

Optimum Temperature in the Electrostatic Desalting of Maya Crude Oil

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Abstract. The main variables that impact the crude oil desalting process were analyzed by developing mathematical models that represent the variation of Maya crude oil density, conductivity and viscosity as functions of temperature. An increase in process temperature has two opposite effects. First, a decrease in oil density and viscosity implies a significant increase in the settling rate of water droplets within the oil phase; which allow for a greater amount of oil to be processed. This increases the profit resulting from performing oil desalting. On the other hand, crude oil conductivity increases exponentially with temperature, which implies a higher rate of power consumption. A simulation model was developed to determine the optimum temperature at which a maximum economic benefit occurs. It was concluded that an optimum temperature occurs at 135°C.

Keywords: Maya crude oil, temperature, desalting, viscosity, density, conductivity.

Resumen. Se estudiaron las principales variables que impactan el proceso de desalado de crudo mediante el desarrollo de correlaciones matemáticas que representan la variación de densidad, conductividad y viscosidad del crudo Maya como funciones de la temperatura. La discusión teórica mostró que un incremento en la temperatura de proceso da lugar a dos efectos contrarios. En primera instancia, una disminución en la densidad y viscosidad implica un aumento en la velocidad de sedimentación de las gotas de agua contenidas en la fase orgánica. Lo anterior permite que mayor cantidad de crudo sea procesada en un mismo periodo. Por lo tanto, se incrementan los beneficios económicos derivados de realizar esta operación. Por otro lado, la conductividad del crudo aumenta de manera exponencial con la temperatura, lo cual implica mayor consumo de energía eléctrica. Se desarrolló un modelo de simulación para determinar la temperatura óptima, en la cual se obtiene el máximo beneficio. Se concluyó que la temperatura óptima de desalado es 135°C.

Palabras clave: Crudo Maya, temperatura, desalado, viscosidad, densidad, conductividad.

Introduction

Heavy crude oil is becoming an increasingly more important option in terms of crude oil refining. This is not especially true due to the fact that this type of feedstock is generally cheaper in the international market. There are three different types of crude oil in Mexico. These are Maya (heavy), Istmo (light) and Olmeca (super light). Of these three, the Maya type represents almost 73% [1] of the national total production. In the past, the answer has been to sell most of the heavy oil in the international market and use the lighter oils for refining in Mexico. However, recent trends have forced PEMEX to reconsider the option of refining heavier crude oil. Pilot tests are currently being made to modify refineries to process heavy feed stocks [2]. A process which requires special attention is the electrostatic desalting. This process is performed prior to atmospheric distillation and its main purpose is to reduce significantly the oil's salt content. This is of special importance because a high salt content in oil can be harmful to most equipment. Regarding the desalting process in Mexico, very little has been researched towards ensuring that the process is fit for Maya crude oil processing. In the specific case of process temperature, we found that it is fixed according to an operations manual that was made by engineering companies that were not familiar with the properties of Maya crude oil. Also, it is to be noted that while most properties of this type of oil have been studied, their dependence on temperature has not

or, at least, it has not been widely reported. The main concern of our research was the determination of the dependence of certain crude oil properties on temperature. The knowledge of this dependence, in addition to providing valuable information about Maya oil, can be used to explore the effect of temperature in the desalting process.

Nature of the Water in Oil Emulsion

During desalting, water is mixed with oil so that salts can be diluted in water and washed from the organic phase. Some of the mixed water then forms an emulsion that must be demulsified to separate water from oil [3]. In the case of crude oil, emulsifiers are present in the form of clay, metallic salts and, most important, asphaltenes. In general, the heavier the crude oil, the greater content of emulsifiers [4].

It has been observed that the suspended water droplets possess an electric charge. For this reason, desalting methods aim at destabilizing the electric array in the droplets. The main element in these methods is the arrangement of two electrodes that generate an electric field among the emulsion. The effect is that droplets vibrate, migrate and, ultimately collide with each other and coalesce. Then the larger drops settle under the effect of gravity. It is worth mentioning that the force that makes coalescence possible is voltage. The amount of electric current is not relevant for droplet coalescence [5].

While such electrostatic processes imply high costs, these are surpassed by far by the advantages derived from crude oil desalting as showed in the next discussion.

The need to desalt crude oil

The salts that are most frequently found present in crude oil feedstocks are sodium, calcium and magnesium chlorides (NaCl, CaCl₂ and MgCl₂). If these compounds are not removed from the oil several problems arise in the refining process. The high temperatures that occur downstream in the process could cause water hydrolysis, which in turn allows the formation of hydrochloric acid (HCl) [6]. The presence of such substance implies serious corrosion problems in the equipment. Also, if a certain amount of salt remains it may cause fouling problems in pipes and heat transfer equipment. Metals from salts can also cause catalyst deactivation and sintering which result in lower catalyst activity [7]. Sodium has been found to be the most harmful metal for catalysts. Figure 1 shows the decrease in catalyst activity, as tested according to the micro-activity test (MAT), due to the presence of sodium within the catalyst active sites. This decrease in activity implies that used catalyst must be replaced more often to maintain a given activity level.

In addition to removing salts, the electrostatic desalting process removes water that is already present in crude oil as well as suspended solids. In the case of water removal, this allows a decrease in pumping costs. Also, if a considerable amount of water enters the preheat train it could vaporize and cause disturbances and vibrations due to high pressure. Such disturbances could be as mild as pipe vibration and noise or as serious so as to cause shut down [7]. Regarding suspended solids, their removal is important because such substances can

go all the way through the refining processes to be expelled with the flue gas. This may cause that flue gas opacity does not comply with environmental requirements. In that event, the flue gas should receive additional treatment prior to being expelled.

Following is a brief explanation of the theoretical principles and actual procedures that take place in the electrostatic desalting process.

The desalting process

Desalting can be performed in a single stage or in two stages, depending on the requirements of the refinery. Dehydration efficiency of a desalter is usually 95% in a single stage and up to 99% in two stages [5]. If mixing is good, dehydration efficiency can be compared with desalting efficiency as most of the salt passed from the organic phase into the water phase. In actual operation, water and oil are preheated and mixed in a 1:20 ratio. It is common that a demulsifier substance is also added, usually 0.005 to 0.01 lb/barrel [6]. Mixture takes place in a mixing device, which is commonly a valve with a 5 to 20 psi pressure drop. It has been observed that good mixing allows for appropriate salt removal from oil. During mixing, salt content in oil is washed with the water and a W/O emulsion is formed.

The emulsion then enters the desalter where it is subject to the action of an intense electric field. Voltage within the desalter is 16,000 to 30,000 volts AC [6]. Such a high voltage provides the coalescing force, whereas electric current has no participation on this effect. Crude oils that are highly conductive require more power to achieve coalescence. The reason of this is that in order to reach the necessary voltage gradient a higher electric current is needed and, therefore, a higher power consumption will be required. Once larger drops have been formed, they settle according to Stokes law [5]:

$$V_s = \frac{2g r^2 (d_w - d_o)}{9\mu_o} \tag{1}$$

where V_s = settling rate, m s⁻¹
 g = gravity, m s⁻²
 r = radius of droplet, m
 d_w = density of water, kg m⁻³
 d_o = density of oil, kg m⁻³
 μ_o = dynamic viscosity of oil, kg m⁻¹ s⁻¹.

Operating temperatures between 95 and 150°C are usually used to increase settling rate because the variables involved in defining it are highly dependant on temperature. This means that setting temperature to an appropriate value is vital to ensure correct operation of a desalting unit. In the case of heavy crude oils, setting temperature is especially important as high viscosity reduces considerably the settling rate.

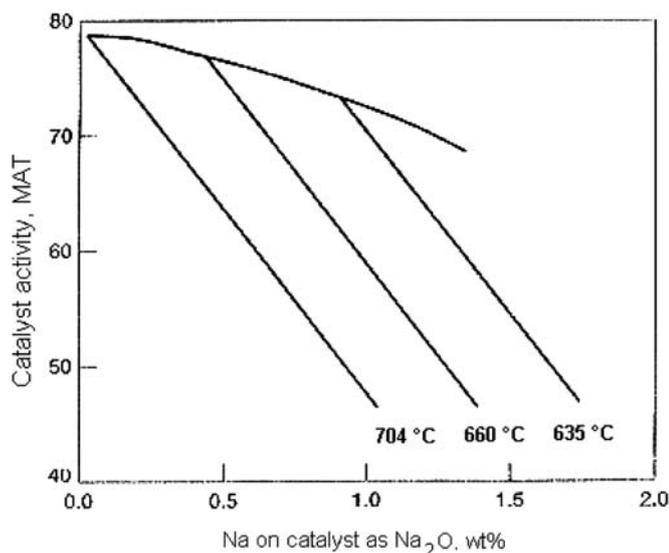


Fig. 1. Catalysts activity loss from sodium contamination.

Analysis of the Effect of Temperature on the Desalting Process

As shown above, settling rate depends highly on temperature. Liquid density and viscosity usually decrease with temperature. The effect is even greater regarding viscosity as the dependence is exponential. This means that increasing operation temperature will raise settling rate and therefore, improve separation. In a given desalter, separation improvement means that a larger quantity of oil can be desalted in the same time.

This would suggest that a higher temperature is more convenient. However, crude oil conductivity increases with temperature and so does the power requirement of the process. Additionally, higher temperatures imply an increase of heating costs.

Given these opposing facts, it is expected that there is an optimum temperature. In the case of Maya feedstock it was necessary to know the dependence of density, viscosity and conductivity on temperature in order to determine if an optimum temperature exists.

Property Testing and Results

a) Density of Maya crude oil as function of temperature

It was determined in accordance to ASTM-D-1298 [8]. The results are shown in Figure 2. The correlation that best fits this data behavior is the following:

$$d_0 = -0.7902 T + 1204.6 \quad (2)$$

where T is temperature, K.

b) Viscosity of Maya crude oil as function of temperature

The standard ASTM-D-445 [9] was used for this purpose. The test was performed at several crude oil temperatures with the above results (Figure 3). The appropriate correlation was:

$$\nu = 6.8659 \times 10^{11} e^{(-0.074521067T)} \quad (3)$$

where ν is cinematic viscosity, cSt (centistokes).

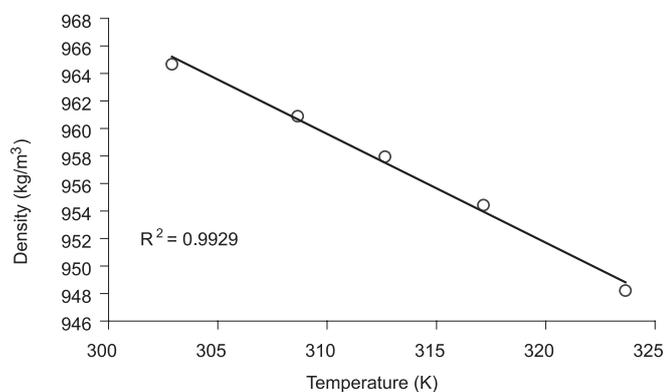


Fig. 2. Maya crude oil density vs. Temperature.

c) Conductivity of Maya crude oil as function of temperature

This property was determined according to the procedures in ASTM-D-3230 [10]. The correlation that best fits the experimental data is the following:

$$\kappa = 0.020205 e^{(0.02695337T)} \quad (4)$$

where κ is conductivity, $\mu\text{S m}^{-1}$. For comparison purposes, conductivity was also determined for a lighter crude oil (Istmo type). The results of Maya and Istmo crude oil conductivity as a function of temperature are shown in Figure 4.

Results from these tests show that the properties of Maya are highly dependant on temperature. Also, Figure 4 shows that the conductivity of Maya is significantly different from Istmo conductivity. If it is considered that Maya and Istmo are classified in different categories due to their density and viscosity, it can be concluded that each crude oil must be studied independently. These equations were used to estimate input data for the simulation model that determines optimum temperature.

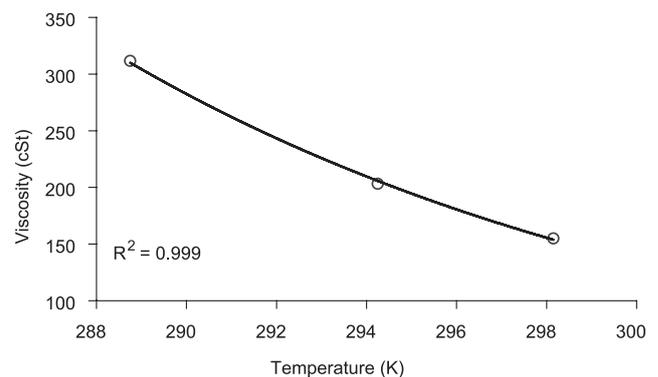


Fig. 3. Maya crude oil viscosity vs. Temperature.

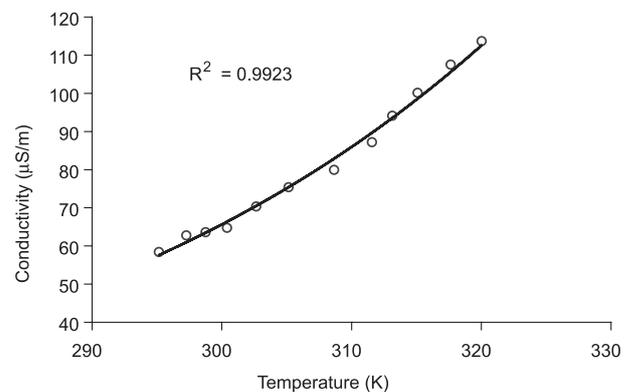


Fig. 4. Maya and Istmo crude oil conductivity vs. Temperature.

Simulation model of a desalter operation at the Ing. Antonio M. Amor Refinery located in Salamanca, Mexico

The model designed to study the effect of temperature on process economics was developed considering a change in current desalting operating temperature, which corresponds to 378.15 K or 105 °C. In order to achieve calculation of changes in process economics, the model should include a way of estimating oil inflow from temperature. The equations presented above allow for calculation of the water droplets' settling rate from temperature. It is assumed [11] that at a given or fixed operating voltage the droplets' population and average size is also fixed. Hence, the amount of water separated from oil is distributed in an equal number of equally-sized drops, at any given temperature. An increase in temperature will only cause the drops to move faster across the water-oil interface, increasing the desalter's water outflow. From equations 2 and 3, equation 1 can be transformed into a temperature-dependant equation. Hence, it is possible to know the drop's settling rate by fixing temperature.

For calculation purposes, the drop's residence time within the desalter is defined as the time it takes for a drop to "fall" a given distance from the oil phase into the water phase. This is shown in equation 5:

$$\theta_d = \frac{h}{V_s} \quad (5)$$

where θ_d = drop's residence time, s
 h = distance covered by the drop, m.

Also, drop flow was defined as the volume of water contained in a drop, which flows within the desalter while falling into the water phase. Mathematically, drop flow is defined as follows:

$$F_d = \frac{V_d}{\dot{\theta}_d} \quad (6)$$

where F_d = drop flow, $\text{m}^3 \text{s}^{-1}$
 V_d = volume of water drop, m^3 .

Because drop flow is the amount of water moved through the desalter by a single drop, the total water flow through the desalter can be calculated by knowing the number of drops. In order to do this, drop flow is estimated for the current operating temperature, at which the total water flow out of the desalter is known. As mentioned before, water size and number are considered to be constant at any give temperature, so the following relation can be assumed:

$$\frac{F_{W(out)}}{F_d} = \frac{F_{W(out)}^*}{F_d^*} \quad (7)$$

where $F_{W(out)}$ = water outflow, $\text{m}^3 \text{year}^{-1}$
 F_d^* = drop flow at current operating temperature, $\text{m}^3 \text{s}^{-1}$
 $F_{W(out)}^*$ = water outflow at current operating temperature, $\text{m}^3 \text{year}^{-1}$.

Finally, equations 5 and 6 can be substituted in equation 7 to obtain the following linear relation between settling rate and water outflow:

$$F_{W(out)} = \frac{V_s}{V_s^*} F_{W(out)}^* \quad (8)$$

It is to be noted that knowledge regarding the size and number of drops, as well as the distance covered by them while settling is not required to estimate water outflow at a given temperature.

The water outflow can then be readily related to oil inflow by considering the desalter's dehydration efficiency and the water/oil feed ratio, as shown by equations 9 and 10:

$$F_{W(in)} = \frac{F_{W(out)}}{\zeta} \quad (9)$$

where $F_{W(in)}$ = water inflow, $\text{m}^3 \text{year}^{-1}$
 η = dehydration efficiency.

$$F_{O(in)} = \frac{F_{W(in)}}{R_{WO}} \quad (10)$$

where $F_{O(in)}$ = oil inflow, $\text{m}^3 \text{year}^{-1}$
 R_{WO} = water/oil feed ratio.

Once the oil inflow has been established for a certain temperature, the changes in costs and benefits can be computed. The main elements considered in the model were the following:

a) Benefit due to flow increase (BFI)

As discussed, if temperature raises the settling rate of water will increase. Thus, a larger amount of crude oil can be treated and produce an extra quantity of derived products that have a higher market value. BFI was estimated as follows:

$$BFI = (F_{O(in)} - F_{O(in)}^*) \left(\sum_{i=1}^n x_i P_i - P_{IM} \right) \quad (11)$$

where BFI = Benefit due to flow increase, USD year^{-1}
 $F_{O(in)}^*$ = Oil reference inflow, $\text{m}^3 \text{year}^{-1}$
 x_i = Proportion of oil that corresponds to product i
 P_i = Market price of product i , USD m^{-3}
 P_{IM} = Price of crude oil in international market, USD m^{-3}
 n = number of distillation fractions considered in the evaluation.

The information used to compute BFI is presented in Table 1 [1, 12, 13].

Table 1.

Product	Volume Fraction (x_i)	Price in USD/m ³ (P_i)*
Gasoline	0.156	485.45
Kerosene	0.020	236.28
Gasoil	0.161	154.54
Lubricants	0.130	1136.36
Residue	0.505	64.82
Distillation loss	0.028	0.00

*As of December of 2003

Also, a international market price (P_M) of 142.15 USD m⁻³ for Maya crude oil was used.

b) Costs derived from increased power requirements (CP)

An increase in crude oil conductivity implies that more electric current is used, maintaining voltage constant. This means that, while coalescence does not increase, the power consumption does. CP was estimated as follows:

$$CP = (P - P^*)tC_{kwh} \quad (12)$$

where

- CP = Power costs, USD year⁻¹
- P = Power at operating temperature, kW
- P* = Power at reference operating temperature, kW
- t = Desalter operating time, hours year⁻¹
- C_{kwh} = Cost of power, USD kWh⁻¹.

c) Pumping costs (CB)

A larger flow requires additional pumping, both for oil as for water. This cost is estimated according to the following expression:

$$CB = \left[(F_{O(in)} - F_{O(in)}^*) + (F_{W(in)} - F_{W(in)}^*) \right] C_P \quad (13)$$

where

- CB = Pumping costs, USD year⁻¹
- F_{W(in)}* = Water reference inflow, m³ year⁻¹
- C_P = Unitary pumping cost, USD m⁻³.

d) Preheating costs (CC)

Increasing temperature generates extra cost due to preheating either oil or water. These costs are calculated as follows:

$$CC = QC_j \quad (14)$$

where

- CC = Preheating costs, USD year⁻¹

Q = Quantity of heat required, J year⁻¹

C_j = Unitary cost of heating energy, USD J⁻¹.

The functions described above can be combined into a single Profit function, which was used to determine optimum temperature. This function is:

$$P = BFI - (CP + CB + CC) \quad (15)$$

Simulation results and conclusions

The results obtained from simulation using data from both the obtained mathematical models to estimate crude properties and operational data from the Ing. Antonio M. Amor Refinery are shown in Figures 5, 6, and 7.

These figures show that an increase in operation temperature generates two possible scenarios. In the first one, the earnings surpass operation costs and profit is obtained. In the second scenario, costs are higher than earnings, which means losses. Within the first scenario, difference between both curves changes with temperature. The maximum difference is observed at 408.15 K or 135°C, which is the optimum temperature.

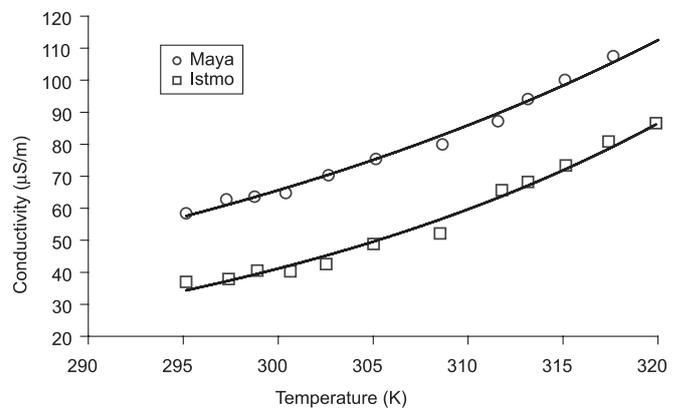


Fig. 5. Costs and benefit trends.

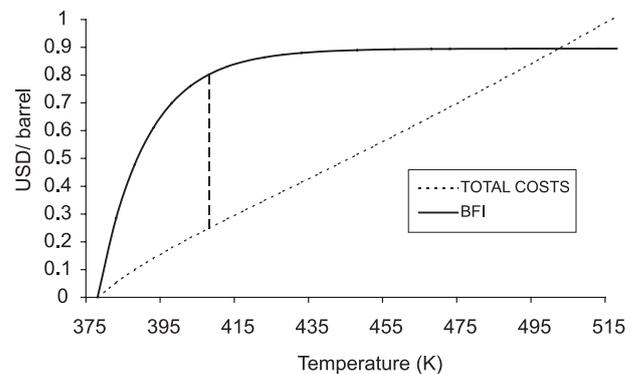


Fig. 6. Profit trend vs. Temperature.

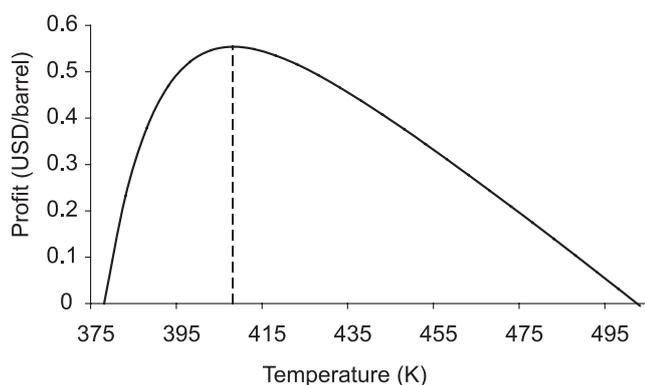


Fig. 7.

If it is considered that current operation temperature is 378 K or 105°C it is evident that a change would be advisable. Such a change can be achieved in several different ways. However, in order to minimize additional heating costs, it is our recommendation that oil be preheated up to more than 135°C so that temperature decreases to 135°C when mixing with water occurs. This is convenient as oil is heated to around 280°C after desalting. If this was done prior to desalting, a profit could be easily obtained without extra investment in equipment.

This kind of analysis is suitable for all crude types. However, aiming it at Maya crude oil allowed a considerable improvement in the knowledge that currently exists on this kind of oil. This will allow future enhancements to be performed to Maya crude oil processing.

Acknowledgement

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