

January 17, 2014

Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
600 E Blvd Ave
Bismarck, ND 58505

Re: Case No. PU-12-813
Case No. PU-13-194
Case No. PU-13-195
Case No. PU-13-706
Case No. PU-13-707
Case No. PU-13-708
Case No. PU-13-742
Case No. PU-13-743

Northern States Power Company
Comprehensive Settlement Agreement

Dear Mr. Nitschke:

Enclosed for filing is an original copy of Advocacy Staff's additional direct testimony supporting the Comprehensive Settlement Agreement in the above captioned proceedings. Staff filed its initial direct testimony supporting the Settlement on December 20, 2013.

I look forward to the formal hearing next week.

Sincerely,



Mike Diller
Director of Economic Regulation

Enclosure

C: Dave Sederquist

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Additional direct testimony of Advocacy Staff

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**BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

In the Matter of the Comprehensive Settlement Agreement

***Case No. PU-12-813
Case No. PU-13-194
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Case No. PU-13-742
Case No. PU-13-743***

ADDITIONAL DIRECT TESTIMONY

OF

MIKE DILLER

ON BEHALF OF THE

**NORTH DAKOTA PUBLIC SERVICE COMMISSION
ADVOCACY STAFF**

January 23, 2014

1 Q: Provide your name and position at the North Dakota Public Service
2 Commission (commission).

3 A: My name is Mike Diller and I am the Director of Economic Regulation.

4
5 Q: Are you the same witness that provided direct testimony supporting the
6 Comprehensive Settlement Agreement on December 20, 2013?

7 A: Yes.

8
9 Q: What is the purpose of your testimony?

10 A: I am providing additional testimony supporting the Settlement Agreement
11 (Settlement). The first part of my testimony includes some of my more
12 substantive opening comments provided to the commission at the Informal
13 Hearing held on January 7, 2014 in a question an answer format so that
14 the commission has access to it in written form. The second part will
15 address questions received from commissioners at the January 7, 2014
16 informal hearing.

17

18 Q: Do you have any concerns about the commission ordering a change in the
19 jurisdictional demand allocation factor without further study?

20 A: I laid out some of my concerns with both the twelve coincident peak
21 (12CP) and the single coincident peak (1CP) methods in my initial
22 testimony supporting the Settlement. Studying the demand requirements
23 and allocation methodologies to make a well informed decision will be
24 much better than challenging the historical method without a sound record
25 to back it up. The commission can certainly order anything it wants but
26 this issue is too big to think that it will not be appealed should the
27 commission adopt 1CP for its rate case order.

28

29 Advocacy staff advanced the idea of 1CP in its rate case position. I tried
30 to advance the 1CP method in the previous rate case but my witness was
31 unable to support it based on his professional judgment. In the current

1 rate case proceeding, my jurisdictional allocation witness filed written
2 testimony supporting 1CP. However, after hearing Northern States Power
3 Company's (NSP) oral testimony at the technical hearing, Mr. Pavlovic
4 waffled in his support of 1CP. The difference between moving from 12CP
5 to 1CP results in allocating more than \$20 million of allocated costs away
6 from North Dakota to NSP's other jurisdictions and represents about 10%
7 of NSP's North Dakota annual revenues.

8

9 As decision makers, the commission is always weighing risks and benefits
10 of one idea against another. The analytics and resulting policies of the
11 commission is what gets me up in the morning. In that vein, the
12 commission should consider not only what would occur should it order
13 1CP and win in court but what would occur if it does not win in court.

14

15 Consider that the parties have agreed to an interim refund of \$4 million
16 which is worth about \$20 per average residential customer. Without
17 ordering 1CP, the commission would be hard pressed to order a larger
18 refund as the Settlement incorporates most of advocacy staff's
19 adjustments. According to NSP's lawyer Mr. Simpser, an answer on
20 appeal to the ND Supreme Court could take as little as 6-8 months and
21 perhaps upward of 2 years. Let's take the lower estimate for the sake of
22 discussion.

23

24 So then, the commission would order a \$4 million refund around February,
25 2014, plus \$20 million more for 1CP or about \$120 (\$24 million / \$4 million
26 x \$20) per residential customer. Of course, if the court decides against
27 the commission six months later to make the math easy, then the rate
28 surcharge for the wrong decision would accumulate to \$30 million (\$20
29 million x 1.5 years) or more than \$150 (\$30 million / \$4 million x \$20) of
30 make-up charges to average residential customers for past use combined

1 with a 2014 interim rate increase that would likely be in place absent a
2 settlement. Explaining that to the public would be difficult.

3

4 There is so much at stake here that I am hopeful that we can study the
5 issue of jurisdictional demand and then decide the matter on a full and
6 complete record that can be supported both in a court of law and the court
7 of public opinion. In the end, the commission still gets to choose which
8 method is used, whether it is now or after it has been studied.

9

10 Q: The Settlement calls for a reshuffling or restacking of the generation mix
11 that is assigned to North Dakota. What value is there in doing so?

12 A: The Settlement provides the commission with something it has
13 increasingly desired: the ability to determine Xcel Energy's electric
14 generation mix for purposes of setting rates in North Dakota. North
15 Dakota's energy policies are different than those of Minnesota and it has
16 caused a lot of rancor between the commission and NSP. This part of the
17 settlement is a big risk to NSP as it will require Minnesota to begin paying
18 for its own prescribed generation programs that North Dakota finds
19 unacceptable. If Minnesota refuses to pay for all of its programs, NSP will
20 be stuck with stranded investment and no chance of full recovery.

21

22 NSP is hoping and trusting that the Minnesota Public Utility Commission
23 (MPUC) will treat them fairly and that the North Dakota commission will do
24 the same resulting in no stranded investment. The logic that a state
25 causing the costs should be willing to pay for the costs is pure; but still
26 presents a risk to NSP.

27

28 Let me provide some examples of what may occur in the restacking of
29 generation resources for North Dakota. If the commission were to decide
30 that the Community-Based Energy Development (CBED) projects required
31 in Minnesota are not acceptable for North Dakota ratepayers, North

1 Dakota rates would decrease by about \$1.2 million a year. If the
2 commission decided that the biomass projects in Minnesota were not
3 acceptable for North Dakota ratepayers, North Dakota's cost of providing
4 service would decline by nearly \$6 million a year. Going forward, if the
5 commission finds that solar energy is too expensive and that the new
6 1.5% mandate in Minnesota is unacceptable, again North Dakota
7 ratepayers would benefit by avoiding sharing in the costs of expensive
8 generation facilities.

9

10 Further, I think controlling our own generation resource mix makes it at
11 least conceivable that a partnership could be formed to build a North
12 Dakota generation facility with other local utilities whereby NSP would
13 agree to use this energy to serve North Dakota customers and not burden
14 any of the other jurisdictions with its cost. Controlling our own generation
15 mix and our own destiny in North Dakota is one of the cornerstones of the
16 Settlement.

17

18 Q: At the informal hearing, Commissioner Kalk expressed concern about the
19 Competitive Acquisition Process (CAP) in Minnesota and whether NSP
20 lobbied for it so as to make it easier for the Company to pick their own
21 generation. Please comment.

22 A: I am unable to address to what extent NSP lobbied for CAP. However,
23 given our experience with the current CAP before the MPUC, CAP makes
24 it more difficult for NSP to simply self-build generation and ignore the
25 offerings from the marketplace. To date, the CAP in Minnesota for
26 additional peaking plant facilities has resulted in the Administrative Law
27 Judge recommending against NSP's proposals to build gas combustion
28 turbines in favor of a combination of solar generation and capacity buys
29 that would be provided from outside entities. Opening up the bid process
30 to meet generation would appear to be a strong free market solution and a
31 good business practice. However, ensuring low cost bids through a

1 competitive process can be quickly eliminated and obscured if the MPUC
2 chooses based on environmental preferences and mandates over least
3 cost planning.

4

5 Q: At the informal hearing, Commissioner Kalk wondered if the Company
6 would accept a larger increase upfront followed with no rate increases for
7 the next several years. Please comment.

8 A: The Company quickly responded at the informal hearing arguing for the
9 matching principle (revenues should match expenses) and the desire for a
10 more steady net income. I am unable to address whether NSP would
11 agree to this alternative approach but if the financial results are the same
12 except for the possibilities of reporting vacillations in North Dakota
13 earnings, I don't know why NSP would not consider the alternative. This
14 approach would require a change in the Settlement so that over-earnings
15 in the early years would not be returned to customers.

16

17 To smooth out reported earnings, the commission could require that any
18 over-earnings be rolled forward as a regulatory liability to offset future
19 under-earnings in the years to come. That said, this approach would be a
20 little more complex and it would create some intergenerational issues
21 whereby customers in Year 1 would subsidize the actual cost of providing
22 service to customers in the later years.

23

24 Q: At the informal hearing, Commissioner Kalk indicated that he would
25 support extending the smart switches installed in Fargo to the cities of
26 Grand Forks and Minot. Please comment.

27 A: This was discussed between the parties early in the rate case
28 investigation and we decided that more experience with the new Fargo
29 switches was desired before expanding the applications further. For
30 further information, NSP provided a thorough analysis of the issue in its
31 late filed Exhibit D.

1 Q: At the informal hearing, Commissioner Fedorchak expressed concern
2 about the number of rate cases filed by NSP, the protracted need for more
3 rate increases and the drivers of the cost increases.

4 A: It is true that in the last 5 years NSP requested 4 rate increases while
5 Otter Tail Power Company (Otter Tail) and Montana-Dakota Utilities Co.
6 (MDU) have only sought a rate increase once during the same time
7 period.

8

9 However, Otter Tail has added three large wind farms to its operations in
10 recent years each of which could have generated a rate case absent the
11 Company's Renewable Energy Recovery Rider. To date, every dollar of
12 cost recovery for these wind farms has come through the Rider. Similarly,
13 both Otter Tail and MDU employ Transmission Cost Recovery Riders as
14 well as Environmental Cost Recovery Riders which have not been
15 deployed to date by NSP.

16

17 Still, NSP has been falling back in its competitive rate position with respect
18 to the other electric entities providing service in North Dakota. These
19 entities include municipalities, cooperatives and investor-owned utilities.
20 From a cost of service perspective, each type of entity has its advantages
21 and disadvantages but tracking the overall standing among the electric
22 service providers over time suggests that NSP is struggling to keep up. In
23 2004, NSP's average retail rate (total revenues / total sales) for electricity
24 ranked 12th out of 36 reporting entities (1st being the cheapest). By 2011,
25 NSP had fallen to 22nd. The U.S. Energy Information Administration (EIA)
26 does not have 2012 data available for all North Dakota providers at this
27 time to provide a more current update.

28

29 The "drivers" of the rate increases are primarily capital investment related.
30 Staff went over the financial projections with the Company during our
31 settlement negotiation process and was able to agree in principal with the

1 forecast so long as an earnings backstop was part of the Settlement.
2 Naturally, the further out one goes in projecting costs, the riskier and more
3 difficult the task to produce reliable numbers. Staff has asked NSP to put
4 a "finer point" on the projected cost drivers at the January 23, 2014 formal
5 hearing.

6

7 Q: At the informal hearing, Commissioner Christmann desired a North Dakota
8 rate comparison with Otter Tail and MDU as they are the only other
9 investor-owned utilities operating in the State. Please comment.

10 A: Using the same ranking analysis as discussed earlier whereby NSP went
11 from being ranked 12th to 22nd between the years of 2004 to 2011, MDU
12 went from being ranked 25th to 18th and Otter Tail went from 21th to 15th
13 over the same time period. In other words, while NSP rates became less
14 competitive with other North Dakota electric service providers, both MDU
15 and Otter Tail became more competitive. According to the EIA, Otter
16 Tail's 2012 average retail rates (total revenues / total sales) was 7.34
17 cents per kWh; MDU's was 7.83 cents per kWh; and NSP's was 8.10
18 cents per kWh. I suspect this trend will turn around some as MDU and
19 Otter Tail customers begin paying for the Big Stone environmental
20 upgrades.

21

22 Q: At the informal hearing, Commissioner Christmann expressed concern
23 about doing a study on the jurisdictional allocation of demand costs
24 immediately after ordering on the Settlement because if the study
25 indicated the factor used in the Settlement was wrong, the study
26 information would be old and not useful by the time the next rate case was
27 filed. Please comment.

28 A: Generally speaking, the demand curves of both NSP's North Dakota
29 operations and its total system operations are similar from one year to the
30 next so the right allocation method based on demand characteristics today
31 would be useful for many years and would not grow stale in a couple of

1 years' time. Further, a study is more concerned with discovering and
2 developing a plan of fair cost apportionment based on cost causation.
3 Because the end result will be based on principles and not outcomes, the
4 element of time is not so important.

5
6 Beyond that, I am not sure that a jurisdictional demand factor for
7 generation assets is even necessary if the resource restacking is done
8 differently than what has been envisioned thus far in this proceeding.
9 Suggesting something totally different at this stage of the Settlement is a
10 little risky but I believe the comprehensive nature and framework of the
11 Settlement for developing the best path forward will allow for this type of
12 consideration.

13
14 Let me explain. Perhaps NSP would be agreeable to setting North
15 Dakota's share of plants permanently rather than changing North Dakota's
16 share of plant "ownership" from one year to the next based on a demand
17 allocation factor. In doing so, NSP would operate its North Dakota
18 generation system more like a stand-alone utility yet with the benefits of
19 an integrated system.

20
21 For a very long time, NSP has been assigning the costs of its generation
22 assets to North Dakota based on a 12CP factor. Let's assume that the
23 factor has changed little over time and that North Dakota ratepayers have
24 essentially been paying for 5.75% of the generation assets to date. Could
25 we not agree to permanently direct assign that share of generation assets
26 to North Dakota? Convincing the other state jurisdictions to allow direct
27 assignment for assets we have been paying for anyway would be easier
28 than trying to move all the other states to a different and more nebulous
29 demand factor. The other states would not need to change anything they
30 are doing now. They could all still use 12CP; it would just be applied to a
31 little smaller generation base. It would lessen the likelihood of stranded

1 investment. It would avoid arguing about 1CP verses 12CP. It would
2 avoid fluctuations in North Dakota's assignments of generation assets
3 from one year to the next. Accounting for the costs would be easier and
4 cleaner.

5
6 I realize that I have thrown this idea into the pool of ideas late but do so
7 without caution for a couple of reasons. One, I would like to hear a
8 response from the Company as to the merits of this approach. Secondly, I
9 do it to highlight the fact that this Settlement is a framework for ever-
10 evolving thought on how we might best proceed with NSP into the future.
11 The Settlement has developed a great set of goals and priorities. I look
12 forward to the new ideas to come and the implementation of smart policy.

13

14 Q: Does this conclude your additional testimony?

15 A: Yes, it does.

16