Flexible processing

Modularised gas processing equipment is a proven solution to deliver fast, effective acid gas and contaminant removal, as well as natural gas liquids (NGL) recovery for North American shale gas resources. Through a packaged plant delivery model, modularised amines, adsorption, and cryogenic turboexpander equipment skids can be prefabricated and delivered to customer locations, reducing costs and increasing profits due to speed to gas. Modularised solutions can be particularly advantageous for gas flow rates below 500 million ft$^3$/d and scalable to higher flows by incorporating multiple equipment trains. Packaged equipment simplifies gas processing projects by offering faster construction times, greater reliability as a result of proven shop-fabricated quality, and easier installation.
via skid-mounted delivery, compared to field fabricated solutions.

This article incorporates these themes to provide a decision framework to guide appropriate selection of gas processing technologies. Within the presented framework, it is not only important to select the proper processing technology but also to consider the interactions among each gas process unit and to adjust sequencing of the process steps to optimise operations, thereby increasing operating flexibility within the overall gas processing system. Experience within the gas processing space has proven that flexibility should serve as a key attribute when selecting the proper solution for gas processing, including LNG applications. Flexible operating and investment capabilities are becoming more important as the industry develops more sub quality and distributed gas reserves, as it is likely the variability of the feed gas composition and feed flow rates will increase.

**Gas processing technology decision guide**

Numerous factors impacting the upstream resource, midstream project specifics, and downstream commitments affect the selection of gas processing technologies. The key decision blocks and variables underlying a design decision making matrix are displayed in Figure 1.

The upstream factors impacting gas processing technology selection include:
- Hydrocarbon (HC) distribution composition of NGLs and/or crude oil within the feed stream.
- Production profile of the hydrocarbon reserve.

**Figure 1. Flow schematic representing key decision criteria for gas processing projects.**

| Table 1. AGR (acid gas removal) functional process block detail |
|-----------------------------------|-----------------|-----------------|---------------- |
| **Functional requirements** | **Process options** | **Key selection criteria** | **Interactions/comments** |
| Reduce CO₂, H₂S, mercaptan and COS | Solvents | In | Out | Interference of heavy hydrocarbons |
| Concentrate for further processing (tail gas treating) | Membranes | Gas flow rate | Gas quality targets | Sequencing with dehydration |
| Minimise hydrocarbon losses | Adsorbents | Concentration | AG disposal/product options | Relative H₂S/CO₂ |

Chemical (chem-sorb, scavengers)

Pressure

Value/penalty for CO₂ use/discharge?
Feed gas contaminants including acid gas (CO₂, H₂S, mercaptans), mercury, arsenic and nitrogen.

Feed gas pressure and flow rate.

Ambient conditions such as temperature.

Onshore/offshore situation of resource and processing equipment.

Regional fiscal regime impacting project funding.

Environmental constraints, either local or global.

When considering plant configurations and design decisions, operating flexibility should serve as a key design objective for the processing system. Flexibility is important due to the complex interrelationship and relative uncertainties among input upstream factors, interactions among the processing plant functional blocks, and overall delivered project economics and/or downstream commitments.

Within the gas plant configuration, the dynamic interactions among functional blocks within Figure 1 will also drive processing systems towards more flexible operations. As an example, the AGR process block within Figure 1 is detailed in Table 1 to show the various decision elements underlying appropriate technology selection.

Figure 2. AGR, HCM and OCM process block decision tree for sample scenario.

Figure 3. Integrated natural gas processing flow scheme for case study.
An example of an integrated AGR, HCM and OCM decision tree for a sub quality gas feed and specified products for export by pipeline is included in Figure 2. Of course, the decision tree would be similar for LNG applications, with the added complexity of adding the downstream liquefaction step.

When determining the proper solution set for a gas processing project, it is important to conduct the following three exercises in unison:

- Select the proper technology solution within each processing block.
- Account for interactions across different processing blocks.
- Adjust the sequence of processing blocks for optimisation.

For this particular feed, which is high in CO\textsubscript{2} and H\textsubscript{2}S, an amine unit integrated with a licensed turboexpander and mercury guard bed, highlighted in red in Figure 2, is identified as the appropriate technology selection to meet the product specifications.

### Integrated packaged solutions

Delivering gas treating solutions via packaged modular process units can provide clear economic and schedule advantages for small and mid-sized LNG projects, particularly in situations of distributed (or remote) gas reserves or when the lead-time for start-up of gas processing units represents a critical path element. Some industry participants are also considering packaged modular process units for larger-scale projects by incorporating multiple equipment trains.

Table 2 illustrates the benefits of packaged modular vs. field (or stick) built processing units based upon a number of project criteria.

Individual packaged process units can be integrated to ensure overall system flexibility is optimised. This capability played a vital role in the rapid development and success of the US wet shale gas industry and is likely to contribute to the success of the development of sub quality and unconventional gas elsewhere. An example is the Thomas Russell Company, now majority owned by Honeywell and sold under the UOP Russell product family. The Thomas Russell story parallels the US shale gas revolution. As a result of the perseverance of visionary entrepreneurs, dry shale gas production increased by a factor of 10 in just six years and now makes up 30% of total US gas production. The rapid increase in supplies outstripped demand and the market price of dry natural gas fell to the point that it is no longer economic to drill for dry gas in most shale gas reservoirs in the US. Natural gas production continues to rise because drilling activity shifted to wet shale gas and oil producing significant volumes of associated gas. This shift to wet shale gas and shale oil was enabled by the NGL recovery packaged equipment solutions provided by Thomas Russell. Without these gas processing solutions, these vital resources could not be developed. The Thomas Russell ‘fast gas’ business model was key to enabling quick resource monetisation. Its pre-fabricated modular process units could be quickly installed and had much lower lead-times than customised or stick-built plants with no loss of quality. The UOP Russell product line is now ready to enable shale gas, shale oil, and wet conventional gas resource development globally.

### Case study: sub quality gas

An example feed gas high in H\textsubscript{2}S and CO\textsubscript{2} is shown in Table 3 to serve as a basis for this case study.

The UOP modeled process flow diagram presented in Figure 3 incorporates acid gas, mercury, mercaptan, water, and NGL removal via an integrated process flow scheme that utilises gas-phase separation of RSH and COS within the sulfur plant. An integrated flow scheme will provide higher overall facility operating efficiency, increased hydrocarbon recovery, and increased sulfur recovery compared to a conventional flow scheme that utilises liquid phase desulfurisation. Additionally,
when an integrated gas plant project is executed via prefabricated modular supply of key process units, including the AGRU, MolSiv, and NGL, significant lead-time acceleration and reduced start-up complexity will be achieved vs. field (stick) built process units. For LNG applications, an added modular liquefaction unit can be integrated into the system.

The integrated process can adjust to changing mercaptan feed conditions with a minimal impact to operating costs. As the mercaptan content in the feed increases, the integrated scheme has the flexibility required to treat this new feed with minimum revamp of the units. The operating strategy involves changing the cycle time of the MolSiv unit and rerouting the regeneration gas streams. No incremental MolSiv vessels or Selexol columns are required. Figure 4 shows the impact of the increasing mercaptan contents in the feed on the MolSiv unit cycle time and the regeneration flow. As the regeneration flow is increased, the associated equipment in the regeneration loop, such as heater, cooler and compressor, will need to be increased in their duty or size. Depending on the mercaptan increase, the regeneration equipment may already have the extra capacity. As the regeneration flow increases, the pressure drop across the Selexol unit also needs to be managed carefully. Additionally, increasing mercaptan feed will have a minor impact on operating costs. A 50% increase in mercaptan feed has been modeled to result in only a 3 to 4% increase in total operating costs.

In cases of high or increasing H₂S and CO₂ feed composition, a packaged membrane system can be incorporated upstream of the AGRU, as shown in Figure 5. Incorporating a membrane system prior to the AGRU for bulk CO₂ and H₂S removal can offer the following advantages for acid gas removal vs. a stand-alone AGRU:

- Operating flexibility: ability to respond to changing acid gas feed composition via high turndown capability.
- Investment flexibility: membrane capacity can be easily expanded by incorporating additional elements to existing membrane modules or by installing incremental membrane modules.
- Capital cost reduction potential: can lower capital cost and size of the AGRU at the expense of incremental membrane capital.

Operating cost reduction potential: can provide operating cost advantages vs. stand-alone AGRU in situations where electricity is cost-advantaged vs. steam.

Furthermore, membranes can be particularly advantageous for remote locations where labour or solvent replenishment capabilities are a concern or in situations where plant plot space is limited.

**Summary**

UOP believes an integrated design approach with an emphasis on flexibility for both operations and investment decisions will prove critical to successfully monetising new gas resources. Flexibility is important due to the complex interrelationship among input upstream factors, interactions among the processing plant functional blocks, and overall delivered project economics and/or downstream commitments. Furthermore, incorporation of modularised process units into an integrated package can accelerate project schedules and help stage investment decisions.

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### Table 3. Feed gas conditions for case study

<table>
<thead>
<tr>
<th>Feed gas conditions</th>
<th>Mol %</th>
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<tbody>
<tr>
<td>H₂S</td>
<td>23%</td>
</tr>
<tr>
<td>CO₂</td>
<td>10%</td>
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<tr>
<td>N₂</td>
<td>&lt;0.1%</td>
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<tr>
<td>Methane</td>
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<td>C₂+ hydrocarbons</td>
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<td>H₂O</td>
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<td>COS</td>
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<tr>
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<td>Flowrate (million ft³/d)</td>
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<td>Temperature (°C)</td>
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<tr>
<td>Pressure (bara)</td>
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</tbody>
</table>

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**Figure 5.** Integrated flow scheme incorporating a membrane prior to the AGRU.