COMMERCE DEPARTMENT

August 29, 2018

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G004/M-18-454

Dear Mr. Wolf:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc.'s (Great Plains or the Company) Demand Entitlement Filing (Petition).

The Petition was filed on June 29, 2018 by:

> Tamie A. Aberle
> Director of Regulatory Affairs
> Great Plains Natural Gas Company
> 705 West Fir Avenue
> PO Box 176
> Fergus Falls, Minnesota 56538-0176

The Department will provide its recommendations to the Minnesota Public Utilities Commission (Commission) after the Company files its update on November 1, 2018. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ SACHIN SHAH
Rates Analyst

SS/ja
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G004/M-18-454

I. SUMMARY OF THE UTILITY'S PROPOSAL

Pursuant to Minnesota Rules part 7825.2910, subpart 2, Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc. (Great Plains or the Company), filed a petition on June 29, 2018 with the Minnesota Public Utilities Commission (Commission) to change the levels of demand for natural gas pipeline capacity (Petition). The Petition is the second in which the Company's South District and North District were combined based on the Commission's September 6, 2017 Order in Docket No. G004/GR-15-879.[11]

For the area of the Company's system that was previously known as the North District, Great Plains requested that the Commission accept its contracted 5,000 dekatherm (dth) per day of forward haul on the Viking system with receipt point of Emerson, and 10,000 dth per day of back haul capacity with a receipt point of Chisago, which when combined with the proposed incremental 2,400 dth per day on Viking, is expected to be sufficient to meet the estimated peak-day demand. The proposed capacity in this area for the 2018-2019 heating season is an increase by 800 dth from the 2017-2018 heating season.

For the area of the Company's system that was previously known as the South District, Great Plains proposed to have the same volume of Northern Natural Gas Company's (NNG or Northern) capacity available as the prior year. However, Great Plains did not release 1,300 dekatherms per day of excess capacity as was done in prior years. The Company instead proposed to use 1,000 dth of the capacity to transport gas to the NNG/Viking Gas Transmission (VGT) interconnection at Chisago, and ultimately backhaul the gas to Minnesota cities including, but not limited to Vergas, Pelican Rapids, Fergus Falls, and Breckenridge. In other words, the Company proposed to use the NNG contract to serve customers that were historically in the North District.

[1] The Commission's Order states: "Regarding the consolidation of the rates in the North and South Districts: A. Great Plains shall implement a consolidated base cost of gas and purchased gas adjustment (PGA) beginning July 1, 2017. B. Great Plains shall consolidate its distribution rates according to its three-phase process implemented during the two years following implementation of the general rate increase resulting from this proceeding.

The Company projected a 5.6 percent reserve margin for the upcoming heating season. Great Plains estimated that its proposal would cause an increase in rates for residential customers of $0.0098 per dekatherm or approximately $0.76 per year for customers assuming an annual usage of 77.9 dth.

Great Plains requested that the Commission allow recovery of the associated demand costs in the Company's monthly PGA for each district effective November 1, 2018.

II. PREVIOUS COMMISSION ORDERS

In its June 8, 2017 Order in Docket No. G004/M-16-557 (16-557 Order), the Commission made the following disposition:

- Accepted the Company's proposed design-day method for the South District and the North District;
- Required Great Plains, in its future demand entitlement filings, to check the regression models it ultimately uses for autocorrelation, and correct the models if autocorrelation is present; and
- Approved Great Plains' proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2016.

In its May 15, 2018 Order in Docket No. G004/M-17-521 (17-521 Order), the Commission accepted the Company's proposed design-day method and approved the Company's proposed levels of demand entitlement and recovery of associated demand costs.

III. DEPARTMENT ANALYSIS

The Minnesota Department of Commerce, Division of Energy Resources' (Department) analysis of the Company's request includes the following areas:

- the proposed overall demand entitlement levels;
- the design-day requirements, including compliance with the Commission's 16-557 Order;
- the reserve margins; and
- the PGA cost recovery proposals.

A. PROPOSED OVERALL DEMAND ENTITLEMENT LEVELS

In regards to NNG capacity, Great Plains stated in its initial filing, as it has in prior years, that NNG's reallocation of TF-12B and TF-12V services are not known until the November update and that the changes are not significant normally. The reallocation changes are in accordance with NNG's tariff approved by the Federal Energy Regulatory Commission (FERC).[2] According to Great Plains in prior demand entitlement dockets, there is no deliverability difference between TF-12B and TF-12V services, but TF-12B service is less expensive than TF-12V service.

The Company proposed to bid for 2,400 dth per day of incremental VGT pipeline via a third party. The proposed capacity was meant to replace a contract of 1,600 dth per day that expired after the 2017-2018 heating season. The net proposed increase of VGT capacity is 800 dth per day for the 2018-2019 heating season. Specifically, Great Plains stated:

> Great Plains proposes to acquire 2,400 Dk/day of seasonal capacity from a third party on VGT, as shown on Exhibit B, Page 1. This 2,400 Dk/day of seasonal capacity is to replace the 1,600 Dk/day seasonal firm capacity purchase contract with BP Canada Energy Marketing Corp., which expired after the 2017-2018 heating season. If Great Plains is unsuccessful in its attempt to secure seasonal capacity on VGT, the option to purchase a delivered supply of natural gas at either of the VGT city gates will be available on a term or spot basis. The Company will update the Commission regarding the final seasonal capacity contract or delivered supply purchase by November 1, 2018.
>
> Great Plains proposes to utilize 1,000 Dk/day of currently contracted NNG capacity, previously contracted for future use for NNG city gate delivery, as supplemental capacity to provide delivery from NNG market locations to the NNGNGT interconnect (Chisago). This is a reduction in amounts held as supplemental capacity of 300 Dk/day from the prior heating season, as demand continues to increase on city gate interconnects with NNG.

Thus, there was no change in the aggregate volume of NNG capacity year over year except for what Great Plains proposed to use as supplemental capacity to deliver gas to the NNG/VGT interconnection at Chisago.

[2] Under its federally approved tariff, NNG is allowed to adjust a utility's assigned level of contracted capacity based on the utility's usage of its NNG-based capacity over the previous five-month period (May through September).

Table 1 below provides a comparison of the Company's current and proposed overall level of entitlements.

Table 1: A Comparison of Great Plains' Current and Proposed Entitlements

Pipeline	Current Entitlement (dth/day)	Proposed Entitlement (dth/day)	Change (dth/day)	Percent Change
VGT	16,600	17,400	800	4.82%
NNG	17,845	18,145	300	1.68%
Total	34,445	35,545	1,100	3.19%

As indicated in Table 1, the Company's proposal would result in an increase of 1,100 dth to the overall demand entitlement level compared to the current entitlement level. As discussed in further detail in Docket No. G004/M-15-645, Great Plains entered into a 10-year TFX annual contract with NNG for 2,000 dth/day effective November 1, 2015. In the Company's updated comments and compliance filing dated October 29, 2015,[3] the Company stated that "although this amount of capacity exceeds current requirements, Great Plains believes it will require this amount of capacity in the near future."

The 2018-2019 heating season is the second in which the Company has not released 1,300 dth per day of capacity. As noted above, Great Plains indicated that 1,000 dth per day of the amount released in prior years will be used to deliver gas to the NNG/VGT interconnection at Chisago and ultimately will backhaul the gas to cities on what was historically considered the Company's North District. The remainder, or 300 dth per day, will be used to deliver gas to cities on what was historically considered the South District of its system, due to increased demand.

The Department analyzes below the proposed changes, the proposed design-day requirements, and the proposed reserve margin for Great Plains.

B. DESIGN-DAY REQUIREMENTS

The Company used the same basic design-day method in this docket that the Commission accepted in Docket No. G004/M-03-303. In previous demand entitlement proceedings, the Department and Commission Staff expressed concerns that Great Plains' design-day method might under-estimate the need for natural gas on a peak day for the South District and the

[3] Docket No. G004/M-15-645.

North District.[4] In response to these concerns, the Commission ordered the Company and the Department to work cooperatively on developing a design-day analysis that would address the concerns raised by the Department.[5] Subsequently, Great Plains submitted a Compliance Filing on June 27, 2012 in Docket No. G004/M-10-1164. In that Compliance Filing, Great Plains provided additional discussion and analysis regarding its design-day method using different scenarios (i.e., as filed 36 months, 36 winter months only, 60 winter months only) as requested by the Department. The Department concluded that, "As noted above, despite these concerns, the Department believes that the Company's design-day analysis does not appear to produce unreasonable results."[6] The Commission agreed with the Department's conclusion that, while concerns about sample size and changing weather patterns still exist, the Company's design-day methodology was acceptable because its results were not unreasonable.

The Commission's *June 8, 2017 Order* in Docket No. G004/M-16-557 stated the following:

> Required Great Plains, in its future demand entitlement filings, to check the regression models it ultimately uses for autocorrelation, and correct the models if autocorrelation is present;

In its Petition, Great Plains stated the following:

> In addition, Great Plains monitored its data and regression models for the presence of autocorrelation and whether it has statistical significance to the projected design day requirement, as agreed to in Docket No. G004/M-17-521. While the results indicate autocorrelation is present, Great Plains does not have the means to determine the effect of autocorrelation on the design day requirement without purchasing additional software. Great Plains continues to support its current methodology, previously approved, as the modeling produces reasonable results.

---

[4] The Department's concerns on this issue are discussed in detail in the following documents:

- the Department's July 2, 2008 *Comments* in Docket No.G004/M-07-1401;
- the Department's July 31, 2009 *Comments* in Docket No. G004/M-08-1306;and
- the Department's February 5, 2010 *Comments* in Docket No.G004/M-09-1262.
  Commission Staff's concerns are discussed in detail in their September 9, 2010 *Briefing Papers*, which were contemporaneously submitted in each of these three dockets.

[5] *See* Ordering Paragraph No. 2 of the Commission's September 30, 2010 *Order* in Docket Nos. G004/M-07-1401, G004/M-08-1306, and G004/M-09-1262.

[6] The Department's concerns on this issue are discussed in detail in the following documents: the Department's March 18, 2013 *Comments* in Docket No. G004/M-12-740; and the Department's August 19, 2013 *Comments* in Docket No.G004/M-13-566.

> As shown on Exhibit A, Great Plains has calculated a projected design day requirement of 33,674 Dk/day. This projection consists of 16,472 Dk/day for firm customers receiving natural gas from city gates interconnecting with VGT and 17,202 Dk/day for those firm customers receiving natural gas from city gates interconnecting with Northern Natural Gas (NNG).
>
> Great Plains has a long history of successfully serving its customers gas requirements in a safe, reliable and economical fashion. The Company believes its regressions are accurate, can be relied upon for forecasting demand requirements, and the resulting design day peak capacity requirements are not unreasonable. Great Plains serves approximately 24,000 customers and is intimately familiar with its customer's gas usage, conservation and growth characteristics.

The Department appreciates Great Plains' discussion of autocorrelation described above. The Department has previously discussed the issue of autocorrelation and its potential impact and will not repeat that discussion here.[7] The Department does not advocate that Great Plains purchase statistical software for the sole purpose of addressing autocorrelation in its models and agrees with the Company's previous statement[8] that it is not an appropriate cost for the company to pass on to its customers.

As noted above, Great Plains partially complied with the Commission's *June 8, 2017 Order* by checking its models for autocorrelation. However, Great Plains did not correct the models for autocorrelation. The Department corrected the models for autocorrelation and makes the following observations:

- Great Plains' projected design-day was 33,674 dth/day and after correcting for autocorrelation, the projected design-day changed to 33,978, or approximately by 304 dth, which is a 0.9% change;

- Great Plains must plan for its design-day;

[7] See the Department's *August 27, 2015 Comments* in Docket No. G004/M-15-645 at pages 4-5, and *November 10, 2016 Response Comments* in Docket No. G004/M-16-557 at page 8, and the Department's *November 29, 2017, Comments* in Docket No. G004/M-17-521 at pages 4-8.
[8] *Id.*

- Interstate pipeline capacity contracts are usually subscribed to for relatively long durations, for example 10 years. Great Plains recently signed a 10-year contract with NNG for an annual TFX service;[9] and

- Capacity is usually added in larger "chunks."

In addition, Great Plains has previously agreed to continue monitoring its data and models for autocorrelation. The Department appreciates Great Plains' prior agreement to monitor its data and models. As a result, based on all of the above information, the Department concludes that Great Plains' models can be used by Great Plains in planning for its design day.

Consistent with prior analyses presented by the Department in Docket Nos. G004/M-11- 1075, G004/M-12-740, and G011/M-13-566, the Department used two methods to gauge the reasonableness of the Company's design-day amounts for Great Plains' consolidated system (previously known as the South District and the North District): 1) using data from the previous five heating seasons; and 2) using data from the heating season with the overall greatest peak sendout per firm customer that occurred before the previous five heating seasons.[10]

1. Consolidated System (North and South District)

The Department multiplied the peak sendout per firm customer for the 2014-2015 heating season of 1.2370 dth, which is the highest peak sendout per firm customer in the previous five heating seasons, by the expected number of firm customers for the 2018-2019 heating season of 24,240 to arrive at an estimated design-day amount of 29,985 dth/day. This amount is 3,689 dth/day less than the Company's proposed design-day level of 33,674 dth/day.

Thus, using the method based on the highest firm peak sendout data for the previous five heating seasons, Great Plains appears to have a sufficient level of entitlements for the 2018-2019 heating season for its system.

In past demand entitlement filings, the South District's 1995-1996 heating season represented the highest peak sendout per firm customer in the previous 22 heating seasons. Whereas for the North District, the 1999-2000 heating season represented the highest peak sendout per firm customer in the previous 22 heating seasons.

---

[9] See the Department's August 31, 2016 Comments in Docket No. G004/M-15-645 (Docket 15-645) and the November 9, 2016 Supplemental Comments in Docket No. 15-645

[10] The data used by the Department is taken from Exhibit D of the Company's Petition and prior demand entitlement filings.

The Department also calculated an estimated design-day amount using data from the 1999-2000 heating season, which represents the highest peak sendout per firm customer in the previous 22 heating seasons for Great Plains' system. Specifically, the Department multiplied the peak sendout per firm customer for the 1999-2000 heating season of 1.5322 dth by the expected number of firm customers for the 2018-2019 heating season of 24,240 to arrive at an estimated design-day amount of 37,141 dth. This amount is 3,467 dth more than the Company's proposed design-day level of 33,674 dth/day.

Given the previous system configuration, the Department also calculated an estimated design-day amount using data from the 1995-1996 heating season, which represents the second highest peak sendout per firm customer in the previous 22 heating seasons for Great Plains' system. Specifically, the Department multiplied the peak sendout per firm customer for the 1995-1996 heating season of 1.5197 dth by the expected number of firm customers for the 2018-2019 heating season of 24,240 to arrive at an estimated design-day amount of 36,838 dth. This amount is 3,164 Dth more than the Company's proposed design-day level of 33,764 dth/day. The Department addresses this situation further in Section III.B.2 below.

2. Reasonableness of Great Plains' Design-Day Analyses

As noted above, when the all-time peak-day sendout is analyzed, it appears that Great Plains may not have sufficient capacity to serve firm customers on a Commission design-day. However, in its 2010 demand entitlement proceeding, Great Plains stated that the peak-day use-per-customer figures during past heating seasons are no longer appropriate metrics because of the many changes (*e.g.,* the movement of firm customers to interruptible service, customer losses due to natural disasters, customer growth and losses, energy conservation) that have occurred since 1995, resulting in steadily declining use per customer. In that same proceeding, the Department observed that, in general, Great Plains' assertions about changes in use per customer over time appear to be plausible and should be reflected in estimates of use per customer.

The extreme weather in the 2013-2014 heating season offers further insight into reliance on the all-time versus the 5-year peak-day sendout to evaluate the Company's design-day estimate. Great Plains experienced an outage in January 2014 when the TransCanada pipeline, which supplied gas to the VGT Company that serves Great Plains' customers in the former North District, exploded. Further, Great Plains experienced some extremely cold weather during the months of January through March 2014.[11] Despite these challenges, the peak sendout during the 2013-2014 heating season of 27,693 dth was below Great Plains' estimated design-day of 29,433 dth.

---

[11] See pages 3 through 5 of the Company's August 29, 2014 Filing in Docket No. E,G999/AA-14-580.

In addition, Great Plains had an even greater peak sendout of 29,099 dth in the 2014-2015 heating season, which was also below Great Plains' estimated design-day of 31,124 dth.

As noted above, the Commission in its January 9, 2014 *Order* in Docket No. G004/M-13-566, accepted the Company's proposed design-day method for the South and North District, as recommended by the Department.

The Department recommends that the Commission accept the Company's same proposed design-day method for its system.

C. PROPOSED RESERVE MARGIN

In the Company's 2007, 2008, and 2009 demand entitlement proceedings, the Commission stated the following:[12]

> Great Plains shall reduce its reserve margin in Docket No. G-004/M-09-1262 to approximately five percent or explain why it is not reasonable to do so.

Table 2 below compares Great Plains' authorized and proposed reserve margins.

Table 2: Great Plains' Authorized Reserve Margins for the 2017-2018 Heating Season and

Proposed Reserve Margins for the 2018-2019 Heating Season

2017-2018 Reserve Margin	Proposed Reserve Margin
5.23%	5.56%

Great Plains has kept its reserve margin near the 5 percent target that was established by the Commission in prior demand entitlements.

As fully discussed previously,[13] the Department notes that, in contrast to the electric utility industry, natural gas reserve margins are utility-specific rather than regionally specific.

[12] *See* Ordering Paragraph No. 4 of the Commission's September 30, 2010 *Order* in Docket Nos. G004/M-07-1401, G004/M-08-1306, and G004/M-09-1262.
[13] See the Department's *November 29, 2017 Comments* in Docket No. G004/M-17-521.

However, given Minnesota's efforts to expand natural gas use in under- and unserved areas, and the increasing use of natural gas for electricity generation, there is a growing need to more closely examine reserve margins and to integrate natural gas supply planning with electric resource planning. The Department will provide an update on the information requests it has sent previously and the responses when it files its final recommendations and comments after Great Plains files its update on November 1, 2018, in addition to information provided in the annual service quality and annual automatic adjustment reports, to ascertain, among other things, the number and timing of interruptions (curtailments) that may be occurring, and the causes of those curtailments, as a first step in assessing whether the demand entitlements procured, including reserve margins in place at those times, were sufficient or justified, and to continue monitoring the growing inter-relationship between the natural gas and electric industries.

D. THE COMPANY'S PGA COST RECOVERY PROPOSAL

The demand entitlement amounts listed above and in the Company's Petition represent the demand entitlements for which Great Plains' firm customers would pay. In its Petition, the Company used its July 2018 PGA to compare its proposed changes for its North District and South District.[14] Great Plains presented an analysis indicating that the Company's demand entitlement proposal would result in the following estimated annual rate impacts for customers in the North and South District:

- an annual bill increase of $0.76 or approximately 0.1 percent, for the average residential customer consuming 77.9 dth annually; and

- an annual bill increase of $4.26 or approximately 0.2 percent, for the average firm general service customer consuming 434.4 dth annually.

III. THE DEPARTMENT'S RECOMMENDATIONS

In the instan*t* Petition, Great Plains' analysis produces results that are acceptable for planning for the design-day. However, the Department will file its final recommendations after the Company's November 1, 2018 update on its demand entitlement proposal.

/ja

[14] *See* Exhibit C of the Company's Petition. The exhibit is shown for both the North and South Districts.

Department Attachment 1
Docket No. G04/M-18-454
Great Plains Demand Entitlement Historical and Current Proposal

				Proposed As of 11/1/18			
Contract Type	2015-2016 Quantity (Mcf)	2016-2017 Quantity (Mcf)	2017-2018 Quantity (Mcf)	2018-2019 Quantity (Mcf)	Change in Quantity (Mcf)	Change in Capacity (%)	Change in Design Day (%)
VGT							
FT-A (12-month)	13,000	13,000	13,000	13,000	-		
FT-A (5-month)	2,700	3,400	2,000	2,000	-		
BP (5-month)	-	-	1,600	-	(1,600)		
Seasonal Capacity				2,400	2,400		
Total VGT	**15,700**	**16,400**	**16,600**	**17,400**	**800**		
NNG							
TFX (12-month)*	2,000	2,000	700	1,000	300		
TFX (5-month)	6,200	6,200	6,200	6,200	-		
TF12B	4,604	5,421	4,854	4,854	-		
TF12V	2,931	2,114	2,681	2,681	-		
TF5	3,410	3,410	3,410	3,410	-		
TFX (Capacity Release)	(1,300)	(1,300)	-	-	-		
Total NNG	**17,845**	**17,845**	**17,845**	**18,145**	**300**		
Total Entitlement	**33,545**	**34,245**	**34,445**	**35,545**	**1,100**	**3.19%**	**0.41%**
Total Annual Transportation	**22,535**	**22,535**	**21,235**	**21,535**	**300**	**1.41%**	
Total Winter Only Transport	**11,010**	**11,710**	**13,210**	**14,010**	**800**	**6.06%**	
Percent of Winter Only Capacity	32.82%	34.19%	38.35%	39.41%			

*Demand profile includes 1,000 dk: Remaining 1,000 dk used to deliver gas to Viking interconnect at Chisago for 1,300 dk FT-A (12 Months) "back-haul" contract to Vergas, MN.

Source: Great Plains Exhibit B

Department Attachment 2
Docket No. G04/M-18-454
Great Plains Demand Entitlement Analysis*

	Number of Firm Customers			Design-Day Requirement			Total Entitlement Plus Peak Shaving			Reserve Margin	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Heating Season	Number of Customers	Change from Previous Year	% Change From Previous Year	Design Day (Dth)	Change from Previous Year	% Change From Previous Year	Total Design-Day Capacity (Dth)	Change from Previous Year	% Change From Previous Year	Reserve (7) - (4)	% Reserve [(7)-(4)]/(4)
2018-2019	24,240	243	1.01%	33,674	941	2.87%	35,545	1,100	3.19%	1,871	5.56%
2017-2018	23,997	184	0.77%	32,733	335	1.03%	34,445	200	0.58%	1,712	5.23%
2016-2017	23,813	(69)	-0.29%	32,398	131	0.41%	34,245	700	2.09%	1,847	5.70%
2015-2016	23,882	358	1.52%	32,267	1,143	3.67%	33,545	900	2.76%	1,278	3.96%
2014-2015	23,524	296	1.27%	31,124	1,691	5.75%	32,645	2,000	6.53%	1,521	4.89%
2013-2014	23,228	290	1.26%	29,433	339	1.17%	30,645	0	0.00%	1,212	4.12%
2012-2013	22,938	164	0.72%	29,094	158	0.55%	30,645	159	0.52%	1,551	5.33%
2011-2012	22,774	40	0.18%	28,936	(393)	-1.34%	30,486	(1,380)	-4.33%	1,550	5.36%
2010-2011	22,734	(2)	-0.01%	29,329	(515)	-1.73%	31,866	(1,170)	-3.54%	2,537	8.65%
2009-2010	22,736	85	0.38%	29,844	119	0.40%	33,036	(1,170)	-3.42%	3,192	10.70%
2008-2009	22,651	49	0.22%	29,725	(714)	-2.35%	34,206	0	0.00%	4,481	15.07%
2007-2008	22,602	1	0.00%	30,439	(406)	-1.32%	34,206	0	0.00%	3,767	12.38%
2006-2007	22,601			30,845			34,206			3,361	10.90%
Average			0.59%			0.76%			0.36%		7.53%

	Firm Peak-Day Sendout			Per Customer Metrics			
	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Heating Season	Firm Peak-Day Sendout (Dth)	Change from Previous Year	% Change From Previous Year	Excess per Customer [(7) - (4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per Customer (7)/(1)	Peak-Day Send per Customer (12)/(1)
2018-2019	unknown			0.0772	1.3892	1.4664	unknown
2017-2018	28,641	112	0.39%	0.0713	1.3640	1.4354	1.1935
2016-2017	28,529	1,283	4.71%	0.0776	1.3605	1.4381	1.1980
2015-2016	27,246	(1,853)	-6.37%	0.0535	1.3511	1.4046	1.1409
2014-2015	29,099	1,406	5.08%	0.0647	1.3231	1.3877	1.2370
2013-2014	27,693	3,471	14.33%	0.0522	1.2671	1.3193	1.1922
2012-2013	24,222	5,513	29.47%	0.0676	1.2684	1.3360	1.0560
2011-2012	18,709	(4,269)	-18.58%	0.0681	1.2706	1.3386	0.8215
2010-2011	22,978	1,442	6.70%	0.1116	1.2901	1.4017	1.0107
2009-2010	21,536	(1,731)	-7.44%	0.1404	1.3126	1.4530	0.9472
2008-2009	23,267	540	2.38%	0.1978	1.3123	1.5101	1.0272
2007-2008	22,727	852	3.89%	0.1667	1.3467	1.5134	1.0055
2006-2007	21,875			0.1487	1.3648	1.5135	0.9679
Average			3.14%	0.0998	1.3247	1.4245	1.0665

*The Petition is the second in which the Company's South District and North District were combined based the ruling in Docket No. G004/GR-15-879. The Department combined the districts for comparison.
Source: Great Plains Exhibit D