Blake G. Powell
Sara Hardner Leon
Darrick W. Eugene
Michelle Alcala
Mackenzie Lewis
Casandra Johnson
William C. Bednar, *Of Counsel*

POWELL & LEON L.L.P

Jay Youngblood
Tyler, Texas

John J. Janssen, Ph.D.
Corpus Christi, Texas

Geneva L. Taylor
Houston, Texas

Rick W. Powell
Pittsburg/Lewisville, Texas

July 10, 2018

Via Hand Delivery
Ms. Michelle Luera
Texas Comptroller of Public Accounts
Data Analysis & Transparency Division
111 E. 17th Street
Austin, Texas 78774

Re: Application #1262 from Targa Delaware, LLC (Falcon Plant) to Culberson County – Allamoore Independent School District

Dear Ms. Luera:

Please find enclosed the amended Application pages concerning the above-referenced Application, pursuant to your June 20th, 2018 email correspondence (attached hereto as **EXHIBIT A**).

Thank you so much for your attention to the foregoing. Please do not hesitate to contact me should you have any questions.

Sincerely,

Shelly Leung

Shelly Leung
Paralegal

Enclosures

EXHIBIT A

From: Michelle Luera
Sent: Wednesday, June 20, 2018 12:13 PM
[redacted]
Subject: Apps#1261 Culberson County-Allamoore ISD - Targa Delaware, LLC (Peregrine Plant) - Application Review and Follow-up Items

Dear Mike and Sara,
I am the analyst processing the application submitted to Culberson County-Allamoore ISD by Targa Delaware, LLC.

In reviewing the application 1261, I have noted a few items that will require revision or further clarification. In lieu of sending a deficiency letter, I am requesting to have the following issues resolved per this email. Please review and submit a response by COB, Friday, July 6th. If these issues are not resolved and I do not receive the information by the date above, then a deficiency letter may be issued.

Section 8: Limitation as Determining Factor

- The applicant answered no to Question 4 - Has the applicant made public statements in SEC filings or other documents regarding its intentions regarding the proposed project location? An internet search found results to the contrary. Currently online there are SEC filings with public statements regarding the projects. Please update Section 8 and submit a revised page 4 of the application.

Section 9: Projected Timeline/Tab 14-Schedule A1

- September 2018 is listed as the first year of qualifying time period. This needs to be updated. The date does match up with Schedule A1 which list 2019 as the first year of the QTP. Please reconcile and submit updated sections of the application accordingly.

Section 11: Investment

- The minimum qualified investment listed for the school district is incorrect. It should be $20 Million. Please submit a revised Section 11.

Section 14: Wage & Employment Information/Tab 13

- The average weekly wage for all jobs(all industries) in the county was incorrectly calculated. It's not 110% of the county average weekly wage for all jobs. You drop the 110%. Also, the 2017 3rd Qtr. wage is $938. All four quarters of 2017 are now available on TRACER. Please recalculate the average weekly wage for all jobs and update Section and Tab 13.

Tabs 4, 7 & 8

- The description indicated the project is a cryogenic natural gas processing plant. I need more information. What is this natural gas specifically made up of? What is processing doing? How many acres make up the project area/RZ? – 120 acres? A couple of components listed require further explanation – buildings and SCADA. Please provide additional information on these items and how they tie back to the project. Please include the response in the descriptions and submit revised Tabs 4, 7 and 8.
- Please provide a summary of the following as it not clear from the description: A description of the 1) feedstock source, 2) final products produced and 3) interconnections (discuss any possible interconnections with operations at or near the site that may impact the proposed project.). Please include the response in the descriptions and submit revised Tabs 4, 7 and 8.

EXHIBIT A

Tab 11

- The sixth map provided shows a schematic drawing of the proposed plant. Would it be possible to get the same map but zoomed in so that is easier to read. In general with most of the maps, there are not many markers and that be a result of the location of the project – rural area. Not many roads are listed.

Signature Page

- Please include a new signature page

I will issue a completeness letter once I receive the information and all outstanding issues are resolved. If the deadline above is not doable, please notify me to let me know when our office can expect your submission. If you have any questions regarding any of items above please let me know. Thanks.

Best regards,

Michelle Luera, CTCM
Senior Research Analyst
Data Analysis and Transparency Division
Texas Comptroller of Public Accounts
111 E. 17th St.
Austin, TX 78774
(512)463-6053
(800)531-5441 ext.3-6053
fax (512)475-0664

AMENDMENT 1 [6/27/18]

SECTION 6: Eligibility Under Tax Code Chapter 313.024

1.	Are you an entity subject to the tax under Tax Code, Chapter 171?	☑ Yes	☐ No
2.	The property will be used for one of the following activities:		
	(1) manufacturing	☑ Yes	☐ No
	(2) research and development	☐ Yes	☑ No
	(3) a clean coal project, as defined by Section 5.001, Water Code	☐ Yes	☑ No
	(4) an advanced clean energy project, as defined by Section 382.003, Health and Safety Code	☐ Yes	☑ No
	(5) renewable energy electric generation	☐ Yes	☑ No
	(6) electric power generation using integrated gasification combined cycle technology	☐ Yes	☑ No
	(7) nuclear electric power generation	☐ Yes	☑ No
	(8) a computer center that is used as an integral part or as a necessary auxiliary part for the activity conducted by applicant in one or more activities described by Subdivisions (1) through (7)	☐ Yes	☑ No
	(9) a Texas Priority Project, as defined by 313.024(e)(7) and TAC 9.1051	☐ Yes	☑ No
3.	Are you requesting that any of the land be classified as qualified investment?	☐ Yes	☑ No
4.	Will any of the proposed qualified investment be leased under a capitalized lease?	☐ Yes	☑ No
5.	Will any of the proposed qualified investment be leased under an operating lease?	☐ Yes	☑ No
6.	Are you including property that is owned by a person other than the applicant?	☐ Yes	☑ No
7.	Will any property be pooled or proposed to be pooled with property owned by the applicant in determining the amount of your qualified investment?	☐ Yes	☑ No

SECTION 7: Project Description

1. In **Tab 4**, attach a detailed description of the scope of the proposed project, including, at a minimum, the type and planned use of real and tangible personal property, the nature of the business, a timeline for property construction or installation, and any other relevant information.

2. Check the project characteristics that apply to the proposed project:

- ☑ Land has no existing improvements
- ☐ Land has existing improvements *(complete Section 13)*
- ☐ Expansion of existing operation on the land *(complete Section 13)*
- ☐ Relocation within Texas

SECTION 8: Limitation as Determining Factor

1.	Does the applicant currently own the land on which the proposed project will occur?	☑ Yes	☐ No
2.	Has the applicant entered into any agreements, contracts or letters of intent related to the proposed project?	☐ Yes	☑ No
3.	Does the applicant have current business activities at the location where the proposed project will occur?	☐ Yes	☑ No
4.	Has the applicant made public statements in SEC filings or other documents regarding its intentions regarding the proposed project location?	☑ Yes	☐ No
5.	Has the applicant received any local or state permits for activities on the proposed project site?	☐ Yes	☑ No
6.	Has the applicant received commitments for state or local incentives for activities at the proposed project site?	☐ Yes	☑ No
7.	Is the applicant evaluating other locations not in Texas for the proposed project?	☑ Yes	☐ No
8.	Has the applicant provided capital investment or return on investment information for the proposed project in comparison with other alternative investment opportunities?	☐ Yes	☑ No
9.	Has the applicant provided information related to the applicant's inputs, transportation and markets for the proposed project?	☐ Yes	☑ No
10.	Are you submitting information to assist in the determination as to whether the limitation on appraised value is a determining factor in the applicant's decision to invest capital and construct the project in Texas?	☑ Yes	☐ No

Chapter 313.026(e) states "the applicant may submit information to the Comptroller that would provide a basis for an affirmative determination under Subsection (c)(2)." If you answered "yes" to any of the questions in Section 8, attach supporting information in Tab 5.

AMENDMENT 1 [6/27/18]

SECTION 9: Projected Timeline

1. Application approval by school board . . . May 2018
2. Commencement of construction . . . November 2018
3. Beginning of qualifying time period . . . January 2019
4. First year of limitation . . . January 2020
5. Begin hiring new employees . . . June 2019
6. Commencement of commercial operations . . . September 2019
7. Do you propose to construct a new building or to erect or affix a new improvement after your application review start date *(date your application is finally determined to be complete)*? . . . ☑ Yes ☐ No

   Note: Improvements made before that time may not be considered qualified property.
8. When do you anticipate the new buildings or improvements will be placed in service? . . . September 2019

SECTION 10: The Property

1. Identify county or counties in which the proposed project will be located: Culberson County
2. Identify Central Appraisal District (CAD) that will be responsible for appraising the property: Culberson County CAD
3. Will this CAD be acting on behalf of another CAD to appraise this property? . . . ☐ Yes ☑ No
4. List all taxing entities that have jurisdiction for the property, the portion of project within each entity and tax rates for each entity:

   County: Culberson County, .233880 - 100% *(Name, tax rate and percent of project)*

   City: N/A *(Name, tax rate and percent of project)*

   Hospital District: Culberson Cty Hosp., .18373 - 100% *(Name, tax rate and percent of project)*

   Water District: N/A *(Name, tax rate and percent of project)*

   Other *(describe)*: N/A *(Name, tax rate and percent of project)*

   Other *(describe)*: N/A *(Name, tax rate and percent of project)*
5. Is the project located entirely within the ISD listed in Section 1? . . . ☑ Yes ☐ No

   5a. If no, attach in **Tab 6** additional information on the project scope and size to assist in the economic analysis.
6. Did you receive a determination from the Texas Economic Development and Tourism Office that this proposed project and at least one other project seeking a limitation agreement constitute a single unified project (SUP), as allowed in §313.024(d-2)? . . . ☐ Yes ☑ No

   6a. If yes, attach in **Tab 6** supporting documentation from the Office of the Governor.

SECTION 11: Investment

NOTE: The minimum amount of qualified investment required to qualify for an appraised value limitation and the minimum amount of appraised value limitation vary depending on whether the school district is classified as Subchapter B or Subchapter C, and the taxable value of the property within the school district. For assistance in determining estimates of these minimums, access the Comptroller's website at **comptroller.texas.gov/economy/local/ch313/**.

1. At the time of application, what is the estimated minimum qualified investment required for this school district? . . . 20,000,000.00
2. What is the amount of appraised value limitation for which you are applying? . . . 25,000,000.00

   Note: The property value limitation amount is based on property values available at the time of application and may change prior to the execution of any final agreement.
3. Does the qualified investment meet the requirements of Tax Code §313.021(1)? . . . ☑ Yes ☐ No
4. Attach a description of the qualified investment [See §313.021(1).] The description must include:
   a. a specific and detailed description of the qualified investment you propose to make on the property for which you are requesting an appraised value limitation as defined by Tax Code §313.021 (**Tab 7**);
   b. a description of any new buildings, proposed new improvements or personal property which you intend to include as part of your minimum qualified investment (**Tab 7**); and
   c. a detailed map of the qualified investment showing location of tangible personal property to be placed in service during the qualifying time period and buildings to be constructed during the qualifying time period, with vicinity map (**Tab 11**).
5. Do you intend to make at least the minimum qualified investment required by Tax Code §313.023 (or §313.053 for Subchapter C school districts) for the relevant school district category during the qualifying time period? . . . ☑ Yes ☐ No

AMENDMENT 1 [6/27/18]

SECTION 14: Wage and Employment Information

1. What is the estimated number of permanent jobs (more than 1,600 hours a year), with the applicant or a contractor of the applicant, on the proposed qualified property during the last complete quarter before the application review start date (date your application is finally determined to be complete)? 0

2. What is the last complete calendar quarter before application review start date:

   ☑ First Quarter ☐ Second Quarter ☐ Third Quarter ☐ Fourth Quarter of 2018 *(year)*

3. What were the number of permanent jobs (more than 1,600 hours a year) this applicant had in Texas during the most recent quarter reported to the Texas Workforce Commission (TWC)? 0

   Note: For job definitions see TAC §9.1051 and Tax Code §313.021(3).

4. What is the number of new qualifying jobs you are committing to create? 10

5. What is the number of new non-qualifying jobs you are estimating you will create? 0

6. Do you intend to request that the governing body waive the minimum new qualifying job creation requirement, as provided under Tax Code §313.025(f-1)? . . . . . ☐ Yes ☑ No

   6a. If yes, attach evidence in **Tab 12** documenting that the new qualifying job creation requirement above exceeds the number of employees necessary for the operation, according to industry standards.

7. Attach in **Tab 13** the four most recent quarters of data for each wage calculation below, including documentation from the TWC website. The final actual statutory minimum annual wage requirement for the applicant for each qualifying job — which may differ slightly from this estimate — will be based on information from the four quarterly periods for which data were available at the time of the application review start date (date of a completed application). See TAC §9.1051(21) and (22).

   a. Average weekly wage for all jobs (all industries) in the county is 949.00

   b. 110% of the average weekly wage for manufacturing jobs in the county is 1,105.78

   c. 110% of the average weekly wage for manufacturing jobs in the region is 850.13

8. Which Tax Code section are you using to estimate the qualifying job wage standard required for this project? . . . . . ☐ §313.021(5)(A) or ☑ §313.021(5)(B)

9. What is the minimum required annual wage for each qualifying job based on the qualified property? 44,207.00

10. What is the annual wage you are committing to pay for each of the new qualifying jobs you create on the qualified property? 44,207.00

11. Will the qualifying jobs meet all minimum requirements set out in Tax Code §313.021(3)? . . . . . ☑ Yes ☐ No

12. Do you intend to satisfy the minimum qualifying job requirement through a determination of cumulative economic benefits to the state as provided by §313.021(3)(F)? . . . . . ☐ Yes ☑ No

    12a. If yes, attach in **Tab 12** supporting documentation from the TWC, pursuant to §313.021(3)(F).

13. Do you intend to rely on the project being part of a single unified project, as allowed in §313.024(d-2), in meeting the qualifying job requirements? . . . . . ☐ Yes ☑ No

    13a. If yes, attach in **Tab 6** supporting documentation including a list of qualifying jobs in the other school district(s).

SECTION 15: Economic Impact

1. Complete and attach Schedules A1, A2, B, C, and D in **Tab 14**. Note: Excel spreadsheet versions of schedules are available for download and printing at URL listed below.
2. Attach an Economic Impact Analysis, if supplied by other than the Comptroller's Office, in **Tab 15**. *(not required)*
3. If there are any other payments made in the state or economic information that you believe should be included in the economic analysis, attach a separate schedule showing the amount for each year affected, including an explanation, in **Tab 15**.

SECTION 16: Authorized Signatures and Applicant Certification

After the application and schedules are complete, an authorized representative from the school district and the business should review the application documents and complete this authorization page. Attach the completed authorization page in **Tab 17**. **NOTE:** If you amend your application, you will need to obtain new signatures and resubmit this page, Section 16, with the amendment request.

1. Authorized School District Representative Signature

I am the authorized representative for the school district to which this application is being submitted. I understand that this application is a government record as defined in Chapter 37 of the Texas Penal Code.

print here Ken Baugh
Print Name *(Authorized School District Representative)*

Superintendent
Title

sign here Ken Baugh
Signature *(Authorized School District Representative)*

7-9-18
Date

2. Authorized Company Representative (Applicant) Signature and Notarization

I am the authorized representative for the business entity for the purpose of filing this application. I understand that this application is a government record as defined in Chapter 37 of the Texas Penal Code. The information contained in this application and schedules is true and correct to the best of my knowledge and belief.

I hereby certify and affirm that the business entity I represent is in good standing under the laws of the state in which the business entity was organized and that no delinquent taxes are owed to the State of Texas.

print here John D. Thompson
Print Name *(Authorized Company Representative (Applicant))*

Vice President, Tax
Title

sign here
Signature *(Authorized Company Representative (Applicant))*

6/25/18
Date

RUTH HENDERSON
Notary Public, State of Texas
Comm. Expires 11-25-2018
Notary ID 128454554

(Notary Seal)

GIVEN under my hand and seal of office this, the

25th day of June, 2018

Ruth Henderson
Notary Public in and for the State of Texas

My Commission expires: November 25, 2018

If you make a false statement on this application, you could be found guilty of a Class A misdemeanor or a state jail felony under Texas Penal Code Section 37.10.

AMENDMENT 1 [6/27/18]

Detailed Description of Project

AMENDMENT 1 [6/27/2018]

DETAILED PROJECT DESCRIPTION OF QUALIFIED INVESTMENT
CULBERSON COUNTY - ALLAMOORE INDEPENDENT SCHOOL DISTRICT

Targa Delaware, LLC (or "the Company") is a leading midstream energy company whose primary activities include:

- Gathering, treating, processing and transporting natural gas and natural gas liquids to a variety of markets and states
- Storing, fractionating, treating, transporting, and selling NGL's and NGL products, including services to LPG exporters
- Gathering, storing, and terminaling crude oil
- Storing, terminaling, and selling refined petroleum products

Targa currently operates over 27,000 miles of pipeline, 40 gas processing plants, 4 G&P crude terminals, 2 fractionation locations, 1 hydrotreater facility, 1 gas treating facility, 18 NGL terminals, 3 petroleum logistics facilities, and 2 storage facilities. There are also transportation assets, including 700 railcars, 90 tractors, and 20 barges. Locations for these operations included Arizona, Florida, Kansas, Louisiana, Maryland, Mississippi, North Dakota, New Mexico, Oklahoma, Texas, and Washington.

Targa's pipeline footprint provides substantial flexibility in where future facilities or investments may be located. Capital investments are allocated to projects and locations based on expected economic return and property tax liabilities can make up a substantial ongoing cost of operation.

Proposed Project Description

Targa Delaware, LLC proposes to build a new 250 mmscf/d Gas Processing Plant in Culberson County – Allamoore ISD, Texas on a reinvestment zone of approximately 80 acres. Projected timeline for Targa to start construction is November of 2018 and start hiring the new employees in June of 2019. This should allow for completion and commencement of commercial operations to start in September of 2019.

Cryogenic Natural Gas Processing Plant

The Gas Processing Plant will manufacture both dry natural gas, and natural gas liquids for sale to consumers and refiners. Equipment systems will include a refrigerated cryogenic gas plant, inlet & liquids handling, dehydration & treating, liquids stabilization, and gas/liquids delivery. If completed, the gas processing plant

will be designed to process 250mmcf/d of gas and would include the components listed below.

- Buildings (Maintenance and Operations), Foundations, Inlet Separator, Amine Unit, Boilers, Heat Exchangers, Natural Gas/Air/H2O Piping, Control
- Valves, Dehydration Units, Knock Out Drums, Slug Catcher, Compressors, Vessels, Heat Exchanger, SCADA (monitoring software) plus Controls.
- ENVIRONMENTAL: (A) Flare-Stack, Scrubber, Leak Detection; (L) Liners, Containment.

After installation, this would provide a long-term processing, compression and residue gas takeaway in the Delaware Basin Region of Texas.

Summary of plant feed stock and finished products

1. Feedstock Source: Raw Natural Gas produced at the well-head and transported through gathering systems from various producers in the Permian Basin.
2. Final Products Produced:
    a. Mixed NGL's: The mixed NGL's will be transported via pipeline from the plant to multiple markets for storage and further fractionation.
    b. Natural Gas: The residue gas will be compressed and delivered to a newly constructed pipeline adjacent to the facility to be delivered to multiple markets.
3. Interconnections
    a. The plant will be interconnected via newly constructed pipelines to allow the final products to be delivered to the market.

AMENDMENT 1 [6/27/2018]

Summary of Components

- Inlet Slug Catchers
- Inlet Separation and Filtration
- Amine treating for CO2 Removal
- TEG dehydration for H2O Removal
- Thermal Oxidizers
- Molecular Sieve Dehydration
- GSP Cryogenic Gas Plants
- Residue Recompression units
- Heat Medium Systems
- Flare System (common for all trains)
- Water supply, drain systems, waste water
- Utilities (fuel, air, R.O. water)

AMENDMENT 1 [6/27/18]

Processing Natural Gas

Natural gas, as it is used by consumers, is much different from the natural gas that is brought from underground up to the wellhead. Although the processing of natural gas is in many respects less complicated than the processing and refining of crude oil, it is equally as necessary before its use by end users.

Natural gas is composed almost entirely of methane. However, natural gas found at the wellhead, although still composed primarily of methane, is by no means as pure. Raw natural gas comes from three types of wells: oil wells, gas wells, and condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas'. This gas can exist separate from oil in the formation (free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed 'nonassociated gas'. Gas wells typically produce raw natural gas by itself, while condensate wells produce free natural gas along with a semi-liquid hydrocarbon condensate. Whatever the source of the natural gas, once separated from crude oil (if present) it commonly exists in mixtures with other hydrocarbons; principally ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds.

Natural gas processing consists of separating all the various hydrocarbons and fluids from the pure natural gas, to produce what is known as 'pipeline quality' dry natural gas. Major transportation pipelines usually impose restrictions on the make-up of the natural gas that is allowed into the pipeline. That means that before the natural gas can be transported it must be purified. While the ethane, propane, butane, and pentanes must be removed from natural gas, this does not mean that they are all 'waste products'.

In fact, associated hydrocarbons, known as 'natural gas liquids' (NGLs) can be very valuable by-products of natural gas processing. NGLs include ethane, propane, butane, iso-butane, and natural gasoline. These NGLs are sold separately and have a variety of different uses; including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy.

AMENDMENT 1 [6/27/18]

A Natural Gas Processing Plant
Source: Duke Energy Gas Transmission Canada

While some of the needed processing can be accomplished at or near the wellhead (field processing), the complete processing of natural gas takes place at a processing plant, usually located in a natural gas producing region. The extracted natural gas is transported to these processing plants through a network of gathering pipelines, which are small-diameter, low pressure pipes. A complex gathering system can consist of thousands of miles of pipes, interconnecting the processing plant to upwards of 100 wells in the area. According to the American Gas Association's Gas Facts 2000, there was an estimated 36,100 miles of gathering system pipelines in the U.S. in 1999.

The actual practice of processing natural gas to pipeline dry gas quality levels can be quite complex, but usually involves four main processes to remove the various impurities:

- Oil and Condensate Removal
- Water Removal
- Separation of Natural Gas Liquids
- Sulfur and Carbon Dioxide Removal

AMENDMENT 1 [6/27/18]

Oil and Condensate Removal

The actual process used to separate oil from natural gas, as well as the equipment that is used, can vary widely. Although dry pipeline quality natural gas is virtually identical across different geographic areas, raw natural gas from different regions may have different compositions and separation requirements. In many instances, natural gas is dissolved in oil underground primarily due to the pressure that the formation is under. When this natural gas and oil is produced, it is possible that it will separate on its own, simply due to decreased pressure; much like opening a can of soda pop allows the release of dissolved carbon dioxide. In these cases, separation of oil and gas is relatively easy, and the two hydrocarbons are sent separate ways for further processing. The most basic type of separator is known as a conventional separator. It consists of a simple closed tank, where the force of gravity serves to separate the heavier liquids like oil, and the lighter gases, like natural gas.

Gas Processing Engineers
Source: ChevronTexaco Corporation

Water Removal

In addition to separating oil and some condensate from the wet gas stream, it is necessary to remove most of the associated water. Most of the liquid, free water associated with extracted natural gas is removed by simple separation methods at or near the wellhead. However, the removal of the water vapor that exists in solution in natural gas requires a more complex treatment. This treatment consists of 'dehydrating' the natural gas, which usually involves one of two processes: either absorption, or adsorption.

Absorption occurs when the water vapor is taken out by a dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface.

Glycol Dehydration

An example of absorption dehydration is known as Glycol Dehydration. In this process, a liquid desiccant dehydrator serves to absorb water vapor from the gas stream. Glycol, the principal agent in this process, has a chemical affinity for water. This means that, when in contact with a stream of natural gas that contains water, glycol will serve to 'steal' the water out of the gas stream. Essentially, glycol dehydration involves using a glycol solution, usually either diethylene glycol (DEG)

or triethylene glycol (TEG), which is brought into contact with the wet gas stream in what is called the 'contactor'. The glycol solution will absorb water from the wet gas. Once absorbed, the glycol particles become heavier and sink to the bottom of the contactor where they are removed. The natural gas, having been stripped of most of its water content, is then transported out of the dehydrator. The glycol solution, bearing all of the water stripped from the natural gas, is put through a specialized boiler designed to vaporize only the water out of the solution. While water has a boiling point of 212 degrees Fahrenheit, glycol does not boil until 400 degrees Fahrenheit. This boiling point differential makes it relatively easy to remove water from the glycol solution, allowing it to be reused in the dehydration process.

An innovation in this process has been the addition of flash tank separator-condensers. As well as absorbing water from the wet gas stream, the glycol solution occasionally carries with it small amounts of methane and other compounds found in the wet gas. In the past, this methane was simply vented out of the boiler. In addition to losing a portion of the natural gas that was extracted, this venting contributes to air pollution and the greenhouse effect. To decrease the amount of methane and other compounds that are lost, flash tank separator-condensers work to remove these compounds before the glycol solution reaches the boiler. Essentially, a flash tank separator consists of a device that reduces the pressure of the glycol solution stream, allowing the methane and other hydrocarbons to vaporize ('flash'). The glycol solution then travels to the boiler, which may also be fitted with air or water-cooled condensers, which serve to capture any remaining organic compounds that may remain in the glycol solution. In practice, according to the Department of Energy's Office of Fossil Energy, these systems have been shown to recover 90 to 99 percent of methane that would otherwise be flared into the atmosphere.

Solid-Desiccant Dehydration

Solid-desiccant dehydration is the primary form of dehydrating natural gas using adsorption, and usually consists of two or more adsorption towers, which are filled with a solid desiccant. Typical desiccants include activated alumina or a granular silica gel material. Wet natural gas is passed through these towers, from top to bottom. As the wet gas passes around the particles of desiccant material, water is retained on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the bottom of the tower.

Separation of Natural Gas Liquids

Absorption Towers
Source: Duke Energy Gas Transmission Canada

Natural gas coming directly from a well contains many natural gas liquids that are commonly removed. In most instances, natural gas liquids (NGLs) have higher value as separate products, and it is thus economical to remove them from the gas stream. The removal of natural gas liquids usually takes place in a relatively centralized processing plant, and uses techniques like those used to dehydrate natural gas.

The Cryogenic Expansion Process

Cryogenic processes are used to extract NGLs from natural gas. Lighter hydrocarbons, such as ethane, are often more difficult to recover from the natural gas stream. In certain instances, it is economic to simply leave the lighter NGLs in the natural gas stream. However, if it is economic to extract ethane and other lighter hydrocarbons, cryogenic processes are required for high recovery rates. Essentially, cryogenic processes consist of dropping the temperature of the gas stream to around -120 degrees Fahrenheit.

There are many ways of chilling the gas to these temperatures, but one of the most effective is known as the turbo expander process. In this process, external refrigerants are used to cool the natural gas stream. Then, an expansion turbine is used to rapidly expand the chilled gases, which causes the temperature to drop significantly. This rapid temperature drop condenses ethane and other hydrocarbons in the gas stream, while maintaining methane in gaseous form. This process allows for the recovery of about 90 to 95 percent of the ethane originally in the gas stream. In addition, the expansion turbine can convert some of the energy released when the natural gas stream is expanded into recompressing the gaseous methane effluent, thus saving energy costs associated with extracting ethane.

The extraction of NGLs from the natural gas stream produces both cleaner, purer natural gas, as well as the valuable hydrocarbons that are the NGLs themselves.

Sulfur and Carbon Dioxide Removal

In addition to water, oil, and NGL removal, one of the most important parts of gas processing involves the removal of sulfur and carbon dioxide. Natural gas from some wells contains significant amounts of sulfur and carbon dioxide. This natural

gas, because of the rotten smell provided by its sulfur content, is commonly called ‘sour gas’. Sour gas is undesirable because the sulfur compounds it contains can be extremely harmful, even lethal, to breathe. Sour gas can also be extremely corrosive. In addition, the sulfur that exists in the natural gas stream can be extracted and marketed on its own. In fact, according to the USGS, U.S. sulfur production from gas processing plants accounts for about 15 percent of the total U.S. production of sulfur.

Sulfur exists in natural gas as hydrogen sulfide (H_2S), and the gas is usually considered sour if the hydrogen sulfide content exceeds 5.7 milligrams of H_2S per cubic meter of natural gas. The process for removing hydrogen sulfide from sour gas is commonly referred to as ‘sweetening’ the gas.

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Gas processing is an instrumental piece of the natural gas value chain. It is instrumental in ensuring that the natural gas intended for use is as clean and pure as possible, making it the clean burning and environmentally sound energy choice. Once the natural gas has been fully processed, and is ready to be consumed, it must be transported from those areas that produce natural gas, to those areas that require it.

AMENDMENT 1 [6/27/18]

Description of Qualified Investment

AMENDMENT 1 [6/27/2018]

DETAILED PROJECT DESCRIPTION OF QUALIFIED INVESTMENT
CULBERSON COUNTY - ALLAMOORE INDEPENDENT SCHOOL DISTRICT

Targa Delaware, LLC (or "the Company") is a leading midstream energy company whose primary activities include:

- Gathering, treating, processing and transporting natural gas and natural gas liquids to a variety of markets and states
- Storing, fractionating, treating, transporting, and selling NGL's and NGL products, including services to LPG exporters
- Gathering, storing, and terminaling crude oil
- Storing, terminaling, and selling refined petroleum products

Targa currently operates over 27,000 miles of pipeline, 40 gas processing plants, 4 G&P crude terminals, 2 fractionation locations, 1 hydrotreater facility, 1 gas treating facility, 18 NGL terminals, 3 petroleum logistics facilities, and 2 storage facilities. There are also transportation assets, including 700 railcars, 90 tractors, and 20 barges. Locations for these operations included Arizona, Florida, Kansas, Louisiana, Maryland, Mississippi, North Dakota, New Mexico, Oklahoma, Texas, and Washington.

Targa's pipeline footprint provides substantial flexibility in where future facilities or investments may be located. Capital investments are allocated to projects and locations based on expected economic return and property tax liabilities can make up a substantial ongoing cost of operation.

Proposed Project Description

Targa Delaware, LLC proposes to build a new 250 mmscf/d Gas Processing Plant in Culberson County – Allamoore ISD, Texas on a reinvestment zone of approximately 80 acres. Projected timeline for Targa to start construction is November of 2018 and start hiring the new employees in June of 2019. This should allow for completion and commencement of commercial operations to start in September of 2019.

Cryogenic Natural Gas Processing Plant

The Gas Processing Plant will manufacture both dry natural gas, and natural gas liquids for sale to consumers and refiners. Equipment systems will include a refrigerated cryogenic gas plant, inlet & liquids handling, dehydration & treating, liquids stabilization, and gas/liquids delivery. If completed, the gas processing plant

will be designed to process 250mmcf/d of gas and would include the components listed below.

- Buildings (Maintenance and Operations), Foundations, Inlet Separator, Amine Unit, Boilers, Heat Exchangers, Natural Gas/Air/H2O Piping, Control
- Valves, Dehydration Units, Knock Out Drums, Slug Catcher, Compressors, Vessels, Heat Exchanger, SCADA (monitoring software) plus Controls.
- ENVIRONMENTAL: (A) Flare-Stack, Scrubber, Leak Detection; (L) Liners, Containment.

After installation, this would provide a long-term processing, compression and residue gas takeaway in the Delaware Basin Region of Texas.

Summary of plant feed stock and finished products

1. Feedstock Source: Raw Natural Gas produced at the well-head and transported through gathering systems from various producers in the Permian Basin.
2. Final Products Produced:
    a. Mixed NGL's: The mixed NGL's will be transported via pipeline from the plant to multiple markets for storage and further fractionation.
    b. Natural Gas: The residue gas will be compressed and delivered to a newly constructed pipeline adjacent to the facility to be delivered to multiple markets.
3. Interconnections
    a. The plant will be interconnected via newly constructed pipelines to allow the final products to be delivered to the market.

AMENDMENT 1 [6/27/2018]

Summary of Components

- Inlet Slug Catchers
- Inlet Separation and Filtration
- Amine treating for CO2 Removal
- TEG dehydration for H2O Removal
- Thermal Oxidizers
- Molecular Sieve Dehydration
- GSP Cryogenic Gas Plants
- Residue Recompression units
- Heat Medium Systems
- Flare System (common for all trains)
- Water supply, drain systems, waste water
- Utilities (fuel, air, R.O. water)

AMENDMENT 1 [6/27/18]

Processing Natural Gas

Natural gas, as it is used by consumers, is much different from the natural gas that is brought from underground up to the wellhead. Although the processing of natural gas is in many respects less complicated than the processing and refining of crude oil, it is equally as necessary before its use by end users.

Natural gas is composed almost entirely of methane. However, natural gas found at the wellhead, although still composed primarily of methane, is by no means as pure. Raw natural gas comes from three types of wells: oil wells, gas wells, and condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas'. This gas can exist separate from oil in the formation (free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed 'nonassociated gas'. Gas wells typically produce raw natural gas by itself, while condensate wells produce free natural gas along with a semi-liquid hydrocarbon condensate. Whatever the source of the natural gas, once separated from crude oil (if present) it commonly exists in mixtures with other hydrocarbons; principally ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds.

Natural gas processing consists of separating all the various hydrocarbons and fluids from the pure natural gas, to produce what is known as 'pipeline quality' dry natural gas. Major transportation pipelines usually impose restrictions on the make-up of the natural gas that is allowed into the pipeline. That means that before the natural gas can be transported it must be purified. While the ethane, propane, butane, and pentanes must be removed from natural gas, this does not mean that they are all 'waste products'.

In fact, associated hydrocarbons, known as 'natural gas liquids' (NGLs) can be very valuable by-products of natural gas processing. NGLs include ethane, propane, butane, iso-butane, and natural gasoline. These NGLs are sold separately and have a variety of different uses; including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy.

AMENDMENT 1 [6/27/18]

A Natural Gas Processing Plant
Source: Duke Energy Gas Transmission Canada

While some of the needed processing can be accomplished at or near the wellhead (field processing), the complete processing of natural gas takes place at a processing plant, usually located in a natural gas producing region. The extracted natural gas is transported to these processing plants through a network of gathering pipelines, which are small-diameter, low pressure pipes. A complex gathering system can consist of thousands of miles of pipes, interconnecting the processing plant to upwards of 100 wells in the area. According to the American Gas Association's Gas Facts 2000, there was an estimated 36,100 miles of gathering system pipelines in the U.S. in 1999.

The actual practice of processing natural gas to pipeline dry gas quality levels can be quite complex, but usually involves four main processes to remove the various impurities:

- Oil and Condensate Removal
- Water Removal
- Separation of Natural Gas Liquids
- Sulfur and Carbon Dioxide Removal

AMENDMENT 1 [6/27/18]

Oil and Condensate Removal

The actual process used to separate oil from natural gas, as well as the equipment that is used, can vary widely. Although dry pipeline quality natural gas is virtually identical across different geographic areas, raw natural gas from different regions may have different compositions and separation requirements. In many instances, natural gas is dissolved in oil underground primarily due to the pressure that the formation is under. When this natural gas and oil is produced, it is possible that it will separate on its own, simply due to decreased pressure; much like opening a can of soda pop allows the release of dissolved carbon dioxide. In these cases, separation of oil and gas is relatively easy, and the two hydrocarbons are sent separate ways for further processing. The most basic type of separator is known as a conventional separator. It consists of a simple closed tank, where the force of gravity serves to separate the heavier liquids like oil, and the lighter gases, like natural gas.

Gas Processing Engineers
Source: ChevronTexaco Corporation

Water Removal

In addition to separating oil and some condensate from the wet gas stream, it is necessary to remove most of the associated water. Most of the liquid, free water associated with extracted natural gas is removed by simple separation methods at or near the wellhead. However, the removal of the water vapor that exists in solution in natural gas requires a more complex treatment. This treatment consists of 'dehydrating' the natural gas, which usually involves one of two processes: either absorption, or adsorption.

Absorption occurs when the water vapor is taken out by a dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface.

Glycol Dehydration

An example of absorption dehydration is known as Glycol Dehydration. In this process, a liquid desiccant dehydrator serves to absorb water vapor from the gas stream. Glycol, the principal agent in this process, has a chemical affinity for water. This means that, when in contact with a stream of natural gas that contains water, glycol will serve to 'steal' the water out of the gas stream. Essentially, glycol dehydration involves using a glycol solution, usually either diethylene glycol (DEG)

or triethylene glycol (TEG), which is brought into contact with the wet gas stream in what is called the 'contactor'. The glycol solution will absorb water from the wet gas. Once absorbed, the glycol particles become heavier and sink to the bottom of the contactor where they are removed. The natural gas, having been stripped of most of its water content, is then transported out of the dehydrator. The glycol solution, bearing all of the water stripped from the natural gas, is put through a specialized boiler designed to vaporize only the water out of the solution. While water has a boiling point of 212 degrees Fahrenheit, glycol does not boil until 400 degrees Fahrenheit. This boiling point differential makes it relatively easy to remove water from the glycol solution, allowing it to be reused in the dehydration process.

An innovation in this process has been the addition of flash tank separator-condensers. As well as absorbing water from the wet gas stream, the glycol solution occasionally carries with it small amounts of methane and other compounds found in the wet gas. In the past, this methane was simply vented out of the boiler. In addition to losing a portion of the natural gas that was extracted, this venting contributes to air pollution and the greenhouse effect. To decrease the amount of methane and other compounds that are lost, flash tank separator-condensers work to remove these compounds before the glycol solution reaches the boiler. Essentially, a flash tank separator consists of a device that reduces the pressure of the glycol solution stream, allowing the methane and other hydrocarbons to vaporize ('flash'). The glycol solution then travels to the boiler, which may also be fitted with air or water-cooled condensers, which serve to capture any remaining organic compounds that may remain in the glycol solution. In practice, according to the Department of Energy's Office of Fossil Energy, these systems have been shown to recover 90 to 99 percent of methane that would otherwise be flared into the atmosphere.

Solid-Desiccant Dehydration

Solid-desiccant dehydration is the primary form of dehydrating natural gas using adsorption, and usually consists of two or more adsorption towers, which are filled with a solid desiccant. Typical desiccants include activated alumina or a granular silica gel material. Wet natural gas is passed through these towers, from top to bottom. As the wet gas passes around the particles of desiccant material, water is retained on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the bottom of the tower.

Separation of Natural Gas Liquids

Absorption Towers
Source: Duke Energy Gas Transmission Canada

Natural gas coming directly from a well contains many natural gas liquids that are commonly removed. In most instances, natural gas liquids (NGLs) have higher value as separate products, and it is thus economical to remove them from the gas stream. The removal of natural gas liquids usually takes place in a relatively centralized processing plant, and uses techniques like those used to dehydrate natural gas.

The Cryogenic Expansion Process

Cryogenic processes are used to extract NGLs from natural gas. Lighter hydrocarbons, such as ethane, are often more difficult to recover from the natural gas stream. In certain instances, it is economic to simply leave the lighter NGLs in the natural gas stream. However, if it is economic to extract ethane and other lighter hydrocarbons, cryogenic processes are required for high recovery rates. Essentially, cryogenic processes consist of dropping the temperature of the gas stream to around -120 degrees Fahrenheit.

There are many ways of chilling the gas to these temperatures, but one of the most effective is known as the turbo expander process. In this process, external refrigerants are used to cool the natural gas stream. Then, an expansion turbine is used to rapidly expand the chilled gases, which causes the temperature to drop significantly. This rapid temperature drop condenses ethane and other hydrocarbons in the gas stream, while maintaining methane in gaseous form. This process allows for the recovery of about 90 to 95 percent of the ethane originally in the gas stream. In addition, the expansion turbine can convert some of the energy released when the natural gas stream is expanded into recompressing the gaseous methane effluent, thus saving energy costs associated with extracting ethane.

The extraction of NGLs from the natural gas stream produces both cleaner, purer natural gas, as well as the valuable hydrocarbons that are the NGLs themselves.

Sulfur and Carbon Dioxide Removal

In addition to water, oil, and NGL removal, one of the most important parts of gas processing involves the removal of sulfur and carbon dioxide. Natural gas from some wells contains significant amounts of sulfur and carbon dioxide. This natural

gas, because of the rotten smell provided by its sulfur content, is commonly called ‘sour gas’. Sour gas is undesirable because the sulfur compounds it contains can be extremely harmful, even lethal, to breathe. Sour gas can also be extremely corrosive. In addition, the sulfur that exists in the natural gas stream can be extracted and marketed on its own. In fact, according to the USGS, U.S. sulfur production from gas processing plants accounts for about 15 percent of the total U.S. production of sulfur.

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AMENDMENT 1 [6/27/18]

Description of Qualified Property

AMENDMENT 1 [6/27/2018]

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CULBERSON COUNTY - ALLAMOORE INDEPENDENT SCHOOL DISTRICT

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AMENDMENT 1 [6/27/2018]

Summary of Components

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AMENDMENT 1 [6/27/18]

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AMENDMENT 1 [6/27/18]

A Natural Gas Processing Plant
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AMENDMENT 1 [6/27/18]

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Gas Processing Engineers
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Gas processing is an instrumental piece of the natural gas value chain. It is instrumental in ensuring that the natural gas intended for use is as clean and pure as possible, making it the clean burning and environmentally sound energy choice. Once the natural gas has been fully processed, and is ready to be consumed, it must be transported from those areas that produce natural gas, to those areas that require it.

AMENDMENT 1 [6/27/18]

Calculation of Wage Information - Based on Most Recent Data Available

110% of County Average Weekly Wage for all Jobs

2017	1Q	$905
2017	2Q	$959
2017	3Q	$938
2017	4Q	$994

$ 3,796 /4 = $949.00 average weekly salary

110% of County Average Weekly Wage for Manufacturing Jobs in County

2009	1Q	$980
2010	2Q	$1,060
2010	3Q	$1,222
2011	3Q	$759

$ 4,021 /4 = $1,005 average weekly salary

x1.1 (110%)

$ 1,105.78

110% of County Average Weekly Wage for Manufacturing Jobs in Region

$40,188.00 per year in Rio Grande Council of Governments published July 2017

X1.10 (110%)

$44,206.80

$850.13 **Avg. Weekly**

AMENDMENT 1 [6/27/18]

Quarterly Census of Employment and Wages
Original Data Value

Series Id: ENU4810940010

State: Texas
Area: Culberson County, Texas
Industry: Total, all industries
Owner: Total Covered
Size: All establishment sizes
Type: Average Weekly Wage
Years: 2007 to 2017

Year	Qtr1	Qtr2	Qtr3	Qtr4
2007	422	429	483	550
2008	556	677	577	627
2009	702	595	602	623
2010	492	535	518	569
2011	514	555	550	584
2012	536	610	589	617
2013	579	625	580	599
2014	595	598	612	624
2015	706	712	724	741
2016	709	729	786	814
2017	905	959	938	994