ENGINEERING PRACTICE

VOLUME 10 NUMBER 45

JULY 2024

IACPE
INTERNATIONAL ASSOCIATION OF CERTIFIED PRACTICING ENGINEERS

WWW.IACPE.COM

In This Issue

Volume 10 | Number 45

SPECIAL FEATURES

Procurement Service Cycle Definition

Mansoor Mohseni

One of the important phases of doing Industrial Projects is Procurement Service. For each Industrial Project, after making Engineering Studies and specifying the required Hardware and Software and completing detail data of all required equipment and devices, relevant documents including data sheets, specifications and Material Requisitions (MR) will be issued, which are the basis of Procurement Cycle.

Engineering phase of Industrial projects are done by Basic and Detail Design Companies, while the Procurement Service may be done by other parties or companies or even by project investors or their consultants, although in some type of contracts (as an example EPC) it may be done by Engineering Companies. Nevertheless, The Procurement Service Cycle will be started by sending the prepared Material Requisition (with all attachments) to some selected vendors to receive their proposals or offers on requested items. By receiving such proposals or offers, they shall be studied for compliance with project requirements and discussed for missed items or modifications on differences until to reaching to final state. In fact, all proposals or offers shall be balanced on optional items further to satisfying main requirements, in such a way that all of them to be balanced at final state in technical point of view. Such a target will be achieved by technical queries with vendors and getting their clarification replies up to receiving their final offers. Now their offers can be compared with each other's for preparation of Technical Bid Analysis (or Technical Bid Evaluation) by which all received offers will be ranked due to technical studies. Prepared TBA/TBE and final commercial offer of vendors (which are in accordance with their Technical Offers) will be discussed by responsible persons to make tender selection and award the won vendor. After assigning the wined (/selected) vendor and attending Kick-Off Meeting (which produces final agreements and exact scope of works and supplies) and signing the contract, the final Purchase Requisition (PR) or Purchase Order (PO) will be issued (which will be the basis of future checking or discussion on scope of works or supplied items).

By signing the contract and based on a defined time schedule vendor will produce required documents and send them for checking and review. During VDR (Vendor Document Review) detail data of vendor design for exact compliance with project requirements are checked and commented on for any required modifications. Accordingly, vendors will implement received comments or provide suitable replies for their designs up to receiving approval on material take off and design documents for starting the fabrication at shop. Based on agreements of contract during the fabrication and at the end of fabrication, client may have rights for some inspections at vendor shop to confirm continuing the progress (or holding the job). Usually in some requisitions of industrial projects after readiness of vendor products, clients have rights to attend in vendor shop to do Factory Acceptance Test, by which they may allow for issuing release note (or hold for some modifications). For requisitions of complex packages (like turbines, compressors, Control & Safety Systems…) it would be better to have FAT, while for some bulk requisitions it may have some random tests (/inspection) during the fabrication process, or even for some requisitions client may issue release note just based on finalizing the received documents (due to good vendor trade history). However, after issuing release note the produced items will be inspected by inspector for good and right packing and confirming the packing list.

The produced items then will be shipped and delivered to the project site (according to type of agreements in contract). At the project site the packing items will be opened and will be checked for quantity and healthiness based on sent packing list (Open Package/Packing

Inspection = OPI). For some requisitions the extracted items will be sent to warehouse in order to be kept at suitable place/ environment and will be ready for installation at suitable time, but for complex packages (like turbines, compressors, Control & Safety Systems, …) the received items will be assembled to each other, or installed by schedule in order to reach mechanical completion (considered time schedule may contain some warehouse periods too). During mechanical completion and after that, vendor specialists may attend the project site as Site Acceptance Test (SAT) or Site Assistance Support to commissioning and start up the mentioned package. After the project operation phase, vendor may support the client for future technical assistance or supporting spare part items (as After Sale Support service).

Figure 1 can summarize the explained cycle by graphical block diagrams. This cycle is used generally during industrial projects, but it is not the unique cycle and, in some projects, (and based on type of project and selected mode of project implementation/ contract) other cycles can be found which may have some reduced blocks or vice versa by some extra blocks or even by some intermediate routes. Nevertheless figure-1 and above explained cycle can get the reader to be familiarized with the required steps and actions during Procurement Service Cycle of industrial projects.

Complexity of Procurement Service Cycle

Based on Figure-1 and explained definition, it seems that Procurement Service Cycle is a routine process which shall be done regularly and by easy management, but in fact such phase of each industrial project is very complicated and in some project's occurrence of faults in this phase can hold the project progress and may force long delays to project success.

Let us review the complexity of Procurement Service Cycle by means of simple study case and then accordingly find how we can overcome to problems by general review. Consider in one industrial project we need a quantity of medium trucks. Such items will be needed at project site at early stages of Project Construction Phase for transferring usual materials to or from project site to other places, or they can be used inside the project site for transferring the materials between different locations. Based on such requirements (with other further details) the required Material Requisition is provided and sent to different vendors, and then we have received different offers based on Figure-2.

Figure-2 shows that we may have some different offers for our requisition from some suppliers/ vendors, while by a glance we can find selecting the right item is hard due to some difficulties. Before investigating the difficulties, kindly please notice that our study case is simple example to review the subject process and may not be true in real situation, and so some assumptions may seem unrealistic, but we mention them just for better

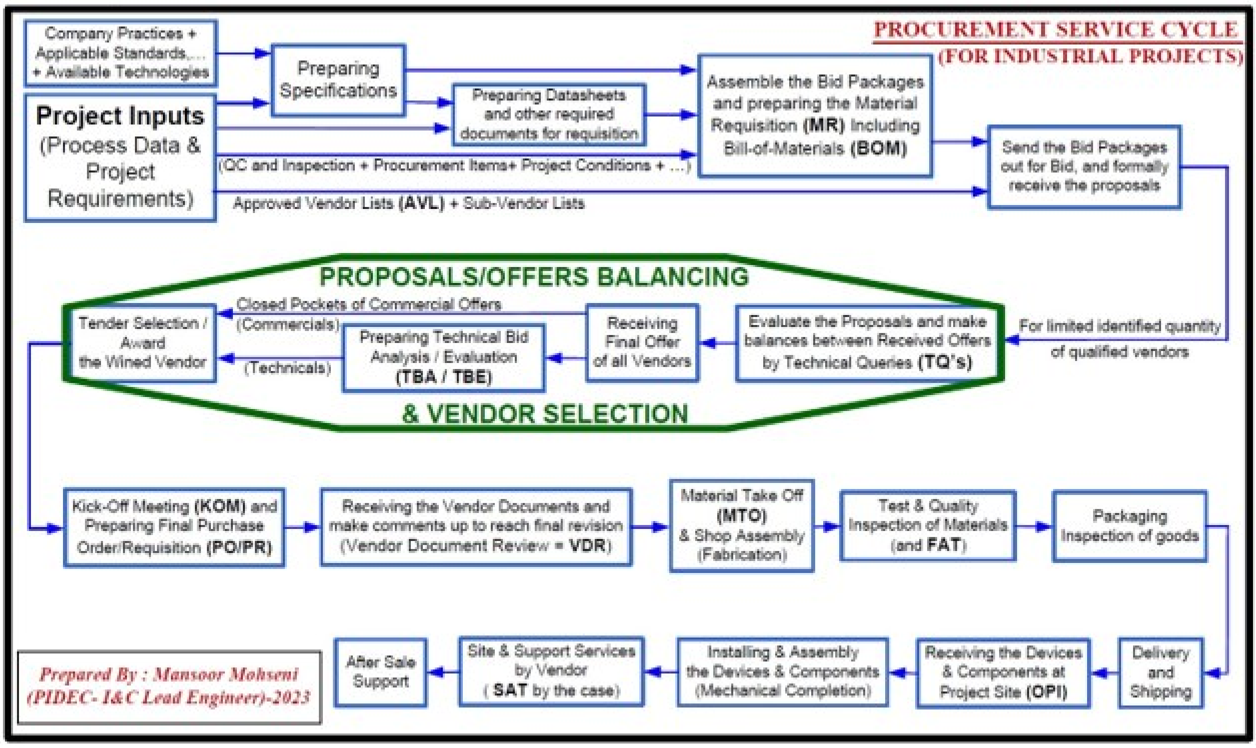

Figure-1: Procurement Service Cycle (For Industrial Projects) understandings. First, the quantity of received offers may be high and it may cause problems for us on time of offer reviews and wasting the time for preparing TBA/TBE (please note that Figure-2 is the result of offers studies and is prepared after some long time). Some received offers seem to not be accepted due to being much higher or lower than our requirements. Some offers have less details and some of them have ambiguities in their offers. Some offers have some focus on overall facilities while less description of main facilities (in Figure-2 some colored pictures may have less details on main facilities). However some offers are prepared based on sent MR, and they comply with main project requirements while they shall be balanced for options or less important requirements to each other's.

One important point that the reader shall care about is, Figure-2 just shows the overall review of different received offers and does not contain some important items which are vital for vendor selection/decision. For example, Figure-2 doesn't have any information for delivery time/ availability based on project schedule, quality assurance and approvals for mentioned facilities, vendor facilities for matching client extra requirements (or any changes in product), vendor support facilities at project location, aftersales facility, and so on.

Nevertheless, in the next part we will mention some items which have effects on procurement cycle service, and the reader can conclude by considering them the difficulty problems may be decreased.

Some Considerations for Procurement Service Cycle

In this part some considerations are mentioned which may have relations to Procurement Service Cycle:

1. Procurement Service Cycle has a close relation with project time schedule, and doing this phase shall be completely based on project time schedule. Generally ling delivery items shall be started at an early stage and other items shall be proceeded by project management requests.
2. The Procurement Service Cycle has a close relation with project considered budget and so this phase shall be started and followed by project control (on budget) too.
3. The project requirements which are mentioned in MR (by different documents/ attachments such as datasheet, specifications, …) shall be enough clear and complete which vendors and suppliers easily found them right. (For example, on our above sample

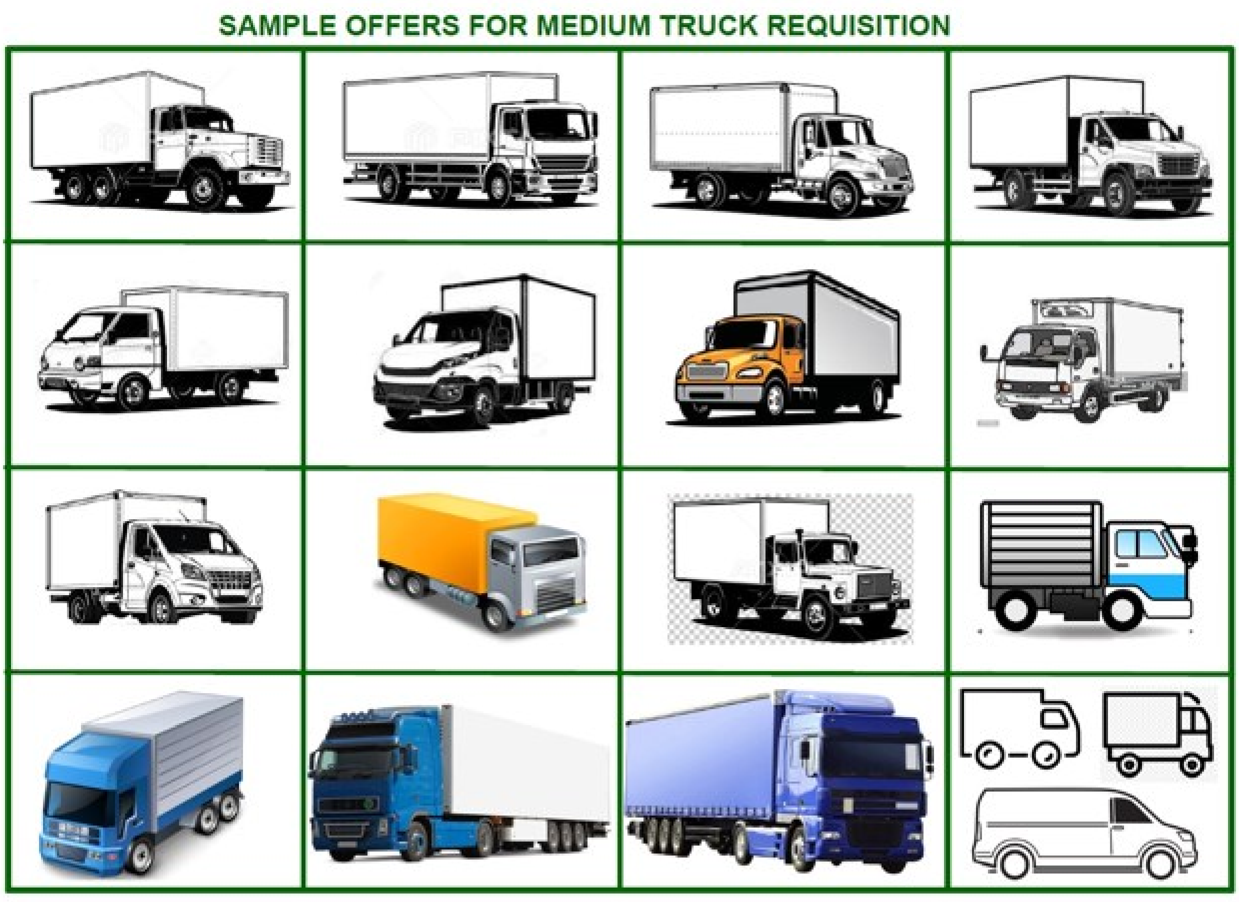

Figure-2: Sample Offers for Medium Truck Requisition Example case study, the truck function, capacity, and approximate / acceptable dimensions shall be mentioned clearly).

4. The project requirements which are mentioned in MR (by different documents/ attachments such as datasheet, specifications, …) shall not be very tight and fixed which can be supplied by just specified vendor (or cannot be supplied by any vendor).

5. For complicated MR's further to usual documents, some extra attachments (like diagrams, sketches, flow charts, tables, descriptions, …) may help vendors to find more quickly the project requirements at early stage. So, the project requirements and input data shall be studied clearly by the engineering team to prepare a complete package of information.

6. At some industrial projects, it is required to prepare TBA/TBE by at least some specified number of (different) vendors from Approved Vendor List (AVL). To save the time and the efficiency of Procurement Service Cycle, it would be better to send MR to known prequalified vendors/ suppliers and the number of selected vendors to be equal to minimum specified number plus one (N+1), and then on the case of any vendor decline, then ask for new vendor. Sending the MR to a greater number of vendors, although has the facility for keeping specified number of vendors in TBA/TBE on the case of more than one vendor declined or rejecting un-qualified vendor's offers but take more time to study the offers. If the vendors/ suppliers have enough quality on MR subject so their offer may have more chance for acceptance (and not rejecting), it guarantees the minimum number of specified vendors/ suppliers, and the study of their offers need less time.

7. In some cases, suppliers may propose their offers based on products of some vendors, while those vendors may have proposed their offers separately too. In such cases you may have to study if the original vendor would better support the project or not. So please consider such an advantage in your TBA/TBE.

8. In vendors balancing step, all proposals shall be studied in parallel way so that the differences of all proposals shall be clear and specified, and by some investigations you may select the best option and ask all vendors/ suppliers to change their proposals accordingly, or in a close condition to selected option. In fact, at the end of vendors balancing all offers shall reach at approximately the same conditions (from technical point of view).

9. At the TBA/TBE, the different extra options shall be listed, and advantages and disadvantages of any options shall be clarified too (further to advantage of considering extra options).

10. Except for main project requirements which all proposals shall meet them, for extra options please ask vendors/ suppliers to offer their extra facility as option (which can be selected or rejected by client).It is very important that take care for uniformity of considerations of main project requirements in main body of offers (and not in optional case), since some vendors in order to make lower price for their proposals , suggests some of main project requirements in their optional body of their offers.

11. It shall be mentioned that the vendors balancing shall be done clearly with exact obsessions, since any differences in proposed items may change each proposal price and has important role for vendor selection. By low cares or wrong vendors balancing, you may cause wrong vendor (low real ranked vendor) is selected by responsible persons due to considering commercial points. It is very important to notice that vendor selection usually will be done based on two factors: Technical points and commercial items (and of course the commercial points may have bigger weight).

12. During the BID stage, you shall ask vendors to prepare an exact signed deviation list by them, which is considered as official document and to be considered in TBA/TBA preparation references.

13. All official certificates and references shall be gotten from vendors during BID stage for confirmation of their proposal contents. However, known end user satisfaction approvals also can be good references for comparing different vendors.

14. Spare parts items of project requirements and after sale supporting facility of vendors/suppliers shall be clearly discussed with vendors and to be reflected in their proposals accordingly.

15. If Material Requisition is related to complex package which needs FAT, SAT, and site Assistance Supports, such items shall be discussed with vendors and the results shall be reflected in their proposals clearly.

The above-mentioned items are just some main items which shall be considered in Procurement Service Cycle, but there are many other items have existed which are more detailed and some of them are related specially to type of Industrial Project and the considered project mode (contract type). Also, some other items can be considered as experiences of responsible persons for Procurement Service Cycle and the existed company practices for doing such facility, but generally can say that attending experienced engineers in it will increase the efficiency and success of good progress results.

References

I&C Engineer Roles & Responsibilities – Instrumentation Design

(https://instrumentationtools.com/ic-engineer-roles-responsibilities-instrumentation-design/)

Instrumentation Engineer Activities & Documents – Detail Design Phase

(https://instrumentationtools.com/instrumentation-engineer-activities-documents-detail-design-phase/)

Instrumentation and Control Project Packages – Detail Engineering

(https://instrumentationtools.com/instrumentation-and-control-project-packages/)

Author

Mansoor Mohseni now is working in PIDEC (Petrochemical Industries Design & Engineering Company) as I&C Lead Engineer for about 23 years. Before PIDEC, he was working in INSIG (Iran National Steel Industrial Group) as head of Control & Automation Dept. of wire rode mill for about 10 years.

The Role of Hydrocracking Technologies in the Modern Downstream Industry

Dr. Marcio Wagner da Silva

The necessity to reduce the environmental impact and the higher sustainability of the industrial processes normally is translated in stricter regulations and higher control upon the industries activities, mainly to those that have a high environmental footprint as the crude oil production chain. This fact is positive and welcome, in view of the necessity to preserve the natural resources and the needed technological development to meet these regulations.

One of the most impacting regulations to the downstream industry is the necessity to reduce the sulfur content in the maritime fuels, known as IMO 2020, this regulation established which from the maximum sulfur content in the maritime transport fuel oil (Bunker) is 0,5 % (m.m) against the previously 3,5 % (m.m). The main objective is to reduce the SOx emissions from maritime fleets, significantly decreasing the environmental impact of this business.

The marine fuel oil, known as bunker, is a relatively low viscosity fuel oil applied in diesel cycle engines to ships movement. Before 2020, the bunker was produced through the blending of residual streams as vacuum residue and deasphalted oil with dilutants like heavy gasoil and light cycle oil (LCO), due to the new regulation, a major part of the refiners will not be capable to produce low sulfur bunker through simple blend.

Due be produced from residual streams with high molecular weight, there is a tendency of contaminants accumulation (sulfur, nitrogen, and metals) in the bunker, this fact makes difficult meet the new regulation without additional treatment steps, what should lead to increasing the production cost of this derivative and the necessity to modifications in the refining schemes of some refineries. Figure 1 presents a schematic diagram of how the bunker was produced before the IMO 2020.

The drastic reduction of sulfur content in the final product, lead refiners to look for alternatives to reduce the sulfur content in the intermediate streams, and this is a hard task to refiners processing heavy and extra-heavy crudes.

Beyond the necessity to add value to bottom barrel streams in compliance with the IMO 2020, the increasingly restrict environmental regulations requires even more capacity to produce cleaner distillates, imposing another challenge to refiners processing extra-heavy crudes. The growing trend of petrochemical integration is another great challenge to refiners with access to extra-heavy crudes once requires more complex and expensive refining hardware, in this sense, the hydrocracking and deep hydrocracking technologies can be a fundamental tool to allow the refiners

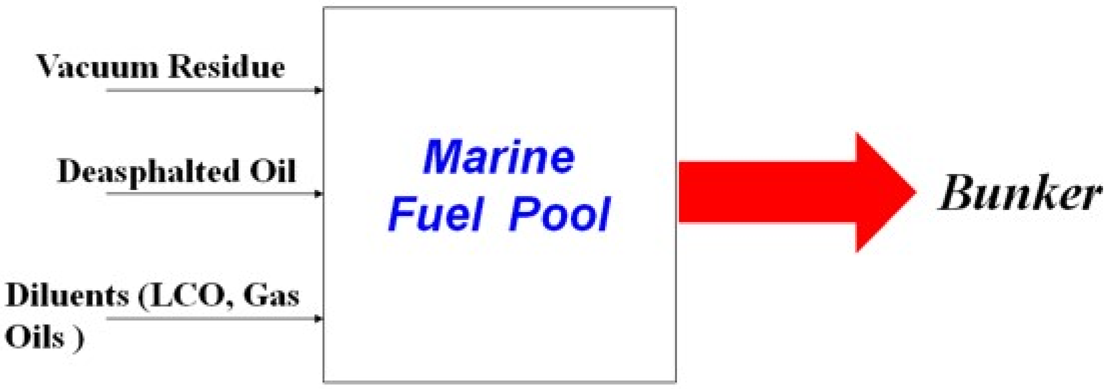

Figure 1 – Bunker Production Process before IMO 2020

with high capital investment capacity to reach a highlighted competitive positioning in the downstream market through adequate balance of bottom barrel conversion capacity and petrochemicals maximization.

Even before the war the spread between VLSFO and HSFO justify the investments by refiners to produce the low sulfur fuel. Furthermore, it's important to considering the increasingly stricter regulations and the trend of reduction of the HSFO market in the middle term (as presented in Figure 3), this fact plus the trend of reduction in transportation fuels demand and growing demand of petrochemicals at global level tends to favor refiners relying on most complex refining hardware that are capable to processing heavy crude oils and maximize the added value to the processed crude.

Flexible refining hardware in relation of the processed crude slate is an important competitive advantage in the downstream sector, mainly the processing of heavy and extra-heavy crudes due to his lower acquisition cost when compared with the lighter crude oils. The difference in the acquisition cost between these oils is based on in the yield of high added value streams which these oils present in the distillation process, once the lighter crudes normally show higher yields of distillates than the heavier crudes, his market value tends to be higher. As an example, Figure 4 presents the evolution of the discount of WCS (West Canadian Select) crude oil to WTI (West Texas Intermediate) crude oil over the time.

The WCS is considered a heavy crude (API grade between 19 and 22) with a sulfur content around 3,0 % while the WTI is considered a reference crude with a medium API grade around 40 with very low sulfur content (around 0,3 %), Figure 1 shows a significant price gap between these crudes, leading to a relatively advantage to refiners capable to add value to these crudes, especially considering the IMO 2020 that requires even more refining capacity to add value to the bottom

Figure 2 – VLFSO and HSFO Fuel oil Spreads (Ship & Bunker, 2022)

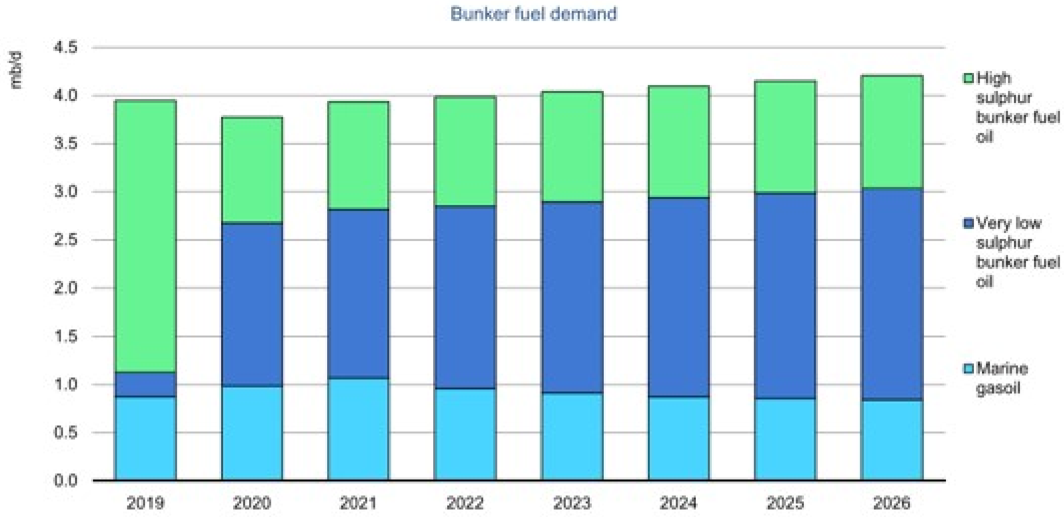

Figure 3 – Growing Participation of VLFSO in the Bunker Market (IEA, 2021)

barrel streams. Normally, the valuation of crude is defined by the quality, the available market in other words it's necessary to find refiners capable to process this crude oil, and the capacity to transport the crude oil to the consumer market. Heavier crudes tend to present discounts related to lighter crudes due to these three variables:

- Quality – Heavier crudes present lower yield of distillates and high added value derivatives like diesel, kerosene, and gasoline than lighter crudes.
- Consumer market – The refiners able to process heavier crudes need to rely on adequate bottom barrel conversion capacity, in other words, more complex refineries, restricting the consumer market in comparison with lighter crudes.
- Transportation – Heavier crudes present higher logistics costs due to higher energy consumption.

Despite these characteristics, refiners with adequate refining hardware and easy access to heavier crudes can use the price gap between light and heavy crudes as opportunity to improve the refining margins, mainly considering the IMO 2020 that reduced, even more, the acquisition cost of heavier and sourer crudes and due to their characteristics, the hydrocracking technologies broke significative restrictions of the refining hardware to add value to these discounted crudes.

Processing Extra Heavy Crudes – The Hydrocracking Alternative

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 5 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.

Catalysts applied in hydrocracking processes can be amorphous (alumina and

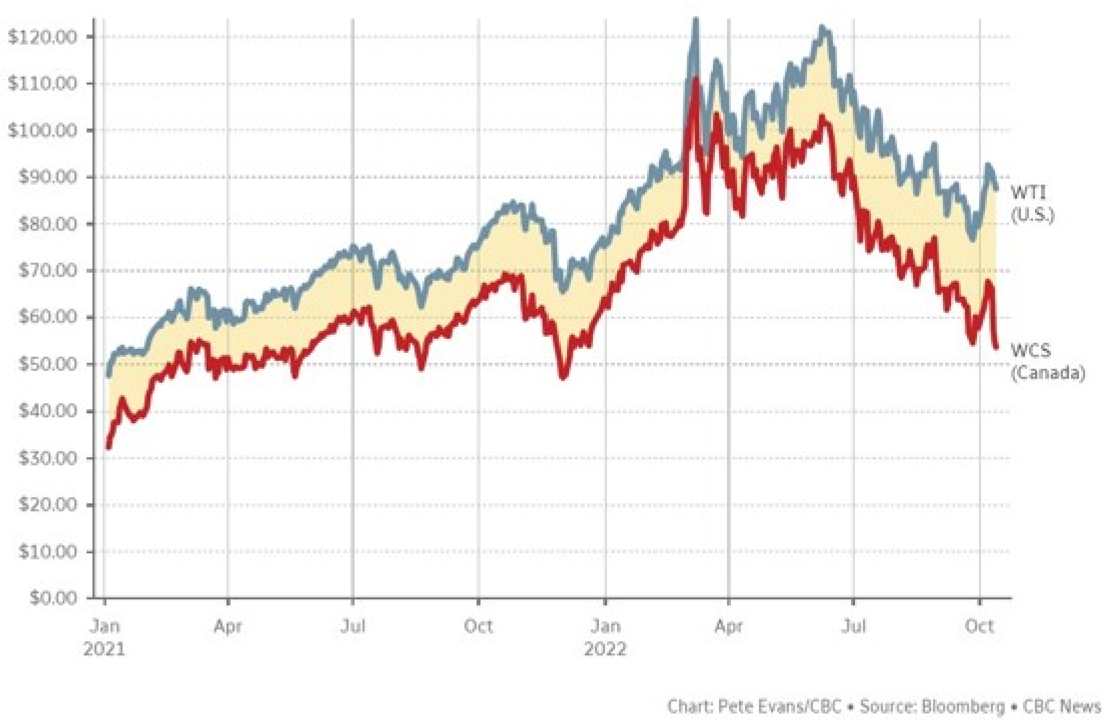

Figure 4 – Price gap between WTI and WCS crude oils (CBC News, 2022)

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. The active metals used in this process are normally Ni, Co, Mo and W in combination with noble metals like Pt and Pd.

It's necessary a synergic effect between the catalyst and the hydrogen because the cracking reactions are endothermic and the hydrogenation reactions are exothermic, so the reaction is conducted under high partial hydrogen pressures and the temperature is controlled in the minimum necessary to convert the feed stream. Despite these characteristics, the hydrocracking global process is highly exothermic, and the reaction temperature control is normally made through cold hydrogen injection between the catalytic beds.

According to the feed stream quality (contaminants content), its necessary hydrotreating reactors installation upstream of the hydrocracking reactors, these reactors act like guard bed to protect the hydrocracking catalyst.

The principal contaminant of hydrocracking catalyst is nitrogen, which can be present in two forms: Ammonia and organic nitrogen.

Ammonia (NH3), produced during the hydrotreating step, has a temporary effect reducing the activity of the acid sites, mainly damaging the cracking reactions. In some cases, the increase of ammonia concentration in the catalytic bed is used like an operational variable to control the hydrocracking catalyst activity. Organic nitrogen has a permanent effect blocking the catalytic sites and leading to coke deposits on the catalyst.

As exposed above, extra-heavy crude oils or with high contaminants content can demand deep conversion technologies to meet the new quality requirements to the bunker fuel oil. Hydrocracking technologies can achieve conversions higher than 90% and, despite the high operational costs and installation can be attractive alternatives.

The hydrocracking process is normally conducted under severe reaction conditions with temperatures that vary from 300 to 480 oC and pressures between 35 to 260 bar. Due to process severity, hydrocracking units can process a large variety of feed streams, which can vary from gas oils to residues that can be converted into light and medium derivates, with high value added.

Figure 6 shows a typical process arrangement to hydrocracking units with two reaction stage and intermediate gas separation, adequate to treat high streams with high contaminants content like nitrogen.

The residue produced by hydrocracking units have low contaminants content, able to be directed to the refinery fuel oil pool aiming to produce low sulfur bunker, allowing the market supply and the competitiveness of the refiners.

The process shown in Figure 6 presents a fixed bed hydrocracking unit, to heavier crudes, this unit can be inadequate due to the low operating life cycle, in this case the ebulated bed and slurry phase reactors can be more effective, despite the higher capital spending. The capital requirement is one of the most important restrictions to refiners to adopt the hydrocracking technologies both to capital and operating capital due to the

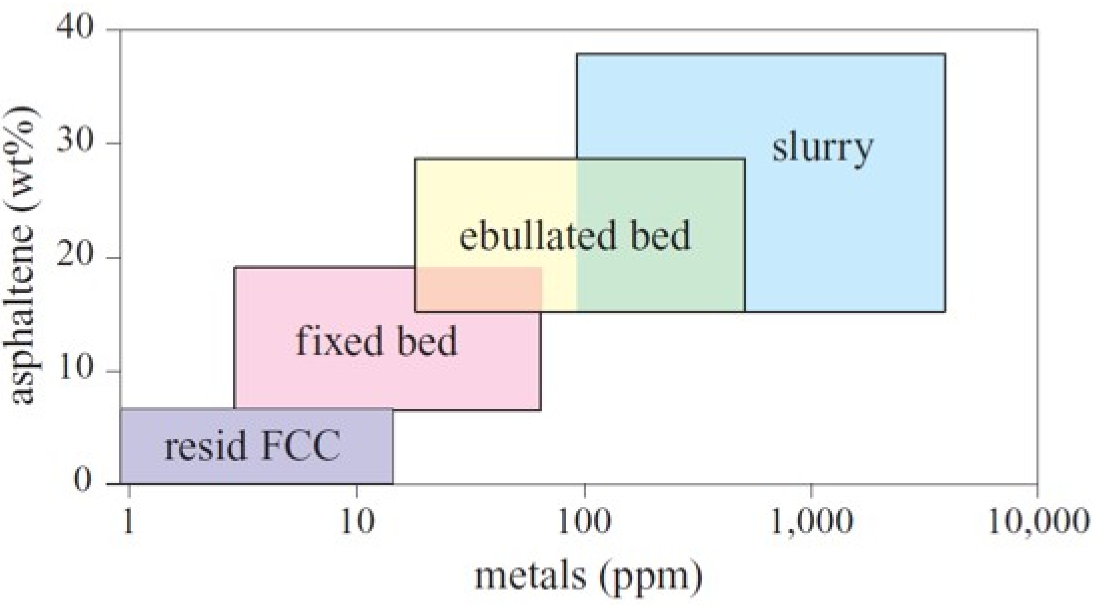

Figure 5 – Residue Upgrading Technologies According to the Contaminants Content (Encyclopedia of Hydrocarbons, 2006)

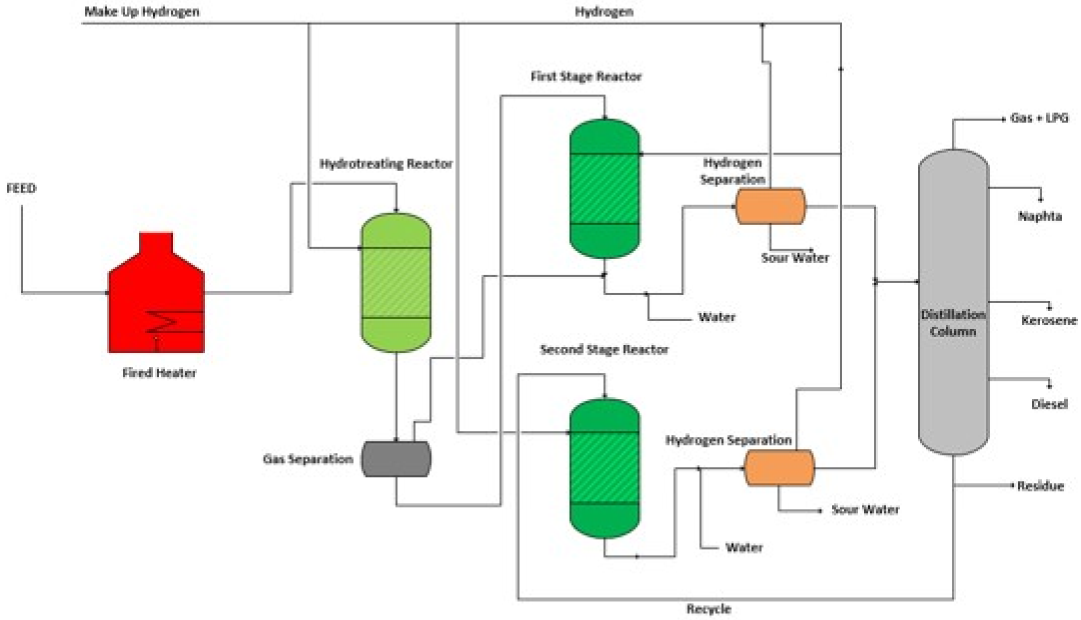

Figure 6 – Typical Arrangement for Two Stage Hydrocracking Units with Intermediate Gas Separation

necessity of larger hydrogen generation units, catalysts costs, etc. Figure 7 presents a comparison between residue upgrading alternatives related to the capital investment (CAPEX) and effectiveness in the bottom barrel processing.

As presented in Figure 7, the hydrocracking technologies present the higher level of required capital spending, on the other side offer the higher conversion to bottom barrel streams, a necessity to refiners processing heavy and extra-heavy crudes. According to Figure 3, the other alternatives are not effective in treating residue streams with high carbon residue and metals, common characteristics of extra-heavy crude oils. In this case, the hydrocracking alternative is the most technically adequate solution.

According to data from Global Data Company, the global installed hydrocracking capacity in 2022 was around 12,500 Mbd and will growth under an average annual growth rate of 5,0 % until 2027 and this growth will be headed by USA, China, India, and Saudi Arabia.

Deep Hydrocracking Technologies – Recovering More Added Value from the Crudes

As aforementioned, 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 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 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 while the H-Oil™ process by Axens Company is presented in Figure 9.

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 10 presents a basic process flow diagram for the VCC™ technology by KBR Company.

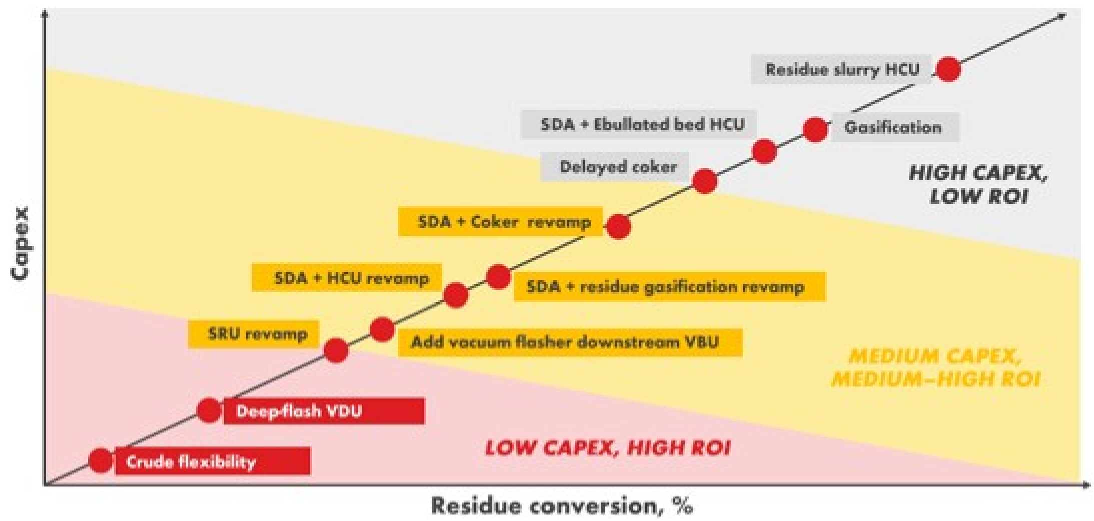

Figure 7 – Capital Spending x Residue Conversion to Residue Upgrading Technologies (Shell Catalysts and Technologies, 2019)

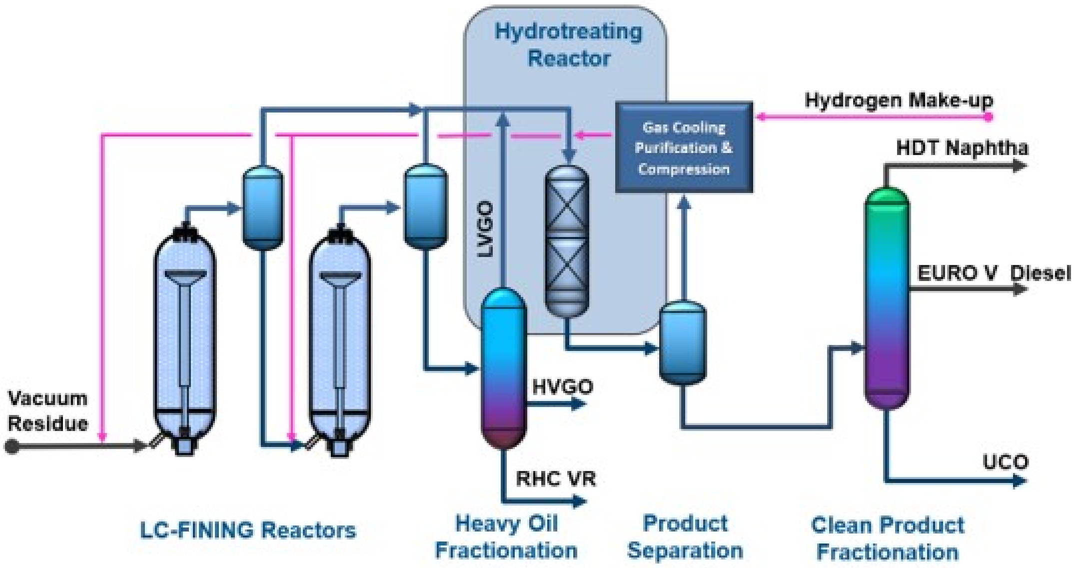

Figure 8 – Process Flow Diagram for LC-Fining™ Technology by CLG Company

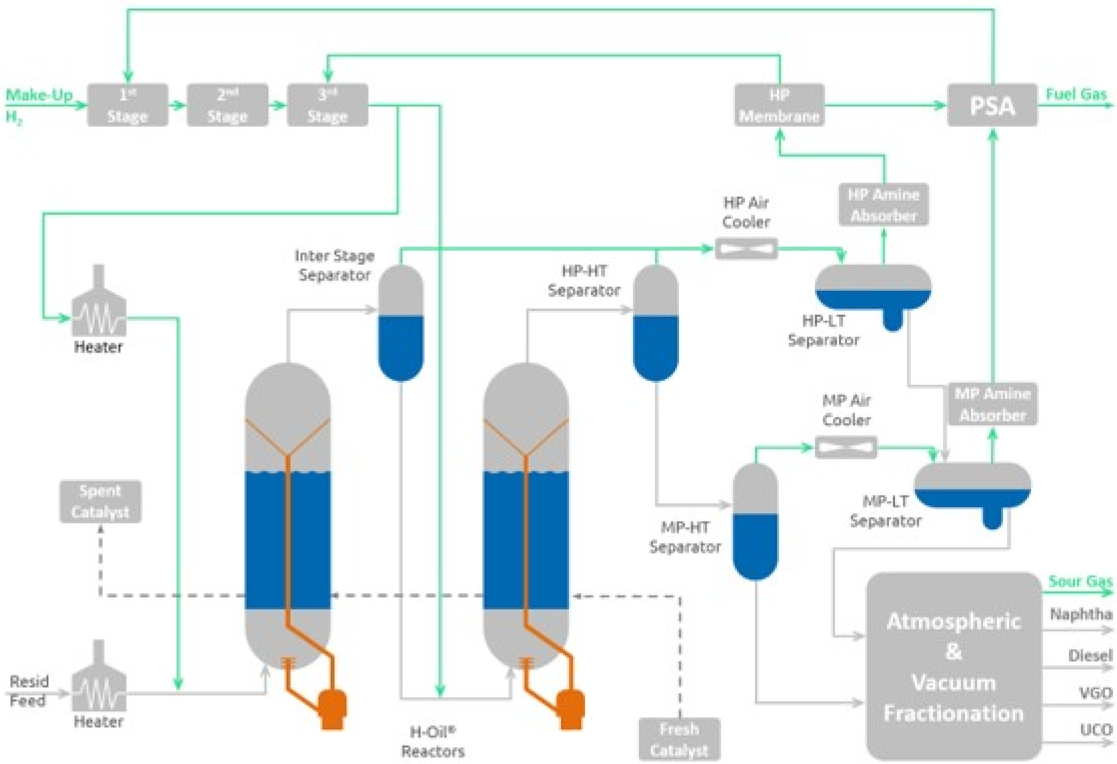

Figure 9 – Process Flow Diagram for H-Oil™ Process by Axens Company

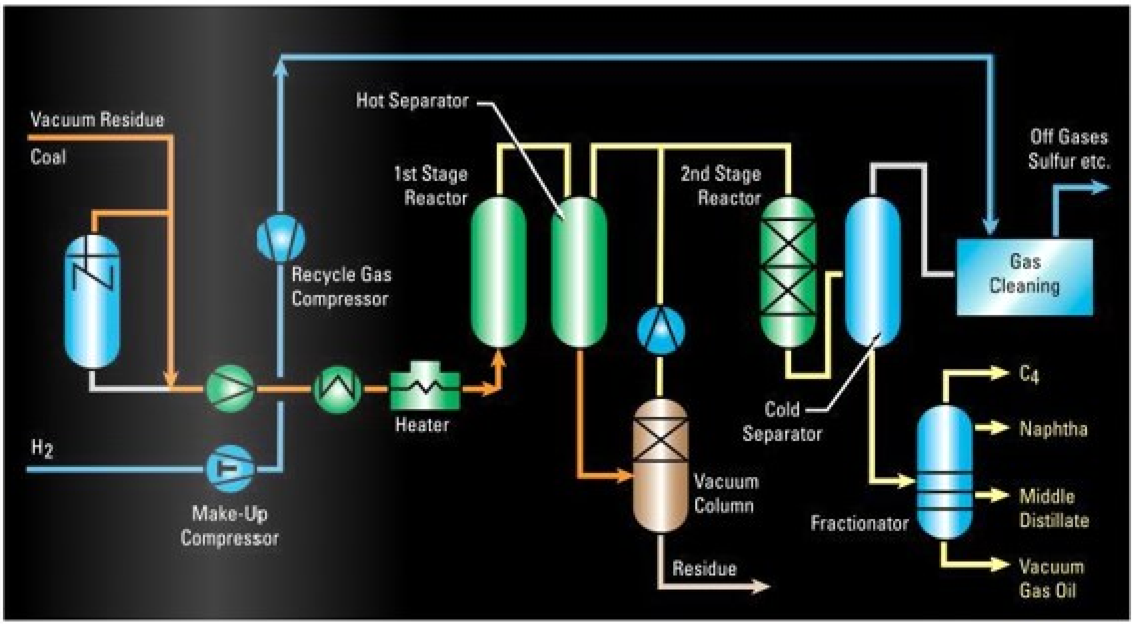

Figure 10 – Basic Process Arrangement for VCC™ Slurry Hydrocracking by KBR Company (KBR Company, 2019)

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 11 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. Figure 12 presents a basic process flow diagram for the LC-Slurry™ technology developed by Lummus 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.

Deep Conversion Refining Hardware – Petrochemicals from Bottom Barrel Streams

As aforementioned the residue upgrading units are capable to improve the quality of

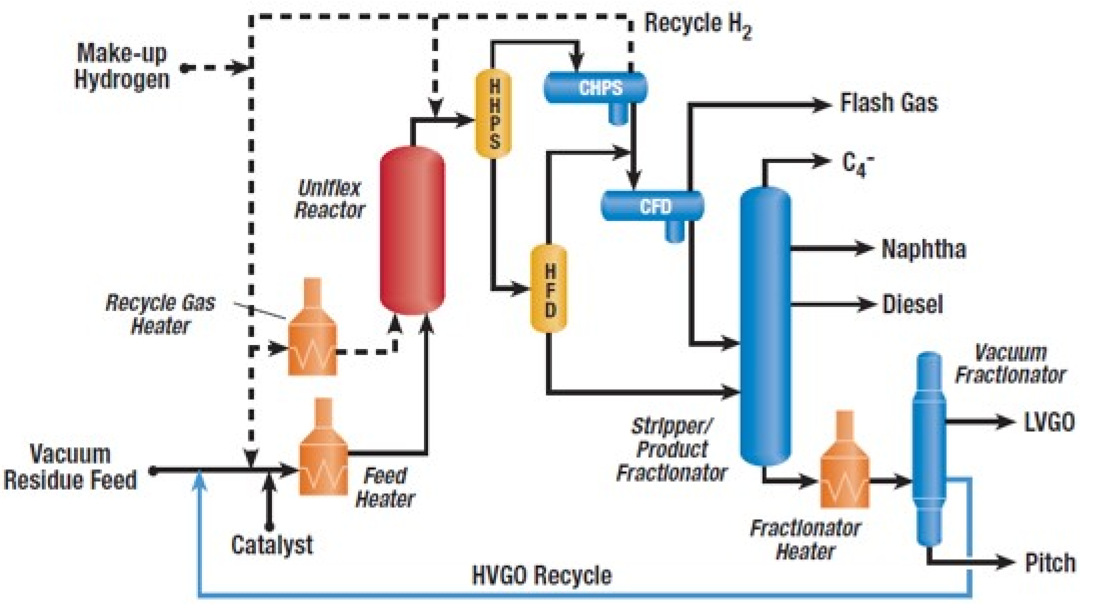

Figure 11 – Process Flow Diagram for Uniflex™ Slurry Phase Hydrocracking Technology by UOP Company (UOP Company, 2019).

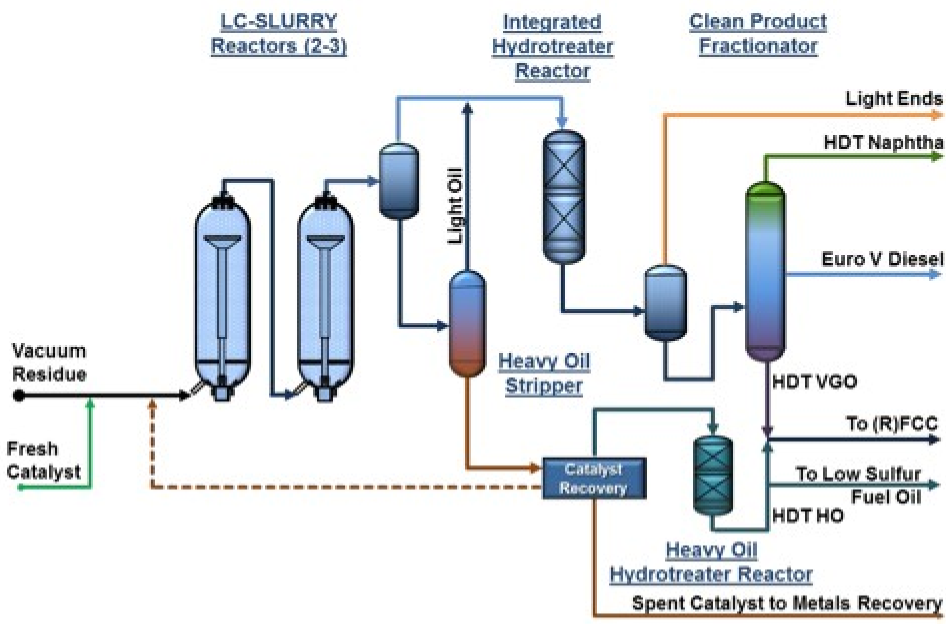

Figure 12 – Basic Process Arrangement for LC-Slurry™ Technology developed by Lummus Company (BISWAS et. al., 2017)

bottom barrel streams, the main advantage of the integration between residue upgrading and petrochemical units like steam cracking is the higher availability of feeds with better crackability characteristics.

Bottom barrel streams tend to concentrate aromatics and polyaromatics compounds that present uneconomically performance in steam cracking units due the high yield of fuel oil that presents low added value, furthermore, the aromatics tends to suffer condensation reaction in the steam cracking furnaces, leading to high rates of coke deposition that reduces the operation lifecycle and raises the operating costs. In this case deep conversion units like hydrocracking can offer higher operational flexibility.

Once cracking potential is better to paraffinic molecules, and the hydrocracking technologies can improve the H/C in the molecules converting low added value bottom streams like vacuum gasoil to high quality naphtha, kerosene, and diesel the synergy between hydrocracking and steam cracking units, for example, can improve the yield of petrochemical intermediates in the refining hardware, an example of highly integrated refining configuration relying on hydrocracking is presented in Figure 13.

Considering the recent trend of reduction in transportation fuels demand followed by the growth of petrochemicals market makes the presence of hydrocracking units in the refining hardware raise the availability of high-quality intermediate streams capable to be converted into petrochemicals, an attractive way to maximize the value addition to processed crude oil in the refining hardware. As presented in Figure 13, the synergy between carbon rejection and hydrogen addition technologies like FCC and hydrocracking units can offer an attractive alternative, 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 of light products like naphtha, LPG, and olefins.

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.

As aforementioned, facing the current trend of reduction in transportation fuels demand at the global level, the capacity of maximum adding value to crude oil can be a competitive

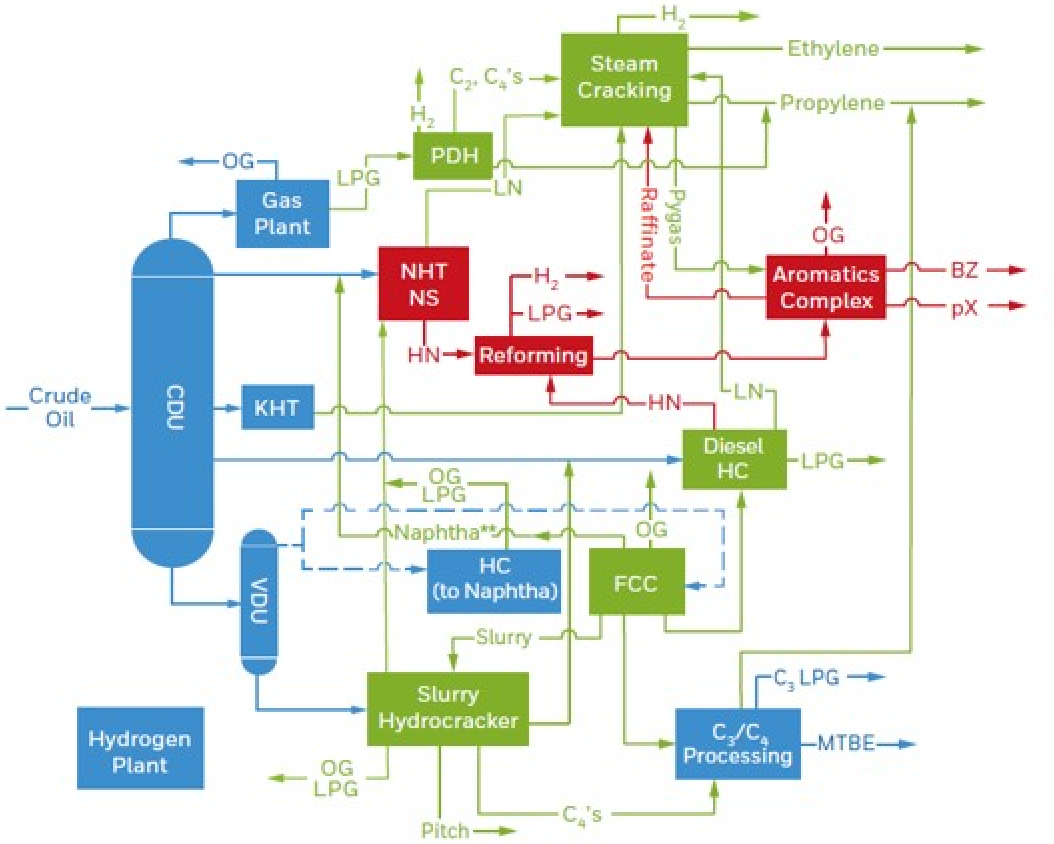

Figure 13 – Integrated Refining Scheme Relying on Residue Upgrading and Petrochemical Maximization Technologies (UOP, 2019)

differential to refiners. Due to the high capital investment needed for the implementation that allows the conventional refinery to achieve the maximization of chemicals, capital efficiency becomes also an extremely important factor in the current competitive scenario as well as the operational flexibility related to the processed crude oil slate.

Although the advantages presented by closer integration between refining and petrochemical assets, it's important to understand that the players of downstream industry are facing with a transitive period where the transportation fuels are responsible by great part of the revenues. In this business scenario, it's necessary to define a transition strategy where the economic sustainability achieved by the status (transportation fuels) needs to be invested to build the future (maximize petrochemicals). Keeping the eyes only in the future or only in the present can be a competitive mistake.

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 concentrates 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 recycle ratio. Higher recycling 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 sulphur components, high CCR, high nitrogen content, and aromatics concentration.

The sulphur 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. Hydrocracker's processing feeds with high nitrogen content tend 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 sulphur and nitrogen reduces the hydrogen partial pressure, raises 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 sulphur 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.

The Lubricating Market – Short Lifetime to Solvent Route

According to the recent forecasts, the global market of automotive lubricants will grow under annual rates of around 6,3 % between 2022 and 2030 reaching a total market size of USD 120 billion in 2030. Figure 14 presents the growing trend for the automotive lubricants market. The high added value of lubricants in comparison with the transportation fuels accompanied by the trend of reduction in transportation fuels demand indicates an attractive alternative to refiners with adequate refining hardware to improve his revenues and the competitiveness in the downstream market.

Like others crude oil derivatives, economic and technological development have been required the production of lubricating oils with higher quality and performance, moreover with lower contaminants content.

The main quality requirements for lubricating oils are viscosity, flash point, viscosity index (viscosity change with temperature), fluidity point, chemical stability, and volatility.

According to the American Petroleum Institute (API), the lubricating base oils can be classified as described in Table 1.

The lube oils from groups II, III and IV have higher quality than base oils from the group I, the content of contaminants like sulphur and unsaturated compounds are significantly reduced, moreover, the viscosity index are superior for groups II, III, and IV.

The main disadvantage of the solvent route, when compared with the hydrorefining route, is that the solvent route can produce only Group I lubricating oil, this can limit his application to restricted consumer markets, which can reflect in the economic viability. Figure 15 presents a forecast to the market share evolution to different kinds of base oils in the market.

According to the data from Figure 15, is expected a significant reduction in the demand by Group I base oils, leading to a great competitive loss to refiners relying on base oil production exclusively through solvent routes.

Another solvent route disadvantage is the solvents applying which can cause environmental damage and needs specials security requirements during the processing, production of low value-added streams like aromatic extract is another disadvantage. In this sense, refiners relying on solvent routes tend

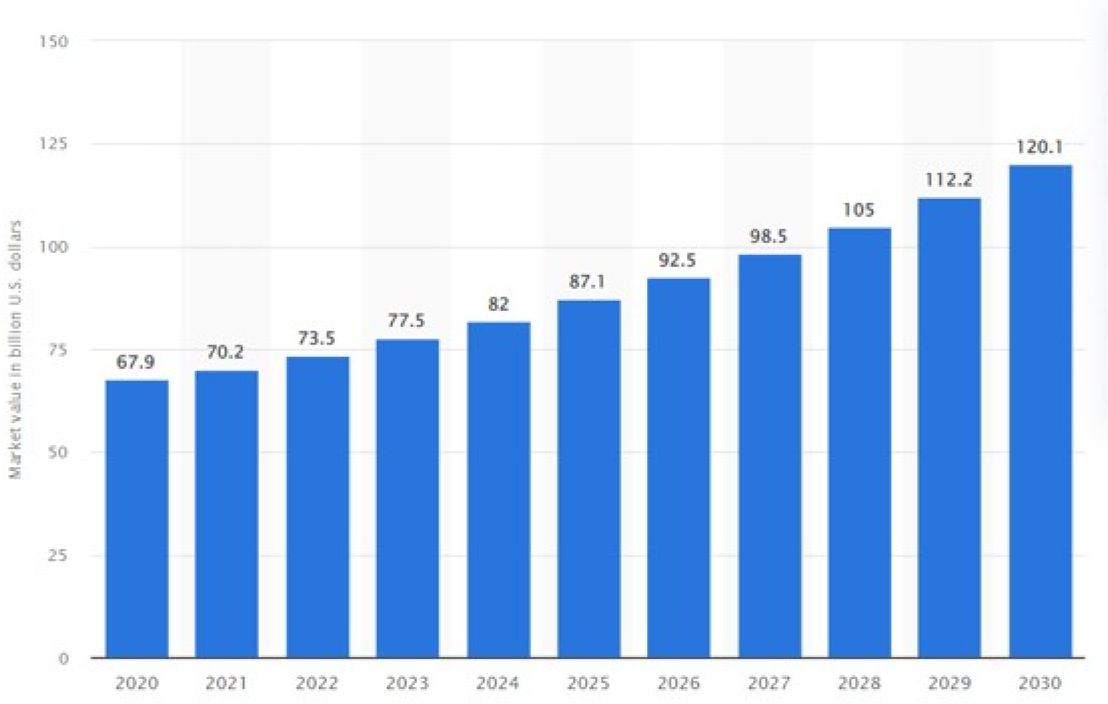

Figure 14 – Growing Trend in the Demand by Automotive Lubricants (STATISTA, 2022)

Table 1 – Lubricating Base Oils Classification

Group	Typical Production Process
I	Solvent Extraction
II	Hydrocracking/Hydrotreating or Hydrocracking + Solvent Extraction
III	Hydrocracking/Hydrotreating
IV	Synthetic

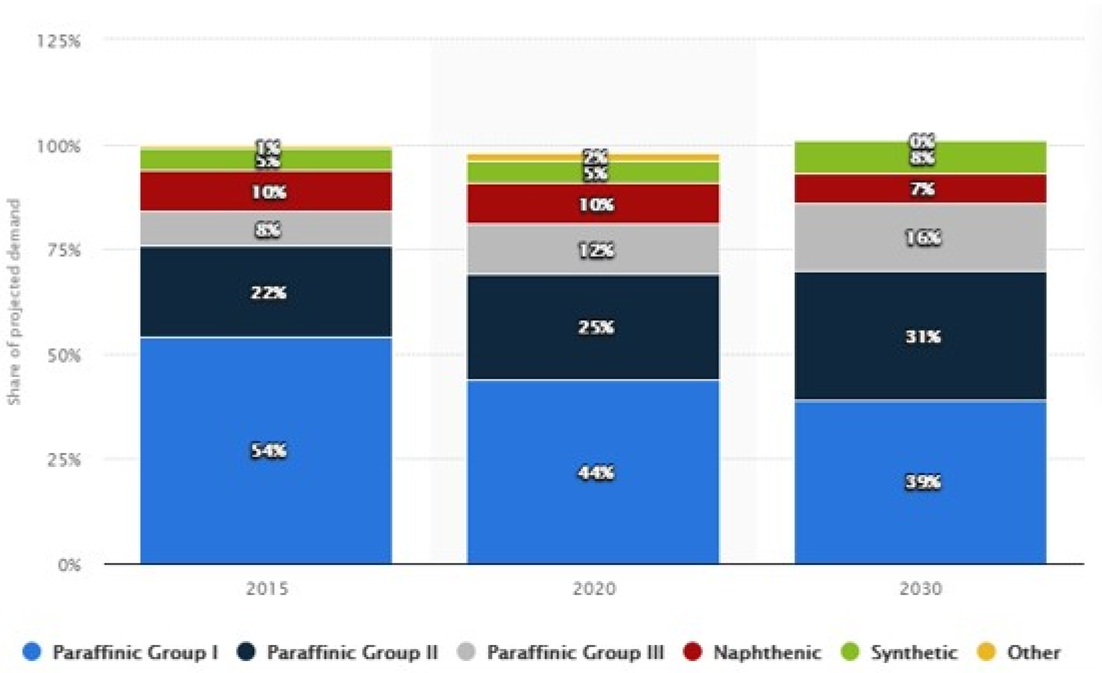

Figure 15 – Base Oil Demand Distribution (STATISTA, 2020)

to lose market in the next years and face difficulties finding markets for his products, reducing in a significant manner their competitiveness in the downstream market.

Producing High Quality Lubricating Oils – The Hydroprocessing Route

In the lubricating oil production by hydrorefining, the physical processes of the solvent route are substituted by catalytic processes, basically hydrotreating processes. Figure 16 shows a block diagram of the processing sequence to produce base lube oils through hydrorefining route.

In this case the fractionating in the vacuum distillation step has more flexibility than in the solvent route, once the streams will be cracked in the hydrocracking unit, so another distillation step is necessary.

After the vacuum distillation and propane deasphalting steps, the process streams are sent to a hydrotreating unit, this step seeks to saturate polyaromatic compounds and remove contaminants like sulfur and mainly nitrogen which is a strong deactivation agent for the hydrocracking catalyst.

In the hydrocracking step, the feed stream is cracked under controlled conditions and chemical reactions like dehydrocyclization, and aromatics saturation occur which give to the process stream the adequate characteristics to the application as lubricants.

The following step, hydroisomerization, seeks to promote isomerization of linear paraffins (which can reduce de viscosity index) producing branched paraffins.

After the hydroisomerization the process stream is pumped to hydrofinishing units to saturate remaining polyaromatic compounds and to remove heteroatoms, in the hydrofinishing step the water content in the lube oil is controlled to avoid turbidity in the final product.

In hydrotreating units dedicated to produce lubricant, one of the focuses of the hydrotreating process is to reduce the concentration of long chain paraffin. To achieve this goal is applied a specific catalyst bed containing dewaxing catalysts (ZSM-5). One of the most known hydrodewaxing technology in the market is the MSDW™ process, commercialized by ExxonMobil Company. A basic process flow diagram for MSDW™ process is shown in Figure 17.

HDF = Hydrofinishing

Another available hydrodewaxing technology is the Isodewaxing™ process, developed by Lummus Company, this process is shown in Figure 18.

At this point is important to quote that the main quality requirements of the lubricating oils are put under control through the following processes:

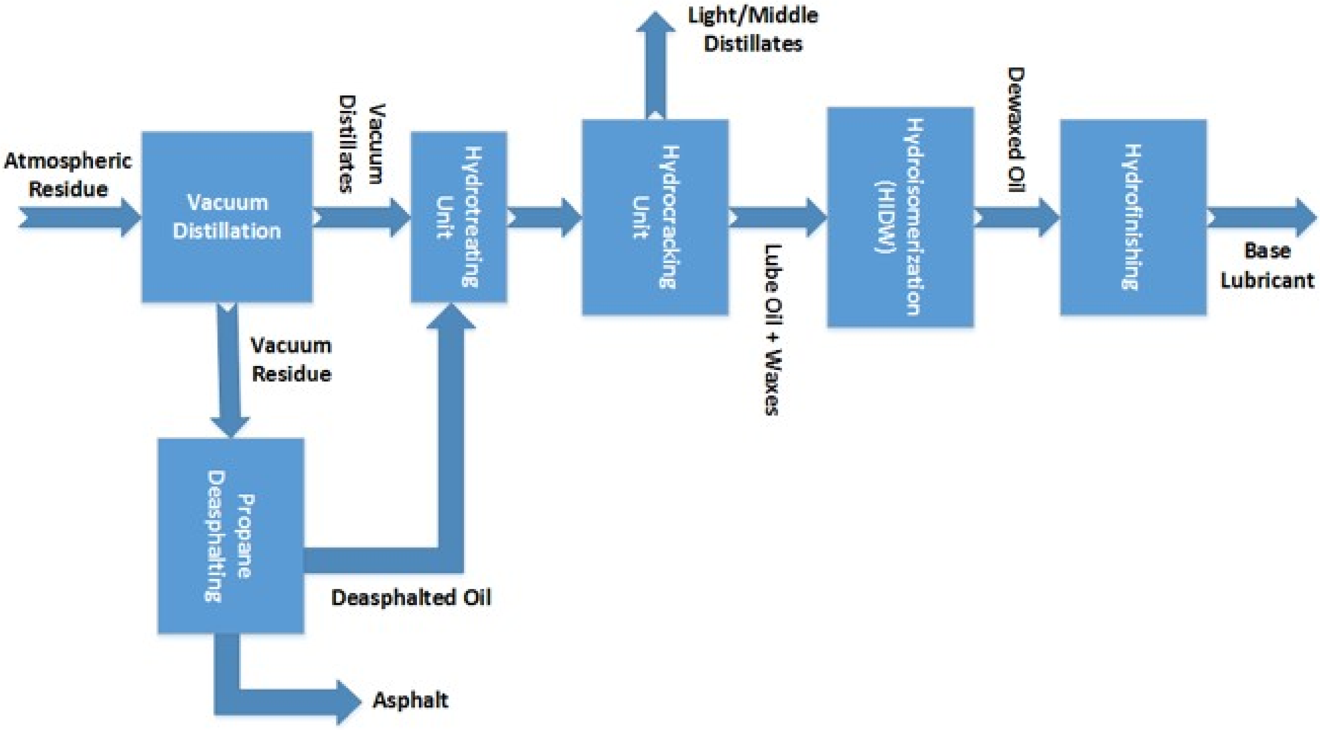

Figure 16 - Processing Scheme for Base Lubricating Oil Production through Hydrorefining Route

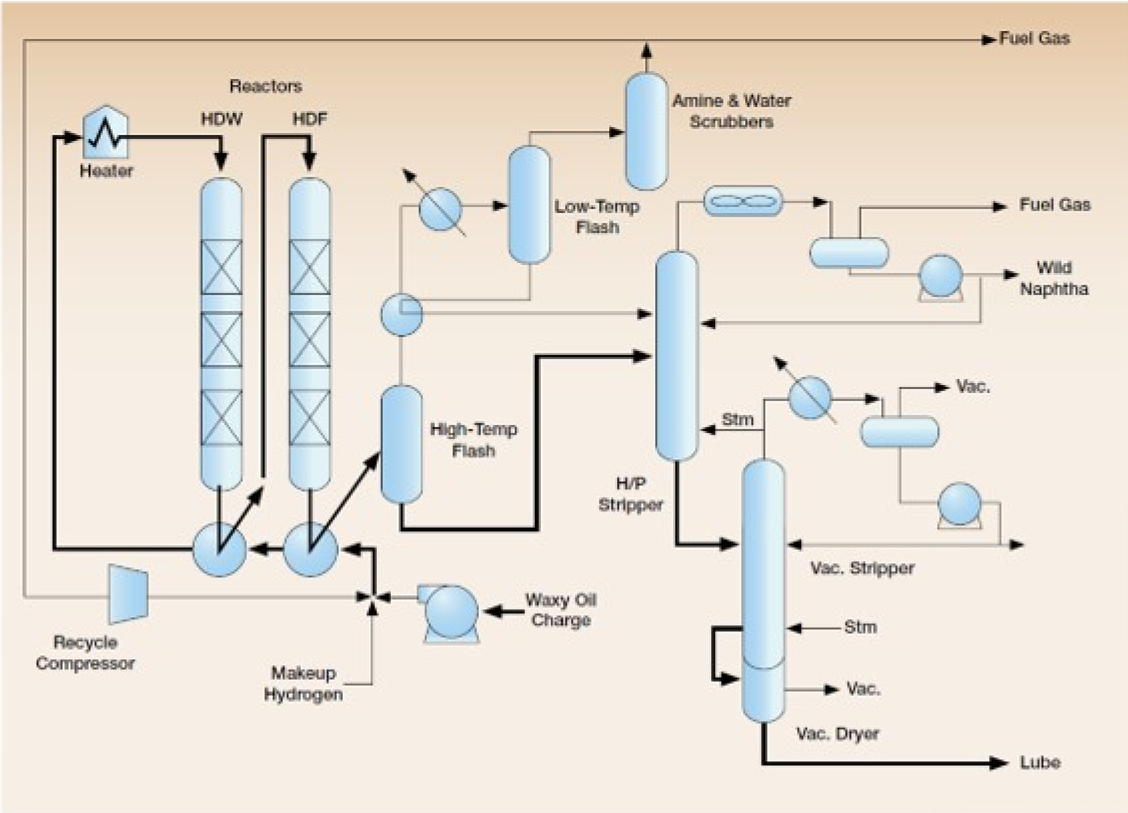

Figure 17 – Basic Process Flow Diagram for MSDW™ Dewaxing Technology by ExxonMobil Company (ExxonMobil Website).

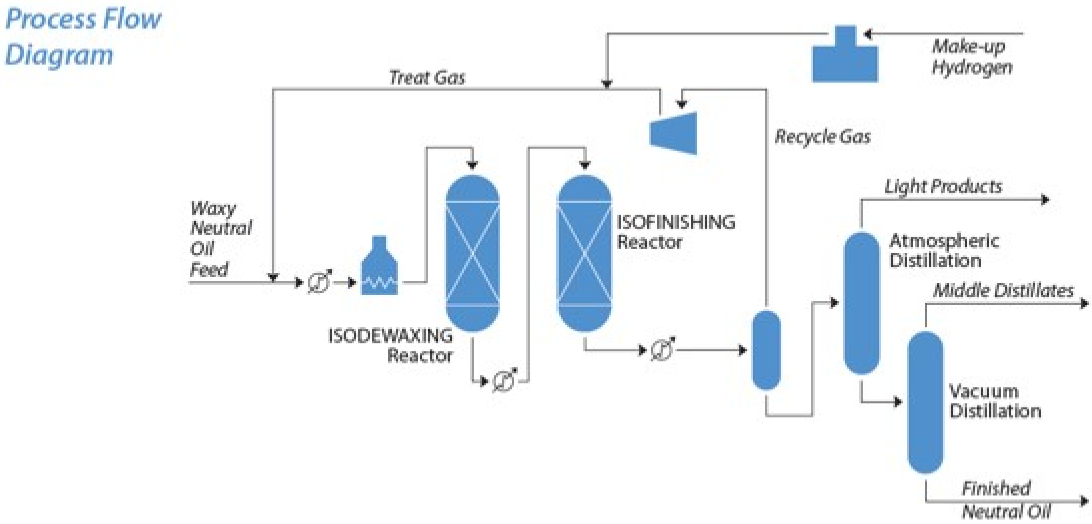

Figure 18 – Basic Process Flow Diagram for the Isodewaxing™ technology by Lummus Company.

- Viscosity – The viscosity of the lubricating oil is controlled in the distillation step, managing the cuts in the crude distillation units or in the distillation columns after hydrocracking units.
- Viscosity Index (VI) – This variable is controlled in the hydrocracking step through the reduction in the aromatics content..
- Saturates – Another parameter that is adjusted in the hydrocracking step, through reduction of aromatics.
- Pour Point – This quality requirement is controlled in the hydrodewaxing step, through the reduction of waxes content

As an example, Figure 19 presents a refining configuration capable of producing high quality lubricating oils based on hydrorefining route.

Despite the high capital spending involved in the hydroprocessing route, it's possible to achieve better quality, higher added value, and products with growing demand against the production of Group I lube that presents contraction demands. In this scenario, is expected which refiners relying on exclusively solvent routes, lose market share, forcing revamps of the existing lubricating production units or the exit from the market.

As discussed above is expected a significant growth of the global hydrocracking installed capacity is expected for the next years. As expected, this growth will be headed by the Asian refiners as presented in Figure 20.

The headed by Asian players is expected once these players present high integration level between refining and petrochemical assets, requiring high bottom barrel conversion capacity to maximize the yield of petrochemicals, again this shows the competitive advantage for the Asian players due to the highest flexibility and profitability of their refining hardware.

Conclusion

Comply with IMO 2020 put under pressure the refining margins of low complexity refineries and reduced conversion capacity, once there is the tendency to raise the prices of low sulfur crude oils, furthermore, the higher operational costs depending on the technological or optimization solution adopted by the refiner. The challenge is even harder to refiners processing heavy and extra-heavy crudes, in this case, despite the high capital spending the hydrocracking technologies can offer an attractive alternative, beyond this, hydrocracking technologies appears like a fundamental enabler to ensure high conversion of bottom barrel streams, especially considering the growing trend of integration between refining and petrochemical assets. For refiners processing low sulfur crudes, the solvent deasphalting technologies can be an attractive way to comply with IMO 2020.

The downstream industry faces a transitive period with deep changes in the consumer market where the necessity to decarbonize the energy matrix requires a increasing participation of renewables in the crude oil refineries and the technology development like electric vehicles and 3 D printing have great potential to destroy transportation fuels demand, leading to deep changes in the production profile of crude oil refineries. Stricter regulations like IMO 2020 raises, even more,

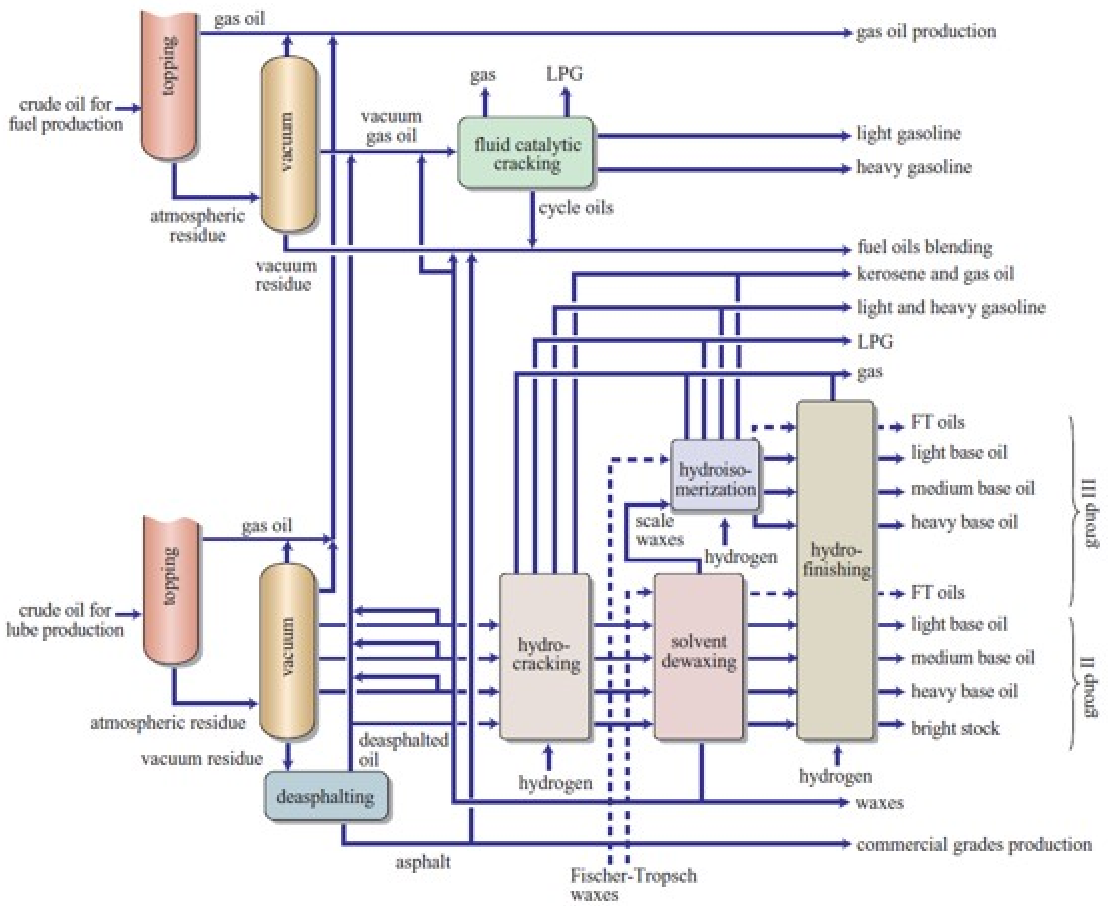

Figure 19 – Lubricating Oil Production Based on Hydrorefining Route (Encyclopedia of Hydrocarbons, 2006)

the relevance of the residue upgrading capacity to the competitiveness in the downstream industry, creating pressure over the refiners with low complexity refining hardware, in this sense, refiners with high capital investment capacity are looking for closer integration with petrochemical assets as a strategy to reduce costs and improve revenues.

Regarding the lubricating market, due to the accelerated technological development, especially in the automotive market, the Group I lubricating oil tend to lose market in the next years this fact tends to lead the refiners to look for capital investment aiming to sustain their competitiveness in the lubricating market.

As aforementioned, despite the high capital investment of the hydroprocessing units, the higher added value of the Groups II and III lubricants and the growing market can justify the investment mainly considering the trend of reduction in transportation fuels demand at a global level in the middle term that has been leading the refiners to look ways to ensure market share and revenues in the downstream industry through the maximization of high added value derivatives with the growing market as petrochemicals and lubricating oils.

Another side effect for lubricating producers based on solvent routes due to the competitiveness loss is raising the imports to supply the internal market, leading to an external dependence of critical production input as well as negative effects on the balance of payments. This reinforces the relevance of capital investments in hydrocracking processing units as strategy to maximize the added value to crude oil reserves, especially considering the transition period faced by the downstream market where the petrochemicals tend to overpass transportation fuels as main driver of crude oil demand at global level.

Again, it's important to understand the transitive period faced by the downstream industry and maintain competitive operations with the current focus in transportation fuels while the transition to petrochemicals is prepared in a sustainable manner aiming to keep economic sustainability and competitiveness in the downstream market, in other words, our current operations will sustain our desired future.

References

ALDESCU, M. Challenges of Heavy Crude Processing. PTQ Magazine, 2012.

BARIC, J. Next Level Hydrocracker Flexibility – Unlocking High Performance in Today's Turbulent Markets. Shell Global Solutions White Paper, 2020.

BISWAS, G.; GILLIS, D.; HURNY, R. LC MAX and LC Slurry – High Conversion Residue Hydrocracking Technologies, Chevron-Lummus Company, 2017.

BROWN, B.; NAIR, R.; SLEIMAN, T. Fuel Oil Markets Show Resilience After Twin Challenge of IMO 2020 and Pandemic, S&P Global Platts, 2021

CACKETT, S. – IMO 2020 and Bottom of the Barrel Opportunities (Shell Catalysts and Technologies). Presented at 2nd Residue Hydrotreat, Kuwait, 2019.

CLARK, J.; SILVA, M. W. – Delayed Coking as a Sustainable Refinery Solution. PTQ Magazine, 2021.

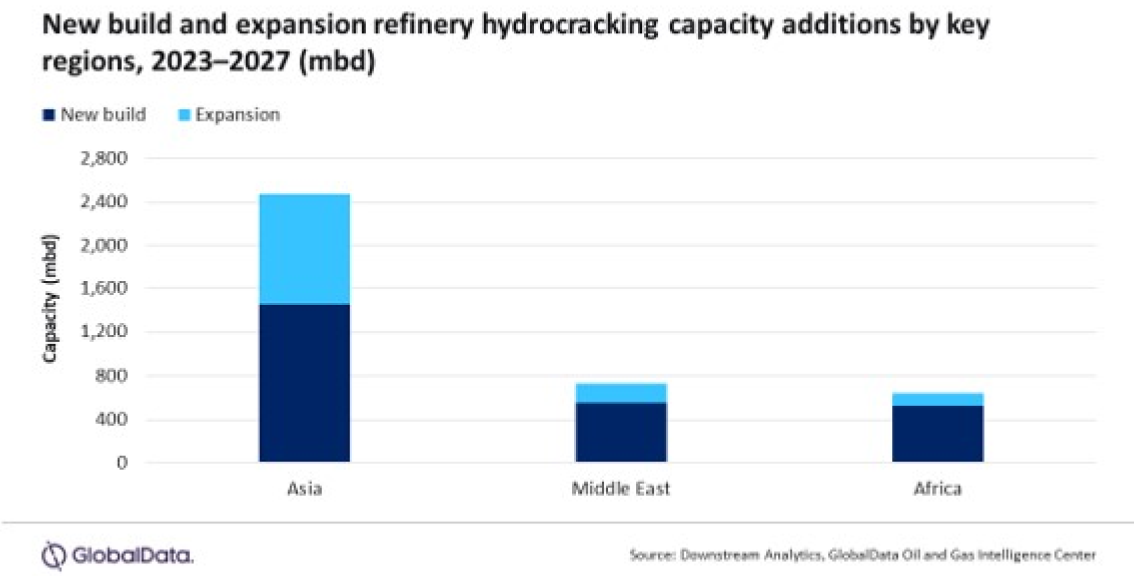

Figure 20 – Participation in the Global Growth of Hydrocracking Capacity by Region (Global Data Company, 2023)

Encyclopedia of Hydrocarbons (ENI), Volume II – Refining and Petrochemicals (2006).

FRECON, J.; LE BARS, D.; RAULT, J. – Flexible Upgrading of Heavy Feedstocks. PTQ Magazine, 2019.

GARY, J. H.; HANDWERK, G. E. Petroleum Refining – Technology and Economics.4th ed. Marcel Dekker., 2001.

Mckinsey & Company. Lubes growth opportunities remain despite switch to electric vehicles, 2018.

MUKHERJEE, U.; GILLIS, D. – Advances in Residue Hydrocracking. PTQ Magazine, 2018.

ODEY, F.; LACEY, M. IMO 2020 – Short-term implications for the oil market - Schroder's, 2018.

ROBINSON, P.R.; HSU, C.S. Handbook of Petroleum Technology. 1st ed. Springer, 2017.

SILVA, M. W. – More Petrochemicals with Less Capital Spending. PTQ Magazine, 2020.

VU, T.; RITCHIE, J. Naphtha Complex Optimization for Petrochemical Production, UOP Company, 2019.

ZHU, F.; HOEHN, R.; THAKKAR, V.; YUH, E. Hydroprocessing for Clean Energy – Design, Operation, and Optimization. 1st ed. Wiley Press, 2017.

Author

Dr. Marcio Wagner da Silva is Process Engineer and Stockpiling Manager on Crude Oil Refining Industry based in São José dos Campos, Brazil. Bachelor's in chemical engineering from University of Maringa (UEM), Brazil and PhD. in Chemical Engineering from University of Campinas (UNICAMP), Brazil. Has extensive experience in research, design and construction to oil and gas industry including developing and coordinating projects to operational improvements and debottlenecking to bottom barrel units, moreover Dr. Marcio Wagner have MBA in Project Management from Federal University of Rio de Janeiro (UFRJ), in Digital Transformation at PUC/RS, and is certified in Business from Getulio Vargas Foundation (FGV).

Economic Insulation for Industrial Piping

Jayanthi Vijay Sarathy

Thermal Insulation for Industrial Piping is a common method to reduce energy costs in production facilities while meeting process requirements. Insulation represents a capital expenditure & follows the law of diminishing returns. Hence the thermal effectiveness of insulation needs to be justified by an economic limit, beyond which insulation ceases to effectuate energy recovery. To determine the effectiveness of an applied insulation, the insulation cost is compared with the associated energy losses & by choosing the thickness that gives the lowest total cost, termed as 'Economic Thickness'.

The following module provides guidance to estimate the economic thickness for natural gas piping in winter conditions as an example case study.

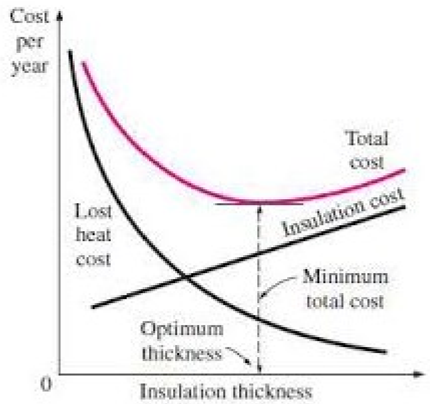

Figure 1. Economic Insulation Thickness Selection

Design Considerations

To estimate the economic insulation thickness, the following factors are to be given attention – Energy costs (steam/electricity), annual hours of operation, operating surface temperature, pipe dimensions, estimated cost of insulation, and average exposure to the ambient. These are critical to predict the thermal resistances and heat transfer coefficients and the total heat loss or gain, from or to the system.

Lower heat transfer coefficients & thermal conductivity offer a lower rate of heat loss/ gain. It is for this reason; materials that provide low thermal conductivity are chosen to provide insulation. To provide effective insulation, the conductive heat transfer from the metal has to be kept lower than the convective heat transfer on the insulation's external side to prevent the outer insulation temperature from increasing drastically.

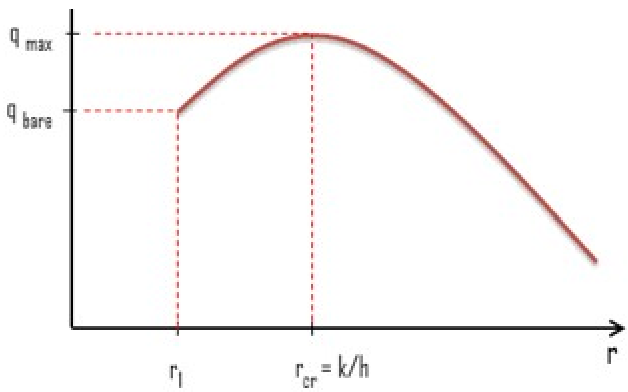

Figure 2. Critical Insulation Thickness

From the above, when insulation is applied on a bare pipe of a given nominal diameter, the heat transfer rate increases as the insulation radius/thickness increases. As the insulation thickness increases, until reaching the critical radius [Rc], there is a progressive fall in the convective resistances causing higher heat losses from the pipe.

Therefore, for insulation to be properly effective in restricting heat transmission, the outer pipe radius R2 must be greater than or equal to the critical radius [Rc] of the insulation. If this condition is not satisfied, no useful purpose will be served with the chosen material of insulation.

Case Study & Assumptions

To demonstrate the economic insulation calculations, a case study is made based on a natural gas piping operating in cold winter conditions. In addition, certain assumptions are made for this example case study.

1. Ambient temperature [Ta] is taken as 00C & wind velocity is taken as 18 km/h (5 m/s).
2. The pipe inside heat transfer [HT] coefficient [hi] is neglected since it is small compared to outer/ambient HT coefficient.
3. Radiation is accounted for with the emissivity of the outer bare pipe taken as 0.9 while insulation emissivity is 0.13.
4. Heat transfer through pipe & insulation material is assumed to be perfectly radial & critical thickness is estimated at steady state conditions, i.e., at equilibrium.

Design Data

For estimation of heat transfer coefficients, the process data used is as follows,

Table 1. Natural Gas Composition

Component	MW	Mol%
-	[kg/kmol]	[%]
Methane [CH_4]	16.04	76.23
Ethane [C_2H_6]	30.07	10.00
Propane [C_3H_8]	44.01	5.00
i-Butane [i-C_4H_{10}]	58.12	1.00
n-Butane [n-C_4H_{10}]	58.12	1.00
i-Pentane [i-C_5H_{12}]	72.15	0.30
n-Pentane [n-C_5H_{12}]	72.15	0.10
Water [H_2O]	18.02	0.25
Carbon dioxide [CO_2]	44.01	3.00
Hydrogen Sulphide [H_2S]	34.08	0.07
Nitrogen [N_2]	28.01	3.00
Total		**100.0**

The air properties between -250C & 500C are computed using fitted equations as follows,

1. Air Density [kg/m3] is computed as,

$$\rho_{Air} = 0.0000158T^2 - 0.0134T + 3.7622$$

2. Air Specific Heat [kJ/kg.K] is computed as,

$$C_{p,air} = 1.006$$

3. The thermal conductivity [W/m.K] of air is,

$$k_{Air} = -2.69 \times 10^{-8}T^2 + 9.04 \times 10^{-5}T + 9.56 \times 10^{-4}$$

4. The thermal diffusivity [m2/s] of air is,

$$\alpha_{Air} = 1.99 \times 10^{-10}T^2 + 1.5 \times 10^{-8}T - 7.96 \times 10^{-7}$$

5. The dynamic viscosity [kg/m.s] of air is,

$$\mu_{Air} = -4.22 \times 10^{-11}T^2 + 7.19 \times 10^{-8}T + 8 \times 10^{-7}$$

6. The kinematic viscosity [m2/s] of air is,

$$\gamma_{Air} = 1.02 \times 10^{-10}T^2 + 3.1 \times 10^{-8}T - 2.69 \times 10^{-6}$$

7. The Prandtl Number of air is computed as,

$$Pr = -5.12 \times 10^{-7}T^2 + 3.7 \times 10^{-5}T + 0.7642$$

Based on the above correlations, for an ambient temperature of 273.15 K, the air properties are as follows,

Table 2. Air Properties at Ambient Conditions

Parameter	Value	Unit
Density [ρ_{air}]	1.293	kg/m^3
Specific Heat [$C_{p,air}$]	1.006	kJ/kg.K
Thermal Conductivity [k_{air}]	0.0236	W/m.K
Thermal Diffusivity [α_{air}]	0.000018	m^2/s
Dynamic Viscosity [μ_{air}]	0.000017	kg/m.s
Thermal Exp. Coefficient [β_{air}]	0.0037	1/K
Kinematic Viscosity [γ_{air}]	0.000013	m^2/s

Natural Gas Pipe Construction Details

The construction details of the natural gas pipe are as follows in Table 3.

The Process data used for the case study is in Table 4.

The gas compressibility factor, Z is predicted using DAK EoS. Gas line pressure drop is estimated using Weymouth equation. Due to the presence of water in the natural gas stream, ice & hydrate formation tendencies exist. For a flow pressure of 16.14 bara, the hydrate temperature is 9.520C.

Therefore, insulation is to be provided to ensure hydrate & ice formation does not take place. A Hydrate P-T plot is therefore presented as follows in Figure 4.

Table 3. Pipe Construction Details

Parameter	Value	Units
Pipe Material	Carbon Steel	
Design Pressure	11.0	bara
Design Temperature	100	^0C
Pipeline DN	6.625	in
Pipe WT	3.58	mm
Pipe ID	161.1	mm
Pipe Length incl. Fittings [L_e]	1,000	m
Pipe Total OD [D_3]	269.875	mm
Pipe Thermal Cond. [k_{pipe}]	45	W/m.K
Pipe Surface Emissivity[ε]	0.90	-
Ambient Temperature [T_{amb}]	0	^0C
Wind Velocity [V_a]	18	km/h
Insulation Material	Urethane Foam	
Insulation Thermal Cond. [k_{ins}]	0.018	W/m.K
Insula. Surface Emissivity [ε]	0.13	-

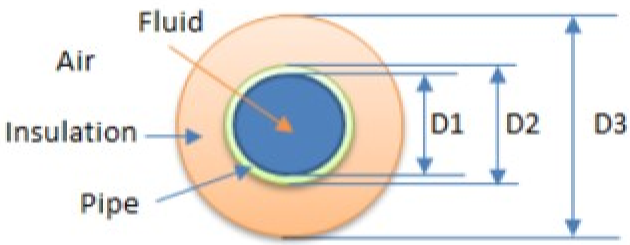

Figure 3. Pipe Construction

Table 4. Pipe Inlet Process Data

Parameter	Value	Units
Pipe Gas Flow Rate [Q]	12.0	MMSCFD
Pipe Inlet Pressure [P_1]	20.0	bara
Pipe Temperature [T_1]	40.0	^0C
Gas MW	21.16	kg/kmol
Pipe Inlet Cp	2.0967	kJ/kg.K
Compressibility Factor [Z_1]	0.9539	-
Gas Flow [Act_m3/h]	742	m^3/h
Gas Density [r]	17.04	kg/m^3
Mass Flow [m]	12,643	kg/h

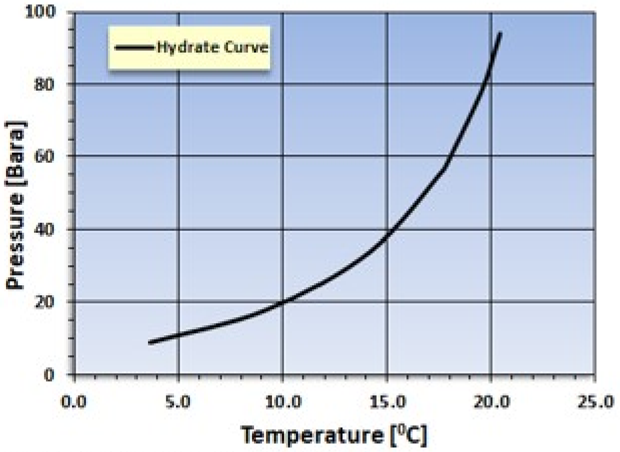

Figure 4. Hydrate P-T Curve

Results

With the methodology employed, the pipe process results computed with Weymouth & DAK-EoS are as follows,

Table 5. Pipe Process Results

Parameter	Value	Units
Pipe Inlet Velocity [V]	10.0	[m/s]
Pipe Exit Velocity [V_e]	10.5	[m/s]
Pipe Exit Temperature [T_e]	39.2	[0C]
Pipe Exit Pressure [P_e]	19.07	[bara]
Pressure Drop [ΔP]	0.93	[bar]
ΔP per km [ΔP/L]	0.93	[bar/km]

The dQ vs. Insulation radius plot shows a decreasing trend between heat loss from a bare pipe [Qbare] and heat loss from an insulated pipe [QIns] with increase in insulation thickness.

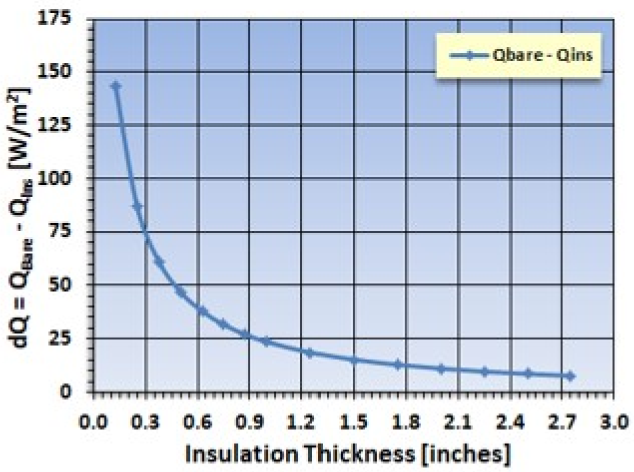

Figure 5. dQ vs Insulation Thickness

A plot between the total annual costs & insulation thickness shows that the annual total cost of the energy losses is the least at 2” insulation thickness representing 53,694€.

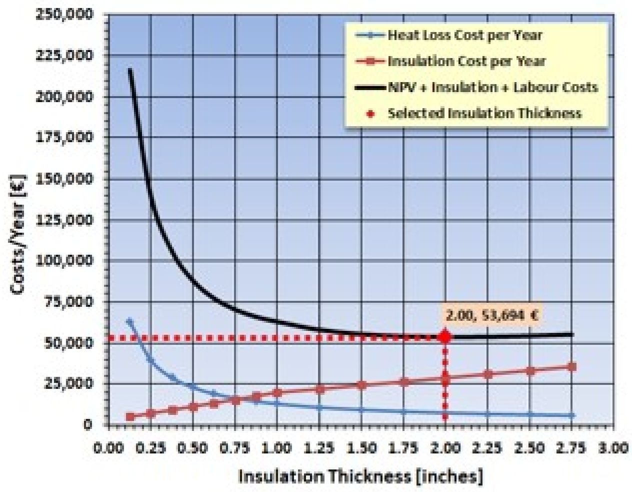

Figure 6. Costs per Year vs. Insulation Thickness

Appendix A: Design Methodology

To estimate the thermal insulation required, the heat losses & heat transfer coefficients are accounted based on 3 modes of heat transfer driven by temperature differences – namely, pipe wall conduction, free convection, forced convection & ambient radiation. For the bare pipe & insulation cases, air flows over the pipe surface thereby forming a film with a certain temperature. This film temperature determines the rate of heat losses through the pipe surface/insulation. The air film temperature [Tairfilm] on the insulation surface is estimated iteratively. Therefore, for the first iteration,

$$T_{airfilm,ins,1} = T_{amb}[°C] + 1°C$$

Radiation Heat Transfer

To estimate the radiation heat transfer between the ambient & concrete insulation on the tank, the expression is written as, [1],

$$h_r = \varepsilon \times \sigma\left(T_{airfilm,} + T_a\right)\left(T_{airfilm}^2 + T_a^2\right)$$

Where, s = 5.67´10^{-8} W/m^2/K
e = Surface emissivity

The radiation mode expressed above is written in a manner like convection, i.e., the radiation rate equation is linearized making the heat rate proportional to the temperature difference rather than to the difference between two temperatures to the fourth power.

Forced Convection

To calculate the external heat transfer coefficient [h_o], Nusselt number for forced convection over circular cylinder with cross flow can be estimated using Churchill and Bernstein correlation [1]. This equation is valid for all *Re.Pr* ³ 2 and the correlation is expressed as,

$$Nu = 0.3 + \frac{0.62\, Re^{1/2}\, Pr^{1/3}}{\left[1 + \left(\frac{0.4}{Pr}\right)^{2/3}\right]^{1/4}}\left[1 + \left(\frac{Re}{282000}\right)^{5/8}\right]^{4/5}$$

Prandtl Number [Pr] of ambient air is,

$$Pr = \frac{C_{P,air}\mu_{air}}{k_{air}}$$

Reynolds number [Re] becomes,

$$Re = \frac{V_{air}D_3\rho_{air}}{\mu_{air}}$$

The above correlation is valid for all ranges of Reynolds number (*Re*) and *Pr* ³ 0.2, where all properties are evaluated at film temperature. It is to be noted that as per [1], Churchill & Bernstein correlation is reasonable over a certain range of conditions but for most engineering calculations, the accuracy is not expected to be much better than 20% because these are based on more recent results encompassing a wide range of conditions.

Natural/Free Convection

To estimate the heat transfer due to natural convection, the correlation by Churchill & Chu [1] can be used and is of the form,

$$Nu = \left\{0.6 + \frac{0.387\, Ra^{1/6}}{\left[1 + \left(\frac{0.559}{Pr}\right)^{9/16}\right]^{8/27}}\right\}^2$$

Where, Rayleigh number (Ra) is computed as,

$$Ra = \frac{g \times \beta_{air} \times \left[T_{airfilm} - T_a\right]D_3^3}{\alpha_{air}\gamma_{air}}$$

Where, *b* = Thermal expansion coefficient
a$_{air}$ = Thermal diffusivity

Therefore, the combined heat transfer coefficient is computed as,

$$Nu_{combined} = \left[Nu_{free}^4 + Nu_{forced}^4\right]^{1/4}$$

$$h_{comb} = \frac{k_{air} Nu_{comb}}{D_3}$$

Therefore, the external heat transfer coefficient, $h_{air,\ overall}$, is computed as,

$$h_0 = h_{comb} + h_r$$

Bare Pipe & Insulation Resistance

The resistance offered by the bare pipe & insulation is estimated as follows,

$$R_{bare} = \frac{D_2 ln\left[\frac{D_2}{D_1}\right]}{2k_{pipe}}$$

$$R_{Ins} = \frac{D_3 ln\left[\frac{D_3}{D_2}\right]}{2k_{ins}}$$

Total Resistance – Bare Pipe & Insulation

For bare pipe, the total resistance is calculated as,

$$R_{Total} = R_{bare} + \frac{1}{h_0}$$

For Insulated Pipe, the total resistance is calculated as,

$$R_{Total} = R_{Bare} + R_{Ins} + \frac{1}{h_0}$$

Piping Heat Losses

$$U = {}^{1}/_{R_{Total}}$$

$$\left(\frac{Q}{A}\right)_{Loss} [W/m^2] = U \times (T_1 - T_a)$$

$$\left(\frac{Q}{A}\right)_{Loss} [W/m] = \left(\frac{Q}{A}\right)_{Loss} [W/m^2] \times \pi D_3$$

$$Q_{Loss}[kW] = \left(\frac{Q}{A}\right)_{Loss} [W/m] \times L_e$$

$$T_{airfilm,ins,2} = T_1 - \left[\left(\frac{Q}{A}\right)_{Loss} [W/m] \times R_{ins}\right]$$

The above set of heat transfer calculations are performed first for a bare pipe & then performed for various insulation thicknesses to estimate the heat losses, Q_{Loss} [W/m^2] and Q_{Loss} [kW], Q_{Loss} [kWh/year] which is computed by multiplying Q_{Loss} [kW] with the annual working hours.

Insulation Economics

The economic thickness of insulation depends on the insulating & maintenance costs and the annual value of heat loss. This would depend on the cost of producing energy & thermal conductivity of the lagging. Generally thicker insulation will represent higher investment costs and lower heat loss costs. The annual heat losses are computed as,

$$C_{Loss} = \left(\frac{Q}{A}\right)_{Loss} [kW] \times n \times Q_{cost}/kWh$$

Where, n = number of annual hours

Insulation Costs is the product of insulation volume and insulation cost per m^3.

$$V_{Ins}[m^3] = \frac{\pi}{4}[D_3^2 - D_2^2] \times L_e$$

$$C_{Ins} = V_{ins} \times [C_{ins}/m^3]$$

Labor Costs is the product of cost per unit meter & length of pipe

$$C_{Labour} = L_e \times [C_{lab}/m]$$

The cost of energy losses is quantified by the Net Present Value (NPV) of the future energy costs during an insulation life of typically 5 years. For this module, a discount rate [i] of 15% is used. The number of annual working hours is taken as 8,000 hours, cost of energy (electricity to run the gas compressor) is taken as 0.10€/kWh and the insulation cost is taken as 50€/m^3. The annual value of the energy losses for 5 years is calculated as,

$$NPV = R \times \frac{1 - [1 + i]^{-n}}{i}$$

Where, R is the cost of energy losses

The annual total cost is computed as,

$$C_{Total} = NPV + C_{Ins} + C_{Labour}$$

The Insulation thickness corresponding to the lowest total cost will be the economic thickness of insulation.

Appendix A: Heat Transfer Coefficients

Heat Transfer Calculations - Iterative Procedure						
Parameter	Units	1	2	3	4	5
$T_{air\ film,\ ins}$	[°C]	1.0	0.6	0.6	0.6	**0.6**
Radiation Heat Transfer						
h_{Rad}	[W/m².K]	0.60	0.60	0.60	0.60	**0.60**
Forced Convection Heat Transfer						
Pr	-	0.7358	0.7359	0.7359	0.7359	**0.7359**
Re	-	100,249	100,524	100,524	100,524	**100,524**
Nu_{Forced}	-	218.8	219.2	219.2	219.2	**219.2**
h_{Forced}	[W/m².K]	19.22	19.23	19.23	19.23	**19.23**
Natural Convection Heat Transfer						
Ra	-	2.85E+06	1.66E+06	1.66E+06	1.66E+06	**1.66E+06**
Nu_{Free}	-	19.69	16.86	16.86	16.86	**16.86**
h_{Free}	[W/m².K]	1.73	1.48	1.48	1.48	**1.48**
Combined Convection Heat Transfer						
$Nu_{Combined}$	-	218.8	219.2	219.2	219.2	**219.2**
$h_{Combined}$	[W/m².K]	19.22	19.24	19.24	19.24	**19.24**
Total External Heat Transfer						
h_o	[W/m².K]	19.83	19.84	19.84	19.84	**19.84**
Pipe Wall Resistance						
R_{pipe}	[m².K/W]	1.55E-03	1.55E-03	1.55E-03	1.55E-03	**1.55E-03**
Insulation Resistance						
R_{ins}	[m².K/W]	3.54	3.54	3.54	3.54	**3.54**
Total Resistance						
R_{Total}	[m².K/W]	3.59	3.59	3.59	3.59	**3.59**
U	[W/m².K]	0.28	0.28	0.28	0.28	**0.28**
Q/A	[W/m²]	11.1	11.1	11.1	11.1	**11.1**
Q_{Loss}	[W/m]	9.4	9.4	9.4	9.4	**9.4**
$Q_{Total\ Loss}$	[kW]	9.4	9.4	9.4	9.4	**9.4**

Appendix B: Economic Analysis

Pipe Insulation Economics		
Bare Pipe Q_{Loss} [W/m²]	769.9	*Copy-Paste in Cell Z31 only for Ins. Thick of 0 mm*
With Insulation [W/m²]	11.0	*Copy-Paste in Cell Z32 Onwards & Below*
$Q_{Total\ Loss}$ With Ins [kW]	9.3	*Copy-Paste in Cell AA32 Onwards & Below*
Annual Working Hours	8000	
Cost of Electricity/kWh	0.10 €	
Insulation Cost /m³	50.00 €	
Life of Insulation [Yrs]	5	

Selected Insulation Thickness	
Thickness Chosen [in]	2.00
Thickness Chosen [mm]	50.80
Critical Radius [mm]	0.91
Insulation Effective	Yes

Insulation Thickness		Q_{Loss}	$Q_{Total\ Loss}$	$Q_{Loss/Yr}$		Labour Cost		Ins. Cost	Ins.+Lab Cost	NPV Discount	NPV [Yrly Q_{Loss}]	NPV+Ins+Lab Cost
[mm]	[inches]	[W/m²]	[kW]	[kWh/yr]	[€]	[€/m]	[€]	[€]	[€]	[%]	[€]	[€]
0.0	0.00	899.9	-	-	-	-	-	-	-	-	-	-
3.175	0.13	143.6	78.8	630,263	63,026 €	5 €	5,000 €	86 €	5,086 €	15.0	211,274 €	216,359 €
6.350	0.25	86.9	49.4	395,317	39,532 €	7 €	7,000 €	174 €	7,174 €	15.0	132,516 €	139,691 €
9.525	0.38	61.4	36.1	288,904	28,890 €	9 €	9,000 €	266 €	9,266 €	15.0	96,845 €	106,111 €
12.700	0.50	47.0	28.6	228,968	22,897 €	11 €	11,000 €	361 €	11,361 €	15.0	76,753 €	88,115 €
15.875	0.63	37.9	23.8	190,604	19,060 €	13 €	13,000 €	459 €	13,459 €	15.0	63,893 €	77,353 €
19.050	0.75	31.6	20.5	163,955	16,395 €	15 €	15,000 €	561 €	15,561 €	15.0	54,960 €	70,521 €
22.225	0.88	27.0	18.0	144,365	14,437 €	17 €	17,000 €	665 €	17,665 €	15.0	48,393 €	66,058 €
25.400	1.00	23.5	16.2	129,355	12,936 €	19 €	19,000 €	773 €	19,773 €	15.0	43,362 €	63,135 €
31.750	1.25	18.5	13.5	107,856	10,786 €	21 €	21,000 €	998 €	21,998 €	15.0	36,155 €	58,153 €
38.100	1.50	15.2	11.6	93,186	9,319 €	23 €	23,000 €	1,235 €	24,235 €	15.0	31,237 €	55,473 €
44.450	1.75	12.8	10.3	82,525	8,252 €	25 €	25,000 €	1,485 €	26,485 €	15.0	27,664 €	54,149 €
50.800	2.00	11.0	9.3	74,418	7,442 €	27 €	27,000 €	1,748 €	28,748 €	15.0	24,946 €	53,694 €
57.150	2.25	9.6	8.5	68,040	6,804 €	29 €	29,000 €	2,024 €	31,024 €	15.0	22,808 €	53,832 €
63.500	2.50	8.5	7.9	62,885	6,289 €	31 €	31,000 €	2,312 €	33,312 €	15.0	21,080 €	54,392 €
69.850	2.75	7.6	7.3	58,629	5,863 €	33 €	33,000 €	2,613 €	35,613 €	15.0	19,653 €	55,266 €

References

"Fundamentals of Heat and Mass Transfer", Incropera, DeWitt, Bergman, Lavine, 6th Edition.

Author

Vijay Sarathy holds a Master's Degree in Chemical Engineering from Birla Institute of Technology & Science (BITS), Pilani, India and is a Chartered Engineer from the Institution of Chemical Engineers, UK. His expertise over 10 years of professional experience covers Front End Engineering, Process Dynamic Simulation and Subsea/Onshore pipeline flow assurance in the Oil and Gas industry. Vijay has worked as an Upstream Process Engineer with major conglomerates of General Electric, ENI Saipem and Shell.

KLM Technology Group is a technical consultancy group, providing specialized services and training to improve process plant operational efficiency, profitability and safety. We provide engineering solutions by offering training, technical services, best practices, and engineering designs to meet the specific needs of our partner clients. Since 1997, KLM Technology Group has been providing engineering, operations, and maintenance support for the hydrocarbon processing industry.

WWW.KLMTECHGROUP.COM

Engineering Solutions, Standards, and Software

KLM Technology Group

Why Sustainable Carbonization Biomass Energy Technology is Important in Energy Transition and Net Zero Carbon Emission

Hamid Reza Seyed Jafari, Babak Danesh, Esra Kayhan,
Seyed Mohammad Reza Seyed Jafari

What is energy transition and net zero carbon emission?

The **energy transition** refers to the shift from fossil fuels (like coal, crude oil, and natural gas) to cleaner and more sustainable energy sources such as biomass (hazelnut shell, spent coffee ground, walnut shell, wood, sawdust… and renewable (solar, wind…) energies and biofuels (bio jet, biodiesel, bio gasoline…). It involves adopting renewable energy technologies, improving energy efficiency, and reducing greenhouse gas emissions.

Net zero carbon emissions means achieving a balance between the amount of carbon dioxide (CO2) emitted into the atmosphere and the amount removed or offset. In other words, the total emissions are effectively canceled out, resulting in no net increase in atmospheric CO2 levels. Achieving net zero typically involves reducing emissions through various strategies (such as using clean energy sources, improving energy efficiency, and carbon capture) and offsetting any remaining emissions by activities like reforestation or carbon sequestration via switching from non-renewable energies to renewable and sustainable technologies. If everyone had access to clean, affordable energy, the road to a carbon-neutral world—net zero emissions by 2050 (of further global decisions UN of Paris summit 2015) would be faster.

Sustainable carbonization biomass

Biomass carbonization is the process of transforming waste biomass into energy-rich charcoal. During this slow pyrolysis process, biomass may be heated to high temperatures (exceeding 850°C) in an inert atmosphere. Here are the key products of biomass carbonization:

1. Charcoal (Char): The primary product, rich in carbon, is obtained by expelling volatile components from the biomass. Charcoal has enhanced heating value and energy content.

2. Gaseous Products: Combustible gases like carbon monoxide (CO), hydrogen (H_2), and methane (CH_4) are released. Carbon dioxide (CO_2) and other condensable vapors (e.g., water, acetic acid, methanol, acetone, and tars) are also produced.

3. Graphite and Graphene: The extracted carbon from char can be used to create valuable materials like graphite and graphene.

4. Torrefaction: A mild carbonization process that produces a solid biomass fuel with improved properties for combustion.

Biomass carbonization opens new doors for commercial and scientific applications, contributing to renewable energy and environmental sustainability. After carbonization of any biomass feedstock as a charcoal product its heating value (MJ/Kg) goes up, because of its moisture and volatile compounds will be removed in any pyrolysis furnace of a processing line in which producing briquette or biochar.

For example, the carbonization of spent coffee grounds (SCG) biomass to produce shisha charcoal typically involves a pyrolysis process. While the exact temperature can vary depending on the specific method and desired properties of the charcoal, research suggests that temperatures can range from **450°C to 800°C** and its temperature to produce shisha charcoal of hazelnut shell biomass can range from **600°C to 850°C**. The process is usually carried out for a duration of around **2 hours** at these temperatures to ensure proper carbonization[6].

Biochar (charcoal) production process flow diagram

As usual a production process line of agricultural biomass to biochar and charcoal involves several stages as follows (figure 1):

1. Feeding: biomass feedstocks such as SCG; Hazelnut shells, sawdust…are fed into the carbonization furnace using the feeder. Blending of different mass ratios (20%, 30%, 40%, and 50% …of any biomass feedstocks) is one of the best ways of increasing of heating value and its strength of finished products of charcoal that may be occurred by operation operators. For example: Activation energy for combustion varied depending on the blending ratio, ranging from 90.9 to 215.3 kJ/mol.

2. Carbonization and devolatilization:

   2.1. Carbonization: The continuous carbonation furnace processes the shells into charcoal at high temperatures and evacuates volatile compounds of biomass feedstock which is a bad factor for finished products of charcoal. Note: For startup of pyrolysis furnace, we should firstly use a fossil fuel such as: LPG, Gas Oil… then its heating material is switched to the hydrocarbon volatile material consumption inside any biomass feedstock in which is different from its type to type and is very important in energy saving of the whole process of biochar production line.

   2.2. Devolatilization:

   Devolatilization refers to the process during which volatile components (such as water, organic compounds, and gases) are released from solid biomass when it is heated.

   Biomass contains various volatile components, including moisture, hemicellulose, cellulose, and lignin. As the temperature increases, these components undergo thermal decomposition.

- The main stages of devolatilization are:
- Drying: Removal of moisture (water) from the biomass.
- Hemicellulose Decomposition: Breakdown of hemicellulose into simpler compounds (e.g., sugars, furans).
- Cellulose Decomposition: Conversion of cellulose into volatile gases (e.g., CO, CO_2, CH_4).
- Lignin Degradation: Lignin breaks down into phenolic compounds and other volatile products.

   The rate of devolatilization depends on factors like heating rate, particle size, and bio-

   Charcoal Oxidation:

   - Char is the solid residue left behind after devolatilization. It consists mainly of carbon.
   - Char oxidation occurs when oxygen (usually from air) reacts with the carbon in char, leading to combustion.
   - The overall reaction for char oxidation is: Charcoal + $1/2O_2$ gives, CO_2

   The process involves several steps, including:

   - Surface Reaction: Oxygen molecules adsorb onto the char surface, forming reactive sites.
   - Gasification: Carbon reacts with oxygen to produce carbon monoxide (CO).
   - Further Oxidation: CO reacts with more oxygen to form CO_2.

   Factors affecting charcoal oxidation include temperature, oxygen concentration, and charcoal porosity.

3. Crushing: The charcoal is crushed into smaller particles (3-5mm) using the charcoal crusher. Note: Crasher location may be before or after carbonization pyrolysis furnace depending on its size of biomass, if its size is large shall be located before furnace such as palm leaves biomass feedstock.

4. Mixing: The charcoal powder may be mixed with a binder (such as starch, water…) in the wheel mixer.

5. Pressing: The mixture is then pressed into briquettes using the hydraulic press (or an extruder machine). Note: The CAPEX of an extruder machine is a few times lower than hydraulic machine but vice versa its maintenance cost is higher than hydraulic machine.

6. Drying: The briquettes are dried in the heat pump dryer to achieve the desired moisture content. Note: It may be not needed and depends on only the moisture content of finished product (briquette or cubic shape of charcoal).

7. Packaging: Finally, the dried briquettes and charcoals are packaged for marketing.

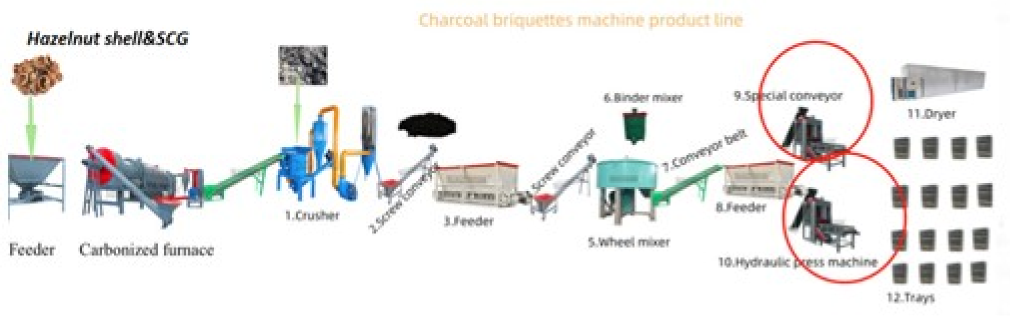

Figure 1- Agricultural sustainable biomass processing line of charcoals

How does biomass compare to fossil fuels in terms of emissions?

Biomass feedstocks and fossil fuels differ significantly in terms of emissions. Let's break it down:

1. Greenhouse Gas Emissions:

- Biomass: When burned, biomass releases carbon dioxide (CO_2) into the atmosphere. However, this CO_2 is part of the natural carbon cycle, as plants absorb CO_2 during growth. If managed sustainably, biomass can be considered carbon neutral.
- Fossil Fuels: Coal, oil, and natural gas release CO_2 that was sequestered underground for millions of years. These emissions contribute significantly to climate change.

2. Other Pollutants:

- Biomass: Burning biomass can emit particulate matter, nitrogen oxides (NO_x), and volatile organic compounds (VOCs). However, modern biomass facilities use filters and advanced combustion techniques to minimize these pollutants.
- Fossil Fuels: Fossil fuels emit not only CO_2 but also sulfur dioxide (SO_2), nitrogen oxides, and other harmful substances. These pollutants contribute to air quality problems and health issues.

3. Renewability:

- Biomass: Derived from organic materials (wood, crop residues, etc.), biomass is renewable if managed sustainably.
- Fossil Fuels: Finite resources; extraction depletes them permanently.

4. Land Use Impact:

- Biomass: Requires land for cultivation or forestry. Sustainable practices are essential to prevent deforestation.
- Fossil Fuels: Extraction disrupts ecosystems and landscapes.

5. Energy Efficiency:

- Biomass: Less energy-dense than fossil fuels, so more biomass is needed to produce the same energy.
- Fossil Fuels: Higher energy density.

6. Overall Assessment:

- Biomass can be a viable renewable energy source when managed sustainably.
- Transitioning away from fossil fuels is crucial for mitigating climate change.

Fuel oil products and biomass fuels heating values

When comparing the energy content values of biomass and oil products, there are several key points to consider:

1.Energy Density: Oil products generally have a higher energy density compared to biomass. This means that a smaller volume of oil can produce more energy than the same volume of biomass when burned.

2. Calorific Value: The calorific value, or the amount of energy released during combustion, is typically higher in oil products. For example, crude oil has a calorific value of about **42-47 MJ/kg**, while biomass materials like wood have a lower range, typically around **15-18 MJ/kg**, hazelnut shell 18-22 MJ/Kg, spent coffee ground 22 MJ/Kg.

3. Efficiency: The conversion efficiency of biomass to energy is often lower than that of oil products due to the higher moisture content and less efficient combustion processes[5].

4. Environmental Impact: Biomass is considered more environmentally friendly as it is a renewable resource and can be carbon neutral. The combustion of oil products releases more greenhouse gases and contributes to pollution.

5. Cost and Availability: Biomass can be more cost-effective and locally available, reducing the need for transportation and the associated emissions. Oil products, being globally traded commodities, can be subject to price volatility and geopolitical issues.

In summary, while oil products have a higher energy content value, biomass offers benefits in terms of sustainability and environmental impact. The choice between the two often depends on the specific application, availability, and environmental considerations.

The energy content of biomass and oil products, measured in kilojoules per kilogram (kJ/kg), varies significantly due to differences in their chemical composition and density:

- Biomass: The energy content of biomass materials like wood chips, agricultural residues, or hazelnut shells typically ranges from **10,000 to 22,000 kJ/kg**. This is the Lower Heating Value (LHV) which accounts for the energy used to evaporate water during combustion.
- Oil Products: In contrast, oil products such as gasoline, diesel, and crude oil have much higher energy contents, with values generally ranging from **42,000 to 47,000 kJ/kg**. This represents the Higher Heating Value (HHV), which includes the total energy content without accounting for water evaporation.

It's important to note that these values are approximate and can vary based on the specific type of biomass or oil product, as well as the conditions under which they are measured. Biomass has a lower energy content per unit mass compared to oil products, which is why larger quantities of biomass are required to produce the same amount of energy as a smaller quantity of oil.

Typically, the calorific values for different fuels of oil & biomass products, measured in mega joules per kilogram (MJ/kg) are following as too (Table-1).

1. Hard Coal: Approximately 29 MJ/kg

2. Crude Oil: Around 42 MJ/kg

3. Woodchips (25% moisture content): About 14 MJ/kg

4. Wood pellets (10% moisture content, starting from dry wood waste): Approximately 17 MJ/kg

5. Grasses/straw (15% moisture content): Roughly 14.5 MJ/kg

What are the environmental benefits of using agricultural biomass as a source of energy in net zero carbon emission?

The environmental benefits of using biomass sources (like hazelnut shell charcoal and spent coffee grounds charcoal…) are significant such as below:

1. Carbon Neutrality: Biomass is considered carbon-neutral because the carbon dioxide (CO2) released during combustion is roughly equal to the amount absorbed by the plants during their growth cycle. This helps in reducing the net emissions of CO2, which is a major greenhouse gas contributing to climate change.

2. Waste Reduction: Utilizing agricultural waste products like hazelnut shells and spent coffee grounds for charcoal production helps in reducing waste. This not only minimizes the environmental impact of waste disposal but also adds value to what would otherwise be discarded materials.

3. Sustainable Energy: Biomass can be replenished over time by growing more plants and trees, making it a sustainable source of energy. In contrast, fossil fuels are finite and contribute to resource depletion.

4. Reduced Emissions: When compared to fossil fuels, biomass typically results in lower emissions of sulfur and other pollutants. This can lead to improved air quality and a reduction in acid rain and smog.

5. Soil Improvement: The use of biochar, a product of biomass carbonization, can improve soil quality. It increases nutrient availability, microbial activity, and water retention, which can enhance crop production.

6. Energy Security: By diversifying the energy mix and reducing dependence on imported fossil fuels, biomass contributes to energy security and stability.

Table 1-Heating value of agricultural biomass and oil & gas products

	Hazelnut shell	SCG	Gasoline	Natural Gas	LPG
Biomass energy, MJ/kg	18-22	22			
Fossil Energy, MJ/kg			45	38	46

7. Economic Benefits: The biomass industry can create new jobs in rural areas where agricultural waste is abundant, thus providing economic benefits and supporting local economies.

These benefits highlight the potential of biomass sustainable energy as a key component in the transition towards a more sustainable and environmentally friendly energy system and in combat with climate crisis.

How can we encourage sustainable biomass practices globally in energy transition and net zero carbon emission?

Promoting sustainable biomass practices globally requires a multifaceted approach. Here are some strategies forecasted below. Remember that a global shift toward sustainable biomass requires collective effort and long-term commitment too.

1. Policy and Regulations:

- Governments should create and enforce policies that incentivize sustainable practices.
- Set clear guidelines for land use, harvesting, and reforestation.

2. Research and Education:

- Invest in research on best practices, efficient technologies, and environmental impacts.
- Educate stakeholders (farmers, industry, consumers) about sustainable biomass.

3. Financial Incentives:

- Subsidies or tax breaks for sustainable biomass production.
- Grants for research and development.

4. Collaboration and Partnerships:

- Foster collaboration among governments, NGOs, industry, and local communities.
- Share knowledge and resources globally.

5. Community Engagement:

- Involve local communities in decision-making.
- Empower them to participate in sustainable biomass projects.

6. Lifecycle Assessment:

- Evaluate the entire lifecycle of biomass, from production to end use.
- Consider emissions, energy efficiency, and social impacts.

7. Integration of non-renewable with renewable feedstocks and energies in refineries & petrochemical complexes**:

- Change phase of non-renewable to renewable industries in downstream and upstream of oil & gas & petrochemical sectors in energy transition period.

Conclusion

Agricultural Biomass can be burned (after carbonization technology) for heat energy or converted into electricity (via boilers) and it’s a crucial resource alongside other renewables in our commitment to reach net zero targets along with managed oil & gas consumptions in different, sectors.

In summary, biomass energy contributes significantly to decarburization efforts and a new approach to combat climate change and global warming, but it requires sustainable practices and global support to ensure its effectiveness.

References

Environmental benefits of biomass – European Biomass Industry Association. https://www.eubia.org/cms/wiki-biomass/employment-potential-in-figures/environmental-benefits/.

Carbonization of Wasted Biomass and Carbon Sequestration. https://link.springer.com/chapter/10.1007/978-981-32-9872-9_3.

Biomass and the environment - U.S. Energy Information Administration (EIA). https://www.eia.gov/energyexplained/biomass/biomass-and-the-environment.php.

Environment Friendly Production of Coconut Shell Charcoal, https://link.springer.com/chapter/10.1007/978-981-19-6688-0_15.

Environment Friendly Production of Coconut Shell Charcoal ... - Springer. https://link.springer.com/content/pdf/10.1007/978-981-19-6688-0_15.pdf.

https://doi.org/10.1007/978-981-19-6688-0_15.

Carbon emissions of different fuels - Forest Research. https://www.forestresearch.gov.uk/tools-and-resources/fthr/biomass-energy-resources/reference-biomass/facts-figures/carbon-emissions-of-different-fuels/.

Fuels - Higher and Lower Calorific Values - The Engineering ToolBox. https://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html.

Petroleum fuels: petrol, diesel, LPG kerosene and their additives. https://www.econology.info/fuels-petroleum/.

Calorific Value of Fuel – Energy and environment. https://ebooks.inflibnet.ac.in/esp07/chapter/calorific-value-of-fuel/.

Biomasses - Energy Content when Used as Fuel - The Engineering ToolBox. https://www.engineeringtoolbox.com/biofuel-energy-content-d_1356.html.

Fossil vs. Alternative Fuels - Energy Content - The Engineering ToolBox. https://www.engineeringtoolbox.com/fossil-fuels-energy-content-d_1298.html.

Benchmarking biofuels—a comparison of technical, economic; https://energsustainsoc.biomedcentral.com/articles/10.1186/s13705-014-0020-x.

Relationships between biomass composition and liquid products https://www.frontiersin.org/articles/10.3389/fenrg.2015.00045/full.

Biomass characteristics – European Biomass Industry Association. https://www.eubia.org/cms/wiki-biomass/biomass-characteristics-2/.

https://doi.org/10.3389/fenrg.2015.00045.

Fossil vs. Alternative Fuels - Energy Content - The Engineering ToolBox. https://www.engineeringtoolbox.com/fossil-fuels-energy-content-d_1298.html.

Biomass Conversion to Energy | SpringerLink. https://link.springer.com/chapter/10.1007/978-3-642-28418-2_1.

Relationships between biomass composition and liquid products https://www.frontiersin.org/articles/10.3389/fenrg.2015.00045/full.

Frontiers | Estimation and Comparison of Bio-Oil Components; https://www.frontiersin.org/articles/10.3389/fenrg.2015.00028/full.

Liquefaction of Biomass for Bio-oil Products | SpringerLink. https://link.springer.com/chapter/10.1007/978-3-319-49595-8_11.

https://doi.org/10.3389/fenrg.2015.00045.

https://doi.org/10.3389/fenrg.2015.00028.

Environmental Biomass Wood Hazelnut Olive Coconut Charcoal Pyrolysis. https://xuyemachinery.en.made-in-china.com/product/nELpkgMvmTYA/China-Environmental-Biomass-Wood-Hazelnut-Olive-Coconut-Charcoal-Pyrolysis-Carbonization-Furnace.html.

Intermediate pyrolysis of hazelnut shell,https://sciety.org/articles/activity/10.21203/rs.3.rs-4292816/v1.

Relationships between Carbonization Temperature and Pyrolysis Products. https://www.jstor.org/stable/43754649.

Intermediate pyrolysis of hazelnut shell, https://www.researchsquare.com/article/rs-4292816/v1.

Carbonization Furnace - The Complete Guide for Your Business. https://charcoalplant.com/info/carbonization-furnace-the-complete-guide-for-your-business/.

En.wikipedia.org. https://en.wikipedia.org/wiki/Pyrolysis.

Emerging potential of spent coffee ground valorization for fuel pellet. https://link.springer.com/article/10.1007/s10668-022-02361-z.

Solid Fuel Characteristics of Pellets Comprising Spent Coffee Grounds (SCG). https://mdpi-res.com/d_attachment/energies/energies-14-00371/article_deploy/energies-14-00371-v2.pdf.

A Review of Recent Advances in Spent Coffee Grounds, https://www.frontiersin.org/articles/10.3389/fceng.2022.838605/full.

Bioenergy with Carbon Capture and Storage - Energy System - IEA. https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage/bioenergy-with-carbon-capture-and-storage.

What Is Carbon Capture And Storage (CCS)? | IBM. https://www.ibm.com/think/topics/carbon-capture-storage.

Carbon Capture | MIT Climate Portal. https://climate.mit.edu/explainers/carbon-capture.

The Role of Carbon Capture and Utilization, Carbon Capture and Storage .... https://pubs.acs.org/doi/epdf/10.1021/acs.iecr.9b06579.

A Critical Survey of Bioenergy with Carbon Capture and Storage (BECCS .... https://link.springer.com/chapter/10.1007/978-3-030-90720-4_10.

En.wikipedia.org. https://en.wikipedia.org/wiki/Bioenergy_with_carbon_capture_and_storage.

Net Zero by 2050 – Analysis - IEA - International Energy Agency. https://www.iea.org/reports/net-zero-by-2050.

Energy transformations for net-zero emissions. https://www.iea.org/reports/energy-technology-perspectives-2020/energy-transformations-for-net-zero-emissions.

This is how we can achieve net zero by 2050, according to the UN. https://climatechampions.unfccc.int/this-is-how-we-can-achieve-net-zero-by-2050-according-to-the-un/.

The net-zero transition: Its cost and benefits https://www.mckinsey.com/capabilities/sustainability/our-insights/the-net-zero-transition-what-it-would-cost-what-it-could-bring.

Biomass Carbonization | Intech Open. https://www.intechopen.com/chapters/70472.

Chapter 2. Wood carbonization and the products it yields. https://www.fao.org/4/x5555e/x5555e03.htm.

Hydrothermal carbonization of biomass and waste: A review - Springer. https://link.springer.com/content/pdf/10.1007/s10311-021-01311-x.pdf.

A comprehensive review of the pyrolysis processhttps://academic.oup.com/ooms/article/1/1/itab014/6446520.

Hydrothermal Carbonization of Waste Biomasshttps://www.mdpi.com/

Hydrothermal Carbonization of Spent Coffee Grounds - MDPI. https://www.mdpi.com/

Hydrothermal Carbonization of Spent Coffee Grounds for Producing ... - MDPI. https://www.mdpi.com/2071-1050/14/14/8818.

Activated Carbon Production from Coffee Waste via Slow Pyrolysis https://bing.com/search?q=temperature+of+carbonisation+of+spent+coffee+grounds+in+pyrolysis+furnace+for+shisha+charcoal.

Response surface methodology applied to spent coffee residue (SCG), https://link.springer.com/article/10.1007/s13399-021-01536-4.

6 start-ups, ideas and power plants shaping biomass. https://www.drax.com/sustainable-bioenergy/6-start-ups-ideas-power-plants-shaping-biomass/.

Ten of the world's largest renewable energy projects. https://www.power-and-beyond.com/ten-of-the-worlds-largest-renewable-energy-projects-a-1bbd49e672adb3070f0b14207f506003/.

Examples of Sustainability Initiatives in Biomass Power Generation. https://www.renovainc.com/en/sustainability/biomass/.

Biomass Feedstocks Innovation Programme: successful projects. https://www.gov.uk/government/publications/biomass-feedstocks-innovation-programme-successful-projects.

Authors

Hamid Reza Seyed Jafari, PhD candidate in technology transfer management(IAU), is a senior technical advisor of deputy planning of petroleum ministry in Iran in downstream oil & gas & petrochemical with more than 35 years' experience with B.Eng. Degree in Chemical Engineer from Petroleum University (PUT), M.Eng. Degree in Industrial Engineer (IUST) , Doctorate Business Administration diploma (UT), Economic & Management in Downstream Oil& Gas diploma from French Institute of Petroleum (IFP energies School) in France . He has expert in switching non – renewable to renewable and biofuel energies in refineries and petrochemical sectors and decarburization & sustainable activities in energy transition and net zero carbon emission in different sectors (industry, transportation, building, power plant, biofuels…) to mitigate climate crisis and global warming.

Babak Danesh, is general director in SDT Energy Company in Turkey and expert in decarburization development technology especially in renewable energy of wind. He is also active and involved in ISTU University in Turkey and his academic fields are in electrical & renewable wind energy.

Ms. Esra Kayhan, is CEO in SDT Energy Company in Turkey and expert in decarburization development technology especially in green hydrogen and algae fuel. He is also active and involved in ISTU University in Turkey and her academic field is chemical engineering.

Seyed Mohammad Reza Seyed Jafari is a B.Eng. Chemical Engineer and MBA with more 7 years' experience in HSE of oil & gas sectors & and DBA diploma of IT.

The View from Rock Bottom: Today's Oil and Gas Companies….Part of the Problem, or Crucial to the Solution?

Ron Cormier

The oil and gas industry is facing increasing demands to clarify the implications of energy transitions for their operations and business models. Overall, the oil and gas industry is at a pivotal point, with significant challenges and opportunities as it navigates the global energy transition.

The last few years have been filled with often-spirited debate about the global energy transition and the move away from fossil fuels to fully embrace renewables and alternatives. This is to keep the lights on, fuel vehicles, and power the world's economy, all with minimal emissions. But there are a growing number of signs that a rapid shift from petroleum is not realistic, which has implications in many areas, including which refinery expansion projects move forward (and their location), when oil demand might peak, and which of the many forecasts for gasoline and distillate production will prove to be the most accurate.

There are glimmers of changing expectations and realizations that energy use cannot realistically transition rapidly. That involves acknowledgement that gasoline, diesel, jet fuel, LPG, ethane and other hydrocarbons play critically important evolving roles in improving the lives of billions of people in the non-OECD world, and that shifting to non-hydrocarbon alternatives will take many years. Plus, there is a risk of stranded low-complexity assets in the oil and gas sector, where reserves or infrastructure may become obsolete or devalued due to shifts towards low-carbon energy sources.

Humankind needs to rethink the pace of refining capacity additions and product demand over the next few years. The oil and gas industry is facing increasing demands to clarify the implications of energy transitions for their operations and business models, and to explain the contributions that they can make toward reducing greenhouse gas (GHG) emissions, i.e., achieving the goals of the Paris Agreement.

Increasing social, commercial, and environmental pressures on many oil and gas companies raise complex questions about the role of these fuels in a changing energy economy, and the position of these companies in the regions in which they operate. The economics of oil and gas are changing due to fluctuations in global prices, advancements in renewable energy technologies, and increasing societal and investor pressures for sustainable practices. Companies are increasingly considering the long-term financial risks associated with fossil fuel investments.

But the core question, against a backdrop of rising GHG (greenhouse gas) emissions, is a relatively simple one: should today's oil and gas companies be viewed only as part of the problem, or could they also be crucial in solving it?

Geography Matters…

Energy transition will proceed faster in developed countries, as petroleum demand is well past its peak in Europe and Japan, and is peaking in the U.S. That said, petroleum demand is expected to remain "sticky" even in those regions amid obstacles to the wider adoption of alternatives, including consumer acceptance. The pace of the energy transition will vary by region and depend on multiple factors, including policy, technology development, and market dynamics.

Replacing petroleum with alternatives will be particularly difficult in emerging economies — India, Southeast Asia, the Middle East and Africa — because petroleum demand needs to continue growing to sustain the economic growth that supports upward mobility and increasing populations. For example, per-capita petroleum demand in India in 2023 was just 6% that of the U.S., while African per-capita demand was at just 5% of U.S. levels.

India is expected to lead the way in global demand growth with a jump of 6.6 MMb/d of liquid fuels demand between 2023-45, followed by Africa with a 3.7 MMb/d increase. Demand in other parts of Asia — excluding China and Japan — is expected to grow by 3 MMb/d, while the Middle East sees a demand growth increase of 2.6 MMb/d over the same period.

China's population has peaked and economic growth is easing, giving it the ability to slow petroleum demand growth. China's growth is expected to slow with demand peaking in 2040, but total liquids demand still rises by 1.5 MMb/d from 2023-45.

All Players Included….

"No energy company will be unaffected by clean energy transitions. Every part of the industry needs to consider how to respond. Doing nothing is simply not an option", says Dr. Fatih Birol, IEA Executive Director.

These three considerations are useful to provide the boundaries for these predictions.…

First, the prospect of rising demand for the services that energy provides due to a growing global population – some of whom remain without access to modern energy (many still cook with dung as their heat source) – and an expanding global economy.

Second, the recognition that oil and natural gas play critical roles in today's energy and economic systems, and that affordable, reliable supplies of liquids, solids and gases (of different types) are necessary parts of a vision of the future.

And last but far from least, the imperative to reduce energy-related emissions in line with international climate targets.

These elements may appear to be in contradiction with one another, but this is not necessarily the case. The WEO Sustainable Development Scenario (SDS) charts a path fully consistent with the Paris Agreement by holding the rise in global temperatures to "well below 2°C … and pursuing efforts to limit it to 1.5°C", and meets objectives related to universal energy access and cleaner air. The SDS and the range of technologies that are required to achieve it provide a benchmark for the discussion throughout this report.

The other scenario referenced in the analysis is the Stated Policies Scenario (STEPS), which provides an indication of where today's policy ambitions and plans would lead the energy sector. These outcomes fall far short of the world's shared sustainability goals. There must be balance between short-term returns with long-term license to operate.

The oil and gas industry faces the strategic challenge of balancing short-term returns with its long-term operations. Societies are simultaneously demanding energy services and reductions in emissions. Oil and gas companies have been proficient at delivering the fuels that form the bedrock of today's energy system; the question that they now face is whether they can help deliver climate solutions.

Per the IEA, this could be possible if the oil and gas industry takes the necessary steps. As such, it opens a way – which some companies are already following – for the oil and gas industry to engage with the "mass coalition", considered essential to tackle climate change. This effort would be greatly enhanced if more oil and gas companies were firmly and fully onboard. The costs of developing low-carbon technologies represent an investment in companies' ability to prosper over the long term.

Every part of the industry needs to consider how to respond to clean energy transitions. No oil and gas firm will be unaffected, so every part of the industry needs to consider how to respond. The industry landscape is diverse and there is no single strategic response that will make sense for all. Attention often focuses on the Majors—seven large integrated oil and gas companies that have an outsized influence on industry practices and direction.

But the industry is much larger: the Majors account for 12% of oil and gas reserves, 15% of production and 10% of estimated emissions from industry operations. National oil companies (NOCs) – fully or majority-owned by national governments – account for well over half of global production and an even larger share of reserves. There are some high-performing NOCs, but many are poorly positioned to adapt to changes in global energy dynamics.

So far, investment by oil and gas companies outside their core business areas has been less than 1% of total capital expenditure. For the moment, there are few signs of a major change in company investment spending. For those companies looking to diversify their energy operations, redeploying capital towards low-carbon businesses requires attractive investment opportunities in the new energy markets as well as new capabilities within the companies.

Now, leading individual companies spend around 5% on average on projects outside core oil and gas supply, with the largest outlays in solar, nuclear, and wind. Some oil and gas companies have also moved into new areas by acquiring existing non□core businesses, for example in electricity distribution, electric vehicle charging and batteries, and tidal energy capture, while stepping up research and development activity.

A much more significant change in overall capital allocation will be required to accelerate energy transitions.

The Wait and See Game

Many solutions could help reduce the environmental footprint of the oil and gas industry. There is a lot that the industry could do today to reduce the environmental footprint of its own operations. Uncertainty about the future is a key challenge facing the industry, but this is no reason for companies to “wait and see” as they consider their strategic choices. Minimizing emissions from core oil and gas operations should be a first-order priority for all, whatever the transition pathway.

There are ample, cost-effective opportunities to bring down the emissions intensity of delivered oil and gas by minimizing flaring of associated gas and venting of CO_2, tackling methane emissions, and integrating renewables and low-carbon electricity into new upstream and liquefied natural gas (LNG) developments. As of today, 15% of global energy-related GHG emissions come from the process of getting oil and gas out of the ground and to consumers. Reducing methane leaks to the atmosphere is the single most important and cost-effective way for the industry to bring down these emissions.

Electricity Cannot Be the Only Vector for the Energy Sector’s Transformation

The hundreds of thousands who lost power for up to a week or more after Hurricane Beryl’s assault on Texas this month could be thinking twice about that EV purchase. While working gas stations initially saw long lines after the storm passed, motorists could still get there — avoiding downed power lines and trees, of course.

Electricity cannot be the only vector for the energy sector’s transformation. A commitment by oil and gas companies to provide clean fuels to the world’s consumers is critical to the prospects for reducing emissions. The 20% share of electricity in global final consumption is growing, but electricity cannot carry energy transitions on its own against a backdrop of rising demand for energy services.

Bringing down emissions from core oil and gas operations is a key step in helping countries to get environmental gains from using less emissions-intensive fuels. However, it is also vital for companies to step up investment in low-carbon hydrogen, bio methane and advanced biofuels, as these can deliver the energy system benefits of hydrocarbons without net carbon emissions. Within ten years, these low-carbon fuels would need to account for around 15% of overall investment in fuel supply. California has made great strides developing feasible hydrogen generation, distribution, and safe automotive platform consumption developments with industry’s help; Air Products and Chemicals, Inc. has played a large co-development role with California over the last 15 years.

The Oil and Gas Industry Will Be Critical for Key Capital-intensive Clean Energy Technologies to Reach Maturity

The resources and skills of the industry can play a central role in helping to tackle emissions from some of the hardest-to-abate sectors. This includes the development of carbon capture utilization and storage (CCUS), low-carbon hydrogen, biofuels, and offshore wind. Scaling up these technologies and bringing down their costs will rely on significant capex, large-scale engineering and project management capabilities; qualities that are a good match to those of large oil and gas companies.

For CCUS, three-quarters of the CO_2 captured today in large-scale facilities is from oil and gas operations, and the industry accounts for more than one-third of overall spending on CCUS projects. If the industry can partner with governments and other stakeholders to create viable business models for large-scale investment, this could provide a major boost to deployment. Occidental Petroleum (with large investor backing from Warren Buffet's Berkshire Hathaway), is playing a key development role. Economic merit is gaining momentum accordingly.

A Fast-Moving Energy Sector Would Change the Game for Upstream Investment

Investment in upstream projects is still needed even in rapid transitions, but the type of resources that are developed, and how they are produced, changes substantially.

Production from existing fields declines at a rate of roughly 8% per year in the absence of any investment, larger than the nominal fall in global demand. Consequently, investment in existing and some new fields remains part of the picture. But as overall investment falls back and markets become increasingly competitive, only those with low-cost resources and tight control of costs and environmental performance would be able to benefit.

A Shift from "Oil and Gas" to "Energy"

A shift from "oil and gas" to "energy" takes companies out of their comfort zone but provides a way to manage transition risks. Some large oil and gas companies are set to make a switch to "energy" companies that supply a diverse range of fuels, electricity and other energy services to consumers. This means moving into sectors, notably electricity, where there is already a large range of specialized actors and where the financial characteristics and scale of most low-carbon investment opportunities are (with the partial exception of offshore wind) a long way from traditional oil and gas projects.

Electricity provides long-term opportunities for growth, given that it overtakes oil in accelerated energy transitions as the main element in consumer spending on energy. It also opens the door to larger and more broad reductions in company emissions, relieving social pressures along the way, although investors will watch carefully the industry's ability to balance diversification with expected returns and dividends.

NOCs Face Some Particular Challenges, As Do Their Host Governments

The stakes are high for NOCs that are charged with the stewardship of national hydrocarbon resources, and for their host governments and societies that often rely heavily on the associated oil income. Changing energy dynamics have prompted several countries to renew their commitment to reform and to diversify their economies; fundamental changes to the development model in many major resource holders look unavoidable.

NOCs can provide important elements of stability for economies during this process, if they are operating effectively and alert to the risks and opportunities. Some leading NOCs are stepping up research efforts targeting models of resource development that are compatible with deep decarbonization, e.g. via CCUS, trade in hydrogen or a focus on non-combustion uses of hydrocarbons.

Not Only are Energy Transition Dynamics Limiting Investments in Refining, They Also Are Shaping the Types of Projects Which Progress and Their Location.

Investment continues to focus on distillate and petrochemical production, while shutdowns of existing refining capacity lean toward gasoline production. This dynamic is especially prevalent in Asia Pacific and Middle East projects, many of which are integrated with petrochemical facilities, although more than 70% of capacity increases in the next five years are expected to occur in India and Africa. In the U.S., while large-capacity expansion projects are very unlikely, there should continue to be smaller "capacity creep" projects along the U.S. Gulf Coast. Net distillate and "other" capacity — much of it petrochemical — will increase by more than 2.3 MM b/d through 2028, vs. about 1.1 MM b/d for gasoline (while resids capacity continues to decrease; a question then for the world's highway surface raw materials???).

Gasoline demand will continue to be impacted much more than middle distillates or petchem feedstocks, as alternatives (especially electric vehicles (EVs) become more readily available. Global motor gasoline demand peaks before 2035 and is less than 100M b/d above 2023 levels by 2045.

By contrast, global middle distillate demand does not peak before 2045 and rises by 7.7 MM b/d between 2023-45. Of that, 4.6 MM b/d (60%) will come from jet fuel, which is particularly difficult to replace and the only fuel for which demand is still growing in the developed world.

NGL demand for petrochemicals — ethane, propane and butane — will also grow on the back of robust supply and a lack of ready alternatives, increasing by 4.3 MM b/d over the same span. As domestic fuel demand declines, the U.S. refining industry will face challenges finding new homes for its production. The ability to meet these challenges will differ regionally, with US Gulf Coast refiners advantaged by their ability to tap attractive export markets.

However, US Gulf Coast refiners will have to grow exports of gasoline, diesel and jet fuel by more than 1.6 MM b/d (70% of that gasoline) starting from 2023-45 to achieve the 480 Mb/d of forecasted “capacity creep”, which will be concentrated at the most competitive, highly complex refineries. There will also be significant incentives for hydro-cracker projects at certain refineries to shift yields in favor of distillates over gasoline, while gasoline-centric refineries — particularly along the US West and East coasts and Mid-continent — are most likely to see plant closures. Without the oil and gas industry, the transformation of the energy sector will be more difficult and more expensive

The Transformation of the Energy Sector Can Happen Without the Oil and Gas Industry, but Illogical

Without such influence, results would be more difficult and more expensive, and likely make for a longer achievement timeline. Oil and gas companies need to clarify the implications of energy transitions for their operations and business models, and to explain the contributions that they can make to accelerate the pace of overall change. This process has started and company commitments to reduce emissions or emissions intensities are becoming increasingly common.

However, the industry can do much more to respond to the threat of climate change. Regardless of which pathway the world follows, climate impacts will become more visible and severe over the coming years, increasing the pressure on all to find solutions. These solutions cannot be found within today’s oil and gas framework.

Refining capacity additions have increased a bit from earlier this year but are still expected to trail global demand growth over the next five years. On a net basis — taking expected shutdowns into account — global refining capacity increases by 3 MM b/d, or an average of 600 M b/d annually from 2024-28, and up from the 2.4 MM b/d noted earlier in 2024.

The recognition that a move away from fossil fuels (and petroleum specifically) will not happen swiftly has led to some renewed interest in adding refining capacity. However, interest in making large, long-lead-time investments in traditional refining projects (particularly those focused on transportation fuels) remains challenged; this dynamic will continue for the long term.

That seems a good spot to ponder the foundation and color for such coming energy sector views. Until the September edition of Engineering Practice Magazine, we on the publishing staff with our readership in the Northern Hemisphere wish you all an enjoyable summer. We appreciate your continued interest, readership, and support.

References

“Inside Fatih Birol’s Push to Transform the IEA into a Clean Energy Authority”, Time Magazine, February, 2024, Justin World, Paris

“Carbon Capture, Utilization, and Storage”, IEA50 Magazine, Energy Systems, January, 2020

“Slow Your Roll - How A Slower Energy Transition Might Impact Oil Producers, Refiners, and Consumers”, RBN Energy, LLC, John Auers, July, 2024

“Yale Carbon Capture Takes Next Steps in Leadership and Research”, Yale News, Jim Shelton, July, 2024

“California Sustainable Aviation Fuel Facility Report”, Air Products, and Chemicals, Inc., APCI Website, Serif Ghasemi, Chairman, President, July, 2024.

“The Top Warren Buffett Stock Is Helping Microsoft Solve a Big Problem” (Occidental and MS), The Motley Fool, Matt DiLallo, July, 2024.

IACPE
INTERNATIONAL ASSOCIATION OF
CERTIFIED PRACTICING ENGINEERS

IACPE.COM