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COGENERATION FLEXIBILITY FOR REFINERY STEAM MANAGEMENT

Bill Mintern, Chief Engineer, Irving Oil Refinery

Introduction

Oil refineries have evolved over the past three decades increasing their demand for utilities such as water, steam and electricity. Large refineries require stable utilities which are efficient and cost effective. Utility plants become integrated with refinery process units to take advantage of all heating and cooling sources. As refineries increase throughput to several hundred thousand barrels per day, energy is one of the highest operating expenses.

Keeping utilities available for refinery use continues to be challenging. Profitable utility plants use cogeneration systems to provide power and steam to the refinery as well as export power to the municipality. It is important to have a system that is versatile and flexible to adapt to the conditions of the refinery. Scheduled maintenance of steam generators, cogeneration equipment and refinery electrical systems will call upon utility plants to adjust operation to fulfill steam and power needs. Unplanned events such as lightening storms, heavy rains, power outages and plant upsets need utility systems to respond quickly to keep the plant in operation. Sometimes the response to maintain production means the steam and power generators will be at their maximum designed capacity. It crucial to properly maintain this equipment; thereby, necessary to have a utility plant, in particular a cogeneration system, able to operate in the most efficient and effective mode for the conditions present.

1 Steam Generation Management

Energy represents the single largest operating expense incurred by a refinery, usually accounting for 50% of total operating costs. Refineries lose energy, as much as 20%, through inefficient configurations and equipment, leakage, waste, poor controls, etc. These inefficiencies become more critical during periods of low profit margins affecting revenue.

1.1 Evolution of Steam Generation at Oil Refineries

Steam generators, ie. Boilers are the common installation in utility plants to produce steam for refinery use. Boilers are classified as either fire tube or water tube design. They use fuel to create heat to convert water into steam. Figure 1 shows a typical water tube boiler arrangement.

Steam is usually heated through a bank of tubes after separation in the steam drum. This additional heat is known as superheat. Superheated steam is ideal for transmission through long pipe racks as it will remain dry when it loses heat in the pipe rack. Process units can be designed to produce superheated steam also and be connected to the same header as the boiler.

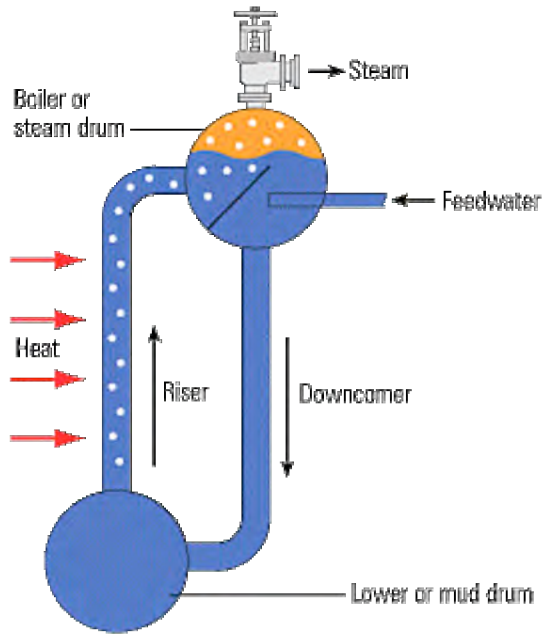

Figure 1: Boiler Arrangement

To maintain header pressure the boilers themselves can be modulated by employing a boiler master control scheme. This control is unique to each boiler and monitors fuel and air requirements to allow the boiler to produce its design steam production. Boiler masters at 50%, for example, adjust the boiler combustion controls to allow the boiler to produce 50% of its design steam capacity. By manually adjusting this output (biasing) each boiler can be preset to put out a specific amount of steam per hour. Plant Master controls are usually pressure controllers which have the output connected to the boiler master setpoint. Plant masters with a set point, SP = 600 psig, control steam pressure by modulating fuel to each boiler simultaneously. As shown in figure 2, boilers can be controlled in a parallel arrangement to supply one main header.

Refinery process units themselves have been designed to contain heat exchange equipment that will produce steam for use in the plant itself and possibly export it to other areas of the refinery.

Individual boilers may be given more or less output, biasing, to ensure even distribution of load across the utility plant. Fuel compensation values can be incorporated into the boiler master control loop to allow the boiler to more accurately reflect its design steam production as fuels may change in their BTU value over time.

Fuel gas is a term given to refinery by-products such as LPG and natural gas produced in the process units in the production of heavy oil and gasoline. These gases are collected in a system which distributes fuel to the refinery. Fuel gas plants can include water separators, strippers and scrubbers designed to remove contaminants such as ammonia and sulfur from the fuel prior distribution into the refinery fuel gas system. Natural gas from an outside source is commonly used as a pressure control medium to supplement the header. Ideal fuel gas control is such that the refinery demands are slightly greater than the off gas produced and natural gas can be added to maintain pressure. Excess off-gas will over pressure the system and pressure relief will occur usually into the flare system, thus, inefficiently burning the gas to atmosphere.

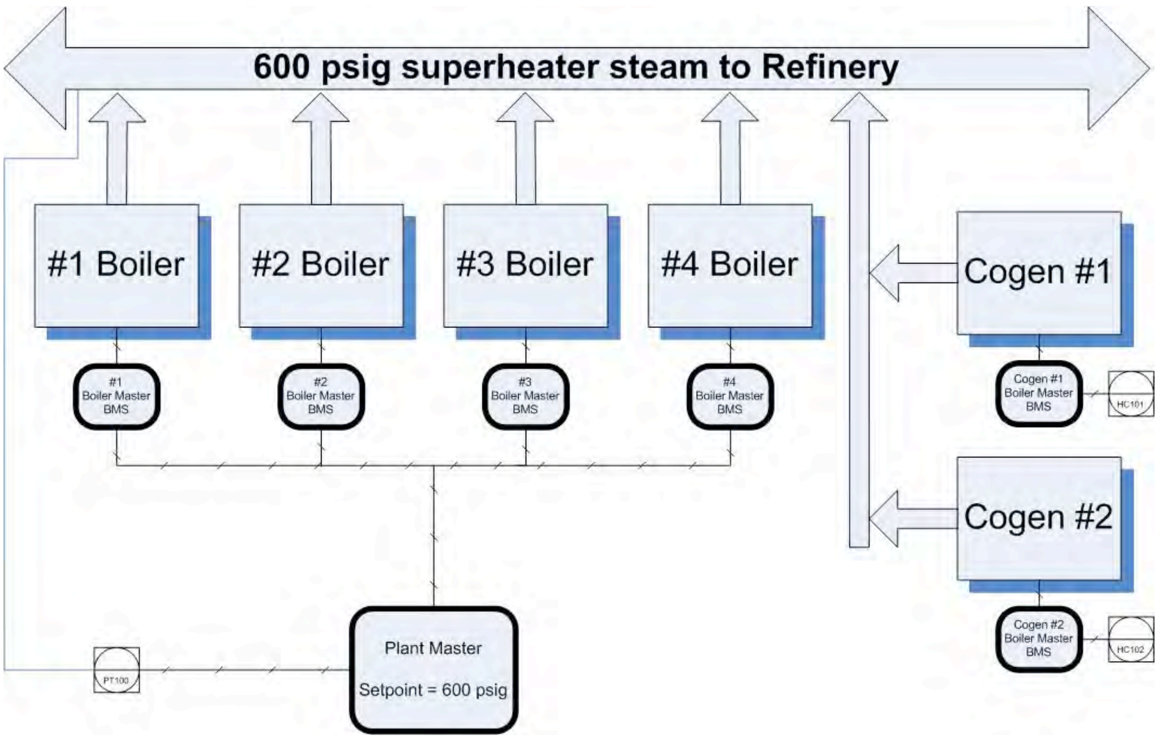

Figure 2: Boiler Plant Master Configuration

Steam is typically delivered at different pressures throughout the refinery. High pressure (HP), medium pressure (MP) and low pressure (LP) steam headers are contained throughout. Process units can be deemed a net importer or net exporter of steam. HP steam (usually 600 - 900 psig) is produced in the utilities area in a steam generator. MP steam (100-200 psig) and LP steam (40-60 psig) headers are supplied by process units and inside utility plants. Steam reducing stations are pressure control valves used to control steam flow to maintain headers at either MP or LP pressures. Operation of back pressure steam turbines is another way to reduce steam to supplement MP or LP header pressure. Refineries can contain dual motor / turbine driven rotating equipment. To keep the reducing station valves in control cycling of turbines may be required.

Efficient plant operation keeps the steam cycle closed meaning there is every attempt made to recover steam from all users in the for of steam condensate and re-use it in the feed water treatment stage. Steam leaks, condensate leaks and un-controlled venting of steam can prove very costly. Typical water treatment costs can range between $10 -$15 per pound of fresh water introduced to the steam cycle. Steam system over-pressure is controlled on the HP header using pilot operated PSV's and plant master control. Over-pressure on the MP and LP systems are controlled by PSV's and vents to atmosphere. Steam venting is a common problem during utility plant operation as all steam header pressures may be controlled to their respective set points; however, steam flows are excessive to either the MP or LP system causing the vents to open.

1.2 Early Refinery Steam Systems

Older refinery steam systems would have included power boilers and / or package boilers constructed on site to deliver steam for plant start-up and steam header pressure control. In early construction, natural draft power boilers were used to start the plant from a "no steam" condition. These units are typically 100,000 – 200,000 lbs / hour steam production. Fuels used include natural gas, LPG, refinery off-gas and fuel oil. As these plants progressed package boilers were used for expansion purposes. These were cheaper to build as they would arrive on site as a shop-assembled unit requiring only final field erection and connection to plant piping systems. These units were larger in steam production and connected easily to any existing steam production controls. The latest additions to refineries have included heat recovery steam generators, HRSG's. These units can be between 200,000 – 500,000 lbs / hour steam production.

1.3 Steam Requirements for Plant Start Up

When commissioning a utility plant within a refinery, especially during initial commissioning, attention must be given to the fact that process units may not be coming online simultaneously. In fact some process units may not begin construction for several months after commissioning the utilities area. This means the turndown of the utility plant must be low enough to safely operate the boilers and still be able to maintain adequate control of the steam header pressure. Low steam demand can cause online steam generators to be 'base loaded'. This means the boiler master controller is in manual operation with a preset output. This will ensure the boiler continues operation at a specified steam production rate regardless of header pressure. Adjacent boilers can continue to be modulated through the plant master pressure controller. Base loading steam generators does not affect combustion control and safety of the boiler. It does, however, render that piece of equipment ineffective during changes in refinery steam demand. Efficient operation of the utility plant would mean having boilers produce steam at their optimum rate which is usually at the 80 – 90% range. Unfortunately, utility boilers cannot constantly operate within these ranges as refinery wide steam demand can vary greatly. HRSG's when used as ‘fresh air fired’ steam generators are highly inefficient. Excess oxygen from combustion can be as high as 18%. In order for these units to be cost effective in this mode, they must be biased to the upper end of their design range. Some steam systems can have multiple units online with some base loaded. During the commissioning phase of new process units, the utilities plant will have to vary the steam production as the overall refinery demand may decrease.

These process units can be net importers or net exporters of steam. Operation of these plants in a profitable mode require 95 – 100% throughput; as such their steam production will not change. Utility systems must be designed and managed to provide constant refinery steam pressure even during process plant upsets.

1.4 Steam Plant Management without Cogeneration

Long term management of these systems requires an understanding of the planned operation of the refinery and projected steam demands. During turnarounds and minor maintenance outages steam demand will decrease requiring a boiler or boilers to be taken offline. These procedures are planned and executed over a minimum 12 - 18 hour period. Safe shutdown and start-up of these steam generators require sufficient time for tube expansion, casing expansion and piping expansion. Older power boilers and package boilers have fixed boiler settings, generator tubes, superheater tubes, baffles that are encased in castable refractory. Too rapid of heat transfer can cause the settings to expand faster than the castable refractory can withstand and cracking can result. Over time refractory cracking will cause casing heat damage and leakage. Modern HRSG’s have more resilient insulation or refractory allowing start-up times to be reduced significantly.

Table A: Steam Action Plan A

Typical Cost Analysis For Spring 2001 Turnaround Steam System Management Options.

Asset	Normal Minimum Load (MLB/hr)	Minimum Load Load (MLB/hr) OPTION A	Minimum Load (MLB/hr) OPTION B	Minimum Load (MLB/hr) OPTION C
Boiler # 1	100	0	0	0
Boiler # 2	100	0	0	0
Boiler # 3	140	140	0	140
Boiler # 4	200	200	200	200
HRSG # 1	280	280	280	0
HRSG # 2	280	280	280	280
TOTAL:	1100	900	760	620
Steam Waste Required to Meet Min. Load (MLB/hr):		300	160	20
Cost of Steam Wasted ($US/day):		($39,036)	($26,570)	($6,233)
Net Cost to refinery ($US/day):		($39,036)	($26,570)	($6,233)
Net Cost for 4- week period ($US):		($1,093,008)	($743,960)	($174,524)

As illustrated in Table A, a steam management plan for an upcoming maintenance turnaround will include calculation of process unit net steam production as well as shutdown and start-up schedules for steam generators when process plants are to be returned to service. Refinery steam demand has been calculated to be ~ 600,000 lbs / hr of HP steam.

Option A shows two steam generators offline with larger units in operation causing significant steam wastage. Over the course of the turnaround the cost can amount to over $1 million. Option B chooses three steam generators to be offline; however, the most inefficient equipment is not considered. Option C indicates a configuration where three steam generators are required to be offline during the maintenance turnaround with one being a larger more inefficient HRSG. As shown above, the costs for this scenario are much less and utility plant capacity reduced. Though calculated refinery steam production is 600,000 lbs / hr of superheated HP steam, online process plant that experience upsets during the turnaround window could instantaneously increase the demand to a value higher than the most cost effective scenario of Option C. The result is a steam header pressure falling with little choice but to take process plants offline to recover steam pressure. Planned turnarounds can range from $5 million – $30 million. Part of their budget is the planned revenue from process units that remain online during these outages. Unscheduled shut down of these plants due to steam deficiencies can have a profound affect on company profits.

2 Increased Demand for Utilities at Large Refineries

Oil refineries have expanded over the past several decades into complex, highly integrated processing systems. With increasing demand across the globe for fossil fuels as well as the increasing regulations imposed on atmospheric emissions, refineries have adopted new technologies to maintain high efficiency and reliability throughout the refining process. As these technologies are introduced into the plant, the demand for utilities becomes paramount - provide cost-effective and reliable steam, air and water to process units such to continue maintaining a competitive position in the market.

With the advent of large process unit such as diesel hydro-treaters and heavy distillate cracking units overall refinery steam production will increase as these will be net exporters of HP steam. Some cracking units can produce > 800,000 lbs / hr steam sometimes this is more than the entire utility plant itself. These process units will need large amounts of resources to keep them operating at these rates. Utility plants, aside from producing feed water for utility steam generators will have to treat, store and deliver feed water to these process units as well.

2.1 Steam Emergency Plans

Steam, air and water demand can be difficult resources to manage also. Large process units can require higher amounts of utilities during start-up mode as piping and vessels may require flushing and steam headers need to be purged and dry. Steam header pressure control will require the utility plant to produce steam at 90 – 95% of its design rate. As the demand increases to ~100% pressure control may be jeopardized. Conversely, when these large process units are online and suffer an unplanned partial or full shutdown, their net steam production will change quickly. If header pressure begins to fall, the utility plant will be required to increase steam production. Again the demand could reach ~100% of design steam production. As this correction is needed within minutes, boilers that may have been taken offline due to projected steam demand will be unavailable to assist in plant master control. Unplanned shutdown of process equipment including utility equipment may be attributed to a number of different factors. They can include operator error, equipment malfunction, local power interruption or refinery wide power interruption.

It may be necessary at this point to be able to invoke a steam emergency plan to quickly reduce refinery steam demand and return the plant master to control. Steam emergencies can be issued in phases. Phase 1 can include reduction of non-process related steam usage such as steam heaters for vessel regenerations, steam driven equipment used for maintenance, or steam reduction to storage tanks. This beginning stage is to target steam usage easily and without monetary consequences. Phase 2 includes removing steam from process units to the point when profit may be affected. Units may be shutdown or have federates reduced to allow steam demand to decrease. Still the refinery can operate, however, at a reduced rate. A Phase 3 emergency can include full scale shutdown of multiple plants to maintain steam header pressure. Most utilities are able to island themselves away from the rest of the refinery and keep minimum boilers online using reducing station vents to maintain minimum design flows through the system. Critical rotating equipment such as air compressors and feedwater pumps are usually steam driven. This philosophy continues throughout the process units as well to better mitigate such emergencies.

In these emergencies steam generating equipment must remain operating within their design parameters. As each phase is implemented process units will begin to decrease their amount of fuel they would normally send to the refinery fuel gas header. Natural gas is commonly used a supplemental source of fuel yet it may not be able to provide the system with enough fuel, consequently jeopardizing flame stability for steam generators. As these units are continuing to deliver power to the refinery grid, they also become a reliable source of heat for steam generation when the refinery fuel system is failing.

Motor control circuits, for example, will remove power to the motor windings and when power is restored these circuits will not re-start the motor. These motors are coupled to pumps, compressors and cooling fans. It is imperative to maintain power to process equipment at all times. Loss of this equipment can have serious effects in a matter of seconds as pressures and levels can increase rapidly. Mechanical pressure relief and overflow drains can have environmental consequences.

Safety Instrumented System (SIS) is designed to activate equipment to guard against these types of incidents. Controlled pressure relief to a refinery flare system and emergency shutdown valves are used to bring systems offline in a safe, controlled manner. The SIS is powered by an un-interruptible power supply (UPS) which is connected in series with the rectified DC power supply. The SIS controller should never see any power loss even when refinery power is removed.

3 Cogeneration and Steam System Reliability

Throughout the years, refineries have had great success in improving steam production efficiency; boiler combustion flue gas analysis, adapting to changing market pricing with fuel flexibility, connecting to natural gas systems, and integrating cogeneration into the steam system have decreased operating costs and improved plant reliability. Inefficient boiler and HRSG operation have been corrected with construction of cogeneration units.

3.1 Cogeneration Systems

These units can offer revenue from power production as well as produce steam from waste heat. Cogeneration plants are popular as they have thermal efficiencies of ~ 85%. Such applications are favorable in refineries as steam can be produced cheaper and more reliable energy is produced on site. This can buffer the refinery from outside electrical grid power interruptions. Transferring from cogeneration to other modes is essential to maintain constant steam production. Designing as many modes into the system will enable the refinery to comply with GTG maintenance, HRSG maintenance as well as unplanned events. Figure 3 shows a typical cogeneration system.

Cogeneration Plants can be operated in a variety of modes. Simple gas turbine generator, GTG operation can be performed through a bypass stack as indicated above. The mode is commonly referred to as simple cycle mode. The HRSG can be operated simultaneously with its fresh air fan supplying air for combustion. This is referred to as fresh air mode. Each mode by itself can prove very costly to operate. Daily price for fresh air mode can easily approach $100k if markets demand premium fuel pricing. Combining the two systems with diverters open to the GTG / HRSG and closed to the bypass stack and fresh air fan is cogeneration mode. Refinery steam costs are reduced as the waste heat from the GTG unit is used to produce steam in the HRSG. With GTG exhaust providing waste heat the HRSG can produce ~ 40% of full design capacity. Some HRSG designs may not favor these low rates as water circulation is too low. Feed water pre-heaters called economizers are rows of tubes in the back end of HRSG that heat feed water from flue gas leaving the HRSG. Low circulation of feed water results in the economizer not receiving sufficient cooling and water can change to the steam phase within the tube causing tube and support damage from rapid expansion of water. Most HRSG's require auxiliary combustion to bring the unit to its designed turndown ~50-55% of full capacity. Operation of these units in cogeneration mode usually keep HRSG's at 75 – 80% constant production, base loaded, to offload the conventional boilers. Plant master control may be better achieved if HRSG's are base loaded and boilers are varying in steam output.

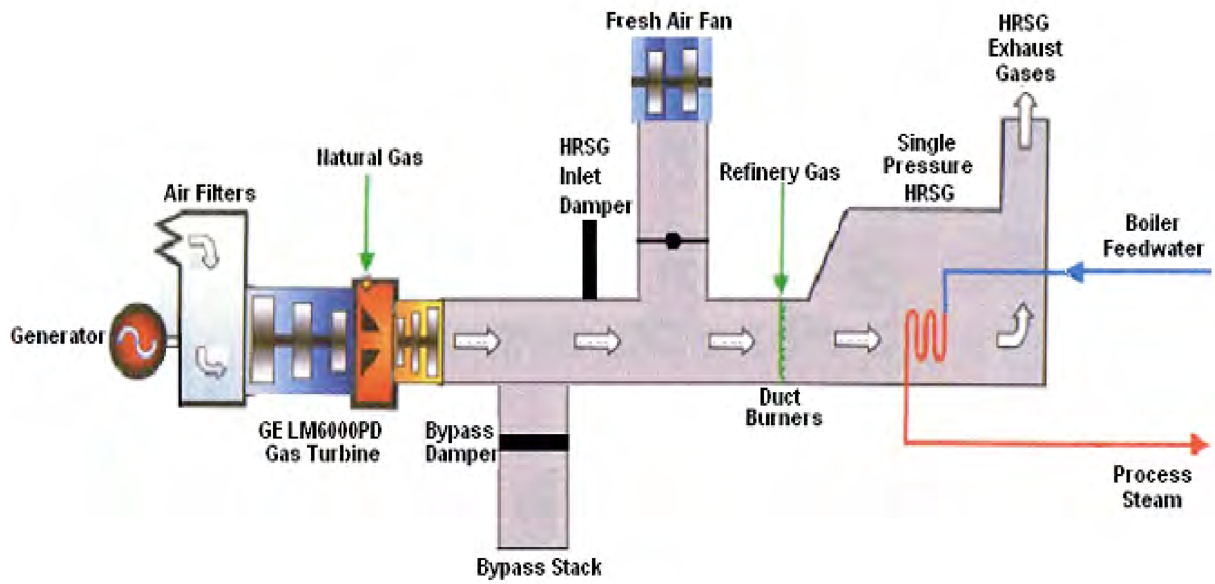

Figure 3: Typical Cogeneration Configuration

Natural gas as a supplemental fuel for refinery fuel gas can be reduced, even eliminated, with very little effect on refinery operation. Loss of natural gas to a gas turbine generator can definitely threaten operation of the gas turbine if BTU values are not within the mapping schedule of the machine. Most GTG's are connected to a natural gas supply which is sustainable via pipeline infrastructure. GTG's require compressed fuel to operate the combustor and this is achieved using natural gas compressors. These compressors are used to give the maximum amount of fuel to the GTG for power generation.

3.2 Steam Plant Management with Cogeneration

As mentioned in section 2, steam management must forecast demand over a specific operating timeline. As boilers go offline, more risk may be introduced with less steam producers available; however, HRSG's in cogeneration mode are costly to bring offline if steam production forecasts are minimized.

Table B: Steam Action Plan B

Cost Analysis For Fall 2009 Turnaround Steam System Management Options.

Asset	Normal Minimum Load (MLB/hr)	Fall T/A Minimum Load (MLB/hr) OPTION A	Fall T/A Minimum Load (MLB/hr) OPTION B	Fall T/A Minimum Load (MLB/hr) OPTION C
Boiler # 1	100	0	0	0
Boiler # 2	100	0	0	0
Boiler # 3	140	140	0	140
Boiler # 4	200	200	200	200
COGEN # 1	280	280	280	0
COGEN # 2	280	280	280	280
TOTAL:	1010	900	760	620
Steam Waste Required to Meet Min. Load (MLB/hr):		300	160	20
Cost of Steam Wasted ($US/day):		($39,036)	($26,570)	($41,233)
Net Cost to refinery ($US/day):		($39,036)	($26,570)	($41,233)
Net Cost for 4- week period ($US):		($1,092,994)	($743,957)	($1,154,524)

Table B illustrates a steam action plan similar to Table A. In this case Option C is not the most cost effective option as GTG power is under contract to sell to the municipal grid. If steam is not required the GTG must run alone which is extremely inefficient and costly. Table B shows that operating a GTG without being configured in cogeneration can cost more than operating steam generators to vent over 30% of their steam to atmosphere.

4 Cogeneration Flexibility

Over the past two decades, large refineries have seen electricity costs increase profoundly; therefore, steam generation is still needed as a basic form of motive energy. Costs included are boiler equipment capital and maintenance, water treatment, storage, and piping system maintenance. Electricity as a form of energy is less expensive to construct and maintain yet power generation alone is not cost effective due to the cost of fuel. In Atlantic Canada, natural gas has become available for industrial use since 2000 connecting provincial systems to the northeastern US pipeline. However, natural gas prices have increased substantially and made it very expensive to use as a fuel source for power generation. In a refinery, waste fuels are created as by-products of the refining process and are available as refinery fuel. Natural gas is an ideal supplemental component for refinery fuel gas but not to be used as the sole source in refinery fuel. It is the combination of natural gas and refinery fuel gas producing steam and power that create a utility system which can be highly versatile, cost effective, and in fact, most times revenue generating.

4.1 Power Generation using Cogeneration Plants

Cogeneration plants have been constructed inside major industries for decades. It has been proven a reliable and efficient means of providing the facility with affordable steam and electricity. Power can be sold to the public utility as an alternate source of revenue. Refineries with cogeneration systems would also enter into agreements to sell any excess power generated to the grid. This type of connection to the municipal system offers stability to the grid and a source of electricity should the public utility generators go offline. Refineries need highly flexible cogeneration systems to maintain reliable plant operation and continue to fulfill contract obligations by providing electricity to the public utility. Different modes and the ability to transfer between modes are required to maintain continuous operation within the refinery while adhering to power sales contracts and GTG / boiler maintenance schedules.

The mode of operation for the cogeneration plant is chosen to be the most cost effective for the conditions in the plant at that time. Unscheduled maintenance and process unit upsets may require immediate mode change. The most common modes of operation are as follows:

- Cogeneration Mode – GTG is lined up to exhaust heat into the inlet duct of the HRSG. Steam is generated from waste heat BTU’s as well as any supplemental fuel combustion using HRSG burners. The GTG is generating electricity connected to the refinery power grid and also to the municipal grid.
- Simple Cycle Mode – GTG is lined up to exhaust heat into a bypass stack to atmosphere. The GTG is generating electricity connected to the refinery power grid and also to the municipal grid.
- Fresh Air Mode – Combustion air is provided by a forced draft (FD) fan. HRSG is producing steam using burners only.

Other capabilities of a cogeneration system can include the ability to start from a no power situation (Black Start), supplying power to the refinery alone (Island mode) and generate power from natural gas supply pressure only (Run Back mode). These options can create a system which becomes a fundamental component in refinery start-ups as well as recovery from significant upsets due to process unit shutdowns or total refinery power loss.

4.2 Energy Management in Planned Events

Most GTG maintenance schedules require offline preventive maintenance every 1000 – 3000 hours of run time. Such PM work can include water washing turbine and compressor blades, borescope readings of internal hardware and generator / service transformer inspections. During these scheduled outages the refinery would need to have the ability to continue to provide steam throughout the plant.

'Hot transfer' is referred to the procedure of switching between cogeneration mode and fresh air mode. This ability is needed to impose minimum impact on steam production during the change-over. Less sophisticated means could include complete shutdown of both GTG and HRSG. Manually inserting a steel plate to block off the path of GTG exhaust, thus, allowing the HRSG to be re-started in fresh air mode. These earlier designs were cheaper to construct as they did not have to build automated dampers with burner management logic to transfer modes and still could operate a system with the economic benefits of cogeneration. Time and resources required to change modes of operation in this design can prove more costly. The change takes significantly longer as these steel plates are large and difficult to maneuver. Extra manpower and crane operation may be required. GTG outages are extended with power utilities imposing penalties if duration exceeds planned outage.

Power from cogeneration is typically connected to the refinery high voltage (HV) bus. Figure 4 illustrates a refinery power distribution system. As shown a large refinery can have two or three main substations as expansions over the years require more capacity for power.

Refinery equipment is connected to refinery bus breakers as shown in Figure 4. Voltages are stepped down to MV levels, ie. 4160V, 2400V or 600V. All electrical equipment is connected inside the motor control centers (MCC) where complete or individual electrical isolations can be performed. Well designed refinery substation and main substations allow power to be delivered to the plant through different breakers. On the HV side where the gas turbine generators are connected these main substations need to be able to provide power to the entire refinery if one generator is to be isolated for maintenance. Properly sequenced opening and closing of specific breakers allow power to cross over to opposite side of the main substation. This is achieved by the use of tie breakers. A switching sequence to isolate transformer TX 2-A may be as follows:

1. Close tie-breaker TB2-1
2. Open main breaker MB2-A
3. Open grid power breaker 1-3
4. Open grid power breaker 1-4

This procedure allows bumpless transfer of line voltage to the refinery bus 2-A and isolates all points of energy to transformer Tx 2-A. There can be a number of isolations required to perform scheduled maintenance on various pieces of equipment. Electrical configurations such as Figure 4 illustrate what breakers are required to route power through the facility and into the grid.

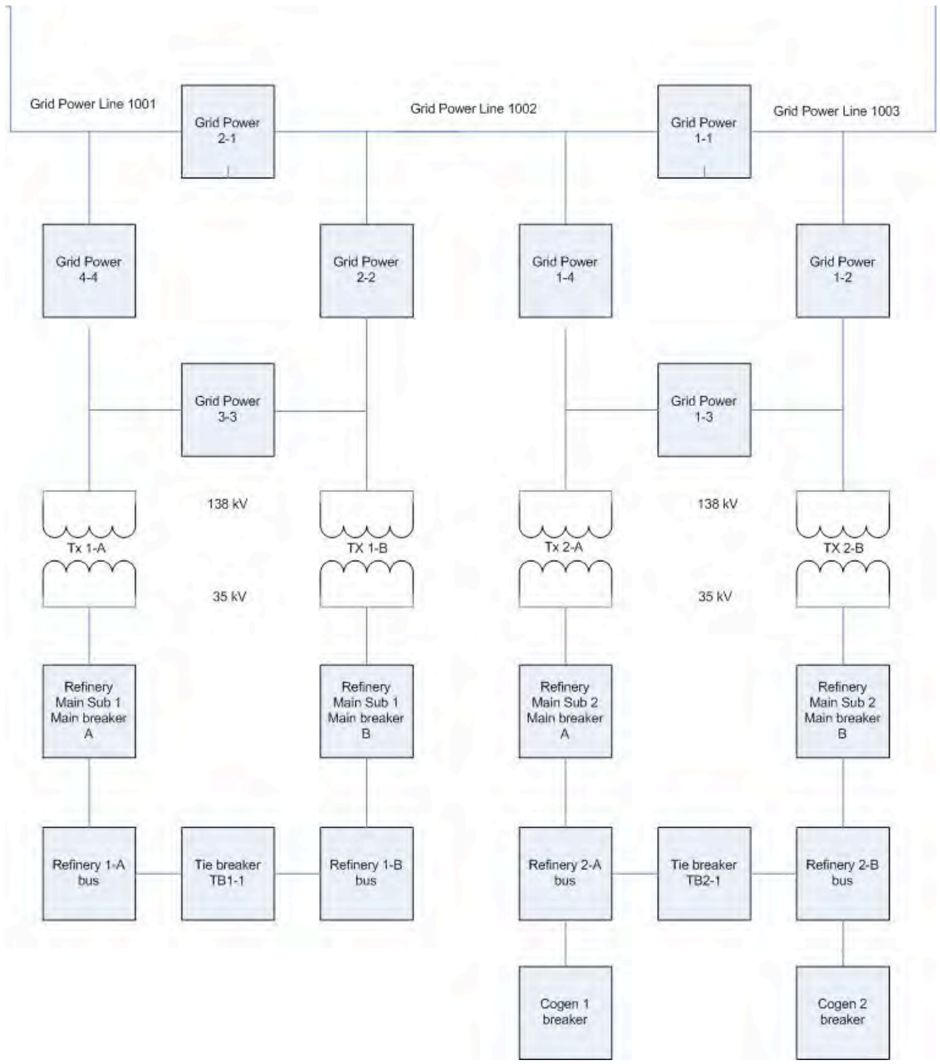

Figure 4: Refinery Power distribution System

Aside from the electrical impact GTG maintenance can have on refinery operation, the steam generation impact can be much more severe. As discussed previously, steam availability is critical for refinery operation especially in colder months. Bringing a GTG offline for maintenance requires transferring from cogen mode to fresh air mode. There is sophisticated logic programming designed to allow the HRSG to continuously generate steam while the GTG transfers exhaust heat from the HRSG inlet to the bypass stack. These controls need to monitor HRSG pressure and burner flame intensity at all times during the transfer. The FD fan replaces the GTG exhaust to provide air for combustion. Guillotine dampers are used to direct combustion air to the HRSG burners. Figure 5 shows a cogeneration system in Fresh Air mode. Notice the change in position of the dampers from figure 3. Hot Transfer procedures can take place when GTG or HRSG maintenance is scheduled. These transfers have little or no impact on the steam system. Without this type of logic, HRSG shutdown and purging would have to take place. National Fire Protection Association (NFPA) instructions require ~ 5 times the volume of the HRSG as a cold purge prior to lighting any combustion system. These times can be from 15 – 35 minutes depending on the size of the HRSG. Refinery steam systems can suffer greatly if this transfer occurs and requires cold purging. When returning to cogeneration mode, the same purge is required yet reduced as air flow from GTG exhaust is much greater. Decisions to hold off from returning to cogen mode can impact fuel costs which could amount to over $5000 per hour. Delaying transfer is usually due to steam requirements in the plant and be unable to withstand the loss of steam production. Decreasing steam demand to facilitate a transfer can also cost money as process plant may have feed rates reduced or operation altered to mitigate the loss of steam supply.

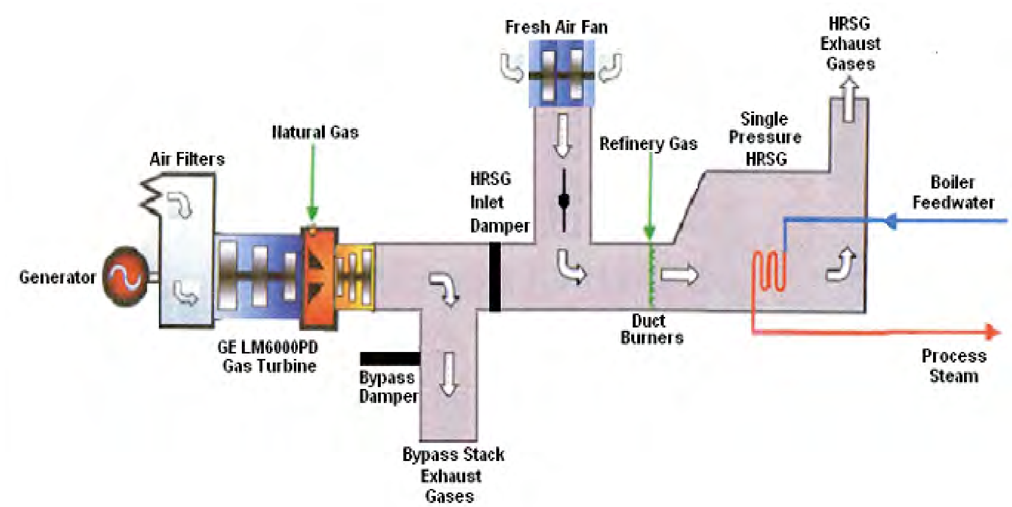

Figure 5: Typical Fresh Air / Simple Cycle Configuration

4.3 Energy Management in Unplanned Events

Power generation within a large facility plays a key role in providing reliable electricity during unstable events such as lightening storms, municipal grid fluctuations, and grid equipment failure. Steam loss in the refinery causes adjacent steam generators to increase firing to maintain pressure. Cogeneration systems are able to provide steam to the refinery header in a number of ways depending on what has unplanned event has taken place.

Loss of GTG power is not noticed on the refinery's grid as power will instantaneously change direction to flow into the system. Probability of unplanned outages due to power failures are reduced as GTG power will adjust instantaneously to supply only the refinery grid if municipal breakers open and the refinery is separated from it. GTG's are designed to govern fuel to reduce the torque on the generator rotor keeping the synchronous speed at 3600 rpm. This quick action of the governor allows the GTG to react to municipal power loss, load changes within the plant when islanded, and loss of compressed fuel to the combustor. Factors contributing to this outage can be failure of gas turbine, generator failure or associated equipment, HRSG shutdown resulting in immediate shutdown of GTG exhaust or grid voltage imbalances which relay protection circuits lock out generator breakers to protect the system.

Loss of grid power and subsequent faults on the grid will cause grid breakers to open and the entire refinery can suddenly become isolated from the municipal power grid. The “Island mode” configuration can be incorporated into the cogen system design also. Island mode requires GTG’s to only generate what is needed within the refinery. When the GTG responds to achieve this output decreases because power is no longer able to be exported from the facility. Loss in GTG output has an immediate effect on HRSG steam production. HRSG design needs a minimum amount of flow through it to properly cool the tubes. Supplemental firing will have to increase to keep the HRSG above the minimum turndown ratio. If GTG output decreases past the amount that its exhaust heat flow is too low to sustain HRSG combustion duct burners will shut down and the HRSG steam production will decrease. Island mode poses a problem to maintain steam production in the event of as power failure in a mode that can still be connected to the refinery electrical system. Cogeneration plants with two or more generators will have logic built in that ensures the frequency of the refinery grid is steady at 60Hz. To achieve this one generator is an operation that controls the frequency at 60 Hz. This is called ‘isochronous mode’. This takes care of any power demand variations within the refinery. Adjacent generators are then placed in a mode that generates constant power at a constant setpoint. This mode is commonly referred to as ‘droop mode’. A GTG in droop mode will be firing at its maximum rate to produce maximum power. When in coupled to a HRSG it will allow for full steam generation. Isochronous mode; however, does not guarantee GTG output will be high enough to sustain HRSG supplemental firing. Hot transferring to a simple cycle arrangement as shown in figure 5 can maintain full HRSG steam production and allow for changing electrical loads.

Should the entire facility suffer a complete power outage cogeneration systems must be able to come online in island mode first. In order to do this auxiliary - equipment must be in place to provide start-up utilities, mainly electricity and steam. To ensure refinery shut down and start-up is possible in a “black out” condition diesel driven emergency generators are usually situated through out the facility. This equipment is needed to provide 600V emergency power for essential equipment only. Each emergency generator is connected to an emergency board to which is connected any SIS devices, UPS power and critical equipment which impacts environment or safety. These generators should be programmed to start, stabilize and deliver emergency power in ~ 15 seconds from the time power is lost to the emergency board. As emergency power is established, at least one GTG can have its essential hardware connected to this emergency power. When the GTG is started and ready to produce electricity, it can be delivered to the refinery main bus. Steam generation can be made possible as the GTG waste heat is now available for HRSG feedwater. Steam headers can be re-established through reducing stations and atmospheric venting can begin as refinery process plants begin start-up sequences. Large refineries which suffer unplanned shutdowns can incur expenses of several million dollars per day. Black start capability will reduce down time substantially as the refinery does not have to rely on the local power grid to be available before process plant start-up can begin.

It is not always the loss of electrical power that can cause plant instability. Interruption of fuel sources can rapidly change combustion quality and even threaten burner operation in refinery heaters and steam generators. Burner Management Systems, BMS, will respond to remove fuel from combustion equipment should pressure drop below design or flame stability is threatened. HRSG BMS may activate and trip supplement firing; however, GTG exhaust may still continue to provide heat for steam generation. Loss of natural gas compressors during normal operation of the plant can cause serious collateral events possibly resulting in steam emergencies and refinery shutdown. GTG combustors are programmed with 'run back' logic which allows the fuel pressure to be reduced to supply pressure and still operate to produce waste heat and power. The programming of the combustor will stage the gas turbine down in output to a value that is still greater than the minimum requirement for supplemental firing for cogen mode. This lower GTG output may produce less power for export but will not have an effect on steam production or power generation as the grid power can be instantaneously aligned to import power should demand exceed what is being generated. Run back logic should be tested annually.

5.0 Future Considerations

As power generation within any facility becomes more reliable in even the most abnormal circumstances, a shift to more electrical driven equipment may occur. Large steam driven turbines up to 40,000 HP require significant amounts of steam for start-up. Ensuring steam dryness is critical to avoid damage of turbine blades and other equipment. Venting large amounts of steam initially is usually performed to bring steam to superheated temperatures thus eliminating any condensate. Steam generating equipment must be able to deliver steam during these pre-start up exercises which can last for several hours. Boilers and HRSG steam equipment are expensive to maintain and are under government regulation to operate. A large portion of a maintenance budget can be allotted to boiler maintenance as a large refinery depends on its resource. A cogeneration system can provide the electrical power needed to augment steam driven with motor driven. Large motors can be brought online without any steam requirement. As refineries shift their operation to rely heavily on motor driven equipment, the focus also shifts from steam generation to power generation.

5.1 Additional Cogeneration Equipment

In order to become more self sufficient in power generation multiple cogeneration units can be built. HRSG firing can be controlled by plant master controllers which vary the amount of supplemental fuel to maintain steam header pressure. The control is programmed to allow the HRSG to reduce firing to the minimum designed turndown in cogen mode. At low steam demand, GTG's can hot transfer to simple cycle mode and HRSG's can be taken offline. Multiple cogeneration units build upon power generation contracts to supply electricity to the municipal grid to produce revenue. Such cogeneration systems configured as previously explained are very expensive to operate in simple cycle mode and over a long term of operating in this mode can negate any profits forecasted.

5.2 Combined Cycle Plants

In order to use the steam generated in a cogeneration system a full condensing steam driven turbine can be connected to the refinery steam header to consume any excess steam produced. This steam turbine if connected to a generator can also be a power producer. This type of arrangement is known as Combined Cycle operation. Figure 6 illustrates a typical combined cycle plant.

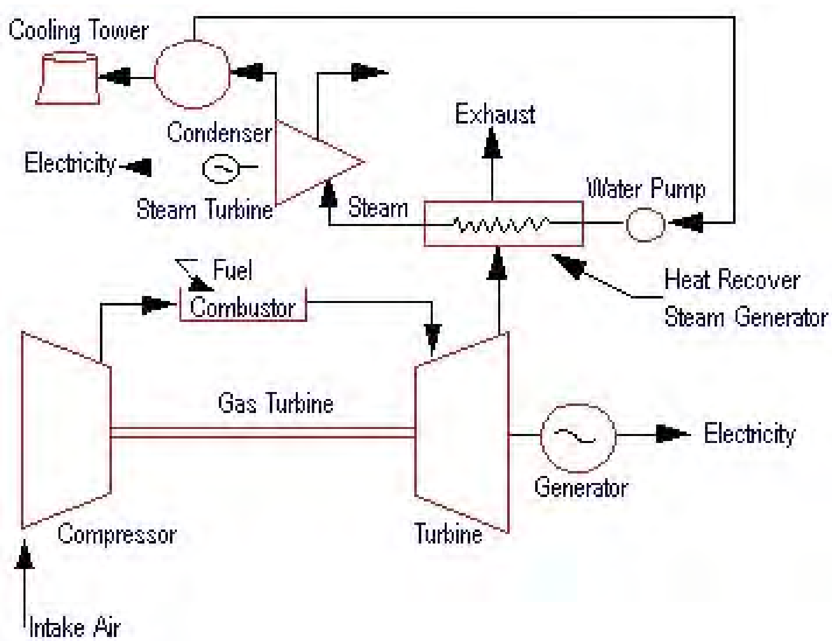

Figure 6: Typical Combined Cycle Plant

Combined cycle plants are highly efficient as they greatly reduce the need for simple cycle mode. Multiple units are online with the valve to the steam turbine generator controlled by the plant master. As refinery steam demand increases, the valve will decrease output to keep steam for process use. As refinery steam demand decreases the steam valve will increase output and send steam to drive the generator and produce electricity.

5.2 Turbo Expanders

Turbo expanders or Power Recovery Turbines (PRT's) are commonly installed in refinery catalytic cracking units as a cost effective means to drive rotating equipment. They operate using waste heat from the process as it is exhausted into the air similar to a gas turbine. Efficiencies can reach 98% which is 15 – 25% higher than a cogen unit. Turbo expanders can have equivalent greenhouse benefits in reducing CO_2 emissions as the power it produces offsets the requirements for cogen or import power. Figure 7 is a turbo expander in a fluid catalytic cracking unit (FCCU).

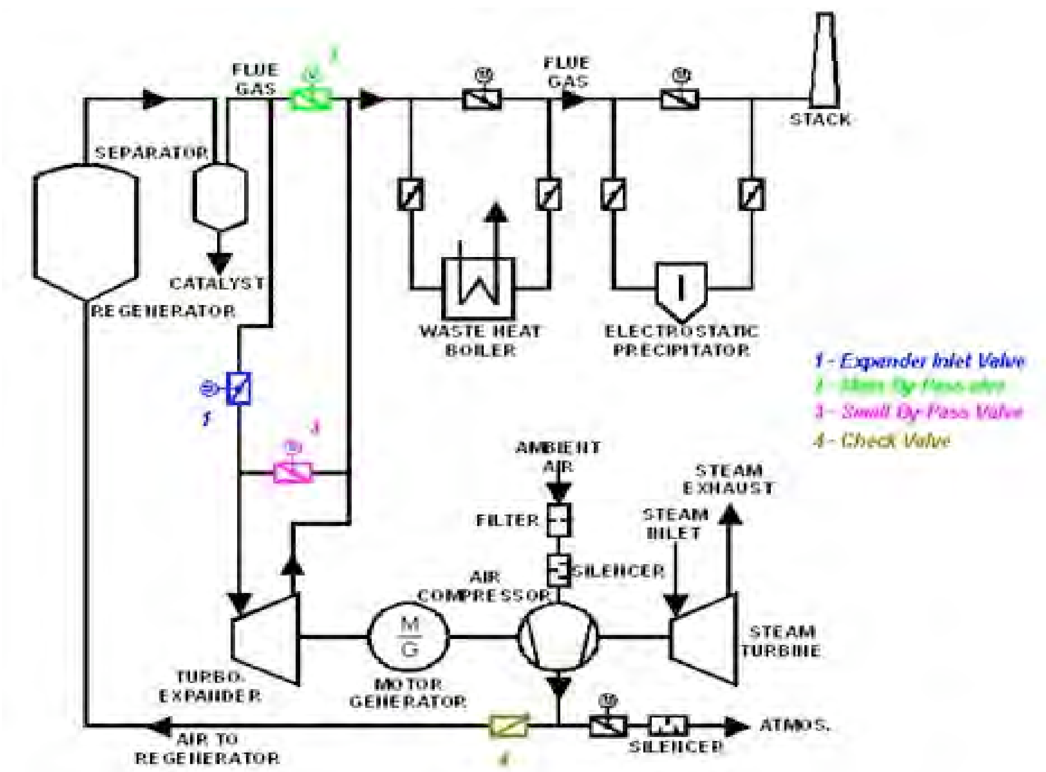

Figure 7: FCCU Turbo Expander

The majority of FCCU turbo expanders in North America are built as integrated "power train" arrangements. The FCCU main air blower equipment is driven by a back pressure steam generator and a motor / generator coupled together on the same shaft. This power train allows transfer of the turbo expander energy to the MAB at almost 98% efficiency. Turbo expanders can supply 85 – 115% of the horsepower required by the MAB. The motor / generator can take care of the shortage or excess power.

6.0 Recommendations

Any large facility requires steam and power are most competitive when these utilities can be available continuously. It is not an option to take utility plants offline without a steam and power management plan. As oil refineries have evolved through the decades new equipment configuration introduced have aided in reliability and increase revenue for utility systems that are usually considered a liability rather than an asset.

When such utilities are lost process units in a refinery will suffer downtime. These unplanned outages can have serious environmental and monetary consequences. Costs to have some plants offline can easily exceed $1 million per day. Refineries with multiple steam generation equipment begin to benefit from their flexibility to continue to provide steam to the plant during planned events such as scheduled maintenance and unplanned outages caused by severe weather or equipment failure. Cogeneration systems allow steam and power to be available during these same conditions and increase profitability for the facility. Designing these systems with the ability to remain online during any event is why refineries are willing to make the initial investment in cogeneration.

New technology has allowed steam management to continue to evolve also. Combined cycle plants have more options to use excess steam to turn steam driven generators and continue to generate power for export. Turbo expanders take advantage of waste heat from process plants to drive high horsepower machinery. These turbo expanders can also couple to generators and deliver electricity to the plant as well as export to the grid.