UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North Dakota Pipeline Company LLC **Docket No. OR14-21-000**

MOTION FOR LEAVE TO ANSWER AND ANSWER OF CONCORD ENERGY LLC, ENSERCO ENERGY LLC, ENWEST MARKETING LLC AND WPX ENERGY MARKETING, LLC TO REPLY COMMENTS OF NORTH DAKOTA PIPELINE COMPANY LLC

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Pursuant to Rules 212 and 213 of the Federal Energy Regulatory Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212 and 385.213, Concord Energy LLC (Concord), Enserco Energy LLC (Enserco), EnWest Marketing LLC (EnWest) and WPX Energy Marketing, LLC (WPX) (collectively referred to as "the Shippers") respectfully move for leave to answer and hereby submit their Answer to the Reply Comments filed by North Dakota Pipeline Company LLC (NDP) on March 31, 2014. In support of their Motion and Answer, the Shippers state as follows:

MOTION FOR LEAVE TO ANSWER NDP

On February 12, 2014, NDP filed a Petition for Declaratory Order (NDP Petition) seeking the approval of a rate design and tariff structure for new pipeline expansions. In that Petition NDP sought to impose the cost of operating and building that new system on existing shippers of its pipeline system.

On March 14, 2014, the Shippers filed a Protest to the NDP Petition (Shippers' Protest). On March 31, 2014, NDP filed a Reply to the Shippers' Protest. The full NDP Reply is 102 pages long and contains three new affidavits along with three new attachments. NDP also advances several new arguments in its Reply.

Under the Commission's rules, NDP is not permitted to file a Reply to the Shippers' Protest. The NDP Reply is clearly a substantive Answer to the Protest and is therefore prohibited by Rule 213(a)(2). However, in event, the Commission accepts the NDP Reply, the Shippers respectfully request the Commission to find that good cause exists pursuant to Rule 213(a)(2) for them to file this Answer to the NDP Reply.

The Shippers recognize that answers to responses are not routinely accepted.[1] In the past, however, the Commission has permitted answers for various reasons demonstrating good cause.[2] The Commission has held that good cause exists when an answer or response, "will facilitate the decisional process or aid in the explication of issues,"[3] "clarify the issues in dispute and… ensure a complete and accurate record,"[4] help resolve complex issues,[5] "correct factual misstatements,"[6] or provide "useful and relevant information to the Commission which… assist[s] in the decision-making process."[7] The Shippers respectfully suggest that those circumstances are present here, particularly in view of the length of the NDP Reply, and the inclusion of new arguments, together with several new affidavits and exhibits.

ANSWER TO NDP REPLY

In its Reply to the Shippers' Protest, NDP stated that it requested a number of different rulings by the Commission in its Declaratory Order Petition relating to rates,

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[1] Rule 213(a)(2) provides that responses to answers are generally not allowed, "unless otherwise ordered by the decisional authority."
[2] *Buckeye Pipe Line Co*., 45 FERC ¶ 61,046 at 61,160 (1988).
[3] *Transwestern Pipeline Co*., 50 FERC ¶ 61,211 at 61,672, n. 5 (1990).
[4] *TransNexen Gas Pipe Line Corp*., 68 FERC ¶ 61,338 at 62,354 (1994) (permitting answer to protest).
[5] *Ohio Power Co*., 46 FERC ¶ 61,180 (1989).
[6] *S. Minnesota Mun. Power Agency v. N. States Power Co*., 57 FERC ¶ 61,136 at 61,194 (1991).
[7] *Transwestern Pipeline Co*., 50 FERC ¶ 61,362 at 62,090, n. 19 (1990).

tariff structure and rate design. NDP claims that in their Protest, the Shippers focused "virtually all of their attention" on the Expansion Rate Component.[8] NDP's position is not correct. In their Protest the Shippers challenged as unjust and unreasonable all aspects of the tariff rate structure that NDP wishes to implement, including the rates that committed shippers would pay under the terms of the NDP Transportation Service Agreement (TSA) and the rates that uncommitted shippers would be paying from Clearbrook to Superior, WI.

NDP is correct, however, in pointing to the Expansion Rate Component and the Downstream Rate Component as the principal issues for the Commission to resolve. That is because the underlying basis of the entire NDP tariff and rate design rests on NDP's ability to require uncommitted shippers on its present pipeline system to pay the majority of the costs that NDP will incur in building and operating its new pipeline system.

A. NDP'S Petition Must Be Denied Because NDP Has Failed to Establish That Its New Pipeline System Is Needed and Will Benefit Shippers on the Existing NDP Pipeline.

If the Commission were to approve the NDP Petition, the rates that current shippers would be charged for transportation from Beaver Lodge to Clearbrook at the very outset of the Sandpiper project would be 94% to 125% higher than current rates.[9] In a Supplemental Declaration attached to this Answer as Exhibit 1, Shipper expert Peter K.

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[8] Reply Comments of North Dakota Pipeline Company LLC to Protests of and Comments on Petition for Declaratory Order (hereinafter, "NDP Reply"), dated March 31, 2014, page 2, footnote 3.

[9] See Table 1 and paragraphs 13-14 of the Sworn Declaration of Peter K. Ashton in Support of Protest and opposition of Concord Energy LLC, Enserco Energy LLC, Enwest Marketing LLC, and WPX Energy Marketing LLC to North Dakota Pipeline Company LLC Petition for Declaratory Order, dated March 13, 2014, hereinafter "Ashton Declaration."

Ashton demonstrates that the rate from Clearbrook to Superior at the outset of the Sandpiper project would be more than 150% higher than existing rates.[10]

In its Petition, NDP recognized that in order to impose that type of burden on existing shippers it had to establish as a matter of fact that its new pipeline was needed and would benefit existing shippers on the NDP system.[11] Therefore, in its Petition, NDP said that it was providing evidentiary support of the need and benefits of its pipeline project.[12]

However, in its Reply, NDP is attempting to back track. It first claims that there is no requirement under the Interstate Commerce Act (ICA) that the Commission determine that a new pipeline is needed.[13] NDP then goes on to cite cases in which the Commission approved a declaratory order petition for a new pipeline without ever considering whether the project was needed.[14]

NDP's new position is simply incorrect. The Commission has clearly held that before the costs of building and operating a new or expanded pipeline system can be imposed on existing shippers, the pipeline must establish that the new system is needed and will benefit them.[15]

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[10] See Supplemental Sworn Declaration of Peter K. Ashton (hereinafter "Ashton Supplemental Declaration"), Table 3. This Supplemental Sworn Declaration is attached to this Answer as Exhibit 1.

[11] NDP Petition, pages 43-44.

[12] NDP Petition, pages 43-44.

[13] NDP Reply, page 6.

[14] NDP Reply, page 6.

[15] *See Enbridge Energy Company, Inc. Enbridge Energy, Limited Partnership*, 123 FERC ¶ 61,130 at P 48-50 (2008) (denying a petition for declaratory order when it was uncertain "when, if ever" the benefits to the shippers will be realized); *Enbridge Energy, Limited Partnership*, 117 FERC ¶ 61,279 at P 28 (2006) ("Lacking adequate evidence of such benefits, we cannot conclude that Enbridge has shown that it would be just and reasonable to charge those other shippers a rate surcharge that would subsidize construction of the Enbridge affiliate's extension pipeline.").

We respectfully submit that the data submitted by NDP does not enable the Commission to make those findings in this case.

1. The Report of the North Dakota Pipeline Authority Showing that Ample Present and Future Take-Away Capacity Will Exist for Bakken Crude Oil Whether or Not the Sandpiper Project Is Constructed Is Un-rebutted.

Even accepting all of NDP's assumptions as to future crude oil production – a proposition that Mr. Ashton points out is contrary to reports of the Energy Information Administration and the U.S. Geological Survey[16] – the data published by the North Dakota Pipeline Authority (ND Pipeline Authority) establishes that existing and future pipeline and rail facilities are more than ample to transport Bakken crude oil from North Dakota without the NDP Sandpiper project. It is true that NDP and its experts carp at the margins of that conclusion by claiming that the actual rail capacity is only two-thirds the amount reported by the ND Pipeline Authority and that rail is not as secure as pipe. But, even

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The cases cited by NDP do not state anything to the contrary. NDP cites an SFPP proceeding in which the Commission noted that "oil pipelines do not need to seek approval from the Commission before beginning construction of the pipeline (or a pipeline expansion)." *SFPP, L.P.*, 140 FERC ¶ 61,220 at P 50 (2012). However, the *SFPP* case focused on whether a pipeline could use certain throughput assumptions in calculating its cost of service for an existing pipeline that had already been built - a point that the Commission explicitly makes. *SFPP, L.P.* 140 FERC ¶ 61,220 at P 50 ("Shippers do not cite a single oil pipeline case in which the Commission has imposed such a throughput adjustment for *existing* oil pipeline capacity.") (Emphasis in the original). The Commission further noted that there was no question raised as to whether the SFPP pipeline expansion was prudent or that the expansion was used or useful. *SFPP, L.P.* 140 FERC ¶ 61,220 at P 48.

NDP also cites a string of cases regarding petitions for declaratory order in which, unlike the present case, the pipeline did not seek a single combined rate component for both existing and expansion pipelines. In addition, almost all the cases that NDP cited involved entirely new construction of projects that were largely unopposed.

As we have pointed out previously, in cases that did involve the imposition of a single rate component for existing and new pipeline facilities, the Commission recognized that existing shippers and all intervenors agreed that the project was needed. *Colonial Pipeline Company*, 116 FERC ¶ 61,078 at P 43-44 (2006); *Calnev Pipe Line LLC*, 120 FERC ¶ 61,073 at PP 24-25 (2007).

[16] Ashton Supplemental Declaration, paragraph 26.

discounting the rail capacity reported by the ND Pipeline Authority by one-third, there is still more than ample take-away capacity for Bakken crude oil.[17]

2. The Data Submitted by NDP Shows that Current Pipeline Capacity Is Adequate.

NDP has not been able to explain away the fact that the existing NDP system has not been constrained.

In an Affidavit attached to the NDP Reply, Bruce MacPhail provides information regarding nominations made to NDP and the available capacity of the line.[18] That data shows that from January 2013 to April 2014 – a period in which considerable rail capacity has come on stream – the existing NDP pipeline has not been apportioned in eight out of 16 months. However, if the full 210,000 bpd design capacity of the pipeline had been available, the pipeline would not have been apportioned in 10 out of 16 months. Of the remaining 6 months, two of them are highly anomalous with nominations in one month amounting to almost 3 million barrels and in another month more than a half million barrels. Furthermore, as Mr. Garner points out in his Supplemental Declaration attached to the Shippers' Answer as Exhibit 2, in at least six months of the July 2013 to April 2014

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[17] According to the North Dakota Pipeline Authority Report, which is Attachment A to the Sworn Declaration of Robert Garner dated March 13, 2014, there will be 783,000 bpd of pipeline take-away capacity in the Bakken area by year-end 2014 along with 1,195,000 bpd of rail take-away capacity. Reducing the rail capacity available at year-end 2014 by one-third results in 796,666 bpd of rail take-away capacity. That diminished rail take-away capacity, added to the 783,000 bpd of pipeline take-away capacity, amounts to 1,579,666 bpd of total take-away capacity in the region, which is well over the 2026 production peak of 1.4 million bpd computed by NDP's consultant Steven D. Crane in his analysis attached to NDP's Petition.

[18] Affidavit of Bruce MacPhail in Support of Reply Comments of North Dakota Pipeline Company LLC to Protests of Petition for Declaratory Order, page 9.

period, NDP offered shippers the opportunity to transport more crude oil on the pipeline after it had declared that the pipeline was apportioned.[19]

3. There Is Meager Shipper Support for the Sandpiper Project

In its Reply, NDP makes much over the alleged support that it has received from shippers for the Sandpiper project. However, even considering the letters of support that NDP discusses, the fact is that shipper support is very minimal. Apart from Marathon Petroleum Company LP (Marathon), NDP has not stated who its committed shippers are. But it is highly probable that the great majority of the committed volume has been subscribed to by Marathon, *i.e.*, an equity owner of the pipeline. Moreover even with that support, the volume committed to during the Open Season is only 35% of the capacity of the total system including the Sandpiper project. In fact, the amount of shipper support is probably considerably less, since Marathon is in all probability, simply shifting its current throughput to a different category.

Apart from Marathon, NDP has received letters of support from only seven current shippers (only 4%) out of the 185 shippers on its pipeline system.[20] Statoil, which NDP discusses at length in its Reply, merely says that it "regularly … evaluat[es] new,

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[19] Sworn Supplemental Declaration of Robert P. Garner, paragraph 37. Communications from NDP to shippers indicting that the pipeline could transport more crude oil after NDP declared that it was apportioned are attached to Mr. Garner's Supplemental Declaration as Attachment F.

[20] According to letters of support or comments filed in Docket OR14-21, the following companies indicated that they were current or existing shippers on the NDP system: Slawson Exploration Company, Inc.; Flint Hills Resources, LP; QEP Resources, Inc.; Tidal Energy Marketing (U.S.) L.L.C.; Whiting Petroleum Corporation; Oasis Petroleum North America LLC; EOG Resources, Inc.

commercial transportation opportunities."[21] In short, there is scant shipper support for NDP's Sandpiper project.

4. The Muse Report Is Flawed, Disputed and Cannot, as a Matter of Law, Be Used as a Basis of Evidentiary Findings.

In support of its claim that the pipeline project is needed, NDP has submitted a Report by Muse Stancil & Co. (Muse). Muse contends that there is a market for Bakken crude oil in the Mid-West and Eastern Canada that will fill the Sandpiper pipeline throughout its useful life. The Muse Report is virtually the only evidence that NDP has submitted to establish that the Sandpiper project is needed. However, in their Sworn Declarations attached to the Shippers' Protest, Mr. Garner, Managing Partner of EnWest, and Mr. Ashton pointed out in detail the defects in the Muse analysis. In additional Supplemental Sworn Declarations attached to this Answer, Mr. Garner and Mr. Ashton respond to the attempt of Neil Earnest, President of Muse, to resuscitate the Muse Report. Since that response is discussed in detail in the Declarations themselves, we will not repeat that full discussion here. In summary the points that Mr. Garner and Mr. Ashton make are:

- After the first year of operation, rates for uncommitted shippers on the Sandpiper system from Beaver Lodge to Superior could rise by over 300% over existing rates.[22] With rates reaching that level, it is highly likely that the Sandpiper project will be underutilized;

[21] Letter in Support filed by Statoil Marketing and Trading (US) Inc., dated March 14, 2014.
[22] Ashton Supplemental Declaration, page 12, Table 3.

- Claims made by the economic consultants hired by NDP regarding various markets for Bakken crude oil (Eastern Canada, the Gulf Coast, West Coast and East Coast) are misleading, inaccurate, or highly speculative; and
- NDP's Muse Study is a black box with only NDP having access to the inputs to the Muse model or the model itself. Since neither the Commission nor the Shippers have had any access to that information, it would be unreasonable for the Commission to rely on the Muse report for any facts or conclusions.

5. Conclusion

Under clear Commission precedent, NDP cannot impose the cost of building and operating the Sandpiper project on existing shippers of the NDP pipeline system unless it establishes that (i) the Sandpiper project is needed and (ii) the Sandpiper project will benefit existing shippers.[23] NDP has failed to establish either proposition. Its only evidence that the project is needed – the Muse Report – has been convincingly rebutted by other experts. Moreover, the Muse Report is not entitled to any weight since it is based entirely on a model, including assumptions and inputs to that model that are secret and have not been shared with the Shippers' experts.[24]

As far as the second criterion – the benefits to existing shippers – NDP has not submitted any convincing evidence. In fact, the evidence that does exist goes the other

[23] *Enbridge Energy Company, Inc. Enbridge Energy, Limited Partnership*, 123 FERC ¶ 61,130 at P 48-50 (2008); *Enbridge Energy, Limited Partnership*, 117 FERC ¶ 61,279 at P 28 (2006) ("Lacking adequate evidence of such benefits, we cannot conclude that Enbridge has shown that it would be just and reasonable to charge those other shippers a rate surcharge that would subsidize construction of the Enbridge affiliate's extension pipeline.")

[24] *See Mojave Pipeline Co.*, 39 FERC ¶ 61,336 at p. 62,061 (1987) (upholding an ALJ finding that a company must responded to a data request despite the information being proprietary trade secrets because the information "really goes to the core of the issues.").

way and establishes that there is already excess capacity on the existing NDP pipeline system.

The most favorable possible conclusion that can be drawn in support of NDP is that both the need for the Sandpiper project and the benefits, if any, that it will confer on existing shippers, are highly disputed issues of fact. Discovery and evidentiary proceedings would therefore be required for the Commission to reach any findings of fact or conclusions with respect to this issue.[25]

Under these circumstances, we respectfully suggest that the Commission cannot conclude that it is just and reasonable for NDP to increase the rates of existing shippers by its proposed Expansion Rate Component and Downstream Rate Component to pay for the Sandpiper expansion.

B. NDP Has Not Abandoned Its "True-Up" Mechanism; It Has Simply Re-Packaged It.

In the Declaratory Order Petition that the Commission rejected on March 22, 2013, NDP had proposed a "true-up" mechanism in which uncommitted shippers would be required to pay additional amounts if the pipeline failed to achieve its cost of service. Under that arrangement, uncommitted shippers would in effect guarantee that regardless of the volume that the pipeline ships, it would always receive its construction costs, operating costs and a return on its equity. The pipeline had in effect transferred virtually all risks to its uncommitted shippers. Those uncommitted shippers were also captive

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[25] *General Motors Corp v. FERC*, 656 F.2d 791, 98 (D.C. Cir. 1981) (reminding the Commission that "it bears a weighty burden in justifying a denial of an evidentiary hearing."); *Express Pipeline Partnership*. 76 FERC ¶ 61,245 at 62,253 (1996) (noting that "[t]he Commission must hold evidentiary hearings only when there are material issues of fact in dispute and where those issues cannot be resolved on the basis of the written record").

shippers on the existing pipeline system

In its current Petition, NDP claims that it has abandoned that prior true-up mechanism and scolds the Shippers for suggesting in their Protest that it has not really done so. But a careful reading of the NDP Reply confirms our original analysis.

NDP is asking the Commission to approve a tariff and rate design that, other than for power costs and indexation, fixes the rates that committed shippers will pay for the life of the pipeline at the rates specified in its TSA. That means that apart from actual power cost increases and indexation, regardless of the costs the pipeline incurs in the future, and irrespective of whether or not the pipeline ever achieves its revenue requirement, committed shippers will never pay a rate that is higher than the rate fixed by the TSA.

The question is then presented as to what is likely to happen after the first year of operation if the pipeline's costs exceed the revenues that it receives. That could, in fact, easily occur since (i) there is no demonstrable need for the additional capacity NDP is proposing to build; (ii) rates to use the NDP pipeline will at the outset probably be double existing rates; and (iii) at numerous shipper meetings the NDP project received almost no shipment commitments, other than from equity owners of the pipeline itself.

It is therefore quite likely that the pipeline will fail by a wide margin to attract sufficient shipments to meet its design capacity. Under those circumstances, the pipeline's cost of service, including the funds necessary to service the debt used to build the pipeline and the funds necessary to meet NDP's return on the equity it has invested in the pipeline, will exceed the revenues the pipeline is achieving. Under the rate design that NDP is asking the Commission to approve, the pipeline's only recourse to achieve its revenue requirement would be to attempt to increase rates to captive uncommitted shippers.

In his Supplement Declaration Mr. Ashton shows that under these circumstances, rates to captive uncommitted shippers could easily rise to $8.12 a barrel, or more than 300% greater than existing rates.[26] Of course, if the pipeline's throughput declines by a greater amount than Mr. Ashton assumes in his examples, rates to uncommitted shippers will rise even more.

There is little difference between that process and the true up guarantee that NDP originally sought.

In its Reply, NDP claims that all of this is just wild speculation and Mr. MacPhail offers four elaborate hypotheticals to show that uncommitted shippers will pay lower rates than committed shippers. But all of Mr. MacPhail's hypotheticals assume as a given that the pipeline will be shipping 100% of its design capacity. For the reasons we discuss above, it is highly unlikely that the pipeline will be doing so. Furthermore, all of Mr. MacPhail's hypotheticals are based only on the pipeline's first year of operation. The critical period of analysis is not just the first year but the second year forward.

With respect to this period – *i.e.*, Year 2 forward – NDP says two things. First, likely rate increases for uncommitted shippers in the second year of the pipeline's operations are just too speculative to even contemplate. Secondly, NDP says that issues such as prudency in constructing the pipeline in the first place and whether the pipeline is "used and useful" should be deferred to some later date.

Surely, that position is incorrect.

NDP is asking the Commission to approve *at this time* a rate design and tariff

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[26] Ashton Supplemental Declaration, Table 3.

package that, in effect, ensures that it will be the uncommitted shippers that will bear the risk that the pipeline fails to satisfy its revenue requirement. Under NDP's proposed rate design there is, therefore, a great likelihood that uncommitted shipper rates will rise significantly above fixed committed shipper rates in order to ensure that regardless of the shipper volume that the pipeline attracts, it will still recover all of its costs and profits.

We respectfully submit that those matters must be decided at this time. They are an inherent part of NDP's tariff and rate design.

C. Contrary to NDP's Position, It Is Perfectly Appropriate For the Shippers to Challenge NDP's Committed Rate Structure.

In its Protest, the Shippers challenged a number of aspects of NDP's tariff and rate structure for committed shippers.

The Shippers pointed out, as discussed above, that freezing committed shipper rates to the level specified in the TSA results in a discriminatory burden being placed on uncommitted shippers in the likely event that the pipeline's throughput falls below its design capacity. The Shippers also pointed out that the fuel and power charges which the committed shippers pay are discriminatory because they result in substantial expenses being inappropriately shifted to uncommitted shippers.[27]

The Shippers further pointed out that the entire Sandpiper project appears to be inappropriately oriented to satisfying the interests of its equity owner, Marathon, to the prejudice of current captive shippers on the current NDP pipeline.[28] Although NDP has pointedly refrained from specifying exactly how much of its shipment commitment is attributable to Marathon, it is highly likely that Marathon's commitment constitutes the

[27] Shippers' Protest, page 40; Ashton Declaration, pages 10-11, 15.
[28] Garner Declaration, pages 18-20.

vast majority of the 155,000 bpd commitment. It is also clear that, as a result, the Sandpiper project is geared towards serving primarily Marathon's interest. For example, a portion of the TSA specifies that Marathon can withdraw its commitment, thereby effectively scuttling the entire Sandpiper project, if Enbridge Pipelines (Illinois) L.L.C. does not build another pipeline that Marathon needs to reach its Illinois and Ohio refineries.[29] The Shippers maintain that requiring captive shippers on the current NDP pipeline system to pay extraordinary rate increases and assume almost all of the risks of new pipeline construction in order to further Marathon's interest in building the Sandpiper project is inherently discriminatory and unjust and unreasonable.

In its Reply, NDP does not address all of these points. Instead, it claims that the Commission's decision in *Seaway Crude Pipeline Co. LLC*[30] precludes the Shippers from contesting the committed rate structure of the Sandpiper project.

We respectfully submit that the *Seaway* decision does no such thing.

Seaway stands for the proposition that once the Commission approves a rate design that specifies committed rates in a TSA, uncommitted shippers cannot *at a later date* challenge those rates as unjustified on a cost of service basis. However, the key element here is the Commission's prior approval of the committed rates. *Seaway* does not mean that uncommitted shippers cannot challenge a pipeline's rate design and TSA provisions when a petition for declaratory order is first filed. In fact, the provisions of the *Seaway* decision, which we quoted at length in our Protest, indicate that in determining whether a

[29] Attachment A to the MacPhail Affidavit, Section 4.02(b) regarding the Southern Access Extension Pipeline Project.
[30] *Seaway Crude Pipeline Co. LLC*, 146 FERC ¶ 61,151 (2014).

proposed pipeline rate design is just and reasonable the Commission can examine cost of service data with respect to committed shipper rates.[31]

Furthermore, in his Supplemental Sworn Declaration, Mr. Ashton discusses at length the way committed and uncommitted rates are linked by the rate design that NDP is asking the Commission to approve at this time.[32] In fact, the examples that Mr. Ashton provides in his Supplemental Declaration point out specific instances in which the NDP rate design requires uncommitted shippers to improperly subsidize the rates established for committed shippers.[33]

It is therefore entirely appropriate for the Shippers to challenge the committed rate structure that NDP is now asking the Commission to approve as discriminatory and unjust and unreasonable.

D. NDP's Reply Underscores the Need for the Cost Data and the Discovery that the Shippers Have Requested.

The NDP Reply highlights the need for the discovery and cost data that the Shippers requested in their Motion to Intervene and Compel Limited Discovery dated February 25, 2014.[34]

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[31] Shippers' Protest, pages 43-44; *Seaway Crude Pipeline Co. LLC*, 146 FERC ¶ 61,151 at paragraphs 15, 33.
[32] See Ashton Supplemental Declaration, pages 9-14.
[33] See Ashton Supplemental Declaration, Table 3-4, paragraphs 20-22.
[34] See Motion to Intervene and Petitions or Motions of Concord Energy LLC; EnWest Marketing LLC and WPX Energy Marketing, LLC to: (A) Shorten the Period for Responses by Respondent North Dakota Pipeline Company LLC to These Petitions and Motions; (B) Compel Limited Discovery; (C) Extend the Comment Date for Responses to North Dakota Pipeline Petition for Declaratory Order; and (D) Enter an Appropriate Protective Order in this Proceeding. On March 4, 2014, St. Paul Park Refining Company LLC joined in seeking the discovery that the Shippers requested. Motion to Intervene of St. Paul Park Refining Company LLC and Answer in Support of Petitions and Motions of Concord Energy LLC, EnWest Marketing LLC, and WPX Energy Marketing, LLC, pages 5-6.

A total of 12 affidavits and Sworn Declarations have now been filed by NDP and the Shippers, each presenting differing and conflicting evidence regarding the need for the NDP pipeline expansion and the benefit, if any, that it would confer on existing shippers of the NDP pipeline system.[35]

In addition, there are now at least four affidavits and Sworn Declarations that present differing evidence regarding the way the NDP tariff and rate design will impact uncommitted shippers as well as the discriminatory aspects of that rate design.[36] The Shippers' evidence present a strong case for the proposition that underlying cost data for

[35] Three affidavits were attached to NDP's Petition: (1) the Affidavit of Bruce MacPhail in Support of Petition for Declaratory Order; (2) the Affidavit of Neil K. Earnest in Support of Petition for Declaratory Order, and (3) the Affidavit of Steven D. Crane in Support of Petition for Declaratory Order. There were five Sworn Declarations attached to the Shippers' Protest: (1) Sworn Declaration of Brad Vodicka in Support of Concord Energy LLC's Protest and Opposition to North Dakota Pipeline Company LLC's Petition for Declaratory Order; (2) Sworn Declaration of Jonathan Molis in Support of Enserco Energy LLC's Protest and Opposition to North Dakota Pipeline Company LLC's Petition for Declaratory Order and Enserco's Motion to Intervene; (3) Sworn Declaration of Robert P. Garner in Support of EnWest Marketing Company LLC's Protest and Opposition to North Dakota Pipeline Company LLC's Petition for Declaratory Order and EnWest's Motion to Intervene; (4) Sworn Declaration of William Woodard in Support of WPX Energy Marketing LLC's Protest and Opposition to North Dakota Pipeline Cimpany LLC's Petition for Declaratory Order and WPX Energy Marketing's Motion to Intervene; and (5) Sworn Declaration of Peter K. Ashton in Support of Protest and opposition of Concord Energy LLC, Enserco Energy LLC, EnWest Marketing LLC and WPX Energy Marketing, LLC to North Dakota Pipeline Company LLC Petition for Declaratory Order. Attached to this Answer are two additional Sworn Declarations, one by Rob Garner of EnWest and another by Peter K. Ashton. Attached to the NDP Reply were three affidavits: (1) Affidavit of Bruce MacPhail in Support of Reply Comments of North Dakota Pipeline Company LLC to Protests of Petition for Declaratory Order; (2) Affidavit of Neil K. Earnest in Support of Petition for Declaratory Order; and (3) Affidavit of William J. Rennicke in Support of Petition for Declaratory Order. Additional affidavits were filed in this proceeding on behalf of St. Paul Park Refining Company.

[36] Mr. MacPhail has submitted two affidavits in this proceeding, one attached to NDP's Petition and the other to the NDP Reply. Shippers' witness Peter K. Ashton has submitted two Sworn Declarations, one that was attached to the Shippers' Protest and another attached to this Answer.

the pipeline is essential at this time in order to avoid approval of a discriminatory and unjust and unreasonable rate structure.

As part of its Protest, the Shippers presented a detailed list of the disputed factual issues present in this case.[37] The NDP Reply and the Answer of the Shippers underscore the existence of numerous factual disputes that must be resolved before the NDP Petition can be approved.

We respectfully submit that under these circumstances, the Commission must either deny the NDP Petition or refer this case to an evidentiary hearing as contemplated by Section 385.211(a)(4) of the Commission's Procedural Regulations.

CONCLUSION

For the reason set forth above, Concord, Enserco, EnWest and WPX respectfully request that the Commission:

(1) Deny the Petition for Declaratory Order that North Dakota Pipeline Company LLC (NDP) filed on February 12, 2014; or

(2) In the alternative, set this matter for evidentiary hearing requiring NDP to submit a full cost of service and granting the Protestants full rights to discovery as set forth in 18 CFR § 385.401 to 18 CFR § 385.411 of the Commission's Rules of Practice and Procedure.

[37] See Exhibit A to the Shippers' Protest.

Respectfully submitted,

/s/ Melvin Goldstein

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Dated: April 15, 2014

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding in accordance with 18 C.F.R. § 385.2010(f)(3).

Dated at Washington, D.C., this 15th day of April, 2014.

/s/ Aaron Wesley Korenewsky
Aaron Wesley Korenewsky
Legal Assistant
GOLDSTEIN & ASSOCIATES, P.C.
1757 P. St, NW
Washington, D.C. 20036

EXHIBIT 1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North Dakota Pipeline Company LLC **Docket No. OR14-21-000**

SWORN SUPPLEMENTAL DECLARATION OF PETER K. ASHTON

Peter K. Ashton, states as follows, pursuant to the provisions of 18 U.S.C. § 1746:

1. My name is Peter K. Ashton, and I am a senior consultant with Premier Quantitative Consulting, Inc., an economics and financial consulting firm with offices in Concord, Massachusetts and Orlando, Florida. I am the same Peter K. Ashton who previously provided a sworn declaration in support of the Protest and Opposition of Concord Energy LLC, Enserco Energy LLC, EnWest Marketing LLC and WPX Energy Marketing LLC (referred to as "the Shippers") to North Dakota Pipeline LLC's Petition for Declaratory Order.

2. I have been asked by counsel for the Shippers to review the reply comments of North Dakota Pipeline (NDP) as well as the affidavits of Bruce MacPhail and Neil K. Earnest in support of that Reply.[1] In particular I was asked to respond briefly to various comments and criticisms of my prior Declaration.

Summary of Conclusions

3. Based on my review, I find that NDP has failed to seriously consider or respond to the major flaw in the rate design method that it is advocating. That flaw is the fact that existing uncommitted shippers will be forced to pay a rate that is about double the rate they currently pay even though they will not benefit from the expanded capacity. Furthermore, after initial rates have been established, uncommitted shippers, but not committed shippers, will be at risk for

[1] Reply Comments of North Dakota Pipeline Company LLC to Protests of and Comments on Petition for Declaratory Order, March 31, 2014, hereinafter "NDP Reply."

additional rate increases at any time throughput on the expanded and extended portions of the pipeline does not equal the full design capacity of the line. Since uncommitted shippers will represent at least 65% of total capacity on the new pipeline, the risk that is being placed on uncommitted shippers is very significant. I do not believe it appropriate for NDP to dismiss that risk as "baseless speculation."

4. The information and examples provided by Mr. MacPhail in his affidavit regarding the operation of the tariff rate structure in fact support the example that I provided in my prior Declaration showing that uncommitted shippers after the initial year will bear all of the risk that the pipeline's throughput will fail to meet its design capacity. I provide another example in this Declaration using Mr. MacPhail's "hypothetical example" to further demonstrate this point. That example also shows that, contrary to NDP's assertions, the uncommitted and committed rates are interrelated.

5. In my prior Declaration, I also pointed out that the power charge and the capital cost risk-sharing mechanisms of NDP's rate design are discriminatory. NDP's Reply dismisses my argument as "speculative" but never rebuts the contention that the rate design is discriminatory. To be clear I show in this Supplemental Declaration how the capital cost risk-sharing mechanism could lead to discrimination and cross-subsidization. In addition, contrary to NDP's assertions, the discriminatory aspects of the NDP capital cost risk sharing confirms that the uncommitted rate is directly related to the committed rates.

6. In my prior Declaration, I pointed out certain basic flaws in a report prepared by Muse Stancil & Co., "Market Prospects and Benefits Analysis for the Sandpiper Project" (Muse). One of the documents attached to the NDP Reply is an affidavit by Neil K. Earnest, President of Muse. Mr. Earnest's affidavit supports my view that the Muse model cannot be fully evaluated

without access to the model itself as well as the data and assumptions which underlie the model. Since no one other than Muse itself has access to this information, I do not believe that the Muse Report should be given any weight in this case. In addition, although Mr. Earnest claims to have adjusted some of the errors I previously pointed out in his model, his adjustments still do not correct errors that I believe still exist in his analysis. Moreover, Mr. Earnest fails to address the most glaring potential error in his Report – i.e, the likely overstatement of future Bakken area crude oil production.

7. In his most recent affidavit, Mr. Earnest claims that my comment that wide crude price differentials in the future will be an impediment to the Sandpiper project is overstated. In this Declaration, I show why my statement is entirely correct, based on statements made by Mr. Earnest's own client. Finally, I point out in this Declaration how the most recent results reported by Mr. Earnest cast additional doubt on the conclusions reached by the Muse model, suggesting that the Sandpiper project might not in fact be needed. My analysis again illustrates why it is critical that both the Commission and experts of the Shippers have access to the Muse model and data in order to properly evaluate the conclusions that the Muse Report reaches.

8. In the ensuing portions of this Declaration, I will first discuss issues related to the NDP rate design and the views expressed in Mr. MacPhail's affidavit. I will then respond in greater detail to the affidavit of Mr. Earnest.

NDP's Rate Design Will Lead to a Substantial Rate Increase for Uncommitted Shippers and Force Them to Assume the Risk that the Pipeline Will Be Underutilized

9. NDP's reply comments address, but do not refute, a fundamental point that I made in my initial Declaration. If the project is approved, the initial uncommitted rates could be as much as

94% to 125% higher than the existing NDP tariff.[2] The "hypothetical" examples contained in the affidavit of Mr. MacPhail also support this position. Although Mr. MacPhail's examples only relate to the Beaver Lodge to Clearbrook segment of the Sandpiper project, his "base case" shows an 80% increase in the uncommitted rate relative to the current rate in the initial year the project becomes operational. If the uncommitted rate were to increase to its maximum possible level permitted by the rate design that NDP is asking the Commission to approve, i.e., one cent less than the committed priority rate, the increase over existing rates would be 91%.[3] These increases are in line with the increases that I showed in my original Declaration.[4]

10. In view of the serious questions raised by existing uncommitted shippers as to whether the Sandpiper project is needed,[5] it is unreasonable and unfair for these uncommitted shippers to pay such a large increase in rates if there is no benefit to them.

11. Equally important is the fact that in its Reply, NDP failed to respond to the potential impact of its rate design after initial rates have been established. That issue involves the rates that NDP might well establish for uncommitted shippers if throughput on the expanded and

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[2] See Table 1 and paragraphs 13-14 of the Sworn Declaration of Peter K. Ashton in Support of Protest and opposition of Concord Energy LLC, Enserco Energy LLC, EnWest Marketing LLC, and WPX Energy Marketing LLC to North Dakota Pipeline Company LLC Petition for Declaratory Order, hereinafter "Ashton Declaration."

[3] The maximum initial uncommitted rate, according to the NDP rate design, is one cent less than the committed priority rate which in Mr. MacPhail's example is $2.40 per barrel. Therefore the initial uncommitted rate could be as high as $2.39 per barrel. That rate would amount to an increase of 91% over the assumed existing rate of $1.25 per barrel. While Mr. MacPhail claims these are "hypothetical" rates, they are very close to actual existing rates as well as the anticipated rates shown in the Sandpiper Project Transportation Services Agreement (TSA).

[4] Ashton Declaration, paragraph 13.

[5] See the comments of St. Paul Park Refining Company LLC, Concord Energy LLC, Enserco Energy LLC, EnWest Marketing LLC and WPX Energy Marketing LLC. In addition, Flint Hills states that it does not oppose the Project but neither does it endorse it. In fact Flint Hills states that if NDP proposes in the future to change the initial rates through a method other than indexing, NDP should remain at risk for costs associated with any such underutilization (Motion to Intervene and Comments of Flint Hills Resources LP, pages 1-2 and 6-7). This is the same point that is raised by the protesting shippers.

extended portions of the pipeline does not materialize or meet the design capacity of the line. NDP states that it will face the "same risk as any other oil pipeline" that it will be unable to recover its costs.[6] However in the case of NDP, the issue involves future throughput and new capacity for which the demand has not yet been demonstrated. The only indication of any demand for the new pipeline is the 155,000 bpd throughput to which committed shippers have subscribed. However, that throughput is only 35 % of the total capacity of the new pipeline. In addition, Mr. Garner states that the vast majority of this demand comes from Marathon Petroleum Company LP, an equity owner of the pipeline who is already shipping crude oil on the existing line.

12. Unlike an existing pipeline which has demonstrated commercial viability, the Sandpiper project will not have done so at the time initial rates are established with the start-up of the pipeline. NDP is very careful to state that using design capacity eliminates "any throughput risk for uncommitted shippers *at the time of start-up*."[7] [Emphasis added] It never addresses what could happen after start-up if throughput does not meet design capacity. I have shown that at that point in time all of the risk shifts to uncommitted shippers. Since committed volumes represent at most 35% of the capacity of the new pipeline, uncommitted shippers could be asked to pay for the rest of the new capacity and, after initial rates are set, to assume the risk of throughput falling short of design capacity. This is a far different situation than "any other oil pipeline" which unlike the Sandpiper project has a demonstrated record of commercial viability.

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[6] NDP Reply, page 7. NDP also states that "there is no greater risk to shippers that they will be impacted by future changes in costs or throughput than exists on any other oil pipeline regulated by the Commission" (page 25). However this statement ignores the fact that there is substantial evidence that actual throughput will not meet design capacity since it is new pipeline capacity that is at issue.

[7] NDP Reply, pages 11-12.

13. In response to this point, NDP merely claims that the issue involves "baseless speculation."[8] In my opinion the risk that uncommitted shippers will face is neither baseless nor speculative, but is based on two critical facts: (1) NDP's stated position reserving its right to file non-indexation cost of service-based rate increases in the future; and (2) evidence indicating that the capacity of the Sandpiper project is not needed and thus may not be utilized. As I indicated in my prior Declaration, NDP has explicitly reserved its right to establish rates for uncommitted shippers after the first year of operation on the basis of non-indexation rate setting mechanisms.[9] Therefore, if throughput falls below the design capacity of the Sandpiper project, NDP could seek an uncommitted rate increase under 18 CFR 342.4(a) that would enable NDP to recover all of its costs plus a return for the expansion and extension segments based on the actual quantity of crude oil transported by the pipeline. Since the committed rates are essentially fixed by the TSA,[10] it is the uncommitted shippers who would face a significant rate increase after the first year of operation. In addition, there is considerable evidence in this case that the additional capacity of the Sandpiper project is not needed and therefore may not be used.[11] Thus not only has NDP stated that it could raise uncommitted rates substantially after the first year of operation, there is also evidence that throughput would fall short of design capacity.

14. In his affidavit accompanying NDP's Reply, Mr. MacPhail provides a series of examples intended to illustrate the operation of the rate structure being proposed by NDP.[12] In order to frame these examples Mr. MacPhail must have had a detailed understanding of the cost of

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[8] NDP Reply, page 12.
[9] Ashton Declaration, paragraph 22.
[10] The only exceptions are fuel and power costs and the application of the annual FERC index.
[11] See the comments of St. Paul Park Refining Company LLC, Concord Energy LLC, Enserco Energy LLC, EnWest Marketing LLC and WPX Energy Marketing LLC.
[12] See Affidavit of Bruce MacPhail in Support of Reply Comments of North Dakota Pipeline Company LLC to Protests of Petition for Declaratory Order, paragraphs 8-13 (hereinafter "MacPhail Reply Affidavit".

service and revenue requirement for the new pipeline. NDP has not shared that information with the Commission or the Shippers even though it would greatly facilitate the analysis of NDP's proposed rate design methodology. Second, the examples that Mr. MacPhail describes are limited and do not go to the heart of the issue. The examples focus entirely on the determination of the initial rate in the first year of operation and assume throughput equal to 100% of design capacity. Mr. MacPhail's examples fail to address the critical issue I raised in my initial Declaration as to what could happen to the initial uncommitted rate *after* the first year of operation if throughput falls short of design capacity. NDP states in its reply comments that Mr. MacPhail's examples show that NDP's rate design method will not require uncommitted shippers to "automatically backstop the risk of underutilization."[13] But, since none of Mr. MacPhail's examples deal with any assumptions regarding actual throughput, this statement is simply incorrect. Nevertheless his examples can be used to illustrate this issue and explain why uncommitted shippers could bear all of the risk of underutilization once the pipeline is in operation.[14]

15. Table 1 shown below uses the same assumptions that Mr. MacPhail uses in his examples regarding committed rates, uncommitted rate, and the initial calculation of the Expansion Recovery Component (ERC) of $1.00. That ERC figure is based on a revenue requirement of $160.6 million[15] spread across a design capacity of 160.6 million barrels. It is important to note that committed shippers are effectively paying the $1.00 ERC since it is embedded in the

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[13] NDP Reply, pages 26-27.

[14] Mr. MacPhail's examples focus exclusively on the expansion segment from Beaver Lodge to Clearbrook, but he states that the same method and results would apply to the Clearbrook to Superior segment. I show below that the impact of a throughput deficiency on the extension portion can have an even more serious impact on the rates uncommitted shippers could pay.

[15] This $160.6 million revenue requirement reflects the removal of $7.5 million from the uncommitted shippers' cost of service.

committed rates that have been determined of the basis of total design capacity.[16] More importantly, since the committed rates are fixed except for indexation and the power charge, the committed shippers' contribution to this revenue requirement is also fixed at $56.6 million (see line 10 of Table 1 below). Therefore any shortfall in the revenue requirement after year one can only be recovered from uncommitted shippers if NDP were to seek a rate increase greater than the increase permitted under the Commission's indexation rules.

16. Table 1 indicates what happens after year 1, assuming that throughput fails to meet design capacity. I assume total throughput of 267,000 barrels per day (b/d) which assumes that 25% of the new capacity is actually used while the remainder is not utilized. As an indication that this throughput amount is not purely "speculative," the 267,000 bpd amount that I use is greater than the volume *nominated* to the existing pipeline in all but four of the last 16 months the pipeline has been in service.[17]

[16] These assumptions are no different from Table 4 of my initial Declaration. In fact I derived an ERC for the Beaver Lodge to Clearbrook segment of $1.03 per barrel which is almost identical to Mr. MacPhail's estimate of $1.00 per barrel.
[17] See paragraph 15 of MacPhail Reply Affidavit.

Table 1
Impact of Volume Shortfall on Uncommitted Rate Based on MacPhail Example

Line No.				
1	Committed Priority Rate (per barrel)	MacPhail Aff. p. 4	$	2.40
2	Committed Non-Priority Rate (per barrel)	MacPhail Aff. p. 4	$	2.18
3	Initial Uncommitted Rate (per barrel)	MacPhail Aff. p. 4	$	2.25
4	ERC Revenue Requirement	MacPhail Aff. p. 4		$168,100,000
5	ERC Rev. Rqmt less $7.5MM	MacPhail Aff. p. 4		$160,600,000
6	Design Capacity (barrels)	MacPhail Aff. p. 4		160,600,000
7	Initial ERC (per barrel)	MacPhail Aff. p. 4	$	1.00
8	Throughput Beaver Lodge to Clearbrook (year 1)	Assumption		97,455,000
9	Commited shippers throughput	Throughput commitment		56,575,000
10	Committed shippers "contribution" to ERC	ln 7 * ln 9	$	56,575,000
11	Uncommitted shippers' throughput	ln 8 - ln 9		40,880,000
12	Remaining revenue requirement (assuming no change)	ln 9 - ln 10		$104,025,000
13	Revised ERC for uncommitted shippers	ln 12 / ln 11	$	2.54
14	New uncommited rate	Base rate ($1.25) + ln 13	$	3.79

Note:
Indexation and variation in power charges are omitted from consideration for simplicity

17. As Table 1 indicates, committed shippers will pay the same amount ($56.6 million) toward the revenue requirement leaving the remaining revenue requirement of $104 million (line 12 of Table 1) to be paid by uncommitted shippers. However, these shippers only accounted for throughput of 40.9 million barrels over which the remaining revenue requirement would be spread. Therefore the ERC rate would increase from $1.00 per barrel in the initial year to $2.54 per barrel or an increase of 154% and would result in a total rate of $3.79 per barrel as shown in lines 13 and 14 of Table 1. Under NDP's proposed rate design, committed priority shippers could pay a rate that is equal to one cent more than this uncommitted rate ($3.80 per barrel) in order to maintain their priority status. But as I pointed out in my initial Declaration, they would have no incentive to do so since there is more than sufficient capacity on the pipeline. Consequently having priority status has no value. Therefore, the priority committed shipper would choose to give up its priority status and would continue to pay the $2.40 per barrel rate.

The uncommitted shippers would then pay a rate of $3.79 per barrel which would be 58% *higher* than the higher of the two committed rates.[18]

18. A similar analysis applies to the downstream extension portion of the new pipeline which would run from Clearbrook to Superior. This analysis is shown in Table 2 below. I start with the assumed uncommitted downstream rate component which is taken from Schedule B of the TSA and reflects the difference between the Beaver Lodge to Clearbrook rate and the Beaver Lodge to Superior rate. I then compute the uncommitted revenue requirement for the downstream segment based on this rate and the assumed uncommitted portion of the total design capacity. This analysis assumes that all of the 155,000 b/d of committed capacity is transported to Superior. This revenue requirement is shown in line 5 of Table 2. Next I show what happens to the downstream rate component when actual throughput is less than design capacity. I start with the same throughput as shown on Table 1 but adjust for some portion of the uncommitted volume being offloaded at Clearbrook and sent to the Minnesota Pipeline. I assume only 50% (30,000 b/d) of the capacity of the Minnesota line is used which is likely a conservative (low) assumption. As line 7 shows that leaves only about 30 million barrels of uncommitted volume moving to Superior over which the revenue requirement of $129 million must be spread. I divide the revenue requirement of $129 million by the actual uncommitted throughput of 30 million barrels and I obtain the revised uncommitted downstream rate component of $4.33 per barrel which is an increase of 174% over the initial downstream rate component.

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[18] The new uncommitted rate would be 75% higher than the committed non-priority rate. This assumes that the base rate component of $1.25 per barrel does not change, however given the reduction in throughput it is likely NDP would also raise the base rate component.

Table 2
Impact of Volume Shortfall on Uncommitted Rate for Extension Segment

Ln. No.			
1	Initial uncommitted downstream rate component*	Assumption per Sch B to TSA	$1.58
2	Design capacity - downstream extension	Petition for Declaratory Order, p. 15	138,700,000
3	Committed shippers' throughput to Superior	Per 155,000 b/d commitments	56,575,000
4	Uncommitted shippers' portion of design capacity	ln 2 - ln 3	82,125,000
5	Uncommitted shippers' revenue requirement for extension segment	ln 1 * ln 4	$129,593,250
6	Actual throughput	Table 1	97,455,000
7	Uncommitted throughput to Superior	ln 6 - ln 3 less 30,000 b/d deliveries to Minnesota PL	29,930,000
8	Revised uncommitted downstream rate component	ln 5 / ln 7	$4.33

* Assumes $7.5 million credit for uncommitted shippers has been deducted

19. Table 3 simply compares the existing uncommitted rates from Beaver Lodge to Clearbrook and Clearbrook to Superior as well as the total rate from Beaver Lodge to Superior. The second column shows the initial uncommitted rates based on the examples given by Mr. MacPhail and the TSA, and the third column shows the uncommitted rates based on the analyses I have presented in Table 1 and Table 2. As the Table indicates, not only is the initial total rate about 100% higher than the existing rate, but if NDP experiences a throughput deficiency and seeks a non-indexation rate increase, the total rate increase to uncommitted shippers could be over 300%.

Table 3
Summary on Uncommitted Rates

	Existing Rates	Initial Rates*	Potential Rate after Year 1
Beaver Lodge to Clearbrook	$1.32	$2.25	$3.79
Clearbrook to Superior	$0.63	$1.58	$4.33
Beaver Lodge to Superior	$1.95	$3.83	$8.12
Total Increase			316%

* Based on MacPhail example and Schedule B of the TSA

20. Therefore, contrary to NDP's position that the committed and uncommitted rates are independent of each other,[19] the examples in these Tables show that they are in fact significantly related. Because NDP calculates the revenue requirement over the total design capacity including the committed volume and because the committed rates are essentially fixed except for the power charge and indexation, after the first year of operation, the uncommitted rate can fluctuate significantly as shown in the example in Table I. Thus contrary to NDP's statement that "the uncommitted shippers will not pay a higher rate as a result of the committed shipper provisions,"[20] in fact, as my example shows, after initial rates are established, uncommitted shippers could very well pay substantially higher rates as a result of the fixed nature of the committed rate design.[21]

[19] NDP Reply, pages. 24-26.
[20] NDP Reply, page 24.
[21] NDP claims that the MacPhail examples are intended to address concerns about the determination of uncommitted rates, (NDP Reply, page 26) but as noted above none of the examples deal with the issue of actual throughput failing to meet design capacity or the potential impact on uncommitted rates after initial rates are determined.

21. NDP also claims that NDP's power charge and capital cost risk sharing mechanisms for committed shippers do not affect uncommitted shippers.[22] Again this is simply incorrect. In my initial Declaration I provided an example that showed how the capital cost risk sharing adjustment contained in the TSA could affect the uncommitted rate.[23] I showed that the committed shippers' share of final construction costs that exceeded Class 3 estimates were limited by the TSA.[24] Therefore, if the final construction cost exceeded the Class 3 estimate by $200 million, then under the TSA's risk sharing mechanism, it would be the uncommitted shippers who would have to pay the unrecovered portion of the cost variance that committed shippers are excused from paying. I showed in my example that this would cause uncommitted shippers to pay a disproportionate share of these costs and in effect subsidize committed shippers. I illustrate this point in Table 4 below which shows the shift in the allocation of the investment costs in the uncommitted shippers' revenue requirement used to compute the ERC. With higher than anticipated investment costs of $200 million the portion of the assumed investment cost borne by the uncommitted shippers shifts from 32.6% to 36.8% as shown in line 6 of Table 4.

[22] NDP Reply, page 28, footnote 31.
[23] Ashton Declaration, paragraphs 18-20.
[24] Ashton Declaration, paragraph 18.

Table 4
Analysis of Cost Risk Sharing Mechanism

Ln. No.		($ Millions) Base	Actual	Source
1	Class 3 Estimate	$ 1,400		Assumption
2	Actual Cost		$ 1,600	Assumption
3	Increased cost		$ 200	Assumption
	Allocation By Category:			
4	Committed service	$ 944	$ 1,011	Per TSA 50% risk share
5	Uncommitted service	$ 456	$ 589	ln 2 - ln 4
6	Percent Borne by Uncommitted Shippers	32.6%	36.8%	Base = ln 5 / ln 1; Actual = ln 5 / ln 2
7	Proportionate share of increased cost in uncommitted revenue requirement (ERC)		$ 65	ln 3 * Base ln 6
8	Actual increased cost in uncommitted revenue requirement (ERC)		$ 133	Actual ln 5 - Base ln 5
9	Subsidy Paid by Uncommitted Shippers		$ 67	ln 8 - ln 7

22. Table 4 also shows the amount that uncommitted shippers would pay if their share of expenses were simply calculated on the basis of their proportionate share of the design capacity shown in line 7 of $65 million. In other words, if not for the risk sharing mechanism in the TSA, uncommitted shippers would pay $65 million in the example in Table 4. Instead, Line 8 shows that the actual amount by which the revenue requirement for the ERC would increase is $133 million. The difference between those two figures amounting to $67 million is in effect the subsidy or the additional amount that uncommitted shippers would pay in the example as a result of the cost sharing mechanism contained in the TSA. Thus contrary to NDP's assertions, even the initial uncommitted rate is affected by the committed rates and the potential exists under NDP's rate design for uncommitted shippers to subsidize committed shippers.

Mr. Earnest's Affidavit Simply Shows Why Access to the Muse Model is Essential for the Commission and Shipper Experts to Evaluate its Conclusions

23. The affidavit of Mr. Earnest of Muse Stancil attached to the NDP Reply actually illustrates a major point that I made in my initial Declaration. There I stated:

> It is my understanding that the Muse model and the inputs into the model are considered proprietary and therefore are not available to the public for review and analysis. As a result, key assumptions such as future crude oil supply, price differentials and refining values cannot be evaluated. The Muse report notes that these are important inputs and results of the model,[25] yet no data is provided on these key factors. As I noted earlier, changes in the values of crudes in different downstream markets can have a significant impact on the choice of transportation mode, but I am unable to evaluate this issue fully because no such data has been provided. [26]

In his affidavit, Mr. Earnest discusses the issue of crude price and refined product value differentials which are embedded in his model. But he fails to provide the data that would enable us to determine what differentials actually exist in his model and the extent to which they may change over time.[27] Also Mr. Earnest states, contrary to his initial affidavit, that he included some additional local North Dakota refining capacity in his model,[28] but again without access to the model and the underlying data neither I nor the Commission has any way of confirming this statement. In fact even if Mr. Earnest did add 20,000 bpd of North Dakota refining capacity as he now states, that amount is still significantly less than the amount of North Dakota refining capacity that the North Dakota Pipeline Authority projects will be added in the next two years.[29]

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[25] Muse Report, pages 33-35.
[26] Ashton Declaration, paragraph 43.
[27] Affidavit of Neil K. Earnest in Support of Petition for Declaratory Order, March 31, 2014, hereinafter "Earnest Reply Affidavit."
[28] Earnest Reply Affidavit, paragraph 28.
[29] Attachment A to the Declaration of Robert Garner which is a table created by the North Dakota Pipeline Authority shows the addition of 60,000 b/d of North Dakota refining capacity by 2015.

24. Mr. Earnest also claims that I am "not familiar with the basic principles of optimization"[30] in the context of the use of rail capacity in the Muse model. Mr. Earnest is mistaken. In my past experience I have worked with linear programming models on numerous occasions including the application and evaluation of refinery optimization models and transportation optimization models. My point in my initial Declaration was simply that without access to the Muse model, the statements made in the Muse Report could be interpreted to mean that rail capacity had been artificially limited in the model. Furthermore, Mr. Earnest's comments regarding the amount of rail loading capacity that he "gave" the model only underscore the opaqueness of the model.[31] Mr. Earnest appears to imply that the optimal solution yields usage of 825,000b/d of rail transportation, independent of the actual rail loading capacity in any given year, so that that any amount in excess of the 825,000 b/d represents a rail "surplus." This result is presumably based on the fact the Muse model is evaluating the economics of incremental rail transportation against alternatives (including Sandpiper). However, without access to the underlying data, price/supply relationships, and other inputs of the model itself, there is no way for the Shippers or the Commission to evaluate how rail transportation economics change given the potential for additional rail loading capacity that Mr. Earnest simply deems irrelevant. Again, Mr. Earnest's responses underscores the fact that access to the Muse model, its assumptions and data is critical to evaluate its accuracy.

25. In his most recent affidavit, Mr. Earnest also dismissed other errors that I pointed out in the Muse model by stating that the impact of those errors is so minimal that they would have no impact on the modeling results.[32] However, Mr. Earnest fails to address the most significant

[30] Earnest Reply Affidavit, paragraph 31.
[31] Earnest Reply Affidavit, paragraph 31.
[32] Earnest Reply Affidavit, paragraph 30.

potential error in the Muse model, namely the overstatement of crude oil production in the Bakken area. Instead he focuses only on North Dakota refining capacity, the Double H pipeline capacity and the Plains Wascana pipeline capacity. When taken together, these understatements of capacity by Mr. Earnest total 114,000 b/d, which is hardly a minor amount.[33]

26. More importantly, as I discussed in my initial Declaration Mr. Earnest has relied on the Crane forecast of Bakken production whereas two government estimates of future Bakken production reflect significantly lower production levels. I showed that the Energy Information Administration (EIA) of the U.S. Department of Energy projects total Bakken production between 2012 and 2041 will be 8.2 billion barrels,[34] whereas Mr. Crane projects total Bakken production between 2012 and 2041 will total 11.1 billion barrels. EIA has just recently released its updated forecast of Bakken tight sands production, taking into consideration recent increases in production.[35] This new forecast by EIA indicates that total production from the Bakken between 2012 and 2041 will be slightly higher at 8.4 billion barrels. Furthermore, the EIA estimate is actually higher than a recent projection by the U.S. Geological Survey (USGS) which indicates that total production over that period will be only 7.5 billion barrels.[36] The Crane estimate is 48% higher than the USGS estimate and 32% higher than the EIA estimate. EIA now projects that peak production will occur in 2017 at slightly less than 1.1 million b/d whereas

[33] Mr. Earnest has understated future expected North Dakota refining capacity by 40,000 b/d, the Double H pipeline capacity by 54,000 and the Plains Wascana pipeline capacity by 20,000 b/d for a total of 114,000 b/d. When compared to EIA's estimates of future Bakken production, they represent over 10% of projected production.

[34] U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook, 2013, April 2013, www.eia.gov/forecasts/aeo.

[35] http://www.eia.gov/forecasts/AEO/section_issues.cfm#tight_oil and file: ref2014.d102413a.exls.

[36] U.S. Geological Survey, Assessment of Undiscovered Oil Resources in the Bakken and Three Forms Formations Williston Basin Province, Montana, North Dakota, and South Dakota 2013, http://pubs.usgs.gov/fs/2013/3013/.

Crane projects peak production at 1.38 million b/d in 2026 an estimate that is 25% higher and peaks much later than the EIA forecast. The latest EIA data indicate that the Bakken will experience more rapid decline rates than previously forecast which will mean that Bakken production will peak sooner, virtually at the same point in time as the Sandpiper project would be completed. Mr. Earnest's failure to address these conflicting future production estimates suggests strongly that if we were to use the EIA or USGS estimates, we would find that the currently existing transportation capacity is considerably more than sufficient without the Sandpiper project.[37]

27. Mr. Earnest also claims that I stated that wide crude oil price differentials mean unequivocally that Sandpiper will be underutilized. In response he states that following my logic, whenever the differential narrows Sandpiper will be in apportionment.[38] I would respond to Mr. Earnest as follows. First it is important to note that in my initial Declaration I pointed out that it was Mr. Earnest's client, NDP, not I, that offered the argument that large crude oil price differentials between the midcontinent and coastal markets were the reason that the *existing* North Dakota pipeline was being underutilized.[39] I go on to point out that I generally agree with that argument and it shows why NDP's "new" argument that downstream pipeline bottlenecks are the reason why the existing NDP is underutilized is without merit.[40] Simple logic suggests that if the existing NDP is not being fully utilized at the present time, then there would appear to

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[37] Mr. Earnest does evaluate the impact of a 20% reduction in Bakken production for a single year (2019) and finds that it does not change his fundamental conclusion "at least for 2019." (Earnest Reply Affidavit, paragraph 15). However, this analysis is limited to only one year and tests a reduction in production that is far less than reduced production figures, using either the EIA or USGS projections.

[38] Earnest Reply Affidavit, paragraph 26.

[39] Ashton Declaration, paragraph 33.

[40] Construction of these downstream pipelines is not guaranteed and based on NDP's prior statements will not influence crude oil price differentials.

be no strong compelling need for the Sandpiper project contrary to the conclusions reached by the Muse Report. Moreover, as I stated in my initial Declaration, Mr. Earnest's client NDP agrees with me that changing crude oil price differentials are something over which NDP has "no control."[41] While there is every reason to believe that crude oil price differentials will widen and narrow in the future in response to a number of different factors, the construction of Sandpiper, as NDP states, will have no impact on changes in those differentials. Nevertheless, the inability to observe the impact of different crude oil pricing forecasts within the Muse model precludes any analysis of Mr. Earnest's assumptions. For example, Mr. Earnest notes that given market transparency, a wide differential might lead to East Coast refiners outbidding Midwestern refiners for Bakken crude oil, which will narrow the differential and reduce or eliminate the incentive to use rail. Yet, Mr. Earnest has not provided any analysis of how differences in crude oil pricing forecasts, including those with significant potential volatility, might change the outlook for utilization of the Sandpiper pipeline. This seems particularly germane, since NDP recognizes that it has no control over price differentials. To the extent various factors continue to drive wide price differentials, there is every reason to believe that the Sandpiper project, if built, would be significantly underutilized.

28. Mr. Earnest further suggests that refiners' decisions about crude selection are driven entirely by pricing differentials.[42] While I agree that differences in crude prices and values observed by refiners will influence their choice of crude oils, there are a host of other factors that influence that decision as well as the fact that market imperfections often prevent refiners from acting in the manner suggested by Mr. Earnest. For example, many refiners have equity interests in crude oil production and may therefore wish to utilize their own production in their own

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[41] Ashton Declaration, paragraph 35.
[42] Earnest Reply Affidavit, paragraph 26.

refineries rather than going into the open market for all of their crude purchases. In addition, as Mr. Garner points out in his initial Declaration, not all light crude oils are of the same quality. Bakken crude in particular has a superior composition which means that certain refiners will continue to utilize it using rail facilities.[43] Market imperfections also drive how and into which markets various crude oils will flow. Investments in rail capacity by East Coast and West Coast refiners may continue to make rail a preferred option for certain refiners even if, as Mr. Earnest suggests, the possible construction of one or more Canadian pipeline projects connects Western Canadian crude production to eastern or western Canadian ports. However, as with the downstream U.S. projects that NDP claims will alleviate the Midwestern transportation bottleneck, these Canadian projects are not yet fully permitted or completed, and there is no guarantee they will ever be constructed. In that event, U.S. coastal refiners will have to rely on rail as their only option to deliver Bakken crude to their refineries.

29. Furthermore, in response to shipper criticism, Mr. Earnest has run various sensitivity scenarios in which he tested changes to various assumptions and found that even with these changes the Sandpiper project would operate at capacity.[44] But, Mr. Earnest only ran these scenarios for a single year, 2019. He did not evaluate the impact of differing factual assumptions for other years. As a result, it is an open question as to whether Sandpiper would be fully utilized in any year other than 2019 under the different scenarios that Mr. Earnest says he tested.

30. Each of these points simply highlights the fact that by using the Muse Report as the principal, if not the sole, basis of its projection that there is a need for the Sandpiper project and that it will be fully utilized, NDP is forcing us to grope in the dark. Neither we nor the

[43] Sworn Declaration of Robert P. Garner in Support of EnWest Marketing LLC's Protest and Opposition to North Dakota Pipeline Company LLC's Petition for Declaratory Order and EnWest's Motion to Intervene, paragraph 24.
[44] Earnest Reply Affidavit, paragraph 15.

Commission know what inputs and assumptions were used in reaching the conclusions stated in the Muse Report. We also have been kept in the dark as to how the model itself works. As a result, in my opinion, it would be unjust and unreasonable for the Commission to rely on the Muse Report for any fact finding or conclusions.

I, Peter K. Ashton, state under penalty of perjury that the foregoing is true and correct to the best of my information and belief.

Peter K. Ashton

April 14, 2014

EXHIBIT 2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North Dakota Pipeline Company LLC **(Docket No. OR14-21-000**

SWORN SUPPLEMENTAL DECLARATION OF ROBERT P. GARNER IN SUPPORT OF ANSWER OF CONCORD ENERGY LLC, ENSERCO ENERGY LLC, ENWEST MARKETING LLC AND WPX ENERGY MARKETING, LLC'S

Robert P. Garner, states as follows, pursuant to the provisions of 18 U.S.C. § 1746:

1. My name is Robert P. Garner. As described in my previous Declaration attached to the Protest of Concord Energy LLC (Concord), Enserco Energy LLC (Enserco), EnWest Marketing LLC (EnWest) and WPX Energy Marketing, LLC (WPX) (collectively, "the Shippers"), I am the Managing Partner of EnWest and have been involved in the petroleum industry for the past 35 years. I have been in a management position with EnWest ever since it was formed in 2007.

2. I am providing this Declaration in support of the Shippers' Answer to North Dakota Pipeline Company LLC's Reply (NDP Reply).

SUMMARY OF CONCLUSIONS

3. In this Declaration, I respond to certain comments made by NDP as well as by Neil K. Earnest, William J. Rennicke and Bruce MacPhail, NDP experts who submitted affidavits in support of the NDP Reply. Specifically, I point out that:

- Contrary to Mr. Rennicke's contentions, there is ample rail capacity to transport crude oil from the North Dakota Bakken area at the present time and the foreseeable future;

- It is completely incorrect for NDP to state in its Reply that the Shippers are improperly benefiting from the status quo;
- There are no "benefits" that uncommitted shippers will receive if the Sandpiper Project goes into service; to the contrary, the burden that the Sandpiper project will place on captive shippers of the present NDP pipeline system will be very substantial;
- The Muse Stancil & Co. (Muse) Optimization Modeling Program which Mr. Earnest sponsors cannot be relied on to produce accurate results;
- Mr. Earnest claims' regarding the availability of American Mid-western and eastern Canadian markets for Bakken crude oil are unsupportable;
- Mr. Earnest is incorrect in claiming that Bakken crude oil will not continue to be transported by rail to Gulf Coast refineries. Contrary to Mr. Earnest's contention Eagle Ford crude oil from Texas will not supplant Bakken crude;
- Contrary to Mr. MacPhail's contention, the current NDP pipeline system has not recently been subject to substantial prorationing.

A. NDP's Statements in Its Reply Comments Do Not Accurately Reflect the Rail Facilities That Will Continue to be Available to Transport Crude Oil From the Bakken.

1. The Conclusions Mr. Rennicke Reaches in His Affidavit Do Not Accurately Reflect the Availability of Rail Transportation in the Bakken.

4. NDP relies on the affidavit of William J. Rennicke to support its claim that rail transportation is limited and will not be available to meet the needs of Bakken crude oil producers. Mr. Rennicke bases that conclusion on the results of a nationwide rail capacity study conducted by the Association of American Railroads (AAR) in 2007. In

his affidavit, Mr. Rennicke quotes a portion of that study that indicates that "without investment in the North Dakota primary rail lines, the projected growth in grain, coal and other historically important rail transported commodities in North Dakota will exceed available rail capacity."[1] In support of that conclusion, Mr. Rennicke refers to a diagram in the AAR study, which he labeled "Exhibit II-1, titled Year 2035 Corridor Volumes Compared to Year 2007 Corridor Capacity."[2] This Exhibit suggests that the rail system in North Dakota will be under the most severe levels of congestion in 2035.

5. In my business activities I have made extensive use of rail transportation. In fact at one point in my career I managed a fleet of more than 800 railcars. I have also over the past seven years become very knowledgeable regarding current and future availability of rail transportation in the Bakken. It is from that background that I reviewed the entire AAR study to which Mr. Rennicke refers in his affidavit. Based on that review, I have come away with an entirely different assessment of the availability of rail transportation than Mr. Rennicke.

6. The portion of the AAR study to which Mr. Rennicke refers is a case study, which *assumes* that from 2005 on no investments whatsoever will be made in primary rail lines.[3] We know, however, that the assumption of that case study does not comport with reality. Rail companies have already upgraded and made considerable investments in their rail systems since the time the AAR report was published and intend to continue to

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[1] Affidavit of William J. Rennicke in Support of Petition for Declaratory Order (hereinafter "Rennicke Affidavit"), paragraph 12.

[2] Rennicke Affidavit, page 7.

[3] Rennicke Affidavit, paragraph 12. The 2007 AAR report indicates that it used 2005 Surface Transportation Board Carload Waybill data in order to establish and estimate various corridor volumes, at that time the most recent comprehensive information available. See the section titled Methodology in "National Rail Freight Infrastructure Capacity and Investment Study," Association of American Railroads, September 2007.

do so into the future. For example, I provided, as part of Attachment B to my prior Declaration attached to the Shippers' Protest, a press release from BNSF. In that press release, BNSF stated that it was undertaking an investment of $220 million in its North Dakota rail system alone.[4] Moreover, the AAR study shows that with improvements, future rail capacity in North Dakota will actually exceed demand.[5] Figure 6.1 of the AAR study, which I have attached to this Declaration as Attachment A, shows that the primary North Dakota rail lines are marked in green, indicating an "A," "B" or "C" Level of Service (LOS). According to Figure 4.4 from the same study, a LOS grade of A, B or C indicates that the Volume-Capacity ratio on those lines are below capacity, with "low to moderate train flows with capacity to accommodate maintenance and recover from incidents."[6] Therefore, rather than suggesting that the North Dakota rail system will be severely constrained in the coming decades, the Association of American Railroads suggests the exact opposite.

2. Rail Transportation of Other Commodities Will Not Adversely Affect the Transportation of Bakken Crude Oil.

7. In his affidavit, Mr. Rennicke also points out that crude oil shipments by rail will have to share rail capacity with various other commodities. I agree with that statement. However, I do not believe, as Mr. Rennicke states, that crude oil shipments will be constrained by the shipment of other commodities. For example, a principal use of rail lines in the past has been the transportation of coal. However rail transportation of coal

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[4] Sworn Declaration of Robert P. Garner in Support of EnWest Marketing LLC's Protest and Opposition to North Dakota Pipeline Company LLC's Petition for Declaratory Order and EnWest's Motion to Intervene (hereinafter, "Garner Declaration"), pages 5-6; Attachment B to Garner Declaration, page 1.

[5] Figure 6.1 of "National Rail Freight Infrastructure Capacity and Investment Study," attached to this Declaration as part of Attachment A.

[6] Figure 4.4. This Figure is attached to my Declaration as part of Attachment A.

has declined substantially over the past 20 years.[7] In 2012, Class I railroads transported 6.20 million carloads of coal.[8] Those shipments are 12.1 percent less than coal shipments by rail in 2011, and 19.6 percent less than the peak rail carloads in 2008.[9] In fact, current coal movements by rail are at the same levels as they were in 1994,[10] and will undoubtedly continue to decline in the future. On the other hand, crude oil shipments currently amount to only 3% of all rail car movements.[11] As a result, there is certainly sufficient capability in the nationwide rail system for crude oil transportation to increase significantly in the near future, especially since other major commodities, such as coal, experience demand declines. My own experience indicates that rail lines welcome new crude oil traffic to fill the gap left by declining volumes of coal.

B. NDP's Statement That the Shippers Who Have Protested NDP's Petition for Declaratory Order Are Unfairly Benefiting from the Status Quo Is Misleading and Untrue.

8. In its Reply, NDP claims that since the Shippers who are protesting its Declaratory Order Petition have not been subject to prorationing, they are "beneficiaries" of the status quo.[12] That position is simply untrue. EnWest's business is entirely dependent on moving the crude oil that the company purchases from producers on the NDP pipeline system. With increases in rail car movements, our business has suffered. If rail transportation continues to provide better netbacks for producers, our business will continue to suffer. That is precisely what will happen if the Sandpiper project is

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[7] "Railroads and Coal," Association of American Railroads, August 2013, page 6. That report is attached to this Declaration as Attachment B.
[8] Attachment B, page 6.
[9] Attachment B, page 6.
[10] See the graph titled "Originated Carloads of Coal by U.S. Class I Railroads," on page 7 of Attachment B to this Declaration.
[11] See Exhibit III-1: 2012 US Class I Freight Railroad Revenue Share by Commodity, inserted into Mr. Rennicke's Affidavit, page 10.
[12] NDP Reply, page 5.

approved. Since we are tied by logistical factors and capital investments to the NDP pipeline system, our business will continue to be eroded because the rates that Sandpiper will charge will make the pipeline even more uncompetitive when compared to rail alternatives. Therefore, even though my own company's access to rail is constrained, many of the producers that form our market will choose rail over the expanded NDP pipeline system.

9. It is therefore fundamentally misleading to say that EnWest benefits unfairly from the status quo. EnWest's competitive position has been undermined to a certain extent by the status quo and would be further undermined by the new Sandpiper project which will make it even more uncompetitive to use the NDP pipeline.

10. As far as new shippers are concerned, the expansion of the NDP pipeline into the Sandpiper project is not needed to solve that situation. When it completes the repairs that it is currently making to the existing system and restores the capacity to 210,000 bpd, NDP could simply increase the set aside for new shippers. I believe that there would then be adequate capacity to satisfy the demands of historic shippers and permit new shippers to transport greater volumes. It is truly ironic that NDP, which instituted the current rules on its pipeline in order to reduce the number of new shippers, is now attempting to portray itself as an injured party.

11. NDP's comments should also be considered in the context of the extremely minimal support that the Sandpiper project has received from the shippers on the present NDP system. NDP states that the Protestants only represent 3% of the shippers on the NDP system.[13] In fact, I believe that they represent a significantly greater volume of

[13] NDP Reply, page 22.

pipeline throughput. But regardless of the throughput amounts, the fact is that there are approximately 185 shippers on the NDP pipeline system. After hearing about the Sandpiper project, only 15 companies even asked to see the TSA and likely fewer than that number actually signed it.[14] That amounts to very minimal support indeed.

C. The Muse Model Is Fundamentally Defective. In Addition, It Fails to Take Into Account the Fact that Crude Oil at Clearbrook Has Been Priced on the Basis of a Cushing, OK Benchmark

12. The results contained in the Muse Report are based on a LP Optimization Model. I cannot comment on the particular model that Muse uses because Muse has not revealed any of the inputs to its model, or the specific manner in which it is run. But, I am personally familiar with and have used several LP Optimization Models in the past for refining operations and in capital investment projects, with varying degrees of satisfaction. What I have taken away from my experience with these models is the fact that the more variables included in the models, the less accurately the program operates and the less conclusive are the results that the model produces.

13. The Muse LP program is trying to model the entire North American market for all refineries, refinery run rates, refinery crude slates, pipeline capacities, pipeline expansions, and current and future crude production levels, for each year during a 20 year period. It will certainly encounter the problems that I described above because of its breadth and very large number of variables. Therefore, the results that the Muse model produces should be considered from a highly skeptical standpoint, particularly since the Shippers have no way to test and verify Muse's conclusions without discovery.

[14] NDP Petition, pages 23-24.

14. There is a further, more specific problem with the results of the Muse model. The Muse model predicts that the construction of the Sandpiper project will lead to greater volumes of crude oil flowing south where it will interconnect with other pipelines to refineries in Illinois and Ohio. According to Muse and Mr. Earnest the netback differential that shippers will receive from these shipments will be greater than the netback from shipping crude oil to the West Coast and East Coast by rail. However, in making this assessment, Mr. Earnest has missed an important point.

15. For the last 12 to 18 months, the price to a refiner of Bakken crude oil on the NDP system has been established at Clearbrook, with the actual price based on an adjustment to a Cushing, OK benchmark price. There are several consequences that follow from this fact. First, the netback to crude oil producers in shipping crude by rail to East Coast and West Coast destinations are higher than the Cushing netback price with adjustments for Clearbrook. Therefore, unless the pricing of Bakken crude oil changes substantially, it will continue to be more attractive to a Bakken crude oil producer to ship its production by rail to longer East Coast and West Coast destinations than to have it priced at Clearbrook on the bases of a Cushing adjustment.

16. Furthermore, there is no sound basis to Mr. Earnest's conclusion that a demand for the Sandpiper project is demonstrated by a recent announcement of a capacity constraint on pipelines moving crude oil from Cushing to Wood River or Patoka. The most that can be said about prorationing of this pipeline is that the market might suggest that more pipeline capacity is needed from Cushing to Wood River and Patoka, not that the Sandpiper project is needed or would be successful. The suggestion that Midwestern refineries would be dependent on or inherently prefer Bakken crude oil to crude from

other production fields in the country is simply not correct. Midwest refiners can access crude oil types that are similar to North Dakota Bakken crude oil from the Gulf Coast, off shore sources, the Permian Basin, the Rocky Mountain region, the Midcontinent production area and Canada. These refiners will purchase crude oil from the production regions that provide the lowest cost feedstock.

D. The Protestants in this Case as Well as Dozens of Other Current NDP Shippers Have Little Alternative to the NDP Pipeline System.

17. In its Reply, NDP suggests that there are few if any shippers that are "captive" to the NDP pipeline system.[15] Addressing this same issue from a somewhat different perspective, Mr. Earnest poses the following question in his most recent affidavit, "If rail enables producers to achieve higher netbacks than does pipelines, as Mr. Garner argues, why is any Bakken crude oil being shipped by pipeline today?"[16] The answer to Mr. Earnest is simple: There is a fairly substantial volume of crude oil in the Bakken field that is captive to the NDP system. This crude oil is either locked into the NDP system because it is directly connected by spur lines into the NDP system with no other means of movement or because it is under contractual obligation that effectively requires it to be transported on the NDP pipeline.

18. For example, all of truck unloading facilities that discharge crude oil directly into the NDP system are situated on property that must be leased directly from NDP. These leases are for a term of 3 to 5 years and are designed to require NDP shippers who have entered into them to ship a minimum monthly volume on the NDP pipeline system through their truck unloading facilities or pay a deficiency amount as well as face the risk

[15] NDP Reply, pages 27-28.

[16] Affidavit of Neil K. Earnest in Support of Petition for Declaratory Order (hereinafter "Earnest Affidavit"), dated March 31, 2014, page 10.

having their lease cancelled. If any of these shippers stops using the truck unloading facility that is connected to the NDP pipeline for as little as three months, NDP can declare the shipper in default of its contract and immediately cancel its lease.

19. Additionally, if a shipper does not ship on the NDP pipeline for a period of three months, then that shipper loses its historical shipper status and the associated volumes attributed to that historical status, a shipper status that they have built up over years of being an ongoing shipper on the system. Their option at that point, should they lose the historical status, is to become a new shipper which limits their throughput volume to approximately 168 bpd. That throughput amount is not even sufficient to maintain minimum volume obligations for the NDP truck unloading facilities. Each one of these shippers is economically captive to the NDP pipeline system.

20. There are also a number of other reasons why a producer that elected to connect its gathering lines to the NDP system or to another company's gathering system is unable to move its crude oil by other means. The producer may be under landowner restrictions or lease location issues, or, as stated above, contractual obligations that compel it to continue to ship on the NDP system.

21. It is, moreover, surely disingenuous for NDP to state that, "all shippers that can access the North Dakota Pipeline System (including the protestants) have the ability to ship their volumes by rail from either Stanley or Berthold, North Dakota, where rail loading terminals are connected to the pipeline system."[17] NDP knows quite well that the rail facility at Stanley is privately owned and used for proprietary business only, and that

[17] Affidavit of Bruce MacPhail in Support of Reply Comments of North Dakota Pipeline Company LLC to Protests of Petition for Declaratory Order (hereinafter, "MacPhail Reply Affidavit"), paragraph 19.

the rail facility at Berthold, which is a part of the Enbridge system, is fully contracted and does not have any space for other shippers such as the protestants.

E. Response to Muse Claims about Canadian Markets

22. In discussing comments I made regarding Canadian refinery demand and pipeline access in Canada, I believe that Mr. Earnest has taken some of my comments out of context or has misunderstood my intent. I also believe that other assumptions made about the Canadian market by Mr. Earnest are rather speculative.

1. Comments Regarding Mid-Continent and Eastern Canadian Refiners

23. In my Declaration, I point out that it would be very unlikely that Western Canadian crude oil producers who regard American Mid-Western and Eastern Canadian refineries as significant markets for their crude oil production would permit Bakken crude oil to displace them. Mr. Earnest says in response that it will be the refiners and not the producers that will be making that decision.

24. It is of course correct that the choice as to which crude oil they purchase will be made by the refiners. My point was simply that the Western Canadian crude oil producers will establish whatever price is necessary to continue to induce Mid-Western and Eastern Canadian refineries to choose to buy crude oil from them. This observation is validated by the fact that for the last 18 months, the NDP system has not been significantly prorated and for at least several months during that same period the Enbridge mainline pipeline has also not been under prorationing. At that time refiners in the Midwest could have accessed significantly larger volumes of Bakken crude oil, but instead chose to run cheaper crude oil, much of which originated in Western Canada.

25. Moreover, Mr. Earnest fails to respond to the point that I made in my prior Declaration that since a number of refineries in Eastern Canada are owned by companies that have their own production fields in Canada, it is very likely that these refineries would continue to run their own crude oil, rather than buy third party barrels from Bakken producers. This is particularly true since the transportation rates that these refiners would pay from Canadian sourced barrels would be lower than the crude oil coming off the Sandpiper system.

2. Potential Canadian Pipeline Projects

26. Mr. Earnest further contends that there will be an increased demand for Bakken crude oil in Eastern Canada and the Midwest because at some point in the future additional high capacity Canadian pipelines will be completed and will create new markets for the Canadian crude oil that is now being transported to American Mid-western and Eastern Canadian refineries. However, the exact timetable for construction and service of these lines is rather vague in Mr. Earnest's affidavit and it is far from clear that any of these pipelines will actually be completed. In fact, an Enbridge project to the coast of western Canada has been in the projection stage for over 10 years, with little if any progress in completing it.[18] An attempt to use these pipelines to project a market for Bakken crude oil would be pure speculation.

27. Moreover, even if these pipelines were in fact built, the logistic costs to transport sweet Canadian crude to markets other than the Mid-Western American and Eastern

[18] "Update 1-Enbridge rekindles oil sands pipeline plan," Reuters, dated February 21, 2008: http://uk.reuters.com/article/2008/02/21/enbridge-gateway-idUKN214813032008022; also see the National Energy Board's (NEB) web portal on the project, which includes various regulatory documents as well as a report with 209 required conditions for approval for the project: http://gatewaypanel.review-examen.gc.ca/clf-nsi/hm-eng.html.

Canadian markets to which they have historically been transported could be prohibitively expensive. For example, these Canadian sweet crude oil volumes would have to be transported on pipelines designed to ship heavy, sour crude. The crude oil would also have to be transported from inland terminals to port terminals on the coast, be loaded onto barges or ships, further transported to delivery ports, offloaded into terminals, and then transported by pipeline or truck to the eventual markets. Terminal fees, pipeline fees (potentially on both ends), shipping rates, and losses of volume and quality along the whole process are important considerations. When all of these logistical costs and considerations are factored in, I think it is highly unlikely that current Western Canadian crude oil producers will be aggressively seeking markets to replace their current American Mid-Western and Eastern Canadian refinery customers.

F. Response to Claims Regarding Gulf Coast Refineries

28. The Muse Report claims that the present demand for Bakken crude oil by Gulf Coast refineries will dry up because of lower priced local crude oil alternatives. In my prior Declaration, I pointed out the defects in the Muse analysis. The criticism of my comments in Mr. Earnest's latest affidavit is not correct.

29. The first issue in this connection is the extent of the Gulf Coast market. I had pointed out that the Muse Report failed to account for two million barrels a day of the Gulf Coast market.[19] In response Mr. Earnest says that he properly excluded the two million barrels a day because the refineries in the Corpus Christi area are not regarded as a prospective market for Bakken crude oil producers.[20]

[19] Garner Declaration, pages 16-17.
[20] Earnest Affidavit, dated March 31, 2014, paragraph 21.

30. However, the Corpus Christi refinery complex amounts to about 650,000 bpd. That still leaves 1.35 million bpd of refining capacity that seems to have been simply ignored by the Muse Report.

2. Demand for Eagle Ford Crude

31. In my prior Declaration, I also commented on the fact that Eagle Ford crude oil, one of the principal crude oil production streams that Mr. Earnest states will replace current Bakken shipments to Gulf Coast refineries is "primarily a light condensate that can be used in only limited quantities in most refineries because of the unbalanced composition of its components when processed in a refinery."[21] Mr. Earnest states that he disagrees.[22] But, an article that was published on Muse's own website agrees with my position.

32. I am attaching to my Supplemental Declaration as Attachment C an article entitled "Eagle Ford Impacting Liquids Market." The article is dated March 2012 and was written by Lesa S. Adair and Susan L. Starr. Ms. Adair is Chief Executive Officer of Muse. The article, which was published in *The American Oil and Gas Reporter*, states as follows:

1) "Liquid production [of Eagle Ford crude oil] is mostly light sweet crude oil and condensate, with condensate making up approximately 50 percent of the produced volume;"[23]

2) "Industry forecasts indicate that producers expect the total crude and condensate production rate to reach between 500,000 and 800,000 bbl/d

[21] Garner Declaration, paragraph 35.
[22] Earnest Affidavit, dated March 31, 2014, paragraph 24.
[23] Attachment C, page 1.

by 2020, with approximately 50 percent of the liquids volume attributable to condensate production;"[24]

3) "Some refiners will have physical 'light ends' capacity limitations, and will be unable to run significant volumes of condensate because of the higher volume of light naphtha produced;"[25]

4) "The naphtha content also will be limiting as a result of the overall decline in U.S. gasoline demand attributable to the nation's economic downturn;"[26] and

5) "Such limitations on condensate demand provide economic incentives for projects such as Kinder Morgan's recently announced condensate splitter project with planned capacity of 25,000 bbl/d and possible expansion to 100,000 bbl/d."[27]

33. Accepting the analysis of Muse's own staff, I believe that it is clear, as I stated previously, that Eagle Ford crude oil consists of a very large amount of condensate and is to an appreciable extent unsuitable for use in Gulf Coast refineries.

34. In fact, an article published by RBN Energy LLC on January 27, 2014, describes the "flood of condensate range material coming out of the Eagle Ford into Houston and Corpus Christi."[28] According to RBN Energy it, "expects total field condensate

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[24] Attachment C, page 1.
[25] Attachment C, page 3.
[26] Attachment C, page 3.
[27] Attachment C, page 3.
[28] "Whole Lotta Splittin' Going On - Processing Gulf Coast Condensate," RBN Energy, LLC, dated January 27, 2014, page 1: https://rbnenergy.com/whole-lotta-splittin-going-on---processing-gulf-coast-condensate. This article is attached to this Declaration as Attachment D.

production from Texas to reach 900 Mb/d by the end of 2016. Trouble is Gulf coast refiners need condensate like a hole in the head."[29]

35. Finally, Mr. Earnest states that apart from Eagle Ford crude oil, other crude oil production is increasing in Texas, Oklahoma, and Kansas, and, potentially, in New Mexico fields. However, this production does not increase the likelihood that the NDP Sandpiper pipeline will be fully utilized as the Muse Report projects. Most of this growing production can just as easily (and in some cases perhaps even more easily) flow north to the Mid-west rather than in a southerly direction to the Gulf Coast. This crude oil would therefore compete with Bakken crude trying to access Midwest markets. The Muse Report appears to agree with this analysis, stating as follows:

> The net light crude supply from the Permian Basin (West Texas and southeastern New Mexico) has been allocated to the Gulf Coast region for this analysis. It also could have been allocated to the Mid-Continent, as both regions have high-capacity pipeline connectivity to West Texas. Had the net Permian Basin crude oil supply been allocated to the Mid-Continent, it would make the Mid-Continent net long and the Gulf Coast net short light crude oil.[30]

36. It is certainly possible that if this crude oil production had been allocated in the Muse model to Mid-western refineries, the results that Muse reports regarding the likely transportation of crude oil on the Sandpiper line could have been entirely different.

G. Mr. MacPhail's Statement that the NDP Pipeline Has Recently Been Subject to Significant Prorationing Is Simply Not Correct.

37. In his current Declaration, Mr. MacPhail produces a chart that shows the capacity on the pipeline for each month, the amount of crude oil nominated on the NDP pipeline system, and his indication as to whether the NDP was prorated or not during those

[29] Attachment D, page 2.
[30] Muse Report, page 16, footnote 15.

respective months.[31] I believe that the available data from a previous case before FERC involving NDP and St. Paul Park Refining Co. provides a better indication of the actual usage of the pipeline.[32] According to NDP in that document, during the period of January 2012 through July 2013 the pipeline was not operating in apportionment. In each month of the eight month period from December 2012 to July, 2013, the pipeline transported less than 127,000 bpd, as compared to its design capacity of 210,000 bpd. I am attaching to my Declaration as Attachment E an Appendix to the Commission's decision in the *St. Paul* case, which shows the throughput of the NDP pipeline.

38. In addition, Mr. MacPhail's claim, that the pipeline has been prorated 8 times in the 10-month period from July 2013 through April 2014 is highly misleading. During that period small upstream sections of the NDP system had been prorated but the main portion of the NDP line from Minot to Clearbrook, according to our observations, had been prorated only slightly in April 2014. In fact, e-mails that NDP sent to us in the months of July, November, and December of 2013, and January, February, and March of 2014 notified us along with all other shippers on the NDP pipeline that there was space on the line for additional shipments between Minot and Clearbrook. I am attaching copies of those e-mails to my Declaration as Attachment F.

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[31] MacPhail Affidavit, dated March 31, 2014, page 9.

[32] *St. Paul Park Refining Co. LLC v. Enbridge Pipelines (North Dakota) LLC*, 145 FERC ¶ 61,050 (October 17, 2013).

I, Robert P. Garner, state under penalty of perjury that the foregoing is true and correct to the best of my information and belief.

Robert P. Garner
April 14, 2014

ATTACHMENT A

4.4 Current Volumes Compared to Current Capacity

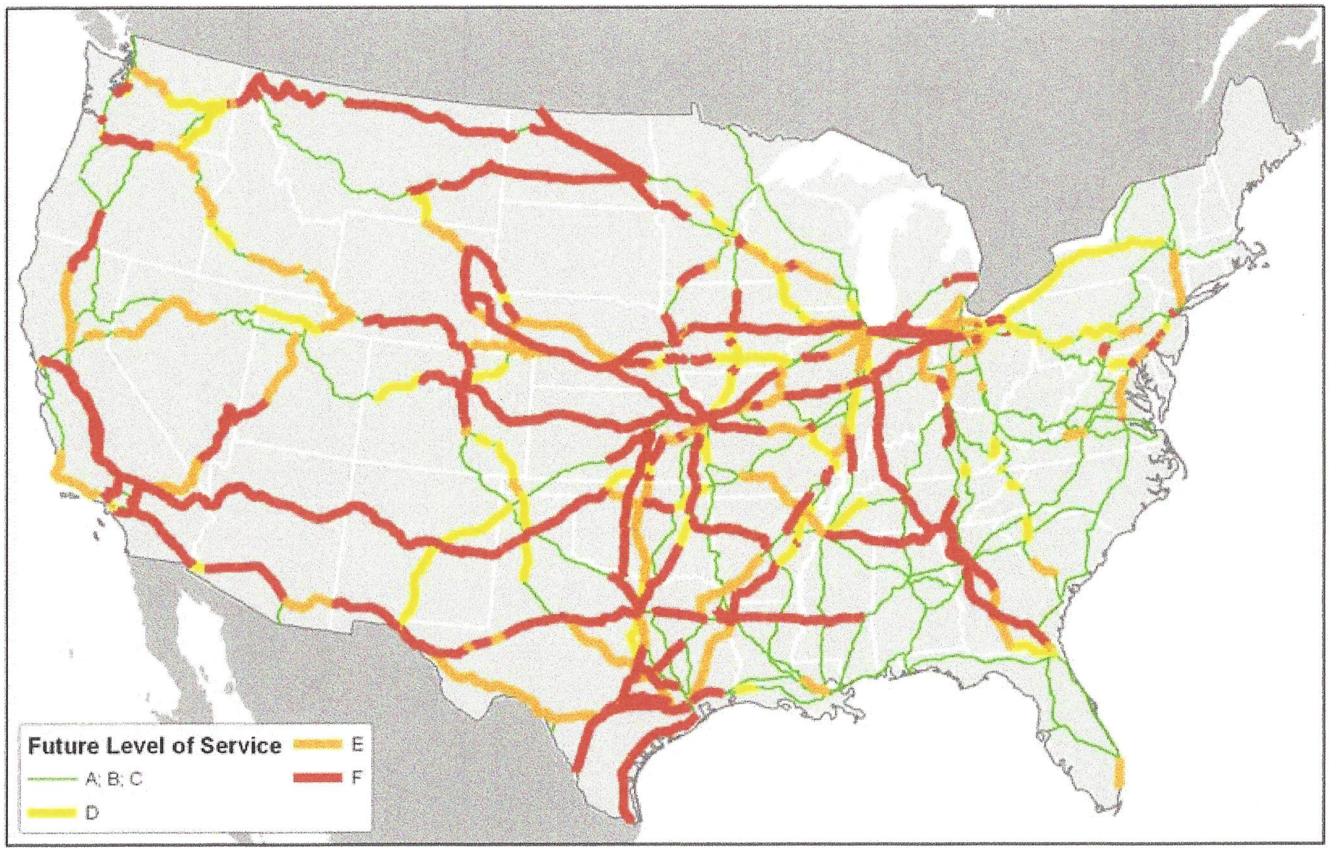
Current corridor volumes were compared to current corridor capacity to assess congestion levels. This was done by calculating a volume-to-capacity ratio expressed as a level of service (LOS) grade. The LOS grades are listed in Table 4.3.

Table 4.3 Volume-to-Capacity Ratios and Level of Service (LOS) Grades

LOS Grade	Description		Volume/Capacity Ratio
A B C	Below Capacity	Low to moderate train flows with capacity to accommodate maintenance and recover from incidents	0.0 to 0.2 0.2 to 0.4 0.4 to 0.7
D	Near Capacity	Heavy train flow with moderate capacity to accommodate maintenance and recover from incidents	0.7 to 0.8
E	At Capacity	Very heavy train flow with very limited capacity to accommodate maintenance and recover from incidents	0.8 to 1.0
F	Above Capacity	Unstable flows; service break-down conditions	> 1.00

Source: Cambridge Systematics, Inc.

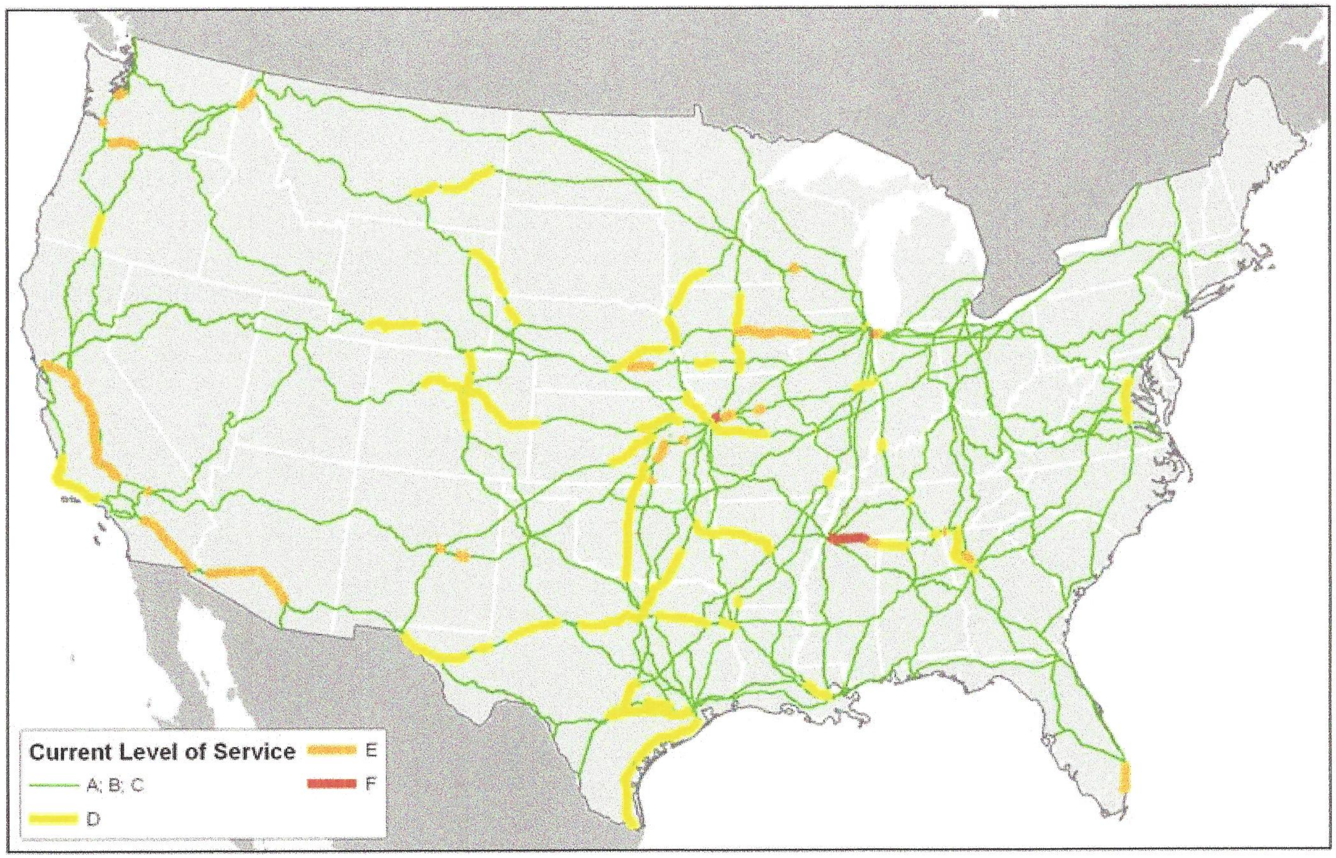
Figure 5.4 Future Corridor Volumes Compared to Current Corridor Capacity
2035 without Improvements



Source: Cambridge Systematics, Inc.

Note: Volumes are for the 85th percentile day.

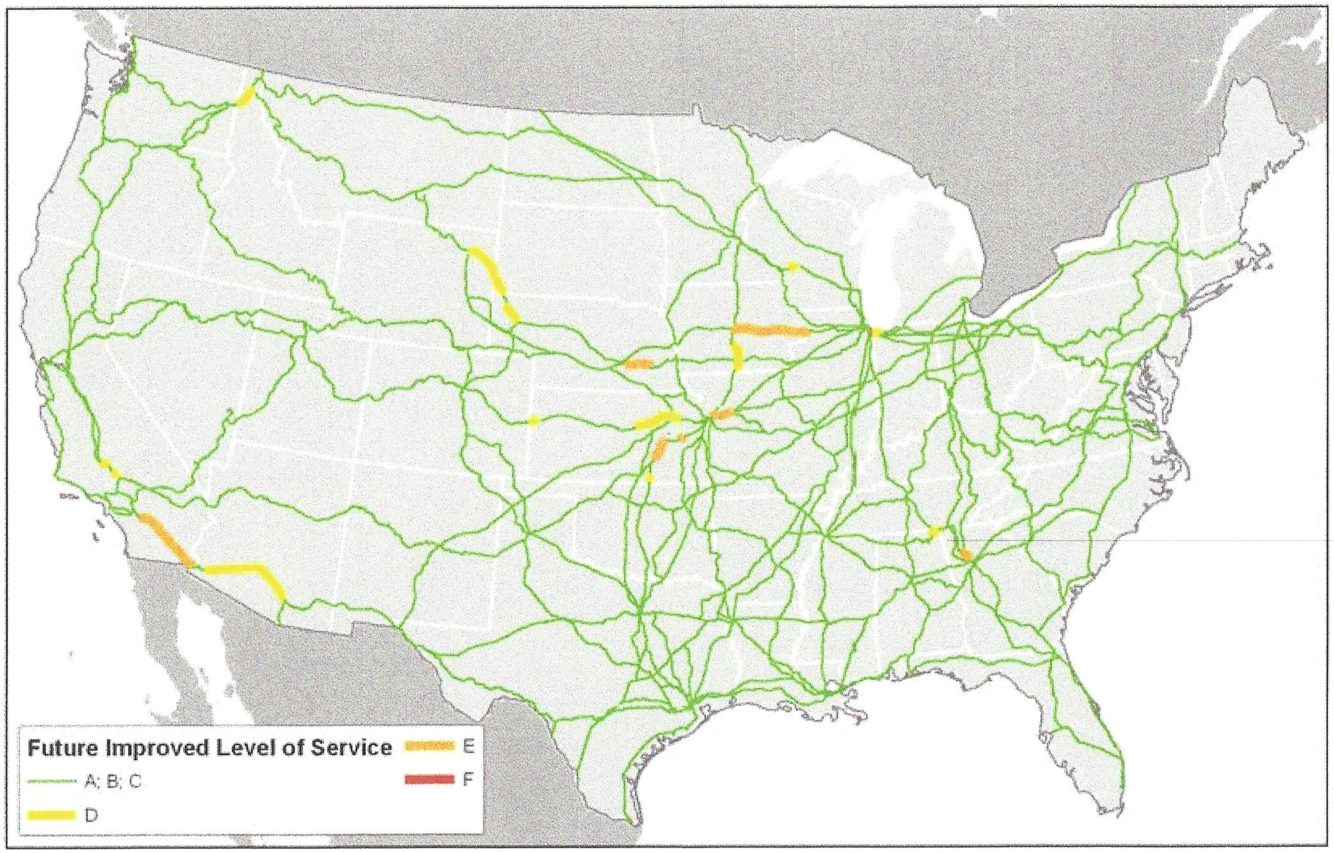
Figure 4.4 Current Train Volumes Compared to Current Train Capacity



Source: Cambridge Systematics, Inc.

Note: Volumes are for the 85th percentile day.

Figure 6.1 Future Train Volumes Compared to Future Train Capacity
2035 with Improvements



Source: Cambridge Systematics, Inc.

Note: Volumes are for the 85th percentile day.

ATTACHMENT B

Railroads and Coal

Association of American Railroads **August 2013**

Summary

No single commodity is more important to America's railroads than coal. Coal accounted for 41.0 percent of rail tonnage and 21.6 percent of rail gross revenue in 2012. Most coal in the United States is consumed at coal-fueled power plants. Historically, coal has dominated U.S. electricity generation because it is such a cost-effective fuel choice, and freight rail is a big reason for that. More than 70 percent of the coal delivered to coal-fueled power plants is delivered by rail. Electricity is also generated using other fuels, including nuclear power, wind, solar power, hydroelectric power, and natural gas. Recently, the price of natural gas has fallen sharply, increasing the competitiveness of electricity generated from natural gas vis-à-vis electricity generated from coal. In addition, increasingly stringent environmental regulations have targeted coal-fueled generation. Consequently, electricity generated from coal — and associated rail coal volumes — have fallen. Whether this is a short- or a long-term phenomenon remains to be seen.

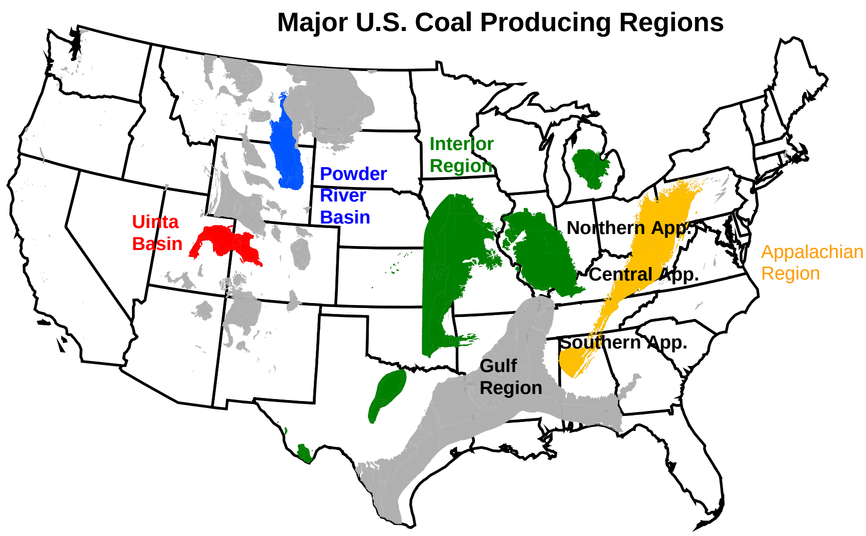
Overview of Coal

Coal is formed over millions of years through pressure and temperature by the slow underground decomposition and chemical conversion of plant matter in what at one time were enormous swamps. Over time, the plant matter is transformed into peat, then lignite, then subbituminous coal, then bituminous coal, and finally anthracite.

Coal has value primarily because it yields a lot of energy when it's burned. It can be steam coal (used in power plants) or metallurgical coal (used to make coke for steelmaking). Energy content is measured in British Thermal Units (BTUs). On average, one ton of coal yields 20 to 21 million BTUs, but energy content varies considerably by type of coal. For example, the average heating value of bituminous coal is around 24 million BTU per ton; for subbituminous, 18 million; for lignite, 13 million; and for anthracite, 23 million. Coal quality also varies based on the level of impurities found in the coal.

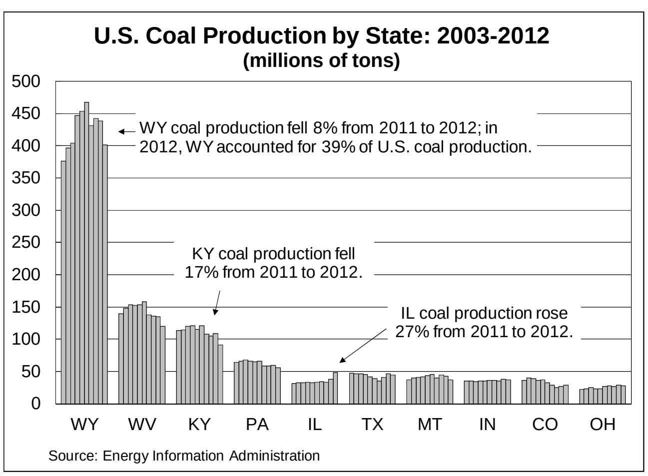
U.S. Coal Production

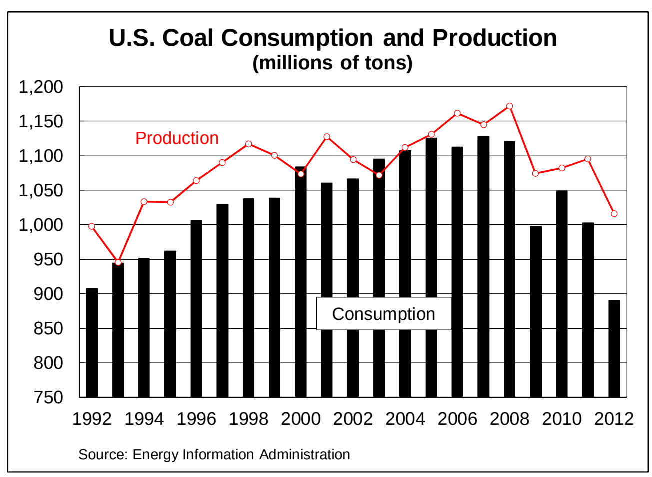
According to the Energy Information Administration (EIA), U.S. coal production was 1.02 billion tons in 2012, down 7.2 percent from 2011's 1.10 billion tons and the lowest annual total since 1993. The all-time peak production was 1.17 billion tons in 2008. The decline in coal output in 2012 from 2008 was 155 million tons. That's much more than the amount of coal produced each year in West Virginia, the nation's second largest coal-producing state. Wyoming accounted for 39 percent of U.S. coal production in 2012, followed by West Virginia (12 percent) and Kentucky (9 percent). Nine of the top ten mines in terms of annual coal production are in Wyoming. The top 45 mines account for more than 60 percent of U.S. coal production.



Most U.S. coal production takes place in three major coal-producing areas:

- "Appalachian" coal is mined in Pennsylvania, Maryland, Virginia, West Virginia, Tennessee, Alabama, Ohio, and eastern Kentucky. It is often further broken down into Southern, Central, and Northern Appalachia.
- "Interior" coal is mined in Illinois, Indiana, Missouri, Texas, and western Kentucky.
- "Western" coal is mined in Wyoming, Montana, Utah, Colorado, North Dakota, New Mexico, and Arizona. Most Western coal originates in the Powder River Basin (PRB) of northeast Wyoming and southeast Montana. PRB coal has low sulfur content. Over the past two decades its consumption has surged due to increasingly-stringent clean air laws.



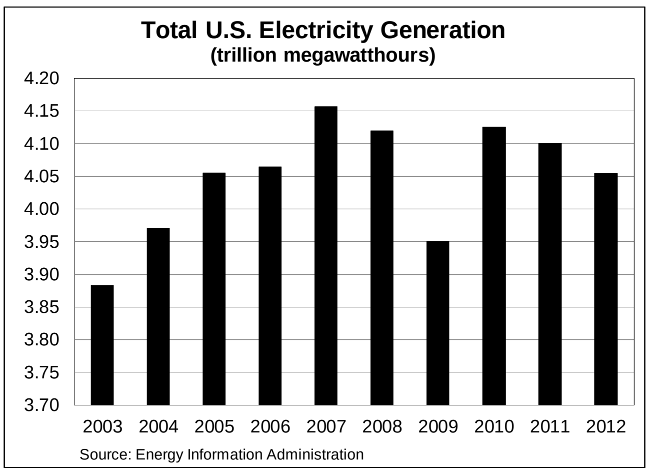


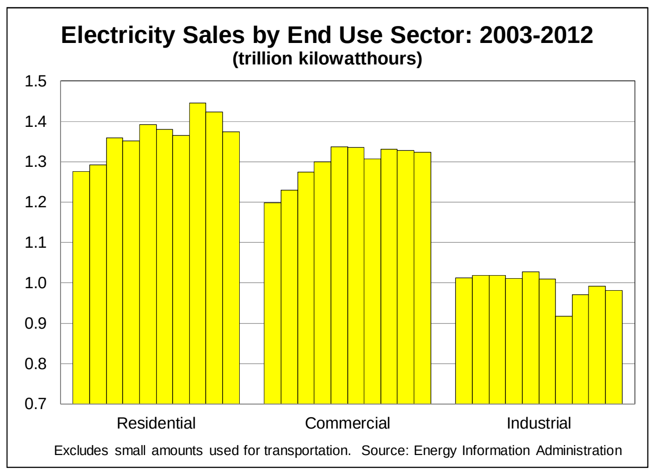
U.S. Coal Consumption

U.S. coal consumption in 2012 was 890.5 million tons, down 11.2 percent from 2011's 1.00 billion tons and 21.1 percent lower than the 2007 peak of 1.13 billion tons. In 2012, 92.6 percent of coal consumption was for electricity generation; 2.3 percent was to produce coke; and 5.1 percent was for other purposes, including combined heat and power plants.

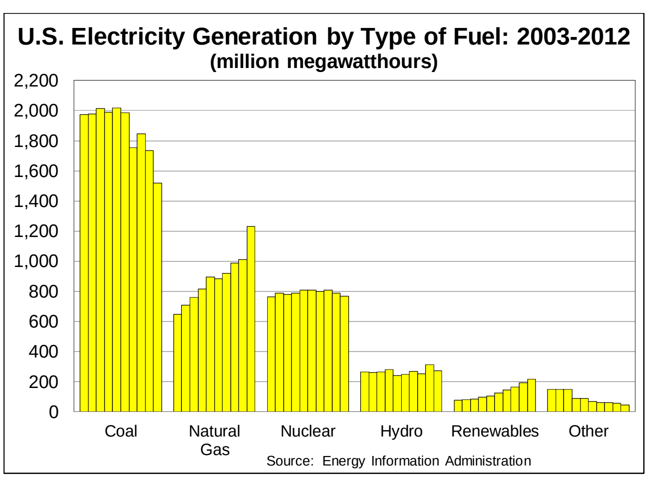
Because power plants account for so much of U.S. coal consumption, the electricity marketplace is key to coal's fortunes. Historically, U.S. electricity production has risen steadily: from 1949 to 2007, total year-over-year U.S. electricity generation fell just twice: in 1982 (-2.3 percent) and in 2001 (-1.7 percent). However, total U.S. electricity generation fell in four of the five years since 2007, including declines of 0.6 percent in 2011 and 1.1 percent in 2012.

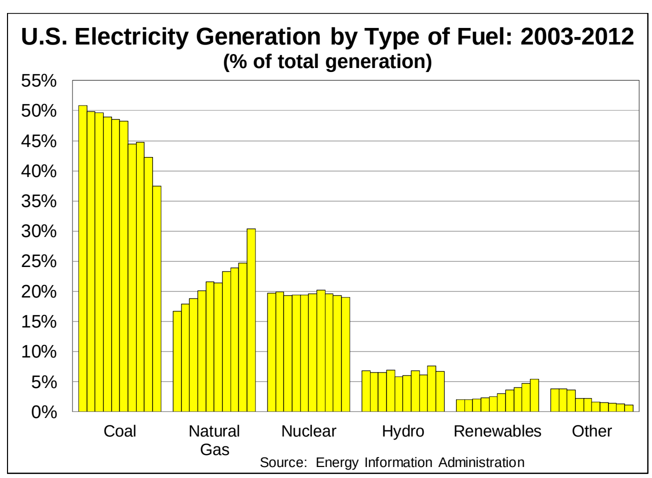
A huge base of electricity is needed for day-to-day purposes, but on the margin electricity demand is largely a function of weather and the economy. In 2008 and 2009, lower electricity generation was in large part a function of the severe recession. (Note the big decline in "industrial" electricity in 2009 from 2008 in the chart below right.) The big increase in total electricity generation in 2010 from 2009 was in part due to stronger industrial demand. There was also a big increase in residential electricity demand in 2010 (see the "residential" bars in the chart) caused largely by a much hotter than usual summer, which meant more demand for electricity for air conditioning. The decline in 2012 from 2011 is a function of, among other things, continued slow economic growth and continued improvements in fuel efficiency.





In the United States, the main fuel sources for generating electricity are (in order) coal, natural gas, nuclear power, hydroelectric power, and renewables such as wind and solar. If market shares stayed constant, coal-based generation would rise or fall with total electricity generation. Market shares don't stay constant, though, and both the absolute amount of electricity generated from coal and coal's share of the total has been trending down the past few years.



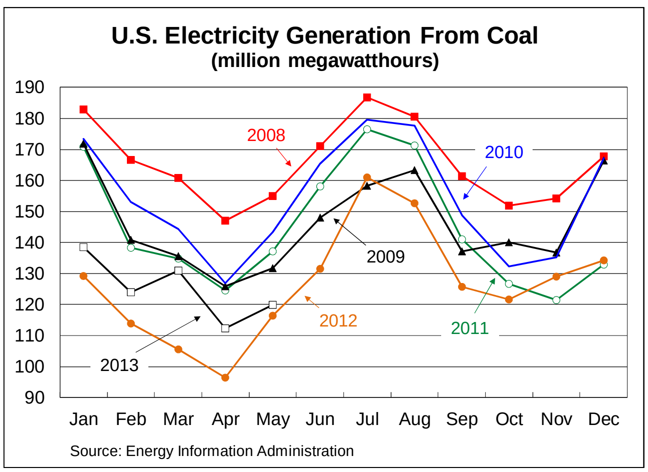


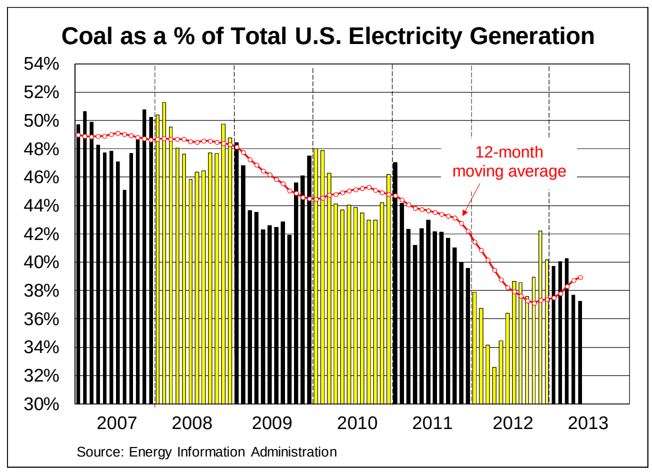
The chart on the bottom of the previous page shows the absolute amount of electricity generated by various fuels; the chart on the bottom right of the previous page shows the percentage of total generation accounted for by each fuel.

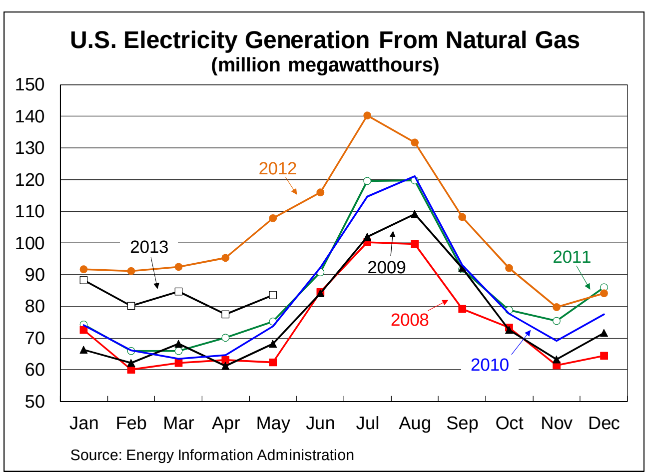
For coal, the news isn't good. In the 1990s, coal's share of electricity generation averaged 56 percent. By 2002, it was down to 50 percent. By 2012, it had fallen to 37 percent, by far its lowest share since sometime prior to when EIA data begin in 1949. Meanwhile, the natural gas share rose from 17 percent in 2003 to 30 percent in 2012, and renewables' share rose from 2 percent in 2003 to 5 percent in 2012.

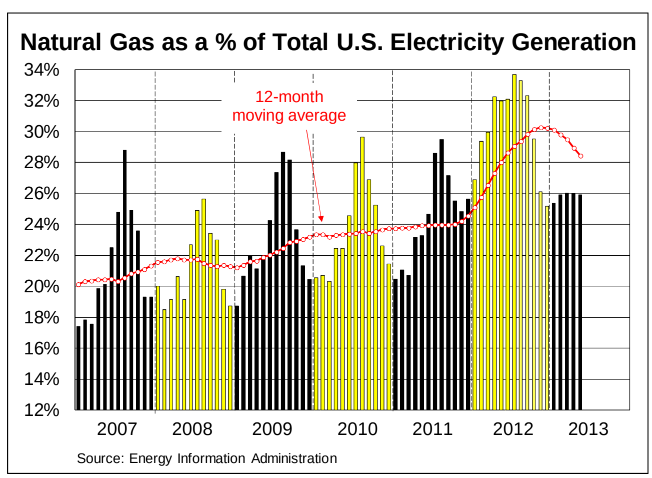
Different fuels dominate electricity generation in different states. For example, Indiana was the 12th largest electricity generator in 2012; coal accounted for 81 percent of its generation. California was the 4th largest electricity generator, but coal accounted for just 1 percent of its generation. Electricity generators in California, the Pacific Northwest, and New England use relatively little coal; generators in the Midwest, Southeast, and Southwest burn much more.

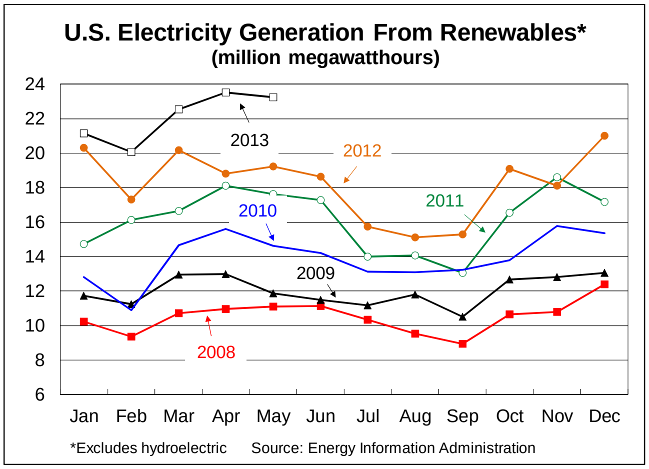
The decline in coal's share of electricity generation has accelerated in the past couple of years (see the charts below). Meanwhile, the natural gas share has been trending sharply upward. The renewable share has been rising too, though from a low base.

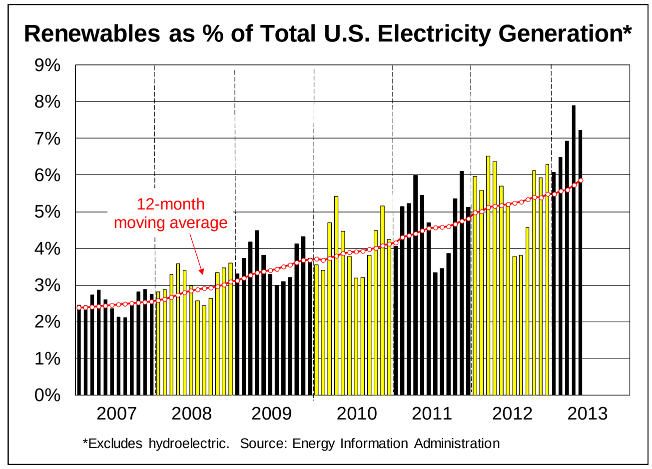




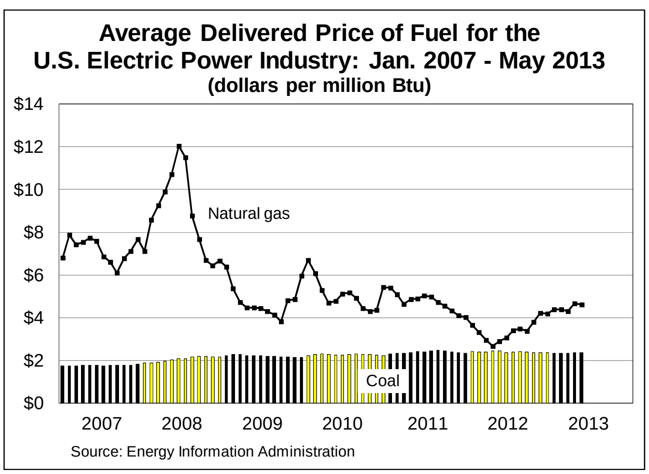


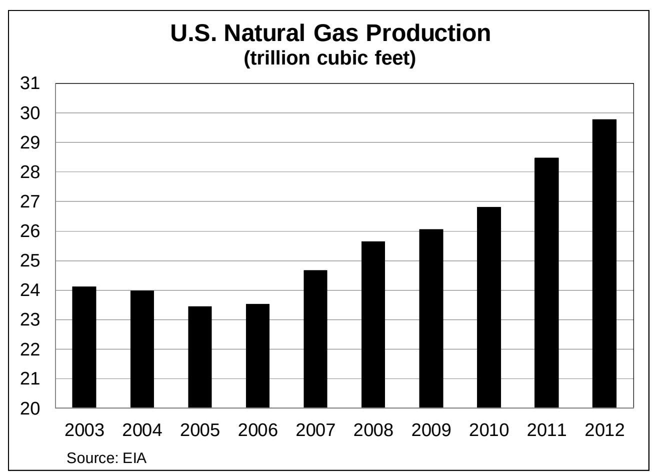






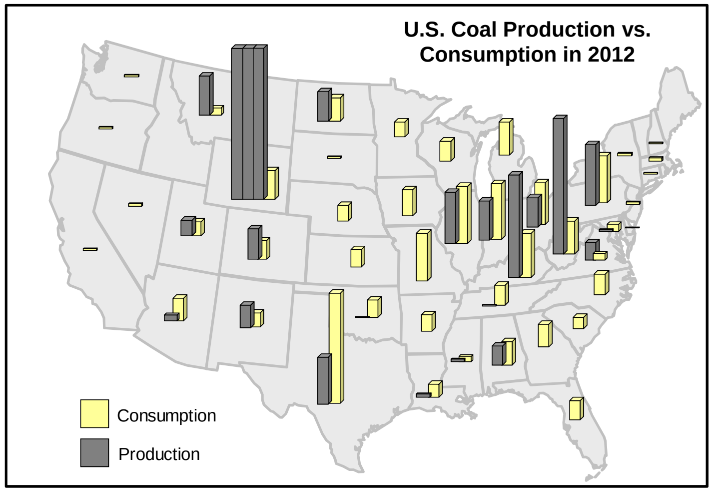
As noted earlier, there has been significant displacement of coal-fueled electricity with electricity generated from other sources, especially natural gas. Natural gas is seen by many as more environmentally benign than coal, and that's certainly played a key role (and could play an even bigger role in the future), but economic issues have probably been even more important. Natural gas is much cheaper for electricity producers than it was just a few years ago (see chart below left) thanks to sharply higher natural gas production (see chart below right) brought about by technological advances in natural gas extraction, especially "hydraulic fracturing," commonly known as "fracking."





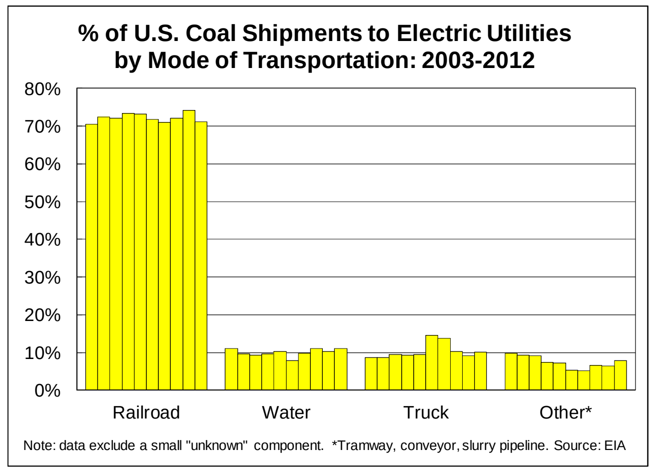
There is still an enormous amount of uncertainty regarding the future of the natural gas market. Some say very low natural gas prices are here to stay; others say they are bound to rise, possibly by a great deal. The more they rise, everything else equal, the less competitive natural gas-based electricity generation will be compared with coal-based electricity generation. Some say fracking is perfectly safe, and they have the support of key policymakers who think it's a godsend for the economy. Others say fracking is an environmental catastrophe waiting to happen and want to ban it. Time will tell who's right and who's wrong, but there's no question that coal — and railroads that haul coal — will be greatly affected by what happens. Coal will, without question, have a significant long-term place in America's energy supply, but how big that piece will end up being isn't known at this time.

Coal Transportation



U.S. coal production is focused in a relatively small number of states, but coal is consumed in large amounts all over the country. This is possible because the United States has the world's most efficient and comprehensive coal transportation system, led by railroads.

All major surface transportation modes carry large amounts of coal. According to the EIA, 70 percent of U.S. coal shipments were delivered to their final domestic destinations by rail in 2012, followed by truck (11 percent); water (12 percent, mainly barges on inland waterways); and the aggregate of conveyor belts and tramways (7 percent, mainly at minemouth plants). The rail share is higher than it was 20 years ago largely because of the growth of Western coal that often moves long distances by train.



Railroad Coal Traffic

Coal is the most important single commodity carried by U.S. freight railroads. In 2012, it accounted for 41.0 percent of tonnage, 21.9 percent of carloads, and 21.6 percent of gross revenue for U.S. Class I railroads. Coal is also an important commodity for many non-Class I railroads. Coal accounts for approximately one in five freight railroad jobs.

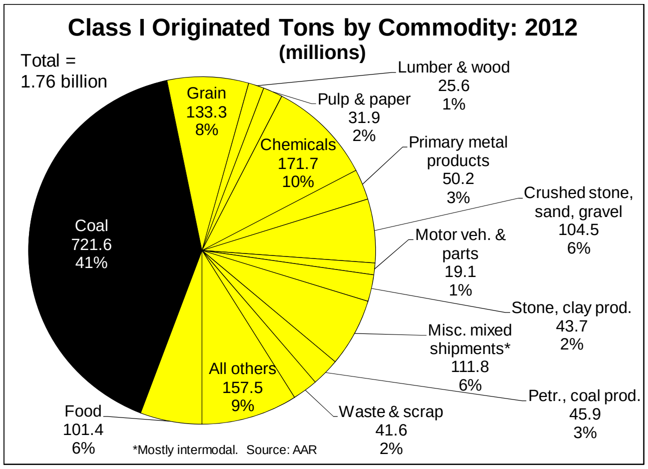
Coal's share of U.S. electricity generation has fallen sharply due to a surge in generation from inexpensive natural gas and, to a lesser extent, more electricity generation from renewable sources like wind and solar, and due to environmental pressures that have limited coal consumption. Rail coal traffic has suffered accordingly.

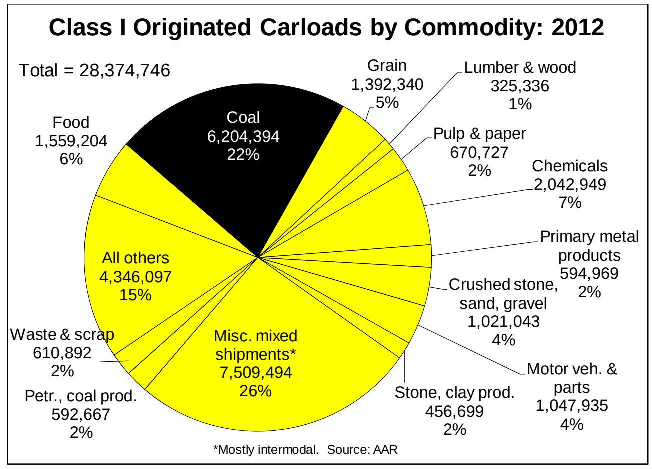
In 2012, Class I railroads originated 6.20 million carloads of coal, down 12.1 percent from 2011's 7.06 million carloads and down 19.6 percent from the peak of 7.71 million carloads in 2008. Put another way, Class I railroads originated 1.51 million fewer carloads of coal in 2012 than they did in 2008. If you assume, for simplicity, 115 carloads per coal train, that's more than 13,000 fewer trainloads of coal in 2012 than in 2008.

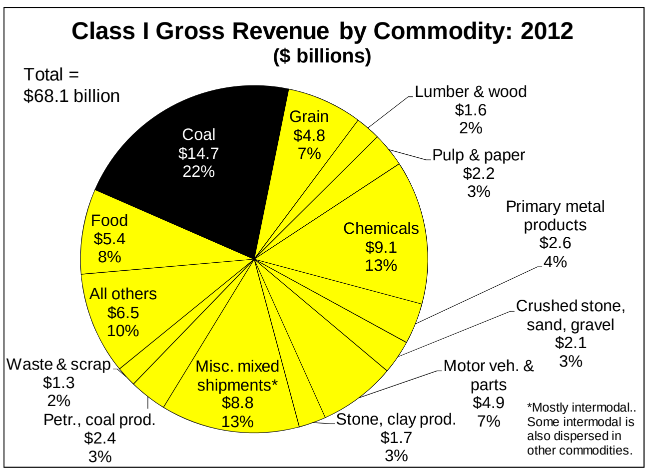
Class I railroads originated 721.6 million tons of coal in 2012, down 11.6 percent from 2011's 816.0 million tons and down 17.9 percent from 2008's peak of 878.6 million tons. The decline in rail coal tonnage in 2012 from 2008 was 157.0 million tons.

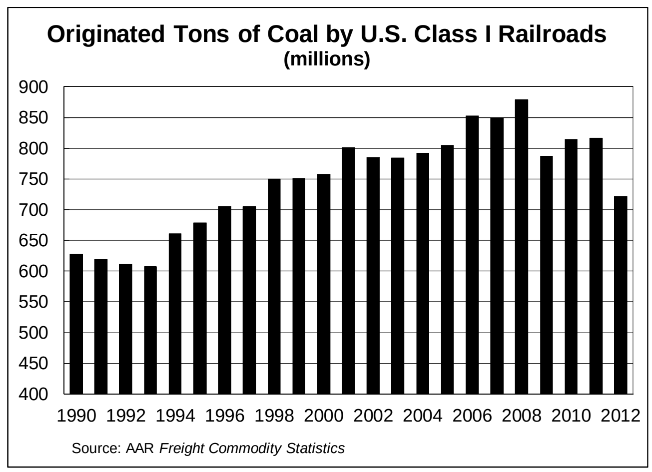
Railroads have typically derived more revenue from coal than from any other commodity (though the broad "intermodal" category accounted for more revenue than coal from 2003 to 2007 and will probably do so again in the future). Class I gross revenue from coal was $14.7 billion in 2012, down from $16.1 billion in 2011.

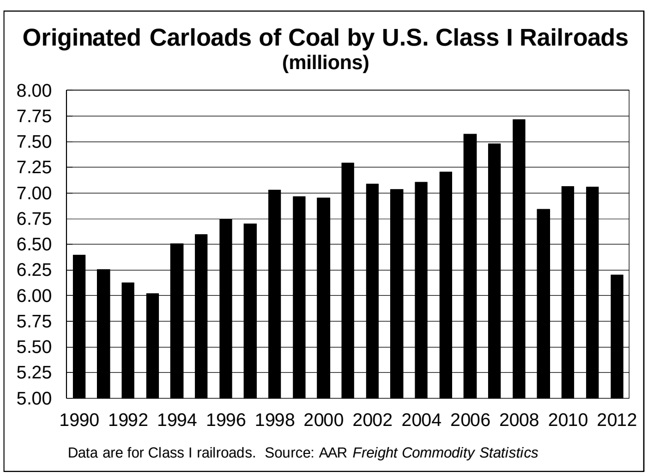
The charts below, with data from the AAR's Freight Commodity Statistics publication, show annual coal-related rail traffic data. The charts on the next page show weekly and monthly rail coal traffic data, sourced from the AAR's Weekly Railroad Traffic publication.

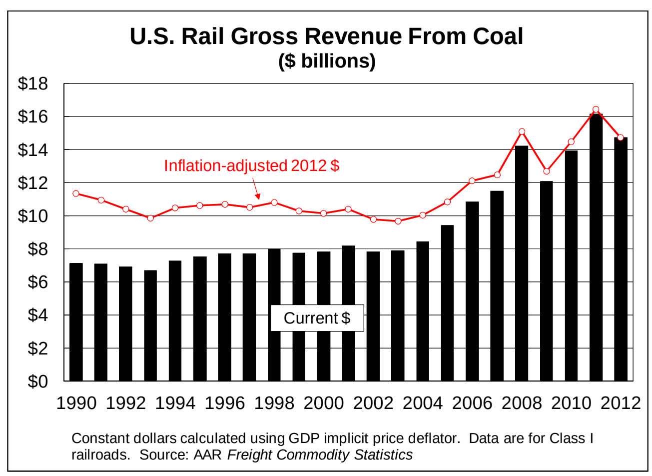


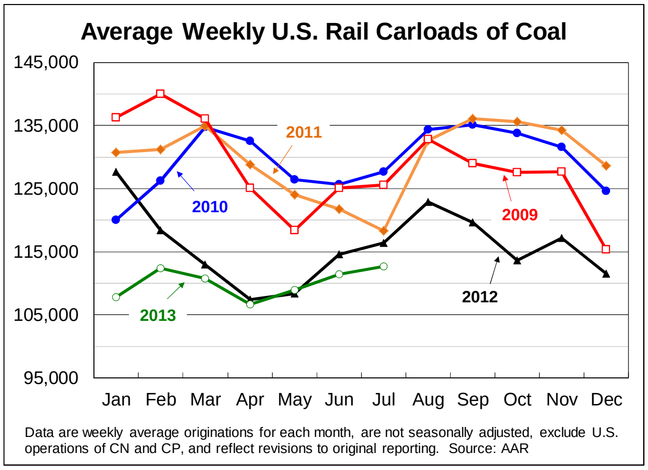


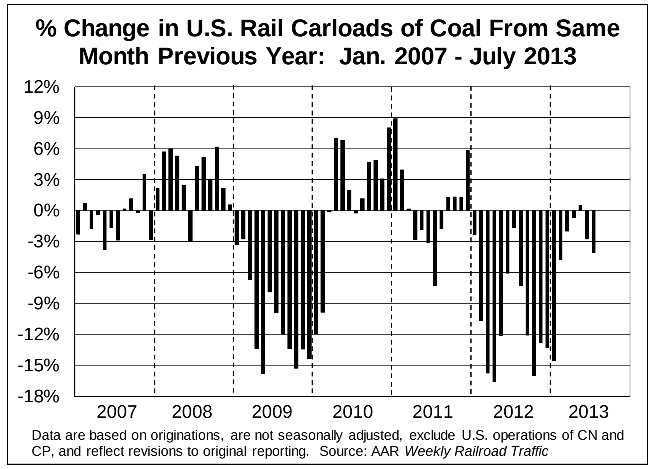


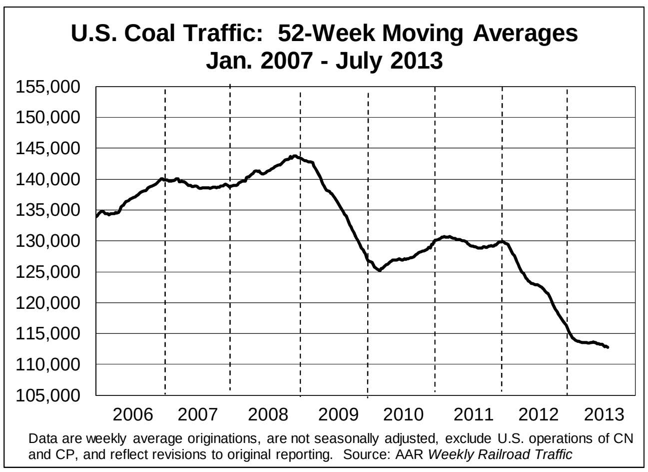


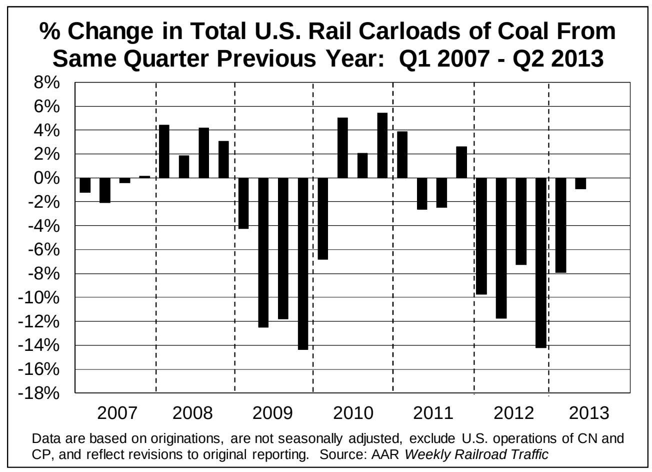












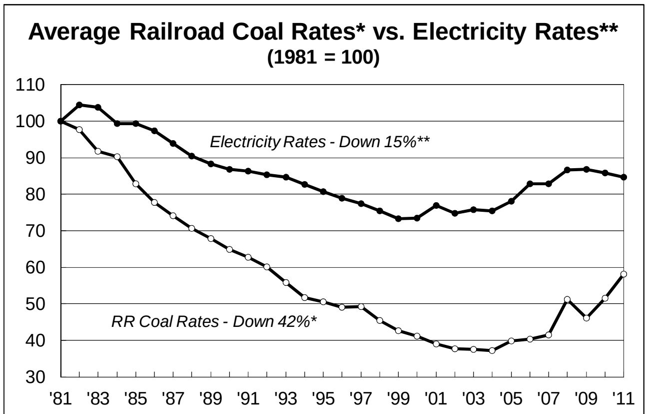
Thanks to huge productivity gains — including increasing use of lighter weight aluminum freight cars — railroads have dramatically increased their coal-carrying efficiency. In 2012, the average coal car carried 116.3 tons, up 18 percent from the 98.2 tons in 1990. Approximately 55 percent of coal is carried in gondolas; the rest is carried in hopper cars.

Nearly all coal transported by rail moves in highly productive unit trains, which operate around the clock, use dedicated equipment, generally follow direct shipping routes, and have lower costs per unit shipped than non-unit trains. Due in part to the high consumption of low-sulfur Western coal by utilities throughout the country, the average length of haul for rail coal movements has trended upward over the years, reaching 848 miles in 2011 — an all-time high. Rail coal movements exceeding 1,500 miles are not uncommon.

Coal dominates rail traffic in major coal producing states. In Kentucky, West Virginia and Wyoming, for example, coal accounted for 87 percent, 93 percent, and 96 percent, respectively, of total originated rail tonnage in 2011. Due to its widespread use in generating electricity, coal also accounts for a major share of terminated rail tons for many states. For example, in 2011 coal accounted for 51 percent of rail tons terminated in North Carolina, 59 percent in Wisconsin, and 42 percent in Georgia.

Since it incorporates both distance and weight, revenue per ton-mile (RPTM) is a useful surrogate for rail rates. In 2011 (the most recent year for which RPTM data for coal are available), average RPTM for coal was 2.88 cents, by far the lowest such figure among major commodities carried by railroads. Average RPTM in 2011 for all commodities other than coal was 5.78 cents, double the comparable coal figure.

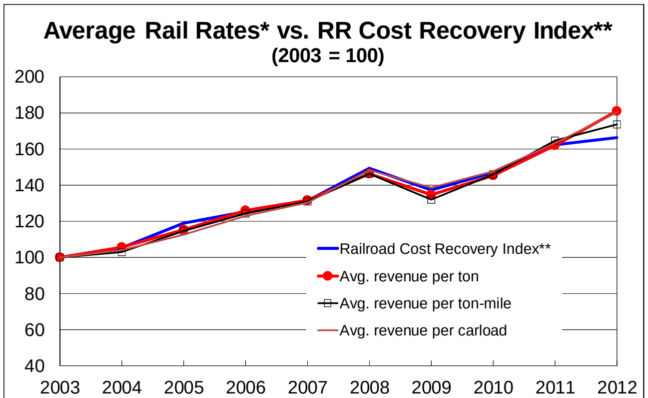
Adjusted for inflation, coal RPTM was 42 percent lower in 2011 than in 1981. This means a typical coal shipper can ship close to twice as much coal today for what he paid 30 years ago. The average decline in rail coal rates is much greater than the average decline in the price of electricity (see the chart at right). The general pattern of sharply lower coal RPTM applies to movements in railroad-owned cars and in non-railroad-owned cars, as well as for movements of different distances.



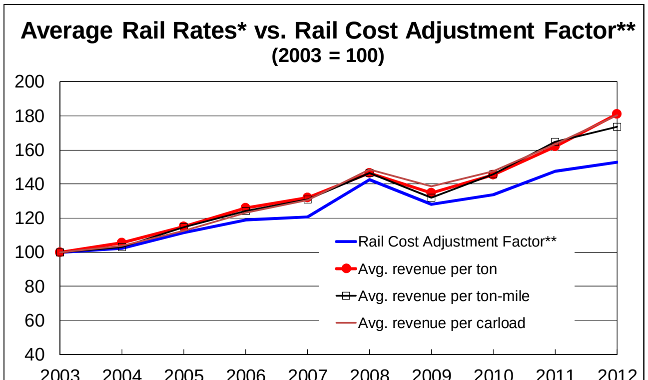
*Average rail revenue per ton-mile for coal, adjusted for inflation.
**Average revenue per kwh, all sectors, adjusted for inflation. Sources: EIA, AAR

In some recent years, average rail rates (measured by revenue per ton-mile, revenue per ton, and revenue per carload) have increased. Generally speaking, railroads — like nearly all U.S. industries — set their prices based on market conditions, not on their input costs. That said, over the past 10 years, increases in rail rates have closely tracked increases in the costs of inputs to rail operations.

The chart below left shows the very close positive correlation between average rail rates (as measured by average Class I revenue per ton, revenue per carload, and revenue per ton-mile) and the AAR's Rail Cost Recovery Index (RCR). The RCR measures inflation facing railroads in much the same way that the consumer price index measures inflation in the overall economy. Likewise, the chart below right compares rail rates (again as measured by average Class I revenue per ton, revenue per carload, and revenue per ton-mile) with the Rail Cost Adjustment Factor (RCAF). The RCAF is an alternative measure of rail inflation prepared by the Association of American Railroads under the direction of the Surface Transportation Board and subject to independent outside audit every two years. The RCAF chart also shows that there is a very close correlation between rail rates and rail input costs.

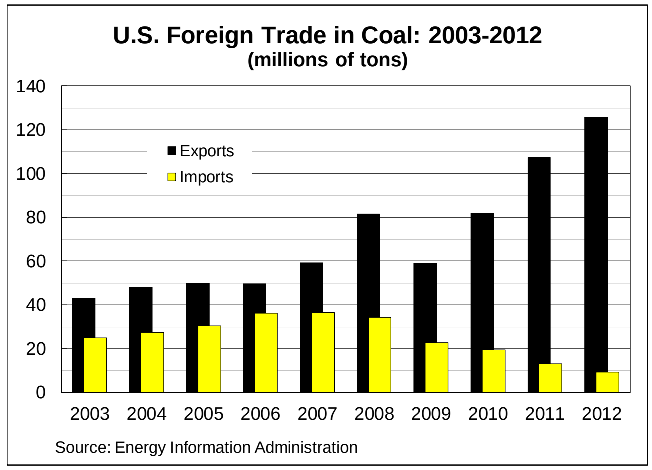


*As measured by average Class I revenue per ton-mile, revenue per carload, and revenue per ton for all commodities. **The Railroad Cost Recovery Index measures changes in the price levels of inputs to freight rail operations. Data are for Class I railroads. Source: AAR



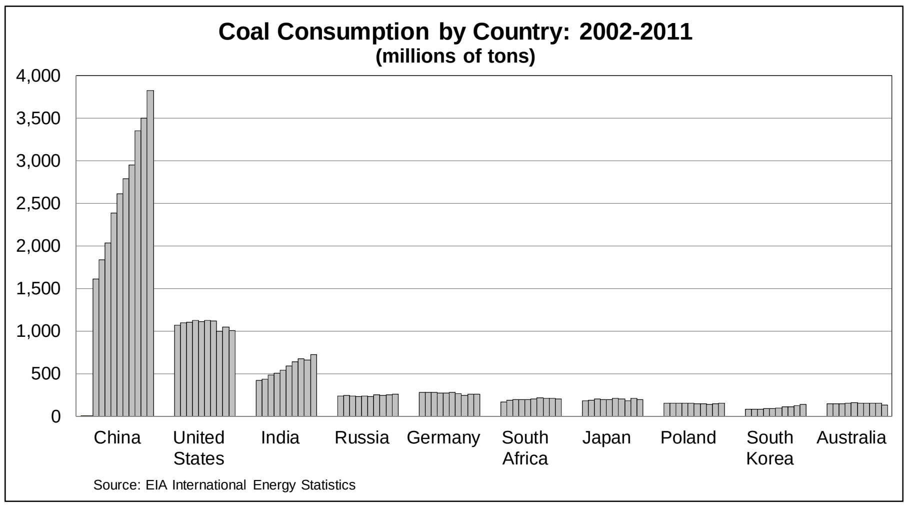
*As measured by average Class I revenue per ton-mile, revenue per carload, and revenue per ton for all commodities. **The Rail Cost Adjustment Factor is a forecast of rail input prices prepared at the direction of the STB and subject to outside audit every two years. For the purposes of this chart, the original RCAF forecast was adjusted to account for the difference between the forecast and actual input prices. Source: AAR

U.S. Coal Foreign Trade



U.S. coal exports were a record 125.7 million tons in 2012, up from 107.3 million tons in 2011. A large portion of U.S. coal exports travels by rail, so an uptick in coal exports has a clear positive effect on railroads. In 2012, the top recipients of U.S. coal exports were the Netherlands, the United Kingdom, China, South Korea, Italy, and Brazil. Over the past ten years, metallurgical coal has accounted for 59 percent of U.S. coal exports, and steam coal for 41 percent.

U.S. coal producers are hopeful that coal exports will grow in the future, with Asia — especially China and India — seen as a key market. In 1980, China accounted for approximately 16 percent of world coal consumption and the United States accounted for approximately 17 percent. In 2011, the U.S. share was down to 12 percent, but the China share was up to 47 percent. If current trends continue, within a few years China could be consuming about as much coal as all the other countries in the world combined. In 2012, U.S. coal exports to Asia were 32.5 million tons, including 10.1 million tons to China and 6.8 million tons to India. The lure of higher coal exports to Asia is the main impetus for plans, as of this writing unfulfilled due to opposition by some in the environmental community, to build new coal export terminals in the Pacific Northwest. U.S. coal imports are a tiny percentage of U.S. coal consumption — just 1.0 percent in 2012 — and have been trending downward for the past few years.



Environmental Challenges

Over the years, the affordability of coal-based electricity has been a major factor behind America's economic growth and global competitiveness. In the years ahead, coal will continue to be required to meet America's growing energy demand and keep electricity supplies reliable and affordable. That said, coal and coal-fueled electricity generation face serious environmental challenges, including challenges related to emissions (greenhouse gases, mercury, particulates, etc.), coal ash disposal, effluents, and other issues.

Huge progress has been made in addressing many of these challenges. For example, from 1970 to 2011, emissions of sulfur dioxide (SO2), nitrogen oxides (NOx), and particulate matter (PM) per kilowatt-hour from coal-fueled electricity generation have been reduced by almost 90 percent, according to EIA and EPA data. By 2015, more than 90 percent of U.S. coal-fueled electric generating capacity will install advanced emission controls to further reduce emissions of SO2, NOx, PM, mercury, acid gases, and non-mercury metals.

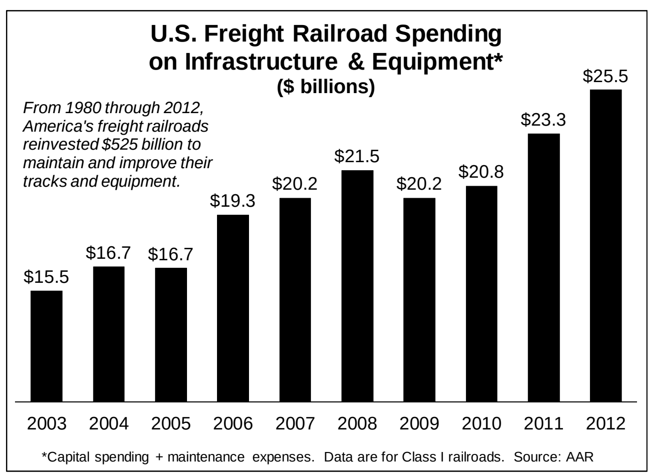
Some current and potential future EPA regulations risk drastic cuts in coal use (and, not coincidentally, sharply higher electricity prices). Electric utilities need both reasonable standards and adequate compliance deadlines to avoid disruptions that could raise electricity costs and perhaps even threaten electricity reliability. In addition to reasonable EPA regulations, railroads support the development of advanced carbon capture and storage and other clean coal technologies. By doing so, America would continue to produce affordable electricity from its abundant domestic coal; energy independence would be promoted; and the environment would be protected. It represents a win-win-win situation for all parties involved.

Continued Rail Reinvestments

America's demand for safe, effective, and affordable freight transportation that promotes economic growth and enhances America's competitiveness in the global economy is sure to grow in the years ahead. Freight railroads are the best way to meet this demand. That's why railroads have kept investing heavily in their networks. Despite the recent recession, in recent years America's privately owned freight railroads have been reinvesting more than ever before back into their networks. From 1980 through 2012, they reinvested $525 billion — their own funds, not taxpayer funds — on renewal, maintenance, and expansion of their infrastructure and equipment. That's more than 40 cents out of every rail revenue dollar.

In the years to come, railroads will be asked to do more and more. How well railroads can do this will depend in part on actions by policymakers in Washington. For example, for years debate has ensued regarding the proper type and scope of railroad regulation. The balanced approach ushered in by The Staggers Rail Act of 1980 — under which regulators protect shippers against anticompetitive railroad actions but otherwise permit railroads to largely decide for themselves how to run their operations — should be retained.

Railroads themselves pay nearly all of the costs to build and maintain their networks. Adequate investments can only be made if rail earnings are high enough to attract the capital needed to pay for these investments. That won't happen if unbalanced and unnecessary regulation interferes with the ability of railroads to earn adequate revenues.



Conclusion

How rail coal traffic behaves in the months and years ahead will depend on the same factors that have affected coal recently, including the competitiveness of fuels other than coal for electricity generation, weather, coal exports, and environmental laws and regulations. Through technological advances, innovative service, competitive rates, and aggressive reinvestment programs, railroads have shown their willingness and ability to provide high value transportation service to coal shippers throughout the country.

ATTACHMENT C

THE AMERICAN OIL & GAS REPORTER®

MARCH 2012

The “Better Business” Publication Serving the Exploration / Drilling / Production Industry

Eagle Ford Impacting Liquids Market

By Lesa S. Adair
and Susan L. Starr

ADDISON, TX.–The productivity of the Eagle Ford Shale has been unlocked over the past three years with the application of improved horizontal drilling and hydraulic fracturing techniques first honed by producers developing the Barnett Shale to the northeast.

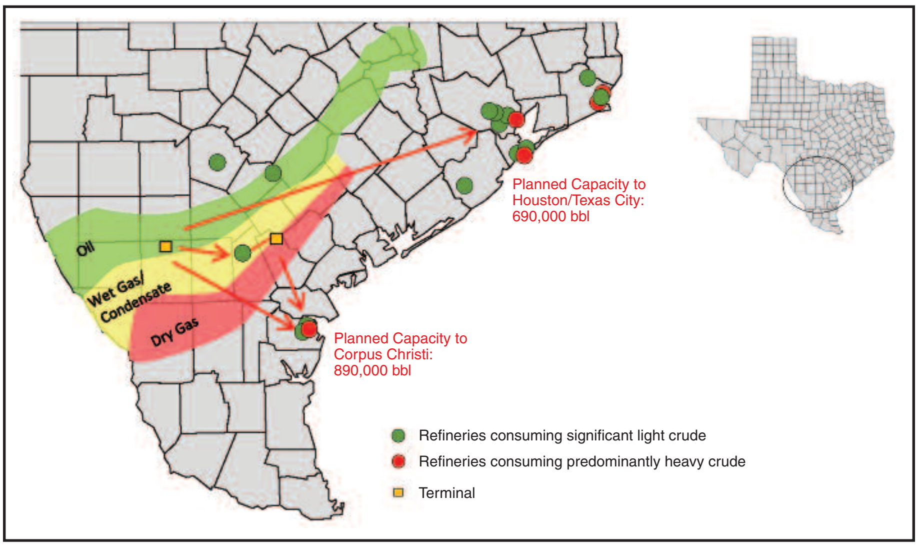
Since the Eagle Ford discovery well was drilled by Petrohawk in 2008 in the Hawkville Field in La Salle County, Tx., production has soared as drilling and development activity has transitioned from first the dry gas window to the liquids-rich gas and now crude oil windows. Producers such as Anadarko Petroleum, Apache Corp., Cabot Oil & Gas, Chesapeake Energy, EOG Resources, Marathon, Newfield Exploration and Pioneer Natural Resources are among the play’s leading operators, and are driving the rapidly expanding production volumes.

Figure 1 provides an overview of the geographic extent of the Eagle Ford play. Liquid production varies widely, with wells on the southeastern flank producing dry gas, wells on the “interior” of the play producing wet gas and condensate, and wells to the northwest producing oil. Liquid production is mostly light sweet crude oil and condensate, with condensate making up approximately 50 percent of the produced volume. Condensate quality varies significantly throughout the play, with API gravities ranging from 45 to 60 degrees.

The rapid pace of reserve development in the Eagle Ford is challenging producers, midstream service providers and downstream customers alike to provide adequate infrastructure to timely monetize the play’s prolific reserves.

FIGURE 1

Regional Map of Eagle Ford Shale Play



As shown in Figure 2, the growth in Eagle Ford production has been phenomenal, with the average crude and condensate rate increasing from a mere 600 barrels a day in 2008 to more than 120,000 bbl/d in 2011. Companies are dedicating significant resources to the region and production rates are expected to continue to increase through at least 2020.

Figure 3 provides a summary of historical and expected future crude and condensate production rates. Industry forecasts indicate that producers expect the total crude and condensate production rate to reach between 500,000 and 800,000 bbl/d by 2020, with approximately 50 percent of the liquids volume attributable to condensate production. Eagle Ford crude and condensate is being delivered to local and regional refiners, displacing foreign light crude imports. With Texas imports of light crude averaging 800,000 bbl/d from 2008 to 2011, the anticipated increase in Eagle Ford output over time will easily be accommodated by regional demand.

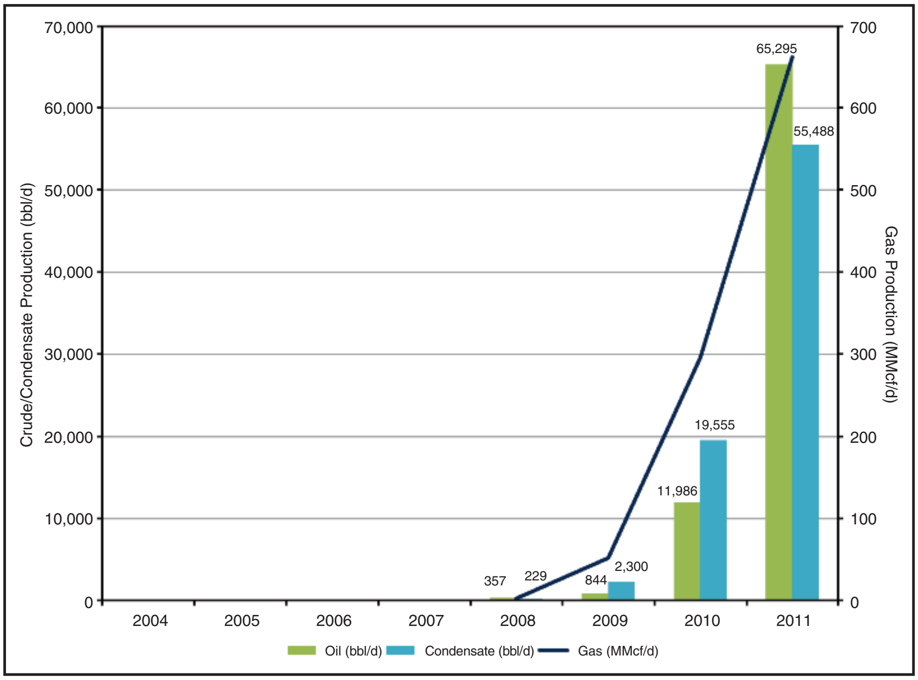
Natural gas liquids production from the Eagle Ford is expected to grow along a trend similar to crude oil, with production ramping up from essentially zero in 2008 to between 300,000 and 400,000 bbl/d by 2020. In contrast to the regional crude supply balance, Texas NGL supply and demand has been fairly balanced over the past few years. Texas imports of foreign, waterborne NGLs from 2009 to 2011 have been negligible, making the longer-term disposition of NGLs more complex.

Gulf Coast Oil Markets

As shown in Figure 1, refineries are located within or adjacent to the Eagle Ford play, or very nearby in the South

FIGURE 2

Historical Eagle Ford Production



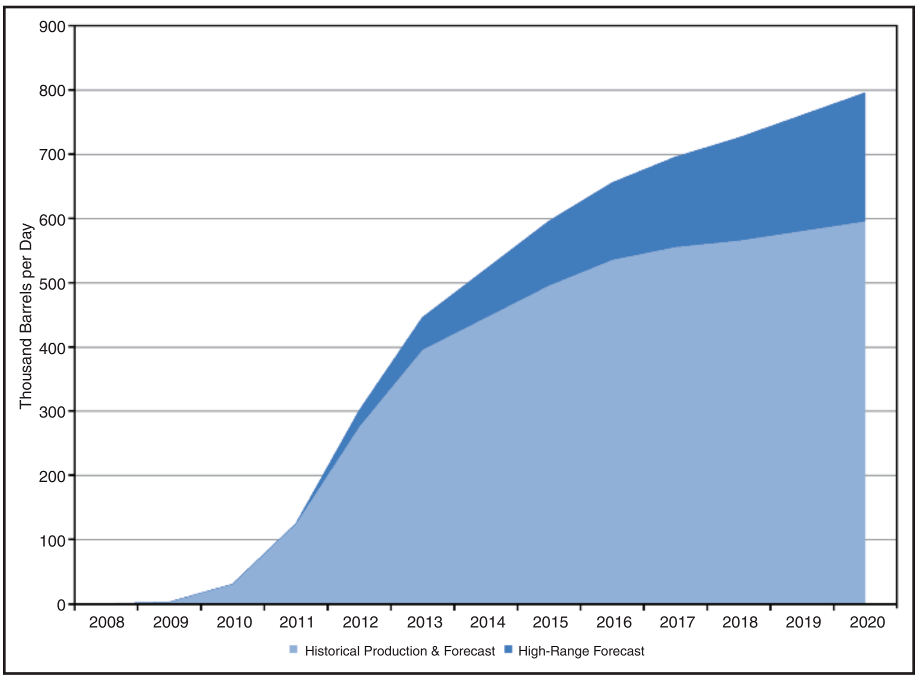
Source: Railroad Commission of Texas

Texas region and along the Texas Gulf Coast. Today, U.S. Gulf Coast refiners process a mix of locally produced, offshore Gulf of Mexico, and foreign crudes, with each refinery typically running a blend of light, medium, and heavy crude grades.

Refineries also operate within the Eagle Ford play area at Three Rivers and San Antonio. In addition, an idled refinery at Nixon, Tx., is scheduled to restart in 2012, resulting in 125,000 bbl/d of available local crude refining capacity.

FIGURE 3

Actual and Forecast Eagle Ford Crude Oil and Condensate Production



Three refineries operate at Corpus Christi and provide an additional 640,000 bbl/d of regional capacity. Several integrated refineries process crude and condensate farther up the Texas Gulf Coast, with 2.4 million bbl/d of capacity in the Texas City/Houston area and another 1.1 million bbl/d of capacity in the Beaumont/Port Arthur area. Farther to the east but accessible by water are refining centers located at Lake Charles, La., and along the Lower Mississippi River in Louisiana.

The long-term outlook for U.S. Gulf Coast refinery crude runs is flat to declining, in step with forecasted U.S. refined product demand. Some near-term increases in crude inputs are expected to offset refinery closures in the Northeast and the Caribbean. Other than the Motiva refinery expansion in Port Arthur, Tx., (adding 275,000 capacity bbl/d in 2013, refining primarily foreign crude), no further refinery expansions are anticipated on the U.S. Gulf Coast.

Planned Eagle Ford crude and condensate infrastructure will transport produced volumes primarily to Corpus Christi and Houston. Significant pipeline, terminal and some limited rail capacity is under development and much of the announced capacity is backed by producer commitments. Marine terminal capacity is being developed in Corpus Christi, Houston and Texas City to facilitate Eagle Ford crude and condensate deliveries to other U.S. Gulf Coast refining centers and petrochemical producers.

Eagle Ford liquids also may have access to refiners located farther to the east, with pipeline projects being promoted to originate eastbound shipments out of the Houston/Port Arthur area. Based on current Eagle Ford production forecasts, planned regional infrastructure development appears to exceed requirements.

Displacing Foreign Imports

Gulf Coast crude oil demand is met today by a combination of domestic production and foreign crude/condensate imports. The impact of the dramatic increase in production from the Eagle Ford is being felt already in local refineries, and to a lesser extent, by other U.S. Gulf Coast refiners. Eagle Ford crude/condensate production averaged 130,000 bbl/d in 2011, while imports of light crude oil into Texas declined by just under 300,000 bbl/d from 2010 to 2011.

In the Corpus Christi area (including Three Rivers), imports of light crude oil fell by 117,000 bbl/d during 2011, reflecting the availability of locally produced Eagle Ford volumes. In the future, Eagle Ford crude and condensate volumes will be distributed more widely and will compete with light crude imports to the Houston/Texas City area. Houston/Texas City refineries imported 325,000 bbl/d of light crude on average in 2011.

Medium and heavy crude imports are not expected to be impacted significantly by increases in Eagle Ford production. Medium crude imports to Texas in 2011 averaged 715,000 bbl/d. Future imports of medium crude are less likely to be displaced by Eagle Ford production without significant price downgrades for Eagle Ford producers. In the Houston/Texas City area, a large portion of the refining capacity is dedicated to upgrading lower-valued, heavy crude streams that the lighter Eagle Ford production will not displace.

Although most Gulf Coast refiners and petrochemical producers will be able to process Eagle Ford condensate production, the total volume of condensate processed by any one facility will be limited by a number of factors that are expected to impact the offered market price. Some refiners will have physical "light ends" capacity limitations, and will be unable to run significant volumes of condensate because of the higher volume of light naphtha produced.

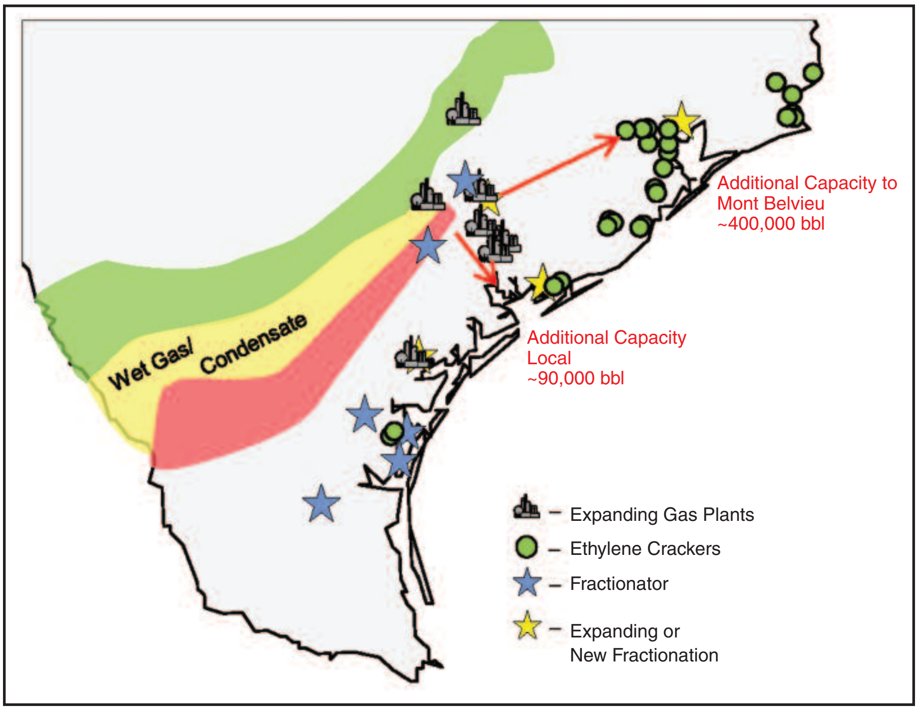
Conversely, condensate streams produce little to no heavy volume fractions (or "bottoms") to feed expensive coker units that operate in many Gulf Coast refineries to upgrade lower-value, heavy feedstock to higher-valued products. The naphtha content also will be limiting as a result of the overall decline in U.S. gasoline demand attributable to the nation's economic downturn. Naphtha also is utilized as feedstock in the petrochemical sector, but has been economically disadvantaged relative to lighter feedstock alternatives since 2008.

Such limitations on condensate demand provide economic incentives for projects such as Kinder Morgan's recently announced condensate splitter project with planned capacity of 25,000 bbl/d and possible expansion to 100,000 bbl/d. Condensate will be separated into naphtha, distillate and gas oil streams for sale into specific, higher-valued markets in the refining and petrochemicals sectors. From 2008 through October 2011, approximately 230,000 bbl/d of naphtha and gas oil was imported to meet refinery and ethylene feedstock demand in Texas. In the future, components fractionated out of Eagle Ford condensate streams will compete with foreign imports to meet market demand.

Eagle Ford condensate or naphtha derived from the condensate also may be supplied as diluent utilized in transporting heavy Canadian crude to U.S. markets. Announced infrastructure and pipeline projects being considered to link Houston/Port Arthur markets to the St. James, La., area would enable efficient transport of Eagle Ford production to meet diluent demand.

FIGURE 4

Gulf Coast Petrochemical Manufacturing, Gas Processing Plants and NGL Fractionation Facilities



Gulf Coast NGLs Market

Many world-scale petrochemical manufacturing facilities that consume light naphtha and NGLs as primary feedstock are located along the U.S. Gulf Coast. Figure 4 provides a summary of the gas processing plants, fractionation facilities and petrochemical plants located near the Eagle Ford play and along the Texas Gulf Coast. The numerous gas processing plants located in the region, in West Texas and as far north as the Rocky Mountains recover mixed streams of NGLs that are shipped to fractionation centers for separation into purity products such as propane, butane and natural gasoline.

Planned infrastructure projects terminating on the U.S. Gulf Coast also will expand the regional availability of NGLs produced in other areas, including the Bakken Shale in North Dakota as well as the Marcellus and other shale plays under development.

Ethylene is manufactured from NGL, naphtha, and gas oil. In most cases, petrochemical producers with capabilities to switch from gas oil and naphtha to lighter feedstock such as ethane have done so, and projects have been completed to convert heavy feedstock capacity to process lighter, NGL-derived feedstock.

Several additional "feedstock flexibility" projects also are under way. In Texas, NGL supply has been sufficient to meet the changing demand from ethylene producers. In the past four years, Texas imports of waterborne purity products (propane, butane and pentanes plus) from foreign sources have decreased from approximately 45,000 bbl/d in 2008 to about 2,000 bbl/d in 2009 and 2010. Through October 2011, none of these products were imported to Texas, while exports of propane and butane totaled 120,000 bbl/d.

The increased availability of domestically produced NGL has sparked a resurgence in the U.S. petrochemical industry.

In 2010, Eastman restarted idled ethylene production capacity in Longview, Tx., and Dow is expected to restart capacity in Hahnville, La., this year. Numerous ethylene expansion projects have been announced, totaling more than 2,800 million pounds a year of additional capacity (Westlake, Williams, and Formosa) that is expected to start up on the U.S. Gulf Coast between 2012 and 2015.

Chevron, Phillips and Dow have announced new grass-roots U.S. Gulf Coast facilities totaling more than 7.5 billion pounds to be completed by 2017, and Sasol is considering the construction of a world-scale cracker to be located near Lake Charles in Louisiana. Outside of the region, grass-roots projects have been announced to take advantage of new supplies of NGLs produced in rich gas regions such as the Marcellus Shale. Much of the new capacity is focused on ethane as the primary feedstock, resulting in a likely overhang in the supply of propane and heavier NGL components.

New Infrastructure Required

Significant pipeline, processing and fractionation infrastructure will be required to meet the needs of Eagle Ford producers in the future. Existing gas transportation infrastructure in South Texas is being utilized and additions are being made to ensure adequate gas gathering and transportation capacity will be available to support gas processing operations. In some cases, dry gas transportation systems have been converted to wet gas service and are being repurposed to meet gas gathering needs.

Increased NGL production will come from new or expanded gas processing capacity. Announced projects are expected to add 1.7 billion cubic feet a day of new capacity for Eagle Ford producers in 2012 and another 2.0 Bcf/d in 2013 (Copano, Enterprise, Southcross, DCP, Boardwalk and ETP). The development of raw mix NGL pipeline capacity also is under way to provide processors with ready outlets for recovered liquids.

Two new long-haul pipelines (DCP, Lone Star/ETP) are being developed to transport NGLs from plants in the Permian Basin and the Eagle Ford to fractionators at Mont Belvieu, Tx. Pipeline capacity also is being developed to transport raw mix from Eagle Ford-dedicated processing plants to local fractionators. Some of the new pipeline capacity will connect with existing NGL pipeline infrastructure supplying facilities in the Mont Belvieu area and petrochemical facilities along the U.S. Gulf Coast (ETP/Copano and Enterprise). Pipeline additions and expansions are expected to provide Eagle Ford processors with 90,000 bbl/d of capacity to supply local fractionators and approximately 400,000 bbl/d of transportation capacity to Mont Belvieu.

New fractionation capacity is needed with the increase in the supply of NGL raw mix. New facilities are being constructed to process the increasing NGL volumes from the Eagle Ford and other rich gas plays in West Texas, North Texas, Oklahoma and the Rockies. A total of 72,000 bbl/d of local fractionation capacity will be added by 2013 to serve Eagle Ford producers (Copano, Southcross and Formosa).

Regionally, operators in Mont Belvieu have announced projects totaling 380,000 bbl/d to be operational by year's end 2013 (Enterprise, Gulf Coast Fractionators, Cedar Bayou, Mont Belvieu and Lone Star NGL). Capacity expansions at Mont Belvieu serve not only Eagle Ford producers, but will process raw mix NGL supplied from other regions as well.

Regional infrastructure projects also will be required to facilitate transportation and delivery of purity projects to end-use customers and petrochemical manufacturers along the Gulf Coast and in other markets. Because of the large growth in expected NGL production from the Eagle Ford and other shale plays throughout the country, several liquefied petroleum gas export terminals have been announced. Additional propane and butane export capacity of 110,000 bbl/d is expected to be operational by 2013 with the development of another 150,000 bbl/d under consideration.

The rapid expansion of production from the Eagle Ford area has sparked significant support for developing regional infrastructure to gather, treat, process and transport produced oil, condensate and natural gas. Liquids produced from the Eagle Ford play will impact market supply and demand balances in South Texas, along the Gulf Coast and the Lower Mississippi River. Ultimately, the disposition of these liquids depends on the quality relative to competing supplies, production rates over time, infrastructure availability, and demand from refiners and petrochemical producers along the Gulf Coast and in other economically accessible markets. ❒

LESA S. ADAIR

Lesa S. Adair is a vice president and director at Muse, Stancil & Co. in Addison, Tx., where she consults on technical and commercial issues in the energy industry. Adair has 25 years of experience in the energy sector, holding engineering, operations management and marketing/risk management positions prior to joining Muse. She frequently is retained to assist clients with mergers/acquisitions, project assessment/development, asset valuation, contract negotiation, market analysis, royalty valuation, damage assessment and dispute resolution. Adair holds a B.S. in chemical engineering and an M.B.A. with a concentration in finance.

SUSAN L. STARR

Susan L. Starr is a senior principal of Muse, Stancil & Co. She has 20 years of experience in the oil and gas industry, holding various positions at Conoco and ARCO before joining Muse in 1997. She has conducted extensive reviews of supply, demand and distribution of petroleum and natural gas products, with several recent projects involving Eagle Ford markets. Market studies have included competitive assessments of pipeline and terminal capacity, detailed customer analysis, and analysis of import/export opportunities. Starr holds a B.S. and an M.S. in chemical engineering and an M.B.A. with a concentration in finance.

ATTACHMENT D

Whole Lotta Splittin' Going On - Processing Gulf Coast Condensate

published by Sandy Fielden on Mon, 01/27/2014 - 20:00

Four midstream companies are building or planning condensate splitter capacity to process at least 400 Mb/d of Eagle Ford production by 2016. These facilities will join BASF/Total, who have been operating a 75 Mb/d splitter at Port Arthur since 2000. Gulf Coast refiners are also increasing their capacity to process lighter crudes. These infrastructure developments are being made in response to a flood of condensate range material coming out of the Eagle Ford into Houston and Corpus Christi. Today we detail these plans.

This blog is an excerpt from our newest RBN Drill Down report titled **Like a Box of Chocolates – The Condensate Dilemma** which examines the major developments in the world of condensates for the past few years and looks forward through 2018. The analysis begins with an overview of the condensate family, including field condensate, natural gasoline and naphtha. The remainder of the report then reviews (a) field condensate production forecast by major basin, (b) the supply/demand balance for natural gasoline, (c) Gulf Coast condensate splitter infrastructure and projects, and (d) a special spotlight on Utica condensate supply and infrastructure development. More information on this report is available here. Drill Down reports are part of the RBN Backstage Pass premium services package.

Today we are continuing our recent series on infrastructure being developed to process and transport increasing volumes of condensate produced in the Ohio Utica. In that series we described how refiner Marathon Petroleum (MPC) plans to handle more light condensate in their refineries in Canton, OH and Catlettsburg, KY and to construct condensate splitters at both facilities that will process 60 Mb/d between them (see Whole Lotta Splittin' Going On). This time we turn our focus to similar plans to construct condensate splitters and specialized processing capacity to handle very light crude at Gulf Coast refineries and terminals.

We start with a recap on condensates – a topic that we have discussed frequently over the past two years. Condensates are light hydrocarbons containing a significant percentage of naphtha range materials. There is no universal standard for what defines a condensate, but 50 degrees API gravity is typically used to differentiate condensates from light crude oil (see Fifty Shades of Condensate Which One Did You Mean?). Lease condensate is produced at or near the wellhead, typically from stabilizer units. Plant condensates, more commonly known as natural gasolines, are part of the NGL stream from natural gas processing plants and produced from fractionation facilities as a 'purity' NGL product (a.k.a., pentanes plus or C5) - (see Like A Box of Chocolates – The Condensate Dilemma).

The challenge for US midstream and refining companies is to find markets for growing volumes of condensate materials being produced– not just in the Utica – but in many of the US shale plays, in particular in the Eagle Ford in South Texas (see The Eagle Ford Condensate Challenge) but also in the West Texas Permian Basin and in the Anadarko. We have written about the market for condensates to be used as diluent for heavy crude in Western Canada (see Fifty Shades of Eh). But that Canadian market is a long way from Texas, they generally prefer processed natural gasoline to field condensate and more heavy crude is being moved by rail on heated cars that require a lot less diluent – or none.

And it is field condensate production that is growing in Texas and headed to Gulf Coast refineries by pipeline and by boat (see Too Much Too Soon). RBN Energy expects total field condensate production from Texas to reach 900 Mb/d by the end of 2016. Trouble is Gulf coast refiners need condensate like a hole in the head. They are already getting more light sweet crude from the Bakken and the crude oil side of Eagle Ford than they can use. Their lack of respect for condensate led to $20/Bbl discounts for condensate purchases at the wellhead a few weeks back (see Knocking on Heaven's Door Part I), and condensate prices remain at least $10-12/bbl below Light Louisiana Sweet (LLs) crude oil. Which leaves a challenge for Texas producers trying to find a home for their condensate barrels – especially since they can't be exported because they fall under the terms of the US ban on crude oil exports (see Fifty Shades Lighter - The Export Problem).

So if not Canada and not exports and if refineries are already overwhelmed by too much light crude, then where can condensate find a home on the Gulf Coast? The most obvious answer is to increase the capacity to process condensate into refined products that can legally find a home in the export market even if they are not in demand domestically. As a result, refiners and midstream companies are starting to invest in that capacity and we expect that trend to continue.

There are three related but different processes that will help Gulf Coast refiners consume more condensate. The first is to simply add more stabilizers in the field, which basically flashes off lighter hydrocarbons (methane and NGLs) so that the condensate barrels can meet the shipping specifications of long-haul pipelines, trucks and rail transportation. Condensate stabilizers do not transform condensate into refined products but they do make it less volatile and easier for refineries to handle. We described how stabilizers work in our "Like a Box of Chocolates" blog series. Many smaller condensate stabilizers are already in place at or near the wellhead in the Eagle Ford. The picture below shows a 2 Mb/d stabilizer manufactured by Exterran. Larger units stabilize condensate before it is shipped on a pipeline – for example the Plains All American condensate stabilizer complex in Gardendale, TX that can currently process 80 Mb/d of Eagle Ford condensates and will be expanded to 120 Mb/d during 2014.

Source: Exterran www.exterran.com (Click to Enlarge)

A second process that increases the capacity of existing refineries to handle greater volumes of lighter crudes and condensates is to add a topping unit to the existing configuration. A topping unit is a simple atmospheric distillation unit in its own right (see Complex Refining 101 – Distillation). Such a topping unit is used to separate out crude oil fraction such as naphtha's, distillates and fuel oils that are then blended into finished products or further processed in more complex refinery units. Very light crudes and condensate can typically be separated into naphthas that become part of the gasoline blend pool and some distillates used to make diesel. Adding a topping unit gives a typical Gulf Coast refinery flexibility to process greater volumes of condensate that they would not otherwise be able to handle. That is because typical Gulf Coast refineries have more complex units to process heavier crudes and they are not configured to handle large volumes of light naphtha.

So far only Valero has announced plans to add topping units to their Gulf Coast refineries. They plan to add a 70 Mb/d topping unit to their Corpus Christi refinery by 3Q 2015 as well as a 90 Mb/d unit to their Houston refinery. Valero also plans to expand light crude processing at their Port Arthur refinery by 15 Mb/d by the end of this year. Other refiners have announced upgrades to their configurations that will allow them to process additional lighter crude volumes. In December 2012 Flint Hills Resources (FHR – part of Koch Industries) applied for permits to revamp the 70 Mb/d West Refinery part of their 300 Mb/d refining complex in Corpus Christi to process lighter Eagle Ford crude. Phillips 66 announced completed upgrades at their Alliance (Belle Chase, LA) and Sweeny (Old Ocean, TX) refineries to facilitate an undisclosed increase in light crude processing – by reconfiguring existing capacity – at their 3Q 2013 Earnings conference call.

All of which brings us to condensate splitters – the third way to process condensate. Arguably a condensate splitter and a refinery-topping unit are one and the same except that the latter are part and parcel of a larger refinery that produces finished refined products and splitters are typically stand-alone units, operated separately, that only make intermediate, semi-finished products like naphthas and distillates. Also a topping unit can generally handle regular crude streams whereas a splitter is generally only used to process condensate. As with all things condensate, there is a certain amount of confusion about definitions and we have to rely on the operator to tell us whether they are splitting or topping. The picture below shows a 225 Mb/d condensate splitter in Saudi Arabia.

Source: Al Arabiya News (Click to Enlarge)

At any rate there are now at least four condensate splitting facilities under construction or on the drawing board to be built across the Gulf Coast. Only one is up and running today and has been operating since 2000. That is the **75 Mb/d 60/40 BASF/Total** jointly owned condensate splitter at **Port Arthur, TX** that is connected to the nearby Total refinery. The BASF/Total splitter processes light crude and condensate, mostly delivered by barge and pipeline from the Eagle Ford.

ATTACHMENT E

APPENDIX

Month	**Enbridge North Dakota Deliveries in Barrels Per Day to Berthold Rail**	**Enbridge North Dakota Deliveries in Barrels Per Day to Clearbrook**
January 2012		204,067
February 2012		206,403
March 2012		194,877
April 2012		203,535
May 2012		208,996
June 2012		209,481
July 2012		187,435
August 2012		200,038
September 2012		177,341
October 2012		186,594
November 2012		148,132
December 2012		123,064
January 2013		93,198
February 2013		96,038
March 2013	14,008	96,416
April 2013	21,351	70,083
May 13	31,530	108,725
June 2013	34,183	123,036
July 2013	28,850	126,036

ATTACHMENT F

EnWest Rob Garner

From: epndshipperservices@enbridge.com
Sent: Thursday, June 27, 2013 8:52 AM
Subject: July 2013 Call for Crude

Follow Up Flag: Follow up
Flag Status: Flagged

Categories: Red Category

ENBRIDGE om2sis

EPND has space available for Clearbrook Deliveries in July 2013. There is 18,400 bpd available for Clearbrook deliveries, with 11,400 bpd available from upstream of Berthold, 5,700 bpd available at Sherwood and 1300 available at Newburg.

The new Tariff rules are in place for this call for crude. They are outlined in FERC No. 71.15.0 Section 40 (e). Interested parties that currently have a prepayment or letter of credit as financial assurance may need to increase their amounts as the call for crude minimum batch is 10,000 barrels or 323 bpd. Please forward the volume you are interested in to epndshipperservices@enbridge.com before 12:00 pm CDT June 28th, 2013.

If you have any questions please let us know.
Thank you.

Per Testimony
46,085 avail

EnWest Rob Garner

From: epndshipperservices@enbridge.com
Sent: Tuesday, October 15, 2013 4:42 PM
To: Undisclosed recipients:
Subject: EPND November Allocations

ENBRIDGE om2sis

Shippers,

EPND is in apportionment from East Fork to Ramberg for November 2013. All other line segments are not in apportionment. Shippers who nominated will not receive a November 2013 binding nomination. EPND will work with shippers and operators to provide transportation service as nominated.

If there is interest in revising a current November nomination or submitting an original November nomination, please do so through the OM2 site https://om2.cnpl.enbridge.com/omm/controller.

Thank you,

Shipper Services

EnWest Rob Garner

From: epndshipperservices@enbridge.com
Sent: Wednesday, October 23, 2013 7:18 AM
To: Undisclosed recipients:
Subject: EPND Space Available

ENBRIDGE om2sis

Customers,

EPND has unrestricted space available in the system for November to the following delivery points:

Clearbrook
Bakken Pipeline
Berthold Rail
Stanley

Space will be available on a first come first serve basis.

Thank you,

EPND Shipper Services

EnWest Rob Garner

From: epndshipperservices@enbridge.com
Sent: Monday, November 18, 2013 2:46 PM
To: Undisclosed recipients:
Subject: EPND December Allocations

ENBRIDGE om2sis

Shippers,

EPND is in apportionment from East Fork to Ramberg for December 2013. All other line segments are not in apportionment. Shippers who nominated will not receive a December 2013 binding nomination. EPND will work with shippers and operators to provide transportation service as nominated.

If there is interest in revising a current December nomination or submitting an original December nomination, please do so through the OM2 site https://om2.cnpl.enbridge.com/omm/controller.

Thank you,

Shipper Services

EnWest Rob Garner

From: epndshipperservices@enbridge.com
Sent: Tuesday, December 17, 2013 7:24 AM
To: Undisclosed recipients:
Subject: January 2014 Allocations

ENBRIDGE om2sis

Shippers,

EPND is in apportionment at Alexander receipts, from East Fork to Ramberg and for deliveries to Tesoro at Ramberg for January 2014. All other line segments are not in apportionment. Shippers who did not nominate to Tesoro at Ramberg will not receive a January 2014 binding allocation. EPND will work with shippers and operators to provide transportation service as nominated.

If there is interest in revising a current January nomination or submitting an original January nomination, please do so through the OM2 site https://om2.cnpl.enbridge.com/omm/controller.

Thank you,

Shipper Services

EnWest Rob Garner

From: epndshipperservices@enbridge.com
Sent: Tuesday, February 11, 2014 10:24 AM
To: Undisclosed recipients:
Subject: February Call for Crude

ENBRIDGE om2sis

North Dakota Pipeline Company has space available for Clearbrook Deliveries in February 2014. There is 1,450 bpd available for Clearbrook deliveries.

The new Tariff rules are in place for this call for crude. They are outlined in FERC No. 2.0.0 Section 40 (e). Interested parties that currently have a prepayment or letter of credit as financial assurance may need to increase their amounts as the call for crude minimum batch is 10,000 barrels or 357 bpd. Please forward the volume you are interested in to epndshipperservices@enbridge.com before 12:00 pm CST February 12th, 2014.

Any additional volumes allocated will be added to shipper's binding allocation.

If you have any questions please let us know.
Thank you.

EnWest Rob Garner

From: epndshipperservices@enbridge.com
Sent: Thursday, March 06, 2014 7:13 AM
To: Undisclosed recipients:
Subject: March Call for Crude

ENBRIDGE om2sis

North Dakota Pipeline Company has space available for Clearbrook Deliveries in March 2014. There is 3,000 bpd available for Clearbrook deliveries.

The new Tariff rules are in place for this call for crude. They are outlined in FERC No. 2.1.0 Section 40 (e). Interested parties that currently have a prepayment or letter of credit as financial assurance may need to increase their amounts as the call for crude minimum batch is 10,000 barrels or 323 bpd. Please forward the volume you are interested in to epndshipperservices@enbridge.com before 8:00 am CST March 7th, 2014.

Any additional volumes allocated will be added to shipper's binding allocation.

If you have any questions please let us know.
Thank you.

EnWest Rob Garner

From: epndshipperservices@enbridge.com
Sent: Tuesday, March 18, 2014 11:43 AM
To: Undisclosed recipients:
Subject: March 2014 Call for Crude

North Dakota Pipeline Company has space available for Clearbrook Deliveries in March 2014, as a result of capacity recovery as we are advancing our integrity management program. There is 10,000 bpd available for Clearbrook deliveries.

The new Tariff rules are in place for this call for crude. They are outlined in FERC No. 2.1.0 Section 40 (e). Interested parties that currently have a prepayment or letter of credit as financial assurance may need to increase their amounts as the call for crude minimum batch is 10,000 barrels or 323 bpd. Please forward the volume you are interested in to epndshipperservices@enbridge.com before 12:00 pm CST March 19th, 2014.

Any additional volumes allocated will be added to shipper's binding allocation.

If you have any questions please let us know.

Thank you.