IMPROVING ETHANE EXTRACTION
AT THE PETRONAS GAS GPP-A FACILITIES IN MALAYSIA

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ABSTRACT

The Gas Processing Plant A Complex (GPP-A) in Kerteh, Terengganu, Malaysia operated by PETRONAS Gas Berhad (PGB) contains three turbo expander ethane recovery plants. With the increase in demand for ethane that Malaysia is currently experiencing, plus a desire to improve plant operating stability at the GPP-A Complex, PGB began investigating technology upgrades to increase ethane recovery and improve plant performance.

This paper discusses the process technology upgrades studied by PGB, and the design and construction efforts to retrofit the chosen technology into the existing facilities. The operating experiences encountered during the recent startup and commissioning of the revamped units are also presented.

INTRODUCTION

PETRONAS Gas Berhad (PGB), a subsidiary of Petroleum Nasional (PETRONAS), the national oil and gas company of Malaysia, operates six gas processing plants. The GPP-A Complex includes the GPP-1, -2, -3, and -4 trains and the GPP-5 and -6 trains are located at the GPP-B Complex. Both complexes are located in peninsular Malaysia, near Kerteh, and have a combined production capacity of 2.75 BSCFD of sales gas which is supplied to Malaysia's power sector. Additionally, the GPP facilities produce separate ethane, propane, butane, and condensate products which are either supplied to the adjacent PETRONAS Petrochemical Integrated Complex or exported to neighboring countries.

During the Asian economic crisis of 1997-1998, ethane and its derivative, ethylene, enjoyed tremendous demand and high pricing as indicated by the following data:

1996 – US$350/tonne
1998 – US$550/tonne

Since commissioning of the GPP-2, -3, and -4 plants in the early 1990's, the design ethane recovery of 80% had never been sustained. Recovery levels ranged from 65 to 72%, and attempts to increase recovery by changing operating conditions resulted in plant instabilities and upsets. As a result, it became increasingly difficult for PGB to maintain the nominal ethane production for its customers. This, coupled with the economic incentives, resulted in PGB's decision to undertake an Ethane Extraction Improvement (EEI) project in early 2000 to investigate alternatives for enhancing the ethane production capability of the GPP-2, -3, and -4 trains located in the GPP-A Complex.

ETHANE EXTRACTION IMPROVEMENT STUDY

The goals of the initial EEI study were to make a preliminary assessment of the current operating conditions of the three GPP trains and to determine the extent of modifications required to:

1. Improve ethane recovery to above 90%.
2. Improve the ability of the Plants to accommodate changes in feed gas compositions.
3. Improve the reliability and stability of the plant operations.
4. Maintain a sales gas output of 250 MMSCFD per train at the increased ethane recovery.

The result of this study indicated the turbo expander trains could easily be retrofit using either of three Ortloff NGL recovery technologies; Gas Subcooled Process (GSP), modified Cold Residue Reflux (CRR), or Recycle Split-Vapor (RSV)[1], all capable of achieving the desired sales gas production and ethane recovery target value.

A summary of the study results are shown in Table I.

Table I
Product Recovery
(Average Increase per Train in Tonnes/Hour)

Lean Composition			
	Ethane	Propane	C_4+
GSP	4.90	0.409	0.278
CRR	5.91	0.533	0.308
RSV	6.03	0.571	0.362
Rich Composition			
	Ethane	Propane	C_4+
GSP	6.89	0.593	0.569
CRR	6.89	0.593	0.569
RSV	6.91	0.682	0.587

Calculated
Average Ethane Recovery Factors

	Base	GSP	CRR	RSV
Lean Feed Gas	71.53%	94.23%	97.87%	96.88%
Rich Feed Gas	79.69%	95.26%	95.26%	95.38%

As part of the technology assessment, the study highlighted that the main sales gas pipeline compressors were fed from a common header of not only the GPP-2, -3 and -4 trains, but also the GPP-1 facility as well. The GPP-1 train is a dew point control plant which meant "wet" sales gas was mixing with the otherwise "dry" sales gas stream from the GPP-2, -3 and -4 plants. The RSV process required a dry gas stream be recycled from the discharge of these pipeline compressors to each of the three trains for use as an additional tower reflux stream. The inclusion of the GPP-1 sales gas stream with that of GPP-2, -3 and -4 meant that no dry recycle gas stream was available and therefore precluded the application of the RSV technology into the GPP trains.

Additional analysis of the remaining two retrofit options indicated that the CRR process would require re-wheeling the existing Sales Gas Compressor for each train, whereas the GSP option would not require this modification. The re-wheeling was estimated to cost approximately US$300,000 exclusive of additional plant downtime. Considering the overall project cost impact and schedule constraints imposed by the CRR option, it was determined that GSP was the optimum technology for retrofitting of the GPP trains, providing excellent recovery improvements and operating flexibility. In addition to the increased recovery, the GSP design also provided the additional benefit of increasing sales gas production by 10% above current capacity (i.e. 276 MMSCFD vs. 250 MMSCFD) for the lean feed composition without further equipment modifications. The decision was made by PGB to proceed with the GSP retrofit design for the GPP-2, -3 and -4 facilities early in the second quarter of 2001. The final design basis conditions resulted in a GSP retrofit design capable of achieving a calculated ethane recovery of 95.56% when processing the lean feed gas and 97.46% when processing the rich feed gas stream without additional residue or refrigeration compression.

Original Low Temperature Separation Unit Design

The Low Temperature Separation Units (LTSU), i.e. cryogenic sections, of the GPP-2, -3, and -4 trains are of the same configuration, each originally designed to provide a net residue gas product flow rate of 250 MMSCFD at an ethane recovery level of 80%. The cryogenic section of the plants is a traditional single-stage expander process configuration with supplemental mechanical refrigeration. This basic process configuration is shown on the simplified schematic in Figure 1.

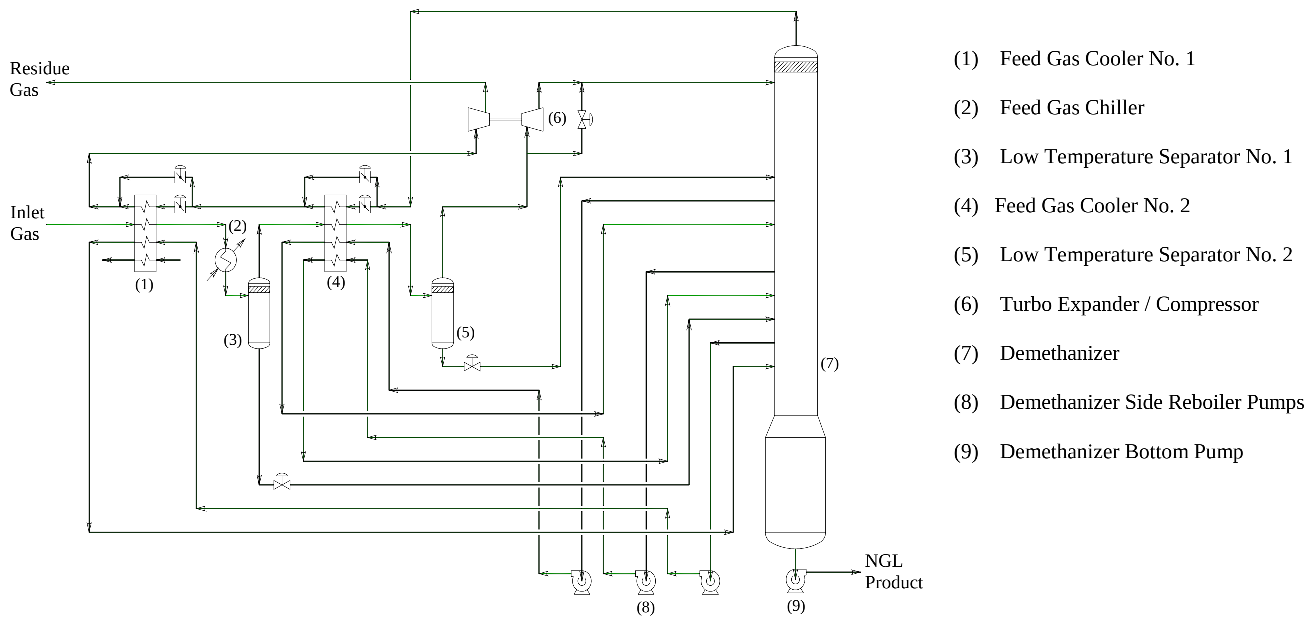

Figure 1 - LTSU Process Flow Schematic

GSP Retrofit

The advantages and basic design features of a GSP retrofit of an industry standard single-stage (ISS) NGL recovery plant have been previously discussed. [2,3] For this project, the retrofit required the addition of three new equipment items and modifications to two existing items. Table II summarizes these equipment changes.

Table II
Equipment Changes

New Equipment	
1.	Ethane Absorber, stainless steel packed column
2.	Subcooler, brazed aluminum heat exchanger
3.	Ethane Absorber Bottoms Pumps, 2-100%, vertical in-line, API 610
Existing Equipment	
1.	Tray modifications to Demethanizer
2.	Re-wheel of Turbo Expander / Compressor

The simplified sketch shown in Figure 2 shows the basic process configuration for the GSP retrofit of the GPP-2, -3, and -4 trains.

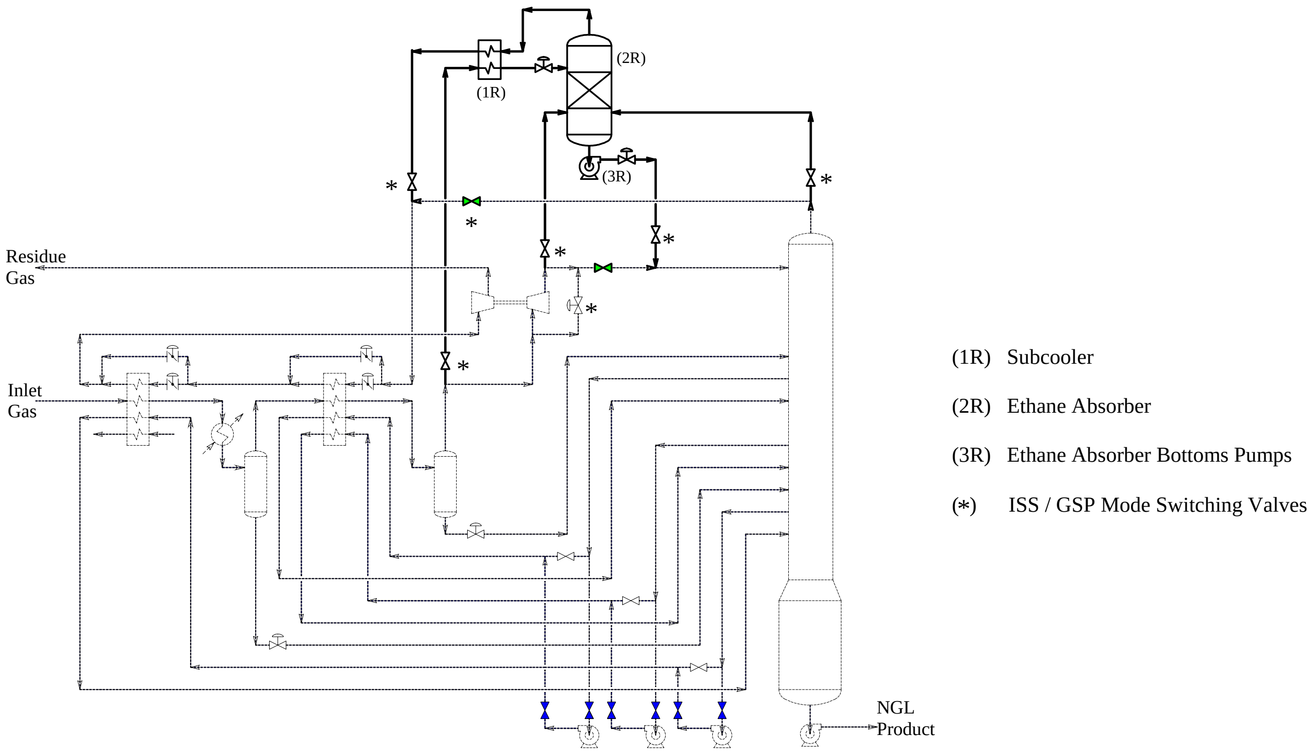

Figure 2 - GSP Retrofit Process Flow Schematic

One of the most unique features of this retrofit was the requirement for the plant to be able to revert back to its original ISS operating mode. This requirement was imposed due to two main reasons. First, even though retrofits of NGL plants are fairly common in the U.S. market, retrofits are a relatively new concept outside of North America. Secondly, the EEI project was the first major venture undertaken by PGB on any of their existing facilities. As a result, the retrofit was designed in such a way that the GSP system could be completely isolated, if need be, and the LTSU operated in the original ISS mode. This was accomplished through the addition of several mode switching valves which can be seen in Figure 2. Aside from the physical plant modifications, this also meant that the existing equipment modifications, i.e. Demethanizer and Turbo Expander / Compressor, although optimized for the GSP operating conditions, still had to be able to operate efficiently in the ISS operating mode, as well.

In addition to the GSP retrofit modifications, an additional study was conducted concurrently with the GSP design on the Demethanizer side reboiler pumps. The GPP plants were originally configured with pumped side reboiler loops for the top, middle, and bottom side reboiler services. Since start-up, these pumps have operated sporadically resulting in inefficient Demethanizer operations. The study concluded that the three sets of pumps could be shut down and completely bypassed, thereby, converting the pumped reboiler loops to thermosyphon circulation.

PROJECT STRATEGY

As previously mentioned, the EEI project was the first major venture undertaken by PGB on any of their existing facilities, and therefore a strong integrated management team of PGB operations and project management was assigned to coordinate the design, procurement, construction, and commissioning activities of the project.

The project strategy was to also maximize local content throughout the project while developing in-house technical and management expertise. As such, PETRONAS' consulting company, OGP Technical Services, was appointed to execute the detailed design, procurement, construction management, and commissioning activities. Ortloff Engineers, Ltd., the process technology licensor, provided continued process design support, technical review, and approval of various key design documents throughout the engineering and commissioning phases of the project.

PETRONAS' subsidiary trading company, Malaysian International Trading Corporation (MITCO), provided the procurement expertise, while a local contractor was awarded the construction contract of all three retrofits. This strategy is known as "multi-contracting", wherein PGB awarded over sixteen procurement and construction packages. By self-performing this work, PGB estimates a savings of approximately US$3,000,000 in comparison to adopting a traditional turn-key engineering, procurement, and construction contract (EPCC).

Project Risk Assessment

PETRONAS' expanding global operations necessitate continuous risk profiling assessments on business ventures that involve potential risk exposure. Consequently, the EEI project team embarked on extensive risk assessment exercises throughout the project to continuously evaluate risks associated with engineering, construction, and/or commissioning activities, as well as any other aspects that could negatively impact the desired project outcome. Two types of risk profiling were specifically adopted for the project; Project Risk Assessment (PRA) for overall risk reviews and Project Independent Review (PIR) for specific areas of concern.

PRA entailed brainstorming sessions by the project team and specific discipline observers. Twelve aspects of the project were deliberated and evaluated, including areas such as scheduling, quality control, contractual, stakeholders, contractor, HSE, financing, and technology risks. PIR meetings were engineering and/or construction reviews by independent parties on specific areas of particular concern, usually before the project embarked on a major milestone, such as the issuance of the Invitation To Bid (ITB) quotation packages or at the end of detailed engineering. Each session report was then closely monitored by the project team, and hence, as the project progressed, each risk ranking was reduced through mitigating actions. In total, six sessions were conducted throughout the 2-1/2 years of project duration, not including an additional ten internal and external audits which emphasized safety, quality, and integrity issues. As a result of this effort, total change orders invoiced at project end were less than 5% of total contract price, and 800,000 man-hours were achieved without a Lost Time Incident (LTI) during the period ending January 2004.

Project Execution

As previously mentioned, the GPP-2, -3, and -4 plants are duplicate designs. The only difference is that the GPP-2 layout is a mirror image of the GPP-3 and -4 plants. This meant that tie-in and equipment locations and pipe routings were essentially the same for all plants. Even though a complete set of drawings were issued for each job, the duplicity of design substantially reduced the number of engineering man-hours which would have otherwise been expended for three separate designs.

As-built drawings are always a major concern with retrofit projects, and consequently three months of engineering time was spent on verification of existing plant drawings. This work included underground scanning to confirm subsurface piping locations and photogrammetry to effectively verify existing pipe routings. These were very valuable exercises in that early identification of any discrepancies minimized costly delays, not only in re-design costs, but in construction costs and overall project delays. In total, the engineering effort for all three retrofits was completed in 5 months.

Construction

The construction sequence for the three retrofit projects varied between sites and was dependent to a large extent on the scheduled turnarounds of the three plants. The GPP-4 plant was the first to be retrofit. The construction work was performed in two phases. The initial phase consisted of installation of all the operating mode switching valves which also served as tie-in valves, bypass piping for the side reboiler pumps, tray modifications to the existing Demethanizer, and the installation of the new mechanical center section (MCS) for the existing expander/compressor. In addition to these activities, the expander casing also had to be shipped to the vendor's shop located in Kuala Lumpur for minor machining to adjust flow clearances and shipped back to the jobsite. All of this work was achieved within the scheduled 8-day GPP-4 plant turnaround.

After the completion of the Phase I work, the GPP-4 resumed operation in the ISS operating mode. At this time, the second phase of the retrofit construction activities commenced which involved the installation of the new GSP equipment and associated piping and instrumentation. This work was performed over a 7-month period and involved working in a live plant which required tremendous effort to ensure the safety of all plant and construction personnel. The construction of the retrofits of GPP-2 and -3 were similar except that the sequence of the Phase I and Phase II work was reversed in order of execution.

One of the most challenging aspects of the retrofit construction activities involved the modifications and replacement of the MCS for the existing Turbo Expander / Compressor units. Being identical plants, the GPP-2, -3, and -4 plants shared a common spare MCS. During the time leading up to the final shut down of GPP-4, the spare rotor was sent to the U.S. for re-wheeling. During the re-wheeling of the spare rotor, the three trains would not have a spare MCS available. After the GPP-4 expander/compressor was modified, the replaced rotor assembly was sent to the U.S. for modification. This then became the MCS for the GPP-3 expander/compressor. Likewise, the GPP-3 rotor was modified and placed in the GPP-2 expander/compressor with the GPP-2 expander/compressor MCS being modified for use as the common spare for all three plants.

Retrofit Commissioning

To minimize risk, each plant was initially re-started in the ISS mode. After stable operation, the plant was warmed-up and operated in essentially a dew point control mode. At this time, gas was routed into the new GSP system. The basic steps in transitioning from an ISS to a GSP operating mode were as follows:

1. Pressure up the GSP system using Demethanizer overhead vapor.
2. Cool down the GSP system using cold Demethanizer overhead vapor.
3. Completely divert Demethanizer overhead vapor into the Ethane Absorber and Subcooler.

4. Completely divert the expander discharge from the Demethanizer to the Ethane Absorber and commission the bottom pumps to return Ethane Absorber liquids to the Demethanizer as reflux.

At this point, the plant is actually running in a modified ISS mode with the Ethane Absorber functioning like a separator. The final step in converting the plant from ISS to the GSP operating mode is to route a portion of the vapor feeding the expander to the Subcooler for use as the reflux stream to the Ethane Absorber.

The critical factors in making this last transition are to closely monitor the cool down rate of the Subcooler. A brazed aluminum heat exchanger is limited to a cool down rate of 1 to 2°C/minute. Secondly, the initiation of the GSP flow through the Subcooler is gradually increased to design rates to once again avoid thermal shock to the Subcooler and upsets to the expander/compressor as the inlet flow to the expander is reduced.

The commissioning of the three plants was:

GPP-4	March 2003
GPP-3	August 2003
GPP-2	December 2003

RETROFIT PERFORMANCE

GPP-4

As mentioned, the GPP-4 retrofit was the first to be commissioned. After switchover from the ISS to GSP operating mode, the existing Demethanizer experienced flooding problems as the plant was cooled down toward design operating temperatures. Evidence of flooding was indicated by a significant increase in the differential pressure in the top section of the column (Trays 1 to 13). Additionally, as the condition worsened, the level would increase in the Ethane Absorber, indicating a carry-over condition from the Demethanizer. Upon further investigation, the flooding seemed to occur at a consistent Low Temperature Separator No. 2 temperature of -52°C.

This upset led to a design review of the internals which indicated that the downpipes from the top chimney tray to Tray 1 were inadequately sized for the new liquid rates feeding the top of the Demethanizer. This is one key aspect of a GSP design, wherein the liquid loading in the top section of the Demethanizer is significantly higher in GSP mode than in the ISS mode when the expander discharge is feeding the top of the tower. Believing the sizing of the downpipes was the direct cause of the carry-over, a redesign was developed for the GPP-3 plant which was the next plant to be modified. Until GPP-4 can be shut down again, the redesigned downpipes for the Demethanizer top chimney tray cannot be installed. Therefore, the decision was made to continue operating GPP-4 in the GSP mode at slightly warmer conditions to minimize the risk of flooding. The GSP design still achieved approximately 91.7% calculated recovery with this operating constraint, based on field performance evaluation test data.

GPP-3

The downpipe sizing error discovered on GPP-4 was corrected as part of the tray modification work during the GPP-3 shut down. The GPP-3 retrofit was then commissioned and experienced the same flooding condition as GPP-4 under similar process operating conditions. This led to the conclusion that there must be other bottlenecks in the tray design of the Demethanizers that were not showing up on existing column drawings. As with GPP-4, the GPP-3 plant could not be shut down and therefore, the plant continues to operate in the GSP mode with warmer than design operating conditions. Although the modification to the downpipes did not eliminate the flooding, this change did mitigate the problem in that the plant has achieved a calculated recovery of 93.4%.

The continued flooding in the GPP-3 Demethanizer, even after the downpipe modification, led to further investigations into the cause of the operating problems experienced in GPP-3 and -4. GPP-2 had yet to be modified, so the effort centered on discovering the cause so additional changes could be implemented on the GPP-2 Demethanizer. The ensuing investigation led to two additional discoveries. First, a report issued in 1993 by the original EPC consortium highlighted a similar flooding condition of the Demethanizer which appeared to be directly related to the temperature of the Low Temperature Separator No. 2. A tower scan was also performed at that time which indicated foaming occurring on Tray 7 which is the feed tray for the separator liquids. Attempts to alleviate the problem in 1993 led to field modifications being made to the configuration of Trays 4 through 7. Figure 3 shows the changes implemented and current tray configuration prior to the retrofit.

This sketch shows that Trays 5 and 6 were removed. A seal pan with 2 – 8" drain pipes was installed to feed downflowing liquids from Tray 4 to Tray 7. Although an active tray, two (2) chimneys were also added to Tray 7. All of these steps were the early attempts to alleviate the problem and in the end, stop the carry-over from the Demethanizer.

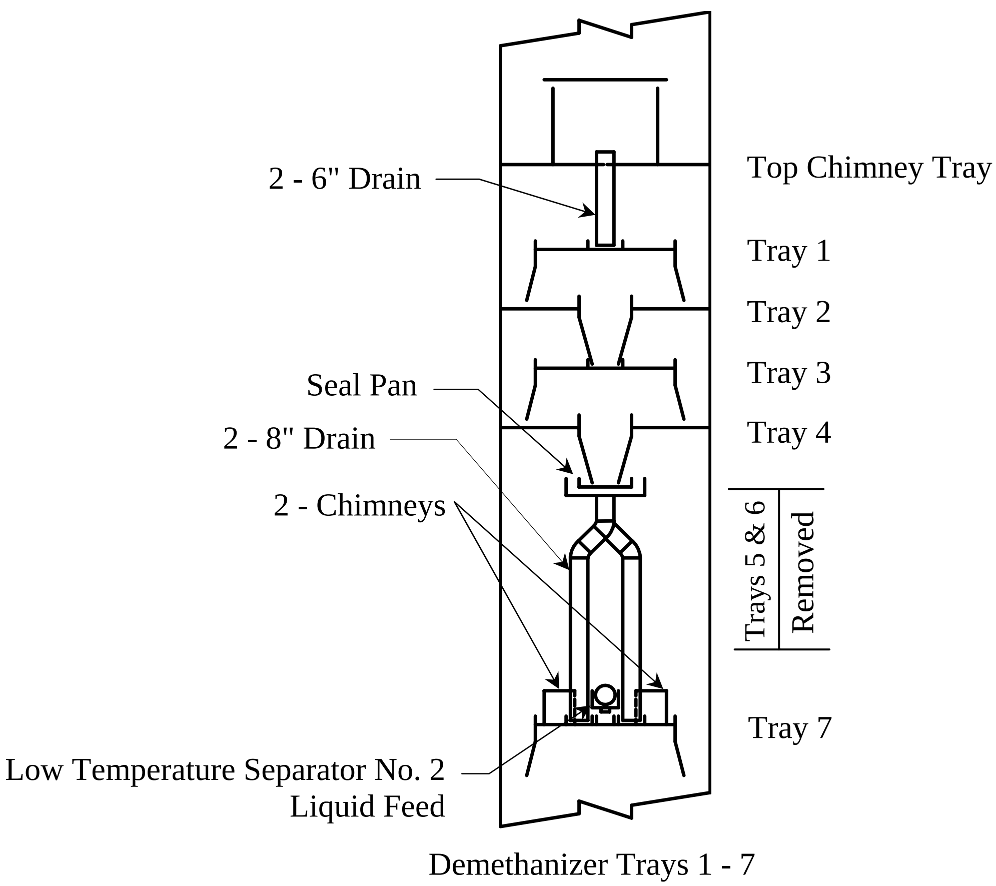

Figure 3 - Demethanizer Tray Configuration

At this time, there was enough uncertainty of the design of the Demethanizer trays that a decision was made to thoroughly inspect the GPP-2 Demethanizer internals to aid in ascertaining what might be causing the flooding condition. Upon entry into the tower, hydrocarbon liquid was found in the seal pan directly under Tray 4. This was unusual in that one would normally expect hydrocarbon liquids in the top of a Demethanizer to be light ends and weather-off rather rapidly once the tower has been warmed up to ambient conditions and made ready for entry.

A decision was made to sample the liquid trapped in the seal pan. A summary of the lab analysis is shown in Table III. Of particular interest, is the presence of aromatics such as benzene, toluene, and xylene. These constituents are known to have relatively high solidification temperatures in relation to the typical operating temperatures of an NGL recovery plant. A sensitivity analysis was performed in the process simulation model by adding 0.1 mol% of benzene in the feed gas to the LTSU. The simulation results indicated this feed gas composition could indeed lead to concentrations in the Low Temperature Separator No. 2 liquids that could cause a freezing condition when flashed to Demethanizer pressure. However, this issue has yet to be verified as the root cause of the flooding phenomena and further analysis will be required to determine the over-all impact of these aromatics in the Demethanizer operations.

Table III
GPP-2 Demethanizer Hydrocarbon Liquid Analysis (Vol %)
(Field Lab Data)

	Naptha	Paraffin	Aromatic		Total
C_5	0.03	0.04			0.07
C_6	3.27	4.22	0.46	Benzene	7.95
C_7	16.77	17.51	7.50	Toluene	41.78
C_8	12.28	17.47	7.13	M-Xylene	36.88
C_9	3.60	6.96	0.92	O-Xylene	11.48
C_{10}	0.68	1.12			1.80
Total	36.61	47.32	16.02		99.95

GPP-2

After inspection of the Demethanizer internals, several additional modifications were implemented in hopes of alleviating the flooding problem. The most significant changes made were:

1. Downpipes from Tray 4 to Tray 7 were re-routed to feed into the downcomer area of Tray 7.
2. Even though chimneys had been installed in Tray 7, the active panels had never been blanked off. These were replaced with blank panels which converted Tray 7 into a true chimney tray configuration.
3. Drain holes were installed on the seal pan under Tray 4 so as to eliminate the possibility of the accumulation of heavy hydrocarbons as was experienced during the initial inspection.

There were also other modifications made with respect to tray valve gauge thicknesses and inlet wier heights.

As mentioned, the GPP-2 retrofit was commissioned in December 2003 and once again, experienced the same flooding condition experienced on GPP-3 and -4. Again, the plant operating conditions were adjusted to maintain a safe margin from flooding and the plant has continued running in the GSP mode. As with the other two plants, the additional changes noted above did not eliminate the tower flooding, however, plant performance was improved in that the GPP-2 plant achieved a calculated recovery of slightly over 95%, based on field test data.

GPP-2, -3, AND -4 PROCESS EVALUATION

Even with the known operating bottleneck in the Demethanizer, plant performance testing has been completed on all three plants and the data analyzed. In summary, the calculated ethane recovery for the three plants, as reported here-in, is:

Table IV
Calculated Ethane Recovery

GPP-2	95.07%
GPP-3	93.44%
GPP-4	91.74%

As previously stated, changes implemented to the trays in the GPP-2 and GPP-3 Demethanizers did not eliminate the flooding problem, however, the stepwise increase in performance does tend to support the idea that these changes have in fact helped to mitigate the impact. This is further supported by the process evaluation of the performance test data. For example, by reducing the number of theoretical stages in the Demethanizer, the GPP-3 simulation resulted in a very reasonable match of the performance test data, especially the Demethanizer temperature profile. This analysis supports the field observations that the GPP-3 tower was operating at or near actual carry over and the top section was in a flooded condition reducing actual tray efficiency. This observation also correlates well with the increased ethane recovery on GPP-2 resulting from improved tray efficiencies in the upper section of the tower due to the additional changes implemented, as outlined above.

CONCLUSION

As of March 2004, all site activities have been completed and efforts are underway to ascertain the cause of the Demethanizer flooding and the possible correlation with aromatic contamination in the LTSU feed gas which could result in a freezing condition within the tower. Until such time as that can be verified, significant improvements have been observed in plant operations. The most noticeable are:

1. Improved stability of the LTSU to accommodate changes in the inlet gas composition.
2. "Snowball" upsets often encountered in the ISS mode have been eliminated.
3. The plants maintain stable operation even with fluctuating concentrations of carbon dioxide in the feed gas.
4. The increased ethane production has provided PETRONAS more flexibility to sustain an uninterrupted ethane supply to its customers.

In all, the retrofits have achieved all of the goals as set forth in the original study.

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