All Electric Motor Drives for LNG Plants

Bobby Martinez, P.E.
Director, Technology Licensing
ConocoPhillips Company
3000 Post Oak Blvd
Houston, TX 77056-6503
bobby.d.martinez@conocophillips.com

Cyrus B. Meher-Homji, P.E.
Principal Engineer, Turbomachinery Group
Bechtel Corporation
3000 Post Oak Blvd
Houston, TX 77056-6503
cmeherho@bechtel.com

John Paschal, P.E.
Principal Engineer, Electrical Technology Group
Bechtel Corporation
3000 Post Oak Blvd
Houston, TX 77056-6503
jpaschal@bechtel.com

Anthony Eaton, P.E., PhD
Formerly ConocoPhillips Company, LNG PDC Director
4800 Fournace Place
Bellaire, TX 77401

Gastech 2005
Bilbao, Spain

INTRODUCTION

There is increasing interest by some in the LNG marketplace for using electric motors to drive LNG plant compressors as opposed to the more traditional practice of using gas turbine drivers. The reasons for this interest are the potential for higher plant availability and lower compressor driver life cycle costs. The interest is also driven by improved plant operational flexibility (by using full-rated power variable frequency drives (VFD) that allow compressor speed variation and startup without depressurization), decoupling of plant production and ambient temperature (typical gas turbines lose approximately 0.33% of their output for every one degree F increase in ambient temperature), reduced maintenance costs and downtime for the motors and the VFDs (as compared to gas turbines), reduced plant air emissions (by replacement of the gas turbine drivers with motors), and enhanced safety due to the absence of the gas turbine fuel system. It should be noted that availability does not take into account actual production

It is anticipated these potential benefits become more pronounced when comparing electric motors to <u>large single-shaft</u> gas turbine drivers such as the Frame 7EA or 9E. These single-shaft gas turbine drivers require starting motors in the range of 12-20 MW to start in a depressurized mode. Given this scenario, it makes sense to consider the total replacement of the gas turbine and starter motor with a single, large electric motor. However, the choice of the associated power generation solution can impact the economic viability of an electrically driven LNG plant.

Other benefits cited for an electrically driven LNG plant are:

1. It is easier to dial in an LNG production rate when compared to gas turbines (especially single shaft, constant speed).
2. Motor delivery times are shorter than that of a gas turbine driver.
3. A centralized power system could reduce facility emissions when compared to an all gas turbine drive solution.
4. Plant availability can be higher than the 93 to 94% typically cited for Frame 7EA gas turbine driven plant into today's market place. The higher plant availability derives from the fact that the motors require minimal maintenance and can be kept operational for six years at a time.
5. LNG production is not impacted by ambient temperature swings.
6. An electrically driven LNG facility requires less maintenance when compared to a gas turbine driven compressor solution.
7. Frequent turnarounds are not required for motor driven LNG plant.
8. LNG plant operation can be exceptionally profitable when low cost, reliable electricity is available from a nearby hydroelectric facility.
9. When generating power with gas turbine generator sets, electrical energy from the "plus-one" generator can be sold as an added revenue stream.
10. Enhanced safety resulting in the removal of the gas turbines from the hydrocarbon process area.

A few comments concerning ambient temperature swings and production efficiency are necessary before proceeding with this paper.

Ambient temperature swings impact both gas turbine performance and propane refrigerant condensing temperature. As the ambient temperature increases, the condensing pressure of propane and other refrigerants increase. This increase in pressure translates into power and thus places a higher demand on the gas turbine or motor driver. If this power is not available, overall LNG production will be curtailed. To circumvent this effect, the power plant must possess sufficient power to overcome not only ambient temperature effects on the LNG process, but also the gas turbine power generator.

The term "availability" is widely used in the industry to measure a facilities ability to perform. However, although this term is important, a better production based performance metric is the production efficiency. Production efficiency is conservative and more realistic of an LNG plant's ability to perform at design production rates. Availability and production efficiency will be referenced throughout this paper. To avoid confusion these terms are defined by Jardine & Associates [6] as follows:

$$Availability = \frac{\mathrm{MTTF}}{\mathrm{MTTF} + \mathrm{MTTR} + (\mathrm{Mean\ Logistics\ Delay})}\text{, where}$$

MTTF *= Mean Time to Failure*
MTTR *= Mean Time to Repair*
Mean Logistics Delay *= Mean time required to assemble necessary items to perform repair, such as manpower, tools, parts, etc.*

$$PE = \frac{\mathrm{Predicted\ \ Achieved\ Production}}{\mathrm{Potential\ Production}}\text{, where}$$

Predicted Achieved Production *= Total field life production as predicted by the reliability, availability and maintainability model (RAM), while taking all production critical factors into account.*

Potential Production *= Field life production as determined by deliverability profile for the system.*

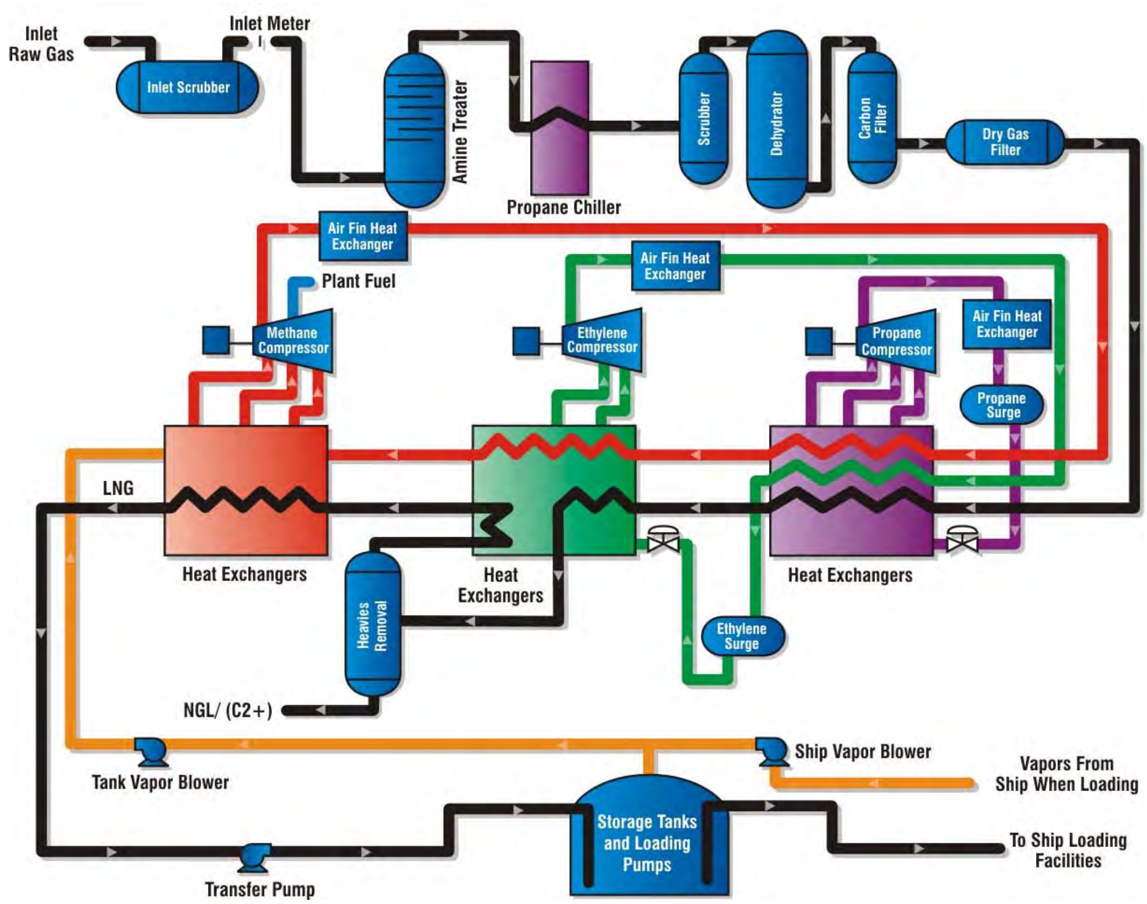
In the cited definition of availability it is clear it has nothing to do with predicted achieved production. For example, if the LNG plant is producing 0.1 mtpa of LNG daily throughout the year, the plants availability is 100%. However, since the plant's potential production is much greater than the 0.1 mtpa, the production efficiency value would be extremely low.

INCORPORATION OF ELECTRIC MOTOR DRIVES IN THE PHILLIPS OPTIMIZED CASCADE LNG PROCESS.

The ConocoPhillips-Bechtel Global LNG Product Development Center (PDC) has developed and studied several LNG driver configurations that utilized industrial gas turbines, aero derivatives, electrical motors, steam turbines and combinations thereof. This paper focuses on an electrically driven LNG plant design that employs the ConocoPhillips LNG Process (formerly referred to in the trade as the Phillips Optimized Cascade LNG Process).

The ConocoPhillips LNG Process has been utilized in plants worldwide and is presently employed by eight (8) world class LNG Trains with sizes between 3 and 5 MTPA in operation and/or under construction. Figure 1 provides a simplified overview of the ConocoPhillips LNG Process technology.

Figure 1: Schematic of the ConocoPhillips LNG Process



*CoP LNG services are provided by ConocoPhillips Company, Phillips LNG Technology Services Company and Bechtel Corporation via a collaborative relationship with ConocoPhillips Company. CoP LNG, ConocoPhillips and its logo are trademarks of ConocoPhillips Company. Bechtel and its logos are trademarks of Bechtel Group Inc.

Plant availability, reliability and overall production efficiency has been a hallmark of the ConocoPhillips LNG Process for years. The standard design for the ConocoPhillips LNG Process incorporates a "two trains in one" concept. That is, the refrigerant cycle (Propane, Ethylene and Methane) has a minimum of two compressors operating in parallel, while the liquefaction plant is a single train. It is the parallel configuration of the refrigerant compressors that allows the plant to operate at production rates in excess of 50% while a single gas turbine compressor unit is off line. Furthermore, it is this operating flexibility, equipment reliability, and overall inherent design of the ConocoPhillips LNG Process technology that allows the LNG plants employing this technology to demonstrate production efficiencies greater than 95% [1, 5].

Recently, the ConocoPhillips-Bechtel Collaboration PDC team developed designs around large gas turbine drivers such as the Frame 7EA and Frame 9E [2]. The first and simplest concept was to utilize a single Frame 7EA gas turbine per refrigerant cycle. Although this arrangement achieves an availability of greater than 95% (or a production efficiency of approximately 92%), it did not make sense to discard the two trains in one concept [3,6]. Therefore, two of the three Frame 7EA gas turbines were equipped with both propane and ethylene coupled together on the same shaft. Whereas, the third Frame 7EA is dedicated solely to the methane refrigerant cycle. Figure 2A demonstrates this hybrid, "two trains in one" concept

The basis of comparison for this report is the Frame 7EA gas turbine parallel configuration as demonstrated in Figure 2A. The Frame 7EA gas turbine drivers and respective starter-helper motors were replaced by an electric motor. However, the methane refrigerant cycle Frame 7EA driver was replaced with two 45 MW electric motors. This configuration would ensure maximum flexibility and overall plant availability.

Figure 2A: Frame 7E gas turbine plant configuration

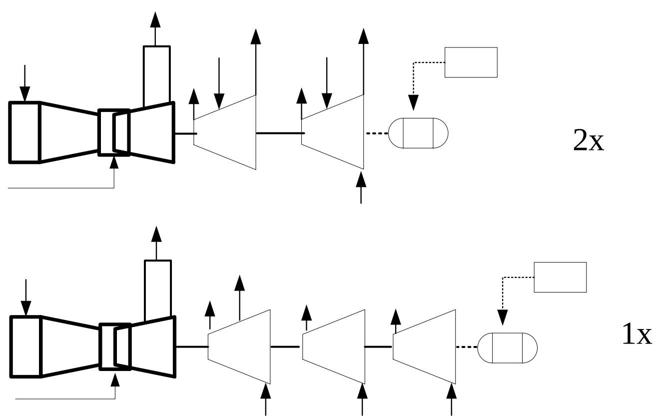
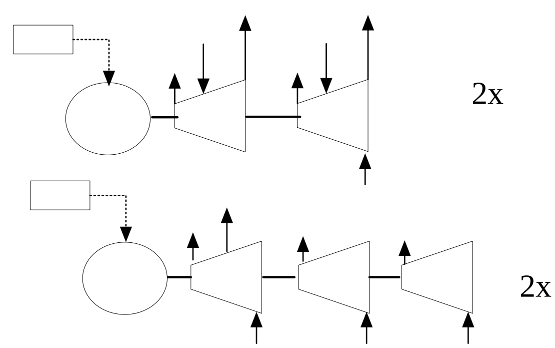


Figure 2B: Electric motor plant Configuration



STUDY OBJECTIVES

The fundamental objectives of this study were to examine various electric motor drive solutions, make a determination of the benefits claimed, and evaluate the technical risks and derive estimates of the installed costs. Specific goals of this study include but were not limited to:

- Summarize the varied experience levels of different motor suppliers in the power ratings under consideration.
- Evaluate the different VFD technology solutions.
- Determine the flexibility and cooperation level of the different large motor and VFD suppliers.
- Evaluate the different technical solutions proposed by the vendors in terms of innovativeness and total installed cost, including the auxiliary electrical equipment and switchgear needed.
- Derive a set of technical options and then estimate total installed costs for these options.
- Plan a way forward for implementation of the design concepts.
- Conduct a preliminary HAZOP study relating to the motor driven design concept.
- Conduct a preliminary Life Cycle Analysis to determine the sensitivities of using electric motor drivers to key parameters, e.g. cost of electricity, cost of fuel and plant availability.
- Examine power generation solutions to support the all-electric LNG concept. This is an area of significant importance and complexity unless low cost, reliable external (third party) grid power is available. For potential LNG projects envisioned, a determination was made that self generation would be a must, unless economical hydroelectric power was available
- Identify issues relating to rotor dynamics, performance etc., with the motor-compressor strings

ELECTRIC MOTOR DESIGN & MOTOR/VFD SUPPLIERS

The Frame 7EA ISO power rating is approximately 83 MW (111,303 shp). As compared to a 12 to 15 MW starter-helper motor, the size of a single electric motor required to replace the gas turbine starter-helper configuration can range from 95 to 100 MW. To date, motors of this size typically operate at much slower speeds than those required of LNG facility refrigerant compressors. However, because the industry views generators as being synonymous to motors, and given their vast experiences in building generators greater than 250 MW, motors of this size are not considered new technology. In essence, these motors can be built without employing new designs or materials.

Suppliers have indicated that 2-pole motors equipped with variable frequency drives (VFDs) are the most attractive and economical solution for the power ranges under consideration. Apparently the crossover point in terms of cost between a 4-pole and 2-pole motor is around 50 MWs. Electric motor suppliers stated that the 2-pole motors can be built to API 546 standards and operate at high efficiencies. Electric motor and VFD suppliers considered for this study included: Mitsubishi-Melco-Toshiba, Alstom, Ansaldo Robicon, ABB, Brush Motors, and Siemens.

The approach of a motor solution for the ConocoPhillips LNG Process is to use the same size motors for the parallel ethylene/propane refrigerant cycles as presented in Figure 2B while splitting the methane into 2 parallel 45 MW motor trains. These motors are premised to operate at 50Hz. VFDs were also included in the final design to facilitate starting and to ensure operating flexibility and availability of the compressor trains.

Variable Frequency Drivers (VFD) and Solutions for Large Electric Motors

Present applications of the Frame 7EA gas turbine driver within LNG Plants are coupled with starter-helper motors. This is because of the single-shaft design which unlike a two-shaft gas turbine cannot produce high torque at low speeds. The kW rating of the starter-helper motor is dependent upon the gas turbine and compressor system breakaway torque and gas loading during acceleration. For example, the starting power required for a non-pressurized Frame 7EA gas turbine and compressor could be between 12 to 15 MW. The VFD provides the high end starting torque which is very attractive.

The electric motor plant replaces the gas turbine configuration with an electric motor of equivalent power. This change introduces a host of concerns that must be addressed. These concerns include but are not limited to:

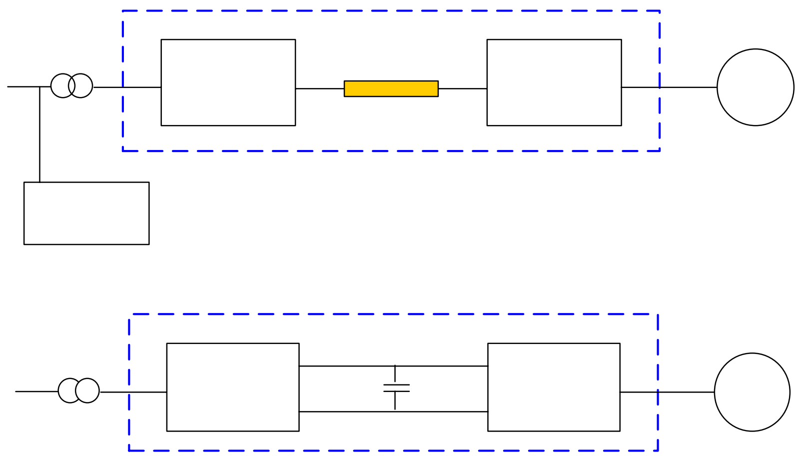
- The start-up of the compressor train (ensuring adequate torque-speed capability to allow appropriate acceleration with minimal dwell time at the critical speeds)
- Restart of the compressor train after a motor trip (time required). Note restart of the Cascade LNG plant has a very short duration (minutes).
- Range of operability (efficient turndown) - there are limitations generally imposed on the speed range of the motor and these are typically rotor dynamic constraints
- Torsional analysis of the full compressor train under start up conditions, compressor transients such as surge, and electrical transients such as power dips
- Interaction of torsional and lateral vibration. This could be accentuated with the presence of a gearbox which may be needed to optimize compressor operation.
- Sensitivity of the motor to excitation of its critical speeds
- Effects imposed on the power system resulting from motor trips (this is by far the most critical issue affecting the electrical system stability), switch gear and power distribution failure. Transient stability issues which are rare can easily be overcome in the Cascade LNG plant by simply tripping all synchronous machines resulting from a major event, and then simply restart the plant.
- VFD
    - availability and efficiency
    - induced low frequency harmonics
    - stable operation during a power disturbance
    - rapid speed response and range of variable speed (*this is usually constrained by the rotor dynamics of the motor and this requirement is linked very much to the process*)
    - Operation at degraded levels of the VFD may present problems depending on the specific compressor curves that exist.

- Motor speed variability - this issue relates to the lateral rotor dynamics of the electric motor

Although out-of-the-box thinking was promoted, new technology and materials of construction was a design constraint utilized to mitigate risk. Further, risk mitigation required concepts to be simple and facilitate operation, maintenance and repairs of respective equipment with minimal impact to LNG production. Suppliers had to provide the appropriate redundancy to ensure LNG production is not negatively impacted due to VFD failure and the inability to accommodate power system disturbances.

Supplier solicitation revealed VFD configurations existed for 50 MW motors utilizing both Load Commutated Inverter (LCI) and Gate Commutated Turn Off Thyristor (GCT) technology. Although there are several other VFD solutions, this paper will focus on the benefits of the LCI and GCT VFD drive systems. Simplified schematics of the proposed drive system configurations are presented in Figure 3.

Figure 3



The LCI is a conventional drive system that uses a low switching (on/off) frequency device known as a thyristor. The GCT is a more advanced drive system that uses the latest high switching frequency device. Comparisons of these two technologies are presented in Table 1.

Table 1: LCI technology Vs. GCT Inverter

COMPARISON PARAMETER	LCI TECHNOLOGY	GCT INVERTER
Experience with large systems	Proven, though none at the large power levels of this study	Proven, though none at the large power levels of this study
Line Harmonics	<11% (12 pulse) Harmonic filters typically required	<5%, Harmonic filters not required when high pulse number rectifier sections are employed
Robustness at AC power disturbance	More limited ride through capacity	Has very robust ride through capacity
Torque ripple	Larger torque ripple <7% for 12-pulse. More concern for torsional excitation of string	<0.5% Less concern for torsional issues
Efficiency	High	High at the design point and minimal variation at off design.
Reliability	Proven technology, and have been utilized for a longer length of time.	Proven technology, somewhat newer in application but with some large application references.

Installation space	High because of space for harmonic filters	No harmonic filter space required.

The benefits of the GCT drive system are clearly more favorable than LCI. But, how would one configure a drive system for a 100 MW motor? According to some manufacturers the drive system can be implemented in either a parallel or series configuration as presented in both Figures 5 & 6 respectively. The parallel drive system configuration consists of multiple drive systems correctly connected for a 45 to 50 MW electric motor. The same is true of the series configuration. The end result would be a 2 x parallel or series arrangement for the 90 - 100 MW electric motor.

Figure 5: Parallel Drive System

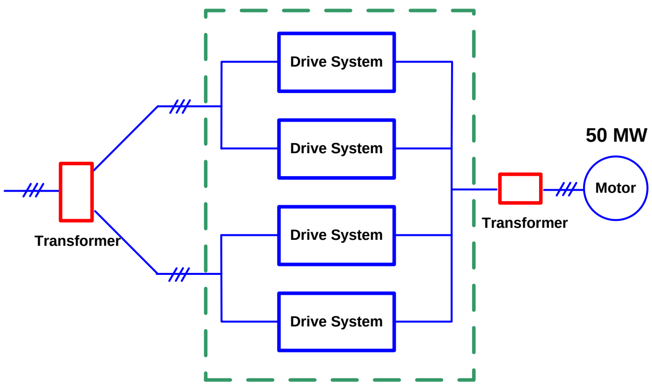
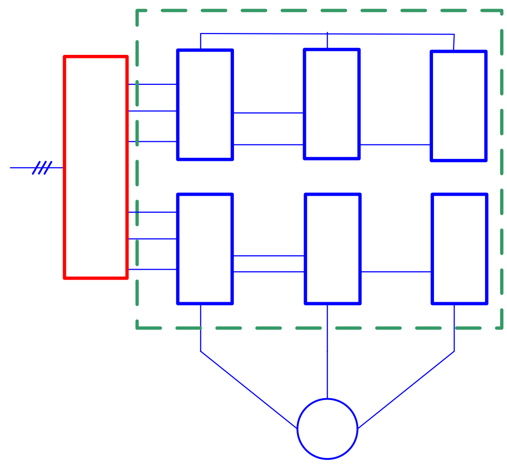


Figure 6: Series Drive System



Benefits of the VFD

The VFD provides a high degree of “ride–through” capability when there is a supply voltage dip. The use of 12, 24, or 30 pulse VFDs results in lower harmonics induced within the network. While a specific project evaluation must normally be made on a case-by-case basis, it is quite likely that no harmonic filters would be required. Further, the low torque ripple helps in the torsional design of the motor-compressor string.

The proposed drive system configurations presented by the suppliers were found to be inherently reliable and redundant, and therefore stand-alone redundancy is not required. Furthermore, because the technology is not new, replacement parts are readily available.

Starter VFD vs Full VFD

VFD selection is highly dependent upon the client’s needs. For example, a full functioning VFD could be placed on one of the propane/ethylene circuits while simply equipping the remaining propane/ethylene and methane refrigerant circuits with only a single starter-VFD. Another option is to equip all refrigerant compressor circuits with full functioning VFDs for maximum flexibility. Because of the varying possibilities a comparison of benefits was performed. The results of this comparison are presented in Table 2.

Table 2: Starter VFD to a full functioning VFD comparison

FEATURE	STARTER VFD	FULL VFD
Cost	Lower - depends on configuration and on the rating of the drive. (can be 80%-90% of the full VFD cost after including switchgear for N+1.)	Higher
Ability to ride out power dip (Voltage sags etc)	Does not exist, compressor string will trip-requiring shut down and resynchronizing and refrigerant depressurization or evacuation.	Has ability to ride out significant power dips
Variable Speed Operation	None- compressor has to run at fixed speed governed by the grid frequency.	Ability to vary speed allowing speed control and turndown as needed
StartUp	Depending on size of starter VFD, would require depressurization	Ability to start under full pressure conditions as ample torque available
Startup sequence	Sequential start of compressor trains	Can start simultaneously
Antisurge control	Has to be via throttling	Speed control possible
Potential for Consequential damage if trip	Possible that bearings and other components may be damaged.	Minimized by dynamic breaking using VFD
Switch gear	Complex switchgear required for	Relatively simple switchgear
Overall LNG Availability	Lower	Higher (more rapid startup, ability to operate under speed control etc)
Plot plan requirements	Lower	Slightly higher.

Although the starter VFD requires less total installed cost, the Full VFD provides maximum operating flexibility during start up, trips, electrical transients, ambient swings, turndown, etc., which will more than justify itself. Thus, the design team must evaluate and relationship between TIC and the life cycle benefits of the respective options.

POWER PLANT SOLUTION CONSIDERATIONS

Power plant configuration and sizes are numerous requiring thorough analyses when selecting a solution that best fits the need of the project premises. In the case of this study both N+0 and N+1 sparing philosophy was evaluated for the three power solutions considered:

- Simple cycle self generation utilizing,
- Combined cycle self generation utilizing,
- Across the fence Utility electric supply (preferably from a reliable and economical supplier).

With a few exceptions, a long term-reliable and risk free electric supply in most of the countries where LNG plants may be built would be unavailable for the large power demand required by an LNG plant. Further, there considerable political risk and uncertainty with regards to the cost of tariff and energy pricing over the life of the LNG Plant.

Self generation simple cycle power plant solution is the least complicated to operate, involves the shortest installation time and lowest overall total installed cost (TIC) when compared to a combined cycle plant. The combined cycle power plant solution is more complicated to operate (high pressure steam system ranging from 800-1500 psi), requires greater attention to maintenance, requires a larger plot plan and is greater in TIC than the simple cycle solution. However, the combined cycle solution does benefit from a much greater thermal efficiency (48% -vs- 33%) and comes in larger blocks of power. It should be noted that higher thermal efficiencies are achievable for various power plant combined cycle configurations. Examples of combined cycle power solutions are presented in Table 3.

Table 3: Combined Cycle Power Plant Solutions

Power Plant			ISO Power (MW)	Site Power (MW)	# of units required for 300MW	Total Power (MW)
Option	(Combined Cycle)					
1	GE	S106B	64.3	57	6, n+1	342
2	GE	S206B	130.7	114	4, n+1	456
3	GE	S107EA	130.2	116	4, n+1	456
4	GE	S109E	193.2	188	3, n+1	564

The N+1 philosophy required to achieve a high plant availability of greater than 96% can result in surplus power. Under such conditions, exporting of power can offset the capital burden.

Power plant reliability and availability are very important to the success of an electrically driven LNG Plant. Consolidation of power can impact LNG plant availability because of power instabilities due to generator trip, mechanical failures, electrical faults, and transient events [4]. These influences can be mitigated by selecting a power plant solution that consists of multiple power generation packages. However, a thorough investigation of the power plant solution must be performed on a case-by-case basis, taking into account, capital cost, operating cost and the stability of the system to transient upsets.

ECONOMIC ANALYSIS

Power Solution Overview

LNG plants are typically based on the lowest possible TIC. The lowest TIC option for an electrically driven LNG plant is a third party external grid. However, the capital investment differential between a gas turbine and electrically driven LNG plant can be rather high. It is true the electric motor costs less than a gas turbine, but the power system of the LNG plant has now grown from 30 to greater than 260 MW. The LNG plant must now accommodate a large power distribution system with built in redundancy. Depending on the location of the LNG plant, the availability of real estate can be a challenge. This is especially true if additional LNG trains are premised.

An alternative to and external grid is self generation. This alternative best serves the LNG project if the respective shareholders control the power generation plant. However, caution should be exercised if the self generation power plant assumes a power exporting role. Load shedding philosophy becomes a challenge in that, who has priority during scheduled maintenance, generator trips, equipment failures, etc.? This philosophy can greatly impact the LNG plant's ability to deliver contracted rates and therefore this is a risk that must be clearly understood and managed appropriately.

Self generation power solutions are provided in various sizes, configurations and technologies. This study focuses on “simple” and “combined” cycle power generation solutions. The simple cycle power generation plant is basically a large gas turbine coupled directly to a generator which is in turn coupled to a power distribution system. This is typical of most LNG plants but at a much smaller scale, i.e., 10 to 30 MW. However, the combined cycle power solution is more complex but more thermally efficient. This power solution is like the simple cycle solution however, the gas turbine is equipped with a waste heat recovery unit to generate high pressure, superheated steam. The high pressure steam (800 to 1500 psi) is used to drive a steam turbine which is coupled to a generator and associated power distribution system. The complexity of this type of power plant resides in the steam generation and recovery system thereof.

Economic Evaluation

The economic analysis for this study is based on US Gulf Coast cost data. To set the stage for the economic comparison between the Frame 7EA gas turbine driven LNG plant and that of electric motors, the following parameters were considered:

1. Self generation power solution consists of multiple packages necessary to ensure LNG plant availability greater than 96% is achieved.
2. The basis for comparison is the ConocoPhillips Frame 7EA gas turbine driver LNG plant and respective starter-helper motors and required power generation.
3. An overall plant power requirement is 260 MW.
4. LNG tanks are critical path and therefore no schedule advantage is assumed.
5. Inlet gas feed rate to the LNG plant is assumed fixed.
6. OPEX
    a. 2.5% of TIC for GT Plant
    b. 1.5% of TIC for external grid power solution
    c. 2.5% of TIC for the simple cycle power plant solution
    d. 3% for combined cycle power plant solution
7. Fuel gas value equal to that of LNG.
8. The sales price of LNG is on an FOB plant basis and valued at 4.5 US$ per million Btu flat rate over a 20 year plant life.
9. Gas cost was based on a flat rate of 0.5 US$ per million Btu.
10. Cost of power plant real estate not included in the analysis.
11. Variable LNG plant OPEX was 0.08 US$ per million standard cubic feet per day.
12. Power plant sparing philosophy is N+0.
13. Gas composition consisted of 96% methane, 3% ethane and 1% propane.
14. LNG Plant Frame 7EA gas turbine plant production efficiency, 94%.
15. Owners cost, tax credits, subsidies, etc. are not including

The external electrical grid solution is the least capital intensive option but not without sacrifice. If one assumes an energy cost of $0.07/kW-h for a running load of 260 MW, the differential (*power solution* NPV_{10} *– gas turbine base* $NPV_{10} = \Delta NPV_{10}$) net present value for a rate of return of 10% (ΔNPV_{10}) between the gas turbine and the electrically driven LNG plant is a positive 8 million US$. This value is based on a plant production efficiency of 96% which in some cases could be rather generous. Figure 7A and 7B demonstrate how production efficiency and grid power pricing influence comparative project ΔNPV_{10}. As the production efficiency decreases and/or third party grid power supply pricing increase, the comparative ΔNPV_{10} becomes negative, whereas, the opposite is true. These results indicate a clear understanding of the economic parameters is crucial when evaluating a grid power solution. This is especially true given the geographical locations for which LNG plants are being installed. External grid supplied power in these countrys is not always available and reliable for such large power demands.

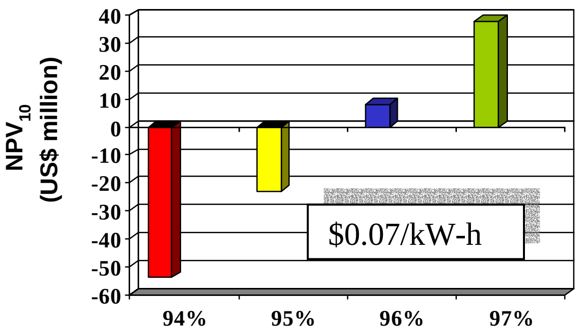


Figure 7A

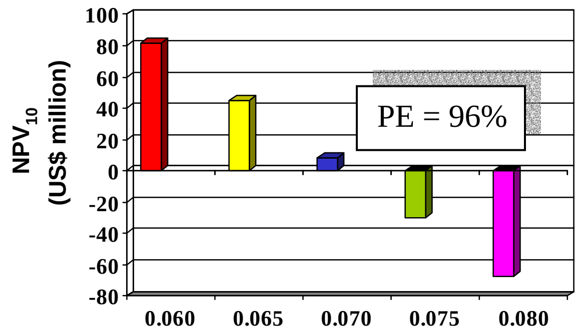


Figure 7B

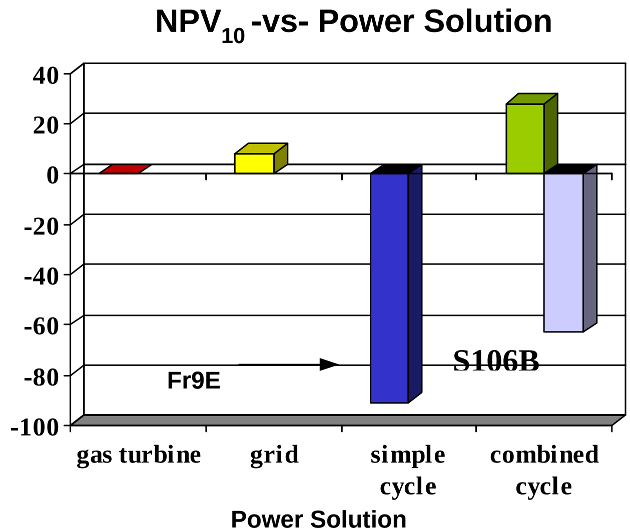
The alternative to grid power is self power generation. Self power generation can either consist of a simple or combined cycle solutions. Each solution has its advantages and disadvantages. Table 4 demonstrates some key differences between the simple and combined cycle solutions.

Table 4: Simple Cycle Vs. Combined Cycle

Simple Cycle	**Combined Cycle**
• Lower thermal efficiency	• Higher thermal efficiency
• Lower initial CAPEX	• Higher Initial CAPEX
• Lower OPEX	• Higher OPEX
• Higher stability	• Lower Stability
• Small real estate requirement	• Large real estate requirement
• Simple to operate	• Complex to operate
• Shorter delivery	• Longer delivery

A comparative analysis of all three power solutions is presented in Figure 8. The key drivers when compared to the gas turbine driven LNG plant are: capital investment, operating cost, incremental LNG, energy pricing ($/kW-h) and overall LNG plant production efficiency.

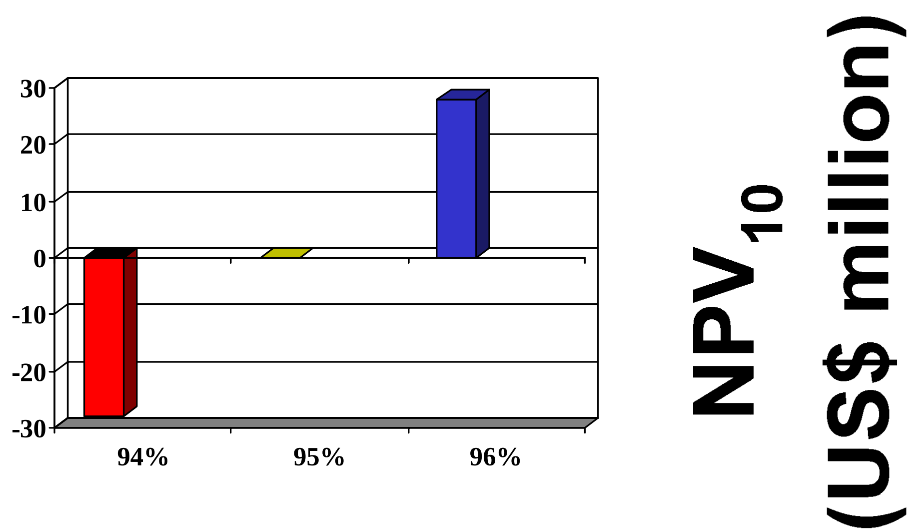
Figure 8



Total installed cost (TIC) for the self generation power plant solution is based US Gulf Coast values such as $550/kW for the simple cycle solution and $737 for the combined cycle solution. Economies of scale are realized with the N+1 philosophy driving the combined cycle solution to $719/kw for an equivalent power of 390 MW. The N+1 sparing philosophy ensures an overall LNG plant production efficiency in excess of 95% but unfortunately the additional capital investment negatively impacts the comparative ΔNPV_{10} as shown in Figure 8 (N+1). However, N+1 solution was not considered when performing the economic comparisons. If the N+0 option can provide the availability and reliability requirements of an LNG plant, then given the assume economic parameters, the LNG plant overall production efficiency must be in excess of 95% to be economic when compared to the gas turbine driven solution. Figure 9 demonstrates the influence production efficiency has on the N+0 combined cycle power plant solution.

Figure 9

.



The simple cycle solution presented in the Figure 8 is the most unattractive of all the power solutions considered. Although the TIC is lower than the combined cycle power plant solution, the combined cycle power plant has a net thermal efficiency of approximately 48% compared to 32% for the simple cycle plant. When compared to the Frame 7EA gas turbine driven LNG plant, the fuel savings resulting from the combined cycle plant benefits from incremental LNG sales thus boosting project NPV. However, the simple cycle power plant solution economics can be improved by employing aero derivative gas turbines. For example the General Electric LM6000 has an approximate net thermal efficiency of 40% which is 8 points better than the Frame 9E.

The results of this analysis suggest the economic comparison between the gas turbine driven LNG plant and an all electrical solution is marginal. Of course the economic parameters considered are finite and a more detailed analysis is warranted.

CONCLUSION

An electric motor driven LNG plant is theoretically a viable solution with today's technology. Motor manufacturers are confident that large motors around 90-100 MW are feasible as they will be essentially the same technology as large two pole generators that have been built to sizes exceeding 250 MW. Furthermore, large motors and VFDs can be built without employing new technology and materials of construction thus minimizing technical risk.

The success of any LNG plant is fostered by low capital investment (CAPEX), low operating cost (OPEX), and high production efficiency. A third party, external grid power solution can satisfy the capital investment and low operating cost drivers, but it could fall short in the area of plant production efficiency thus negatively impacting project economics. The self generation plant requires a much greater up front capital investment than a gas turbine driven LNG plant. This initial capital investment is further complicated by the need to achieve a production efficiency greater of 96% necessary to boost the project NPV.

In conclusion, while an electric motor driven LNG plant is technically feasible, careful attention is required when evaluating the project economics. For example, what is the value being placed on the fuel gas? Is there credit for reducing CO2 emissions? Is there sufficient real estate for the LNG plant and power plant solution? Does it make sense to export power? Can the burden of a power plant be shared by other users such as that of an industrial park? If so, what will be the load shedding philosophy? Is there truly a schedule advantage when the LNG tanks are critical path? Is TIC the driver? What about simplicity of design? Where will the plant be located? The answers to these questions and many others will be site dependent and client driven.

Acknowledgements
The ConocoPhillips-Bechtel study team would like to thank all of the suppliers who participated in this study.

1. Avidan, Varnell, Martinez, "Natural Gas Liquefaction Process Designers Look for Larger, More Efficient Liquefaction Designs", Oil & Gas Journal, August 2003

2. Avidan, Martinez, Messersmith, “LNG Liquefaction Technologies Move Toward Greater Efficiencies, Lower Emissions, Oil & Gas Journal, August 2002
3. Buoncristiano, Camatti, Salvadori, Avidan, Martinez, - “New Generation of LNG Plants Based on Innovative Liquefaction Train Configurations”, LNG 14 March 2004
4. Fumiharu Hori and Hitoshl, JGC Corporation, Japan, “A Large (9 mta) Electric Motor-Drive LNG plant is Feasible”, LNG Journal, January/February 2004, pg 53
5. Redding, Hernandez, Qualls, Avidan, “ Egyptian LNG, The Value of Standardization”, Gastech 2005, Bilao, Spain.
6. Qualls, Eaton, Schmidt, “Enhanced Reliability, Efficiency, And Availability LNG Facilities”, Gastech 2005, Bilbao, Spain