گزارش فاز سوم

تعیین گستره و شرح تأسیسات سطح الرضی، برآورد هزینه های سرمایه ای، برآورد هزینه های عملیاتی و برآورد درآمد های حاصل از طرح پیشنهادی

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South Pars

Studies to Enhance Condensate Recovery, Contract No. 085029 Report No. 3, Surface Facilities & Capital Costs

Revision No. 0.0 - January 2008

This report summarizes the outcomes of the studies undertaken by Iranian Gas Institute to ascertain and define the offshore and on-shore facilities, referred to as "Surface Facilities", which are required to be installed and operated to achieve the goals set out for production of additional reservoir fluid and recycling of the lean sour gas into the reservoir as fully described in the Report No. 2, with a view to enhance the condensate recovery in South Pars Field.

The south pars recycling facilities are proposed to be developed to duplicate the production rate of the reservoir fluid from the field, located some 100 km offshore, and to treat the additional gas and condensate on onshore to produce conditioned lean sour gas for recycling into the reservoir, the stabilized condensate and treated propane and butane for export by marine tankers and the treated ethane for delivery to the local chemical plants.

The proposed identical configuration call for the design and development of the facilities required for the development of recycling scheme for four typical blocks of 11.8x11.8 km size of south pars to cater for the most feasible integration, to provide the required flexibilities for the alternative architectures of the producing and injection wells for the achievement of the optimum sweep efficiency, with due consideration given to optimizing the development in terms of capital cost and reliability.

Certain feasible and successful design features adopted in the development of the south pars production facilities such as simultaneous development of k2,k3 and k4 reservoirs from the same platform in each phase, a 7" monobore Corrosion Resistant Alloy (CRA) well completion to achieve the intended high rate, the minimum pressure of 1800 psig for the sealines inlet and the two phase flow transmission of the reservoir fluid to onshore which minimize the offshore

facilities, have been considered to be similarly adopted in the proposed development of the recycling scheme.

Due consideration in term of the capital cost and the reliability of the operation has been given in the course of development of the proposed recycling scheme and accordingly amongst the several process configuration options, the most feasible design configuration which also demonstrate the reliability as well as the financial and

economic viability of the proposed investment have been eventually adopted and proposed.

In amplification to the above certain design feature of the proposed configuration are discussed herein under:

1. The reservoir fluid of the proposed scheme can be delivered for onshore treatment through two sealines instead of the proposed four sealines option, with considerable project cost reduction and contributing to overall decrease in operating expenses. However the two sealine option does not provide the high rate for turn down which would be essentially required in two phase flow pattern during operational and maintenance constrains. Therefore the four sealine design option which enhances the operational reliability of the recycling scheme has been considered and been finally proposed.

2. The conditioned lean gas can be delivered to the compression platform through one sealine. However this design configuration option does not provide the preferred operational flexibilities to the system. Accordingly and with due consideration given to the reliability of the system two sealines have been proposed for transmission of the lean gas to offshore compression platforms.

3. The treatment of the reservoir fluid allocated to recycling can be limited to water and hydrocarbon dew point correction of the gas, propane and butane extraction and treatment and stabilization of the condensate similar to the original scope of work of the phases 6, 7&8 of south pars. In the said design configuration option deep cut extraction of ethane plus cuts are not considered. However with due consideration of the sharp growing demand for ethylene during the next three decades in the far east, in particular in china and India and the attractive profit margin of the ethylene which is excess of $1000 per tone, we have considered to employ deep cut technology for the extraction of ethane and heavier cuts from the gas before being delivered for recycling. Accordingly and in order to prevent CO2 freezing in the cryogenic extraction system, we have considered to employ sweetening of 50% of the fluid to reduce the overall CO2 content of the feed gas to a safe margin, before being directed to the cryogenic system in the proposed design configuration. This proposed design configuration option with a considerable impact on the economic viability of the project, also provide an attractive available capacity for pick shaving demands in the future export contracts.

4. In view of the above the design configuration option proposed for onshore facilities include:

    4.1. Common slug catcher for receiving gas and liquid from four 32” sealines , where primary level of gas and liquid separation is achieved,

    4.2. Four trains of gas sweetening with MDEA solvent each with 500 MMSCFD complete with inlet and sweet gas separation and filtration, absorbers and amine regeneration,

4.3. Four water dew point units each with 1000 MMSCFD capacity on a four 33% tower configuration, employing molecular sieve adsorption which are alumina silicate fixed bed molecular sieve operating in down flow where virtually all the water contained in the wet gas is removed achieving an out let water dew point less than – 166 degree Fahrenheit at operating pressure which would be the bone dry gas required for the following cryogenic trains as ell as for sour gas transmission to offshore compressor platforms,

4.4. Cryogenic NGL extraction and fractionation units where up to 92% of ethane, 99% of butane and 99% of propane content of the bone dry sour gas leaving the dehydration units shall be extracted and fractionated, the sour gas leaving the top of demethanizer section of NGL extraction unit at – 152 ° F will be warmed up and compressed to 2200 psi before being delivered to offshore compressor platform through two 36" sealines for further compression to 5200 psi and injection into the reservoir. Provisions have been considered in the design configuration option to export up to 2000 MMSCFD of sweet, dry gas from each of the typical onshore facilities for pick shaving purposes,

4.5. The condensate stabilization units, where the condensates are stabilized, before being sent to the stabilized condensate storages,

4.6. Process water treatment unit where the process water will be treated before being disposed to the sea,

4.7. MEG regeneration unit where the MEG will be regenerated and pumped to transfer to offshore wellhead platforms through four piggy back lines.

5. With due consideration of optimizing the development, in term of capital cost , reliability and employing maximum feasible and practicable integration, we have considered simultaneous development of K2, K3 and K4 reservoirs and drilling of all producing and injection wells, within one block, from a single platform. We have further considered two phase flow pattern for transmission of wet fluid to onshore treating plant with a view to minimize offshore facilities.

6. The proposed design configuration option call for a shared facilities for a common development criteria for four blocks and provide maximum practicable sharing and integration of the facilities whilst enhancing the reliability of the system.

7. with due consideration to optimizing the development in term of capital cost and operating expenses the offshore facilities have been minimized and remote control devises have been proposed to be employed to enable maximum possible unmanned operation of the offshore facilities. The main functions of the offshore processing facilities in the proposed design configuration option are summarized as:

7.1. Well testing of the reservoir fluid for monitoring of the reservoir. This will be carried by on a task force by onshore personnel through four test separators and associated instrumentation installed one on each block wellhead platform,

7.2. Separation of free and condensed water from the reservoir production in the Free Water K.O. Drums which are to provided one for each wellhead platform,

7.3. Degassing and treatment of oily water prior to disposal to the sea,

7.4. Transmission of the saturated reservoir production to the onshore treatment plant via four 32" sealines, one for each wellhead platform, which will operate in two phase mode namely gas and liquid phases, where the liquid phase is composed of free water and condensate, injection of MEG at the inlet of each sealine for the inhibition of both hydrate and corrosion,

7.5. Transmission of lean gas with standard water and hydrocarbon dew point from onshore treatment plant to offshore compression platforms through two 36" sealines each around 100 Kim. long and two compression platforms to boast the pressure of lean gas prior to being injected into reservoir from around 2000 psi to 5300 psi. The compression platforms will operate on a remote control basis. All platforms will be unmanned, whereas the major maintenance works shall be performed by personnel from onshore and routine and emergency operation will be carried out from nearby offshore complex built by NIOC.

I. Surface Facilities

In view of the aforementioned discussions the proposed typical recycling design configuration option is based on production of 4000 MMSCFD additional reservoir fluid , around 1000 MMSCFD from each block , transmission of the reservoir fluid in two phase flow system(gas and liquid) to the onshore facilities for treatment of the reservoir fluid for part sweetening to reduce CO2 content of the mixed residue gas of the sweetening trains to suitable range for cryogenic temperatures , dehydration, ethane plus deep cut extraction, fractionation and treatment of the extracted products to ethane, propane, butane and C5+ cuts with internationally accepted specifications, stabilization of the gas condensate and transmission and compression of the residue gas to offshore compressor platform for further compression and injecting of the compressed lean sour gas into the reservoir and the sale of the stabilized condensate and ethane plus cuts fractionated from deep cut extractions, consisting of the following units;

A. Four identical wellhead platforms, 15 slot each, one wellhead platform including ten new producing wells in each block. The locations of wellhead platforms and the new producing wells will be in accordance with the results of the proposed new reservoir simulation. The platforms will be unmanned. Each

wellhead platform will be equipped with a test separator and the associated instrumentations for monitoring of the reservoir fluid. Each wellhead platform will also be equipped with a Free Water K.O. Drum and oily water degassing and treatment facilities for separation and disposal of free and condensed water from the reservoir. Furthermore each wellhead platform will be equipped with chemical injection system for injection of MEG into the sealine and also a high pressure injection package for periodical chemical injection into the wells.

B. Transmission system for reservoir fluid to the onshore treatment facilities including a 32" sealine for each block. The transmission system for reservoir fluid to onshore will operate in two phase flow pattern, where the liquid phase is composed of condensed hydrocarbon and water. The transmission system also includes a 4 ½" piggyback MEG sealine for transmission of MEG from onshore facilities into each wellhead platform. Injection of MEG for inhibition of both hydrate formation and corrosion to the reservoir fluid transmission system will be made at the inlet of each sealine.

C. Transmission system for the delivery of the treated lean gas from onshore facilities to the main offshore compressors platform will be composed of two 36" sealines.

D. Four identical injection / compressor platforms, including 10 injection wells, covering the compression and injection capacity, for each block will be installed and operated to boast the pressure of treated sour lean gas from around 2000 psi to 5200 psi and the injection of the compressed lean gas into the reservoir through injection wells. The compressor platforms will be equipped with SCADA system to operate on remote control basis and with chemical injection packages. This unit will also include high pressure sealines from the injection / compression platforms to the wellhead platforms for injection purposes.

E. Onshore gas treatment facilities with overall 4000 MMSCFD throughput consisting of the following units:

    a. **Inlet Separation,** consisting of common slug catcher in two 50% units for receiving gas and liquid from four 32" sealines, where primary level of gas and liquid separation will be achieved. The secondary level of separation of vapor and liquid of the inlet stream will be achieved in the inlet feed separators of the following treating units.

    b. **Gas Sweetening Trains,** for removal of the acid gases from 2000MMSCFD which is 50% of the reservoir production on recycling scheme, consisting of four 500 MMSCFD typical sweetening trains, employing MDEA solvent, complete with inlet and sweet gas separation and filtration systems, absorbers and amine regeneration systems and all other related equipment, instrumentations, control systems and utilities with total inlet throughput of 2000 MMSCFD. 50% of the vapor leaving the slug catchers will be allocated for sweetening and will be directed to the sweetening trains for removal of the acid gases. The acid gases leaving the amine regenerations will be blended with the

other 50% of the vapor out of slug catchers which will by-pass the sweetening trains before being directed to following dehydration units.

c. **Dehydration Units,** consisting of four water dew point trains each with 1000 MMSCFD capacity on a four 33% adsorption tower configuration , employing alumina silicate, molecular sieve fixed beds operating in down flow and virtually adsorb all the water contained in the wet gas, achieving an outlet water dew point of less than -166 degree Fahrenheit at operating pressure. It would be essential to achieve this very low water dew point to prevent hydrate formation in the following cryogenic trains where the temperature of gas will be reduced to as low as -152 ° F for deep cut extraction purposes. Two water dew point trains will receive and dehydrate the treated gas from sweetening trains whereas the other two water dew point trains will receive the sour untreated vapor from the inlet slug catchers. The dehydration trains will be equipped with properly seized inlet separation which will provide the secondary separation level of the vapor and liquid phases of the raw inlet streams and also with inlet filtration for removal of particulates and entrained hydrocarbon, glycol and water and outlet filtration equipment for removal of dusts from adsorption beds.

d. **Condensate Stabilization Units,** consisting of non-refluxed reboiled trayed distillation columns, reboilers, coolers, two 100% overhead vapor compressors for each stabilizer which will compress the combined butane and higher stabilizer off gas to 1100 psig in order to be recycled back into the inlet feed drum of the unit. The bottom product of stabilization units will be a 6.56 psia RVP pentane plus (C5+) stabilized condensate which will be pumped to stabilized condensate storage tanks.

e. **NGL Extraction Units,** consisting of eight demethanizers each with 500 MMSCFD capacities complete with all related machineries and equipment required for extraction of up to 92% of ethane and 99% of propane and butane from the bone dry gas stream leaving the dehydration units. The final residue gas at - 153° F from the top of the demethanizer will heat exchange with split stream and then with warm inlet gas in the gas chiller and will subsequently be heated up and then boasted by the expander compressor and then will be further boasted in the Export Gas Unit before being directed to the 36” sealines for delivery to offshore compressor platforms. The dried gas from dehydration units will have to be blended to reduce the CO2 content before being directed to the cryogenic extraction units. The residue gas from the top of the demethanizers will be at around 310 psia after having been expanded in the unit’s turbo expander. The pressure of the residue gas from the top of demethanizer will be initially boasted in the expander compressor to 399 psia and further increased to 2200 psia before being delivered out of onshore treating facilities. The C2+ NGL from the bottom of demethanizers will be directed to the NGL Fractionation Unit for being fractionated and then treated.

f. **NGL Fractionation Units,** consisting of eight trains which will handle the total NGL extracted from 4000 MMSFD dried gas from the water dew point units after having been blended. Each fractionation train will be designed with additional allowance in the equipment sizing to accommodate approximately 10% return of off – specification products. The NGL to each train will be supplied on pressure control to deethanizer which consists of a 45 tray distillation operating at 2240 kPag equipped with a kettle style hot oil reboiler providing bottom heat on temperature control, and a kettle style propane refrigerated overhead reflux partial condenser operating at -6 deg C, reflux/ethane separation drum and reflux pumps. The deethanizer shall be designed to produce a deethanized bottom product with less than 1% ethane in the propane which will be directed on level control to the depropanizer, and an overhead ethane vapor stream containing less than 1% propane. The CO2 and H2S content of the ethane vapor product of the deethanizer will have to be absorbed by MDEA solvent and then dried to meet the required specification. The bottom product of the deethanizer containing less than 1% ethane will be directed to depropanizer. Depropanizer consists of a 45 tray distillation tower operating at2068 kPag equipped with a kettle type reboiler providing bottoms heat on temperature control and a bank of fan driven air cooled reflux total condenser operating at 60 deg C, reflux drum and reflux pumps. The overhead product of the depropanizer will be 98% pure liquid propane and will be further treated for removal of H2S and mercaptans to meet the commercial grade C3 specification and then pumped to the pressurized storage. The bottom product of the depropanizer which will contain less than 1% propane will be directed on level control to debutanizer. Each debutanizer consist of a 35 tray distillation column operating at 700 kPag equipped with a kettle type reboiler providing bottom heat on temperature control and a bank of fan driven air cooled reflux total condensers operating at 60 deg C, reflux drum and reflux pumps. The debutanizer shall be designed to produce 98% pure liquid butane as a top product. The top product shall further treated for removal of mercaptans to meet the specifications for commercial grade C4 and then shall be pumped to storage system. The bottom product of the debutanizer shall be a debutanized condensate with less than 12 RVP and shall be cooled and directed on level control to the condensate storage tanks.

g. **MEG Regeneration Unit,** consisting of three phase separation and filtration for recovering the MEG from the combined inlet slug catchers and a MEG regeneration column complete with heater, condenser and pumps which will be utilized to regenerate and pump MEG through two 41/2” piggyback sealines to the offshore wellhead platforms.

h. **Export Gas Unit,** consisting of gas scrubbers, residue gas compressors and the compressors after coolers, where the residue gas from the NGL EXTRACTION UNIT will be compressed to 2200 psia, cooled to 57 deg C and scrubbed before being delivered to offshore facilities for injection into the reservoir.

i. **Chemical Plants,** In addition to the abovementioned onshore gas treatment plant, 11 chemical plants with facilities similar to the olefin plant No. 11 with the total capacity of 11.6 million tones of ethylene per annum are recommended to be constructed in Mogham area (70 km east of Assalluyeh) for the production of ethylene from ethane cut extracted from the recycling project.

II. CAPITAL COST ESTIMATE FOR ONE TYPICAL RECYCLING SCHEME

The capital cost estimate for the surface facilities including production and injection wells drilling and completions and all related utilities, flares etc. required for the proposed single typical recycling scheme has been carried out using updated data from south pars previous developments and the Iranian Gas Institute in-house statistical information. The cost estimate is of +/- 30% accuracy and reflects 2008 prices for project completion in Assalluyeh area, based on recommended design configuration outlined under “section I. SURFACE FACILITIES “of this report.

The cost estimate also includes the first charge of catalysts and chemicals and the price of the spare parts for the first two years operation of the facilities.

CAPEX SUMMARY	$ US MILLION
1. 40 Production Wells Complete	1600
2. 40 Injection Wells Complete	1620
3. Offshore facilities complete	2840
4. Reservoir Fluid and MEG Transmission Sealines	740
5. Lean Sour Gas Transmissin Sealines	432
6. Onshore Facilities Complete	2500
TOTAL CAPEX	9732

III. CAPITAL COST ESTIMATE FOR FULL FIELD DEVELOPMENT

A. For south pars planned full field development , seven typical recycling schemes as defined above are required and recommended to be considered to achieve the intended enhanced ethane plus recovery.

B. The total CAPEX for the full recycling development will be 68.124 $ US billion.

C. The total CAPEX required for eleven chemical plants described under item I – E – i above will be 6.6 $US billion.

D. The grand total CAPEX for full recycling development and chemical plants will be 74.724 $ US billion.

IV. OPEX

A. The annual operating expenses for all offshore and onshore facilities of the proposed recycling full development in south pars is estimated based on the updated and adjusted actual expenses on similar establishments and will be equal to 714 $ US million per year.

B. The annual operating expenses for eleven nos. chemical plants based on updated actual data on similar establishments is estimated to be 604.0 $ US million per year.

C. The grand total operating expenses for south pars full recycling development and chemical plants for production and sale of ethylene is estimated to be 1,318 $ US million.

V. REVENUES

The potential revenues from the proposed recycling schemes extended for the full field development are categorized and estimated as follows:

a) The approximate estimate of revenues expected from the sale of the additional condensate which will be recoverable and available as a result of the execution of the proposed recycling project, with 2008 prices will be 320 $ US billion. This is based on the assumption that 3.2 MMMSTB of additional condensate will be recovered after the development of the proposed recycling scheme, as outlined in the report No. 2 of this study. This estimate is approximate due to limited reservoir data available and incorporated in the reservoir simulation. Accordingly we have recommended for further studies to be carried out incorporating full reservoir data. Subsequent to the performing of the following additional studies as recommended in section 2 of our aforementioned report a more accurate estimate of the expected revenues from the enhanced condensate recovery would be made available. Pending the outcome of the proposed studies and in order to maintain our conservative approach all through our economic evaluation of the project, we have accounted for 80% of

the this revenue which would be 256 $ US billion, in our economic evaluation of the proposed recycling scheme:

1. The full field 3D simulation study using all static and dynamic reservoir data
2. The study of the effect of alternative patterns on condensate recovery
3. The proposed fracture study
4. Running of FMI or FMS log
5. Core and SCAL tests
6. Transient well tests

b) Revenues expected out of the sale of 117.28 million tones of additional products which would be made available from the sale of C3 and C4 extraction and recovery from the eventual abandoned gas in the field, based on 2008 prices will be 93.82 $ US billion. This estimate is based on a conservative approach, assuming that only 50% of the C3 and 40% of C4 content of the abandoned reservoir gas would be extracted and recovered.

c) Additional revenues expected out of production and sale of ethylene from 136.4 million tones of enhanced ethane extracted from abandoned gas in the reservoir, with 2008 prices will be 104.72 $ US billion. This estimate is based on a conservative approach, with the assumption that only 50% of ethane content of the abandoned reservoir gas volume would be extracted and recovered.

d) The summary of the expected revenues out of the sale of the enhanced recoveries from full development of the proposed recycling scheme, with 2008 prices are as follows:

	$ US BILLION
A. From the sale of enhanced condensate:	256.00
B. From the sale of enhanced propane and butane :	93.82
C. From the sale of additional ethylene:	104.72
TOTAL:	454.54

VI. ANNUAL REVENUES FROM RECYCLING PRODUCTS

With due considerations to the economic viability of the project, the proposed design configuration option, through application of cryogenic and deep cut technology, set a

scene for maximizing the extractions from reservoir fluid produced for recycling before the residue lean sour gas is directed to offshore compressor platforms for further compression and injection into the field.

The annual revenues out of the sale of the products from the overall full development of the recycling projects with the privilege of the present worth values, brought forward on direct ratio from a span of 10 to 35 years, based on 2008 prices are summarized below:

	$ US BILLION PER ANNUM
A. Recycling Condensate	31.68
B. Propane & Butane	11.76
C. Ethylene	10.76
TOTAL	54.20