NATIONAL ASSOCIATION OF
PUBLICLY TRADED PARTNERSHIPS

Testimony of National Association of Publicly Traded Partnership
Before the Texas House of Representatives
Ways and Means Committee Hearing on
Specific Provisions of the Franchise Tax and Equity of the Overall System
June 5, 2012

Thank you Chairman Hilderbran and members of the Ways and Means Committee for holding a hearing on issues related to the revised franchise tax, and specifically equity and administrative issues that have had an unintended negative impact on certain industries, resulting in inequitable tax policy. It is our hope that when the opportunity to address inequities presents itself next year several of the issues we outline here today will be addressed.

The National Association of Publicly Traded Partnerships, known as the NAPTP, represents a group of uniquely established entities that are treated as partnerships for the purposes of federal taxation. These entities that are publicly traded partnerships (PTPs), commonly referred to as master limited partnerships, must meet certain qualifying thresholds to retain such tax treatment. Today, there are approximately 100 PTPs that trade on the national stock exchanges , and approximately 60 PTPs operate in Texas.

These 60 companies represent a tremendous investment in the Texas economy. In 2011, our members invested more than $4 billion in capital assets in the State of Texas. Our investment results in more than $390 million being paid to the State in property, Margin and severance taxes in 2011.

NAPTP wanted to take this opportunity to highlight two very important inequities resulting from the current provisions of the Margin tax that have a particularly negative impact on our members. These are:

- Inability of our members to take limited or all deductions for the Costs of Goods Sold (COGS)
- Inability of our members to qualify as a “wholesale entity” in order to be taxed at the .5 percent rate

<u>Inability to take COGS</u>
Midstream PTPs engage in gathering, treating, processing, fractionating and storing of natural gas, crude and liquids. Midstream PTPs enter into contracts to, among other things, purchase energy resources at the well-head and transport energy resources for a fee. However, many midstream PTPs do not qualify, or cannot take deductions, for costs of goods sold (COGS) because of some historic structures in their business transaction models, where they lack legal title or ownership of the goods being transported, manufactured or sold. In some cases, a pipeline will have title to some, but not all of the product. While the statute states the owners of the commodity (in our case) will be based on the facts and circumstances including the benefits and burdens of ownership, the Comptroller has made it clear it will look only to legal title. Allowing some pipelines to take deductions while others cannot creates

inequities between operators and ultimately leads to a competitive advantage or disadvantage based on their chosen model of transactional structures to accomplish similar business.

When an entity is denied the ability to take COGS, the issue is further compounded by the limited amount of labor costs associated with that entity. Despite having more than $20 billion in assets in the state, we employ approximately 14,000 people. Therefore, the labor costs are nominal compared to the overall investment, and ultimate cost of running our facilities. In many cases, operators of these assets depend on contractors or contract labor companies to support their operations which as provide for a significant number of high quality, high paying jobs that escape being included as part of the Texas compensation deductions.

Even when an entity qualifies for COGS, the ability to deduct the three largest costs related to the operating assets (depreciation, interest expense and operational expense) is limited or completely disallowed. The statute requires that an entity own the goods being sold in order to qualify for the COGS deduction. For our members, an entity's ability to deduct COGS is unrelated to the activity the entity is performing, but rather is directly dependent upon whether or not the entity has legal title to the product. In many cases, these entities do not hold title to some or all of the product they are handling. The result is that COGS associated with processes performed for one party may be deductible, but the COGS associated with these same processes performed for another company are disallowed simply based on how the contract is written and not the activities being performed. This matter is purely contractual, and does not impact the physical actions being taken by an entity during the course of their business. Therefore, entities engaged in these activities should be able to take COGs regardless of the ownership of the product.

Furthermore, the level of commitment each operator makes in the state is dependent on the debt required to finance that investment. As stated earlier, our members are making tremendous capital investments in the state. Without the debt, the investment would not occur. Yet, the interest paid on the debt is not considered as part of a COGS.

Additionally, not only are our members heavily regulated for environmental and operational matters, but the capital investment must be maintained in order to protect the integrity of the enormous energy systems and equipment already in place. The industry faces heavy costs burdens associated with safety, environmental and Homeland security regulations, just to name a few. However, as it currently stands, many of these operational costs cannot be deducted. It would seem reasonable to consider these expenses in the COGS deduction as they are necessary and even required, to conduct business.

For some of our members, these inequities are further inflated by the unitary reporting requirements in the law. Some midstream companies will have facilities that are dependent or related to each other, even though their activities differ. Many operating expenses are once again disallowed because the unitary group must choose which deduction to take (70 percent, COGS, or compensation). For example, PTPs with processing and marketing facilities are able to take limited COGS, while those PTPs with gathering and transporting operations are not. When an entity engages in both of these areas, the related transportation business not only is prohibited from taking COGS, but will be taxed at 100 percent of its revenue, not at the 70 percent limitation. Prohibiting the deduction of all operating expenses, and limiting COGS deductions to only those entities that have title to a product results in a significant and inequitable tax burden on certain PTPs that play a significant role in supporting the Texas economy.

These situations are highlighted by the following examples showing how three different pipelines, doing exactly the same thing, are taxed differently because of their choice or historical approach to contractual agreements.

Pipeline A

Type of Pipeline:
Natural Gas Gathering and Transportation Pipeline

Revenue Generated from:
Purchasing raw gas, treating it, and then reselling it downstream.

Tax Example:

Revenue: $1,000,000,000
COGS: $900,000,000

Margin: $100,000,000

Apportionment: 25%

Taxable Margin: $25,000,000

Tax Rate: 1 percent

Total Tax: $250,000

Pipeline B

Type of Pipeline:
Natural Gas Gathering and Transportation Pipeline

Revenue Generated from:
Transporting raw gas, treating it, and delivering it end point determined by contract for a fee.

Tax Example:

Revenue: $1,000,000,000
Compensation: $30,000,000

Margin (not greater than 70% of revenue): $700,000,000

Apportionment: 25%

Taxable Margin: $175,000,000

Tax Rate: 1 percent

Total Tax: $1,750,000

Difference: The entity cannot deduct COGS because it does not own the product it is transporting.

Pipeline C

Type of Pipeline:
Natural Gas Gathering and Transportation Pipeline

Revenue Generated from:
Purchasing raw gas, treating it, and then reselling it downstream - and -transporting raw gas, treating it, and delivering it end point determined by contract for a fee

Tax Example:

Revenue: $1,000,000,000
COGS: $700,000,000

Margin: $300,000,000

Apportionment: 25%

Taxable Margin: $75,000,000

Tax Rate: 1 percent

Total Tax: $750,000

Difference: The entity can include only a portion of the costs of gas (fuel), depreciation, salaries, utilities or insurance in the COGS deduction.

Inability to Qualify for Wholesale Rate

The Margin tax in its current state is based on an antiquated Standard Industrial Code (SIC) system that does not account for the way midstream assets are owned and operated, and most importantly, how they generate revenue. There is no category for midstream or pipeline assets under the SIC Codes. It could be that the evolution of government regulations have not caught up to changes in the way the pipeline industry is structured and operates since the last revision of the SIC. Because there is no specific SIC in which a PTP can identify, midstream PTPs that provide or engage in wholesale activities are wrongly prohibited from being taxed appropriately at the half percent rate because they have no way in which to qualify for the lower rate.

This situation is further complicated by the fact that while midstream PTPs can meet the requirement of TTC 171.002(c)(1), it will be difficult, if not impossible, for them to meet the requirements of (c)(2). This is because one of the primary businesses of some midstream PTPs is the processing of raw gas sold by marketing affiliates, which is necessary for the downstream transportation of those products. Processing gas is the preparation of gas in order for it to be consumed or used in manufacturing.

Furthermore, under the current franchise tax, certain pipelines are prohibited from taking the wholesale rate because they are considered a “utility.” The pipeline industry would argue that transportation pipelines are not classic utilities in the same manner as telecommunication, electric or local distribution service providers (see TTC 171.002(c)(3)). However, the definition of “utility” has yet to be adequately revised to address this confusion. Until it is, an inequity will result because some pipelines that are nonutilities could possibly qualify for the half-percent rate, while those that are considered “utilities” will be taxed at one percent.

Traditional utilities normally are allowed to collect the cost of taxes from their customers. It should also be pointed out that non-utility providers cannot pass this tax through to their customers because of the midstream industry is highly competitive; therefore, a one percent tax rate on gross receipts is unreasonably burdensome to midstream PTPs because their total revenues are high but their profit margins are low.

Conclusion

It is our understanding that many PTPs engaged in transportation activities, like those in the midstream industry, have been unfairly burdened by the revised franchise tax. Our business models and activities simply do not fit into the categories provided for in the statue. The pipeline industry respectfully requests this Committee and the Legislature to consider and address the issues that we have raised today. We understand that the State must make difficult decisions during the upcoming legislative session.

The industry looks forward to working with the Committee and members of the legislature in the coming months. Please let us know how the industry can be of assistance.