

THE SHALE REVOLUTION: FRAC FLEET EMISSIONS



TABLE OF CONTENTS

Preface	3
Introduction.....	4
Results Summary	6
Thermal Efficiency & Engineering Concepts.....	8
Analysis Methodology.....	10
Emissions.....	13
Simple Financial Analysis.....	18
Operational Considerations	21
Redundancies	21
Fuel Considerations.....	23
Manpower Considerations	26
Operational Footprint.....	26
Summary/Conclusions	27
Author Bios	27
Appendix.....	28
Additional Natural Gas Discussion.....	28
Definitions	28
Further Emissions Data.....	29

PREFACE

The shale revolution has transformed world energy markets. Roughly 130,000 folks every day are rising out of extreme poverty as a direct result of more affordable energy (living on less than \$2 per day). The recent transformation of U.S. electric power production from coal dominated to natural gas dominated has been the largest factor in the U.S. leading all other nations in reducing greenhouse gas (GHG) emissions. U.S. per capita greenhouse gas emissions are at a sixty-year low! U.S. LNG exports, together with Australia and Qatar, are helping drive a similar shift to natural gas in the global electric power sector that is still coal dominant. Natural gas has also enabled the rise of renewable electric power generation.

While the benefits of the shale revolution are manifest, nothing comes for free. Nothing is without impacts. Liberty and our whole industry work tirelessly to reduce the impacts of oil and gas production locally and globally. Liberty has developed extremely quiet fracturing fleets to mitigate the impacts when shale development is in towns or cities. We have switched to containerized sand across all our fleets to remove dust and noise from pneumatic blowers. Sophisticated routing technologies reduce truck traffic. Our drive to increase efficiency of operations has more than halved the time that it takes to complete a well pad. These are just a few of the mitigations for local communities.

This paper analyzes a parallel shift towards natural gas' growing role in powering hydraulic fracturing fleets. In the electric power sector, the rise of natural gas has been displacing coal. In the frac fleet world, natural gas is displacing diesel either through dual fuel engine technology or via natural gas turbine powered electric frac fleets. For the 2 last years, Liberty has also been conducting research into gas reciprocating engine power generation solutions. Our research shows the shift from either dual fuel or turbine powered frac fleets to 100% gas fueled reciprocating engines provides a significant reduction in CO₂e.

INTRODUCTION

Air emissions from frac fleets is the central subject of this paper. We focus on the most significant local pollutants, Oxides of Nitrogen (NOx), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC's). Fortunately, Sulfur Oxides (SOx) are no longer produced in meaningful quantities in diesel or dual fuel engines. Globally, we will focus on greenhouse gas (GHG) emissions. This paper explores the costs, emissions profiles, and provides a basis for understanding the differences between the five next generation technologies for frac fleets: Tier IV diesel engines, Tier IV dual fuel (Dynamic Gas Blending (DGB)) engines, gas turbine powered electric frac fleets, direct-drive gas turbines, and gas reciprocating engine powered electric fleets. We only briefly cover direct-drive gas turbines as their small scale means even lower thermal efficiency and likely higher methane leakage. Gas reciprocating engines are basically diesel engines with a spark plug that utilize natural gas as a fuel source. While new to the non-road mobile world, these engines have been used for decades in electrical generation and gas compression.

Two somewhat difficult concepts which are vital to understand in the discussion of competing engines are Thermal Efficiency and Thermal Derate. To use a car analogy, the thermal efficiency is basically how many miles per gallon each engine would provide. The thermal efficiency derate is the mileage reduction these engines would suffer in the real world, for instance if the car were driving into the wind or uphill. Like cars, these variances typically only result in a decrease in efficiency and the effects can be compounded, going up a hill and into the wind for example. **Table 1** illustrates this point.

Table 1 - Thermal Efficiency and Derate Example

	Factory 100% Load	Thermal Efficiency Deficit	Additional Fuel Burned	Permian Case	Thermal Efficiency Deficit	Additional Fuel Burned
Gas Reciprocating	43.0%	0.0%	0.0%	42.7%	0.0%	0.0%
Tier IV Dual Fuel	35.0%	8.0%	18.6%	35.0%	7.7%	18.6%
17MW Turbine	34.5%	8.5%	19.8%	28.5%	14.2%	33.3%
6MW Turbine	30.5%	12.5%	29.1%	29.0%	13.7%	32.1%
3.7MW Direct Drive Turbine	30.0%	13.0%	30.2%	27.0%	15.7%	36.8%

At first glance, it seems that the 8.5 percentage point difference in thermal efficiency between the gas reciprocating engine and the 17 MW turbine is relatively modest. However, this difference results in a 19.8% increase in fuel consumption, which translates into both higher fuel costs and higher emissions. This is where the concept of Thermal Derate becomes important. For the gas reciprocating and dual fuel engines in the Permian case (details below) the turbochargers compensate for the higher temperature and lower atmospheric pressure. Thus, the thermal efficiency is unchanged. The turbines, however, suffer both a part load and a temperature thermal derate (uphill and into the wind). Under these conditions the 17MW turbine uses 33% more fuel. Because the 6MW turbines are loaded at 85% vs. 58% for the 17MW turbines, the smaller turbines suffer less thermal derate and are more thermally efficient than the larger turbines in this particular Permian case.

Another way of framing this concept is through heat rate. Heat rate defines the amount of heat energy needed to power the engine. Typically, CNG will have a lower heating value of around 939.2 BTU/scf to 1,000 BTU/scf. Therefore, the heating value of an engine drives the fuel consumption, which in turn drives the GHG emissions. Each manufacturer publicly provides ISO heat rates on their equipment spec sheets. These can be seen in **Table 2** below under "ISO Heat Rate" for different engine and turbine models. From there, engine losses were calculated based on engine loading and ambient temperature (i.e. deviations from ISO) and applied to the heat rate. For the Tier IV Dual Fuel engines, the published ISO heat rate is greater than the actual heat rate seen after engine loading and ambient temperature conditions are applied. This is because of the

wide range of engine loads, engine speeds, and gears that the engine can utilize compared to the turbines and gas reciprocating engine. Engine losses were then calculated based on transmissions, power end, fluid end, etc. losses and, again, applied to the heat rate. At each step, CO₂ was calculated based on the conversion factor of 123.75 lbs CO₂/mmbtu for CNG. In **Table 2** this can be seen under the columns “CO₂ Emissions (g/kW-hr).” Methane slippage was also considered using a CO₂ conversion factor of 122.89 lbs CO₂/mmbtu and a methane conversion factor of 0.344 lbs CH₄/mmbtu, which is assuming a methane slippage of 0.7% by mass, the worst possible case out of all the engines while at load. These results can be seen under the columns titles “CO₂e Emissions – Assuming Methane Slippage (g/kW-hr).” In every case, the lowest emissions from the gas reciprocating engine followed by the tier IV dual fuel engine, even with the assumption that the Vericor ASE50B turbine does not experience methane slippage.

Table 2 - Heat Rate Example

	ISO Heat Rate (BTU/kW-hr)	CO ₂ Emissions (g/kW-hr)	CO ₂ e Emissions - Assuming Methane Slippage (g/kW-hr)	Engine Losses	New Heat Rate (BTU/kW-hr)	CO ₂ Emissions (g/kW-hr)	CO ₂ e Emissions - Assuming Methane Slippage (g/kW-hr)	Losses After Engine	New Heat Rate (BTU/kW-hr)	CO ₂ Emissions (g/kW-hr)	CO ₂ e Emissions - Assuming Methane Slippage (g/kW-hr)
MTU GG20V4000D2 Gas Reciprocating Engine	7,825	439.22	466.71	-2%	7,971	447.42	475.42	-19%	9,485	532.40	565.72
CAT 3512E Tier IV Dual Fuel Engine	9,759	547.78	582.06	+5%	9,250	519.21	551.70	-9%	10,083	565.97	601.39
GE LM2500+G4 Turbine	9,070	509.11	540.97	-21%	11,000	617.44	656.08	-19%	13,090	734.75	780.74
Vericor ASE50B Turbine	11,363	637.81	637.81	-23%	14,000	785.83	785.83	-11%	15,540	872.27	872.27

Virtually all electric frac fleets in the field today are driven by power-dense gas turbine engines that can produce 30+ megawatts (MW) to supply a roughly 15-20 MW demand on a frac pad. In most basins considered for this paper the electrical grid is not robust enough to supply this amount of power. In the areas that have a robust grid, the challenge of coordinating a very large transient load with the utility and the high cost of the infrastructure required makes this solution, potentially, a niche application. It has also been suggested that excess energy generated by these turbines could be fed onto the grid but the same limitations that make delivery of these loads to the pad problematic also make intermittent distribution from most basins problematic. Therefore, in this paper we are not considering grid power and we assume that electric fleets will be powered primarily using electricity generated on location. In some scenarios, it may be possible to draw a portion of the power, i.e. 5MW, from the grid. The remainder of the power would be generated on location, effectively a hybrid approach. While this specific case is not considered in the paper, one can appreciate that it would only negatively impact the emissions results from large turbines. Drawing some fraction of the power from the grid would further reduce the load the turbine would operate at, further reducing thermal efficiency as well. The modular approach of multiple gas reciprocating engines could more easily be adjusted to accommodate a hybrid approach with little change in load *per engine*.

From a pressure pumping standpoint, the technologies are all viable, so the “best” solution depends on other factors. For the most part the decision boils down to the three E’s: Emissions, Economics, and Efficiency. Each of these factors will differ based on the basin of operation and frac fleet technology employed. Because of this, case studies were performed for many of the large shale plays across the US, with an emphasis on the Permian (largest basin) and Williston Basins (most extreme winter weather). Typical frac designs, altitudes, ambient temperatures, pressures and flow rates were used to run models for emissions and fuel consumption to compare Tier IV diesel, Tier IV dual fuel and electric frac fleets (e-fleets), powered by gas turbines or gas reciprocating engines. On the emissions front we compared Carbon Dioxide Equivalent (CO₂e), Nitrogen Oxides (NO_x), Carbon Monoxide (CO) and Volatile Organic Compounds (VOC’s).

Twenty years ago, it was not uncommon to have 5,000 parts per million (ppm) of Sulphur in diesel fuel. Today the average Sulphur content for both on-road and non-road diesel is below 15 ppm. This greater than 99% reduction in Sulphur content of the fuel has effectively reduced Sulphur Dioxide (SO₂) emissions from diesel engines to zero. Therefore, SO₂ emissions are not included. VOC emissions are relatively low in gas turbines and conventional diesel engines and extremely low in today's Tier IV diesel engines.

The EPA utilizes a 25X multiplier for Methane vs CO₂ for its greenhouse gas impact. In other words, in this study each gram of Methane emitted will be considered the equivalent of 25 grams of CO₂. The combined Methane converted to equivalent Carbon Dioxide emissions plus the actual Carbon Dioxide emissions is what constitutes CO₂e, or greenhouse gas emissions (GHG's). This paper will compare Tier IV dual fuel fleets, and turbine or gas reciprocating engine powered electric fleets (e-fleets) to Tier IV diesel fleets based on emissions, economics, and efficiency in the considered basins. In addition, there will be discussions to address key concepts in implementing the new fleets, including fuel considerations, redundancies, and manpower.

Scientifically accurate measurements of load, fuel burn, emissions, etc. cannot be achieved in the field. Reliable results require a lab environment where the variables can be tightly controlled. Engine manufacturers create computer models that predict performance based on thousands of hours of lab testing at various load points, temperatures, and atmospheric pressures. The data for this paper was created by using multi-variate interpolation of that data to accurately predict the emissions based on our customers frac designs. The one emission that can be inferred reasonably accurately in the field is CO₂. In an engine that is properly loaded, nearly 100% of the hydrocarbons injected into the engine are oxidized allowing the CO₂ emitted to be calculated based on the amount and type of fuel consumed. An example calculation will be included in a supplementary document.

One key concept to address with both dual fuel and e-fleets is that they both introduce the ability to utilize field gas at well-sites that might otherwise be flared. This reduces the emissions of the overall system if field gas is being used. Turning flare gas to a local beneficial use has significant environmental benefits in addition to the benefits covered in this paper from substituting natural gas for diesel in powering frac fleets.

RESULTS SUMMARY

When analyzing the Tier IV diesel/dual fuel and e-fleets, it is necessary to examine the power conversion thermal efficiencies of each system because they drive emission profiles. E-fleets powered by gas turbines are sensitive to anything that changes the mass flow or the density of the air at the intake of the compressor. Factors that have a significant effect are ambient air temperature, altitude, idling and load profile of the turbine. Diesel and dual-fuel engines mitigate changes in air density with turbochargers, so their operating efficiencies are largely unaffected by any of these variables. The same is true for gas reciprocating engines, which are equipped with a high-altitude turbocharger.

The efficiency of the system will have an impact on the emissions profile of the different fleets given typical operating conditions. Overall, e-fleets powered by gas turbines have higher greenhouse gas (CO₂e) and Carbon Monoxide (CO) emissions than both gas reciprocating engines and dual fuel fleets. The gas reciprocating e-fleet produces significantly lower CO₂e emissions than either dual fuel fleets or gas turbines. Gas recips, however, exhibit an increase in CO compared to dual fuel engines. Conversely, while all three technologies have extremely low Nitrogen Oxide emissions, diesel/dual fuel fleets and gas reciprocating engines will have higher NO_x emissions than gas turbine powered e-fleets. In a Permian case study, for example, Tier IV dual fuel fleets resulted in 99.9% less CO emissions and 42.9% less CO₂e emissions compared to dry low emission (DLE) turbine powered e-fleets. Gas reciprocating engines showed a 64% reduction in CO₂e and an 89% reduction in CO compared to turbine powered electric fleets. However, in the same study, DLE turbines resulted in 77.8% less NO_x emissions compared to dual fuel fleets and 47% less NO_x compared to gas reciprocating engines.

Tier IV dual fuel engines and gas reciprocating engine powered electric fleets generally have lower capital costs than gas turbine powered electric fleets. They should also have shorter rig up/rig down times and thus higher operational efficiency. We expect gas reciprocating engines to have lower operating costs than dual-fuel fleets, but don't yet have empirical data to quantify this benefit.

Dual fuel fleets consume significantly less fuel than turbines due to higher thermal efficiency and, if gas supply is interrupted, they automatically switch to 100% diesel. Gas turbines may require an additional back up fuel supply to reduce downtime if an interruption of the primary gas supply is experienced. Gas reciprocating engines will also require back up gas in the case of an interruption. However, gas reciprocating engines will benefit from significantly lower gas consumption than both turbines and dual fuel fleets due to higher thermal efficiency. Operators supplying field gas to the service company should expect fuel savings for turbine, gas reciprocating engine, and dual fuel powered fleets when compared to a conventional diesel fleet. E-fleets, both gas turbine and gas reciprocating engine, are also expected to have reduced maintenance costs compared to both diesel and dual fuel fleets.

A summary of the findings can be found in **Table 3** below.

Table 3 - Summary Table

SUMMARY TABLE (USING TIER IV DIESEL AS BASELINE)				
Emissions				
	CO2e	CO	NOx	Total Emissions
Tier IV Dual Fuel	-6% lower	-60% lower	4% - 5% higher	791 g/hkW-hr
Turbine-Powered E-Fleet	20% to 300% higher	380x to 1800x higher	60% to 80% lower	1,017 g/hkW-hr
Gas Recip-Powered E-Fleet	-40.3% Lower	71X higher	56% lower	505 g/hkW-hr
Economics				
	Capital Cost	Fuel Cost (CNG/LNG)	Fuel Cost (Field Gas)	Maintenance Cost
Tier IV Dual Fuel	-5% higher	30% to 40% lower	55% to 60% lower	Similar
Turbine-Powered E-Fleet	-50% higher	15% to 40% lower	75% to 80% lower	10% to 20% lower
Gas Recip-Powered E-Fleet	-11% higher	55% to 62% lower	92% lower	5% to 10% lower
Efficiency				
	Rig Up Time	Equipment Redundancies	Footprint	
Tier IV Dual Fuel	Similar	Similar	Similar	
Turbine-Powered E-Fleet	Higher	Lower	Similar	
Gas Recip-Powered E-Fleet	Similar	Similar	Similar	

THERMAL EFFICIENCY & ENGINEERING CONCEPTS

As stated previously, operational conditions will have an impact on the thermal efficiencies of gas reciprocating engines, turbines, and diesel/dual fuel engines. Headline efficiencies for diesel engines are given at standard conditions of 77°F and 500 feet of altitude and for turbines are usually given at ISO conditions, defined as 59°F, 60% relative humidity and ambient pressure at sea level altitude. In real life oil-field operation, however, the ideal condition is far from reality. For both gas and dual fuel reciprocating engines, there must be an extreme deviation from ISO for any meaningful derate to occur. Conditions this extreme will be very rarely seen in. For example, gas recip engines will not begin to derate until 7,000 ft elevation at any given temperature and 130°F for any given altitude. In contrast to diesel, dual fuel, and gas reciprocating engines, gas turbines are much more sensitive to variations in ambient conditions.

Figure 1 shows the de-rate trend for two gas turbines running in simple cycle when exposed to changing ambient temperatures. Turbines experience this effect because ambient temperature alters the density of the air. Changes in the air density affects the mass flow into the compressor directly affecting turbine performance. Turbines will also de-rate with increasing elevations, but the impact on thermal efficiency is quite modest. This is because at higher altitudes the power output declines in parallel with lower fuel consumption due to less available oxygen for combustion. Altitude will affect the power output of the turbine by altering the fuel flow volume. This relationship can be seen in **Figure 2** below.

Figure 1 - Gas Turbine Thermal Efficiency vs. Ambient Temperature at 100% Load

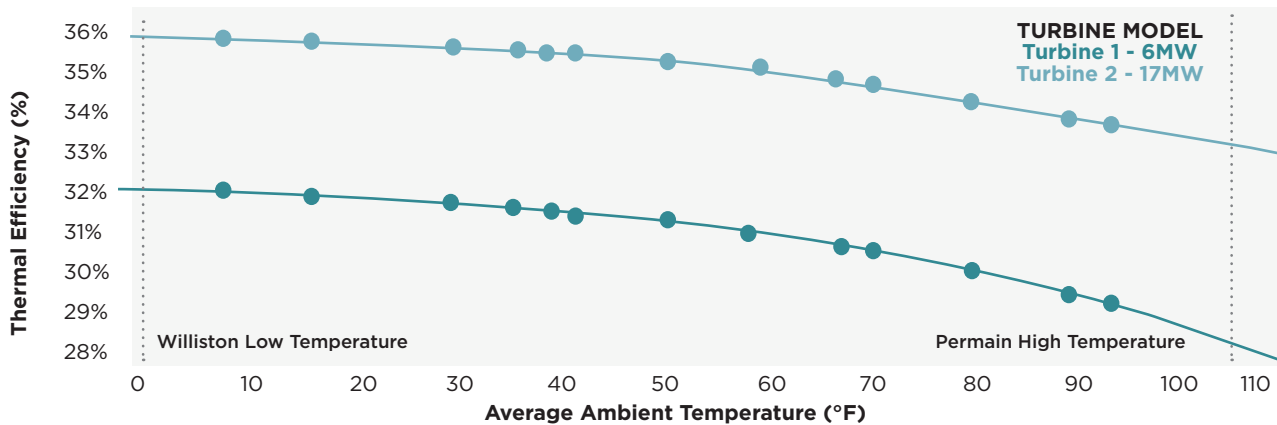
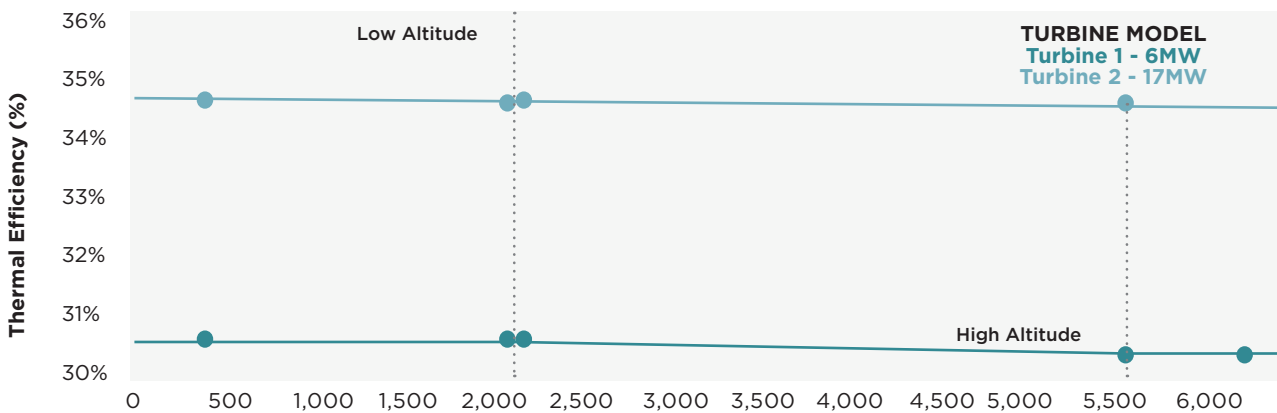


Figure 2 - Gas Turbine Thermal Efficiency vs. Altitude at 67°F & 100% Load



Gas turbines achieve optimal thermal efficiencies at 100% load. A decrease in load will result in a decrease in thermal efficiency for all engines as shown in **Figure 3**. The stars represent load points for the Permian Basin case study. Reducing the load on the turbine results in reduced fuel mass flow entering the turbine in addition to reduced compression. This lowers the temperature in the combustion chamber, resulting in less efficient combustion of the fuel. Reduced combustion efficiency results in reduced thermal efficiencies and an increase in unburned hydrocarbons, hence higher emissions and increased methane slip.

Figure 3 - Thermal Efficiency vs. Part Load De-rate Curve at 67°F

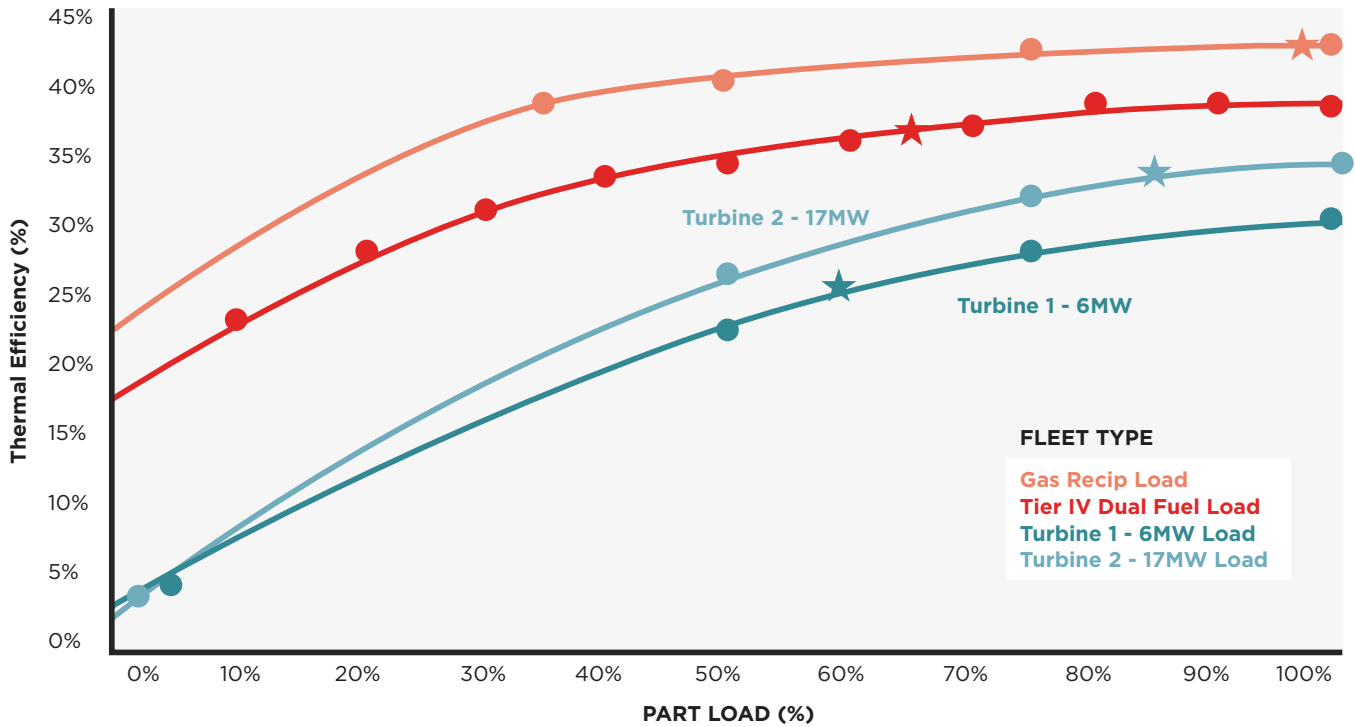


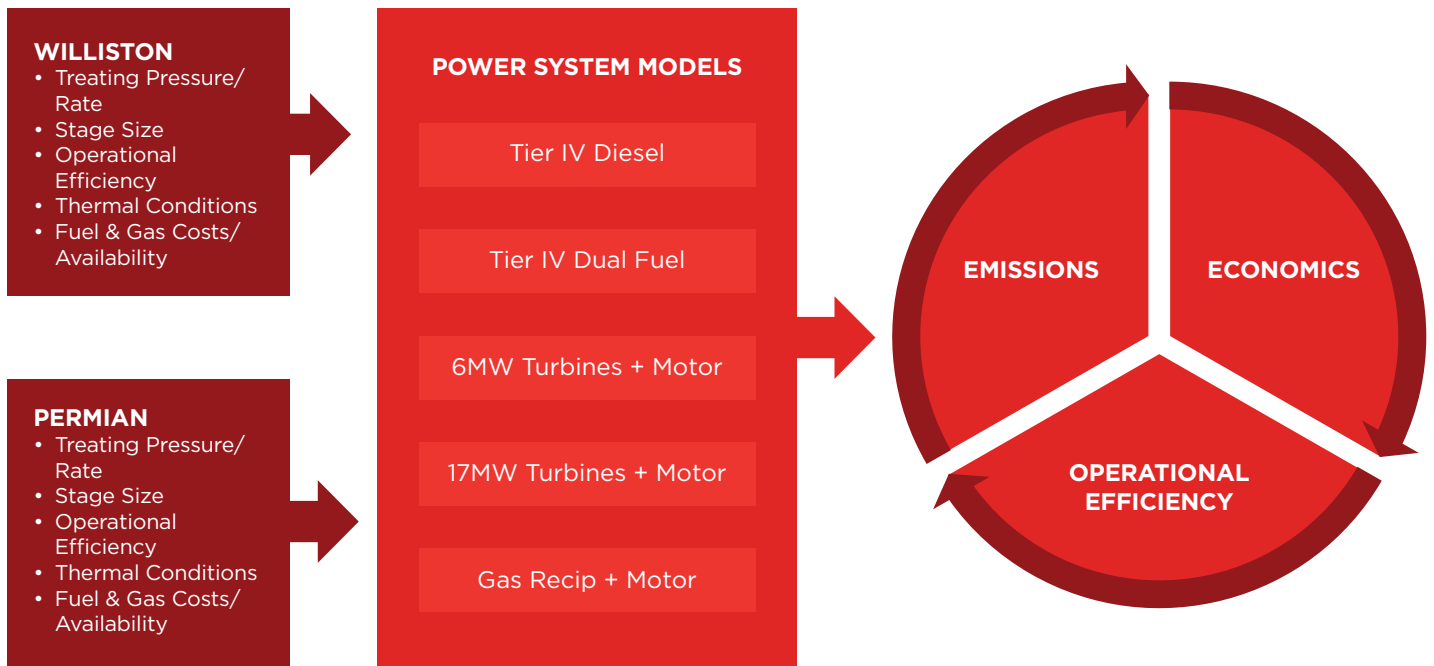
Figure 3 also shows a similar curve for dual fuel engines. Diesel engines were not included on this plot because they have an identical trend to dual fuel engines. There is, however, a unique condition with diesel and dual fuel engines. Operators have the choice to run in different gear and engine RPM combinations. Turbocharged reciprocating dual fuel and diesel engines are designed to ensure that air density and the air fuel ratio are unaffected by minor changes in ambient temperature or pressure. For dual fuel systems, the gas substitution ratios are automatically controlled to maintain efficiency based on gas quality and engine load. However, these choices have a small effect on thermal efficiency. The data points shown are an average of the minimum and maximum thermal efficiencies at each load. There can be about a $\pm 1.5\%$ swing in efficiency at each data point depending on engine RPM and gear. For turbines, dual fuel, and diesels alike, as the load on the engine increases, the thermal efficiency also tends to increase. This is also true for gas reciprocating engines, although they are not as affected by load. Gas reciprocating engines have a much higher thermal efficiency than both dual fuel engines and gas turbines. This is because they are equipped with a high-altitude turbocharger and their ability to optimize to one engine speed instead of multiple.

As operational conditions vary from baseline (ISO conditions), we see a disproportionate effect on turbine efficiency. To demonstrate this effect, assume the following departure from ISO conditions, 60% engine load at 90°F and an altitude of 5,000 ft. Compared to ISO conditions for this case, turbine thermal efficiency will drop from 32% to 24% while the diesel/dual fuel engine will drop from 37% to 35%. Gas reciprocating engines will drop from 43% to 42% in response to the reduction in engine load. ISO conditions are very rarely, if ever, achievable in oil field applications.

ANALYSIS METHODOLOGY

This whitepaper presents the results of a technical analysis of several power system solutions for powering a hydraulic fracturing fleet. For comparison purposes, Tier IV diesel, Tier IV dual fuel, two different turbine models powering electric fleets, and an electric fleet powered by gas reciprocating engines were evaluated at different operating points which simulate fracturing conditions in North American shale basins. Emission and economic profiles were generated, and operational impacts were considered. See **Figure 4** below for overall workflow. Sensitivities were then evaluated for each major factor such as operational efficiency, engine and turbine load profile, thermal/environmental conditions, fuel costs, natural gas quality, and availability.

Figure 4 - General Analysis Methodology



The Permian and Williston basins were selected to evaluate baseline operational profiles. These basins were chosen to capture the widest range of environmental conditions as well as typical frac job parameters for fleet size requirements and pumping demands. For each case study, the main factors considered for modeling were ambient temperature, altitude, pumping rate, pressure, proppant amount, natural gas quality, and fluid totals. These parameters are shown in **Table 4** below for the two basins. For the models, average pressures and rates were used. Max rate and pressure were considered to account for the highest power demands.

Table 4 - Basin Model Parameters

	Average Temp (°F)	Average Altitude (ft)	Average Rate (bpm)	Max Rate (bpm)	Average Pressure (psi)	Max Pressure (psi)	Total Proppant per Stage (lbs)	Clean Fluid Total (bbls)	Slurry Fluid Total (bbls)	Stages per Well	Time per Stage (hrs)
Williston	41.4	2,124.8	65.0	72.0	8,128	8,805	200,461	4,407	4,646	59	1.25
Permian	65.5	2,180.6	93.0	100.0	8,011	9,185	452,701	10,032	10,541	55	1.78

For modeling purposes, the 67°F was used for the Williston and 67.3°F was used for the Permian based on data availability. However, it is more important to consider the full range of operating conditions from the extreme cold in the Williston basin, with temperatures sinking below 0°F, and the Permian which often has temperatures above 100°F. From the coldest operating conditions in the Williston to the hottest in the Permian, turbines will experience a 9% drop in thermal efficiency.

Daily operational efficiencies of 45%, 58% and 70% were used as the estimated data points for pump time versus non-pumping time. For example, in the 45% daily efficiency case there was an assumed 10.8 hours of pump time and 13.2 hours of non-pumping time. For most fleets it was assumed that during non-pumping time the engines and turbines were left idling. This allowed the impact of different idling behaviors between reciprocating engines and turbines to be evaluated. However, the gas reciprocating engines will shut off when there is no power being drawn. When they are required, they will turn themselves back on. The only caveat is that the engines will require a warmup time to heat the turbo before they are able to run at full load. Therefore, the model for the gas reciprocating engines assumes 5 minutes of idle time per engine before every stage. This equates to ~30 minutes of idle per gas recip per day for the Permian model. Gas turbines do not have this capability as it will severely accelerate the timeline of routine maintenance due to hot starts and stops.

Each power system was modeled from the power source to the hydraulic pump; all other equipment such as blenders, hydration units, various sand equipment, etc. were not included in the power, emissions, and fuel consumption calculations. In other words, only the turbines/gas recip engines were considered for the e-fleet and only the engines on the frac pumps were considered for the diesel and dual fuel fleets. This simplification, however, captures most emissions generated. Typically, all auxiliary equipment will only account for ~1,750 kW to 2,000 kW, or 8% to 10% of the total power required for the location.

For the diesel and dual fuel fleets, the model assumed that each 2500 horsepower pump was operating at a typical engine load of ~65%. This resulted in a diesel displacement of ~70-75%, meaning that the dual fuel pumps were utilizing ~70-75% natural gas and ~25-30% diesel. These diesel displacement numbers were confirmed by Tier IV dual fuel field trials. Average rates and pressures from **Table 4** were used to determine how many pumps were operating for each case. For example, in the case of the Permian it took 13 active pumps to achieve a rate of 93 bpm if each pump was running at ~65% load. The total number of pumps per basin is shown in **Table 5** below.

Table 5 - Diesel & Dual Fuel Pump Configuration Model by Basin

	Number of Active Pumps	Active Pumping HHP Demand	Active Pumping hkW Demand
Williston	9	14,812	11,045
Permian	13	20,888	15,576

For the turbine e-fleet case the number of turbines and load on each was determined by the power required to meet the equivalent demand after de-rate, 12-17 MW in most cases. Two turbine designs were considered, Turbine Case #1: 3-4 ~6 MW turbines and Turbine Case #2: 1-2 ~17 MW turbines. In both cases the electric motor efficiency was assumed to be 92%, which means that if the gas turbines deliver 20 MW of power to the electric motors, the motor would deliver 18.4 MW to the pump. Additional transformers and power factor reduction due to a high inductive load could cause significant further electrical losses. These additional losses can be meaningful (5%+) and are easy to measure in an operating system, but difficult to calculate. Thus, we have chosen to ignore them in this analysis. The turbine configuration for each of the case studies is shown in **Table 6** below.

Table 6 – Turbine Configuration Model by Basin

		Number of Active Turbines	Load on Turbine (%)	Power per Turbine (MW)	Total Power (MW)
E-Fleet Turbine #1 - 6MW	Williston	3	81.0%	3.98	11.93
E-Fleet Turbine #1 - 6MW	Permian	4	85.8%	4.21	16.82
E-Fleet Turbine #2 - 17MW	Williston	1	83.0%	11.93	11.93
E-Fleet Turbine #2 - 17MW	Permian	2	58.6%	8.41	16.82

For the gas reciprocating engines, a similar approach was taken. The same active pumping horsepower demand as shown in **Table 4** above was assumed, along with the 92% electric motor efficiency. Therefore, the total power demand was identical to that of the gas turbine powered e-fleet. The number of required units as well as their load and power outputs can be seen in **Table 7** below.

Table 7 – Gas Reciprocating Engine Configuration by Basin

		Number of Active Engines	Load on Engines (%)	Power per Engine (MW)	Total Power (MW)
Gas Recip	Williston	5	95.3%	2.39	11.93
Gas Recip	Permian	7	96.0%	2.40	16.82

The models were run at multiple temperatures in each basin to determine how temperature will affect performance. For the case studies, however, the temperatures discussed above were used for each basin. Using these temperatures creates constants required for case studies, but in the worst case, high temperature applications may result in an additional turbine required to start the equipment, which could then be powered off. By contrast, gas reciprocating, dual fuel and diesel engines will not be hindered by this challenge.

Methane Number (MN) is a number that is calculated from the percentage of the constituents of the gas, i.e., Methane, Ethane, Butane, etc. Methane Number is related to BTU value, but it is a better predictor of how an engine will perform burning a given gas. For all models, an 82 MN gas with a lower heating value of 939.2 BTU/scf was used. However, gas quality will have a significant effect on the emissions of gas turbines and operating parameters of both gas reciprocating engines and dual fuel engines. For a more in-depth explanation, please refer to the “Fuel Considerations” section below.

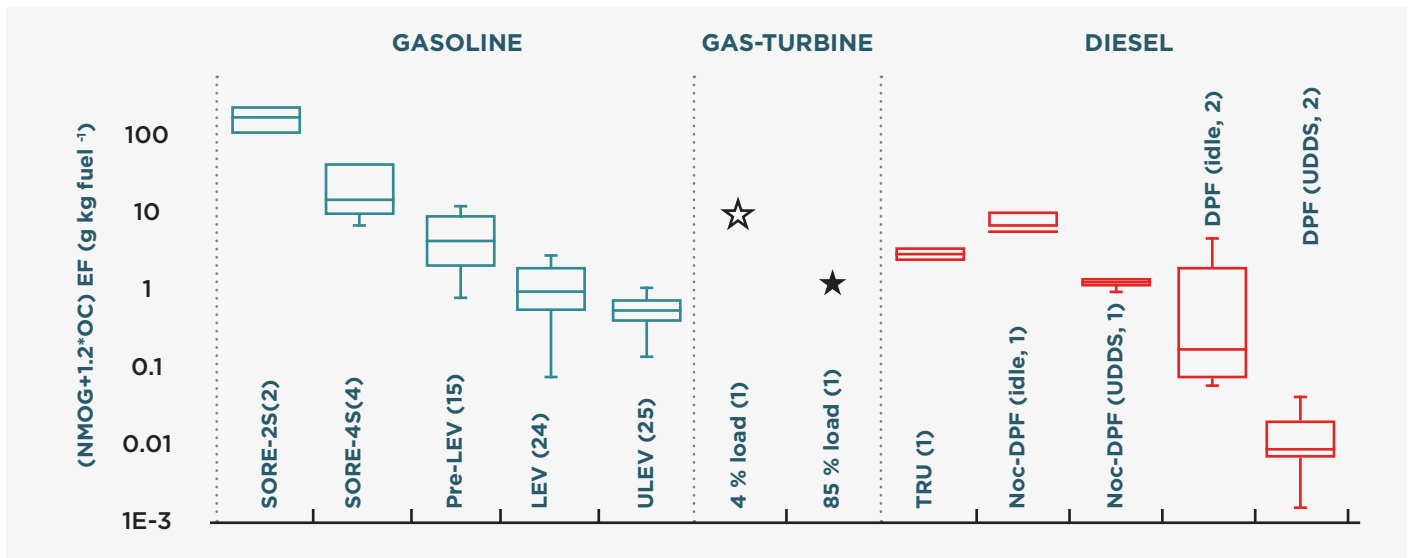
EMISSIONS

Since the amount of work (power supplied) was the same across all the cases being examined, emission comparisons were normalized by dividing total emissions (in grams) by the total amount of work done (in hydraulic kW-hr). **Equation 1** shows the equation used. This methodology compares the relative performance, in terms of emission efficiency, of four different technology solutions against each other without quantifying absolute totals which are subject to a large range of variables that are intentionally outside the scope of this report. In addition, this methodology allows the impact of the very different idling behaviors between traditional reciprocating engines and turbines to be quantified.

$$\frac{\text{Emissions Constituent (grams)}}{\text{Work Completed (hkW - hr)}} = \text{Emissions Efficiency} \left(\frac{\text{grams}}{\text{hkW - hr}} \right) \quad \text{Equation 1}$$

The study shows there is a trade off in emissions when it comes to dual fuel versus e-fleets. In every case tested for this paper, dual fuel had lower CO₂e and CO emissions while e-fleets had lower NO_x emissions. The same is true with the introduction of gas reciprocating engines into the study. Gas recip engines provide reduced CO₂e emissions from both other technologies, but an increase in CO compared to dual fuel engines and an increase in NO_x compared to gas turbines. VOC's are somewhat of a special case for many reasons. There have been several papers written on the creation of VOC's and how they affect human health. Q. Lu et al. (2017) does an excellent job of explaining VOC emissions and outlining the inclusion of Semi-Volatile Organic Compounds (SVOC's) and Intermediate Volatile Organic Compounds (IVOC's) in a more comprehensive organic emission profile. For this analysis we will expand our discussion of VOC's to include all Non-Methane Organic Gasses (NMOG's). As can be seen in Figure 5, both highly loaded gas turbines and diesel engines without diesel particulate filters (DPF's) have similar, very low NMOG emissions. Tier IV diesel engines fitted with a diesel oxidation catalyst (DOC) or a diesel with a DPF perform much better than the gas turbines or standard diesel engines with respect to NMOG emissions.

Figure 5 - VOC Emissions Source Q. Lu et al. (2017)



In the case studies presented, daily operational efficiencies of 45%, 58% and, 70% were assumed. For the dual fuel, diesel engine, and gas turbine cases, the engines were left at idle during non-pumping time. However, for the gas reciprocating engine case study it was assumed that in between stages they were turned off, as this is a technology built in to the gas recip. There was an additional “Case 3” created to better load the turbines in the Permian. To do this, we assumed one 17 MW turbines and one 6 MW turbine which brought the load on each turbine up to 88%. This data point is shown for the 70% daily efficiency scenario. Under these conditions, **Figure 6**, **Figure 7**, and **Figure 8** below show the CO₂e, CO and NO_x emissions for the Permian. Similar plots can be seen for the Williston basin in the Appendix below.

Figure 6 - CO₂e Emissions in the Permian Basin at 67°F

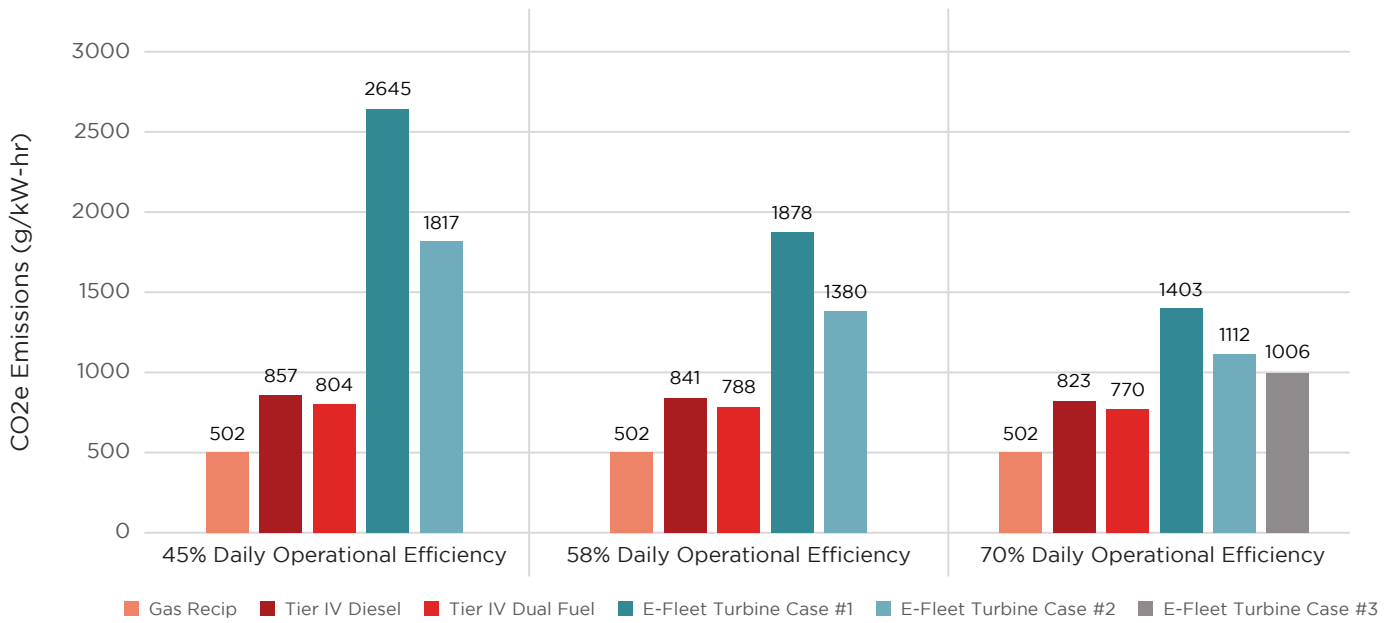


Figure 7 - CO Emissions in the Permian Basin at 67°F

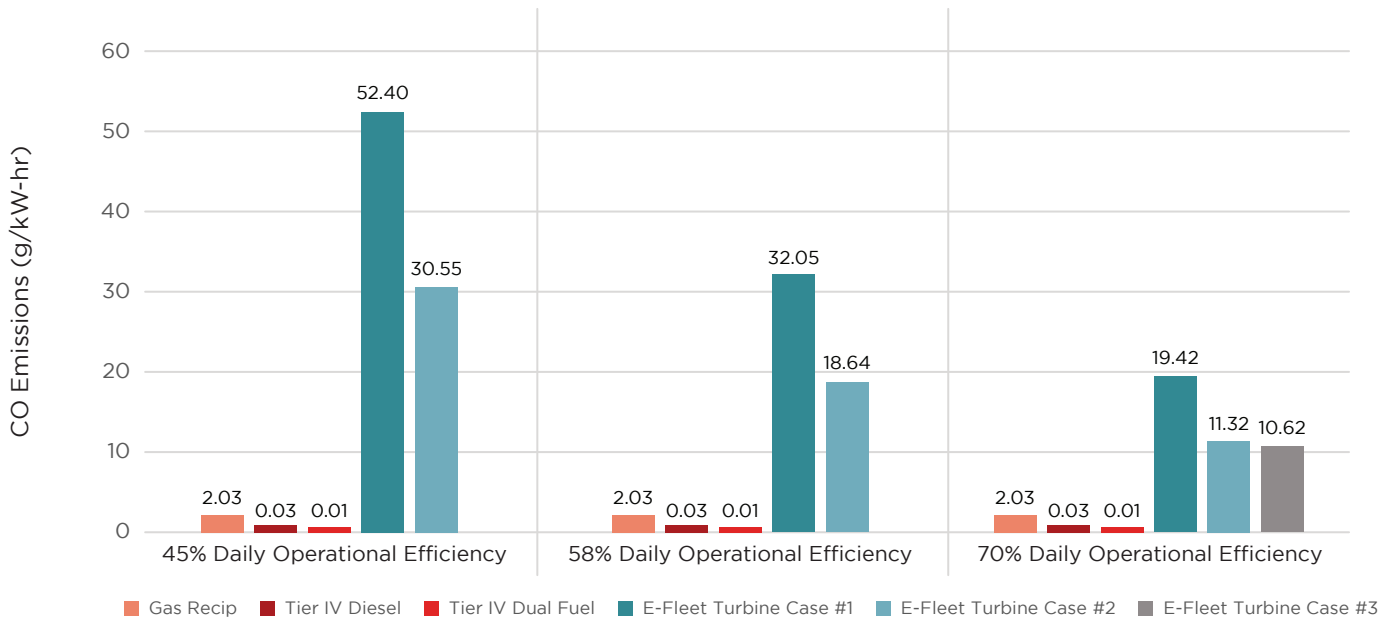
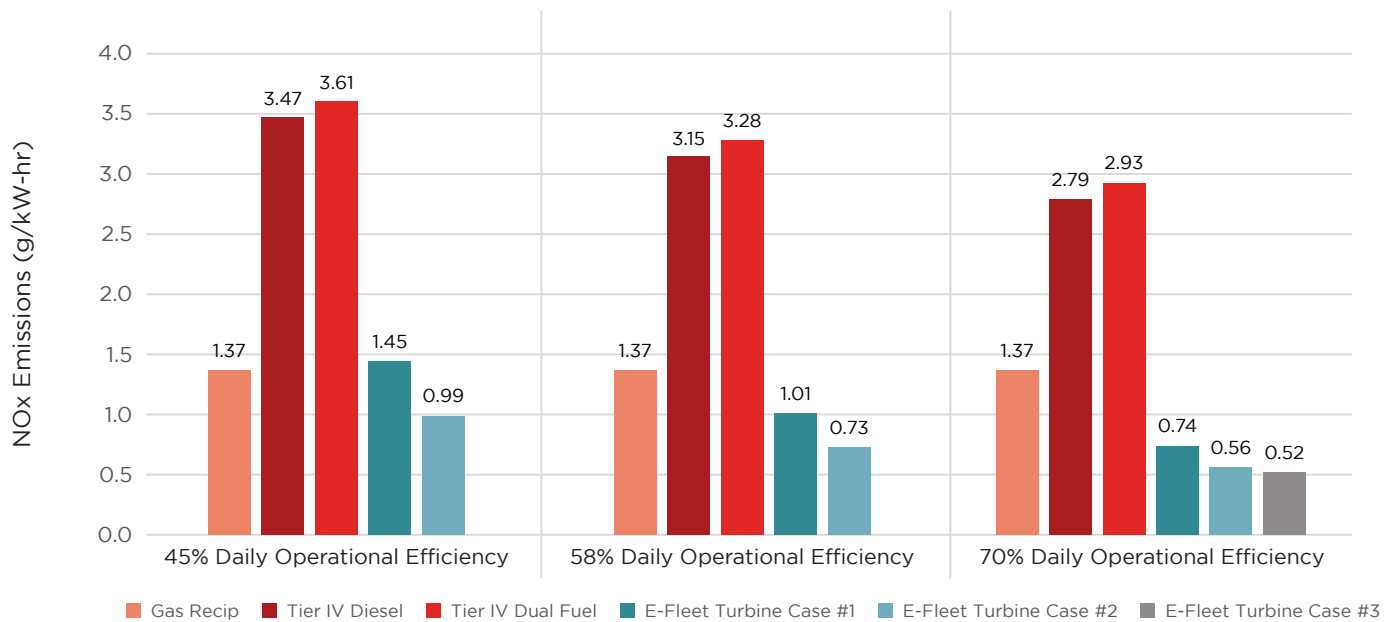


Figure 8 - NOx Emissions in the Permian Basin at 67°F



All gas turbine powered e-fleet cases resulted in a significant increase in CO₂e and CO emissions compared to both dual fuel fleets and gas reciprocating engine powered e-fleets. Conversely turbine powered e-fleets demonstrated at minimum 50% lower NO_x emissions compared to the diesel/dual fuel fleets. In the 45% daily efficiency case, the NO_x emissions of the gas recip are comparable to the gas turbine emissions. However, gas turbines will generally have lower NO_x emissions than the gas recip engine. The emissions are much higher for Turbine Case #1 than Turbine Case #2 and Turbine Case #3. This is because there are more units on location due to the lower power each unit can provide, which results in a compounded lowered efficiency. Lower efficiency, as discussed above, results in higher emissions. Turbine Case #3 results in further reduced emissions per unit of work done for e-fleets. This is a result of the turbines running at more favorable loads, which result in higher thermal efficiencies, as discussed above.

The same holds true with a reduction in daily operational efficiency, especially with turbines. This can be seen below in **Figure 9**, **Figure 10**, and **Figure 11**, which illustrate this effect for the Permian Case. As daily efficiency, or pump time per day, increases, the emissions per hour of work done decrease dramatically on all fronts for gas turbines. This is because when turbines are left idling, emissions of unburned hydrocarbons (Methane), CO, and NO_x are increased significantly. Dual fuel fleets burn no gas and comparatively small amounts of fuel at idle. Thus, they have consistently low Methane emissions at low loads, so the emissions curves seen below for dual fuel/diesel are practically flat compared to the turbine curves. For the gas recip cases, daily efficiency will not affect the normalized emissions curves because the units turn off during idle and the amount of time idling to warm up is extremely minimal. Therefore, the idle time does not change the normalized emissions curve. For context, the idle time changes the CO₂e emissions from 498 g/kW-hr to 502 g/kW-hr in the Permian case.

Figure 9 - CO₂e Emissions vs. Daily Operational Efficiency for Permian Basin

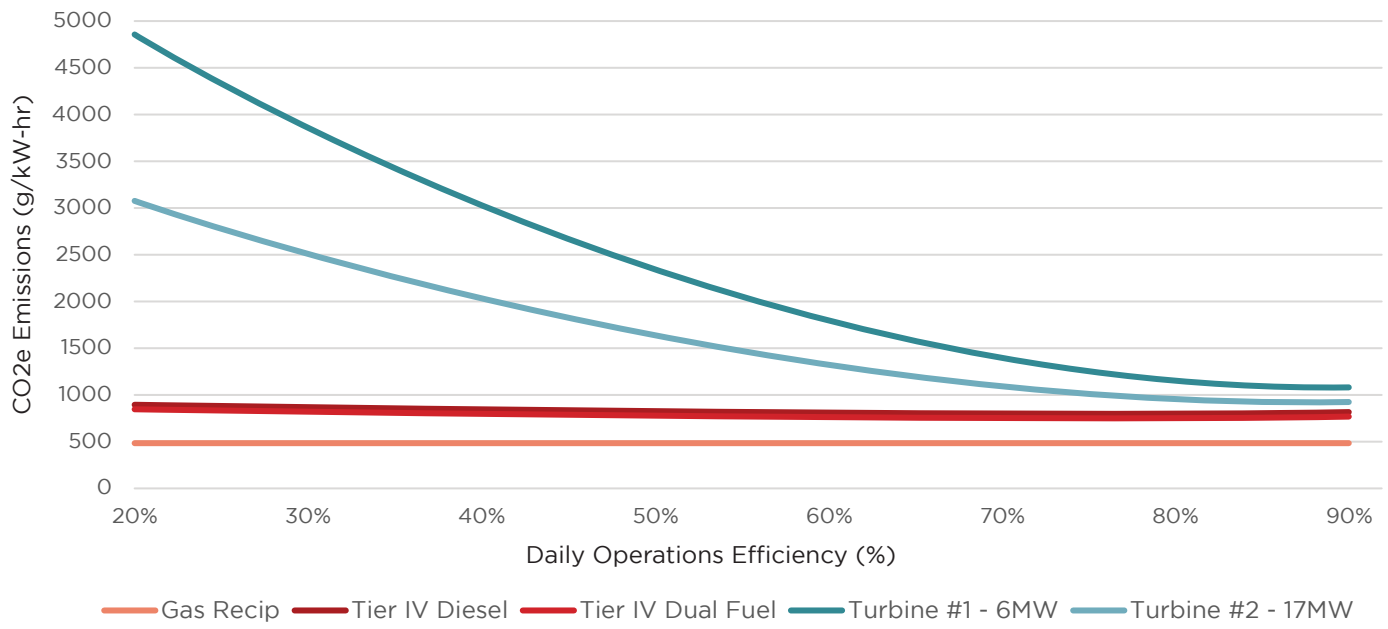


Figure 10 - CO Emissions vs. Daily Operational Efficiency for Permian Basin

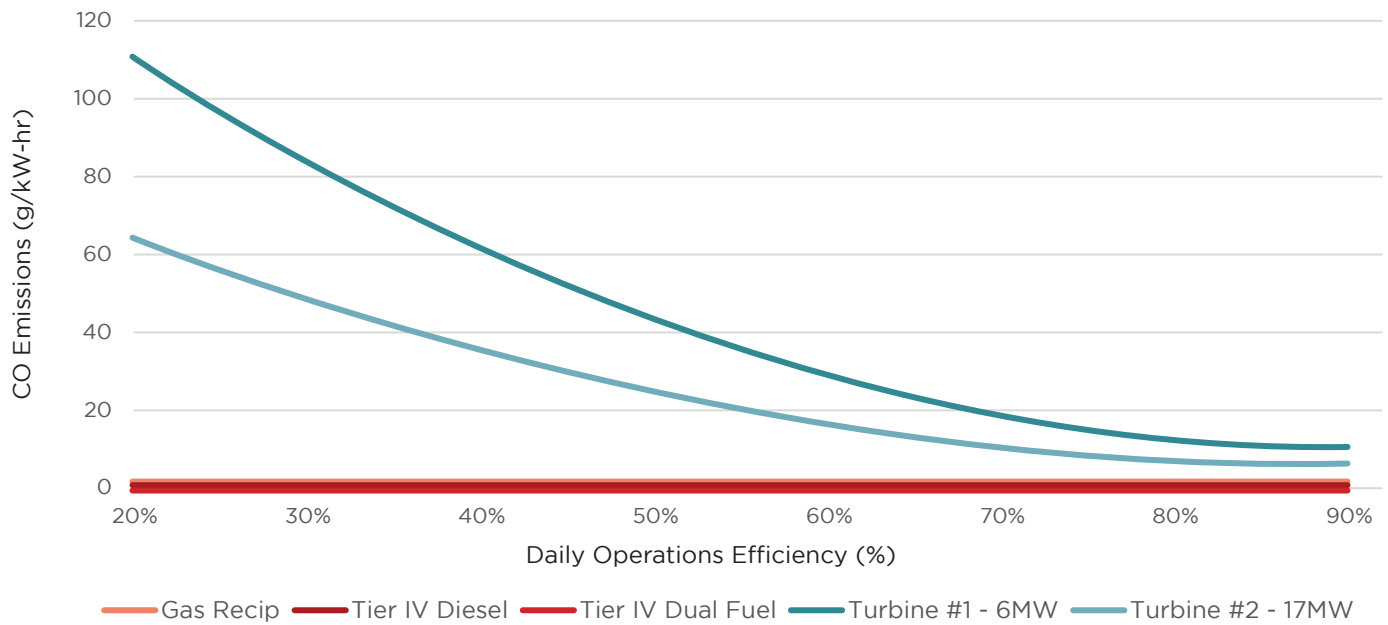


Figure 11 - NOx Emissions vs. Daily Operational Efficiency for Permian Basin

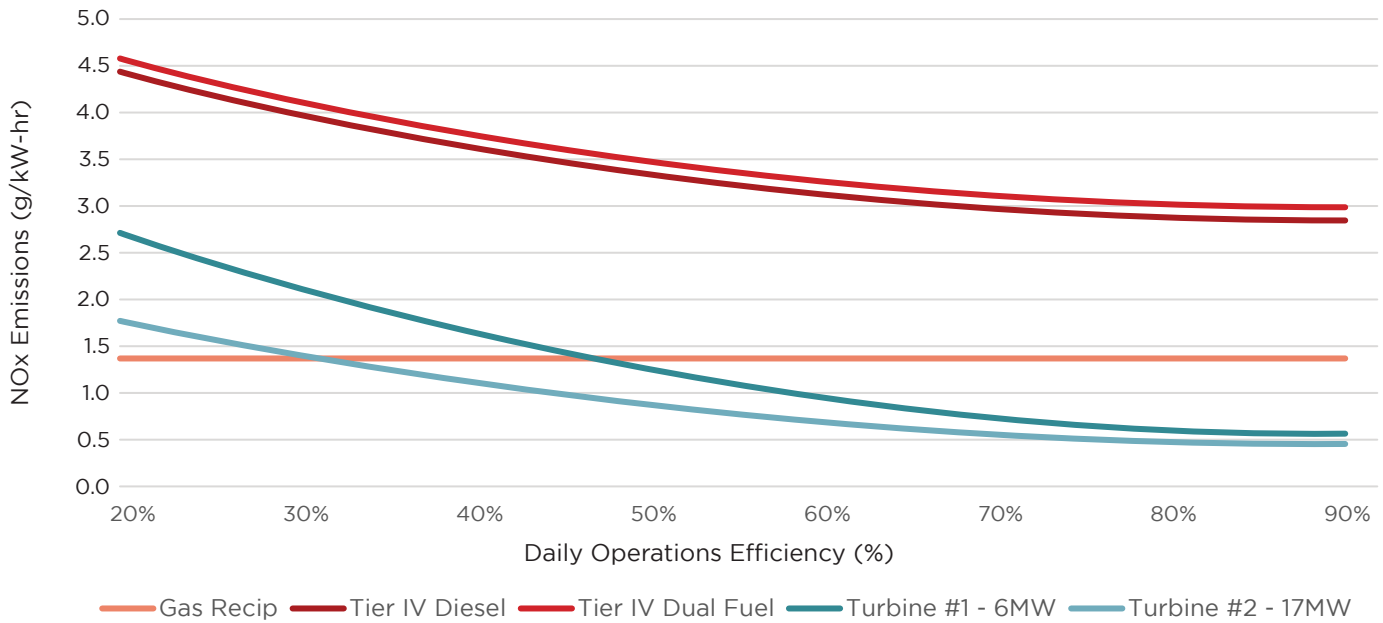
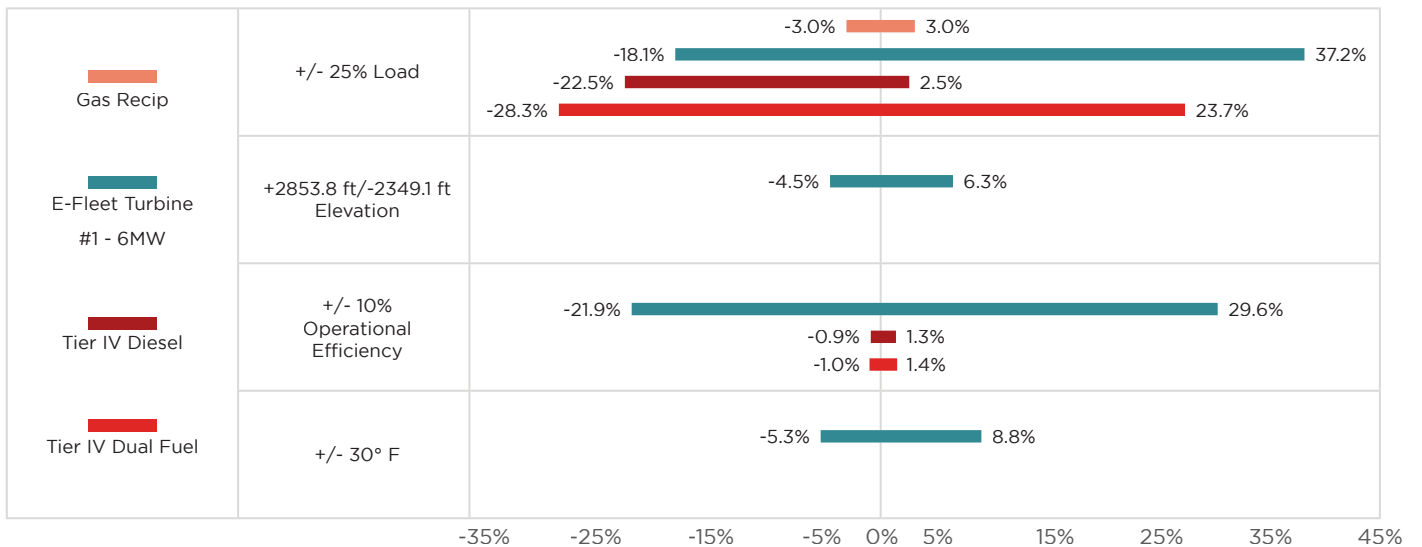


Figure 12 below shows the sensitivity of CO₂e emissions based on different operational factors. While altitude and temperature have the smallest effect on emissions of turbines, operational efficiency and load profile have the largest effect. This is a notable finding as the two factors that have the greatest effect are also the most controllable factors. Optimizing these factors will greatly improve the emissions profiles for gas turbines. However, the total impact on emissions ends up being lower for dual fuel engines per the chart below.

Diesel/dual fuel engines have minimal sensitivities to changes in elevation or temperature. These engines are more sensitive to load profile than operational efficiency. Operational efficiency does not have as large of an impact due to reduced emissions while idling. Similar to gas turbines, optimizing these factors will improve the emissions profiles for dual fuel and diesel engines.

Gas recip engines will only be affected by load in this case. As stated above, only extreme cases on altitude and temperature will affect their efficiency. Additionally, because of their ability to shut down during idle, the minimal amount of idle time will not change the emissions efficiency. Therefore, optimizing the load on the units will optimize the emissions.

Figure 12 - CO₂e Emissions Sensitivities Based on Operational Factors



Dual fuel, diesel fleets, and gas reciprocating engine powered e-fleets will have reduced CO₂e and CO emissions compared to turbine powered e-fleets. However, even though Tier IV diesel/dual fuel fleets and gas reciprocating engines have very low NO_x emissions, turbines provide a significant additional reduction. In Case 3, the best-case e-fleet scenario, the turbine powered e-fleet still produces ~23% more CO₂e, 354 times more CO, but has an ~82% reduction in NO_x emissions compared to Tier IV diesel engines.

SIMPLE FINANCIAL ANALYSIS

This section of the report outlines some basic financial considerations for the various options. Specifically, estimates are provided for initial capital costs of each of the various solutions. Maintenance schedules and parts & labors cost assumptions were created and used to compare operating costs. Lastly fuel costs were evaluated based on assumptions for fuel pricing or natural gas supply channels. No calculations are provided with respect to payback metrics given the many variables that could differ from company to company.

Table 8 below shows the capital investment and operational expenses associated with Tier IV diesel, Tier IV dual fuel, and e-fleets powered by both gas turbines and gas reciprocating engines. The CAPEX shown applies to the entire fleet, not just the power sources. The gas turbine powered e-fleets require the highest CAPEX, although it will vary based on turbine and fleet configuration. For this analysis, \$40 MM was used for Tier IV diesel, \$43MM was used for Tier IV dual fuel, \$63MM was used for gas turbine e-fleets, and \$45MM was used for gas recip e-fleets. A Tier IV diesel fleet requires the least CAPEX while Tier IV dual fuel fleets and gas recip e-fleets fall in the middle.

Table 8 - Financial Analysis Table

	Tier IV Diesel	Tier IV Dual Fuel	Gas Turbine E-Fleet	Gas Recip E-Fleet
CAPEX (\$MM)	\$37 to \$42	\$39 to \$44	\$50 to \$70	\$40 to \$50
OPEX (\$/pumping hour)	\$1,740.38	\$1,819.92	\$1,616.41	\$1,685.89

Maintenance cost was estimated by summing the cumulative costs of parts & labor required to power each fleet system, including the pumps, for the life of the product then dividing by the cumulative pumping hours accrued on the fleet. Although the majority of maintenance expenses are associated with fluid end and consumables such as seats, valves, and packings, they would remain the same for diesel, dual fuel, and e-fleets. The table was also simplified by only showing the Permian case at 58% daily efficiency, as all other cases show the same relationship. The major difference for e-fleets is that the equipment which replaces engines and transmissions requires minimal routine maintenance followed by less frequent, but higher cost, rebuilds. This equipment includes the gas turbine/gas recip engine, switchgear, transformers, VFD's and electric motors. For the most part, the maintenance on these pieces of equipment are visual inspections, cleaning, greasing and oil changes when needed. Gas turbines also require an air filter replacement bi-annually. Although diesel/dual fuel fleets also require similar maintenance, it is more frequent and extensive. Therefore, we believe e-fleets will have approximately an 11% reduction in maintenance costs over diesel/dual fuel. If a 4,000-pumping hour year is assumed, the gas turbine e-fleet would benefit from about \$800,000 worth of maintenance savings per year compared to the diesel/dual fuel fleet. There is an active debate in the area of maintenance savings but if we assume an additional \$20MM investment for e-fleets, an annual maintenance saving of \$3.25MM would be required for 10 years at a discount rate of 10% to achieve a positive NPV.

Most of the e-fleet savings come in the form of fuel cost. There are three potential types of natural gas which can be utilized on a frac location: compressed natural gas (CNG), liquified natural gas (LNG), and field gas. The unit of measurement used to define natural gas is diesel gallons equivalent (DGE) in order to easily compare natural gas data to diesel data. The conversion is based on the BTU content of the natural gas. One diesel gallon equivalent is equal to the amount of gas, in standard cubic feet, required to produce the same amount of energy as one gallon of diesel. In this case, 1 DGE = 139.3 scf. **Figure 13** and **Figure 14** below show the fuel cost per stage for a 58% daily efficiency in the Permian and Williston, respectively. For the dual fuel cases, the cost includes the respective natural gas and diesel expenses. The prices assumed were: \$2.85 for diesel, \$1.60/DGE for CNG, and \$1.36/DGE for LNG. All assumed prices include an estimated transportation cost. For field gas, a miscellaneous price, which includes transportation, of \$0.30/DGE was assumed along with the daily cost of \$3,000/day for the location field gas treatment equipment. For the Permian plot below, the price per stage for field gas was calculated using the following method:

$$\text{Diesel } \$/\text{Stage} = 2206.29 \frac{\text{gal}}{\text{stage}} \times \frac{\$2.85}{\text{gal}} = \$6,288 \quad \text{Equation 2}$$

$$\text{Dual Fuel } \$/\text{Stage} = \left(603 \frac{\text{gal}}{\text{stage}} \times \frac{\$2.85}{\text{gal}} \right) + \left(\left(\frac{\$0.30}{\text{DGE}} \times 1601.55 \frac{\text{DGE}}{\text{stage}} \right) + \left(\frac{\$3000}{\text{day}} \times \frac{\text{day}}{7.82 \text{ stage}} \right) \right) = \$2,581 \quad \text{Equation 3}$$

$$6\text{MW Turbine Fuel } \$/\text{Stage} = \left(\frac{\$0.30}{\text{DGE}} \times 3303 \frac{\text{DGE}}{\text{stage}} \right) + \left(\frac{\$3000}{\text{day}} \times \frac{\text{day}}{7.82 \text{ stage}} \right) = \$1,375 \quad \text{Equation 4}$$

$$17\text{MW Turbine Fuel } \$/\text{Stage} = \left(\frac{\$0.30}{\text{DGE}} \times 3411 \frac{\text{DGE}}{\text{stage}} \right) + \left(\frac{\$3000}{\text{day}} \times \frac{\text{day}}{7.82 \text{ stage}} \right) = \$1,407 \quad \text{Equation 5}$$

$$\text{Gas Recip Fuel } \frac{\$}{\text{stage}} = \left(\frac{\$0.30}{\text{DGE}} \times 1727 \frac{\text{DGE}}{\text{stage}} \right) + \left(\frac{\$3000}{\text{day}} \times \frac{\text{day}}{7.82 \text{ stage}} \right) = \$909 \quad \text{Equation 6}$$

Figure 13 - Fuel Cost per Stage at 58% Daily Efficiency in the Permian Basin

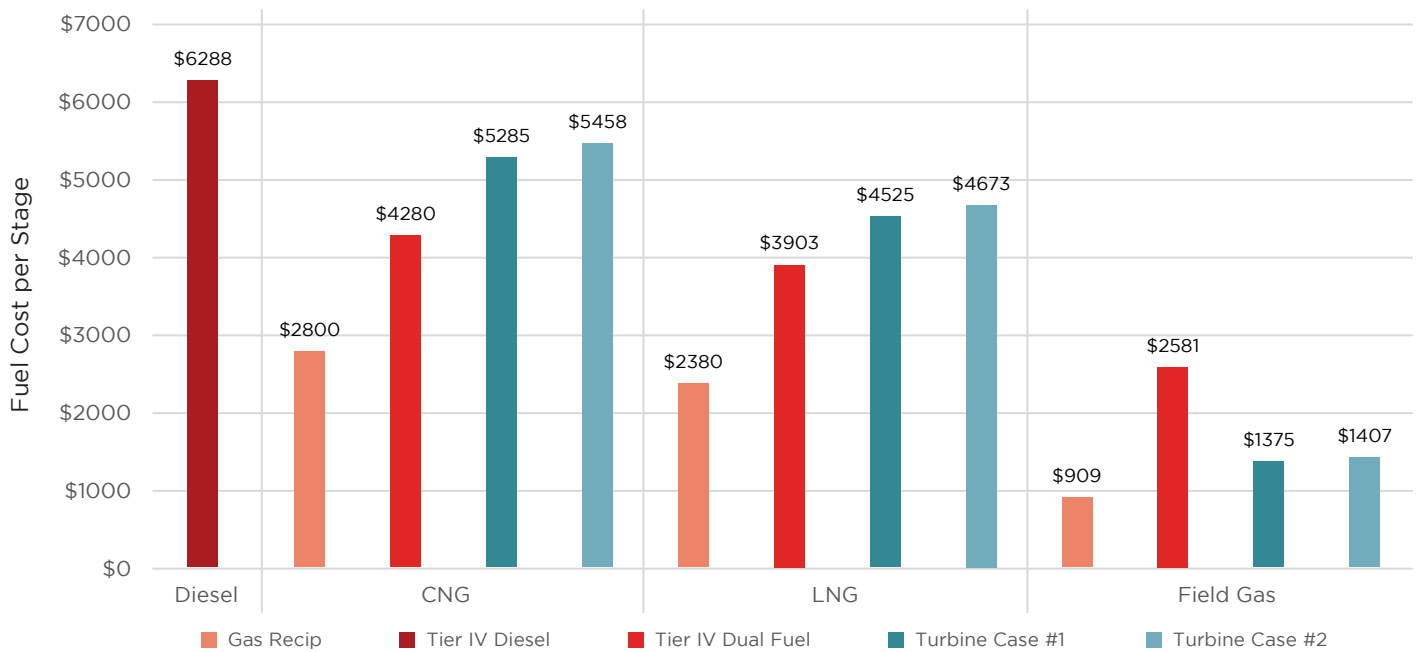
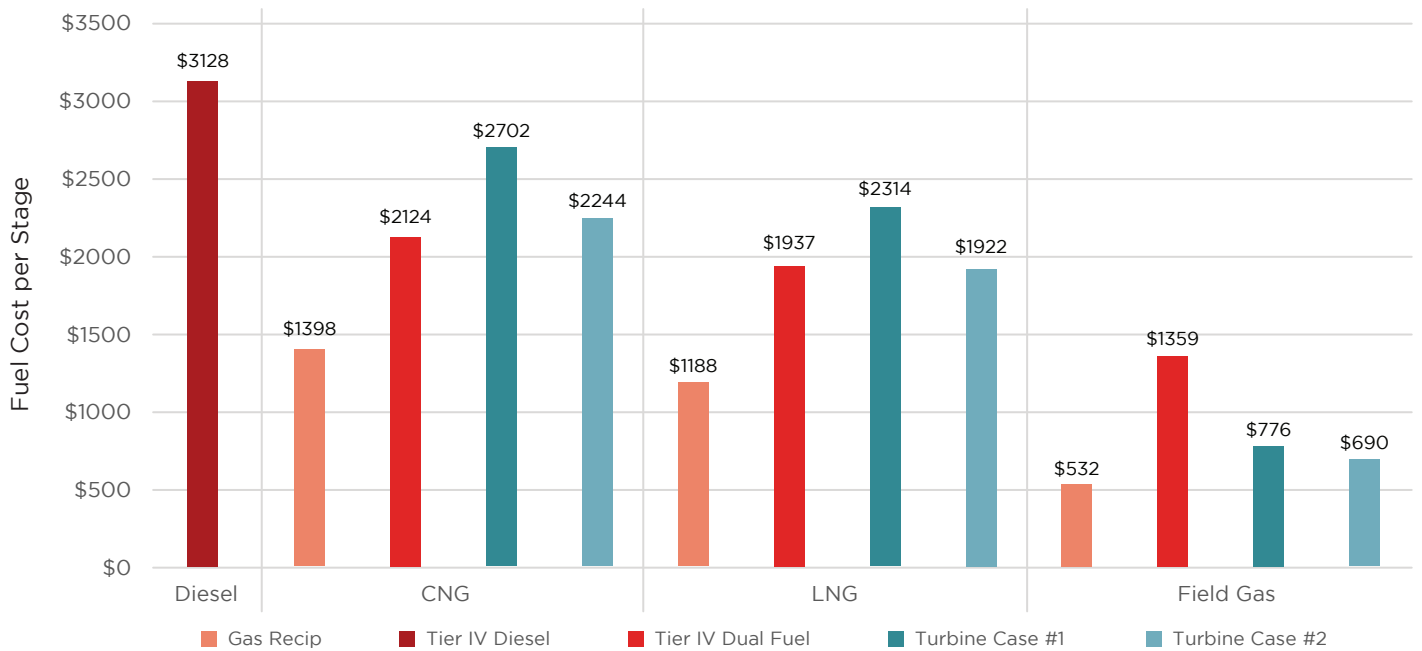
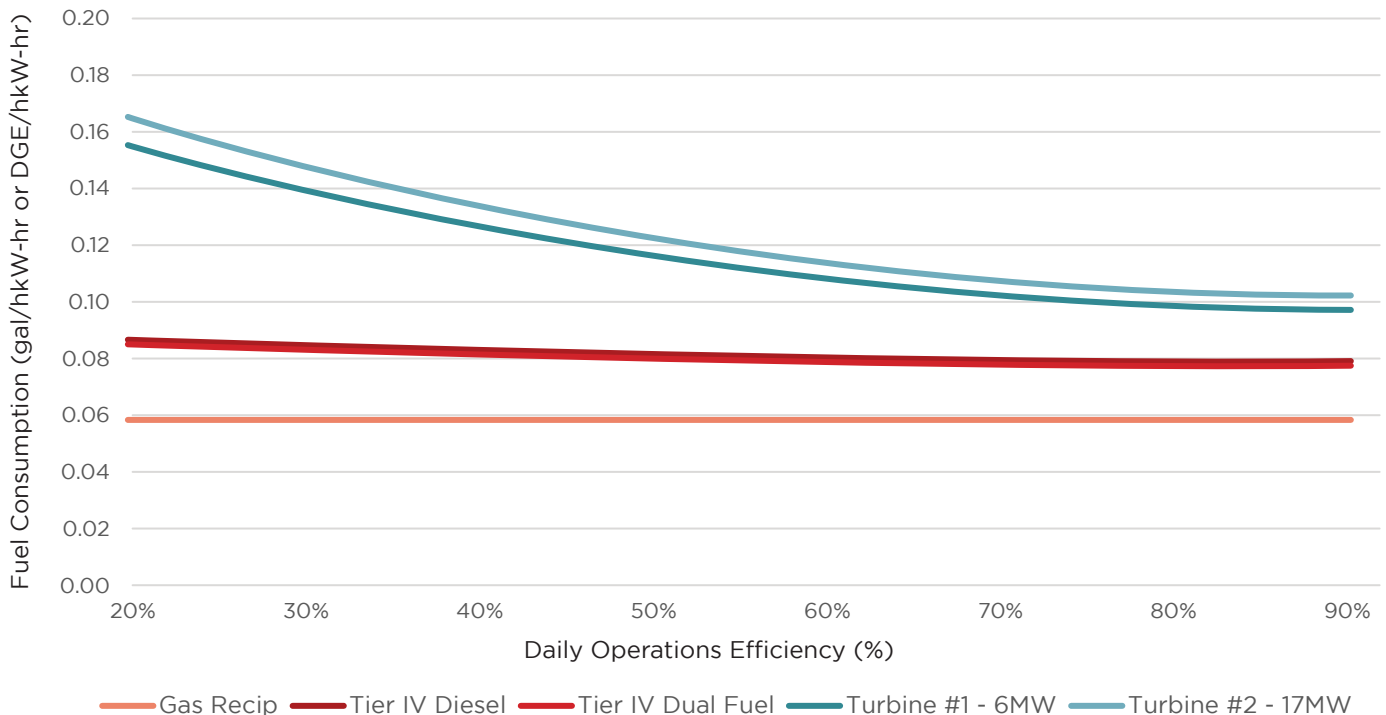


Figure 14 - Fuel Cost per Stage at 58% Daily Efficiency in the Williston Basin



Dual fuel and e-fleets have reduced fuel costs per stage compared to diesel fleets. There are large variations in the price and availability of LNG and CNG within each basin, affecting the ultimate reduction. In the both the Permian and Williston Basins, the lowest cost per stage resulted from the gas reciprocating engine configuration when using only field gas. However, as with the emissions, the largest fuel consumption savings result from higher daily efficiencies. This concept is reflected in **Figure 15** below. As the daily efficiency increases, fuel consumption per hour of work done decreases significantly, especially in the turbine cases due to idling consumption.

Figure 15 - Permian Case: Fuel Consumption vs. Daily Operational Efficiency for Diesel, Dual Fuel & E-Fleets



As seen in **Figure 15**, gas turbines require almost double the fuel compared to dual fuel fleets. This benefit is offset by the fact that dual fuel fleets require diesel as well as natural gas. In the end the higher fuel consumption of the turbines offset the higher cost of the diesel component of the dual fuel fleet and the two had very similar fuel costs when burning CNG or LNG. On the other hand, gas reciprocating engines offer both a reduced consumption volume and the utilization of only natural gas, thus optimizing both fuel cost and usage.

In conclusion, e-fleets have larger initial investment than diesel/dual fuel fleets. However, the cost to operate e-fleets and the fuel costs (compared to diesel) are smaller if and when operating efficiently. Depending on the contract between the service company and the operator, both companies could have potential savings. As far as an investment from the service company's perspective, the dual fuel fleet is the generally better option compared to the e-fleet. Dual fuel has a lower initial CAPEX requirement which outweighs the e-fleets' reduced maintenance costs.

OPERATIONAL CONSIDERATIONS

REDUNDANCIES

With traditional diesel fleets, it is common practice to have additional horsepower on location so that if maintenance is needed mid-stage on a pump, another pump can make up for the lost rate. This operating theory should also be followed in the dual fuel and e-fleet landscape. With dual fuel, the infrastructure and maintenance patterns of the fleets will be almost identical to diesel fleets. Fuel redundancy is also a consideration. If there is an interruption in the gas supply to the dual fuel engine it seamlessly switches to 100% diesel. The dual fuel pumps carry their own backup fuel supply.

One of the purported attributes of e-fleets is that the pumps will need less maintenance due to reduced vibrations. Although this may have a small effect on maintenance patterns, it is not likely to result in a noticeable difference. The primary drivers of pump maintenance on location are treating pressure, proppant concentration, and proppant type. For this reason, we assumed that the same amount of reserve horsepower be available for all types of fleets.

Although the smaller, multiple turbine set up has increased emissions and costs, operationally they provide the desired redundancy. If one turbine goes down, there should be enough power to flush the well. However, if there is one single large turbine powering the fleet, the risk of screening out increases. If the single turbine fails during a stage, there is no other source of power to flush the well, resulting in a screen out and wellbore full of sand. For this reason, Turbine Case #1 makes the most sense operationally. One potential solution to the risk involved with having a single turbine powering the fleet is to have an extra, smaller turbine on location which can be used to flush the well in the case of a turbine failure. Another solution could be to have diesel/dual fuel pumps inline that can be used for a short period of time. In the case that the pump down equipment is still diesel/dual fuel, pump down could also be used to flush the well. Both options come with an incremental capital cost, although the turbine would be much higher than a dual fuel/diesel solution. Backup fuel supply for turbines require additional tanks of CNG or LNG and the associated equipment. There is an additional cost associated with having this equipment on location.

It is also assumed that in the case of the gas reciprocating engines, at minimum one extra unit would be available on location at all times. This would allow for the same redundancies discussed above for the gas turbines.

For gas reciprocating engines, one concern is the interruption of supply when using field gas. There are two possible solutions to this issue: have an extra transport of natural gas on location or use a battery package system. In the case of the extra transport, each transport can carry 430,000 scf of natural gas. This would

equate to ~3 hours of pumping at full load. In almost all cases, this would allow for not only flushing the well, but also fully completing the stage itself. In the case of the battery package, if the gas recip could not supply power, the spread could be run off the batteries. Depending on the load requirement and the amount of charge of the battery, this could last for anywhere from 7 minutes to a complete flush. Unlike the extra transport solution, this method would most likely not allow for the completion of the stage. Additionally, there is approximately a 10% roundtrip loss in efficiency when charging and discharging the batteries. Simply put, this means that this method will require more fuel.

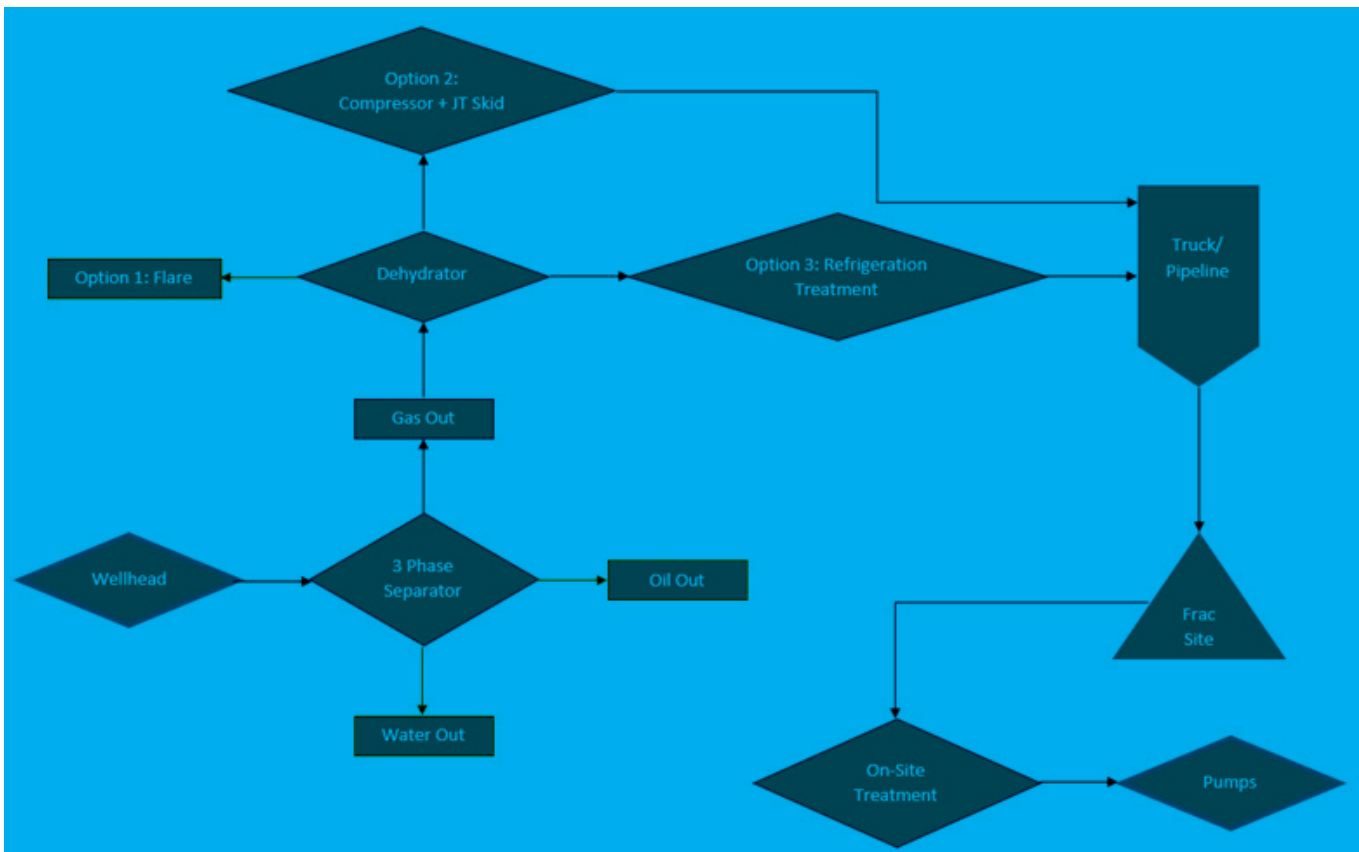
A simple analysis of the impact of the 10% loss was run to determine the effects based on fuel consumption and, by extensions, carbon emissions. In the Permian case study, if a battery package rated to 2.134 MW-hr provided 1 MW-hr worth of energy to the spread during a 1.5-hour stage, the batteries would have to be charged to at least 77.3%, given the 10% loss in efficiency. This would equate to a two-battery system, which was chosen in this case because it is the minimum package required to sustain 1 MW-hr for a full 1.5-hour stage. It would take ~2.3 hours to charge the batteries to 77.3% by increasing the gas recip engine loads to 100%, which would provide 705.72 kW to the batteries. However, it would take ~3 hours to fully charge the batteries. Therefore, for simplicity it was assumed that the batteries were charged for two full stages, then discharged for one full stage. Without having used the battery pack, 601.32 mmBTU would be consumed over the course of 3 stages. With the battery pack, 605.96 mmBTU would be consumed in order to charge and discharge the battery pack. Overall, this is less than a 1% increase in energy consumption and therefore will not move the needle meaningfully on fuel consumption or carbon emissions.

Furthermore, if a 3-battery package system is assumed for an emergency flush, the batteries would be able to provide 3.201 MW-hr worth of energy to the system. If flush is required to be 35 bpm at 8000 psi, and the 10% round trip loss is considered, the batteries would need to provide ~7500 kW of power for flush. In this case, the batteries would be able to sustain flush for ~25 minutes if they are at full charge at the beginning of the flush. At 60% charge, they would only be able to flush for ~15 minutes. In some extreme cases, specifically slickwater designs at high proppant loading, a full flush would not be achieved unless a rate of 60 bpm was sustained. Assuming the increased rate would also increase the pressure to ~10,000 psi, the batteries would only be able to flush for ~12 minutes at full charge. Therefore, depending on design and wellbore configurations, if the gas supply is interrupted, there are some cases where the batteries would not be able to complete a full flush.

FUEL CONSIDERATIONS

Field gas has been at the forefront of the push towards e-fleets. There are considerable cost savings if gas turbines and gas reciprocating engines can be run entirely on field gas. Field gas is low cost and abundant in most basins and in many cases, it will be flared if it is not used in this application. However, in order to use field gas to power gas turbines or dual fuel fleets, it must first be treated. **Figure 16** shows the general flow path of field gas from wellhead to flare or frac site.

Figure 16 – Potential Field Gas Flow Path



In order to use field gas, the necessary infrastructure must first be put into place to process the gas. The CAPEX associated with this infrastructure can vary based on the artificial lift practices in place. Turbines generally require the gas to be compressed to around 500 psi. Dual fuel engines require a lower feed pressure of about 100 psi. If gas lift is being used nearby it will be relatively inexpensive and simple to begin using field gas to power completions equipment. Gas lift requires that the gas be compressed and delivered in high pressure lines. If gas lift is not being utilized, high pressure gas lines and compressors must be purchased. The cost of these can vary, but in general a high-pressure gas line will cost around \$25,000 per mile and typical compression stations cost around \$200,000 in CAPEX and \$10,000/year in auxiliary operation costs. There may be further processing equipment on location in order to remove liquids, remove H₂S and regulate temperature and pressure. This will typically cost around \$3,000 to \$6,000 per day, a cost that may be all, or at least partially, offset by the sale of the liquids.

The main hurdle associated with field gas is keeping the quality of gas up to specifications. In general, decreased fuel quality will result in higher emissions and lower thermal efficiencies. In some cases, the fuel quality may cause emissions to drop below the EPA and/or governments' standards. Not to mention the additional complications that arise with anomalies such as Hydrogen Sulfide in field gas, which causes damage to the engines and turbines. Table 8 below shows the CO₂ emissions percent change for gas turbines running at 100% load in the Permian at 70.3°F based on natural gas quality. As depicted, fuel quality will have a massive effect on the emissions of turbines. For further discussion on Methane Number, please see appendix.

Table 9 – CO2 Emissions Based on Fuel Quality

Fuel Type	Methane Number	LHV (BTU/scf)	6MW Turbine - CO2 Emissions Percent Change	17MW Turbine - CO2 Emissions Percent Change
Field Gas Sample 1	<46.8	1,509	9%	7%
Field Gas Sample 2	<46.8	1,421	6%	6%
Field Gas Sample 3	48.0	1,290	6%	6%
Field Gas Sample 4	50.0	1,266	9%	9%
Field Gas Sample 5	65.0	1,123	6%	6%
Field Gas Sample 6	56.0	1,197	5%	5%
LNG Sample	72.0	1,039	1%	1%
CNG Sample	70.7	999	3%	3%
San Diego Pipeline Quality	81.2	939	0%	0%

In addition to impacting the emissions of a turbine, fuel quality will affect the operational reliability of a turbine. When turbines are burning clean, dry gas, they are wonderfully reliable. Wet gas, on the other hand, will present liquid slugs into the system which can damage the gas compressor or turbine itself. There have been reported cases of substantial downtime caused by poor gas quality. Therefore, gas treatment is necessary in order to condition the gas and drop out as much liquid as possible.

Fuel quality will not affect dual fuel engines in the same way. A decrease in fuel quality in this case results in potential decreased diesel displacement, not a change in emissions. For example, decreasing the Methane Number by 20 for a Tier IV dual fuel engine will result in an averaged 19% reduction in diesel displacement across the entire fleet. This means that overall, 19% less natural gas is being used. This measure was taken across multiple engine speeds and loads. The change in diesel displacement with changing fuel quality also depends heavily on these factors. All of these factors combined will also determine individual engine diesel displacement. For Tier IV Dual Fuel engines, the displacement will fall in the range of 65% to 85%. If this range cannot be achieved, substitution will not happen.

When diesel displacement is decreased, the emissions caused by the additional diesel will be equivalent, and in some cases better, than those caused by a low-quality natural gas. With a greater amount of diesel being pumped in relation to the lower quality gas, the emissions remain virtually the same. If the Methane Number changes from 82MN to 57MN when operating at an engine load of 50% and an engine speed of 1600 rpm, the CO2 emissions will increase from 599.7 g/hkW-hr to 600.8 g/hkW-hr. Under the same conditions at an engine speed of 1700 rpm, CO2 emissions will decrease from 660.9 g/hkW-hr to 634.0 g/hkW-hr. While the diesel displacement does not significantly affect the emissions, it will increase the fuel costs, as diesel is more expensive than natural gas.

In the case of gas reciprocating engines, a lower quality gas will result in an engine output derate. The units will start to experience this at approximately 72MN. For a methane number around 55MN, which is the average for the field gas samples shown in **Table 8** above, the gas recip will experience a deration factor of 0.73. Therefore, for these engines, it would be necessary to run more engines in order to make up for the reduced power output. This would result in an increase in overall emissions, as there would be more units running. Although the engine would derate by 51%, it is possible to run the engine with natural gas methane numbers as low as 35MN.

Typically, CNG or LNG must be on location as a backup in the case that field gas cannot be pumped because of lowered quality or other operational factors. LNG will typically have a Methane Number around ~72M while CNG will typically have a Methane Number around ~74MN. In most basins LNG and CNG will be readily available.

Figure 17 shows a general availability map for CNG in the US and **Figure 18** shows a general availability map for LNG in the US.

Figure 17 - CNG Availability in the US from Certarus

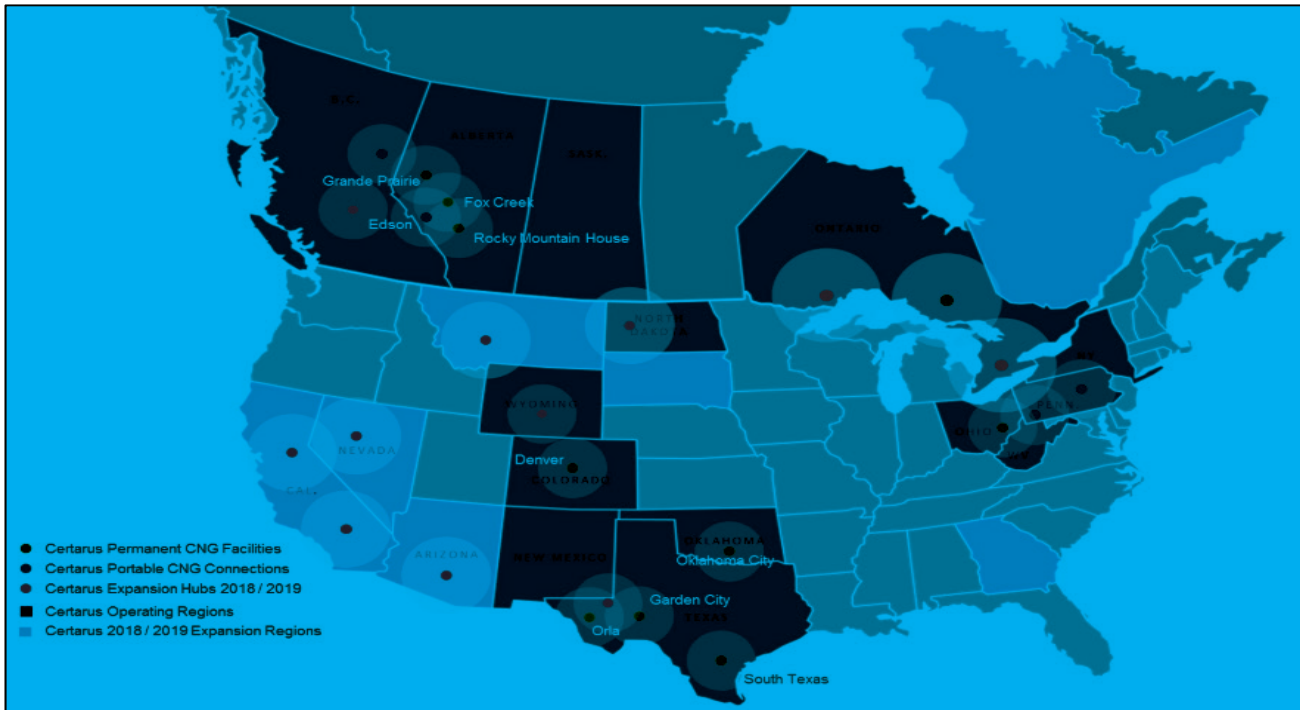
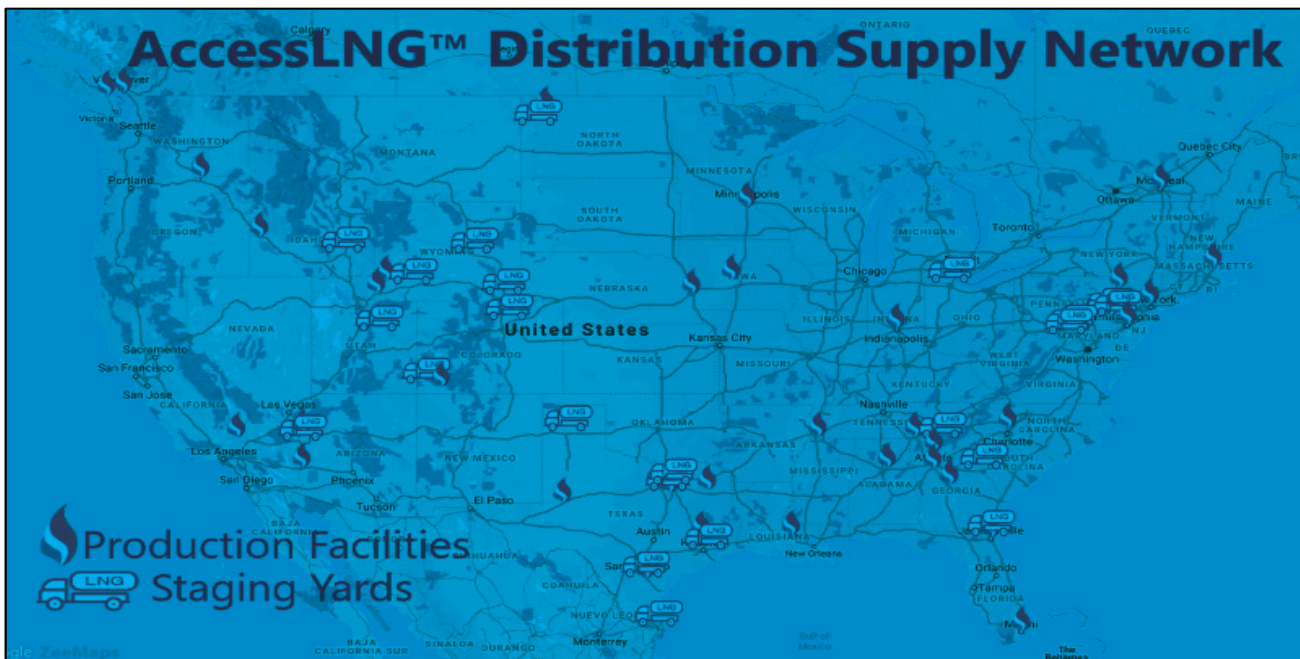


Figure 18 - LNG Availability in the US



Although there are some areas of operation which are not covered in the above maps, CNG and/or LNG can be trucked to most locations from the current infrastructure. If the demand is high enough in a potential area of operation currently lacking infrastructure, a new distribution station could be constructed in about 6 months.

In general, it is easier to transport and store LNG given its higher density in liquid form. A transport can carry about three times as much LNG as CNG, which means that LNG requires fewer loads. For an average frac job, approximately 4-6 trailers worth of CNG would cover a day of operations while LNG would need 1-2 trailers.

MANPOWER CONSIDERATIONS

There are several key differences in staffing requirements for a conventional fleet powered by a reciprocating engine versus an e-fleet using a gas turbine or a gas reciprocating engine. While pump maintenance, sand, chemicals and job execution duties remain unchanged (as does the number of people required), specific maintenance expertise is different. The traditional role of a diesel engine mechanic is replaced by different specialized knowledge, specifically maintenance and operation of a gas turbine/gas reciprocating engines and maintenance and operation of medium and high voltage electrical equipment. This means a transition from a traditional fleet to an e-fleet when considering infrastructure and training required within a service company. On the other hand, a dual fuel fleet is virtually identical to a traditional diesel fleet and, as a result, the transition from diesel to dual fuel is minimal.

OPERATIONAL FOOTPRINT

Because of the power density of an electric motor, additional options are available for pump design. These include locating 2 pumps on a single trailer, driven by a single electric motor, or using a single higher horsepower pump, again driven by a single motor. This would reduce the footprint required by the pumps on location because only half of the pump trailers would be needed. The reduction in space used by the pumps is then offset by the need for the turbine(s), conditioning skids, switchgears, etc. As a result, an e-fleet has a similar footprint to a traditional frac fleet. This is also true if the e-fleet is powered by gas reciprocating engines. The number of units required would be about equivalent in footprint to the number of gas turbines required for an e-fleet.

There is a method, however, that can be employed to effectively reduce the footprint for e-fleets on the actual wellsite. Utilizing remote power generation would remove the turbine(s) and gas processing/storage equipment from the location. From a centralized location, it would be possible to run the power to multiple locations. It should be noted that this solution involves additional capital cost and complexity to install the necessary localized grid.

SUMMARY/CONCLUSIONS

As with all forms of energy, there is a trade off in optimizing the “Three E’s” when switching between energy sources. In the case of dual fuel versus e-fleets, the best case will be distinguished by optimizing equipment and operational efficiencies. In general gas turbine e-fleets will result in lowered NOx emissions while dual fuel will have decreased CO_{2e} and CO emissions, comparatively. Gas reciprocating engines offer further CO_{2e} emissions compared to dual fuel fleets. Additionally, although gas turbine e-fleets have a higher initial investment compared to dual fuel fleets, they have cost savings based on maintenance and fuel practices. The gas reciprocating e-fleet offer the best of both worlds in reduced initial investment and reduced maintenance costs.

Dual fuel fleets will be easy to implement, as they are very similar to the existing infrastructure of diesel fleets. The largest hurdle will be, if choosing to use field gas with e-fleets, keeping the quality of gas above the Methane Number required to keep emissions within standards. For dual fuel fleets, the fuel quality must be kept above the Methane Number required for the engines, as discussed above. E-fleets will have additional hurdles in implementation, as they represent a more significant change in equipment.

Overall, all technologies presented are options which can be utilized to meet the criteria of a pressure pumping fleet. It is up to both the service company and operator to decide their efficiency, emissions, and economic priorities to determine which technology to capitalize on. In either case, maximizing efficiencies should be at the forefront of this progression in order to further reduce emissions and costs.

AUTHOR BIOS

Roy Aune - Roy is the Director of Research and Development for Liberty Oilfield Services. He has an extensive project background in resource extraction in mining and served as Director of Engineering for Amcol International and CEO of Cronimet Chrome Mining South Africa prior to joining Liberty.

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Chris Wright - Chris is the CEO and Chairman of Liberty Oilfield Services and Executive Chairman of Liberty Resources. He has been a career energy entrepreneur.

Chris received an undergraduate degree in Mechanical Engineering from MIT and then pursued graduate studies in Electrical Engineering at U.C. Berkeley and MIT in the area of power electronics and semiconductor device physics. He also worked briefly on fusion energy at MIT and solar energy at Berkeley. Chris has authored over 60 technical papers on a wide variety of energy technologies, most significantly in the area of hydraulic fracturing surrounding the start of shale revolution in the late 1990’s.

Ron Gusek - Ron Gusek has been the President of Liberty Oilfield Services since November 2016. Before assuming the role of President, Mr. Gusek was the VP of Technology and Development from 2014 to 2016. Over the past 20 years, Ron has garnered extensive oil and gas experience in North America and extended his knowledge of operations through travels to Asia, Russia, and the Middle East.

Within Liberty, Ron’s focus includes new technology and innovation, service quality, efficiency, and optimization. Ron holds a B.S. in Mechanical Engineering from the University of Alberta. Ron has also held previous roles at Sanjel Corporation, Zodiac Exploration and Pinnacle Technologies with a primary focus on hydraulic fracturing in unconventional reservoirs.

Madison Hollaway - Madison is a Staff Engineer in the Research and Development Department at Liberty Oilfield Services. She has worked as a field engineer with Liberty in multiple shale plays throughout the US, including the Williston, Permian, and DJ Basins. Madison received her undergraduate degree in Petroleum Engineering from Texas A&M University, where she graduated Cum Laude.

APPENDIX

Additional Natural Gas Discussion

Methane number is a measure used to determine the knock resistance of fuel. The knock of a fuel is basically when the fuel burns unevenly due to the air and fuel mixture. This is a function of fuel composition, with a specific emphasis on Methane, ethane, propane, and butane. Pure Methane has an index value of 100, which indicates that it is highly resistant to knock. On the other hand, Hydrogen has a value of 0, indicating that it has no resistance to knock. The Methane Number is an indication of the equivalent Methane/Hydrogen mixture of that fuel. For example, if a gas has a Methane Number of 80, burning that gas would be like burning a mixture of 80% Methane and 20% Hydrogen. A link to a Methane Number calculator is listed below:

Methane Number Calculator

As discussed above, as Methane Number decreases, emissions will increase. This is very dependent on the composition of the fuel as well. If there are two 80MN fuels, one with 2% hexane+ and one with 5% hexane+, the one with the higher percentage of hexanes will result in higher emissions. Overall, as the hydrocarbon chains get longer, the emissions will increase.

DEFINITIONS

- **Simple Cycle Turbines** - the turbines have no method of waste heat recovery. In this case, the steam which results from burning the gas is not utilized. This is currently the only option for frac applications.
- **Combined Cycle Turbines** - the steam which is created from burning the gas is rerouted into a steam turbine. This increases the efficiency and power of the system. For the time being, the equipment required for this technology is too large to maneuver to a frac location.
- **DGE** - diesel gallon equivalent. This unit is utilized to easily compare natural gas volumes to diesel volumes. The conversion factor from standard cubic feet (scf) to diesel gallon equivalent is: 1 DGE = 139.3 scf.
- **Dual Fuel Engine** - a dual fuel engine utilized a mixture diesel and natural gas when a load is applied.
- **Diesel Displacement** - the ratio of natural gas to diesel which is being used to power the engine. For example, if diesel displacement is 75%, a blend of 75% natural gas and 25% diesel is being used. During operation, the dynamic gas blending system continuously monitors the engine and combustion for abnormal and uncontrolled combustion cause by anomalies and general reduced quality in the natural gas. When an abnormality is detected, diesel displacement will be decreased in order to return the combustion to normal operating conditions.
- **Emissions**
 - **CO₂e** - Carbon Dioxide Equivalent. This includes all greenhouse gases. Each gas has an equivalent global warming potential (GWP) to Carbon Dioxide. For example, Methane will contribute 25x more to global warming than Carbon Dioxide. All components of CO₂e and their associated GWP can be seen below. For this analysis only CO₂ and CH₄ were considered while calculating CO₂e emissions. Both turbines and diesel/dual fuel engines generate trace amounts of N₂O, but they are not a significant source of greenhouse gases.

Table 10 - CO2 Equivalent GWP

Greenhouse Gas	Global Warming Potential (GWP)
Carbone Dioxide (CO ₂)	1
Methane (CH ₄)	25
Nitrous Oxide (N ₂ O)	298
Hydrofluorocarbons (HFCs)	124 - 14,800
Perfluorocarbons (PFCs)	7,390 - 12,200
Sulfur Hexafluoride (SF ₆)	22,800
Nitrogen Trifluoride (NF ₃) ³	17,200

o **NOx** - encompasses both Nitrogen Oxide (NO) and Nitrogen Dioxide (NO₂). These emissions are one of main constituents of smog. When combined with unburned hydrocarbons in the atmosphere, smog will appear.

o **CO** - Carbon Monoxide. When animals and humans are exposed to extremely concentrated amou nts of CO, it can be extremely toxic.

- **Greenhouse Gases** - these include Carbon Dioxide (CO₂), Methane (CH₄), Nitrous Oxide (N₂O), Hydrofluorocarbons (HFCs), Perfluorocarbons (PFCs), Sulfur Hexafluoride (SF₆), and Nitrogen Trifluoride (NF₃). These seven gases contribute to global warming. Neither NO_x nor CO are considered greenhouse gases.
- **Thermal Efficiency** - energy in versus energy out. In this case, energy in is the energy provided by the fuel, measured by the lower heating value. Energy out is the power produced by the turbine/pump.

FURTHER EMISSIONS DATA

Below are the CO₂e, CO, and NO_x emissions for the Williston, **Figure 19** to **Figure 21**.

Figure 19 - Williston CO₂e Emissions at 67.3°F

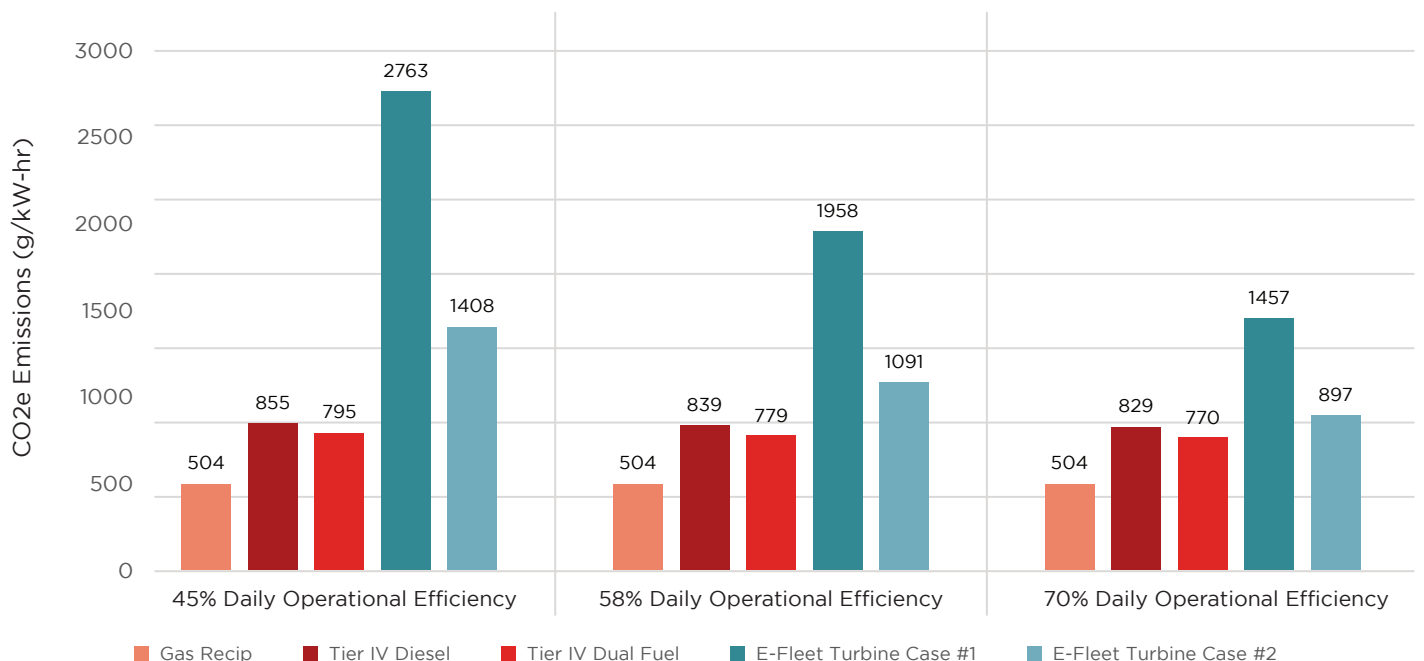


Figure 20 - Williston CO Emissions at 67.3°F

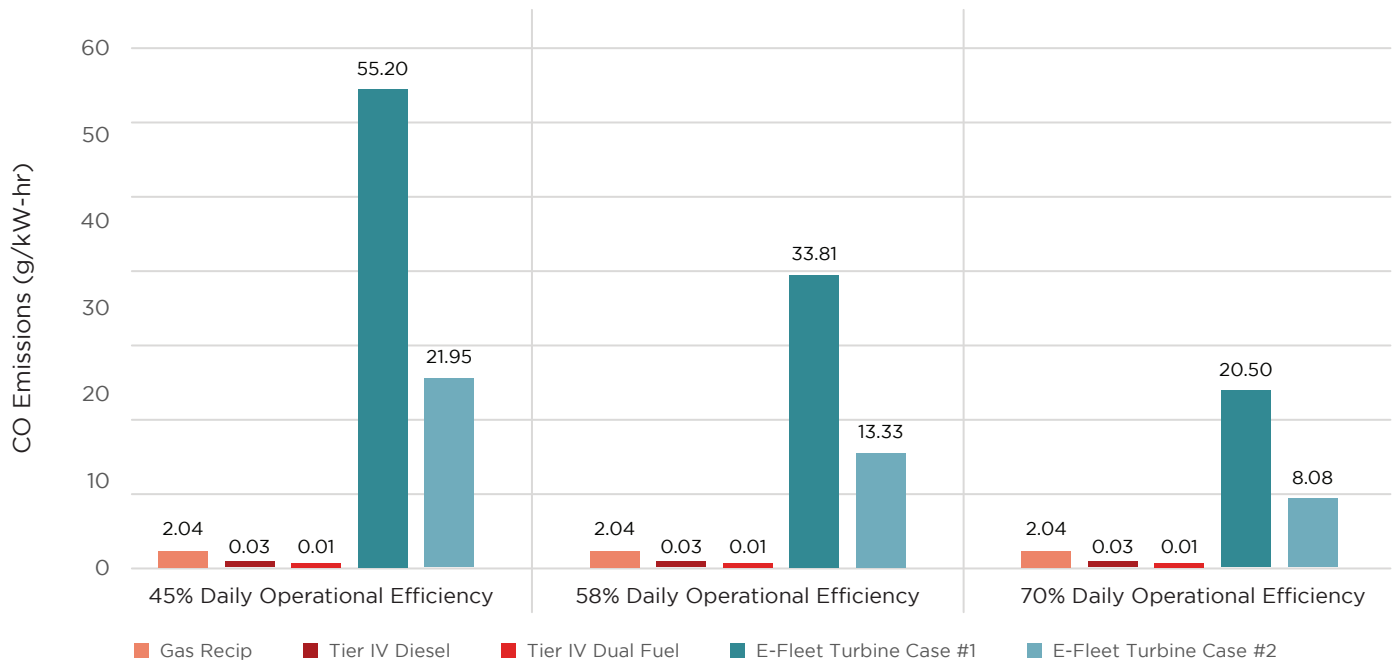
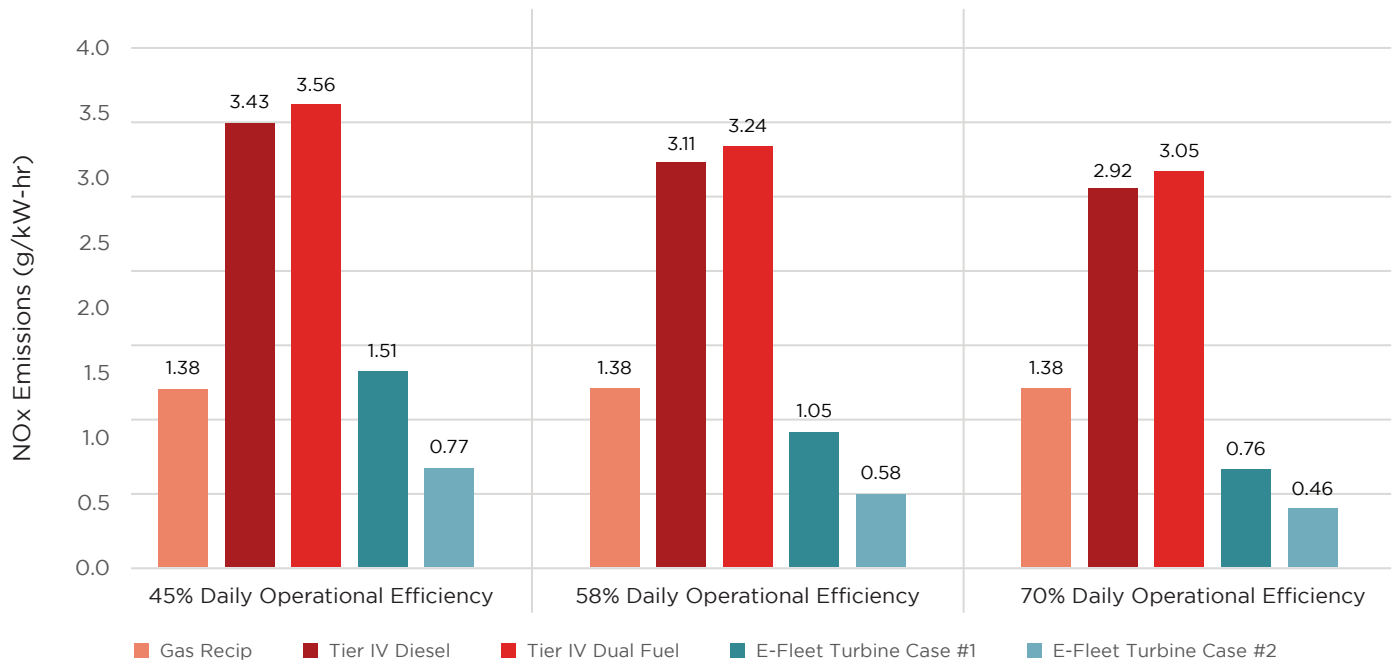
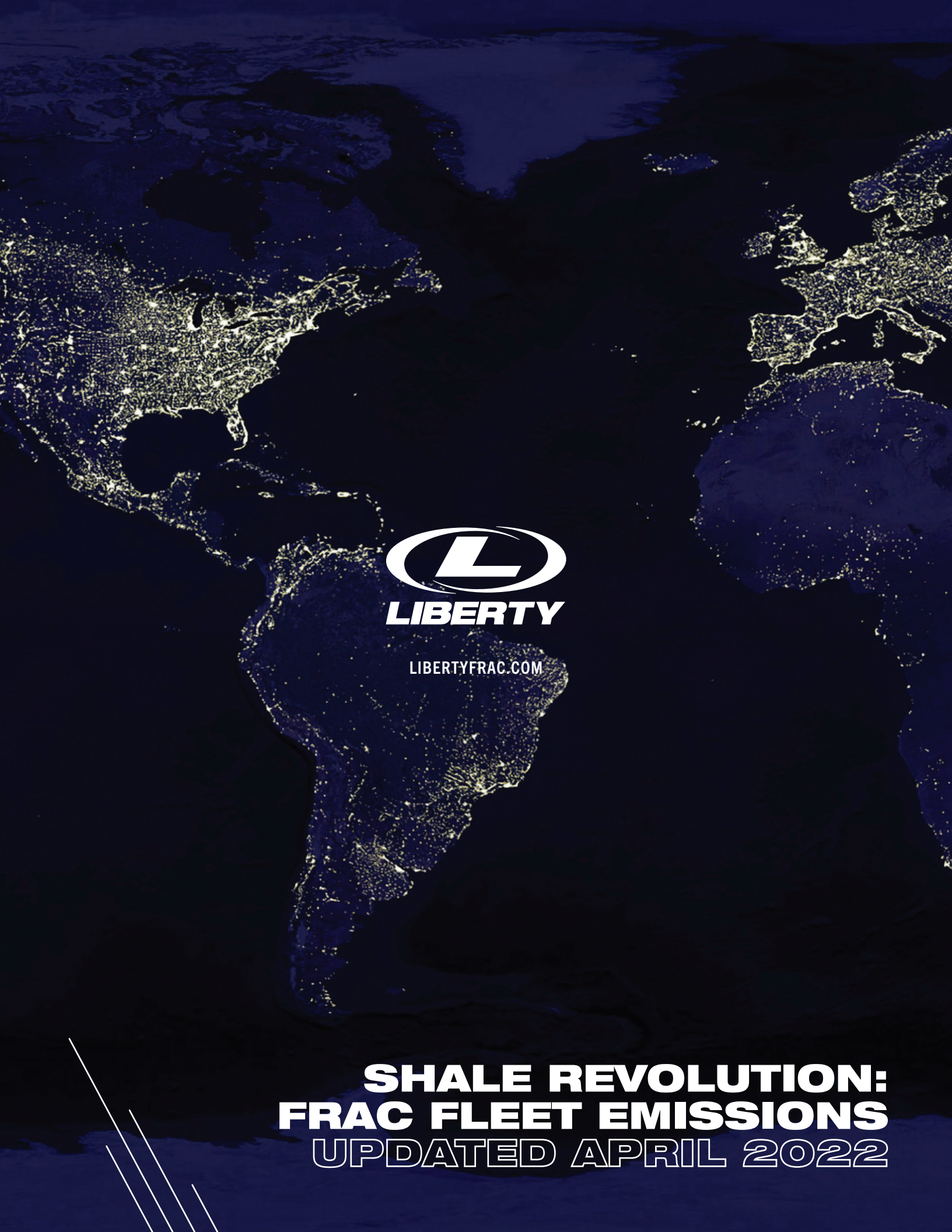


Figure 21 - Williston NOx Emissions at 67.3°F





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