Hybrid Systems: Combining Technologies Leads to More Efficient Gas Conditioning

William Echt
UOP LLC

Introduction

Various processes are used to condition raw natural gas to pipeline quality. Acid gas removal and dehydration are the most commonly employed, and among these processes, various technologies are available to the design engineer. For instance, dehydration can be accomplished via glycol or molecular sieves, depending upon the product gas specification. Carbon dioxide and/or hydrogen sulfide removal can be accomplished via amines, hot potassium carbonate or membranes. The choice of technology, or combination of technologies, is dependent upon the needs of the gas processor.

This paper focuses on the use of membranes and amines for CO_2 removal from natural gas. The basic operation and the advantages and disadvantages of each technology are reviewed. The combination of these technologies, referred to as a "hybrid" CO_2 removal system, offers unique characteristics that are explored in detail. Operating experiences from several hybrid units are presented to show the advantages that combining technologies brings to the gas processor.

An economic analysis highlights the substantial cost benefits of hybrid systems when used to process large volumes of gas. The savings in capital and operating expenses can be extended to hybrid systems consisting of membranes and any other downstream solvent process.

CO_2 Removal with Amines

CO_2 removal using amines is well understood because it has been widely used for acid gas removal. For the purposes of this paper it is assumed the reader is familiar with this technology. To quickly summarize:

- An aqueous alkanolamine solution is contacted in an absorber column with natural gas containing CO_2.
- The basic amine reacts with the acidic CO_2 vapors to form a dissolved salt, allowing purified natural gas to exit the absorber.
- The rich amine solution is regenerated in a stripper column, concentrating the CO_2 into an acid gas stream.
- Lean solution is cooled and returned to the absorber so that the process is repeated in a closed loop.

A typical flow scheme for this technology is shown in Figure 1. Improvements on the use of conventional amines in this conventional flow scheme include:

- Process configurations and equipment that reduce capital costs and energy consumption
- Use of specially formulated solvents to reduce solution circulation rates and energy consumption

Some of the papers exploring these improvements are listed in the bibliography (Ref. 1,2,3).

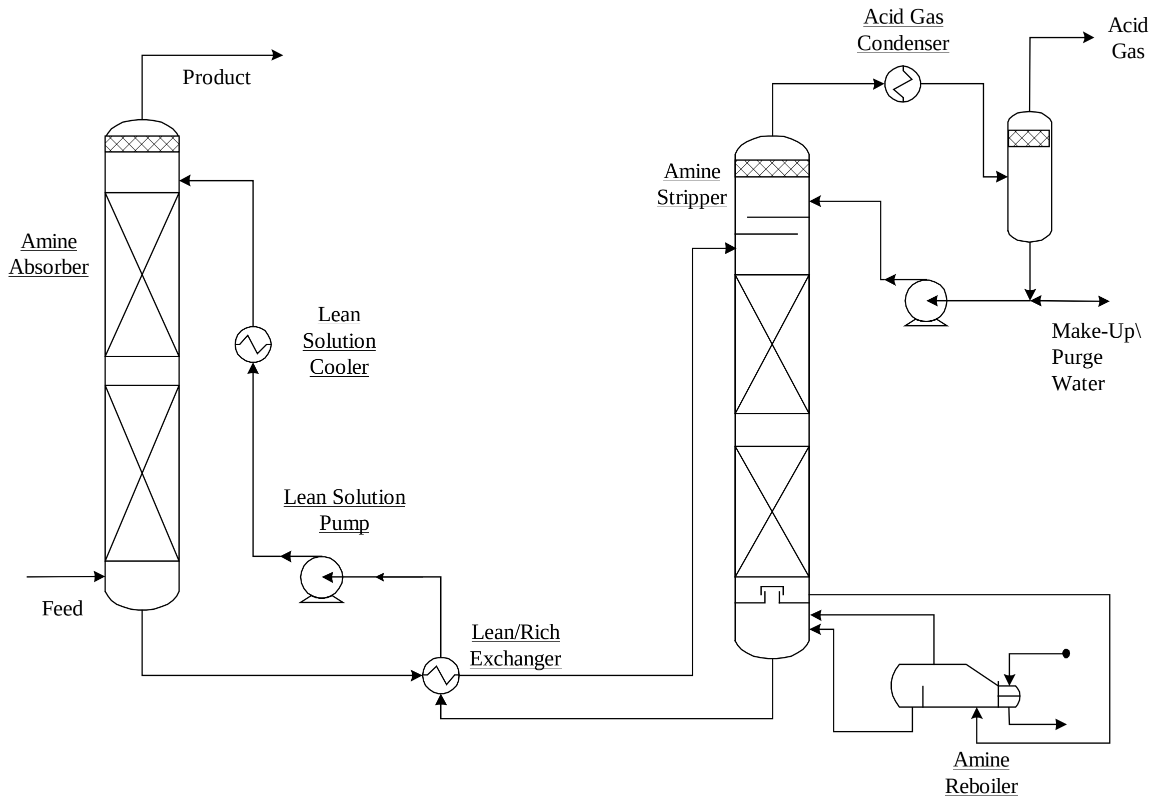


Figure 1: Conventional Amine Unit Flow Scheme

Once a design has been completed for a CO_2 removal system using amines, the critical parameters affecting capital and operating costs are shown in the following table:

	Operating Cost	**Capital Cost**
Circulation Rate	Pump kW-hrs, solvent losses	Pump cost, solvent inventory
Reboiler Duty	Energy requirement	Affects stripper column size
Column Diameters	-	Most expensive equipment
Solvent Cost	Solvent makeup	Solvent initial fill

The total gas flow rate and the CO_2 content of the gas processed will affect system costs. If an upstream operating unit removes CO_2 from the feed gas, the downstream amine unit can be smaller.

CO_2 Removal with Membranes

Semi-permeable membranes are a mature technology that has been applied in natural gas processing for over 20 years (Ref. 4). Membranes are currently used for CO_2 removal from natural gas at processing rates from 1 MMSCFD to 250 MMSCFD. New units are in design or construction to handle volumes up to 500 MMSCFD.

It has been recognized for many years that nonporous polymer films exhibit a higher permeability toward some gases than towards others. The mechanism for gas separation is independent of membrane configuration and is based on the principle that certain gases permeate more rapidly than others (Figure 2).

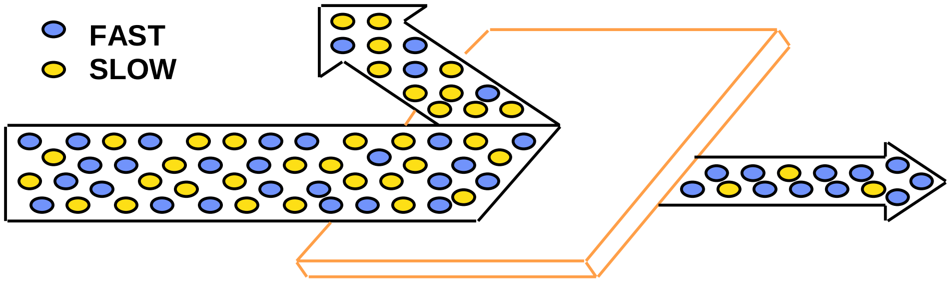


Figure 2: Thin Semi-Permeable Barriers that Selectively Separate Some Compounds from Others

"Permeability" is a measure of the rate at which gases pass through the membrane. "Selectivity" refers to the relative rates of permeation among gas components. The permeation rate for a given gas component is determined by the molecule's size, its solubility in the membrane polymer and the operating conditions of the separation. Selectivity allows a gas mixture of two or more components, of varying permeability, to be separated into two streams, one enriched in the more permeable components and the other enriched in the less permeable components. Figure 3 shows the relative permeability of the components most common in a natural gas stream.

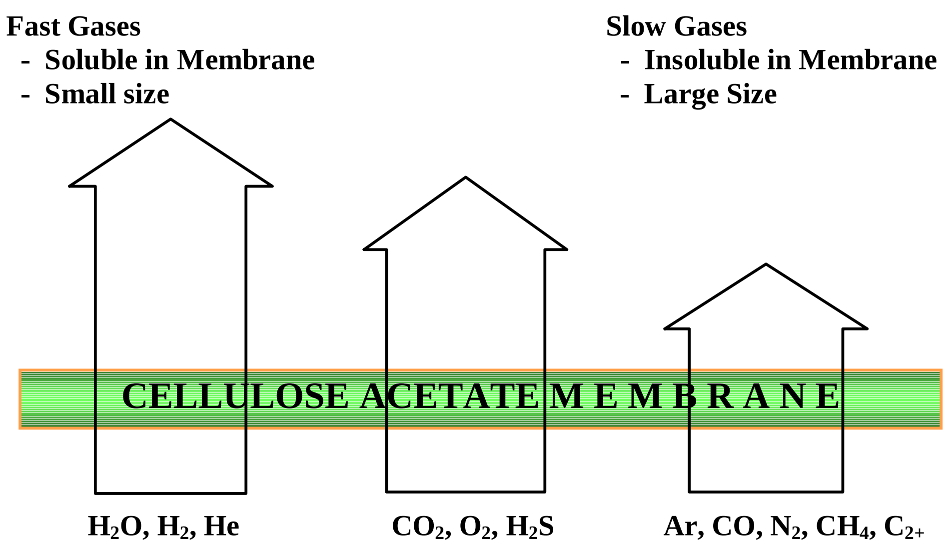


Figure 3: Relative Solubility of Some Typical Gas Components

Membrane Configuration

The technical breakthrough in the application of membranes to natural gas separation came with the development of a process for preparing cellulose acetate in a state which retains its selective characteristics but at greatly increased permeation rates than were previously achieved (4, 5). The new membrane was called asymmetric and was first cast into a flat sheet. The major portion of the asymmetric membrane is an open-pore, sponge-like support structure through which the gases flow without restriction. All the selectivity takes place in the thin, non-porous polymer layer at the top (Figure 4). Asymmetric membranes are made out of a single material. The permeability and selectivity characteristics of asymmetric membranes are functions of the casting solution composition, film casting conditions and post-treatment, and are relatively independent of total membrane thickness, though this parameter is closely controlled in the manufacturing process.

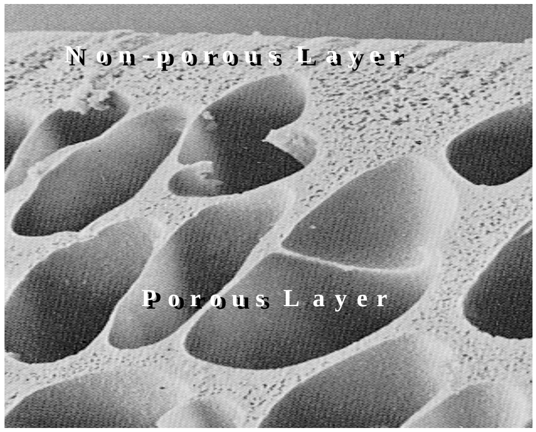


Figure 4: Asymmetric Membranes Use a Single Polymer with a Thin Selective Layer and a Porous Support Layer

Methods were later developed to incorporate this asymmetric membrane structure for gas separation in a hollow fiber configuration rather than a flat sheet. Hollow fibers have a greater packing density (membrane area per packaging volume) than flat sheets, but typically have lower permeation rates. Both configurations of cellulose acetate membranes have their individual advantages and disadvantages.

In order for membranes to be used in a commercial separation system they must be packaged in a manner that supports the membrane and facilitates handling of the two product gas streams. These packages are generally referred to as elements or bundles. The most common types of membrane elements in use today for natural gas separation are of the spiral-wound type and the hollow-fiber type.

Spiral-wound elements, as shown in Figures 5 and 6, consist of one or more membrane leaves. Each leaf contains two membrane layers separated by a rigid, porous, fluid-conductive material called the permeate spacer. The spacer facilitates the flow of the permeate gas, an end product of the separation. Another spacer, the high pressure feed spacer, separates one membrane leaf from another and facilitates the flow of the high pressure stream linearly along the element. The membrane leaves are wound around a perforated hollow tube, known as the permeate tube, through which permeate is removed. The membrane leaves are sealed with an adhesive on three sides to separate the feed gas from the permeate gas, while the fourth side is open to the permeate tube.

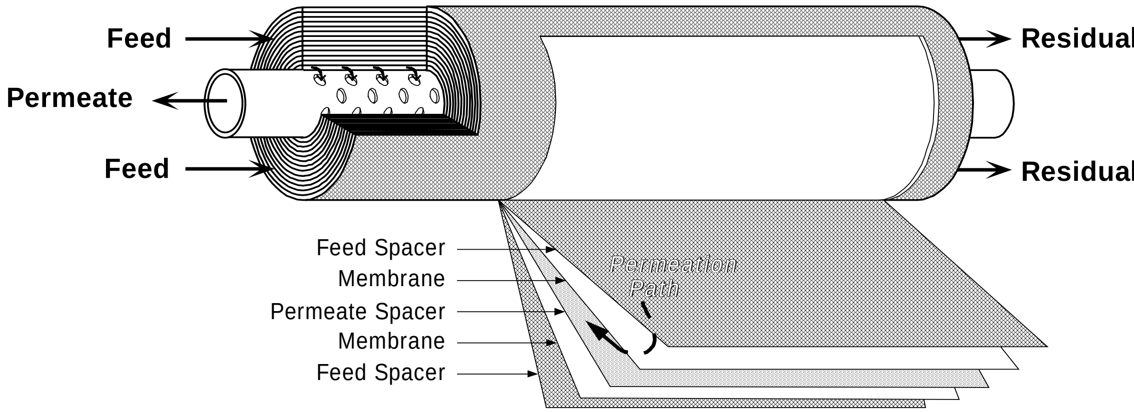


Figure 5: Spiral-Wound Membrane Element

The operation of the spiral-wound element can best be explained by means of an example. In order to separate carbon dioxide from a natural gas, the feed mixture enters the pressure vessel (tube) at high pressure and is introduced into the element via the feed spacer. The more permeable CO_2 and H_2O rapidly pass through the membrane into the permeate spacer, where they are concentrated as a low pressure gas stream. This low pressure CO_2 gas stream flows radially through the element in the permeate spacer channel and is continuously enriched by additional CO_2 entering from other sections of the membrane. When the low pressure CO_2 reaches the permeate tube at the center of the element, the gas is removed in one or both directions. The high pressure residual gas mixture remains in the feed spacer channel, losing more and more of the carbon dioxide and being enriched in hydrocarbon gases as it flows through the element, and exits at the opposite end of the element.

The membrane system consists of membrane elements connected in series and contained within pressure tubes as shown in Figure 6. A rubber U-cup attached to the element serves to seal the element with the inner diameter of the pressure tube, thereby forcing the feed gas to flow through the element. The pressure tubes are mounted in racks on a skid (Figure 7).

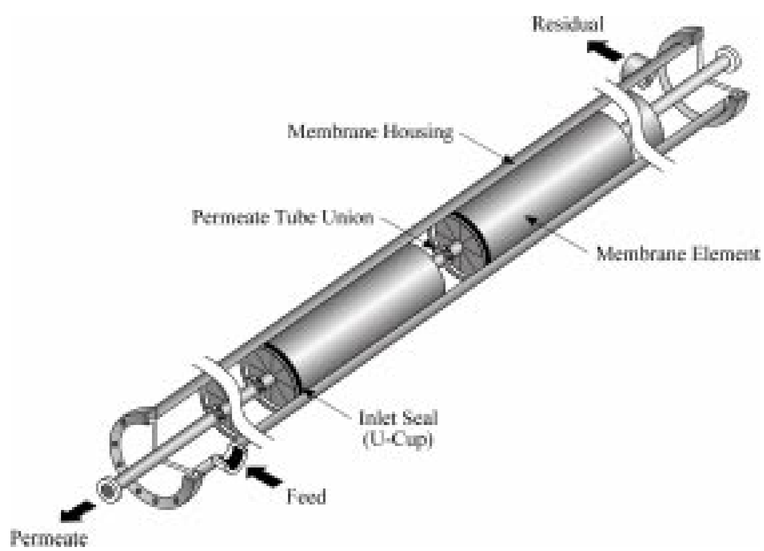


Figure 6: Spiral-Wound Membrane Tube

Figure 7: Skid-Mounted Membrane Tubes Containing Spiral-Wound Elements

To construct hollow fiber elements, very fine hollow fibers are wrapped around a central tube in a highly dense pattern. The feed natural gas flows over and between the fibers and the fast components permeate into the middle of the hollow fiber. The wrapping pattern used to make the element is such that both open ends of the fiber terminate at a permeate pot on one side of the element. The permeate gas travels within the fibers until it reaches the permeate pot, where it mixes with permeate gas from other fibers. A permeate pipe allows the collected gases to exit the element. An illustration is shown in Figure 8.

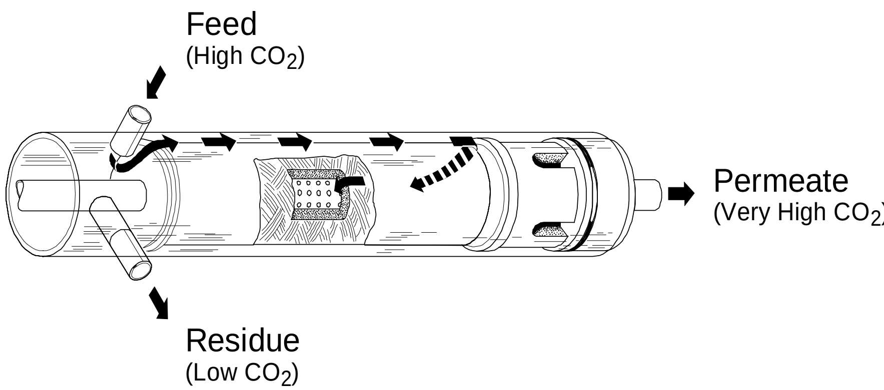


Figure 8: Hollow Fiber Membrane Element

As the feed gas passes over the fibers, the components that do not permeate eventually reach the center tube in the element, which is perforated like the spiral-wound permeate tube. In this case, however, the central tube is for residual gas collection, not permeate collection.

Many optimizations are possible for either element configuration. For hollow fibers, an important parameter is adjusting fiber diameter – finer fibers give higher packing density while larger fibers have lower permeate pressure drop and so use the feed-to-permeate-side pressure drop driving force more efficiently.

While each element type has its own advantages, the mechanism for gas separation is independent of the membrane configuration and is based on the principle that certain gases permeate more rapidly than others. This is due to the combination of diffusion and solubility differences, whereby a gas mixture of two or more gases of varying permeability may be separated into two streams, one enriched in the more permeable components and the other enriched in the less permeable components.

Feed Gas Pretreatment

Early applications of membranes in the field quickly educated suppliers to the need for adequate pretreatment of the feed stream when processing natural gas. Membrane life was found to be too short. Unlike some earlier membrane applications where the feed was relatively pristine, natural gas can contain a myriad of contaminants that quickly reduce membrane effectiveness and force premature replacement of the elements. Since membrane replacement is a critical operating cost, the industry soon adopted minimum pretreatment standards, such as the configuration shown in Figure 9.

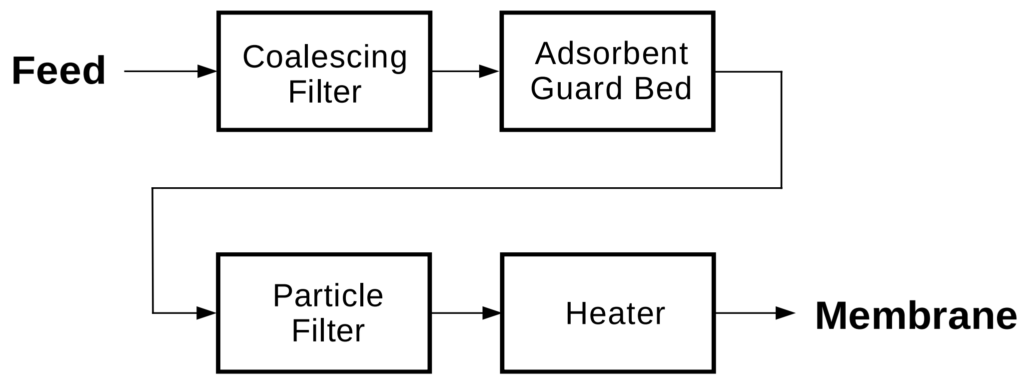


Figure 9: Standard Pretreatment

This configuration removes most common contaminants. The coalescing filter removes solid particulate matter and trace amount of free liquids. Liquids must be removed from the feed gas because they will deposit on the surface of the membrane and reduce mass transfer and lower the permeability of the fast gases. The result is a lower capacity for the system.

The guard bed uses activated carbon to remove the heaviest hydrocarbon fractions, including lube oil. For smaller systems, the sacrificial bed is typically designed to operate from six to twelve months between adsorbent replacements. A downstream particle filter catches any fines or dust from the adsorbent bed.

Finally, a feed preheater is often employed to provide a uniform gas temperature to the membrane. Because of the pressure drop across the membrane, Joule-Thompson cooling is always present within the membrane element. Since the CO_2 content is also changing, the dew point of the hydrocarbon gas can change significantly from the front of the tube to the back. The preheater is used to provide a “dew point margin,” ensuring that there is no condensation on the membrane surface. Liquid hydrocarbons not only reduce system capacity, they may permanently damage the membrane.

With time, membrane systems became larger and the gas stream more varied. Membrane suppliers saw a need for better pretreatment to remove the heavy fractions of hydrocarbons upstream of the membrane. Chilling to drop out heavy hydrocarbon fractions is now more common. Regenerable adsorbent systems have also been developed to provide a positive cut off of heavy ends. These systems, while more expensive to build and operate than the minimum pretreatment standards, greatly increase the reliability of the downstream membranes and are justified by longer element life. It is essential that large banks of membrane elements be protected from harmful contaminants.

Membrane Flow Schemes

A single stage unit is the simplest application of membrane technology for CO_2 removal from natural gas. As shown in Figure 10, a feed stream, which has been pretreated, enters the membrane module, preferably at high system pressure and high partial pressure of CO_2. High-pressure residue is delivered for further processing or to the sales gas pipeline. Low-pressure permeate is vented, incinerated, or put to use as a low-to-medium BTU fuel gas. There are no moving parts, so the system works with minimal attention from an operator. As long as the feed stream is free of contaminants, the elements should easily last five years or more, making the system extremely reliable and inexpensive to operate.

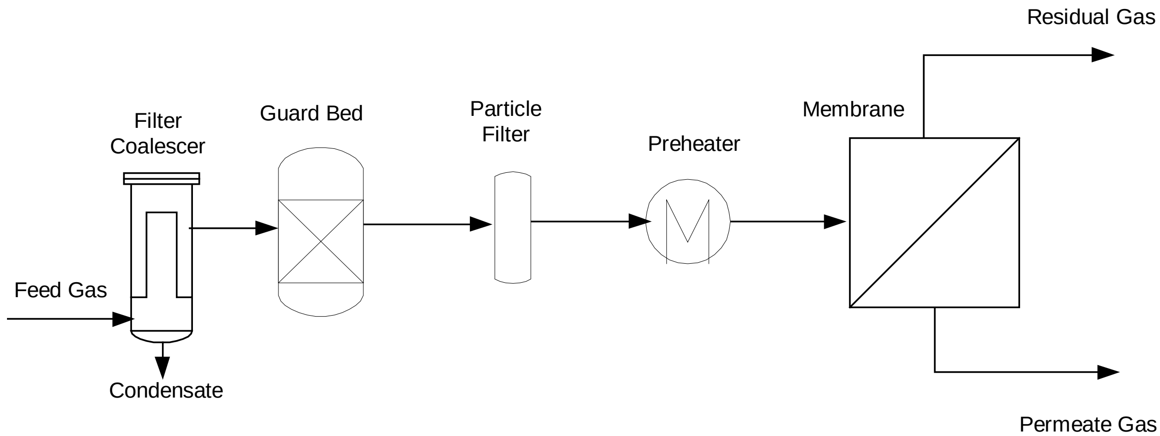


Figure 10: Single-Stage Flow Scheme

No membrane acts as a perfect separator, however. Some of the slower gases will permeate the membrane, resulting in hydrocarbon loss. This is the principle drawback to single-stage membrane systems. In order to recover hydrocarbons that would otherwise be lost in the permeate stream, a two-stage system can be employed (Figure 11).

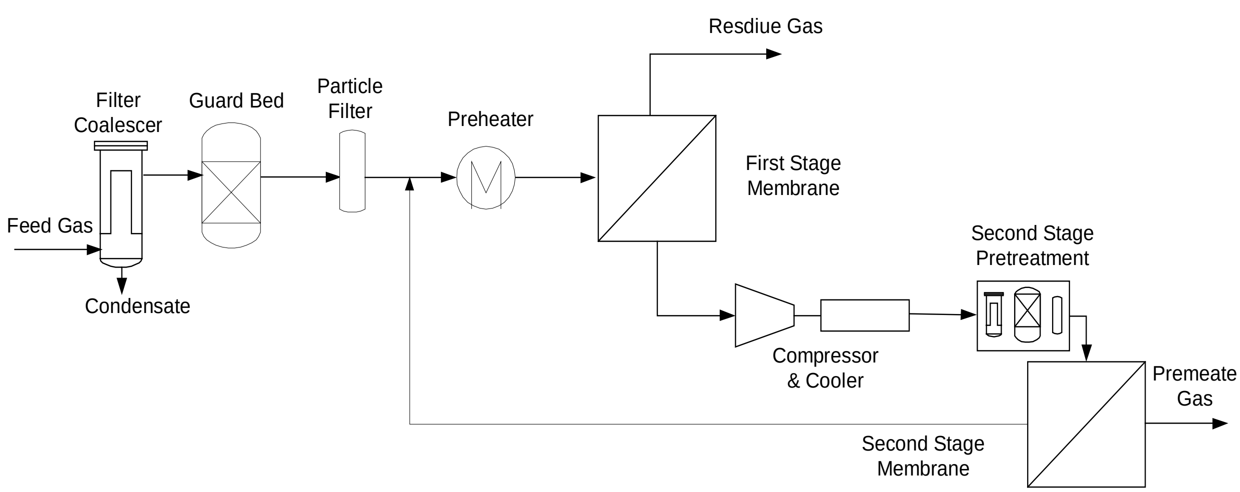


Figure 11: Two-Stage Flow Scheme

The permeate from the first stage, which may be moderately rich in hydrocarbons, is compressed, cooled and sent to a second stage of pretreatment to remove entrained lube oil and provide temperature control. A second stage membrane is then used to remove CO_2 from the stream prior to recycling the residue gas to the first stage membrane.

The investment and operating cost of a two-stage system can be substantially higher than a single-stage unit, due to the use of compression. It should be noted that this compression does not require any spare capacity. The first stage in this flow scheme will continue to make on-specification CO_2, at full capacity, even if the second stage is off line. There would be a temporary increase in hydrocarbon loss until the recycle compressor is put back on line. This operating penalty is typically small in comparison to the cost of spare compression.

Improvements can be made to these process flow schemes to improve performance and reduce capital cost, however, such a discussion is outside the scope of this paper.

Once a design has been completed for CO_2 removal with membranes, the critical parameters affecting capital and operating costs are shown in the following table:

	Operating Cost	**Capital Cost**
Pretreatment	Energy use, consumables	Standard vs advanced
Stage Cut	Hydrocarbon losses	Single-Stage vs two-stage
Number of Stages	Compressor fuel	Compression
Membrane Elements	Replacement elements	Initial fill of elements

System costs will be affected by the total gas flow rate, the temperature, pressure, and CO_2 content of the gas processed. If a downstream operating unit removes CO_2 after an initial cut with membranes, the upstream membrane unit can be smaller, and more likely can remain a single-stage configuration.

Advantages and Disadvantages of Amines and Membranes

Initially, membranes were restricted to either small natural gas streams or those with very high CO_2 content, such as in enhanced oil recovery CO_2 floods. As the technology became better known, the technology spread into a wider variety of natural gas streams. Now that the technology is mature, one can stand back and look at the relative strengths and weaknesses of the process versus the more established amine technology. The table below looks at some key areas for comparison:

Table 1: Comparison of Amine and Membrane CO_2 Removal Systems

Operating Issues		
	Amines	**Membranes**
User Comfort Level	Very familiar	Still considered new technology
Hydrocarbon Losses	Very low	Losses depend upon conditions
Meets Low CO_2 Spec.	Yes (ppm levels)	No (<2% economics are challenging)
Meets Low H_2S Spec.	Yes (<4 ppm)	Sometimes
Energy Consumption	Moderate to high	Low, unless compression used
Operating Cost	Moderate	Low to moderate
Maintenance Cost	Low to moderate	Low, unless compression used
Ease of Operation	Relatively complex	Relatively simple
Environmental Impact	Moderate	Low
Dehydration	Product gas saturated	Product gas dehydrated
Capital Cost Issues		
	Amines	**Membranes**
Delivery Time	Long for large systems	Modular construction is faster
On-Site Installation Time	Long	Short for skid-mounted equipment
Pretreatment Costs	Low	Low to moderate
Recycle Compression	Not used	Use depends upon conditions

There can be no hard and fast rules applied to the comparisons made in Table 1 because all CO_2 removal systems are, by nature, site specific. That is to say, the systems differ according to the natural gas being processed, the location of the installation and the economic parameters used by the end customer. The statements in the table are only general guidelines.

Hydrocarbon recovery is an important issue to understand. Amine units do lose some feed gas hydrocarbons to a flash gas stream or the acid gas stream due to solubility and entrainment. Typical losses are less than 1% of the feed gas. Depending upon the processing conditions, hydrocarbon losses in a single-stage membrane can run from 2% to 10% of the feed gas or more. Two-stage membrane units have typical losses ranging from 2 to 5% of the feed gas hydrocarbons. If the permeate is very high in CO_2, it is typically vented or flared. Higher hydrocarbon losses in the permeate can sometimes be an advantage, because the stream can then be used for fuel gas, like a direct fired hot oil system heater, or be compressed and sent to a turbine for power generation.

Hydrogen sulfide is another point to consider. Since the permeation for H_2S is similar to that of CO_2, the two gases will permeate in approximately the same ratio from the feed gas to the permeate gas. For gas streams with trace amounts of H_2S, a membrane can usually produce a product stream that meets a 4 ppm(v) pipeline specification. As the feed concentration of H_2S

rises to 100 ppm(v), the product gas concentration may rise to 10-30 ppm, depending on the CO_2 in the feed and the CO_2 product specification. Amines are required to make pipeline specifications when significant levels of H_2S are present in the feed gas.

Membranes are inherently easier to operate than an amine unit because there are fewer unit operations. In a single-stage unit, the only moving parts are the gas molecules. With a second stage, only a compressor is added. In general, fewer operators and maintenance workers are needed to run a membrane system.

When it comes to cost of operation, the life of the membrane elements must be taken into account. Contaminants reduce the efficiency of the separation and the membrane surface is subject to degradation over time. In most plants, replacement of the membrane elements is done on an incremental basis. It is generally not necessary to replace a complete charge of membrane elements all at once. When periodic element replacement is compared to continuous solvent make-up, it appears that membranes have a slight edge in lower costs for consumables. Add to that advantage the lower labor cost and membranes should be lower cost operations. Maintenance costs are certainly lower when a single stage membrane is compared to amines.

Advantages of Hybrid Configurations

In some situations, placing a single stage membrane system upstream of an amine unit has a very positive effect. The presence of one unit eliminates the shortcomings of the other and the combined "hybrid" system becomes less expensive to build and operate and more flexible in handling changes in feed gas conditions. Here is a list of most of the potential benefits when using a hybrid system:

Table 2: Comparison of Hybrid to Amine and Membrane CO_2 Removal Systems

Operating Issues		
	Hybrid vs Amine Only	**Hybrid vs Membrane Only**
Hydrocarbon Losses	Increased losses, unless there is a use for the permeate	Slight increase in losses, but typically no compression
Meets Low CO_2 Spec	Same	Yes, much better
Meets Low H_2S Spec	Same	Yes, much better
Energy Consumption	Lower	Higher
Operating Cost	Lower	Higher
Maintenance Cost	Slightly higher	Higher
Ease of Operation	Slightly more complex	More complex
Dehydration	Product still saturated	Re-saturates product gas
Corrosion Potential	Lower (lower loadings)	Not a concern
Amine Foaming	Virtually eliminated	Not a concern
Capital Cost Issues		
	Hybrid vs Amine Only	**Hybrid vs Membrane Only**
Recycle Compression	Not a concern	Eliminates need for compression
Total Installed Cost	Same to lower	Higher
Very Large Gas Flow	Significant savings	Higher

As before, no hard and fast rules should be applied here, as these comparisons are very dependent upon the natural gas being processed, the operating conditions, the economic variables and the location of the processing facility. It is important to understand the areas where each technology in a hybrid system performs best.

The size of an amine unit is directly related to the moles of CO_2 removed from the feed gas. As CO_2 content rises from low to moderate partial pressures in the feed, the rich solvent loading increases to somewhat offset the increased demand for solvent. But as partial pressures increase to high levels, the solvent approaches a maximum loading. At that point, any increase in CO_2 can only be removed by increasing the circulation rate. The same is not true for membranes. Permeation increases as the feed gas CO_2 partial pressure increases, making the membrane much more efficient at high concentration of CO_2. As mentioned earlier, meeting low sales gas specifications causes single-stage membranes to loose efficiency, while amines work very economically. By combining the technologies in series to treat gases with a high partial pressure of CO_2, the membrane operates where it is best (high concentrations of CO_2) and the solvent system works where it is best (achieving low specification for treated gas CO_2 content).

The obvious, and first, application of hybrid systems was in enhanced oil recovery (EOR). The CO_2 content is extremely high, 70% or more, in these plants. An example is given later in this paper. Clearly, high-CO_2 natural gas streams are good candidates for using membranes to remove all or part of the acid gas.

There has been at least one published paper that addressed the economic viability of hybrid systems. In 1991 McKee, et al (Ref. 5) concluded that hybrid systems can be economical when CO_2 concentrations are lower than found in EOR applications. Though their study limited feed rates to 75 MMSCFD, the authors encouraged readers to investigate higher flow rates, and alternative solvent processes in conjunction with membranes.

Because membranes are more efficient for processing high partial pressures of CO_2, the capital and operating costs are typically lower for a hybrid when compared to a solvent-only system. The issue that must be carefully monitored is the amount of hydrocarbon (specifically, methane) lost with the CO_2 in the permeate stream. If the losses are too high in the membrane section, it offsets the lower reboiler duty obtained by treating the gas upstream of the solvent unit. If losses are too high, a two-stage membrane may be appropriate. Another alternative is to identify a low-Btu fuel gas user on or adjacent to the site. Direct-fired boilers and hot oil heaters are good candidates for using low-Btu fuel gas (100-300 Btu/ft^3). When a large amount of permeate is available, it can be compressed and sent to a gas turbine for generating electricity.

Recently, a study was conducted for a plant with a design flow of 240 MMSCFD and an inlet CO_2 content of 41%. The specification was 3% CO_2 upstream of the cold plant to insure a 5% pipeline specification in the residue sales gas. Detailed cost estimates were developed for stand-alone amines and a hybrid unit. Stand-alone membranes were not considered due to customer preferences.

A very interesting result came out of this study. Due to tower diameter limits, the solvent system was forced to a 2-train configuration. By contrast, the hybrid configuration was a single train, single-stage membrane followed by a single-train amine unit in series. Two-in-series had definite advantages over two-in-parallel:

- Flexibility for changing CO_2 content: If the CO_2 came in high, the membrane could compensate by taking out more CO_2 with the same area, taking a burden off the downstream amine unit. If the CO_2 came in low, membrane area could be taken off line to reduce hydrocarbon losses.
- The pretreatment in front of the membrane reduced heavy hydrocarbon contamination downstream, eliminating potential foaming in the amine unit.
- The capital cost of the two options was almost identical, but operating costs were lower for the hybrid, despite the higher hydrocarbon losses, because the reboiler duty of the solvent unit was reduced.

Some examples of existing and planned hybrid systems will help to demonstrate the advantages of combining membranes with amines.

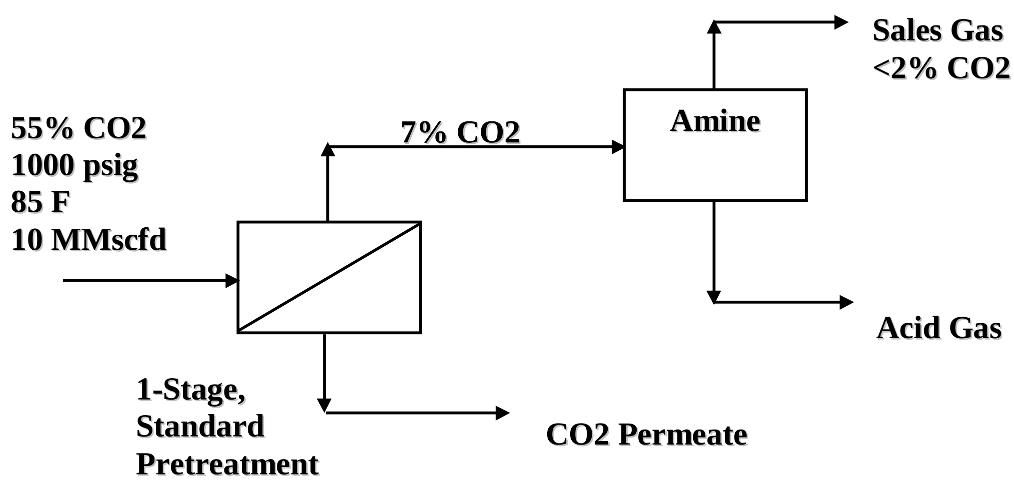
Examples of Working Hybrid Systems

There are many hybrid systems currently operating around the world. Data is not available on all of the applications, but some are presented here to demonstrate the ways in which hybrids are used.

Early applications of membrane technology were in the area of enhanced oil recovery with CO_2 flood. Several EOR projects in West Texas use a combination of membranes and amines to recover CO_2 that is returned to the surface and recover the valuable hydrocarbons in the gas. In general, high CO_2 content of a gas is a good indicator for the use of membranes and/or hybrid systems. As will be shown, low CO_2 pipeline specifications are another reason to adopt a hybrid configuration.

Plant 1

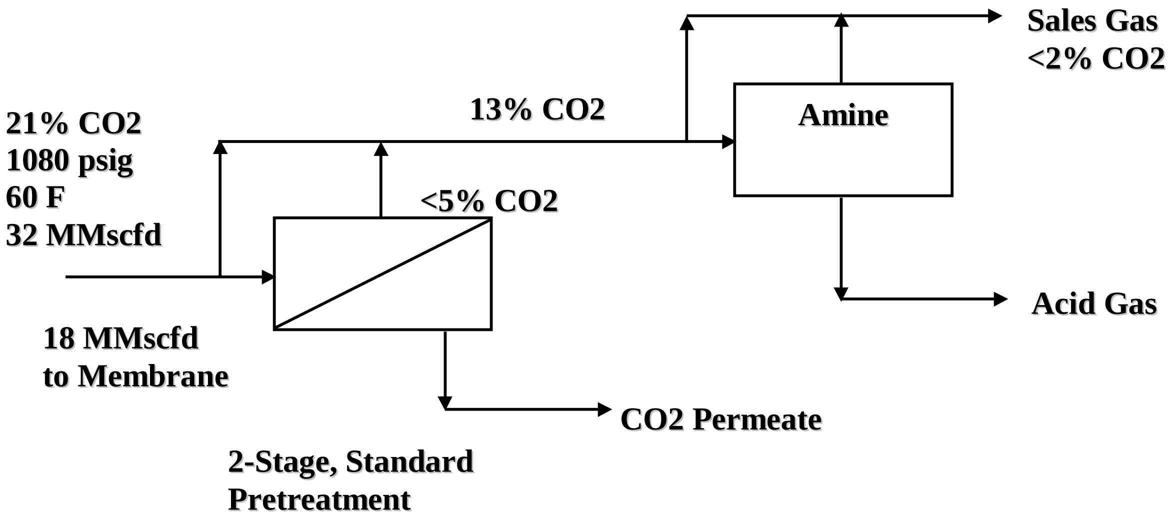
The first plant is an example of how *not* to apply a hybrid system. The plant processed a very dry gas in west Texas. Standard pretreatment was employed because the gas had virtually zero propane-plus hydrocarbon fraction. The initial cut of CO_2 was made with a single stage membrane. The problem was the hydrocarbon loss in the membrane. Reducing CO_2 from 55% to 7% in a single stage results in high losses. A better design would have been to remove less CO_2 with the membrane and more with the amine.



Due to low gas prices, the plant was operated for over eight years, delivering gas on specification with very little downtime. The plant did not buy any replacement elements during the entire eight-year run, enhancing the reputation of membrane technology. As natural gas prices gas rose in 2000, the owner could no longer ignore the loss of sales gas from the membrane stage. A decision was made to replace the small downstream amine unit with a new, larger SELEXOL® unit. Now only half the membrane area is used, removing less CO_2, resulting in lower hydrocarbon losses.

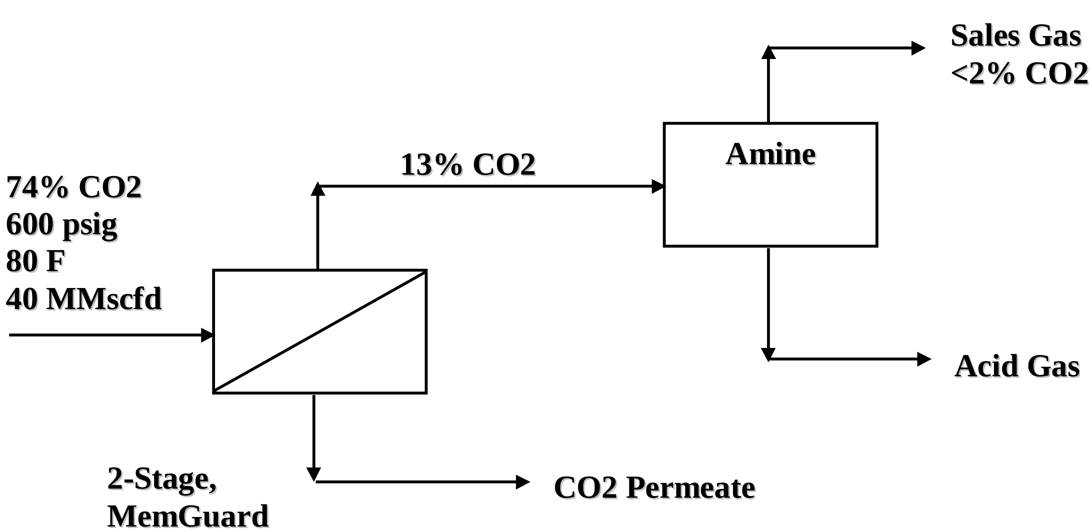
Plant 2

The second plant has done a very good job of maximizing capacity. Half the gas is processed in a two-stage membrane to reduce CO_2 from 21% to <5%. The remainder of the gas bypasses the membrane and is blended to obtain 13% CO_2 going to the amine unit. Despite the deep cut taken by the membrane unit, hydrocarbon losses are reduced by using a two-stage membrane configuration. This unit has operated for six years with very little trouble.



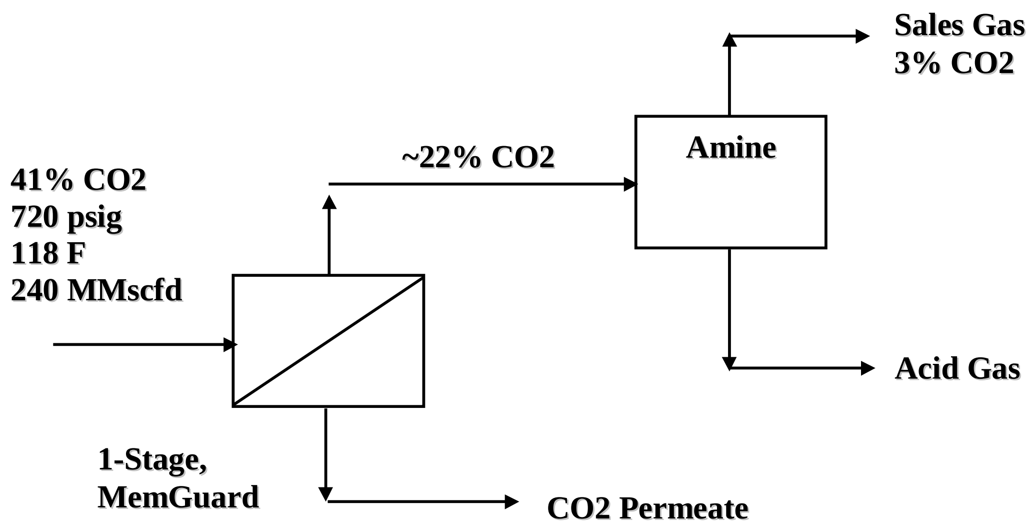
Plant 3

The plant represents a new facility currently in engineering. It is an EOR project in the Rocky Mountains. As shown above, the deep cut in the membrane hybrid is taken with a two-stage unit rather than a single-stage to maintain a high hydrocarbon recovery.



Plant 4

This final plant is also in engineering. This is the unit, discussed above, which was the subject of an engineering study. One of the interesting aspects of the hybrid arrangement is that the inter-unit CO_2 specification can be optimized to fit the economics of the processing facility. Generally, the more CO_2 removed in the membrane unit, the better the quality (heating value) of the permeate. A "lighter cut" produces a lower BTU value fuel gas. The inter-unit CO_2 content can be optimized to produce a permeate which can be used as fuel on site. Common uses would be as fuel for a steam boiler or hot-oil fired heater, as blending stock into a fuel header or, once compressed, as fuel to a turbine for generation of electricity.



The final section of this paper will show the economics for a fifth plant, this one still in the planning stages.

Hybrid Economic Evaluation

To illustrate some advantages of hybrid systems, a recent evaluation is presented in which a large amount of gas is to be processed. In this case, the natural gas processor wants to remove CO_2 upstream of an NGL recovery plant. Stand-alone solvent systems are compared to hybrid units, which pair a single-stage membrane with either hot potassium carbonate or a specialty amine using a low-energy flow scheme.

The designs for the stand-alone solvent systems reveal that they cannot be built economically in a single train configuration at the remote location. The limiting factor is the diameter of the absorber and regenerator. They exceed the width that can be accommodated during trucking equipment to the site. The hybrid configuration offers an opportunity to reduce the size of the solvent system while keeping all the equipment within the transportation limitations.

The equipment costs for each system were estimated and then an installed cost was determined by applying a multiple to the equipment cost. The installation factors were chosen based on typical costs for units of similar scope and size. Operating costs were estimated based on heat duty, solvent cost, membrane element replacement and the cost of electricity. The relative results are shown in Table 3.

Table 3: Cost Comparison for Stand-alone and Hybrid Systems

CO_2 Removal 20% to <2%	**STAND-ALONE**		**HYBRID**	
	Case 1	**Case 2**	**Case 3**	**Case 4**
	Hot Pot	Amine	Hot Pot	Amine
	2 Trains	2 Trains	1 Train	1 Train
Capital Cost	1.1	1.2	Base	1.1
Annual Operating Cost	1.9	1.7	Base	1.0
Total Cost (1)	1.4	1.4	Base	1.1

(1) Total cost = Capital cost plus five years of operating cost.

In this example, the hybrid case pairing a membrane unit and hot potassium carbonate was the least expensive option. The stand-alone hot potassium carbonate system was 10% higher in capital cost and 90% more expensive to operate. A quick comparison of total costs, using a simple formula to add five years of operating cost to the capital cost, shows both single-train hybrid options to be lower in cost than either stand-alone two-train system.

It should be noted that this analysis did not assume any hydrocarbon loss for the hybrid systems. It was assumed that any methane in the permeate would be burned to produce reboiler heat in the solvent system and supply low-Btu gas into the site fuel header. If these options had not existed, operating cost would have increased significantly for the hybrid options.

Conclusions

Membrane systems for CO_2 removal from natural gas are a mature technology. There is sufficient experience in units around the world for the gas processor to feel confident in choosing membranes to process natural gas.

Combining membranes with solvents has the potential to increase the advantages of each technology and reduce the disadvantages of each technology. Membranes operate best at high partial pressures of CO_2, while solvents operate best when treating to low CO_2 specifications. Therefore, a high-pressure gas with a high concentration of CO_2 that must be conditioned to pipeline specification is a very good candidate for using a hybrid system consisting of a membrane unit followed by a solvent unit.

Capital and operating costs are typically equivalent or lower for the hybrid unit applied to small gas volumes. Operators used to working on solvent systems can typically handle both unit operations with ease.

For processing large gas flow rates where two or more trains may be required, a hybrid can reduce the system to a single, less expensive train. If an existing solvent system needs to be modified to handle an increase in feed gas CO_2 concentration, adding a membrane upstream can be a very attractive method of expanding the system capacity.

The most economic hybrid designs use the permeate gas on site as fuel for a heater or electric generator. Close attention must be paid to the value of the methane in the membrane permeate stream. The least expensive option is to employ a single-stage membrane. Two-stage membrane units can also be an economical part of a hybrid system.

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