas end uses/disposal pathways used may be useful in determining the extent to which employing new systems or utilization pathways would result in further GHG reductions relative to existing practices.
[82] 4,580 kt of methane. See Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019 (2021). (U.S. EPA, 2021i)

landfill gas to energy projects. EPA estimates that approximately an additional 20 percent of MSW landfills could economically recover their landfill gas for a useful purpose (U.S. EPA, 2021e).

For the agricultural sector, EPA's and the U.S. Department of Agriculture's AgSTAR initiative is a collaborative program that promotes the use of biogas recovery systems to reduce methane emissions from livestock waste (U.S. EPA, 2021f). In 2019, livestock GHG emissions (enteric fermentation plus manure management) were 260.6 MMT CO_2e.[83] AgSTAR provides information on current biogas recovery projects (U.S. EPA, 2021g) and market opportunities of potential additional projects (U.S. EPA, 2021h). AgSTAR estimates there are more than 300 dairy and swine manure anaerobic digester biogas recovery systems in the U.S. and 8,100 additional operations could support biogas recovery systems. In addition, new technologies may make biogas systems feasible at poultry and beef lot operations.

In July 2021, the North Carolina Farm Bill included provisions to streamline permitting for the construction of biogas digester systems to collect methane from livestock waste lagoons for the purpose of producing electricity. According to North Carolina's Clean Energy Plan (NC DEQ, 2019), there are siting concerns for biogas plants that affect feasibility. These include the long-term production potential of waste ponds and the pipeline distance to farms. In many cases, RNG producers will seek to collect biogas from multiple farms in proximity to each other for the projects to be economically viable.

An example of the use of biomethane in the utility sector is the Optima KV project in eastern North Carolina (Cavanaugh, 2021). In this project, five hog farms pipe their raw biogas to a central facility where the biogas is further processed prior to injection into a natural gas pipeline. Duke Energy uses this biomethane for power production at two combined cycle facilities. While the project only supplies approximately 9 MMBtu/h of biomethane to Duke Energy, the overall GHG reductions are potentially substantial. Assuming the biogas Duke Energy uses at its two facilities would otherwise be emitted to the atmosphere without any treatment, the GHG emissions would be approximately 42,000 tons of CO_2e per year. Relative to this assumed business-as-usual scenario, capturing the biogas through this project and using it to displace fossil natural gas provides enough GHG reductions to offset approximately 7 percent of the annual emissions from a typical combined cycle facility.[84]

Another sector with significant biogas recovery potential is municipal wastewater treatment plants. In the U.S., there are more than 16,000 wastewater treatment plants, but only about 1,300 use anaerobic digestion to produce biogas (DOE, n.d.). In 2019, wastewater from these facilities emitted 18.4 MMT CO_2e[85] methane in the U.S.[86]

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[83] 9.637 kt of methane and 66 kt of nitrous oxide. See Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019 (2021). (U.S. EPA, 2021i)

[84] In 2019, the average combined cycle EGU emitted 560,000 tons of CO_2. If instead, the business-as-usual baseline is that the biogas would be flared (and not emitted directly to the atmosphere), the additional reductions from the use of biomethane for energy would only account for the reduced use of fossil fuel derived natural gas—offsetting approximately one percent of the emissions of an average combined cycle EGU.

[85] 736 kt of methane. See Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019 (2021). (U.S. EPA, 2021i)

[86] It should also be noted that producing biogas from wastewater treatment does not have potential additional land use concerns.

6.6 Industrial Byproduct Fuels

Other potential fuels for combustion turbines include combustible industrial byproducts. These fuels are often used on site in boilers but can also be flared or vented directly to the atmosphere. To the extent industrial byproduct fuels are not already being used to power industrial processes (meaning that these emissions are currently being released without any productive use applications), using them to generate electricity in lieu of natural gas could result in minimal additional overall GHG emissions.[87]

Blast furnace gas (BFG) is one of these potential fuels. In a typical steel-making process, metallurgical coal (*i.e.*, coking coal) is used in a blast furnace to both produce the heat necessary to power a blast furnace and to reduce the iron ore to form molten pig iron. BFG is the byproduct of the chemical reduction of iron ore and typically contains about 5 percent hydrogen, 50 percent nitrogen, and 20 percent CO_2. BFG has a heating value of about 100 Btu/ft^3, or about one-tenth the heating value of natural gas (Seaman, 2013). With such a low heating value, the byproduct gas is insufficient for use in high-efficiency gas turbines and needs to be captured, processed (*i.e.*, particulates removed), and combined with coke oven or natural gas, which have significantly higher amounts of hydrogen and methane. It is possible to use processed BFG in a combustion turbine to generate electricity to power the steel-making facility as well as process heat. In some instances, the electricity can be sold to the grid. Steel mills with heat recovery units and combustion turbines for power generation not only cite reduced energy costs, increased efficiency and reliability, and environmental benefits as motivating factors, but also job creation and preservation (Seaman, 2013).[88]

6.7 Liquid Fuels

The primary liquid fuel used in combustion turbines is fuel oil that is either used a backup fuel or in locations where natural gas is not available. For fuel oil, there are two approaches that could potentially reduce overall GHG emissions. One is to substitute fuels with lower overall GHG emissions relative to conventional fuel oil derived from petroleum products. Another option would be conventional fuel oil that has been refined using low carbon hydrogen (IHS Markit, 2021).

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[87] In general, replacing onsite boilers with a combustion turbine CHP application reduces net GHG emissions compared to generating the thermal output and electric output separately. If the gas is typically flared or released untreated to the atmosphere, the overall GHG reductions would be larger.

[88] Other possibilities for reduced GHG emissions from the steel-making process include Hydrogen Breakthrough Ironmaking Technology (HYBRIT), a novel approach being explored by European steel manufacturers. In this scenario, GHG are reduced by replacing coke and other fossil fuels with hydrogen (Peplow, 2021). Other options for steel mills to reduce CO_2 emissions are syngas (produced from natural gas) or full CCUS.

7.0 Embodied Carbon of a Combustion Turbine EGU

Multiple states and local governments are taking steps to reduce the embodied carbon in building materials used for construction projects as part of improving the sustainability of construction projects.[89] Embodied carbon is the total GHG emissions attributed to the materials used in a construction project. Embodied carbon includes extraction, transportation, manufacture, construction, maintenance, sequestration, absorption, and end of life/disposal. For fossil fuel-fired EGUs, the majority of the overall GHG emissions associated with the EGU result from operation,[90] but there are opportunities to reduce the embodied carbon of the EGU. Options to reduce embodied carbon include construction techniques that reduce the quantity of materials necessary for construction and the use of materials with reduced embodied carbon (*e.g.*, low GHG concrete and steel).

For example, if a 250-MW simple cycle facility uses 3,200 cubic yards of structural concrete, there are various lower-GHG concrete options available to reduce the embodied carbon of the construction project. Assuming there are 400 lb of embodied carbon[91] in each cubic yard of business-as-usual concrete, the structural concrete alone would include 640 tons of embodied CO_2e. Even if the owner/operator used concrete with no embodied carbon, this GHG reduction would only be equivalent to the emissions from operating the facility at full load for approximately 4 hours. Therefore, while consideration of embodied carbon may be part of overall programs and/or initiatives to reduce GHG emissions and could enhance the market for low-GHG building materials, it is not a primary consideration for the overall GHG emissions for combustion turbine EGUs.

[89] See https://carbonleadershipforum.org/states-act-to-reduce-embodied-carbon/; https://www.greenbuildingadvisor.com/article/new-state-laws-would-lower-climate-impact-of-concrete; and https://www.marincounty.org/-/media/files/departments/cd/planning/sustainability/low-carbon-concrete/12172019-update/low-carbon-concrete-code.pdf?la=en

[90] While renewables and nuclear generation have no onsite GHG emissions, the embodied carbon of these generation technologies is significantly more than fossil fuel-fired EGUs.

[91] Embodied carbon is expressed in units of CO_2e.

8.0 Alternative to Combustion Turbines

The primary competitors for simple cycle facilities are reciprocating internal combustion engines (RICE) facilities. Natural gas-fired RICE are currently limited to approximately 20 MW in size, but multiple RICE installations can effectively create power plants of hundreds of MW (EIA, 2019; Wartsila, 2020a). RICE tend to have higher efficiencies than comparable simple cycle facilities, but emissions of criteria and hazardous air pollutants (HAPs) can be higher. The maximum practical brake thermal efficiency[92] of a RICE is approximately 60 percent (Edwards *et al.*, 2011) and the most efficient available models have design efficiencies of 50 percent (LHV). While recoverable byproduct heat (often called waste heat) from RICE is lower than that of combustion turbines, the energy can still be used for hot- and low-pressure steam applications. A RICE CHP can significantly improve the overall efficiency of a RICE EGU. In addition, newer engine designs and technologies have the potential to further improve the efficiency of alternatives to combustion turbine EGUs (Bloom Energy, 2021; Mainspring, 2021).

An important consideration when comparing the overall GHG performance of RICE to combustion turbines is that certain RICE designs have higher methane slip[93] than combustion turbines, reducing the efficiency advantage. Recent studies and AP-42 data show that lean burn designs yield higher combustion slip, averaging 3 percent of methane feed gas, while rich burn designs average 0.4 percent of methane feed gas emitted as slip (U.S. EPA, 2020a,b; Vaughn *et al.*, 2019, 2021; Zimmerle *et al.*, 2019). It appears that after-exhaust controls, such as selective noncatalytic reduction (SNCR), reduce slip observed in recent field studies. We also note that RICE manufacturers are developing designs with improvements to turbochargers, design components, ignition systems, the use of exhaust gas recirculation (EGR), and oxidation catalysts that can reduce unburned methane. Stationary, land-based RICE can reduce methane slip to 1 gram per kilowatt hour (g/kWh) (less than 1 percent) (Ewing, 2020; Wartsila, 2020b) and two-stroke engines can reduce methane slip to less than 0.3 g/kWh (less than 0.2 percent) (MAN Energy Solutions, n.d.).[94]

[92] Brake thermal efficiency is the ratio of power available at the crankshaft divided by the heat input (*i.e.*, fuel input) to the engine.
[93] Methane slip is unburned methane that passes through the engine and is emitted in the exhaust.
[94] A 1 percent methane slip increases onsite stack GHG emissions in CO_2e by approximately 10 percent, and a 0.2 percent slip increase onsite stack GHG emissions in CO_2e by approximately 2 percent. In comparison, combustion turbines methane slip estimates are approximately 0.01 percent and would increase onsite stack CO_2e emissions by approximately 0.1 percent.

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