INTERVENING WHEN FEED GAS IS TOO LEAN: HEAVIES REMOVAL CHALLENGES FOR LNG PROJECTS

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ABSTRACT

Pipeline-quality feed gas for US LNG projects poses a unique challenge: heavy hydrocarbon removal. Most of the feed gas from a pipeline network has been pre-processed to extract valuable NGLs, so it typically is lean. However, this gas still can contain small amounts of heavy hydrocarbons and BTEX that will freeze out during the liquefaction process and must be removed. For such lean feed gas, traditional hydrocarbon removal methods such as a scrub column or an expansion and condensation scheme may not meet all required liquefaction specifications because there is only a small quantity of C2-C5 components present (which are typically used to absorb the heavy components). When actual natural gas compositions to liquefaction plants are even leaner than previously estimated and designed for, these treatment units are further stressed to meet the target specifications. Consequently, increased pressure drop/freezing in cryogenic exchangers has been observed in multiple North American LNG projects.

For North American LNG projects early in the development cycle, most attention is placed on the liquefaction unit and familiar choices are made for gas treatment that are common for large-scale LNG trains that have been built over the last several decades. Conventional heavies removal designs are often considered for North American projects due to their perceived process simplicity and low capital cost (CAPEX). However, conventional designs come with their own set of operational limitations -- particularly due to their inability to generate sufficient reflux, resulting in unstable distillation column operation when feed gas is lean. Technology selection that does not best fit the feed gas composition, and the operational/turndown requirements, can lead to freezing issues that result in higher operational costs and reduced availability.

This paper reviews proven technologies that show benefits for heavy hydrocarbons removal systems for lean feed compositions. The discussion includes an analysis among heavy hydrocarbons removal technologies using a case study approach which considers different ranges of feed gas compositions and delineates an optimal selection for each composition. The paper also highlights relative CAPEX and OPEX estimations among different technologies and the significant impacts to liquefaction process efficiency. Qualitative review of reliability and flexibility of the heavy hydrocarbons removal unit operation also is provided. The paper also addresses considerations for the integration of heavy hydrocarbons removal in large scale and multi-train small scale LNG units.

INTRODUCTION

UOP and Kiewit, based on previous work experience, have found that one size does not fit all when it comes to gas treating for LNG plants. While many gas treatment process configurations are sound designs based on expected feed gas composition ranges, the actual operational experience seen in North America is that feed gas compositions have been extremely lean – leaner than ever anticipated. Whenever plant configurations are consistently operating outside of their design boundaries, operational challenges will result. This paper was developed in order to promote natural gas treatment alternatives that may be suitable when feed gas is “too lean”. Additionally, these schemes can result in an economic design with minimal operational intervention.

GAS PROCESSING BLOCK FLOW SCHEME FOR LNG

Figure 1 shows a typical block flow diagram for North American LNG Plants. Some variations like the preference for locating the H_2S removal unit (upstream vs. inside acid gas removal) and mercury removal unit (upstream of Amine unit vs. downstream of Molecular Sieve unit) is observed. These sensitivities in the overall block flow for gas processing is omitted for this paper as it does not impact the subject matter of dealing with lean feed gas compositions.

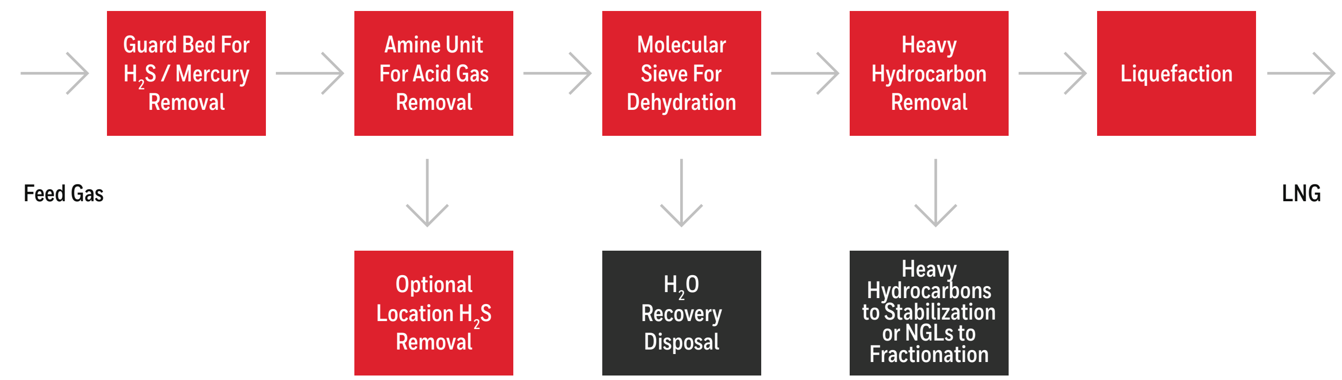


Figure 1: Block flow diagram for North American LNG projects

OPTIONS FOR HEAVY HYDROCARBON REMOVAL

OPTION 1. CONVENTIONAL HEAVIES REMOVAL DESIGN

The LNG industry has been using conventional heavies removal technology for the last 40-50 years. Figure 2 shows a schematic of a conventional turboexpander-based process. Most North American LNG projects have adapted a design that is similar in concept to the design as shown in Figure 2. There are other similar cryogenic schemes that have been successfully used as well. The type of system used depends on the inlet conditions of the gas stream and the desired recovery levels of hydrocarbon. Process schemes range from a simple high pressure wash column utilizing external refrigeration to the turbo-expander plant as shown in Figure 2.

Conventional Cryogenic Heavy Ends Removal System

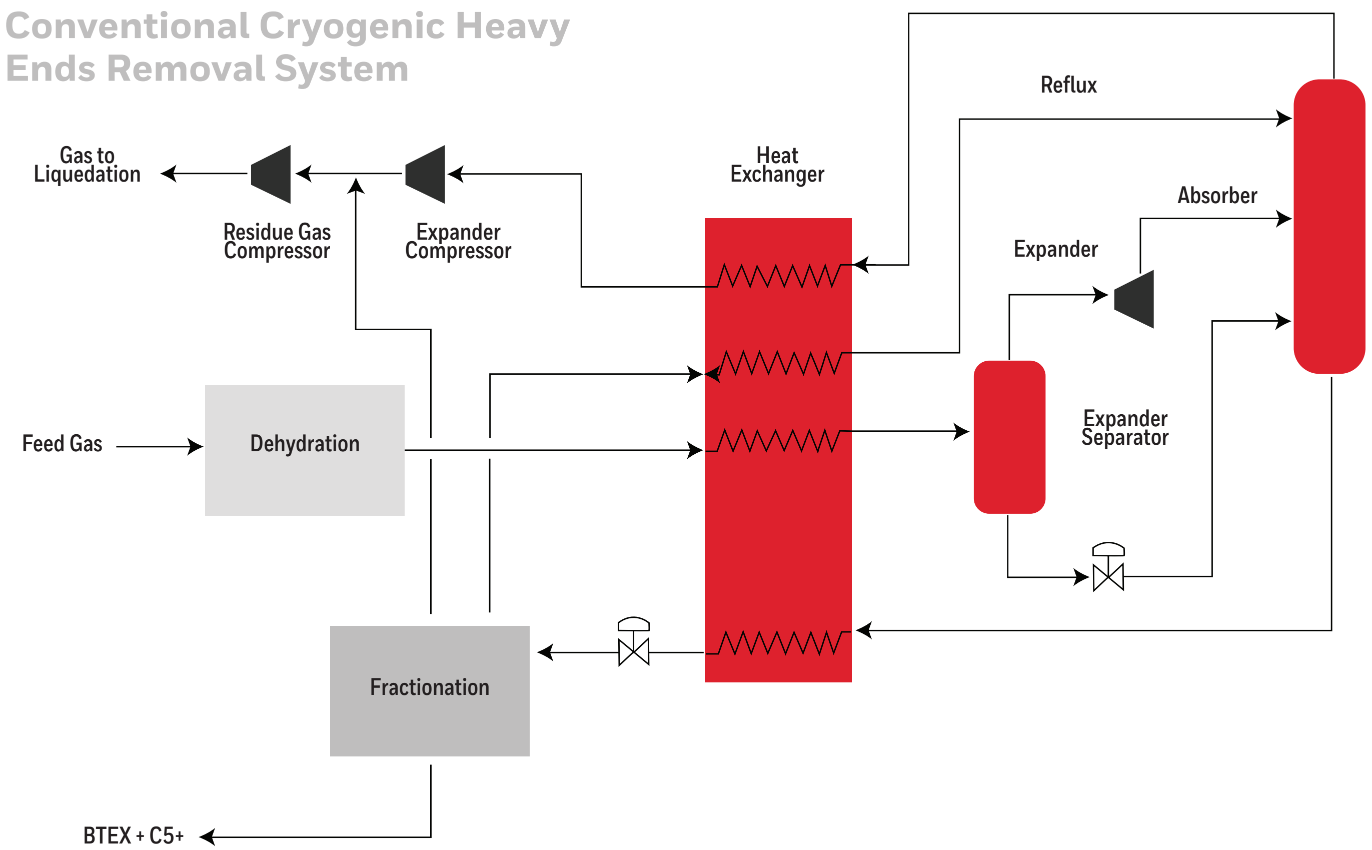


Figure 2: Conventional Heavies Removal Design Using a Turbo-Expander Configuration

Such cryogenic flowschemes have worked well for reasonably rich feed gas with relatively high amount of C_{3+} in the feed. For the lean feed gas as is currently observed in North America, it is difficult to create the necessary reflux streams to adequately absorb the heavies from the predominantly methane stream in a cryogenic process. As the gas becomes leaner, heavies removal becomes even more difficult to the extent that it may require injection of mid-level components such as propane or butane to help absorb the heavy tail. Without intervention, this condition could result in continuous heavies slip which can end with solids formation in the liquefaction system cryogenic heat exchangers and even in downstream equipment resulting in blockage. Blockages can lead to excessive downtime over the life of the plant. Moreover, lack of adequate quantities of these mid-level hydrocarbon components may result in operational difficulties, not only in the Demethanizer, but also in downstream fractionation columns. As a result, these operational difficulties can possibly result in highly operator intensive “batch operations” in the debutanizers/deethanizers.

OPTION 2. ADSORPTION-BASED HEAVIES REMOVAL DESIGNS

Adsorption systems are commercially proven for removal of water and heavy hydrocarbons to protect equipment and meet pipeline specifications.[1,2] However, the typical hydrocarbon removal unit using a single adsorbent, such as silica gel, cannot efficiently remove heavy hydrocarbons and water to the levels required for LNG pretreatment. Efficiently removing hydrocarbons and water to tight LNG specification levels requires a combination of different types of high performance adsorbents. In order to overcome these challenges, the SeparSIV™ Process is proposed for two schemes outlined below. The first system is the most compact of the two options to show the advantages of using SeparSIV for these heavies removal challenges.

OPTION 2A. ADSORPTION-BASED HEAVIES REMOVAL DESIGN COMBINED WITH DEHYDRATION UNIT

This adsorption-based configuration combines dehydration and heavies removal in the same unit using the SeparSIV process. Figure 3 shows the block flow of the combined heavies removal system for the pre-treatment section.

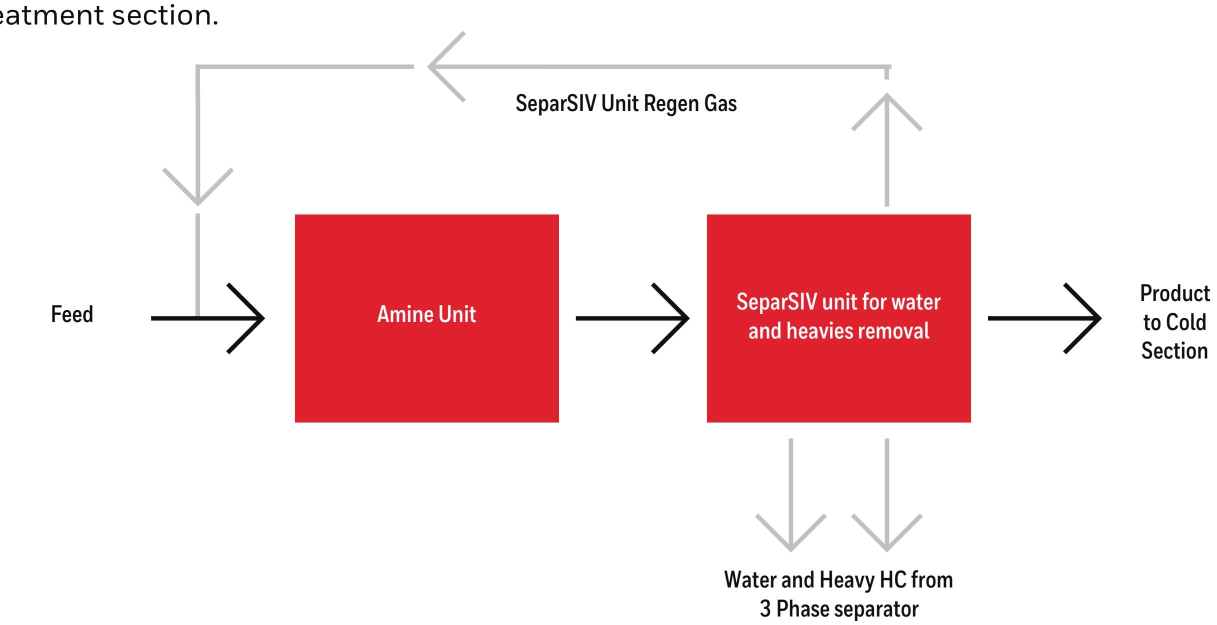


Figure 3: Combined Dehydration and Heavies Removal Using the SeparSIV Process (Option 2a)

The SeparSIV process utilizes Thermal Swing Adsorption technology (TSA) with a multi-layer system of adsorbents to target and optimize adsorption of C_{5+} to less than 0.1 mole%, BTEX and C_{8+} to < 1ppmv, and water down to <0.1 ppmv. Figure 4 shows the loading capacity of C_5 and C_8 as a function of partial pressure of these components on different layers of adsorbent (SS-3 and SS-7). The idea is to use the right adsorbent to surgically remove the targeted impurity in the right order. The technology can be combined with an advanced control system that enables the process to flexibly adjust to varying feed gas compositions.

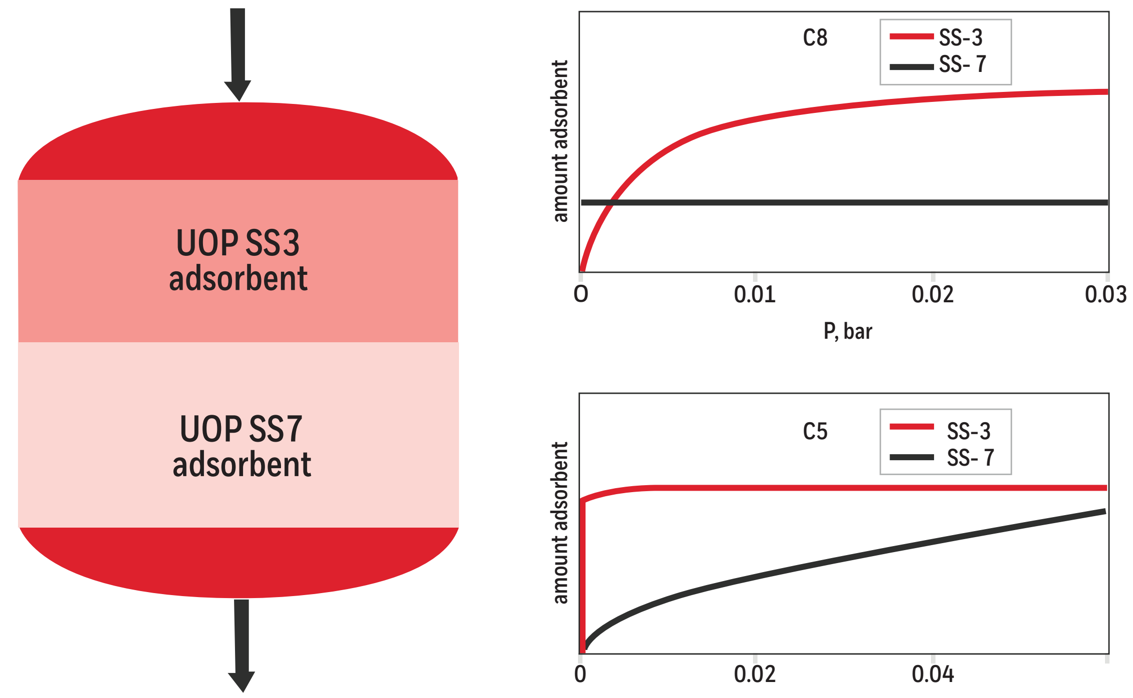


Figure 4: Example Adsorption Profile of C_5 and C_8 using SeparSIV Technology

With adsorption-based technology, the higher the carbon number, the easier it is to adsorb. SeparSIV can remove water and C_6 plus hydrocarbon fractions while leaving the C_4 and lighter hydrocarbon fractions in the LNG product. This works well with overall LNG plant needs as heavy hydrocarbon removal is desirable to prevent freezing but leaving light hydrocarbons in the LNG product can command better value for LNG when traded on a thermal (BTU) basis. This process can also be adjusted to “surgically” remove additional contaminants like mercaptan sulfur and mercury when suitable treatment of regeneration gas is implemented.

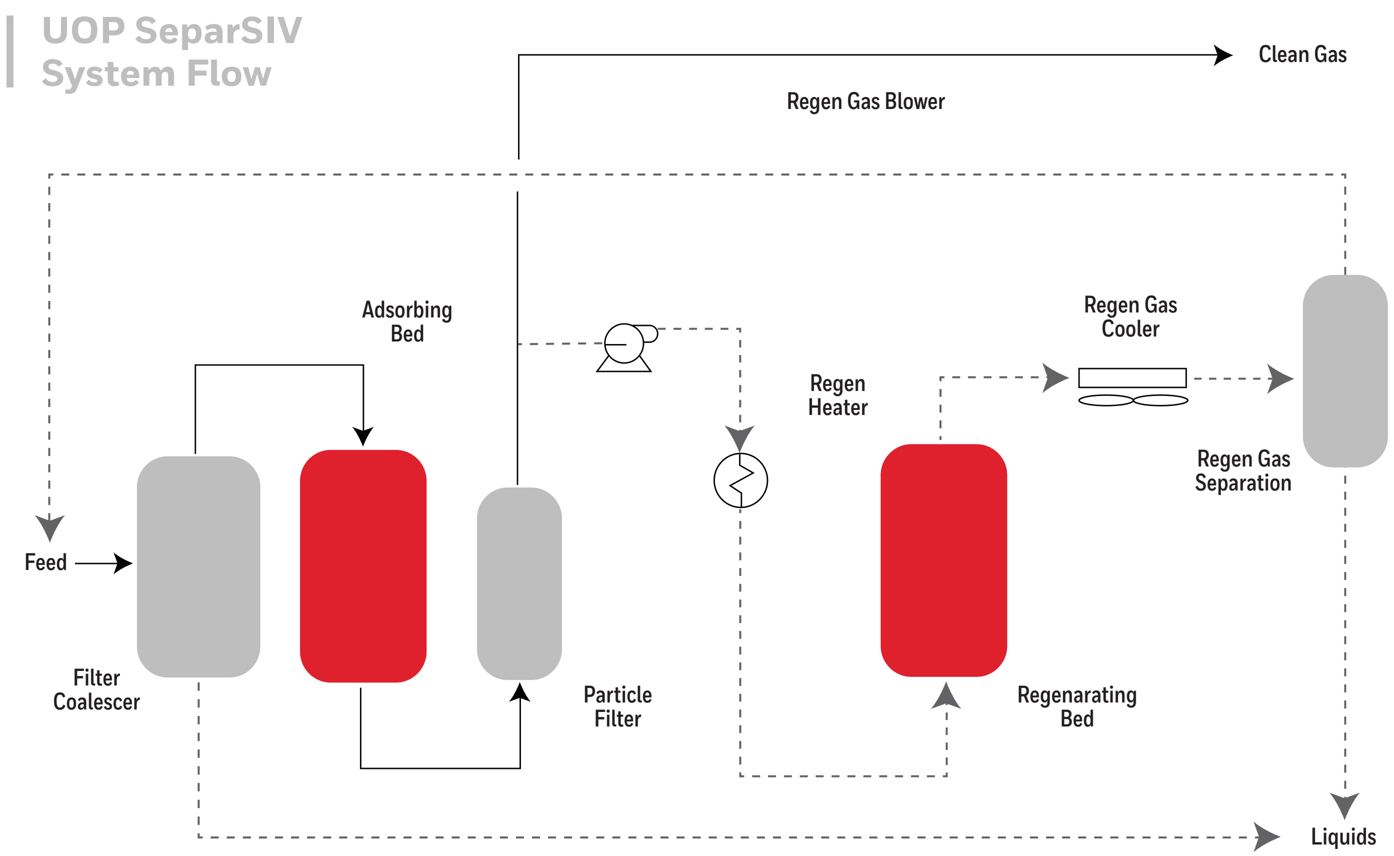


Figure 5: Process Flow Schematic of SeparSIV Unit

Combining water and heavy hydrocarbon removal in a single unit requires a water and hydrocarbon management strategy. Since water and hydrocarbons are condensed in the same regeneration drum, an efficient effluent separation system needs to be designed along with the use of a three-phase separator; this strategy will then allow for bulk separation of water and heavy hydrocarbons. Water saturated liquid hydrocarbons can then go to a separation system for efficient water removal. The hydrocarbons can be further stabilized to meet the required condensate Reid Vapor pressure.

We have considered the combined water and heavy hydrocarbon removal adsorption-based scheme (Option 2a, Figure 3) as the preferred option to compare with conventional heavies removal scheme (Option 1). A combined adsorption system will minimize the equipment count and result in greater CAPEX and OPEX savings. However, it is worthwhile to consider a decoupled process strategy when reviewing a range of configurations and options.

OPTION 2B. ADSORPTION-BASED HEAVIES REMOVAL DESIGN WITH SEPARATE DEHYDRATION AND HEAVIES REMOVAL UNIT

In some cases, when the heavy hydrocarbon concentration in the feed gas is higher than typically seen for North American LNG plants, it may not be possible to adequately remove heavy hydrocarbons from the regeneration circuit without chilling it to lower than the hydrate formation temperature. In such cases, a separate dehydration and SeparSIV heavy hydrocarbon removal unit will be required (Figure 6). Heaviest possible feed gas composition needs to be evaluated as an important criteria[Ref 4] for separating or combining the dehydration and heavies removal unit.

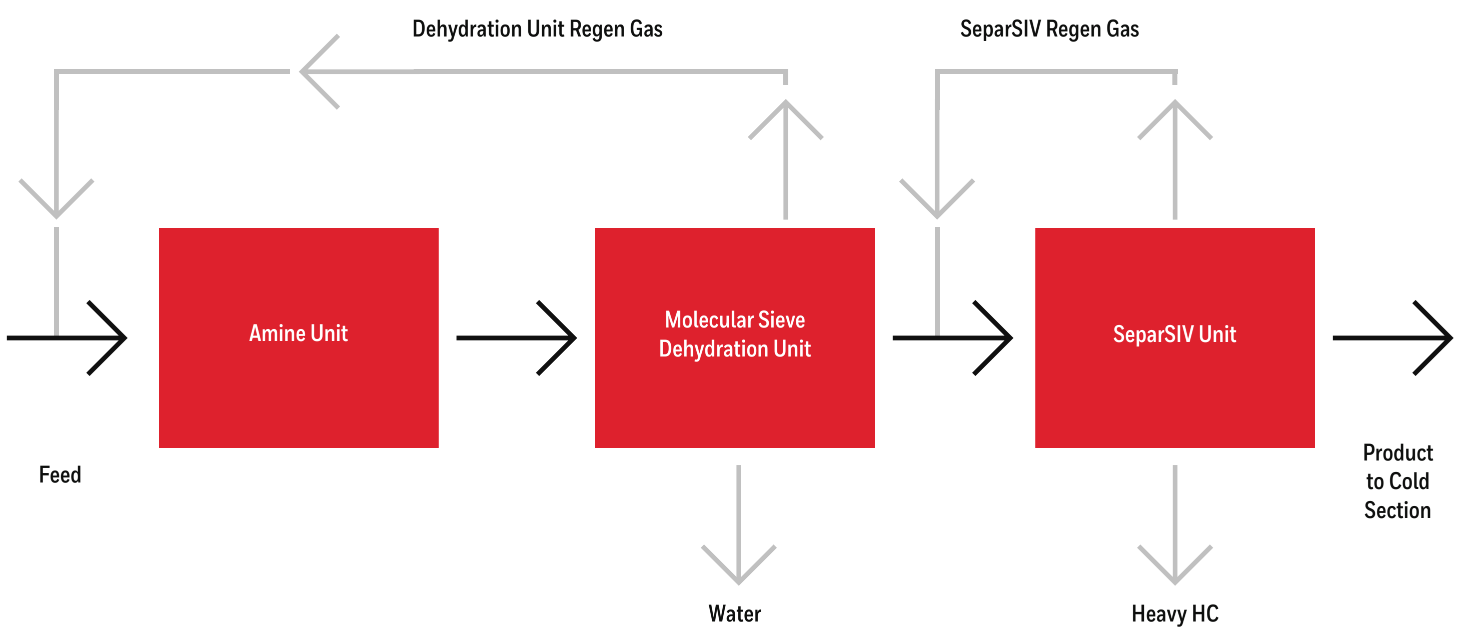


Figure 6: Separate Dehydration Unit + SeparSIV for heavies removal (Option 2b)

The separate process units are very similar conceptually and operationally. This configuration is more simplistic than the combined scheme (Option 2a) and decouples the water removal and heavy hydrocarbon removal functions. Consequently, each unit has its own regeneration gas compressor, regeneration heater and individual separation drums and coolers. In some cases, some plant owners may prefer to decouple the services in order to have a configuration that breaks up the process units into discreet steps. We have provided a quantitative comparison of CAPEX and OPEX for all three process configurations in this paper on a relative basis.

SEPARSIV IN COMPARISON TO A MOLECULAR SIEVE DEHYDRATION UNIT

In many aspects, a SeparSIV process is similar to the well-known molecular sieve dehydration unit used for water removal in all LNG plants. The unit design and operation is fundamentally similar; impurities are removed during an adsorption cycle and later recovered and sent outside the system during a regeneration cycle. Table 1 shows characteristics when comparing a conventional dehydration unit to SeparSIV.

Parameter	Dehydration	SeparSIV
Absorbent	UI-94 (typical)	Layers of various adsorbent
Cycle time	24 hours	2-3 hours
Stand by time	In hours	In minutes
Regen rate	About 5-10%	>10%
Cycle type	Single bed in regen	Series heat & cool (two beds in regen)
Vessel insulation	External	Internal
Regen KO Drum	2 phase separator	3 phase separator (2 phase OK)
Regen temperature	550 F	550 F
Regen gas tyoe	Outlet of Dehy unit	Oulet of SeparSIV
Regen gas destination	Recycled back to amine	Recycled back to amine
Loading capacity	<10 lb/100 lb sieve for water	Same for water, <lb/100 lb sieve for heavies

Table 1: Comparing SeparSIV to Traditional Molecular Sieve Dehydration

HIGHLIGHTS OF SEPARSIV SYSTEMS TO NOTE:

- Faster cycle times: the SeparSIV system operates on a similar principle as many of the US LNG Peak shaver plants.
- Internal insulation for adsorbent vessels: This characteristic will allow shorter cooling/ heating time by reducing thermal inertia.
- Additional bed in regeneration: Having one bed in regeneration heating and one in regeneration cooling at all times cuts the required regeneration rate in half compared to a single bed in regeneration. This configuration is needed to allow for faster cycle times.
- Relatively higher regeneration flow rate compared to dehydration.

KEY DESIGN DETAILS OF ADSORPTION-BASED HEAVY HYDROCARBON REMOVAL SYSTEM

Knowing the preferred concept is one thing, but the key to successful project execution is the EPC-licensor collaboration. This collaboration is required to design a system which is inherently stable; therefore, the team placed a lot of focus on design details.

- During dehydration system regeneration, only water peak is observed during the desorption step. Sometimes during high rates of desorption, the Regeneration compressor trips if it falls short of power. Adequate design margins should be applied to the equipment in the Regeneration gas loop. SeparSIV is similar in operation except that it has two peaks during desorption. Additionally, one will not only see variable flows in the regeneration drum but also different combinations of components at different times of the regeneration cycle based on desorption mechanism. Regeneration KO drum needs to be sized with adequate design criteria.

- To ensure a more inherently stable design and a wide operating mode, the team stresses on not designing equipment for just a few data points but recommends conducting dynamic simulation analysis which will analyze the desorption dynamics as a function of time. To size the downstream system without this analysis can cause long-term operational issues.

- Just like any other design, the sizing of the SeparSIV vessel is generally based on worst case scenarios which commonly leads to oversized equipment. Establishing a good design basis and operating envelope is prudent to ensure that all equipment is sized properly when the amount of heavy hydrocarbon is out of range: higher or significantly lower than the design case.

RATING THE HEAVY HYDROCARBON REMOVAL OPTIONS

In concluding these introductory sections on heavy hydrocarbon removal, Table 2 shows the relative benefits and disadvantages of the systems based on key selection criteria. While every project has their unique characteristics, these vales were determined based on potential North American LNG plants supplied by lean pipeline feed gas.

	Conventional HRU	**SeparSIV for Water and Heavies Removal**	**Molecular Sieve Dehydration + SeparSIV Unit**
Most Suitable For	*Heavier Feed > 2 gallon per 1000 SCF C2+ content*	*Leaner Feed < 2 gallon per 1000 SCF C2+ content*	*Leaner Feed < 2 gallon per 1000 SCF C2+ content*
Pressure drop	Highest	Lowest	Lower
Product BTU value	Lower	Higher	Higher
Equipment count	Highest	Lowest	Lower
Turndown capability	Lower	Higher	Higher
Feed gas flexibility	Lower	Higher	Highest
Reliability for leaner feed	Lower	Higher	Higher
Ease of start-up, time for start-up	Complex, longer	Simpler, shorter	Simpler, shorter
Water and Liquid HC management	Simple	Most complex	Complex

Table 2: Benefits and Disadvantages of the Options Considered

OPERATIONAL STABILITY AND BEST LIFE-CYCLE ECONOMICS

For LNG projects, the most important parameter for long-term financial success is maximizing annualized production. Today's LNG plant operators minimize plant downtime by employing strategies such as increasing reliability of critical equipment, using redundant instruments for process trips, and by using more robust and reliable control schemes and systems. Freezing of heavy hydrocarbon components can result in multiple unplanned plant shutdowns which require subsequent defrosting and restart – valuable time lost. These disturbances will result in a significant reduction in annualized LNG production and can have a significant effect on the need for short-term manpower and required support resources.

By design, a SeparSIV system has less moving parts and is considerably easier to start-up as compared to a cryogenic turboexpander unit. A conventional HRU has a long start-up due to heat exchanger cool-down requirements (typically a brazed aluminum heat exchanger) and they require a reletively long period of time to stabilize the operation. These start-up durations also apply to the engineering contractor during commissioning and start-up of the facilities. Reducing start-up and operational tuning time by switching to SeparSIV technology is helpful from both the engineering contractor and owner's perspective.

ECONOMIC EVALUATION CASE STUDIES AND METHODOLOGY

The basis for this case study is a United States Gulf Coast location utilizing air cooling with a nominal LNG production of approximately 5.5-6.0 MTPA. An example of the expected feed gas composition is shown below. The team used a wide range of feed composition. Table 3 is an example of a representative composition that was used for the analysis.

Stream Name	Example Feed
Composition, Mole Fraction	
Nitrogen	0.005036
Carbon Dioxide	50 ppmv
Methane	0.951716
Ethane	0.035249
Propane	0.004028
n-Butane	0.001900
n-Pentane	0.001000
Cyclopentane	0.000025
n-Hexane	0.000201
Cyclohexane	0.000035
n-Heptane	0.000201
Benzene	0.000091
n-Octane	0.000151
Toluene	0.000040
n-Nonane	0.000060
E-Benzene	0.000005
o-Xylene	0.000005
p-Xylene	0.000005
n-Decane	0.000025
n-C11	0.000010
n-C12	0.000005
n-C13	0.000005
Hydrogen sulfide	4ppmv
Water	Saturated

Table 3: Typical Feed Composition assumed for US LNG

UOP simulated process flow schemes 1 and 2 (a and b) with the same feed gas composition, temperature, pressure and flow rate for both SeparSIV and the conventional heavy hydrocarbon removal process. Conventional heavy hydrocarbon removal process was simulated using UOP Ortloff's process knowhow in UniSim software using the Peng-Robinson Equation of State. A rigorous proprietary in-house dynamic adsorption process simulator based on fundamental adsorption data and pilot plant results has been developed by UOP for the SeparSIV process. This simulation model has been validated by commercial plant data from several operating units. Figure 7 shows a comparison of the model predictions with pilot plant data.

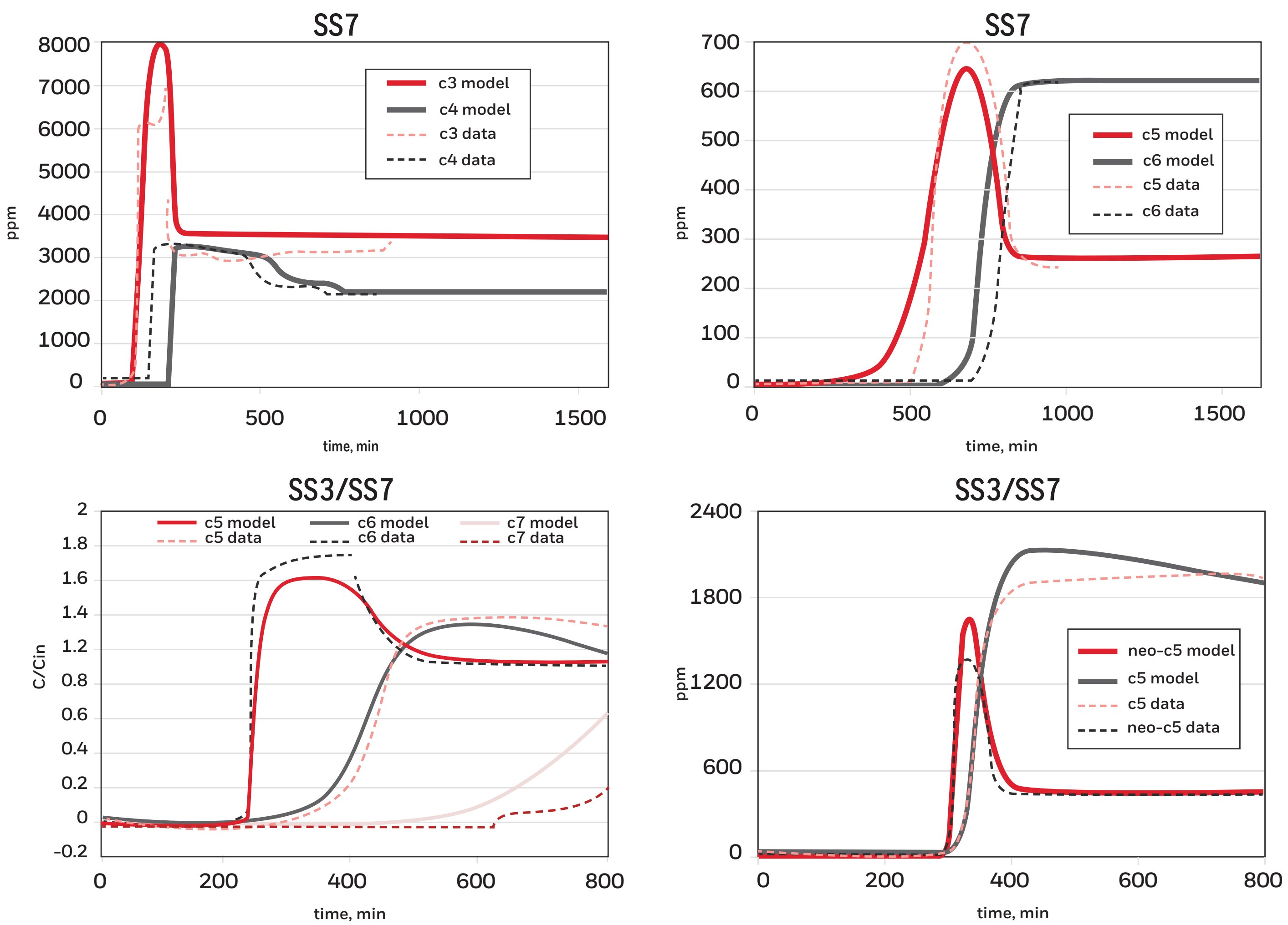
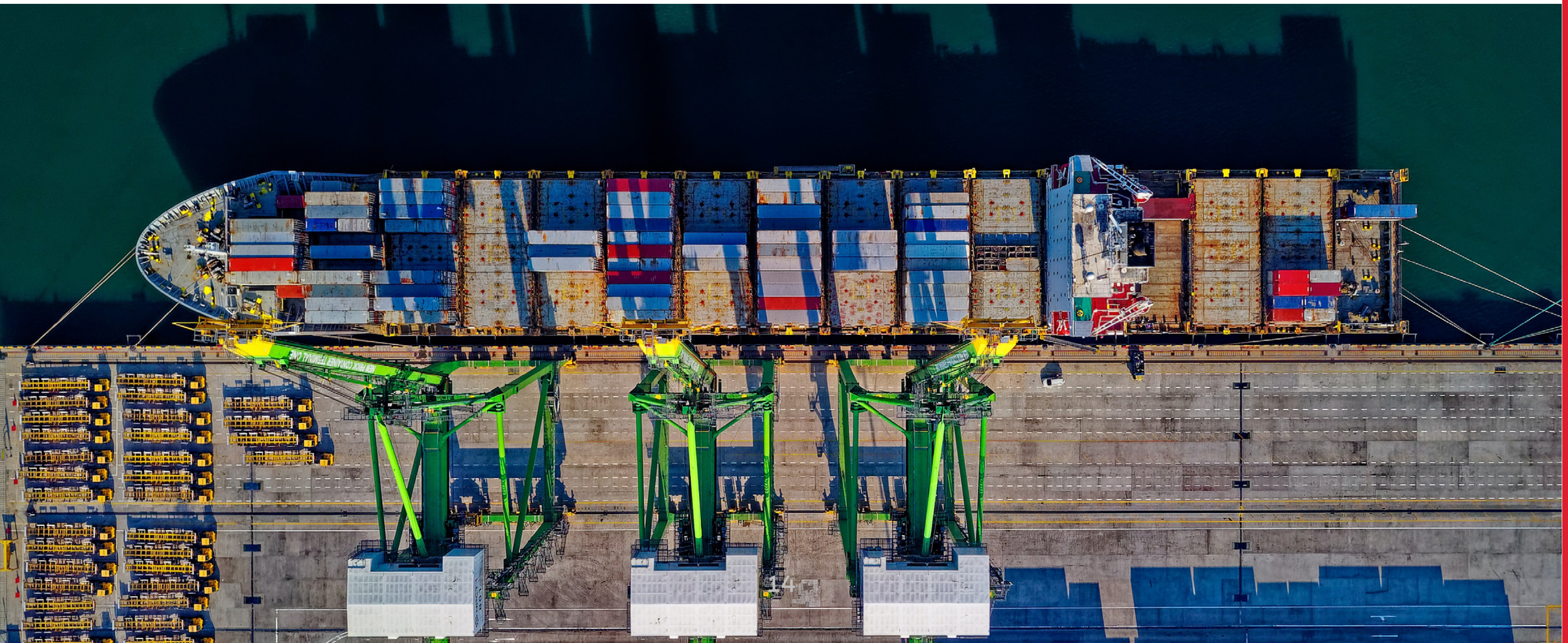


Figure 7: SeparSIV Model Predictions vs. Pilot Plant Data

The resulting sizing information was used by the UOP-Kiewit team to develop all equipment sizing and subsequently to estimate CAPEX and OPEX values for each case. These values were used by the UOP-Kiewit team to study the performance and economic benefits of SeparSIV compared to the conventional turbo-expander process.



CAPEX AND OPEX STUDIES

CAPITAL COST (CAPEX) ESTIMATE:

Case studies were run to analyze the CAPEX for the options shown below.

- Comparison of conventional Dehydration and HRU versus Combined SeparSIV/Dehydration
- Comparison of conventional HRU versus SeparSIV (assuming dehydration is a standalone unit)

The capital cost estimate was based on a US Gulf Coast project. The approach used for a combined dehydration and SeparSIV scheme is primarily a modular design as it does not require tall columns. The conventional HRU cost estimate is primarily based on a stick-built construction because of the nature of the equipment. Eliminating the HRU is a major "win" from a construction standpoint. It is one of the toughest structures to design as many of these columns are top supported and require a very complicated structure/foundation. In addition to the design "win", the construction of such large and heavy columns can prove to be one of the difficult logistical elements to manage and construct.

Based on the analysis, the Combined SeparSIV/Dehydration (Option 2a) has the biggest CAPEX savings over a traditional HRU (Option 1). This savings is due to the significant equipment reduction from Option 1, which are duplicated in separate dehydration and SeparSIV (Option 2b).

Beyond the obvious improvement over the Conventional HRU, below equipment is an example of CAPEX savings when SeparSIV is used (Option 2a and 2b) in lieu of Conventional HRU:

- Potential to eliminate the Booster/Residue compressor or require a smaller compression system
- Potential to eliminate or shrink the Booster/Residue compressor also eliminates any auxiliary power generation equipment (for example a LM2500+G4 or equivalent)
- Potential to eliminate or require a smaller Booster/Residue air cooler

Note that Booster/Residue gas compressor is used to boost the pressure to the desired liquefaction pressure (Figure 2).

Further CAPEX reductions are achieved through combining the dehydration and SeparSIV equipment. Below is an example of equipment count reduction when dehydration and SeparSIV are combined:

• Set of Regeneration gas compressors
• Single Regeneration heater
• Single Regeneration cooler
• Single Regeneration liquid knock-out drum
• Reduction in number of adsorption beds
• Reduction in expensive switching valves and depressurizing valves
• Reduction in significant quantities of piping (some of this piping needs additional attention because of cyclic services)

From the EPC perspective, the team sees significant benefit in implementing the combined-dehydration approach (Option 2a). The CAPEX savings were analyzed by Kiewit based on UOP licensor design information. The CAPEX analysis was done primarily considering the total installed cost of only Pretreatment (Mercury, Amine, Dehydration, Heavies Removal and Power generation associated with these units). This approach was followed because LNG projects can have a wide variation in total project cost based on technical complexity and civil, marine, and infrastructure costs[3]. Table 4 indicates the capital cost reduction compared to the base cost of the conventional design.

Design	PRETREATMENT CAPEX
Conventional HRU and Dehydration (Option 1)	1.0
Combined Dehydration-SeparSIV (Option2a)	0.65 - 0.70
Separate Dehydration and SeparSIV (Option2b)	0.81 - 0.87

Table 4: CAPEX Comparison Table

OPERATING (OPEX) COST ESTIMATE

The same nominal train size of 5.5-6.0 MTPA was considered with high-pressure liquefaction in the range of 1150-1200 psig. For a feed gas pressure of 1000 psig, the HRU needs to run at around 600 psig. This translates to a pressure reduction followed by subsequent pressure boost using a compressor downstream of the HRU.

For the case study in question, this translates to additional compression power when conventional HRU is used (shown in Figure 8 below). Figure 8 demonstrates the pressure profile across process units for different options. However, when the SeparSIV technology is used, there is no need for pressure letdown which saves significant recompression power. As can be seen in Table 5, the total power requirement is around 10-15% lower for the SeparSIV combined design. The power savings for SeparSIV between the two options (2a and 2b) is not significantly different. The slight difference stems from the fact that the combined bed has only one regeneration gas compressor.

Technology	Overall Liquefaction-pretreatment Power
Option 1: Traditional HRU	1.0
Option 2a and b2: Dehydration and Heavies removal with SeparSIV	0.85 - 0.9

Table 5: Power Comparison Between Conventional HRU and SeparSIV

As shown in Figure 8, there is a significant efficiency penalty at the HRU because of the required drop in operating pressure. Downstream of the HRU, a pressure boost is required to achieve high pressure liquefaction. In contrast, the SeparSIV option does not require a pressure drop for operational reasons. Therefore, for the SeparSIV option, as seen in Figure 8, the pressure at the inlet to liquefaction mirrors feed gas pressure minus the hydraulic losses. The additional pressure increase for SeparSIV as seen in Figure 8 is the difference between feed pressure and the desired liquefaction pressure.

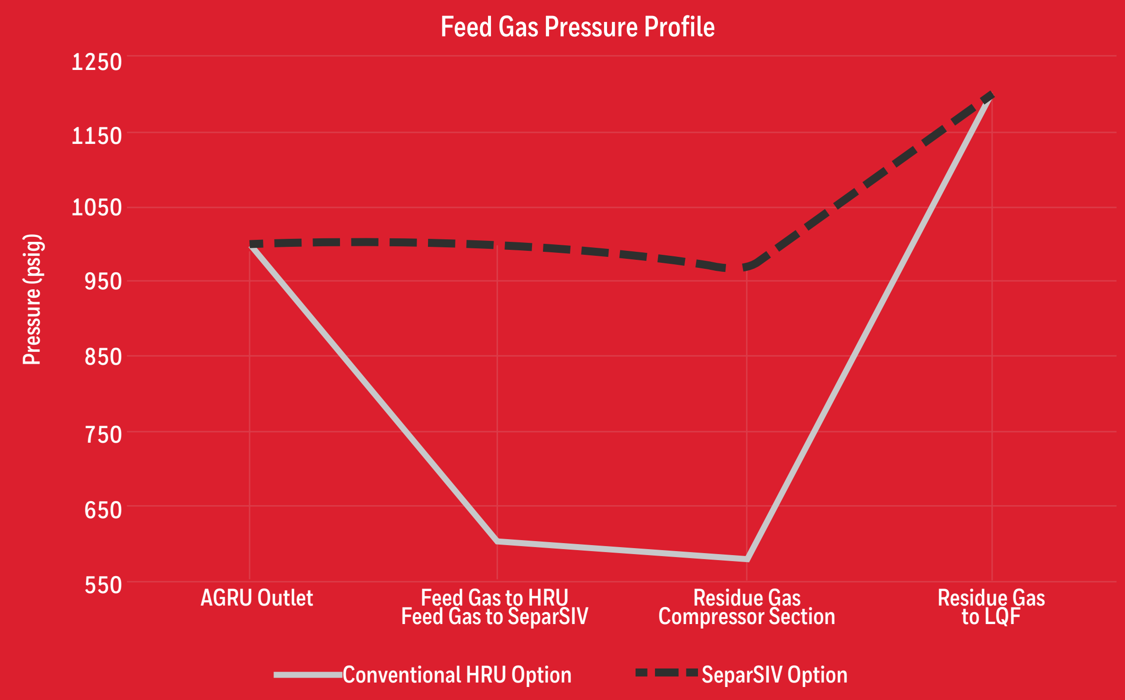
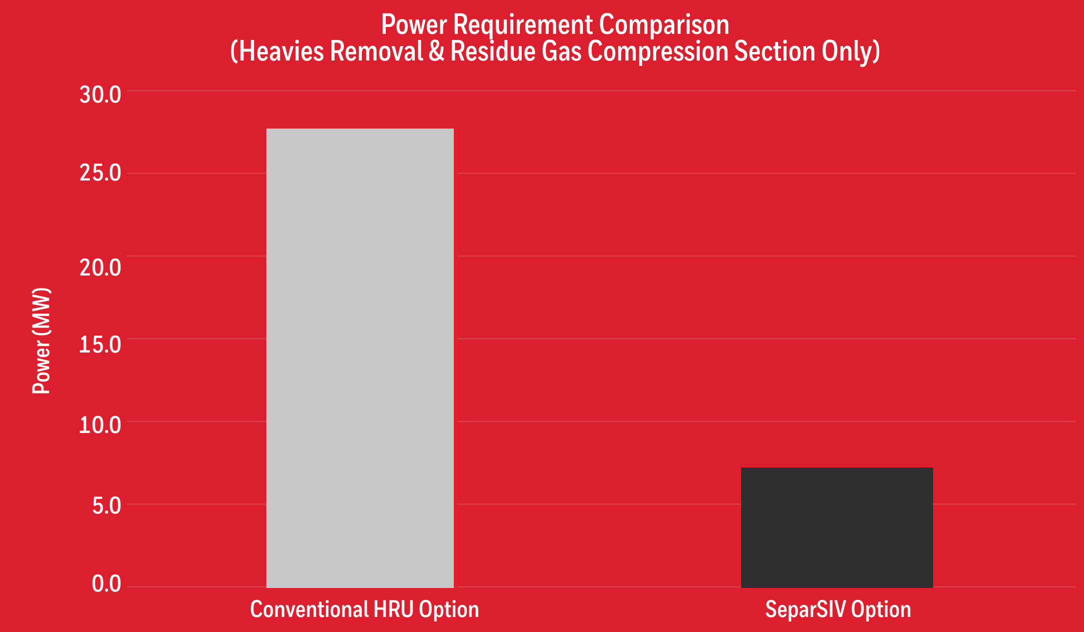


Figure 8: Compression Pressure Profile for Schemes 1 and 2a



This power reduction also translates to greenhouse gas (GHG) reduction and significant CAPEX savings. This savings is due to the reduced power and requires installation of less power generation equipment than for Scheme 1. Frequently, auxiliary power is provided by standalone gas turbines. Power reduction for the SeparSIV process results in elimination of an auxiliary turbine and its corresponding GHG emissions. This benefit is crucial when considering the broad initiative to render LNG “more green” and efficient than other forms of energy.

SMALL SCALE LNG

APPLICATIONS IN SMALL-SCALE LNG

This team has been involved in small scale projects where a similar design approach has been used. Small-scale LNG projects have the same challenges with lean pipeline quality feed gas in North America as large-scale projects. SeparSIV technology is not only applicable for large-scale plants but can also be utilized for small-scale plants and peak shavers.

A solvent-free system is possible for small-/mid-scale LNG plants with less than 2% CO_2 such that adsorption based units can simultaneously remove water, CO_2, and heavy hydrocarbons while keeping the spent regeneration gas level to <10%. If the spent regeneration gas can be used as fuel or sent back to the sales gas pipeline, this system can offer a great alternative to conventional solvent-based LNG pretreatment. Kiewit-UOP is currently working on small-scale LNG projects with these same design features to support future LNG projects.

RETROFITTNG AN EXISTING UNIT

SeparSIV technology can also be used to retrofit existing molecular sieve dehydration units to remove C_{9+} such that an existing conventional heavies removal system can be debottlenecked. In such cases, typical changes needed are a change-out of the dehydration adsorbent with SeparSIV adsorbent, a change in cycle times and regeneration flow rate, along with water and hydrocarbon liquid management. Retrofit systems inherently come with design limitations due to fixed vessel sizes and corresponding regeneration circuit.

CONCLUSION

Adsorption systems have been utilized by the industry for multi-contaminant removal for several years. Collective industry experience of fast-cycle peak shaver LNG plants for simultaneous CO_2 and water removal, large baseload LNG plants for simultaneous water and mercaptan removal, membrane pretreatment plants for heavy hydrocarbon and water removal have already demonstrated that the ability to model, design, engineer and construct such units is well proven in the industry. Multiple reference units are in operation and a large baseload unit is under construction using SeparSIV technology. Based on observed challenges in multiple North American LNG plants and the known advantages that adsorption-based systems can offer to resolve these challenges, these systems should be considered for traditional base designs. A CAPEX, OPEX and qualitative analysis undertaken by the team indicates that SeparSIV process can offer a reliable and cost-effective alternative compared to conventional heavies removal technologies when it comes to lean feed gas – even when it seems “too lean”.

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