PRODUCED WATER TREATMENT AND DISPOSAL IN OIL WELLS: CASE STUDY OF GIALO FIELD 59, EASTERN SIRTE BASIN, LIBYA

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Abstract: Produced water management has become a critical challenge in mature oil fields due to the increasing water cut and stringent environmental regulations. This study evaluates the treatment and disposal system of produced water in the Gialo Field (Block 59), located in the Eastern Sirte Basin, Libya. The main objective is to assess the efficiency and operational performance of the integrated treatment facilities implemented at Gialo-1 and Gialo-2 stations. The adopted treatment process consists of sequential stages including primary separation in settling and skimming tanks, chemical injection (scale inhibitors, demulsifiers, H_2S scavengers, and oxygen scavengers), and secondary treatment using Induced Gas Flotation (IGF) units. The treated water is subsequently pressurized and reinjected into disposal wells to ensure safe environmental management and reservoir pressure maintenance.

Field data indicate that the system handles produced water volumes exceeding 240,000 barrels per day, with oil-in-water concentration reduced from approximately 400 ppm at the inlet to about 150 ppm after primary treatment, followed by further polishing in IGF units to meet reinjection specifications. The integration of a Vapor Recovery Unit (VRU) and emergency handling systems enhances environmental protection and operational reliability. The results demonstrate that the implemented system provides an effective and technically reliable solution for large-scale produced water management. However, continuous monitoring, optimization of chemical dosing, and process control are essential to maintain performance under variable field conditions. This study highlights the applicability of integrated treatment systems as a practical model for managing produced water in similar mature oil fields.

Keywords: Oil, water, crude oil-water separator, water treatment.

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1. Introduction

The Sirte Basin, also known as the Sirt Basin, occupies the north-central part of Libya along the northern margin of the African Plate. Geographically, it extends between latitudes 28°00′–31°00′ N and longitudes 14°00′–20°00′ E and covers nearly 600,000 km^2, including both onshore and offshore sectors within the Mediterranean region. It is recognized as the youngest and most economically significant sedimentary basin in Libya due to its exceptional hydrocarbon potential. Globally, the Sirte Basin is regarded as one of the major petroleum provinces, ranking among the largest hydrocarbon-producing basins in Africa. Previous studies estimate its recoverable reserves at nearly 43 billion barrels of oil equivalent distributed across numerous giant and medium-sized oil fields (Ahlbrandt, 2001). The basin hosts several prolific carbonate petroleum systems associated mainly with Upper Cretaceous, Paleocene, and Eocene reservoirs. Although most hydrocarbon production is concentrated onshore, offshore areas also possess considerable exploration potential, particularly in water depths approaching 200 m (Hallett, 2002). Geologically, the basin consists of thick Mesozoic and Cenozoic sedimentary successions deposited within a structurally complex framework of horsts, grabens, platforms, and deep troughs. These tectonic elements played a major role in controlling sedimentation patterns, hydrocarbon generation, and reservoir distribution throughout the basin evolution. Among the important producing fields within the Sirte Basin is the Gialo oil field, discovered in 1956 and currently operated by Waha Oil Company. The field lies in the southeastern sector of the basin and represents one of Libya’s key hydrocarbon-producing assets (Ahlbrandt, 2001). During oil and gas production, large volumes of water are commonly extracted together with hydrocarbons. This water, known as produced water, originates either from formation water naturally present in the reservoir or from injected fluids used to maintain reservoir pressure (Murray, 2013). As reservoirs mature, the proportion of produced water generally increases, especially during the late production stages and after long-term waterflooding operations (Bennion et al., 1998). Produced water may contain dispersed oil, dissolved salts, suspended solids, heavy metals, treatment chemicals, and naturally occurring radioactive materials. Consequently, improper handling or disposal can create serious environmental concerns affecting soil, groundwater, and surrounding ecosystems. For this reason, efficient treatment technologies are required to reduce contaminants and improve water quality before disposal or reuse. The present study investigates produced water treatment practices in the Gialo oil field with emphasis on improving treatment efficiency and minimizing environmental impacts associated with produced water disposal.

2. Study Area

The investigated area is located within Block 59 of the Gialo oil field in the eastern part of the Sirte Basin. The field extends approximately between latitudes 28°03′06″ and 28°51′00″ N and longitudes 19°42′00″ and 21°30′00″ E. Geographically, the area lies nearly 300 km south of Ajdabiya and around 30 km south of Gialo town. The Gialo field represents one of the major oil-producing regions in eastern Libya and contains extensive petroleum infrastructure, including production wells, separation facilities, water-handling systems, and disposal units. Its location within the southeastern Sirte Basin makes it an important site for studying produced water generation and treatment processes under desert environmental conditions, (Figure 1).

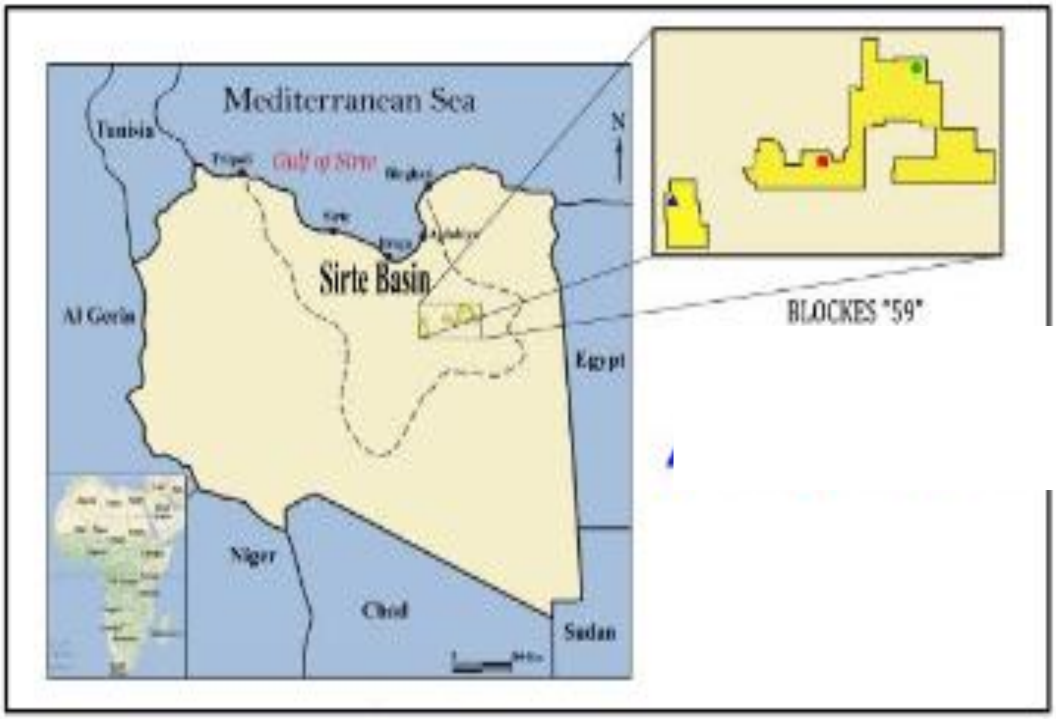


Figure 1. Location map of the study area

3. Lithostratigraphy

The lithostratigraphic succession of the Sirte Basin is generally classified into three main depositional sequences: pre-rift, syn-rift, and post-rift successions (Barr and Weegar, 1972; Hallett, 2002). The pre-rift sequence mainly consists of the Hofra (Gargaf) Formation and the Sarir (Nubian) Formation. These units unconformably overlie the Precambrian crystalline basement and are composed predominantly of pre-Lower Cretaceous continental sedimentary deposits. The syn-rift sequence represents sediments deposited from the Late Cretaceous to Late Eocene during active tectonic subsidence associated with basin rifting. This succession includes several important formations such as Sarir, Bahi, Maragh, Lidam, Etel, Rachmat, Tagrifat, Sirte, Waha, Beda, Zelten, Harash, Gialo, and Awjilah formations. These formations record alternating marine and continental depositional environments controlled by repeated tectonic movements and sea-level fluctuations. The post-rift sequence comprises Lower Eocene to Miocene sediments dominated by shallow marine carbonate deposits formed under relatively stable tectonic conditions. These deposits include the Arida, Diba, and Marada formations and reflect widespread marine regression and the development of tidal to supratidal environments across the basin.

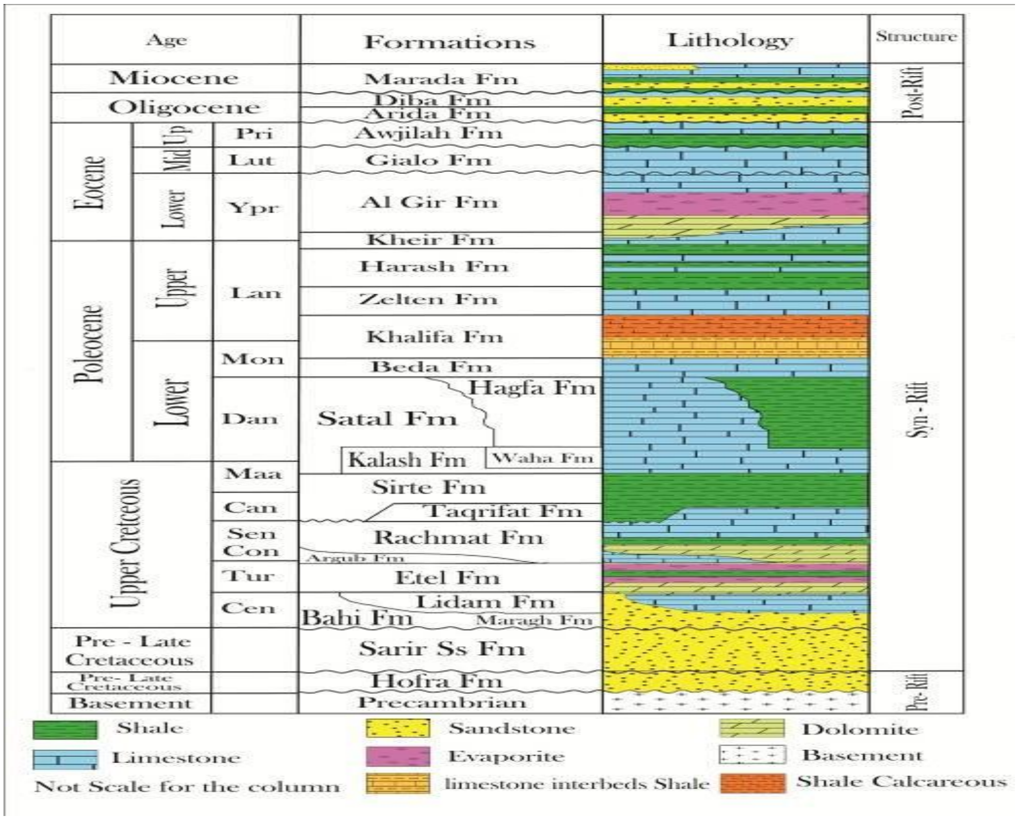


Figure 2. Stratigraphic section in Eastern Sirte Basin

Source: (Barr & Weegar, 1972; Hallett, 2002)

4. Geologic Setting

The Sirte Basin is widely interpreted as part of the southern Tethyan rift system that developed during the Early Cretaceous as a result of regional extensional tectonics (Abadi et al., 2008; Capitanio et al., 2009; Abouessa et al., 2012). The tectonic evolution of the basin involved significant crustal extension followed by syn-rift subsidence and extensive sediment accumulation from the Cretaceous through the Eocene. Before the Late Cretaceous, the Sirte region formed a relatively stable structural high. Subsequent tectonic activity caused major block faulting and graben formation, transforming the area into a structurally differentiated sedimentary basin. During the Late Mesozoic and Early Cenozoic, much of the region became submerged beneath shallow marine conditions, leading to extensive carbonate and shale deposition. Hydrocarbon accumulations in the Sirte Basin occur within reservoirs ranging in age from Cambrian to Tertiary and are commonly associated with horst and graben structural systems. Upper Cretaceous marine shales constitute the principal source rocks responsible for hydrocarbon generation throughout the basin. The Sirte Basin remains one of the richest petroleum provinces in North Africa, with estimated reserves exceeding 45 billion barrels of oil and nearly 33 trillion cubic feet of natural gas (Abadi et al., 2008).

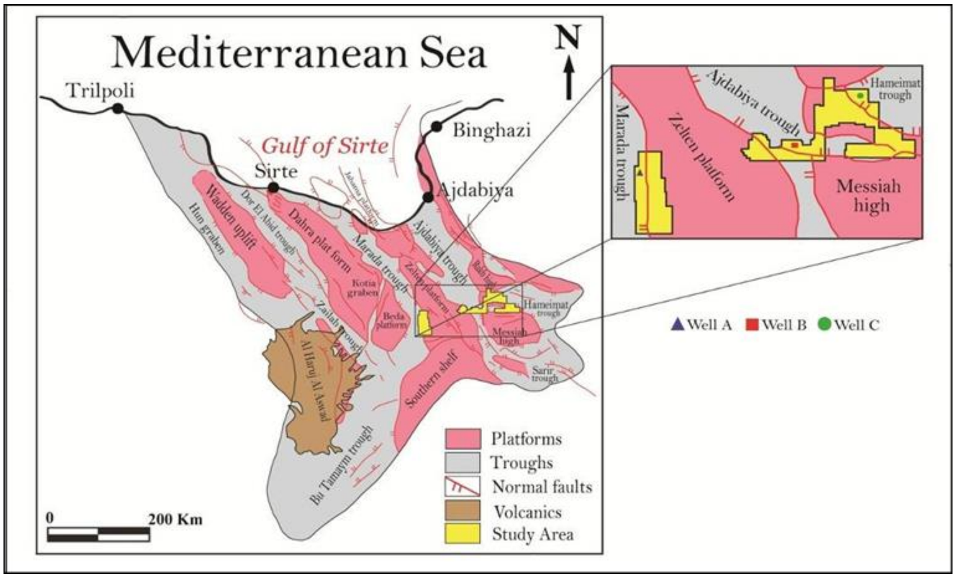


Figure 3. Major structural elements of the Sirte Basin and Study area

Source: (Abadi 2002; Saheel et al., 2010)

5. Background

The Gialo Field (Block 59) is an important oil-producing field located in the southeastern part of Libya, approximately 75 km south of the city of Jalu. The field lies within the southeastern sector of the Sirte Basin, which is one of the most productive petroleum basins in North Africa (Ahlbrandt, 2001; Hallett, 2002). Exploration activities in the Gialo area began in 1956, when the first exploratory well was drilled and successfully produced oil in commercial quantities. During the following decades, several important hydrocarbon discoveries were made in the northern part of the Gialo field, particularly within the Nubian and Raml formations, which represent significant reservoir units in the Sirte Basin petroleum system (Hallett, 2002). The field is operated by Waha Oil Company, which has drilled more than 1,100 wells, approximately 80% of which are producing oil and gas wells. The company operates several major oil fields in the region, including the Waha Field, which represents the largest producing field, in addition to the Dahra Field and the recently developed Al-Fargh Field, along with several smaller satellite fields. Crude oil produced from these fields is transported through a network of pipelines to the Es Sider Oil Terminal on the Mediterranean coast, where it is exported to international markets (Ahlbrandt, 2001). This study presents a process description of the facilities installed for the treatment of produced water generated from the Gialo-1 oil production station. The Gialo-1 and Gialo-2 stations operate with similar processing schemes; however, the Gialo-1 station has a higher treatment capacity compared with the Gialo-2 station. The main objective of this study is to address the issue of associated (produced) water generated in the Jalu-59 oil field, operated by Waha Oil Company. The research focuses on evaluating the treatment methods implemented at the Gialo-1 and Gialo-2 facilities, as well as examining the mechanisms used to protect the surrounding environment and prevent contamination of groundwater resources. Produced water generated from oil production often contains hydrocarbons, salts, heavy metals, and other contaminants that may pose risks to human health, agriculture, and ecosystems if not properly treated (Murray, 2013). Therefore, this study investigates the available treatment processes used to treat produced water and explores methods for improving water quality so that it can be safely managed and reused without causing environmental damage (Bennion et al., 1998)

6. Research Method

The produced-water treatment system implemented in the Gialo field consists of multiple sequential processing stages designed to remove oil, gas, suspended solids, and dissolved contaminants before reinjection into disposal wells.

6.1 Inlet Vessel and Inlet Pumps

The two existing 24-inch GRE pipelines previously connected to the disposal pond will be redirected to the GIALO-1 Treatment and Injection Station. The produced water flow will be driven by the initial source pressure and the elevation difference between the source and the facility, subject to confirmation following the site survey. Produced water from the pipelines will flow by gravity into the Receiving Vessel (VE-101), which is installed at an appropriate elevation. The vessel is equipped with inlet devices designed to reduce turbulence and mitigate wave formation caused by potential two-phase flow in the incoming lines. The primary function of VE-101 is to provide suction to the inlet pumps P-101 A/B/C/D and to allow the separation and collection of gas released from the produced water due to pressure flashing after the interface level control valves at the source facilities. Four inlet pumps are installed, typically with three operating and one on standby, each having a capacity of 100,000 BWPD and equipped with Variable Speed Drivers (VSDs). These pumps transfer the produced water from the receiving vessel to the Settling Tank (TK-101). The total flow rate of produced water pumped to TK-101 is measured by FI-007, which is used as the basis for calculating chemical injection rates and determining the disposal well injection rate during normal operating conditions.

Continuous water handling is ensured by maintaining a constant level in VE-101 through the level controller LIC-001, which regulates the pump speed via the VSD system. Pump speed increases when the incoming flow rises and decreases when the flow is reduced. If the flow becomes insufficient for three pumps, one pump is stopped; conversely, an additional pump is started when the flow exceeds the capacity of the operating pumps. The receiving vessel operates under controlled pressure using a gas blanketing system. The self-regulating valve PCV-074 introduces blanketing gas if the pressure drops below 0.213 psig (150 mm WC), while PCV-012 vents excess gas to the Vapor Recovery Unit (VRU) when the pressure exceeds 0.284 psig (200 mm WC). In practice, the vent valve operates continuously due to gas released from the produced water in the pipelines. In case of operational upset, when produced water cannot be processed by the treatment facility, the flow is diverted through bypass lines to the Emergency Pit (BA-101). Additionally, if the level in VE-101 exceeds the High-High Level (HHL) limit, the resulting pressure increase breaks the hydraulic seal and allows the water to discharge into the emergency pit. Once normal operation is restored, the inlet pumps reduce the vessel level and the siphon effect ceases while maintaining the hydraulic seal to prevent air ingress into the system. If the level decreases to the Low-Low (LL) limit detected by LIA-013, the Emergency Shutdown (ESD) system stops the pumps to prevent damage. Due to the short residence time of produced water in VE-101, significant solids accumulation is not expected. Nevertheless, the vessel is equipped with a system to allow sludge removal from the bottom. For maintenance purposes, the system also includes isolation valves at the inlet nozzles and bypass lines with isolation valves directing flow to the emergency pit for each incoming 24-inch pipeline.

6.2. Chemical Injection

Chemical injection is performed at the discharge of the inlet pumps, prior to water entering the Settling Tank (TK-101). The injected chemicals include Scale Inhibitor, Reverse De-emulsifier, H_2S Scavenger, and O_2 Scavenger, with dosing rates determined based on laboratory analyses (Refer to Table 1).

i. Scale Inhibitor prevents scaling caused by water composition.
ii. Reverse De-emulsifier facilitates emulsion breaking in the settling tank and IGFs.
iii. H_2S Scavenger reduces hydrogen sulfide concentration to meet injection specifications.
iv. O_2 Scavenger lowers dissolved oxygen; its injection rate is increased when recycling water from the emergency basin.

Each chemical is supplied through a dedicated injection package, consisting of a storage tank with mixer and a reciprocating dosing pump. Tanks are filled from barrels using an instrument air-driven pump (Fig .4). Tagging of the injection system is as follows:

Table 1. Injection containers and equipment used

Chemical	Package Tag	Tank Tag	Dosing pump tag
Reverse De-emulsifier	PK-101	TK-102	P-109
H2S Scavenger	PK-102	TK-103	P-110
O2 Scavenger	PK-103	TK-104	P-111
Scale inhibitor	PK-104	TK-105	P-122

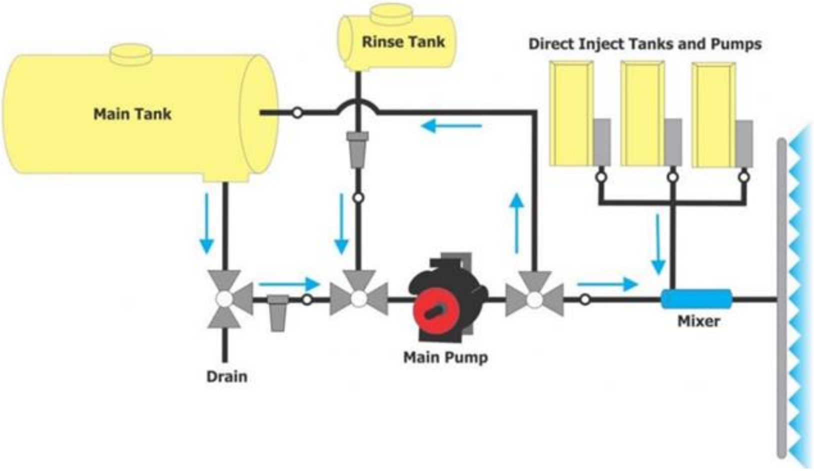


Figure 4. Chemical injection mechanism

6.3. Settling and Skimming

Produced water enters the Settling Tank (TK-101) through a specialized inlet system designed to promote efficient separation. TK-101 is a fixed-roof tank equipped with a dedicated skimming system to remove oil from the water surface. The process reduces the oil content from 400 ppm at the inlet to a maximum of 150 ppm at the outlet, with recovered oil collected by gravity into the Skimmed Oil Drum (VE-102). The settling tank also allows solid particles to settle, ensuring compliance with the maximum particle size specification for treated water. From TK-101, water flows by gravity into the three Induced Gas Flotation units (IGF-101 A/B/C**)**. The tank level is maintained constant using a liquid leg on the outlet line, while piping configuration ensures equal distribution to all three IGFs. To facilitate gravity flow and prevent air ingress, TK-101, IGFs, and VE-102 are gas-blanketed from a common header via PCV-062 set at 100 mm WC, while vapors are collected in the same header and controlled by PCV-011 at 150 mm WC. This system ensures efficient gas collection from the treated water and maintains process integrity.

6.4. Induced Gas Flotation (IGF)

The Induced Gas Flotation units (IGF-101 A/B/C) are designed to remove insoluble oil and suspended solids from produced water to meet injection specifications for oil-in-water and total suspended solids (TSS). Produced water first enters the inlet compartment, where primary solids settling occurs. This compartment acts as a surge dampener and a buffer for initial oil skimming and solids removal. The flow then passes through four sequential active flotation cells, separated by baffle plates, where oil removal is enhanced using external eductors. This configuration allows flow fluctuations of up to 10% without significant loss of efficiency. In the final stage, water enters a quiescent compartment, where final separation occurs. From this section, a centrifugal recirculation pump (one operating and one standby per unit) recycles water to the eductors to generate fine gas bubbles required for flotation.

Table 2. Recirculation Pumps per IGF Unit

Induced Gas Flotation Unit Tag	Associated Recirculation Pump Tag
IGF-101A	P-106 A/B
IGF-101B	P-107 A/B
IGF-101C	P-108 A/B

Each flotation cell is equipped with an ETS dual nozzle/eductor system, which induces gas through an adjustable needle valve and ensures uniform dispersion of fine bubbles. Proper control of gas flow and back pressure enables optimal bubble size, allowing efficient attachment of oil droplets and suspended solids, which then rise to the surface. Heavier particles that settle at the bottom are removed during maintenance.

Oil and suspended solids accumulate as froth on the liquid surface and are continuously removed adjustable spillover weirs. The separated oil is collected and transferred by gravity to the Skimmed Oil Drum (VE-102). Level control is achieved using on/off control valves (LCVs) regulated by high- and low-level switches. A gas blanket of approximately 100 mm WC is maintained to ensure effective flotation and prevent air ingress, while hydrocarbon vapors are routed to the Vapor Recovery Unit (VRU). Each IGF unit is also equipped with a sampling point on the treated water outlet for performance monitoring.

6.5. Booster Pumps

The treated Produced Water will be evacuated from IGF-101 A/B/C dedicated chamber based on the level controller LIC-015A/B/C. Each IGF-101 A/B/C will have its own Level Control Valve LCV-015 A/B/C on the discharge lines of associated Booster Pump P-102 A/B/C. Pump P-102D will be able to replace either of the P-102 A/B/C Booster Pumps. If the FIC-109,110,111 will control the minimum flow through pumps, and in case water flow rate becomes lower than the certain set point, the pump will be shut down to protect the booster pumps against the low flow. If the samples taken from each IGF-101A/B/C show the water quality off spec, the water will be diverted to emergency pit BA-101 until it becomes suitable for injection. Each Booster pump will have its own line to the common header towards emergency pit BA101. Booster pumps P-102A/B/C/D transfer the produced water from the IGF-101 A/B/C and raise the pressure in the common suction header of the HP Injection Pumps. The total flow-rate of the booster pumps is measured with FI-050.

6.6. Hp Injection Pumps and Flow Distribution

HP Injection Pumps P-103 A/B/C/D/E/F/G (normally 6 in operation and one stand by) with the nominal flow-rate of 50,000 BWPD/each are meant to raise the pressure of the produced water to enable the injection in the wells: #SWD-10, #SWD-17, #SWD-11, #SWD-12, #SWD-13 and #SWD-5. All the pumps have the suction from a common header and discharge in a common header. Each pump will be protected against minimum pressure with PSLL and against maximum pressure on the casing with the PSHH. Their tags are shown in the table below:

Table 3. Injection pumps maximum and minimum pressure used by PSLL

Injection Pump Tag	Low Line Pressure -Low Suction Pressure Transmitter	High-High Casing Pressure Transmitter
P-103 A	PT/PALL-37A	PT/PAHH-39A
P-103 B	PT/PALL -37B	PT/PAHH-39B
P-103 C	PT/PALL -37C	PT/PAHH-39C
P-103 D	PT/PALL -37D	PT/PAHH-39D
P-103 E	PT/PALL -37E	PT/PAHH-39E
P-103 F	PT/PALL -37F	PT/PAHH-39F
P-103 G	PT/PALL -37G	PT/PAHH-39G

The discharge header will be protected for the overpressure with the pressure safety valves PSV-040A/B, discharging to the emergency pit BA-101. Three of the HP Injection Pumps i.e. P-103 A/B/C will be provided with VFD’s and the others i.e. P-103 D/E/F/G will work at full speed.
The intent is to control the pressure of the common discharge header PIC-044 with three of the injection pumps while the others will work at full speed. Normally should work 6 pumps and one will be stand By
The flow distribution to the six wells will be done by individual wells flow control valves (choke type) that will distribute even the total flow rate measured at FI-07 (FI-50- in case of off spec water evacuation to the Emergency Pit) with individual flow control loops. The pressure of each line of injected water to wells will be measure downstream the flow control valve. The instruments’ tag are shown in the table below.

Table 4. Measuring the pressure of the line from the injected water

Well	Flow Control loop	Well Line Pressure
#SWD-10	FIC-041	PI-042
#SWD-17	FIC-047	PI-048
#SWD-11	FIC-053	PI-054
#SWD-12	FIC-059	PI-060
#SWD-13	FIC-065	PI-066
#SWD-5	FIC-71	PI-072

6.7. Emergency Water Treatment

In the normal water treatment there is not air ingression in none of the water streams. The oxygen could get into contact with the Produced Water from the remaining oxygen incoming with other streams.
In case of upset at the Receiving Vessel’s VE-101, Inlet Pumps P-101A/B/C/D or in case off-spec water analysis results from IGF-101 A/B/C the water is evacuated into the emergency pit BA-101. This is an open lined pit where the water takes contact with air. As per Client requirement the disposed water have

to be recovered and re-introduced it into the Produced Water injection stream. This is achieved using the pump P-105 associated to the Emergency Pit BA-101. The stream pumped by P-105 will be measured by FI-109 and the flow rate will be manually adjusted. The discharge line of the pump P-105 will be in the feed line to the Settling Tank TK-101 downstream of the inlet pumps but upstream of chemicals injection. Since there will be time gap between water emergency disposal and water recovery, the reinjected water should be considered as saturated with salts and oxygen. The ratio of air contaminated water re-injection/normal Produced Water is 1/30.

Pump will be started manually by operator and will be shut-down at LL Level (LI-002). The Oxygen Scavenger injection during this re-injection of contaminated water should be increased to meet the final water specification.

6.8. Auxiliary Process Units

The skimmed oil will be collected from the Settling Tank TK-101 and from the IGF 101 A/B/C into the Skimmed Oil Drum VE-102. The flow will be ensured by gravity, VE-102 being located underground. The Skimmed Oil Drum VE-102 will be blanketed and the vapours will be collected by the same systems as TK-101 and IGF 101 A/B/C to favour the gravity flow.

The condensate recovered in VRU will be collected in the same Skimmed Oil Drum VE102. Since the skimming operation is not a very precise one, there is a possibility of presence of produced water in the skimmed oil drum VE-102. The collected liquid will be pumped back to GIALO 1 Station with the Pump P-104 A/B (one active, one stand by). The pumps will be controlled by the level controller LIC-078 on start/stop logic. In case of abnormal Low-Low Liquid Level at LS-077 ESD will stop the running pump. The flow-rate of the recycled oil/water to GIALO 1 will be measured with FT-077.

6.9. Vapours Recovery Unit

Vapours Recovery Unit will collect vapours from Receiving Vessel VE-101 and from the common header of Skimming Tank TK-101, IGF-101A/B/C and Skimmed Oil Drum VE-102. The VRU will collect the recovered vapours in a suction scrubber, will compress them with a suitable type compressor at 50 psig, will cool down the compressed gas at 122oF using an Air Cooler and, after separation in a KO Drum will deliver the gas back to GIALO 1 Station through new pipeline. There will be a vapours recycle line to enable the continuous operation of the compressor. The condensate from the KO Drum will be recycled to the Skimmed Oil Drum VE-102.

7. Results Analysis

7.1 System Implementation and Performance

The results of this study indicate that Oasis Oil Company implemented an integrated produced water management system to ensure environmental safety at the Gialo-1 and Gialo-2 stations. The system consists of two produced water handling and disposal trains with a total capacity of approximately 500,000 barrels per day (BPD).

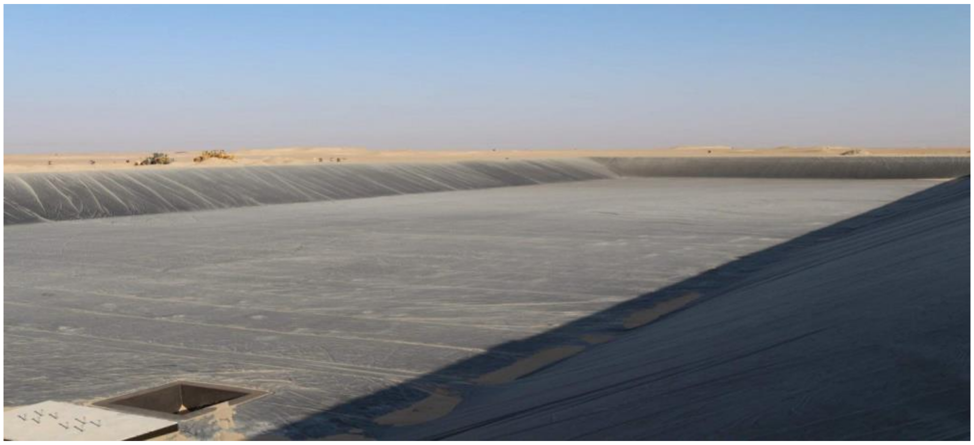


Figure 5. Water drainage system in the Gallo field

Produced water is transferred from production facilities through two 24-inch pipelines per station to a receiving vessel, then pumped (each pump with a capacity of 100,000 BWPD) to the settling and skimming tanks. Each tank has a capacity of 10,000 barrels and is designed with a residence time exceeding 30 minutes to enhance oil–water separation efficiency. Following primary treatment, the water flows to Induced Gas Flotation (IGF) units, where residual oil is removed. The recovered oil is collected in a skimmed oil tank with a capacity of 3,250 barrels and returned to the production system. The treated water is then transported via booster pumps to a high-pressure injection station located approximately 6–7 km from the treatment facility. Final disposal is achieved through injection wells operating at a wellhead pressure of approximately 700 psig. The system also includes an emergency basin (100,000 barrels capacity), with additional backup capacity to handle operational upsets. A Vapor Recovery Unit (VRU) is installed to capture hydrocarbon vapors and minimize environmental emissions.

7.2 Environmental Impacts of Produced Water

Produced water management remains a critical environmental concern in oil and gas operations. Untreated discharge can lead to contamination of soil, groundwater, and surface water, as well as degradation of ecosystems. Produced water typically contains elevated concentrations of dissolved salts, hydrocarbons, heavy metals, naturally occurring radioactive materials (NORM), microorganisms, and chemical additives such as corrosion and scale inhibitors. Additionally, hydrogen sulfide and other sulfur compounds may pose toxicity and corrosion risks. Large volumes of produced water can also contribute to soil erosion, land degradation, and risks associated with spills, leaks, and infrastructure failure. Furthermore, subsurface interactions may alter groundwater quality through ion exchange and mineral accumulation.

7.3 Produced Water Rate

Produced water generation varies significantly over the lifecycle of an oil field. Initially, water production is relatively low but increases over time, often exceeding oil production rates in mature fields (Table 5 &6). In the Gialo fields, the average produced water rate is approximately 237,992 barrels per day (Figure 6). This variation is influenced by geological conditions, fluid properties, reservoir behavior, and production techniques. Samples collected from selected wells in October 2022 indicate that a substantial portion of produced water is treated and reinjected, while excess volumes are directed to disposal pits when necessary.

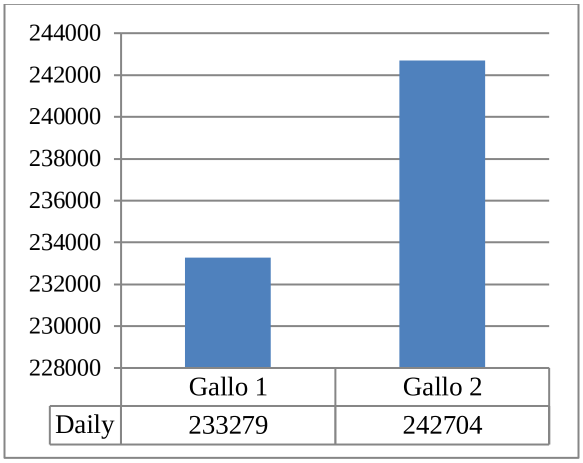


Figure 6. Shows the daily production rate of the Gallo field in 2022

Table 5. The names of the wells the Gallo 1 field and the percentage of its production

Well name	Oil production	Water production
C-175	7407	53181
T-140/150	16445	69312
T-180	15811	60268
C-182	4344	50717

Table 6. The names of the wells the Gallo 2 field and the percentage of its production

Well name	Oil production	Water production
C-275	4197	51263
T-240/250	28762	62558
T-280	23658	65398
C-276/ C-278	10126	65167

To quantitatively evaluate the performance of the produced water treatment system, the oil removal efficiency was calculated based on the measured oil-in-water concentrations before and after treatment.

The oil removal efficiency (η) is expressed as:

η (%) = [(C_in − C_out) / C_in] × 100

where:
C_in = inlet oil concentration (ppm)
C_out = outlet oil concentration (ppm)

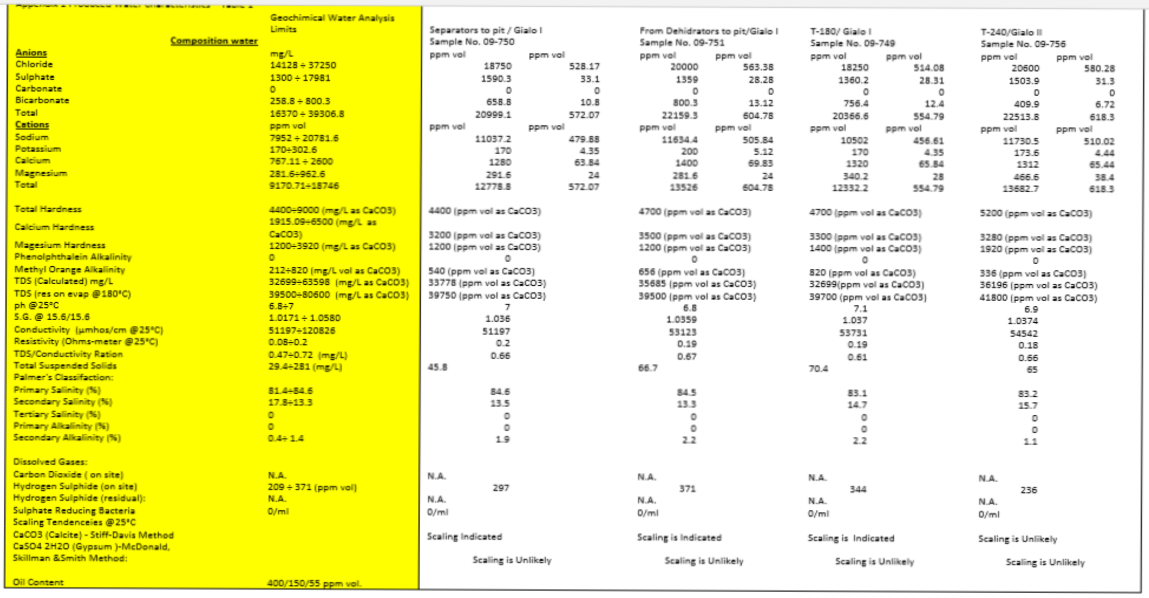
Based on field data from the Gialo treatment system, the oil concentration is reduced from approximately 400 ppm at the inlet of the settling tank to about 150 ppm after primary treatment.

Thus, the primary treatment efficiency is:
η = [(400 − 150) / 400] × 100 = 62.5%

This indicates that the settling and skimming process alone removes approximately 62.5% of the oil content. Following this stage, the Induced Gas Flotation (IGF) units provide further polishing of the produced water by removing finer oil droplets and suspended solids. Typically, IGF systems are capable of reducing oil concentration to values below 50 ppm under optimal operating conditions. Therefore, the overall system efficiency can be estimated to exceed 85–90%, depending on operating parameters such as chemical dosing, flow rate, and bubble generation efficiency. In comparison with international standards, the American Petroleum Institute (API) recommends that oil-in-water concentrations for reinjection or discharge should generally be below 40 ppm, depending on reservoir conditions and environmental regulations. The obtained results from the Gialo field indicate that the treatment system approaches acceptable limits for reinjection, although further optimization may be required to consistently meet stricter environmental standards. Moreover, previous studies (e.g., Bennion et al., 1998; Murray, 2013) have shown that conventional gravity separation typically achieves efficiencies between 50–70%, while IGF systems can increase total removal efficiency to above 90%. The performance observed in this study is therefore consistent with published literature, confirming the reliability of the adopted treatment configuration. However, system performance remains sensitive to variations in produced water composition, particularly in terms of salinity, droplet size distribution, and the presence of stable emulsions. This highlights the importance of continuous monitoring and optimization of chemical injection rates to maintain high treatment efficiency. Overall, the analysis demonstrates that the integrated treatment system implemented in the Gialo field provides a technically effective solution for oil removal, with performance levels comparable to international practices.

7.4 Oil Content Reduction

The results show that the oil content decreases from approximately 400 ppm at the inlet to about 150 ppm after primary treatment in the settling and skimming tank. Further reduction is achieved in the Induced Gas Flotation (IGF) units, where the oil concentration reaches approximately 55 ppm. This reduction demonstrates the effectiveness of the multi-stage treatment process in progressively removing oil from the produced water stream. The primary treatment stage is responsible for the removal of free oil, while the IGF units enhance the removal of dispersed oil droplets and suspended solids (refer to Figure 7).

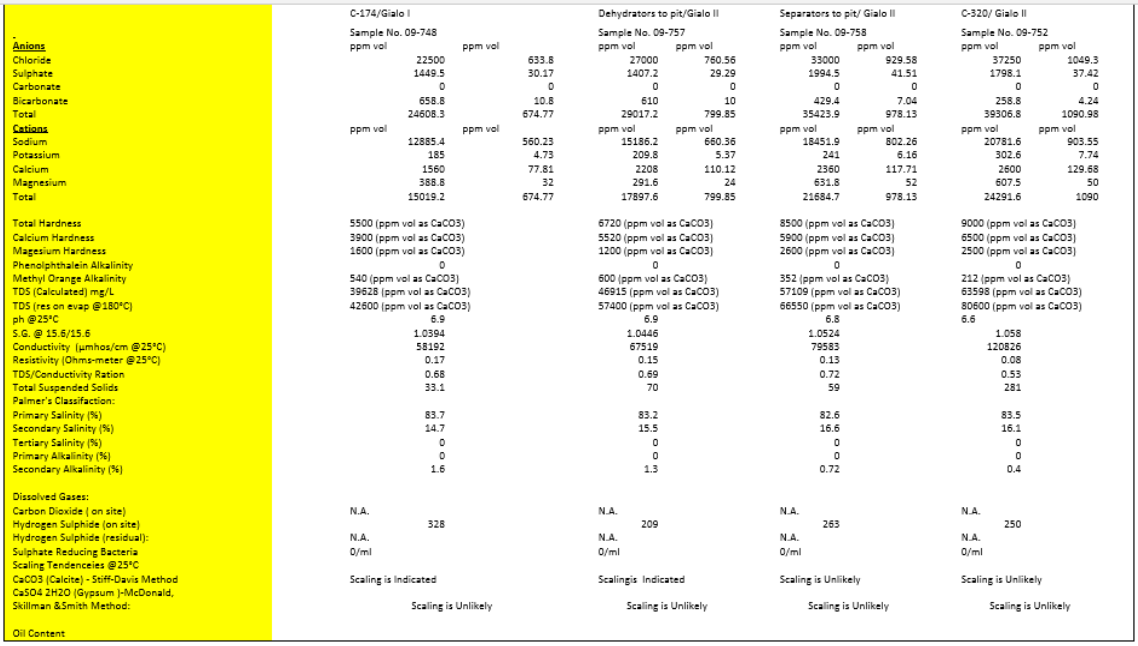


Composition water	Geochimical Water Analysis Limits	Separators to pit / Gialo I Sample No. 09-750		From Dehidrators to pit/Gialo I Sample No. 09-751		T-180/ Gialo I Sample No. 09-749		T-240/Gialo II Sample No. 09-756	
Anions	mg/L	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol
Chloride	14128 ÷ 37250	18750	528.17	20000	563.38	18250	514.08	20600	580.28
Sulphate	1300 ÷ 17981	1590.3	33.1	1359	28.28	1360.2	28.31	1503.9	31.3
Carbonate	0	0	0	0	0	0	0	0	0
Bicarbonate	258.8 ÷ 800.3	658.8	10.8	800.3	13.12	756.4	12.4	409.9	6.72
Total	16370 ÷ 39306.8	20999.1	572.07	22159.3	604.78	20366.6	554.79	22513.8	618.3
Cations	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol
Sodium	7952 ÷ 20781.6	11037.2	479.88	11634.4	505.84	10502	456.61	11730.5	510.02
Potassium	170÷302.6	170	4.35	200	5.12	170	4.35	173.6	4.44
Calcium	767.11 ÷ 2600	1280	63.84	1400	69.83	1320	65.84	1312	65.44
Magnesium	281.6÷962.6	291.6	24	281.6	24	340.2	28	466.6	38.4
Total	9170.71÷18746	12778.8	572.07	13526	604.78	12332.2	554.79	13682.7	618.3
Total Hardness	4400÷9000 (mg/L as CaCO3)	4400 (ppm vol as CaCO3)		4700 (ppm vol as CaCO3)		4700 (ppm vol as CaCO3)		5200 (ppm vol as CaCO3)	
Calcium Hardness	1915.09÷6500 (mg/L as CaCO3)	3200 (ppm vol as CaCO3)		3500 (ppm vol as CaCO3)		3300 (ppm vol as CaCO3)		3280 (ppm vol as CaCO3)	
Magesium Hardness	1200÷3920 (mg/L as CaCO3)	1200 (ppm vol as CaCO3)		1200 (ppm vol as CaCO3)		1400 (ppm vol as CaCO3)		1920 (ppm vol as CaCO3)	
Phenolphthalein Alkalinity	0	0		0		0		0	
Methyl Orange Alkalinity	212÷820 (mg/L vol as CaCO3)	540 (ppm vol as CaCO3)		656 (ppm vol as CaCO3)		820 (ppm vol as CaCO3)		336 (ppm vol as CaCO3)	
TDS (Calculated) mg/L	32699÷63598 (mg/L as CaCO3)	33778 (ppm vol as CaCO3)		35685 (ppm vol as CaCO3)		32699(ppm vol as CaCO3)		36196 (ppm vol as CaCO3)	
TDS (res on evap @180°C)	39500÷80600 (mg/L as CaCO3)	39750 (ppm vol as CaCO3)		39500 (ppm vol as CaCO3)		39700 (ppm vol as CaCO3)		41800 (ppm vol as CaCO3)	
ph @25°C	6.8÷7	7		6.8		7.1		6.9	
S.G. @ 15.6/15.6	1.0171 ÷ 1.0580	1.036		1.0359		1.037		1.0374	
Conductivity (µmhos/cm @25°C)	51197÷120826	51197		53123		53731		54542	
Resistivity (Ohms-meter @25°C)	0.08÷0.2	0.2		0.19		0.19		0.18	
TDS/Conductivity Ration	0.47÷0.72 (mg/L)	0.66		0.67		0.61		0.66	
Total Suspended Solids	29.4÷281 (mg/L)	45.8		66.7		70.4		65	
Palmer's Classifaction:									
Primary Salinity (%)	81.4÷84.6	84.6		84.5		83.1		83.2	
Secondary Salinity (%)	17.8÷13.3	13.5		13.3		14.7		15.7	
Tertiary Salinity (%)	0	0		0		0		0	
Primary Alkalinity (%)	0	0		0		0		0	
Secondary Alkalinity (%)	0.4÷ 1.4	1.9		2.2		2.2		1.1	
Dissolved Gases:									
Carbon Dioxide (on site)	N.A.	N.A.		N.A.		N.A.		N.A.	
Hydrogen Sulphide (on site)	209 ÷ 371 (ppm vol)	297		371		344		236	
Hydrogen Sulphide (residual):	N.A.	N.A.		N.A.		N.A.		N.A.	
Sulphate Reducing Bacteria	0/ml	0/ml		0/ml		0/ml		0/ml	
Scaling Tendenceies @25°C									
CaCO3 (Calcite) - Stiff-Davis Method		Scaling Indicated		Scaling is Indicated		Scaling is Indicated		Scaling is Unlikely	
CaSO4 2H2O (Gypsum)-McDonald, Skillman &Smith Method:		Scaling is Unlikely		Scaling is Unlikely		Scaling is Unlikely		Scaling is Unlikely	
Oil Content	400/150/55 ppm vol.								

Figure 7. Progressive reduction of oil-in-water concentration from inlet to IGF treatment units in the Gialo Field

7.5. Geochemical Characteristics of Produced Water

The analysis indicates high concentrations of dissolved ions, including sodium, chloride, calcium, and magnesium, reflecting the highly saline nature of the produced water. The total dissolved solids (TDS) and conductivity values are significantly elevated, confirming that the water is highly mineralized. In addition, the data show considerable hardness levels and the presence of hydrogen sulfide (H_2S) and sulphate-reducing bacteria (SRB). The scaling tendency indicators included in the analysis suggest that scale formation is likely under operating conditions. Variations in water composition between sampling points are also observed, indicating heterogeneity in produced water characteristics across the field (Figure 8).

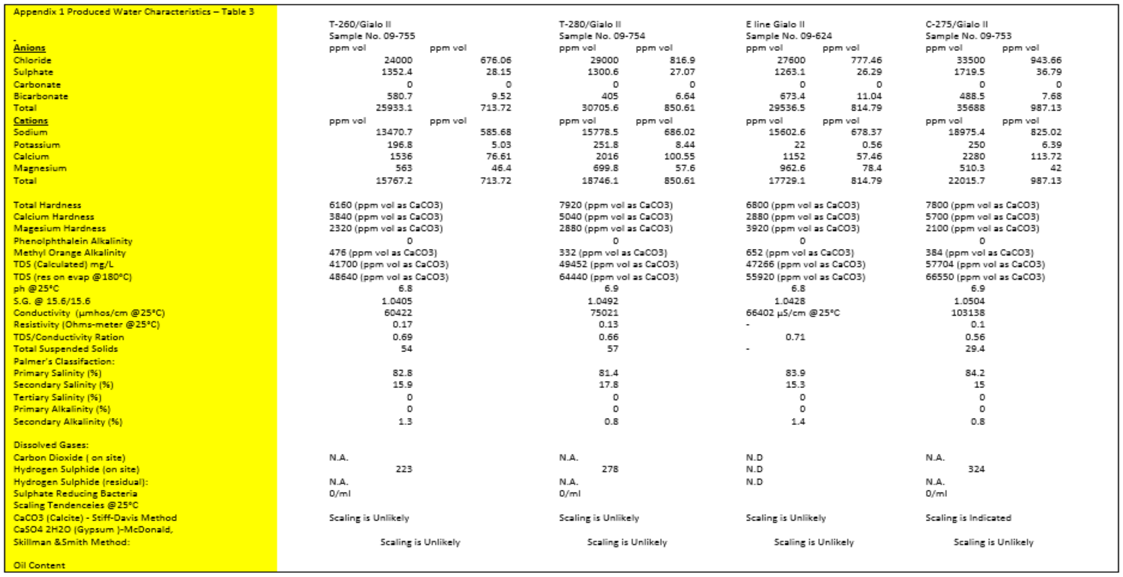


	C-174/Gialo I		Dehydrators to pit/Gialo II		Separators to pit/ Gialo II		C-320/ Gialo II	
	Sample No. 09-748		Sample No. 09-757		Sample No. 09-758		Sample No. 09-752	
Anions	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol
Chloride	22500	633.8	27000	760.56	33000	929.58	37250	1049.3
Sulphate	1449.5	30.17	1407.2	29.29	1994.5	41.51	1798.1	37.42
Carbonate	0	0	0	0	0	0	0	0
Bicarbonate	658.8	10.8	610	10	429.4	7.04	258.8	4.24
Total	24608.3	674.77	29017.2	799.85	35423.9	978.13	39306.8	1090.98
Cations	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol
Sodium	12885.4	560.23	15186.2	660.36	18451.9	802.26	20781.6	903.55
Potassium	185	4.73	209.8	5.37	241	6.16	302.6	7.74
Calcium	1560	77.81	2208	110.12	2360	117.71	2600	129.68
Magnesium	388.8	32	291.6	24	631.8	52	607.5	50
Total	15019.2	674.77	17897.6	799.85	21684.7	978.13	24291.6	1090
Total Hardness	5500 (ppm vol as CaCO3)		6720 (ppm vol as CaCO3)		8500 (ppm vol as CaCO3)		9000 (ppm vol as CaCO3)	
Calcium Hardness	3900 (ppm vol as CaCO3)		5520 (ppm vol as CaCO3)		5900 (ppm vol as CaCO3)		6500 (ppm vol as CaCO3)	
Magesium Hardness	1600 (ppm vol as CaCO3)		1200 (ppm vol as CaCO3)		2600 (ppm vol as CaCO3)		2500 (ppm vol as CaCO3)	
Phenolphthalein Alkalinity	0		0		0		0	
Methyl Orange Alkalinity	540 (ppm vol as CaCO3)		600 (ppm vol as CaCO3)		352 (ppm vol as CaCO3)		212 (ppm vol as CaCO3)	
TDS (Calculated) mg/L	39628 (ppm vol as CaCO3)		46915 (ppm vol as CaCO3)		57109 (ppm vol as CaCO3)		63598 (ppm vol as CaCO3)	
TDS (res on evap @180°C)	42600 (ppm vol as CaCO3)		57400 (ppm vol as CaCO3)		66550 (ppm vol as CaCO3)		80600 (ppm vol as CaCO3)	
ph @25°C	6.9		6.9		6.8		6.6	
S.G. @ 15.6/15.6	1.0394		1.0446		1.0524		1.058	
Conductivity (µmhos/cm @25°C)	58192		67519		79583		120826	
Resistivity (Ohms-meter @25°C)	0.17		0.15		0.13		0.08	
TDS/Conductivity Ration	0.68		0.69		0.72		0.53	
Total Suspended Solids	33.1		70		59		281	
Palmer's Classifaction:								
Primary Salinity (%)	83.7		83.2		82.6		83.5	
Secondary Salinity (%)	14.7		15.5		16.6		16.1	
Tertiary Salinity (%)	0		0		0		0	
Primary Alkalinity (%)	0		0		0		0	
Secondary Alkalinity (%)	1.6		1.3		0.72		0.4	
Dissolved Gases:								
Carbon Dioxide (on site)	N.A.		N.A.		N.A.		N.A.	
Hydrogen Sulphide (on site)	328		209		263		250	
Hydrogen Sulphide (residual):	N.A.		N.A.		N.A.		N.A.	
Sulphate Reducing Bacteria	0/ml		0/ml		0/ml		0/ml	
Scaling Tendenceies @25°C								
CaCO3 (Calcite) - Stiff-Davis Method	Scaling is Indicated		Scalingis Indicated		Scaling is Unlikely		Scaling is Unlikely	
CaSO4 2H2O (Gypsum)-McDonald, Skillman &Smith Method:	Scaling is Unlikely		Scaling is Unlikely		Scaling is Unlikely		Scaling is Unlikely	
Oil Content								

Figure 8. Produced water geochemical analysis indicating high salinity, hardness, and scaling potential in Gialo Field facilities

7.6. Visual Observation of Oil–Water Separation

The image indicates the formation of oil–water emulsions, suggesting incomplete phase separation under natural conditions (See Figure 9). The observed emulsion behavior reflects the complexity of the produced water system and the presence of fine oil droplets that are not easily separated through gravity-based processes. This observation supports the need for advanced treatment stages to achieve effective oil removal.



Appendix 1 Produced Water Characteristics – Table 3

	T-260/Gialo II		T-280/Gialo II		E line Gialo II		C-275/Gialo II	
-	Sample No. 09-755		Sample No. 09-754		Sample No. 09-624		Sample No. 09-753	
Anions	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol
Chloride	24000	676.06	29000	816.9	27600	777.46	33500	943.66
Sulphate	1352.4	28.15	1300.6	27.07	1263.1	26.29	1719.5	36.79
Carbonate	0	0	0	0	0	0	0	0
Bicarbonate	580.7	9.52	405	6.64	673.4	11.04	488.5	7.68
Total	25933.1	713.72	30705.6	850.61	29536.5	814.79	35688	987.13
Cations	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol	ppm vol
Sodium	13470.7	585.68	15778.5	686.02	15602.6	678.37	18975.4	825.02
Potassium	196.8	5.03	251.8	8.44	22	0.56	250	6.39
Calcium	1536	76.61	2016	100.55	1152	57.46	2280	113.72
Magnesium	563	46.4	699.8	57.6	962.6	78.4	510.3	42
Total	15767.2	713.72	18746.1	850.61	17729.1	814.79	22015.7	987.13
Total Hardness	6160 (ppm vol as CaCO3)		7920 (ppm vol as CaCO3)		6800 (ppm vol as CaCO3)		7800 (ppm vol as CaCO3)	
Calcium Hardness	3840 (ppm vol as CaCO3)		5040 (ppm vol as CaCO3)		2880 (ppm vol as CaCO3)		5700 (ppm vol as CaCO3)	
Magesium Hardness	2320 (ppm vol as CaCO3)		2880 (ppm vol as CaCO3)		3920 (ppm vol as CaCO3)		2100 (ppm vol as CaCO3)	
Phenolphthalein Alkalinity	0		0		0		0	
Methyl Orange Alkalinity	476 (ppm vol as CaCO3)		332 (ppm vol as CaCO3)		652 (ppm vol as CaCO3)		384 (ppm vol as CaCO3)	
TDS (Calculated) mg/L	41700 (ppm vol as CaCO3)		49452 (ppm vol as CaCO3)		47266 (ppm vol as CaCO3)		57704 (ppm vol as CaCO3)	
TDS (res on evap @180°C)	48640 (ppm vol as CaCO3)		64440 (ppm vol as CaCO3)		55920 (ppm vol as CaCO3)		66550 (ppm vol as CaCO3)	
ph @25°C	6.8		6.9		6.8		6.9	
S.G. @ 15.6/15.6	1.0405		1.0492		1.0428		1.0504	
Conductivity (µmhos/cm @25°C)	60422		75021		66402 µS/cm @25°C		103138	
Resistivity (Ohms-meter @25°C)	0.17		0.13		-		0.1	
TDS/Conductivity Ration	0.69		0.66		0.71		0.56	
Total Suspended Solids	54		57		-		29.4	
Palmer's Classifaction:								
Primary Salinity (%)	82.8		81.4		83.9		84.2	
Secondary Salinity (%)	15.9		17.8		15.3		15	
Tertiary Salinity (%)	0		0		0		0	
Primary Alkalinity (%)	0		0		0		0	
Secondary Alkalinity (%)	1.3		0.8		1.4		0.8	
Dissolved Gases:								
Carbon Dioxide (on site)	N.A.		N.A.		N.D		N.A.	
Hydrogen Sulphide (on site)	223		278		N.D		324	
Hydrogen Sulphide (residual):	N.A.		N.A.		N.D		N.A.	
Sulphate Reducing Bacteria	0/ml		0/ml				0/ml	
Scaling Tendenceies @25°C								
CaCO3 (Calcite) - Stiff-Davis Method	Scaling is Unlikely		Scaling is Unlikely		Scaling is Unlikely		Scaling is Indicated	
CaSO4 2H2O (Gypsum)-McDonald, Skillman &Smith Method:	Scaling is Unlikely		Scaling is Unlikely		Scaling is Unlikely		Scaling is Unlikely	
Oil Content								

Figure 9. Evidence of stable oil–water emulsions demonstrating incomplete phase separation in produced water

8. Discussion

The obtained results demonstrate that the produced water treatment system implemented in the Gialo Field achieves a relatively high oil removal efficiency, which can be attributed to the integrated multi-stage treatment approach. The combination of gravity separation (settling and skimming) followed by Induced Gas Flotation (IGF) provides both bulk oil removal and fine droplet polishing. The primary removal efficiency (~62.5%) observed in the settling tank is consistent with the physical principles of gravity separation, where larger oil droplets rise due to density differences between oil and water. The effectiveness of this stage is influenced by residence time, droplet size distribution, and flow stability. The relatively good performance indicates that the tank design and retention time are adequate for separating free oil; however, the remaining oil fraction likely consists of smaller and more stable emulsified droplets that cannot be removed by gravity alone.

The subsequent improvement in water quality through IGF units is primarily due to the generation of fine gas bubbles, which enhance the attachment and flotation of small oil droplets and suspended solids. The efficiency of this process depends on bubble size, gas dispersion, and the effectiveness of chemical additives such as demulsifiers. The use of chemical injection upstream of the treatment units plays a critical role in destabilizing emulsions and improving separation efficiency, which explains the overall system performance approaching 85–90%. Despite the satisfactory performance, the system may not always consistently achieve the more stringent international discharge standards (e.g., <40 ppm oil-in-water), particularly under fluctuating operating conditions. Variations in produced water composition, including salinity, temperature, and the presence of stable emulsions, can significantly affect separation efficiency. In addition, operational factors such as pump performance, flow rate variations, and chemical dosing inaccuracies may lead to deviations from optimal performance. When compared with other produced water treatment technologies, the current system represents a conventional and widely applied configuration in the oil and gas industry. While gravity separation combined with IGF is considered reliable and cost-effective, it is not necessarily the most advanced solution available. Technologies such as hydrocyclones, membrane filtration, and dissolved air flotation (DAF) systems may achieve higher removal efficiencies, particularly for very fine oil droplets. However, these alternatives often involve higher capital and operational costs, increased maintenance requirements, and greater sensitivity to fouling. Therefore, the adopted system can be considered optimal from a practical and economic perspective for large-scale field operations, especially in remote locations such as the Gialo Field. It provides a balanced compromise between efficiency, reliability, and operational simplicity. Nevertheless, several improvements can be proposed to enhance system performance. First, optimization of chemical dosing through real-time monitoring and control could significantly improve emulsion breaking and overall separation efficiency. Second, upgrading IGF units with improved eductor designs or microbubble generation systems may enhance fine oil removal. Third, the integration of a polishing stage, such as compact flotation units or media filtration, could help achieve stricter discharge or reinjection standards. Finally, implementing advanced monitoring systems and automation could improve process stability and reduce operational variability. In conclusion, the system demonstrates strong technical performance and operational reliability; however, targeted optimization and the potential integration of advanced treatment technologies could further enhance efficiency and ensure compliance with more stringent environmental requirements.

8.1 Interpretation of Oil Removal Efficiency

The results presented in Fig (7) indicate that the produced water treatment system achieves a substantial reduction in oil content across successive treatment stages. The primary separation stage reduces the oil concentration from 400 ppm to 150 ppm, corresponding to an oil removal efficiency of approximately 62.5%. This performance is consistent with gravity separation mechanisms, where larger oil droplets rise due to density differences between oil and water. The further reduction to approximately 55 ppm after IGF treatment demonstrates the effectiveness of flotation processes in removing smaller and more stable oil droplets. The overall treatment efficiency is estimated to exceed 85%, which aligns with typical performance ranges reported in the literature for combined gravity separation and flotation systems.

8.2 Influence of Water Chemistry on Treatment Performance

The geochemical characteristics shown in Fig (8) play a significant role in determining the performance of the treatment system. The high salinity and elevated concentrations of calcium and magnesium contribute to increased water hardness and promote scale formation, particularly carbonate and sulfate scales. The presence of hydrogen sulfide (H_2S) and sulphate-reducing bacteria (SRB) introduces additional operational challenges, including corrosion and microbiologically induced fouling. These factors necessitate the continuous use of chemical additives such as scale inhibitors, H_2S scavengers, and biocides. Furthermore, the variability in water composition across the field suggests that treatment efficiency may fluctuate depending on operating conditions. This highlights the importance of adaptive process control and optimization of chemical dosing to maintain consistent performance.

8.3 Role of Emulsions in Separation Efficiency

The visual observations presented in Fig (9) confirm the presence of stable oil–water emulsions in the produced water. These emulsions are likely formed due to the combined effects of high salinity, fine suspended particles, and natural surface-active compounds such as asphaltenes and resins. The stability of these emulsions limits the effectiveness of gravity-based separation and explains the residual oil content observed after primary treatment. As a result, the application of demulsifying agents becomes essential to destabilize emulsions and enhance oil droplet coalescence. In addition, the IGF units play a critical role in overcoming these limitations by generating fine gas bubbles that attach to oil droplets and promote their flotation. This combined physicochemical approach significantly improves the overall separation efficiency.

9. Conclusion

This study presents a comprehensive evaluation of the produced water treatment system implemented in the Gialo Field, Eastern Sirte Basin, Libya. The analysis demonstrates that the integrated treatment approach, combining gravity separation, chemical injection, and Induced Gas Flotation (IGF), provides an effective solution for managing large volumes of produced water under complex field conditions. The results indicate that the system achieves a significant reduction in oil-in-water concentration, decreasing from approximately 400 ppm at the inlet to about 55 ppm after IGF treatment. The primary separation stage contributes substantially to bulk oil removal, while the IGF units enhance the removal of fine oil droplets and suspended solids, resulting in an overall treatment efficiency exceeding 85%. These findings are consistent with typical performance ranges reported for similar treatment configurations. The geochemical analysis reveals that the produced water is highly saline, with elevated concentrations of dissolved ions, significant hardness, and clear scaling tendencies. In addition, the presence of hydrogen sulfide (H_2S) and sulphate-reducing bacteria (SRB) introduces operational challenges related to corrosion, scaling, and microbial activity. These factors highlight the critical role of chemical treatment in maintaining system performance and integrity. Visual observations further confirm the presence of stable oil–water emulsions, which limit the effectiveness of gravity-based separation and necessitate the use of demulsifiers and flotation technologies. The combined physicochemical nature of the treatment process emphasizes that produced water management is a complex, multi-parameter system governed by both fluid properties and operational conditions. Despite the satisfactory performance of the current system, certain limitations remain. The treatment efficiency is sensitive to variations in water composition, flow conditions, and chemical dosing, which may affect the consistency of meeting stringent environmental or reinjection standards. Therefore, continuous monitoring and process optimization are essential to ensure stable and reliable operation. Future work should focus on improving system performance through advanced monitoring and control strategies, optimization of chemical injection, and the potential integration of additional polishing technologies. Furthermore, the development of predictive models for treatment efficiency under varying field conditions could provide valuable tools for enhancing operational decision-making. Overall, this study provides a field-based assessment of produced water treatment performance and highlights the importance of integrated treatment strategies in achieving efficient, reliable, and environmentally responsible water management in mature oil fields.

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