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PEOPLE'S DEMOCRATIC REPUBLIC OF ALGERIA
MINISTRY OF HIGHER EDUCATION AND SCIENTIFIC RESEARCH
UNIVERSITY OF M'HAMED BOUGARA - BOUMERDES
FACULTY OF HYDROCARBONS AND CHEMISTRY
DEPARTMENT OF PROCESS AUTOMATION AND ELECTRIFICATION



**End of Studies Dissertation
To Obtain the Diploma of
Master**

Branch: Hydrocarbons.

Option: Instrumentation in the Petrochemical Industry.

Presented by:

Abderraouf RADJOUH

Titled:

**Study of the XGF868i Flare Gas Flow Meter Solution at the
HBNS Oil Field with Addressing Its Lack of Data Integration into
the ICSS Control System.**

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Dedication

**IN THE NAME OF ALLAH, THE MOST BENEFICENT, THE
MERCIFUL**

With enormous pleasure, an open heart, and immense joy, I dedicate my work:

To my dear, respectful, and beloved parents, whose unwavering support, encouragement, and love have been my guiding light throughout my life.

To my supportive brother ZAKARIA SAHNOUN, my caring sisters ASMA and HADJER, and their husbands ALI GRINE and MAROUANE KERRAR, for being a source of motivation and for their support throughout my entire academic career.

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ملخص

تتناول هذه الرسالة نقص البيانات التفصيلية لغاز الشعلة والبيانات التشخيصية من أجهزة قياس التدفق في نظام التحكم في موقع مجموعة بركين. يتضمن الحل إنشاء 17 نقطة تناظرية، تمثل كل منها بيانات محددة تم استردادها من أجهزة قياس التدفق عبر اتصال مودباص. تم إنشاء تكوينات متقدمة، مثل إعدادات التنبيه والبيانات التاريخية، للتحليل واستكشاف الأخطاء وإصلاحها. بالإضافة إلى ذلك، تم تطوير واجهات المستخدم لستة مشاعل، مما يوفر سهولة الوصول من غرفة التحكم وأيضًا اتاحت الوصول عن بعد من خلال حل خادم هانيويل الإلكتروني. تساهم هذه التحسينات في عمليات أكثر أمانًا وكفاءة ومسؤولية بيئيًا.

Résumé

Cette thèse aborde le manque de données détaillées sur les gaz de torchère et de données de diagnostic des débitmètres XGF868i dans le système de contrôle ICSS du site HBNS du Groupement Berkine. La solution comprend la création de 17 points analogiques, chacun représentant des données spécifiques récupérées des débitmètres via la communication Modbus. Des configurations avancées, telles que les paramètres d'alarme et de données historiques, ont été établies pour l'analyse des données et la surveillance avancée de ces débitmètres. De plus, des IHM ont été développées pour six torchères, offrant un accès facile depuis la salle de contrôle et permettant également un accès à distance via la solution Honeywell E-server. Ces améliorations contribuent à des opérations plus sûres, plus efficaces et respectueuses de l'environnement.

Abstract

This thesis addresses the lack of detailed flare gas data and diagnostic data from XGF868i flow meters in the ICSS control system at the Groupement Berkine HBNS site. The solution includes creating 17 analog points, each one representing specific data retrieved from the flow meters via Modbus communication. Advanced configurations, such as alarm and historical data settings, were established for analysis and troubleshooting. Additionally, HMIs were developed for six flares, providing easy access from the control room and also enabling remote access through the Honeywell E-server solution. These enhancements contribute to safer, more efficient, and environmentally responsible operations.

Keywords: Flare Gas Flow Measurement, Ultrasonic Technology, Flaring System Monitoring Optimization, Honeywell ICSS, Modbus Communication.

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Nomenclature

DCC	Document Control Center
HBNS	Hassi Berkine South
CPF	Central Processing Facility
CCR	Central Control Room
PCS	Process Control System
ESD	Emergency Shutdown System
DCS	Distributed Control System
ICSS	Integrated Control and Safety System
SCADA	Supervisory Control and Data Acquisition
SM	Safety Manager
SS	Safety System
OWS	Operator Work Stations
EWS	Engineering Workstation
HMI	Human-Machine Interface
EPKS	Experion Process Knowledge System
RTU	Remote Terminal Unit
PLC	Programmable Logic Controller
FTA	Field Termination Assemblies
SIL	Safety Integrity Level
FTE	Fault Tolerant Ethernet
PCDI	Peer Communication Data Interface
QDB	Quick Database
EMDB	Enterprise Model Database
RTDB	Real-Time Database
ERDB	Engineering Record Database
FGS	Field Gathering Station
SGB	Switchgear Building
RVP	Reid Vapor Pressure

General Introduction

In the oil and gas industry, flaring—the controlled burning of excess natural gas—is a common practice. While it is often employed for safety reasons, flaring significantly contributes to greenhouse gas emissions and exacerbates global warming. Recognizing the environmental impact, regulatory authorities worldwide, including Algeria's ALNAFT, have implemented fiscal measures such as taxes to incentivize the reduction of flaring activities. These taxes are typically calculated based on the volume of gas flared, underscoring the importance of accurate measurement and reporting. However, accurately measuring flare gas flow rates presents unique challenges due to the variable nature of gas composition, temperature fluctuations, wide flow ranges, and more.

Groupement Berkine HBNS conducted a study to find a solution for flare gas flow measurement that overcomes these challenges and eliminates inaccurate estimation methods. They identified the Baker Hughes XGF868i ultrasonic flare gas flow meter as a viable solution and installed it in 2018. This installation included the integration of three different data points from the flow meter: the average flare gas volumetric flow rate, flare gas temperature, and pressure.

The core problem lies in the absence of detailed flare gas process data from the ultrasonic flare gas flow meters within the existing control system. This lack of visibility hinders operators' ability to gain a comprehensive understanding of real-time flaring processes, impeding optimization efforts and potentially compromising safety. Additionally, the absence of diagnostic data necessitates time-consuming manual verifications of the flow meters' health, diverting valuable manpower from other critical tasks.

In this thesis, I will start by studying the solution implemented by Groupement Berkine to measure the volumetric flare gas flow rate. I will then study the integration of the data provided by these flow meters into the control system, which is the Honeywell ICSS. This will provide a solid understanding of the system before moving on to the practical part of this thesis, where I will offer a comprehensive solution to the identified problems.

The goal of this research is to integrate the crucial XGF868i flow meter data into the ICSS effectively. This involves configuring SCADA points, developing intuitive Human-Machine Interfaces (HMIs), and leveraging the E-server solution for enhanced data accessibility. The integration of real-time process and diagnostic data will empower operators

and engineers with valuable insights, enabling proactive maintenance, efficient troubleshooting, and informed decision-making.

In essence, this thesis bridges the gap between theoretical understanding and practical implementation, offering a comprehensive solution to the challenges associated with the flaring system at the HBNS oil field. By harnessing the power of advanced technology and data integration, this research contributes to a safer, more efficient, and environmentally responsible operation.

Chapter 1

Groupement Berkine Presentation

1. Introduction

The national oil and gas company SONATRACH was founded in 1963 and plays an important role in the development of the national economy, with a turnover exceeding \$50 billion in 2022. While Sonatrach's global ranking in oil production fluctuates, it remains a top producer. SONATRACH continues to hold significant positions in global energy exports, ranking as the 1st oil & gas company in Africa, 4th in the world as an LNG (liquefied natural gas) exporter, 3rd in the world as an LPG (liquefied petroleum gas) exporter, and 5th in the world as a natural gas exporter. Given that almost all of Algeria's energy resources are made up of relatively abundant hydrocarbons (recoverable reserves estimated at over 12 billion barrels as of 2023), the energy sector plays a key role in the country's economic and social development. Its mission is to ensure long-term coverage of national energy needs and to finance economic development through the export revenue of these hydrocarbons. [1]

The missions of the national company have been expanded; initially limited to the transportation and commercialization of hydrocarbons, it has since expanded its scope to all areas of the oil industry, including Upstream (Exploration & Production), Midstream (Transportation, Liquefaction, and Separation), and Downstream (Refining, Petrochemicals, and Commercialization). [2] Among the company's missions are:

- Conservation of national energy reserves.
- Replenishment and expansion of hydrocarbon reserves.
- Intensification of exploitation efforts and capitalization of studies realized in this field.
- Developing a better understanding of the subsurface and identifying hydrocarbon reserves.
- Diversification of markets and export products.
- Meeting the country's energy needs.
- Adopting modern techniques through continuous training.

In accordance with this framework, SONATRACH and ANADARKO PETROLEUM CORPORATION have established GROUPMENT BERKINE, tasked with managing all production from the SONATRACH-ANADARKO partnership in the Hassi Berkine region.

2. Presentation of Groupement Berkine

2.1. Evolution of Groupement Berkine

The GROUPEMENT BERKINE was created in 1998 as a joint-venture operations entity between SONATRACH and ANADARKO PETROLEUM CORPORATION, two energy companies specialized in exploration, production, processing, and selling hydrocarbons. This association manages all production activities in the Hassi Berkine field.

On August 8, 2019, OCCIDENTAL PETROLEUM CORPORATION announced the successful completion of its acquisition of Anadarko Petroleum Corporation. However, this acquisition does not negatively impact Groupement Berkine. Instead, Groupement Berkine stands to benefit from the expertise gained as it transitions from Anadarko to another global energy leader, Oxy Corporation. [3]

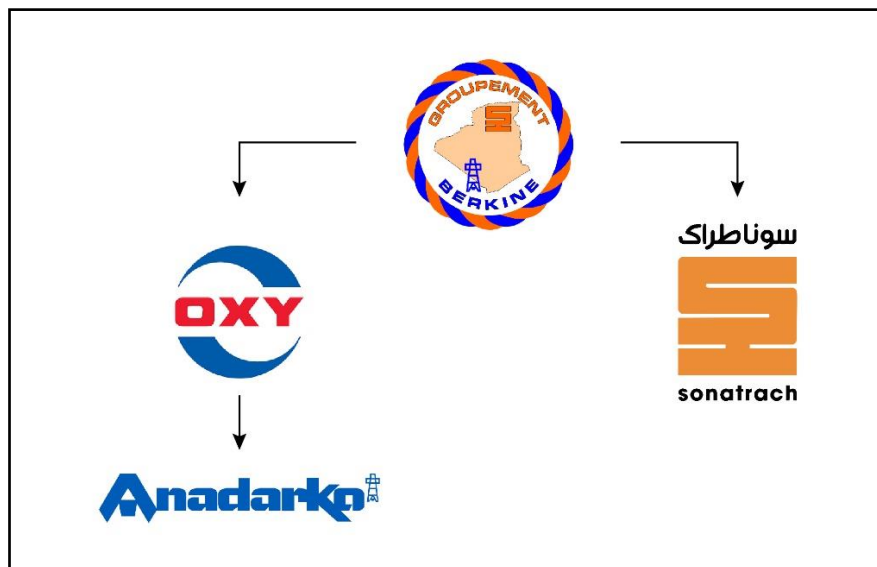


Figure 1.1: Groupement Berkine and Partner Companies Logos.

2.2. Organization Structure of Groupement Berkine

The organizational structure of Groupement Berkine, with its head office located in Hassi Messaoud, is as follows:

At The Hassi Messaoud Site (General Direction):

- Head Office
- Director Support
- Reservoir Direction
- Drilling Department

- HSE Department (Health, Safety, and Environment)
- Contracts Department
- Finance Department
- Human Resources Direction
- Means Department
- General ITT Department (IT & Telecommunications)

In Their Respective Fields:

- HBNS Operations Direction
- El Merk Operations Direction

3. Presentation of the Berkine Basin [4]

The Berkine Basin or Hassi Berkine is the most explored geological basin in Algeria over the past three decades and has revealed the largest oil and gas discoveries.

The Berkine Basin is located in the desert of Algeria, about 250 km to the South-East of Hassi Messaoud, and about 900 km southeast of Algiers. It covering an area of 102,395 km², constitutes the western part of the Ghadames Basin, that occupies the eastern region of Algeria, the southern region of Tunisia, and the western region of Libya.

The Ghadames Basin region refers to an important oil and gas region, which is a large intracratonic basin, meaning it's a geological depression within the stable interior of the African continent. Over millions of years, this basin accumulated organic materials which transformed into vast oil and gas reserves.

Geographical boundaries of the Berkine Basin:

- Dahar Dome to the north.
- Tunisian and Libyan borders to the east.
- Hassi Messaoud to the west.
- Ilizi Basin to the south.

This basin is bounded by the following geographical coordinates:

- Latitude 29° 30' N.
- Longitude 5° 55' E.

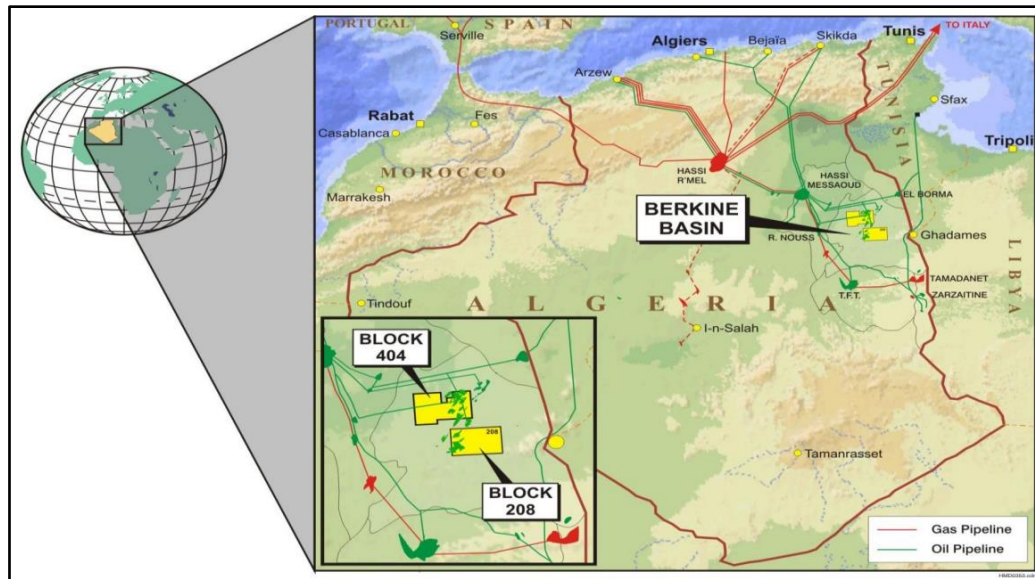


Figure 1.2: Emplacement du Basin Berkine.

Groupement Berkine operates in two blocks within the Hassi Berkine area. The first and main block is Block 404, occupied by the HBNS field, where the main product is crude oil. The second block is Block 208, occupied by the El Merk field, where the main products are crude oil, LPG, and gas condensates. El Merk field is considered as a project that complements the HBNS field (Block 404).

Both the HBNS and El Merk fields have distinct and separate infrastructures, each including central processing facilities, satellites, pipelines, field gathering stations, metering units, and export pipelines. Figure 1.2 shows the distance between them.

Next, I will focus my study on the HBNS field (Block 404), where I conducted my practical internship for this final year project.

4. Presentation of the HBNS Field [5]

4.1. History

The Algero-American joint venture engineering and construction company, BROWN & ROOT CONDOR, began working on the initial phase of the HBNS's CPF in 1996. In 1999, B&RC started engineering for the Hassi Berkine extension project. Thus, GEPCO and ENGTP are among the companies that participated in the realization of this project.

The Hassi Berkine Development project underwent several milestones, with the significant ones outlined in the timeline table below:

Date	Event
October 1989	Signature of the exploitation contract between SONATRACH and ANADARKO ALGERIA CORPORATION.
February 1996	Allocation of PEA (provisional exploitation permit) for HBNS.
May 1998	First introduction of hydrocarbons into the CPF.
September 1998	Signature of the provisional acceptance of train 1.
January 1999	Daily shipment of crude oil via the 30'' OH3 pipeline.
August 1999	Award of the 26-month construction contract for phase 2.
September 2001	Provisional acceptance of train 2.
January 2002	Provisional acceptance of train 4.
April 2002	Provisional Acceptance of Train 3.
March 2002	First production of HBNSE.
October 2003	The Start-up of dynamic counting units (LACT METRING), after approval by the ONML.

Table 1.1: Key Milestones in the Development of HBNS Field.

4.2. Overview Of the HBNS Field

- **Location:** The HBNS field is located in Block 404 of the Berkine Basin, about 950 km southeast of Algiers and 300 km southeast of Hassi Messaoud.
- **Surface Area:** The field covers an area of about 240 km².
- **Production Capacity:** Currently, the field produces around 62,000 barrels of stabilized oil per day, with the CPF capable of supporting oil pretreatment of up to 300,000 barrels per day.
- **Destination of Finished Products:** The finished products are transported to Haoud El Hamra (HEH).
- **Position of HBNS Relative to Other Regions:**
 - **Ourhoud Organization:** Located 50 km southwest.
 - **BRN:** Situated 60 km northeast.
 - **CEPSA:** Found 50 km southeast.
 - **MLN:** Positioned 140 km southwest.

4.3.2. Industrial Base

The industrial base includes:

- CPF.
- HSE Block, Logistics Office, Training Center, Fire Fighting Station.
- White House: maintenance department services.
- Warehouse, 2 Maintenance Workshops.
- Administrative Block, DCC (technical).
- Service station, CPF Substation.

4.3.3. Hassi Berkine Base Camp (HBBC)

HBBC living base is composed of:

- 3 living bases: HBBC1, HBBC2, HBBC3.
- 3 restaurants, 2 lounges.
- 2 gyms, 1 swimming pool, a football field, and other playing grounds.
- 1 mosque.
- A maintenance workshop of HBBC.
- 1 Infirmary block.
- 1 water treatment plant.
- 1 telecommunication workshop.
- Offices of service companies that serve the HBNS field (catering, laundry, security).
- Aerodrome.

4.4. Organization Structure of the HBNS Field [6]

During my internship at HBNS, I underwent a comprehensive orientation program. Initially, I received detailed instructions on safety protocols, such as the mandatory use of personal protective equipment (PPE) and familiarization with emergency procedures, including the emergency number 44444. Additionally, a tour through the various divisions and departments allowed me to get a general idea of each one's activities and objectives.

The HBNS field is organized as follows:

4.4.1. Human Resources Department

Human Resources is essential for maintaining a company's workforce and organizational framework. Here's an overview of the HR department's responsibilities:

- Monitoring staff issues.

- Handling social requests.
- Managing schedules, vacations, and travel arrangements.
- Managing staff contracts.
- Supervising career development.
- Facilitating promotions and transfers.

4.4.2. Document Control Center (Dcc)

The DCC serves as the company's living memory, managing the receipt, processing, and distribution of information through the use of a database called "DOCUMENTUM." This electronic document management system facilitates the computerization of document creation, updates, retention, dissemination, and reuse. To achieve these objectives, DCC staff ensure the database is populated by inserting various consolidated documents from both phases of the CPF.

4.4.3. Health, Safety And Environment (Hse) Department

The HSE division establishes rules, guidance, and processes designed to protect employees, staff, visitors, and the environment from harm in the workplace. The department comprises the following services:

4.4.3.1. Occupational Health Service

This service is primarily responsible for providing medical consultations and care for all personnel working in the HBNS field, including workers, staff, and visitors. It possesses the necessary treatment methods and medications for patients.

4.4.3.2. Prevention Service

This service plays a vital role in safeguarding workers, visitors, and staff by proactively identifying and minimizing workplace risks. Through comprehensive risk assessments, accident analysis, safety program development, training initiatives, and continuous improvement efforts, the service strives to achieve a 'zero accident' goal. This comprehensive approach reduces injuries, fosters a strong safety culture, enhances productivity, and ensures legal compliance.

4.4.3.3. Intervention Service

The primary function of this service is to establish an effective organizational plan for intervention in the event of an accident. Depending on the situation, it utilizes mobile or fixed intervention methods, including:

- **Fixed means:** The fire-fighting system includes a water discharge system for open spaces and CO₂ gas cylinders for enclosed spaces.
- **Mobile means:** Trucks equipped with extinguishing systems using powder, CO₂, or foam, ambulances, and mobile fire extinguishers.

4.4.4. Technical Department

Its role is to conduct technical studies on every proposed change by the departments or made to any machine or facility at the CPF level, whether for the process or other activities elsewhere, regardless of level and/or priority. These changes must be made in order to:

- Increase efficiency.
- Adapt to technical innovations.
- Eliminate risks.
- Maintain the integrity of new techniques and operations.
- Improve aspects of health, safety, and the environment for staff, as well as facilities and locations.

Any modification to equipment must first be made at the technical department level.

4.4.5. Chemistry And Corrosion Department

Handles various chemical treatments at the field level (CPF, EP), as well as the inspection and control of corrosion in CPF facilities, piping, and off-site locations.

4.4.6. Fdev Department

Oversees project implementation in both CPF and wells, particularly when heavy and complex tasks are required. This includes constructing new wells, repairing corroded pipelines, and modifying existing wells or CPF facilities.

4.4.7. Exploitation Division

The role of this division is to establish an effective monitoring and control plan for all CPF units, ensuring optimal operating quality of the crude production process. To facilitate this task and reduce monitoring complexity, the CPF is divided into several zones. These zones are

managed by the central control room (CCR), utilizing Honeywell ICSS (Integrated Control and Safety System) and Operator Work Stations (OWSs). The OWS enables operators to continuously monitor and control all CPF functions. Process disturbances, emergency conditions, and audible and visual alarms are announced through display screens in the OISs.

Operators in the control room can perform various functions, including:

- Starting or stopping the CPF, a train, or any equipment within the CPF.
- Monitoring the flow, pressure, and temperature of crude, gas, or any fluid circulating in the CPF.
- Checking CPF equipment health.
- Reporting malfunctions and raising work requests.

4.4.8. Production Engineering Department

This department comprises two services:

4.4.8.1. Production Service

This service is responsible for two primary functions:

4.4.8.1.1. Production Monitoring

This involves monitoring all stages of crude production from the wells to the CPF, including the injection process of gas and water. It notably supports continuous control of process parameters at the wells, such as pressure, temperature, and flow. EP technicians ensure that anomalies in these parameters are addressed through maintenance interventions.

4.4.8.1.2. Allocation & Measurement

This function is responsible for the calculation of allocations related to production measurements taken at regular time corresponding to the number of hours of opening and closing the wells valves. Several supervisory systems, such as SCADA, are utilized to facilitate valve control and communication with other unit services.

4.4.8.2. Well Service

The service's mission is to oversee intervention and maintenance operations in wells to effectively address production constraints. They manage all operations from the wellhead to downhole equipment. Wells in the HBNS field are categorized into three areas: HBN, HBNS, and satellite, mirroring the division among well engineers. This division enables effective control and monitoring of interventions.

Tasks include:

- Reviewing job instructions from the production service, detailing objectives, problems, and necessary tools.
- Developing intervention programs for wells.
- Liaising with intervention service providers like Halliburton and SLB.
- Coordinating logistics for well intervention projects.
- Supervising intervention service providers, ensuring adherence to defined programs, and reporting any issues.

4.4.9. Logistics Department

This division handles the management and maintenance of various departments to create a convenient work environment. It comprises two services:

4.4.9.1. Transport Service

- Provides transportation and service vehicles for staff.
- Ensures the management, control, and maintenance of all transportation equipment.
- Manages road and air transport.
- Conducts base and road cleaning during sandstorms.

4.4.9.2. Intendance Service

This service manages catering, procurement, accommodation, and hospitality. Additionally, it is responsible for gardening, hygiene, and maintenance work at the living base.

4.4.10. Material Division

The Material Division oversees the management and control of stock materials, ensuring the supply of all equipment needed across the entire HBNS field. To achieve this, the division utilizes the MUSIS software for material management and control operations. These responsibilities encompass:

- Reception: Handling materials received from suppliers.
- Management: Managing storage and the issuance of materials using Pick-lists (PL).
- Procurement: Creating requisitions to supply or replenish stock.
- Cataloging: Compiling catalogs of new items for reference and organization.

4.4.11. Maintenance Division

The objectives of this department are:

- To provide efficient maintenance services to ensure high-level oil production, meeting customer requirements while adhering to all legal, health, safety, and environmental standards.
- To ensure that all facilities and equipment, both at the CPF and off-site (in the wells), are operating at the required levels of performance and reliability through the application of preventive maintenance and corrective maintenance techniques.
- To conduct preventive maintenance, corrective maintenance, overhauls (during general equipment revisions), and FCP implementations (Field Change Proposals).
- To take actions to improve the reliability of facilities and equipment through problem-solving techniques and failure analysis.

The maintenance division consists of 5 services: represented in the following figure:

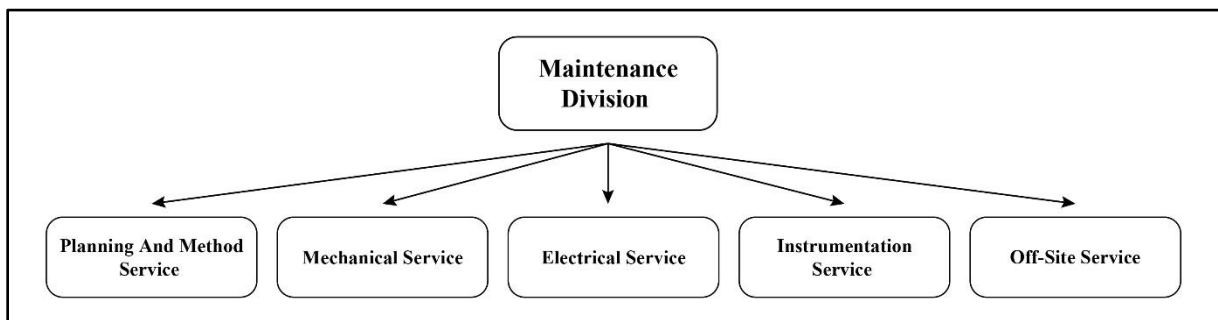


Figure 1.4: HBNS Maintenance Division.

4.4.11.1. Planning And Method Service

From a work organization standpoint, the Planning & Methods department is the central service in the maintenance division. This is the service to which work requests are issued by all clients of the maintenance division. The maintenance division primarily provides maintenance services for three clients, which are:

1. **The exploitation division**, which manages production operations at the CPF.
2. **The production engineering division**, which manages all types of wells.
3. **The technical department**, which handles technical modifications within a given project through Field Change Proposals (FCP) and oversees the technical monitoring of new projects.

Requests are classified and archived, then dispatched to one of the four specialized services based on their specific needs. Requests needing mechanical attention are handled by the mechanical service, while those needing electrical work are directed to the electrical service. Off-site interventions, such as those involving the SCADA system, are managed by the Off-Site service. Requests requiring instrumentation or regulation adjustments are routed to the instrumentation service.

The tasks of the Planning & Methods department can be summarized as follows:

- **Shutdown planning:** During shutdowns, all relevant components (equipment, unit, or production train) stop, and a general overhaul is conducted on all equipment and instruments of the component.
- **General overhaul planning:** CPF components undergo annual or triennial overhauls depending on the equipment and units. Note that in most cases, they call on the supplier or one of its representatives to carry out the overhaul tasks. Nevertheless, the participation of Groupement Berkine instrumentation personnel is always required regardless of the official executor of the overhaul tasks.
- **Technical evaluation of spare parts:** This service manages spare parts supply and is responsible for conducting technical evaluations by studying the technical and mechanical specifications of each part.
- **Follow-up on work requests:** The HBNS maintenance management system is based on the MUSIS Data Stream 7i network application. Work requests are classified into 03 categories: preventive, corrective, and shutdown. Additionally, the methods service handles their tracking until they are closed.

4.4.11.2. Mechanical Service

It ensures the operation of static machines such as tanks, separators, and pipelines, as well as rotating equipment including pumps, motors, compressors, turbines, and manual valves through preventive, conditional, and corrective maintenance. There are two main functions related to conditional maintenance:

4.4.11.2.1. Vibration Analysis Cell:

Its role is to acquire and analyze vibrations in all rotating machines (turbines, compressors, motors, pumps, etc.). Then, it diagnoses and intervenes in case of simple problems; otherwise, it calls in specialists, who are usually the manufacturers.

4.4.11.2. Lubricating Oil Analysis Cell:

Oil samples are taken periodically for testing viscosity, contamination (water, dust, air, etc.), and ferocity (percentage of iron in oil). Each test provides a curve that is compared to the reference curve, and then a decision is made to either completely change the oil or replace the worn-out equipment.

4.4.11.3. Electrical Service

The role of this service is to perform all corrective or preventive maintenance work related to the electrical part of the HBNS field to keep all electrical equipment in good condition or repair them in case of breakdowns.

Electrical maintenance activities include inspection and repair of:

- Voltage transformers
- High-voltage wiring and cables
- Electrical machines
- Electrical cabinets
- Solar panels

4.4.11.4. Instrumentation Service

This service is crucial for ensuring the reliable, accurate, and precise operation of various measurement and control systems throughout the HBNS CPF. Responsibilities include maintaining and optimizing:

- Electronic and pneumatic regulators
- Temperature, pressure, flow, and level sensors (including switches, indicators, and transmitters)
- Process valves and safety instruments
- Control systems (DCS, PLC, SCADA)

This proactive approach guarantees optimal performance, minimizes downtime, and ensures the integrity of data used for critical operational and safety decision-making. Additionally, the team has the expertise to troubleshoot and rapidly resolve unexpected malfunctions, further safeguarding the installation's efficiency.

4.4.11.5. Off-Site Service

The Off-Site Service, consisting of various sections including instrumentation, electricity, mechanics, and SCADA, provides maintenance services for the production engineering division, involving wells and manifolds, as well as for the Technical Department to implement FCP on wells. This service is responsible for both corrective and preventive maintenance of all wells. It conducts preventive maintenance every 3 to 6 months and performs corrective maintenance when necessary.

5. Conclusion

The HBNS field exemplifies Algeria's dedication to the energy sector, underscored by the successful collaboration between SONATRACH and its international partners. Its comprehensive organizational structure and unwavering focus on safety and efficiency demonstrate the technical expertise essential for successful hydrocarbon production. In the next chapter, I will study the core processes at the HBNS field's CPF

Chapter 2

Study of the Core Processes in the CPF of HBNS Site

1. Introduction

Crude oil freshly extracted from wells is a complex mixture of hydrocarbons, water, gas, and salts. These impurities pose several challenges: they can corrode pipelines, interfere with accurate measurement instruments, and complicate the refining process. To ensure safe transport, meet industry standards, and optimize refinery operations, crude oil undergoes a pretreatment process that removes these impurities. This process is essential for transforming raw oil into a usable and valuable resource.

In this chapter, I'll delve into the core processes of the CPF. I'll start by studying crude oil pretreatment, which produces the final desired product in the HBNS field. Then, I'll briefly explore the produced water treatment system before delving into the gas recovery system. Finally, I'll discuss the essential utilities that support these operations, including the flare system.

2. Central Processing Facility Objective

Crude oil extracted from the wellhead is a mixture of liquid or gaseous hydrocarbons and water. The primary goal of the CPF is to remove gas, water, and salt from the crude oil to produce stabilized oil. To achieve this, the crude oil is sent to processing trains where it undergoes separation, dehydration, desalting, and stabilization. The stabilized oil is then stored and exported via a pipeline.

Produced water undergoes treatment and serves various purposes within the HBNS field. It is used as a water supply for processes within the CPF, such as dilution water in the feed of the desalters. Furthermore, treated produced water is reinjected into the reservoir to maintain its recommended volume and pressure, ensuring optimal oil production and extending its lifespan. This resourcefulness is complemented by water obtained from source water wells and from water produced by the process trains.

Since most of the wells operated by this group do not produce sufficient gas for commercial production and export, the gas separated from the crude oil is compressed and

dried. A portion of this gas is sent to the PK0 power plant, while another portion fuels internal turbines and other essential utilities. The remainder is utilized for two primary purposes:

- **Gas Lift:** This compressed gas is injected into oil production wells at a specific pressure to assist in lifting the oil to the surface. Gas lift reduces the density of the oil column in the well, making it easier for the reservoir's natural pressure to push the oil upwards.
- **Re-injection:** This compressed gas is distributed to designated gas injection wells for the essential purpose of maintaining reservoir pressure and ensuring both a continuous production flow and an effective sweep of recoverable fluids. By re-injecting gas, the natural pressure within the oil reservoir is maintained, resulting in a steady flow of oil from production wells.

The excess gas that cannot be utilized for fuel, gas lift, or re-injection is sent to flare stacks for safe combustion.

The role of the CPF is summarized in the following figure:

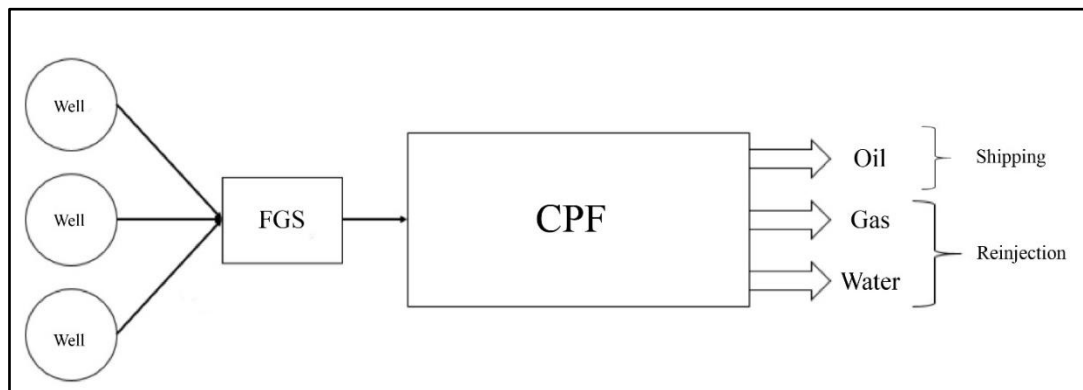


Figure 2.1: Schematic Overview of CPF Objective.

3. Wells

Under the pressure of the reservoir, fluids are pushed to the surface through the well until the wellhead, which can be defined as a means of controlling the rise of crude oil. The fluid produced from the reservoir is a mixture of hydrocarbons, salts, sediments, metals, etc. Often, it is a two-phase mixture:

- A liquid phase composed of:
 - Heavy hydrocarbons (very viscous).
 - Vaporizable light hydrocarbons.
 - Formation water.

- A gas phase composed of gaseous hydrocarbons and light vapors.

4. Field Gathering Stations

The primary function of the FGS (Field Gathering System) is to gather fluids from a group of wells and transport them to the CPF in an organized manner. This minimizes the number of inlet pipes required at the CPF and reduces the cost of creating individual pipelines to each well. Additionally, the FGS enables the determination of production levels and the value of the various components within the crude oil. To support these functions, the FGS is equipped with several manifolds, including:

- **Production manifold:** This manifold receives the crude oil from the wells and routes it to the CPF for further processing.
- **Test manifold:** This manifold is used to divert a small portion of the crude oil for testing purposes.
- **Gas lift injection manifold:** This manifold injects gas into the wells to help lift the oil to the surface.
- **Water injection manifold:** This manifold injects water into the reservoir to maintain pressure and improve oil recovery.
- **Pressure relief system:** This system is a safety device that automatically releases pressure from the manifolds when it exceeds a safe limit to prevent safety hazards.

5. The Core Processes in the CPF [7]

5.1. Crude Oil Pretreatment Process

The CPF consists of four processing trains and auxiliary systems. These trains are nearly identical but operate independently, each designed to process 75,000 barrels of crude oil per day (bbls/day). Due to different partnerships, the trains are dedicated to specific oil fields: Trains 1, 2, and 3 serve the HBNS and Satellite fields, while Train 4 handles production from the HBN field. While the facility has a total design capacity of approximately 300,000 bbls/day, current production is around 62,000 bbls/day.

Within the CPF, each processing train aims to produce stabilized oil that meets the defined specifications. The treatment process consists of three main compartments:

1. **Separation (oil/gas/water):** The fluid passes mainly through:
 - The inlet separator.
 - The preheating exchanger.

- The HP separator.
2. **Electrostatic desalting (salt removal).**
 3. **Crude oil stabilization:** The crude oil passes through:
 - The stabilization column.
 - The pumps of stabilization column.
 - The furnace of stabilization column.

The stabilized oil is stored before being shipped via pipeline to Houd El Hamra. Additionally, the process includes two Re-run systems designed to adjust the parameters of non-stabilized oils (out of specification). The first Re-run system is connected to trains 1/2/3 (serving the HBNS and Satellite fields), and the second is connected to train 4 (serving the HBN field). The following figure represents the general flow diagram of the CPF.

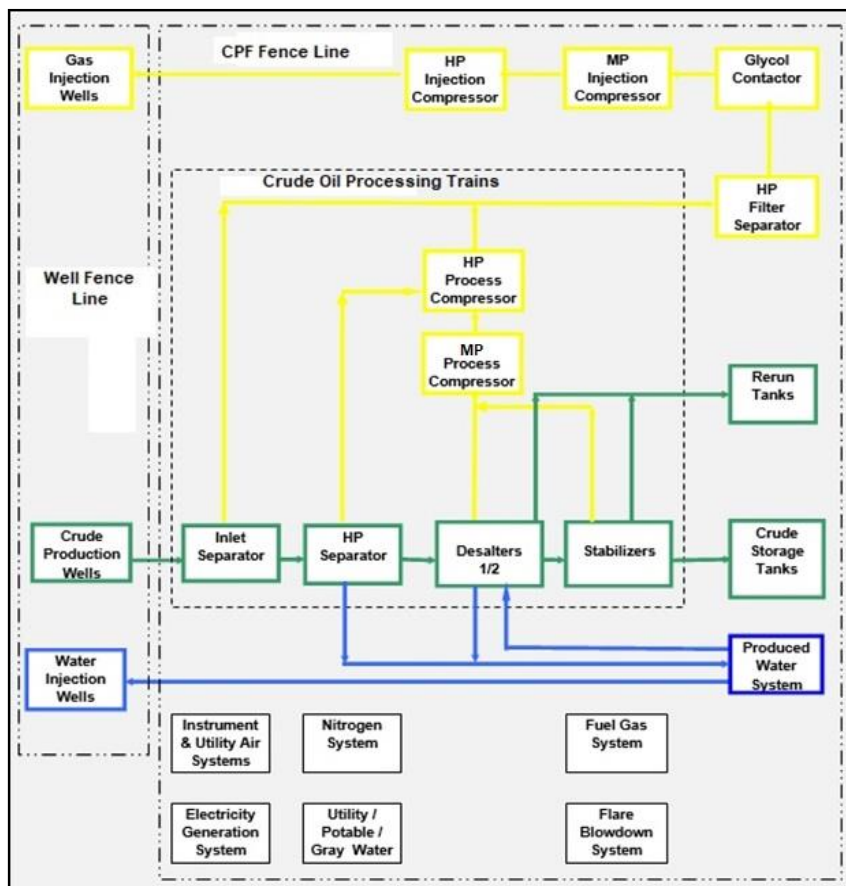


Figure 2.2: Overview of HBNS CPF Process.

5.1.1. Inlet Separator

Separators are mechanical devices used to separate either a mixture of liquids or liquids and a gas. To achieve this, the separator design must be tailored to the specific type of separation required. Separators are generally classified into three main types:

- **Bi-Phase Separators:** These separate a liquid from a gas or two liquids.
- **Tri-Phase Separators:** These separate a mixture into three phases:
 - Heavy liquid.
 - Light liquid.
 - Gas.
- **Gas Purifiers:** These remove liquid droplets from a gas stream.

The primary function of the separator systems is to extract gas, water, salt, and other elements like sand from crude oil in accordance with a well-defined process and technical parameters.

5.1.1.1. Operation of the Bi-Phase Inlet Separator: (41 Bar / 50 ° C)

The bi-phase inlet separator serves as the first stage of separation after crude oil recovery. It separates gas from crude oil containing brine and a liquid hydrocarbon.

1. **Crude Oil Entry:** Crude oil enters the top of the separator through a flow control valve controlled by a flow regulator and moves along an inlet deflector.
2. **Water Separation:** Inside the separator, water particles combine to form droplets that converge by gravity towards the bottom of the separator.
3. **Hydrocarbon Separation:** Lighter liquid hydrocarbon molecules rise to the surface, where they vaporize and join the gas molecules. These combined gas and vapor phases exit the vessel through a hold-up device. This device's purpose is to capture any liquid molecules entrained with the gas and return them to the liquid level of the vessel through a drainage system.
4. **Separated Liquid Removal:** The liquid, separated from the gas it contained, leaves the separator and flows along a weir to be directed to the HP separator via a preheater.

The operation of the inlet separator is illustrated in the following figure:

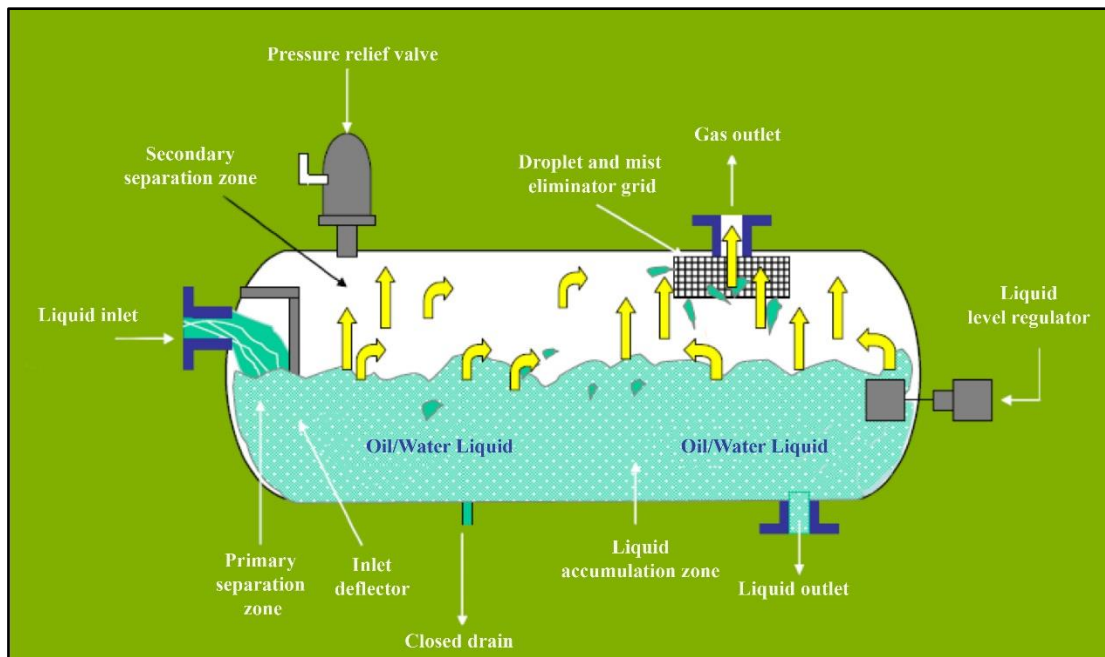


Figure 2.3: Operation of the Inlet Separator.

5.1.2. Preheating Exchanger

Preheating exchangers play a crucial role in optimizing the desalting process by ensuring the oil entering the desalters maintains a temperature above a specific minimum. Oil from the inlet separator is routed to the preheating exchanger where, through heat exchange, the exiting stabilized oil from the stabilization column heats the incoming oil. The preheating exchanger maintains an internal target temperature (TIC) of 57°C (134.6°F) for optimal desalting efficiency. The operation of the preheating exchanger is illustrated in the following figure:

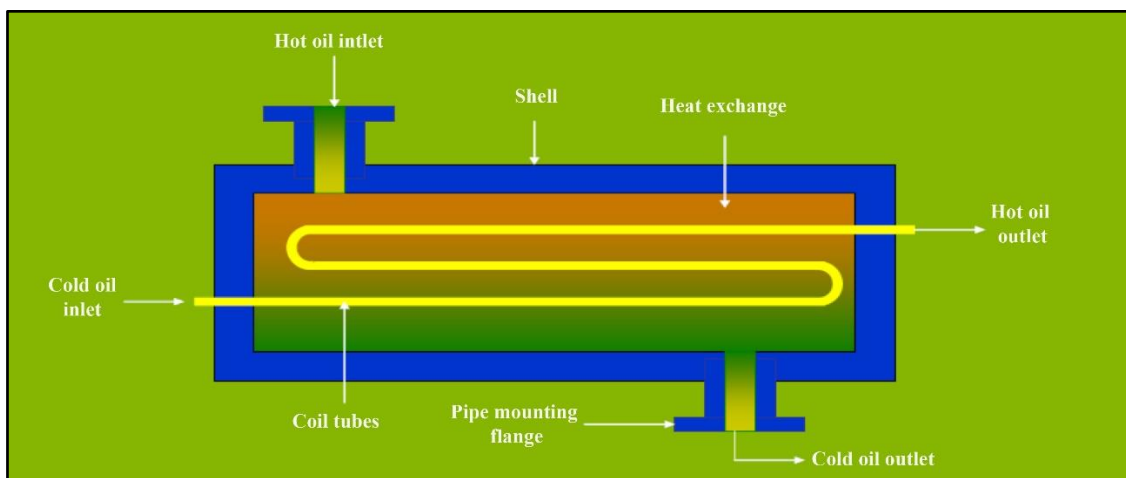


Figure 2.4: Operation of the Preheat Exchanger.

5.1.3. HP Separator

Utilizing the principle of density-based separation, three-phase separators are employed to separate two liquids with densities differing from that of a gas. In our case, this involves separating mixtures of water, oil, and gas. Three-phase separators necessitate a distinct internal design compared to two-phase separators. A longer retention time is required for effective separation (about 3 min), exceeding that of a bi-phase separator.

An emulsion is a stable mixture of two or more liquids that normally wouldn't mix, heterogeneous mixture of liquids, in this case, oil and water. Where tiny droplets of water are dispersed throughout the oil. Therefore, chemicals called emulsion breakers are added to the separator. These chemicals mix with the two liquids and induce emulsion breakdown, that disrupt the emulsifiers surrounding the droplets, allowing them to join together and facilitate the separation of oil and water.

5.1.3.1. Operation of the Tri-Phase HP Separator: (22 Bar / 50 ° C)

1. **Oil Inlet:** Oil exiting the preheater enters the HP separator through a pipe located at the top. The feed stream impinges on the inlet diverter, initiating liquid/gas separation.
2. **Gas Removal:** The gas escapes through the droplet and mist eliminator and enters a suction vessel for the gas compression process.
3. **Liquid Separation:** The HP separator is divided into two sections by an overflow weir. The two liquids flow towards the oil weir, where they are separated by gravity.
4. **Oil Collection:** At the oil weir, the lighter liquid (oil) overflows into the liquid accumulation section. The denser water remains in the first part of the separator.
5. **Interface Control:** The interface between the two liquids is continuously regulated by a level control valve (LIC). This ensures that water is not inadvertently withdrawn instead of oil.
6. **Oil Discharge:** The oil is ultimately directed to the single-stage desalting unit.

The operation of the high-pressure separator is illustrated in the following figure:

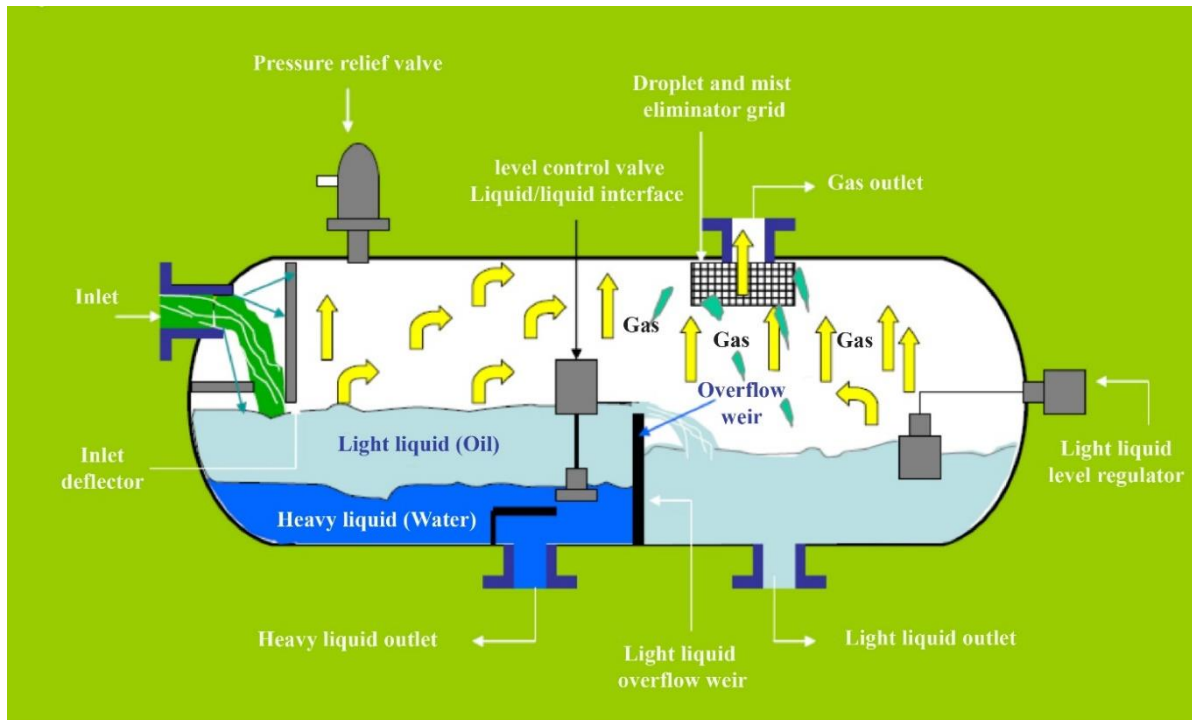


Figure 2.5: Operation of the HP Separator.

5.1.4. Desalters

Crude oil extracted from wells contains undesirable amounts of water and salt, which are contaminants that reduce its quality. High concentrations of water and salt in crude oil can contribute to internal corrosion and even cause clogging issues in CPF equipment. Desalters are designed to lower the salt concentration in crude oil to meet shipping specifications that require a maximum of 40 ppm.

5.1.4.1. Operation of the Desalters:

The desalting process involves adding and mixing dilution water with the oil. A fresh water injection valve ensures a proper mixture of fresh water and oil before entering the desalter, as this enhances the efficiency of salt removal from the oil. The dilution water absorbs the salts. The system design incorporates an identical first-stage and second-stage desalter operating in series. Oil from the HP separator feeds the first and second desalter stages sequentially.

5.1.4.2. First-Stage Desalter (15 Bar / 49 ° C)

The First-stage desalter is divided into two compartments:

1. **Separator Compartment:** Designed to separate gas and a significant portion of the water present in the oil. The gas is transferred to the suction vessel or to the HP flare.
2. **Desalting Compartment:** The oil-water mixture from the separator compartment flows through a weir and enters the desalting compartment, subsequently passing through a high-voltage field created by energized electrodes. This forces water droplets to coalesce into larger drops, which separate from the oil and settle at the bottom of the desalter. This water is then removed, treated, and re-injected into the wells. The desalted and dehydrated oil continues to the second stage.

The free water content in the oil leaving the first-stage desalter must be 0.5% of its volume. If necessary, the oil from the first-stage desalter can be directed to the off-spec tank.

5.1.4.3. Second-Stage Desalter (13 Bar / 49 ° C)

The oil received from the first stage is mixed again with dilution water and undergoes the same processes as the preceding stage. The free water content leaving this stage must also be 0.5% of its volume. The theoretical salt content in the oil should be 36 PPM (parts per million). The operation of the desalter is illustrated in the following figure.

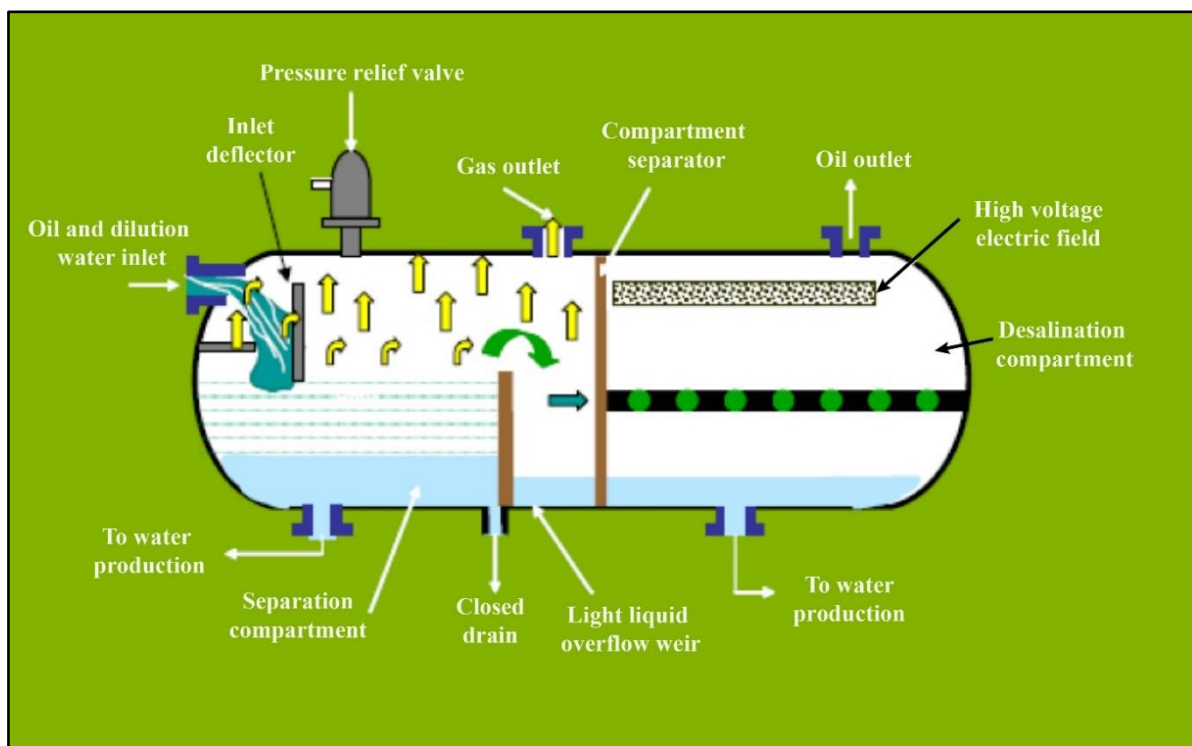


Figure 2.6: Operation of the CPF First and Second Stage Desalter.

5.1.5. Stabilization Column and Furnace

The primary purpose of the stabilization column is to remove light hydrocarbons from crude oil, reducing its vapor pressure, which is required prior to transporting the oil via pipeline for sale. The oil's tendency to vaporize is affected by ambient temperature, and the required vapor pressure standards vary seasonally. In summer, the standard Reid Vapor Pressure (RVP) is 7.4 psi (pounds per square inch), equivalent to around 0.51 Bar, while in winter, it increases to 10.0 psi, or approximately 0.68 Bar.

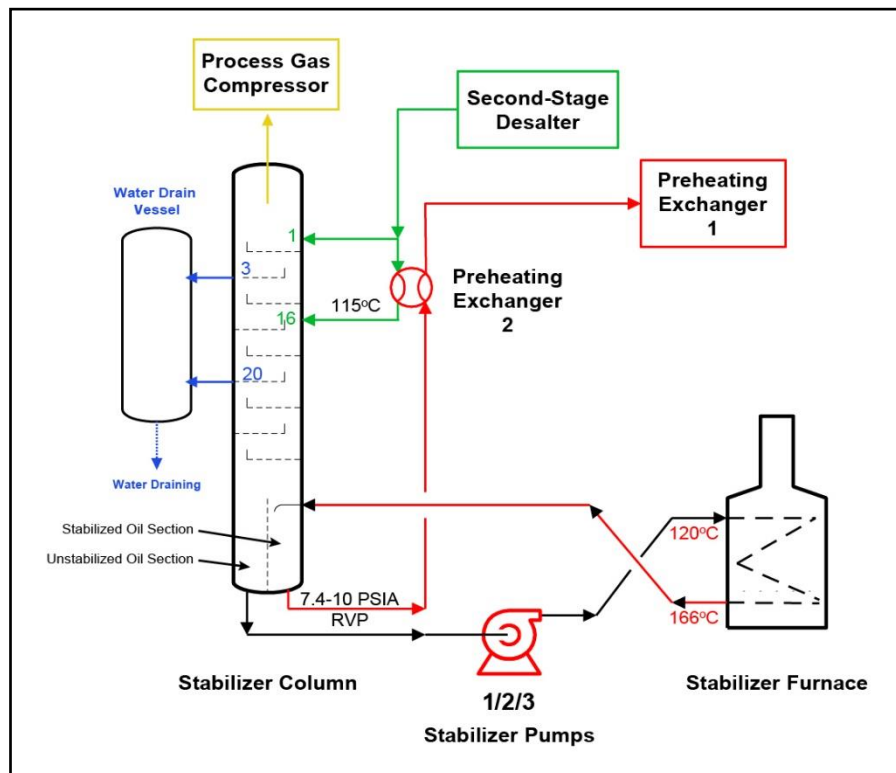


Figure 2.7: The Operation of the Stabilization System.

5.1.5.1. Operation of the Stabilization system

The stabilization column is a multi-stage tower comprising 32 trays. Fifteen of these trays are located in the rectification section (upper section), while the remaining seventeen are located in the drying section (lower section).

The oil from the second-stage desalter enters the stabilization system and is split at a ratio of about 1/3 to the preheating exchanger, heated by exchanging heat with the stabilized oil coming off the bottom of the stabilizer tower. It then enters the column at the 16th tray (hot feed). The remaining 2/3 goes directly to the top of the stabilizer tower at the first tray (cold

feed). Two flow control valves control the split, with the first valve controlling the flow to the top of the stabilizer tower and the second valve controlling the flow to the preheating exchanger.

Three pumps located at the foot of the column send unstabilized oil from the bottom of the column to the furnace for heating to a temperature of approximately 166° C (331° F), enhancing the degassing of light hydrocarbons contained in the feed. This preheated oil is then injected back into another section of the column to finalize the separation of light hydrocarbons from the oil and migrate up the tower in gaseous form.

As the gas migrates up the tower through the tower trays, it contacts the oil flowing down from the top. This interaction helps to remove the lighter hydrocarbon ends from the oil and the heavier hydrocarbon ends from the gas, resulting in stabilized oil at the bottom and predominantly light end gas at the top of the stabilizer tower. Gas off the top of the stabilizer tower goes to the process gas compressor, where it is compressed and ultimately sent to the Injection Gas Compressors. Water condensing in the column is drawn off at trays 3 and 20 and is sent to the water drain vessel.

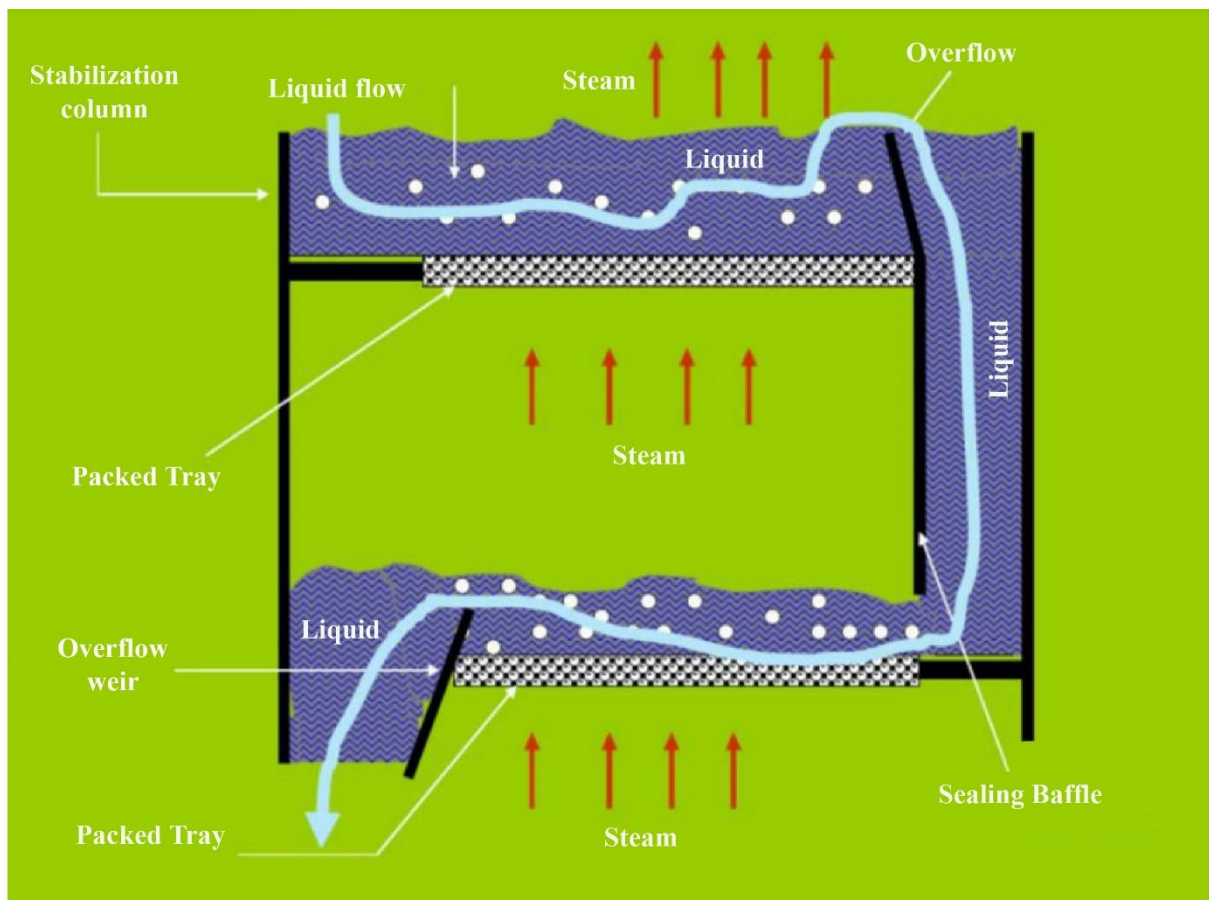


Figure 2.8: Operation of the Column Trays.

5.1.6. Metering, Storage, and Shipping

The stabilized crude oil from the stabilization column passes through two preheating exchangers in the train, serving as a heating source to prevent energy wastage. It then moves through air coolers for cooling before entering the Lact Metering unit. This unit's primary function is to accurately and separately measure the quantity of stabilized oil processed by the HBNS and HBN trains. The flow rate of oil passing through the Lact Metring unit is measured using turbine meters. The metering skids are designed to provide precise and continuous flow measurement with negligible uncertainties. Another metering system, known as the Lact Metring Fiscal, is designed to account for the entire CPF feed. This system is used to perform the daily balance.

The stabilized oil is then stored in the storage tank system and subsequently transferred by pumping to the pipelines for export.

Specifications	Values
RVP Max	0.69 bar (10 Psia)
BS&W Max Basic Sediment (Sand, dirt, and other solid impurities) and Water	0.5% volume
Salinity Max (NACL)	40 ppm
Sulfur Max	0.2% weight
Storage temperature Max	55 °C

Table 2.1: Specifications of Stabilized Oil.

Off-Specification System (Re-Run)

The off-specification system is designed to provide emergency storage for oil that does not meet shipping and RVP specifications. Therefore, it is automatically diverted to the rerun system after the stabilization process.

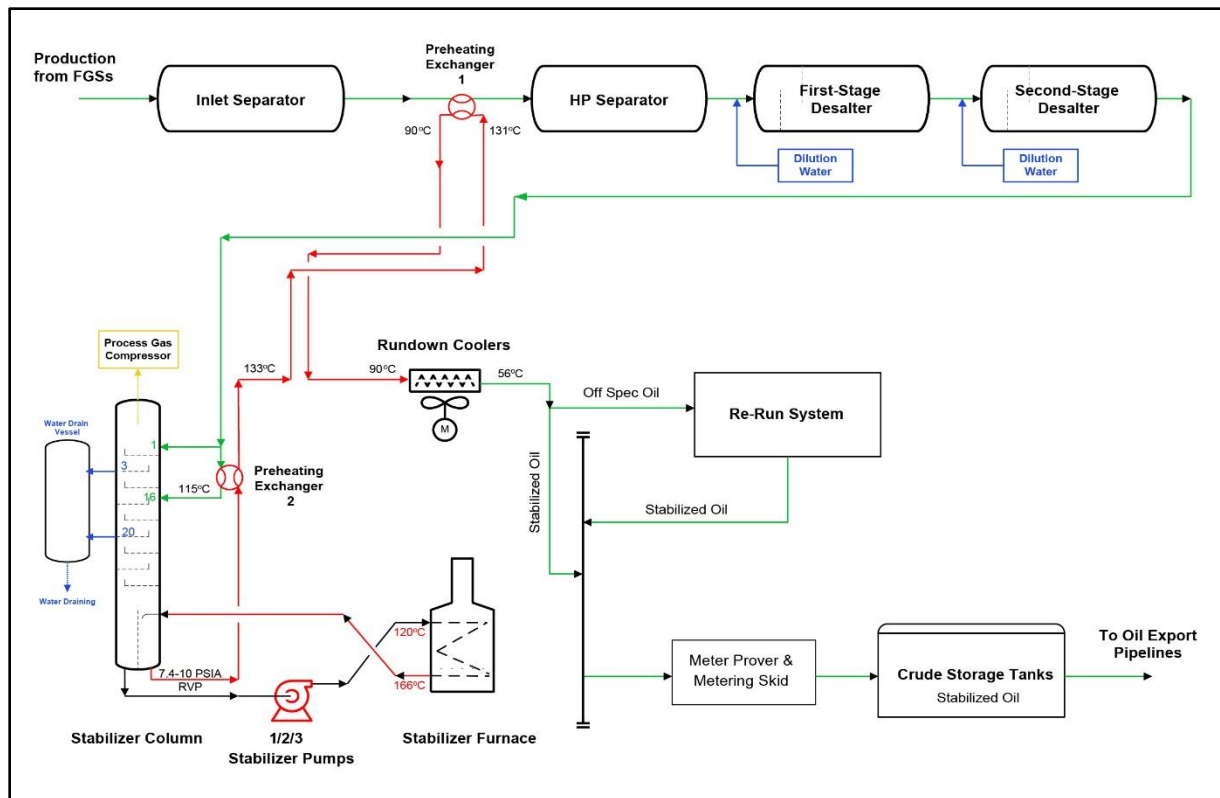


Figure 2.9: The Operation of the Oil Handling in CPF Train.

5.2. Produced Water System

The purpose of the produced water systems is to collect produced water from the four trains, specifically from the HP Separators, Desalters, and Rerun system, which then goes to a Produced Water Flash Drum. In the flash drum, water enters and any entrained gas flashes off, while the oil collected in the upper bucket of the flash drum is directed to a Rerun system for oil recovery. The drum's bottom water is pumped to a De-Oiler to remove oil droplets from the water. The produced water then proceeds to the Produced Water Treatment.

5.2.1. Produced Water Treatment Unit (PWT)

The purpose of the PWT unit is to collect de-oiled water, which then passes through sand filters to remove the largest solid particles before being stored in a storage tank. Subsequently, the water passes through hyper-filters designed to remove any remaining solid particles before finally being sent to the Water Flood unit.

5.2.2. Water Flood Unit

This unit is responsible for treating water from the producing wells. The water initially undergoes filtration and compression. It is then mixed with the produced water from the end of

the PWT unit and injected into the wells. At the inlet of this unit, chemical injection points are provided for final water treatment.

5.3. Gas Recovery Systems

The gas recovery system is designed to treat and prepare gases from various processing units to meet the required specifications for reinjection into the reservoir. This process ensures that the gas is at the optimal pressure (300 bars) for effective reinjection.

5.3.1. Gas Compression

Gas from the desalters and stabilizers within each train typically exits at a pressure below 16 bars. This gas passes through the IP Process Gas Compressor to increase its pressure to 16 bars. It is then combined with gas from the HP separator (approximately 22 bars) and sent to the HP Process Gas Compressor for further compression to 40 bars. This brings it in line with the inlet separator pressure, ready to proceed to the Glycol Dehydration System.

5.3.2. Gas Glycol Dehydration

Wet gas from both the inlet separators and process gas compressors enters a Glycol Contactor. Within this contactor, the gas mixes with a special chemical solution called glycol, which absorbs water vapor contained in the gas. This results in the dry gas needed for injection and fuel gas systems.

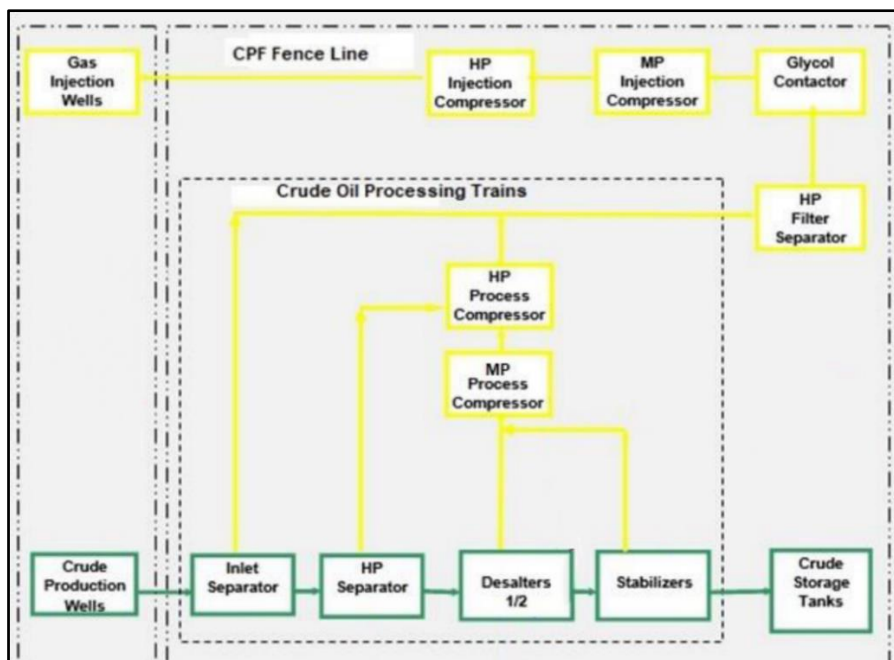


Figure 2.10: Overview of Gas Recovery System Process.

5.3.3. Gas Reinjection

The CPF houses four turbo reinjection compressors responsible for preparing the gas for injection. Dehydrated gas flows from the glycol units to the gas injection headers and undergoes a two-stage compression process. The MP Injection Compressor raises the pressure from 40 bars to 130 bars, then goes to the MP Injection Coolers for cooling, followed by the HP Injection Compressor, which boosts it to a final pressure of 300 bars. Finally, the high-pressure gas goes to the HP Discharge Coolers, resulting in cooled high-pressure gas ready for distribution to gas injection wells.

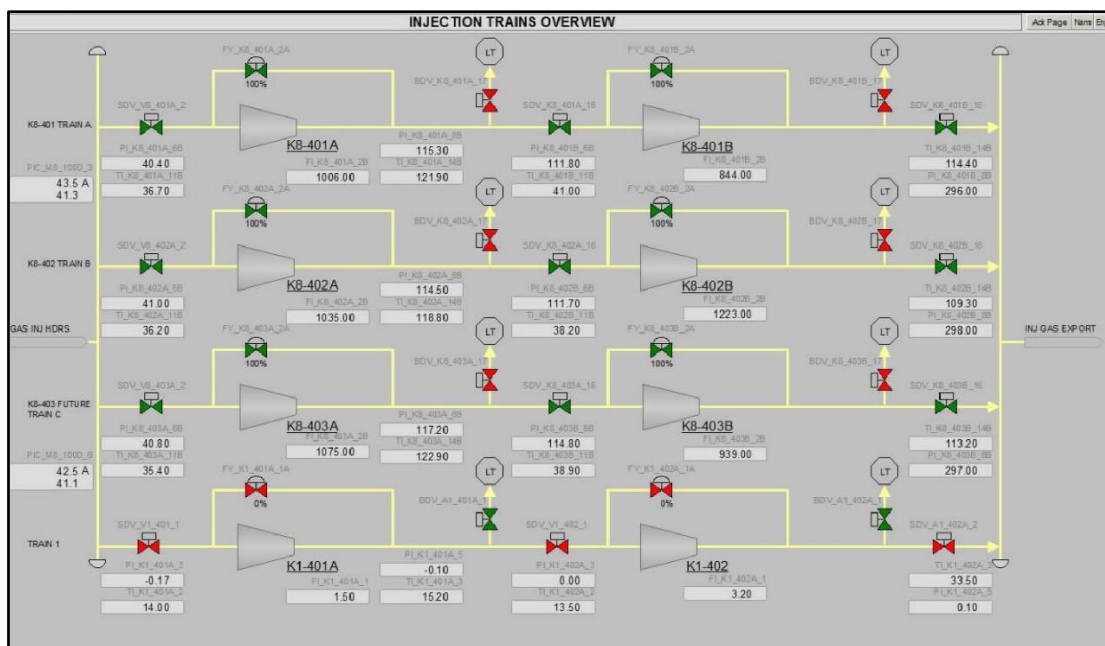


Figure 2.11: HMI of the Injection Trains Overview.

6. Utilities [8]

Utilities play a significant role in the operation of the CPF, as an issue in this unit can cause a general shutdown of the CPF. While there are numerous units and systems in the CPF, I will focus on three specific ones in this chapter that serve to enhance understanding of this project.

6.1. Compressed Air Unit

This is a critical unit responsible for providing dehydrated and compressed air to various instruments, including those used for control and safety purposes, as well as actuators such as regulation valves for level, pressure, and flow, and other systems within the CPF. It is designated by different names such as "Instrument Air" or "Air Service." It is used in pneumatic

control as the driving fluid, ensuring the movement of valve stems for regulation, and for safety devices, sending safety signals with inverse logic.

6.2. Fuel Gas Unit

This unit is responsible for providing fuel gas (combustible gas) for CPF needs and the PK0 power plant. The dry gas from the Glycol Dehydration column undergoes heating and filtration before being divided into two separate systems: the HP and LP systems. Each system serves a distinct purpose, with the HP system powering the gas turbine compressors and supplying the PK0 power plant, while the LP system is utilized for operating furnaces and torch pilots.

6.3. Flare and Blowdown Systems

Flare systems play a crucial role in the CPF by safely disposing of hazardous hydrocarbons, vapors and gas streams relieved from different scenarios and sources within the CPF area. These scenarios encompass critical phases such as:

- **Startups:** When one or all of the production facilities are initially started up, process gases may not meet the required specifications for safe processing. Flare systems collect and burn these gases, preventing them from remaining in the system.
- **Shutdowns:** During maintenance or emergency shutdowns of the entire CPF, a train, or a gas compression system, pressure within the systems and equipment must be depressurized. Flare systems handle the vented gases, ensuring safe pressure relief.
- **Abnormal operating conditions:** In cases of malfunctions or process upsets, flare systems provide a controlled outlet for off-spec gases or emergency releases.

The CPF flare system consists of 6 flare systems with different sources: including a high pressure (HP) flare, a low pressure (LP) flare, an atmospheric pressure (AP) flare, a low temperature (LT) blowdown flare, a waterflood flare (WF), and a Vapor Recovery Flare. The following criteria are used for design of these flare systems:

- Relief of liquids into the flare systems will be avoided by automatic dumping of liquid. The drum located at the end of the flare header will remove entrained liquid.
- The locations of the flares are to minimize the lengths of flare headers. Flares are designed considering the prevailing wind direction at the plant site and simultaneous

flaring of all flares. The Flare Systems should be maintained at all times to ensure the proper disposal of waste gases.

- Flare systems operate continuously, ensuring that hazardous substances are safely disposed of at all times, even during normal operations. This continuous operation is ensured by a constant supply of Pilot Gas from the fuel gas unit. This is crucial for maintaining environmental safety and preventing accidents.

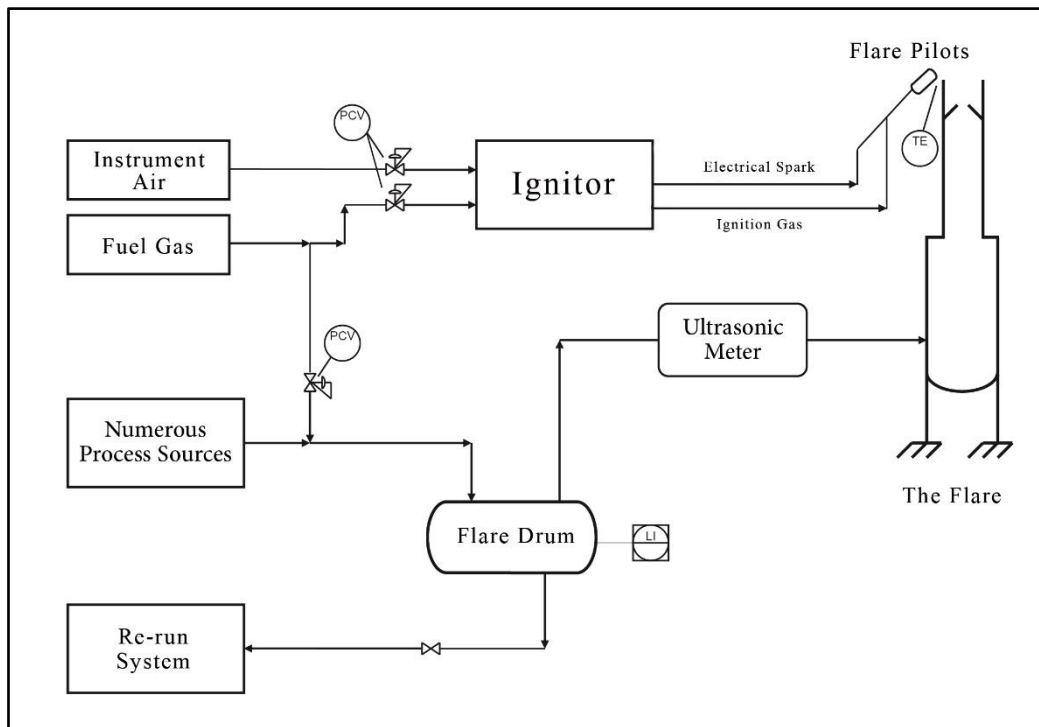


Figure 2.12: Overview of Flare System Design.

6.3.1. The LT Flare System

The purpose of the LT Flare System is to collect and burn blowdown streams from high-pressure sources that may reach low temperatures due to auto refrigeration. The LT Flare System provides relief and blowdown for the Injection Gas Compressor Systems. This will be a non-operational flare primarily used for the blowdown of injection compressors and the injection gas pipelines.

6.3.2. The HP Flare System

The HP Flare System is designed to handle the maximum gas rate expected during Full Field Exploitation. It collects and burns any waste streams and hydrocarbon gases at pressures of 10.3 barg (150 psig) and higher, which are generated from higher pressure sources such as

the oil trains and the process gas compressor systems. These waste streams and gases are then relieved to the HP Flare for burning.

6.3.3. The LP Flare System

The LP Flare System collects and burns hydrocarbon gas streams below 10.3 barg (150 psig) from low-pressure sources in the CPF.

6.3.4. The AP Flare System

The purpose of the AP Flare System is to collect and burn the vented gases at near-atmospheric pressure. These gases come from sources like Closed Drain Drums and Rerun Tanks. Rerun Tanks normally vent to the AP Flare during regular inflow.

6.3.5. The WF Flare System

The WF Flare System is designed to collect and burn the vented gases from all the produced water system, encompassing both the Produced Water Treatment and Waterflood units.

6.3.6. The Vapor Recovery Flare System

The purpose of the Vapor Recovery Flare System is to collect and burn non-condensable overhead gases from the two Glycol Still Column Condensers. The system is designed to operate at pressures above 0.02 barg (0.3 psig).

6.3.7. The Blowdown System

The Blowdown System allows depressurization of various process equipment or systems for emergency or safety conditions. Blowdown is initiated either automatically or manually. Gases are routed through blowdown valves to the HP Flare, LP Flare, or LT Flare Systems.

7. Conclusion:

During my practical internship, I explored and studied the core processes at HBNS field's Central Processing Facility (CPF), which I have summarized in this chapter. Understanding these processes allows us to better appreciate the challenges and opportunities within the CPF, driving continuous and efficient improvements. The next chapter will focus on

the study of flaring challenges and the solutions implemented by Groupement Berkine, concluding with the various issues and problems that I will address in this project.

Chapter 3

Study of Flaring Challenges and Groupement Berkine's Solution

1. Introduction

In the heart of the Sahara Desert, amidst the vast oil fields of Algeria, a constant flame burns atop towering structures. This flare, fueled by natural gas, is a familiar sight across oil-producing regions, highlighting both the potential and the environmental cost of extracting fossil fuels.

In this chapter, I will delve into an overview of gas flaring and its types in upstream oil production operations. I will also explore the relationship between flaring activity and fiscal taxes, as well as the challenges associated with this activity. Additionally, I will discuss how Groupement Berkine reacts to these challenges and its initiative in addressing them. Finally, I will outline the various issues and problems that I will address in this thesis or project.

2. Definition of Flaring

Flaring is a process used in the oil and gas industry to burn off excess gas released during various operations, such as oil production, and refining. This controlled burning converts the gas into carbon dioxide, reducing the release of methane, a potent greenhouse gas, into the atmosphere. Flaring is typically employed when it is not feasible to capture and utilize the gas for commercial purposes, such as when there is insufficient infrastructure or economic viability to transport and sell the gas. It is primarily used as a safety measure to prevent the buildup of pressure in equipment and to dispose of unwanted gas in a controlled manner.



Figure 3.1: Real Flare System.

3. Types of flaring [9]

There are various types and scenarios that lead to gas flaring at oil production facilities, grouped into three defined categories known globally: routine flaring, safety flaring, and non-routine flaring.

The below examples of routine, safety, and non-routine flaring are illustrative and therefore not an exhaustive list.

3.1. Routine Flaring

Definition	Examples of Routine Flaring
<p>Routine flaring of gas at oil production facilities is flaring during normal oil production operations in the absence of sufficient facilities or amenable geology to re-inject the produced gas, utilize it on-site, or dispatch it to a market.</p> <p>Routine flaring does not include safety flaring, even when continuous.</p>	<p>Includes:</p> <ul style="list-style-type: none"> - Flaring from oil/gas separators; - Flaring of gas production that exceeds existing gas infrastructure capacity; - Flaring from process units such as oil storage tanks, tail gas treatment units, glycol dehydration facilities, produced water treatment facilities, except where required for safety reasons.

Table 3.1: Routine Flaring Definition and Examples.

3.2. Safety Flaring

Definition	Examples of Safety Flaring
<p>Safety flaring of gas is flaring to ensure safe operation of the facility.</p>	<p>Includes flaring of:</p> <ul style="list-style-type: none"> - Gas stemming from an accident or incident that jeopardizes the safe operation of the facility; - Blow-down gas following emergency shutdown to prevent over-pressurization of all or part of the process system; - Gas required for a flare's pilot flame;

	<ul style="list-style-type: none"> - Gas produced as a result of specific safety-related operations, such as safety testing, leak testing, or emergency shutdown testing.
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Table 3.2: Safety Flaring Definition and Examples.

3.3. Non-Routine Flaring

Definition	Examples of Non-Routine Flaring
<p>Non-routine flaring of gas is all flaring other than routine and safety flaring.</p> <p>Non-routine flaring is typically intermittent and of short duration. It is either planned or unplanned.</p>	<p>Includes flaring during:</p> <ul style="list-style-type: none"> - Temporary (partial) failure of equipment that handles the gas during normal operations, until their repair or replacement, e.g., failure of compressors, pipeline, instrumentation, controls; - Temporary failure of a customer's facilities that prevents receipt of the gas; - Initial plant/field startup before the process reaches steady operating conditions and/or before gas compressors are commissioned; - Startup following facility shutdowns; - Scheduled preventive maintenance and inspections; - Construction activities, such as change of operating conditions, plant design modifications; - Process upsets when process parameters fall outside the allowable operating or design limits and flaring is required to stabilize the process again.

Table 3.3: Non-Routine Flaring Definition and Examples.

Categorizing each type of gas flaring in this way allows identification of potential actions for its mitigation in new or existing facilities. This mitigation may be through:

- Commercial solutions, on-site utilization, or re-injection for routine flaring.
- Improved facility design and/or operational procedures for routine, non-routine, and safety flaring.

4. Impact of Flared Gas on the environment [10]

Flaring is the controlled burning of unwanted natural gas during oil production. While often intended as a safety measure, its significant environmental consequences demand attention.

4.1. Greenhouse gases (GHG)

Greenhouse gases (GHG) are gases present in the atmosphere that retains some of the heat received from the sun in the atmosphere. An increase in the concentration of greenhouse gases in the atmosphere results in a rise in its temperature. Three greenhouse gases are responsible for 98% of global warming across various sources and industries. These gases are carbon dioxide (CO₂ 79%), methane (CH₄ 14%), and nitrous oxide (N₂O 5%).

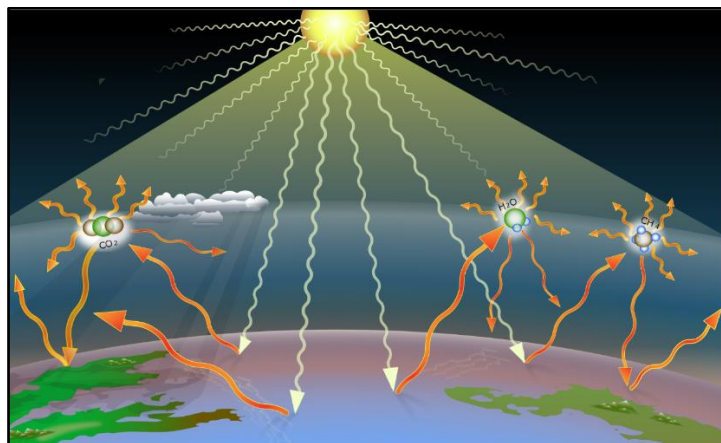


Figure 3.2: Greenhouse Gases Effect.

4.2. Flaring contribution to climate change

Flaring of natural gas during oil and gas production significantly contributes to climate change by releasing these three potent greenhouse gases (GHG) into the atmosphere, including carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O).

- **Carbon Dioxide (CO₂):** The associated gas being flared is primarily composed of methane (CH₄) and other hydrocarbons. When these hydrocarbons burn in the flare, they react with oxygen in the air. This combustion process converts the carbon within the hydrocarbons into carbon dioxide (CO₂). Although not as potent as methane, CO₂ is the most abundant greenhouse gas emitted during flaring. It traps longwave radiation from the sun, gradually warming the planet, with a lifetime of 100 years.
- **Methane (CH₄):** Methane is a much more potent greenhouse gas than CO₂, trapping significantly more heat per molecule with a lifetime of 12 years. While flaring partially converts methane to CO₂, some methane escapes unburned, contributing heavily to climate change.
- **Nitrous Oxide (N₂O):** Emitted from flaring in smaller quantities compared to CO₂ and CH₄, N₂O has the highest global warming potential among these three gases. Every molecule of N₂O released during flaring has a significant impact on the planet's temperature. N₂O is the most potent greenhouse gas, 25 times more "warming" than methane and 300 times more than CO₂, with a lifetime of 120 years.

The combined effect of these greenhouse gas emissions from flaring disrupts the Earth's energy balance, leading to:

- Rising global temperatures.
- More extreme weather events (heatwaves, droughts, floods).
- Melting glaciers and rising sea levels.
- A lasting modification of meteorological balances and ecosystems.

The responsible parties for these environmental impacts include oil and gas companies that operate flaring facilities, as well as regulatory agencies responsible for overseeing flaring practices and enforcing environmental regulations.

5. Flaring Background

5.1. The Paris Agreement [11]

The Paris Agreement, adopted at the 21st Conference of the Parties (COP21) to the United Nations Framework Convention on Climate Change (UNFCCC) in 2015, is an international treaty that addresses the critical issue of climate change. It emphasizes the

importance of sustainable development, which aims to meet the needs of the present without compromising the ability of future generations to meet their own needs. The agreement has been joined by 197 parties, including 194 states and the European Union, showcasing a broad international commitment to combat climate change.

The primary objective of the Paris Agreement is to reduce greenhouse gas emissions. To achieve this, participating countries must set national targets, known as Nationally Determined Contributions (NDCs), which are tailored to their specific circumstances and development priorities. These targets are regularly reviewed and updated to incorporate advancements and increase ambition.

5.2. The Algerian State Commitment [12]

Algeria ratified the Paris Agreement on Climate Change, which officially came into effect for the nation on November 19, 2016. This was formalized through Presidential Decree No. 16-262, demonstrating Algeria's commitment to the global effort to limit temperature rise through reduction of greenhouse gas emissions. Under the Paris Agreement, Algeria has pledged to balance its greenhouse gas emissions with reductions and sustainable practices, as detailed in its Nationally Determined Contributions (NDCs).

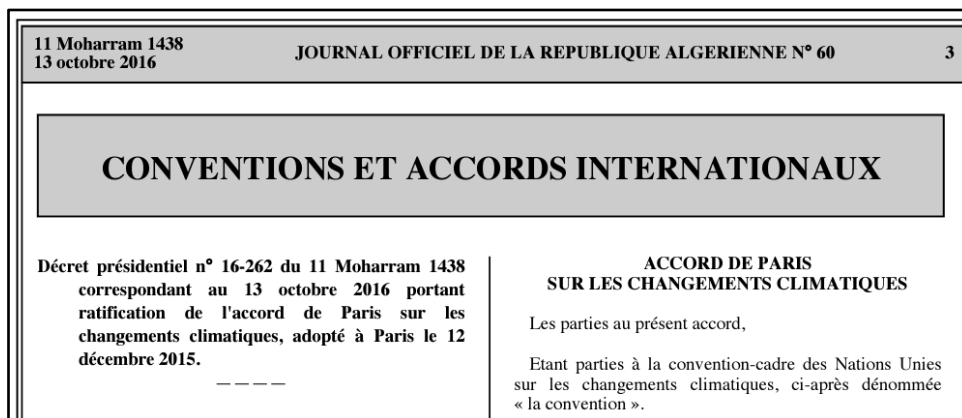


Figure 3.3: Presidential Decree No. 16-262.

5.3. Flaring tax [13]

In line with Algeria's commitment to the Paris Agreement, the Algerian government has instituted a specific tax on gas flaring associated with hydrocarbon activities. This tax applies to operations within the Sonatrach Group, including its subsidiaries, different fields and partnerships, which are required to report the exact volume of flared gas monthly. Specifically,

flaring operations incur a non-deductible tax of twelve thousand dinars (12,000 DZD) per thousand normal cubic meters (NM³) of gas flared.

The measurement of exact flare gas flow is crucial as it allows for detailed analysis of flaring practices in Algeria, assessing their environmental impact, and setting targets to minimize greenhouse gas emissions in alignment with the goals of the Paris Agreement.

Furthermore, the Algerian state has designated ALNAFT (The National Agency for the Valorization of Hydrocarbon Resources) as the body responsible for overseeing the taxation of flaring activities and related matters. ALNAFT plays a pivotal role in regulating activities in the upstream hydrocarbon sector in Algeria, which includes exploration, research, and extraction of hydrocarbons. Entities wishing to engage in these activities must comply with regulations set forth by ALNAFT.

5.4. Flaring Challenges

The primary challenge faced by the Algerian government and ALNAFT, is the absence of a standardized methodology for measuring flared gas volumetric flow that provide accurate measurement. Despite the mandate for these volumes to be disclosed for taxation, specific technology, device or procedures for measurement and calibration have not been prescribed. Additionally, it remains unclear which entity's measurements are considered authoritative. This lack of clear guidelines has led to uncertainty regarding the enforcement and accuracy of the reported data. The problem of accurately measuring flared gas is not unique to Algeria; it is an international concern within the oil and gas industry. The variable nature of gas behavior makes accurate measurement difficult, and currently, there is no industry-wide accepted method to verify the accuracy of available flare flow meters, known as a flare gas prover system. Accurate measurements are crucial, especially for fiscal transactions. These challenges, particularly the difficulties in measuring flared gas and the implementation of a flaring system prover, will be further discussed in a forthcoming chapter.

5.5. Flared Gas Estimation Approach

Initially, Groupement Berkine, along with the different fields of Sonatrach and other Sonatrach partnerships in Algeria, estimated flared gas volumes using various calculation and simulation programs. The most commonly used program is HYSYS, which allows users to create process models and simulate them using complex calculations. This approach was

avored because it was cost-effective while awaiting more definitive methods or measuring devices mandated by the state and ALNAFT for this specific activity.

However, these estimates are known to be inaccurate and unreliable for planning extension projects, primarily because they involve sensitive data such as gas volumes and pressures. Errors in estimating these parameters can lead to hazardous events and significant operational issues. The inaccuracies primarily stem from the instability of gas flows within the Central Processing Facilities (CPF) and unpredictable events like emergency shutdowns and blowdowns. This instability is exacerbated by the varying characteristics of the crude oil extracted from different wells, which contributes to fluctuations in flared gas volumes. Consequently, the real field conditions, with their inherent instability and variability, differ significantly from the simulated models, leading to skewed results. Despite these challenges, such estimates are still routinely made to comply with regulations that require monthly reports on flared gas volumes.

5.6. Groupement Berkine Study

Given that the Groupement Berkine is one of the largest and oldest oil and field in Algeria, and thanks to its field experience and significant financial liquidity, the Groupement Berkine decided to take the initiative under the patronage of Sonatrach to study the problems related to measuring flared gas, aiming to move away from ineffective estimation methods. The goal is to find the best flow method for measuring flared gases that provides accurate measurements.

After an in-depth study, Groupement Berkine found that the best method suited to its needs and the criteria of its flaring system is the Baker Hughes solution, specifically the XGF868I ultrasonic flare flow meters provided by Panametrics. Panametrics, a company of Baker Hughes, has been a pioneer in sensor technology for over 60 years. Known for its innovative culture, its proven technologies are widely recognized across various industries, including oil and gas. Baker Hughes has offered ultrasonic flare flow meters to industry leaders as a superior method for measuring gas flares for over four decades. This device is used in 80% of global cases in this field and provides the most accurate measurements possible, with an error margin of only 2%. [14]



Figure 3.4: The XGF868I Ultrasonic Flare Flow Meter.

5.7. Groupement Berkine Solution

Therefore, Groupement Berkine ordered six measurement devices from Baker, which were installed in 2018 at the HBNS site and connected to the control room monitoring system. They began operation immediately. Like all other Sonatrach and partnership fields using the estimation approach, HBNS field started sending monthly measurements to relevant authorities, including ALNAFT. After several years of data accumulation, ALNAFT noticed a significant difference in the reported measurements between the fields using estimation methods and HBNS field. This discrepancy sparked increased interest in Baker's flow meters and the methods used to verify and validate the accuracy of measurements. This is crucial for fiscal transactions. The goal is to generalize this method, organize flaring activities, and make it a standard and mandatory practice for anyone involved in flaring operations.

Demand for a method that verifies the accuracy of Baker's flow meters has increased. Consequently, the instrumentation team contacted Baker to find a solution that ensures the accuracy of these measurements. The only solution provided by Baker is a verification method known as the "Validation process." This requires preventive maintenance to be performed annually on ultrasonic flowmeters. During this process, a special device developed by Baker, called the zero-flow box, is used to check the health and accuracy of the meters, and to recalibrate them if any deviations are found. This ensures efficient operation throughout the year and guarantees an accuracy of 2%.

5.8. Validation Process [15]

Groupement Berkine requested a validation service for six flare flowmeters that were commissioned in 2018. Since their installation, no validation had been performed on these meters. It is expected that the meter readings will improve following the validation. On January 10, 2024, a field service engineer was mobilized to the HBNS site to perform the required job. This verification process, carried out under the supervision of the instrumentation team, occurred one month before the start of my internship.

The process concluded with the issuance of a document by a Baker expert, confirming that this procedure was performed safely and successfully. The document contains detailed information about the validation job conducted at the HBNS site, including the Field Service Summary Procedure, the meters' accuracy and health, and the tests they underwent. It also includes all relevant certifications and acceptance reports related to the gas flowmeters, conducted to verify their accuracy. This document from the validation process serves as proof of the accuracy of the measurements provided by these flowmeters for a period of one year and can be presented to any authority or individual requesting proof of measurement accuracy or any other information about these flare flow meters.

6. The Project Problematics:

In 2018, the installation of flare gas flow meters primarily focused only on gathering information about the flow of flared gas, specifically for transmission to ALNAFT to submit to taxes. Consequently, during the installation phase, Baker's expert incorporated only three essential parameters within the flaring system into the DCS for operators to monitor in the control room, which are: flared gas flow, gas pressure, and gas temperature.

The XGF868I ultrasonic flare gas flow meters, from Baker Hughes, are highly sophisticated instruments designed to provide precise measurements. They achieve this accuracy by utilizing multiple data and parameters collected via sensors within the flaring system. These data are then processed through complex algorithms within the XGF868I computer to yield accurate flare flow measurements.

While the majority of data collected by the flare gas flow computer sensors haven't been integrated into the DCS due to their unnecessary nature, they are utilized by the algorithms to calculate accurate volumetric flow rate. However, certain data hold significant potential for

HBNS site processes and could be vital in addressing various challenges and solving critical problems within HBNS site. These issues can be summarized as follows:

1. The absence of detailed process data about the flare gas in the HBNS's DCS, making it difficult for operators to gain a comprehensive understanding of real-time flaring system processes. This lack of data hinders the ability to make informed optimization decisions and identify potential safety hazards.
2. The absence of all diagnostic data about Baker's flare gas flow computers in HBNS's DCS, which creates a blind spot in remotely monitoring their health. As a result, workers are forced to perform daily manual verifications, a time-consuming task due to the computers' distributed locations. This diverts them from their primary responsibilities of monitoring and maintaining other important instruments in the CPF. Without diagnostic data, issues often go undetected until the verification day, leading to unexpected downtime and disruptions in flared gas flow measurement. Furthermore, the absence of a comprehensive database containing the flare gas flow computer's behavior hampers Baker experts' ability to collaborate remotely with the instrumentation team and to swiftly analyze and resolve issues without field intervention. Consequently, this exacerbates the problem, causing prolonged downtime and increased field intervention costs.

7. Conclusion:

The integration of vital data and parameters provided by the flare gas flow meters into the DCS is essential for optimizing operational efficiency. Utilizing this integrated data in Honeywell's monitoring and analytical solutions is crucial for maximizing the effectiveness of the flare gas flow meters and addressing the critical problems discussed earlier, thereby ensuring the profitability of Groupement Berkine's investment.

To effectively resolve these issues, it is necessary to conduct a thorough study of the ICSS system architecture and operation, specifically where Baker Hughes's flare gas flow meters are integrated as a third-party device using Modbus RTU, and gain a deep understanding of the third-party communication. This will be the primary focus of the next chapter.

Chapter 4

Study of the Honeywell ICSS Architecture and Third-Party Systems Integration

1. Introduction

This facility's operations are complex and require an unwavering control and automation system. A solid strategy with the flexibility to integrate third-party systems and devices for specific tasks is essential to ensure both reliable control and safety. This is where Honeywell's Integrated Control and Safety System (ICSS) comes into play.

In this chapter, I will delve into the architecture and functionalities of the Honeywell ICSS at the HBNS site, with a focus on the integration of third-party systems and devices using Modbus RTU communication. I will examine how data flows from field devices to the Human-Machine Interfaces (HMIs) in the Central Control Room (CCR).

2. Integrated Control and Safety System

2.1. Definition of the ICSS

At the HBNS site, the Honeywell ICSS (Integrated Control and Safety System) serves as the master automation system. This system seamlessly combines Honeywell's DCS solution, Experion® PKS (Experion Process Knowledge System), and the safety system solution, Safety Manager, into a single, unified architecture.

As a unified control system by Honeywell, the ICSS efficiently minimizes integration challenges between control and safety systems, ensuring harmonization and enhancing both performance and safety across the HBNS site. Consequently, it simplifies operations and reduces both maintenance time and costs. It is designed to enable operators for effective monitoring, control, and data acquisition from diverse processes under one system, from the wells to oil export.

2.2. Key Functions of the ICSS

The ICSS enables the following main tasks:

- Controlling the CPF's processes (PCS) using Experion PKS C300 Controllers.

- Managing all site safety through the Process Shutdown System (PSD) and the Emergency Shutdown System (ESD) functions, using the Honeywell Safety Manager System.
- Monitoring fire and gas in the CPF using the Honeywell Safety Manager System.
- Integrating, monitoring, and controlling third-party automation and control systems and devices from various vendors in the CPF through the Experion SCADA system using Modbus RTU.
- Integrating, monitoring, and controlling well statuses from the Remote Terminal Units (RTUs) through the Experion SCADA system using Modbus RTU.
- Operating Human-Machine Interfaces (HMIs) and displays in the Operator Workstations (OWS) and Engineering Workstations (EWS) in the Central Control Room (CCR) using Station software.
- Facilitating the interaction of third-party software with the current ICSS system via a dedicated OPC server, enabling seamless data exchange between different devices and systems.

The following figure represents the architecture of the ICSS.

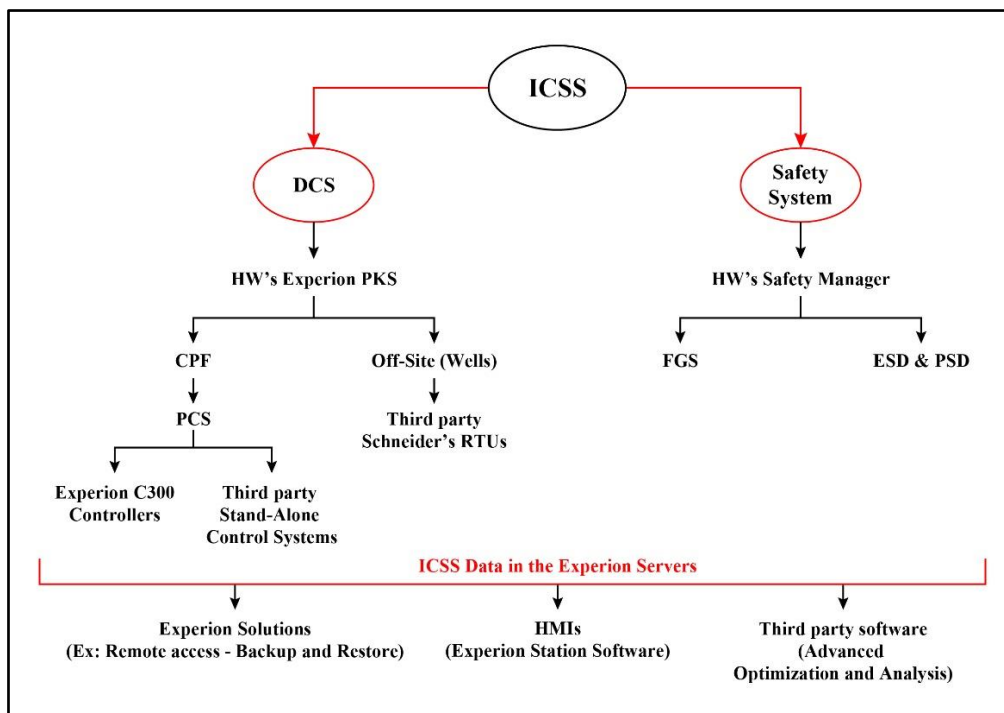


Figure 4.1: Architecture of the ICSS.

3. Distributed Control System

3.1. Definition of the DCS

A DCS (Distributed Control System) is specifically designed to control and monitor large-scale industrial processes that operate continuously, such as the oil production fields like HBNS site. As its name suggests, it features multiple controllers distributed throughout the CPF, with each managing a specific area or process. While individual controllers handle local tasks, a DCS provides a central point for operators to monitor and manage the entire system in CCR.

3.2. Honeywell's DCS solution, Experion® PKS

The Experion Process Knowledge System (PKS) is an advanced automation platform solution that comprises a variety of Honeywell's high-edge hardware solutions and a suite of innovative software applications. It has the capability to seamlessly integrate specialized third-party automation and control systems or devices from various vendors. This comprehensive system takes customers beyond traditional Distributed Control System (DCS) functionality, enhancing process performance, increasing people effectiveness, and providing peace of mind.

One of the game-changing advantages of the Honeywell DCS is its concept of redundancy. It supports device and network redundancy through an FTE (Fault Tolerant Ethernet) network, which significantly increases reliability and ensures high availability. This robust feature guarantees process continuity even in the event of a device failure, making the system exceptionally reliable and efficient.

4. ICSS Architecture of HBNS [16]

The Honeywell ICSS has five levels, but only the first three are particularly important for this project.

4.1. Level 0

This is the base level, which includes various Inputs and Outputs (I/O). These devices directly interact with the physical process, including: transmitters, switches, speed drives, and control valves.

Sensors transmit analog or digital signals that represent process variables and status to the I/O modules. The types of I/O available are:

- **Analog Input (AI):** Reads continuous signals such as temperature or pressure.

- **Analog Output (AO):** Sends control signals to adjust devices like valves or motors.
- **Digital Input (DI):** Detects on/off states from switches.
- **Digital Output (DO):** Sends on/off commands to actuators.

4.2. Level 1

Level 1 components are housed within switchgears.

4.2.1. Switchgear Buildings

Switchgears are buildings distributed across the CPF, each dedicated to the real time control and management of specific units or systems within the CPF. These include:

1. **Central Control Room (CCR):** used for overall control of the CPF using the ICSS.
2. **Main Switchgear Building (MGB)** for utility units and systems (compressed air, fuel gas, nitrogen, electricity).
3. **30 KV Switchgear Building** for incoming power supply by SONELGAZ.
4. **Switchgear Building 2 (SGB2)** for Train 1.
5. **Switchgear Building 3 (SGB3)** for the metering, storage, and export systems.
6. **Switchgear Building 4 (SGB4)** for Trains 2, 3, 4, and the dehydration unit.
7. **Injection Compressor Building** (remote F&G panel, DCS station).



Figure 4.2: Aerial Overview of HBNS Site's CPF.

These buildings contain several electrical cabinets, divided into two main types. The first type is marshalling cabinets, which receive I/O signals directly from the nearest junction boxes that collect groups of I/O signals from field devices. These cabinets organize the signals and pass them through electronic cards that filter the signals. The signals are then grouped into an FTA (Field Termination Assemblies) cable before being transmitted to the second type of cabinet, where they are connected to the I/O modules. The FTA cable is a sheath that groups

all the I/O cables, reducing clutter and enabling neat connections. The following figure illustrates an FTA cable.

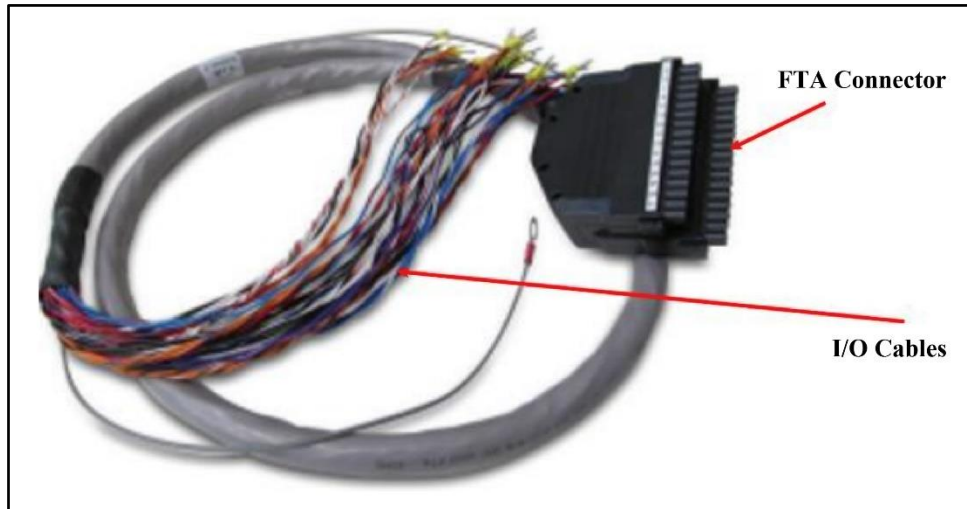


Figure 4.3: Illustration of FTA cable.

The second type consists of control cabinets, which contain various automation and control systems along with their associated modules. These systems are specifically designed to manage units and systems that perform specialized tasks. However, the entire process is centrally overseen and conducted from the CCR using the ICSS via OWS.

These automation and control systems are categorized into two types:

1. **Honeywell Systems:** These include Honeywell's C300 controllers, which are used for PCS, and Honeywell Safety Managers for SS and FGS.
2. **Third-Party Systems (Non-Honeywell):** These encompass a variety of programmable logic controllers (PLCs) from different leading manufacturers used for specialized tasks. For instance, Siemens PLC controls the PWT, Allen Bradley PLC manages furnace operations, and GE Mark VI controllers are used for turbine control.

4.2.2. Experion PKS C300 Controllers [17]

A controller is an evolution of a PLC, offering higher processing capabilities and supporting a large number of I/Os. It is used for automating complex tasks. However, with current technological advances, PLCs have become more efficient, and the distinction between them and controllers has blurred.

The Experion PKS C300 controller forms the heart of the Experion control system. It is a secure, out-of-the-box DCS controller that provides best-in-class process control capabilities and security. The C300 controller supports a wide variety of process control applications, including continuous and batch processes, and integrates with smart field devices. It also supports advanced process control and custom algorithm blocks, allowing users to create custom code to run in the controller.

The C300 operates Honeywell's deterministic Control Execution Environment (CEE) software, which executes control strategies on a constant and predictable schedule. It transparently integrates standard and open communication protocols such as Ethernet IP, Profinet, Fieldbus, HART, OPC, Profibus, and Modbus, addressing the requirements of a wide range of applications. The C300 controller can operate in both redundant and non-redundant configurations, with redundancy achieved by connecting two C300 controllers with an FTE cable.

4.2.2.1. FTE

Fault Tolerant Ethernet (FTE) is Honeywell's proprietary networking protocol designed for industrial control systems like ICSS. FTE enhances standard Ethernet to provide high reliability and redundancy with no single point of failure. Its key feature is the "Yellow/Green" dual network approach, which minimizes downtime by seamlessly switching traffic to a backup path during network failures. Additionally, FTE supports rapid network speeds, potentially up to 1 Gbps.

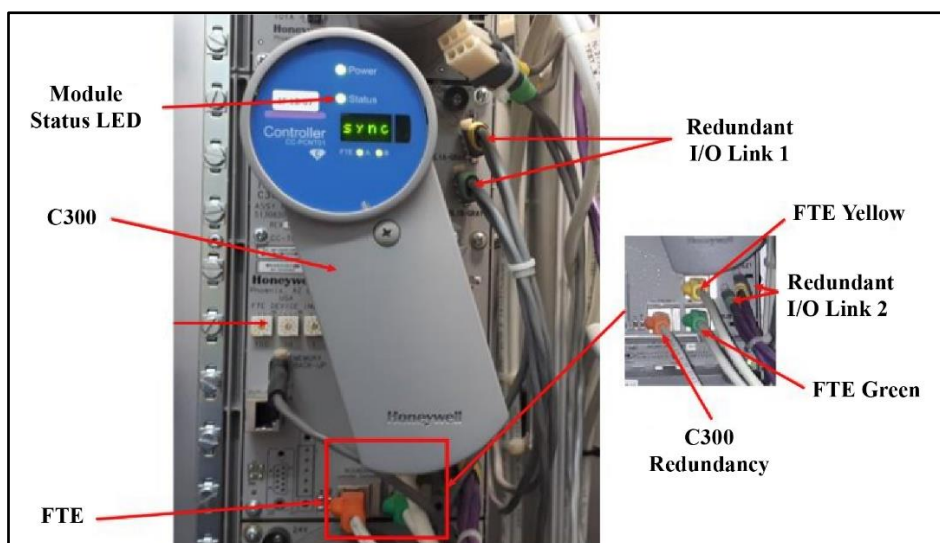


Figure 4.4: Illustration of C300 Controller.

4.2.2.2. I/O Link

IO-Link (Input Output Link) is a short-distance, bidirectional industrial communications network protocol, using a type of industrial fieldbus to link the C300 and I/O modules. IO-Link can be either gray or violet, used to share sent data to avoid network overload. Each IO-Link has a yellow and a green connector, sending the same data through each cable, ensuring redundancy. The following figure represents an IO-Link cable.

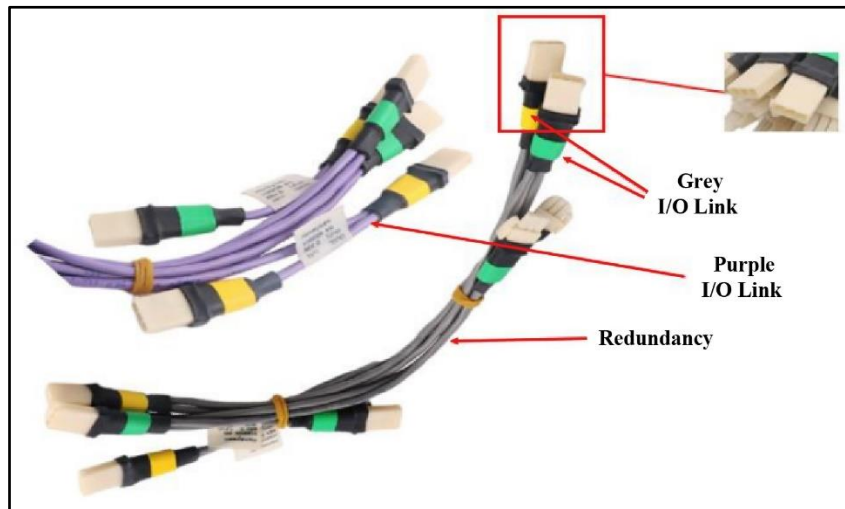


Figure 4.5: Illustration of IO-Link cable.

A single IO-Link cable connects all I/O modules and the C300, distinguishing data from each module by its address. The following figure shows the connection between a C300 and I/O modules.

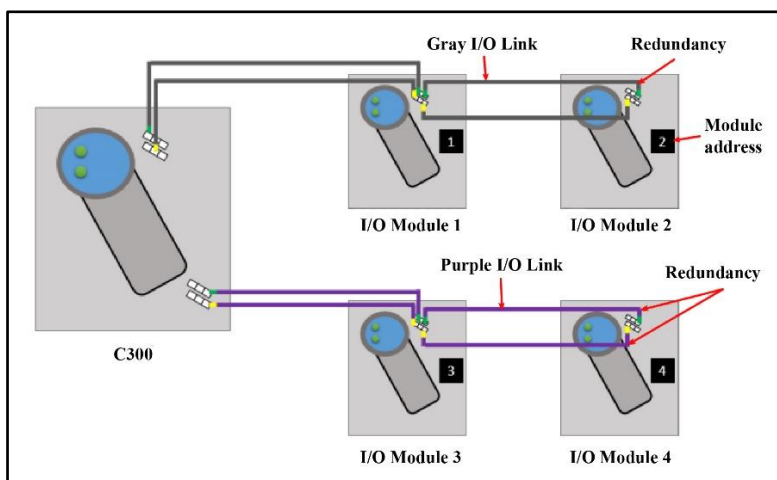


Figure 4.6: Connection Between a C300 Controller and I/O Modules.

4.2.2.3. Series C I/O Modules [18]

These modules connect the controller to instruments. The most commonly used modules are:

- **Digital Input:** These modules are used to receive 24V DC discrete (on/off) signals from field devices.
- **Digital Output:** These modules send 24V DC discrete signals to control devices
- **Analog Input/HART Input:** These modules accept 4-20mA analog signals from transmitters measuring process variables like pressure, temperature, and flow. They also support HART communication, which allows for bi-directional communication with HART-enabled field devices for configuration, diagnostics, and additional process variable information.
- **Analog Output:** Supports standard 4-20 mA outputs used to send control signals to adjust devices like valves or motors.

The following figure represents a digital output module.

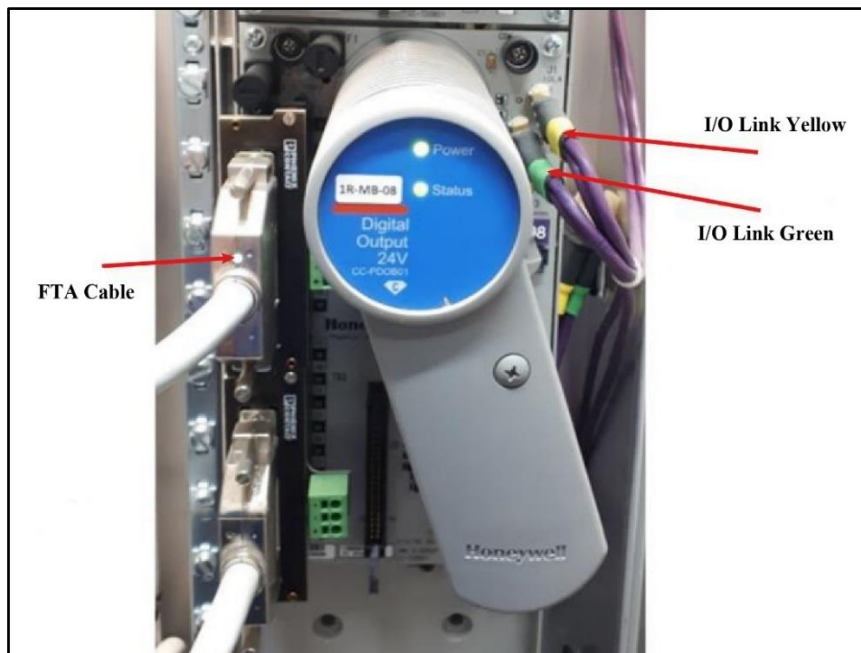


Figure 4.7: Illustration of the Honeywell Series C Digital Output Module.

4.2.2.4. CF9 Module

In addition to monitoring network traffic and blocking undesirable traffic, the CF9 (Control Firewall) module acts as a switch, networking various C300s and Safety Managers

connected to it using FTE cable, enabling data exchange. The following figure represents a CF9.

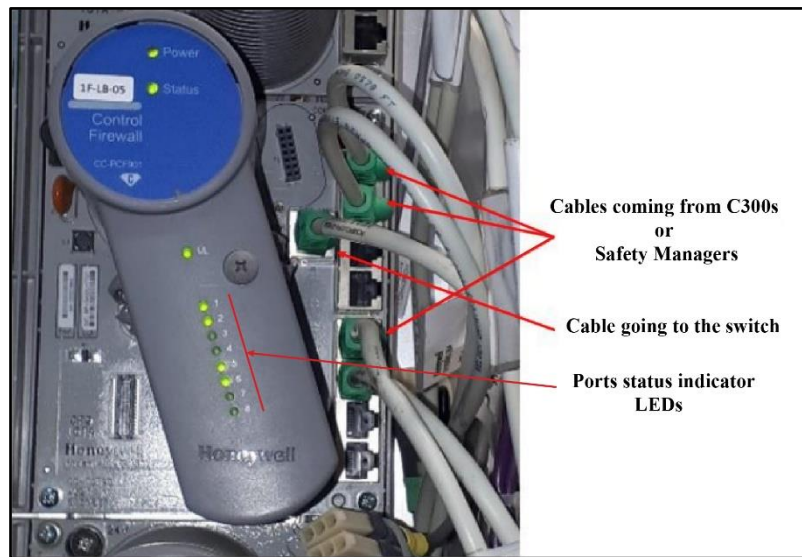


Figure 4.8: Illustration of CF9.

4.2.3. Honeywell Safety Manager (SM) [19]

In industrial automation, safety PLCs are specifically designed to meet stringent safety standards. They adhere to Safety Integrity Levels (SIL), which measure a device's ability to perform critical safety functions reliably. Honeywell's Safety Manager (SM), a key component of the ICSS, is a prime example of safety system solution. It is a SIL 3 certified system, ensuring exceptional safety and availability for industrial sites like HBNS site.

The Safety Manager acts as a safeguard, preventing the escalation of process alarms triggered by equipment failures, sudden parameter fluctuations, or human error that could lead to shutdowns. This is crucial for maintaining safe and efficient operations in critical industrial processes. Its fault-tolerant design with redundant CPUs guarantees continuous operation even during system maintenance or upgrades, making it a vital tool for safe and efficient industrial processes.

The SM supports various network protocols, including FTE, standard Ethernet, and Modbus. This versatility allows for seamless integration with a wide range of systems. Specifically, the SM can connect to the ICSS in two ways: either via FTE at the CF9 located at level 1, which also allows data exchange between the C300 and the SM, or through the switch in the control room to send its data directly to the Experion Server if the SM is inside the CCR. If the SM and the C300 are not in the same switchgear, communication between them is possible

using PCDI (Peer Communication Data Interface), which sends information over the FTE network without going through the servers.

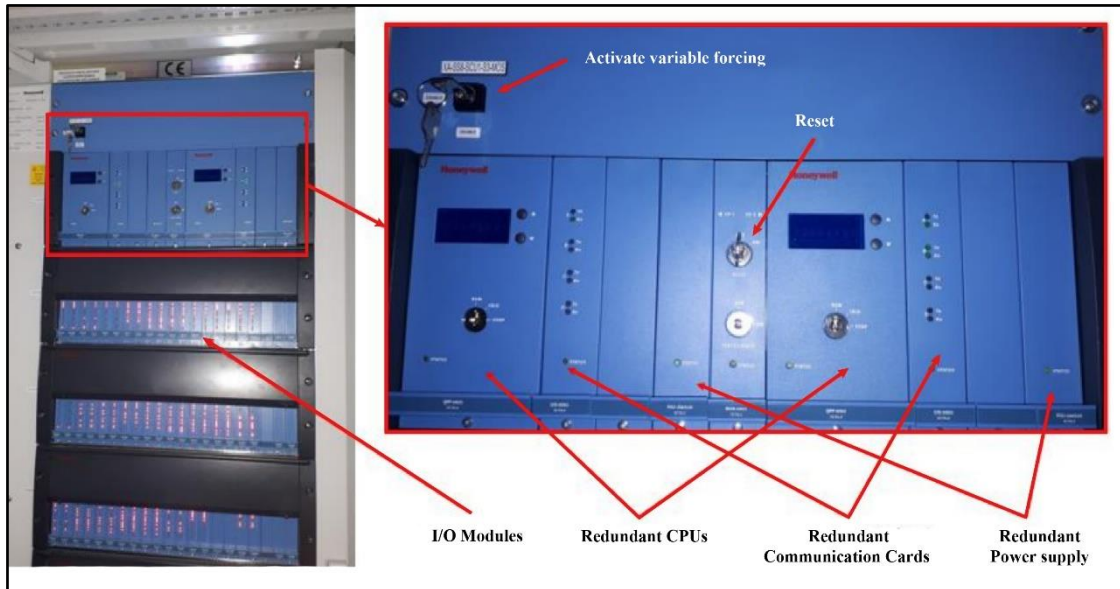


Figure 4.9: Illustration of the SM.

Different SM controllers communicate with each other via the SIL 4 certified SafeNet network protocol, which guarantees fast and reliable communication.

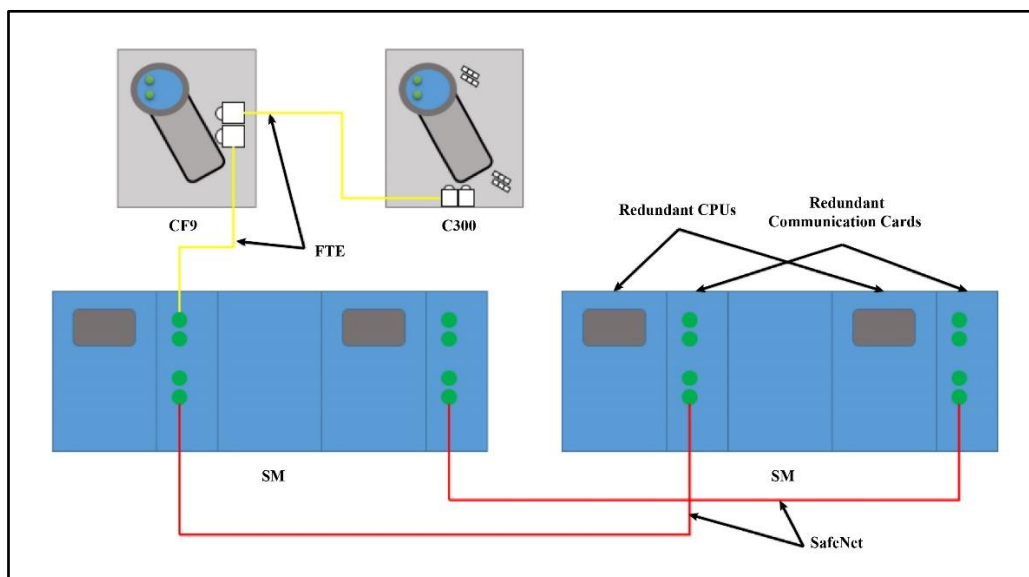


Figure 4.10: FTE and SafeNet connections of the SM.

At the HBNS site, the Honeywell Safety Manager is responsible for the following systems:

4.2.3.1. Safety System (SS)

The Safety System comprises the PSD and ESD functions, operating independently from the PCS. It is responsible for keeping critical process variables under control and, in case of process troubles or risk, it will shut the main equipment down, bringing the plant to a safe condition.

4.2.3.2. Fire and Gas System (FGS)

The Fire and Gas System operates independently from both the PCS and SS systems. It monitors the status of the plant using various detectors (e.g., fire detectors, smoke detectors). When it detects fire or gas events, it initiates safe actions to keep the plant in a safe condition.

4.2.4. 3rd Party Systems and devices

A significant advantage of Experion PKS system, is their ability to seamlessly integrate specialized third-party automation and control systems or devices. These dedicated systems and devices, often designed for specific tasks, processes, or units, bring unmatched expertise and precision to complex operations that might otherwise pose challenges. This integration enables the Honeywell ICSS at HBNS site to leverage unique capabilities, optimize control strategies, and boost overall efficiency within the industrial environment.

At HBNS, the CPF incorporates various third-party automation and control systems and devices, such as flare flow meters and various types of PLCs from leading manufacturers like Siemens (for PWT control), Allen Bradley (for furnace operations), and GE (for injection compressors and turbine control).

These non-Honeywell systems and devices are integrated using the Modbus RTU serial communication protocol over two different standards, RS-232 or RS-485 depending on the desired type of communication. Their data is converted to FTE using a Terminal Server before being transmitted to the FTE switch at Level 1 for integration with the ICSS.

4.2.4.1. Modbus RTU [20]

Modbus RTU (Remote Terminal Unit) is a widely adopted open industrial protocol used for serial communication between devices. The protocol's straightforward structure and message format make it easy to understand and implement, reducing development time and costs. This protocol is known for its simplicity, reliability, robustness, and cost-effectiveness

making it a popular choice for industrial automation. In HBNS site setup, non-Honeywell systems and devices utilize Modbus RTU to exchange data with the ICSS.

4.2.4.1.1. Limitations of Modbus RTU

While Modbus RTU is a reliable and widely used protocol, it has certain limitations that can impact its performance in industrial applications. These limitations include:

- **Limited Speed:** Because Modbus RTU uses serial communication, it can be relatively slow compared to modern networking protocols like Ethernet, especially over longer distances. For example, at the HBNS site's CPF, the flare flow computer sends data that takes 30 seconds to arrive in the ICSS and get updated in the HMI. This slow speed is why Modbus RTU is not used in safety networks like SafeNet, where critical time control is essential, and safety data or commands need to arrive within 1 second.
- **Limited Distance:** The maximum distance for reliable communication using Modbus RTU is typically around 1 km, depending on the physical layer standard (e.g., RS-232, RS-485). At the HBNS site, using Modbus RTU for data exchange between non-Honeywell systems and the ICSS requires careful planning. The placement of PLCs in cabinets must be close to the Terminal Server inside the SGB to ensure reliable communication. Similarly, field devices like flare flow computers must be within the permissible distance from the Terminal Server to maintain reliable data transmission.

4.2.4.1.2. Modbus RTU Data Transfer

Modbus RTU messages or frames are encoded in binary format, making them compact and efficient for transmission over serial lines, each consisting of:

- **Device Address:** Identifies the target slave device. Represented in 8 bits.
- **Function Code:** Specifies the type of operation to be performed by the slave device. It's a numerical code that corresponds to a specific Modbus RTU command. By using different function codes, the master device can efficiently access and manipulate a wide range of data points within multiple devices.

Represented in 8 bits. Common Function Codes:

- **03 (Read Holding Registers):** Read the contents of multiple consecutive holding registers from the slave device. Reads the values of up to 125 holding registers.

- **06 (Write Single Register):** Write a new value to a single holding register in the slave device.
- **16 (Write Multiple Registers):** Write new values to multiple consecutive holding registers.
- **01 (Read Coils):** Read the ON/OFF status of multiple discrete coils.
- **05 (Write Single Coil):** Turn a single coil ON or OFF.
- **Data:** The actual information being transmitted (e.g., sensor readings, control commands). Data within Modbus devices is organized into registers. These registers are memory that can store different types of information, such as input values (e.g., sensor readings), output values (e.g., control signals), and configuration parameters. Each register has a specific address, size it can store and the master device can access these registers by specifying their address in the Modbus message.
- **Error Check (CRC - Cyclic Redundancy Check):** An error-checking mechanisms to ensure that the data that was sent is the same as the data that was received in case there's interference and minimize the risk of transmission errors.

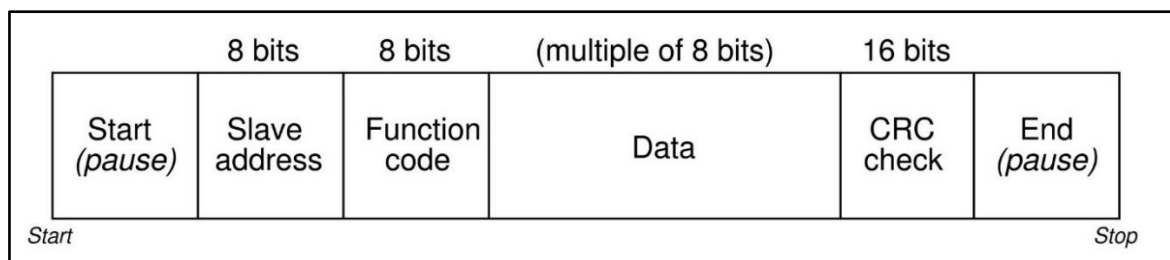


Figure 4.11: Modbus RTU Message Frame.

4.2.4.1.3. Types of Modbus RTU Data

Modbus RTU supports different data types for various applications:

- **Discrete Inputs:** They represent single-bit binary values (0 or 1) that typically indicate the ON/OFF status of physical devices like switches or sensors. They are read-only, meaning their state can only be monitored but not changed through Modbus RTU. Their addresses range from 10001-20000.
- **Coils:** They represent single-bit binary values. However, the key difference is that coils are read/write. This means they can be used to both monitor and control the state of devices. Their addresses range from 00001-10000.
- **Input Registers:** These hold 16-bit unsigned integer values (0 to 65535). While they are often used to store analog measurements (like temperature or pressure) after they've

been digitized, they can technically hold any numerical data within that range. Input registers are read-only. Their addresses range from 30001-40000.

- **Holding Registers:** These are also 16-bit unsigned integer values, but they are read/write, allowing both monitoring and modification of their contents. They are commonly used for storing configuration settings, setpoints, or other data that needs to be adjusted by the master device. Their addresses range from 40001-50000.

While Modbus RTU itself only defines these basic data types (bits and registers), it's common for devices to use multiple registers together to represent more bigger and complex data types. For example:

- **32-bit Integer:** Two consecutive holding registers can be combined to represent a 32-bit integer value using standard formats like IEEE 754.

4.2.4.1.4. Modbus RTU Physical Layer

Modbus RTU is implemented via 2 different standards, RS-232 or RS-485 depending on the desired type of communication.

4.2.4.1.4.1. RS232 (Recommended Standard 232)

- **Characteristics:**
 - **Purpose:** Primarily designed for point-to-point communication, links between two devices. (Ex: PLC to Terminal Server).
 - **Duplex Type:** Full duplex, it can send and receive data simultaneously.
 - **Wiring:** Typically uses a DB9 connector with dedicated pins for transmit (Tx), receive (Rx), and ground (GND). Easy to implement and understand.
 - **Distance:** Limited to shorter distances, usually up to about 15 meters. Not suitable for longer communication distances.
 - **Speed:** Supports lower data rates, generally up to 115.2 kilobits per second (kbps) for standard implementations, not ideal for high-speed data transfer.

4.2.4.1.4.2. RS485 (Recommended Standard 485)

- **Characteristics:**
 - **Purpose:** Designed for multi-drop communication in industrial environments. It has a Multi-Drop Capability on a single bus.

- **Duplex Type:** Full duplex for the four-wire configuration, and half duplex in two-wire configurations.
- **Wiring:** Typically uses twisted-pair cables (two-wire or four-wire configurations).
- **Distance:** Can reach longer distances, up to 1200 meters. Ideal for networks that need to cover larger areas.
- **Speed:** Supports higher data rates, up to 10 megabits per second (Mbps) or more, depending on the distance. Suitable for applications requiring faster data transmission.

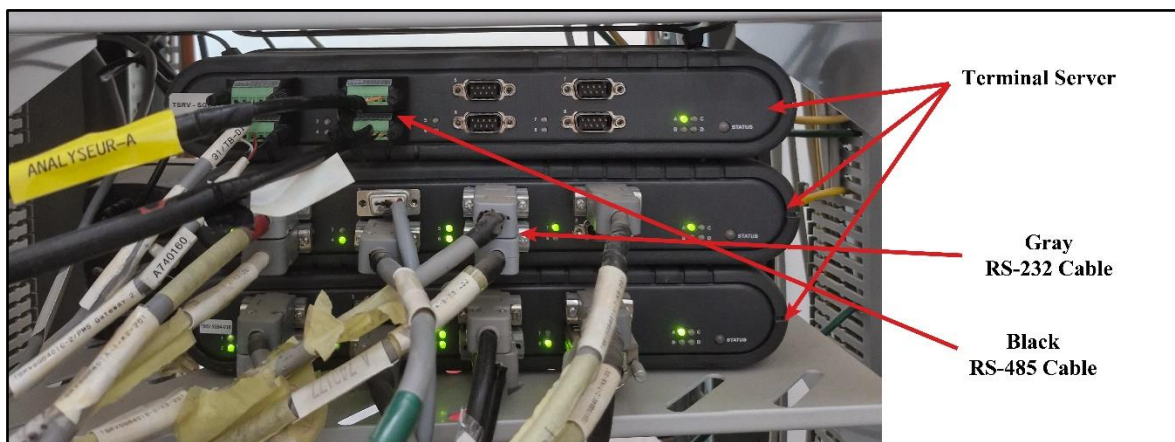


Figure 4.12: Modbus RTU Cable.

4.2.4.2. Terminal Server

A terminal server plays a crucial role in integrating Modbus RTU devices with the ICSS. As Modbus RTU utilizes serial communication, it is not directly compatible with the FTE network, which operates on a different protocol. The terminal server acts as a bridge between these two worlds. It receives Modbus RTU data from the 3rd party systems and field devices and converts it into the FTE format, and then transmits it to the FTE switch L1. This conversion process allows seamless integration of the non-Honeywell devices into the ICSS, enabling centralized monitoring and control of the entire system.



Figure 4.13: Illustration of Terminal Server.

4.2.5. FTE Switch

The FTE switch networks all connected devices. In this case, it networks the various CF9s and terminal servers that contain third-party systems in the same switchgear, allowing data exchange between all level 1 elements in the same room. The switch uses the FTE network to link level 1 and level 2 elements.

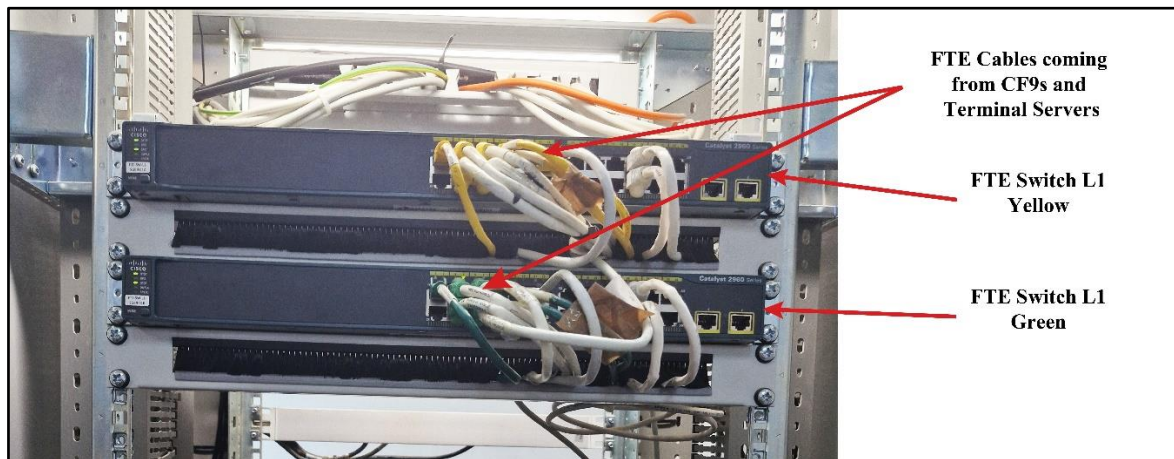


Figure 4.14: Illustration of FTE Switch.

4.2.6. FTE Network [21]

A unique local area network (LAN) topology developed by Honeywell, designed for network redundancy. The FTE network ensures high data transfer reliability, containing two parallel hierarchical trees with redundant switches (FTE Yellow and FTE Green), connected at the highest level by a 'crossover' cable. This allows network communication through an alternative path when the main path is corrupted. Each connected device has an FTE address.

All level 1 data is shared at the FTE switch level 1, outputting to an FTE/Fiber Optic converter (FOC), converting FTE data for fiber optic transmission to the distant control room. In this room, data is reconverted to FTE using another FOC and enters FTE switch networking

level 2 elements. The following figure represents the FTE network hierarchy in one of the Switchgear buildings.

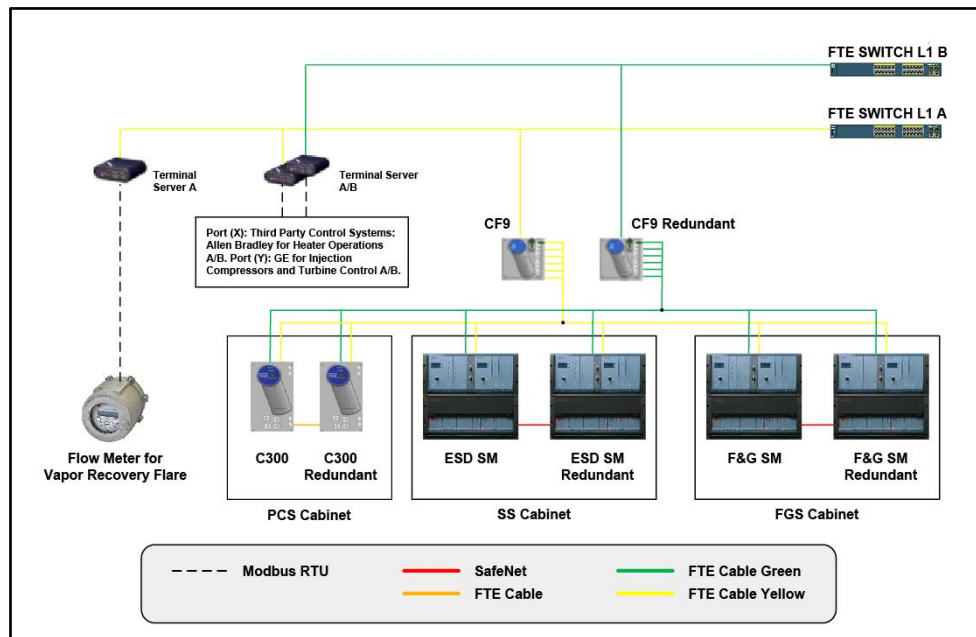


Figure 4.15: Illustration of FTE Network Hierarchy in a Switchgear Building 4 Level 1.

4.3. Level 2

Level 2 represents the supervision and control network in the CCR, collecting data from the FTE network and providing control screens for the operator. It includes redundant servers and HMIs.

4.3.1. Servers [22]

A server is a high-performance computer system, used for processing, storing, and managing data.

Honeywell partners with computer manufacturers to design and build server platforms tailored specifically according to Honeywell specifications for the demanding requirements of Experion process control systems. This ensures optimal performance, reliability, and compatibility for critical industrial applications.

The control room at HBNS houses eight Dell PowerEdge R420 rack servers, configured as four pairs. Within each pair, one server acts as the primary while the other serves as a redundant backup to ensure high availability in case of failure. All eight servers are interconnected through an FTE network.



Figure 4.16: Dell PowerEdge R420 rack servers.

4.3.1.1. Experion Server

The Experion Server is a central component of the Experion PKS, serving as the system's main data repository and historian dedicated to data within the CPF. It collects a wide range of data, including process values, diagnostics, alarms, and events, from various sources across the CPF. This includes all C300 controllers, Safety Managers, and third-party systems and devices, such as flare flow meters.

Once collected, the server processes, stores, and manages this data, making it accessible to multiple clients over a network. These clients include HMIs displayed in the Experion Station software, C300 controllers, and third-party software applications used for advanced optimization and analysis. The Experion Server comprises four distinct databases, each serving a specific purpose to effectively organize and manage this wealth of information.

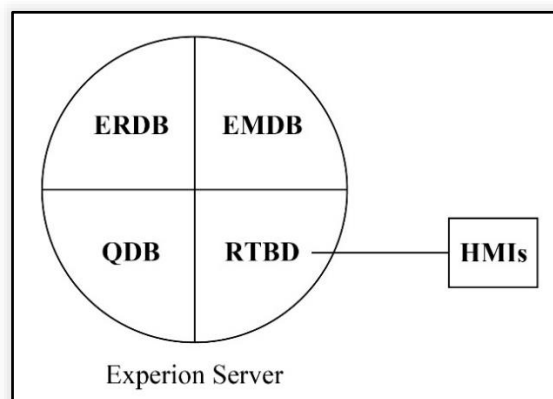


Figure 4.17: Experion Server Breakdown.

1. **ERDB (Engineering Record Database):** This database contains the data of control strategies and configuration of the C300 controllers. It stores the latest control strategies for the CPF created by the control builder to allow offline modification and then uploads it to the RTDB to be online, where it is executed by the C300 controllers.
2. **EMDB (Enterprise Model Database):** It's a database that provides a model of the HBNS site, focusing on the CPF and its assets. It shows how all the different parts of the CPF work together, including departments, processes, units, data, and computer systems such as servers, OWS, and EWS. It also provides detailed information about these components, including their limits and network addresses.
3. **QDB (Quick Database):** This database houses the data flow path configuration of each third-party system and device in the CPF to the Experion Server, including the Baker Hughes Flow Meters. It stores the latest data flow path configurations created by the Quick Builder software, allowing for offline modification before uploading to the RTDB for online implementation by the third-party systems and devices.
4. **RTDB (Real-Time Database):** This database contains all real-time data from the CPF, making it accessible to any client that requires it, such as HMIs, thereby allowing real-time data to be displayed. It also facilitates seamless data exchange between the C300 controllers and other control systems within the entire CPF. This integration ensures efficient communication, real-time monitoring, and coordinated control across all systems, enhancing overall operational efficiency and reliability.

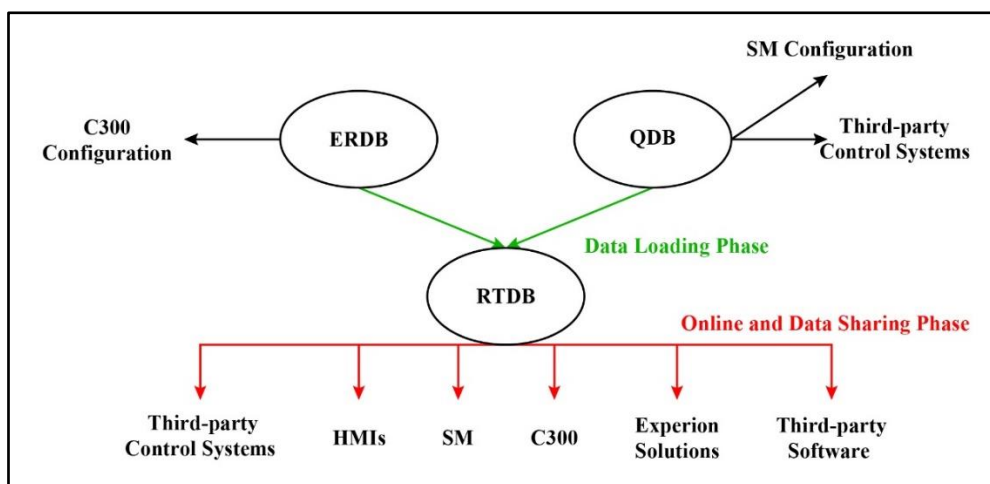


Figure 4.18: RTDB Communications.

4.3.1.2. Experion SCADA Server

The Experion SCADA Server operates similarly to the Experion Server, utilizing three identical databases: QDB, EMDB, and RTDB. However, unlike the Experion Server, the SCADA Server does not require an ERDB, as it does not configure or program C300 controllers and Safety Managers.

The key distinction between the two servers lies in their focus. The Experion Server primarily handles data related to the CPF, while the SCADA Server focuses on data from the offsite wells and satellite fields of the HBNS site. Both servers play a crucial role in monitoring, controlling, and optimizing operations, but their specific data sources and applications differ.

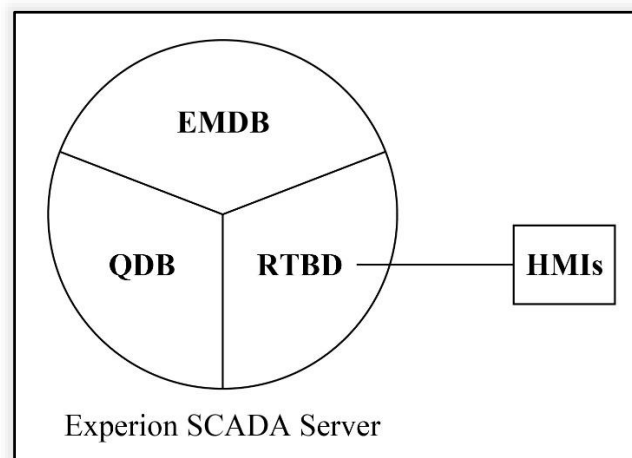


Figure 4.19: SCADA Server Breakdown.

4.3.1.3. Domain Controller Server

This server acts as the heart of a Windows domain network, managing user accounts, groups, permissions, and passwords within the Experion domain. [23]

4.3.1.4. EBR (Experion Backup & Restore) Server

This dedicated server serves as a backup and recovery system, restoring data from all other servers in case of any problem. It protects against system failures due to viruses, application failures, disk corruption, accidental deletion, natural disasters, and other hardware/software issues. [24]

4.3.2. Human-Machine Interfaces (HMIs)

Human-Machine Interfaces (HMIs) are essential tools for operators to monitor and interact with industrial processes. Honeywell's Experion Station software serves as the platform

for accessing and displaying HMIs within the ICSS. It provides a visual representation of real-time data gathered from the four Experion servers in the system. Through Experion Station, operators can issue commands to control the process, view and analyze real-time process parameters and diagnostics, monitor and acknowledge alarms, and assess the overall system status. The software's intuitive graphical interface simplifies complex data, making it easier for operators to understand and control processes using screens, keyboards, and other input devices.

HMIs within Experion Station retrieve data directly from the Experion servers for CPF data and from the SCADA servers for offsite well data, primarily communicating with the RTDB within each server via the high-speed FTE network.

These HMIs in the CCR are displayed on different workstations, including:

- **Engineering Work Stations (EWS):** The Engineering Stations provide access to engineering functions while the system is online. The EWS are mainly used for maintenance configuration and system diagnostics.
- **Operator Work Station (OWS):** An OWS is a dedicated station for monitoring and controlling the processes of the system.
- **Dedicated Station:** This station is used for monitoring, featuring a large 70" screen to display system status and performance.

4.4. Communication between C300, SM, and 3rd party automation systems

Information or data can be transmitted between control systems using various methods. The choice of communication method depends on the overall control philosophy of the process, the desired level of safety, and the specific preventive measures implemented.

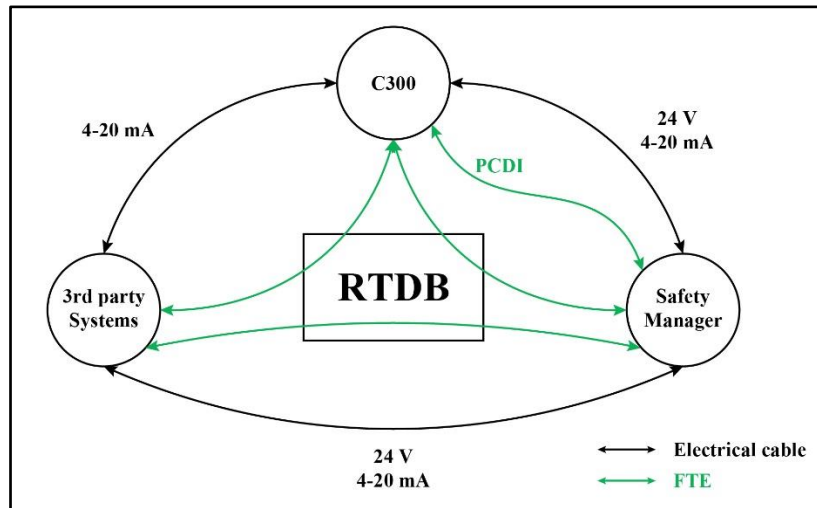


Figure 4.21: Communication Methods between Control Systems at HBNS's CPF.

5. Configuration Studio

Configuration Studio, an innovative software platform by Honeywell, is a crucial component of the ICSS system. This platform integrates a suite of software tools designed to configure and control key aspects of the ICSS system, including:

- Integration configuration for third-party systems and devices using Quick Builder software.
- C300 configuration and control using Control Builder software.

These solutions are consolidated into a single platform, making them easily accessible and ensuring comprehensive control of the ICSS system from one central location.

6. Conclusion

In this chapter, we explored the architecture and main levels of the ICSS, gaining insight into the system designed to ensure the high reliability of the HBNS site's control system. I highlighted a key aspect of my project: integrating third-party systems and devices via Modbus RTU communication. This integration will facilitate the inclusion of flare gas flow computer data into the ICSS in the practical part of this project.

In the next chapter, we will delve into Baker Hughes's Flare Gas Flow Meters, examining their crucial role, functionalities, and integration with the ICSS.

Chapter 5

Study of Baker Hughes XGF868i Ultrasonic Flare Gas Flow Meters

1. Introduction

Accurate measurement of flare gas is critical in the oil and gas industry, impacting both environmental compliance and operational efficiency, particularly when related to fiscal reporting and taxes.

In this chapter, I will address the challenges of flare gas flow metering and outline the criteria that led Groupement Berkine to select the Baker Hughes XGF868i Ultrasonic Flare Gas Flow Meters. Furthermore, I will delve into the technical specifications and functionalities of the XGF868i, with a focus on its installation, operation, preventive maintenance, and integration with the Integrated Control and Safety System (ICSS).

2. Definition of Flow Meter

A flow meter is an instrument designed to quantify the flow rate of a fluid, either liquid or gas, passing through a pipe over a given time. In many flow meters, a flow transmitter (FT) is integrated or used in conjunction with flow sensors. The FT converts the raw measurement signal from the flow sensors into a standardized electrical or digital output for easy transmission, processing by servers, and display on HMIs.

3. Definition of Flare Gas Flow Meters

Flare gas flow meters are used in facilities such as CPFs (Central Processing Facilities) in oil and gas production fields, refineries, and chemical plants to measure gas flows in flare lines. In many parts of the world, this is a regulatory requirement.

When it comes to obtaining the volumetric flow rate, various technologies are available for flare gas flow meters. Each technology is based on different physical principles and has its own performance characteristics and accuracies. These meters play a crucial role in industrial settings by monitoring and controlling emissions released during flaring processes. These meters come in two primary categories:

1. **Mass Flow Rate Meters:** These meters calculate the mass flow rate of the gas first which is the mass of gas passing through per unit time, and then use the gas density to convert this measurement into the volumetric flow rate. Examples include Coriolis and thermal mass flow meters.
2. **Direct Volumetric Flow Rate Meters:** These meters measure the volumetric flow rate of the gas directly, which is the volume of gas passing through per unit time. Examples include differential pressure flow meters and ultrasonic flow meters.

Selecting the optimal flare gas flow meter depends on several factors, including the flare gas composition, the expected range of flow rates, the surrounding environmental conditions, and the level of accuracy required for regulatory compliance and operational efficiency. Ultimately, a comprehensive understanding of the different flow meter technologies and their strengths and limitations is essential for choosing the most suitable option for a given flare application.

4. Flare Gas Measurement Challenges of HBNS Site

Flare gas measurement in upstream oil and gas production faces several challenges due to the unique characteristics of flare systems and the harsh conditions they operate in. These challenges lead to inaccuracies in volumetric flow measurement and errors in the reported volumetric flare gas flow rate. The main challenges in the HBNS's flaring system include:

4.1. Variability of Gas Composition

Flare gas is not a single, pure gas but a mixture of various light hydrocarbons, such as methane (CH₄) and ethane (C₂H₆), along with carbon dioxide (CO₂) and other gases. Its composition can vary significantly over time due to different gas sources from the central processing facility (CPF), varying well characteristics, and operational conditions (Changes in Production Rates).

This changing composition affects the gas's density, creating complexity for flow meter technologies whose volumetric flow rate calculations depend on density, such as differential pressure flow meters. Additionally, flow meters like Coriolis and thermal meters, which calculate volumetric flow rate indirectly, are designed to measure mass flow rate directly but still require calibration with a gas of known density to convert the measurement into volumetric flow rate. If the actual flare gas density differs significantly from the calibration density, the measurement may not be accurate, leading to errors in the calculated volumetric flow rate.

4.1.1. Impact of Molecular Weight on Flare Gas Density

Each component in the flare gas mixture has a different molecular weight. For example, CO₂ (carbon dioxide) has a larger molecular weight than CH₄ (methane):

- Molecular weight of CH₄ (methane): 12 (C) + 4 (H) = 16 g/mol
- Molecular weight of CO₂ (carbon dioxide): 12 (C) + 2 × 16 (O) = 44 g/mol

As the composition of flare gas changes, with varying proportions of lighter and heavier components, the average molecular weight of the mixture also changes. Since density is directly proportional to molecular weight (see Equation 5.3), this significantly impacts the gas density. Consequently, this affects the relationship between mass flow rate and volumetric flow rate (see Equation 5.4). Therefore, if the density of the flare gas changes, the volumetric flow rate will also change.

The ideal gas law: $PV = nRT$ *(Equation 5.1)*

The definition of density: $\rho = \frac{m}{V}$ *(Equation 5.2)*

Combining the ideal gas law with the definition of density, we get:

$$\rho = \frac{(P \times M)}{(R \times T)}$$

(Equation 5.3)

Volumetric Flow Rate: $Q = \frac{\dot{m}}{\rho}$ *(Equation 5.4)*

Where:

P = pressure of a gas. | V = volume of a gas. | n = number of moles of a gas. |

R = ideal gas constant (8.314 J/(mol·K)). | T = temperature of a gas. |

ρ = density. | m = mass of gas. | M = molar mass of the gas mixture. |

Q = volumetric flow rate. | ṁ = mass flow rate.

4.2. Temperature and Pressure Variation

Flare gas measurement faces significant challenges due to fluctuations in temperature and pressure. These variations arise mainly from diverse sources within the CPF, each with different pressure and temperature. Additionally, changes in ambient conditions impact flare gas temperature, particularly in the Algerian Sahara, where it is very hot during the day and very cold at night. Finally, operational conditions, such as production rates, upsets, and

shutdown procedures, lead to changes in the flow rate of gases sent to the flare, directly affecting pressure. When the flow rate increases, pressure within the system rises due to more gas molecules colliding with each other and the pipe walls. Conversely, when the flow rate decreases, fewer gas molecules result in less frequent collisions and lower pressure.

Changes in temperature and pressure affect the gas's density (see Equation 5.3), leading to similar issues as the variability of gas composition previously discussed. Flare gas flow meter technologies that use density to determine volumetric flow rate are impacted by these changes. When gas density increases, the volumetric flow rate decreases, and conversely, when gas density decreases, the volumetric flow rate increases.

Additionally, variations in temperature and pressure affect gas volume changes (see Equation 5.1). Changes in pressure and temperature within the flare system cause gas compression (contraction) or expansion. Once the gas leaves the flare system and returns to atmospheric conditions, it reverts to its actual volume. This can lead to misinterpretations by flare gas flow meters, resulting in either overestimation or underestimation of the actual flow. Such inaccuracies can cause significant errors in the reported volumetric flow rate of flare gas, which is crucial for emissions monitoring and regulatory compliance.

4.2.1. Impact of Temperature and Pressure on Flare Gas Density

Temperature fluctuations, directly impact the volume of the gas they are proportional. As temperatures rise, the gas molecules expand, increasing the gas volume. Conversely, decreasing temperatures lead to gas contraction and reduced volume. Similarly, pressure variations, influence the volume of flare gas they are inversely proportional. Increased pressure compresses the gas molecules, reducing the volume, while lower pressure allows the gas to expand. (see Equation 5.1).

4.3. Wide Flow Rangeability

A significant challenge in flare gas measurement arises from the extreme variations in flow rates, known as high flow rangeability. This variability stems from the dual nature of flare systems, which handle both low, continuous flows of purge gas under normal operating conditions and sudden, high-volume flows during process upsets or emergencies. This wide range of flow rates presents a significant challenge for flare gas flow meters, as they must accurately measure both extremes, while maintaining precision across the entire spectrum.

The turndown ratio, a measure of the flow meter's operating range and flexibility, is the ratio between the maximum and minimum flow rates it can accurately measure. For example, a flow meter with a 2000:1 turndown ratio can measure flows from 0.05% to 100% of its maximum capacity. So, if its maximum flow rate is 1000 m³/h, this meter can measure down to 0.5 m³/h.

Traditional flow meters often struggle with such high turndown ratios, as they may not be sensitive enough to measure low flows accurately or robust enough to handle the high pressures and velocities associated with upset flows. which leads to inaccurate flow readings and potential underreporting of emissions.

4.4. Turbulent Flow Profile

Turbulent flow profile poses a significant challenge in flare gas measurement due to the complex and chaotic nature of gas movement within the flare system. This turbulence arises from several factors, primarily high gas flow rates and pipe geometry.

High gas flow rates, particularly during process upsets or emergency releases, are a major contributor to turbulence. The large volume of gas rushing through the pipes creates turbulent eddies and fluctuations in gas velocity, disrupting the smooth, laminar flow preferred for accurate measurement. In addition to flow rate, the pipe geometry itself plays a crucial role. Large pipe diameters can further amplify turbulence due to increased space for the gas to move unpredictably, providing more space for turbulent mixing. Abrupt changes in pipe direction, such as bends, create swirling vortices. Rough pipe walls due to corrosion can disrupt the smooth flow of gas along the pipe walls, further exacerbating this turbulence and disrupting the laminar flow that is ideal for many flow meters.

The resulting turbulent flow profile is characterized by a non-uniform velocity distribution across the pipe's cross-section and swirling eddies. This makes it difficult for many flow meters to accurately determine the average velocity, especially those relying on measuring velocity at a single point. Accurately determining the average velocity is essential for calculating the volumetric flow rate, and turbulence leads to less accurate readings. [25]

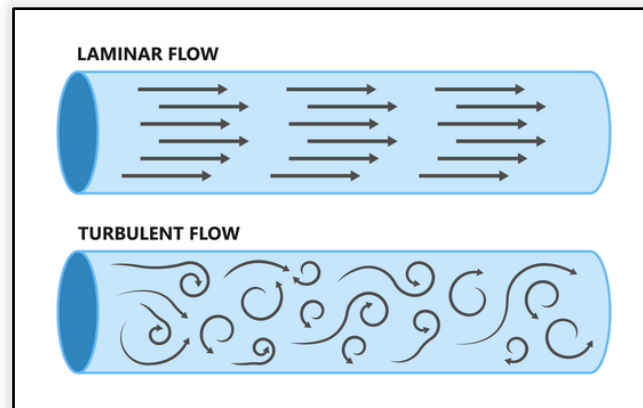


Figure 5.1: Comparison of Laminar and Turbulent Flow.

5. Flare Gas Meters Challenges

5.1. Absence of Flare Gas Flow Meters Standard

The flare gas industry lacks a comprehensive framework of established standards and guidelines for flow measurement, because it is not a mastered industry, primarily due to the unique challenges associated with the flaring system. Unlike the natural gas industry, which benefits from detailed standards provided by international organizations such as ISO (International Organization for Standardization) and API (American Petroleum Institute), covering various aspects of flow meters including design, installation, operation, calibration, maintenance, and prover systems, the flare gas industry lacks similar regulatory oversight.

While some standards for different natural gas flow meter technologies offer guidelines for their use in flare gas measurement under specific conditions and recommendations, along with associated uncertainty intervals, they still lack the specificity needed to master this unique application. As a result, there is currently no single, globally recognized standard that exclusively and directly addresses flare gas flow meters across all measurement technologies.

5.1.1. Consequences of the Lack of Standards:

- The absence of standards leads to inconsistent measurement practices across the industry, hindering the ability to compare data and ensure fair transactions.
- The lack of specific standards makes it difficult for operators to confidently select, compare, and evaluate different flare gas flow meters. Without common benchmarks based on desired accuracy levels, there is a risk of choosing unsuitable flow meters that may not provide accurate and reliable measurements for flaring applications.

- Vendors and manufacturers are compelled to develop complex, high-technology flare gas flow meters tailored for this challenging application. This includes proprietary solutions for calibrating and verifying the accuracy of their flare gas flow meters, according to their own specifications and guidelines. This not only increases the cost of these meters but also limits operators' flexibility by locking them into specific vendor ecosystems for maintenance and calibration. These repetitive tasks are performed periodically, further driving up expenses.
- The absence of standardized approaches fosters an environment where innovation may be stifled within the industry. Rather than focusing on open, standardized solutions that could benefit the entire sector, the focus shifts towards proprietary solutions.

5.2. Absence of Prover Systems for Accuracy Checking

Proving is the process of verifying a flow meter's accuracy by comparing its measurements to a known flow rate reference provided by a prover system. If the meter's measurements deviate from the standard beyond acceptable tolerances, it indicates that the meter is inaccurate and requires calibration. This crucial process is applied to flow meters responsible for providing sensitive flow rates related to fiscal matters (financial transactions), such as buying, selling, and taxes, where measurement accuracy has significant financial implications. Prover systems are typically used in metering units to perform this verification, helping to maintain fairness and transparency in these transactions. [26]

5.2.1. Master Meter Provers

Master Meter Provers are among the most commonly used types of prover systems, particularly in natural gas metering. These systems employ a highly accurate, calibrated master flow meter installed in parallel with the main pipeline in the metering unit. The master flow meter measures the same flow rates passing through the working flow meter, allowing for a direct comparison of their readings.

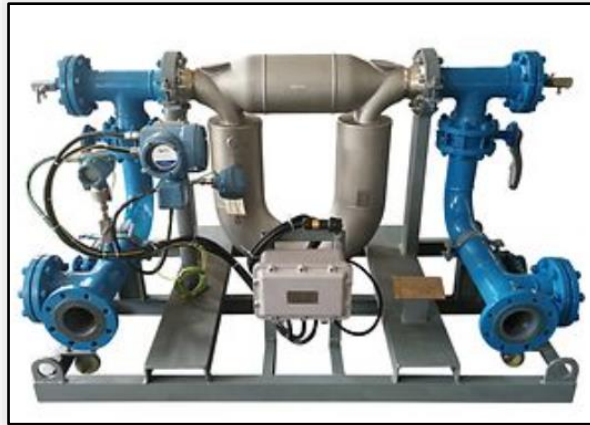


Figure 5.2: Master Meter Prover System.

5.2.2. Challenges in Implementing Prover Systems for Flare Gas Flow Meters

- **Physical Size and Complexity:** Designing a prover system capable of accommodating the unique challenges of flare gas flow meters, including the natural behavior of flare gas and its sensitivity to various parameters, would likely result in a large and complex apparatus with high costs. This complexity makes it impractical for many flaring sites.
- **Safety considerations:** Introducing a prover into the flaring system could increase the risk of accidents or explosions. Flare gases are typically released during gas excess or shutdowns, necessitating safe gas evacuation from the CPF. These gases are hazardous and potentially explosive, with high velocities and volume. Therefore, adding a prover might not be the most desirable choice for ensuring safe operations.
- **Industry standards and regulations:** Currently, there are no specific industry standards or regulations mandating the use of flowmeter provers for gas flaring. Consequently, there is less incentive for manufacturers to develop such products.

5.2.3. Consequences of the Absence of Prover Systems for Flare Gas Flow Meters

The absence of a standardized proving method to verify the accuracy of flare gas flow meters creates difficulties in convincing regulatory authorities with the accuracy of reported flaring data. This uncertainty casts doubts on the accuracy of the measurements obtained by flare gas flow meters. As a result, concerns arise regarding the effectiveness of the accuracy checking solutions and calibration technologies provided by companies in the flaring solution industry.

6. Groupement Berkine Criteria for Choosing Baker Hughes Flare Gas Flow Meter

- **High Accuracy Technology Solution and Fit for Design:**

Baker Hughes provides high-accuracy measurement solutions using Advanced Ultrasonic technology that fit the technical criteria of the HBNS flare system and address its flare gas measurement challenges.

- **The Use of Advanced Ultrasonic Flow Measurement:**

The inherent advantages of this technology – including independency of gas composition, high accuracy, and fast response times, reliability without the need for routine maintenance – make it well-suited for the demanding conditions of flaring operations. Baker Hughes has been selected for this project not only due to their utilization of ultrasonic flow technology but also their commitment to continuous innovation and advancement in this field.

- **Market Reputation and Technological Innovation:**

- Baker Hughes (and its Panametrics business) holds a considerable market share in flare gas flow measurement across various industries, including oil and gas, refining, and petrochemicals.
- They are known for quality, reliability, and technological innovation.

- **Existing Relationship and Ongoing Support:**

- Groupement Berkine has previously worked with Baker Hughes and maintains a good relationship with them.
- They continue to receive maintenance interventions for systems at the CPF of HBNS site, such as the Bently Nevada system used for vibration detection and monitoring of gas turbines.

- **Local Presence in Algeria:**

Baker Hughes has a strong presence in Algeria, with offices in both Hydra and Hassi Messaoud. This local presence offers several advantages:

- **Enhanced Serviceability:** The accessibility of after-sales service facilitates swift and efficient communication, making it easier to schedule and execute interventions.
- **Rapid intervention capabilities:** Local offices enable the swift deployment of service teams for maintenance and technical support, minimizing downtime.

- **Lower Maintenance Costs:** Having local offices reduces the expenses associated with bringing in foreign technicians and equipment, leading to more cost-effective maintenance.
- **Reduced Time and Expenses for Equipment Logistics:** Proximity of local offices means less time and cost spent on shipping and handling equipment, resulting in faster service and lower logistical costs.

7. Baker Hughes DigitalFlow XGF868i Flare Gas Ultrasonic Flowmeter

7.1. The Baker Hughes Panametrics DigitalFlow XGF868i

The Baker Hughes Panametrics DigitalFlow XGF868i flowmeter is a comprehensive ultrasonic solution designed for precise flare gas measurements. Strategically positioned within the flow line upstream of the flare stack, this flow metering system plays a crucial role in quantifying volumetric flow rates before the gas is combusted. The XGF868i's advanced technology provides high accuracy reliable data essential for flaring and emissions monitoring and reporting, regulatory compliance, and process optimization in CPF.

7.2. Baker Hughes Flare Gas Flow Meter System Composition

The Baker Hughes flare gas flow meter system consists of several key components working together harmoniously to ensure accurate and reliable measurements:

7.2.1. XGF868i Flow Meter

The core of the system, the XGF868i Flow Meter, houses the electronics and signal processing capabilities. It receives data from the transducers and transmitters, performs calculations, and outputs flow measurements. The XGF868i can be located up to 300 m from the transducers.

The DigitalFlow XGF868i's onboard computer utilizes advanced signal processing and a proprietary correlation detection method known as Correlation Transit-Time™, developed by Panametrics (a Baker Hughes business). This technique employs sophisticated algorithms and signal processing to overcome challenges related to the flaring system and the nature and behavior of flare gas, as discussed previously. This approach enables accurate detection and measurement of the travel time of ultrasonic pulses, facilitating precise measurement of flare gas flow parameters such as velocity, volumetric flow rate, and molecular weight.



Figure 5.3: The Panametrics DigitalFlow XGF868i Flowmeter.

7.2.2. T5 Transducers (Dual-Channel Configuration)

The system is equipped with a pair of transducers (upstream and downstream) for each Channel. They share identical types, functions, and dimensions. These ultrasonic transducers are installed on the flow cell to transmit and receive ultrasonic signals, measuring the time it takes for sound waves to travel upstream and downstream in the flare gas flow. The dual-Channel configuration enhances accuracy by mitigating the effects of turbulent flow conditions.

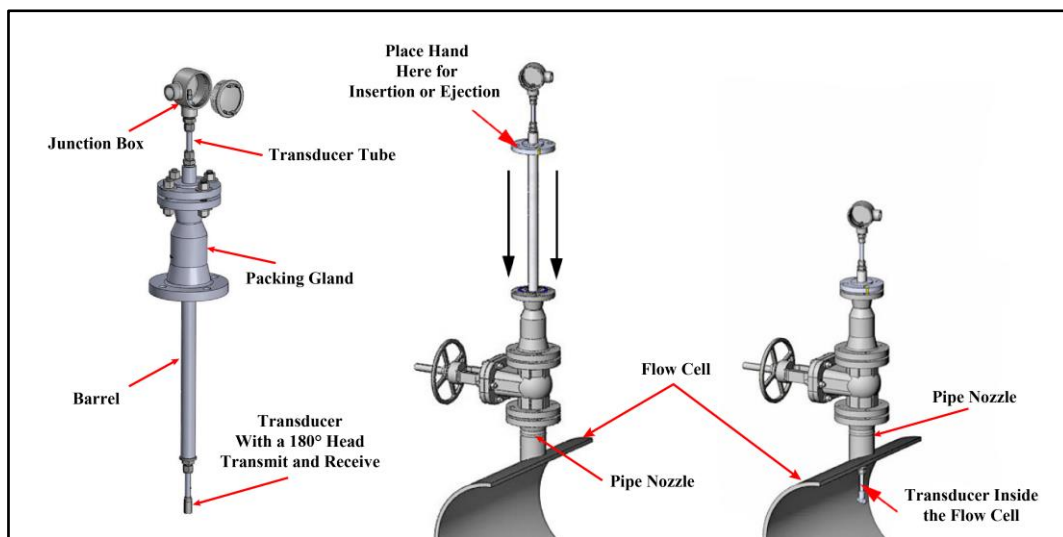


Figure 5.4: The T5 Transducers Assembly Mechanism in Flow Cell.

7.2.3. Flow Cell

A specialized pipe section containing pipe nozzles in well-defined positions and specific angles ensures optimal conditions for accurate ultrasonic measurements. These pipe nozzles facilitate the insertion of the transducers.

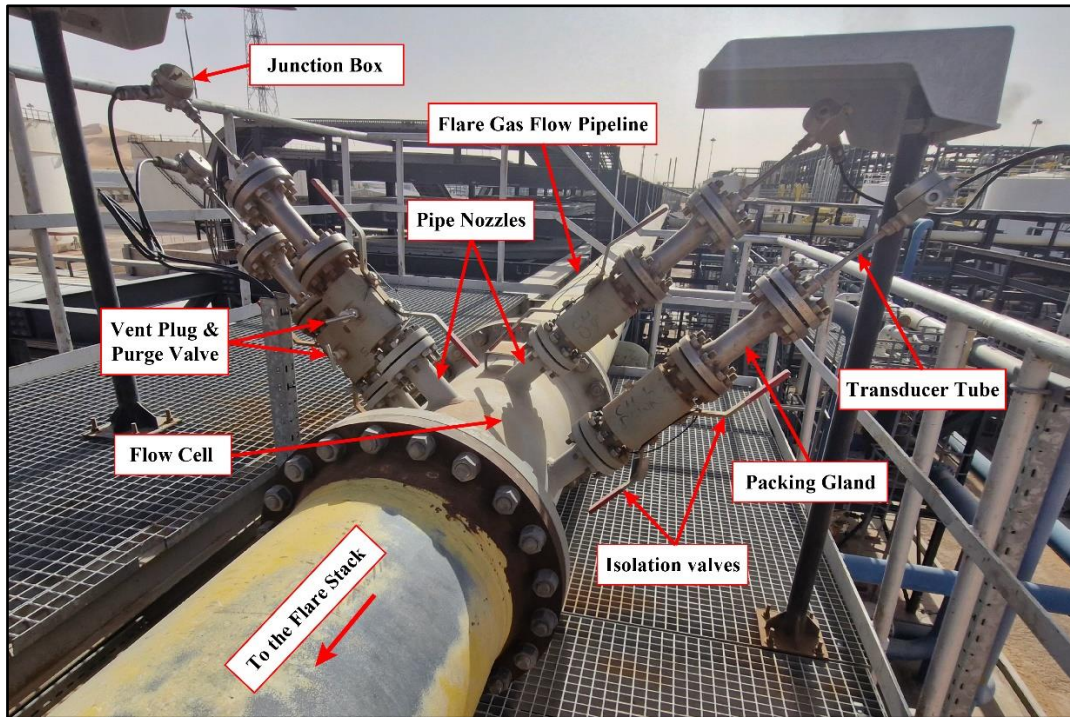


Figure 5.5: Real Dual-Channel Configuration of T5 Transducers with Flow Cell in Flare System.

7.2.4. Temperature and Pressure Transmitters

These separate instruments measure the flare gas temperature and pressure within the flow line. This data is integrated into the XGF868i Flow Meter to compensate for gas volume changes due to compression or expansion, enabling accurate standard volumetric flow conversion (1 atm, 15°C). This standardized value allows for easier comparison and analysis of flow rates across different operating conditions.

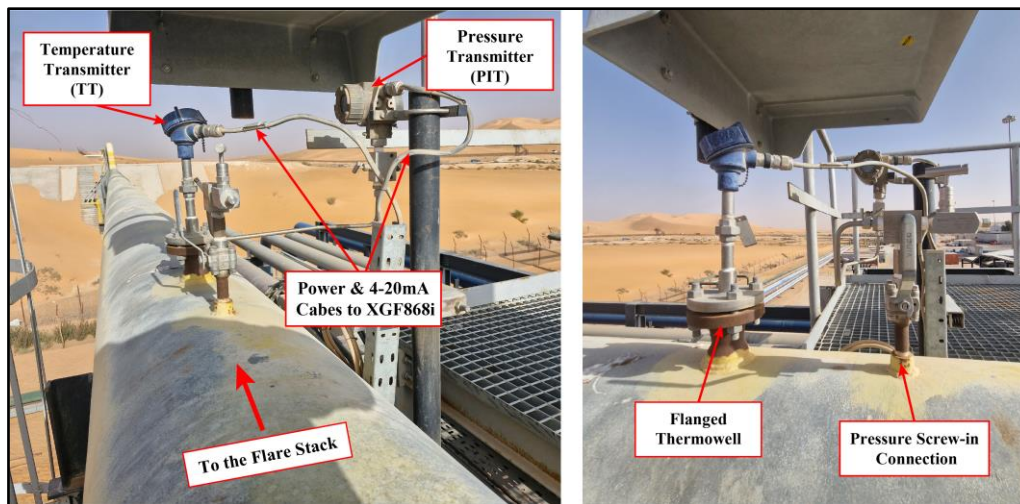


Figure 5.6: Real Temperature and Pressure Transmitters in a Flare System.

7.3. Key Features and Benefits

- **Independence from Gas Composition:** Utilizing ultrasonic technology, where volumetric flow measurement relies primarily on gas velocity rather than gas composition, ensures precise and accurate flare gas volumetric flow rate measurement.
- **Support Wide Flow and Velocity Rangeability:** Patented ultrasonic transducers provide a significant advantage in flare gas flow meters with a wide turndown ratio of 4000:1. These transducers cover a velocity range from 0.03 m/s to 120 m/s, ensuring precise measurement across a broad spectrum of flow rates. They are highly sensitive, accurately measuring low velocities down to 0.03 m/s, and robust enough to handle high velocities up to 120 m/s. This capability allows for accurate measurement of both very low and extremely high flow rates.
- **Tolerance for Turbulent Flow:** The Two-Channel configuration ensures full pipe coverage by dividing the cross-section of the pipe into two equal areas. Each Channel covers half of the cross-section, providing immunity to turbulent flow profiles and detailed gas flow information. Channel one and Channel two operate on the same principle, providing the same parameters with different values. This setup improves measurement accuracy from 5% with a one-Channel system to 2% with a two-Channel system by averaging the values from both Channels, thereby minimizing errors and increasing accuracy, even in turbulent conditions.
- **Minimal Maintenance:** Designed with no moving parts, this system eliminates the risk of blockages or damage, minimizing maintenance requirements, costs, and downtime.

- **Durability in Dirty or Wet Conditions:** Patented ultrasonic transducers, constructed from titanium or other durable metals, resist corrosive environments typically found in flaring systems.
- **Compact Housing:** The DigitalFlow XGF868i's electronic components are housed in a compact, explosion-proof/flame-proof transmitter package, allowing installation close to the flow measurement point and simplifying wiring.

7.4. The XGF868i Ultrasonic Flare Gas Flow Meter Working Principles [27]

7.4.1. Velocity Measurement

Ultrasonic flow measurement technology primarily relies on flare gas velocity measured within the flow cell to determine the volumetric flare gas flow rate. This is achieved by sending ultrasonic pulses generated from the transducer heads in both upstream and downstream directions for each Channel through the flare gas. The XGF868i Flow Meter measures the time it takes for ultrasonic pulses to travel upstream (t_{up}) and downstream (t_{dn}) through the flare gas flow. The difference in these transit times is directly proportional to the flare gas velocity (see Equation 5.5).

$$\text{Flare Gas Velocity Equation: } V = \frac{P^2}{2L} \times \frac{(t_{up} - t_{dn})}{(t_{up} \times t_{dn})} \quad (\text{Equation 5.5})$$

Where:

V = Flare Gas Velocity. | P = Path length. | L = Axial length. | t_{up} = Upstream transit time. |

t_{dn} = Downstream transit time.

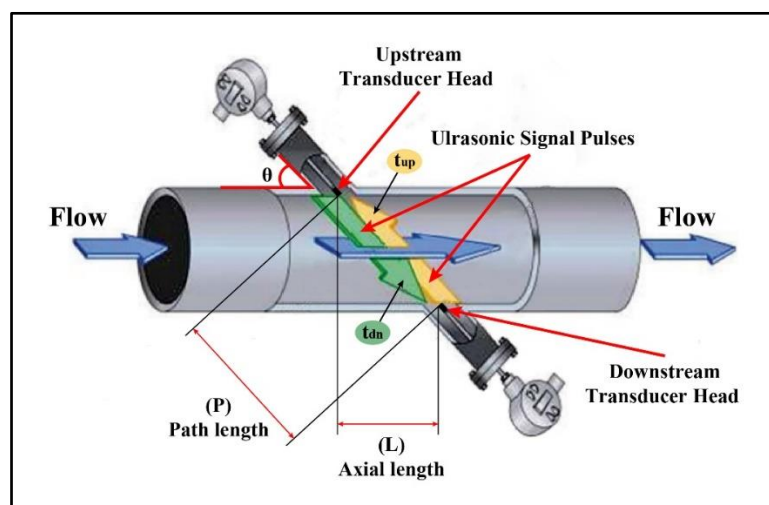


Figure 5.7: Transit Time in a Single Channel Ultrasonic Flow Meter.

7.4.2. Flare Gas Volumetric Flow Calculation

The flare gas volumetric flow rate is calculated by multiplying the calculated flare gas velocity by the cross-sectional area of the flow cell.

Volumetric Flow Rate Equation: $Q_{ACT} = V \times A$ (Equation 5.6)

Where:

Q_{ACT} = Actual flare gas volumetric flow rate (in cubic meters per second). | V = Flare Gas Velocity (in meters per second). | A = Cross-sectional area of the flow cell (in square meters).

7.4.3. Compensated Flow Calculation

The temperature and pressure data from the external transmitters are incorporated to compensate for gas volume changes, ensuring accurate standard volumetric flow calculations. The standard conditions used at the HBNS site are:

- **Base Pressure :** 14.7 psi (101325 Pa).
- **Base Temperature:** 15 degrees Celsius (288.15 Kelvin).

Standard Volumetric Flow Rate Equation: $Q_{STD} = Q_{ACT} \times \frac{P_f}{P_b} \times \frac{T_b}{T_f}$ (Equation 5.7)

Where:

Q_{STD} = Standard volumetric flow rate. | P_f = Flowing pressure. | P_b = Base pressure. |

T_f = Flowing temperature. | T_b = Base temperature.

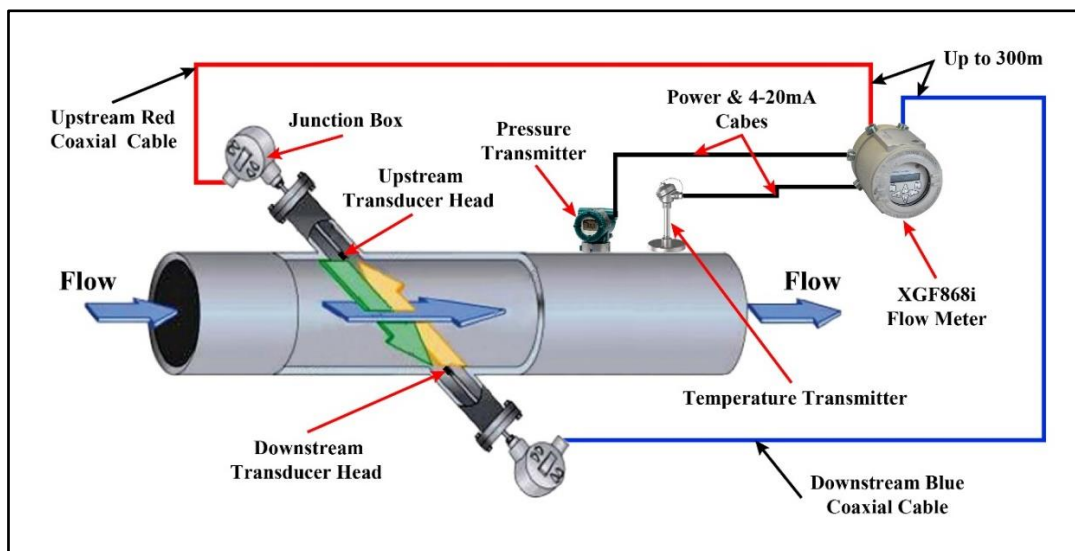


Figure 5.8: Flare Gas Flow Measurement with XGF868i and P/T Compensation.

7.4.4. Sound Speed Calculation

The transducers measure the transit time for ultrasonic pulses to travel a fixed distance within the gas. This allows for the calculation of the speed of sound in the gas, influenced by its molecular weight and composition. For each channel, the system takes the average of both the upstream and downstream sound speeds.

Upstream Sound Speed **Equation:** $C_{up} = \frac{P}{t_{up}}$ *(Equation 5.8)*

Downstream Sound Speed **Equation:** $C_{dn} = \frac{P}{t_{dn}}$ *(Equation 5.9)*

One Channel Sound Speed **Equation:** $C = \frac{P}{2} \times \frac{t_{up} + t_{dn}}{t_{up} \times t_{dn}}$ *(Equation 5.10)*

Where:

C_{up} = Upstream Sound Speed. | C_{dn} = Downstream Sound Speed. | C = One Channel Sound Speed.

7.4.5. Molecular Weight Determination

The DigitalFlow XGF868i employs a proprietary method developed by Panametrics to calculate the molecular weight of flare gas. Unlike traditional approaches that rely on the adiabatic index (gamma, γ), which is related to the molecular structure of the flare gas (i.e., the number of atoms composing the flared gas), as showing in Equation 5.11, the XGF868i uses a sophisticated algorithm. This algorithm directly relates the speed of sound in the gas to its molecular weight without needing to know the specific gas composition or its adiabatic index.

Flare Gas Molecular Weight **Equation:** $MW = \frac{\gamma RT}{C^2}$ *(Equation 5.11)*

Where:

MW = Molecular weight. | γ = Gamma: adiabatic index (the heat capacity ratio). |

C = Speed of sound. | R = Universal gas constant. | T = Temperature (absolute).

7.5. Flare Gas Volumetric Flow Computing with XGF868i and C300 Controller

The XGF868i flow meter displays the volumetric flow rate in standard cubic meters per hour (SCMH), a unit commonly used in industrial settings due to its alignment with typical operational practices and reporting periods.

The flow meter continuously measures the instantaneous volumetric flare gas flow rate in less than a second. It records the average of these measurements every second in its registers to obtain the flare gas volumetric flow rates for each second. These second-by-second flow rates are added into a running total. After accumulating data for 3600 seconds (one hour), the total volume is averaged and displayed on the flow meter's LCD screen as an hourly measurement (SCMH).

The flare gas volumetric flow rates for each second, stored in the registers, are sent to a dedicated C300 controller. This controller performs arithmetic calculations to provide total volumes for longer periods, such as hourly, daily, or monthly totals, facilitating the reporting and analysis of flare gas volumetric flow rates. The C300 controller handles these calculations by summing up flow rates over time and applying the necessary conversion factors.

7.6. The XGF868i Ultrasonic Flare Gas Flow Meter Calibration Job

The validation process of the XGF868i flare gas flow meter is a crucial preventive maintenance task required annually for each ultrasonic flowmeter. This process comprises several procedures to ensure the health and accuracy of the meters, and performs calibration if any deviations are identified. The validation is exclusively performed by a Baker Hughes expert, adhering to specific guidelines and proprietary methods unique to Baker Hughes. These high-technology solutions and specialized techniques are known and mastered only by their experts.

The process concludes with the issuance of a document by the Baker Hughes expert, confirming the safe and successful completion of the procedure. This document guarantees that the meter meets all operational and performance standards and passes all Panametrics criteria for equipment verification, including accuracy and health.

This validation document serves as proof of the accuracy of the measurements provided by the flowmeters for a period of one year. It ensures efficient operation throughout the year and guarantees an uncertainty of 2%. This document can be presented to any authority requesting proof of measurement accuracy or other information about the flare flow meters.

7.6.1. Baker Hughes Flare Gas Flow Meter Preventive Maintenance Procedures

7.6.1.1. Initial Walk Down and Data Gathering

The verification process includes an initial walk down to identify any outstanding issues with the installation, such as wiring, preamp, and cabling.

7.6.1.2. Mechanical Inspection of Transducers

A mechanical inspection of the transducers is performed, including a visual verification to ensure the integrity of the transducers and to clean any accumulated debris from the transducer heads.

7.6.1.3. Zero-Flow Verification

Zero-flow verification evaluates the operation and adjusts the parameters of the transducer pair in a controlled, no-flow environment. This process involves installing the transducers into a zero-flow box to eliminate any external flow influences. Using air as the process medium, and employing a thermocouple to measure the temperature inside the box and a sound speed calculator, the theoretical sound speed in the air can be determined and compared to the meter's calculated sound speed. The meter must calculate an actual sound speed within $\pm 1\%$ of the theoretical sound speed to pass the test, ensuring the transducers operate correctly and the system accurately measures sound speed in a no-flow condition.

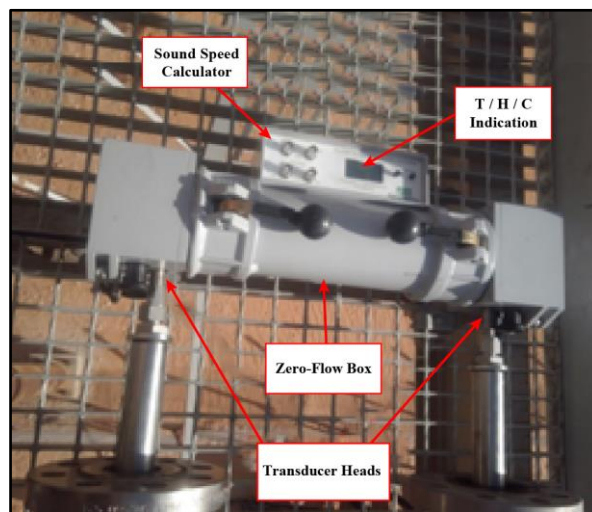


Figure 5.9: Zero-Flow Box Verification.

7.6.1.4. Flow System Evaluation

The flow system is evaluated using certified reference transducers to verify that the electronics, preamplifier, and coaxial cables are functioning within Panametrics specifications.

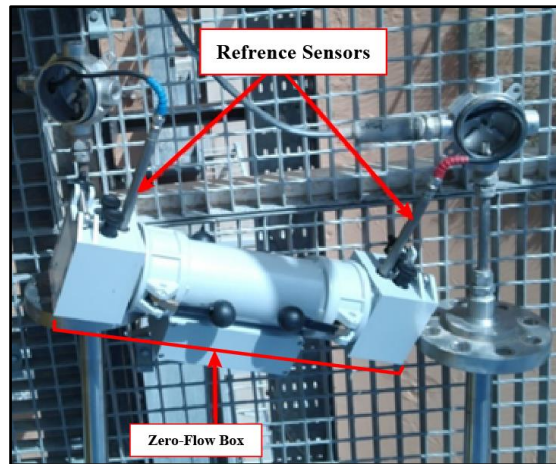


Figure 5.10: Flow System Evaluation with Zero Flow Box and Reference Transducers.

7.6.1.5. Simulated Flow Verification

The XGF868i flow meter is electronically tested using a laptop to simulate flow rates at 30%, 60%, and 90% of its full measurement range, then back to zero flow. This process ensures the meter's readings are within the acceptable 2% tolerance and verifies its accuracy and performance across the measurement range.

7.7. XGF868i Flow Meter Connections:

The XGF868i flow meter communicates with various devices using 9 cables, each with a specific purpose, interfacing with the back of the flow computer. These connections include both inputs and outputs:

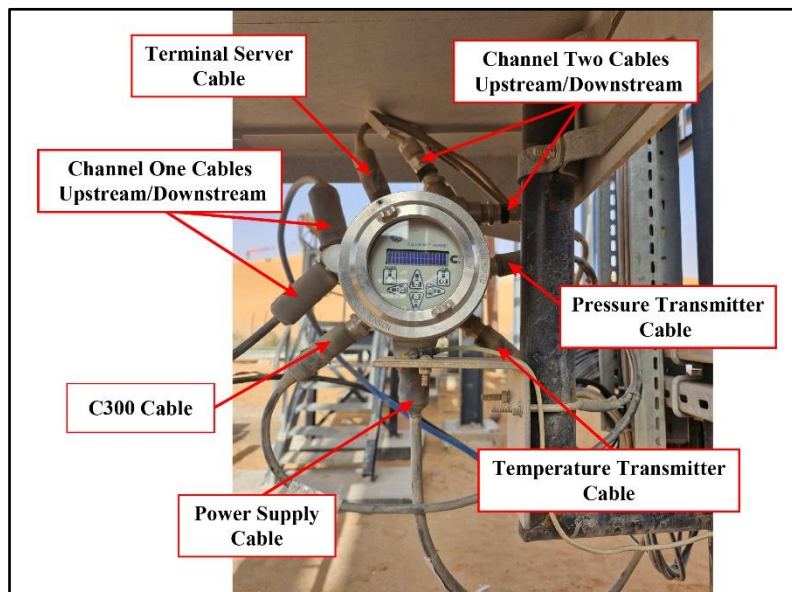


Figure 5.11: XGF868i Flow Meter Connections.

1. Power Supply Cable:

- **Type:** A 220 VAC cable (3-wires: line power, neutral, earth ground).
- **Purpose:** Provides electrical power to the flow meter, supplied by the 30 KV Switchgear Building.

2. Temperature Transmitter Cable:

- **Type:** 1 shielded twisted pair (STP) for 4-20mA signal (2 wires: +SIG and - RTN), 1 wire for 24VDC power.
- **Purpose:** Carries temperature data to the flow meter and provides power to the transmitter.

3. Pressure Transmitter Cable:

- **Type:** Same as the temperature transmitter cable.
- **Purpose:** Carries pressure data to the flow meter and provides power to the transmitter.

4. Channel One Cables:

- **Type:** Two cables, each consisting of a pair of coaxial cables with 2 wires: Upstream SIG (+) and Upstream RTN (-), with lengths ranging from 3 m to 330 m maximum.
- **Purpose:** Serve as inputs, transmitting ultrasonic signals between the flow meter and the transducers—one cable for the upstream transducer and the other for the downstream transducer.

5. Channel Two Cables: Identical to the Channel One cables.

6. C300 Cable:

- **Type:** 1 shielded twisted pair (STP) for 4-20mA signal (2 wires: +SIG and - RTN).
- **Purpose:** This cable provides a 4 to 20 mA standard analog signal as output from the XGF868i flow meter, sending the standard flare gas flow rate measurements to the C300 for computing.

7. Terminal Server Cable:

- **Type:** RS485 half-duplex cable (2-wires: RS485+ and RS485-).

- **Purpose:** This cable Enables serial communication using the Modbus RTU protocol between the XGF868i flow meter and the terminal server at switchgear level 1 for data exchange with the ICSS.

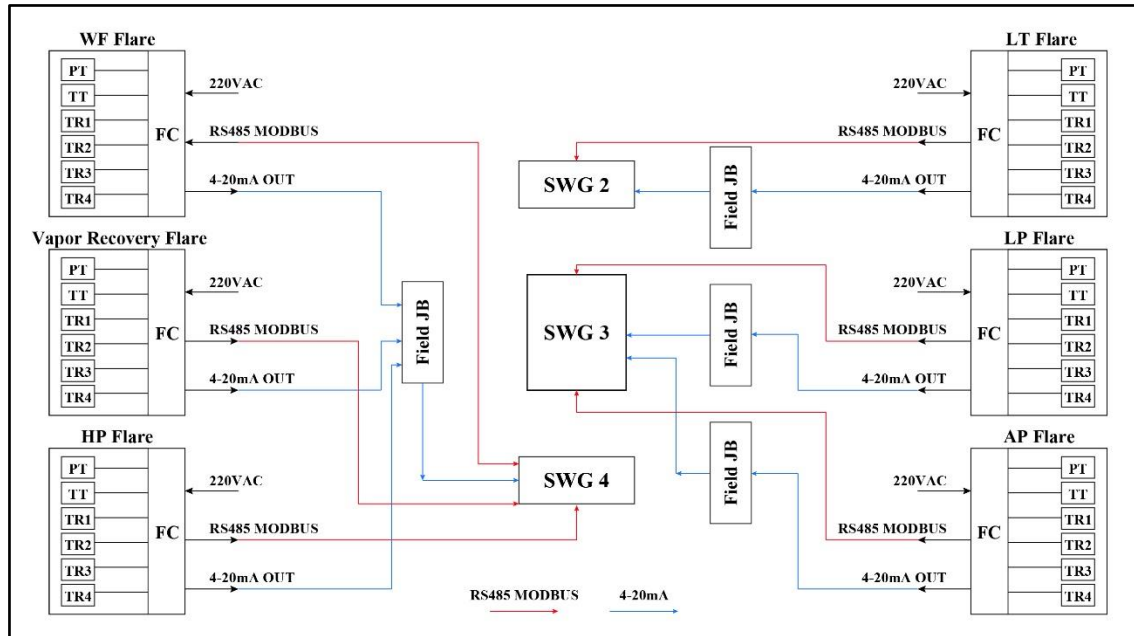


Figure 5.12: XGF868i Flow Meters Network Integration Diagram.

8. Conclusion:

In this chapter, I conducted a detailed study on the challenges and difficulties of flare gas flow measurement. I thoroughly examined the Baker Hughes XGF868i Flare Gas Flow Meter, highlighting its advanced features, crucial role, functionalities, and integration with the ICSS. This comprehensive analysis provided a solid foundation for the practical aspect of this project, concluding that the XGF868i is a robust and accurate system that effectively addresses the challenges of flare gas measurement. Fully exploiting the measurements from these flow meters and integrating them into the DCS is very beneficial for CPF monitoring, optimization, and analysis.

In the next and final chapter, I will focus on the practical implementation of the project, addressing the issues discussed in Chapter 3.

Chapter 6

Integration of the Ultrasonic Flare Gas Flow Meter Data in the ICSS

1. Introduction

In the validation report, a Baker Hughes expert recommended integrating the data and parameters provided by their advanced flow meter as a best practice. The expert explains the importance of utilizing this data to address various operational challenges and enhance process optimization, thereby ensuring the profitability of Groupement Berkine's investment. Additionally, the expert included the Modbus register addresses for all data recorded by the XGF868i flare gas flow meter, specifying the size and type for each parameter.

In this last chapter, we will delve into the practical aspects of integrating the process and diagnostic data. We will examine the SCADA point configuration within the ICSS, the creation of HMIs, and the use of the E-server solution. Finally, we will discuss the benefits of these implementations.

2. Experion Station software

Experion Station is a software that enables the displays of the HMIs of all the HBNS site, knowing as the HMI component of the ICSS system, supporting operations control and monitoring functions. It offers a wide range of features, and the ones we will use in this project include:

- **Alarm management capabilities:** This feature helps operators promptly identify and respond to critical situations, enhancing overall system safety and efficiency.
- **Data trending:** This functionality allows for the visualization and analysis of historical data, aiding in the monitoring of system performance and the identification of trends for process optimization.

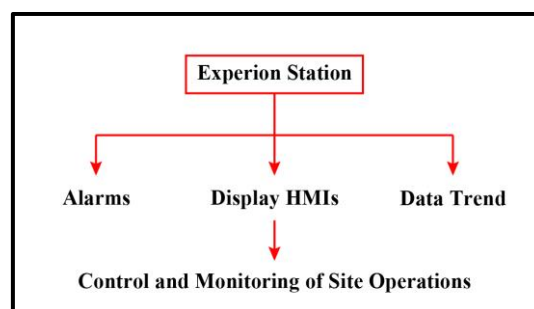


Figure 6.1: Experion Station Functionality.

3. Quick Builder Software

Quick Builder software is an innovative solution provided by Honeywell through the Configuration Studio platform. It is designed to create and manage data flow path configurations by creating channels, controllers, and points. This software enables seamless integration of SCADA points from third-party systems and devices within the CPF to the Experion servers. By defining specific data flow paths, Quick Builder ensures that the server knows precisely where to send and retrieve data requests, facilitating efficient and accurate data management.

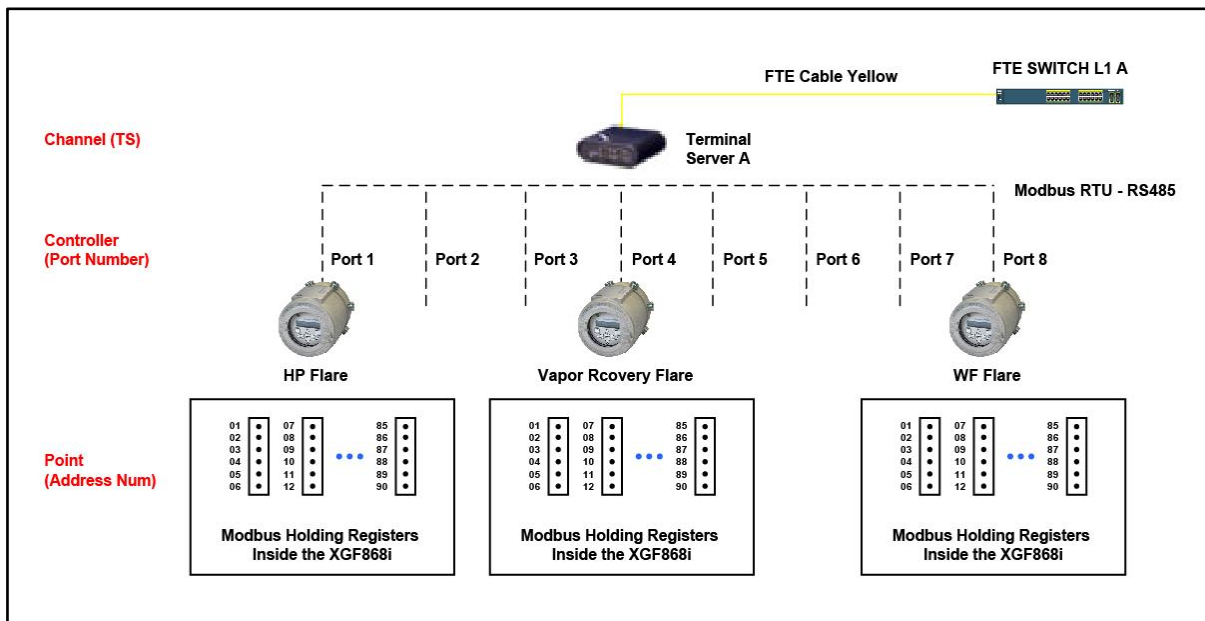


Figure 6.2: Experion Station Functionality.

The Modbus map of the XGF868i, provided by the expert in the validation report, is shown in the following figure:

MBUS Reg #	Description	Size in Bytes
1	!Clear Ch1 Totalizers*	2 (16 bit signed)
2	!Clear Ch2 Totalizers*	2 (16 bit signed)
3	Ch1 Velocity	4 (2 16-bit int)
5	Ch1 Act Volumetric	4 (IEEE 32 bit)
7	Ch1 Std Volumetric	4 (IEEE 32 bit)
9	Ch1 Fwd Totals	4 (2 16-bit int)
11	Ch1 Rev Totals	4 (2 16-bit int)
13	Ch1 #Tot Digits	2
14	Ch1 Mass Flow	4 (IEEE 32 bit)
16	Ch1 Fwd Mass Totals	4 (2 16-bit int)
18	Ch1 Rev Mass Totals	4 (2 16-bit int)
20	Ch1 #Mass Tot Digits	2
21	Ch1 Timer	4 (2 16-bit int)
23	Ch1 Error Code	2
24	Ch1 Sound Speed	4 (2 16-bit int)
26	Ch1 Molecular Weight	4 (2 16-bit int)
28	Ch1 Sig Strength Upstream	4 (2 16-bit int)
30	Ch1 Sig Strength Downstrm	4 (2 16-bit int)
32	Ch1 Temperature to Modbus	4 (2 16-bit int)
34	Ch1 Pressure to Modbus	4 (2 16-bit int)
36	Ch2 Velocity	4 (2 16-bit int)
38	Ch2 Act Volumetric	4 (IEEE 32 bit)
40	Ch2 Std Volumetric	4 (IEEE 32 bit)
42	Ch2 Fwd Totals	4 (2 16-bit int)
44	Ch2 Rev Totals	4 (2 16-bit int)
46	Ch2 #Tot Digits	2
47	Ch2 Mass Flow	4 (IEEE 32 bit)
49	Ch2 Fwd Mass Totals	4 (2 16-bit int)
51	Ch2 Rev Mass Totals	4 (2 16-bit int)
53	Ch2 #Mass Tot Digits	2
54	Ch2 Timer	4 (2 16-bit int)
56	Ch2 Error Code	2
57	Ch2 Sound Speed	4 (2 16-bit int)
59	Ch2 Molecular Weight	4 (2 16-bit int)
61	Ch2 Sig Strength Upstream	4 (2 16-bit int)
63	Ch2 Sig Strength Downstrm	4 (2 16-bit int)
65	Ch2 Temperature to Modbus	4 (2 16-bit int)
67	Ch2 Pressure to Modbus	4 (2 16-bit int)
69	Avg Velocity	4 (2 16-bit int)
71	Avg Act Volumetric	4 (IEEE 32 bit)
73	Avg Std Volumetric	4 (IEEE 32 bit)
75	Avg Fwd Totals	4 (2 16-bit int)
77	Avg Rev Totals	4 (2 16-bit int)
79	Avg #Tot Digits	2
80	Avg Mass Flow	4 (IEEE 32 bit)
82	Avg Fwd Mass Totals	4 (2 16-bit int)
84	Avg Rev Mass Totals	4 (2 16-bit int)
86	Avg #Mass Tot Digits	2
87	Avg Timer	4 (2 16-bit int)
89	Avg Error Code	2
90	Avg Sound Speed	4 (2 16-bit int)

Figure 6.3: Modbus Map for XGF868i.

4. First Solution

Our first solution focuses on integrating detailed process and diagnostic data from Baker Hughes's flow computers directly into the ICSS, following the XGF868i Modbus Map provided by experts. This integration includes measurements from both flow computer channels and averaged values. The process data includes detailed gas parameters from the flaring system, such as Standard Volumetric Flow, Gas Molecule Weight, Gas Velocity, Gas Pressure, and Gas Temperature. The diagnostic data provides insights into the flow meter's health remotely, including parameters such as Sound Speed, Signal Strength, and Error Codes.

4.1. Accessing Quick Builder Software

To access the Quick Builder tool, open the Configuration Studio application and navigate to the Control Strategy section. From the SCADA Control Panel, select the desired task, which will direct you to a new window containing the Quick Builder software.

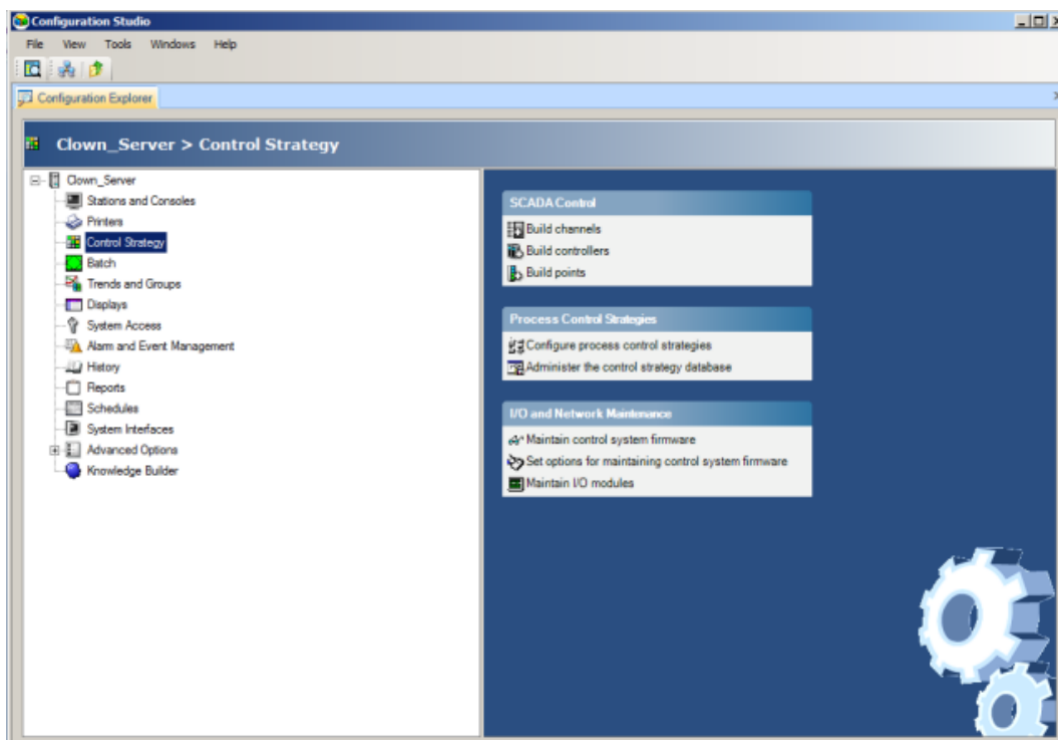


Figure 6.4: Configuration Studio Window.

4.2. Modbus Channels Configuration

The channel configuration identifies all the terminal servers used as Modbus channels to integrate third-party flow meters data into the ICSS. These terminal servers act as bridges, receiving Modbus data from different flow meters through their ports, converting it into Ethernet, and sending it through the FTE network using their IP addresses. In our case, we have six terminal servers, one for each flare system. The Modbus channels were created previously when the first three data sets were integrated.

Name	Description	Item Number
XGF_SGB201	SCADA Channel XGF8681_105A SGB2	CHN86
XGF_SGB301	SCADA Channel XGF8681_102A SGB3	CHN81
XGF_SGB302	SCADA Channel XGF8681_104A SGB3	CHN82
XGF_SGB401	SCADA Channel XGF8681_101 SGB4	CHN83
XGF_SGB402	SCADA Channel XGF8681_101A SGB4	CHN84
XGF_SGB403	SCADA Channel XGF8681_755 SGB4	CHN85

Main	Port	Redundant Port
Name: XGF_SGB401		
Description: SCADA Channel XGF8681_101 SGB4		
Associated Asset: PCU8		
Marginal Alarm Limit: 25		
Fail Alarm Limit: 50		
Diagnostic Scan Rate: 60 secs		
Write Delay: 0 milliseconds		
Connect Timeout: 10 secs		
Read Timeout: 2 secs		
Item Type: Modbus Channel		

Main	Port	Redundant Port
Port Type: TerminalServer		
Protocol: Modbus RTU		
Terminal Server TCP Host Name: 172.16.2.79		
Terminal Server TCP Port No.: 8005		
Idle Timeout: 180 secs		
Checksum: NONE		

Port	Redundant Port
Port Type: None	

Figure 6.5: Quick Builder Channels Configuration.

4.3. Modbus Controllers Configuration

The controller configuration identifies the port ID of each terminal server used for connecting terminal servers to the flow meters, enabling Modbus communication. This configuration specifies the type of Modbus data communicated from each port ID, which in our project is the Holding Register. The ports will receive analog data in 16-bit integer format from each register in the flow meters. We have six ports, one for each terminal server. The Modbus controllers were created previously when the first three data sets were integrated.

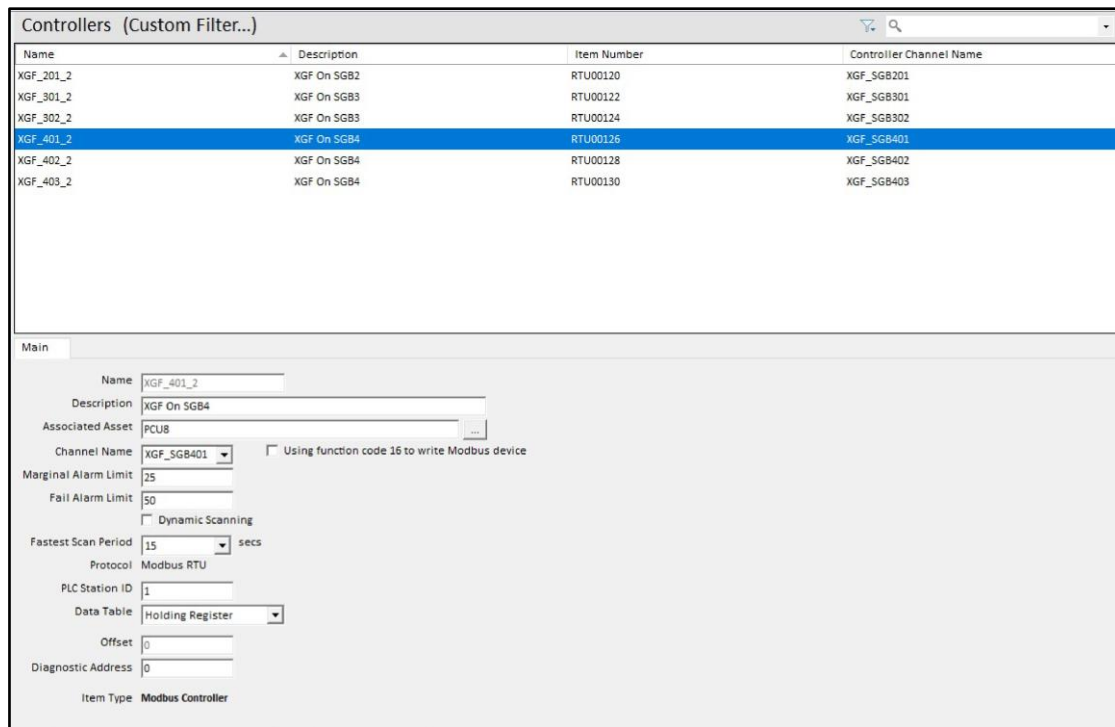


Figure 6.6: Quick Builder Controllers Configuration.

4.4. Modbus Points Configuration:

The points configuration identifies all the third-party data to be retrieved from each flow meter registers and sent to its respective terminal server. Our integration begins by creating 17 new analog points, giving each a name which becomes its tag name, in accordance with the points naming guidelines.

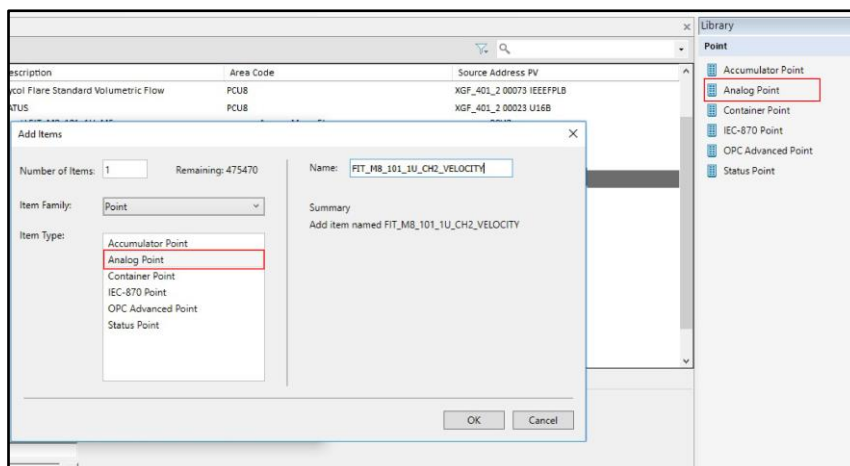


Figure 6.7: New Analog Point Creation.

Next, the configuration specifies details about the desired analog data in the registers using the Modbus map provided by the XGF868i flow meter. This includes their specific register addresses, ranges, units, and the respective port name through which the data will be transferred.

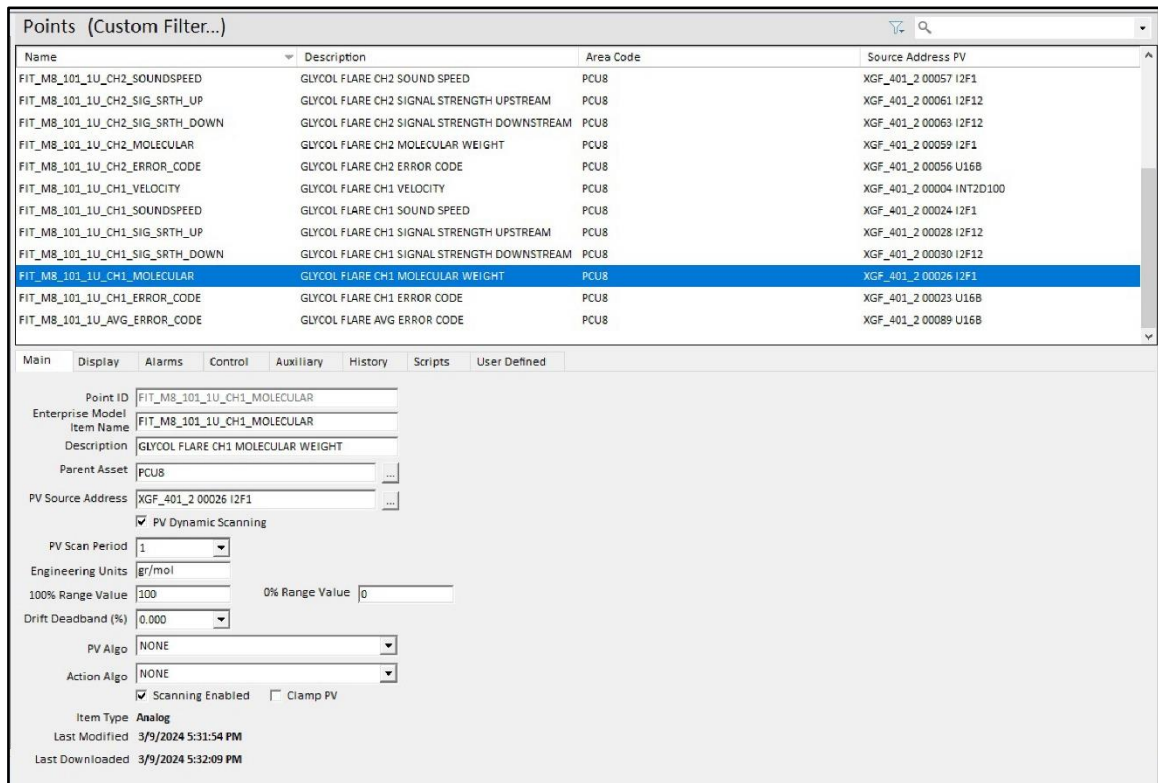


Figure 6.8: One Analog Point Main Details.

4.5. Alarm Configuration:

The Quick Builder enables the alarm configuration of all points by accessing the alarm section for each point and configuring it. This configuration includes selecting the type of alarm and its priority. Each priority type has a specific symbol to be displayed in the Experion Station. Additionally, the configuration includes setting the limit value at which the alarm will trigger, indicating that the limit has been exceeded in the Experion Station.

In this project, we created five alarms: one for the average velocity point and four for the signal strength, both upstream and downstream, for each channel. We cannot see the results because the flaring system is stable and the XGF868i is functioning well, so the alarms do not pop up.

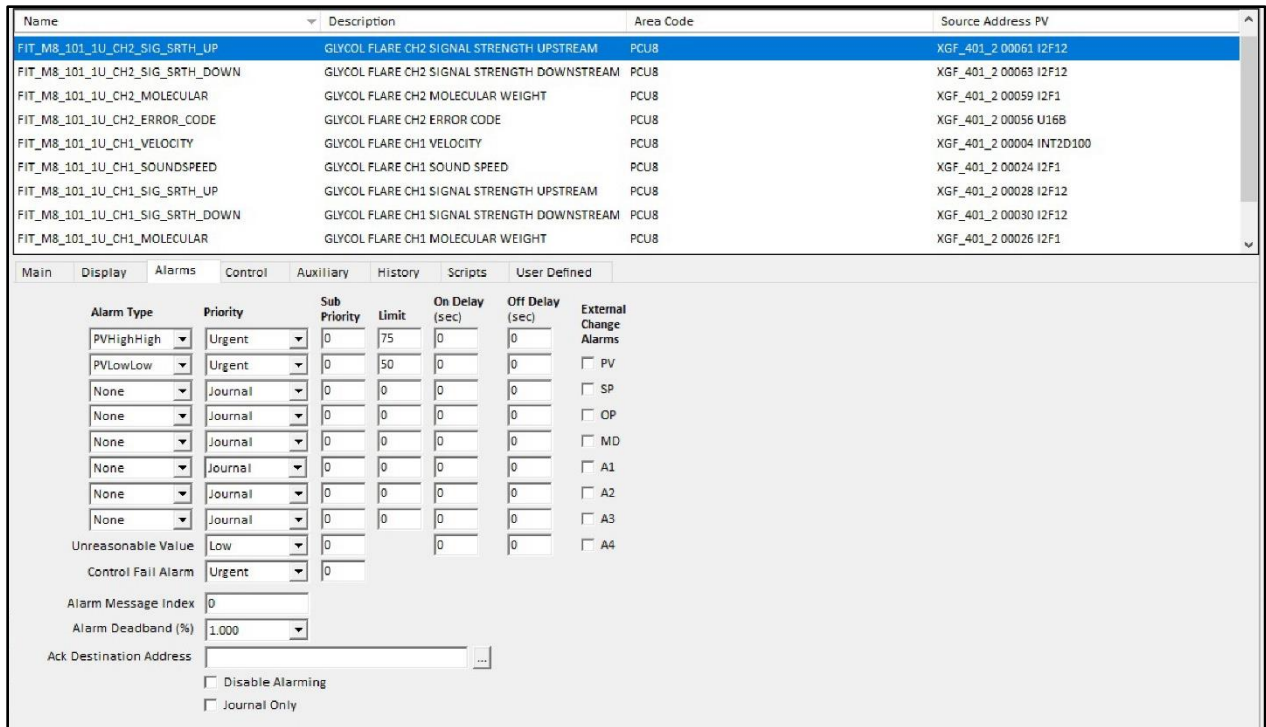


Figure 6.9: Alarm Configuration Point of Signal Strength Upstream Channel 2.

4.6. History Configuration

The Quick Builder enables the historical data logging of each point in the RTDB of the Experion server. Generally, data history is maintained for important data that can help us in the long term. Since the flaring systems' data are crucial, we configured history logging for all 17 points created earlier to store this valuable data in the server. This configuration includes selecting the sampling time for the data provided by each point to be saved.

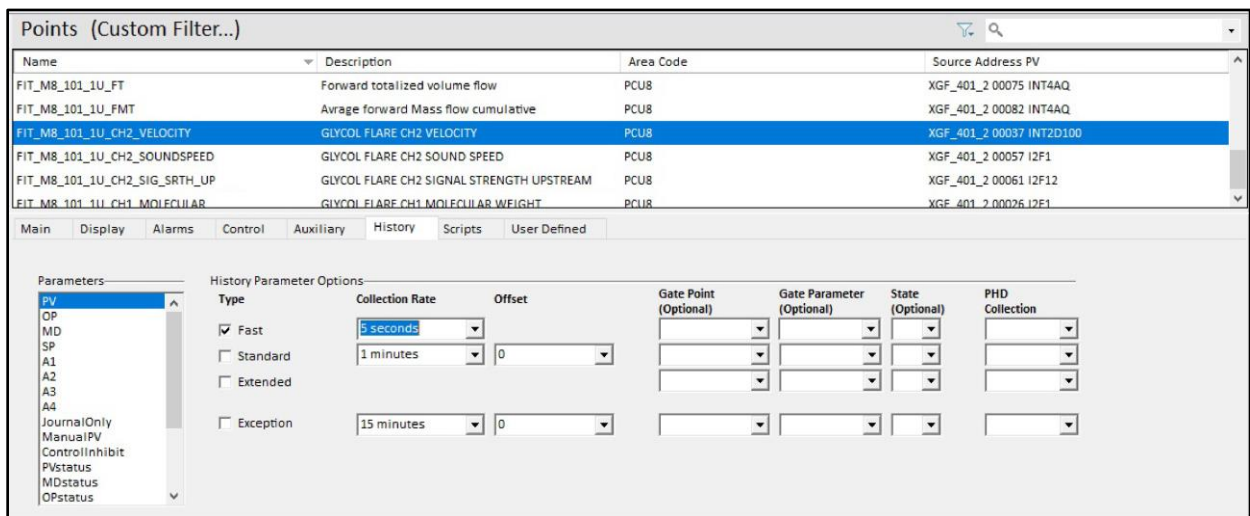


Figure 6.10: History Configuration Point of Velocity Channel 2.

4.7. Station Trends

By saving the SCADA points in the server, we can utilize these data in the Station Trends feature. Station Trend is an advanced feature that enables the plotting of SCADA points over a period of time, from the specific time the data is stored in the RTDB to real-time updates. This advanced capability aids in investigations and troubleshooting. It also helps compare multiple data points simultaneously, such as measurements between channel one and channel two, or related data to see their influence on each other, such as gas velocity and SV flow rate.

- 1- After opening the station software, we can access the trend tool.

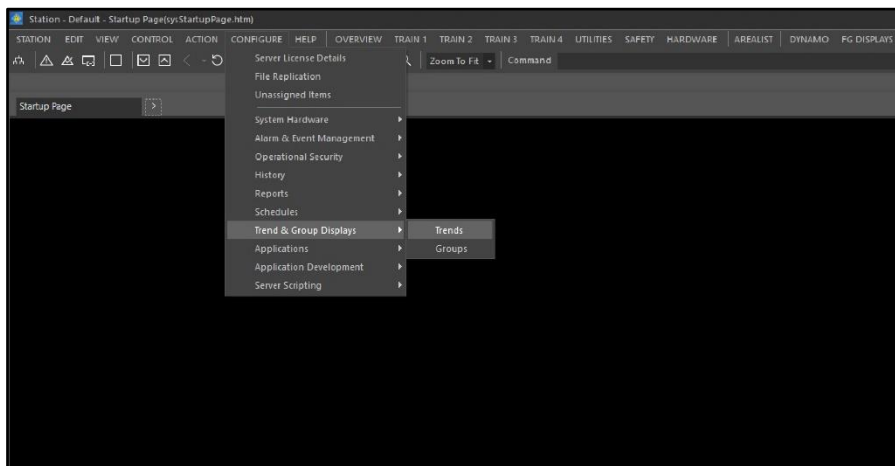


Figure 6.11: Station Interface for Accessing the Trend Tool.

- 2- Then we chose an available trend number, which serves as memory to save the trend configuration, so we don't have to repeat the process each time we want to view the same trend. We selected 115 as the memory number that contains our trend. To keep the configuration, we created a name for our trend and chose the period and sample interval for trend 115. This way, we ensured that our settings were saved and could be easily accessed whenever needed.

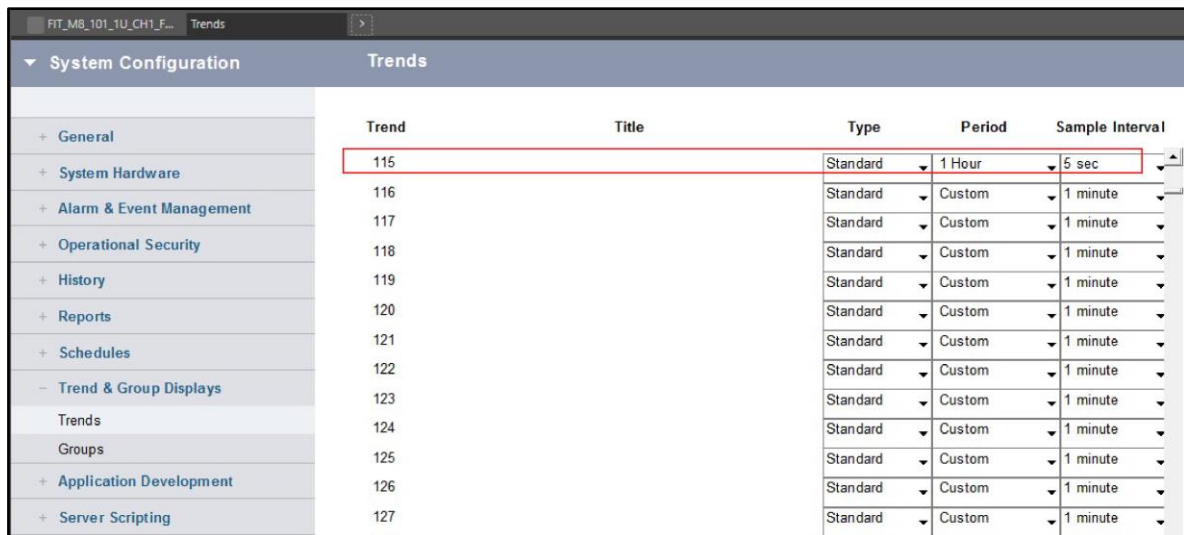


Figure 6.12: Trends Feature Interface.

- After selecting the 115- trend, we enter its configuration to begin tagging all 17 SCADA points related to the VR flare. This tagging process involves entering the respective point tag names. Additionally, we have the flexibility to customize the color of each point to suit our requirements. Once the 115-trend configuration is complete, we simply click the "View Trend" button to obtain the trend results.

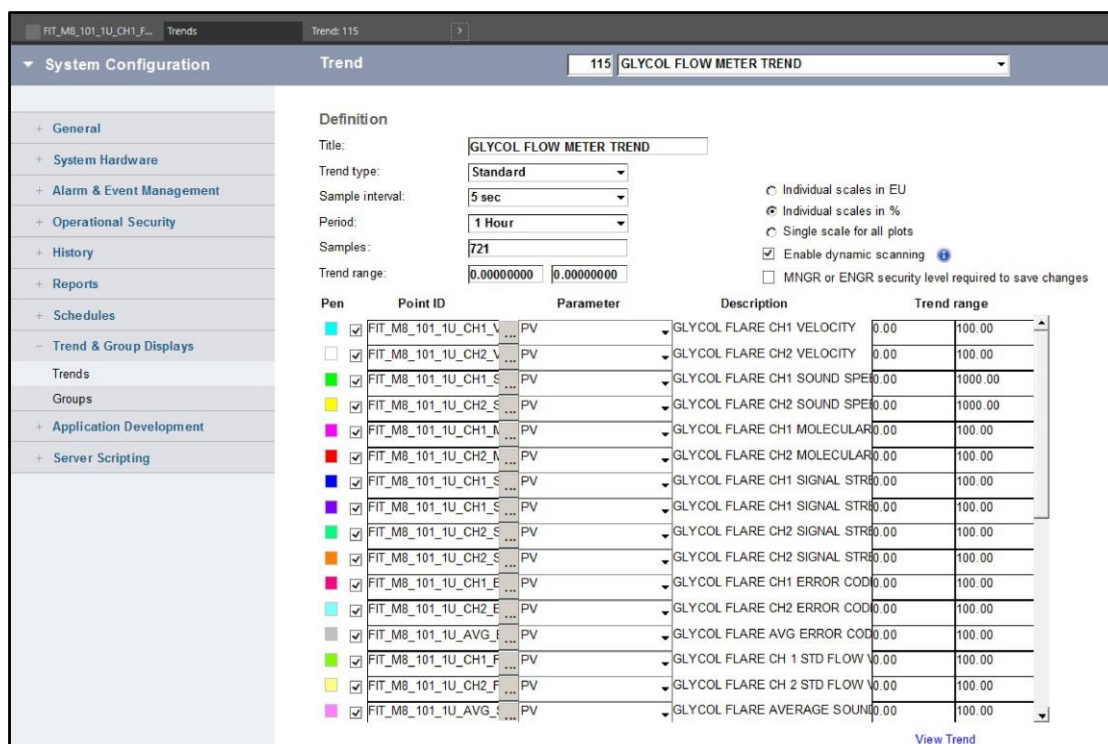


Figure 6.13: Tagging SCADA Points in the 115 Trend Configuration.

The final result is illustrated in the following figure:

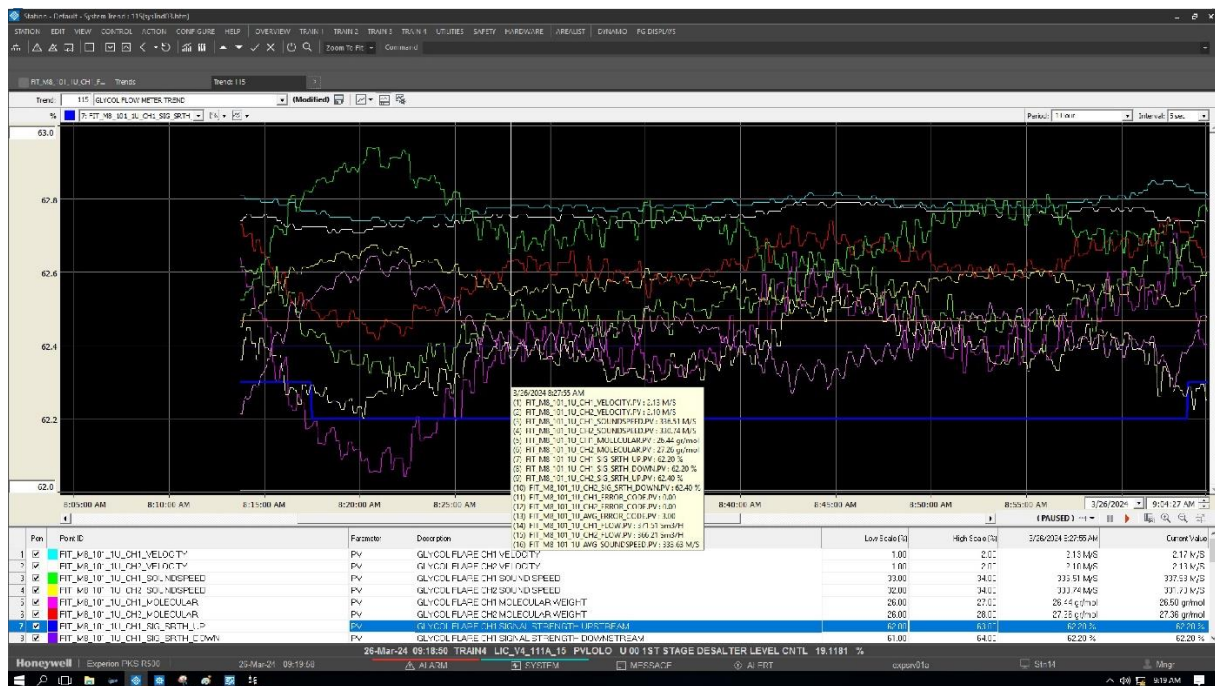


Figure 6.14: Result of 115-Trend.

5. Second Solution

Our second solution focuses on creating well-structured HMIs for each flare, detailing parameters from their respective flow meters in an organized manner using the HMI WEB Display Builder software. These HMIs are then uploaded to be displayed alongside other HMIs of the HBNS site in the CCR, enabling operators to monitor them efficiently through the Experion Station software.

- HMI WEB Display Builder Software:** This is the graphic building tool of Experion PKS, used to build, configure, and program HMIs. It provides a comprehensive suite of features for creating detailed and intuitive graphical interfaces in both simple and advanced ways.

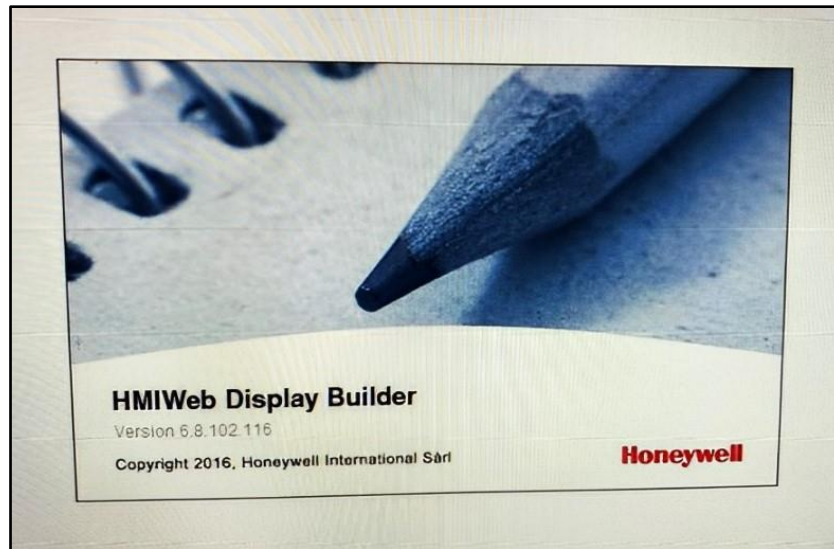


Figure 6.15: HMIWeb Display Builder Software Intro.

5.1. Main HMI

Firstly, we modified the Main HMI (AREA LIST), which is the primary navigation HMI containing buttons that provide quick access to all facility HMIs of the CPF. We created a direct button labeled "Flare Flow System" that leads to the six flare systems. In the HMI WEB Display Builder software, we used the rectangular shape tool, then customized the shape properties to add the HMI tag name of the corresponding page. Additionally, we used the text tool to label the button, ensuring clear navigation to the next HMI.

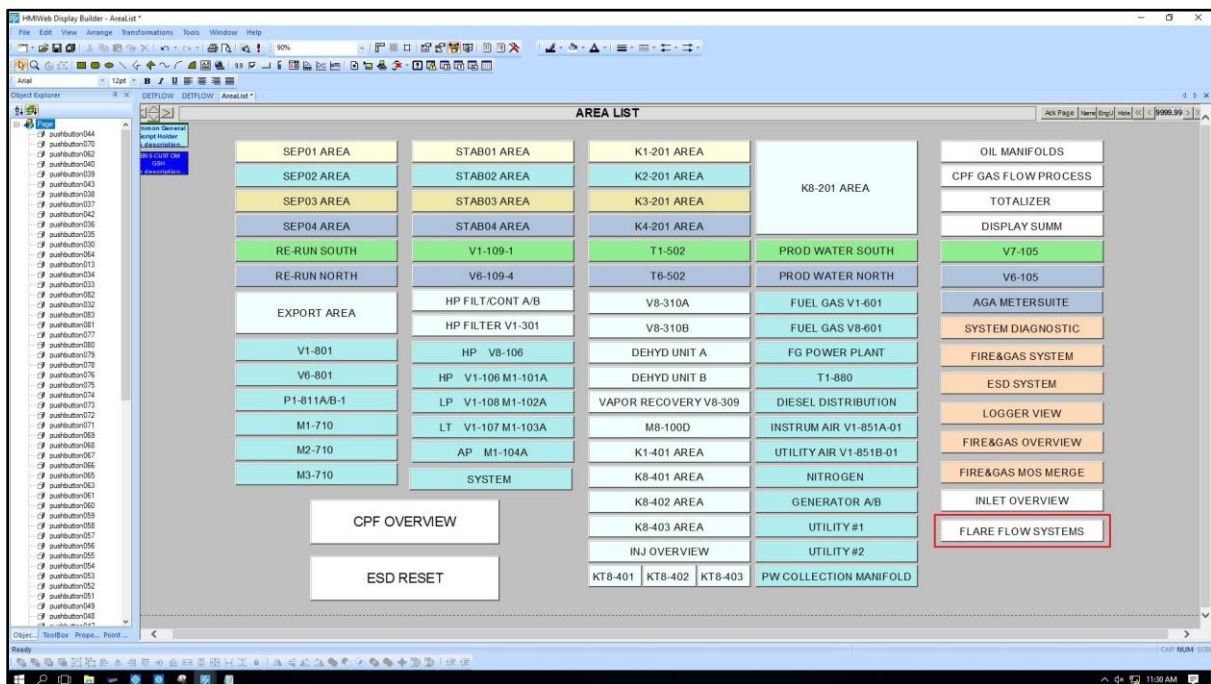


Figure 6.16: Main HMI Modified.

5.2. Flares Flow System HMI

Next, we created an HMI that provides access to all flare systems, allowing operators to easily select the desired flare to access detailed flow meter parameters and real-time data. The Flares Flow System HMI was developed using the same intuitive tools as the Main HMI, linking each flaring system bouton to its corresponding page by just inserting the Specific Flare Flow System HMI tag name in the bouton shape properties.

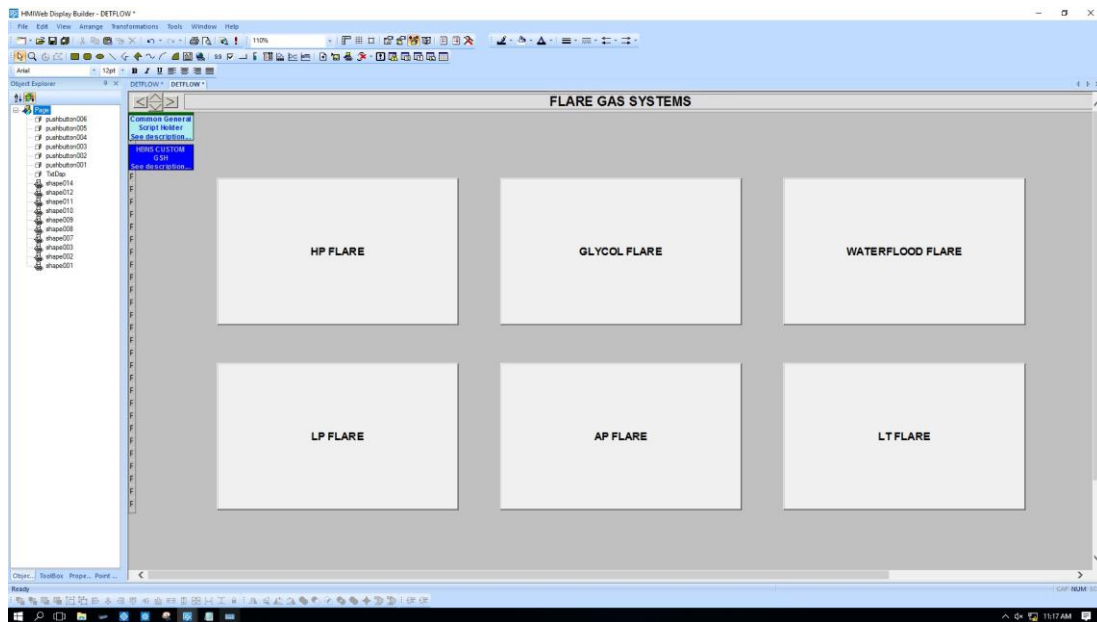


Figure 6.17: NEW Flares Flow System HMI.

5.3. Specific Flare Flow System HMI

After selecting one of the flare flow systems, you will access the final desired HMI, which contains all the process and diagnostic data for the selected flare in an organized manner. Each channel's values are displayed separately, positioned next to each other for easy comparison. At the end, the average values, as well as temperature and pressure readings, are presented.

We created these HMIs using the dynamic shape tool and its parameters, which enable adding the tag name of the SCADA point created in Quick Builder. Once the tag name is inserted, it begins collecting data directly from the RTDB and displays it in the HMI. Additionally, we used the text tool to write the units next to each parameter to improve clarity and to label the title of each group of parameters. This process was repeated for all parameters across all six flares.

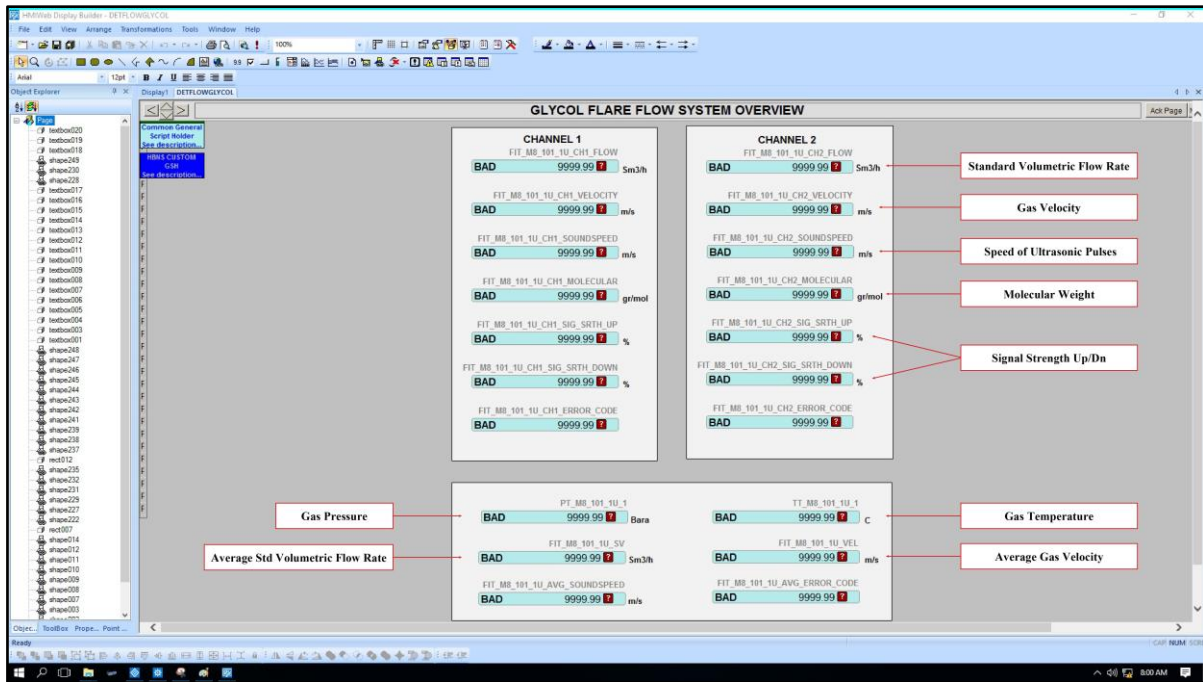


Figure 6.18: Process and Diagnostic Data HMI for the VR Flare Flow System.

To get this final HMI result that can be accessed and displayed through the Experion Station Software:

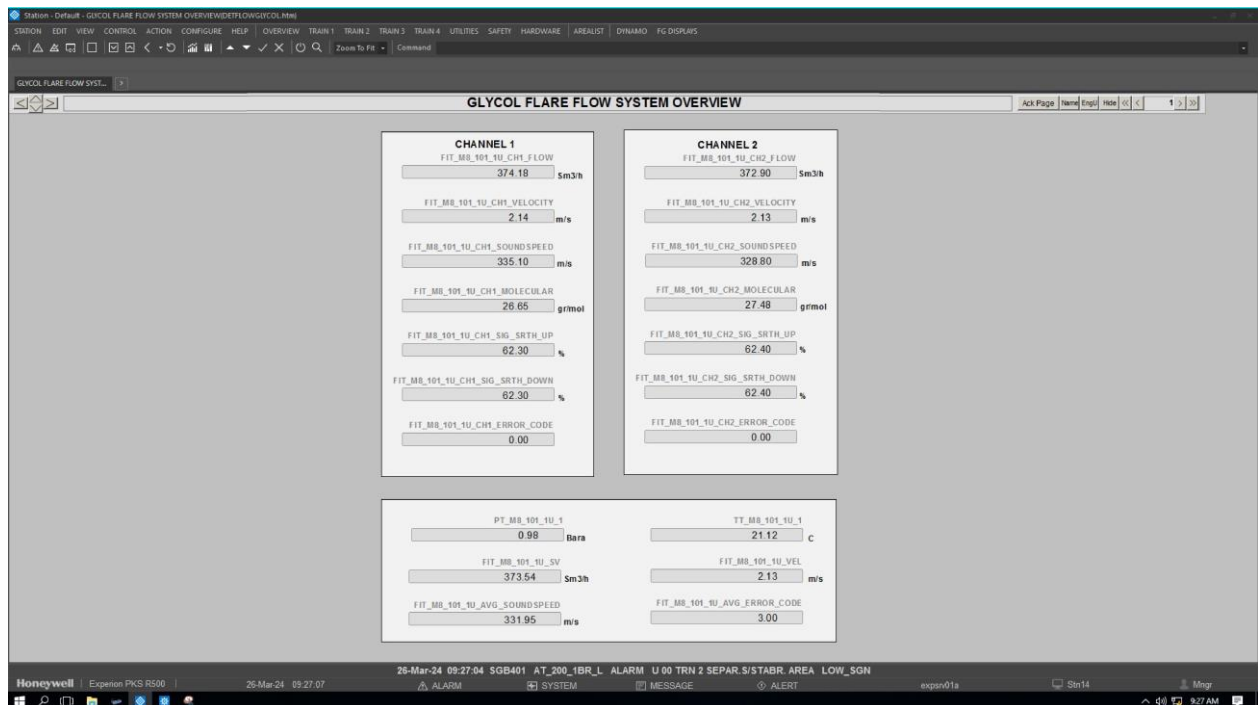


Figure 6.19: Final HMI of the Glycol Flare Flow System.

6. Third Solution (E-Server)

Our third solution involves integrating the HMIs created in the second solution into the Honeywell E-server. This server connects the ICSS system network to the HBNS site network, ensuring seamless data availability through the internet within the HBNS site domain.

This integration allows casual users, including the maintenance division manager and engineers from various departments, to have read-only access to the same HMIs as the operators in the CCR. Using a standard browser such as Google, users can securely access real-time data from Experion and SCADA servers remotely. This eliminates the need to disrupt CCR operators or displace engineers to the Engineering Workstations for data access, thereby streamlining workflow and enhancing productivity.

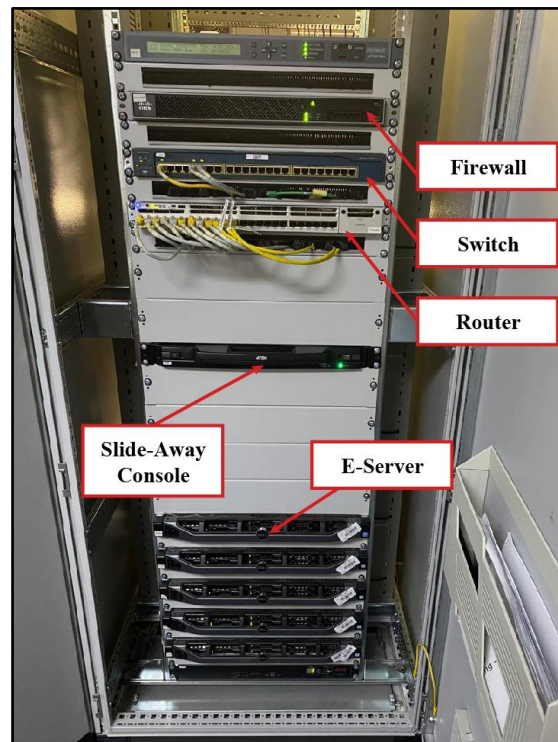


Figure 6.20: Server Cabinet Containing E-Server.

After creating and uploading the HMIs to the system, we exported their files from the HMI WEB Display Builder software and placed them in a designated folder along with other site HMIs in the E-server system. This folder allows the server to read the HMIs as clients and provide them with data from the Real-Time Database (RTDB), ensuring data availability throughout the HBNS site domain via the internet.

This process is facilitated by using the Aten Master View Max slide-away console in the E-server cabinet, which enables efficient communication with the E-server. This setup ensures that real-time data is readily accessible and enhances operational efficiency across the site.

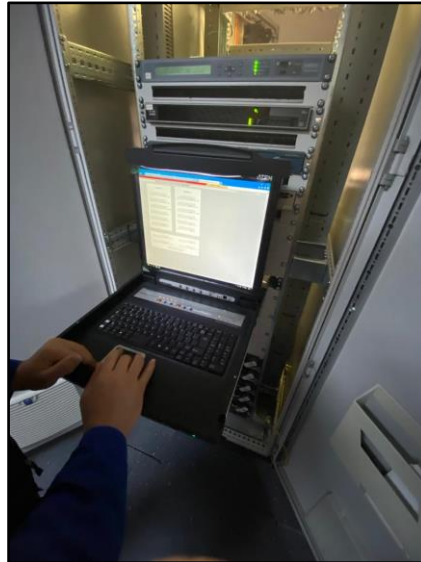


Figure 6.21: HMIs Integration Using the Aten Master View Max Slide-Away Console.

Example of the E-server access from the engineer office, that shows the one of Flare flow system HMI created:

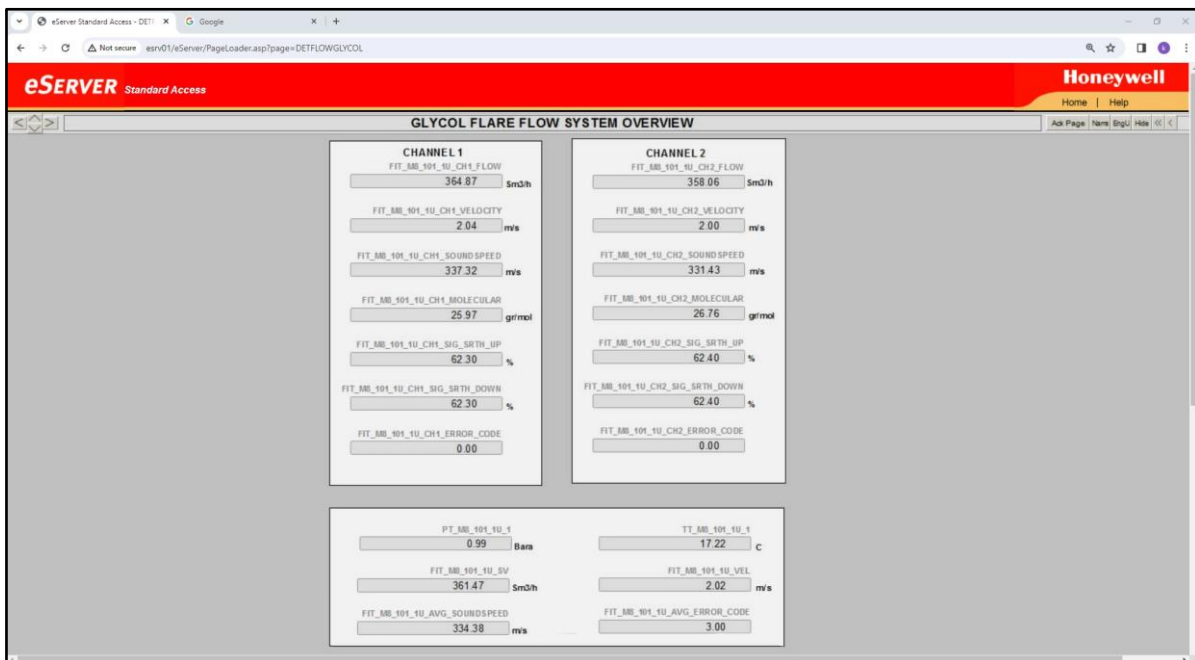


Figure 6.22: Remote Access to HMI of the Glycol Flare Flow System.

7. Process Data Integration Key Benefits

- **Enhancing Safety and Understanding of the Flare System Process:** Operators in the control room gain a deeper understanding of real-time flaring system processes by accessing detailed, reliable, and well-structured data. Additionally, they can avoid potential safety hazards by monitoring flare gas velocity to ensure it does not exceed safe limits.
- **Real-Time Flare Gas Composition Monitoring:** The integration of real-time molecular weight monitoring provides operators with immediate insights into the composition of flared gas, enabling continuous monitoring of separation efficiency. Oil droplets in flare gas can impede the combustion process at the flare stack, resulting in incomplete combustion where not all hydrocarbons are fully oxidized. This reduces flare efficiency and leads to increased emissions of pollutants such as unburned hydrocarbons, carbon monoxide (CO), and black carbon. These pollutants significantly contribute to air pollution, smog formation, and climate change. Black carbon particles are particularly harmful when inhaled, causing respiratory problems and other health issues.

In addition to environmental and health impacts, oil droplets can damage equipment in the flare system, including valves and piping, due to buildup and corrosion. Damaged equipment can lead to leaks and malfunctions, resulting in unplanned downtime and costly repairs.

By tracking the composition of the gas being flared, operators can identify inefficiencies or anomalies in the separation process. An increase in molecular weight indicates the presence of heavier oil droplets, signifying a suboptimal separation process. This data-driven approach enables operators to make informed decisions to optimize separation operations, minimize equipment maintenance, and ensure a reliable and efficient flaring system. This reduces hydrocarbon emissions and minimizes tax burdens associated with excessive flaring. This proactive strategy not only improves environmental performance but also contributes to cost savings through efficient resource utilization.

- **Data-Driven Approach for Technical Studies:** Due to the aging equipment in the CPF of HBNS from 1998 and Groupement Berkline's goal to reduce emissions and protect the environment, the technical department is undertaking numerous upgrades and optimization projects. These efforts aim to reduce emissions and increase the efficiency of the CPF. The technical department benefits from streamlined access to accurate and

organized flare gas data, which helps them understand the HBNS gas circulation within the CPF. This empowers them to conduct thorough studies that inform the selection of appropriate units aligned with HBNS flaring system design. The result is a more optimized flaring process, characterized by increased efficiency and reduced emissions.

8. Diagnostic Data Integration Key Benefits

The XGF868i identify the problems that happens on the flow meter system automatically, and provide error codes to specify the problem occurred. There is two error codes provided by the flow meter:

- **Channel 1 and 2 Error Code Status:** This feature provides detailed information about any issues that occur in each channel of the flow meter. For every specific problem, Baker Hughes specifies the cause and the actions that should be taken by instrumentation engineers or Baker Hughes experts.
- **Average Error Code Status:** This function is utilized to assess the health of the flow meter. It helps determine if there are any issues present. If a problem is detected, the error code provides information on the exact location of the issue, where: E0 = Both in error. | E1 = Channel 2 in error. | E2 = Channel 1 in error. | E3 = Both ok.
- **Real-Time Remote Device Health Monitoring:** The integration offers real-time visibility into the health of the flow computer, enabling proactive maintenance and minimizing potential downtime. This real-time monitoring is crucial for our system, given its direct impact on tax-related processes.
- **Swift Troubleshooting:** The instrumentation team gains immediate access to diagnostic data, facilitating rapid problem identification and resolution. This ensures minimal disruption to operations and maintains system integrity.
- **Remote Expert Support:** Easy access to diagnostic data enables seamless collaboration with Baker Hughes experts for remote analysis and troubleshooting for any Unclear issues. This proactive approach saves valuable time and resources by resolving issues efficiently without the need for on-site interventions, by just sending screen shoots of the trends, or export the HMI data to excel and send it to them.
- **Cost-Effective Operations:** Field interventions by Baker Hughes experts incur significant expenses. However Remote analysis conducted under the validation contract utilizes Baker Hughes' expertise without incurring the expenses associated with on-site

field interventions. This cost-effective approach ensures efficient issue resolution while optimizing operational expenses.

9. Conclusion

In conclusion, this chapter detailed the successful integration of XGF868i flare gas flow meter important data into the HBNS oil field's ICSS, including real-time process and diagnostic data. Leveraging Experion Station, Quick Builder, and HMIWeb Display Builder, we enhanced safety, optimized processes, and enabled data-driven decisions. The E-server solution further extends data access, fostering efficiency. This comprehensive integration maximizes the XGF868i's value, contributing to a safer, more efficient, and environmentally responsible operation.

General Conclusion

This work was carried out as part of my final year project in the maintenance department, specifically in the instrumentation service of the Groupement Berkine HBNS site. The focus was on addressing the issues associated with the data integration of the XGF868i flare gas flow meters.

The first problem, the absence of detailed process data within the control system, was resolved by integrating real-time process data from the XGF868i flow meters into the ICSS using Quick Builder and HMI WEB Display Builder software. This integration provided operators and engineers with valuable insights into the performance of the flaring system, optimized processes, enabled data-driven decision-making, and informed technical studies.

The second problem, the lack of remote monitoring capabilities for the health of the flow meters, was addressed by integrating diagnostic data into the ICSS and enabling the register of these data to be used for trends for advanced monitoring and investigation. This allowed for real-time monitoring of the flow meters' health, enabling swift troubleshooting, proactive maintenance, and reducing the need for costly field interventions. The integration of flare gas flow meter data into the ICSS is not merely a technical upgrade; it is a strategic investment in operational excellence and environmental stewardship.

After an extensive study of the Baker Hughes XGF868i flare gas flow meter and its robust design, advanced algorithms, and ability to overcome flaring system challenges, I am confident that this solution will see widespread adoption in Algerian oil and gas fields and refineries. It is my hope that ALNAFT, the regulatory authority for flaring activities in Algeria, will consider making this technology a standard practice for accurate flare gas flow measurement and taxation.

This project has been a valuable opportunity to apply my academic knowledge to real-world industrial challenges. It has provided me with significant practical hands-on experience and a deeper understanding of various aspects of instrumentation engineering, including CPF instrumentation, flaring systems, flare gas flow measurement challenges, ultrasonic measurement technology, Honeywell ICSS architecture, basic usage of Honeywell software applications, Modbus communication, and data flow from the field to the control system. This experience marks a significant step in my career as an instrumentation engineer in the petrochemical industry.

Finally, I hope that this work will be useful to future promotions and to anyone interested in flare gas flow meter

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