Reducing the CO2 Footprint: Employing Cogeneration to Improve the Energy Efficiency of Thermal Oil Recovery Projects

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Abstract

Thermal recovery technologies such as Cyclic Steam Stimulation, Steam Assisted Gravity Drainage and Steam Flood are extremely energy intensive, requiring the combustion of fossil fuels to produce the steam and resulting in emissions of carbon dioxide and other pollutants. Newer technologies such as Solvent Extraction may also require the injected medium to be heated to maximise oil recovery from the reservoir.

Thermal projects often generate the heat and power required in separate facilities, with the electricity often being supplied from remote central generation facilities. In many cases it may be possible to integrate a cogeneration plant into the process. Using a single, suitably sized on-site Cogeneration facility, a locally available fuel can reliably provide both the power and heat required for the project, achieving overall energy efficiency to levels in excess of 75%, while helping to reduce the global CO₂ footprint of the Oil & Gas industry and reducing reliance on imported electrical power. The design of Cogeneration plant can also help ensure maximum availability and uptime of production facilities.

In most cases the heat produced by a Cogeneration plant is a by-product of electricity production, but it is also possible to utilise waste heat from some processes to produce useful energy. Waste gases from processes are also potential fuels for a Cogeneration plant, helping to reduce or eliminate gas flaring, and improve environmental performance across the whole oil production chain.

There are numerous different ways to configure a Cogeneration plant depending on the type of fuel available and the ratio between power and heat required by the project. This paper will examine some of the different Cogeneration plant configurations and fuel options using Gas or Steam Turbines, or a combination of both, that could be applied to a thermal recovery project to maximise energy efficiency and plant availability.
Introduction

The production of heavy oil, extra heavy oil and bitumen using steam-based Thermal EOR technologies is energy intensive. As well as the fuel required in boilers to produce the steam required, there is also the electrical energy required to drive pumps and compressors, power control systems etc. In many instances, thermal projects have their own on-site steam generation facility and purchase electricity from an external supplier, who in most instances uses fossil fuels to generate electricity.

Both steam and power generation from fossil fuels result in carbon dioxide (CO₂) emissions. Typically a boiler is around 80% efficient, whereas a typical fuel mix in power generation gives a fuel to electricity efficiency of between 35 and 40% depending on the age and type of the power plant – while a modern gas-fired combined cycle plant may achieve close to 60% efficiency, an old small to medium sized coal-fired plant may only achieve 30% efficiency or less. In addition to the losses involved in power generation, there are also losses in the electricity transmission and distribution system which have to be taken into account.

In the figure above, it can be seen that for independent production of electricity and steam, potentially only 55% of the energy contained within the fuel is converted into the energy required at the production facilities. As CO₂ emissions are proportional to fuel efficiency, this creates a large carbon footprint for the heavy oil recovery industry. In addition, the oilfield operator has no control over the fuel mix used to generate electricity, as coal-fired power stations emit far more CO₂ per MWh of electricity generated than gas-fired power plant. Within the European Union for example, the CO₂ emissions per MWh of electricity generated vary between 0.023 tonnes/MWhₑ (Sweden) and 1.191 tonnes/MWhₑ (Poland), with an average of 0.46 tonnes per MWh.

Figure 1: Typical scenario for independent production of Electricity and Steam

Figure 2: Emission factors for fuel combustion (tonnes CO₂ per MWh)
Energy efficiency can be improved by employing on site Cogeneration – the simultaneous generation of heat and electricity from a single primary fuel source – as shown in Figure 3 below. Not only does Cogeneration greatly increase the overall energy efficiency – the example shown achieving around 80% efficiency – with the subsequent reduction in global CO2 emissions, it also provides a degree of security of supply of electricity as the site is no longer vulnerable due to outages in the external power supply network. The operator can also choose the most suitable fuel or fuels, based on on-site or local availability, which could possibly reduce the carbon footprint of oil production by thermal processes still further, as well as offering the operator operational cost savings. However, it needs to be borne in mind that while Cogeneration can reduce the ‘global’ CO2 footprint of heavy oil production, it will increase the ‘local’ CO2 footprint and will generally produce increased local levels of emissions associated with combustion, such as oxides of nitrogen and carbon monoxide, compared to a boiler only solution for steam production.

![Figure 3: Typical Scenario for Electricity and Steam Production at a Cogeneration Plant](image)

Cogeneration systems are typically based on two basic types of power cycles – bottoming or topping. A bottoming cycle is one where the fuel is primarily used to provide process heat with waste heat from the process recovered to generate electricity, while a topping cycle utilises the primary energy source to generate electricity with the rejected waste heat captured in the form of useful thermal energy and supplied to the process. Cogeneration schemes in thermal EOR applications tend to be based on the topping cycle, although these can be sub-divided into 2 types: electricity match or heat match. However, it is also possible to employ back-pressure steam turbines using the bottoming cycle concept.

**Cogeneration Plant Configurations**

There are several technologies which can be used as the source of heat and power in a Cogeneration plant, but for installations requiring steam the most common two prime movers are Gas Turbines and Steam Turbines. The selection of the optimal
technology depends on the ratio of heat energy to electrical energy required, but must also take into account any local operational limitations such as water quality, personnel expertise etc. Open Cycle Gas Turbines, back-pressure Steam Turbines, Steam Turbines with steam extraction and even Combined Cycle configurations can all be considered in the drive to optimize the efficiency of energy production.

Figure 5: Simple Cogeneration Schematics for Gas Turbines and Steam Turbines

The most common Cogeneration technology used in thermal recovery processes is the Gas Turbine. A modern industrial Gas Turbine in the 5 to 50MW power range has an electrical efficiency between 30 and 37%. Most of the ‘wasted’ energy is contained within the exhaust gas stream, so there is considerable scope to recover this heat to produce steam in a Waste Heat Recovery Unit (WHRU). This simple configuration gives overall efficiencies in the range of 75% to 85% depending on the Gas Turbine and steam pressure required. The steam production, and overall energy efficiency, can be boosted by adding a duct burner in the exhaust system between the turbine and the WHRU – in some cases the amount of steam produced can be doubled and energy efficiencies of over 90% achieved. Figure 6 below illustrates the typical steam production achievable for Siemens’ range of Light Industrial Gas Turbines in both fired and unfired configurations.

Figure 6: Typical Gas Turbine Steam Raising Capabilities

However, in many thermal recovery applications, it is usual that even with supplementary firing installed, a gas turbine cannot exactly match the electrical load required and provide all the heat required. This gives the Operator a choice of whether to install a heat-matched system or an electricity-matched system. In a heat-matched system, the Gas Turbine is selected based on its ability to provide all the heat required, which means that it is likely to generate far more electrical power than the production facilities themselves require. This necessitates the export of surplus electrical power to the local power network.

an electricity-matched system, the Gas Turbine is selected to provide just the power required by the production facilities, while the shortfall in steam is made up by installing additional conventional fired boilers.

An alternative to a Gas Turbine-based Cogeneration plant is to use a back pressure Steam Turbine. Conventional fired boilers can be used to produce the steam, but at a higher pressure than required for distribution across the site, with the steam passing through a back pressure Steam Turbine, which generates electricity while reducing the steam pressure to that required for distribution to the wellpads. As 100% of the steam produced passes through the Steam Turbine, the scheme is heat matched to the site’s steam requirements, while producing a large proportion of the electricity required by the facilities. It is possible using Siemens’ SST range of Steam Turbines to operate on saturated steam, with no requirement for any superheat, keeping the steam system simple and minimizing cost impacts of installing Cogeneration. As an indication, a steam flow of 20,000 kg/h of saturated steam entering a Siemens’ SST-600 Steam Turbine at 140 Bara and exhausting at 66 Bara can generate just over 5.7MW of electricity, greatly reducing the amount of electricity purchase necessary from a 3rd party supplier with minimal impact on the steam system design.

A third alternative is to use both turbine technologies in a Combined Cycle configuration. One or more gas turbines could be combined to produce steam for a back-pressure steam turbine, to maximise power generation while still providing the necessary process heat. Stand-alone fired boiler(s) would ensure process steam availability in case of a gas turbine outage.

Figure 7: Schematic showing possible Combined Cycle with Cogeneration configuration
Fuel Choices for a Cogeneration Plant

While a wide range of fuels can be used to fuel a Cogeneration plant, the choice has an impact on the overall efficiency, CO₂ emissions, capital costs and operating costs.

‘Pipeline quality’ natural gas is the most common choice. A clean-burning fuel and competitively priced fuel, consisting mainly of methane (CH₄), it produces the least CO₂ emissions per MWh of electricity generated of any fossil fuel. Dry Low Emissions burners in both Gas Turbines and Boilers mean low local emissions of oxides of nitrogen (NOₓ) and carbon monoxide too (CO). Natural gas is therefore the preferred fuel for both Gas Turbine- and Steam Turbine-based Cogeneration plant. However, in more remote locations it may not be possible to obtain a supply of ‘pipeline quality’ natural gas, or it may require considerable investment to build the necessary infrastructure to deliver supplies.

Oil production usually also means production of associated gas, a raw untreated natural gas which can contain constituents not found in ‘pipeline quality’ natural gas. Such gases are often considered a nuisance, and traditionally have been flared with significant environmental impact, but could in fact be a low cost source of fuel. Associated gases can be lean (high content of inerts such as nitrogen, N₂, and carbon dioxide), rich (high content of heavier hydrocarbons such as propane, butanes and pentanes), and sour (containing hydrogen sulfide, H₂S). Such gases are locally available, but need additional, and often costly, treatment to bring them to a specification suitable for sale. They therefore could be used as a fuel for a Cogeneration plant, but their specification could lie outside the range of gas fuels acceptable in the Dry Low Emissions (DLE) combustion systems of Gas Turbines, creating potential regulatory issues if stringent emissions legislation is applicable. To overcome this issue, Siemens have developed DLE combustion systems for their Gas Turbines that can accept a wide range of associated gases and still meet applicable emissions limits for NOₓ and CO in almost all parts of the World. It should be noted though, that while Gas Turbines, and boilers, are tolerant to certain levels of H₂S in fuel gas, combustion of H₂S results in the creation of oxides of sulfur (SOₓ) and if sulfur emission limits are in place, the only way to ensure compliance is to remove the sulfur prior to combustion. Therefore, if available in sufficient quantities, associated gas can offer the similar benefits to natural gas but with additional economic and local environmental benefits. If insufficient associated gas is available to provide all the fuel required for the Cogeneration plant, it can be blended with ‘pipeline quality’ natural gas.

Liquid fuels, such as diesel or kerosene, can also be used to fuel a Cogeneration plant, although these are relatively expensive and would require transportation to site in large quantities. It is not usually economic to use liquid fuels as the main Cogeneration plant fuel, nor would a large reduction in carbon footprint be achievable due to the high carbon content of the fuels, although it is relatively common to use liquid fuels as a ‘standby’ fuel in case of loss of gas supply, or non-availability of gas in the commissioning phase of a project if associated gas is envisaged as being the main fuel. Siemens’ Gas Turbines can be equipped with dual fuel DLE combustion systems, able to minimize local emissions of NOₓ and CO on both gaseous and liquid fuels. For some Gas Turbine models, such as the Siemens SGT-500, it is possible to compensate for lack of gas fuel by bi-fuelling – the simultaneous use of both gas and liquid fuels, although there are usually minimum levels for each fuel and a minimum power output at which bi-fuelling can be used.

In some of the more remote locations where thermal recovery techniques may be employed, the availability of ‘premium’ fuels such as natural gas or diesel can be a huge problem, and the solution to supply issues is to use a proportion of the crude oil produced as the fuel to provide both power and heat. While a boiler / steam turbine-based solution is generally used in this situation, there are a small number of Gas Turbine models, including the Siemens SGT-500, that are able to operate with treated crude oil as the main fuel.

In certain circumstances, the use of process wastes, such as asphaltenes from the Upgrading process, may be considered as a boiler fuel for a Steam Turbine-based Cogeneration plant. Depending on the size of the Cogeneration plant and the amount of locally available material, biomass-based wastes may also be considered as a boiler fuel. The use of biomass, being generally regarded as a carbon neutral fuel, would reduce the carbon footprint of heavy oil operations below the levels achievable using any fossil fuel. It is possible to gasify materials such as asphaltenes and biomass to create a suitable gas fuel for a Gas Turbine, but this is a costly option and would normally only be economically viable on very large Cogeneration schemes.

Improving Energy Efficiency through Waste Heat Recovery

Within thermal production facilities, there are also opportunities outside of a central Cogeneration plant to utilize waste heat from the processes to generate electricity – the so-called bottoming cycle referred to earlier. Within heavy oil production facilities, there are two obvious areas where this can be achieved: in an on-site Upgrader, and in place of a steam pressure reduction valve.

The Upgrading process overall is an exothermic process, and waste heat can be recovered to produce steam for use elsewhere within the facility. If a central Cogeneration plant is installed, this steam can be fed to a central Steam Turbine-based
Cogeneration plant to boost the electrical power output, or a separate steam turbine could be installed.

On many thermal EOR schemes, it is usual to generate steam in a central facility and then distribute the steam at relatively high pressure to the wellpads, where the steam pressure is reduced by using a pressure reduction valve before injection into the reservoir. The steam energy released during the pressure reduction across the valve is simply wasted. By replacing the pressure reduction valve with a small back pressure Steam Turbine, it is possible to generate additional electricity. In some cases, the wellpads are located a considerable distance from the central facilities, requiring an electrical power distribution system to be installed over several kilometers: utilizing energy otherwise wasted from pressure reduction could generate enough electricity to satisfy the power needs of the wellpad. For example, for saturated steam flows between 30,000 kg/h and 80,000 kg/h, reducing the steam pressure from 42 bar to 30 bar across a Siemens SST-060 Steam Turbine could generate between 70kW and 700kW.

Even if only small quantities of heat are required by the processing facilities, and no conventional Cogeneration system is installed or is economically viable to install, it may still be possible to improve the overall energy efficiency of a plant by utilizing Organic Rankine Cycle (ORC) systems to turn waste heat from the power generator into electricity, a variation on the conventional combined cycle system. ORC systems use organic fluids as the heat transfer medium rather than water / steam, and so can recover energy from low-grade heat sources. Data from ORC system suppliers indicates that it is possible to generate 1kW of electricity for every 10hp of engine horsepower, reducing CO2 emissions by 1 tonne CO₂e per year for every 1hp of engine horsepower.

The ability to recover energy and generate electricity from low-grade heat sources also opens up the possibility of replacing process coolers with ORC systems to improve energy efficiency. At present, around 100°C appears to be the minimum temperature for heat recovery using an ORC system.

By combining a central Cogeneration facility with waste heat recovery potential throughout the process, it is possible to maximize the total energy efficiency of the facility and minimize its carbon footprint.

Conclusions

On-site Cogeneration can play a significant role in reducing both the local and global environmental impact of thermal oil recovery processes, as well as contributing to the energy security of the facilities, maximizing uptime and production revenues. With the range of power generation technologies and fuel possibilities available, Cogeneration can make a significant contribution to reducing the global CO2 emissions of the oil industry when calculated on a ‘wellhead to wheels’ basis.

References

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