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TURBOMACHINERY HYDROCARBON LOSS RECOVERY SYSTEMS

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Abstract

Recovery and valorization techniques of hydrocarbon/waste gases associated with turbomachinery represents one of the many challenges the industry must face to meet the increased regulatory controls limiting hydrocarbon emissions that are progressively intensifying.

The main hydro-carbon release sources of a typical turbo-compressor unit are:

- *The pneumatic starting system (a gas expander used to start the gas turbines where the pressurized process or fuel gas is used as motive fluid)*
- *The process gas trapped inside the centrifugal compressor loop that is vented in the environment during a prolonged shutdown (e.g. a shutdown aimed at a major overall maintenance activity)*
- *Centrifugal compressor dry seal gas (DGS) primary vent (a small but continuous loss of process gas in the environment).*

The solutions developed to cope with the existing assets require a design that promotes technical and economic viability, maximizing the environmental benefits.

In this paper, a set of solutions for the recovery of wasted gases listed above is presented and discussed in detail. Its integration with gas valorization systems and existing gas processing lines is also described. Some selected cases, providing both the technical and the economic feasibility are also analyzed.

Within the description of the solution, focus is put to the following key activities:

- *Revamping of existing equipment to resolve inefficiencies*
- *Preventing waste gas losses through adoption of dedicated recovery solutions*
- *Integration of recovered gas into either existing processes or valorization systems*

Emission control rules are progressively becoming more and more stringent, limiting the atmospheric release of hydrocarbon gases. These requirements have triggered the development of new technical solutions to limit even small gas streams typically neglected in the past.

The presented solutions are designed to maximize the positive impact in the wasted gas reduction and to be economically viable, contributing to reach the desired environmental sustainability target.

Oil and gas operators, and industry in general, have a growing interest in eco-friendly solutions.

Introduction

The cleanest burning fossil fuel is the natural gas that is mainly composed by Methane.

Methane produces more heat and light energy by mass than any hydrocarbon, or fossil fuel, including coal and gasoline, providing a great environmental benefit as it produces remarkably less carbon dioxide and any pollutants that contribute to unhealthy air. As natural gas is used, as substitute of coal and to generate electricity or in lieu of gasoline to fuel cars, trucks and buses, the less greenhouse gas emissions and smog related pollutants are produced.

Nevertheless, un-combusted methane released into the atmosphere is environmentally unfriendly. In fact, methane contributes to climate change due to because it traps heat in the atmosphere. Although methane's lifespan in the atmosphere is relatively short compared to those of other greenhouse gases, it is more effective at trapping heat than are those other gases.

This brings the concept of Global Warming Potential (GWP), a measure of how much heat a greenhouse gas traps in the atmosphere up to a specific time horizon, relative to carbon dioxide. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide and is expressed as a factor of carbon dioxide (whose GWP is standardized to 1).

In a span of hundred years the GWP of Methane is about 28 [1] or, in other words, along 100 years a ton of CH_4 traps 28 times more heat than a ton of CO_2.

Although there are natural processes in soil and chemical reactions in the atmosphere that help to remove methane from the air, it is important for all human activities releasing methane to the atmosphere to be conducted in ways that reduce their methane emissions. This includes the development of processes to capture methane that would otherwise be released to the atmosphere and use it as a fuel or recycle into the process.

In recent years, the regulatory framework has spread market instruments to reduce carbon emissions such as the carbon pricing (CP), a cost applied to carbon pollution to encourage polluters to reduce the amount of greenhouse gases they emit into the atmosphere. It usually takes the form of a carbon tax or the obligation to issue emission permits, generally known as carbon emissions trading.

To date, 57 carbon pricing initiatives have been implemented or are scheduled for implementation. It consists of 28 emissions trading systems (ETSs), and 29 carbon taxes primarily implemented on a national level. These carbon pricing initiatives would cover 11 gigatons of carbon dioxide equivalent ($GtCO_2$ e) or about 20 percent of global greenhouse gas (GHG) emissions [2].

Thanks to the CP initiatives, the recovery and valorization of small amount, compared to the main process stream entity, of hydrocarbons leakages is now becoming economically

viable, which was not the case in years past. There is in fact a favorable environment to explore systems and methods to reduce the turbomachinery carbon foot print.
About this last subject, hydrocarbon capture and valorization methods, the so called “recovery systems,” aimed to recycle/valorize the turbomachinery process leakages rather then send it in atmosphere or flare, will be described within this paper.

The main hydro-carbon release sources of a typical turbo-compressor unit are:

- Centrifugal compressor dry gas seal (DGS) primary vent (a small but continuous loss of process gas in the environment).
- The process gas trapped inside the centrifugal compressor loop that is vented in the environment during a prolonged shutdown (e.g. a shutdown aimed at a major overall maintenance activity).
- The so called pneumatic starting system for gas turbines (a gas expander used to start the gas turbines where fuel gas is used as motive fluid).
- The so-called fuel gas warm up system for gas turbines (a fuel gas that flows across fuel piping and then diverted into atmosphere upstream the shut off valve in order to heat fuel gas piping materials).

Dry Gas Seal (DGS) Primary Vent leakage Recovery Systems.

The DGS primary vent could be recovered by reinjecting it in the compressor process loop itself, preferably into the suction side, the fuel gas system or any other low-pressure hydrocarbon line whether present in the plant.

In some cases, the DGS primary circuit is buffered with Nitrogen (N_2), thus the vented gas is composed mostly by Nitrogen (~90%), as a result the only gas valorization is through re-injection, while no combustion is possible. Re-cycling might be possible only if small N_2 contamination can be accepted.

The recovery method mainly depends by the pressure of the destination source and they could be roughly split for destination pressure lower that 2 bar-a, lower than 6 bar-a and for higher pressures.

<u>OPTION 1: Suction pressure lower than 2 bar-a</u>

In this case the primary vent lint is reinjected directly into compressor suction through the usage of piping and valves. The primary vent of all compressors on the same shaft (providing the service application is the same) can be commonly collected into a same header and through a control valve is re-injected into the Compressor suction, preferably upstream the suction scrubber. The pre-existing line to atmosphere (ATM) (and or flare) shall be kept in order to re-direct primary vent into ATM (or flare) during off design conditions or in general when the suction pressure will grow up above 2 bar-a.

This system is applicable also injecting the primary vent into a hydrocarbon line with a pressure lower than 2 bar-a whether present at site.

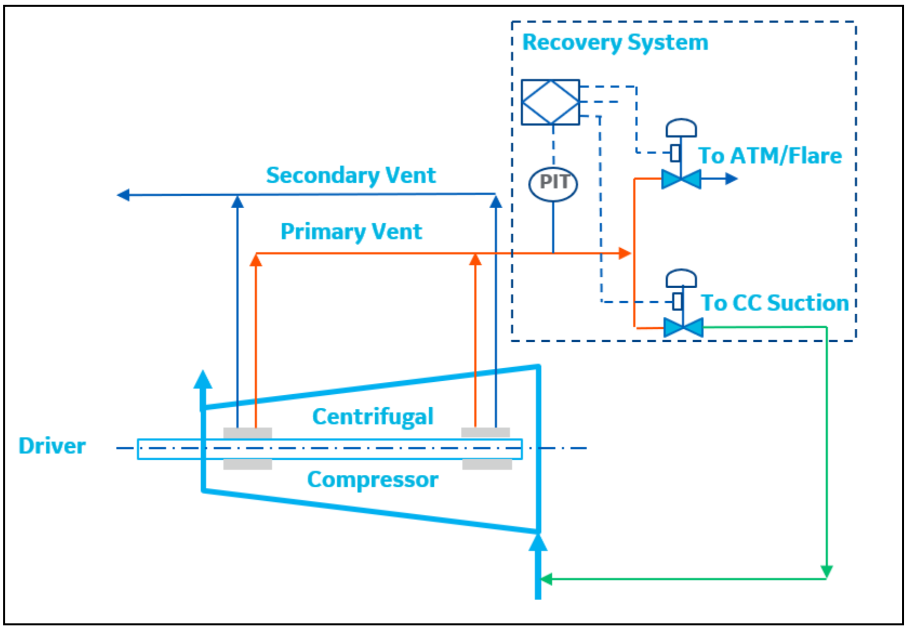

Figure 1 Simplified schematic diagram of a dry gas seal primary vent recovery system with reinjection on CC suction (suction pressure <2 bar-a). Copyright 2019 Baker Hughes, a GE company, LLC ("BHGE"). All rights reserved.

<u>OPTION 2. Suction pressure lower than 6 bar-a</u>

If the centrifugal compressor suction pressure is within 6 bar-a, the primary vent is reinjected into the compressor suction itself through a pump jet (ejector). The pump jet will use a spilled flow from compressor discharge as motive fluid, preferable extracted from primary seal gas buffer line downstream seal gas filter. The ejector suction side shall be connected to the primary vent and the ejector discharge to the Compressor suction, preferably upstream to the suction scrubber. Since the pump jet is usually designed to work in only one process condition, a recycle line and backpressure regulator valve shall be foreseen to accommodate the seal gas leakages flow variations. The pre-existing line to atmosphere (and or flare) shall be kept in order to the redirect primary vent into ATM (or flare) during off design conditions or in general when the suction pressure will grow up above 2 bar-a.

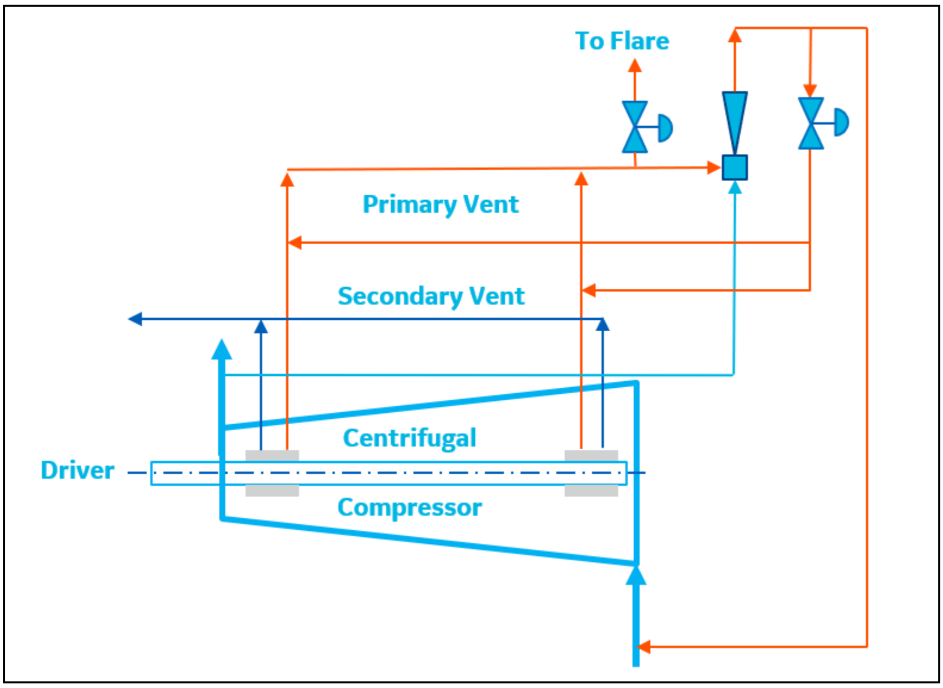

Figure 2 Simplified Schematic diagram of a dry gas seal primary vent recovery system with reinjection on CC suction (suction pressure <6 bar-a).

OPTION 3. Suction pressure higher than 6 bar-a or injection into fuel gas circuit

If the suction pressure of the centrifugal compressor is higher than 6 bar, it is difficult to re-pressurize the primary vent leakage with means other than a booster compressor, preferably of volumetric type.

Using a compressor, the leakage can be re-injected into the fuel gas system (if the process gas is suitable as fuel), preferably upstream the fuel scrubber, or into compressor suction header.

Dependently by the destination pressure the compressor could be with one or more intercooled stages and usually the absorbed power is within 20 kW.

The pre-existing line to atmosphere (and or flare) shall be kept in order to the redirect primary vent into ATM (or flare) during off design conditions, booster maintenance activities or in general when the booster is not running when is supposed to.

This system is also applicable when pumping the primary vent into a hydrocarbon line if it is present on site.

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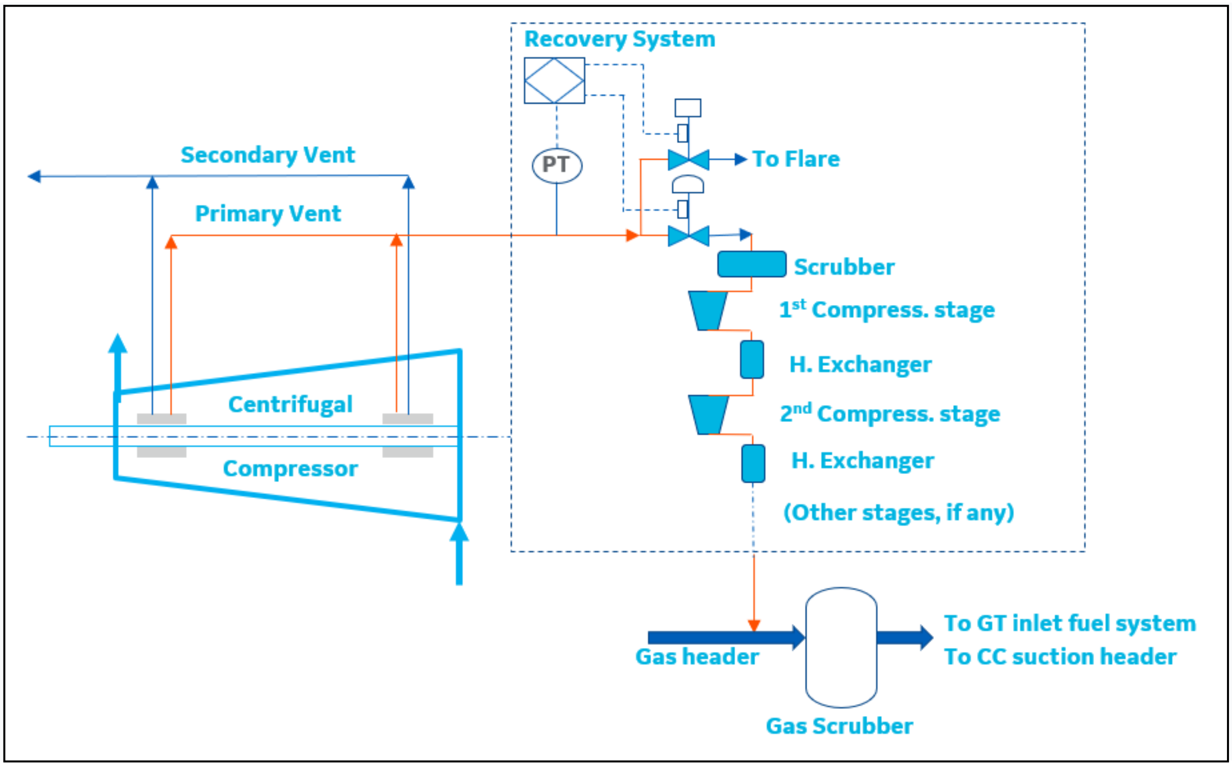

Figure 3 Simplified schematic diagram of a dry gas seal primary vent recovery system with reinjection on CC suction or GT inlet fuel System (suction pressure ≥ 6 bar-a).

Centrifugal Compressor Gas Loop Recovery System

Every time the compressor is stopped for maintenance activities or in general for a lengthy shutdown, the gas entrapped between the isolation valves (suction and discharge ones) will be vented in ATM or burned in flare.

The gas inside the centrifugal compressor loop could be many thousands of cube meters because it is pressurized at the settle out condition (an intermediate pressure between suction and discharge), and moreover, this type of gas release in the atmosphere could happen many times during the year depending on the way the process plant is operated.

It is possible to use a booster compressor to pump this gas entrapped inside the compressor loop in stand still condition, toward the plant suction header, helping to avoid venting to the ATM.

It is also possible, if the gas composition is suitable as fuel, to recycle it into a fuel gas system of a turbine or a boiler.

The booster compressor is sized to empty the compressor loop up to a determined pressure (even up to 1.3 bar-a) in a certain time (normally 2÷12 hours). The final empty pressure depends by the recovery necessity of the plant end-user while time may depend by several operation and process constraints. E.g. the in cold environments the compressor loop shall be emptied before the entrapped gas temperature will drop below a certain value for reducing the chances of condensing water or heavier hydrocarbons. In most cases, the booster absorbed power is not higher than 75 kW.

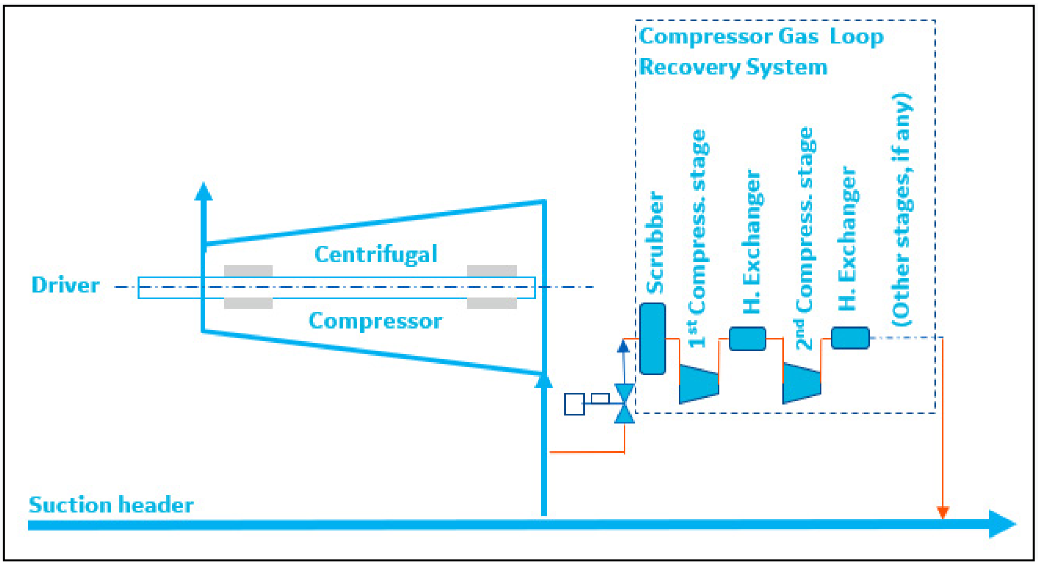

Figure 4 Simplified schematic diagram of CC gas loop recovery system. Copyright 2019 Baker Hughes, a GE company, LLC ("BHGE"). All rights reserved.

<u>Solution 1 Combined Recovery System (centrifugal Compressor Gas Loop and DGS primary vent leakage)</u>

A booster compressor sized to recover the Centrifugal Compressor Gas Loop is more than an order of magnitude, in terms of flow rate, bigger than a booster sized to recover the DGS primary vent leakage. Thus, in an unlikely case, a booster, specifically sized for recovering the gas loop, will be used to recover the DGS primary vent, an excessive vacuum will be caused on the primary vent line leading to an emergency trip with process blow down.

Despite this huge difference in flow capability, it is possible to use the same machine to make both recovery services through the introduction of an accumulation volume on DGS primary vent side.

When the centrifugal compressor is not running and is depressurized, the booster compressor will shift process gas from the compressor gas loop to the suction header.

Instead, when the centrifugal compressor is running, the primary vent will be collected inside an accumulation volume. As soon as the pressure inside the accumulation volume reaches a certain threshold, the booster compressor will start, pumping the gas from the accumulation volume to the suction header. When the pressure inside the accumulation volume comes back to the initial value, the booster will stop while the primary vent is continuously flowing toward the volume itself.

Through DGS primary vent recovery mode, the booster compressor will work intermittently with a frequency that depends from the primary flow and from the accumulation volume. The starting occurrences could be approximately between twice an hour and once each 4 hours. Starting too frequently risks overdoing the maximum number of starts and stops acceptable from the electric motor. By the other side, foreseen a low number of start-ups, will lead to size a bulky and expensive accumulation volume. The pressure range across the accumulation volume, in alignment with the start and stop of the booster, will be in the span of around 1.3÷2.5 bar-a dependently by existing alarm and trip pressure thresholds on the primary vent.

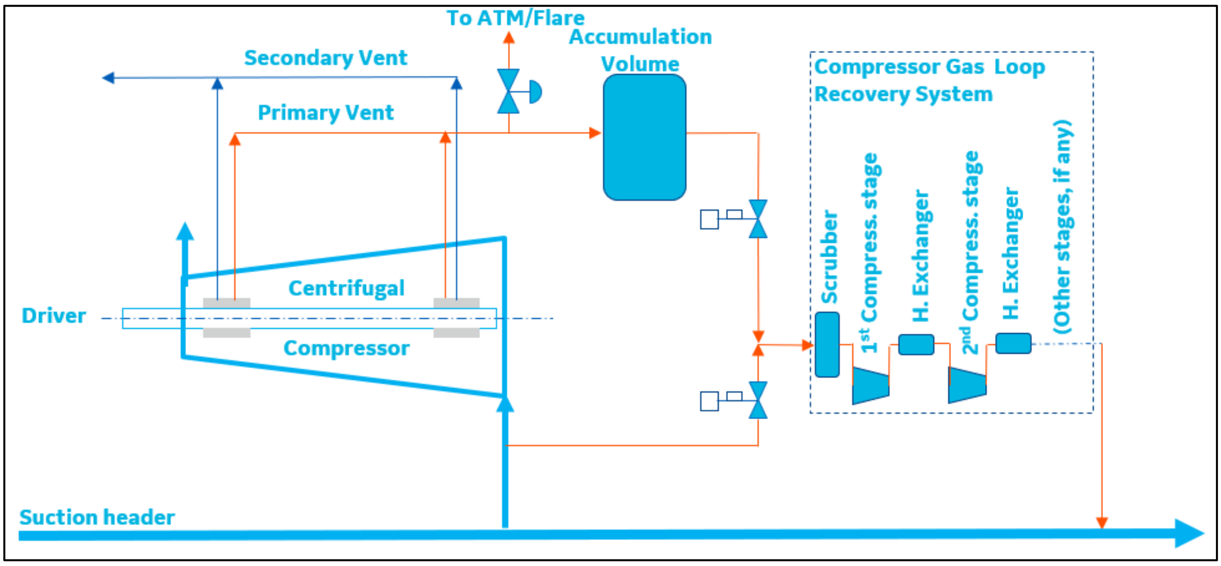

Figure 5 Simplified schematic diagram of a combined DGS primary vent leakage and CC gas loop recovery system.

Solution2: Extended Combined Recovery System

As seen in the previous chart, the accumulation volume helps to manage with the same booster compressor leakages with a widely different flow rate. We could take advantage of this possibility collecting (if required or convenient) all the other hydrocarbon leakages present into the turbomachinery train or in the closer plant.

If the driver is a gas turbine in a turbomachinery train, there may be two consistent sources of hydrocarbon release into atmosphere or flare:

- The fuel gas warmup system that releases many hundreds of kg of fuel gas in few minutes just before to start the unit
- The pneumatic starting system (mainly applicable for old turbines), that, as well, releases hundreds of kg of fuel gas during the unit start-up sequence

Moreover, there are other sources like process valves actuators (old types were actioned with process gas), process equipment and piping depressurization vents and so on.

A process gas leakages map could be generated considering various factors in a plant, led by carbon regulation and/or carbon tax, gas price, plant operation and company carbon emission philosophy. When completed part of the leaks can be recovered connecting them to the accumulation volume. Specific attention would be given to the specific leak source constrains (acceptable backpressure, composition…) and thus volume of the accumulator and the booster start up logics shall be properly defined.

In general, if the gas composition is suitable as fuel, it could be recycled into the fuel gas system of a turbine or a boiler.

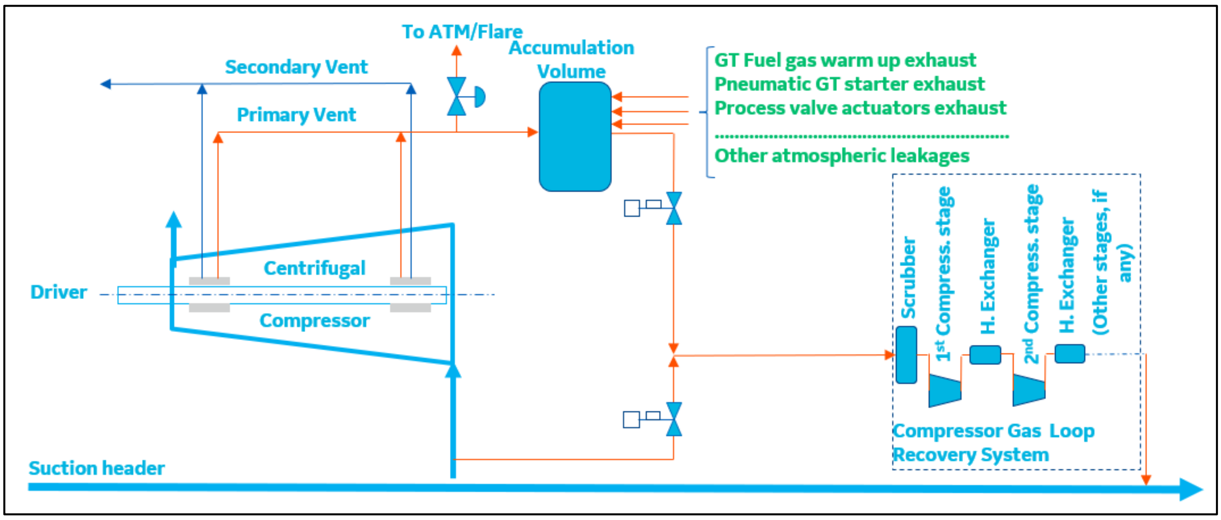

Figure 6 Simplified Schematic diagram of an extended turbomachinery hydrocarbon leakage recovery system.

This plant arrangement helps to recover and valorize almost all the hydrocarbon leakages of a turbo-machinery unit for oil and gas service in mechanical drive application.

Discussion and case study

In this section a case study is discussed in detail: DGS primary vent and Compressor gas loop recycling into compression suction are analyzed along one year of operations (Solution 1).

A typical pipeline compression station has been selected for this study. The station is comprised of two installed turbo-compression trains working in parallel and composed by two 25MW base load gas turbine and their relevant pipeline centrifugal compressor.

Let's call TC1 and TC2 the two turbo-compression units that pump the natural gas into pipeline distribution system.

Assumption:

TC1 will run 8000 hrs/year with no stops

TC2 will 3000 hrs/years mainly into the winter time with 2 (two) depressurized stops.

The DGS primary vent leakages is 20 Nm^3/h for each compressor

Each centrifugal compressor gas loop (between CC suction and discharge isolation valve) is 100 m^3

Suction header pressure = 75bar-a

The following simplified schematic drawing is applied:

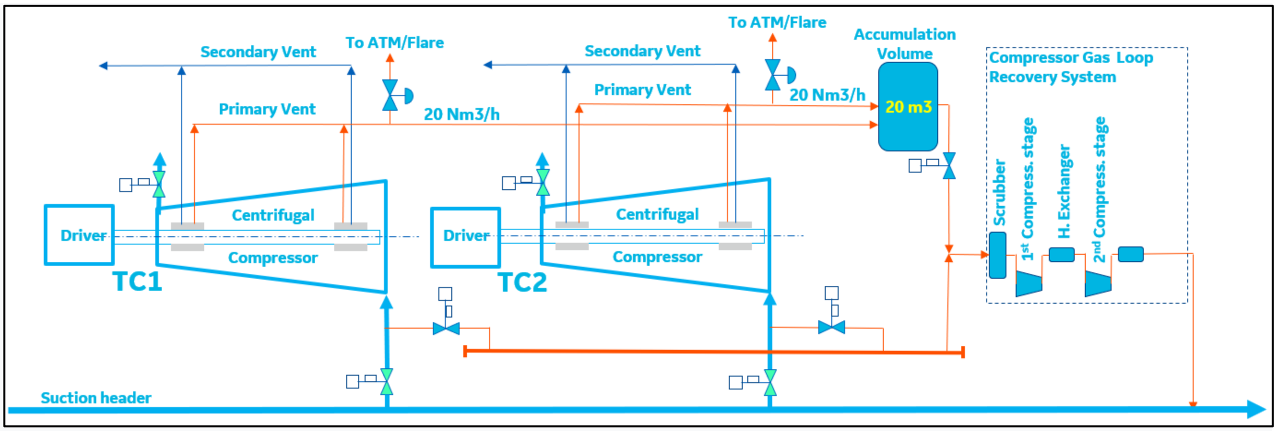

Figure 7 Case Study Simplified Schematic diagram: combined DGS primary vent leakage and CC gas loop recovery system

<u>Description of the system applied</u>

The selected system, aimed to reinject on the CC suction header, the primary vent when the main compressor is running, and the process gas loop when the main compressor is on depressurized shutdown, comprises the following:

- A three-stage reciprocating compressor (RC) driven by a 55kW LV electric motor. It packaged inside an acoustic enclosure with an air-cooler on the roof
- A 20Nm3/h accumulation volume to recover the primary vent that allows a compressor start-up approximately each 2 hours, working in a pressure range of 1.3÷2.3 bara
- Five (5) Additional process valves (the blue filled valves in Figure 7) to select the wanted process gas loop and/or the primary vents to recover (valves size between 25mm (1") and 50mm (2"))
- Remote PLC to control the RC and process valves
- Interconnecting piping, cables, pressure and temperature instruments

In this case the process gas loop of each CC has been connected to the RC through a pipe, equipped with an isolation valve, that arrives in a piping header.

The primary vents have been connected directly with the accumulation volume and valves have been installed to redirect the vents to ATM in case of failure conditions.

Between the accumulation volume and the RC, a valve is placed to isolate the primary vent when the RC is on maintenance or in off design condition.

On primary vent recovery mode, the reciprocating compressor is controlled by the pressure inside the accumulation volume in order to keep it inside that pressure range, which will help to maintain a correct primary vent flow.

On CC process gas loop recovery mode, the RC compressor will be controlled by the suction pressure inside into centrifugal compressor, starting when activated by operator and stopping around 1.3 bara (just before to achieve vacuum condition).

Outcomes of the solution

- TC1 natural gas emission reduction from DGS primary vent recovery:

$$Recovered\ Gas = Recovered\ gas\ Flow \cdot Time = 20\frac{Nm^3}{h} \cdot 8{,}000\ h = 160{,}000\ Nm^3$$

- TC1 natural gas emission reduction from Gas loop recovery = $0\ Nm^3$(no stops)
- TC2 natural gas emission reduction from DGS primary vent recovery:

$$Recovered\ Gas = Recovered\ gas\ Flow \cdot Time = 20\frac{Nm^3}{h} \cdot 3{,}000\ h = 60{,}000\ Nm^3$$

- TC2 natural gas emission reduction from Gas loop recovery

$$Recovered\ Gas = Stops\ n° \cdot Gas\ loop\ Volume \cdot Suction\ pressure$$
$$= 2\ \cdot 100\ m^3 \cdot 75\ bara\ \approx 15{,}000\ Nm^3$$

Thus, the total yearly installed turbomachinery emission reduction is about 235,000 Nm^3 of natural gas equivalent to 170 tons.

If considered a GWP of 25 [3] in a span of 100 years, it would mean a reduction 4,250 tons of CO2e (CO2 equivalent).

Customer value and Business case

Customers subjected to an average carbon tax of 40$ per tCO2 (tons of CO2e) means about 170,000 CAD$/year, reducing the impact on the owners' costs.

Gas recovered into the transportation loop, considering an average gas price of 1.6 CAD$/GJ [4] other 13,600 CAD$/year may be expected, increasing the value to the shippers.

Conclusion

The increasing regulatory emissions constraints and the growing attention on energy efficiency has boosted the search for technical solutions to reduce the release of contaminants into the atmosphere. In the current evolving regulatory environment, even the recovery of small leakages from dry gas seals or occasionally leakages as the gas process loop is becoming economically viable. In this paper, the technical solutions for compressor DGS primary, process gas loop and in general turbomachinery atmospheric hydrocarbon leakages recovery, are presented together with their integration with the process. The solutions presented are segmented in two categories: recycling into the compression process and valorization as fuel gas. The solutions outline financial feasibility with a payback period spanning from two to five years considering an average carbon taxes and the current carbon price applied to a typical natural gas compression site. The presented solutions are designed to maximize the positive impact in wasted gas reduction and contribute in reaching environmental sustainability targets in oil and gas.

References

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[2] Word Bank, "State and Trends of Carbon Pricing 2019," June 2019.

[3] "Greenhouse Gas Pollution Pricing Act, SC 2018, c 12, s 186".

[4] 2019. [Online]. Available: www.ngx.com.