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(54) Title: METHOD AND SYSTEM FOR PRODUCING FUEL FROM A HEAVY HYDROCARBON FEEDSTOCK

(57) Abstract

A method of providing fuel suitable for the generation of electrical power, which comprises: (i) subjecting a heavy hydrocarbon feedstock to delayed coking to yield coke and liquid hydrocarbon output; (ii) gasifying coke, produced in step (i), to yield synthesis gas; (iii) removing hydrogen sulfide from synthesis gas produced in step (ii); (iv) recovering hydrogen from synthesis gas subjected to the hydrogen-sulfide-removal of step (iii); (v) hydrotreating liquid hydrocarbon output produced in step (i), a substantial amount of the hydrogen used in said hydrotreatment being hydrogen recovered in step (iv); and (vi) transporting liquid hydrocarbon output subjected to step (v), and synthesis gas subjected to step (iii) and/or both steps (iii) and (iv), for use as fuel in a combustion turbine adapted for the generation of electrical power; and further a method of generating electrical power, and systems for producing said fuel and generating electrical power.

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# METHOD AND SYSTEM FOR PRODUCING FUEL FROM A HEAVY HYDROCARBON FEEDSTOCK

## FIELD OF THE INVENTION

This invention relates to fuels for the generation of electric power in an economically and environmentally attractive way and the utilization of heavy refinery residue or other heavy hydrocarbon feedstocks for such purpose.

## BACKGROUND OF THE INVENTION

The refining of crude oil involves numerous complex processes which result in valuable products such as gasoline, diesel oil and different grades of fuel oil. In a typical initial step, the crude oil is distilled into fractions of different densities and boiling ranges, such as fuel gas, LPG, naphtha, gas oil and fuel oil. These fractions are further treated, blended and otherwise processed to produce the desired qualities and quantities of end products. The most desirable range of products generally comprises those used for transportation fuels, for example, naphtha and gas oils.

The heaviest fraction produced by the distillation process is known as vacuum residue, which results from a distillation stage performed under vacuum. Vacuum residue contains the largest hydrocarbon molecules found in the crude oil and also contains most of the undesirable impurities. As such, it can present a disposal problem. One way of dealing with this has been to upgrade vacuum residue - that is, convert it to lighter hydrocarbon fractions via coking or hydroprocessing. Another is to blend vacuum residue with lighter fractions to produce heavy fuel oil for use in industrial furnaces, including those for the generation of electric power. It is a significant drawback that such method of power generation typically requires extensive flue gas clean-up to remove sulfur compounds.

Preliminarily, we note that in a typical coking process the heavy fuel is cracked at elevated temperature utilizing a semicontinuous format to yield lighter hydrocarbon products and coke. Such coking processes are referred to as delayed coking; this technology is widely known and practiced. Examples of delayed coking may be found in U.S. Patent Nos. 4,797,197 and 4,394,250. But, the products of delayed coking of heavy hydro-carbon materials - i.e., gaseous, liquid and coke products - are not considered well-suited for efficient use as fuel in electric power generation without further treatment. The gaseous product would need to be freed of environmentally objectionable hydrogen sulfide, and the liquid products are unsaturated and unsuited for prolonged storage, and contain compounds of sulfur and nitrogen. While these problems can be remedied by treatment with hydrogen in the presence of a catalyst, a process commonly known as hydrotreating, this does not overcome problems attendant to producing a cost-effective fuel via delayed coking. This is because the last component of delayed coking's output, coke - which also needs to be utilized for maximum efficiency - contains most of the sulfur from the original feedstock to the coker, and if used as fuel in a power boiler, would require the use of scrubbers or other emission abatement technology. This substantially adds to capital cost.

An alternative type of coking, instead of utilizing a semicontinuous format, involves the use of a fluidized bed to effect fluid coking, yielding an output which may include liquid products and coke, and then a gasification step to treat the coke. This process is continuous, and is known as "Flexicoking". It is described in U.S. Patent No. 4,297,202 and in *Hydrocarbon Processing* (Sept. 1982), pp. 1631. The purpose and use of Flexicoking is to upgrade heavy refinery liquids. The gasification part of Flexicoking is carried out at low pressures, using steam and air as the oxidant, and produces a dilute fuel gas with a low Btu value (approximately 100 BTU/SCF). This gas is typically used in combination with richer gas streams as fuel in refinery furnaces.

Flexicoking does not generate hydrogen sufficient to hydrotreat the co-produced liquid, so that hydrotreatment requires an external source of hydrogen. Furthermore, the gasification output of Flexicoking is unsuited for power generation in a combustion turbine since it is of pressure too low to be used without prior compression; instead, it has been suggested that the gas from the Flexicoking process could be used to generate steam, which then could be used to generate power in a steam turbine. Also, the gas's composition is not well-suited for direct combustion in conventional combustion turbines typically utilized for power generation. Moreover, the Flexicoking process entails increased capital costs. These disadvantages are a disincentive to the application of Flexicoking in the field of the present invention.

On the other hand, technology for using heavy hydrocarbon fuels in the "as is" condition also has shortcomings. In recent years the high sulfur, nitrogen and metals content of vacuum residue and similar "bottom of the barrel" heavy refinery liquids have made these materials unacceptable as power plant fuel, unless the power plant is equipped with expensive scrubber equipment. The use of such scrubber equipment, however, has significant disadvantages in that it substantially adds to the capital cost of the power generation process as previously indicated, and further that it reduces the efficiency of the power production cycle.

One environmentally clean technique for using such heavy fuels is known as the Integrated Gasification Combined Cycle (IGCC), which converts the heavy fuels to clean fuel gas that can be used in a combustion turbine/steam turbine combined cycle. IGCC technology is marketed by a number of oil companies and engineering firms. In IGCC the heavy fuel is gasified in a reactor with air or oxygen to produce raw synthesis gas. Synthesis gas consists primarily of hydrogen, carbon monoxide, hydrogen sulfide, and may also contain carbonyl sulfide and other impurities. If air is used instead of oxygen in the gasification reaction, the synthesis gas will also contain nitrogen. This gas is then combusted in a gas turbine to drive a power generator. Waste heat can be recovered in the form of steam, which is then used for further power generation.

While an IGCC plant can have a high thermal efficiency, it requires a very high initial capital investment for the process equipment. A typical installed plant would cost in the range of $1,000 to $2,000 per installed kilowatt of capacity. As a result, commercial IGCC plants often rely on some form of subsidy to offset the high initial capital cost.

The aforementioned problems have apparently discouraged direct use of vacuum residue as power plant fuel. For instance, many power plants that previously used dirty residue as fuel have switched to natural gas because it is cleaner and does not require the large investment of an IGCC plant. This has created a corresponding problem for refineries in disposing of vacuum residue.

Accordingly, the art is in need of environmentally clean, low-capital-cost technology for the production of electrical power from vacuum residue or other heavy "bottom of the barrel" feedstocks, and the furnishing of same would constitute a substantial advance.

## OBJECTS OF THE INVENTION

It is an object of the invention to provide a method and system for utilizing heavy hydrocarbon feedstocks such as vacuum residue.

It is another object of the invention to provide a method and system permitting the conversion of heavy hydrocarbon feedstocks into economically feasible and environmentally acceptable fuels for electrical power generation.

It is a further object of the invention to provide a method and system which makes practical use of heavy hydrocarbon feedstocks to produce fuels acceptable for use in a combustion turbine.

It is still another object of the invention to provide a method and system which lower the capital investment required to process heavy hydrocarbon feedstocks into acceptable fuels for generating electrical power.

It is yet another object of the invention to provide a method and system for producing such fuels with acceptably high thermal efficiency and acceptably low levels of harmful byproducts.

## SUMMARY OF THE INVENTION

The instant invention affords methods and systems for providing fuel derived from vacuum residue or other heavy feedstock materials, adapted for the generation of power using one or more combustion turbines. The term "heavy hydrocarbon feedstock" as used herein shall include atmospheric or vacuum residue, vistar, visbreaker bottoms, deasphalter bottoms and other heavy residual liquids or combinations thereof.

Thus, one aspect of the present invention is a method of providing fuel suitable for the generation of electrical power, which comprises (i) subjecting a heavy hydrocarbon feedstock to delayed coking to yield coke and liquid hydrocarbon output, (ii) gasifying coke, produced in step (i), to yield synthesis gas, (iii) removing hydrogen sulfide from synthesis gas produced in step (ii), (iv) recovering hydrogen from synthesis gas subjected to the hydrogen-sulfide-removal of step (iii), (v) hydrotreating liquid hydrocarbon output produced in step (i), a substantial amount of the hydrogen used in said hydrotreatment being hydrogen recovered in step (iv), and (vi) transporting liquid hydrocarbon output subjected to step (v), and synthesis gas subjected to step (iii) and/or both steps (iii) and (iv), for use as fuel in a combustion turbine adapted for the generation of electrical power.

Another aspect of the present invention is a system for providing fuel suitable for the generation of electrical power, which comprises (i) a coker for treating a heavy hydrocarbon feedstock to yield coke and liquid hydrocarbon output, (ii) a gasifier for treating coke, produced in said coker, to yield synthesis gas, (iii) a unit for removing hydrogen sulfide from synthesis gas produced in said gasifier, (iv) a unit for recovering hydrogen from synthesis gas subjected to the hydrogen-sulfide-removal in unit (iii), (v) a unit for hydrotreating liquid hydrocarbon output produced in said coker, said system being configured such that a substantial amount of hydrogen used in the hydrotreatment unit is hydrogen recovered in unit (iv), and (vi) conduit for transporting liquid hydrocarbon output subjected to hydrotreatment in unit (v), as well as conduit for transporting synthesis gas subjected to hydrogen-sulfide-removal in unit (iii) and/or conduit for transporting synthesis gas subjected to hydrogen recovery in unit (iv), for use as fuel in a combustion turbine adapted for the generation of electrical power.

Yet another aspect of the present invention is a method of electrical power generation, which comprises (i) subjecting a heavy hydrocarbon feedstock to coking to yield coke and liquid hydrocarbon output, (ii) gasifying coke, produced in step (i), to yield synthesis gas, (iii) removing hydrogen sulfide from synthesis gas produced in step (ii), (iv) recovering hydrogen from synthesis gas subjected to the hydrogen-sulfide-removal of step (iii), (v) hydrotreating liquid hydrocarbon output produced in step (i), a substantial amount of the hydrogen utilized in said hydrotreatment being hydrogen recovered in step (iv), and (vi) combusting liquid hydrocarbon output subjected to step (v), and synthesis gas subjected to step (iii) and/or both steps (iii) and (iv), in a combustion turbine to generate electrical power.

Still another aspect of the present invention is a plant for generating electric power which comprises (i) a coker for treating a heavy hydrocarbon feedstock to yield coke and liquid hydrocarbon output, (ii) a gasifier for treating coke, produced in said coker, to yield synthesis gas, (iii) a unit to remove hydrogen sulfide from synthesis gas produced in said gasifier, (iv) a unit for recovering hydrogen from synthesis gas subjected to hydrogen-sulfide-removal in unit (iii), (v) a unit for hydrotreating liquid hydrocarbon output produced in said coker, said plant being configured such that a substantial amount of hydrogen utilized in the hydrotreatment unit is hydrogen recovered in unit (iv), (vi) conduit for transporting liquid hydrocarbon output subjected to hydrotreatment in unit (v), as well as conduit for transporting synthesis gas subjected to hydrogen sulfide-removal in unit (iii) and/or conduit for transporting synthesis gas subjected to hydrogen-recovery in unit (iv), to a combustion turbine adapted for the generation of electrical power, and (vii) one or more of said combustion turbine.

The present invention has significant advantages over the prior art, including the IGCC process. It provides for a lower capital cost - for instance, because it involves subjecting only coke, rather than the entire amount of heavy hydrocarbon feedstock, to the expensive gasification step - while providing liquid and gaseous products that may be used in combustion turbines for the generation of electricity. Also, the byproducts from the process create fewer environmental and disposal difficulties than much of the known technology for treating and using heavy hydrocarbon feedstock. Further, because a significant portion of the fuel produced in accordance with the invention is in the liquid state, the invention affords the option of storing liquid fuel material until such time as it is needed to generate a larger amount of power to meet temporarily increased demand, i.e., to enable power generation in a load-following mode. As a result of the foregoing, the invention provides for an economically viable way of using heavy hydrocarbon feedstock to generate electricity.

## DESCRIPTION OF THE DRAWINGS

Figure 1 is a simplified schematic flow diagram of a method and system for fuel production in accordance with the invention.

Figure 2 is a more detailed schematic flow diagram of a method and system (power plant) for generating electrical power in accordance with the invention.

## DESCRIPTION OF CERTAIN PREFERRED EMBODIMENTS OF THE INVENTION

The invention is in a unique combination of process steps or system components (as the case may be). In and of themselves, steps such as coking, gasifying, removing hydrogen sulfide, recovering hydrogen, and hydrotreating liquid hydrocarbon materials, and components for effecting same, may have been utilized heretofore. However, the combination of such steps or components for the stated purposes in accordance with the invention is believed to have been novel and unobvious, and leads to a highly advantageous and desirable result.

It is an important feature of the invention that the various method steps and system (plant) components function cooperatively to yield the desired improvement in cost effectiveness of fueling a power generation facility, and thereby facilitating the provision of economical electrical power. Thus, the invention makes use of considerably less desirable heavy hydrocarbon feedstocks. These are processed in a manner which enables one to access more of the fuel potential of such feedstocks, more efficiently than might otherwise be the case. For instance, the sequence of coking and subsequent gasification produces a gaseous hydrocarbon fuel source, a liquid hydrocarbon fuel source and a synthesis gas fuel source. Because the heavy hydrocarbon feedstock is subjected to coking prior to the gasification step, only the coke itself need actually be gasified, rather than the entire heavy feedstock stream. This is a significant factor in reducing the capital cost of the method compared to the conventional IGCC method. Furthermore, hydrogen recovered from synthesis gas output is judiciously used to hydrotreat liquid hydrocarbon output produced through coking, to improve its fueling capability. This integrated approach is central to achievement of the invention's objectives.

Numerous suitable forms of coking, including the preferred type called delayed coking, and equipment for carrying them out, are known in the art in and of themselves, and any such technology which is suitable considering the specific application can be used. Coking is typically carried out under conditions which one of ordinary skill in the art will be able to determine empirically, and without the need for further invention. Preferably, the coking temperature is from 600 to 1000°F, and the coking pressure is from 15 to 100 psig.

Also, preferably, coking will be carried out so that the large hydrocarbon molecules in the heavy hydrocarbon feedstock are (i) cracked to yield lighter liquid hydrocarbon output and gaseous hydrocarbon output in addition to coke, and (2) the coke, liquid hydrocarbon output and gaseous hydrocarbon outputs are separated. The liquid and gaseous hydrocarbon outputs are advantageously further separated into streams according to the size of the molecules. In a particularly preferred embodiment, the delayed coking step is carried out such that the products are separated into streams comprising: (1) fuel gas, (2) a combination of $C_3$-$C_4$ hydrocarbons and naphtha which in turn can be further separated, (3) light coker gas oil, (4) heavy coker gas oil, and (5) coke. As one example of the output that may be achieved from the coking step, coke constitutes 28.6 wt. % of the total output, the light and heavy coker gas oil constitutes 46.2 wt. % of the total output, the $C_3$-$C_4$ hydrocarbon/naphtha mixture constitutes 16.1 wt. % of the total output, and fuel gas constitutes 9.1 wt. % of the total output. This example refers to a specific case, and it will be understood that different feedstocks and different coking process conditions may yield different results.

Suitable processes for the gasification of said coke are also known in the art in and of themselves. These gasification techniques can be adapted to the invention by those of ordinary skill in the art, without the need for further invention, once they have the teachings herein. The invention preferably involves gasification of the coke via partial oxidation to yield synthesis gas. The oxidant used for such gasification is preferably oxygen, although air or other suitable oxygen-containing gases (including gas mixtures) can be used (though possibly with less satisfactory but nonetheless acceptable results in certain embodiments). For purposes of this discussion, the expression "in the presence of oxygen", when used in connection with gasification, shall be understood to include substantially pure oxygen and other gaseous substances or mixtures containing oxygen or a derivative thereof which under gasification conditions act as a source to produce the required oxygen.

Typically, by-products of the gasification are ungasified carbon and metals-rich slag. If the gasification is carried out at optimum conditions, the ungasified carbon product is minimized, with substantially all of the carbon content being converted into synthesis gas. If the process is run at less than optimum conditions, the amount of unconverted carbon increases. Once in possession of the teachings herein, those skilled in the art will know how to adjust the conditions of the gasification such that the overall efficiency and output of the method are optimized in conjunction with practice of the invention. The exact conditions will vary in relation to the nature of the feedstock, the type of equipment, and other operating parameters.

Depending on the feedstocks used, the synthesis gas produced can contain varying amounts of one or more of hydrogen, hydrogen sulfide, carbon monoxide, carbonyl sulfide, and also nitrogen and other impurities. The synthesis gas is optionally subjected to a quenching step, wherein water or other available coolant is used to reduce the temperature of the gas stream, and also if desired to remove some of the impurities in the synthesis gas. Nevertheless, part or all of the synthesis gas can still be treated to remove hydrogen sulfide and optionally other impurities which may be contained therein. This removal treatment is typically accomplished by absorption in a suitable solvent (e.g., a solvent of the ethanol amine type or other suitable "sour gas" removal solvents) although other known methods may be used. In a preferred embodiment, the synthesis gas is purified by washing in an absorption vessel with chilled methanol or any number of other commercially available solvents. If commercially desirable, the hydrogen sulfide can be fed to an appropriate unit to produce commercially usable sulfur.

Some or all of the synthesis gas is processed to recover hydrogen. In a preferred embodiment, the recovery of hydrogen from the synthesis gas is accomplished by separation, shift conversion, or a combination of both, although other known methods can be used. In an especially preferred embodiment, the hydrogen produced contains less than 5% by volume of impurities. The ratio of hydrogen to residual synthesis gas produced can be varied depending upon the needs of the system.

Further in accordance with the invention liquid hydrocarbon output from the coker is hydrotreated, with a substantial amount of the hydrogen used in said hydrotreatment being recovered from synthesis gas as aforesaid. In a preferred embodiment, all or substantially all of the requirements of such hydrotreatment are met with hydrogen recovered from synthesis gas. In embodiments where the liquid hydrocarbon output to be hydrotreated consists of a plurality of streams, the hydrogen is advantageously also separated into a plurality of streams each sufficient to treat the liquid hydrocarbon stream to which it corresponds.

The purpose of hydrotreatment is to stabilize the liquid fuels by, *inter alia*, reducing the unsaturation level of the streams. In a preferred embodiment, the hydrotreatment produces substantially saturated liquid hydrocarbon output. Hydrotreatment technology is, in and of itself, known in the art and those of ordinary skill when in possession of the teachings herein will be capable of determining the hydrotreatment conditions which are suitable. Hydrotreatment is optionally carried out in the presence of a catalyst such as one composed of cobalt and molybdenum oxides or other similar catalyst. Preferably, hydrotreatment is carried out at a temperature of at least 500°F, and a pressure of at least 500 psig.

It will be understood that, once in possession of the teachings herein, those of ordinary skill will be capable of adapting conventional engineering practices such as the use of recycle streams to practice of the invention and to optimize same depending on the application. Thus, when the liquid hydrocarbon output comprises a plurality of streams, the hydrotreatment of each stream will typically produce fractions of differing liquid hydrocarbon products, each of which can then be separated from the others and combined with the appropriate liquid hydrocarbon output stream, according to molecular weight similarity. For instance, where the liquid hydrocarbon output comprises heavy coker gas oil, light coker gas oil, and $C_3$-$C_4$ hydrocarbon/naphtha, hydrotreatment of the heavy coker gas oil will typically produce fractions of light coker gas oil and $C_3$-$C_4$ hydrocarbon/naphtha, as well as fuel gas. Hydrotreatment of the light coker gas oil will typically produce $C_3$-$C_4$ hydrocarbon/naphtha, as well as fuel gas. The light coker gas oil and $C_3$-$C_4$ hydrocarbon/naphtha thus produced can be combined with the light coker gas oil and $C_3$-$C_4$ hydrocarbon/naphtha streams, respectively, preferably after those streams have been hydrotreated. The fuel gas produced from the hydrotreatment can be combined with the gaseous hydrocarbon output from the coking operation. Preferably, the combination of fuel gas and gaseous hydrocarbon output is treated to remove hydrogen sulfide, which in turn can then be combined with the hydrogen sulfide produced from the treatment of the synthesis gas for common processing.

The inventive method further provides for delivering both synthesis gas, and hydrotreated liquid hydrocarbon output, to one or more combustion turbines adapted for the generation of electrical power. Suitable combustion turbines and technology for utilizing same are commercially available and can be adapted by those of ordinary skill for use in implementing the invention once the objectives and principles thereof are appreciated (i.e., without the exercise of further inventive skill). As previously mentioned, in certain embodiments it is advantageous that all or a portion of the hydrotreated liquid hydrocarbon output be stored rather than immediately fed to a combustion turbine. In this manner, the stored material can serve as a contingent fuel supply for use in augmenting power production during times of increased load. Of course, in certain other embodiments hydrotreated liquid hydrocarbon output is fed directly to a combustion turbine. In a preferred embodiment, waste heat from the combustion turbine(s), and optionally any available waste heat from other operations, is used to produce steam for driving a steam turbine to generate additional power.

Various embodiments of the invention are described in greater detail in the following discussion of the drawings.

Figure 1 illustrates the processing of vacuum residue into fuel suitable for consumption in one or more combustion turbines to generate electrical power. It will be appreciated that in the discussion of Figures 1 and 2 each numbered "stream" is transported via appropriate conduit, and that suitable pumps, valves, storage or holding tanks, and the like are utilized as necessary to accomplish processing of material throughout the system shown in the manner described. Reference to and illustration of each aforementioned stream shall be understood to be a reference to and illustration of the conduit in which the stream is transported as well. In view of the schematic nature of the diagrams, pumps, valves, certain tanks and similar components are not shown for the sake of simplicity.

Vacuum residue stream 1 is fed to delayed coker unit 101. After reaction of the vacuum residue coke stream 11, heavy coker gas oil stream 9, light coker gas oil stream 7, coker naphtha (i.e., naphtha containing $C_3$-$C_4$ hydrocarbons) stream 5 and fuel gas stream 3 exit the unit. Coke stream 11 is fed to gasification unit 105. Gasification is conducted in the presence of oxygen provided via stream 12 to produce synthesis gas; slag (ash) is also produced.

Synthesis gas exits as stream 13 and is fed to quencher unit 111; waste water produced in that unit exits as stream 61. Synthesis gas stream 15 is taken off, and then fed to acid gas removal unit 113 where it is treated to remove hydrogen sulfide, which exits as stream 19. The hydrogen sulfide is fed to sulfur-recovery unit 117 where it is converted into a commercially usable form of sulfur, taken off as stream 23. The purified synthesis gas exits as stream 17 and is then fed to hydrogen-recovery unit 115 where hydrogen is recovered by separation, shift conversion, or a combination of both, and the synthesis gas exits as stream 43. Hydrogen recovered in unit 115 is taken off as stream 25 and fed to hydrotreatment units 103, 107 and 109 as streams 31, 29 and 27. In an alternative embodiment, as shown in phantom, synthesis gas stream 352 exits acid gas removal unit 113 and is fed directly to combustion turbine 350 (shown in the phantom). This can be either in addition to, or instead of, feeding stream 43 to the combustion turbine.

Heavy coker gas oil stream 9, light coker gas oil stream 7 and coker naphtha stream 5 are fed to hydrotreatment units 109, 107 and 103, respectively. Heavy coker gas oil hydrotreatment unit 109 yields hydrotreated heavy coker gas oil exiting as stream 41, hydrotreated light coker gas oil exiting as stream 59, hydrotreated $C_3$-$C_4$ hydrocarbons exiting as stream 55, hydrotreated naphtha exiting as stream 57, and hydrotreated fuel gas exiting as stream 53. The light coker gas oil hydrotreatment unit 107 yields hydrotreated light coker gas oil exiting as stream 39, with which stream 59 is combined, hydrotreated $C_3$-$C_4$ hydrocarbons exiting as stream 49, hydrotreated naphtha exiting as stream 51, and hydrotreated fuel gas exiting as stream 47. Coker naphtha hydrotreatment unit 103 produces $C_3$-$C_4$ hydrocarbons exiting as stream 35, with which $C_3$-$C_4$ hydrocarbon streams 49 and 55 are combined; naphtha exiting as stream 37, with which is combined other naphtha streams 51 and 57; and fuel gas exiting as stream

45. Fuel gas streams 45, 47 and 53 are combined with stream 3 from the delayed coker and fed to hydrogen-sulfide-removal unit 119 to yield fuel gas stream 33 and hydrogen sulfide stream 21a which is fed, as stream 21b, to sulfur recovery unit 117.

Fuel gas stream 33, $C_3$-$C_4$ hydrocarbon stream 35, naphtha stream 37, light coker gas oil stream 39, heavy coker gas oil stream 41 and synthesis gas stream 43 are fed to combustion turbine 350 (shown in phantom) for the generation of electrical power.

Figure 2 illustrates the generation of electrical power using vacuum residue at a feed rate of about 250,000 lb/hr.

Vacuum residue stream 2 is fed from storage unit 201 into delayed coker unit 203. Coke from the delayed coker exits as stream 4 and is fed (e.g., at a rate of 80,000 lb/hr) to coke preparation unit 227 where it is combined with recycle water (e.g., introduced at a rate of 45,097 lb/hr) from stream 74 (produced in ash removal unit 233, as discussed hereinafter), and fluxing material from stream 94 (e.g., introduced at a rate of 2,400 lb/hr) to form a slurry. The slurry exits as stream 18 (e.g., at a rate of 45,097 lb/hr water and 83,753 lb/hr other material) and is fed to gasification and scrubbing unit 229. Air stream 76 is fed (e.g., at a rate of 116,702 lb/hr) to air separation unit 231 to produce oxygen which is taken off as stream 78 (e.g., at a rate of 81,501 lb/hr) and then divided into two streams, 80 and 82. Oxygen stream 80 is fed (e.g., at a rate of 78,047 lb/hr) to gasification and scrubbing unit 229. Oxygen stream 82 is fed (e.g., at a rate of 3,453 lb/hr) to sulfur recovery unit 237. The gasification process yields synthesis gas which exits as stream 20 and a mixture of slag and water which exits as stream 96 (e.g., at a rate of 57,808 lb/hr water and 4,707 lb/hr slag). Ash (slag) is separated from the water in ash removal unit 233, which produces recycle water exiting as stream 74 and waste water exiting (e.g., at a rate of 7,804 lb/hr) as stream 100.

Synthesis gas stream 20 is fed to cooling clean-up unit 235 where water provided as stream 301 (e.g., at a rate of 55,767 lb/hr) is injected into the synthesis gas to quench it. This produces quench steam, some of which is taken off as streams 327 and 303, and some of which is carried along with the cooled synthesis gas exiting unit 235 as stream 24 (e.g., at a rate of 254,114 lb/hr). Stream 24 is fed to selective AGR unit 241. Process steam condensate from unit 235 is taken off as stream 22, and is recycled (e.g., at a rate of 12,511 lb/hr) to gasification unit 229. Hydrogen sulfide exits the selective AGR unit as stream 92 (e.g., at a rate of 44,503 lb/hr) and is fed to sulfur removal unit 237 where it is converted into a commercially usable form of sulfur taken off (e.g., at a rate of 13,637 lb/hr) as stream 90. Vent gas exits the sulfur removal unit (e.g., at a rate of 41,309 lb/hr) as stream 88. Synthesis gas exits selective AGR unit 241 (e.g., at a rate of 196,509 lb/hr) as stream 26. Part of the synthesis gas is divided out as high pressure stream 28 and fed (e.g., at a rate of 140,299 lb/hr with a heat value of 567.83 MMbtu/hr) to a merge where it is combined with fuel gas stream 52 to form stream 30 (e.g., with a heat value of 700 MMbtu/hr), which is fed to combustion turbine unit 247 for the production of electrical power. The remainder of the synthesis gas from stream 26 is fed (e.g., at a rate of 55,510 lb/hr) to separation unit 239, where hydrogen is recovered; a portion of the hydrogen is taken off as stream 36 to satisfy the hydrotreatment needs of the system and the rest of the hydrogen exits as stream 34. Low pressure synthesis gas from the separation process exits as stream 32 (e.g., at a rate of 52,739 lb/hr with a heat value of 83 MMbtu/hr) and is used to fire supplemental burners of the waste heat boiler units 251 which produce steam.

Coker unit 203 also produces coker naphtha exiting (e.g., at a rate of 40,507 lb/hr) as stream 6, light coker gas oil exiting (e.g., at a rate of 53,842 lb/hr) as stream 8, heavy coker gas oil exiting (e.g., at a rate of 62,396 lb/hr) as stream 10 and fuel gas exiting as stream 102. Streams 6, 8, and 10 are fed to storage units 207, 209, and 211 and then to hydrotreatment units 213, 215, and 217, respectively. The three hydrotreatment units use hydrogen provided by stream 36.

The hydrotreated naphtha exits unit 213 as stream 38 and is fed to storage unit 223. The hydrotreated heavy coker gas oil exits unit 217 as stream 42, and hydrotreated light coker gas oil exits unit 215 as stream 40, which streams are combined in storage unit 225. From storage, naphtha stream 44 is fed to combustion turbine 243, and heavy/light coker gas oil stream 46 is fed to combustion turbine 245, both for the production of electrical power.

Hydrotreatment units 213, 215, and 217 produce fuel gas, which exits as streams 70, 68, and 66, respectively; these are combined into stream 72, further combined with fuel gas of stream 102 (from coker unit 203) and fed to compressor unit 205. The compressed fuel gas exits unit 205 as stream 16 and is fed to amine treatment unit 219.

Fuel gas, so treated, emerges as stream 48 (e.g., at a rate of 22,895 lb/hr, 7.9 MMSCFD, with a heat value of 470.7 MMbtu/hr) and is divided into streams 52 and 54. Stream 52 is combined with synthesis gas from stream 28, into stream 30 for use in combustion turbine 247. Stream 54 is divided into stream 56 (e.g., with a heat value of 110.5 MMbtu/hr) which is used in the coking process as fuel, and stream 58 which is in turn divided into streams 60, 62, and 64 (e.g., with heat values of 12.3 MMbtu/hr, 7.0 MMbtu/hr, and 7.6 MMbtu/hr, respectively) for use in hydrotreatment units 213, 215 and 217 as shown. Excess fuel gas is taken off as stream 50 (e.g., with a heat value of about 201 MMbtu/hr).

Hydrogen-sulfide-laden solvent exits unit 219 as stream 84 which is fed to amine stripping unit 221, along with steam from stream 335 to produce hydrogen-sulfide-rich gas, which exits unit 221 as stream 86 (e.g., at a rate of 6,885 lb/hr) and is fed to sulfur removal unit 237 for the purpose of recovering sulfur.

Excess heat produced in combustion turbines 243, 245 and 247 is used in heat exchange units 251 to generate high pressure steam which is taken off as streams 315, 309, and 319. These streams are combined into stream 321, which is fed to steam turbine unit 249. Low pressure steam exits the heat exchange units 251 as streams 311, 313, and 317, which are combined in header 323, and fed to a second admission point of steam turbine 249.

High pressure steam is withdrawn from stream 315 as stream 325 and is fed to gas cooling unit 235, for use as process steam in the shift reaction. After moderate pressure steam exits unit 235 as stream 303 (e.g., at a rate of 48,000 lb/hr) it is divided into stream 305 which is fed back to the hydrotreatment process and stream 307 which is recycled (e.g., at a rate of 45,994 lb/hr) to the steam turbines.

Low pressure steam exits gas cooling unit 235 as stream 327 (e.g., at a rate of 77,000 lb/hr) and is divided into stream 329 fed (e.g., at a rate of 56,000 lb/hr) to hydrogen sulfide removal unit 241 and stream 331, which is in turn divided into stream 335 fed into amine stripping unit 221 (e.g., at a rate of 7,000 lb/hr), and stream 333 taken off (e.g., at a rate of 14,000 lb/hr) for any suitable use.

Accordingly, in a preferred embodiment of one of its aspects the invention is a system for providing fuel suitable for the generation of power, which comprises (i) means for subjecting heavy hydrocarbon feedstock to delayed coking to yield coke, liquid hydrocarbon output and gaseous hydrocarbon output, (ii) means for gasifying coke, produced in said delayed coking means, to yield synthesis gas, (iii) means for removing hydrogen sulfide from synthesis gas produced in said gasifying means, (iv) means for recovering hydrogen from synthesis gas subjected to hydrogen-sulfide-removal in said hydrogen-sulfide-removal means, (v) means for hydrotreating liquid hydrocarbon output produced in said delayed coking means, (vi) means for transporting hydrogen, recovered by said hydrogen-recovery means, to said hydrotreating means, and (vii) means for transporting liquid hydrocarbon output subjected to hydrotreatment in said hydrotreating means, as well as means for transporting synthesis gas subjected to hydrogen-sulfide-removal in said hydrogen-sulfide-removal means and/or means for transporting synthesis gas subjected to hydrogen-recovery in said hydrogen-recovery means, for use as fuel in combustion turbine means for the generation of electrical power.

Further, in a preferred embodiment of another of its aspects the invention is a plant for generating electrical power which comprises (i) means for subjecting a heavy hydrocarbon feedstock to delayed coking to yield coke, liquid hydrocarbon output and gaseous hydrocarbon output, (ii) means for gasifying coke, produced in said delayed coking means, to yield synthesis gas, (iii) means for removing hydrogen sulfide from synthesis gas produced in said gasifying means, (iv) means for recovering hydrogen from synthesis gas subjected to hydrogen-sulfide-removal in said hydrogen-sulfide-removal means, (v) means for hydrotreating liquid hydrocarbon output produced in said delayed coking means, (vi) means for transporting hydrogen, recovered in said hydrogen-recovery means, to said hydrotreating means, (vii) combustion turbine means for generating electrical power, and (viii) means for transporting liquid hydrocarbon output subjected to hydrotreatment in said hydrotreating means, and means for transporting synthesis gas subjected to hydrogen-sulfide-removal in said hydrogen-sulfide-removal means and/or means for transporting synthesis gas subjected to hydrogen-recovery in said hydrogen-recovery means, to said combustion turbine means.

The terms and expressions which have been employed are used as terms of description and not of limitation, and there is no intention in the use of such terms and expressions of excluding any equivalents of the features shown and described, or portions thereof. It will be recognized that various modifications are possible within the scope of the invention claimed.

WHAT IS CLAIMED IS:

1. A method of providing fuel suitable for the generation of electrical power, which comprises the steps of:

(i) subjecting a heavy hydrocarbon feedstock to coking to yield coke and liquid hydrocarbon output;

(ii) gasifying coke produced in step (i) to yield synthesis gas;

(iii) removing hydrogen sulfide from synthesis gas produced in step (ii);

(iv) recovering hydrogen from synthesis gas subjected to the hydrogen-sulfide-removal of step (iii);

(v) hydrotreating liquid hydrocarbon output produced in step (i), a substantial amount of the hydrogen utilized in said hydrotreatment being hydrogen recovered in step (iv); and

(vi) transporting liquid hydrocarbon output subjected to step (v), and synthesis gas subjected to step (iii) and/or both steps (iii) and (iv), for use as fuel in a combustion turbine adapted for the generation of electrical power.

2. A method as defined in claim 1, which comprises subjecting said heavy hydrocarbon feedstock to delayed coking.

3. A method as defined in claim 1, which comprises gasifying said coke by partial oxidation.

4. A method as defined in claim 1, wherein substantially all of the hydrogen requirement for the hydrotreating of said liquid hydrocarbon output is provided by hydrogen recovered in step (iv).

5. A method as defined in claim 1, wherein step (vi) comprises transporting liquid hydrocarbon output

subjected to step (v), for utilization as fuel, without any intermediate storage.

6. A method as defined in claim 1, wherein step (vi) comprises temporarily storing liquid hydrocarbon output subjected to step (v) before transporting it for utilization as fuel.

7. A method as defined in claim 1, wherein said liquid hydrocarbon output produced in step (i) comprises a plurality of liquid hydrocarbon streams.

8. A method as defined in claim 7, wherein said liquid hydrocarbon output comprises a first stream comprising heavy coker gas oil, a second stream comprising light coker gas oil, and a third stream comprising a mixture of $C_3$-$C_4$ hydrocarbons and naphtha.

9. A method as defined in claim 1, wherein step (i) also yields a gaseous hydrocarbon output.

10. A method as defined in claim 1, wherein in step (vi) said transportation is to a plurality of combustion turbines.

11. A method of electrical power generation, which comprises:

(i) subjecting a heavy hydrocarbon feedstock to coking to yield coke and liquid hydrocarbon output;

(ii) gasifying coke, produced in step (i), to yield synthesis gas;

(iii) removing hydrogen sulfide from synthesis gas produced in step (ii);

(iv) recovering hydrogen from synthesis gas subjected to the hydrogen-sulfide-removal of step (iii);

(v) hydrotreating liquid hydrocarbon output produced in step (i), a substantial amount of the hydrogen utilized in said hydrotreatment being hydrogen recovered in step (iv); and

(vi) combusting liquid hydrocarbon output subjected to step (v), and synthesis gas subjected to step (iii) and/or both steps (iii) and (iv), in a combustion turbine to generate electrical power.

12. A method as defined in claim 11, which further comprises transferring heat from said combustion turbine to a heat exchanger such that steam is produced, and transporting said steam to a steam turbine for use in the generation of electric power.

13. A method as defined in claim 11, which comprises subjecting said heavy hydrocarbon feedstock to delayed coking.

14. A method as defined in claim 11, which comprises temporarily storing liquid hydrocarbon output subjected to step (v) before combusting it.

15. A method as defined in claim 11, wherein substantially all of the hydrogen requirement for the hydrotreating of said liquid hydrocarbon output is provided by hydrogen recovered in step (iv).

16. A method as defined in claim 11, wherein step (i) also yields a gaseous hydrocarbon output and said gaseous hydrocarbon output is combusted in a combustion turbine.

17. A method as defined in claim 11, which comprises utilizing a plurality of combustion turbines, and further comprises combusting liquid hydrocarbon output subjected to step (v), and synthesis gas subjected to step (iii) and/or both steps (iii) and (iv), in different ones of said combustion turbines.

18. A system for providing fuel suitable for the generation of electrical power, which comprises:

(i) a coker for treating a heavy hydrocarbon feedstock to yield coke and liquid hydrocarbon output;

(ii) a gasifier for treating coke, produced in said coker, to yield synthesis gas;

(iii) a unit for removing hydrogen sulfide from synthesis gas produced in said gasifier;

(iv) a unit for recovering hydrogen from synthesis gas subjected to hydrogen-sulfide-removal in unit (iii);

(v) a unit for hydrotreating liquid hydrocarbon output, produced in said coker, said system being configured such that a substantial amount of hydrogen utilized in the hydrotreatment unit is hydrogen recovered in unit (iv);

(vi) conduit for transporting liquid hydrocarbon output subjected to hydrotreatment in unit (v), as well as conduit for transporting synthesis gas subjected to hydrogen-sulfide-removal in unit (iii) and/or conduit for transporting synthesis gas subjected to hydrogen recovery in unit (iv), for use as fuel in a combustion turbine adapted for the generation of electrical power.

19. A system as defined in claim 18, wherein said coker is a delayed coker.

20. A system as defined in claim 18, wherein said coker also produces a gaseous hydrocarbon output, and which further comprises conduit for transporting gaseous hydrocarbon output produced in said coker for use as fuel in a combustion turbine.

21. A system as defined in claim 18, wherein said conduit communicates with a plurality of combustion turbines.

22. A system as defined in claim 21, which comprises conduit for transporting a first portion of said synthesis gas subjected to hydrogen sulfide-removal in unit (iii) to at least one said combustion turbine, and conduit for transporting a second portion of said synthesis gas subjected to hydrogen-sulfide-removal in unit (iii) to hydrogen recovery unit (iv).

23. A system for providing fuel suitable for the generation of power, which comprises:

(i) means for subjecting a heavy hydrocarbon feedstock to delayed coking to yield coke, liquid hydrocarbon output, and gaseous hydrocarbon output;

(ii) means for gasifying coke, produced in said delayed coking means, to yield synthesis gas;

(iii) means for removing hydrogen sulfide from synthesis gas produced in said gasifying means;

(iv) means for recovering hydrogen from synthesis gas subjected to hydrogen-sulfide-removal in said hydrogen-sulfide-removal means;

(v) means for hydrotreating liquid hydrocarbon output produced in said delayed coking means;

(vi) means for transporting hydrogen, recovered in said hydrogen-recovery means, to said hydrotreating means; and

(vii) means for transporting liquid hydrocarbon output subjected to hydrotreatment in said hydrotreating means, as well as means for transporting synthesis gas subjected to hydrogen-sulfide-removal in said hydrogen-sulfide-removal means and/or means for transporting synthesis gas subjected to hydrogen-recovery in said hydrogen-recovery means, for use as fuel in combustion turbine means for the generation of electrical power.

24. A system as defined in claim 23, which comprises means for transporting gaseous hydrocarbon output produced in said delayed coking means for use as fuel in said combustion turbine means.

25. A system as defined in claim 23, which comprises means for transporting, for use as fuel in said combustion turbine means, said gaseous hydrocarbon output in mixture with synthesis gas subjected to hydrogen-sulfide-removal in said hydrogen-sulfide-removal means.

26. A plant for generating electrical power, which comprises:

(i) a coker for treating a heavy hydrocarbon feedstock to yield coke and liquid hydrocarbon output;

(ii) a gasifier for treating coke, produced in said coker, to yield synthesis gas;

(iii) a unit to remove hydrogen sulfide from synthesis gas produced in said gasifier;

(iv) a unit for recovering hydrogen from synthesis gas subjected to hydrogen-sulfide-removal in unit (iii);

(v) a unit for hydrotreating liquid hydrocarbon output produced in said coker, said plant being configured such that a substantial amount of hydrogen utilized in the hydrotreatment unit is hydrogen recovered in unit (iv);

(vi) conduit for transporting liquid hydrocarbon output subjected to hydrotreatment in unit (v), as well as conduit for transporting synthesis gas subjected to hydrogen-sulfide-removal in unit (iii) and/or conduit for transporting synthesis gas subjected to hydrogen-recovery in unit (iv), to a combustion turbine adapted for the generation of electrical power;

(vii) one or more of said combustion turbine.

27. A plant as defined in claim 26, which further comprises a steam turbine for generating electrical power, and a heat exchanger for utilizing heat, transferred from at least one said combustion turbine, to generate steam which is introduced into said steam turbine.

28. A plant as defined in claim 26, wherein said coker is a delayed coker.

29. A plant as defined in claim 26, which comprises a plurality of said combustion turbines.

30. A plant as defined in claim 26, wherein said coker also produces a gaseous hydrocarbon output, and which further comprises conduit for transporting gaseous hydrocarbon output produced in said coker to a combustion turbine.

31. A plant as defined in claim 30, which comprises conduit for transporting a first portion of said synthesis gas subjected to hydrogen-sulfide-removal in unit (iii) to at least one said combustion turbine, and conduit for transporting a second portion of said synthesis gas subjected to hydrogen-sulfide-removal in unit (iii) to hydrogen-recovery unit (iv).

32. A plant for generating electrical power, which comprises:

(i) means for subjecting a heavy hydrocarbon feedstock to delayed coking to yield coke, liquid hydrocarbon output, and gaseous hydrocarbon output;

(ii) means for gasifying coke, produced in said delayed coking means, to yield synthesis gas;

(iii) means for removing hydrogen sulfide from synthesis gas produced in said gasifying means;

(iv) means for recovering hydrogen from synthesis gas subjected to hydrogen-sulfide-removal in said hydrogen-sulfide removal means;

(v) means for hydrotreating liquid hydrocarbon output produced in said delayed coking means;

(vi) means for transporting hydrogen, recovered in said hydrogen-recovery means, to said hydrotreating means;

(vii) combustion turbine means for generating electrical power; and

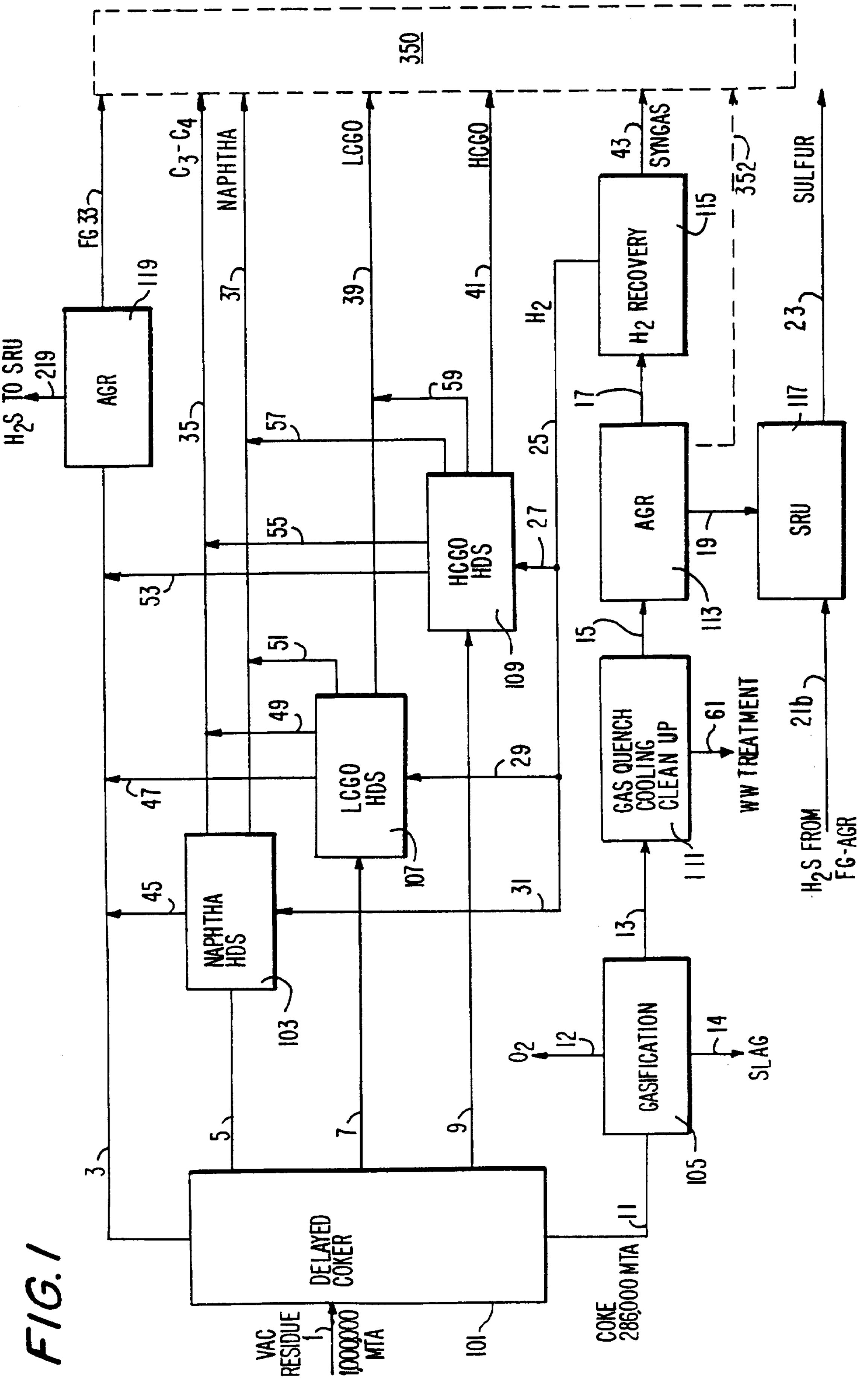
(viii) means for transporting liquid hydrocarbon output subjected to hydrotreatment in said hydrotreating means, and means for transporting synthesis gas subjected to hydrogen-sulfide-removal in said hydrogen-sulfide-removal means and/or means for transporting synthesis gas subjected to hydrogen-recovery in said hydrogen-recovery means, to said combustion turbine means for utilization as fuel.

33. A plant as defined in claim 32, which further comprises steam turbine means for generating electrical power, and heat exchanger means for utilizing heat, transferred from said combustion turbine means, to generate steam, and means for

transporting said steam to said steam turbine means.

34. A system as defined in claim 32, which comprises means for transporting gaseous hydrocarbon output produced in said delayed coking means to said combustion turbine means.

35. A system as defined in claim 32, which comprises means for transporting, to said combustion turbine means, said gaseous hydrocarbon output in mixture with synthesis gas subjected to hydrogen-sulfide-removal in said hydrogen-sulfide-removal means.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NAPHTHA HDS
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31
13
GASIFICATION
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$O_2$
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14
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9
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101
11
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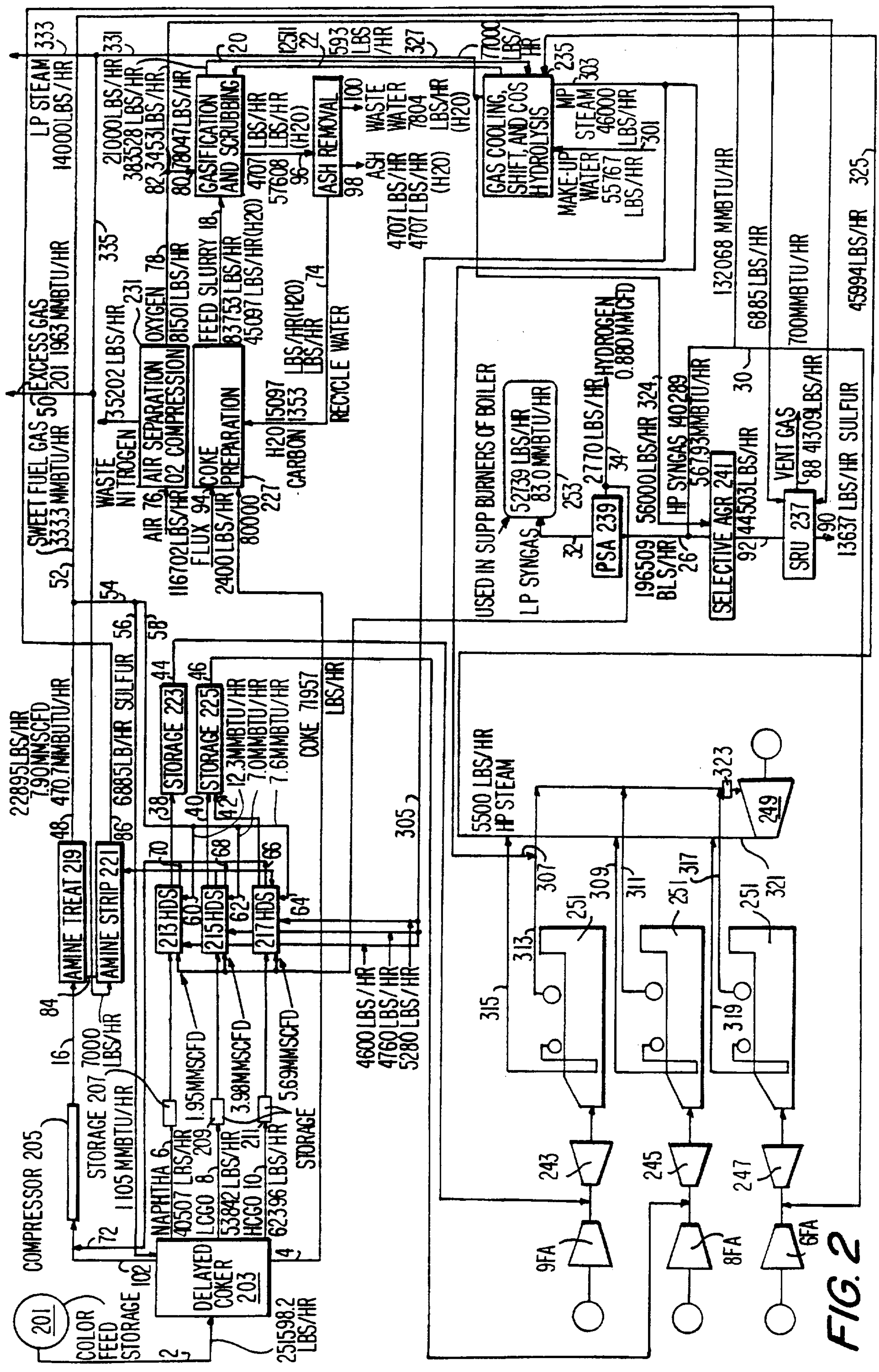
COKE 286,000 MTA

FIG. 1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STORAGE 207
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40507 LBS/HR
LCGO 8
53842 LBS/HR
HCGO 10
62396 LBS/HR
STORAGE
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3.98MMSCFD
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4600 LBS/HR
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AMINE STRIP 221
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6885LB/HR SULFUR
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SWEET FUEL GAS 50
333.3 MMBTU/HR
EXCESS GAS
201 1963 MMBTU/HR
LP STEAM 333
14000LBS/HR
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AIR SEPARATION
O2 COMPRESSION
35202 LBS/HR
OXYGEN 78
81501LBS/HR
FLUX 94
2400 LBS/HR
COKE PREPARATION
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FEED SLURRY 18
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(H2O)
593 LBS/HR
7000 LBS/HR
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MAKE-UP WATER
55767 LBS/HR
MP STEAM
46000 LBS/HR
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USED IN SUPP BURNERS OF BOILER
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6885 LBS/HR
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VENT GAS
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SRU 237
13637 LBS/HR SULFUR
45994LBS/HR
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249
251
243
245
247
9FA
8FA
6FA

FIG. 2

# INTERNATIONAL SEARCH REPORT

International application No.
PCT/US97/10964

**A. CLASSIFICATION OF SUBJECT MATTER**

IPC(6) :C10G 9/00; C10J 3/00, 3/20; C10B 47/00; F02C 3/00, 6/00
US CL :Please See Extra Sheet.
According to International Patent Classification (IPC) or to both national classification and IPC

**B. FIELDS SEARCHED**

Minimum documentation searched (classification system followed by classification symbols)

U.S. : 208/131, 97; 196/104, 105; 48/197R, 203, 89, 102R; 201/23, 27; 60/39.02, 39.12, 645

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

APS search terms: delayed coking, gasification, electricity, hydrodesulfurization, synthesis gas, generation, integrated, turbine

**C. DOCUMENTS CONSIDERED TO BE RELEVANT**

| Category* | Citation of document, with indication, where appropriate, of the relevant passages | Relevant to claim No. |
|---|---|---|
| Y | US 4,261,167 A (PAULL et al) 14 April 1981 (14/04/81), see entire document, especially col. 2, lines 12-23 and 41-62, col. 3, lines 40-54, and the figure. | 1-35 |
| Y | US 4,036,736 A (OZAKI et al) 19 July 1977 (19/07/77), see col. 4, lines 65-68 and col. 5, lines 15-49. | 1-35 |
| Y | US 3,923,635 A (SCHULMAN et al) 02 December 1975 (02/12/75), see col. 4, lines 55-60 and col. 5, lines 53-57. | 1-35 |
| Y | US 3,986,349 A (EGAN) 19 October 1976 (19/10/76), see col. 4, lines 20-30. | 1-35 |
| A | US 4,927,430 A (CALDERON) 22 May 1990 (22/05/90). | 1-35 |

[X] Further documents are listed in the continuation of Box C. [ ] See patent family annex.

* Special categories of cited documents:

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier document published on or after the international filing date

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"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

| Date of the actual completion of the international search | Date of mailing of the international search report |
|---|---|
| 28 JULY 1997 | 06 OCT 1997 |

| Name and mailing address of the ISA/US | Authorized officer |
|---|---|
| Commissioner of Patents and Trademarks<br>Box PCT<br>Washington, D.C. 20231 | WALTER GRIFFIN |
| Facsimile No. (703) 305-3230 | Telephone No. (703) 308-0661 |

Form PCT/ISA/210 (second sheet)(July 1992)★

## INTERNATIONAL SEARCH REPORT

International application No.
PCT/US97/10964

### A. CLASSIFICATION OF SUBJECT MATTER

IPC(6) :C10G 9/00; C10J 3/00, 3/20; C10B 47/00; F02C 3/00, 6/00
US CL :Please See Extra Sheet.
According to International Patent Classification (IPC) or to both national classification and IPC

### B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

U.S. : 208/131, 97; 196/104, 105; 48/197R, 203, 89, 102R; 201/23, 27; 60/39.02, 39.12, 645

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

APS search terms: delayed coking, gasification, electricity, hydrodesulfurization, synthesis gas, generation, integrated, turbine

### C. DOCUMENTS CONSIDERED TO BE RELEVANT

| Category* | Citation of document, with indication, where appropriate, of the relevant passages | Relevant to claim No. |
|---|---|---|
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| Y | US 4,036,736 A (OZAKI et al) 19 July 1977 (19/07/77), see col. 4, lines 65-68 and col. 5, lines 15-49. | 1-35 |
| Y | US 3,923,635 A (SCHULMAN et al) 02 December 1975 (02/12/75), see col. 4, lines 55-60 and col. 5, lines 53-57. | 1-35 |
| Y | US 3,986,349 A (EGAN) 19 October 1976 (19/10/76), see col. 4, lines 20-30. | 1-35 |
| A | US 4,927,430 A (CALDERON) 22 May 1990 (22/05/90). | 1-35 |

[X] Further documents are listed in the continuation of Box C. [ ] See patent family annex.

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"O" document referring to an oral disclosure, use, exhibition or other means

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"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

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## INTERNATIONAL SEARCH REPORT

| International application No. |
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A. CLASSIFICATION OF SUBJECT MATTER:
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208/131, 97; 196/104, 105; 48/197R, 203, 89, 102R; 201/23, 27; 60/39.02, 39.12, 645