STRANDED NATURAL GAS
ROADMAP

U.S. DEPARTMENT OF ENERGY

NATIONAL ENERGY TECHNOLOGY LABORATORY

CONTENTS

SUMMARY

While there is currently an abundance of natural gas in the U.S. market, significant gas resources remain economically undeveloped, which is referred to as stranded, for a variety of reasons. This document categorizes and quantifies those resources and summarizes ongoing Department of Energy (DOE) research efforts that are focused on removing the barriers to economic development for specific categories.

The vast majority of the United States (U.S.) stranded natural gas is stranded for economic reasons; the cost of development and production is too great when compared to the value of the gas in the marketplace. This disparity has been exacerbated by the success of recent technological advancements in the development of unconventional gas and oil reservoirs. There is currently a lot of gas available at a relatively low price.

But the mission of DOE is to make certain that additional supplies of domestic natural gas will become available over time at a reasonable price, as reserves are drawn down and resources that are currently considered to be stranded are developed. There are six stranded natural gas resource categories (and sub-categories) where DOE research is currently focused. The table below identifies the estimated volume of stranded gas, the current DOE research and development (R&D) effort, and the recommended actions to be taken.

CATEGORY	ESTIMATED VOLUME (TCF)	DOE R&D EFFORT	RECOMMENDED ACTION
Flared Associated Gas	5-10	Gas Conversion Program currently in development	Advance new Program as planned.
Stranded Due to Distance to Market (Alaskan North Slope)	~270	None currently. Have done related economic analyses in the past.	Consider ways to leverage CO_2 capture and injection research from CCUS program.
Stranded Due to High Cost to Develop			
Arctic Onshore Methane Hydrates	53.8	Past Program (Methane Hydrates Arctic Assessment and Testing) and Current Methane Hydrates Program	Advance current Program as planned.
Deepwater Offshore	25.56	Past Program (Section 999 Offshore) and Current Offshore Program.	Advance current Program as planned.
Offshore Methane Hydrates	100s to 1000s	Past Program (Methane Hydrates GOM Assessment Work) and Current Methane Hydrates Program	Advance current Program as planned.
Difficult Unconventional	~1200	Current Unconventional Gas Program	Advance current Program as planned.

BACKGROUND/NEED

The Energy Information Administration's (EIA) Annual Energy Outlook 2019 projects the continuing transformation of U.S. power generation from a largely coal-fueled past into an increasingly gas-fueled future *(see Figure 1).*

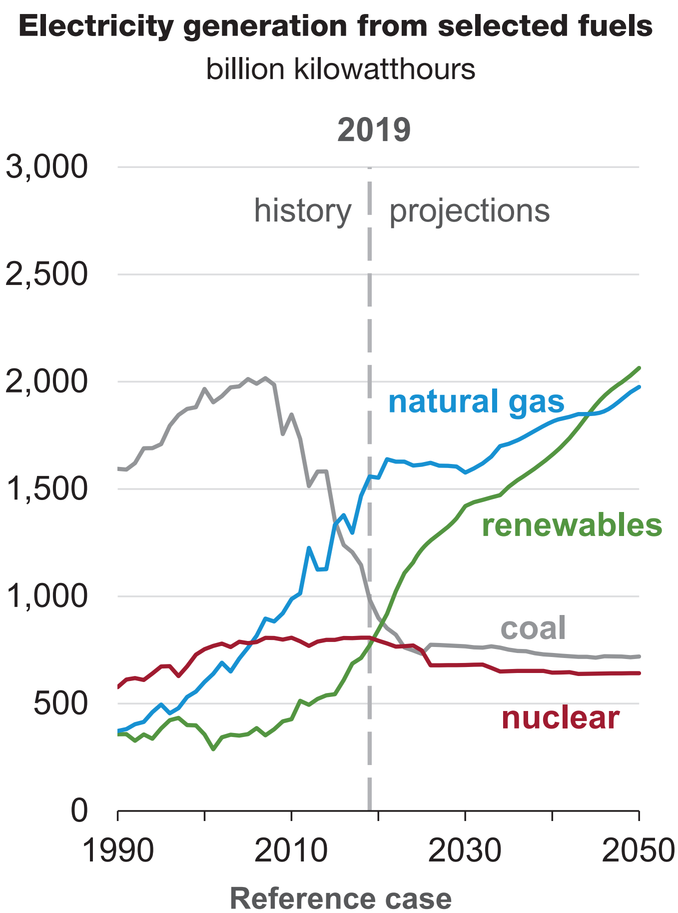

Figure 1. U.S. electric power generation by fuel, past and future (billion kilowatt-hours)[1]

The supply of natural gas for this long term transformation is expected to come primarily from the continued development of unconventional natural gas resources (shale gas, tight gas) and from associated gas produced along with unconventional oil (tight oil), supplemented by a relatively small but steady supply from conventional onshore and offshore gas *(see Figure 2).*

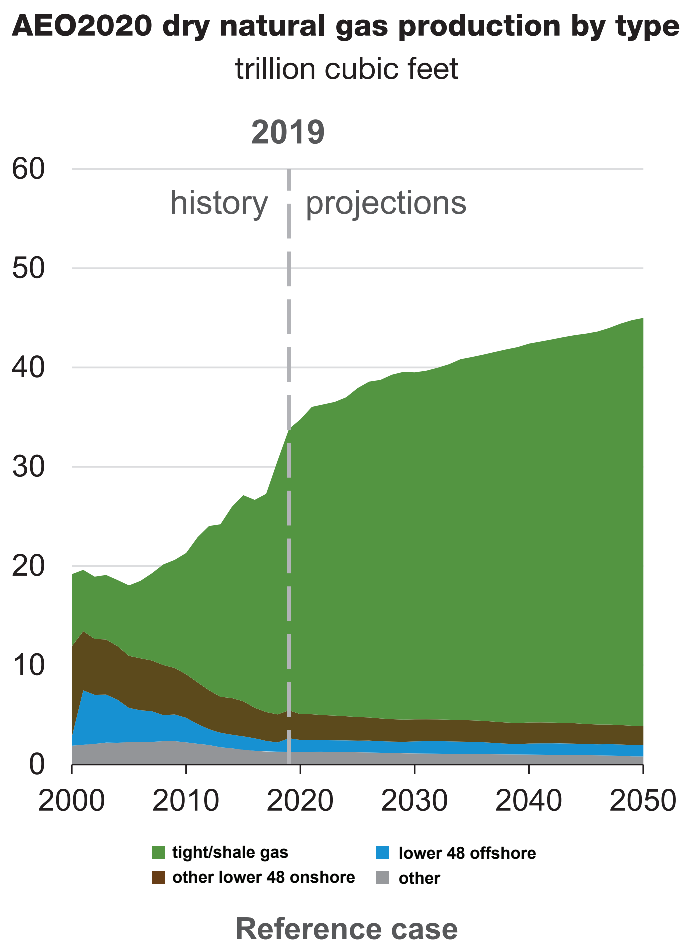

Figure 2. U.S. dry natural gas production, by type (trillion cubic feet)[2]

1. AEO 2020, January 2020, https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Full%20Report.pdf
2. AEO 2020, January 2020, https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Full%20Report.pdf

Both the EIA and independent experts, such as IHS, project that the primary contributors to U.S. natural gas supply through 2050 will be the Appalachian Basin (primarily the Marcellus Shale) and associated gas from Lower 48 tight oil plays (primarily the Permian, Eagle Ford and Bakken plays), supplemented by steady production from other onshore Lower 48 gas plays *(see Figure 3).* This level of production is projected to not only supply U.S. demand but also to enable increased levels of liquefied natural gas (LNG) exports from U.S. terminals. The EIA expects LNG exports to more than double over the next 10 years *(see Figure 4).*

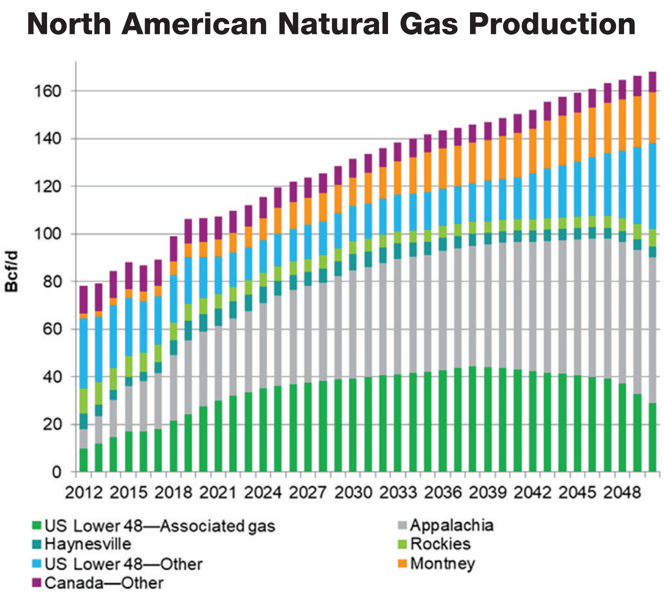

Figure 3. North American natural gas production, by source (billion cubic feet per day)[3]

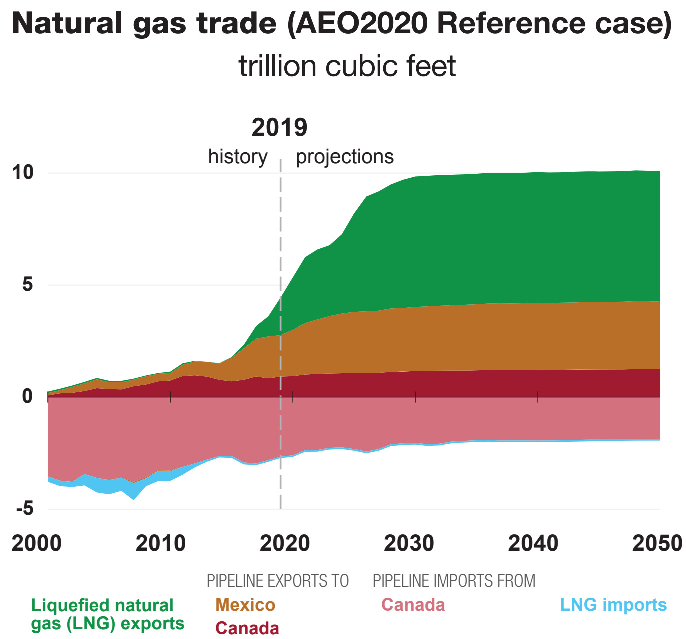

Figure 4. U.S. natural gas trade (trillion cubic feet)[4]

3. IHS Markit, "North American Natural Gas Long-Term Outlook," August 2019
4. AEO 2020, January 2020, https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Full%20Report.pdf

The relatively low price required to access this expected future supply of natural gas is illustrated by the flatness of the IHS supply-cost curve *(see Figure 5)*, which shows that 1,250 Tcf are available at a breakeven price of $4/MMBtu or less from these sources alone; enough to supply projected demand for at least the next three decades.

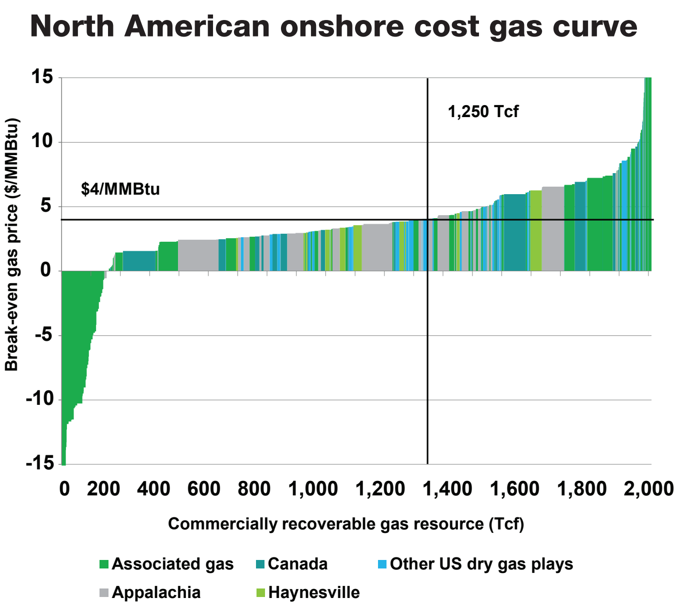

Figure 5. Natural gas supply/cost curve[5]

Beyond that point additional supplies of harder-to-produce natural gas will require higher gas prices for economic development. The supply-cost curve shows that developing the next 750 trillion cubic feet (Tcf) of gas from these same primary sources will require prices as high as $15 per one million British Thermal Units (MMBtu), assuming current technology.

Moreover, the supply-cost curve shown here does not include other sources of North American natural gas that could be made available at similar or even higher prices, either before or beyond 2050 (e.g., methane hydrates from Arctic onshore deposits).

Despite the apparent abundance of natural gas resources, it is important to recognize that continued efforts to accelerate the development of technologies that can further flatten and extend the supply-cost curve, lowering the cost of accessing increased volumes of natural gas both currently and out beyond 2040-50, is an important objective if a long-term, low-cost domestic supply of natural gas is to remain a prominent feature of U.S. economic growth beyond the next 20-30 years. The goal of DOE's Stranded Natural Gas Roadmap is to outline a DOE research framework for achieving this objective.

WHAT ARE STRANDED NATURAL GAS RESOURCES?

Broadly defined, stranded natural gas is an accumulation of natural gas that is economically unrecoverable. Examples include:

1. Associated gas that is produced along with crude oil and flared because a pipeline and compression facilities to capture it for sale are either uneconomic or delayed. Relatively small volumes of natural gas are vented, and this action is typically unrelated to development economics; the larger portion of this gas is flared.
2. Natural gas accumulations that are far from markets and cannot be economically produced due to the high cost of transportation (e.g., natural gas pipeline or LNG liquefaction facility costs are too high given the size of the accumulation and the expected value of the gas in the marketplace).
3. Natural gas that contains relatively high concentrations of non-hydrocarbon constituents (e.g., carbon dioxide (CO_2), nitrogen (N_2), hydrogen sulfide) and where the cost of installing the required equipment to treat the gas to sales pipeline quality makes development uneconomic, given the size of the accumulation and its market value.
4. Natural gas accumulations where the costs of drilling and production are high compared to the productive potential and development is thus uneconomic. Examples include: very deep onshore gas resources, very deep water offshore, Arctic offshore, methane hydrates in the onshore Arctic or deep water marine areas, geologically complex reservoirs that have not been proven to be amenable to hydraulic fracturing (e.g., unconventional plays such as the New Albany Shale in the Illinois Basin), and shallow, low pressure reservoirs in mature producing areas where the flow rates and recoverable volumes will not support the cost of drilling and production.
5. Natural gas accumulations that cannot be developed due to regulations, given the limits of current technology. For example, the Marcellus Shale formation beneath the City of Pittsburgh in Allegheny Country, Pennsylvania contains an enormous amount of gas-in-place, but it cannot be developed because wells are not permitted to be drilled in populated areas and drilling extremely long horizontals to tap the resource would be cost-prohibitive.

Most of the natural gas resources in the U.S. that are not currently being developed can be placed into one or more of these categories. Each of the above categories are discussed below and an approximation of the volumes of gas involved in each is estimated. These estimates, while admittedly rough "back-of-the-envelope" approximations, provide a general sense of the relative distribution of stranded gas among the various categories; where the bigger volumes are to be found. This is important because the technology necessary to "un-strand" the gas will vary from category to category, and it is good to know what sort of "prize" can be associated with any specific technology research and development initiative.

5. IHS Markit, "The Shale Gale turns 10: A powerful wind at America's back," July 2018

ESTIMATES OF U.S. VOLUMES OF STRANDED GAS FOR SPECIFIC CATEGORIES

Associated Gas Being Flared

Currently, the largest volumes of natural gas being flared due to a lack of availability of pipeline infrastructure in the U.S. are located in the Bakken Shale play in North Dakota and across a number of tight oil plays in the Permian Basin. The primary reason of this situation is economics.

From the end of 2018 to February 2020, the price of natural gas at Henry Hub has declined to just under $2.00 per MMbtu from more than $4.50.[6] In addition, the overall costs to transport associated gas to market can be too high to make sales profitable, especially in areas where oversupply is widespread, leaving increased flaring the only option for maintaining oil production. As a result of the increase in flaring, regulations are continuing to evolve, and it is now becoming somewhat harder to flare large volumes of natural gas. Some operators are actively seeking ways to reduce flaring.[7]

Flaring in the Permian Basin of West Texas and southeastern New Mexico set an all-time record during the first quarter of 2019, averaging as much as 661 million cubic feet per day (MMcf/d). Analysts expected volumes to stay above 650 MMcf/d until the Gulf Coast Express pipeline came online.[8] After the pipeline entered serviced in late September 2019, gas prices appeared to indicate that the project had quickly filled to its full capacity.[9] Flows on the Gulf Coast Express aren't reported publicly, but gains in Permian gas production since last summer would likely be sufficient to fill about 65% of the pipeline's total capacity. In addition, Kinder Morgan announced a three-month delay to startup of the 2.1 billion cubic feet per day (Bcf/d) Permian Highway Pipeline. Regulatory approvals for the project, which have been slower in coming than previously anticipated, have delayed the pipeline's estimated in-service date to first-quarter 2021.

Current Texas Railroad Commission (TRRC) projections are that approximately 50,000 to 200,000 million cubic feet per day (Mcf/d) of current flaring will be reduced over the next 12 to 18 months (beginning February 2020) as new pipeline systems are completed. However, the drilling of additional new wells will also increase the need to add new flares. Total gross flaring volumes in Texas could increase as produced oil volumes increase.[10]

If flaring continues at current rates for 2 more years an additional 500 billion cubic feet (Bcf) of gas could be flared in the Permian Basin alone. One day's worth of this level of flaring (650 MMcf/d) is equivalent to generating 89,526 megawatt-hours (MW-hrs) from a modern Natural Gas Combined Cycle Power Plant, capable of powering 8,159 homes for a year. Nearly 3 million homes could be powered for a year with the power produced over a year's worth of flaring at this rate. Burning this gas results in 13 million metric tons per year of CO_2 emissions.

In the Bakken Shale of North Dakota's Williston Basin, about 20% of the roughly 85 Bcf per month *(see Figure 6)*, or 560 MMcf/d, will continue to be flared until pipeline infrastructure that is currently under construction is completed. One day's worth of this flaring is equivalent generating 77,201 MW-hrs from a modern Natural Gas Combined Cycle Power Plant, capable to powering 7,036 homes for a year. About 2.6 million homes could be powered for a year with the power produced over a year's worth of flaring at this rate. Burning this gas results in 11.3 million metric tons per year of CO_2 emissions.

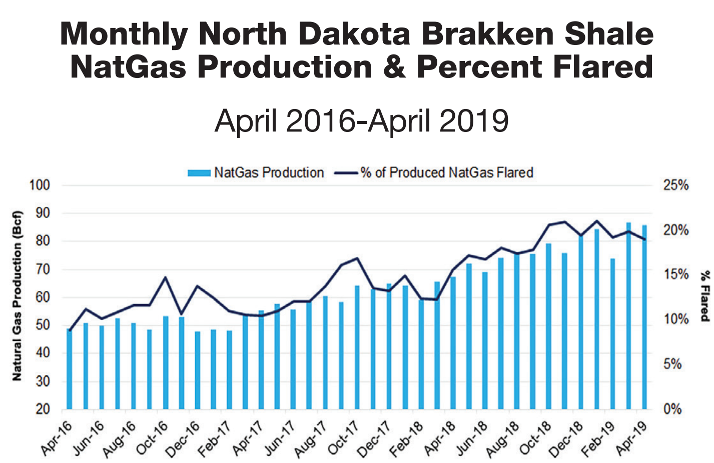

Figure 6. Bakken Shale Production Flared and Vented[11]

6. EIA, https://www.eia.gov/dnav/ng/hist/rngwhhdd.htm
7. Sitton, R., 2020, TRRC report on flaring in Texas, https://www.rrc.state.tx.us/media/56420/sitton-texas-flaring-report-q1-2020.pdf
8. NGI, https://www.naturalgasintel.com/articles/118822-natural-gas-flaring-bug-hits-oil-hotspots-in-bakken-permian
9. S&P Global Platts, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/010920-permian-basin-2020-forward-gas-prices-hit-fresh-record-lows
10. Sitton, R., 2020, TRRC report on flaring in Texas, https://www.rrc.state.tx.us/media/56420/sitton-texas-flaring-report-q1-2020.pdf
11. NGI, https://www.naturalgasintel.com/articles/118822-natural-gas-flaring-bug-hits-oil-hotspots-in-bakken-permian

The North Dakota Pipeline Authority estimates that midstream processing/pipeline capacity should match production sometime in 2020. **This means that an additional 100's of Bcf of gas could likely be flared in the Bakken before processing/pipeline capacity matches production.**

IHS Markit has published a projection of associated natural gas production out to 2050.[12] This projection identifies several important findings:

- Assuming West Texas Intermediate (WTI) crude oil prices average about $63/barrel in real terms through 2030, the subsequent growth in drilling programs means that the momentum in oil production in the Permian Basin should remain strong. Consequently, associated gas production is expected to continue its upward trajectory.
- Associated natural gas produced throughout the U.S. is anticipated to grow on the strength of oil prices and new takeaway capacity; it is expected to increase by 13.6 Bcf/d, to 39.4 Bcf/d in 2030—representing 38% of U.S. Lower-48 production, up from a share of 26% in 2018. The primary sources of growth are the Permian Basin (Texas), SCOOP (Oklahoma, Colorado), STACK, and Wattenberg areas.
- Specific to the Permian Basin, associated natural gas production is expected to average 12,500 MMcf/d in 2020 (an incremental 3,400 MMcf/d) and grow by another 8,800 MMcf/d through 2030, pushing total associated natural gas production to 21,300 MMcf/d in 2030. With low-cost operations, an inventory of drilled-but-uncompleted (DUC) oil wells and new takeaway pipeline capacity coming online over the next five years, the Permian Basin will remain one of the defining areas for U.S. Lower-48 associated production for this decade.
- Approximately 14.5 Bcf/d of new gas pipeline takeaway capacity is proposed to alleviate gas constraints from the Permian Basin. IHS expects that 8.0 Bcf/d of gas pipeline capacity will need to be built over the next five years.
- Beyond the Permian Basin and Bakken Shale, the next tranche of associated gas production growth will come from the SCOOP/STACK, Denver-Julesberg Niobrara, and Eagle Ford plays.
- Following significant growth during the 2020s, total associated gas production will reach a peak in 2035 at 40.5 Bcf/d and then begin to moderate to 37.7 Bcf/d in 2040 as oil development declines.

Continued development of these oil plays will require flaring from production operations, even if the expected pipeline additions reduce the need for large amounts of flaring of associated gas. **The expectation is that there will be a continued need for some degree of associated gas flaring in all these plays for the next two decades.**

The EIA's accounting of flared and vented gas in the U.S. shows that the total is currently (2018) on the order of 1.25 Bcf/d *(see Figure 7).*

It should be noted that EIA data does not align perfectly with state estimates of flaring, such as the TRRC and North Dakota state sources. This is due to the fact that the EIA uses models to anticipate production while the TRRC, for example, uses actual reported data from operators. This means that TRRC data can lag by as much as 12 months. Also, TRRC considers oil and condensate separately, whereas most other analyses combine them. The actual amount of gas being flared is likely to be higher than the 1.25 Bcf/d EIA total.

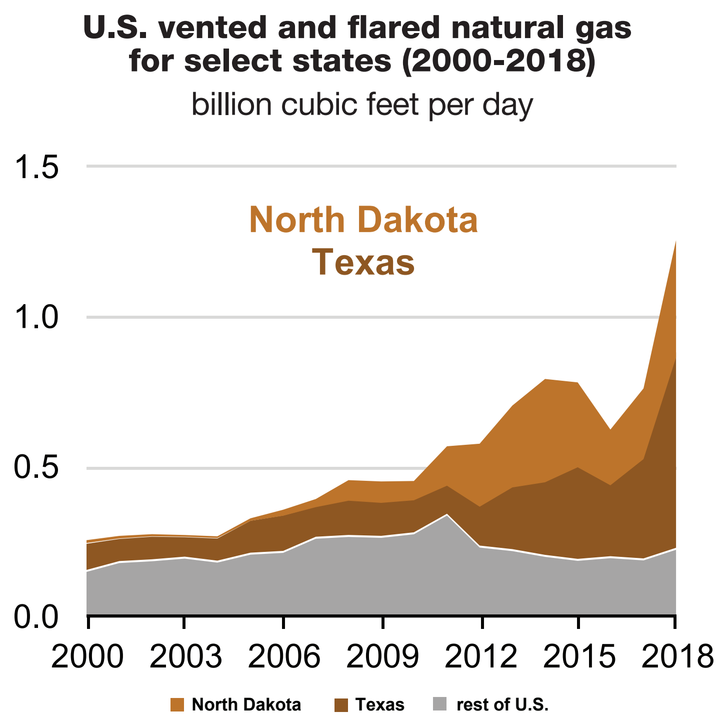

Figure 7. U.S. vented and flared gas volumes[13]

But if we consider this amount to be a peak that will decline over the next decade as pipeline capacity increases, substantial volumes of gas will still be flared.

Over the next 20 years it is likely that a volume of gas of at least 5 Tcf is likely to be flared before sufficient takeaway capacity is in place to bring the level of flaring and venting back to pre-2005 levels. This volume could be doubled if capacity increases are delayed and oil prices rise to support increased drilling.

12. IHS Markit, 2019, "North American Natural Gas Long-Term Outlook," February 28, 2019, accessed via NETL subscription
13. EIA, https://www.eia.gov/todayinenergy/detail.php?id=42195

Natural Gas Accumulations Far from Markets

In the U.S., perhaps the greatest accumulation of natural gas stranded due to remote location is on the North Slope of Alaska. There is no significant local market, no pipeline connecting North Slope natural gas with markets in Canada or the Lower-48, and no LNG facility in Alaska capable of supplying nearby Asian markets. The Alaska Department of Natural Resources estimates[14] North Slope natural gas proven reserves and undeveloped resources to include the following:

- 35 Tcf of proven gas reserves on the North Slope, including Prudhoe Bay Unit (24.8 Tcf) and Point Thomson fields.
- 15+ Tcf of known, undeveloped gas resources including Burger Field (OCS) and Foothills gas accumulations.

In addition, recent assessments by the U.S. Geologic Survey (USGS) estimate over 220 Tcf (mean) of undiscovered, technically recoverable conventional associated and non-associated natural gas resources in onshore and offshore Arctic Alaska.[15] A more recent USGS assessment estimates that within the Central North Slope alone (onshore area between the Alaska National Petroleum Reserve and the Arctic National Wildlife Preserve), the mean undiscovered, technical recoverable natural gas resource (associated and non-associated) is 8.94 Tcf.[16]

Methane hydrates and shale gas could potentially add 100s of Tcf to future North Slope gas resources once technical and economic challenges to production are overcome. These resources are accounted for in another category.

North Slope gas potential is a lower priority development target due to the lack of existing outlets to world gas markets. Currently, 8 Bcf/d of produced associated gas is reinjected on the North Slope to support oil production, a significant volume of gas. For comparison, Canada's daily natural gas consumption averaged 10 Bcf/d in 2017.[17] The economics of building and operating an LNG facility or a long-distance pipeline similar to the Trans-Alaskan oil pipeline have not yet been demonstrated to be acceptable to investors.

Even if the economics of these transport options were to improve, another challenge to natural gas production on the North Slope is the high CO_2 content of much of the gas produced there. Gas treatment facilities to remove the CO_2 and reinject it without emitting it into the atmosphere would be expensive to install and operate under Arctic conditions.[18]

In addition to the volumes of gas stranded on the North Slope, there are other volumes of natural gas in Alaska and the Lower 48 states that are far from current markets but are technically recoverable. The Potential Gas Committee (PGC) produces estimates of technically recoverable gas resources based on surveys of members every two years.[19] The PGC's December 2018 Report estimates total mean technically recoverable natural resources at 3,374 Tcf (3,124 Tcf in the Lower 48 states). If the EIA's proved gas reserves for year-end 2017 (464 Tcf) are added to that total, the "future gas supply of the U.S." can be estimated at 3,838 Tcf. This technically recoverable resource total is substantially more than the 2,000 Tcf of economically recoverable gas shown in the supply-cost curve in Figure 5. Some portion of the 1800+ Tcf difference between these totals is due to the economic penalty resulting from distance to market. It would be safe to say that at least 100s of Tcf of gas are stranded due to distance from market in the Lower 48 states and non-arctic Alaska and ~270 Tcf more on the Alaskan North Slope.

14. ADNR, http://dnr.alaska.gov/commis/Presentations/Alaska_North_Slope_Gas_Potential_Sept_2016.pdf
15. USGS, 2019, Geology and Assessment of Undiscovered Oil and Gas Resources of the Arctic Alaska Province, 2008, https://pubs.er.usgs.gov/publication/pp1824E
16. USGS, 2020, Assessment of Undiscovered Oil and Gas Resources in the Central North Slope of Alaska, 2020, https://pubs.er.usgs.gov/publication/fs20203001
17. https://www.alaskapublic.org/wp-content/uploads/2016/08/160824-Wood-Mackenzie-AKLNG-competitiveness-study.pdf
18. https://www.adn.com/business-economy/energy/2016/08/06/heres-the-10-billion-reason-for-the-high-cost-of-alaska-lng/
19. PGC, 2019, http://potentialgas.org/wp-content/uploads/PGC_2019_Press_Conference_Slides.pdf

Natural Gas Accumulations with High Levels of Contaminants

In 1998 the Gas Research Institute published a report titled "Chemical Composition of Discovered and Undiscovered Natural Gas in the Continental U.S., 1998 Update." This document reported on "sub-quality" gas having 2% or greater CO_2, 4% or greater N_2 and 4 parts per million (ppm) or greater H_2S. Gas resources were categorized into multiple composition groups and designated into seven "low" quality categories depending upon the relative amounts of all three contaminants (e.g., high percentages of all three was the lowest "low" quality, high N_2 only was the highest "low" quality. This table below summarizes the results.

While a good portion of the proven reserves in 1998 have undoubtedly been produced over the intervening 20 years, it would be safe to say that a good portion of the total undiscovered resource (let's say two thirds), and perhaps all of the discovered but non-producing high $N_2/CO_2/H_2S$ *(see Category 7 from Table 1)* resource is still unproduced. **This could mean that perhaps 455 Tcf of "low" quality gas remains stranded.**

CATEGORY	PROVEN RESERVES (BCF)	1996 PRODUCTION (BCF)	PRODUCTION TO PROVEN RESERVES RATIO	UNDISCOVERED RESOURCE (BCF)	DISCOVERED, NON-PRODUCING (BCF)
1. High N_2 only	15,617	1,453	0.09	74,144	
2. High CO_2 only	17,932	2,102	0.12	248,739	
3. High H_2S only	5,691	630	0.11	38,572	
4. High N_2 and High CO_2	1,577	152	0.10	31,932	
5. High N_2 and High H_2S	600	79	0.13	3,324	
6. High CO_2 and High H_2S	12,697	1,209	0.10	77,428	
7. High N_2, CO_2 and H_2S	6,585	296	0.04	21,902	128,000
TOTAL	60,698	5,920		496,042	128,000

Table 1. Sub-quality natural gas resources in Lower 48 States as of 1996 (wet, billion cubic feet)[20]

Natural Gas Accumulations with High Development Costs Relative to Recovery

As noted above there are a wide variety of resource types within this category. It is possible to make some rough estimates of each; they are listed below.

- **Arctic Onshore Methane Hydrates –** Methane hydrates are a difficult natural gas resource to develop economically due to the costs of arctic drilling and production coupled with what is likely to be relatively low pressure, low flow rate wells and the need for some sort of flow assistance. The USGS has estimated that the Alaskan North Slope contains an estimated 53.8 Tcf of undiscovered, technically recoverable natural gas resources stored within gas hydrate formations.[21]
- **Arctic Offshore –** Offshore oil and gas development is expensive relative to onshore, and arctic offshore is very expensive relative to non-arctic offshore. The PGC 2018 Report estimates the Alaska Offshore total potential resource at 193.8 Tcf.[22]
- **Deepwater Offshore –** Deepwater offshore development is expensive in general and natural gas production poses challenges due to hydrates formation in flowlines. The PGC 2018 Report estimates the total potential gas resource for water depths >1000 m at 25.56 Tcf, all in the Gulf of Mexico.

20. GRI, 1998, "Chemical Composition of Discovered and Undiscovered Natural Gas in the Continental United States, 1998 Update," GRI-98/0364.2
21. USGS, 2019, USGS Updates Gas Hydrate Assessment for Alaska North Slope, https://www.usgs.gov/news/usgs-estimates-538-trillion-cubic-feet-natural-gas-hydrate-resources-alaska-north-slope
22. PGC, 2019, http://potentialgas.org/wp-content/uploads/PGC_2019_Press_Conference_Slides.pdf

- **Offshore Methane Hydrates –** Methane hydrate production is a difficult technical and economic challenge onshore, added offshore costs make the problem only that much more difficult. The Bureau of Ocean Energy Management (BOEM) has completed assessments of the in-place methane hydrate resource across the U.S. offshore regions and determined that the mean resource volumes total 51, 338 Tcf (21,702 Tcf on the Atlantic Outer Continental Shelf (OCS), 8,192 Tcf on the Pacific OCS and 21,444 Tcf on the Gulf of Mexico OCS). No estimates of technically or economically recoverable resource have been made. However, even if only a few percent were to be recoverable it would total 100s to 1000s of Tcf.
- **Deep Onshore –** Depth (>15,000 feet (ft)) adds significant costs to drilling and completion. The Potential Gas Committee (PGC) 2018 Report estimates a total potential gas resource at 138.52 Tcf for depths between 15,000 feet and 30,000 feet.
- **Difficult Unconventional –** There are several plays where operators have not seen enough positive indications of productivity from the application of current drilling and completion approaches to justify development (e.g., Illinois Basin and Great Warrior Basin plays). Coalbed methane development has decreased substantially in the face of lower prices over the past 5-10 years. The PGC 2018 estimates probable, possible and speculative recoverable resources for conventional, tight and shale reservoirs, as well as coalbed methane plays, for each of seven regions. One could reasonably assume that the possible and speculative resource estimates for shale resources (at depths less than 15,000 ft), combined with all the coalbed methane resource estimates, are a reasonable estimate of the unconventional resource that remains stranded due to difficulty in achieving commercial rates of production. The following table summarizes the results.
- **Shallow, Low Pressure Mature Fields –** The economics of maintaining low pressure shallow gas wells in marginal and mature fields has been very challenging in the face of low gas prices. The volume of gas stranded in shallow low-pressure reservoirs or behind pipe in marginal or abandoned fields is difficult to estimate. The Interstate Oil and Gas Compact Commission (IOGCC) used to produce an annual Marginal Well Report, the last issue of which was produced in 2016.[23] That report notes that in 2016 a total of 1.88 Tcf was produced from more than 381,000 marginal gas wells, many of them in Texas, Pennsylvania, Oklahoma, West Virginia and Ohio. Between 5 and 10 thousand wells are plugged and abandoned each year due to low rates and low gas prices, leaving whatever gas remains to be produced stranded in the reservoir. It would be reasonable to assume that many of these wells could be maintained if lower cost production methods could be applied or prices were to rise, or both. A reasonable estimate of stranded gas in this category might be in the 1 to 10 Tcf range.

This approach suggests that the volume of onshore unconventional resources that remain stranded due to difficulty in achieving commercial rates of production might be on the order of 1,200 Tcf.

REGION	SHALE POSS. (TCF)	SHALE SPEC. (TCF)	ALL CBM (TCF)	TOTAL
Atlantic	506	64	16	586
North Central	3	3	12	18
Gulf Coast	107	44	3	154
Mid-Continent	152	93	8	253
Rocky Mountain	46	24	53	123
Pacific	0	0	3	3
Alaska	0	0	57	57
TOTAL	814	228	152	1194

Table 2. PGC 2018 Report's most likely volumes of shale gas possible and speculative resources and CBM resources in onshore reservoirs at depths less than 15,000 ft (Tcf).[24]

23. IOGCC, 2016, http://iogcc.ok.gov/Websites/iogcc/images/MarginalWell/Marginal%20Well%202016%20-%20FINAL.pdf
24. PGC, 2019, http://potentialgas.org/wp-content/uploads/PGC_2019_Press_Conference_Slides.pdf

Natural Gas Accumulations Stranded Due to Regulatory and Technology Limitations

This category could be considered a special subset of the previous category, as the resource could eventually become recoverable if lower-cost advanced technologies can be developed or if the regulations are revised. One example of this is the natural gas resource located within the boundaries of Allegheny County in Pennsylvania, where drilling is not permitted due to the density of surface development in the City of Pittsburgh. Some experts estimate recoverable resources in the county at 152 trillion cubic feet equivalent (Tcfeq); that is, 58.2 Tcfeq in the Marcellus, 42 Tcfeq in the Burket-Geneseo, and 51.9 Tcfeq in the Utica.[25] Similar situations exist in other producing regions where unconventional resources are located under metropolitan areas or in areas that are off limits to drilling. For example, the Barnett Shale resource under the Dallas-Fort Worth, Texas metropolitan area,[26] and the Niobrara and other horizons under Denver, Colorado. **It would be reasonable to assume that natural gas volumes on the order of 100s of Tcf are stranded due to offset regulations and/or a lack of available technology to safely extract gas from underneath densely populated areas or areas where surface access is restricted.**

All of the estimates above are compiled in Table 3, which also highlights categories where DOE has ongoing or has had past R&D programs. Each of the current research areas (highlighted in red in Table 3) and several potential research areas (highlighted in green in Table 3) are discussed in more detail in the following section.

25. AAPL, https://www.mlbc-aapl.org/docs/AAPL_Allegheny_County_2017_02_09_For_Distribution_b.pdf
26. EIA, https://www.eia.gov/oil_gas/rpd/shaleusa1_letter.pdf

CATEGORY	VOLUME (TCF)	NOTES	DOE R&D EFFORT
Flared Associated Gas	5-10	Conservatively assumes a peak in associated gas flaring in 2020 with decline to pre-2005 levels by 2040 as pipeline capacity increases	Gas Conversion Program currently in development
Stranded Due to Distance to Market (Alaskan North Slope)	~270	Does not include methane hydrates	None currently. Have done related economic analyses in the past. Consider ways to leverage CO_2 capture and injection research from CCUS program.
Stranded Due to Distance to Market (Lwr. 48 States and non-Arctic Alaska)	100s or more	Assumed to be less than 1,800 Tcf. Includes onshore and offshore, conventional and unconventional resources.	None
Stranded Due to Poor Gas Quality	455	Estimate based on adjustment of 1998 GRI assessment	Past Program (Gas Processing)
Stranded Due to High Cost to Develop			
Arctic Onshore Methane Hydrates	53.8	USGS estimate (reduced from previous USGS estimate)	Past Program (Methane Hydrates Arctic Assessment and Testing) Current Methane Hydrates Program
Arctic Offshore	194	2018 PGC Report for Alaska region	None
Deepwater Offshore	25.56	2018 PGC Report for OCS greater than 1000 meters water depth	Past Program (Section 999 Offshore) Current Offshore Program
Offshore Methane Hydrates	100s to 1000s	Based on BOEM estimate of 51,338 Tcf of gas-in-place in methane hydrates	Past Program (Methane Hydrates GOM Assessment Work) Current Methane Hydrates Program
Deep Onshore	138.52	2018 PGC Report for all onshore regions, depths between 15,000 and 30,000 feet	Past Program (Deep Trek Program)
Difficult Unconventional	~1200	Based on possible and speculative resources for shale reservoirs and total CBM resource estimates in 208 PGC report	Current Unconventional Gas Program
Shallow Low Pressure Gas in Mature Fields	1-10	Estimate based on Marginal Well Report from IOGCC	Past Programs (Stripper Well Program)
Stranded Due to Regulatory/Technology Constraints	100s	~150 Tcf in Allegheny Co., PA alone, other cities like Dallas-Ft. Worth and Denver could easily have similar volumes	None

Table 3. Estimates of stranded gas volumes by category and indication of current and past DOE research programs focused on individual categories.

CURRENT DOE PROGRAMS FOCUSED ON SPECIFIC STRANDED GAS CATEGORIES

In the following sections we discuss individually each of five stranded gas categories where DOE currently has ongoing research programs or is considering additional research: flared associated gas, North Slope and offshore methane hydrates, high cost to develop natural gas in deepwater offshore, high cost to develop in challenging unconventional reservoirs, and natural gas resources that are a long distance from markets (North Slope).

Flared Associated Gas

DOE has launched an R&D effort focused on the development of technologies that can help to reduce the volumes of natural gas flared, by providing cost effective methods for capturing and monetizing this gas. There are already several existing commercial and semi-commercial methods for doing this, but NETL is focused on developing novel approaches that involve conversion of relatively small flow rates of gas into usable chemical products (e.g. methanol). This section summarizes current options and describes DOE R&D pathways.

Currently Commercial (or Pre-Commercial) Technologies to Monetize Gas that Would Be Flared

Commercial or pre-commercial technologies exist for capturing gas that would otherwise be flared and converting it into usable or marketable products. These fall under the seven main categories listed below. A few examples of available technologies are included below as well.

1. **Compressing natural gas and trucking it short distances for use as a fuel for oil field activities –** Gas can be compressed at the well pad and trucked to a gas processing plant or to a location where it can be used as a fuel. This approach may be feasible at wells relatively close to a processing plant or other point where gas can be put into the pipeline system (20 to 25 miles or less). The Environmental Protection Agency (EPA) looked at the feasibility of trucking compressed natural gas (CNG) in Western North Dakota and determined that at least 89% of flared gas in one area could be economically captured this way.[27]
    a. GE and Ferus NGF have tested a system for Statoil in the Bakken Shale that they call the "Last Mile Fueling Solution" because it takes the gas the final distance, or the last mile, from the point of supply at the wellhead to the point of use without the need for pipes on the ground. It combines GE's CNG in a Box technology with Ferus's oil field logistics to deliver CNG for powering rigs, truck fleets, electric generators, and other equipment.[28]
    b. Certarus offers a portable CNG compression and transport solution. This technology is designed primarily as a CNG supply solution, using portable CNG tanks to deliver gas to end users when pipeline transport is not possible. A portable gas compression unit could be utilized to compress gas that would otherwise be flared and store it in a portable container for transport and use elsewhere in the operating area. Footprint is 45 ft x 20 ft.[29]
2. **Extracting Natural Gas Liquids for the flare gas stream before flaring the remaining methane (a partial solution) –** Natural gas liquids (NGLs) can be removed from associated gas using mobile equipment on well pads and trucked away for sale. Such systems work best with rich associated gas streams. The residue dry gas remaining after NGL recovery can be captured with CNG trucking or used for power generation. Commercial systems that can capture C_5 and heavier hydrocarbons are simple and inexpensive, but only reduce flaring a limited amount. Technologies that also capture C_3 and C_4 capture a larger portion of the input gas and result in less flaring but require a larger initial investment. Higher rates of flare reduction can be achieved by coupling NGL recovery with other technologies.
    a. Pioneer Energy's Flarecatcher™ mobile associated gas processing plants in sizes from 400 to 5,000+ Mcf/d that extracts NGLs from raw associated gas and delivers dry gas for use in power generation or conversion to CNG or LNG. Pioneer Energy's Vaporcatcher™ oil tank battery vapor capture systems scaled to 400 Mcf/d process storage tank vapors to separate produced NGLs into commercial propane, liquefied petroleum gas (LPG), and natural gas condensates.[30]
    b. GTUIT's modular system uses mechanical refrigeration and compression to achieve NGL recovery.[31]

27. Clean Air Task Force, "Putting Out the Fire: Proven Technologies to Improve Utilization of Associated Gas from Tight Oil Formations," November 17, 2015
28. Bakken, "Taming North Dakota's Gas Flares," September 10,
29. Certarus website, https://certarus.com/portable_hubs.php
30. Pioneer Energy, Products, Mobile Flare Gas Capture Solutions & Modular Gas Processing Plants
31. GTUIT, Gas Capture System Dramatically Cuts Emissions

3. **Converting the gas to electric power using small-scale generators –** A variety of technologies are available for local power generation, including reciprocating engines and gas turbines. Local load systems work best when using lean associated gas (e.g., the residual gas after NGL recovery).
   a. Capstone Turbines offers portable gas-fueled micro-turbine generators for gas-to-power solution. The smallest units are 30kW (operates on 10 Mcf/d of 1MMBtu/Mcf gas at ~60 psi) and 65kW (operates on 20 Mcf/d). The 30kW unit's dimensions are 30 x 60 x 71 inches. The largest Capstone micro-turbine is 1,000 kW (operates on 264 Mcf/d).[32]
   b. Alphabet Energy's thermoelectric combustor that converts heat from flared gas into electric power.[33]
   c. CompAp has developed a bi-fuel system for combining natural gas and diesel to generate power using flare gas.[34]
   d. Gulf Coast Green Energy and ElectraTherm partnered with the HESS Corp. to test the ElectraTherm Power+ Generator™, a distributed waste-heat-to-power technology, at a North Dakota oil well to reduce oil and gas flaring. The project captures the natural gas that would otherwise be flared to generate emission-free electricity.[35]
4. **Small-scale, gas-to-methanol or gas-to-liquids conversion plants –** Systems have been developed to convert natural gas to chemicals or fuels on site. These systems have not been applied to many U.S. flaring situations to date.
   a. GasTechno® systems for producing methanol or gas-to-liquids products (e.g., high-grade diesel fuel).[36]
   b. Primus Green Energy's modular systems for conversion of flare gas into methanol or fuels.[37]
   c. CompactGTL's small-scale, modular gas-to-liquids technology.[38]
   d. Calvert Energy's small-scale gas-to-liquids solution can convert natural gas into high cetane, zero sulfur diesel. The target market is the subset of large flares where associated gas is being flared while waiting on pipeline infrastructure. The Calvert technology converts 1 million standard cubic feet per day (MMscf/d) of natural gas into 100 barrels per day (bpd) of syn-diesel. The footprint for a 100 bpd plant is about 4 meters long x 3 meters wide x 5 meters high.[39]
5. **Converting captured gas to LNG and trucking it short distances for use as a fuel for oil field activities –** Gas can also be liquefied and trucked to a location where it can be used as a fuel. This may be appropriate when the gas does not require a large amount of conditioning.
   a. Galileo Technologies, in partnership with SPATCO Energy Solutions, supplied a solution for Terra Energy in the Bakken Shale play to integrate flare gas capture and LNG production right at the wellhead.[40]
6. **Utilizing gas that would otherwise be flared for beneficial use at the well pad**
   a. Heartland Water Technology offers a system that utilizes gas at the wellsite to evaporate produced water, producing a concentrated brine or solid salt waste stream for disposal, the volume of which is significantly less volume than the produced fluid volume.[41]
7. **Improving the efficiency of existing flare reduction technologies to further reduce flare volumes**
   a. EcoVapor Recovery Systems LLC offers a technology for capturing condensate tank vapors that are not captured by existing vapor recovery units and that include oxygen and are using a proprietary catalytic system to recover the gas for sale.[42]

While many of these technology solutions have been tested and found to work, they have not been widely applied. The problem is not a failure of technology but of economics. The capital cost of installation (or the rental cost), plus the costs of operation, do not appear to justify widespread application of these solutions. Contributing factors may also include the following:

- Ease and familiarity of operators with flaring relative to alternatives
- Fact that producers do not want to be in the business of collecting, transporting and selling chemicals, fuels, CNG, or LNG
- Gas composition issues that make some technologies less profitable or harder to apply
- Legal or royalty issues related to the conversion and sale of gas into other products
- Lack of familiarity with regulations that might apply to these methods
- Lack of familiarity with the technology and the need to avoid hiring or training additional staff.

32. Capstone website, https://www.capstoneturbine.com/
33. Alphabet Energy, E1 Thermoelectric Generator
34. ComAp, Power Generation from Flared Gas
35. GulfCoast Green Energy, Flare Gas to Power
36. GasTechno, GasTechno Flare Gas Recovery
37. Primus Green Energy, Commercial Applications, Flared Associated Gas
38. CompactGTL, Small scale, modular Gas-to-liquids (GTL) technology
39. Calvert website, http://calvertenergy.eu/index.html
40. Galileo Technologies, Distributed LNG Production: Galileo's flare reduction solution for Bakken
41. Heartland Water Technology website, https://www.heartlandtech.com/
42. EcoVapor website, https://www.ecovaporrs.com/

R&D Pathways for Flared Associated Gas Conversion

In response to the Administration's FY19 Budget Request and House/Senate FY19 appropriations, DOE ran a funding opportunity announcement (FOA) in 2019 to solicit research proposals focused on mitigating emissions from midstream natural gas infrastructure. One of the areas of interest focused on accelerating the development of technologies capable of converting gas that would otherwise be flared into transportable, value-added products. It is envisioned that successful technologies developed in this research and development effort will be integrated into small-scale modular systems that, in the future, can be transported from one flare site to the next for use during periods when natural gas gathering and sales systems are not yet functional.

The FOA targeted two areas where basic research needs have been identified: (1) multifunctional catalysts and (2) modular conversion equipment designs.

1. **Multi-Functional Catalysts:** One area where research is needed is the early-stage development and evaluation of multifunctional catalysts for the direct conversion of methane to liquid petrochemicals (e.g., methanol, ethanol, ethylene glycol, acetic acid, C_3 and C_4 analogs, C_4+ olefins, and Benzene, Toluene, Xylene) that can be easily transported and are suitable for subsequent conversion into commercial products. Research in this area will focus on methods for process intensification at the nano- to micro-scale and on facilitating high catalyst activity, product yield, selectivity, and mass/heat transfer rates.
2. **Modular Equipment Design Concepts for Conversion to High-Value Carbon Products:** Another area of interest is the development of novel equipment and process design concepts for achieving high-selectivity pyrolysis, which is integral to the manufacture of high-value carbon products (e.g., carbon nano- or micro-fibers, carbon nano-tubes, and graphene sheets) from methane or the mixtures of methane, ethane, propane, and butanes representative of natural gas streams being flared. Research in this area will focus on the application of process intensification at modular equipment scales suitable for deployment and transport between remote locations where gas is being flared.

Of particular interest are approaches that:

- Result in modular, compact, integrated, and transportable technologies
- Have a large turndown ratio and can operate continuously under varying feed rates and compositions
- Have the potential to convert a higher fraction of an associated gas stream, lessening the requirements for NGL recovery
- Can make use of oxygen in the air directly without the need for a separate air fractionation unit, or can make direct use of a weak oxidant, such as CO_2, which may be more readily available—in the case of direct conversion technologies that require oxygen (e.g., partial oxidation of methane to methanol, oxidative coupling of methane)
- Can make use of excess hydrogen in methane to offset energy requirements of the conversion process
- Initially target high-value, small-volume product markets but can pivot toward commodity markets as the technology develops and matures
- Result in technology platforms capable of producing a variety of products using the same or similar materials, equipment, or processes.

As a result of the 2019 FOA, there are nine new, ongoing projects in the program, summarized in the following table.

PROJECT	PERFORMER	COMPLETION DATE	FOCUS
Modular System for Direct Conversion of Methane into Methanol via Photocatalysis	Stanford University, Susteon, Casale SA	2021	Develop process for photocatalytic activation of methane at a gas-water interface such that methanol can be formed at room temperature. Use photons to excite hydroxyl radicals in aqueous media, which then excite methane to form methanol on a catalyst surface. Identify the best photocatalyst to achieve the highest selectivity and methane conversion efficiency. Design and build a new photoreactor system that is modular and scalable for direct methane to methanol conversion.
Electrocatalytically Upgrading Methane to Benzene in a Highly Compacted Microchannel Protonic Ceramic Membrane Reactor	Clemson, Oak Ridge National Lab	2022	Develop process intensified technology for methane dehydroaromatization (MDA) in highly compacted microchannel protonic ceramic membrane reactors (HCM-PCMRs) by integrating multiple functions of single-atom catalysis, electrocatalysis, membrane catalysis, membrane separation, and advanced manufacturing.

PROJECT	PERFORMER	COMPLETION DATE	FOCUS
Core-Shell Oxidative Aromatization Catalysts for Single Step Liquefaction of Distributed Shale Gas	NC State U., Lehigh U., WVU, Susteon, Kenan Institute, Shell	2022	Design and demonstrate a multifunctional, core-shell catalyst for conversion of methane, ethane and propane to liquid aromatics. This catalyst combines breakthroughs in the understanding of alkane dehydroaromatization (DHA) and redox-based selective hydrogen combustion catalysts to overcome limitations of conventional DHA.
Isolated Single Metal Atoms Supported on Silica for One-Step Non-Oxidative Methane Upgrading to Hydrogen and Value-Added Hydrocarbons	University of Maryland, University of Delaware	2022	Enable efficient, non-oxidative methane conversion (NMC) via catalyst innovation to convert methane in one step to olefins and aromatics and hydrogen co-product. The catalysts are made of supported single metal atoms and operated at medium-high temperatures. The single metal atoms achieve methane activation by heterogeneous surface dehydrogenation to generate a hydrocarbon pool and limit coke formation.
Process Intensification by One-Step, Plasma-Assisted Catalytic Synthesis of Liquid Chemicals from Light Hydrocarbons	Notre Dame	2022	Design, develop, and test a process for direct light hydrocarbons-to-liquid conversion via a modular and flexible plasma-assisted catalytic reactor. Leads to the development of new catalytic materials designed specifically for operation under plasma stimulation. Control of plasma properties, coupled with appropriate catalyst selection, will generate non-thermal intermediates and open surface kinetic pathways at ambient temperature and pressure to facilitate high production rates of liquids from natural gas feeds at the wellhead.
Methane Partial Oxidation over Multifunctional 2-D Materials	U. South Carolina, Pajarito Powder, U. Colorado at Boulder	2022	This project creates a process for partial oxidation of methane to methanol using a set of multifunctional, graphene-based materials as selective catalysts using scalable techniques. This project will computationally design the active sites for the catalyst that will then be synthesized based on atomically dispersed metal-nitro-carbide active sites.
Gas to Carbon Fiber Crystals	PARC, Modular Chemical, eo, Creative Engineers, Inc., UC Riverside, ETCH, Inc.	2022	Develop a modular, field-transportable, methane pyrolysis unit that converts flared natural gas into hydrogen that is used to provide process heat and solid carbon powder. Also, develop a molten metal carbon fiber production process that converts the carbon powder into high-value carbon fiber by using a carbon-saturated molten metal reservoir.
Modular Processing of Flare Gas for Carbon Nanoproducts	Colorado U.	2022	Develop a natural gas conversion to carbon nanoproducts using a one-step chemical vapor deposition (CVD) process to grow carbon nanoparticles and nanofibers (CNF) during natural gas decarbonization.
Microwave Catalysis for Process Intensified Modular Production of Carbon Nanomaterials from Natural Gas	WVU	2022	Develop a new, low-cost modular process that directly converts flare or stranded gas to carbon nanomaterials and hydrogen using a microwave-enhanced, multifunctional catalytic system in a single step without emitting carbon dioxide.

DOE's objective is to accelerate the development of modular conversion technologies that, when coupled with the currently commercial alternatives outlines in the previous section, will provide a complete portfolio of options for companies seeking to monetize flared gas volumes of practically any magnitude and at any location.

Continued investments in R&D focused on these modular conversion technologies is the best pathway for expanding the economic options available to producers seeking to monetize stranded gas.

North Slope and Offshore Methane Hydrates

The primary mission of the Methane Hydrates R&D Program is to collaborate with industry, academia, international research organizations, and other U.S. government agencies to advance scientific understanding of gas hydrates as they occur in nature and their potential role as a resource. In pursuit of this primary mission, the program is proceeding along three parallel paths. The first path is to confirm the scale and nature of the potentially recoverable resource through drilling and coring programs. The second is to develop the technologies needed to safely and efficiently find, characterize, and recover methane from hydrates through field testing, numerical simulation, and laboratory experimentation. The third is to better understand gas hydrate's role in the natural environment, including its linkage to global climate change.

There are seven ongoing projects in the program, summarized in the following table.

PROJECT	PERFORMER	COMPLETION DATE	FOCUS
Alaska Natural Gas Hydrate Production Testing: Test Site Selection, Characterization and Testing Operation	U.S. Geological Survey (USGS)	06/01/2020	Geologic and engineering assessment of the Eileen gas-hydrate accumulation and support of DOE and its industry partners in evaluating, planning, and preparing for drilling and testing gas hydrate research wells in northern Alaska.
Deepwater Methane Hydrate Characterization and Scientific Assessment	University of Texas at Austin	09/30/2024	Investigation of the nature of methane hydrate-bearing sediments for methane hydrate resource appraisal, through drilling, coring, logging, testing, and analytical activities to assess the characteristics of marine methane hydrate deposits in the Gulf of Mexico and/or other areas of the U.S. Outer Continental Shelf.
Natural Gas Hydrates in Permafrost and Marine Settings: Resources, Properties and Environmental Issues	U.S. Geological Survey (USGS)	05/14/2020	Evaluation of the production potential of the known gas hydrate accumulations on the North Slope of Alaska and in the Gulf of Mexico.
Dynamic Behavior of Natural Seep Vents: Analysis of Field and Laboratory Observations and Modeling	Texas A&M Engineering Experiment Station	06/30/2020	Development of a mechanistic model for dissolution of hydrate-coated methane bubbles from natural seeps that fully explains fundamental laboratory and field observations of methane bubbles within the gas hydrate stability zone of the oceans.
Behavior of Sediments Containing Methane Hydrate, Water, and Gas Subjected to Gradients and Changing Conditions	Lawrence Berkeley National Laboratory (LBNL)	09/30/2020	Analysis of gas hydrate behavior by measuring physical, chemical, mechanical, and hydrologic property changes in sediments containing methane hydrate, water, and natural gas that have been subjected to varying stimuli and conditions.
Numerical Studies for the Characterization of Recoverable Resources from Methane Hydrate Deposits	Lawrence Berkeley National Laboratory (LBNL)	09/30/2020	Utilization of previously-developed numerical simulators to perform studies on the characterization and analysis of recoverable resources from gas hydrate deposits, evaluate production strategies for both permafrost and marine environments, and analyze geo-mechanical behavior of hydrate-bearing sediments.
Coupled Hydrologic, Thermodynamic, and Geo-mechanical Processes of Natural Gas Hydrate Production	Pacific Northwest National Laboratory (PNNL)	09/30/2020	Investigation of numerically and experimentally coupled hydrologic, thermodynamic, and geo-mechanical processes which dominate the production of natural gas hydrates from geologic accumulations.

For additional information on this research program, refer to the Hydrate Program Roadmap.

High Cost to Develop Natural Gas Resources in the Deepwater Offshore

Five ongoing projects target the development of new technologies that can reduce the cost of operating in deepwater offshore environments. The challenges these projects are focused on include: methane hydrate deposition in subsea pipelines, cement integrity in deepwater wells, less expensive aluminum options for deepwater components, improved underwater communication, and lower cost multiphase meters. All these technologies are designed to lower the risks and costs of offshore development and thus lead to the production of natural gas resources that are currently considered to be economically stranded.

The five ongoing projects in the program are summarized in the following table.

PROJECT	PERFORMER	COMPLETION DATE	FOCUS
In-Situ Applied Coatings for Mitigating Gas Hydrate Deposition in Deepwater Operations	Colorado School of Mines	3/31/2021	Design, test, and validate robust pipeline coatings for commercial utilization that mitigate hydrate deposition in subsea pipelines.
Hexagonal Boron Nitrate Reinforced Multifunctional Well Cement for Extreme Conditions	C-Crete Technologies, LLC	3/31/2021	Development of a boron-nitride/cement composite with multifunctional, high performance characteristics to prevent offshore spill and leakage at extreme high temperature, high pressure, and corrosive conditions.
Corrosion Resistant Aluminum Components for Improved Cost and Performance of Ultra-Deepwater Offshore Oil Production	Pacific Northwest National Laboratory (PNNL)	9/30/2021	Development of critical technologies that will support the industry's development of aluminum risers for ultra-deepwater drilling.
Project Ultra: Underwater Laser Telecommunications and Remote Access	Oceanit Laboratories, Inc.	12/31/2022	Development of technologies that can address bandwidth and parallelism deficiencies in currently available undersea wireless optical communications technologies using LASER methods.
Advanced Multi-Dimensional Capacitance Sensors Based Multiphase Mass Flow Meter to Measure and Monitor Offshore Enhanced Oil Recovery Systems	Tech4Imaging	12/31/2022	Development of a cost-effective solution for deploying multiphase flow meters in remote subsea oil fields, based on advanced multi-dimensional extensions of Electrical Capacitance Volume Tomography (ECVT) sensors.

For additional information on this research program, refer to the Offshore Program Roadmap.

High Cost to Develop Natural Gas Resources in Challenging Unconventional Reservoirs

Fourteen projects are currently underway that address challenges in reducing the cost and increasing the recovery of unconventional resources, both oil and natural gas. These efforts include field laboratories as well as fundamental research undertaken in physical laboratories. These advanced technologies are applicable to opening up/making available stranded unconventional natural gas resources. Twelve of the projects are focused on improving economics and recovery in plays where natural gas (associated or non-associated) is effectively stranded due to the cost of development (the first twelve summarized in the following table).

PROJECT	PERFORMER	COMPLETION DATE	FOCUS
Development and Field Testing Novel Natural Gas Surface Process Equipment for Replacement of Water as Primary Hydraulic Fracturing Fluid	Southwest Research Institute (SwRI)	12/31/2020	Determination as to whether natural gas available from surrounding well sites or from nearby gas processing plants can be used as the primary fluid in hydraulic fracturing processes.
Fully Distributed Acoustic and Magnetic Field Monitoring Via a Single Fiber Line for Optimized Production of Unconventional Resource Plays	Virginia Polytechnic Institute and State University	9/30/2022	Development of a fiber-optic sensing system capable of real-time simultaneous distributed measurement of multiple subsurface, drilling, and production parameters.
A Novel 'Smart Microchip Proppants' Technology for Precision Diagnostics of Hydraulic Fracture Networks	University of Kansas Center for Research	9/30/2022	Development of a closed-loop fracture diagnostic and modeling system based on novel Smart MicroChip Sensor technology to better characterize propped fracture geometry.
Field Pilot Test of Foam-Assisted Hydrocarbon Gas Injection in Bakken Formations	University of Wyoming	9/30/2023	Implementation of a novel EOR technology that seeks to optimize the performance of foam-assisted hydrocarbon gas injection in Middle Bakken/Three Forks by improving the current scientific understanding of the fundamental mechanisms involved in this process and demonstrating its potential through a field pilot test.
Resource Recovery and Environmental Protection in Wyoming's Greater Green River Basin Using Selective Nanostructured Membranes	University of Wyoming	12/31/2020	Development of a working prototype of a two-part affinity-based membrane separation process for recovering hydrocarbons and separating organics, from produced water.
Hydraulic Fracturing Test Sites (HFTS)	Gas Technology Institute (GTI)	3/8/2021	Carry out a field-based hydraulic fracturing research program for horizontal shale wells in the Midland Basin of West Texas with the objectives of reducing and minimizing potential environmental impacts, demonstrating safe and reliable operations, and improving the efficiency of hydraulic fracturing.
Marcellus Shale Energy and Environment Laboratory (MSEEL)	West Virginia University Research Corporation	3/31/2021	Creation and maintenance of a long-term field site to develop and validate new knowledge and technology to improve recovery efficiency and minimize environmental implications of unconventional resource development.

PROJECT	PERFORMER	COMPLETION DATE	FOCUS
Hydraulic Fracture Test Site II (HFTS2) - Delaware Basin	Gas Technology Institute (GTI)	3/8/2021	Implementation of multiple experiments to evaluate well completion design optimization and environmental impact quantification using an experiment well in the Delaware Basin portion of the Permian Basin of western Texas, targeting the Wolfcamp formation.
The Eagle Ford Shale Laboratory: A Field Study of the Stimulated Reservoir Volume, Detailed Fracture Characteristics, and EOR Potential	Texas A&M Engineering Experiment Station	6/30/2022	Development of ways to improve the effectiveness of shale oil production (and associated gas production) by providing scientific knowledge regarding new monitoring technology for both initial stimulation/production as well as enhanced recovery via re-fracturing and EOR methods.
Tuscaloosa Marine Shale Laboratory	University of Louisiana at Lafayette	6/30/2021	Investigation of gaps in our understanding of the clay-rich Tuscaloosa Marine Shale in order to make development of this emerging shale play more cost-efficient and environmentally sound.
Field Evaluation of the Caney Shale as an Emerging Unconventional Play, Southern Oklahoma	Oklahoma State University	9/30/2023	Establishment of a Caney Shale Field Laboratory in southwestern Oklahoma to conduct a comprehensive field characterization and to validate cost effective technologies that will lead to a comprehensive development plan for the Caney shale, characterized by high clay content and ductile behavior.
Unlocking the Tight Oil Reservoirs of the Powder River Basin, Wyoming	University of Wyoming	9/30/2023	Implementation of a field laboratory in the Powder River Basin to characterize and overcome the technical challenges of developing two large, emerging unconventional/shale oil formations – the Mowry Shale and the Belle Fourche Shale – with the challenging tight sand Frontier Formation serving as an additional objective.
First Ever Field Pilot on Alaska's North Slope to Validate the Use of Polymer Floods for Heavy Oil EOR	University of Alaska - Fairbanks	9/30/2022	Acquisition of scientific knowledge and polymer flood performance data, via the first ever advanced technology-based field pilot to optimize polymer flood design in the Milne Point Unit of the Schrader Bluff heavy oil pool on Alaska North Slope.
Using Natural Gas Liquids to Recover Unconventional Oil and Gas Resources	Battelle Memorial Institute	9/30/2022	Development and testing of an NGL-based well treatment method designed to simultaneously improve the effectiveness of well completions, optimize oil and gas recovery over the life of the well and reduce the impact of fresh water consumption and produced water disposal.

For additional information on this research program, refer to the Unconventional Oil & Gas Program Roadmap.

Natural Gas Resources that are Far from Market (North Slope)

As discussed earlier in this document, there is a large volume of natural gas on Alaska's North Slope stranded by the lack of a means to transport the product to market. Efforts to link the North Slope to lower 48 gas markets by pipeline have failed over the past decades due to poor economics. However, at least two efforts are underway.

Currently, the State of Alaska is working to justify the feasibility of exporting North Slope gas via a pipeline to a tidewater LNG facility and port in South Central Alaska. The Alaska Gasline Development Corporation (state funded), having recently signed agreements with BP and Exxon Mobil, is working on advancing a $44 billion, 3.5 Bcf/d project forward to construct a natural gas pipeline from the North Slope south across the state to an LNG production facility at Nikiski. It includes new North Slope gas handing facilities, an 800-mile pipeline, and an LNG production facility with 2 berths. The project estimates LNG sales could begin around 2025. The Federal Energy Regulatory Commission (FERC) process is well underway with a draft EIS issued.[43]

Similarly, a recent agreement between Alaska based Qilak LNG Inc., a Lloyds Energy company, and Exxon Mobil, proposes exporting gas directly from the North Slope utilizing a nearshore natural gas liquefied facility at Pt. Thompson and ice breaking LNG tankers. Phase I volume would be at least 560 MMcf/d. If the project moves forward the facility could begin exporting LNG in 2025 or 2026. A $5 billion pilot project includes a new onshore gas treatment facility, a short subsea pipeline and a gravity-based LNG liquefaction terminal 6 to 10 miles offshore where water depth would allow LNG carrier access without seafloor dredging.[44] The project will utilize ships like those used in Arctic Russia's Yamal LNG plant but covering a much shorter distance of ice bearing water, 600 nautical miles vs. 2,600 for the Russian project.[45]

The costs of a complete system to transport North Slope natural gas south and export LNG from a warm water port are estimated to be roughly one third gas processing (including CO_2 capture and injection), one third pipeline and one third LNG facilities. Any research that would potentially develop technologies that could reduce any of these three costs or improve the efficiency of any of the related processes would improve economics and support the export of stranded North Slope gas. Because the first two items involve largely "dumb iron" and horsepower, the most likely component where research could provide incremental value is the liquefaction component.

Discussions with industry has produced some research categories where new technology could have potential for improving LNG project economics. These include research on technologies that can:

- Reduce liquefaction costs, currently estimated to be $4/Mcf
- Reduce the cost and/or carbon footprint of power generation for LNG facility
- Improve ice breaking tanker technology
- Improve the LNG liquefaction process to reduce NO_X/SO_X, flu gas etc. emissions
- Reduce the cost of gas processing and/or CO_2 injection

Of these categories only the last aligns with historic DOE research focus areas. **DOE should investigate ways to leverage existing CO_2 capture and storage R&D in ways that make the potential research products specifically applicable to the circumstances in place in Alaska at the point where gas treatment will take place.**

43. https://www.reuters.com/article/usa-alaska-gasline-lng/update-1-us-issues-mixed-report-on-alaska-gaslines-lng-export-plant-idUSL2N23Z1HF
44. https://www.maritime-executive.com/article/lloyds-energy-proposes-lng-plant-off-alaska-s-north-slope
45. https://www.petroleumnews.com/pnads/247606536.shtml

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