UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATION COMMISSION

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

PROTEST OF ST. PAUL PARK REFINING CO. LLC

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March 14, 2014

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATION COMMISSION

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

PROTEST OF ST. PAUL PARK REFINING CO. LLC

1. Pursuant to Rule 211 and to the Notice of Petition for Declaratory Order issued herein on February 19, 2014, St. Paul Park Refining Co. LLC ("SPPRC") hereby protests the petition for declaratory order ("Petition") filed herein by North Dakota Pipeline Company LLC ("NDP") on February 12, 2014. The petition of NDP seeks certain advance rulings on the rate treatment for a proposed expansion and extension of its pipeline system known as the "Sandpiper Project." The proposed project would include a new pipeline installed alongside the existing NDP pipeline from Beaver Lodge, ND to Clearbrook, MN. Petition at 14-16. NDP proposes to recover the cost of the new parallel pipeline by charging uncommitted shippers to Clearbrook and beyond a surcharge styled as an "Expansion Rate Component." Petition at 28-29.

2. SPPRC protests NDP's request for approval of the proposed Expansion Rate Component to be imposed on shippers, such as SPPRC, which take delivery at the Clearbrook destination point. Contrary to the Petition, this Protest demonstrates that the proposed expansion pipeline and expansion surcharge (a) are not needed, (b) do not have broad shipper support, (c) will provide no benefit to shippers taking delivery at Clearbrook, and (d) are not based on any intelligible cost allocation or rate design. Accordingly, the Commission should deny the Petition. If the Petition is not denied, the

Commission should refer the Petition to an Administrative Law Judge for discovery and hearing.

The Petition of NDP

3. According to NDP, the current pipeline from Beaver Lodge to Clearbrook has a capacity of 210,000 bpd, but has been curtailed temporarily to 170,000 bpd by a pipeline integrity program. Petition at 12. The new parallel pipeline to Clearbrook would add 230,000 bpd so that the combined pipeline system would have a capacity of 440,000 bpd. Petition at 15. The proposed Expansion Rate Component would be designed to recover the cost of service of the new pipeline at the time of start-up, calculated pursuant to the Commission's Opinion No. 154-B methodology and using design capacity as the initial throughput assumption.

4. NDP states that it conducted an open season through which it obtained Transportation Services Agreements ("TSAs") containing ship-or-pay commitments for 155,000 bpd. Those commitments represent 35 percent of the new combined pipeline capacity to Clearbrook. Petition at 23. NDP acknowledges that the "anchor shipper" for the project is Marathon Petroleum Corporation ("Marathon"), which is also a part-owner of NDP through a subsidiary company. *Id*. NDP does not disclose the volume commitment contained in the TSA executed by Marathon.

5. NDP's claim that the Sandpiper Project is needed is based on a study by Muse Stancil & Co. ("Muse") entitled "Market Prospects and Benefits Analysis for the Sandpiper Project" dated February 2014 ("Muse study"). The Muse study purports to show that the expanded pipeline system would operate at capacity during its entire useful

life. Petition at 18-22. NDP relies on the Muse study, and on its claim that the existing pipeline is subject to prorationing, as a basis for requiring existing shippers to pay an expansion surcharge designed to recover the cost of the new pipeline.

Motion of SPPRC to Intervene

6. On March 4, 2014, SPPRC filed a timely motion to intervene in this proceeding pursuant to Rule 214 and 18 C.F.R. § 343.2(a). SPPRC is a captive uncommitted shipper of crude oil to the Clearbrook destination on NDP's existing system and would be a captive uncommitted shipper of crude oil to Clearbrook on the proposed expansion system. Thus, SPPRC would be subject to the expansion surcharge proposed by NDP if the surcharge is approved by the Commission. Accordingly, SPPRC has an interest as a customer which may be directed affected by the outcome of this proceeding. *See* Rule 214(b)(2)(ii)(B). The position of SPPRC, and the basis in fact for that position, are set forth in the prior motion of SPPRC to intervene and in this Protest.

Lack of Shipper Support or Benefits

7. SPPRC questions NDP's claim that the proposed expansion has received widespread shipper support. Petition at 24-25. NDP concedes that the "anchor shipper" for the project is Marathon Petroleum Corporation ("Marathon"), which is a part-owner in NDP through a subsidiary company. Petition at 23, n.27. NDP does not disclose how much of the 155,000 bpd in committed contract volume is accounted for by Marathon, nor does NDP indicate the extent to which other committed shippers are affiliated with NDP or Marathon. Thus, discovery is needed to determine the actual level of independent shipper support for the proposed expansion.

8. As a regular uncommitted shipper to Clearbrook, SPPRC has no reason to support the proposed expansion. As explained below, SPPRC does not believe the expansion pipeline proposed by NDP is necessary or desirable to meet the transportation needs of SPPRC. SPPRC has not suffered from chronic prorationing on the NDP system, and SPPRC has seen no operational evidence that the system is subject to persistent excess demand.

9. Contrary to the Petition, imposition of the proposed expansion surcharge on existing uncommitted shippers is not supported by the Commission's prior decisions in *Colonial Pipeline Co.*, 116 FERC ¶ 61,078 (2006), *order denying reh'g*, 119 FERC ¶ 61,183 (2007) or *Calnev Pipe Line LLC*, 120 FERC ¶ 61,073 (2007). In both those cases, there were undisputed constraints on existing capacity and there was universal agreement that the expansion capacity was needed. In this case, there is evidence that the prior congestion on the NDP system has been relieved and that the system has recently operated well below capacity. Here, unlike the *Colonial* and *Calnev* cases, SPPRC and other shipper parties have expressed serious doubts that the proposed expansion pipeline is needed.

10. Moreover, the purported shipper benefits cited by NDP have no value to SPPRC. The proposed expansion surcharge will require SPPRC to pay a higher transportation cost for the level of service it currently receives, while SPPRC is entirely satisfied with its current level of service. Nor will SPPRC benefit from the increased price of Bakken crude oil which NDP predicts as a result of the expansion. To the extent that the expansion causes an increase in the price of Bakken crude oil, the effect will be

to increase the feedstock acquisition cost of the SPPRC refinery served by NDP, which will in turn increase the refined product prices paid by the customers of SPPRC. Any such crude oil price increase will harm, not benefit, the business of SPPRC and its customers.

11. Indeed, NDP's Petition acknowledges that the proposed expansion pipeline is not designed or intended to benefit shippers to Clearbrook. The Petition concedes that the existing system did not operate at capacity in 2013, but claims that new pipeline projects downstream from Superior will create strong demand for the expanded upstream NDP system. Petition at 14. This confirms that the expansion pipeline is designed to benefit and will benefit shippers to destinations downstream from Superior, not shippers, such as SPPRC, which use the existing system to reach Clearbrook. Thus, NDP is proposing to collect a surcharge from upstream Clearbrook shippers to pay for an expansion designed to benefit shippers to downstream destinations.

Limited Prorationing

12. As mentioned above, SPPRC has not experienced any chronic prorationing on the NDP system, and SPPRC has seen no operational evidence that the system is subject to persistent excess demand. On the contrary, the recent instances of prorationing experienced by SPPRC have involved specific segments and have been temporary and transitory in nature. SPPRC has not incurred the type of sustained curtailment which could justify a major expansion. Discovery is needed to establish the extent to which prorationing is, or is not, a sustained problem on the NDP system.

13. In his attached Affidavit, Mr. Justin Amoah disputes NDP's claim that demand for space on its system has consistently outstripped available capacity. Petition at 12. Mr. Amoah explains that, 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. Amoah Affidavit at P 9.

14. Mr. Amoah also points out that 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 was less than three percent of its 145,000 bpd capacity. The management of BPEP reported that its capacity "was not well utilized in 2013." Amoah Affidavit at P 10.

Unexplained Cost Allocation and Rate Design

15. The Petition does not explain which costs will support the committed rates and which costs will support the uncommitted rates and the expansion surcharge. In this regard, the Petition merely states that uncommitted shippers will have no responsibility for the cost of the portion of the pipeline used to transport committed volumes, and that NDP will deduct $7.5 million from the cost of service for the upstream facilities in recognition of the premium paid by priority committed shippers. Petition at 42. The Petition provides no economic or regulatory basis for the amount of the cost-of-service deduction. Thus, discovery is needed to provide an understanding of the basis for the

proposed $7.5 million deduction and the proposed allocation of costs between the committed and uncommitted rates.

16. NDP claims that uncommitted shippers will be protected against the risk that the expansion pipeline will be underutilized because NDP will use full capacity as the design throughput volume in calculating the initial Expansion Rate Component. Petition at 28-29. However, NDP reserves the ability to change the surcharge by any of the Commission's ratemaking methodologies, which presumably would include cost-of-service ratemaking pursuant to 18 C.F.R. §§ 346.1, *et seq*. Petition at 26, n.30. That option could allow NDP to increase the expansion surcharge to account for a shortfall in actual throughput volume, which would place the impact of underutilization squarely on the uncommitted shippers. Thus, if the Commission allows NDP to impose the expansion surcharge, the Commission should require NDP to use full capacity as the design throughput volume in calculating any future change in the initial Expansion Rate Component.

Errors in the Muse Study

17. In his attached Affidavit, Mr. Amoah concludes that the Muse study is a highly questionable attempt to overcome the simple fact that there is and will continue to be adequate takeaway serving the Williston Basin for the foreseeable future. Amoah Affidavit at P 3. Mr. Amoah provides a detailed table showing 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. Amoah Affidavit at P 3.

18. Mr. Amoah further explains that the Muse study, in attempting to dismiss the excess capacity serving the Williston Basin, relies on a highly speculative prediction that shippers will shift away from rail transportation to Sandpiper. Amoah Affidavit at P 4; 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. An affiliate of NDP has also invested in an 80,000 bpd rail facility that allows crude oil volumes to reach the "premium markets" the Muse study contends will be served by Sandpiper. Amoah Affidavit at P 4. 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 TSAs.

19. The Muse study contends that Sandpiper would allow shippers to reach "premium markets" for light sweet crude oil. Muse study at 11. However, Mr. Amoah points out that 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. Amoah Affidavit at P 5. In fact, 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. Amoah Affidavit at P 6.

20. Furthermore, Mr. Amoah notes that the Muse study admittedly does not consider or 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; Amoah Affidavit at P 7. 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. Amoah Affidavit at P 7.

21. Finally, the Muse study uses estimates for rail freight rates that may not be accurate. Mr. Amoah points out that 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. Amoah Affidavit at P 8. 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. *Id.*

Deficiencies in the Muse Study

22. In addition to the errors identified by Mr. Amoah, the attached expert affidavit of Dr. Daniel S. Arthur identifies deficiencies in the Muse study which undermine the credibility of its conclusion that the Sandpiper Project would be fully utilized. Dr. Arthur finds that the Muse study fails to provide information to support several assumptions which have a material impact on the analysis and conclusions in the study. These unsupported assumptions include 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 value inputs to the Muse model. Arthur Affidavit at PP 8-12.

23. Dr. Arthur also finds that the Muse study provides incomplete information regarding the capacities and prices of transportation alternatives and the capacities of refineries. He observes that the Muse study apparently assumes that the transportation and refinery capacities that are known today, as well as several transportation projects expected to be in service over the period 2014-2020, will be the capacities that persist over the period 2016-2035. Dr. Arthur finds it more reasonable to expect that there will be changes in transportation and refining capacities in response to changes in crude oil production volumes in various basins, including the Bakken region and other production basins in North America. Arthur Affidavit at PP 13-15.

24. Finally, Dr. Arthur sees no indication that the Muse study factored into its analysis any potential alternative scenarios other than its set of baseline assumptions with and without the Sandpiper Project. He notes that alternative scenarios would provide

information on whether the Muse study's conclusion that the expanded NDP system after the Sandpiper Project would be operating at or near capacity for the forecast period 2016-2035 is robust under alternative scenarios, or whether other plausible scenarios exist whereby the expanded NDP system may not operate at full capacity over that period. Arthur Affidavit at P 16.

25. Dr. Arthur concludes that the deficiencies in the Muse study undermine the credibility of its conclusion that the expanded NDP system will operate at or near capacity for the forecast period 2016-2035. He observes that it is not possible, in the brief period of time available to respond to the petition of NDP for a declaratory order, to perform a more complete or thorough analysis. However, Dr. Arthur identifies several categories of information regarding the inputs, assumptions, and optimization model used in the Muse study which are needed in order for the validity of the study to be intelligently evaluated. Arthur Affidavit at P 17.

Need for Discovery and Hearing

26. If the Commission does not deny the Petition, it should refer the Petition to an Administrative Law Judge for discovery and hearing. The Muse study purports to justify NDP's claim that there is a pressing need for new takeaway capacity out of the Bakken. However, as demonstrated herein, the Muse study is based on questionable, unsupported, and unverifiable assumptions. Discovery and hearing are therefore necessary for the Commission to resolve the issues of fact created by the Muse study. As the Commission recognized in *Express*, discovery is appropriate in a declaratory order

proceeding to resolve disputed issues of fact that cannot be resolved on the basis of pleadings alone. *Express Pipeline Partnership*, 76 FERC ¶ 61,245, 62,253 (1996).

27. In addition, there are material issues of fact regarding the extent of prorationing on the NDP system. The Petition claims that prorationing has been persistent and that there is growing demand for capacity. Petition at 11-14. This Protest, and the Affidavit of Mr. Amoah, indicate that recent prorationing has been intermittent and that there is no evidence of excess demand for capacity on the NDP system. Amoah Affidavit at PP 9-10. Information regarding recent system-wide prorationing, which is within the possession of NDP, is needed to resolve this factual issue.

28. There is also a material factual issue regarding the level of independent shipper support for the proposed expansion. NDP acknowledges that part-owner Marathon accounts for an undisclosed portion of the 155,000 bpd in TSA commitments. Only NDP has the information necessary to determine the extent to which the 155,000 bpd in TSA commitments is by NDP affiliates or by independent shippers. Discovery is needed to obtain the pertinent information.

29. The Commission's procedural rules expressly contemplate that protests against petitions may be set for hearing. Rule 211(a)(1) provides that any person may file a protest against any petition. Rule 211(a)(3) provides that the Commission will consider protests in determining further appropriate action. Rule 211(a)(4) specifies that a protest is not part of the decisional record where a proceeding is set for hearing.

30. Thus, there are multiple disputed issues of material fact in this case which warrant denial of the Petition or require discovery and hearing. To summarize, those disputed factual issues include:

a. Whether there is a need for additional takeaway capacity to serve the Williston Basin in the foreseeable future.

b. Whether prorationing on NDP has been persistent or intermittent in the recent past or can be expected to be persistent or intermittent in the foreseeable future.

c. Whether Sandpiper can be expected to operate at full capacity over its useful life as predicted by the Muse study.

d. Whether current rail shippers can reasonably be expected to shift to Sandpiper as predicted by the Muse study.

e. Whether shippers which take delivery a Clearbrook will actually benefit from the proposed expansion pipeline.

f. Whether there is broad independent shipper support for the expansion pipeline.

g. What is the proposed basis for allocating costs between the committed and uncommitted rates and does that basis constitute a reasonable rate design?

h. What design throughput volume does NDP propose to use in calculating future changes in the Expansion Rate Component and will that rate design protect uncommitted shippers from the risk of underutilization?

31. In addition, Dr. Arthur identifies several basic categories of missing or incomplete information which are required in order for the validity of the Muse study to be intelligently evaluated. Arthur Affidavit at P 17. Those basic information requirements include:

a. Complete information on assumptions made regarding inputs to the optimization model.

b. Complete information on outputs of the optimization model, including information on estimated transportation flows and the shadow price of crude oil in the producing basins predicted by the optimization model.

c. A description of Muse's process for validating the results of the optimization model, together with related documents.

d. A working version of the 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.

Conclusion

32. For the foregoing reasons, the Commission should deny the Petition. If the Petition is not denied, the Commission should refer the Petition to an Administrative Law Judge for discovery and hearing.

Respectfully submitted,

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/s/Marcus W. Sisk, Jr.
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Attorneys for St. Paul Park Refining Co. LLC

March 14, 2014

CERTIFICATE OF SERVICE

I hereby certify that I have this 14th day of March, 2014, served the foregoing Protest of St. Paul Park Refining Co. LLC by email on each person designated on the official service list compiled by the Secretary of the Commission in this proceeding.

/s/ Frederick G. Jauss IV
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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

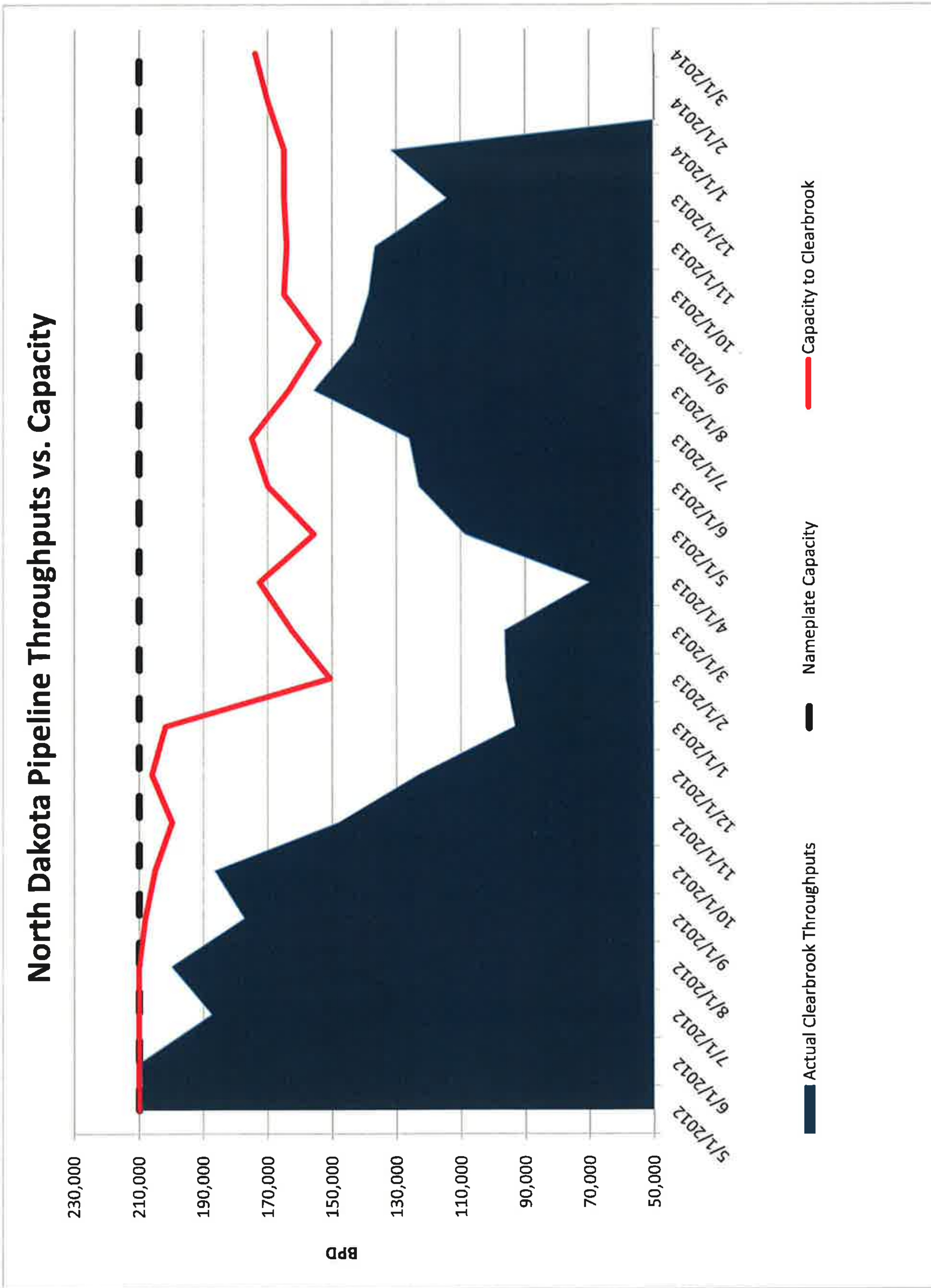
My commission expires: 10/7/15

EXHIBIT A

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**

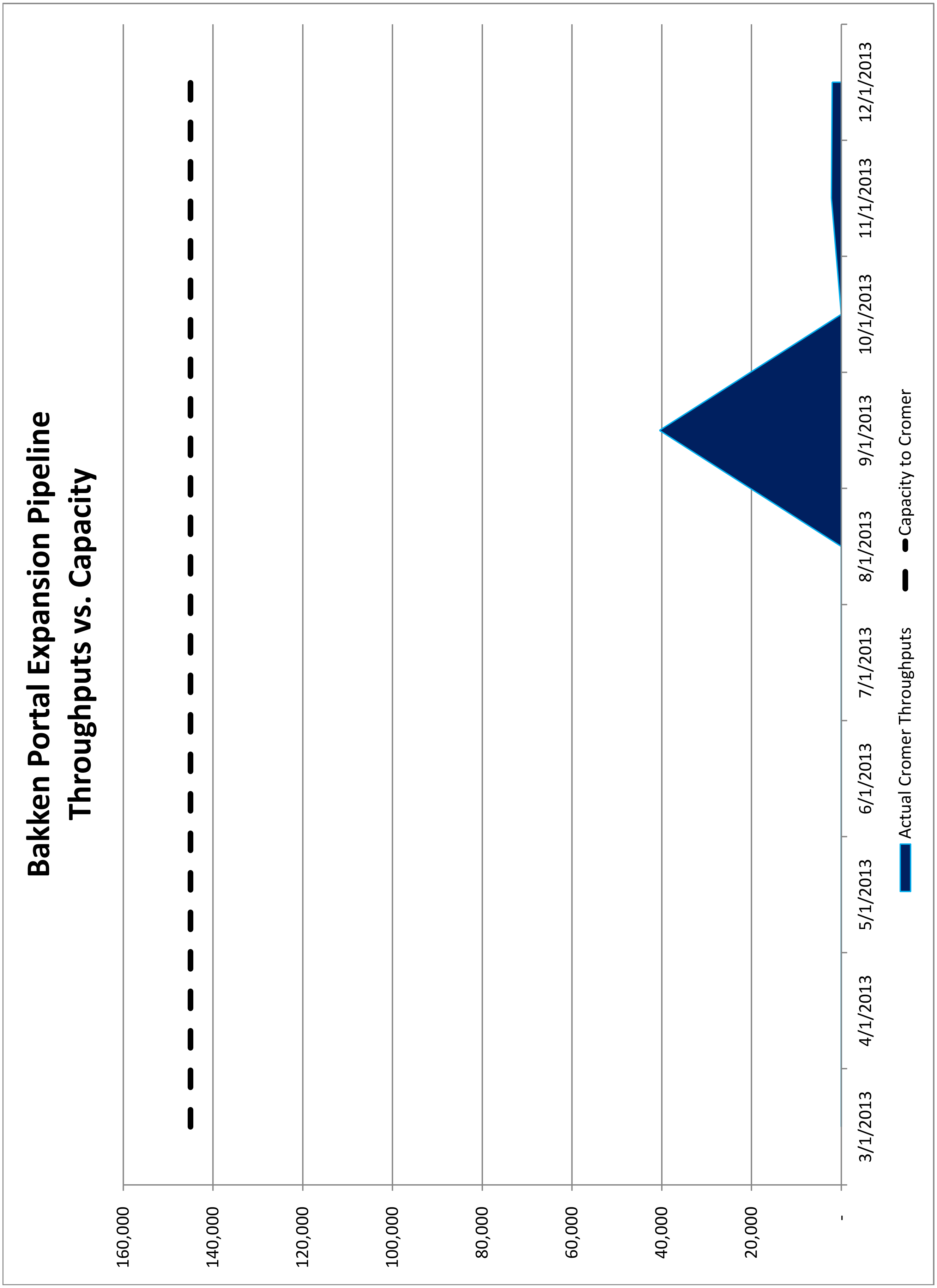
EXHIBIT B


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

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

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

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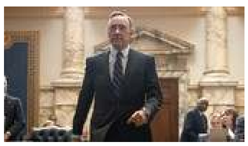

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HESS CORPORATION

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

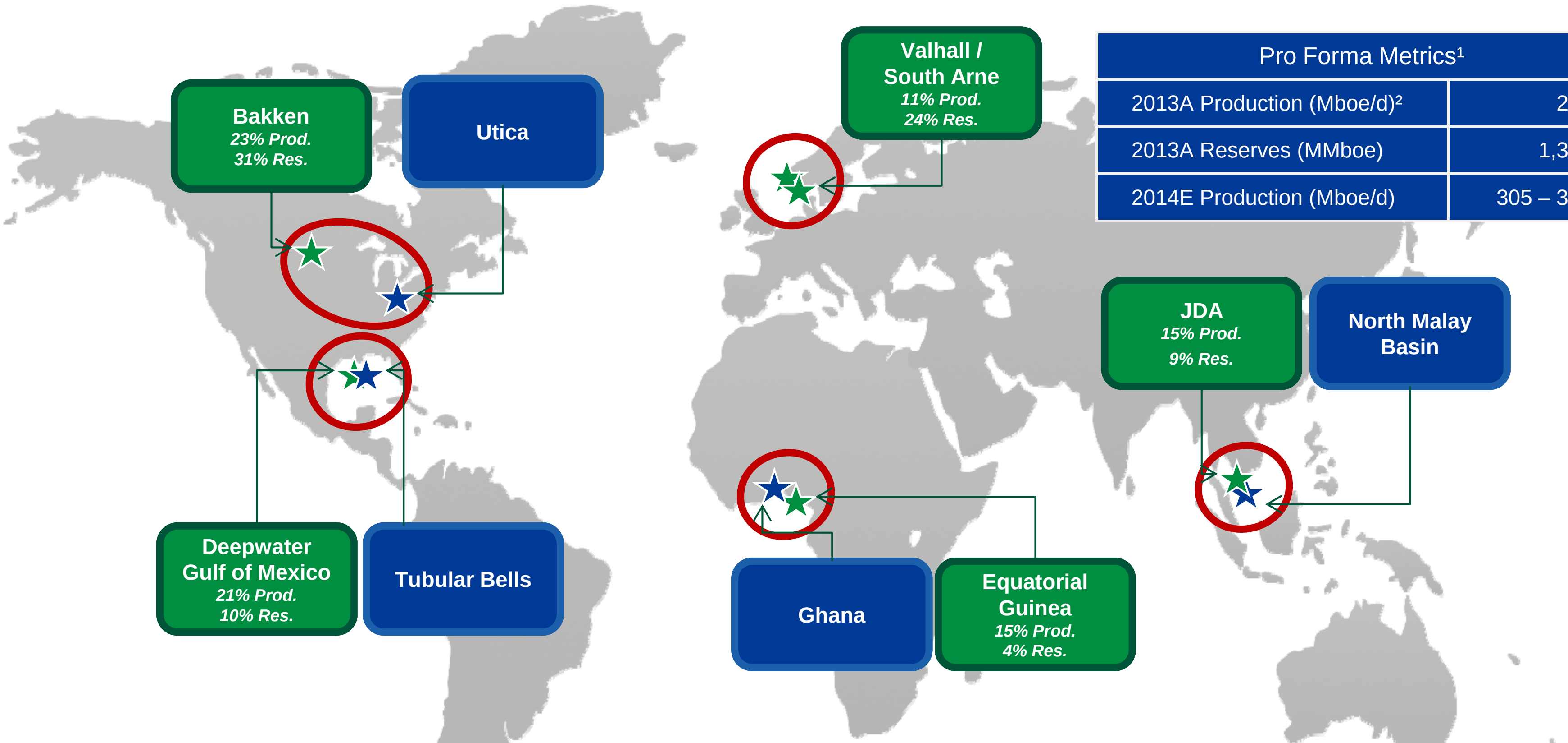
Progress on Divestitures Announced in 2013

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

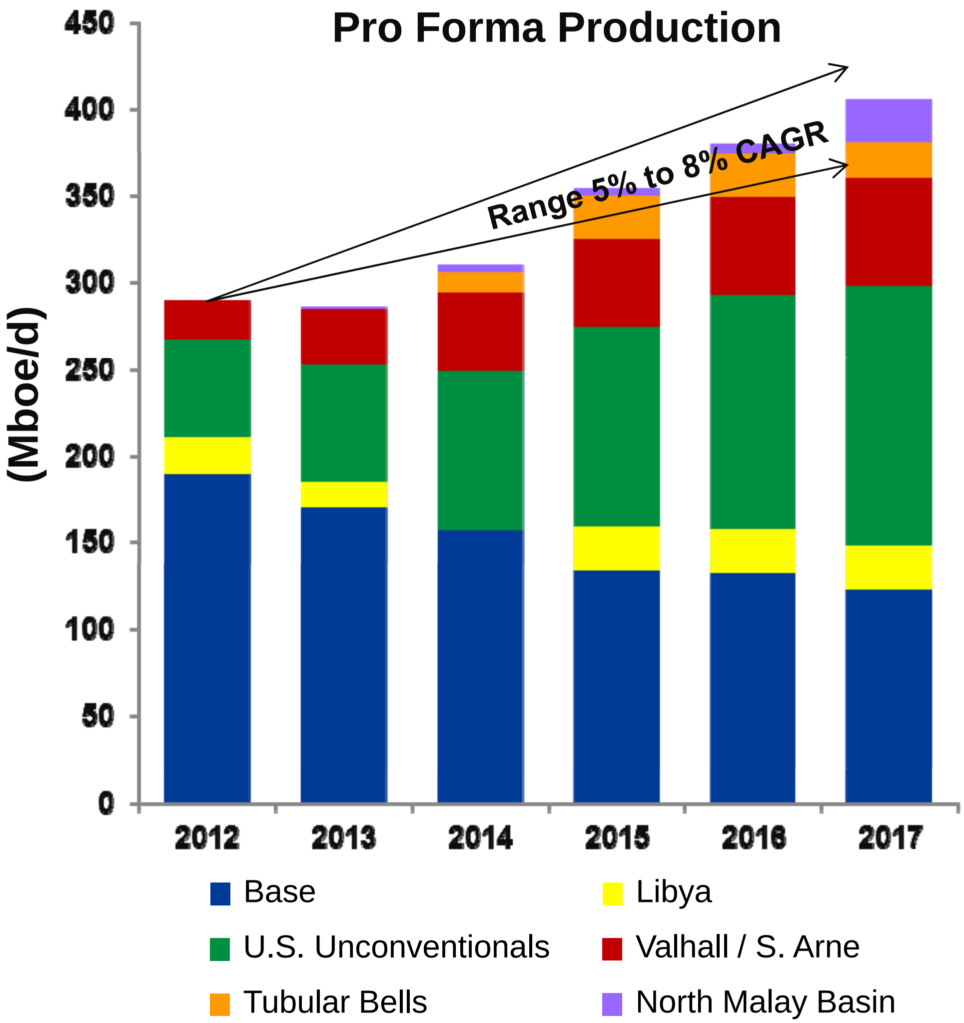
[1] Beryl area, Azerbaijan assets, Eagle Ford, Russia subsidiary (Samara Nafta), Indonesia and Thailand assets assumed sold as of January 1, 2013.
[2] Actual 2013 production includes Libya (15 Mboe/d); 2014 production guidance excludes Libya

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

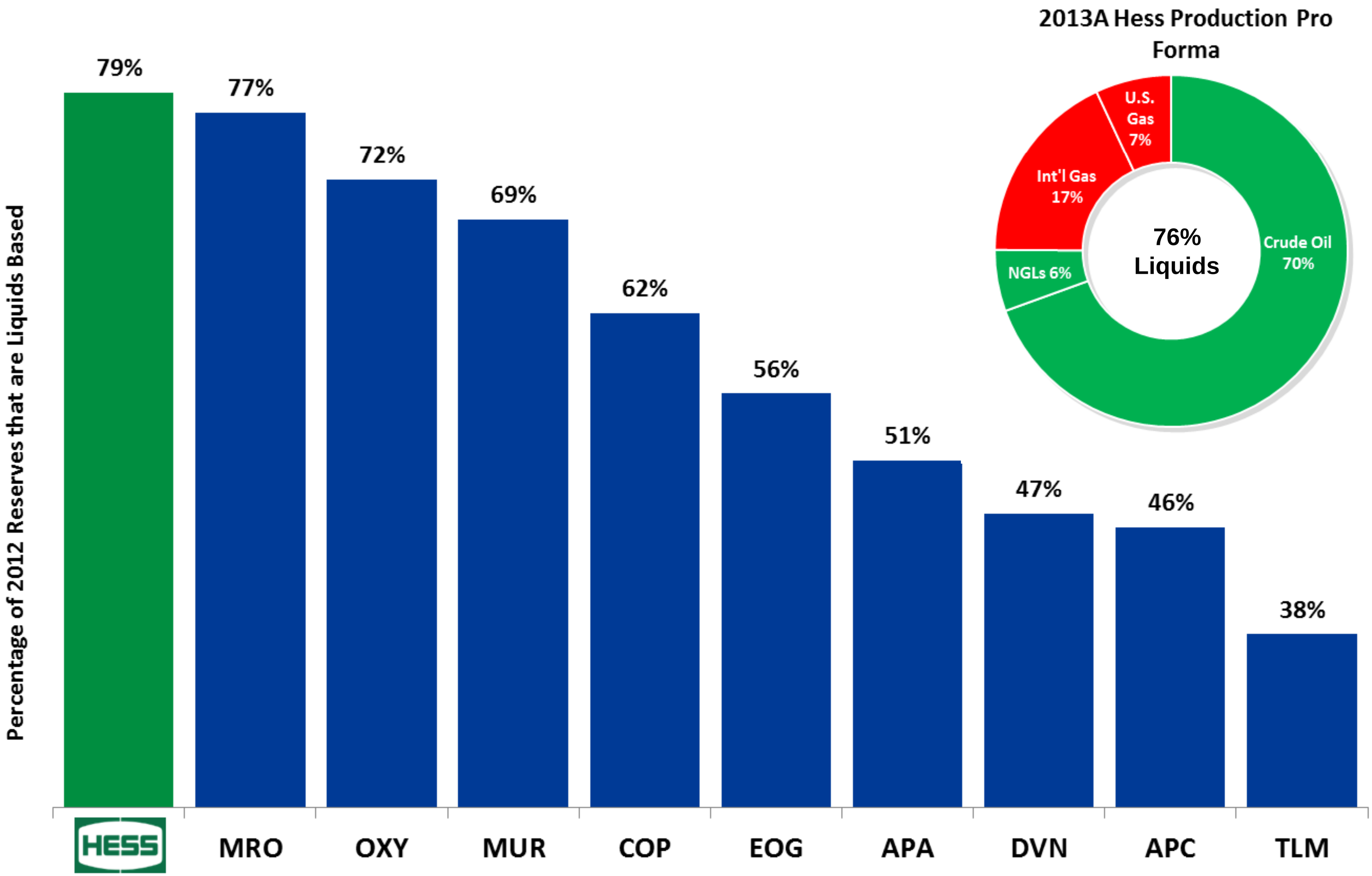
Exploitation
- High return infill drilling opportunities
- Tubular Bells first oil in 3Q14
- North Malay Basin early production commenced 4Q13; full field in 2017

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.

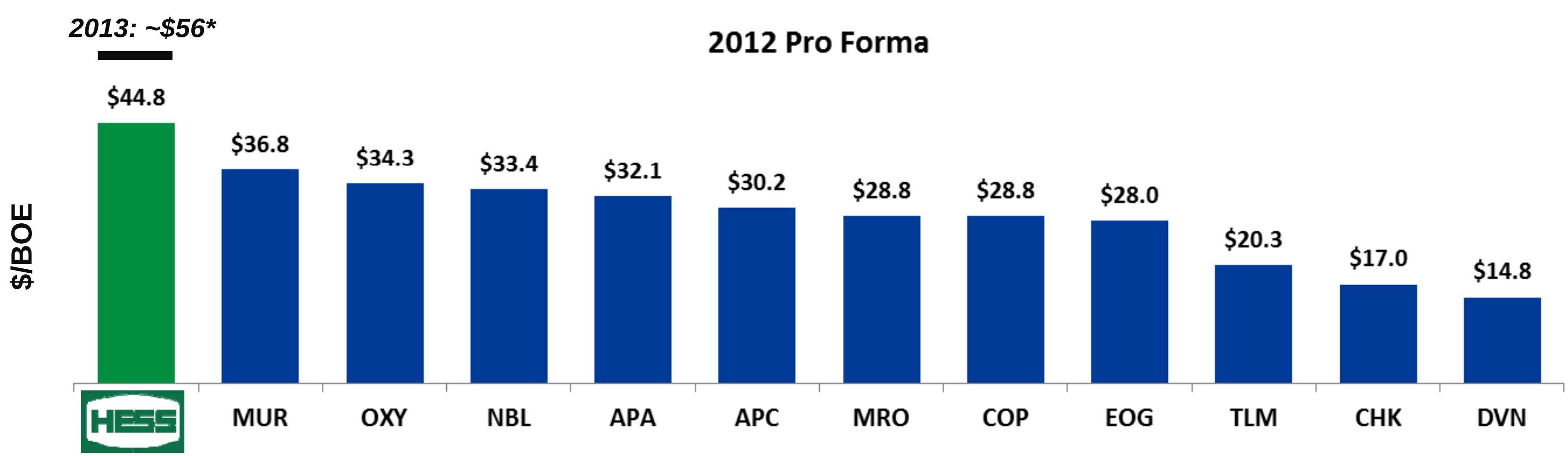
Leading Oil-Linked Asset Base



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

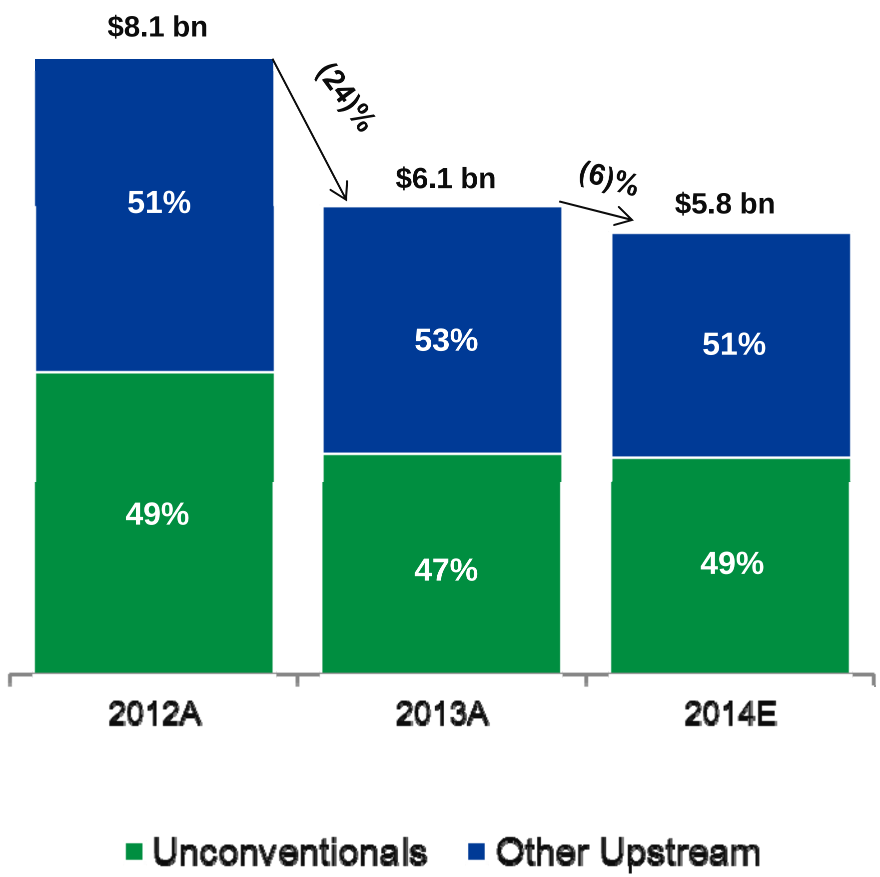
Hess 2012 cash margin is pro forma for asset sales. Actual cash margin was $40.3; Five-year data are actual

Source: Evaluate Energy, including hedges and oil sands; excluding specials

Enhanced Financial Flexibility and Providing Current Returns to Shareholders

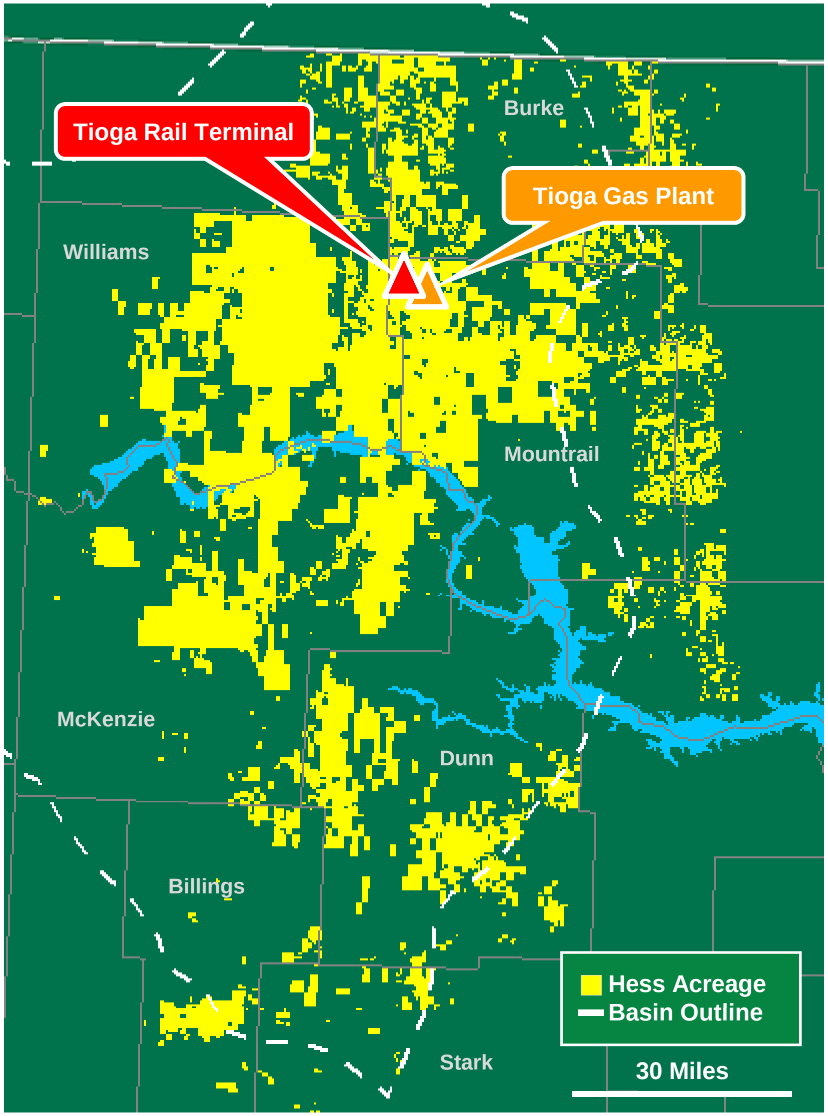
- **Financial Flexibility to Fund Future Growth**
  - Paid down $2.4 billion of short term debt with initial divestiture proceeds
  - Increasing cash balance by $1 billion
- **Portfolio Free Cash Flow Positive Post 2014**
  - Substantial reductions in capital and exploratory expenditures
  - $150 million 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

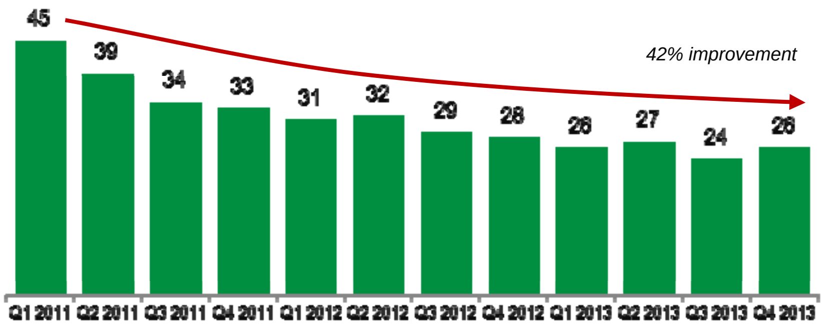
▪ Asset Details

- 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

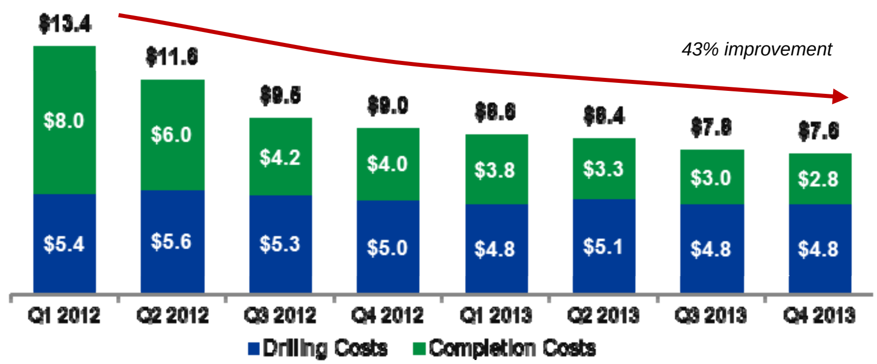
Driving Performance in the Bakken

Reducing Well Costs…

Drilling Performance: Spud-to-Spud Days

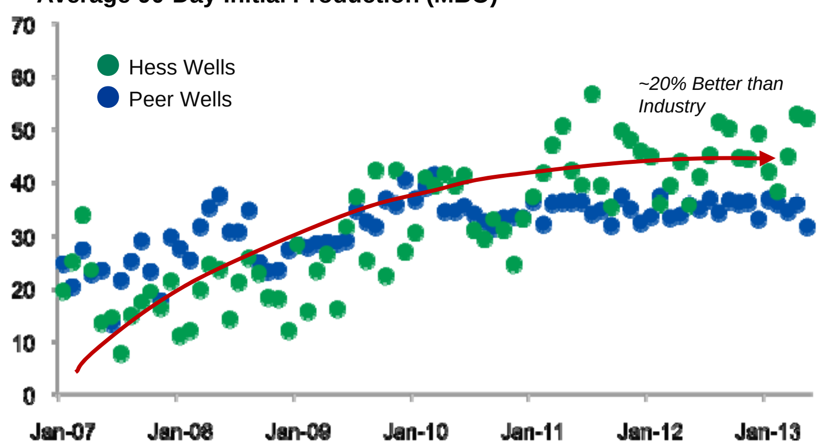


Drilling & Completion Costs ($mm)

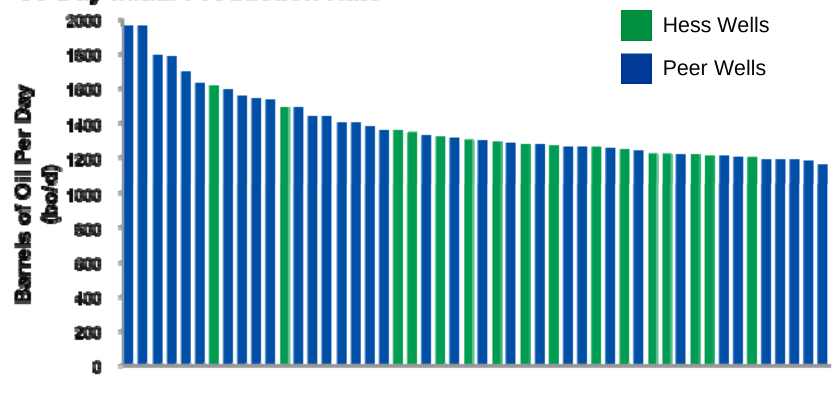


…While Optimizing Well Productivity

Average 90-Day Initial Production (MBO)



30-Day Initial Production Rate



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

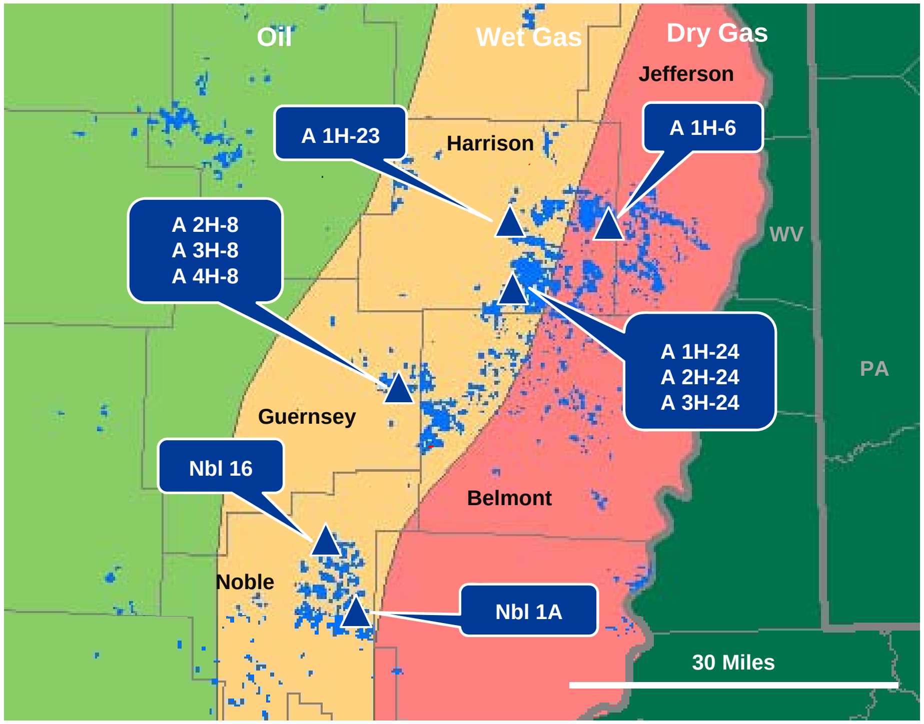
Asset Details

- **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**

Unconventional	Exploitation	Exploration

Core Position in Emerging Ohio Utica Shale Play

HESS

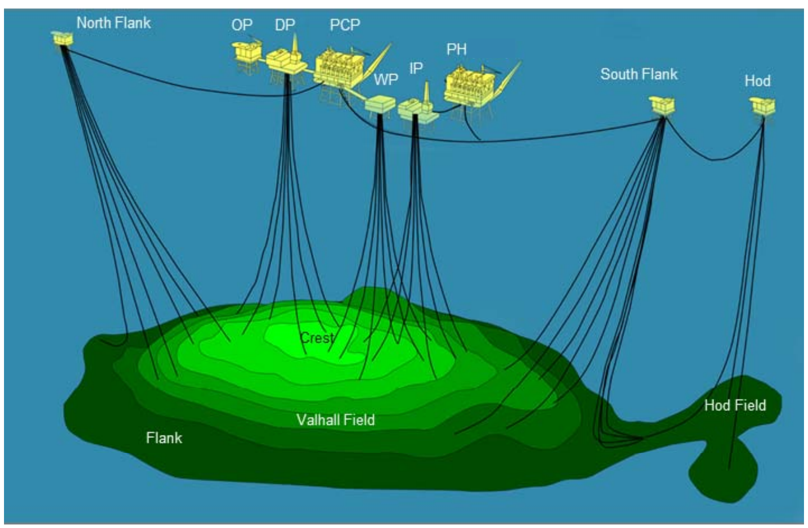


Well No	County	Well Test Result
Nbl 1A (Consol Op.)	Noble	1,950 boe/d, 39% Liquids
Nbl 16 (Consol Op.)	Noble	3,604 boe/d, 61% Liquids
Athens A 1H-24	Harrison	2,519 boe/d, 52% Liquids
Green A 1H-6	Harrison	1,432 boe/d, 20% Liquids
Cadiz A 1H-23	Harrison	2,251 boe/d, 57% Liquids
Athens A 2H-24	Harrison	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

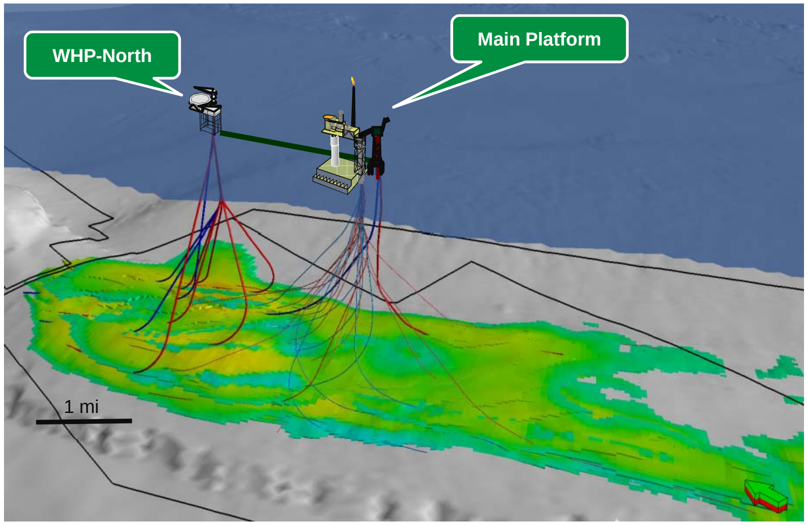

Valhall Complex – Norwegian North Sea



- **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

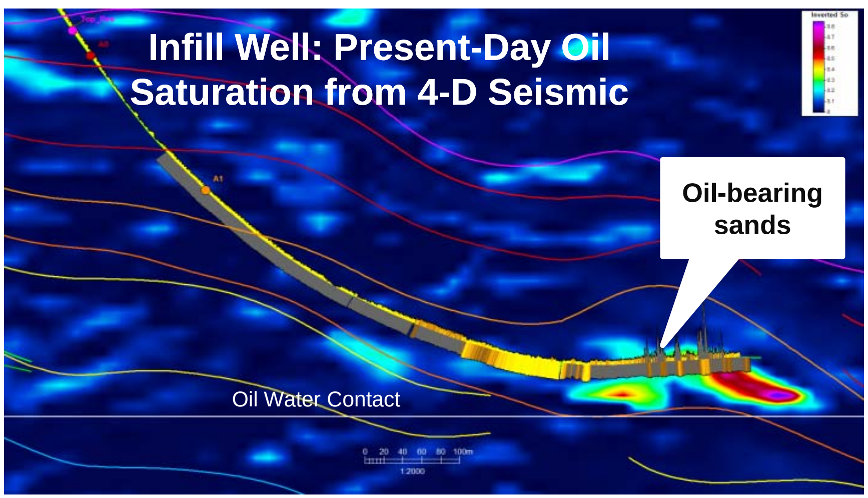
South Arne – High Margin with Exploitation Upside


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

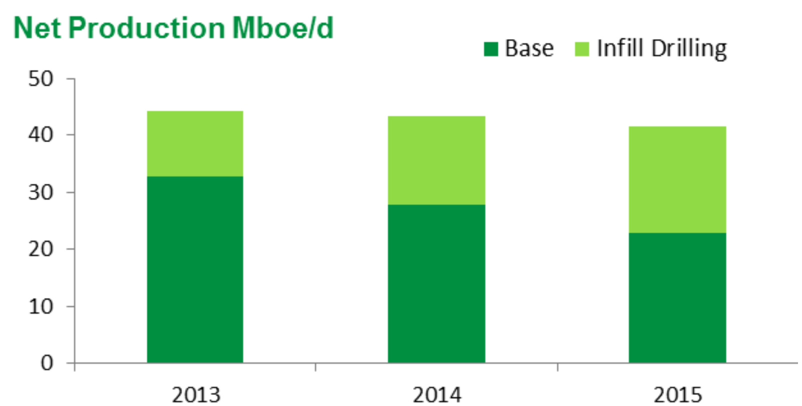


Strategic / Portfolio Context

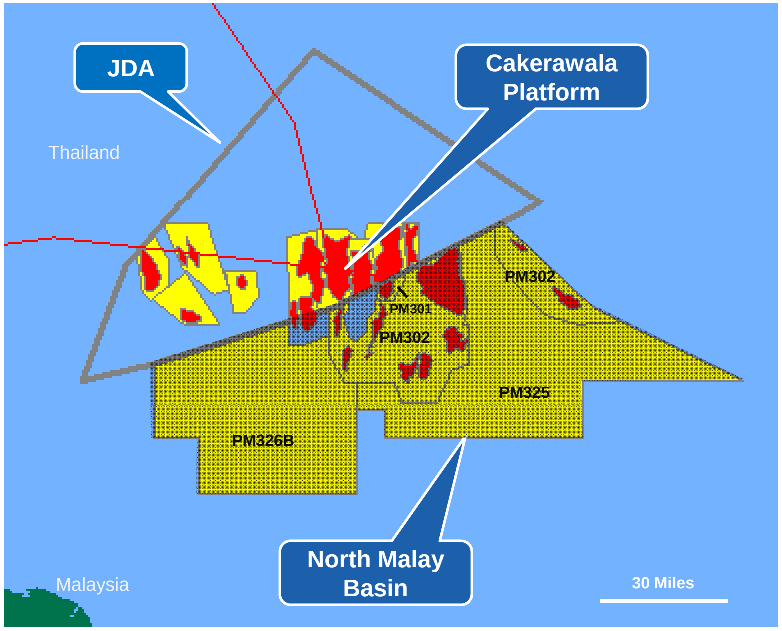
- High margin and strong cash flow
- Material contributor to production
- 4D seismic has resulted in additional high value drilling opportunities to maintain production plateau
- Leverages deep water capability

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

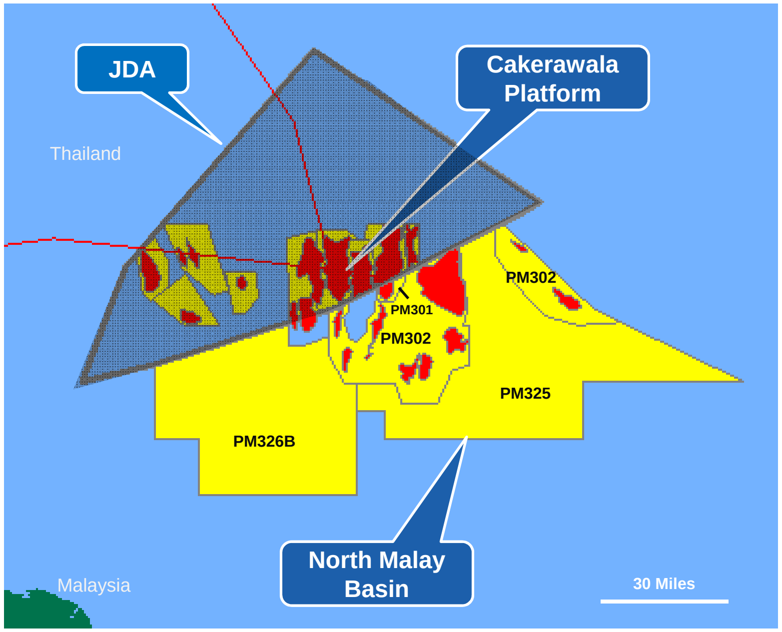


Cakerawala Platform

- **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



Wellhead Platform Installation

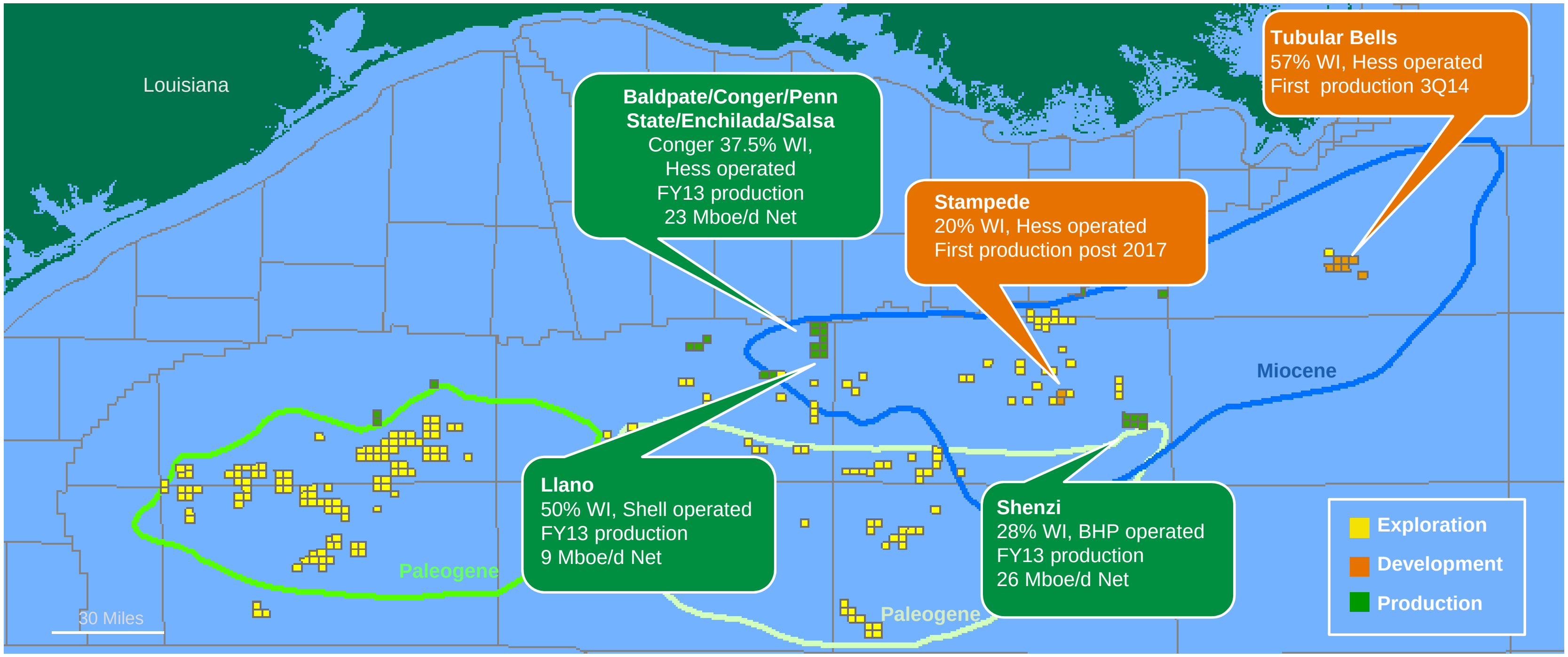
- **Strategic / Portfolio Context**
  - Low risk development of 9 discovered gas fields
  - Material production and free cash flow 2017+
  - Leverages JDA experience and capabilities
  - Material exploration upside

- **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

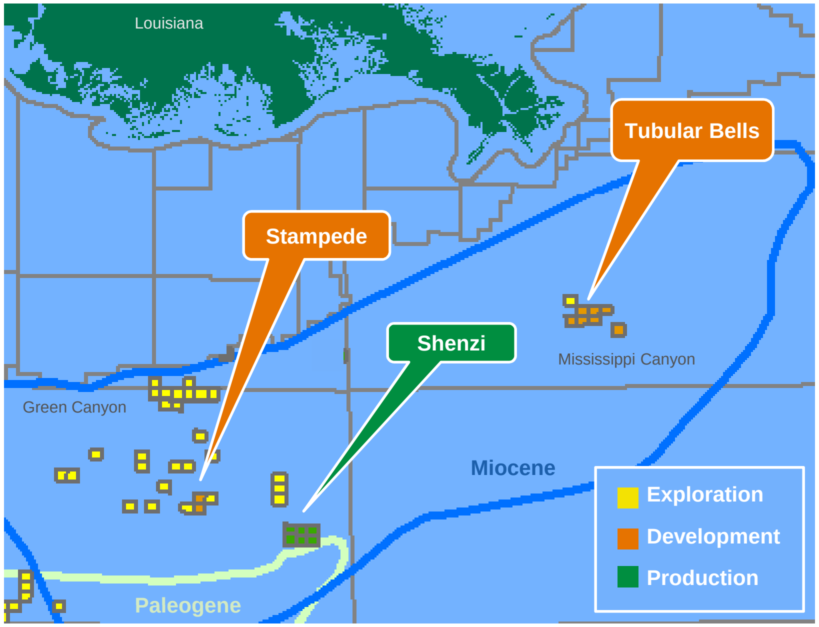
Deepwater Gulf of Mexico Portfolio

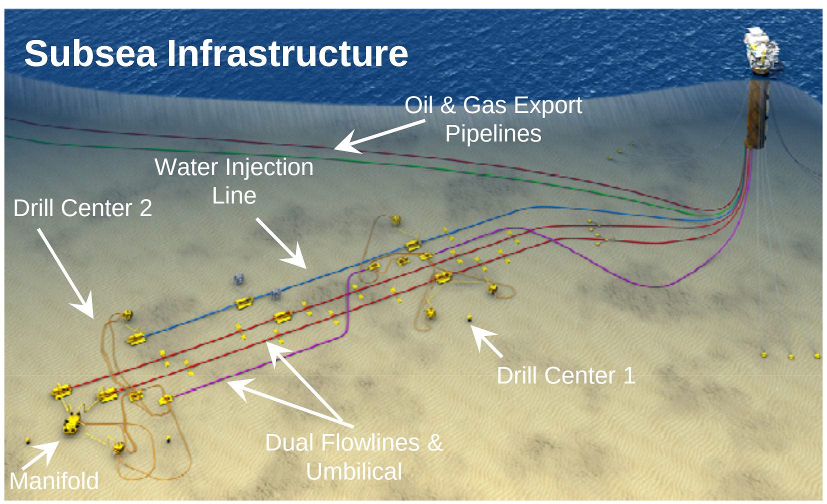
- **Strategic / Portfolio Context**
  - Target to maintain production of ~70 Mboe/d through 2017
  - Material, high margin assets with successful exploitation track record
  - Leverages proven deepwater capability
  - Exploration upside

- **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



Tubular Bells – High Margin Asset; On Line 3Q14





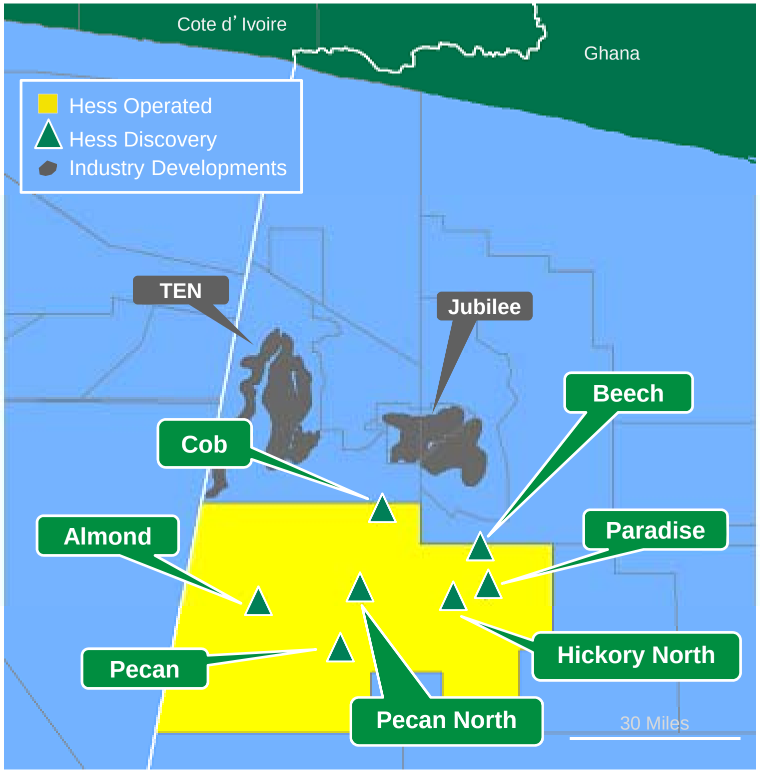
▪ Strategic / Portfolio Context

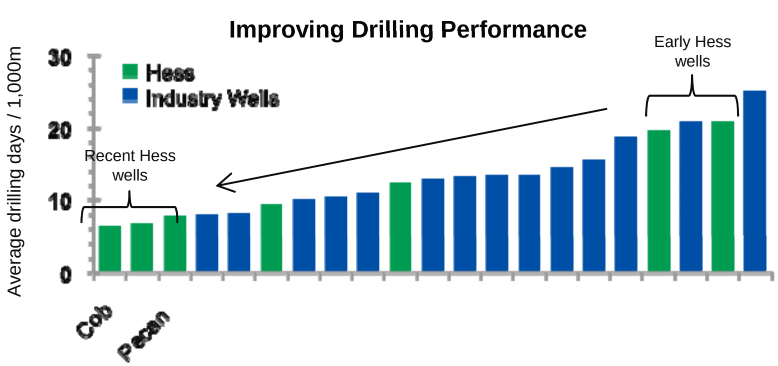
- Material high margin asset
- Key contributor to production growth and cash flow
- Leverages deepwater capability
- Recent drilling provides further upside

▪ 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

Ghana – Deep Water Tano Cape Three Points



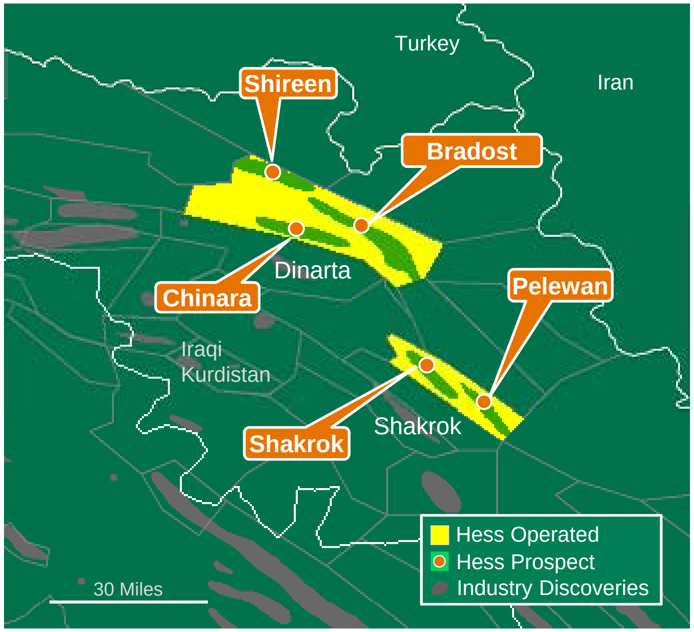


Source: Rushmore (West Africa drilling greater than 1,200 meters WD)

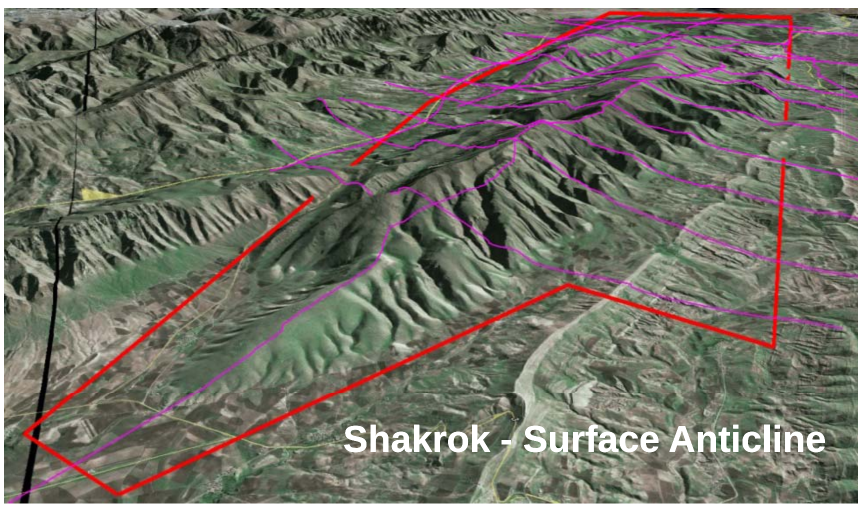
- Hess 90% W.I., operator
- 7 discoveries material to resource base
- Builds on West African deep water experience
- Industry leading well costs
- Pursuing partnership strategy
- Plan to drill 3 appraisal wells, commencing 2H14

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.

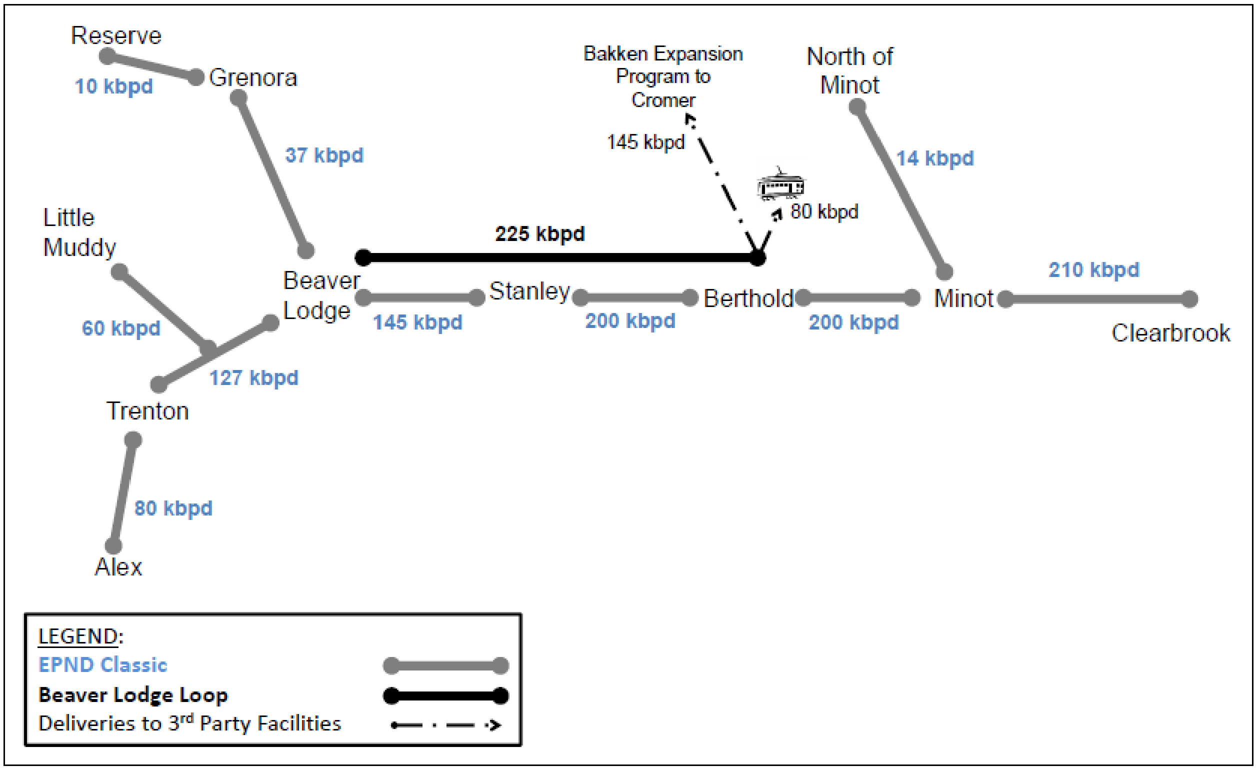
9. At that point, the existing mainline between Beaver Lodge and Clearbrook had reached its maximum capacity without building a new parallel pipeline. In order to create additional export capacity from the Bakken without having to construct a new

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

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.

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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.

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")

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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]

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[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

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[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

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[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 14[rd] 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.

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.

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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.

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