Gas Enhanced Membrane Fuel Gas Conditioning Solutions for Compressor Stations with Ultra High BTU Gases in Oil-rich Shale Plays

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ABSTRACT

Raw unprocessed natural gas is widely used to power field engines and turbines that drive compressors or generate power. In condensate-rich shale-gas plays such as Utica, Bakken, Niobrara, Marcellus, Eagle Ford, the raw shale gas is super rich in heavy hydrocarbons. These raw gases do not meet the methane number, Wobbe Index requirements for fuel gas. Problems include pre-detonation, de-rates, emissions issues. Also, mechanical reliability & engine efficiencies are reduced resulting in production loss.

Recently unique reverse-selective membranes to preferentially remove heavy hydrocarbons from raw shale-gas have been introduced. This paper discusses a new hybrid patented process combining membrane with a Joule Thompson effect (JT process). This unique hybrid design lends flexibility to handle wider swings in the raw feed gas quality, pressures and temperatures and still deliver spec-quality fuel gas. Field site-data is presented for the membrane unit installed at Energy Transfer's compressor site in the Eagle Ford shale area. Additionally as valuable heavy hydrocarbons are removed from the fuel gas and recovered in the downstream Energy Transfer's NGL plant, substantial additional revenues are generated leading to low payback times.

Many membrane fuel gas conditioning units have been installed around the world for reducing the heavy hydrocarbons from the fuel gas. The hybrid design is also adopted recently by a number of operators including major players like Markwest Energy, Petrofac etc. These units have been used for Wartsila, Caterpillar, Waukesha, Superior and other reciprocating engine makers and also for turbine fuel gas conditioning.

INTRODUCTION

In many shale-gas plays, especially wet- and/or condensate-rich shale gas plays, only raw and super rich heavy shale gas is available as fuel for compressor drives and power generation turbines. Due to availability of extremely rich (High BTU Value) raw gas in such shale-gas plays, operators usually experience engines de-rate, foul engine components causing mechanical reliability issues & reduced compressor efficiencies, thereby leading to frequent shutdowns. Since the gas has excessive amounts of ethane, propane, butanes and C_{5+} hydrocarbons, this ends up in a very low methane number for gas engines, or too high a Wobbe Index for turbines. In order for the engines to run smoothly, the gas engines are required to be de-rated and hence cannot be run at or near full capacity. In turbines, coking on the nozzles and in the combustion chamber leads to reduced efficiencies due to fouling or damage to the blades.

Additionally, in both gas engines and turbines, increased emissions of unburned VOCs will result if the inlet gas is too rich. Compressor engine exhausts are a major source of a variety of strictly regulated emissions including NOx, CO, and non-methane hydrocarbons (VOC). Operators have to meet several stringent emissions requirements to remain within the thresholds of allowable emissions limits of the above mentioned components. In cases where the raw fuel gas is rich, high levels of heavy hydrocarbon content in the fuel gas are responsible for incomplete combustion and/or pre-detonation in the gas engines leading to increased CO and non-methane hydrocarbons emissions (NMHC) beyond the acceptable limits[1].

Membranes provide a simple solution to these highly rich fuel gas related issues discussed above. For ultra-rich fuel gases, MTR has developed and demonstrated a unique hybrid design combining the proven membrane process with a Joule Thompson (JT) process for fuel gas conditioning. The raw unprocessed gas after basic handling in a JT unit is processed using a special type of membrane that is more permeable to heavy hydrocarbons and acid gases than to methane. Membrane Technology and Research, Inc. (MTR), of Newark, CA, has developed commercial systems and processes incorporating specialized membrane technology to treat heavy and/or sour fuel gas streams[3]. The process, known as FuelSep™, is in use at a number of sites and for a variety of upstream fuel gas streams. To date, these membranes have been installed at more than hundred sites for heavy hydrocarbons separation from natural gas. Skid–mounted compact membrane units make the FuelSep™ process particularly suitable for remote wellheads and compression stations where high levels of heavy hydrocarbons present in the fuel gas are reduced significantly.

MEMBRANE BACKGROUND

Membrane systems to remove carbon dioxide were introduced to the natural gas processing industry in the mid-1980s. These conventional-type membranes separate gases primarily based on differences in molecular size. The small carbon dioxide molecules permeate faster through the membranes compared to the relatively larger methane molecules, but retain the even larger heavy hydrocarbon molecules in the gas stream. In contrast, a new type of membrane that utilizes differences in gas solubility to permeate both heavy hydrocarbons and carbon dioxide has been developed, and these enhanced capabilities provide new opportunities for membrane use in natural gas separations.

HOW MEMBRANES WORK

Membranes used to filter liquids are often finely microporous, but membranes used to separate gases have only transient pores so small they are within the range of the thermal motion of the polymer chains that make up the selective polymer layer. Permeation through gas separation membranes is therefore best described by a process called solution-diffusion. Gas molecules dissolve in the polymer membrane as in a liquid and then diffuse across the membrane and then desorb from the polymer on the opposite interface which is typically maintained at a lower pressure as compared to the feed. The rate of gas permeation is a product of a solution term (how many molecules dissolve in the membrane), and a diffusion term (how fast each individual molecule diffuses across the membrane). Fuel gas-conditioning membranes are chosen from materials that maximize the effect of the solution term. Although each individual molecule of butane, for example, diffuses more slowly across the membrane than each individual molecule of methane, the very high solubility of butane more than compensates for the slower diffusion. Fuel gas conditioning membranes therefore preferentially permeate water, carbon dioxide, hydrogen sulfide, C_{2+} hydrocarbons and BTEX aromatics, while retaining methane. Because most of us are familiar with conventional filtration, this result feels counter-intuitive. Nevertheless, these unique properties are what make the membranes particularly useful in fuel gas conditioning applications.

MEMBRANE STRUCTURE

Membranes used to separate heavy hydrocarbons from natural gas typically have multilayer composite structures of the type shown in Figure 1. Composite membranes are used because the optimum materials for performing the separation are rubbery polymers, which are mechanically weak. Furthermore, to obtain high permeation rates, the selective membrane must be very thin, typically between 0.5 and 5.0 µm thick. Finally, the membrane must be able to support a pressure differential of 200 to 1,500 psi.

Even though composite membranes have extremely thin selective layers, many square meters of membrane are required to separate a useful amount of gas. The units into which large areas of membrane are packaged are called membrane modules. In the FuelSep™ process, spiral-wound membrane modules of the type illustrated in Figure 1 are used. The membranes are formed into a sealed membrane envelope, and then, with appropriate feed and permeate channel spacer netting, are wound around a perforated central collection pipe. The module is placed inside a tubular pressure vessel. One to six modules may be connected in series within each pipe. Pressurized feed gas passes axially down the module, across the membrane envelope on the feed side. A selective portion of the feed permeates into the membrane envelope, where it spirals towards the center and is collected through the perforated permeate collection pipe. The treated gas is withdrawn from the feed side at the residue end of the module.

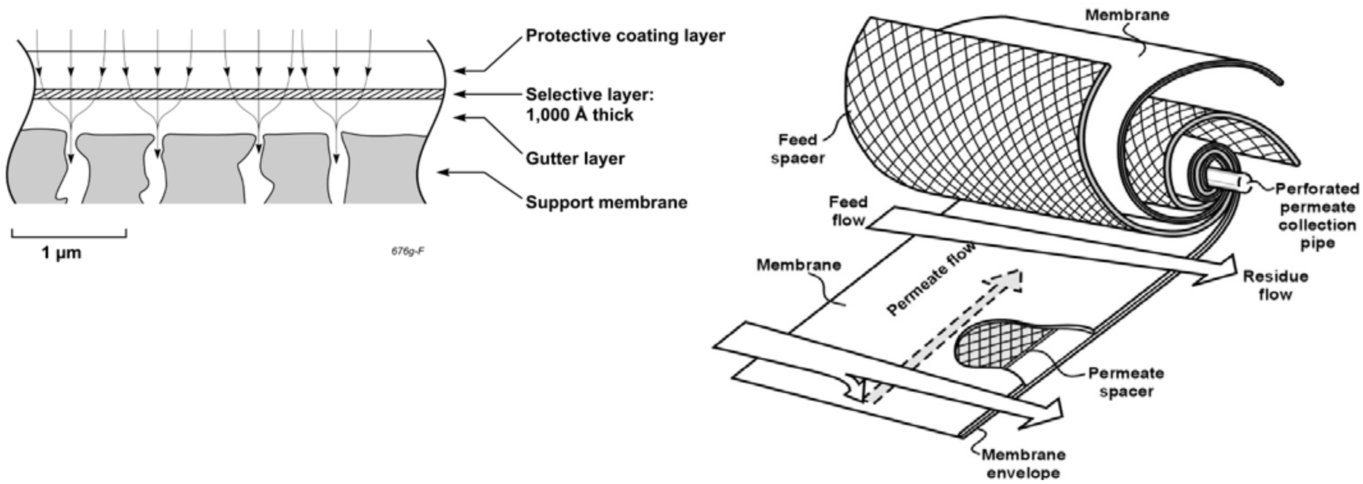

Figure 1. Schematic illustrations of a composite membrane and a spiral-wound module of the type used in fuel gas conditioning units.

ADVANTAGES

The key advantages of a membrane FGCU can be summarized thus:

- **Simple, passive system**
- **High on-stream factor (typically >99%)**
- **Ambient temperature operations**
- **Minimal or no operator attention**
- **Small footprint with low weight**
- **Large turndown ratio**
- **Rapid start up and shut down**
- **Low maintenance**
- **Low capital and operating costs**
- **Units are mobile and can be redeployed to other locations**
- **Handles fluctuating feed gas compositions**

Ease of Operation: A membrane FGCU is completely passive, has no moving parts, and requires no chemicals to operate. The system can reach steady state performance within a few minutes of startup, and can be fully automated and remotely monitored, so that it can run unattended. Little or no maintenance is needed.

Easy Low cost Installation: Units are skid-mounted and can be installed wherever a reasonably level patch of gravel or soil can be provided, without needing a permanent foundation. Normally, a skid will operate in one location for months or years, but skids are very robust, and can be trucked to a new site if circumstances change.

Flow-rate Range: Membranes are modular in nature; and subsequently, FuelSep™ can be used as a stand-alone operation to process gas streams from as low as 0.1 MMscfd to upwards of 100 MMscfd and more. In most upstream applications for fuel gas conditioning, typical membrane units are designed for fuel gas flow-rates of 0.05 MMSCFD for a single genset up-to 5 MMSCFD for a large multi-unit compressor station.

No Pre-treatment: Typically, the feed gas requires no pretreatment, except for standard filtration.

Fuel Gas Dehydration: Membranes dehydrate the fuel gas; no separate hydrate control is required.

Feed BTU Variations: It is not uncommon to experience variations in the BTU levels in the raw field gas. Such BTU variations in the raw feed gas can be easily handled by adding additional membrane modules to the existing membrane unit thereby maintaining a continuous and consistent delivery of clean conditioned fuel gas at an acceptable range of BTU values.

CASE STUDY

Higher BTU (Hot Gas) or Heavy Hydrocarbon Rich Fuel Gas for Gas Engines

The paper will discuss the decision strategy employed, operational performance review of the hybrid design involving JT process and membranes installed at Energy Transfer's natural gas compressor station. The process schematic along with the photograph of the Fuel Gas Conditioning Unit (FGCU) installed for Regency (Energy Transfer) is shown in Figure 2. Energy Transfer was planning to install a natural gas fired engine to drive a housed compressor to compress gas to a higher pressure for moving gas into the sales pipeline and to drive the compressor engines installed on its VRU unit (vapor recovery unit). The raw gas was the only available source of fuel for driving the gas engines for compressors due to the remote location of the compressor-site. The raw gas was highly rich in heavy hydrocarbons, especially with a high ethane content of 12 % and a HHV of 1220 BTU/SCF.

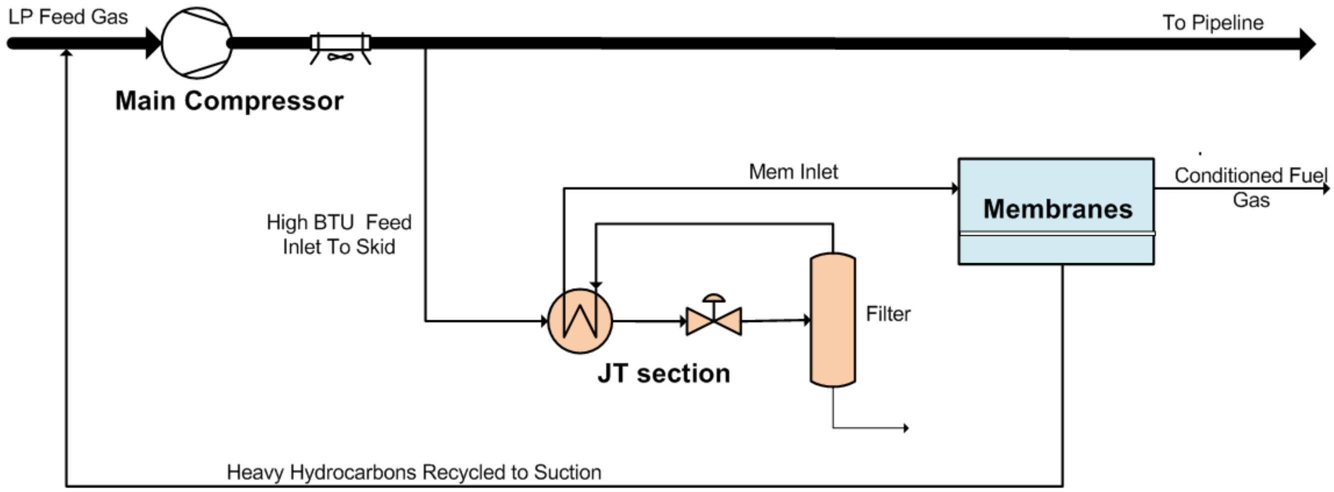

Figure 2. Block diagram & Photograph of the Hybrid JT and Membrane system at Energy Transfer's compressor station in Eagle Ford shale play. The membrane modules are contained in the horizontal pressure vessel. The unit is designed to generate maximum of 0.5 MMscfd of conditioned fuel gas.

Issues Faced By Client

The client faced several potential difficulties in operating the gas engines at the site predominantly due to the high levels of heavy hydrocarbons in the raw fuel gas, and is listed below:

a. Knocking-Detonation Issues –

   The raw fuel gas would have caused operational issues related to knocking, detonation etc. leading to increased wear and tear of the engine components and increased maintenance costs.

b. Engines Cannot be Started –

The raw gas available for fuel was so rich in heavy hydrocarbons, that the client was unable to even start the engines, hence unable to move the raw gas into the sales gas pipeline resulting in an in-ability to flow the field and therefore a loss in revenues.

c. Engines Warranties Violation

The engine manufacturer's warranties were tied to a typical max BTU limit of 1150 BTU/SCF on the HHV of the fuel gas; and, if the client were to use the engines with the high BTU raw fuel gas, then it would have immediately nullified their engine warranties.

Options Evaluated By Client

Energy Transfer evaluated several options to resolve the above issues, which are listed below (Table 1):

a. JT Process Only
   A JT (Joule Thompson) process works on the principle of pressure throttling to achieve low temperatures in order to condense liquids out from the raw feed gas. The process results in recovering conditioned fuel gas with lower BTU content. However, JT process is not efficient enough to condense lighter components such as ethane and propane (C2/C3) out from the raw gas which are major contributors for a high BTU value. Also, low temperature in the fuel line is another issue which poses challenge to deal with hydrate formation. Moreover, any increase in the raw gas BTU will lead to further increase in the BTU values of the fuel gas, throwing it further out of spec. Due to all these limitations, the JT process could not meet the client's requirements on site.

b. Refrigeration
   Refrigeration has similar issues like JT process related to liquids formation: low temperatures, hydrates etc. Again, lighter component such as ethane cannot be condensed out from the raw fuel gas even with typical operating temperatures of about -20^{o}F for regular propane based refrigeration systems. The process is more complicated than JT as it involves moving parts and may also require special permitting if required to classify it as a process.

c. Membranes + JT

For Ultra-rich fuel gases, MTR has developed a unique hybrid design combining the proven membrane process with a Joule Thompson (JT) process for fuel gas conditioning. In this design, the JT process comprising of a heat exchanger and a pressure reducing valve is installed upstream of membranes. Since the high pressure (HP) gas is throttled to medium pressure, warm temperature is experienced at the JT outlet as opposed to the solo JT process where HP gas is throttled to a very low pressure thereby leading to very low temperatures at the process exit. The JT process removes the C4+ components and minimizes the heavy hydrocarbons load on the membrane, and also provides superheated feed gas to membranes. In addition to further removing the C3+ components of the fuel gas, membranes also significantly reduce the ethane content which further lowers the BTU content of the fuel gas. And finally, from an operational perspective, membranes offer the added advantage of being able to handle changes in the feed BTU and/or pressure variations and still deliver the required spec quality fuel gas to the engines. The hybrid design thus completely eliminates the challenges faced by the solo JT process and provides an optimal solution for super rich BTU shale plays.

Based on the above discussed factors and the overall simplicity of the hybrid design, the client decided to install a Membranes + JT combo unit for fuel gas conditioning for their compressor engine fuel.

Table 1. Comparative Evaluation Matrix for JT, Refrigeration and Membrane processes.

	JT Process	Refrigeration	Membranes + JT
Reduce Ethane (C2)	**No**	**No**	**Yes**
Moving Parts	**No**	**Yes**	**No**
Raw Feed Gas – BTU Variability Handled?	**No**	**No**	**Yes**
Raw Feed Gas – Pressure Variability Handled?	**No**	**Likely**	**Yes**

Membrane Hybrid Fuel Gas Conditioning Unit

A. Technical Details

Compressor Station Details – Energy Transfer installed MTR's membrane hybrid fuel gas conditioning unit at one of their compressor stations in Eagle Ford shale. Following are some relevant details for the compressor station:

a. Type & No. of engines - 1 x CAT 3304 + 1 x CAT 3306 + 1 x CAT 3516
b. Total site rated engine horsepower - 965 hp
c. Total engines fuel demand - 0.35 MMscfd
d. Total gas compressed - 35 MMscfd
e. Compressor suction pressure - 680 psig
f. Compressor discharge pressure - 980 psig

Membrane System Details - Following is a list of some relevant details of the membrane system installed at Energy Transfer's compressor station:

a. Fuel generating capacity - 0.5 MMscfd
b. Fuel spec quality (HHV) - 1150 BTU/SCF
c. No. of membrane Vessels - ONE (1)
d. Feed pressure - 630 psig
e. Permeate pressure (VRU Suction) - 150 psig

Process – Process schematic for the hybrid fuel gas conditioning scheme is shown in Figure 2. The inlet to the membrane unit is taken as a slip-stream from the high pressure compressor discharge line @ 980 psig. The HP feed gas is first passed through a heat exchanger where it is subsequently cooled down against the throttled feed stream. The feed gas is next throttled to 630 psig and enters a filter coalescer which removes the liquid condensates formed before entering the membrane vessels. The membrane vessel splits the inlet into two streams:

1. The membrane vessel preferentially permeates heavy hydrocarbons and the resulting permeate stream enriched in the heavies is routed back to the suction of the existing VRU unit @ 150 psig.

2. A conditioned fuel gas stream with a reduced HHV content which is next throttled to a lower pressure and routed to the fuel header as fuel for gas engines.

B. Field Operational Data

Gas Composition – BTU Reduction

Table 2 shows the gas compositions of the raw feed entering and conditioned gas exiting the JT+ membrane hybrid system based on actual field site data in Eagle Ford shale play. The system removes heavy hydrocarbons from raw gas, thereby reducing the HHV of the raw gas from 1200 BTU/SCF to 1072 BTU/SCF in the conditioned fuel gas. The CAT methane number also has a significant improvement from 52.4 (raw gas) to 74 (conditioned fuel gas). The conditioned gas thus easily meets the minimum methane number requirement of 60 for CAT engines. In addition to the removing C3+ components, the ethane content has also considerably reduced from 12.1% to 6.1% in the fuel (almost 50% reduction). This reduction is completely unattainable in a typical JT or a propane based refrigeration systems. Moreover, lowering of the BTU value in the fuel gas also allows the compressor engines to be tuned within acceptable emissions limits thereby avoiding any detonation related issues in the engines.

Table 2. Performance Data for a membrane FGCU installed at Energy Transfer's compressor station in TX.

Stream	Raw Feed Gas	Conditioned Fuel Gas
Methane Number	52.4	73.9
HHV (Btu/scf)	1220	1072
Component (mol%)		
Methane (C1)	79.1953	91.0939
Ethane (C2)	12.1721	6.1202
Propane (C3)	4.5876	1.5407
Butanes (C4)	2.3434	0.6018
Pentanes (C5)	0.6029	0.1005
Hexanes plus (C6+)	0.1905	0.0304
Nitrogen (N_2)	0.0751	0.1560
Carbon Dioxide (CO_2)	0.8331	0.3565

C. Hybrid Membrane Design in various Shale plays

In addition to the Eagle Ford shale, the patented hybrid design can also be implemented in various other shale plays such as Bakken, Utica and Niobrara shale where extremely rich raw gas is available on site. Table 3 shows the BTU reduction that can be achieved by deploying the design to these shale plays. Simulations have been performed based on various shale gas compositions while using the same pressure/temperatures and fuel demands as was used for the Energy Transfer's design case.

Table 3. BTU Reduction achieved using the hybrid Membrane design.

Shale Plays	Feed HHV Raw Gas	Fuel HHV Conditioned Gas	Net HHV Reduction
Eagle Ford	1220	1100	120
Niobrara	1263	1114	150
Utica	1309	1134	175
Bakken	1390	1155	235

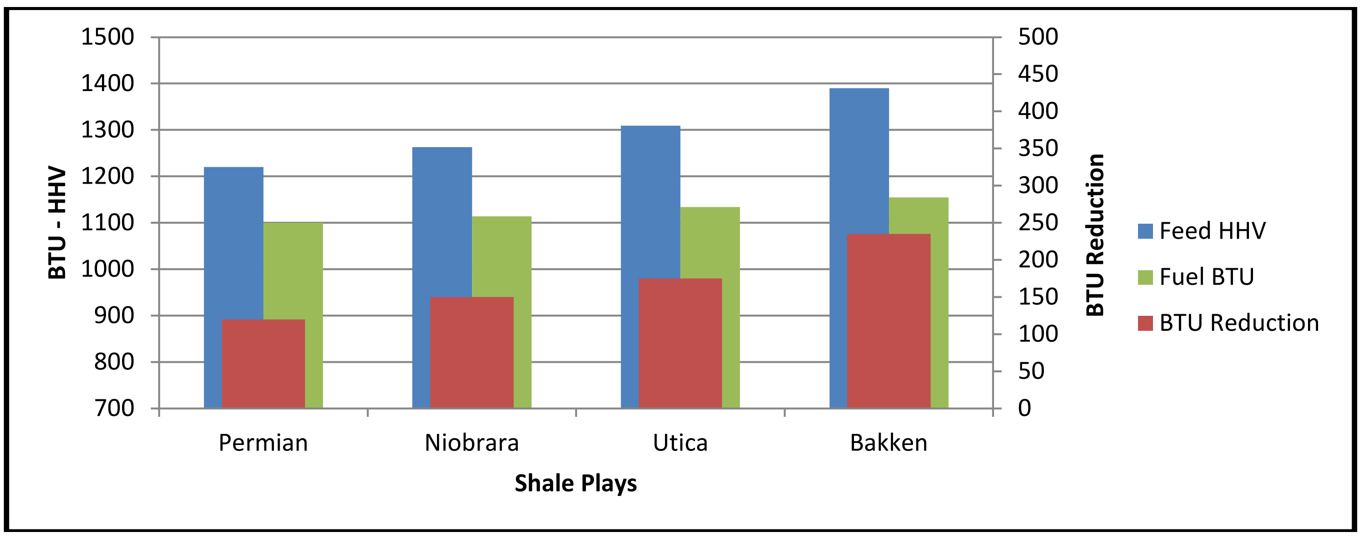

Figure 3. The column presents the BTU reduction by the membrane hybrid system achieved in various shale plays.

Figure 3 clearly indicates that a much higher BTU reduction is realized when the available raw gas is super rich in C2+ components. Table 2 supports the findings indicated in Figure 3 which shows that as the BTU content in the feed gas increases, the hybrid membrane system performs more efficiently by removing even higher amounts of heavy hydrocarbons. For example, for Eagle Ford shale play with a feed HHV of 1220 BTU/SCF, the BTU reduction in the fuel gas is 120 BTUs which increases to 175 BTUs for the Utica shale with a feed BTU of 1309 BTU/SCF. Note that one of the major reasons for this increased BTU level is the increased ethane content in the feed shale gases. The ethane content goes up from 12% in Eagle Ford shale to approximately 23% in the Bakken shale along with a considerable increase in the amount of C3+ components as well. The front end JT scheme removes the bulk of the C4+ components efficiently, thereby reducing the membrane load resulting in lower membrane area (cost optimized approach). The membranes at the back end then further lower the C2 and C3+ content, that was not removed by the JT process, thus efficiently bringing the BTU level to down to the spec limit. With the hybrid design in place, the feed to fuel BTU reduction achieved is from 120 BTU in Eagle Ford shale to 275 BTU in Bakken shale region.

It should be noted simulation results reported in Table 2 are obtained by using the typical gas composition available for different shale plays. The other conditions such as feed Pressure, temperature, fuel demand, heat exchanger design and the membrane modules utilized are kept constant to analyze the performance of the patented technology (JT + Membrane hybrid) for various shale plays. Thus, the simple design can be implemented with ease in various shale plays with medium rich to ultra-rich BTU.

<u>Additional Condensate Recovery</u>

If unprocessed raw gas (high BTU) is burned in the gas engines as fuel gas, this would result in wasting relatively larger amounts of heavy hydrocarbons which are more valuable if recovered in the liquid phase. On the other hand, instead of burning them in fuel, MTR's membrane hybrid technology, results in easy condensate recovery in two stages. A part of the NGLs in raw gas are recovered at the front end JT scheme. The remaining heavies are further recovered after exiting the membranes in gas phase. For Regency (Energy Transfer), the heavies-rich permeate stream coming off the membrane skid was sent to VRU suction to recover the lighter components. The resulting rich stream from the VRU was then routed to the suction drum of the main compressor which was further sent downstream to processing plants that was better suited to recover and handle the NGL's from the permeate stream. Figure 4 presents the block diagram of the entire process at Energy Transfer. Approx 30 bbl/d of additional C3+ are recovered amounting to approx $ 0.73 MM/year of additional revenues.

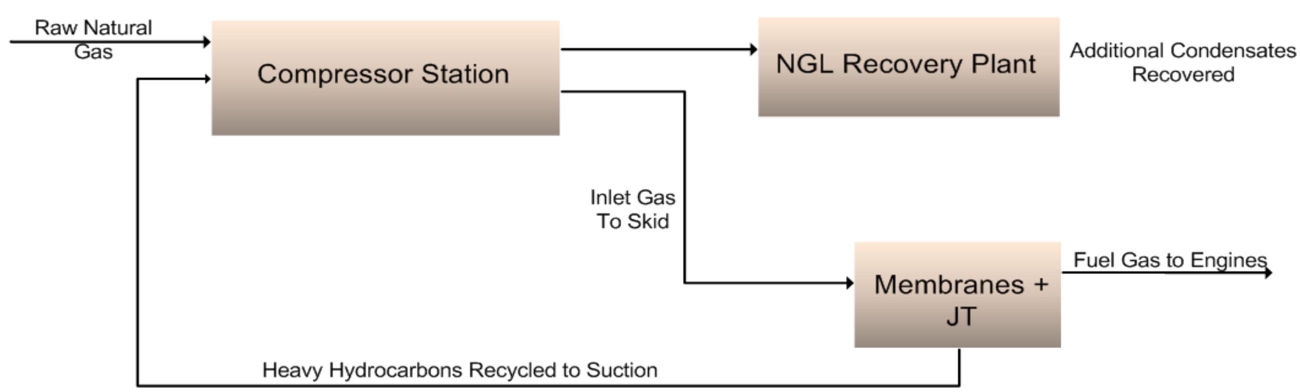

Figure 4. Block diagram of a membrane unit installed at a compressor station with a downstream NGL recovery Plant.

It should be noted in the absence of a Vapor Recovery Unit, the heavies rich permeate stream from the membranes can be directly routed to the suction of the main compressor from where it is routed to the downstream NGL recovery plant.

The membrane hybrid design facilitates the recovery of valuable heavy hydrocarbons as additional liquid condensates – partly on the site itself (at the front end JT process), and the remaining at the downstream condensate recovery plant. This results in additional revenues leading to very attractive payback times for the MTR's FuelSep™ hybrid process. In the absence of the process, these valuable heavy hydrocarbons are simply burned as raw fuel gas in the gas engines and hence lost.

Table 4 shows the additional C3+ recovered and the revenue generated from these NGLs in various shale plays. In the absence of MTR's hybrid design, these heavy hydrocarbons are burnt as fuel gas & hence lost.

Table 4. Additional C3+ condensates recovered due to the hybrid fuel gas conditioning process for various shale plays.

Shale Plays	Bbl/d	$/Year
Eagle Ford	30	$735,000
Niobrara	43	$1,053,500
Utica	47	$1,151,500
Bakken	73	$1,788,500

CONCLUSIONS

The following conclusions can be made from the onsite data available from Regency.

- **Low BTU Fuel –** The hybrid scheme significantly lowered the heavy hydrocarbon content from the High BTU rich raw feed gas to generate Lower BTU lean fuel gas which meets the fuel quality spec of a minimum CAT methane number of 60 for the Caterpillar engines driving the compressor station. The lean fuel gas significantly reduces pre-detonation and knocking issues in the engines, thereby significantly reducing operating maintenance costs at the station.

- **Increase BTU Reduction -** The hybrid membrane process works very efficiently for super rich shale plays where meeting the spec without the scheme is highly challenging. As the BTU content in the feed gas increases, the hybrid membrane system performs more efficiently by removing even higher amounts of heavy hydrocarbons.

- **Additional Condensate Recovery –** The heavy hydrocarbons recovered on-site (from JT scheme) and downstream NGL plant lead to very attractive payback time for MTR's patented technology. In the absence of MTR's hybrid design, these heavy hydrocarbons are burnt as fuel gas & hence lost.

High Btu content of fuel gas is a ubiquitous problem faced by compressor station operators especially in the oil-rich shale areas. By lowering the heavy hydrocarbon content of the fuel gas, MTR design provides lean fuel gas to the engines thereby providing higher reliability and online operating time, while reducing maintenance costs. The lean fuel gas also enables the operator to minimize the de-rates on the engines and stay within the permissible emission limits. The increased hydrocarbons recovery due to recycling the heavies back to the compressor station further leads to quick payback times.

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