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Hydrostatic Pressure Testing of Piping

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INTRODUCTION

Pressure testing of a new pipe is required prior to commissioning to prove its integrity at operating pressure.

Hydrostatic testing is the most common pressure testing method. Testing of an in-service pipeline may be done as part of a preventative program to verify pipe integrity. In-service pipelines may also be tested if operating pressure are to be increased, modifications to the pipe are made or a change in line service planned.

Hydrostatic pressure testing is universally known and accepted as a means of demonstrating the fitness of a pressurized component for pipe service. After a test, a pipe can be expected to safely contain its intended operating pressure. The confidence level that a pipe or pressure vessel is fit for safe service increases as the ratio of test pressure to operating pressure increases. Hydrostatic test reveals weaknesses of pipe by causing ruptures or leaks.

When compared to other equipment in a hydrocarbon processing plant, the piping network is designed to the most stringent standards. Mechanical Engineering codes require a 400% safety factor in the design of these systems. The piping system is normally considered the safest part of the plant. However, even with this level of safety, reviews of catastrophic accidents show that piping system failures represent that largest percentage of equipment failures.

Since these systems are responsible for many catastrophic accidents, operations, design, and maintenance personnel should understand the potential safety concerns. Failure of an operating piping can result in health and safety concerns, damage to property and has the potential for significant environmental impact. Consequently, it is important to ensure that a pipe is free of leaks and is capable of maintaining its integrity at an approved operating pressure in order to limit the risk to the public and the environment.

In some countries, approval from regulatory agencies must be acquired prior to testing. regulatory approvals have been put in place to minimize the risk of unacceptable environmental impact or adverse impacts on other water users as a result of testing activities.

This test has a lot of considerations that must be considered (before or after the test) to obtain maximum result. The purpose of this article is to show how to do the hydrostatic pressure testing in accordance with the steps, procedures and rules.

DEFINITION OF HYDROSTATIC PRESSURE TEST

Hydrostatic pressure testing involves the filling of a section of pipe to be tested with water, adding additional water to the piping until the desired test pressure is reached and maintaining the pressure in the pipe for a period specified by regulatory authorities.

Many piping standards are using hydrostatic pressure testing in order to prove the integrity of the pipe and welds to the owner company, regulatory authorities and the public. This procedure is conducted on new pipelines as well as on in-service pipelines when a change of service is proposed, an increase in operating pressure is planned or to verify the integrity of the piping.

Hydrostatic pressure testing of new pipe is undertaken following completion of backfilling. Prior to filling the pipe with a water, a cleaning pigs must be run through the test section to remove any debris (e.g. welding litter, dirt) from the pipe. The pipe section to be tested is then filled with test water.

The volume of water required for a test is dependent upon the length of the test section and diameter of the pipe (see table).

Water sources commonly include rivers, lakes, ponds, dugouts, borrow pits, wells and municipal water supplies. Isolation valves may be used to break long sections of new pipe into smaller test sections that vary in length depending upon the topography traversed and construction season. Alternatively, the pipe may be cut and test heads welded on to allow testing.
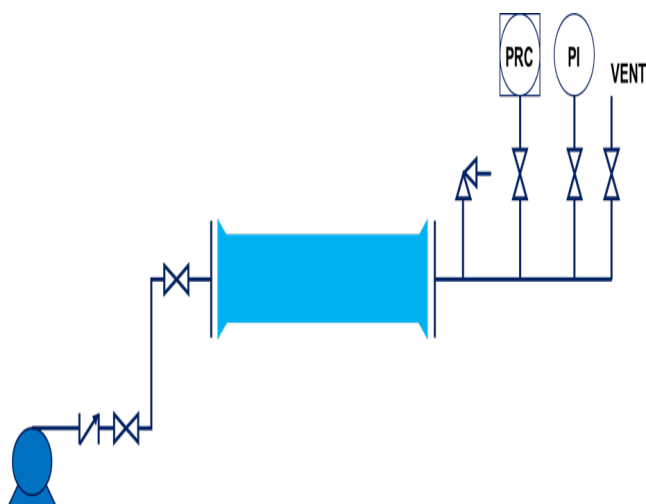
Figure 1 : Hydrostatic pressure testing of pipe.

Outside Diameter		Wall Thickness (mm)	Fluid Volume (m³/km)
(mm)	(inch)		
60.3	2	3.2	2.3
88.9	3	3.2	5.3
114.3	4	3.2	9.1
168.3	6	4.0	20.2
219.1	8	6.4	33.4
273.1	10	6.4	53.2
323.9	12	7.9	74.6
406.4	16	9.5	117.9
508.0	20	12.7	182.9
559.0	22	12.7	223.6
609.6	24	12.7	268.4
762.0	30	12.7	426.1
813.0	34	12.7	487.2
914.4	36	12.7	620.2
1067.0	42	12.7	852.1
1219.0	48	12.7	1118.9

Table : Hydrostatic test water volume requirements for standard pipe size.

Water is reused along a pipeline from one test section to another in order to minimize water requirements. Since the test section of an operating pipe may be downstream from the nearest terminal or fill point, the water may be required to travel along the pipe for a considerable distance prior to reaching the test section.

Water for testing and flushing shall be clean and free from any suspended or dissolved substances which could be harmful to the pipe material or internal coating (where applied) or which could form deposits within the pipeline, or which may be unacceptable at the disposal location.

Care shall be taken to insure the use of clean water for hydrostatic tests and the sea water is prohibited to be used. Hydrostatic testing shall be performed using potable water with a chloride content of max 50 ppm for austenitic steels.

Planning of a hydrostatic test program involves the selection of an appropriate test water source. Ideally the source water should be:

- of high quality
- available in large volumes
- located near the optimum fill location
- accessible with a minimum of disturbance
- within the same drainage basin as the discharge point
- economical

The potential exists during water withdrawal to adversely affect aquatic life, soils and land use. The degree of risk to these environmental components can be influenced by the:

- source water withdrawal rate
- volume withdrawn
- timing
- location and sensitivity of the withdrawal point
- activity needed to prepare, use and abandon the withdrawal site

The main objective of analyzing selection the source water is to confirm that substances that could pose a discharge problem are not being introduced. Surface water or groundwater may be tested for total dissolved solids, salts (electrical conductivity, sodium absorption ratio), pH, trace metals and suspended solids. The selection of a test water source is also dependent upon the ability to obtain approval from regulatory agencies and the landowner.

Tested piping shall be internally cleaned to remove all remaining dust and foreign matter by water flushing or blowing with air. Flushing shall be done with clean water using

hydrostatic test water where possible. Water used for special flushing or cleaning of austenitic stainless steel shall not contain more than 50 ppm chlorides, i.e. Where special treatment is required, such as cleaning of compressor suction and lube oil piping, a separate procedure shall be prepared by contractor's Operations/Commissioning Group.

EQUIPMENT OF TESTING

In hydrostatic test, all personnel within test are a shall be required to wear eye and hearing Personnel Protective Equipment (PPE). Furthermore, there are some equipment used in hydrostatic pressure test as follows:

- Pressure pump
- Pressure recorder
- Temperature recorder
- Deadweight pressure gauge
- Pressure gauges
- Stroke counter
- Hydrostatic test yield plot
- High pressure hoses
- Check valves
- Fill pipe
- Filter
- Water samples

PREPARATION OF TESTING

All joints, including welds, shall be accessible and left uninstalled, unpainted and exposed for examination during the test. Joints previously tested in accordance with this specification may be insulated or covered.

Piping designed for vapor or gas shall be provided with additional temporary supports, if necessary, to support the weight of the test liquid. Where required, temporary supports shall be specified in the pressure test documents.

Lines which are counterweight supported shall be temporarily blocked during testing in order to sustain the weight of the test fluid. Spring hangers which have been provided with stops for carrying the test load normally do not require additional temporary supports: If this is not the case, temporary support must be provided before filling the system.

PROCEDURES OF TESTING

The hydrostatic pressure testing operations shall be carried out by an experienced test engineer who shall have no other duties during the hydrostatic testing operations. The test engineer shall be in full charge of all activities related to the hydrostatic testing operations.

The test engineer shall prepare a procedure for all pressure testing operations, including a statement of the responsibilities of his subordinates. The test procedure shall be submitted to the Principal for approval not less than 3 days prior to commencement of testing or as specified in the scope of work. No part of the hydrostatic pressure testing operations shall commence until the approval is given in writing.

The test procedure shall include, but not be limited to:

- List of nominated personnel who are to supervise the pressure testing operations with their qualifications, tasks, responsibilities and authorities.
- Detailed schedule giving proposed dates of the main activities, tests and mobilization dates of the nominated personnel.
- Details of the selected test sections, including assemblies and pre-test sections.
- Identification of potential safety and environmental hazards, including the necessary measures and emergency plans.
- Details of the line-fill water, including the source, treatment method, discharge/disposal and permits.
- Details of the test equipment, including layouts and size and/or performance.
- Details of the test section preparation, including cleaning, gauging and filling.
- Details of the hydrostatic pressure test preparation, including temperature stabilization period.
- Details of the hydrostatic pressure tests, including pre-test, strength test and leak tightness test.
- Details of the post-testing activities, including depressurizing and documentation.
- Details of the post-testing activities, including depressurizing and documentation.

The normal location for the pressure test gauge is at grade near the pressure test pump and at the highest point of the piping system. Readings may be made at higher points providing the gauge pressure reading plus the static head between grade and the point of measurement does not exceed the maximum test pressure.

Piping systems shall be filled from a low point and filtered with a 10 micron filter. During filling of the system all air or gaseous substance shall be vented from high point to the maximum extent possible. Hydrostatic test water will be discharged to the nearest storm water drains.

Hydrostatic test pressure shall be maintained for a sufficient length of time to visually determine if there are any leaks, but not less than ten (10) minutes. Test pressure shall not be required to be maintained in excess of two hours after notification to contractor.

After completion of the test, pressure shall be released by opening the valve gradually so as not to endanger personnel or damage equipment. As a rule of thumb, pressure releasing rate shall be less than 300 kg/cm2/hr. For piping line for which pressure releasing rate is to be specified, refer to specific job requirements. After completion of the test, the piping and equipment shall be drained completely.

PRESSURE OF TESTING

The minimum of hydrostatic test of piping designed for internal pressure at any point in the system shall be as follows :

Not less than 1-1/2 times of the design pressure.
For a design temperature above the test temperature, the minimum test pressure shall be as calculated by the following equation.

Eq. 1 $$Pt = \frac{1.5 \cdot P \cdot St}{S}$$

Where:

Pt = minimum calculated hydrostatic test pressure (kg/cm^2)
P = internal design pressure (kg/cm^2)
St = allowable stress at test temperature (kg/cm^2)
S = allowable stress at design temperature (kg/cm^2)
See Table I, Appendix A, ASME B31.3
When St and S are equal, test pressure is 1.5 x P.

Where the test pressure as defined minimum yield strength at test temperature, the test above would produce a stress in excess of the specified pressure shall be reduced to a pressure at which the stress will not exceed the specified minimum yield strength at the test temperature.

The maximum test pressure at which the stress produced will not exceed the specified minimum yield strength may be calculated by the following equation:

Eq. 2 $$Pm = \frac{2S \cdot E \cdot t}{D}$$

Where:

Pm = maximum test pressure (kg/cm^2)
S = specified minimum yield strength at test temperature (kg/cm^2)
t = specified pipe wall thickness minus mill tolerance (cm)
D = outside diameter (cm)
E = quality factor (see ASME B31.3 table A-1 B)

For hydrostatic testing of piping designed for external pressure as follows:

- Lines in external pressure service shall be subjected to an internal test pressure of 1-1/2 times the external differential design pressure but not less than a gauge pressure of 1.055 kg/m2 (15 psi).
- Jacketed lines, the internal line shall be pressure tested on the basis of the internal or external design pressure, whichever is critical. This test shall be preformed prior to completion of the jacket.
- The jacket shall be pressure tested of the basis to the jacket design conditions.
- Where systems require hydrostatic testing through static equipment, the test pressure shall be selected so as not to exceed vessel test pressure.

SAFETY OF TESTING

The safety related issues including but not limited to the following should be addressed in Job Hazard Analysis (JHA) to be made by contractor for performance of Pressure Testing activities:

- Appointment of contractor's Test Controller who is in attendance and responsible throughout the testing and inspects the welding during testing.
Appointment of the subcontractor's test controller who will be responsible for ensuring safe testing in accordance to the specification.

- Display of safety warning signs to alert workers in the vicinity of the pressure testing with line, identification.
- Pressure test training and maintenance of a competency register as required by contractor Safety Plan.
- Pressure rating for the test manifold and the test equipment and the required inspection/testing.

RECORD OF TESTING

Records shall be made of each piping system test. These records, when completed, shall be submitted as part of the test and inspection certificates which are required for pre-commissioning. Records shall include:

Date of test
- Identification of piping system and any vessels or equipment tested with the piping system.
- Test medium
- Test pressure and maintaining time
- Minimum ambient temperature

All test records and authorized contractor certifications shall be retained in the Test Package records for turnover to the Owner. Test data base shall be established to monitor status and progress.

DOCUMENTATION OF TESTING

All recorder charts shall be signed by the test engineer when placed on and taken off the recorder. All recorder charts taken during the hydrostatic pressure test shall also be signed by the Company.
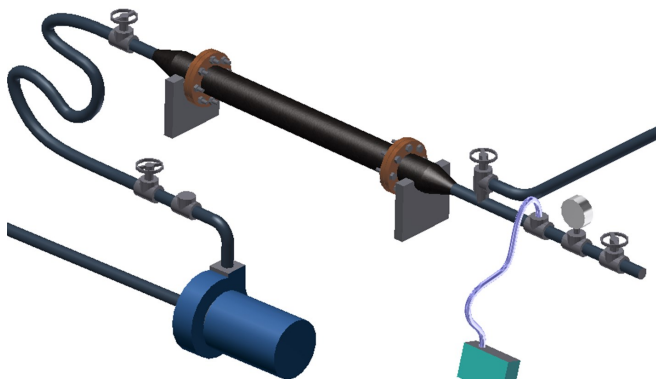

Figure 2 : Record of pressure.

Upon completion of a successful section test a "hydrostatic test certificate" shall be completed and signed by the Contractor and Company.

This shall be supported by original hand-written test data of which photocopies shall be handed to the Company. A separate certificate shall be completed for each test, including pre-test and assembly testing.

For each complete pipeline, the Contractor shall compile a "final hydrostatic test report", with a general introduction including all relevant pipeline data, detailing each hydrostatic pressure test. The contents, as a minimum, shall include the following:

- Originals of all "hydrostatic test certificates"
- Originals of all recorder charts
- All pressure readings
- All temperature readings
- Volumes of water added or bled off
- Instrument test certification
- Air content plot and calculation
- Pressure and temperature plots against time
- Pressure/temperature correlation calculation
- Details of line-fill treatment packages
- Pig register of cleaning, gauging and filling
- Photographic record of the used gauging plates
- Leak locating (if carried out)
- Pig register of dewatering (if carried out)
- Details of line-fill water disposal (if carried out)
- Rectification records (if carried out)
- Any special features of the test
- Test procedure

RECTIFICATION REQUIREMENTS OF TESTING

If a leak is suspected, pressure reduced to less than 80 % of the test pressure before carrying out a visual examination. If it is not possible to locate the suspected leak by visual examination, use a method which enables the locating of leaks at test pressure without endangering the personnel carrying out the work.

To tie-in or to rectify any defects, it may be necessary to partially or completely dewater the test section. For partial dewatering of test sections containing treated water, the use of bi-directional pigs, remotely controlled inflatable isolation plugs and/or hyperbaric spheres should be considered to isolate the repair or tie-in location from the water-filled test section, instead of total dewatering.

Bi-directional pigs propelled by compressed air should be used for displacement of the line-fill water. Pigging shall be carried out against a back-pressure of hydrostatic head plus 1 bar so that air does not enter into the water-filled section. No attempt should be made to dewater the test section by letting the water run out under the effects of gravity.

The test section shall not be left in the partially or completely dewatered condition longer than one week without any further internal corrosion protection. Depending on the post-dewatering period and the line-fill water quality, it may be necessary to purge the test section with nitrogen or swab it with fresh water and/or inhibition slugs to avoid internal corrosion.

REFERENCE

 "Guidelines Hydrostatic Test Water Management", Canadian Association of Petroleum Producers, Canada, 1996.

"Process Piping", ASME B31.3 Code, 2012.

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Pressure Relief Valve Design— A Short Tutorial

Jayanthi Vijay Sarathy

Pressure vessels are equipped with a relief device for the purposes of mechanical protection against over pressure scenarios. Typically, once the design parameters of the vessel are determined based on the process conditions, the relief valve [RV] parameters such as set pressure [SP], overpressure, accumulation, vessel's MAWP based on material selection and plate thickness and the hydrostatic head is worked out.

The following article demonstrates how the above parameters are determined based on ASME/API standards for pressure vessels operating under internal pressure.

GENERAL NOTES

The various definitions of pressure terminologies for the pressure vessel is described as follows,

Fig 1. Vessel Pressure Terminology

1. Going by ASME Sec VIII Div 1 [Ref 1], the definition of Design pressure [DP] and Maximum Allowable Working pressure [MAWP] is defined as,

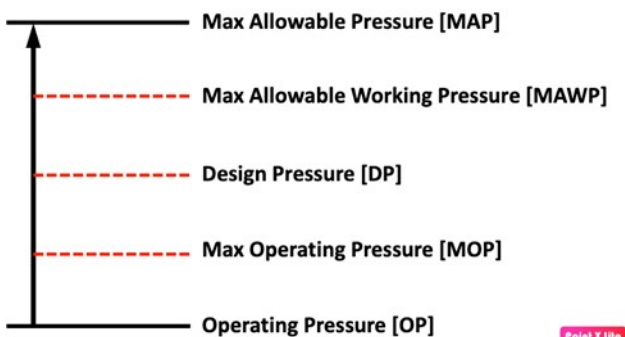   • Design Pressure - The pressure used in the design of a vessel component together with the coincident design metal temperature, for the purpose of determining the minimum permissible thickness of physical characteristics of the different zones of the vessel. When applicable, static head shall be added to the design pressure to determine the thickness of any specific zone of the vessel.

2. Maximum Allowable Working Pressure [MAWP] - The maximum gauge pressure

permissible at the top of a completed vessel in its normal operating position at the designated coincident temperature for that pressure. This pressure is the least of the values for the internal or external pressure to be determined by the rules of this Division for any of the pressure boundary parts, including the static head thereon, using nominal thicknesses exclusive of allowances for corrosion and considering the effects of any combination of loadings listed in UG-22 that are likely to occur at the designated coincident temperature. It is the basis for the pressure setting of the pressure relieving devices protecting the vessel. The design pressure may be used in all cases in which calculations are not made to determine the value of the maximum allowable working pressure.

2. The Maximum Operating Pressure [MOP] is taken as the highest gauge pressure which provides operational flexibility and is typically set at 105% of the operating pressure [OP] or a minimum of 1 barg higher than the vessel's OP.

3. Design pressure [DP] is typically taken to be 110% of the Maximum operating pressure [MOP] but can vary from project to project depending on local regulations. However non-pressure loads [such as motors, piping, insulation, instrumentation, etc], are to be excluded as per ASME Sec VIII UG-22. Since the vessel experiences higher pressure at the bottom due to the static head contributed by the liquid, the static head is to be included in the vessel's wall thickness estimation as per ASME Sec VIII UG-27. Design pressure [DP] is only to be used to determine the minimum vessel thickness required.

4. MAWP needs to include both the static head contributed by the liquid and non-pressure loads but excluding the corrosion allowance [CA]. MAWP may be assumed to be the same as DP when calculations are NOT made to determine the MAWP.

5. To estimate the Maximum allowable pressure [MAP], the corrosion allowance is to be added to the selected wall thickness. MAP is the highest permissible pressure based on the vessel's weakest parts for a new and cold condition.

6. As per ASME Sec VIII UG-99(b), vessels designed for internal pressure shall be subjected to hydrotesting such that at each point in the vessel, the hydrotest pressure must be at least equal to 130% of MAWP multiplied by the lowest stress ratio [LSR].

6. The terminology associated with pressure safety relief valve can be inferred from API Recommended Practice 520 as,

    1. Set Pressure [SP] - The inlet gauge pressure at which the pressure relief device [PRD] is set to open under service conditions.

2. Accumulation - The pressure increases over the MAWP of the vessel, expressed in pressure units or as a percentage of MAWP or design pressure. Maximum allowable accumulations are established by applicable codes for emergency operating and fire contingencies.

3. Overpressure - The pressure increases over the SP of the relieving device. Overpressure is expressed in pressure units or as a percentage of set pressure. Overpressure is the same as accumulation only when the relieving device is set to open at the MAWP of the vessel.

4. Relieving Pressure - The inlet pressure and temperature on a PRD during an overpressure condition. The relieving pressure is equal to the valve set pressure plus the overpressure. The temperature of the flowing fluid at relieving conditions may be higher or lower than the operating temperature.

5. As per API 520, Part 1 [Ref 2], in accordance with the requirements of the ASME Code, accumulated pressure shall be limited to 110% of the MAWP in vessels that are protected by a single pressure-relief device sized for operating (non-fire) contingencies. The set pressure of the device shall not exceed MAWP. Accordingly, the allowable accumulation is 3 psi when the MAWP is between 15 psig and 30 psig in accordance with the ASME Code.

6. For multiple RVs, the accumulated pressure shall be limited to 116% of the MAWP in vessels that are protected by multiple pressure relief devices sized for operating (non-fire) contingencies. The set pressure of the first device shall not exceed the MAWP. The set pressure of the additional device or devices shall not exceed 105 % of the MAWP. Accordingly, the allowable accumulation is 4 psi when the MAWP is between 15 psig and 30 psig.

7. For fire case, the accumulated pressure shall be limited to 121% of the MAWP in vessels that are protected by pressure-relief devices [PRDs] sized for fire contingencies. This applies to single, multiple, and supplemental device installations.

8. Single or multiple devices sized for fire case may also be utilized for relieving requirements attributed to operating (non-fire) contingencies, provided that the constraint of 110% and 116% (of MAWP) accumulated pressure for the non-fire contingencies is observed.

9. A multiple device installation requires the combined capacity of two or more devices to alleviate overpressure. The set pressure of the first device shall not exceed the MAWP. The set pressure of the last device to open shall not exceed 105% of MAWP.

10. A supplemental device installation provides relieving capacity for an additional hazard created by exposure to fire or other unexpected sources of external heat. The set pressure of a supplemental device for fire shall not exceed 110% of the MAWP.
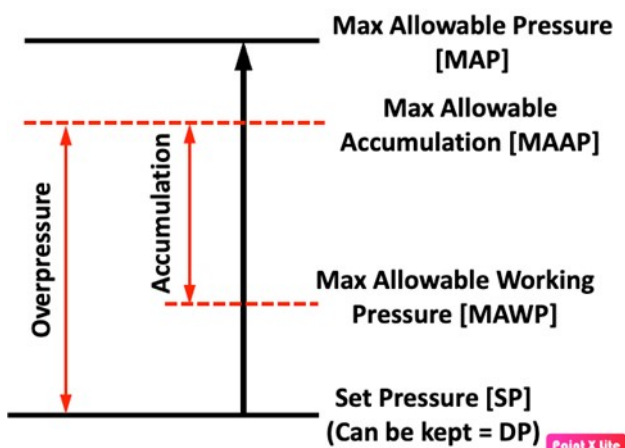
11. As per ASME Sec VIII Div 1, for vessels under internal pressure, the shell wall thickness [t] is estimated as,

$$t = \frac{(P \times R)}{(S \times E) - (0.6 \times P)}$$ (1)

Where,

t = Wall thickness excluding CA [in]

P = MAWP [psig]

R = Inside radius before addition of CA [in]

S = Maximum Allowable Stress [psi]

E = Joint Efficiency [-]

12. Re-arranging, MAWP is calculated as,

$$P = \frac{(S \times E \times t)}{R + (0.6 \times t)}$$ (2)

Table 1-SP and Accumulation for PRDs [Ref 2]

Contingency	Single Device Installations		Multiple Device Installations	
	Max SP [%]	Max Accumulated Pressure [%]	Max SP [%]	Max Accumulated Pressure [%]
Non Fire Case				
First Relief Device	100	110	100	116
Additional Device(s)	-	-	105	116
Fire Case				
First Relief Device	100	121	100	121
Additional Device(s)	-	-	105	121
Supplemental Device	-	-	110	121

CASE STUDY

A vertically oriented pressure vessel of 60 inches diameter operates at an MOP of 100 psig and MOT of 120□. The ambient temperature and barometric pressure is taken as 100□ and 14.7 psia. The max liquid level in the vessel is 50 ft. The DP criteria to determine the vessel's DP, DT, MAWP, is shown below,

Table 2. Design Pressure Criteria [Ref 3]

Design Pressure [DP] Criteria		
MOP Range [psig]		DP Margin [% / psi]
0	50	15 psi
51	250	10%
251	500	10%
501	1000	50 psi
1001	above	5%

The design temperature margin is taken as 77°F [25°C]. The vessel's liquid content has a density of 850 kg/m³. The vessel's material of construction [MOC] is as follows,

Table 3. Vessel's Shell Details

Parameter	Value
Vessel Head Type	2:1 Ellipsoidal
Plate Material	SA-516 Gr 70
Allow Stress [S] at DT [psi]	20,015
Allow Stress [S_a] at Ambient [psi]	20,015
Joint Efficiency [-]	0.85
Shell Radius [in]	30
Corrosion Allowance [CA] [in]	0.125

METHODOLOGY

Based on the data provided, the design pressure from Table 2 is,

$$Design\ Pressure\ [DP] = 1.1 \times 100 = 110\ psig$$ (3)

$$Design\ Temperature\ [DT] = 120 + 77 = 197°F$$ (4)

Taking, RV Set Pressure [SP] =DP = 110 psig, the liquid head is estimated as,

$$Head\ [H] = \frac{(50 \times 0.3048) \times 850 \times 9.812 \times 14.7}{10^5} = 18.7\ psi$$ (5)

The shell pressure [P] is then estimated as,

$$P = DP + H = 110 + 18.7 = 128.7$$ (6)

The minimum shell thickness [t_{min}] estimated as per ASME Sec VIII Div 1 is,

$$t_{min} = \frac{128.7 \times 30}{(20,015 \times 0.85) - (0.6 \times 128.7)} = 0.228\ in$$ (7)

Taking one size higher, the selected plate wall thickness or nominal thickness without CA, is 0.2362 inches [Ref 4]. For the nominal thickness, the maximum allowable working pressure [MAWP] is,

$$MAWP = \frac{20,015 \times 0.85 \times 0.236}{30 + (0.6 \times 0.236)} = 133\ psig$$ (8)

Taking a corrosion allowance of 0.125 in, the nominal thickness is,

$$t_{nom} = 0.2362 + 0.125 = 0.3612 \, in \tag{9}$$

Taking the nominal thickness, the maximum allowable pressure [MAP] is,

$$MAP = \frac{20,015 \times 0.85 \times 0.3612}{30 + (0.6 \times 0.3612)} = 203 \, psig \tag{10}$$

To estimate the hydrostatic head [ASME Sec VIII, UG-99(b)], the LSR value is estimated as,

$$LSR = \frac{S_a}{S} = \frac{20,015}{20,015} = 1 \tag{11}$$

$$P_{Hydro} = 1.3 \times MAWP \times LSR \tag{12}$$

$$P_{Hydro} = 1.3 \times 133 \times 1 = 173 \, psig \tag{13}$$

With the MAWP calculated, the relief valve [RV] pressure settings can be estimated. For this case study, the RV's maximum allowable accumulation pressure [MAAP], allowable over pressure and relieving pressure [P_1] is performed for single and multiple RV installations and for fire and non-fire cases.

A. For Single RV – Non Fire Case

$$MAAP = 1.1 \times 133 = 146.6 \, psig \tag{14}$$

$$Allowable \, Overpressure = MAAP - SP \tag{15}$$

$$Overpressure = 146.6 - 110 = 36.6 \, psi \tag{16}$$

$$Relieving \, Pressure \, [P_1] = MAAP + P_{baro} \tag{17}$$

$$P_1 = 146.6 + 14.7 = 161.3 \, psia \tag{18}$$

B. For Single RV – Fire Case

$$MAAP = 1.21 \times 133 = 161.3 \, psig \tag{19}$$

$$Overpressure = 161.3 - 110 = 51.3 \, psi \tag{20}$$

$$P_1 = 161.3 + 14.7 = 176 \, psia \tag{21}$$

C. For Multiple RV – Non Fire Case

First Relief Valve [RV]

$$MAAP = 1.16 \times 133 = 154.6 \, psig \tag{22}$$

$$Overpressure = 154.6 - 110 = 44.6 \, psi \tag{23}$$

$$P_1 = 154.6 + 14.7 = 169.3 \, psia \tag{24}$$

Additional Relief Valve [RV]

$$SP = 1.05 \times 133 = 140 \, psig \tag{25}$$

$$MAAP = 1.16 \times 140 = 154.6 \, psig \tag{26}$$

$$Overpressure = 154.6 - 140 = 14.7 \, psi \tag{27}$$

$$P_1 = 154.6 + 14.7 = 169.3 \, psia \tag{28}$$

D. For Multiple RV – Fire Case

The first RV max set pressure [SP] follows the same as single RV fire case [SP = 100% of MAWP].

The additional RV max set pressure [SP] follows the same as multiple RV fire case [SP = 105% of MAWP].

For the supplemental valve,

$$SP = 1.1 \times 133 = 146.6 \, psig \quad (29)$$

$$MAAP = 1.21 \times 133 = 161.3 \, psig \quad (30)$$

$$Overpressure = 161.3 - 146.6 = 14.7 \, psi \quad (31)$$

$$P_1 = 161.3 + 14.7 = 176 \, psia \quad (32)$$

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Surface Production Operations – Design of Oil Handling Systems and Facilities, Ken Arnold, Maurice Stewart, 3rd Ed.

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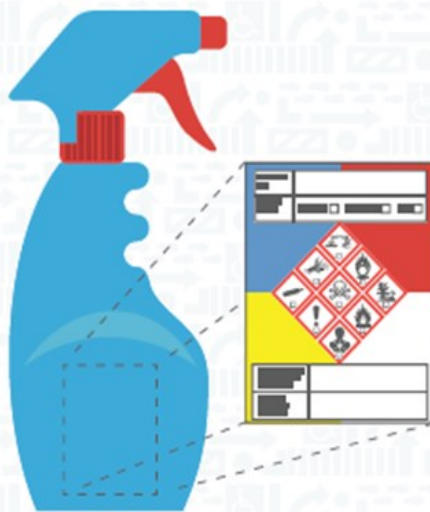
APPENDIX A

Relief Valve [RV] Design		
Parameter	Value	Unit
Equipment Number	V-100	-
Barometric Pressure	14.7	psia
Ambient Temperature	100	°F
Max Operating Pressure [MOP]	100	psig
Max Operating Temperature [MOT]	120	°F
Design Temperature [DT] Margin	77	°F

Relief Valve [RV] parameters		
Design Pressure [DP]	110	psig
Design Temperature [DT]	197	°F
RV Set Pressure [SP] = DP	110	psig
MAWP [ASME Sec VIII Div 1]	133	psig
Hydrotest Pressure [ASME UG-99]	173	psig

Single RV Installation		
Non Fire Case		
Maximum Accumulated Pressure [MAAP]	146.6	psig
Allowable Overpressure	36.6	psi
Relieving Pressure [P₁]	161.3	psia
Fire Case		
Maximum Accumulated Pressure [MAAP]	161.3	psig
Allowable Overpressure	51.3	psi
Relieving Pressure [P₁]	176.0	psia

Multiple RV Installation		
Non Fire Case		
Maximum Accumulated Pressure [MAAP] - First RV	154.6	psig
Allowable Overpressure - First RV	44.6	psi
Relieving Pressure [P₁] - First RV	169.3	psia
Additional RV Set Pressure [SP] [105% of MAWP]	140.0	psig
Maximum Accumulated Pressure [MAAP] - Additional RV	154.6	psig
Allowable Overpressure - Additional RV	14.7	psi
Relieving Pressure [P₁] - Additional RV	169.3	psia
Fire Case		
Maximum Accumulated Pressure [MAAP] - First RV	161.3	psig
Allowable Overpressure - First RV	51.3	psi
Relieving Pressure [P₁] - First RV	176.0	psia
Additional RV Set Pressure [SP] [105% of MAWP]	140.0	psig
Maximum Accumulated Pressure [MAAP] - Additional RV	161.3	psig
Allowable Overpressure - Additional RV	21.3	psi
Relieving Pressure [P₁] - Additional RV	176.0	psia
Supplemental RV Set Pressure [SP] [110% of MAWP]	146.6	psig
Maximum Accumulated Pressure [MAAP] - Supplemental RV	161.3	psig
Allowable Overpressure - Supplemental RV	14.7	psi
Relieving Pressure [P₁] - Supplemental RV	176.0	psia

Liquid Level [ft] 2
Head Type 2:1 Ellipsoidal
Radius [R]
Max Liq Level [ft] 50
Liquid Level [ft] 60
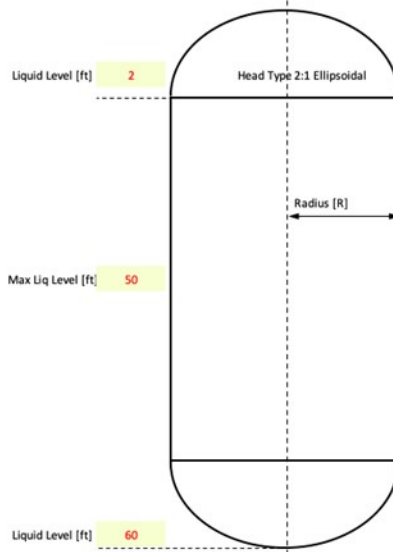
Shell Details		
Plate Material	SA-516 Gr 70	-
Allowable Stress [S] at Design Temperature	20,015	psi
Allowable Stress [Sₐ] at Ambient Temperature	20,015	psi
Lowest Stress Ratio [LSR] [ASME Sec VIII UG-99(b)]	1	-
Shell Pressure [P = DP + H]	128.7	psig
Joint Efficiency [E]	0.85	-
Shell Radius [R]	30	in
Shell Min. Thickness [t] @[DP+H]	0.228	in
Plate Thickness Chosen [Nominal thickness w/o CA]	0.236	in
Shell Max Allowable Working Pressure [MAWP]	133	psig
Corrosion Allowance [CA]	0.125	in
Nominal Thickness [with CA] [t_CA]	0.3612	in
Shell Max Allowable Pressure [MAP]	203	psig
Hydrotest Pressure [UG-99] [1.3 x MAWP x LSR]	173	psig

Vessel Hydrostatic Head		
Vessel Liquid Level [L]	50	ft
Vessel Liquid Density [ρ]	850	kg/m³
Liquid Static head [H]	18.7	psi

Design Pressure [DP] Criteria			
MOP Range [psig]		DP Margin [% / psi]	DP
0	50	15	
51	250	10%	110
251	500	10%	
501	1000	50	
1001	above	5%	

Contingency	Single Device Installations		Multiple Device Installations	
	Max SP [%]	Max Accumulated Pressure [%]	Max SP [%]	Max Accumulated Pressure [%]
Non Fire Case				
First Relief Device	100	110	100	116
Additional Device(s)	-	-	105	116
Fire Case				
First Relief Device	100	121	100	121
Additional Device(s)	-	-	105	121
Supplemental Device	-	-	110	121

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HEAT TRANSFER TECHNOLOGY
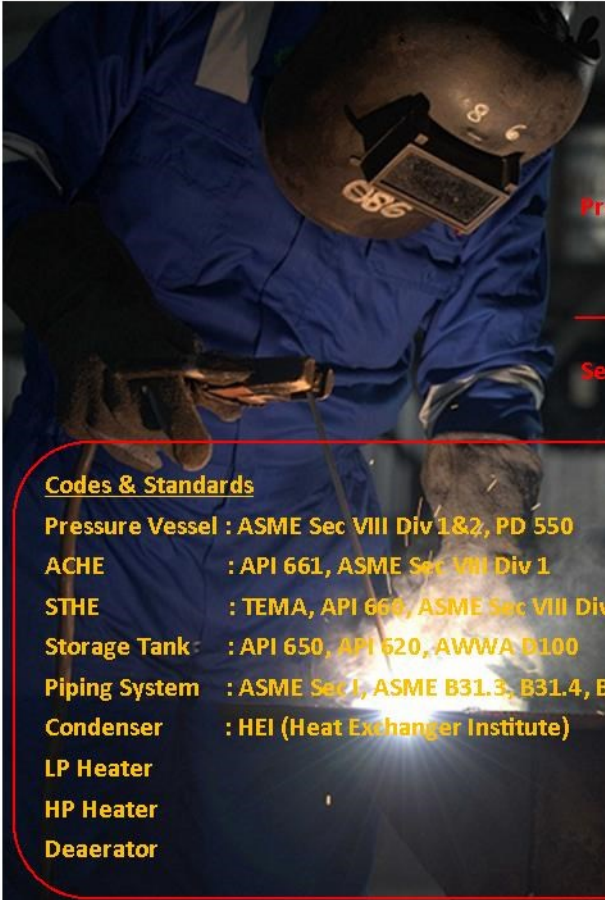
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ACHE   : API 661, ASME Sec VIII Div 1
STHE   : TEMA, API 660, ASME Sec VIII Div 1&2
Storage Tank : API 650, API 620, AWWA D100
Piping System : ASME Sec I, ASME B31.3, B31.4, B31.8
Condenser   : HEI (Heat Exchanger Institute)
LP Heater
HP Heater
Deaerator

Certifications

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The National Board of Boiler and Pressure Vessel Inspectors (NB & R)
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Coprocessing Biomass in Crude Oil Refineries – Challenges and Opportunities

Dr. Marcio Wagner da Silva

INTRODUCTION AND CONTEXT

The increasing necessity to reduce the environmental impact produced by fossil fuels have been created a trend of decarbonization of the energetic matrix at a global level, creating then a new challenge to the crude oil production and processing chain. The current geopolitical crisis due to the war between Ukraine and Russia put another element in this scenario, the necessity to reduce the carbon intensity at same time to keep and ensure the energy security for the nations.

Under this scenario, one of the available alternatives is raising the renewable fuels participation in the energetic matrix as well as the higher use of renewable raw materials in the feed stream of crude oil refineries and this fact has been led some refining technology licensors to dedicate efforts to develop processes for this purpose.

The adoption of synergies between fossil fuels and renewables in the downstream industry depends on the market where the refiner is inserted, mainly related to the availability of renewable raw materials as well as the capacity of the installed refining hardware to processing the renewable streams.

Despite these limitations, it's important to understand that the renewables are already a reality in the market, contributing to the reduction of the demand for fossil raw material, according to data from International Energy Agency (IEA), the COVID 19 pandemic causes the first contraction in biofuels market in two decades, as presented in Figure 1 .

Despite this contraction in 2020, the stricter regulations and policy pressure tends to drive a fast recovery and expansion in the biofuels demand still according to data from IEA presented in Figure 2.

Considering these trends, it's possible to estimate the impact of biofuels in the crude oil reefing industry and the coprocessing of renewable raw material in the traditional crude oil refineries can be an attractive decarbonization strategy. After the COVID 19 pandemic, some refiners decided to convert some refining assets to process renewable raw material, reinforcing this trend in the new scenario of downstream industry.
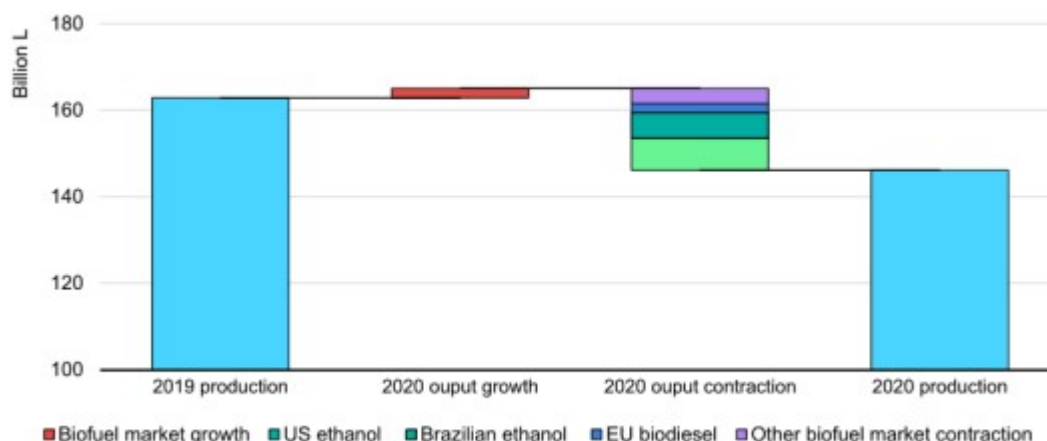

Figure 1 – Biofuels Production in 2019 and the Contraction in 2020 (IEA, 2020)
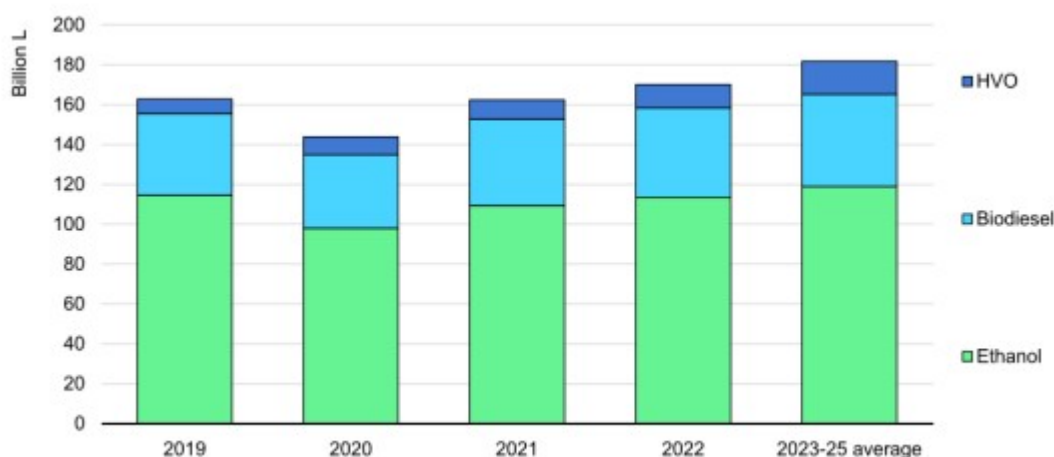
BIOFUELS PRODUCTION IN BRAZIL

Brazil has a long tradition in biofuels production, in 1975 due to the petroleum crisis the Brazilian authorities launched an alternative fuel program called PROALCOOL, where the main intention was to support the development of the ethanol from sugar cane as automobile fuel in substitution of gasoline to reduce the external dependence of the Brazilian energetic matrix.

According to the Brazilian Petroleum Agency (ANP), in 2019 the Brazilian ethanol production reached 35,3 million m3 considering the volumes of anhydrous and hydrated ethanol. This production reveals consistent growing in the production over the years, Figure 3 shows the ethanol production profile over the last years in the Brazilian market.

Based on data from Figure 3, the Brazilian ethanol production growth in an average annual rate of 2,30%, considering only the anhydrous ethanol the annual growth is even more expressive, reaching 2,60 % in 2010-2019 period. By the law, the gasoline commercialized in

Brazil have 27 % in volume of anhydrous ethanol which is applied to improve the gasoline quality (octane boosting) and to ensure participation of renewable fuels in the Brazilian energetic matrix. The hydrated ethanol is commercialized in gas stations as pure fuel to automobiles, still according to data from ANP, in 2019 the Brazilian production of hydrated ethanol reached 24,9 million m3 with an average annual growth of 2,10% considering the 2010-2019 period.

Brazil is a great transportation fuel consumer, and the main driver of the Brazilian economy is the Diesel due to the country dimensions and the transport infrastructure which relies on road transport, the total production of diesel in the Brazilian market reached close to 41 million m3 in 2019. By law force, the diesel commercialized in the Brazilian territory needs to contain 12 % in volume of biodiesel and the intention of the Brazilian government is to raise this percentual to 15 % in 2023. Figure 4 presents the evolution of the Brazilian biodiesel production between 2010 and 2019 in million m3.

Top: Figure 2 – Global Biofuels Production Forecast (IEA, 2020)

Bottom: Figure 3 – Evolution of Brazilian Ethanol Production (ANP, 2020)
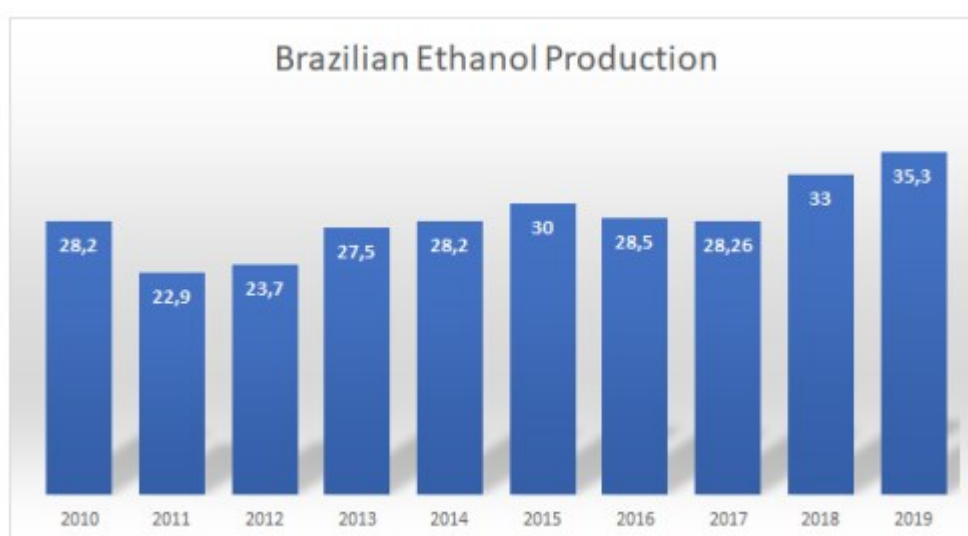
The main raw material applied to produce bio-diesel in Brazil is soybean oil with close to 68 % of the total production followed by the animal fat with 11 %.

As described above, the biofuels are fundamental to sustain the energetic matrix and economic development of Brazil. The blending of anhydrous ethanol to the gasoline and biodiesel to diesel represents a kind of strategy to produce cleaner fuels, but this not the only strategy which are being applied to the refiners aiming to reduce the environmental footprint of the transportation fuels.

An important trend of the energy transition in the downstream industry is the coprocessing of renewables raw material in the crude oil refineries. This strategy involves feeding the renewable raw material directly to the refining process, which represent a more challenging decarbonization strategy.

CHALLENGES OF RENEWABLES COPROCESSING IN CRUDE OIL REFINERIES

The use of renewable raw material in the crude oil refineries has been discussed in the last decades. The adoption of synergies between fossil fuels and renewables in the downstream industry depends on the market where the refiner is inserted, mainly related to the availability of renewable raw materials as well as the capacity of the installed refining hardware to processing the renewable streams.
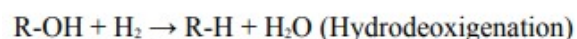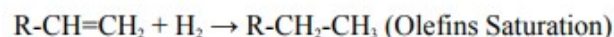
One of the most common processing routes is the utilization of vegetable or animal oils in the feedstock of conversion or treating units to produce high quality fuels and petrochemicals. The renewable raw material can be directly processed together fossil streams in conversion units like fluid catalytic cracking (FCC) to produce transportation fuels and olefins.

The use of renewable streams also can be applied as a feed stream of hydrotreating units, aiming to produce high quality fuels like Diesel and Jet Fuel.

Some refiners and technology licensors have been developed process technologies that make possible the higher synergy of renewables with the conventional refining industry.

In the petrochemical sector, the production of petrochemical intermediates also has been adopted renewables processing routes as ethanol to produce ethylene. Some Companies has been applied the ethylene production through ethanol dehydration since 2010 and some technology licensors have been developed processing routes also dedicated to producing ethylene from ethanol.

Despite the advantages of environmental footprint reduction of the refining industry operations, renewables processing presents some technological challenges to refiners. The renewable streams have a great number of unsaturations and oxygen in his molecules which lead to high heat release rates and high hydrogen consumption, this fact leads to the necessity of higher capacity of heat removal from hydrotreating reactors aiming to avoid damage to the catalysts. The main chemical reactions associated with the renewable streams hydrotreating process can be represented as below:

$$R\text{-}CH=CH_2 + H_2 \rightarrow R\text{-}CH_2\text{-}CH_3 \text{ (Olefins Saturation)}$$

$$R\text{-}OH + H_2 \rightarrow R\text{-}H + H_2O \text{ (Hydrodeoxigenation)}$$

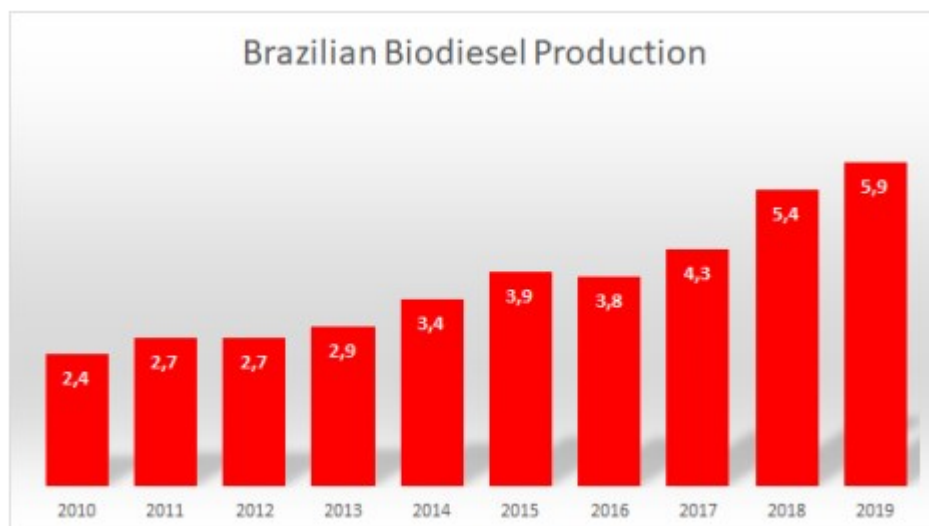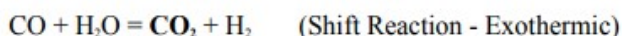Where R represents a hydrocarbon.

Figure 4 – Evolution of Brazilian Biodiesel Production (ANP, 2020)

These characteristics lead to the necessity of higher hydrogen production capacity by the refiners as well as quenching systems of hydrotreating reactors more robust or, in some cases, the reduction of processing capacity to absorb the renewable streams. In this point it's important to consider a viability analysis related to the use of renewables in the crude oil refineries once the higher necessity of hydrogen generation implies in higher CO_2 emissions through the natural gas reforming process that is the most applied process to produce hydrogen in commercial scale.

$$CH_4 + H_2O = CO + 3H_2 \quad \text{(Steam Reforming Reaction - Endothermic)}$$

$$CO + H_2O = CO_2 + H_2 \quad \text{(Shift Reaction - Exothermic)}$$

Despite the concern related to the CO_2 emissions due to hydrogen production there are some cleaner hydrogen production routes that present attractive alternatives to the downstream players like the steam reforming of biomethane, reverse water gas shift (RWGS), and the electrolysis process.

These characteristics lead to the necessity of higher hydrogen production capacity by the refiners as well as quenching systems of hydrotreating reactors more robust or, in some cases, the reduction of processing capacity to absorb the renewable streams.

This fact leads some technology licensors to dedicate his efforts to look for alternative routes for hydrogen production in large scale in a more sustainable manner. Some alternatives pointed can offer promising advantages:

- Natural Gas Steam Reforming with Carbon Capture – The carbon capture technology and cost can be limiting factor among refiners;

- Natural Gas Steam Reforming applying biogas – The main difficult in this alternative is a reliable source of biogas as well as their cost.;

- Reverse water gas shift reaction ($CO_2 = H_2 + CO$) – One of the most attractive technologies, mainly to produce renewable syngas;

- Electrolysis – The technology is one of the more promising to the near future.

As aforementioned, hydrogen is a key enabler to the future of the downstream industry and the development of renewable sources of hydrogen is fundamental to the success of the efforts to the energy transition to a lower carbon profile. In the current scenario, the best alternative to refiners is optimize the hydrogen consumption minimizing the operating costs and CO_2 emissions.

Another challenge associated with renewables processing is the cold start characteristics of the derivatives, mainly Diesel and Jet Fuel. The renewable feed streams produce highly paraffinic derivatives after hydrotreating step, in this sense, the final derivative tends to show a higher cloud point which can be a severe restriction in colder markets as the northern hemisphere.

In these markets, refiners tend to apply catalytic beds containing dewaxing catalysts (ZSM-5) in his hydrotreating units or cloud point depressors additives which can raise the operation costs. Recently, the literature is classifying the hydrogen production routes in four classes as follow (Based on IEA data from 2019):

1 – Brown Route – Hydrogen production from coal gasification without carbon abatement system (CCS). This route presents the higher emission rate of greenhouse gases (19 t CO_2/t H2) and an average production cost of US$ 1,2 to 2,1 per kg H2;

2 – Gray Route – This is the conventional hydrogen production route adopted by the most part of the refiners, which applies steam reforming of natural gas without CCS. This route still presents high emission of greenhouse gases (11 t CO_2/t H2) and an average production cost of US$ 1,0 to 2,1 per kg H2;

3 – Blue Route – This route encompasses the conventional steam reforming of natural gas with CO_2 abatement system. In this case, the CO_2 emissions are drastically reduced (0,2 t CO_2/ t H2), but the average production cost reaches US$ 1,5 to 2,9 per kg H2;

4 – Green Route – As presented above, the green route is based on electrolysis through renewable electricity. In this case it's possible to reach zero CO_2 emissions, but the average production cost is still considered high (US$ 3,0 to 7,5 per kg H2).

The technology development and scale-up gains tends to reduce the production costs of cleaner routes over the next years. Currently, the best alternative to refiners is to optimize the hydrogen consumption to keep under control the operating costs as well as, control the emissions of greenhouse gases.

Today's production of hydrogen is via carbon-intensive processes, with use of hydrogen concentrated in the refining, ammonia, and methanol sectors

Dedicated hydrogen production pathways used (2018)
% of dedicated production

Hydrogen use sectors (2018)
Mt H₂
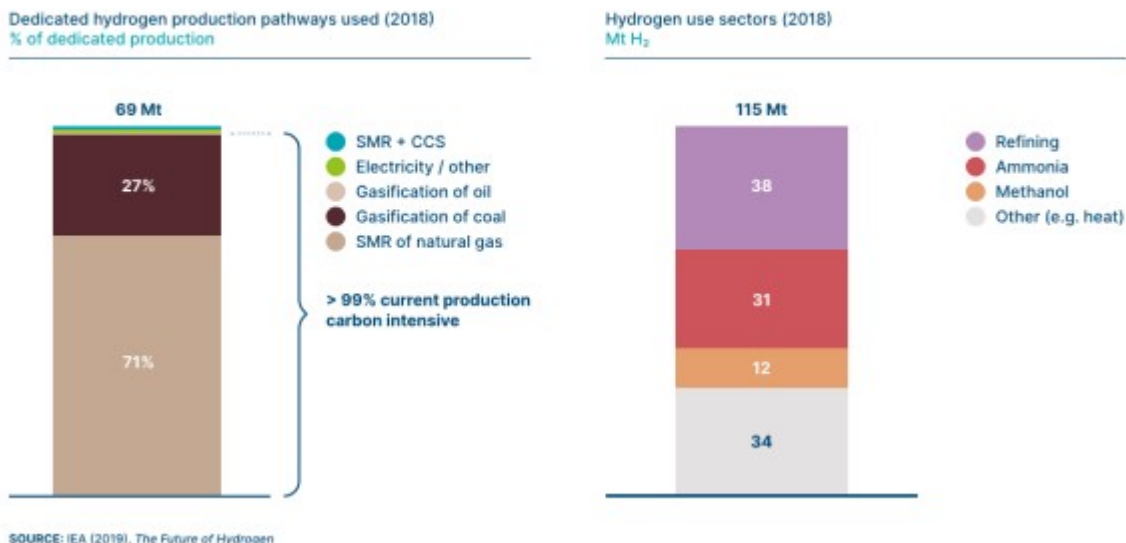
SOURCE: IEA (2019), The Future of Hydrogen

Figure 5 – Main Production Routes and Hydrogen Consumers (ETC Global Hydrogen Report, 2021)

Nowadays, as presented in Figure 5, the crude oil refining industry is the main hydrogen consumer followed by the ammonia production.

Still based on data from Figure 5, 71 % of the hydrogen produced by dedicated processes is from natural gas steam reforming and 27 % from coal gasification, both routes present high emissions of greenhouse gases (mainly CO_2). According to the reference, the difference (close to 75 Mt of hydrogen) is related to the generation where the hydrogen is produced as a by-product like naphtha catalytic reforming or propane steam cracking as example. Crossing the data from Figure 6, it's clear the relevance of the necessity of the energy transition efforts in the downstream sector to the success of the global transition to a low carbon and hydrogen economy.

THE HYDROTREATED VEGETABLE OIL (HVO) – AN ATTRACTIVE ROUTE TO REACH "GREEN DIESEL"

As presented above, the necessity to build a continuous supply of more sustainable transportation fuels are leading the refiners to consider processing renewables raw materials in the refining hardware to achieve cleaner and less carbon fuels. One of the most promising initiatives in this sense in the production of Hydrotreated Vegetable Oil (HVO) to compose the Diesel pool of some refineries, the process consists of in processing renewable material like palm oil in conventional diesel hydrotreating units to produce the called "green diesel".

At this point it's interesting to make a differentiation between the Biodiesel and HVO, the biodiesel is produced through the transesterification, producing a mixture of fatty acids and methyl esters, the HVO basically composed by normal paraffin which is result of hydrotreating reactions. The great advantage of the HVO in comparison with the biodiesel is the similarity of properties in relation with the fossil diesel, the density of the HVO tends to be lower than the fossil diesel and cetane number tends to be high, being a perfect additive in a final mixture, in the other side the high concentration of normal paraffin lead to a worse cold flow characteristics, which can be bypassed through the use of dewaxing beds in hydrotreating reactors applying ZSM-5 catalysts to control the dimension of paraffin chain, due to these characteristics the HVO can be a better blending agent to the final diesel than the traditional biodiesel produced by transesterification as presented in Figure 6.

One of the most relevant challenges of the HVO production is the cost of raw material as well as the choice of this raw material. Another great challenges to the HVO production in the traditional crude oil refineries is the catalyst applied in the process, normally the hydrotreating catalysts are composed by metal sulfide like NiMo or CoMo carried over Alumina, but the low sulfur concentration and the water production during the hydrotreating reaction of renewable raw materials tends to
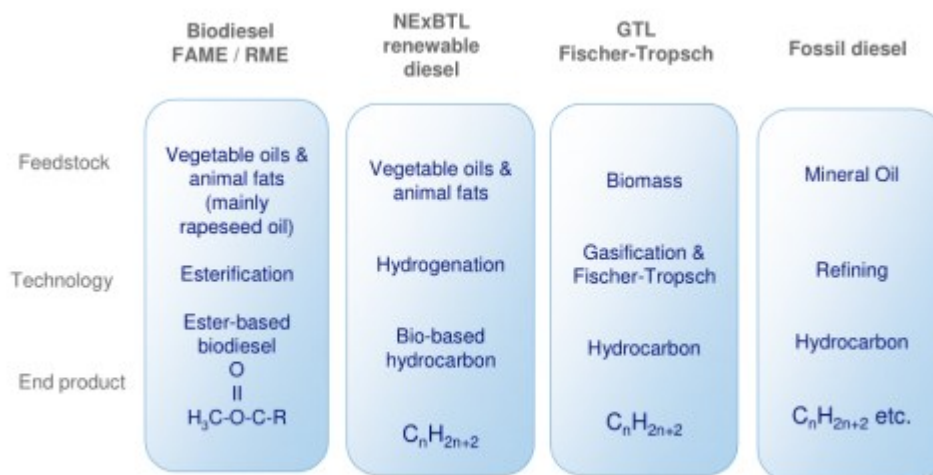
Figure 6 – Renewable Diesel Composition based on Production Route (LINDFORS, 2010)

deactivate these catalysts. An alternative in this case is to feed H2S with the feed stream, but there is always the risk to contaminates the final derivative with high sulfur content, the use of noblest metal like Ru and Pt as active metal can solve this problem, but the operating cos can be prohibitive.

Another challenge related to the HVO production is the higher heat release in the hydrotreating reactors which requires a well dimensioned quenching systems, it's important to remember that the conventional hydroprocessing reactors are designed to deal with low contaminants concentration while the renewables raw materials present high quantity of unsaturated molecules and oxygen, leading to a high heat release rate.

Another issue related with the coprocessing of renewables raw material in crude oil refineries is the tendency of water retention in the final derivatives. Due to the chemical structure, the biodiesel for example, tends to retain more than 8 times more moisture than fossil diesel which can lead to issues like microbiological degradation of the fuel in the transport and storage systems. The soluble water content in pure biodiesel can reach close to 1.800 ppm while the value to the diesel with 20 % of biodiesel can reach close to 280 ppm of soluble water, and the diesel with 5 % of biodiesel can present until 150 ppm, this fact will lead the refiners to adequate their hardware to allow the water removal from the final derivatives applying draining systems or the application of salt filters to control the moisture content in the final derivatives.

From the point of view of crude oil producers, the renewables coprocessing can be faced as overcome through enjoying the change in the profile of crude oil consumption where is observed a growing demand by petrochemicals intermediates like ethylene, propylene, and BTX while the transportation fuels like gasoline and diesel present falling demand.

JET FUEL – A CHALLENGING CASE OF DECARBONIZATION

A special and challenging case of decarbonization of fossil fuel is the jet fuel. Jet fuel is a mixture of hydrocarbons between C5 to C15 with a boiling range of 150 oC to 300 oC, is applied as fuel to Jet turbines, normally applied in aviation. Due to the severity of use conditions, the Jet fuel has quality requirements quite restricted, the combustion needs to be the cleaner possible to avoid depositions, by this reason the polyaromatics content is controlled, this is achieved through the smoke point test.

The characteristics of flow under low temperature are fundamental to the Jet fuel, due to the operational conditions that can achieve temperatures of – 50 oC. The maximum freezing point to commercial jet fuel is – 47oC, by this reason, it's fundamental to ensure an adequate cut point in the distillation step to avoid the drag of heavy paraffins to the intermediate kerosene. The thermal stability is measured through the JFTOT (Jet Fuel Thermal Oxidation Test) test which simulates the operational conditions that the fuel is submitted.

The corrosivity and chemical stability in relation to the materials applied to the construction of turbines are controlled through the content of total sulfur, mercaptan sulfur, and H2S. Normally the jet fuel is submitted to

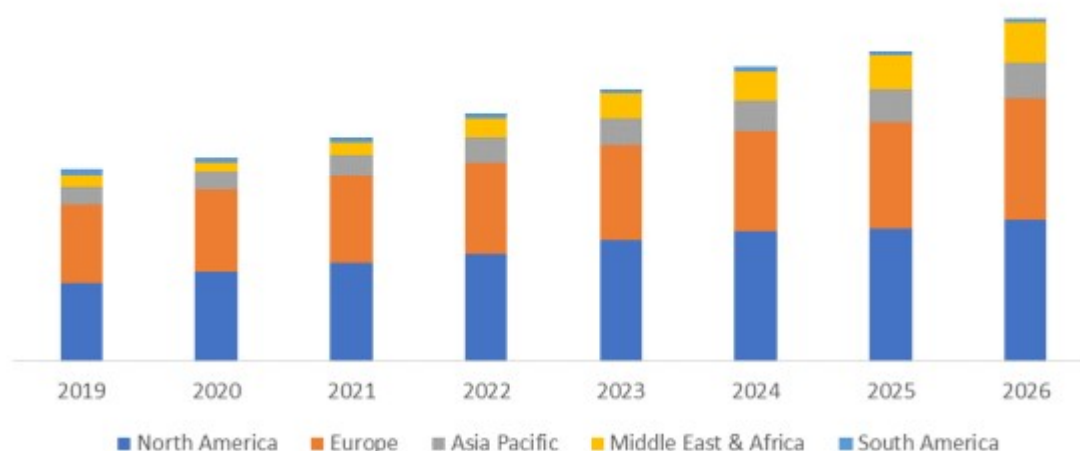## Global Aviation Fuel Market, by Region 2019-2026 (USD Billion)

Figure 7 – Evolution of Jet Fuel Market (Market Research, 2020)

caustic treating step to control of these compounds, in modern refining units this step is carried out in hydrotreating units. The flash point (minimum 40 oC) and the electric conductivity are other requirements directly related to the security in the derivative handling. Figure 7 presents the evolution of the jet fuel market in the last years and forecast for the short term.

According to data from Air Transport Action Group (ATAG), the aviation sector was responsible by emission of 915 million tons of CO_2 in 2019, 12 % of the total emissions from the transport sector.

The growing demand and significant emissions of greenhouse gases are the main drivers for the requirement from the society to reduce the carbon intensity of the jet fuel. This fact led refiners and technology developers to dedicate efforts to develop Sustainable Aviation Fuels (SAF) to be blended with fossil jet fuel and minimize the carbon footprint of the aviation sector.

The main jet fuel production routes are the hydrotreated vegetable oil (HVO) or the hydrotreated esters and fatty acids (HEFA), as described above. In this case, one issue is that the yield of jet fuel is relatively low (about 15 %) once the conventional operating conditions favors diesel production.

Another promising production route is the thermochemical process applying biomass as feedstock, in this case it's possible to apply biomass gasification and Fischer-Tropsch synthesis or thermal or catalytic pyrolysis to produce biojet fuel. Among the technologies dedicated to produce renewable jet fuel we can quote the catalytic hydrothermolysis and biochemical routes which applies fermentation processes. Figure 8 presents a forecast of the Sustainable Aviation Market to 2025, 2050 and 2060.

As presented in Figure 8, the increasing pressure to reduce the carbon intensity of the energetic matrix tends to raise the participation of the biofuels in the market, reducing the consumption of fossil fuels, which can be considered a demand destruction. In this sense, the players of downstream industry needs to consider the revamp of their refining hardware aiming to allow an increasing rate of renewables coprocessing, especially related to the hydrogen generation capacity as well as alternative and high added value routes to add value to crude oil, like petrochemicals, lubricants, etc.

CONCLUSION

The energy transition is not a question of choice to the players of downstream industry, it's a demand from the society and a survival question in middle term. Decarbonization of the energetic matrix requires even more flexibility and agility by refiners aiming to keep and improve his refining margins in the scenario of reduction in the transportation fuels demand and growing demand by petrochemicals, however, as aforementioned there is available processing technologies capable to allow the coprocessing of renewables and
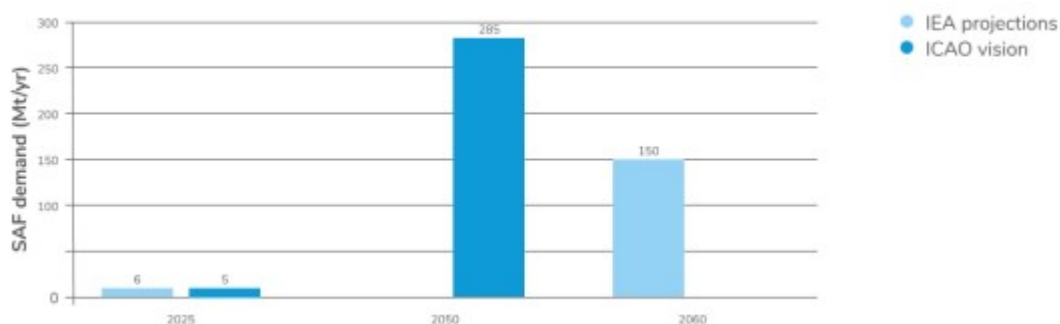
Figure 8 – Global Sustainable Aviation Fuel Demand Forecast (Sustainable Aviation, 2020)

fossil feed streams in crude oil refineries, reducing the environmental impact of downstream industry.

Nowadays, is still difficult to imagine the global energetic matrix free of fossil transportation fuels, especially for in developing economies and raise the participation of renewable raw material in crude oil refineries can be an attractive strategy, the Brazilian case reinforces that, even in nations with great demand by transportation fuels, the biofuels can develop a fundamental role in the energetic matrix.

Despite the recent forecasts indicates a falling demand by transportation fuels and growing demand by petrochemicals, the transportation fuels are still fundamental to sustain the economic development of nations, especially in developing economies. This fact reinforces, even more the necessity to reduce the carbon emissions in the crude oil processing chain and the biofuels can develop a fundamental role to the achievement of this goal in the downstream industry. Although the environmental benefits it's important to consider that the growing market of biofuels can bring some side effects like the shortage of renewable feedstock and, in extreme cases, competition between the fuels and food production.

The growing participation of the biofuels in the energetic matrix also calls the players of the downstream industry to action in order to prepare their refining hardware to increasing rate of renewables coprocessing aiming to keep and enlarge their participation in transportation fuels market, at same time, this scenario can act as a driver for closer integration between refining and petrochemicals assets in order to ensure added value to the crude oil through petrochemicals taking into account the increasing demand destruction of fossil transportation fuels caused by biofuels. Despite the advantages of biofuels and renewables coprocessing in crude oil refineries, it's fundamental

to understand that a real decarbonization is only possible through renewable hydrogen production sources as well as efficient carbon capture technologies.

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Rock Bottom View:

Clean Water: a Human Right, or a Privilege????

Ronald J. Cormier, *Engineering Practice* Contributing Author

This month, we take a look at water insecurity – including everything from a lack of drinking water to the threat of homes being swept away – which can have serious implications for people's wellbeing. Flood victims in Pakistan have experienced post-traumatic stress disorder, for instance. All this means that clean water has become a source of widespread climate injustice, especially in the most vulnerable countries.

Water is essential to life, yet 771 million people in the world - 1 in 10 - lack access to it. According to a report by the World Economic Forum, the water crisis is the #5 global risk in terms of impact to society. In 2020, 6% of the world population did not have access to an improved water source. Access to safe water can protect and save lives, just because it's there. Access to safe water has the power to turn time spent into time saved, when it's close and not hours away. Access to safe water can turn problems into potential: unlocking education, economic prosperity, and improved health.

Every human being deserves to define their own future, and water makes that possible. We've transformed more than 52 million lives with access to safe water and sanitation, and together we can reach even more people. We, as responsible innovators and purveyors of fuels and petrochemicals, require and utilize lots of water for both processing and dilution of finished products. Let's consider for a second water as an unlimited resource like the air that we breathe, or the atmosphere that supports and protects our very being.

WATER AND HEALTH…
Contaminated water and poor sanitation are linked to transmission of diseases such as cholera, diarrhea, dysentery, hepatitis A, typhoid and polio. Absent, inadequate, or inappropriately managed water and sanitation services expose individuals to preventable health risks. This is particularly the case in health care facilities where both patients and staff are placed at additional risk of infection and disease when water, sanitation and hygiene services are lacking. Globally, 15% of patients develop an infection during a hospital stay, with the proportion much greater in low-income countries.

Inadequate management of urban, industrial and agricultural wastewater means the drinking water of hundreds of millions of people is dangerously contaminated or chemically polluted. Natural presence of chemicals, particularly in groundwater, can also be of health significance, including arsenic and fluoride, while other chemicals, such as lead, may be elevated in drinking- water as a result of leaching from water supply components in contact with drinking-water.

Some 829 000 people are estimated to die each year from diarrhea as a result of unsafe drinking-water, sanitation and hand hygiene. Yet diarrhea is largely preventable, and the deaths of 297 000 children aged under 5 years could be avoided each year if these risk factors were addressed. Where water is not readily available, people may decide handwashing is not a priority, thereby adding to the likelihood of diarrhea and other diseases. Diarrhea is the most widely known disease linked to contaminated food and water but there are other hazards. In 2017, over 220 million people required preventative treatment for schistosomiasis – an acute and chronic disease caused by parasitic worms contracted through exposure to infested water.

In many parts of the world, insects that live or breed in water carry and transmit diseases such as dengue fever. Some of these insects, known as vectors, breed in clean, rather than dirty water, and household drinking water containers can serve as breeding grounds. The simple intervention of covering water storage containers can reduce vector breeding and may also reduce fecal contamination of water at the household level.
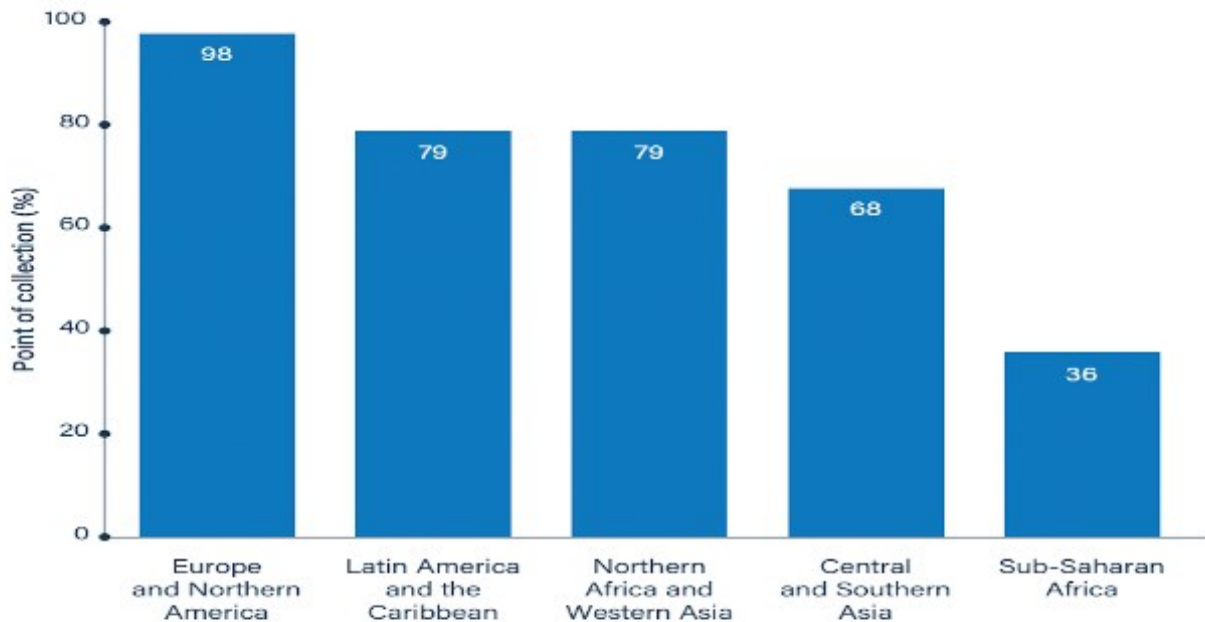
Proportion of population using contamination-free drinking water sources in 2020 (%). State Of The World's Drinking Water report (Unicef, WHO, World Bank), CC BY-SA

AROUND THE WORLD

Alarmingly there are more people now without access to clean water than there were three decades ago. In 2022 the State of the World's Drinking Water report by the WHO, UNICEF and the World Bank, noted that one-quarter of the world's population is left without access to safe drinking water. People in sub-Saharan Africa haven't benefited from investment and have the lowest levels of access.

In many poorer countries, access to drinking water is not recognized as a basic human right. Access in two of those countries, Malawi and Zambia, found that water was neither privatized, nor a state provision. People in these countries instead relied on development aid and donor funding to sink bore holes or provide water pumps in rural areas, and if there was no aid they had to organize clean water themselves on a small community basis. Many pumps and wells do not work, or they are vandalized, and as a result many find themselves drinking unclean water.

Image courtesy of worldvision.com

In such countries there is lots of jockeying between politicians, traditional leaders and communities over who actually owns or should govern water points. Many different actors are involved, including public and private organizations, NGOs, faith-based originations and donors. This all makes the job of providing water even less straightforward, and coordinating these different actors is paramount.

This lack of coordination, combined with an over-reliance on donors and a lack of local input in decision-making leads me to wonder at what point will access to water actually become a national priority in water insecure countries.

IN THE USA

The subject of water protection/availability is not in the U.S. Constitution. The word "water" appears only once in the Constitution, in a provision that permits Congress to auction off enemy warships. The Bill of Rights guarantees all sorts of things, like the right to refuse overnight accommodations to U.S. soldiers, but it doesn't say anything about a glass of water. It was impossible to foresee the Flint, Michigan water scandal—or even indoor plumbing—in 1790.

The U.S. Code contains thousands of mentions of water, but nowhere does it state that water is a human right. In fact, the only such statement in the whole of U.S. law is in the California Water Code, which boldly declares that "every human being has the right to safe, clean, affordable, and accessible water." Two sentences later, however, the code undercuts

its guarantee with a teeny detail: The government doesn't have to actually provide the water. It's the legislative equivalent of "Just sayin'!."

By contrast on the international front, the United Nations General Assembly voted in 2010 to recognize "the right to safe and clean drinking water as a human right." But here, again, there are caveats. First, the U.N. permits the "progressive realization" of human rights. Countries must only do their best with the resources available to provide water. Therefore, the 1.1 billion people worldwide who lack a water tap are not suffering a human rights violation, as long as their governments are making an effort. The other major caveat is that the U.N. declaration does not apply to Americans. The United States and 40 other countries abstained from the U.N. vote to recognize access to water as a human right.

This is only the beginning of the inquiry, though.

Human rights come in many forms; they aren't all prohibitions hammered into the stone tablet of the Bill of Rights. Americans tend to talk about only this kind of right, though. For this, blame Thomas Jefferson. "We hold these truths to be self-evident, that all men are created equal, that they are endowed by their Creator with certain unalienable Rights, that among these are Life, Liberty and the pursuit of Happiness."

Jefferson's passage is so crystal clear that it has come to define the word right in the American mind. But Jefferson is describing just one kind of right: the preexisting negative right. Preexisting because it doesn't need a government to create it, and negative because it describes something the government cannot do: It cannot take the right away. Leave us alone to pursue happiness, Jefferson says, and we'll be fine. Most of the rights in the Bill of Rights are corollaries to Jefferson's description, but the Bill doesn't ever claim to be a complete and exclusive list of human rights.

Positive rights are not foreign to the U.S. Constitution, by the way. The guarantee of a jury trial, for example, is arguably positive. The government must take an action to provide it.

Now, answer these questions: Do you have a right to participate in the Social Security system? Do you have a right to be free from discrimination in the workplace? Of course, you do. You will not find these rights in the Constitution, though.

Harvard law professor Cass Sunstein argues that President Franklin D. Roosevelt's New Deal–era 'programs represented a second Bill of Rights—positive human rights based on the idea that the government must provide a basic standard of living to all citizens through statute and regulation. Since FDR's death, many of these promises, like the guarantee of a basic income in old age, have become quasi-constitutional and nearly as sacred as the Bill of Rights itself.

Which brings us back to water. Clean, safe drinking water belongs in this category, according to a forthcoming paper by Suffolk University law professor Sharmila Murthy. A web of state laws and federal statutes—from the Clean Water Act to the Resource Conservation and Recovery Act to the Safe Drinking Water Act—stands for the proposition that providing safe, clean water is an absolute government obligation. Public outrage at the recent wave of drinking water crises also supports the idea that the American public views access to clean water as a basic human right. It hardly matters that the founding fathers failed to mention it in the Bill of Rights.

The definition of an improved drinking water source includes "piped water on premises (piped household water connection located inside the user's dwelling, plot or yard), and other improved drinking water sources (public taps or standpipes, tube wells or boreholes, protected dug wells, protected springs, and rainwater collection)." Note that access to drinking water from an improved source does not ensure that the water is safe or adequate, as these characteristics are not tested at the time of survey. But improved drinking water technologies are more likely than those characterized as unimproved to provide safe drinking water and to prevent contact with human sewage.

Viewed from this perspective, the question is not whether a human right to water exists, but whether our state and federal governments are fulfilling it. The answer, for the residents of Flint, Michigan, Hoosick Falls, New York, and Jackson, Mississippi, is clearly no.

The United States has a shameful history of denying basic rights to people of color, and the concentration of water violations in Black communities echoes those injustices. The United Nations Special Rapporteur on the human right to safe drinking water and sanitation suggested in 2014 that the city of Detroit, by shutting off water to poor Black families, had failed in its obligation to fulfill water rights in a non-discriminatory fashion. The NAACP and ACLU have made similar claims.

Image courtesy of naco.org

Water administrators have a saying: "Water is God's gift . . . but He forgot to lay the pipes." It's time for the state and federal governments to accept the idea that responsibility for some human rights falls to them.

Until July's edition, we hope "The View" offers readers with a few key aspects to consider, toward heightened respect for the very resource which nourishes our lives on Earth.

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