All Electric Driven Refrigeration Compressors in LNG Plants Offer Advantages

by Fritz Kleiner, **Siemens AG**, Industrial Applications, Oil & Gas Business Unit,
and Steve Kauffman, **Shell Development (Australia) Pty. Ltd.**, LNG & GTL

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Abstract

Refrigeration turbo compressors in modern LNG liquefaction plants are traditionally driven by industrial heavy duty gas turbines. With an ongoing industry trend towards larger train sizes, and more emphasis placed on higher energy efficiency and lower greenhouse gas (GHG) emissions, the use of very large electric motors to drive the compressors becomes of increasing interest and the first "all electric driven" LNG plant will soon go into operation in Norway. Economic and operational advantages of this alternate drive concept are discussed for the owners & operators of LNG liquefaction plants, a typical comparison study of the two alternatives is shown, and some details of the electrical drive technology employed are presented.

Introduction:

Evaluating electric drive LNG processes has moved on from when the concept of using synchronous motors and combined cycle power generation plants was introduced at the Doha Conference on Natural Gas in 1997. Logically at that time, evaluation efforts were directed at technical aspects, in particular, focusing on technical risk as well as economic comparisons. Studies by ChevronTexaco [1] and Shell Global Solutions corroborate the view that such risks are well known and manageable through detailed design. Subsequent further development of the motor drive system by a number of (European) manufacturers, specifically for LNG application, validates this view [3] [4]. Most conclusively however, the successful manufacturing, testing and full compressor/drive string testing now completed for the Norwegian Snøhvit project has shifted owner/operator's interest in the electric drive from risk assessment to opportunity framing, especially if the total refrigeration system, including the power plant, forms the basis for performance guarantees.

Deliberately putting the remainder of the LNG process plant aside, the comparison focuses on the two driver concepts and their characteristics. And to make a sound comparison of the two driver alternatives – traditional mechanical vs. evolutionary electrical – one must list the individual properties of these designs.

All gas turbines, by nature of their physics and design, have inherent limitations when compared to equivalent electric motors:

- high thermal and mechanical stresses with resulting lifetime reductions of certain components and re-occurring service requirements
- complexity and sensitivity of machines due to numerous very tight clearances and tolerances between stationary and rotating parts
- available only as type-tested standardized products with given output ratings and limited speed range
- relatively poor efficiency and high greenhouse gas emissions when compared to combined cycle
- inability to start by itself and to accelerate loaded compressors (single shaft only)
- reduced power output at high ambient temperatures and poor part load efficiency
- limited vendor competition.

None of the above applies to electric motor variable speed drivers of equivalent rating & performance, and this is the key to considering electric motor compressor drivers as a viable alternative for new installations.

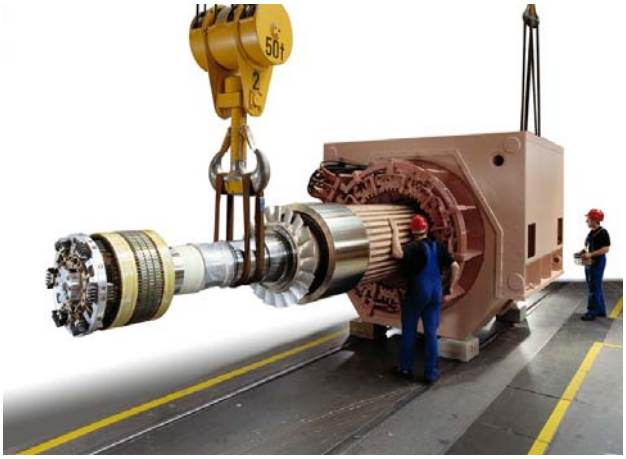

Fig.1: Refrigeration compressor driver motor rated 65MW @ 3600 rpm for a new LNG plant in Norway.

Economic & operational advantages of electric motor drivers

For Shell Development Australia (SDA), the interest in electric drives emerged primarily from the observation that high overall efficiency would be achieved simply in this drive concept because waste heat from all gas turbines would be exploited while retaining independence between process and utility equipment and systems. This interest is further motivated by the potential to reduce both cost and GHG emissions; cost for obvious reasons, and emissions to meet company policy and Government Strategy in Australia, both having a clear focus on emissions reduction and energy efficiency (i.e. continuous improvement). Although not defined prescriptively in the legislative

environment, the Western Australia Sustainability Strategy (2003) has clear objectives for a four-fold increase in industry eco-efficiency by 2020.

A high level comparison of direct and electric drive concepts identified the following opportunities as substantive reasons to examine electric drives more closely:

- Utilise waste heat from all gas turbine exhausts, thus achieving lower GHG emissions, in a simple way and without complicating the equipment used in the process area.
- Eliminate asset downtime and shut down/ maintenance costs associated with gas turbine drive maintenance.
- Phase costs associated with combined cycle capability to a later date such as an expansion of the complex.
- Reduce fuel gas consumption, both from an OPEX perspective but also as a means to defer subsequent upstream drilling.
- Segregate combustion and convective heat recovery equipment from the high pressure liquid hydrocarbon equipment in the process area.
- Reduce flaring by avoiding refrigerant depressuring and enabling quicker re-starts.

More detailed assessment of these opportunities demonstrates that an electric motor variable speed drive (VSD) of equivalent rating is significantly less expensive to buy & operate than a gas turbine. Additionally, the installation cost of a gas turbine direct drive in an LNG facility is about double its cost as a generator drive. Infrastructure improvements at the site itself can increase the price tag of the electric system, but not dramatically. In very large installations, the construction of power transmission systems or even an associated power plant may be justified if the „Total Cost of Ownership“ is considered and not only the capital investment for the LNG plant.

Electric drive systems are sized for the maximum average ambient, or cooling water temperature – up to 40°C (air) and 32°C (water), respectively, no de-rating is required. Full power is instantly available over the entire temperature & speed range, and the number of successive and cumulative start-stop and load cycles is generally uncritical.

Electric motor variable speed drives in the upper Megawatt (MW) power range have energy efficiencies >95% – over the entire useful speed range, typically 80…105% of rated speed. Even if the energy conversion in the power plant is taken into consideration, the electric drive's efficiency is typically better than that of GT direct drives due to the higher efficiency of the large C.C. power plant.

Mainly due to low thermal and mechanical stresses in the motor, and no wear parts in the drive system*), service & maintenance expenses of electrical drive systems are only a fraction of those encountered for GT drivers: Under certain assumptions, there is no scheduled maintenance for periods up to 6 years of continuous operation, and even after that no costly parts need to be replaced.

Full power is instantly available upon issuing the START command, regardless of the ambient and motor temperature, and the number of successive starts is also unlimited: Unlike a fixed-speed electric motor that is started „across the line“ (DOL starting) the variable speed drive does not draw more than rated current from the power system during starting, and is thus not thermally and/or mechanically stressed beyond its rated duty.

And the electronically controlled starting torque is always sufficient to start even a *fully loaded* compressor – a valuable asset in case of process trips because the compressor circuit does not have to be depressurized (no flaring or loss of refrigerant) and the cryogenic process elements do not warm up.

Electric drive systems of this class are always custom engineered for the application on hand, allowing the compressor to be optimized in capacity & speed for the process on hand, and not being limited by a given GT rating. In case of twin compressor bodies, these can often be arranged on either side of the motor shaft, providing ready access to the inner bundles, bearings, and seal cartridges of vertically-split compressors, without disturbing the basic alignment of the compressor bodies. This feature is the key to larger LNG train capacities since electric motors can readily be built up to today's limit ratings of the compressors.

The Turborotor Motors

Brushless synchronous motors with solid steel two-pole turbo rotors are the design of choice for high performance applications such as LNG liquefaction – they have been in service for decades in various industries to drive centrifugal pumps and compressors, in ratings up to 40 MW and speeds to 6600 rpm (not in this combination!) and their construction is practically identical to that of turbo *generators* in power stations – which have output ratings exceeding 600 MW.

In 2003 Siemens built and load-tested the first „all electric“ refrigeration compressor drivers for a new LNG liquefaction plant, with rated powers of 65 MW and 32 MW at 3600 rpm, respectively, and such drives are offered in ratings exceeding 80 MW at the same speed.

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*) A properly lubricated sleeve bearing is not considered a wear part and does not require regular service

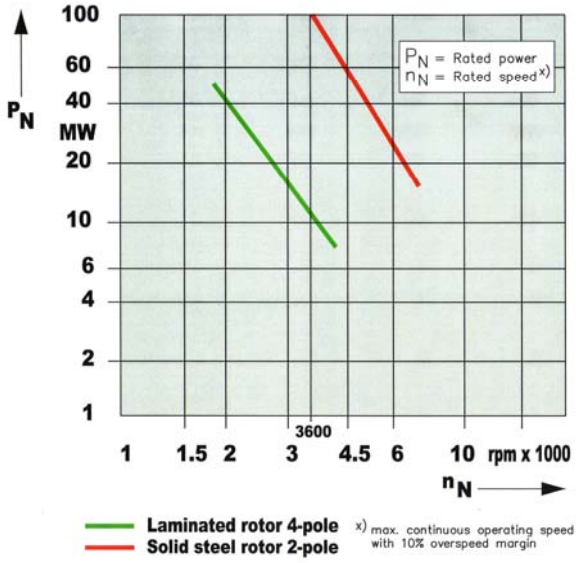

*Fig.2: Theoretical limit rating curves for 2-pole compressor drive motors. **Note**: Any specific rating near these limit curves must be verified for an actual application*

For lower power ratings the shaft speed can be increased somewhat; the present limit being the circumferential rotor speed of 200 m/s and rotordynamic considerations: Flash-gas compressors in LNG plants are good examples and include a 17 MW brushless synchronous motor operating at speeds up to 6660 rpm and 23 MW depletion compressor drivers with speeds up to 6300 rpm.

Totally enclosed horizontal air-water cooled motors (TEWAC) in class of protection E Ex(p) IP54 acc. to IEC are typically used for compressor applications in Zone 1 or 2 hazardous environments, certified by the authority having jurisdiction for the project site. If no cooling water is available on site, totally enclosed air-air cooled machines (CACA) can be used in some cases but for extreme ambient conditions with temperatures frequently exceeding 45°C, mechanically refrigerated chilled-water sets may have to be used. Open ventilated motors, such as WP or IPR enclosures, are generally not used in extreme environments in order to protect the winding insulation systems from contaminants in the cooling air.

Hydrodynamic pedestal-type sleeve bearings with fixed or tilting pads and forced oil lubrication are standard, even though endshield mounted sleeve bearings can be used to advantage in certain cases. Rotor dynamics are typically in-line with API 546 (synchronous motors) or API 617 (centrifugal compressors) requirements and generally the compressor lube oil circuit is also used for the motor.

Couplings between motor and compressor shafts are mostly multiple-diaphragm dry types from reputable vendors, whereby special attention is given to short-circuit moments. Flanged couplings with quilt shaft have also been used, but stepped cylindrical shaft ends for hydraulic shrink fit of the coupling is the rule. It is normal practice to mount both the compressor and the motor on a common baseplate or skid, and to test the entire assembly under load in the factory prior to dispatch to the job site. Full load performance tests of such compression systems can be performed up to about 80 MW, with most job equipment being part of the test, thus reducing the installation time & risk considerably.

The Drive

To convert the fixed power line frequency (50 or 60 Hz, depending on country of installation) into the variable voltage & frequency pair required to operate the synchronous motor over the specified speed range, a solid-state frequency converter is used, called by some in the industry „the drive“. Whereas there is a variety of „drives“ on the market for lower power ratings, there is only one proven frequency converter employed for power ratings above about 20 MW, the load commutated inverter, or LCI drive.

Fig.3: One-half of a 65 Megawatt LCI-type frequency converter or „drive“ for the motor shown in Fig.1.

This simple, robust and time tested frequency converter employs readily available disk-type thyristors (or silicon controlled rectifiers, SCRs) as solid state power switching elements. They are mounted in standardized equipment cubicles for installation indoors, or in purpose-built power centre modules outdoors.

Heat losses of the power semiconductors are removed from the converter via a closed-loop deionized water circuit that in turn can be recooled to ambient air, or to an external cooling water loop.

The entire drive system, including motor and auxiliaries, is closed loop controlled and fully protected by a microprocessor based control system. Due to its robustness and smart protection functions it meets highest availability requirements without the need for excessive redundancy.

Auxiliary Systems

To match the drive's input voltage to the power line voltage on site, an oil-filled outdoor converter transformer is required. This isolation transformer also provides for the 12-pulse line reaction of the converter towards the power system, and for fault current

limitation in the power semiconductors, avoiding fuses in the power circuits altogether. This transformer is connected via power cables to the frequency converter, and screened cables also link the „drive“ to the motor.

In the motor, the same 12-pulse circuits reduce the torque ripple, which is produced by the non-linear frequency converter and is superimposed on the mean torque of the motor, to levels uncritical for the compressors: A complete torsional analysis of the rotating string is nevertheless performed to identify and quantify potentially harmful harmonic torque amplifications, and to size the shafts and couplings of the machines.

The frequency converter with its cooling & control systems, LV switchgear, MCC and UPS systems, and the local operator interface are typically installed in prefabricated power centre modules (containers) at the manufacturers location where they are also tested and pre-commissioned prior to shipment. These custom engineered modules are unconditionally suited for installation outdoors in the climate zone specified, if necessary with full climate control, and meeting local building codes. With this modular building concept, the number of shipping colli and the amount of installation work on site are minimized. This module concept also facilitates the various performance and load tests typically specified for such compression systems.

LCI-type frequency converters produce power line harmonics as a side effect. To maintain the limit values prescribed by the utility company or by National Codes, harmonic filters may have to be used and they, too, can be installed inside prefabricated power modules, ready for connection. The sizing, building and protection of harmonic filters is routine for experienced drive system suppliers and they are safe and reliable passive subsystems, both in indoor & outdoor installations.

Testing

LNG plants are mostly located in remote areas of the world and in extreme climate zones. Lack of performance or malfunctions of subsystems after installation can have grave financial consequences and complete testing of compression systems at the manufacturer’s location is thus normal. To make sure that the electrical drive system performs as specified prior to this full-load test at the compressor manufacturer's test facility, they can be load-tested as well in the motor factory: With two or more identical drive systems on order at the same time, they can be tested at or near full load & speed in the so-called back-to-back mode, i.e. one unit operates as motor, the other one as generator.

Fig4: Back-to-back performance test of two 65MW compressor driver motors in the Berlin motor plant.(The associated „drives“ are located outside the building)

Such tests are expensive and time consuming but they can be performed by major drive system suppliers – the modular construction principle described above greatly assists to this end.

The associated power plant

Electric motors driving refrigeration compressors in LNG plants need electricity – lots of it and on an uninterrupted basis: The availability of the drive and thus the refrigeration system is practically identical to that of the power transmission system, or the associated power station. LNG plants most always being located far away from a solid infrastructure, these power plants typically operate in an island mode, i.e. without being connected to a transmission grid. And since the turbo generators in the power plant are driven by gas turbines – typically much larger ones than used for direct compressor drivers – and these engines also require maintenance every so often, an extra turbo generator is installed for 5 or 6 year uninterrupted power supply to the LNG process – following the so called n+1 principle. This, of course, is a burden on the capital budget for the LNG project and it may be advantageous to assign the financing, construction & operation of the power plant to an independent power producer (IPP) company that then provides the needed Kilowatt-hours „over the fence“ to the LNG plant on a long-term contract basis, in exchange for fuel gas and a fixed kWh-rate. Such IPP plants can then additionally supply electric power to neighbouring communities or industries, often a strong incentive for local governments to approve the LNG project – and the reduced total greenhouse gas emissions of an „all electric“ LNG plant can be another incentive for political decision makers to approve the project.

Depending on the individual manufacturer’s concept, power plants dedicated to „all electric“ LNG plants may comprise of 3 or more large turbo generators per LNG train, operating in parallel at part load during normal operation. For maximum efficiency and minimum total emissions, they are preferably planned as a combined cycle power plant, utilizing the waste heat from the GTs in heat recovery steam generators (HRSGs) that in turn

feed a steam turbo generator set – standard, proven and commercially available technology. Energy efficiencies of 50% can be achieved with these plants, taking account of the part load operation and the use of relatively low grade fuel gas with N_2 contents of 25% and more. This capability, combined with the requirement for utmost availability of the turbines, does typically not result in the use of the most modern GTs but in the selection of the most robust engines with the longest service history & maintenance intervals.

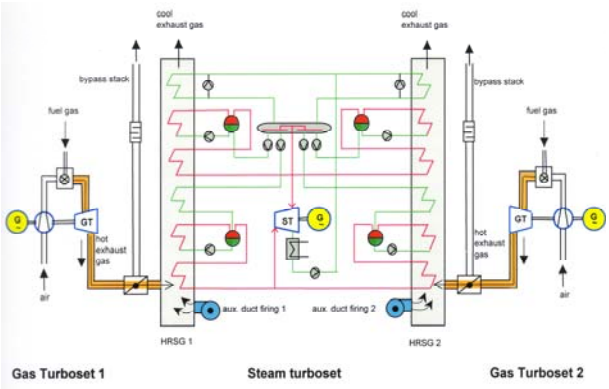

Fig.5: Thermal schematic diagram of a combined-cycle power plant to supply an „all electric" driven LNG plant in an island-mode of operation.

If one of the turbo generators is lost unexpectedly during normal plant operation, this constitutes the most severe disturbance of the refrigeration system: The unscheduled outage of a compressor or a vsds (initiated by the process itself or by the rotating string's own protective systems) is considered less critical and service can typically be restored within a short time because the vsds can always re-start the *fully loaded* compressors.

Compensating for the unexpected loss of a turbo generator in the power station requires a quick re-distribution of the total electrical load onto the remaining running turbo sets, without violating the voltage & frequency limits of the electrical system, or the speed limits of the turbines and compressors, respectively – a demanding task. With suitable steam reserves, and specific control actions in the power plant and the compressor & drive systems, this situation can be coped with, generally *without losing the refrigeration process*. Computer simulations of the thermodynamic, electrical, and mechanical systems are used to identify weak spots during the design phase, and performance guarantees should be provided for the entire refrigeration system.

Case study

Being able to maximise the various opportunities with electric drives discussed so far, is not simply a change of driver type. Process type, process configuration and driver choice must all be considered if the benefits suggested are to be fully exploited. While this wider topic is not covered in this paper, the resulting quantification of these benefits is provided. The case study used liquefaction processes configured to suit direct or electric drives and designed specifically to meet the same (nominal) project parameters. Cost, reliability and environmental performance were assessed, both as single train and multi-train facilities. The multi-train aspect of the study was important to emulate a focus on continuous improvement, the reasons for which are explained later. A nominal gas composition was chosen (962 BTU/scf C1-C5 content and around 7% CO_2).

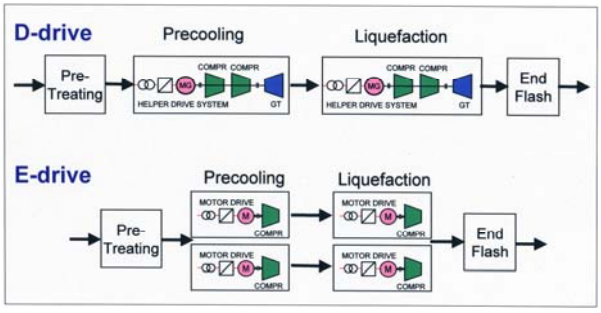

Fig.6: Comparison of direct and E-drive solutions as used in the study: C3MR vs. DMR process

The direct drive concept used (abbreviated as D-drive) entails the well known application of two Frame 7 industrial HD gas turbines, utilising either propane or mixed refrigerant for the pre-cooling cycle and a lighter mixed refrigerant for the main cryogenic cycle (i.e. typical C3MR and dual-mixed refrigerant type processes). The turbines are each equipped with a 20MW starter/helper motor and the pre-cooling and main cryogenic cycles are arranged in series. Waste-heat is recovered from the precooling gas turbine exhaust., Process heat is distributed by a conventional hot oil or hot water system.

The electric drive concept (E-drive) entails the LNG Gamechanger™ configuration of Shell Global Solutions, which deploys a similar dual-mixed refrigerant process, and arranges the motor-compressor sets partly in parallel. Waste-heat is similarly recovered via the power-generation turbine exhausts. Additional harnessing of waste heat to support combined cycle facilities was also explored.

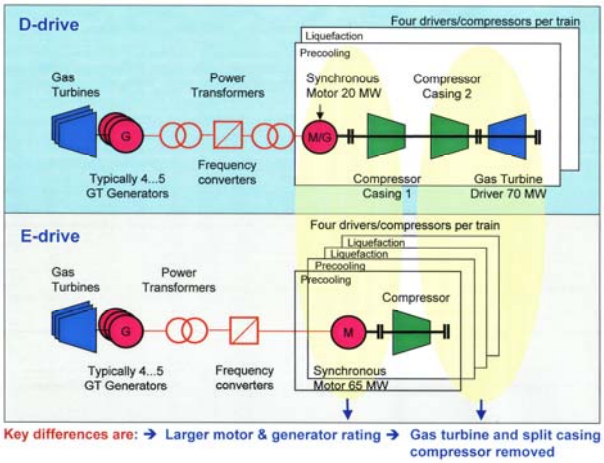

Fig.7:Moving from D-drive to E-drive entails the enlargement of the electric motor and the elimination of the GT.

Both concepts have the same number of rotating equipment per train; 4 drivers and 4 compressors. Both concepts also require the same individual components to transmit electricity from generation to mechanical power, either as a helper drive in the D-drive case, or as main drive in the E-drive case.

In fact, the 5 mtpa direct drive train has evolved into a type of hybrid direct/electric concept. As such it already uses the identical drive system designs as employed for E-drive.

The key differences between the concepts are the up-scaling of motors from 20 MW to 65 MW, and the elimination of the gas turbine driver, in some cases a split casing type compressor, in other cases an axial compressor and the large shaft linking driver and compressors as a single rotating string. With fewer components and more robust drivers the E-drive has the potential for significantly improved operating reliability and availability.

Economic drivers for electric drive

The cost/benefit equation for electric drive is summarised in Table 1 for a train size of 5 mtpa. Cost has been expressed as the "incremental" EPC cost difference between E-drive and D-drive for a train delivering the same daily LNG production. This approach is quite robust because the equipment involved and utility systems design remains the same in both concepts. It is only size of the utility systems which differ. Comparing this result to the work of Shu et al [1] for a comparison of 4 mtpa trains, which reached a similar conclusion, it is postulated that the higher electrical load needed for the 5 mtpa D-drive concept (i.e. being a hybrid electric/direct drive concept), only enhances the advantages to be realised from a full E-drive arrangement..

COST – Additional cost of E-drive train	**<US$ 20M**
Main equipment differences	
Electric drive train:	**Direct drive train**:
360 MW centralised power plant inclusive of N+1 sparing philosophy	110 MW centralised power plant inclusive of N+1 sparing philosophy
Centralised waste heat recovery supporting hot oil or hot water heat distribution system.	Local waste heat recovery from precooling gas turbine supporting hot oil or hot water heat distribution system
Variable speed motor drive systems	Gas turbine plus helper motor drive systems
Larger electrical distribution and auxiliary systems	Smaller electrical distribution and auxiliary systems
ANNUAL BENEFIT (total of items below)	**US$ 34.1M**
Minimum ten (10) additional on-stream days per year, which is around 150,000 tonnes p.a LNG at constant daily capacity. Priced at US$ 3.5/MBTU f.o.b.	US$ 29.6M
Reduced maintenance and shutdown costs averaged over 6 year maintenance cycle as typically used for direct drive plants.	US$ 1.8M
Reduced fuelgas by 5%, priced at US$ 1.0/ MBTU.	US$ 2.1M
Reduced emissions and losses by around 100,000 t.p.a CO_2e.	US$ 0.6M

Table 1: Cost/benefit tabulation of D-drive vs. E-drive in large LNG plants

However, because the electric drive configuration at 5 mtpa is far from any equipment size constraint, it retains potential to be larger without any change to configuration, technical step-out, or equipment type deployed. To study this potential economy of scale, three designs were made and compared; a 5 mtpa direct drive (as a datum) and two electric drive options, one at 6 mtpa and the other at 7.5 mtpa. The latter corresponding to a 65 MW motor/compressor string, seen as a logical analogue to support an upper limit for study purposes. Power generation in the electric drive cases included co-generation of electricity and process heat. The option of combined cycle generation was explored as a continuous improvement feature of an expanding facility.

A detailed cost method was adopted to accurately assess the benefits with changing train size. Heat and material balances were developed with individual equipment sizing and electrical line-lists used to cost major items consistently in all designs. Build-up to Total Installed Cost was carried out by Shell Global Solutions with cost differences between options being validated by separate engineering services and cost methodology being externally audited to enhance confidence in the study results.

A key observation was that the 2 x Frame 7 direct drive design could, at a stretch, reach just over 5 mtpa while the electric drive could approach 7.5 mtpa. Results demonstrated that the specific cost of a single E-drive train can be expected to continue to decline with increasing train size, reaching some 20% lower than the direct drive datum. More importantly, this allows the capacity of a single E-drive train to be tailored specifically to the aspirations of owners.

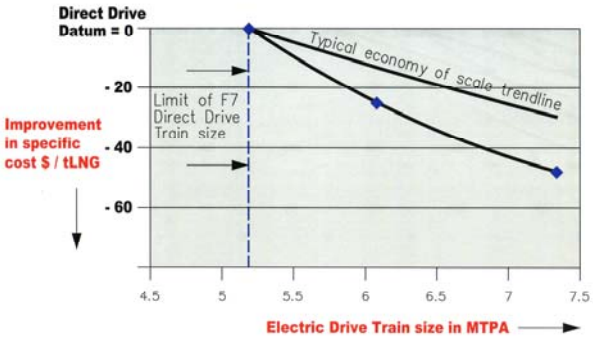

Fig.8: Capital efficiency is improved with larger train sizes using E-drive concepts and allows owners to select any train size as best fits the opportunity. Example: Single train greenfields development with co-generation of process heat & power

Continuous Improvement

Returning to earlier remarks relating to energy efficiency, focus in Australia on managed programs of improvement continues to grow. With reporting of greenhouse emissions to the Australian Greenhouse Office, industry performance is increasingly available publicly. Accordingly, the need to demonstrate the application of company policies of continuous improvement in environmental performance is becoming increasingly important. In this regard two differences between the direct and electric drive technologies are particularly relevant:

i) In the medium term, E-drive has the potential to phase-in continuous improvement via a later conversion to combined cycle, and
ii) In the long term, the centralization of power generation in E-drive will position the complex to best accommodate fluegas treatment technologies if and when their viability emerges.

The study addressed only medium term considerations, hence did not quantify long term costs related to fluegas treatments. A long term perspective has been explored by others e.g. Kikkawa & Lui [2] when examining the potential for zero emissions in the LNG supply chain, and this advantage for E-drive remains noteworthy and significant in the context of future capital investment for emissions reduction.

It is the option in the E-drive concept to phase-in the adoption of combined cycle benefits to accompany economic advantages from brownfields expansion, that is particularly advantageous to an owner in the medium term.

This flexibility is achieved with little regret or pre-investment penalty and allows a venture to pursue cost minimization when getting established, and GHG minimization when building to eventual plateau operation. The corollary for the D-drive is to commit to an "acceptable" compromise between cost and energy minimization at the greenfields phase since little scope exists to retrofit future improvement.

Figure 9 quantifies the value of this choice for owners by showing study results for two expansion paths, one for a direct drive facility, the other for an electric drive, each arriving at the same plateau capacity of circa. 15 mtpa.

Starting with the direct drive, where the single train data presented earlier is provided for reference, Figure 9 shows the cost efficiency generated by a two-train greenfields project and the impact to both cost and GHG efficiency if waste heat recovery is extended to allow steam to also provide motive power to the cryogenic compressors.

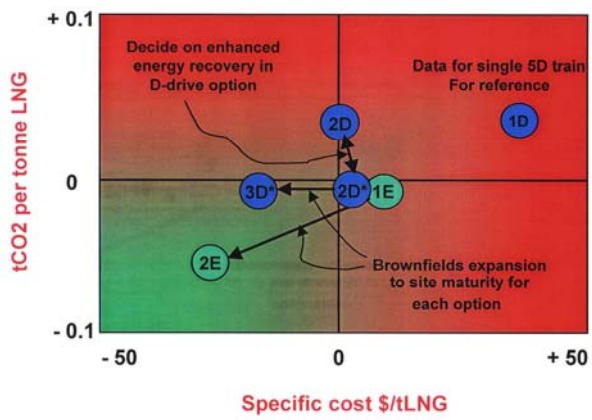

Fig.9: High-capacity E-Drive shows specific cost and GHG advantages in future expansion scenarios

Use of "carbon tax" and "As Low As Reasonably Practicable" (ALARP) principles is typical to decide the appropriate compromise between minimum cost, point 2D, and minimum GHG, point 2D*. However, once the configuration is chosen, little scope exists to improve energy performance when adding duplicate trains. Thus, while cost improvements are achieved with brownfield expansions, point 3D*, GHG improvements are not.

The electric drive option, with 7.5 mtpa trains shown as point 1E, achieves very similar greenfield characteristics, and with the option to convert

the co-generation power plant used for single train operation to a combined cycle plant when a second train is added, the expansion plan can achieve substantial cost and GHG improvements, point 2E.

Hence from a medium term perspective, an E-drive plant operating at 15 mtpa (2 trains) achieves a specific cost approximately 10% lower than a direct drive plant operating at 15 mtpa (3 trains), whilst achieving some 13% lower GHG emissions. These benefits, being around $300M and 750,000 t.p.a CO_2, are significant incentives to contemplate.

Conclusion

Considering these advantages, the electric motor variable speed drive is in many cases a viable and economically attractive alternative to the mechanical gas turbine driver for centrifugal refrigeration compressors. With competitive & reliable electric power available at or near the jobsite, or from an associated power plant, this alternative should be evaluated at a very early stage of any new project. Several reputable manufacturers are experienced and qualified to engineer & supply integrated refrigeration systems, alternatively with gas turbines or electric motor compressor drivers, including the compressors themselves, and the power plant, or just parts thereof.

Finally, the key advantages of the „all electric“ drive system in comparison to traditional GT drivers are repeated:

- continuous process operation is possible for six years with expected availabilities of the refrigeration compression system (including the power plant) approaching 360 days,
- installed and operating costs can be significantly lower; IPP schemes are available to reduce initial investment,
- very little maintenance in the process area and few operational spares required on site,
- custom-engineered drivers up to 80 MW@3600 rpm with no power reduction at elevated temperatures are available and can be fully load tested together with the compressors,
- process train sizes of >5 mtpa benefit most from the E-drive concept, especially if environmental constraints must be observed,
- the flexibility to later engineer combined cycle schemes allows for effective cost and environmental improvement plans to be adopted.

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The authors:

Fritz Kleiner is a merchant marine officer and communications engineer by education. He is with Siemens for 37 years and served in various locations and functions, ranging from service and sales engineer to manager international projects in the USA, and project manager for large industrial drive systems in Germany. He specializes in Megawatt size electric motor variable speed drive systems for the process industry and today is director business development electrical drive systems for turbo machines in the oil & gas industry of Siemens AG, PG Industrial Applications, in Erlangen, Germany. You can reach him at fritz.kleiner@siemens.com

Steve Kauffman is currently the Senior LNG Advisor with Shell Development Australia. He became involved in the LNG business in 1985 and in recent years, as a Consultant in the LNG and Gas processing group of Shell Global Solutions International BV in The Hague, has been responsible for the technical integration of various LNG developments, including Shell’s Floating LNG and Electric Drive concepts. He has also served as HSE Manager and

Economics/Scheduling Manager for Shell Australia's Geelong refinery. He holds a Bachelor of Chemical Engineering degree (1981) from Melbourne University. You can reach him at steve.kauffman@shell.com