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How to... TUNNEL TRAY
How to Design and Optimize Tunnel Trays

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Tunnel trays are more than only „trays with rectangular bubble caps". There are two variants of orientation of the tunnels on the active area with specific features. Even though there is only few and rather old public literature of Tunnel trays, this tray type is used in many applications.

Tunnel trays have many things in common with Bubble Cap trays. On the other hand, they are also very different and have specific features that make them the first choice for some

applications!

There is only few literature about Tunnel trays. Most of the research work and publications were done 60 years ago (e.g. HOPPE/ MITTELSTRASS 1967, DIERY 1960).

Similar to the bubble caps is the flow path of the gas through riser and cap (Fig. 1): The gas ascends in the riser (a), is redirected in the top of the cap (b) (reversal area) and then flows downwards to the gap (c). Finally, the gas enters the liquid layer through the openings of the cap (d).

By this the riser and the cap form a siphon, where liquid cannot weep. Tunnel trays (like Bubble Cap trays) are therefore able to handle very small liquid rates. There is no weeping as an operational limit!
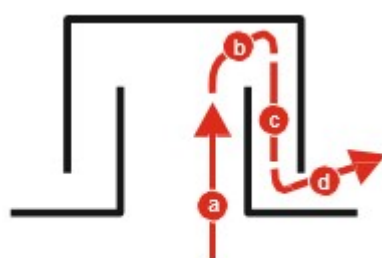

Fig. 1: Gas Flow Path

The length of a tunnel is set by the dimension of the active area or by construction issues. To handle even small gas load without having trouble with tray levelness or hydraulic

gradient, the tunnel caps are slotted. This corresponds to the idea of notched outlet weirs distributing liquid to the entire length.

The slots at the skirt act as dynamic openings (Fig. 2): At a small gas load, only the top of the slots of the skirt is used by the gas. The more gas is flowing, the more the slots are opened by the gas. The pressure drop characteristic of a Tunnel tray is therefore more like that of a float valve (dynamic openings) tray than that of a sieve tray (static openings). Because of the gas flow path (with its redirections) the dry pressure drop of the Tunnel tray is slightly higher than that of Sieve or Valve trays.
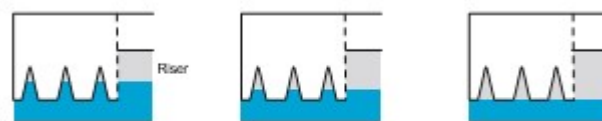
Fig. 2: Dynamic behavior of the skirt openings

The main difference to bubble caps is the shape of risers and caps. The rectangular tunnels have a length and a width. Hence, there are two principle arrangements of the tunnels on the active area.

When liquid flows through the lanes between the tunnels directly from the inlet to the outlet of the tray (Fig. 3), the configuration is called STREUBER design. This variant can also be used for high liquid load, as the hydraulic gradient of the straight lanes is less than the hydraulic gradient of a comparable bubble cap design.

Fig. 3: Single-pass STREUBER design

Fig. 4: Two-pass STREUBER design

Fig. 6: Pushing effect of tunnel caps.

Tunnel trays of type STREUBER can be designed as single or multi-pass trays. Fig. 4 shows a two pass design.

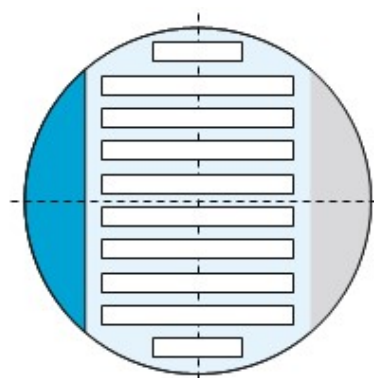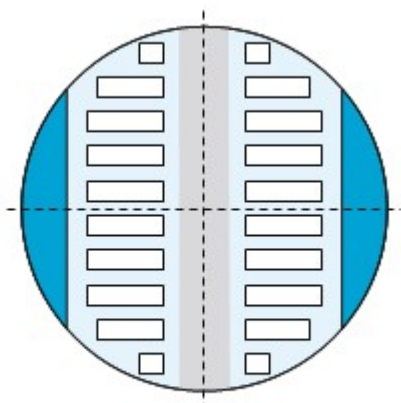The perpendicular orientation of the tunnels is called THORMANN design (Fig. 5). Liquid is meandering around the tunnel caps. The path of the liquid is quite long. The flow path length is about the sum of all tunnel lengths.

This type is used for applications with the need of high residence time (e.g. chemical absorption) or for small liquid load.
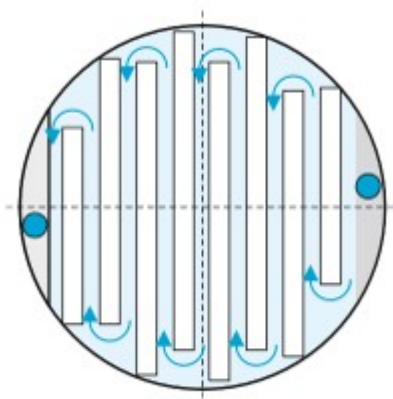

Fig. 5: Tunnel THORMANN design

The defined liquid path is a great feature of the THORMANN design. The liquid path of a Bubble Cap tray at a comparable liquid load is random. In the worst case, most of the active area is stagnant and liquid passes only few bubble caps along a favorite path. By using a Thormann type tray, liquid is guided across the entire active area and will be in contact with all gas.

At a long flow path, you normally would have to deal with a high liquid gradient. To solve this problem, the tunnel openings are acting as pushing elements (Fig. 6). For caps fabricated

from metal material, there are bended flaps directing the gas in flow direction of the liquid (Fig. 6, left). For plastics and carbon material the slots are fabricated with an inclination to the
cap length achieving the same pushing effect (Fig. 6, right).
Since the THORMANN design is used for small liquid load, there is normally no need for multi- pass designs in meanings of having several downcomers. But at large tower diameters even for THORMANN designs there can be several flow passes (Fig. 7).
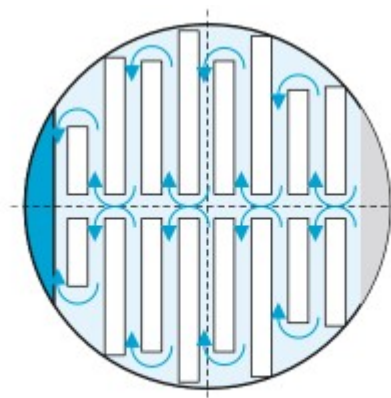
Fig. 7: Multiple flow passes at THORMANN designs.

Another aspect in comparing Bubble Cap trays to Tunnel trays is fabrication. On one hand it is easier to fabricate the caps for tunnels by bending than deep drawing for bubble caps. For special materials you will therefore realize Tunnel trays, because bubble caps are no economical alternative. On the other hand the fabrication of the risers at a Tunnel tray deck has always to do with welding. This is costly.

DESIGN OF RISER, CAP AND DOWNCOMER
Fig. 8 shows a sketch of a downcomer with clearance, a tunnel cap (STREUBER-type), with its riser and an outlet weir.
As for all tray designs there should be a static sealing of outlet weir to clearance (A). This sealing is important for startup (especially at low liquid load).
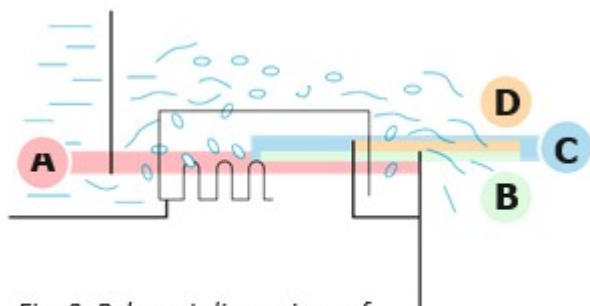
Fig. 8: Relevant dimensions of tunnel cap, riser, clearance, and outlet weir

When the tray is running at low liquid and low gas load, gas will leave the cap at the top most slot area. This point should be submerged (B).

The liquid level above the top of the gas outlet of the cap defines the minimum contact time for the gas. It is called „static slot submergence".

At presence of liquid flow there will be an additional weir crest height. This dynamic slot submergence (C) defines the contact time of the gas with the liquid at operation.

Finally the riser height should preferably be higher than the outlet weir (D). Whenever there are waves on the tray or the hydraulic gradient is high, the risk of weeping should be minimized.

The Operating Area of a Tunnel tray is defined by different limits. In Fig. 9, a qualitative operation diagram is shown. Please note, that the position and shape of all curves depend on the physical data, the tray and cap geometry and the gas/liquid load. Each curve can be limiting!

The Operating Point (Op in Fig. 9) of the tunnel cap, riser, clearance, and outlet weir design case (as well as the minimum and maximum load) has to stay inside all limiting curves. For stable operation and good efficiency there is a useful operation area with narrower limits.

The first step in analyzing a design is to calculate all relevant limits and parameters. For a Tunnel tray design there are 9 main parameters shown as curves in Fig. 9.

There are some additional effects you will have to look at: entrainment, head loss at downcomer exit (clearance), flow regime, downcomer residence time, efficiency, hydraulic gradient, spray height, sealing, construction issues, statics, … About 40 parameters have to be calculated and checked (e.g. software TRAYHEART OF WELCHEM).

Fig. 9: Qualitative Operation Diagram for Tunnel trays

In the following sections, all 9 main limiting curves of Fig. 9 are described. Each suggested action for preventing a certain effect may result in fertilizing another. The main task for designing trays is to balance these different and contradicting effects.
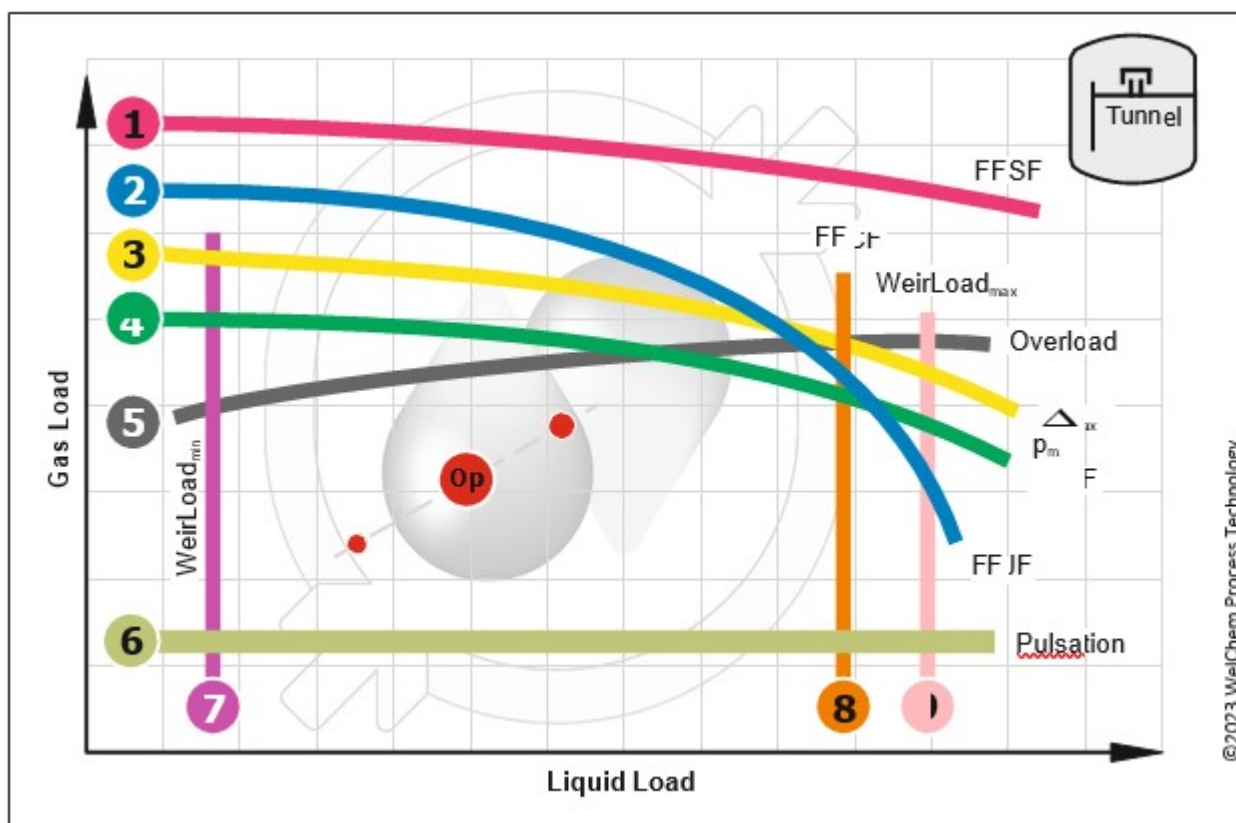
1 System Flood FFSF

There is a system limit set by the superficial gas velocity in the tower. When the gas velocity exceeds the settling velocity of liquid droplets („Stokes Law Criterion"), gas lifts and takes much of the liquid with it. A well known model was published by STUPIN AND KISTER 2003.

This flooding effect cannot be reduced by use of other tray types or by increasing tray spacing.
The only way is to enlarge the gas cross section area (e.g. enlarging tower diameter or reduce downcomer area).

For Tunnel trays you will rarely touch this limit, as Tunnel trays are used for handling small liquid rates (THORMANN).

2 Jet Flood FFJF

There are several definitions in literature for the so-called Jet Flood. Similar definitions are Entrainment Flood, Massive Entrainment, Two - Phase Flood or Priming. For practical understanding, Jet Flood describes any liquid carried to the tray above by the gas stream. This leads to a shortcut recycling of the liquid with loss of tray efficiency, additional pressure drop and additional downcomer load.

Jet Flood is only calculated for STREUBER designs. For THORMANN designs there is another limiting mechanism (see curve 5).

You can reduce Jet Flood by
A. lowering the gas velocity (higher open area, i.e. higher tunnel length, higher escape area)
B. enlarging the tray spacing
C. lowering the froth height on the tray deck (by reducing weir height or weir crest height)
D. enlarging the active area (i.e. the gas flow area) by sloping the downcomers

3 Pressure Drop

In most cases there is specified a maximum allowable pressure drop of the tower. You have to ensure that the pressure drop per tray does not exceed a certain value. This leads to a limiting curve within the operation diagram.

To reduce the pressure drop of a design, you can
A. lower the gas velocity by enlarging the length of tunnels or change their geometry
B. lower the froth height on the tray deck (by reducing weir height or weir crest height)
C. enlarge the active area (with space for more tunnels) by reducing the downcomer area or sloping the downcomers

4 Aerated Downcomer Backup FFAF

This limiting effect is also known as Downcomer Backup Flood. It describes the (aerated) backup of the downcomer due to pressure drop effects. It is important to not mix this up with the Choke-Flood-effects (ref. to 8).

The level of the liquid in the downcomer is the result of (i) head loss at the clearance, (ii) the liquid height on the outlet deck, (iii) an inlet weir (if present) and (iv) the pressure drop of the tray itself. All these effects can be expressed by "hot liquid height". This resulting level in the downcomer has to compensate these effects! Taking into account the aeration of the liquid in the downcomer, the level has to be less than tray spacing plus weir height.

To reduce a high Aerated Downcomer Backup value you have to

A. reduce the pressure drop of the tray (ref. to curve 3)
B. reduce the head loss of the clearance (use higher clearance height or radius lips or recessed seal pans in case of insufficient sealing)
C. avoid inlet weirs

Please note, that it is no option to enlarge the downcomer area to reduce this flooding ef-

5   Overload Caps

At high gas loads, the space between the tunnel caps is dried – the liquid cannot enter this region and is blown to a froth layer above the caps.

THORMANN designs are dealing with the pushing effect of the openings. By overloading the slots the lanes between the tunnels are blown free and this pushing effect is off. Thus, for THORMANN designs this limit is more relevant than the Jet flood.

A. To prevent overload of caps, you can adapt the design of the caps (more slots, enlarge width of slots, higher skirt)
B. enlarge the tunnel length

6   Pulsation

The slots of tunnel caps are opened by the gas flow. To have a stable operation, the gas has to open all slots of all bubble caps. If there is not enough gas (minimum slot velocity not reached), the tunnels are pulsating.

A. To reduce Pulsation you have to change cap design (less slots, reduce width of slots)
B. reduce tunnel length

7   Minimum Weir Load

The uniform thickness of the two-phase layer is essential for the successful operation of a tray. To achieve this uniform flow, the tray panels have to be in level and the outlet weir has to be installed accurately.

To compensate small tolerances, the weir crest should be higher than 3mm.

At small liquid loads (as typically for THORMANN designs) there are often piped downcomers with very small weir lengths.

To ensure these minimum values, you can use
A. notched weirs (for STREUBER designs)
B. blocked weirs (often used with Tunnel trays)

8   Choke Flood

The maximum liquid throughput of a downcomer is limited by the liquid velocity and the effect of overload (so called Choke Flood). The maximum allowable liquid velocity in the down- comer depends on the density ratio of gas to liquid, the tray spacing and the system factor. (The system factor describes the difficulty of phase separation. For common applications it is 1.0.) The most popular downcomer choke flooding calculation was published by GLITSCH 1993.

Another effect of Choke Flood at center and off- center downcomers is initiated by the mutual interference of the two liquid flows into the downcomer.

To prevent downcomer Choke Flood you have to

A. enlarge the downcomer area
B. implement more flow passes (with in sum an overall higher downcomer area)
C. enlarge the tray spacing (if limiting)
D. install anti-jump baffles for center / off-center downcomers

9   Maximum Weir Load

The maximum liquid flow handled by a downcomer can also be limited by the weir. A high weir crest height corresponds to a high wet pressure drop. The design limit for standard trays is about 37mm.

For Tunnel Trays (especially for THORMANN designs) this limit is somehow theoretical.

To prevent overload of the weir, you have to extend the weir length by

A. larger downcomers with longer weirs (or multi-chordal downcomers)
B. more flow passes
C. swept-back weirs at the side downcomers

CONCLUSION

The Tunnel tray complements the field of application of the Bubble Cap tray: For very low liquid load the THORMANN design (with defined contact time and path) and for high liquid load the STREUBER design (with smaller liquid gradient) is favorable.

A Tunnel tray must be designed correctly and implemented well in terms of construction and fabrication in order to prove itself in operational practice.

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Volker Engel studied process engineering at the Technical University of Munich and did his Ph.D. thesis on packed columns with Prof. Johann G. Stichlmair. Since 1998 he has been the managing director of WelChem Process Technology GmbH and head of the TrayHeart software. TrayHeart has developed into a state-of-the-art design tool for trays and internals in process technology.

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Is It Possible to Inject Hydrogen to Natural Gas Pipeline?

Hamid Reza Seyed Jafari, Seyed Mohammad Reza Seyed Jafari

INTRODUCTION

Based on new search results, it is possible to inject hydrogen into natural gas pipelines, but there are some technical challenges and limitations. Hydrogen can be blended with natural gas up to a certain percentage (around 15%) without requiring major modifications to the pipeline infrastructure or the end-use applications. However, higher concentrations of hydrogen may cause issues such as hydrogen embrittlement of steel pipelines, permeation and leakage of hydrogen, and compatibility of compression and metering equipment. Therefore, converting existing natural gas pipelines to deliver pure hydrogen may require more substantial modifications.

BENEFITS

Also, injecting hydrogen into natural gas pipelines has some benefits such as energy storage, resiliency, and emissions reductions. Blending hydrogen with natural gas can help mitigate the negative effects of greenhouse gases and climate change by neutralizing carbon emissions. Blending hydrogen can also provide a steady demand for hydrogen production and utilization.

PET ANALYSIS

There are some of the challenges, costs, technologies, and policies related to hydrogen injection into natural gas pipelines as follows:

- Challenges: Hydrogen injection may cause embrittlement of steel pipelines, permeation and leakage of hydrogen, compatibility of compression and metering equipment, safety hazards due to flammability and explosion risks, and uncertainty of end-use applications.

- Costs: Hydrogen injection may reduce the upfront capital costs of hydrogen projects by using existing natural gas infrastructure. However, hydrogen production from renewable sources is still more expensive than natural gas or hydrogen from fossil fuels. Moreover, hydrogen injection may increase the operational costs of pipeline maintenance and monitoring.

- Technologies: Hydrogen injection requires technologies such as blending devices, separation units, leak detection systems, pipeline monitoring methods, and hydrogen-compatible appliances. Some of these technologies are still under development or need further improvement.

- Policies: Hydrogen injection requires policies such as standards and regulations for hydrogen quality, blend limits, safety measures, and emissions accounting. Some of these policies are still under development or need further harmonization at the EU and national levels.

INJECTING HYDROGEN IN NATURAL GAS GRIDS OPERATION

Governments and utilities worldwide are looking to low- and zero-carbon hydrogen injection into the natural gas grid to displace fossil fuel consumption and reduce emissions.

S&P Global Platts Analytics' Scenario Planning Service took an in-depth look into this topic in an special report, Hydrogen injection into California gas grid: a strategy to solidify demand to drive supply.

Hydrogen has a much lower energy density than natural gas on a volumetric basis. For this reason, end-users of a blended gas would require a higher volume of gas to achieve the same number of British Thermal Units versus end-users consuming pure natural gas. Hence, a 5% blending of hydrogen by volume does not directly translate into a 5% displacement of fossil fuel consumption.

As hydrogen blending increases, the average calorific content of the blended gas falls, and thus an increased volume of blended gas must be consumed to meet the same energy needs. For instance, a 5% blending by volume of hydrogen would only displace 1.6% of natural gas demand.

Pipeline injection has recently been featured in the national hydrogen strategies of the Netherlands and Australia, in addition to a host of small-scale pilot projects.

The graphic below shows the scale of various pilot projects exploring the impacts of hydrogen blending across countries. California has taken the lead on studying hydrogen injection in the US – with a Public Utilities Commission (CPUC) ruling from November 2019 giving utilities twelve months to propose a preliminary renewable hydrogen injection standard.

HYDROGEN BLENDING LIMITS IN NATURAL GAS GRID BY VOLUME
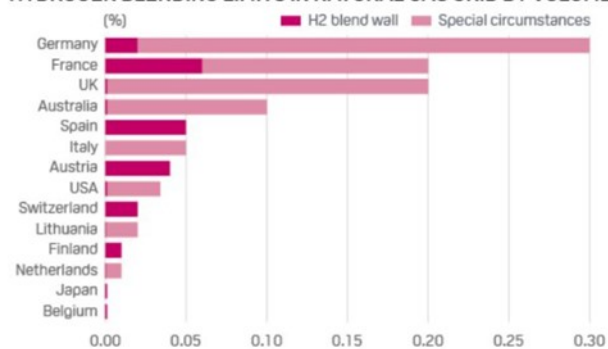
Source: S&P Global Platts

LOW EMISSIONS REDUCTION POTENTIAL

How the hydrogen is produced (as significant implications for the emissions reduction achieved from displacing natural gas)? Many policymakers, including California's CPUC, appear to be hesitant to subsidize fossil hydrogen even in cases where CCS technology is employed.

Steam methane reforming (SMR) is the source of over 70% of global hydrogen supply today. If the hydrogen were produced via this pathway without coupling with carbon capture and storage (CCS) technology, it would result in a significant increase in total emissions, a net increase in natural gas demand, and significant additional costs.

Assuming 100% of hydrogen were sourced from zero-carbon electricity, and energy delivered to end users was held constant, 5% hydrogen blending by volume in the California natural gas grid would reduce state-wide emissions by 2.0 million tons of CO_2 in 2019, or less than 1% of state emissions. Hydrogen production of this magnitude would consume over 16% of the state's ample zero-carbon power generation.

Platts Analytics has found also that, all things being equal, hydrogen blended into the natural gas grid has a low CO_2 abatement potential versus other hydrogen-decarbonisation end use strategies. A kg of zero-carbon hydrogen used to displace grid methane has less than 20% of the impact of an equal amount employed in some of the most effective decarbonisation pathways such as low-carbon steel and materials production.

The benefits of hydrogen injection into the natural gas grid could extend past direct fossil fuel displacement and system decarbonisation. Early 2020, the Dutch central government released their national hydrogen strategy, which outlined potential regulatory support for hydrogen injection mandates as a form of stable near-term demand for the product. That has the potential to give a boost to hydrogen sector development.

As seen in the graphic below, taken from analysis done by US utility PG&E, at lower blend volumes the natural gas grid and its end users would require very little adjustment to accommodate hydrogen. This positions the natural gas grid, given the appropriate regulatory mandates, as a very low-cost source of hydrogen demand, providing greater certainty for investors in hydrogen supply.

A ramping up of supply would put downward pressure on levelized costs via economies of scale and learning-by-doing. This could further improve the economics of hydrogen in other applications with higher average per-kg decarbonisation potentials.

At higher blending ratios, some retrofits to the grid may be necessary. Some costly challenges of high volume blending include steel embrittlement of pipeline material and damage to burners caused by fuel combustion aberrations.

SENSITIVITY OF NATURAL GAS INFRASTRUCTURE TO HYDROGEN BLENDING
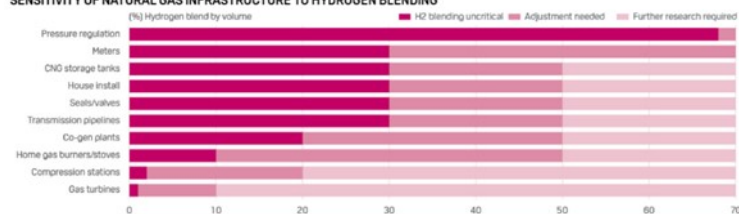
Source: PG&E

Because of low production efficiency of modern electrolysers and the relatively low carbon footprint of natural gas combustion versus other fossil fuels, hydrogen injection has a low average CO_2 abatement potential per kg of hydrogen versus other zero-carbon hydrogen usages.

Grid injection is, however, an attractive source of near-term demand for hydrogen at low blend volumes due to low incremental costs. Increasingly, regions with aspirations to develop a low-carbon hydrogen economy are likely to turn to grid injection as a means of cultivating a market and stimulating investment into supply.

COUNTRIES REFERENCES

Based on search results, some of the countries that inject hydrogen to natural gas pipeline are **Germany**, **Norway**, **the Netherlands** and **Australia**. These countries have either defined blending targets for 2030 or launched pilot projects to explore the impacts of hydrogen blending. Hydrogen blending is seen as a first step to decarbonising natural gas and reducing CO_2 emissions.

COST

Green hydrogen production is more expensive than natural gas production in most regions. The levelised cost of hydrogen production from natural gas ranges from **USD 0.5 to USD 1.7 per kilogramme (kg)**, while the cost of green hydrogen production from renewable energy sources varies depending on the electricity price and the electrolyser capacity factor, but it is typically between **USD 3 and USD 6.5 per kg**. However, green hydrogen production costs are expected to decline in the future as renewable energy costs decrease and electrolyser efficiency improves.

WATER ELECTROLYSIS

Green hydrogen is hydrogen that is produced by using renewable energy sources, such as solar or wind power, to split water into hydrogen and oxygen through a process called electrolysis. Green hydrogen is also referred to as "clean hydrogen" because it does not produce any direct emissions of greenhouse gases or pollutants. Green hydrogen is different from other types of hydrogen, such as grey hydrogen (produced from fossil fuels such as coal), blue hydrogen (produced from natural gas with carbon capture and storage), or turquoise hydrogen (produced from methane pyrolysis).

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Centrifugal Compressor Settle Out Conditions

Jayanthi Vijay Sarathy

Centrifugal Compressors are a preferred choice in gas transportation industry, mainly due to their ability to cater to varying loads. In the event of a compressor shutdown as a planned event, i.e., normal shutdown (NSD), the anti-surge valve is opened to recycle gas from the discharge back to the suction (thereby moving the operating point away from the surge line) and the compressor is tripped via the driver (electric motor or Gas turbine / Steam Turbine).

In the case of an unplanned event, i.e., emergency shutdown such as power failure, the compressor trips first followed by the anti-surge valve opening. In doing so, the gas content in the suction side & discharge side mix.

Therefore, settle out conditions is explained as the equilibrium pressure and temperature reached in the compressor piping and equipment volume following a compressor shutdown.

IMPORTANCE OF SETTLE OUT CONDITIONS

The necessity to estimate settle out conditions,

1. Settle Out Pressure (SOP) & Settle Out temperature (SOT) determines the design pressure of the suction scrubber & piping.

2. The suction scrubber pressure safety valve's (PSV) set pressure as well as the dry gas sealing pressures are decided by the settle out pressure.

3. When the compressor reaches settle out conditions, process gas is locked inside the piping and equipment and grips the compressor rotor from rotating effectively when restarted. Hence depressurizing is done by routing the locked gas to a flare, via the vent valve to reduce the pressure and achieve effective re-start.

ESTIMATING SETTLE OUT CONDITIONS

Although there are many process simulations tools that can be used to conduct a transient study to determine settle out conditions, hand calculations based on first principles of thermodynamics can also be easily employed. In order to do so, the gas compressor system can be reduced with the assumptions as follows, with the philosophy of using a lumped parameter model, in which an energy balance is made across the total volume of the compressor loop taking into account, the compressor deceleration rate.
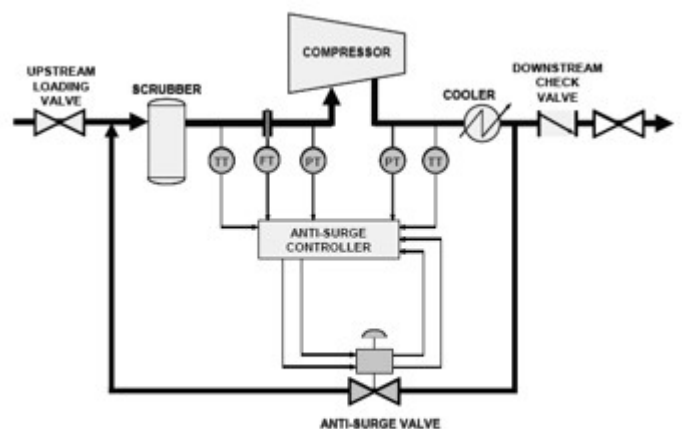
Figure 1. Schematic of Compression System

The assumptions made for this module are,

1. The compressor loop system is a closed loop & no gas has escaped the system.

2. The rate of closure of the suction & discharge block valve in addition to the check valve on the discharge side is neglected.

3. The air cooler is assumed to be running at constant duty before and after the compressor is shut down. If the cooler failure occurs due a power trip, then heat rejection (QCooler = 0) is considered to stop instantaneously.

4. The piping is considered to be adiabatic & no heat escapes from the equipment & piping.

5. The suction scrubber, if considered to have accumulated liquids, then this volume is subtracted from the equipment volumes.

6. The time delay between the fully closed position & fully open position of the Anti-surge valve (ASV) and check valve is not considered.

7. When the driver coasts down after a trip, some amount of residual work is done on the gas.

8. Compressor shutdown times are also influenced by the fluid resistance, dynamic imbalance, misalignment between shafts, leakage and improper lubrication, skewed bearings, radial or axial rubbing, temperature effects, transfer of system stresses, resonance effect to name a few and therefore in reality, shutdown times can be lower than estimated by the above method.

CALCULATION METHODOLOGY

The lumped parameter methodology applied to the compressor loop can be depicted as,

When Anti-Surge Valve (ASV) Opens, Hot side gas and cold side gas mix till an Equilibrium Temperature and Pressure is reached. a.k.a. Settle Out Conditions
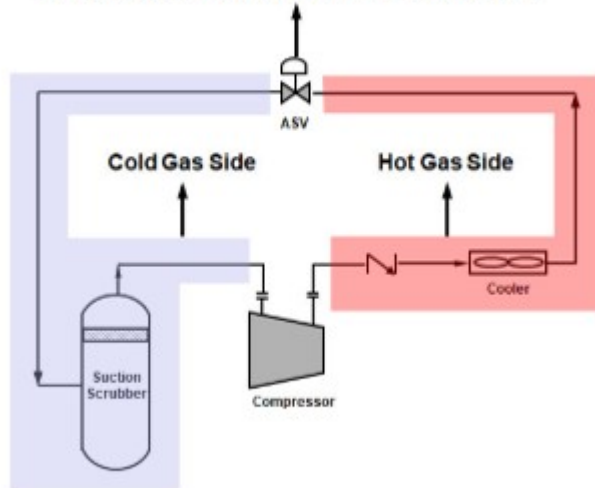
Figure 2. Gas Compressor Loop

Based on the assumptions made, the Settle Out Temperature (SOT) can be estimated as,

$$T = SOT = \frac{(m_S c_{p,S} T_S + m_D c_{p,D} T_D) - Q_{Cooler} + (m_S + m_D)(H_P(t))}{m_S c_{p,S} + m_D c_{p,D}} \quad (1)$$

Where,

$$H_p(t) = A(Q)^2 + B(QN) + CN^2 \quad (2)$$

$$N = N(t) = \frac{1}{\frac{1}{N_0} + \frac{216000k(t - t_0)}{(2\pi)^2 J}} \quad (3)$$

Where,

$H_P(t)$ = Rate of change of polytropic head as the compressor coasts down [kJ/kg/s]

$N(t)$ = Rate of compressor speed decay [rpm/s]

m_s = Suction side gas mass [kg]

m_D = Discharge side gas mass [kg]

T_s = Suction temperature before shutdown [K]

T_D = Discharge temp before shutdown [K]

$C_{p,s}$ = Suction Side Heat Capacity [kJ/kg.K]

$C_{p,D}$ = Discharge Side Heat Capacity [kJ/kg.K]

Q_{Cooler} = Cooler Duty [kJ/s]

k = Fan Power Law Constant

J = Total Inertia of Compressor System [kg.m^2]

The Settle Out Pressure (SOP) can be estimated

$$SOP = \frac{m \times Z_{avg} \times R \times SOT}{MW \times (V_1 + V_2)} \quad (4)$$

Where,

m = Total gas mass [kg]

Z_{avg} = Average Compressibility Factor [-]

R = Gas Constant [m^3.bar/kmol.K]

MW = Gas Molecular weight [kg/kmol]

SOT = Settle Out Temperature [K]

V_1 = Suction side volume [m^3]

V_2 = Discharge Side Volume [m^3]

CASE STUDY

A validation case study is made for a Tank Vapour compressor in a Gas Compression Plant. Suction pressure exists at 1.05 bara, 540C with a discharge pressure of 5.5 bara,

1280C. The coast down period is calculated initially followed by performing settle out calculations. An assumption is made, that the air cooler continues to operate after shutdown. The compressor maps used is

Table 1. Compressor Performance Curves

H_p	Q	Q/N	H_p/N^2
[kJ/kg]	[Am³/s]	[(Am³/h)/rpm]	[kJ/(rpm²)]
136.2	3.0778	0.000322	1.493E-06
133.9	3.4278	0.000359	1.468E-06
130.5	3.6806	0.000385	1.431E-06
126.6	3.8472	0.000403	1.388E-06
123.6	3.9583	0.000414	1.355E-06
115.8	4.1111	0.000430	1.269E-06
109.6	4.1806	0.000438	1.201E-06
100.0	4.2500	0.000445	1.096E-06
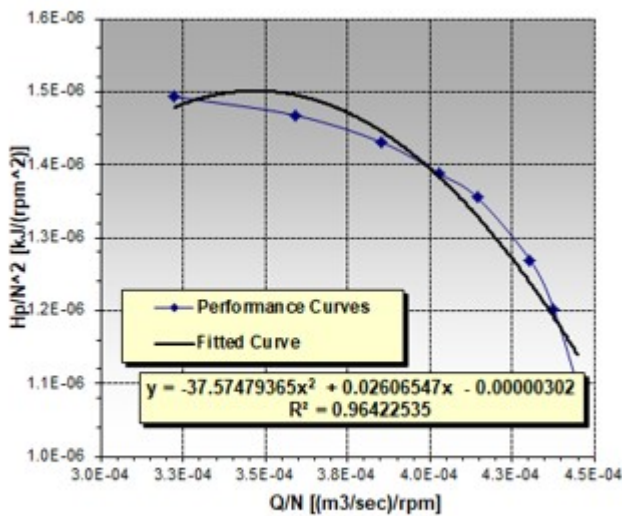
Figure 3. Compressor Performance Curves

Performing calculations as shown in previous sections in MS-Excel based on Table 2 & 3,

Table 2. Compressor Coast down Input Data

Compressor Design Details		
Compressor Inertia	376	kg.m²
Gear Box Inertia	38	Kg.m²
EM Inertia	150.6	kg.m²
Total Inertia (J)	380.6	kg.m²
EM /GT Speed	1493	rpm
Operating Speed	9551	rpm
Gear Ratio (GR)	6.40	-
Fan law constant (k)	8.38E-05	N.m.min²
Fan law Constants (*k*)		
% Speed	Speed [rpm]	k [N.m.min²]
105	10029	7.57E-05
100	9551	7.00E-05
95	9073	6.68E-05
90	8596	6.42E-05
80	7641	6.03E-05
70	4776	1.66E-04
Avg. Fan Law constant (k)		8.38E-05

It is to be noted, with the Q vs. H_p curve at 9551 rpm, Fan laws were used to derive the compressor curves for other speeds, from 70% to 105%.

Table 3. Settle Out Conditions Calculations

Suction Piping Data		
Piping Volume	74.55	m^3
Gas Mass Density	1.66	kg/m^3
Mass Specific Heat	*1.83*	kJ/kg.K
Gas Temperature	54.1	^{0}C
Comp. Factor (Z_1)	0.9875	-
Suction KO Drum %Vol. Liq	20.0	%
Gas Mass- Suction Side	*98.82*	kg
Discharge Piping Data		
Piping Volume	7.87	m^3
Gas Mass Density	*7.53*	kg/m^3
Mass Specific Heat	*2.16*	kJ/kg.K
Gas Temperature	128.3	^{0}C
Comp. Factor (Z_2)	0.9622	-
Discharge KO Drum % Vol. Liq	10.0	%
Gas Mass – Discharge Side	*11.22*	kg
Cooler Data		
Cooler Duty	1432	kW
Cooler Outlet Specific Heat	2.03	kJ/kg.K

Using the estimated coast down time value of 115 sec for the case studied, the settle out pressure (SOP) & Settle Out Temperature (SOT) is calculated as 0.81 bara, 55.70C & a Settle Out Time of 175 sec. The transient plots of the SOP & SOT based on HYSYS simulations of the case study is as follows,
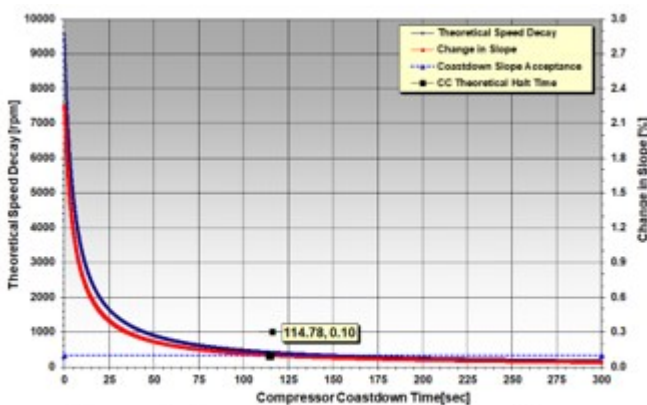
Figure 4. Compressor Coast down Time

The calculated Settle out temperature (SOT) Trend compared with HYSYS 2006.5 is shown as follows,
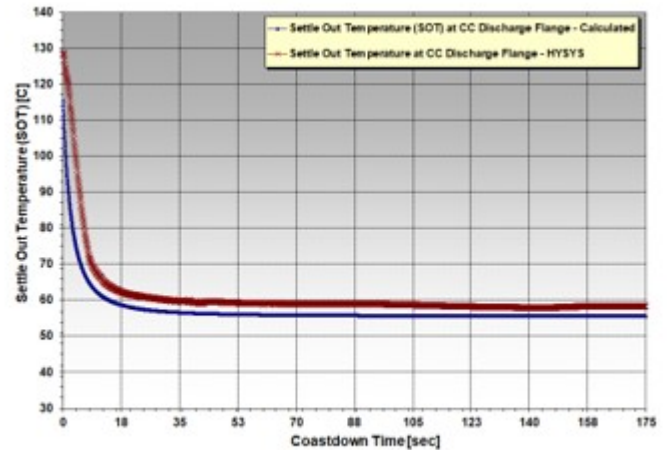
Figure 5. Settle Out Temperature Trend

A comparison made between HYSYS Simulations & the methodology presented shows,

Table 4. HYSYS vs. Calculated Results

Parameter	HY-SYS	Calculat-ed	% Error
SOT [^{0}C]	58.4	55.7	-4.8
SOP [bara]	0.53	0.81	+34.6
Settle Out Time [s]	167	175	+4.8

The SOT & Settle Out Time shows an error margin of < ±5%. Whereas for SOP, between the HYSYS predicted value of 0.34 bara and calculated value of 0.81 bara, represents ~35% error. The author attributes the error in SOP partly to the suction & discharge valve closure time in HYSYS when some vapours were discharged & the remaining for the reasons explained in the next section.

EFFECT OF ASSUMPTIONS ON RESULTS

1. Approximation of compressor curves to Fan Laws – Fan laws are more applicable to fluids with low compressibility, smaller pressure ratios & constant density. Use of these laws would distort the Compressor manufacturer's data thereby causing a difference in calculations. Since the overlap area is significant, the performance curve used in the calculations is assumed to be same throughout the period of coast down. Figure 6 shows the shift in the compressor performance curves.
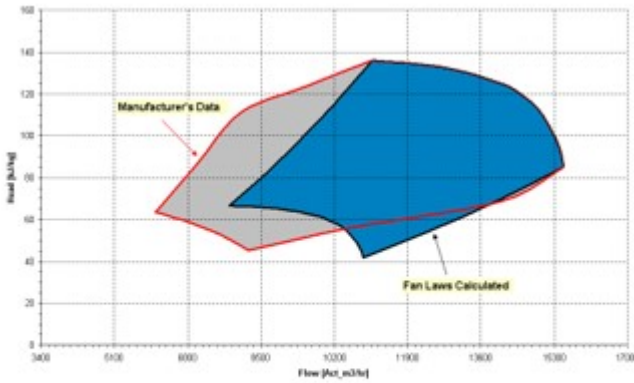
Figure 6. Comparison of Performance Curves between Fan Laws Generated & Vendor Data

2. Equilibrium conditions during Settle Out – During coast down, equilibrium conditions are not reached in the compressor plant piping since the system is dynamic with the gas moving & this is tracked in HYSYS 2006.5. However the calculations methodology considers complete equilibrium being reached at every time step. This causes a difference in the final settle out temperature (SOT) & settle out pressure (SOP).

3. Average Mass Specific Heat Capacity – The calculations methodology considers a constant averaged mass specific heat in the suction & discharge as well as cooler volumes. However, in commercial solvers such as HYSYS 2006.5, the mass heat capacity is computed at every time step which affects the final SOP & SOT.

4. Density & Z Variations – In the calculations made, density and compressibility factor (Z) was assumed to be constant, whereas HYSYS provides density & 'Z' corrections with change in temperature & pressure at every time step.

DESIGN STANDARDS (API 521/NORSOK)

1. In designing suction side of compressor piping & equipment, providing a design margin between settle out pressure and design pressure prevents unnecessary flaring. As per API 521, "Pressure relieving and Depressuring Systems", 5th Edition, Jan 2007, "Design Pressure shall be a minimum of 1.05 times the settle out pressure at maximum pressure drop, calculated assuming the suction side is operated at normal operating pressure and compressor discharge pressure is set to the maximum achievable".

2. As per NORSOK P-001, "The maximum

as the settle out pressure occurring at co-incident PAHH" (High-High Pressure Alarm) "on both suction side and discharge side, adding a 10% margin for determining design pressure or PSV set pressure". Therefore, NORSOK P-001 standard provides a more conservative estimate of settle out pressure since it takes into account the highest possible suction & discharge pressures.

ANNEXURE A: SETTLE OUT CONDITIONS DERVIATION

The settle out conditions is calculated by considering the suction & discharge volumes as, Suction side gas mass

$$m_S = \left[\left(V_{SuctionSide} - \%V_{SuctionScrubberLiquidVolume} \right) \times \rho_S \right] \quad (1)$$

Discharge side gas mass

$$m_D = \left[\left(V_{DischargeSide} - \%V_{DischargeScrubberLiquidVolume} \right) \times \rho_D \right] \quad (2)$$

Performing heat balance over the closed loop system,

$$E_{In} = E_{Out} \quad (3)$$

Or, $Q_{Suction} + Q_{Discharge} + Q_{CC} = Q_{Cooler} \quad (4)$

Taking that the energy reaching the gas through the compressor is acting only on the mass of gas enclosed & calculating on a per second basis,

$$m_S c_{p,S} (T - T_S) + m_D c_{p,D} (T - T_D) + m H_P = Q_{Cooler} \quad (5)$$

Taking $m = (m_S + m_D)$ & rearranging Eq. (5)

$$T = SOT = \frac{(m_S c_{p,S} T_S + m_D c_{p,D} T_D) - Q_{cooler} + (m_S + m_D)(H_P(t))}{m_S c_{p,S} + m_D c_{p,D}} \quad (6)$$

The mass specific heat for the cooler in Eq. (6) is taken to be an average value between the upstream & downstream flow. The polytropic head, $H_P(t)$ is treated as a function of time & is calculated by fitting the performance curves (Q vs. H_p).

$$\frac{H_P}{N^2} = A\left(\frac{Q}{N}\right)^2 + B\left(\frac{Q}{N}\right) + C \quad (7)$$

A graph is plotted between $\left(\dfrac{Q}{N}\right)$ (along x-axis) & $\dfrac{H_p}{N^2}$ (along y-axis) to obtain the constants A, B & C, followed by rewriting Eq. (E.7) as,

$$H_p(t) = A(Q)^2 + B(QN) + CN^2 \qquad (8)$$

In Eq. (8), the compressor speed (N) is calculated as shown in Eq. (9)

$$N = N(t) = \cfrac{1}{\cfrac{1}{N_0} + \cfrac{216000k(t-t_0)}{(2\pi)^2 J}} \qquad (9)$$

The volumetric flow calculated using Fan Laws assuming $k_1 = k_2$ during coast down is,

$$\frac{Q_t}{Q_{t+1}} = \frac{N_t}{N_{t+1}} \qquad (10)$$

$$\text{Or, } Q = Q_{t+1} = \frac{N_{t+1} \times Q_t}{N_t} \qquad (11)$$

It is to be noted that, the value of 'Q' flowing into the compressor is approximated to value of 'm' in Eq. (5) (which is constant) since the density lies between suction & discharge density. The settle out pressure is calculated using Ideal Gas equation as,

$$P = SOP = \frac{n \times \left[\dfrac{(Z_1 + Z_2)}{2}\right] \times R \times SOT}{V_{Total}} \qquad (12)$$

$$\text{Or, } SOP = \frac{m \times Z_{avg} \times R \times SOT}{MW \times (V_1 + V_2)} \qquad (13)$$

ANNEXURE B: COMPRESSOR COAST DOWN DERVIATION

The decay rate of driver speed is governed by the inertia of the system consisting of the compressor, coupling, gearbox & driver, which are counteracted by the torque transferred to the fluid. Neglecting the mechanical losses,

$$T = -(2\pi)J\left(\frac{dN}{dt}\right) \text{ [N-m]} \qquad (1)$$

Where,

J = System Inertia (Compressor + gearbox + driver) [kg-m^2],

where,

$$J = J_C + \left[\frac{J_M}{(Gear \cdot Ratio)^2}\right]$$

N = Compressor Rotor speed [rpm] or [min^{-1}]

The speed decay rate as well as the system inertia determines the compressor torque. Therefore, the power transferred to the gas, is

$$P = (2\pi NT) \text{ N} \cdot \text{m}/\text{min} \qquad (2)$$

Substituting Eq. (1) in Eq. (2), the power transferred during (ESD),

$$P = 2\pi N \times \left[-(2\pi)J\left(\frac{dN}{dt}\right)\right] \qquad (3)$$

Applying fan power law as an approximation in which 'k' is relatively unvarying for a given curve,

$$P \propto N^3 \Rightarrow P = kN^3 ; k = \frac{60P}{N^3}(N \cdot m \cdot min^2) \Rightarrow P = \frac{kN^3}{60} \qquad (4)$$

Substituting Eq. (4) in Eq. (3),

$$\frac{kN^3}{60} = 2\pi N \times \left[-(2\pi)J\left(\frac{dN}{dt}\right)\right] \qquad (5)$$

Integrating Eq. (6), and also multiplying by (60^2) to convert sec^2 (rev/s) to min^2 (rev/min)

$$\int_{N=N_0}^{N=N(t)} \frac{dN}{N^2} = \frac{k \times 60}{-(2\pi)^2 J} \int_{t_0}^{t=t} dt \qquad (7)$$

$$\left[\frac{N^{-2+1}}{-2+1}\right]_{N_0}^{N(t)} = \frac{k \times 60}{-(2\pi)^2 J} \times (t-t_0) \Rightarrow \left[\frac{1}{N}\right]_{N_0}^{N(t)} = \frac{60k(t-t_0)}{(2\pi)^2 J} \qquad (8)$$

$$\frac{1}{N(t)} - \frac{1}{N_0} = \frac{60k(t-t_0)}{(2\pi)^2 J} \Rightarrow \frac{1}{N(t)} = \frac{1}{N_0} + \frac{60k(t-t_0)}{(2\pi)^2 J} \Rightarrow N(t) = \cfrac{1}{\cfrac{1}{N_0} + \cfrac{60k(t-t_0)}{(2\pi)^2 J}} \qquad (9)$$

Where, N_0 is the compressor speed before ESD. The 2nd denominator term exists with units N.m.min/kg.m^2 & is converted to min^{-1} which gives,

$$N(t) = \frac{1}{\dfrac{1}{N_0} + \dfrac{216000k(t - t_0)}{(2\pi)^2 J}} \qquad (10)$$

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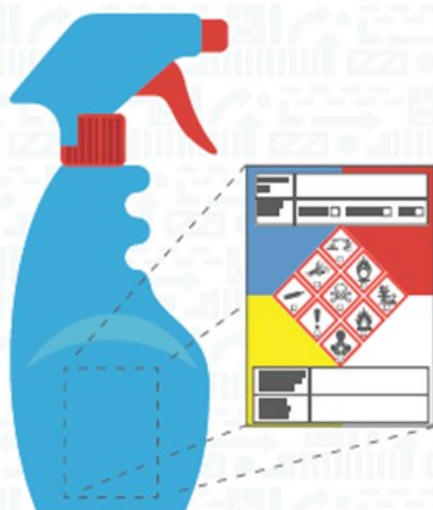
FCC and Hydrocracking Technologies: From Competitors to Profitable Synergic Processing Units in Modern Refining Schemes

Dr. Marcio Wagner da Silva

INTRODUCTION AND CONTEXT

Nowadays, the capacity to add value to the bottom barrel streams represents great competitive advantage among refiners, especially considering the stricter regulations like the IMO 2020 that imposes significant reduction in sulfur content of marine fuel oils (BUNKER), requiring even more capacity to treat bottom barrel streams, especially to refiners processing heavier crude oils and put under pressure the refining margins that are still in recovery in the post pandemic scenario, as exemplified for the USA market in Figure 1.

Under this scenario, process units called bottom barrel, able to improve the quality of crude oil residue streams (Vacuum residue, Gas oils, etc.) or convert them to higher added value products gain strategic importance, mainly in countries that have large heavy crude oil reserves. These process units are fundamental for to comply the environmental and quality regulations, as well as to ensure profitability and competitivity of refiners through raising refining margin. In a most recent trend, the reduction in transportation fuels demand is leading the refiners to look for closer integration with petrochemical assets, creating a the relatively high capital investment. necessity to maximize the yield of petrochemicals in the refining hardware. The use of residue

upgrading technologies to produce petrochemicals against transportation fuels can be an attractive route in some markets.

Available technologies to processing bottom barrel streams involve processes that aim to raise the H/C relation in the molecule, either through reducing the carbon quantity (processes based on carbon rejection) or through hydrogen addition. Technologies that involve hydrogen addition encompass hydrotreating and hydrocracking processes while technologies based on carbon rejection refers to thermal cracking processes like Visbreaking, Delayed Coking and Fluid Coking, catalytic cracking processes like Fluid Catalytic Cracking (FCC) and physical separation processes like Solvent Deasphalting units. Some refining schemes can apply the synergy between residue upgrading technologies aiming to ensure higher added value to the processed crude oils as well as meet the regulations and ensure higher refining margins in the downstream sector, an interesting case is the combination of Hydrocracking and Fluid Catalytic Cracking Technologies, normally these technologies are faced as competitors technologies due to the feed streams that are processed, but in some cases the synergy between the hydrocracking and FCC technologies can ensure high bottom barrel conversion capacity and profitability, despite
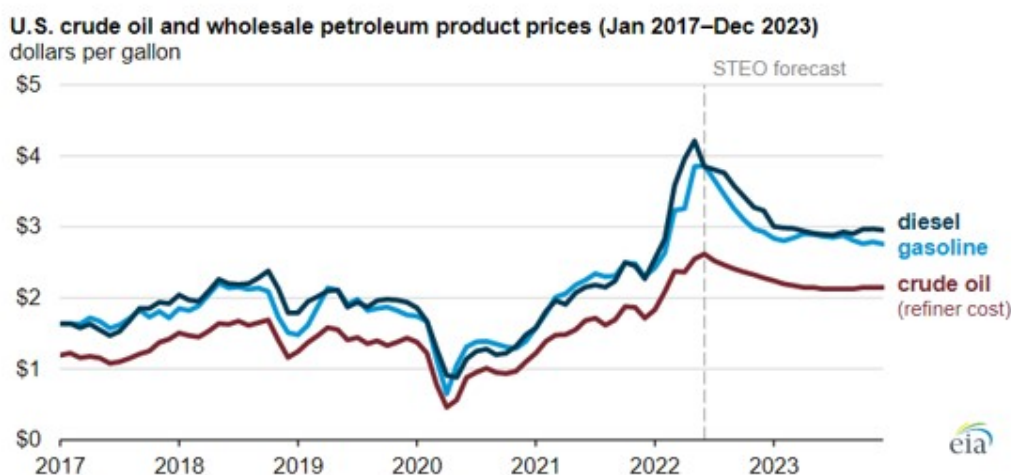

U.S. crude oil and wholesale petroleum product prices (Jan 2017–Dec 2023)
dollars per gallon

Figure 1 – USA Refining Margins

FLUID CATALYTIC CRACKING TECHNOLOGIES – CARBON REJECTION ROUTE

The installation of catalytic cracking units allows the refiners to process heavier crude oils and consequently cheaper, raising the refining margin, mainly in higher crude oil prices scenario or in geopolitics crises that can become difficult the access to light oils. The typical Catalytic Cracking Unit feedstream is gas oils from vacuum distillation process. However, some variations are found in some refineries, like sending heavy coke naphtha, coke gas oils and deasphalted oils from deasphalting units to processing in the FCC unit.

In a conventional scheme, the catalyst regeneration process consists in the carbon partial burning deposited over the catalyst, according to chemical reaction below:

$$C + \frac{1}{2} O_2 \rightarrow CO$$
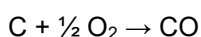
The carbon monoxide is burned in a boiler capable of generating higher pressure steam that supplies others process units in the refinery. Figure 2 presents a process scheme for a typical Fluid Catalytic Cracking Unit (FCCU).

The principal operational variables in a fluid catalytic cracking unit are reaction temperature, normally considered the temperature in the top of the reactor (called riser), feed stream temperature, feed stream quality (mainly carbon residue), feed stream flow rate and catalyst quality. Feedstock quality is especially relevant, but this variable is a function of the crude oil processed by the refinery, so is difficultly can be changed, but for example, aromatic feedstock's with high metals content are refractory to cracking and conducting to a quick catalyst deactivation.

An important variation of the fluid catalytic cracking technology is the residue fluid catalytic cracking unit (RFCC). In this case, the feedstock to the process is basically residue from atmospheric distillation column, due to the high carbon residue and contaminants (metals, sulphur, nitrogen, etc.) are necessary some adaptations in the unit like catalyst with higher resistance to metals and nitrogen and catalyst coolers furthermore, it's necessary apply materials with most noble metallurgy due the higher temperatures reached in the catalyst regeneration step (due the higher coke quantity deposited on the catalyst), that raises significantly the capital investment to the unit installation. Nitrogen is a strong contaminant to the FCC catalyst because they neutralize the acid sites of the catalyst which are responsible for the cracking reactions.

When the residue has high contaminants content, is common the feed stream treatment in hydrotreating units to reduce the metals and heteroatoms concentration to protect the FCC catalyst. Typically, the average yield in fluid catalytic cracking units is 55% in volume in cracked naphtha and 30 % in LPG.

Usually, catalytic cracking units are optimized to aiming the production of fuels (mainly gasoline), however, some process units are optimized to maximize the light olefins production (propylene and ethylene). Process units dedicated for this purpose have his project and operational conditions significantly changed once the process severity is strongly raised in this case.

The reaction temperature reaches 600 oC and higher catalyst circulation rate raises the gases production, which requires a scaling up of gas separation section.
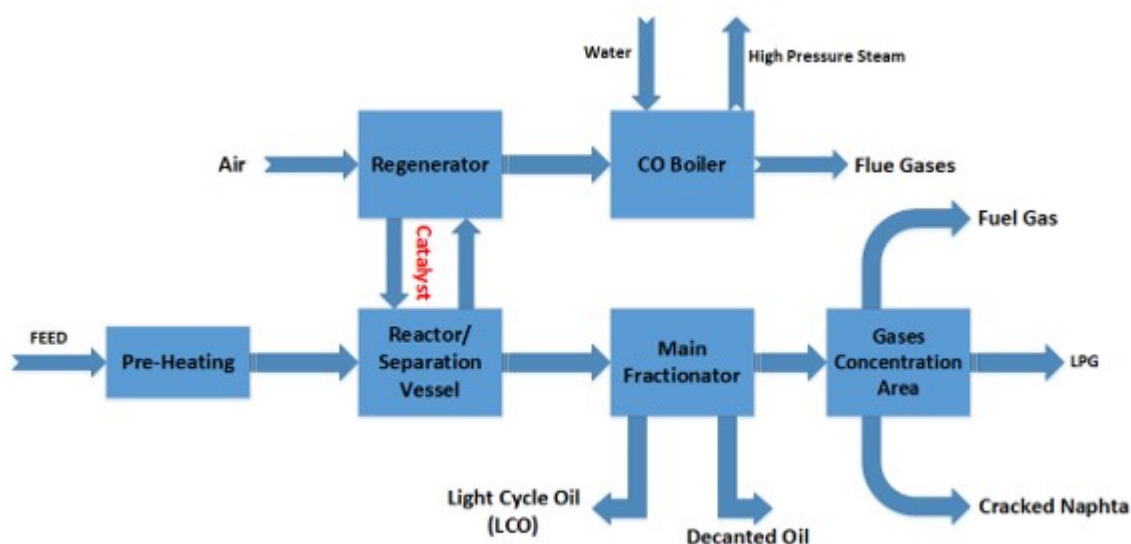

Figure 2 – Schematic Process Flow for a Typical Fluid Catalytic Cracking Process Unit (FCCU)

Over last decades, the fluid catalytic cracking technology was intensively studied aiming mainly the development of units capable of producing light olefins (Deep Catalytic Cracking) and to process heavier feedstocks. The main licensers for fluid catalytic cracking technology nowadays are the companies KBR, UOP, Stone & Webster, Axens, and Lummus Company.

Despite the great operational flexibility which fluid catalytic cracking technology give for the refineries, some new projects have dismissed these units in the refining scheme, mainly when the new refinery objective is to maximize middle distillates products (Diesel and Kerosene) once this is not the focus of the fluid catalytic cracking unit.

IMPROVING THE YIELD OF PETROCHEMICALS IN THE REFINING HARDWARE – THE PETROCHEMICAL FCC TECHNOLOGIES

As quoted earlier, in markets with high demand by petrochemicals, the petrochemical FCC can be an attractive alternative to refiners aiming to ensure higher added value to bottom barrel streams. An example of FCC technology developed to maximize the production of petrochemical intermediates is the PetroFCC™ process by UOP Company, this process combines a petrochemical FCC and separation processes optimized to produce raw materials to the petrochemical process plants, as presented in Figure 3. Other available technologies are the HS-FCC™ process commercialized by Axens Company, and INDMAX™ process licensed by Lummus Company.

To petrochemical FCC units, the reaction temperature reaches 600 oC and higher catalyst circulation rate raises the gases production, which requires a scaling up of gas separation section. The higher thermal demand

makes advantageous operates the catalyst regenerator in total combustion mode leading to the necessity of installation a catalyst cooler system.

Figure 4 presents the results of a comparative study, carried out by Technip Company, showing the yields obtained by conventional FCC units, optimized to olefins (FCC to olefins), and the HS-FCC™ designed to maximize the production of petrochemical intermediates.

It's observed a higher reaction temperature (TRX) and a cat/oil ratio five times higher when are compared the conventional process units and the petrochemical FCC (HS-FCC™), leading to a growth of the light olefins yield (Ethylene + Propylene + C4='s) from 14 % to 40%.

The installation of petrochemical catalytic cracking units requires a deep economic study taking into account the high capital investment and higher operational costs, however, some forecasts indicate growth of 4,0 % per year to the market of petrochemical intermediates until 2025. In this scenario can be attractive the capital investment aiming to raise the market share in the petrochemical sector, allowing then a favorable competitive positioning to the refiner, through the maximization of petrochemical intermediates. Figure 5 presents a block diagram showing a case study demonstrating how the petrochemical FCC unit, in this case the INDMAX™ technology by Lummus Company, can maximize the yield of petrochemicals in the refining hardware.

In refining hardware with conventional FCC units, further than the higher temperature and catalyst circulation rates, it's possible to apply the addition of catalysts additives like the
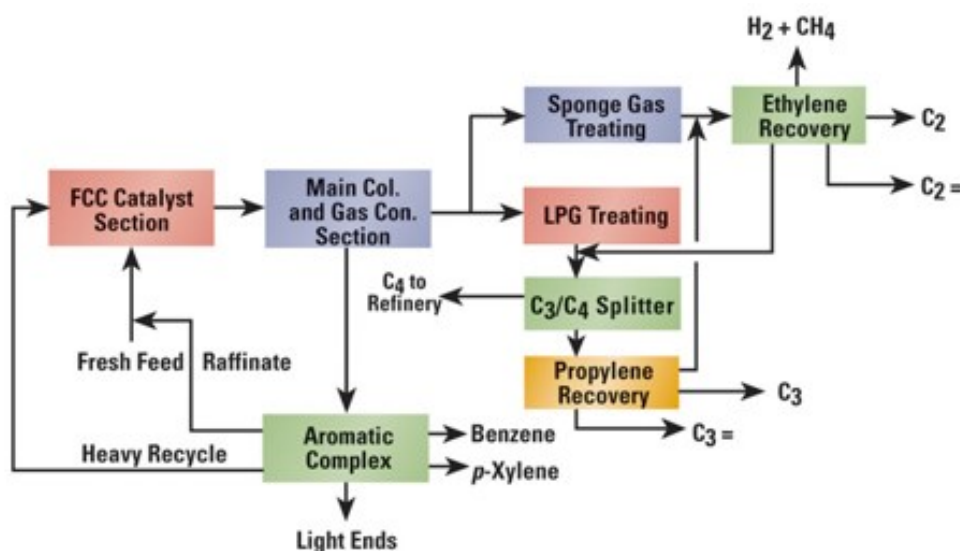
Figure 3 – PetroFCC™ Process Technology by UOP Company.

Ylelds, wt %
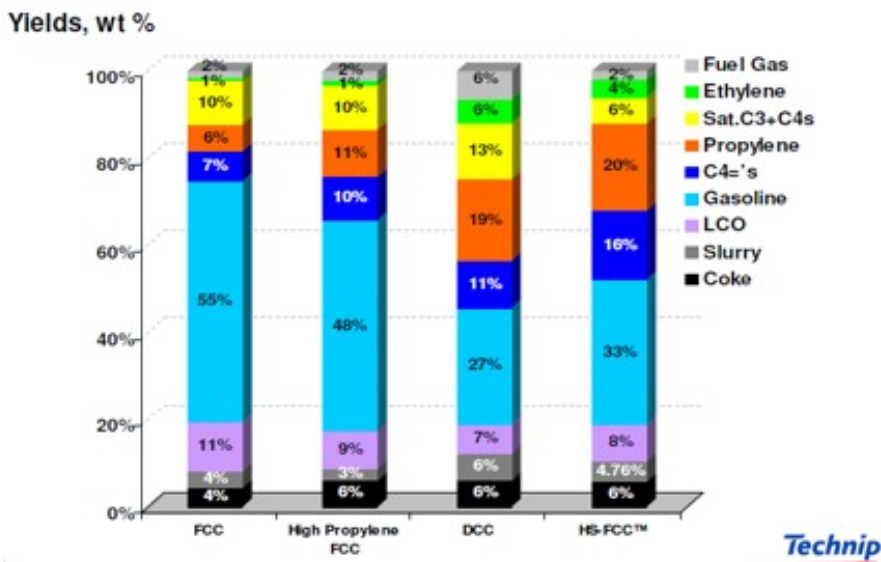
	Conv. FCC	HP FCC	DCC	HS-FCC™
ROT	530℃ (986℉)	550℃ (1022℉)	580℃ (1076℉)	600℃+ (1112℉+)
Contact time	2 - 5 s	2 - 5 s	10 s	0.5 - 1 s
C/O	5	10	15	25
Recycle	None	LCN	LCN	None

Figure 4 – Comparative Study between Conventional FCCs and Petrochemical FCC (HS-FCC™)

zeolitic material ZSM-5 that can raise the olefins yield close to 9,0% in some cases when compared with the original catalyst. This alternative raises the operational costs, however, as aforementioned can be economically attractive considering the petrochemical market forecasts. Figure 6 presents some optimization strategies to improve the petrochemical yield in conventional FCC units.

The use of FCC catalyst additives such as ZSM-5 can increase unit propylene production by up to 8.0%.

Installation of catalyst cooler system raises the process unit profitability through the total conversion enhancement and selectivity to noblest products as propylene and naphtha against gases and coke production. The catalyst cooler necessary when the unit is designed to operate under total combustion mode due to the higher heat release rate as presented below.

$$C + \tfrac{1}{2} O_2 \rightarrow CO \text{ (Partial Combustion)} \quad \Delta H = -27 \text{ kcal/mol}$$

$$C + O_2 \rightarrow CO_2 \text{ (Total Combustion)} \quad \Delta H = -94 \text{ kcal/mol}$$

AR: Atmospheric Residue
RHDS: Residue Hydro Desulfurization
ERU: Ethylene Recovery Unit
PRU: Propylene Recovery Unit
OCT: Olefin Conversion Technology
HDS+AEU: Hydrodesulfurization, Aromatics Extraction Unit
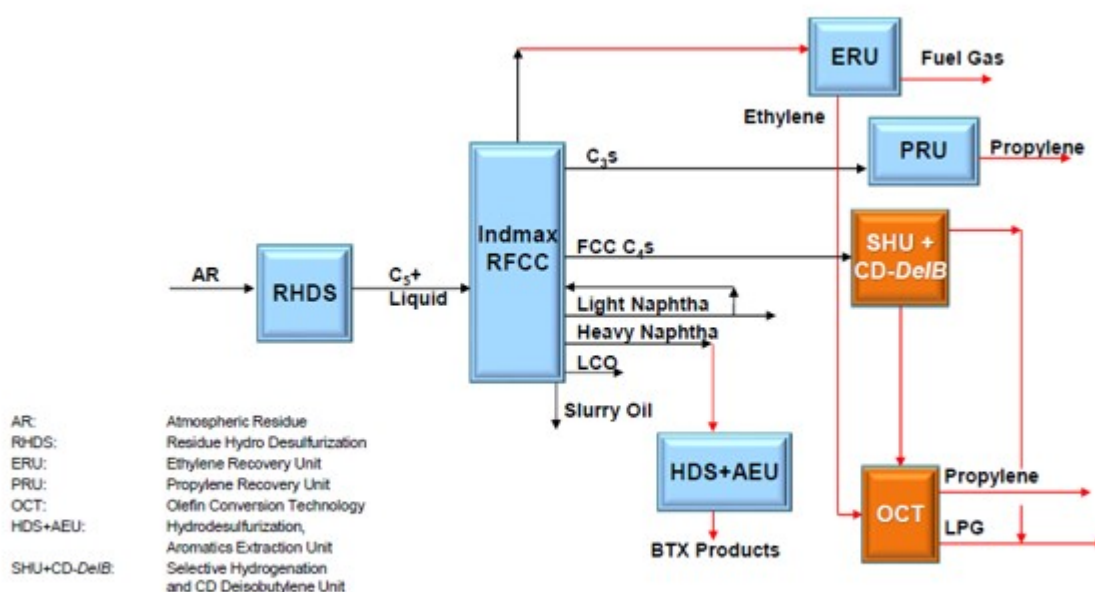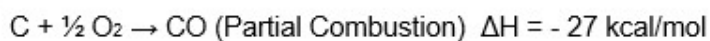SHU+CD-DelB: Selective Hydrogenation and CD Deisobutylene Unit

Figure 5 – Olefins Maximization in the Refining Hardware with INDMAX™ FCC Technology by Lummus (SANIN, A.K., 2017)

1. Higher temperature (TRX)
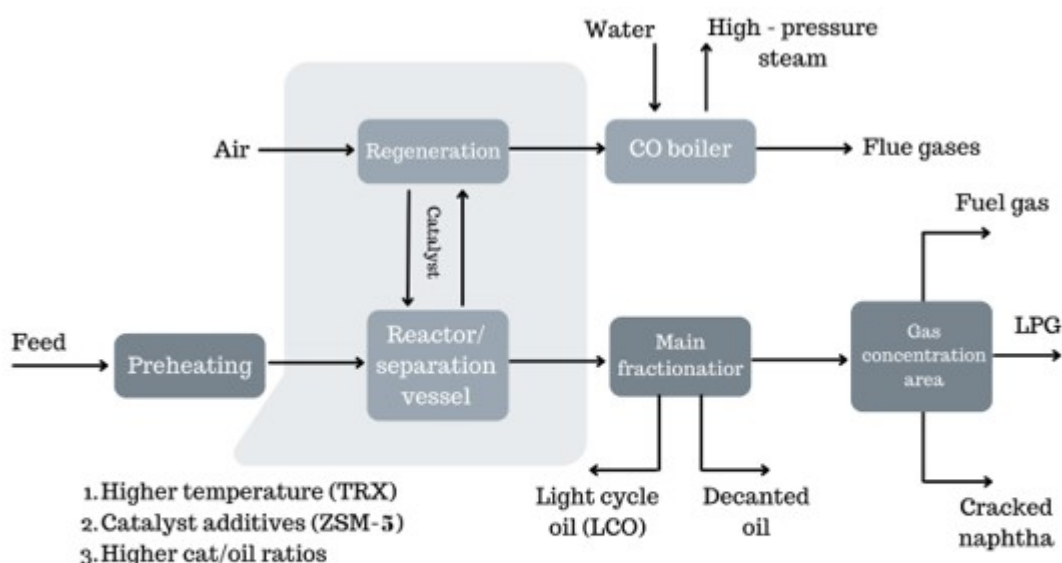2. Catalyst additives (ZSM-5)
3. Higher cat/oil ratios

Figure 6 - Optimization of Process Variables in FCC Units to Improve the Yield of Petrochemicals Intermediates

In this case, the temperature of the regeneration vessel can reach values close to 760 oC, leading to higher risks of catalyst damage which is minimized through catalyst cooler installation. The option by the total combustion mode needs to consider the refinery thermal balance, once, in this case, will not the possibility to produce steam in the CO boiler, furthermore, the higher temperature in the regenerator requires materials with noblest metallurgy, this significantly raises the installation costs of these units which can be prohibitive to some refiners with restricted capital access.

Among another petrochemical FCC technologies, it's possible to quote the Maxofin™ and K-COT™ processes developed by KBR Company and the SCC™ technology developed by Lummus Company.

Due to the higher production of light olefins, mainly ethylene, another important difference between conventional and petrochemical FCC units is related to the gas recovery section, while in conventional FCC is applied absorber columns, in petrochemical units is applied cryogenic processes though refrigeration cycles in similar conditions which are applied in steam cracking units, as example we can quote the ACO™ technology developed by KBR Company.

The cryogenic processes applied to olefins recovery raises, even more, the capital requirement to petrochemical FCC units when compared with conventional FCCs, despite this, the growing market for petrochemicals and falling demand for transportation fuels, tends to compensate the higher investment.

DEEP HYDROCRACKING TECHNOLOGIES – HYDROGEN ADDITION ROUTE

Refiners processing heavy and extra-heavy (or high sulfur) crudes face a great challenge to meet the IMO 2020 once is extremely difficult to comply with the new regulation through carbon rejection technologies, in this case, the hydrogen addition technologies are fundamental.

The hydroprocessing of residual streams presents additional challenges when compared with the treating of lighter streams, mainly due to the higher contaminants content and residual carbon (RCR) related with the high concentration of resins and asphaltenes in the bottom barrel streams. Figure 7 shows a schematic diagram of the residue upgrading technologies applied according to the metals and asphaltenes content in the feed stream.

Higher metals and asphaltenes content led to a quick deactivation of the catalysts through high coke deposition rate, catalytic matrix degradation by metals like nickel and vanadium or even by the plugging of catalyst pores produced by the adsorption of metals and high molecular weight molecules in the catalyst surface. By this reason, according to the content of asphaltenes and metals in the feed stream are adopted more versatile technologies aiming to ensure an adequate operational campaign and an effective treatment.

Despite the high performance, the fixed bed hydrocracking technologies can be not economically effective to treat residue from heavy and extra-heavy due to the short operating lifecycle. Technologies that use
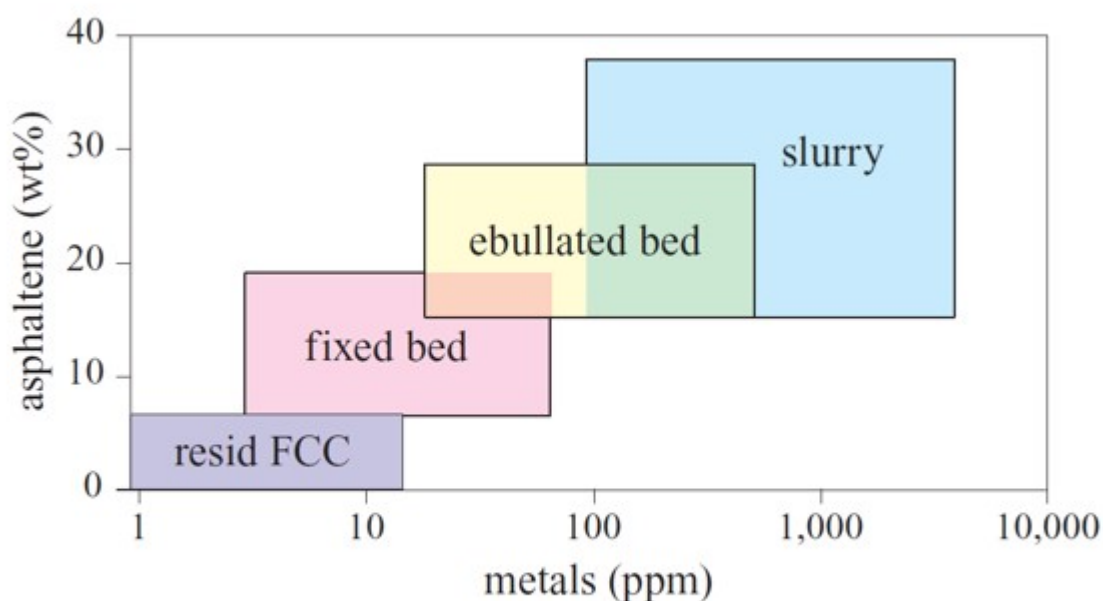

Figure 7 – Residue Upgrading Technologies According to the Contaminants Content (Encyclopedia of Hydrocarbons, 2006)
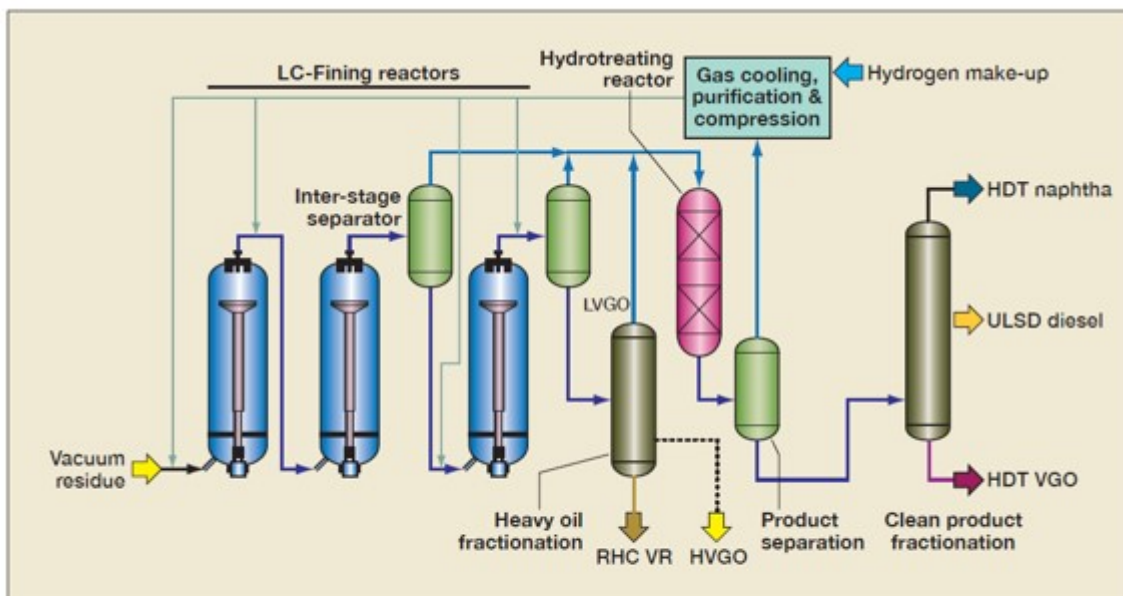
Figure 8 – Process Flow Diagram for LC-Fining™ Technology by CLG Company (MUKHERJEE & GILLIS, 2018)

ebullated bed reactors and continuum catalyst replacement allow higher campaign period and higher conversion rates, among these technologies the most known are the H-Oil and Hyvahl™ technologies developed by Axens Company, the LC-Fining Process by Chevron-Lummus, and the Hycon™ process by Shell Global Solutions. These reactors operate at temperatures above of 450 oC and pressures until 250 bar. Figure 8 presents a typical process flow diagram for a LC-Fining™ process unit, developed by Chevron Lummus Company another technology is the H-Oil™ process by Axens Company.

Catalysts applied in hydrocracking processes can be amorphous (alumina and silica-alumina) and crystalline (zeolites) and have bifunctional characteristics, once the cracking

reactions (in the acid sites) and hydrogenation (in the metals sites) occurs simultaneously.

An improvement in relation of ebullated bed technologies is the slurry phase reactors, which can achieve conversions higher than 95 %. In this case, the main available technologies are the HDH™ process (Hydrocracking-Distillation-Hydrotreatment), developed by PDVSA-Intevep, VEBA-Combicracking Process (VCC)™ commercialized by KBR Company, the EST™ process (Eni Slurry Technology) developed by Italian state oil company ENI, and the Uniflex™ technology developed by UOP Company. Figure 9 presents a basic process flow diagram for the VCC™ technology by KBR Company.
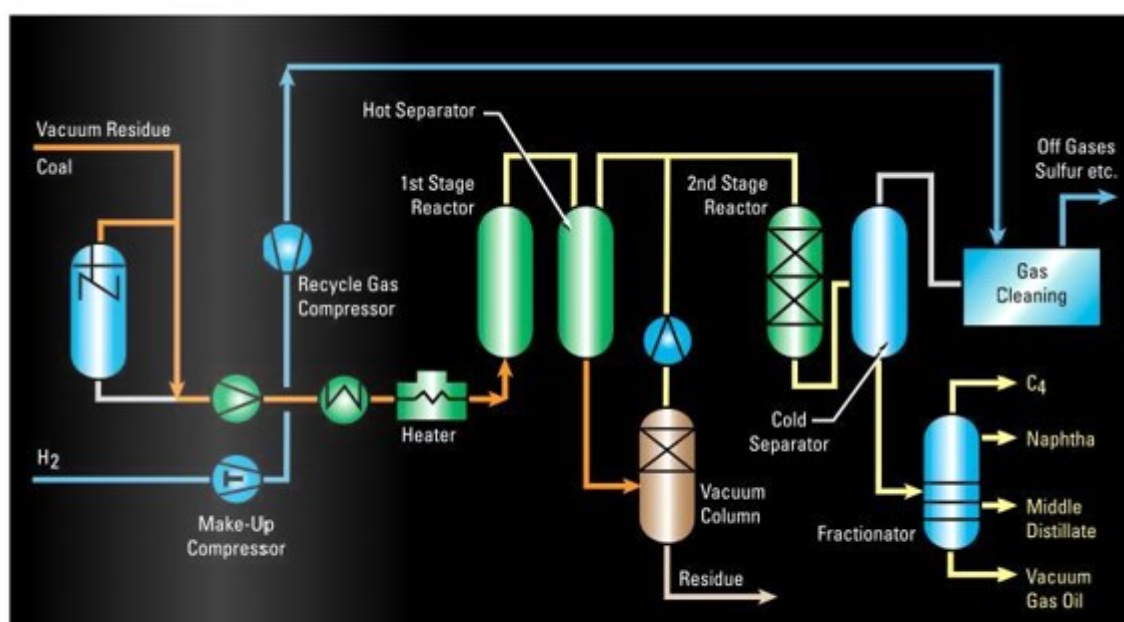

Figure 9 – Basic Process Arrangement for VCC™ Slurry Hydrocracking by KBR Company (KBR Company, 2019)|
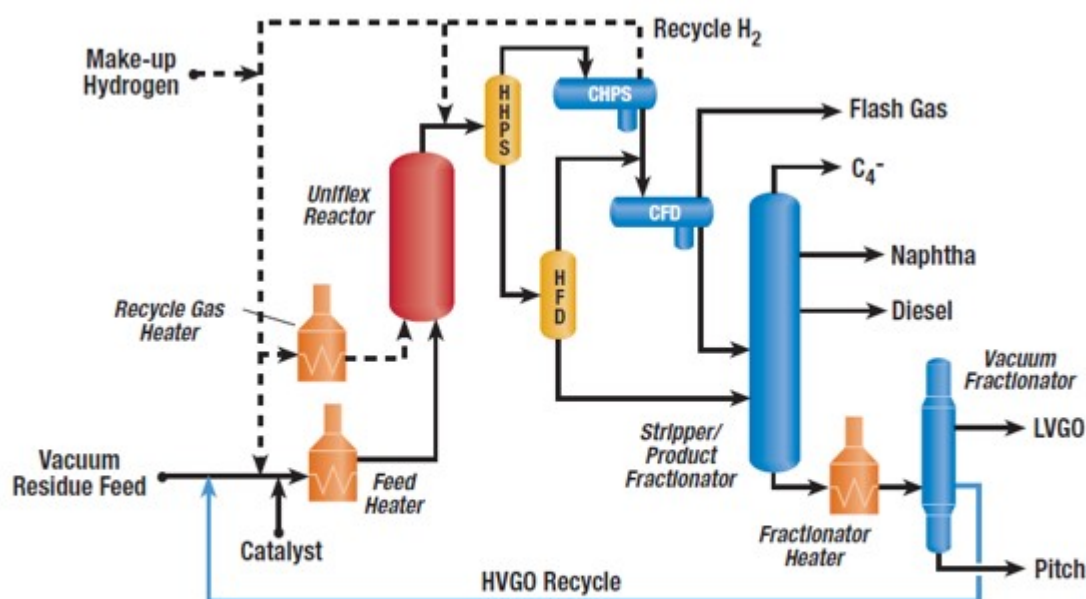
Figure 10 – Process Flow Diagram for Uniflex™ Slurry Phase Hydrocracking Technology by UOP Company (UOP Company, 2019).

In the slurry phase hydrocracking units, the catalysts in injected with the feedstock and activated in situ while the reactions are carried out in slurry phase reactors, minimizing the reactivation issue, and ensuring higher conversions and operating lifecycle. Figure 10 presents a basic process flow diagram for the Uniflex™ slurry hydrocracking technology by UOP Company.

Other commercial technologies to slurry hydrocracking process are the LC-Slurry™ technology developed by Chevron Lummus Company and the Microcat-RC™ process by Exxon Mobil Company. Aiming to meet the new bunker quality requirements, noblest streams, normally directed to produce middle distillates can be applied to produce low sulfur fuel oil, this can lead to a shortage of intermediate streams to produce these derivatives, raising his prices. The market of high sulfur content fuel oil should strongly be reduced, due to the higher prices gap when compared with diesel, his production tends to be economically unattractive.

PETROCHEMICAL INTEGRATION – STRONG DEPENDENCE OF HIGH BOTTOM BARREL CONVERSION

The focus of the closer integration between refining and petrochemical industries is to promote and seize the synergies existing opportunities between both downstream sectors to generate value to the whole crude oil production chain. Table 1 presents the main characteristics of the refining and petrochemical industry and the synergies potential.

As aforementioned, the petrochemical industry has been growing at considerably higher rates when compared with the transportation fuels market in the last years, additionally, represent a noblest destiny and less environmental aggressive to crude oil derivatives. The technological bases of the refining and petrochemical industries are similar which lead to possibilities of synergies capable to reduce operational costs and add value to derivatives produced in the refineries.

Table 1 – Refining and Petrochemical Industry Characteristics

Refining Industry	Petrochemical Industry
Large Feedstock Flexibility	Raw Material from Naphtha/NGL
High Capacities	Higher Operation Margins
Self Sufficient in Power/Steam	High Electricity Consumption
High Hydrogen Consumption	High Availability of Hydrogen
Streams with low added Value (Unsaturated Gases & C2)	Streams with Low Added Value (Heavy Aromatics, Pyrolysis Gasoline, C4's)
Strict Regulations (Benzene in Gasoline, etc.)	Strict Specifications (Hard Separation Processes)
Transportation Fuels Demand in Declining at Global Level	High Demand Products
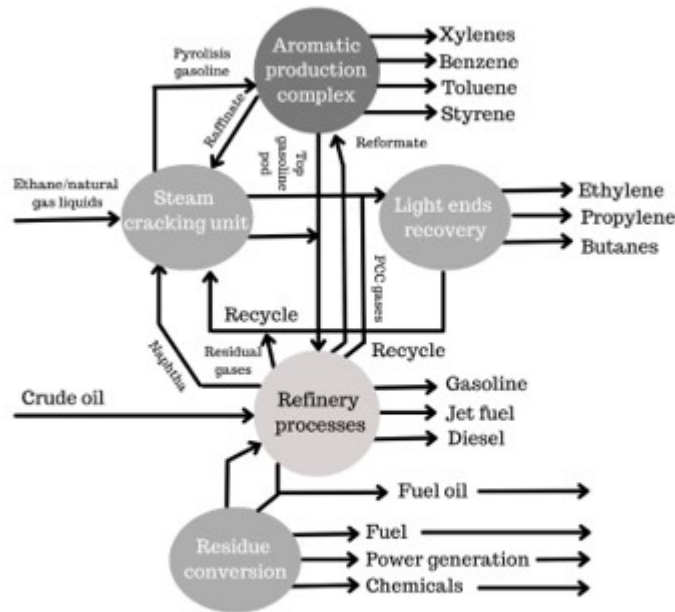
Figure 11 – Synergies between Refining and Petrochemical Processes

Figure 11 presents a block diagram that shows some integration possibilities between refining processes and the petrochemical industry.

Process streams considered with low added value to refiners like fuel gas (C2) are attractive raw materials to the petrochemical industry, as well as streams considered residual to petrochemical industries (butanes, pyrolisis gasoline, and heavy aromatics) can be applied to refiners to produce high quality transportation fuels, this can help the refining industry meet the environmental and quality regulations

to derivatives.

The integration potential and the synergy among the processes rely on the refining scheme adopted by the refinery and the consumer market, process units as Fluid Catalytic Cracking (FCC) and Catalytic Reforming can be optimized to produce petrochemical intermediates to the detriment of streams that will be incorporated to fuels pool. In the case of FCC, installation of units dedicated to produce petrochemical intermediates, called

Figure 12 – Petrochemical Integration Levels (IHS Markit, 2018)

Figure 13 – Saudi Aramco Crude Oil to Chemicals Concept (IHS Markit, 2017)

petrochemical FCC, aims to reduce to the minimum the generation of streams to produce transportation fuels, however, the capital investment is high once the severity of the process requires the use of material with noblest metallurgical characteristics.

The IHS Markit Company proposed a classification of the petrochemical integration grades, as presented in Figure 12.

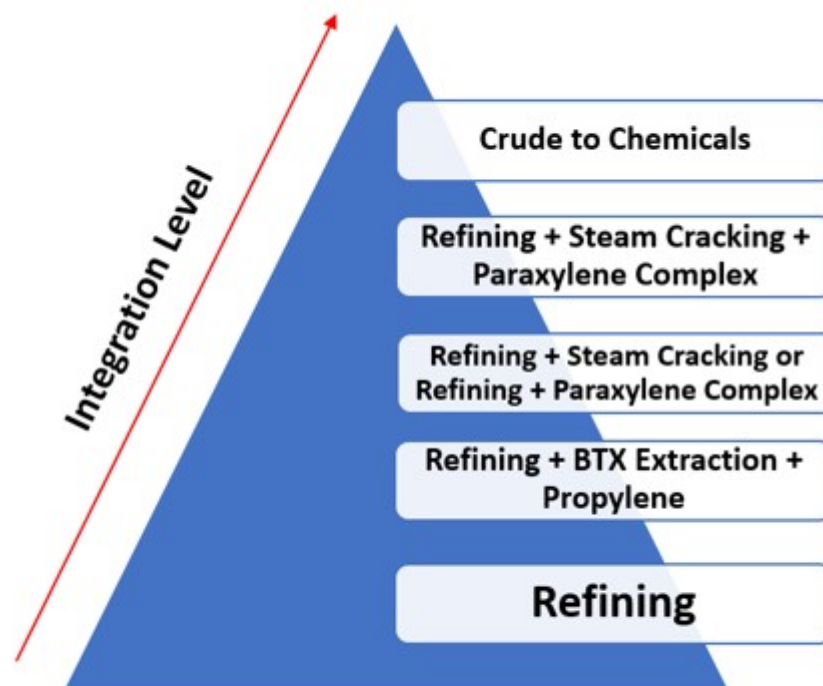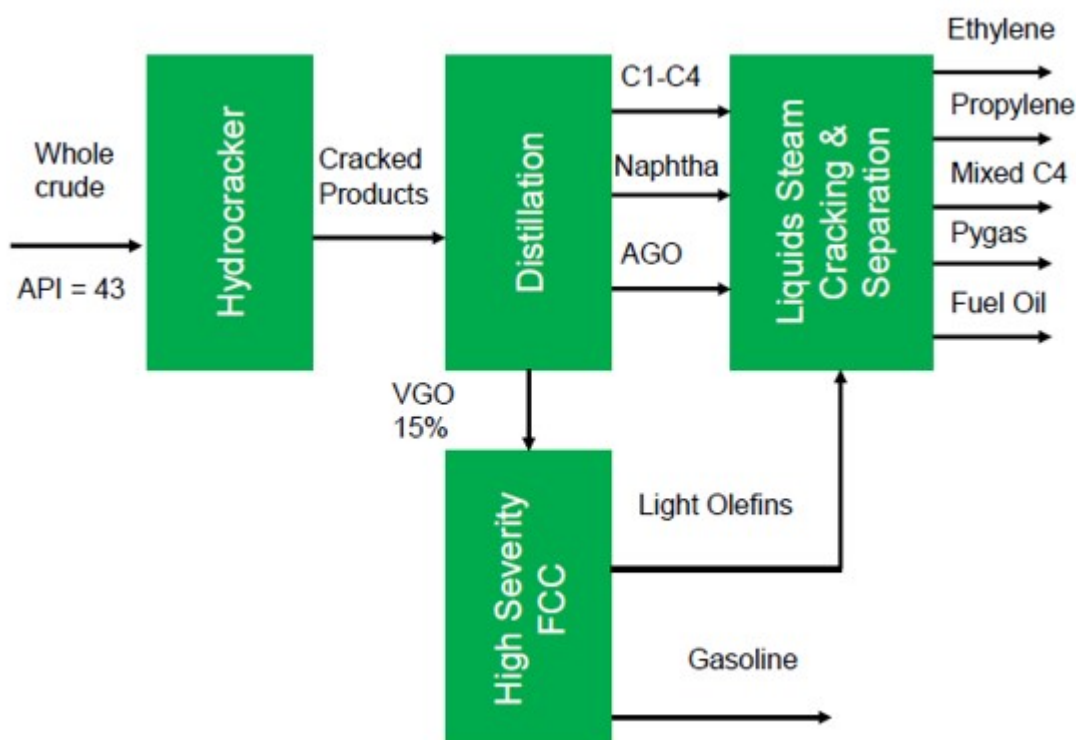According to the classification proposed, the crude to chemicals refineries is considered the maximum level of petrochemical integration.

THE CRUDE OIL TO CHEMICALS – WHAT IS THE ROLE OF FCC AND HYDROCRACKING?

Due to the increasing market and higher added value as well as the trend of reduction in transportation fuels demand, some refiners and technology developers has dedicated his efforts to develop crude to chemicals refining assets. One of the big players that have been invested in this alternative is the Saudi Aramco Company, the concept is based on the direct conversion of crude oil to petrochemical intermediates as presented in Figure 13.

The process presented in Figure 18 is based on the quality of the crude oil and deep conversion technologies like High Severity or petrochemical FCC units and deep hydrocraking technologies. The processed crude oil is light with low residual carbon that is a common

processing scheme involves deep catalytic conversion process aiming to reach maximum conversion to light olefins. In this refining configuration, the combination of hydrocracking and petrochemical FCC is applied to ensure maximum added value to the processed crude oil through near zero production of transportation fuels. Figure 14 present a comparison between the petrochemicals yields of traditional refineries, a benchmark integrated refinery and Hengli crude to chemicals complex, according to data from IHS markit.

Analyzing Figure 14 it's possible to note the higher added value reached in crude to chemicals refineries when compared even with highly integrated refineries.

SYNERGY BETWEEN HYDROCRACKING AND FCC UNITS – A HIGH BOTTOM BARREL CONVERSION REFINING HARDWARE

As aforementioned, sometimes the hydrocracking and FCC technologies are faced by competitors technologies in the refining hardware due to the similarities of feed streams that are processed in these units. In some refining schemes, the mild hydrocracking units can be applied as pretreatment step to FCC units, especially to bottom barrel streams with high metals content that are severe poison to FCC catalysts, furthermore the mild hydrocracking process can reduce the residual carbon to FCC feed, raising the performance of FCC unit and improving the yield
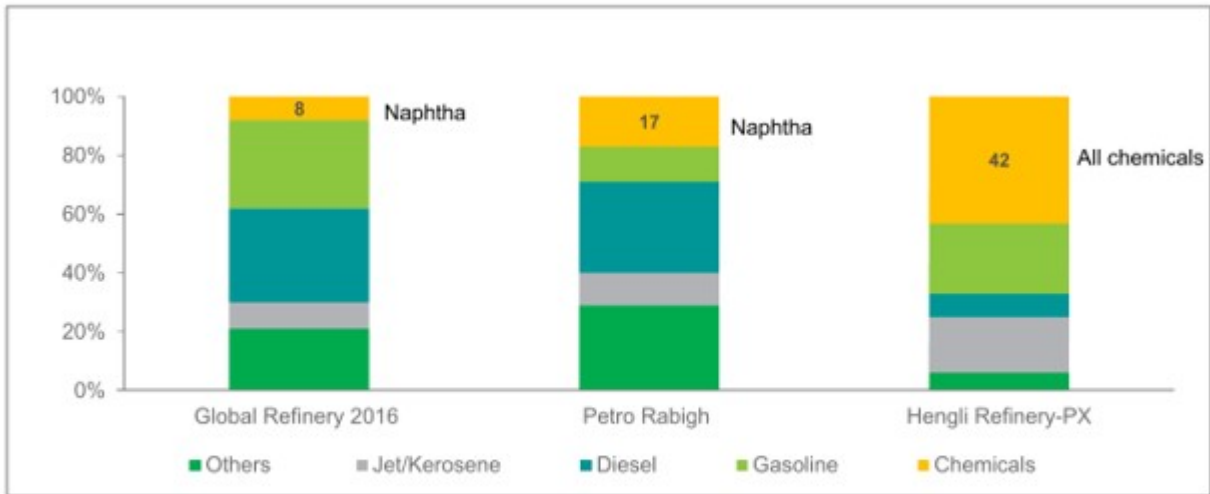
Figure 14 – Petrochemicals Yield Comparison (IHS Markit, 2018)
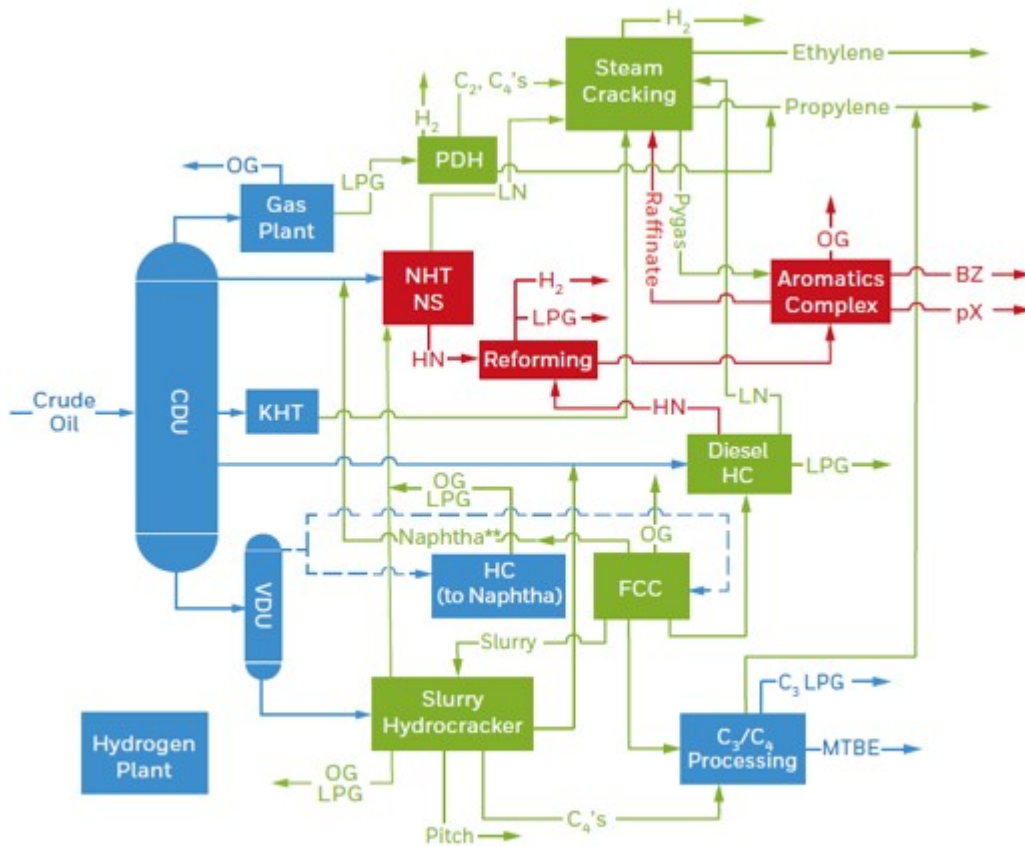

Figure 15 – Example of an Integrated Refining Focusing on Petrochemicals Scheme by UOP Company

of light products like naphtha, LPG, and olefins. Figure 15 presents an example of high integrated refining configuration relying on hydrocracking and FCC technologies.

As presented in Figure 15, the integrated refining scheme rely on deep residue upgrading technologies as hydrocracking and fluid catalytic cracking (FCC) is capable to reach the production of high-quality petrochemicals, according to the market trends. In some refining configurations, mild hydrocracking technologies are applied upstream of FCC units aiming to improve the quality of the FCC products, mainly the sulfur content.

Examples of mild hydrocracking technologies are the IsoTherming™ process developed by the Dupont Company, and the SPC™ Process licensed by Haldor Topsoe Company, a simplified process flow diagram for SPC™ process is presented in Figure 16.

Considering the great flexibility of deep hydrocracking technologies that are capable to convert feed stream varying from gas oils to residue, an attractive alternative to improve the bottom barrel conversion capacity is to process in the hydrocracking units the uncracked residue in FCC unit aiming to improve the yield of high added value derivatives in the refining hardware, mainly middle distillates like diesel and kerosene. This configuration can be especially attractive for gasoline Tier 3 production (with maximum 10 ppm sulfur) for refiners processing high sulfur crudes.

THE SIDE EFFECT OF CRACKED FEEDS – A SPECIAL CHALLENGE TO HYDROCRACKING UNITS

The most common cracked feeds directed to hydrocracking units are residual streams from FCC like Light Cycle (LCO) and Decanted Oil (DO) and Heavy Coker Gasoil (HCGO) from Delayed Coking units. Another less common feed is residue from Visbreaking units.

The main characteristics that influence in the hydrocracking performance for each feedstock is presented below:

- FCC Cycle Oils – Present high aromaticity that are normally refractory to cracking reactions as well as refractory sulfur components, raising the sulfur content in the final products and reduction in diesel cetane number, on the other side, normally presents low basic nitrogen content that is a poison to the hydrocracking catalysts.

- Thermal Cracking Feeds – Normally presents low aromatics content but concentrate refractory sulfur components.

The Heavy Coker Gasoil (HCGO) is an interesting case study as a feed to hycrocracking unit. Refiners with high complexity refining hardware can rely on the synergy between delayed coking and hydrocracking technologies to ensure added value to bottom barrel streams.

The quality of the HCGO relies on the quality of the feed to the delayed coking unit as well as the operating mode of the unit, mainly the
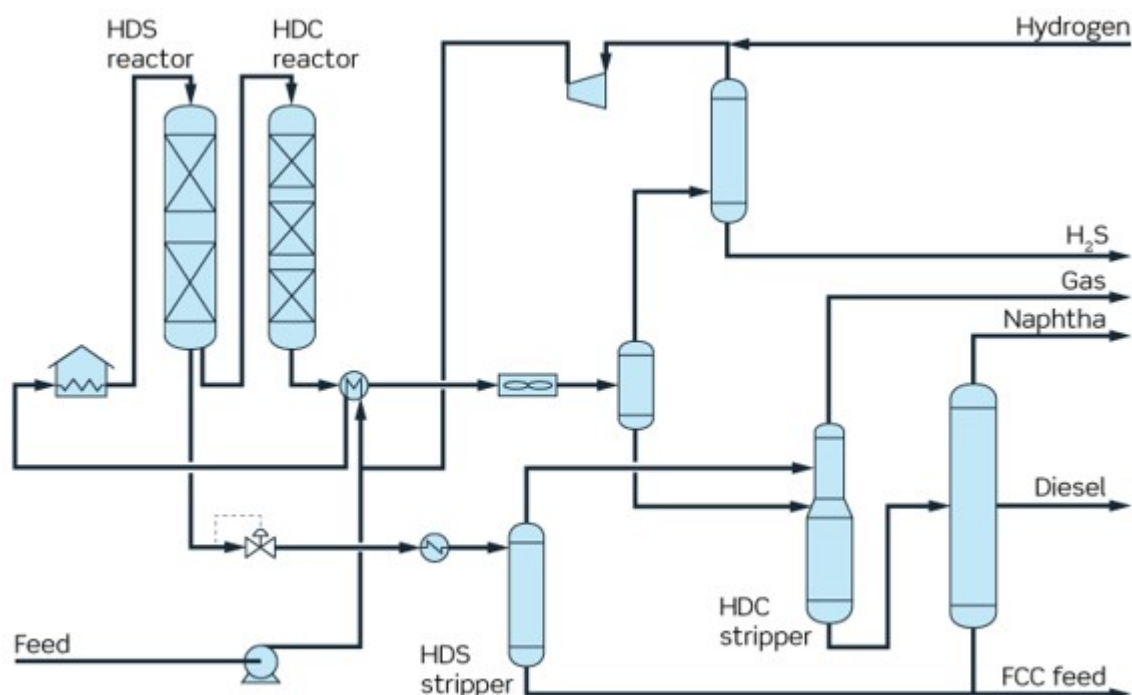

Figure 16 – Process Flow Diagram for the SPC™ by Haldor Topsoe Company

recycle ratio. Higher recycle ratios produces better quality HCGO once reduces Conradson Carbon Residue (CCR), reducing the contaminants content like metals, sulfur, and nitrogen.

Despite this advantage, the delayed coking operators normally minimize the recycle ratio to minimum as possible aiming to raise the fresh feed processing capacity and the quality of HCGO is not an optimization focus of the refinery. For this reason, normally the HCGO is a hard feed to hydrocracking units due to the high content of refractory sulfur components, high CCR, high nitrogen content, and aromatics concentration.

The sulfur and nitrogen content raises the heat release in the first bed (Higher exothermal profile) that can produce damage to the catalysts, the nitrogen tends to inhibit the cracking reaction leading to lower conversion in the unit. Hydrocrackers processing feeds with high nitrogen content tends to apply processing configuration with intermediate gas separation to control the catalyst activity. The higher production of H2S and NH3 due to the higher concentration of sulfur and nitrogen reduces the hydrogen partial pressure, raise the necessity of wash water to the units, and can raise the corrosion rate in the processing unit.

Aromatics compounds tend to raise the hydrogen consumption, the heat release in the catalyst bed, and are precursors of coking deposition that deactivate the catalyst. Other side effects of the cracked feeds to hydrocracking units are the impact over the quality of the final products like lower cetane number of diesel, higher smoke point of kerosene, lower viscosity index in the lubricating oils and higher sulfur content.

As described above, processing cracked feeds in hydrocracking units present some additional challenges to refiners related to hydrogen consumption, better quench design of the catalyst bed due to the higher exothermic profile of the reactions, and lower global activity of the catalyst due to the higher poison content, like basic nitrogen. These characteristics lead the refiners processing cracked feeds in hydrocracking units to invest more capital in feed treating systems like filtering and guard beds, despite this apparent disadvantage, refiners able to add value to bottom barrel streams can enjoy highly competitive advantage considering the downstream market post IMO 2020. For refiners processing extra-heavy bottom barrel streams, the deep hydrocracking technologies like slurry phase hydrocracking can be an interesting option, despite the high capital and operating costs.

CONCLUSION

The current scenario indicates a competitive advantage to refiners capable to maximize the yield of petrochemicals in the refining hardware ensuring higher added value to the processed crude oils and the adequate synergy between refining technologies is a basic concept in the downstream sector and one of the first steps to define adequate refining configuration. The synergy between residue upgrading technologies is increasingly relevant to the refiners aiming to keep and improve the economic sustainability of the refiners, especially considering the downstream market post IMO 2020, considering the limitations of FCC technology to treat heavier feed stocks, the synergy with hydrocracking and mild hydrocracking units can allow a higher level of bottom barrel conversion and maximum production of high added value derivatives.

Despite the relatively high capital cost, the synergy between hydrocracking and FCC units are economically attractive the refiners inserted in markets with higher demand by lighter derivatives, especially petrochemicals and middle distillates. Although the benefits of petrochemical integration, it's fundamental taking in mind the necessity to reach a circular economy in the downstream industry, to achieve this goal, the chemical recycling of plastics is essential. As presented above, there are promising technologies which can ensure the closing of the sustainability cycle of the petrochemical industry.

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Resolving Process Distillation Equipment Problems

Karl Kolmetz , Timothy M. Zygula

INTRODUCTION

In most chemical processing systems two main unit operations dominate; chemical reaction followed by separation. The chemical reaction step is normally completed in a reactor. The reactor can be in numerous forms, from a plug flow reactor, to a CSTR (Continuously Stirred Tank Reactor), which can be in the form of a batch reactor, to a fixed or a fluidized catalytic bed reactor. From the reactor the reactants are then sent to a separation unit. The reactants are separated into desired products, unreacted products for recycle, and unwanted or co products.

Most Separation Units contain distillation equipment. Distillation Equipment was developed to separate ethanol from the by-products of fermentation. From the original batch stills, distillation equipment has progress to the type of trayed and packed columns used today. Today columns range from absorbers, extractors, strippers, and rectifying towers. They include vapor / liquid columns, liquid / liquid columns, and extractive distillation and reactive distillation columns. Vapor / liquid columns are designed to separate products by boiling point differences. Liquid / Liquid columns are designed to separate products by a physical property difference such as polarity. Extractive and reactive distillation columns shift equilibrium by removing one of the products to improve the equilibrium distribution.

GENERAL DISTILLATION EQUIPMENT DESIGN

The first step in resolving any distillation problem is to understand the operating and technical fundamentals of the column. Knowledge of how a column functions, hydraulic constraints, thermodynamic and equilibrium limits, and heat and material balances are required. This knowledge needs to be accumulated in advance of formulating any resolution of a problem.

At least three types of distillation equipment problems exist. The first problem is inappropriate design, the second problem is inappropriate operation, and the third is potential

Co-products
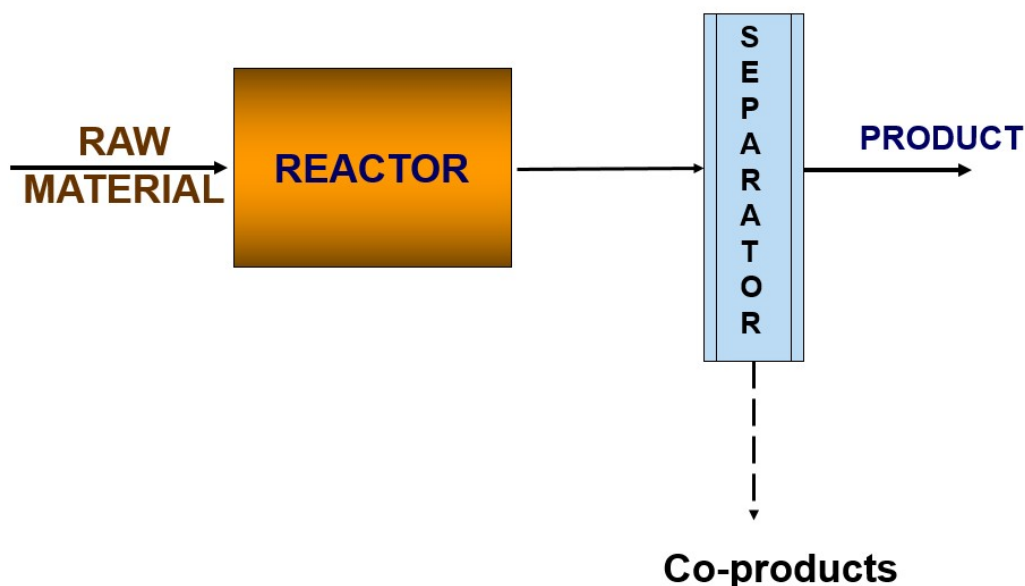
damage to internal equipment. Before a process is shut down for repairs the inappropriate design and damage to internal equipment should determined, and inappropriate operation should be eliminated.

Extractive Distillation Columns
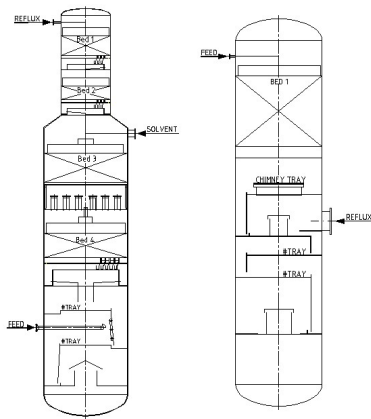
APPROPRIATE STAGE DESIGN

The design of stage operations has progressed from a trial and error basis to a computer-modeled system. The computer-modeled system came become an error-based system if operational feedback is not utilized. The computer model should match existing field data if the tower is operating properly, and if not, field data should be re-verified. If field data is accurate, the model should be adjusted to match existing data. The computer model can be verified by developing a McCabe-Thiele plot to verify the number of separation stages required. If you assume that the model is correct in all cases, you will soon have opportunities for new employment.

Trayed Columns utilize a pressure and temperature differential, to create a mass transfer gradient, to separate the products. Packed Columns generate a mass transfer area by providing a large surface area over which the liquid can transfer heat and mass to the vapor.

Pressure is a very important constraint in stage design. In low-pressure systems the vapor is considered the continuous phase and in high-pressure systems the liquid is considered the continuous phase. In low-pressure systems packing can be successfully utilized. In high-pressure systems packing can fail, due to a back mixing mechanism, therefore trays are the preferred system.

The temperature at which the reflux can be condensed usually determines the tower pressure. Normally the preferred temperature is that of cooling water. If cooling water cannot be used, the pressure is set using the best combination of variables. One variable is the increased cost of cooling at lower pressures.

Often at lower pressure, refrigeration is needed equating to increased operating cost. A balance has to be constructed between capital cost and operating cost. This balance is also utilized in the determination of the amount of reflux verses the number of stages. This balance is between the energy requirement verses the cost of the additional stages. Computer based models has made this balance optimal.

MINIMUM REFLUX RATIO AND MINIMUM NUMBER OF STAGES BY USE OF SIMULATION

To determine the minimum reflux ratio and the minimum number of stages, one develops a reflux-stage plot and extrapolates from it. To develop this plot, simulation runs are performed at different number of stages while keeping the material balance, product compositions, and the ratio of the feed stage to the number of stages constant. The reflux ratio is allowed to vary. Then a plot of the number of stages versus reflux or reflux ratio is plotted. The curve is extrapolated asymptotically to an infinite number of stages to obtain the minimum reflux ratio and asymptotically to an infinite reflux ratio to obtain the minimum number of stages

Optimization of Feed Stage by Simulation
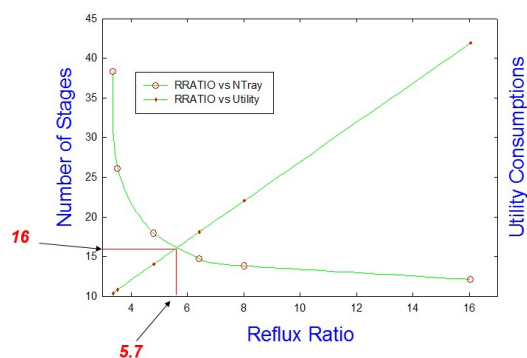
To determine the optimum feed stage, simulation runs can be performed at several different feed positions. In the simulation runs, the material balance, reflux ratio, and total number of stages need to be kept constant. Then two main plots can be created. One plot is the McCabe-Thiele diagram and the other is a concentration versus feed stage diagram. The McCabe-Thiele diagram is plotted using the mole fraction data calculated for each stage by the simulation. The equilibrium data and the operating lines are determined from this data. The McCabe-Thiele diagram then shows how an optimum feed stage versus a non-optimum feed stage looks when using the simulation data.

In industry many different types of reboilers are used. Overviews of three types used are given below.

1.Vertical Thermosyphon Reboiler

A vertical thermosyphon reboiler is very similar to a long tube evaporator and a climbing film evaporator. Liquid from the column sump flows through the inlet leg of the reboiler, enters the bottom channel, and is distributed uniformly to the tubes. A shell-side fluid, often condensing steam heats the tubes. Condensate flow in this type of reboiler is vertical. The process fluid entering the tubes is below its boiling point due to static head effects and must undergo sensible heating; for vacuum systems, such heating may consume a significant portion of the tube length.

Heat is transferred by both nucleate boiling and two-phase convective mechanisms. The two-phase mixture exiting from the heated zone returns to the column for disengagement of the phases, with the net vapor representing the needed boil-up for the distillation process and the liquid representing a recycle. Good design calls for vaporization per pass in the range of 10% to 30%; thus, there is a significant recycle flow.

The advantages of the vertical thermosyphon reboiler are the low residence time of the process liquid, the low liquid inventory of process fluid and, the low floor area required. Another advantage of this type of reboiler is the high heat transfer coefficients that are obtained. Vertical thermosyphon reboilers are usually the best value for the heat supplied. This type of reboiler can be used in fouling services because these exchangers are easy to clean.

The disadvantage of this type of exchanger is that they require extensive amounts of headroom. A distillation column may have to be raised off the ground in order to accommodate the reboiler. This may cause a mechanical design problem with the column. Stability of the column may become an issue.

2. Horizontal Thermosyphon Reboiler

This is perhaps the most common type of reboiler. A horizontal thermosyphon reboiler consists of a horizontal shell and tube exchanger with a single horizontal baffle. The process fluid flows along the shell-side along the length of the tube bundle from its point of entry midway along the shell to the ends.

The flow of process fluid through the reboiler is governed by thermosyphon action, although a pump could be installed in the inlet pipe if necessary. The flow rate through this type of reboiler is controlled by density differences.

The main advantage of the horizontal thermosyphon reboiler is the ease of removing the tube bundle for cleaning. Also, the horizontal arrangement permits a lower elevation of the return line. This allows for a lower column elevation in relation to the reboiler elevation.

3. Kettle Type Reboiler

The kettle reboiler is similar to a shell-side evaporator. The heating fluid is usually condensing steam flows inside the tubes, which are commonly U-Tubes. The U-Tube bundle occupies the lower part of the K-Type shell. Liquid boiling is outside the tubes and the eccentric bundle arrangement makes available space for vapor-liquid disengagement. An internal weir controls the liquid level in the shell. The liquid level is such that the top of the bundle is only just submerged. The liquid enters the reboiler by gravity feed. A valve usually controls the feed. The overflow from the weir is the bottom product of the distillation column. If necessary a pump can be installed in the pipe between the distillation column and the reboiler. A properly designed kettle can produce a near-equilibrium vapor mixture and thus can provide an extra theoretical stage for the separation. It has an advantage of convenient bundle removal for tube inspection, and is relatively insensitive to varying loads of vapor production. It is comparatively expensive, however due to the type of shell design used for this type of reboiler.

Trayed Columns Design

One of the very first trays to be developed was the sieve tray. It is essentially a plate with holes punched into the plate. The number and size of the holes is based on the vapor flow up the tower. The liquid flow is transported down the tower by downcomers, a dam and overflow device on the side of the plate, which maintains a set liquid level on the tray. To maintain the liquid level on the tray a minimum amount of vapor traffic up the tower must be maintained, or the liquid level on the tray will weep down to the next tray through the holes punched on the plate. Typically sieve deck trays have a

Some of the latest developments in tray design include changes to the downcomer and changes in the valve design. The downcomer requires a disengaging area to separate the liquid from the vapor. This area requires a minimum distance that normally sets the tray spacing. To use multiple downcomers reduces this distance and the total height of the tower. The liquid is required to travel across the deck to the next downcomer. If the valves are designed to help direct the liquid flow across the deck, by directing the vapor, the total time on the deck will be reduced leading to increased capacity. Trays are the most commonly selected type of tower internal. Generally trays perform well at high liquid and vapor loadings. At low flow parameters the capacity and efficiency of trays can be reduced.

Some other items to consider when deciding to use trays in a tower.

1. Trays have downcomer capacity problems in heavy foaming services.

2. Trays have a high resistance to corrosion.

3. Trays have higher pressure drop than structured packing or random packing.

4. Entrainment is an issue with trays. Trays usually have more entrainment than packing. Excessive entrainment can lead to efficiency loss.

5. Excessive vapor and liquid mal-distribution can lead to a loss of efficiency in a tray tower.

Good Reflux Inlet Feed Design

Mal-distribution can be caused by the feed and reflux inlet design. A good feed and reflux design will affect the equilibrium on the feed tray and the adjacent trays slightly. A poor inlet design can affect several trays above and below the feed point. If a tower has 20 trays and a poor inlet feed design disrupts the equilibrium on 4 of the trays, the capacity and efficiency of the tower can be reduced by 20%. Installing better inlet designs is an efficient way to improve separation.

Not Good Reflux Inlet Feed Design

Good Feed Design
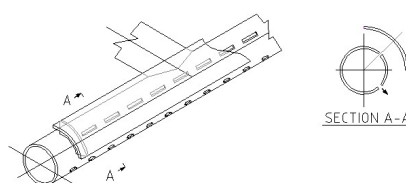
Trayed Columns Trouble Shooting

Trayed Columns utilize a pressure and temperature differential to separate the products. The weir holds a liquid level of each tray. The vapor must over come this liquid head to move up the column. On the tray the vapor and liquid are contacted and then above the tray they are separated. Any deviation that develops that restricts the vapor and liquid from contacting and then separating will deteriorate the column's ability to meet design specifications.

Deviations that will restrict the ability of a column to contact include, but are not restricted to;

1.Corroded, fouled, or eroded tray valves and feed devices,
2.restrictions in downcomers,
3.physical damage.

Deviations that will restrict the ability of a column to separate include, but are not restricted to;

1.excessive rates,
2.contaminates that cause foaming,
3.improperly sized downcomer openings,
4.liquid entrainment
5.foaming
6.excessive liquid back-up in the downcomers
7.physical damage.

Because a trayed column uses a pressure and temperature differential to separate the products, the pressure and temperature profile of a column is a key indicator of how the column is performing. The column temperature and pressure should gradually increase as one surveys down the column.

A calculation can be developed for what the column pressure drop should be, based on the number of stages and the height of the weir, or downcomer dam. If a column has twenty trays and a weir height of three inches the vapor has to over come a liquid height of sixty total inches. The equivalent height of one pound of water is 27.68 inches. Therefore sixty inches of water equates to 2.16 pounds of pressure drop. This calculation will need to be corrected by the specific gravity of the actual liquid on the tray.

This pressure drop calculation is an essential tool in tower trouble shooting. If the pressure drop is low, tower may be weeping, internal tray man ways may be dislodged, or reflux flow may be inaccurate on the low side. If the pressure drop is high downcomers may be

restricted, whole trays may be dislodged, or reflux flow rate may be inaccurate on the high side.

After a calculation of what the pressure drop should be, a pressure survey should be performed. It should be preformed with the same pre-calibrated gauge, if not by the engineer, under the supervision of the engineer. Gauges can be damaged in installation and care should be used in the installation of the gauge. Field mounted pressure gauges contain a high level of uncertainty and should not be used for trouble shooting.

A temperature profile will also provide valuable information as to the operations of the tower. If thermo-wells and thermocouples are not available at the desired points throughout the tower, an IR temperature scan gun can be used at the inspection ports through the insulation. If the temperature profile is not consistent several causes are possible, hydraulic tray flooding or weeping, potential tray damage and fouled or corroded trays or downcomers.

In distillation towers there are actually two accumulators. The first is normally obvious, the over head receiver, the second is the bottom section of the tower. These accumulators are used to stabilize the operation of the tower and down stream operations. This internal surge drum creates an inventory to act as a buffer. If this internal level is allowed to rise above the reboiler return, stripping inlet, or feed inlet flooding can occur.

There is an inherent error built into sight glass and level instrumentation. The sight glass and level instrumentation contain non aerated liquid, called clear liquid, which is not a true indication of the condition of the liquid within the tower. The liquid within the tower will have two levels, a clear liquid level below the aerated liquid level. Because the aerated level will have lower specific gravity than the clear liquid within the instrumentation, the tower level will be higher than the instrumentation indicates. If the level in the tower is higher than the feed or reboiler return entrained liquid can be carried to the next stage causing flooding.

SYNOPSIS OF TRAY TROUBLESHOOTING

Do simple checks first.

1.Assure that levels are accurate. Have operations move levels and view changes in the field.
2.Calculate column pressure drop and then measure pressure drop. Review survey pressure reading to operation's readings.
3.Survey column temperature profile. Review survey temperature reading to operation's readings.

Tower Level Errors
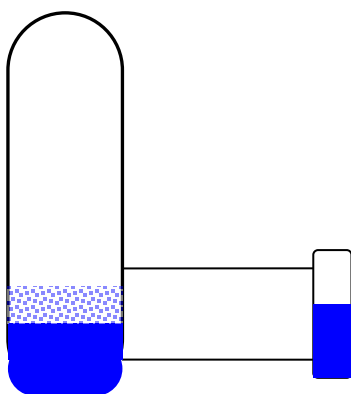
VERIFY TOWER OPERATIONS

Perform tower simulation to verify Tower Stage efficiency. Sometimes the feed compositions changes and tower is no longer able to meet desired specifications due to thermodynamic or equilibrium constraints. Needed to perform the simulation will be;

1.Accurate tower feed, Overhead, and Bottoms laboratory analysis
2.Accurate tower mass balance, within 2%.
3.Heating and cooling medium temperatures.

If the tower simulation confirms the limits are not beyond thermodynamic or equilibrium constraints and additional check may be to have the tower scanned to look for tray damage. This type of troubleshooting method can determine internal damage, vapor liquid maldistribution, and packed and trayed tower fouling. Because of economic constraints, scanning should be chosen only after the simple checks and the limits are confirmed. Scanning can sometimes confirm the problem that was identified by the other checks.

RANDOM AND STRUCTURED PACKED COLUMNS DESIGN

Random and Structured Packed Columns generate a mass transfer area by providing a large surface area over which the liquid can transfer heat and mass to the vapor. The packed column has several distinct advantages and some disadvantages.

A major advantage to packed columns is the reduction in pressure across the column. In high-pressure systems, this is not as important, but in low-pressure systems this can reduce the temperature, if polymerization is a concern as in a Styrene Monomer plant, or reduce the upstream pressure to help improve furnace yields, as in an ethylene plant.

Typically the column pressure drop for a packed column is less than that of a trayed column because of the percent open area. Typical percent open are of a trayed column is 8 to 12%, whereas a packed column can approach 50%. Liquid accumulation for a packed column is lower than that of a trayed column. This is important when degradation of products can occur at higher residence times.

Another advantage of packed column is reduced foaming. Packing generates thin films instead of fine droplets for mass and heat transfer, reducing entrainment when foaming agents are present. An additional advantage is that residence time within a packed column is shorter leading to less polymerization potential. Because the residence time is short, control systems may need to be modified to account for this difference. For example, the control of a tower bottoms may be based on temperature or boil-up rate verses level.

Here are some points when trying to decide if structured packing should be the application of choice. The vapor and liquid rates, or loadings, of the tower are important when considering structured packing. Generally structure packing performs well at low liquid and vapor loadings. At high flow parameters the capacity and efficiency of structured packings can be significantly reduced. Structured packing is generally most efficient in low-pressure distillation applications.

Some other items to consider when trying to decide to use packing in a tower.

1.Random packing does not perform well in heavy fouling applications.

2.Packing has a low resistance to corrosion due to thickness of packing.

3.Packing is a low-pressure drop device that provides high efficiency. This is why structured packing is extremely successful in low-pressure distillation applications.

4.Packing performs well in foaming applications.

The design of a packed column includes the packing, liquid distributors, and liquid collectors. After the packing the liquid distributor is the most important part of the tower internals. It can determine the success or failure of the column. Packed towers are more sensitive to liquid and vapor mal-distribution than trayed towers. Therefore, it is critical that vapor and liquid enter packing evenly distributed. The performance of the packing depends heavily on the initial vapor and liquid distribution entering the packing. Poor vapor and liquid distribution to a packed bed can result in a loss of efficiency.

The liquid inlet distributor is the device that diffuses the liquid across the mass transfer area. This device must be designed properly or the liquid will not create the surface area required for separation. Many times the liquid inlet distributor is the main problem area for random and structured packed column problems. The liquid distributor types include V-notched channel distributor and the pan or orifice distributor.

The V-notched channel distributor is mainly used in towers of greater than three feet in diameter and is the preferred choice. The V-notches allow high liquid turndown and can handle liquids that contain solids or that have fouling potential. The pan or orifice distributor is similar to a sieve tray in operation and is normally used in towers of less that three feet in diameter with clean services.

To avoid the loss of efficiency due to channeling, the liquid should be collected and re-distributed every 15 to 20 feet. Above twenty feet the channeling becomes high and the efficiency is greatly reduced. The liquid should be collected in a chevron type collector to evenly distribute the vapor to the next bed. The liquid should be taken and re-distributed with a V-notched type distributor.

Bed limiters or hold down grids are used to prevent expansion of the bed at high flow rates. They are attached to the tower wall by means of a support ring. Bed limiters or hold down grids should not be designed to produce a restriction in vapor flow and increase the tower pressure drop.

Tower internals must be installed taking particular care to insure levelness of parting boxed, troughs and similar equipment. In small columns moderate misalignments may be tolerated, but in large towers tolerances must be held to no more than +/- 1/8 inch (3 mm).

One of the great disadvantages of packing is the inability to properly inspect the installation. If the installers crush the packing during the installation the tower can flood because of reduced open area. A trayed tower is more controllable and the intermediate sections are inspectable.

RANDOM AND STRUCTURED PACKED COLUMNS TROUBLE SHOOTING

Random and Structured Packed Columns generate a mass transfer area by providing a large surface area over which the liquid can transfer heat and mass to the vapor. Any deviation that develops that restricts the liquid from forming this large surface area will deteriorate the column's ability to meet design specifications.

Deviations that will restrict the ability of a column to generate this area include, but are not restricted to;

1.Packing damaged during installation,

2. incorrect distributor design or installation.
3.fouled packing,

4.packing flooding
5.contaminates that cause foaming,
6.liquid entrainment into a packed bed.

7.physical damage.

The pressure and temperature profile of a column is a key indicator of how the column is performing. The column temperature and pressure should gradually increase as one surveys down the column.

A calculation can be developed for what the column pressure drop should be, based on the height to the bed of the packing. For most packed beds the pressure drop should be between 0.1 to 0.8 inches of water per foot of packing. Below this rate the liquid may not be evenly spread across the packing and or the liquid rate may be inaccurate on the low side. Above this rate the packing may be fouled or damage not allowing the liquid to exit from the packing and / or the liquid rate may be inaccurate on the high side.

After a calculation of what the pressure drop should be, a pressure survey should be performed. It should be preformed with the same pre-calibrated gauge, if not by the engineer, under the supervision of the engineer. Gauges can be damaged in installation and care should be used in the installation of the gauge. Field mounted pressure gauges contain a high level of uncertainty and should not be used for trouble shooting.

A temperature profile will also provide valuable information as to the operations of the tower. If thermo wells and thermocouples are not available at the desired points throughout the tower, an IR temperature scan gun can be used at the inspection ports through the insulation. If the temperature profile is not consistent several causes are possible, hydraulic flooding, potential damage and fouled or corroded packing.

SYNOPSIS OF PACKING TROUBLESHOOTING

Do simple checks first.
1. Assure that levels are accurate. Have operations move levels and view changes in the field.
2. Calculate column pressure drop and then measure pressure drop. Review survey pressure reading to operation's readings.
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Verify Tower Operations

Perform tower simulation to verify Tower Stage efficiency. Sometimes the feed compositions changes and tower is no longer able to meet desired specifications due to thermodynamic or equilibrium constraints. Needed to perform the simulation will be;

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2. Accurate tower mass balance, within 2%.
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If the tower simulation confirms the limits are not beyond thermodynamic or equilibrium constraints and additional check may be to have the tower scanned to look for tray damage. Because of economic constraints, scanning should be chosen only after the simple checks and the limits are confirmed. Scanning can sometimes confirm the problem that was identified by the other checks.

STRATEGIES FOR FIELD WORK
1. Do not trip over the same obstacle twice.
2. Look out for other obstacles and prevent from tripping over them.
3. Arrange and time the obstacles to suit our purposes.
4. Monitor critical obstacles closely and clear them on time.
5. Do not assume there is only one critical obstacle.
6. Be wary of new obstacles and new untested techniques.

CONCLUSIONS
In column trouble shooing it is important to understand the fundamentals of distillation, the choice of tower internals and externals and how they interact. Several recommendations have been presented and should be evaluated for the best application. Keep in mind to always do the simple checks first, and use the available tools to verify that the separation that is desired is achievable.

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Rock Bottom View

Ronald J. Cormier, Engineering Practice Contributing Author

Hello again, via another edition of "The View from Rock Bottom". TVRB originally took its name from my old writing porch along the shore of the Pedernales River at The Rock Bottom Ranch in Central Texas, USA. Since we were last together, I have permanently re-located to central Mexico along the northern shore of Lake Chapala, just south of Guadalajara, Mexico's second largest city. The area has BOTH the elevation of Denver, Colorado, and the latitude of Honolulu, Hawaii. Daytime temperatures are moderate, and evenings are borderline chilly.

After twelve blistering Texas summers at RBR, and ever-rising, oppressive summer heat levels between 2011-2023, the region's temperatures have become most unpleasant during the summer. Actually, for those who do not have refuge from the heat, the situation is downright harmful to human health. Hence during summers, we found ourselves house-bound, "protected' only by central air conditioning. However, this modern miracle also proved to be a worrisome single source of failure, if the unit were to malfunction during the summer's intense strain on the unit. The other option was to clear out and simply travel away during the worst of the weather. While many would view the "remedy" as a normal extended vacation for retirees, in actuality, we became climate refugees. In reality, we were held captive by worsening atmospheric conditions on Planet Earth, driven by global warming.

An unrelenting stretch of blistering days amid the ongoing heat wave has put this summer on track to be one of Texas' (and much of the south and southwest parts of the US, plus globally along these same latitudes) most extreme, weather data shows. Although June was only Texas' 16th warmest on record by climatologist, a long period of very hot days between mid-June and mid-July has made this summer one of the most intense in terms of extended high temperatures.

In June, a sample of 38 weather stations across the state recorded a temperature at or above 100 degrees F (38C) 250 times — the fifth-greatest monthly total for that month in the past three decades, according to a Texas Tribune analysis of National Weather Service data. The average temperature for June was 82.2F (28C) degrees, which was 2.6 degrees above the 20th century average, according to data provided by the state climatologist.

You might say, "so what", or "I don't understand the connection", or "meh, it's simply a normal cycle that Earth moves through over time". Whatever your view on the issue, and/or probable causes for global warming, it matters little vs. the reality of hesitation and the critical dilemma for human health. Man-made chemical constituents can and are causing problems for the Earth's atmosphere, contributing to various worsening environmental issues.

MAJOR PROBLEMATIC SUBSTANCES INCLUDE:

1. "Greenhouse Gases (GHGs)": Greenhouse gases, such as carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases, trap heat in the Earth's atmosphere and cause the greenhouse effect. Increased concentrations of these gases, primarily due to human activities, lead to global warming and climate change.

2. "Ozone-Depleting Substances (ODS)": Chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), and halons are

examples of ODS that contribute to the depletion of the ozone layer in the stratosphere. This depletion allows more harmful ultraviolet (UV) radiation from the sun to reach the Earth's surface, posing health risks and impacting ecosystems.

3. "Particulate Matter (PM)": Particulate matter consists of tiny particles suspended in the air, including dust, soot, and aerosols. PM can cause respiratory and cardiovascular health problems when inhaled and affects air quality and visibility.

4. "Volatile Organic Compounds (VOCs)": VOCs are emitted from various sources, including industrial processes, vehicle emissions, ranching, and certain consumer products. They can contribute to the formation of ground-level ozone (a component of smog) and have adverse health effects.

5. "Nitrogen Oxides (NOx)": NOx, primarily from vehicle exhaust and industrial sources, contributes to the formation of ground-level ozone and particulate matter. It also plays a role in acid rain, which can harm ecosystems and aquatic life.

6. Sulfur Dioxide (SO2): SO2 is produced by burning fossil fuels containing sulfur, such as coal and oil. It contributes to the formation of acid rain, which can damage forests, soil, and bodies of water.

7. Mercury (Hg): Mercury emissions, mainly from coal-fired power plants and industrial processes, can lead to the accumulation of mercury in the environment. Mercury becomes methyl mercury in water bodies, accumulating in fish and posing health risks to humans and wildlife.

8. Ammonia (NH3): Ammonia is released from agricultural activities and other sources. It can contribute to air pollution and ecological problems, such as eutrophication in water bodies.

9. Chlorine and Bromine Compounds: In addition to ODS like CFCs, certain chlorine and bromine compounds can contribute to ozone depletion in the stratosphere.

Addressing these problematic chemical constituents is crucial to protect the Earth's atmosphere and mitigate the adverse impacts on climate, human health, and ecosystems. Efforts to reduce emissions, adopt cleaner technologies, and promote sustainable practices are essential steps in safeguarding the environment.

Releasing CO2 (carbon dioxide) into the atmosphere is a problem due to its significant role in contributing to climate change and its associated impacts on the environment and human well-being.

KEY REASONS WHY ESPECIALLY CO2 EMISSIONS ARE A CONCERN:

Greenhouse Gas Effect: CO2 is a greenhouse gas, which means it traps heat in the Earth's atmosphere. While greenhouse gases are essential for maintaining a habitable climate by retaining some of the sun's heat, human activities have led to an excessive increase in CO2 levels. This enhanced greenhouse effect is causing the Earth's temperature to rise, resulting in global warming and climate change.

2. Global Warming: As CO2 concentrations in the atmosphere increase, they enhance the greenhouse effect, leading to a rise in global temperatures. This warming contributes to various adverse impacts, such as more frequent and intense heatwaves, melting polar ice caps and glaciers, rising sea levels, and shifts in weather patterns.

3. Ocean Acidification: A significant portion of the excess CO2 released into the atmosphere is absorbed by the world's oceans. When CO2 dissolves in seawater, it forms carbonic acid, leading to a decrease in ocean pH. This process is known as ocean acidification, which has detrimental effects on marine life, especially on organisms with calcium carbonate shells and skeletons like corals, mollusks, and certain plankton species.

4. Disruption of Ecosystems: Climate change driven by CO2 emissions can disrupt ecosystems and biodiversity. Some species may struggle to adapt to changing conditions, leading to shifts in habitats and potential extinction risks. Additionally, altered weather patterns can impact agriculture and food production, threatening food security in some regions.

5. Extreme Weather Events: Rising global temperatures due to CO2 emissions can intensify extreme weather events such as hurricanes, droughts, floods, and wildfires. These events can cause significant damage to infrastructure, agriculture, and human communities. By now, we are very familiar with tragic global weather-event catastrophes almost daily, covered by the evening news channels.

6. Health Impacts: Climate change caused by CO_2 emissions can have indirect effects on human health, such as increased heat-related illnesses, worsening air quality, and the spread of certain diseases as the range of disease-carrying vectors expands.

ACTION NEEDED NOW…..

Addressing the issue of excess CO_2 emissions is crucial to mitigate the impacts of climate change and protect the planet's ecosystems and human societies. Implementing measures to reduce emissions, transitioning to cleaner energy sources, and fostering sustainable practices are essential steps to combat this global challenge.

SO WHAT MUST WE DO?????…..

Most critical and familiar to our industry's practices is carbon capture for petrochemicals and refining. Carbon capture refers to the process of capturing and storing carbon dioxide (CO_2). emissions that are generated during petrochemical and refined fuels/lubes production or other related industrial processes. Petrochemicals and fuels are chemicals derived from petroleum or natural gas, and their production can contribute to greenhouse gas emissions and climate change.

Carbon capture technologies aim to mitigate these emissions by capturing CO_2 before it is released into the atmosphere and storing it underground or utilizing it for other purposes. The process typically involves the following steps:

Capture: CO_2 is captured from the flue gases or exhaust streams of petrochemical plants and refineries using various methods such as absorption, adsorption, or membrane separation.

Compression: The captured CO_2 is compressed to a higher pressure, making it suitable for transportation and storage.

Transportation: The compressed CO_2 is transported via pipelines, ships, or trucks to the storage site or utilization facility.

Storage: The CO_2 is either stored deep underground in geological formations, such as depleted oil and gas fields or saline aquifers or utilized in processes like enhanced oil recovery (EOR) where CO_2 is injected into oil reservoirs to increase oil production while simultaneously storing the CO_2 underground.

Hence carbon capture for petrochemicals and fuels can help reduce the environmental impact of the industry by mitigating CO_2 emissions. It is part of a broader strategy to transition to more sustainable and low-carbon practices in the petrochemical/fuels sector. It's worth noting that while carbon capture can play a role in reducing emissions, it is not a standalone solution for addressing climate change. Other strategies such as energy efficiency, renewable energy adoption, and sustainable product design should also be considered to achieve substantial emissions reductions in the long term.

INDUSTRIAL EFFORTS UNDERWAY….

Occidental Petroleum (Oxy) is an international energy company that operates in the oil and gas industry. Oxy is a leader in capturing and handling carbon before its harmful effects harm the atmosphere. Below is a general overview of carbon capture for petrochemicals/fuels and its potential application within the industry.

Along with Oxy, several other major energy companies are involved in carbon capture efforts to reduce greenhouse gas emissions. Companies like ExxonMobil, Shell, BP, Chevron, and Total were among those investing in research and development of carbon capture technologies.

These companies explored various methods, such as direct air capture, carbon capture and storage (CCS) from industrial facilities and utilizing carbon capture to enhance oil recovery. Some are also involved in joint projects and collaborations with governments and other companies to accelerate the deployment of these, as well as upcoming technologies.

Carbon capture can help reduce the environmental impact of the industry by mitigating CO_2 emissions. It is part of a broader strategy to transition to more sustainable and low-carbon practices in the sector. These major firms are analyzing and designing innovation in sustainable project design including critical elements……

Energy Efficiency: plays a crucial role in addressing climate change by reducing greenhouse gas emissions and mitigating the impact of energy consumption on the environment. It involves using less energy to achieve the same or improved level of output or services. Here are some key points highlighting the importance of energy efficiency for climate change:

Emissions Reduction: Improving energy efficiency across sectors such as buildings, industry, transportation, and appliances reduces the overall energy demand. This leads to a decrease in the burning of fossil fuels, the primary source of greenhouse gas emissions. By reducing emissions, energy efficiency helps mitigate climate change.

Cost Savings: Energy-efficient practices and technologies can result in significant cost savings for individuals, businesses, and governments. By using energy more efficiently, less energy is wasted, leading to lower energy bills and operational costs. These savings can then be invested in further energy efficiency measures or other sustainable initiatives.

Renewable Energy Integration: Energy efficiency complements the adoption of renewable energy sources. By reducing energy demand through efficiency measures, the need for energy generation from fossil fuels is decreased. This allows renewable energy sources such as solar and wind to provide a higher percentage of the energy mix, further reducing greenhouse gas emissions.

Sustainable Development: Energy efficiency supports sustainable development goals by promoting responsible and efficient use of resources. It helps to reduce energy poverty, improve energy access, and enhance energy security, making communities more resilient and less reliant on fossil fuels.

Job Creation and Economic Growth: The implementation of energy efficiency measures creates job opportunities in various sectors, including construction, manufacturing, and renewable energy industries. Additionally, energy efficiency initiatives stimulate economic growth by driving innovation, promoting technological advancements, and attracting investment in clean energy technologies.

Co-benefits: Energy efficiency offers co-benefits beyond climate change mitigation. It improves air quality by reducing pollutants emitted during energy production and consumption, leading to better public health outcomes. Energy-efficient buildings also provide enhanced comfort, indoor air quality, and productivity for occupants.

FUELING THE FUTURE....

Delegates from most of the world's largest economies met in Goa, India, in late July to discuss the energy transition as extreme heat takes hold in many areas across the globe. The G20 Energy Transitions Working Group Meeting was intended to set tone and strategy, and while there were some points of agreement, the summit ended without any consensus on phasing out fossil fuels. Investors in energy and renewables are especially taking note ahead of a gathering of G20 leaders in September and the COP28 forum in December.

Snapshot: Greenhouse gases like carbon dioxide, methane and nitrous oxide continue to reach new record highs, while increasing temperatures, a loss of biodiversity and extreme weather events are said to be growing in intensity. It doesn't help that much fossil fuel manufacturing usage is being outsourced to developing nations, where deregulation of environmental protections has been used to advance their economies. This can even be seen among countries that are powering the green revolution, like nickel smelting for EV batteries, with further criticism being leveled at the sustainable commitments of some of the world's most profitable companies.

Many nations are also attempting to shore up their domestic fuel stockpiles as Russia's war in Ukraine and geopolitical tensions elsewhere threaten to weaponize energy supplies. The U.S. Senate last week voted to block China from purchasing oil from the Strategic Petroleum Reserve, while U.S. Energy Secretary Jennifer Granholm reiterated calls for additional supplies as "it gets dangerous when the prices are so high." At the same time, the American government has plowed billions of dollars in subsidies and tax breaks into businesses involved in electric vehicle technology and the energy transition, but other countries may not be able to finance such initiatives or those priorities, and that makes finding a consensus quite complicated.

Outcome statement: *"Given that fossil fuels currently continue to play a significant role in the global energy mix, eradication of energy poverty, and in meeting the growing energy demand, the importance of making efforts towards phase down of unabated fossil fuels, in line with different national circumstances*

was emphasized by some members." **The gathering also failed to set a specific global goal for renewable energy development, and there was also disagreement about the effectiveness of carbon capture technologies. To note, G20 countries account for more than three-quarters of global emissions and world's gross domestic product.**

WE ALL MUST LEND A HAND…

To maximize the potential of energy efficiency, governments, businesses, and individuals can adopt various measures. These include implementing energy-efficient building codes, promoting energy-efficient appliances and equipment, conducting energy audits, adopting sustainable transportation options, and raising awareness about energy conservation practices.

As always, Engineering Practice Magazine (EPM) and the International Association of Certified Practicing Engineers (IACPE), directly supports and actively promotes resourcing necessary, to encourage upcoming STEM and engineering talent to train, graduate, and apprentice in evolving vocations which will positively affect this burgeoning field of expertise.

Until September, please stay cool (or warm if in the southern hemisphere), prosperous, and content. We greatly appreciate our readership's continued interest in and support for our work. If we may better cover subjects of interest and benefit to our mutual Earth, please let us know.

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