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Article

Produced Water from the Oil and Gas Industry as a Resource—South Kuwait as a Case Study

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Abstract: Produced Water (PW) represents the largest waste stream in the oil and gas industry. As a water resource and as a source of valuable minerals such as alkali salts, it is has been highly undervalued, especially in hyper-arid regions. The beneficial use of PW ranges from water reinjection to elevated oil recovery from reservoirs with almost instantaneous returns, to the extraction of minerals from PW, which involves a number of different processes and setups. The economic value of PW-derived end products offers alternative revenue sources, with market fluctuations and conditions different from those of the hydrocarbon market. The end products of water and industrial salt support local industries such as agriculture, reflecting positively on the gross domestic product (GDP). Furthermore, resource extraction from PW of the oil and gas industry helps countries augment their circular economy. In this regard, the economic feasibility of three scenarios—the use of PW for oil recovery, the use of PW as an alternate source of water and industrial salt, and a hybrid process of both—is explored. The results show that there is great potential for water reuse in Enhanced Oil Recovery operations, as well as in the reduction in freshwater consumption for oil- and gas-extraction operations in the state of Kuwait by up to 4.8 percent when PW generated by SK oilfields is considered, and by 42 percent if PW from all oilfields in Kuwait is reused in the same manner.

Keywords: water reuse; salt reclamation; oil recovery; calcium carbonate; oil waste management; recycling; water disposal; enhanced oil recovery

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1. Introduction

Produced water (PW) is the most significant waste stream by volume in the oil and gas industry [1]. Kuwaiti oilfields are reported to produce an average of two million barrels of PW per day, together with three million barrels of oil [2]. Kuwait sits on a substantial oil reserve, exceeding 100 billion barrels [3], and it is expected that its oil production will continue well into the next century, based on the oil reserves and production capacities [4]. Kuwait's oil production exceeds by far its net consumption rates (by more than 7.75 times) [5]. With its plentiful natural gas reserves that reach 63 trillion cubic feet (1.78 trillion m^3) [6], it is positioned for prolonged energy surpluses in the future. On the other hand, Kuwait faces dire scarcity of mineral deposits and fresh water. Thus, Kuwait has a renewable water supply of less than 5 m^3/capita per year. This leads to significant imports of agricultural goods. Also, the oil and gas industry, Kuwait's largest industry, imports minerals for its operational needs in exploration and production activities. For the moment, seawater desalination satisfies 90% of the water needs of the state, including 90% of the potable water [7], the other 10% being ground water, 92% of which is used for domestic and industrial activities [8]. The remainder comes from wastewater treated by reverse osmosis processes. In Kuwait, recycled water is more affordable than desalinated water [9,10]. Kuwait's seawater desalination capacity is 1.6 million m^3 per day [11]. Salt reclamation from seawater desalination is not carried out. It must be noted that seawater desalination has a significant ecological impact, due to the release of the brine reject into the Arabian Gulf [12] and the emission of $PM_{2.5}$ [13].

On the other hand, PW from oil and gas operations in Kuwait is not yet utilized sufficiently. Indeed, over many years, much of the PW has been disposed of into the sea, in desert evaporation ponds, and in disposal wells [14]. In recent times, it was noted that by reusing PW, for instance for drilling and fracturing operations, water transportation and the usage of freshwater can be reduced [14–16]. Thus, although recently there are noticeable developments in the treatment of PW, the management of such processes and their economic impact are left largely unexplored [17]. There is a great opportunity to maximize the use of modern treatment techniques to create value end products from PW waste streams. The incorporation of at least some PW treatment technologies is a common way to enhance the economic returns of an oilfield's production operations, such as by using treated PW for water reinjection in enhanced oil recovery (EOR) [18]. The value of practicing PW treatment and management techniques increases as the generated PW quantities increase with the reservoir's age, as in some cases it reaches 98 percent of the produced fluid, with only 2 percent of the fluid being oil [19,20]. Kuwait has been primarily disposing of PW generated in its oilfields without further use [21]. Figure 1 (below) illustrates the water management system in a specific oil-producing field in South Kuwait (SK oilfield). Also, here, the water cuts of the oil-producing wells continue to increase [22,23], so that the operating conditions will be in favor of more sustainable methods of handling excessive PW amounts [24]. It is important to develop current practices further, to accommodate the increasing quantities of PW.

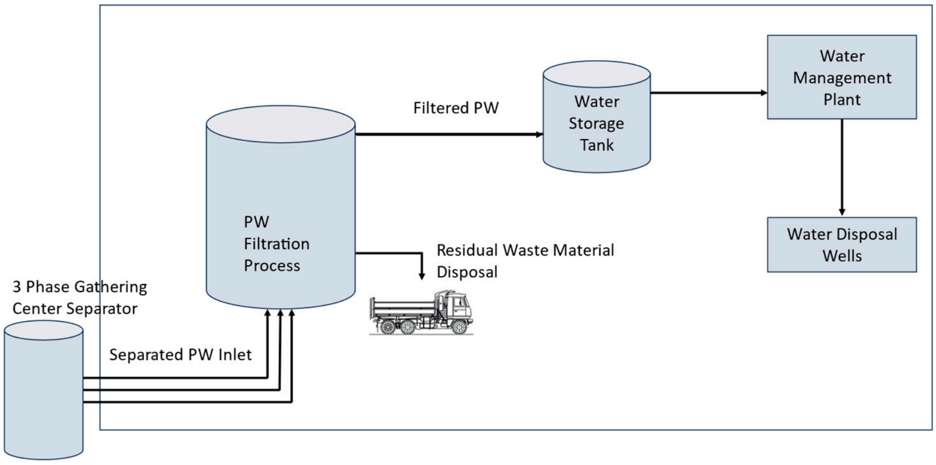

Figure 1. Existing PW management system and facility design of SK oilfield (Scenario 0).

Knowing that PW has varying characteristics depending on the producing reservoir's geology and its hydrocarbon density [1], it is important to understand the PW characteristics and quality before suggesting a treatment technique or developing a management system. The main concerns in regard to PW quality are its salinity and the share of water in the produced fluid (water cut). These two factors may cause significant damage to expensive and vital subsurface equipment for production operations such as production tubing [25]. Typically, PW salinity ranges from 1000 to 400,000 mg/L [26], where an excessive presence of total dissolved solids (TDS) is mainly in the form of salts [27], of which sodium (Na), magnesium (Mg), calcium (Ca) and boron (B) may be of industrial use once reclaimed from the PW streams [28], and which can be further developed into different products. In Kuwait, such processes have been investigated for desalination plants which produce clean water and reject brine, but not yet for PW generated at oilfields [29,30]. This comes about, even though there is an extreme deficiency in the availability of freshwater in the country [31] and the use of treated PW as irrigation water could lead to an increase in vegetation cover and could help mitigate desertification and dust movement through sandstorms [32]. The environmental costs of any treatment are becoming increasingly important, especially with the transition to cleaner energy and operating procedures such as Zero Liquid Discharge [33]. Therefore, knowing that PW is contaminated with chemical additives introduced by the drilling, fracturing, or workover processes in operating the well that have toxic properties [34], it is of great importance that any resource production-process enhancement must consider the environmental aspects. Reducing any negative environmental influences associated with PW treatment should go hand-in-hand with seeking economic gains.

This contribution investigates the possibility of utilizing PW from an oil production operation in South Kuwait with its specific characteristics as shown in Table 1, where, momentarily, PW is not utilized and is channeled into disposal wells (Figure 1, Scenario 0).

Table 1. Typical Characteristics of PW from a South Kuwaiti oilfield.

Components		Kuwait Produced Water Raw Sample 1 (mg/L)	Kuwait Produced Water Raw Sample 2 (mg/L)
Oil & Grease (Gravimetric, pH adjusted)		<5	306
TSS (0.45 μm)	**No Rinse**	11	95
	After Rinse	10	36
Total Dissolved Solids		132,780	193,350
Dissolved Oxygen		3	N/A*
pH at 25 °C		6.88	6.02
Cations	**Sodium**	35,600	51,500
	Potassium	1520	1800
	Calcium	7670	11,200
	Magnesium	1730	3050
	Barium	2.3	2.4
	Strontium	255	460
	Total Iron	1.36	N/D**
	Dissolved Iron	0.44	<0.01
Anions	**Chloride**	75,660	110,090
	Sulphate	18	355
	Bicarbonate	140	300
Additional Components	**Silicon**	12.3	N/D**

N/A*: data not available; N/D**: not detected.

2. Characteristics of PW from South Kuwaiti Oilfields and Possible Treatment Methods for PW

Table 1 shows typical characteristics of PW samples from an oilfield in South Kuwait, which the authors gathered in the years 2022 and 2023. The constituents can be divided into salts and oil. Both will need to be removed by different methods in order to have water of sufficient quality to be used for drinking water or for irrigation which accounts for 4 percent of the country's water consumption [10]. Oil will need to be removed when industrial salt is to be harvested. Also, PW needs to be purified, if it is to be used in EOR. The suspended oil within the PW is reflected in Table 1 as oil and grease, with a range of 5 to 306 mg/L. Regulation gives an upper limit of oil content of less than 0.1 mg/L in treated PW designated for potable use [35]. This would mean that 98 percent of oil found in sample 1 would need to be removed. In order to achieve this, a number of filtration and separation techniques were assessed to choose the most appropriate and sustainable process. Then, there is the salt content, expressed here as TDS, with a range of 132,780 to 193,350 ppm. A TDS content of less than 450 ppm (=less than 0.7 ds/m) is seen as safe for irrigation water for almost all plants, while a TDS content of 450–2000 ppm (0.7–3.0 ds/m) is viewed as posing a slight-to-moderate risk to the irrigated plants [36]. Again, 99.5 to 99.8 percent of the salt content needs to be removed before the water can be used for irrigation, which is more than potable water requirements demand. It is noteworthy that the ratio of ion abundance Na(sodium)/K(potassium/Ca(calcium)/Mg(magnesium) is significantly different in PW found in South Kuwaiti production sites [Na (23.4)/K (1)/Ca (5.05)/Mg (1.14)] (Table 1) than that found in saltwater from the Arabian Gulf at Kuwait [Na (34.5)/K (1)/Ca (1.09)/Mg (3.83)] [37], where especially notable is the fact that K is more abundant in seawater than in PW and that Mg is more abundant than Ca in seawater, but the reverse is true for PW. As Ca is the easier ion among Ca, Mg and K to crystallize, it should be easier to obtain sodium salt of high purity from PW than from seawater, with the caveat that the hydrocarbon content is removed from PW first.

There are numerous techniques to purify PW, which break down into four categories. First, there are physical processes, based on the fact that oil and water for the most part separate into two phases of different density and depend on gravity and centrifugal separation [38,39]. Techniques include the use of three-way separators (oil–gas–water), corrugated plate separators and hydrocyclones [39,40], all of which can be used in the first phase of the purification of PW. Induced gas flotation is another technique depending on gravity, and is often used as a secondary treatment method [41]. All of these are used to separate oil from water. Then, there are filtration processes [38,42], which range from microfiltration, separating out larger particles, ultrafiltration, e.g., with ceramic membranes, leading to separation of remnant oil particles from the water [43], to reverse osmosis [44], which effectively separates all the total dissolved solids (TDSs), as well as chemical additives, from the water. These can be combined with distillation techniques such as membrane distillation [45–47]. Thirdly, chemical processes can be used such as flocculation and coagulation [48,49], processes that are more commonly found in wastewater treatment plants. Finally, there are the finishing stages, which can involve adsorption filtration [50], including sand filtration [51].

3. Waste Reclamation from Oilfield PW, Optimum Utilization of PW and Potential Economic Gains

Numerous waste materials are generated in oil- and gas-extraction processes. Historical numbers on the production of oil and gas and their predicted continuance bring to attention possible economic return. In this regard, it needs to be realized that Kuwaiti PW, on average, has four times the salinity of seawater and would thus also lend itself to harvesting of salts. As Kuwaiti oil production operations are situated inland, PW purification would necessarily be situated in locations away from the seawater desalination plants that are located on the Arabic Gulf coastline. This is especially important when regarding the production of desalted, purified water from PW, as some of the oil production sites inland are in the neighborhood of agricultural lands, so that the use of the purified PW as irrigation water comes to mind. Focusing on an existing oil extraction operation in South Kuwait, we aim to understand the economic benefits of three different processes: (1) increasing the oilfield hydrocarbon output by using the PW in an Enhanced Oil Recovery process; (2) reducing the waste generated by better separation of oil and water and by extracting from it high-quality salt, leading to commercially sellable products such as ten-pound brine/industrial grade salt (NaCl) and treated PW, with oil traces in PW collected and fed back into the oil stream, or (3) implementing a hybrid solution involving both processes (1) and (2). In the manuscript, scenarios 1–3 are presented in that order, where, initially, every scenario is schematically outlined and, subsequently, the fixed and variable costs are calculated on the basis of current pricing. Thereafter, the returns are estimated according to the current valuation of oil, treated water, and industrial salt in Kuwait.

The removal of Ca and Mg from PW is essential for high-quality salt reclamation [52,53]. Therefore, chemical precipitation of Ca and Mg is required to purify PW before NaCl reclamation, in order to extract purer salt [54]. The standard NaCl content in salt fit for human consumption is 94.7%, and for industrial salt it is 98.5% [55]. The salt industry has implemented chemical precipitation processes to enhance the quality of the produced salts, where chemicals such as sodium carbonate (Na_2CO_3) and sodium hydroxide (NaOH) are added [56]. This approach has been applied previously to PW from oil extraction activities, too [52,57]. For this, we analyze three possibilities: (a) the production of NaOH on-site by the electrolytic chloralkali process and the addition of NaOH to PW saturated with carbon dioxide (CO_2); (b) sourcing NaOH externally, with an addition of NaOH to PW saturated with CO_2; and (c) acquiring soda (Na_2CO_3) commercially, with the addition of Na_2CO_3 to PW.

Produced industrial salts can be used for a number of industries, such as for the setting of dyes in fabrics, for the production of glass, polyester, plastics and leather. Salt helps in cleaning gas and oil wells and is an important component in the manufacture of paper, tires, brass, bleach and case-hardened steel.

In the following, the results will be assessed for scenarios 1–3 for the oilfield in South Kuwait. The analysis will focus on the cost–revenue balances, but will take the environmental effects of each scenario into consideration. A proposed facility expansion of the existing facility in South Kuwait to accommodate processes 1–3 is shown in Figure 2 (below).

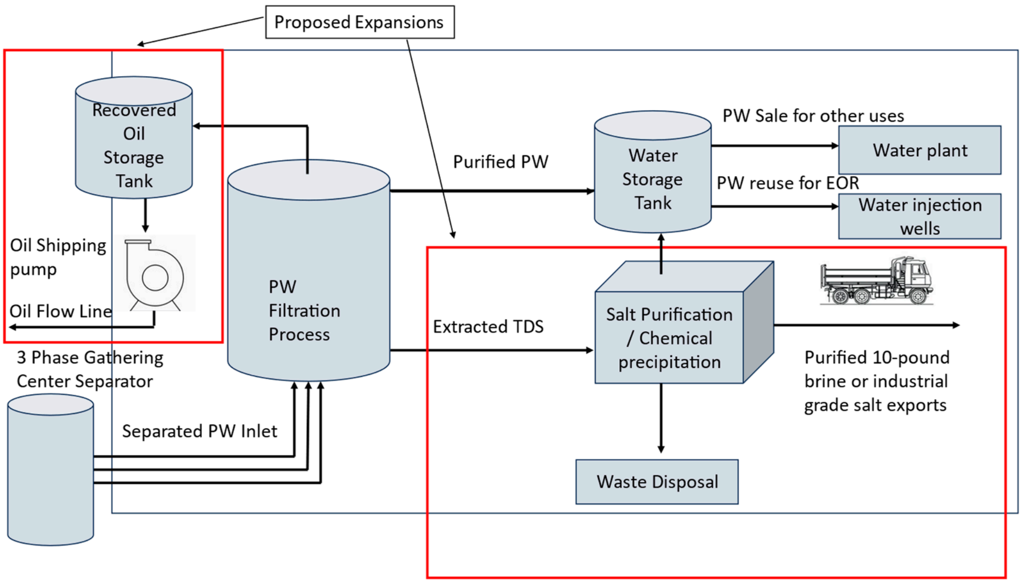

Figure 2. Proposed expansion-facility design for salt reclamation.

For *Scenario 1*, it is proposed that the treatment process of PW comprises two separation steps, namely gravity separation and a subsequent ceramic membrane filtration. The two disposal methods that are analyzed are the water injection of the treated PW as an EOR technique and a conventional PW disposal in Class II Disposal wells.

For *Scenario 2*, the process includes gravity separation, ceramic membrane filtration and sorption filtration using biomass as sorbent material, such as walnut shells. In a subsequent step, alkaline earth cations will precipitate as carbonates from the de-oiled PW, as discussed above. The treated water will be subjected to a solar distillation, where, from the remaining brine, purified sodium chloride (NaCl) is extracted and the distilled water can be used as irrigation water. Here, three sub-scenarios were analyzed: (a) (Scenario 2-I) NaOH needed for the precipitation of alkaline earth ions is produced on-site; (b) (Scenario 2-II) NaOH is sourced externally; (c) (Scenario 2-III) Na_2CO_3 is sourced externally. For scenarios 2-I and 2-II, CO_2 is acquired commercially.

Scenario 3 merges scenarios 1 and 2 in such a way that 50% of the PW will be used for EOR and 50% will be used for agricultural irrigation with reclamation of industrial salt.

The following assumptions were made for the study, which best reflect the circumstances and infrastructural restrictions of the oil production facility in South Kuwait:

1. All PW, separated from oil and gas, is gathered at one large gathering center for storage in the form of mega tanks.
2. The distance between the large gathering center water storage tanks and the proposed site for the facility is 1 km. The chosen distance is similar to that in the plant design of the SK oilfield).
3. PW is transferred entirely through pipelines.
4. Pipelines are made from carbon steel.
5. Water treatment, facility maintenance, facility operations, electricity, and disposal operations are included in the model operational cost.
6. Water treatment costs include chemical additives and filtration costs.
7. Pipelines and trucks are included in the model transportation cost, where the lease value of the trucks is embedded.
8. Reinjection operations include all the costs associated with treatment operations, including chemical additives and filtration costs (for scenarios 1 and 3)
9. Fifty percent of the treated water is sent to reinjection wells by pipeline and the rest is sold as treated water at the tipping value (scenario 3)
10. There is a 15-percent oil production increase in the oilfield after water injection.
11. The water cut in the produced liquid increases by 3 percent every year over the next 5 years. This estimate is based on the witnessed trend of an annual increase in the water cut in the SK oilfield [22]. Only 50 percent of the PW is to be reinjected (see also point 9).
12. The oil output is steady after the initial increase.
13. The new facility is an expansion to the current water management system.
14. Treated water transportation costs by pipeline are USD 0.50 per barrel [58]. The costs of water transportation include all shipping of treated PW within the oilfield facilities up to the border of the oilfield area.
15. The cost of injection for one barrel of water is USD 1–3 [59] (scenarios 1 and 3).
16. We assume that no more disposal wells need to be drilled in the next 5 years.
17. The treated-water tipping fee is constant throughout the 5-year period (scenarios 2 and 3).
18. The cost of water transportation outside the oilfield is handled by the government authorities (scenarios 2 and 3).

4. Materials and Methods

The calculations for this work were carried out on the basis of experimental work on different purification techniques of PW stemming from the SK oilfield, which allowed the authors to select a viable combination of separation processes to focus on. Results of some of the experimental work can be found in Refs [22,25,52,60–62]. These processes are being scaled up, where a proto-type for the solar distillation to desalinate PW of the characteristics found in the SK oilfield is being built. Costs for the processes were screened from the suppliers and manufacturers of the equipment.

Calculations in this study were performed with a series of objective functions. Each objective function is to determine an accurate calculation for every parameter in our proposal for resource production-efficiency enhancement. The recovered oil in this study is discounted by 5 percent of the general market value for oil, considering its competitive status versus naturally extracted crude oil. This is to incentivize buyers for this category of crude oil. Table 2 displays the acronyms used in the objective functions.

Table 2. Abbreviation list for objective functions.

Abbreviation	Description
TC (n) with n = 0–3	Total Production Costs for scenarios 0–3
VC (n) with n = 0–3	Variable Costs for scenarios 0–3
X	Number of Units
FC (n) with n = 0–3	Fixed Costs for scenarios 0–3
TR (n) with n = 0–3	Total Revenue for scenarios 0–3
NO (n) with n = 0–3	Net outcome for scenarios 0–3
OSR	Oil Sales Revenue under the current scenario
SSR	Salt Sales Revenue
WSR	Water Sales Revenue
IRR	Internal Rate of Return
FV	Future Value
PV	Present Value
FSVTW	Future Sale Value of Treated Water
PWT	Produced Water Treatment
PTC	Present Treatment Cost
PEC	Present Extraction Cost
FSVGBO	Future Sale Value of Gained Barrels of Oil
API	American Petroleum Institute
IRR	Internal rate of return
PWI	Produced Water Injection

TC (1–3) represent the total costs incurred for scenarios 1–3, where certain costs are already included in scenario 0, which represents the current operation. For all scenarios, the total costs (TCs) with respect to all of the varying parameters can be expressed by Equation (1):

$$\text{TC (1–3)} = \text{VC (1–3)} + \text{FC (1–3)} \tag{1}$$

where TC (1) for scenario 1 is the total production cost if PW is partially re-injected for EOR. In general, VC are the varying costs and FC are the fixed costs. The varying costs include a range of costs for the reinjection of PW and the disposal of PW, and the fixed costs are the costs associated with initial construction costs and maintenance/replacement costs. The total production costs of treated water can be calculated by multiplying the varying volumes of PW to treat by the cost of treatment per unit volume, (bbl), which is then added to the fixed costs of the process, given by the cost of a construction or a fixed purchase.

TC (2) for scenario 2 is the total production cost of a process in which PW is used as a resource for salts (industrial salt) and purified water. Here, alkaline earth salts such as Ca and strontium (Sr) would need to be precipitated prior to the recovery of industrial salt by evaporation. The precipitation proceeds either by the addition of sodium hydroxide (NaOH) in the presence of CO_2 or by the addition of soda (Na_2CO_3). Again, VC (2) are the varying costs, x is the number of related variations in each case, and FC (2) are the fixed costs. The varying costs include the changing costs of PW treatment. The fixed costs are the costs associated with the initial construction costs of new elements into the PW management system, such as the added purification systems and the solar distillation unit, as well as their maintenance/replacement costs. Additionally, the construction of a caustic soda/soda production plant is contemplated to have on hand NaOH for the precipitation of unwanted metal ions, specifically of Ca^{2+}, prior to the harvesting of industrial salt (scenario 2a). Otherwise, sodium hydroxide (NaOH) or soda ash (Na_2CO_3) needs to be acquired externally. Other fixed costs include the transport of PW through pipelines.

TC (3) for scenario 3 is the total production cost of a process where PW undergoes a a purification similar to that of scenario 2, where PW is divided equally, to be re-injected into the subsurface for enhanced oil recovery (EOR), with the remaining half to be exploited as a resource for salts (industrial salts) and purified water to be used as irrigation water. VC (3) are again the varying costs and FC (3) are the total fixed costs, which cover every element of the hybrid process.

The total revenues (TRs) of scenarios 1–3, which represent the additional incomes as compared to the current operation (scenario 0), can be expressed by Equations ((2)–(4)). For scenario 1, it can be expressed as

$$\text{TR (1)} = \text{FSVGBO} \tag{2}$$

where TR (n) is the total current revenue of oil sales at the specific oilfield in Kuwait using current scenario (OSR) at the current market value of 1 barrel of crude oil and FSVGBO is the added oil output due to the enhanced oil recovery.

Scenario 2 is governed by Equation (3)

$$\text{TR (2)} = \text{SSR} + \text{WSR} + \text{OSR} \tag{3}$$

where TR (2) is the total expected revenue after the implementation of the Waste Reclamation Project (WRP), SSR is the Salt Sales Revenue, WSR stands for the Water Sales Revenue and OSR is the added Oil Sales Revenue due to better oil–water separation.

Scenario 3 is governed by Equation (4)

$$\text{TR (2)} = \text{SSR} + \text{WSR} + \text{OSR} + \text{FSVGBO} \tag{4}$$

The scenarios (1)–(3) are compared with the present PW processing and disposal, named scenario (0), for which current numbers exist and a prediction of the development of the costs has been established. In scenario (0) PW is subjected to a 3-way separator, API oil–water separators, and then disposed of in drilled wells of type Class II.

The above calculations are performed using the values referred to in Tables 3 and 4.

Table 3. Sales value of end products stemming from the treated PW.

Item	Sales Value (USD) per Unit
Sodium chloride (industrial salt)	260/ton [63]
Chlorine	250/ton [64]
Hydrogen	7220/ton [65]
Purified PW	0.79/barrel * [66]
Recovered crude oil	65.73/barrel *
Calcium carbonate	50–350/ton [67]

* (1 barrel of oil = 0.159 m^3).

Table 4. The process or item cost as a factor of the studied scenarios.

Process or Item	Cost per Unit (USD)
Disposal well operational costs (a)	0.5/barrel * [54]
Disposal well operational costs (b)	2.5/barrel * [54]
Cost of gravity-based oil–water separation	0.08/barrel * [68]
Disposal well construction cost	100/barrel *
Ceramic membrane treatment cost	0.51/barrel * [69]

Table 4. *Cont.*

Process or Item	Cost per Unit (USD)
Cost of ceramic membrane-treatment facility	48.543/barrel * [69]
EOR water injection costs (a)	1/barrel * [59]
EOR water injection costs (b)	3/barrel * [59]
Walnut-shell filtration system cost	23.256/barrel * [35]
Walnut-shell filtration operational cost	0.003/barrel * [35]
Carbon dioxide purchases	215/ton [70]
33w% aq. Hydrochloric acid purchases	89/ton [71]
Solar distillation cost (a)	1.113/barrel * [72]
Solar distillation cost (b)	5.4/barrel * [72]
Sodium carbonate purchases	200/ton [73]
Sodium hydroxide purchases	260/ton [74]
Sodium hydroxide production costs	1.4/ton [64]

* (1 barrel of oil = 0.159 m^3).

It must be noted that, although throughout the text numerical figures are given to their last digit, this is due to the nature of the calculations. The numerical figures themselves are very approximate values, due to uncertainties and potentially unidentified influencing variables. However, the purity of different value products from PW of the SK oilfield obtained under different conditions of purification and separation has been determined by us in the laboratory, albeit on a much smaller scale.

5. Results and Discussion

Cost calculation of Scenario 0 (currently following PW treatment method, Figure 3):

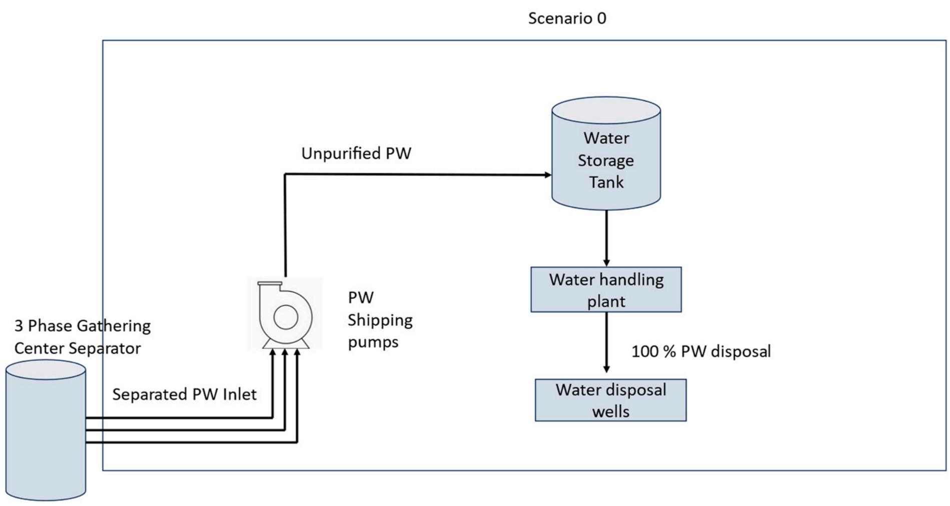

Figure 3. Current scenario in SK oilfield.

TC (0) per year = cost of drilling a disposal well and the continuous costs of operating it per barrel of water disposed (variable, depending on quantities of PW).

$$TC\ (0) = VC\ (0) + FC\ (0).$$

For the current situation where the PW is being disposed of entirely in the SK oilfield with no further use or treatment apart from gravity-based oil–water separation, which costs USD 0.08/barrel [65], the calculation should be based on a disposal capacity of

1,000,000 barrels of PW per day, where details of the calculations are found in the Supplementary Section A.

Given that the infrastructure is mostly available, it is important to consider the paid amounts as being of the current value, to properly compare the fixed and variable costs of all other scenarios.

Cost calculations of Scenario 1 (50 v% water injection of the treated PW for EOR and 50 v% disposal in a conventional Class II disposal well, Figure 4):

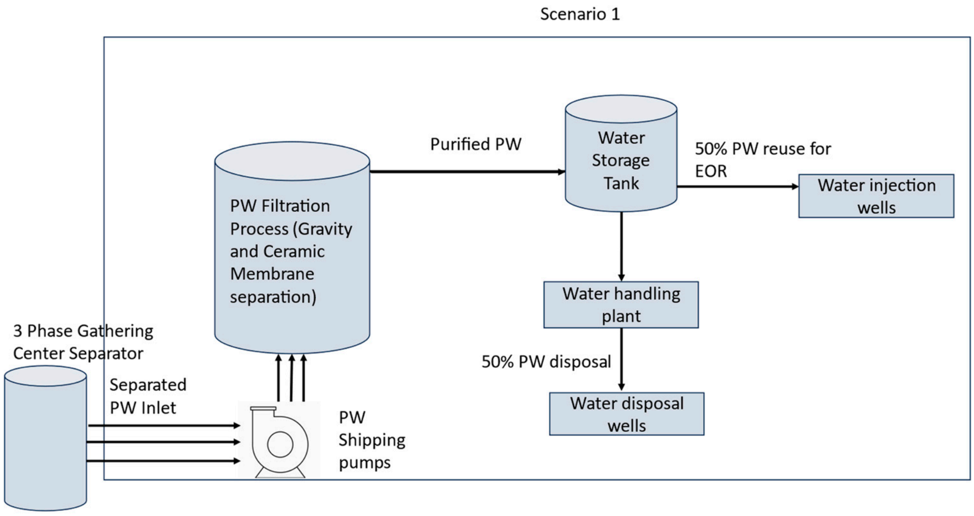

Figure 4. The process layout for SK oilfield according to scenario 1.

To enhance the productivity of an oilfield with the use of water injection, a sequence or a pattern is required [75]. Figure 5 (below) displays a seven-well injection pattern proposed for the water injection system to reuse treated PW in EOR techniques for the specified oilfield in South Kuwait. Such layouts have been implemented before, in different locations, and have proved to be successful in increasing the oil output in the producing wells [76]. For each six oil-producing wells, an injection well is drilled to create a water drive and to increase the pressure in the reservoir, consequently increasing the pressure in the formation and leading to a higher flow of fluid within the formation pores to the production zones of the wells, resulting in a larger flow of production fluid to the surface.

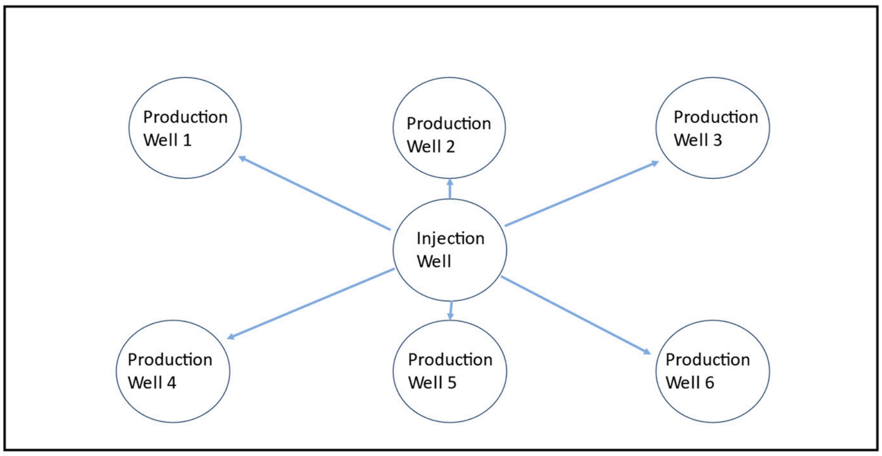

Figure 5. Proposed water-injection well pattern.

Commercial disposal wells costs are typically between USD 0.50 and USD 2.50 per barrel of fluid [77], whilst water injection costs range from USD 1 to USD 3 [78]. In some regional cases in the GCC, for every 10 barrels of injected water, 1 barrel of oil has been recovered [76].

The scenario 1 that was considered is designed to employ ceramic membrane technology, along with gravity separation prior to EOR water injection for 50 percent of the PW amounts generated, and the remaining 50 percent of PW is to be disposed of by using the current methods comprising traditional Class II disposal wells, as earlier in Scenario 0. Here, the PW that is disposed of in the wells is of higher purity than in scenario 0, due to gravity and ceramic membrane filtration, as in our previous studies the oil content was successfully reduced by 98.4% (from 306 mg/L to less than 5 mg/L oil) [60]. The reason that not all PW is re-injected into the production zone is that there is a risk of blocking the formation and preventing the flow of oil from the porous rocks to the producing wells [79]. Excessive water injection may disrupt the original stress equilibrium, resulting in a fault slip that would lead to a leakage in hydrocarbons [61].

The cost of gravity separation and hydrocyclones is USD 0.509 per m^3 of PW or USD 0.08 per barrel of PW [68]. The operational cost for ceramic membranes at a crossflow velocity of 2.0 m/s is USD 0.23/m^3, giving an overall total cost of USD 3.21/m^3 or USD 0.51 per barrel [69]. Therefore, a total variable cost of 0.59 USD per barrel of PW for gravity separation and ceramic membrane treatment was incorporated into TC (1).

The second segment of TC (1) calculations, after PW treatment, is the utilization of PW quantities for EOR (water injection) and disposal with 500,000 barrels of treated PW to be reinjected for EOR purposes and 500,000 barrels to be disposed of by means of traditional disposal wells.

The capital expenditure to use ceramic membranes is USD 7,330,000 for every 55,100,000 barrels of PW treated per year (151,000 barrels per day) [69]. Therefore, the total capital expenditure (CAPEX) or initial costs to build the ceramic membrane treatment facility is calculated to be USD 48,543,000. To be able to accommodate the increments in PW generated as stated in our prediction of a 3% annual volume increase of PW, the fixed costs were calculated for a 1,200,000-barrel capacity, to accommodate the increasing PW quantities over a 5-year period. Hence, the total cost rises to USD 58,143,600.

This gives us a lower range value of TC (1a) and an upper range value of TC (1b), where the difference in costs lies in the variable rates for water injection and disposal. Details of the calculations are found in the Supplementary Section B.

On the revenue side, TR (1) is dependent on the oil production increase due to EOR processes, which again is dependent on the quantities of water reinjected into the production zone. For TR (1), it is proposed that for every 10 barrels of injected PW, 1 additional barrel of oil will be produced. This leads to the following calculation for TR (1), which is further explained in Supplementary Section C:

$$\text{Injected Water Quantities (IWQ) (in barrels)} \times \left(\frac{1}{10}\right) = \text{Gained Oil quantities (barrels)}$$

In order to properly calculate the economic returns of the increased oil production, an adjusted 5-year average of OPEC oil prices has been used in the formula.

Finally, for scenario 1, returns for the first year are expected to range from USD 532,000,000 in added economic revenue to a loss of USD 198,000,000. These results reflect the initial capital costs of drilling injection and disposal wells, with the latter being without any economic return. In the second year, returns range from USD 710,000,000 in added revenue to a revenue loss of USD 20,000,000.

Cost calculations of Scenario 2 (PW use as a source of industrial salt and of purified water).

In scenario 2 (Figure 6), ceramic membrane technology, gravity separation and adsorption filtration (with the use of biomass/activated carbon) are considered to treat the input PW from the SK oilfield. Thereafter, PW is treated with NaOH/CO_2 or with Na_2CO_3 to precipitate unwanted $CaCO_3$ and strontium carbonate ($SrCO_3$). The PW is directed towards a solar distillation pond to recover valuable salts from PW and usable water. In scenario 2-I, construction of a caustic soda/soda production plant is planned. To that end, part of the PW brine stream is directed to the caustic-soda production plant, while the remainder is funneled to the solar distillation unit. In scenario 2-II, caustic soda is acquired externally, and all PW is directed to the solar distillation unit.

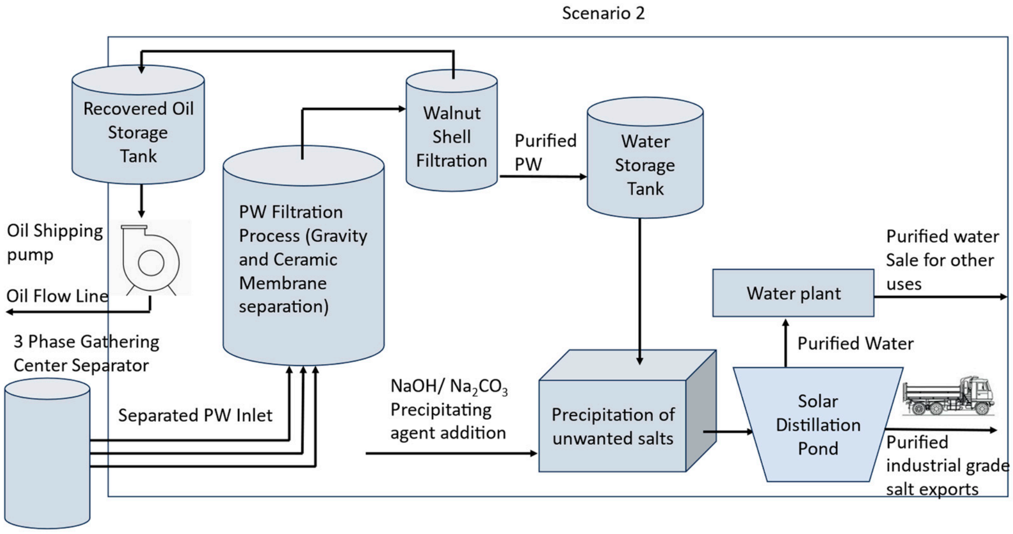

Figure 6. The analyzed process layout for SK oilfield for scenario 2.

For all scenarios 2-I, 2-II and 2-III, the fixed costs for a walnut-shell filtration system is USD 1,000,000 for a 43,000-barrel capacity facility [35]. Therefore, the total cost for a 1,000,000-barrel capacity facility was calculated, along with the varying cost component of USD 0.3 per barrel of PW treated. Added to this are the costs of the ceramic membrane filtration and the gravity separation, discussed above. Below are shown are the calculated total costs for these operations, TC (2)-filtration, with the details of the calculations in the Supplementary Section D.

Next, the costs for the precipitation of unwanted salts for the industrial-salt recovery process are calculated for scenarios 2-I (NaOH produced on-site by the electrolytic chloralkali process), 2-II (NaOH sourced externally), and 2-III (Na_2CO_3 sourced externally). In scenarios 2-I and 2-II, the needed carbon dioxide (CO_2) is sourced externally. With respect to this, the chemical reactions (a)–(c) apply.

It could be observed that much of Ca and Sr present in PW from South Kuwaiti oil production processes can be precipitated as carbonates. Interestingly, most of the heavy metal content is also eliminated from the PW, most likely as metal hydroxides, metal carbonates and as mixed metal salts. The precipitation can be enacted by the addition of NaOH to PW that has been saturated with CO_2. Initially, the alkaline earth metals precipitate as hydroxides, which have higher water solubility than the corresponding carbonates, but which convert to the less-soluble carbonates over some time, to give overall reaction (a). A faster, but potentially more expensive, process is the addition of soda (sodium carbonate, Na_2CO_3), which leads to the immediate formation of the metal carbonates (reaction (b)). For the precipitation of Ca^{2+} according to reaction (a), NaOH can either be sourced externally (2-II) or can be produced on-site by electrolysis of brine (aq. NaCl) according to reaction (c), producing chlorine at the anode and hydrogen at the cathode as side products of the reaction.

(a) $2NaOH + CO_2 + CaCl_2 \rightarrow CaCO_3 + 2NaCl + H_2O$

(b) $CaCl_2 + Na_2CO_3 \rightarrow CaCO_3 + 2NaCl$

(c) $2NaCl + 2H_2O \rightarrow 2NaOH + Cl_2 + H_2$

Added costs in the precipitation process by the addition of aq. HCl after the precipitation.

It must be noted that the treated PW has to be brought back to the pH value that it had prior to the precipitation of $CaCO_3/SrCO_3$. This needs to be carried out by the addition of aq. HCl, so that for every sodium ion added in the precipitation process, either through NaOH or Na_2CO_3, a chloride ion is added. In the case of having prepared NaOH on site by electrolysis of brine (scenario 2-I), the by-products chlorine and hydrogen can be utilized to prepare the necessary HCl in a plant on-site, according to reaction (d).

$$\text{(d) } H_2 + Cl_2 \rightarrow 2\ HCl$$

However, the facility costs of a production plant of hydrogen chloride including the set-up of the production facility and the running costs in the first five years of operation can be set at USD 735/ton HCl or USD 242/ton 33w% HCl.

In scenarios 2-II and 2-III, HCl has to be sourced externally at a cost of ca. USD 89/ton 33w% aq. HCl. To cover an addition of 3.561 tons NaOH, 9833 tons of 33w% HCl are needed at a price of USD 875,200 per day or USD 319,000,000 per year.

Revenue calculations for scenarios 2 (filtration) and scenarios 2-I–2-III (precipitation) [TR(2) and TR (2-I, 2-II and 2-III)].

Membrane filtration and adsorption filtration: One source of revenue in TR (2) is the reclaimed oil quantities from the ceramic membrane filtration/adsorption processes. The data are based on experiments carried out by the authors using a ceramic membrane filtration and biomass filtration using typical PW from the SK field, where the oil recovery rate during the ceramic membrane/PW adsorption processes in the studies was between 0.0935 percent (14.5 mL of oil for every 15,200 mL of PW) to 0.25 percent (38 mL of oil for every 15,200 mL of PW) [78]. The quantity of recoverable barrels of PW per day for a generation rate of 1,000,000 barrels of PW is between 935 barrels and 2500 barrels per day, with an API of 16.02°.

The average crude oil from the reservoirs of the SK oil field has 16.05° API gravity and 5.42% sulfur content. It can be concluded from Table 5 that crudes from SK oilfields are of relatively lower quality as compared to crudes from other Kuwaiti oilfields, such as from the Minagish oilfield. Table 5 shows the classification into light, medium and heavy oil, depending on the API value. Against this background, our oil samples recovered from the filtration operations above showed 18.5° API gravity, a sulfur content of 4% and a pH of 7–8. With this, the recovered oil is of relatively high commercial value. It must be noted that the barrel price of crude oil sold by GCC countries was USD 69.79 in 2018, before decreasing in the COVID-19 years to USD 41.47 in 2020, recovering to USD 69.89 in 2021 and increasing to USD 100.08 in 2022 [80]. The average oil selling price over the last 5 years was USD 69.05 [80].

Precipitation of $CaCO_3$—scenarios 2-I–2-III:

Table 5. Comparisons of oil quality and prices.

Characteristics	Wafra Eocene Crude [81]	SK Oilfield Recovered oil	Minagish Oilfield [82]
API gravity	18.5°	16.02°	28° to 33.4°
Sulfur content	3.32%	5.42%	2.6%
5-year average selling price (USD)	69.05 *	65.73 **	69.20
Classification of oils according to API. Light oil: higher than 31.1° API, medium oil: 31.1–22.3° API, heavy oil: less than 22.3° [83]			

* Calculated 5-year average selling price. ** The calculation for heavy oil was adjusted with a 5-percent reduction in selling price.

In all scenarios 2-I–2-III, revenue comes from precipitated $CaCO_3$, where in scenarios 2-II and 2-III this is the only revenue coming from the precipitation process. In our experiments, the $CaCO_3$ produced was just below the required purity for certain applications, where it must also be noted that there is a Sr content and many of the heavy metals present in the PW, albeit in very small concentrations, crystallize with $CaCO_3$ (see above). Apart from that, there always has been a small concentration of Na^+ in our precipitated $CaCO_3$. Nevertheless, it can be expected that higher-purity $CaCO_3$ can be reached with a slightly better controlled precipitation process.

With this in mind, 1 ton of $CaCO_3$ has a value of USD 50–350, depending on the purity [74]. Therefore, the revenue from 4451.25 tons $CaCO_3$ per day ranges from USD **81,000,000** per year to USD **569,000,000** per year.

In scenario 2-I, NaOH is prepared by electrolysis from brine [see reaction (c)], and here chlorine gas and hydrogen gas are produced as side products. The sales value of hydrogen reaches USD 7220 per metric ton on the global markets [65], or USD 7.22 per kg. Therefore, every kg of NaOH produced will provide a revenue of USD 0.1805 from hydrogen sales. Chlorine sells at USD 250/ton [64]. Therefore, every kg of NaOH produced will provide a revenue of USD 0.195 (for 886 g Cl_2) from chlorine sales. This gives a total of USD 0.3755/kg NaOH-produced revenue from the by-products of NaOH production, [71] where the market value of H_2 produced would be USD 235,000,000 and the value of Cl_2 would be USD 288,000,000 per year. Detailed calculations can be found in the Supplementary Section E.

Should H_2 and Cl_2 be seen as sources of revenue, then HCl needs to be acquired externally at a cost of USD 319,000,000 per year, as mentioned above, and is carried out for scenarios 2-II and 2-III. Otherwise, Cl_2 and H_2 created as side products are used to produce the needed HCl, and thus do not contribute to additional revenue. Depending on the market values, the capacity utilization of the NaOH and HCl plants, and other logistic considerations, a different mix of sales and acquisitions of chlorine, hydrogen and hydrogen chloride/hydrochloric acid will be appropriate under different circumstances. This is only true for scenario 2-I, as in the other scenarios H_2 and Cl_2 are not produced and HCl needs to be sourced externally.

Also, it must be noted that sodium hydroxide has a market value of USD 260 per ton [63]. Therefore, the NaOH production can be laid out in such a way that more NaOH is produced than is needed for the $CaCO_3$ precipitation. Momentarily, while a certain percentage of filtered PW is diverted to the NaOH production in scenario 2-I, the sodium content of the diverted PW is merged again with the main stream of PW during the precipitation process. Should it be found beneficial to produce excess NaOH to sell on the market, then the sodium needed for it will be diverted permanently from the PW stream and will no longer be available to produce industrial salt.

Net Outcome [TR (2)-filtration + TR (2-I,2-II and 2-III) – TC (2)-filtration – TC (2-I,2-II and 2-III)]

The oil–water separation in PW using membrane- and adsorption-filtration processes costs **USD 03,000,000** per year. There are revenues from oil recovery in this process valued from USD **22,000,000** per year to USD **60,000,000** per year. This leads to an overall loss of USD **243,000,000** per year to USD **281,000,000** per year, as shown in Supplementary Section F.

In the precipitation process of unwanted alkaline earth metals, especially of Ca^{2+}, we have to distinguish between three scenarios: 2-I, 2-II, and 2-III. Details of the calculations are in Supplementary Section G and the cost- and revenue-variation impacts are shown in Supplementary Section H. For reasons of simplicity, for all scenarios HCl is sourced externally.

According to the calculations shown in Table 6 above, only scenario 2-1, where NaOH is produced on-site and chlorine and hydrogen gases are sold, whereas hydrochloric acid is sourced externally, produces a profit at this stage. It must be highlighted that the authors did not figure in the needed infrastructure for the distribution, storage and sale of chlorine and hydrogen gases.

Table 6. Scenario minimum and maximum calculated outcomes.

Scenario	Minimum Net Outcome (USD)	Maximum Net Outcome (USD)
Scenario 2-I	129,000,000	616,000,000
Scenario 2-II	−243,000,000	−730,000,000
Scenario 2-III	−95,000,000	−583,000,000

The most significant factor in the elevated costs of the precipitation process for scenarios 2-I and 2-II is the purchase of CO_2. It must be noted that momentarily excess gases separated from the petroleum/PW are flared, after separation of the H_2S component. The composition of the gas of the SK site is very similar to that published by Alqaheem [84] (Table 7). A number of efforts have been undertaken to utilize either the material or the heat content of the excess gas. Where the gas is flared on-site, the heat content can be utilized. The generated CO_2 can be sequestered. The utilization of CO_2 in enhanced oil recovery through injection into the subsurface has been investigated extensively. It is this CO_2 gas, however, which can be used in processes 2-I and 2-II, which would significantly reduce the cost of these processes.

Table 7. Composition of gas from SK oilfield that will be flared after treatment (adapted from Ref. [84]).

Methane (CH_4)	65.0%	Propane (C_3H_8)	5.0%	CO_2	12.0%	H_2O	1.0%
Ethane (C_2H_6)	10.0%	Butane (C_4H_{12})	2.5%	H_2S	4.0%	N_2	0.5%

The fixed cost for carbon capture and utilization for a post-combustion capture technology facility is estimated to be USD 45 per ton of CO_2 captured [85], and the transport costs are USD 0 to 7 per ton of CO_2. This is more cost-effective than buying CO_2 at USD 215 per ton. A generic scheme of including carbon sequestration in the processes of scenario 2 is shown in Figure 7.

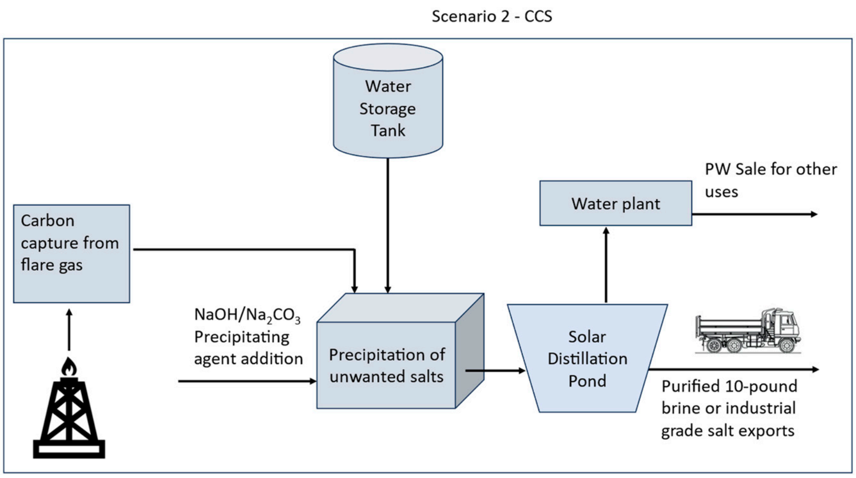

Figure 7. Processes according to scenario 2, augmented by carbon capture in the form of CO_2 from flare gases of the oil production operation.

Desalination of PW and production of industrial salt using an average solar distillation. After the precipitation of $CaCO_3$, PW is subjected to desalination by solar distillation An average solar distillation total cost of USD **1,189,000,000** per year is used in our calculations for the simplicity of data presentation, noting that an upper value of USD 1,971,000,000 (USD 1,000,000 × 5.4 × 365) and a lower value of USD 406,000,000 (USD 1,000,000 × 1.113 × 365 {fixed and operational costs for the solar distillation} have been recorded, which are detailed in Supplementary Section I. A further comparison for the cost of different thermal- and electrical-energy-dependent desalination methods is shown in section J of the Supplementary Material.

In scenario 2-I, close to 1 million barrels of PW carrying an upper range of 51.500 ppm Na^+ (130.880 ppm NaCl) are directed towards the solar distillation units. Here, 15,605 tons of NaCl can be produced per day, with a value of USD 780,000 per day (at USD 50 per ton NaCl) to USD 4,000,000 per day (at USD 260 per ton NaCl).

In scenarios 2-II and 2-III, the PW streams are enriched with NaCl, due to the addition of externally sourced sodium salts during the precipitation process. This adds an additional 5203 tons NaCl to the PW stream per day. Therefore, 20,808 tons of NaCl can be produced per day in both scenarios 2-II and 2-III, with a value of USD 1,000,000 per day (at USD per ton NaCl) to USD 5,000,000 per day (at USD 260 per ton NaCl).

This amounts to USD 286,000,000 per year—USD 1,481,000,000 per year for NaCl reclamation from PW derived from scenario 2-I and USD 380,000,000 per year—USD 1,975,000,000 per year for PW derived from either scenario 2-II or scenario 2-III.

The second product from the desalination step is the desalted water, which, at USD 0.79 per barrel, sells at USD 790,000 per day (USD 288,000,000 per year).

Overall cost analysis

In all scenarios (I-III) presented, the three products, $CaCO_3$, NaCl (industrial salt) and desalinated water, are of commercial value, as is the oil separated from the PW. The results are displayed in Table 8 below:

Table 8. Scenarios 2-I–2-III cost analysis.

Scenario	Cost (USD)	Revenue (USD)	Net Outcome (USD)
2-I	864,000,000	677,000,000	−186,000,000
2-II	1,201,000,000	771,000,000	−429,000,000
2-III	1,053,000,000	771,000,000	−282,000,000

It can be seen from the above that all scenarios 2-I–2-III lead to an overall loss, when forced to be operated with lowest sales prices of the products. Nevertheless, the more interesting scenario is scenario I, where NaOH is produced on-site. This offers two side products of commercial value, Cl_2 and H_2. These two can also be used to produce the HCl needed for the completion of the precipitation process. However, HCl may well be cheaper to source externally than to produce on-site, especially if no such production facility is yet present, as is the case in the SK oilfield operation. If needed, Cl_2, H_2 and HCl can be sold in different volumes, depending on market demands. This helps lower the break-even price that $CaCO_3$ needs to be sold at.

Table 9 depicts the net outcomes of scenario-0, scenario-1, and scenarios 2-I–2-III. It can be seen that scenario 1 is the only profitable case throughout, with more than an estimated USD 530 million in net revenue per annum. Scenario 2-I was found to be 43.5 percent cheaper than the currently practiced method at the SK oilfield for the first year of implementation. From the second year onwards, the total revenues from scenario 2-I exceed the operational costs by 20 percent, resulting in an operating profit of more than USD 115,000,000 per annum, generated from the reclamation and sales of valuable materials found in PW streams. Scenario 2-II turned out to be more expensive than scenario 0, while scenario 2-III was cheaper than scenario 0, with scenarios 0 and 2-II generating losses even in the second year, after excluding the fixed costs. From the second year onwards, scenario 2-III records marginal profits estimated to reach USD 21 million per annum only. Therefore, scenario 2-I is the most cost-effective case of all scenarios 2 and compared to scenario 0, as it is expected to retrieve the losses in the first year, including the fixed costs, within 1.63 years.

Table 9. Comparison in costs and revenues (in USD) between Scenario 0 (SK oilfield) and Scenarios 1, 2-I, 2-II and 2-III.

	Scenario 0	Scenario 1	Scenario 2-I	Scenario 2-II	Scenario 2-III
	FC + VC	FC + VC	FC + VC	FC + VC	FC + VC
Total Cost	332,000,000	665,000,000	864,000,000	1,200,000,000	1,053,000,000
Total Revenues	0	1,200,000,000	677,000,000	772,000,000	772,000,000
Net Outcome	−332,000,000	534,000,000	−187,000,000	−428,000,000	−281,000,000

The processes just analyzed mimic a process studied by Wenzlick [86], but with a different end product, along with minor adjustments, as indicated in Figure 8. It must be noted, however, that, interestingly, the sulfate content of the PW from the SK field, as analyzed, has a relatively low sulfate concentration, so that an addition of barium chloride ($BaCl_2$) to remove the sulfate as $BaSO_4$ is not needed, which obviates at least one filtration process. Also, we replaced the Mechanical Vapor Recompression (MVR) with a solar distillation for the final desalination process. Most studies carried out with MVR are with PW with 50,000 ppm salt concentration or less. Higher salt concentrations, as for the PW of the SK oilfield, necessitate a higher operating pressure [87] and therefore a higher operating cost, surpassing the minimum of 2 kWh energy required to produce 1 m^3 of distillate from the PW stream at USD 2.2/kWh operational cost. In all cases where MVR was introduced, the brine revenue did not exceed the MVR cost and the tipping fee was the decisive factor in generating profits [85]. It must be noted that recently a recovery of water and minerals from a produced water stream from oil and gas production was proposed, using a low-temperature evaporation and crystallization dynamic vapor recovery [88].

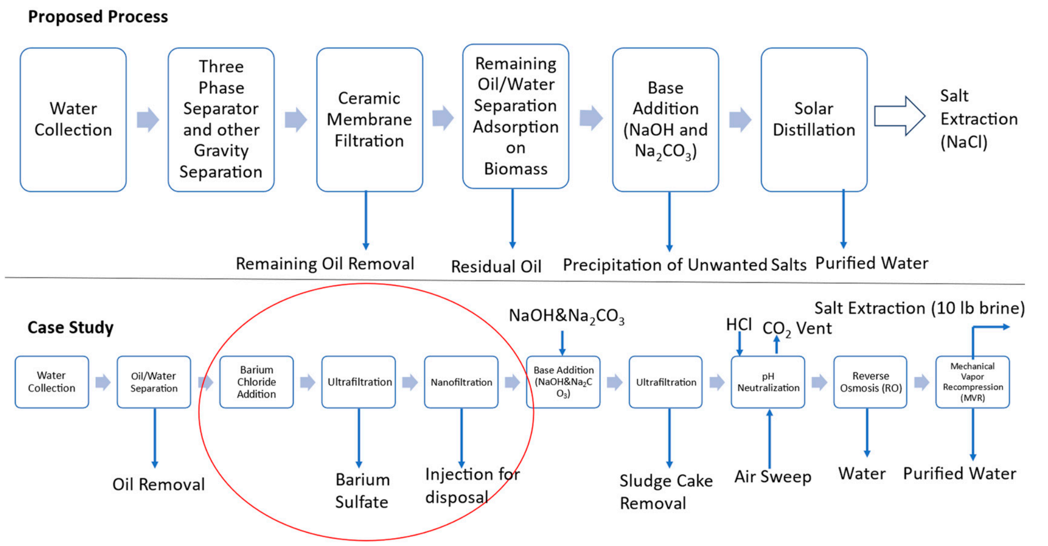

Figure 8. Overview of the proposed PW treatment process and a case study by Wenzlick and, Siefert, using mechanical vapor recompression (MVR) [86]. "Reproduced with permission from Wenzlick and Siefert., Desalination; published by Elsevier, 2020".

The red circle defines the steps eliminated for the proposed process, as the precipitation of barium sulfate is not needed in the studied case.

In scenarios 0 and 1 of the current proposal, either all or part of the PW is being pumped into disposal wells. It must be noted that disposal wells can be categorized into Class I and Class II wells. Class I wells are used to inject hazardous and non-hazardous wastes into deep, confined rock formations. Class I wells are typically drilled thousands of feet below the lowermost underground source of drinking water to prevent contamination of freshwater aquifers. As an example, around 800 operational Class I wells currently exist in the United States, of which 17 percent are hazardous-waste-disposal wells and 53 percent are used for the injection of non-hazardous industrial waste. Most Class I hazardous-waste wells are located at industrial facilities and dispose of waste generated on-site. They serve industries such as petroleum refining, chemical production, municipal waste treatment and pharmaceutical production [89].

Currently, Class II wells are used only to inject fluids associated with oil and natural-gas production. Class II fluids are primarily brines (salt water) that are brought to the surface while producing oil and gas. The number of Class II wells varies from year to year based on fluctuations in oil and gas demand and production. Approximately 180,000 Class II wells are in operation in the United States, where only 20 percent of the total are disposal wells and the rest are distributed between enhanced recovery wells and hydrocarbon storage wells [89].

Usually, the injection of produced water is carried out by the operator who generated it, where it is injected into underground permeable rock formations with no oil or gas production, and sealed above and below by continuous, waterproof layers where most operators maintain their own saltwater disposal wells (SWDs), similar to the operators of the SK oilfield. Commercial disposal is an alternative option for oil and gas operators who do not wish to operate any PW treatment facility. Here, a third party is paid for the injection of PW into a Class I or II disposal well [89]. However, Class I wells are rarely approved to be offsite [90].

Due to the similarity between the industrial and commercial activities, it can be expected that regulations for PW disposal wells for the oil and gas industry could be revised, in that Class I disposal wells are to be used exclusively, especially since other petroleum refining waste material is disposed of in Class I wells.

When comparing the costs associated with the disposal in the different well classes, it is found that Commercial Class II saltwater disposal facilities charge USD 0.50 to USD 1.00 per barrel of water injected, which is within the current disposal well ranges calculated in our proposal, while Class I wells charge USD 7.50 to USD 10.50 per barrel injected [91]. Therefore, a regulatory change in a re-classification of PW to a hazardous waste and the requirement of a specialized third-party entity for proper disposal, using Class I disposal wells, will result in significantly increased expenditures, amounting to 3-to-4 times the maximum calculated disposal costs given in our proposal (found in Tc1b). The disposal costs could be expected to rise from USD 456,000,000 to a range of USD 1,369,000,000 to 1,825,000,000 per year.

This potential change in disposal costs due to a change in the permitted disposal-well class for PW disposal will lead to a deficit in scenario 1, ranging from USD −318,000,000 to −774,000,000 per year for the first year only, when not considering the median costs or the expected annual increase, as the generated quantities rise on an annual basis. Such significant economic burden will force the operating oil company to re-consider scenarios 2-1 or 3 (see below) as alternatives to scenarios 0 and 2 as they treat the produced water efficiently and have fewer PW-disposal activities. Table 10 shows the total outcome for scenario 1 in the case of PW being classified as a hazardous material in a 5-year net-outcome comparison:

Table 10. Costs and revenues (in USD) of scenario 1 with 5-year projection, taking regulatory changes into account.

Scenario 1 with Regulatory Changes with Regard to the Use of Disposal Wells							
Year	**Initial Fixed Cost (USD)**	**Operational Cost (a)**	**Operational Cost (b)**	**Median Total Cost**	**Expected Revenue**	**Annual Outcome**	**IRR**
1	178,000,000	1,367,000,000	1,825,000,000	1,775,000,000	1,200,000,000	−576,000,000	−32.42
2	0	1,410,00,000	1,880,000,000	1,645,000,000	1,236,000,000	−409,000,000	−24.88
3	0	1,452,000,000	1,936,000,000	1,694,000,000	1,273,000,000	−421,000,000	−24.88

Table 10. *Cont.*

Scenario 1 with Regulatory Changes with Regard to the Use of Disposal Wells							
Year	**Initial Fixed Cost (USD)**	**Operational Cost (a)**	**Operational Cost (b)**	**Median Total Cost**	**Expected Revenue**	**Annual Outcome**	**IRR**
4	0	1,496,000,000	1,994,000,000	1,745,000,000	1,311,000,000	−434,000,000	−24.88
5	0	1,541,000,000	2,054,000,000	1,797,000,000	1,350,000,000	−447,000,000	−24.88
Total	178,000,000	7,267,000,000	9,689,000,000	8,656,000,000	6,369,000,000	−2,288,000,000	−26.43
	Net Outcome −2,288,000,000						

Regulatory changes in the use of disposal wells will also have an effect on scenario 0, which is followed currently in the SK oil field. Table 11 (below) demonstrates the difference between Scenario 0 with altered disposal wells and Scenario 2-1, where the waste material is collected and reused:

Table 11. Comparison of net outcomes (in USD) between scenario 0 upon a change in regulations on the use of disposal wells (SK oilfield) and Scenario 2-I, both in the first year of operation.

	Scenario 0-(B)	**Scenario 2-I**
	FC + VC	**FC + VC**
Total Costs	1,489,000,000	864,000,000
Total Revenues	0	677,000,000
Net Outcome	−1,489,000,000	−187,000,000

Table 11 shows that scenario 2-I is 8 times cheaper than scenario 0, when regulatory changes are put into place, with the net losses from scenario 2-I being 12.5 percent of the net losses of scenario 0. Discounting the fixed costs of establishing the infrastructure, scenario 2-I remains profitable, though from the second year onwards.

The double effect of lower oil prices and more stringent environmental controls expose the oil producing company to even higher potential losses, with the returns barely reaching half of the required expenses, resulting in an alarming situation that is best avoided by preventive strategic planning. This means that a sudden shift towards the exclusive use of Class I wells for PW disposal would cause a major issue for oil and gas operators. Their production capacity would be at risk, due to the unavailability of enough Class I disposal wells to accommodate all the PW quantities currently disposed of in Class II disposal wells, as there are only 800 wells of the first type compared to 180,000 of the latter [87]. Therefore, it is of strategic importance to plan ahead of any possible environmental regulatory changes and secure a safe disposal infrastructure in the long term. A rise in the demand for Class I disposal wells may also increase the prices asked for by commercial disposal-well providers. Nevertheless, it is difficult to predict the market price of Class I disposal wells at any specific time. This again is a potential risk that may jeopardize the oil companies' production operations and further affect their financial returns. Kuwait usually follows US standards related to the oil industry, such as API standards, and commits to international agreements to preserve the environment under the UN, which makes it vulnerable to these changes.

Scenario 1 uses 50% of the PW produced for EOR operations. However, EOR water injection is not a flexible solution for the increasing amounts of PW generated at a specific oilfield. The excessive reinjection of treated or untreated produced water can cause many complications. Therefore, it is important to consider the potential setbacks when contemplating alternative solutions to reuse or recycle increasing amounts of PW. Low-salinity water injection can cause a number of problems for the hydrocarbon-producing formation. Thus, alteration of water salinity and the migration of fine particles lead to the blockage of the pore walls of the producing formation, causing a decline in the pores' permeability [92]. This can alter the well's injectivity as quickly as 100 days after starting the water injection, and within three years the reduction in injectivity can reach 77 percent. The higher the injection pressure or rate, the faster the observed decrease in injectivity [93]. Furthermore, the changing characteristics of PW and its incompatibility with the oil-producing formations can result in the rapid formation of scale, which again leads to a diminishing producing-pore size [94]. This is also partly due to the invasion of foreign particles [95], which in turn reduce the flow of oil from the formation to the wells, resulting in an oil production loss [96]. So, it is important to consider the protection of the reservoir in the process of the oilfield development, and the possible extent of damage to the reservoir due to its sensitivity to different attributes such as water, salt, fluid velocity and acids. Because of these reasons, we do not recommend a full-fledged EOR water injection scenario, referred to in the manuscript as scenario 1. Scenario 1 is the most profitable approach, but it is associated with complexities and with the most risks.

Scenario 3—a hybrid proposal

Due to the risks described above, associated with scenario 1, a hybrid proposal (Figure 9) was considered, which is essentially a 50:50 hybrid of scenario 1 and scenario 2-1. So, scenario 3 comprises gravity separation, ceramic-membrane and adsorption filtration as PW purification methods, and water injection (EOR), along with solar distillation as later-stage processes for an efficient PW utilization, bringing the two high-potential-revenue-generating scenarios together.

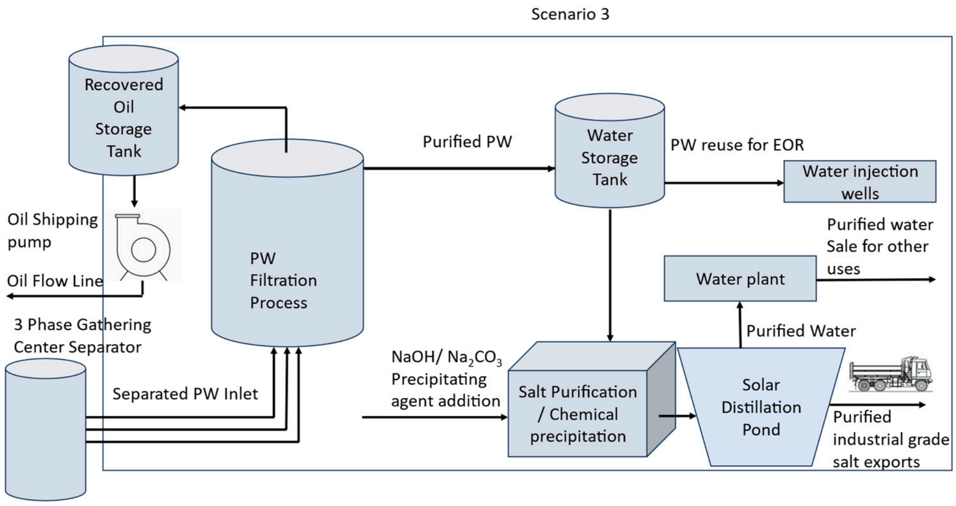

Figure 9. Scenario 3 proposed-solution process for SK oilfield.

For scenario 3, the points discussed for scenarios 1 and 2 remain valid. The quality of the $CaCO_3$ that is precipitated has a significant effect on the economic return of this portion of the process. A HCl plant on-site is of benefit, as is the carbon sequestration from the flare gases of the oil production process in the form of CO_2.

Scenario 3, however, is free from concerns about regulatory changes regarding PW disposal wells. The infrastructure needed for scenario 2 has to be put in place for scenario 3, in addition to the infrastructure needed for the reinjection of PW. On the other hand, scenario 3 provides the most flexibility of all scenarios.

EOR injection is of higher economic return only when the variable costs are well controlled. Otherwise, a large deficit or loss is incurred, especially when the EOR-injection and solar-distillation costs rise. Financially, a merger between both scenarios 1 and 2, as proposed in scenario 3, outweighs the current disposal methods implemented in the SK oilfield, and similar disposal activities practiced in other oilfields within the State of Kuwait, as it generates profits.

As our previous calculations showed, the only profitable model among the versions of scenario 2 is scenario 2-I, and only after eliminating the fixed costs of the first year. Therefore, scenario 2-I has been selected as a component of the hybrid proposal, along with scenario 1 (EOR), albeit without a disposal of 50% of the PW in disposal wells, as this 50% will now be treated according to scenario 2-I. The economic calculations for the first year, including fixed costs, are found in section K of the Supplementary Data.

Tables 12 and 13 show economic calculations for the proposed hybrid process (scenario 3) for the first year and for the following 4 years, here excluding fixed costs. All the PW-related costs and revenues are adjusted to the expected 3-percent increase in PW generation over the projected period of 5 years for each scenario (in USD millions). Table 12 works with the lower range of injection costs, Table 13 with the higher range of injection and distillation costs.

Table 12. Five-year projection N(3a) for the proposed hybrid process, using lower injection costs.

Proposed Hybrid Process (Lower Injection Costs)					
Year	**Initial Fixed Cost (USD)**	**Operational Costs 3a**	**Expected Revenue**	**Annual Outcome**	**IRR**
1	146,000,000	680,000,000	938,000,000	112,000,000	13.60%
2	0	700,000,000	966,000,000	266,000,000	38.00%
3	0	721,000,000	995,000,000	274,000,000	38.00%
4	0	743,000,000	1,025,000,000	282,000,000	38.00%
5	0	765,000,000	1,056,000,000	291,000,000	38.00%
Total	146,000,000	**3,609,000,000**	**4,981,000,000**	1,226,000,000	**33.96%**
Net Outcome		**1,226,000,000**			

Table 13. Five-year projection N(3b) of the proposed hybrid process using higher injection and distillation costs.

Proposed Hybrid Process (Higher Injection and Distillation Costs and Product Sale Value)					
Year	**Initial Fixed Cost (USD)**	**Operational Costs 3b**	**Expected Revenue**	**Annual Outcome**	**IRR**
1	146,000,000	1,827,000,000	1,201,000,000	−773,000,000	−39.15%
2	0	1,882,000,000	1,237,000,000	−645,000,000	−34.29%
3	0	1,938,000,000	1,274,000,000	−665,000,000	−34.29%
4	0	1,997,000,000	1,312,000,000	−685,000,000	−34.29%
5	0	2,057,000,000	1,351,000,000	−705,000,000	−34.29%
Total	146,000,000	9,701,000,000	6,375,000,000	−3,472,000,000	**−35.79%**
Net Outcome		**−3,472,000,000**			

Again, the calculations indicate that the injection costs for EOR are critical to the economic feasibility of the hybrid solution, where the hybrid solution can generate more than USD 1.226 billion over the course of 5 years, including the initial capital expenses, with an average rate of return exceeding 81 percent on an annual basis. This is considered very economical in terms of revenue, and such forecasts should be very encouraging for oilfield operators or production companies, e.g., for Kuwait Oil Company or Kuwait Gulf Oil Company. The economic calculations for the following 4 years, excluding fixed costs, are as displayed in Table 13 below, with all the PW-related costs and revenues adjusted to the expected 3-percent increase in PW generation over the projected period of 5 years for each scenario (in USD millions), with the detailed calculations found in the Supplementary Section K:

The large difference between Tc-3a and Tc-3b in the costs of water injection has reflected on the proposal's profitability, where the average IRR dropped from 72% to −50%. This highlights the importance of managing the operational costs within the planned limits, to avoid any operational losses once the project is commissioned.

The final solution comprises the following processes: (a) gravity separation, (b) ceramic membrane filtration, (c) adsorption filtration, (d) EOR water injection and (e) solar distillation. The process is designed to have three layers of filtration to remove all impurities. Secondly, water injection has a great economic advantage, and increases the SK oilfield output by 50,000 barrels per day. This incentivizes the operating company to pursue this solution as the largest revenue source, namely increased oil production, and utilizes, in part, the existing infrastructure, minimizing capital requirements. The reclamation of salt from the PW stream, as well as the sales of treated PW, offer additional constant revenues and at the same time eliminate or at least reduce a significant waste stream of the oil extraction in the SK oilfield as a clear measure to preserve the local environment. This is in line with the strategic goals of the state authorities.

Expected Impact of Enhanced Oil-Recovery Operations on Kuwait's Economy

The Kuwaiti economy is highly reliant on oil sales. When oil prices are high, the economic contribution of oil sales towards the national GDP increases to more than 55 percent (Figure 10). The volume of oil is another important factor affecting the revenue from crude oil exports. Water injection naturally increases the pressures in the reservoir and results in an increased oil output [97]. The earlier calculated percentages are used to predict the economic impact on Kuwait's GDP once it is implemented in all its existing oilfields.

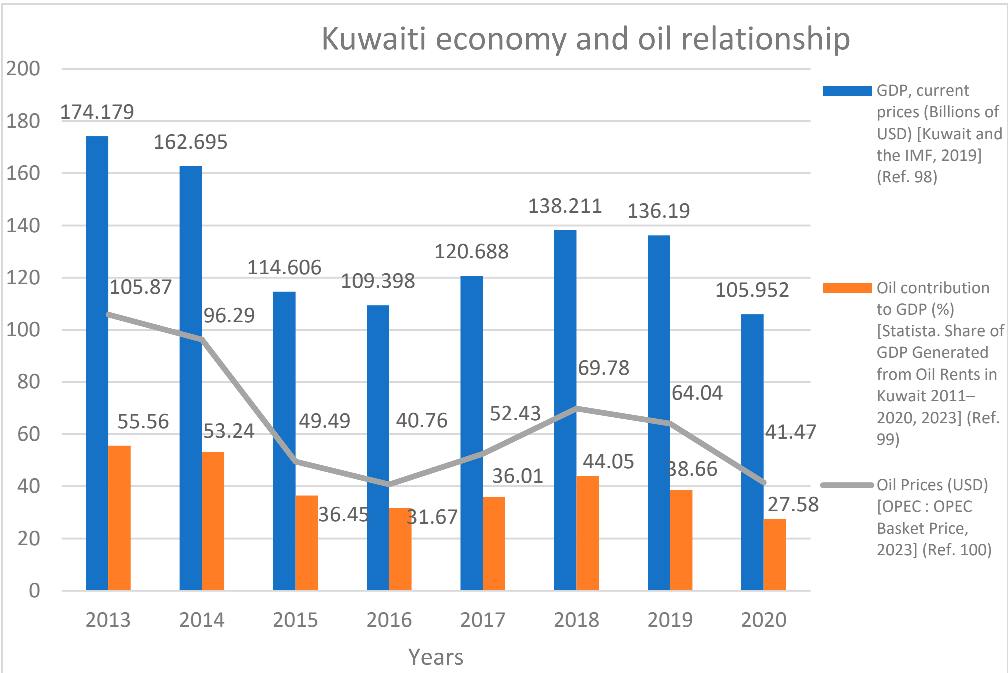

Figure 10. Oil production in relation to Kuwait's economy [98–100].

Due to the fact that Kuwait's GDP is up to 50% dependent on oil activities, a 20% uptick in its producing capacity would result in a 10% increase in its gross domestic product (GDP) and also in its GDP per capita. The Government of Kuwait depends on oil revenues to cover 90 percent of its fiscal budget. Therefore, an 18% incremental increase in oil revenues in the fiscal budget of the government of Kuwait can be expected for scenario 1, assuming that oil prices are consistent over the same period. Figures 11 and 12 demonstrate the possible outcomes of developing two of Kuwait's major oilfields through water-injection EOR methods.

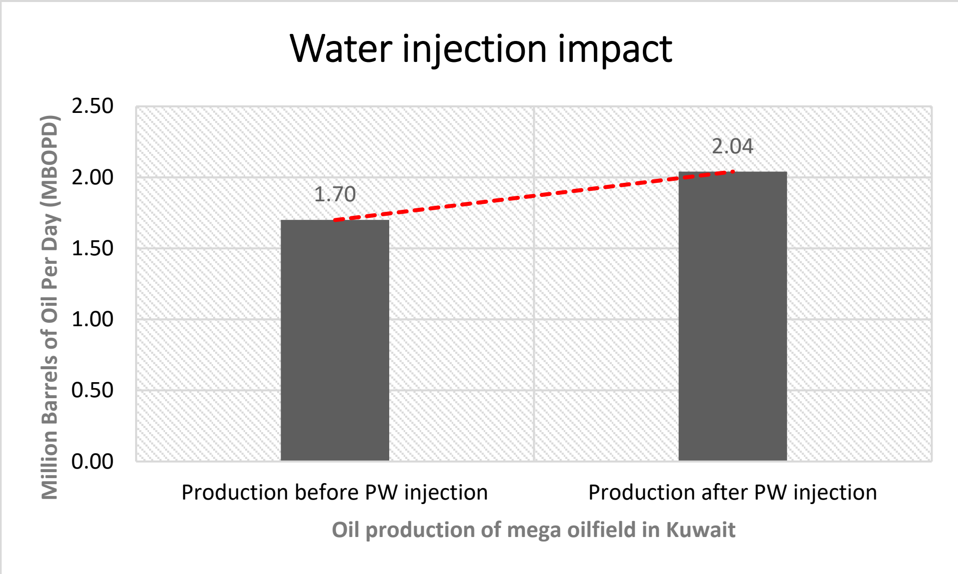

Figure 11. Predicted impact of water injection on the mega oilfield in Kuwait [101].

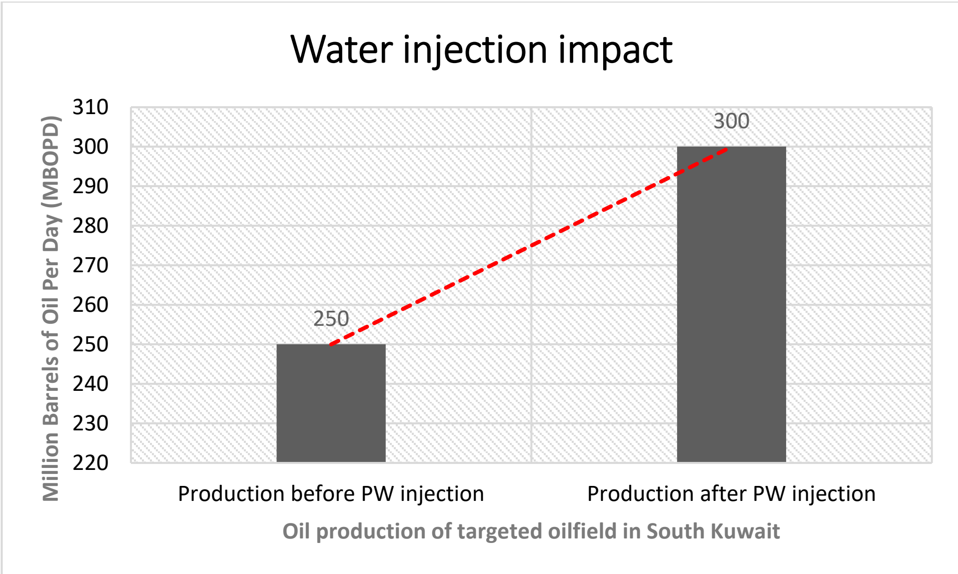

Figure 12. Predicted impact of water injection on the production in a South Kuwait oilfield.

Due to the natural fluctuation in oil prices, as shown in Figure 10 (above), it is important to have the possibility to compensate with an adjustment in the volume of oil produced. EOR techniques such as the one discussed above in scenarios 1 and 3 can help satisfy increased oil demand.

6. Conclusions and Recommendations

This contribution forwarded three different PW-treatment schemes for a facility in South Kuwait that currently solely separates oil and water in PW by gravity separation before pumping the PW into disposal wells. The predicted outcomes of the schemes of all scenarios use underlying data from laboratory experiments. The current situation at the SK oilfield, called scenario 0 in the paper, has been studied extensively on-site. At the SK oilfield, the situation is not very different from other oilfields in Kuwait, where the absence of appropriate regulations, proper standards and economic factors obstruct the beneficial reuse of PW [17].

Scenario 1 introduced a scheme in which PW is purified more rigorously than is currently carried out through filtration and adsorption steps, before half of the PW is to be used for EOR and half is disposed of in disposal wells. This will result in enhanced oil production at the site. Scenario 2 introduced a scheme where, after oil–water separation, Ca was removed from PW as precipitated calcium carbonate ($CaCO_3$), along with other alkaline earth carbonates, before the treated PW was subjected to solar distillation. Here, $CaCO_3$, industrial salt and treated water are seen as products. For the precipitation of $CaCO_3$, CO_2 and NaOH are needed, as well as HCl, to equilibrate the pH of PW. These three chemicals make the scheme costly. To best mitigate costs, it was found beneficial to have a NaOH production on-site. HCl could be sourced externally if a market can be found for the valuable side products of the NaOH production, Cl_2 and H_2. Flare gases can be the source of the needed CO_2, if a carbon sequestration facility is constructed on-site. A number of variables make for the commercial feasibility of the scheme proposed in scenario 2. One important variable is the purity of the precipitated $CaCO_3$, which will determine its sales price. Scenario 3 combines scenario 1 and scenario 2, but obviates the use of the disposal wells of scenario 1. A scheme relying on disposal wells can run into a problem in the future of a potential regulatory change, whereby PW from oil and gas production can no longer be discarded of in Class II disposal wells, but only in the more expensive Class I disposal wells. In all scenarios 1-3, better separation of oil from water than is currently the case leads to additional revenue, due to the collection of additional crude oil of good quality.

In Kuwait, 350,000 barrels of oil are consumed to produce electricity and water per day [102]. With an average value of USD 65.73 per barrel of oil, the total cost is approximately USD 23 million per day or USD 8.4 billion per year. Knowing that the current water-desalination capacity of Kuwait is 1.65 million m^3 per day [103], and that 18 percent of the local energy consumption is utilized for water desalination [104], we can conclude that almost 63,000 barrels of oil per day are required to supply Kuwait with freshwater from desalination plants, with a total cost of USD 4.14 million per day and USD 1.51 billion per year [62].

Reusing PW also reduces the water footprint for the state of Kuwait, as it results in less overall freshwater consumption in the oil industry, and also finds more alternatives to the great dependence on desalination plants [8], where Kuwait consumes ~4.67 million to 23.35 million barrels of freshwater per day to sustain the current oil output of the country [105]. Therefore, if 50 percent of purified PW is reused instead of freshwater, either for irrigation or for oil- and ga- production operations, we can reduce by 19-to-94 percent the freshwater production coming from other sources [62].

It would be possible to purify at least 4,375,000 barrels of PW per day if the hybrid solution is implemented in all of the oilfields in Kuwait. This is an equivalent of 695,569 m^3 water per day or 42 percent of the current total desalination production capacity. Thus, we could reduce the oil consumption for water desalination processes by 26,558 barrels of oil per day, equivalent to a market value of USD 1,745,000 per day or USD 637,000,000 per year. The SK oilfield currently generates 1,000,000 barrels of PW and roughly 250,000 barrels of oil, with a water cut reaching 80% [22], which accounts for almost 23% of the total quantities produced in Kuwait's oilfields. It can contribute an estimated equivalent of USD 146,000,000 per year in oil consumption value or 9.6 percent of total freshwater consumption.

As environmental regulations are consistently revised, a change in disposal-well categories or requirements may intensely impact the operational costs of the PW disposal processes. Therefore, it is important to plan effectively and avoid risks of regulatory setbacks that may jeopardize the oil production operations and cause a supply chain risk for Kuwait's national oil companies [17] as the quantities of PW continue to rise [22].

Supplementary Materials: The following supporting information can be downloaded at: https://www.mdpi.com/article/10.3390/resources13090118/s1, Section (A). Total Costs (Scenario 0) Calculations. Section (B). Total Costs (Scenario 1) Calculations. Section (C). Total Revenues (Scenario

1) Calculations. Section (D). Total Cost (Scenario 2) Calculations. Section (E). TC(2-I), TC(2-II) and TC(2-III)-precipitation. Section (F). NO Scenario 2-I, NO Scenario 2-II and NO Scenario 2-III. Section (G). Cost Analysis of Scenarios 2-1 to 2-III. Section (H). Calculations for the Solar Distillation. Section (I). Total Cost Calculations for Scenario 3 (hybrid solution). Section (J). Desalination processes unit cost table ($/m^3). Section (K) Total Cost Calculations for Scenario 3 (hybrid solution).

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