CHAPTER NINE

Refinery Water Systems

Water is used in an oil refinery for the following purposes:

- Cooling.
- Steam generation.
- Domestic and sanitation purposes.
- Washing products.
- Flushing equipment, pipelines, and hydrotests.
- Fire fighting.

Water usage in the refinery also generates large volumes of water contaminated with oil and other chemical impurities. Part of this water can be reused after treatment, while the remainder must be discharged to sea or other water bodies. But, before this can be done, the aqueous effluent must be treated to remove oil, chemical, biological, and other impurities, so that the impact on the environment is minimal. The principle wastewater streams that require treatment are oily water effluents, biological waste generated by the refinery workforce, and sour water streams containing dissolved H_2S and NH_3.

COOLING WATER SYSTEM

Refining operations are conducted at elevated temperatures. In a rough overall sense, a refinery must be in heat balance. All heat added in the forms of fuel burned, steam consumed, or coke burned must be removed by one of the various cooling systems. Water cooling is one such system. The others are air cooling and heat exchange with other streams. Cooling accounts for about 90% of the total refinery water requirements. Approximate cooling water requirements of a refinery can be estimated as a function of refinery complexity.[1]

Water in a refinery's cooling system either travels through the system once or is recirculated. In a once-through system, pumps suction water from a source, such as a sea, river, or lake, and deliver it to process units or other water users within the refinery. After passing through the cooling equipment, the hot cooling water is conducted to a point of disposal through a pressure system of piping or through a gravity flow system.

In recirculated systems, pumps suction water from a cooling tower basin and deliver it to cooling equipment. After passing through water user equipment, the hot cooling water is discharged through a pressure return system to the top of the cooling tower. The water cooling system includes heat exchangers, pumping equipment, distribution piping, water intake stations, and cooling towers.

In some refineries in coastal areas, warm water (at approximately 113°F) returning from the process heat exchangers and other equipment is first cooled by heat exchange with sea water in sea water exchangers then sent back to the cooling tower for further cooling (Figure 9-1). The advantage of this system is that the heat load on the cooling tower is reduced and corrosive sea water do not come in contact with process equipment. Good, soft water, containing very little dissolved solids, salts, and iron, allows the use of carbon steel for coolers and condensers. Sea water, on the other hand, contains large amounts of dissolved salts (Table 9-1), is a good conductor of electric current, and causes severe corrosion of metals. For example, carbon steel registers a corrosion penetration rate of more than 2 mm/yr in sea water. Nonferrous materials, such as aluminum, brass, and titanium, have to be used, in the case of direct sea water cooling.

SEA WATER COOLING SYSTEM

A typical direct sea water cooling system is shown in Figure 9-2. Because of the large volume of water intake for cooling, water is pumped from the sea to an inlet sump through a battery of low lift pumps. Sea water next flows through a system of bar screens, scrapper screens, and rotary screens to the suction of the high lift pump manifold. The screen system prevents entry of marine life, seaweed, algae, and the like into pump suction. To prevent growth of algae and fungi and suppress microbial activity, chlorine is injected (0.5–1.0 ppm) into sea water before it enters the suction of the high lift pump battery. As sea water is very corrosive, reinforced concrete pipes are used for all piping greater than 30 in. diameter.

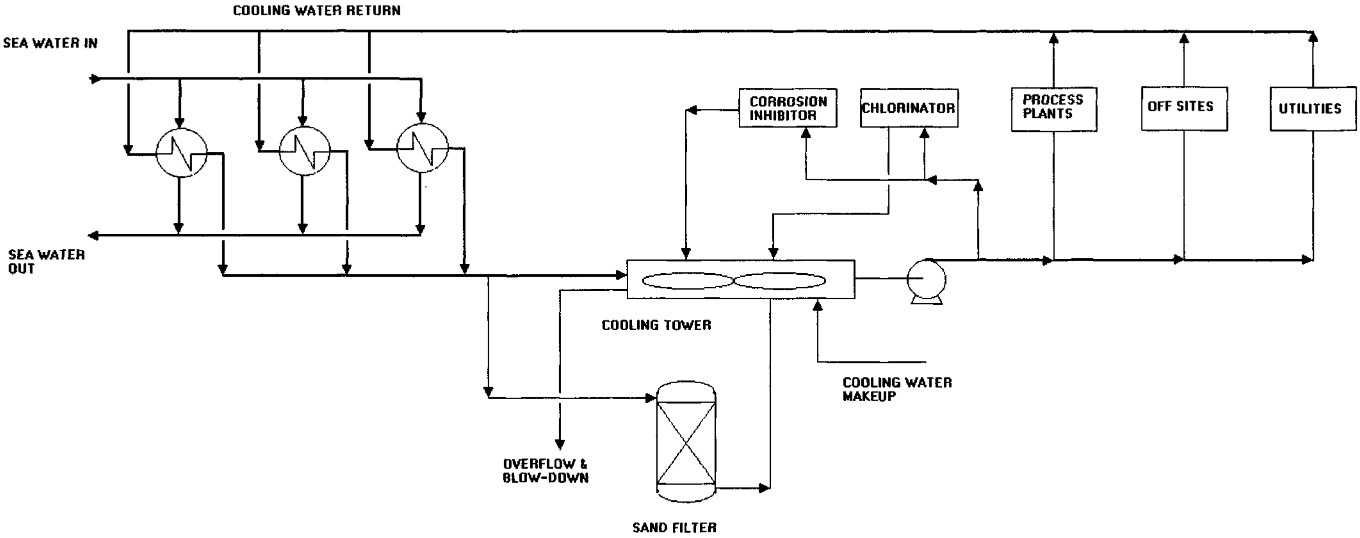

Figure 9-1. Refinery cooling water system.

Table 9-1
Typical Sea Water Analysis

PARAMETER	UNITS	
TOTAL DISSOLVED SOLIDS	ppm	49,700–51,200
NACl	ppm	39,000–41,000
TOTAL HARDNESS		8,200
ALKALINITY	AS $CACO_3$	114
DENSITY	kg/m^3	1,030
TEMPERATURE	°F	90
VISCOSITY	CP	0.76

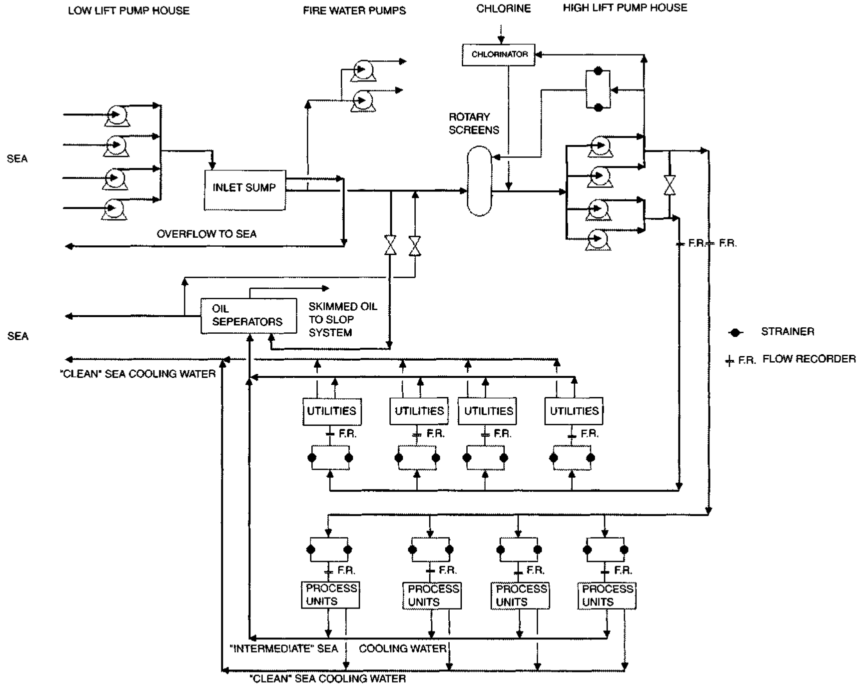

Figure 9-2. Direct sea water cooling system.

Below 28 in. diameter, cement lined steel pipes are used for sea water service. The battery of high lift pumps supplies sea water to a sea water manifold running throughout the refinery, from which individual process units and utilities tap their cooling water supply. To prevent any grit, debris, or scale from entering the exchangers, strainers are placed at the entry of every process or utility unit. Warm sea water coming out of an exchanger is segregated into two manifolds: a "clean" sea cooling water and an "intermediate" sea cooling water.

Intermediate, or oil-contaminated, sea water, by definition, is that sea water used in service where the oil side of exchanger is operating at 55 psig or greater. All contaminated sea water may be routed through the intermediate sea cooling water manifold to a battery of corrugated plate interceptor separators before discharging it to sea. If the oil side of the exchanger is operating at less than 55 psig, all such returning sea water is routed to the clean sea cooling water manifold and discharged directly to the sea.

COOLING TOWERS

The cooling towers function by direct removal of heat from water by air flow and vaporizing a portion of water. Both forms of cooling are accomplished by a counterflow of air and water. The towers are constructed of wood, metal, or concrete with wood or plastic packing for distribution of the water flow. A portion of water passing over the cooling tower is vaporized. Any solid this water contains is left behind and increases the concentration of solids in water. To limit the concentration of solids and prevent their deposit on cooling surfaces, it is necessary to blow down a certain percentage of circulating water. Further water loss occurs when water drifts off the tower in the wind, called *drift* or *windage loss.*

The initial step in the design of cooling water systems is to determine the design temperature and system capacity. The system capacity varies with design temperature as limited by process conditions. The usual cooling range is between 25 and 30°F. The inlet temperature of water to cooling equipment is established by ambient conditions, generally in the range 75–86°F, and the outlet temperature is in the range 104–114°F. The type and quality of water set the outlet water temperature. The maximum temperature of water in the heat exchangers must be limited to prevent corrosion and deposit of solids.

Cooling tower losses are usually evaluated as follows:

1. Evaporation losses are approximately 1% of tower throughput for each 10°F of cooling tower temperature differential.
2. Drift loss is limited in the design of the cooling tower to 0.2% cooling water throughput.

3. Miscellaneous liquid loss is assumed to equal 15% of evaporation losses minus the drift losses.
4. Blow-down is determined on assumption that makeup water can be concentrated five to six times in the cooling tower. Blow-down losses can be estimated approximately by the following empirical relationship:

$$B = \frac{10.7 \times \Delta T \times R}{100{,}000}$$

where

B = blow-down rate, gpm;
ΔT = temperature differential, °F;
R = circulation rate, gpm.

BOILER FEEDWATER SYSTEM

Municipal water feed to the refinery must be upgraded to boiler feedwater quality by further treatment (see Figure 9-3). Boiler feedwater is used as makeup to fired and nonfired steam generators located in the utility plants and process units. Boiler feedwater is also used for process purposes.

Fresh water, as received from an outside supply, may not have enough pressure to fill tank TK-101. Booster pump P-101 is used to elevate the water supply pressure. Feedwater is stored in tank TK-101, holding approximately 72-hr supply. Water is pumped by P-102 to water filter V-101, which removes most entrained solids. Filter aids are added at the discharge of P-102, using a dozing pump to facilitate removal of suspended solids. Filtered water next passes through a bed of cation and anion resins in V-102 and V-103, which remove all anions and cations in the water by an ion exchange process. A high-purity water, which is essentially free of salts, is produced and stored in tank TK-102. Demineralizer beds are exhausted after 3–7 days operation, and they are regenerated by treatment with dilute sulfuric acid (cation resins) and caustic soda (anion resins). Each demineralizer bed is equipped with automatic regeneration facility. The typical feedwater and BFW water qualities are shown in Table 9-2. The demineralized water is supplied to all low-pressure deaerators as makeup to LP boiler water system.

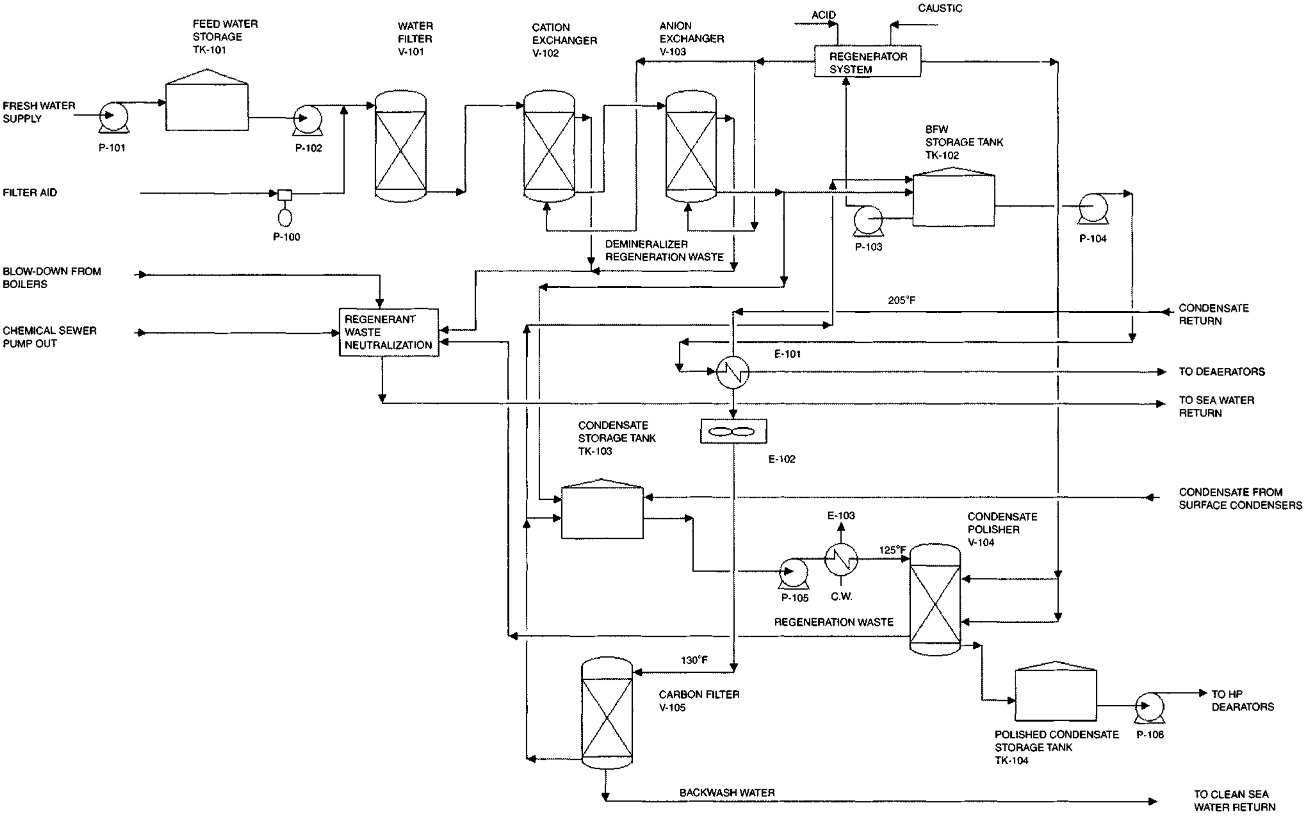

Figure 9-3. Treatment for boiler feedwater (BFW). HP = high pressure.

Table 9-2
Properties of Various Water Streams

	UNITS	FRESH WATER[1]	DISTILLED WATER[2]	LP BOILER FEEDWATER[3]	CONDENSATE RETURN[4]	POLISHED CONDENSATE[5]
CONSTITUENTS	AS					
CALCIUM	CaCo$_3$	57	10			
MAGNESIUM	CaCo$_3$	40				
SODIUM	CaCo$_3$	77	40			
POTASSIUM	CaCo$_3$	2				
AMMONIA	CaCo$_3$	0.2	0.04			
TOTAL ANIONS						
BICARBONATES	CaCo$_3$	9	5			
SULFATE	CaCo$_3$	81	10			
CHLORIDE	CaCo$_3$	87	35			
FLUORIDE	CaCo$_3$	0.4				
ALKALINITY	CaCo$_3$	9	5		10	<1
TOTAL HARDNESS	CaCo$_3$	97	10	<0.3	1	<0.02
pH		7.2	6.3–6.7			
SILICA	SiO$_2$	1.4	0.05		1	
IRON	Fe	0.3	<1			
COPPER	Cu		<1			<0.015
TURBIDITY	jtu	3	4	<1	5	<1
TDS		238	60	<30	10	<0.5
SPECIFIC CONDUCTANCE	umho/cm	400	100		20	<1

NOTES:

[1] WATER RECEIVED FROM MUNICIPAL SUPPLY.

[2] WATER FROM A DESALINATION PLANT.

[3] DEMINERALIZED WATER FEED TO LOW-PRESSURE BOILERS.

[4] UNCONTAMINATED CONDENSATE RETURNED FROM THE PROCESSING UNITS.

[5] POLISHED CONDENSATE FEED TO HP BOILERS.

LP = LOW PRESSURE; TDS = TOTAL DISSOLVED SOLIDS; JTU = JACKSON TURBRIDITY UNITS; ALL DISSOLVED SALT CONCENTRATIONS IN PPMW.

CONDENSATE POLISHER

Condensate is returned to the water treatment system from two sources:

1. Steam condensate condensed in surface condensers is considered clean and returned directly to condensate storage tank TK-103. Conductivity monitoring is provided on the surface condenser condensate header. This measurement detects any saltwater leakage into the condensate that may occur due to condenser failure. To save as much water as possible, two set points are provided on the conductivity controller. If the conductivity exceeds 100 micro-mho, the surface condenser condensate is diverted to a utility water storage tank. If a severe leak occurs and the condensate conductivity exceeds 500 micro-mho, the condensate is considered too contaminated to save and is diverted to a sewer.
2. Condensate is also collected from refinery's process equipment and returned to the water treatment system. This condensate is considered potentially contaminated with oil. The condensate passes through an activate carbon filter V-105 before entering condensate storage tank TK-103. The carbon filters are typically designed to process feed with 20 ppm oil and reduce it to less than 0.3 ppm oil in the filtered condensate. The condensate is next passed through condensate polisher V-103, which removes any dissolved salts contamination picked up.

The process condensate is returned to the water treatment unit at approximately 205°F. Since the ion exchange resin in condensate polisher V-104 is extremely temperature sensitive, this stream is cooled to 130°F. BFW heat exchangers E-101 and E-102 by exchanging heat with LP boiler feedwater.

During the operation of the steam system, the demand for HP boiler feedwater exceeds the returned condensate from all sources. To make up for this shortfall, demineralized water from BFW storage tank TK-102 is used. The design flow rate for this service is dictated by the loss of condensate.

Polished condensate is supplied as makeup to all high-pressure deaeators as HP boiler feedwater. In addition, the process condensate and surface condenser condensate are returned from the steam system as feed to condensate polisher system.

NEUTRALIZATION

The neutralization system is designed to collect the acid and caustic regeneration waste prior to discharge to the sea or another outlet. Facilities are provided to add acid and caustic to produce a neutral wastewater stream. The neutralization basin has two separate chambers, each designed to hold regeneration waste from three regenerations of cation exchangers, three regenerations of anion exchangers, and one regeneration of condensate polisher. Also used in neutralization are a 98% sulfuric acid and 50% caustic solution for ion exchange regeneration.

UTILITY WATER SYSTEM

As shown in Figure 9-4, the utility water distribution system comprises the following subsystems: potable water and irrigation water makeup, utility water distribution stations, makeup water for cooling towers, and fire water makeup.

POTABLE WATER

Both potable and irrigation water are supplied through the utility water distribution system in the refinery. The refinery may draw its potable water supply from a municipal water supply or a desalination plant in coastal refineries. For supply to refinery drinking water and safety showers, further treatment is required. The treatment consists of passing through a bed of activated carbon in the form of extrudates and supported on a bed of graded quartz. Filtered water is next cooled to 85°F in a water cooler and chlorinated. The treated water must have a residual chlorine content of no less than 0.5 mg/liter.

In case the refinery potable water supply comes from a desalination plant, the total dissolved solids (TDS) may be very low, on the order of 2 mg/liter. The water must be chemically conditioned to make it potable and increase the TDS to potable water requirements (80 mg/liter minimum). Chemical conditioning consists of dosing measured amounts of calcium chloride, sodium bicarbonate, and sodium carbonate into the feedwater stream. Typical dosage of chemicals are these:

Calcium chloride: 28 mg/liter
Sodium bicarbonate: 62 mg/liter
Sodium carbonte: 12 mg/liter

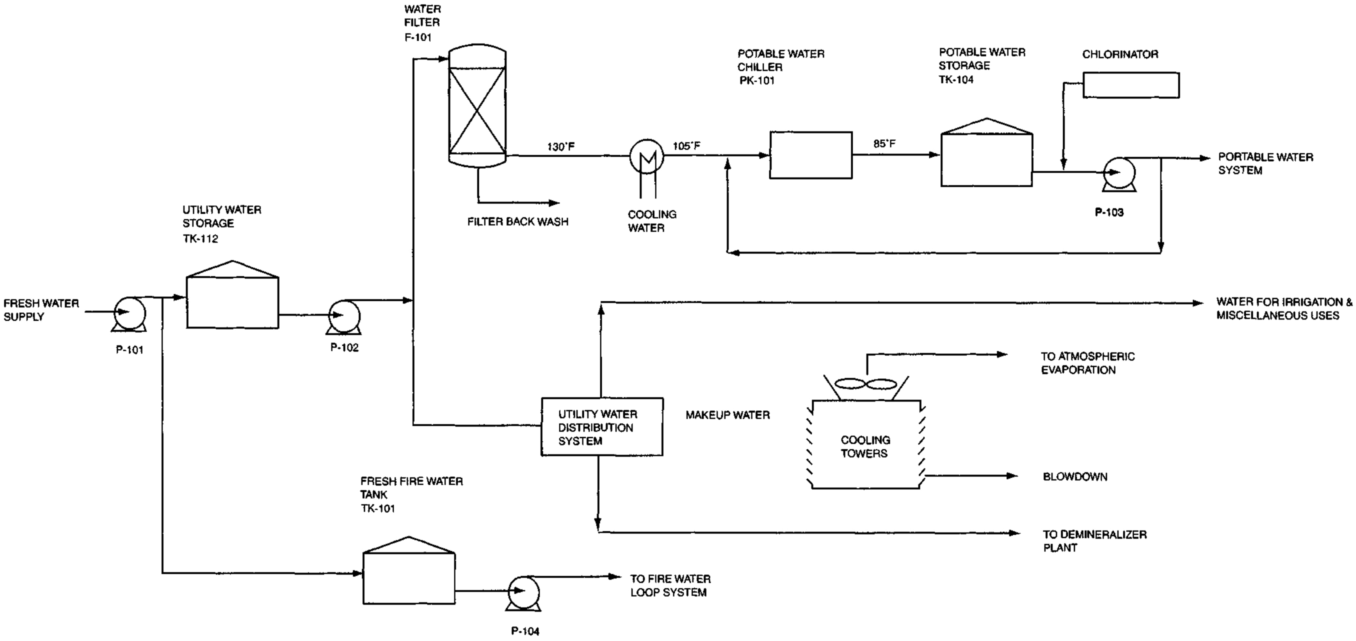

Figure 9-4. Refinery utility water system.

Table 9-3
Potable Water Quality Requirements

PARAMETER	UNITS	
TOTAL DISSOLVED SOLIDS	mg/liter, minimum	80
ALKALINITY	mg/liter as $CaCO_3$	60–80
pH		APPROXIMATELY 8.7
CHLORINE, RESIDUAL	mg/liter, minimum	0.5

If a refinery has an assured supply of carbon dioxide, an alternative conditioning treatment is possible. In this case, carbon dioxide is directly injected into feedwater, and this water is passed through a bed of limestone, where calcium bicarbonate is formed. Excess CO_2 is necessary for the correct hardness level. The remaining CO_2 is neutralized with a nonlimestone-based alkali (caustic soda) to avoid forming turbidity. Typical potable water quality requirements are shown in Table 9-3. The average potable and irrigation water demand is estimated at 35–75 gal/day per person working in the refinery, the higher figures being for hotter climates.

The instantaneous demand for potable water is based on two criteria. The first is the computed peak demand resulting from the number of potable water fixtures in the refinery. The second consideration is the simultaneous use of safety showers. An average safety shower requires water flow of approximately 65 gal/minute. The designed irrigation water usage is generally based on approximately 3 in. water per week applied to the irrigated area of the refinery.

FIRE WATER SYSTEM

Many hydrocarbon processing plants are located along waterways, so that availability of fire water is essentially guaranteed. Similarly, coastal refineries may use sea water as backup fire water in an emergency. If, however, fire water is obtained from municipal sources, storage of the water would be required, for it is unlikely that a municipal water supply system would permit the volumes of draw-down required to fight a fire. The wide variety and varying intensity of fires possible in hydrocarbon processing facilities make precise calculation of fire water requirements difficult. Instead, fire water usage in case of actual fires from historical data of the industries is relied on.

The size of the storage tank should be sufficient to provide a 4–6 hr supply at the estimated maximum fire water rate. A good general figure for estimating fire water is 2500–3000 gpm (gallons per minute) in case of an actual fire. Another important consideration is system pressure. The knowledge of the system capacity as well as the suggested layout of the hydrants, monitors, and water spray systems are the basic input required to determine the size and configuration of the distribution system. The other major input is the residual pressure requirements. The minimum pressure desirable at the extremity of the system is 70 psig, with 100 psig required anywhere in the process area. The maximum pressure that can be tolerated on a handheld hose is 100 psig nozzle pressure and that is a consideration in setting maximum system pressure.

REFINERY WASTEWATER TREATMENT

During the processing of oil in the refinery, large volumes of water flow through the processing units in the form of cooling water, process water, steam, equipment washings, unit hydrotests, and the like; and these streams pick up small quantities of hydrocarbons or oil from equipment and spillage. Oil-contaminated storm water flows from the curbed areas of the refinery add to this load. The objective of the treatment is to separate oil from the wastewater before this water is allowed to be discharged into the sea or any other water body, with minimum negative environmental impact. Typical tolerance limits for refinery effluent discharged into marine coastal areas is shown in Tables 9-4 and 9-5.

Water streams that need treatment is shown in Figure 9-5. Contaminated drainage and storm flows from process areas are routed to retention basins. Storm water is retained for the removal of floating oil, then discharged to the sea with no further treatment. Incidental contaminated drainage is retained for removal of floating oil and pumped to the API oil/water separator system for additional treatment.

Retention basins are designed to collect all water transported to the contaminated sewer network. This includes contaminated storm and fire water flows as well as continuous nuisance flows from daily maintenance operations throughout the refinery. The normal operation of the basins is to provide preliminary oil removal from nuisance flows, using the belt oil skimmers, and act as a sump preparatory to pumping of these flows to API separators.

Table 9-4
Liquid Effluent Discharge to Sea*

PARAMETER	UNIT	REFINERY AVERAGE
TEMPERATURE	°C	45
pH	S.U	5.5–9.0
CHEMICAL OXYGEN DEMAND	mg/l	200
BIOLOGICAL OXYGEN DEMAND	mg/l	30
TOTAL SUSPENDED SOLIDS (TSS)	mg/l	45
OIL/GREASE	mg/l	10
PHENOLS	mg/l	1
SULFIDES	mg/l	0.5
NITROGEN AS AMMONIA	mg/l	10
PHOSPHATES – INORGANIC	mg/l	0.5
CYNIDES	mg/l	1
IRON	mg/l	2
FREE CHLORINE	mg/l	0.6
CHROMIUM AS CrO_4	mg/l	0.3
ZINC	mg/l	0.001–0.05

*TYPICAL REFINERY STANDARDS.

Table 9-5
U.S. Refineries (EPA) Standards*

PARAMETER	UNITS	AVERAGE	MAXIMUM
TEMPERATURE	°C	35	37
pH			6–9
CHEMICAL OXYGEN DEMAND	KG/DAY	2371	4571
BIOLOGICAL OXYGEN DEMAND	KG/DAY	338	610
TOTAL SUSPENDED SOLIDS (TSS)	KG/DAY	270	427
OIL/GREASE	KG/DAY	99	185
PHENOLS	KG/DAY	2.1	4.4
SULFIDES	KG/DAY	1.8	3.8
NITROGEN AS AMMONIA	KG/DAY	136	273
PHOSPHATES – INORGANIC			
CYNIDES			
IRON			
FREE CHLORINE			
CHROMIUM AS CrO_4	KG/DAY	3.3	9.5
ZINC	KG/DAY	1.7	3.8

*FOR A 180,000 BPD REFINERY ON THE U.S. GULF COAST.

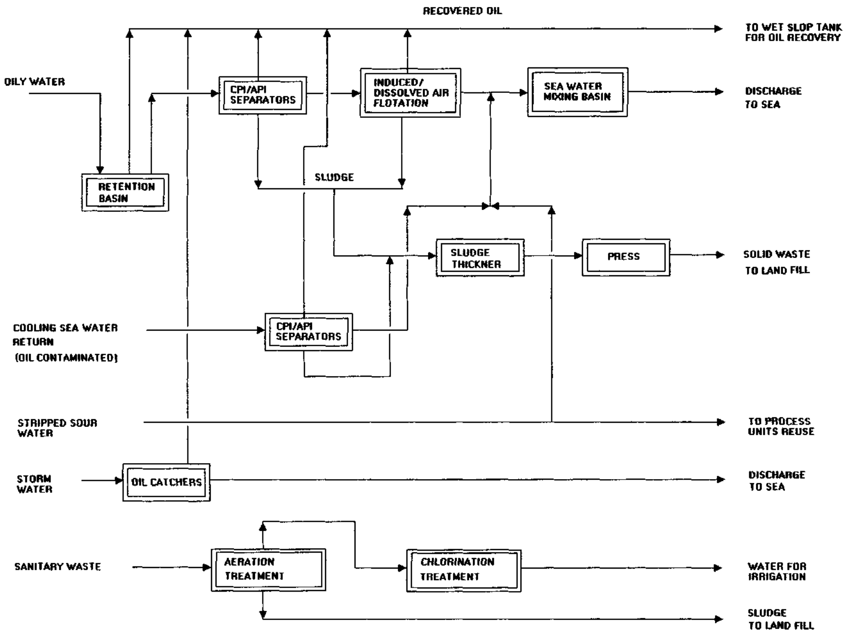

Figure 9-5. Refinery aqueous effluent treatment system. CPI = corrugated plate interceptor.

Flows in excess of nuisance flows, such as contaminated rainwater and fire control runoff, is also collected in the retention basins. This flow is retained for sufficient time for preliminary oil removal using belt and rope skimmers. After this partial deoiling, the water is discharged to the sea.

In coastal refineries, the saline wastewater consists of potentially oil-contaminated once-through sea cooling water, boiler blow-down, and cooling tower blow-down. Oil-contaminated sea water is typically sea water used where the oil side of the exchanger is operating at 55 psig or greater. Potentially oil-contaminated sea water is passed through a battery of API separators. The effluent is combined with uncontaminated once-through sea cooling water in a sea water mixing basin prior to discharge to sea.

Oily wastewater generated in the refinery is segregated into two streams: one low (160–250 ppm) and one high in oil content (>250 ppm). The low-oil stream is made up primarily of stripped sour water and desalter underflow. This stream requires no further treatment and is routed directly to mixing basin, where it is combined with sea cooling water prior to discharge to sea.

The high-oil stream originates from the oily water sewer, oily water pumped out of retention basins, and desalter underflows. The oil in the desalter underflows is in two forms: emulsified and free oil. All potentially high-oil-content streams are treated for the removal of oil using a corrugated plate interceptor type API oil/water separators followed by dissolved air flotation (DAF) oil/water separators. Effluent from DAF units is combined with nonoily wastewater streams and returning cooling water in the sea water mixing basin and discharged to the sea.

The sanitary sewage of the refinery is collected and treated in an aeration unit, which reduces the BOD (biological oxygen demand) and COD (chemical oxygen demand) of the influent. The biological sludge is separated and clarified aqueous effluent is chlorinated to reduce coliform bacteria before discharging this water for irrigation purposes. The sludge separated is disposed of as landfill.

TREATMENT OF OILY WATER

Water from desalters is cooled from 225°F to approximately 130°F in exchanger E-101 to prevent thermal damage to CPI oil/water separator plates (see Figure 9-6). The cool effluent next joins all other potentially contaminated water streams for removal of oil in CPI-type API separators CPI-101A and CPI-101B. CPI separators remove most of the free oil and some of the settleable solids associated with influent streams (Table 9-6). They do not reduce emulsified oil, H_2S, or NH_3. Oil removed from the CPI units is sent to a wet slop oil tank for oil recovery by pump P-101. The effluent water from CPIs is pumped to DAF surge tank TK-101. The oily sludge that settles to the bottom of the CPI units is drawn off periodically by a vacuum truck and taken to a sludge dump.

Waste treatment processes require a relatively steady-state operation to function optimally. Normal and emergency flows fluctuate dramatically throughout a normal operating day. These flows vary from periods of little or no flow to periods of flow approaching the design capacities of the lines. Surge tank TK-101 is therefore located prior to dissolved air flotation units to minimize erratic peak of flows and ensure optimum operation.

DAF units DAF-101A and DAF-101B treat all wastewater from the DAF surge tank. Wastewater is drawn from the surge tank using two pumps operating simultaneously. The flow from the tank is controlled using a manually operated control valve. The DAF unit reduces the oil

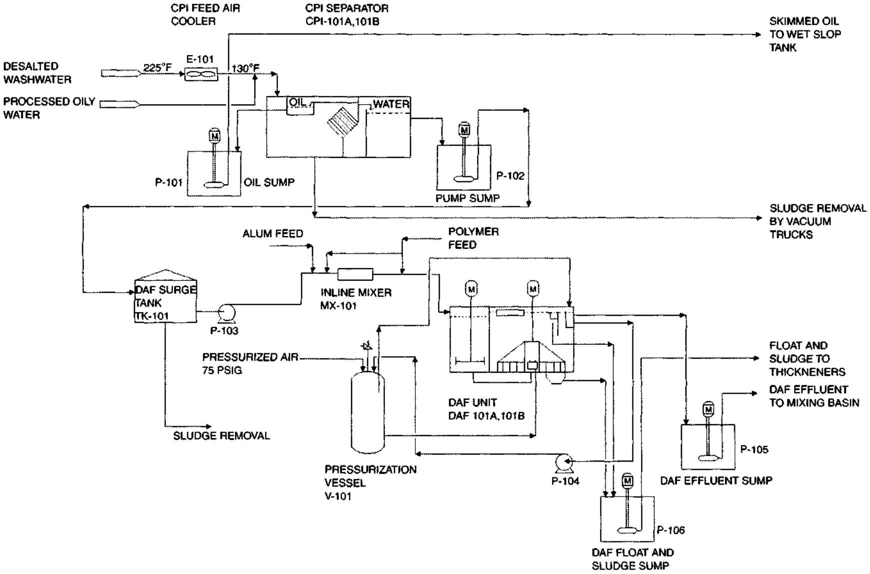

Figure 9-6. Primary oil separation from water. M = motor (pump driver).

Table 9-6
Operating Data of an API Separator (CPI type)

PARAMETERS	UNITS	INFLUENT	EFFLUENT
DESALTED WASHWATER FEED			
SUSPENDED SOILDS	ppm	500	500
TOTAL SOLIDS	ppm	750	750
FREE OIL	ppm	250	20
EMULSIFIED OIL	ppm	160	160
TOTAL OIL	ppm	410	180
COD	ppm	1000	500
BOD	ppm	620	310
PHENOLS	ppm	3	3
SULFIDES AS H_2S	ppm	10	10
NITROGEN AS AMMONIA	ppm	35	35
TEMPERATURE	°F	225	130
OILY WATER FEED			
TOTAL OIL	ppm	2200	190

content of wastewater (emulsified plus free oil) to about 15 ppm. De-emulsifying agents, such as polyelectrolytes or alum, are added to DAF influent in inline mixer MX-101 to increase the oil removal efficiency of each DAF unit. Typical operating conditions and effluent qualities from a DAF unit are shown in Tables 9-7 and 9-8. Three DAF units are normally provided, each sized with 50% of the design capacity, to permit routine maintenance and cope with wide fluctuations in flow.

Sludge management consists of mechanical thickening, dewatering, and sludge storage. The sludge originates from the CPI system and DAF

Table 9-7
DAF Unit Influent and Effluent Quality

PARAMETERS	UNITS	INFLUENT	EFFLUENT
SUSPENDED SOILDS	ppm	<500	20
FREE OIL	ppm	50	3
EMULSIFIED OIL	ppm	160	10
TOTAL OIL	ppm	210	13
COD	ppm	640	300
BOD	ppm	320	150
PHENOLS	ppm	1.8	1.8
SULFIDES AS H_2S	ppm	10	8
NITROGEN AS AMMONIA	ppm	35	15
pH		6.5–7.5	6.0–7.0

Table 9-8
DAF Unit Operating Conditions

PARAMETERS	UNITS	
FLOW RATE/UNIT	gpm	240
RECYCLE RATE, % FEED		50
AIR TO SOLID RATIO		0.1–0.3
AIR PRESSURE	psig	75
AIR FLOW RATE	scfm	2.0–5.0
FLOTATION DETENTION TIME	min	40
HYDRAULIC LOADING	gpm/ft^2	0.5–2.0
COAGULATING CHEMICAL		
ALUM (10% SOLUTION) DOSAGE	ppm	10–20
FLOCCULATING CHEMICAL		
POLYMER SOLUTION	ppm	0.5

units. The sludge contains considerable water, oil, and some solids, which may be considered hazardous or toxic. Thickening is done in a thickener, followed by dewatering by a belt press to reduce sludge volume. The decanted or released water is returned to CPI system. The dewatered sludge, rich in solids and oil, is conveyed to a sludge storage area by conveyer belt to await disposal as landfill. Polyelectrolytes are added to the sludge as thickener and in the belt press influent to increase solid removal efficiency for both thickener and belt presses.

Effluent from the DAF units is combined with nonoily wastewater streams and cooling water return in a mixing basin and discharged to the sea or other water body.

WET SLOP OIL SYSTEM

The slop oil streams from sour water stripper, wastewater treatment, the oil terminal, and such contain large quantities of water, which need to be separated, using heating, settling, and by adding oil/water-emulsion-breaking chemicals (see Figure 9-7).

Wet slop treatment is a batch operation. All the wet slop produced is pumped to two wet slop tanks, T-101A and T-101B. Each tank is provided with a floating roof and a swing arm suction line. The tanks are in service alternately. When a tank gets full, its contents are heated and mixed by pumping the liquid through wet slop heater E-101 and back to the tank. LP steam is used to raise and maintain the wet slop temperature to 120°F. To

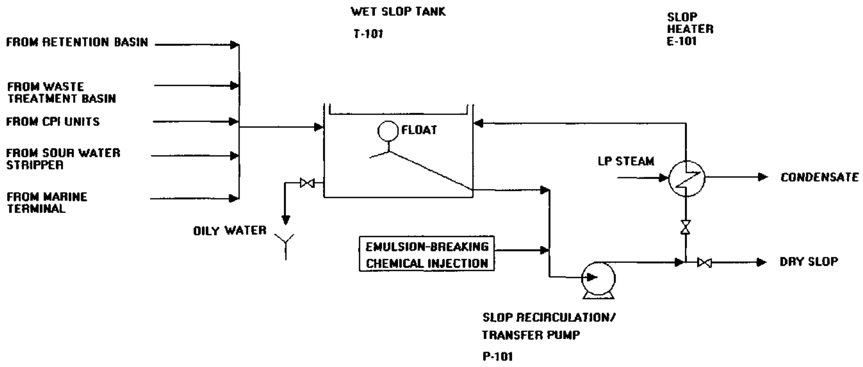

Figure 9-7. Wet slop system. LP = low pressure.

facilitate the breaking up of oil/water emulsions, an emulsion-breaking chemical is added to the wet slop oil during pump/mix cycle.

The water-free slop oil is pumped to a dry slop oil tank. The oil-free water is drained to oily water sewer and returned to the CPI system. The entire operation, consisting of collection, heating, and transfer, is a manual batch type operation.

TREATMENT OF SANITARY SEWAGE

All sanitary sewage in the refinery is collected in a common sewage lift station, from which it is pumped to equalization tank TK-101 (see Figure 9-8). The sewage equalization tank is sized for approximately 6 hr retention of normal flows plus capacity to accommodate surges associated with peak flows from the lift station. The equalization tank is aerated to prevent the sanitary wastewater from becoming septic. The sewage is treated in two aeration tanks TK-103, with each unit having the capacity to treat approximately 75% of daily refinery sewage production. The design thus provides flexibility to allow normal maintenance while maintaining the required degree of treatment.

The aeration treatment reduces both the BOD and suspended solids loading down to 30 mg/liter. The effluent stream from the aeration units is chlorinated in TK-105 to reduce the coliform bacteria content to acceptable level. The treated effluent is discharged to the sea. Operating conditions and quality of effluent after treatment are shown in Table 9-9.

During the aeration process, biological sludge, approximately 9% of the feed volume, is produced. This sludge is removed from sludge digester tank TK-102 by vacuum trucks and disposed of off plot.

SOUR WATER TREATMENT

Sour water, rich in NH_3 and H_2S content, is produced from refinery crude distillation units, hydrocracker, hydrodesulfurization units, gas handling, amine regenerators, delayed cokers, sulfur plant tail gas treating units, and the like. Sour water is produced by the steam stripping operation during crude distillation hydrotreating and hydrocracking operations. During most hydrocracking and hydrotreating operations, NH_3 and H_2S

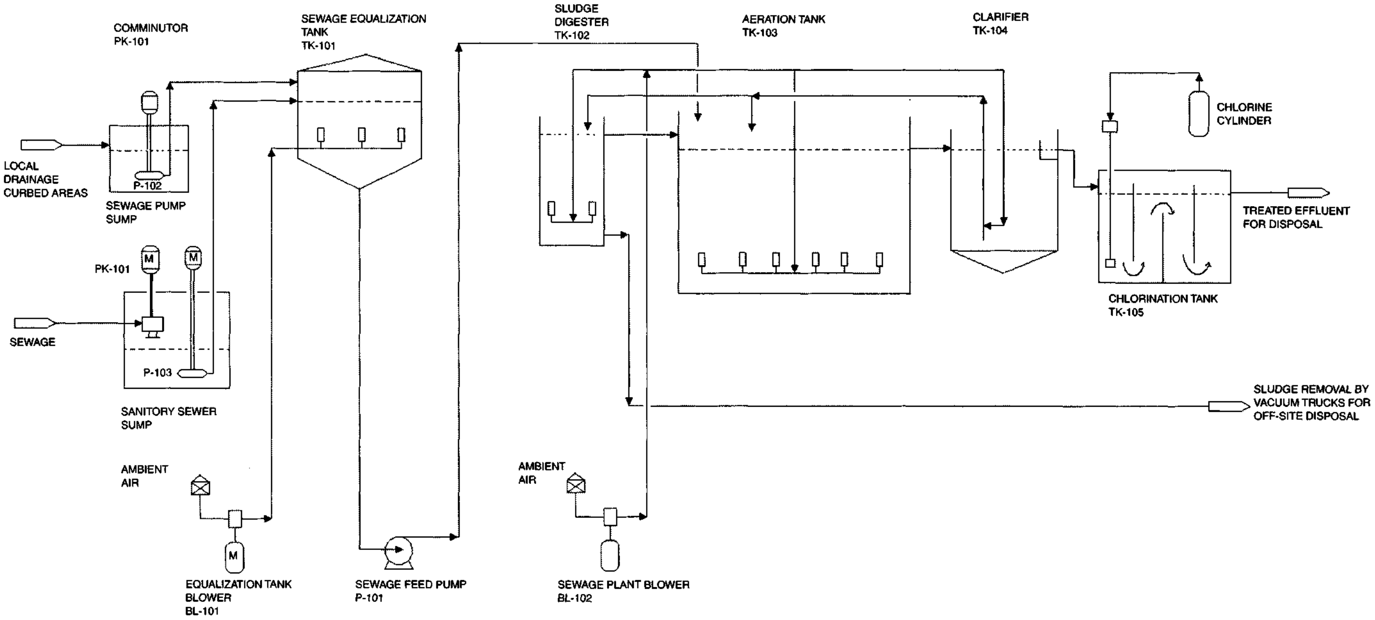

Figure 9-8. Sewage treatment system.

Table 9-9
Sanitary Sewage Treatment (Aeration Unit) Operating Conditions and Stream Quality

PARAMETERS	UNITS	INFLUENT	TREATED EFFLUENT
FLOW RATE/UNIT	gpd	60,000	
SUSPENDED SOLIDS	ppm	<500	30
BOD	ppm	300	30
COD	ppm	1000	30
TOTAL OIL	ppm	150	0
TOTAL NITROGEN AS NH_3	ppm	80	0
pH		6.5–7.5	6.5–8.0
TEMPERATURE	°F	90–95	90–95
DETENTION TIME	hr	22	
vol/lb BOD	ft^3	48.5	
AIR SUPPLIED, lb/BOD REMOVED	SCF	105	
RESIDUAL OXYGEN	ppm	2	>2
CHLORINE RESIDUAL	ppm	0.5–1.0	

are formed in the reactors due to elimination of sulfur and nitrogen in the feed. These two react to form solid ammonium sulfide salts. Ammoniacal condensate injection is required in the reactor effluent ahead of HP separation to prevent deposit of solid ammonium sulfide salts in pipes. Deposit is prevented by dissolving most of the ammonia and approximately an equal quantity of H_2S in water, followed by removing the resulting aqueous solution from the system in the form of sour water. Also in hydrotreating plants, steam stripping of desulfurized liquid streams, to remove H_2S, produces sour condensate containing dissolved H_2S.

Sour water coming from various refinery units has a very high concentration of H_2S and NH_3, typical values being 10,000–20,000 and 5000–10,000 ppmw, respectively. This water also contains some suspended and dissolved hydrocarbons. The composition of sour water from a distillate hydrocracker unit is shown in Table 9-10. Typically a 200 MBPD refinery of medium complexity may produce 1000 gpm sour water. After removing NH_3, H_2S, and small amount of oil, this water can be reused.

Table 9-10
Sour Water Composition

SOURCE	SOUR WATER, GPM	NH_3, PPMW	H_2S, PPMW	OIL, PPMW
HP DRUM (2585 psig)	80.4	12750	20400	—
LP DRUM (500 psig)	8.1	6800	25500	10
STRIPPER OVERHEAD DRUM	30.3	850	3400	5
TOTAL	118.8			

NOTES:
BASIS 44,000 BPSD HYDROCRACKER UNIT.
FEED SULFUR = 2.6 WT%, NITROGEN 695 ppmw.

SOUR WATER STRIPPING UNIT

Ammoniacal water streams from various refinery units are mixed and cooled with cooling water in E-101 to approximately 120°F (see Figure 9-9). The cooled effluent is degassed in V-101. The gases evolved are sent to flare. The degassed foul water is pumped by P-101 to tank TK-101 and kept under fuel gas blanket. Sufficient detention time is allowed in this tank to separate out traces of oil in the water. Separated oil is skimmed off with a swing arm suction line and sent to the slop oil system. The water is pumped to steam stripper column V-103, with about 40 sieve plates.

Ammonia and H_2S are stripped from this water in column V-103, with 40 plates. The column has a thermosyphon reboiler E-104, heated with 150 psig steam. Feed before entering the column is heated to approximately 205°F by heat exchange with the V-103 bottom stream in E-102 and feed enters the column V-102 at the 30th plate. To provide reflux to the column, a sidestream is withdrawn from the 34th plate, cooled to 150°F from 195°F and returned to the top plate of the column. Column top pressure is maintained at 15 psig. The top vapor distillate containing most of H_2S and NH_3 is sent to sulfur plant or flare. The bottom product, stripped water at approximately 262°F, is first cooled to 175°F by heat exchange with incoming column feed. It is next cooled in air cooled exchanger E-105 then in trim cooler E-106 to 105°F before sending the stream outside the battery limit.

The operating conditions of a sour water stripping unit are shown in Table 9-11. The unit utility consumption and yields are shown in Tables 9-12 and 9-13.

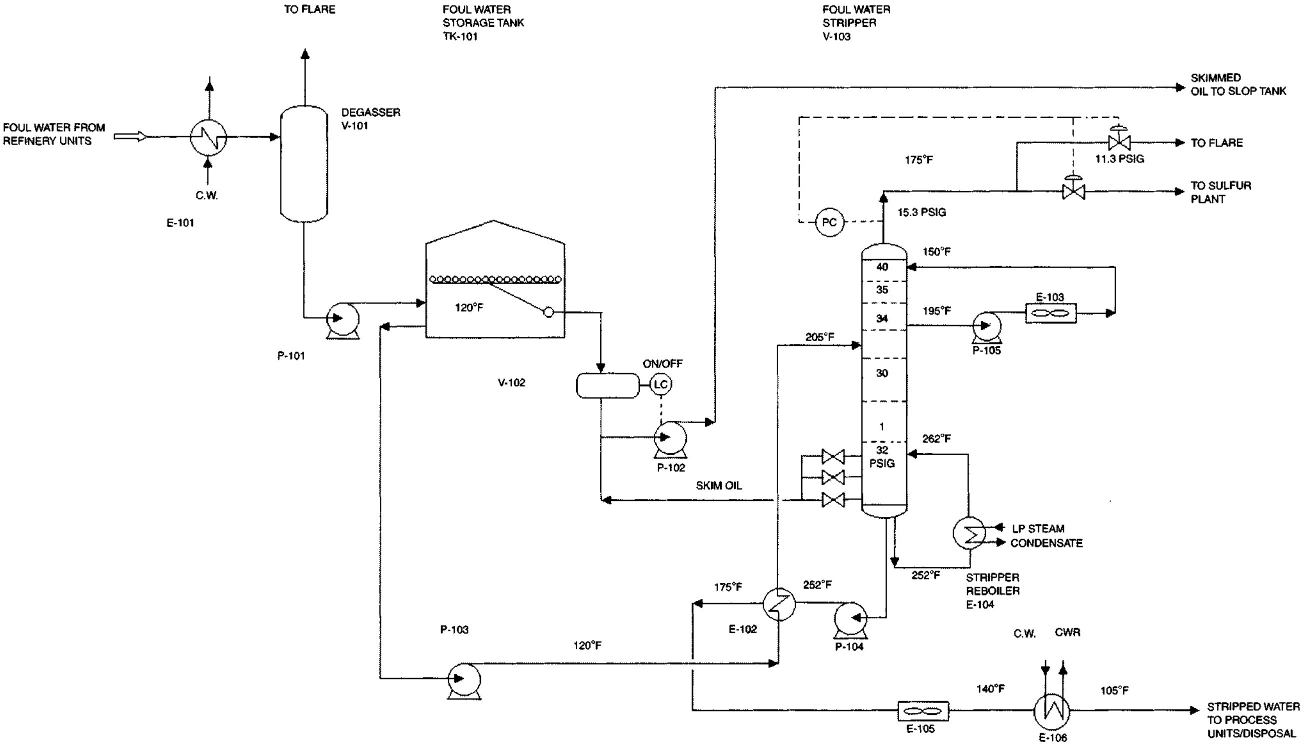

Figure 9-9. Sour water supply. C.W. = cooling water; LP = low pressure; CWR = cooling water return.

Table 9-11
Sour Water Stripper Operating Conditions

PARAMETER	UNIT	
STRIPPER FEED TEMPERATURE	°F	205
STRIPPER TOP TEMPERATURE	°F	175
STRIPPER TOP PRESSURE	psig	15.3
STRIPPER REBOILER TEMPERATURE	°F	262
STRIPPER BOTTOM PRESSURE	psig	32.0
TOTAL NUMBER OF PLATES IN STRIPPER		40
NUMBER OF PLATES ABOVE FEED PLATE		10
REFLUX RATIO, REFLUX/FEED		3.13
REFLUX TEMPERATURE	°F	150
STRIPPED WATER DISCHARGE TEMPERATURE	°F	105

Table 9-12
Sour Water Stripper Utility Consumption per Ton Feed

UTILITY	UNITS	CONSUMPTION
STEAM	mmBtu	0.345
ELECTRICITY	kWhr	2.73
COOLING WATER	MIG*	0.135

*MIG = 1000 IMPERIAL GALLONS.

EXAMPLE 9-1

A 200-mbpcd refinery requires 90,000 gpm sea water for cooling. Sea water is supplied through a 72 in. (internal diameter 1800 mm) pipe from a water intake pit located 4 km from the refinery battery limits. Sea water is to be supplied at a pressure of 75 psi to the manifold, located at an elevation of 22 ft from the intake pit. Determine the power consumption for pumping sea water supply to the refinery. Assume a surface roughness factor of 100 for the pipe. Sea water properties can be assumed as follows:

$$\text{Temperature} = 90°\text{F}$$

$$\text{Density} = 1.030\,\text{kg/m}^3$$

$$\text{Viscosity} = 0.76\,\text{cp}$$

Table 9-13
Material Balance of a 500 gpm Sour Water Stripper Unit

	UNITS	SOUR WATER FEED	TREATED WATER	SIDE REFLUX	SOUR GAS TO SULFUR PLANT
STREAM					
WATER	lb mol/hr	13620.90	13562.50	33408.50	58.40
H_2S	lb mol/hr	97.50	0.06	2549.20	97.44
NH_3	lb mol/hr	98.70	0.29	5563.40	98.41
TOTAL	lb mol/hr	13817.10	13562.85	41521.10	254.25
TOTAL FEED	lb/hr	250190.00	244730.00	782880.00	6050.00
H_2S	ppmw	13251	0	(11.07 Wt%)	(54.87 Wt%)
NH_3	ppmw	6707	20	(12.08 Wt%)	(27.71 Wt%)
mol Wt		18.1	18	18.9	23.8

The first step is to determine the pressure drop in the pipe, using William-Hazen's equation as follows:

$$\Delta P = \frac{10.67 \times Q^{1.85} \times \rho \times L}{C^{1.85} \times D^{4.87}} \times 10^{-4}$$

where

ΔP = pressure drop, kg/cm^2;
Q = flow rate, m^3/sec;
ρ = density of fluid, kg/m^3;
L = equivalent of pipe, m;
C = pipe roughness factor;
D = internal diameter of pipe, m.

Here

$Q = 5.68;$
$L = 4000;$
$C = 100;$
$\rho = 1030;$
$D = 1.8.$

$$\begin{aligned}\Delta P &= \frac{10.67 \times (5.68)^{1.85} \times 1030 \times 4000 \times (10)^{-4}}{100^{1.85} \times (1.8)^{4.87}} \\ &= 1.245\,\text{kg/cm}^2 \\ &= 17.71\,\text{psi}\end{aligned}$$

$$\begin{aligned}\Delta P\ (\text{feet of fluid}) &= \frac{(\Delta P \text{ in psi})}{(0.434 \times \text{specific gravity})} \\ &= 39.61 \text{ feet}\end{aligned}$$

Total head required = discharge pressure + vertical discharge elevation + frictional ΔP, as follows:

	psi	WATER, ft
DISCHARGE PRESSURE	75.00	167.80
VERTICAL ELEVATION	9.83	22.00
FRICTIONAL LOSSES	17.71	39.61
TOTAL PUMP HEAD	102.54	229.41

$$\text{Brake Horse Power (BHP)} = \frac{\text{gpm} \times \Delta H \times \text{specific gravity}}{3960 \times \eta}$$

$$\text{kW power} = \text{BHP} \times 0.746$$

where

gpm = flow rate, gal/min;
ΔH = head, ft of fluid;
η = pump efficiency

Assuming a pump efficiency of 70%,

$$\begin{aligned}\text{Pump BHP} &= \frac{90{,}000 \times 229.41 \times 1.03}{3960 \times 0.70}\\ &= 7671.8\end{aligned}$$

$$\begin{aligned}\text{Pump kW power} &= 7670.5 \times 0.746\\ &= 5{,}723\end{aligned}$$

NOTE

1. *Oil and Gas Journal* (June 21, 1976).