PROCESS RETROFITS MAXIMIZE THE VALUE OF EXISTING NGL AND LPG RECOVERY PLANTS

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ABSTRACT

At many locations, existing NGL and LPG recovery plants are generating less revenue than they might because of limitations in capacity, recovery efficiency, and/or operating flexibility. Rather than building new plants to relieve this constraint on revenue, in many cases the better alternative is to revamp the existing plant.

As many past retrofit projects have shown, the return on the investment required to revamp an existing plant is considerably greater than the return from constructing a new facility. The existing plant already has significant infrastructure (utility systems, buildings, etc.) that can be used as-is after the revamp. With careful process selection for the retrofit, the modifications to the existing processing plant can be minimized to reduce the capital cost, reduce the construction period, and minimize the plant downtime required to make the final tie-ins.

Capacity increases of 30% or more are common when retrofitting existing NGL/LPG plants to use the newer, high efficiency liquids recovery technology. In many cases, recovery efficiency can also be improved significantly. For NGL recovery plants, operating flexibility can also be added by adapting the plant to either recover or reject ethane, allowing efficient ethane recovery when market conditions are favorable and high propane recovery when the ethane market is depressed.

This paper presents several examples of past retrofit projects to show the economic advantages over new construction. Guidelines are also given to help operating companies evaluate the economic benefits that can result from retrofitting their existing processing plants.

INTRODUCTION

Gas processing for liquids recovery is becoming increasingly competitive. In many locations, the majority of the gas being processed belongs to third-parties, forcing gas processors to compete with each other for processing rights. Consequently, the efficiency of a given gas processing plant is often the crucial factor in determining plant profitability, as plant efficiency not only dictates the plant operating cost but also determines to a large degree the amount of gas dedicated to the plant.

For an existing NGL (natural gas liquids) or LPG (liquefied petroleum gas) recovery plant, much of what makes up the operating cost of the plant cannot be changed. The liquids recovery process employed in the plant sets the energy requirements for the plant, and the fixed costs for the plant (personnel costs, taxes, etc.) are usually dictated by the facility and its location.

In many cases, however, a process retrofit can dramatically improve the economics of an existing plant by reducing the unit operating cost and boosting product revenues. Retrofitting the existing plant to a more efficient process can provide the following benefits:

- Higher process efficiency reduces the energy consumption per unit of gas processed.
- Higher process efficiency allows increased plant throughput with the same gas compression power, reducing the fixed costs per unit of gas processed.
- Increased plant throughput translates into greater product sales and revenue.
- Liquid recovery efficiency can also be increased, further raising product sales and revenue.
- Process flexibility can be improved by adding efficient ethane rejection capability.

A process retrofit can provide all the advantages of a new state-of-the-art processing plant at a fraction of the cost. The majority of the cost for a new gas processing plant is <u>not</u> the cost of the cryogenic process equipment in the processing units – it is the cost of the plant infrastructure (land, treating, storage, utility systems, buildings, etc.) and the gas compression equipment. Since the existing NGL or LPG plant already has the infrastructure and compression in place, a process retrofit can usually be accomplished with little or no costs for these plant components. Further, most of the existing processing equipment can often be reused or reapplied in the retrofit process design, minimizing the capital cost of the plant revamp.

This paper will discuss what is involved in a typical plant retrofit and show what can be achieved with a technology retrofit. We believe the benefits will encourage plant owners to consider a retrofit even for those applications where it may not seem feasible or practical on a first look.

RETROFITTING VERSUS DEBOTTLENECKING

Understanding the difference between retrofitting and debottlenecking is crucial to seeing the possibilities for a given facility. Owners are usually pleasantly surprised but somewhat skeptical of the throughput results that can be achieved with a process technology retrofit, especially if there have been problems with the existing facility at the original design rate. This is because most owners are familiar only with the debottlenecking approach to expansion, and still think of the current limitations of the individual pieces of equipment rather than considering that the process conditions change significantly for the retrofit process design to eliminate limitations and problem areas.

Consider, for example, a plant owner with two separate gas processing plants operating in a particular region. Both plants were built during the 1970s, one with a capacity of 100 MMSCFD and one with a capacity of 40 MMSCFD. The pipelines serving the plants could easily be configured to supply all the gas to the larger plant if it had sufficient capacity, which would then allow shutting down the smaller plant and consolidating all operations at the larger plant. The net result would be the elimination of all costs associated with the smaller plant, with the added benefit of an idle processing plant that could be relocated or sold.

One approach to this opportunity would be to investigate debottlenecking the larger plant to add 40 MMSCFD of capacity. In most cases, a review of the existing equipment would quickly determine that there are a number of major systems and equipment items that are too small for the desired plant capacity. Among these would be the dehydrator beds, cold separator, expander, and column. The pressure drops through the existing heat exchangers and interconnecting piping would be very high unless they were replaced. And most importantly, additional gas compression would have to be added to accommodate the higher gas throughput.

With this approach, nearly everything in the plant would be found to be inadequate and require replacement. A 40% increase in plant capacity just does not appear to be economically feasible.

Contrast this now with a process technology retrofit to achieve the same benefit. In a typical process retrofit, most of the existing equipment is retained, rather than replaced like it would be when debottlenecking a plant. The reason for this is that the retrofit process design typically unloads the existing equipment by sharing the load with the equipment added for the process retrofit. Supplemental equipment is added in key areas to provide the desired plant throughput by adding parallel capacity to the existing equipment. The existing equipment sizes no longer constrain the plant capacity, but instead simply determine the size of the equipment to be added. And, in most cases, the existing gas compression is sufficient to achieve the desired capacity increase, often at higher product recovery levels, due to the efficiency gains made possible by the newer technology being retrofitted into the plant.

A further advantage to retrofitting is less impact on plant operations. A debottlenecking project typically requires much more plant downtime than a process technology retrofit. In a debottlenecking project, the equipment to be replaced must be removed before the new equipment can be set in place, requiring that the plant be out of service during the entire time. In most retrofit projects, the new equipment can be set, piped, tested, purged, and checked out while the existing equipment continues to operate as before. When everything is ready, the plant is shut down, the final tie-ins are made, and the retrofitted plant is started back up with the new equipment in service. Since plants cannot generate revenue unless they are operating, minimizing the downtime is critical to the expansion project economics.

When the retrofit approach is considered for the plant in question, a 40% increase in capacity becomes economically feasible. In most cases, the simple pay-out for a process retrofit can be measured in months due to the improvements in plant capacity, recovery efficiency, and ease of operation.

OTHER BENEFITS TO RETROFITTING

Retrofitting an existing processing plant to use the latest technology not only allows expanding the plant capacity, it allows correcting the limitations and deficiencies inherent in first and second generation process designs at the same time. Generally, this means that plant operations are more stable after the retrofit, making the plant easier to operate and optimize.

First generation NGL/LPG technology is employed in most of the gas processing plants constructed in the 1960s and 1970s. These designs provide no external reflux feed and no fractionation stages above the expander feed nozzle on the column. This has often been referred to as the industry standard single-stage or ISS process.

Many first generation expander plants experience instability problems associated with vapor-liquid equilibrium and carbon dioxide (CO_2) freezing, both due in large measure to the dependence of such plants on using the expander outlet stream to provide column reflux. Since a colder expander inlet temperature produces a colder expander outlet temperature and generates more liquid in the top column feed, keeping the cold separator temperature as low as possible is necessary to maximize product recovery. Unfortunately, in most cases this means operating the separator at high pressure and low temperature, a region of the phase envelope for a typical natural gas stream where the vapor-liquid ratio changes quickly.[1] This means that small changes in the separator temperature cause large changes in the amount of vapor entering the expander, resulting in sudden changes in the expander speed which then cause the tower pressure to surge, process gas temperatures to fluctuate, etc. until the whole plant is oscillating. The only way to maintain stable operation is to keep the separator temperature warmer than optimum to avoid this region of instability, limiting the product recoveries than can be achieved.

A second problem for most first generation expander plants is a low tolerance for CO_2 in the feed gas. In most cases, the CO_2 concentration must be kept below 0.5% (often requiring inlet gas treating) to avoid CO_2 buildup in the column that exceeds the solubility limits of the tower liquids, or else CO_2 freezing inside the tower will result. Again, the only recourse is to warm up the separator so that the column remains warm enough to avoid freezing, with the warmer column temperatures causing a corresponding loss in product recoveries.

The second generation NGL/LPG technology was developed to address both of these limitations of the first generation processes.[2] Most of the expander plants built during the 1980s and 1990s are based on second generation technology, which is characterized by an external reflux stream and fractionation stages above the expander feed. This eliminates dependence on the expander to generate tower reflux and provides better recovery at lower energy consumption. However, the second generation processes are often not flexible enough to allow easy adjustment of product recoveries in response to the rapid changes in product values that are typical in today's gas processing environment.

Most operators of first and second generation expander plants are hesitant to reject ethane because of the penalty they suffer in propane recovery as a result. Whereas the price of liquid ethane is based almost entirely on its value as a petrochemical feedstock, the value of propane as both fuel and feedstock makes its price as a liquid more stable. This means that propane is nearly always more valuable as a liquid than as BTUs in the plant residue gas, so losing propane recovery in order to reject ethane to the residue gas can be costly. Third generation NGL/LPG technology was developed to add flexibility to expander plants for high propane recovery regardless of the ethane recovery by providing two external reflux streams for the column. The dual reflux streams are both placed above the expander feed for most ethane recovery designs, and placed above and below the expander feed for most propane recovery designs.[3]

Third generation NGL/LPG technology can be retrofit into nearly any existing first generation or second generation expander plant, as shown by the examples presented in the following section. In all cases, the existing plant gains the advantages of the third generation technology, so that plant capacity is expanded, recovery efficiency is improved, plant operations are simplified, and recurring operating problems are eliminated.

EXAMPLES

Case 1 — Western U.S. NGL Recovery Plant

Figure 1 shows an NGL recovery plant built in the mid-1980s to recover NGL from pipeline gas using a first generation process design. The plant was originally designed to achieve about 80% ethane recovery when processing up to 346 MMSCFD of feed gas. Due to its strategic location, the plant was in a position to process considerably more gas (up to 450 MMSCFD total) if its capacity could be expanded at a reasonable cost.

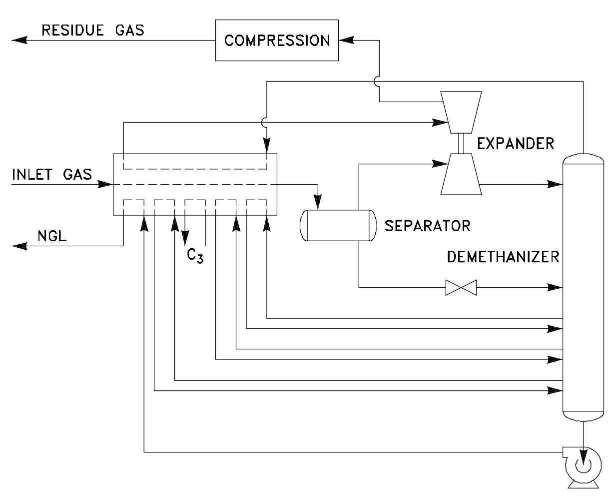

Figure 1 — Original Design

The process economics for the expansion had to take into account the highly variable ambient temperatures and their effect on available compression horsepower in this region of the country. Preliminary studies had already determined that the plant could not be debottlenecked at reasonable cost to achieve the desired capacity increase, but debottlenecking would not have allowed any significant increase in ethane recovery. The plant also routinely experienced cold separator phase envelope instabilities with the current feed composition.

A feasibility study for a third generation technology retrofit, on the other hand, indicated that the capacity improvement and recovery improvement could both be accomplished with relatively modest additions to the processing plant and modifications to the existing gas compression equipment. Further, the retrofit would make it possible to take full advantage of the greater compression power available from the gas turbine drivers during the winter. The inlet gas conditioning units (treating and dehydration) were debottlenecked during an earlier project, so only the processing facilities and compression had to be addressed for the process retrofit. A performance test was conducted on the existing plant to verify equipment operating parameters and confirm that there were no deficiencies in the existing equipment.

Figure 2 shows the plant design after being retrofit to use the Ortloff **R**ecycle **S**plit-**V**apor (RSV) process.[4] The key changes were:

- An absorber with pumps was added to serve as an extension to the existing demethanizer
- A new heat exchanger was added for the external reflux streams
- The internals of the cold separator were modified for better separation efficiency
- The demethanizer internals were revised for the new operating conditions
- The expander was re-wheeled for better expansion and compression efficiency
- The product pumps were modified to increase their capacity
- The residue gas compressors were re-wheeled and the gas turbine drivers were upgraded

The new heat exchangers parallel the existing exchangers so that no modification were necessary to the existing exchangers. Most of the increase in plant capacity is utilized to provide the lower external reflux stream for the new absorber, so the load on the existing exchangers and cold separator is no higher than the original design. With the RSV design, the load on the existing demethanizer column is actually lower than the original design, so its internals were revised for more efficient operation at the lower column loadings.

Since the RSV process has two external reflux streams for rectifying the expander outlet vapor, it has the capability of adjusting the quantity of the upper reflux stream to trade off product recovery for plant throughput and vice versa. When ambient temperature is higher and less power is available from the gas turbine drivers, the upper reflux can be reduced or eliminated entirely, making more of the gas compression power available for residue gas compression. When the weather is colder and the turbine power production is greater, the additional compression power can be used for the upper reflux stream to increase product recoveries. This flexibility is shown graphically in Figure 3. Table 1 compares the original plant design with the retrofit design to show the improvements in capacity (30%) and recovery efficiency (13-24 ethane percentage points).

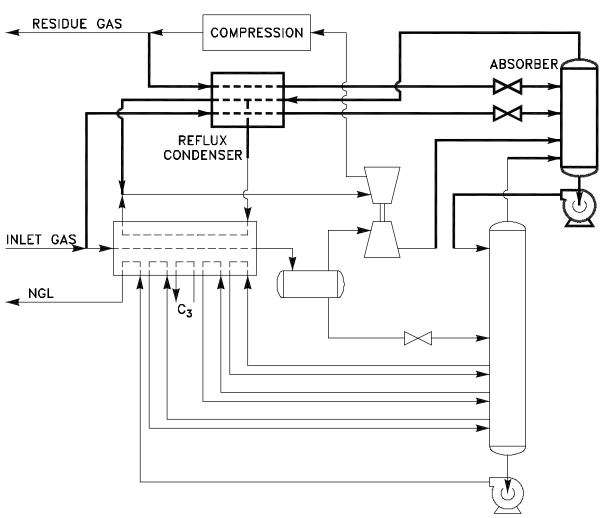

Figure 2 — Retrofit Design

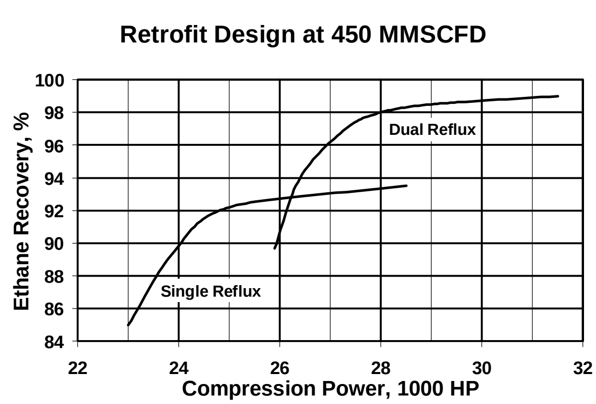

Figure 3 — Recovery vs. Compression Power

This retrofit was completed during the first quarter of 1999. With the exception of the compressor upgrades, all of the equipment for the retrofit was installed while the existing plant continued to operate. A short plant shutdown was all that was required before making the process tie-ins and restarting the retrofitted plant. Subsequent plant performance tests have confirmed the recovery performance shown in Figure 3. The instability problems inherent in the first generation design were also completely eliminated.

Table 1 — Retrofit Comparison

	Original Design	Retrofit	
		Summer	Winter
Inlet Rate, MMSCFD	346	450	450
External Reflux Mode	n/a	Single	Dual
Ethane Recovery, %	77	93	99
Propane Recovery, %	98	99	100

Case 2 — Southern Canada LPG Recovery Plant

Figure 4 shows an LPG recovery plant built in the mid-1990s to recover LPG from pipeline gas using a third generation process design, the Ortloff **I**mproved **O**verhead **R**ecycle (IOR) process. Although the plant was primarily designed for propane recovery (capable of recovering 99% of the propane when processing up to 1,000 MMSCFD of feed gas), the plant was also capable of recovering up to 40% of the ethane when operated in incidental ethane recovery mode. In recent years, the value of liquid ethane in the region has increased enough to favor deeper ethane extraction, so the plant owner began investigating a process conversion to increase the ethane recovery capability.

However, the plant feed gas contains a significant concentration of CO_2. Carbon dioxide falls between methane and ethane in terms of relative volatility.[5] One unfortunate consequence of this is that high ethane recovery in a typical NGL recovery plant usually results in high CO_2 concentrations in the NGL product. Process studies indicated that if the plant was converted to ethane recovery and operated for maximum ethane recovery, the CO_2 content of the NGL product would exceed the pipeline specification of 6.0 mole % (relative to the total methane, ethane, and carbon dioxide contained in the product). Operating the plant in this manner would require adding either inlet gas or product treating, either of which would be very costly additions.

A more economical alternative is to use third generation technology to recover ethane while simultaneously controlling the CO_2 content of the NGL product. Figure 5 shows how this plant can be retrofit to use the Ortloff **G**as **S**ubcooled **P**rocess (GSP) with the Ortloff **C**arbon **D**ioxide **C**ontrol (CDC) feature. The main changes to the processing plant for this retrofit are:

- The deethanizer column is operated as a demethanizer (i.e., on C_1:C_2 ratio control)
- The deethanizer overhead is routed to the bottom of the absorber
- Piping is added to route part of the absorber bottoms to the top of the deethanizer
- The overhead condenser is converted to subcooler service
- The expander is re-wheeled for the new service conditions
- The separator liquid heater pass is converted to side reboiler service

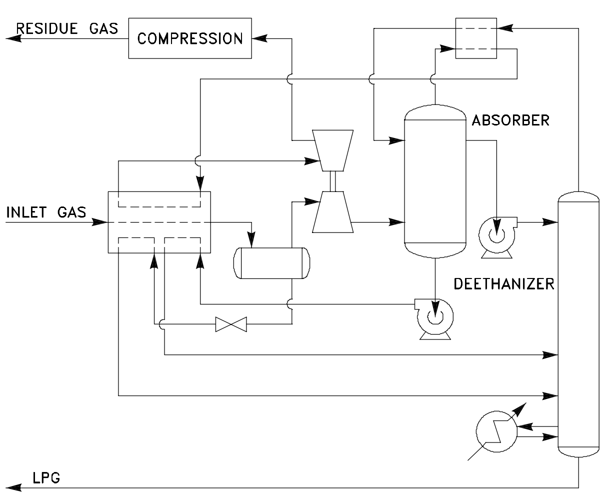

Figure 4 — Original Design

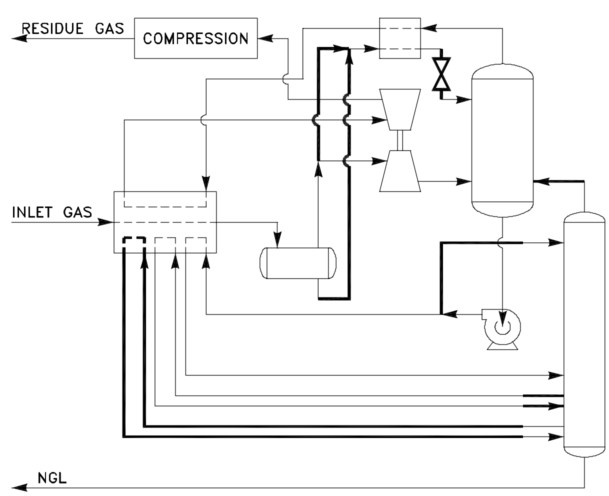

Figure 5 — Retrofit Design

- Expander separator liquids are routed to the subcooler
- A bottom reboiler heated with inlet gas is added

With these changes, the two columns effectively operate as a single column like those typically found in a GSP plant. Unlike a conventional GSP column, however, a portion of the tower liquids from below the expander feed is heated and then supplied to the lower column at an intermediate point. This introduces more methane lower in the column than would otherwise be present, helping to strip the carbon dioxide from the liquids flowing downward in the column. Methane is much more efficient for stripping CO_2 than ethane because it is much more volatile than CO_2. The CO_2 content of the NGL product can be controlled by adjusting the quantity of liquid routed to the inlet heat exchanger, while the temperature at the bottom of the lower column is used to control the C_1:C_2 ratio in the NGL.

A comparison of plant operation before and after the retrofit is given in Table 2. By including the CDC design feature in the retrofit, it is possible to achieve good ethane recovery efficiency without the need to treat the NGL product for CO_2 removal. Additional residue compression is needed to allow operation of the columns at a pressure low enough to support the ethane recovery improvement. This retrofit will be implemented by the owner in the near future.

Table 2 — Retrofit Comparison

	Original Design	Retrofit Design
Inlet Rate, MMSCFD	1,000	1,200
Ethane Recovery, %	0-40	84
Propane Recovery, %	99	97
CO_2 / (C_1 + C_2 + CO_2) in NGL, %	n/a	5.8

Case 3 — Western U.S. NGL Recovery Plant

Figure 6 shows an NGL recovery plant built in the mid-1980s to recover NGL from pipeline gas using a first generation process design. The plant was originally designed for about 60% ethane recovery when processing up to 165 MMSCFD of feed gas. There was more gas available for processing than could be accommodated in the plant, and an ownership position in the product pipeline serving the region made higher ethane recovery attractive.

Preliminary scoping studies indicated that an additional 70 MMSCFD of gas was available if the plant could be expanded to this throughput. However, the available capacity in the product pipeline would allow up to 90% ethane recovery when processing 235 MMSCFD of feed gas. This magnitude of capacity increase (42%) and recovery improvement (30 percentage points) could not be accomplished without increasing the gas compression power, so the owner decided to add a second residue gas compressor that would boost the available power by 38%. This was then set as the basis for the retrofit study.

Although the feed gas to this plant contains CO_2, there is no inlet treating. The existing plant operated at low enough ethane recovery levels that CO_2 freezing in the demethanizer was generally not a problem, and has an existing product treater to remove the minor amount of CO_2 recovered in the NGL product. Since increasing plant throughput and increasing the ethane recovery would both increase the amount of CO_2 captured in the NGL, controlling the CO_2 content of the NGL became the key constraint on the retrofit project. As a result, a GSP/CDC retrofit was selected for the plant so that the revamped plant could be operated for high ethane recovery without increasing the load on the product treater.

Figure 7 shows the plant design after being retrofit to use the Ortloff GSP process with the CDC design feature. The main changes made for the retrofit were:

- An absorber with pumps was added to serve as an extension to the existing demethanizer
- A new heat exchanger was added for the external reflux stream
- The inlet gas shell and tube heat exchangers were rearranged for better heat integration
- The internals of the cold separator were modified for better separation efficiency
- The demethanizer internals were revised for the new operating conditions
- The demethanizer side reboiler was converted to CDC service

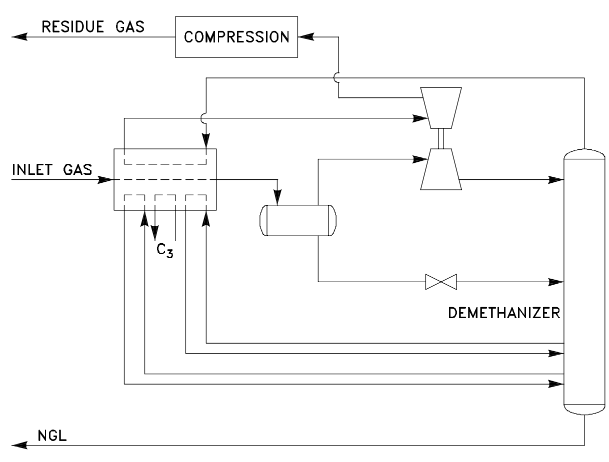

Figure 6 — Original Design

- The expander was re-wheeled for better expansion and compression efficiency
- A new residue gas compressor was added to boost available power

Note that in this application, the split for the external reflux stream is taken downstream of the cold separator, so the existing heat exchangers and cold separator must operate at the higher plant throughput. Although the inlet pressure drop is higher than normal with this arrangement, the additional residue gas compression power can compensate for the slight loss this causes in the refrigeration provided by the expander so that product recoveries are not significantly affected. After modification to its internals, the existing cold separator had sufficient capacity to handle the increased gas flow, so this arrangement was selected since it minimized the changes to the existing piping.

A comparison of plant operation before and after the retrofit is given in Table 3. With the CDC feature included in the retrofit design, the CO_2 content of the NGL product can be controlled as needed to avoid overloading the existing product treater. Figure 8 summarizes process simulations used to evaluate the benefits of CDC, illustrating the typical ethane recovery performance of CDC-equipped processes versus unmodified processes when the plants are operated to control the CO_2 content of the NGL product. In particular, note how flat the recovery curve is for CDC as less and less CO_2 is allowed in the NGL, and how steep the non-CDC curve becomes at low CO_2 contents. The superior stripping characteristics of methane vapor compared to ethane vapor is responsible for the much slower decline in ethane recovery when using CDC to reduce the CO_2 levels in the NGL product.[6]

This retrofit was completed during the first quarter of 1999. All of the new equipment for the retrofit was installed while the existing plant continued to operate.

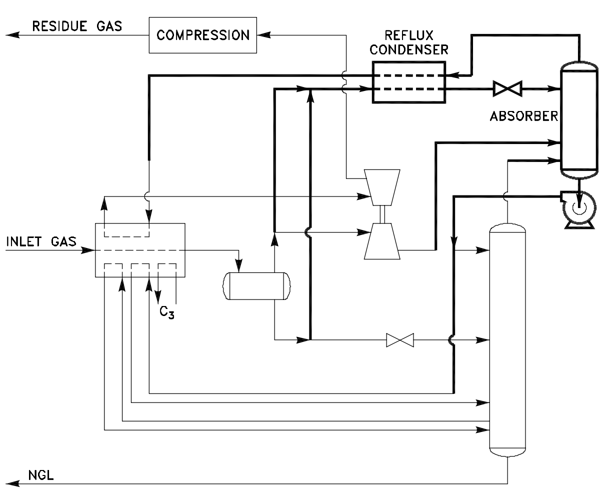

Figure 7 — Retrofit Design

A plant shutdown was then used to modify the inlet heat exchanger piping and make the process tie-ins before restarting the retrofitted plant. Subsequent plant performance tests have confirmed the recovery performance and CO_2 control shown in Figure 8.

Table 3 — Retrofit Comparison

	Original Design	Retrofit Design
Inlet Rate, MMSCFD	165	235
Residue Gas Compression, HP	9,500	13,100
Ethane Recovery, %	60	90
Propane Recovery, %	95	99
CO_2 in NGL, Lb-mole/H	< 21	21

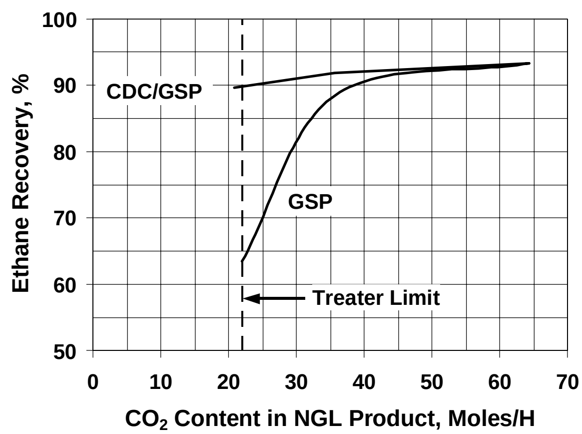

Figure 8 — Ethane Recovery Comparison

Case 4 — Southern U.S. NGL Recovery Plant

Figure 9 shows an NGL recovery plant built in 1972 to recover NGL from a gathering system using a first generation process design. The plant was originally designed for 900 MMSCFD of feed gas, but was processing only about 500 MMSCFD, recovering about 55% of the ethane and 93% of the propane. The plant has a single large gas turbine driven residue compressor and a parallel identical steam turbine driven residue compressor. The steam turbine driven machine was not being used due to the low plant inlet rate.

Although this plant is located near many large ethylene crackers, the ethane market in this region is cyclic due to huge fluctuations in gas price. The plant was only capable of 85% propane recovery efficiency while recovering 20% of the ethane in an ethane rejection mode of operation. The combination of available residue compression and poor recovery in both ethane recovery and ethane rejection modes presented some unique retrofit possibilities.

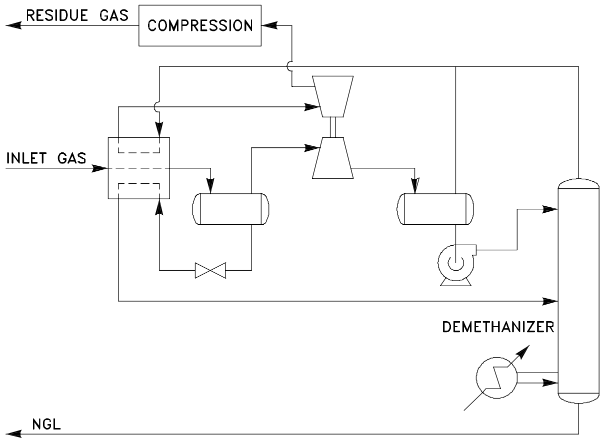

Figure 9 — Original Design

The plant has no product treating, so the 1.5 vol % CO_2 concentration limit in the NGL product was a constraint on the processes that could be considered for the retrofit. This led to the selection of the Ortloff RSV process combined with the CDC design feature to give ultra-high ethane recovery capability with no need for CO_2 removal from the product, plus the capability to go to full ethane rejection while maintaining in excess of 99% propane recovery. The retrofit design is shown in Figure 10. The main changes to be made for the retrofit are:

- An absorber with pumps will be added to serve as an extension to the existing demethanizer
- A new heat exchanger will be added for the external reflux streams
- The demethanizer internals will be revised for the new operating conditions
- The expander was re-wheeled prior to the retrofit

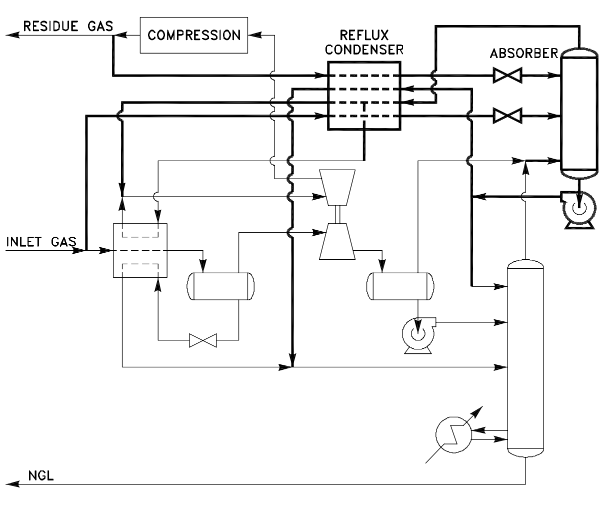

Figure 10 — Retrofit Design

- The second residue gas compressor will be operated to boost available power by 100%, although the actual power requirement is much less

The new heat exchanger for the reflux streams parallel the existing exchangers because this simplified the changes to the plant piping. Since the plant will be operating substantially below its original design capacity, the demethanizer internals will be modified for more efficient mass transfer at the new design conditions. Completion of the project is scheduled for 2003. Table 4 gives a comparison of plant operation before and after the retrofit. Note that CDC allows the ethane recovery to increase substantially while keeping the CO_2 content of the NGL below the specified maximum of 1.5 vol%.

Table 4 — Retrofit Comparison

	Current Operation	Retrofit Design
Inlet Rate, MMSCFD	500	600
Residue Gas Compression, HP	18,000	36,800
Ethane Recovery, %	55	99
Propane Recovery, %	93	100
CO_2 in NGL, vol %	1.5	1.5

PROCESS RETROFIT STUDY PROCEDURE

A description of the procedure for conducting a process retrofit study on a cryogenic NGL/LPG recovery plant has been given previously.[7] In general, most successful retrofit studies follow a procedure similar to the following:

1. The original process design for the plant is simulated using the original feed gas composition. This allows checking the original design basis and provides baseline design information that may be missing for some equipment items.
2. The simulation is updated for any equipment changes made since the plant was built. Both simulations should give good agreement with all available equipment data sheets, or else the deviations must be explained and noted.
3. The simulation is then adjusted to model current plant operations with the current feed composition, flow rates, temperatures, and pressures as input to the simulation. The simulation should be adjusted to give the best agreement between the actual field data and the model, then used to identify any equipment not performing as expected.[8]
4. Any significant deficiencies in equipment performance must be analyzed and resolved before proceeding further. A common deficiency encountered in these studies is poor heat transfer in

heat exchangers due to fouling. A decision must be made whether to accept such deficiencies as a part of the retrofit design basis or to plan on corrective action during a subsequent shutdown to rectify the deficiencies.

5. The heat exchanger performance and pressure drops determined from the simulation in Step 3 are used as the starting point for the retrofit study (subject to any corrections planned for equipment deficiencies discovered). A trial inlet gas flow rate is assumed, the equipment parameters (particularly heat transfer, pressure drop, and compressor efficiency) are adjusted appropriately for the effects of flow rate, and a simulation of the retrofit process design for the plant is prepared.

6. The capacity requirements for the cold separator and tower, the performance of the expander, and compression requirements are computed using the results of the simulation and then compared to what is available from the existing equipment. If no limitations are found, the trial inlet gas flow rate is increased and the simulation and capacity checks are repeated. This continues until either vessel size, column size, expander performance, or compression power becomes limiting.

The inlet gas flow rate determined by iteration in Steps 5 and 6 is generally set as the design basis for the retrofit study. Each equipment item must then be rigorously checked for the new operating conditions. Some equipment such as expanders and plate-fin heat exchangers are best checked by the suppliers, while other equipment can be checked by the design engineers. The items to be checked for the new design conditions should include the following:

(1) Design temperatures, pressures, and metallurgy for all equipment items and piping

(2) Exchanger pressure drop and/or transfer area limitations, potential for tube vibration

(3) Cold separator capacity and liquid surge volume

(4) Expander frame size and lube oil system limitations

(5) Column internals (tray loadings, downcomer stackups, liquid distributors, etc.)

(6) Column reboiler and side reboiler hydraulics

(7) High pressure drop or velocity in existing piping

(8) Capacity of control valves, flow meters, and pressure relief systems

(9) Compression and product pump power and capacity limitations

The results of these rigorous checks may indicate limitations in the existing equipment that must be accommodated in the retrofit design basis. If so, the design simulation should be updated and the equipment checks repeated as necessary. Once this has been completed, then the other plant systems impacted by the new operating conditions (gas treating, gas dehydration, etc.) should be examined to determine if expansion will be required. A cost estimate can then be prepared so that the overall project economics can be evaluated. Additional iterations may be necessary to determine the optimum plan for the facility as decisions are made regarding the tradeoffs between compression, capacity, and product recovery, as well as the impact of changes in plant throughput on other plant systems.

COST OF PROCESS RETROFITS

Given the wide variety of processes employed in the existing NGL/LPG recovery plants and the wide variation in product values in different regions, each retrofit opportunity is unique. The cost of applying a retrofit to a particular plant is affected by many factors, most importantly the amount of equipment in the existing facility that can be reused with the retrofit process design. This makes it difficult to determine the cost of the retrofit without investing some time in studying the existing plant and the alternatives for revamping it, then preparing cost estimates for the selected alternative.

Nevertheless, we have found that many retrofit opportunities follow the same general outline for revamping the existing processing plant. The most common scenario is as follows:

- The existing plant uses first generation technology for ethane or propane recovery.
- The compression power is sufficient for a 30% capacity increase using third generation technology.
- Parallel heat exchangers and an absorber column with pumps can be added to retrofit the plant to use third generation technology.
- The existing heat exchangers and cold separator are adequate for the portion of the plant inlet gas that will feed the expander.
- The existing expander can be re-wheeled for efficient operation at the new conditions.
- A parallel mole sieve bed can be added to the existing dehydration system.
- The product pumps can be debottlenecked for the increase in production.

Schematically, this scenario can be represented as shown in Figure 11. Once these changes have been implemented, the processing plant will be capable of processing about 30% more inlet gas, ethane recovery

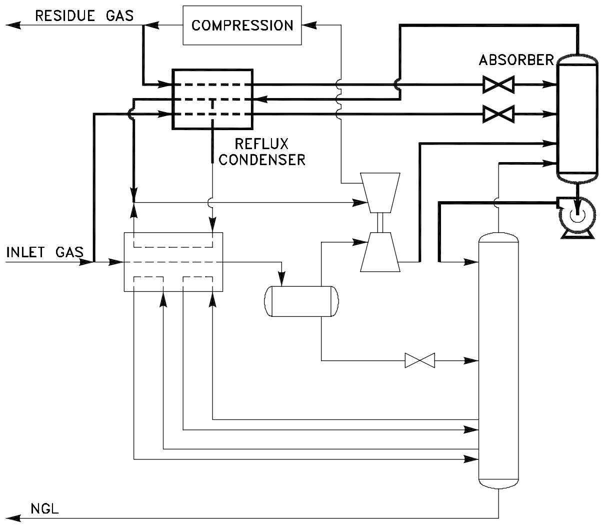

Figure 11 — Typical Plant Retrofit

will improve by 10-20 percentage points, and the plant will be capable of easily switching from high ethane recovery to full ethane rejection while maintaining high propane recovery over the full range of operation.

The approximate cost for this retrofit scenario is given in Figure 12. These costs are for the cryogenic equipment additions only. Compression and treating equipment items need to be estimated separately. This cost information should be sufficiently accurate for use during initial scoping studies for investigating the merits of a retrofit at a particular plant.

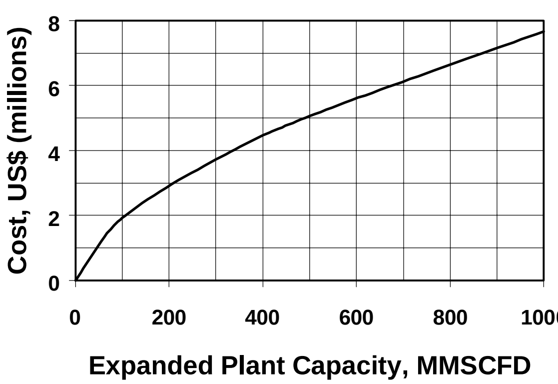

Figure 12 — Approximate Cost of Retrofit

CONCLUSIONS

Many existing NGL/LPG recovery plants are in a position to substantially increase operating revenues by increasing plant throughput, increasing product recoveries, or both. In most cases, a process retrofit can accomplish this at very reasonable cost because most of the existing process equipment can be reused more or less as-is. Process retrofits also allow correcting operating problems in the existing plant by upgrading the process technology. Compared to debottlenecking an existing plant, a process retrofit will normally cost less, have less impact on plant operations during construction, and simplify plant operations once in place.

Most of the NGL/LPG recovery plants in operation today are based on the older first generation and second generation expander plant technology. These plants can be upgraded to the state-of-the-art third generation technology by judicious application of process retrofits, allowing these older plants to achieve the efficiency and ease of operation found in the new plants being built today.

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