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Cost-effective design reduces C_2 and C_3 at LNG receiving terminals

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Gas Processing

An LNG receiving terminal with a C_2+ or C_3+ separation facility can receive LNG feeds with varying compositions, meet stringent calorific value export gas specifications, and decrease capital and operating costs. A study shows that process schemes for extracting C_2 or C_3 from rich imported LNG are feasible, effective, and economical.

A minor required change in typical LNG receiving terminal equipment includes modification of the sendout pumps' casing to a higher pressure rating; however, no additional compression is required.

Compared to a system that requires sendout gas compression or an inert-gas injection system to dilute the sendout gas, C_2+ or C_3+ separation can reduce the capital investment by at least 40% and decrease operating costs.

The cost-effective designs include additional facilities that are not standard in most receiving terminals. This includes a separation system, which consists primarily of one or two fractionation columns with plate-and-fin or shell-and-tube exchangers for overhead condensers.

The designs use low-temperature LNG as a cooling medium for the column overhead to achieve an economic separation. These designs require no gas compression because they use LNG as a refrigerant in a direct-contact condenser; this condenses enriched C_1 vapor from the column overhead to produce a lean LNG for liquid pumping.

The designs also use existing vaporizers to vaporize column feed.

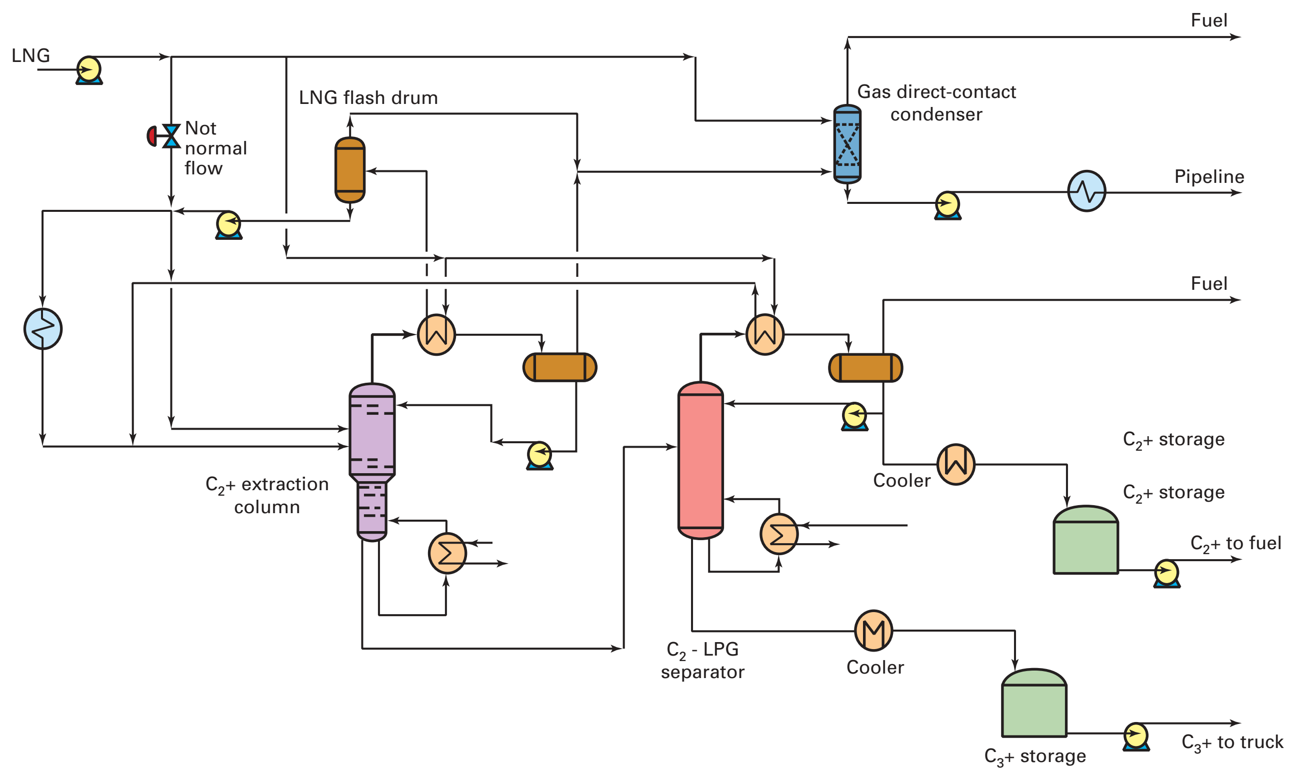
LNG terminals

Gas companies that serve North American markets have strict requirements for the composition of natural gas from their LNG receiving terminals in terms of calorific value and quality.

LNG receiving terminals require less C_2 and C_3 in the LNG than what most existing baseload plants produce. Be-

C_2+ REMOVAL PROCESS

Fig. 1



cause it is generally not cost effective to reduce C_2 and C_3 at the baseload plant, and this type of operation reduces LNG production at the baseload LNG facility, it is better to install the process at the LNG receiving terminal.

Companies are planning to build more than a dozen new LNG grassroots receiving terminals to serve the North American market. Other companies are constructing or planning expansions of existing LNG receiving terminals in North America.

Due to more-stringent requirements, supplies from virtually all LNG plants at either the baseload liquefaction plant or the receiving terminal must reduce C_2 and C_3 content.

Most LNG produced worldwide cannot meet the gas specifications required in North America.

Table 1 shows that California Air Resources Board specifications for CNG have lower limits for than pipeline gas (10 mole % of C_2, 6 mole % of C_3).[1]

Table 1 also shows a specification for the Mexico pipeline gas. Only selected LNG suppliers provide light LNG to meet the CNG specifications. Table 2 shows typical LNG compositions.

If a terminal requires C_2 or C_3 for fuel, it will need to process LNG with a component extraction unit.

LNG buyers have different requirements; therefore, reducing C_2 and C_3 at the baseload LNG plant is not desirable because of:

- Less LNG produced.
- Additional compression equipment required.
- The desire to operate all LNG trains at the same conditions.

After initial feed-gas treatment in an LNG baseload plant (acid-gas removal, dehydration, mercury removal, etc.), a scrub column removes benzene and C_5+ components to ensure that they will not freeze in the main cryogenic heat exchanger. To control LNG calorific value, the scrub column also removes some C_2+ components.

The feed-gas pressure for most baseload LNG plants is greater than 60 bara. If the plant must remove heavier hydrocarbon components to meet a typical North American market calorific value of 1,070 btu/cu ft, the scrub column must operate at a pressure less than the critical pressure of about 40 bara.

For a baseload LNG plant, refrigerant efficiency depends on the operating pressure of feed gas entering the main cryogenic heat exchanger. A lower calorific value, therefore, would require recompression of feed gas from the scrub column to the main cryogenic heat exchanger, which is expensive.

In addition, multiple LNG train plants often operate at similar conditions and produce the same composition of LNG instead of multiple specifications.

C_2 and C_3 removal makes more sense for receiving terminals especially for the North American market. Although these additional facilities increase capital costs, they create an opportunity for competitive pricing because the plant can meet export specifications while feeding LNG from many different suppliers.

Alternative designs

The proposed schemes use LNG as the refrigeration medium and use liquid pumping instead of gas compression to achieve the required separation. Fractionation columns separate heavy components from the LNG.

The operator can either export extracted C_2+ components or use them as fuel for power generation or for submerged combustion vaporizers.

Both schemes eliminate compressors; however, they do require a gas direct-contact condenser in which overhead vapor from the heavy extraction column recondenses with cold LNG.

Column overhead condensers, which are plate-and-fin or shell-and-tube exchangers, use low-temperature LNG as the cooling medium. Column feed vaporizes in the existing vaporizers.

It then pumps the condensed LNG to the gas sendout pressure of about 85 barg. LNG is regasified in the vaporizers and sent out via the export gas pipeline.

The first scheme's design satisfies a maximum specification of 6 mole % C_2 using two fractionation columns. The C_2+ extraction column separates C_1 from C_2+ components. The C_2-LPG separator extracts C_2 from C_3+ components.

The second scheme's design satisfies a maximum specification of 3.6 mole % C_3+ components. The C_3+ extraction column is a packed bed or tray column.

C_2+ hydrocarbon removal

In a typical example, rich imported LNG contains excessive heavier components: 87 mole % C_1, 11.4 mole % C_2, 1.3 mole % C_3, and some heavier components.

The fractionation section processes about half of the LNG from the sendout pump. The other half of the cold LNG serves as the refrigerant and mixes with overhead vapor (richer in methane) from the C_2+ extraction column to produce a warm condensed LNG in the gas direct-contact condenser.

Condensed LNG contains less than 6 mole % C_2, which is pumped to the vaporizers for sendout to the export pipeline.

TYPICAL PIPELINE SPECIFICATIONS

Table 1

Component, mole %	California Air Resources Board CNG Minimum	California Air Resources Board CNG Maximum	Mexico natural gas Maximum
C_1	88		
C_2		6	
C_3+		3	3.6

TYPICAL LNG COMPOSITIONS

Table 2

	Terminal location						
Component, mole %	Das Island, Abu Dhabi	Whitnell Bay, Australia	Bintulu, Malaysia	Arun, Indonesia	Lumut, Brunei	Bontang, Indonesia	Ras Laffan, Qatar (RasGas)
Methane	87.10	87.80	91.20	89.20	89.40	90.60	89.60
Ethane	11.40	8.30	4.28	8.58	6.30	6.00	6.25
Propane	1.27	2.98	2.87	1.67	2.80	2.48	2.19
Butane	0.141	0.875	1.36	0.511	1.30	0.82	1.07
Pentane	0.001	–	0.01	0.02	–	0.01	0.04

Fig. 1 shows a detailed process flowsheet.

Total installed cost of the C_2+ hydrocarbon removal system is \$35-40 million for an LNG receiving terminal with a capacity of 1,000 MMscfd sendout gas.

Fractionation section

The C_2+ component removal section also produces LPG for export and a C_2-rich cut for plant fuel or export.

The fractionation section consists of two fractionation columns: a C_2+ extraction column and a C_2-LPG separator.

A gas direct-contact condenser recondenses vapor from the extraction column reflux drum.

The extraction column receives vaporized LNG from the existing LNG vaporizers and cold LNG from the existing LNG feed pumps.

The cold LNG is also the cooling medium in the column overhead condensers. Extraction column products include a leaner LNG vapor stream overhead and a C_2+ stream from the bottoms.

Overhead vapor from the extraction column recondenses against cold LNG in a gas direct-contact condenser. Condensed vapor is pumped up to about 85 barg, regasified in the existing LNG vaporizers, and sent to the export gas pipeline.

Extraction column bottoms go to the C_2-LPG separator, which produces an LPG stream from the bottoms and a C_2+ cut from the overhead.

Both streams are cooled and stored in tanks.

Operation description

The exact amount of cold feed LNG that the fractionation section processes (roughly 50%) depends on the required C_2+ specification. The exact LNG pipeline pressure will depend the buyer's specification.

The extraction column usually operates at 40 bara. A lower operating pressure improves separation efficiency, but also increases column size and reduces the fractionation column overhead vapor condensing capacity.

This pressure setting is reasonable because it is less than the system critical pressure needed to achieve separation.

The C_2-LPG separator operates at 20 bara. The operator can change C_2 and C_3 specifications based on fuel-quality requirement or other quality requirements for using or selling C_2 and C_3.

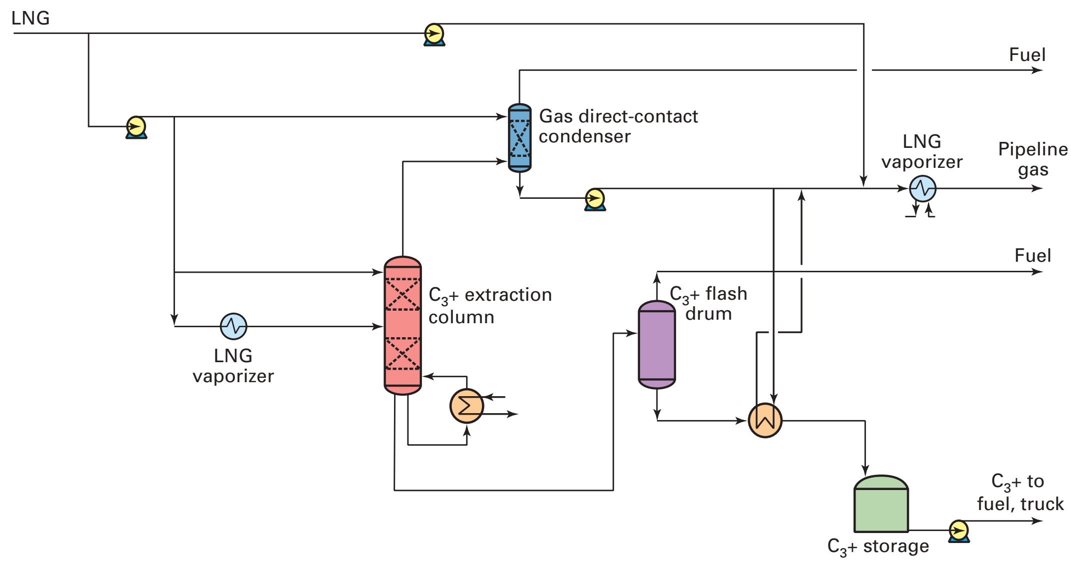
C_3+ hydrocarbon removal

In the second example, LNG feed contains excessive heavy components: 87.8 mole % C_1, 8.3 mole % C_2, and 3.9 mole % C_3+.

In this example, the LNG produced satisfies a Mexican pipeline gas C_3+ specification of less than 3.6 mole %.

C_3+ REMOVAL PROCESS

Fig. 2



The C_3+ removal system processes about 19% of the pumped-out LNG. Remaining LNG feeds directly to the vaporizers.

Total installed cost of the C_3+ hydrocarbon removal system is \$5-8 million for an LNG receiving terminal with a gas sendout capacity of 1 bscfd.

The C_3+ extraction column processes about 8% of the 19% LNG fed to the C_3-removal system (Fig. 2).

The remaining 11% of the LNG enters the gas direct-contact condenser as an absorbent and refrigerant. It mixes with the C_1-rich overhead vapor from the extraction column to produce a condensed LNG with a maximum 3.6 mole % of C_3+.

To ensure that condensed liquid stays in the liquid phase, LNG leaving the direct-contact condenser is subcooled at least 5° C.

This subcooling requires about 11% of the cold pumpout LNG to recondense and refrigerate the extractor overhead vapor.

Condensed LNG is pumped up to about 85 barg, regasified in the existing LNG vaporizers, and sent to the gas pipeline.

Process description

The C_3+ removal process also produces LPG products for export or for terminal fuel use.

Approximately 30% of the LNG that enters the packed-bed extraction column feeds directly to the top as an absorbent.

The other 70% first goes to existing LNG vaporizers; the vapor then enters the column between the two packed beds.

The extraction column separates C_3+ components from the LNG feed. Vapor leaving the extraction column mixes with cold LNG in the gas direct-contact condenser.

Extraction column bottoms stream flows to the C_3+ flash drum, in which light components flash to the top as fuel.

The C_3+ stream from the bottom of the flash drum first depressurizes to atmospheric pressure, is cooled with cold LNG, and feeds to the C_3+ storage tanks.

Liquid from the direct-contact condenser pumps to about 85 barg, flows through existing LNG vaporizers and to the export gas pipeline.

Operation description

The extraction column operating pressure is 40 bara. A lower operating pressure improves separation efficiency, but increases column size because this is less than the critical pressure for separation.

A process simulation determined the need for four theoretical stages between the liquid and vapor feed and three stages between the vapor feed and bottoms for the C_1 and C_3+ separation.

In the extraction column, 90% of the C_3 flows to the column bottoms, which contains no more than 10 mole % of C_1.

Vapor leaving the extraction column is recondensed when mixed with cold LNG in the gas direct-contact condenser. To ensure that the condensed liquid is at least 5° C. subcooled for easy pumping, cold LNG flow to the condenser is at least 20% more than vapor flow. ❖

Reference

1. California Air Resources Board, "Specifications for Compressed Natural Gas," Board Administration and Regulatory Coordination Unit, Division 3, Chapter 5, Article 3, §2292.5.

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