AFFIDAVIT OF

JUSTIN AMOAH

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATION COMMISSION**

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

AFFIDAVIT OF JUSTIN AMOAH

Being duly sworn, the undersigned Justin Amoah hereby states as follows:

1. My name is Justin Amoah, and I serve as a Crude Oil Trader for St. Paul Park Refining Company LLC ("SPPRC"). My business address is 770 S. Post Oak Lane, Suite 270, Houston, TX 77056. I am submitting this affidavit in support of the protest of SPPRC in the above-captioned proceeding.

2. I have been asked by SPPRC to review and evaluate the petition for declaratory order ("Petition") filed by North Dakota Pipeline Company LLC ("NDP") with the Federal Energy Regulatory Commission on February 12, 2014, and the supporting study by Muse Stancil & Co. ("Muse") entitled "Market Prospects and Benefits Analysis for the Sandpiper Project" dated February 2014 ("Muse study").

3. The Muse study is a highly questionable attempt to overcome the simple fact that there is and will continue to be more than adequate takeaway capacity serving the Williston Basin for the foreseeable future. Attached as Exhibit A is a detailed table that shows that there will be more than 2.25 million bpd of takeaway capacity in place by the end of 2015, prior to Sandpiper's proposed start in the first quarter of 2016. The Muse study itself adopts a production forecast indicating that Williston Basin production

will peak at approximately 1.4 million bpd in the 2025-27 timeframe, after which it will begin to decline. Muse study at 25. Thus, there will continue to be sufficient takeaway capacity to handle all of the current and future Bakken production through the 2035 period, leaving no logistical need for the Sandpiper Project.

4. In attempting to dismiss the excess capacity serving the Williston Basin, the Muse study relies on a highly speculative prediction that shippers will shift away from rail transportation to Sandpiper. Muse study at 6-7. The Muse study ignores the fact that substantial producers, marketers, and refiners have made large financial commitments to ship production by rail from Montana and North Dakota, including investments by Statoil and Hess, which rank among the largest producers in the region. *See* "Statoil Using Rails to Ease Bottleneck," Wall Street Journal, August 29, 2012; "Hess Credit Suisse Presentation," February 11, 2014. An affiliate of NDP has also invested in a rail 80,000 bpd facility at Berthold that allows crude volumes to reach premium markets. *See St. Paul Park Refining Co. LLC v. Enbridge Pipelines (North Dakota) LLC*, Docket No. OR13-28-000, "Affidavit of Robert Steede In Support of Motion to Dismiss and Answer of Enbridge Pipelines (North Dakota) LLC In Response to Complaint of St. Paul Park Refining Co. LLC" at P 10 (August 14, 2013). The Muse study essentially assumes that these shippers, and others which have made equally large financial commitments, would abandon their investments in rail in favor of using Sandpiper, an assumption which has no basis in fact. In this regard, it is highly unlikely that shippers with significant investments in rail have made volume commitments to Sandpiper by executing Transportation Services Agreements.

5. The Muse study contends that Sandpiper would allow shippers to reach "premium markets" for light sweet crude oil. Muse study at 11. However, markets for light sweet crude oil are already accessible by rail at Cushing, Oklahoma, the East Coast, the West Coast, and the Gulf Coast. The crude oil markets in those regions are all currently priced at a premium relative to the upper mid-continent market, where Sandpiper will terminate.

6. For example, producers, marketers, and refiners operating in the Williston Basin have confirmed that rail transportation gives them the ability to move Bakken crude oil out of the once-constrained Williston region to markets offering premium prices. *See* "Bakken crude prices rise as railroad reach grows" Wall Street Journal, October 4, 2012.

7. Furthermore, the Muse study admittedly does not consider nor analyze costs that are fundamental in evaluating the Sandpiper Project. Those costs include "physical loss allowances, miscellaneous pump-over fees at pipeline interconnections, terminal storage costs, and working capital costs." Muse study at 31. By excluding such costs—which are not equivalent across separate transportation systems—the Muse study does not accurately portray the economics of the Sandpiper Project relative to other projects.

8. Finally, the Muse study uses estimates for rail freight rates that may not be accurate. Many rail shippers have been provided with private freight rates by railroads that are well below the estimated rail costs used in the Muse study. Some rail shippers

also have their own loading and unloading facilities and therefore do not pay the loading and unloading fees used in the Muse study.

9. On the subject of prorationing, NDP's claim that demand for space on its system has consistently outstripped available capacity is not supported by the facts. Petition at 12. Since September 2012, temporary integrity maintenance work has been primarily responsible for any necessary prorationing. By the end of the third quarter of 2014, the full nameplate capacity of 210,000 bpd should be available. Even with the temporary reduction in available capacity, prorationing in 2013 was intermittent, not sustained. Exhibit B shows the available capacity and actual throughput on the NDP system from May 2012 through March 2014.

10. Moreover, the Bakken Portal Expansion Pipeline ("BPEP"), which is owned by an affiliate of NDP, has been severely underutilized since its inception in March 2013. BPEP transported less than 4,500 bpd between March 2013 and January 2014, which is less than three percent of its 145,000 bpd capacity. In reporting its operating results, BPEP stated that its capacity "was not well utilized in 2013." *See* Enbridge Income Fund Holdings Inc., "Management's Discussion and Analysis, December 31, 2013. Exhibit C shows the nameplate capacity and actual throughput on the BPEP system from March 2013 through December 2013.

Justin Amoah

March 14, 2014

VERIFICATION

State of Texas

County of Harris

Before me Donna Arnold, a notary public, on this day personally appeared Justin Amoah, known to be as the person whose name is subscribed to the foregoing Affidavit, and stated to me that the facts contained in said Affidavit are true and correct to the best of his knowledge and belief.

Given under my hand and seal this 14 day of March, 2014.

NOTARY PUBLIC STATE OF TEXAS
DONNA ARNOLD
My Commission Expires
October 7, 2015

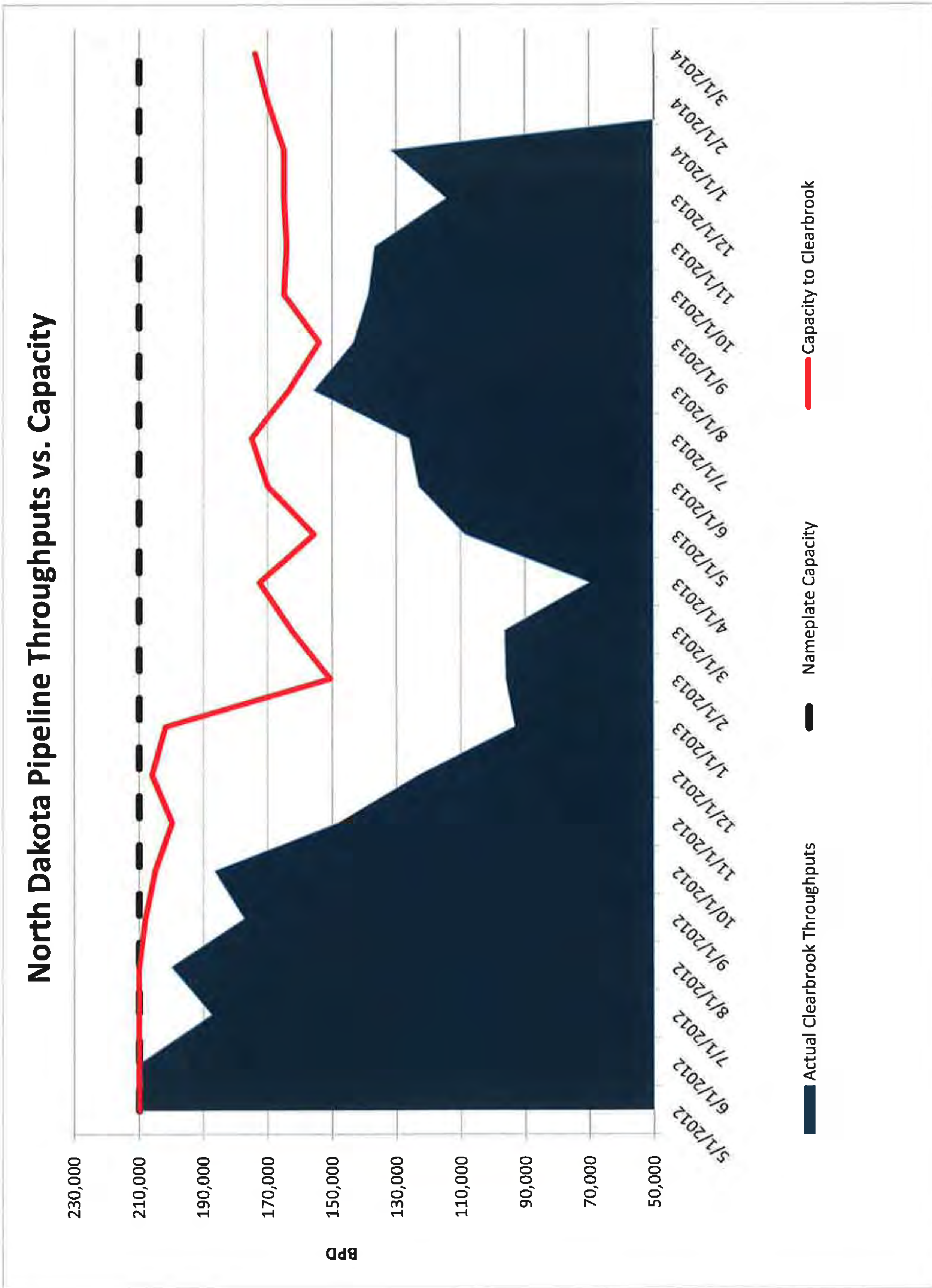
Donna Arnold
Notary Public

My commission expires: 10/7/15

EXHIBIT A

North Dakota & Montana Takeaway Capacity At Year End 2015 (Prior to the Proposed Sandpiper Expansion)		
Facility / Pipeline	**Location**	**Capacity (BPD)**
EOG Rail	Stanley, ND	65,000
Hess Rail	Tioga, ND	60,000
Dakota Plains / World Fuel Services Rail	New Town, ND	80,000
Crestwood Colt Rail	Epping, ND	120,000
Bakken Oil Express Rail	Dickinson, ND	200,000
Savage Rail	Trenton, ND	90,000
Enbridge Berthold Rail	Berthold, ND	80,000
Musket Rail	Dore, ND	60,000
Plains Manitou Rail	Ross, ND	65,000
Plains Van Hook Rail	Van Hook, ND	65,000
Basin Transload / Global Partners Stampede Rail	Columbus, ND	100,000
Basin Transload / Global Partners Beulah Rail	Beulah, ND	60,000
Red River Supply Rail	Williston, ND	10,000
Enserco Rail	Gascoyne, ND	10,000
Northstar Transloading	East Fairview, ND	180,000
North Dakota Port Services	Minot, ND	10,000
Bakken Transload	Ross, ND	10,000
Great Northern Midstream Rail	Fryburg, ND	60,000
Total Rail Takeaway Capacity		**1,325,000**
North Dakota Pipeline	Clearbrook, ND	210,000
Bakken Portal Expansion Pipeline	Cromer, SK	145,000
Pony Express Pipeline	Cushing, OK	230,000
Butte Pipeline	Guernsey, WY	150,000
Butte Loop	Guernsey, WY	50,000
Plains Bakken North Pipeline	Regina, SK	50,000
Total Pipeline Takeaway Capacity		**835,000**
Tesoro Manadan Refinery	Mandan, ND	71,000
Dakota Prairie Refining	Dickinson, ND	20,000
Total Refinery		**91,000**
TOTAL NORTH DAKOTA + MONTANA TAKEAWAY CAPACITY		**2,251,000**

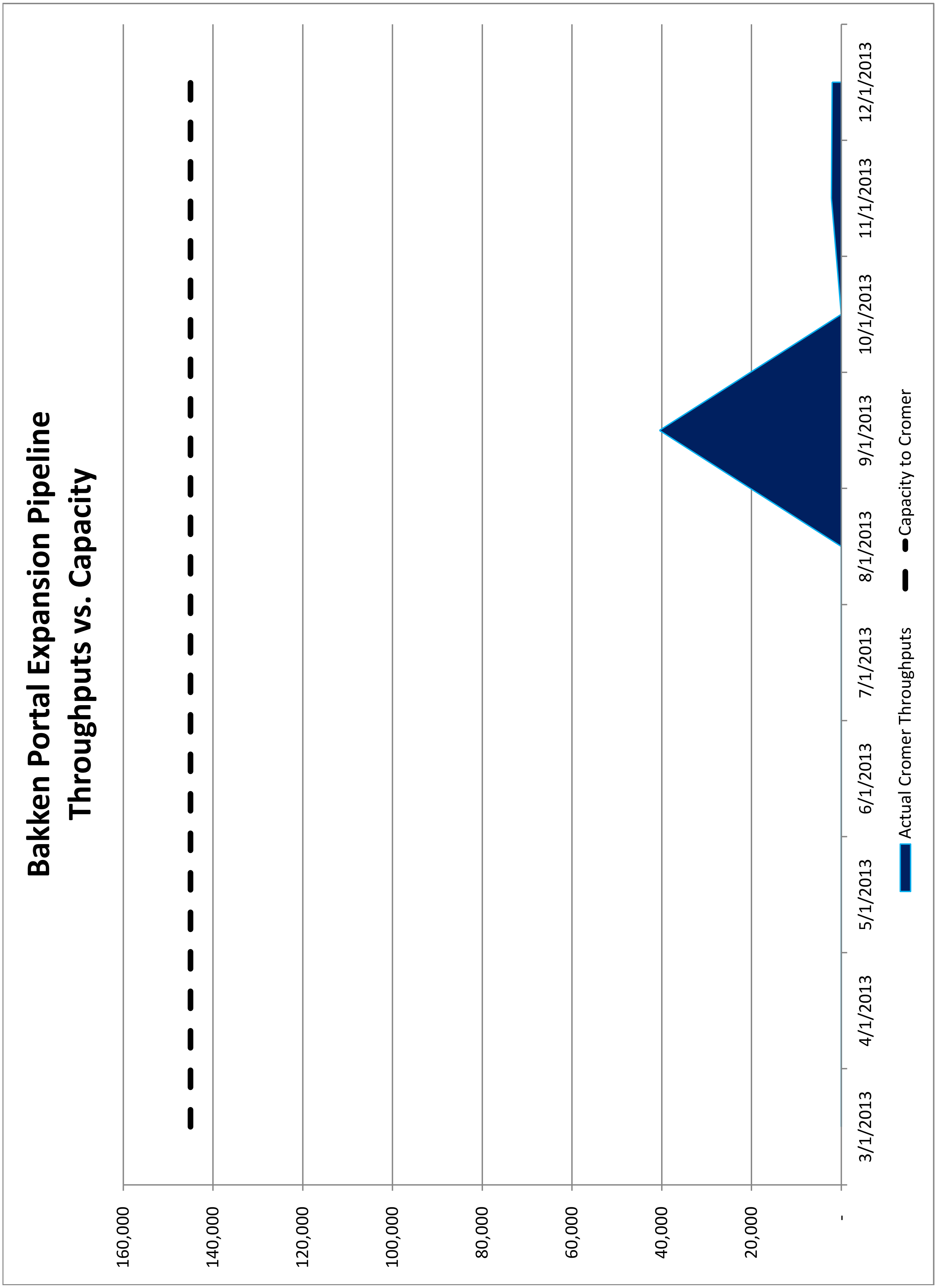
EXHIBIT B


North Dakota Pipeline Throughputs vs. Capacity
BPD
230,000
210,000
190,000
170,000
150,000
130,000
110,000
90,000
70,000
50,000
5/1/2012
6/1/2012
7/1/2012
8/1/2012
9/1/2012
10/1/2012
11/1/2012
12/1/2012
1/1/2013
2/1/2013
3/1/2013
4/1/2013
5/1/2013
6/1/2013
7/1/2013
8/1/2013
9/1/2013
10/1/2013
11/1/2013
12/1/2013
1/1/2014
2/1/2014
3/1/2014
Actual Clearbrook Throughputs
Nameplate Capacity
Capacity to Clearbrook

North Dakota Pipeline Throughputs vs. Capacity

Date	Nameplate Capacity	Capacity to Clearbrook	Actual Clearbrook Throughputs	NDP Utilization
5/1/2012	210,000	210,000	208,996	99.5%
6/1/2012	210,000	210,000	209,481	99.8%
7/1/2012	210,000	210,000	187,435	89.3%
8/1/2012	210,000	210,000	200,038	95.3%
9/1/2012	210,000	208,000	177,341	85.3%
10/1/2012	210,000	205,000	186,594	91.0%
11/1/2012	210,000	199,720	148,132	74.2%
12/1/2012	210,000	206,000	123,064	59.7%
1/1/2013	210,000	201,750	93,198	46.2%
2/1/2013	210,000	150,600	96,068	63.8%
3/1/2013	210,000	162,600	96,416	59.3%
4/1/2013	210,000	172,600	70,033	40.6%
5/1/2013	210,000	155,600	108,725	69.9%
6/1/2013	210,000	170,000	123,036	72.4%
7/1/2013	210,000	175,000	126,036	72.0%
8/1/2013	210,000	163,475	155,760	95.3%
9/1/2013	210,000	154,000	143,303	93.1%
10/1/2013	210,000	165,000	138,698	84.1%
11/1/2013	210,000	164,100	136,656	83.3%
12/1/2013	210,000	165,000	114,322	69.3%
1/1/2014	210,000	165,000	131,772	79.9%
2/1/2014	210,000	170,000	N/A	N/A
3/1/2014	210,000	174,000	N/A	N/A
4/1/2014	210,000	189,000	N/A	N/A

EXHIBIT C


Bakken Portal Expansion Pipeline
Throughputs vs. Capacity
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
3/1/2013
4/1/2013
5/1/2013
6/1/2013
7/1/2013
8/1/2013
9/1/2013
10/1/2013
11/1/2013
12/1/2013
Actual Cromer Throughputs
Capacity to Cromer

Bakken Portal Expansion Pipeline Throughputs vs. Capacity			
Date	**Capacity to Cromer**	**Actual Cromer Throughputs**	**BPEP Utilization**
3/1/2013	145,000	-	0.0%
4/1/2013	145,000	-	0.0%
5/1/2013	145,000	-	0.0%
6/1/2013	145,000	-	0.0%
7/1/2013	145,000	-	0.0%
8/1/2013	145,000	-	0.0%
9/1/2013	145,000	40,514	27.9%
10/1/2013	145,000	0	0.0%
11/1/2013	145,000	2,198	1.5%
12/1/2013	145,000	2,028	1.4%
1/1/2014	145,000	-	0.0%
2/1/2014	145,000	N/A	N/A
3/1/2014	145,000	N/A	N/A
4/1/2014	145,000	N/A	N/A

CITED ARTICLES

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit ______

BUSINESS

TOP STORIES IN BUSINESS

1 of 12

Corporate Economists Are Hot Again

2 of 12

Boeing Readies Secure Smartphone

3 of 12

Big Data Comes to the Farm, Sowing Mist...

Securities Class Action: Endangered Spe...

BUSINESS

Statoil Using Rails to Ease Bottleneck

By ÁNGEL GONZÁLEZ
Updated Aug. 29, 2012 6:20 p.m. ET

HOUSTON— Statoil AS STL.OS +0.13% A said it is leasing more than 1,000 railroad cars to carry crude oil from fields in North Dakota to refiners across North America, in a bid to overcome pipeline bottlenecks that plague the booming oil-producing region.

The Norwegian oil giant's railroad effort is a new sign of how the U.S. pipeline network is having a hard time keeping pace with the oil boom triggered by hydraulic fracturing, forcing companies to come up with creative workarounds.

Nowhere is the challenge more apparent than in North Dakota, which this year unseated Alaska as the country's second-largest oil-producing state. In May the state produced 639,000 barrels per day, or about 10% of the oil produced in the U.S., up from 364,000 barrels per day in May 2011, according to the U.S. Energy Information Administration.

Beginning in early September, the trains that Statoil will have secured with long-term leases will have the capacity to move some 45,000 barrels of crude per day to refiners across North America, more than enough to cover the entirety of the company's current net production there, company spokesman Ola Morten Aanestad said. Potential destinations include refineries in the East, West and Gulf Coasts and Canada, Mr. Aanestad said.

It would take 14 or 15 days for the trains to make a round trip to Canada, the U.S. East Coast or the Gulf of Mexico, including the loading and unloading of crude, Statoil said. The company didn't disclose the party it was leasing rail cars from or the price it would pay.

The railroad effort would help Statoil get a better price for oil produced in the Bakken and Three Forks oil-shale formations in North Dakota, which currently trades at discounts ranging between $5 and $20 per barrel because of the limited capacity to transport it to refining centers elsewhere in the U.S., resulting in a supply glut. On Wednesday, oil futures in New York settled at $95.49 per barrel, down 84 cents.

Statoil became a big player in the Bakken Shale when it agreed last year to buy independent firm Brigham Exploration Co. for $4.4 billion. The Norwegian company, which also has significant investments in south Texas's oil-rich Eagle Ford Shale and in the natural-gas rich Marcellus Shale in the Northeast, is seeking to establish itself as a major producer of U.S. unconventional oil and gas.

"The rail solution supporting the Bakken business will increase the value of the oil significantly. This translates to substantial profits as production continues to grow," Torstein Hole, senior vice president for Statoil's U.S. onshore activities, said in a statement.

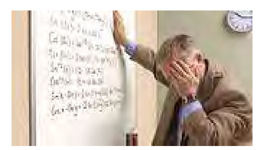
Statoil is not the first energy company to see railroads as an outlet to its fast-rising production in the Bakken region. In June, more than 325,000 barrels a day of North

Popular Now What's This?

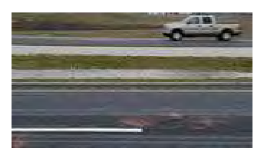
ARTICLES

1 Help! I'm on a Conference Call

2 Opinion: Best of the Web Today: Our Overregulated Government



3 Road Upgrades Get Bipartisan Push



4 Job Hunt? Dig Up Those SAT Scores

5 Opinion: Dave Camp: How to Fix Our Appalling Tax Code

VIDEO

1 James Murphy's Subway Sounds

Page 69 of 385

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit ______

Dakota crude were estimated to be shipped by rail, more than double the amount seen at the end of last year, according to the state's Pipeline Authority.

Refiner Phillips 66 PSX -0.99% has bought 2,000 cars to bring crude from the U.S. interior to its refineries all over the country. Tesoro Corp. also plans to bring in Bakken crude to its Anacortes, Wash., refinery by train starting in September. Marathon Oil Corp. MRO -0.76% , an oil producer with large Bakken operations, ships about 14% of its Bakken production by rail.

Statoil, which is majority owned by the Norwegian government, says it plans to increase its North America oil-and-gas production from under 100,000 barrels of oil equivalent per day in 2011 to more than 500,000 barrels of oil equivalent per day in 2020.

—Ben Lefebvre contributed to this article.

Write to Ángel González at angel.gonzalez@dowjones.com

Email Print Save Comments Order Reprints

2 How to Revolutionize the Dreaded Conference Call

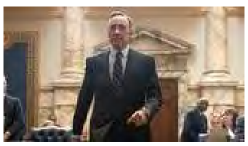
3 'Snowhow' Keeps Nordic Airports Open All Winter

4 Downton Abbey's Daisy Has a Better Life Than You

5 The State of Love and Sex in Single America

WSJ In-Depth

Ukraine Hunts Ousted Leader



Netflix to Pay Comcast for Speed

How Mexico Nabbed a Drug Kingpin

Sony Tries to Crack Smartphone Market

Jason Collins, the Nets and the 'Who Cares' Crowd

Teen's Care Spurs Wider Fight

Add a Comment

View All Comments (3)

JOURNAL COMMUNITY

Community rules

To add a comment please

Log in

Create an Account

Your real name is required for commenting.

Track replies to my comment

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

HESS CORPORATION

CREDIT SUISSE ENERGY SUMMIT

FEBRUARY 11, 2014

Forward-Looking Statements and Other Information

This presentation contains projections and other forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These projections and statements reflect the company's current views with respect to future events and financial performance.

No assurances can be given, however, that these events will occur or that these projections will be achieved, and actual results could differ materially from those projected as a result of certain risk factors. A discussion of these risk factors is included in the company's periodic reports filed with the Securities and Exchange Commission.

We use certain terms in this presentation relating to reserves other than proved, such as unproved resources. Investors are urged to consider closely the disclosure relating to proved reserves in Hess' Form 10-K, File No. 1-1204, available from Hess Corporation, 1185 Avenue of the Americas, New York, New York 10036 c/o Corporate Secretary and on our website at www.hess.com. You can also obtain this form from the SEC on the EDGAR system.

Pure Play E&P – Driving Shareholder Value

- **Focused World Class Portfolio**
  - **Visible growth in production of 5%-8% CAGR (2012 Pro Forma - 2017)**
  - **Long life assets in areas where Hess has proven capability**
  - **Five key areas represent 80% of reserves and 87% of production**
  - **Highest leverage to oil prices in peer group; industry leading cash margin**

- **Three Pronged Strategy to Drive Growth and Returns While Managing Risk**
  - ***Unconventional:*** **Strong production growth from leading U.S. shale positions**
  - ***Exploitation:*** **Lower risk development of discovered resources**
  - ***Exploration:*** **Focused exploration supports long term growth**

- **Financial Flexibility to Fund Future Growth**
  - **Reduced debt and increased cash on balance sheet**
  - **Significant reduction in capital and exploratory expenditures**
  - **Expect to be free cash flow positive post 2014**

- **Providing Current Returns to Shareholders**
  - **Increased annual dividend by 150% to $1 per share**
  - **Up to $4 billion share repurchase funded by 2013 restructuring; commenced 3Q13**
  - **Additional return of capital from sale of Utica dry gas and monetization of Bakken midstream**

Continuing commitment to capital discipline

Transformation to Pure Play E&P

What We've Promised		Key Deliverables
Focused Pure Play E&P	✓	• Divested more than 50% of E&P assets over 4 years • Built leading U.S. shale positions, e.g. Bakken & Utica • Increased production visibility and industry leading cash margins
Exit Downstream	✓	• Closed HOVENSA and Port Reading facilities • Sold Energy Marketing ($1.2 billion) • Sold Terminals ($1.75 Billion) • Remaining divestitures underway
Financial Flexibility to Fund Future Growth	✓	• E&P spend cut 24% in 2013 and 6% in 2014 • $150 million annual cost reduction underway • Reduced debt and increased cash on balance sheet
Providing Current Returns to Shareholders	✓	• Increased annual dividend by 150% to $1.00/sh • Commenced share repurchase of up to $4 billion • Additional cash returns planned from monetization of Bakken midstream

Delivering on commitments and creating value

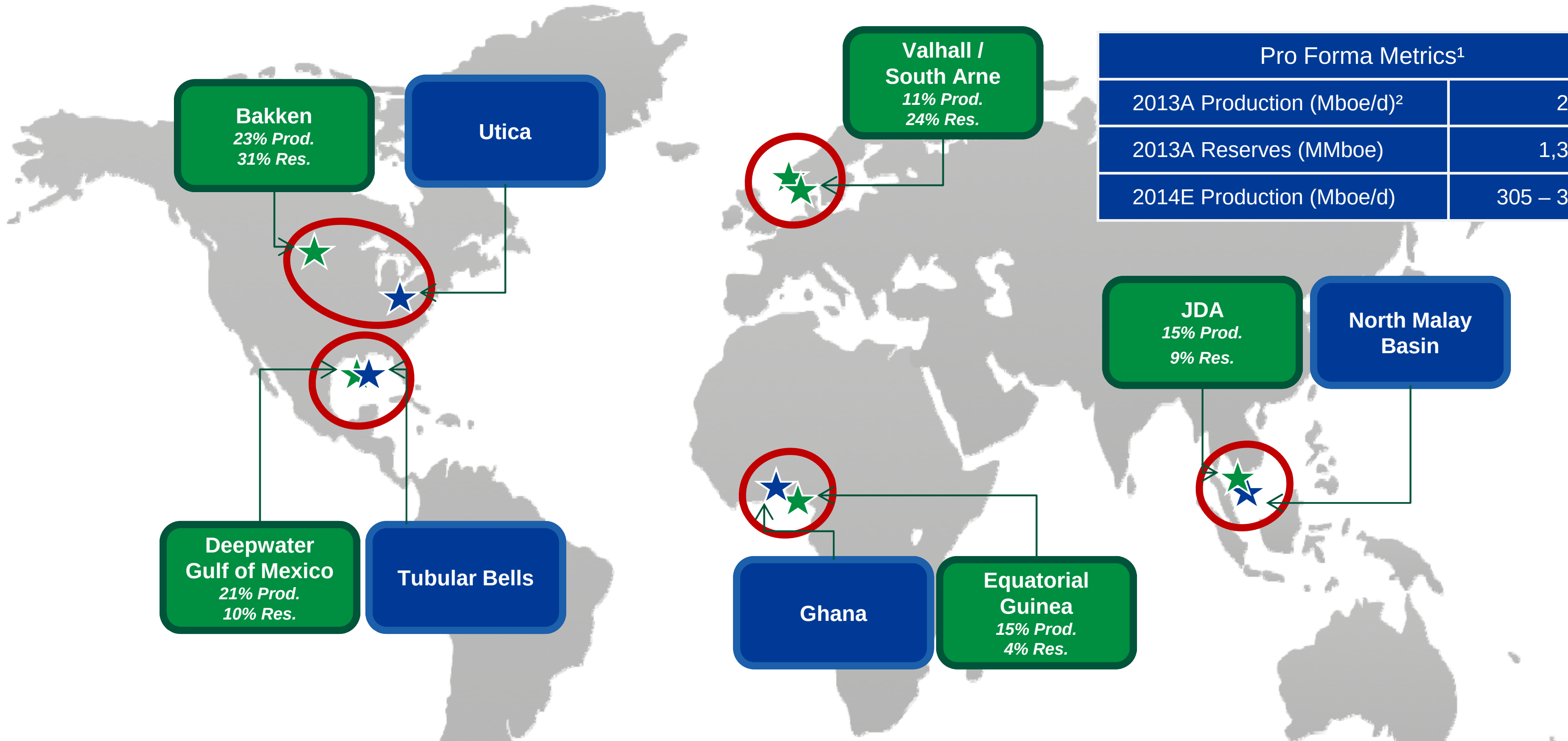
Progress on Divestitures Announced in 2013

Asset	Terms Agreed Date	Completion Date	After Tax Proceeds (in millions)
Beryl	Oct-2012	Jan-2013	$440
Azerbaijan (ACG)	Sep-2012	Mar-2013	$880
Eagle Ford	Mar-2013	May-2013	$280
Russia (Samara-Nafta)	Apr-2013	May-2013	$1,900
Energy Marketing	Jul-2013	Nov-2013	$1,200
Terminal Network	Oct-2013	Dec-2013	$1,750
Indonesia (Natuna)	Dec-2013	Dec-2013	$650
Indonesia (Pangkah)	Dec-2013	Jan-2014	$650
Thailand (Sinphuhorm + Pailin)	In Progress		-
Energy Trading (Hetco)	In Progress		-
Retail	In Progress (Form 10 filed for tax-free spin)		-
Bakken Midstream Assets	Preparing for monetization by 2015		-

Total Completed: $7.8 billion

E&P Portfolio Focused in Five Areas

Located in Areas Where Hess is Competitively Advantaged



Pro Forma Metrics[1]	
2013A Production (Mboe/d)[2]	285
2013A Reserves (MMboe)	1,362
2014E Production (Mboe/d)	305 – 315

Five Areas Represent 80% of Reserves / 87% of Production

Existing Key Assets   New Growth Assets

[1] Beryl area, Azerbaijan assets, Eagle Ford, Russia subsidiary (Samara Nafta), Indonesia and Thailand assets assumed sold as of January 1, 2013.
[2] Actual 2013 production includes Libya (15 Mboe/d); 2014 production guidance excludes Libya

Three Pronged Strategy to Drive Growth and Returns

Unconventional

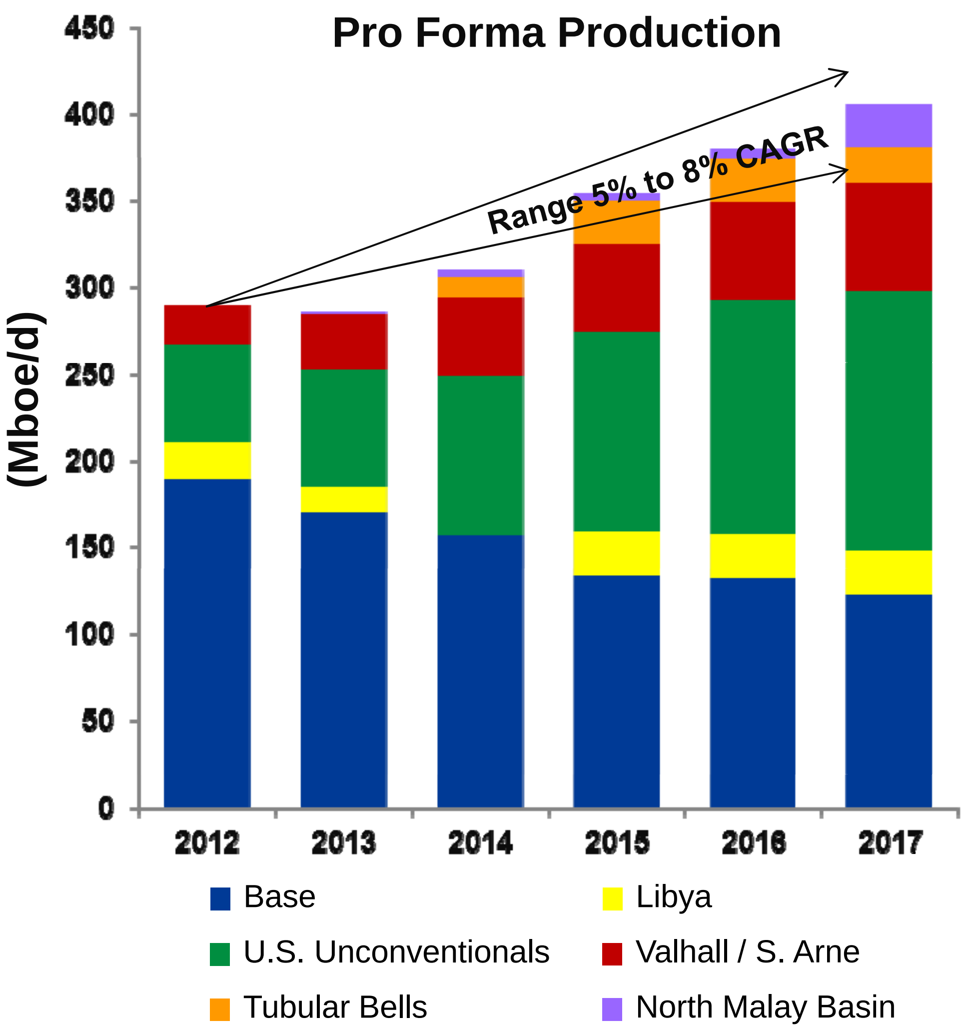
- Bakken free cash positive in 2015
- Large inventory of high return Bakken well locations – goal of 150mbd by 2018
- Leading position in emerging Utica wet gas window

Exploitation

- High return infill drilling opportunities
- Tubular Bells first oil in 3Q14
- North Malay Basin early production commenced 4Q13; full field in 2017

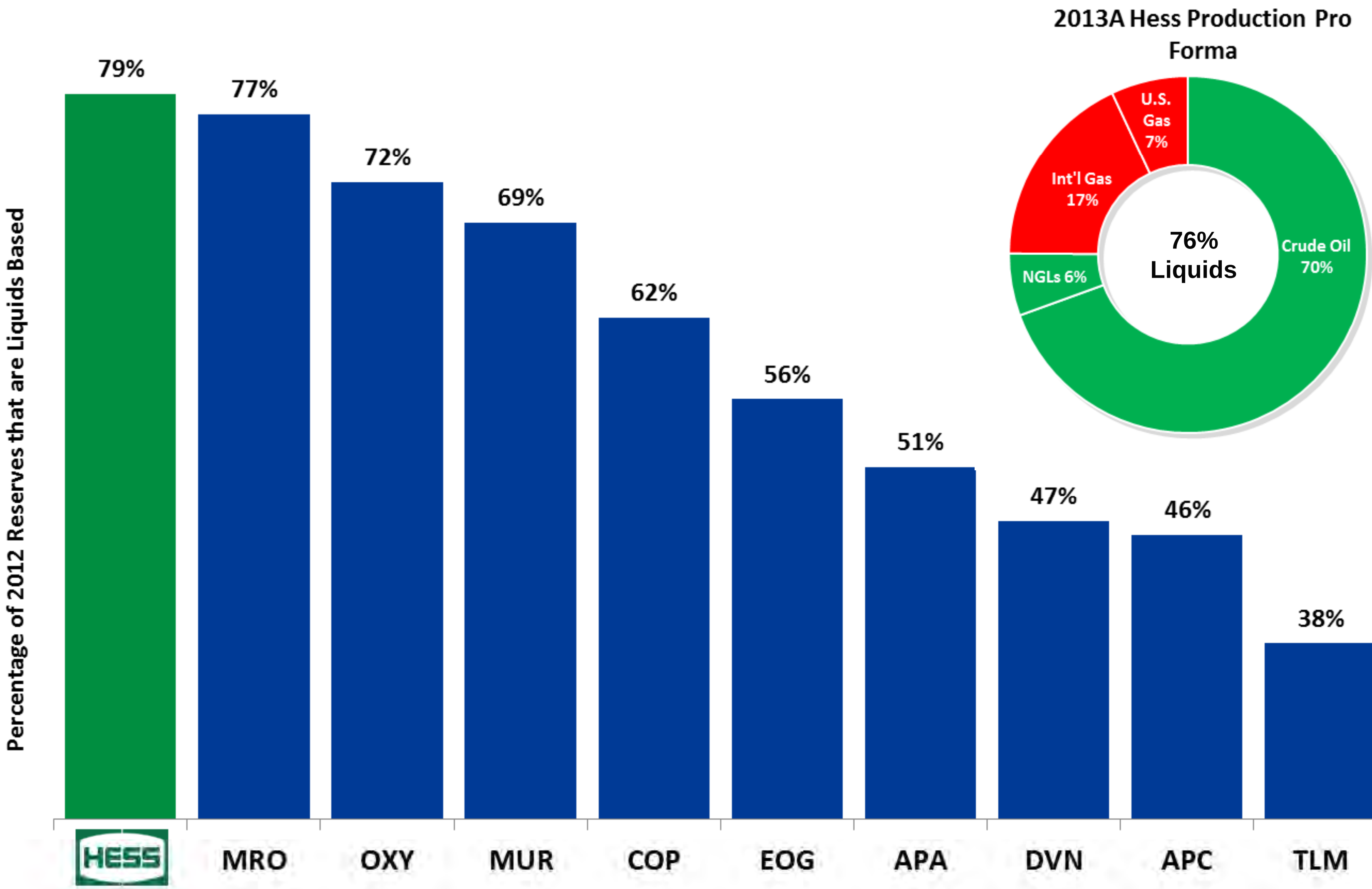
Exploration

- Reduce risk through partnering
- Geographically focused:
  - Deepwater Gulf of Mexico
  - Offshore West Africa
  - Kurdistan
  - Malaysia



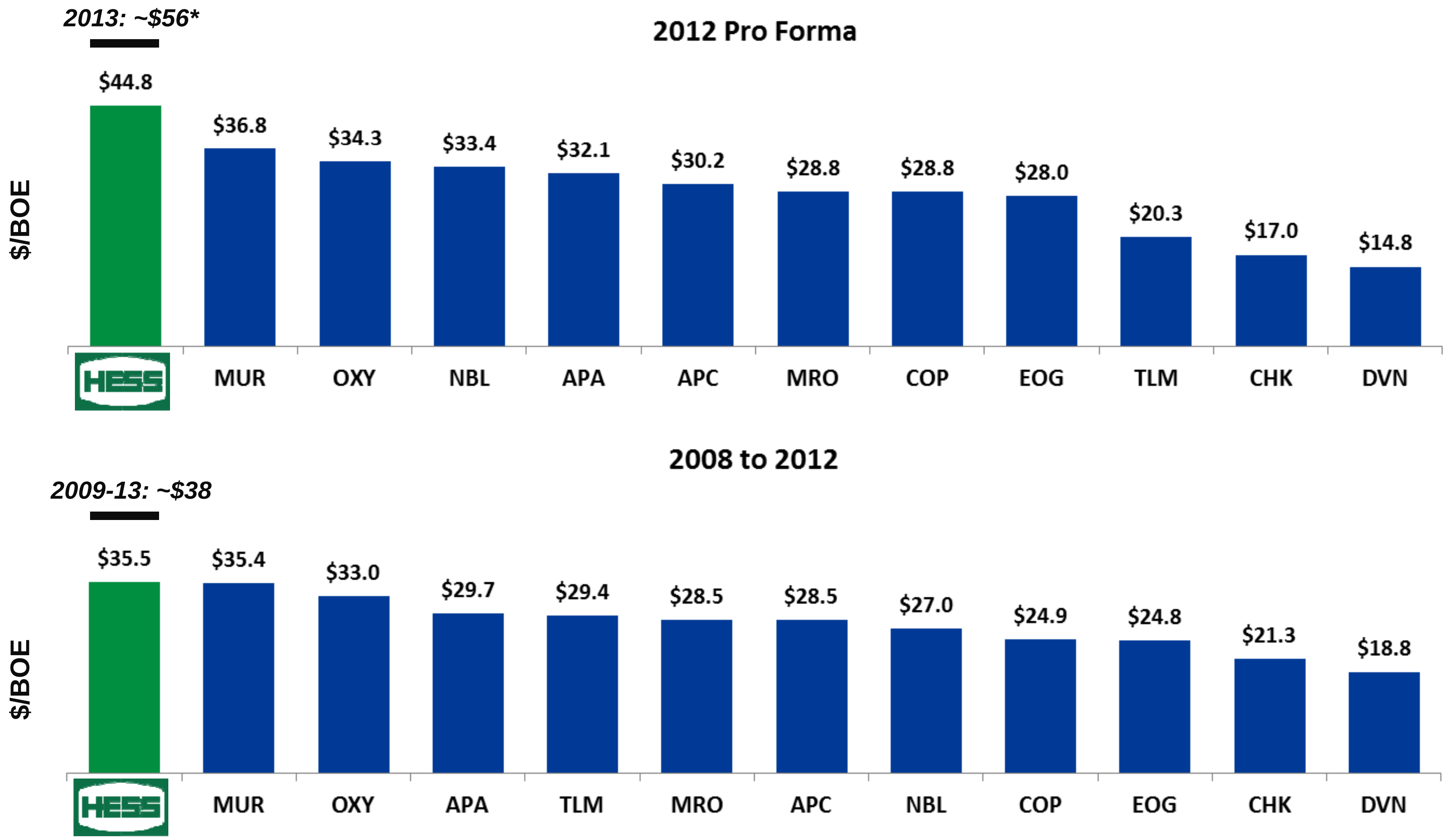
Note: 2013 actual production 336 Mboe/d. 2014 guidance is 305-315 Mboe/d.

Leading Oil-Linked Asset Base



Source: SEC filings, company annual reports, and company press releases
Note: Percentage of reserves that are liquids based for peers calculated as per 2012 year-end SEC filings; Hess pro forma

Industry Leading Cash Margin

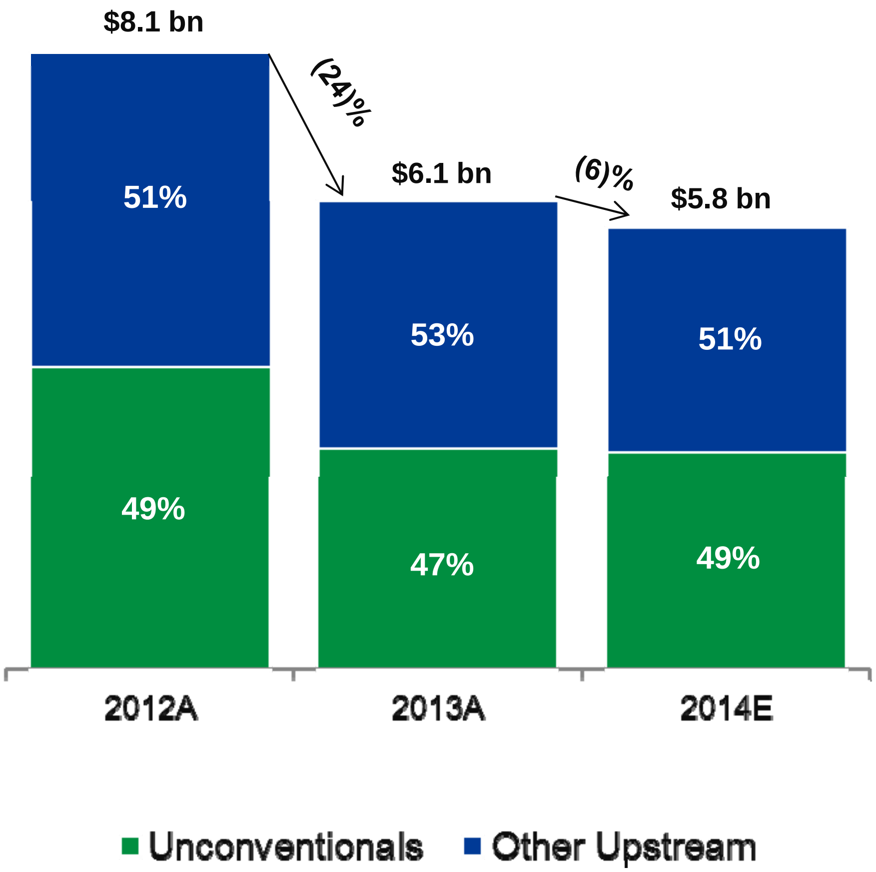


* 2013 Hess pro forma cash margin includes Libya (~$57 excluding Libya)
Note: E&P Cash Margin = E&P Net Income + DD&A + Exploration Expense
Hess 2012 cash margin is pro forma for asset sales. Actual cash margin was $40.3; Five-year data are actual
Source: Evaluate Energy, including hedges and oil sands; excluding specials

Enhanced Financial Flexibility and Providing Current Returns to Shareholders

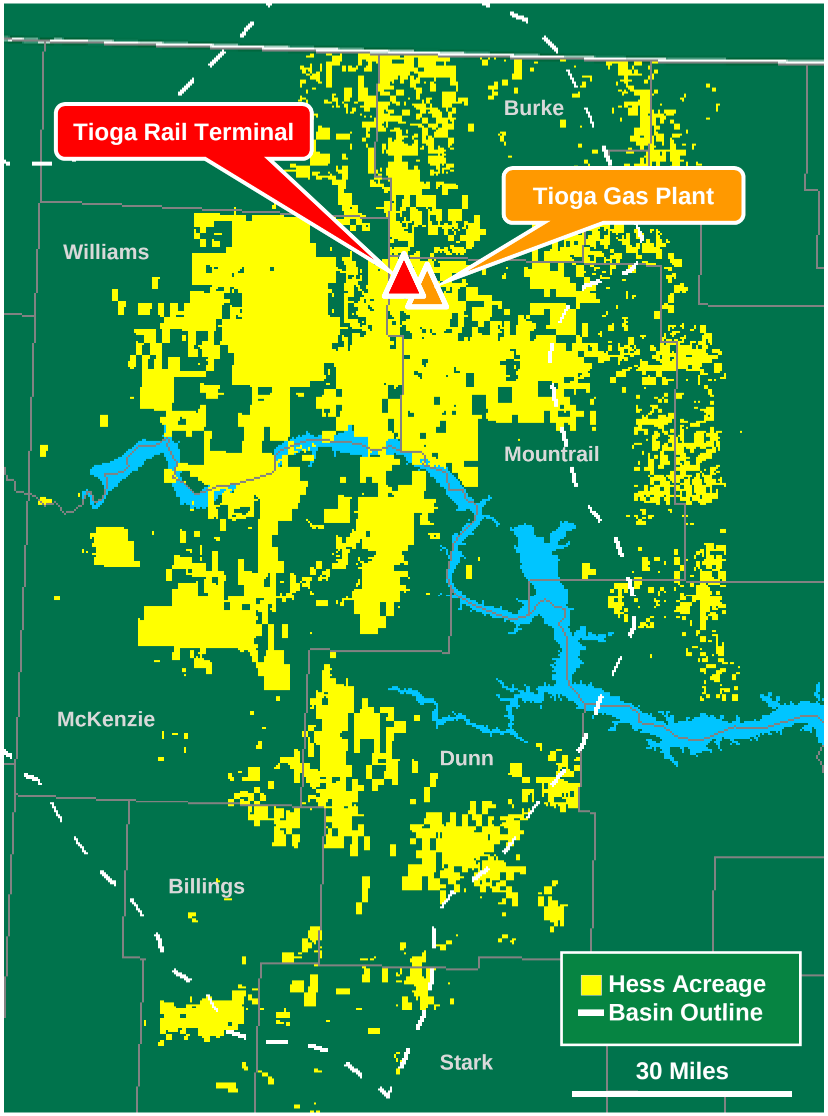
- **Financial Flexibility to Fund Future Growth**
  - Paid down $2.4 billion of short term debt with initial divestiture proceeds
  - Increasing cash balance by $1 billion
- **Portfolio Free Cash Flow Positive Post 2014**
  - Substantial reductions in capital and exploratory expenditures
  - $150 million cost reduction program underway
- **Providing Current Returns to Shareholders**
  - Annual dividend increased 150% to $1.00 per share in 3Q13
  - Authorized share repurchase program of up to $4 billion

Total Upstream Capital and Exploratory Expenditures



ASSET OVERVIEW

World Class Position in Bakken Shale



▪ Strategic / Portfolio Context

- Single biggest contributor to production growth through 2018
- Competitively advantaged; lean manufacturing and infrastructure
- Industry leading well cost and productivity
- Material upside through infill drilling in Middle Bakken and Three Forks
- Tighter infill testing program underway in 2014

▪ Asset Details

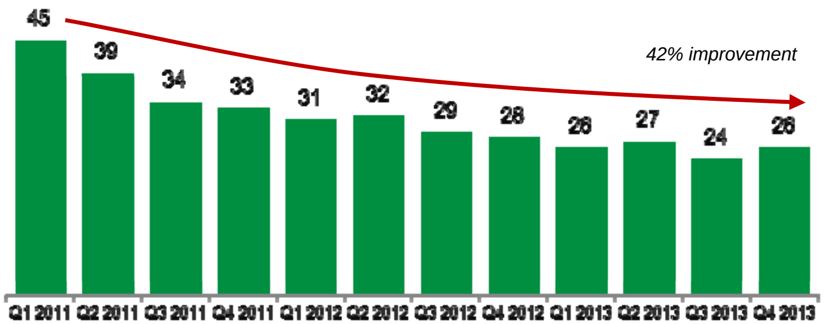
- 640,000 net acres; Hess ~70% W.I., operator
- 17 rig program in 2014; Capex of $2.2 B
- 2014 net production forecast is 80-90 Mboe/d
- Net production goal of ~125 Mboe/d in 2016
- Net production goal of ~150 Mboe/d in 2018
- >3,000 total operated drilling locations
- 2013 30 Day IPs: 750-900 boe/d
- 2013 EURs: 550,000-650,000 boe
- Estimated recoverable resource ~1.2 Bboe

HESS

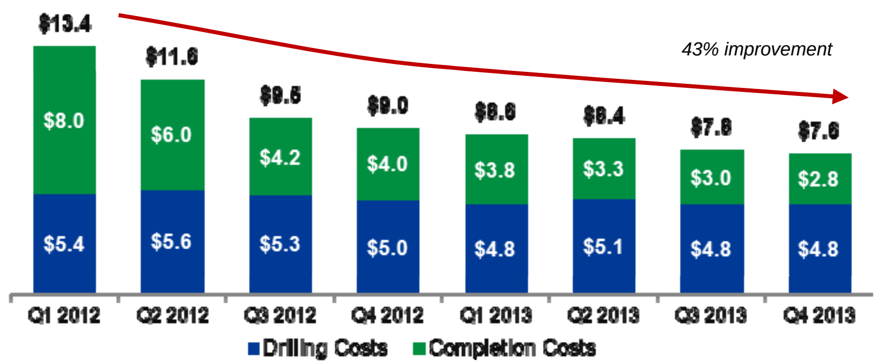
Driving Performance in the Bakken

Reducing Well Costs…

Drilling Performance: Spud-to-Spud Days

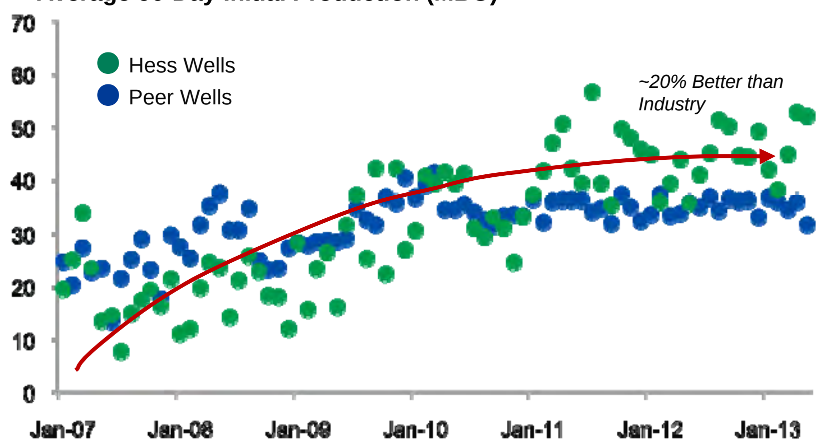


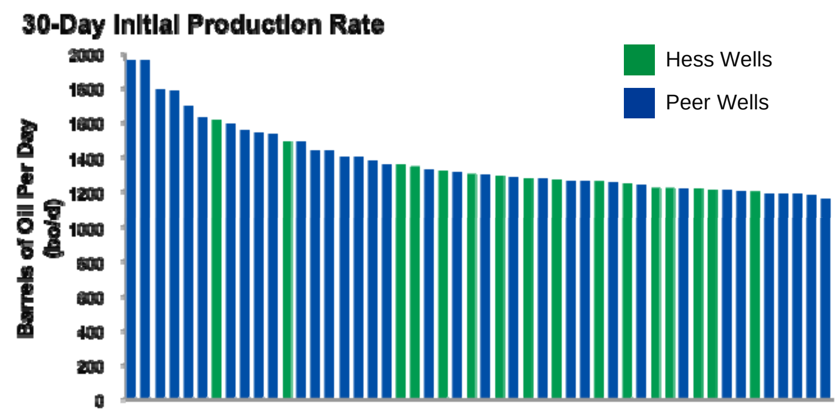
Drilling & Completion Costs ($mm)



…While Optimizing Well Productivity

Average 90-Day Initial Production (MBO)





Hess Completed 16 of the Top 50 Wells in the Bakken since 2012

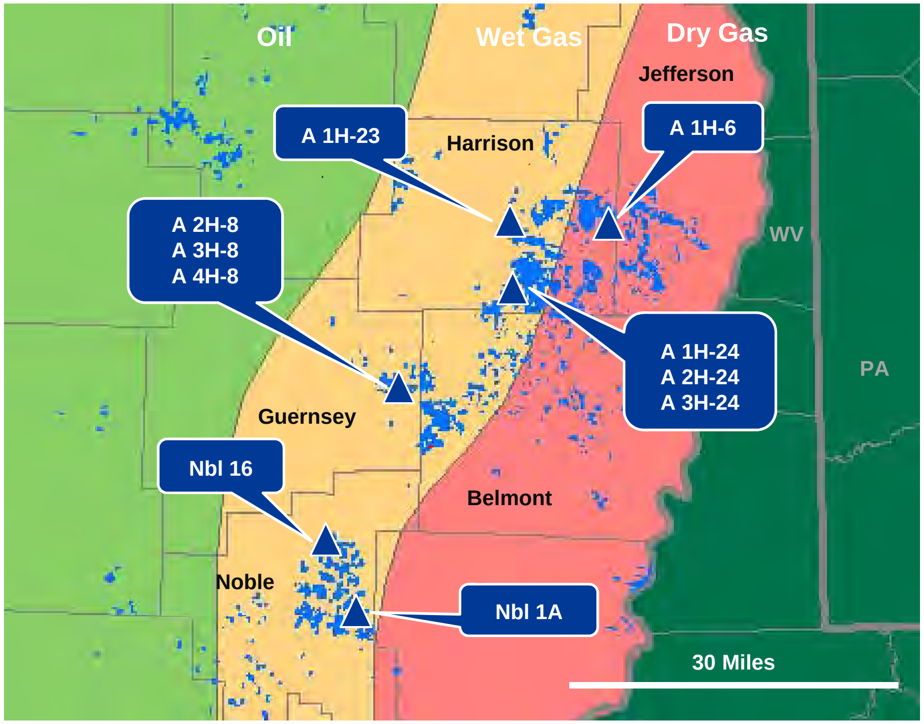
Source: NDIC Database

Significant Value Uplift From Bakken Infrastructure

- **Strategic / Portfolio Context**
  - Flexibility to access highest value markets
  - Maximize value per boe
  - Intend to monetize in 2015; maintain operating control

- **Asset Details**
  - **Tioga Rail Terminal**
    - 54 Mb/d capacity; expandable to 120 Mb/d
    - 9 crude oil train sets of 104 cars each
      - Entire fleet meets latest Petition 1577 standards
    - 240 Mbbls crude oil storage
    - 12 Mb/d NGL loading capacity
  - **Tioga Gas Plant**
    - Expansion from 110 Mmcf/d to 250 Mmcf/d
    - Increased NGL fractionation
    - Ethane sold under long-term contract
  - **Field Compression, Pipeline and Gathering Systems**

Core Position in Emerging Ohio Utica Shale Play



Well No	County	Well Test Result
Nbl 1A (Consol Op.)	Noble	1,950 boe/d, 39% Liquids
Nbl 16 (Consol Op.)	Noble	3,604 boe/d, 61% Liquids
Athens A 1H-24	Harrison	2,519 boe/d, 52% Liquids
Green A 1H-6	Harrison	1,432 boe/d, 20% Liquids
Cadiz A 1H-23	Harrison	2,251 boe/d, 57% Liquids
Athens A 2H-24	Harrison	2,489 boe/d, 48% Liquids
Athens A 3H-24	Harrison	2,111 boe/d, 49% Liquids
Oxford A 2H-8	Guernsey	1,421 boe/d, 66% Liquids
Oxford A 3H-8	Guernsey	1,211 boe/d, 65% Liquids
Oxford A 4H-8	Guernsey	1,819 boe/d, 67% Liquids

Strategic / Portfolio Context

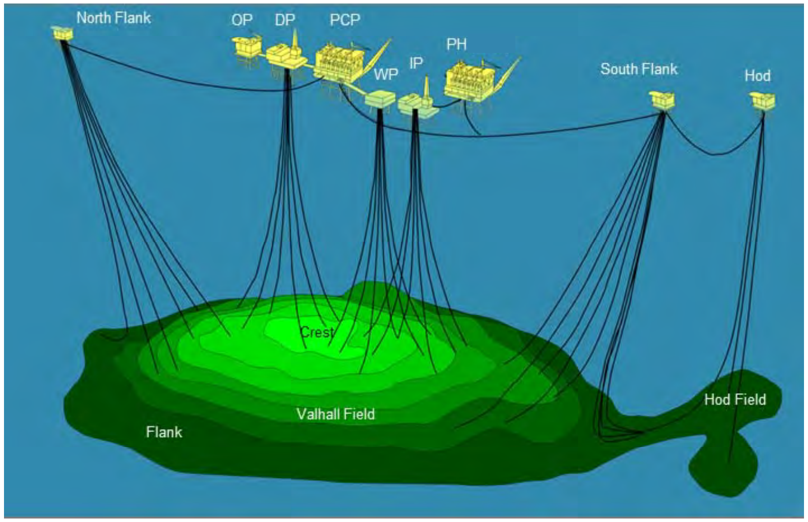
- Material position in wet gas area
- Leverages Bakken capability
- 2014 focused on appraising wet gas acreage
- Shift from appraisal to development in 2015
- Sold 74,000 acres in the dry gas area for $924 million in January 2014

Asset Details

- 50% W.I; 96% gross N.R.I.
- ~42,000 core net acres
- ~32 wells planned in wet gas area in 2014
- Overall 2014 capex of $550 million

Valhall – Multi-Year Drilling Opportunities

Valhall Complex – Norwegian North Sea

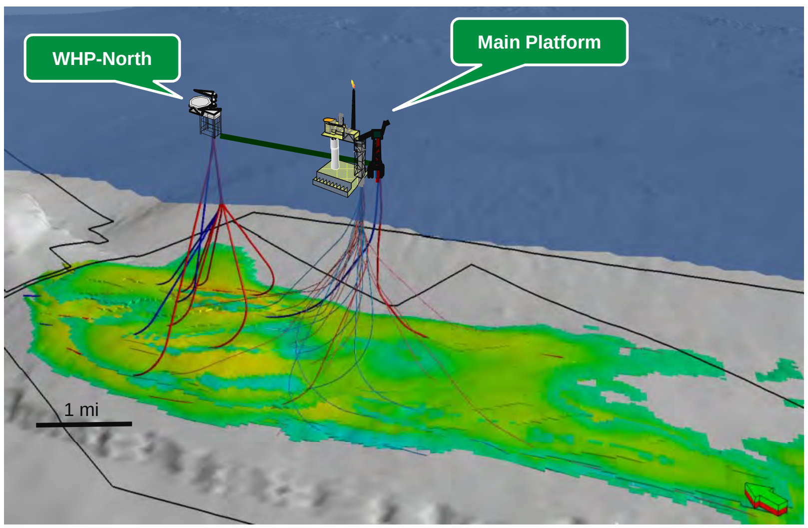


- **Strategic / Portfolio Context**
  - Long life, material asset; 3.2 Bboe originally in place (gross)
  - Key forward contributor to reserves, production and cash flow
  - Leverages chalk reservoir experience and capability

- **Asset Details**
  - Hess ~64% W.I.; BP operated
  - Field redevelopment completed 1Q13
  - Multi-year drilling program commenced in 2013
  - 2014 capex of $300 million
  - 2014 net production forecast is 30-35 Mboe/d
  - Net production goal of 40-50 Mboe/d by 2017

South Arne – High Margin with Exploitation Upside

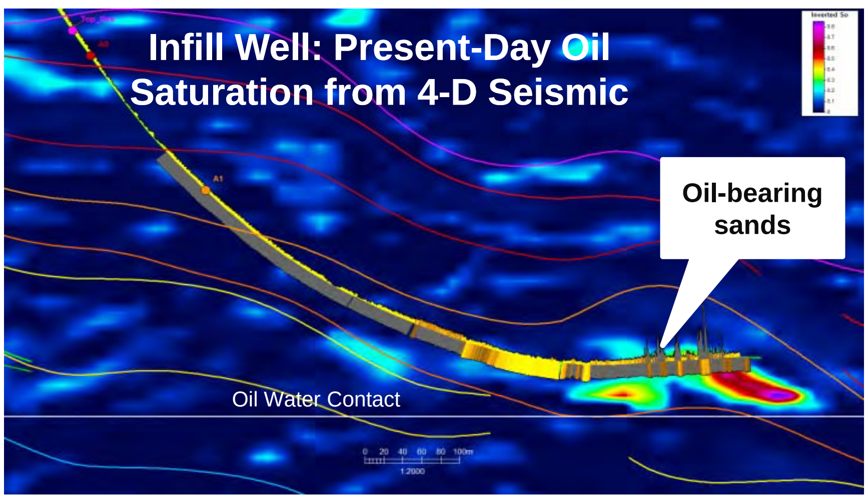

South Arne Platform - Denmark



- ## Strategic / Portfolio Context
  - High margin and free cash flow
  - Exploitation upside through infill drilling and near field tie backs
  - Leverages chalk reservoir experience and capability

- ## Asset Details
  - Hess ~61% W.I., operator
  - Multi-year drilling program commenced in 2013
  - 2014 capex of $200 million
  - 2014 net production forecast is 10-15 Mboe/d
  - Net production goal of 15-20 Mboe/d by 2017

Equatorial Guinea Block G – 4-D Seismic Unlocking Value

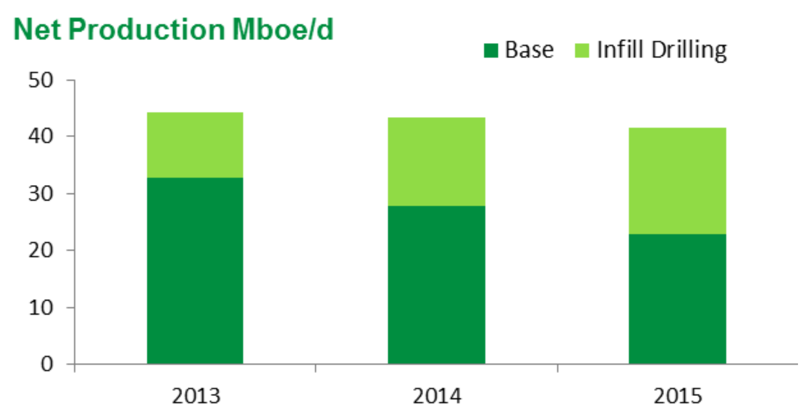


Strategic / Portfolio Context

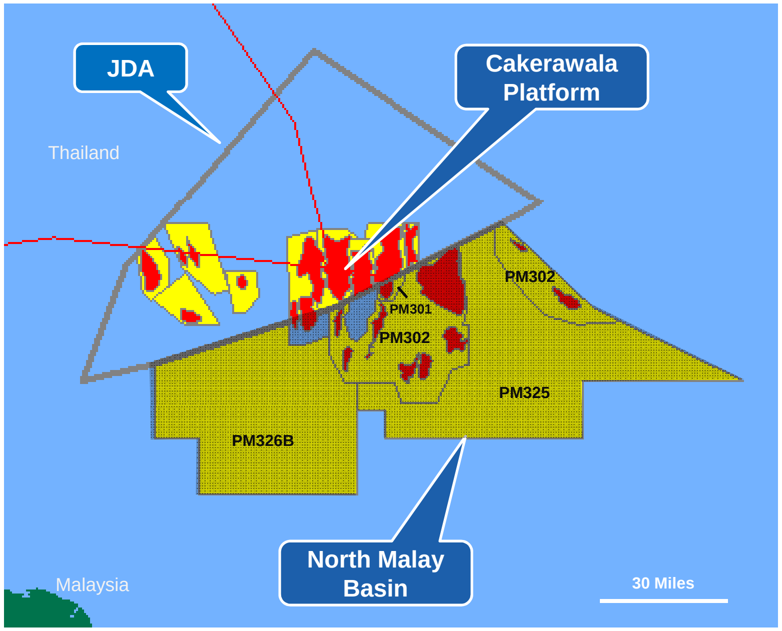
- High margin and strong cash flow
- Material contributor to production
- 4D seismic has resulted in additional high value drilling opportunities to maintain production plateau
- Leverages deep water capability

Asset Details

- Hess 81% W.I., operator
- 2014 capex of $350 million
- Net production forecast is 40-45 Mboe/d in 2013-2015



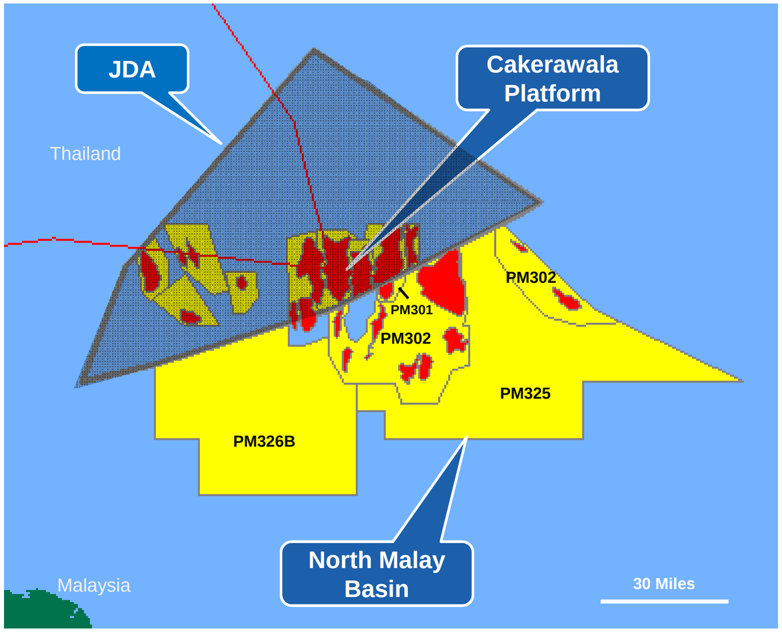
JDA – Material Production and Free Cash Flow



- **Strategic / Portfolio Context**
  - Low cost, long life gas asset
  - Material production and free cash flow
  - Exploitation upside
  - Leverages offshore development capabilities

- **Asset Details**
  - Hess 50% W.I.
  - 2014 capex of $300 million
  - 2014 net production forecast is ~250 MMcfe/d
  - Oil linked gas price
  - PSC through 2029

North Malay Basin – Low Risk Oil-Linked Gas Development



- **Strategic / Portfolio Context**
  - Low risk development of 9 discovered gas fields
  - Material production and free cash flow 2017+
  - Leverages JDA experience and capabilities
  - Material exploration upside

- **Asset Details**
  - Hess 50% W.I., operator
  - 2014 capex of $400 million
  - Early production forecast is 40 MMcf/d 2014-2016
  - Full field production forecast is 165 MMcf/d 2017+
  - Oil linked gas price
  - PSC through 2033

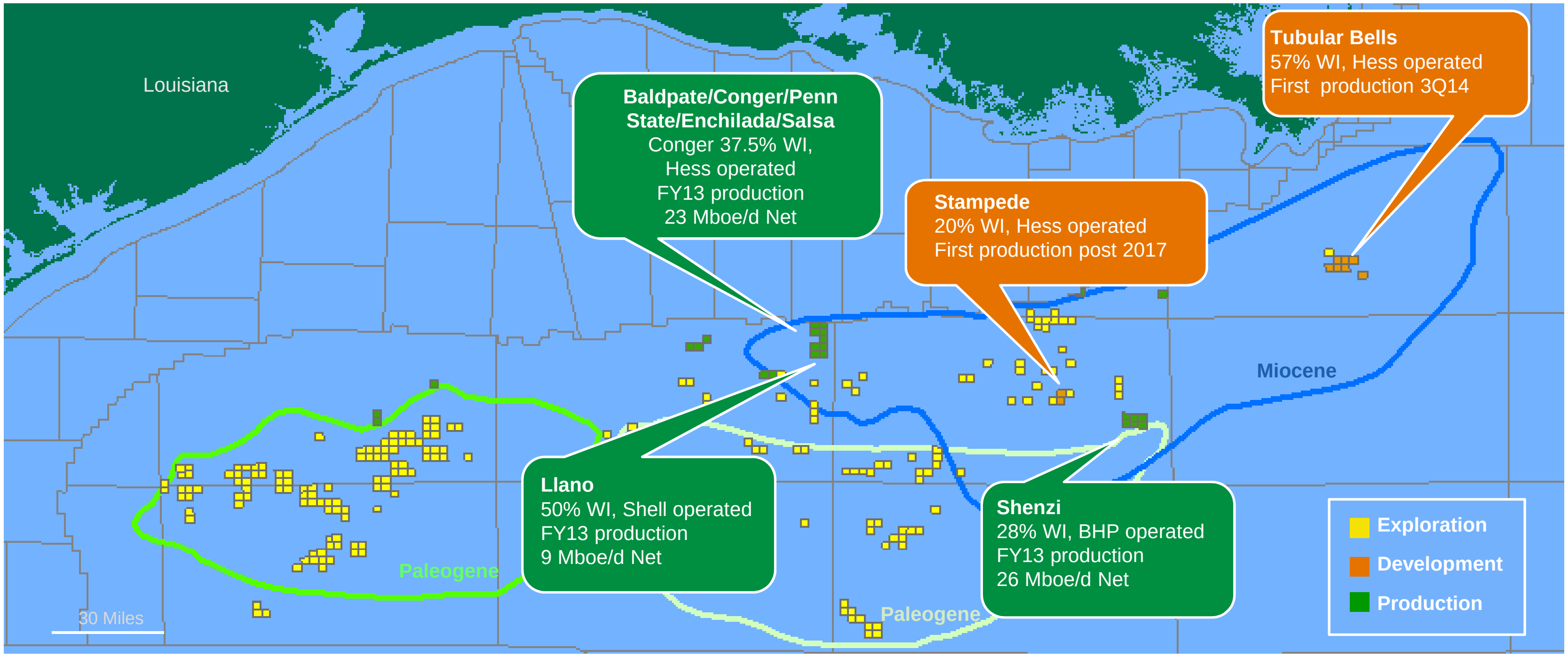
Deepwater Gulf of Mexico Portfolio

Strategic / Portfolio Context

- Target to maintain production of ~70 Mboe/d through 2017
- Material, high margin assets with successful exploitation track record
- Leverages proven deepwater capability
- Exploration upside

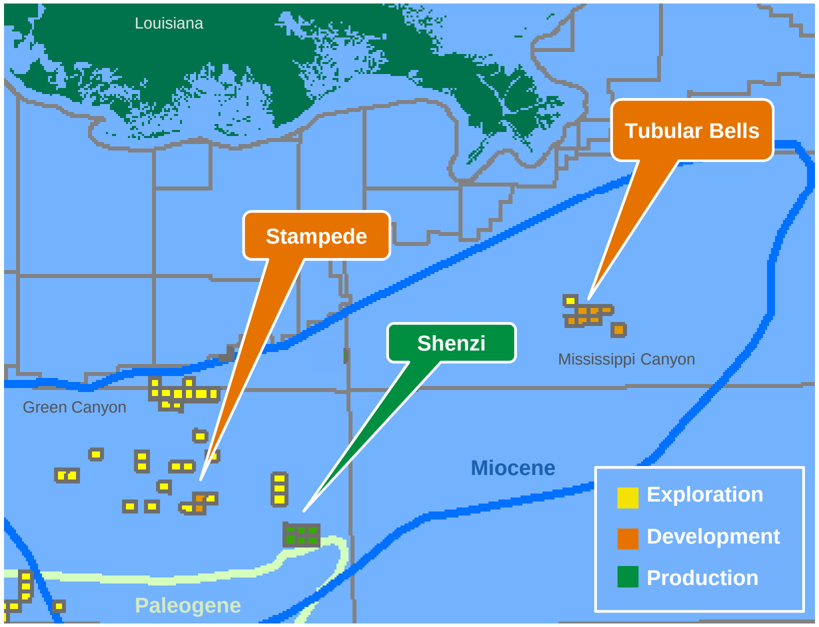
Asset Details

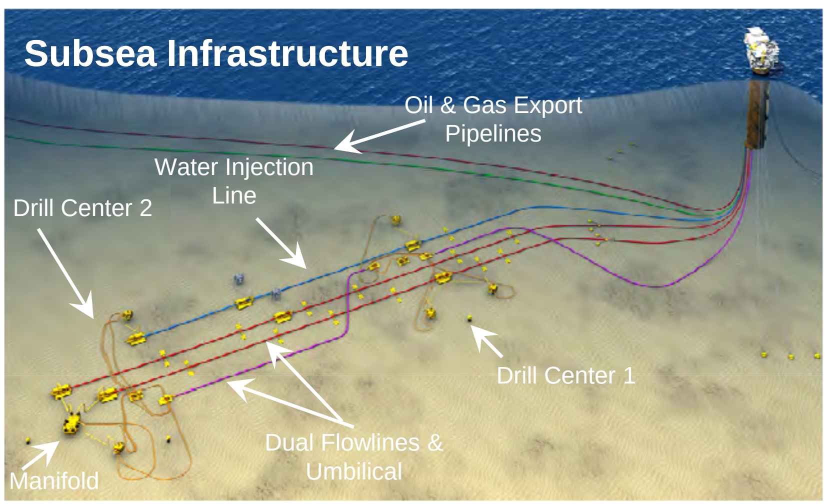
- Key producing assets: Shenzi, Conger and Llano
- Two major operated developments
  - Tubular Bells first production in 3Q14
  - Stampede sanction decision in 2H14
- Large acreage position in Miocene and Paleogene plays



Unconventional | Exploitation | Exploration

Tubular Bells – High Margin Asset; On Line 3Q14





Strategic / Portfolio Context

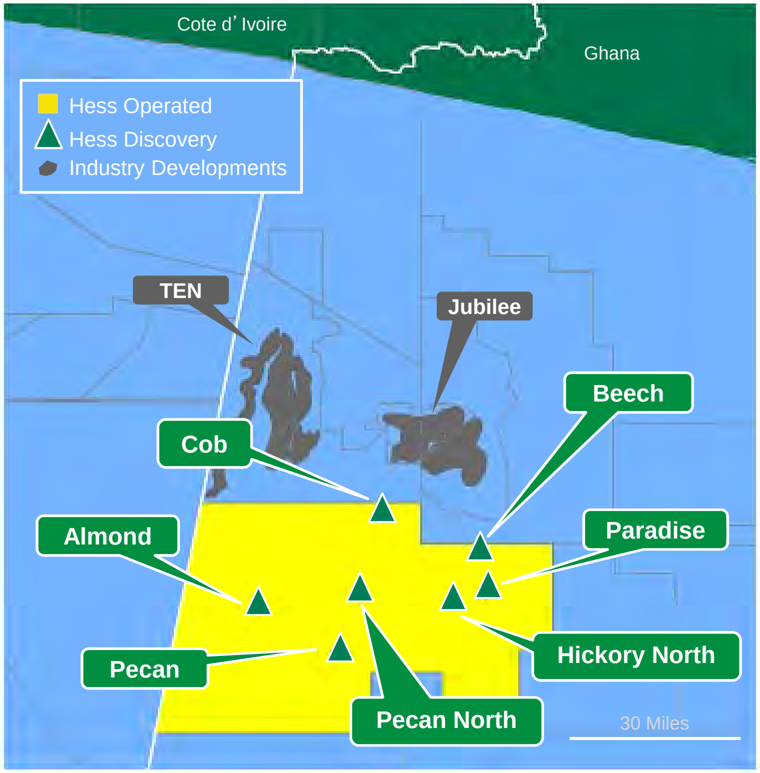
- Material high margin asset
- Key contributor to production growth and cash flow
- Leverages deepwater capability
- Recent drilling provides further upside

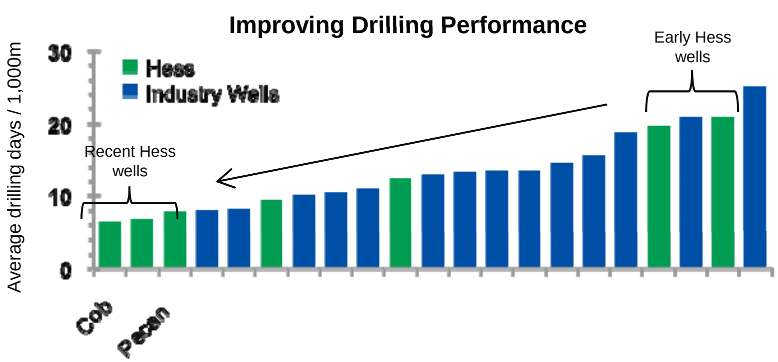
Asset Details

- Hess 57% W.I., operator
- Water Depth: 4,400 feet
- Subsea wells tied back to third party owned SPAR facility
- 2014 capex of $400 million
- First production targeted for 3Q14 at net rate of ~25 Mboe/d

Unconventional | Exploitation | Exploration

Ghana – Deep Water Tano Cape Three Points



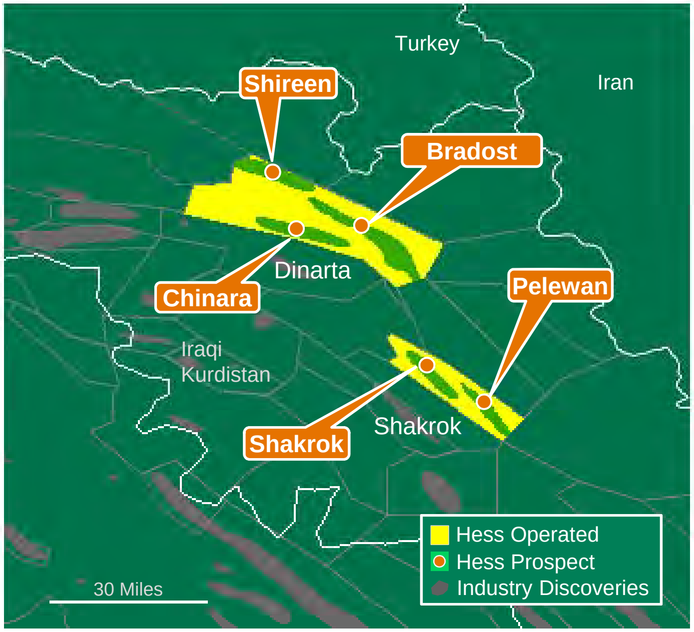


Source: Rushmore (West Africa drilling greater than 1,200 meters WD)

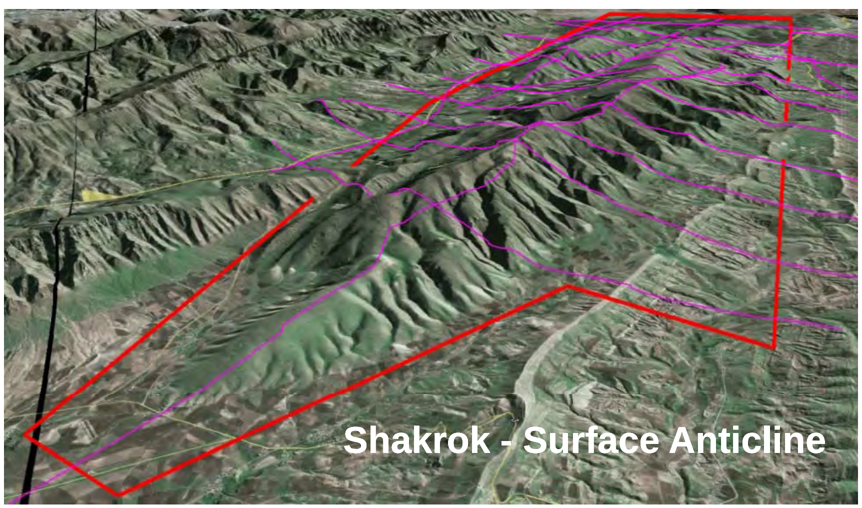
- Hess 90% W.I., operator
- 7 discoveries material to resource base
- Builds on West African deep water experience
- Industry leading well costs
- Pursuing partnership strategy
- Plan to drill 3 appraisal wells, commencing 2H14

Well Name	Completion Date	Net Pay (ft)	Hydrocarbon	Water Depth (ft)
Paradise-1	Jun-11	415	Oil and gas condensate	6,040
Hickory North-1	Jun-12	98	Gas condensate	6,455
Beech-1	Jul-12	146	Oil	5,623
Almond-1	Oct-12	53	Oil	7,251
Pecan-1	Dec-12	245	Oil	8,245
Cob-1	Jan-13	31	Oil	6,330
Pecan North-1	Feb-13	40	Oil	7,411

Kurdistan – Dinarta and Shakrok



- Hess 64% W.I., operator
- Spud Shakrok in 3Q13; TD and production testing 2Q14
- Expect to spud Shireen in 2Q14
- Surface anticlines with oil seeps
- 8 recent nearby discoveries with >200MMboe each
- >425,000 gross acres



Pure Play E&P – Driving Shareholder Value

- **Focused World Class Portfolio**
- **Three Pronged Strategy to Drive Growth and Returns While Managing Risk**
- **Financial Flexibility to Fund Future Growth**
- **Providing Current Returns to Shareholders**

Continuing commitment to capital discipline

HESS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

St. Paul Park Refining Co. LLC	)	
	)	
Complainant,	)	
	)	
v.	)	**Docket No. OR13-28-000**
	)	
Enbridge Pipelines (North Dakota) LLC	)	
	)	
Respondent.	)	

AFFIDAVIT OF ROBERT STEEDE
IN SUPPORT OF MOTION TO DISMISS AND ANSWER OF
ENBRIDGE PIPELINES (NORTH DAKOTA) LLC
IN RESPONSE TO COMPLAINT OF ST. PAUL PARK REFINING CO. LLC

Robert Steede, being first duly sworn, states as follows:

1. My business address is 2505 16 Street SW, Ste. 100, Minot, North Dakota, 58701.

2. My current position is Director at Enbridge Pipelines (North Dakota) LLC ("Enbridge North Dakota"), which I have held since September 2012. I am responsible for the safe and reliable operation of the Enbridge North Dakota system. Prior to becoming a Director, I was the Manager of Environmental Operations – U.S since October 2010.

3. I am providing this affidavit in support of the Motion to Dismiss and Answer of Enbridge North Dakota to the Complaint of St. Paul Park Refining Co. LLC.

4. The Enbridge North Dakota System originates in the Bakken oil fields in western North Dakota and extends east to Clearbrook, Minnesota. Enbridge North Dakota has embarked on a series of staged expansions to meet demand from the Bakken region, including the investment of more than $800 million. As a result, the capacity into Clearbrook increased from 80,000 barrels per day ("bpd") to approximately 210,000 bpd, and additional export capacity totaling 225,000 bpd has been created to serve connecting facilities at Berthold, North Dakota. This has been a benefit to shippers and the region as a whole by providing greater access to downstream markets.

5. Two of these expansions, known as the Phase 5 and Phase 6 expansions, were the subject of settlements approved by the Commission. Together, those expansions resulted in 81,000 bpd of expanded capacity into Clearbrook.

6. Following the Phase 5 expansion and earlier expansions, the demand for transportation continued to outpace the capacity of the Enbridge North Dakota system, resulting in prolonged prorationing. In response to shipper requests, Enbridge North Dakota developed the Phase 6 expansion. The Phase 6 expansion included significant improvements to the system, such as increased horsepower at twelve pump stations, measurement and station upgrades at Clearbrook, extensive use of Drag Reducing Agent ("DRA"), which enhances the capacity of a crude oil pipeline by facilitating flows, and installation of tankage at Beaver Lodge. Enbridge North Dakota undertook the Phase 6 Expansion Project in 2009 and 2010 at a cost of approximately $145 million. The Phase 6 expansion added approximately 40,000 bpd of capacity into Minot from the western end of the pipeline system and approximately 51,000 bpd of capacity from Minot to the

eastern end of the system at Clearbrook. The Clearbrook shippers were the intended beneficiaries of the Phase 6 expansion.

7. The cost recovery method for the Phase 6 expansion was established in a settlement approved by the Commission ("2008 Settlement"). Enbridge North Dakota relied on the 2008 Settlement to undertake the large investment necessary to complete the Phase 6 expansion. The settlement methodology, allowing Enbridge North Dakota to recover the costs of the expansion through a seven-year surcharge on all barrels to Clearbrook with an annual true-up to actual costs and volumes, was an essential part of Enbridge North Dakota's decision to go forward with the Phase 6 Expansion, which has benefitted shippers by providing increased capacity to Clearbrook and downstream markets during a time of booming production in the Bakken region. The provision limiting the application of the surcharge to Clearbrook volumes was an important aspect of the 2008 Settlement, because the Phase 6 expansion was designed to benefit, and would primarily benefit, shippers moving to Clearbrook as opposed to other destinations. The seven-year term of the Phase 6 surcharge was also a critical component of the 2008 Settlement on which Enbridge North Dakota relied in making its investment of $145 million in the Phase 6 Expansion Project. Since that time, the 2008 Settlement has functioned as intended. Because the surcharge is based on forecasted costs and volumes, the amount has fluctuated depending on various factors, including throughput on the system to Clearbrook. The annual true-up mechanism ensures the surcharge reflects actual costs and volumes, thereby protecting shippers from any over-recovery. Consistent with that methodology, the surcharge amount was lower in 2011 and 2012

than in 2010. The decrease in the surcharge in 2011 and 2012 was largely the result of Enbridge North Dakota's actions to increase capacity on the system through the sour removal project and total pipeline control project, but would not have been automatic without the 2008 Settlement. In 2010 and 2011 when the Settlement methodology resulted in a decrease in the surcharge, St. Paul Park accepted the Settlement mechanism without protest.

8. Subsequent to the Phase 6 expansion, Enbridge North Dakota continued its efforts to expand the system. In 2011, Enbridge North Dakota undertook a sour removal project and total pipeline control project, which further increased capacity without increasing tariff rates for shippers. The sour removal project consisted of eliminating segregated movements of sour crude oil on the system, which enabled Enbridge North Dakota to place all barrels in a continuous stream, thereby enhancing the capacity available to shippers. Along with increased use of DRA, the total pipeline control expansion improved communication between stations and increased line pressure protection which enabled a more efficient operating system, thereby increasing the capacity from 185,000 bpd to 210,000 bpd. Those two projects resulted in a total of 49,000 bpd of additional capacity into Clearbrook, bringing the total capacity to Clearbrook from its post-Phase 6 expansion level of 161,000 bpd to approximately 210,000 bpd.

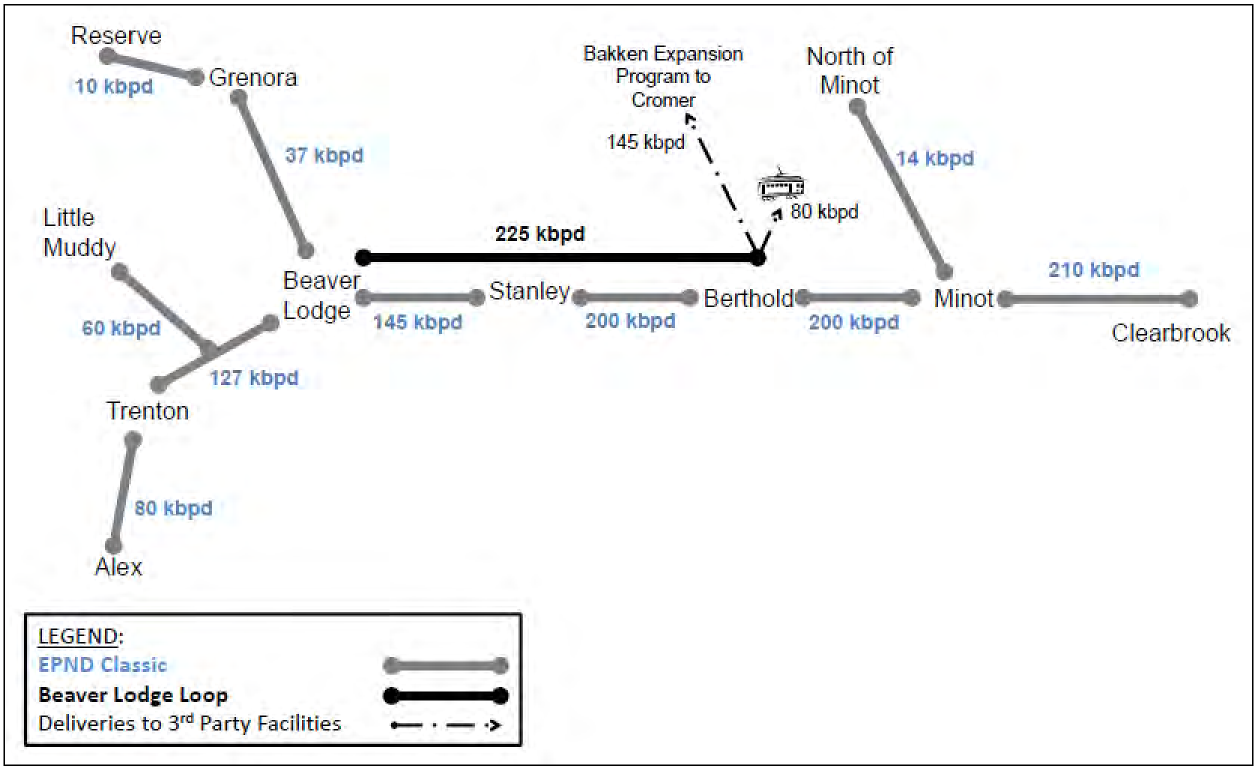
9. At that point, the existing mainline between Beaver Lodge and Clearbrook had reached its maximum capacity without building a new parallel pipeline. In order to create additional export capacity from the Bakken without having to construct a new

pipeline to Clearbrook, Enbridge North Dakota (in coordination with affiliated pipelines) undertook the Bakken Expansion Program. That Program consisted of: (1) Enbridge North Dakota constructing a new line from Beaver Lodge to Berthold (the "Beaver Lodge Loop"); (2) the reversal and reopening of the Portal Line, which is a line extending north from Berthold to the U.S.-Canada border; and (3) the reversal and refurbishment of a pipeline from the U.S.-Canada border to Steelman, Saskatchewan, and the building of a new line from Steelman to Cromer, Manitoba, where that line connects to the Enbridge Mainline in Canada, permitting access to downstream markets via the Lakehead System in the U.S.

10. The Beaver Lodge Loop was originally planned with a capacity of 145,000 bpd to match the capacity of the two northbound segments between Berthold and Cromer. However, Enbridge North Dakota subsequently changed the design of the Beaver Lodge Loop so that its capacity was expanded to 225,000 bpd into Berthold. The additional 80,000 bpd of capacity on the Beaver Lodge Loop is available to feed a rail terminal at Berthold operated by an affiliated company (Enbridge Rail North Dakota LLC), which went into service in March 2013. The Berthold Rail Facility has a takeaway capacity of up to 80,000 bpd.

11. Enbridge North Dakota offered firm service on the Beaver Lodge Loop through open seasons held in 2010 and 2012 at rates set under the Transportation Service Agreements offered in the open seasons. Under the rate structure, the costs of the Beaver Lodge Loop are recovered from the shippers that deliver to Berthold (both committed and uncommitted) through the rates charged for movements to Berthold as a delivery point.

None of the costs of the Beaver Lodge Loop are recovered through the rates charged to shippers to Clearbrook. The Beaver Lodge Loop went into service on February 1, 2013. As is evident from the diagram below, the Beaver Lodge Loop created enough capacity to serve deliveries at Berthold.



Accordingly, the capacity added through the Phase 6 expansion continued to be available for shippers who delivered into Clearbrook, as the 2008 Settlement anticipated.

12. The Phase 6 surcharge is not applied to the shippers that deliver their crude oil into Berthold, either into the Bakken pipeline going north or the Berthold Rail Facility. Instead, those shippers bear the costs of the more recent Beaver Lodge Loop Project. Similarly, shippers moving barrels to Clearbrook do not bear any costs of the Beaver Lodge Loop Project.

13. For the past four years, Enbridge North Dakota has calculated the Phase 6 surcharge according to the methodology as agreed to by shippers in the 2008 Settlement. The surcharge has fluctuated depending on various factors including capacity, volumes, and costs. To illustrate, below is a chart of the surcharge as filed each year:

Year	Surcharge
2010	$0.6078
2011	$0.3993
2012	$0.2257
2013	$0.8269

As shown in the chart, in 2011 and 2012 the surcharge decreased relative to the initial 2010 surcharge amount. This resulted primarily from Enbridge North Dakota's efforts to increase capacity on the system from about 160,000 bpd to about 210,000 bpd through the sour removal project and total pipeline control project, without increasing tariff rates for shippers. The surcharge mechanism automatically flowed the resulting rate decreases through to shippers.

14. As shown in the chart below, the throughput to Clearbrook began declining in November of 2012, before beginning to recover in the past three months.

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

The chart shows that there is no correlation between the monthly deliveries to Clearbrook and Berthold Rail. The throughput to Clearbrook began declining well before the Berthold Rail Facility became operational. The decline in volumes to Clearbrook began several months before the Berthold Rail Facility commenced service, and since that facility has been operating, the volumes to Clearbrook have increased substantially at the same time the Berthold volumes were increasing. The average volume transported to Clearbrook in January of 2012 was 204,067 bpd, while the average for January 2013 was less than half that amount at 93,198 bpd. All of that decline pre-dated the existence of the Berthold Rail Facility and occurred due to shippers' individual nominating decisions based on crude price differentials, over which Enbridge North Dakota has no control. When there is a large price differential between crude oil prices in the midcontinent area and prices in the coastal regions (as existed in 2012 and the first half of 2013), shippers have an incentive to transport crude by rail carrier to the higher value markets so long as the differential exceeds the rail transport cost. Where the price differentials shrink (as has recently occurred), that incentive declines and shippers typically revert to pipeline movements of oil. The throughput moving to Clearbrook increased to an average of 123,036 bpd in June of this year, despite barrels moved at the new Berthold Rail Facility, which went into service in March. The barrels moved to the Berthold Rail Facility have to date been far less than the throughput decrease at Clearbrook.

15. Pursuant to the 2008 Settlement, Enbridge North Dakota filed a new rate in Tariff No. 72.22.0, updating the calculation of the Phase 6 surcharge for 2013 to 82.69 cents per barrel. In calculating the Phase 6 surcharge, Enbridge North Dakota forecasted total trunkline throughput at 160,000 bpd. The throughput estimate was conservative. In order to forecast throughput, Enbridge North Dakota assumed actuals for the months in which it had data, and then assumed the pipeline would operate at close to capacity for the remainder of the year. As shown in the chart, the actual volumes to date for 2013 have fallen below the projection, although volumes are expected to increase in the second half of the year. The surcharge is trued-up at the end of each year to actual volumes. In the true-up, any discrepancy between the forecasted throughput and actuals for the year is factored into the surcharge calculation for the next year. If Enbridge North Dakota's

throughput forecast for 2013 turns out to be higher than actual throughput for the year, Enbridge North Dakota will not retain any of the over-recovery. Instead, the discrepancy will be trued-up in the 2014 surcharge calculation, thereby returning the over-recovery amount to the shippers through a lower 2014 surcharge. The true-up eliminates any risk of harm to shippers resulting from Enbridge North Dakota's throughput forecast.

16. To the extent there are loading and unloading fees charged to shippers on the North Dakota system, they are imposed by third-party operators other than Enbridge North Dakota, and over which Enbridge North Dakota has no control. These rates are the subject of private agreements to which Enbridge North Dakota is not a party. The one fee Enbridge North Dakota does charge at Berthold is a terminal fee of 20.92 cents and it applies to all barrels gathering into or truck unloading onto Enbridge North Dakota facilities at Berthold, regardless of whether that barrel ultimately ends up at Berthold Rail, Clearbrook or other destinations sites.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and accurate.

August 14, 2013

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

MarketWatch
THE WALL STREET JOURNAL.

Oct. 4, 2012, 2:24 p.m. EDT

Bakken crude prices rise as railroad reach grows

By Ben Lefebvre

HOUSTON--The rapidly growing crude oil flow out of North Dakota has broken out of its transportation bottleneck thanks to an expanding railway network, lifting prices for the crude and profits for those who pump it.

Bakken oil prices in September traded at a premium to U.S. crude benchmark West Texas Intermediate for the first time in nearly a year.

Much of the credit goes to the newly developed system of rail lines and terminals built by Tesoro Corp. (NYSE:TSO) , EOG Resources (NYSE:EOG) , Statoil ASA (NYSE:STO) and others, which have started hauling the crude from its geographically isolated source to refineries all over the country.

The growing availability of the North Dakota crude demonstrates how new sources of crude unleashed by hydraulic fracturing are rapidly changing the U.S. oil market. Bakken's wider reach is benefitting coastal refiners who had been dependent on more expensive imported crude, but dull the edge for those in the Midwest who had depended on its formerly steep discounts to pad their profit margins.

"Rail terminals are enabling shipments to St. James [Louisiana], East Coast and West Coast terminals, avoiding the traffic jam" at Cushing, Oklahoma, where most of the Bakken crude shipped via pipeline ends up, said Rusty Braziel, president of energy consulting firm RBN Energy. "This has pulled some barrels out of the pipelines and resulted in an overall tightening of the supply-demand balance."

Hess Corp. (NYSE:HES) , EOG and others had until recently produced more oil out of North Dakota's Bakken shale formation than pipeline and rail cars could haul, leading to a regional supply glut and discounted prices for the crude. Most Bakken crude that did travel through pipeline wound up at the Cushing, Okla., oil storage hub, which is under its own glut because of the recent boom in U.S. oil production resulting from hydraulic fracturing. The average Bakken discount since November 2011 was $7 below WTI, hitting as low as $28 in February, according to Platts data.

Bakken oil production in July reached 675,000 barrels a day, an all-time high and more than twice as much as could be carried by pipeline, according to the North Dakota Department of Mineral Resources. But as more rail lines and terminals have been built in the North Dakota region--Statoil said in August it is leasing more than 1,000 railroad cars to carry crude oil from North Dakota to refiners across North America--Bakken oil has still become available to more buyers, boosting its price.

At Clearbrook, Minn., where Bakken crude is loaded into a pipeline, Bakken oil cost $5 more than WTI for most of September, according to Platts.

"We have a big flexibility built into these crude-by-rail systems," said Bill Thomas, president of EOG Resources, which produced 56,400 barrels of oil equivalent a day in the Bakken last year and has spent three years building rail systems out of North Dakota. "We really take most of our crude mostly from the Bakken to the Gulf Coast and get a really good price," he said in a conference call with investors.

The Bakken premium will likely last until late 2013, when TransCanada Corp. (NYSE:TRP) , Enterprise Products Partners LP (NYSE:EPD) and other pipeline companies finish projects that will expand the amount of crude oil flowing out of the Cushing oil hub, according to a recent Raymond James report.

Once pipelines are in place, WTI will flow more efficiently to the U.S. Gulf Coast refining hub and Bakken crude prices will fall back while producers search for other markets for their crude, said Raymond James energy analyst Stacey Hudson. At that point, Bakken crude will once more have to fight for room in the marketplace.

"The question is, where do you want to send your Bakken barrels once Cushing gets fixed?," Ms. Hudson said.

More expensive Bakken crude eats into the advantage some refiners with ready access to it had. Tesoro, whose refineries in Mandan, North Dakota, and Anacortes, Wash., use the crude extensively, is especially apt to see its profit margins shrink as the Bakken price rises.

"There are a few refiners like Tesoro's Mandan refinery that are not enjoying as big a discount as they were last year," RBN Energy's Mr. Braziel said.

But Valero Energy Corp. (VLO) and other refiners still prefer it to the more expensive coastal crude, which can still cost up to $20 more.

"There's still incentive to run it," said Bill Day, spokesman for Valero, which runs 140,000 barrels a day of Bakken crude at its refinery in Memphis, Tenn.

Subscribe to WSJ: http://online.wsj.com?mod=djnwires

ENBRIDGE INCOME FUND HOLDINGS INC.

MANAGEMENT’S DISCUSSION AND ANALYSIS

December 31, 2013

MANAGEMENT'S DISCUSSION & ANALYSIS
FOR THE YEAR ENDED DECEMBER 31, 2013

This Management's Discussion and Analysis (MD&A) dated February 10, 2014 should be read in conjunction with the audited financial statements and notes thereto of Enbridge Income Fund Holdings Inc. (ENF or the Company) as at and for the year ended December 31, 2013, which are prepared in accordance with International Financial Reporting Standards (IFRS). Unless otherwise noted, all financial information is presented in Canadian dollars. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

OVERVIEW

ENF is a publicly traded corporation whose common shares trade on the Toronto Stock Exchange under the symbol ENF. The Company's business is limited to ownership of its interest in Enbridge Income Fund (the Fund) and its objective is to pay out a high proportion of available cash in the form of dividends to shareholders. At December 31, 2013, ENF held 85.6% (2012 – 84.5%) of the issued and outstanding trust units of the Fund, representing a 40.8% (2012 – 40.3%) overall economic interest in the Fund, with the balance held by Enbridge Inc. (Enbridge), a North American transporter, distributor and generator of energy. The Fund is involved in the generation, transportation and storage of energy through its interests in 579 (524 net) megawatts (MW) of renewable and alternative power generation capacity (Green Power), its liquids transportation and storage business in Western Canada (Liquids Transportation and Storage) and natural gas transmission through its 50% interest in the Canadian segment of Alliance Pipeline (Alliance Canada).

ENF Financial Performance

	Three months ended December 31,		Year ended December 31,	
	2013	2012	**2013**	2012
(thousands of Canadian dollars, except share and per share amounts)				
Distribution and other income	**23,102**	16,611	**91,044**	59,835
Earnings	**22,139**	16,591	**86,570**	59,828
Earnings per common share, basic and diluted	**$0.39**	$0.39	**$1.55**	$1.48
Cash flow from operating activities	**22,814**	13,975	**92,174**	53,071
Dividends declared	**19,233**	15,918	**75,264**	52,758
Dividends per common share	**$0.340**	$ 0.317	**$1.342**	$1.244
Total assets[1]			**1,346,926**	1,254,240
Number of common shares outstanding[1]			**56,491,000**	51,723,000

1 As at December 31, 2013 and 2012.

The Company's earnings and cash flows are derived from its investment in the Fund and are dependent upon its ownership interest, the level of cash distributions paid by the Fund, and income taxes.

The proceeds from an equity offering by the Company in February 2013 were used to subscribe for an additional 4,768,000 trust units of the Fund, increasing its overall ownership of Fund trust units to 85.6%. Effective with the November 2013 distribution, the Fund increased its distribution rate to $0.135 per Fund trust unit per month. As a result of the Fund's increased distribution rate and the Company's increased ownership interest, the Company realized incremental earnings during the year ended December 31, 2013 compared to the year ended December 31, 2012.

In December 2012, the Company increased its overall ownership of Fund trust units to 84.5% in connection with an equity offering by the Fund. The Fund used the proceeds to acquire a portfolio of crude oil storage facilities and wind and solar power generation facilities. The assets acquired included the Hardisty Contract Terminals, the Hardisty Storage Caverns, the 99 MW Greenwich Wind Project, the 15 MW Amherstburg Solar Project and the 5 MW Tilbury Solar Project (the Crude Oil Storage and Renewable Energy Assets). The contribution of incremental cash flows from this portfolio of assets enabled the Fund to increase its distribution rate to $0.134 per Fund trust unit per month effective with the December 2012 distribution. Comparatively, the Company received distributions equivalent to $0.121 per Fund trust unit per month during the first 11 months of 2012.

The Company incurs income taxes on distributions received from the Fund, the level of which will vary depending on the taxability of such trust distributions in any given year. To the extent a portion of the distribution represents a tax-free inter-corporate dividend or return of capital, cash tax will not be incurred on a portion of the distribution. The Company recorded current income tax expense on a portion of distributions received during the year ended December 31, 2013, whereas distributions received in the comparable period of 2012 were not taxable.

The Company's objective is to pay out a high proportion of available cash in the form of dividends to shareholders. The Company declared dividends totalling $75.3 million during the year ended December 31, 2013, a rate equivalent to $0.111 per common share per month for the first ten months and $0.115 per common share for November and December 2013. The 3% increase in the monthly dividend in November 2013 reflects organic growth of the Fund's existing asset base. This represents a payout ratio of 86.9% in 2013, compared to a payout ratio of 88.2% in 2012. Retained cash is expected to be used for future income tax payments and acts as a reserve to sustain dividends long term.

Enbridge Income Fund Financial Performance
A summary of financial information of the Company's investee, Enbridge Income Fund, derived from the Fund's consolidated financial statements prepared in accordance with U.S. GAAP, for the years ended December 31, 2013 and 2012 is provided below. Readers are encouraged to read the Fund's financial statements and MD&A which are filed on SEDAR at www.sedar.com.

Year ended December 31,	**2013**	2012
(thousands of Canadian dollars)		
Cash available for distribution, Enbridge Income Fund[1]		
Green Power	**155,823**	121,412
Liquids Transportation and Storage	**130,194**	74,151
Alliance Canada	**68,383**	70,850
Corporate	**(91,244)**	(70,863)
Cash available for distribution, Enbridge Income Fund	**263,156**	195,550
ECT preferred unit distributions	**(116,127)**	(80,798)
Cash retained	**(41,278)**	(41,177)
Cash distributions declared to trust unitholders by Enbridge Income Fund	**105,751**	73,575
Percentage of units held by ENF	**84.5%-85.6%**	80.7%-84.5%
Distribution and other income, ENF	**91,044**	59,835
Income tax	**(4,474)**	(7)
Earnings, ENF	**86,570**	59,828

1 See Non-GAAP Measures.

The Fund's cash available for distribution (CAFD) totaled $263.2 million for the year ended December 31, 2013, compared with $195.6 million for the prior year. The increase in CAFD was attributable to incremental cash flows from the portfolio of crude oil storage and wind and solar power generation facilities acquired in December 2012 and the Bakken Expansion which was placed into service in March 2013, offset partially by an increase in interest expense, associated with the debt incurred to finance a portion of the acquisition.

FORWARD-LOOKING INFORMATION

In the interest of providing the Company's shareholders and potential investors with information about the Company and its investee, the Fund, and the Fund's subsidiaries and joint ventures, including management's assessment of future plans and operations of the Company and the Fund, certain information provided in this MD&A constitutes forward-looking statements or information (collectively, "forward-looking statements"). This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. In particular, forward-looking statements include:

- *expected earnings or earnings per share;*
- *expected costs related to projects under construction;*
- *expected scope and in-service dates for projects under construction;*
- *expected timing and amount of recovery of capital costs of assets;*
- *expected capital expenditures;*
- *expected future dividends, Fund distributions and taxability thereof;*
- *the Fund's expected cash available for distribution; and*
- *expected future actions of regulators.*

Although the Company believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and the processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas, natural gas liquids and green energy; prices of crude oil, natural gas, natural gas liquids and green energy; expected exchange rates; inflation; interest rates; the availability and price of labour and construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approval for the Fund's projects; anticipated in-service dates; and weather. Assumptions regarding the expected supply and demand of crude oil, natural gas, natural gas liquids and green energy, and the prices of these commodities, are material to and underlay all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Fund's products and services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company and the Fund operate, may impact levels of demand for the Fund's products, services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings and associated per unit or per share amounts, or estimated future distributions or dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates and expected capital expenditures, include: the availability and price of labour and construction materials; the effects of inflation on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather, customer and regulatory approvals on construction schedules.

The Company's forward-looking statements and forward-looking statements with respect to the Fund are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, changes in tax law, tax rates, exchange rates, interest rates and commodity prices, including but not limited to those risks and uncertainties discussed in this MD&A and in the other filings of the Company and the Fund with Canadian securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Company's and the Fund's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, the Company and the Fund assume no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements whether written or oral, attributable to the Company or the Fund or persons acting on the Company's or the Fund's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to the Fund's cash available for distribution (CAFD). CAFD represents the Fund's cash available to fund distributions on trust units and Enbridge Commercial Trust (ECT) preferred units as well as for debt repayments and reserves. CAFD consists of operating cash flow from the Fund's underlying businesses less deductions for maintenance capital expenditures, the Fund's administrative and operating expenses, corporate segment interest expense, applicable taxes and other reserves determined by the Manager of the Fund. This measure is important to shareholders as the Company's objective is to provide a predictable flow of dividends to shareholders and the Company's cash flows are derived from its investment in the Fund. CAFD is not a measure that has standardized meaning prescribed by United States Generally Accepted Accounting Principles (U.S. GAAP) and is not considered a GAAP measure. Therefore, this measure may not be comparable with similar measures presented by other issuers.

CORPORATE STRUCTURE

ENF was incorporated on March 26, 2010 under the *Business Corporations Act* (Alberta) (ABCA) for the sole purpose of participating in the Plan of Arrangement (the Plan) to restructure the Fund, which became effective December 17, 2010. Pursuant to the Plan, all publicly held units of the Fund and 5,000,000 units held by Enbridge were exchanged on a one-for-one basis for common shares of the Company, resulting in the Company owning 25,125,000, or 72.6%, of the Fund's issued and outstanding trust units. The Company's common shares commenced trading on the Toronto Stock Exchange on December 21, 2010 under the symbol ENF.

In October 2011, the Company subscribed for 14,616,000 trust units of the Fund at a price of $18.75 per unit to partially fund the Fund's acquisition of three renewable power generation facilities owned by subsidiaries of Enbridge (the 2011 Transaction). The assets acquired were the 80 MW Sarnia Solar Project, the 190 MW Ontario Wind Project and the 99 MW Talbot Wind Project. Following the 2011 Transaction and related equity financing by the Fund, the Company held 39,741,000, or 80.7%, of the Fund's issued and outstanding trust units.

In December 2012, the Company subscribed for 11,982,000 trust units of the Fund at a price of $23.15 per unit to partially fund the Fund's acquisition of crude oil storage facilities and three renewable power generation facilities owned by Enbridge and subsidiaries of Enbridge (the 2012 Transaction). Following the 2012 Transaction and related equity financing by the Fund, the Company held 51,723,000 or 84.5%, of the Fund's issued and outstanding trust units.

The proceeds from an equity offering by the Company in February 2013 were used to subscribe for an additional 4,768,000 trust units of the Fund at a price of $25.00 per common share, increasing its overall ownership of trust units of the Fund to 56,491,000, or 85.6%. The Fund used the proceeds of the issuance to repay debt used to fund capital expenditures and to partially fund ongoing capital expenditures associated with its organic expansion strategy.

The Company is managed by Enbridge Management Services Inc. (EMSI or the Manager), a wholly-owned subsidiary of Enbridge. EMSI also manages the Fund and the Fund's subsidiary Enbridge Commercial Trust (ECT).

STRATEGY

The Company's business is limited to the ownership of its interest in the Fund. The Company's objective is to provide a predictable flow of cash dividends to its investors.

The Fund's strategy is focused on:

- maximization of the efficiency and profitability of its existing assets while ensuring safe and reliable operations;
- pursuing organic growth and expansion opportunities; and
- acquisition and development of energy infrastructure businesses that are complimentary and consistent with the risk and return profile of its existing business.

Each of the Fund's businesses is closely focused on system performance and operating effectiveness. Green Power strategies are driven by the objective to manage and maintain its facilities in such a way to maximize power generation and related revenue when the relevant wind, solar or waste heat energy resource is available. The Liquids Transportation and Storage business in Saskatchewan is focused on attracting new volumes to the System through increasing customer connections while working with customers to create reliable transportation solutions and toll structures to retain and attract growing regional production over the long term. The Liquids Transportation and Storage business at Hardisty, Alberta, is situated at a major hub for aggregating and exporting crude oil out of the Western Canadian Sedimentary Basin (WCSB). It is focused on connecting Canada's oil producers to markets in eastern Canada and the United States. Alliance Canada is implementing solutions to enhance its unique capability to safely and cost-effectively transport liquids rich gas (gas with a high component of inherent natural gas liquids) to attract growing production of high-value, liquids rich gas in the WCSB.

The expansion and extension of existing systems and facilities has been a significant driver of growth in recent years and the Fund continued to execute on its organic expansion strategy during 2013. The Bakken Expansion Program undertaken within Liquids Transportation and Storage was declared in service on March 1, 2013, bringing 145,000 barrels per day (bpd) of new capacity to producers in the Bakken region in North Dakota. The Fund continues to actively search for new opportunities to profitably grow the footprint of its existing assets and announced a $25 million Rail Interconnection Project in January 2014.

The Fund also seeks to achieve growth through acquisitions of complimentary energy infrastructure. In 2012 the Company delivered strong dividend growth through acquisitions from its sponsor, Enbridge. The assets acquired are all underpinned by long-term fixed price contracts which generate steady cash flow and lower the Fund's risk profile.

Preservation of financial flexibility will continue to be a strategic priority. Ongoing access to cost effective sources of debt and equity capital is critical to the successful execution of the Fund's strategy to expand existing assets and acquire or develop new energy infrastructure.

ENBRIDGE INCOME FUND RECENT DEVELOPMENTS

Cromer Rail Interconnection Project

On January 29, 2014, the Fund announced plans to construct a pipeline interconnection that will connect the Westspur System and Bakken Expansion to a crude oil rail terminal near Cromer, Manitoba. The estimated cost of the project is $25 million and is expected to be in-service in the fourth quarter of 2014. The project is fully backstopped by the operator of the crude oil rail terminal pursuant to a five-year Financial Support Agreement. In addition, the Fund has an option to acquire 50% of the rail terminal which is currently capable of handling 30,000 bpd and is expandable to 60,000 bpd.

Westspur Settlement
On April 1, 2013, the Fund announced it concluded a settlement (the Settlement) with a group of shippers relating to new tolls on the Westspur System. At the request of certain shippers that did not execute the Settlement, the National Energy Board (NEB) did not remove the interim status from the historical tolls and made the new tolls interim as well. A modified agreement was subsequently entered into with substantially all of the shippers, and such shippers requested the NEB make both the historical tolls and the new tolls (collectively, the "Tolls") final. On February 6, 2014, the NEB ordered the Tolls final.

The Settlement establishes a toll methodology for an initial term of five years and will renew for additional one year terms thereafter unless otherwise terminated. Pursuant to the Settlement, the tolls on the Westspur System are fixed and increase annually with reference to an inflation index, subject to throughput remaining within a prescribed volume band close to volumes recently transported on the Westspur System. To preserve a relatively stable cash flow profile, toll surcharges or discounts will be applied should throughput increase or decrease on a sustained basis outside this pre-defined band. Additionally, tolls will be increased should integrity or regulatory costs exceed defined thresholds or if new capital projects are undertaken.

The Settlement resulted in the discontinuance of rate regulated accounting for the Westspur System and as such the Fund recorded an after-tax write-off of $12.0 million in the first quarter of 2013 related to previously-recorded deferred revenue which will not be collected under the terms of the Settlement. The financial impact of the Settlement is not expected to materially affect the Fund's consolidated financial prospects, distribution coverage or practices.

Bakken Expansion
The Bakken Expansion was undertaken to expand crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in North Dakota. This project, undertaken by the Fund in Canada and Enbridge Energy Partners (EEP), a party related to Enbridge, in the United States, reversed and expanded an existing pipeline, running from Berthold, North Dakota, to Steelman, Saskatchewan, and constructed a new 16-inch pipeline from a new pump station near Steelman to the Enbridge terminal near Cromer, Manitoba. It was placed into service in March 2013, providing capacity of 145,000 bpd to producers in North Dakota. Expenditures incurred by the Fund for the Canadian portion of the project through December 31, 2013 were approximately $165 million. After completion of site remediation and post-implementation expenditures, the total cost of the Canadian portion of the Bakken Expansion is expected to be under the original budget of approximately $190 million.

As a result of high crude oil differentials between local delivery points and markets not serviced by downstream pipelines, capacity was not well utilized in 2013. Crude differentials narrowed and throughputs improved modestly in the second half of 2013. The Fund continues to collect cash tolls regardless of actual system throughput pursuant to firm take-or-pay commitments totaling 100,000 bpd, a portion of which are subject to a waiver of 25% of the take-or-pay amount in 2013.

Whitecourt Recovered Energy Project
The Whitecourt Recovered Energy Project is a new waste heat recovery facility being constructed by NRGreen, adjacent to a compressor station on the Alliance Pipeline near Whitecourt, Alberta. The Fund has contributed approximately $42 million as at December 31, 2013 to the Whitecourt Recovered Energy Project. Completion of the project has been delayed due to various construction and equipment delivery challenges. Originally scheduled to be completed in 2013, completion is now anticipated to occur in the second quarter of 2014.

ENBRIDGE INCOME FUND OPERATIONAL OVERVIEW
The performance of the Company's investment in the Fund is ultimately derived from the underlying operating segments through which the Fund executes its low-risk business strategy. An overview of the Fund's operating segments, Green Power, Liquids Transportation and Storage and Alliance Canada is provided below.

Green Power

Overview
Green Power includes assets that produce electricity from renewable and alternative energy sources. Each of the wind and solar assets is currently operating and has full-service operations and maintenance contracts with third parties. The cost to generate electricity through wind and solar resources is significantly lower than most other technologies, given the absence of fuel costs.

Green Power consists of the following:

Wind Projects
The Fund has a 100% interest in the following projects which have an aggregate power generation capacity of 388 MW:

- The Ontario Wind Project, located near Lake Huron, Ontario, utilizes 115 turbines with an aggregate capacity of 190 MW.
- The Talbot Wind Project, located on the north shore of Lake Erie, Ontario, utilizes 43 turbines with an aggregate capacity of 99 MW.
- The Greenwich Wind Project, located on the north shore of Lake Superior, Ontario, utilizes 43 wind turbines with an aggregate capacity of 99 MW.

All power produced from these wind projects is sold to the Ontario Power Authority (OPA) pursuant to power purchase agreements (PPAs) which expire between 2028 and 2031.

The Fund also has interests in three wind power projects with a net capacity of 26 MW including:

- A 50% interest in the SunBridge Wind Project at Gull Lake, Saskatchewan, which utilizes 17 turbines with an aggregate capacity of 11 MW (6 MW net to the Fund).
- A 33% interest in each of the Magrath and Chin Chute Wind Projects in southern Alberta, each utilizing 20 turbines with an aggregate capacity of 30 MW per project (10 MW per project net to the Fund).

The power from SunBridge is delivered into the Saskatchewan power grid, while the energy produced at Magrath and Chin Chute is delivered into the Alberta power grid. Power price swap agreements, which are in place to mitigate the risk of fluctuating power prices in Alberta, expire between 2017 and 2024.

Solar Projects
The Fund has a 100% interest in the following solar generation projects with an aggregate capacity of 100 MW:

- The Sarnia Solar Project, an 80 MW solar project located near Lake Huron, in Sarnia, Ontario, comprised of approximately 1.3 million thin film panels with a surface area of 966,000 m^2.
- The Amherstburg Solar Project, a 15 MW solar project near Sarnia, Ontario, comprised of approximately 0.2 million thin film panels with a surface area of 175,700 m^2.
- The Tilbury Solar Project, a 5 MW solar project located near Sarnia, Ontario, comprised of 0.1 million thin film panels with a surface area of 67,700 m^2.

All power produced from these solar projects is sold to the OPA pursuant to PPAs which expire between 2028 and 2031.

In response to amendments passed by Ontario's Independent Electricity System Operator (IESO) in November 2012 which would allowed curtailment of intermittent generators in times of surplus generation, the Fund and other renewable power generators reached an agreement with the OPA in February 2013 to amend certain existing PPAs to include both annual and contract term curtailment caps beyond which renewable power generators will be compensated for forgone production. The Fund expects uncompensated curtailment, which will impact the Ontario Wind Project, Talbot Wind Project and Greenwich Wind Project, to be less than 1% of the operating hours of the affected assets both annually and over the life of the PPAs.

NRGreen

The Fund also has a 50% interest in NRGreen. NRGreen operates four waste heat recovery facilities with an aggregate capacity of 20 MW (10 MW net to the Fund), all of which are located in Saskatchewan at compressor stations along the Alliance Pipeline. The first facility located at Kerrobert, Saskatchewan has been operating since December 2006. The three other facilities, located in Loreburn, Estlin and Alameda, Saskatchewan, began operations during 2008. Electricity is generated by harnessing the waste heat produced by gas turbines at Alliance Canada's compressor stations and converting the waste heat to electrical energy.

The power generated from the NRGreen facilities is sold under long-term PPAs to SaskPower. The PPAs expire ten years after the in-service date for each facility with two five-year options to renew at NRGreen's election, to provide an additional ten-year extension to the initial PPA term.

Liquids Transportation and Storage

Overview

The Fund's Liquids Transportation and Storage business serves customers in Western Canada and North Dakota and includes the Saskatchewan System which transports crude oil and natural gas liquids (NGLs) from producing fields and facilities in southeastern Saskatchewan, southwestern Manitoba and North Dakota to Cromer, Manitoba where the crude oil and NGLs enter Enbridge's Mainline System to be transported to the United States or eastern Canada. Liquids Transportation and Storage also includes related terminals and tankage facilities in Saskatchewan and the Hardisty Contract Terminals and Hardisty Storage Caverns located near Hardisty, Alberta, a key crude pipeline hub in Western Canada.

Collectively referred to as the Saskatchewan System, the Saskatchewan Gathering, Westspur, Weyburn and Virden pipeline systems, as well as the Canadian portion of the Bakken Expansion, collectively comprise approximately 545 kilometres of trunk line and approximately 1,800 kilometres of gathering pipeline. The Bakken Expansion is a joint project which further expands crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in North Dakota. The capacity of each of the Saskatchewan Gathering and the Westspur Systems is 255,000 bpd, the capacity of the Weyburn and Virden Systems is approximately 47,000 bpd and 37,000 bpd, respectively, and the capacity of the Bakken Expansion is 145,000 bpd. The Saskatchewan System also includes storage terminals and tankage facilities in Saskatchewan, comprised of 21 above ground storage tanks with total capacity of approximately 450,000 barrels.

The Saskatchewan Gathering System tolling agreement is designed to provide toll revenues sufficient to recover operating costs, depreciation, deemed interest expense, deemed income tax, a return on rate base and an administrative expense allowance. The rate base upon which the equity return is calculated will change over time due to depreciation as well as maintenance and enhancement capital additions and expansions. Tolls on the Westspur, Weyburn and Virden Systems are based on agreements with customers, and are updated to reflect changes in market conditions when warranted. Tolls on the Bakken Expansion are based on long term take-or-pay agreements with anchor shippers, market-based tolls for spot capacity and the recovery of operating costs incurred. Earnings from the Westspur, Weyburn, Virden and Bakken Systems reflect toll revenue less costs incurred.

The Hardisty Contract Terminals are located adjacent to Enbridge's Mainline System terminal in Hardisty, Alberta and are comprised of 18 above ground crude oil storage tanks, ranging in size from 250,000 to 560,000 barrels, and one above ground condensate storage tank with a capacity of 250,000 barrels, which together have an aggregate storage capacity of 7.5 million barrels. The Hardisty Storage Caverns are comprised of four underground salt caverns and two above ground storage tanks, with approximately 3.5 million barrels of storage capacity. The above ground storage tanks are used primarily to facilitate movement of crude oil in and out of the caverns, as well as limited trim blending of product when operationally required. Each of the Hardisty assets has long-term take-or-pay storage contracts in place with credit-worthy counterparties in respect of virtually all of their storage capacity. Most of the revenue received under the storage contracts is comprised of fixed fees for storage capacity, with a small component derived from usage fees for services which vary with demand. Upon expiry or termination of existing contracts, Enbridge will enter into escalating take-or-pay contracts with the Fund for an additional 15 years at the then prevailing contract rate. The proximity of the Hardisty storage facilities, which are adjacent to Enbridge's Mainline System operational terminal and at the junction of various regional receipt and export pipelines, make it an attractive option for oil producers to manage their operational needs and the effects of price swings.

Alliance Canada

Overview
Alliance Canada consists of 1,560 kilometres of the Alliance System's natural gas mainline pipeline beginning near Gordondale, Alberta and connecting to Alliance US at the Canada/United States border near Elmore, Saskatchewan. Alliance Canada also includes the Alliance System's lateral pipelines, which connect the mainline to a number of upstream receipt points, primarily at natural gas processing facilities in northwestern Alberta and northeastern British Columbia, and related infrastructure.

The Alliance System is designed to transport 1,325 million cubic feet per day of natural gas on a firm service basis primarily from supply areas in northwestern Alberta and northeastern British Columbia to delivery points near Chicago, Illinois. Additional transportation capacity is available to shippers for no additional cost other than the cost of the associated fuel requirements through Authorized Overrun Service (AOS).

Alliance Canada has transportation service agreements (TSAs) with shippers for substantially all of its available firm transportation capacity. The TSAs are designed to provide toll revenues sufficient to recover prudently incurred costs of service, including operating and maintenance, depreciation, an allowance for income tax, costs of indebtedness and an allowed return on equity of 11.26% after tax, based on a deemed 70/30 debt/equity ratio. The initial term of the TSAs expires in December 2015, with the exception of a small proportion of shippers that have elected to extend their contracts beyond 2015.

Tolls and tariffs for Alliance Canada are regulated by the NEB. Toll adjustments, based on variances between the cost of service forecast used to calculate the toll and the actual cost of service, are made annually. Following consultation with shippers, amended tolls are filed annually with the NEB.

Alliance Canada expects to continue to be competitive with other export pipelines given its geographic positioning and its ability to efficiently move liquids-rich gas to market. It is seeking to secure new term contracts for capacity for periods beyond 2015 and is in the process of discussing its service offerings with the shipper community.

LIQUIDITY AND CAPITAL RESOURCES

The cash distributions the Company receives from its investment in the Fund are its primary source of liquidity. The Company pays out a high proportion of the distributions received from the Fund after prudently reserving for contingencies and future taxes, with the objective of sustaining a predictable stream of dividends to its shareholders. Cash not required to fund dividends or to meet working capital requirements is advanced to subsidiary corporations of the Fund pursuant to a demand loan, which the Company may request repayment of at any time. At December 31, 2013, the Company had $24.3 million outstanding pursuant to the demand loan. The Company did not have any outstanding long-term debt as at December 31, 2013 and 2012.

The Company's working capital requirements are not expected to be significant in 2013. The Company has an agreement with ECT whereby ECT reimburses the Company for certain corporate costs.

Additional capital resources to finance the Company's future investment in the Fund, if necessary, are expected to be available through access to equity markets. The Company maintains a current equity shelf prospectus with Canadian securities regulators, which enables ready access to Canadian public capital markets, subject to market conditions.

Operating Activities
Cash flows from operating activities totaled $92.2 million for the year ended December 31, 2013 (2012 – $53.1 million). Cash flows from operating activities represented distributions received from the Fund, net of income taxes and changes in operating assets and liabilities. The Fund declared distributions of $1.612 per unit in 2013 or $221.9 million in aggregate (2012 – $1.462 per unit or $154.4 million in aggregate).

Financing Activities
In February 2013, the Company completed an equity offering of 3,820,000 common shares of the Company at a price of $25 per common share for gross proceeds of $95.5 million. Concurrent with the closing, Enbridge subscribed for 948,000 common shares at a price of $25 per common share on a private placement basis to maintain its 19.9% ownership interest in the Company.

The Company declared monthly dividends at a rate of $0.11125 per share for the months January to October 2013 and $0.1146 per share for the months of November and December 2013. The Company declared monthly dividends at a rate of $0.103 per share for the months January to November 2012 and $0.11125 per share for the month of December 2012.

Investing Activities
The proceeds from the issuance of common shares of $119.2 million ($95.5 million public offering and $23.7 million private placement) were used by the Company to subscribe for 4,768,000 trust units of the Fund at a price of $25 per unit in the first quarter of 2013, increasing the Company's overall ownership of Fund trust units to 85.6%. Also included in investing activities are advances to a subsidiary corporation of the Fund pursuant to a demand loan, of which $24.3 million was outstanding as at December 31, 2013.

SELECTED ANNUAL FINANCIAL INFORMATION

(thousands of Canadian dollars, except per share amounts)	**2013**	2012	2011
Distribution and other income	**91,044**	59,835	40,270
Earnings	**86,570**	59,828	37,326
Total assets	**1,346,926**	1,254,240	806,074
Dividends per common share	**$1.342**	$1.244	$1.166

Significant items that have impacted the selected annual financial information are as follows:

- The Company increased its investment in the Fund to 80.7% of the Fund's issued and outstanding trust units in October 2011 with an investment of $274.1 million, the proceeds of which were used to partly fund the 2011 Transaction. The contribution of incremental cash flows from the 2011 Transaction enabled the Fund to increase its distribution rate to $0.121 per unit per month effective with the November 2011 distribution which supported a corresponding increase in the Company's dividend.
- In December 2012, the Company increased its overall ownership of Fund trust units to 84.5% with an investment of $277.4 million, the proceeds of which were used to partially fund the 2012 Transaction. Following the completion of the 2012 Transaction, the Fund increased its distribution to $0.134 per unit effective with the December 2012 distribution, which supported a corresponding increase in the Company's dividend.
- In February 2013, the Company completed a bought deal underwriting offering of 3,820,000 common shares at a price of $25.00 per common share for gross proceeds of $95.5 million. Enbridge also subscribed for an additional 948,000 common shares at a price of $25.00 per common share for gross proceeds of $23.7 million. The Company used the aggregate gross proceeds of $119.2 million to subscribe for 4,768,000 trust units of the Fund, which increased distribution and other income during the year ended December 31, 2013. This increased the Company's investment in the Fund to 85.6%.
- The Company's Board of Directors approved an increase in the Company's monthly cash dividend, from $0.111 per share to $0.115 per share, effective with the November 2013 dividend payment.

RELATED PARTY TRANSACTIONS

In connection with the Company's February 2013 offering of 3,820,000 common shares, the Fund reimbursed the Company for share issue costs of $4.1 million. Proceeds from the offering of common shares were used by the Company to purchase additional trust units of the Fund.

In connection with the Company's December 2012 offering of 9,597,000 subscription receipts, the Fund reimbursed the Company for share issue costs of $9.2 million. Proceeds from the offering of subscription receipts were used by the Company to purchase additional trust units of the Fund.

In 2013, the Company advanced $17.5 million (2012 – $6.8 million) to a subsidiary corporation of the Fund pursuant to a subordinated demand loan. At December 31, 2013, $24.3 million (2012 – $6.8 million) was outstanding. Interest on the demand loan was charged at 4.25% per annum. Interest income earned on the loan was $0.6 million (2012 – $0.1 million) for the year ended December 31, 2013 and $85,436 (2012 – $16,278) was included in accounts receivable and other as at December 31, 2013.

At December 31, 2013, accounts payable to Enbridge totaled $1,770 (2012 – $23,835) related to corporate costs paid by Enbridge on behalf of the Company. Accounts payable to the Fund were nil (2012 – $0.2 million) at December 31, 2013.

The Company has an agreement with ECT whereby ECT reimburses the Company for certain corporate costs. ECT reimbursed the Company $1.0 million (2012 – $1.4 million) for corporate costs incurred in 2013. At December 31, 2013, accounts receivable from ECT totaled $0.1 million (2012 – $0.4 million).

The Company has an agreement with Enbridge Management Services Inc. (EMSI), a wholly owned subsidiary of Enbridge, to provide management and administrative services to the Company. EMSI also provides management and administrative services to the Fund and the Fund's subsidiary, ECT. Provided that the Fund is paying a base fee to EMSI for the services received by the Fund, there is no fee payable to EMSI by the Company as was the case for the years ended December 31, 2013 and 2012.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company pays out a high proportion of cash in the form of dividends to investors, while maintaining a reliable and low-risk business model. The Company and the Fund perform annual corporate risk assessments to identify potential risks. Risks are ranked based on the severity and likelihood both before and after mitigating actions. In addition, the Fund has adopted a Cash Flow at Risk (CFAR) policy to manage exposure to movements in interest rates, foreign exchange rates and commodity prices across all segments. CFAR is a statistically derived measurement that quantifies the maximum adverse impact on cash flows over a specified period of time within a pre-defined level of statistical confidence. The Fund's CFAR limit has been set at 2.5% of forward annual CAFD.

Market Price Risk

The Company's other comprehensive income (OCI) is subject to market price risk resulting from changes in the fair value of the Company's investment in the Fund, which is referenced to the Company's common share price. The Company does not typically manage this risk. A $1.00 increase or decrease in the Company's common share price at December 31, 2013 would have resulted in an increase or decrease in OCI, before income taxes of $56.5 million (2012 – $51.7 million) due to the revaluation of the investment.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Accounts payable and accrued liabilities and dividends payable are due within one month. In order to manage this risk, the Company forecasts its cash flow over the near and long term and ensures that sufficient funds will be available when required. The Company's primary source of liquidity is cash distributions it receives from its investment in the Fund. Additional liquidity, if necessary, is expected to be available through collection of amounts advanced to a subsidiary of the Fund pursuant to a demand loan.

The future level of distributions received from the Fund may vary depending on, but not limited to, the performance of the Fund's businesses, the level of continued investment or the Fund's ability to obtain financing. Further factors which may impact the Fund's ability to sustain distributions include future demand for the services provided by its businesses, the effective maintenance of the productive capacity of its assets and the Fund's ability to comply with covenants in its debt agreements and repay or refinance its debt as it comes due.

The Company oversees its investment in the Fund through its Directors who are also ECT Trustees. The ECT Board of Trustees provides oversight into the productive capacity of each operating segment and the future sustainability of distributions through regular maintenance programs, periodic maintenance capital expenditures and the pursuit of growth opportunities, where it sees fit.

Credit Risk

Credit risk arises from the possibility that counterparties may default on their contractual obligations to the Company. The demand loan due from a subsidiary of the Fund, accounts receivable, interest receivable, distributions receivable and cash and cash equivalents are subject to credit risk, the maximum exposure of which is their carrying value as presented on the statement of financial position. The Company manages its exposure to credit risk by ensuring counterparties are of high credit quality.

Fair Value of Financial Instruments

At December 31, 2013 and 2012, the Company's financial instruments were comprised of the Company's investment in the Fund, a demand loan due from a subsidiary corporation of the Fund, cash and cash equivalents, accounts receivable, distributions receivable, accounts payable and accrued liabilities and dividends payable. The fair value of the Company's investment in the Fund is based on the quoted market price of the Company's common shares adjusted for assets and liabilities of the Company which are not applicable to the Fund. The fair value of cash and cash equivalents, the demand loan due from a subsidiary of the Fund, accounts receivable, distributions receivable, accounts payable and accrued liabilities and dividends payable approximates their carrying values due to their short-term maturities.

Business Risks

Readers are referred to the Fund's risk factor disclosure under the headings "Green Power – Business Risks", "Liquids Transportation and Storage – Business Risks", "Alliance Canada – Business Risks" and "Risk Management" in the Fund's MD&A and "Risk Factors" in the Company's AIF and the Fund's AIF.

The following are certain risk factors relating to the activities of ENF and ownership of ENF common shares.

Future Dividends

Dividends declared on the common shares will be wholly-dependent on the declaration of distributions by the Fund. Future dividend payments by the Company and the level thereof are uncertain as the Company's dividend practices and the funds available for the payment of dividends from time to time will be dependent upon, among other things, operating cash flow generated by subsidiaries of the Fund and their respective operations and investments, financial requirements for the Fund and its subsidiaries' operations and the Fund's ability to execute its growth strategy. Further, the Company must satisfy solvency and liquidity tests imposed by the ABCA in respect of the declaration and payment of dividends.

Pre-emptive Right

Pursuant to pre-emptive rights contained in the Fund Trust Indenture, the Company and Enbridge are entitled to acquire any Fund trust units proposed to be issued by the Fund in proportion to their respective economic interest in the Fund, taking into account the ECT Preferred Units. If the Company fails to fully subscribe for its proportionate economic interest, its holdings in the Fund may be diluted.

Restriction in Business Activities

The Company's business is restricted to investment in the Fund. Therefore, the Company's financial results are dependent on the Fund. The inability of the Fund to manage its business effectively could have a material adverse impact on the Company's operations and prospects. Further, the level of the consolidated indebtedness of the Fund and its subsidiaries from time to time could impair the Company's ability to obtain additional financing on a timely basis to take advantage of permitted business opportunities that may arise.

Availability of Financing

If the Company pays out a high proportion of the distributions received from the Fund to shareholders by way of dividend, it may have to enter into financings or other transactions involving the issuance of securities by the Company in order to obtain funds for business purposes. An inability to raise new equity capital may limit the Company's ability to grow and execute its business plan. The issuance of equity securities may also be dilutive to shareholders.

CRITICAL ACCOUNTING ESTIMATES

Long-term Investment

The Company holds an investment in the Fund, representing 85.6% (2012 – 84.5%) of the outstanding Fund trust units as at December 31, 2013. The Company accounts for its investment as an available-for-sale financial asset. Management concluded that the Company does not control the Fund, but rather that Enbridge, through the combination of direct and indirect equity interests, ECT preferred unit investment and its role as manager of the Fund, is the primary beneficiary of the Fund. Significant estimates are also required in determining the fair value and recoverability of the investment. The fair value of the investment is estimated by relying on the quoted market price of the Company's common shares adjusting for other assets and liabilities not attributable to the Fund and significant or prolonged declines in fair value below cost are assessed for evidence of impairment.

CHANGES IN ACCOUNTING POLICIES

Fair Value Measurement

Effective January 1, 2013, the Company adopted IFRS 13, *Fair Value Measurement* which defines fair value and provides a single IFRS framework for the measurement and disclosure of fair value within IFRS standards. As the adoption of this standard impacted disclosure only, there was no impact to the Company's financial position for the current or prior periods presented.

Future Accounting Policy Changes

IFRS 9, *Financial Instruments* addresses classification and measurement of financial assets. IFRS 9 replaces the model for measuring equity instruments and will require recognition of the Company's investment in the Fund at fair value through earnings. The mandatory effective date for accounting periods beginning on or after January 1, 2015 was removed in November 2013 until the IFRS 9 project is finalized. Although immediate application of IFRS 9 is permitted, the Company does not anticipate early adoption of this standard.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian securities law. Based on the requirements of National Instrument 52-109 (NI 52-109), EMSI, the Manager of ENF, evaluated the effectiveness of ENF's disclosure controls and procedures (as defined in NI 52-109) and concluded that ENF's disclosure controls and procedures were effective as of December 31, 2013.

Management's Report on Internal Controls Over Financial Reporting

The Manager of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the Canadian Securities Administrators. ENF's internal control over financial reporting is a process designed, under the supervision and with the participation of executive and financial officers of the Manager of ENF, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with IFRS.

The Company's internal controls over financial reporting include policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of ENF;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of ENF's assets that could have a material effect on the financial statements.

ENF's internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations of any control system. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with ENF's policies and procedures.

EMSI, the Manager of ENF, assessed the effectiveness of ENF's internal control over financial reporting as of December 31, 2013, based on the framework established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, the Manager concluded that ENF maintained effective internal control over financial reporting as of December 31, 2013.

SELECTED QUARTERLY FINANCIAL INFORMATION
The following table presents a summary of the Company's quarterly financial results.

	2013				2012			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
(thousands of Canadian dollars, except per share amounts)								
Revenues	**23,102**	22,924	22,836	22,182	16,611	14,434	14,399	14,391
Earnings	**22,139**	21,507	21,770	21,154	16,591	14,638	14,315	14,284
Earnings per common share, basic and diluted	**0.39**	0.38	0.39	0.40	0.39	0.37	0.36	0.36
Dividends declared, per common share	**0.340**	0.334	0.334	0.334	0.317	0.309	0.309	0.309

- The Company increased its dividend per common share by 3.0% to $0.115 per month effective with the November 2013 dividend.
- The Company subscribed for 4,768,000 trust units of the Fund in February 2013. The incremental ownership of trust units of the Fund increased the amount of distributions received on the trust units of the Fund and therefore, increased the Company's revenues and earnings.
- The Company increased its dividend per common share by 8.0% to $0.111 per month effective with the December 2012 dividend, which corresponded with a distribution increase from the Fund.
- The Company subscribed for 11,982,000 trust units of the Fund in December 2012 in connection with the acquisition of a portfolio of crude oil storage and wind and solar assets, which increased the total trust units of the Fund owned by the Company from 39,741,000 to 51,723,000. The incremental ownership of trust units of the Fund increased the amount of distributions received on the trust units and therefore, increased the Company's revenues and earnings.

OUTSTANDING SHARE DATA
As at February 10, 2014, 56,491,000 common shares and 1 special voting share of the Company were issued and outstanding.

ENBRIDGE INCOME FUND HOLDINGS INC.

FINANCIAL STATEMENTS

December 31, 2013

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Income Fund Holdings Inc. (ENF)

Financial Reporting
The management of Enbridge Management Services Inc. (EMSI) is responsible for the accompanying financial statements. The financial statements have been prepared in accordance with International Financial Reporting Standards and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors and the Audit Committee are responsible for all aspects related to governance of ENF. The Audit Committee, composed of independent and financially literate directors, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The Audit Committee meets regularly during the year with management, internal auditors and independent auditors to review the financial statements, Management's Discussion and Analysis, and Annual Information Form, as well as internal controls related thereto, prior to submission to the Board of Directors for approval.

Internal Control over Financial Reporting
To meet its responsibility for reliable and accurate financial statements, management has established or assumed responsibility for monitoring and maintaining adequate systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable, timely and accurate, and that assets are safeguarded from loss or unauthorized use and transactions are executed in accordance with management's authorization. The internal control system includes an internal audit function as well as monitoring of an established code of business conduct.

PricewaterhouseCoopers LLP, appointed by the shareholders as ENF's independent auditors, conducts an examination of the financial statements in accordance with Canadian generally accepted auditing standards.

"signed"
Perry F. Schuldhaus
President

"signed"
Colin K. Gruending
Chief Financial Officer

February 10, 2014

February 10, 2014

Independent Auditor's Report

To the Shareholders of
Enbridge Income Fund Holdings Inc.

We have audited the accompanying financial statements of Enbridge Income Fund Holdings Inc., which comprise the statements of financial position as at December 31, 2013 and December 31, 2012 and the statements of comprehensive income, changes in shareholders' equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

PricewaterhouseCoopers LLP
111 5 Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825, www.pwc.com/ca

pwc

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Enbridge Income Fund Holdings Inc. as at December 31, 2013 and December 31, 2012 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants

ENBRIDGE INCOME FUND HOLDINGS INC.
STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2013**	2012
(thousands of Canadian dollars, except per share amounts)		
Distribution and other income *(Note 4)*	**91,044**	59,835
Income tax *(Note 6)*	**(4,474)**	(7)
Earnings	**86,570**	59,828
Items that may be reclassified to earnings		
Other comprehensive income/(loss)		
Unrealized fair value change in available-for-sale investment *(Note 4)*	**(42,386)**	164,336
Income tax (expense)/recovery *(Note 6)*	**5,309**	(20,542)
	(37,077)	143,794
Comprehensive income	**49,493**	203,622
Basic and diluted earnings per common share	**1.55**	1.48

The accompanying notes are an integral part of these financial statements.

ENBRIDGE INCOME FUND HOLDINGS INC.
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

Year ended December 31,	**2013**	2012
(thousands of Canadian dollars)		
Share capital		
Common shares *(Note 5)*		
Balance at beginning of year	**802,683**	525,300
Issued for cash	**119,200**	277,383
	921,883	802,683
Special voting share *(Note 5)*	**-**	-
Balance at end of year	**921,883**	802,683
Share premium *(Note 5)*	**192,458**	192,458
Retained earnings		
Balance at beginning of year	**9,562**	2,492
Earnings	**86,570**	59,828
Common share dividends declared	**(75,264)**	(52,758)
Balance at end of year	**20,868**	9,562
Accumulated other comprehensive income		
Balance at beginning of year	**212,266**	68,472
Other comprehensive income/(loss)	**(37,077)**	143,794
Balance at end of year	**175,189**	212,266
Total shareholders' equity	**1,310,398**	1,216,969

The accompanying notes are an integral part of these financial statements.

ENBRIDGE INCOME FUND HOLDINGS INC.
STATEMENTS OF CASH FLOWS

Year ended December 31,	**2013**	2012
(thousands of Canadian dollars)		
Operating activities		
Earnings	**86,570**	59,828
Deferred income taxes	**114**	35
Changes in operating assets and liabilities		
Accounts receivable and other	**2,457**	(2,329)
Distributions receivable	**(699)**	(2,144)
Accounts payable and accrued liabilities	**(591)**	137
Income taxes payable	**4,323**	(2,456)
	92,174	53,071
Financing activities		
Subscription receipts issued *(Note 5)*	**-**	222,170
Common shares issued *(Note 5)*	**119,200**	55,213
Common share dividends paid *(Note 5)*	**(74,544)**	(51,097)
	44,656	226,286
Investing activities		
Purchase of Enbridge Income Fund trust units *(Note 4)*	**(119,200)**	(277,383)
Demand loan advances to investee *(Note 10)*	**(17,450)**	(6,800)
	(136,650)	(284,183)
Change in cash and cash equivalents	**180**	(4,826)
Cash and cash equivalents at beginning of year	**90**	4,916
Cash and cash equivalents at end of year	**270**	90
Supplementary cash flow information		
Income taxes paid	**37**	4,658

The accompanying notes are an integral part of these financial statements.

ENBRIDGE INCOME FUND HOLDINGS INC.
STATEMENTS OF FINANCIAL POSITION

December 31,	**2013**	2012
(thousands of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	**270**	90
Accounts receivable and other	**221**	2,678
Demand loan due from investee *(Note 10)*	**24,250**	6,800
Distributions receivable *(Note 4)*	**7,640**	6,941
	32,381	16,509
Investment in Enbridge Income Fund *(Note 4)*	**1,314,545**	1,237,731
	1,346,926	1,254,240
Liabilities and shareholders' equity		
Current liabilities		
Accounts payable and accrued liabilities	**79**	670
Income taxes payable	**4,323**	-
Dividends payable *(Note 5)*	**6,474**	5,754
	10,876	6,424
Deferred income taxes *(Note 6)*	**25,652**	30,847
	36,528	37,271
Shareholders' equity		
Share capital *(Note 5)*	**921,883**	802,683
Share premium *(Note 5)*	**192,458**	192,458
Retained earnings	**20,868**	9,562
Accumulated other comprehensive income	**175,189**	212,266
	1,310,398	1,216,969
	1,346,926	1,254,240

The accompanying notes are an integral part of these financial statements.

Approved by the Board of Directors:

"signed"
E.F.H. Roberts
Director

"signed"
Gordon G. Tallman
Director

ENBRIDGE INCOME FUND HOLDINGS INC.
NOTES TO THE FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Income Fund Holdings Inc. (ENF or the Company) is a publicly traded corporation, incorporated on March 26, 2010 under the laws of the Province of Alberta. The Company's common shares commenced trading on the Toronto Stock Exchange on December 21, 2010. The Company holds an investment in Enbridge Income Fund (the Fund), which is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta. The Company's registered office is 3000, 425 – 1st Street SW, Calgary, Alberta, Canada.

The business of ENF is limited to investment in the Fund. The Fund is involved in the generation, transportation and storage of energy through its green power generation facilities, liquids transportation and storage facilities and 50% interest in the Canadian segment of the Alliance Pipeline.

2. BASIS OF PREPARATION

The Company prepares its financial statements in accordance with International Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

Amounts are stated in Canadian dollars, the Company's functional and presentation currency, unless otherwise indicated.

The Company has consistently applied the same accounting policies throughout all periods presented, as if these policies had always been in effect.

The policies applied in these financial statements are based on IFRS issued and outstanding as of February 10, 2014, the date the Board of Directors approved the statements.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Measurement
These financial statements have been prepared under the historical cost convention except for the revaluation of available-for-sale financial assets to fair value.

Cash and Cash Equivalents
Cash and cash equivalents include short-term investments with an initial term to maturity of three months or less.

Financial Instruments
The Company classifies financial assets and liabilities as held for trading, available-for-sale, loans and receivables and financial liabilities at amortized cost. All financial instruments are initially recorded at fair value on the statement of financial position. Subsequent measurement of the financial instrument is based on its classification.

Available-for-Sale
Available-for-sale financial assets are non-derivatives that are not classified in any of the other categories. The Company's available-for-sale asset is comprised of an investment in the Fund. Available-for-sale financial assets are recognized initially at fair value plus transaction costs and subsequently carried at fair value. Gains or losses arising from changes in fair value are recognized in other comprehensive income (OCI). Distributions from available-for-sale instruments are recognized in earnings when the Company's right to receive payment is established.

The Company accounts for its investment in trust units of the Fund as an available-for-sale financial asset rather than under the equity method of accounting, which would typically apply in situations where an investor has significant influence over an investee, due to the redeemable nature of the trust units. The Fund trust units do not qualify as equity instruments under IFRS due to the redemption feature which permits holders to redeem trust units for cash, subject to certain limitations. Further, the Company does not consolidate its investment in the Fund as its investment does not confer control. Enbridge Inc. (Enbridge) is the controlling party for accounting purposes through the combination of its direct and indirect equity interests and preferred unit investment in Enbridge Commercial Trust (ECT), a subsidiary of the Fund, as well as through Enbridge's role as manager of the Fund.

Loans and Receivables
Loans and receivables, which include cash and cash equivalents, accounts receivable, demand loan due from investee and distributions receivable, are measured at amortized cost, using the effective interest rate method, net of any impairment losses recognized.

Financial Liabilities at Amortized Cost
Other financial liabilities are recorded at amortized cost using the effective interest rate method and include accounts payable and accrued liabilities and dividends payable.

Impairment
With respect to loans and receivables, the Company assesses the assets for impairment when it no longer has reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the loan or receivable to its estimated realizable amount, determined using discounted expected future cash flows.

For available-for-sale financial assets, the Company assesses at the end of each reporting period whether there is objective evidence that a financial asset is impaired. In the case of equity investments classified as available-for-sale, a significant or prolonged decline in the fair value of the security below its cost is evidence that the asset is impaired. If any such evidence of impairment exists, the cumulative loss, measured as the difference between the acquisition cost and the current fair value, less any impairment loss on that financial asset previously recognized in earnings, is removed from OCI and recognized in earnings. Impairment losses on available-for-sale equity instruments are not reversed.

Income Taxes
The liability method of accounting for income taxes is followed. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

Earnings per Share
Basic and diluted earnings per share is calculated by dividing earnings for the year by the weighted average number of common shares outstanding during the year. At December 31, 2013 and 2012, no potentially dilutive instruments were outstanding.

Dividends
Dividends on common shares are recognized in the Company's financial statements in the period in which the dividends are declared by the Board of Directors of the Company.

Accounting Estimates
The preparation of financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the financial statements. Significant estimates and assumptions used in preparation of the financial statements include, but are not limited to: the fair value of available-for-sale financial assets *(Note 8)* and income taxes *(Note 6)*. Actual results could differ from these estimates.

Changes in Accounting Policies
Effective January 1, 2013, the Company adopted IFRS 13, *Fair Value Measurement* which defines fair value and provides a single IFRS framework for the measurement and disclosure of fair value within IFRS standards. As the adoption of this standard impacted disclosure only, there was no impact to the Company's financial position for the current or prior periods presented.

Future Accounting Policy Changes
IFRS 9, *Financial Instruments* addresses classification and measurement of financial assets. IFRS 9 replaces the model for measuring equity instruments and will require recognition of the Company's investment in the Fund at fair value through earnings. The mandatory effective date for accounting periods beginning on or after January 1, 2015 was removed in November 2013 until the IFRS 9 project is finalized. Although immediate application of IFRS 9 is permitted, the Company does not anticipate early adoption of this standard.

4. INVESTMENT IN ENBRIDGE INCOME FUND

Year ended December 31,	**2013**	2012
(thousands of Canadian dollars)		
Balance at beginning of year	**1,237,731**	796,012
Investment acquired	**119,200**	277,383
Fair value change for the year	**(42,386)**	164,336
Balance at end of year	**1,314,545**	1,237,731

Plan of Arrangement
On December 17, 2010, pursuant to a plan of arrangement (the Plan) to restructure the Fund, all publicly held trust units of the Fund and 5,000,000 trust units of the Fund held by Enbridge were exchanged on a one-for-one basis for common shares of the Company, resulting in the Company owning 25,125,000, or 72.6%, of the Fund's issued and outstanding trust units. The Company's common shares commenced trading on the Toronto Stock Exchange on December 21, 2010.

Renewable Energy Acquisition
In October 2011, the Company subscribed for 14,616,000 trust units of the Fund at a price of $18.75 per unit to partially fund the Fund's acquisition of three renewable power generation facilities owned by subsidiaries of Enbridge (the 2011 Transaction). The assets acquired were the Sarnia Solar Project, the Ontario Wind Project and the Talbot Wind Project. Following the 2011 Transaction and related equity financing by the Fund, the Company held 39,741,000, or 80.7%, of the Fund's issued and outstanding trust units.

Crude Oil Storage and Renewable Energy Acquisition
In December 2012, the Company subscribed for 11,982,000 trust units of the Fund at a price of $23.15 per unit to partially fund the Fund's acquisition of crude oil storage facilities and three renewable power generation facilities owned by Enbridge and subsidiaries of Enbridge (the 2012 Transaction). The assets acquired were the Hardisty Contract Terminals, the Hardisty Storage Caverns, the Greenwich Wind Project, the Amherstburg Solar Project and the Tilbury Solar Project. Following the 2012 Transaction and related equity financing by the Fund, the Company held 51,723,000 or 84.5%, of the Fund's issued and outstanding trust units.

Enbridge Income Fund

The Fund is involved in the generation, transportation and storage of energy. The Fund conducts business through three operating segments: Green Power, Liquids Transportation and Storage, and Alliance Canada. The Green Power segment includes interests in renewable and alternative power generation facilities. The Liquids Transportation and Storage segment includes the Saskatchewan System crude oil and liquids pipeline systems which connects to the Enbridge Mainline System at Cromer, Manitoba, as well as liquids storage assets in both Saskatchewan and Alberta. Alliance Canada consists of the Fund's 50% interest in the Canadian portion of the Alliance System which transports natural gas from supply areas in northwestern Alberta and northeastern British Columbia to delivery points near Chicago, Illinois.

Summarized financial information of the Fund, derived from the Fund's consolidated financial statements prepared in accordance with United States generally accepted accounting principles (U.S. GAAP), is as follows:

Year ended December 31,	**2013**	2012[1,2]
(thousands of Canadian dollars)		
Revenues	**403,224**	389,642
Earnings	**79,815**	89,651

December 31,	**2013**	2012[2]
(thousands of Canadian dollars)		
Total assets	**2,756,810**	3,000,404
Total liabilities	**2,197,052**	2,555,731

1 Retrospectively adjusted to furnish comparative information related to an acquisition of crude oil storage facilities and wind and solar power generation facilities in December 2012.
2 Previously issued consolidated financial statements for the Fund have been revised. See "Revision of Prior Period Financial Statements" section.

Revision of Prior Period Financial Statements

In connection with the preparation of the Fund's consolidated financial statements for the three months ended March 31, 2013, an error was identified in the manner in which the Fund's investee, Alliance Canada, recorded a deferred regulatory asset associated with the difference between depreciation expense calculated in accordance with U.S. GAAP and negotiated depreciation rates recovered in transportation tolls. This resulted in an overstatement of the Fund's carrying value of its investment in Alliance Canada. Further, a deferred income tax liability and an offsetting regulatory asset were recognized by the Fund related to the carrying value of its investment. The Fund assessed the error and concluded that the related amount was not material to any of its previously issued consolidated financial statements. The Fund revised its previously issued consolidated financial statements to correct the effect of this error. This non-cash revision does not impact cash flows for any prior period.

The Fund's summarized financial information, prepared in accordance with U.S. GAAP, would differ had it been prepared under IFRS. The most significant differences between U.S. GAAP and IFRS applicable to the Fund are as follows:

Rate Regulation
The operations of Alliance Canada and certain Liquids Transportation and Storage businesses are subject to regulation by various authorities which exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. The timing of recognition of certain revenues and expenses impacted by regulation and the recognition of regulatory assets and liabilities under U.S. GAAP differs from IFRS. IFRS does not historically recognize regulatory assets and liabilities and also prohibits recognition of the equity component of allowance for funds used during construction (AFUDC), which is permitted under U.S. GAAP. At December 31, 2013, the Fund's net regulatory asset as presented in accordance with U.S. GAAP was approximately $60.9 million (December 31, 2012 – $72.9 million) including an equity component of AFUDC. The earnings impact of rate regulation was an approximate after tax decrease of $8.9 million for the year ended December 31, 2013 (2012 – $8.2 million increase).

Property, Plant and Equipment
Under U.S. GAAP similar assets are grouped and depreciated as a pool. Gains or losses are not recognized when the assets are disposed or retired. IFRS does not permit the pool method of accounting and would require gains or losses on retirement to be recognized in earnings.

Preferred and Trust Unit Presentation
Under U.S. GAAP, the ECT preferred units and trust units of the Fund are presented as mezzanine equity on the Consolidated Statements of Financial Position between long-term liabilities and unitholders' deficit. The ECT preferred units and trust units of the Fund are recorded at their maximum redemption value with changes in estimated redemption value reflected as a charge or credit to deficit.

Under IFRS, the ECT preferred units would be designated as a financial liability at fair value through profit or loss. The Fund's trust units would be recognized at amortized cost and presented as a liability by virtue of the holders' right to redeem the trust units for cash, subject to certain limitations. Adjustments to estimated future cash flows of a financial liability carried at amortized cost would be recognized in earnings.

Distribution Income
The Fund declared distributions on a monthly basis from January to October 2013 at a rate of $0.13417 per unit and at a rate of $0.13525 per unit for the months of November and December 2013. The Fund declared distributions on a monthly basis from January to November 2012 at a rate of $0.12067 per unit and at a rate of $0.13417 per unit for the month of December 2012.

5. SHARE CAPITAL AND SHARE PREMIUM

Authorized

The authorized share capital of the Company consists of an unlimited number of common shares with no par value, first preferred shares issuable in series limited to one half of the number of common shares issued and outstanding at the relevant time and one special voting share.

Issued and Outstanding

	2013		2012	
Year ended December 31,	Number of Shares	Amount	Number of Shares	Amount
(thousands of Canadian dollars except number of shares)				
Common shares				
Balance at beginning of year	**51,723,000**	**802,683**	39,741,000	525,300
Issued for cash	**4,768,000**	**119,200**	11,982,000	277,383
Balance at end of year[1]	**56,491,000**	**921,883**	51,723,000	802,683
Special voting share[1]	**1**	**-**	1	-
Balance at end of year	**56,491,001**	**921,883**	51,723,001	802,683

1 Enbridge owns 11,242,000 (2012 – 10,294,000) common shares and the special voting share.

Plan of Arrangement

Pursuant to the Plan, 20,125,000 trust units of the Fund held by public unitholders, together with 5,000,000 trust units of the Fund held by Enbridge, were exchanged for 25,125,000 common shares of the Company on December 17, 2010.

The initial stated capital of the Company for purposes of the *Business Corporations Act* (Alberta) (ABCA) was established to be $251.2 million, as determined at the discretion of the Company's Board of Directors. The residual amount of $192.5 million by which the fair value of the consideration received exceeded the stated capital was assigned to Share Premium. The Board may elect in the future to reinstate Share Premium to stated capital under certain circumstances.

Common Shares

Each common share represents an equal undivided beneficial interest in the net assets in the event of termination or wind-up of the Company. Holders of common shares are entitled to one vote per share at meetings of the Company's shareholders.

Dividends

The Board of Directors of the Company declared monthly dividends at a rate of $0.11125 per share for the months January to October 2013 and $0.1146 per share for the months of November and December 2013. The Board of Directors of the Company declared monthly dividends at a rate of $0.103 per share for the months January to November 2012 and $0.11125 per share for the month of December 2012.

On January 15, 2014, the Company declared a dividend of $0.1146 per share to be paid on February 18, 2014 to shareholders of record on January 31, 2014.

Special Voting Share
Enbridge, the holder of the special voting share is entitled to receive notice of and to attend all annual and special meetings of shareholders and is entitled to elect one director to the Board for so long as it beneficially owns or controls, directly or indirectly, between 15% and 39% of the issued and outstanding common shares, provided that if it elects to exercise its right to elect one director, it will not exercise the votes attaching to the portion of common shares representing its pro-rata representation on the Board in respect of the election of the remaining directors of the Company at meetings of shareholders. The holder of the special voting share will not be entitled to receive, in respect of the special voting share, any dividends or to participate in any distribution of the property or assets of the Company upon the liquidation, dissolution or winding-up of the Company. The special voting share may only be transferred or assigned to an affiliate of Enbridge.

2013 Common Share Offering and Private Placement
In February 2013, the Company completed a bought deal underwriting offering of 3,820,000 common shares at a price of $25.00 per common share for gross proceeds of $95.5 million. Enbridge also subscribed for an additional 948,000 common shares at a price of $25.00 per common share for gross proceeds of $23.7 million. The Company used the aggregate gross proceeds of $119.2 million to subscribe for 4,768,000 units of the Fund.

2012 Subscription Receipts Offering and Private Placement
In November 2012, the Company completed a bought deal underwriting offering of 9,597,000 subscription receipts at a price of $23.15 per subscription receipt for gross proceeds of $222.2 million. The gross proceeds were held by an escrow agent pending closing of the 2012 Transaction.

In December 2012, shareholders of the Company approved the 2012 Transaction, the gross proceeds from the subscription receipt offering of $222.2 million were released from escrow and each holder of a subscription receipt automatically received one common share of the Company without further consideration together with $2.0 million representing October and November dividends. Enbridge also subscribed for an additional 2,385,000 common shares at a price of $23.15 per common share for gross proceeds of $55.2 million. The Company used the aggregate gross proceeds of $277.4 million to subscribe for 11,982,000 units of the Fund and the Fund in turn used these proceeds to complete the 2012 Transaction.

Earnings Per Common Share
Earnings per common share is calculated by dividing earnings by the weighted average number of common shares outstanding. Weighted average shares outstanding used to calculate both basic and diluted earnings per share were 55,746,408 for the year ended December 31, 2013 (2012 – 40,430,376).

Shareholders' Rights Plan
The Shareholders' Rights Plan is designed to ensure the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties, acquires or announces its intention to acquire shares which combined with existing holdings would represent 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur, each rights holder other than the acquiring person and related parties will have the right to purchase common shares of the Company at a 50% discount to the market price at the time.

Dividend Reinvestment and Share Purchase Plan

Under the Dividend Reinvestment and Share Purchase Plan, registered shareholders may reinvest dividends in common shares of the Company and make additional cash payments to purchase common shares, free of brokerage or other charges. Common shares may be issued directly from the treasury by the Company, be purchased through the facilities of the TSX or be acquired through a combination of the two methods. For the years ended December 31, 2013 and 2012, the Company did not issue common shares from the treasury pursuant to the Dividend Reinvestment and Share Purchase Plan.

6. INCOME TAXES

The initial acquisition of Fund trust units under the Plan did not constitute a business combination, nor did the transaction affect earnings. As such, recognition of the resulting deferred income tax liability relating to the estimated taxable temporary difference of $71.4 million which arose on initial recognition of the investment in the Fund is not permitted.

At December 31, 2013 and 2012, deferred income taxes represented the difference in accounting and tax bases of the Investment in Enbridge Income Fund, less the deferred income tax liability not recognized on initial acquisition of the investment on December 17, 2010.

Income tax expense for the year ended December 31, 2013 was comprised of current income tax expense of $4.4 million (2012 – $28,114 recovery) and deferred income tax expense of $0.1 million (2012 – $35,119).

Income Tax Rate Reconciliation

Year ended December 31,	**2013**	2012
(thousands of Canadian dollars)		
Earnings before income taxes	**91,044**	59,835
Combined statutory income tax rate	**25.0%**	25.0%
Income taxes at statutory income tax rate	**22,761**	14,959
Decrease resulting from		
Non-taxable dividend	**(18,175)**	(14,923)
Return of capital	**(112)**	-
Other	**-**	(29)
Income tax expense	**4,474**	7
Effective income tax rate	**4.9%**	-

7. RISK MANAGEMENT

Market Price Risk

The Company's OCI is subject to market price risk resulting from changes in the fair value of the Company's investment in the Fund, which is referenced to the Company's common share price. The Company does not typically manage this risk. A $1.00 increase or decrease in the Company's common share price at December 31, 2013 would have resulted in an increase or decrease in OCI, before income taxes of $56.5 million (2012 – $51.7 million) due to the revaluation of the investment.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Accounts payable and accrued liabilities and dividends payable are due within one month. In order to manage this risk, the Company forecasts its cash flow over the near and long term and ensures that sufficient funds will be available when required. The Company's primary source of liquidity is cash distributions it receives from its investment in the Fund. Additional liquidity, if necessary, is expected to be available through collection of amounts advanced to a subsidiary of the Fund pursuant to a demand loan.

Credit Risk
Credit risk arises from the possibility that a counterparty may default on its contractual obligations to the Company. Demand loan due from investee, accounts receivable, interest receivable, distributions receivable and cash and cash equivalents are subject to credit risk, the maximum exposure of which is the carrying value as presented on the statement of financial position. The Company manages its exposure to credit risk by ensuring counterparties are of high credit quality. At December 31, 2013, accounts receivable were due from ECT and the Fund.

8. FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of financial instruments reflects the Company's best estimates of market value based on valuation techniques, supported by observable market prices where available. The fair value of cash and cash equivalents, loans and receivables and other financial liabilities approximate their carrying value due to the short period to maturity.

The Company categorizes those financial assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1
Level 1 includes financial instruments measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a financial instrument is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company did not have any financial instruments categorized as Level 1 as at December 31, 2013 or December 31, 2012.

Level 2
Level 2 includes financial instrument valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. The fair value measurement of the investment in the Fund is classified as Level 2, as the valuation technique references the quoted market price of the Company's common shares, and adjusts for assets and liabilities not applicable to the Fund. At December 31, 2013, the Company's investment in the Fund had a fair value of $1.3 billion (December 31, 2012 – $1.2 billion).

Level 3
Level 3 includes financial instrument valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the financial instruments' fair value. Generally, Level 3 financial instruments are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company did not have any financial instruments categorized as Level 3 as at December 31, 2013 or December 31, 2012.

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as at December 31, 2013 and December 31, 2012.

9. CAPITAL DISCLOSURES

The Company defines capital as shareholders' equity less cash and cash equivalents. Capital totaled $1.3 billion (2012 – $1.2 billion) at December 31, 2013.

The Company's objectives when managing capital are to provide liquidity for additional investment in the Fund and to generate adequate returns and predictable cash flow for distribution to shareholders in the form of dividends. New capital, if necessary, may be raised through the issuance of equity securities.

10. RELATED PARTY TRANSACTIONS

In connection with the Company's February 2013 offering of 3,820,000 common shares, the Fund reimbursed the Company for share issue costs of $4.1 million. Proceeds from the offering of common shares were used by the Company to purchase additional trust units of the Fund.

In connection with the Company's December 2012 offering of 9,597,000 subscription receipts, the Fund reimbursed the Company for share issue costs of $9.2 million. Proceeds from the offering of subscription receipts were used by the Company to purchase additional trust units of the Fund.

In 2013, the Company advanced $17.5 million (2012 – $6.8 million) to a subsidiary corporation of the Fund pursuant to a subordinated demand loan. At December 31, 2013, $24.3 million (2012 – $6.8 million) was outstanding. Interest on the demand loan was charged at 4.25% per annum. Interest income earned on the loan was $0.6 million (2012 – $0.1 million) for the year ended December 31, 2013 and $85,436 (2012 – $16,278) was included in accounts receivable and other as at December 31, 2013.

At December 31, 2013, accounts payable to Enbridge totaled $1,770 (2012 – $23,835) related to corporate costs paid by Enbridge on behalf of the Company. Accounts payable to the Fund were nil (2012 – $0.2 million) at December 31, 2013.

The Company has an agreement with ECT whereby ECT reimburses the Company for certain corporate costs. ECT reimbursed the Company $1.0 million (2012 – $1.4 million) for corporate costs incurred in 2013. At December 31, 2013, accounts receivable from ECT totaled $0.1 million (2012 – $0.4 million).

The Company has an agreement with Enbridge Management Services Inc. (EMSI), a wholly owned subsidiary of Enbridge, to provide management and administrative services to the Company. EMSI also provides management and administrative services to the Fund and the Fund's subsidiary, ECT. Provided that the Fund is paying a base fee to EMSI for the services received by the Fund, there is no fee payable to EMSI by the Company as was the case for the years ended December 31, 2013 and 2012.

AFFIDAVIT OF DR. DANIEL S. ARTHUR

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North Dakota Pipeline Co. LLC	)	Docket No. OR14-21-000

AFFIDAVIT OF DANIEL S. ARTHUR

I. BACKGROUND

1. My name is Daniel S. Arthur. I am a Principal at The Brattle Group, an economic and management consulting firm located at 44 Brattle Street, Cambridge, Massachusetts. I have over fifteen years of experience consulting to firms in the regulated energy transmission industries on pricing and ratemaking, competition and antitrust issues, and market assessment. I have filed testimony on cost-of-service matters in prior Federal Energy Regulatory Commission ("Commission") dockets including SFPP, L.P. Docket Nos. OR03-5-000, OR03-5-001, IS08-390, and IS09-437 and Mid-America Pipeline Company, LLC Docket Nos. IS05-216-003, *et al*. I have also filed testimony on cost-of-service matters in Enterprise TE Products Pipeline LLC Docket No. IS12-203-000. I have also presented testimony in prior proceedings before the Commission regarding oil pipeline market-based rates, including testimony in the Magellan Pipeline Company, L.P.,[1] Enterprise TE Products Pipeline Company LLC,[2] and Enterprise Products Partners L.P. and Enbridge Inc. proceedings.[3] Additional details of my professional and educational background are appended to this affidavit as Attachment A.

2. I have been asked by St. Paul Park Refining Co. LLC ("SPPRC") to evaluate the information and analysis contained in North Dakota Pipeline Company LLC's ("NDP")

[1] *Magellan Pipeline Co., L.P.*, Docket No. OR10-6-000 (2011).
[2] *Enterprise TE Products Pipeline Company LLC*, Docket No. OR11-6-000 (2011).
[3] *Enterprise Products Partners L.P. and Enbridge Inc.*, Docket No. OR12-4-000 (2012).

February 12, 2014 petition for declaratory order ("Petition") requesting certain advance rulings on the rate treatment for a proposed expansion and extension of its pipeline system known as the Sandpiper Project, and specifically the study by Muse Stancil & Co. ("Muse") entitled "Market Prospects and Benefits Analysis for the Sandpiper Project" dated February 2014 ("Muse Study") attached to NDP's Petition.[4]

II. INTRODUCTION AND SUMMARY

3. The Muse Study purports to provide a quantitative assessment of the expanded NDP system and the implications of the Sandpiper project on Bakkan crude oil pricing.[5] The Muse Study concludes that the expanded NDP system after the Sandpiper project will be operating at or near capacity for the forecast period 2016 through 2035.[6] In order to reach this conclusion, Muse constructed an optimization model that relies on a specific set of assumptions on the inputs to the model, including the crude oil supply by major production area and grade of crude oil, capacities and expansions of transportation alternatives (including pipeline volume commitments), prices for the transportation alternatives, refinery crude oil capacity and refinery specific constraints, and the refining value of the crude oil grades at each refinery.[7]

4. Because of missing or incomplete information regarding several of the assumptions contained in the Muse Study, it is not possible to determine whether the analysis and conclusions contained therein are accurate absent additional information. Several of the assumptions where no or incomplete information is provided would be expected to have a material impact on the analysis and conclusions of the report, and if those assumptions do not reflect accurate projections, the ultimate conclusions of the report may not be accurate. The assumptions with no information provided in the Muse Study include the assumed crude oil production and grade of crude oil for several geographic areas, and assumed prices for refined petroleum products that presumably affect the crude oil refining values inputs to the model.[8]

[4] The Muse Study is included in Exhibit 4 to NDP's Petition.

[5] Muse Study at 3.

[6] Muse Study at 6 - 7.

[7] Muse Study at 34 - 41.

[8] Muse Study at 35, 41.

5. Other assumptions where incomplete information is provided in the Muse Study include the capacities and prices of transportation alternatives, and refinery capacities. However, based on the information provided in the Muse Study, it is not clear that the assumptions are reliable over the 20-year period 2016 through 2035. It appears that the Muse Study assumes that the transportation and refinery capacities that are known today, as well as several transportation expansion projects projected to be in service over the period 2014 through 2020 will be the capacities that persist over the 20-year period of 2016 through 2035.[9] However, given the changes in volume of crude oil production presently occurring in various producing basins, including the Bakken area as well as other producing basins in North America, it is reasonable to expect that there will be changes in transportation capacities, as well as potential changes in the refinery capacities, occurring in response to changes in the crude oil production volumes in various basins.

6. It is not clear that the Muse Study has factored into its analysis any potential alternative scenarios other than its set of baseline assumptions with and without the Sandpiper project expansion.[10] Alternative scenarios would provide information on whether the Muse Study's conclusion that the expanded NDP system after the Sandpiper project will be operating at or near capacity for the forecast period 2016 through 2035 is robust under alternative scenarios, or whether other plausible scenarios exist whereby the expanded NDP system may not fully operate at capacity over the 20-year period 2016 through 2035.

III. KNOWN AND UNKNOWN ASSUMPTIONS IN THE MUSE STANCIL OPTIMIZATION MODEL

7. The Muse Study states that it relies on mathematical linear programming techniques to optimize the aggregate crude oil netback price in all producing basins examined, given the numerous assumptions regarding the crude oil production volumes, types of crude oil produced, transportation capacity and prices, refinery capacity, and crude oil refining values.[11] The Muse Study provides a brief overview of the assumptions made in the model inputs, however, the Muse Study does not provide sufficient information to be able to determine all of the inputs used in the optimization model, or the impact of the assumptions on the ultimate conclusions contained therein. The assumptions with missing information

[9] Muse Study at 35 – 41.

[10] Muse Study at 33.

[11] Muse Study at 33 – 41.

provided in the Muse Study include the crude oil supply by major production area and grade of crude oil, and assumed prices for refined petroleum products that presumably affect the crude oil refining values inputs to the model.[12] Other inputs where incomplete information provided include the capacities and prices of transportation alternatives, and refinery capacities. As discussed further below, it is not clear that the single set of assumptions made regarding transportation capacities and prices, and refinery capacities, is accurate over the 20-year period of the study.

A. MISSING INFORMATION REGARDING CRUDE OIL PRODUCTION INPUTS

8. The Muse Study states that it relies on forecasts of U.S. crude oil production by region provided by Crane Energy and the Energy Information Administration ("EIA"), and a forecast of crude oil production for Western Canada provided by the Canadian Association of Petroleum Producers ("CAPP").[13] In addition, because several of these forecasts end prior to the 2035 end-date of Muse's analysis, the forecasts are "extended" by Muse out to 2035.[14]

9. The EIA and CAPP crude oil production forecasts are publicly available; however, it is my understanding that crude oil production forecasts by Crane Energy are not publicly available. While there is a forecast of crude oil production in the states of North Dakota and Montana provided by Crane Energy attached to NDP's Petition,[15] there is no information provided for forecasts provided by Crane Energy for other US regions such as West Texas, the Rockies, or Alaska that were stated to be provided by Crane Energy in the Muse Study.[16] There is also no information provided in the Muse Study regarding the "extensions" of forecasts to 2035 performed by Muse.[17]

10. The crude oil production forecasts that are used as inputs in the Muse Study have an effect on the volumes predicted to move on the various transportation alternatives that are also inputs to Muse's optimization model. Crude oil production levels are changing rapidly in several producing areas in the US and Canada, with the change experienced and forecast in the Bakken formation being only one area that is experiencing significant production

[12] Muse Study at 35, 41.

[13] Muse Study at 35.

[14] *Id*.

[15] Exhibit 3 to NDP's Petition.

[16] Muse Study at 35.

[17] *Id*.

changes. For example, while production in the Bakken formation in the Williston Basin in North Dakota and Montana increased approximately 500% since 2009 to approximately 1 million barrels per day,[18] production in the Eagle Ford formation in south Texas also increased significantly from less than 1,000 barrels per day in early 2009 to nearly 1 million barrels per day by mid-2013.[19]

11. As crude oil production changes occur geographically, the price of crude oil at a basin will be affected by the capacity and prices of transportation alternatives moving product from the producing area to refineries. If transportation capacity out of a basin becomes constrained, the price of crude in the basin will decrease as production continues to increase, making purchasing crude in the basin more attractive in terms of price to refineries, and ultimately leading to changes in transportation capacity. Thus, the forecast of crude oil production in a particular geographic area relative to transportation capacity is a significant input to an optimization model attempting to estimate flows of crude oil from multiple production basins to refineries. Changes in the forecast of crude oil production in each producing basin should have an impact on whether transportation alternatives are found to be operating at or below capacity as a result of running an optimization model. However, based on the information contained in the Muse Study, it is not possible to tell what the assumed level of the crude oil production is at multiple production areas over the 20-year time period examined, and whether the forecasts are reasonable.

B. MISSING INFORMATION REGARDING CRUDE OIL REFINING VALUE INPUTS

12. The Muse Study states that a key input to its optimization model is the value of various North American crude oils to the potential refinery customers.[20] In order to derive these refining values, Muse relies on the AspenTech PIMS® linear programing system that is used by refineries to optimize refinery operations.[21] However, inputs to this linear programming model to optimize refinery operations and determine the value of various crude oils are the prices of the refined products produced from the various crude oils

18 *See* the graph of Williston Basin (that contains the Bakken formation) crude oil production contained on page 24 of the Muse Study.

19 *See* the EIA's Feb. 10, 2014 analysis titled "Eagle Ford Production Increasingly Targets Oil Rich Areas," available electronically at http://www.eia.gov/todayinenergy/detail.cfm?id=14951.

20 Muse Study at 41.

21 *Id*.

refined at the refinery.[22] The Muse Study does not provide any information on the assumptions made regarding the prices, and relative prices, for the refined products downstream of the individual refineries included in its optimization model that would affect the various values of crude oil inputs to the refineries. If the assumed prices for refined products are not accurate, then the resulting refining values for the various crude oils are also not likely to be accurate.

C. Incomplete Information Regarding Assumptions For Other Inputs That May Not Be Accurate Over the 20-Year Period Examined

13. The Muse Study does provide limited, but incomplete information on several input assumptions to its optimization model. These assumptions where only limited information is provided include the capacities and prices of transportation alternatives, and refinery capacities. However, based on the information provided in the Muse Study, it is not clear that the assumptions are reliable over the entire 20-year period 2016 through 2035. The assumptions made regarding transportation and refinery capacities will have an impact on whether an optimization model estimates that a specific transportation alternative such as the expanded NDP system will be operating at or below capacity over a 20-year period. If the assumptions regarding the capacities and prices of transportation alternatives, and refinery capacities, are not accurate, then the results of the optimization model are also likely not to be accurate.

14. It appears that the Muse Study assumes that the transportation and refinery capacities that are known today, as well as several transportation expansion projects projected to be in service over the period 2014 through 2020, will be the capacities that persist over the 20-year period of 2016 through 2035.[23] However, as crude oil production changes, including the amounts of various types of crude oil, both transportation capacities and refinery capacities to process various types of crude change. Changes in transportation capacity should be expected to correspond with changes in the geographic location of the changes in crude oil production, in the same manner that NDP is proposing to expand as crude oil production from the Bakken formation continues to increase. However, because the Muse Study does not provide any information on its assumed forecasts of crude oil production in

[22] *See* the description of the AspenTech PIMS® model available electronically at https://www.aspentech/com/PIMS_Brochure.pdf .

[23] Muse Study at 35 – 41.

many areas of the U.S., it is not possible to determine whether the assumptions made regarding transportation capacity are accurate given the assumptions regarding crude oil production. In addition, changes in crude oil production relative to assumed transportation capacity can lead to bottlenecks in the interconnected transportation system that could lead to some pipelines being found not to be operating at capacity due to constraints in downstream pipelines. Further, as constraints develop that are expected to persist, it is likely that the constraint would eventually be alleviated through capacity expansion. However, it appears that the Muse Study does not incorporate any future capacity expansions that result from pipelines being estimated to be at capacity, but rather assumes that pipelines that are found to be operating at capacity simply remain at capacity.

15. With respect to transportation prices, it appears that the Muse Study assumes transportation prices remain constant at current levels for existing capacity, with missing information regarding Muse's assumptions for the prices for expansion projects assumed to go into service in the future.[24] In addition to changes in crude oil transportation capacity occurring in response to changes in crude oil production, there are likely to be changes in transportation rates on existing systems that occur over a 20-year period. These changes in transportation rates are likely to occur as volumes change, as systems change capacity, or as systems depreciate or experience other cost changes. Changes in transportation rates are likely to have an impact on which transportation alternatives are estimated to be operating at or near capacity in an optimization model. Whether the assumptions made by Muse regarding transportation prices over the 20-year period are accurate cannot be determined without information regarding the prices Muse assumed for future expansions, and whether the assumed transportation capacities are consistent with the assumed changes in crude oil production.

IV. LACK OF ALTERNATIVE SCENARIO ANALYSIS

16. It appears that the Muse Study conducted only two sets of input assumptions for each year it analyzed, one set with the NDP system at its current capacity, and a second set of assumptions with the only change from the first set being an expansion of the NDP system capacity to include the Sandpiper project.[25] Examining the results of an optimization model over multiple sets of input assumptions at varying the levels of crude oil production,

[24] Muse Study at 40.

[25] Muse Study at 33.

transportation capacities and prices, and refinery capacities would provide information on whether the Muse Study's conclusion that the expanded NDP system will be operating at or near capacity for the forecast period 2016 through 2035 is robust under alternative scenarios, or whether other plausible scenarios exist whereby the expanded NDP system may not fully operate at capacity over the 20-year period 2016 through 2035.

V. CONCLUSIONS

17. The deficiencies in the Muse Study described above undermine the credibility of its conclusion that the expanded NDP system will be operating at or near capacity for the forecast period 2016 through 2035. In the brief period of time available to respond to the petition of NDP for a declaratory order, it is not possible to perform a more complete or thorough analysis. However, before the validity of the Muse Study can be intelligently evaluated, Muse should be required, at a minimum, to provide the following information:

- Complete information on assumptions made regarding inputs to Muse's optimization model;
- Complete information on outputs of the optimization model, including information on estimated transportation flows and the shadow prices of crude oil in the producing basins predicted by the optimization model;
- A description of, and documents related to, Muse's process for validating the results of the optimization model;
- A working version of the Muse Crude Oil Market Optimization Model, or some mechanism for access to the model in order to perform model runs using alternative assumptions to examine the sensitivity and robustness of the conclusions presented in the Muse Study under varying input assumptions.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

North Dakota Pipeline Co. LLC) Docket No. OR14-21-000

AFFIDAVIT

COMMONWEALTH OF MASSACHUSETTS)
) ss.
COUNTY OF MIDDLESEX)

Daniel S. Arthur, being first duly sworn, deposes and says he is the same Daniel S. Arthur, whose Affidavit accompanies this Affidavit of Daniel S. Arthur, that such testimony was prepared by him; that he is familiar with the contents thereof; and the facts set forth herein are true and correct to the best of his knowledge, information, and belief; and that he does adopt the same as his sworn testimony in this proceeding.

Daniel S. Arthur

On this 14rd day of March 2014, before me, the undersigned notary public, personally appeared Daniel S. Arthur, proved to me through satisfactory evidence of identification, which were personally known to Notary to be the person whose name is signed above, and who swore or affirmed to me that the contents of the document are truthful and accurate to the best of his knowledge and belief.

Marjorie J. Fischer
Notary Public

My commission expires November 7, 2014

MARJORIE J. FISCHER
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
November 7, 2014

DANIEL S. ARTHUR
Principal

Cambridge, MA | +1.617.864.7900 | Daniel.Arthur@brattle.com

Dr. Daniel Arthur is an economist consulting and providing litigation support primarily in the natural gas and oil industries. His economic areas of specialty include antitrust, pricing and ratemaking, and regulatory economics. Dr. Arthur holds both an M.A. and a Ph.D. in Economics from Northwestern University. He also has a B.S. in Business (Finance and Economics) and a B.S. in Mathematics and Statistics from Miami University. Prior to joining *The Brattle Group,* Dr. Arthur worked at Indiana University, where he worked on a team performing research in health economics. Dr. Arthur joined *The Brattle Group* in 1997.

AREAS OF EXPERTISE

- Antitrust
- Pricing and Ratemaking
- Regulatory Economics

EXPERIENCE

Antitrust

For numerous clients, Dr. Arthur has been involved in antitrust and market power cases before the Federal Energy Regulatory Commission, the Federal Trade Commission, and civil antitrust cases. Dr. Arthur's antitrust work includes the analysis of horizontal and vertical market power that would result from a proposed merger as well as the historical review of pricing behavior to determine whether market power was in fact exercised by an entity (or entities). Some of Dr. Arthur's consulting experience includes:

- On behalf of an oil refiner, Dr. Arthur presented testimony before the Federal Energy Regulatory Commission analyzing the market power held by a refined petroleum products pipeline seeking market based rates. Dr. Arthur's analysis focused on the competitiveness of alternatives to the pipeline from the refiner's perspective and the ability of the pipeline to increase prices in its destination markets. This analysis focused on the competitiveness of several geographic markets as well as how contracting between entities affects the substitutability of alternatives in the market.

- For a hearing before the Federal Energy Regulatory Commission and subsequent civil litigation, Dr. Arthur analyzed the market power resulting from control of natural gas pipeline capacity. The analysis involved defining the relevant markets, examining the anti-competitive behavior of holders of capacity to the destination market, and examining affiliate operations in the upstream market. One area of focus in this case was the impact of capacity constraints on the definition of the relevant market as well as the substitutability of alternatives to purchasing delivered natural gas. Analysis included examining the pricing behavior of market participants as well as examining the physical withholding of transportation capacity from the market.

- As the result of a settlement in a civil antitrust case, Dr. Arthur assessed the damages to entities consuming natural gas and electricity due to anti-competitive behavior in the natural gas transportation market. These damage estimates were performed at the class and individual entity level for numerous types of consumers and were used as the basis for the division of over $1 billion in settlement funds.

- On behalf of a natural gas pipeline involved in an antitrust suit, Dr. Arthur analyzed whether the pipeline was (or is) a monopolist within a specific market. His analysis focused on defining the relevant product and geographic markets and assessing which firms competing within the relevant markets possessed market power. Analysis for this case focused on three factors in defining what the alternatives available in the relevant market are: (1) the impact of capacity constraints; (2) natural gas pipelines' ability to expand; and (3) the substitutability of purchasing the right to pipeline capacity on the secondary release market to contracting directly with the pipeline for primary capacity rights.

- Dr. Arthur assisted in the development of expert testimony regarding the evaluation of market power and allegations of a conspiracy to monopolize by a gas gathering, processing and natural gas liquids transportation company in Texas. Analysis in this case involved: (1) a detailed comparison of the cost of entry into the natural gas processing market to the prices charged for the service; (2) the contracting behavior of purchasers of natural gas gathering and processing services; and (3) the relationship between the regulated natural gas liquids pipeline's rate and its underlying cost structure.

- Dr. Arthur assisted in the evaluation of whether a crude oil pipeline possessed market power in the context of a market based rates application before the Federal Energy Regulatory Commission. The primary issue in this case was how the substitutability of different grades of crude oil from a refiner's perspective affects the ability to use alternative pipeline transportation.

- On behalf of an electric utility, Dr. Arthur was part of a team which assessed the state of intrastate transmission, storage, and distribution services of the natural gas utilities in California, focusing on the aspects of the market that were functioning well under current regulations, where there existed or the potential existed for market power abuse, and made recommendations for restructuring or changing regulatory policy.

- On behalf of an owner of a natural gas pipeline, Dr. Arthur analyzed the antitrust implications of the owner's acquisition of another natural gas pipeline in the geographic area. This analysis was performed prior to making the decision on whether to acquire the pipeline and assisted the client in determining how the Federal Trade Commission would view the proposed transaction.

- Dr. Arthur assisted in the development of expert testimony on vertical market power relating to a proposed merger of a gas distribution company and an electric utility, examining the relationship between the natural gas and electric markets. Analysis focused on determining what the relevant product and geographic markets are and the incentives that would result from the proposed merged entity, as well as an assessment of whether behavioral or structural remedies would be necessary to alleviate potential market power concerns.

- Dr. Arthur analyzed the anti-competitive incentives that would result from the combination of two general partners of partnerships involved in natural gas liquids processing, fractionation, transportation, and trading. This analysis included examining the incentives to manipulate the availability of infrastructure to influence the commodity price, as well as the extent of the information regarding competitors' and customers' market positions that would be obtained as a result of the proposed combination.

Pricing and Ratemaking

Dr. Arthur's experience includes participation in several ratemaking proceedings for crude oil pipelines, refined petroleum products pipelines, natural gas pipelines, and natural gas liquids pipelines. Some of Dr. Arthur's areas of analysis in these proceedings include:

- Rate Base Determination: Dr. Arthur's analysis in several proceedings includes the issue of what is a reasonable rate base level when there are historical contracts that provided for the recovery of capital associated with the initial investment in the facilities.

- Income Tax Allowance: A contested issue in numerous proceedings, Dr. Arthur has been involved in the determination of the level of income tax allowance that should be provided to the unit holders of the master limited partnership that owns the regulated pipeline.

- Allocation of Unallocated Overhead Expenses to the Regulated Pipeline: Dr. Arthur has analyzed what a reasonable allocation is of unallocated overhead expenses from the parent organization to the regulated pipeline subsidiary using methodologies employed at the Federal Energy Regulatory Commission.

- Rate Design: Dr. Arthur's work regarding costs associated with pipeline expansions includes analyzing the question of whether to allocate the expansion costs to a subset of the pipeline system's customers, or to roll-in the costs with the rest of the system's costs and allocate the costs across all customers based on volumes and distances.

- Volume Level for Going-Forward Rates: Dr. Arthur's analysis for determining just and reasonable rates to be established on a going-forward basis includes examining what a representative level of volumes to be used to derive rates is. Proceedings where this issue has been particularly relevant is when there has been a recent capacity expansion or pro-rationing has been occurring due to operational restrictions that are expected to be lifted in the future.

- Analysis of Changed Circumstances: Dr. Arthur assisted in the development of expert testimony in an oil pipeline ratemaking proceeding before the Federal Energy Regulatory Commission, addressing the establishment of substantially changed circumstances in the economic basis of the rates in order for a shipper to successfully challenge an existing pipeline rate.

Other Economic Analysis

- On behalf of electric utilities owning nuclear generation plants and for testimony filed in Federal court, Dr. Arthur developed an empirical model of a trading market for rights to remove spent nuclear fuel. The model determined when individual utilities could expect their spent nuclear fuel to be removed if a trading market for rights existed.

- For a proposed gas pipeline expansion, Dr. Arthur analyzed whether there existed sufficient market demand to justify the expansion, and the impact of the proposed expansion on existing pipelines and producers.

- For an arbitration, Dr. Arthur assisted in the determination of the underlying events that caused a refined products pipeline to enter into bankruptcy protection. Dr. Arthur's analysis included an examination of the pipeline's changing financial position through time, sources of financing, requests for regulated rate changes, and the required pipeline integrity management program.

PUBLICATIONS

Comments (along with Dr. Romkaew P. Broehm and Mr. Gary Taylor) before the Commodities Futures Trading Association regarding the notice of Proposed Rulemaking Prohibition of Market Manipulation, 17 CFR Part 180, RIN Number 3038-AD27, January 2011.

"Improving the Performance of Natural Gas Markets in Electricity System Reliability" (with Matthew O'Loughlin and Elizabeth Lacey), *Electric and Natural Gas Business: Using New Strategies, Understanding the Issues*, Robert E. Willet, Editor, 2004: 75-89.

"Oil Pipeline Complaint Procedures Are Being Clarified," (with Matthew P. O'Loughlin and Steven H. Levine), *Natural Gas*, Vol. 20, No. 2, (September 2003).

"Gas Use in Electricity Generation: Increases Uncertain in Northeast, Midwest" (with Matthew P. O'Loughlin and Steven H. Levine), *Natural Gas Industry Analysis for Gas Year 2000-2001*, Robert E. Willett, Editor, 2000.

"Revision Rates Following Knee Replacement in the United States" (with D. Heck, C. Melfi, L. Mamlin, B. Katz, R. Dittus, and D. Freund), *Medical Care* 36(5) (May 1998): 661-669.

"Outcome Implications for the Timing of Bilateral Total Knee Arthroplasties" (with M. Ritter, L.A. Mamlin, C.A. Melfi, B.P. Katz, and D.A. Freund), *Clinical Orthopaedics and Related Research* No. 345 (1997): 99-105.

"Selecting a Patient Characteristics Index for the Prediction of Medical Outcomes Using Administrative Claims Data" (with C. Melfi, E. Holleman and B. Katz), *Journal of Clinical Epidemiology* 48(7) (1995): 917-26.

TESTIMONY

Before the Federal Energy Regulatory Commission, *Buckeye Pipe Line Company*, on behalf of Delta Air Lines, Inc., Continental Airlines, Inc., JetBlue Airways Corporation, United Air Lines, Inc. and US Airways, Inc., Docket Nos. OR13-3-000, December 2012.

Before the California Public Utilities Commission, *Application of SFPP, L.P.* on behalf of Chevron Products Company, Phillips 66 Company, Southwest Airlines Company, Ultramar Inc., and Valero Marketing & Supply Company, Application No. 12-01-015, November 2012, February 2013, April 2013.

Before the Federal Energy Regulatory Commission, *Delta Air Lines, Inc., et al. v. Buckeye Pipeline Company, L.P.* on behalf of Delta Airlines, Continental Airlines, Inc., JetBlue Airways Corporation, United Air Lines, Inc., and US Airways, Inc., Docket No. OR12-28-000, September 2012.

Before the Federal Energy Regulatory Commission, *Mobil Pipe Line Company*, on behalf of Suncor Energy Marketing, Inc., Canadian Natural Resources Limited, and Husky Marketing and Supply Company, Docket No. IS12-553-000, September 2012.

Before the Federal Energy Regulatory Commission, *Enterprise Products Partners L.P. and Enbridge Inc.* on behalf of Continental Resources, Inc., Husky Marketing and Supply Company, Suncor Energy Marketing, Inc., and Canadian Natural Resources Limited, Docket No. OR12-4-000, August 2012

Before the Federal Energy Regulatory Commission, *NuStar Logistics, L.P.*, on behalf of Valero Marketing and Supply Company, Docket Nos. IS12-502-000 and IS12-503-000 (not consolidated), July 2012.

Before the Federal Energy Regulatory Commission, *Buckeye Pipe Line Company*, on behalf of Delta Air Lines, Inc., Docket Nos. OR12-185-000, June 2012.

Before the Federal Energy Regulatory Commission, *Osage Pipeline Company, LL*, on behalf of HollyFrontier Refining and Marketing, LLC, Docket No. OR12-21-000, June 2012.

Before the Federal Energy Regulatory Commission, *Mobil Pipe Line Company*, on behalf of Suncor Energy Marketing, Inc. and Canadian Natural Resources Limited, Docket No. OR07-21-000, June 2012.

Before the Federal Energy Regulatory Commission, *Plantation Pipe Line Company*, on behalf of United Airlines Fuel Corporation, Docket No. IS12-382-000, June 2012.

Before the Federal Energy Regulatory Commission, *Plains Pipeline, L.P.,* on behalf of Valero Marketing and Supply Company, Docket No. IS12-362-000, June 2012.

Before the Federal Energy Regulatory Commission, *Nustar Logistics, L.P.*, on behalf of Valero Marketing and Supply Company, Docket No. IS12-314-000, June 2012.

Before the Federal Energy Regulatory Commission, *Seaway Crude Pipeline Company LLC*, on behalf of Suncor Energy Marketing, Inc., Canadian Natural Resources Limited, and Denbury Onshore LLC, Docket No. IS12-226-000, April 2012, October 2012.

Before the Federal Energy Regulatory Commission, *Enterprise TE Products Pipeline Company LLC*, on behalf of National Propane Gas Association *et al.*, Chevron Products Company, CHS, Inc., HWRT Oil Company LLC, and Truman Arnold Companies, Docket No. IS12-203-000, April 2012, October 2012.

Before the Federal Energy Regulatory Commission, *Enterprise TE Products Pipeline Company LLC*, on behalf of National Propane Gas Association *et al.*, Chevron Products Company and HWRT Oil Company LLC, Docket Nos. IS12-160-000 and IS12-165-000 (not consolidated), February 2012.

In arbitration, *Natural Gas Pipeline Company of America LLC v. Kinder Morgan Kansas, Inc.,* on behalf of Natural Gas Pipeline Company of America LLC, June 2011.

Before the Federal Energy Regulatory Commission, *Enterprise TE Products Pipeline Company LLC*, on behalf of Chevron Products Company and Lion Oil Company, Docket No. OR 11-6-000, April 2011, February 2012.

Before the Federal Energy Regulatory Commission, *SFPP, L.P.,* on behalf of Chevron Products Company, ConocoPhillips Company, Southwest Airlines Co., and Valero Marketing and Supply Company, Docket No. IS09-437-000, March 2010.

Before the Federal Energy Regulatory Commission, *Magellan Pipeline Company, L.P.*, on behalf of Frontier Oil and Refining Company, Docket No. OR10-6-000, March 2010, January 2011.

Before the California Public Utilities Commission, *Application of SFPP, L.P.*, on behalf of Chevron Products Company and ConocoPhillips Company, Application Nos. 09-05-014 *et al.*, December 2009.

Before the Federal Energy Regulatory Commission, *SFPP, L.P.*, on behalf of Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co., US Airways, Inc., Chevron Products Company, ConocoPhillips Company, and Valero Marketing and Supply Company, Docket No. IS08-390-002, January 2009, June 2011, February 2012.

Before the Federal Energy Regulatory Commission, *SFPP, L.P.*, on behalf of America West Airlines, Inc., Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co., US Airways, Inc., Chevron Products Company, and ConocoPhillips Company, and Valero Marketing and Supply Co., Docket No. OR03-5-000, June 2008, October 2008.

Before the Federal Energy Regulatory Commission, *SFPP, L.P.*, on behalf of Chevron Products Company and ConocoPhillips Company, Docket No. OR03-5-001, April 2008.

Before the Federal Energy Regulatory Commission, *Mobil Pipe Line Company*, on behalf of Suncor Energy Marketing Inc. and Canadian Natural Resources Limited, Docket No. OR07-21-000, October 2007, November 2007, April 2008, July 2008.

Before the Federal Energy Regulatory Commission, *SFPP, L.P.*, on behalf of Chevron Products Company, ConocoPhillips Company, and Valero Marketing and Supply Company, Docket Nos. OR96-2-012, *et al.*, April 2007.

Before the Federal Energy Regulatory Commission, *Mid-America Pipeline Company, LLC*, on behalf of National Propane Gas Association, AmeriGas Propane, L.P., CHS, Inc., ConocoPhillips Company, Ferrellgas, L.P., and Targa Liquids Marketing and Trade, Docket Nos. IS05-216-003, *et al.*, March 2007.

Before the Federal Energy Regulatory Commission, *SFPP, L.P.* on behalf of ConocoPhillips Company, Docket Nos. OR96-2-000 *et al.*, April 2006.

Declarations before the Superior Court of the State of California in support of Ex Parte Applications for Entry of Third and Fourth Distribution Orders in Natural Gas Antitrust Cases I, II, III, and IV [J.C.C.P. Nos. 4221, 4224, 4226 and 4228], April 2005, May 2005, December 2005.

Before the Federal Energy Regulatory Commission, *Sunoco Pipeline L.P.* on behalf of ConocoPhillips Company, Docket No. OR05-7-000, June 2005, August 2005.

Before the Federal Energy Regulatory Commission, *Shell Pipeline Company L.P.* on behalf of ConocoPhillips Company, Docket No. OR02-10-000, January 2004, March 2004.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

MOTION TO INTERVENE AND COMMENTS
OF FLINT HILLS RESOURCES, LP

Pursuant to Rule 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"),[1] Flint Hills Resources, LP ("Flint Hills") submits its motion to intervene and comments in the above-captioned proceeding, which was instituted by the Petition for Declaratory Order ("Petition") filed on February 12, 2014, by North Dakota Pipeline Company LLC ("NDPC" or "the Company").[2]

I. SUMMARY OF COMMENTS

Flint Hills does not oppose construction of NDPC's proposed Sandpiper Project ("Sandpiper" or "the Project"). Nor does Flint Hills take a position with respect to NDPC's projected utilization of the Project. There are several aspects of the Petition, however, which require clarification. *First,* the Commission should clarify that uncommitted shippers will not bear financial responsibility for underutilization of the Sandpiper Project should shipper demand prove to be less than NDPC anticipates. Even if NDPC proposes in the future to change the initial rates through a method other than indexing, NDPC should remain at risk for costs associated with any such

[1] 18 C.F.R. § 385.214 (2013).

[2] NDPC was formerly known as Enbridge Pipelines (North Dakota) LLC.

underutilization.[3] At the least, the Commission should clarify that approval of the rate structure proposed in the Petition does not limit the ability of parties to oppose any future proposal by NDPC to allocate costs associated with underutilization of the system to uncommitted shippers if and when such a rate filing is submitted.

Second, the Commission should clarify that, to the extent that the tariff rate structure proposed by NDPC contemplates recoupment through uncommitted rates of any revenue deficiency associated with the discounted committed rates, the Petition should be denied as inconsistent with Commission policy. The Commission should clarify that any approval of the use of discounted rates for Committed Non-Priority shippers is without prejudice to parties' rights to challenge any proposal to recover the costs associated with discounting the Committed Non-Priority rates from uncommitted shippers at the time NDPC makes its initial rate filing for the Sandpiper Project.

Finally, the Commission should require NDPC to provide additional information concerning its proposal to credit $7.5 million to the cost of service of each major segment of the Sandpiper Project. Without additional context, it is impossible for the Commission or the participants to determine whether this specific aspect of NDPC's proposed tariff rate structure is reasonable.

II. MOTION TO INTERVENE

A. Interest of Flint Hills

Flint Hills Resources Pine Bend, LLC owns and operates a crude oil refinery at Pine Bend, Minnesota that receives crude oil delivered via the NDPC system at

[3] The Commission should also find that NDPC's proposed definition of "design capacity," does not comport with Commission policy, and specify that NDPC must propose a definition of design capacity consistent with Commission policy when it makes its initial rate filing, at which time parties will have an opportunity to address the issue in detail. *See* Petition at 29, n.32.

Clearbrook, Minnesota. Flint Hills historically has purchased and shipped both North Dakota sweet and sour production on NDPC as feedstock for the Pine Bend Refinery. Therefore, Flint Hills has a direct and substantial economic interest in matters involving the transportation of North Dakota crude oil production to the Pine Bend Refinery. As a shipper and purchaser on the NDPC system, Flint Hills has a direct and substantial economic interest in this proceeding that cannot be protected adequately by another shipper. Accordingly, Flint Hills moves to intervene as a party.

B. Communications

Communication with respect to this matter should be addressed to:

Travis A. Pearson
FLINT HILLS RESOURCES, LP
4111 East 37th Street North
Wichita, KS 67220
Telephone: (316) 828-8594
Travis.Pearson@fhr.com

David D'Alessandro
John E. McCaffrey
STINSON LEONARD STREET LLP
1775 Pennsylvania Ave, N.W., Suite 800
Washington, DC 20006
(202) 785-9100
david.dalessandro@stinsonleonard.com
john.mccaffrey@stinsonleonard.com

III. DESCRIPTION OF THE FILING

NDPC asks the Commission to issue a declaratory order approving a number of principles relating to the proposed tariff rate structure and prorationing practices of NDPC's Sandpiper Project. The $2.7 billion Project will consist of two primary segments: (1) an upstream expansion of the existing system consisting of a 24-inch pipeline running from Beaver Lodge to Clearbrook, Minnesota ("Upstream Expansion") estimated to cost $1.5 billion; and (2) a downstream extension consisting of 30-inch pipeline running 233 miles from Clearbrook to Superior, Wisconsin ("Downstream Extension") projected to cost $1.2 billion.[4] NDPC states that the current capacity of its

[4] *See* Petition at 14-15.

single line from Berthold to Clearbrook is 210,000 barrels per day ("bpd"). The Upstream Expansion would increase this capacity by 230,000 bpd, for a total of 440,000 bpd.[5] The Downstream Extension is expected to have an annual average capacity of 380,000 bpd.[6]

The Petition presents a significantly different rate framework from the one NDPC proposed in its 2012 declaratory order petition rejected by the Commission.[7] The principal difference between the earlier filing and the new Petition is that NDPC has dropped its proposal for a rate for uncommitted shippers based on actual costs and actual throughput with a true-up mechanism. NDPC now proposes to support the Sandpiper Project with ship-or-pay contract commitments for a portion of the Project capacity. Specifically, NDPC states that, after conducting an open season, it has executed Transportation Services Agreements ("TSAs") for 155,000 bpd.[8]

The Petition proposes three categories of shippers:

Committed Priority Shippers are committed under ship-or-pay TSAs and pay a rate expected to be *above* the comparable rate for uncommitted shippers. In exchange for the higher rate, Committed Priority Shippers would not be prorated under ordinary operating conditions. NDPC states that "the majority" of the committed volumes will be subject to the premium rate for priority service.[9] Notably, if the rate for Committed Priority Shippers should ever fall below the uncommitted rate, the Committed Priority

---

[5] *Id.* at 15.

[6] *Id.* NDPC states that the 60,000 bpd difference between the upstream capacity of 440,000 bpd and the downstream capacity of 380,000 bpd is attributable to the volume typically delivered to the Minnesota Pipeline at Clearbrook each month. *See id.* at 15, n.15.

[7] *Enbridge Pipelines (North Dakota) LLC*, 142 FERC ¶ 61,212 (2013).

[8] Petition at 23.

[9] *Id.*

Shippers would have the choice of paying a rate one cent per barrel higher than the uncommitted rate *or* opting to be treated as a Committed Non-Priority Shipper.[10]

Committed Non-Priority Shippers are committed under ship-or-pay TSAs and would pay a rate expected to be *below* the comparable rate for uncommitted shippers.[11] These customers would be subject to proration, but would be deemed to have a history for proration purposes equal to the greater of their volume commitment or average shipments during the applicable base period.[12]

Uncommitted Shippers would pay the uncommitted rate – including rolled-in costs of the new Sandpiper capacity. While a shipper like Flint Hills taking deliveries at Clearbrook would not pay the additional rate for the Downstream Expansion, a customer taking deliveries at Superior would pay the entire rate for both segments.[13]

The Petition states that initial uncommitted rates will be based on the design capacity of the North Dakota Pipeline.[14] The uncommitted rates would be based on FERC's Opinion No. 154-B methodology, with indexing.[15]

[10] *Id.* at 37-38.

[11] *Id.*at 25-26.

[12] *Id.*

[13] *Id.* at 41.

[14] *Id.* at 29.

[15] *Id.*

IV. COMMENTS

A. Underutilization Risk

1. Any Commission Order Approving NDPC's Proposed Rate Structure Should Clarify that Uncommitted Shippers Will Not Bear Financial Responsibility for Underutilized Capacity on the Sandpiper Project

The Commission should clarify in any order approving the Company's proposed tariff rate structure that NDPC will remain at risk for underutilization of the Sandpiper capacity, even if NDPC proposes a change to the initial rates using a method other than indexing. The Commission's general policy is to require initial rates for new projects to be calculated based on the design capacity of the project, with the pipeline at risk for underutilization of the project capacity.[16] Although NDPC's proposed initial rate structure ostensibly adheres to this policy, NDPC reserves the right to file to adjust the uncommitted rates by a method other than indexing.[17] Absent the clarification requested by Flint Hills, therefore, NDPC could circumvent the protection that use of design capacity provides uncommitted shippers by filing to change the rates using a method other than indexing.

NDPC asserts that its proposed rate structure for the Sandpiper Project adequately protects uncommitted shippers from the risk that the Project will be underutilized, pointing, in particular, to its proposal to calculate initial uncommitted rates based on the design capacity of the expanded system.[18] By calculating rates in this manner, NDPC argues, "throughput risk will fall on the pipeline, not on the existing shippers, at the time

[16] *See White Cliffs Pipeline, L.L.C.*, 126 FERC ¶ 61,070 at P 31 (2009); *Enbridge Energy Co., Inc.*, 110 FERC ¶ 61,211 at PP 44-46 (2005).

[17] Petition at 26, n.30.

[18] Petition at 43.

of start-up of Sandpiper."[19] NDPC also maintains that the Petition makes a sufficient factual showing that the Sandpiper Project is likely to be utilized at or near capacity through 2035.[20]

As a threshold matter, the Commission should find that NDPC's proposed definition of "design capacity" as used in the Petition is not consistent with Commission policy.[21] NDPC purports to define "design capacity" as "'annual average capacity' meaning the volume of crude oil the pipeline can be expected to transport over the course of a year."[22] Contrary to the Company's assertion, this definition of design capacity is not consistent with Commission precedent. While NDPC is correct that design capacity is not necessarily a pipeline's "maximum theoretical capacity," neither is it defined by the volumes the pipeline "can be expected to transport over the course of a year."[23] NDPC's definition conflates design capacity with annual throughput. Determining design capacity instead involves an engineering analysis aimed at identifying the "design day" capacity that a pipeline will be able to transport on a year-round basis regardless of variables such as the effect of ambient temperature on system facilities, as the cases cited by NDPC itself make clear.[24] While Flint Hills does not believe this issue must be resolved conclusively here, the Commission should direct NDPC to propose a definition

[19] *Id.*

[20] *Id.*

[21] *See id.* at 29, n.32.

[22] *Id.*

[23] *Id.*

[24] *See Islander East Pipeline Co., L.L.C.*, 97 FERC ¶ 61,363 at PP 144-145 (2001); *Alliance Pipeline, L.P.*, 80 FERC ¶ 61,149 at 61,597 (1997); *see also Portland Natural Gas Transmission System*, 125 FERC ¶ 61,198 at P 16 (2008).

of design capacity consistent with Commission policy when it makes its initial rate filing, at which time parties will have an opportunity to address the matter in detail.

Notwithstanding this disagreement over how to define design capacity, Flint Hills agrees that, at least for the *initial* uncommitted rates, calculation of rates based on the properly-established design capacity of the Sandpiper Project would insulate existing uncommitted shippers from throughput risk should the utilization of the Project fall short of the Company's projections. In this respect, NDPC's proposed rate structure conforms with Commission policy, which generally requires that initial rates for new projects be calculated based on the design capacity of the project, with the pipeline at risk for underutilization of the project capacity.[25]

NDPC makes no commitment, however, to remain at risk for underutilization of the Sandpiper Project beyond establishment of the initial rates. While the Company states that it intends "to rely primarily on indexing of the initial uncommitted rates"[26] – which would preserve the use of design capacity in calculating the uncommitted rates – NDPC specifically states that it "reserves the same right that all other oil pipelines have to utilize the other rate-changing methods set forth in the Commission's regulations to the extent those other methods may apply in the future."[27] As to underutilization risk, NDPC argues that the Company's reservation of its right to change the initial rates "imposes no greater risk on uncommitted shippers than exists on any other oil pipeline regulated by the Commission."[28]

[25] *White Cliffs*, 126 FERC ¶ 61,070 at P 31; *Enbridge Energy Co.*, 110 FERC ¶ 61,211 at PP 44-46.

[26] Petition at 26, n.30.

[27] *Id.*

[28] *Id.* at 43.

NDPC's reservation of the right to use a rate-changing method other than indexing in the future to change the initial rates, unaccompanied by any commitment to insulate uncommitted shippers from underutilization risk, potentially shifts the Sandpiper throughput risk back on to uncommitted shippers like Flint Hills. Although Flint Hills takes no position at this time with respect to NDPC's utilization projections for the Sandpiper Project, the Project, like any large pipeline project, faces some level of underutilization risk. Contrary to NDPC's assertion that uncommitted shippers would face "no greater risk . . . than exists on any other oil pipeline regulated by the Commission" should Sandpiper be underutilized, NDPC is asking the Commission to approve a rate structure under which the rates for committed shippers would be fixed by TSAs. This means that uncommitted shippers on the NDPC system indeed face "greater risk" of being required to pay the costs of underutilized capacity that cannot be allocated to committed shippers. Such risk is heightened by the fact that only about 67 percent of the Sandpiper capacity is committed under TSAs (*i.e.*, 155,000 bpd of the 230,000 bpd Upstream Expansion capacity), and 36 percent of the total capacity of the expanded and extended NDPC system.[29]

To be sure, NDPC proposes that the rates for Committed Priority Shippers would always remain at least one cent higher than the uncommitted rate.[30] In theory, this commitment would require Committed Priority Shippers to share the costs associated with any underutilized capacity should NDPC seek to change its initial rates to allocate such costs to uncommitted shippers. But NDPC qualifies the commitment by proposing that if the rate for Committed Priority Shippers should ever fall below the uncommitted

[29] *Id.* at 36-37.

[30] *Id.* at 37-39.

rate (thereby invoking the requirement to increase the Committed Priority rate above the uncommitted rate), the Committed Priority Shippers would have the *choice* of paying a rate one cent per barrel higher than the uncommitted rate *or* being treated as a Committed Non-Priority Shipper.[31] In choosing to be treated as a Committed Non-Priority Shipper, a Committed Priority Shipper would pay only the discounted ship-or-pay rate, and thus, would presumably be insulated from an allocation of costs associated with underutilized capacity.[32] While a Committed Priority Shipper opting to become a Committed Non-Priority Shipper would give up the right to avoid proration under ordinary operating conditions, if capacity on NDPC system was being *underutilized* such that costs were being shifted to the uncommitted rate, such underutilization makes it more likely that a Committed Shipper would be willing to relinquish its priority status without fear of proration, thereby avoiding sharing in the costs associated with underutilized capacity.

For these reasons, the Commission should clarify in any order approving the rate structure that NDPC would remain at risk for underutilization of the Sandpiper capacity even if NDPC proposes a change to the initial rates in the future through a methodology other than indexing.

2. At a Minimum, the Commission Should Clarify that Approval of NDPC's Proposed Tariff Rate Structure does not Foreclose Parties from Challenging the Allocation of Costs Associated with any Underutilized Capacity on the Sandpiper Project in a Future Rate Filing

If the Commission declines to clarify that NDPC remains at risk for underutilized capacity on the Sandpiper Project, the Commission should, at a minimum, specifically clarify that approval of the rate structure proposed in the Petition does not limit the ability

[31] *Id.*

[32] *Id.*

of parties to oppose any future proposal by NDPC to allocate costs associated with underutilization of the system to uncommitted shippers if and when such a rate change is proposed. While NDPC notes that future rate changes "will be subject to the Commission's existing regulations,"[33] the Petition is not clear concerning the extent to which NDPC contends that approval of the proposed rate structure would foreclose objections to the future allocation of costs to uncommitted shippers.

The Commission should specify that any approval of NDPC's proposed committed/uncommitted rate structure does not serve as authorization, either express or implied, that NDPC may allocate to uncommitted shippers the costs associated with underutilization of the Sandpiper Project that are not recoverable from committed shippers. Parties must have the opportunity, should NDPC ever seek to change its initial rates based on design capacity, to oppose having to pay a higher uncommitted rate because of the TSAs' limits on the costs that may be recovered from committed shippers.

The Commission should also state that approval of the Petition does not foreclose objections to the Sandpiper capacity as imprudent or not used and useful. NDPC appears generally to agree that granting the Petition would not foreclose such challenges to Project cost recovery. NDPC's Petition does not request, for example, an advance finding that the Sandpiper Project capacity will be deemed used and useful, as was granted in *Calnev Pipe Line LLC*, 120 FERC ¶ 61,073 at P 28 (2007). Nor does NDPC request an advance finding that the decision to construct the Sandpiper Project is prudent. Based on NDPC's March 4, 2013 Response to Concord Energy LLC, *et al.*, moreover, NDPC appears to agree that parties would have the right to raise prudence and used and

[33] Petition at 43.

useful objections to the Sandpiper capacity.[34] Uncommitted shippers and other interested parties should not be foreclosed from opposing any future request to shift costs associated with underutilized capacity to uncommitted rates on the grounds that the decision to construct the Sandpiper Project was imprudent and/or that the Sandpiper capacity is not used and useful, and the Commission should so state in any order granting NDPC's Petition.

B. The Commission Should Clarify that Uncommitted Shippers Are Not Responsible for any Revenue Shortfall Associated with Discounted Committed Capacity

As explained above, NDPC's proposed rate structure includes a class of Committed Non-Priority Shippers who are expected to be charged a discounted rate relative to the uncommitted rates. Because NDPC's Petition lacks all but the most basic descriptive information about how NDPC's rates will be designed, it is impossible to tell from the Petition whether NDPC proposes to recoup any revenue deficiency associated with these discounts in uncommitted rates. To the extent, however, that NDPC may be contemplating such a discount adjustment to the uncommitted rates, the Commission should clarify that such an adjustment is inconsistent with Commission policy absent additional support.

The Commission recently explained in *Seaway Crude Pipeline Company LLC*, 146 FERC ¶ 61,151 (2014), that the availability of a cost-based uncommitted rate resembles a recourse rate under the Commission's natural gas alternative rate policy.[35] Similarly, the Commission indicted that committed shipper contracts resemble negotiated

[34] *See North Dakota Pipeline Company LLC*, "Response of North Dakota Pipeline Company LLC to Concord Energy LLC, Enwest Marketing LLC, And WPX Energy Marketing, LLC Motions to Compel Limited Discovery, Extend the Comment Date, and Enter a Protective Order" at 12, n.10 (March 4, 2014).

[35] *See Seaway*, 146 FERC ¶ 61,151 at P 31 (citing *Alternatives to Traditional Cost-of-Service Ratemaking of Nat. Gas Pipelines*, 74 FERC ¶ 61,076 (1996) ("Alternative Rate Policy").

rates under the Alternative Rate Policy.[36] Committed rates established by contract, the Commission explained in *Seaway*, need not be based on costs, and may be either higher or lower than a cost-of-service recourse rate.[37] Under the Commission's Alternative Rate Policy cited in *Seaway*, pipelines generally are not permitted to apply a discount-type adjustment for negotiated rates absent a specific showing that the negotiated rate was required to meet competition and that the adjustment does not have an adverse impact on recourse rate shippers.[38] In considering whether a discount-type adjustment for a negotiated rate is appropriate, the Commission will consider whether the pipeline should be entitled to retain any negotiated revenues in excess of the recourse rate.[39]

Here, the Petition does not specifically address how the discounted rates will be designed relative to the uncommitted rates, let alone justify any discount-type adjustment to the uncommitted rates. In the absence of such evidence, the Commission should clarify that NDPC is not entitled to adjust uncommitted rates to account for the discount provided to Committed Non-Priority Shippers. At a minimum, the Commission should clarify that approval of NDPC's proposed rate structure in this docket would be without prejudice to parties' right to challenge any proposal to recover the costs associated with discounting the Committed Non-Priority rates at the time NDPC makes its initial rate filing for the Sandpiper Project.

---

[36] *Id.*

[37] *See id.* at PP 26, 30-31.

[38] *See, e.g.*, *Texas Gas Transmission, LLC*, 138 FERC ¶ 61,175 at P 35 (2012).

[39] *Id.* at PP 35-39.

C. Additional Information is Necessary to Evaluate NDPC's Proposal to Credit $7.5 Million to the Cost of Service of Each Segment of the Sandpiper Project

The Commission should require NDPC to clarify its proposal to deduct $7.5 million from the cost of service of each major segment of the Sandpiper Project.[40] This $15 million credit proposal ($7.5 million per Sandpiper segment) is seemingly part of the "proposed tariff rate structure" for which NDPC requests Commission approval in this proceeding. Given the lack of rate information in the Petition, however, NDPC's $15 million credit proposal lacks any context that would allow Flint Hills or other interested parties to evaluate the reasonableness of the proposal. While a $15 million credit presumably is better than no credit at all, it is impossible to judge the reasonableness of this proposal in the overall context of the Sandpiper Project rate structure based on the limited information in the Petition. Accordingly, NDPC should be required to provide additional information concerning its proposed $15 million credit and support for why this level of credit is reasonable in the overall context of the Sandpiper rate structure proposal.

V. CONCLUSION

Based on the foregoing, Flint Hills respectfully requests the Commission to grant its motion to intervene in this docket and to consider its comments. In particular, the Commission should: (1) clarify that uncommitted shippers will not bear financial responsibility for underutilization of the Sandpiper Project should shipper demand be less than NDPC anticipates, even if NDPC proposes in the future to change the initial rates through a method other than indexing; (2) in the alternative, clarify that any approval of

[40] Petition at 42.

the rate structure proposed in the Petition does not limit the ability of parties to oppose any future proposal by NDPC to allocate costs associated with underutilization of the system to uncommitted shippers if and when such a rate filing is submitted; (3) clarify that the Commission is not approving any shifting of costs associated with discounted committed capacity to uncommitted rates, and any approval of the use of discounted rates for Committed Non-Priority shippers is without prejudice to parties' rights to challenge any proposal to recover the costs associated with discounting the Committed Non-Priority rates at the time NDPC makes its initial rate filing for the Sandpiper Project; and (4) require NDPC to provide additional information and support concerning its proposal to credit $7.5 million to the cost of service of each major segment of the Sandpiper Project.

Respectfully submitted,

/s/ John E. McCaffrey

Travis A. Pearson
FLINT HILLS RESOURCES, LP
4111 East 37th Street North
Wichita, KS 67220
316-828-8594

David D'Alessandro
John E. McCaffrey
Stinson Leonard Street LLP
1775 Pennsylvania Avenue, NW
Suite 800
Washington, DC 20006
202-785-9100

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document, via electronic or first class mail, upon each party on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission in this proceeding.

Dated at Washington, D.C., this 14th day of March, 2014.

/s/ John E. McCaffrey

John McCaffrey
Stinson Leonard Street LLP
1775 Pennsylvania Avenue, NW
Suite 800
Washington, DC 20006
202-785-9100
jmccaffrey@stinson.com

Document Content(s)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PROTEST AND OPPOSITION AND RENEWED MOTION TO INTERVENE OF CONCORD ENERGY LLC, ENSERCO ENERGY LLC, ENWEST MARKETING LLC AND WPX ENERGY MARKETING, LLC IN RESPONSE TO NORTH DAKOTA PIPELINE COMPANY LLC PETITION FOR DECLARATORY ORDER

TABLE OF CONTENTS

TABLE OF AUTHORITIES

DECISIONS

REGULATIONS

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

PROTEST AND OPPOSITION AND RENEWED MOTION TO INTERVENE OF CONCORD ENERGY LLC, ENSERCO ENERGY LLC, ENWEST MARKETING LLC AND WPX ENERGY MARKETING, LLC IN RESPONSE TO NORTH DAKOTA PIPELINE COMPANY LLC PETITION FOR DECLARATORY ORDER

Pursuant to Rule 211 of the Commission's Rules of Practice and Procedure, 18 C.F.R § 385.211, Concord Energy LLC (Concord), Enserco Energy LLC (Enserco), EnWest Marketing LLC (EnWest) and WPX Energy Marketing, LLC (WPX), collectively referred to as "Shippers," hereby submit this Protest and Opposition to the Petition for Declaratory Order (Petition) that North Dakota Pipeline Company LLC (NDP) filed on February 12, 2014 with the Federal Energy Regulatory Commission (FERC or Commission).

Concord, EnWest and WPX have previously requested that the Commission grant their Motion to Intervene in all proceedings involving the NDP Declaratory Order pursuant to 18 C.F.R. § 385.214.[1] They respectfully renew that Motion at this time, and are joined by Enserco in requesting that they be permitted to intervene as parties in all proceedings involving the NDP Declaratory Order.

[1] 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, Docket OR14-21-000, dated February 25, 2014.

I. SUMMARY OF PROTEST

This is the second time that NDP and its predecessor, Enbridge Pipelines (North Dakota) LLC (Enbridge), have asked the Commission to approve a pipeline expansion project that has been repeatedly rejected by shippers in North Dakota.

On November 12, 2012, Enbridge first sought Commission approval of its Sandpiper project. Because shippers in North Dakota had repeatedly rejected participating in the project, Enbridge never held an Open Season. Instead, it filed a Declaratory Order petition that asked the Commission to impose the costs of building a new pipeline on shippers of the existing pipeline, more than doubling the rates that they would pay. At that time, as well as at the present time, there was considerable unused capacity in the existing Enbridge line.

On March 22, 2013 the Commission rejected the Enbridge Petition without prejudice. The Commission first pointed out that, "Enbridge North Dakota's filing does not contain the cost support required by Part 346 of the Commission's regulations to establish cost-of-service rates."[2] The Commission then stated that if Enbridge refiles its Petition, it needed to file rates, "fully supported pursuant to the Commission's regulations."

Neither Enbridge nor NDP has done so. The current NDP Petition is much the same as the Enbridge 2012 filing, and does not include a cost of service.

As in 2012, NDP is now proposing to add a new 230,000 barrels per day (bpd) pipeline from Beaver Lodge, ND to Clearbrook, MN. When combined with its present pipeline, NDP would have the capacity to transport 440,000 bpd of Bakken crude oil to

[2] *Enbridge Pipelines (North Dakota) LLC,* 142 FERC ¶ 61,212 at P 28 (2013).

Clearbrook. NDP further proposes to extend its pipeline from Clearbrook to Superior, WI by constructing 233 miles of 30-inch pipe that would have an annual average pipeline capacity of 380,000 bpd. In connection with the new extension from Clearbrook, MN to Superior, WI, NDP proposes to eliminate Clearbrook as a destination for North Dakota shippers.

And again, once the new line is constructed, NDP is also proposing to raise the rates that current captive shippers would have to pay to levels that could potentially be double or more the current rates. In addition, NDP is again proposing to impose on uncommitted shippers the obligation of ensuring the pipeline's rate of return regardless of whether the new capacity that NDP proposes to build is in fact actually used by any shipper. In its Petition, NDP claims that it is abandoning any "true-up" mechanism, which previously required uncommitted shippers to bear the risk that shippers will not actually use the entire new capacity that NDP is building.[3] NDP's statement is not correct. In its current Petition, it appears that NDP is asking uncommitted shippers to pay whatever rate is necessary after the first year of operation in order to ensure NDP's rate of return and recovery of its costs, including the cost of investment in the new and expanded pipeline segments.

In fact, contrary to NDP's representations in its Petition, there are still further similarities between the Enbridge 2012 proposal that the Commission rejected and the present NDP Petition. In its 2012 project, Enbridge abandoned an Open Season for lack of shipper interest. In its 2014 solicitations, NDP found as little support for the pipeline project as Enbridge encountered in 2012. According to NDP, there are approximately 185

[3] Petition for Declaratory Order of North Dakota Pipeline Company LLC (NDP Petition), OR14-21-00, dated February 12, 2014, pages 42-43.

shippers on the NDP pipeline in North Dakota. Yet only 15 shippers, 8% of the total number of shippers on the NDP pipeline, were sufficiently interested to even ask for a *pro forma* Transportation Services Agreement (TSA) during the Open Season that NDP conducted from November 26, 2013 to January 24, 2014. NDP does not state how many of those 15 shippers went on to actually execute a TSA. However, only 155,000 bpd of the 440,000 bpd of total capacity of the Beaver Lodge to Clearbrook pipeline were committed during the Open Season.

Moreover, at least one of the committed shippers, Marathon Pipeline Company (Marathon), and possibly more, is an affiliate of the pipeline. According to news reports, Marathon is the "anchor" shipper on the pipeline and its parent company, Marathon Petroleum Corp., holds a 27% equity interest in NDP.[4] Thus, it appears that the majority of the 155,000 bpd subscribed to during the Open Season is attributable to affiliates of the equity owners of the pipeline. Moreover, as we will discuss more fully below, it also appears that the very structure of the Sandpiper project is designed to permit Marathon to use capacity for which uncommitted shippers will be paying to transport crude oil at lower rates to its Illinois and Ohio refineries.

[4] NDP stated that Marathon Pipeline Company was the anchor shipper for the project. According to a recent Wall Street Journal article, "Marathon Petroleum Corp., which operates refineries in Detroit, Mich., Canton, Ohio, and Catlettsburg, Ky., has agreed to help foot the $2.6 billion construction bill and provide much of the oil in exchange for a 27% stake in Enbridge's North Dakota pipeline network." See "In Dakota Oil Patch, Trains Trump Pipelines," Alison Sider, *Wall Street Journal*, dated March 3, 2014. http://online.wsj.com/news/articles/SB10001424052702304071004579407140444547268?mg=reno64wsj&url=http%3A%2F%2Fonline.wsj.com%2Farticle%2FSB10001424052702304071004579407140444547268.html.

It is clear that, NDP's current Petition represents an effort by the pipeline to use the Commission's processes to require captive shippers to finance and pay for a project that a majority of the shipping community does not want or need.

In this Protest, we will discuss in detail the reasons why a majority of the shipper community has not supported the Sandpiper project and why there is no justification for imposing on uncommitted shippers the unnecessary burden and unreasonable rate design that NDP is proposing.

- First, there is no substance to NDP's claim that an additional 230,000 bpd of pipeline capacity from Beaver Lodge to Clearbrook is necessary to meet crude oil demand for North Dakota Bakken production. Virtually every governmental study shows that current pipeline and rail facilities are more than sufficient for the foreseeable future to transport Bakken crude oil production from North Dakota to refining centers throughout the United States.[5]
- A Muse Stancil & Co. (Muse) study that NDP commissioned to support its contention that additional pipeline capacity is necessary is seriously flawed. It fails to taken into account existing North Dakota pipelines, is based on

[5] The Declaration of Robert P. Garner (Garner Declaration), which is attached to this Protest as Exhibit D, discusses North Dakota Pipeline Authority data regarding the capacities of rail and pipeline projects in the Bakken. See Exhibit D, pages 5-6, as well as Attachment A to Exhibit D. The Declaration of Peter K. Ashton (Ashton Declaration), attached as Exhibit F to this Protest, discusses data from the Energy Information Agency (EIA) and United States Geological Survey (USGS) regarding crude production in the Bakken. See Exhibit F, pages 23-24.

secret data that Muse refuses to share with either shippers or the Commission, and is contradicted by NDP's own prior statements.[6]

- The present NDP pipeline is adequate. The present capacity of the NDP pipeline from Beaver Lodge to Clearbrook is 210,000 bpd. During a prior Enbridge proceeding, NDP reported to the Commission that only 100,000 bpd – i.e., less than 50% of the pipeline's capacity – were shipped on the pipeline during certain months in the January 2012 to July 2013 period.[7] The monthly average shipment on the pipeline for the 12-month period from August 2012 through July 2013 was only 129,000 bpd or only about 60% of capacity.[8] In addition, the Shippers have stated in sworn Declarations attached to the Protest that they have been able to ship all the crude oil they wished on the NDP pipeline in 2013 and 2014.
- There is approximately 1 million bpd of rail take-away capacity in Western North Dakota today. That rail take-away capacity is expected to increase by 2016 to approximately 1.35 million bpd, an amount equal to the maximum level of production expected in the whole Bakken for the foreseeable future.
- The NDP rate design appears to impose inordinate cost burdens on uncommitted shippers. NDP is proposing to charge committed shippers – largely, we believe, affiliates of the equity owners of the pipeline – as little

[6] See Ashton Declaration, page 21-22, discussing statements made by Robert Steede in proceeding OR13-28-000.
[7] Appendix to *St. Paul Park Refining Co. LLC v. Enbridge Pipelines (North Dakota) LLC,* 145 FERC ¶ 61,050 (October 17, 2013).
[8] *Id*.

as one cent above the rates that uncommitted shippers pay in the first year. However, after that first year of operation, NDP could, under the rate design that it is now asking the Commission to approve, impose rates on uncommitted shippers that substantially exceed the rates that committed shippers pay. That could well mean that uncommitted shippers would bear the lion's share of the cost of constructing and operating a pipeline that they do not need. In fact, based on a review of the NDP rate structure, it is possible that current captive shippers could see their rates more than double if the NDP rate design were approved.

- The NDP project structure is inherently discriminatory and appears to be designed to confer economic benefits on an affiliated shipper, Marathon, at the expense of uncommitted shippers.

There is yet another critical issue that the Shippers are asking the Commission to address. As we pointed out previously, in its 2013 Decision dismissing the Enbridge Sandpiper project, the Commission pointed to the requirements that rates be justified by a cost of service filing, unless NDP was seeking market based rates or rates agreed to by all shippers on the pipeline.[9] However, in its current Petition, NDP is instead attempting to push all cost issues to a later stage of this proceeding. Doing so would place an unjust and unreasonable burden on the Shippers. It is therefore critical that cost and rate issues be decided *at this time*. If the NDP rate design were approved at this time as NDP requests, the Shippers' only recourse to contest cost and rate issues would be to file a Protest of an NDP cost of service *after* the new Sandpiper pipeline has already been constructed. The

[9] *Enbridge Pipelines (North Dakota) LLC,* 142 FERC ¶ 61,212 at P 28, 30.

Shippers would then only have 15 days to fully analyze and describe to the Commission the defects in NDP's cost structure. Moreover, even if the Shippers were successful in their Protest, the most likely outcome would be a protracted evidentiary hearing and subsequent appeal proceedings with the Shippers paying the pipeline's rates until the very end of the case. We respectfully suggest that this is a burden that is unjust and unreasonable.

For each of these reasons, the Commission should not approve an NDP rate design at this time that permits the pipeline to load disproportionate and unreasonable costs onto uncommitted captive shippers of the present NDP pipeline. We therefore respectfully urge the Commission to reject outright NDP's proposed Expansion Surcharge on uncommitted shippers and the rate design it proposes to establish. If, however, the Commission does not do so, it should certainly establish evidentiary hearing procedures, with all the attendant rights of discovery, so that disputed issues of fact regarding the underlying justification for the pipeline expansion and the costs that uncommitted shippers should properly bear if the pipeline project proceeds can be fairly resolved. That type of evidentiary hearing is expressly contemplated in Section 385.211(a)(4) of the Commission's procedural regulations.[10] To underscore the necessity of holding an evidentiary hearing if the NDP Petition is not denied, we are attaching to this Protest as Exhibit A, a list of disputed issues of fact, which NDP has the burden of proving in order to justify the relief it seeks in its Petition for Declaratory Order.

II. COMMUNICATIONS AND CORRESPONDENCE

Communications and correspondence regarding this Protest should be directed to:

[10] 18 C.F.R. § 385.211(a)(4).

David R. Steinman
General Counsel
Concord Energy LLC
7901 Shaffer Parkway
Littleton, CO 80127
303-468-1256
david.steinman@concordenergy.com

Thomas C. Godbold
EVP, General Counsel
Twin Eagle Resource Management, LLC
8847 W Sam Houston Parkway N
Houston, TX 77040
713-341-7378
Tom.Godbold@termna.com

Robert P. Garner
Managing Partner
EnWest Marketing LLC
2501 Wall Avenue
Ogden, UT 84401
801-393-7680
rob.garner@enwestmarking.com

Thomas G. Noulles
Senior Counsel
WPX Energy, Inc.
One Williams Center, Suite 3800
Tulsa, OK 74172
539-573-4229
Thomas.noulles@wpxenergy.com

Melvin Goldstein
Matthew Corcoran
GOLDSTEIN & ASSOCIATES, P.C.
1757 P Street, N.W.
Washington, D.C. 20036
202-872-8740
mgoldstein@goldstein-law.com
mcorcoran@goldstein-law.com

Counsel for Concord Energy LLC, Enserco Energy, LLC, EnWest Marketing LLC and WPX Energy Marketing, LLC

III. STATEMENT OF ECONOMIC INTEREST AND MOTION TO INTERVENE OF CONCORD, ENSERCO, ENWEST AND WPX

A. Concord

Concord is a marketer of crude oil in North Dakota, Montana and Colorado. As the sworn Declaration of Brad Vodicka (Vodicka Declaration) attached to this Protest as Exhibit B demonstrates, Concord purchases crude oil from supply sources throughout the Bakken Shale Region and transports this crude oil to appropriate markets. Concord is currently a shipper on NDP's pipeline system, and has been a regular shipper of record on the NDP pipeline system for the past three years. Concord has also made substantial investments in order to use the NDP pipeline system, including the construction of lact inject facilities at Ramberg, ND, as well as investments in truck unloading facilities, tankage and other facilities to determine crude oil quantities and quality control.

B. Enserco

As the sworn Declaration of Jonathan Molis (Molis Declaration), attached to this Protest as Exhibit C states, Enserco is a privately-held subsidiary of Twin Eagle Resource Management, LLC (Twin Eagle). Enserco owns and operates crude oil logistical assets in North Dakota, Montana and Wyoming. Enserco's parent company, Twin Eagle, engages in the acquisition of crude oil from North Dakota, Montana, Utah and Wyoming producers at the well head. Presently, a significant portion of Enserco's business activities is focused on the Bakken producing areas of North Dakota. Enserco has been a regular shipper of record on the NDP pipeline system and its predecessor, Enbridge Pipelines (North Dakota) LLC (Enbridge) for the past six years.

C. EnWest

As the sworn Declaration of Robert P. Garner, attached to this Protest as Exhibit D indicates, EnWest has been a regular shipper of record on the NDP pipeline system for at least the past three years and plans to continue shipping crude oil into the foreseeable future. EnWest has also made substantial investments in order to use the NDP pipeline system, including the construction of a crude oil injection facility at the NDP site at Stanley, ND. EnWest's investments at Stanley include truck unloading facilities, tankage, as well as other facilities to determine crude oil quantities and quality control.

D. WPX

In his sworn Declaration, attached to this Protest as Exhibit E, William Woodard, WPX's Director of Crude Trading, states that WPX is a substantial shipper of crude oil on the NDP pipeline system and intends to continue to use the NDP pipeline in the future.

In addition, the parent company of WPX, WPX Energy, Inc., is an independent oil and gas exploration and production company specializing through subsidiaries in producing natural gas, natural gas liquids and oil from non-conventional resources such as tight-sands and shale formations. WPX Energy, Inc. holds approximately 81,000 net acres on the Fort Berthold Indian Reservation, where it produces approximately 28,000 bpd from the Bakken Shale formation.

Accordingly, Concord, Enserco, EnWest, and WPX each have a substantial economic interest in this proceeding and have standing to file this Protest. The Shippers therefore respectfully request that their Motion to Intervene be granted.

IV. BACKGROUND

As discussed above, this is the second time that NDP and its predecessor, Enbridge, have asked the Commission to approve a rate design for a new pipeline that few independent shippers want or need. When Enbridge sought Commission approval of the Sandpiper project in 2012, the Commission strongly suggested that it needed to come forward with a cost of service that justified the rates it was proposing to charge.

Neither Enbridge nor NDP has done so.

A. NDP Position in this Proceeding.

Rather than submitting a cost of service for Commission approval, in its present Petition, NDP is instead asking the Commission to approve a rate design that has major cost implications for uncommitted shippers, with the cost of service to follow at some unspecified time in the future.

As a part that rate design, NDP is specifically asking the Commission to approve the imposition of an "Expansion Surcharge" on uncommitted shippers for the Beaver Lodge to Clearbrook segment as well as a Downstream Extension rate for the new Clearbrook to Superior line. The uncommitted shippers who would pay those fees are largely the historic shippers on the present NDP pipeline system. NDP's entire justification for the Expansion Surcharge is its claim that (i) there is a pressing need for additional pipeline capacity on the NDP system in order to relieve prorationing; and (ii) the precedents established by the Commission in the *Colonial*[11] and *Calnev*[12] cases.

With respect to the first item – the pressing need for additional capacity on the exiting NDP pipeline – NDP relies entirely on a study conducted by Muse, a consulting firm. With respect to the second item - the *Colonial* and *Calnev* cases - NDP is relying on Commission precedent in which every shipper acknowledged the need for expanding the capacity of the pipeline.

Although NDP states that it is no longer proposing a "true-up" system in which uncommitted shippers are asked to effectively guarantee NDP's full cost recovery and return on equity even if the pipeline is undersubscribed, the actual NDP Petition appears to state the opposite. We discuss this aspect of the NDP rate design as well as the alleged justification for any expansion of the existing NDP pipeline system in a subsequent portion of this Protest.

---

[11] *Colonial Pipeline Company*, 116 FERC ¶ 61,078 (2006), *order denying reh'g*, 119 FERC ¶ 61,183 (2007).
[12] *Calnev Pipe Line LLC*, 120 FERC ¶ 61,073 (2007).

B. NDP Pipeline Expansion Proposal

In its Petition, NDP outlines a pipeline construction project that is physically the same as the 2012 Sandpiper proposal.

The NDP pipeline presently originates at Alexander, ND, and terminates at Clearbrook, MN. At Clearbrook, an affiliate of NDP, Lakehead Pipeline Partners (Lakehead), interconnects with the NDP system and transports North Dakota crude oil to such destinations as Superior, WI, Chicago, IL, and Cushing, OK. NDP proposes to more than double its current 210,000 bpd pipeline from Beaver Lodge to Clearbrook by adding another 230,000 bpd of capacity.[13] In addition, NDP proposes to build a 380,000 bpd pipeline from Clearbrook, MN to Superior, WI.[14]

C. Justification for Expansion Surcharge on Uncommitted Shippers

The crude oil that NDP transports largely originates in the Bakken producing fields. As the Commission is well aware, the Bakken producing area of North Dakota has become one of the principal sources of crude oil in the United States. In the past, the result of increasing Bakken production has been bottlenecks in transporting Bakken crude out of the area to refining centers in other parts of the country. Those bottlenecks have occurred in the transportation of crude oil from North Dakota to Clearbrook, MN, as well

[13] Petition for Declaratory Order of North Dakota Pipeline Company LLC, OR14-21-00, dated February 12, 2014, page 15. Enbridge's 2012 Petition stated that the expansion capacity would amount to 225,000 bpd, increasing capacity to a total of 435,000 bpd. Petition for Declaratory Order and Offer of Settlement of Enbridge Pipelines (North Dakota) LLC, OR13-6-000, dated November 2, 2012, page 7.

[14] Petition for Declaratory Order of North Dakota Pipeline Company LLC, OR14-21-00, dated February 12, 2014, page 15. Enbridge's 2012 Petition stated that this line would have an initial capacity of 375,000 bpd. Petition for Declaratory Order and Offer of Settlement of Enbridge Pipelines (North Dakota) LLC, OR13-6-000, dated November 2, 2012, page 7.

as in the transportation of crude oil from Clearbrook on the Lakehead system to Superior, WI.

However, the marketplace has already reacted in a decisive manner to these transportation constraints. First, NDP has expanded its pipeline system on the basis of market factors. On February 28, 2012, Enbridge Energy Partners L.P. and other Enbridge entities announced an open season for the transportation of 145,000 bpd of Bakken crude oil from Berthold, ND, to Cromer, Manitoba, which connects to the Enbridge Mainline System (Bakken Pipeline Expansion).[15] This system reaches American refineries as far south as the US Gulf Coast. At the same time, Enbridge announced the construction of an 80,000 bpd rail facility at Berthold, ND.[16] This facility too would transport Bakken crude oil to American refining centers. Enbridge announced the completion of the Bakken Pipeline Expansion on March 4, 2013.[17]

In addition to this pipeline expansion, the market has supported the development and expansion of an extensive rail transportation system. As of December 2013, this rail system has had the ability to transport 965,000 bpd of crude oil from Bakken fields to refining centers throughout the country. By year-end 2014, another 230,000 bpd will have been added to this capability, so that the rail take-away capacity from the Bakken will be 1,195,000 bpd.[18]

---

[15] "Enbridge Launches Binding Open Season for Sanish Pipeline Project and Bakken Expansion Program," Enbridge Press Release, February 28, 2012: http://www.enbridge.com/MediaCentre/News.aspx?yearTab=en2012&id=1557567.
[16] *Id.*
[17] "Enbridge Energy Partners and Enbridge Income Fund Announce Completion of Bakken Pipeline Expansion Project, News Release," March 4, 2013: http://www.enbridge.com/MediaCentre/News.aspx?yearTab=en2013&id=1693907.
[18] Attachment A attached to the Sworn Declaration of Robert P. Garner (hereinafter "Garner Attachment A").

As a result of this rapid expansion of rail transport, there is at the present time, sufficient rail and pipeline transportation facilities to ship approximately 1.5 million bpd of Bakken crude oil.[19] The use of extensive rail transport clearly indicates that the market regards the availability, pricing and terms of service of rail transport as equally desirable as the pipeline service on the Enbridge and NDP systems.

Furthermore, the present NDP pipeline system has been underutilized. According to the Order on Complaint in FERC Docket OR13-28-000, the existing NDP line transported less than 100,000 bpd from Beaver Lodge to Clearbrook in several months between January 2012 to July 2013. In April 2013, the NDP shipped only 70,083 bpd.[20] On average, throughput during that January 2012 to July 2013 period was less than 75% of the 210,000 bpd capacity of the pipeline. During the period August 2013 to the present date, the NDP pipeline has also been able to transport virtually all of the crude oil tendered to it.[21]

NDP nonetheless cites a study it commissioned from Muse to support its position that the Sandpiper project is needed. The Muse report states that in its opinion, sufficient demand for pipeline transportation exists from Beaver Lodge to Superior to fill the entire pipeline expansion throughout its expected life. Muse bases this conclusion on its view that the demand for Bakken crude oil by Midcontinent and Eastern Canadian refineries is so strong that they will fill the entire Sandpiper pipeline. According to Muse, rail

---

[19] Garner Attachment A.
[20] *St. Paul Park Refining Co. LLC v. Enbridge Pipelines (North Dakota) LLC*, 145 FERC ¶ 61,050 (October 17, 2013) at P 35. Also see the Appendix attached to that order.
[21] Garner Declaration, page 8; Vodicka Declaration, page 2; Molis Declaration, page 2; Declaration of William Woodard, page 2.

transportation to these locations is significantly more expensive and therefore will not be competitive with the rates that it believes Sandpiper will charge.

However, as we will discuss in greater detail below, the Muse study is seriously flawed.

- The Muse report concludes that it is downstream pipeline capacity constraints that have prevented NDP from transporting crude oil at the capacity of the line during 2012 and 2013. That position, however, is directly contrary to the position that Enbridge took in a prior Commission proceeding. In the OR13-28-000 proceeding, Enbridge contended that it was not downstream capacity constraints but rather widening crude oil price differentials at different locations in the United States that led to the underutilization of the NDP, a position that the Commission itself accepted.
- It does not appear that the Muse report considered all of the pipelines and refineries in North Dakota that presently consume and transport Bakken crude oil and will do so in the future.
- The Muse report appears to treat rail transportation as a "second best alternative" based on its alleged higher cost without recognizing the substantial investment in rail capacity that already exists and is currently being made to transport Bakken crude oil.
- The Muse study fails to take into account the growing investment in rail transportation by refining operations around the country. For example, a number of West Coast refiners, including Tesoro, Valero, and Phillips 66 have announced plans to build rail-offloading facilities at their refineries in Washington and

California. There are over 80 rail loading and unloading facilities being built or in the process of being built around the country.

- It is very unlikely that U.S. Mid-Continent refineries in PADD II will use Bakken crude oil transported by Sandpiper as the Muse study concludes. In 2012 over 1.2 million bpd of crude oil from western Canada were imported into PADD II. The expansions of Enbridge's Canadian system means that even more Western Canadian crude oil, not Bakken crude, will be used in this area.
- Muse's suggestion that Bakken crude can break into the Eastern Canadian market is also fanciful. This region receives large quantities of its pipeline crude oil supplies from Western Canadian producers and Canadian producers view this area as a target market for their growing production. It is faulty economic logic to assume that those producers will permit their markets to be eroded by Bakken crude oil without taking responsive action. Furthermore, 330,000 bpd of Eastern Canadian refining capacity is not even connected to pipelines.
- The Muse report and its "black box" model appear to be highly sensitive to assumed future production levels in the Bakken area. Consequently, if production does not reach the levels Muse assumes, the supposed benefits that Muse claims would flow from the expansion of the NDP will never materialize.
- Muse's claim that $5 billion in benefits would inure to producers if the NDP expansion were constructed is a misleading and overstated figure.

In any event, the Muse study is of limited value in this proceeding because both the model Muse uses and the inputs to that model are supposedly proprietary and confidential and will not be shared with the Shippers or their experts. Surely the

Commission should not give any weight to a disputed expert report, particularly when the expert has failed to reveal the underlying basis of his assumptions and conclusions.

D. The Colonial and Calnev Cases

Based on the Muse study – which is so seriously flawed that no meaningful conclusions can be drawn from it – NDP claims that the Commission's *Colonial*[22] and *Calnev*[23] cases establish a precedent for imposing an Expansion Surcharge on the existing uncommitted shippers for the construction of the Sandpaper project.

In *Colonial*, the Commission stated that Colonial had indicated that its pipeline system running between Houston, TX and Linden, NJ had been under significant prorationing during the summer and winter months, and expected to be further constrained in the near future by increased Gulf Coast refinery capacity of approximately 700,000 bpd.[24] The Commission specifically stated in granting the petition that all intervenors in this case, including the two protestants, agreed that the new transportation capacity was needed.[25]

A similar situation existed in the *Calnev* proceeding, in which the pipeline proposed constructing a 16-inch diameter line to parallel its existing system from Colton, CA to Las Vegas NV. Space on the existing Calnev system had been significantly constrained by growing demand from southern Nevada - demand that was expected to continue to grow and had even been the focus of an inquiry by the Board of

[22] *Colonial Pipeline Company*, 116 FERC ¶ 61,078 (2006), *order denying reh'g*, 119 FERC ¶ 61,183 (2007).
[23] *Calnev Pipe Line LLC*, 120 FERC ¶ 61,073 (2007).
[24] *Colonial*, PP 4-6
[25] *Colonial*, P 43.

Commissioners of Clark County, NV.[26] In approving Calnev's petition, the Commission specifically stated:

> It is important to recognize that all of Calnev's shippers agree that the proposed expansion is necessary to meet the increasing demand for capacity in Calnev's markets, especially in the Las Vegas area. Because of the increasing demand for motor fuel and jet fuel in the Las Vegas area, all parties agree that demand will outstrip supply in the next few years and that the only viable method of meeting the long term demands of the region is a pipeline expansion.[27]

Clearly that is not the situation in this case. NDP has not been in significant prorationing. All parties do not agree that the production of crude oil in the Bakken exceeds the take-away capacity. Quite to the contrary, it is clear that the NDP pipeline expansion is not needed to meet demand. The facts of the present case do not have any similarity to either the *Colonial* or the *Calnev* cases.

E. Rate Issues Embedded in the NDP Rate Design

It is important that the Commission be aware of the implications of the rate design issues that NDP is asking it to decide at this time.

First, NDP is asking the Commission to determine at this time that uncommitted shippers, which includes the historic shippers on the present NDP pipeline system, should pay a substantial portion of the costs of constructing NDP's new pipeline system and thus pay significantly higher rates than they currently pay.

Secondly, NDP is asking the Commission to approve at this time a rate regime in which committed shippers will, throughout the life of the pipeline, only be required to pay the base rates specified in their TSA's plus a flow through power charge. The direct consequence of this proposition is that uncommitted shippers might well be required to

[26] *Calnev*, PP 4-5.
[27] *Calnev*, P 24.

pay rates that are substantially higher than committed shippers in order to ensure that the pipeline recovers its costs including its rate of return, regardless of the volume of crude oil that the pipeline actually transports. We discuss this point in detail below.

It is true that certain portions of the NDP Petition state that uncommitted shippers will pay at least one cent below the rates of committed shippers and that the pipeline has abandoned a "true-up" mechanism guaranteeing the pipeline's cost recovery and rate of return. However, other portions of the NDP Petition seemingly contradict those statements. The Shippers are very concerned that the Commission's approval of the rate design that NDP proposes will place inordinate financial burdens on uncommitted shippers and relieve the pipeline and its shipping affiliates from assuming any risk.

We discuss this issue as well below.

Finally, the rate design that NDP proposes could well result in more than doubling the rates that current shippers pay, without providing any corresponding benefit to them. We point out below why this portion of the NDP rate design is unjust and unreasonable.

V. BASIS OF PROTEST AND OPPOSITION TO NDP PETITION FOR DECLARATORY ORDER

A. NDP has Failed to Demonstrate That There Is an Economic Justification for Constructing a Pipeline That Doubles the Present Capacity of the NDP Line.

The entire NDP Petition is based on NDP's allegation that the current NDP pipeline is inadequate to meet the demand for transportation of crude oil and that doubling the capacity of the line is required to alleviate serious congestion. The acceptance of this proposition is the entire basis for the imposition on uncommitted shippers of the

Expansion Surcharge for the Beaver Lodge to Clearbrook segment and the Downstream Extension rate component for the new Clearbrook to Superior line.[28]

However, NDP's claim is without basis and unsupported by the facts.

1. Government Reports Indicate that There Is More Than Ample Take-Away Capacity of Bakken Crude Oil and That the NDP Sandpiper Project Is Not Needed and Will Not Be Used.

As Peter K. Ashton, a transportation economist states in his sworn Declaration attached to this Protest as Exhibit F, an assessment of the need for a new pipeline transportation project can generally be made by comparing the current and expected demand with the current and prospective facilities that can meet this demand.[29]

This comparison of supply and demand conclusively demonstrates that there is no need for the additional capacity that the Sandpiper project would provide.

Attachment A to the sworn Declaration of Robert P. Garner includes a chart of crude oil pipelines and crude oil rail transportation facilities in the Bakken area of North Dakota. The chart was prepared by the North Dakota Pipeline Authority. An excerpt of that chart is provided below.

US Williston Basin Crude Export Options - January 22, 2014
Year End System Capacity, Barrels Per Day (BPD)

	2007	2008	2009	2010	2011
Pipeline / Refining Total	230,000	272,000	286,000	337,500	413,000
Rail Only Total		30,000	95,000	115,000	265,000
All Transportation Total	230,000	302,000	381,000	452,500	678,000
	2012	**2013**	**2014**	**2015**	**2016**
Pipeline / Refining Total	463,000	583,000	783,000	843,000	1,168,000
Rail Only Total	660,000	965,000	1,195,000	1,355,000	1,355,000
All Transportation Total	1,123,000	1,548,000	1,978,000	2,198,000	2,523,000

[28] NDP Petition, pages 5-6, 28-29.
[29] Ashton Declaration, page 29.

As the chart demonstrates, the North Dakota Pipeline Authority has stated that by year end 2013, there was a total of 583,000 bpd of pipeline and refinery take-away capacity from the Bakken. During that same 2013 period, there was 965,000 bpd of take-away rail capacity. The total take-away capacity was therefore 1,548,000 bpd. The North Dakota Pipeline Authority predicts that by the end of 2015, there will be a total of 843,000 bpd of pipeline capacity without the Sandpiper project.[30] Rail capacity is predicted to be 1,355,000 bpd. The total projected take-away capacity at the end of 2015, not including the Sandpiper expansion, is therefore 2,198,000 bpd.

As Mr. Ashton reports in his Declaration, the Energy Information Agency (EIA) reports that in 2013, about 930,000 bpd of crude oil were produced from the Bakken. The EIA predicts that 950,000 bpd will be produced in 2021.[31] Those figures are considerably lower than the production estimate of Steven D. Crane, an expert for NDP. According to the Crane analysis, crude oil production by year-end 2015 will be approximately 1.2 million bpd and Bakken crude oil production in 2026 will peak at 1.4 million bpd.

The U.S. Geological Survey of the U.S. Department of the Interior also projects significantly lower production rates from the Bakken area than Mr. Crane, a fact that Mr. Crane himself notes in his affidavit.[32] USGS projects only 7.4 billion barrels will be produced from the Bakken area between 2012 and 2041 whereas Mr. Crane projects a figure that is 50% higher (11.1 billion barrels).[33]

---

[30] According to Garner Attachment A, total pipeline capacity by year end 2016 would be 1,168,000 bpd, which includes estimate of 225,000 bpd of capacity for Sandpiper. See Garner Attachment A.
[31] Ashton Declaration, pages 23-24.
[32] Crane Affidavit, page 5.
[33] See Ashton Declaration, pages 23-24.

Using the EIA data, it is entirely clear that more than sufficient take-away capacity presently exists for Bakken crude oil. *Current pipeline and rail capacity is more than 1 million bpd in excess of production*. Using EIA's projected production, pipeline and rail take-away capacity will still be more than 1 million bpd greater than production.

The same conclusion is compelled using the higher Crane and North Dakota Pipeline Authority production forecast data. *Current pipeline and rail capacity is more than 982,000 bpd in excess of production using the Crane forecast*. Using Crane's projected 1.2 million bpd production for 2015, pipeline and rail take-away capacity will be 998,000 bpd more than production.

The data that Federal and North Dakota state agencies have published clearly demonstrate that there will be more than ample take-away capacity for Bakken crude oil without the NDP Sandpiper project. That conclusion stands even using the crude oil production projections of NDP's own expert.

2. There Is Excess Unused Capacity on the Present NDP Pipeline.

For at least the past two years there has been excess capacity on the existing NDP pipeline system.

On March 1, 2013 Enbridge filed tariffs, which included the Phase 5 and Phase 6 surcharges for the pipeline expansions it built from 2006 to 2009. In connection with that March 1, 2013 filing, Enbridge provided considerable data regarding the operation of the pipeline.[34] In the Appendix to its decision in that case, the Commission stated the throughput on the NDP pipeline. It reported that the average monthly throughput from

[34] See Oil Pipeline Tariff Filing filed in Docket IS13-189-000, dated March 1, 2013.

January 2012 to July 2013 on the NDP pipeline was 155,973 bpd.[35] The Commission also reported that in certain months deliveries on the pipeline to Clearbrook were less than 100,000 bpd. Since the pipeline has a capacity of 210,000 bpd, the decline in throughput on the existing pipeline was certainly dramatic.

The overall situation has not changed since July 2013. As the sworn Declarations of representatives of Concord, Enserco, EnWest and WPX state, all four companies have been shippers on the NDP system and intend to continue shipping on the NDP line into the foreseeable future.[36] All four companies have also stated that they have not been subject to prorationing and have not been prevented by prorationing from shipping crude oil on the NDP pipeline. [37]

It is also significant that in explaining the dramatic decline in throughput in the Phase 6 Surcharge case, Enbridge claimed that it was the result of individual shipper decisions based on the fact that crude oil price differentials between the Midcontinent and U.S. coastal areas had widened considerably.[38] According to Enbridge it was those price differentials that gave shippers an incentive to transport Bakken crude by rail carrier to higher value markets.[39] That is a far cry from NDP's contention in this case that crude oil

[35] Appendix to Order on Complaint, 145 FERC ¶ 61,050 (October 17, 2013).
[36] The declarations are attached to this Protest as Exhibits B, C, D, and E.
[37] On page 6 of its Motion to Intervene dated March 4, 2014, St. Paul Park Refining Company LLC (SPPRC) states that it has not suffered from chronic prorationing on the NDP system and has seen operational evidence that the system is subject to persistent excess demand. The Affidavit of Justin Amoah attached to SPPRC's Motion also states that prorationing on the system was intermittent, and that temporary integrity maintenance on the system was primarily responsible for any sporadic prorationing. Affidavit of Justin Amoah, page 4.
[38] Motion to Dismiss and Answer of Enbridge Pipelines (North Dakota) in Response to Complaint of St. Paul Park Refining Co. LLC, OR13-28-000, dated August 14, 2013, pages 20-21. Also see the Affidavit of Robert Steede attached to that Motion, pages 8-9.
[39] *Id*.

deliveries from the Bakken have been constrained because of downstream pipeline limitations.

There are still further facts that refute NDP's contention that its present pipeline is inadequate to satisfy demand. In his Declaration, Mr. Garner points out that the NDP pipeline system taken as whole has even more unused capacity than just the Beaver Lodge to Clearbrook segment. In addition to this segment of the pipeline there is further capacity on another part of the NDP system. In its Phase 6 project, NDP built a 145,000 bpd pipeline connection between Berthold, ND and Steelman, Saskatchewan. From Steelman, the line continues to Cromer, Manitoba where it connects to the Enbridge system mainline. The pipeline then delivers crude oil at Clearbrook, Superior and points beyond.

As a result, when the present 210,000 bpd take-away capacity from Beaver Lodge is added to the 145,000 Berthold to Cromer to Clearbrook connection, there is a total of 355,000 bpd of take-away capacity of Bakken crude from North Dakota on the NDP system. According to Mr. Garner, the Berthold to Cromer connection is significantly underutilized and is currently transporting only 4,500 bpd.[40]

Consequently, the *existing* combined NDP/Enbridge system provides sufficient capacity to transport the crude oil of all committed shippers on the Sandpiper project. According to the Petition, the NDP pipeline, which is now at 170,000 bpd, will be able to use all of its 210,000 bpd design capacity in early 2015. That is equivalent to 40,000 bpd more than the pipeline is now shipping. The Berthold to Cromer segment of the NDP pipeline has a design capacity of 145,000, but is now only transporting 4,500 bpd. That leaves an additional 140,500 bpd that is not being used. The 40,000 bpd for the NDP main

[40] Garner Declaration, page 8.

line and the 140,500 for the Berthold to Cromer line equals 180,500 bpd of additional capacity. That surplus is more than sufficient to service the 155,000 bpd of the Sandpiper project's committed shippers

3. The Lack of Shipper Interest in Sandpiper Provides Telling Evidence That It Is Not Needed or Wanted.

In its Petition NDP states that there are 185 shippers on its pipeline system. According to NDP only 15 shippers were sufficiently interested in the NDP Open Season to request further information. Presumably significantly few shippers actually subscribed to committed capacity. Furthermore, of the 440,000 bpd capacity of the new line, only 155,000 bpd were committed. Thus, only 8% of the shippers on the pipeline were sufficiently interested in the NDP Open Season to request further information, and NDP received commitments for only 35% of the pipeline. Moreover, the majority of this 155,000 bpd was subscribed to by an equity owner of the pipeline.

Clearly, a majority of the shipping community does not believe that the new Sandpiper expansion is needed or will benefit them.

4. New Rail Facilities That Are Currently Under Construction or Recently Put into Service Obviate Any Need for the Sandpiper Project.

New rail facilities that are presently under construction in the Bakken highlight the fact that there is no need for the additional Sandpiper capacity.

- Dakota Plains has recently expanded its New Town, ND terminal by constructing a double loop track to accommodate two 120-car unit trains, a high-speed loading facility designed to handle 10 rail cars simultaneously, and transfer stations to receive crude oil from local gathering pipelines and trucks. The $50 million dollar project was commissioned on December 18.[41] According to Attachment A to the Garner Declaration, an additional 50,000 bpd of rail transportation capability is expected to be available by year-end 2014 at the New Town terminal, for a total of 80,000 bpd of rail transportation capability.

- A new open rail transload facility is being constructed by Mountrail Rail, Inc. in Palermo, ND and is intended to be in service in 2014.[42] This facility will have a rail throughput capacity of 160,000 bpd.

As Attachment B to the Garner Declaration shows, there are also nearly 80 U.S. rail projects that are either under construction or were recently put into service that involve rail loading facilities at production sites or unloading facilities at refineries and terminals across the country. A number of these projects enable Bakken crude to reach West Coast and Gulf Coast refiners by rail.

5. Koch Pipeline Company, L.P.'s Abandonment of Its Pipeline Project Further Underscores the Lack of Demand for Additional Pipeline Capacity in the Bakken.

On July 1, 2013, Koch Pipeline Company, L.P. (Koch Pipeline) launched the first phase of a non-binding open season for its Dakota Express Pipeline (Dakota Express). The proposed project, which would include approximately 600 miles of new pipeline construction, was intended to transport Bakken crude oil from western North Dakota to

[41] "Dakota Plains to Open Expanded Crude Terminal in North Dakota Next Week, Progressive Railroading, dated December 3, 2013: http://www.progressiverailroading.com/rail_industry_trends/article/Dakota-Plains-to-open-expanded-crude-terminal-in-North-Dakota-next-week--38596. This article is attached as part of Attachment B to the Garner Declaration.
[42] Attachment A to the Garner Declaration shows that by year end 2014, that 160,000 bpd would be available from this project. Mountrail Rail, Inc. also maintains a website: http://mountrailrail.com/

points in Hartford and Patoka, Illinois.[43] The project was slated to enter service in 2016, with an expected initial capacity of approximately 250,000 bpd.[44]

Phase I of Koch Pipeline's open season was designed to last for 45 days, closing on August 14, 2013. A press release issued by Koch Pipeline on July 1, 2013 stated that if sufficient shipper interest was received in Phase I, the company could proceed to the Phase II open season, during which binding commitments would be sought.

On January 22, 2014, however, the Dakota Express project was abruptly cancelled. Though no formal explanation was given as to why the pipeline project was cancelled, it has been suggested in the press that it was likely due to lack of shipper interest.[45]

6. Despite a Recent Accident, Rail Will Continue to Provide Cost-Effective and Safe Transportation of Bakken Crude Oil.

NDP will undoubtedly claim that the data which we have reported above regarding take-away capacity relies to a very heavy extent on rail transportation from the Bakken. We expect that NDP will also claim that rail transportation is inherently less safe than pipelines, thereby creating a demand for the Sandpiper project.

It is of course true that there has been a recent accident in Quebec involving rail transport of Bakken crude oil.[46] It is also true that governmental agencies have been

---

[43] "Open Season on Proposed Bakken Pipeline Project Begins Today," Koch Pipeline Company, L.P. News Release, dated July 1, 2013. This News Release is attached as part of Attachment B to the Garner Declaration.
[44] *Id*.
[45] "Crude Pipeline Wars in the Bakken," *Oil & Gas Financial Journal*, dated February 25, 2014: http://www.ogfj.com/articles/2014/02/crude-pipeline-wars-in-the-bakken.html; A Wall Street Journal article from March 3, 2014 suggested that tepid shipper interest was to blame for Koch's cancellation of the project. See "In Dakota Oil Patch, Trains Trump Pipelines," Alison Sider, *Wall Street Journal*, dated March 3, 2014: http://online.wsj.com/news/articles/SB10001424052702304071004579407140444547268?mg=reno64wsj&url=http%3A%2F%2Fonline.wsj.com%2Farticle%2FSB10001424052702304071004579407140444547268.html. This material is attached to the Garner Declaration as part of Attachment B.

focusing on the safety of rail transportation.[47] However, those inquiries have resulted in improvements in rail transport that will increase, not decrease, rail transportation.[48]

In addition, as NDP certainly knows pipeline transportation does not eliminate the possibility of accidents and spills. For example, on July 26, 2010, Enbridge notified the Environmental Protection Agency (EPA) that a rupture of one of its lines had occurred near Talmadge Creek in Marshall, Michigan. Over 843,000 gallons of crude oil were discharged into the Kalamazoo River. We refer to this incident only to show that safety issues are present whenever crude oil is transported, not to cast any blame on NDP.

B. The Muse Report Does Not Provide Convincing Evidence That the Sandpiper Project Is Needed or That It Will Be Used.

The only evidentiary support in the entire NDP Petition for the proposition that the Sandpiper expansion is needed and will be used is the Muse Report.

But, the Muse Report is so flawed that it cannot properly serve as an evidentiary basis for finding that an Expansion Surcharge should be imposed on unwilling historic shippers of the present NDP pipeline. At best, the Muse Report presents disputed factual issues that need to be set for hearing before the Commission can resolve them.

The first and most basic flaw of the Muse report is the fact that it ignores the data that shows existing and projected crude oil take-away capacity from the Bakken. Muse

[46] "U.S. Announces New Nation-wide Train Safety Regulations in Response to Lac-Mégantic Disaster," *National Post*, dated August 3, 2013: http://news.nationalpost.com/2013/08/03/u-s-announces-new-nation-wide-train-safety-regulations-in-response-to-lac-megantic-disaster/.
[47] *Id*.; "North Dakota Governor Addresses Crude-by-Rail Safety with BNSF, Trinity," *Progressive Railroading*, dated January 15, 2014: http://www.progressiverailroading.com/safety/news/North-Dakota-governor-addresses-crudebyrail-safety-with-BNSF-Trinity--39106.
[48] Garner Declaration, pages 7-8.

never even addressed the reports of governmental agencies that show that there is more than enough take-away capacity to meet any possible projections of crude oil production.

Instead of addressing existing pipeline and rail facilities, Muse postulated that (i) there is a growing demand for Bakken crude oil by Mid-Continent and Eastern Canadian refiners; (ii) shipping crude oil by rail to these refineries would be more costly than using the Sandpiper expansion; (iii) the demand for the Bakken crude oil that is being transported to the Gulf Coast will diminish because of the availability locally of less expensive sweet crude oil; and (iv) netbacks to producers using the Sandpiper project will be greater than alternative transportation.

None of these points is valid.

In his Declaration, Mr. Ashton points to a number of deficiencies in the Muse report.[49] These include the fact that the assumed future production from the Bakken is likely overstated given the lower forecasts generated by the USGS and EIA. Mr. Ashton states that if either the EIA or USGS forecast for the Bakken were used in the Muse model in place of the Crane forecast, the Muse model would probably show no need for the Sandpiper project. Mr. Ashton also notes that there may be an inconsistency between the price forecast underlying the Bakken production estimate generated by Mr. Crane and the price results from the Muse model.[50]

Mr. Ashton further points to the fact that the Muse report did not consider all options for consuming and moving Bakken crude oil and has understated the capacity of those other options.[51] By understating the capability of competing transportation and

[49] Ashton Declaration, paragraphs 42-53.
[50] Ashton Declaration, paragraph 45.
[51] Ashton Declaration, paragraph 47-51.

refining outlets, Mr. Ashton states the Muse model is skewed to show greater benefits for the Sandpiper project than actually exist, even assuming the production supply forecasts are accurate.[52] Mr. Ashton then points to the errors in the Muse report in stating the capacity of certain pipelines and new refineries in North Dakota. Mr. Ashton shows that Muse's understatements of these pipelines, which will transport Bakken crude, and refineries, that will consume Bakken crude in North Dakota, represent almost half of the capacity of the Sandpiper expansion project.[53] Mr. Ashton also indicates that the Muse report significantly understates available rail transportation capacity and appears to always treat rail capacity as a "second best" alternative due to its higher cost without considering other factors that could make rail transportation preferable to pipeline transportation.[54] These other factors include widening crude price differentials, the ability of rail to reach refineries to which pipelines cannot deliver crude oil and the significant investments already made in rail capacity by producers and shippers of Bakken crude.

Finally Mr. Ashton shows that the claimed benefits of the Sandpiper project of almost $5 billion computed by Muse are vastly overstated, even assuming all of the inputs and assumptions underlying the Muse model are correct and that in all likelihood there are no benefits to producers from the Sandpiper project and certainly none for existing uncommitted shippers.[55]

Mr. Garner also discusses the Muse Report in his Declaration.

Mr. Garner points out that there is no economic basis to Muse's conclusion that the construction of the Sandpiper pipeline will permit Bakken crude oil to replace existing

---

[52] Ashton Declaration, paragraph 48.
[53] Ashton Declaration, paragraph 48-50.
[54] Ashton Declaration, paragraph 51.
[55] Ashton Declaration, paragraph 52.

crude oil supplies to U.S. Mid-Continent and Eastern Canadian refineries. Mr. Garner discusses the fact that these refineries are currently buying Western Canadian crude oil and Canadian producers will certainly not permit American Bakken crude deliveries to undercut their markets.[56] In fact, according to Mr. Garner, when faced with price competition in the past, Canadian producers have taken whatever measures they believed necessary to preserve their market.[57] There is every reason to believe that they will continue to do so in the future, particularly in view of the long distance pipelines that Trans Canada and Enbridge are building from Western Canadian crude oil fields to Eastern Canadian refineries.[58]

As for the Muse Report's conclusion that Gulf Coast markets will be drying up for further Bakken crude oil supplies, Mr. Garner points to the fact that Muse ignored at least two million bpd of Gulf Coast refining capacity that is presently receiving Bakken crude oil or could become markets for Bakken crude oil in the near future.[59] These refiners would most likely continue to receive rail shipments of Bakken crude oil even if the Sandpiper project were completed because pipeline shipments, in contrast to rail shipments, are made from a common stream and include interface contamination.[60] Furthermore, one of the principal local sweet crude oils, which the Muse Report claims will replace the Bakken market, Eagle Ford crude oil, is primarily a light condensate that

[56] Garner Declaration, pages 14-16.
[57] Garner Declaration, page 15.
[58] Garner Declaration, page 17.
[59] Garner Declaration, pages 17-18.
[60] Garner Declaration, page 12.

can be used in only limited quantities in most refineries because of the unbalanced composition of its components.[61]

In sum, all of the principal assumptions and conclusions of the Muse Report are either flawed, incorrect or disputed.

C. The NDP Rate Design Is Unjust, Unreasonable and Discriminatory.

As we have pointed out above, in its prior Decision dismissing the 2012 Sandpiper Petition for Declaratory Order, the Commission discussed the fact that Enbridge (now NDP) had failed to file a cost of service and directed Enbridge to ensure that any future petition is fully supported under the Commission's regulations. NDP has once again failed to file a cost of service specifying its costs for constructing and operating the Sandpiper expansion and the precise rates that NDP will establish for the shippers on its pipeline.

Instead, NDP is requesting the Commission to approve its rate design at this time and put off until a later date any consideration of cost issues. If the Commission were to accede to NDP's request, Shippers may never be able to contest cost and rate issues that result directly from the rate design methodology in the current NDP Petition. The Shippers therefore urge the Commission to either require NDP to respond at this time to discovery as the Shippers requested in a Motion and Petition which they filed on February 26, 2014 or dismiss the present NDP petition pending the submission of a full cost of service analysis. Alternatively, the Commission could convene an evidentiary hearing to resolve all disputed factual issues.

[61] Garner Declaration, page 18.

The provision of cost information at this time is particularly important since the meager data that NDP has provided strongly suggests that its entire rate design is unjust, unreasonable and discriminatory.

1. Approval of the NDP Rate Design Could Result in Uncommitted Shippers Ensuring That NDP Will Fully Recover Its Costs of Operation and Return on Equity Regardless of the Quantity of Crude Oil the Pipeline Actually Ships.

In the prior proceeding, several Commissioners expressed concern about Enbridge's attempt to require uncommitted shippers to assume the risk that the pipeline will fully recover all of its costs of construction and operation and a substantial return of equity – regardless of the volume of crude oil the pipeline actually ships.[62] In its current Petition, NDP claims that it has abandoned that "true-up" feature of its prior Petition.

However, it is far from certain that NDP has really done so.

In its Petition, NDP states that initially, it will establish rates for uncommitted shippers on the basis of the current grandfathered pipeline rates plus a component that reflects the Expansion Surcharge.[63] According to the affidavit submitted by Mr. MacPhail, the Expansion Surcharge will be based on a cost of service using the Commission's Opinion 154-B methodology.[64] For the purpose of this cost of service Mr. MacPhail states that volume will be based on the pipeline's design capacity.[65] Mr. MacPhail defines "design capacity" as: "synonymous with 'annual average capacity,'

[62] *Enbridge Pipelines (North Dakota) LLC*, 142 FERC ¶ 61,212, page 2 (Commissioners Clark and Norris dissenting) ("Certain shippers, for example, claim that Enbridge North Dakota seeks a guaranteed return on equity through its proposed annual true-up mechanism. … However, the Commission must ensure that, in addressing Enbridge North Dakota's cost recovery mechanisms, shippers are protected from risks that should appropriately be assigned to the pipeline.")
[63] MacPhail Affidavit, page 28.
[64] *Id*., page 29-30.
[65] *Id*.

meaning the volume of crude oil the pipeline can be expected to transport over the course of a year (as opposed to the maximum theoretical capacity)."[66]

Although it is not entirely clear, we interpret Mr. MacPhail's statement as meaning that the post-construction throughput of the pipeline expansions, i.e., 230,000 bpd from Beaver Lodge to Clearbrook and 380,000 bpd from Clearbrook to Superior, will be used in establishing initial rates for uncommitted shippers.

However, the regulatory regime that NDP uses will apparently be substantially different in establishing rates for uncommitted shippers after the pipeline's first year of operation. According to Mr. MacPhail, "Thereafter [the first year], the initial uncommitted rate will be subject to the Commission's usual rate-changing regulations."[67] We believe that this statement means that following the first year, NDP will file a cost of service that establishes rates to uncommitted shippers on the basis of the actual throughput of the pipeline.

At that time, we anticipate that NDP will argue that the actual quantity of crude oil that the pipeline transports, not the larger design capacity, should be used in its cost of service. NDP will contend, we believe, that the issue of "used and useful" was already definitively established in this Declaratory Order proceeding when the Commission approved the construction of a pipeline with a capacity of 440,000 bpd from Beaver Lodge to Clearbrook and 380,000 bpd from Clearbrook to Superior. If this view of NDP's statements in the Petition is correct, NDP will, after the first year of pipeline operations, effectively require uncommitted shippers to ensure that even if the pipeline is utilized substantially below its capacity, it will still recover all of its costs of operation and a

[66] MacPhail Affidavit, note 5.
[67] MacPhail Affidavit, page 29.

significant return on equity. Thus, NDP will require the uncommitted shippers to assume the risk that the Sandpiper expansion will not be used at its design capacity.

This view of NDP's plans is further supported by the committed/uncommitted rate structure that NDP is asking the Commission to approve.

According to Section 6.01.1(d) of the TSA attached to the MacPhail Affidavit, a committed shipper can at any point abandon its right to be free of prorationing and become an uncommitted shipper. However, the rates that the TSA guarantees that the former committed shipper pays will continue to be the base rate specified in the TSA with an increment for fuel and power costs for different pipeline segments.[68] As Mr. Ashton points out in his Declaration, this aspect of the rate design that NDP is asking the Commission to approve at this time, will mean that uncommitted shippers could pay rates that are significantly more than the rates that committed shippers will pay.

In his Declaration Mr. Ashton provides a detailed example that illustrates this point.[69]

Contrary to its statement in its Petition, NDP is not really abandoning the "true-up" requirement in its prior Petition, it is simply re-packaging it.

2. The NDP Petition and Rate Design Confer Discriminatory Benefits on Equity Owners of the Pipeline at the Expense of Uncommitted Shippers.

The Shippers do not oppose NDP building a new pipeline—if NDP wishes to do so using its own funds. What the Shippers do object to is NDP seeking to impose on the Shippers the costs of a pipeline system that they do not need or want in order to benefit the equity owners of NDP.

[68] TSA Section 6.01.01 and 6.02.
[69] Ashton Declaration, pages 15-19.

That is precisely what is happening here.

NDP has attracted committed shippers for only 35% of the pipeline capacity it is planning to build. Although we do not have the detailed information that we sought in discovery to determine who the committed shippers are, the majority of the 155,000 bpd volume to which committed shippers have subscribed is undoubtedly attributable to affiliates of equity owners of the pipeline. We also believe these affiliates of equity owners are already shipping considerable quantities of crude oil on the existing NDP pipeline. Therefore the 155,000 subscription will not be entirely new crude oil shipments, but rather a shift from the current pipeline to the expansion.

It is in fact apparent that the major motivating factor of the Sandpiper project was an effort to assure Marathon Petroleum Corporation, an equity owner of the pipeline and the "anchor" committed shipper, that Sandpiper will enable it to deliver crude oil to its Illinois and Ohio refineries. For example, Paragraph 4.02(b) of the TSA states that Marathon can terminate its commitment to the Sandpiper project if Enbridge does not begin construction of the Southern Access Extension. As Mr. Garner points out in his Declaration, the Southern Access Extension is designed to enable Marathon to supply crude oil to its Illinois and Ohio refineries.[70] Marathon's termination of its commitment would of course also terminate Sandpiper as well. It therefore appears that the rationale for building Sandpiper is an effort by NDP, acting in concert with Marathon, to ensure a supply source to the Marathon refineries which, under the current Sandpiper rate design, would be financed by unwilling historic shippers on the present NDP pipeline system. The arrangement embodies discrimination.

[70] Garner Declaration, pages 20-21.

Moreover, in view of the profitability of NDP, Enbridge and Marathon, it is manifestly unfair for NDP to ask captive shippers to build it a new pipeline. For example, NDP reported very high operating profits in its most recent FERC Form 6 report. For 2012 when the pipeline was operating at significantly less than full capacity it reported an operating margin of 35% and in 2011 the pipeline earned an operating margin of 54%.[71] Enbridge Energy Partners L.P., the sole owner of NDP until November 2013, reported an operating margin of 25% for its liquids pipeline operations in 2013 and a 52.5% operating margin in 2012.[72] Effective November 25, 2013, Marathon Petroleum's pipeline segment has also earned very high profit margins – in 2013 it earned a 39% operating margin and in 2012 it generated a 47% margin.[73]

NDP and its equity owners can certainly afford to build a pipeline if they wish to do so. But, it is highly discriminatory for NDP to ask the Commission to impose on uncommitted captive shippers the costs of a pipeline which is designed to benefit primarily its equity owners.

D. It is Manifestly Unfair for NDP to Seek Commission Approval of Its Entire Rate Design at this Time While Withholding Any Meaningful Cost Information.

The NDP Petition asks the Commission to approve definitively its rate design at this time in the absence of meaningful cost data. It would be manifestly unfair to the uncommitted shippers on the NDP pipeline for the Commission to do so.

As we have pointed out above, NDP's rate design as outlined in its Petition and the TSA's that it signed with committed shippers could well require uncommitted shippers to

[71] Enbridge Pipelines (North Dakota) LLC, FERC Form 6, 2012 page 114.
[72] Enbridge Energy Partners, LP, SEC Form 10-K, 2013.
[73] Marathon Petroleum Corporation, SEC Form 10-K, 2013, pages 42-43.

pay the lion's share of the cost of constructing and operating the pipeline in the future. The Commission's approval at this time of a rate design that is not supported by cost data could therefore equate to the approval of uncommitted rates that exceed committed rates when the pipeline is not fully subscribed. That possibility is quite real since the pipeline is not being fully utilized at this time and has not attracted substantial shipper interest.[74]

These factors make it imperative that cost data be provided at this time, as the Shippers requested in the discovery motion that they filed on February 25, 2014.

In fact, in its Decision in *Seaway Crude Pipeline Company LCC* last month, the Commission underscored the importance of cost data in evaluating a pipeline's rate design. The Commission stated as follows:

> Cost-of-service data may also, in certain instances, be relevant in determining whether certain rate structures proposed by an oil pipeline are just and reasonable. Requiring that an oil pipeline provide cost-of-service data recognizes that such information may be relevant to deciding the issues, but it is not a requirement that all rates must be cost-based rates.[75]

Referring specifically to the committed service rates established in a TSA, the Commission also pointed out that:

> One area where contract modification may be appropriate is in certain circumstances where it is necessary to protect third parties, primarily where the negotiated rate places an excess burden on other customers. Such a party would still need to demonstrate that the negotiated rate was unjust and unreasonable.[76]

---

[74] *Enbridge Pipelines (Southern Pipeline) LLC*, 144 FERC ¶ 61,044 (2013) (denying rate challenges where Commission had approved prior 2 to 1 cost ratio for uncommitted versus committed rates).

[75] *Seaway Crude Pipeline Company LLC*, 146 FERC ¶ 61,151 at P 15 (Feb. 28, 2014); *Express Pipeline Partnership*, 75 FERC ¶ 61,303 at p. 61,867 (1996), *order on rehearing and declaratory order*, 76 FERC ¶ 61,245 (1996) (requiring cost of service data when all of the initial rates were challenged);

[76] *Seaway Crude Pipeline Company LLC*, 146 FERC ¶ 61,151 at P 33.

As the Shippers' expert witness Peter K. Ashton points out in his Declaration, in this case, the examination of cost data is critical in determining whether NDP's rate structure is just, reasonable and non-discriminatory. Mr. Ashton states as follows in his Declaration:

> […] the Petition states that uncommitted shippers will pay their "relative share" but it provides no information on how costs will be allocated so that uncommitted shippers pay that "relative share." As a result, neither the Commission nor the shippers have any idea of how costs will be allocated among the three classes of shippers and whether the result may be discriminatory. Since we do not have access to the cost data and cost allocation methodology that supports the committed rate and the costs that NDP will likely use to support the uncommitted expansion rate and the downstream extension rate, it is simply impossible to determine whether NDP's rate design is reasonable or non-discriminatory. However, as I discuss in greater detail below, based on the limited information that is available, it does not appear that the NDP rate design is either fair, reasonable or non-discriminatory.[77]

There are still further reasons why cost data should be considered at this time.

According to the NDP Petition, the Commission's consideration of cost data should be staged. First, according to NDP, the Commission should approve its entire rate design at this time, including the rates that committed shippers will pay. NDP would then submit its costs at a later date when NDP formally requests that the Commission approve the actual rates that uncommitted shippers will pay.

However, that process places inordinate and unreasonable burdens on uncommitted shippers. If NDP were permitted to delay presenting cost data until the date on which it files a cost of service requesting Commission approval of its rates, the Shippers' recourse would be to file a Protest. Under the Commission's protest procedure, the Shippers would then have only 15 days to analyze the NDP cost structure, develop their position with the assistance of experts and present their fully developed position as to

[77] Ashton Declaration, paragraph 9.

why the Commission should not sanction the rates that NDP proposes. Moreover, the Shippers would have to do so in the context of a rate design which the Commission has, if it accedes to NDP's request, already approved. That rate design would presumably approve the rates specified in the TSA for committed shippers. As a result, uncommitted shippers might well be precluded from arguing in later stages of this proceeding that the actual cost data that NDP produces demonstrates that committed shippers should bear a larger portion of the unrecovered costs of the pipeline. Uncommitted shippers might also be precluded from contending that NDP's actual cost data also demonstrates that other aspects of the NDP rate design are unjust, unreasonable, and discriminatory and should never have been approved in the first place.

Furthermore, under Commission precedents, the best that uncommitted shippers could expect in a Protest proceeding would be an Order suspending the NDP rates for one day and permitting them to go into effect pending the outcome of an evidentiary hearing.[78] That would mean that uncommitted shippers could be paying more than double the present NDP tariff for the two to three years that could be required to ultimately resolve the case.[79]

We submit that under the circumstances present in this case, that process would result in an unjust and unreasonable adverse impact on shippers.

The Shippers therefore respectfully request the Commission to consider cost issues at this time.

---

[78] *SFPP, L.P.*, 128 FERC ¶ 61,214 at P 21 (2009) (noting normal practice of suspending for one day); *SFPP, L.P.*, 121 FERC ¶ 61,211 (2007); *Buckeye Pipe Line Company*, 13 FERC ¶ 61,267 (1980).
[79] Ashton Declaration, Table 1.

VI. RELIEF REQUESTED

The Shippers do not oppose the construction of the NDP or any other pipeline that could transport Bakken crude oil. If NDP or Enbridge wishes to construct a new pipeline that parallels the existing NDP pipeline in North Dakota and Minnesota, it should certainly do so. NDP does not even need FERC approval to build that new line.[80] However, NDP should not be asking others – such as the captive shippers on the existing NDP pipeline – to pay for a pipeline that primarily benefits the equity owners of the NDP pipeline system.

Therefore, for the reasons discussed above, Concord Energy LLC, Enserco Energy LLC, EnWest Marketing LLC and WPX Energy Marketing, LLC respectfully request that the Commission:

(1) Grant their Motion to Intervene in this proceeding;

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

(3) In the alternative, dismiss the NDP Declaratory Order Petition pending the submission of a full cost of service;

(4) In the further alternative, set this matter for evidentiary hearing with full rights by the Protestants to discovery as set forth in 18 CFR § 385.401 to 18 CFR § 385.411 of the Commission's Rules of Practice and Procedure.

---

[80] *SFPP, L.P.*, 140 FERC ¶ 61,220 at P 50 (2012) ("Unlike natural gas pipelines, oil pipelines do not need to seek approval from the Commission before beginning construction of a pipeline (or a pipeline expansion), but an oil pipeline may file a petition for declaratory order seeking certain assurances regarding rate treatment and other issues"), *order clarified*, 141 FERC ¶ 61,051 (2012).

Respectfully submitted,

/s/ Melvin Goldstein

Melvin Goldstein
Matthew A. Corcoran
GOLDSTEIN & ASSOCIATES, P.C.
1757 P Street, N.W.
Washington, D.C. 20036
202-872-8740
mgoldstein@goldstein-law.com
mcorcoran@goldstein-law.com

Counsel for Concord Energy LLC, Enserco Energy LLC, EnWest Marketing LLC and WPX Energy Marketing, LLC

Dated: March 14, 2014

CERTIFICATE OF SERVICE

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 14th day of March, 2014.

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

EXHIBIT A

EXHIBIT A

DISPUTED FACTUAL ISSUES

The issues of fact listed below are disputed.

For each disputed factual issue, a reference is provided to the discussion of that particular issue in North Dakota Pipeline Company LLC's (NDP) Petition; the Protest filed by Concord Energy LLC, Enserco Energy LLC, EnWest Marketing LLC and WPX Energy Marketing, LLC (collectively "Shippers"); or the Answer of St. Paul Park Refining Company (SPPRC) to the Shippers Motion to Compel Discovery.

<u>Disputed Issues of Fact</u>

1. **The level of shipper support for NDP's Sandpiper project:**

   [NDP Petition: pages 8, 23-24, 43; MacPhail Affidavit: page 21; Shippers' Protest: pages 8, 30; Garner Declaration: pages 17-20; Ashton Declaration: page 23; SPPRC Answer: page 6];

2. **The economic need for the 230,000 bpd of additional pipeline capacity NDP proposes to build from Beaver Lodge, ND to Clearbrook, MN:**

   [NDP Petition: pages 12, 18-19, 21; MacPhail Affidavit: page 20; Shippers' Protest: page 29];

3. **The economic need for the 380,000 bpd extension NDP proposes to build from Clearbrook, MN to Superior, WI:**

   [NDP Petition: pages 17-19; MacPhail Affidavit: pages 14-16; Shippers' Protest: page 29];

4. **The correct crude production forecast for the Bakken region through 2016 as well as the correct projected level of crude production at its peak:**

[Crane Affidavit: pages 2-3, Exhibit SDC-2; Muse Stancil Analysis: pages 15, 23-25; Shippers' Protest: pages 19, 26; Garner Declaration: pages 4-6, Attachment A; Ashton Declaration: pages 24-25];

5. **The amount of pipeline and rail take-away capacity that presently exists to transport Bakken crude from North Dakota to American refining facilites:**

[NDP Petition: pages 13-14; Muse Stancil Analysis: pages 7-8, 38-39; Shippers' Protest: pages 10, 18-19, 25-26; Garner Declaration: pages 5-7, 12, Attachments A and B; Ashton Declaration: pages 23-24, 28; SPPRC Answer: pages 8-9; Amoah Affidavit: pages 1-2,];

6. **The amount of pipeline and rail take-away capacity that will be available in the foreseeable future to transport Bakken crude from North Dakota to American refining facilities:**

[Shippers' Protest: pages 20-21, 26, 30; Ashton Declaration: pages 12, 23-25, 27-28];

7. **The extent, if any, of prorationing on the NDP pipeline system during 2013 and 2014:**

[NDP Petition: pages 12-14; MacPhail Affidavit: pages 9-12; Shippers' Protest: pages 16, 23, 28; Garner Declaration: page 7; Ashton Declaration: pages 6, 8-11, 16-21, Vodicka Declaration, page 2; Woodard Declaration, page 2; Molis Declaration: page 2; SPPRC Answer: page 7; Amoah Affidavit: page 4];

8. **The extent to which rail transportation will be used in the foreseeable future for Bakken crude oil:**

[NDP Petition: page 14; MacPhail Affidavit: pages 19-20; Earnest Affidavit:

pages 2-3; Muse Stancil Analysis: pages 7, 30-32, 39-40; Shippers' Protest: pages 20-21; Garner Declaration: pages 4-5; Ashton Declaration: pages 28-30];

9. **The benefits, if any, of the Sandpiper project to Bakken producers:**

[NDP Petition: pages 21-22; Muse Stancil Analysis: pages 5, 10-12; Ashton Declaration: pages 30-31; SPPRC Answer: pages 9-11; Amoah Affidavit: pages 2-3];

10. **The likelihood that Bakken producers will transport substantial quantities of crude oil to U.S. Mid-Continental refineries if the Sandpiper project were completed:**

[Muse Stancil Analysis: pages 16, 20-21; Shippers' Protest: page 21; Garner Declaration: pages 13-15];

11. **The likelihood that Bakken producers will transport substantial quantities of crude oil to Eastern Canadian refineries if the Sandpiper project were completed:**

[Muse Stancil Analysis: pages 16, 19-20; Shippers' Protest: page 21; Garner Declaration: pages 15-16, Attachment C];

12. **The level of demand for Bakken crude in the Gulf Coast region in the foreseeable future:**

[Muse Stancil Analysis: pages 16, 21-22; Garner Declaration, page 16];

13. **The impact of NDP's proposed rate structure on the rates of uncommitted shippers and the risks uncommitted shippers will be assuming:**

[NDP Petition: pages 7, 24; MacPhail Declaration: pages 22-23, 26; Ashton Declaration: pages 6, 8];

14. **The extent to which existing uncommitted shippers will be paying for the Sandpiper project:**

    [NDP Petition: pages 26, 29, 42; MacPhail Affidavit: page 3; Shippers' Protest: pages 7, 39; Ashton Declaration: pages 5-6];

15. **The extent to which uncommitted shippers will be subsidizing the rates of the committed shippers:**

    [Ashton Declaration: page 13];

16. **The impact on the rates that uncommitted shippers will pay in the future if throughput on the new pipeline falls significantly below design capacity:**

    [Shippers' Protest: pages 39-40; Ashton Declaration: pages 8-10, 15-16, 18-19];

17. **The impact on uncommitted shippers of the differential treatment of power costs in the NDP rate structure proposal:**

    [Ashton Declaration: page 11];

18. **The impact on uncommitted shippers of the differential treatment of capital construction cost variances in the NDP rate structure:**

    [Ashton Declaration: pages 12-13];

19. **The extent to which uncommitted shippers will be subsidizing and conferring undue benefits on equity owners of the pipeline if the NDP rate design were approved:**

    [Shippers' Protest: pages 34-38; Ashton Declaration: pages 6-7, 13-14].

EXHIBIT B

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

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

Brad Vodicka states as follows, pursuant to the provisions of 18 U.S.C. § 1746:

1. My name is Brad Vodicka. I am the Executive Vice President of Crude Oil Marketing for Concord Energy LLC (Concord). The business address of Concord is 707 17th Street, Suite 3020, Denver, Colorado 80202. I have been employed by Concord since 2013.

Concord's Substantial Economic Interest in this Proceeding

2. Concord is a marketer of crude oil in North Dakota, Montana and Colorado. Concord typically purchases substantial quantities of crude oil from crude oil production companies. It then transports that crude oil in common carrier pipelines to appropriate markets. At the present time, a major portion of Concord's business activities is focused on the Bakken producing areas of North Dakota. In serving this market, Concord transports substantial quantities of crude oil on the pipeline system operated by North Dakota Pipeline Company LLC (NDP). Concord has been a regular shipper of record on the NDP pipeline system and its predecessor, Enbridge Pipelines (North Dakota) LLC (Enbridge) for the past 3 years.

3. Concord has also made a substantial investment in order to use the NDP pipeline system, including the construction of lact inject facilities at Ramberg, North Dakota. Concord's investments also include truck unloading facilities, tankage, as well as other facilities to determine crude oil quantities and quality control.

4. As a result of its investment in these lact inject facilities, Concord does not have viable economic alternatives to using the existing NDP pipeline system.

5. Concord will therefore be impacted to a substantial extent by the Petition for Declaratory Order that NDP filed with the Commission on February 12, 2014 and has a direct and substantial economic interest in the outcome of this proceeding that no other party can adequately represent.

Prorationing Status of NDP

6. I understand that NDP is claiming that its present pipeline system from Beaver Lodge ND to Clearbrook MN is constrained and has been subject to prorationing for some time. I do not believe that statement is correct. For at least the past 36 months, Concord has been able to ship all of the crude oil it wished on the NDP pipeline system. In fact, when the NDP pipeline is restored to its design capacity of 210,000 bpd in 2015, there will be more than sufficient capacity to meet any foreseeable demand on the pipeline for capacity.

I Brad Vodicka state under penalty of perjury that the foregoing is true and correct to the best of my information and belief.

Executed on March 11, 2014.

EXHIBIT C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

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

Jonathan Molis, states as follows, pursuant to the provisions of 18 U.S.C. § 1746:

1. My name is Jonathan Molis. I am the Manager of Projects and Business Development for Enserco Energy LLC (Enserco). The business address of Enserco is 1900 16th Street, Suite 450, Denver, Colorado 80202.

Enserco's Substantial Economic Interest in this Proceeding

2. Enserco is a privately-held subsidiary of Twin Eagle Resource Management, LLC (Twin Eagle). Enserco owns and operates crude oil logistical assets in North Dakota, Montana and Wyoming. Enserco's parent company, Twin Eagle, engages in the acquisition of crude oil from North Dakota, Montana, Utah and Wyoming producers at the well head. Their services include marketing, storage, trucking, and producer services.

3. At the present time, a significant portion of Enserco's business activities is focused on the Bakken producing areas of North Dakota. In serving this market, Enserco transports substantial quantities of crude oil on the pipeline system operated by North Dakota Pipeline Company LLC (NDP). Enserco has been a regular shipper of record on the NDP pipeline system and its predecessor, Enbridge Pipelines (North Dakota) LLC (Enbridge) for the past 6 years.

4. I have reviewed the Petition for Declaratory Order that NDP filed with the Federal Energy Regulatory Commission on February 12, 2014. The approval by the Commission of the Sandpiper project that NDP outlines in its Petition will adversely affect Enserco to a very substantial extent. Enserco therefore has standing to protest the NDP Petition and no other person can adequately represent Enserco's interests.

Prorationing Status of NDP

5. I understand that NDP is claiming that its present pipeline system from Beaver Lodge, North Dakota to Clearbrook, Minnesota is constrained and has been subject to prorationing for some time. I do not believe that statement is correct. For at least the past 12 months, Enserco has been able to ship all of the crude oil it wished on the NDP pipeline system. In fact, when the NDP pipeline is restored to its design capacity of 210,000 barrels per day (bpd) in 2015, there will be more than sufficient capacity to meet any foreseeable demand on the pipeline for capacity.

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

Jonathan Molis

March 13, 2014

EXHIBIT D

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

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

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

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

1. My name is Robert P. Garner. I am the Managing Partner of EnWest Marketing LLC (EnWest). The business address of EnWest is 2501 Wall Avenue, Ogden, UT 84401. I have been in a management position with EnWest ever since it was formed in 2007.

EnWest's Substantial Economic Interest in this Proceeding

2. EnWest is a marketer of crude oil in North Dakota, Montana, Utah, Colorado and Wyoming. EnWest typically purchases substantial quantities of crude oil from crude oil production companies. It then transports that crude oil in common carrier pipelines to appropriate markets. At the present time, a major portion of EnWest's business activities is focused on the Bakken producing areas of North Dakota. In serving this market, EnWest transports substantial quantities of crude oil on the pipeline system operated by North Dakota Pipeline Company LLC (NDP). EnWest has been a regular shipper of record on the NDP pipeline system and its predecessor, Enbridge Pipelines (North Dakota) LLC (Enbridge) for the past four years. EnWest has also made a substantial investment in order to use the NDP pipeline system, including the construction of a crude

oil injection facility at the NDP site at Stanley, ND. EnWest's investments at Stanley include truck unloading facilities, tankage, as well as other facilities to determine crude oil quantities and quality control.

3. I have reviewed the Petition for Declaratory Order that NDP filed with the Federal Energy Regulatory Commission (FERC or Commission) on February 12, 2014. The approval by the Commission of the Sandpiper project that NDP outlines in its Petition will adversely affect EnWest, to a very substantial extent. EnWest therefore has standing to protest the NDP Petition and no other person can adequately represent EnWest's interests.

Background of NDP Sandpiper Project

4. NDP presently operates a crude oil pipeline that originates at various points in North Dakota and terminates at Clearbrook, MN. At Clearbrook, an affiliate of NDP, Lakehead Pipeline Partners (Lakehead), receives the crude oil transported by NDP and transports it to Superior, WI. From Superior, Lakehead and various connecting pipelines transport the crude oil to refining centers in the Midwest and Gulf Coast. Presently, the throughput capacity of the NDP is 210,000 bpd, although NDP has at times operated the pipeline at considerably lower levels.

5. In its Petition, NDP is proposing to build a new pipeline in North Dakota that would parallel its existing pipeline system. The new NDP pipeline would be a 24-inch line that would carry an additional 230,000 bpd of crude oil, increasing capacity to 440,000 bpd. NDP also proposes to build a 380,000 bpd 30-inch pipeline from Clearbrook, MN to Superior, WI.

6. Enbridge, NDP's predecessor, previously sought approval of an almost identical project through a Petition and Offer of Settlement it filed with the Commission on November 2, 2012 (2012 Petition). On November 27, 2012, EnWest filed a Protest against NDP's 2012 Petition, arguing, as it is now, that the NDP Sandpiper project was unnecessary, was opposed by its existing shippers, and would place the financial burden and risks of the project on uncommitted shippers who did not support or need the excess capacity.[1] On March 22, 2013, the Commission denied NDP's 2012 Petition without prejudice and, after discussing cost of service data, told Enbridge that if it wished to file a new Petition it had to conform to the Commission's regulations for establishing initial pipeline rates.[2]

7. In its current Petition for the Sandpiper project, NDP seeks approval of the same project that Enbridge had filed two years ago. Once again, there is no cost of service attached to the Declaratory Order Petition.

Forecasted Bakken Production and Take-Away Crude Oil Capacity From Bakken Producing Areas

8. Over the past 25 years, I have had considerable experience with the production of Bakken crude oil, the facilities for transporting crude oil from the Bakken producing areas and the prices that the market has established. This experience was acquired, in part, as Manager Crude and LPG Supply for Flying J Inc., which was, at the time I worked for the company, the eighth largest crude oil producer in the Rocky Mountain region. Flying J had extensive crude oil production properties in North Dakota in

---

[1] Both Concord Energy LLC and WPX Energy Marketing LLC filed Motions to Intervene in FERC Docket OR13-6-000. Concord Energy LLC later filed a notice on December 6, 2012, stating that it adopted as its own the positions articulated by EnWest in its Protest.

[2] *Enbridge Pipelines (North Dakota) LLC,* 142 FERC ¶ 61,212 (March 22, 2013).

particular. On the basis of my experience, I do not believe that the demand that NDP forecasts for the pipeline system that it is proposing to build is anywhere near accurate. In my opinion, the NDP project will be largely unused and will become a substantial burden for current and future shippers. My opinion is based on (i) generally accepted projections of Bakken crude oil production over the next eight to ten years; (ii) the available "take-away" capability for Bakken crude oil; and (iii) the comparative prices available on pipelines as compared to rail shipments.

9. With respect to projected crude oil production of Bakken crude oil, NDP provides the Affidavit of Stephen D. Crane. Mr. Crane projects through his analysis that Bakken area crude production will reach roughly 1.2 million bpd by year-end 2015.[3] Mr. Crane also states that production will peak at 1.4 million bpd by 2026.[4] According to Mr. Crane's crude forecast table, which was provided in conjunction with his affidavit as part of Attachment SDC-2, the average production for 2014 will be approximately 996,000 bpd.

10. I am providing as Attachment A to my Declaration, a compilation of crude oil take-away facilities in the Bakken prepared by the North Dakota Pipeline Authority.[5] These facilities consist of both pipelines and rail transport facilities. According to this compilation, at year-end 2013, total crude oil pipeline throughput capacity from the Bakken area was 583,000 bpd. Rail facilities at year-end 2013 had the capability of transporting 965,000 bpd of Bakken crude oil. The total take-away capability of North

---

[3] Affidavit of Steven D. Crane in Support of Petition for Declaratory Order, dated February 10, 2014, page 2.
[4] *Id.*
[5] ND Pipeline Authority Oil Transportation Table, North Dakota Pipeline Authority, prepared January 22, 2014, accessed February 28, 2014 at: http://northdakotapipelines.com/oil-transportation-table/.

Dakota Bakken crude oil at year-end 2013 was therefore 1,548,000 bpd. According to the same compilation, total crude oil pipeline throughput capacity will amount to 783,000 bpd at year end 2015, while rail capabilities will equal approximately 1,355,000 bpd. Total take-away capability in the Bakken will therefore be 2,198,000 bpd at year-end 2015. This means that the total take-way capability for 2015, before Sandpiper is operational, will be 998,000 bpd *more* than the 1.2 million bpd of crude oil that NDP projects. In other words, the *current* take-away capability of 1,548,000 bpd in the Bakken area is more than sufficient to handle the Bakken production that NDP asserts will reach the market at any time between the present date and 2026.

11. The data in Attachment A further demonstrates that there will certainly not be a market demand in 2015 or 2016, for the additional pipeline capacity NDP is proposing to put on stream through Sandpiper. Attachment A shows that if all the pipeline expansion projects that are now being proposed were in fact constructed, pipeline take-away capacity of Bakken crude in 2016 will be 1,168,000 bpd. This figure is nearly equal to the crude oil that NDP projects will be produced in 2016. If we were to add the anticipated rail take-away capacity to the projected pipeline capacity, then the total take-away capability from the Bakken in 2016 would be 2,523,000 bpd – *more than double* NDP's projection of Bakken crude production.

12. Furthermore, for those shippers who are not captive to various pipelines, rail transportation from the Bakken area is currently a very attractive economic alternative to pipeline transportation and is very likely to increase in attractiveness in the future. I attach to my Declaration as Attachment B various news articles and press releases discussing recent rail investment and development in the region. For example, BNSF

Railway announced on August 15, 2013 that it was investing $220 million to improve and expand rail capacity in North Dakota, a process that would include the replacement of about 315 miles of rail and 415,000 ties. The same press release indicated that as part of a greater capital improvement program BNSF intended to invest $1 billion in new locomotive, freight car and equipment acquisitions, many of which would service North Dakota.

13. As I discuss later in this Declaration with particular reference to inaccuracies in the Muse Stancil study commissioned by NDP, there are a number of advantages to Bakken crude oil producers in using rail rather than pipelines. As a result, a number of large refineries have made significant investments in rail loading and unloading facilities. There is no doubt that rail will continue to be an attractive transportation option for producers and consumers of Bakken crude.

14. I am aware of the fact that there have been some accidents of rail trains carrying Bakken crude oil. However, I do not believe that these accidents will have any appreciable effect on the use of rail cars and new safety measures will enhance the use of rail cars to transport Bakken crude oil. The federal agencies responsible for rail movements (Department of Transportation, Pipeline and Hazardous Materials Safety Administration, and Federal Railroad Administration), the American Petroleum Institute, and Transportation Community Awareness and Emergency Response (TRANSCAER) are all working together with the goal of zero rail accidents. Secondly, several companies have already replaced their rail car fleets with new generation rail cars built to higher standards. Safety issues revolving around product specifications, rail car design, rail road

operation, rail track conditions, and emergency response are all being effectively addressed.

15. In view of the wide use of rail transportation and the existing pipelines available in North Dakota, I do not believe that there is any viable market for the additional capacity that NDP proposes in its Petition through its Sandpiper project. My opinion, I believe, is further supported by the fact that there appears to be excess capacity on the NDP system at this time. My company, for example, has been able to ship all the crude oil it wished to ship on the present NDP pipeline system for at least the past 18 months. I know that Concord Energy LLC, Enserco Energy LLC, and WPX Energy Marketing, LLC, who have joined EnWest in protesting the Sandpiper project have made similar statements. In addition, the Butte pipeline system that terminates in Guernsey, WY is only operating at between 60% and 70% of capacity.

16. There are still other reasons why the present NDP pipeline system is sufficient to handle any additional crude oil that will reasonably be tendered for shipment. For example, I do not believe that the 155,000 bpd of Sandpiper committed capacity represents new shipments on the NDP pipeline. I think it is very likely that a substantial part of the 155,000 bpd is already being shipped on the NDP system by historic shippers. But, even if the 155,000 bpd did represent entirely new shipments, the existing Enbridge/NDP pipeline could easily accommodate that supposed new supply.

17. Enbridge completed its Phase 6 project in March 2013. The Enbridge Phase 6 project involved building a new pipeline from Berthold, ND to Steelman, Saskatchewan. From Steelman, the pipeline continues to Cromer, Manitoba where it connects to the main Enbridge pipeline to Clearbrook. This Phase 6 pipeline project has a capacity of

145,000 bpd, and only 4,500 of that total capacity is now being used.[6] Therefore, the excess unused capacity of the Enbridge Phase 6 project and the additional 40,000 bpd that NDP states will come on stream in 2015 when repairs are completed to the existing NDP pipeline can easily accommodate any additional crude oil, including the 155,000 bpd that shippers have committed to the Sandpiper project.

18. For these reasons, pipeline expansion projects in the Bakken have drawn very limited interest from shippers. I am aware of at least two major pipeline projects in the region that were recently cancelled due to lack of shipper interest. Koch Pipeline Company L.P.'s (Koch Pipeline) held a non-binding open season in July 2013 for its Dakota Express pipeline. The Dakota Express line would have involved the construction of approximately 600 miles of new pipeline between North Dakota and points in Patoka and Hartford, Illinois. This new line would have also utilized the existing Wood River Pipeline system and Hartford terminal. Koch Pipeline had projected that the new line would go into service in 2016 with an expected initial capacity of approximately 250,000 bpd. Koch Pipeline specifically stated that if the company received sufficient shipper interest after the close of its 45-day Phase I open season, it would launch a second binding open season. In January 2014 Koch Pipeline announced that the project had been cancelled.[7]

---

[6] 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, OR14-21-000, dated March 4, 2014, page 7; Amoah Affidavit, page 4.
[7] See Lynn Doan, *Bloomberg*, "Koch Ends Plans for Pipeline to Illinois from Bakken," dated January 21, 2014: http://www.bloomberg.com/news/2014-01-22/koch-ends-plans-for-pipeline-to-illinois-from-bakken.html. A Wall Street Journal article dated March 3, 2014 suggested that tepid shipper interest was to blame for Koch's cancellation of the project. See "In Dakota Oil Patch, Trains Trump Pipelines," Alison Sider, *Wall Street*

19. Another major pipeline project designed to transport Bakken crude was Oneok Inc.'s Bakken Crude Express pipeline. According to news articles discussing the pipeline's cancellation, the proposed 1,300-mile pipeline would have run adjacent to the existing Overland Pass Pipeline, allowing for shipments from points in North Dakota to Cushing, OK.[8] The project, expected to cost $1.8 billion would have had a throughput capacity of 200,000 bpd. In November 2012, the project was cancelled due to lack of shipper interest.[9]

The Muse Stancil Report

20. I have read the Muse Stancil (Muse) Report that NDP attached to its Petition. I understand that Muse concludes that the Sandpiper project will be fully utilized because: (a) there is a pressing need that is not being currently met by Mid-Continent and Eastern Canadian producers for Bakken crude oil; (b) rail transport cannot compete with the $3.69 rate that Muse believes the Sandpiper pipeline will charge uncommitted shippers; (c) current markets for Bakken crude in the Gulf Coast are saturated with local production and refineries on the Gulf Coast that run primarily sour crude oil do not need

---

Journal, dated March 3, 2014: http://online.wsj.com/news/articles/SB10001424052702304071004579407140444547268?mg=reno64wsj&url=http%3A%2F%2Fonline.wsj.com%2Farticle%2FSB10001424052702304071004579407140444547268.html. These articles are provided as part of Attachment B to this Declaration, as is a Koch Pipeline open season press release discussing the project.

[8] "Oneok Shares Fall After Bakken Pipeline Canceled," Mike Lee, *Bloomberg*, dated November 28, 2012: http://www.bloomberg.com/news/2012-11-28/oneok-shares-fall-after-bakken-pipeline-canceled.html; ONEOK Cancels 200,000 bpd Bakken Pipeline Project, *Chicago Tribune*, dated November 27, 2012: http://articles.chicagotribune.com/2012-11-27/news/sns-rt-oneok-bakkenpipeline-update-1l1e8mrbzd-20121127_1_overland-pass-pipeline-bakken-crude-express-pipeline-oneok-partners-lp. These articles are provided as part of Attachment B to this Declaration.

[9] *Id.*

any more sweet crude oil; and (d) the netback to producers from using the Sandpiper pipeline will be so high that they will fill the line.

21. I do not think Muse's conclusions are valid.

22. First, the Muse Report begins with the fundamental fallacious assumption that rail transportation of crude oil from the Bakken area of North Dakota is inferior to pipeline transportation.[10] That statement might have been true five to ten years ago. But it is no longer the case. In order to understand crude oil markets today, it is essential to recognize that even though rail transportation from the Bakken might be more expensive than pipelines on a barrel mile basis, rail can be used by Bakken producers to access markets that have substantially higher netbacks than the markets to which pipelines deliver crude oil. When producers transport crude oil on the NDP system to Clearbrook and on the Enbridge Lakehead system to Superior, they receive a price for that crude oil which is generally determined as a discount from the Cushing, OK West Texas Intermediate (WTI) price. In contrast, producers that use rail connections in North Dakota in order to deliver crude oil to the Gulf Coast, West Coast or East Coast will receive a price that is based on world crude oil prices with a Brent Crude Index as the benchmark. Brent-based prices, adjusting for transportation costs, generally result in a significantly higher netback to producers than prices determined on the basis of a Cushing WTI index.

23. It is for that reason that the quantities of crude oil transported on the NDP began to fall precipitously beginning in July 2012. For example, even though the NDP pipeline

[10] "Absent Sandpiper, Bakken crude oil producers must either forgo incremental sales to the crude oil markets accessible via the Enbridge Mainline, or use rail transportation which is typically is more costly, to access these markets." Exhibit 4 of the NDP Petition, page 5.

can transport up to 210,000 bpd, the NDP pipeline only transported 70,000 bpd in April 2013.[11] In contrast, as I will discuss below, rail transportation increased significantly during this time period. It is important to realize that the low utilization of the NDP pipeline in 2013 and 2014 as well is not due to a lack of downstream pipeline connections as NDP claims in its Petition. Rather, the reason is because rail has now become a permanent feature of transportation from the Bakken and enables producers to achieve higher netbacks. In fact, refiners throughout the United States are embarked on major efforts to tie in their plants to rail connections from the Bakken.

24. Refiners are doing so for a number of reasons. First, Bakken crude oil is an excellent product for refinery feedstock. It is a whole bodied crude that is low in undesirable bottoms as well as low in sulfur and liquid petroleum gases (LPG). In addition, refiners on the Gulf Coast, West Coast and East Coast have had to buy considerable quantities of their feedstocks on the world market at world market prices serviced by ships on the high seas. They view domestic Bakken crude as considerably more economic, taking into account the quality of Bakken crude oil and relative transportation costs. In addition, rail transport assures refiners that they will receive the precise crude oil that they purchase rather than a commingled crude oil that pipelines deliver from a common sweet stream. This is particularly true since crude oil delivered from a common stream can be contaminated by other crude oil interfaces during pipeline transportation. Rail also now permits refiners to rely on more ratable delivery schedules than pipelines.

---

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

25. For these reasons, there is approximately 1 million bpd of rail take away capacity from Bakken fields at the present time, and by 2016 that figure will rise to 1.35 million bpd. That quantity of rail takeaway capacity – i.e., 1.35 million bpd – is equal to the entire quantity of Bakken crude production in the foreseeable future.

26. As a result of these economic factors, there are now more than 80 crude oil rail loading and unloading facilities in place or in the process of being built in the United States.[12] In addition, refiners on both the East and West Coast of the United States have recently signed long term supply agreements to obtain Bakken crude oil by rail. For example, PBF Energy, Inc., which operates a 190,000 bpd refinery in Delaware City, Delaware made significant investments in rail unloading facilities in 2012 and expanded those facilities in 2013.[13] PBF now has the ability to unload 110,000 bpd of Bakken crude oil.[14]

27. On the West Coast, according to the Canadian Association of Petroleum Producers' (CAPP) June 2013 Crude Oil Forecast, Markets & Transportation Report: "Tesoro has announced plans to unload trains in Washington and then transfer the crude to vessels for further distribution to its refineries in California by 2014. Valero has announced plans for rail unloading facilities at its refinery at Benicia, near San Francisco that is scheduled to be completed in mid-2014. The current plans are for receipts of up to

---

[12] "Factbox-U.S. Crude-By-Rail Projects; Valero to Start Up Port Arthur TX Project," *Chicago Tribune*, dated February 12, 2014: http://articles.chicagotribune.com/2014-02-12/news/sns-rt-usa-cruderail-factbox-20140210_1_bpd-port-arthur-tx-canadian-crude-production. This article is attached to this Declaration as part of Attachment B.
[13] *Crude Oil Forecast, Markets & Transportation*, Canadian Association of Petroleum Producers, dated June 2013, page 13. This report is attached as Attachment C to this Declaration.
[14] *Id*.

70,000 b/d of crude oil from North Dakota and Montana or western Canada."[15] A Reuters article dated December 10, 2013 elaborated on the interest of refineries in crude by rail options, stating that an executive of Tesoro Corp. saw rail-unloading capacity for North Dakota Bakken crude oil all along the U.S. West Coast growing to nearly 1 million bpd through 2015, an increase of more than 300% from current unloading capacity.[16] According to that same article, Tesoro Corp. is investing $100 million in a joint-venture railport project in Washington State, with a capacity of about 300,000 bpd.[17] Additionally, "Phillips 66 has announced plans to build a rail offloading facility at its Ferndale refinery to receive both Bakken and western Canadian crude oil."[18]

28. With this background, I would like to focus on the particular conclusions of the Muse study. Muse would have us believe that there is a market of Mid-Continent and Eastern Canadian refiners that is ripe for the plucking by Bakken producers if only the current NDP pipeline were doubled in size. I frankly don't know why anyone would believe that since the present NDP pipeline has been operating at only a fraction of its capacity. But, aside from that point, the facts of current demand and supply of crude oil to Mid-Continental U.S. and Eastern Canadian refineries do not support Muse's assertions.

29. As far as the U.S. Midwest– i.e., Eastern PADD II – is concerned, there are 13 refineries located in Michigan, Illinois, Indiana, Kentucky, Tennessee and Ohio. These

---

[15] *Id*., page 18.
[16] See "UPDATE 1 - Tesoro - West Coast Crude Rail Unloading to Hit Nearly 1 Mln Bpd," Reuters, dated December 10, 2013. This article is attached as part of Attachment B.
[17] *Id*.
[18] Attachment C, page 18.

refineries collectively use approximately 2.5 million bpd of crude oil.[19] In 2012, these refineries imported over 1.2 million bpd of crude oil. Ninety-seven percent of these imports were from Western Canada.[20] Canadian crude oil producers delivered a total of approximately 1.7 million bpd into the entire American Midwest region in 2012.[21] I do not believe that there is any real possibility that Western Canadian producers will permit North Dakota Bakken crude oil to replace any of the crude oil Mid-Continent refiners are now receiving from Western Canada. In fact, if anything, Western Canadian crude oil will occupy an increasing portion of this PADD II market.

30. In its June 2013 Report, CAPP states that: "The potential growth of western Canadian crude oil supplies exceeds the demand growth outlook in the whole of the North American market. The United States, given its geographic proximity will remain the primary market for western Canadian crude oil."[22] CAPP further states that Canadian crude oil production will double within the next 15 years.[23] In the past Canadian crude oil producers have made it absolutely clear that they will protect their American Mid-Continent markets. For example, we have seen Canadian producers dump crude onto the U.S. market in the past when production in Canada was in excess supply relative to market demand. This situation resulted in the past in a substantial price squeeze on those Bakken producers that did not have rail options. There is no doubt whatever that Canadian producers will not willingly abandon their Mid-Continent American refinery markets to make room for Bakken crude oil, since their alternative would be to shut in

[19] *Id*., page 15.
[20] *Id*.
[21] *Id*., pages iii, 14.
[22] *Id*., page 19.
[23] *Id*., page 3.

their production. Muse's conclusion that Bakken will replace Western Canadian crude oil in the U.S. Mid-Continent if the Sandpiper project is built is both highly unrealistic as well as highly improbable. PADD II refiners will simply use the availability of Bakken productions as leverage to obtain lower prices for the crude oil that western Canadian producers are selling them. Canadian producers will ensure that they become the lowest cost crude suppliers to the region.

31. It is equally improbable that Bakken crude oil will find a market in Eastern Canada as Muse concludes. The Muse Report states that the Sandpiper project will enable Bakken producers to transport their crude oil by pipeline to Eastern Canadian refiners because Bakken producers will receive a higher netback than from rail shipments to other locations. According to Muse, Bakken producers will therefore fill the Sandpiper pipeline with crude oil destined for Eastern Canada.

32. There is absolutely no basis to Muse's conclusions.

33. According to CAPP, the total capacity of refineries in eastern Canada is about 1.3 million bpd and includes refineries located in Ontario, Québec and Atlantic Canada.[24] Of that total refining capacity, approximately 330,000 bpd is located in Halifax and St. John. It is common knowledge that the refineries at these locations are not connected to any pipelines. Therefore, the Sandpiper project cannot possibly transport to them. CAPP states that the four refineries in Ontario have a combined refining capacity of 393,000 bpd.[25] CAPP also states that Statistics Canada stated that Ontario refineries received 366,200 bpd of crude oil with 336,700 bpd (92 per cent) derived from domestic Canadian

[24] *Id.*, page 11.
[25] *Id.*

sources.[26] I find it hard to believe that Canadian crude oil producers will simply allow Bakken North Dakota producers to supplant their markets. The majority of refineries in eastern Canada are owned by Canadian companies, that also produce substantial quantities of crude oil in Western Canada. I think it is highly unrealistic to expect these companies to shut in their own production while buying third party production from the Bakken. In fact, TransCanada Corp. understands well the demand in Eastern Canada for crude and is building the Energy East Pipeline which will be operational in the fourth quarter of 2017 and will transport up to 1.1 million bpd of crude from western Canada to all of the refineries on the East Coast of Canada as well as to export terminals.[27] Energy East Pipeline's recent Open Season was fully subscribed.

34. Muse also reached the conclusion that Bakken producers will find a contracted market for their crude oil in the Gulf Coast because the demand of Gulf Coast refineries is for sour crude oil not the sweet light crude oil that is found in the Bakken. Muse also points to the fact that Gulf Coast refiners will use the sweet crude oil that is now being produced from new fields in Texas rather than Bakken crude. Both Muse conclusions are incorrect.

35. First, Muse only discussed six million bpd of the eight million bpd of Gulf Coast refining capacity. The remaining two million bpd of refining capacity, which Muse simply ignored, are situated in refineries that are currently using, or could well become a market for Bakken crude oil. In addition, Gulf Coast refineries are considering converting their facilities to enable them to run sweet crude oil in view of plentiful new

---

[26] *Id.*, page 12.
[27] "TransCanada to Proceed with 1.1 Million Barrel/Day Energy East Pipeline Project to Saint John," dated August 1, 2013. Material regarding the Energy East Pipeline project is attached as part of Attachment D to this Declaration.

supplies available in the United States. Furthermore, contrary to Muse's assumption, some of the new supplies of sweet crude oil from Texas, such as the Eagle Ford field, are not comparable to Bakken crude. Eagle Ford crude 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. On the other hand, Bakken crude is a very balanced crude that enables some refineries to run almost exclusively on this type of crude oil. For this reason, there is an oversupply of Eagle Ford condensate and producers of Eagle Ford are actually separating the condensate into components and then trying to export a major portion of the components. If we factor in the fact that Eagle Ford crude is not comparable or competitive with Bakken crude and further consider the fact that Muse never addressed two million bpd of refining capacity in the Gulf Coast that is a current or potential market for Bakken crude oil, it becomes apparent that Muse's assessment of the crude oil market on the Gulf Coast is flawed. Neither current market demand in the Gulf Coast nor market requirements in the future exclude Bakken crude oil from continuing to make inroads into the market. The sheer size of the Gulf Coast market and the fact that Gulf Coast refineries are now considering retooling their plants to run more sweet crude will continue to provide profitable netbacks for Bakken rail deliveries.

Shipper Reaction to the Project that NDP is Proposing

36. It is not only my opinion that the NDP Sandpiper project is not economically viable. In opposing a previous incarnation of the project, I discussed several occasions in which shippers had voiced their concerns with NDP about the sustainability of NDP's Sandpiper plans. I had stated during that proceeding that there had been at least four

occasions from January 2012 to September 2012 that I was aware of in which shippers had raised very substantial concerns about the economic viability of the project and the rates that NDP proposed to charge. These shippers told NDP they would not financially support the pipeline being proposed and would not subscribe to pipeline capacity offered in an open season.[28] The project being opposed in those meetings and the project being proposed in NDP's current Petition are virtually the same.

37. Shipper support for the current incarnation of the project is similarly muted. Of the 440,000 bpd of pipeline capacity being made available, only 155,000 bpd were subscribed to during the open season. While NDP does not state how many shippers actually signed Transportation Service Agreements (TSA) for the project, only 15 apparently signed the confidentiality agreement necessary to gain access to the pro forma TSA. NDP recognizes that there are at least 185 shippers on the current NDP pipeline system, which means potentially fewer than 8% of all shippers on the current system were willing to become committed shippers. Of those shippers, the anchor shipper for the project is also a part owner of NDP, Marathon Petroleum Corporation.[29]

38. Enbridge's announcement that Marathon Petroleum Corporation (Marathon), through its subsidiary Williston Basin Pipeline Company LLC, has acquired a 37.5% equity interest in the NDP and is the "anchor" committed shipper on the NDP expansion raises very substantial questions regarding the motivation of both NDP and Marathon in

[28] Sworn Declaration of Robert P. Garner attached to Protest, Complaint, Opposition, Request for Rejection and Motion to Intervene of EnWest Marketing LLC in Response to Enbridge Pipelines (North Dakota) LLC Petition for Declaratory Order and Offer of Settlement, Docket OR13-6-000, dated November 26, 2012, pages 5-6.

[29] "Marathon Petroleum Corporation Commits to Sandpiper Project," Marathon Petroleum Corporation Press Release, dated November 25, 2013: http://ir.marathonpetroleum.com/phoenix.zhtml?c=246631&p=irol-newsArticle&ID=1879930&highlight.

proceeding with the Sandpiper project.[30] These questions are highlighted by a provision of the TSA that permits Marathon to terminate its commitment to the NDP if another Enbridge pipeline, the Southern Access Extension, is not built.[31] I think it is important that the Commission understand the background of Marathon's involvement in both pipelines in deciding whether the entire structure of the Sandpiper project is discriminatory.

39. Marathon is one of the largest refining companies in the United States. It operates large refineries in Robinson, IL; Canton, OH; Catlettsburg, KY; as well as other locations in the Mid-West.[32] One of Marathon's major supply routes to transport crude oil to its Illinois and Ohio refineries is a Marathon Pipeline LLC pipeline that originates in Patoka, IL. I am attaching to my Declaration as Attachment E, an enlarged version of the map provided in the Canadian Association of Petroleum Producers' (CAPP) June 2013 Report, which is also attached to my Declaration as Attachment C, which shows the supply route from Patoka to the Marathon refineries in Illinois and Ohio.

40. In the past, Marathon has faced bottlenecks at Superior in transporting crude oil to Patoka for further shipment to its Midwest refineries. As a result, Marathon has been a strong supporter of an alternative supply route, the Enbridge Southern Access Extension. This pipeline is a 165-mile line from Flanagan, IL to Patoka. The initial capacity of this proposed pipeline is 300,000 bpd. Marathon is able to connect to Flanagan and thereafter Patoka by using the Enbridge Lakehead pipeline from Superior, WI.

---

[30] NDP Petition, footnote 1.
[31] Attachment A to the MacPhail Affidavit, Section 4.02(b).
[32] The Robinson refining capacity is 206,000 barrels per day (bpd); the Canton refining capacity is 80,000 bpd; the Catlettsburg refining capacity is 240,000 bpd.

41. With this background, it is apparent that the Sandpiper project is simply a vehicle for permitting Marathon to supply its Illinois and Ohio refineries and shifting the costs of enabling Marathon to do so to the uncommitted captive shippers on the present NDP pipeline. In fact, if Marathon is not able to use the NDP to supply its refineries, then the entire Sandpiper project will collapse. As I pointed out above, the TSA says that Marathon can pull out of the Sandpiper project if Enbridge does not provide the pipeline connection that Marathon needs from Flanagan to Patoka.[33] These facts underscore the extent to which the entire Sandpiper project represents an effort by a major equity owner of the pipeline to use the funds of uncommitted shippers to finance its own crude oil supply plans.

Captive Shippers on the NDP Pipeline System

42. I anticipate that NDP may respond to the information that I have presented in this Declaration by claiming that a shipper that did not wish to support the project could avoid shipping entirely on the NDP system. However, that position ignores the fact that a number of shippers have already made substantial fixed investments in order to permit them to ship crude oil on the NDP pipeline. EnWest, as I pointed out at the beginning of my Declaration, has invested a considerable amount of capital in a crude oil injection facility in Stanley, ND. That investment, together with a truck unloading facility and tankage were necessary to enable EnWest to inject crude oil into the NDP system.

43. Shippers, including EnWest, cannot simply walk away from these types of investments without suffering substantial financial losses. At the same time, EnWest has

[33] Attachment A to the MacPhail Affidavit, Paragraph 4.02(b).

no need for the additional capacity that the 230,000 bpd expansion facilities would provide.

44. In addition to the shippers that have made investments similar to EnWest, there are also are a number of production fields and gathering systems that are connected only to the NDP pipeline. These producers and shippers built their facilities on the basis of the existing NDP system and are also captive to the pipeline.

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

March 13, 2014

ATTACHMENT A

US Williston Basin Crude Oil Export Options - January 22, 2014

Year End System Capacity, Barrels Per Day

	2007	2008	2009	2010	2011	2012	2013	2014	2015*	2016*
Butte Pipeline	92,000	104,000	118,000	118,000	145,000	160,000	160,000	160,000	160,000	160,000
Butte Loop (Q3 2014)	-	-	-	-	-	-	-	110,000	110,000	110,000
Tesoro Mandan Refinery	58,000	58,000	58,000	58,000	58,000	68,000	68,000	68,000	68,000	68,000
Enbridge Mainline North Dakota	80,000	110,000	110,000	161,500	185,000	210,000	210,000	210,000	210,000	210,000
Enbridge Bakken Expansion Program (Q1-11/Q1-13)	-	-	-	-	25,000	25,000	145,000	145,000	145,000	145,000
Plains Bakken North (Up to 70,000 BOPD)	-	-	-	-	-	-	-	40,000	40,000	40,000
Enbridge Sandpiper* (Q1 2016)	-	-	-	-	-	-	-	-	-	225,000
TransCanada Keystone XL* (2016)	-	-	-	-	-	-	-	-	-	100,000
Dakota Prairie Refinery (Q4 2014/Q1 2015)	-	-	-	-	-	-	-	-	20,000	20,000
Thunder Butte Refinery (2015)	-	-	-	-	-	-	-	-	20,000	20,000
Dakota Oil Processing Refinery (2015)*	-	-	-	-	-	-	-	-	20,000	20,000
Hiland Partners Double H Pipeline (Q3 2014, Up to 100,000 BOPD)	-	-	-	-	-	-	-	50,000	50,000	50,000
Pipeline/Refining Total	**230,000**	**272,000**	**286,000**	**337,500**	**413,000**	**463,000**	**583,000**	**783,000**	**843,000**	**1,168,000**
EOG Rail, Stanley, ND (Up to 90,000 BOPD)	-	-	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000
Dakota Plains, New Town, ND	-	-	-	20,000	30,000	30,000	30,000	80,000	80,000	80,000
Various Sites in Minot, Dore, Donnybrook, Gascoyne, and Stampede (est)	-	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Inergy COLT Hub, Epping, ND (Q2 2012)	-	-	-	-	-	120,000	120,000	120,000	120,000	120,000
Hess Rail, Tioga, ND (Up to 120,000 BOPD)	-	-	-	-	-	60,000	60,000	60,000	60,000	60,000
Bakken Oil Express, Dickinson, ND	-	-	-	-	100,000	100,000	200,000	200,000	200,000	200,000
Savage Services, Trenton, ND (Q2 2012 Unit Trains)	-	-	-	-	-	90,000	90,000	90,000	90,000	90,000
Enbridge, Berthold, ND (Q4 2012)	-	-	-	-	-	10,000	80,000	80,000	80,000	80,000
Great Northern Midstream, Fryburg, ND (Q1 2013)	-	-	-	-	-	-	60,000	60,000	60,000	60,000
Musket, Dore, ND (Q2 2012)	-	-	-	-	-	60,000	60,000	60,000	60,000	60,000
Plains, Ross, ND	-	-	-	-	20,000	20,000	65,000	65,000	65,000	65,000
Plains - Van Hook, New Town, ND	-	-	-	-	-	35,000	65,000	65,000	65,000	65,000
Global/Basin Transload, Zap, ND (Estimate Not Confirmed)	-	-	-	-	20,000	40,000	40,000	40,000	40,000	40,000
Mountrail Rail - Palermo, ND		-	-	-	-	-	-	160,000	160,000	160,000
Northstar Transloading - Fairview, MT (Q3 2014)	-	-	-	-	-	-	-	20,000	180,000	180,000
Rail Only Total	-	30,000	95,000	115,000	265,000	660,000	965,000	1,195,000	1,355,000	1,355,000
All Transportation Total	**230,000**	**302,000**	**381,000**	**452,500**	**678,000**	**1,123,000**	**1,548,000**	**1,978,000**	**2,198,000**	**2,523,000**

*Project Still in the Review or Proposed Phase

Source: ND Pipeline Authority Chart/Table Data, North Dakota Pipeline Authority, prepared January 22, 2014, accessed February 2014 at http://northdakotapipelines.com/datastatistics/; Click on red option on top titled Oil Transportation Table at http://northdakotapipelines.com/oil-transportation-table/

ATTACHMENT B

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

Home > Media > News Releases > 2013 > August > BNSF Plans $220 Million Capital Program In ND To Expand Rail Capacity

News Release

BNSF Plans $220 Million Capital Program in North Dakota to Improve and Expand Rail Capacity

FORT WORTH, TEXAS, August 15, 2013:

BNSF Railway Company (BNSF) plans to invest an estimated $220 million to improve and expand rail capacity in North Dakota this year.

BNSF's 2013 capacity enhancement projects in North Dakota include constructing three new sidings west of Minot near Manitou, Tioga, and Palermo; extending the sidings near Glen Ullin and Hillsboro; improvements to six sidings between Minot and Grand Forks; raising10 miles of track over Devils Lake by 1 to 5 feet to keep the track above rising water; upgrading the line between Berthold and Northgate on the Canadian border; installing Centralized Traffic Control signal systems on three sidings near Devils Lake, Hillsboro and Towner; constructing a new double crossover track east of Williston; and lengthening existing tracks or adding new tracks at BNSF rail yards in Mandan, Minot and Williston.

BNSF will also continue its robust track maintenance program in North Dakota, which will include nearly 1,900 miles of track surfacing and undercutting work, the replacement of about 315 miles of rail and 415,000 ties, as well as significant signal upgrades for federally mandated positive train control (PTC).

“BNSF's capital investments in North Dakota will help ensure our network is prepared for growing demand for freight rail,” said Matthew K. Rose, chairman and chief executive officer. “We are focused on investing to meet our customers' expectations and on expanding capacity where growth is occurring. Given the importance of a low cost supply chain to the U.S. economy, our privately funded rail infrastructure is well positioned to help all North Dakota industries compete in global markets.”

The planned capital investments in North Dakota are part of BNSF's record 2013 capital commitment of $4.3 billion. The largest component of the capital plan is spending $2.3 billion on BNSF's core network and related assets. BNSF also plans to spend approximately $1 billion on locomotive, freight car and other equipment acquisitions, many of which will serve North Dakota. The program also includes about $200 million for positive train control and $800 million for terminal, line and intermodal expansion and efficiency projects.

Unlike other modes of transportation, U.S. freight railroads use their own private dollars, not tax dollars, to build and maintain their freight rail networks. Since the year 2000, BNSF has invested more than $42 billion to improve and expand its freight rail network.

About BNSF

BNSF Railway is one of North America's leading freight transportation companies operating on 32,500 route miles of track in 28 states and two Canadian provinces. BNSF is one of the top transporters of consumer goods, grain and agricultural products, low-sulfur coal, and industrial goods such as petroleum, chemicals, housing materials, food and beverages. BNSF's shipments help feed, clothe, supply, and power American homes and businesses every day. BNSF and its employees have developed one of the most technologically advanced, and efficient railroads in the industry. We work continuously to improve the value of the safety, service, energy, and environmental benefits we provide to our customers and the communities we serve. You can learn more about BNSF at www.BNSF.com.

BNSF Headquarters
BNSF Railway Company
2650 Lou Menk Dr. 2nd Floor
Fort Worth, TX 76131-2830
P.O. Box 961057
Fort Worth, TX 76161-0057
Phone: (817) 352-1000

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

Bloomberg

Koch Ends Plans for Pipeline to Illinois From Bakken

By Lynn Doan - Jan 21, 2014

Koch Pipeline Co. called off plans to build a 250,000-barrel-a-day crude line to Illinois from North Dakota's Bakken formation, where a shale boom has helped lift domestic production to the highest in a quarter-century.

The indirect subsidiary of Koch Industries Inc., one of the largest private companies in the U.S., is no longer developing the so-called Dakota Express pipeline, Jake Reint, a Koch spokesman, said by e-mail yesterday. He didn't provide a reason for the decision. The Wichita, Kansas-based company was scheduled to begin a 45-day open season to gauge interest from potential shippers on the line in July.

"The non-binding open season for the Dakota Express pipeline is no longer being pursued," Reint, based in Wichita, said in the e-mail.

Hydraulic fracturing and horizontal drilling have helped producers reach shale deposits of oil across the middle of the U.S. from North Dakota to Texas, sending domestic output to the highest level since 1988. Koch proposed the Dakota Express line to help get the growing glut of oil to refiners in the U.S. Midwest. It was considering a extension to the Gulf Coast.

Koch would have used its existing Wood River pipeline, which has delivered crude to refineries in the Minneapolis-St. Paul region, to complete the project, the company said in June. While the Wood River line "remains operable and in good condition," Koch stopped accepting nominations on it in February 2013, Reint said yesterday.

To contact the reporter on this story: Lynn Doan in San Francisco at ldoan6@bloomberg.net

To contact the editor responsible for this story: Dan Stets at dstets@bloomberg.net

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit ___

BUSINESS

TOP STORIES IN BUSINESS

1 of 12

Streaming Oscar Outage Shows Web Limita...

2 of 12

Behind Oscar Selfie: Samsung's Ad Plan

3 of 12

Maserati Unveils New Coupe

RadioShack Closing Up 1,100 Stores

BUSINESS

In Dakota Oil Patch, Trains Trump Pipelines

Flexibility of Shifting Crude to Higher Priced Markets Strands Proposed Projects

By ALISON SIDER CONNECT

March 3, 2014 7:31 p.m. ET


Two pipelines stalled for little demand. Shown, railcars in North Dakota. *Associated Press*

Moving North Dakota's oil riches out of state on trains was supposed to be a stopgap solution until pipelines could be built.

But even as crude gushes from the state's Bakken Shale at a rate of nearly 1 million barrels a day, some pipeline companies are abandoning proposed projects, and it is becoming clear that rail transport won't be a temporary phenomenon.

In January, Koch Pipeline Company walked away from a project because of what it said was tepid interest by local oil producers. A year earlier Oneok Partners OKS +0.59% LP canceled plans for a $2 billion pipeline from North Dakota to Oklahoma for the same reason.

Rail is almost always a more expensive way to transport crude than pipelines—as much as twice the price a barrel over similar distances. But in North Dakota's case, rail's greater flexibility to ferry oil to where it fetches the highest price trumped the economics of pipelines, said energy experts.

Riding the Rails
Crude oil shipping capacity out of North Dakota, by method of

The abandoned pipeline projects could have tied into existing and proposed lines bringing oil to refiners in Texas and Louisiana, a market already awash in oil from nearby shale fields.

Popular Now What's This?

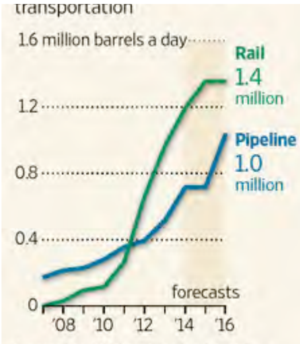
ARTICLES

1 Behind Oscar Selfie: Samsung's Ad Plan


2 Opinion: Stephens: Anatomy of a Feckless Presidency


3 Behind the West's Miscalculations in Ukraine


Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit ________



Source: North Dakota Pipeline Authority
The Wall Street Journal

Ethan Bellamy, an analyst at Robert W. Baird & Co., said producers want the ability to sell oil flowing out of the Midwest to the highest bidder—often refineries in Washington state, New Jersey and Pennsylvania that are only accessible by rail.

"Making a pipeline volume commitment is like getting married. Shipping by rail is like a one-night stand," said Baird's Mr. Bellamy. "Right now I suspect producers would rather stay bachelors."

In part, the crude produced in North Dakota is a low-sulfur type that is highly prized right now among East Coast refiners. On average, the state's oil sold for $74 a barrel in January, much less than the about $104 a barrel that East Coast refineries paid to import overseas oil during the same month, according to state and federal data. Even with the between $5 and $15 a barrel cost of shipping crude via train, it still made economic sense to head east.

Greg Garland, chief executive of U.S. refiner Phillips 66, PSX +0.57% said while demand for Bakken crude is greatest along the East and West Coasts, that's not where proposed pipelines are headed. "We don't think you'll see pipelines going east and west," he said.

Trains also can reach refineries that pipelines cannot, said Tad True, a vice president at True Cos., which operates pipelines in North Dakota and Wyoming. That flexibility means there is little incentive to build or expand lines to carry oil from North Dakota, Mr. True said. His company believes new pipeline construction will largely be to connect the network of pipes already in the ground to rail systems—so they fit together more seamlessly, he added.

Train operators including BNSF Railway Co. and Union Pacific Corp. UNP +1.63% moved nearly three-fourths of all the oil pumped in North Dakota in December, according to the latest state estimates. That same month, crude oil flowing through pipelines slumped 2%.

The state agency formed to facilitate pipeline development estimates that even after the handful of new pipelines currently under construction start transporting oil in 2016, well over half of North Dakota's crude oil shipping capacity will remain on the rails.

One major pipeline company hopes to buck the trend. Enbridge Inc. ENB.T +1.32% is building a new line that would carry as much as 225,000 barrels of oil a day out of North Dakota when it goes into service in 2016. Marathon Petroleum Corp. MPC +0.29% , which operates refineries in Detroit, Mich., Canton, Ohio, and Catlettsburg, Ky., has agreed to help foot the $2.6 billion construction bill and provide much of the oil in exchange for a 27% stake in Enbridge's North Dakota pipeline network.

Helping keep hopes alive for more such projects is the congestion and the potential hazards on rail shipments leaving the area. Oil tanker traffic has stressed parts of the rail system unaccustomed to hauling such large volumes of crude. In the past year a string of derailments—one deadly—caused massive explosions.

Last week, the U.S. Transportation Dept. issued new rules requiring that Bakken crude be tested before it is shipped on trains. The American Association of Railroads also agreed to a number of voluntary safety measures for transporting crude, such as lowering some speed limits and redirecting trains around high-risk areas. Still, the new regulations aren't expected to be costly or create a burden on oil companies that want to rail North Dakota crude, said Wells Fargo WFC +0.93% energy analyst Roger Read.

But in the long run, producers say they would like more pipelines build. "Our philosophy is that pipelines are the best transportation solution, because it takes traffic off the road and you've seen the consequences of the burden on the railroad system," Whiting Petroleum Corp. WLL +1.57% spokesman Jack Ekstrom said.

—Russell Gold contributed to this article.

4 Opinion: Bob Corker: Now the Auto Union Wants to Muzzle Public Officials

5 The Debate Over Juice Cleanses and Detox

VIDEO

1 Viral Oscar Selfie Sponsored by Samsung

2 Ukraine Explained: Russian Troops Enter Crimea

3 Oscars 2014: The Best and Worst Dressed

4 Oscars 2014: Social Media Winners and Losers

5 Photos of the Day – Bird Escapes Tiger in Germany

KOCH PIPELINE COMPANY, L.P.

News Release

July 1, 2013

Contact: Heidi Larson
651-292-8062
Heidi@goffpublic.com

Open Season on Proposed Bakken Pipeline Project Begins Today

Wichita, KS – Koch Pipeline Company, L.P. ("Koch Pipeline") today launched Phase I of a non-binding open season for the Dakota Express Pipeline, a proposed pipeline to transport Bakken crude oil from western North Dakota to Hartford, Illinois and Patoka, Illinois. Koch Pipeline is actively exploring a connection at Patoka, Illinois, to the Eastern Gulf Crude Access Pipeline, which would be capable of delivering Bakken crude oil to eastern U.S. Gulf Coast refineries. Dakota Express Pipeline would begin service in 2016 with an expected initial capacity of approximately 250,000 barrels per day.

The project presents an opportunity for Koch Pipeline to bring Bakken crude oil from the Williston Basin to the U.S. market more efficiently by using a combination of new and existing pipeline infrastructure. Koch Pipeline's system is anticipated to provide a competitive solution for shippers to access important crude oil demand centers.

The Dakota Express Pipeline would include approximately 600 miles of new pipeline construction while also utilizing Koch Pipeline's existing Wood River Pipeline and Hartford terminal. Historically, the Wood River Pipeline has transported crude oil south to north from Hartford, Illinois, to the Saint Paul, Minnesota, area. Koch Pipeline has completed an engineering feasibility study on reversing the flow of the Wood River Pipeline and utilizing it as part of the Dakota Express Pipeline system.

Phase I of the open season, which will last 45 days, and will close on August 14, 2013, is non-binding and intended to solicit expressions of interest from potential shippers. If sufficient shipper interest is received in Phase I, Koch Pipeline may proceed to Phase II of the open season, during which binding commitments would be sought. The project is subject to management approval and receipt of necessary permits.

About Koch Pipeline Company
Koch Pipeline Company, L.P. has earned numerous local, state and national safety awards. Koch Pipeline operates more than 4,000 miles of pipelines in Texas, Wisconsin, Minnesota, Missouri, Iowa and Illinois that transport crude oil, refined products, ethanol, natural gas liquids, and chemicals. Koch Pipeline recently completed a series of pipeline construction projects in south Texas to expand the ability to transport Eagle Ford crude oil to U.S. Gulf Coast refineries. Koch Pipeline Company, L.P. is an indirect, wholly owned subsidiary of Koch Industries, Inc. Learn more at www.kochpipeline.com.

Shipper inquiries:
Bruce Eldredge, Business Development Manager, Koch Pipeline Company, L.P.
DakotaExpressPipeline@kochpipeline.com
316-828-7394

###

Bloomberg

Oneok Shares Fall After Bakken Pipeline Canceled

By Mike Lee - Nov 28, 2012

Oneok Inc. (OKE), the company spending as much as $4.8 billion to expand its network, fell after a subsidiary canceled plans for a $1.8 billion pipeline connecting the Bakken shale formation to crude oil terminals in Oklahoma.

Oneok, based in Tulsa, Oklahoma, declined 1.5 percent to $44.88 at the close in New York. Earlier, it fell 3 percent, the biggest intraday drop since Aug. 1.

Oneok Partners LP (OKS), which is controlled by Oneok Inc., wasn't able to sign up enough oil producers to justify building the Bakken Crude Express pipeline, President Terry Spencer said in a statement yesterday. The 1,300-mile (2,100-kilometer) pipeline would have given Oneok a toehold in the lucrative oil transportation business in Montana and North Dakota. The company already is one of the region's largest natural gas processors.

An "abundance of rail," which allows producers to ship oil to higher-priced markets on the East Coast, probably made the project unviable, according to a research note from Tudor Pickering Holt & Co.

The Bakken, part of the Williston Basin that stretches from Canada into North Dakota and Montana, holds an estimated 3.6 billion barrels of crude, according to the U.S. Energy Department. Production is expected to hit 1 million barrels a day in five years. A lack of pipelines to bring the oil to refiners has caused crude in North Dakota to trade at a discount to West Texas Intermediate, the U.S. benchmark.

The Oneok pipeline would have carried as much as 200,000 barrels a day to the oil storage hub at Cushing, Oklahoma. The company is already building a pipeline to ship natural gas liquids such as propane and butane, which are produced in the Bakken.

"While we are disappointed with the results of the open season, we remain committed to serving Williston Basin producers for their natural gas, natural gas liquids and crude-oil infrastructure needs," Spencer said in the statement.

To contact the reporter on this story: Mike Lee in Dallas at mlee326@bloomberg.net

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

UPDATE 1-ONEOK

Cancels 200,000 bpd Bakken pipeline project

November 27, 2012 | Reuters

NEW YORK, Nov 27 (Reuters) - ONEOK Partners LP has cancelled plans to construct a 200,000 barrel per day pipeline to carry crude oil from the prolific Bakken shale deposit to Cushing, Oklahoma, due to a lack of long-term shipper commitments.

The natural gas and transport company in April announced plans to construct the Bakken Crude Express pipeline, which aimed to take advantage of the lack of pipe capacity to take oil from the Williston Basin in North Dakota and Montana to markets.

Companies have been racing to build out pipeline capacity to accommodate surging production from the Bakken, and oil traders said ONEOK's move to cancel the project could be an early sign that there are sufficient plans on the books at present to handle expected output levels.

"Despite the robust outlook for crude-oil supply growth in the Williston Basin in the Bakken Shale, we did not receive sufficient long-term commitments under the terms we needed to construct the Bakken Crude Express Pipeline," Terry Spencer, ONEOK Partners president, said in a statement released on Tuesday.

Crude from the Bakken, as well as from the Canadian oil sands, has been backing up at Cushing - the delivery point for the U.S. oil futures contract, and shippers have used rail, trucks, and barges to move it to the Gulf Coast refining hub, where it fetches a hefty premium.

Recently, companies have been announcing plans to ship more crude on railways to East Coast refineries, where plants have traditionally been forced to pay high prices to import crude from overseas, weakening margins and even forcing some plants to close.

ONEOK planned the Bakken Crude Express Pipeline to run partially parallel to a natural gas liquids pipeline already under construction that will run from the Williston Basin in Montana to Colorado. The oil line would then have run next to the Overland Pass Pipeline, in which ONEOK has a 50 percent interest, from Colorado to Oklahoma.

(Reporting by Matthew Robinson; editing by Matthew Lewis)

NEWS

All Sections

Home > Featured Articles

FACTBOX-U.S. crude-by-rail projects; Valero to start up Port Arthur TX project

February 12, 2014 | Reuters

(Updates Valero Energy Corp projects)
HOUSTON, Feb 12 (Reuters) - U.S. oil producers, refiners and logistics companies are deep into the crude-by-rail movement with dozens of projects throughout the United States and crude
movements via rail that jumped 71 percent in 2013 compared to the prior year.
Rapid proliferation of oil-by-train shipments started more than three years ago to get oil to markets as pipeline infrastructure lagged booming U.S. and Canadian crude production. The
Association of American Railroads said more than 780,000 barrels per day moved by rail in 2013,
more than 10 percent of average U.S. output of 7.5 million bpd last year. AAR said crude movements were expected to reach about 782,465 barrels per day in 2013, a 71 percent jump from
457,151 bpd in 2012.
The East and West coasts, in particular, turned to rail to tap cheaper U.S. and Canadian crude with no major oil pipelines in operation, or even planned, to move inland crude to those markets.
Valero Energy Corp, the largest U.S. refiner, is moving forward with a plan to start up a new 70,000 bpd rail offloading facility at its 290,000 bpd refinery in Port Arthur, Texas, in the fourth quarter of 2014. The company says it will take "price-advantaged North American
crude," but a spokesman noted further that Valero has been eager to get heavy Canadian crude to
the Port Arthur plant for some time.
However, rail evolved past a stopgap measure into an integral crude sourcing mode for refiners, adding flexibility to choose the best-priced crude from various shale and tight oil plays. Contracts are shorter, and they are not completely locked into specific types of crude moved from fixed points via pipeline.

Here is a rundown of nearly 80 U.S. rail projects - both loading at production sites and unloading at refineries and terminals - that have emerged as U.S. shale and Canadian production grows:

WEST COAST

Company Name Type Location State Capacity (bpd) Crude Status

Tesoro Corp Ref Anacortes WA 50,000 (refinery Bakken Operational
120,000 bpd)

U.S. Oil and Ref Tacoma WA N/A (refinery 40,700 Bakken Operational
Refining bpd)

Tesoro Corp Port Port of WA 120,000 initially, Bakken Approved by port
and Savage Vancouver expandable to 280,000 and July 23, awaiting
Services Canadian OK from state
governor;
operational in 2014

Phillips 66 Ref Ferndale WA 30,000 bpd capacity Bakken Permits approved;
total; currently and operational in Q4
receiving 20,000 of Canadian 2014
N.American crude via
mixed-freight
shipments (refinery
100,000 bpd)

BP Plc Ref Cherry WA 60,000 (refinery Bakken Operational
Point 225,000 bpd)

Royal Dutch Ref Anacortes WA N/A (Puget Sound Bakken, Awaiting permits
Shell refinery 145,000 bpd) Canadian

Alon Energy Ref Bakersfield CA Up to 70,000 Bakken, Awaiting permits
USA (Bakersfield, Texas
Paramount and Long Permian
Beach refineries, Basin,

three refineries Canadian
70,000 bpd)

Plains All Term Bakersfield CA Phase I 65,000 to Bakken, Phase I mid-2014,
American 70,000; Phase II can Niobrara, Phase II awaiting
double volumes to up Eagle permits to test an
to 140,000; pipelines Ford inactive pipeline
can then move crude to move railed
to refineries in Los crude to San
Angeles and San Francisco area
Francisco areas

Valero Energy Ref Benicia CA 30,000 to 50,000 bpd Inland Seeking permits;
Corp (132,000 bpd U.S. and delayed until 1Q
refinery) Canadian 2015 from 4Q 2013
to allow for
environmental
assessment

Valero Ref Wilmington CA 60,000 (78,000 bpd Inland Seeking permits
refinery) U.S. and
Canadian

Grays Harbor Port Aberdeen(Gr WA Up to 50,000 with a Bakken, Seeking permits
Rail Terminal ays Harbor) 120-car unit-train Canadian
(U.S. delivery every two
Development days
Group)

Westway Port Aberdeen(Gr WA Up to 50,000 bpd with Bakken, Seeking permits
Terminals LLC ays Harbor) 120-car unit train Canadian
delivery every other
day (expands from 18
loading/unloading
spots to 76)

Tesoro Ref Martinez CA Unit train to Bakken Operational
third-party rail
offloading (refinery
166,000 bpd)

Phillips 66 Ref Rodeo CA Extend rail Bakken, Seeking permits
infrastructure at Canadian
Arroyo Grande to take
up to 20,000
(Refinery 120,200
bpd)
Questar Corp Load Essex CA Considering rail Permian Pipeline segment
loading facility at must be converted

Essex to move crude to crude from
via rail to 96-mile natural gas for
pipeline in rail project to go
Whitewater, CA, forward; if
connected to West approved, converted
Hynes crude-oil pipeline to start
distribution system up 2015 or 2016
in Long Beach, CA.

EAST COAST

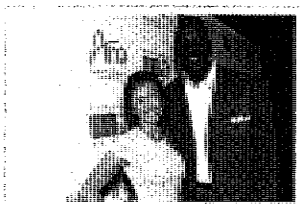
Company Name Type City State Capacity (bpd) Crude Status

Phillips 66, Ref Linden NJ 80,000-90,000 at Bakken Operational
Global times 70,000 (Railed
Partners LP to Albany, NY, then
barged to 238,000 bpd
Bayway refinery in
Linden, New Jersey)

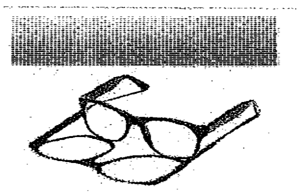
Plains All Term Yorktown VA 140,000 Bakken, Operational
American Niobrara,
Eagle
Ford

1 | 2 | 3 | Next

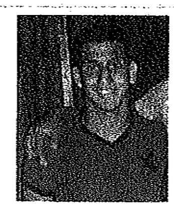
Featured Articles



Michael Jordan marries longtime girlfriend



A closer look at online shopping for eyeglasses



Missing SIU student from Morton Grove found dead

MORE:

Harold Ramis, Chicago actor, writer and director, dead at 69

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

NEWS

All Sections

Home > Featured Articles

(Page 2 of 3)

FACTBOX-U.S. crude-by-rail projects; Valero to start up Port Arthur TX project

February 12, 2014 | Reuters

PBF Energy Ref Delaware DE Up to 100,000 Bakken, Bakken Operational; to
City 40,000 Canadian and expand Bakken
(refinery 182,200 Canadian; offloading to up to
bpd) some 125,000 Bakken by
Bakken 3Q 2014, 80,000
barged to Canadian by 3Q 2014
160,000
bpd
Paulsboro
, NJ

Philadelphia Ref Philadelphi PA 160,000; plus another Bakken Operational
Energy a 30,000 via rail and
Solutions barge combination
(refinery 330,000
bpd)

Monroe Energy Ref Trainer PA Can receive Bakken Barge shipments
35,000-40,000 via operational
barge once railed to
Albany NY; plans to
receive up to 75,000
bpd (refinery 185,000
bpd)

Buckeye Term Albany NY 130,000 (rail to Bakken, Operational
Partners barge, onward to in
300,000 bpd Irving partnersh
Oil refiner in St. ip with
John, New Brunswick) Irving
Oil

Sunoco Term Eagle Point NJ 40,000 (rail to Bakken Operational
Logistics barge)
Partners LP

Enbridge Inc Term Eddystone PA 80,000 by end 2013; Bakken First phase
(Near to expand to 160,000 operational,
Philadelphi (rail to barge) expansion in 2014
a)
Buckeye Term Perth Amboy NJ Capacity undisclosed Bakken 2Q 2014
Partners LP

Phillips 66 Ref Linden NJ 75,000 bpd Bakken Building new rail
offloading;
Operational in
second half 2014

GULF COAST
Company Name Type City State Capacity (bpd) Crude Status

Kinder Morgan Term Houston TX 210,000 Cushing Under construction,
Energy Oklahoma, startup in February
Partners LP West 2014
, Texas,
Watco Bakken,
Companies LLC Canadian
and Mercuria

Plains All Term St. James LA 140,000 Niobrara Operational
American

Plains All Load Gardendale TX 25,000 Eagle Operational
American Ford

Genesis Load Wink TX 75,000 Permian Operational;
Energy LP Basin Expansion to
increase loading to
140 railcars
targeted for 4Q
2014

Cetane Energy Load Carlsbad NM 70,000 Permian Operational
LLC and Murex Basiin
LLC

Rangeland Load Loving NM 100,000 in phases Permian 2Q 2014
Energy Basin

Genesis Term Walnut Hill FL 75,000 Bakken, Operational
Energy (near Mobile West
Bay AL) Texas

Valero Ref St. James LA 100,000 (via Bakken Operational
Capline to 180,000
bpd Memphis,
Tennessee, refinery

Sunoco Term Nederland TX 21,500 Bakken Operational
Logistics

Alon Energy Ref Krotz LA 6,000 (refinery Inland Operational
Springs 80,000 bpd) U.S, type
depends
on price

Genesis Term Natchez MS 43,000 (adding 60 Canadian Operational
Energy railcar spots to
existing 40 in 1Q
2014)

NuStar Energy Term St. James LA in talks with Canadian No announced plans
LP producers to expand yet

NuStar Term St. James LA 70,000 at each Bakken Both operational
Energy, EOG facility
Resources Inc

Canadian Term Port of AL 75,000, up to 120 Canadian Seeking permits
National Mobile tank cars per day
Railway (offload crude,
and backhaul
Arc Terminals condensate)

Petroplex Term St. James LA 70,000 (engineering Bakken, 1Q 2015
International Parish and design for bulk Canadian
LLC, head of liquids terminal
a consortium including unit
backed by train)
Macquarie
Group
and
others

Valero Ref Port Arthur TX 70,000 bpd Canadian 4Q 2014
and other
North
American
crudes

Valero Ref St. Charles LA 20,000 via rail, Canadian, 1Q 2014; seeking
35,000 bpd via with room permit to increase
barge(refinery to take rail offloading
205,000 bpd) some capacity to 30,000
inland
U.S.
light-swe
et

Genesis Term Maryland LA N/A (near Exxon Bakken, Operational in
Energy Mobil Corp's Eagle second quarter
502,500 bpd Ford, 2014
refinery in Baton Canadian
Rouge)

GT Logistics Term Port Arthur TX 100,000 (rail to Bakken Operational
Omniport barge)
Terminal

Jefferson Term Port of TX 70,000 (rail to Eagle Operational
Refinery LLC Beaumont barge) Ford,
(Orange Bakken,
County Canadian
Terminal)

Kansas City Term Port Arthur TX N/A (in talks to N/A
Southern develop rail to Canadian
barge)

Kinder Morgan Term Battleground TX 6,000 bpd N/A Phase I
Energy Oil initially operational,
Partners and Specialty (unloading for 12 expansion startup
TransMontaign Terminal cars, expandable to in fourth quarter
e Partners LP Company LLC 30 cars) 2014
(BOSTCO)

EOG Resources Load Harwood TX Average 12,000 at Eagle Operational
98 shipments of Ford
about 45,000
barrels per train
in 2012

EOG Resources Load Barnhart TX Average 3,000 at 24 Permian Operational
shipments of about Basin
45,000 barrels per
train in 2012

Navigator Load Big Spring TX 60,000 bpd Permian Targeted for fourth
Energy Basin quarter 2014
Services
Genesis Load Raceland LA 140,000 bpd Eagle August 2014
Energy Ford,
Bakken,
Canadian,
Permian
Basin,
Niobrara

MIDCONTINENT
Company Name Type City State Capacity (bpd) Crude Status

Enbridge Load Berthold ND 120,000 Bakken Operational

Plains All Load Manitou and ND 65,000 at Manitou; Bakken Operational; Van
American Van Hook 35,000 at Van Hook Hook to 65,000
bpd by mid-2014

Musket Corp Load Dore ND 60,000 Bakken Operational

EOG Resources Load Stanley ND 65,000 Bakken Operational
(Watco)

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

NEWS

All Sections

Home > Featured Articles

(Page 3 of 3)

FACTBOX-U.S. crude-by-rail projects; Valero to start up Port Arthur TX project

February 12, 2014 | Reuters

Hess Corp Load Tioga ND More than 60,000 Bakken Operational
(Watco)

Inergy Load Epping ND More than 135,000 Bakken Operational

Dakota Plains Load New Town ND 80,000 Bakken Operational
Holdings

Lario Load Bakken Oil ND 100,000 expandable Bakken Operational
Logistics Express, to 200,000
near
Dickinson

Savage Load Trenton ND 90,000 Bakken Operational
Services

Great Northern Load Fryburg ND 60,000 Bakken Operational
Midstream LLC

Global Basin Load Columbus ND 160,000 Bakken Operational
LP, Basin and Beulah
Transload LLC

Northstar Load Fairview MT 100,000 (Q1 2014) Bakken Operational
Transloading

Delek U.S. Ref El Dorado AR 25,000 light U.S. Inland Startup in early
Holdings or 12,000 Canadian. U.S., 2014
Can also access Canadian
20,000 bpd of light
crude offloading at
a third-party
facility adjacent
to the refinery
(refinery 80,000
bpd)

HollyFrontier Ref Artesia NM 70,000 (refinery WTS, WTI, Operational
Corp 105,000 bpd) Canadian

Marquis Energy Term Hayti MS 75,000 (rail to Bakken, Operational; to
Miss. barge) Canadian increase to
150,000

Indigo Term Osceola AR 140,000 (rail to Bakken, Startup in late
Resources Miss. barge) Canadian 2014

SEACOR Term Sauget IL 65,000 (rail to Bakken, Operational
Holdings Inc (Gateway Miss. barge) Canadian
Terminals)

Savage Term Lordstown OH N/A (transloading Utica, when Awaiting
Services at Ohio Commerce production takers
Center, expanding ramps up
for unit trains)

Kinder Morgan, Term Stroud OK 65,000 bpd, Bakken Operational
Watco offloading EOG
Companies output crude to
Hawthorn Pipeline

Buckeye Load Chicago IL Crude arrives via Bakken, Operational
Partners pipeline, loaded on Canadian
railcars to go to
West, East and Gulf
coasts; capacity
undisclosed

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

ROCKIES
Company Name Type City State Capacity (bpd) Crude Status

Plains All Load Carr, Tampa CO 15,000 at Carr, to Niobrara Carr operating,
American expand to 30,000; expansion slated
65,000 at Tampa for 2014; Tampa
(ships to CA, LA) operational

Musket Corp Load Windsor CO Initially 16,000 Niobrara Operational
expandable to more
than 30,000
Enersco Load Douglas WY 60,000 expandable Bakken, Manifest
Midstream LLC, to 120,000 Niobrara, shipments under
subsidiary of Canadian way, unit-train
Twin Eagle capability added
Resource by March 2014
Management

Eighty-Eight Load Guernsey WY 80,000 Bakken, Operational
Oil LLC Niobrara,
Canadian,
Big Horn
Basin,
Wyoming

Cogent Energy Load Caspar WY 80,000 Niobrara Late spring 2014
Solutions LLC
and Granite
Peak
Development
LLC

Savage Load Price, Salt UT 9,000 Unita Awaiting takers
Services Lake City Basin

United Energy Load 7 sites in More than 68,000 Bakken, Operational
Trading ND, CA, CO, Niobrara,
WY, TX Eagle
Ford,
Permian
Genesis Energy Load Douglas WY 70,000 Niobrara Operational

Sources: Company filings, presentations and announcements; North Dakota Pipeline Authority

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

» Print

UPDATE 1-Tesoro- West Coast crude rail unloading to hit nearly 1 mln bpd

Tue, Dec 10 2013

* West Coast offloading expected to reach 910,000 bpd by 2015
* Rail-to-barge project part of growth

By Kristen Hays

HOUSTON, Dec 10 (Reuters) - Independent refiner Tesoro Corp sees rail unloading capacity all along the U.S. West Coast for North Dakota Bakken crude oil growing to nearly 1 million barrels per day through 2015, an executive said on Tuesday.

The projected jump to 910,000 bpd from the industry's current unloading capacity of 218,000 bpd - an increase of more than 300 percent - includes Tesoro's $100 million joint-venture railport project in Washington state, Keith Casey, senior vice president of strategy and business development for Tesoro, said on a webcast of the company's annual meeting with analysts.

Other refiners and logistics companies are building or seeking to build smaller projects to bring in cheaper crude via rail as well.

"Loading capacity is keeping pace with production growth," Casey said.

The growth will accommodate increasing efforts by West Coast refiners to tap inland U.S. and Canadian heavy crudes via rail - cheaper alternatives to imports and Alaskan crude - as no major pipelines move crude to that largely isolated market.

Tesoro's rail-to-barge project with Savage Services is the largest of the offloading projects announced so far.

Tesoro Chief Executive Greg Goff told analysts that the railport is seeking a state permit that would allow handling of up to 380,000 barrels per day of crude.

"That will be the permit," Goff said. "But the way the system is being built, rail shipments we estimate will be around 300,000 barrels per day there."

Tesoro expects the permit to be awarded by the third quarter next year.

Casey said West Coast refiners now receive about 810,000 bpd in what he called "substitutable" waterborne imports and Alaskan crude, or shipments that can be replaced by cheaper crudes received via rail.

The region's expected rail unloading capacity growth to 910,000 bpd will more than surpass that, he said.

Tesoro is committed to take up to 60,000 bpd of crude railed to the Port of Vancouver once the project starts up in late 2014 and early 2015, and the joint venture can offer the rest to other west Coast refiners.

Several also are working on their own rail offloading projects, including BP Plc, Phillips 66 and Alon Energy USA. Tesoro also rails up to 50,000 bpd of Bakken crude to its 120,000 bpd refinery in Anacortes, Washington.

CRUDE FLEXIBILITY

Goff noted that Tesoro doesn't have long-term contracts for imports, so the company can easily substitute cheaper U.S. crude at its refineries.

"In no case do we have long-term contracts that limit our flexibility to take crude" except for a seven-year deal with Newfield Exploration Co to supply the company's 57,500 bpd refinery in Salt Lake City, Utah, Goff said.

"Otherwise, we have the flexibility to optimize on a short-term basis," he said.

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit ______

<< Rail Magazine Articles Home

12/3/2013

Rail Industry Trends Article

Dakota Plains to open expanded crude terminal in North Dakota next week

Rail Industry Trends

Dakota Plains Holdings Inc.'s Pioneer Terminal expansion in New Town, N.D., is nearly finished and will be commissioned on Dec. 18, the company announced last week.

The $50 million project includes a double loop track to accommodate two 120-car unit trains, a high-speed loading facility designed to handle 10 rail cars simultaneously, and transfer stations to receive crude oil from local gathering pipelines and trucks. Canadian Pacific will serve the loading facility.

One gathering pipeline already is in service and is expected to handle about 8,000 barrels per day, Dakota Plains officials said in a press release.

Construction also continues on a $15 million frac sand terminal the firm is jointly building in New Town with UNIMIN Corp. To open in May 2014 and be served by CP, the terminal will feature 8,000 tons of fixed sand storage space, an enclosed transloading facility and four ladder tracks. Interim frac sand transloading is expected to start in January while construction of the permanent facility continues, Dakota Plains officials said.

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

OIL&GAS FINANCIAL JOURNAL

Search

Subscribe: **Newsletter** | **Magazine**

Home Oil Markets People Business Solutions E & P Midstream Capital Deal Monitor Unconventional Resources Research

Home > More Latest Unconventional Resources > Crude pipeline wars in the Bakken

Crude pipeline wars in the Bakken

February 25, 2014

Sandy Fielden, RBN Energy

Since the start of 2014 two competing pipeline projects designed to provide crude producers in North Dakota with additional takeaway capacity have met with very different fates. The first proposal – the Sandpiper project launched by Enbridge in late 2012 has completed a successful Open Season and petitioned federal regulators for approval of its tariff structure. Sponsor Koch Industries quietly canceled the second competing proposal – the Dakota Express pipeline first proposed in July 2013. Looking at rail and pipeline takeaway capacity versus crude production in North Dakota, both these pipelines are "nice to have" not "need to have". Today we begin a two part analysis of these competing projects.

Earlier this month (February 13, 2014) the North Dakota Pipeline Company (jointly owned by Enbridge and Marathon Petroleum Company – MPC) petitioned the Federal Energy Regulatory Commission (FERC) for a Declaratory Order approving the principals of a revised tariff structure for their Sandpiper crude oil pipeline project. [An earlier petition for a Sandpiper Tariff structure approval made at the end of 2012 was denied by the FERC in March 2013 in part due to shipper concerns about how the pipeline would be financed.] The Sandpiper project involves expansion of Enbridge's North Dakota Pipeline System that has current capacity to deliver 210 Mb/d of crude from western North Dakota to the Enbridge Mainline

Topic Index

View Oil & Gas Financial Journal articles by to

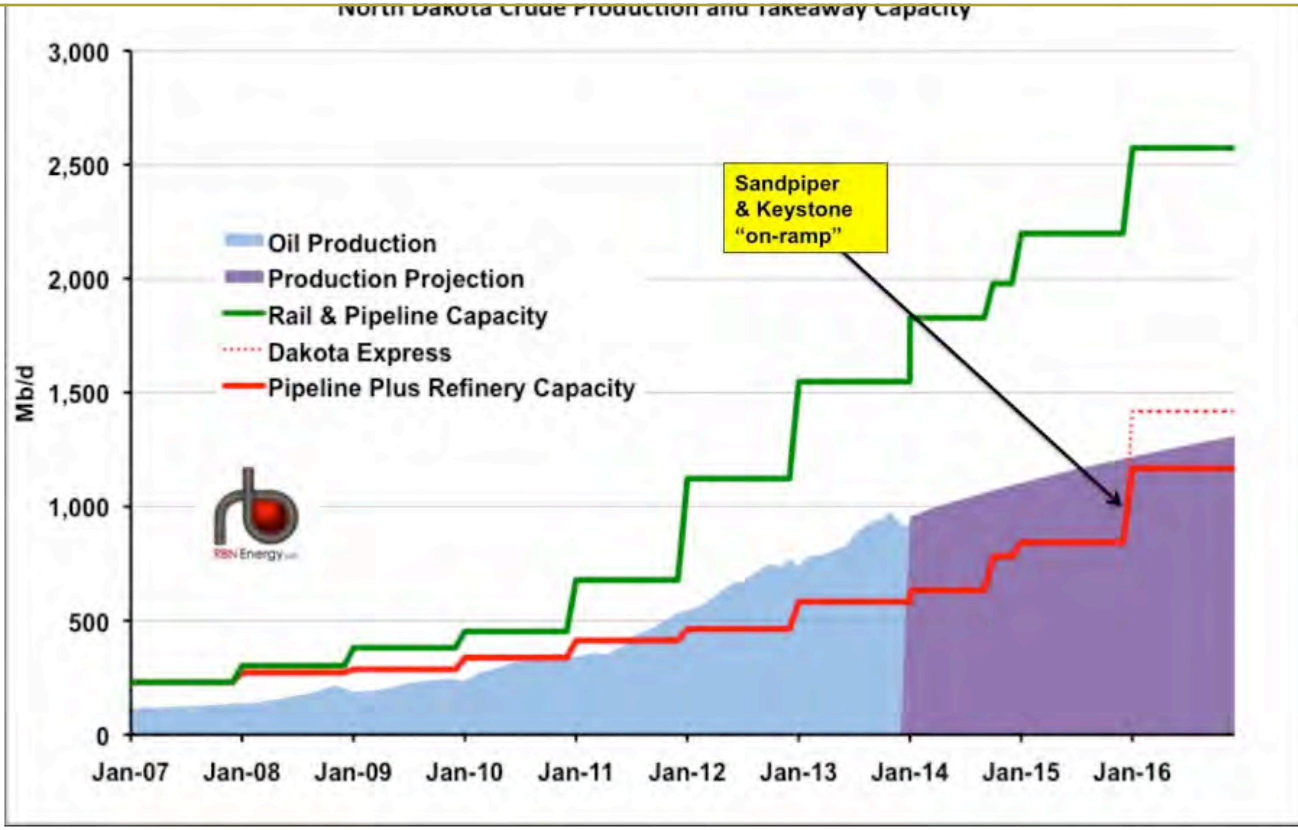
Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit ________

230 Mb/d initial capacity expected online in 2016. During that Open Season Enbridge announced in November 2013 that MPC (through subsidiary Williston Basin Pipeline Company) would purchase 37.5 percent of Sandpiper, which will translate into 25 percent of North Dakota Pipeline Company when the project is completed. In the process MPC also became the anchor shipper on Sandpiper.

Three weeks before the latest Sandpiper petition to the FERC, a rival pipeline project to move Bakken crude out of Western North Dakota, known as the Dakota Express pipeline, was cancelled by Koch industries (January 22, 2014) without explanation. We assume that Dakota Express was cancelled because of a lack of shipper interest during the initial non-binding 45 day Open Season that Koch held for the pipeline in July and August 2013.

In this two part blog series we try to untangle why Sandpiper appears to be succeeding where Dakota Express failed. But before we get to that we look at whether either of these pipelines is actually needed by North Dakota producers. Analyzing "the stack" – comparing actual and projected crude production in North Dakota against existing and proposed takeaway capacity, provides the answer to that question. In the Bakken such "stack" analysis requires us to account for both pipeline and rail loading capacities, since both compete for shipper business in North Dakota. Below is our "stack" chart based on data provided by the North Dakota Pipeline Authority (NDPA).

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit ________



Source: NDPA and RBN Energy

The chart shows actual Bakken crude oil production in North Dakota up until December 2013 (pale blue shaded area) and projected production through the end of 2016 (purple shaded area based on NDPA and Bentek estimates). The solid red line is pipeline takeaway capacity out of North Dakota plus local refinery consumption. From 2014 onwards that number includes build out projects expected to be complete by the end of 2016 including the addition of 230 Mb/d of capacity on Sandpiper and 100 Mb/d on the Keystone XL Bakken Marketlink "on-ramp" at Baker, Montana during 2016. Above the solid red line is a dotted line representing the Dakota Express capacity if that project had not been cancelled. The green line is rail-loading capacity on top of the pipeline and refinery numbers (not including Dakota Express).

Assuming for a minute that North Dakota producers relied entirely on pipeline takeaway (after local refinery consumption) to get their crude to market, the solid red line on the chart shows that they would have been inadequately served from 2011 onwards because production exceeded pipeline capacity. In fact pipeline capacity only comes close to meeting crude

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit ________

But of course that assumption ignores the huge growth in rail loading terminal capacity in North Dakota that was easily making up for any pipeline shortfall by 2012 and accounted for more than double the available pipeline capacity in 2013. In fact if only rail-loading capacity were available, it would theoretically be able to handle projected crude production in 2016 without any pipelines let alone building two new ones. (We say theoretically because the actual capacity of rail facilities to move barrels is typically less than their nameplate, due to operating constraints, rail car availability and other vagaries of rail transportation.) Bottom line - pipeline and rail load capacity together currently provide more than adequate crude takeaway capacity from the Bakken such that the Sandpiper or Dakota Express additions in 2016 are “nice to have” not “need to have” additions.

So in effect two pipeline projects were launched by Enbridge and Koch in December 2012 and July 2013 respectively, even though there was already more than adequate combined rail and pipeline crude takeaway capacity from North Dakota. Which begs the question – why did these projects see the light of day at all and why has Sandpiper apparently succeeded where Dakota Express failed?

The answer to the first question – why launch a pipeline project when there is adequate rail takeaway capacity already – is fairly easy. It comes down to meeting long term pent up demand for additional pipeline capacity out of North Dakota. And there was plenty of demand for pipeline expansion before the build out of rail capacity in North Dakota during 2012 and 2013 as crude production surged past takeaway capacity. So although crude-by-rail loading terminals came to the rescue of beleaguered North Dakota producers in 2012 (see From a Famine of Pipeline to a Feast of Rail) that did not happen before they had suffered big pricing discounts for their crude versus the domestic benchmark West Texas Intermediate (WTI). So while crude by rail increased Bakken producer netbacks (market price less transport costs from the wellhead – see for example Brent, WTI and the Impact on Bakken Netbacks), rail transport is more expensive than pipelines. That means pipelines still offer a better transport deal for producers when the route offered is flexible enough to reach the refining markets where prices are best. As a result, even though there was adequate rail capacity in North Dakota, the right pipeline project could still be attractive to producers. The key word here is flexibility – giving producers the option of pipeline routes to market that compliment the rail options they have now grown used to having.

And that is where we will go in the second part of our analysis – to assess whether either Dakota Express or Sandpiper offered North Dakota producers the flexibility to beat existing rail alternatives.

Related Articles

ATTACHMENT C

CAPP
CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

Crude Oil

Forecast, Markets & Transportation

June 2013

On Cover:
Cenovus *in situ* project
BP Whiting refinery - courtesy of BP: photo by Marc Morrison

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

EXECUTIVE SUMMARY

CAPP annually publishes its long-term outlook for Canadian crude oil production to provide a basis on which to build a common understanding among stakeholders, including industry, governments, and the general public regarding the growth in Canadian oil supply and the need for additional market access.

The key points of this year's outlook are:

- Canadian oil production continues to grow and although oil sands remains the largest component of growth, the resurgence of conventional crude oil production represents the largest year over year change to the previous forecast. This resurgence in conventional tight oil is occuring both in Canada and the U.S., enabling greater continental energy security and changing the historical flows throughout North America.
- The main market opportunities occur in the replacement of offshore foreign crude imports in Canada and the United States and in the potential for exports beyond North America.
- Transportation capacity is currently tight and in addition to new pipeline options coming forward, rail has quickly become another way to move oil to market.

Crude Oil Production and Supply

Canadian crude oil production is expected to grow steadily to 2030. Oil sands production reaches 5.2 million b/d by the end of the outlook. Declining eastern Canada production is offset by growth in conventional production from western Canada, so combined production stabilizes at a level of almost 1.5 million b/d. Compared to last year's forecast, conventional production is higher by 300,000 b/d while oil sands production is up by 200,000 b/d by 2030.

Canadian Crude Oil Production

million b/d	2012	2015	2020	2025	2030
Total* Canadian (including oil sands)	3.2	3.9	4.9	6.0	6.7
Eastern Canada	0.2	0.2	0.2	0.2	0.1
Western Canada					
Conventional (including condensate)	1.2	1.4	1.4	1.4	1.4
Oil sands	1.8	2.3	3.2	4.5	5.2

*Totals may not add up due to rounding.

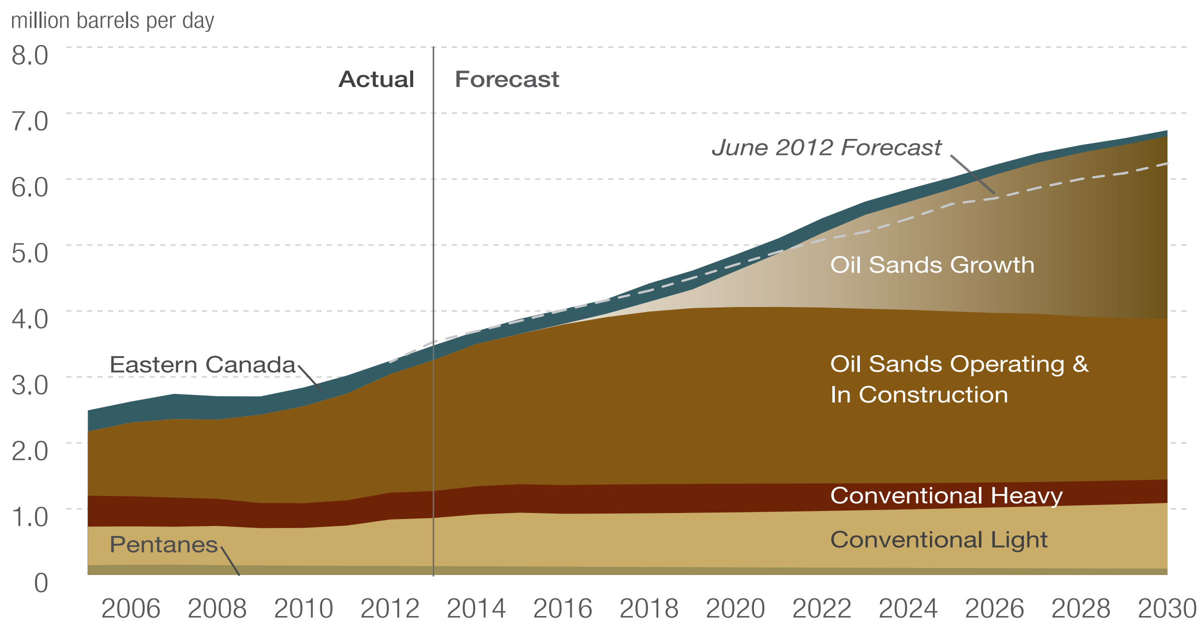
Conventional Oil

The application of advanced drilling technology to previously inaccessible tight oil reserves has reversed the steady decline seen in conventional production over the last several decades. Currently conventional production in western Canada is 1.2 million b/d and is expected to grow to 1.4 million b/d by 2015. Light, tight crude oil production is expected to account for most of this growth.

Oil Sands

The oil sands represent the vast majority of Canada's crude oil reserves, so naturally this resource will be the primary driver for future overall growth. The 2013 outlook for oil sands is similar in aggregate to last year's forecast but with a higher growth outlook for *in situ* production that offsets a lower growth outlook for mining production.

Canadian Oil Sands & Conventional Production



Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

In 2012, 1.8 million b/d were produced from the oil sands of which 800,000 b/d was from mining and 1.0 million b/d were recovered by *in situ* techniques. Looking ahead to 2030, mining production is forecast to increase to 1.7 million b/d and *in situ* production is forecast to grow to 3.5 million b/d.

Eastern Canada

Eastern Canada produced about 6 per cent, or 202,000 b/d of total Canadian crude oil production. Hebron, the fourth major offshore project, is expected to begin production by the end of 2017 and will help offset declines from mature existing projects.

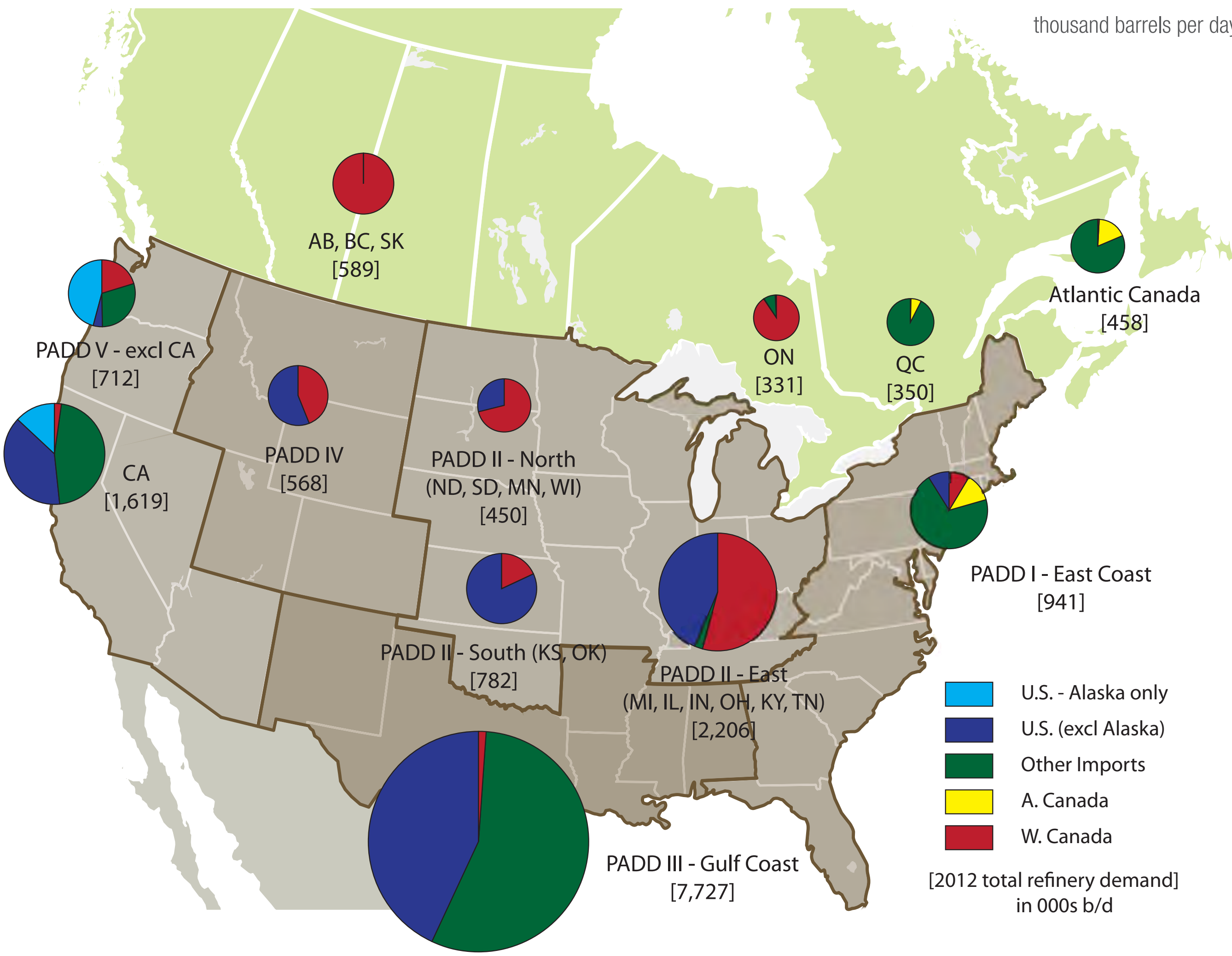
Crude Oil Markets

Given the growing production outlook, the need to reach new markets is a top priority for Canadian oil producers. A fundamental shift is occurring in the market due to strong growth in light crude oil production, which is replacing offshore imports to the light oil refineries in eastern Canada and the United States. Markets for growing heavy oil supplies are primarily found in the U.S. Midwest and Gulf Coast. New market opportunities are also emerging as a result of growing demand in Asia.

Eastern Canada

Refineries in Québec and Atlantic Canada currently import 86 per cent of their requirements. This means there is a potential 700,000 b/d domestic market for growing Canadian oil supplies. Refineries in Ontario have already shifted their main source of supply and obtain more than 90 per cent of their crude oil feedstock from Canadian supplies.

2012 Canada and U.S. Crude Oil Demand by Market Region



Sources: CAPP, CA Energy Commission, EIA, Statistics Canada

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

United States

Crude oil demand by U.S. Gulf Coast refineries in 2012 was almost 8 million b/d. Most of these refineries have the capacity to process heavy crude oil that has traditionally been imported primarily from Venezuela and Mexico. Over 2.2 million b/d of heavy crude oil imports were processed in 2012. Canadian producers could displace some of these imported volumes and is forecast to supply at least 1.1 million b/d to this market by 2020 up from the 100,000 b/d that is currently supplied.

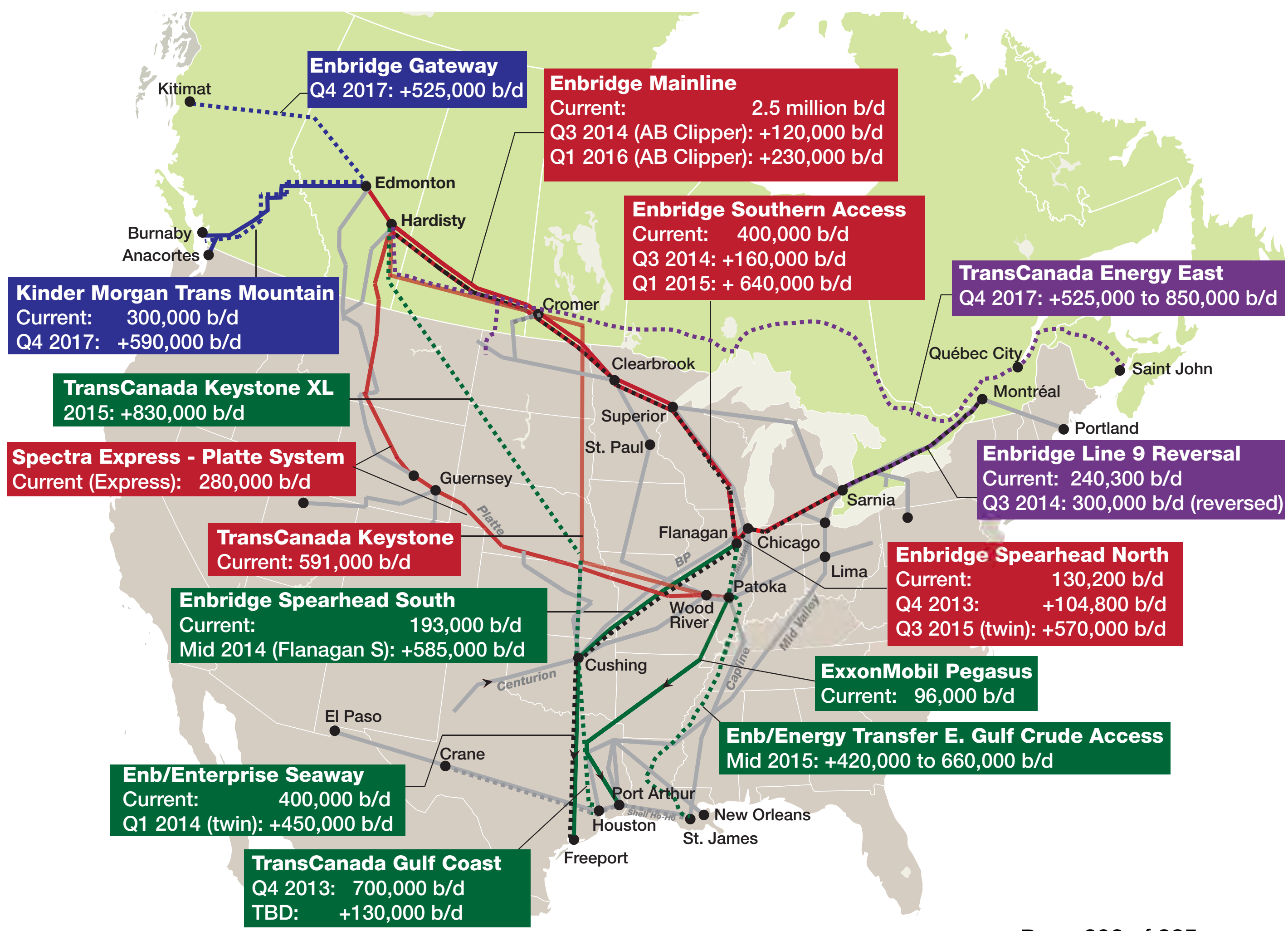
In 2012, Canada supplied 1.7 million b/d to the Midwest, making it Canada's largest export market. A number of refinery conversion projects for processing heavy crude oil have recently been completed and are anticipated to increase demand in the region by 460,000 b/d by 2020.

Refineries in Washington and California need to replace their traditional sources of supply that are now declining and may represent a future market opportunity for Canadian producers.

Asia

Asia is a region of strong growth in energy demand to which Canada currently has very limited access. China and India in particular are obvious markets as they currently have the fastest growing economies in the world. According to the U.S. Energy Information Administration (EIA), their combined oil imports are forecast to increase by 6 million b/d; going from 9.2 million b/d in 2012 to 15.7 million b/d by 2030.

Canadian & U.S. Crude Oil Pipelines and Proposals



Crude Oil Transportation

Transportation capacity is currently tight, however, there have been no reports of this resulting in production being shut-in. This outlook assumes transportation capacity can grow to accommodate the projected increase in supply.

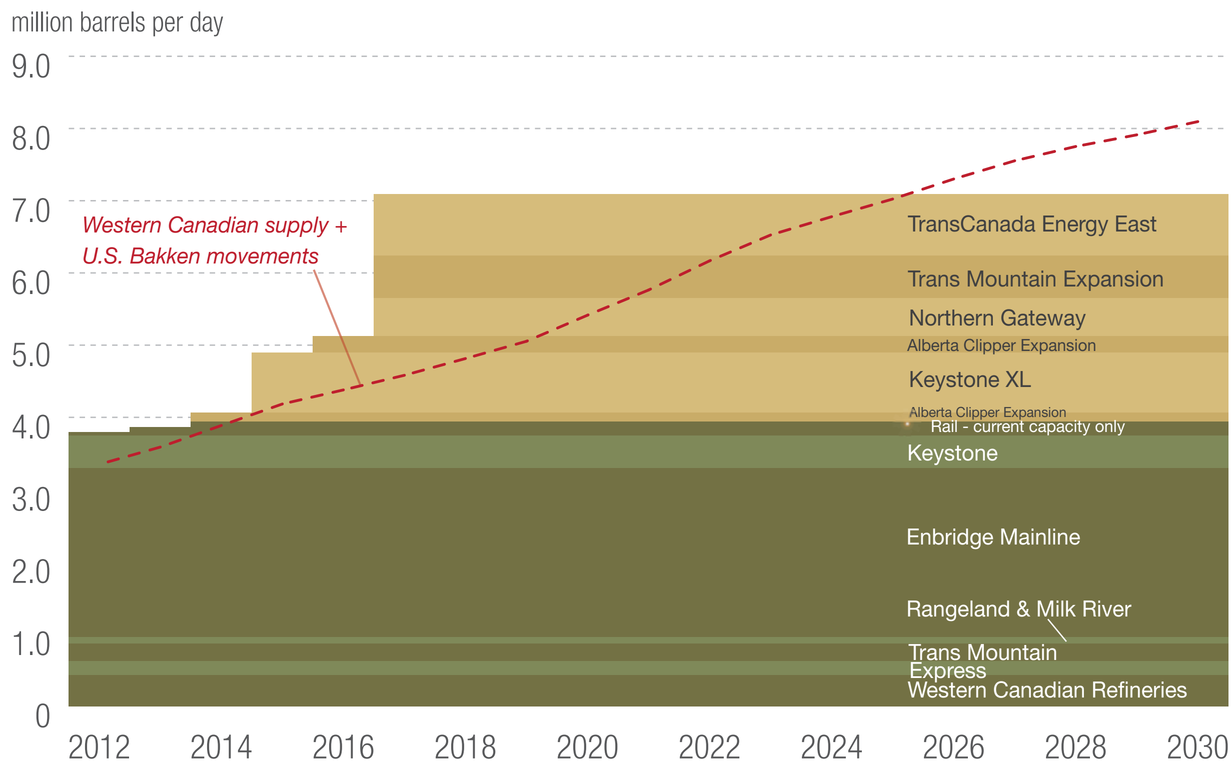
Western Canadian supplies are essentially landlocked and will need additional transportation infrastructure to bring this growing oil supply to markets. Protracted approval processes for new pipeline projects are resulting in a variety of creative transportation proposals to access markets.

It is clear that based on the pipeline projects being proposed (see figure on previous page), industry continues to broaden the scope of markets that it wants to access. Transportation projects involve both the expansion and conversion of existing infrastructure as well as the development of new infrastructure to diversify market access for Canadian producers.

Rail is a growing transportation option for moving crude oil to markets, which is being enabled by construction of new loading facilities and the manufacturing of new tank cars.

The figure below shows the existing and proposed takeaway capacity from the Western Canada Sedimentary Basin versus forecasted supply. Only current railway capacity is shown although this capacity could be increased significantly to fulfill future demand relatively quickly.

WCSB Takeaway Capacity vs. Supply Forecast



Capacity shown can be reduced by temporary operating and physical constraints.

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

Figures

Tables

1 | INTRODUCTION

CAPP annually publishes its long-term outlook for Canadian crude oil production to provide a basis on which to build a common understanding among stakeholders, including industry, governments, and the general public regarding the growth in Canadian supply and the need for additional market access. This report also includes a summary of market opportunities available in North America and globally; and discusses the transportation projects being developed to connect the growing crude oil supplies to various markets.

Canadian crude oil production is expected to grow steadily to 2030. The oil sands represent the vast majority of Canada's crude oil reserves, so naturally this resource will be the primary driver for future overall growth. CAPP's estimate of industry capital spending on oil sands development is $23 billion for 2013, which is unchanged from the estimated expenditure for 2012. In addition, declining production from eastern Canada is offset by growth in conventional production from western Canada.

1.1 Production and Supply Forecast Methodology

CAPP surveyed oil producers in Saskatchewan regarding their annual drilling outlook by well type (horizontal or vertical), as well as their anticipated initial production rates. The conventional production by province component of the forecast was developed through internal analysis of historical trends, the Saskatchewan survey, expected drilling activity, recent announcements, and discussions with industry stakeholders and government agencies.

The oil sands component of the forecast is derived from CAPP's survey of all oil sands producers and as such, reflects the latest industry insight on factors such as production capability from individual projects and general market opportunities. In this analysis, production is not constrained by lack of any transportation infrastructure. However, the report does compare the supply that the analysis produces against the current and proposed pipeline and rail projects to determine where bottlenecks may occur. CAPP does not forecast crude oil prices. Producers responded to the survey with an outlook based on their own internal view of the long-term oil price. In this manner, CAPP is assuming that the oil price will be sufficient to make these projects economic so that this production will be available to the market.

Producers were surveyed for the following data:

a) expected production by project and phase;

b) upgraded light crude oil production; and

c) amount of synthetic crude oil and condensate used as diluent required to move the volumes to market.

The survey results were then risked based on each project's stage of development. Past performance of each company's existing projects or phases was also considered in determining the pace of activity in future project stages, which is an important factor in the case of *in situ* projects that typically have their production capacity divided into multiple phases. The overall forecast was then verified for reasonableness against historical trends. No constraints were put on the forecast due to availability of condensate for blending purposes.

1.2 Market Demand Outlook Methodology

CAPP surveyed refiners in Canada and the U.S. to develop its market outlook. No risk adjustments were made to the responses. However, some assumptions based on discussions with refiners and publicly available information were made and EIA data was used to complete gaps in the survey data for actual demand for each region of the U.S.

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit

2 | CRUDE OIL PRODUCTION AND SUPPLY FORECAST

Although crude oil is known primarily as a feedstock for transportation fuels such as gasoline, it is actually used in the manufacture of a wider range of products that include plastics and even pharmaceuticals. Not surprisingly, all the industrialized countries of the world are extremely dependent on crude oil. According to the EIA, Canada currently ranks as the sixth largest crude oil producing country in the world and remains the largest source of crude oil imports by the United States. The Oil & Gas Journal ranks Canada's 173 billion barrels of proven crude oil reserves as the world's third largest reserves after Venezuela and Saudi Arabia.

2.1 Canadian Crude Oil Production

In 2012, total Canadian production increased from 2011 levels by 223,000 b/d to over 3.2 million b/d and continued growth is forecast in the long term. Eastern Canada produced about 6 per cent, or 202,000 b/d of the total Canadian crude oil production. Western Canada produced 3.0 million b/d from combined conventional and oil sands production. Table 2.1 shows the forecast for total Canadian production divided between eastern and western Canada. Figure 2.1 shows the total Canadian production forecast. Conventional production from western Canada is expected to remain fairly constant at around 1.4 million b/d throughout the outlook period while production from the oil sands is expected to grow from 1.8 million b/d today to 5.2 million b/d at the end of the forecast period. It is this growth from oil sands production that drives the overall increase in current production levels from 3.2 million b/d to 6.7 million b/d in 2030.

Table 2.1 Canadian Crude Oil Production

million b/d	2012	2015	2020	2025	2030
Total* Canadian (including oil sands)	3.24	3.88	4.85	6.03	6.74
Eastern Canada	0.20	0.23	0.25	0.18	0.09
Western Canada	3.04	3.65	4.61	5.85	6.65

*Totals may not add up due to rounding.

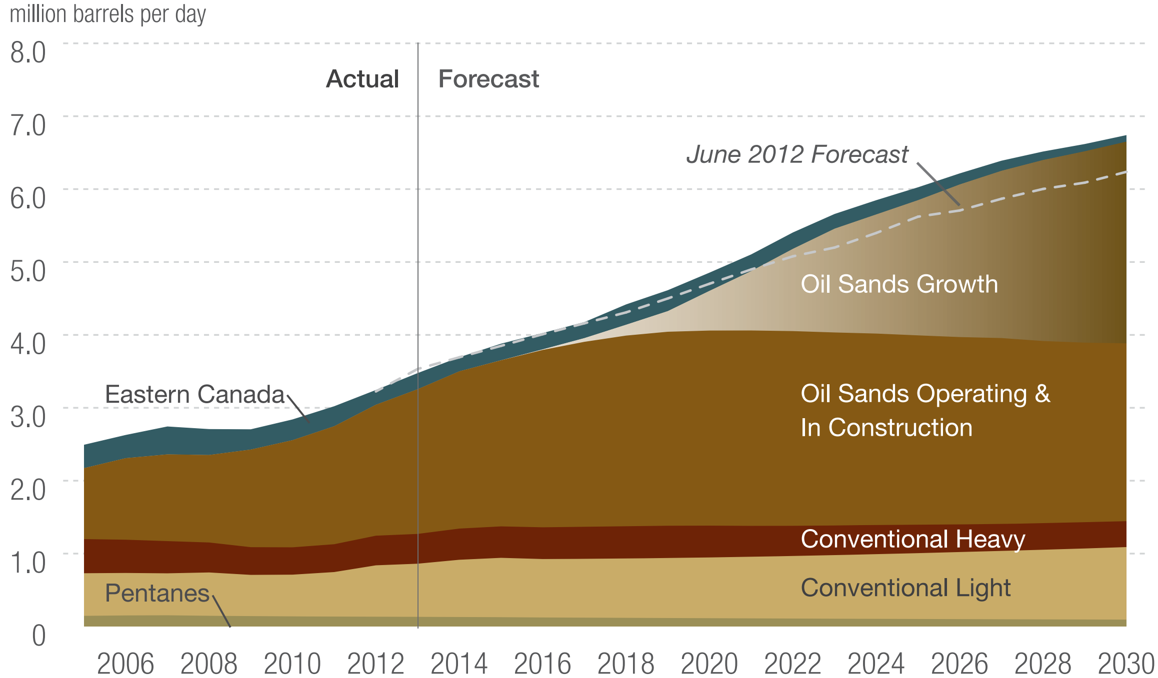
2.2 Eastern Canadian Crude Oil Production

Eastern Canada's crude oil production is sourced from Atlantic Canada supplemented by a small volume coming from Ontario. Since 2007, some minor volumes have been produced from New Brunswick but Atlantic Canada's oil resources are essentially being developed by three offshore oil projects: Hibernia, Terra Nova and White Rose, located off the shores of Newfoundland and Labrador. Continued drilling development at satellite fields associated with these projects (e.g. Hibernia South Extension, North Amethyst and West White Rose) has extended production at these facilities. First oil from Hebron, the fourth major project, is expected by the end of 2017.

In 2012, production declined by 26 per cent to 197,000 b/d. This decrease of 69,000 b/d from 2011 production mostly resulted from extended maintenance shutdowns and to a lesser extent, natural declines at all three projects. Hibernia was offline for 30 days between August and September; Terra Nova for 183 days between June and December and White Rose for 102 days between May and August. Production in 2013 is projected to increase due to a return to steady-state operations.

The outlook for Atlantic Canada production is slightly higher than forecast last year due to an increase in the reserve estimate for the Terra Nova field. In April 2013, the Canada-Newfoundland and Labrador Offshore Petroleum Board stated that it expected the field to operate until 2027, seven years more than it previously estimated.

Figure 2.1 Canadian Oil Sands & Conventional Production



2.3 Western Canadian Crude Oil Production

Western Canadian crude oil production can be divided between conventional and oil sands production. Both categories are expected to contribute significantly to the forecast outlook for western Canadian oil production (Table 2.2). Oil sands production essentially only occurs in the province of Alberta, while conventional resources underlie Alberta, northeast British Columbia, Saskatchewan and parts of Manitoba and the Northwest Territories.

Table 2.2 Western Canadian Crude Oil Production

million b/d	2012	2015	2020	2025	2030
Total*	3.04	3.65	4.61	5.85	6.65
Conventional (including condensate)	1.25	1.37	1.38	1.40	1.44
Oil sands (bitumen & upgraded)	1.80	2.28	3.22	4.45	5.21

*Totals may not add up due to rounding.

Relative to CAPP's 2012 report, production at the latter end of the outlook period from 2020 to 2030 is higher than previously forecast and shows an average annual growth of 200,000 b/d. Conventional production is forecast to contribute about 1.4 million b/d to the total output; the impact of the steep declines expected from mature fields is expected to be entirely offset by production from new horizontal wells. Compared to last year's forecast, conventional production is higher by 300,000 b/d in 2030. Oil Sands production is higher than previously forecast by 200,000 b/d in 2030 due to greater anticipated production from *in situ* wells.

2.3.1 Conventional Crude Oil Production

Conventional crude oil production from western Canada is benefiting from the application of horizontal multistage hydraulic fracturing in tight oil basins to reinvigorate mature basins, a recent trend that has been even more pronounced in the United States. Horizontal drilling has doubled or even tripled the percentage of the resource that industry expects to be able to recover from the reservoirs. Historically, conventional production had been declining steadily since 2002 but flattened out in 2011. Production, including condensates in 2012, was 1.2 million b/d, which returned production to levels not seen since 2004. Further growth is anticipated as conventional production is forecast to ultimately reach 1.4 million b/d despite a decline in condensate production which is primarily recovered from natural gas wells. In last year's report, conventional production was expected to increase in the next few years and then decline during the latter part of the forecast. This latest forecast, however, shows a revised outlook to reflect the expectation that production from new wells will more than offset the natural declines from existing wells in the next few years before maintaining production levels for the remainder of the forecast period. Most of the conventional production comes from Alberta and Saskatchewan and is primarily light crude oil (Figure 2.2). The split between heavy and light conventional crude oil will remain essentially constant to 2030.

Alberta

According to the Alberta Energy Resources Conservation Board (ERCB), out of the 3,107 new oil wells placed on production in 2012, horizontal wells, including those using multistage fracturing techniques, accounted for 2,379 or 77 per cent. This is more than double the number of new horizontal wells placed on production in 2010, the first year horizontal drilling really ramped up in the province.

There are six key shale oil formations in Alberta that have been identified to represent a crude oil in-place endowment of about 424 billion barrels. These formations are Duvernay, Muskwa, Montney, Banff/Exshaw, Nordegg and Wilrich. It is important though to differentiate this estimate from recoverable reserves. Typically recoverable reserves form less than 5 per cent of the in-place reserve estimate. Alberta is leading tight oil drilling activity in western Canada due to the potential of plays such as the Cardium and Viking.

In 2012, conventional Alberta oil production, excluding condensates, was 556,000 b/d and is forecast to increase by 257,000 b/d to 813,000 b/d by 2030. In contrast, in last year's report production was forecast to decline to 522,000 b/d by 2030. With only a few years of production data from horizontal wells, it is too early to establish the ultimate flow rates for wells drilled using the newer technology. However, if the early performance is any indication, CAPP's current forecast outlook may be conservative.

Saskatchewan

The Bakken play is widely recognized as the source of the skyrocketing production in North Dakota but the delineated play area also reaches into Montana, and Canada, including parts of Saskatchewan and a small portion of southwest Manitoba.

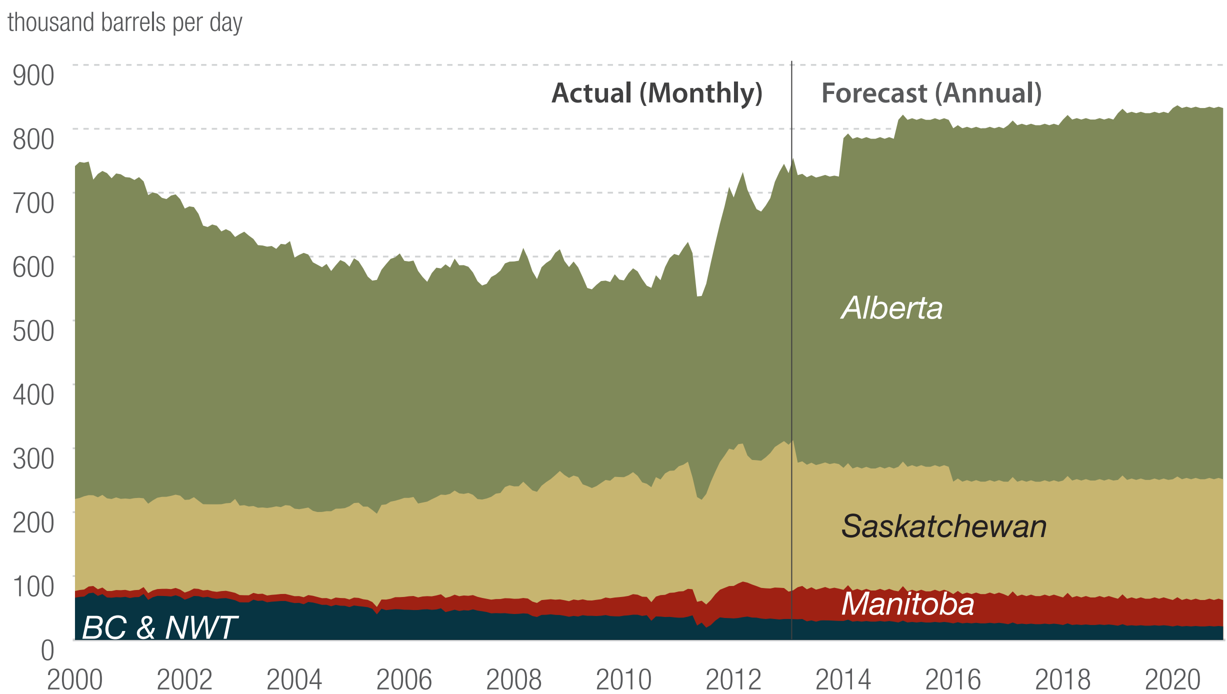
Total (light and heavy) Saskatchewan oil production is currently 470,000 b/d and is forecast to increase to 490,000 b/d by 2030. This is similar to last year's forecast. In 2012, CAPP initiated its survey of Saskatchewan oil producers and has surveyed them again in early 2013 for an update to their drilling plans. Robust drilling and production from horizontal wells is expected to generally grow production year over year throughout the forecast period.

Manitoba, NWT

Manitoba production has steadily increased from 2004 and has more than tripled since then but from a total Canadian context, Manitoba accounts for 7 per cent of light conventional production from western Canada.

Little production currently comes from the Northwest Territories but investment dollars are being attracted to one of North America's oldest fields – the Sahtu region of Canada's Northwest Territories (NWT). Canol oil shale in the NWT is attracting significant attention but assessments of this play are in the very preliminary stages.

Figure 2.2 Western Canada Conventional Production (Light & Medium) 2000-2020



2.3.2 Oil Sands

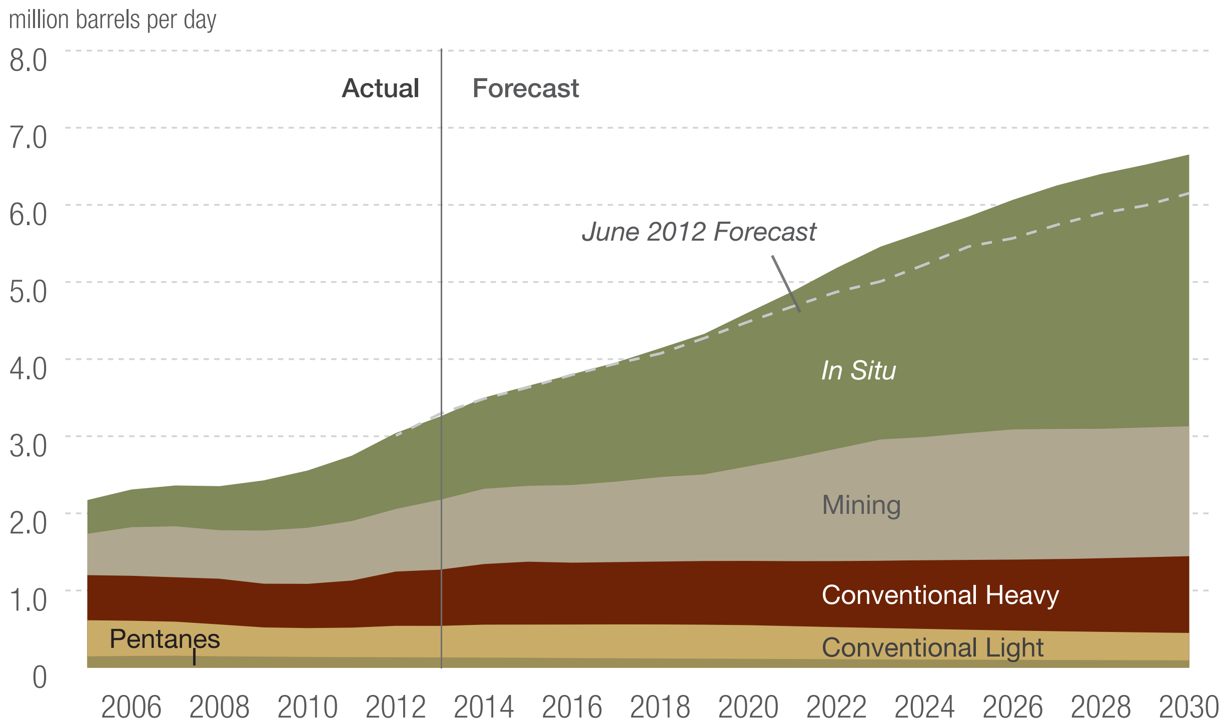
Three designated oil sands areas in northern Alberta have been defined and used to differentiate the extra heavy crude oil, produced from these regions, termed bitumen, from conventional crude oil production. The regions are referred to as the Athabasca, Cold Lake and Peace River deposits (Figure 2.3). The ERCB estimated at year-end 2012, that these areas contain remaining established reserves of 168 billion barrels.

Depending on the depth of the deposit, one of two methods is used to recover the bitumen. Surface or open pit mining can be used to recover bitumen that occurs near the surface. At greater depths, *in situ* techniques are employed. These refer to both, primary development, that uses methods similar to conventional crude oil production, and enhanced development techniques - the main methods being cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD).

Of the remaining established reserves in Alberta, 33 billion barrels or 20 per cent is considered recoverable by mining and 135 billion barrels or 80 per cent can be recovered using *in situ* techniques.

Figure 2.3 Oil Sands Regions

Figure 2.4 Western Canada Oil Sands & Conventional Production



Compared to CAPP's 2012 forecast, while this latest oil sands forecast is very similar in aggregate for most of the outlook period, this similarity is in fact the net result of a higher growth outlook for *in situ* production that offsets the lower growth outlook for mining production. In 2012, oil sands production totaled 1.8 million b/d. Of these volumes, 1.0 million b/d were recovered by *in situ* techniques. Mining production is forecast to grow up to 1.7 million b/d by 2030. Most of the growth is expected from *in situ* production, which is forecast to grow to 3.5 million b/d by 2030 (Table 2.3).

Table 2.3 Oil Sands Production

million b/d	2012	2015	2020	2025	2030
Total*	1.80	2.28	3.22	4.45	5.21
Mining	0.81	0.98	1.23	1.65	1.68
In Situ	0.99	1.30	2.00	2.81	3.52

*Total may not add up due to rounding.

Production volumes from oil sands are typically reported using the upgraded crude oil volumes from integrated projects instead of the raw bitumen volumes processed by these projects. The yield losses associated with upgraded bitumen volumes from non-integrated have been included in the supply volumes that are discussed in the next section of this report. Production from oil sands currently accounts for 59 per cent of western Canada's total crude oil production. In this forecast, oil sands production rises from 1.8 million b/d in 2012, to double in 10 years and reaches 5.5 million b/d by 2030 (Figure 2.4). The oil sands forecast by 2030, is approximately 200,000 b/d higher than forecast in the last report. Please refer to Appendix B.1 for detailed production data.

Currently, Nexen's Long Lake project is the only *in situ* project coupled with upgrading facilities whereas in contrast, historically all mined bitumen has been transformed into upgraded light crude oil. However, Imperial's Kearl mining project started producing bitumen at the end of April 2013 and is the first mining project operating without an affiliated upgrader. This project will deliver diluted bitumen to the market. Some *in situ* volumes from Suncor's Firebag project are upgraded at the Suncor upgrader.

Existing integrated operating and upgrading projects are listed below:

- Suncor Steepbank and Millennium Mine;
- Syncrude Mildred Lake Mine and Aurora Mine;
- Athabasca Oil Sands Project (AOSP);
- Shell Jackpine Mine; and
- Canadian Natural's Horizon Project.

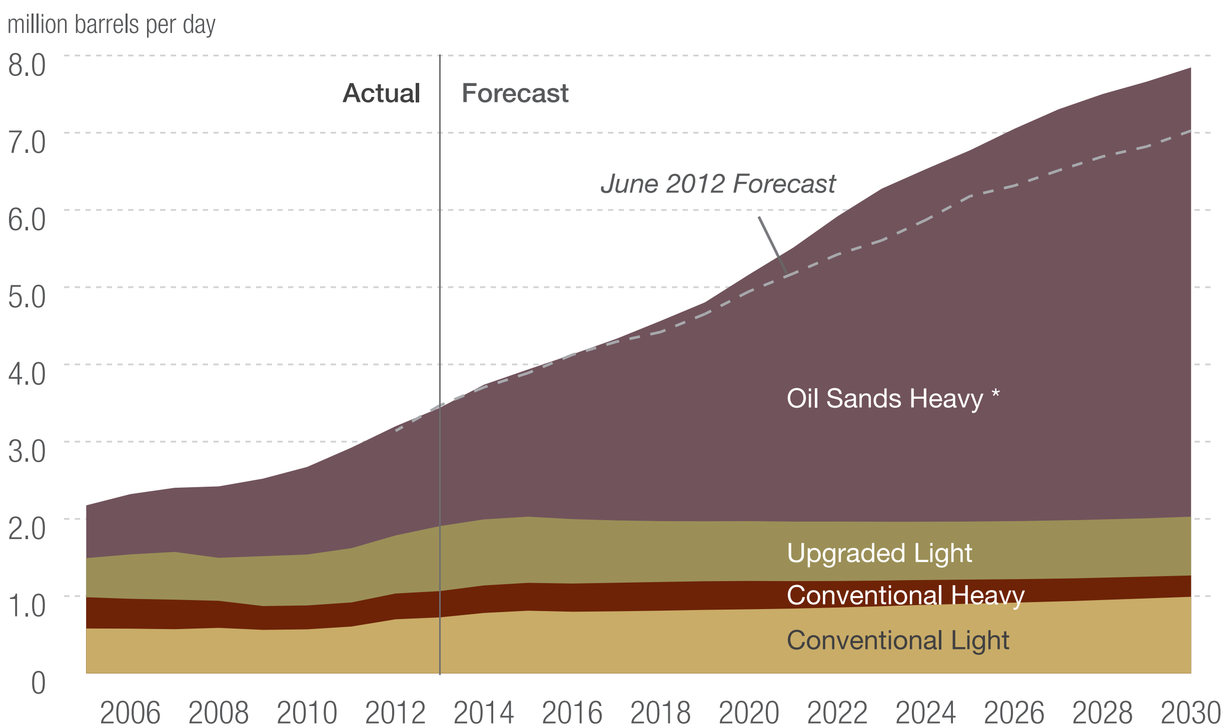
2.4 Western Canadian Crude Oil Supply

The composition of the various crude types available in the market differs from crude oil at the production level. Both conventional heavy crude oil and bitumen from oil sands are either upgraded or blended in order to be transported or to meet optimal refinery specifications. In addition, some volumes of light crude oil may also be used for blending. In any event, it is this crude oil supply that is available after upgrading and blending that is more relevant to market observers because it is these volumes that are ultimately delivered to the end-use markets.

In this report, CAPP categorizes the various crude oil types that comprise western Canadian crude oil supply into the following main categories: Conventional Light, Conventional Heavy, Upgraded Light and Oil Sands Heavy. Oil Sands Heavy includes upgraded heavy sour crude oil, bitumen diluted with upgraded light crude oil (also known as "SynBit") and bitumen diluted with condensate (also known as "DilBit"). Blending for DilBit differs by project but requires approximately a 70:30 bitumen to condensate ratio while the blending ratio for SynBit is approximately 50:50. Bitumen volumes transported by rail are currently relatively minor; however, these volumes would require less diluent for blending versus moving by pipeline or may even be transported as raw bitumen (also known as "RailBit").

In 2012, about 1.0 million b/d or 58 per cent of the total bitumen produced in Canada was upgraded, including volumes of bitumen that were processed at the Suncor refinery in Edmonton. This refinery intake was included since it can process oil sands feedstock. Upgraded volumes are forecast to rise to 1.5 million b/d by 2030. The five bitumen upgraders located in Alberta produce a variety of upgraded products. Suncor produces light sweet crude and medium sour crudes, including diesel; Syncrude, Canadian Natural Horizon, and Nexen Long Lake produce light sweet synthetic crude; and Shell produces an intermediate refinery feedstock for the Shell Scotford refinery, as well as sweet and heavy synthetic crude.

Figure 2.5 Western Canada Oil Sands & Conventional Supply



* Oil Sands Heavy includes some volumes of upgraded heavy sour crude oil and bitumen blended with diluent or ugpraded crude oil.

Canada's upgrading capacity is not expected to rise proportionally as bitumen production rises due to a number of investment challenges. These include the high capital costs incurred with upgrading and the need for a sustained differential between light and heavy crude oil of at least $25 per barrel. It is difficult for a new upgrader to compete with the option of transporting heavy crude oil to existing refineries located throughout North America with spare coking capacity that are able to refine such heavy crudes.

If it is not upgraded, bitumen is so viscous at its production stage that it needs to be diluted with a lighter hydrocarbon or diluent to create a type of crude that meets pipeline specifications for density and viscosity. Bitumen at 10° Celsius has the consistency of a hockey puck and generally cannot be moved on pipelines. Less diluent is required when bitumen is moved by rail where it is transported in heated rail cars that lower the viscosity of the bitumen. The main source of diluent is condensate that is recovered from processing natural gas in western Canada. This source of condensate is declining while the needs of growing bitumen production already exceed this supply and continues to grow. In 2012, over 260,000 b/d of imported condensates, diluents from upgraders, as well as quantities of butane were needed to supplement the condensate supply from natural gas wells. This latest forecast is not constrained by the availability of condensate imports as new sources of condensate are assumed to be available to meet market requirements. Refer to Section 4.7 for details on existing and proposed diluent import pipeline projects. The potential for bitumen to travel by rail with reduced diluent requirement has not been factored into the analysis of condensate demand but this would reduce the estimated need for diluent to the extent it becomes a significant transportation option.

Table 2.4 shows the projections for total western Canadian crude oil supply. Refer to Appendix B.2 for detailed data. Light crude oil supply is projected to be relatively stable at around 1.6 million /d throughout the outlook. Heavy crude oil supply is projected to grow from 1.8 million b/d in 2012 to 3.6 million b/d in 2020 to more than triple the current volume in 2030, when it reaches 6.1 million b/d.

Table 2.4 Western Canadian Crude Oil Supply

million b/d	2012	2015	2020	2025	2030
Total*	3.20	3.94	5.16	6.77	7.85
Light	1.45	1.67	1.60	1.65	1.75
Heavy	1.75	2.27	3.56	5.12	6.09

*Total may not add up due to rounding.

The Upgraded Light crude oil supply includes the light crude oil volumes produced from:

- Upgraders that process conventional heavy oil, e.g., the Husky Upgrader at Lloydminster and the CCRL Upgrader in Regina;
- Integrated mining and upgrading projects, e.g., Suncor, Syncrude and Canadian Natural Resources operations;
- Integrated *in situ* projects, e.g., the Nexen Long Lake project; and
- Off site upgraders, e.g., the Athabasca Oil Sands Project.

Compared to the 2012 forecast, the upgraded light crude oil supply is lower due to the announcement of some upgrader projects being cancelled. The Oil Sands Heavy category is forecast to increase from 1.4 million b/d to 5.8 million b/d by 2030 as a result of increased production volumes and higher imported diluent requirements for these additional non-upgraded volumes (Figure 2.5).

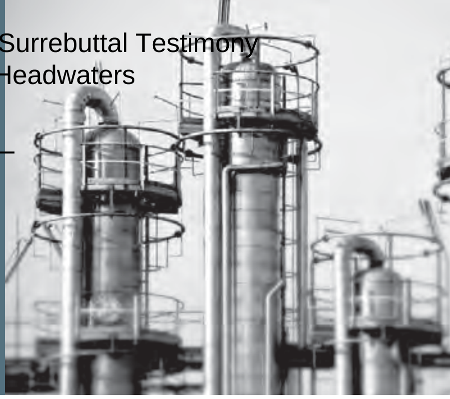
2.5 Crude Oil Production and Supply Summary

The production outlook in eastern Canada from offshore Atlantic Canada is expected to be stable at levels above 200,000 b/d until 2024, supported by production from satellite fields and the Hebron project starting up in 2017. This outlook has been revised slightly upward to reflect the Canada-Newfoundland and Labrador Offshore Petroleum Board's latest, higher reserve estimate for the Terra Nova field.

CAPP's 2013 production forecast predicts continued strong growth in western Canada and is higher than the previous outlook by 500,000 b/d by the end of the outlook in 2030. This is due to upward revisions primarily in the conventional category but also better performance from the oil sands than previously anticipated, specifically from *in situ* projects. The overall Canadian picture in terms of the supply outlook is 820,000 b/d higher in 2030 due to the cumulative effects of higher production, lower yield losses associated with less upgrading, and higher volumes of imported condensates needed to blend with the greater volumes of non-upgraded bitumen being produced.

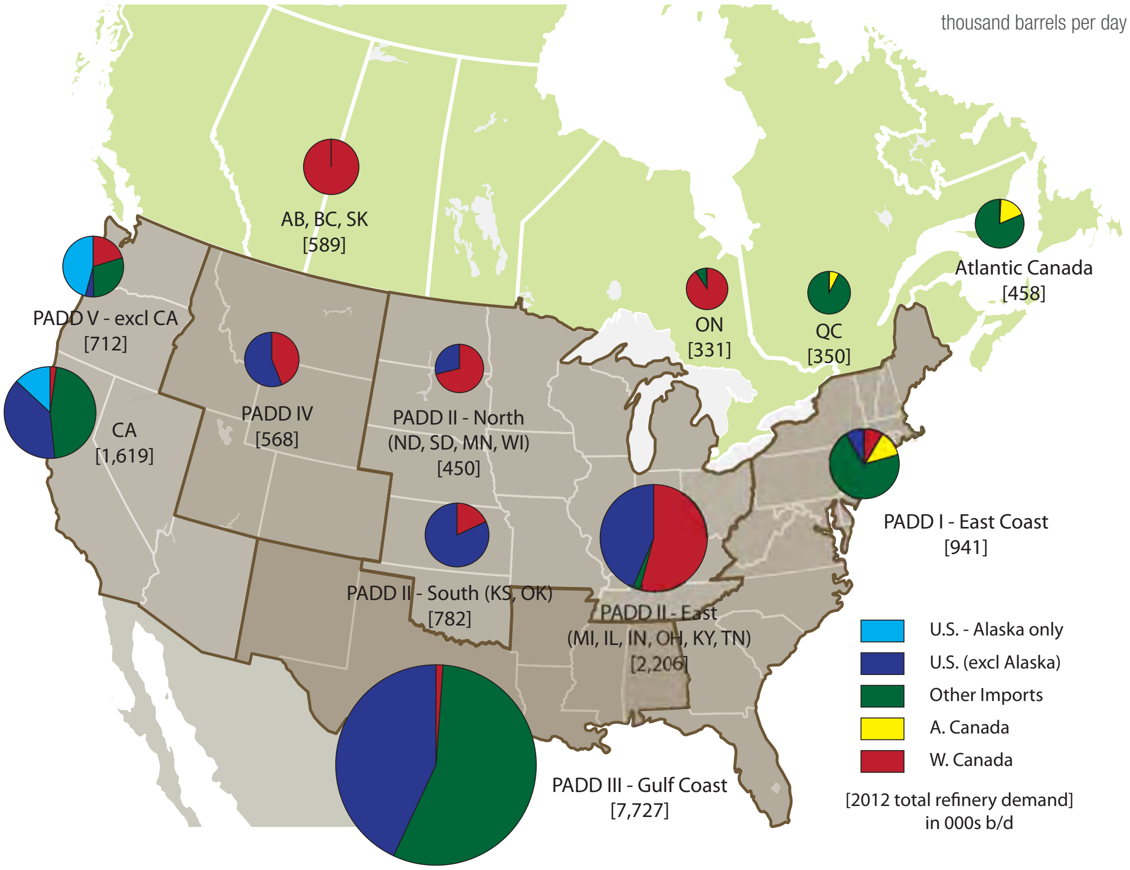
Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

3 | CRUDE OIL MARKETS



Given the growing production outlook discussed in the previous section, the need to reach new markets is a top priority for Canadian oil producers. This chapter examines the demand outlook for Canadian crude oil and reports on the new developments in both traditional and potential markets that could be reached. Figure 3.1 shows the relative demand for crude oil in the major refining regions in Canada and the United States. The Gulf Coast is a key target market in North America for Canadian producers due to the large amount of refining capacity and the ability to process heavy crude oil. There are also other opportunities in eastern Canada, particularly the refineries in Québec and the Atlantic provinces. New market opportunities are also emerging as a result of growing demand in Asia.

Figure 3.1 Canada and U.S. Market Demand for Crude Oil in 2012 by Source



Sources: CAPP, CA Energy Commission, EIA, Statistics Canada

In 2012, Canadian refineries processed 894,000 b/d of western Canadian crude oil. The remaining 2.3 million b/d or 72 per cent of available supplies was exported (Figure 3.2). PADD II is the largest regional market for western Canadian crude oil. Depending on the development of various rail and pipeline projects, refineries in eastern Canada have indicated a potential doubling of current demand for western Canadian crude oil by 2020. In addition, demand from refineries in the U.S. Gulf could reach over 1 million b/d.

3.1 Canada

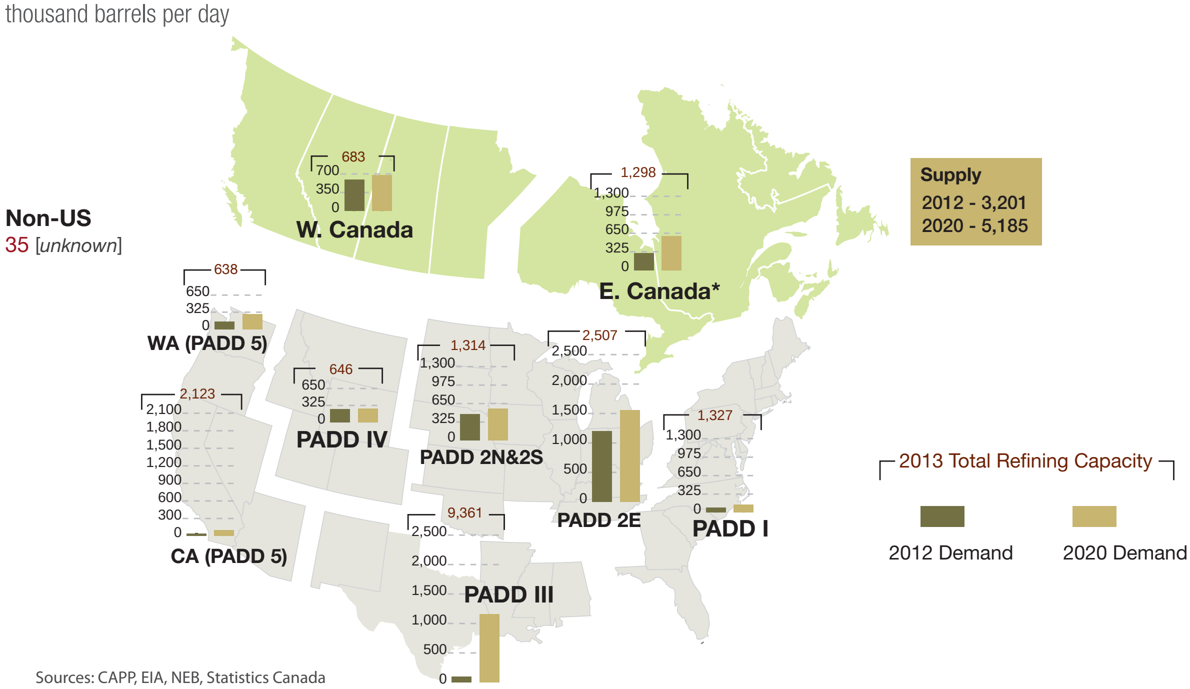
Canadian refineries have the capacity to process almost 2 million b/d of crude oil. However, only about 60 per cent of the crude oil processed in Canada is sourced from domestic production since refineries in eastern Canada have only limited access to western Canadian crude oil supplies. In 2012, Canadian refineries processed 894,000 b/d of western Canadian crude oil; 110,000 b/d of crude oil produced in eastern Canada; and 722,000 b/d of foreign imports. The current oil pipeline network exiting western Canada is connected to refineries in western Canada and Ontario. Based on data from Statistics Canada, in the last two years, Québec refineries have received small volumes of western Canadian crude while Atlantic Canada refineries received crude oil from western Canada for the first time in July 2012. Some refineries are developing transportation solutions involving rail and/or trucks to diversify their supply portfolio. The domestic demand for western Canadian crude oil is expected to increase to 1.3 million b/d by 2020 as a result of planned refinery expansions and future transportation infrastructure developments.

3.1.1 Western Canada

The eight refineries located in western Canada have a total refining capacity of 683,000 b/d. In 2012, they refined 589,000 b/d of crude oil that was sourced exclusively from western Canada. By 2020, western Canadian crude oil should remain the sole feedstock for these refineries and demand is expected to increase by 86,000 b/d to 675,000 b/d (Figure 3.3). Future additional crude oil receipts are related to a debottlenecking project at the Moose Jaw refinery, expansion plans at the Consumers' Co-operative Complex refinery, which are both located in Saskatchewan, and the startup of the Sturgeon refinery near Redwater in Sturgeon County, about 45 km northeast of Edmonton, Alberta. The Moose Jaw refinery is an asphalt refinery while the other refineries produce a wide range of petroleum products.

Figure 3.2 Market Demand for Western Canadian Crude Oil: Actual 2012 and 2020 Additional

thousand barrels per day

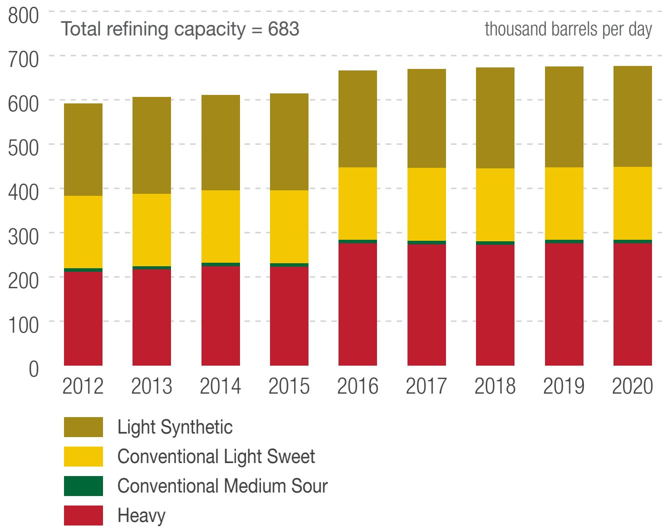


Sources: CAPP, EIA, NEB, Statistics Canada

* E.Canada demand for W. Canadian crude oil in 2012 consisted almost entirely of receipts from Ontario. Projected receipts in 2020 include growth from Québec and Atlantic provinces.

Note: 2012 demand exceeds available supply likely due to factors such as inventory adjustment and data discrepancies in information collection.

Figure 3.3 Western Canada:
Crude Oil Receipts from Western Canada



Source: 2013 CAPP Refinery Survey

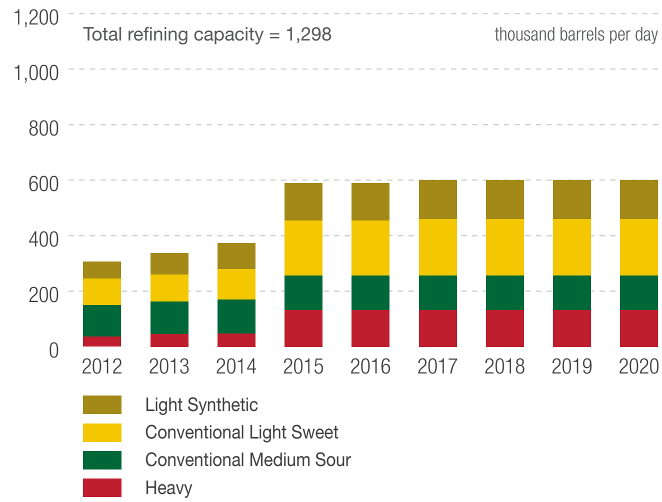
North West Redwater Partnership's proposed Sturgeon refinery will take bitumen feedstock with its first phase designed to process 50,000 b/d. Partners are North West Upgrading Inc. and Canadian Natural Upgrading Ltd., a wholly owned subsidiary of Canadian Natural Resources Ltd. The Alberta Petroleum Marketing Commission, an agent of the province of Alberta, will supply 75 per cent of the feedstock under 30-year processing agreements and Canadian Natural will supply the rest. The suppliers will receive proportionate shares of the products. Construction is planned to start in spring of 2013 and projected to take three years. Two additional phases that would each provide capacity of 50,000 b/d are envisioned for the refinery. The main product will be ultralow-sulphur diesel.

Newspaper publisher, David Black has announced a proposal to build a $13 billion, world-scale, export refinery in Kitimat, British Columbia. The refinery would be designed specifically to process DilBit and would be capable of processing 550,000 b/d; it could be operating by 2020.

3.1.2 Eastern Canada

Total capacity of refineries in eastern Canada is about 1.3 million b/d and includes the refineries located in Ontario, Québec and Atlantic Canada. In 2012, western Canada supplied 340,000 b/d to these refineries amounting to only 29 per cent of total refinery demand. Almost all of these receipts were delivered to Ontario. It should be noted, however, that the refineries in the other eastern provinces have just started to receive western Canadian supplies via rail. By 2020, overall demand in this market for western Canadian crude oil is expected to increase significantly if the Enbridge Line 9 reversal project and the TransCanada Energy East project proceed (Figure 3.4).

Figure 3.4 Eastern Canada:
Crude Oil Receipts from Western Canada



Source: 2013 CAPP Refinery Survey

Ontario

The four refineries located in Ontario have a combined refining capacity of 393,000 b/d. The Nova Chemical refinery and petrochemical complex, located in Sarnia, is not included in this number as crude oil is not the primary feedstock. The majority of the crude processed at the Ontario refineries is sourced from western Canada but they also refine some foreign imported crude oil and crude oil transferred from Atlantic Canada. The supply from the latter two sources arrive on the Atlantic seaboard by tanker and are then transported through the Portland-to-Montréal Pipeline before being transported on the Enbridge Montréal-to-Sarnia Pipeline (Line 9).

Enbridge plans to re-reverse the direction of Line 9 to flow east from Sarnia, Ontario to Montréal, Québec. It is already in the process of of reversing the first phase of the project which would enable crude oil to flow east from Sarnia to North Westover, Ontario in 2013. Once in service, this first phase could provide light crude oil to Imperial's refinery in Nanticoke, Ontario. Refer to Section 4.6 for details on oil pipelines to Eastern Canada. Ultimately, all refineries in the region will have access to a variety of sources and will select their feedstock based on availability and price.

According to Statistics Canada, Ontario refineries received 366,200 b/d of crude oil. A further breakdown of these supplies shows 336,700 b/d (92 per cent) from domestic sources; 17,700 b/d (5 per cent) from the North Sea; 3,800 b/d (1 per cent) from Venezuela; 1,700 b/d (0.5 per cent) from the U.S.; and 6,400 b/d (2 per cent) from other foreign sources.

Québec & Atlantic Provinces

Québec has two refineries with a combined capacity of 402,000 b/d while the three Atlantic refineries have total capacity of 503,000 b/d. The crude oil processed at these refineries generally originates from either Atlantic Canada or foreign sources. Of note, Statistics Canada data indicated that the Québec refineries have received small volumes of western Canadian crude since 2011. Valero has recently announced plans to build rail off-loading facilities at its refinery in Levis, Québec in order to receive more volumes of light western Canadian crude oil. Despite the considerable distance, Atlantic Canada also received western Canadian crude oil deliveries in 2012 by rail. These refineries are designed to process mostly light crude oil.

If Enbridge's Line 9 re-reversal proposal is successful, western Canadian crude oil could be transported by pipeline to Montréal and then further in the province by alternative modes of transport. Refineries in these provinces would have access to the growing light oil production from both western Canada and the U.S. Bakken in Montana and North Dakota. Once crude oil reaches Montréal, companies could barge oil from there to Québec City, and potentially even ship it by rail to the Irving refinery in Saint John, New Brunswick. In the meantime, the Irving refinery is expected to receive a regular supply of Bakken crude oil by rail. Its first shipment, in June 2012, was 72,000 barrels aboard a 102 car unit train. By 2018, TransCanada's Energy East pipeline project proposes to provide pipeline access from western Canada to Québec City and all the way to Saint John, New Brunswick.

3.2 United States

Canada and the U.S. are natural trading partners due to their geographic proximity. Canada is the top foreign supplier of crude oil to the U.S. while the U.S. is almost Canada's only market. New U.S. production from enhanced drilling programs in the shale and tight oil plays in the Eagle Ford and Permian basins in Texas and Bakken in North Dakota, have caused a displacement of foreign imports of light crude oil. Despite this fact, imports from Canada grew by 200,000 b/d or 9 per cent versus 2011. Growing western Canadian crude oil supplies are predominately heavy crude oil, therefore, the U.S. Gulf Coast refineries, with their substantial heavy oil processing capabilities, remain a key target market.

The U.S. Department of Energy divides the 50 states into five market regions termed the Petroleum Administration of Defense Districts or PADDs. These PADDs were originally created during World War II to help allocate fuels derived from petroleum products. Today, this delineation continues to be used to describe the U.S. market regions.

3.2.1 PADD I (East Coast)

Since a portion of previously idled refinery capacity restarted in 2012, the refining capacity on the U.S. East Coast now totals 1.3 million b/d. The 10 refineries that form this capacity are located in the states of Delaware, Georgia, New Jersey, Pennsylvania, and West Virginia. Table 3.1 summarizes the refining capacity developments in this region.

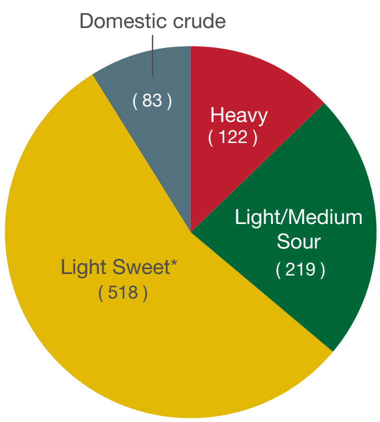
Most of the refineries in the region process light sweet crude (Figure 3.5). In 2012, imports of foreign crude oil by refineries in PADD I totaled 941,000 b/d, which is significantly lower than in 2011. This decline was due to a combination of some refining capacity being idled for most of the year and some displacement of foreign imports with growing domestic supplies. In 2013, there should be an increase in the total volumes processed in the region given that some previously idled refineries have returned to operations (Table 3.1). The boom in U.S. shale has presented a new source of supply for refineries in this region.

Table 3.1 Summary of Recent Refinery Developments in PADD I

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Monroe Energy LLC	Trainer, PA	185	restarted Sep 2012 (previously idled since Sep 2011)	Monroe Energy LLC, a wholly owned subsidiary of Delta Airlines, purchased the idled refinery in April 2012; The transaction closed in Sep 2012 and the refinery has restarted.
PBF Energy	Delaware City, DE	190	restarted Oct 2011	PBF purchased the refinery in an idled state from Valero in June 2010. The refinery was idle from Nov 2009 to Oct 2011.
Philadelphia Energy Solutions	Philadelphia, PA	330	July 2012	Although it continued operations, Sunoco had announced that it would close the refinery if no buyer was found. In July 2012, the Carlyle Group announced a 50/50 joint venture with Sunoco to create Philadelphia Energy Solutions, a new entity that would own and operate the refinery.
Sunoco	Marcus Hook, PA	175 (loss)	shutdown Feb 2012	The refinery was idled since Dec 2011. Sunoco shut down the refinery in Feb 2012.

Figure 3.5 2012 PADD I: Foreign Sourced Supply by Type and Domestic Crude Oil

Total refining capacity** = 1,327 thousand barrels per day



* Includes small volumes of Medium Sweet
** Capacity as of Jun 2013; two refineries were idled in late 2011
Source: EIA

The east coast refineries are primarily supplied by waterborne crude delivered from the U.S. Gulf Coast and internationally-sourced crude. However, with the development of new rail unloading facilities, a number of the east coast refineries have growing access to Bakken crude oil produced in North Dakota. Phillips 66 and PBF Energy have signed agreements for Bakken crude supplies for its east coast refineries. There was also speculation that growing production from the Utica shale would present another prospect for increased domestic supplies of crude in the future. Given the fact these volumes would originate in Ohio, these crude oil supplies would need to travel a much shorter distance by rail to reach refineries on the east coast. However, recent reports suggest that the future potential from the Utica shale is more gas prone.

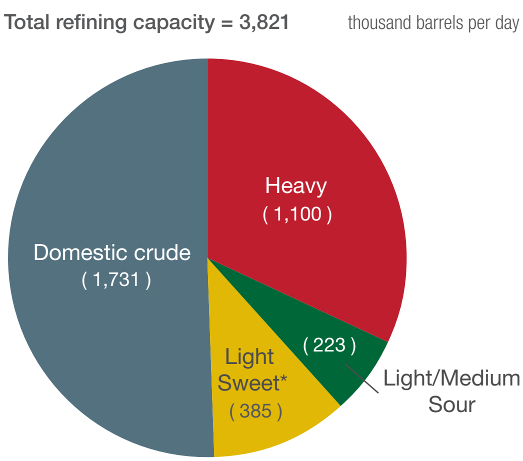
PADD I refineries imported 194,300 b/d of crude oil from Canada in 2012. About 64,800 b/d was sourced from western Canada and was primarily delivered to the United refinery in Warren, Pennsylvania.

Imports of heavy crude oil from western Canada could rise in the next few years via deliveries by rail. PBF Energy has made significant investments in its rail unloading facilities in 2012 for its Delaware refinery and intends to expand this capacity in 2013. PBF Energy's current rail unloading facility has 110,000 b/d of capacity comprised of about 40,000 b/d of heavy crude oil capacity and 70,000 b/d for light crude oil. The company also plans to increase heavy unloading capacity by another 40,000 b/d by Q4 2013. Although PBF Energy's Paulsboro refinery does not have a rail unloading facility, crude oil could be moved by barge from the Delaware facility up river to Paulsboro.
PBF Energy's Paulsboro and Delaware City refineries and NuStar Energy's asphalt refinery in New Jersey are the only refineries on the east coast with the coking capacity to process heavy bitumen blends from western Canada.

3.2.2 PADD II (Midwest)

Over 3.8 million b/d of refining capacity is located in PADD II. In 2012, these refineries received 1.7 million b/d of foreign sourced crude oil, almost all of which was from western Canada and were predominantly heavy supplies (Figure 3.6). In 2012, this market absorbed almost all of the growth in western Canadian supplies.

Figure 3.6 2012 PADD II: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA

PADD II can be further divided into the Northern, Eastern, and Southern PADD II states. The primary market hubs within PADD II are located at Clearbrook, Minnesota for the Northern PADD II states; Wood River-Patoka, Illinois area for the Eastern PADD II states; and Cushing, Oklahoma for the Southern PADD II states.

The Midwest region is currently Canada's largest market due to its close proximity, large size and established pipeline network. However, this traditional market has become saturated as evidenced by the high level of inventories from growing domestic production and imports from western Canada. A number of refineries have recently been upgraded to increase the heavy oil processing capacity in the region, which accounts for most of the expected growth in heavy oil demand.

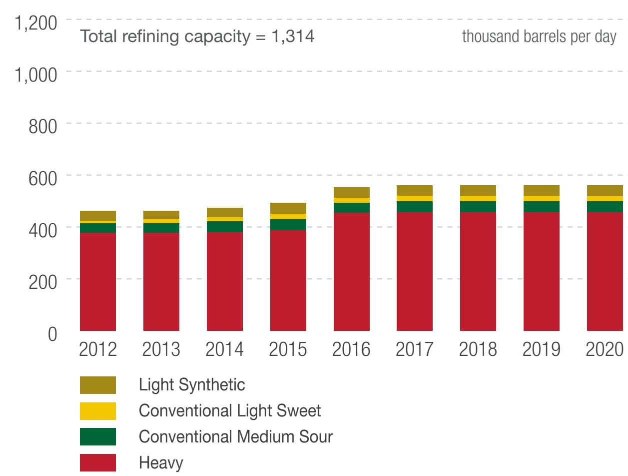
Northern and Southern PADD II

There are four refineries in Northern PADD II; two that are located in Minnesota, and one each in North Dakota and Wisconsin. These refineries have a combined capacity of 507,000 b/d. In 2012, imports from western Canada totaled 320,000 b/d and were the only source of foreign imports. These foreign imports comprised over 70 per cent of the total crude oil feedstock demand in the region. Approximately 89 per cent of these volumes were heavy crude oil supplies.

The seven refineries in Southern PADD II, all of which are located in Kansas or Oklahoma, account for a combined capacity of 807,000 b/d. Almost all of the foreign imports into the region were also sourced from western Canada but in contrast to Northern PADD II, U.S. domestic production satisfies most (over 80 per cent) of the feedstock demand for these refineries. The majority, or 66 per cent, of the 142,000 b/d of western Canadian crude oil imports were heavy oil supplies.

Given the small relative size of these two markets and increased competition with U.S. light oil production the growth in demand for western Canadian crude oil is limited. It is forecast to grow by 100,000 b/d by 2020 (Figure 3.7).

Figure 3.7 PADD II (North & South): Crude Oil Receipts from Western Canada



Source: 2013 CAPP Refinery Survey

Table 3.2 Summary of Recent Refinery Upgrades in Northern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Northern Tier Energy LP	St. Paul Park, MN	82	Completed May 2013	A 10% expansion of its crude distillation unit. Capacity increased from 72,000 b/d.
Tesoro	Mandan, ND	68	Completed June 2012	Increased crude capacity by 10,000 b/d to 68,000 b/d to process more Bakken crude oil.

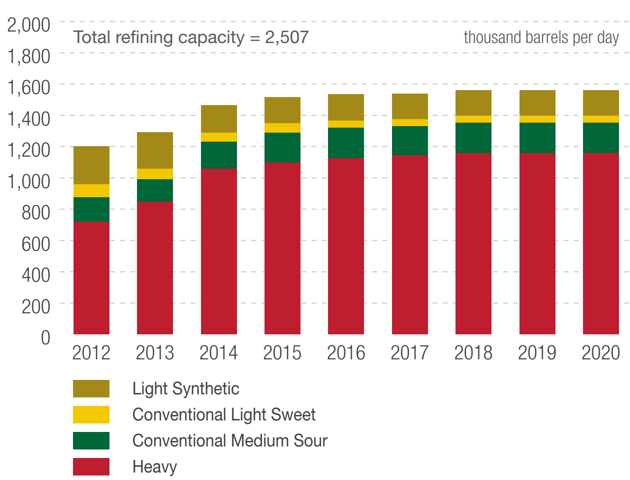
Table 3.3 Summary of Recent Refinery Upgrades in Eastern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
WRB Refining	Roxana, IL	306	Completed Nov 2011	New 65,000 b/d coker; increased total crude oil refining capacity by 50,000 b/d and heavy oil capacity to 240,000 b/d.
BP	Whiting, IN	413	2H 2013	Construction of 70,000 b/d new coker and a new crude distillation unit. The modernized refinery will have the capacity to process up to 85% heavy crude vs 20% currently
Marathon	Detroit, MI	120	Completed Nov 2012	Increase heavy oil processing capacity by 80,000 b/d; total crude oil refining capacity increased by 14,000 b/d.

Eastern PADD II

The total refining capacity in Eastern PADD II is over 2.5 million b/d from 13 refineries located throughout the six states of Michigan, Illinois, Indiana, Kentucky, Tennessee and Ohio. In 2012, this market collectively imported over 1.2 million b/d of crude oil supplies, of which 97 per cent were sourced from western Canada. Imports of heavy western Canadian crude oil are estimated to increase from current levels by over 400,000 b/d by 2020 (Figure 3.8) with the completion of a number of previously announced refinery projects designed to increase heavy oil processing capacity at various refineries. Although the BP refinery in Whiting, Indiana is anticipated to come on stream in the second half of 2013, the refinery is not expected to operate its full heavy processing capacity until 2014. Table 3.3 summarizes the recent and upcoming refinery upgrades announced for Eastern PADD II.

Figure 3.8 PADD II (East): Crude Oil Receipts from Western Canada



Source: 2013 CAPP Refinery Survey

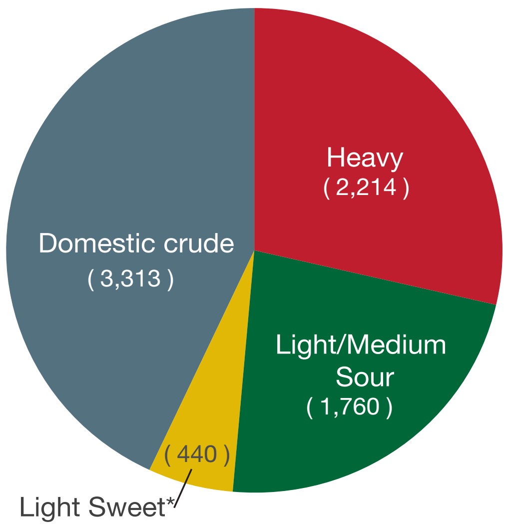
3.2.3 PADD III (Gulf Coast)

The U.S. Gulf coast area has a capacity of 9.4 million b/d from 50 refineries. Refineries are located in Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas. Louisiana and Texas account for the vast majority of refining capacity in this region with 8.6 million b/d.

Foreign imports of crude oil totaled 4.4 million b/d in 2012, of which 2.2 million b/d was heavy crude oil. Only 100,000 b/d of western Canadian crude was able to reach the U.S. Gulf Coast region due to limited pipeline infrastructure. As a result of surging production from U.S. shale and tight oil plays such as the Eagle Ford and Permian Basin in Texas, some refineries along the U.S. Gulf Coast no longer import light-sweet crude since domestic production is available to fill their feedstock requirements. Venezuela, Mexico, Columbia and Brazil collectively account for 88 per cent of all heavy imports into the region, with Mexico and Saudi Arabia each accounting for 22 per cent and Venezuela following closely at 20 per cent. Crude oil imports from Saudi Arabia consist mostly of light and medium sour crude oil types. The opportunity for growing supplies from western Canada lies in the displacement of heavy imports that does not directly compete with U.S. domestic production, which is primarily comprised of light crude oil. In addition, some refineries are also contemplating blending Canadian heavy crude oil with Eagle Ford light oil to create a medium sour crude oil that could displace additional offshore imports (Figure 3.9).

Figure 3.9 2012 PADD III: Foreign Sourced Supply by Type and Domestic Crude Oil

Total refining capacity = 9,361 thousand barrels per day



* Includes small volumes of Medium Sweet
Source: EIA

Crude oil imports from Mexico fell by 130,000 b/d to below 1 million b/d for the first time since 1994, reflecting the steady decline in Mexico's crude oil production. Venezuelan imports have declined 27 per cent from 2005 levels to 906,000 b/d in 2012, a trend that will likely continue as Venezuela increases exports to China.

Despite Venezuela having the world's largest reserves of crude oil and announcing projects designed to increase production capacity by over 2 million b/d, growth in Venezuelan production will be difficult to achieve. There has been substantial under investment in the oil industry as a result of diverting oil revenues to fund social programs and considerable investments will be needed to just offset the decline in production from the mature fields. If there is no substantial growth in production, exports to the U.S. will be limited as Venezuela has substantial supply commitments to China, Cuba, the Dominican Republic and Nicaragua.

There are three new pipeline projects planned for operations over the next three years that will be major conduits between western Canadian producers and the Gulf Coast market. By 2020, CAPP has estimated that this market could receive at least an additional 1.1 million b/d based on contractual commitments on the Keystone XL and Flanagan South pipelines.

Table 3.4 summarizes the recently completed major refinery upgrades and future upgrades announced for the region.

Table 3.4 Summary of Recent Refinery Upgrades in PADD III

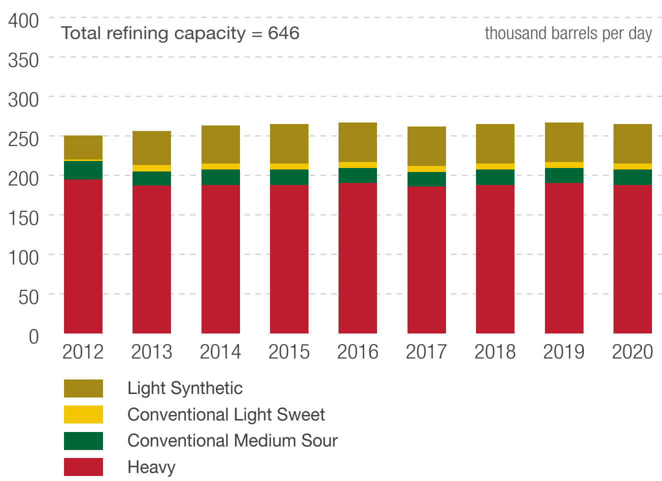
Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Motiva Enterprises	Port Arthur, TX	285	2012	Addition of new single-train distillation unit with capacity of 325,000 b/d that would increase total capacity to over 600,000 b/d. New 95,000 b/d delayed coker; 85,000 b/d catalytic reformer, 75,000 b/d.
Valero	McKee, TX	170	2014	Increase capacity by 25,000 b/d. Expansion will process WTI and locally produced crude oil.
Valero	Port Arthur, TX	310	Q3 2012	New hydrocracker.
Valero	Norco, LA	250	Q4 2012 completed	New hydrocracker. Recently completed FCC revamp. Ramp up to full operations by Q2 2013.
LyondellBasell Industries NV	Houston, TX	268	2015	Increase ability to process heavy crude oil from 60,000 b/d to 175,000 b/d.

3.2.4 PADD IV (Rockies)

There are 17 refineries throughout Colorado, Montana, Utah, and Wyoming representing the refining capacity in PADD IV. The total refining capacity in this market region is 646,000 b/d and all foreign imports are sourced from western Canada.

In 2012, PADD IV refineries processed 250,000 b/d of Canadian crude oil, representing 44 per cent of total feedstock requirements in the region. Receipts of heavy western Canadian supply are forecast to remain steady with slight growth in light synthetic volumes anticipated in 2013, which level off thereafter (Figure 3.10). If Canadian heavy crude oil continues to be priced at an attractive discount, refineries are expected to continue to take heavy volumes to optimize refinery configuration despite the light crude oil surplus in the region.

Figure 3.10 PADD IV: Crude Oil Receipts from Western Canada

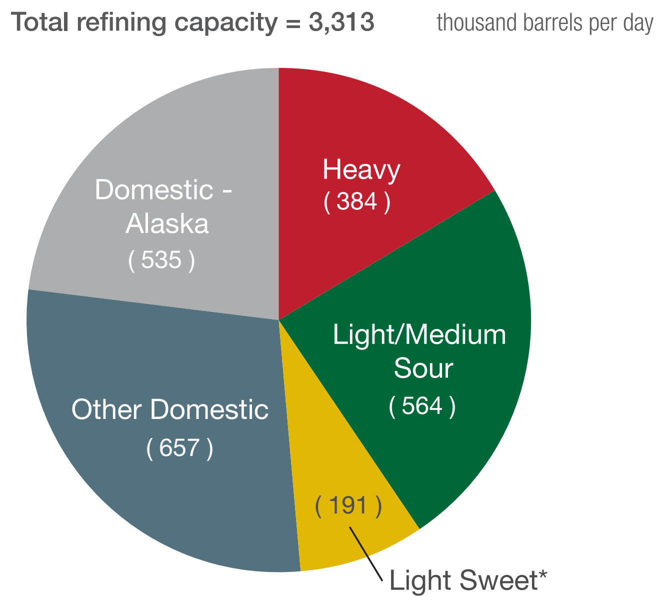


Source: 2013 CAPP Refinery Survey

3.2.5 PADD V (West Coast)

PADD V is geographically divided from the rest of the U.S. by the Rocky Mountains and this geographical isolation has affected the development of crude supply sources to the region. The states in PADD V that have refineries are Alaska, California, Hawaii, and Washington. These refineries are located in close proximity to production in California and Alaska and also have good access to tankers that can import crude from more distant regions. There is over 3.3 million b/d of refining capacity in the region. Foreign imports typically supply around 50 per cent of the crude oil feedstock demand (Figure 3.11) and this share is expected to supplement the declining production from Alaska.

Figure 3.11 2012 PADD V: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA

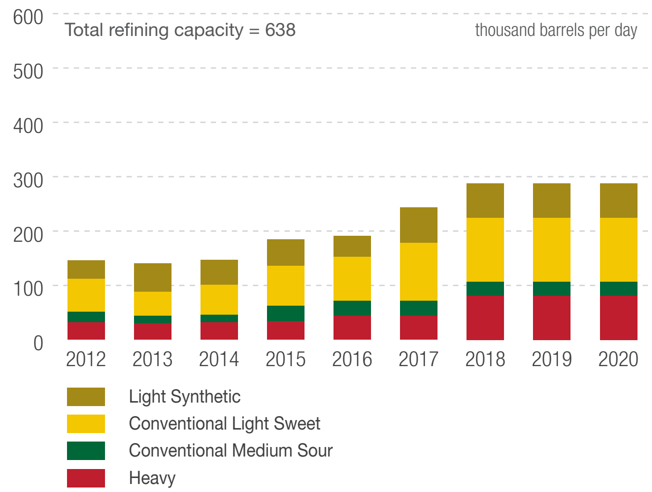
The following section only focuses on Washington and California as demand from the refineries in these states account for both current and future prospects for western Canadian crude oil in this region.

Washington

Refining capacity in Washington totals 638,000 b/d. There is no indigenous crude oil production within the state so its five refineries have been primarily supplied with Alaskan production delivered by tanker. However, Alaskan production has fallen dramatically from its peak in 1988 of over 2 million b/d to only 525,000 b/d in 2012. The Washington refineries have become increasingly dependent on foreign imports but some have also recently been able to start using rail to access some of the growing crude oil production supply in North Dakota.

In 2012, Washington refineries received 241,000 b/d of foreign imports, 81 per cent of which was supplied by the top three sources – Canada (60 per cent); Russia (13 per cent); and Angola (8 per cent). Results from CAPP's refinery survey indicate crude oil demand from western Canada doubling in 2020 from current levels (Figure 3.12). This growth in demand relies on the successful construction of proposed pipeline projects that would reach the west coast. Refer to Section 4.5 Pipelines to the West Coast for details.

Figure 3.12 Washington: Crude Oil Receipts from Western Canada



Source: 2013 CAPP Refinery Survey

In 2012, Washington started to receive deliveries of light sweet North Dakota Bakken crude oil by rail. Continued investment in rail facilities has been announced to primarily enable receipts of additional volumes from this supply source and accommodate deliveries from western Canada as well. Phillips 66 has announced plans to build a rail offloading facility at its Ferndale refinery to receive both Bakken and western Canadian crude oil.

California

California dominates PADD V in terms of state production and refining capacity. There are 16 refineries, almost all of which are located near the coast in the Los Angeles and the San Francisco Bay areas and contribute a total refining capacity of 2.1 million b/d. There is no direct pipeline access to neighboring producing regions so domestic supplies have historically come from indigenous supplies and shipments by tanker from Alaska.

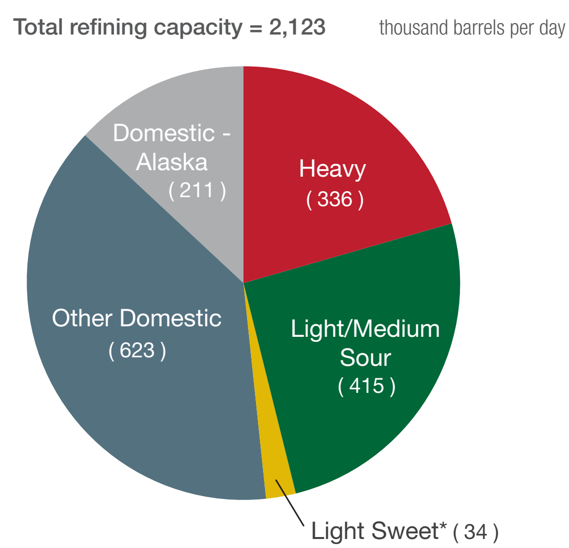
The steady decline in California production seen since 1997 has stabilized in the last two years. Recent surveys from the U.S. EIA have indicated that 15.4 billion barrels of oil (64 per cent) of the total recoverable shale oil in the U.S. can be found in California. Notable plays include the Monterey Shale in southern and central California and the Kreyenhagen. Although California's potential growth in unconventional oil production is enormous, there are many challenges to overcome before significant commercial production develops. For example, an efficient regulatory framework still has to be developed, the appropriate stimulation techniques have to be identified and even then the costs of development could still be prohibitively high.

In the meantime, as Alaskan crude oil production continues to decline, an opportunity has risen for supplemental supplies to serve the state from the Bakken in North Dakota and potentially Canada. Western Canadian crude oil can reach this market either on the Trans Mountain pipeline to the Westridge dock or by rail to the west coast where it would be loaded onto tankers. The Enbridge Gateway pipeline and the Trans Mountain Pipeline Expansion projects represent future opportunities for greater Canadian access to the California market. Direct pipeline access to this market is unlikely due to its limited size but there could potentially be increased access through rail.

Development of rail terminal infrastructure has been slower in California than in Washington due to a more complicated permitting process. Tesoro has announced plans to unload trains in Washington and then transfer the crude to vessels for further distribution to its refineries in California by 2014. Valero has announced plans for rail unloading facilities at its refinery at Benicia, near San Francisco that is scheduled to be completed in mid-2014. The current plans are for receipts of up to 70,000 b/d of crude oil from North Dakota and Montana or western Canada.

In 2012, California refineries imported 784,400 b/d of crude oil from foreign sources (Figure 3.13). Almost two-thirds of these imports were sourced from Saudi Arabia (27 per cent); Ecuador (19 per cent); and Iraq (18 per cent). Canada accounted for only 5 per cent of total foreign imports.

Figure 3.13 2012 PADD V (California): Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA and California Energy Commission

3.3 Asia

At an aggregate level, demand for oil in North America is either flat or even declining but the demand for crude oil and petroleum products in the Asia-Pacific countries comprises the fastest growing in the world. Table 3.5 shows oil demand from 2010 to 2013 in major Asian markets. Western Canadian oil producers are essentially land-locked and need tidewater access to gain market share in what is now the world's premium crude oil market. The earliest in service date for any of the proposed pipeline projects to the west coast to reach this market is at the end of 2017.

China and India are two of the fastest growing economies in the world and naturally, their demand for oil is growing accordingly (Figure 3.14). China's current ability to process large volumes of heavy crude oil from Canada may be limited but new refineries with high conversion capacity are being built due to China's higher demand for diesel fuel versus gasoline. Generally speaking, refineries able to process heavy crude oil can increase their production of diesel more easily than those configured to process light crude oil. Heavy crudes typically yield greater quantities of heavier and less valuable residual fuel oil. That residual fuel oil can then be converted to increase the yield of middle distillates such as diesel.

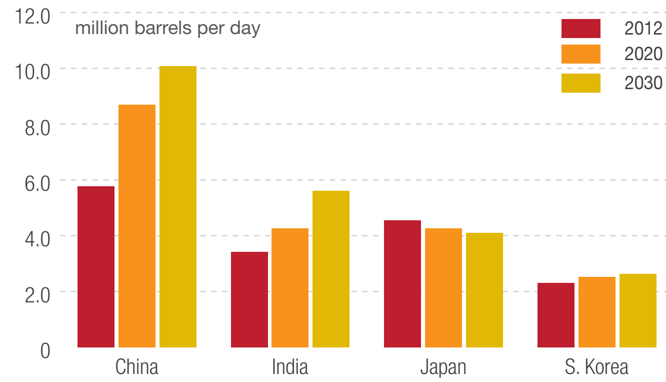
Indian Oil Corp., India's largest refining company has expressed interest in investing in Canada's oil sands with the intent to gain access to these supplies for export but the lack of transportation infrastructure, specifically pipelines, remains an obstacle. Continued delays in establishing tidewater access could translate into a foregone opportunity to serve these large markets.

Table 3.5 Total Oil Demand in Major Asian Countries

million b/d	2010	2011	2012	2013
China	8.85	9.23	9.60	9.98
India	3.37	3.52	3.65	3.74
Japan	4.46	4.48	4.73	4.56
Korea	2.27	2.23	2.27	2.27

Source: IEA Oil Market Report, April 2013

Figure 3.14 Net Oil Imports: Asia 2012 to 2030



Source: EIA 2013 Annual Energy Outlook, Early Release

3.4 Markets Summary

The potential growth of western Canadian crude oil supplies exceeds the demand growth outlook in the whole of the North American market. The United States, given its geographic proximity will remain the primary market for western Canadian crude oil. In particular, Canadian producers need to extend their access to the Gulf Coast, which is the home of numerous complex refineries that account for over half of the total refining capacity in the nation. Besides the significant size of this market, most of these refineries are configured with the ability to process heavy western Canadian supplies. The development of rail infrastructure during the next two years will help to debottleneck transportation constraints and connect western Canadian crude oil to smaller niche markets such as eastern Canada, the U.S. East Coast and PADD V. On a global scale, the attention of producers is shifting away from the U.S. to Asian countries where demand is forecast to grow significantly. Canadian producers are aware of these changing market dynamics and continue to focus on developing all opportunities to extend or expand into new markets.

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

4 CRUDE OIL PIPELINES

Crude oil in western Canada is essentially landlocked and will need additional transportation infrastructure to bring this steadily growing supply to markets. The transportation capacity available to deliver western Canadian crude oil supplies to markets is currently tight. This fact, combined with the phenomenal rise in U.S. production has contributed to the large price discounts on western Canadian crude oil relative to crude oil sold on world markets. There has been further development in a number of pipeline proposals and increased use of transportation by rail to connect growing Canadian production to markets. This chapter examines these proposals in more detail. Figure 4.1 shows major existing and proposed projects which provide take away capacity from the Western Canada Sedimentary Basin (WCSB) to key export markets including eastern Canada, Asia and the U.S. Gulf Coast.

Figure 4.1 Canadian and U.S. Crude Oil Pipelines - All Proposals

Page 315 of 385

4.1 Existing Crude Oil Pipelines Exiting Western Canada

There are four major pipelines which move western Canadian crude out of the WCSB. The Enbridge Mainline and the Kinder Morgan Trans Mountain pipelines originate at Edmonton, Alberta. The Spectra Express and the TransCanada Keystone pipelines originate at Hardisty, Alberta. Together, these pipelines provide about 3.5 million b/d of capacity out of western Canada. In addition, a number of proposals have been announced that could increase this capacity during the next five years (Table 4.1). Currently capacity is tight. Operational and physical constraints can reduce available capacity to below stated capacity.

Table 4.1 Major Existing Crude Oil Pipelines and Proposals Exiting the WCSB

Pipeline	Capacity (thousand b/d)	Target In-Service
Enbridge Mainline	2,500	Operating since 1950
Enbridge Alberta Clipper Expansion	+120	Q3 2014
Enbridge Alberta Clipper Expansion	+230	Q1 2016
Kinder Morgan Trans Mountain	300	Operating since 1953
Trans Mountain Expansion	+590	Q4 2017
Spectra Express *downstream Platte operating since 1952	280	Operating since 1997*
TransCanada Keystone	591	Operating since 2010
TransCanada Keystone XL	+830	2015
Enbridge Northern Gateway	+525	Q4 2017
TransCanada Energy East	+525 to 850	Q4 2017
Total Existing Capacity		**3,548**
Total Proposed Capacity		**+2,820 to 3,145**

The following sections briefly summarize the existing pipeline projects. The proposed pipeline projects are discussed in the subsequent sections distinguished by the destination markets.

4.1.1 Enbridge Mainline

The Enbridge Mainline consists of numerous lines which deliver light and heavy crude oil as well as refined products from western Canada, Montana and North Dakota to markets in western Canada, the U.S. Midwest and Ontario. The Mainline connects with a number of pipelines in the U.S.: the Minnesota Pipeline at Clearbrook, Minnesota; Spearhead South and Flanagan South at Flanagan, Illinois; Chicap at Patoka, Illinois; Mustang at Chicago, Illinois and Toledo at Stockbridge, Michigan. The annual average receipt capacity from western Canada into the Mainline system is about 2.4 million b/d. However, the effective capacity is slightly less due to operational pressure restrictions on certain lines and physical constraints at terminals on the system.

There is also some U.S. production which enters the Enbridge Mainline and competes for capacity on the pipeline and in turn reduces the available capacity for crude oil from western Canada. The Enbridge North Dakota pipeline originates at Plentywood, Montana and ends at Clearbrook, Minnesota. It has a current capacity of 210,000 b/d which serves local markets and markets further east. Some U.S. crude oil production from the Bakken formation currently enters the Enbridge Mainline system at Clearbrook, Minnesota.

In response to significant growth in North Dakota and Montana, Enbridge is proposing an expansion of its North Dakota system. The project known as Sandpiper would include: a new 24-inch diameter pipeline from Beaver Lodge, North Dakota to Clearbrook, Minnesota with an incremental capacity of 225,000 b/d and a new 24-inch diameter pipeline from Clearbrook, Minnesota to Superior, Wisconsin with an initial capacity of 375,000 b/d. As part of the project scope, Enbridge would relocate the interconnection of the Enbridge North Dakota pipeline to the Lakehead System from Clearbrook, Minnesota. As a result, about 375,000 b/d of Bakken crude could enter the Enbridge Mainline at Superior, Wisconsin. The target in-service date for this project is January 2016.

The Enbridge Bakken Expansion project from Berthold, North Dakota to Cromer, Manitoba was put in service in March 2013. It provides 145,000 b/d of capacity to move U.S. Bakken crude into the Mainline destined for markets in the U.S. Midwest, Midcontinent and eastern Canada.

Enbridge Mainline Expansions - Alberta Clipper and Southern Access

Enbridge has planned two major expansions for its Mainline which will allow western Canadian crude to reach existing markets in the Midwest and Ontario and new markets in the U.S. Gulf Coast. The Alberta Clipper is a 36-inch diameter pipeline which extends from Hardisty, Alberta to Superior, Wisconsin. It is integrated with and forms part of the Enbridge Mainline.

The current capacity of the line is 450,000 b/d. Enbridge has received regulatory approval to expand the Alberta Clipper pipeline by 120,000 b/d. The target in-service date is Q3 2014. There are further plans to expand the line by an additional 230,000 b/d in Q1 2016. Upon completion of these expansions, the Alberta Clipper line will have reached its ultimate capacity of 800,000 b/d.

The Southern Access Pipeline is part of the Lakehead System (U.S. Mainline) and runs from Superior, Wisconsin to Flanagan, Illinois. The current capacity is 400,000 b/d. Enbridge has announced plans to expand the line by 160,000 b/d in Q3 2014. As part of its Light Oil Market Access program, Enbridge plans to increase capacity on the line by an additional 640,000 b/d in Q1 2015. Upon completion of these expansions, the Southern Access pipeline will have reached its ultimate capacity of 1.2 million b/d.

4.1.2 Spectra Express-Platte

In March 2013, Spectra Energy acquired the Express-Platte pipeline system from Kinder Morgan for $1.5 billion. The Express Pipeline is a 24-inch diameter pipeline that originates at Hardisty, Alberta and terminates at the Casper, Wyoming facilities on the Platte Pipeline. The pipeline capacity on Express is 280,000 b/d. In 2012, the average monthly throughput was 192,000 b/d versus 174,000 b/d in 2011. The ability to move crude on the Express pipeline is limited due to insufficient downstream capacity on the Platte pipeline.

The Platte Pipeline which is a 20-inch diameter pipeline moves crude oil from Western Canada, the Rockies (PADD IV), including the Bakken play area to refineries in the Midwest (PADD II). It runs from Casper, Wyoming to Wood River, Illinois. The capacity on the pipeline ranges from 164,000 b/d in Wyoming to 145,000 b/d in Illinois. In 2012, the average monthly deliveries into the Platte system were 216,000 b/d versus 193,000 b/d in 2011.

4.1.3 Kinder Morgan Trans Mountain

The Trans Mountain system is currently the only crude oil pipeline to Canada's west coast. It originates at Edmonton, Alberta, delivering both crude oil and petroleum products, to points in British Columbia, Washington, and the Westridge marine terminal. From the marine terminal located at Burnaby, British Columbia, crude oil is loaded onto vessels for offshore exports destined to California, the U.S. Gulf Coast and Asia.

The current capacity on the pipeline system is 300,000 b/d (assuming 20 per cent of the volumes being transported are heavy crude oil). Of the total capacity, 221,000 b/d is allocated to refineries with connections in British Columbia and Washington State and 79,000 b/d is allocated to the Westridge terminal for marine exports. Of the capacity designated to the marine terminal, 54,000 b/d or 68 per cent is underpinned by firm contracts and the remainder is available for spot shipments. Capacity on this pipeline has been in apportionment since late 2010.

4.1.4 TransCanada Keystone

The Keystone pipeline system originates at Hardisty, Alberta to Steele City, Nebraska. From this junction crude oil can be transported east to terminals in Wood River and Patoka, Illinois or south to Cushing, Oklahoma. The pipeline system can deliver a total of 590,000 b/d between the two routes. The pipeline started up in June 2010 while the Cushing extension came online in February 2011. About 530,000 b/d of capacity is contracted.

4.2 New Regional Infrastructure Projects in Western Canada

The major pipelines which move western Canadian crude out of the basin are investing significant capital in regional pipeline infrastructure to move incremental production to markets. The upstream expansions into Hardisty, Alberta could feed the Enbridge Mainline, Keystone, Keystone XL and the proposed TransCanadaEnergy East Pipeline into Eastern Canada.

4.2.1 Enbridge - Alberta Regional Pipeline

Enbridge - Edmonton to Hardisty

Enbridge is proposing to build a 36-inch diameter pipeline from Edmonton to Hardisty with a capacity of 800,000 b/d. The project includes five new tanks and terminal facilities at the Edmonton South terminal. The estimated cost is $1.8 billion. A regulatory application was submitted in December 2012 and the NEB has indicated that it would complete its review by April 2014, at the latest, in accordance with legislated time limits. The target in-service date is 2015.

4.2.2 TransCanada - Alberta Regional Pipelines

Heartland Pipeline and Terminal

TransCanada is proposing a 36-inch diameter pipeline from Heartland to Hardisty, Alberta the initiating point of its Keystone pipeline system with an ultimate capacity of 900,000 b/d. Heartland is an industrial area north of Edmonton, Alberta. At Hardisty, Alberta the pipeline would have connections to Keystone, Keystone XL and Energy East and Hardisty infrastructure. At the Heartland terminal, there will be up to 1.9 million barrels of tankage capacity available. The target in-service date for the Heartland pipeline is the second half of 2015.

Grand Rapids Pipeline Project

TransCanada announced a partnership with Phoenix Energy Holdings Limited (Phoenix) to develop the Grand Rapids Pipeline in northern Alberta. Each party will own 50 per cent of the proposed pipeline system. The project includes both a crude oil line and a diluent line between the producing area northwest of Fort McMurray and Heartland. The system could move up to 900,000 b/d of bitumen blend and up to 330,000 b/d of diluent. TransCanada anticipates filing a regulatory application in Q2 2013. The project has a target in-service date of 2017. TransCanada will operate the pipeline and Phoenix has entered into a long-term commitment to ship crude oil and diluent on the pipeline system.

4.3 Oil Pipelines to the U.S. Midwest

The U.S. Midwest is the largest market for western Canadian crude oil. The key market hubs in this region are located at Wood River and Patoka in Illinois and at Cushing, Oklahoma. Table 4.2 summarizes the pipelines which deliver Canadian crude oil to the Midwest.

4.3.1 Spectra Express-Platte

See Section 4.1.2.

4.3.2 TransCanada Keystone

See Section 4.1.4.

4.3.3 Southern Access Extension

Enbridge is proposing an extension to its Southern Access line which would run from Flanagan, Illinois to Patoka, Illinois. Enbridge will be holding a second open season in Q2 2013 to determine interest from shippers. The pipeline size and capacity will be determined following the open season. The target in-service date is Q2 2015.

4.3.4 Enbridge Line 6B

As part of Enbridge's Eastern Access Phase 2 program a segment of Line 6B will be replaced, from Ortonville, Michigan to the U.S. / Canada, border which would increase capacity from 240,000 b/d to 500,000 b/d in 2014. An expansion of the Line 6B between Chicago, Illinois and Stockbridge, Michigan from 500,000 b/d to 570,000 b/d will occur in 2016.

4.3.5 Minnesota Pipeline System

The Minnesota Pipeline system runs from Clearbrook, Minnesota to the Twin Cities. It is operated by Koch Pipeline Company. The pipeline delivers crude to the Northern Tier refinery in St. Paul Park and the Pine Bend refinery owned by Flint Hills in Rosemont. The system has a current capacity of 465,000 b/d that can be expanded to 650,000 b/d.

Table 4.2 Summary of Crude Oil Pipelines to the U.S. Midwest

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Minnesota Pipeline	Clearbrook, MN	Minnesota refineries	Operating	465
Enbridge Mainline	Superior, WI	various delivery points via L5, L6, L14/64, Spearhead North Flanagan, IL	Operating	1,551
Southern Access Expansion	Superior, WI	Flanagan, IL	Proposed - Q3 2014	+70
Southern Access Expansion			Proposed - Q1 2015	+260
Enbridge Spearhead North	Flanagan, IL	Chicago, IL	Operating	130
Spearhead North Expansion			Proposed - Q4 2013	+105
Enbridge Spearhead North Twin	Flanagan, IL	Chicago, IL	Proposed - Q3 2015	+570
Enbridge Spearhead South	Flanagan, IL	Cushing, OK	Operating	193
Enbridge Flanagan South	Flanagan, IL	Cushing, OK	Proposed - Q3 2014	+585
Enbridge Mustang	Lockport, IL	Patoka, IL	Operating	100
Spectra Express-Platte	Guernsey, WY	Wood River, IL	Operating	145
TransCanada Keystone	Hardisty, AB to Steel City, NE	east to Patoka, IL / Wood River, IL or south to Cushing, OK	Operating	591

4.3.6 Koch Wood River

The Minnesota refineries receive western Canadian crude oil via connections to the Enbridge system as well as via deliveries from the Express-Platte pipeline system to Wood River, Illinois and a connection to the Wood River Pipeline. In January 2013, Koch Pipeline filed its tariff with the FERC advising the line is being purged and that nominations will no longer be accepted and that the tariff was to remain in effect until linefill was delivered and the tariff cancelled.

4.3.7 Spearhead

The Spearhead Pipeline receives crude oil from the Enbridge Mainline and originates at Flanagan, Illinois. From there, crude oil can be transported to Griffith, Indiana via Spearhead North (commonly referred to as Line 62) or to Cushing, Oklahoma on Spearhead South (commonly referred to as Line 55). The current capacity on Spearhead North is 130,200 b/d. It will expanded by 104,800 b/d to 235,000 b/d by the end of 2013. As part of its Light Oil Market Access, Enbridge is considering a twin of the Spearhead North line along the existing pipeline which would provide an incremental capacity of 570,000 b/d by Q3 2015.

The current capacity on Spearhead South is 193,000 b/d. The proposed Flanagan South Pipeline Project discussed in section 4.4 would provide an additional 585,000 b/d along this pipeline corridor in 2014.

4.3.8 Enbridge Toledo Pipeline Expansion

The 16-inch diameter pipeline runs from Stockbridge, Michigan to Toledo, Ohio and has a capacity of 100,000 b/d. In May 2013, Enbridge completed construction of a new 20-inch diameter pipeline which added 80,000 b/d. A total capacity of 180,000 b/d is now available to satisfy refineries in Toledo, Ohio and Detroit, Michigan. This pipeline is commonly referred to as Line 7.

4.4 Oil Pipelines to the U.S. Gulf Coast

The Gulf Coast represents the most significant opportunity for market growth for heavy Canadian crude oil supplies in North America. Refineries in the region rely on domestic supply and imports primarily from Mexico, Saudi Arabia, and Venezuela to meet their requirements.

Table 4.3 Summary of Crude Oil Pipelines to the U.S. Gulf Coast

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
ExxonMobil Pegasus	Patoka, IL	Nederland, TX	Operating	96
Seaway	Cushing, OK	Freeport, TX	Operating	400
Seaway Twin Line			Proposed - Q1 2014	+450
TransCanada Keystone XL	Hardisty, AB	Steele City, NE	Proposed - 2015	
TransCanada Cushing Extension	*Steele City, NE*	*Cushing, OK*	*Operating*	
TransCanada Gulf Coast	*Cushing, OK*	*Nederland, TX*	*Proposed - Q4 2013*	+700
			Proposed - TBD	+130
Enbridge/Energy Transfer Eastern Gulf Crude Access	Patoka, IL	St, James, LA	Proposed - Mid 2015	+420 to 660

Given the significant increase in western Canadian and Bakken production and a lack of takeaway capacity at Cushing, Oklahoma, a number of pipeline projects are vying to bring supply from the Midwest to the U.S. Gulf Coast (Table 4.3).

4.4.1 ExxonMobil Pegasus

The ExxonMobil Pegasus Pipeline is one of only two pipelines that can currently deliver Canadian crude oil to the U.S. Gulf Coast Pegasus is a 20-inch diameter pipeline with a capacity of 96,000 b/d. It runs from Patoka, Illinois to Nederland, Texas. Western Canadian crude can access the Pegasus pipeline via three routes: the Enbridge Mainline then onto the Mustang pipeline; the Express/Platte system then onto the Woodpat Pipeline; and the Keystone Pipeline.

4.4.2 Enbridge Flanagan South

The Flanagan South Pipeline project is a 36-inch diameter pipeline that will be built along the existing Enbridge Spearhead South Pipeline. The pipeline which originates at Flanagan, Illinois and terminates at Cushing, Oklahoma would have an initial capacity of 585,000 b/d. The pipeline is currently under construction and has a target in-service date of July 2014. Enbridge has indicated that Flanagan South can be expanded up to 785,000 b/d through the addition of horse power.

4.4.3 Enbridge/Enterprise Seaway

The Seaway Pipeline is jointly owned by Enbridge Inc. and Enterprise Products Partners L.P. The pipeline flow was reversed in May 2012 to move crude oil from Cushing, Oklahoma to the U.S. Gulf Coast. The capacity on the pipeline gradually increased from 150,000 b/d to 400,000 b/d by January 2013, however, a lack of takeaway capacity at Jones Creek, located on the southern end of the pipeline, has limited the effective capacity at this time. The pipeline has experienced considerable levels of apportionment since coming into service.

Enbridge and Enterprise have secured sufficient commercial support to build a new twin line along the existing Seaway pipeline. The project scope includes laterals from Jones Creek to the Echo terminal that is connected to the Houston refinery complex and from Echo to the Port Arthur/Beaumont refinery complex.

The initial capacity on the new Seaway twin line is 450,000 b/d. Once completed, the Seaway pipeline system would have a total capacity of 850,000 b/d. The target in-service for the lateral from Jones Creek to Echo is late 2013 while target in-service date for the Seaway twin and lateral from Jones Creek to Port Arthur/Beaumont is Q1 2014.

4.4.4 Enbridge/Energy Transfer Eastern Gulf Crude Access

In February 2013, Enbridge and Energy Transfer announced a joint development for the Eastern Gulf Crude Access Pipeline Project. The project involves the conversion of a 30-inch diameter pipeline from natural gas service to crude oil service of certain segments of pipeline that are currently in operation as part of the natural gas system of Trunkline Gas Company, LLC. The pipeline would provide service from Patoka, Illinois to refining markets near Memphis, Tennessee, Baton Rouge and St. James in Louisiana. Western Canadian crude and Bakken crude can access the Patoka Hub via a number of existing and proposed pipelines including: Enbridge Southern Access Extension, TransCanada Keystone, Mustang, Ozark Pipeline/Woodpat Pipeline.

The pipeline capacity would range from 420,000 b/d to 660,000 b/d depending on the crude slate and level of commitments from shippers. An open season is anticipated in Q2 2013. Subject to regulatory approval, the 30-inch diameter pipeline would provide oil service in mid-2015.

4.4.5 TransCanada Keystone XL

In May 2012, TransCanada filed a new Presidential Permit application for Keystone XL for a proposed pipeline from Hardisty, Alberta to Steele City, Nebraska. In September 2012, TransCanada submitted an environmental report to the Nebraska Department of Environmental Quality. On January 23, 2013, the revised route in Nebraska was supported by the Governor of the state of Nebraska. A draft supplemental Environmental Impact Statement (EIS) was issued and a public comment period ended on April 22, 2013. The U.S. Department of State is continuing its review and will issue a final EIS. The next step in the regulatory process is the national interest determination. Should the project be approved, it would provide 830,000 b/d of capacity in 2015.

The Bakken Marketlink project from Baker, Montana, to Cushing, Oklahoma is designed to allow receipts of up to 100,000 b/d of crude oil from the Williston Basin, using capacity on the northern leg of Keystone XL. The Bakken Marketlink project is underpinned by 65,000 b/d of firm commitments.

4.4.6 TransCanada Gulf Coast

TransCanada Keystone announced that it was proceeding with its Gulf Coast Project regardless as to whether its Keystone XL project receives regulatory approval. The 36-inch diameter pipeline would provide capacity from Cushing, Oklahoma to Port Arthur and Houston, Texas. The initial capacity is 700,000 b/d which can be expanded to 830,000 b/d. Construction started in August 2012 and the target in-service date is late 2013.

The Keystone Pipeline System which includes Keystone, the Gulf Coast Project and the Keystone XL would provide 1.4 million b/d of capacity of which 1.1 million b/d is underpinned by long term contracts.

4.5 Oil Pipelines to the West Coast of Canada

The Kinder Morgan Trans Mountain pipeline is currently the only pipeline transporting crude oil from Alberta to the west coast. There is significant interest in building new pipeline capacity to the west coast. Once crude oil reaches the coast, it can be loaded off onto crude carriers to reach markets such as California, the U.S. Gulf Coast and Asia. Table 4.4 summarizes the Enbridge Northern Gateway and Kinder Morgan's pipeline proposals to the west coast.

Table 4.4 Summary of Crude Oil Pipelines to the West Coast of Canada

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Kinder Morgan Trans Mountain	Edmonton , AB	Burnaby, BC	Operating	300
Kinder Morgan Trans Mountain Expansion			Proposed - Q4 2017	+590
Enbridge Northern Gateway	Bruderheim, AB	Kitimat, BC	Proposed - Q4 2017	+525

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

4.5.1 Enbridge Northern Gateway

The Northern Gateway Project includes a new 36-inch diameter crude oil pipeline with an initial capacity of 525,000 b/d from Bruderheim, Alberta (near Edmonton, Alberta) to Kitimat, British Columbia. The National Energy Board conducted extensive public hearings which concluded on May 1, 2013. Final oral arguments for the project will be heard in June 2013. The regulator will issue its recommendation on the project by December 29, 2013 as per the legislated time limits. A final decision will then be made by the Governor in Council. The target in-service date for the project is late 2017.

4.5.2 Kinder Morgan Trans Mountain Expansion

Kinder Morgan has proposed to expand its existing system (see section 4.1.3) with the addition of a new 36-inch diameter pipeline (twin pipeline to existing line), new pump stations, tanks and new tanker berths. If approved and constructed, the Trans Mountain system would then be comprised of two pipelines, the existing line (Line 1) and a new line (Line 2).

Line 1 could transport 350,000 b/d of refined petroleum products and light crude oil; heavy crude oil could also be moved but at a loss of capacity. The new Line 2 would have a capacity of 540,000 b/d for heavy crude oil and could also transport light crude oil, if necessary. The new pipeline and this configuration would add 590,000 b/d to the system for a total capacity of 890,000 b/d.

The expansion is underpinned by contracts totaling 707,500 b/d under 15 and 20-year commitments. The target in-service date is late 2017. In May 2013, Kinder Morgan received approval of its tolling methodology and principles for the proposed expansion on its system. The company plans on submitting a facilities application with the NEB in the fall of 2013.

4.6 Oil Pipelines to Eastern Canada

In 2012, refineries in Eastern Canada imported 680,000 b/d of crude from foreign sources. There is currently no pipeline infrastructure that connects western Canadian crude oil supply to markets in Atlantic Canada. This market represents an opportunity for western Canadian producers. Table 4.5 lists the pipeline proposals that could be conduits to this market

4.6.1 Enbridge Line 9 Reversal

The Enbridge Line 9 is a 30-inch diameter crude oil pipeline which runs from Montréal, Québec to Sarnia, Ontario. Line 9A refers to the portion from Sarnia, Ontario to North Westover, Ontario while 9B refers to the portion from North Westover, Ontario to Montréal, Québec. The pipeline has a current capacity of 240,000 b/d. In 2012, Enbridge received regulatory approval and is currently in the process of reversing the flow of Line 9A. The pipeline will move primarily light crude oil from Western Canada and the Bakken play. Of note, when Line 9 was first built, it moved crude from western Canada to Ontario and Montréal, Québec. The flow of the pipeline was reversed in 1999 and is expected to be re-reversed later this year.

In November 2012, Enbridge submitted a regulatory application to reverse the flow on Line 9B and increase the capacity by 60,000 b/d through the use of a drag reducing agent which does not require building additional facilities. The NEB will be holding a written hearing with oral final arguments in the summer of 2013. The target in-service date for Line 9B reversal is Q3 2014.

Table 4.5 Summary of Crude Oil Pipelines to Eastern Canada

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Enbridge Line 9 re-Reversal	Sarnia, ON	Montréal, QC	Proposed	+300
9A	Sarnia, ON	North Westover, ON	Q3 2013	
9B	North Westover, ON	Montréal, QC	Q3 2014	
TransCanada Energy East	Hardisty, AB	Québec City, QC / St. John, NB	Proposed - Q4 2017	+525 to 850

4.6.2 TransCanada Energy East

TransCanada announced the Energy East Pipeline Project which includes the conversion of a natural gas pipeline to oil service and new pipeline segments to provide transportation service from Hardisty, Alberta to Québec City, Québec and St. John, New Brunswick. The proposed pipeline would have a capacity ranging from 525,000 to 850,000 b/d depending on market requirements. Currently there is a receipt point planned in southeast Saskatchewan that would enable Saskatchewan Bakken and other volumes to enter into the system. TransCanada is holding a binding open season which closes on June 17, 2013. The target in-service date for deliveries to Québec City and St. John is Q4 2017 and 2018, respectively.

4.7 Diluent Pipelines

Table 4.6 provides a summary of projects which aim to bring diluent supply which may be required to satisfying growing supply of heavy oil from western Canada.

4.7.1 Enbridge Southern Lights

The Southern Lights pipeline which runs from Manhattan, Illinois (near Chicago) to Edmonton, Alberta has been moving diluent since 2010. The current capacity of the pipeline is 180,000 b/d. In Q1 2013, Enbridge conducted an open season for 50,000 b/d of capacity available under firm contracts. In early May, Enbridge announced that the responses exceeded the amount of capacity available. As a result, Enbridge will conduct another open season later this year and will pursue an expansion of the diluent line from 180,000 b/d to 275,000 b/d.

4.7.2 Enbridge Northern Gateway Diluent

As part of its Northern Gateway Project, Enbridge is proposing a diluent pipeline that would run from Kitimat, British Columbia to Bruderheim, Alberta. The proposed capacity of the pipeline is 193,000 b/d. The Joint Review Panel (JRP) conducted extensive public hearings which concluded on May 1, 2013. Final arguments for the project will be heard in June 2013. The NEB will issue its recommendation on the project by December 29, 2013, at the latest, as per the legislated time limits.

4.7.3 TransCanada Grand Rapids Diluent

As part of its Grand Rapids Pipeline, TransCanada is proposing a diluent line from the Heartland region to Fort McMurray. The pipeline would have a capacity of 330,000 b/d in 2017. A regulatory application is expected to be filed with the provincial regulator in 2013.

4.7.4 Kinder Morgan Cochin Reversal Project

Kinder Morgan has secured firm transportation commitments for its Cochin Reversal Project. The project would allow movement of light condensate from Kankakee County, Illinois to existing terminal facilities near Fort Saskatchewan, Alberta. The project requires modifying the western leg of the Cochin pipeline to connect to the Explorer Pipeline Company located in Kankakee County and the reversal of product flow to move condensate northwest to Canada. The existing Cochin pipeline system is a 12-inch diameter multi-product pipeline with a current capacity of 70,000 b/d. The Cochin Reversal project will have a capacity of 95,000 b/d. During the open season, Kinder Morgan secured more than 100,000 b/d of commitments for a minimum 10-year term. The target in-service date for the project is July 2014 subject to regulatory approval.

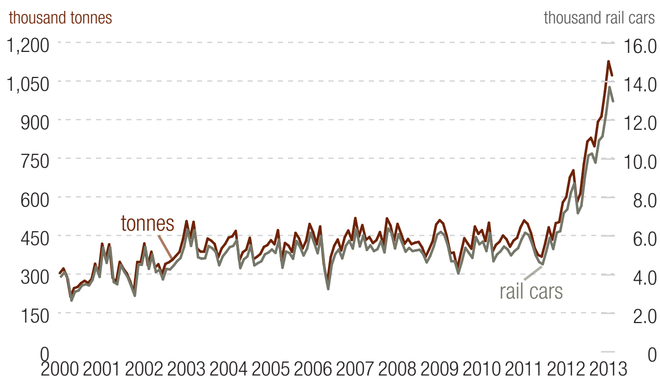
Table 4.6 Summary of Diluent Pipelines

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Enbridge Southern Lights Southern Lights Expansion	Flanagan, IL	Edmonton, AB	Operating Proposed - TBD	180 +95
Enbridge Northern Gateway	Kitimat, BC	Bruderheim, AB	Proposed - Q4 2017	+193
Kinder Morgan Cochin Conversion	Kankakee County, IL	Fort Saskatchewan, AB	Proposed - Q3 2014	+95
TransCanada Grand Rapids	Heartland, AB	Fort McMurray, AB	Proposed - 2017	+330

4.8 Rail

Transporting crude oil by rail has been growing quickly in the U.S. for a number of years but this trend is only now just emerging for crude oil originating from western Canada. Statistics Canada data reports 12,989 rail cars (1.1 million tonnes) were loaded in February 2013 transporting fuel oils and crude petroleum – a 60 per cent growth from February 2012 (Figure 4.2). According to the National Energy Board, in 2012, approximately 46,000 b/d of crude oil was exported to the U.S. by rail with most going to the U.S. Gulf Coast (48 per cent) and PADD I (43 per cent) with the remainder exported to PADD II and PADD V. This upward trend becomes more apparent when the fact that exports were as high as 120,000 b/d in December is considered. Experts forecast these exports to reach as much as 200,000 b/d by the end of 2013.

Figure 4.2 **Canadian Fuel Oil and Crude Petroleum Moved by Rail: Car Loadings & Tonnage**



Source: Statistics Canada

Figure 4.3 CP Rail Network

Source: Canadian Pacific Railway

Although rail tends to be a more expensive transportation option for crude oil it has a number of advantages over pipelines that help make it a viable alternative. In the long term, rail may even act as a complementary mode of transportation to pipelines as pipeline bottlenecks are alleviated. Extensive rail infrastructure is already in place, allowing producers the flexibility to reach essentially any market on the continent that has an unloading facility. Until pipelines are available, this means producers could reach higher priced markets using rail. In addition, movement of bitumen by rail requires significantly less diluent than pipelines, which can represent significant cost savings. Also, the sulphur content restriction on the crude oil transported by rail is less than when transported by pipelines. Refiners may also have greater certainty regarding the quality of crude oil received since there will be no mixing with other batches during transport, which is an event that often occurs during pipeline transportation.

Rail tracks are already in place to deliver crude oil to a number of markets from western Canada (Figure 4.3 and Figure 4.4). Therefore the major additional capital expenditures that are required are for terminal facilities needed for the uploading and offloading of crude oil. Larger, long-term terminal facilities with the capacity to load 100 car unit trains (65,000 to 70,000 barrels) that provide significant economies of scale can take from one to two years to be built. In contrast, start-up transloading facilities (which are smaller scale and limited to 2,000 to 20,000 barrels) can be put in place in only a few months.

The other main limitation on increasing current capacity is the availability of rail cars. There is about a two year waiting period from the time of ordering to the time of delivery. According to industry estimates, the backlog for tank rail car orders is close to 48,000. It is expected that that between 12,000 to 15,000 cars will be delivered in 2013 for crude oil; the majority of these will be insulated coil cars that are needed for transporting heavy crude oil. The capacity from currently operating and announced uploading facilities from western Canada is estimated at approximately 300,000 b/d by 2014 (Figure 4.5).

Figure 4.4 CN Rail Network

Source: Canadian National Railway

Rail Quick Facts

- Rail car capacity carrying light oil: 600 to 700 bbls
- Rail car capacity carrying heavy oil: 500 to 525 bbls
- RailBit and raw bitumen is transported in coiled and insulated rail cars to prevent solidifying in cold weather
- Unit train: 70 to 120 cars carrying only crude oil
- Manifest trains are mixed cargo trains delivering to different destinations
- Unit trains are used to carry one type of cargo from one location to another
- Economics for transport by rail improves with unit trains, however, unit train offloading capability is needed at destination

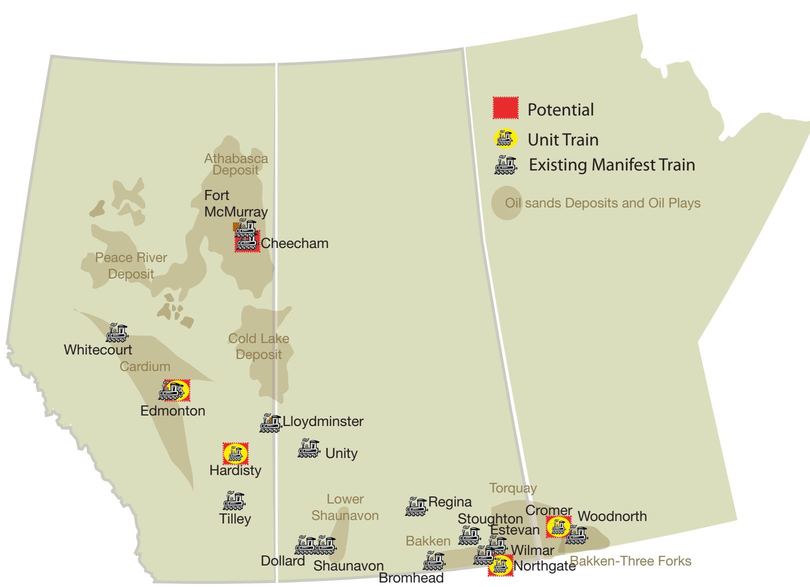
G-7 Generations' Alberta-Alaska Railway Concept

G7G Railway Corp. has introduced the concept of a new rail link from Fort McMurray to the Delta Junction in Alaska where oil would enter the Trans-Alaska (TAPS) pipeline system to reach tidewater at the Valdez marine terminal. The project proponents are in the process of seeking financial support to produce a feasibility study for this project.

Churchill Export Port

Churchill Gateway Development Corp. is looking to transform the Port of Churchill in northern Manitoba into a key export hub for western Canadian crude oil. It has traditionally been a key export point for western Canadian grain but is currently under utilized. Some challenges include the fact that the port is only ice-free from July to mid-October. The shipping season could be extended if shippers used icebreakers to accompany tankers but the added cost may be prohibitive. Target markets would include Europe, and refineries along the east coast of Canada and the U.S. The port is at the northern terminus of the Hudson Bay Railway owned by railroad holding company, OmniTRAX.

Figure 4.5 Rail Loading Terminals in Western Canada



Major Announced Rail Uploading Terminals in Western Canada

Operator	Location	Capacity (thousand b/d)	Scheduled Startup
Tundra	Cromer, MB	Phase 1 - 30 Phase 2 - 30	Q3 2013 Q1 2014
Keyera	Cheecham, AB	32	Q3 2013
Canexus	Bruderheim, AB (near Edmonton, AB)	70	Q3 2013
Gibson	Hardisty, AB	60	2014
Ceres Global	Northgate, SK	70	Q4 2013

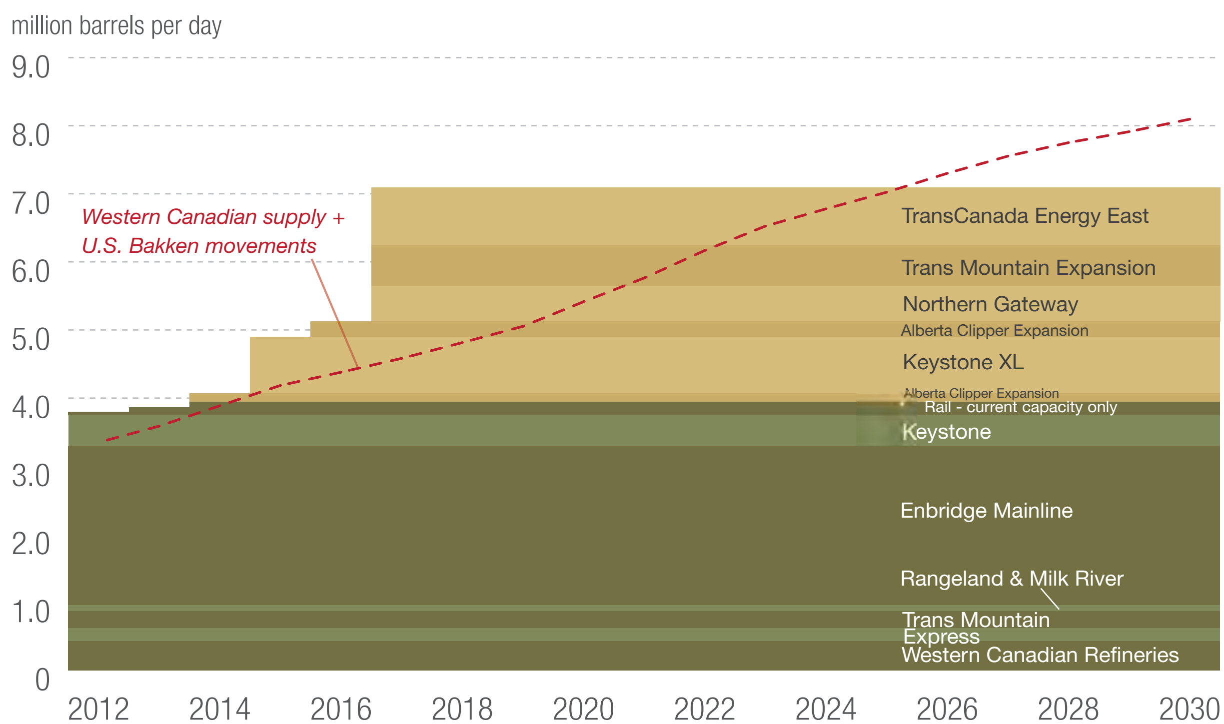
4.9 Pipeline Summary

The dynamics of the North American crude oil market are changing as growing western Canadian and Midcontinent crude oil production emerges while North American crude oil consumption is anticipated to be fairly flat. Despite the forecast for flat demand for crude oil, the U.S., specifically the Gulf Coast, remains a large, attractive market for western Canadian producers due to the opportunity to displace crude oil supplies from international sources. A number of pipeline proposals to the Gulf Coast have recently been announced that will increase access by 2014 through connections to existing infrastructure as well as new projects. In addition to looking for increased penetration to U.S. markets, western Canadian crude oil producers are also seeking much greater market diversification through increased connectivity to eastern Canadian and world markets. This would primarily be achieved through more pipeline capacity to the west coast, where crude oil could be shipped to the burgeoning economies of Asia. There is also significant interest in improving connectivity to western Canadian supplies for all Canadians. As such, a number of projects to increase pipeline access from western Canada to eastern Canadian markets are being pursued.

Projects that increase the downstream capacity of existing pipelines have been proposed that could partially alleviate tight capacity as access to markets is enhanced. However, additional capacity exiting western Canada will need to be built if growing production is to avoid facing chronic apportionment as a result of limited pipeline capacity to desired markets. Figure 4.4 shows the existing and proposed takeaway capacity exiting the WCSB versus forecasted supply. The forecasted supply volume was developed by coupling CAPP's latest supply forecast of western Canadian production with U.S. Bakken volumes that could utilize a portion of the capacity that exits western Canada.

Transportation of crude oil by rail is growing since it has the advantage of quick start-up and its network extends to a number of markets that are currently not connected through the pipeline network. However, pipelines will remain the preferred mode of transportation for crude oil. This analysis indicates that additional transportation capacity exiting western Canada will be required by 2014.

Figure 4.6 WCSB Takeaway Capacity vs Supply Forecast



Capacity shown can be reduced by temporary operating and physical constraints.

GLOSSARY

API Gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.
Barrel	A standard oil barrel is approximately equal to 35 Imperial gallons (42 U.S. gallons) or approximately 159 litres.
Bitumen	A heavy, viscous oil that must be processed extensively to convert it into a crude oil before it can be used by refineries to produce gasoline and other petroleum products.
Coker	The processing unit in which bitumen is cracked into lighter fractions and withdrawn to start the conversion of bitumen into upgraded crude oil.
Condensate	A mixture of mainly pentanes and heavier hydrocarbons. It may be gaseous in its reservoir state but is liquid at the conditions under which its volumes is measured or estimated.
Crude oil (Conventional)	A mixture of pentanes and heavier hydrocarbons that is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volumes is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or bitumen.
Crude oil (heavy)	Crude oil is deemed, in this report, to be heavy crude oil if it has an API of 27° or less. No differentiation is made between sweet and sour crude oil that falls in the heavy category because heavy crude oil is generally sour.
Crude oil (medium)	Crude oil is deemed, in this report, to be medium crude oil if it has an API greater than 27° but less than 30°. No differentiation is made between sweet and sour crude oil that falls in the medium category because medium crude oil is generally sour.
Crude oil (synthetic)	A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from the oil sands.
Density	The mass of matter per unit volume.
DilBit	Bitumen that has been reduced in viscosity through addition of a diluent (or solvent) such as condensate or naphtha.
Diluent	Lighter viscosity petroleum products that are used to dilute bitumen for transportation in pipelines.
Extraction	A process unique to the oil sands industry, in which bitumen is separated from their source (oil sands).
Feedstock	In this report, feedstock refers to the raw material supplied to a refinery or oil sands upgrader.
Integrated mining project	A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.
***In Situ* recovery**	The process of recovering crude bitumen from oil sands by drilling.
Merchant upgrader	Processing facilities that are not linked to any specific extraction project but is designed to accept raw bitumen on a contract basis from producers.

Oil Condensate, crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing and is liquid at the conditions under which its volume is measured or estimated.

Oil sands Refers to a mixture of sand and other rock materials containing crude bitumen or the crude bitumen contained in those sands.

Oil Sands Deposit A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated from any other such accumulation. The ERCB has designated three areas in Alberta as oil sands areas.

Oil Sands Heavy In this report, Oil Sands Heavy includes upgraded heavy sour crude oil, and bitumen to which light oil fractions (i.e. diluent or upgraded crude oil) have been added in order to reduce its viscosity and density to meet pipeline specifications.

Open Season A period of time designated by a pipeline company to determine shipper interest on a proposed project. Potential customers can indicate their interest/support by signing a transportation services agreement for capacity on the pipeline.

Pentanes Plus A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and is obtained from the processing of raw gas, condensate or crude oil.

PADD Petroleum Administration for Defense District that defines a market area for crude oil in the U.S.

Refined Petroleum Products End products in the refining process (e.g. gasoline).

Specification Defined properties of a crude oil or refined petroleum product.

SynBit A blend of bitumen and synthetic crude oil that has similar properties to medium sour crude oil.

Train (Manifest) Manifest trains carry multiple cargoes and make multiple stops. These are small group or single car load.

Train (Unit) Unit trains carry a single cargo and deliver a single shipment to one destination, lowering the cost and shortening the trip.

Upgrading The process that converts bitumen or heavy crude oil into a product with a lower density and viscosity.

West Texas Intermediate WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

APPENDIX A
ACRONYMS, ABBREVIATIONS, UNITS AND CONVERSION FACTORS

Acronyms

API	American Petroleum Institute
CAPP	Canadian Association of Petroleum Producers
EIA	Energy Information Administration
ERCB	(Alberta) Energy Resources Conservation Board
FERC	Federal Energy Regulatory Commission
IEA	International Energy Agency
NEB	National Energy Board
PADD	Petroleum Administration for Defense District
U.S.	United States
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

Canadian Provincial Abbreviations

AB	Alberta
BC	British Columbia
MB	Manitoba
NWT	Northwest Territories
ON	Ontario
QC	Québec
SK	Saskatchewan

Units

b/d	barrels per day

Conversion Factor

1 cubic metre = 6.293 barrels (oil)

U.S. State Abbreviations

AL	Alabama
AK	Alaska
AZ	Arizona
AR	Arkansas
CA	California
CO	Colorado
CT	Connecticut
DE	Delaware
FL	Florida
GA	Georgia
ID	Idaho
IL	Illinois
IN	Indiana
IA	Iowa
KS	Kansas
KY	Kentucky
LA	Louisiana
ME	Maine
MD	Maryland
MA	Massachusetts
MI	Michigan
MN	Minnesota
MS	Mississippi
MO	Missouri
MT	Montana
NE	Nebraska
NV	Nevada
NH	New Hampshire
NJ	New Jersey
NM	New Mexico
NY	New York
NC	North Carolina
ND	North Dakota
OH	Ohio
OK	Oklahoma
OR	Oregon
PA	Pennsylvania
SC	South Carolina
SD	South Dakota
TN	Tennessee
TX	Texas
UT	Utah
VT	Vermont
VA	Virginia
VI	Virgin Islands
WA	Washington
WV	West Virginia
WI	Wisconsin
WY	Wyoming

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit ____

APPENDIX B.1

CAPP Canadian Crude Oil Production Forecast 2013 – 2030

thousand barrels per day — Actual (2012) / *Forecast* (2013–2030)

CONVENTIONAL	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Light & Medium																			
Alberta	408	447	516	543	553	558	565	574	581	588	598	611	626	636	645	657	671	687	703
B.C.	21	19	18	17	16	16	15	14	13	13	12	11	11	10	10	9	9	8	8
Saskatchewan [1,2]	211	201	191	195	176	179	183	186	189	193	198	203	209	215	221	227	233	238	244
Manitoba	50	50	50	50	47	45	44	43	42	41	41	40	39	38	37	37	36	35	34
N.W.T.	13	12	11	11	10	10	9	9	8	8	7	7	7	6	6	6	6	6	5
Ontario	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Atlantic Provinces [3]	197	218	192	225	221	217	276	284	247	226	222	199	193	174	149	136	114	97	87
W. Canada Light & Medium	**704**	**729**	**786**	**815**	**802**	**807**	**815**	**826**	**833**	**842**	**856**	**873**	**891**	**906**	**919**	**935**	**954**	**974**	**995**
E. Canada Light & Medium	**198**	**219**	**193**	**226**	**222**	**218**	**277**	**285**	**248**	**227**	**223**	**200**	**194**	**175**	**150**	**137**	**115**	**98**	**88**
Heavy																			
Alberta Conv. Heavy	148	151	152	149	146	143	140	137	135	132	129	127	124	122	119	117	115	112	110
Saskatchewan Conv. Heavy [1,2]	259	258	275	282	289	296	301	303	302	295	287	279	272	266	261	256	252	248	245
W. Canada Heavy	**406**	**408**	**428**	**431**	**435**	**439**	**441**	**440**	**437**	**427**	**416**	**406**	**396**	**388**	**380**	**373**	**367**	**361**	**355**
PENTANES/CONDENSATE	**139**	**135**	**130**	**127**	**124**	**121**	**119**	**116**	**113**	**111**	**109**	**107**	**105**	**103**	**101**	**99**	**97**	**96**	**94**
W. Canada Conventional (incl. condensates)	**1,246**	**1,270**	**1,343**	**1,373**	**1,361**	**1,368**	**1,375**	**1,382**	**1,384**	**1,380**	**1,381**	**1,385**	**1,392**	**1,396**	**1,400**	**1,408**	**1,418**	**1,431**	**1,445**
E. Canada Conventional (incl. condensates)	**202**	**221**	**193**	**226**	**222**	**218**	**277**	**285**	**248**	**227**	**223**	**200**	**194**	**175**	**150**	**137**	**115**	**98**	**88**
OIL SANDS (BITUMEN & UPGRADED CRUDE OIL)																			
Oil Sands Mining	811	906	976	984	1,007	1,044	1,095	1,123	1,227	1,337	1,457	1,572	1,598	1,645	1,689	1,687	1,679	1,683	1,684
Oil Sands *In situ*	986	1,079	1,182	1,296	1,436	1,546	1,671	1,823	1,996	2,160	2,344	2,501	2,664	2,808	2,977	3,158	3,304	3,407	3,524
TOTAL OIL SANDS	**1,797**	**1,985**	**2,158**	**2,280**	**2,443**	**2,590**	**2,766**	**2,946**	**3,223**	**3,497**	**3,801**	**4,074**	**4,262**	**4,454**	**4,666**	**4,845**	**4,983**	**5,090**	**5,208**
W. Canada Oil Production	*3,042*	*3,255*	*3,501*	*3,653*	*3,804*	*3,958*	*4,141*	*4,328*	*4,606*	*4,877*	*5,182*	*5,459*	*5,654*	*5,850*	*6,066*	*6,253*	*6,401*	*6,521*	*6,653*
E. Canada Oil Production	*202*	*221*	*193*	*226*	*222*	*218*	*277*	*285*	*248*	*227*	*223*	*200*	*194*	*175*	*150*	*137*	*115*	*98*	*88*
TOTAL CANADIAN OIL PRODUCTION	**3,245**	**3,476**	**3,694**	**3,879**	**4,026**	**4,176**	**4,418**	**4,613**	**4,854**	**5,104**	**5,405**	**5,659**	**5,848**	**6,025**	**6,216**	**6,390**	**6,516**	**6,619**	**6,741**
OIL SANDS RAW BITUMEN**																			
Oil Sands Mining	930	1,032	1,109	1,117	1,143	1,184	1,243	1,276	1,387	1,506	1,634	1,756	1,783	1,831	1,874	1,884	1,888	1,892	1,894
Oil Sands *In Situ*	996	1,116	1,216	1,332	1,471	1,579	1,701	1,853	2,027	2,191	2,378	2,536	2,699	2,844	3,014	3,195	3,343	3,446	3,563
TOTAL OIL SANDS	**1,926**	**2,148**	**2,325**	**2,449**	**2,614**	**2,763**	**2,944**	**3,129**	**3,414**	**3,696**	**4,012**	**4,292**	**4,482**	**4,674**	**4,888**	**5,080**	**5,231**	**5,338**	**5,457**

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit ________

Notes:

1. *CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m³.*
2. *CAPP has revised from the June 2007 report historical light/heavy ratio for Saskatchewan starting in 2005.*
3. *Atlantic Canada production includes Newfoundland & Labrador production and negligible volumes from New Brunswick.*

*** Raw bitumen numbers are highlighted. The oil sands production numbers (as historically published) are a combination of upgraded crude oil and bitumen and therefore incorporate yield losses from integrated upgrader projects. Production from off-site upgrading projects are included in the production numbers as bitumen.*

APPENDIX B.2 CAPP Western Canadian Crude Oil Supply Forecast 2013-2030

Blended Supply to Trunk Pipelines and Markets *thousand barrels per day*

	Actual	*Forecast*																	
CONVENTIONAL	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total Light and Medium	700	725	782	811	798	803	811	822	829	838	852	869	887	902	915	931	950	970	991
Net Conventional Heavy to Market	334	340	356	361	365	370	372	371	367	355	344	332	322	312	304	296	289	282	276
TOTAL CONVENTIONAL	**1,034**	**1,065**	**1,138**	**1,172**	**1,163**	**1,173**	**1,183**	**1,192**	**1,196**	**1,194**	**1,196**	**1,201**	**1,209**	**1,214**	**1,218**	**1,227**	**1,239**	**1,252**	**1,267**
OIL SANDS																			
Upgraded Light (Synthetic)[1]	752	841	855	857	834	807	788	777	775	771	770	763	755	752	752	753	754	755	761
Oil Sands Heavy [2]	1,413	1,532	1,744	1,907	2,133	2,353	2,593	2,835	3,194	3,548	3,952	4,312	4,565	4,808	5,080	5,323	5,508	5,655	5,817
TOTAL OIL SANDS AND UPGRADERS	**2,166**	**2,374**	**2,599**	**2,763**	**2,967**	**3,160**	**3,381**	**3,611**	**3,969**	**4,319**	**4,722**	**5,075**	**5,320**	**5,559**	**5,832**	**6,076**	**6,263**	**6,410**	**6,578**
Total Light Supply	1,452	1,566	1,637	1,668	1,632	1,610	1,600	1,598	1,604	1,610	1,622	1,631	1,642	1,653	1,667	1,685	1,704	1,726	1,752
Total Heavy Supply	1,747	1,872	2,100	2,267	2,498	2,722	2,965	3,205	3,561	3,904	4,296	4,644	4,887	5,120	5,383	5,618	5,797	5,937	6,093
WESTERN CANADA OIL SUPPLY	**3,199**	**3,438**	**3,738**	**3,935**	**4,130**	**4,333**	**4,564**	**4,804**	**5,165**	**5,513**	**5,918**	**6,276**	**6,529**	**6,773**	**7,051**	**7,303**	**7,501**	**7,662**	**7,846**

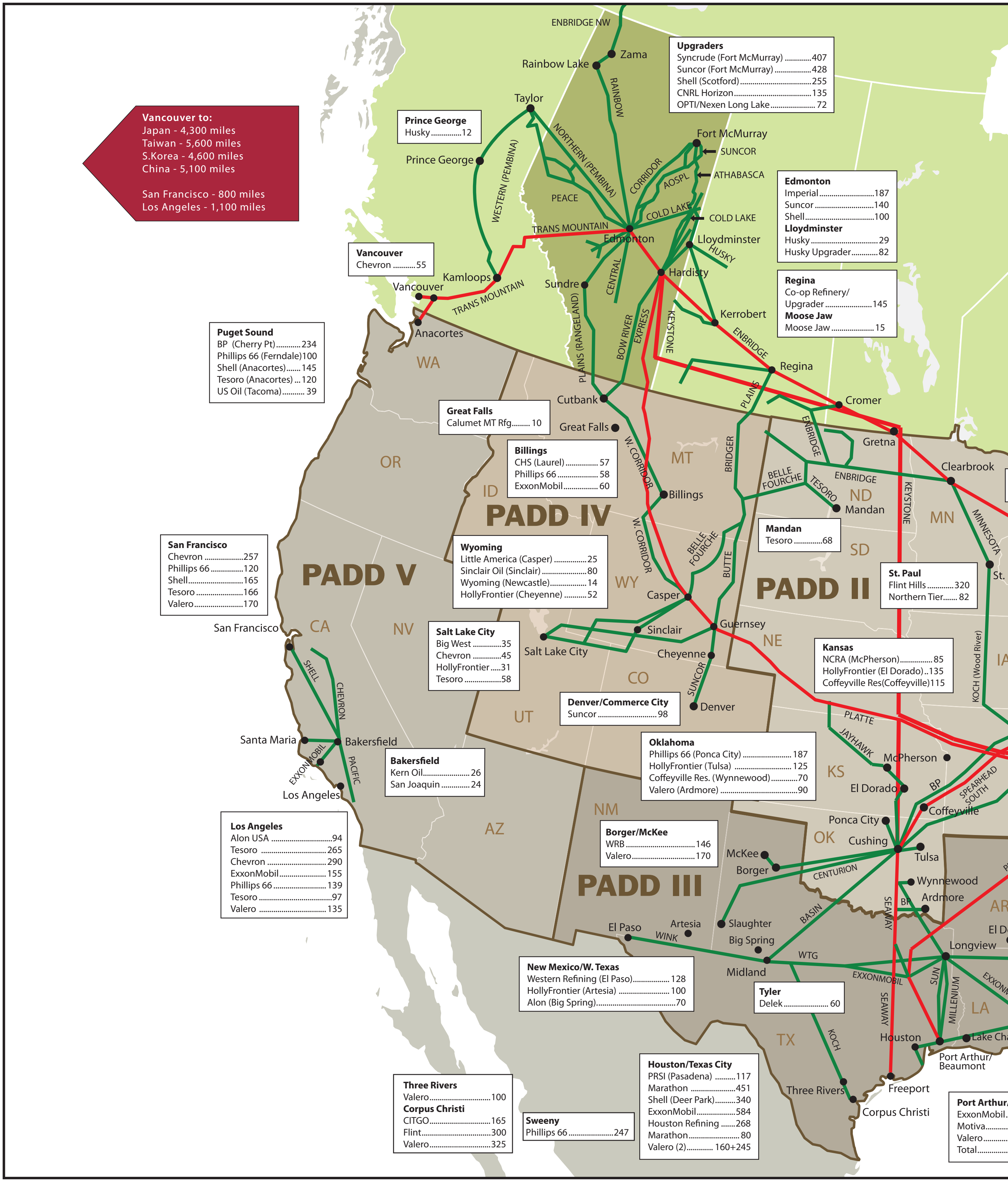
Notes:

1. *Includes upgraded conventional.*
2. *Includes: a) imported condensate b) manufactured diluent from upgraders and c) upgraded heavy volumes coming from upgraders.*

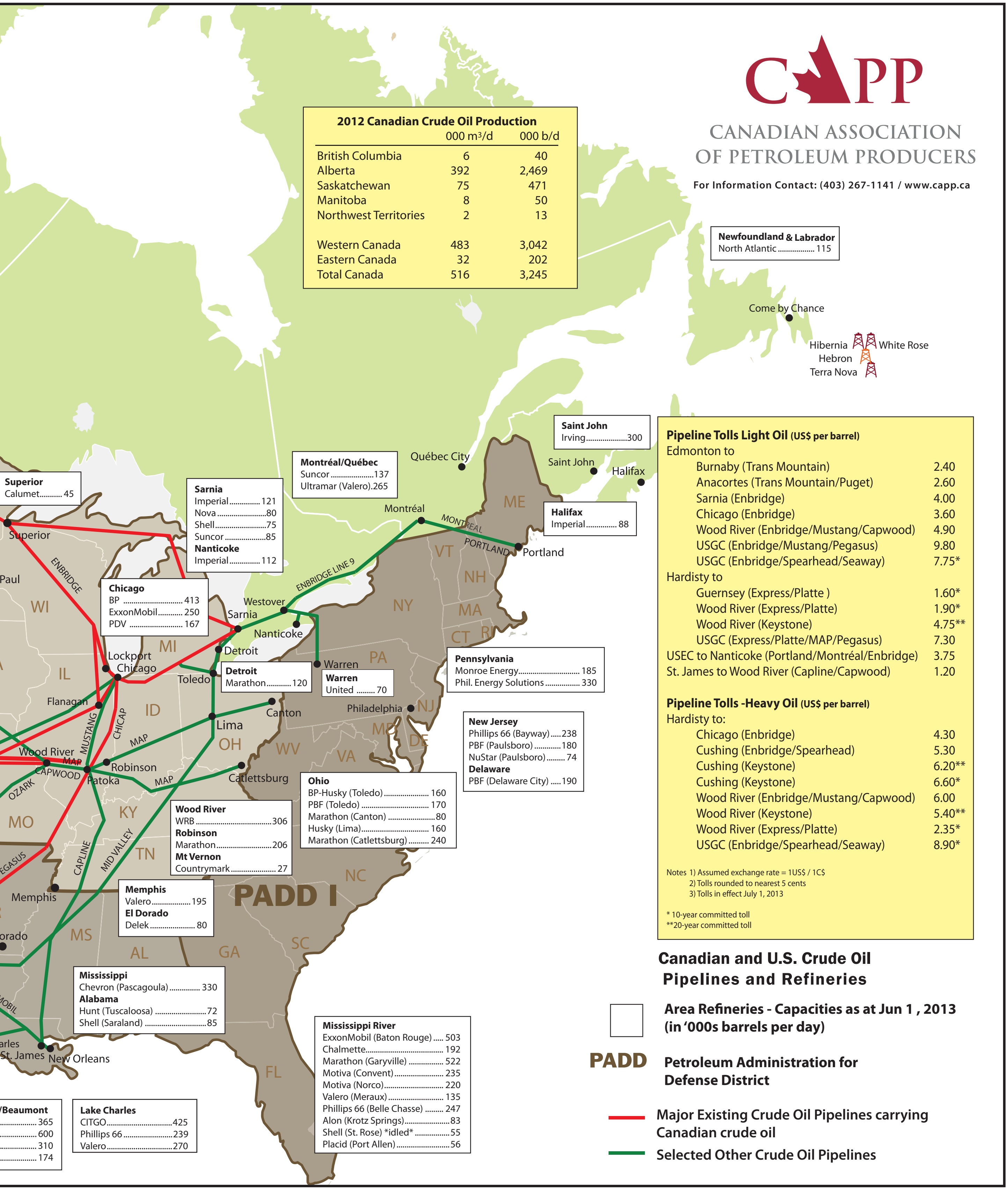
Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______

APPENDIX C

Crude Oil Pipelines and Refineries



Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______



Designed by Western Sky Creative www.westernsky.ca

CAPP
CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP's member companies produce about 90 per cent of Canada's natural gas and crude oil. CAPP's associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues of about $100 billion-a-year.

CAPP's mission is to enhance the economic sustainability of the Canadian upstream petroleum industry in a safe and environmentally and socially responsible manner, through constructive engagement and communication with governments, the public and stakeholders in the communities in which we operate.

Get in on the oil sands discussion

Mobile Application

Get the facts on your mobile device!
FACTS
Oil Sands

Upstream Dialogue:
The Facts on Oil Sands

Available for free download to Android, Apple, and BlackBerry devices by searching "Oil Sands" in the app stores.

Twitter
@OilSandsToday

Facebook
Oil Sands Today

Websites

www.oilsandstoday.ca www.capp.ca/upstreamdialogue

Calgary Office:

2100, 350 - 7 Avenue SW
Calgary, Alberta, Canada
T2P 3N9

Phone: 403-267-1100
Fax: 403-261-4622

Ottawa Office:

1000, 275 Slater Street
Ottawa, Ontario, Canada
K1P 5H9

Phone: 613-288-2126
Fax: 613-236-4280

St. John's Office:

403, 235 Water Street
St. John's, Newfoundland and Labrador
Canada A1C 1B6

Phone: 709-724-4200
Fax: 709-724-4225

www.capp.ca • communications@capp.ca • June 2013 • **2013-0013**

ATTACHMENT D

TransCanada to Proceed with 1.1 Million Barrel/Day Energy East Pipeline Project to Saint John

Successful Open Season Confirms Strong Support to Move Crude Oil to Eastern Canada

CALGARY, ALBERTA--(Marketwired - Aug. 1, 2013) -

Editor's note: News Conference today at 9:30 a.m. (MDT). Details below.

TransCanada Corporation (TSX:TRP) (NYSE:TRP) (TransCanada) is pleased to announce it is moving forward with the 1.1 million barrel per day (bbl/d) Energy East Pipeline project based on binding, long-term contracts received from producers and refiners. The conclusion of the successful open season confirmed strong market support for a pipeline with approximately 900,000 bbl/d of firm, long-term contracts to transport crude oil from Western Canada to Eastern Canadian refineries and export terminals.

"We are very pleased with the outcome of the open season for the Energy East Pipeline held earlier this year and are excited to move forward with a major project that will bring many benefits across Canada," said Russ Girling, TransCanada's president and chief executive officer. "This is an historic opportunity to connect the oil resources of western Canada to the consumers of eastern Canada, creating jobs, tax revenue and energy security for all Canadians for decades to come."

Girling added that interest in Energy East supports refineries' desire to have access to a stable and reliable supply of Western Canadian crude oil - pushing out more expensive crude oil from foreign regimes. Eastern Canada currently imports approximately 700,000 bbl/d. It also confirms the desire producers have to support safe and innovative ways to get their crude oil to market.

"Energy East is one solution for transporting crude oil but the industry also requires additional pipelines such as Keystone XL to transport growing supplies of Canadian and U.S. crude oil to existing North American markets," added Girling. "Both pipelines are required to meet the need for safe and reliable pipeline infrastructure and are underpinned with binding, long-term agreements."

The project is expected to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets. The Energy East Pipeline will have a capacity of approximately 1.1 million bbl/d and is anticipated to be in service by late-2017 for deliveries in Québec and 2018 for deliveries to New Brunswick.

The Energy East Pipeline project involves converting a portion of natural gas pipeline capacity in approximately 3,000 kilometres (1,864 miles) of TransCanada's existing Canadian Mainline to crude oil service and constructing approximately 1,400 kilometres (870 miles) of new pipeline. The pipeline will transport crude oil from receipt points in Alberta and Saskatchewan to delivery points in Montréal, the Québec City region and Saint John, New Brunswick, greatly enhancing producer access to Eastern Canadian and international markets. The pipeline will terminate at Canaport in Saint John, New Brunswick where TransCanada and Irving Oil have formed a joint venture to build, own and operate a new deep water marine terminal.

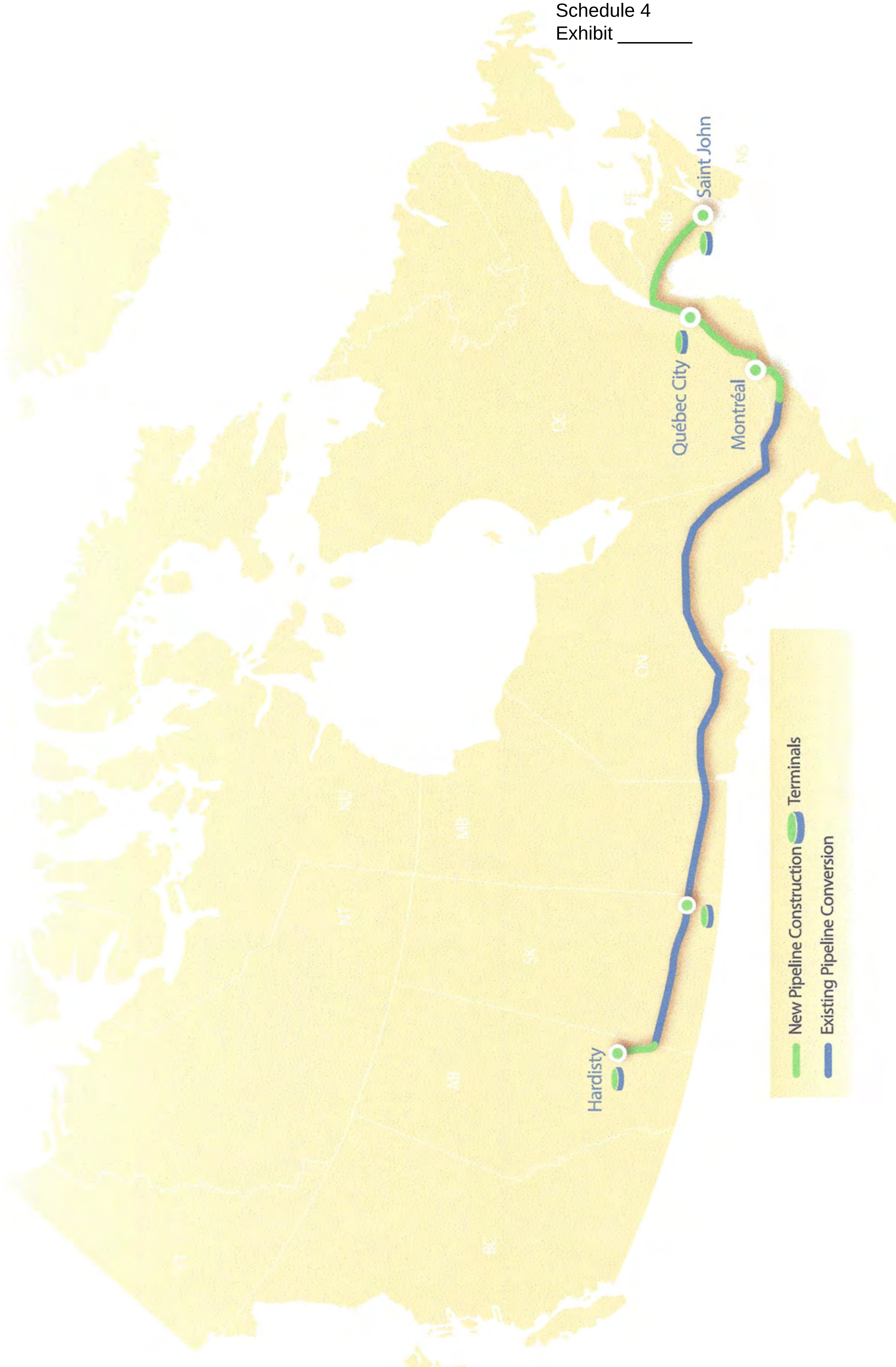
While Energy East will use a portion of Canadian Mainline capacity, TransCanada is committed to continuing to meet the needs of its gas customers in eastern Canada and the N.E. United States.

Our 60 years of pipeline experience has taught us that to advance a project of this size, we must engage in open and meaningful discussions with Aboriginal communities and key stakeholder groups. TransCanada has been out in the field collecting data and engaging with Aboriginal and stakeholder groups for the past several months as part of its initial design and planning work for the project and that will continue.

"TransCanada is a leading North American energy infrastructure company with one of the best safety records in the industry and that is something we are very proud of," concluded Girling. "Energy East will be designed and operated with a singular focus on safety - that is what Canadians expect and that is what TransCanada will deliver. We all recognize that oil is essential in our daily lives. We need it to heat our homes, operate our vehicles and make thousands of products we rely on every day. What we must do is ensure the oil is transported safely and reliably."

The company intends to proceed with the necessary regulatory applications for approvals to construct and operate the pipeline project and terminal facilities in early 2014.

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit _______



ATTACHMENT E

Richard Smith Surrebuttal Testimony
Friends of the Headwaters
Schedule 4
Exhibit ________

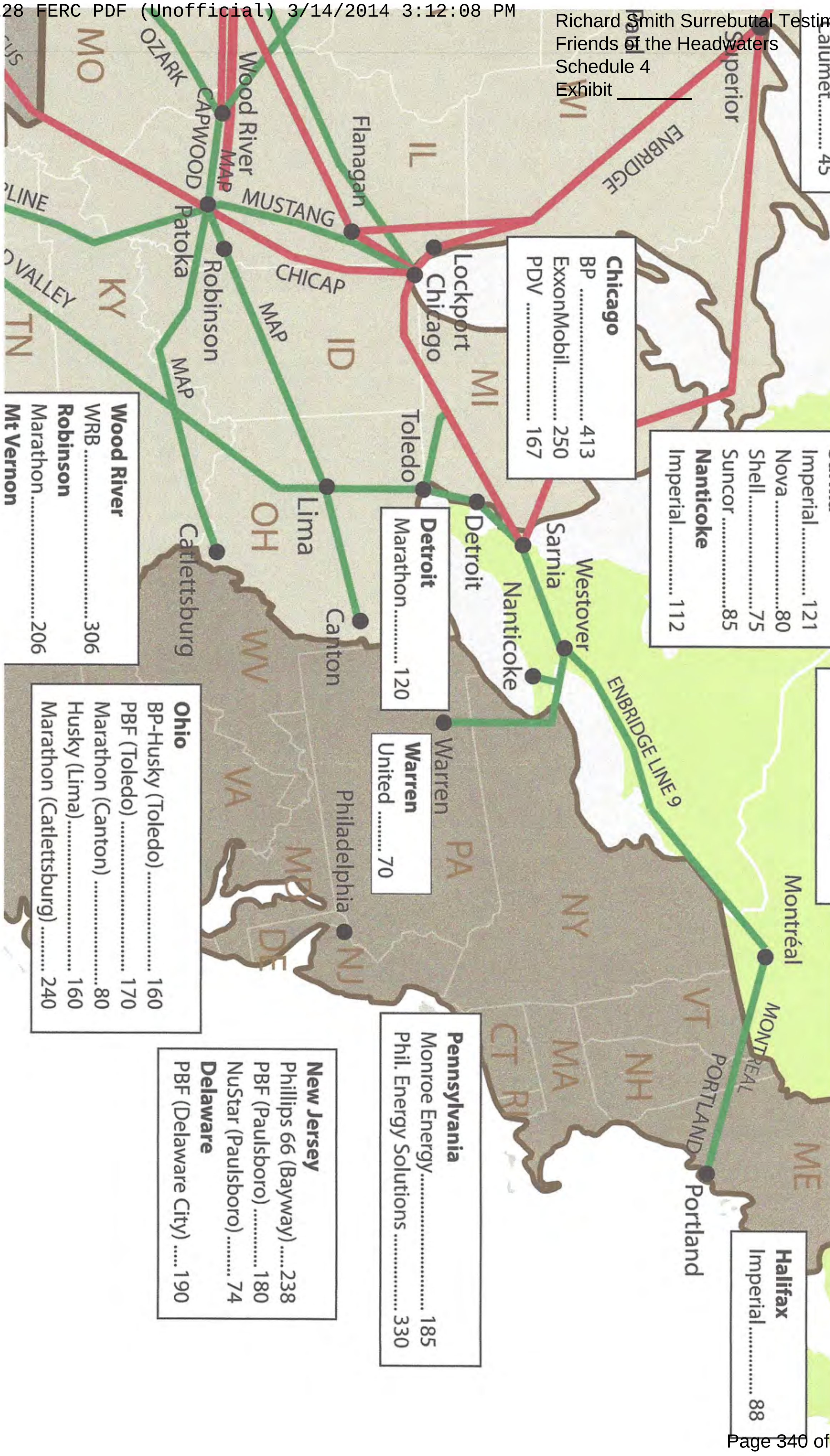


EXHIBIT E

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

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

SWORN DECLARATION OF WILLIAM WOODARD IN SUPPORT OF WPX ENERGY MARKETING LLC'S PROTEST AND OPPOSITION TO NORTH DAKOTA PIPELINE COMPANY LLC'S PETITION FOR DECLARATORY ORDER AND WPX ENERGY MARKETING'S MOTION TO INTERVENE

William Woodard states as follows, pursuant to the provisions of 18 U.S.C. § 1746:

1. I am Director, WPX Crude Trading, WPX Energy Marketing, LLC ("WPX"). My business address is One Williams Center, 720 Level, Tulsa, OK 74172.

2. WPX's parent company, WPX Energy, Inc. ("WPX Energy") is an independent oil and gas exploration and production company specializing through subsidiaries in producing natural gas, natural gas liquid and oil from non-conventional resources such as tight-sands and shale formations. WPX Energy holds approximately 81,000 net acres on the Fort Berthold Indian Reservation, in North Dakota, where it produces approximately 28,000 barrels of crude oil per day (bpd) from the Bakken Shale formation.

3. WPX provides sales and marketing services for WPX Energy, Inc.'s crude oil production not previously dedicated to gathering companies. Virtually all of the crude oil that WPX markets is transported on the pipeline system that is owned and operated by North Dakota Pipeline Company LLC ("NDP").

4. In addition, WPX is party to an agreement with a NDP affiliate, which involves a multi-year commitment to utilize rail-loading services for volumes received from NDP at the NDP affiliate's Berthold Station.

5. WPX intends to continue to use the NDP pipeline in the future either through buy/sell arrangements with other parties or as a shipper in its own name.

6. As Director of WPX Crude Trading I am knowledgeable as to the shipment of crude oil on the NDP system. During the past year, WPX has been able to ship or arrange the shipment of all of the crude oil it wished to transport on the NDP pipeline. Therefore during the past year, I have not been aware of any curtailment in the shipment of WPX Energy crude oil on the NDP pipeline because of prorationing.

7. I am familiar with the Petition for Declaratory Order that NDP filed with the Commission on February 12, 2012. WPX would be adversely affected to a substantial extent by the project that NDP plans to implement as described in its Petition. WPX therefore wishes to Protest and state its Opposition to the NDP Petition.

8. Since no other person can adequately represent WPX's position, WPX respectfully requests leave to intervene in that proceeding as a party.

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

WILLIAM WOODARD

Executed on March 11, 2014.

EXHIBIT F

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

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

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. Previously I was the President of Innovation & Information Consultants, Inc. (IIC, Inc.), an economics and management consulting firm located in Concord, Massachusetts. I have analyzed all facets of the petroleum industry including regulatory issues related to pipeline ratemaking and pipeline operations. I have filed testimony in several rate matters before FERC in which I analyzed rates, developed cost of service and stand alone cost models and analyzed petroleum markets. Most recently, I have testified in *Enterprise TE Products Pipeline Company LLC,* Docket No. IS12-203-000 on issues related to cost of service and rate design. I have also testified in *SFPP, L.P.,* Docket No. IS05-230-000 and in *SFPP, L.P.*, Docket No. IS08-390-002. Other cases include *Big West Oil Co. and Chevron Products Co. v. Anschutz Ranch East Pipeline, Inc.,* Docket No. OR01-03-000 and OR01-05-000 (consolidated); *Big West Oil Co. and Chevron Products Co. v. Frontier Pipeline Co.,* Docket No. OR01-02-000 and OR01-04-000 (consolidated); *Big West Oil, LLC, Chevron Products Company, and Tesoro Refining and Marketing Company v. Express Pipeline LLC and Platte Pipe Line Company*, Docket No. OR02-5-000; *Big West Oil, LLC, Chevron Products Company,*

Sinclair Oil Corporation and Tesoro Refining and Marketing Company v. Express Pipeline LLC, Docket No. OR02-8-000; *Big West Oil, LLC, Chevron Products Company, and Tesoro Refining and Marketing Company v. Platte Pipe Line Company*, Docket No. IS02-384-000; and *Sinclair Oil Corporation v. BP Pipelines (N.A.), Inc.*, Docket No. OR02-6-02. I have also assisted various shippers in other matters before FERC, including FERC's review and analysis of the Form 6 reporting requirements (*Revision to and Electronic Filing of the FERC Form 6 and Related Uniform Systems of Accounts*, Docket No. RM99-10-000 and *Review of FERC Form Nos. 6 and 6-Q*, Docket No. RM07-9-000) and the five year review of the rate indexation rules (*Five Year Review of Oil Pipeline Pricing Index*, Docket No. RM00-11-000 and Docket No. RM05-22-00) of the Commission.

2. In addition to the matters before FERC to which I just referred, I have also testified on several occasions before the California Public Utilities Commission (CPUC) on issues related to pipeline rates, access, cost allocation, market power, and other issues. I recently provided testimony in *Application of SFPP, L.P.* in A.12-01-015, and before that I testified in *Application of SFPP, L.P*. in A.09-05-014 et al. on rate, cost of service and market power issues. I have also presented testimony on cost of service and rate design issues in the *Application of San Pablo Bay Pipeline LLC*, A.08-09-024 and several other cases. I have attached a copy of my curriculum vita to this declaration, which provides more detail on my background and experience.

3. I have been asked by counsel for Concord Energy LLC, Enserco Energy LLC, EnWest Marketing LLC and WPX Energy Marketing, LLC to evaluate the Petition for Declaratory Order filed with the Commission by North Dakota Pipeline Company LLC (NDP) on February 12, 2014. The NDP submission relates to its proposed Sandpiper Project and is the second time NDP and its predecessor, Enbridge Pipelines (North Dakota) LLC (Enbridge) have asked the

Commission to approve a pipeline expansion project. I provided a declaration in November 2012 in support of EnWest Marketing's Protest against the first Sandpiper expansion proposal. In particular, I have been asked to comment on the proposed rate design, the likely impact of the rate design on uncommitted shippers, and the market need for the Sandpiper project.

Overview of the Sandpiper Project

4. As in 2012, NDP is proposing to add a new 230,000 barrels per day (bpd) pipeline from Beaver Lodge, North Dakota to Clearbrook, Minnesota. When combined with its present pipeline, NDP would have the capacity to transport 440,000 bpd of Bakken crude oil to Clearbrook. NDP further proposes to extend its pipeline from Clearbrook to Superior, Wisconsin by constructing 233 miles of 30-inch pipeline that would have an annual average capacity of 380,000 bpd. This new pipeline would eliminate Clearbrook as a destination for North Dakota shippers. NDP held an open season and obtained volume commitments totaling 155,000 bpd. These commitments are divided into two classes of service: (1) committed priority and (2) committed non-priority service. Priority committed shippers would not be subject to prorationing, whereas non-priority committed shippers would be subject to prorationing. NDP proposes to recover the costs of the Sandpiper project through a rate design structure based on three classes of service. This includes the two classes of committed service described above as well as uncommitted shippers, who did not sign Transportation Service Agreements (TSA) and represent about 65% or more of the total capacity of the new pipeline.[1]

[1] The 65% figure is based on total capacity from Beaver Lodge to Clearbrook of 440,000 and 155,000 of committed capacity. The uncommitted capacity is therefore 285,000 [65% = 285,000/440,000]. Of the 155,000 bpd capacity that was subscribed, it is not known if any or all of that capacity would continue on the extension from Clearbrook to Superior or be sent south from Clearbrook on the Minnesota Pipeline. If some or all of that crude oil is transported south on the Minnesota Pipeline, then uncommitted shippers could be potentially responsible for up to 75% of the capacity on the pipeline extension from Clearbrook to Superior [75% =

5. NDP also claims that the Sandpiper project is necessary and will benefit all classes of shippers because (i) there is a demonstrable need for the project; (ii) the new pipeline will be at full capacity; and (iii) the pipeline will provide substantial economic benefits to producers of Bakken crude oil.[2] These assertions are based on a report prepared by Muse Stancil (Muse), sponsored by Neil K. Earnest which is attached to the Petition.[3]

6. NDP claims that a large share of the costs of the Sandpiper project will be borne by the committed shippers. Yet as noted above committed shippers will only be shipping at most 35% of the capacity on the expansion portion of the pipeline from Clearbrook to Superior. NDP proposes to recover the remaining costs through a rate structure that will vary by the three classes of service. The committed shippers will pay a base rate plus a flow-through power cost based on actual costs plus any other existing surcharges. NDP states that priority service will pay a substantial premium relative to non-priority committed shippers, and priority committed shippers will pay a premium of at least one cent above the initial uncommitted rate.[4] Non-priority committed shippers will pay a discount relative to uncommitted shippers.

7. The base rate for committed shippers was specified in the TSA that committed shippers signed during the NDP Open Season and is subject to change only if capital costs diverge from the Class 5 estimates used to generate this base rate.[5] The uncommitted rate to Clearbrook will consist of the existing indexed base rate, any existing surcharges and an expansion rate

---

285,000/380,000]. This would seem to indicate that uncommitted shippers will be paying a large majority of the costs on the expansion portion of the pipeline.

[2] Petition for Declaratory Order of North Dakota Pipeline Company LLC (“NDP Petition”), pages 19-20.

[3] See Exhibit 4 to the NDP Petition.

[4] NDP claims that the initial premium that priority committed shippers will pay over the uncommitted rate will be in the range of $0.15 to $0.30 per barrel, but notes that the actual differential may vary (MacPhail Affidavit, page 26). Since NDP did not provide cost data with its Petition, it is impossible to evaluate this claim.

[5] See Section 7.03 of the TSA attached to the MacPhail Affidavit.

component which NDP states is designed to capture a "relative share" of the costs of the pipeline expansion.[6] However NDP never defines what a "relative share" is or how it will be determined, so it is impossible to determine the ultimate rate impact.[7] For the Clearbrook to Superior extension, NDP states that the uncommitted rate will be based on an Opinion 154-B cost of service analysis for the "relative share" of the costs of that segment assigned to uncommitted shippers. The TSA included an "illustrative" uncommitted rate, but the actual uncommitted rate will not be known until NDP files its cost of service analysis.

Summary of Issues and Conclusions

8. Based on my review and analysis of the Petition and the attachments to the Petition, I have concluded as follows:

- NDP has failed to provide sufficient information and data to enable the Commission or shippers on the pipeline to fully understand and evaluate the likely impacts of the rate design and rate structure being proposed. As one example, it is clear that NDP must have developed a cost of service analysis including a cost allocation methodology to develop the data shown in the TSA as well as the data discussed in the affidavit of Mr. MacPhail, but NDP has not provided any cost of service information in its Petition.
- Nevertheless, despite the limited information available, it appears that the Sandpiper proposal would require existing, uncommitted shippers to pay for a substantial portion of the new and expanded pipeline initially, and in the long run, uncommitted shippers are likely to pay a highly disproportionate share of the

[6] NDP Petition, page 41.
[7] See MacPhail Affidavit, page 28.

costs of the new pipeline and assume virtually all of the risks of under recovery of the cost of the project.

- Apart from NDP's assertions, there is no evidence that existing shippers have been under continuous prorationing or that insufficient transportation capacity exists and will exist in the future to move crude oil out of the Bakken area.
- The Muse report is based on proprietary information and data and therefore cannot be reasonably evaluated. However, based on what information is provided, the Muse report suffers from a series of flaws and omissions that calls into serious question its conclusions.
- In my opinion existing shippers will not see any benefits from this new pipeline and should not be required to pay for it, let alone pay for what appears to be a highly disproportionate share of the new capacity.

NDP Has Failed to Provide Adequate Information to Evaluate Its Proposed Rate Design and Cost Allocation Methodology

9. NDP has failed to provide any cost of service information in its Petition even though it is requesting the Commission to approve its rate design at this time. My understanding is that the rate design approvals that NDP is requesting at this time are approvals of the base rates that committed shippers will pay as specified in the TSA and a rate structure in which priority committed shippers would be able to pay only one cent a barrel more than uncommitted shippers. Under that rate design, it is likely that the pipeline will incur substantial additional unrecovered cost. Under the NDP rate design those costs will probably be borne by uncommitted shippers. As I pointed out previously, the Petition states that uncommitted shippers will pay their "relative share" but it provides no information on how costs will be allocated so that uncommitted shippers pay that "relative share." As a result, neither the Commission nor the shippers have any

idea of how costs will be allocated among the three classes of shippers and whether the result may be discriminatory. Since we do not have access to the cost data and cost allocation methodology that supports the committed rate and the costs that NDP will likely use to support the uncommitted expansion rate and the downstream extension rate, it is simply impossible to determine whether NDP's rate design is reasonable or non-discriminatory. However, as I discuss in greater detail below, based on the limited information that is available, it does not appear that the NDP rate design is either fair, reasonable or non-discriminatory.

10. Based on the information contained in the Petition, it is clear that NDP must have performed a cost of service analysis including a cost allocation study. First, it has calculated base rates for committed service which are shown in Attachment A to the TSA.[8] Indeed it is my understanding that these are the rates that NDP requests the Commission to approve as part of its Petition for Declaratory Order. Committed shippers will represent 35% or less of the total capacity of the pipeline, and for the downstream expansion portion they could represent less than 35%. Yet it is impossible to determine what level of costs will be recovered in the committed base rates.

11. NDP states that it "expects" that the rate for priority committed service will be 30 cents per barrel higher than the initial uncommitted rate for movements to Superior and 15 cents per barrel higher than the initial uncommitted rate to Clearbrook.[9] NDP goes on to state that if final construction costs change, then the priority committed rate might well be only be 1 cent higher than the *initial* uncommitted rate.[10] Clearly for NDP to be able to make statements such as these

---

[8] Schedule B to Attachment A to the MacPhail Affidavit.
[9] NDP Petition, page 27.
[10] I place emphasis on the word "initial" as NDP is careful in its Petition to use that word whenever it discusses the uncommitted rate. As I point out below, the reason that NDP underscores the fact that it is discussing only "initial" rates is because NDP might well increase

regarding the likely range of expected initial rates, it must have developed a cost of service and cost allocation analysis.

12. NDP also goes on to state that in computing the rates for uncommitted shippers it will deduct $7.5 million from the cost of service of the expansion facilities and another $7.5 million from the cost of service underlying the extension rate. NDP provides no basis for these figures but simply asserts that these deductions will ensure that uncommitted shippers pay less than their proportionate share of the costs. Again, it is impossible to assess the accuracy of this statement without access to the underlying cost data and allocation methodology that NDP is using. But what is clear is that NDP must have performed those calculations in order to have made the $7.5 million calculation and predict the impact it will have on uncommitted rates while allowing it to recover its cost of service from all shippers.

The Limited Evidence Available Suggests that Uncommitted Ratepayers Will Face Large Rates Increases, Assume All Volume Risk and Likely Pay a Disproportionate Share of the Costs of the Project

13. I have constructed Table 1 below to illustrate the impact on the initial rates for uncommitted shippers of the portion of the NDP rate design that provides that uncommitted shippers would pay an initial rate that could be anywhere from 30 cents per barrel less to 1 cent per barrel less than the priority committed rate for a ten year commitment. As Table 1 demonstrates, initial uncommitted rates could be as much as 94% to 125% higher than the existing uncommitted rate for these same movements as shown in Table 1.[11] Moreover, even if the initial priority committed rate premium ends up falling within the range predicted by NDP

---

the uncommitted rate significantly after the first year of operation if the pipeline does not operate at or near design capacity.

[11] I have excluded the Phase 6 surcharge in each case as committed and uncommitted shippers will pay the same surcharge.

(between 15 and 30 cents per barrel higher than the initial uncommitted rate), uncommitted shippers will still pay a rate that is between 84% and 110% higher than the existing rate.

Table 1
Rate Increase for Uncommitted Shippers

	Existing Rates for Uncommitted Service*	Maximum Uncommitted Rate^	Difference	Percent Increase
Beaver Lodge to Clearbrook	$ 1.32	$ 2.56	$ 1.24	94%
Beaver Lodge to Superior**	$ 1.95	$ 4.36	$ 2.41	124%

Sources:
Enbridge Pipelines (North Dakota) LLC, Oil Pipeline Tariff Filing, March 1, 2013
Enbridge Energy Partners Tariff FERC No. 43.13.0
Schedule B to NDPL TSA
* *Excludes Phase 6 surcharge*
** *Assumes existing movement from Clearbrook to Superior via Lakehead system*
^ *Base committed priority rate for ten year term at less than 20,000b/d volume commitment plus illustrative power charge less one cent*

14. Table 1 compares existing base rates for uncommitted service to Clearbrook and to Superior with the maximum initial uncommitted rate NDP states could occur which is one cent less than the priority committed rate. The existing uncommitted rate to Clearbrook is the base rate taken from Enbridge Pipelines (North Dakota) LLC March 1, 2013 tariff filing, and indexed according to the July 2013 FERC indexation increase. To show the existing base rate from Beaver Lodge to Superior I add to that base rate to Clearbrook the rate for movement on Enbridge's Lakehead system from Clearbrook to Superior. The maximum uncommitted rate is simply the base rate for committed priority service plus the illustrative power charge as shown in Schedule B to Attachment A of the Affidavit of Mr. MacPhail less one cent. In all cases for simplicity, I omit consideration of the Phase 6 surcharge.

15. The limited information NDP provided also suggests that there is a strong likelihood that uncommitted shippers will pay a disproportionate share of the costs of the Sandpiper project. There are several reasons that contribute to this result. NDP's rate structure envisions that committed shippers will pay a "flow through power cost charge" which includes a true-up mechanism so that committed shippers will pay only actual power costs.[12] On the other hand, uncommitted shippers will pay a power cost that is embedded in the initial Opinion 154-B cost of service study which will be indexed each year into the future. Uncommitted shippers therefore will pay a power cost that will in all probability increase every year, while committed shippers pay actual power costs which are likely to fluctuate to lower as well as higher levels. To the extent that actual power costs decline from the initial estimate, committed shippers will receive an unfair and discriminatory advantage by paying a lower power cost component in their rates than uncommitted shippers. Over a ten year period, the discriminatory impact could be quite substantial.

16. For instance, I have assumed in the example in Table 2 below that (i) in the first year of pipeline operations both committed and uncommitted shippers pay the same power cost of $0.30 per barrel and (ii) over a ten year period, uncommitted shippers face a 5% indexation increase each year, while the actual power costs that committed shippers pay increase by only 1% per year on average.[13] By the 10th year, uncommitted shippers will be paying $0.16 per barrel more for power costs than committed shippers. In other words uncommitted shippers will be paying

[12] Power costs includes fuel, power and DRA.
[13] Over the past five years, the annual average increase in the FERC index for oil pipelines has been slightly more than 5% whereas the actual annual inflation rate for energy and electricity as measured by the Bureau of Labor Statistics over the last five years has averaged slightly more than 1% per year.

almost 50% more than committed shippers for the fuel and power that the pipeline uses. This conclusion is illustrated in Table 2 below.

Table 2
Discriminatory Impact of Differential Treatment of Power Costs

	Initial Power Cost	Inflation Index over 10 years*	Power Cost After 10 Years
Uncommitted Service	$ 0.30	1.629	$ 0.49
Committed Service	$ 0.30	1.105	$ 0.33
Premium Paid by Uncommitted Shippers			$ 0.16
Percent Premium Paid by Uncommitted Shippers			47%

* Committed service faces a 1% per year average actual cost inflation
Uncommitted shippers face a 5% indexation increase each year

17. In my opinion there is no reason for the NDP rate design to treat power costs differently between committed and uncommitted shippers. The additional costs uncommitted shippers will be paying seems to me discriminatory on its face.

18. Under NDPA's proposed rate design, uncommitted shippers also appear likely to assume disproportionately higher pipeline costs as a result of a capital cost-sharing risk adjustment contained in the TSA.[14] In his affidavit, Mr. MacPhail describes a cost variation sharing mechanism under which committed shippers will only pay for 50 percent of any variance between NDP's Class 3 capital cost estimate and final construction costs.[15] For example, if actual costs exceed the Class 3 estimate by $10 million, then the base components of the

[14] Section 7.04 of the TSA describes the cost variation sharing mechanism. The language is specifically directed to the committed base components.
[15] MacPhail Affidavit, page 25. A Class 3 estimate is part of the cost estimate classification system for various industries and reflects a preliminary cost estimate with semi-detailed cost data used for budget, authorization and control purposes. See Association of Advancement of Cost Engineering.

committed service rates will only include 50 percent of this variance, and the remaining $5 million will not be included in the base component for the committed rates. The Petition does not define the impact of those remaining cost variances on uncommitted service and whether in the example the pipeline's unrecovered $5 million are included in the uncommitted expansion and extension rates. Table 3 below presents a hypothetical example which indicates that under certain assumptions, the proposed capital cost risk-sharing mechanism would shift a higher proportion of costs to uncommitted shippers.

Table 3
Analysis of Cost Variance Sharing Mechanism

($ millions)	Base	Actual
Class 3 Estimate	$ 1,400	
Actual Cost		$ 1,600
Difference		$ 200
Allocation By Category:		
Committed service	$ 944	$ 1,011
Uncommitted service	$ 456	$ 589
Percent Borne by Uncommitted	32.6%	36.8%

19. In Table 3, I have assumed – hypothetically – that the upstream expansion Class 3 estimate for total capital costs is $1.4 billion. I have also assumed that final capital construction costs are actually $1.6 billion, which represents slightly less than a 15 percent increase over the Class 3 estimate. In the example, I further assume that initially costs are shared proportionate to volume on the expanded portion of the pipeline. Consequently committed shippers would pay 67% of those costs and uncommitted shippers would pay 33%.[16] The $1.4 billion Class 3 cost estimate would therefore be allocated by assigning $994 million to committed shippers and $456

[16] I computed this amount assuming that of the 230,000 bpd of expansion capacity, 155,000 (67%) is committed capacity and therefore the rest (75,000 – 33%) is uncommitted capacity.

to uncommitted shippers. That would leave a $200 million difference since actual costs are not $1.4 billion but $1.6 billion. Under the TSA, committed shippers would incur only 50 percent of their share of the $200 million cost variance between actual costs and the Class 3 estimate. Therefore total costs allocated to the committed shippers would be $1.01 billion.[17] The TSA clearly indicates that the cost variance sharing mechanism only applies to the base components of the committed rates.[18] Therefore I assume that the pipeline would pass through the “unrecoverable” committed portion of the cost variance sharing mechanism to uncommitted shippers. In this case, that additional cost would be allocated through the cost of service analysis underlying the upstream expansion rate, and uncommitted shippers’ allocation of total costs would, in the example I am using, increase from 32.6% to 36.8% as shown on Table 3.

20. In my opinion increasing the share of the uncommitted shippers’ costs because the TSA limits the amount of costs allocated to committed shippers unfairly discriminates against uncommitted shippers. Under the NDP rate design, if cost overruns do occur, uncommitted shippers would be unfairly subsidizing committed shippers.

21. Uncommitted shippers also face significant exposure to large rate increases because under the proposed rate design they will assume virtually all of the risk associated with the extension and expansion projects. The Petition indicates that the initial uncommitted shipper rate will be based on cost of service studies for the upstream expansion and downstream extension portions of the project using the Commission’s standard Opinion 154-B methodology. NDP further states that the initial cost of service will assume a “design capacity” of the pipeline

[17] The amount I calculated represents 67 percent of the Class 3 estimate plus 67 percent of 50 percent of the $200 million cost overrun.
[18] See Attachment A to the MacPhail Affidavit, Article 7, pages 23-24.

system in establishing rates.[19] Although the term "design capacity" is not defined in the Petition or the TSA, NDP states in Mr. MacPhail's Affidavit that the term "design capacity" is synonymous with "annual average capacity" meaning the volume of crude oil the pipeline can be expected to transport over the course of a year (as opposed to the maximum theoretical capacity). It would therefore appear from Mr. MacPhail's Affidavit that if the pipeline is expected to transport less than its full design capacity in the first year of operation, the fact that it is underutilized will not directly affect the rates that uncommitted shippers will be responsible for paying. I interpret the NDP Petition as stating that in the first year of operation, rates will be established on the basis of a 440,000 bpd throughput for the Beaver Lodge to Clearbrook segment and a throughput of 385,000 bpd from Clearbrook to Superior.

22. However, that situation is substantially different after the first year of operation. Although NDP indicates the rates of uncommitted shippers will be indexed following the pipeline's initial year of operation as prescribed by the Commission's indexation policy, NDP also states that it "reserves the right to use other rate-changing methods set forth in the Commission's regulations to the extent possible."[20] NDP's statement that it could establish the rates of uncommitted shippers after the first year of operation on the basis of non-indexation rate-setting mechanisms exposes uncommitted shippers to significant rate increases. Under the Commission's regulations if NDP were able to show a "substantial divergence" between the actual costs incurred on the expansion and extension segments – including the debt service and return on equity the pipeline believes it is entitled to receive – and the rate that would result from

[19] See NDP Petition at page 29, citing MacPhail Affidavit at ¶74.
[20] MacPhail Affidavit, footnote 4, page 23.

application of the index, it could file a new cost of service.[21] Under that new cost of service, NDP could seek uncommitted rates that essentially enable the pipeline to recover all of its costs and a return on equity for the expansion and extension segments based on the *actual* quantity of crude oil the pipeline transports.

23. However, the TSA, states that, aside from the fuel and power costs and application of the annual FERC index which I previously discussed, the base rate for committed shippers will not change.[22] As a result, it would be the uncommitted shippers who would face a significant rate increase on the basis of the pipeline's inability to cover its costs and rate of return for the expansion and extension segments. In essence NDP is saying in its proposed rate design that the uncommitted shippers will bear all of the risk, after the first year of operation, that the pipeline's throughput will actually meet its full design capacity. If it does not, then the rates that the uncommitted shippers will be required to pay could be set at a high enough level to ensure that NDP recovers all of its costs as well as the rate of return it seeks. In view of the serious questions, which the Shippers have raised as to whether the expansion and extension is needed in the first place, there is a very substantial possibility that uncommitted rates will rise to very high levels.

24. In fact, the potential for a significant rate increase for uncommitted shippers is clear in an example that assumes that throughput volumes fall short of design capacity. Although NDP has not provided cost of service or cost allocation data, I have assumed that the illustrative

[21] 18 CFR 342.4(a) states that a carrier may change a rate if it shows that there is a substantial divergence between the actual costs experienced by the carrier and the rate resulting from application of the index such that the rate at the ceiling level would preclude the carrier from being able to charge a just and reasonable rate within the meaning of the ICA.
[22] The priority committed rate would be set at one cent above the uncommitted rate, but as discussed below, given the reduced level of throughput on the pipeline, no committed shipper would choose to maintain its priority status and thus no shipper would pay that rate.

uncommitted rate specified in the NDP TSA, Exhibit B from Beaver Lodge to Clearbrook is based on a certain design capacity that matches the initial cost of service for the upstream expansion. In other words, I am assuming that the rate that NDP states is the rate that permits it to fully recover its cost of service assuming that the pipeline actually transports the design capacity.[23] In my example I use this rate and assume that the rate generates sufficient revenues to enable the pipeline to fully recover its cost of service. I am further assuming a design capacity of 75,000 barrels per day applicable to the uncommitted capacity on the expansion segment.[24] The initial Expansion Rate component is equal to $1.0314 per barrel which is equal to the uncommitted rate stated by NDP in Exhibit B to the TSA less the existing rate. The revenue requirement (or cost of service) for the expansion portion of the uncommitted service is then computed using the uncommitted design capacity of 75,000 bpd and initial Expansion Rate component of $1.0314 per barrel for a total revenue requirement of $28.2 million from uncommitted shippers.[25]

25. If we were to assume that actual uncommitted volumes in year 1 were only 10,000 bpd, rather than 75,000 bpd, then NDP would under-recover its cost of service by 87 percent in year 1. That under-recovery would be approximately one percent less, or 86 percent in Year 2, if we assume that (i) the Expansion Rate component would be indexed in year 2 by 5%; (ii) the volume transported in Year 1 remained at 10,000 bpd; and (iii) the initial cost of service that

---

[23] The example and assumptions that I am using focuses upon the upstream expansion rate component, although a similar example would apply to the downstream extension rate component as well.

[24] I compute this amount by assuming that of the 230,000 bpd of expansion capacity, 155,000 bpd is committed capacity and therefore the rest (75,000) is uncommitted capacity.

[25] For simplicity I do not deduct the $7.5 million that NDP states it will deduct form the cost of service for uncommitted service as that does not alter the fundamental conclusion of the analysis.

NDP submitted remained the same. [26] Under these circumstances, NDP would file a rate increase on the upstream expansion rate component claiming that it satisfied the substantial divergence test of Section 342.4(a) of the Commission's regulations. All other factors remaining equal, it would seem that NDP would in fact satisfy the substantial disparity standard in view of the volume shortfall.[27]

26. As Table 4 below illustrates, these factors could result in a rate increase for uncommitted shippers to $6.7401for the Expansion Surcharge for a total Expansion Rate component of $7.7355 per barrel or a 650% increase from existing rates.

[26] If we were to assume that the cost of service increases in year 2 then the under recovery amount would increase as well.
[27] It is unclear from the Petition, but NDP could file for an increase on the total uncommitted rate, including the base component, but again for simplicity I have simply focused on the Expansion Rate component.

Table 4
Illustrative Example of Volume Shortfall on Uncommitted Shipper Rates

Assumed revenue requirement for uncommitted service - expansion portion	(a)	$28,234,575
Assumed uncommitted volume for expansion portion (bpd)	(b)	75,000
Total annual volume	(c) = (b) * 365	27,375,000
Initial COS-based Uncommitted Expansion Rate Component*	(d) = (a) / (c)	$1.0314
Actual volumes - Year 1 (10,000 b/d)	(e)	3,650,000
Total uncommitted revenue - Year 1	(f)	$3,764,610
Underrecovery - Year 1	(g) = (a) - (f)	$24,469,965
Percent underrecovery in Year 1	(h) = (g) / (a)	87%
Indexed rate - Year 2 (assuming 5 percent indexation rate)	(i) = (d) * 1.05	$1.0830
Uncommitted service revenues in Year 2 assuming Year 1 volumes	(j) = (i) * (e)	$3,952,841
Underrecovery in Year 2 assuming no change in cost of service**	(k) = (a) - (j)	$24,281,735
Percent underrecovery forecasted for Year 2	(l) = (k) / (a)	86.0%
New rate necessary to cover cost of service	(m) = (a) / (e)	$7.7355
Rate increase from Year 1 to Year 2 based on full recovery	(n) = (m) - (d)	$6.7041
Percent increase in Expansion rate to recover costs given volume shortfall	(o) = (n) / (d)	650%

* Assumes a rate of $2.3414 per barrel less the existing $1.31 per barrel Beaver Lodge to Clearbrook rate
** It is likely that the cost of service would increase in year 2 and this would only increase the underrecovery

27. I believe that Table 4 illustrates how uncommitted shippers would pay for the entire volume shortfall of the pipeline and, under the NDP rate design, would be the only group assuming the risk that the expansion portion of the project would not meet the design capacity of the line.[28]

28. I think it is somewhat disingenuous for the Petition to attempt to mask the fact that the uncommitted shippers are assuming all of the risk that the throughput of the pipeline will fall below its design capacity by stating that in the event the committed priority rate falls below the uncommitted rate, as would occur in the illustration above, then committed priority shippers will have the option to maintain their priority status by paying the uncommitted rate plus one cent per barrel. If the throughput of the pipeline falls below its design capacity, it would be foolish for a committed shipper to pay the uncommitted rate plus one cent. Having priority in the event of

[28] The same analysis can be shown for the uncommitted extension rate as well.

prorationing has no value whatever if the pipeline has excess capacity. What would likely happen under these circumstances is that committed priority shippers would elect to forego their priority status since it would have no value and shift to becoming non-priority committed shippers. They would then pay a rate that is lower than uncommitted shippers.[29]

29. The Petition is ambiguous regarding the specific rate a committed priority shipper would pay if the priority committed rate falls below the uncommitted rate. It is also unclear whether a shipper electing to give up its priority status pays the same rate as a committed non-priority shipper, or alternatively pays a rate that is less than the uncommitted rate but higher than the non-priority committed rate. However, regardless of which of the two rates a committed shipper foregoing its priority status pays, the effect of the NDP rate design is to shift virtually all of the volume risk of the pipeline to the uncommitted shippers.[30]

Uncommitted Shippers Have Not Faced Any Constraints in Using the Existing NDP Pipeline and Sufficient Capacity to Handle Bakken Crude Will Exist in the Future

30. An assessment of whether the Sandpiper project is necessary can generally be made by comparing the current and expected demand for crude oil take away capacity in North Dakota with the current and prospective facilities that can meet this demand. In making this assessment, I would first consider the recent historical pattern of usage and then turn to expected future demand and supply.

[29] NDP Petition, page 27.
[30] Moreover depending on how costs are actually being allocated between committed and uncommitted service, with priority committed shippers now paying a lower rate than in year 1, NDP's revenues will decline further which could prompt NDP to request an additional rate increase from uncommitted shippers.

31. It is my understanding that existing uncommitted shippers have been able to access the NDP without prorationing in recent years.[31] Indeed public data shows that throughput on the NDP since 2012 has not been at capacity which raises questions as to why existing uncommitted shippers should be asked to pay for a substantial portion of the new pipeline. The data shown in Table 5 below indicates that throughput on the NDP has been significantly below capacity during much of 2012 and at least through July 2013. In fact during the period August 2012 through July 2013, the pipeline was operating at only about 60% of capacity and even over the entire period January 2012 through July 2013, it was operating at slightly less than 75% of capacity.

[31] Declaration of Robert P. Garner, page 8; Declaration of William Woodard, page 2; Declaration of Brad Vodicka, page 2; Declaration of Jonathan Molis, page 2.

Table 5
Throughput on NDP 2012 – 2013

	Throughput on NDPL to Clearbrook (B/D)	Capacity (B/D)	Utilization
Jan - 12	204,067	210,000	97%
Feb -12	206,403	210,000	98%
Mar- 12	194,877	210,000	93%
Apr - 12	203,535	210,000	97%
May - 12	208,996	210,000	100%
Jun - 12	209,481	210,000	100%
Jul - 12	187,435	210,000	89%
Aug - 12	200,038	210,000	95%
Sep - 12	177,341	210,000	84%
Oct - 12	186,594	210,000	89%
Nov - 12	148,132	210,000	71%
Dec - 12	123,064	210,000	59%
Jan - 13	93,198	210,000	44%
Feb -13	96,038	210,000	46%
Mar - 13	96,416	210,000	46%
Apr - 13	70,083	210,000	33%
May - 13	108,725	210,000	52%
Jun - 13	123,036	210,000	59%
Jul - 13	126,036	210,000	60%
Averages:			
Aug 12 - July 13	129,058	210,000	61%
Jan 12 - July 13	155,973	210,000	74%

Source: Enbridge Pipelines (North Dakota) Motion to Dismiss Complaint of St. Paul Park Refining in OR13-28, August 14, 2013

32. In its Petition, NDP recognizes that the pipeline experienced a significant shortfall in throughput and states that the reason was a lack of downstream pipeline capacity.[32] According to NDP, existing supplies of Bakken crude currently do not have access to sufficient pipeline capacity beyond Clearbrook, Superior, and Chicago to reach downstream markets. NDP states that it was this lack of downstream pipeline facilities that led to rail service being used instead of the NDP. NDP claims that once various expansion projects for pipelines downstream of Sandpiper are completed, there will no longer be a constraint on NDP, and not only will it return

[32] NDP Petition, pages 13-14.

to full capacity, but there will be a clear need for the expanded capacity provided by the Sandpiper project.[33]

33. However, this explanation is contradicted by the explanation that Enbridge gave the Commission in 2013 when the shortfall in NDP throughput was being experienced. In response to a Complaint filed by St. Paul Refining regarding the Phase 6 surcharge for 2013 on the NDP, Enbridge explained the shortfall in throughput as follows:

> [The decline] occurred due to individual shippers' nominating decisions based on crude price differentials, over which Enbridge North Dakota has no control. When there is a large price differential between crude oil prices in the midcontinent area and prices in the coastal regions (as existed in 2012 and the first half of 2013), shippers have an incentive to transport crude by rail carrier to the higher value markets so long as the differential exceeds the rail transport cost.[34]

34. The Commission agreed with this assessment in its Decision, stating:

> […] the economics of crude price differentials dictate a shipper's choice of rail or pipeline transportation. When there is a large price differential between mid-continent and coastal markets, shippers will transport by rail to the higher value coastal markets as long as the price differential exceeds the cost of rail transport.[35]

35. Clearly whenever crude oil price differentials diverge by a significant amount NDP is and will be underutilized as shippers use rail service *notwithstanding any new downstream pipeline capacity*. Since, as Enbridge correctly stated, crude oil pricing differentials is something over which it has "no control," its construction of additional pipeline capacity in North Dakota to reach Superior and Chicago is a somewhat risky venture.

36. Moreover, the downstream pipeline projects that NDP believes will create a market for its expansion and extension projects are not connected to refineries on either the U.S. West Coast

---

[33] NDP Petition, page 14.
[34] Affidavit of Robert Steede, filed with the Motion to Dismiss and Answer of Enbridge Pipelines (North Dakota) LLC to Complaint of St. Paul Park Refining Co. LLC, OR13-28-000, August 14, 2013.
[35] *St. Paul Park Refining Co. LLC v. Enbridge Pipelines (North Dakota), LLC*, 145 FERC ¶ 61,050 (October 17, 2013).

or the U.S. East Coast which is where the crude oil price differentials widened sufficiently to make rail transport economic in 2012 and 2013. Therefore, there is no guarantee that these downstream projects will prevent these wide crude oil price differentials from reappearing in the future. Finally, these downstream projects are not yet completed, and there is no guarantee that they will all be completed. For these reasons, even if we were to assume that the downstream pipeline constraint argument offered by NDP were correct, there would still be no assurance that the downstream bottleneck would no longer constrain the NDP pipeline.

37. There also appears to be a real lack of genuine interest in the Sandpiper project. NDP states that there are 185 shippers on its pipeline system. However, according to the Petition, only 15 shippers were sufficiently interested in the open season to request further information. Presumably fewer shippers actually subscribed to committed capacity. Thus, only 8% of the shippers on the pipeline were sufficiently interested in the open season to request further information.

38. In addition to the evidence of excess capacity on the existing NDP pipeline system and the absence of strong shipper interest in the Sandpiper project, projections of Bakken production and the available transportation alternatives to ship crude oil out of North Dakota strongly suggest that there will be sufficient capacity to handle Bakken crude in the future without the Sandpiper project. The Declaration of Robert P. Garner of EnWest includes a chart of crude oil pipelines and crude oil rail transportation facilities in the Bakken area of North Dakota based on data compiled by the North Dakota Pipeline Authority. This chart indicates that by year end 2013, there was a total of 583,000 bpd of pipeline and refinery takeaway capacity from the Bakken. During that same 2013 period, there was 965,000 bpd of rail capacity and total take-away capacity was therefore 1,548,000 bpd. The North Dakota Pipeline Authority predicts that

by 2016, there will be a total of 943,000 bpd of pipeline and refinery takeaway capacity without the Sandpiper project. The chart also indicates that pipeline capacity will be expanded by another 80,000 bpd for an eventual total of 1,023,000 bpd of crude oil take away capacity. Rail capacity in 2016 is predicted to be 1,355,000 bpd. The total projected 2016 take-away capacity, not including the Sandpiper expansion, is therefore 2,298,000 bpd.

39. This transportation infrastructure is more than sufficient to handle current and projected Bakken production. There are widely varying estimates of expected production from the Bakken area. Stephen D. Crane, who is NDP's expert on crude oil production, projects a continued increase in annual production peaking at 1.38 million bpd in 2026. On the other hand, the Energy Information Administration (EIA) of the U.S. Department of Energy, projects that peak production will occur much earlier in 2021 at slightly less than 1 million bpd.[36] Whereas Mr. Crane projects total Bakken production between 2012 and 2041 to reach 11.1 billion barrels, EIA estimates that total production over that period will be 8.2 billion barrels, and this figure is actually higher than a recent projection by the U.S. Geological Survey[37] which indicates that total production over that period will be only 7.5 billion barrels.

40. If we were to rely on the USGS and EIA data, there is more than sufficient transportation and refining infrastructure to handle peak production in the Bakken. In fact by 2016 the data from the North Dakota Pipeline Authority suggests that there will almost be enough pipeline and refining capacity alone to handle peak production. If we were to include the potential expansion

---

[36] U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook, 2013, April 2013, www.eia.gov/forecasts/aeo. This forecast appears to exclude conventional production which is only 0.1% of total forecast production according to the USGS and therefore is immaterial.

[37] 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/.

capacity of the Plains Bakken North[38] and Hiland Partners Double H[39] pipelines in our assessment, then total pipeline and refinery takeaway capacity – not including any rail facilities – would be 1.023 million bpd which would be sufficient to handle Bakken production using the EIA and USGS estimates of production. Even using the higher production estimates of Mr. Crane, there would be more than sufficient capacity including some rail transport (approximately 400,000 bpd at peak) to meet peak production without the Sandpiper project.

41. The highly varying levels of projected peak production and its duration is certainly one reason that there has been limited interest by shippers in additional pipeline facilities in North Dakota. Over the last two years, two other pipeline projects have been announced and sought to gain acceptance through open seasons, but have failed to receive sufficient interest and subsequently have been abandoned. These projects include the ONEOK Bakken Crude Express pipeline which would have transported 200,000 b/d of Bakken crude to Cushing, OK.[40] And just recently, Koch Pipeline announced that it failed to receive sufficient interest in its proposed Dakota Express pipeline which would have moved 250,000 bpd of Bakken crude to Illinois.[41]

The Muse Report Does Not Provide Convincing Evidence That the Sandpiper Project Is Needed or That It Will Be Used.

---

[38] The Plains Wascana Pipeline is discussed on page 30 of the Muse report. As discussed below, Muse understates the potential capacity of this line.

[39] This pipeline is mentioned in footnote 25 of the Muse report. As I discuss below, Muse understates the project's capacity, which was given as far higher by the North Dakota Pipeline Authority and press materials. See "Hiland Partners Planning New Bakken Oil Pipeline: Potential Capacity of 100,000 b/d to Guernsey, WY," April 8, 2013: http://bakkenshale.com/pipeline-midstream-news/hiland-partners-planning-new-bakken-oilpipeline/.

[40] "Oneok Cancels Bakken Crude Express Pipeline, *Oil & Gas Journal*, November 27, 2012: http://www.ogj.com/articles/2012/11/oneok-cancels-bakken-crude-express-pipeline.html.

[41] "Crude Pipeline Wars in the Bakken," *RBN Energy*, February 25, 2014: http://www.ogfj.com/articles/2014/02/crude-pipeline-wars-in-the-bakken.html.

42. The NDP Petition relies heavily on the Muse report for the proposition that the Sandpiper project is needed, will be fully utilized, and will provide benefits to all, including existing shippers. The Muse report is based on proprietary information and data and therefore cannot be completely evaluated. However, based on the information that is provided, I believe that the Muse report suffers from a series of flaws and omissions that calls its conclusions into serious question.

43. 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,[42] 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.

44. The Muse report states[43] that it relied on the Crane forecast for Bakken production as well as for production in other parts of the United States, other than for the Gulf of Mexico. I discussed previously the fact that that the Crane forecast for the Bakken region is significantly higher than the EIA and USGS forecasts for the Bakken area. Since no information was provided for Crane's forecasts for other U.S. regions, we do not know whether they are similarly skewed and to what extent incorrect crude oil projection data might affect Muse's conclusions regarding demand for competing transportation resources.

[42] Muse report, pages 33-35.
[43] Muse report, page 35. Muse notes that it has extended these forecasts for the period 2026-2035, but again no information is provided on how such an extension was developed.

45. In addition, we do not know the assumed crude oil price forecast that underlies the Crane supply estimates. This factor too could have a significant impact on the model. For example, we cannot determine if the price forecasts used to generate the Crane supply estimates are consistent with the crude oil price results that come from the Muse model. However, this would be an important test we would want to perform to evaluate the internal reliability of the Muse model. If these price estimates were inconsistent, it would raise serious questions about the reliability of the Crane supply estimate, the Muse model or both.

46. It is, in fact, quite likely that the Muse model is very sensitive to assumed levels of crude oil production and supply in the Bakken region as well as throughout the U.S. Consequently, if either the EIA or USGS forecast for the Bakken were used in the Muse model in place of the Crane forecast, I would expect that the Muse model would show no need for the Sandpiper project and no consequent benefits for producers as a result of the construction of the Sandpiper expansion. But again, without access to the model and its inputs, neither I nor the Commission itself has any way of evaluating this alternative scenario.

47. There are still other problems with the Muse study. The Muse report did not consider all available options for consuming and transporting Bakken crude oil and has understated the capacity of those other options. By understating the capability of competing transportation and refining alternatives, it is very likely that the Muse model has been skewed to show greater benefits for the Sandpiper project than actually exist – even assuming that the production supply forecasts Muse uses are accurate.

48. For example, in discussing the potential refiners of Bakken crude oil, Muse has omitted two refineries that the North Dakota Pipeline Authority has listed as having capability to process North Dakota crude oil by 2015. These are the Dakota Prairie Refinery and the Dakota Oil

Processing Refinery. Each of these facilities has the capability of handling 20,000 bpd of Williston Basin crude oil. They were not considered by Muse, but are listed by the North Dakota Pipeline Authority as consumers of Williston Basin crude oil.[44]

49. The Muse report mentions the Hiland Partners Double H pipeline in a footnote[45] stating that it could add 46,000 bpd of additional capacity from Baker MT to Guernsey, WY. In fact the plans for this pipeline are for capacity to reach 100,000 bpd, not the 46,000 bpd assumed by Muse. Again this capacity is recognized by the North Dakota Pipeline Authority as well as trade press reports relating to the pipeline.[46] The Muse report also understates the potential capacity of the Plains Wascana Bakken North Pipeline which it states has a capacity of 50,000 bpd. The North Dakota Pipeline Authority states that this pipeline has the potential to reach 70,000 bpd capacity. These understatements of potential pipeline transportation capacity and refining consumption of Williston Basin crude represent almost half of the capacity of the Sandpiper expansion project.

50. The Muse report also understates the available rail capacity to handle Bakken crude oil. It states that in 2013 available rail capacity was 865,000 bpd when in fact the North Dakota Pipeline Authority shows that there was 965,000 bpd of rail capacity to handle Williston Basin crude oil. Furthermore, Muse states that it used a figure of 825,000 bpd of "effective rail capacity for Bakken crude" in its model for 2016 and beyond.[47] Muse does not define what it means by "effective capacity" although it claims that the capacity figure for rail makes no difference in the model because the model never uses more than that amount of current rail

[44] Garner Attachment A.
[45] Muse report, page 28, footnote 25.
[46] "Hiland Partners Planning New Bakken Oil Pipeline: Potential Capacity of 100,000 b/d to Guernsey, WY," April 8, 2013: http://bakkenshale.com/pipeline-midstream-news/hiland-partners-planning-new-bakken-oilpipeline/.
[47] Muse report, page 40.

capacity. However, the North Dakota Pipeline Authority shows that in 2016 there will be 1,355,000 bpd of rail capacity, a figure far higher than the amount that Muse assumes in its model.

51. The assumption that the Muse model never uses more rail capacity than is currently available also calls into question the assumptions underlying the model. The model appears to treat rail capacity as always being a "second best" alternative because of its higher cost. But, Muse does not appear to ever consider other factors that could make rail transportation preferable to pipeline transportation. As I discussed previously, changes in regional crude oil price differentials can and have altered the economics of rail vs. pipeline transportation for Bakken crude in recent years and could very well do so again in the future. In addition, it is important to take into account the fact that rail facilities enable shippers to reach some refineries that pipelines simply cannot and will not reach in the future. This is particularly true for West Coast and East Coast U.S. markets where crude price differentials have in the past made it economic to ship by rail and may continue to do so in the future.[48] It is also important for any assessment of supply and demand for transportation facilities to take into account the fact that some producers and shippers of Bakken crude have invested in rail facilities, and thus have a preference to use rail as opposed to paying the cost of a new pipeline. I therefore believe that the Muse approach is defective since it appears to have artificially constrained the model it is using by limiting future rail capacity to only 825,000 bpd when in fact actual rail capacity will be significantly greater in the future and there are a number of economic factors that could well result in further utilization of rail capacity.

[48] "Who Wants an Oil Pipeline?" *Wall Street Journal*, March 4, 2014, p. B1.

52. Finally, the Muse report provides an estimate of what it considers are the benefits to producers of the Sandpiper project as a result of receiving higher prices for Bakken crude. It claims that over the period 2016-2035, producers that use the expanded Sandpiper pipeline will receive on average $0.56 per barrel more for Bakken crude and that this differential translates into a "benefit" of slightly less than $5 billion. This "benefit" is grossly overstated for several reasons. First as the Muse report points out the benefited stated is a pre-tax figure. Second it is an undiscounted number and simply reflects the multiplication of the $0.56 per barrel figure by the roughly 8.67 billion barrels that will be produced over time.[49] To determine the economic value today we would have to discount this figure over the life of the project which reduces the value to about $1.4 billion and on after-tax basis to less than $1 billion.[50] Of course, these corrected figures still utilize what appear to be faulty and erroneous assumptions and inputs into the Muse model which have the effect of overstating any beneficial impact of the Sandpiper project.

53. Given these flaws and apparent errors in the Muse report, I do not believe that it should be relied upon as the basis for concluding that the Sandpiper project is needed or will confer benefits on Bakken producers or shippers. What is known is that uncommitted shippers will pay a much higher rate for transportation than they are currently paying and that there is no demonstrable need for the additional capacity the Sandpiper pipeline would provide. The existing pipeline has not been in continual prorationing and most shippers do not want or need this new pipeline. Moreover, other viable transportation options exist, and the project shifts virtually all of the throughput risk onto a group that has stated that it does not need or want to pay for the project – the uncommitted shippers. In my opinion existing shippers will not see any

[49] This is confirmed at page 11, footnote 10 to the Muse report.
[50] This calculation assumes a 12% discount rate and a 35% tax rate.

benefits from this new pipeline and should not be required to pay for it, let alone pay for what appears to be a highly disproportionate share of that new capacity.

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

March 13, 2014

ATTACHMENT A

Peter K. Ashton

Peter K. Ashton is a senior consultant with Premier Quantitative Consulting, Inc. and previously founded and was the president of Innovation & Information Consultants, Inc. Prior to founding Innovation & Information Consultants, Inc., Mr. Ashton was a senior consultant with Putnam, Hayes & Bartlett, Inc. and Charles River Associates Incorporated. He has directed major consulting projects for private clients as well as in the public sector. Mr. Ashton's primary fields of expertise are the economic analysis of energy industries, regulatory and transportation economics, valuation and transfer pricing issues. A sample of Mr. Ashton's work in these areas includes the following.

Regulatory Analysis, Expert Testimony and Litigation Support

- Mr. Ashton has assisted numerous ratepayers and ratepayer groups in various regulatory proceedings and investigations involving the analysis of revenue requirements, cost of service models, estimates of a reasonable rate of return, analysis of operating costs, cost allocation methods, functional analysis of costs and rate design methodologies.

- Mr. Ashton provided expert testimony before the Federal Regulatory commission (FERC) on various issues related to a refined products pipeline’s request for a rate increase in its regulated markets. Mr. Ashton analyzed the rate design methodology employed by the pipeline’s rate design expert and Mr. Ashton demonstrated how that rate design methodology led to cross subsidization between market-based rate destinations and regulated destinations. He quantified the magnitude of the cross subsidization, and offered an alternative approach to rate design that eliminated any subsidization. In addition, Mr. Ashton criticized the approach taken by the pipeline to transfer certain regulated assets to a non-regulated entity and the corresponding charge-back fee that was assessed by the non-regulated entity to the regulated entity. His testimony and advice to the client provided the basis for a successful settlement of the matter shortly prior to hearing.

- Mr. Ashton recently testified before the California Public Utilities Commission in a pipeline rate proceeding in which he computed the cost of service and just and reasonable rates for a crude oil pipeline that had recently been declared a common carrier. He developed a cost of service model and a fully allocated cost model to design rates for the pipeline. Mr. Ashton also developed a just and fair rate of return for the pipeline based on a proxy group analysis. He also critiqued the rate design model and the cost of service analysis of the opposing expert.

- He opined regarding the just and reasonable rates for a major refined products pipeline system in California before the California Public Utilities Commission in two separate proceedings. Mr. Ashton developed a cost of service model and projected future anticipated throughput as part of his rate analysis. He criticized the rate of return model used by the pipeline’s expert and showed that a reasonable rate of return was 250 basis points lower than claimed by the pipeline. He also demonstrated that the overhead cost allocation model used by the pipeline was flawed and led to subsidization between regulated and unregulated affiliates. Finally, he developed a rate design model and showed that just and reasonable rates should be 20-25% lower than what the pipeline was charging.

- Mr. Ashton testified before the Maine Public Utilities Commission regarding rate design, the functional allocation of costs and the cost of service for a utility that served both regulated and unregulated markets. Mr. Ashton demonstrated the existence of cross subsidization between the regulated and unregulated markets and the harm imposed on ratepayers.

- Mr. Ashton testified in a rate case before FERC involving the calculation of just and reasonable rates for an interstate common carrier refined products pipeline in the southwest. Mr. Ashton's analysis focused on determining the appropriate rate of return, analyzing the just and reasonable operating expenses of the pipeline including allocation of overhead expenses, and projecting throughput volumes on the pipeline taking into account the temporary impact of the economic recession on the demand for petroleum products. Mr. Ashton also provided rebuttal testimony on these issues, and provided assistance to attorneys in the cross examination of other expert witnesses.

- Mr. Ashton provided expert testimony before the Maine Public Utilities Commission regarding the rates charged by a regulated water transportation carrier who also provided unregulated service. He analyzed the regulated entity's revenue requirement and found that it was including costs for the regulated entity that should be allocated to the non-regulated subsidiary. He also testified that the entity's cost allocation model was flawed and the revenue and plant factors were skewed to allocate an unreasonable level of costs to the regulated entity.

- Mr. Ashton provided expert analyses regarding the FERC's policy regarding the calculation of the rate of return on equity for oil pipelines. He assisted in the development of various position papers, provided comments on the submissions of others and researched the impact of the proposed rule on oil pipeline ratemaking. He also analyzed the results of a similar proceeding held earlier by the National Energy Board and commented on the pros and cons of each proposed approach.

- He testified twice in U.S. Tax Court regarding the nature of the formula used to compute the Windfall Tax enacted by the U.K. government in 1997. The issue was whether the tax was imposed on the difference between two values for recently privatized companies, and as a result whether the tax constituted a tax on value not a tax on income. Mr. Ashton opined that the formula was indeed a valuation formula based on a market multiples or capitalized earnings valuation methodology and thus was a valuation tax not an income tax. He also testified regarding generally accepted valuation methodologies commonly used in the appraisal business.

- Mr. Ashton testified regarding the fair market value of various leasehold interests held by a major integrated oil and gas producer. He analyzed the value of certain leases in the Alaskan Outer Continental Shelf (OCS) area that had been purchased in the late 1980s. Based on his analysis, Mr. Ashton found that these leases no longer had any value as of 1992 as most other companies had relinquished their interests and all exploratory activity had ceased in this remote area. He also analyzed the cost to develop resources in this area, and demonstrated that it would take oil prices in excess of $125 per barrel to make these leases economic as of 1992.

- Mr. Ashton prepared an expert report and testified regarding the value of crude oil produced in the Gulf of Mexico, and evaluated the cost of transporting this crude oil to onshore marketing points. He evaluated the prices reported by producers of crude oil in this area, and reviewed various transactions relating to this crude oil to determine the market value of this crude oil. He developed estimate of damages in this matter as it relates to the proposer determination of the value of crude oil.

- Mr. Ashton has prepared expert reports and testified on numerous occasions in cases involving the computation of lost earnings, lost profits, and other economic losses associated with wrongful death, personal injury and a variety of breach of contract claims and other claims of business loss. He has estimated lost profits using various methods and he has also developed various models of earnings capacity in different professions. He has also commented on the expert reports of others and provided assistance in the analysis of such reports, including cross examination of opposing experts.

Public Policy and Tax Issues

- Coauthored a major study that examined the impact of antitrust enforcement activity relating to merger and acquisition activity on small businesses in several industries. Mr. Ashton utilized empirical data to analyze both pre- and post merger industry structure to assess the effects of divestiture and other enforcement actions, as well as situations in which no enforcement activity occurred. Major findings included the fact that enforcement activity had less of an impact than exogenous factors in changing market structure and performance.

- Mr. Ashton has performed a detailed analysis of the impacts of deepwater royalty relief on leasing, exploration and production in the Gulf of Mexico. This study involved the use of econometric models of MMS leasing behavior that analyzed the impacts of competition, royalty relief, changes in technology, movement in oil and gas prices and numerous other factors on lease bonus bids and the number of leases sold. Mr. Ashton also projected future impacts of various royalty relief scenarios on royalty and lease bonus revenue as well as impacts on future exploration, development and production of oil and gas resources in the Gulf of Mexico.

- Assisted various gasoline and heating oil dealers understand the causes for price volatility in the market, and the role that various factors including crude oil pricing, demand, speculation in futures trading, and other factors may have had on the increase in spot prices for these products at various points in time.

- For the U.S. Small Business Administration, Mr. Ashton directed a study that examined the differential impact of the trend toward electronic commerce and procurement by the federal government. The study concluded that small firms generally are less effective in taking advantage of e-business and e-procurement tools, although small firms are making improvements in their ability to attract business via the web.

- Mr. Ashton has analyzed various cost sharing agreements in the pharmaceutical and medical products industries and associated buy-in and buy-out payments for the transfer of intellectual property related to these agreements. Mr. Ashton has valued the intangible property under these agreements and estimating the reasonably anticipated benefits accruing from such intangibles. He has computed running royalty payments and lump sum payments as compensation for the buy-in and buy-out payments.

- Mr. Ashton completed an expert report valuing various intangible assets transferred by a domestic parent to various foreign corporations for purposes of developing an appropriate arm's length royalty rate consistent with the Section 482 transfer pricing regulations. He examined the relative profitability contributed by these intangible assets domestically and also applied a CPM approach to the application of the intangibles in various foreign markets. He also reviewed and assessed the Section 6662 transfer pricing report of the taxpayer.

- He analyzed the fair market value of the worldwide assets of a major multinational company for purposes of determining an appropriate method and basis for allocating interest expense under Section 861 of the IRS regulations. Mr. Ashton has provided expert advice to the Treasury Department on this issue, pointing out the need for consistency with the relevant regulations and use of appropriate valuation methods.

- Prepared expert analyses computing an arm's length royalty consistent with Section 482 of the IRS regulations for various intangible assets transferred under a licensing agreement between a domestic parent and a foreign subsidiary. The work involved estimating the value of the technology being transferred and determination of an appropriate royalty rate.

- Analyzed the impact of various tax expenditure programs on small and large firms. Mr. Ashton utilized detailed data from the Treasury to assess the impact on effective tax rates of various programs such as foreign tax credits, low income housing credit, accelerated depreciation, and the business means and entertainment tax deduction.

Business Strategy Studies

- For an oil producer, Mr. Ashton evaluated a proposed sliding scale royalty agreement for leasehold interests that were pegged to future oil prices. Mr. Ashton analyzed the most likely royalty payment under the proposed scheme given information on projections of crude oil prices, inflation and production costs over the next ten years. He analyzed alternatives to the proposed royalty schedule and quantified the effect of these alternatives on the estimated royalty payments.

- Prepared a detailed study of crude oil marketing in the United States and changes which have occurred in the manner in which crude oil is bought, sold, and traded over the last twenty years. Examined the manner in which crude oil is shipped throughout the country, and the impact of transportation alternatives on marketing options. Also compiled a large database on spot and other relevant crude oil prices and data on quality adjustment factors for use in evaluating various crude oils. Provided supplemental analyses regarding specific market areas in the United States including the Rocky Mountain producing area.

- Mr. Ashton completed a forecast of supply and demand factors influencing future oil and gas development and production activity in the Rocky Mountain states. This work included an analysis of the demand and supply for crude oil and refined products in the Rocky Mountain states, including imports of refined products from states outside the area. He also examined the role of Canadian imports into the Rocky Mountain area and projected the demand for such imports over the next 40 years.

Mr. Ashton received an A.B. degree in Economics and Political Science from Colby College (*magna cum laude* and *Phi Beta Kappa*) in 1976, and received an M.I.A. degree in International Economics and Business from the School of International Affairs at Columbia University in 1978.

Publications and Speeches (Last 10 Years)

Modeling Exploration, Development and Production in the Gulf of Mexico, U.S. Department of Interior, Minerals Management Service, Environmental Studies Program, Herndon, VA, OCS Study MMS 2—4-018, March 2004.

The Impact of Tax Expenditure Policies on Incorporated Small Businesses, with Justin White, U.S. Small Business Administration, Office of Advocacy, Washington, D.C., April 2004.

Trends in Electronic Procurement and E-Commerce and Their Impact on Small Business, with Mary Ann Buescher, U.S. Small Business Administration, Office of Advocacy, Washington, D.C., June 2004.

Report on Gasoline Pricing in Florida, with Dr. Keith Leffler, prepared for the Office of the Attorney General, State of Florida, June 2005.

Effects of Royalty Incentives for Gulf of Mexico Oil and Gas Leases, U.S. Department of Interior, Minerals Management Service, Economics Division, Herndon, VA, OCS Study MMS 2004-077, September 2005.

An Empirical Approach to Characterize Rural Small Business Growth and Profitability, with Lee O. Upton and Meghan Overom, U.S. Small Business Administration, Office of Advocacy, Washington, D.C. December 2005.

Analyzing the Impact of Antitrust on Small Business, with Lee O. Upton, U.S. Small Business Administration, Office of Advocacy, Washington, D.C., April 2008.

"The Crude Oil Price Bubble of 2008: The Role of Speculators and Devalued Dollars," with Meghan O. Law, IIC, Inc. Working Paper, 2009; updated 2011.

Testimony (Last 4 Years)

Application of San Pablo Bay Pipeline Company, LLC for Approval of Tariffs for the San Joaquin Valley Pipeline, A.08-09-024 et al., prepared answering testimony, filed December 2009; reply testimony, filed March 2010; trial testimony, May 2010.

Application of SFPP, L.P., A.09-05-014 and A.08-06-008, prepared answering testimony, filed December 2009.

Enbridge Pipeline's Application for Approval of Incentive Toll Principles of Settlement for the Year 2010 and Final 2010 Tolls and Tariffs for the Enbridge Mainline System, in the Matter of Hearing Order RH-2-2010, Sworn Affidavit and Prepared Written Testimony, August and September 2010.

James B. Crook v. Hawk Scallop, Inc., C.A. No. 09-10682-RWZ, Expert report, August 2010, and trial testimony, January 2011.

Mark Henderson v. Atlantic Pelagic Seafood, LLC, CV-00068-DBH, Expert report, January 2011, trial testimony, February 2011.

Commonwealth of Kentucky v. Marathon Petroleum Corporation et al., Sworn affidavits and oral testimony in a matter relating to Motion for Temporary Injunction in Civil Action No. 07-CI-00751, May 2011.

Alan D. Katz vs. Spirit Cruises, LLC, C.A. No. 2009-1372-E, Expert report, June 2011, and trial testimony, January 2012.

Alfred Zarthar v. Ronald Consentino, C.A. No. 10-00813, et al., Expert report, December 2009; trial testimony, June 2012.

Enterprise TE Products Pipeline, Docket No. IS12-203-000, Answering testimony, October 2012; cross-answering testimony, November 2012.

Application of SFPP, L.P. to Change Rates for Pipeline Transportation Service, A.12-01-015, Direct testimony, November 2012, Reply and Supplemental Reply testimony, February 2013, and Rebuttal testimony, April 2013.

Pramer Oyster Company, Inc., et al. v. Patriot Marine et al., Expert report, May 2013; deposition testimony, June 2013.

Document Content(s)