Lean feeds are becoming increasingly common as more LNG plants currently in the planning stage are based on unconventional gas resources, such as tight sands gas, shale gas, coal-bed methane, and even domestic pipelines. At the same time, the feed gas to some operating LNG plants is also gradually being replaced by newer sources such as deep water gas. These new feed gas sources may have one thing in common, the gas contains more methane and considerably less natural gas liquid (NGL) components than conventional feed gas sources, while they may also contain some levels of heavy paraffins and aromatic hydrocarbons similar to heavy crude oil.

Fei Chen and Christopher M. Ott, Air Products and Chemicals Inc., USA, discuss the technology options to tackle new challenges in lean gas liquefaction.
to conventional feed gas sources. Effective, efficient and versatile liquefaction solutions are needed to address the challenges brought by this trend.

**Challenges**

The challenges that many operating LNG plants and new LNG projects are facing come from the unique characteristics of lean feed gas.

Figure 1 compares a typical feed gas composition (directly from a conventional gas well for example) with a lean feed gas composition. The gas composition (mole %) is shown on the vertical axis as a log scale, and various components in the feed gas are shown on the horizontal axis. Regardless of the composition of the feed, the concentration of each component generally decreases as the hydrocarbon chains become longer. The main difference is that the lean feed gas contains significantly lower ethane (C2), propane (C3), butane (C4) and pentane (C5) components (primary constituents of NGL) than the typical feed gas.

Surprisingly, many lean feed gas sources contain disproportionately high amounts of heavy hydrocarbons (HHCs), which are often in the same orders of magnitude as those in the typical feed gas. The amount of these heavy components can exceed the maximum amount allowed to avoid freezing in the liquefaction process, as shown by the green clouds in Figure 1. The components such as benzene (BZ), ethyl-benzene (ETBZ), octane (C8) and nonane (C9) are particularly challenging as even small amounts of these components can freeze at LNG temperatures. When frozen, these components can block small passages such as strainers, valves or plate fin heat exchangers. In extreme cases, the frozen components will plug even larger passages, such as butterfly valves or wound coil heat exchangers. It may be possible to adjust plant operation to clear the blockage by raising the cold end temperature and dissolving the frozen components. However, such operation typically deviates from the plant’s normal or design conditions. It also shifts the problem to downstream equipment and the LNG storage tank, as the dissolved components will again precipitate when the LNG is further cooled. In extreme cases, the blockage could become so severe that it is necessary to shutdown and defrost the plant, leading to loss of LNG production and ultimately lost revenue.

The removal method of these HHCs often depends on the content of NGL components such as C2, C3 and C4. It is difficult for a traditional distillation column to operate stably and efficiently on lean feed gas as there are not enough NGL components present to provide sufficient reflux and downward liquid traffic in the column.

Another unique characteristic of some unconventional gas sources is that the gas composition entering the plant can vary significantly over a relatively short period of time, because the gas is usually taken from multiple sources. Figure 2 shows how the composition at a particular plant varied over the course of a month. The methane content (red line) drifted between 92% and 98%, characterised by several days of nearly steady values followed by rapid change to another nearly steady value. The total heavy hydrocarbon content, represented as C6+ (blue line), varied between 20 ppm and 200 ppm, changing by a factor of approximately 10.

To prevent freeze-out of HHCs and to minimise the impact of the feed composition variability on the plant operating conditions, the liquefaction unit and its associated equipment must be sufficiently versatile to handle these new challenges.

**Solutions**

There are many traditional options for removing HHCs from natural gas feeds that have been reliably used in the LNG industry, such as a frontend NGL extraction unit, an integrated scrub column, a partial condensation drum and adsorption units.

**Frontend NGL extraction**

A frontend NGL extraction unit is a separate operation upstream of the liquefaction unit. It generates refrigeration using a turbo expander on the feed while operating a scrub column at reduced pressure to remove HHCs and recover NGL components. Feed gas processed in this unit can then be compressed to high pressure and fed to the liquefaction unit.

These units effectively remove HHCs, but contain many pieces of operating and rotating equipment that impact the capital investment and could impact the availability of the LNG plant. A frontend NGL extraction unit can handle a wide variety of feed gas compositions, but it may be difficult to adjust promptly to accommodate changing feed gas compositions. In addition, a lean feed gas may not contain enough NGL components to justify the investment or to run the scrub column efficiently.

Frontend NGL extraction units have been used effectively...
in many baseload LNG plants, especially when high levels of NGL extraction were desired.

**Integrated scrub column**

Another option is to use a scrub column that is integrated into the liquefaction unit. Integrated scrub columns are frequently used in baseload LNG plants to remove HHCs and recover refrigerants for make-up. This option has the advantage of eliminating the cold box and turbo expander associated with frontend NGL extraction units. However, in order for adequate separation to occur in the column, the system must be operated at a pressure with a sufficient margin below the critical point. Therefore, a significant reduction in column pressure may be necessary, which negatively impacts liquefaction efficiency. Leaner feeds require lower pressures and colder temperatures, which reduce efficiency and increase power consumption even more. Additionally, an integrated scrub column may not be easy to operate if the feed gas composition changes significantly in a short period of time.

**Partial condensation**

Partial condensation is similar to the integrated scrub column but with the column eliminated. In this simple arrangement, feed gas is partially cooled in the liquefaction unit to condense a portion of the HHCs. This liquid and vapor is then separated to remove the condensed HHC rich liquids from the overhead leaner natural gas. Partial condensation has no particular requirement for NGL content in the feed gas and is relatively simple to operate and adjust to meet changing feed gas compositions. However, similar to the scrub column, it may be necessary to reduce the operating pressure in the partial condensation drum to maintain an adequate margin from the critical point. Unavoidably, the liquid product from the separator drum will contain most of the NGL components and a moderate amount of methane. This stream can be used as fuel, injected in an adjacent pipeline, or fractionated to separate NGL’s and recover methane. Partial condensation is typically more effective in removing hexane (C6) and heptane (C7) as opposed to low solid solubility components such as C8, C9, BZ and ETBZ, as sufficient removal of these heavier components requires colder operating temperatures and results in more methane loss in the off-spec NGL byproduct. Partial condensation drums have frequently been used in LNG peak shaving plants due to the low capital cost and operational simplicity.

**Adsorption**

An effective way to remove low solid solubility components is with a temperature swing adsorption (TSA) unit similar to the dehydration units used in many baseload LNG plants. Adsorption cycles and adsorbents are designed to selectively remove aromatics and some heavy parafins. Dry feed gas enters a packed adsorbent bed that removes target HHCs. After exiting the adsorbent bed, a portion of the feed gas is used as regeneration gas, while the remaining feed gas is fed to the liquefaction unit. The regeneration off gas can be recycled, used as fuel, or injected into adjacent pipelines.

The adsorption process typically prefers high feed pressure to increase adsorption capacity for the target HHCs. Unlike other technologies that are based on vapour-liquid equilibrium, the adsorption process does not require reducing the feed gas pressure and has no lower limit on the NGL components in the feed. It is even possible to operate the adsorption unit at supercritical pressures. It can remove trace amounts of HHCs from lean feed gas without impacting liquefaction efficiency. Adsorption units have been used in LNG peak shaving and mid-size LNG plants.

One limitation of the adsorption unit is that the equipment size and adsorbent quantity increase with increasing HHC concentrations. It may not be

![Figure 3. Frontend adsorption combined with partial condensation.](image-url)
economically favourable to use adsorption for feed gas containing large amounts of HHCs, because the adsorbent bed may be unrealistically large, require multiple parallel trains, and consume a significant amount of regeneration gas.

Adsorption/partial condensation hybrid
Understanding the pros and cons of each technology led to the development of many novel solutions for lean gas liquefaction. One example is to combine adsorption and partial condensation, creating a process (Air Products patent pending) that both effectively removes HHCs and tolerates a changing feed gas composition. As schematically shown in Figure 3, after a portion of the HHCs are removed by the adsorption system, the feed gas enters the liquefaction unit where it is partially condensed. The resulting two phases are separated in the drum to remove the remaining HHCs into the NGL rich liquid. The purified overhead vapour is then liquefied and subcooled in the main cryogenic heat exchanger (MCHE) to produce the final LNG product.

This arrangement has two benefits:
- Removing only a portion of the HHCs in the adsorption unit keeps the equipment and adsorbent quantity small.
- With a portion of the HHCs already removed prior to the liquefaction unit, less liquid is required in the partial condensation drum, so it operates at a higher pressure, improving the liquefaction efficiency.

Case study
A case study can help to explain the differences between the options. An LNG plant with design capacity of ~0.5 million tpy is taking feed gas from a pipeline, which ultimately has two lean gas sources, as shown in Table 1. The gas from source 1 is very lean and does not contain anything heavier than C7. The gas from source 2 contains some low solid solubility components (e.g., C8, C9 and BZ). However, C6 and C7 are below their freeze-out limit in LNG.

For most of the time, the feed gas is a 50/50 mix of the gas from the two sources, but from time to time its composition may become close to one of the sources, depending on feed gas availability. To prevent freeze-out, C6 and C7 in the combined feed must be removed to below their solid solubility limit in LNG of approximately 150 and 40 ppm respectively, while C8, C9 and aromatics must be removed completely.

Based on the characteristics of the feed gas, using a frontend NGL extraction unit is technically feasible, but it would require many additional pieces of equipment. The unit would also be unable to make sufficient NGL product to help offset the capital investment.

Operating an integrated scrub column would be infeasible as there is not enough C2, C3 and C4 components in the feed gas to provide reflux and downward liquid traffic in the column.

Due to the relatively high concentration of C8, C9 and aromatics, using a partial condensation drum, while technically feasible, is not economical. The feed gas needs to be pre-cooled to -70 to -80 °C and its pressure needs to be reduced by 20 – 30% to remove enough of these components. This would reduce liquefaction efficiency and result in significant methane loss into the cold NGL rich by-product stream.

A frontend adsorption unit alone would not be practical and economical, as removing all the HHCs to acceptable levels would require large adsorbers holding large adsorbent quantities. A significant portion of feed gas will also need to be used as regeneration gas.

The adsorption/partial condensation hybrid option offers the best and most versatile solution for this particular application. The adsorption unit only needs to remove a portion of the HHCs while the partial condensation drum can be maintained at higher pressure and still effectively remove the remaining HHCs. When the feed gas composition varies between the two sources, the

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Table 2. Comparison of HHC removal options for the case study

<table>
<thead>
<tr>
<th></th>
<th>Frontend NGL extraction unit</th>
<th>Integrated scrub column</th>
<th>Partial condensation</th>
<th>Adsorption</th>
<th>Adsorption and partial condensation hybrid</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equipment count</td>
<td>Much more</td>
<td>Less</td>
<td>Much less</td>
<td>Less</td>
<td>More</td>
</tr>
<tr>
<td>C2 – C5 product recovery</td>
<td>High</td>
<td>Most</td>
<td>Less</td>
<td>None</td>
<td>Less</td>
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<tr>
<td>C2 – C5 requirement for unit operation</td>
<td>Some</td>
<td>More</td>
<td>Some</td>
<td>None</td>
<td>Some</td>
</tr>
<tr>
<td>HHC removal effectiveness</td>
<td>Excellent</td>
<td>Good</td>
<td>Difficult removing low solid solubility components</td>
<td>Excellent removing trace amounts of HHCs</td>
<td>Excellent</td>
</tr>
<tr>
<td>Byproduct(s)</td>
<td>A small NGL stream with small C1 loss</td>
<td>A small NGL stream with small C1 loss</td>
<td>A large cold liquid stream with moderate C1 loss</td>
<td>A large C1 stream with HHC</td>
<td>a. C1 stream with HHC; b. A small cold liquid stream with some C1 loss</td>
</tr>
<tr>
<td>Liquefaction efficiency</td>
<td>High</td>
<td>Lower, due to reduced feed pressure</td>
<td>Lower, due to reduced feed pressure</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Overall rating for the case study</td>
<td>May not be cost effective</td>
<td>Not feasible</td>
<td>Not efficient</td>
<td>May not be effective/feasible</td>
<td>Best and most versatile</td>
</tr>
</tbody>
</table>

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operating conditions for the adsorber and the partial condensation unit can be easily adjusted to accommodate the change. In extreme cases, e.g., if the plant solely takes gas from source 1 for an extended time, the adsorber may be completely shut down and bypassed. On the other hand, if the plant solely takes gas from source 2, the partial condensation drum can be kept at feed pressure, maintaining liquefaction efficiency and minimising methane loss. Overall, this hybrid arrangement effectively removes HHCs while providing an efficient, flexible and compact liquefaction process.

A key lesson from this case study is that seemingly minor changes in feed gas composition can have a dramatic effect on the optimum solution. As previously stated, often in the early stages of project development, the feed gas composition is not fully known, and even if known it can vary significantly over time. Therefore, the technology choice should consider the sensitivity to changing feed gas composition, and the best choice will not be overly sensitive to such changes. Table 2 summarises the various options for this case study.

**Adsorption experience and capability**

Using adsorption to remove HHCs prior to an LNG liquefaction plant may not be common in the LNG industry, but adsorption is a mature technology. Since the 1970s, Air Products has designed and operated adsorption units ranging from very small sizes to over several hundred tonnes per hour of feed gas. This experience covers several industries including the air separation industry for frontend pretreatment, nitrogen and oxygen production, refinery for the production of hydrogen and syngas, and the natural gas industry for HHCs, CO₂ and water removal, as well as helium purification.

To support these operating units, Air Products has developed adsorption capabilities focusing on adsorbent development, adsorbent properties characterisation, thermodynamic and kinetic parameters measurement, and pilot scale testing. In parallel, the company has also developed proprietary adsorption simulation software that is a true dynamic simulator with first principles of adsorption physics built into it. The associated database is established based on experimental results from laboratory and pilot scale units, and then fine-tuned using performance results from full scale operating facilities. For over 25 years this tool has provided sophisticated computer modeling capabilities that reliably predicts adsorption unit performance. As many LNG projects are considering lean feed gas compositions, Air Products has refined and utilised this simulation software to evaluate the performance of HHC adsorption units for LNG applications.

When an adsorbent bed becomes saturated with a particular component, the component’s concentration at product end will begin to rise. This is known as breakthrough. The breakthrough curve of a component is a key aspect used to design HHC removal adsorption units. Typically, an adsorbent bed is sized such that the cycle switches to regeneration before the target molecule breaks through. Figure 4 shows breakthrough curves for two heavy hydrocarbons, component A and component B. Both would freeze in LNG if their breakthrough concentrations exceed the maximum allowed value. The dotted data represent real plant test data and the solid lines represent the predicted breakthrough using Air Products’ proprietary modeling tool and database. This agreement adds confidence to using this capability to predict and evaluate adsorption performance for LNG applications.

**Conclusion**

HHCs exist in almost all natural gas feeds. For liquefaction applications using lean feed gas sources, the HHC components, the relatively lower NGL contents, and the varying compositions all present new challenges for the liquefaction process. Fortunately, there are several options for HHC removal, each offering unique benefits. There is no single answer as each feed gas is different and each project has different requirements. The technology choice for removing HHCs primarily depends on the concentrations of NGL and HHCs present in the feed gas. The optimum, or even only practical, solution will vary from project to project. Even small changes in trace components may change the optimum choice, so it is important to select an option that is efficient, yet robust and reliable. These options should be investigated early in the project to prevent costly redesign and ensure project success.

**References**

1. Luo, X; Liu, Y.N; Miller, W; Ott, C and Schmidt, W., ‘Selecting the Optimal Technology for Mid-size LNG Plants’, presented at Modular & Mid-Scale LNG Conference, Lafayette, LA, 2011.

