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Modular Design of a Base Load LNG Plant

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1 ABSTRACT

Starting in 1996 Linde AG and Statoil ASA developed a new process for natural gas liquefaction. The Mixed Fluid Cascade (MFC®) process was successfully commercialized in the Snøhvit LNG plant, which is located in Hammerfest/Norway, with 4.3 mtpa LNG capacity. Based on the valuable information, which was collected during engineering and operation of the Snøhvit LNG plant, a second generation of the MFC® concept was established. The main objective of this work was to adjust the formerly arctic concept to a more generic design, which can be applied in virtually all relevant regions of the world, where large base load LNG plants are required. The main differentiator to competing liquefaction technologies is the use of three refrigeration cycles including two mixed refrigerant loops for the actual liquefaction and subsequent sub-cooling of the natural gas. The choice of the pre-cooling refrigerant, however, depends very much on the climatic site conditions. In a cold or even arctic climate the ambient temperature is so low that a conventional propane pre-cooling system contributes only marginally to the overall cooling demand. In these cases (Snøhvit, Sakhalin) a mixed refrigerant pre-cooling cycle is the superior choice. In a warm or tropical climate a 4-stage propane cycle, however, is the most appropriate and economic pre-cooling method.

A very successful technological step-out of the Hammerfest LNG plant was the implementation of the all electric concept. Five LM6000 aeroderivative gas turbines supply electric power to a distribution system, which feeds all major power consumers including the large motors for the three refrigerant compressors. While the relative power consumption of these three motors is 40/20/40% in Hammerfest, the present concept aims for identical motor sizes with 1/3 of the total power each to achieve the largest possible plant capacity for a given maximum power rating of the motors. In addition, this common part approach simplifies spare part logistics. A more generic approach to power generation would be either importing electric power 'over the fence' or including a state-of–the-art combined cycle power plant into the overall project scope.

NGL extraction is done usually with a scrub column process, which recovers also make-up components for the refrigerant cycles. A scrub column is the right solution for LNG production without special heating value limitations. In many cases, however, either the GCV is limited and/or the market value of recoverable NGL hydrocarbons is higher than that one of LNG. Under these circumstances a dedicated NGL recovery plant upstream of the LNG plant is more efficient and more cost effective. With such an approach LPG and C5+ can be extracted with very high recovery levels. Even ethane recovery can be integrated readily, if a nearby ethane cracker justifies the extra investment. Downstream NGL recovery the lean natural gas is compressed to almost 100 bar and can be used in part or optionally as sales gas in domestic pipeline systems. The lean and compressed natural gas no longer shows a phase transition during cool-down to storage conditions, as the process is now operated above the critical pressure. Thus, any sort of two-phase driven effects can be avoided, which has a positive effect on operational stability during start-up and turn-down phases. Operation of the natural gas liquefaction (or rather continuous density increase) at elevated pressure also reduces the specific energy of the refrigeration cycles, as heat from natural gas can be rejected at an elevated temperature level. This effect helps to increase the plant capacity for a fixed driver concept.

In case of high nitrogen concentrations in the feed stock, nitrogen has to be rejected from LNG to avoid roll-over in the storage tank. Traditionally, the surplus nitrogen is removed in the end flash system and ends up in the fuel gas for the gas turbines. Highly efficient gas turbines may not be eligible for such a configuration, as the absolute nitrogen concentration and even worse rapid Wobbe index changes are not acceptable for DLN combustors. The proposed configuration integrates a nitrogen rejection unit (NRU) into the end flash gas. Clean nitrogen with low hydrocarbon content is sent to the atmosphere, while the resulting hydrocarbon fraction is recycled to the feed gas line. Fuel gas for the gas turbines in the power station can be tapped from the full flow feed gas line in ample quantities at very constant conditions. If the natural gas contains helium in commercially attractive quantities, a helium extraction and liquefaction unit can be amended to the NRU.

In a nutshell, the modular approach of the 2nd generation MFC® concept opens the door for LNG projects of any size between 3 and 15 mtpa per train, when not only efficient LNG production is of the essence. Rather, valuable by-products like helium, sales gas, NGLs and power can be made available at interesting conditions.

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2 MODULAR LNG PLANT CONCEPT

2.1 Preamble

Most of the existing base load LNG plants are based on an evolutionary concept, which is characterized by the following features

- scrub column for heavies removal,
- moderate NGL recovery rate, mostly for make-up purposes,
- mechanical drive for refrigeration compressors via gas turbines,
- end flash gas utilization as gas turbine fuel.

This paper will discuss a sequential design approach, in which recent achievements of gas processing has been considered adequately. The main elements of the block diagram in Fig. 1 will be explained in detail during the course of this paper.

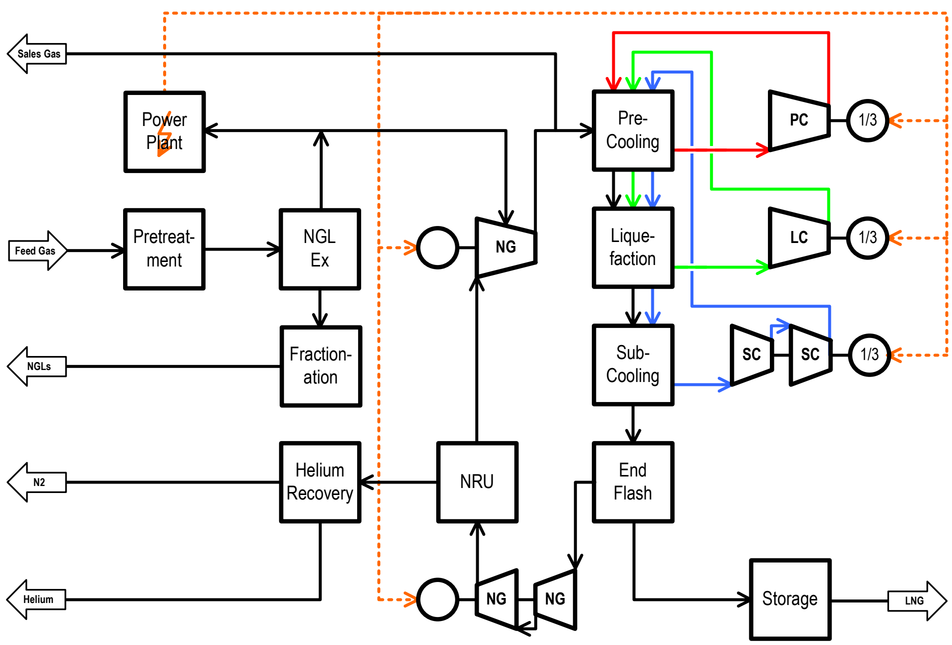

Fig. 1 Block diagram of a Modular LNG plant

2.2 Pretreatment

Sour gas removal is performed mostly via an amine system, in which CO_2 and H_2S are captured by a reversible chemical reaction. Regeneration of the rich (= sour gas loaded) amine requires a significant amount of heat to reboil the amine regeneration column. In case of a shortage of sufficient quantities of hot oil or steam the use of a two stage amine system[1] should be considered, which reduces the reboiler duty by up to 50%.

If the CO_2 concentration in the natural gas exceeds a level of about 10 vol%, alternatives to amine systems should be considered. This may include bulk removal of CO_2 via membranes[2], in which CO_2 permeates selectively while hydrocarbons stay under pressure on the retentate side. To reach the required CO_2 specification of 50 vol ppm for the sweetened gas CO_2 adsorption on molecular sieves or CO_2 absorption by amines is required, as membranes reduce the CO_2 content only down to a level of a few vol% without causing unacceptably high hydrocarbon losses into the permeating CO_2 fraction. Full CO_2 capture from the natural gas feed stock and subsequent sequestration has been implemented and proven in the Hammerfest/Norway LNG plant since 2007.

Depending on the concentration and species of sulfur components special considerations about sulfur emissions into the environment have to be undertaken. Extraction of COS and/or mercaptanes and subsequent conversion into elemental sulfur by means of a Claus unit are proven concepts.

Mercury is present in most of the natural gas well streams. Historically, the major concern about mercury was corrosive attack to aluminum alloys, which are widely used in the cryogenic part of LNG plants. More recently also HSE issues have been discussed intensively. Especially amine systems and dehydration units contain fillings like solvents and adsorbents, which get contaminated severely during plant operation and create handling risks for operators in case mercury trapping takes place only after dehydration. This design had to be chosen in the past, if activated carbons beds with sulfur or silver doting had been used. These mercury traps would not recover from accidental wetting. Since several years, however, mercury guard beds are commercially available, which are based on zeolitic material. Such material recovers fully from temporary wet operation and can be installed safely upstream of the CO_2 removal step.

Recommendations for the pretreatment section are

- locate mercury guard beds at the front end to protect equipment AND people,
- consider sequestration of CO_2, which has been captured from natural gas, and
- involve reputable licensors into the conceptual design.

2.3 NGL Extraction

Traditionally, all heavier hydrocarbons (C_{5+}) and to some extent natural gas liquids (C_2 to C_4) are removed from the feed gas in a scrub column in order

- to avoid freezing of heavies, especially aromatic material,
- to meet residue specifications (C_4 content) of the LNG, and
- to provide make-up components (C_2 and C_3) for the refrigeration cycles.

Surplus quantities of LPG are frequently re-injected into the LNG to boost the heating value / Wobbe index to levels as requested especially in Far East markets. As the liquefaction of the lean natural gas downstream of the scrub column preferably runs at elevated pressure the scrub column is operated close to the critical pressure (i.e. 50 to 60 bar for a typical gas composition). The scrub column concept is well proven and advisable under the above mentioned circumstances.

If, however, deep LPG recovery or even C_{2+} recovery is economically recommendable, conventional scrub column configurations hit their limits. Close to the critical point high NGL recovery rates involve large quantities of co-recovered liquid methane in the scrub column bottoms due to the low relative volatility (k-value) between methane and ethane and/or propane. Methane condensation actually takes place at the wrong spot of the process. Methane, which is present in the scrub column bottoms, needs to be re-vaporized in a demethanizer and re-liquefied together with the lean natural gas to end up eventually in the LNG product. This mode of operation is inefficient as it requires substantial reprocessing of methane rich fluids.

A more efficient and cost effective concept is a dedicated NGL recovery step between pretreatment and liquefaction. There is a wide choice of licensed[3] and public domain technologies, which can be applied for this purpose. All of them involve a cryogenic column (demethanizer or deethanizer), whose operating pressure is limited by the critical pressure of the bottoms to a range between 30 and 35 bar. Lean natural gas downstream NGL recovery is not only a perfect feedstock for an LNG plant, but can be sent also to a gas pipeline as sales gas. This requires recompression of the lean sales gas to typically about 100 bar in a single stage pipeline compressor. A common header for lean natural gas feeding both the pipeline grid and the LNG plant provides an attractive means to balance demand on either side.

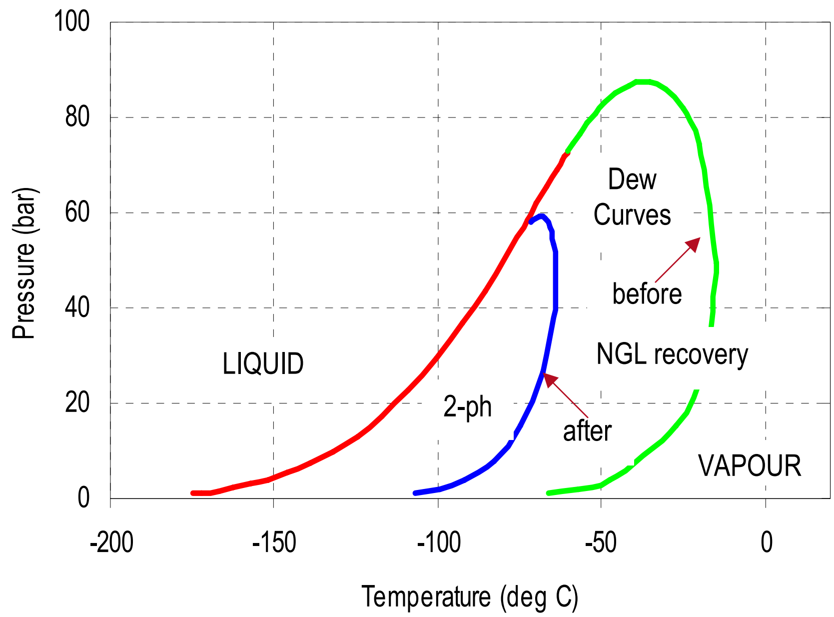

Fig. 2 Phase envelope of natural gas before and after NGL recovery

Fig. 2 shows the typical effect of NGL (in this case C_{3+}) recovery on the phase envelope of the natural gas. Untreated (rich) gas, which frequently is brought by pipeline to the LNG plant site, has dew point conditions according to pipeline specifications, i.e. the hydrocarbon dew point is somewhat below ambient temperature. Heavy components in the rich gas shift the maximum pressure of the gas, under which partial condensation can occur, to almost 100 bar. After NGL extraction the size of phase envelope shrinks significantly. In the absence of C_{3+} components the dew point is lowered by about 50 deg C and the upper limit of the two-phase regime is at about 60 bar. Hence, NGL extraction plus subsequent lean gas compression to about 100 bar provide very favorable conditions for the downstream liquefaction plant, as partial condensation with all undesired operational consequences (turn-down behavior, flow stability, etc.) no longer takes place.

Recommendations for the NGL extraction are

- recover NGLs in a dedicated process unit, if LPG and/or ethane has a high market value,
- compress the lean gas to such a pressure level that no two-phase regime develops in the downstream liquefaction plant, and
- involve reputable licensors into the conceptual design.

2.4 Liquefaction

Liquefaction (warm climate) using the MFC®3 process

Linde's patented[4] base load LNG process, which has been developed jointly with Statoil, is characterized by three independent refrigeration cycles. The intermediate (liquefaction) cycle and the coldest (sub-cooling) cycle use mixed refrigerants in any case, while the type of refrigerant in the warmest (pre-cooling) cycle depends mostly on the ambient temperature. The Mixed Fluid Cascade (MFC®) process is suffixed with a figure 3 in case propane is used for pre-cooling.

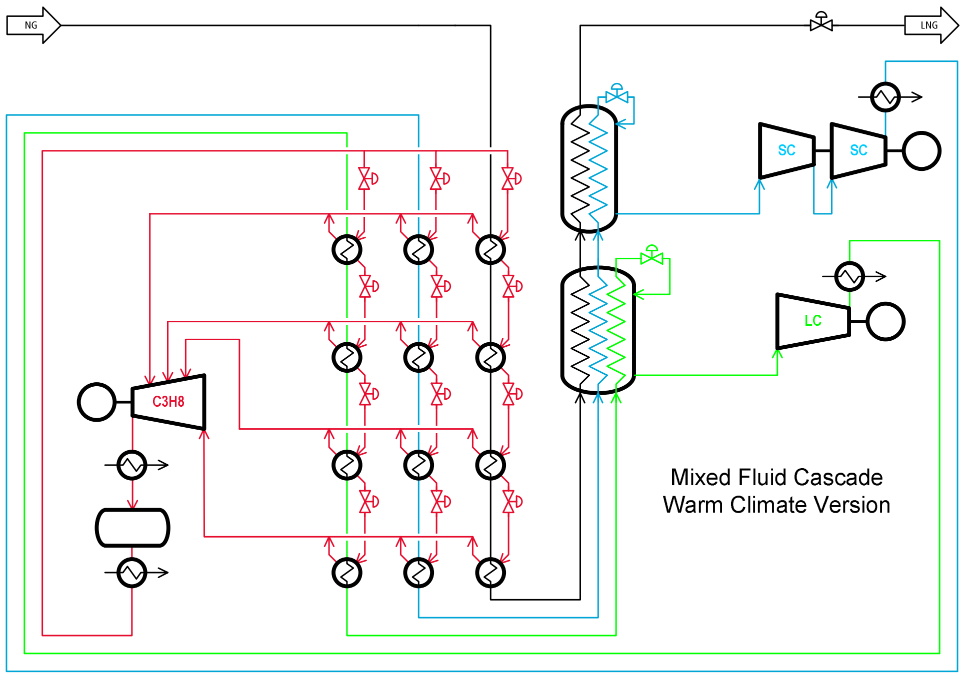

Fig. 3 MFC®3 process with propane pre-cooling for a warm climate

Fig. 3 shows a simplified process sketch for the MFC®3 process with propane pre-cooling. As discussed above NGL extraction is not implemented via a scrub column, but rather with an independent process step, which is not shown in Fig. 3. Hence, the lean and compressed natural gas does not cross a two-phase region. Now, there is no specific need to meet a certain process temperature by any of the three refrigeration cycles. Now, the load between the three refrigeration cycles can be balanced perfectly. That means the shaft power of all three compressor trains is identical. With such a configuration, which is unique amongst the present Base Load LNG technologies, the largest LNG capacities can be achieved with a given set of main compressor drives.

	process temp-erature at warm end of cryogenic system	**lowest temperature of pre-cooling refrigerant**	**specific energy consumption**	**remarks**
	degree C	degree C	kWh/t_{LNG}	
Middle East 1	50	-31	325	C3 pre-cooling, with NRU
Middle East 2	45	-34	289	C3 pre-cooling, without NRU
South America	48	-33	308	C3 pre-cooling, all air cooling
generic design	40	-20	285	MR pre-cooling, all coil wound heat exchangers
European Arctic (in operation)	10	-55	236	MR pre-cooling, scrub column, no load balancing

Table 1 Examples for MFC® implementation

This load balanced concept is compatible with the use of propane pre-cooling only as long as the ambient temperature is not too low. In a warm Middle East climate a load balanced MFC®3 design results in a lowest operating temperature of the pre-cooling cycle with about -30 to -35 deg C. A lower limit for an economic propane pre-cooling temperature is -35 deg C. Below this limit propane compressor suction line sizes would grow significantly and the risk of air ingress into the closed cycle increases, when the propane system is operated too close to the atmospheric pressure. Typical results from mostly pre-FEED and FEED studies are compiled in Table 1.

As soon as the relevant ambient temperature is consistently lower than above mentioned, either the propane pre-cooling compressor no longer can contribute with one third of the overall shaft power to the overall duty or the choice of the pre-cooling refrigerant needs to be reconsidered.

The absolute LNG rundown rate can be increased by boosting the operating pressure of the natural gas during liquefaction. Fig. 4 shows that at constant overall shaft power of the three refrigeration cycle compressors the LNG production grows by 10%, if the operating pressure increases from 70 to 90 bar. Of course, more power is required for lean gas compression, but if the plant capacity is limited by the main refrigerant compressor drivers, an increased operating pressure is a easy method to achieve more production.

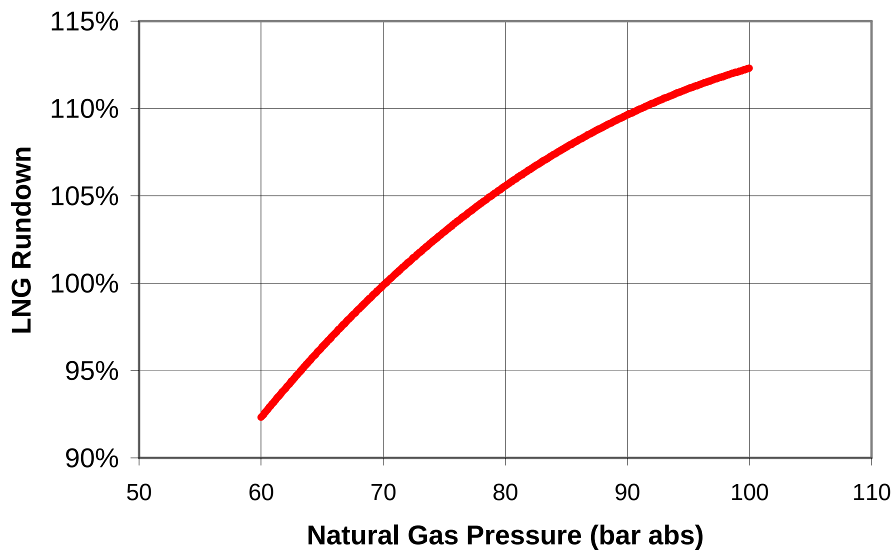

Fig. 4 LNG rundown flow rate versus operating pressure at constant refrigeration power

Liquefaction (cold climate) using the MFC® process

In a moderate or cold climate propane pre-cooling and perfect load balancing amongst the three refrigeration cycles is no longer feasible. Under these circumstances the 'arctic' version of the Mixed Fluid Cascade process (as implemented in Hammerfest/Norway for Snøhvit LNG) with three mixed refrigerant cycles is the preferred solution.

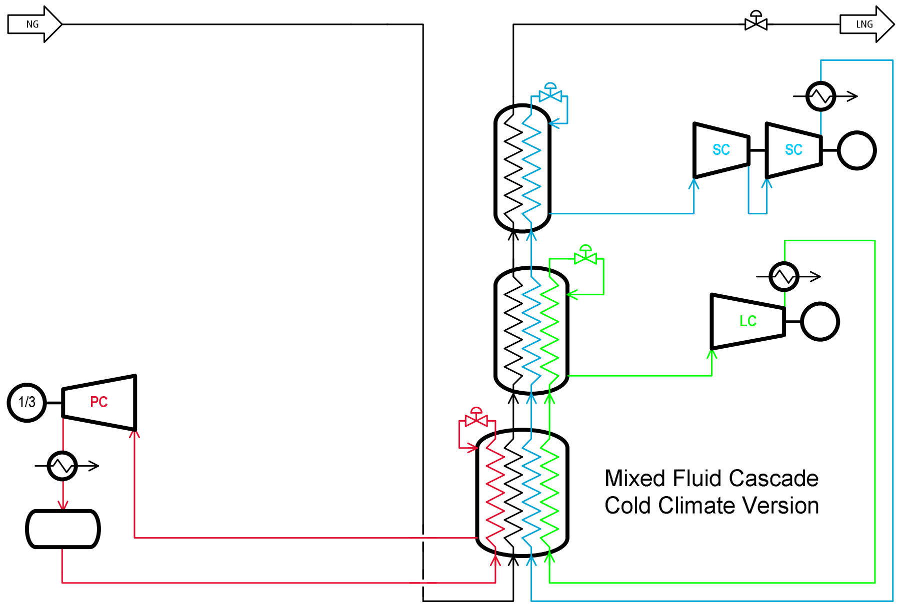

Fig. 5 MFC® process (all CWHE) with mixed refrigerant pre-cooling for a cold climate

The type of heat exchanger in the pre-cooling cycle depends on the selected refrigerant composition. While a pure component like propane can be vaporized efficiently in a kettle with either a tube bundle (TEMA design) or a submerged plate-fin heat exchanger (block-in-shell design), a mixed refrigerant requires a countercurrent type heat exchanger. Here, the choice can be made between plate-fin heat exchangers (PFHE) and coil wound heat exchangers (CWHE). An all CWHE design as shown in Fig. 5 has been developed to cope with a high operating pressure and a large liquefaction capacity. The corresponding compressors and gas turbine drivers, which are shown in Fig. 6, are proven meanwhile in the prestigious Qatar Mega trains[5].

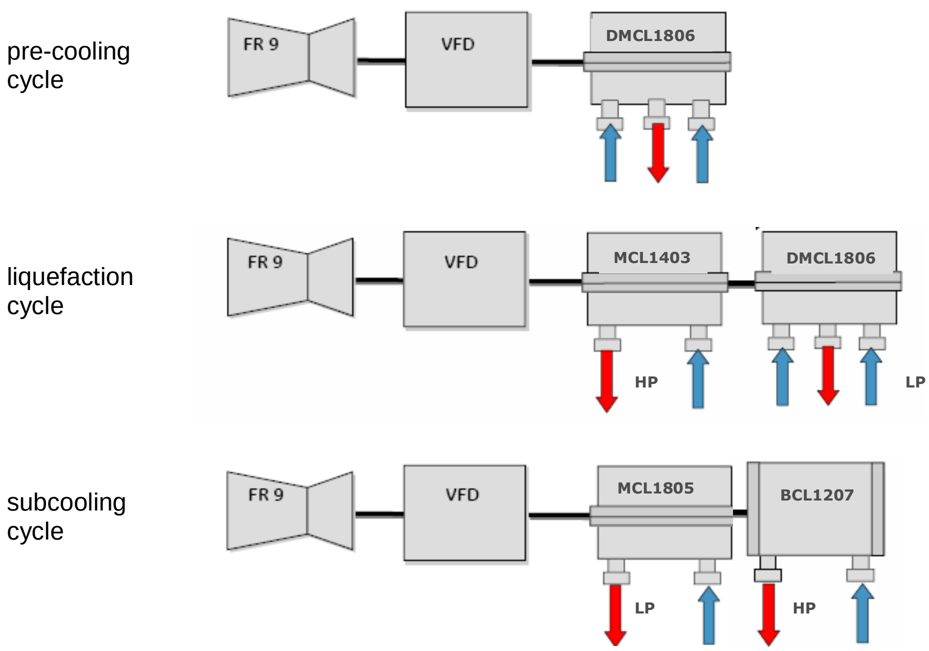

Fig. 6 Compressor selection for a large MFC® plant

For the selected plant parameters an LNG rundown capacity of 12 mtpa has been worked out[6]. Depending on actual site conditions a capacity between 10 mtpa (hot climate) and 15 mtpa (cold climate) can be expected.

Recommendations for the liquefaction section are

- upstream NGL recovery and lean gas compression to above the critical pressure of the lean natural gas simplify perfect load balancing between the three refrigeration cycle compressors, and
- propane pre-cooling is more economic than MR pre-cooling, as long as load balancing is feasible.

2.5 All Electric Concept

Three gas turbines in series for one single LNG train may raise concerns about the train availability, as scheduled maintenance and unscheduled downtime caused by the mechanical drives may add up to more than one month per year. A smart concept, which overcomes this limitation, is using all electric drives. Gas turbines no longer drive the process compressors directly, but rather are installed in a dedicated power station with a redundant configuration of rotating equipment. It is advisable to apply a combined cycle concept, which uses the gas turbine waste heat for steam generation. This steam may be used in the process for heating purposes and/or for power generation via steam turbines. An overall efficiency of 55 to 60% can be achieved with this approach, which is unsurpassed by any conventional mechanical drive concept.

This all electric concept includes a variable speed drive system (VSDS), which enables speed control of the electric motors in a wide range. Electric motors in the required speed range (between 3000 and 3800 rpm) are available with a rated power output of up to 80 MW. The achievable train size of up to 6 mtpa will be sufficient for most of the LNG projects worldwide.

2.6 Nitrogen Rejection

In a conventional plant design the end flash gas from the tail end of the LNG production frequently changes in quality and quantity, when operation requires process adjustments to external influences like plant load, ambient temperature, loading/holding mode, and so on. The result is modifications in the Wobbe index, which cannot get tolerated by highly efficient and clean burning (LoNox) gas turbines. Therefore, the end flash gas is not the preferred fuel source for modern gas turbines in any configuration.

An alternative concept uses lean natural gas as gas turbine fuel and reprocesses the end flash gas in a nitrogen rejection unit (NRU). The NRU splits the end flash gas into clean nitrogen with less than 1 vol% methane, which can be sent to the atmosphere without further processing. The remaining hydrocarbon fraction will be re-liquefied either jointly with the feed stream to the LNG plant or separately within the NRU itself.

The described method provides good quality fuel to the gas turbines at any required flow rate and maintains low nitrogen levels in the LNG even at high nitrogen concentrations in the natural gas. This enhanced operational flexibility does not impact the plant efficiency, but rather increases its availability.

2.7 Helium Recovery

As soon as the natural gas contains at least 1000 vol ppm helium a commercial production can be considered. The best source for helium extraction in an LNG plant is the nitrogen fraction of the NRU. Technology for helium purification and liquefaction is widely available and has been implemented several times successfully[7].

2.8 Conclusions

This papers shows in detail the benefits of a modular design with following main features

- state-of-the-art NGL recovery upstream of the liquefaction plant instead of a scrub column for heavies removal only,
- deep NGL recovery instead of moderate NGL recovery rate,
- electric drives instead of mechanical drive for refrigeration compressors,
- nitrogen rejection and optional helium recovery instead of end flash gas utilization as gas turbine fuel.

In a nutshell, disintegration of complex LNG schemes helps to improve operability, increases efficiency and strengthens robustness of the plant.

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