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The Basics of Model for Marginal Testing Of Costs for Disposal of Extracted Formation Water

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Abstract
Formation water is extracted throughout the life of fields of hydrocarbons together with oil and/or gas. Oil dehydration costs, as well as those of production water reinjection represent significant components in the total cost of mature oil and gas fields. The optimization of the aforesaid costs, from the point of technology and economics, can affect both profitability (cost-effectiveness) and development of the oil field in the future. The methodology of calculating unit cost will be elaborated in this paper for the treatment of produced water (dehydration) and the production of water reinjection. The methodology of calculating the unit cost for the disposal of produced water will be applied during the production of mature oil and gas fields. Unit cost for the disposal of produced water for the period during 2009 – 2014 will be calculated in the selected example. The development of this particular calculation model for the disposal costs of produced water is crucial for the economic analyses of hydrocarbon exploitation from mature fields.

Keywords
Petroleum production economics; cost analyses; cost calculation methodology; water treatment costs

1. Introduction

Formation water is produced during the working life of hydrocarbon reservoirs along with oil and/or gas. Dissolute heavy metals, radioactive, inorganic and organic substances, etc. can be found in the formation water. Formation water (free and bound water inside the oil or drops of water inside the gas stream) is separated through the process of dehydration. Considering the potentially negative influence of formation water on the environment, the Mining Law (*Narodne novine* no 56/13) states that formation water is to be disposed of or injected into the oil or gas reservoir. This paper describes the technological process of oil dehydration on a certain oil and gas field in the Croatian part of the Pannonian basin system, that is; the Eastern part of the Sava depression (see **Fig. 1**).

The focus is on the oil and gas field in its mature phase of production of sandstone reservoir(s), the so-called ''mature field''. For the purpose of calculating the structure of injection costs regarding 1 m^3 of formation water, the oil and gas field (A) with a relatively large formation water injection and treatment system has been described. The dehydration process is performed in three gathering stations, while the formation water injection is performed in the formation water injection station (central system). The formation water is gathered into the central system in one place and it is injected into the injection wells through the injection ring pipeline system with the help of reciprocating pumps. The calculation methodology of the total cost of produced water disposal and the costs and unit cost of formation water separation in the dehydration process regarding the chosen reservoir for the period of 2009 to 2014 is described in this paper.

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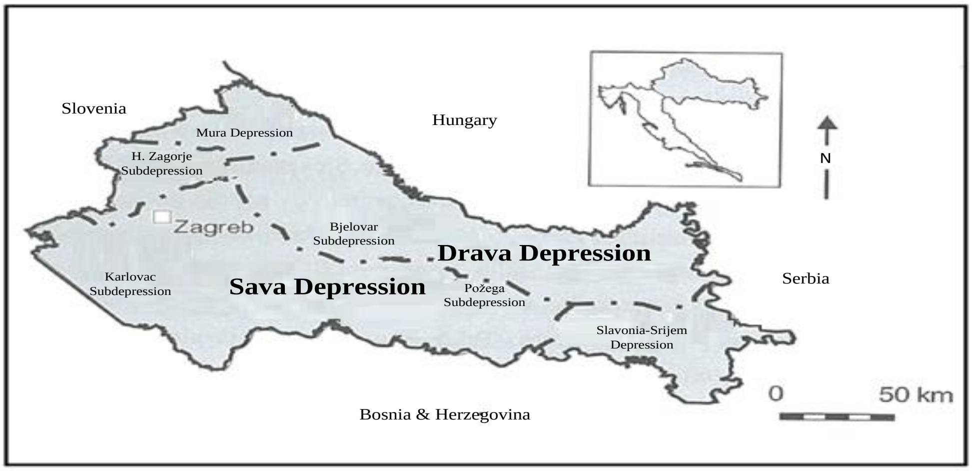

Fig. 1. Depressions located within the Croatian part of the Pannonian basin (**Velić et al., 2015**)

The economy of formation water disposal becomes extremely important in the production of oil originating from fields that are under exploitation for a longer period of time. In this kind of field, the water cut in the total quantity of the produced fluids is increased. Global produced water production is estimated at around 39 500 000 m³/d (250 million barrels per day) compared with around 12 600 000 m³/d (80 million barrels per day of oil) (**Fakhru'l-Razi et al. 2009**). This makes the oil production gradually become emulsion production with an increasing water cut. Due to the fact that the water needs to be separated and specifically disposed, the costs of oil production regarding fields in the mature phase of production largely depend on the separation and produced water disposal costs. Therefore, the elaboration of the cost analysis and the economy of produced water separation and disposal model is an important part of oil production economy analysis regarding fields in the mature phase of exploitation. Although in Croatia, most reserves are located in the sandstone reservoirs and were discovered by 1990 (e.g., **Velić et al., 2012**), the success of proposed methods could be also checked in other reservoir lithofacies, primarily in breccia and conglomerates.

2. Extracted water disposal

Extracted water can be injected and permanently stored into depleted hydrocarbon reservoirs or it can be injected into the reservoir with the purpose of supporting the reservoir pressure and increasing hydrocarbon recovery. Produced water injection is performed by a single or central system. The mutual dependency of produced water injection and hydrocarbon production is shown in **Figure 2**.
The grey elements in **Figure 2** represent the factors that cannot be influenced (tax regime, geological factors and oil and gas prices), while the uncoloured elements represent factors that can be influenced by the produced water injection (number of wells, well maintenance, injection rate, reservoir pressure support, etc.). By means of properly planned water injection production, additional hydrocarbon recovery can be obtained and therefore, additional profit for the oil company can be made.

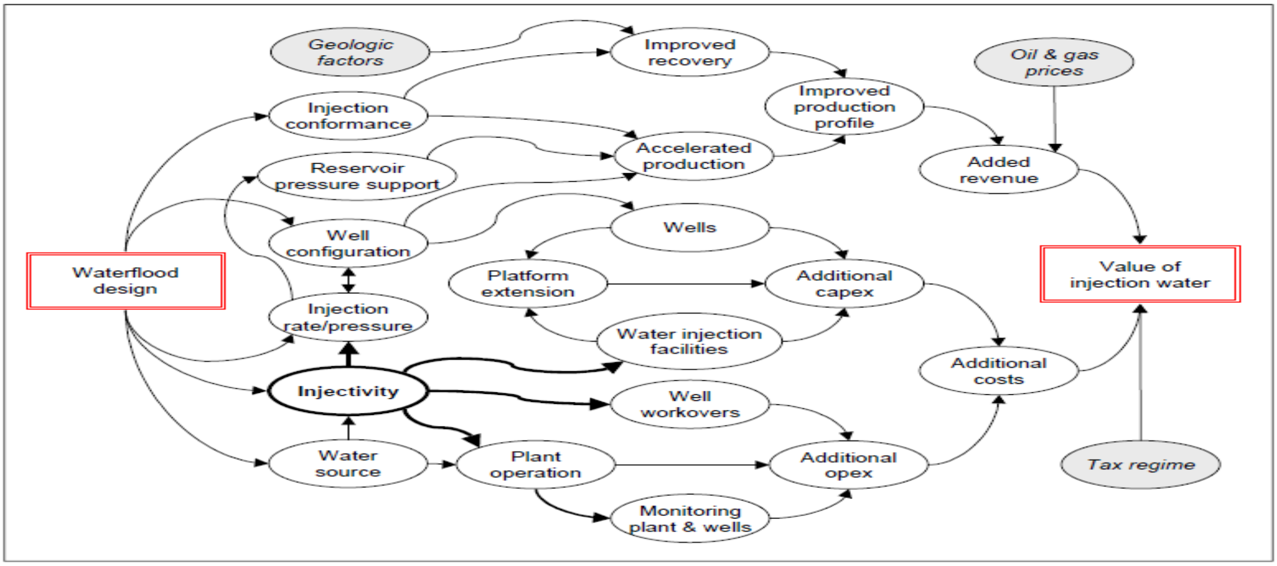

Fig. 2. A Simplified meaning diagram of formation water disposal (from the design to the exploitation of oil and gas fields) (**Palsson et al., 2003**)

The primary oil and gas exploitation is hydrocarbon production from the reservoir with the reservoir's energy and with additional mechanical lifting. After primary hydrocarbon production, the application of secondary methods in hydrocarbon production (produced water injection) follows, with the aim of increasing hydrocarbon recovery. After the application of secondary methods in hydrocarbon production, the application of tertiary methods in the hydrocarbon production follows (the injection of CO_2, polymers and so on). With the finalization of the tertiary methods in hydrocarbon production, the circle of oil and gas field exploitation is finalized. Such oil and gas field exploitation is represented in **Figure 3**.

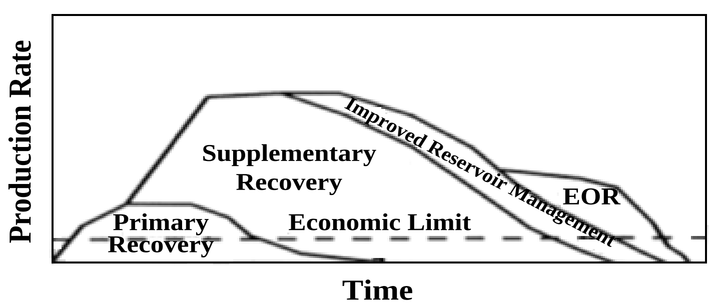

Fig. 3. The cycle of oil and gas fields exploitation (**Evans, 2001**)

Figure 3 shows that the application of secondary methods during production lasts longer than the application of primary and tertiary production methods regarding hydrocarbon production. During the application of secondary methods in hydrocarbon production, the largest capacity of hydrocarbon production is realized. This can be seen in **Figure 3**; therefore, this is the period when the oil fields' largest profit is realized. By analysing the costs of produced water separation and injection, the hydrocarbon production economic limit can be decreased; by reducing capital and operating costs. In order for this to be realized, all costs related to produced water disposal need to be analysed. In the case of the mature phase of hydrocarbon exploitation fields, the limit between profit and production economic is relatively small and its consequence is a short period return on investment. Therefore; by decreasing the everyday operating costs of exploitation field hydrocarbon production, and especially by a more economic manner of produced water disposal, the lifespan of the exploitation field production is prolonged. A greater difference between the realized profit and the production's economic limit makes way for greater investments in future hydrocarbon production.

3. The Methodology of Unit Cost Calculation Regarding Extracted Water Disposal

The dehydration and formation water disposal expenses represent a significant component in the total cost regarding mature oil and gas fields. In a specific moment this can be crucial for the calculation of the break-even point and the business decision regarding the continuation of hydrocarbon exploitation in such fields. The costs' elements that are considered in the calculation of the total produced water injection unit costs according to **Palsson et al. (2003)** are:

-CAPEX: capital investments into the wells, capital investments into the injection equipment, the injection pumps capacity increase,

-OPEX: injection pumps maintenance costs, costs of chemical dosages (corrosion inhibitors etc.), current maintenance equipment and well and equipment monitoring costs,

-OTHER EXPENSES: tubing replacements in the well (every three to five years, depending on the location), acid stimulation of layers (every year or up to three years, depending on the location).

The costs' elements that are included in the calculation of the total unit cost regarding the formation of water injection according to **Bailey et al. (2000)** are:

- Lifting of fluid from reservoir to surface (CAPEX and OPEX and utility costs),
- Separation of fluids (CAPEX and OPEX costs, utility and chemical costs),
- De-oiling (separation of bound water) (CAPEX and OPEX costs and chemical costs),
- Filtering of formation water (CAPEX and OPEX and utility costs),
- Process circulation (pumping) of fluids (CAPEX and OPEX and utility costs),
- Injection of fluids (CAPEX and OPEX costs),
- Electric energy surface processing system costs,
- Drilling, well workover and completion.

In both cost calculation methodologies, the calculated cost of produced water disposal is shown per barrel (bbl), that is, per m^3 of formation water. The earlier described methodologies of cost calculation concern relatively large water injection systems (from 3 181 m^3/d to 31 810 m^3/d **(Bailey et al. 2000)** and 20 000 m^3/d **(Palsson et al. 2003)** of injected produced water). Therefore, in the continuation of this paper, the methodology of cost calculation regarding produced water disposal for relatively small water injection systems that prevail in the Republic of Croatia will be described.

4. The Methodology of Unit Cost Calculation Regarding Extracted Water Disposal on Oil-Gas Field A

The total and unit cost calculation regarding extracted water disposal on oil and gas fields consists of the following calculations:

a) Unit cost calculation regarding produced water separation,
b) Unit cost calculation regarding extracted water injection.

4.1. The Methodology of Unit Cost Calculation Regarding Extracted Formation Water

The elements of produced water separation (dehydration) are the following: maintenance of boiler-room, demulsifier station, heat exchanger, free water and dehydrator separator, energy sources, chemicals, employees and amortisation costs.

4.1.1. The Boiler-Room and the Demulsifier Station Maintenance Costs

On oil and gas field A, there are three boiler-rooms and demulsifier stations. The costs that are included in the cost calculation regarding the boiler-room are: an annual inspection, servicing of circulation pumps, servicing and inspection of electromotor, supplies, etc., while the costs that are included in the cost calculation of the demulsifier station are electromotor and metering pumps maintenance. The total cost of the demulsifier station and boiler-room are represented in equation **(1)**:

$$TCBRDS=BRC+DSC \tag{1}$$

Where:
TCBRDS- total cost of the boiler-room and the demulsifier station (HRK),
BRC- boiler-room costs (HRK),
DSC- demulsifier station costs (HRK).

In the overall cost calculation regarding dehydration on oil and gas field A, the TCBRDS cost needs to be multiplied by three, due to the fact that the dehydration takes place in three gathering stations.

4.1.2. The Costs of Heat Exchanger and Treatments Vessels Maintenance

In order for regular technological processes on oil and gas field A to take place, six heat exchangers, three freewater knockouts and three dehydrators are needed. A heat exchanger has the shape of double concentric tubes, and can also be made with pipe grids through which one media flows, and from the outside strikes the transverse flow (**Bošnjaković 1950**). Therefore, the integral elements of the costs regarding the heat exchanger include: the change of the tube bundle (two tube bundles are changed annually), mechanical-chemical cleaning (three heat exchangers are cleaned annually) and emergency breakdowns. The cost of the freewater knockout includes maintenance and control check-up of breather vents and flame arrester, centrifugal pump maintenance and emergency breakdowns. The dehydrator cost includes: chemical-mechanical cleaning (once per year), control check-up, flame arrester and breather vents maintenance and emergency breakdowns. The total cost of the heat exchanger, the freewater knockout and dehydrator are shown in equation (**2**):

$$CHETV=CHE+FKC+DC \tag{2}$$

Where:
CHETV- total cost of the heat exchanger and treatment vessels (HRK),
CHE- costs of the heat exchanger (HRK),
FKC- freewater knockout costs (HRK),
DC- dehydrator costs (HRK).

In the total cost calculation regarding the dehydration on oil and gas field A, the CHETV costs need to be multiplied by three, which has been explained in chapter 4.1.1.

4.1.3. Energy Source Costs

Electric energy and natural gas consumption constitutes the total cost of the energy sources. Natural gas is consumed for six months during the year for the needs of the boiler-room. The quantity of gas spent in the process of dehydration is taken by experience and equals 30 % of the total annual gas consumption regarding each of the three gathering stations. Therefore, the annual amount of gas (on all of the gathering stations) multiplied with the selling price of natural gas constitutes the total cost of natural gas. The fluid flow that ensures a normal proceeding of the dehydration process in three gathering station is secured by three centrifugal pumps with 11 kW of power, three centrifugal pumps with 1.5 kW of power and three reciprocating pumps with 0.55 kW of power. The efficiency of the pumps on field A is 0.8. The number of working hours of the pumps has been calculated according to the amount of fluid flow through the pump, so the consumption of electric energy is calculated according to equation (**3**):

$$EEC= PP \cdot H \cdot \eta \cdot SP \tag{3}$$

Where:
EEC- electric energy costs (HRK),
PP- pump power (kW),
H- number of working hours,
η- pumps' efficiency,

SP- the selling price of electric energy for industry (HRK/kWh).

By calculating the natural gas and electric energy costs, we can calculate the overall energy sources' expenses according to the following equation **(4)**:

$$TESC = NGC + EEC \quad (4)$$

Where:
TESC- total energy sources costs (HRK),
NGC- natural gas costs (HRK),
EEC- electrical energy costs (HRK).

4.1.4. Demulsifier Costs

The chemical substance used in the dehydration process is a demulsifier. The annual cost of the demulsifier depends on its market price and the quantity used in the process of dehydration. Therefore, the costs are calculated with the equation **(5)**:

$$DE = DC \cdot DMP \quad (5)$$

Where:
DE- demulsifier expenses (HRK),
DC- annual demulsifier consumption (kg),
DMP- demulsifier's market price in the observed year (HRK/kg).

4.1.5. Employee and Amortisation Costs

Amortisation costs depend on capital investments. If the observed year has larger capital investments, then a certain sum regarding the amortisation is added. If this is not the case, the amortisation costs do not exist. The amortisation costs regarding the majority of elements in the process equals zero, because the equipment is considered to have already been amortised. The cost regarding employees depends on their number, their gross annual salary and time share in the employee's total number of business hours that is needed for regular development of the dehydration process. The employee and amortisation costs are calculated in the equation **(6)**:

$$EAC = A + NE \cdot GAS \cdot x \quad (6)$$

Where:
EAC- employees' and amortisation costs (HRK),
A- amortisation (HRK),
NE- number of employees,
GAS- employee's average gross annual salary (HRK),
x- estimated time share in the employee's total business time which is required for the development of a normal dehydration process.

4.1.6. The Total Cost of Formation Water Separation

The total cost of formation water separation equals the sum of expenses listed in the previous chapters. Therefore the equation for total dehydration cost is **(7)**:

$$FWSC = BRDSC + CHETV + EEC + DE + EAC \quad (7)$$

Where:
FWSC- formation water separation costs (HRK),

BRDSC- boiler-room and demulsifier station costs (HRK),
CHETV- heat exchanger and treatment vessels costs (HRK),
EEC- electric energy costs (HRK),
DE- demulsifier expenses (HRK),
EAC- employee and amortisation costs (HRK).

The dehydration per unit of separated formation water in m^3 unit cost can be expressed from the total cost.

4.2. The Methodology of Formation Water Injection Unit Cost Calculation

Formation water injection costs consist of the following expenses: workover and capital workover, injection pumps maintenance, electric energy, chemicals, construction work, employee costs, amortisation and other expenses.

4.2.1. Workover and Capital Well Workover expenses

Workover and capital workover expenses include well workover, injection equipment replacement and other mining work. The equation to use regarding total workover and capital workover costs is **(8)**:

$$WWCC=W+CW \tag{8}$$

Where:
WWCC- workover and capital workover costs (HRK),
W- workover costs (HRK),
CW- capital workover costs (HRK).

4.2.2. Injection and Dispatch Pumps Maintenance Costs

The following costs are included into the annual injection and dispatch pumps maintenance costs: general repairs of pumps, current maintenance of pumps and oil replacement inside the pumps. The equation regarding the total injection pumps maintenance costs is **(9)**:

$$IDPC=GRPC+CMPC+ORC \tag{9}$$

Where:
IDPC- injection and dispatch pumps costs (HRK),
GRPC- general repair of pumps costs (HRK),
CMPC- current maintenance of pumps costs (HRK),
ORC- oil replacement costs (HRK).

4.2.3. Electric Energy Costs

In order for the formation water injection in the formation water injection station to take place, oil and gas field A has five electromotors at our disposal that secure five centrifugal pumps. These have a power of 37.5 kW. The dispatching of formation water from the gathering stations to the formation water injection station is secured by three centrifugal pumps with a power of 1.5 kW. The efficiency of pumps in the station for formation water injection and the dispatch pumps is 0.8. The number of working hours is calculated according to injection quantities and the injection pumps' capacity. The electric energy cost regarding formation water injection is calculated according to the equation **(3)** as well as the electric energy costs in the formation water injection.

4.2.4. Scale Inhibitor Costs

The chemical that is used in the formation water injection process is the scale inhibitor. The annual scale inhibitor costs depend on its market price and the amount of resources spent in the formation water injection process. The scale inhibitor cost is calculated according to the equation **(5)** as well as the demulsifier cost in formation water separation.

4.2.5. Construction Work Costs and Other Expenses

The construction preparation and remediation of well sites, road access to the wells, excavations of pipelines and similar construction work constitute the expenses regarding construction work, while the other expenses are those that can appear in the maintenance of the entire system of formation water injection (e.g. surface equipment maintenance). The equation for the construction work costs and other expenses calculation is **(10)**:

$$CWOC=CWE+OE \tag{10}$$

Where :
CWOC- total cost of construction work and other expenses (HRK),
CWE- construction work expenses (HRK),
OE- other expenses (HRK).

4.2.6. Employee and Amortisation Costs

Employee and amortisation costs are calculated according to the equation **(6)**. In the employee and amortisation costs regarding formation water injection, there is a certain amount of amortisation due to larger investments in injection wells and equipment. The estimated time share in the employees' total business hours is different than in the case of produced water separation due to the visiting of wells on the exploitation field.

4.2.7. Total Cost of Formation Water Injection

The total cost of formation water injection is equal to the sum of the expenses listed in the previous chapters. Therefore, the equation for the total cost of formation water injection is as follows **(11)**:

$$FWIC=WWCC+IDPMC+CWOC+EEC+SIC+EPWIA \tag{11}$$

Where:
FWIC- formation water injection costs (HRK),
WWCC- workover and capital workover (HRK),
IDPMC- injection and dispatch pumps maintenance costs (HRK),
CWOC- construction work and other costs (HRK),
EEC- electric energy costs (HRK),
SIC- scale inhibitor costs (HRK),
EPWIA- employee and produced water injection amortisation (HRK).

The unit cost of produced water injection can be calculated from the total cost of produced water injection. This is obtained when the total cost is divided per unit of injected formation water per m^3.

4.3. The Calculation of Unit Cost of Extracted Water Disposal

By calculating dehydration and formation water injection costs, their sum provides the total annual cost of extracted water disposal. According to this, the equation for the total extracted water disposal cost is **(12)**:

$$TCEWD=FWSC+FWIC \tag{12}$$

Where:
TCEWD- total cost of extracted water disposal (HRK),
FWSC- formation water separation costs (HRK),
FWIC- formation water injection costs (HRK).

Produced water disposal unit cost is gained by adding the dehydration unit cost to the formation water injection cost. This is expressed in m³ of disposed formation water.

5. The Technological Dehydration and Extracted Water Injection System on Oil and Gas Field A

The process of fluid gathering on oil and gas field A is done in three gathering stations, the dehydration process is performed in the sole gathering station, and the separated produced water is distributed from the produced water injection station to the wells. The technological process of produced water separation and preparation for injection on oil and gas field A is represented in **Figure 4**.

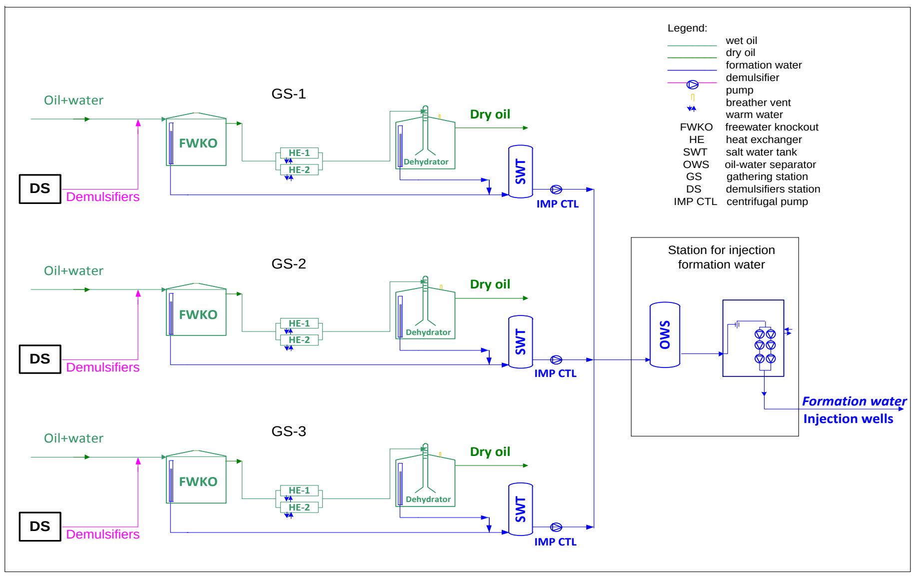

Fig. 4. The technological process of formation water separation and collection in the oil and gas field A

Prior to entering into the freewater knockout, the demulsifier from the demulsifier station is added into the entering fluid with the purpose of breaking the oil and produced water emulsion. The retention time of the produced water in the treatments vessels is from 3 to 30 minutes **(Arnold & Stewart, 2008)**. The time of free water separation in the free water knockout ranges between 3-10 minutes (**Stewart & Arnold 2009**). In the free water separator, 95 % of the produced water is separated and this separated water is then directed to the salt water tank. The water and oil emulsion is directed towards the heat exchangers where the emulsion is heated to 40-45 °C whereby the flow through the tube bundle is counter current. By heating the fluid, the efficiency of the demulsifier in the heat exchanger is improved. Bound water separation in the dehydrator is also improved, and its efficiency is enhanced if pour-point depressant is added. After it is heated, the fluid enters the dehydrator, where bound water separation takes place. After finalizing the dehydration process, 99 % of the produced water is separated from the fluid. By controlling the content of water in the oil (up to 1 %), the degree of dehydration efficiency in the gathering station is evaluated. The separated bound water in the dehydrator gets sent through the water siphon into the salt water tank, where it travels from the produced water and is dispatched towards the salt water injection station. In this process, four centrifugal pumps with a maximum capacity of 50 m³/ h are used. The produced water separated in the dehydration process in three gathering stations of oil and gas field A is dispatched towards the produced water injection station. In the produced water injection station, besides the produced water separated during the dehydration process, the produced water drained from the stock tank can also be gathered. The total amount of produced water prior to the injection passes through the oil- water separator where possibly some amount of oil might remain. The produced water enters from the separator into the tanks, where the scale inhibitor is added. With the help of five reciprocating and centrifugal pumps with

automatic or manual control, the produced water is dispatched towards the wells. The work of the injection pumps is adjusted according to the amount of produced water for injection.
The produced water injection on oil and gas field A is performed from the salt water injection station, towards the eleven wells in the injection ring. The water-injection pressures depend on the technical condition of the subsurface and surface well equipment.

6. The Calculation of Extracted Water Disposal in the Example of Oil and Gas Field A

For a calculation of produced water dehydration unit cost to be made, it is necessary to be familiar with the amount of input fluid in the gathering stations. The amount of fluid produced on oil and gas field A ranges from 542 000 m³ per year to 572 000 m³ per year where the bound and free water account for81 % to 83 % of the total amount of fluid. **Table 1** shows the produced amounts of fluid for the period from 2009 to 2014.

Table 1. Produced volume of total liquid and formation water in the facilities of oil and gas field A

Year	Total fluids (m^3)	Formation water (m^3)	Water cut (%)
2009	561 908	456 404	81.22
2010	570 296	464 281	81.41
2011	542 444	454 810	83.84
2012	564 209	472 073	83.66
2013	572 376	479 280	83.73
2014	567 320	467 698	82.43

It can be clearly seen in **Table 1** that the change in the amount of the produced fluid alters the amount of produced formation water. The energy sources' prices (the electric energy and natural gas) for the mentioned period are shown in **Table 2.**

Table 2. Industrial energy sources' prices for the period from 2009 to 2014

Year	Electrical power (HRK/kWh)	Natural gas (HRK/m^3)
2009	0.55-0.56	2.43
2010	0.57-0.58	3.60
2011	0.57	3.99
2012	0.57-0.60	4.47
2013	0.58-0.61	4.35
2014	0.66-0.68	3.91

Sources: Energy in Croatia 2013, Sector analysis IEZ, 2014.

Based on the amount of produced water from **Table 1** and the energy sources' price from **Table 2**, an economic calculation regarding the cost of m³ of produced water obtained in the dehydration process and the unit cost of the produced water injection volume unit from the salt water reservoir to the injection wells for the period from 2009 to 2014 will be made.

6.1. The Free and Bound Water Separation in the Process of Dehydration on Oil and Gas Field A Objects

The budget regarding the produced water separation in the process of dehydration covers the following expenses: boiler-room and demulsifier station maintenance, heat exchanger maintenance, dehydrator and freewater separator maintenance, the expense of energy sources (natural gas and electric energy), chemicals, employee expenses, etc. All of the expenses that were taken into account were obtained from real costs (INA Plc. company's documentations) regarding the analysed time period in this paper. The operating and capital costs of the dehydration process for the time period from 2009 to 2014 range between 968 000 HRK and 1 850 000 HRK, depending on the sum of capital investments for equipment regarding this period. According to this, the unit cost of produced water separation in the dehydration process for the observed period ranges from 2.09 HRK/m^3 to 3.99 HRK/m^3. A detailed presentation of all expenses regarding the stated items can be seen in **Table 3**.

Table 3. Expenses and unit cost of formation water separation in the process of dehydration in oil and gas field A

The year 2009				The year 2012			
Description:	Amount (HRK)	Unit cost (HRK/m^3)	%	Description:	Amount (HRK)	Unit cost (HRK/m^3)	%
Boiler room and demulsifiers station maintenance	39 135	0.09	2.63	Boiler room and demulsifiers station maintenance	21 068	0.04	2.01
Heat exchangers and process vessels maintenance	432 000	0.95	29.07	Heat exchangers and process vessels maintenance	439 000	0.93	41.79
Energy	702 896	1.54	47.29	Energy	323 674	0.69	30.80
Chemicals	254 160	0.56	17.10	Chemicals	235 761	0.50	22.44
Staff costs and amortization	58 061	0.13	3.91	Staff costs and amortization	31 104	0.07	2.96
Total:	1 486 252	3.26	100.00	Total:	1 050 606	2.23	100.00
The year 2010				The year 2013			
Description:	Amount (HRK)	Unit cost (HRK/m^3)	%	Description:	Amount (HRK)	Unit cost (HRK/m^3)	%
Boiler room and demulsifiers station maintenance	39 135	0.08	2.11	Boiler room and demulsifiers station maintenance	21 068	0.04	1.98
Heat exchangers and process vessels maintenance	430 000	0.93	23.24	Heat exchangers and process vessels maintenance	440 500	0.92	41.39
Energy	1 040 248	2.24	56.21	Energy	315 163	0.66	29.60
Chemicals	283 160	0.61	15.30	Chemicals	255 438	0.53	23.99
Staff costs and amortization	58 061	0.13	3.14	Staff costs and amortization	32 400	0.07	3.04
Total:	1 850 604	3.99	100.00	Total:	1 064 568	2.22	100.00
The year 2011				The year 2014			
Description:	Amount (HRK)	Unit cost (HRK/m^3)	%	Description:	Amount (HRK)	Unit cost (HRK/m^3)	%
Boiler room and demulsifiers station maintenance	21 068	0.05	2.18	Boiler room and demulsifiers station maintenance	10 456	0.02	1.07
Heat exchangers and process vessels maintenance	442 000	0.97	45.64	Heat exchangers and process vessels maintenance	355 782	0.76	36.37
Energy	288 848	0.64	29.83	Energy	283 585	0.61	28.98
Chemicals	187 071	0.41	19.32	Chemicals	296 173	0.63	30.27
Staff costs and amortization	29 484	0.06	3.03	Staff costs and amortization	32 400	0.07	3.31
Total:	968 471	2.13	100.00	Total:	978 396	2.09	100.00

Heat exchanger maintenance costs represent the largest share of the total cost regarding heat exchanger and treatment vessel maintenance, as well as the energy sources costs that range from 65 % to 80 %. The amortisation for gathering stations parts regarding oil and gas field A is zero HRK due to the station elements' old age. It is considered that these elements have payed off during a longer period of time through amortisation. Due to the reduction of operative costs, natural gas is not spent throughout the whole year, but only in the winter and spring months. The amount of electric energy spent is calculated on the basis of working hours of pumps and electromotors.

The reason for the relatively high dehydration cost is the separation of the dehydration process into three gathering stations. The increase in the number of heat exchangers, dehidrators, boiler rooms, demulsifier stations, etc. following an additional increase in the maintenance and reparation expenses is a consequence of this.

6.2. Unit Cost of a m^3 of Extracted Water Injection on Oil and Gas Field A

The produced water injection on oil and gas field A is performed in eleven injection wells. The expenses taken into consideration in the produced water injection cost calculation are the expenses regarding the flow path from the salt water reservoir to the injection wells. The cost calculation and the produced water injection unit cost have been made for the last six years, and the costs have been taken from the documentation that is property of the INA Plc. company. **Table 4** shows the produced water injection costs for the period from 2009 to 2014.

Table 4. Expenses and unit cost of formation water injection in oil and gas field A

The year 2009				The year 2012			
Quantity of injected formation water (m^3)	456 404			Quantity of injected formation water (m^3)	472 073		
Number of injection wells	11			Number of injection wells	11		
Description:	Amount (HRK)	Unit cost (HRK/m^3)	%	Description:	Amount (HRK)	Unit cost (HRK/m^3)	%
Well maintenance	1 640 460	3.59	62.75	Well maintenance	284 625	0.60	14.02
Maintenance of injection pumps	119 600	0.26	4.57	Maintenance of injection pumps	730 227	1.55	35.95
Electrical power	261 862	0.57	10.02	Electrical power	586 563	1.24	28.89
Chemicals	0	0.00	0.00	Chemicals	163 454	0.35	8.05
Staff costs and amortization	492 302	1.08	18.83	Staff costs and amortization	210 000	0.44	10.34
Construction work and other expenses	100 143	0.22	3.83	Construction work and other expenses	55 790	0.12	2.75
Total:	2 614 367	5.72	100.00	Total:	2 030 659	4.30	100.00
The year 2010				The year 2013			
Quantity of injected formation water (m^3)	464 281			Quantity of injected formation water (m^3)	479 280		
Number of injection wells	11			Number of injection wells	11		
Description:	Amount (HRK)	Unit cost (HRK/m^3)	%	Description:	Amount (HRK)	Unit cost (HRK/m^3)	%
Well maintenance	1 020 789	2.20	38.11	Well maintenance	0	0.00	0.00
Maintenance of injection pumps	331 718	0.71	12.38	Maintenance of injection pumps	131 403	0.27	6.42
Electrical power	625 777	1.35	23.36	Electrical power	293 687	0.61	14.35
Chemicals	0	0.00	0.00	Chemicals	226 424	0.47	11.06
Staff costs and amortization	623 795	1.34	23.29	Staff costs and amortization	144 000	0.30	7.03
Construction work and other expenses	76 736	0.17	2.86	Construction work and other expenses	1 251 781	2.61	61.14
Total:	2 678 815	5.77	100.00	Total:	2 047 295	4.27	100.00
The year 2011				The year 2014			
Quantity of injected formation water (m^3)	454 810			Quantity of injected formation water (m^3)	467 698		
Number of injection wells	11			Number of injection wells	11		
Description:	Amount (HRK)	Unit cost (HRK/m^3)	%	Description:	Amount (HRK)	Unit cost (HRK/m^3)	%
Well maintenance	1 849 181	4.07	48.52	Well maintenance	0	0.00	0.00
Maintenance of injection pumps	123 553	0.27	3.24	Maintenance of injection pumps	736 973	1.58	22.31
Electrical power	543 223	1.19	14.26	Electrical power	248 253	0.53	7.51
Chemicals	203 854	0.45	5.35	Chemicals	248 620	0.53	7.53
Staff costs and amortization	831 812	1.83	21.83	Staff costs and amortization	144 000	0.31	4.35
Construction work and other expenses	259 048	0.57	6.80	Construction work and other expenses	1 925 958	4.12	58.30
Total:	3 810 671	8.38	100.00	Total:	3 303 804	7.06	100.00

The produced water unit price for the period from 2009 to 2014 ranges from 4.27 HRK/m^3 to 8.38 HRK/m^3, while the expenses for the stated period ranges between 2 030 000 HRK and 3 811 000 HRK. The chemical expenses are shown in the costs table from 2011 because that is when the scale inhibitor dosage is applied. The mean value of produced water injection, if the current year has not had capital and current workovers is about 4 HRK/m^3, and increases for 2-4 HRK/m^3 in the case of anterior work.

7. The Extracted Water Disposal Unit Cost on Oil and Gas Field A

The produced water disposal unit cost consists of the dehydration unit cost (produced water separation) and produced water injection unit cost. Produced water disposal unit cost on Oil and Gas field A is shown in **Figure 5**.

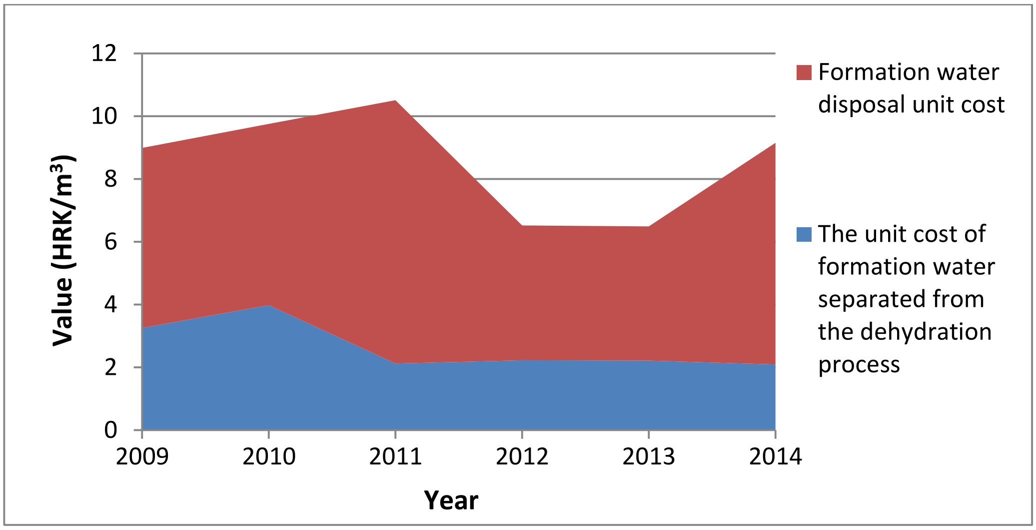

Fig. 5. The unit cost of extracted water disposal and dehydration in oil and gas field A

The produced water disposal costs regarding oil and gas field A in the last six years range between 6.49 HRK/m^3 and 10.51 HRK/m^3. The increase in the unit cost of total water disposal in 2011 is caused by the increase of the current and capital workover, and a weak growth in 2013 and 2014 was caused by the investments on the injection ring. A sudden fall of the produced water disposal costs is a consequence of the recession and economic crisis, which, on the other hand, caused a reduction in capital investments. By reducing capital investments into the injection system, the costs will continue decreasing in 2015 and 2016. An average share of dehydration unit cost in the produced water disposal unit cost for the observed period equals about 30.9 % which is a consequence of produced water gathering and treatment (dehydration) in three gathering stations, which has been explained in previous chapters.

The unit cost of produced water disposal in the *Shell company* ranges from 0.15 \$/m^3 to 15.00 \$/m^3 (the average exchange rate according to the *Croatian National Bank* was 1 \$ = 7.87 HRK in 2002), depending on the produced water injection volume and location of the field (**Khatib & Verbeek, 2002**). For produced water injection volumes from 3 181 m^3 per day to 31 810 m^3 per day the average produced water injection cost is 0.578 \$/bbl, that is 3.66 \$/m^3. (**Khatib & Verbeek, 2002**) and the distribution of costs regarding the produced water disposal cycle is shown in **Figure 6.**

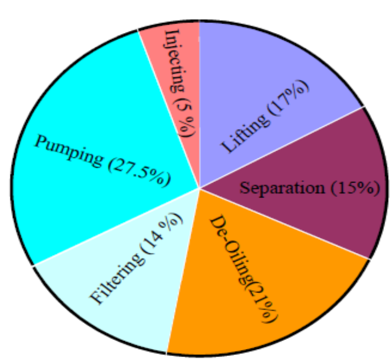

Fig. 6. The distribution of cycle costs of formation water disposal (**Khatib & Verbeek, 2002**)

Figure 6 clearly shows that 50 % of the produced water disposal costs pertain to produced water separation (dehydration). For cost calculation regarding the produced water disposal of the Shell company, capital and operative costs, pumping, injection and chemicals for separation, filtration, dehydration, etc. The average produced water disposal unit costs for the last six years regarding oil and gas field A amount to 8.57 HRK/m^3, and the dehydration makes 30.9 %. This comparison shows that the INA d.d. company, with an example oil and gas field dealt with in this paper, offers lower costs of produced water disposal compared to other large oil companies in the world.

8. Conclusion

This paper presents the technology of produced water separation; it elaborates the basis of economic analysis and offers the methodology of calculation regarding produced water separation and disposal. The unit cost of produced water separation and disposal in the process of oil and gas fields' exploitation is calculated on the basis of the chosen example. Thereby, the basis of the economic analysis of produced water separation and disposal have been elaborated, considering the fact that this is an important component of oil production from oil fields in the mature phase of exploitation.

The costs of extracted water separation and injection in oil and gas fields in the mature phase of exploitation represent an important component of the total expenses, which can in a certain moment, be crucial for the break-even point calculation and the business decisions regarding the continuation of hydrocarbon exploitation. This is the reason why the extracted water disposal unit cost calculation is important for decision making regarding the continuation of the exploitation. The examination, analysis and cost calculation of produced water disposal and separation represents an important component in the economic analysis of hydrocarbon exploitation in the mature phase of oil and gas field work.

On average, on oil and gas field A about 466 000 m^3 of produced water per year is injected into the sand sequences of geological age of the Lower Pont. The calculated unit cost of formation water separation in the dehydration process ranges from 2.09 HRK/m^3 to 3.99 HRK/m^3 (0.31 $/m^3 to 0.60 $/m^3). The formation water injection unit cost foroil and gas field A regarding the observed period ranges from 4.27 HRK/m^3 to 8.38 HRK/m^3 (0.64 $/m^3 to 1.25 $/m^3). The dehydration unit costs' share in the total water disposal unit cost amounts to about 30.9%.

The relatively low cost of produced water injection is a consequence of the produced water injection central system application, and the high cost of produced water separation (dehydration) is caused by the renewal of the dehydration process in three gathering stations. By optimizing the produced water injection equipment (changing the pumps and the electromotor), more efficient and thereby cheaper produced water disposal is ensured, especially in the case of change or the rationalization of injection wells and pumps. By changing particular elements in the technological process, the costs can be greatly affected and thereby the economic parameters improved or detiorated, more precisely; those concerning the technological process. In the case of improvement, it is mostly necessary to make additional investments in order for this improvement to be realized.

The explored field of the formation water disposal economy could be considered as a new exploration method, at least in the Croatian hydrocarbon fields. It was developed due to the relatively restricted literature found regarding renowned magazines dealing with the observed topic. There is no exact methodology found regarding formation water disposal calculation, but calculated cost and expenses are included. The methodology of formation water disposal described in this paper is probably the first to describe the exact methodology regarding the observed topic in the Croatian part of the Pannonian Basis System for sandstone hydrocarbon reservoirs. Moreover, the described methodology is very likely applicable to all sandstone oil and gas fields in such areas, of course with local geological and technological variations, i.e. in a similar technological process of formation water separation and injection.

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Sažetak

Slojna voda se pridobiva tijekom radnog vijeka ležišta ugljikovodika zajedno s naftom i/ili plinom. Troškovi dehidracije i utiskivanja slojne vode predstavljaju kod naftno-plinskih polja u poodmaklom razdoblju eksploatacije značajnu komponentu u ukupnim troškovima polja. S tehnološko-ekonomskog stajališta optimizacijom navedenih troškova može se značajno utjecati na rentabilnost i budući rad polja. U ovom radu obradit će se metodologija izračuna jediničnog troška (trošak po jedinici proizvoda) procesa odvajanja slojne vode (dehidracije) i utiskivanja slojne vode. Metodologija izračuna jediničnog troška zbrinjavanja slojne vode primijenit će se na naftno-plinskom polju koje je u poodmakloj fazi eksploatacije. Za razdoblje od 2009. godine do 2014. godine na odabranom primjeru izračunata je jedinična cijena zbrinjavanja slojne vode. Odabrani primjer je konkretan proizvodni pogon bez navođenja naziva ležišta. Kreiranje posebnog modela za izračun troškova odvajanja i utiskivanja slojne vode predstavlja bitnu komponentu analize ekonomičnosti eksploatacije ugljikovodika u poodmaklom razdoblju rada naftno-plinskih polja.