121 FERC ¶ 61,122
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Northern Natural Gas Company Docket No. RP07-425-000

ORDER FOLLOWING TECHNICAL CONFERENCE

(Issued October 31, 2007)

1. This order following technical conference addresses Northern Natural Gas Company's (Northern) May 1, 2007 filing proposing new gas quality specifications as well as certain revisions contained on *pro forma* tariff sheets in Northern's August 3, 2007 post-technical conference filing. As discussed more fully below, Northern has failed to support through technical and operational evidence its proposed gas quality specifications, and accordingly, the tariff sheets filed on May 1, 2007 are rejected, except for those sheets proposing definitions, as more fully discussed below.

Background

2. On May 1, 2007, Northern, pursuant to section 4 of the Natural Gas Act (NGA), submitted revised tariff sheets proposing to incorporate gas quality specifications, and provisions allowing it to waive those specifications, in its FERC Gas Tariff. Northern proposed that the tariff sheets become effective June 1, 2007. Northern proposed new natural gas quality specifications in section 44 of its General Terms and Conditions (GT&C) to give it the authority, *when necessary*, to take action when gas quality could negatively affect Northern's facilities. Northern maintains that it designed the proposed changes to protect the integrity of its operations and facilities, while maintaining significant flexibility and increased access to natural gas supplies.

3. Northern proposed new gas quality specifications for (1) oxygen, (2) carbon dioxide, (3) heating value, (4) gas temperature, (5) cricondentherm hydrocarbon dew point (CHDP), (6) butanes and heavier hydrocarbons, (7) total inerts, (8) Wobbe Index, and (9) hazardous substances. Northern proposed to add a general waiver provision that allows it to accept gas that does not conform to the tariff quality specifications. Northern includes notice procedures in the proposal if it needs to suspend the general waiver. If

Northern suspends the general waiver it would then determine the priority for allocating or curtailing non-compliant gas quantities based on the scheduling priorities in its GT&C.

4. By order issued on May 31, 2007, the Commission accepted and suspended Northern's tariff sheets, to become effective November 1, 2007, and established a technical conference.[1] The Commission found that Northern's proposed gas quality specifications raised numerous technical, engineering, and operational issues that it could more completely address at a technical conference. Staff convened the technical conference on July 24, 2007. On August 3, 2007, Northern filed supplemental information and revised *pro forma* tariff language at the request of the Commission Staff. Several other parties also submitted exhibits or testimony that challenged the technical aspects of the proposal or suggested alternative proposals. Accordingly, the Commission addresses the supplemental information below where relevant. Finally, parties filed initial comments on August 14, 2007, and reply comments on August 28, 2007.

Northern's Motion

5. On October 17, 2007, Northern filed a motion to hold in abeyance Commission action on certain issues in its gas quality filing. Northern also requested a shortened answer period. Northern states that while settlement of certain issues will not be possible, Northern and other parties believe that settlement discussions can be fruitful with respect to certain other issues. The issues that Northern believes may be potentially resolved by a settlement are heating value, gas temperature, butanes and heavier hydrocarbons, total inerts, Wobbe Index, and sulfur. Northern refers to these issues as the Deferred Issues and requests that the Commission hold in abeyance any action on the Deferred Issues until March 1, 2008. Northern commits that it will not move to place its proposed specifications with respect to the Deferred Issues into effect until March 1, 2008. Northern states that it will provide a report to the Commission no later than January 15, 2008, to inform the Commission of such settlement discussions.

6. On October 18, 2007, a notice was issued indicating that answers to Northern's motion were to be filed on or before October 22, 2007. A number of parties filed answers stating that they do not oppose Northern's motion. On the other hand the Kansas Independent Oil and Gas Association (KIOGA) and Daystar Petroleum, Inc. (Daystar) filed an answer opposing the deferral of Commission action.

7. Daystar asserts that the record is now before the Commission for decision. Daystar states that Northern sought a tariff filing and the Commission offered a technical conference proceeding to allow Northern an opportunity to demonstrate a need for the new restrictions and respond to the protests. Daystar states that the technical conference was held in July and comments and reply comments have been filed. Daystar asserts that

[1] *Northern Natural Gas Company*, 119 FERC ¶ 61,213 (2007).

the November 1 effective date of the tariff sheets is approaching and there is no reason to defer ruling on the record. Daystar asserts that there is no reason to continue to disrupt investment and planning for new supply for another 6 months while Northern uses the Commission process to wear down opposition. Daystar argues that a ruling rejecting Northern's inadequate filing would provide certainty as to tariff standards and allow the parties and the Commission and its Staff to avoid the burden and expense of continued settlement negotiations.

8. The Commission denies Northern's motion to hold in abeyance Commission action on the Deferred Issues. While the Commission certainly encourages settlement negotiations, the Commission finds that the gas quality specifications proposed by Northern need to be addressed as an integrated package. The Commission finds that taking a piecemeal approach of acting on certain of Northern's proposal before the November 1 effective date and deferring action on certain other issues would create needless uncertainty for Northern's shippers. As discussed further below, the Commission is rejecting, as a whole, Northern's proposed gas quality specifications as unsupported. The Commission finds that the determinations in this order will give Northern guidance with respect to the deficiencies in its filing that will allow it to provide the appropriate technical, operational, and scientific information necessary to support any future section 4 filing or a settlement if Northern and its shippers choose to pursue that option.

Discussion

A. Introduction

9. At the outset, the Commission would like to emphasize that the *Gas Quality Policy Statement*[2] was not a pretext for pipelines to completely revamp the gas quality and interchangeability standards in their tariffs. The Commission issued the *Policy Statement* to provide pipelines with an opportunity to modify their tariffs to correct ongoing gas quality or interchangeability problems, to make changes in anticipation of new supply sources, or to make adjustments due to operational changes to the pipeline system. In the *Policy Statement*, the Commission sought, among other things, to minimize any unnecessary restrictions on gas supplies.[3] Further, as the Commission stated in *AES v. FGT*, when a pipeline "proposes to tighten its gas standards, it must

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[2] *Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs*, 115 FERC ¶ 61,325 (2006) (*Policy Statement*).

[3] *Policy Statement* at P 41.

demonstrate an operational or other reason why such tightening is necessary."[4] Northern has not met this burden, and accordingly, the Commission is rejecting Northern's proposal and its revised tariff sheets. Further, several alternate proposals offered for Commission consideration by the parties that were not included in Northern's filing are outside the scope of this proceeding. Specifically, these include all sulfur, nitrogen, and hydrogen sulfide specifications.

10. A number of parties have protested Northern's proposal in general. SemGas Gathering, L.L.C. (SemGas), Minnesota Energy Resources Corporation (MERC), Wisconsin Public Service Corporation (WPSC), and the Indicated Shippers[5] state that the combined effect of Northern's proposed gas quality specifications will be the curtailment of significant gas quantities available on Northern's system. Virginia Power Energy Marketing, Inc. (Virginia Power) asserts the proposal would create a barrier between eastern and midwest markets and the new gas supplies being developed in the Rocky Mountain region which would enter Northern's system through Market Area receipt points.

11. The Kansas Corporation Commission (KCC) is concerned that Northern's proposal could curtail supplies originating in the gas producing areas of Kansas, thereby adversely affecting the overall economy of the state. They assert that many of the small, independent gas producers and suppliers would have to install expensive gas treating equipment to ensure that their gas would meet Northern's specifications. The KCC also states that these circumstances would lead ultimately to premature abandonment of Kansas gas wells. The KCC and SemGas request that, if the Commission approves Northern's gas quality provisions, the Commission should direct Northern to include a waiver for Kansas gas. They cite to industry guidelines addressing an exception for service territories with demonstrated experience with gas supplies whose gas quality characteristics are outside of Northern' proposed specifications.[6] The Indicated Shippers urge the Commission to grandfather existing gas flows because of the significant commercial reliance upon existing gas quality specifications.

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[4] *AES Ocean Express LLC v. Florida Gas Transmission Company*, 119 FERC ¶ 61,075 at P 165 (2007).

[5] Indicated Shippers is made up of the following companies: Anadarko Petroleum Corporation, BP America Production Company, BP Energy Company, Chevron U.S.A. Inc., Marathon Oil Company, ExxonMobil Gas & Power Marketing Company, a division of Exxon Mobil Corporation, Occidental Energy Marketing, Inc., Occidental Permian Ltd., and Coral Energy Resources, L.P.

[6] *See* "White Paper on Natural Gas Interchangeability and Non-Combustion End Use," NGC+ Interchangeability Work Group (2005) (Interchangeability White Paper), at 26.

12. In its response to the protestor's assertions regarding the availability of supplies, Northern opines that such views are speculative and contrary to evidence included in its filing. Northern claims it performed an analysis of gas quality parameters from the 95 active receipt points on processed gas segments of its system. Northern further claims that it determined that the supplies currently connected at these receipt points, when blended, meet all of the gas quality specifications in Northern's proposal, even during seasonal periods when some gas quality provisions were more strict, such as CHDP (operationally) and carbon dioxide. Northern addresses the concerns with Kansas gas supplies, and argues that although it recognizes that gas has flowed for nearly 40 years without any operational issues, Northern still must have the flexibility in its tariff to resolve future issues.

13. The Wyoming Pipeline Authority (WPA) and the Rockies Express Shippers,[7] contend that Northern and its ratepayers should bear the economic burden of gas quality specifications dictated by "peculiar conditions," either in Northern's storage fields or by the colder than average temperatures in Northern's service territory. Northern should not expect the rest of the interstate pipeline system to bear these costs. They argue that producers and other pipelines should not bear the expense of building expensive gas quality treating facilities only for the benefit of Northern and its end-users. Madison Gas and Electric Company (MGE), Alliant Energy – Wisconsin Power and Light Company and Interstate Power and Light Company (Alliant), and Wisconsin Electric Power Company (We Energies) oppose WPA's and the Rockies Express Shippers' assertions. They state that the arguments fail to recognize that gas quality specifications directly relate to the safe and reliable delivery of gas system-wide. They contend that all parties will benefit from Northern's safe and reliable delivery of gas, and should share in the costs incurred to ensure that safe and reliable delivery.

14. Some protests raise issues concerning Northern's proposal and assert that its standards create a "balkanizing effect" on the pipeline grid. The Indicated Shippers claim that Northern's proposed standards create this balkanizing effect because its provisions are more stringent than those of any interconnecting pipeline.[8] The Indicated Shippers point to an example where Northern proposes a Wobbe Index of 1,365 that is significantly lower than other pipelines' proposals in Northern's geographical area. The Indicated Shippers contend that Wobbe Index values within the vicinity of Northern's region include 1,380, proposed by Natural Gas Pipeline Company of America (NGPL) for receipts in its system. The Rockies Express Shippers and the Indicated Shippers state that Northern continues its efforts to balkanize the national gas grid, just as it attempted

[7] Ultra Resources, Inc., and Sempra Rockies Marketing, LLC comprise the Rockies Express Shippers.

[8] *See* Appendix A to the Indicated Shippers initial comments.

in its previous rate case, and notes the Commission rejected it then and should do so here, as well.[9]

15. Northern states that the Indicated Shippers did not fully compare its proposed standards to NGPL's already approved and pending standards. Northern compares its standards in its pleading and states that upon closer inspection, its standards are very comparable.[10] Northern further states that, in any event, its proposed specifications are supported by extensive operating and technical evidence. The Commission examines Northern's technical and operational evidence, as more fully discussed below.

B. Carbon Dioxide and Oxygen Limits

1. Northern's Proposal

16. In its filing, Northern proposes to retain its current carbon dioxide limit of 2 percent for its entire system, and add a provision limiting carbon dioxide to 1 percent during the injection season, April 1 to October 31 for its processed gas segments. Further, Northern proposes to reduce its current oxygen limit for its entire system from 0.2 percent to 10 parts per million (ppm), or 0.001 percent. Northern contends that it needs to apply its proposed oxygen limit across the whole system because gas received on the unprocessed gas segments could possibly return to Northern at the tailgate of a processing plant. Northern claims that oxygen would become problematic at the plant tailgate and oxygen would then enter a processed gas segment.

17. Northern states that its storage fields are typically the areas where, during the final stages of injection, high carbon dioxide partial pressures exist in the presence of water. These circumstances create carbonic acid that becomes corrosive to the steel pipeline. Northern maintains that it developed its carbon dioxide tariff specification to protect its storage and pipeline facilities from corrosion, and LNG peak shaving facilities by applying a lower carbon dioxide and oxygen limit on a seasonal basis. Northern continues and opines that the lower limit would apply outside of the heating season on processed gas segments only, thereby maximizing gas supply at the time of peak demand. Northern further maintains that its seasonal 1 percent carbon dioxide and stricter oxygen limit will mitigate corrosion by carbonic acid in its storage fields.

18. Northern bases its 1 percent carbon dioxide limit proposal on a technical report that states:[11]

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[9] *Northern Natural Gas Company*, 108 FERC ¶ 61,083 (July 2004 Order), P 34.

[10] Northern's Reply Comments, p. 71-72.

[11] Corrosion rates are expressed as the rate of metal loss in milli-inches per year (mpy).

> *[g]eneral corrosion rates in oxygen-free, carbon dioxide-containing solutions (10 psi carbon dioxide partial pressure) were less than 1 mpy. Maximum general corrosion rates in H_2S-free solutions containing oxygen or oxygen and carbon dioxide (10 psi) ranged from 0.6 mpy to 12.9 mpy.*[12]

19. Northern states that this report demonstrates that it can achieve acceptable corrosion rates by limiting the carbon dioxide in the gas to 10 psi in partial pressure.[13] The carbon dioxide mole percentages that would correspond to a 10 psi partial pressure for the respective storage facilities and formations are: 0.68 percent for Cunningham, 0.77 percent for Lyons, and 0.80 percent for Redfield.[14] Northern argues that its proposed 1 percent limit is higher than it considers ideal, but this level avoids negatively impacting supplies. Northern also presents evidence of large volumes of water in its storage fields, which, as discussed briefly above, is a necessary element for carbonic acid corrosion. Northern states that samples of water from its storage fields prove the presence of carbon dioxide as a flash gas.[15]

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[12] Pipeline Research Council International document number PRCI PR-015-9313, "Carbon Dioxide/Hydrogen Sulfide Corrosion Under Wet Low Flow Gas Pipeline Conditions in the Presence of Bicarbonate, Chloride, and Oxygen," page A-13.

[13] Dalton's Law of Partial Pressures, or additive pressures, states that the total pressure exerted by a mixture of gases is equal to the sum of the pressures exerted by its components.

[14] The conversion method to calculate the corresponding mole percentage for a partial pressure of 10 psi at storage pressure would be:

$$y_j = \frac{p_j}{p_T}$$

where y_j is the mole percentage of component j, P_j is the partial pressure of the component j, and p_T is the total pressure in the storage reservoir. For instance, the storage field at Cunningham has an injection pressure of 1,460 psi. Using the method above produces this result:

$$y_{CO_2} = \frac{10\,psi}{1{,}460\,psi} = 0.68\%$$

[15] Flash gas is the amount of dissolved gas in a sample liquid that is released in controlled laboratory conditions. Flash gas can be obtained in a laboratory technique using a process called "flash vaporization." When the gas is flashed from the liquid, a compositional analysis can then be obtained.

2. **Carbonic Acid Induced Corrosion**

20. Generally, internal steel pipe corrosion is an electro-chemical process, in which a chemical reaction occurs along with a transfer of electrons. In the case of carbonic acid induced corrosion on steel pipe, an electrolyte (water) is required along with dissolved carbon dioxide to electrically leach iron from the steel pipe surface. In short, carbonic acid forms when carbon dioxide dissolves into water. As carbon dioxide increases in the gas stream, there will be an increase in the amount of carbonic acid in the water. Here, in the following reaction (1), carbon dioxide is dissolved in water and is in equilibrium with carbonic acid:

$$CO_2 + H_2O \leftrightarrow H_2CO_3 \leftrightarrow H^+ + HCO_3^- \quad (1)$$

The last term in this simplified equation represents carbonic acid in its dissociated form, in which carbonic acid (which is only slightly soluble) dissolves into a bicarbonate anion and a hydrogen cation. Corrosion occurs at the pipe surface, with two simultaneous reactions; anodic and cathodic. In the anodic reaction (2), elemental iron (Fe^{2+}) is dissolved into the water from the surface of the steel leaving behind 2 free electrons ($2e^-$), while a cathodic reaction (3) occurs, in which the free electrons are pulled toward a cathode, hydrogen (H+) at the surface:

$$Fe \rightarrow Fe^{++} + 2e \quad (2)$$

$$2H^+ + e \rightarrow H_2 \quad (3)$$

The complete reaction:

$$CO_2 + H_2O + Fe \rightarrow FeCO_3 + H_2 \quad (4)$$

21. Oxygen does not dissolve into water to form an acid. However, according to the testimony of Bruce D. Craig,[16] oxygen plays an active role in the corrosion process by reacting with hydrogen ions on the metal surface, enhancing the corrosion process, also described as a depolarization of the hydrogen ions. According to Mr. Craig, this reaction occurs:

$$4H^+ + O_2 + 4e \rightarrow 2H_2O \quad (5)$$

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[16] Bruce D. Craig's Direct Testimony filed before the Public Utilities Commission of the State of California in Docket R.04-01-025, Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California, filed in Appendix B to the Indicated Shippers Initial Comments, p. 3.

Further, Mr. Craig notes that both gases can cause corrosion to occur in the water phase synergistically; however one cannot easily determine this rate.

3. <u>Northern's Evidence</u>

22. Northern proposed similar provisions in its rate case proceeding in Docket No. RP04-155-000, *et al.*, to address carbonic acid induced corrosion. In rejecting those proposals the Commission determined that:

> *[s]pecifically, Northern has inadequately: (1) delineated the extent and causes of corrosion in its storage fields; (2) shown that its proposed tolerance levels for carbon dioxide and oxygen would resolve any corrosion problems; and (3) shown that there are not lower cost ways to address any existing corrosion which would have less adverse impact on the development of new supplies.* [17]

23. In the instant proposal, Northern restates its position that its current limits for carbon dioxide and oxygen do not adequately address safety and integrity issues on its pipeline system because of internal corrosion and the impact caused by its LNG operations. Northern believes it provided substantial evidence showing internal corrosion in its pipeline system and underground storage facilities, the inability to liquefy gas at its LNG peaking facilities when carbon dioxide levels are too high, and, finally, similar issues relating to downstream customers that own underground storage and/or LNG peaking facilities. Northern argues that high carbon dioxide concentrations will cause operational problems with liquefaction processes because it must remove the carbon dioxide before it can liquefy the natural gas.

24. In its supporting evidence, Northern provides photographs and laboratory analysis of pipe samples and corrosion coupons extracted from its storage facilities. Northern also shows data indicating increasing levels of carbon dioxide levels in its Market Area, from about 1.2 percent in 2002 to 1.7 percent in 2007. Further, Northern provides independent expert reports and models confirming its assertion that carbon dioxide and oxygen received on its system are responsible for corrosion.

25. To support its claim of corrosion caused by carbon dioxide and oxygen from data of historical conditions on its pipeline system, Northern submits two thermodynamic models that represent Northern's downhole and surface storage facilities. Northern asserts that the results from these studies confirm historical observations while also exhibiting that excessive corrosion is occurring at its current specification. Specifically,

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[17] July 2004 Order, P 33.

Northern states that an independent study by Honeywell[18] confirms its historical corrosion data from the Cunningham storage field. Northern also states that the results from studies performed both by Honeywell and by its witness, James A. Dougherty,[19] indicate excessive corrosion rates for both surface and downhole piping on levels above its currently effective carbon dioxide and oxygen limits. Both studies are based on the corrosion studies performed by C. de Waard and D. E. Milliams.[20]

26. Honeywell uses a computer program, PREDICT, to estimate the corrosion rate which includes a built-in scale correction factor. The program also takes into account these other effects: temperature, saturation pH, gas/oil ratio, water content, dew point, chlorides, carbon dioxide to hydrogen sulfide ration, water phase characterization, carbon dioxide partial pressure, ionic strength of components, and oxygen and filming. The analysis included 2 scenarios for downhole and surface pipe uniform metal corrosion; one in a limited water wetting, and one in a complete water wetting system. Northern states that its Cunningham storage facility is better represented by complete water wetting because of the production of massive water volumes during withdrawal conditions, and continues its analysis based on that scenario.

27. Northern supports its historical corrosion data by the results given in the study. Specifically, the Honeywell shows downhole corrosion rates of 73.1 mpy. To confirm this result with its historical observations, Northern compares this with a corroded pipe sample, labeled as "CNU23001 00+56 BOTTOM", (exhibited in a Sherry Labs report, discussed more fully below) where it shows a corrosion rate of 63 mpy (0.188 inch wall thickness that failed in about three years due to localized pitting). Northern states that this rate was within the range of predicted general wall loss corrosion.

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[18] "Corrosion Modeling of a Depleted Oil/Gas Reservoir Storage Facility," (Cunningham Study) on May 8, 2007, and "Corrosion Modeling of an Aquifer Gas Storage Facility (Redfield)," (Redfield Study) on June 21, 2007, prepared by Mr. Vishal Lagad and Mr. Sridhar Srinivasan, Honeywell International, Inc. (Honeywell), Houston, TX. Both of these studies use PREDICT 4.0, a software program that incorporates a thermodynamic model to estimate corrosion rates based on a variety of operational conditions.

[19] *Report on Carbon Dioxide* by James A Dougherty, NACE Corrosion Specialist No. 2733, November 27, 2006.

[20] C. de Waard, D.E. Milliams, "Prediction of Carbonic Acid Corrosion in Natural Gas Pipelines", 1st International Conference of the Internal and External Protection of Pipes, Paper F1, Univ. of Durham, UK, 1975. In this study, they developed a nomogram, which is a graphical plot that is used to quickly solve certain types of equations. And, in this particular case, the nomogram is used to determine the corrosion rate.

28. Further, Honeywell performs a sensitivity analysis, with inputs varying on the forward looking carbon dioxide levels and also includes synergistic oxygen effects at varying levels of oxygen; 0 parts per billion (ppb), 10 ppb, 25 ppb, 50 ppb, and 100 ppb. Northern argues that the results of this study show that forward looking, increasing levels of carbon dioxide on its system, coupled with oxygen effects will cause excessive corrosion rates.

29. Generally, Honeywell's Redfield Storage Field Study predicts low corrosion rates because of high in-situ bicarbonate concentrations in formation water. The study explains that high bicarbonate concentrations promote higher pH levels, and therefore, such buffered systems show lower corrosion rates than systems with low bicarbonate levels. The report concluded that the carbon dioxide content in the vapor phase should be limited to less than 1.6 mole percent and that oxygen should be less than 50 ppb (or carbon dioxide less than 1.6 mole percent and oxygen less than 100 ppb). This is based on a corrosion rate at less than 1 mpy. The study also concluded that irrespective of carbon dioxide levels, maintaining a dissolved oxygen level at 25 ppb or less will aid in minimizing potential for significant corrosion from dissolved oxygen.

30. Honeywell's Cunningham Storage Field Study predicts excessive corrosive rates for its scenario 2 study, without the presence of oxygen, and its worst case result for downhole conditions was in excess of 70 mpy. The Cunningham Field does not have a high in-situ bicarbonate concentration. For surface conditions without the presence of oxygen, the study provides worst case results that were in the range of 10 mpy. The study concludes that oxygen in amounts as small as 10 ppb will aggravate the corrosivity of the system.

31. Mr. Dougherty's analysis showed substantial corrosion rate impacts for increasing carbon dioxide levels up to 2 percent.[21] Predicted increased corrosion rates for surface facilities range from 30 to 134 percent, and up to 32 mpy of uniform wall loss. For downhole facilities, increased corrosion rates range from 20 to 140 percent, up to 71 mpy of uniform wall loss. The report concluded that pitting rates can be many times the predicted rate of uniform corrosion rates, and that rates greater than 15 mpy are categorized as severe.

32. Northern argues that the oxygen levels in its storage fields far exceed the level that causes corrosion as a *single* component, and as a *combined* component with carbon dioxide. In further support of its oxygen proposal, Northern provides a letter from an industry expert[22] discussing the solubility of oxygen under certain conditions, or how much oxygen needs to exist in the stream in order to reach a 50 ppb concentration in the

[21] Mr. Dougherty's analysis did not include oxygen effects.

[22] March 28, 2007 Letter from Jim Svetgoff, Technical Sales Rep. to Baker Petrolite.

pipeline water for all three storage fields. The letter states that for several decades, oil companies tried to keep the dissolved oxygen concentration in their water injection systems below 50 ppb. The letter recommends that Northern adopt a 10 ppm oxygen specification, because it is the "most common." The letter finally states that a dissolved oxygen concentration of 50 ppb will result in corrosion rate of 6.0 mpy.

33. Northern also submits a study from Exponent[23] in which it provides analysis of the effects of carbonic acid on portland cement downhole. Northern asserts that the current levels of carbon dioxide in the storage field would produce severe deterioration of downhole cement. The report uses an application of Henry's Law[24] in which the equilibrium of both the phase-change and acid-base behavior is mathematically modeled. Using water sample data provided by Northern, Exponent concluded that conditions were severe for concrete attack. Exponent notes that due to the nature of the sampling methodologies and analytical techniques, the average dissolved carbon dioxide concentration calculated in this study were probably considered to be lower than the concentrations in the formation water. However, Exponent stated that no alternative or duplicate samples were submitted at the time of writing of the report. Exponent concludes that gaseous carbon dioxide concentrations should be less than 60 ppm aqueous, and that mole percentages ranged from 0.05 percent down to 0.01 percent, significantly less then Northern's proposal.

34. Northern states that it uses multiple corrosion management techniques to protect the integrity of its pipeline for safety, reliability, and economic reasons. State and Federal laws require Northern to maintain the safety and reliability of its system, and Northern states that it operates its pipeline in a prudent manner and in accordance with industry standards. Regarding carbonic acid corrosion, limiting water influx at receipt points is a crucial step. Northern's tariff currently implements a 6 pounds of water per MMcf limit. Indicated Shipper's witness, Mr. William D. Grimes, a corrosion expert states that Northern's water limit is based on the reasoning that gas with that specification or lower will not condense water at any reasonably expected pipeline condition or pressure.[25] However water influx is an issue in Northern's storage fields because when

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[23] *Carbon Dioxide Content in the Northern Natural Gas Underground Storage* by Piotr D. Moncarcz, Tracey D. Flowers, and Naysan Khoylou Emami, March 26, 2007.

[24] Henry's Law states that the equilibrium concentration of a species in the liquid phase is directly proportional to the concentration of that species in the gaseous phase. Henry's Constant is a constant of proportionality, and for carbon dioxide the constant is approximately $10^{-1.47}$ M atm^{-1} at 25 degrees C.

[25] Mr. Grimes cites as support the Gas Processors Suppliers Association "Engineering Data Book, ed. 10", Figure 20-3, "Water Content of Hydrocarbon Gas", which states that gas at 75° F, 500 psi will, in equilibrium with liquid water, contain about 50 pounds/MMsf water vapor.

the field is cycled, water (liquid and vapor) is drawn from the storage field and into both the well bore and surface facilities. Northern has three storage fields, all of which produce water during withdrawal where the Lyons and Redfield Fields produce massive amounts of water. Northern states that the pressure maintained in these producing horizons indicates water drive, where the energy to maintain pressure in the reservoir is largely provided by hydrostatic pressure of an encroaching water source. As the pressure reduces during storage withdrawal, water encroaches toward the well-bore, especially during winter peak demand because drawdown pressure is at its highest level.

35. In this proceeding and in Northern's previous rate case, its corrosion management standards came under scrutiny from parties objecting to Northern's proposal. Northern claims that it manages corrosion on its system by, first and foremost, precluding the introduction of corrosive constituents. This includes monitoring receipt points, and also the removal of constituents that have been introduced into the system by collecting the accumulation of liquids by pigging, and liquids on low points in the pipeline which are not piggable are 'swept' to move liquids out of the system. Northern states that it analyzed collected liquids for corrosive materials, and that based on the results of the analysis, it then applies corrosive inhibitors. Northern also performs continuous monitoring of its pipeline such as smart tool inspections. Northern uses wellhead separators at the surface, and tubing and packer assemblies down hole to manage corrosion. In its evidence, Northern provides a summary of its approach to manage corrosion.[26]

36. With regard to its LNG liquefaction peaking operation, Northern opines that higher carbon dioxide concentration will disrupt the liquefaction process. In its data response, Natural presented evidence of both LNG and non-LNG customers communicating concerns about high levels of carbon dioxide, and in one instance an LNG customer shut down operations due to the carbon dioxide levels.[27] Northern states that LNG facilities use molecular sieves to remove the carbon dioxide, and that the mole sieves at Northern's two LNG facilities, Garner and Wrenshall, are not designed for carbon dioxide concentrations above 1 percent.

4. <u>Protests and Comments</u>

37. Several parties filed comments concerning Northern's proposal. With the exception of two local distribution companies in Northern's Market Area, Metropolitan Utilities District of Omaha (MUD) and NICOR Gas Company (Nicor), most parties oppose Northern's proposal. Nonetheless, Nicor and MUD submitted supporting comments and state they believe Northern's evidence confirms that corrosion is occurring

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[26] Northern's Reply Comments, p.62-64.

[27] Northern's data request response No. 4.

at a higher rate, due to increased carbon dioxide on Northern's system. MUD argues that Northern needs the change in its current specifications to ensure continued reliability on its LNG facilities. MUD states that its LNG facilities were designed and built in the 1970's when the level of carbon dioxide in the gas was 0.8 percent to 1.0 percent, and that it has received gas over the course of thirty plus years with a carbon dioxide level at or below 1.0 percent. In 2007, MUD claims that it saw carbon dioxide levels in the gas stream feeding its LNG facility that ranged from 1.1 percent to 1.6 percent. MUD states that its LNG facilities cannot accept gas with a carbon dioxide level at Northern's current tariff limit of 2 percent, and estimates that modifying its plant to accept a 2.0 percent carbon dioxide concentration would cost MUD $4 million. Nicor argues that its own assets will benefit from Northern's proposal of stricter oxygen and carbon dioxide limits. However, Nicor states that Northern's proposal would probably not eliminate Northern's corrosion problem.

38. Xcel Energy Services, Inc. (Xcel), Wyoming Pipeline Authority (WPA), Aquila, Inc. (Aquila), the Coalition,[28] Independent Petroleum Association of Mountain States (IPAMS), and Targa Midstream Services, L.P., and Targa Texas (collectively, Targa) argue essentially that Northern's proposal will cause serious supply disruptions including basin price distortions and premature abandonment of existing, proven reserves. They also argue the proposal could frustrate shippers by impairing their ability to enter into firm contracts. Xcel argues that Northern's response to its queries regarding the availability of gas supplies if it blocked major receipt points was deficient and that Northern lacked interest in the issue. Xcel asserts that Northern must show that it considered the range of alternatives available to solve safety and reliability concerns short of imposing more restrictive quality specifications.[29] Xcel further asserts that Northern, although appearing to remain neutral to the supply issue outside its pipeline system, has an economic incentive to increase demand for its Field Area supply sources.

39. Xcel avers that a majority of Northern's Field Area firm transportation contracts will expire in October, 2007. Xcel argues that certain of the receipt points most likely to be affected by the suspension of a carbon dioxide waiver are pipeline interconnects located in the Market Area that have the capacity to deliver large volumes of Rocky Mountain gas into Northern, e.g. Trailblazer Pipeline Company and Rockies Express

[28] The Coalition is made up of Connect Energy Services, LLC, Enbridge Marketing (U.S.) L.P., Enbridge Pipelines (Texas Gathering), L.P., Encana Marketing (USA) Inc., PVR Midstream LLC, Tenaska Marketing Ventures, and Yates Petroleum Corporation.

[29] *See Fn. 9,* P 31.

Pipeline, LLC.[30] Xcel asserted that Northern's proposal would shrink supply options available to Market Area shippers, and increase the demand for Northern's Field Area capacity. Xcel states that Northern attempts to use the *Policy Statement* as a tool for increasing system utilization at the expense of gas availability.

40. Some of the opposing parties strongly assert that Northern's corrosion problems are based on the presence of water in Northern's storage fields. Indicated Shippers and IPAMS, argue that Northern's proposed reductions will not resolve Northern's corrosion problem. The Indicated Shipper's corrosion expert[31] argues that Northern's proposed reductions for oxygen and carbon dioxide will not materially reduce corrosion risk, or make a significant difference in Northern's corrosion control management or the associated costs. To support this contention, they exhibit their own computer model, and show that a reduction in carbon dioxide from 2 percent to 1 percent in its HYDROCOR[32] results (at 1200 psi down hole and 79°F) shows a reduction of carbon dioxide induced corrosion by only one third. Indicated Shippers and IPAMS believe this impact is negligible, and does not address other corrosion mechanisms. Indicated Shippers contend that the root cause of the corrosion is water from Northern's storage fields. These parties note that without liquid water, carbon dioxide and oxygen cannot cause corrosion.

41. Indicated Shippers also argue that Northern's Honeywell study to simulate corrosion rates in the presence of a fully wetted scenario supports the Indicated Shippers argument that corrosion rates are dependent on the presence of Northern's storage field water. Further, testimony entered by these parties specifically question the basis for some of the effects of the mathematical algorithm embedded in the Honeywell study, the PREDICT model. Indicated Shippers and IPAMS question the scientific basis for the chemical synergy between dissolved carbon dioxide and oxygen. In contrast, they continue, modeling with HYDROCOR indicates that low levels of oxygen have little effect on corrosion in gas containing an order of 1 percent to 2 percent carbon dioxide, with no synergistic oxygen-carbon dioxide enhancing effects. Indicated Shippers state that the HYDROCOR model is widely recognized as a more conservative measure of corrosion risk than the PREDICT model.

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[30] In the July 2004 Order, the Commission was concerned that a stricter carbon dioxide specification could impede the flow of less expensive Rocky Mountain gas to Midwest markets, resulting in higher natural gas prices.

[31] Testimony Following Technical Conference of William D. Grimes.

[32] HYDROCOR is another thermodynamic model that estimates rates of corrosion.

42. Indicated Shippers point to a joint industry study[33] to compare PREDICT's results with HYDROCOR's results, and concluded that the PREDICT's software was inconsistent with actual test data in most cases, and cited that the main discrepancy was due to large bicarbonate levels skewing the results. It also questions Northern's corrosion analysis showing severe microbial corrosion on multiple samples,[34] and states that Northern did not address or provide any explanation as to how alleged corrosion costs and risks are affected by microbial action, and whether Northern treated its pipeline for microbes. Indicated Shippers state that without including and addressing such corrosion management risk and factors, there is no technical basis upon which the Commission could make an informed decision in support of Northern's proposal. Indicated Shippers suggest that Northern could address the overall corrosion rate experienced on its system by tighter corrosion control management, such as more frequent pigging.

43. The Indicated Shippers state that Northern failed to consider lower cost alternatives suggested by the Commission in Northern's rate case proceeding.[35] Some of these suggestions include protective pipe coatings and linings, materials selection, inhibitors, and inserting cleaning pigs to remove accumulated soils and debris from the walls of the pipeline. The Indicated Shippers assert that the Commission should use its previous decision as the framework and basis to reject Northern's current proposal. Also, the Indicated Shippers assert that the Commission should reject Northern's proposal based on its previous framework of analysis, stating that Northern failed to delineate the extent and causes of the problem of corrosion, and that Northern has not justified that its proposal will resolve its problems.

44. Regarding LNG facilities, the Indicated Shippers state that Northern has not submitted several necessary items of information, namely: 1) specific problems that LNG peak shavers have experienced regarding carbon dioxide levels; 2) the impact on those facilities of reducing the carbon dioxide levels from 2 percent to 1 percent; 3) the number of LNG peak shavers connected to Northern's system (compared to the number of supply receipt points); or, 4) the cost of retrofitting LNG peak shavers to accommodate carbon dioxide levels at 2 percent. Indicated Shippers argue that Northern submitted some information regarding operational issues from downstream peak shaving units, and that the bulk of those complaints came from Xcel. Northern states that Xcel already

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[33] "Evaluation of CO_2 Corrosion Prediction Models Final Report Kjeller Field Data Project," Institute for Energy Technology, at 29 (Oct. 13, 2000), which is attached to Indicated Shippers Protest at Appendix C.

[34] Northern's Data Response, No. 2, "2 of 3", page 35, shows a table with analysis of the type of corrosion on various corrosion coupons and a significant fraction of the corrosion is classified as "MIC" or [M]icrobiological [I]nduced [C]orrosion.

[35] *Northern Natural Gas Company*, 108 FERC ¶ 61,083, at 61,423, P 25 (2004).

installed equipment so that it could operate its peak shavers at the 2 percent carbon dioxide level.

5. **Commission Determination**

45. The Commission finds that the Indicated Shippers are correct in that the Commission should use the framework of analysis used in Northern's previous rate case to decide on the merits of Northern's current proposal. The Commission again recognizes that Northern has corrosion problems on its system, specifically around its storage facilities, and as Northern itself has pointed out, corrosion on its system is the result of several causes.

46. The Commission examined Northern's evidence of corrosion on its pipeline system, and recognizes that the problem is not limited to carbonic acid corrosion, as the evidence does point to other corrosive species such as microbes (microbiological induced corrosion, or MIC), chlorine, and hydrogen sulfide. Neither Northern's proposal, nor its evidence addresses these other corrosive species, and the Commission finds that the results of Northern's analysis includes the effects of other corrosive species, effectively skewing the evidence in favor of its proposal. Further, the Commission finds that Northern's independent studies do not provide sufficient evidence to support its proposal, nor do these studies support Northern's assertion that its historical observations support the results of the study.

47. The presence of carbon dioxide in Northern's gas stream is not disputed by any party in this proceeding, nor the presence of large amounts of water in its storage fields. However, the extent to which carbon dioxide alone is causing the corrosion problem on Northern's system is not discussed by Northern. For instance, Northern provides evidence of carbonic acid attack in corrosion coupons extracted from sampling equipment in its storage field that exhibited carbonic acid corrosion. [36] Northern discusses 2 specific samples analyzed by Sherry Labs.[37] According to the report, corrosion coupon labeled "sample 1"exhibited "isolated pits on both flat surfaces and edges…primarily caused by carbonic acid." The actual report also stated that the isolated corrosion pitting contained elevated amounts of chlorine, sulfur, and calcium. It showed small undercut narrow mouthed pits emanating from the bottom of the degraded area. The report speculates that this sample was cleaned before receipt to remove any chloride or sulfur residue. Further, corrosion coupon labeled "sample 4" indicated isolated pitting "primarily caused [by] a weak acid (i.e. carbonic acid)." However, the report also states that an X-Ray Energy Dispersive Spectrographic Microprobe (EDS) revealed elevated levels of chlorine around the pit. Also, the report states that a "remnant of a lip that is

[36] Northern's Data Response No. 2, p. 5.

[37] Sherry Labs report number 07040373-001-v1, dated April 18, 2007.

usually produced by undercut pitting was detected." The report concluded that the sample analysis provided inconclusive results. It states, on page 5, that because the samples were likely cleaned prior to the laboratory receiving them, X-ray diffraction could not be used to determine their mineralogical composition."

48. Further, the report also concluded that, "based on past experiences and literary reference, pits that exhibited a jagged profile, narrow mouthed openings, were cavernous, scalloped, undercut, and intersecting were *not* considered to be caused by a weak acid (i.e. carbonic acid), especially when active anions (*i.e.* chlorine, sulfur) were detected." The report finally stated that "since the results of several modes of corrosion have overlapping characteristics (both MIC and strong acid attacks produced cavernous undercut pits for instance) and the absence of additional data, it was difficult to ascertain the exact cause of degradation other than to possibly discriminate between a strong and weak acid. It is also possible that multiple forms of corrosion were active."

49. In addition to corrosion coupons, Northern presented photographical evidence of actual pipe samples extracted from the Cunningham Field. Northern states that a leak caused by corrosion pitting occurred in the Cunningham Field on line number CNU23001 in 2006. According to Northern, it had run a smart pig on all Cunningham Field lines in 2003, and no internal corrosion was evident in that same line at CNU23001. Northern claims that corrosion caused complete failure of the pipe in about three years. Northern sent corroded pipe samples that exhibited leaks to two different laboratories to determine the cause of corrosion. According to a Sherry Labs report,[38] "severe pitting damage occurred inside of the pipe particularly along areas of standing condensate." According to sample CNU23001 00+56 BOTTOM, there was severe pitting damage, in which pitting corrosion penetrated the pipe wall at a thickness of 0.188 inches. Mineralogical assessments concluded that it was due to carbonic acid as indicated by the condensate containing salt and corrosion products. The report further indicated that there were no pipe abnormalities to enhance the formation of pitting, and that oxygen was also present to accelerate the corrosion process.

50. Northern also provides a Baker Vertiline Inspection report that provides the results of a "smart pig" to find pipe wall abnormalities. A "smart pig" is a tool used to make inline tool inspections which analyze and report magnetic flux leakage[39] while simultaneously cleaning the pipeline. The report indicates an inspection run on CNU23001 and there were several very active magnetic flux leakage responses. Northern performed verification digs at some of those responses, and 2 of them exhibited corrosion. Northern made a self-inspection of the pipe and found severe pitting.

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[38] Sherry Labs Report number 2006100675, dated October 30, 2006.

[39] Active magnetic flux leakage indicates abnormalities in the pipe wall, and could indicate corrosion.

Northern concluded that one portion of the pipe (section 2236.66) exhibited corrosion due to carbonic acid (*see* Northern's Data Response No. 2, p. 5) but did not have any accompanying mineralogical analysis to appropriately determine the corrosive species responsible for the pitting damage.

51. The Commission finds that Northern's evidence in reference to its pipe and corrosion coupons do not indicate the extent that carbonic acid corrosion was solely responsible for corrosion. The samples taken from the same field indicate multiple corrosive species, and Northern submitted no evidence that delineated to what extent each species contributed to the corrosion. Further, there were no specific details given about the procedures Northern performed to mitigate the corrosion that caused these specific failures beyond general statements Northern made about its corrosion management practices, and how inadequate its current management practices were. The Commission finds that Northern's analysis and evidence regarding its corrosion coupons and pipe samples are inconclusive regarding the extent that carbon dioxide, and oxygen, are responsible for corrosion on Northern's system.

52. The Commission reviewed Northern's use of two mathematical models, the Honeywell model, and the Institute for Energy Technology (IFE) model performed by Northern's analyst. In the Honeywell study, Northern performed two separate applications; one applying to the Redfield storage facility, and the other, the Cunningham storage facility. Honeywell also applied a sensitivity study using the Honeywell model to support Northern's oxygen limit proposal. Northern confirms its analysis with the Honeywell results.

53. The Commission finds that Northern's conclusions based on its mathematical models are flawed, and that the results of the Honeywell report do not correspond to Northern's historical experience. The Commission cannot find a legitimate basis for which to give merit to Northern's analysis or the Honeywell study. First, Northern states that the Honeywell study does not predict pitting rates and shows worst case results of an "uninhibited corrosion rate." Northern correlates an instance of localized corrosion pitting to a uniform wall loss corrosion rate in its model. Second, Northern does not include any reasonable effects of its corrosion management program, a reducing factor which should be accounted for, in its model. For instance, Northern asserts that under elevated pressures, the worst case, general wall loss, uninhibited corrosion rate of 70 mpy[40] would corrode production tubing in its storage fields (wall thickness 0.303 inches) at 23 percent a year. The Commission finds that assertion misleading because it is the worst case corrosion rate (Northern uses the term conservative), on uninhibited production tubing. There is no mention of any procedures performed to mitigate this corrosion, and a reasonable adjustment made to the corrosion rate to account for it.

[40] *See* Honeywell Cunningham Field study, p. 7.

54. Further, even though oxygen is a corrosion enhancing element, since we determine that the Honeywell model fails to support Northern's proposal, we similarly find that the model's purported oxygen effects also do not support the proposal. Further, the Commission finds that Northern's evidence fails to provide a technical basis on the mechanics of oxygen corrosion (irrespective of carbon dioxide). Northern bases its proposal on only general statements that such oxygen specifications are the "most common" in the industry. Finally, Northern's corrosion samples do not show specifically, the level of corrosion caused solely by the presence of oxygen.

55. Northern submits a study from Exponent[41] that presents an analysis of the effects of carbonic acid on portland-based casing cement materials downhole. However, the Commission finds that Northern omitted any evidence of downhole corrosion of the casing cement used in its storage facility wells. Further, Northern has not presented evidence that its proposed specifications would resolve casing cement corrosion which we believe also requires examination to measure its contribution to the degradation of Northern's storage wells and surface appurtenances.

56. With regard to LNG facilities, Northern provides evidence of customer complaints concerning high levels of carbon dioxide, but these instances are not persuasive because Northern did not identify any events that caused a shut-down or created a safety or reliability issue. Also, as pointed out by the Indicated Shippers, most of these instances were raised by Xcel, who subsequently retrofitted its equipment to operate at a carbon dioxide concentration of 2 percent. Also, Northern's current tariff imposes a maximum limit of 2 percent on its system. The Commission finds no basis for a stricter carbon dioxide limit when there is little evidence of operational problems associated with its current level.

57. Accordingly, the Commission concludes that Northern's proposed oxygen and carbon dioxide specifications have not been sufficiently supported by the evidence, nor found necessary to continue the safe operation of its LNG peaking operations, or similar LNG facilities downstream. Since Northern has not provided sufficient technical support to give the Commission reason to give its proposal proper consideration, it will not address the protests concerning alternative corrosion management strategies, or cost causation.

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[41] *Carbon Dioxide Content in the Northern Natural Gas Underground Storage* by Piotr D. Moncarcz, Tracey D. Flowers, and Naysan Khoylou Emami, March 26, 2007.

C. Higher Heating Value

1. Northern's Proposal

58. Northern proposes a new gas quality specification for gas received into a processed gas segment; the higher heating value (HHV) cannot exceed 1,100 Btu/scf. Northern's existing effective tariff provides that gas receipts must have a HHV greater than or equal to 950 Btu/scf.[42] Northern does not seek to impose a maximum HHV on the unprocessed gas segments of its pipeline. Northern states its primary purpose in adopting this specification is to conform to the Interchangeability White Paper, with a slight adjustment. Northern believes it needs to lower the maximum Btu limit to achieve compatibility with the United States Department of Transportation, Pipelines and Hazardous Materials Administration's (PHMSA) regulations pertaining to high consequence area (HCA) analysis.[43] Finally, Northern asserts that the United States Environmental Protection Agency's (EPA) definition of natural gas is based upon an upper Btu limit of 1,100 Btu/scf.[44] Northern also states that to the extent that the HHV does not impact operations, Northern will continue to accept gas that does not meet the specification. Northern also clarifies in its GT&C, the definitions of Dekatherm and Total or Gross HHV, specifically that Btu is calculated on a *higher HHV* basis.

2. Protests and Comments

59. Several parties filed protests of Northern's HHV proposal. Nicor Gas states that the proposed upper limit is so far above Northern's actual experience that they are concerned that such an excessive boundary will invite shippers to flood Northern's system with high Btu natural gas that could potentially harm end-use residential and industrial equipment. Nicor states that although this scenario is doubtful, it would prefer Northern to modify its Btu limit to a maximum of 1,065 Btu/scf. On the other hand, Mewbourne Oil Company (Mewbourne) states that limiting receipt point to a maximum of 1,100 Btu/scf could preclude supplies above that limit, and with Northern's currently

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[42] See Northern's GT&C filing on May 1, 2007, "Total or Gross Heating Value. The term "total or gross heating value" means the total calorific value, expressed in Btus when one cubic foot of anhydrous gas at sixty degrees Fahrenheit (60°F) is combusted with dry air at the same temperature and the products of combustion are cooled to sixty degrees Fahrenheit (60°F). The Btu specified is on a higher heating value (HHV) basis."

[43] Northern states that it is also subject to 49 CFR § 192, Subpart O, which provides that Northern must develop integrity management programs for its gas transmission pipelines located where a leak or rupture could do the most harm.

[44] *See* Northern's June 28, 2007, Data response # 5 at 4 and Northern's July 24, 2007, presentation at 28.

effective blending practices, the limit would drive down an overall acceptable HHV in Northern's gas stream.

60. Xcel argues that Northern's maximum and minimum HHV limit should correspond with its other tariff specifications, specifically, the interchangeability parameter Wobbe Index. Xcel argues that the upper limit of Northern's HHV exceeds the threshold for risk tolerance of incomplete combustion in the Weaver Incomplete Combustion Index at the current maximum Wobbe Index.[45] Xcel also states that the lower HHV limit would also not correspond to Northern's proposed specification of 4 percent for total inerts beyond the Beaver Compressor station, and would correspond to an upper limit of 970 Btu/scf. Xcel urges the Commission to reject Northern's HHV proposal and instead direct Northern to adopt a range of 970-1,090 Btu/scf.

61. KIOGA argues that a regional waiver covering HHV is appropriate for supplies originating from Kansas. KIOGA states that Kansas gas has flowed on Northern's system for nearly 40 years, and has never caused a safety and utilization problem. They argue that this type of waiver is consistent with the Interchangeability White Paper .[46]

62. The Indicated Shippers contend that Northern failed to justify its upper limit of 1,100 Btu/scf. They state that PHSMA's HCA analysis does not specifically limit the HHV to 1,100 Btu/scf. Indicated Shippers further state that Northern fails to demonstrate a need to change its current HHV, or show that such a change will cause any operational problems for its system. Also, Indicated Shippers dispute Northern's claim regarding EPA's definition of "natural gas" as stating an upper limit of 1,100 Btu/scf. Indicated Shippers state that Northern did not provide any specifics or references that support this definition. The Indicated Shippers speculate that Northern was referencing the EPA's performance standards for stationary turbines, and opines the Commission should not use this as a legitimate basis for this standard.[47] Indicated Shippers state that this particular standard defines natural gas as having greater than a 70 percent methane concentration, or having a higher HHV between 950-1,100 Btu/scf. Indicated Shippers argues that it is very unlikely that natural gas on Northern's system or any other pipeline will have a methane concentration less than 80 percent.[48] Further, Indicated Shippers contend that

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[45] *See* Xcel's Technical Conference Presentation at p. 4.

[46] *See* at P 17 (2006).

[47] Indicated Shippers cite 40 C.F.R. § 60.4420.

[48] *See* Gas Research Institute, "Variability of Natural Gas Composition in Select Major Metropolitan Areas of the United States," at 16, Figure 2-3, (March 1992). This is a frequency distribution weighting national percent of samples demonstrating that there is no sample less then 80 percent methane.

Northern did not provide any data that supported a 1,100 Btu/scf HHV to protect engines or demonstrate that any engines in its territory would actually receive gas that would cause detonation.

63. Northern states that its proposed Wobbe Index will allow the proposed limit of 1,100 Btu/scf without exceeding the Weaver Incomplete Combustion Index. Northern justifies its proposed lower limit because it enables more supply to its system. Further, Northern states that Nicor's proposal of adopting a maximum HHV of 1,065 Btu/scf does not have enough sufficient detail to support a change to its proposal.

3. Commission Determination

64. The Commission reviewed Northern's proposed maximum HHV specification and its supporting evidence. The Commission finds that Northern fails to identify any specific operational problems involving its system in regards to receiving gas with a HHV higher than its proposed limit, or even operational problems where the blended gas stream was higher than the proposed limit. Northern's own evidence[49] reveals that the flow-weighted average HHV in its Market Area has been relatively stable over the past five years. Specifically, the flow-weighted average has been 1,009 Btu/scf with a standard deviation of ± 7 Btu/scf.[50] Furthermore, Northern asserts that very few of Northern's existing receipt points are above its proposed maximum limit and the receipt points that are above the limit generally are only small volume points. Also, Northern states that "receipts at these points have historically been accommodated through incidental blending" and it expects to continue this blending.[51]

65. The Commission finds that Northern's evidence merely references general concerns of potential operational problems, but fails to identify a connection with actual problems on its system. Northern references various industry studies and recommendations,[52] but does not present or note any examples or instances where the system was endangered or compromised due to the lack of a maximum HHV gas quality standard. Northern merely points to generalities in the Policy Statement, technical literature, the Interchangeability White Paper and its own consultant recommendations as

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[49] *See* Northern's July 24, 2007, presentation at 28.

[50] *Id* at 29.

[51] *See* Northern's August 14, 2007, initial comments, at 12.

[52] Northern states that it had experienced detonation on reciprocating engines with variations in fuel of +/- 20 Btu. *See* Northern's June 28, 2007, Data response # 5 at 2. This addresses operational problems with HHV variability, not HHV limits.

justification for its proposal without regard to its own specific operational requirements and history.

66. As a separate matter, the Commission addresses Northern's methodology in developing its HHV limit. Northern states that it's primary purpose in determining its HHV proposal is to conform to the Interchangeability White Paper recommendation of 1,110 Btu/scf, but adjusted the limit downward to correspond with the maximum HHV used in the HCA calculation. According to Northern's evidence, this adjustment is based on the HHV content being no greater than 1,100 Btu/ft^3.[53] The Commission disagrees with Northern. The regulation states that the multiplication factor used for HCA calculation depends on the HHV, but not that the HHV be limited to a certain value, such as 1,100 Btu/scf.[54] Further, Northern asserts that an EPA definition of natural gas is based upon an upper Btu limit of 1,100 Btu/scf supports its upper limit. However, Northern fails to provide any cite reference to discover the proper application of this regulation in the context of its proposal. Thus, the Commission finds that Northern has not proven that its proposal is necessary to accommodate the HCA analysis as required by 49 C.F.R. § 192.903.

67. In conclusion, Northern has failed to provide substantial evidence to confirm its assumption much less demonstrate that its proposal is even necessary. Based upon this, the Commission rejects Northern's proposal for a HHV maximum limit. The Commission accepts the revised definitions for Dekatherm and Total or Gross HHV; specifically that Btu is calculated on a *higher heating value* basis, as it is consistent with industry standards.

D. <u>Gas Temperature</u>

1. <u>Northern's Proposal</u>

68. Northern proposes to adopt a provision that the gas temperature at all receipt points shall be at least 35 °F. Northern states that temperatures below freezing result in "frost balls" on the piping, and frost balls can interfere with control valve operation and induce frost heaving. Northern also states that temperatures below zero degrees Fahrenheit on steel pipe with limited ductility can cause brittle failures, and that extreme temperature changes induce thermal stresses on the piping. Northern does not exhibit any documented operational issues in which gas temperatures have caused problems.

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[53] TTO Number 13, Integrity Management Program Delivery Order DTRS56-02-D-70036, "Potential Impact Radius Formulae for Flammable Gases Other than Natural Gas Subject to 49 CFR 192."

[54] 49 C.F.R. § 192.903 notes that: "0.69 is the factor for natural gas and that this number will vary for other gases depending upon their heat of combustion."

2. Commission Determination

69. The Commission finds that Northern fails to provide sufficient evidence for its proposal to implement a gas temperature specification on its system. Northern has not shown that this new specification is necessary for its system or for downstream entities. Specifically, Northern presents no evidence of any operational problems due to gas temperatures below its proposed threshold nor shows any changed circumstances that will put the system at risk from gas temperatures of less than 35 degrees F. The Commission therefore rejects Northern's proposal as unnecessary, and unsupported.

E. Cricondentherm Hydrocarbon Dew Point

1. Northern's Proposal

70. Northern proposes to post on its website a currently applicable specification for CHDP for all gas receipts nominated for transportation of processed gas. The posted specification for CHDP will vary and depends on system conditions and weather, but may not be lower than the safe harbor of 5 degrees F. If a receipt point operator or shipper does not agree with the hydrocarbon split upon which Northern bases the posted CHDP, it may elect to provide an extended analysis at its own cost at intervals that are no less frequent than once per quarter. Northern also adds a definition for CHDP to its GT&C.

71. Northern states that its proposal will help to prevent hydrocarbon liquid from dropping out in the pipeline, which could cause loss of service at delivery facilities during critical winter peak demand flows. Northern also states that it will allow gas receipts where and when ambient temperatures and operating conditions exist to safely allow higher hydrocarbon dew points. Northern claims it needs this provision because it found hydrocarbon condensate at multiple locations in the Market Area in the first quarter of 2007, and the problem continued in the second quarter, concurrent with the filing of its original application.[55] Northern also states that historic trends indicate further operational problems with hydrocarbon dropout will occur unless it implements a CHDP provision.

2. Protests and Comments

72. The protesting parties include Daystar, Wyoming Pipeline Authority, Indicated Shippers, IPAMS, Rockies Express Shippers, and the Coalition. Generally, the parties oppose Northern's new CHDP standards stating that it failed to provide support for its proposal, and that the proposal would have an adverse impact on existing and new gas

[55] Northern's Reply Comments, p. 37.

supplies. They further state that Northern's proposal is inconsistent with other CHDPs of interconnecting pipelines.

73. The Coalition specifically argues that Northern fails to develop standards governing the use of segment-specific temporary CHDP limits. The Coalition also argues that Northern's proposal does not define geographically where Northern will measure CHDPs. The Coalition contends that the lack of such standards creates uncertainty for producers and their ability to enter into transportation contracts for their supply to flow on Northern's system, and will ultimately cause producers to exercise choice and shift supplies away from Northern. The Coalition further contends that if such standards were in place, it would give shippers the ability to pair receipt points with out of specification gas, to effectively blend the stream to a CHDP within Northern's specification. Finally, the Coalition objects to Northern's system-wide average carbon split for C6+ in instances where no extended gas composition is available.[56] They argue that Northern should identify regional or area-specific carbon splits.

74. The Indicated Shippers argue that Northern fails to demonstrate that the points left of the J-T line in its August 3rd filing[57] were points that had liquids that were operationally unmanageable. The Indicated Shippers also argue that Northern did not address less expensive alternatives for managing liquid dropout, such as liquids handling facilities on site, pressure let-downs, etc.[58]

75. The Rockies Express Shippers and the Wyoming Pipeline Authority argue that Northern and downstream entities operationally sensitive to cold weather should bear the cost burden for controlling hydrocarbon dropout. They argue that those downstream entities that have by choice located to an abnormally cold geographic location, one in which puts a pipeline at risk of cold weather induced hydrocarbon liquid dropout, should bear the cost of managing it.

76. Northern responds to these arguments and states that it is irrelevant if its proposed limit restricts new or existing supply because it has sufficient receipt point capacity to meet demand. Also, Northern states that its historical blending practices enabled sufficient supplies to meet its proposed CHDP specifications. Regarding costs that producers would have to take on for installing facilities to lower the CHDP, Northern states that it presented data to show that producers already have the capability to process the gas to the proposed CHDP standards, but elect not to do so at times. Further,

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[56] Northern's proposed system-wide default carbon split for CHDP is 48/35/15/2.

[57] Northern's response to staff's Post-Technical Conference supplemental data request, filed August 3, 2007.

[58] Indicated Shippers Initial Comments at p. 17.

Northern argues that it is undisputed that its pipeline system operates in geographical areas that are colder than those of other pipelines. Northern states that hydrocarbon dropout is also an occurrence associated with pressure regulation, independent of temperature, and would also warrant a lower CHDP. Northern argues that its adaptation of the Natural Gas Quality + guidelines Appendix B process and its demonstrated operational problems warrant a lower CHDP. Northern states that the Policy Statement recognizes that pipelines would require different CHDP specifications based on their own unique operating circumstances.[59] Northern also states that it considered alternatives to its proposal to manage hydrocarbon liquid dropout, and concluded that each one was infeasible.[60]

3. Commission Determination

77. The Commission reviewed Northern's methodology to adopt a CHDP safe harbor provision, and its supporting evidence. In its methodology, Northern investigates two different CHDP safe harbor levels (5° and 6°) and evaluated each using the process outlined in Appendix B of the Hydrocarbon Drop Out White Paper.[61] As discussed below, the Commission finds that Northern fails to show that its proposed 5° CHDP safe harbor is just and reasonable.

78. First, the Commission finds insufficient Northern's assertion that it provided evidence showing an ongoing problem of unmanageable liquid dropout on its system. While the Commission recognizes that Northern has experienced liquid dropout in the winter of 2006/2007, it has not shown that the liquids encountered were unmanageable, resulting in severe operational problems, *i.e.* an inability to make deliveries. Northern's evidence presents 70 instances of liquid dropout, and 43 of those instances show less than 5 pounds of accumulated liquid.[62] In addition, only in a few of the occurrences where it encountered liquid dropout did Northern experience equipment failure.[63] Further, discussion of these failures was minimal and lacking in detail to provide a sufficient basis for the Commission to view the instances as severe operational problems.

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[59] *See* Commission Policy Statement at P 35.

[60] Northern's Reply Comments, p. 44.

[61] *See* "White Paper on Liquid Hydrocarbon Drop Out In Natural Gas Infrastructure," NGC+ Liquid Hydrocarbon Drop Out Task Group (2005) (Liquid Hydrocarbon Drop Out White Paper), at 26.

[62] Appendix I of Northern's application.

[63] *Id.*

79. Second, the Commission finds that Northern fails to provide any circumstances of changing conditions on its system that would precipitate unmanageable liquid dropout. Northern's evidence shows the accumulation of excessive liquid dropout in its pipeline system during this past winter,[64] but then fails to provide an explanation of how it believes that this trend will continue. Specifically, Northern does not show evidence of any new supply sources with a CHDP composition that would have caused excessive liquid dropout.

80. As a separate matter, Northern's own methodology in developing a CHDP safe harbor proposal is fundamentally flawed. Northern asserts it supported its 5° CHDP safe harbor by its implementation of the Liquid Hydrocarbon Drop Out White Paper recommendation. In the aforementioned Appendix B process, Northern develops two separate phase diagrams, one representing a 5° CHDP safe harbor and the other a 6° CHDP safe harbor, for three different days (January 15, February 7, and March 6) in the winter of 2006/2007 for comparison purposes.[65] In the January 15 scenario, Northern found only 5 additional points (of the 1,486 total points) that could potentially experience liquid dropout at a CHDP of 6° as compared to 5°.[66] The Commission finds negligible the number of incremental points added due to the shift in CHDP. Also, Northern fails to show how liquid dropout at these additional points would be unmanageable. Further, Northern selected certain points that would cover a range of flows, temperatures, and pressures in which to compare, at CHDP safe harbors of 5°, 6°, 10°, and 15°, how much liquid would dropout. Of the four points chosen by Northern, three experienced no dropout at either a 5° or a 6° CHDP. The one point that is expected to have liquid dropout (Stanhope TBS #1), is estimated to produce only 0.47 pounds/day at 5° and 0.54 pounds/day at 6°.[67]

81. The Commission finds that, considering the negligible differences in the number of points in comparison of a 5° or 6° CHDP safe harbor, and the lack of finding that such points will produce an unmanageable accumulation of liquid, it is apparent that Northern did not follow the Liquid Hydrocarbon Drop Out White Paper recommendation, as required by the Commission. Specifically, in the Appendix B process, step number 8

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[64] Northern's technical conference presentation, p. 41 – 43.

[65] Northern developed its phase diagrams (P-T) using the Peng-Robinson Equation of State, based on a representative composition, which assumed the market-area average carbon split (54:34:12). Northern then plotted numerous points, where each point represented data at a single delivery location, using the recorded highest pressure and lowest temperature for that day.

[66] Northern June 29, 2007, Data Response to question 9.

[67] Northern's August 3 response to technical conference request, p. 12.

states the analysis should re-apply steps 3 through 6 by selecting a lower candidate CHDP, or to consider alternatives, which would include, but not be limited to, the installation of gas heating or use multi-stage pressure reduction. Northern initiated the process with a 6° CHDP safe harbor, and in its re-application, reduced it by 1°. The negligible differences that resulted in both candidate CHDP safe harbors shows that Northern did not widen its analysis sufficiently to discover a more appropriate CHDP safe harbor. The Commission accepts Northern's definition for CHDP.

F. Butanes & Heavier Hydrocarbons

1. Northern's Proposal

82. Northern proposes that for all gas received into its system designated for the transport of processed gas, the gas must contain less than 1.5 percent of butanes and heavier hydrocarbons, such as pentane, hexane, heptane, octane, nonane, and decane. Northern's existing effective tariff does not contain a specification for butanes and heavier hydrocarbons. Northern states that it adopts this proposed limit directly from the Interchangeability White Paper recommendations. Northern also supplied evidence outlining its concerns with detonation and combustion stability on Northern's compressor units on its system.

83. Northern states it provides evidence to require its maximum limit on butanes and heavier hydrocarbons to prevent detonation and combustibility concerns. Northern states that the historical flow-weighted butanes and heavier hydrocarbons on Northern's system do not exceed the proposed 1.5 percent limit. Therefore, Northern argues that its proposal will have negligible impact on available supplies.[68]

2. Commission Determination

84. The Commission reviewed Northern's supporting evidence to adopt a limit on butanes and heavier hydrocarbons. The Commission finds that Northern has not provided sufficient evidence. First, Northern fails to identify or point out any specific issues pertaining to its system in regards to the transportation of heavier hydrocarbons. Northern has not shown it needs its proposal to add a limit on butanes and heavier

[68] Northern's Initial Comments at 17 and Reply Comments at 47-48. Despite not having any protestors raise this point after the technical conference nor after its initial comments, Northern responded to two protests made after its original filing. *See* Indicated Shippers' Protest and Request for Rejection at 9 and Northern also appears to be responding to LLOG's Protest filed in response to Northern's original filing. *See* Motion to Intervene and Protest of LLOG Exploration Company LLC at 6.

hydrocarbons to address existing problems or future problems on its system.[69] Therefore the Commission will reject Northern's proposal. The Commission's Policy Statement does not mandate use of the Interchangeability White Paper Interim Guidelines. Rather, the Commission strongly encourages pipelines and their customers to use the Interchangeability White Paper Interim Guidelines as a common scientific reference point for resolving gas quality and interchangeability issues.[70] Moreover, Northern failed to identify any past, current, or future problems with butanes and heavier hydrocarbons or even general changes to the operation of its system that would require the implementation of more restrictive standards. The Commission emphasizes that we find only that Northern has not provided sufficient evidence in its pleadings here to support this proposal. The Commission makes no findings on the merits of whether Northern could justify its proposed gas quality provisions on butanes and heavier hydrocarbons with additional evidence, and we reject the proposal without prejudice to Northern re-filing a properly supported proposal.

G. Total Inerts

1. Northern's Proposal

85. Northern proposes a total inert safe harbor limit of 3 percent upstream of its Beaver Compressor Station and a safe harbor limit of 4 percent downstream of the Beaver Compressor Station.[71] Northern's current tariff does not provide for a limit on inert gases. Northern asserts that operational problems resulting from inerts in the gas stream include increased fuel usage and reduced available pipeline capacity. Further, Northern asserts that it based its sustainable pipeline capacity model for its Market Area on a total inerts level in the gas stream of 4.1 percent. Additionally, Northern states that the 3 percent safe harbor upstream of the Beaver Compressor Station is consistent with interconnecting pipelines on that part of its system and that at times, these pipelines rejected its gas because the gas stream exceeded the downstream pipeline's tariff limits for total inerts at the interconnections.[72]

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[69] Historically, Northern has been well below the proposed limit. *See* Northern's July 24, 2007, Presentation at 48.

[70] Policy Statement at P 33.

[71] Northern's application defines inerts as the total combined carbon dioxide, nitrogen, helium, oxygen, and any other diluent compound, p. 14.

[72] In Northern's June 29, 2007 Data Response, Northern identifies an inability to ship gas on the following pipelines as a result of total inerts: El Paso Natural Gas Company; Oasis Pipeline Company; Coronado Pipeline Enterprises, LLC; and Enbridge Pipeline, LP.

2. **Protests and Comments**

86. Several parties[73] protested Northern's proposal, and all essentially make the same arguments. The parties argue that the Commission should reject Northern's proposal because it fails to meet its burden under Section 4 of the NGA by providing sufficient technical support or operational circumstances in which this specification is necessary. Targa specifically proposes that the safe harbor on Northern's system should start with the 4 percent limit.

87. The protestors contend that Northern's evidence[74] shows only intermittent operational problems and does not detail to what extent the events affected Northern's customers or whether any of the events resulted in shut-in. Also, the protestors argue that Northern has not demonstrated any operational reasons for a deviation from the Interchangeability White Paper recommendation for a safe harbor of 4 percent for total inerts for supply upstream of the Beaver Compressor Station.

88. The protestors also assert that Northern's rationale for its 3 percent safe harbor, "safety and reliability concerns,"[75] is not supported. The protestors claim that Northern instead only provides economic concerns noting that inerts consume pipeline capacity and cause increased fuel usage. The protestors also contend that Northern has not justified the point of bifurcation on its system, at the Beaver Compressor Station, other than merely stating that this point represents a natural geographic divider on its system and that gas upstream comes from more diverse sources and is typically used to supply interconnecting interstate pipelines. Finally, protestors argue that Northern's evidence[76] shows a declining trend of total inerts since mid-2004, to levels below 3 percent.

89. Targa submitted a study on August 3, 2007[77] which shows that it will have to incur substantial capital costs to comply with Northern's total inerts standard for gas entering Northern's system upstream of the Beaver Compressor Station. The analysis concluded that adding a nitrogen reduction unit to its Mertzon plant would cost from $27.5 to $40.6 million. Targa states that if it has to incur these costs, it would be

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[73] Targa, Connect Energy, Daystar, SemGas, and DCP Midstream.

[74] Northern's Data Response No. 13, *Identification and documentation where customers "have been unable to ship gas on pipelines interconnecting in the Permian area as a result of total inerts."*

[75] *See* Northern Technical Conference Presentation, page 2.

[76] *See* Northern's Presentation at the Technical Conference, page 53.

[77] *Nitrogen Reduction Unit Cost Study*, by Carter Tannehill, Natural Gas Consultant, at the request by Targa.

uneconomic to continue processing gas, and as a result, gas supply on the national grid would be reduced. Oxy and DCP Midstream also submitted cost estimates for additional natural gas processing capacity, and quoted figures of $43 million and $14 million, respectively.

3. Commission Determination

90. The Commission recognizes that inert gases can reduce available capacity and increase fuel consumption. Inert gases such as nitrogen and carbon dioxide contain no thermal content. As the volume of inerts in the pipeline is increased, the amount of thermal gases, such as methane and butane are decreased. Therefore, the presence of inert gases in the pipeline reduces its thermal capacity. Inerts also may increase fuel consumption. As a pipeline transports additional mass associated with gas components that have no chemical energy, the fuel use per dekatherm transported increases. The Commission encourages pipelines and their customers to develop solutions to the problem if and when it exists. The Commission reviewed Northern's methodology and supporting evidence of a Total Inerts safe harbor specification, and concludes that Northern has not sufficiently supported its proposal. First, the Commission finds Northern's rationale for adopting its 4 percent safe harbor limit above the Beaver Compressor station to be unpersuasive. Northern has operated its system for years without an inerts limit, and has yet to identify any operational problems where it cannot meet its contractual capacity commitments in the Market Area because inert levels reduced system capacity. Further, Northern states that it assumes a 4.1 percent inert content for the sustainable design capacity of its Market Area. However, Northern provides data showing over the last 3 years that inert levels in its Market Area have trended downward from approximately 4.4 to 2.9 percent.[78] Northern also confuses "available capacity" with contract transportation rights and the impact on existing customers. Northern has not shown that any hypothetical reductions in "available capacity" resulting from high inert levels would have a corresponding effect on its contractual capacity. Further, Northern provides no evidence showing that a rejection of its proposed inert safe harbor limit would cause a diminution of service to existing customers on existing facilities in the Market Area. Essentially, Northern proposes a solution for a problem that does not exist and based upon Northern's own data will not exist absent a reversal in the current trend for inerts on its system. Therefore, the Commission rejects Northern's proposal to implement a 4 percent inert safe harbor limit downstream of the Beaver Compressor Station.

91. Further, we find that Northern has not provided sufficient evidence to also support its proposed 3 percent inert safe harbor limit upstream of the Beaver Compressor Station. Northern asserts that it needs the new limit to ensure delivery into certain pipelines that

[78] Northern's application Appendix L.

require lower inert levels.[79] Northern's evidence[80] includes a log of events where it could not deliver gas into pipelines upstream of the Beaver Compressor Station due to high levels of inerts in its own gas stream.[81] These instances occurred on a localized portion of Northern's system in the Permian Basin. Northern appears to propose an inert limit for its entire system upstream of the Beaver Compressor Station to address a localized problem associated with a few pipeline interconnections.[82] The evidence provided by Northern does not indicate a widespread, reoccurring problem that would require a change in Northern's tariff. Furthermore, according to Northern's own historical data, the concentration of inerts in its gas stream has been trending downward and there have been fewer instances of delivery problems in recent years. For example, Northern details twenty instances in 2005 where inert levels caused delivery problems, but only five examples in 2006.[83]

92. Further, no shipper on Northern's system supports the proposal or detailed any instance where the rejection of gas by a downstream pipeline due to inert concentration caused a problem. Additionally, we agree with Connect Energy Services, et. al. (Coalition) in its initial comments filed on August 14, 2007, that reads "all shippers, including members of the Coalition, are apparently willing to live with the slight risk and consequence of a downstream scheduling cut by interconnecting pipelines." Also, we note that Northern negotiated waivers at several of the affected pipeline interconnections since it made its tariff proposal.[84] Based upon these reasons, the Commission rejects Northern's proposed 3 percent inert safe harbor limit upstream of the Beaver Compressor Station.

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[79] Northern states in Appendix K of its application that the following interconnecting pipelines have limits on total inerts or nitrogen: Viking Gas Transmission Company; Guardian Pipeline, LLC; Great Lakes Gas Transmission Company; Natural Gas Pipeline Company of America; ANR Pipeline Company; Transwestern Pipeline Company; El Paso Natural Gas Company; and Florida Gas Transmission Company, LLC.

[80] *Fn*. 4.

[81] Northern June 29, 2007 Data Response to question 13.

[82] Northern specifically cites the following locations: El Paso Keystone interconnect; El Paso Seminole interconnect; El Paso Waha interconnect; El Paso Plains Interconnect; Oasis Waha Interconnect; Coronado Pecos interconnect; Enbridge Pampa interconnect.

[83] Northern June 29, 2007 Data Response to question 13.

[84] Northern's August 28, 2007 Reply Comments, p. 51.

H. Wobbe Index

1. Northern's Proposal

93. Northern proposes a Wobbe Index range of no less than 1,245 or greater than 1,365. Northern's existing effective tariff contains no specification for a Wobbe Index. Northern states that its proposed Wobbe Index range is based on a five-year flow-weighted average from historical data, with a range of ± 4.6 percent. This range is greater than the ± 4 percent recommended by the Interchangeability White Paper.[85] Northern contends that this range is slightly higher based on wider variations of Wobbe Index experienced in its Market Area. Northern also adds a definition for "Wobbe Index" to its GT&C.

2. Protests and Comments

94. Several parties argued that the Commission should reject Northern's proposal because of lack of sufficient evidence. SemGas argues that Northern's use of the White Paper does not support its proposed Wobbe Index. SemGas is a producer of natural gas in Kansas, and states that the proposed minimum Wobbe Index level would possibly preclude its natural gas supply, which it delivers into Northern's system at a Wobbe Index of approximately 1205. They argue that the Interchangeability White Paper states that gas with a Wobbe Index as low as 1,201 has been successfully utilized in U.S. cities,[86] and further acknowledge that maximum Wobbe levels, not minimum levels were the focus of concern. SemGas argues that Northern's market area has never seen levels as low as 1,205, even when blended with SemGas's supply.

95. Mewbourne argues that a Wobbe Index specification is not necessary on Northern's system because Northern already maintains a stable and predictable gas supply under its current blending practices. Mewbourne opposes any speculation of the introduction of regasified LNG supplies because it does not expect such gas to flow on Northern's system. The Coalition argues that Northern does not need a Wobbe Index specification because it has never had any Wobbe-related operational problems. However, the Coalition states that out of all its gas quality specifications, Northern's proposal disqualifies the most points, and that the truncated maximum value precludes any new, significant LNG sources to Northern's system. The Coalition argues that Northern adopt a Wobbe Index range to include at least a value of 1,400.

96. Golden Spread and Xcel (Generators) both state that it does not oppose a Wobbe Index specification on Northern's system, but argues that the Commission should modify

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[85] *See* Northern's request p. 15 pp 2.

[86] Interchangeability White Paper, P 26.

it to: 1) more closely align with local historical averages experienced in each separate prospective market area serving its facilities; and, 2) follow the Interchangeability White Paper recommendation of a ± 4 percent Wobbe Index variance instead of the proposed ± 4.6 percent. The Generators and CenterPoint contend that Northern's inclusion of its Market Area labeled ABC (Market Area just north of Demarc) skews its system-wide average to enable receipts of less-merchantable, lower Wobbe Index gas supply from Northern's field area.

97. The Generators and CenterPoint argue the Commission should apply a ±4 percent range to regional averages of historical Wobbe Indexes for each separate market area, or alternatively apply a larger system-wide average closer to their local averages, such as eliminating Market Area ABC from its system-wide analysis. They argue that a Wobbe Index system-wide average closer to 1,320 with a ±4 percent range is sufficient to encompass the gas flowing on Northern's system. Xcel claims that the current proposal exposes its generation equipment to variations in Wobbe Index as much as 5.7 percent below their respective local system averages.[87] Golden Spread states that Northern gives conflicting explanations regarding the evidence supporting the range. Golden Spread argues that Northern states in one part of its application, Wobbe Index fluctuations in the field area[88] are the basis for a wider specification, and in another part of the application, the wider specification is necessary to accommodate fluctuations in the Market Area.[89]

98. Golden Spread responds to the Coalition's protest that proposes the adoption of a higher limit and a broader Wobbe range than what Northern proposes. Golden Spread states that the Coalition fails to explain how a wider Wobbe range would ensure that essential equipment operated by Northern's customers would assure safe operation.

99. Finally, the Generators argue for the inclusion of a proposal for a Wobbe Index rate of change. The Generators state that the Commission already implemented similar provisions in other proceedings.[90] The Generators contend that the lack of such a provision puts them at risk for increased costs inherent with mitigating Wobbe fluctuations that could potentially harm natural gas fired electric generators.

100. Northern responds to the protests, and also addresses the proposed modifications to its Wobbe Index specification proposal. Northern essentially restates its position

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[87] Xcel's Initial Comments, p. 11.

[88] Northern's Application, Appendix E.

[89] *Id*, at p. 15.

[90] 119 FERC ¶ 61,075 at PP 139-44 (2007) (Opinion 495).

regarding the adoption of a system-wide Wobbe Index based on historical averages from the Market Area and its position regarding its wider range.

3. Commission Determination

101. The Commission reviewed Northern's methodology in adopting its proposal for a Wobbe Index specification, and also its support for deviating from the Interchangeability White Paper recommendation of a ±4 percent range. The Commission finds that, despite its methodology in adopting a Wobbe Index specification, Northern does not provide evidence of operational issues concerning gas interchangeability problems on its facilities or on downstream entities. Instead, Northern merely makes statements that such standards will help protect downstream equipment from combustion stability problems, and that such standards will ensure gas interchangeability.[91] The Commission also finds that Northern failed to provide evidence showing even general changes to the operation of its system that would require the implementation of more restrictive Wobbe Index standards. Thus, for the reasons discussed above, the Commission rejects Northern's Wobbe Index proposal, but accepts its new definition for "Wobbe Index."

I. Hazardous Substances

1. Northern's Proposal

102. Northern proposes to adopt a new provision that gas will not contain any toxic, hazardous materials or substances, or any deleterious material potentially harmful to persons or to the environment including, but not limited to, polychlorinated biphenyls (PCBs) and substances requiring investigation, remediation or removal under law, regulation, rule or order in effect from time to time. Northern states that its proposal protects its system from contamination of toxic substances. Northern believes that existing supply sources meet this provision.

2. Commission Determination

103. The Commission finds that Northern fails to provide sufficient evidence for its proposal to implement a hazardous substance specification on its system. Northern has not shown that it needs this new specification for its system or downstream entities. Specifically, Northern has not shown that any operational problems due to hazardous substance, and also has not shown that circumstances have changed that will put the system at risk of such materials. The Commission therefore rejects Northern's proposal.

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[91] Northern's Technical Conference presentation.

J. General Waiver, Allocations, and Unprocessed/Processed Gas Segments

1. Northern's Proposals

104. Northern proposes to add a general waiver provision to its tariff that allows Northern to accept gas that does not conform to the tariff quality specifications. The acceptance would be subject to a determination that the gas will not interfere with Northern's ability to maintain an acceptable gas quality in its pipeline through prudent and safe operation of the system, the gas does not affect Northern's ability to provide service to its customers, and that the gas does not adversely affect Northern's ability to deliver gas at its delivery points. The general waivers granted would be subject to suspension under certain operational conditions. In its August 3, 2007 post-technical conference filing, Northern clarified how the waiver and suspension process will work by omitting the applicability of the general waiver to certain gas components.

105. Northern proposed to determine the priority for allocating or curtailing gas not in compliance with any gas quality specification based on the scheduling priorities set for in section 29 of its tariff, except that within each category of service, gas shall be allocated or curtailed in the order of the amount by which the gas deviates from the specification, so that the least compliant gas will be taken off firsts and gas most compliant will be taken off last within each category. In its August 3 filing, Northern added tariff language: (1) clarifying that certain receipt points are subject to automatic shut off based on the gas quality; (2) stating that it may resume receipt of gas if the gas becomes compliant or conditions change; and, (3) clarifying that the receipt point remains subject to the notice of suspension of the general waiver and that allocations may be reinstated if conditions change.

106. Northern's May 1, 2007 filing contained an Appendix A, a list of receipt points on unprocessed segments of Northern's system, along with a map of unprocessed gas lines in Northern's Field Area and a map of unprocessed gas lines offshore. Any portion of Northern's system not identified in Appendix A would be part of the processed gas segments. Appendix A would be subject to change over time. The reason for the distinction between unprocessed and processed segments was that certain of Northern's proposed gas quality specifications would only be applicable to processed gas segments. In its August 3, 2007, filing, in response to the Commission Staff request at the technical conference, Northern proposes to add tariff language to provide for definitions of unprocessed and processed gas segments and procedures for a change to the designation.

2. Commission Determination

107. Northern submitted several procedural tariff provisions related to its proposed gas quality specifications. Northern proposes tariff provisions concerning a general waiver of its gas quality specifications, the allocation or curtailment of gas not in compliance with

its gas quality specifications, and the designation of processed and unprocessed gas segments for the purposes of applying the gas quality specifications. Given that the Commission is rejecting all the gas quality specifications proposed by Northern, the Commission finds that it is appropriate to reject the procedural provisions proposed by Northern because they are inextricably linked to the substantive gas quality provisions themselves. The Commission finds that it makes sense to treat Northern's proposed procedural provisions as part of the integrated package which the Commission is rejecting. The decision here is without prejudice to Northern's submitting such procedures in a future section 4 filing or settlement.

The Commission orders:

Northern's May 1, 2007 tariff sheets are rejected, except for Fourth Revised Sheet No. 203, and Third Revised Sheet No. 206, which propose new or revised definitions.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.