

MONTANA-DAKOTA UTILITIES CO.  
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Docket No. PU-16-666

Rebuttal Testimony  
of  
Darcy J. Neigum

1 **Q. Would you please state your name and business address?**

2 A. Yes. My name is Darcy J. Neigum and my business address is 400  
3 North Fourth Street, Bismarck, North Dakota 58501.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am the Director of System Operations and Planning for Montana-  
6 Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources  
7 Group, Inc.

8 **Q. Are you the same Darcy J. Neigum who filed direct testimony earlier  
9 in this proceeding?**

10 A. Yes, I am.

11 **Q. What is the purpose of your rebuttal testimony in this proceeding?**

12 A. I am responding to the testimony submitted by Richard A. Polich on  
13 behalf of the North Dakota Public Service Commission Advocacy Staff  
14 (Advocacy Staff) in regard to Mr. Polich's recommendation that \$12.27  
15 million of Montana-Dakota's cost for the Lewis & Clark RICE project be  
16 disallowed. Montana-Dakota was facing the potential interruption of 45  
17 MW of customer load and a solution was required to avoid that situation.

1 Montana-Dakota's obligation to serve customers demanded the need to  
2 take actions necessary to avoid service interruptions beginning with the  
3 winter of 2015-2016. As further discussed in my testimony, Montana-  
4 Dakota does not serve the oil field load in the Bakken Region and any  
5 service interruptions would have affected residential customers and  
6 businesses that would have been harmed if interrupted in cold weather  
7 conditions. I am sponsoring Exhibit No.\_\_\_\_ (DJN-2), February 4, 2016  
8 slide presentation I sponsored originally at the February 4, 2016 public  
9 hearing in North Dakota Case No. PU-15-704.

10 I will also address Advocacy Staff witness Sara Cardwell's  
11 testimony regarding the recovery of MISO Schedule 24 through the Fuel  
12 and Purchased Power Adjustment.

13 **Q. When did the Company start to see customer growth on its electric  
14 system as a result of the Bakken oil development?**

15 A. Montana-Dakota started to see electric load growth in the Bakken  
16 Region with the winter of 2011-2012.

17 **Q. What impacts did the Bakken load growth cause on the Company's  
18 electric system and the overall area?**

19 A. Montana-Dakota primarily serves electric customers within the  
20 communities located in the Bakken Region such as Williston, Watford City,  
21 Tioga, Stanley, Kenmare, and Sidney, MT. Montana-Dakota serves very  
22 little direct oil and gas production facilities. Therefore the electric load  
23 growth that Montana-Dakota needed to serve in the Bakken Region was  
24 mainly residential, municipal, and commercial loads which accounted for

1 less than ten percent of the total electric load growth within the Bakken  
2 Region.

3 This load growth within the Bakken Region drove the need for  
4 additional load serving capabilities including local transmission and new  
5 distribution facilities. As the Commission is aware, Montana-Dakota is  
6 dependent on transmission facilities owned by Western Area Power  
7 Administration (Western) and Basin Electric Power Cooperative (Basin  
8 Electric) for bulk delivery of power into the Bakken Region.

9 The level of growth within the Bakken Region caused many impacts  
10 to local communities, local governments, and energy suppliers like  
11 Montana-Dakota. One of the major factors that impacted planning efforts  
12 for the Bakken Region was the development of accurate forecasts of  
13 growth potential including areas where those developments would occur.

14 **Q. Describe the load forecast efforts that the Company undertook to**  
15 **accept for the rapid development of the Bakken Region.**

16 **A.** Following the winter of 2011-2012, when it was evident that the  
17 growth in the Bakken would be a long-term and impacting event, Montana-  
18 Dakota developed a community-by-community load forecast for those  
19 communities within the Bakken Region. This forecast was developed in  
20 consultation with local employees and local community governments and  
21 businesses.

22 **Q. Did you undertake any studies to assist in the development of the**  
23 **load forecast for this area?**

1 A. Yes, to better understand the load growth potential of the Bakken  
2 Region, the North Dakota Industrial Commission in partnership with Basin  
3 Electric and Montana-Dakota, contracted with KLJ Engineering to conduct  
4 an independent load forecast for the Bakken Region. This electric load  
5 forecast, which was completed in October, 2012, looked at both direct and  
6 indirect load growth potential over a 20 year period.

7 The KLJ load forecast largely confirmed the assumptions that  
8 Montana-Dakota had made regarding load growth potential within the  
9 Bakken Region as it pertained to population growth, housing needs, and  
10 communities impacted.

11 Because Montana-Dakota is not the only electric load serving entity  
12 with the Bakken Region, the load forecasting capabilities of Basin Electric  
13 and its members was a critical component of the overall transmission plan  
14 for the region, especially since Montana-Dakota is transmission  
15 dependent on Western and Basin Electric in the Bakken Region.

16 **Q. Did Montana-Dakota's load forecast for the Bakken Region change**  
17 **over time?**

18 A. No, the Company's community-by-community forecast remained  
19 fairly accurate without changes up to the point when development in the  
20 Bakken Region started to scale back with falling oil prices.

21 **Q. How did the rural electric cooperative (REC) load forecasts change?**

22 A. The REC load forecasts were generally more short-term in nature  
23 and did not accurately calculate the growth and longer term impacts of the  
24 oil boom within the Bakken Region. The local RECs electric load forecasts

1 continued to change every year with bigger and bigger impacts on the  
2 overall Bakken Region.

3 The level and impact of the REC forecast changes can be seen in  
4 the February 4, 2016 slide presentation, included as Exhibit No.\_\_\_\_(DJN-  
5 2), from the Company's Generation Resource Recovery Rider filing in ND  
6 PSC Case PU-15-704.

7 On the top slide on page 7 of Exhibit No.\_\_\_\_(DJN-2), the electric  
8 loads of Xcel Energy and Montana-Dakota are represented by the purple  
9 and rose colors at the bottom of the graph. The remainder of the load on  
10 the graph is the RECs.

11 The graphs on pages 8-10 of Exhibit No.\_\_\_\_(DJN-2), show how  
12 these forecasts changed over time and what transmission upgrades and  
13 local generation resources were needed to meet the system intact load  
14 forecast requirements for the Williston Load Pocket area of the Bakken  
15 Region.

16 The top graph on page 10 shows the Williston Load Pocket area of  
17 the Bakken Region being limited on transmission capability to meet the  
18 customer load forecast for the Winter of 2015-2016, even with local  
19 generation running, with a one year delay in the AVS to Nessel 345kV  
20 transmission line. Note, a loss of the AVS to Nessel 345kV transmission  
21 line during the Winter of 2015-2016 would look like the one year delay  
22 scenario from a transmission serving capability standpoint.

23 **Q. What percentage of new load did Montana-Dakota serve in the**  
24 **Bakken Region as compared the RECs?**

1 A. On average, Montana-Dakota served less than ten percent of the  
2 total new electric load growth with the Bakken Region with the majority of  
3 the new electric load growth served by the local RECs.

4 **Q. What were the impacts of the changes to the REC load forecasts?**

5 A. The rapid and continued increasing annual electric forecast  
6 updates for the local RECs put continued strain on the bulk transmission  
7 system in the Bakken Area. This included the need for Basin Electric and  
8 its members to install new reactive energy support devices, local  
9 generation resources, and implement an under voltage load shedding  
10 protection scheme which included the customer load of Montana-Dakota.  
11 These impacts and mitigations can be seen in the graphs on pages 7-10  
12 of Exhibit No.\_\_(DJN-2).

13 **Q. Would you please describe Montana-Dakota's transmission  
14 arrangements in the Bakken Region?**

15 A. Montana-Dakota had a transmission service agreement with  
16 Western, which terminated on December 31, 2015. This transmission  
17 service agreement allowed Montana-Dakota and Western to utilize each  
18 other's electric transmission system up to certain historic load serving  
19 levels. Western owned most of higher voltage transmission facilities in the  
20 Bakken Region which made Montana-Dakota dependent on the electric  
21 transmission system of Western and Basin Electric.

22 As Montana-Dakota's electric load in the Bakken Region grew  
23 above the historic load serving levels in the Western transmission service

1 agreement, Montana-Dakota was required to take transmission service for  
2 all new load growth under Western's open access transmission tariff.

3 **Q. How did Western manage impacts of the load growth on their**  
4 **system?**

5 A. Starting with the winter of 2012-2013, Western implemented a  
6 'Network Load Curtailment/Restoration Procedures' to account for network  
7 load increases that were above the transmission system capabilities in the  
8 Bakken Region. This procedure set priorities of load service and mitigation  
9 responsibilities for customer loads, including Montana-Dakota's, consider  
10 less than firm because of insufficient time to build transmission facilities to  
11 account for load growth within the Bakken Region.

12 **Q. How did Montana-Dakota manage customer curtailment risks**  
13 **associated with less than firm load growth?**

14 A. Montana-Dakota had approximately 45 MW of customer load which  
15 was considered less than firm by Western and Montana-Dakota was able  
16 to initially manage the risks of potential load curtailments under the  
17 'Network Load Curtailment/Restoration Procedures' through (1) customer  
18 demand response programs, (2) the addition of three 2 MW generators,  
19 (3) the contract of 4 MWs of standby generation from the Williston Water  
20 Treatment Plant, (4) the ability to run Lewis & Clark Station on natural gas  
21 at times to increase the MW capacity of the facility, (6) the ability to shift  
22 some customer load around the area, and (7) purchases of capacity and  
23 redispatch energy from Basin Electric until such time as Western and

1 Basin Electric completed the 345kV transmission project from Antelope  
2 Valley Station to Williston and Tioga (AVS to Nessel).

3 **Q. Why didn't the Company just continue the redispatch energy**  
4 **arrangement with Basin Electric?**

5 A. In July of 2014, Montana-Dakota received notice from Western and  
6 Basin Electric that the REC load forecasts in the Bakken Region were  
7 continuing to increase and that delays with the 345kV transmission from  
8 AVS to Nessel would likely cause load curtailments for the 2015-2016  
9 Winter load season under both system intact and contingency load serving  
10 conditions. The L&C RICE units were needed to meet the Company's  
11 growing load service requirements under the 2013 IRP and to meet the  
12 local load serving requirements of the Bakken Region beginning with the  
13 Winter Season of 2015-2016 and beyond.

14 The completion of the AVS to Nessel 345kV line would not solve all  
15 of the transmission capability issues as a loss of the AVS to Nessel 345kV  
16 line put the region in the same position it was in prior to the construction of  
17 the transmission line.

18 **Q. Did the addition of the AVS to Nessel 345kV transmission line cure**  
19 **all of the reliability issues in the Bakken Region?**

20 A. No, the Bakken Region is transmission dependent with the majority  
21 of energy imported into the area with only four transmission lines rated at  
22 230kV and above. The loss of one of these 230kV and above transmission  
23 lines, especially the AVS to Nessel 345kV transmission line, puts the

1 region into transmission constraints on-peak which requires the need for  
2 local generation or load curtailments to maintain safe operating conditions.

3 Western and Basin Electric are working on an additional 345kV  
4 transmission line into the Bakken Region which will further improve the  
5 transmission capability in the area.

6 **Q. What other options did the Company consider versus constructing**  
7 **the RICE units?**

8 A. Montana-Dakota visited with Basin Electric on the potential  
9 partnering in new generation within the Bakken Region to be able to  
10 achieve cost savings with economies of scale in constructing a larger  
11 plant. Basin Electric had already constructed 200 MW of peaking  
12 generation in the Bakken Region and their next generation addition would  
13 not be until the summer of 2016 due to permitting and construction  
14 schedules. At least one of Basin Electric's primary locations for additional  
15 generation was interconnected to one of their REC member's high voltage  
16 distribution facilities which Montana-Dakota was unable to get  
17 transmission service back to MISO because the facilities did not fall under  
18 open access and the REC did not want to provide Montana-Dakota with  
19 transmission service.

20 Montana-Dakota also considered the construction of additional  
21 MISO transmission facilities into the Bakken Region but costs and  
22 schedules associated with construction of new transmission back to a  
23 MISO transmission facility were prohibitive.

1 **Q. Why didn't the Company construct the larger 36 MW plant identified**  
2 **in the 2013 IRP?**

3 A. Montana-Dakota had approximately 45 MW of customer load in the  
4 Bakken Region that was considered less than firm by Western. In previous  
5 years, Montana-Dakota was able to purchase redispatch generation  
6 services from Basin Electric on an available basis. Montana-Dakota  
7 primarily used this redispatch generation service to cover its less than firm  
8 requirements and planned to utilize the standby generation, L&C on  
9 natural gas, moving load within its system, and demand response  
10 programs to minimize the remaining impacts of customer load curtailments  
11 in the Bakken Region.

12 With the Basin Electric redispatch generation not being available for  
13 the winter of 2015-2016 because of its members load growth, Montana-  
14 Dakota determined that the amount of generation that was needed to be a  
15 first run peaking resource was approximately 20 MW. The 20 MW peaking  
16 resource size would be more expensive on a per unit cost than a larger  
17 project, but it would be a lesser overall cost than a larger project. Also, the  
18 permitting, construction activity and interconnection requirements would  
19 be less for a small project than a larger facility which would allow  
20 Montana-Dakota the ability to construct the 20 MW project before the  
21 winter of 2015-2016.

22 **Q. While the 2013 IRP identified the need for peaking capacity in 2015,**  
23 **did the Company's recommended Future Resource Plan at that time**

1 **include the construction of RICE units for the 2015-2016 winter**  
2 **season?**

3 A. No. The 2013 Action Plan indicated the need to further study the  
4 need to install generation in the Williston, North Dakota area. The  
5 Company apprised the Commission of the need to consider the installation  
6 of smaller RICE units earlier than expected in an informational update  
7 meeting held in early May of 2014. This need was confirmed with Basin  
8 Electric's 2014 forecast and communications as provided in Exhibit No.  
9 \_\_\_\_ (DJN-2). Subsequent updates were provided to the Commission in  
10 February 2015 and July 2015 where the Company discussed the  
11 construction of the RICE units underway at an estimated cost of \$40  
12 million.

13 **Q. In summary, as a resource planner with the obligation to serve**  
14 **customers, was construction of the L&C RICE units the best course**  
15 **of action given the conditions facing the Company in mid-2014?**

16 A. Yes. Montana-Dakota's customers were facing a very real threat  
17 of being curtailed during the winter of 2015-2016 without the Company  
18 taking measures to ensure continuation of service. The options available  
19 were limited due to the time frame in which this needed to occur and the  
20 previous efforts that the Company had already undertaken to mitigate  
21 impacts in the past including: entering into energy purchase  
22 arrangements, increasing demand response programs, installing portable  
23 generators, executing customer standby generation agreements, utilizing  
24 redispatch service agreements, running L&C on natural gas if needed,

1 shifting customer load where possible, and considering Company owned  
2 transmission alternatives.

3 Mr. Welte will address why the alternatives identified by Mr. Polich  
4 would not have met that need or would have been available at a lesser  
5 cost than the RICE units that are installed and providing service today.

6 The Company should not be penalized now for taking the actions  
7 necessary to safely and reliably serve customers in a reasonably  
8 economic manner given the conditions facing Montana-Dakota and all  
9 service providers at that time.

10 **Q. In Ms. Cardwell's testimony she describes the MISO Schedule 24**  
11 **charge as a MISO administrative charge. What is the basis for the**  
12 **MISO Schedule 24 charge?**

13 A. MISO Schedule 24 is a recovery of local balancing authority (LBA)  
14 costs incurred by LBA's, like Montana-Dakota, which include daily  
15 operation and maintenance costs, administrative and general costs,  
16 capital costs, costs for systems-in-place, training of personnel, and any  
17 other costs that result from the performance of obligations imposed by  
18 MISO's Tariff on LBAs. Montana-Dakota receives revenues through  
19 Schedule 24 for services as a MISO LBA that it provides and Montana-  
20 Dakota receives charges from neighboring LBA's for services that they  
21 provide to Montana-Dakota.

22 MISO Schedule 24 charges are allocated based upon volumes of  
23 customer load and generation within an LBA.

1 **Q. When did Montana-Dakota begin including MISO Schedule 24**  
2 **charges in its Fuel and Purchase Power costs?**

3 A. MISO Schedule 24 charges were added to the Fuel and Purchase  
4 Power costs as part of the Company's 2010 electric rate case.

5 **Q. Would it be appropriate to continue to recover MISO Schedule 24**  
6 **charges through the Fuel and Purchase Power Tracker?**

7 A. Yes, it would be. These costs are allocated based upon volumes of  
8 load and generation within a MISO LBA similar to other MISO charges in  
9 Fuel and Purchase Power.

10 **Q. Does this conclude your rebuttal testimony?**

11 A. Yes, it does.

# MONTANA-DAKOTA UTILITIES CO.

ND Public Service Commission

Generation Resource Recovery Rider

February 4, 2016



*In the Community  
to Serve*



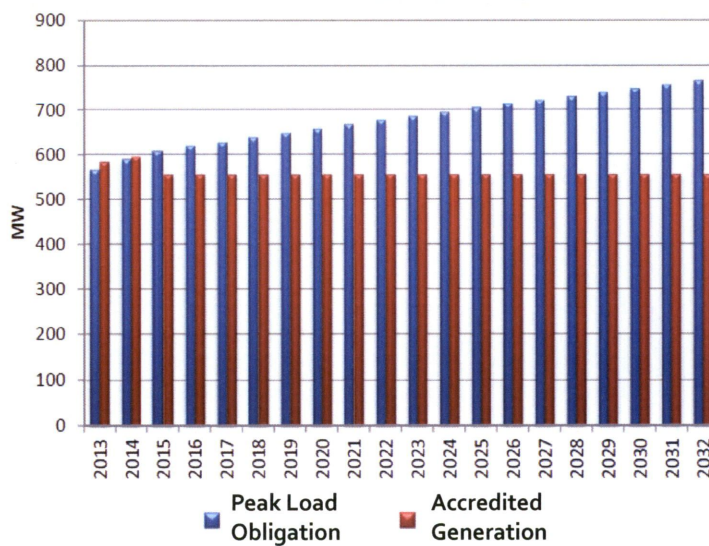
Darcy Neigum  
Director System Operations and Planning

## Need and Timing of Lewis & Clark RICE Units

## Need for Lewis & Clark RICE Project

- Resource Adequacy Needs
  - 2013 Integrated Resource plan
- Reliability Concerns
  - Transmission dependent on Western Area Power Administration and Basin Electric in Bakken area
  - Continued increasing REC load forecasts
  - Lack of adequate transmission for Winter 2015-2016
  - Potential for load curtailments

## 2013 IRP Supply-Side Overview



## 2013 IRP Modeling Results

Year	Base Case: L&C Retired in 2015	Optimal Resource Case	Current MISO Resource Adequacy
2014			
2015	4-ICE (146 MW) Wind PPA (50 MW)	L&C Baghouse Wind PPA (50 MW) 2-ICE (73 MW)	L&C Baghouse Wind PPA (50 MW)
2016		1-ICE (37 MW)	
2017	1-SCCT (72 MW)		1-ICE (37 MW)
2018			
2019			
2020		1-CCCT (200 MW)	1-CCCT (200 MW)
2021+	1-CCCT (129 MW) 1-ICE (36 MW) 1-Wind (20 MW)	1-Wind (20 MW)	
NPV (\$Mil)	3,640	3,525	3,412

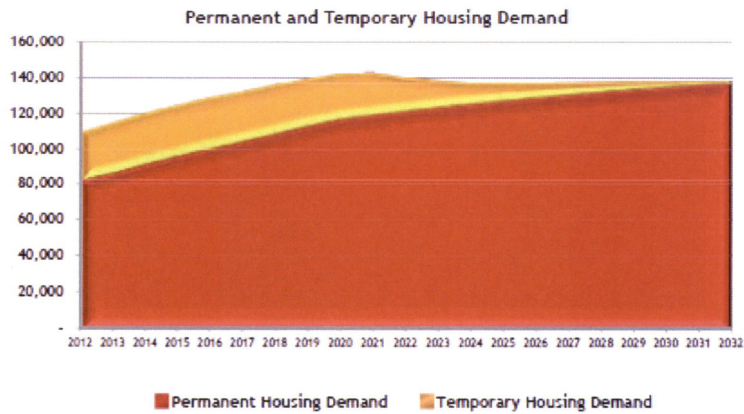
## ND PSC PIE Meeting - February 21, 2013 Transmission System Impacts

- Growth in Bakken has consumed flexibility and margin on electric transmission system
- Less flexibility to schedule outages and maintenance
- "System Intact" load serving capability
- Majority of Montana-Dakota served communities in Western North Dakota will double their electric consumption in next 2-3 years
- Montana-Dakota is getting 10 percent or less of all growth in Western North Dakota

## KLJ Bakken Load Growth Study August 2012 – Final Report



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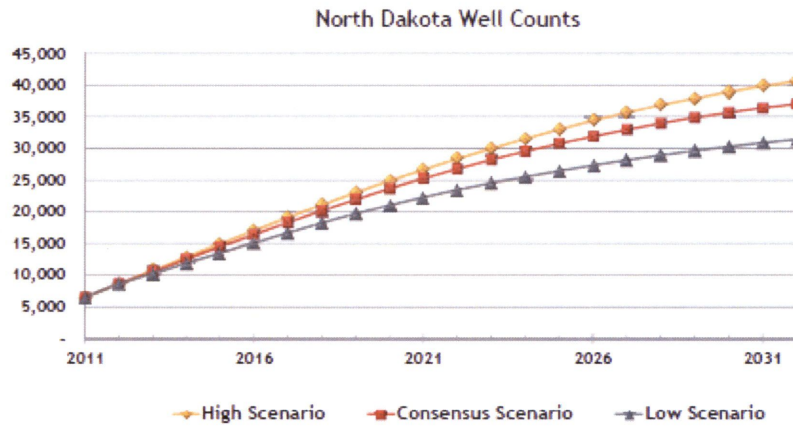
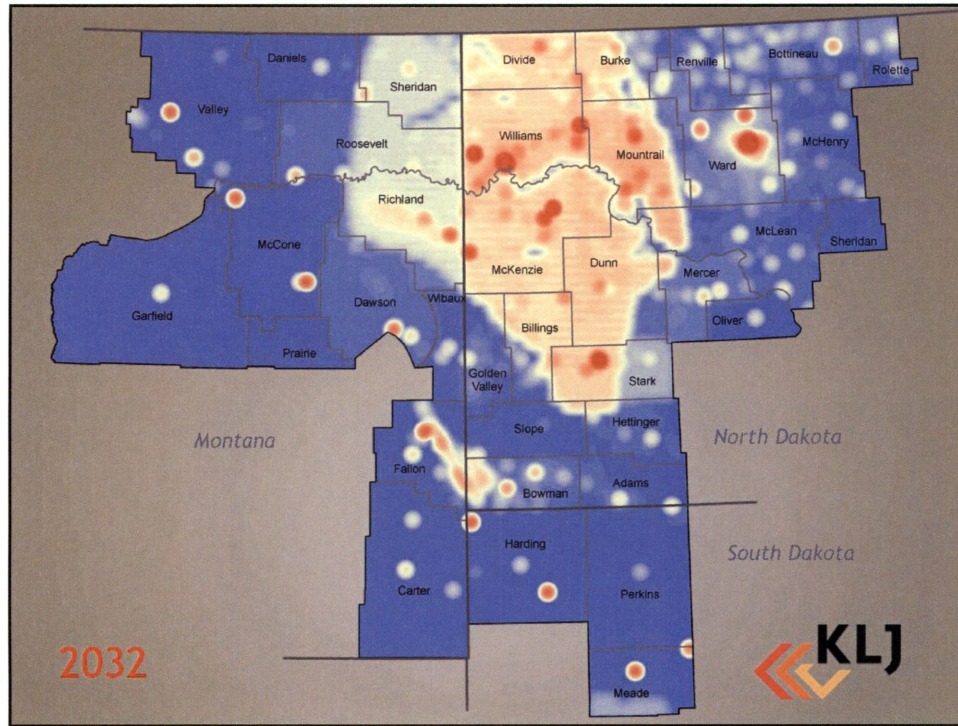


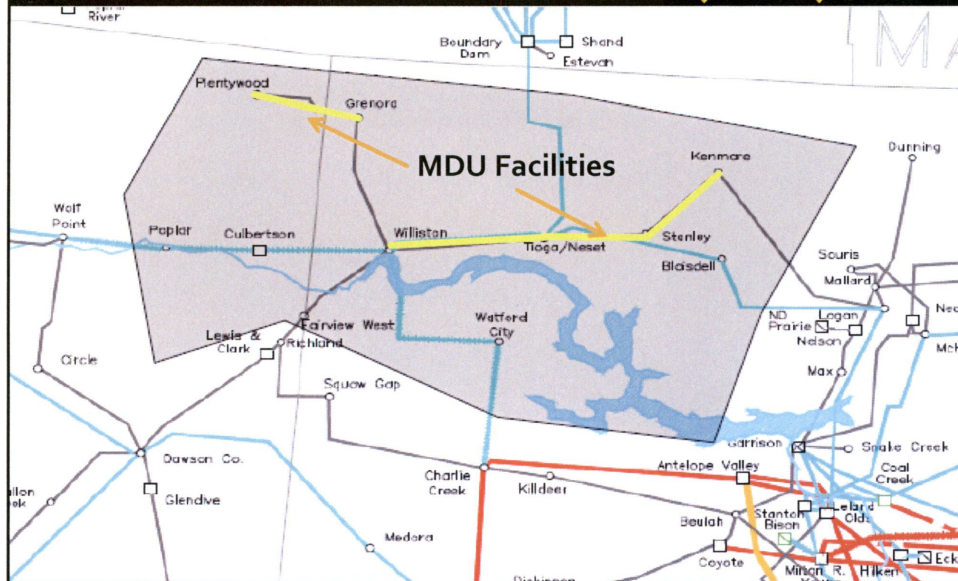
Figure 5: North Dakota Well Counts  
Source: University of North Dakota

## KLJ Bakken Load Growth Study August 2012 – Final Report

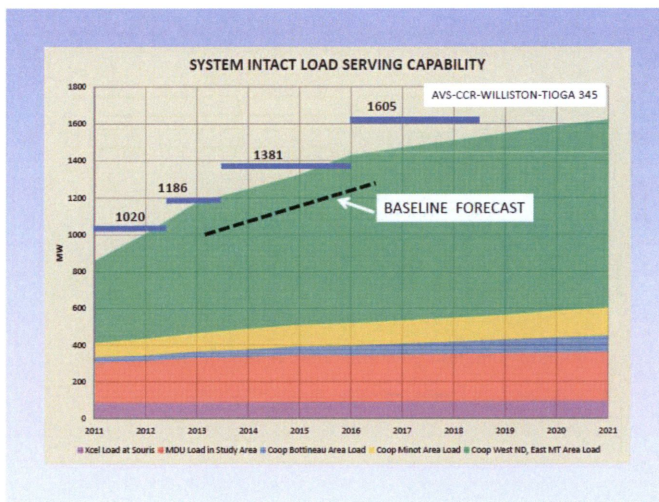
MW Demand			
	2012	2032	Additional
North Dakota	974	3,030	2,057
Montana	204	608	404
South Dakota	31	83	52
<b>Total</b>	<b>1,209</b>	<b>3,721</b>	<b>2,512</b>



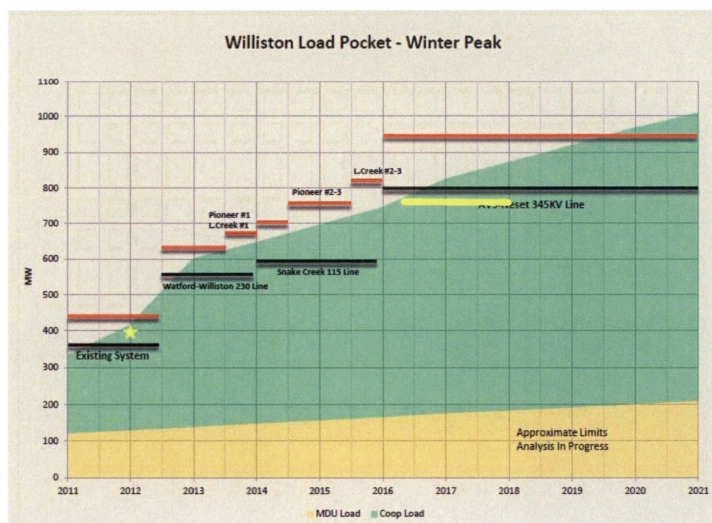
## MDU Transmission System Williston Area Load Pocket (2012)



## Bakken Load Forecasts and Impacts December 2011



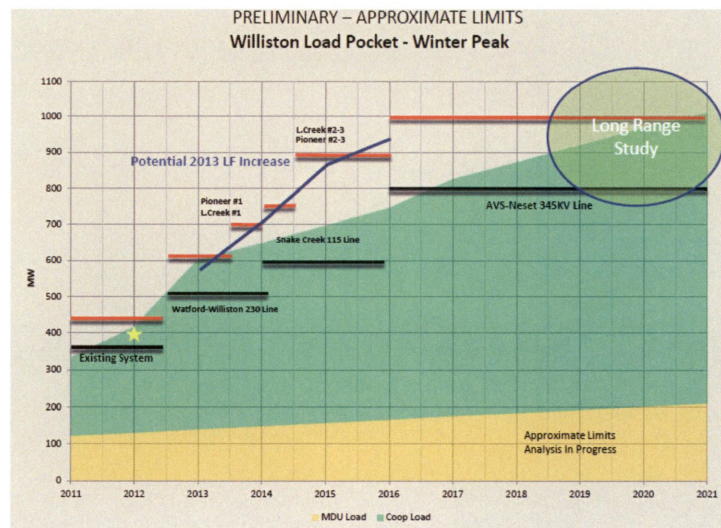
## Bakken Load Forecasts and Impacts November 2012



## Less than Firm Transmission Service Mitigation Efforts

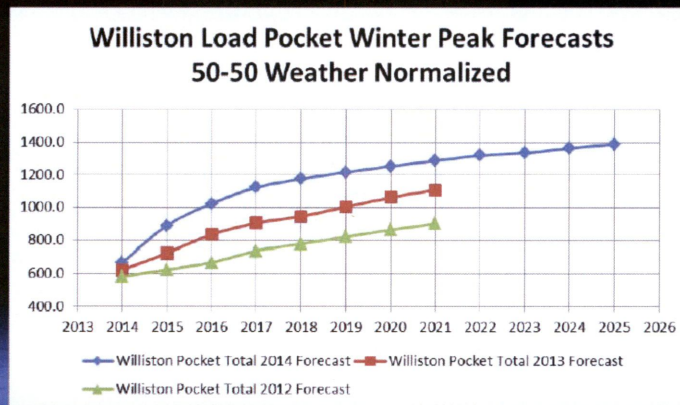
- Manitoba Hydro Import Services
- Demand Response Programs
- Mobile Generation (3 x 2 MW diesel units)
- Redispatch Services (Basin Electric)
  - Transmission congestion service
  - Dependent on available generation
    - Last to be served and first to be curtailed
- Build own transmission or generation
- Need for Basin 345kV transmission line
  - AVS to Williston

## Bakken Load Forecasts and Impacts April 2013

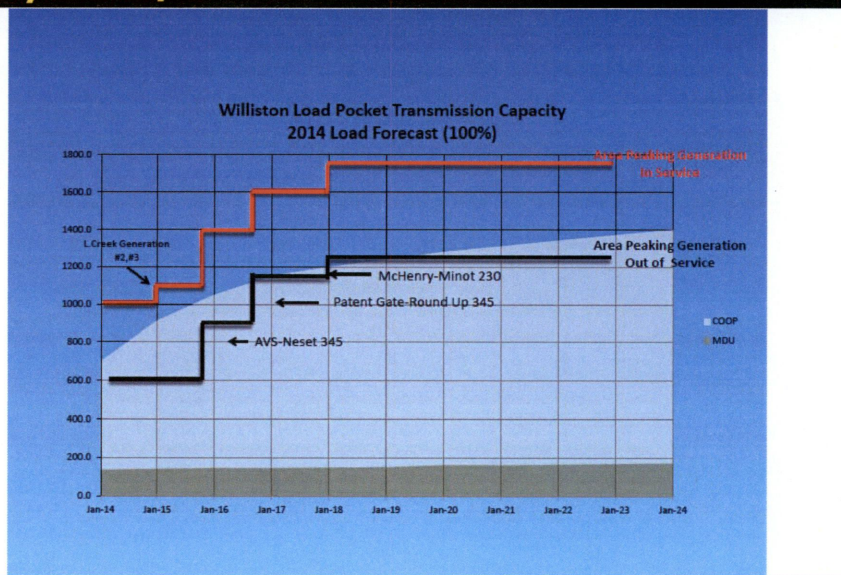


## Bakken Load Forecasts and Impacts July 2014

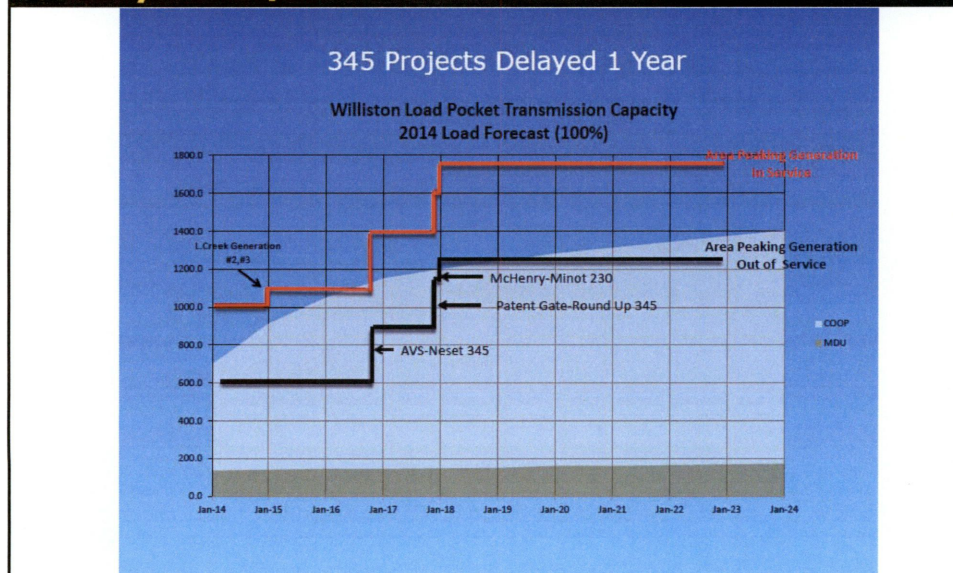
Comparison of Recent Load Forecasts



## Bakken Load Forecasts and Impacts July 2014



## Bakken Load Forecasts and Impacts July 2014



## Potential Transmission Shortfalls for Winter 2015-2016 Season

- Build transmission into Bakken area
  - Line from Beulah or Dickinson
  - Too expensive (>\$100 million) and not enough time to construct
- Partnership opportunities in new generation
  - Project timing issues
  - Lack of access to some sites
- Build own generation
- Unknowns with SPP seams issues including redispatch in Bakken area

## Lewis & Clark RICE Units – 18.6 MW

- Reviewed other potential sites
- Brownfield site at Lewis & Clark was optimal
  - Land, natural gas, water, transmission, labor
- 18.6 MW project size plus demand response with mobile generators met MDU's 'Less Than Firm Requirements'
- Capable of being in-service to meet 2015-2016 Winter Season

## Summary – Lewis & Clark RICE

- Needed to meet customer peak demands
- Transmission dependent on Western & Basin in Bakken area
- Needed to provide reliability support in Bakken area and mitigate customer load curtailments due to inadequate transmission
- Continued increases in REC load forecasts and concerns with in-service date for Basin's 345kV transmission line
- Able to be constructed and online for the Winter of 2015-2016