U.S. POLICY

THE ROLE OF NATURAL GAS IN DECARBONIZING THE U.S. ENERGY AND INDUSTRIAL ECONOMY

C2ES CENTER FOR CLIMATE AND ENERGY SOLUTIONS

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July 2021

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I. INTRODUCTION AND CONTEXT

What role might natural gas play in deep decarbonization? Some think natural gas should play no role at all, while others think we can continue to use natural gas in the future as we have in the past. In fact, we need a third, or middle path, in which we steadily reduce our reliance on natural gas while simultaneously, and radically, improving natural gas' environmental performance. This paper lays out in detail what that middle path looks like. The Center for Climate and Energy Solutions (C2ES) has addressed policy specifics elsewhere, whereas this paper is focused on the feasibility of and emissions reduction from various decarbonization strategies.

The techno-economic approach taken in this paper is grounded in a view that there is a climate crisis today, and the climate crisis will be worse tomorrow unless we take immediate action. As with an accident victim, we need to apply first aid, we need to repair the injury at the hospital, and then we will need to start rehabilitation. We urgently need to use current technology to minimize emissions: the first aid. We also rapidly need to develop better energy technologies to replace today's energy technologies: the hospital. We will then need to implement negative emissions technologies—likely to be very expensive—to remedy the excessive carbon accumulations caused by the world's delays and dithering: the rehab.

This paper is really about the role natural gas can play in applying first aid. How can our massive current production of natural gas, processing and pipeline infrastructure, and gas power plant and petrochemical manufacturing facilities be leveraged to reduce emissions in parallel with the development of more elegant solutions? As we race to invent and deploy radical technological improvements, we have an imperative to try to leverage, mitigate, and repurpose today's assets to stabilize the patient. Tomorrow's perfect does not need to be the enemy of today's good.

To illustrate the point, if we had today a nuclear power plant technology that was widely accepted as safe and scalable, accompanied by a solution to waste disposal issues, that nuclear plant could provide round-the-clock baseload energy. Further, if accompanied by co-located plants to make hydrogen from electrolysis of water, hydrogen storage, and banks of hydrogen fuel cells, excess nuclear energy could be stored and released to meet daily and peak energy demands. Fine. However, the above-described situation does not now exist. What are we going to do today?

C2ES's *"Getting to Zero: A U.S. Climate Agenda"* (GTZ) and *"Climate Priorities for the New Administration and Congress"* outline the policy recommendations that are necessary to pave the path for decarbonizing the power and industrial sectors. The need for carbon pricing or Clean Energy Standards to include a broad selection of technologies as well as needed infrastructure are discussed in the GTZ report.

The focus of the paper is on the potential quantity and cost of carbon abatement strategies that are technologically available now and are practical to implement today. Those immediately available strategies build the middle path for natural gas.[1]

We consider the issues of practicality and policy separately: the fact that a technology is highly practical and cost-effective from an economic and engineering point of view is not, by itself, sufficient to cause the technology to be deployed in the real world: in many cases there are legal barriers or lack of enabling policies that block technologies that otherwise would be adopted quickly.[2]

This middle path for natural gas is but one component of a multi-technology strategy that supports penetration of all zero-emitting and low-emitting energy technologies on the way to a zero-emissions future. A major theme of this paper is that immediate action to decarbonize use of natural gas today can support other low- and zero- carbon technologies—in the future:

- Today: Decarbonized natural gas power plants—with carbon capture— can back up wind, solar photovoltaic (PV) and other intermittent zero-carbon electricity producers, especially to meet day-to-night and seasonal production and consumption mismatches. Thus, such decarbonized natural gas power plants can permit a swifter and deeper penetration of renewables into the power grid without loss of system reliability.[3]

- The future: Low-carbon "blue hydrogen" can build scale and infrastructure that can ultimately be used by zero-carbon "green hydrogen." While all hydrogen is zero-carbon when burned, the manufacturing of that "zero carbon fuel" may or may not emit greenhouse gas.
  - Today's hydrogen production is nearly all "grey hydrogen." It is generally made by the refining process known as cracking natural gas in steam methane reforming (SMR) plants that emit 100 percent the methane feedstock's carbon as carbon dioxide (CO_2).[4] About 10kg of carbon dioxide is emitted per 1kg of hydrogen (H_2) product.[5]
  - The term "blue hydrogen" refers to H_2 manufactured at plants where carbon capture equipment has been added to grey hydrogen SMRs.
  - "Green hydrogen" refers to H_2 made by electrolyzing water with electricity made from zero carbon power generation.

Either blue or green hydrogen manufacture is much less greenhouse gas-emitting than conventional H_2 production. However, given current equipment and feedstock costs, green hydrogen is 3-5 times the cost of grey hydrogen. [6] Cheaper blue hydrogen, about 1.3-1.6 times the cost of grey hydrogen,[7] can be a more cost-effective starting point for the industry: the backbone of a national hydrogen pipeline and fueling infrastructure, which can serve numerous decarbonization strategies, can be initially filled with decarbonized blue hydrogen, with green hydrogen gradually taking over as costs of electrolysis fall.

Many studies have looked at the costs of abating carbon using different techniques in various industries. This paper focuses less on the nuances of avoided carbon cost calculation and more on the trajectory of overall emissions, illustrating what might be accomplished if the U.S. were to proceed in an orderly series of carbon dioxide abatement "Blocks" from cheap to expensive abatement.

In taking a building block approach, we are following the expositional methodology that the U.S. Environmental Protection Agency (EPA) used in the proposed Clean Power Plan (CPP). In the CPP, EPA calculated cumulative Carbon dioxide reductions as states moved through various "Building Blocks" (BBs).[8] EPA's BBs were:

- BB1–2.3 percent reduction of fossil heat rate
- BB2–raising average capacity factor of NGCCs to 75 percent.
- BB3–approximately 21 percent pro rata reduction in fossil steam and NGCC emissions through use of renewables

EPA's stepwise set of calculations allowed analysts to drill down on the practicality of the actions hypothesized in each Building Block. We took the same approach for the same reason. As with EPA's Building Blocks, we assume no strict chronology of implementation: in practice our "Blocks" are likely to overlap or even go out of order. That said, we numbered our Blocks so those with large and inexpensive strategies had lower numbers than those with smaller, more expensive strategies.

The magnitudes of abated carbon dioxide tonnage calculated from each Block are generally consistent with well-known analyses such as those of the International Energy Agency (IEA), International Panel on Climate Change (IPCC), and those used in EPA's technical support documents for the CPP. For instance, we begin the entire analysis postulating a 400 percent increase in installed capacity (i.e., MW—not MWh of generation) of wind and solar PV. In reality, that change is likely to occur simultaneously with many other abatement strategies, such as the concept of running existing gas generators more and running existing coal plants less. That coal-to-gas substitution has been happening in parallel with growth of renewables already, and both were major abatement sources contemplated in the CPP.

The rate of implementation of the carbon dioxide abatement Blocks ultimately depends on the will of the nation and policy-makers. The endpoint of the journey, as the C2ES *Getting to Zero* report lays out, is 100 percent decarbonization by 2050. If, for example, the U.S. put a \$100/MT price on carbon-dioxide emissions tomorrow, the timescale would be compressed; and if the U.S. continues to lack either a price on carbon or compliance-based emissions limits for emitters, the timescale will be longer. If the U.S. decides to pursue expensive decarbonization options first and offers no incentives to more cost-effective options, the order of adoption of abatement options will be shuffled.

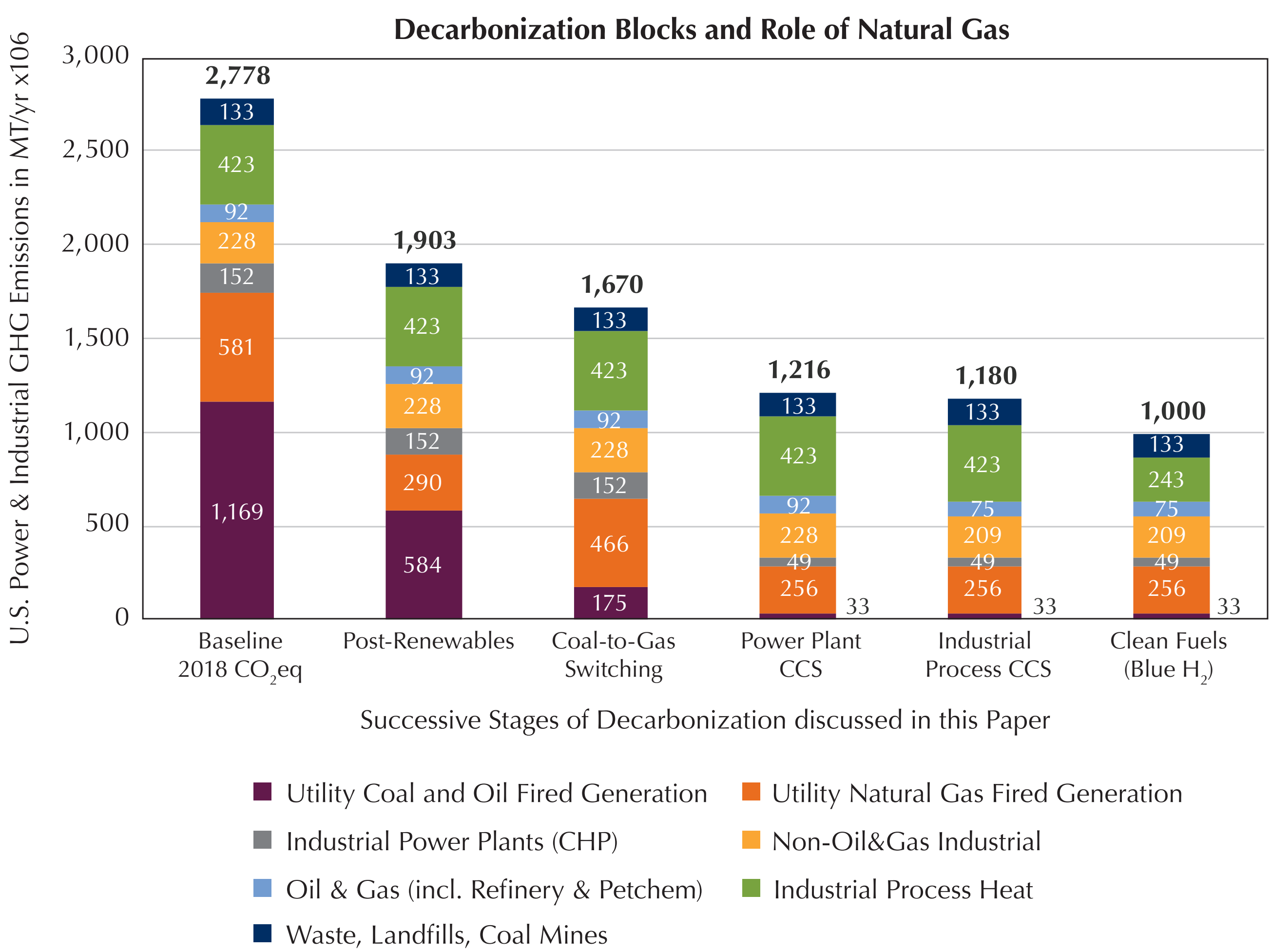
SUMMARY OF BLOCKS OF DECARBONIZATION

Here we give a broad summary of the Blocks discussed above. **Figure 1** shows the major power and industrial emissions categories and the sequential Blocks of decarbonization outlined herein.

The 1st column is baseline emissions, with the 2nd through 4th columns focused on power sector emissions reductions.

- In the 2nd column (Block 1), renewables cut baseline gas emissions to 290 million metric tons per annum (MMTPA) and coal to 584 MMTPA. A cornerstone of decarbonization will be widespread commissioning of new wind and solar PV plants that will displace much of today's fossil-fuel generation. We assume a continuation of today's strong investment in wind and solar PV, with incremental construction of 479,000 MW of new utility-scale wind and solar, quadrupling today's wind and solar fleet. (See **Table 8.**) Construction of Block 1's incremental wind and solar PV will occur over time, together with other strategies considered herein, and will be faster or slower depending on policy.[9]
- Then, in the 3rd column (Block 2), substituting gas for coal causes gas generation emissions to rise to 466 MMTPA (a gross increase of 176 MMTPA). However, that is a net benefit of 233 MMTPA from total fossil power generation. The 176 MMTPA of increased gas emissions is more than offset by a 409 MMTPA decrease in coal emissions. *In practice carbon capture (Block 3) might be simultaneously applied, but we show the steps separately for clarity: readers are asked not to be alarmed by the temporary increase in gas emissions*

FIGURE 1: Carbon Dioxide Cumulative Abatement: Baseline through Block 5



shown. Block 2 is simple fuel switching—moving from burning carbon-intensive fuels such as coal, oil, or petroleum coke to natural gas. As we will show in Section II, this coal-to-gas fuel switching is responsible for about 70 percent of the progress the United States has made in reducing power sector emissions reduction since 2000, and there is still much to be gained from this low-cost strategy before fuel-switching opportunities dwindle.

- In the 4th column (Block 3), once carbon capture is applied to a major portion of NGCCs gas electric generation emissions come to rest at 256 MMTPA (about 44 percent of today's level), with coal emissions having become negligible.[10] (The 256 MMTPA is the orange bar in the fourth column.) Block 3 technology is restricted to known, cost-effective carbon capture technology, i.e., engineering techniques to scrub carbon dioxide out of power plant vent stacks—just as we scrubbed sulfur dioxide out of coal power plant smokestacks to stop acid rain beginning in the 1980s.[11] Note that as a small exception to our practice of looking only at gas emissions, we also showed application of carbon capture to the few remaining coal plants (absent additional policy to accelerate their retirement), dropping coal emissions (dark blue rectangles) from 175 to 33 MMTPA from the 3rd column to the 4th column on **Figure 1**.
- As a final note on gas power generation, limiting gas power plant emissions in Block 3 to 256 MMTPA is neither a prediction nor a desirable endpoint. Technically speaking, more carbon capture could be applied to the gas fleet, but some gas plants run so rarely that carbon capture investments are economically unattractive. As discussed in Section X, much of the remaining gas power emissions represent a lightly used amount of gas generation capacity that runs only during unusually high seasonal peak power demand periods (e.g., those recently occurring in California). Abating that infrequent emissions source could be more efficiently carried done with a variety of technologies such as "blue hydrogen" or "green hydrogen", better batteries, more pumped hydro storage. Evaluating those is beyond the scope of this paper.

Moving on to industrial emissions:

- In the 5th column (Block 4) we use carbon capture to address industrial process emissions of carbon dioxide, dropping total emissions to 1,180 MMTPA. Block 4 shows the impact of carbon capture in industries where natural gas is used as a chemical feedstock or where natural gas is processed before reaching pipelines. [Note that we treat carbon capture at power plants and in industry as two different Blocks, but we would actually expect application of carbon capture in both sectors to proceed concurrently.]
- In the 6th and final column (Block 5), we use clean fuels to lower industrial combustion emissions, ending at 1,000 MMTPA. (The round number was coincidental.) Block 5 is manufacturing of zero-carbon fuels (ZCF) to replace natural gas combustion where it still may be used. The two major candidates to fill this ZCF role are hydrogen and ammonia, and for simplicity we will focus on hydrogen.[12] The hydrogen fuel would be made from natural gas feedstock in hydrogen manufacturing plants that capture or otherwise mitigate 90-100 percent of the carbon.[13] The principal opportunities for stationary emissions reductions with ZCFs appear to be for heating use in heavy industry. Using hydrogen in utility-scale electric fuel cells and using either hydrogen or ammonia in peaking gas combustion turbines are promising electric generation options as well.

The total 1,000 MMTPA "endpoint" in the 6th and final column (i.e., 1 billion tons per year), is also neither a prediction nor an acceptable final endpoint. *It just represents the near-term limit, as we see it, of abatement strategies that relate to natural gas in some way or another.* There are a wide variety of strategies that do not relate to natural gas that can further reduce the billion tons. Among those would be negative emissions obtained by carbon capture on biogenic emissions from paper mills, capture of carbon relating to conversion of limestone in cement plants, massive electrification of industrial heating, capture of carbon dioxide now emitted from combustion of landfill methane, etc. Co-firing of coal plants with biofuels and co-firing of natural gas power plants with green hydrogen and/or biogas are possible, though expensive. Also, technological changes could create major benefits that we are not predicting.

FUEL SWITCHING—BLOCK 2

After considering significant renewable penetration (Block 1), Block 2 is fuel switching: decarbonization will be a long and hard-fought struggle, and until the battle is won, natural gas' role as the lowest-emitting fossil fuel is important. From an engineering point of view, fossil fuels of all types are the current backbone of the U.S. electric industry, petrochemical industry, and transportation sector. It will take a long time and a lot of money to migrate this vast array of legacy fossil fuel users to zero-emitting technologies. Additionally, burning fossil fuels provides the vast bulk of process heat needed to run every type of factory—from canning tomatoes to making toilet paper. On that process heat side of the ledger, it is difficult to achieve by other means the high temperatures and fast heat transfer that are characteristic of fossil fuel boilers and furnaces.

Thus, even the most aggressive International Energy Agency (IEA) decarbonization estimates , which assume $125-140 per metric ton (MT) in carbon taxes, still show the world using approximately 70 percent of today's fossil fuel consumption in 2050, with natural gas usage virtually unchanged.[14] It is common to describe the role of natural gas as a "bridge fuel," but it is likely to take decades to cross the "bridge" to a zero-carbon economy. While we are crossing, it is clearly a good idea to use the particular fossil fuel (natural gas) that emits 57 percent as much carbon dioxide as coal when combusted for heat and approximately 42 percent as much carbon dioxide as coal in modern power plant equipment.[15]

Immediate and aggressive use of fuel switching can reduce the amount of emissions "overshoot" that will otherwise occur while we attempt to implement newer, more expensive, and harder-to-integrate technologies. The term overshoot is meant to convey the likelihood that slow action on greenhouse gas emissions will raise carbon dioxide levels in the atmosphere beyond sustainable levels, thus requiring expensive negative emissions technologies, such as direct air capture, in the latter half of this century. Many experts have concluded that such overshoot is nearly inevitable given current lack of progress in reducing greenhouse gases.[16] Failing to take low-cost steps, like fuel switching, today will vastly magnify the size of the deficit that has to be addressed with expensive remedies later.

In many cases, running existing natural gas plants more and running existing coal plants less is more-or-less a zero-cost near-term carbon reduction strategy, with relative cost depending upon inter-regional fuel price differences. Given the large fleet of currently operating gas plants and the low-capacity utilization rate of those plants in most of the United States, and with the low-capacity utilization likely to be exacerbated by more renewable penetration, it is reasonable to expect that most fuel switching could be done without requiring more gas plants to be constructed.

In few cases where new gas plants must be built to replace coal plants, the comparatively short lifespan of natural gas combined cycle power plants (NGCCs), as opposed to 50- or 60-year lives for large coal and nuclear plants, makes "technology lock-in" less of a concern. In large part this is because the physical wear and tear on combustion turbines, which are effectively jet aircraft engines strapped to the ground, is considerably greater than the wear and tear on steam turbine generators. Some regulated utility experts advise not to count upon more than a 20-year commercially useful life. [17] The relatively short commercial life of NGCCs is seen in the performance of the existing U.S. fleet: NGCCs older than 20 years had a 34 percent average net capacity factor, as opposed to those younger than 20 years with a 56 percent average net capacity factor.[18] In addition, natural gas plants are not compelled to burn only fossil fuel natural gas. Most gas plants can burn some significant portion of hydrogen without modification, and they can of course burn biogas, which can be considered a zero-emission fuel.

CARBON CAPTURE AT THE EMITTING FACILITIES IN POWER AND INDUSTRY—BLOCK 3 AND BLOCK 4

Eventually as most fossil fuel electric generation emissions sources switch to natural gas combustion or renewables, the impact of fuel switching in the power plant sector will dwindle. Carbon capture technology is already available to push into the next phase of addressing emissions on-site at power plants and in heavy industry. Note that for simplicity, we focus on the most frequently used carbon capture technology (aqueous amine solvent scrubbing); however, there are other techniques available and under development.[19]

Carbon dioxide capture is already used in virtually every natural gas processing plant, urea fertilizer plant, and coal-to-chemicals plant in the world. The key amine solvent technology was patented almost 100 years ago, and thousands of these systems are deployed worldwide; they just are not usually deployed for the express purpose of pollution control. Instead, carbon dioxide capture is widely deployed wherever either carbon dioxide is needed as a product (as when a small system is attached to a power plant to capture carbon dioxide for use in a nearby beer plant). Carbon capture is also deployed whenever carbon dioxide is viewed as a contaminant (as when raw natural gas is scrubbed of excessive carbon dioxide content to meet gas pipeline quality specifications). Other than these special cases, there is generally no pre-existing commercial reason to capture the carbon dioxide, and there is no policy-driven pollution control imperative to capture the carbon dioxide. But this is a matter of will, not a matter of technical feasibility or carbon reduction cost-effectiveness. Indeed, two large-scale commercialization projects for coal power plants have been built, the Boundary Dam coal plant in Canada and the Petra Nova project in Texas, and the federal Section 45Q carbon sequestration tax credit partially compensates for lack of more comprehensive carbon pricing or emission limitation.

Depending on the application, carbon capture can be expensive, but it still may be the most cost-effective approach to reduce emissions. These capital-intensive carbon capture systems are most economically appropriate for large facilities or power plants that operate continuously or nearly continuously. This limitation is because, like many other pollution-control devices, carbon capture systems create additional power and/or fuel demands that must be accounted for in economic assessments and calculations of emission reductions.

DECARBONIZED FUELS—BLOCK 5

The final strategy (Block 5) is to "clean up the fuel." That is, instead of combusting natural gas and cleaning up the result, we can (i) manufacture zero-emitting fuels from natural gas while capturing the waste carbon dioxide at these clean fuels plants (i.e., blue hydrogen made from steam methane reforming (SMR with carbon capture), and (ii) convert natural gas combustors to partially or completely combust these zero-carbon fuels. The two most likely candidate decarbonized fuels are hydrogen and ammonia—for simplicity we will concentrate on hydrogen in this paper. A huge swathe of the petrochemical industry depends upon stripping hydrogen gas from natural gas (i.e., methane), with carbon dioxide as a byproduct. Currently this process is a cheap source of hydrogen, and capturing more than 90 percent of the carbon dioxide is estimated to boost the cost of such hydrogen by about 50 percent.[20] This approach is ideal when applying a combustion facility cleanup solution is too expensive, i.e., for smaller, or infrequently used natural gas combustion sources. When hydrogen fuel production is 90 percent decarbonized, hydrogen combustion carbon dioxide emission per unit of fuel heating value is approximately 1/20th that of coal and 1/10th that of natural gas.

FRAMING THE STAGES IN TERMS OF CARBON INTENSITY

Another lens through which to view our analysis is to consider the three stages as transitioning the energy economy from high-carbon fuels to zero-carbon fuels. The best way to quantify this is to use a yardstick of carbon dioxide released per unit of heating value combusted. Heating value is typically determined by figuring out the amount of fuel combustion required to raise the temperature of water. In the U.S., the typical measure is a British thermal unit (Btu), which can raise the temperature of one pound of water by one-degree Fahrenheit. Using blocks of 1 million Btu (MMBtu) convenient for looking at costs and emissions since otherwise natural gas is often reported in thousands of cubic feet, coal in tons, and oil in barrels. [21]

- **Coal-to-gas Fuel Switching Strategy = High carbon → Medium carbon:** Move from fuels like coal (carbon dioxide emissions approximately 206 lbs/MMBtu) and oil (161 lbs/MMBtu) to natural gas (117 lbs/MMBtu)
- **Carbon Capture = Medium carbon → Low carbon:** When using natural gas as a fuel (117 lbs/MMBtu), capture the carbon otherwise emitted (11 pounds/MMBtu remaining emissions)
- **Decarbonized Fuels = Low carbon → Zero carbon:** Ultimately, replace natural gas with zero-carbon gaseous and liquid fuels. Those zero-carbon fuels—such as hydrogen and ammonia—are initially manufactured from natural gas, capturing virtually all the carbon emitted at the zero-carbon fuel production facility (approximately 5 pounds/MMBtu remaining emissions).[22]

TASKS BEYOND THE SCOPE OF THIS PAPER

To keep this paper to a reasonable scope and length, we focus on these main points of gradually ratcheting down fossil fuel emissions based on technologies available within the fossil fuel sector itself, after initially taking account of assumed large penetration of variable generation renewables. We are forced to give short shrift to the following worthwhile and interesting topics:

- The exact time that various reductions occur: Without knowing what agreements, and when, the world's governments reach on emissions reductions, ascribing dates to our various stages of decarbonization would be false precision. It is enough to show a reasonable, stepwise route progressing through large, cheap emissions reductions before moving on to smaller, more expensive emissions reductions.
- Speed of technological progress: It is possible that energy storage technology prices could fall so fast that some of the steps outlined here would be unnecessary as renewable energy would expand further than used in this analysis; fusion or more likely, advanced fission reactors, could succeed in the next decade; or Allam-cycle gas-fired power plants could become cheaper than current NGCCs.[23] Any of these might possibly provide a faster, cheaper route to decarbonization, or they might fizzle out. Starting aggressively on the stages outlined here is a "no regrets", or at least a "fewer regrets," way to hedge our bets.
- Scope of technological alternatives: Dozens of technological routes could be substitutes for stages outlined in the paper, but we do not have the time and space to debate the relative merits of each.
- Fugitive methane emissions: Steps to reduce leaks at the well-head and from pipes can and should progress on a parallel track with the strategies outlined herein; but the existence of these leaks should not be used as a reason to stop progress. Industrial and electric combustion make up approximately 46 percent of U.S. natural gas consumption.[24] U.S. EPA Greenhouse Gas Reporting Program (GHGRP) reports 79.9 MMTPA of carbon dioxide equivalent fugitive methane emissions from oil and gas production, gathering, long distance pipelines, and local gas distribution networks,[25] implying that industrial and electric consumption could be fairly allocated 36.7 MMTPA carbon dioxide equivalent (CO_2eq) of those leaks. That is, those leaks are responsible for approximately 1.3 percent of the 2.778 billion MTPA CO_2eq of overall U.S. stationary emissions. It is not clear that reported emissions comport with actual leaks, since many greenhouse gas reporters are allowed to use EPA-stipulated "emissions factors" rather than being required to perform actual measurements, and C2ES supports measures to promote better monitoring for methane leaks. For purposes of this paper, we acknowledge that steps to deal with methane leaks from production and distribution of gas are important, without analyzing the topic specifically.
- Non-greenhouse gas impacts of fossil fuel production and combustion: The scope of this paper is limited to quantifying current greenhouse gas emissions and means of reducing them. There are myriad land use, criteria air pollutant, hazardous air pollutant, water pollution, and other issues relating to fossil fuels we do not discuss here. That is not because those are unimportant issue: they are just beyond what can be covered in a paper of this length.
- Decarbonization in certain industries unrelated to natural gas: In order to concentrate on the role of natural gas, we do not delve into the major carbon capture opportunities available in the cement industry (mostly from lime kilns), steel blast furnace gases (from use of metallurgical coal), refinery fluidized catalytic cracking units (from petroleum coke combustion in catalyst regeneration), and the paper industry (biogenic emissions from black liquor recovery boilers).

ORGANIZATION OF THE ANALYSIS

In the following sections, we lay out:

II Where we have been: Reducing U.S. power plant sector emissions over the preceding two decades (2000 to 2018) is mostly a story of coal-to-natural gas fuel switching and improved gas power plant efficiency, accompanied by a major and simultaneous boost from wind and solar uptake.

III Where we are today: We estimate natural gas' contribution to existing (2018) U.S. stationary greenhouse gas emissions by parsing U.S. emissions data to spotlight the industries that rely on natural gas, grouping them by the type of emission reductions strategies that are likely to be most important in those industries.26 This creates a baseline case from which we analyze future reduction opportunities.

IV Natural gas is not disappearing soon: Entities such as the International Energy Agency (IEA) and the U.S. Department of Energy's (DOE's) Energy Information Agency (EIA) forecast that even the most aggressive decarbonization pathways, incorporating carbon pricing in high-income countries in excess of $100/MT plus substantial zero-carbon renewable energy penetration, still show substantial natural gas consumption. Thus, we had better learn how to mitigate the impacts of that natural gas consumption. Further, renewables will be a big part of any conceivable future: We create a Renewables-Adjusted Baseline Case that reduces the Baseline Case U.S. emissions to take account of substantial penetration of wind and solar generation into the power grid.

V Fuel switching in the power sector (coal-to-gas): We quantify emissions reductions that could be expected as the fossil generation remaining after substantial renewable penetration continues to migrate from coal combustion to gas combustion. This switching reduces overall emissions, but drives up natural gas power-sector emissions.

VI Power sector facility carbon capture: These are emission reductions from applying carbon capture to the remaining grid reliability-oriented fossil fuel-fired power plants. In addition, many Combined Heat and Power (CHP) plants inside industrial facilities are excellent candidates for carbon capture installation.

VII Industrial and Oil & Gas sector *process emissions* carbon capture: Carbon capture can also be applied to the portions of heavy industry that use natural gas as a feedstock, including natural gas processing plants.

VIII Industrial sector *combustion emissions:* These are emissions reductions that can be accomplished by decarbonizing the fuels the sector combusts. The primary case analyzed involves the two steps of (i) increasing hydrogen production with carbon capture and (ii) converting the smaller furnaces, stoves, and boilers to utilize hydrogen.

IX Conclusion

II. WHERE WE HAVE BEEN: RECENT POWER SECTOR EMISSIONS REDUCTIONS DRIVEN BY NATURAL GAS

In addition to its economic impact, the domestic natural gas boom has reduced power sector greenhouse gas emissions in the United States as natural gas took the place of coal as the main fuel source for electric generation. Natural gas also displaced coal and oil in many industrial processes. Quantifying the role of natural gas in recent emissions reductions enables better assessment the remaining potential for *future* improvements. This section seeks to disaggregate the emissions reductions in the U.S. power sector from 2000 to present,[27] with the three main contributors being: (1) fuel switching from higher-carbon fuels to natural gas; (2) improved efficiencies in natural gas generation technology; and (3) penetration of new renewable technologies to approximately 8 percent of U.S. generation. The methodology was to comparing actual 2018 emissions from generating 2018's actual 4,011 million MWh versus what the emissions would have been if we had made the same amount of electricity using 2000's mix of generators and 2000's efficiency. There is no attempt here to evaluate whether policies could have been improved: This is simply a look in the rearview mirror to see what did happen. Additionally, we do not try to quantify why electric generation grew 10 percent over the 18-year period while real gross domestic product (GDP) rose 42 percent.[28] Some element of GDP outpacing generation was undoubtedly due to conservation and efficiency, but changes in the mix of GDP and mix of energy usage are factors as well.

Of the changes, approximately 3/5 were driven by switching fuels to burn gas and by improving gas power plants, and 2/5 were from wind and PV solar displacing fossil fuels.[29] The primary data source for this conclusion is the U.S. Energy Information Administration's (EIA's) Monthly Energy Review.[30] Note that this analysis is measuring changes in the carbon intensity of generating a particular amount of electricity, and this set of EIA data doesn't tell us about carbon dioxide savings that occurred from efficiency changes during the period considered.

LAST TWO DECADES: MORE ELECTRICITY AND LOWER EMISSIONS

Table 1 simply shows the bottom line—more electricity with lower carbon dioxide emissions. U.S. electricity generation increased by 10.3 percent between 2000 and 2018 to power a growing economy. However, emissions from the power sector actually *fell* by 23.7 percent during that period. The carbon intensity of power generation per MWh had thus fallen by 30.8 percent.

TABLE 1: Reduction in Emissions from Electric Generation 2000-2018 (U.S. EIA)

YEAR	ANNUAL GENERATION (MILLIONS OF MWH)	CARBON DIOXIDE EMISSIONS FROM ELECTRIC GENERATION (MILLIONS OF MT)	EMISSIONS IN MT/MWH
2000	3,637	2,310	0.6350
2018	4,011	1,762*	0.4393
Δ 2000-2018	+ 374	(548)	(0.1957)
% Change	**+ 10.3 %**	**(23.7%)**	**(30.8%)**

*EIA figure of 1.762 billion MT varies slightly from EPA GHGRP figure of 1.750 billion MT, which we use in subsequent tables, because of differences in estimates of solid waste and biofuels consumption, plus small amounts of fugitive methane.

CAUSES OF POWER SECTOR EMISSIONS REDUCTIONS 2000–2018

The 30.8 percent reduction in power sector emissions per MWh of output was driven by several large changes in both the types of generators used and the efficiency of the generators themselves. This backward-looking analysis simply accounts for the changes that occurred, without making any attempt to say whether better policies could have achieved a better result.

The mix of generation changed. First, fossil share of electric generation fell by about 8 percent and wind and solar rose by about 8 percent. Fossil-fueled electricity generation's share fell from 70.6 percent in 2000 to 63.1 percent in 2018. Wind and solar power's share had been only 0.2 percent in 2000 but had risen to 8.5 percent by 2018. However, an equally important shift occurred inside the fossil share, with natural gas cannibalizing coal: natural gas was 20 percent of fossil electricity generated in 2000 and had risen to 54 percent of fossil electricity in 2018. Coal and oil generation dropped from an 80 percent share to 46 percent share of fossil generation over the same pairs of years.

Another important shift—though less important than the generation mix change—was improving gas generation efficiency. A host of new natural gas plants (both natural gas combined cycle [NGCCs] and combustion turbines [CTs]) were built during the 2000-2018 period, and the impact of that newer, better equipment lowered the fleetwide average gas plant fuel consumption from approximately 10.2 million Btu per megawatt hour (MMBtu/MWh) in 2000 to 8.0 MMBtu/MWh in 2018.[31]

The emission reduction due to these various factors is 785 million MT per annum ("MMTPA").[32] **Table 2** quantifies the impacts of these changes in generation mix and efficiency.

- 44.2 percent of the carbon dioxide net emissions reduction came from replacing coal and oil electricity generation with electricity from gas plants (without accounting for efficiency improvements in the gas plants themselves).
- Another 20.3 percent of the net emissions reduction came from improved efficiency of the gas fleet from 2000 to 2018.
- The remaining 42 percent of net emissions reductions resulted from wind and solar electricity displacing fossil fuel-fired electricity (8.2 percent from solar and 33.8 percent from wind).
- Adverse changes totaling 6.5 percent of net emissions increases resulted from falling market shares of zero-carbon generation such as nuclear and hydro, abetted by slight fuel efficiency losses for remaining coal and oil generation.

TABLE 2: Sources of Power Generation Emissions Reductions 2000 to 2018

SOURCE OF EMISSIONS REDUCTION		CARBON DIOXIDE EMISSIONS (REDUCTION) INCREASE, MILLION METRIC TONS PER ANNUM (MMTPA)	% VS. 2000 LEVEL
Generation Mix Changes	Fuel Switching: Coal & Oil →Gas	(346.6)	(44.2%)
	Solar Replacing Fossil Fuels	(64.6)	(8.2%)
	Wind Replacing Fossil Fuels	(265.7)	(33.8%)
Efficiency Changes	Improved Efficiency of Natural Gas Plants	(159.5)	(20.3%)
Other*	Other Items Net	+51.4	+6.5%
	Total Change in Emissions	**(785.0)**	**100.0%**

*Note: "Other" includes emissions increases of 28.6 MMTPA (3.6 percent) from market share losses of baseload zero- carbon resources (primarily nuclear and conventional hydro), plus emissions increases of 22.7 MMTPA (2.9 percent) from generation efficiency decreases in the coal and oil-fired generation sector.

We made one exception here to our usual rule of only showing "gas-related" abatement strategies. It seemed logical to go ahead and show the impact of applying carbon capture to the remaining coal plants that have survived widespread penetration by renewables and successful competition of natural gas plants. On a per ton of carbon dioxide captured basis and assuming similar operating levels (i.e., net capacity factors), carbon capture costs less per ton in the coal power plant industry than in the gas industry

The point of **Table 2** is not that policies were ideal. We simply note that a reasonable estimate of changes attributable to gas generation cannibalizing coal generation, plus better gas efficiencies, is about 500 million metric tons per anum (MMTPA) in emissions reductions. If a country's total emissions were 500 MMTPA, it would rank 16th in the world, just behind Indonesia at #14 (511 MMTPA 2017) and Mexico at #15 (507 MMTPA 2017).[33]

Spotlighting the changes on the fossil generation side, the box below summarizes the technical details of the interplay among fuel carbon intensity, fuel efficiency, and fuel pricing.

BOX 1: Technology: Power Generation Efficiency and Carbon Intensity

The emissions of a fossil fuel power plant are a function of the *carbon intensity* of the fuel used and the *fuel efficiency* of the power plant. The *carbon intensity* is usually measured in terms of weight of carbon dioxide emitted vs. the heating value of the fuel (in British Thermal Units or Btu). The *fuel efficiency* is the amount of electricity output per unit of heat input; its reciprocal—the heat rate—is measured as the number of Btus it takes to make a unit of electricity. The higher the heat rate, the lower the efficiency. Taken together, a power plant that uses a high- carbon-intensity fuel (like coal) at a high heat rate, emits a lot of carbon dioxide, and a power plant that uses a low-carbon-intensity fuel (like natural gas) at a low heat rate, emits far less carbon dioxide.

The inherently lower carbon intensity of natural gas, substantial improvements in natural gas fuel efficiency, and a boost from falling gas prices, all led to significant greenhouse gas reductions from the power sector over the last two decades. The first two factors (carbon intensity and fuel efficiency) led to gas plants having lower *potential* emissions per MWh; but in the end it was cheaper gas prices that motivated utilities to run the gas plants in preference to coal plants, leading to *actual* emissions reductions.

- **Carbon Intensity:** Combusting 1 million Btus (MMBtu) of gas emits about 117 pounds of carbon dioxide, versus 206 pounds/MMBtu for coal–i.e., as a fuel, gas's *carbon intensity* is 57 percent of coal's.
- **Fuel Efficiency:** Gas plants also typically have much better *fuel efficiency* than coal plants. On average, gas plants built in the last two decades have Heat Rates of 7 MMBtu/MWh, versus the existing coal fleet at approximately 11 MMBtu/MWh average – i.e., new gas power plants use about 64 percent of the fuel used by existing coal plants per MWh. The two components of the improved efficiency were improved gas combustion turbine designs, plus in many cases installation of equipment to make steam from waste heat in combustion turbine exhaust, with that extra steam boosting total electric output by approximately 50 percent. The plants that recover waste heat to make more electricity are called natural gas combined cycle (NGCC) plants.
- **Low Intensity and High Efficiency Combined:** The combination of lower fuel carbon intensity and higher plant fuel efficiency means that modern NGCCs emit about 36 percent as much CO_2 per MWh as the existing coal fleet (5 percent x 64 percent = 36 percent). The very newest NGCCs (6.3 MMBtu/MWh) emit about 45 percent of the carbon dioxide emitted by the best new "supercritical" coal plants (8 MMBtu/MWh.
- **Fuel Prices:** A final important factor has been the fall in gas prices vs. coal prices as natural gas production vastly expanded in North America during the last decade. With gas plants using only 64 percent as much fuel as coal, it became cheaper to run gas plants as long as gas prices were no more than 50 percent above coal prices (i.e., coal at $2/MMBtu and gas no more than $3/MMBtu.)
  - A gas plant paying $3 per MMBtu and using 7 MMBtu/MWh has a fuel cost of $21/MWh.
  - A coal plant paying $2 per MMBtu and using 11 MMBtu/MWh has a fuel cost of $22/MWh.
  - The utility operator chooses to run the gas plant with the uncomplicated desire of saving money on fuel cost, but as a collateral consequence the operator now only emits 36 percent of the CO_2 it would have otherwise.

*Heat Rate is usually quoted as thousands of Btus per thousands of Watt-hours (as in 7,000 Btu per kWh. In this report, since most generation is reported in millions of Watt-hours (MWh) and fuel usage is also quoted in millions of Btus (MMBtu), we will report heat rate as millions of Btus per millions of Watt-hours (MMBtu/MWh).

III. CURRENT U.S. EMISSIONS, WITH FOCUS ON NATURAL GAS

Finding the instances in which natural gas can play a strategic role in decarbonization requires separating usage of natural gas from usage of other fossil fuels. We also need to understand the important differences in the three ways natural gas is used in the world industrial economy: as a power plant fuel, as an industrial feedstock, and as fuel for industrial heating.

TRACKING NATURAL GAS EMISSIONS IN U.S. GOVERNMENT DATA

Cross-referencing U.S. EIA and Environmental Protection Agency (EPA) data allows splitting natural gas-related fossil emissions from other fossil emissions for most of the electric generation industry, but for other industries a great deal of detective work is required.[34]

This section examines U.S. emissions of carbon dioxide today, using U.S. government data as a starting point. U.S. government data are categorized for purposes of counting emissions by industry, whereas for our purposes, we seek to categorize emissions based upon the relative difficulty of abatement. Thus, we reorganized the official figures to highlight the categories and quantify where natural gas-related pollution control measures can be most effective in the future.

Section II discussed the role of natural gas in combustion in power plants. Before turning to the task of parsing U.S. government data, it is important to focus on two other major uses of natural gas: as a feedstock and as a heating fuel. The carbon dioxide emissions from each of these two distinct uses of natural gas can be abated with carbon capture, either at the emitting facility or by decarbonizing the fuel before it gets to the facility.

PROCESS USE OF NATURAL GAS

Process emissions are inherent to the transformation of raw materials into finished products—irrespective of the separate fuel needs to heat materials or power equipment. "Process emissions" of natural gas refer to emissions that occur when the physical methane molecule has been used as raw material or feedstock to manufacture a final product, just as logs are used as raw material or feedstock to manufacture paper or plywood.

Natural gas (composed primarily of methane molecules or CH_4) is a backbone feedstock of the chemical industry: methane is the initial raw material for manufacturing a wide variety of chemicals with the key intermediate products being ammonia and methyl alcohol.[35] Carbon dioxide is far cheaper to capture at high concentrations and high pressures, both of which occur in industrial plants that use methane as a feedstock.

For instance, steam methane reformers (SMRs) thermochemically convert methane and water feedstocks into hydrogen gas and carbon dioxide. As the process proceeds, carbon dioxide concentrations (by molecular percentage) can range from 16 percent to nearly 50 percent, with pressures 3-20 times that of ambient air. When concentrations and/or pressures are high, meaningful reductions can be made in the size, and thus the construction cost, of the equipment needed to capture carbon dioxide. Of course, in addition to *process emissions* from SMRs, the thermochemical conversion requires external heat that is provided by combusting natural gas, generating *combustion emissions* as well. As we will see, it is hard to separate the two components in government data since all the emissions typically are released in a single combined vent stack. In some but not all cases, industry is asked to estimate the proportions of process vs. combustion emissions exiting the combined vent stack.

It is important to note that some process carbon dioxide emissions are unrelated to fossil fuel. An example of non-fossil process carbon dioxide emissions is the making of cement, one of the most common products in every economy. Cement is made by heating limestone ($CaCO_3$) at 2,700 degrees F until it converts to lime (CaO, the key binding agent in cement) and carbon dioxide process emissions. Significant *combustion* emissions take place from firing the furnace, but the carbon dioxide *process* emissions result from the chemical change that occurs to the limestone raw material. As with the SMR example, it can be hard to separate the process from the combustion emissions data in the cement industry, because all emissions typically are released in a single combined vent stack.

INDUSTRIAL HEATING USE OF NATURAL GAS

Industrial heating emissions are released through various non-electric processes that combust fossil fuels for the purpose of heating, drying, or transforming (as in our limestone example) raw materials. This source contributes one fifth of U.S. stationary carbon dioxide emissions. As in the power sector, some significant *combustion emissions* reductions have occurred in recent decades as natural gas became a more common industrial fuel, displacing coal and residual oil. For the largest industrial combustion emitters, particularly combined heat and power (CHP) and the largest furnaces and boilers, carbon capture is a viable strategy. But the relatively small size of many industrial combustors makes carbon capture equipment expensive to deploy. Meanwhile, it is difficult to find affordable low- or zero-carbon heating sources that are adequate substitutes.[36]

U.S. STATIONARY SOURCE CARBON DIOXIDE EMISSIONS

Table 3 sorts relevant U.S. stationary emissions into seven broad categories, with four basic strategies offering emissions reductions. Through the balance of the report, we will work through reductions starting with this "Baseline Emissions" table. The main source for these figures is data from U.S. EPA's "FLIGHT" (Facility Level Information on GreenHouse Gases Tool), using 2018 data released in Fall 2019. Please note four key methodology issues:

1. To make it easier for readers to cross-check figures herein, all tables represent metric tons of carbon dioxide equivalent (CO_2eq), a measure that adds to carbon dioxide tonnage the other various greenhouse gases such as methane, with EPA having multiplied each ton of the other greenhouse gases by a coefficient that represents the relative global warming potential of the particular gas vs. that of carbon dioxide.
2. Additionally, FLIGHT summary tables have an overall national summary on a single spreadsheet tab for true point source "Direct Emitters" (i.e., a single plant with a fence line and emissions coming from within the fence line), followed by separate tabs for emitters of large geographic scope including oilfields, gathering pipes, long distance pipelines, and local gas distribution systems: we aggregate all of these into our tables as "stationary emissions."
3. Finally, the tables herein do *not* include biogenic emissions for two reasons. First, EPA does not include biogenic emissions in its overall totals of U.S. greenhouse gas emissions. Second, though some biogenic emissions are listed in FLIGHT (e.g., paper mill combustion of wood waste), other biogenic emissions are not (e.g., carbon dioxide produced by decomposition of organic matter in municipal landfills.) The total amount of biogenic emissions shown by EPA in FLIGHT is 144 million MT in 2018, which, if included, would raise total U.S. stationary emissions to 2,922 million MTPA.
4. FLIGHT combines two types of emissions into subpart 'C' (Stationary Combustion) for a total of 575 million MTPA in 2018. One type is emissions from "inside the fence" power plants that supply off-grid electricity and heat (usually steam) to the host factory. The second type is emissions from furnaces and steam boilers that have no electricity component. We analyzed data from a variety of federal sources to determine that the inside the fence power plants represent 152 million MTPA of non-biogenic carbon dioxide[37], and allocated the balance of 423 million MTPA to the category below called "industrial process heat." We did so because the abatement approaches for industrial power plants differ substantially from the abatement approaches for industrial process heat.

The rightmost column of **Table 3** lists various "strategies for emissions reduction." Renewables, electrification, and methane destruction are all well-known. Penetration of renewables is our "Block 1." The bullet points below summarize the natural gas-related four Building Blocks:

- **Block 2**: Coal-to-gas fuel switching is the primary strategy for reducing remaining coal-fired and oil-fired power plant emissions. High-carbon fuel electric generation, at 42 percent of stationary source emissions and 1.2 billion MTPA, is still ripe for further fuel switching, either to gas or renewables. (Note that coal represents 98 percent of this category.) [38]

- **Block 3:** Power Plant carbon dioxide capture is the primary strategy for reducing emissions from natural gas-fired power plants and industrial "Combined Heat and Power" (CHP) plants. Gas-fired electric generation delivered to the general power grid (termed "electric sector generation") now represents about 21 percent of all stationary source emissions, at approximately 0.58 billion MTPA. Though categorized as "stationary combustion" rather than as "electricity generation" by EPA, there is a large, usually overlooked, CHP sector "inside the fence line" of U.S. industry, making up 5 percent of total stationary non-biogenic emissions at approximately 152 million MTPA, with natural gas being the predominant fossil fuel.[39] We would expect natural gas generation to simultaneously be displaced by renewable penetration as more renewables are built, and to displace coal generation as more coal-to-gas fuel switching occurs. When both these trends have run their course, gas power plants will still emit a large amount of carbon dioxide—somewhat lower than today's tonnage but comprising a larger percentage of remaining emissions. At that point, larger units that run at higher capacity factors are excellent candidates for carbon capture. [Note: a cheaper emissions reduction method for smaller power plant units with lower capacity factors is to switch them to partial or total hydrogen combustion, a strategy we do not analyze in detail herein.]
- **Block 4:** Industrial Process carbon dioxide capture is also the primary strategy for reducing emissions from industrial processes (heavy industry plus Oil & Gas) that use natural gas as feedstock and produce natural gas. This emissions category makes up 11 percent of stationary source emissions, with 8 percent from heavy industry and 3 percent from Oil & Gas. There are select opportunities for carbon capture of industrial process emissions, such as the carbon dioxide released when natural gas is converted to hydrogen in SMRs, as well as some emissions from natural gas processing plants.[40] Industrial process emissions also include significant non-fossil emissions, such the approximately 60 MMTPA of emissions created when limestone is heated for cement and lime.
- **Block 5:** Fuel decarbonization is the primary strategy for reducing industrial process heat emissions in industries that need high heat (>1,000 degrees C) and fast heat transfer. Industrial stationary combustion emissions are a large (at 15 percent) but also heterogenous emissions category. However, this category also contains many natural gas-related emissions sources that are quite hard to decarbonize—such as small natural gas fired

TABLE 3: U.S. Stationary CO_2eq Emissions (Baseline Emissions) 2018

	2018 EMISSIONS (MILLIONS OF MT CO_2EQ)	% OF TOTAL STATIONARY	STRATEGIES FOR EMISSIONS REDUCTION
Utility Coal and Oil Fired Generation	1,169	42%	Fuel Switching Coal → Gas; Renewables
Utility Natural Gas Fired Generation	581	21%	Power Plant carbon dioxide Capture; Renewables
Industrial Power Plants (CHP)	152	5%	
Non-Oil & Gas Industrial	228	8%	Process carbon dioxide Capture
Oil & Gas (incl. Refinery & Petchem)	92	3%	
Industrial Process Heat	423	15%	Clean Fuels; Electrification
Waste, Landfills, Coal Mines	133	5%	Methane Destruction (not discussed)
	2,778	**100%**	

boilers used to make steam at paper mills or food processing factories. (Note that the total "Stationary Combustion / subpart 'C'" reported by EPA (575 MMTPA) includes the CHP emissions (152 MMTPA).) Less demanding processes (lower temperatures, slower heat transfer) are likely to do better using electrification, with the electricity sourced from zero- or low-carbon generation. The natural gas-related emissions reduction strategy discussed herein is substitution of blue hydrogen (hydrogen made from SMRs with carbon capture) in place of natural gas in applications needing high heat and fast heat transfer.

IV. NATURAL GAS IS NOT DISAPPEARING SOON

In a world that is desperate to solve issues of energy poverty, fossil fuels are cheap to produce, cheap to move, cheap to store, and incredibly energy dense. If molecules like methane, ethane, propane, and octane did not already exist, a brilliant chemist would have had to invent them. Yet consumption of fossil fuels is responsible for most of the world's carbon dioxide emissions (and a solid proportion of methane emissions), threatening the world's climate. Since the world's governments have not yet placed meaningful limits on greenhouse gas emissions, those inherent advantages of fossil fuels—with no real countervailing regulatory constraint—continue to create robust demand for fossil fuels. The Kyoto Protocol was adopted in 1997 and became effective in 2005; yet world consumption of fossil oil, gas, and coal rose by a total of 18 percent from 2009-2019 (1.6 percent compound annual growth).[41]

Fossil fuels are so compellingly cheap and convenient that even energy forecasts encompassing Draconian changes to discourage fossil fuels put only a modest dent in consumption. As discussed below (IV.1), the most aggressive decarbonization scenario envisioned by the IEA, a scenario that includes $140/MT carbon dioxide pricing, still projects surprisingly large amounts of remaining fossil fuel consumption, with natural gas gaining market share against coal and oil. The IPCC's "1.5 Degree Report," published in 2018, shows smaller absolute consumption of fossil fuels, but the IPCC still shows the same phenomenon of natural gas gaining market share against coal and oil. Is there a way out of the dilemma of the world's citizens calling for a swift end to fossil fuel production while at the same time they hungrily gobble more fossil fuels every year?

The call for the end of fossil fuels has always needed two caveats. First, not all fossil fuels contribute equally to greenhouse gas emissions. As we have seen, use of one fossil fuel—natural gas—demonstrably *reduced* overall U.S. power sector greenhouse gas emissions in recent years via coal-to-gas fuel switching, while lowering electric generation costs. Reasons cited for the decline in the price of natural gas are many, including technological change that was in part aided by federal funding.[42] However, once gas prices fell, fuel switching was not compelled by regulation: it was a straightforward consequence of power producers' efforts to cut fuel cost of generation.

Second, the climate-related concern is not with fossil fuels *per se*, but rather with the environmental consequences of using them: if greenhouse gas emissions and other environmental issues can be successfully mitigated, fossil fuels may continue to play a role in the energy economy of the future. Techniques like carbon capture (either on combustion sources, or inside industrial plants that use fossil fuels as a feedstock) can eliminate fossil fuel carbon dioxide emissions without eliminating fossil fuels. Fugitive methane emissions can be greatly reduced if regulators push that agenda and if producers, pipelines, and local gas distribution companies does not drag their feet. Safe disposal of "produced water" (the technical name for water that reaches the surface from conventional and hydrofracked gas and oil wells) does not require a technological revolution: rather, what is required is careful permitting and competent operation of properly sited injection wells.

All energy technologies have some environmental consequences, and the question is whether those consequences can be eliminated or mitigated. The environmental consequences of mining lithium and cobalt for batteries or uranium for nuclear power are likewise of concern. So are the huge electricity consumption required to produce silicon crystal for solar panels and the land use issues of wind and solar farms.

Thus, this paper's focus on reducing natural gas *emissions* rather than natural gas *use* is important, considering that even the most ambitious IEA and IPCC scenarios for greenhouse gas reductions show worldwide natural gas consumption two decades from now being only modestly below today's levels (see **Figure 2** and **Table 5**). If the IEA and IPCC are wrong, and fossil fuels are entirely eliminated, the job will be easy. If the IEA and IPCC projections are correct, urgent action to reduce greenhouse gas emissions from natural gas is indispensable.

IEA AND IPCC PROJECTIONS OF GLOBAL FOSSIL FUEL USE, WITH FOCUS ON U.S. NATURAL GAS

IEA: The IEA projects world energy consumption and emissions under three different scenarios:

1. The "Current Policies Scenario" is the least ambitious, encompassing only existing law and policies. A few countries plus the EU have carbon prices, mostly in the $30/MT range by 2040.
2. The "Stated Policies Scenario" shows more ambitious emissions reductions, accounting for "policies and measures that governments around the world have already put in place, as well as the effects of announced policies, as expressed in official targets and plans." [43] A few more countries have carbon pricing, reaching the $40/MT level by 2040.
3. The "Sustainable Development Scenario" or "SDS" is a much more ambitious scenario, corresponding to the type of action needed to achieve a 50 percent chance of limiting temperature rise to 1.65 degrees C.[44] By 2040 "advanced economies" have carbon dioxide emissions prices of $140/MT and "selected developing economies" are at $125/MT.[45]

IEA concludes the high carbon taxes of the SDS would blunt, but would by no means eliminate, fossil fuel demand; and of the fossil fuels, natural gas is almost unaffected by high carbon taxes. **Table 4** below shows the IEA's projected fossil energy demand—using common units of the energy equivalent of one MT of oil—under these three scenarios. The SDS (far right column) is the only scenario that shows total fossil fuel consumption—oil, coal, and gas—below today's level, with an overall drop of 29 percent. However, the drop in consumption is overwhelmingly driven by coal's 62 percent reduction and oil's 32 percent reduction. Natural gas consumption drops by only 3 percent. Please note that the units in **Table 4** are energy consumption, not emissions.

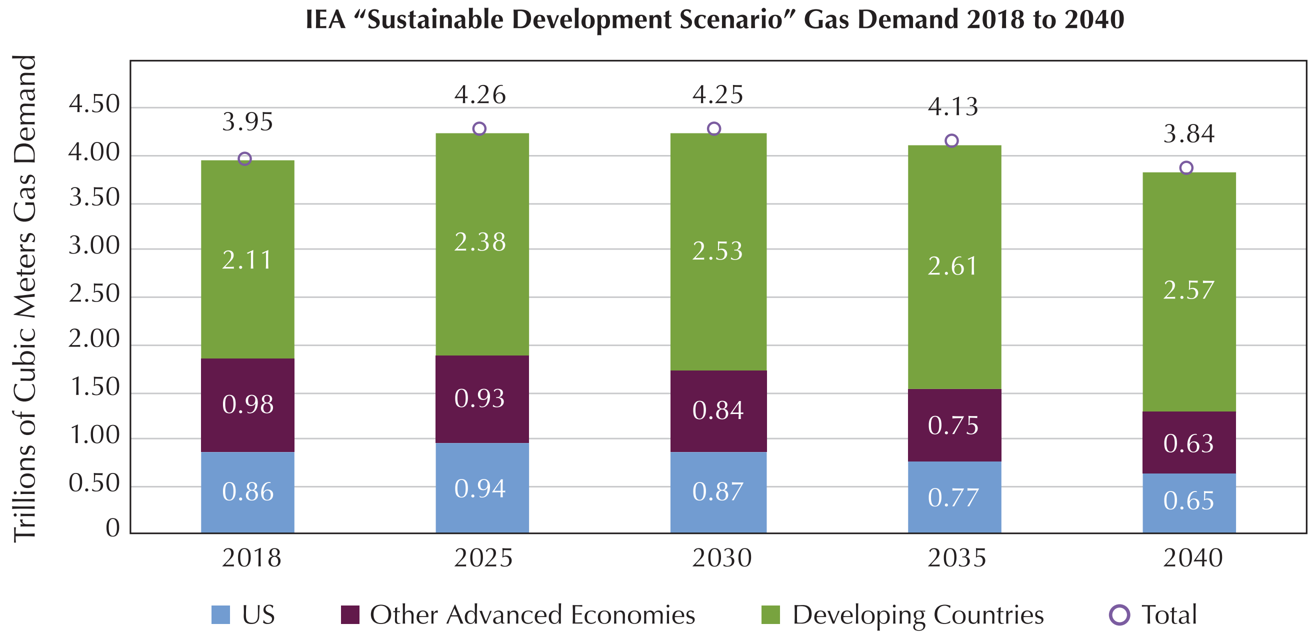
Figure 2 below focuses just on the changes in world natural gas consumption patterns from 2018-2040 in the SDS.[46] [Note: different units from those of **Table 4**.] With a total of 3.84 trillion cubic meters (m^3) of gas consumed worldwide in 2040 the SDS is the most ambitious of three scenarios presented by the IEA, compared to 5.4 trillion m^3 for the "Stated Policies Scenario" and 5.9 trillion m^3 in the "Current Policies Scenario." Total demand of 3.84 trillion m3 in 2040 is only a 3 percent global reduction in gas demand vs. 3.95 trillion m^3 in 2018. However, it should be noted that the SDS scenario depends upon the U.S. and other "Advanced Economies" achieving a combined 31 percent reduction in their natural gas consumption vs. 2018 levels, leaving room for the "Developing Countries" to expand gas consumption by 22 percent.

TABLE 4: IEA World Energy Outlook forecast for Fossil Energy Consumption Under Three Scenarios (Demand Shown in Million MT of Oil Equivalent)

	"TODAY"	CURRENT POLICIES SCENARIO	STATED POLICIES SCENARIO	SUSTAINABLE DEVELOPMENT SCENARIO	CHANGE SDS VS. TODAY
	2018	**2040**	**2040**	**2040**	
Coal	3,821	4,479	3,779	1,470	(62%)
Oil	4,501	5,626	4,921	3,041	(32%)
Natural gas	3,273	4,847	4,445	3,162	(3%)
	13,612	**16,992**	**15,185**	**9,714**	**(29%)**

See Table 1.1 on page 38 in Ibid.

FIGURE 2: Natural Gas Demand 2018-2040 in the IEA's Sustainable Development Scenario (Volumes in $m^3 \times 10^{12}$)



IPCC: The IPCC in its "1.5 Degree C" 2018 report came to similar conclusions about the relative changes in fossil fuel consumption patterns. That is, the IPCC showed precipitous drops in coal and oil, and a more modest drop in gas demand. As an example, the IPCC categorized fossil fuel use in 50 studies whose scenarios either managed to keep warming below 1.5 degrees C or managed to have relatively small amounts of "overshoot" that could later be addressed with carbon dioxide removal (CDR). For comparability to **Table 4** above we converted the IPCC figures in Exajoules (in the original) to millions of metric tons of emissions (MTOE). [47] **Table 5** is not easily comparable to **Table 4** since the timeframe of **Table 5** is a decade longer (2050 vs. 2040) and the temperature target of **Table 5** is lower (1.5 degrees vs. 1.65 degrees).

TABLE 5: Medians of Fossil Fuel Consumption in IPCC Scenarios Achieving Sub-1.5 degrees C or Correctable to 1.5 degrees C With "Low Overshoot"

IPCC FOSSIL FUEL CONSUMPTION FORECAST MEDIANS (MILLIONS OF MTOE)				
	2020	2030	2050	%Change 2020-2050
Coal	3,269	1,051	577	-82%
Oil	4,711	3,729	1,663	-65%
Natural Gas	3,175	2,687	1,816	-43%
Total	**11,154**	**7,467**	**4,055**	**-64%**

V. BLOCK 1: RENEWABLE PENETRATION REDUCES FOSSIL GENERATION

This section portrays the rationale behind our calculated reduction of fossil generation combustion emissions based on penetration of zero-emitting PV and wind, followed by a qualitative discussion of the ultimate economic limitations to relying on those sources.

BLOCK 1: RENEWABLE PENETRATION IMPACT ON FOSSIL FUELS IN THE ELECTRIC SECTOR

In Section III (**Table 3**) we showed a current actual baseline stationary U.S. carbon dioxide emissions level of 2.778 billion MTPA. With the costs having fallen on wind and solar PV generation, some federal tax incentives continuing (such as five year accelerated depreciation on most "renewables" and a permanent 10 percent ITC for solar), corporate interest in buying zero carbon electricity, and more states adopting versions of clean energy standards or renewable portfolio standards, it is clear that significantly more wind and solar PV penetration will and should occur, replacing much of current fossil generation.[48] Once constructed, renewable solar and wind generators have near-zero variable costs of generation at the plant level, although as variable generators (VG), [49] they require some reliability backup from a combination of so-called "spinning reserves", fast-starting fossil generators, or quick-acting storage such as batteries or pumped-hydro storage. So, usually when VG is producing, more expensive fossil fuel generators can be turned down, subject to the minimum spinning reserves level required to maintain system stability. (Of course, if total VG production exceeds total demand less minimum production from spinning reserves and resources that cannot be turned off, then either some VG must either be turned off or sold into inter-regional wholesale markets.)

Table 6 quantifies the impact of our Block 1, with extensive wind and solar power penetration, creating an adjusted baseline. The 2nd column (2,778 MMTPA) is carried over from **Table 3**. Then in the 3rd column, wind and solar resources displace 50 percent of 2018 coal- and gas-fired carbon dioxide emissions on a proportional basis, cutting combined emissions by 875 MMTPA. Revised emissions are 1,903 MMTPA. Note that we are not saying "renewable energy" is *limited* to 50 percent of total generation—rather, in addition to current renewable and other zero-carbon generation, we hypothesize deployment of *incremental generation*

TABLE 6: U.S. "Adjusted Baseline Emissions" after Block1: Stationary Emissions Assuming Extensive Renewable Penetration in Electric Generation

	2018 EMISSIONS (MILLIONS OF MT CO_2EQ)	RENEWABLES REPLACE 50% OF REMAINING FOSSIL	REVISED EMISSIONS (MILLIONS OF MT)
Utility Coal and Oil Fired Generation	1,169	(584)	584
Utility Natural Gas Fired Generation	581	(290)	290
Industrial Power Plants (CHP)	152		152
Non-Oil & Gas Industrial	228		228
Oil & Gas (incl. Refinery & Petchem)	92		92
Industrial Process heat	423		423
Waste, Landfills, Coal Mines	133		133
	2,778	**(875)**	**1,903**

from wind and solar, the output of which is sufficient to cut 2018 fossil *emissions* by 50 percent. Further, we are applying changes to the electric generation mix on a static basis, whereas electricity could grow rapidly if widespread electrification of heating and transportation were to take place: for reference, IEA shows a 0.5 percent compound annual growth rate in electricity consumption under the SDS scenario.

Though our assumption of a 50 percent reduction in gas and coal emissions enabled by renewables growth is a transparently round number, the postulated *emissions* reduction implies a change in relative and absolute *generation patterns* that is consistent with IEA's projections for its SDS described earlier.[50] In the next two tables we compare the *generation* assumptions we used in **Table 6** with the IEA's projections.

As summarized in **Table 7**, IEA shows approximately a 1-for-1 replacement of fossil generation with wind and PV, with increase in bioenergy generation (not shown) making up the difference through 2040. By 2030 fossil production is down approximately 900 TWh and renewables are up by the same amount. By 2040, fossil production is cumulatively down approximately 1,700 TWh and renewables are up 1,900.

Table 8 (below) shows the calculations of generation and capacity changes implied by **Table 6**. Our scenario is roughly comparable to IEA's. That is our increased wind and PV generation of 1,260 TWh a year is about halfway in between IEA's 2030 and 2040 figures of 881 and 1,895 TWh, respectively. And our added wind and PV capacity of 478 GW is about halfway between IEAs 2030 and 2040 figures of 364 and 731 GW, respectively. (Note that the 30 percent Net Capacity Factor (NCF) of combined wind and PV during the period was identical to the blended NCF used by IEA.)

Achieving 875 MMTPA (**Table 6**) of additional emissions reduction by displacing coal and gas with solar and wind resources in the above scenario is not a modest goal: It represents roughly 2.6 times the 331 MMTPA of annual carbon dioxide emissions reductions attributable to wind and solar PV in the entire 2000-2018 period (shown in **Table 2**.) That would raise the wind and PV solar power share of total U.S. electricity generation from 8.5 percent in 2018 to 40 percent (assuming total generation is unchanged). Adding in existing geothermal (0.4 percent), waste and biomass (0.8 percent), hydro (7.5 percent), and nuclear (20.1 percent), approximately 69 percent of the U.S. power sector would be carbon free. Current U.S. installed wind and PV capacity is 157 GW, so the incremental 478 GW (**Table 8** bottom right corner) would represent a quadrupling of U.S. wind and PV.

WHY IS IT SO LIKELY THAT SIGNIFICANT FOSSIL-FIRED ELECTRIC GENERATION REMAINS?

Obviously, the 584 MMTPA of coal emissions and 290 MMTPA of gas emissions, totaling 874 MMTPA) in the last column of **Table 6** could be considerably smaller if wind and solar penetration is greater, especially if accompanied by electrification of industrial heating. The point is that there is a high probability that some significant emissions remain from fossil power generation, even after significant renewable penetration: we cannot pretend those emissions will disappear, so we need to plan how to reduce them.

Before turning to the means of reducing those 874 MMTPA of emissions, we will briefly explain the rationale for some amount of fossil generation remaining for the near- and intermediate-term, as shown in the last column of **Table 6**. That is, 874 MMTPA of emissions

TABLE 7: IEA SDS Changes in Output from U.S. Fossil and Wind/PV Generators (2018–2040)

IEA SUSTAINABLE DEVELOPMENT SCENARIO: CHANGES IN FOSSIL GENERATION AND WIND & PV GENERATION VS. 2018 BASELINE (FIGURES IN ANNUAL TWH, OR MWH X 10^6)					
	2018	**2030 SDS**	**CHANGE: 2018-2030**	**2040 SDS**	**CHANGE: 2018-2040**
Fossil Power Generation	2,841	1,959	(882)	1,141	(1,700)
Wind & PV Generation	362	1,243	+881	2,257	+1,895

See Appendix A-3 in International Energy Agency, World Energy Outlook 2019, (Paris, France: IEA, 2019), https://www.iea.org/reports/world-energy-outlook-2019

TABLE 8: **Output and Capacity Changes Implied by Emissions Reductions in Table 6**

GENERATION AND CAPACITY SHIFTS IMPLIED BY EMISSIONS REDUCTIONS OF TABLE 6				
	REDUCED EMISSIONS PER TABLE 6 (MMTPA)	EIA FLEETWIDE CARBON INTENSITY 2018 (MT/MWH)	IMPLIED FOSSIL OUTPUT REDUCTION (TWH, OR MWH X 10^6)	IMPLIED WIND AND SOLAR CAPACITY NEEDED @30% NCF (GW, OR MW X 10^3)
Coal & Oil	(584)	1.01	(578)	+219
Gas	(290)	0.425	(682)	+259
	(875)		**(1,260)**	**+478**

remain because for economic and power grid reliability reasons, rather than because of general pessimism. It is not possible to do full justice to this subject in a short paper: we simply seek to state that some special uses of fossil fuel electric generation are extremely expensive to replace given current technology, and in the near term we may be better off cleaning up these fossil units than shutting them down.

The key issue is how to incorporate large quantities of cheap wind and solar generation into the energy mix while still maintaining the reliability of power supply required by a modern society. To that end, the future power grid is likely to need a core amount of flexible, utterly reliable, dispatchable, on-demand electric supply capability that emits zero or negligible amounts of carbon dioxide when deployed. This is the Holy Grail of today's utility planners: "firm low-carbon generation." Many different types of equipment will compete to provide that flexible, decarbonized supply capability. Some of the non-fossil options include batteries of different types, pumped hydro storage, and large-scale storage of zero-carbon fuels generated from zero-carbon electric generation that can be used in turbines or fuel cells, etc. Ultimately a portfolio of different grid reliability technologies is likely to emerge—including gas plants with carbon capture and small modular nuclear reactors—driven by the different time scales over which reliability is needed.

Some reliability-oriented technologies are cost-effective to meet short-term reliability issues, while others are more cost-effective to meet long-term reliability issues. Most expert energy system modelers agree that fossil generators, mostly NGCCs equipped with carbon capture equipment, are the key technology for cost-effectively meeting *the long-term reliability issues*. They will survive in the future because they smooth seasonal generation vs. consumption patterns at lower cost than other available alternatives. Further, if NGCCs with carbon capture are procured primarily to deal with seasonal mismatches, they are on hand to deal with day-to-night mismatches as well.

Some quick facts and figures illustrate the types of tradeoffs that drive technology decisions to meet the needs for seasonal reliability. The key insight is that meeting seasonal load changes—such as a doubling of hourly electricity usage between spring and summer—the system needs resources that can provide huge volumes of energy (MWh), as opposed to short bursts of power (MW). We cannot attempt a conclusive analysis in this paper and offer the following as a simplified example, with complex systems portrayed for 1 MW of capacity required to deliver 24MW over one day at a uniform rate (1MWh per hour):

- The most expensive part of a renewable-plus-battery system is the actual battery storage unit, costing about $300,000 today to store one MWh of electricity in a lithium ion battery system.[51] The other parts of the system, such as DC-to-AC inverters and project infrastructure, are minor costs. If that expensive storage cell is being charged every day and discharged every night, the expensive upfront cost is amortized over 365 charging cycles per year. If the battery is charged in the spring to meet summer loads, and charged in the fall to meet winter loads, its cost is amortized over only two charging cycles a year, which is simply economically prohibitive. (This is not a silly example, since large hydroelectric facilities such as Grand Coulee Dam are designed to hold back spring flood waters in order to provide power during the summer, fall, and early winter.) Of course, Li-ion battery prices are expected to decline in the future, with NREL showing a mid-case decline to $150,000 per MWh storage by 2050. The key insight, however, is that virtually all of the battery storage system cost resides in the storage component, rather than the power component—batteries need to be charged and discharged frequently in order to make the investment in the storage component profitable. Cutting the storage capital cost in half, as projected by NREL, does not meaningfully alter that high-capacity utilization imperative.

- An alternative is to greatly overbuild the amount of renewables to meet summer and winter loads while buying fewer batteries; but that tactic creates large amount of wasted generation that cannot be stored during the low-demand spring and fall periods, thus also being quite expensive.
- For roughly the same cost as 8 MWh of battery cells, a utility can buy a 1MW natural gas combined cycle power plant (NGCC) with carbon capture.[52] The NGCC, however, is not limited to 8 MWh: it can run all summer if required, except if equipment breaks or fuel runs out. "Storage costs" are negligible given the vast amount of flexibility in the existing natural gas pipeline network and seasonal natural gas storage reservoirs. Hence, for a utility that needs to be absolutely sure of ability to meet evening air conditioner loads mid-summer, or evening lighting, heating, and appliance needs mid-winter, an NGCC equipped with CCS is a relatively cheap option.

VI. BLOCK 2: COAL-TO-GAS FUEL SWITCHING IN THE POWER SECTOR

Chapter II showed that roughly three-fifths of U.S. power sector emissions reductions of the last two decades were attributable to coal-to-gas fuel switching, plus improved natural gas power plant efficiency. It is likely that more fuel switching will occur over the next decade or so; and switching would accelerate if policies that directly reduce carbon dioxide emissions, such as clean energy standards or carbon pricing, are adopted. Simply put, increasing current gas plant capacity factors while decreasing current coal plant capacity factors is a cheap emissions reduction strategy—at least in the fuel price environment that has prevailed over the last four or five years—with newer vintage natural gas combined cycle plants (NGCCs) emitting roughly one-third the carbon dioxide of the existing fleet average coal plant.

How cheap is this strategy? In **Table 9** we summarize the changes in variable and fixed costs from coal-to-gas fuel switching two ways. First, we compare running an existing coal plant less with running an existing NGCC more to compensate. Second, we do the same comparison in the case where the utility must construct a new NGCC. The full calculations are in Appendix B .[53]

- Preferentially running the *existing NGCC* both costs less ($7.17 savings) and emits less (0.65 MT/MWh reduction), with a savings of $11.06 per MT of carbon dioxide emissions avoided. Here we only need to consider variable costs to produce electricity because the utility has to pay the annual fixed costs of the old coal and existing NGCC whether they run or not (unless a plant is completely retired).
- If the coal plant owner does not have an existing NGCC and has to build a *new NGCC*, the owner has to consider incremental fixed costs related to that newly bought plant, including financing, insuring, staffing, paying property taxes, etc. In that case, despite a slightly better fuel efficiency for the newest generation NGCC, total costs (both variable and fixed) for the new NGCC are $13.35/MWh higher than the variable costs of running the old coal plant, while avoiding 0.69MT/MWh. Still the cost per MT of carbon dioxideemissions avoided is less than $19.40/MT.

Of course, adding carbon capture to remaining coal plants or to new or existing gas plants can reduce emissions even more; but since installing carbon capture equipment is usually (but not always) a more expensive route to carbon dioxide emissions reduction than simple coal-to-gas fuel switching. Discussion of carbon capture is deferred to Chapter VII.[54]

TABLE 9: Calculating Avoided Cost of Carbon Dioxide from Fuel Switching

	EXISTING COAL	EXISTING NGCC	NEW NGCC
Total Variable Cost & Fuel per MWh	$26.88	$19.71	$17.81
Fixed Cost/MWh for New NGCC Only*			$22.42
Total Cost/MWh	$26.88	$19.71	$40.23
Savings (Cost) from Coal-to-Gas		$7.17	($13.35)
Emissions CO_2 MT/MWh	1.02	0.37	0.33
Change in Emissions from Coal-to-Gas		(0.65)	(0.69)
Cost (Savings) per MT CO_2 Avoided		**($11.06)**	**$19.40**

**This is only a relavent cost if utility has to build a new gas plant to accomplish fuel switching.*

Table 10 quantifies the impact of coal-to-gas fuel switching on U.S. emissions. The second column of **Table 10** carries over from **Table 6** of Chapter IV (the adjusted baseline U.S. stationary emissions after significant wind and solar penetration). Then in the third column, natural gas replaces 70 percent of remaining coal-fired electricity generation, which would contribute another **233 MMTPA** in *net* emissions reduction (i.e., coal emissions drop much more than natural gas emissions rise). The 233 MMTPA figure is derived using 2018 U.S. fleetwide average power plant fuel efficiency and fuel carbon intensity factors that combine to 1.007 MT carbon dioxide per MWh of coal generation and 0.424 MT of carbon dioxide per MWh of gas generation. Shown in the fourth column, the revised total U.S. stationary emissions drop to 1.670 billion MTPA.

Coincidentally, the 2014 proposed Clean Power Plan (CPP) generated nearly identical results with a similar strategy. The second emissions reduction "building block" of the CPP saved **252 MMTPA** by increasing the net capacity factors of existing natural gas plants from 43 percent to 62 percent nationally, with the absolute number of MWh switched being virtually identical to **Table 7.**[55]

TABLE 10: Coal-to-Gas Fuel Switching (MMTPA)

	REVISED EMISSIONS FROM TABLE 6 (MILLIONS OF MT CO_2EQ)	UNABATED GAS PLANTS REPLACE 70% OF REMAINING COAL	REVISED EMISSIONS (MILLIONS OF MT)
Utility Coal and Oil Fired Generation	584	(409)	175
Utility Natural Gas Fired Generation	290	176	466
Industrial Power Plants (CHP)	152		152
Non-Oil & Gas Industrial	228		228
Oil & Gas (incl. Refinery & Petchem)	92		92
Industrial Process Heat	423		423
Waste, Landfills, Coal Mines	133		133
	1,903	**(233)**	**1,670**

VII. BLOCK 3: DEPLOYING CARBON CAPTURE ON REMAINING GAS (AND COAL) PLANTS

We now turn to the abatement strategy of adding carbon capture equipment to remaining coal and gas power plants. Recall that Section IV estimated the emissions reductions from deploying expected additional wind and solar resources in the power sector, followed by Section VI showing reductions from additional coal-to-gas fuel switching. From a starting point of 2.778 billion metric tons per year (**Table 3**) we were left with 1.670 billion metric tons per year of stationary emissions (**Table 10**), of which 641 million metric tons per annum (MMTPA) (38 percent) represent utility electric sector emissions. We now also add into the discussion 152 MMTPA (9 percent) emissions from fossil fuel CHP equipment inside the fence line of industrial and Oil & Gas plants.

Coal plants and gas plants are both good candidates for carbon capture. Having cut coal power emissions by 85 percent down to 185 million metric tons per year, the remaining coal plants are the newest and most efficient in the fleet, and their owners are unlikely to retire them if there are commercially reasonable alternatives—such as carbon capture installation—to doing so. Meanwhile, with the gas share of power plant emissions having grown to 73 percent of power sector emissions, those gas plants will likely need to either apply carbon capture or be phased out in order to meet tightening carbon dioxide emissions standards.

HOW MUCH DOES POWER SECTOR CARBON CAPTURE COST?

Without considering any tax incentives or possible revenues from sale of carbon dioxide, and assuming that carbon capture-enabled coal and gas plants run 85 percent of the time, the cost per ton of carbon dioxide emissions avoided is likely to be on the order of $60/MT for a retrofit coal plant and $80-90/MT for a new or retrofit gas plant.[56] The carbon capture systems referred to here are aqueous amine solvent-based systems such as those typically used in fertilizer and natural gas processing plants, and as used in the first two major commercial-scale power plants with carbon capture in North America. This $60-90/MT range for carbon dioxide abatement from carbon capture is more expensive than the fuel switching strategies discussed in the prior section, which is why we quantified the impacts of pure fuel switching before obtaining even more emissions reductions with carbon capture.

When deploying carbon capture on gas or coal power plants, about two-thirds of the avoided cost per metric ton of carbon dioxide are fixed costs that are primarily a function of the original cost of equipment installed. One set of fixed costs is paying back lenders and investors who provided funding for the construction of the carbon capture equipment. The balance of fixed costs is made up of property taxes, insurance, and replacement parts, whose expense is directly proportional to the original upfront cost. Those annual fixed charges must be spread over the actual tons of carbon dioxide avoided. As rough rule of thumb, the original cost of capture equipment is roughly equal to that of the power generation equipment itself: for a coal plant that typically costs approximately $2 million per MW of power, the capture equipment also costs approximately $2 million per MW; and for a NGCC that typically costs approximately $1 million per MW of power, the capture equipment also costs approximately $1 million per MW. Though the coal plant carbon dioxide capture equipment costs approximately twice as much on a *per-MW basis*, the coal plant captures roughly three times as much carbon dioxide per MWh of generation. Combining these two factors, the capital cost per metric ton carbon dioxide capturable per year is for a coal carbon capture system is about 2/3^{rds} that of a natural gas carbon capture system.). The variable costs are relatively similar for coal and gas carbon capture, primarily driven by the electricity needed to run pumps, fans, and compressors, plus the steam heat needed to regenerate solvent (i.e., heating the solution that scrubbed carbon dioxide from power plant exhaust so that the carbon dioxide is released and can be compressed and transported).

As with any pollution control or power generation technology, costs are expected to fall as contractors and manufacturers gain more experience and can capitalize on economies of scale in manufacture of components and chemicals. Though carbon capture systems are widely and routinely deployed in natural gas processing plants and fertilizer plants, industry has much to learn about the most cost-effective way to deploy the same systems in a power plant. In any case, the key metric is not how much carbon capture systems cost (in hundreds of millions of dollar terms), but the cost per tonne of carbon dioxide abatement that occurs when the systems are deployed. This is a metric on which carbon capture systems are cost-effective today when compared to many other strategies for carbon abatement, especially when taking account of the availability of federal carbon sequestration tax credits under Section 45Q.[57] To take an overly simplified example, assume CCS deployed on an NGCC power plant with cost per MT of carbon dioxide abated of $80/MT. Assuming co-located geologic storage with a cost of $5/MT, and a federal §45Q tax credit of $50/MT, net cost is approximately $35/MT abated.

It takes good policy design as well as theoretical techno-economic attractiveness to cause widespread implementation of a good generation technology. If utilities and their regulators are not basing their capital expenditures primarily on comparative costs per tonne of carbon dioxide abated (subject to meeting loads and maintaining reliability) cost-effectiveness is insufficient. Indeed, cost-effectiveness *per se* is not the only, or even the most significant, driver of power plant carbon capture adoption. Even though widely considered a core, cost-effective power sector carbon dioxide reduction technology, adding carbon dioxide capture in the power sector is complicated by three policy factors. First, other low- or zero-carbon technologies can give roughly the same quantity and timing of electric generation as a fossil fuel plant with carbon capture (e.g., a large array of solar panels and banks of batteries sufficient to last through a week of cloudy weather, new types of nuclear plants, geothermal and biomass generators, etc.)—so issue is cost, not technical feasibility. But the comparative cost analyses are complex because those cost analyses involve competing estimates of capital costs, future fuel price trends, and technological change. Second, the power industry is highly regulated in terms of equipment purchase decisions; and thus, disputes among experts over comparative costs quickly migrate to the regulatory arena of Integrated Resource Plans and approval of investment projects. Third, the power industry is also highly regulated in terms of the order in which different types of power plants are utilized (or "dispatched") and thus the utilization rate, which is the key driver of cost of avoided carbon dioxide emissions for a fossil-fuel plant with carbon capture, is also uncertain. Thus, unless the policy environment is conducive to picking the cheapest carbon dioxide abatement strategy, carbon capture implementation may lag.

ESTIMATED EMISSIONS REDUCTION IMPACT OF CARBON CAPTURE FOR THE POWER SYSTEM

Table 10 (Coal-to-gas fuel switching) left us with remaining annual fossil electric generator emissions of 175 MMTPA from utility coal and 466 MMTPA from utility gas power plants. Of the 152 MMTPA of CHP fossil fuel emissions, emissions are approximately 2/3 from natural gas and 1/3 from coal and oil. **Table 11** shows the impact of adding carbon dioxide capture to utility coal and utility gas plants, plus the CHP sector. The technology can capture approximately 90 percent of carbon dioxide in treated flue gas, and we applied this technology to 90 percent of utility coal emissions, 50 percent of gas power plant emissions, and 75 percent of CHP emissions. *[i.e., the reduction on the row showing coal emissions is 175 MMTPA x (90 percent of flue gas treated) x (90 percent capture) = 142 MMTPA.]*

In choosing to retrofit gas power plants that make up 50 percent of natural gas power plant emissions we used a simple cutoff that eliminated gas-fired units whose annual net capacity factors were below 60 percent, thereby culling both the less productive NGCCs and most of the simple cycle peaking CT plants. Recall that there are two major subcomponents of the gas power plant industry: highly efficient, larger NGCCs that run approximately 40-90 percent of the time vs. less efficient, smaller "peaking" CTs that run 2-10 percent of the time.[58] Based on the economics, it will ultimately make more sense to decarbonize the fuel fed into less intensively used units, rather than apply carbon dioxide capture to the combustors themselves. The exact breakeven between adding carbon capture to an NGCC or CT vs. purchasing de-carbonized fuel for the power plant is a subject of a number of studies now underway.

The magnitudes of hypothesized utility power plant carbon capture for the U.S. shown in **Table 11** are roughly similar to those contemplated by IEA. The IEA 2016 World Energy Outlook described its "450 Scenario" as the decarbonization required to keep atmospheric carbon dioxide below 450 parts per million. For this scenario, IEA ran complex modeling exercises to project 2040 emissions. Appendix B shows our extrapolation of IEA's assumed levels of carbon capture.[59] **Table 11** above shows 142 MMTPA captured from U.S. coal plants, and IEA shows 113 MMTPA. Similarly, **Table 11** shows 210 MMTPA captured from gas plants, and IEA shows 141 MMTPA. Given the great uncertainties involved in looking this far into the future, as well as the difficulties of extracting the relevant information from IEA, the approaches are remarkably consistent.

The proportions of U.S. stationary emissions attributable to the different sectors have shifted considerably as we progressed from **Table 3** to **Table 11**. Since Chapters VI, VII, and VIII focused on power sector reductions, electric generation's share of carbon dioxide emissions has dropped and, accordingly, the industrial sector's share of remaining emissions has risen. On **Table 11**, utility sector and CHP electric generation emissions represent only 28 percent of the total (3 percent coal, 21 percent natural gas, and 4 percent CHP), down from 68 percent in 2018 (see **Table 3**). Meanwhile, of the remaining emissions, industrial process and industrial process heat emissions have risen from 26 percent of emissions on **Table 3** to 62 percent of emissions on **Table 11**. Thus, we will turn to these industrial sector emissions.

TABLE 11: Applying Carbon Capture to Coal and Gas Powerplants (MMTPA)

	REVISED EMISSIONS FROM TABLE 8 (MILLIONS OF MT CO_2EQ)	90% CARBON DIOXIDE CAPTURE: 90% OF COAL, 50% OF GAS, 75% OF CHP	REVISED EMISSIONS POST CCS (MILLIONS OF MT)	% OF REVISED EMISSIONS
Utility Coal and Oil Fired Generation	175	(142)	33	3%
Utility Natural Gas Fired Generation	466	(210)	256	21%
Industrial Power Plants (CHP)	152	(103)	49	4%
Non-Oil & Gas Industrial	228		228	19%
Oil & Gas (incl. Refinery & Petchem)	92		92	8%
Industrial Process Heat	423		423	35%
Waste, Landfills, Coal Mines	133		133	11%
	1,670	**(454)**	**1,216**	**100%**

VIII. BLOCK 4: DEPLOYING CARBON CAPTURE FOR INDUSTRIAL PROCESS EMISSIONS

This chapter shows how the tool of carbon capture can be extended beyond the utility power sector to facilities that primarily use carbon dioxide as a feedstock from which other chemicals are made.

INDUSTRIAL PROCESS EMISSIONS RELATED TO NATURAL GAS FEEDSTOCK AND GAS PROCESSING

In this subsection we show the impact of capturing emissions from steam methane reforming (SMR), the process that converts methane feedstock into hydrogen gas. That hydrogen gas is primarily being used in U.S. oil refineries, fertilizer manufacture, and petrochemicals. *Other industrial process or mixed process and combustion emissions that could be captured in industries such as cement production, coal-fired blast furnaces, and refinery catalytic crackers are beyond the scope of this report because their emissions are not related to natural gas.*

Industrial carbon dioxide capture faces a simpler policy and regulatory environment than using the same technology in the electric sector. Taking the example of an SMR unit that makes hydrogen from methane feedstock, no current technology is remotely cost competitive to such a unit. The party making the choice between an SMR and some other equipment (like a hydrogen electrolysis unit) is a chemical manufacturing or industrial gas company: no regulatory policy is involved, and a simple economic analysis makes the choice clear. No Public Utility Commission tells the owner of the SMR how often to run the plant, and most capital-intensive and efficient heavy industrial plants run at high capacity factors (i.e., in the 85-99 percent range).

In this section we focus on "capturable emissions", i.e., the portion of carbon dioxide process emissions that could be captured at reasonably (i) low cost, (ii) at reasonably large facilities that (iii) are not already capturing and selling carbon dioxide:

- The "low cost" criterion referred to above implies reviewing manufacturing technology to avoid pursuing capture of carbon dioxide tons that are disproportionately expensive to capture. For example, the definitive International Energy Agency report shows that capturing most *process emissions* from SMRs costs about $31/MT captured,[60] while capturing the incremental combustion emissions would cost about $108/MT captured.[61]
- We define "reasonably large" as facilities that could capture over 100,000 MT/year. Those are about half the size of representative units on which techno-economic studies have been performed, and are at the minimum size to qualify for the key U.S. tax-incentive for capture and geologic storage of carbon dioxide , Section 45Q (of the U.S. tax code).
- "Not already capturing and selling": Certain SMR facilities such as the Koch fertilizer plant in Enid, OK already sell surplus carbon dioxide for enhanced oil recovery and ultimate geologic storage. Two U.S. fertilizer plants use solid fuel gasification to make hydrogen (a non-SMR technology) and already capture and sell all their carbon dioxide emissions.

The SMR emissions being discussed here relate to existing U.S. SMRs as of 2018, which supply petrochemical plants and oil refineries—they do not include the anticipated new units that will be needed to create decarbonized hydrogen for fuel, a topic discussed in the next section.

The *capturable* process emissions from using natural gas as a feedstock are a relatively small portion of the remaining heavy industry emissions (228 MMTPA) and oil and gas process emissions (92 MMTPA) shown above on the fourth and fifth rows of **Table 11**. That is because other industrial process emissions (e.g., emissions from heating limestone feedstock to make cement, and oil industry processes such as catalyst regeneration in Fluidized Catalytic Cracking Units) are much bigger than natural gas-derived process emissions.

A significant industrial process that uses natural gas as a feedstock is steam methane reforming, in which natural gas (mostly methane, or CH_4) and water are heated in a pressurized vessel (the reformer) and again

TABLE 12: Estimates of Capturable Industrial Process Emissions Quantities (MMTPA)

	ESTIMATED CURRENT "PROCESS EMISSIONS"	CAPTURABLE "PROCESS EMISSIONS"
Standalone SMR Hydrogen Plants	27	15
Ammonia plant SMRs	19	4
Captive Refinery SMR	17	12
Natural Gas Processing Plants	18	5
Total	**81**	**36**

Source: EPA FLIGHT data, 2017 calendar year; original data generated in connection with the recent NPC study on carbon capture and for the Regional Deployment Initiative of the Carbon Capture Coalition.

in a second vessel (the gas/water shift reactor). SMRs, at the exit of the shift reactor, create a mixed-gas stream composed of 16 percent carbon dioxide , 5 percent carbon monoxide (CO), 76 percent hydrogen (H_2), and 3 percent methane.[62] Three industries use SMRs to create hydrogen as an intermediate feedstock:

- **The industrial gas industry** operates SMRs as standalone enterprises, supplying hydrogen to a variety of customers (including petrochemical industries and oil refineries). The SMR-derived hydrogen is mostly supplied "over-the-fence" to refineries, but petrochemical companies making materials such as polypropylene are also customers.
- **The refinery industry** itself operates captive SMRs to make a "lighter" slate of products (hydrocarbons with more hydrogen and less carbon), thereby garnering higher revenues for the same crude oil input.
- Finally, **the ammonia fertilizer industry** uses natural gas feedstock and SMRs to make hydrogen gas. Downstream in the manufacturing process, hydrogen is combined with nitrogen to make ammonia (NH3). In most instances, in North America, the bulk of available process carbon dioxide from ammonia production is already captured. That captured carbon dioxide is not sequestered, but rather is combined in final production steps to create granular urea, a solid nitrogen fertilizer that is much easier to handle than ammonia solution or gas.

Table 12 shows estimates that approximately 31 MMTPA of carbon dioxide could be cost-effectively captured by these three sets of SMR operators. While ammonia manufacturers create and capture substantial process carbon dioxide emissions, little of that carbon dioxide is actually available for sequestration: instead, the captured carbon dioxide is later combined with ammonia on-site to create urea. EPA does not credit a reduction in "process emissions" by the amount of captured carbon dioxide that is combined with ammonia to form urea, because most of the carbon dioxide contained in urea molecules is released to the atmosphere when urea fertilizer gets wet after being spread on farmers' fields.

For the sake of completeness, we also include in **Table 12** a 5 MMTPA of incremental process emissions generated by removing carbon dioxide from raw field gas at facilities called natural gas processing plants. Most gas processing plants produce a stream of high-purity carbon dioxide that just needs some minor cleanup and compression to meet pipeline specifications. But most of the big gas processing plants already are capturing and selling carbon dioxide. Further, most gas processing plants emit less than the 100,000 MTPA carbon dioxide that must be captured to qualify for the §45Q federal carbon capture and storage tax credit. The 5 MMTPA thus represents possible new capture from medium-sized emitters that are not currently capturing and selling carbon dioxide.

IMPACT OF CAPTURING CARBON DIOXIDE FROM INDUSTRIAL PROCESSES

Using the 36 MMTPA capturable process emissions figures in **Table 12**, plus CHP capture of 60 MMTPA, lowers the estimate of remaining emissions from 1,216 MMTPA to 1,180 MMPTA as shown in **Table 13** below.

To review, the combination of coal-to-gas fuel switching, power plant carbon capture, and natural gas-related industrial carbon capture together reduce 2018 Adjusted Baseline Carbon Dioxide Emissions (see **Table 6**) from 1,903 MMTPA to 1,180 MMTPA (shown in **Table 13** above).

A total of 423 MMTPA (36 percent) of the 1,180 MMTPA remaining emissions are from industrial combustion of fossil fuels to generate process heat.[63]

TABLE 13: Capturing Industrial Process Emissions (MMTPA)

	REVISED EMISSIONS FROM TABLE 9 (MILLIONS OF MT CO_2EQ)	SMR CO_2 CAPTURE	REVISED EMISSIONS POST CCS	% OF REVISED EMISSIONS
Utility Coal and Oil Fired Generation	33		33	3%
Utility Natural Gas Fired Generation	256		256	22%
Industrial Power Plants (CHP)	49		49	4%
Non-Oil & Gas Industrial	228	(19)	209	18%
Oil & Gas (incl. Refinery & Petchem)	92	(17)	75	6%
Industrial Process Heat	423		423	36%
Waste, Landfills, Coal Mines	133		133	11%
	1,216	**(36)**	**1,180**	**100%**

IX. BLOCK 5: ADDRESSING INDUSTRIAL COMBUSTION EMISSIONS WITH DECARBONIZED FUELS

Addressing industrial combustion emissions—burning fossil fuels solely for the purpose of obtaining heat to drive manufacturing processes, though sometimes with a secondary motivation of disposing of waste—is a fourth, indispensable step in decarbonization. There are many solutions, but a key near-term solution may be to manufacture fuels that have no greenhouse gases emitted when they are burned. That manufacture can be done in a variety of ways, but a well-known and comparatively cheap method is to use natural gas feedstock to make hydrogen in steam methane reformers (SMRs) that have been outfitted with carbon capture equipment. Note that the highest level aggregation of non-biogenic industrial stationary combustion emissions is the subpart 'C' (Stationary Combustion) catchall category in FLIGHT. In this section we discuss the subset of subpart 'C' emissions remaining after we stripping out industrial inside-the-fence power plants.

THE HETEROGENOUS LANDSCAPE OF INDUSTRIAL COMBUSTION EMISSIONS

Dealing with industrial emissions will be complex, and there are likely to be a very wide variety of applicable solutions. The solutions will be varied because the industrial sector is so heterogeneous in terms of emitter size, emitter capacity utilization rates, the temperature and heat transfer characteristics needed, the type of fuels already in use, and whether the fuels in use are internal byproducts of the industrial process (e.g., blast furnace gas, petroleum coke, or pulp mill black liquor). Among the many ways to reduce industrial combustion emissions are:

- Innovation in processes (for example in steel making more recycling and electric arc furnaces, hydrogen reduction of Fe_2O_3 and Fe_3O_4)
- Efficiency improvements
- Electrification (and renewable and or decarbonized power)
- Sustainable biomass (possibly with carbon capture)
- Manufacture of clean fuels (either via renewable electricity or via fossil feedstocks with carbon capture).

In the prior sections we first considered carbon dioxide reductions that could be garnered by substituting natural gas for higher-carbon fuels (Block 2/Section VI), then how carbon capture might be applied to the power sector (Block 3/Section VII), and third how carbon capture might reduce industrial process and CHP emissions (Block 4/Section VIII).

However, the relatively lower-cost abatement strategies for carbon dioxide emissions discussed in those earlier sections did not tackle the 423 MMTPA of industrial process heat-related "Stationary Combustion" emissions, representing 36 percent of remaining stationary emissions as shown on **Table 13**.[64] EPA's sub-part 'C' "Stationary Combustion" category, which reports 575 MMTPA of 2018 emissions, already excludes the "electric power sector" (term for the utility-run power grid) emissions, and we have further culled 152 MMTPA of "inside-the-fence" fossil-fueled CHPs from the EPA's reported stationary combustion emissions and discussed those in Chapter VII. Thus, these remaining 423 MMTPA of emissions are referred to as Industrial Process Heat emissions.

The primary strategy discussed in this section for decarbonizing the industrial process heat sector is the construction of a new fleet of SMRs, all equipped with carbon capture systems, designed for the express purpose of creating hydrogen fuel for combustion. ("Blue hydrogen" can be used for other decarbonization strategies such as fueling vehicles, but we will confine discussion to industrial heat in this section.) These SMR-CCS units would be unrelated to the existing refining- and petrochemical-oriented SMRs discussed in Section VIII. This step is technically feasible today, but is a relatively expensive means of carbon dioxide abatement that will primarily be applicable to current industrial combustion emitters (i) whose heating needs cannot easily be met by other means such as electrification, and (ii) whose small size renders carbon capture at the point of emissions prohibitively expensive.

The overall stationary combustion emissions of 575 million MTPA, reported under subpart 'C' of the GHGRP (including both electric and non-electric emissions), are an enormous mixed bag of fuel types and emitters, some large and some insignificant.

- Mixed bag of fuel types: Some emissions reported under subpart 'C' may come from combustors that cannot easily convert to hydrogen combustion. As an example, the combustion of blast furnace gas in steel mill "stoves" is reported under subpart 'C'. That fuel is a low-heating-value gas consisting primarily of carbon-monoxide byproduct of coking coal consumed in blast furnaces: there is no simple way to substitute hydrogen in that process.
- Mixed bag of emitters: Emitters range from small steam heating plants for universities and prisons up to enormous steam boilers for heavy industry.
- "Insignificant": There were 5,389 emitters reporting some emissions under subpart 'C' in 2018. However, 82 percent of them (i.e., 4,407) emitted less than 100,000 MTPA apiece.

INDUSTRIAL HEATING APPLICATIONS FOR DECARBONIZED FUELS

From this heterogenous cohort of emitters, we would expect to find some good candidates for decarbonized fuels, often called Zero Carbon Fuels (ZCFs), such as hydrogen. Those good candidates would typically be combustion emitters using natural gas fuel for heating, rather than using more-or-less free byproduct fuel available inside the fence such as blast furnace gas or biofuel. The ZCF candidates would also be smaller emissions sources, those running at low capacity factors, or both. For such emitters it is likely to be more effective to decarbonize the fuel than to add capture equipment to the end-of-pipe vent stack. The target decarbonized fuel users could be served by a local network of hydrogen pipes, all served from a central large SMR unit that runs at or near 100 percent capacity factors. There appear to be a number of clusters nationally, comprising numerous industrial process heat consumers of natural gas who could support a centrally located clean fuels plant, and fully fleshing out supply and demand characteristics is a promising area for future work. That said, the concept is not far-fetched since Air Products currently operates a 600 mile U.S. Gulf Coast hydrogen network stretching from the Houston Ship Channel to New Orleans.[65]

A hypothetical example of this concept could be a multi-company industrial area that contains 10 different industrial furnaces, each combusting 2 million MMBtu of natural gas annually and emitting 106,000 MTPA of carbon dioxide. The furnaces could switch burners from natural gas to hydrogen, which when burned has zero carbon dioxide emissions. The local industries would need to change their fuel supply from natural gas pipelines to a local large SMR that makes 20 million MMBtu/year of hydrogen gas. The natural gas that formerly was routed to the various industrial sites would instead be directed to that centralized SMR. The SMR would make what has been referred to as "blue hydrogen", capturing up to 90 percent of unabated carbon dioxide emissions associated with manufacturing the hydrogen from natural gas.

The carbon dioxide capture unit at the SMR would be far cheaper to build than the alternative of placing many small carbon dioxide capture units at the individual furnaces, and it would also have the advantage of operating at a more consistent, high level:

- At an SMR, the carbon dioxide concentration of gases treated would be approximately 20 percent, vs. approximately 4 percent at industrial furnaces. Engineering studies show such a concentration increase typically reduces upfront investment (per metric ton of carbon dioxide the plant can capture annually) by approximately 30 percent.
- The SMR would gain economies of scale by being roughly 10+ times as large as any capture unit that could have been installed at one of the small furnaces.[66] Increasing the size of the capture unit tenfold (all other things equal) would reduce upfront investment cost (per ton of carbon dioxide the plant can capture annually) by approximately 50 percent.
- Further, a typical SMR would run at more than90 percent capacity factor: IEA's landmark study for SMR carbon capture assumed 95 percent. Industrial furnaces could well run at lower operating factors (e.g., 75 percent).

Compared to the end-of-pipe carbon capture option, the combination of being (i) five times as concentrated,

(ii) 20 times as large, and (iii) running at 95 percent vs. 75 percent operating factors would greatly lower the capital cost, and thus the capture cost per metric ton, of this decarbonized fuel alternative.

The countervailing factor would be higher cost of fuel for factories: the issue is absolute cost of heating fuel, rather than the relative cost of carbon dioxide abatement. The decarbonized fuel strategy can only work in the context of high carbon taxes or strict emissions limits. If a factory is forced to limit its carbon dioxide emissions, then burning de-carbonized fuel is a good option because burning a centrally procured decarbonized fuel is cheaper than the factory installing its own carbon dioxide capture unit. Without such government-imposed carbon dioxide emission limits, it is vastly cheaper for the factory to burn natural gas straight out of the pipeline. The carbon capture enabled SMR uses that same natural gas, in an expensive facility, with heat losses associated with the reforming process, made still more expensive by the addition of carbon capture. The decarbonized fuel is bound to be much more expensive than the carbon-laden ordinary fuel (i.e., pipeline gas). In general terms, if natural gas prices are in the range of $3/MMBtu, hydrogen produced in an SMR with 90 percent carbon dioxide capture will be in the range of $10-12/MMBtu (assuming a large SMR hydrogen manufacturing unit of the type described above, running at a high-capacity factor).[67] Without either carbon pricing in the range of $131-$168/MT or compliance-based emissions limits plant managers will not volunteer to triple or quadruple their fuel bill for heating.

Decarbonizing the production of hydrogen from natural gas feedstock is not the only option being considered for industrial heating needs, and many different solutions will compete in the future. Indeed, C2ES is currently working with the Renewable Thermal Collaborative to examine such options. Among the options beyond blue hydrogen for industrial combustion:

- There is a major focus today on developing bigger and better plants that can produce hydrogen by electrolysis, with electricity supplied by low- to zero-carbon generators. The rub here is that if the electrolysis plant depends on getting low-cost electricity during the periods when there is surplus solar PV- and wind-generated electricity, the expensive electrolysis equipment may run only infrequently. Such a low-capacity factor for the electrolysis equipment would negate the advantage of infrequently available "nearly free" renewable power.
- Generating industrial heat from nuclear fission is another option, though hot water or steam cannot be piped over long distances, which means industrial facilities and nuclear power plants would need to be co-located.
- So, too, would be electric heating, with the electricity derived from zero-carbon electricity sources.
- Reasonably high-temperature steam can be directly created using the same solar "troughs" as used in a number of successful solar thermal power plants.

The choices will ultimately be driven both by cost and by the particular temperature and heat transfer needs of the process involved. Processes that use low-pressure, lower-temperature steam might well use nuclear fission-sourced steam. For example, the steam used to heat dryers in paper mills needs to be only in the approximately 200-300 degree C range.

Certain industrial processes often need both high temperatures (i.e., 1,000-1,800 degrees C) and a high level of "flux" (i.e., fast transfer of heat from the heat-conveying medium to the materials that must be heated).

- As analyzed in a recent Columbia University paper, steam heat from traditional nuclear fission can be captured and transferred safely at 300 degrees C, which is too low a temperature for these high heat/high flux process needs. (This issue is largely overcome in most advanced fission reactors in development.)
- Electric resistive heat can reach 1,800 degrees C—sufficient temperature—but often lacks the necessary flux required.
- Decarbonized hydrogen, like natural gas—creates temperatures at or above 2,000 degrees C and also has a high flux. Thus, decarbonized hydrogen is the key carbon abatement option for this key industrial fuel user group.[68]

QUANTIFICATION OF EMISSIONS REDUCTIONS FROM DECARBONIZED FUELS USE

Table 14 illustrates how this type of approach could reduce a substantial portion of industrial combustion emissions. It is quite difficult to individually separate

CHP units from simple process heat boilers and stoves accurately, since the U.S. Department of Energy (DOE) specifically tracks generating units (including CHPs), but EPA's GHGRP does not typically label emitting equipment in a similar fashion. As an example, for many industrial plants EPA's reported Stationary Combustions are simply back-calculated based on the amount of natural gas delivered to the plant site—without specifically naming the individual pieces of equipment that used the natural gas.

As a rough estimate, we began with the 448 million MTPA reported for the 982 largest emitters under "subpart C" (each reporting over 100,000 MTPA). From that 448 million MTPA of largest emitters we subtracted out the 152 million MTPA of fossil-fuel burning CHP units, with the general rationale that most CHP units are relatively large—and those were dealt with earlier in Section VII.[69] That left an estimated 296 million MTPA of subpart 'C' emitters that are large but whose emissions are not CHP-related. We then assumed that 2/3 of these (rounded to 200 million MTPA) represented large process heat units to which clean fuel substitution could be applied. We then assumed that the fuel was replaced with hydrogen gas manufactured with 90 percent carbon capture, for a reduction of emissions of 180 million MTPA.

Clearly, some of these 296 MMTPA of large, non-CHP, combustion emitters might find it more economical to use electric resistance heat than to purchase decarbonized fuels: that emitter-by-emitter analysis is well beyond the scope of this paper, but that analysis would also be well worth doing.

TABLE 14: Fuel Decarbonization to Address Industrial Combustion Emissions (MMTPA)

	REVISED EMISSIONS FROM TABLE 11 (MILLIONS OF MT CO_2EQ)	REDUCTIONS FROM FUEL DECARBONIZATION	REVISED EMISSIONS POST FUEL DECARBONIZATION	% OF REVISED EMISSIONS
Utility Coal and Oil Fired Generation	33		33	3%
Utility Natural Gas Fired Generation	256		256	26%
Industrial Power Plants (CHP)	49		49	5%
Non-Oil & Gas Industrial	209		209	21%
Oil & Gas (incl. Refinery & Petchem)	75		75	8%
Industrial Process Heat	423	(180)	243	24%
Waste, Landfills, Coal Mines	133		133	13%
	1,180	**(180)**	**1,000**	**100%**

DECARBONIZED FUEL MAY ALSO BE A POWER SECTOR ALTERNATIVE

Though beyond the scope of this paper, the same approach of using hydrogen as the fuel source for small combustion emitters is likely to be applicable to remaining natural gas electric generators as well (*i.e.*, the 256 MMTPA of remaining utility generation natural gas-fired emissions in **Table 14**). That is, for some peaking gas-fueled combustion turbines, it might be better to convert to burning hydrogen than to install an inefficiently small-sized post-combustion carbon capture system. A number of manufacturers have tested operation of traditional combustion turbines—with modifications to the fuel injection and burner systems—so those CTs can use fuel that is primarily hydrogen. Decarbonizing these infrequently used peaking power plants may not be the most urgent near-term priority, however. Based upon proprietary industry databases, it appears that of today's approximately 581 MMTPA of emissions from utility natural gas power plants, only around 10 percent (50 MMTPA) comes from units that run at below a 33 percent net capacity factor.

We mention combustion turbine burning of hydrogen as a practical alternative, since some manufacturers will warrant use of current combustion turbine (CT) models, usually with burner modifications, for partial or 100 percent hydrogen fuel. According to the European Turbine Network, "Special attention is required on modifying the combustor and some auxiliary parts, but most of existing gas turbines can be retrofitted to either partially or fully burn hydrogen."[70] Another possibility would be to use the decarbonized hydrogen in utility-scale banks of fuel cells. In either case, major investments in hydrogen storage would be required. Choice between fuel cells or turbines would depend upon efficiencies of converting fuel to electricity and relative equipment cost (i.e., burner modifications to existing CTs vs. buying an entirely new fuel cell.)

X. CONCLUSIONS

TO GENERATE ONGOING DISCUSSION

1. As the analysis shows, additional reductions will be needed toward mid-century with the industrial sector and likely sooner in the power sector, even after the stages outlined here, to achieve a net zero emissions goal. Many of those additional reductions may be obtained via electrification of process heating needs in heavy industry, as well as deployment of carbon capture to address industrial sectors with large process emissions of carbon dioxide : cement plants, blast furnaces, refinery Fluidized Catalytic Cracking Units, and pulp mill black liquor recovery boilers. We did not discuss those strategies because of this paper's primary focus on the role of natural gas.
2. To avoid the atmospheric carbon dioxide concentration "overshoot" featured in recent IPCC reports and other analyses there is an urgent need to quickly and drastically reduce greenhouse gas emissions. The world pins its hopes on new technological breakthroughs, but some of those breakthroughs may be decades away. In the context of limited world financial resources, the need for fast, gigaton-scale greenhouse gas emissions reductions logically points to finding near-term, low-cost emissions reductions opportunities. Prudent use of natural gas may provide some of those opportunities. The perfect is often the enemy of the good. Let us not let our hopes and efforts for a perfect future deter us from doing good immediately.
3. We focus on natural gas because of any interest in promoting natural production or consumption. Again, we focus on natural gas because methane is a useful molecule, both for combustion and as an industrial feedstock. It can provide a way to reduce hundreds of millions of tons of emissions quickly and cheaply. Natural gas is not a perfect long-term solution, but it offers good transition strategies that we quantified in the paper.
4. Natural gas, as the cleanest fossil fuel, both in terms of conventional pollutants such as sulfur dioxide, particulate, and mercury, as well as greenhouse gas emissions per unit energy produced, is a logical starting point in the near-term search for low-cost power sector emissions reductions as a companion to renewable wind and solar. (Note that thermal NOx emissions are a problem for older natural gas plants, but newest units have dropped NOx by about 90 percent compared to those older units.)
5. Indeed, the record of the last two decades of emissions reductions in the U.S. electric generation sector shows that approximately 60 percent of emissions reductions (approximately 1/2 billion MTPA) were obtained by replacing coal and oil combustion with natural gas combustion, together with adoption of ever more efficient gas power plant technology. Adoption of wind and solar PV generation made up approximately 40 percent of the reductions. It would have been better if all the coal had been switched to zero emitting renewables, but the half billion MT per year reduction is a good thing.
6. There is widespread consensus that with continued cost and technology improvements in wind and solar, there is scope for far deeper penetration of renewables into the power sector, and this paper starts with that premise. With additional policy, like clean energy standards, clean capacity standards, and financial incentives to accelerate deployment even deeper penetration would be achievable.
7. There is also widespread expert consensus that some continued fossil fuel use, although at substantially reduced levels, is likely to be present in the world energy system, including the United States, for many decades to come. Without additional financial incentives that drive development of substitute fuels and processes, reduction in natural gas use is likely to proceed more slowly than reductions in oil and coal use. Technology and policy to assure the ability to mitigate emissions from continued near- and intermediate-term natural gas combustion and use is essential.

8. In power generation, some fossil generation is likely to persist because fossil plants are currently indispensable—from a cost point of view—in balancing day-to-night swings and even more so in accommodating seasonal mismatches in loads vs. generation of power. That is, if the grid only needs four to eight hours of total backup storage, batteries are a good option; if the grid may need many days or weeks of backup storage, gas power plants with carbon capture are significantly cheaper than other alternatives.[71] Hence, absent massive and unforeseen declines in the cost of other technologies, there will be continuing opportunities for gas to substitute for coal in the remaining fossil fuel plants. There will also be an imperative to abate (see No. 10 below, re carbon capture), or otherwise offset, emissions from the remaining natural gas power plants, a*s long as doing so is more cost effective than other means of providing diurnal and seasonal reliability*.
9. We concluded that even after taking account of higher renewable electricity penetration, on the order of 200 MMTPA of incremental net emissions reductions could be achieved by more coal-to-gas fuel switching.
10. We concluded that after that fuel switching, another approximately 450 MMTPA of reductions could be obtained by using carbon capture technology on fossil electric plants, with approximately 1/3 of those reductions coming from coal plants and 2/3 of the abatement from gas plants serving the grid and gas-fired industrial CHP units.
11. We noted that "blue hydrogen" (H_2 made from natural gas feedstock with carbon dioxide captured) is an important advance in its own right (see Nos. 12 and 13), but that an equally important role for blue hydrogen is to jumpstart development of the transportation and distribution of hydrogen generally. That infrastructure, in turn, can pave the way for large-scale production, distribution, and consumption of green hydrogen.
12. We also estimated that within the sector of industrial process emissions, application of carbon capture to steam methane reforming (SMR) processes in refineries, merchant carbon dioxide plants, and ammonia factories, together with sequestration of current carbon dioxide emissions from certain natural gas processing plants could supply another 36 MMTPA of reductions. This figure is relatively small because a number of fertilizer plants and natural gas processing plants already sequester their emissions. Other industrial process emissions are available in sectors such as cement, steel, and refineries that are beyond the scope of this paper.
13. Finally, we investigated the possibility that an expanded fleet of carbon-capture enabled steam methane reformers that make hydrogen from natural gas feedstock could be a key technology in replacing natural gas or other fossil fuels now combusted for industrial process heat. Our best estimate is that this strategy might provide as much as an additional 180 MMTPA of emissions reduction in the industrial heat sector: however, the complexity of fuels and emitter types involved renders this estimate somewhat uncertain, with a need for further investigation.
14. It is possible that use of hydrogen (or possibly ammonia derived from such hydrogen) could be the key to reducing emissions from infrequently used natural gas backup power generation; but since using pure hydrogen or ammonia in combustion turbines is untested at large scale, we did not quantify that opportunity. The key insight is that if a gas power plant runs frequently, it is cheaper to decarbonize the exhaust gases at the power plant; whereas if the gas power plant runs infrequently, it is cheaper to decarbonize the fuel.

APPENDIX A: LIST OF ABBREVIATIONS AND KEY TERMS

BTU	British thermal units
CT	Natural gas Combustion Turbine. Similar to jet aircraft engine, and often used for quick-starting peaking power plants to meet load spikes. If operated on "open-cycle" or "simple cycle" CTs there is no attempt to capture waste heat from the exhaust gases. Can also be operated in "closed cycle" or "combined cycle" as part of an NGCC.
EIA	U.S. Energy Information Administration, part of the Department of Energy that tracks and forecasts U.S. energy production and consumption
EPA	The U.S. Environmental Protection Agency, which tracks greenhouse gas emissions under the GHGRP and the Acid Rain Program
GHGRP	Greenhouse Gas Reporting Program. National system of greenhouse gas reporting supervised by EPA's Office of Air and Radiation (OAR). 40 CFR Part 98, with various "subparts" from 'C' to 'UU' covering different industries emitter types. *https://www.law.cornell.edu/cfr/text/40/part-98*
Heat Rate	The number of Btus required to make one kWh of electricity in a fossil electric generator. Typically in the 8,500-10,000/kWh zone for coal or gas steam generators and simple cycle CTs, and as low as 6,200/kWh for NGCCs. To convert Btus/kWh to MMBtu/MWh multiply numerator and denominator x 1,000. 10,000 Btu/kWh → 10,000,000 Btu/1,000 kWh→ 10 mmBtu/MWh.
IEA	International Energy Agency is a *Paris*-based autonomous intergovernmental organization established in the framework of the *Organization for Economic Co-operation and Development* (*OECD*) in 1974.
IPCC	The Intergovernmental Panel on Climate Change, the United Nations body for assessing the science related to climate change
Mcf	Thousand standard cubic feet of natural gas, with heat content equal to approximately 1 MMBtu (varies somewhat from pipeline to pipeline). "Standard cubic feet" means the gas is at 60 degrees F at sea-level air pressure.
Methane	The predominant constituent of pipeline quality "natural gas." Chemical formula CH_4.
MMBtu	Millions of Btu. We use the U.S. convention of Higher Heating Value (HHV).
MT	Metric ton (also referred to as "tons" in text)
MTPA	Metric tons per annum
MMTPA	Millions of Metric tons per annum
MW	Megawatt (Watts x 106) A measure of generating capacity for a power plant. When this paper refers to "power" or "capacity" we mean MW.
MWh	Electric energy generated by running 1 MW of capacity for 1 hour. When we refer to "electricity", "electric energy", or "generation" we mean MWh. 1MWh = 1,000 kWh.
Natural gas	Wellhead, "field gas" is a highly variable mixture of methane, natural gas liquids, carbon dioxide, sulfur dioxide, water vapor, etc. Once purified in a natural "gas processing plant" to meet quality standards of a pipeline operator, the purified product is approximately 95+ percent methane and is referred to generally as natural gas.

NGCC	Natural Gas Combined Cycle power plant. A configuration of units involving one or more CTs, a heat recovery steam generator (HRSG), and a steam turbine. Two-thirds of electric generation in the configuration is from CTs, but hot exhaust gases from the CTs are used to make steam, with that steam then used to run a supplemental Steam Turbine Generator (about 1/3 of electricity in the configuration).
SMR	Steam Methane Reformer (process that uses steam to strip hydrogen molecules from methane). $CH_4 + 2H_20 \rightarrow 4H_2 + CO_2$ (Confusingly, "SMR" can also be an abbreviation for Small Modular Reactor.)
ZCF	Zero Carbon Fuel, i.e., fuel that emits zero carbon dioxide either as measured at the vent stack or calculated on a Life Cycle Analysis basis.

APPENDIX B: COAL-TO-GAS FUEL SWITCHING AND COST OF AVOIDED CARBON DIOXIDE

TABLE B-1: Fuel Switching Cost From Coal to Existing or New NGCC

Full Calculations	Existing Coal	Existing NGCC	New NGCC
Operating Hours per Year @ 55% NCF	4,818	4,818	4,818
Fuel cost per MMBtu (EIA 2019)	$2.08	$2.53	$2.53
x MMBtu per MWh (Heat Rate/1000)	11.00	7.00	6.25
equals Fuel Cost per MWh	$22.88	$17.71	$15.81
plus Other Variable per MWh	$4.00	$2.00	$2.00
Total Variable Cost & Fuel per MWh	**$26.88**	**$19.71**	**$17.81**
New Construction Cost per MW	Not applicable—Same Fixed Costs Regardless of Operation Rate		$900,000
x Fixed Operating Cost as % of Investment			4%
x Debt, Taxes and Equity Returns as % Investment (Fixed Charge Rate)			8%
Total Fixed Cost, Debt, Tax, Equity			$108,000
Incremental Fixed Cost Pro-Rated per MWh			**$22.42**
Total Variable & Incremental Fixed Cost	$26.88	$19.71	$40.23
Savings (Cost) from Coal-to-Gas		$7.17	($13.35)
MT CO_2 per MMBtu Combusted	0.09	0.05	0.05
MMBtu per MWh	11.00	7.00	6.25
Emissions per MWh	1.02	0.37	0.33
Decreased Emissions per MWh		(0.65)	(0.69)
Cost (Savings) per MT CO_2 Avoided		**($11.06)**	**$19.40**

TABLE B-2: Calculating Avoided Cost of Carbon Dioxide from Fuel Switching (Table 9 Reproduced)

Full Calculations	Existing Coal	Existing NGCC	New NGCC
Total Variable Cost & Fuel per MWh	$26.88	$19.71	$17.81
Fixed Cost/MWh for New NGCC Only*			$22.42
Total Cost/MWh	$26.88	$19.71	$40.23
Savings (Cost) from Coal-to-Gas		$7.17	($13.35)
Emissions CO_2 MT/MWh	1.02	0.37	0.33
Change in Emissions from Coal-to-Gas		(0.65)	(0.69)
Cost (Savings) per MT CO_2 Avoided		**($11.06)**	**$19.40**

*8% figure is the "Fixed Charge Rate" (covering equity, debt amortization, and federal taxes) per US DOE Quality Guidelines for Energy System Studies: Cost Estimation Methodology of Power Plant Performance (NETL-PUB-22580). See p. 19, Table 3.5, which uses a 7.07% Real Rate and 8.086% Nominal Rate.

ENDNOTES

1 In this paper we will simplify by referring to methane (CH_4) as "natural gas." In reality raw natural gas (a.k.a. "field gas") is comprised of a host of chemicals including carbon dioxide, water, and a variety of "natural gas liquids" such as propane, butane, etc. Field gas needs to be stripped of virtually all non-methane constituents before it can meet interstate pipeline safety/quality standards—but the natural gas that arrives at a home or factory still has minor non-methane components including oxygen, carbon dioxide , nitrogen, and trace amounts of NGLs...See Michelle Michot Foss, *Interstate Natural Gas: Quality Specifications and Interchangeability,* (Sugarland, TX: Center for Energy Economics, 2004), *http://www.beg.utexas.edu/files/energyecon/global-gas-and-lng/CEE_Interstate_Natural_Gas_Quality_Specifications_and_Interchangeability.pdf*.

2 Take the example of demand-side management (DSM) of retail electricity consumption, which is widely considered to be one of the cheapest ways to allow more renewable energy on the grid and to reduce carbon dioxide emissions—DSM may be cheap and logical, but we haven't figured out how to structure retail electricity rates so as to elicit participation from homeowners.

3 Or purely zero-carbon gas power plants if current deployments of "Allam Cycle" power plants such as those being developed by Net Power prove to be successful.

4 Thomas Koch Blank and Patrick Molly, *Hydrogen's Decarbonization Impact for Industry,* (Boulder,CO: Rocky Mountain Institute, 2020), *https://rmi.org/wp-content/uploads/2020/01/hydrogen_insight_brief.pdf*

5 Ibid. With a range given of 8-12kg carbon dioxide per 1 kg H_2.

6 "This estimate suggests that hydrogen produced from solar would add dramatic costs: a three- to five-factor increase compared to current SMR technology." See Figure 5 in Julio Friedmann, Zhiyuan Fan, and Ke Tang, *Low-Carbon Heat Solutions for Heavy Industry: Sources, Options, and Costs Today,* (New York, NY: Center on Global Energy Policy, 2019), *https://energypolicy.columbia.edu/research/report/low-carbon-heat-solutions-heavy-industry-sources-options-and-costs-today*

7 Ibid, Table 4. Using low end of each range in Table 4: H_2 from SMR with no capture $8.78/GJ; H_2 from SMR with 53 percent capture $11.02/GJ (1.26x); H_2 from SMR with 64 percent capture $12.19/GJ (1.39x); H_2 from SMR with 89% capture $14.22/GJ (1.62x).

8 The spreadsheet can still be downloaded from EPA notwithstanding the fate of the CPP (see link in fourth bullet point once page opens):"Clean Power Plan Toolbox for States: Documents and Resources," United States Environmental Protection Agency, Archieved, *https://archive.epa.gov/epa/cleanpowerplantoolbox/clean-power-plan-toolbox-states-documents-and-resources.html*

9 The ultimate penetration of wind and PV shown in Block 1 could have been larger or smaller: we simply sized Block 1's 479,000 MW to be consistent with IEA and EPA analyses . While wind and PV penetration is likely to be large, wind and PV are unlikely to entirely displace all combustion-based generation absent major cost declines in storage and transmission. The storage is critical to counteract the intermittency of wind and PV. Construction of new intra-regional transmission lines is critical because wind and utility-scale PV are often located far from load centers in places where current transmission access is poor. Far greater new long-distance inter-regional transmission investments, with a significantly lower capacity utilization rate, are needed if we seek to take advantage of hypothesized lack of correlation in wind and PV generation across regions of the country.

10 We made one exception here to our usual rule of only showing "gas-related" abatement strategies. It seemed logical to go ahead and show the impact of applying carbon capture to the remaining coal plants that have survived widespread penetration by renewables and successful competition of natural gas plants. On a per ton of carbon dioxide captured basis and assuming similar operating levels (i.e., net capacity factors), carbon capture costs less per ton in the coal power plant industry than in the gas industry.

11 There is an exact engineering parallel between systems that remove the two different acid gases, sulfur dioxide and carbon dioxide. CanSolv is the Shell subsidiary that developed the amine solvent carbon dioxide scrubbing system deployed in the first large North American coal power plant carbon capture project. CanSolv originally began as a company that deployed amine solvent sulfur dioxide scrubbing systems to fight acid rain. See "CanSolv SO_2 Capture," Shell, Accessed May 3, 2021, *https://www.shell.com/business-customers/catalysts-technologies/licensed-technologies/emissions-standards/tail-gas-treatment-unit/cansolv.html#iframe=L2NhbnNvbHYtZm9ybQ*

12 The benefit of hydrogen is simplicity. For instance, making hydrogen with electrolysis is a one step process, and steam methane reforming for making "blue hydrogen" is an industry that already exists on a global scale. The drawback of hydrogen is that it is a gas, requiring compression (or liquefaction) and specialized containment vessels to permit large scale storage. Ammonia (NH_3) requires a source of pure nitrogen and extra manufacturing steps (the Haber-Bosch process). However, ammonia is a liquid at ambient temperature and thus is comparatively easy to transport and store, including for use as a long-distance transportation fuel.

13 As we will discuss, making hydrogen from natural gas in a plant in which the waste carbon dioxide is captured and sequestered is one of many paths for manufacture of low- or zero-carbon hydrogen. Such methane feedstock-derived hydrogen (referred to by many as "blue hydrogen") is quite complementary with other emerging hydrogen technologies (such as electrolysis using zero-carbon electricity): we need large quantities of hydrogen as soon as possible to build out pipeline, industrial, and consumer infrastructure.

14 See Table B.5 in International Energy Agency, *World Energy Outlook,* (Paris, France: IEA, 2019), *https://www.iea.org/reports/world-energy-outlook-2019*.

15 Emissions of fugitive methane from gas drilling and from local natural gas distribution systems are a drawback, as are methane emissions from coal mining and petroleum production. But these "upstream" and distribution system emissions can be addressed separately from the combustion emissions under discussion here. 57 percent reference is 206 lbs CO_2/MMBtu for bituminous coal and 117 lbs CO_2/MMBtu for natural gas. The 35 percent figure combines those carbon intensity figures with heat rates of 8,638 Btu/kWh for supercritical coal vs. 6,370 Btu/kWh for 2x1 NGCC. See Table 2 in U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies,* (Washington, DC: Department of Energy, 2020), *https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf*.

16 See IPCC "1.5 degrees" report Chapter 2. *https://www.ipcc.ch/site/assets/uploads/sites/2/2019/02/SR15_Chapter2_Low_Res.pdf*

"Under emissions in line with current pledges under the Paris Agreement (known as Nationally Determined Contributions, or NDCs), global warming is expected to surpass 1.5°C above pre-industrial levels, even if these pledges are supplemented with very challenging increases in the scale and ambition of mitigation after 2030 (high confidence). This increased action would need to achieve net zero carbon dioxide emissions in less than 15 years. Even if this is achieved, temperatures would only be expected to remain below the 1.5°C threshold if the actual geophysical response ends up being towards the low end of the currently estimated uncertainty range. Transition challenges as well as identified trade-offs can be reduced if global emissions peak before 2030 and marked emissions reductions compared to today are already achieved by 2030."

17 Twenty-year figure derived from confidential interview. S&P Global shows average retirement date of all U.S. combined cycle plants at 30 years in 2019, vs. 41 years for coal, 56 years for gas steam turbines, and 44 years for oil generators. As S&P also points out, frequent starting and stopping of gas combined cycle plants shortens the expected life, and such frequent starts/stops are ubiquitous in a grid dominated by intermittent generation. " Average age of US power plant fleet flat for 4th-straight year in 2018," S&P Global Market Intelligence, published January 16, 2019, *https://www.spglobal.com/marketintelligence/en/news-insights/trending/gfjqeFt8GTPYNK4WX57z9g2#:~:text=Average%20fossil%20fuel%20plant%20retirement%20ages&text=Gas%2Dpowered%20gas%20turbines%20and,25%20years%20and%2027%20years.*

18 NCFs sourced from proprietary Energy Velocity data base for all of calendar 2019.

19 Two other important techniques have great advantages if pure oxygen is available. Solid fuels such as coal and petroleum coke can be gasified, with carbon dioxide then captured in well-known cold pressurized solvent processes. The Rectisol system uses methanol, and the Selexol system uses propylene glycol. The developing NetPower "Allam Cycle" power plant combusts natural gas with pure oxygen using carbon dioxide as the "working fluid" in the system.

20 Discussed later on in paper. Source study is IEAGHG Technical Report 2017-02, February 2017, *"Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS."* To reach cost comparison figures, author converted energy costs converted to U.S. values, converted currency from Euro to USD, and eliminated certain incorrect financial calculations.

21 Values for emissions per MMBtu from U.S. EIA. Figure for coal is bituminous coal and for oil is for diesel/heating oil. See "How much carbon dioxide is produced when different fuels are burned?," United States Energy Information Agency, last modified June 17, 2020, *https://www.eia.gov/tools/faqs/faq.php?id=73&t=11*

22 By zero-carbon fuels we mean zero carbon on a lifecycle basis. Hydrogen or ammonia made with natural gas feedstock and carbon capture would technically be ultra-low carbon, but not zero carbon unless 100.00% of carbon dioxide emissions related to their manufacture are captured or mitigated (with biofuels or direct air capture).

23 "Allam cycle" generators, named after British inventor Rodney Allam, are a type of oxy-combustion power plant in which the expansion and contraction of carbon dioxide replaces use of steam (in a steam turbine) or atmospheric air (as in a combustion turbine).

24 "How much natural gas is consumed in the United States?," United States Energy Information Agency, last modified May 3, 2021, *https://www.eia.gov/tools/faqs/faq.php*

25 "2018 Greenhouse Gas Emissions from Large Facilities," U.S. Environmental Protection Agency, accessed 2020, *https://ghgdata.epa.gov/ghgp/main.do#*. EPA multiplies 1 MT of fugitive methane times a factor of 25 to compute the carbon dioxide equivalent in terms of Global Warming Potential over a 100-year horizon. Equivalent values by production/transportation sector in 2018 are 45.2 MMTPA from onshore oil and gas production, 19.1 MMTPA from gathering systems, 2.8 MMTPA from long distance transmission, and 12.8 from local gas distribution networks.

26 This paper relies heavily on U.S. EPA's data base called FLIGHT, or Facility-Level Greenhouse Gas Tool. As the paper is being written 2018 is the last full year of data available.

27 As this paper is written in mid-2020, we take "present" to mean the most recently available U.S. government data. For the U.S. EPA's Greenhouse Gas Reporting Program (GHGRP), the most recent data is for full-year 2018. For EPA and EIA powerplant generation and emissions, the most recent data is for full-year 2019.

28 Real GDP at 2012 \$13.26 trillion 2000 Q4 vs. 2012 \$18.8 trillion in 2018 Q4. See "Real Gross Domestic Product," Federal Reserve Bank of St. Louis, last updated May 2, 2021, *https://fred.stlouisfed.org/series/GDPC1*.

29 There were other minor changes, but the net impact of all these other changes appears to be only about a 0.5 percent reduction.

30 Key tables in the Monthly Energy Review are "Table 11.6 Carbon Dioxide Emissions from Energy Consumption: Electric Power Sector" and "Table 7.2b Electricity Net Generation: Electric Power Sector." *https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf*

31 Calculated using U.S. EIA Month Energy Review tables 7.2b for generation and 11.6 for emissions, converting back to fuel consumption using standard figures of 117 lbs CO_2 per MMBtu natural gas.

32 The 785 million MT can be calculated directly from the figures on Table 1 by subtracting the emissions that would have been produced if 2018's output was generated with 2000's emissions intensity ($4{,}011 \times 10^6$ MWh x 0.635 MT/MWh) and subtracting the actual emissions ($1{,}762 \times 10^6$ MT) leaving a change of 785×10^6 MT.

33 Marilena Muntean et al., Fossil carbon dioxide emissions of all world countries - 2018 Report, (Luxembourg: Publications Office of the European Union, 2018), *https://op.europa.eu/en/publication-detail/-/publication/41811494-f131-11e8-9982-01aa75ed71a1/language-en*

34 See Box at end of this section regarding the difficulties of analyzing the Combined Heat and Power sector.

35 To grossly oversimplify, in most process use of natural gas, either (i) methane (CH_4) is stripped of its hydrogen atoms, which are then combined with nitrogen to make ammonia (NH_3) or (ii) methane is converted to liquid methyl alcohol (a.k.a. methanol CH_3OH), by adding an oxygen atom. Ammonia can be further processed to make solid fertilizers such as urea. Methanol can be further processed to make acetic acid, formaldehyde, etc. Both ammonia and methanol can also be burned as liquid fuels.

36 Julio Friedmann, Zhiyuan Fan, and Ke Tang, *Low-Carbon Heat Solutions for Heavy Industry: Sources, Options, and Costs Today,* (New York, NY: Center on Global Energy Policy, 2019), *https://energypolicy.columbia.edu/research/report/low-carbon-heat-solutions-heavy-industry-sources-options-and-costs-today*

37 The method of extracting this 152 million MTPA was first to parse US EPA's 2018 eGRID data to separate utility power plants carbon dioxide emissions (1,750 million MTPA fossil and biogenic) from inside the fence power plant carbon dioxide emissions (total 328 million MTPA fossil and biogenic). We then used EPA's reported fuel data to further split the 328 million MTPA inside-the-fence power plant emissions between biogenic emissions (176 million MTPA) and fossil emissions (152 million MTPA).

38 For ease of presentation, the relatively insignificant oil- and waste-fueled generation are aggregated with coal. In 2017 oil-fueled electric generation represented 21 MMTPA (2 percent of the 1,168 MMTPA).

39 As a whole, the "behind the fence" non-utility combined heat and power plants were responsible for 328 million MTPA of emissions in 2018; but netting out 140 million MTPA of biofuels and 35 million MTPA of solid waste combustion, that left 152 million MTPA of fossil fuel emissions in the sector.

40 The natural gas processing plants that process raw field gas containing high amounts of carbon dioxide are good candidates for carbon capture, but a number of the largest such plants already capture and sequester their emissions.

41 See pages 22, 37, 47 in British Petroleum, *Statistical Review of World Energy 2019*, (London, BP, 2020), *https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2019-full-report.pdf*

EXAJOULES BY FUEL	2009	2019
Oil Consumption	167.95	193.03
Gas Consumption	105.88	141.45
Coal Consumption	144.53	157.86
World Total Fossil Consumption	418.36	492.34

42 The degree to which the federal government's involvement was pivotal in the widespread deployment of fracking is a matter of some dispute. Forbes published one article downplaying federal involvement as relatively minor in comparison to the work done by Mitchell Energy. *https://www.forbes.com/sites/lorensteffy/2013/10/31/how-much-did-the-feds-really-help-with-fracking/?sh=52c71c6f3edf* Breakthrough Energy takes the opposite view: *https://thebreakthrough.org/issues/energy/us-government-role-in-shale-gas-fracking-history-a-response-to-our-critics%23:~:text=But%20the%20federal%20government%20supported,cracked%20the%20Barnett%20in%20Texas.*

43 See page 751 in International Energy Agency, *World Energy Outlook 2019,* (Paris, France: IEA, 2019), *https://www.iea.org/reports/world-energy-outlook-2019*.

44 See page 80, Ibid.

45 See Table B.5 on page 758, Ibid.

46 See Annex A in Ibid.

47 See table 2.7 on page 133 in Joeri Rogelj, Drew Shindell, and Kejun Jiang, "Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development" in *Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty*, ed. Greg Flato, et al., (Geneva: Intergovernmental Panel on Climate Change, 2018), 93-174, *https://www.ipcc.ch/site/assets/uploads/sites/2/2019/05/SR15_Chapter2_Low_Res.pdf*.

48 It is important to note that each state has its own legal definition of what renewable energy is for purposes of compliance with a state's Renewable Portfolio Standard: for instance, hydropower is clearly renewable energy, but virtually every state excludes some variety of hydro from eligibility as a renewable energy source for RPS purposes. Meanwhile, since RPS typically apply to electricity sold by a utility to a customer, "behind the meter" renewable energy such as rooftop solar, is often excluded from the legal definition of "renewable".

49 We will use the term, "Variable Generation" or VG when discussing the issue of integration of wind and solar to the grid in the context of maintaining reliability.

50 See Table A-3 on pp. 688-689 in International Energy Agency, *World Energy Outlook 2019*, (Paris,France: IEA, 2019), *https://www.iea.org/reports/world-energy-outlook-2019*.

51 Capital cost per kWh of storage capacity for a 400MWh system is shown as $173-$419, or a midpoint of $296/kWh. See page 14 in Lazard, *Lazard's Levelized Cost of Storage Analysis,* (New York: Lazard, 2019), *https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf*

52 $300,000 per MWh of battery storage x 8 hours = $2.4 million. Typical cost estimates for a new NGCC with carbon capture are ~$2 to 2.5 million per MW.

53 We used 55 percent capacity factors; average actual 2019 fuel prices delivered to utilities (EIA) of $2.09/MMBtu for coal and $2.53/MMBtu for natural gas; heat rates of 11,000 for coal, 7,000 for existing NGCC, and 6,250 for new NGCC; variable O&M of $4/MWh for coal and $2/MWh for gas. For the new NGCC we assumed cost of $900/kW with total fixed O&M costs and fixed charge factor of 12 percent of original investment.

54 Carbon capture is often, but not always "more expensive" than fuel switching. There are regions or plants where low coal costs, federal tax incentives for carbon capture, and revenues from sale of carbon dioxide make adding carbon dioxide capture to an existing coal plant cheaper (per MT carbon dioxide avoided) than building a new NGCC (unabated).

55 Authors' calculations based on the excel spreadsheets provided by EPA to document the CPP as first proposed in 2014. See *https://archive.epa.gov/epa/cleanpowerplan/clean-power-plan-proposed-rule-technical-documents.html* (The EPA spreadsheet is named 201430602tsd-state-goal-data-computation_1.xslx.) Downloaded 5/18/2021/. The total savings as shown by EPA for Proposed Goals rolled two steps together, a 6% heat rate improvement for existing coal plants followed by a switch of 441 million MWh per year of generation from coal/oil to gas. The combined impact of heat rate improvements and generation switching (EPA called this "re-dispatch) was 491 MMTPA carbon dioxide reductions, with 89 MMTPA generated by the coal plant heat rate improvements and 402 MMTPA from the actual fuel switch. Our calculations assumed a switch of 406 million MWh per year for a net emissions savings of 233 MMTPA carbon dioxide .

56 The calculations of capture and avoided cost are arcane and subject to dispute. Rubin and Herzog's comprehensive study of studies shows avoided cost of carbon dioxide per MT for NGCC at $58-$121/MT with a mean of $87, and for sub-critical pulverized coal plants at $45-$73/MT with a mean of $73. (Rubin, E.S., et al., The cost of carbon dioxide capture and storage. Int. J. Greenhouse Gas Control (2015)). US DOE's most recent *"Cost and Performance Baseline for Fossil Energy Plants Volume 1"* (NETL PUB-22638 September 24, 2019) shows an avoided cost for NGCC of $91/MT (comparing cases B31A and B31B) and for sub-critical pulverized coal of $60/MT (comparing case B11aA and B11B).

57 §45Q gives $35/MT credit for carbon dioxide injected in oil wells and $50/MT for carbon dioxide injected into passive sequestration sites (2026 figures, after which index to inflation). See Credit for carbon oxide sequestration,

26 U.S. Code § 45Q (2018).

58 Recall that newest generation simple-cycle combustion turbines (CTs) use about 1.5x more fuel per MWh produced than an NGCC (a combination of CTs, heat recovery, and a steam turbine). EIA shows simple cycle new CTs at 9,124-9,905 Btu/kWh, vs. NGCCs at 6,370-6,431 Btu/kWh. See Table 2 in United States Energy Information Agency, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies,* (Washington, DC: Department of Energy, 2020), *https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf*

59 IEA has chosen not to portray country-by-country carbon capture quantities in a clear tabular format. The figures attributed to IEA were extracted from tables and text in IEA's 2019 World Energy Outlook. See International Energy Agency, *World Energy Outlook,* (Paris, France: IEA, 2019), iea.org/reports/world-energy-outlook-2019

60 For experts in SMR technology: We defined carbon dioxide "process emissions" as the carbon dioxide normally available in the shift reactor tail gas. Because only about 2/3 of methane initially injected into the reformer is typically converted to carbon dioxide and hydrogen gas, there is a significant amount of remaining unreacted carbon monoxide and methane; and we included that remaining carbon monoxide and methane that is subsequently combusted for process heat as combustion emissions. The actual methodology used to differentiate process and combustion carbon dioxide under subpart 'G' (Ammonia) seems to allow considerable latitude to reporters. See Office of Air and Radiation, Technical Support Document for the Ammonia Production Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases, (Washington, DC: EPA, 2009), *https://www.epa.gov/sites/production/files/2015-02/documents/ti_g-tsd_ammonia_epa_1-22-09.pdf*.

Note that regulation is ambiguous about whether captured carbon dioxide retained for urea production is or is not subtracted, with 40 CFR § 98.72 stating: "(carbon dioxide *process emissions* reported under this subpart may include carbon dioxide that is later consumed on *site* for urea production, and therefore is not released to the ambient air from the ammonia manufacturing process unit)." See Grenhouse Gases to Report, 40 CFR § 98.72, 2010.

61 The IEAGHG report used Euro as currency, European electricity prices, and cost of imported Russian gas. We converted to U.S. dollars, used U.S. electric and gas prices, adjusted for inflation, and eliminated some financial errors found in the backup spreadsheets. See IEAGHG, *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS,* (Cheltanham, UK: IEAGHG, 2017), https://ieaghg.org/exco_docs/2017-02.pdf

62 It is not economically efficient to attempt to get full conversion of all the methane and carbon monoxide, especially since these remaining burnable gases can be recirculated to be burned for heating purposes. See page 44 in IEAGHG, *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS,* (Cheltanham, UK: IEAGHG, 2017), *https://ieaghg.org/exco_docs/2017-02.pdf*

63 Known in EPA parlance as "General Stationary Fuel Combustion Sources" that are reported under subpart 'C' of EPA's Greenhouse Gas Reporting Program. Recall that we removed 152 MMTPA of CHP fossil fueled emissions from this category and placed them in a separate row of our tables. See "Subpart C – General Stationary Fuel Combustion Sources," US Environmental Protection Agency, accessed May 4, 2021, *https://www.epa.gov/ghgreporting/subpart-c-general-stationary-fuel-combustion-sources*

64 Note for readers cross-checking our figures with EPA data: EPA FLIGHT data for 2018 shows 575MMTPA of carbon dioxide -equivalent emissions from Stationary Emissions reported under subpart 'C'. We reduced that by 152 MMTPA of emissions that represented fossil CHP plants that would be cost-effectively addressable with an end-of-pipe carbon dioxide scrubbing system, dealing with those emissions in Section VIII. The remaining 423 MMTPAemissions are from fossil fuel combustion to generate industrial process heat.. See endnote 37.

65 Document entitled "Air Products U.S. Gulf Coast hydrogen network" downloaded from Air Products website May 15, 2021.

66 The SMR scrubbing unit would actually be more on the order of 15 times as large because of heat losses that occur when methane is converted to hydrogen.

67 The $10-12/MMBtu [HHV] hydrogen was derived by the author from IEA study of carbon capture in steam methane reforming (Replacing European costs of electricity and natural gas with corresponding U.S. prices). Julio Friedmann's paper cited below (Table 4) shows that with $3.5/MMBtu [HHV] gas feedstock cost, blue hydrogen with 89% carbon capture costs $14.22-$17.92/GJ[LHV], which is approximately $13.65-$17.20/MMBtu [HHV]. Using those figures the break-even carbon dioxide price to use blue hydrogen for combustion would be $191-$258/ton carbon dioxide.

68 See Figure 1 in Julio Friedmann, Zhiyuan Fan, and Ke Tang, *Low-Carbon Heat Solutions for Heavy Industry: Sources, Options, and Costs Today,* (New York, NY: Center on Global Energy Policy, 2019), *https://energypolicy.columbia.edu/research/report/low-carbon-heat-solutions-heavy-industry-sources-options-and-costs-today*

69 There is no easy way to trace the CHP units directly. We had to estimate the CHP units by taking total emissions by all U.S. power units and subtracting out emissions that were not subject to continuous emissions monitoring by the U.S. EPA Clean Air Markets Division (CAMD). The totals subject to CAMD monitoring were almost exactly equal to amounts reported under Subpart D, which meant that the balance would have been reported under Subpart C.

70 ETN Global, *The Path Towards a Zero-Carbon Gas Turbine,* (Brussels, Belgium: ETN, 2019), *https://etn.global/wp-content/uploads/2020/02/ETN-Hydrogen-Gas-Turbines-report.pdf* The issue for using hydrogen in CTs instead of natural gas is that the flame speed of hydrogen is an order of magnitude faster than that of methane, thus being harder to control, potentially leading to either flame blowouts or flashback of the flame into the fuel premixing equipment.

71 There are promising technologies for cheap long-term thermal storage that are being explored. They just do not have the proven scalability of NGCCs with CCS, especially since many of the NGCCs are already up, operating, and connected to the grid and gas pipelines.

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The Role Of Natural Gas In De-Carbonizing The U.S. Energy and Industrial Economy

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