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November 9, 2012

VIA E-FILING
Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Room 11G-1
Washington, D.C. 20426

Re: Dairyland Power Cooperative Petition for Declaratory Order
Concerning Formula Rates and Incentives
Docket No. EL13-_____,

Dear Secretary Bose:

Dairyland Power Cooperative ("Dairyland") submits for filing a Petition for Declaratory Order. Dairyland request that the Commission approve the charging of certain incentive rates and related relief for their transmission investments in the Hampton – Rochester – La Crosse transmission project (the "HRL Project"). This relief parallels relief that the Commission has approved for WPPI Energy, Inc. ("WPPI") investments in its Order on Petition For Declaratory Order, Docket No. EL12-67, 141 F.E.R.C. ¶ 61,004 (October 1, 2012), and Xcel Energy Services, Inc. ("Xcel") investments in its Order Granting Incentives and Accepting Proposed Rate Formula Modifications, Subject to Conditions, Docket No. ER07-1415, 121 F.E.R.C. ¶ 61,284 (December 21, 2007). For the facilities for which Dairyland seek approvals for incentive rates, Xcel wholly-owned subsidiaries, WPPI, Dairyland, and others will be co-owners.

This filing contains the Dairyland Petition for Declaratory Order; the Testimony and Exhibits of Phillip M. Moilien (DPC-1 – DPC-5); the Testimony and Exhibits of Jerome Iverson (DPC-6 – DPC-7), and; the Testimony and Exhibits of James Pardikes (DPC-8 – DPC-17).

Because of the relationship between this filing, WPPI's filing in Docket No. EL12-67, and Xcel' filing in Docket No. ER07-1415, Dairyland is serving a copy of this filing electronically on all parties in Docket Nos. EL12-67 and ER07-1415.

Dairyland has paid the required filing fee via pay.gov.

Respectfully submitted,

WHEELER, VAN SICKLE & ANDERSON, S.C.

/s/ Jeffrey L. Landsman

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Enclosures

cc: Service lists in Docket Nos. EL12-67 and ER07-1415.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Dairyland Power Cooperative Docket No. EL13-____-000.

PETITION FOR DECLARATORY ORDER

Pursuant to Rule 207(a)(2) of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.207(a)(2) (2010), Dairyland Power Cooperative ("Dairyland" or "DPC") respectfully petitions the Commission for a declaratory order granting the transmission rate incentives described below in connection with the participation of Dairyland in the regional planning initiative known as the Capacity Expansion by the Year 2020 ("CapX2020"). Dairyland is participating in the development of Hampton – Rochester – La Crosse transmission project (the "HRL Project" or "Project"). This is the same Project in which the Commission has previously provided similar transmission rate incentives to other joint-owners.[1] Among other things, the Project will significantly increase reliability in the Midwest region, and will reduce the costs of delivered power by reducing transmission congestion in the region.

Dairyland seeks the following rate incentives under Section 219 of the Federal Power Act ("FPA"), 16 U.S.C. § 824s (2006), and the Commission's regulations for its participating in the HRL Project:

> (1) the use of a hypothetical capital structure of 35% equity and 65% debt, and;
>
> (2) the recovery of 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond its control.

[1] *WPPI Energy*, 141 FERC ¶ 62,004 (2012) ("WPPI Incentive Rates Order"); *Xcel Energy Servs., Inc.*, 121 FERC ¶ 61,284 (2007) ("Xcel/NSP Incentive Rates Order").

CapX2020 is a joint regional transmission planning initiative of 11 transmission-owning utilities in the upper Midwest to expand the electric transmission grid to ensure continued reliable and affordable service. Dairyland's requested relief is limited to incentives that the Commission has previously granted for the HRL Project and for other portions of the CapX2020 planning initiative for investments by Xcel Energy Services, Inc.,[2] WPPI Energy ("WPPI"),[3] Missouri River Energy Services ("MRES"),[4] Central Minnesota Municipal Power Agency ("CMMPA") and the Midwest Municipal Transmission Group's ("MMTG"),[5] and others.[6] As explained below, Dairyland meets the Commission's criteria for granting the incentives requested.

In this petition, Dairyland seeks only a declaratory order authorizing the two rate incentives listed above. It does not at this time seek Commission approval of a specific rate to implement the requested incentives.[7] Following the Commission's issuance of a declaratory order, Dairyland will cause the Midwest Independent System Operator, Inc. ("Midwest ISO") to make a filing with the Commission under FPA Section 205, 16 U.S.C. § 824d, to implement the recovery of the requested rate incentives through amendments to Attachment O of the Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").[8]

I. COMMUNICATIONS AND CORRESPONDENCE

Dairyland requests that the following persons be included on the official service list in this proceeding, and that all communications concerning this Petition be addressed to the following persons:

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[2] Xcel/NSP Incentive Rates Order at P 53.
[3] WPPI Incentive Rates Order.
[4] *Missouri River Energy Servs.*, 138 FERC ¶ 61,045 (2012) ("MRES Incentive Rates Order").
[5] *Central Minnesota Municipal Power Agency*, 134 FERC ¶ 61,115 (2011) ("CMMPA Incentive Rates Order").
[6] *See, e.g., Otter Tail Power Co.*, 129 FERC 61,287 (2009) ("OTP Incentive Rates Order"); *Great River Energy*, 130 FERC ¶ 61,001 (2010) ("GRE Incentive Rates Order"); *ALLETE, Inc.*, 133 FERC ¶ 61,270 (Dec. 29, 2010) ("ALLETE Incentive Rates Order").
[7] 18 C.F.R. § 35.35(d) (2010).
[8] *Midwest Independent Transmission System Operator, Inc. and Dairyland Power Cooperative*, 131 FERC ¶ 61,187 (2010).

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II. IDENTITY OF THE PETITIONER

Dairyland is a non-stock, not-for-profit Wisconsin generation and transmission cooperative ("G&T") headquartered in La Crosse, Wisconsin. Dairyland is not subject to the rate-making jurisdiction of the Commission.[9] Dairyland is owned by and provides the wholesale power requirements for 25 separate distribution cooperatives in southern Minnesota, western Wisconsin, northern Iowa, and northern Illinois. Direct Testimony of Jerome Iverson, Exh. DPC-6 at 4. Dairyland has all-requirements contracts extending through 2055 with its member distribution cooperatives. *Id*. Dairyland's 25 member distribution cooperatives serve approximately 256,000 member customers. *Id*.

Dairyland is a market participant in the Midwest ISO energy market and has been a Midwest ISO transmission owning member ("TO") since 2010. *Id*. In its capacity as a Midwest ISO TO, Dairyland recovers its annual transmission revenue requirement ("ATRR") under Attachment O to the Midwest ISO Tariff.[10]

III. BACKGROUND

Dairyland is one of eleven regional utilities participating in CapX2020, a comprehensive regional planning initiative. The CapX2020 planning effort resulted in a phased approach, with the first phase comprised of four projects. The four Group 1 projects are:

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[9] *See* FPA Section 201(f), 16 U.S.C. 824(f).
[10] *See*, fn. 8, *supra*.

- an approximately 240-mile, 345 kV transmission line between Brookings County, South Dakota and the southeast corner of the Twin Cities ("Twin Cities – Brooking County");
- an approximately 250-mile, 345 kV line between Fargo, North Dakota and the Monticello substation northwest of the Twin Cities ("Twin Cities – Fargo");
- an approximately 150 mile, 345 kV line from the southeast Twin Cities to Rochester, Minnesota and on to La Crosse, Wisconsin ("HRL Project"); and
- an approximately 70 mile, 230 kV line between the cities of Bemidji and Grand Rapids, Minnesota ("Bemidji – Grand Rapids").

Dairyland is currently participating in the HRL Project only.

In the 2008 Midwest ISO Transmission Expansion Plan ("MTEP") process, a regional transmission planning process overseen by the Midwest ISO, the Midwest ISO's Board of Directors approved the HRL Project as a Baseline Reliability Project. Exh. DPC-6 at 8. The HRL Project will improve reliability in individual communities along the planned route, particularly in Rochester and Winona, Minnesota, and La Crosse, Wisconsin. *Id*. The HRL Project will also provide needed reliability support and maintenance of the regional electrical system. *Id*. The HRL Project will also support the development of new generation in the region, and increase the power transfer capability from Minnesota into Wisconsin. *Id*.

The owners and their expected ownership shares of the HRL Project are Xcel Energy/Northern States Power Company ("Xcel/NSP") (64%), Southern Minnesota Municipal Power Agency ("SMMPA") (13%), Dairyland (11%), Rochester Public Utilities ("RPU") (9%) and WPPI (3%).[11] Exh. DPC-6 at 9-10. Dairyland's 11% share approximates its load ratio share of the Project and was determined through negotiations with the other participants in the Project. *Id*. Dairyland estimates that its 11% share in the currently projected $471 million HRL Project will require an investment of approximately $52 million. *Id*. at 10. These costs may increase due to potential scope changes, additional permitting costs or conditions, litigation delays, and construction cost increases. *Id*.

[11] Uncertainty exists with respect to ownership rights, as highlighted by a recent complaint filed at the Commission by American Transmission Company ("ATC") claiming rights to 50% of the HRL Project's 345 kV facilities. *See*, ATC's Complaint filed with the Commission in Docket No. EL13-9.

IV. STATEMENT OF JURISDICTION

Dairyland is not a "public utility" as defined by the Federal Power Act,[12] and therefore is not subject to traditional rate regulation under FPA Sections 205 and 206. However, Dairyland owns transmission facilities and will recover the costs associated with its investment in the HRL Project through the ATRR it collects under Attachments O of the Midwest ISO Tariff. The Midwest ISO is a public utility, and rates charged under the Midwest ISO Tariff are subject to the Commission's jurisdiction. In Order No. 679,[13] the Commission stated that, "to the extent [its] jurisdiction allows, the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates . . . ."[14] Since DPC is a Midwest ISO TO member and will recover the costs associated with its investment in the HRL Project through the Midwest ISO Tariff Attachments O formula rate that may be revised only through a filing with the Commission, the Commission has jurisdiction to consider the justness and reasonableness of DPC's Attachment O rates.[15] Accordingly, the Commission has jurisdiction to entertain Dairyland's petition for a declaratory order regarding incentive rate treatment, and the Commission has recognized that "encouraging public power participating in such projects is consistent with the goals of [FPA] Section 219 by encouraging a deep pool of participants."[16]

V. PETITION FOR DECLARATORY ORDER

FPA Section 219(a), 16 U.S.C. § 824s(a), directs the Commission to establish incentive-based rate treatments for the "purpose of benefitting consumers by ensuring reliability and

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[12] FPA § 201(f), 16 U.S.C. § 824(f).
[13] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, P. 354 ("Order No. 679"), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31, 236 (2006), ("Order No. 679-A"), *order on reh'g*, 119 FERC ¶ 61,062 (2007).
[14] GRE Incentive Rates Order at P 25 (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 354).
[15] *Id*. (citing *Transmission Agency of Northern California*, 495 F.3d 663, 671-672 (D.C. Cir. 2007) (citing *Pacific Gas & Elec. Co. v. FERC*, 306 F.3d 1112, 1114 (D.C. Cir. 2002))).
[16] Order No. 679 at P 354.

reducing the cost of delivered power by reducing transmission congestion." The Commission issued Order No. 679 pursuant to this obligation.[17] Any request for incentive-based rate treatment under Order No. 679 must include a detailed explanation of how the proposed rate treatment complies with the requirements of FPA Section 219, and a demonstration that the proposed rate treatment is "just and reasonable and not unduly discriminatory or preferential."[18] This demonstration is made by showing that: (1) the facilities for which the incentives are sought comply with the requirements of Section 219 by either ensuring reliability or reducing the cost of delivered power by reducing transmission congestion; (2) that the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project (also known as the "nexus" requirement); and (3) the application of the incentives is just and reasonable.[19] The Commission recognized in Order No. 679 that "to the extent allowed under [the Commission's] jurisdiction, a public power entity should have the same opportunity afforded to jurisdictional entities to recover costs related to new transmission investment," barring inconsistent treatment.[20]

A. The HRL Project is Presumptively Eligible for FPA Section 219 Transmission Ratemaking Incentives Because It Results from a Fair and Open Regional Planning Process and Has Received Approvals From the Minnesota Public Utilities Commission and the Public Service Commission of Wisconsin.

FPA Section 219 requires that the facilities for which incentives are sought either ensure reliability or reduce the cost of delivered power by reducing transmission congestion. Order No. 679 established a rebuttable presumption that this standard is met if: (1) the transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (2) the

[17] *Id*. at P 1.
[18] 18 C.F.R. § 35.35(d).
[19] *Id.*
[20] Order No. 679 at P 356.

transmission project has received construction approval from an appropriate state commission or state siting authority.[21] Order No. 679-A clarified that the authorities and/or process on which it is based must, in fact, consider whether the project ensures reliability or reduces the costs of delivered power by reducing congestion.[22]

As the Commission has already found in proceedings concerning two other owners of the HRL Project, the Project qualifies for the rebuttable presumption.[23] The rationale in those proceedings applies similarly to Dairyland's request, as discussed below and in the testimony of James Pardikes. Exh. DPC-8 at 16-23.

1. The HRL Project Qualifies for the Rebuttable Presumption of FPA Section 219 Standard Compliance Because It Was Approved in the MTEP Regional Planning Process.

The rebuttable presumption applies where "the transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission."[24] The HRL Project has been jointly planned as part of fair and open regional transmission initiatives.

The HRL Project has been planned as part of the MTEP process, a regional planning process overseen by the Midwest ISO. Exh. DPC-8 at 17. In the 2008 Midwest ISO Transmission Expansion Plan (MTEP08), the HRL Project was designated a Regional Expansion Criteria and Benefits 1 (RECB 1) project, also known as a Baseline Reliability Project.

[21] *Id.*
[22] Order No. 679-A.
[23] *See, e.g.,* WPPI Incentive Rates Order at P 14; Xcel/NSP Incentive Rates Order at P 53.
[24] Order No. 679 at P 58.

2. The Approvals of the HRL Project by the Minnesota Public Utilities Commission and the Public Service Commission of Wisconsin Qualifies This Project for the Rebuttable Presumption That The Project Is Eligible for FPA Section 219 Incentives.

The Commission has found that the issuance of a Certificate of Need ("CON") by the Minnesota Public Utilities Commission ("MPUC") on the HRL Project yields the rebuttable presumption that the HRL Project is eligible for Section 219 incentives.[25] The HRL Project received its CON from the Minnesota in 2009.[26] As the Commission previously held, the MPUC conducted an open, on-the record administrative process that involved an extensive evaluation of need for the project, including its impacts on reliability and cost.[27]

Additionally, the Public Service Commission of Wisconsin ("PSCW") issued a Certificate of Public Convenience and Necessity ("CPCN") for the HRL Project on May 30, 2012.[28] The Wisconsin CPCN addresses both the need for the project and the route. The Wisconsin CPCN process is an open, on-the-record administrative process before the PSCW that considers in detail the need for the project, including a consideration of alternatives and the environmental impacts of the proposed project. The PSCW examined local reliability and found that "it is undisputed that the La Crosse local area needs require additional electric infrastructure to provide adequate system reliability."[29] The PSCW also examined regional reliability and

[25] Xcel/NSP Incentive Rates Order at P 53.
[26] Exh. DPC-6 at 10-11; *In the Matter of the Application of Great River Energy, Northern States Power Company (d/b/a Xcel Energy), and Others for Certificates of Need for the CapX 345-kv Transmission Project*, Order Granting Certificates of Need With Conditions, MPUC Docket No. ET-2, E-002, *et al.*/CN06-1115; (May 2, 2009), *on reconsideration*, Order Granting and Denying Motions for Reconsideration, and Modifying Conditions (August 10, 2009) ("MPUC CON Order").
[27] Xcel/NSP Incentive Rates Order at P 53 (finding that Xcel/NSP has "demonstrated that the Minnesota Commission considers whether the project ensures reliability or reduces congestion costs in evaluating an application for a Certificate of Need").
[28] Exh. DPC-6 at 11; *Joint Application of Dairyland Power Cooperative, Northern States Power Company-Wisconsin, and Wisconsin Public Power, Inc., for Authority to Construct and Place in Service 345 kV Electric Transmission Lines and Electric Substation Facilities for the CapX Twin Cities-Rochester-La Crosse Project, Located in Buffalo, Trempealeau, and La Crosse Counties, Wisconsin*, Final Decision, PSCW Docket No. 5-CE-136 (May 30, 2012), *reh'g denied*, (Jul. 17, 2012) ("PSCW CPCN Order").
[29] PSCW CPCN Order at 13.

found that "sufficient need exists for the proposed project to be constructed at 345 kV for its entire length . . . ."[30]

Both the MPUC and the PSCW conducted open, on-the-record administrative processes that involved extensive evaluation of need for the Project, including its impacts on reliability and cost. Therefore, the HRL Project is entitled to the rebuttable presumption that it is eligible for Section 219 incentives.

B. The HRL Project Is Not Routine And Satisfies the Nexus Requirement Because of Its Scope, Effect, and Risks

The Commission requires a demonstration "that there is a nexus between the incentive sought and the investment being made."[31] Order No. 679-A stated that an applicant must demonstrate that "the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project."[32] The nexus test is fact-specific and the Commission must review each application on a case-by-case basis.[33]

The Commission has found the question of whether a project is "routine" to be particularly probative.[34] The Commission will consider "all relevant factors presented by the applicant," and has identified as factors for consideration:

> (1) the scope of the project (e.g. dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region);
>
> (2) the effect of the project (e.g., improving reliability or reducing congestion costs); and
>
> (3) the challenges or risks faced by the project (e.g., siting, internal competition for financing with other projects, long lead times,

[30] *Id*. at 17.
[31] WPPI Incentive Rates Order at P 34.
[32] Order 679-A at P 46.
[33] WPPI Incentive Rates Order at P 34.
[34] WPPI Incentive Rates Order at P 11 (citing *Baltimore Gas & Elec. Co.*, 120 FERC ¶ 61,084, at P 52-55 (2007), *order denying reh'g*, 123 FERC ¶ 61,262 (2008) ("*BG&E*")).

> regulatory and political risks, specific financing challenges, other impediments.)[35]

The Commission clarified that "when an applicant has adequately demonstrated that the project for which it requests an incentive is not routine, that applicant has shown, for purposes of the nexus test, that the project faces risks and challenges that merit an incentive."[36]

As further explained below and by Mr. Pardikes in his testimony, the HRL Project satisfies the nexus requirement because it is not routine, especially for Dairyland. Exh. DPC-8 16-23.

1. The HRL Project's Scale of Investment, Multijurisdictional Route, and Regional Planning Process Demonstrate That the Project Scope Is Not Routine.

The HRL Project would be the first 345 kV transmission project owned by Dairyland in whole or in part, and is much more complex compared to previous transmission projects Dairyland has constructed or owned to date. Exh. DPC-8 at 17. Dairyland's estimated $52 million investment in the HRL Project represents an increase of approximately 23% in net transmission plant over its existing net transmission assets of $225 million. *Id*.

The HRL Project spans multiple state jurisdictions: Minnesota and Wisconsin. This means the Project requires two approvals from two different sets of state utility regulators and other state transportation or natural resource agencies. DPC-8 at 20-21. Right-of-way easements must match up at the state borders, and state permits must be valid at the same time. *Id*. Such permitting duplication provides additional avenues of judicial challenge, thus increasing the chance that aspects of the Project's route may change. *Id*. The federal government has jurisdiction over federal land and aspects of the Project's Mississippi River crossing. *Id*.

[35] *Id*. (citing *BG&E* at P 52).
[36] *Id*. (citing *BG&E* at P 54).

Finally, as explained above, the HRL Project was planned as part of a regional planning process through the Midwest ISO's MTEP process and deemed a Regional Expansion Criteria and Benefits 1 (RECB 1) project. The Commission has previously held that regional projects are not routine by definition.[37]

2. The HRL Project's Impact on Regional Capacity Demonstrates That The Project's Effect Is Not Routine.

The HRL Project will have an effect on local and regional reliability and reduce congestion costs. It significantly increases transmission capacity in the region, and will provide for increasing demand in Rochester and Winona, Minnesota, and La Crosse, Wisconsin. Exh. DPC-8 at 19-20. It will maintain the reliability of the regional transmission system. *Id*. Additionally, it will increase the power transfer capability from Minnesota into Wisconsin, and support the interconnection of new generation, especially renewable energy from the wind-rich areas of western Minnesota and the Dakotas. *Id*. The Commission has previously found that construction of transmission facilities designed to provide access to remote renewable energy resources is not routine.[38]

3. The HRL Project's Risks and Challenges Related to Joint Ownership, Limited Control, Outstanding Permits and Rights-of-Way, and Use of Advanced Technologies Demonstrate That the HRL Project Is Not Routine.

Additional risks exist due to the HRL Project's multi-ownership structure, with multiple types of owners in multiple jurisdictions, including investor-owned (Xcel/NSP), municipal joint action power agencies (SMMPA and WPPI), a municipal electric utility (RPU), and a G&T cooperative (Dairyland). This makes Project governance and obtaining Project participants' approvals more complex. Exh. DPC-8 at 18. Such ownership diversity prolongs and complicates

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[37] *BG&E* at P 58.
[38] *See, e.g., PacifiCorp*, 125 FERC ¶ 61,076 at P 45 (2008); *Green Energy Express LLC*, 129 FERC ¶ 61,165 at P 33 (2009).

decision-making because of different stakeholders, different state regulators, and different governance structures. *Id*. This is Dairyland's first experience with multiple owners jointly owning transmission facilities, and, Dairyland believes, the same is true for the other HRL Project participants except Xcel/NSP. *Id*. For these reasons, there is a substantial potential for increased complexity regarding multiple aspects of the HRL Project, which in turn, increases the Project's risks. *Id*.

Dairyland, as a minority investor in the HRL Project, is also subject to the individual risks of the principal Project participant. For example, the withdrawal of Xcel/NSP's substantial investment and experienced project management team could change the economics of the Project and cause other participants to leave the Project. *Id*. at 19. The pending claim of ATC to 50% of the HRL Project in Docket No. EL13-9 may also affect participation in the Project, and at the very least, creates a great deal of uncertainty regarding the Project participants' expectations.[39]

Route changes, construction delays, and cost increases may still affect the HRL Project. Mr. Pardikes explains the risks caused by the state routing decisions and outstanding judicial review proceedings. Exh DPC-8 at 20-22. He further reveals the uncertainty caused by state and federal construction, environmental, and transportation permits that still need to be obtained. *Id.* at 21. Additionally, right-of-way easements have not yet been secured for Wisconsin and have just started to be acquired in Minnesota. *Id*. The easement acquisition process could result in delays or increases in the cost of land. *Id*. The cost of the HRL Project has already increased from about $345 million in 2007, to the current estimate of $471 million. *Id*. at 22.

Finally, new technologies are more difficult to construct and operate than traditional technologies, and increase the potential of longer lead times and associated costs and risks. *Id*. at 22. The HRL Project will utilize new technologies including advanced conductor designs of steel

[39] *See*, Commission Docket No. EL13-9.

supported aluminum conductors with trapezoidal wire. *Id*. It will also utilize new technologies such as micro-processor based digital protective relays, digital fault recorders, and Programmable Logic Controller ("PLC")-based control and annunciation, tubular steel structures, and fiber-optic based communication. *Id*.

C. Support for Requested Transmission Rate Incentives

Dairyland is seeking: (1) the use of a hypothetical capital structure of 35% equity and 65% debt for the length of the project's financing (35% equity to total capitalization ratio), and; (2) recovery of 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond its control. Dairyland is not seeking recovery of prudently-incurred Construction Work in Progress ("CWIP") or an incentive return on equity ("ROE") rate adder.[40]

1. Requested 35% Equity Ratio (65% Debt Ratio) in Hypothetical Capital Structure

Dairyland seeks to use a hypothetical capital structure in its revenue requirement recovering the costs of the HRL Project, as allowed by Orders Nos. 679 and 679-A. Dairyland requests a hypothetical capital structure of 35% equity and 65% debt for the length of its financing period for the HRL Project.

The testimony of Mr. Pardikes provides numerous reasons and ample analytical support of Dairyland's requested hypothetical capital structure with a 35% equity ratio for the life of the financing related to the Project. *See,* DPC-8 at 23-44.

a) Project Risk.

As stated above and in Mr. Pardikes' testimony, the HRL Project's issues related to joint ownership, limited control, outstanding permits and rights-of-way, and use of advanced

[40] Dairyland is not seeking recovery of costs associated with CWIP because it does not expect to experience significant cash flow strain or significant financing costs during the construction period. *See*, Exh. DPC-8 at 14.

technologies create risk that Dairyland would not face in other, more-certain internal projects. The 35% equity ratio provides a return consistent with this additional risk and will encourage Dairyland to invest in large, complex transmission projects in the future.

Dairyland currently has approximately $225 million of net transmission plant. Exh. DPC-8 at 17. Dairyland's HRL Project investment is expected to total $52 million, and will be financed with debt. *Id*. at 25. As a not-for-profit, non-stock G&T cooperative, Dairyland cannot raise equity capital through a stock offering. *Id*. at 27.

b) Consistent with Dairyland's Improving Metrics and its Goal of Solidifying an "A" Credit Rating with Both Credit Rating Agencies

The requested hypothetical equity ratio provides a level of return necessary to service the HRL debt and continue Dairyland's recent improvements in its financial performance, consistent with achieving its financial policy. Exh. DPC-8 at 40. Dairyland's current credit ratings are "A" (S&P) and Moody's A3 (Moody's equivalent of an "A-"with the S&P). Direct Testimony of Phillip M. Moilien, Exh. DPC-1 at 7. Dairyland has a financial policy goal of being "A" rated with both S&P and Moody's. *Id.* Dairyland's goal is to improve its current A3 Moody's rating to A2, which would be equivalent to its current S&P "A" rating. *Id*. Becoming rated A2 by Moody's, would give DPC some leeway to withstand unexpected downturns in margin and/or unexpected increases in capital expenditures without falling out of Moody's "A" category into the "B" category, which would result in significantly higher financing costs. *Id.* at 8. Obtaining a solid "A" rating from both credit rating agencies has become particularly important as the supply of RUS debt has become less reliable and G&Ts including Dairyland have sought financing from commercial sources. *Id*. at 4. The requested 35% equity ratio has been analytically derived.[41] It provides financial metrics that are consistent with DPC's recent and projected financial ratios,

[41] See Exh. DPC-8 at 36-39 and Exh. DPC-13 for the calculation of the required equity ratio to provide a DSC and other metrics consistent with solidifying an "A" credit rating for both credit rating agencies.

financial metrics of "A" rated G&Ts including projected increases in DPC's actual equity ratio, and solidifying the company's target credit rating of "A". *Id.* at 9-10. More specifically, the requested 35% equity ratio provides a debt service coverage ratio ("DSC") on the HRL Project-related debt of 1.29 that is consistent with Dairyland's improving and projected DSC ratio, and is at the level consistent with achieving an A2 Moody's credit rating. Exh. DPC-1 at 9-10; Exh. DPC-8 at 34. In addition, a hypothetical capital structure on the HRL Project will contribute to DPC obtaining financing on future transmission projects it contemplates at more attractive financing terms, thus leading to lower long-term Midwest ISO rates.

c) Dairyland's Investment in the HRL Project Represents a Larger Risk to Dairyland Member-Owners Than Would the Same Investment to Investor-Owned Utility Shareholders.

Similar to the case made by MRES in their participation in the Fargo and Brookings projects,[42] Dairyland and its distribution cooperatives face even more substantial risks from Dairyland's participation in the HRL Project than the Project's investor owned utility ("IOU") participant (Xcel/NSP). This risk provides additional support for Dairyland's request to use a hypothetical capital structure.

In the event that an IOU defaulted on its debt, its shareholders' risk is limited to the loss of their stock and they are not obligated to make the bondholders whole. Exh. DPC-8 at 37-38. In contrast, Dairyland's distribution cooperatives are both its customers and its owners and are responsible for all of DPC's costs of service, including debt service, through increases in the wholesale rate. *Id.* at 38. The distribution cooperatives' all-requirements contracts with Dairyland obligate them as owners and customers to assume rate increases in order to make the debt service payments and ensure all debt is repaid. *Id*. Therefore, the member-owners of Dairyland will be taking on greater risk than the stockholders in an IOU because the stockholders of an IOU are

[42] MRES Incentive Rates Order at P 29.

only liable for the funds they have paid for stock, not the repayment of the debt. *Id*. Credit rating agencies view the Dairyland distribution members' all-requirements contracts as a key strength and component of the Dairyland's ratings and creditworthiness. *Id*. at 38.

Load in a Midwest ISO pricing zone pays the zone-specific revenue requirements. Dairyland pays the Midwest ISO's NSP transmission rate for Dairyland's member load located in the NSP pricing zone, which reflects Xcel/NSP's equity ratio, income taxes, and historically higher cost of debt. *Id.* at 40-41. Xcel/NSP pays the Midwest ISO's DPC transmission rate for Xcel/NSP's load located in the Dairyland pricing zone, which reflects Dairyland's substantially lower revenue requirement resulting from Dairyland's much lower equity ratio, lower historical interest rates on debt, and Dairyland's tax-exempt status. *Id.* Because Dairyland's risks in the HRL Project are at least as great as Xcel/NSP (and higher as described above), a hypothetical capital structure should be approved for Dairyland to partially address the large disparity in returns and revenue requirements. *Id.* If such a disparity remained unaddressed, Dairyland would be discouraged from making these types of complex transmission investments because the return would not be commensurate with the risk.. *Id*. at 41. Granting Dairyland's proposed hypothetical capital structure would be consistent with the intent of FPA Section 219 to promote transmission capital investment "regardless of the ownership of the facilities."

d) Dairyland Requests the Hypothetical Capital Structure to Apply During the Life of the Financing Related to the HRL Project.

Dairyland seeks to apply the hypothetical capital structure for the life of its financing for the HRL Project. Exh. DPC-8 at 42-44. Dairyland's HRL Project-related debt is expected to be 30-year debt with final maturity in 2046. *Id*. at 44. Dairyland has no ability to issue common stock, and must attain its requested hypothetical capital structure through the life of the financing of the Project in order to provide the returns necessary to achieve the DSC and other key metrics consistent with solidifying an "A" credit rating with both credit agencies. *Id.* at 43. Such a time-frame is also consistent with DPC's members having the ultimate responsibility for Dairyland's debt service for the length of financing. *Id*.

The Commission has previously approved a hypothetical capital structure for the duration of the financing for other CapX2020 participants that are reliant on non-equity financing such as CMMPA, MRES, and WPPI.[43] Approving Dairyland's request for hypothetical capital structure for the entire period of debt financing, combined with abandoned plant cost recovery, will contribute positively to Dairyland's credit rating, and encourage Dairyland's participation in future transmission projects at more advantageous financing terms. *Id*. at 44.

e) Providing Dairyland the Requested Hypothetical Capital Structure Will Further the Commission's Policy Goal of Promoting Public Power Investment in Transmission.

Allowing Dairyland to use a hypothetical capital structure furthers the purposes of Order No. 679 by incentivizing Dairyland, other G&Ts, and other public power entities, to invest in future transmission projects. Exh. DPC-8 at 41-42. Dairyland and other G&T cooperatives and public power entities have limited resources to invest in transmission, and must consider other investments such as generation and more routine transmission projects. *Id*. New, more complex high voltage transmission projects like the HRL Project must provide returns that reflect the risks of the projects if Dairyland is to participate. *Id*.

f) Commission Precedent Supports the Requested Hypothetical Capital Structure.

The Commission has consistently allowed non-jurisdictional investors in CapX2020 projects to apply for hypothetical capital structures together with the standard Midwest ISO

[43] *See*, CMMPA Incentive Rates Order at P 31; MRES Incentive Rates Order at P 37; WPPI Incentive Rates Order at P 32.

ROE.[44] The Commission has recently recognized its precedent of granting use of a hypothetical capital structure by municipal entities that have relied upon non-equity financing,[45] and the Commission's policy reveals the same rationale applies to other non-IOU joint owners of large, risky transmission projects.[46] The Commission found that such comparable treatment is reasonable, and meets the Order No. 697 "nexus" test, because it addresses the project's risks and serves to encourage joint action agencies and their members "to invest further in future transmission expansion projects," and to enhance their "ability to meet . . . debt obligations."[47]

WPPI, another participant in the HRL Project, received Commission approval to use a hypothetical capital structure with a higher equity ratio than the request of Dairyland.[48] Other participants in CapX2020 projects have also received approval to use a hypothetical capital structure higher than the request of Dairyland.[49] Dairyland's requested hypothetical 35% equity capital structure is appropriate based on the financial analysis explained in Mr. Pardikes testimony. Exh. DPC-8 at 37.

g) The Requested Hypothetical Capital Structure is Just and Reasonable Because it Demonstrates the Required Nexus Between the Financial Demands Imposed on Dairyland and the Requested Hypothetical Capital Structure.

Dairyland defers detailed discussion of why its ATRR and rates are just and reasonable for a subsequent filing. Nevertheless, Mr. Pardikes, in his testimony, explains why Dairyland's requested hypothetical capital structure applied to the HRL Project and the requested abandoned plant cost recovery (discussed in Section 2, below) are just and reasonable. Exh. DPC-8 at 51-55.

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[44] WPPI Incentive Rates Order at P 32.
[45] *Id*.
[46] Exh. DPC-8 at 15-16 (noting Order Nos. 679, 679-A, 890, and 1000, and Commissioner Norris's concurring opinion in the WPPI Incentive Rates Order).
[47] MRES Incentive Rates Order at P 38.
[48] *See*, WPPI Incentive Rates Order.
[49] *See, e.g.*, WPPI Incentive Rates Order (45% equity ratio); MRES Incentive Rates Order (45% equity ratio); CMMPA Incentive Rates Order (50% equity ratio).

These reasons include that the requested hypothetical capital structure will provide the necessary coverage on the debt related to the HRL Project, and helps mitigate the risk that the DSC and other key financial metrics related to the Project will put downward pressure on the maintenance and continuing improvement of Dairyland's company-wide metrics. *Id*. at 52. Dairyland's requested hypothetical capital structure is lower than the equity ratios that have been approved for other non-jurisdictional utilities reliant on non-equity financing, as discussed above. *Id*. at 53

2. Abandoned Plant Recovery

Dairyland requests that the Commission authorize Dairyland to recover its prudently-incurred costs associated with the HRL Project if the Project is cancelled or abandoned for reasons not within Dairyland's control. Exh. DPC-8 at 44. The amount recovered, and the prudence of the underlying expenditures, would be established and subject to Commission review through a subsequent filing in the event that Dairyland seeks recovery.[50]

Commission orders have approved such protection for CapX2020 projects, including the HRL Project.[51] Mr. Pardikes' testimony demonstrates that the considerations that justified providing for abandoned plant protection in those prior cases applies here as well. *See, e.g.,* DPC-8 at 54-55. In the Xcel/NSP Incentive Rates Order, the Commission found that the protection should apply to the HRL Project and other projects due to their "scope, size, and long lead-times," and because "they require approvals from multiple jurisdictions, are dependent upon continued participation by multiple owners, and are subject to potential cancellation or modification through the Midwest ISO regional planning process."[52] In the WPPI Incentive

[50] WPPI Incentive Rates Order at P 25 (citing *Primary Power*, 131 FERC ¶ 61,015 at P 124).
[51] *See, e.g.*, WPPI Incentive Rates Order at P 24; MRES Incentive Rates Order at P 24; *Midwest Indep. Transmission Sys. Operator, Inc.*, 138 FERC ¶ 61,043, PP 13, 17 (2012); *Otter Tail Power Co.*, 137 FERC ¶ 61,255, P 52 (2011); CMMPA Incentive Rates Order at P 21; ALLETE Incentive Rates Order at P 6; GRE Incentive Rates Order at P 33; *Otter Tail Power Co.*, 129 FERC ¶ 61,287 (2009), *on compliance*, 131 FERC ¶ 61,129 P 12 (2010); Xcel/NSP Incentive Rates Order at P 63.
[52] Xcel Incentive Rates Order at P 63.

Rates Order, the Commission found "that the [HRL Project] faces substantial risks outside of WPPI's control."[53]

Dairyland stands in a position similar to WPPI in terms of limited control of the Project. Dairyland has a similar small share relative to the lead investor in the HRL Project, has corresponding limited control over the decisions related to planning and operations, and has little or no control over whether the Project will be abandoned. Exh. DPC-8 at 44-45.

For this reason, and as further explained in Mr. Pardikes' testimony, Dairyland's ability to recover prudently incurred costs in the event of the Project's cancellation is important to Dairyland's participation in the Project and is adequately justified.

D. The Total Package of Incentives That Are Tailored to the Risks of the HRL Project is Just and Reasonable.

The Commission in Order No. 679 stated that it requires applicants to demonstrate that the total package of incentives is tailored to the risks and challenges of the specific project.[54] Mr. Pardikes explains in his testimony that the incentives requested by Dairyland are consistent and compatible with other requested incentives. Exh. DPC-8 at 49-51.

Dairyland's requested hypothetical capital structure of 35% equity and 65% debt and the recovery of 100% of prudently incurred abandoned plant costs, work together to reduce the substantial risks borne by Dairyland related to its participation in the HRL Project. *Id*. at 50. The Commission has approved the abandoned cost recovery incentives in the HRL Project in the WPPI and Xcel/NSP Incentive Rates Orders, and approved a hypothetical capital structure for WPPI higher than Dairyland's request. For other CapX2020 projects, the Commission has approved the abandoned cost recovery incentives in the MRES, Xcel/NSP, GRE, OTP, ALLETE, and CMMPA Incentive Rates Orders, and approved a hypothetical capital structure in the MRES,

[53] WPPI Incentive Rates Order at P 24.
[54] Order No. 679 at P 188.

CMMPA, and GRE Incentive Rates Orders. The Commission has also approved multiple rate incentives for particular non-CapX2020 projects.[55]

Mr. Pardikes explains how, among other things, the requested incentives are essential to mitigate the risks to Dairyland caused by its participation in the complex, non-routine HRL Project. Exh. DPC-8 at 54. Without these incentives, Dairyland, other G&Ts, and other public power entities would be less willing to invest in major new transmission projects. *Id.* This will result in higher Midwest ISO transmission rates in the region. *Id*.

As shown here and in Mr. Pardikes' testimony, the total packages of incentives for the HRL Project are specifically tailored to meet the risks and challenges of the project.

VI. TECHNOLOGY STATEMENT

The Commission in Order No. 679 directed applicants for incentive rate treatment to provide a technology statement "describ[ing] what advanced technologies have been considered and, if those technologies are not to be employed or have not been deployed, an explanation of why they were not deployed."[56] Dairyland has prepared a technology statement for the HRL Project, which is provided at Exh. DPC-6 at 17.

VII. LIST OF AFFIDAVITS AND EXHIBITS

DPC-1	Direct Testimony of Phillip M. Moilien
DPC-2	Forecast of Interest Rates included in the May, 2012 DPC Board Approved 10 year Financial Forecast
DPC-3	Table of Federal Permits and Other Compliance Requirements
DPC-4	Moody's Global Corporate Finance Rating Methodology for U.S. Generation & Transmission Cooperatives, December, 2009
DPC-5	Moody's June 26, 2012 Dairyland Power Credit Opinion
DPC-6	Direct Testimony of Jerome Iverson
DPC-7	Map of HRL Project
DPC-8	Direct Testimony of James Pardikes
DPC-9	Estimated Revenue Requirements Difference between DPC and Xcel/NSP with actual capital structure

[55] *See, e.g., ITC Great Plains, LLC*, 126 FERC ¶ 61,223 at P 61 (2009).
[56] Order No. 679 at P 302.

DPC-10	Estimated Revenue Requirements Difference between DPC and Xcel/NSP with hypothetical capital structure
DPC-11	DPC DSC with actual capital structure
DPC-12	DPC DSC with hypothetical capital structure and avg = 1.30
DPC-13	DPC DSC with hypothetical capital structure and NPV = 1.30
DPC-14	DPC TIER with hypothetical capital structure = 35% equity
DPC-15	DPC FFO/Debt with hypothetical capital structure = 35% equity
DPC-16	Incremental FFO/Debt Ratio Associated with Requested Hypothetical Capital Structure
DPC-17	DPC FFO/Interest with hypothetical capital structure = 35% equity

VIII. CONCLUSION

For the reasons presented above and in the accompanying testimony, Dairyland respectfully requests the timely issuance of a declaratory order approving (1) a 35% equity hypothetical capital structure, and (2) abandoned plant recoverability.

Dated this 9th day of November, 2012.

Respectfully submitted,

/s/ *Jeffrey L. Landsman*

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document on those parties listed on the official service list compiled by the Secretary for this docket, and Docket Nos. EL12-67 and ER07-1415.

Dated this 9th day of November, 2012.

Respectfully submitted,

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COUNSEL FOR DAIRYLAND POWER COOPERATIVE

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

Dairyland Power Cooperative	Docket No. EL13-__-000

**DIRECT TESTIMONY
OF
PHILLIP M. MOILIEN**

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DAIRYLAND POWER COOPERATIVE ("DPC") AND SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND

A. Phillip M. Moilien, Vice President and Chief Financial Officer for Dairyland Power Cooperative ("DPC"). My business address is 3200 East Avenue South, La Crosse, WI 54602. I am responsible for accounting, finance, enterprise risk management, corporate budget and supply chain management. I have been in my current position since May, 2011 and have a total of 13 years of utility experience working at DPC and at GEN~SYS Energy, a cooperative that in the past provided power marketing and risk management services to DPC. At GEN~SYS Energy I was the Controller and Risk Manager. From January 2011 to May, 2011 I was the Director of Market Settlements for DPC and acting CFO for GEN~SYS. Prior to working at GEN~SYS Energy and DPC, I worked for over 10 years in the Corporate Tax and Accounting areas for Cargill, Inc., an international producer and marketer of food, agricultural, financial, and industrial products and services headquartered in Minneapolis, Minnesota,. I have a Bachelors degree from Viterbo University (La Crosse, Wis.) in Accounting.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am testifying on behalf of DPC.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH THIS TESTIMONY?

A. Yes. Exhibits DPC-2 through DPC-5.

II. SCOPE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide certain DPC financial and credit rating information related to the financing of DPC's investment in the CapX2020 Hampton, MN - Rochester, MN - La Crosse, WI transmission project (the "HRL Project" or "Project").

III. FINANCING OF THE HRL PROJECT

Q. HOW DOES DPC TYPCIALLY FINANCE ITS CAPITAL ADDITIONS AND HOW DOES DPC PLAN TO FINANCE THE HRL PROJECT?

A. DPC has traditionally financed significant capital additions through loans from the Rural Utilities Service (RUS), an agency of the United States Department of Agriculture, secured by a mortgage to RUS. As discussed below, RUS loans to DPC will be secured under DPC's RUS-approved trust indenture.

The RUS Electric Loan Program provides loans for not-for-profit cooperative associations (including G&Ts), public bodies, and other utilities. DPC intends to finance the HRL Project with long term RUS loans of approximately 30 years. The exact term of the loans are determined by the RUS at the time the loan funds are disbursed, depending on market conditions. In order to gain access to RUS loans, DPC generally files a RUS loan request which includes a financial and load forecast. In the case of the HRL Project, DPC anticipates an abbreviated loan application process because the HRL Project already required significant documentation as part of the Federal Environment Impact Study (FEIS), led by the RUS. The FEIS for the HRL Project has been finalized and the RUS is expected to make its decision regarding approval of the FEIS by mid-November, 2012. If the FEIS is approved by the RUS, DPC will then file the additional documentation necessary to request the loan for the HRL Project. The RUS decision on DPC's HRL loan request is expected sometime in 2013. Under the standard RUS policy, the loan would be approved but the funds would not be disbursed until after the HRL Project goes into service and the final cost report is made available to the RUS. Given the Project is expected to be completed in early 2016, DPC's expects that the final cost report would be available sometime in 2017, typically 12-18 months after the Project is energized. Therefore, DPC assumes that the funds would be disbursed in 2017. The interest rate on the loan would be determined in 2017, at the time of disbursement, based on market conditions. These loans typically have equal annual debt service payments comprised of interest and principal.

Q. PLEASE DESCRIBE RECENT DEVELOPMENTS IN THE RUS FINANCING PROGRAM THAT CAN LIMIT THE SUPPLY OF FINANCING TO G&Ts AND OTHER COOPERATIVES AND HOW DPC HAS ADDRESSED THAT CONCERN.

A. Over the last few years, RUS funding has been limited due to the type of projects that can be funded by RUS. For example, in 2007, RUS stopped accepting loan applications for base-load electric generation. In addition, funding under the RUS loan program is often a candidate for budget cuts. In response to this trend and restrictions on the types of projects that can be funded and potentially less funding in the future, RUS developed an indenture program whereby G&Ts that meet certain financial criteria are allowed to acquire new loans from non-RUS sources such as commercial banks and other institutional investors.. Under traditional RUS mortgage debt, a G&T's assets have a lien against them, which affects the G&T's ability to go to the open market and borrow money.

Over the past several years, 11 G&Ts, including DPC, have been approved by the RUS for the indenture program and 15 more are pending. By replacing its previous RUS mortgage with a new, RUS-approved indenture, DPC now has the flexibility to access market-based sources to meet its funding needs in addition to or in lieu of RUS loans.

Q. IF RUS FINANCING IS NOT AVAILABLE FOR THE HRL DEBT, HOW WILL DPC FINANCE THE HRL PROJECT?

A. At this time, DPC is proceeding under the assumption that RUS funding for the HRL Project is likely. If, however, funds are not available for the HRL Project from RUS due to federal budget cuts or other reasons, DPC will finance the Project with long term debt from commercial sources such as commercial banks and other institutional investors.

Q. PLEASE DESCRIBE THE LEVEL OF DPC's INVESTMENT IN THE HRL PROJECT AND THE PROJECTED TIMING OF THE PROJECT.

A. DPC's investment in the HRL Project is estimated to be about $52 million. Project construction is currently scheduled to begin in 2013 with an anticipated in-service date for the entire Project in early 2016. This timetable could be delayed given appeals of the Minnesota Route Decision, the judicial review proceeding related to the Wisconsin Certificate of Public Convenience and Necessity, and the complaint filed with the Commission in Docket No. EL13-9 by American Transmission Company claiming ownership to a portion of the HRL Project (also see Iverson and Pardikes testimonies, Exhibits DPC-6 and DPC-8).

Q. HOW DOES DPC INTEND TO FINANCE ITS CONSTRUCTION COSTS FOR THE HRL PROJECT BEFORE IT RECEIVES THE PROCEEDS OF THE LOAN?

A. Until the permanent financing is received from RUS, DPC intends to fund its portion of the construction costs of the HRL Project with a syndicated line of credit. The line of credit that will provide interim financing for the HRL Project and other DPC projects awaiting disbursement of permanent funds from the RUS.

At this time, DPC anticipates the interest rates on the line of credit to range from 2.0– 2.5% over the next few years. Given this relatively low cost of construction financing, DPC does not anticipate a cash flow strain from this HRL Project and thus is not requesting recovery of construction work in progress (CWIP) in rate base. DPC will be using its traditional method of accumulating allowance for funds used during construction (AFUDC) until the Project goes into service.

Q. WHAT COST OF DEBT DOES DPC ASSUME FOR THE DEBT TO FINANCE ITS INVESTMENT IN THE HRL PROJECT?

A. DPC is assuming a 5.25% cost of debt to finance the HRL Project investment. This interest rate is the forecasted rate for 2017 and is based on the DPC official financial forecast approved by the Board of Directors in May, 2012 (see Exhibit DPC-2 for long term rates and the line of credit rates used in the May, 2012 forecast). The forecasted RUS interest rate in 2017 of 5.25% is consistent with a recent RUS loan application update made by DPC in July, 2012 in connection with a $262 million loan request to fund multiple DPC projects, with the loan funds to be disbursed over the next five years. RUS required DPC to support this updated loan application using a 5.50% interest rate for long term debt in its 10 year financial forecast and to conduct a sensitivity scenario using a 6.5% long term interest rate.

IV. DPC'S CREDIT RATING AND FINANCIAL METRICS

Q. WHAT ARE THE CURRENT CREDIT RATINGS OF DPC?

A. DPC is currently rated “A” by S&P and A3 by Moody’s, which is the equivalent of an “A-”S&P rating. Moody’s “A” range consists of A1, A2 and A3. Moody’s rating of A2 is the equivalent of an “A” rating with S&P.

Q. WHAT IS DPC’S TARGET CREDIT RATING AND WHY IS IT IMPORTANT?

A. DPC has a goal of improving its Moody’s rating to A2 which would be the equivalent of its current S&P “A” rating. By reaching the A2 rating, DPC helps to ensure that it can sustain one poor year of financial performance without falling entirely out of Moody’s “A” category, into the ”B” category, which would result in significantly higher financing costs. This goal of solidifying an “A” credit rating for both credit rating agencies is consistent with DPC’s Strategic Financial Management Policy approved by the DPC Board of Directors in 2010 and updated in 2012. The policy is designed to ensure that DPC maintains its “A” credit rating with both credit rating agencies to secure access to external funding adequate to finance all necessary capital expenditures and to optimize member value through lowest possible financing costs. Over the last three years, DPC has set its member rates and corresponding margin levels to improve its financial metrics, consistent with its financial policy. Securing access to commercial funding is a necessary goal for most G&Ts including DPC because as discussed above, DPC’s traditional financing source, RUS, has become much more limited in terms of the types of loans that can be made, and its ability to make loans could be vulnerable to federal budget cuts. As a result, DPC has been entertaining financing offers from commercial financing sources for long term debt to be able to supplement RUS funding, as appropriate. By achieving financial metrics consistent with an “A” rated G&T, DPC helps to ensure the lowest possible financing costs from commercial sources (e.g., banks, insurance companies). The higher DPC’s credit rating, the greater the number of commercial suppliers that are willing to offer financing and, all things being equal, the lower the interest rate.

Q. WHAT FINANCIAL METRICS ARE NECESSARY FOR DPC TO IMPROVE ITS MOODY’S CREDIT RATING TO A2?

A. Moody’s credit rating is based on many factors—approximately 40% of these factors are quantitative and the remaining factors are more qualitative (see Exhibit DPC-4 for Moody’s methodology and weightings). Despite the financial metrics appearing to comprise only 40% of the total rating, Moody’s pays close attention to historical and projected financial metrics. These metrics include Debt Service Coverage (DSC) ratio, Times Interest Earned Ratio (TIER), funds from operations divided by debt (FFO/Debt), funds from operations divided by interest (FFO/Interest), and equity to total capitalization ratio. Moody’s current rating of A3 with a stable outlook reflects DPC’s improvement in these metrics over the last three years (see page 1 of June 26, 2012 Moody’s Credit Opinion for DPC, Exhibit DPC-5). It also reflects DPC’s commitment to set its margin levels from member rates consistent with solidifying an “A” credit rating for Moody’s and S&P, as reflected in its Board-approved 2010 and updated 2012 Strategic Financial Management Policy and related Strategic Financial Plan. Moody’s has made it clear that DPC's current A3 rating and an improvement to A2 are predicated on DPC continuing to improve the metrics[1]

Q. **WHAT IS THE SIGNIFICANCE OF DEBT SERVICE COVERAGE RATIO ("DSC") IN A G&T'S CREDIT RATING?**

A. DSC is one of the key quantitative metrics used by the credit rating agencies. DSC provides a measure of the cushion in a company's current year revenue above what is required to pay operating expenses and debt service. Consistent with its Strategic Financial Management Policy, DPC has been setting its member rates and related margin at levels consistent with improving its DSC.

Q. PLEASE DESCRIBE DPC'S HISTORICAL AND PROJECTED DEBT SERVICE COVERAGE RATIOS.

A. The average actual DSC for DPC for the last three years has been 1.23 (2009 = 1.13, 2010 =1.36, 2011 = 1.20), which is a significant improvement over the prior three year average of 1.01 but is still in the lower range of Moody's "A" rated G&Ts. Consistent with its improving trend required by Moody's, and DPC's goal of solidifying its "A" rating by being rated A2 by Moody's, DPC's budgeted DSC for 2012 is 1.24 and its forecast is for DSCs of 1.30 and 1.34 for 2013 and 2014,

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[1] For example, its June, 26, 2012 credit opinion (Exhibit DPC-5) Moody's stated:

" … the stable rating outlook also incorporates an expectation that key financial credit metrics will continue to improve over the near to intermediate term horizon." Exh. DPC-5 at 4. "A reversal of the recent trend of improvement in financial metrics would be viewed negatively. For example, FFO/Debt greater than 6% and FFO + interest / interest greater than 2.0 times on a sustained basis would be more fitting of the current rating level. Failure to achieve these levels as anticipated would place pressure on the rating or outlook." *Id*. ". . . if Dairyland can improve and maintain its metrics at higher levels (for example, greater than 7.5% for FFO/Debt and greater than 2.2 times for FFO interest coverage on a sustained basis), the rating could be revised upward." *Id*.

respectively. This improvement would place DPC's DSC in what would be considered the mid-range (1.2 – 1.4), of Moody's "A" credit rating, the equivalent of the A2 category.

Q. FOR OTHER KEY METRICS, PLEASE DESCRIBE DPC'S HISTORICAL AND BUDGETED 2012 FIGURES.

A. DPC has also improved its other financial metrics over the last three years. DPC's TIER has steadily improved over the last three years: 2009 = 1.17, 2010 =1.25, 2011 = 1.37. This recent performance and DPC's budgeted TIER for 2012 of 1.49 is consistent with Moody's range for "A" rated utilities of 1.2 to 1.4. In the last three years, DPC's ratio of funds from operations to debt (FFO/Debt) has improved from 4.34% to 5.76% and 5.74%, DPC's budgeted FFO/Debt for 2012 is 6.16%, continuing its steady improvement and achieving the minimum of the range of Moody's "A" rated G&Ts. DPC's FFO/Interest ratio has also steadily improved over the last three years: 2009 = 2.04, 2010 = 2.28, and 2011 =2.35. DPC's budget for 2012 is 2.56, continuing DPC's trend of improvement and consistent with Moody's range of 2.0 - 2.5 for "A" rated utilities.

Q. PLEASE DESCRIBE HOW DPC'S CAPITAL EXPENDITURES CAN AFFECT DPC'S KEY METRICS AND THE IMPORTANCE OF RECEIVING SUFFICIENT PROJECT RETURNS, GIVEN DPC'S CONSTRAINED CAPITAL BUDGET.

A. Large capital expenditures such as those incurred on the HRL Project increase interest expense and long term debt and can negatively impact all five of the metrics listed above, particularly in the short run. In fact, Moody's has an expectation going forward of reduced capital expenditures for DPC over the near term as compared to capital spending levels incurred several years ago. Therefore, it is important for DPC to receive returns on its capital investments that reflect the risks of the investment and returns consistent with its improving financial metrics. If the DSC obtained on the HRL Project debt is less than the DPC's companywide target DSC (a 1.30 level consistent with Moody's A2 rating), then DPC will be less inclined to invest in large, risky transmission projects such as the HRL Project in the future. This is particularly the case because DPC's capital projects compete for a limited pool of capital. If DPC does not receive returns reflecting the higher risks of investments such as the HRL Project, then it will naturally choose to invest in other more routine transmission and generation projects that have returns that fairly compensate its members for the project risks.

Q. PLEASE DESCRIBE DPC'S HISTORICAL AND PROJECTED EQUITY TO TOTAL CAPITALIZATION RATIOS.

A. The DPC equity to total capitalization as of December 31, 2011 was 14.6%.[2] This compares to 12.9% for December 31, 2009. Given DPC's plans to continue to set member rates and margins at levels necessary to continue improving its key metrics, DPC expects that this improving trend in equity to total capitalization

[2] Note that DPC's 2011 corporate equity to total capitalization ratio of 14.6% is lower than the figure of 16.5% reported on DPC's 2011 Attachment O because the corporate ratio includes current maturities on long term debt in the denominator whereas the Attachment O does not. This difference in equity ratios is forecasted to significantly narrow over the next 10 years as the denominator is forecasted to grow at a faster rate than the numerator.

will continue. DPC's 10 year financial forecast approved by the Board in May, 2012 forecasts DPC's equity to total capitalization ratio to increase to 22.2% in 2017 and 26.7% by 2021. A supplementary extended forecast approved by the Board in July, 2012 showed the equity to total capitalization ratio continuing to increase to 30.9% by 2024. The average increase in DPC's projected equity ratio from 2011 to 2024 is about 1.25% per year. DPC's improving equity to total capitalization ratio would place DPC in the mid-range of Moody's range of "A" rated G&Ts of 20% - 35% by about 2022.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Dairyland Power Cooperative | Docket No. EL13-__-000

AFFIDAVIT

I, the undersigned, being duly sworn, on oath depose and state that the above and foregoing Prepared Testimony of Phillip M. Moilien is the testimony of the undersigned, and that the testimony and exhibits sponsored by me, to the best of my knowledge, information and belief, are true, correct, accurate, and complete.

Phillip M. Moilien
Phillip M. Moilien

Subscribed and sworn to before me
this 9th day of November, 2012.

Laurie A. Engen
Notary Public, La Crosse County, Wisconsin
My commission expires: 5-25-14

LAURIE A. ENGEN
Notary Public
State of Wisconsin

2012-22 Financial Forecast
Notes & Assumptions

Approved Strategic Financial Planning Committee	5-9-12
Approved Dairyland Mangers Association	5-16-12
Approved by DPC Board of Directors	5-18-12

Key Capital Assumptions & Trends

- Forecast Horizon 2012-2022
- Margins / Rate Drivers
  - DSC, TIER, FFO / Debt %, FFO / Interest, Working Capital & Equity Development
- Capital Plan (2012-2022 $634M)
  - Transmission
    - 2012-21 Long Range Plan
    - CAPX 2020 Construction (2013-2016 $51M)
      - Business Case
  - Generation
    - 2011-13 Workplan
    - Major JPM Environmental Investments (2012-2016 $130M)
    - No New Generation
- Capital expenditures financed with a combination of Internally Generated Funds($177 M), RUS Financing ($257 M) & Market Debt ($200 M)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
STD Interest Rate (LOC)	1.75	2.00	2.00	2.25	2.50	3.00	3.50	4.00	4.50	4.50	4.50
LTD Interest Rate (RUS)	4.25	4.25	4.25	4.50	4.75	5.25	5.75	6.25	6.25	6.25	6.25
LTD Interest Rate (Market)	5.75	5.75	5.75	6.00	6.25	6.75	7.25	7.75	7.75	7.75	7.75

- Depreciation based upon 2012 Revised Depreciation Rates

Table 1-1: Federal Permits and Other Compliance

Agency	Permits/Other Compliances
RUS	RUS Environmental Policies and Procedures (7 CFR 1794)
	National Environmental Policy Act (42 USC 4321)
	National Historic Preservation Act (NHPA) 1966, Section 106
	RUS must comply with section 7(a)(2) of the Endangered Species Act (ESA), which states that “Each Federal agency shall, in consultation with and with the assistance of” USFWS insure that any action authorized, funded, or carried out by such agency is not likely to jeopardize the continued existence of any endangered species or threatened species.
USACE	Section 10 Permit of the Rivers and Harbors Act of 1899 (33 USC 403) for crossing the Mississippi and Black Rivers
USACE and U.S. Environmental Protection Agency (USEPA) Region 5	Individual permit under Section 404 of the Clean Water Act (CWA) of 1977 (33 USC 1344)
U.S. Department of Agriculture Natural Resource Conservation Service (NRCS)	Farmland Conversion Impact Rating (Form AD-1006)
Federal Aviation Administration (FAA)	Objects Affecting Navigable Airspace (Form 7460-1)
Federal Highway Administration (FHWA)	Permits required to longitudinally occupy and cross federal highways and interstate highways (usually delegated to the state Department of Transportation through its Utilities Accommodation Policy)
National Park Service (NPS)	Consultation: National River Inventory (NRI) rivers.
	Land and Water Conservation (LWCF) Fund Act of 1965 (Section 6, as amended; Public Law 88-578; 16 U.S.C. 4601-4 et seq.) approval for Snake Creek Unit of the RJD State Forest and Douglas Trail for MDNR issuance of License to Cross Public Lands and Waters

Agency	Permits/Other Compliances
USFWS	ROW regulations on Refuge land (50 CFR 29.21 to 29.22)
	USFWS Service Manual Chapters 340 FW 3 (ROWs and road closing), 601 FW 1 (Refuge system mission and goals), 603 FW 2 (compatibility)
	Use authorization if right-of-way required on National Wildlife Refuge or Wetland Management District lands (Standard Form 299) and Special Use Permit if crossing National Wildlife Refuge
	Section 7 of the Endangered Species Act 1973 (16 USC 1531–1544)
	Pittman-Robertson Wildlife Restoration Act 16 U.S.C. § 669-669i, concurrence for McCarthy Lake Wildlife Management Area for MDNR issuance of License to Cross Public Lands and Waters
	Bald and Golden Eagle Protection Act (16 USC 668), (50 CFR 22)
	Migratory Bird Treaty Act of 1918(16 USC 703–712)

Source: HRL Project Final FEIS (July 2012) Table 1-1, pp. 76-77.
See http://rurdev.usda.gov/SupportDocuments/02%20Section%201.pdf

Rating Methodology

Moody's Global Corporate Finance

December 2009

U.S. Electric Generation & Transmission Cooperatives

Table of Contents:

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Summary

This rating methodology explains Moody's approach to assessing credit risk in the U.S. electric generation & transmission cooperative sector (G&T co-ops). It replaces the U.S. Electric Generation & Transmission Cooperatives rating methodology that was published in May 2006. While based on the same core principles as the May 2006 methodology, this updated framework incorporates refinements that better reflect the more recent challenges facing G&T co-ops and the way Moody's applies its industry methodologies.

The goal of this report is to help issuers, investors and other interested market participants understand how Moody's assesses credit risk for companies in the U.S. G&T cooperative industry, and to explain how key quantitative and qualitative risk factors map to specific rating outcomes. Cooperative structures in other global industrial sectors may be subject to a number of other considerations and are not intended to be covered by this rating methodology. Our objective is for users to be able to estimate in most cases, within two alpha-numeric rating notches, the likely senior most credit rating for a U.S. electric generation & transmission cooperative.

Moody's analysis of U.S. Electric G&T co-ops focuses on five key rating factors that are considered central to assigning ratings in this sector. The five rating factors encompass 14 elements (or sub-factors), each of which maps to specific letter ratings (see Appendix A). The number of sub-factors is reduced from 22 previously, largely reflecting a combination of several factors that were determined to be somewhat duplicative and to further simplify the rating methodology. The five key factors, which will be detailed in this report, are as follows:

1) Long-Term Wholesale Power Supply Contracts/Regulatory Status

2) Rate Flexibility

3) Member Profile

4) Financial Metrics

5) Size

Moody's Investors Service

In appendix B we have included a detailed rating grid for the 17 G&T co-ops included in this methodology. For each G&T co-op, the grid maps the key rating factors and sub-factors and shows the indicated alpha-numeric rating that is calculated from the overall combination of factors. We also include in appendix C discussions of "outliers" – G&T co-ops whose rating for a specific sub-factor differs by two or more broad rating categories from the actual rating, as G&T co-ops will not always map consistently to their overall rating on every sub-factor.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the U.S. G&T co-op sector. The grid provides summarized guidance on the factors that Moody's believes are most important in assigning ratings to G&T co-ops. The grid is a summary rather than an exhaustive representation of every rating consideration and does not fit every business model equally well. In addition, many of our sub-factor mappings utilize historical financial or statistical data to illustrate the grid; however, our ratings also consider future expectations. Accordingly, the grid indicated rating is not expected to always match the actual rating of each G&T co-op. The text of the rating methodology provides insights on the key rating considerations that are not represented in the grid, as well as the circumstances in which the rating effect for a factor might be significantly different from the weight indicated in the grid.

Readers should also note that this rating methodology does not attempt to provide an exhaustive list of every factor that can be relevant to G&T co-op ratings. For example, our analysis covers factors that are common across all industries (such as debt leverage, liquidity, ownership, and legal structure) as well as factors that can be meaningful on a company specific basis (such as litigation, environmental or carbon exposure, capital expenditure needs, and customer and generation supply diversity).

This publication includes the following sections:

- **About the Rated Universe**: overview of the rated G&T co-op universe
- **About this Rating Methodology**: description of our rating methodology, including a detailed explanation of each of the key factors that drive ratings
- **Assumptions and Limitations**: Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

In addition to appendices A, B, and C, we also provide a brief industry overview (Appendix D) and a discussion of key rating issues for the G&T co-op sector over the intermediate term (Appendix E).

About The Rated Universe

An electric generation & transmission cooperative is a not-for-profit rural electric system whose primary function is to provide electric power on a wholesale basis to its owners. These owners are comprised of a group of distribution co-ops and in some instances may also include small G&T co-ops. Each distribution cooperative sells power on a retail basis to its customers, who are the members that own the distribution co-op.

Moody's currently rates 17 U.S. electric G&T cooperatives, included among which are many of the larger G&T co-ops and a growing number of the medium to smaller-sized ones. The group of 17 has approximately $22.1 billion of debt outstanding and collectively owns/controls or purchases approximately 41,000 megawatts of electric generation capacity. All of these issuers are currently rated investment grade and all except one pending review for possible downgrade and three negative rating outlooks currently carry a stable rating outlook. The G&T cooperatives currently occupy the investment-grade, single-A to high-Baa range.

The credit profile of G&T co-ops on the whole has been stable. Over the past three years, we have added six G&T cooperatives to our rated universe, including Great River Energy, Golden Spread Electric Cooperative, Minnkota Power Cooperative, South Mississippi Power, Big Rivers Electric Corp., and PowerSouth Energy Cooperative, bringing the total to 17 in all. In addition to the six new ratings assigned, three issuers were downgraded, none were upgraded, and three rating outlooks were changed to negative from stable. We also assigned three new commercial paper program ratings for Basin Electric Power Cooperative (Prime-1), Arkansas Electric Cooperative (Prime-1) and Chugach Electric Association (Prime-2). Chugach Electric Association's senior unsecured long-term rating was downgraded in December 2008 to A3 from A2 in conjunction with assigning a Prime-2 short-term rating to its commercial paper program. The downgrade reflected concerns about potential loss of wholesale revenue, re-financing risk, external financing of higher capital expenditures, and the potential need for higher rates, which are subject to Alaska regulatory jurisdiction. In April 2009, Hoosier Energy's senior secured rating was downgraded to Baa1 from A3 and kept on review for possible further downgrade, primarily due to concerns about ongoing litigation with John Hancock Life Insurance Company related to an existing leveraged lease transaction and the potential effects on its liquidity. In September 2009, Oglethorpe Power's rating outlook was changed to negative from stable, primarily reflecting concerns about the costs associated with its plans to partner with others in constructing a new nuclear plant, among other factors. In October 2009, Dairyland Power's A2 Issuer Rating was downgraded to A3 and its rating outlook is negative. The downgrade primarily reflected concerns about weak metrics compared to its prior rating level and the negative outlook captures ongoing concerns that soft market power rates in the Midwest may delay potential opportunities for Dairyland to take advantage of its strong baseload capacity profile by engaging in third party sales. On November 11, 2009, Buckeye Power's rating outlook was changed to negative from stable primarily reflecting the recent weakening of its credit metrics but also our concern as to how long it may take for improvement in the metrics to materialize given the softness in the economy of the region and lower than expected power prices for excess energy sales.

Meanwhile, we note that G&T co-ops have conservatively managed their businesses during the past three years by:

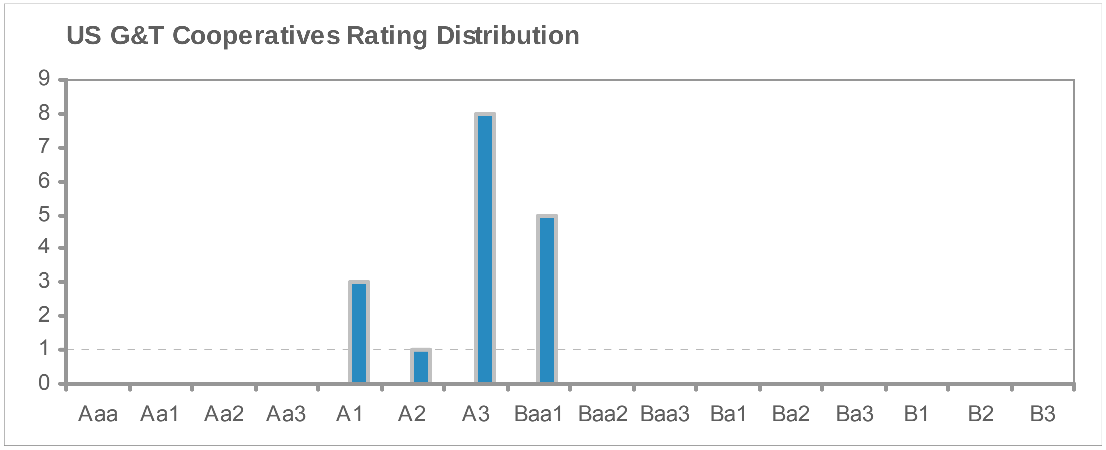
- using long term supply planning to meet increasing demands for power from their member co-ops,
- tightly controlling operating costs,
- increasing rates when necessary, and
- carefully attending to liquidity.

The following table illustrates the distribution of ratings in the U.S. G&T cooperative sector.

Rated Issuers

Company	Current Rating [1]	Commercial Paper/ Short-term Rating	Outlook	Total Debt ($ Millions) (d)
Arkansas Electric Cooperative	A2 (a)	P-1	Stable	644 (e)
Associated Electric Cooperative	A1		Stable	1,478
Basin Electric Power Cooperative	A1	P-1	Stable	2,287
Big Rivers Electric Corp.	(P) Baa1		Stable	1,039 (f)
Buckeye Power Inc.	A1		Negative	1,318
Chugach Electric Association	A3 (b)	P-2	Stable	346
Dairyland Power Cooperative	A3 (c)		Negative	973
Georgia Transmission	A3	P-2	Stable	1,560
Golden Spread Electric Cooperative	A3 (c)		Stable	161
Great River Energy	A3		Stable	2,362
Hoosier Electric Power	Baa1		RUR ↓	1,138
Minnkota Power Cooperative	Baa1 (c)		Stable	258
Oglethorpe Power Corp.	A3	P-2	Negative	4,127
Old Dominion Electric Cooperative	A3		Stable	783
PowerSouth	Baa1 (c)		Stable	1,411
South Mississippi Electric Power Association	A3		Stable	758
Tri-State G&T Association	Baa1		Stable	1,880
Total Unadjusted Debt of Rated G&T Co-ops				**22,524**

Notes:
[1] Ratings are senior secured unless otherwise noted
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating
(d) As of June 30, 2009, unless otherwise indicated
(e) As of July 31, 2009
(f) As of December 31, 2008



About This Rating Methodology

Moody's U.S. electric G&T cooperative rating methodology consists of the six sections listed below.

1) Identification of the Key Rating Factors

The grid in this methodology focuses on five broad rating factors, further broken down into 14 rating sub-factors and their weightings.

Rating Factor / Sub-Factor Weighting - U.S. Electric G&T Cooperatives

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Wholesale Power Contracts and Regulatory Status	20%	% Member Load Served and Regulatory Status	20%
Rate Flexibility	20%	Board Involvement / Rate Adjustment Mechanism	5%
		Purchased Power / Sales (%)	5%
		New Build Capex (% of Net PP&E)	5%
		Rate Shock Exposure	5%
Member / Owner Profile	10%	Residential Sales / Total Sales	5%
		Members' Consolidated Equity / Capitalization	5%
3-Year Average	40%	TIER	5%
G&T Financial Metrics		DSC	5%
		FFO / Debt	10%
		FFO / Interest	10%
		Equity / Capitalization	10%
G&T Size	10%	MWh Sales	5%
		Net PP&E	5%
Total	**100%**		**100%**

These factors are critical to the analysis of U.S. Electric G&T cooperatives and, in most instances, can be benchmarked across the sector. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2) Measurement of Key Rating Factors

We explain the measurements we use to assess performance on each of the rating factors and sub-factors. We explain the rationale for using specific rating factors and provide insights on the way these are applied in the rating decision process. Many of the sub-factors are found in or derived from the financial statements of the G&T co-ops and those of their members, while others are calculated or derived using data gathered from various sources, and observations and estimates by Moody's analysts.

Moody's ratings are forward looking and incorporate our expectations of future financial and operating performance. We use both historical and projected financial results in the rating process; however, this document makes use only of historic data, and does so solely for illustrative purposes. Historical operating results help us understand the pattern of a company's performance and how it compares to its peers. Historical data also assists us in, among other things, looking through the earnings volatility that can sometimes occur during a given year and evaluating whether projected future results are realistic.

This rating methodology uses historical data in most instances based on information as of the latest fiscal year end; however, the sub-factors for financial metrics use three-year averages for the last three fiscal years.

All of the quantitative credit metric measures comprising the sub-factors in Factor 4 incorporate Moody's standard adjustments to the income statement, statement of cash flows, and balance sheet and include adjustments for certain off-balance sheet financings and certain other reclassifications in the income statement and statement of cash flows.

3) Mapping Factors to Rating Categories

After identifying the measurement criteria for each rating sub-factor, we provide a chart that maps the rating sub-factors to specific alpha rating categories (Aaa, Aa, A, Baa, Ba, or B). In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of FFO/Interest is generally acceptable for an A credit versus a Baa credit, etc.

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

In this section (Appendix B), we provide a table showing how each company maps within the specific rating sub-factors. The weighted average of the sub-factor ratings produces a grid indicated rating for each broad factor. We also highlight companies (Appendix C) whose grid indicated performance on a specific factor or sub-factor is higher or lower by two or more broad rating categories from the actual rating. A company whose performance is two or more broad rating categories higher than its actual rating is deemed a positive outlier for that factor. A company whose performance is two or more broad rating categories below is deemed a negative outlier. We also discuss the general reasons for such outliers within a given factor or sub-factor.

5) Discussion of Assumptions, Limitations and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings as well as limitations and key assumptions that pertain to the overall rating methodology.

6) Determining the Overall Grid-Indicated Rating

To determine the overall grid-indicated rating, the indicated rating category for each sub-factor is converted into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-average factor score. The composite weighted-average factor score is then mapped back to an alpha-numeric rating based on the ranges in the grid below.

Composite Rating

Indicated Rating	Aggregate Weighted Factor Score
Aaa	$0.0 \leq x < 1.5$
Aa1	$1.5 \leq x < 2.5$
Aa2	$2.5 \leq x < 3.5$
Aa3	$3.5 \leq x < 4.5$
A1	$4.5 \leq x < 5.5$
A2	$5.5 \leq x < 6.5$
A3	$6.5 \leq x < 7.5$
Baa1	$7.5 \leq x < 8.5$
Baa2	$8.5 \leq x < 9.5$
Baa3	$9.5 \leq x < 10.5$
Ba1	$10.5 \leq x < 11.5$
Ba2	$11.5 \leq x < 12.5$
Ba3	$12.5 \leq x < 13.5$
B1	$13.5 \leq x < 14.5$
B2	$14.5 \leq x \leq 15.0$

For example, an issuer with a composite weighted factor score of 8.2 would have a Baa1 grid-indicated rating. We use a similar procedure to derive the grid-indicated ratings in the tables embedded in the discussion of each of the five broad rating factors.

The Key Rating Factors

Moody's analysis of U.S. G&T co-ops focuses on five broad rating factors:

- Long-Term Wholesale Power Supply Contracts/Regulatory Status
- Rate Flexibility
- Member Profile
- Financial Metrics
- Size

Factor 1: Long-Term Wholesale Power Supply Contracts/Regulatory Status

Why it Matters

Against a backdrop of significant spending for capital projects, volatile fuel costs and looming carbon legislation and related costs, the strength of the wholesale power contracts and the predictable revenue stream they provide for G&T co-ops remains a primary source of credit support. Because the prevalence of rate autonomy is similarly an integral credit factor linked to costs tied to the wholesale power contract, we have combined regulatory status of the G&T and its distribution member/owners, previously considered in Factors 2 and 3, respectively, into Factor 1. In doing so, we also increased the weighting for Factor 1 to 20% from 15% previously.

Long term wholesale power supply contracts between G&T co-ops and their members provide G&T co-ops with a high degree of assurance that costs and capital investment can be recovered from rates charged to customers. These contracts typically require the member co-ops to purchase all or virtually all of their supply requirements from the G&T co-op and generally stipulate that co-op members must pay their pro-rata portion of all of the G&T co-op's fixed and variable costs related to the generation, procurement and transmission of their respective energy needs.

G&T co-ops have more flexibility to increase rates in response to rising costs as regulatory approval is typically not required. The regulatory status/relationship with regulators is important because G&T co-ops that operate in states that have some form of regulatory authority over their rate setting activities may have more difficulty raising rates compared to peers who are not directly subject to regulatory control. Assessing a member/owner’s regulatory status is also important because some are subject to rate regulation, in which case the member may be denied approval for a large rate increase, making it difficult to comply with its contractual obligations to the G&T co-op.

An unsupportive regulatory jurisdiction is a credit negative and leaves co-ops with less flexibility to raise rates if needed. In contrast, absence of regulatory control over the rate setting process is a credit positive. Most co-ops are not subject to rate regulation, and set the rates they charge their members after careful consideration of their underlying cost structure and expected demand for power. They calculate what level of revenues would be required in order to meet operating costs, minimum required interest, and debt service coverage covenants in the RUS mortgage and/or other debt indentures, while also providing some cushion of revenue and equity to protect against adverse events such as sudden increases in costs or operating difficulties with key generating plants.

How We Measure It for the Grid

Based on data that can be derived from various sources, we calculate the percentage of member power supply needs served under the long-term wholesale power contract(s), with consideration as to whether the contracts are all requirements or substantially all requirements in nature. An assessment of the wholesale power contract allows us to identify whether the member co-ops are required to purchase all or virtually all of their supply requirements from the G&T co-op. For G&T co-ops who are not subject to rate regulation, the indicated rating for Factor 1 can range from Aaa to B and is largely determined by the overall percentage of member sales made under the wholesale power contracts. To receive the highest score of Aaa requires a legislative statute that precludes regulatory intervention in any future rate setting process. There are no such instances that currently apply within the rated universe.

We understand that there are currently 10 states that have full regulatory jurisdiction over the level of rates that co-ops can charge their members. These states are: Arizona, Arkansas, Alaska, Kansas, Kentucky, Louisiana, Maine, Maryland, Vermont, and Wyoming. There are a few other states including Indiana, New Mexico, and Michigan where state commissions have partial jurisdiction over G&T co-ops. Even if 100% of members’ needs are met through sales under the wholesale power contracts, G&T co-ops conducting business in any of the aforementioned states would receive an indicated rating for Factor 1 of A at best. Where precisely the few rate-regulated G&Ts score within the range of A to B depends not only on the percentage of members' needs met through sales under the wholesale power contract, but also on our consideration of how supportive of credit quality the regulatory practices are and our understanding of the type of working relationships that prevail between the co-ops and the regulators.

Factor 1: Long-Term Wholesale Power Supply Contracts and Regulatory Status (20%)	Aaa	Aa	A	Baa	Ba	B
Percentage of Member Load Served under Wholesale Power Contracts and Regulatory Status	100% and G&T and its Distribution Member/Owner Cooperatives are Not Rate Regulated by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process	100% and G&T is Not Rate Regulated by State Commission; No legislative statute to preclude regulatory intervention in the future G&T rate setting process; Some Distribution Member/Owner Cooperatives May Be Subject to Rate Regulation by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 80% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory Relationships	< 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory Relationships	< 60% and/or G&T is Rate Regulated by State Commission; Most Distribution Member/Owner Cooperatives are Rate Regulated By State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships

Factor 2: Rate Flexibility

Why it Matters

Prices for fuels used to generate electricity are unregulated in the U.S. and have been subject to dramatic fluctuation over the last couple of years. G&T co-ops need the flexibility to raise rates in order to cover sharply higher prices for fuels, in addition to rising operating costs, and costs associated with existing mandated environmental requirements and those inevitably forthcoming related to carbon emissions along with any capital investment associated with construction of new plants (especially nuclear powered), among other factors.

We note that the number of sub-factors in Factor 2 have been reduced to four from six previously, as regulatory status was combined into Factor 1 and rate competitiveness was combined into Rate Shock Exposure. In doing so, each of the remaining four sub-factors in Factor 2 have been assigned a 5% weighting.

Board Involvement/Rate Adjustment Mechanisms: The extent to which a G&T co-op can ensure timely and full recovery of its costs and investments will have an integral effect on its overall financial performance and thus its creditworthiness. Each G&T coop's board of directors has a fiduciary responsibility to approve, or, where rate regulation applies, to seek regulatory approval of rates that ensure compliance with the financial covenants associated with debt indentures. To the extent that unexpected events arise, causing concerns about ability to comply with covenants, the board should be expected to move quickly to adjust rates upward when needed. Also, variable cost adjustment mechanisms provide for more automatic changes in rates when costs change and increase the speed with which rates can be increased when costs increase. The extent to which variable cost adjustment mechanisms are available is especially important where regulatory jurisdiction applies to a G&T co-op. The existence of variable cost adjustment mechanisms is a credit strength, especially when rate adjustments can be implemented at frequent intervals. Such mechanisms mitigate liquidity pressures that might otherwise arise when the cost of fuels exceeds rates in effect at that time.

Degree of Reliance on Purchased Power: Most of the power supply needs of G&T co-op members are met from generating plants owned by the G&T coops. Some G&Ts rely on market purchases of power to meet a portion of the member needs because their owned resources are insufficient, uneconomic, or periodically unavailable.

Assessing the degree of reliance on purchased power to meet members' demand and the rationale behind that strategy is important because G&Ts who purchase large amounts of power from the market to meet member demands may face increased price volatility for one of their largest costs. Relying on such a strategy also heightens the importance of liquidity, risk management policies and procedures, and counterparty credit assessment.

New Build Exposure Relative to Existing Asset Base: This factor is important because G&T co-ops largely finance capital investment with debt and rely upon rate increases to service the debt. When construction is delayed or runs above budget, the rate increases needed to cover the increased costs could lead to member resistance.

Potential for Rate Shock Exposure: In many respects, the potential for rate shock exposure is linked to rate competitiveness, so we have combined our consideration of rate competitiveness into this sub-factor as part of this updated methodology. Assessing the potential for rate shock exposure is important because a large rate increase can lead to member resistance even when the new higher level of rates is still competitive with other providers of power in the region. If the G&T co-op's rates are noticeably higher than other providers in its geographic area, member unrest could lead to contract challenges or possible withdrawal from the co-op.

How We Measure It for the Grid

Board Involvement/Rate Adjustment Mechanisms: The timing and extent to which a G&T co-op can increase rates is impacted by the activity of its board of directors and a number of rate adjustment mechanisms.

First we assess how active a board has been from a historical perspective with respect to approving or seeking regulatory approval of rate increases and consider the extent to which past behavior might change. To the extent that unexpected events arise, causing concerns about ability to comply with covenants, we believe the board should be expected to move quickly to adjust rates upward when needed. Those G&T co-ops whose boards of directors are exceptionally proactive in adjusting rates as necessary and who benefit from legislative statute that would preclude regulatory intervention in the future rate setting process would most likely receive the highest indicated ratings. In contrast, G&T co-ops with less active or even inactive boards of directors and who otherwise face uncertainty surrounding the extent and timing of cost recovery would receive much lower indicated ratings for this sub-factor.

With respect to situations where variable cost adjustment mechanisms apply, rates that can automatically adjust to fuel and/or purchased power cost increases without requiring action by the Board or regulators are viewed more favorably and generally result in a higher indicated rating for this sub-factor. In instances where recovery of variable cost increases is deferred, we consider the time period over which recovery occurs, with shorter periods obviously being better from a liquidity and credit quality standpoint.

Degree of Reliance on Purchased Power: To measure the degree to which a G&T relies on purchased power in conducting its business, we divide the amount of megawatt hours it purchases during the most recent fiscal year by the total megawatt hours of energy it sells. This data can usually be found in the G&T co-op's latest annual report and/or other published data sources. In those instances where a G&T co-op relies on purchased power to meet less than 40% of its energy requirements during a given fiscal year, the indicated rating for this sub-factor would be at least Baa and improve gradually as the percentage declines according to the Factor 2 table descriptions. Conversely, where the dependence on purchased power exceeds the 40% level, then the indicated rating would be Ba or lower according to the Factor 2 table descriptions.

New Build Exposure Relative to Existing Asset Base: To measure this sub-factor, Moody's divides the estimated future capital expenditures for a particular G&T co-op over the next five years by the net property, plant, and equipment report for the latest fiscal year end. The lower the resulting percentage from this calculation is, the better the indicated rating for the sub-factor will likely be, as the G&T will likely face less need to issue debt and increase rates to cover the higher financing costs.

Potential for Rate Shock Exposure: To measure the potential for rate shock exposure, Moody's continues to look at the extent to which a G&T relies on purchased power to meet its energy demand during the latest fiscal year and its new build exposure. A lower percentage in both instances is generally viewed more favorably under the methodology. In addition, we have expanded our measurement criteria for this sub-factor to also consider the G&T's reliance on coal and other carbon emitting generating resources. Those G&Ts with a high reliance on such resources will be scored lower on this sub-factor due to their vulnerability to potential carbon legislation and accompanying carbon costs.

Cost competitive G&T co-ops have greater flexibility to raise rates to offset cost increases or to build additional equity and would therefore be more likely to receive a higher indicated rating for this sub-factor than those G&Ts who are competitively challenged. Favorable characteristics include low or improving cost structure, lower wholesale prices versus peers, and low distribution member rates versus competitors in the region. Moody's also assesses a G&T co-op's prospects to realize future rate increases in order to offset increasing costs, as compared with others in the region although consistent rate data is often not publicly available. Nonetheless, Moody's seeks whatever public information is available, as well as confidential information on a company by company basis.

Factor 2 - Rate Flexibility (20%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Assess Board Involvement in Setting Rates / Variable Cost Adjustment Mechanisms	Exceptionally proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; Legislative statute to preclude regulatory intervention in the future rate setting process	Proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; No legislative statute to preclude regulatory intervention in the future rate setting process	Active board in support of timely rate filings; possibility for regulatory intervention in the rate setting process in certain instances; frequent fuel cost adjustment capability in place under regulatory practice; timely recovery of any deferrals	Reasonably active board in support of timely rate filings; annual fuel cost adjustment capability in place under regulatory practice; reasonably timely recovery of any deferrals	Inactive board; limited, if any ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	5%
Purchased Power/Total MWh Sales (%)	x < 5%	5% ≤ x < 20%	20% ≤ x < 30%	30% ≤ x < 40%	40% ≤ x < 60%	x ≥ 60%	5%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	x < 5%	5% ≤ x < 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x ≤ 120%	x > 120%	5%
Potential for Rate Shock Exposure	Better rates than all others in the region on a consistent basis; Extremely low (e.g. Less than 10% reliance on purchased power and less than 10% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 0-20% of generation from carbon fuels	Much better rates than most in the region on a consistent basis; Very low (e.g. less than 20% reliance on purchased power and less than 25% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 20-40% of generation from carbon fuels	Better rates than most in the region on a consistent basis; Low (e.g. less than 30% reliance on purchased power and/or less than 50% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 40-55% of generation from carbon fuels	Better rates than some and worse rates than some in the region on a consistent basis; Moderate (e.g. less than 40% reliance on purchased power and/or less than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 55-70% of generation from carbon fuels	Worse rates than most in the region on a consistent basis; High (e.g. greater than 40% reliance on purchased power or greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 70-85% of generation from carbon fuels	Worse rates than all in the region on a consistent basis; Very high (e.g. greater than 40% reliance on purchased power and greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 85-100% of generation from carbon fuels	5%

Factor 3: Member Profile

Why it Matters

Assessing the member profile of a G&T co-op is important because the members who own the G&T co-op are also its primary source of cash flow. Similar to the way we would assess the counterparty credit risk for an IOU that sells sizable amounts of power to another entity, or buys significant amounts of power from a wholesale power producer, we are concerned about the overall creditworthiness of the members. Although we still seek information about the members' expected consolidated demand growth and their consolidated assets, to further simplify this methodology, these two sub-factors previously included in the May 2006 methodology are not specifically incorporated into this update. The following two sub-factors, which are weighted at 5% each, continue to provide good insight into the members' creditworthiness and ability to meet obligations to the G&T co-op under the long-term wholesale power contract.

Residential Sales as a Percentage of Total Sales: The diversity of the members' retail customer mix is important in our analysis of G&T co-ops because substantial reliance upon any single customer or a small number of customers (such as large industrial customers) tends to be associated with greater variability of revenue. Members who own the G&T co-ops tend to serve large residential customer bases, with a majority of energy being sold to such customers, although some sales may be to more volatile industrial and commercial customers. A higher percentage of sales to residential customers is favorable because such sales are generally more stable and predictable.

Members Consolidated Equity to Capitalization: The financial condition of the member/owners, as measured in part by the members' consolidated equity to capitalization, is important because it affects their ability to perform under the wholesale power contracts that members have with their G&T co-op. For the most part, distribution co-ops carry less business and financial risk than G&T co-ops. The difference in the financial strength is largely attributable to the fact that the RUS has historically set tighter financial covenants for the distribution co-ops than for the G&T co-ops. In addition, the distribution co-ops are far less capital intensive than G&T co-ops who own generation assets. Distribution co-ops typically maintain higher levels of equity to total capitalization and stronger interest coverage ratios than G&T co-ops.

How We Measure It for the Grid

Residential Sales as a Percentage of Total Sales: To measure this sub-factor, we first generally aggregate the individual residential energy sales and total energy sales for each member/owner of a particular G&T co-op in the latest fiscal year. This information is generally available through requests made to the G&T because their members provide this data to them. The aggregate residential energy sales level is then divided by the aggregate total energy sales level to derive the aggregate percentage for the year. Under the Methodology, a higher percentage of more stable and predictable residential sales is viewed more favorably than a concentration of sales to large commercial and/or industrial customers.

Members Consolidated Equity to Capitalization: This sub-factor is measured by simply aggregating each member's total equity and debt as reported for the latest fiscal year end. The aggregate totals are then used to divide total members' debt by the sum of total members' debt plus equity. Members generally file financial statements with the RUS or otherwise make such statements available to the G&T that they have an ownership interest in. Most of the G&T co-ops that are covered by the methodology fall into the Baa or A category with consolidated member equity to capitalization in the range of 25% to 50%.

Factor 3 - Member/Owner Profile (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Residential Sales/ Total Sales (%)	x ≥ 80%	75% ≤ x < 80%	50% ≤ x < 75%	40% ≤ x < 50%	20% ≤ x < 40%	x < 20%	5%
Members' Consolidated Equity/Capitalization (%)	x ≥ 65%	55% ≤ x < 65%	50% ≤ x < 55%	25% ≤ x < 50%	20% ≤ x < 25%	x < 20%	5%

Factor 4: G&T Financial Metrics

Why it Matters

Financial strength is an important indicator of a G&T co-op's ability to meet its obligations, including debt service. Moody's considers historical coverage ratios and also places a significant emphasis on the expected trend for coverage metrics when assessing the credit risk of G&T co-ops. In the interest of reducing the number of sub-factors and simplifying this methodology, we dropped the net operating margin metric from

Factor 4 as part of the update of this methodology since the net margin component of the coverage calculations already captures the operating profit. In doing so, we also adjusted the weighting of the remaining five sub-factors in Factor 4 to retain the overall 40% weighting for financial metrics. Nevertheless, we continue to highlight that while some G&T co-ops have large investment portfolios that considerably augment the bottom line, we consider it important that the G&T co-op be profitable on an operating basis. G&T co-ops that rely extensively on profits from investment portfolios and diversified operations to compensate for negative G&T operating margins are still viewed negatively.

Scores under Factor 4 may be higher or lower than what might be produced based on historical results, depending on our view of expected future financial performance.

Times Interest Earned Ratio (TIER) and Debt Service Coverage Ratio (DSC): These two ratios are important because they have governed RUS loan documentation for many years. In addition to TIER and DSC, Moody’s also looks at margins for interest (MFI) as defined in certain indentures.

Funds from Operations Coverage of Interest (FFO/Interest) and FFO/Debt: The FFO/Interest and FFO/Debt metrics are important because they provide insight regarding the amount and quality of a G&T co-op's cash flow and its ability to service its debt.

Equity/Total Adjusted Capitalization: Moody's evaluates the G&T co-op's equity as a percentage of total adjusted capitalization to see how much flexibility there is in the balance sheet to absorb unexpected events. When measuring the level of equity cushion, G&T co-ops and the RUS have tended to rely on equity expressed as a percentage of total assets. However, Moody's and many investors prefer to measure equity as a percentage of total capitalization, because it facilitates comparison with IOU capital structures.

How We Measure It for the Grid

See Moody's Ratings Methodology: Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations - Part 1, July 2005. The ratios used as a basis for this methodology are three year averages of calculations using the latest three fiscal year end statements, including standard adjustments. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios. The ranges for each of the five metrics that would correspond to a particular indicated rating category appear in the table at the bottom of this section. The individual metric definitions are as follows:

TIER:

(Net margins, as represented by net profit after tax before unusual items + Interest + Income Tax) / Interest

DSCR:

(Net margins, as represented by net profit after tax before unusual items + Interest + Depreciation & Amortization) / (Interest + Principal Payment)

FFO / Interest:

(Funds from operations + Interest expense)/ Interest expense

FFO / Debt:

Funds from operations / (Short Term Debt + Long Term Debt, gross)

Equity / Total Capitalization:

(Deferred Taxes + Minority or Non-controlling Interest + Book Equity) / (Short Term Debt + Long Term Debt, gross + Deferred Taxes + Minority or Non-controlling Interest + Book Equity)

Factor 4 - 3-Year Average G&T Financial Metrics (40%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
TIER	x ≥ 1.6x	1.4x ≤ x < 1.6x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
DSC	x ≥ 1.9x	1.4x ≤ x < 1.9x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
FFO/Debt	x ≥ 15%	10% ≤ x < 15%	6% ≤ x < 10%	3% ≤ x < 6%	2% ≤ x < 3%	x < 2%	10%
FFO/Interest	x ≥ 3.25x	2.5x ≤ x < 3.25x	2.0x ≤ x < 2.5x	1.5x ≤ x < 2.0x	1.2x ≤ x < 1.5x	x < 1.2x	10%
Equity/Total Capitalization	x ≥ 50%	35% ≤ x < 50%	20% ≤ x < 35%	5% ≤ x < 20%	3% ≤ x < 5%	x < 3%	10%

Factor 5: G&T Size

Why it Matters

Size, together with Factor 3, Member Profile, has the lowest weighting of the five key factors because it tends to be less important for entities, such as G&T coops, that are subject to limited competition. As part of the update to this methodology, we have eliminated two sub-factors from Factor 5 (i.e. megawatts owned/purchased and revenues) because we found that they were somewhat duplicative and wanted to further simplify the methodology. Nevertheless, we still find that size, as measured by the following two sub-factors, which are weighted at 5% each, does matter.

Megawatt hour sales: This sub-factor is important because it is an indicator for economies of scale (i.e., a G&T co-op is better off if it can spread its fixed costs over a larger number of megawatt hours of electricity, thereby increasing its price competitiveness).

Net Property, Plant, and Equipment: This sub-factor is important because G&T co-ops can benefit from having a larger pool of assets and a more diverse source of fuels to run the generation assets it owns. A G&T co-op that has its assets concentrated in one generating plant could be subject to extreme cost pressures to the extent that it has to buy power on the open market due to an extended outage at its sole generating plant. Similarly, overdependence on one particular fuel source could materially raise costs during a period of prolonged price increases for that commodity.

How We Measure It for the Grid

We identify the amount of megawatt hour sales and net property, plant, and equipment data primarily from the G&T co-op's latest annual report. See the Factor 5 table below for the ranges that would apply for a particular indicated rating for the two sub-factors in Factor 5.

Factor 5 - G&T Size (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Megawatt hour sales (Millions of MWhs)	x ≥ 50	20 ≤ x < 50	11 ≤ x < 20	5 ≤ x < 11	3 ≤ x < 5	x < 3	5%
Net PP&E ($ in Billions)	x ≥ 5	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < 0.3	5%

Rating Methodology Assumptions and Limitations, and Other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The five rating factors in the grid do not constitute an exhaustive treatment of all the considerations that are important for ratings of

G&T co-ops. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we cannot publish. In other cases, we estimate future results based upon past performance, industry trends, demand and price outlook, peer actions and other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

In choosing the metrics for this rating methodology grid, we did not include certain important factors that are common to all companies in any industry, such as the quality and experience of management, assessments of corporate governance and quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and ranking them by rating category in a grid would, in some cases, suggest too much precision in the relative ranking of particular issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental obligations, nuclear decommissioning trust obligations, industrial customer concentrations, financial controls, and the political and economic environment, including possible government interference.

As an example, industrial exposure can vary considerably across the rated universe and this customer class can sometimes be subjected to more cyclicality in terms of energy consumption, which cannot be consistently represented in a simple grid format.

Actual ratings assigned may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, Factors 1 and 2 address long term wholesale power contracts/regulatory status and rate flexibility, respectively; however, there may be instances where the effects of a G&T cooperative's financial metrics will be given greater consideration in an assigned rating than what is indicated by the weighting in the grid.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

The objective of our methodology is for users to be able to estimate in most cases, within two alpha-numeric rating notches, the likely senior most credit rating for a U.S. electric generation & transmission cooperative. For consistency in drawing our conclusions, we rely upon an implied senior secured rating (i.e. the implied senior most rating) for the six G&T cooperatives who have senior secured debt in their respective capital structures but whose current ratings are either senior unsecured Issuer Ratings or whose current ratings apply to a class of debt junior to the senior secured debt. The methodology grid-indicated ratings map to Moody's current assigned or implied senior most ratings as follows (See Appendix B for the details):

Eight cooperatives or 47% have indicated ratings that match the Moody's actual (or implied) senior most rating,

six cooperatives or 35% have indicated ratings within one-notch of Moody's actual (or implied) senior most rating, and

three cooperatives or 18% have an indicated rating within two-notches of Moody's actual (or implied) senior most rating.

U.S. Electric Generation & Transmission Cooperatives

APPENDIX A: U. S. Electric G&T Cooperative Methodology Factor Grid

Factor 1: Long-Term Wholesale Power Supply Contracts and Regulatory Status

Weighting: 20%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Percentage of Member Load Served under Wholesale Power Contracts and Regulatory Status	100% and G&T and its Distribution Member/Owner Cooperatives are Not Rate Regulated by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process	100% and G&T is Not Rate Regulated by State Commission; No legislative statute to preclude regulatory intervention in the future G&T rate setting process; Some Distribution Member/Owner Cooperatives May Be Subject to Rate Regulation by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 80% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory Relationships	< 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory Relationships	< 60% and/or G&T is Rate Regulated by State Commission; Most Distribution Member/Owner Cooperatives are Rate Regulated By State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships	20%

Factor 2: Rate Flexibility

Weighting: 20%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Assess Board Involvement in Setting Rates / Variable Cost Adjustment Mechanisms	Exceptionally proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; Legislative statute to preclude regulatory intervention in the future rate setting process	Proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; No legislative statute to preclude regulatory intervention in the future rate setting process	Active board in support of timely rate filings; possibility for regulatory intervention in the rate setting process in certain instances; frequent fuel cost adjustment capability in place under regulatory practice; timely recovery of any deferrals	Reasonably active board in support of timely rate filings; annual fuel cost adjustment capability in place under regulatory practice; reasonably timely recovery of any deferrals	Inactive board; limited, if any ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	5%
Purchased Power/Total MWh Sales (%)	x < 5%	5% ≤ x < 20%	20% ≤ x < 30%	30% ≤ x < 40%	40% ≤ x < 60%	x ≥ 60%	5%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	x < 5%	5% ≤ x < 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x ≤ 120%	x > 120%	5%
Potential for Rate Shock Exposure	Better rates than all others in the region on a consistent basis; Extremely low (e.g. Less than 10% reliance on purchased power and less than 10% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 0-20% of generation from carbon fuels	Much better rates than most in the region on a consistent basis; Very low (e.g. less than 20% reliance on purchased power and less than 25% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 20-40% of generation from carbon fuels	Better rates than most in the region on a consistent basis; Low (e.g. less than 30% reliance on purchased power and/or less than 50% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 40-55% of generation from carbon fuels	Better rates than some and worse rates than some in the region on a consistent basis; Moderate (e.g. less than 40% reliance on purchased power and/or less than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 55-70% of generation from carbon fuels	Worse rates than most in the region on a consistent basis; High (e.g. greater than 40% reliance on purchased power or greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 70-85% of generation from carbon fuels	Worse rates than all in the region on a consistent basis; Very high (e.g. greater than 40% reliance on purchased power and greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 85-100% of generation from carbon fuels	5%

Factor 3: Member / Owner Profile

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Residential Sales/Total Sales (%)	x ≥ 80%	75% ≤ x < 80%	50% ≤ x < 75%	40% ≤ x < 50%	20% ≤ x < 40%	x < 20%	5%
Members' Consolidated Equity/Capitalization (%)	x ≥ 65%	55% ≤ x < 65%	50% ≤ x < 55%	25% ≤ x < 50%	20% ≤ x < 25%	x < 20%	5%

Factor 4: 3-Year Average G&T Financial Metrics

Weighting: 40%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
TIER	x ≥ 1.6x	1.4x ≤ x < 1.6x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
DSC	x ≥ 1.9x	1.4x ≤ x < 1.9x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
FFO/Debt	x ≥ 15%	10% ≤ x < 15%	6% ≤ x < 10%	3% ≤ x < 6%	2% ≤ x < 3%	x < 2%	10%
FFO/Interest	x ≥ 3.25x	2.5x ≤ x < 3.25x	2.0x ≤ x < 2.5x	1.5x ≤ x < 2.0x	1.2x ≤ x < 1.5x	x < 1.2x	10%
Equity/Total Capitalization	x ≥ 50%	35% ≤ x < 50%	20% ≤ x < 35%	5% ≤ x < 20%	3% ≤ x < 5%	x < 3%	10%

Factor 5: G&T Size

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Megawatt hour sales (Millions of MWhs)	x ≥ 50	20 ≤ x < 50	11 ≤ x < 20	5 ≤ x < 11	3 ≤ x < 5	x < 3	5%
Net PP&E ($ in Billions)	x ≥ 5	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < 0.3	5%

APPENDIX B: Methodology Grid-Indicated Ratings

Rating Factors				Factor 1: Wholesale Power Contracts / Reg Status	Factor 2: Rate Flexibility				Factor 3: Member/Owner Profile		Factor 4: 3-Year Average G&T Financial Metrics					Factor 5: G&T Size	
	Current Rating [1]	Outlook	Indicated Rating	% Memb. Load Served & Reg Stat	Board Involve/Rate Adj. Mech.	Purch. Pwr / Sales (%)	New Build Capex (% Net PP&E)	Rate Shock	Resid. Sales	Member Consol. Eq / Cap	TIER	DSC	FFO / Debt	FFO / Interest	Eq / Cap	MWh sales	Net PP&E
Factor Weighting				20%	5%	5%	5%	5%	5%	5%	5%	5%	10%	10%	10%	5%	5%
Arkansas Electric	A2 (a)	Stable	A3	Baa	A	Aa	Ba	Ba	A	Baa	A	Baa	A	Aa	Aa	A	Baa
Associated Electric	A1	Stable	A2	Aa	Aa	Aa	Baa	Ba	A	A	A	A	A	A	Baa	Aa	A
Basin Electric Power	A1	Stable	A1	Aa	Aa	Aa	B	Ba	Ba	Baa	Aaa	Aa	Aa	Aa	A	A	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	Baa2	Aa	Baa	B	A	B	B	Baa	Aa	Aa	Baa	Baa	B	Baa	Baa
Buckeye Power	A1	Negative	A1	Aa	Aa	Aa	A	B	A	A	A	A	A	Aa	A	Baa	A
Chugach Electric Assoc.	A3 (b)	Stable	A3	Baa	A	Aa	Ba	B	A	Baa	A	Aa	Aa	Aa	A	B	Baa
Dairyland Power	A3 (c)	Negative	Baa1	Aa	Aa	Aa	A	B	A	Baa	Ba	Ba	Baa	Baa	Baa	Baa	Baa
Georgia Transmission	A3	Stable	A2	Aa	Aa	Aa	Baa	Aa	A	Baa	Baa	Ba	Baa	Baa	Baa	Aa	A
Golden Spread Electric	A3 (c)	Stable	A2	A	Aa	B	Ba	B	A	Baa	Aaa	Aaa	Aaa	Aaa	Aaa	Baa	B
Great River Energy	A3	Stable	A3	A	Aa	Baa	Ba	B	A	Baa	A	Baa	A	A	Baa	A	Aa
Hoosier Electric Power	Baa1	RUR ↓	A2	Aa	Baa	A	Baa	B	A	Aa	A	A	A	Aa	Baa	Baa	Baa
Minnkota Power	Baa1 (c)	Stable	A3	Aa	Aa	A	Ba	B	A	Baa	Baa	Baa	Baa	A	Aa	Ba	B
Oglethorpe Power Corp.	A3	Negative	Baa1	A	A	Aa	Ba	Baa	A	Baa	Ba	Ba	Baa	Baa	Baa	Aa	Aa
Old Dominion Electric	A3	Stable	A2	Aa	A	Ba	A	Baa	A	Baa	A	Aa	A	A	A	Baa	A
PowerSouth	Baa1 (c)	Stable	A3	Aa	Aa	Baa	A	B	A	Baa	A	A	Baa	A	Baa	Baa	A
South Mississippi	A3	Stable	A3	Aa	Aa	B	Ba	Ba	A	A	A	Baa	A	A	Baa	Baa	Baa
Tri-State G&T Assoc.	Baa1	Stable	A3	Aa	A	Baa	Ba	B	Ba	Baa	Aaa	Baa	A	Aa	Baa	A	Aa

APPENDIX C: Observations and Outliers for Grid Mapping

Factor 1: Ratings Mapping

The following table details the mapping for the Nature of Long-Term Wholesale Power Supply Contracts/Regulatory Status factor:

FACTOR 1 (20%) Nature of Long-Term Wholesale Power Supply Contracts and Regulatory Status				Negative Outlier / Positive Outlier
G&T Co-op	**Current Rating [1]**	**Outlook**	**% of Member Load Served**	**Indicated Rating**
Arkansas Electric	A2 (a)	Stable	91%	Baa
Associated Electric	A1	Stable	100%	Aa
Basin Electric Power	A1	Stable	100%	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	100%	Aa
Buckeye Power	A1	Negative	100%	Aa
Chugach Electric Assoc.	A3 (b)	Stable	94%	Baa
Dairyland Power	A3 (c)	Negative	100%	Aa
Georgia Transmission	A3	Stable	100%	Aa
Golden Spread Electric	A3 (c)	Stable	90%	A
Great River Energy	A3	Stable	98%	A
Hoosier Electric Power	Baa1	RUR ↓	100%	Aa
Minnkota Power	Baa1 (c)	Stable	100%	Aa
Oglethorpe Power Corp.	A3	Negative	65%	A
Old Dominion Electric	A3	Stable	100%	Aa
PowerSouth	Baa1 (c)	Stable	100%	Aa
South Mississippi	A3	Stable	100%	Aa
Tri-State G&T Assoc.	Baa1	Stable	100%	Aa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 1: Observations and Outliers

The nature of the long-term wholesale power contracts taken together with regulatory status is one of the most important drivers of G&T co-op ratings, so it is not surprising that there are no negative outliers. All of the rated G&T co-ops score quite well with indicated ratings of Aa , A, or Baa. Two of the five positive outliers are directly attributable to comparison of the indicated rating for the sub-factor against an actual senior unsecured Issuer Rating and would not be outliers if compared to an implied senior secured rating one notch higher than the Issuer Rating. The high ratings that so many of the G&T co-ops receive for Factor 1 help offset weaker scores in other areas, especially in Factor 2.

Notwithstanding the solid indicated ratings for Factor 1, we draw attention to the following observations. The protection afforded by wholesale power supply contracts can be eroded by changes in the contracts over time, or more suddenly, due to a need for exceptionally large rate increases.

Under a strict interpretation of the definitions, Oglethorpe Power Corp. (OPC) would receive a Ba indicated rating for Factor 1. This strict interpretation results from the fact that OPC's owned resources are currently providing only about 65% of its members' power requirements. The situation results from a conscious decision by OPC's members to enter into power supply arrangements with third-party suppliers for their future incremental growth as permitted under the amended wholesale power supply contracts, extending through 2050. In Oglethorpe's case, we are not unduly concerned because its members remain joint and severally liable to pay all of the cooperative's costs and we believe Oglethorpe's stable supply of relatively affordable baseload power will become increasingly valuable to its members as their needs grow and they are continually forced to look for additional sources of supply. We believe an indicated rating of A more appropriately captures the degree of credit impact from the current relationships between OPC and its members when considered together with its rate autonomy.

Chugach Electric Association (CEA) is somewhat unique because it operates as a combined G&T co-op and distribution cooperative. As such, the 94% of its sales made to customers includes not only the 39% of energy sales made under wholesale power contracts, but also the 55% of energy sales made directly to retail customers under the tariff and certificated service territory in the state of Alaska. Moody's views direct retail revenues to commercial and residential customers to be of equal, if not somewhat better quality, than wholesale revenues derived from sales to member co-ops.

Factor 2: Ratings Mapping

The following table details the mapping for the Rate Flexibility factor:

Factor 2 (20%) Rate Flexibility									Negative Outlier / Positive Outlier
G&T Co-op	Current Rating [1]	Outlook	Bd. Involve/ Adj. Mech.	Purchased Power/Total MWh Sales	Indicated Rating	New Build Exposure	Indicated Rating	Carbon Exposure	Rate Shock Exposure Indicated Rating
Arkansas Electric	A2 (a)	Stable	A	15%	Aa	107%	Ba	76%	Ba
Associated Electric	A1	Stable	Aa	12%	Aa	59%	Baa	80%	Ba
Basin Electric Power	A1	Stable	Aa	17%	Aa	152%	B	82%	Ba
Big Rivers Electric Corp.	(P) Baa1	Stable	Baa	101%	B	33%	A	89%	B
Buckeye Power	A1	Negative	Aa	8%	Aa	44%	A	90%	B
Chugach Electric Assoc.	A3 (b)	Stable	A	17%	Aa	78%	Ba	90%	B
Dairyland Power	A3 (c)	Negative	Aa	8%	Aa	42%	A	90%	B
Georgia Transmission	A3	Stable	Aa	N/A	N/A	51%	Baa	N/A	Aa
Golden Spread Electric	A3 (c)	Stable	Aa	85%	B	84%	Ba	100%	B
Great River Energy	A3	Stable	Aa	31%	Baa	76%	Ba	98%	B
Hoosier Electric Power	Baa1	RUR ↓	Baa	27%	A	64%	Baa	100%	B
Minnkota Power	Baa1 (c)	Stable	Aa	27%	A	106%	Ba	100%	B
Oglethorpe Power Corp.	A3	Negative	A	8%	Aa	115%	Ba	55%	Baa
Old Dominion Electric	A3	Stable	A	54%	Ba	29%	A	67%	Baa
PowerSouth	Baa1 (c)	Stable	Aa	38%	Baa	29%	A	100%	B
South Mississippi	A3	Stable	Aa	63%	B	76%	Ba	81%	Ba
Tri-State G&T Assoc.	Baa1	Stable	A	32%	Baa	83%	Ba	91%	B

[1] Ratings are senior secured unless otherwise noted.

(a) Secured Facility Bonds ranking junior to RUS security

(b) Senior Unsecured Rating; No secured debt in capital structure

(c) Issuer Rating

Factor 2: Observations and Outliers

Factor 2 contains the most outliers of any of the five key Factors, the substantial majority of which are negative outliers. In particular, over three-quarters of the rated universe are negative outliers for the Rate Shock Exposure sub-factor, largely reflecting the substantial dependence that the sector has on generation from carbon emitting fuels, especially coal. There are also seven negative outliers for the New Build Exposure sub-factor, reflecting the growing need for generating capacity and transmission infrastructure for those G&Ts as they have either grown into what excess capacity they previously had or are projecting growth in demand that exceeds current capabilities. In particular, Oglethorpe's New Build Exposure relates to its plans to participate in construction of a new nuclear plant, which contributed to the recent change in its rating outlook to negative from stable.

Big Rivers, Old Dominion, Golden Spread, and South Mississippi are all negative outliers for the sub-factor measuring Purchased Power as a Percentage of Sales. We anticipate that Big Rivers' outlier status will improve prospectively following the recently completed unwind transaction which re-establishes its direct rights to power produced from its generation assets previously leased to LG&E. Golden Spread's negative outlier status may also improve as it pursues construction of additional generation capacity. Old Dominion and South Mississippi may also seek to increase their respective owned generating capacity; however, in the near term we believe purchased power will remain integral to their resource strategy.

The low ratings for so many of the G&Ts relating to sub-factors in Factor 2 are largely balanced by higher scores in Factor 1 and Factor 4. The rate autonomy and relatively low rates for so many of the G&Ts make it more likely that the members will accept what in many instances will be the continuation of significant expected rate increases over the next several years even after a series of rate increases already implemented over the past few years.

The two positive outliers for the sub-factor relating to Board Involvement/Rate Adjustment Mechanisms are directly attributable to comparison of the indicated rating for the sub-factor against an actual senior unsecured Issuer Rating and would not be outliers if compared to an implied senior secured rating one notch higher than the Issuer Rating.

Factor 3: Ratings Mapping

The following table details the mapping for the Member Profile factor:

Factor 3 (10%) Member / Owner Profile					Negative Outlier / Positive Outlier	
G&T Co-op	Current Rating [1]	Outlook	Res. Sales/ Total Sales (%)	Indicated Rating	Mbrs. Equity / Capitalization (%)	Indicated Rating
Arkansas Electric	A2 (a)	Stable	50%	A	39%	Baa
Associated Electric	A1	Stable	71%	A	50%	A
Basin Electric Power	A1	Stable	36%	Ba	35%	Baa
Big Rivers Electric Corp.	(P) Baa1	Stable	18%	B	34%	Baa
Buckeye Power	A1	Negative	60%	A	50%	A
Chugach Electric Assoc.	A3 (b)	Stable	51%	A	43%	Baa
Dairyland Power	A3 (c)	Negative	70%	A	46%	Baa
Georgia Transmission	A3	Stable	70%	A	43%	Baa
Golden Spread Electric	A3 (c)	Stable	58%	A	45%	Baa
Great River Energy	A3	Stable	57%	A	45%	Baa
Hoosier Electric Power	Baa1	RUR ↓	65%	A	61%	Aa
Minnkota Power	Baa1 (c)	Stable	62%	A	45%	Baa
Oglethorpe Power Corp.	A3	Negative	68%	A	43%	Baa
Old Dominion Electric	A3	Stable	63%	A	36%	Baa
PowerSouth	Baa1 (c)	Stable	69%	A	47%	Baa
South Mississippi	A3	Stable	65%	A	53%	A
Tri-State G&T Assoc.	Baa1	Stable	33%	Ba	49%	Baa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 3: Observations and Outliers

Indicated ratings for Factor 3 map reasonably well to the actual ratings for each of the 17 rated G&T co-ops in this methodology, with just one positive outlier and two negative outliers.

Basin Electric Power Cooperative and Big Rivers are negative outliers for residential sales as a percentage of total sales to retail customers. In Basin Electric's case this is primarily because of the relatively high percentage of sales that Basin makes to non-members due to excess generation capacity. Importantly, off-system sales to non-members have served Basin well through the years and has enabled Basin to avoid member rate increases that otherwise would have been needed to meet financial covenants. Basin's demand growth from its members in recent years has enabled it to grow into some of its excess capacity. As Basin's sales to members continue to increase and off-system sales decline, the percentage of residential sales should continue to increase as it has over the past few years, albeit remaining an outlier. Big Rivers' negative outlier status is directly attributable to the high concentration of sales that its largest member/owner, Kenergy, makes to two aluminum smelters.

The lone positive outlier for Factor 3 relates to Hoosier Electric's members' consolidated equity as a percentage of equity. This status is more a function of the recent downgrade of Hoosier's rating than any noteworthy strengthening of the equity portion of total capitalization.

Factor 4: Ratings Mapping

The following table details the mapping for the Financial Metrics factor:

Factor 4 (40%)
3-Year Average G&T Financial Metrics

Negative Outlier / Positive Outlier

G&T Co-op	Current Rating [1]	Outlook	TIER	Indicated Rating	DSC	Indicated Rating	FFO / Debt	Indicated Rating	FFO / Interest	Indicated Rating	Equity/ Total Cap.	Indicated Rating
Arkansas Electric	A2 (a)	Stable	1.31x	A	1.19x	Baa	9%	A	2.6x	Aa	40%	Aa
Associated Electric	A1	Stable	1.29x	A	1.27x	A	6%	A	2.1x	A	20%	Baa
Basin Electric Power	A1	Stable	2.23x	Aaa	1.50x	Aa	10%	Aa	3.0x	Aa	30%	A
Big Rivers Electric Corp.	(P) Baa1	Stable	1.51x	Aa	1.54x	Aa	6%	Baa	1.9x	Baa	-18%	B
Buckeye Power	A1	Negative	1.36x	A	1.36x	A	7%	A	2.6x	Aa	26%	A
Chugach Electric Assoc.	A3 (b)	Stable	1.25x	A	1.84x	Aa	11%	Aa	2.6x	Aa	29%	A
Dairyland Power	A3 (c)	Negative	1.00x	Ba	1.04x	Ba	3%	Baa	1.6x	Baa	12%	Baa
Georgia Transmission	A3	Stable	1.19x	Baa	1.09x	Ba	4%	Baa	1.9x	Baa	10%	Baa
Golden Spread Electric	A3 (c)	Stable	5.02x	Aaa	3.93x	Aaa	31%	Aaa	5.7x	Aaa	51%	Aaa
Great River Energy	A3	Stable	1.34x	A	1.12x	Baa	7%	A	2.4x	A	13%	Baa
Hoosier Electric Power	Baa1	RUR ↓	1.40x	A	1.37x	A	8%	A	2.5x	Aa	13%	Baa
Minnkota Power	Baa1 (c)	Stable	1.17x	Baa	1.11x	Baa	5%	Baa	2.0x	A	36%	Aa
Oglethorpe Power Corp.	A3	Negative	1.07x	Ba	1.09x	Ba	6%	Baa	1.9x	Baa	11%	Baa
Old Dominion Electric	A3	Stable	1.28x	A	1.46x	Aa	7%	A	2.2x	A	24%	A
PowerSouth	Baa1 (c)	Stable	1.34x	A	1.20x	A	5%	Baa	2.1x	A	10%	Baa
South Mississippi	A3	Stable	1.36x	A	1.18x	Baa	7%	A	2.3x	A	14%	Baa
Tri-State G&T Assoc.	Baa1	Stable	1.72x	Aaa	1.13x	Baa	8%	A	2.8x	Aa	15%	Baa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 4: Observations and Outliers

Factor 4 takes into account historical financial statements. Historic results help us to understand the pattern of a G&T's financial and operating performance and how the G&T compares to its peers. While Moody's rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes.

Although a significant number of the sub-factors in Factor 4 map reasonably well to a G&T's actual rating, there are several instances where positive outlier status is evident. Most notably, Golden Spread is a positive outlier for all its key metrics, reflecting conservative financing strategies through the years. We expect that this situation will begin to change over the next several years as Golden Spread begins to rely on debt financing to fund its investment in new generation capacity. Other positive outliers for various metrics include Basin Electric, Big Rivers, Hoosier Energy, Minnkota Power, and Tri-State G&T Association. The strength of these scores helps balance the weaker scores these G&Ts have in Factor 2, especially as it relates to Rate Shock Exposure and New Build Exposure.

Georgia Transmission Corporation, Oglethorpe Power Corporation, and Dairyland Power are negative outliers on TIER and/or DSC, reflecting greater acceptance by their respective management and boards to manage results close to the minimum required levels contained in their debt indentures. Big Rivers is a negative outlier for equity as a percentage of Total Capitalization, reflecting its negative net worth that has prevailed for many years following approval of its plan of reorganization when it emerged from bankruptcy proceedings. The negative outlier status will eventually become a moot point as the G&T's net worth turns substantially positive following completion of the company's unwind transaction.

Factor 5: Ratings Mapping

The following table details the mapping for the Size factor:

Factor 5 (10%) G&T Size					Negative Outlier / Positive Outlier	
G&T Co-op	Current Rating [1]	Outlook	Megawatt Hour Sales (Millions)	Indicated Rating	Net PP&E ($ Billions)	Indicated Rating
Arkansas Electric	A2 (a)	Stable	13.2	A	$0.80	Baa
Associated Electric	A1	Stable	23.4	Aa	$1.69	A
Basin Electric Power	A1	Stable	19.5	A	$2.41	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	5.2	Baa	$0.91	Baa
Buckeye Power	A1	Negative	9.1	Baa	$1.22	A
Chugach Electric Assoc.	A3 (b)	Stable	2.8	B	$0.46	Baa
Dairyland Power	A3 (c)	Negative	6.7	Baa	$0.97	Baa
Georgia Transmission	A3	Stable	N/A	N/A	$1.49	A
Golden Spread Electric	A3 (c)	Stable	7.6	Baa	$0.20	B
Great River Energy	A3	Stable	15.0	A	$2.08	Aa
Hoosier Electric Power	Baa1	RUR ↓	10.9	Baa	$0.80	Baa
Minnkota Power	Baa1 (c)	Stable	4.9	Ba	$0.24	B
Oglethorpe Power Corp.	A3	Negative	23.3	Aa	$3.64	Aa
Old Dominion Electric	A3	Stable	10.0	Baa	$1.02	A
PowerSouth	Baa1 (c)	Stable	9.0	Baa	$1.23	A
South Mississippi	A3	Stable	9.9	Baa	$0.79	Baa
Tri-State G&T Assoc.	Baa1	Stable	19.0	A	$2.57	Aa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 5: Observations and Outliers

Even the largest G&T co-op, Oglethorpe Power Corporation, is considered to be relatively small by investor-owned electric utility standards, so it is not surprising that there is only one positive outlier in Key Factor 5. The three negative outliers are Chugach Electric, Golden Spread, and Minnkota, reflecting smaller than average size for the rated universe.

There are offsetting considerations in these three cases that merit comment. Although Chugach Electric is a negative outlier for megawatt hours sold it is by far the largest power provider in the state of Alaska and is geographically isolated, which tends to temper concern about its small size. In the case of Golden Spread and Minnkota, there are large capital programs under way, which over time may mitigate their respective negative outlier status for net property, plant and equipment.

APPENDIX D: G&T Co-op Industry Overview

G&T co-ops represent one of the three main forms of ownership for enterprises involved in the generation and delivery of electricity. Investor owned utilities (IOUs) constitute a sizeable majority of the U.S. electricity sector, with government owned municipal or public power entities representing the second largest segment of the market, and G&T co-ops being by far the smallest segment. G&T co-ops do not directly compete with each other or with investor owned utilities or government owned entities in a substantial way because cooperatives mainly provide service to their owner members under long term all requirements power contracts.

The A2 average (senior most) rating assigned for G&T co-ops equals the average rating for municipal or public power entities, and is two notches higher than the Baa1 average rating for (IOUs). G&T co-ops tend to be significantly smaller than investor owned utilities but have higher ratings because they are able to raise rates without the regulatory review required for investor owned utilities. G&T co-ops also face less competition given their contractual relationship with their member owners.

The following chart compares some of the characteristics that distinguish the risk profiles of these three subsets of the U.S. power sector.

Investor-Owned Utilities	G&T Co-ops	Municipal and Public Power
Rate regulated	Most are not rate regulated but their owners may be	Not rate regulated
Profit seeking; operated for the benefit of public shareholders with obligations to serve regulated ratepayers	Not-for-profit; operated for the benefit of their owner members	Operated for public benefit for the region served
Most are larger; may have multiple entities in an issuer family	All are small relative to IOUs	Most are small relative to IOUs
Subject to competition in the wholesale market; sometimes in the retail market	Little competition	Little competition
Some history of defaults, usually as a result of needing rate increases that are too large to be acceptable to ratepayers	Some history of defaults; usually due to need for rate increases that are too large to be acceptable to members	Defaults have been extremely rare
Can file Chapter 11 bankruptcy	Can file Chapter 11 bankruptcy	More impediments to bankruptcy but may be able to file Chapter 9
Tend to have higher rates compared to municipal or public power	Rates tend to be comparable to IOUs	Tend to have lower rates than G&T co-ops and IOUs
Rely extensively on capital markets	Most borrow from the Rural Utilities Service and cooperative financial institutions; larger issuers access the capital markets	Rely on public and private markets for financing needs; may have access to government funding if needed

Comparison with Joint Power Agencies

Moody's rates approximately $35 billion of bonds issued by Joint Power Agencies (JPAs), which have some characteristics in common with electric generation and transmission cooperatives. Both are nonprofit enterprises and are governed by their members. Cooperatives as well as many JPAs serve small rural communities in the U.S. A significant difference between the two is the greater ability of JPAs to issue low cost tax-exempt debt, although cooperatives may borrow at below market rates through the federal Rural Utilities Service.

Since the 1970's, groups of city-owned electric utilities have established JPAs to pool resources to finance the construction of new generation facilities or to jointly purchase electric power supply. Participating members of

JPAs are contractually obligated for power supply through take-or-pay and take-and-pay power sales agreements. These agreements are the underlying security for tax-exempt debt issued by JPAs. The power sales agreements are structured to have the same term as the debt issue.

JPAs have unregulated rate-setting authority and their municipal utility participants can recover costs by independently raising retail rates. The current median municipal scale rating of JPAs is A2. After a period of low debt issuance, JPAs have accelerated the pace of borrowing to finance ownership in new generation plants in order to assist their participant members in meeting demand growth and also to diversify their generation fuel mix.

The key rating factors Moody's considers for JPA ratings include municipal utility participant credit quality, pricing power and market position, as well as governance structure and management abilities of these public sector organizations. Financial position, capital spending, and structural features of borrowing instruments are also important. Key questions embedded in our analysis of these factors are:

- How economic are power sales contracts relative to competitors?
- How are the power supply contracts structured, and what are the bond security provisions?
- What is the average weighted credit quality of participants? What are the demographic and economic characteristics of the service areas of the participating municipal electricity distributors?
- How do JPAs manage their balance sheet and plan for capital spending in order to position the JPA to meet future demand growth and competition?

The price of power the JPA supplies, and the reliability of the power supply, are among the most significant drivers of JPA credit ratings given the importance of these factors to their municipal utility participants. JPAs with the highest cost power are generally rated lower than those with more competitive price structures.

APPENDIX - E

Key Rating Issues over the Intermediate Term

Global Climate Change and Environmental Awareness

There have been significant increases in environmental expenditure estimates among G&T co-ops with significant coal fired generation in recent years as policymakers have mandated pollution control measures and emissions limitations in response to public concerns over carbon. These expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. G&T co-ops may have to implement substantial additional reductions in power plant emissions and could experience progressively higher capital expenditures over the next decade. In the U.S., the planned construction of several new coal plants have been cancelled or at least delayed as a result of opposition from regulators, political leaders, and the public or because cheaper alternatives appeared more compelling due to the significant increase in coal plant construction costs.

Large Capital Expenditures and Rising Costs for New Generation and Transmission

In order to meet rising electricity demand as the U.S. slowly emerges from a recession, many G&T co-ops intend to purchase generating plants or plan to build additional peaking and base load generating capacity, while correspondingly taking steps to upgrade and/or add to transmission infrastructure. As of end of 2008, the aggregate net property plant and equipment for rated G&T co-ops was approximately $12 billion with about an additional $8 billion of capital expenditures planned over the next five years. For those G&Ts that elect to participate in the construction of large, highly capital intensive nuclear plants, which have not been built in the U.S. in many years, the challenges could be particularly daunting and significantly pressure their credit quality.

Larger Rate Increases May Test Members' Willingness To Raise Rates

After a period of rate stability or rate decline throughout the 1980's and 1990's, G&T co-ops are increasing the wholesale rates that they charge their members. The impact of higher prices for fuel and purchased power has not been fully experienced by member co-ops because some purchase contracts have not yet been reset to new market levels.

G&Ts will likely impose large rate increases on co-op members when the G&T's power purchase contracts expire if that coincides with a period of rising market prices or when a large new generating plant is being constructed. Very large increases could test the willingness of members to pay higher rates.

G&Ts who choose to defer increasing rates to their members in the face of sharply higher costs or who are unable to gain approval from regulators to do so when rate regulation applies will likely experience a deterioration in their key credit metrics. Inability to obtain regulatory approval for rate increases has contributed to the bankruptcy of G&T co-ops in the past. As an alternative to imposing a large rate increase at one time, most G&T co-ops try to pursue a strategy of smaller, more frequent rate increases to be phased in over a period of years.

Rates charged by G&T co-ops need to be regionally competitive with rates charged by other power providers. Rate competitiveness of G&T co-ops relative to other power providers is important because it affects the willingness of co-op members to accept rate increases when costs increase. With most other power providers currently facing similar commodity cost volatility and capital spending requirements, as well as more expensive insurance and pension benefits, we do not expect that the rates that G&T co-ops charge their members will be less competitive than those charged by other power providers.

Reliance on Low-Cost Loans from U.S. Government Sponsored Agencies

G&T co-ops rely heavily on low cost loans from the Rural Utilities Service of the U.S. Department of Agriculture (RUS) and from RUS guaranteed loans provided by the Federal Financing Bank (FFB), a government funding arm.

In addition to the RUS, G&T co-ops also rely heavily on loans provided by cooperative financial institutions such as the National Rural Utilities Cooperative Finance Corporation (CFC; A1 senior secured; stable outlook) and CoBank, and local commercial banking institutions.

The RUS is the single largest provider of debt financing to the sector. Given the history of political support for the RUS loan program, our ratings reflect our assessment that the probability of systemic withdrawal of such low cost funding is low. The ratings do, however, incorporate the RUS decision not to provide loans for the construction of base load coal and nuclear plants.

Some cooperatives have elected to repay all RUS loans or otherwise obtain lien accommodations in order to obtain more financial flexibility, which results in a greater reliance upon the capital markets as a source of funding. However, the RUS requires that some of its borrowers obtain at least 30% of their financing from other sources. Larger G&T co-ops, such as those in Moody's rated universe, have sought to increase financial flexibility by accessing the capital markets. We anticipate that more G&T co-ops will do likewise in the future given the RUS decision not to lend for the construction of base load coal and nuclear plants.

Moody's Related Research

Industry Outlooks:

- U.S Regulated Electric Utilities, Six-Month Update, July 2009 (118776)
- U. S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- EMEA Electric and Gas Utilities, November 2008 (112344)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)

Rating Methodologies:

- Regulated Electric and Gas Utilities (118481)
- Unregulated Utilities and Power Companies, August 2009 (118508)
- Regulated Electric and Gas Networks, August 2009 (118786)
- Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations - Part I, July 2005 (93570)

Special Comments:

- Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)
- Carbon Risks Becoming More Imminent for U.S. Electric Utility Sector (115175)
- New Nuclear Generation: Ratings Pressure Increasing (117883)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

U.S. Electric Generation & Transmission Cooperatives

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Moody's Investors Service

MOODY'S INVESTORS SERVICE

Credit Opinion: Dairyland Power Cooperative

Global Credit Research - 26 Jun 2012

La Crosse, Wisconsin, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A3

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Key Indicators

Dairyland Power Cooperative[1]

	Dec-09	Dec-10	Dec-11	3-Year Avg
TIER [2]	**1.2x**	**1.3x**	**1.4x**	**1.3x**
DSCR [2]	**1.1x**	**1.4x**	**1.2x**	**1.3x**
FFO / Debt	**4.3%**	**5.8%**	**5.7%**	**5.2%**
FFO / Interest	**2.0x**	**2.3x**	**2.4x**	**2.2x**
Equity / Capitalization	**12.9%**	**13.6%**	**14.6%**	**13.7%**

[1] All ratios calculated in accordance with Moody's Electric G&T Cooperative Rating Methodology using Moody's standard adjustments [2] Moody's definitions may differ from indenture covenants

Note: For definitions of Moody's most common ratio terms please see the accompanying *User's Guide*.

Opinion

Rating Drivers

Long-term wholesale power contracts and rate-setting autonomy

Relatively modest exposure to market volatility given limited, albeit slightly higher, reliance on purchased power

Moderate capital expenditures for the medium term; longer term, environmental related spending may increase

Improving trend for financial metrics expected to continue

Corporate Profile

Dairyland Power Cooperative ("Dairyland") is an electric generation & transmission cooperative that supplies wholesale electricity to its 25 member distribution cooperatives (who are its owners) and 16 municipal utilities located in the states of Wisconsin, Minnesota, Iowa and Illinois. Dairyland and its cooperative members serve approximately

254,000 connected consumers. The company's owned/controlled generating capacity of approximately 1,368 MW's includes approximately 1,030 MW's of capacity from four coal fired facilities, with the balance provided by a combination of combustion turbine, hydro, landfill gas, wind, solar and biogas fired facilities. The company reported revenues and balance sheet debt of $411 million and $1.012 billion, respectively, at year-end December 2011.

Rating Rationale

Dairyland's A3 issuer rating primarily reflects the company's rate setting authority, which is not subject to state public utility commission regulation, and the full requirements contracts with its distribution members that allow Dairyland to set rates at a level sufficient to recover its costs and achieve the financial metrics required by the terms of its debt. These factors are typical of the electric cooperative structure, and are fundamental to their relatively low business risk framework. The company's capital expenditures have tapered off in recent periods and annual spending in the medium term is anticipated to average just under $90 million. However, in the longer term, spending may again increase gradually as the cooperative looks to address environmental compliance issues. Limiting factors in the rating include Dairyland's small size, and, given its fleet of predominately coal fired generating assets, the longer term potential for rate shock with increasing environmental regulation. Credit metrics have continued to show improvement from the recent past, which enhances Dairyland's position in its current rating category.

DETAILED RATING CONSIDERATIONS

LONG-TERM WHOLESALE POWER CONTRACTS

The A3 issuer rating is driven by Dairyland's rate setting authority that is not subject to state public utility commission regulation, and by its all-requirements contracts that requires the cooperative to serve 100% of its distribution members' energy needs through 2055, which is well beyond Dairyland's final debt maturity in 2040. These contracts permit Dairyland to set rates at levels sufficient to recover its operating expenses, debt service costs and maintain adequate reserves. Rates are typically reset annually by action of the Board but may be adjusted more frequently, if necessary. In addition, Dairyland utilizes a power cost adjustment factor which automatically adjusts rates to reflect actual fuel and purchased power costs less market system sales if these deviate from a specified range, helping to ensure the stability of its financial margins.

Although Dairyland's members' obligations under the contracts are not explicitly joint-and-several, the company's ability to adjust rates should provide the flexibility to mitigate payment failures by any particular members. Furthermore, with generation resources recently added to its asset fleet (for example, Weston 4, a 531MW supercritical coal plant located in Wausau, Wisconsin, in which Dairyland has 30% ownership), there is the potential for increased off-system sales. Given Dairyland's location in MISO, opportunities may be limited in the near-term, but we expect these off-system sales will continue until member demand growth absorbs the increase in generating capacity. While off-system sales are projected to measure less than 20% of total electricity sales on a revenue basis over the next five years, this revenue stream is important to Dairyland because it provides additional revenue which can help mitigate the need for future wholesale rate increases, and maintain more competitive wholesale rates.

RELATIVELY LOW EXPOSURE TO MARKET VOLATILITY THROUGH SIGNIFICANT GENERATION OWNERSHIP AND LIMITED RELIANCE ON PURCHASED POWER

The A3 rating also incorporates Dairyland's reasonably balanced power resource portfolio that avoids undue reliance on purchased power. For example, although Dairyland's purchased power level as a percentage of total MWh sales has increased somewhat in recent years (8% in 2008, 12% in 2009, 21% in 2010, and 32% in 2011), Moody's recognizes that a significant portion of those purchases were made on an economical basis, helping to maintain rate stability, and that the purchased power levels on average are still relatively moderate compared to peers in Moody's rated G&T cooperative universe. Dairyland's ability to provide a significant portion of the member's energy needs via its owned generation fleet reduces its exposure to volatility in the wholesale power markets.

On the cost side, Dairyland also mitigates its exposure to fuel expense volatility by utilizing a laddered approach for its portfolio of coal supply contracts. By securing its future fuel needs ahead of time while leaving room for potentially more economical purchases later, Dairyland is able to better control its cost structure, and foster stability and predictability of cash flows.

CAPITAL EXPENDITURES MAY INCREASE GRADUALLY FOR ENVIRONMENTAL COMPLIANCE

Dairyland's capital spending level has come down significantly from the recent past, after completing a heavy generation build-out period. After averaging approximately $150 million per year in capital expenditures from 2005-07, Dairyland's capital expenditures have gradually declined during the 2008-11 period, and have averaged just under $60 million annually.

The company's future annual spending is now expected to rise to approximately $100 million on average in the 2012-14 period, before declining back to a level closer to $60 million per year in 2015-16. Future capital expenditure needs are focused on environmental upgrades and new regional transmission investment projects. Based on the 2012-16 capital expenditure forecast, approximately 47.5% of total spend is directed towards transmission projects, while 36.6% is directed towards environmental upgrades. The overall environmental expenditure could be shifted or reduced depending on the pace and scope of various legislative and regulatory initiatives currently being contemplated. Additionally, the transmission projects could also be delayed, postponed, or otherwise altered in a way that reduces Dairyland's future expenditures.

Although no new base-load capacity is planned, or needed, we note that the state of Wisconsin (where 18 of Dairyland's 25 members are located) has a target "renewable" standard of 10% of retail sales by 2015, which may result in Dairyland continuing to seek additional renewable energy over the next several years. Dairyland's renewable portfolio at the end of 2011 measured approximately 11.3% of Class A member energy sales.

IMPROVED FINANCIAL METRICS

Dairyland's A3 issuer rating recognizes the recent improvements in its credit metrics. Historically, Dairyland's metrics have been more in line with the "Baa" rating category, largely due to significant capital expenditures for new generation capacity (such as Weston 4) that substantially increased the company's balance sheet debt and put pressure on credit metrics. In the 2005-08 period, for example, Dairyland's funds from operations (FFO) to debt, as calculated in accordance with Moody's standard adjustments for items such as operating leases, steadily decreased from 6.7% in 2005 to 3.0% in 2008, while equity to total capitalization dropped from approximately 16.7% to around 11.7% during the same period.

More recently, however, we have seen improvement in the ratios, primarily helped by lower capital expenditures and implemented rate increases. For example, between 2009-11, FFO to debt has steadily increased from 3.3% to 5.3%, , while equity to total capitalization has improved from 12.1% to 13.7%. Prospectively, Moody's anticipates that Dairyland's credit metrics will continue to improve, aided by proactive financial management, which should further enhance its position within the current rating category.

Nearly 80% of Dairyland's approximately $1 billion of balance sheet debt outstanding at year-end 2011 was comprised of obligations due to the Federal Financing Bank under the USDA Rural Utility Services electric loan program ("RUS"). The debt is secured by substantially all of Dairyland's assets under the RUS mortgage. Additionally, Dairyland's application to RUS to put in place an indenture that will allow for long-term borrowing outside of RUS has been approved. It is Moody's view that the indenture conversion is credit positive, as it will provide Dairyland additional financing flexibility, especially in times when RUS funding might be constrained.

Liquidity Profile

Dairyland has reasonable liquidity supported by its relatively stable and predictable cash flow, its well-sized external credit facility, and to a lesser degree, the member cooperative prepayment program. Even though Dairyland earned higher net income in 2011 than 2010, CFO for the full-year was weaker than the prior year primarily due to the timing of working capital adjustments In the near to medium term, given Dairyland's projected capital expenditure forecast, its internally generated cash flows will likely be insufficient to cover the outlays, and shortfalls will need to be bridged with external financing through the credit facility or long-term debt issuance. As the cooperative begins to make more capital investments for environmental compliance in the longer term, there may be an additional need to rely more heavily on external sources of financing.

Dairyland's primary source of external liquidity is a new 5-year $300 million syndicated facility with CoBank as the lead . The facility provides a number of strategic benefits to Dairyland, particularly given the number of participant banks involved, the upsized commitment of the facility compared to the prior facility, the $100 million accordion feature, and the overall financial flexibility that this source of financing provides to the cooperative. Additionally, the elimination of the ongoing material adverse change language is viewed as credit positive from Moody's perspective.

As of December 31, 2011, Dairyland had approximately $43 million of cash and cash equivalents, and $139.2 million of borrowings outstanding under the $300 million facility.

Over the next five years, Dairyland's debt maturity schedule is modest with approximately $49 million due in 2012, declining to $30 million due in 2016. Moody's believes Dairyland will be able to successfully address these maturities, given the level of planned capital expenditures and ample availability under its $300 million credit facility, especially as we anticipate approval and funding by RUS for Dairyland's pending loan requests. Proceeds from funding by RUS would be used by Dairyland to repay outstanding borrowings under the bank facility.

Rating Outlook

Dairyland's outlook is stable, which reflects the manageable capital expenditure program and the benefits of several recent rate increases which have contributed to the improved financial profile. The stable rating outlook also incorporates an expectation that key financial credit metrics will continue to improve over the near to intermediate-term horizon.

What Could Change the Rating - Up

Notwithstanding recent improvements, given Dairyland's current financial metrics that are in Baa range, its rating is somewhat constrained. However, if Dairyland can improve and maintain its metrics at higher levels (for example, greater than 7.5% for FFO/debt and greater than 2.2 times for FFO interest coverage on a sustained basis), the rating could be revised upward.

What Could Change the Rating - Down

A reversal of the recent trend of improvement in financial metrics would be viewed negatively. For example, FFO/debt greater than 6% and FFO + interest / interest greater than 2.0 times on a sustained basis would be more fitting of the current rating level. Failure to achieve these levels as anticipated would place pressure on the rating or outlook.

Rating Factors

Dairyland Power Cooperative
219800

U.S. Electric Generation & Transmission Cooperatives	**Aaa**	**Aa**	**A**	**Baa**	**Ba**	**B**
Factor 1: % Member Load Served and Regulatory Status (20%)		Aa				
Factor 2: Rate Flexibility (20%)						
a) Board Involvement / Rate Adjustment Mechanism (5%)		Aa				
b) Purchased Power / Sales (5%)				31.6%		
c) New Build Capex / Net PP&E (5%)			A			
d) Rate Shock Exposure (5%)						B
Factor 3: Member / Owner Profile (10%)						
a) Residential Sales / Total Sales (5%)			66.0%			
b) Members' Consolidated Equity / Capitalization (5%)				43.4%		
Factor 4: 3-Year Average Financial Metrics (40%)						
a) TIER (5%)			1.3x			
b) DSC (5%)			1.3x			
c) FFO / Debt (10%)				5.3%		
d) FFO / Interest (10%)			2.22x			
e) Equity / Capitalization (10%)				13.7%		
Factor 5: Size (10%)						
a) MWh Sales (5%)				5.9		
c) Net PP&E (5%)			$ 1.0			
Rating:						
a) Indicated Rating from Methodology			A3			
b) Actual Rating Assigned (LT Issuer Rating)			A3			

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Exhibit No. DPC-6

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Dairyland Power Cooperative	Docket No. EL13-__-000

PREPARED TESTIMONY
OF
JEROME IVERSON

OVERVIEW OF DAIRYLAND POWER COOPERATIVE, DESCRIPTION OF THE CAPX2020 HAMPTON-ROCHESTER-LA CROSSE PROJECT AND RELATED TECHNOLOGY STATEMENT

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jerome Iverson. My business address is 3200 East Avenue South, La Crosse, WI 54602. I am Transmission Strategist for Dairyland Power Cooperative ("DPC") and have been actively involved with the CapX2020 Hampton (MN) - Rochester (MN) - La Crosse (WI) transmission project (the "HRL Project" or "Project") since its inception. I am also the lead in this incentive rate filing. The HRL Project is also commonly referred to as the La Crosse Project.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am testifying on behalf of DPC.

Q. PLEASE BRIEFLY DESCRIBE YOUR RESPONSIBILITIES IN DPC'S CAPX2020 TRANSMISSION EXPANSION INITIATIVE AND THE HRL PROJECT.

A. I have been involved in the CapX2020 HRL Project since its beginning. I did the original La Crosse area transmission study that, together with the study work performed by Rochester Public Utilities for the Rochester area, became the foundation for the HRL Project. I have provided input to the development of the routing options and have supported the various DPC personnel involved with the HRL Project.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have been employed by DPC since January 2002. From 2002 to 2008 I was a transmission planner. My planning work included transmission studies for the La Crosse area that together with similar study work in conducted by Rochester Public Utilities, developed into the HRL Project. Since 2008 my title has been Transmission Strategist, which encompasses various responsibilities in the transmission area such as, regulatory, contract administration, and strategy, in addition to my CapX2020 HRL Project duties described above. Prior to working at DPC, I worked at Xcel Energy as a transmission planner; and at East Central Energy, a Minnesota distribution cooperative, as a Distribution Engineer. I graduated from the University of North Dakota in 1994 with a Bachelor of Science Degree in Electrical Engineering with a Power concentration. I also obtained a Master in Business Administration in 2004 from the University of Saint Thomas (St. Paul, MN). Prior to my experience in the electric utility industry, I served nine years in the U.S. Marine Corps, the last six in electronic maintenance specializing in communications. After leaving the Marines, I continued my military career in the Army National Guard, retiring after 26 years as a Chief Warrant Officer. In the Army National Guard, I was Battalion Maintenance Officer, responsible for readiness and the maintenance of all the weapons, vehicles, communications and electronics. I also have a Bachelor Degree in Electronics Technology from the University of the State of New York. I am also a Registered Professional Engineer in Minnesota, Wisconsin, and Michigan.

<u>II. SCOPE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am sponsoring testimony that provides 1) an overview of DPC, 2) an overview of the HRL Project and DPC's participation in the Project, and, 3) a description of the advanced technologies used in the Project.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. In 2010, I submitted testimony in Docket No. ER11-1955 in support of DPC's filing of its revenue requirement and supporting data for the provision of cost-based Reactive Supply and Voltage Control under Schedule 2 of MISO's Tariff, which was accepted by the Commission. In 2011, I submitted testimony in Docket No. ER12-487 in support of an update to DPC's revenue requirement for Reactive Supply and Voltage Control under Schedule 2 of MISO's Tariff, which was also accepted by the Commission.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY IN THIS CASE?

A. Yes, I am sponsoring Exhibit DPC-7, which is a map showing the approved routes for the HRL Project, and Exhibit DPC-3, which lists Federal Permits applicable to the HRL Project.

III. OVERVIEW OF DPC

Q. PLEASE PROVIDE AN OVERVIEW OF DPC.

A. DPC is a not-for-profit, generation and transmission cooperative serving 25 distribution cooperatives that are the owners of DPC. DPC has all-requirements contracts with its members through 2055. Eighteen are located in Wisconsin, three in Minnesota, three in Iowa and one in Illinois. In addition, DPC serves 15 municipal customers at wholesale with power supply contracts through 2028. DPC owns or has under contract 1123 MW of generation and 3,176 miles of transmission lines. Through DPC, the 25 member cooperatives serve approximately 256,000 member customers. DPC is a market participant in MISO energy markets and joined MISO as a transmission owner in 2010. Of DPC's 25 members' load, 700 MW are located in the DPC pricing zone, 145 MW are in the NSP pricing zone, 40 MW are in the ATC pricing zone and 32 MW are in ITC-Midwest pricing zone. In accordance with the MISO Tariff, DPC load in its own pricing zone pays DPC's bundled wholesale rate. DPC load in other pricing zones pay the MISO network transmission rate applicable to their respective zones.

The DPC pricing zone consists of its own members' load and load of other customers. Of the current total load in the DPC pricing zone of 936 MW, about 32% (300 MW) of the load is non-DPC customer load. These customers include Xcel/NSP (230 MW), Northwestern Wisconsin Electric Company (22 MW), Interstate Power and Light Company (13) MW, Wisconsin Power and Light Company (16) MW, and various municipal utilities (19 MW). After the HRL Project is in service, it is projected that there will be about 173 MW of Xcel/NSP load in the DPC pricing zone, and 26% of the total DPC pricing zone load will be non-DPC load.

IV. HISTORY OF DPC'S PARTICIPATION IN CAPX2020 HRL PROJECT

Q. PLEASE PROVIDE AN OVERVIEW OF CAPX2020 AND ITS PURPOSE.

A. CapX2020 is a joint regional transmission planning initiative of 11 transmission-owning utilities in the upper Midwest to expand the electric transmission grid to ensure continued reliable and affordable service. The CapX2020 utilities include investor-owned utilities, electric cooperatives, municipal agencies and individual municipal utilities, which collectively serve the majority of customers in Minnesota and the surrounding region. The new Group 1 transmission projects to be built are designed to meet increasing demand as well as to support renewable energy expansion and in addition to the HRL Project include the following transmission projects:

- Bemidji-Grand Rapids, 68 miles, 230 kV
- Fargo-St. Cloud, about 210 miles, 345 kV
- Monticello-St. Cloud, about 28 miles, 345 kV

- Brookings County-Hampton, 250 miles, 345 kV

Q. IS DPC CURRENTLY A FORMAL MEMBER OF THE CAPX2020 INITIATIVE ?

A. No, not at this time. Membership in the CapX2020 initiative is not required for DPC's participation in the HRL Project. DPC is, however, contemplating full membership.

Q. PLEASE DESCRIBE DPC'S HISTORY WITH THE HRL PROJECT.

A. In 2004, DPC and Rochester Public Utilities (also a participant in the HRL Project) initiated planning studies to increase reliability in the Rochester, Minnesota, and La Crosse, Wisconsin, areas. These studies evolved into what was later to become the HRL Project as part of the CapX2020 Group 1 Projects. DPC and the other HRL Project participants signed the Project Development Agreement for the HRL Project in 2007. The HRL Project was submitted to MISO and was approved as a Regional Expansion Criteria and Benefits 1 (RECB 1) project (a baseline reliability project) in the 2008 MISO Transmission Expansion Plan (MTEP08). Dairyland was also a contributor in the WIRES Phase II Study (June 1999) where a similar project, the Prairie Island-La Crosse-Columbia 345 kV transmission line was an option.

V. DESCRIPTION OF THE HRL PROJECT

Q. PLEASE PROVIDE AN OVERVIEW OF THE HRL PROJECT.

A. The HRL Project will (i) serve increasing demand in the Rochester and Winona, Minnesota, and La Crosse, Wisconsin, areas, (ii) support and maintain the reliability of the local and regional electrical system, (iii) support the interconnection of new generation, and (iv) increase the power transfer capability from Minnesota into Wisconsin. Increasing the power transfer capability will reduce congestion, increase access to renewable generation (particularly wind energy from the some of the best wind resource areas in the United States), and increase the flexibility for utilities to respond to emerging environmental requirements and potential retirement of generation.

In approving the portion of the HRL Project in Minnesota, the Minnesota Public Utilities Commission (MPUC) ordered the Minnesota portion to be constructed as a double-circuit capable[1] 345 kV Project. The Project will run from a new substation at Hampton (in the greater Minneapolis/St. Paul metropolitan area, close to Red Wing, Minnesota) to the proposed North Rochester Substation between Zumbrota and Pine Island, Minnesota. From Rochester, the line will extend eastward and cross the Mississippi River near Alma, Wisconsin.

From Alma, the line will be built primarily for double circuit 345 kV / 161 kV operation[2] and extend to the La Crosse, Wisconsin vicinity (See Exhibit DPC-7

[1] The line would be constructed with the anticipation of eventually carrying two 345 kV circuits. Poles would be sized to accommodate the two circuits and the conductor and insulators installed would be consistent with 345 kV double-circuit configuration.

[2] Much of the proposed route in Wisconsin will overtake existing 161 kV transmission lines. The new line in Wisconsin will carry both the 345 kV circuit and a replacement for the existing 161 kV circuit on the same poles. The line is not, however, designed to be constructed for future double-circuit 345 kV operation.

for map and the approved routes). Also as part of this Project, two new 161 kV lines have been approved between the North Rochester Substation and the existing Rochester Public Utilities' Northern Hills and Chester 161 kV substations serving Rochester, Minnesota.

Q. WHAT IS THE COST ALLOCATION METHODOLOGY FOR THE HRL PROJECT AND HOW DOES IT DIFFER FOR DPC?

A. The HRL Project is a MISO RECB 1 project. Therefore, 20% of the Project costs incurred by a participant that was a MISO Transmission Owner prior to the Project being approved by MISO in 2008 or qualifies through other conditions for cost sharing in accordance with the MISO Tariff are shared throughout the MISO footprint. The remaining 80% of the Project costs eligible for RECB 1 cost sharing are allocated sub-regionally through the Line Outage Distribution Factor (LODF) methodology, which allocates the costs of the Project to nearby pricing zones based on power flows. Xcel/NSP and SMMPA are eligible for RECB 1 cost allocation treatment. Because DPC was not a MISO Transmission Owner prior to the HRL Project being approved, DPC's HRL costs are not eligible for any RECB 1 cost sharing or LODF cost allocation. Rather, all of DPC's HRL costs will be paid for by the load in the DPC pricing zone. By contrast, the DPC load in the NSP pricing zone is subject to RECB 1 cost allocations of Xcel/NSP's HRL costs.

Q. WHY IS THE HRL PROJECT AN IMPORTANT TRANSMISSION PROJECT?

A. The HRL Project provides a vital load serving and reliability support to the Rochester and Winona areas in Minnesota, as well as the La Crosse area. As stated earlier, initial studies of the Rochester and La Crosse area proved that 161 kV projects were inadequate in the long term, which lead to the HRL Project as a 345 kV solution.

Specifically, the Public Service Commission of Wisconsin determined in granting a Certificate of Public Convenience and Necessity for the HRL Project that the Project will serve the following purposes:

- Local reliability -to serve increasing electric demand in the La Crosse, Wisconsin, and Winona and Rochester, Minnesota, areas.

- Regional reliability - to maintain the reliability of the regional electrical system.

- Generation support - to provide a means for getting local electric generation output onto the electric grid.

- Regional benefits - to enhance power transfers from states located west of the Mississippi River, access to more economical generation, and access to sources of renewable generation.[3]

Q. WHO ARE THE OWNERS OF THE HRL PROJECT AND WHAT ARE THEIR ESTIMATED OWNERSHIP SHARES?

A. The owners and their expected ownership shares of the HRL Project are Xcel Energy / Northern States Power Company (64%), Southern Minnesota Municipal Power Agency (13%), DPC (11%), Rochester Public Utilities (9%) and WPPI

[3] *Joint Application of Dairyland Power Cooperative, Northern States Power Company-Wisconsin, and Wisconsin Public Power, Inc., for Authority to Construct and Place in Service 345 kV Electric Transmission Lines and Electric Substation Facilities for the CapX Twin Cities-Rochester-La Crosse Project, Located in Buffalo, Trempealeau, and La Crosse Counties, Wisconsin*, Final Decision at 16, PSCW Docket No. 5-CE-136 (May 30, 2012).

Energy (3%). DPC's portion approximates its load ratio share of the Project and was determined through negotiations with the other participants in the Project. DPC estimates that its 11% share in the currently projected $471 million HRL Project will be about $52 million plus about $3.2 million in capitalized interest and capitalized overheads.

Q. COULD THE CURRENT PROJECT COST ESTIMATE FOR THE HRL PROJECT INCREASE?

A. Yes. The current estimate could increase due to potential scope changes, additional permitting costs or conditions, litigation delays, and construction cost increases.

Q. WHAT IS THE STATUS OF THE HRL PROJECT?

A. DPC and the other Project participants have been developing and obtaining permits for the HRL Project under a Project Development Agreement. The long term Project agreements are currently being negotiated and finalized. These Project agreements will govern the construction, ownership, operation, and maintenance of the HRL Project, and the Project participants hope to execute the agreements in December 2012, following receipt of all the agency approvals necessary to build the Project.

Q. WHAT UNCERTAINTIES AND POTENTIAL RISKS RELATED TO PERMITTING ARE ASSOCIATED WITH THE HRL PROJECT?

A. On May 22, 2009, the CapX2020 utilities were granted a Certificate of Need (CON) by the Minnesota Public Utilities Commission (MPUC) for three 345-kilovolt electric transmission lines in Minnesota, one of which was the HRL

Project. In April, 2012, the MPUC issued a route permit for the Minnesota portion of the HRL Project. Two parties, one a municipality and the other a group of affected landowners, filed appeals of the MPUC Route Decision with the Minnesota Court of Appeals and these appeals are pending.[4] The HRL Project was granted a Certificate of Public Convenience and Necessity (CPCN) by the Public Service Commission of Wisconsin on May 30, 2012. The CPCN addresses both the need for the project and the route. Judicial review of the approved CPCN is pending.[5]

In addition to approvals from Minnesota and Wisconsin commissions, Federal permits are also required. The Rural Utilities Service (RUS) is the lead Federal agency responsible for developing a Federal Environmental Impact Statement (FEIS) for the HRL Project to comply with the National Environmental Policy Act. The RUS is cooperating with the two other affected Federal Agencies, the U.S. Fish and Wildlife Service and the U.S. Army Corps of Engineers. The final FEIS has been completed and is awaiting a decision by the RUS as to whether they will approve the FEIS or not (the RUS Record of Decision is expected in mid-November).

[4] On September 10, 2012, Oronoco Township filed an appeal on the Route Decision, and on September 12, 2012, landowners in Cannon Falls appealed the Route Decision. On September 20, 2012, the Minnesota Court of Appeals issued an order joining the cases (AR-1607 & AR-1632 respectively). Although a date for the Court to issue a decision has not been scheduled, at this time, a decision may be issued by July 2013.

[5] NoCapX 2020 and the Citizens Energy Task Force filed a Petition for Review of the CPCN decision on August 16, 2012 in Circuit Court for Dane County, Wisconsin (Case No. 12-CV-5328). On October 26, 2012, the Circuit Court issued a decision granting the motion to strike the Petition for Review filed by the Public Service Commission of Wisconsin.

In addition to the RUS Record of Decision, the U.S. Fish and Wildlife Service will need to grant permission for the Project to cross a National Wildlife Refuge. Also, two Army Corps of Engineers section 404 wetlands permits are needed, one for the 161 kV Northern Hills tap line in Minnesota and the other for the rest of the project in Minnesota and Wisconsin including the Mississippi River crossing. This requires near-final spotting of every pole on the project to determine wetlands impacts. Also included are archeological and historic structure surveys, threatened and endangered species surveys and consultations with state and federal agencies and tribes. There are still a considerable number of Federal[6] and state (Minnesota and Wisconsin) permits to be acquired as well as water quality certifications from each state. Also in question is the section of the Project in Wisconsin which runs near the Great River Road Scenic Byway (Great River Road). The Wisconsin Department of Transportation (WisDOT), during the CPCN[7] proceedings, argued against permitting the Project across the Great River Road because of the aesthetic impact. Given the WisDOT's position on the Great River Road, the Project could encounter difficulties with permits under their jurisdiction.

Right of way acquisition has begun in Minnesota but not in Wisconsin. Assuming agency proceedings, court proceedings, and other issues are resolved, and right of way acquisition proceeds as planned, the HRL Project is expected to be completed in early 2016. It is possible that the HRL Project will be finished in

[6] Federal Permits applicable to the HRL Project are listed in Exhibit DPC-3.

[7] PSCW Docket 5-CE-136.

phases with the first phase anticipated to be the North Rochester 345-161 kV substation and 161 kV work in the Rochester, Minnesota area. This would be followed by constructing the 345 kV line from North Rochester to Alma, then continuing on to the La Crosse area, and finally by constructing the 345 kV line from North Rochester Substation to Hampton Substation.

Q. WHAT ADDITIONAL UNCERTAINTY RELATED TO THE HRL PROJECT OWNERSHIP HAS RECENTLY SURFACED?

A. Another uncertainty that may delay the Project is the pendency and outcome of the complaint filed by American Transmission Company LLC (ATC) against Xcel Energy in Commission Docket No. EL13-9-000 seeking an ownership interest in the HRL Project. As some of the comments filed by HRL Project participants in Docket No. EL13-9-000 explained, the filing of the complaint by ATC may adversely affect the ability of certain participants to finance their portions of the Project, and may delay the execution of the ownership, construction management, and other Project agreements until the issues raised in ATC's complaint are resolved.

VII. TECHNOLOGY STATEMENT

Q. PLEASE DESCIBE THE ADVANCED TECHNOLOGIES THAT WILL BE USED IN THE CONSTRUCTION OF THE HRL PROJECT.

A. The HRL Project will make use of advanced conductor designs of steel supported aluminum conductors with trapezoidal wire. It will use new technologies such as micro-processor based digital protective relays, digital fault recorders, Programmable Logic Controller (PLC)-based control and annunciation, tubular steel structures, and fiber-optic based communication. In addition, the HRL Project will utilize helicopters for some construction, use sophisticated aerial surveying methods, use vibratory caissons in appropriate locations to minimize environmental impact, employ various configurations at refuge/river crossings to reduce bird kills, and make use of fiber-optic shield wire for utility system protection. After extensive review of the engineering and permitting constraints of crossing the Mississippi River with a 2300 foot span, the HRL Project intends to make use of a custom conductor likely in a triple bundle configuration.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Dairyland Power Cooperative	Docket No. EL13-__-000

AFFIDAVIT

I, the undersigned, being duly sworn, on oath depose and state that the above and foregoing Prepared Testimony of Jerome Iverson is the testimony of the undersigned, and that the testimony and exhibits sponsored by me, to the best of my knowledge, information and belief, are true, correct, accurate, and complete.

Jerome Iverson

Jerome Iverson

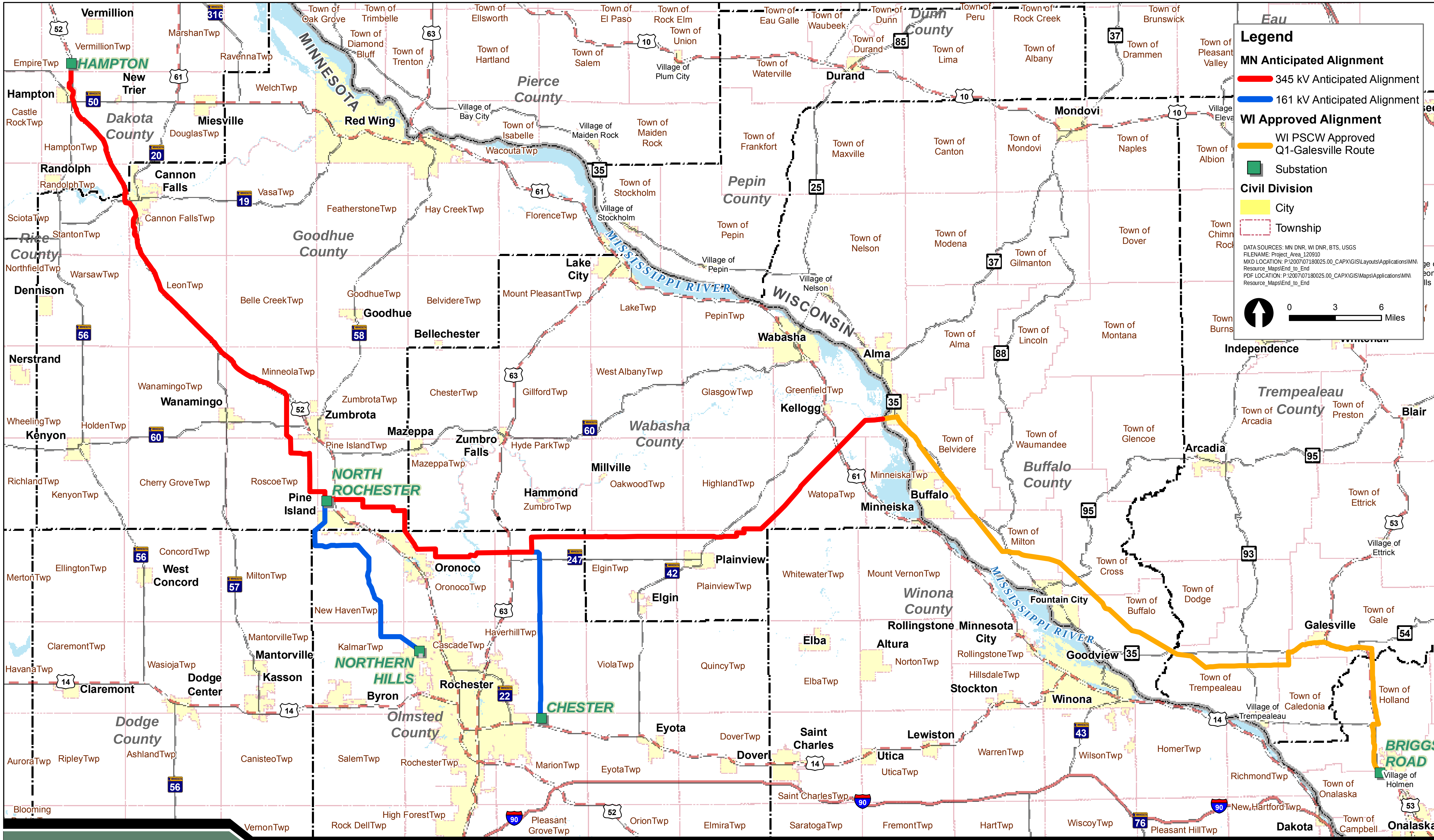
Subscribed and sworn to before me
this 1st day of November, 2012.

Michelle A. Beck

Notary Public, La Crosse County, Wisconsin
My commission expires: 03.13.16

MICHELLE A. BECK
Notary Public
State of Wisconsin

Exh. DPC-7



CapX2020

Hampton • Rochester • La Crosse 345 kV Transmission Project

Xcel Energy • Dairyland Power Cooperative • Rochester Public Utilities • WPPI Energy • Southern Minnesota Municipal Power Agency

Minnesota and Wisconsin Project Area

September 2012

Exhibit No. DPC-8

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Dairyland Power Cooperative | Docket No. EL13-___-000

PREPARED TESTIMONY
OF
JAMES PARDIKES

JUSTIFICATION FOR INCENTIVES OF HYPOTHETICAL CAPITAL STRUCTURE AND ABANDONED PLANT RECOVERY

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is James Pardikes. I am a Vice President and head of the Transmission Strategy and Capital Planning Practice at MCR Performance Solutions ("MCR"). My present business address is 155 N. Pfingsten Road, Suite 155, Deerfield, IL 60015.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am testifying on behalf of Dairyland Power Cooperative ("DPC").

Q. PLEASE BRIEFLY DESCRIBE YOUR RESPONSIBILITIES AS MCR'S HEAD OF THE TRANSMISSION STRATEGY AND CAPITAL PLANNING PRACTICE.

I lead MCR client projects, including assisting generation and transmission cooperatives ("G&Ts"), joint action public power agencies, municipal utilities involving transmission related matters. For the Transmission Strategy area, I have assisted numerous clients in evaluating the economics of joining the

Midwest Independent Transmission System Operator, Inc. ("MISO") as a transmission owner, developed financial models and evaluated the economics and risks of major transmission projects, provided expert testimony and analytics for client requests for transmission rate incentives, managed the preparation of the *pro forma* MISO Attachment O transmission revenue requirement schedules and presented results to managements and boards of directors. As part of leading the Capital Planning area, I work with utilities in evaluating the economics and risks of various capital projects including new generation, transmission and environmental control projects, and apply the concepts of net present value and risk analysis to the evaluations of major projects. In addition, I have assisted G&T clients in the development of their presentations to credit rating agencies. This has included analyzing industry financial metrics data and company credit reports to determine the key factors to improving a utility's credit rating, leading to the development of client company financial targets and financial and business communications to achieve appropriate credit ratings.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Michigan Business School in 1979 with a Bachelor in Business Administration, with an emphasis in Accounting. I obtained a Masters of Business Administration in Finance from Michigan State University in 1982. Upon graduation, I worked for the Consulting Division of Arthur Andersen for five years on strategy projects. This experience included working on several financial modeling assignments for investor owned utilities ("IOUs") and public power electric utilities, where I gained experience in revenue requirements and cost of capital. From 1987-1999, I worked at CSC Planmetrics, a management consulting firm dedicated to serving electric and natural gas utilities, where I focused on wholesale power marketing, strategic planning and retail competitive energy markets for IOUs and G&Ts. From 1999-2001, I worked for Accenture in its Energy practice, where I assisted utility and energy clients in wholesale and competitive retail energy markets. In 2001, I joined MCR, where I am a Vice President and lead the Transmission Strategy and Capital Planning practice. I have authored many MCR Strategy White Papers, including on the topics of new transmission investments within MISO, transmission incentive rates, MISO rate protocols, the economic evaluation of potential MISO membership as a Transmission Owner ("TO"), cost allocation methodologies within MISO, and capital project evaluations, including quantitative risk analysis of major projects.

II. SCOPE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am sponsoring testimony explaining why DPC is entitled to the requested transmission incentives for its ownership stake in the CapX2020 Hampton MN-Rochester MN-La Crosse WI ("HRL Project") transmission project also commonly referred to as the "La Crosse Project." CapX2020 is a joint regional transmission planning initiative of 11 transmission-owning utilities in the upper Midwest to expand the electric transmission grid to ensure continued reliable and affordable service. Mr. Iverson's testimony describes the CapX202 initiative and Dairyland's participation in the initiative in more detail.

My testimony includes discussion of why the DPC investment in HRL transmission qualifies for incentives. DPC is requesting that the Federal Energy Regulatory Commission ("FERC") issue a declaratory order approving the use of a hypothetical capital structure and the recovery of abandoned plant investment in the event that the HRL Project is abandoned for reasons beyond the control of DPC. DPC needs these incentives because of the great importance of and substantial risks involved in the HRL Project,

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY IN THIS CASE?

A. Yes, I am sponsoring Exhibit DPC-9 through DPC-17.

III. SUMMARY OF REQUESTED INCENTIVES

Q. PLEASE SUMMARIZE THE INCENTIVES THAT DPC IS REQUESTING.

A. Table 1 below summarizes the incentives for which DPC is seeking declaratory approval. The requested incentives are a hypothetical capital structure of 35% equity for the life of the financing and recovery of costs shown to have been prudently incurred in the event the HRL Project is cancelled or abandoned for reasons beyond DPC's control. Regarding return on equity ("ROE"), DPC is not requesting an additional ROE incentive adder. DPC will apply the standard ROE for MISO transmission owners of 12.38%.

Table 1

Incentive	Requested by DPC for HRL Project?
Hypothetical Capital Structure for Project Financing Life	Yes
Abandoned Plant Recovery	Yes
100% CWIP in Rate Base	No
Incentive Adder	No, applying standard MISO ROE of 12.38%

Q: PLEASE SUMMARIZE WHY THE COMMISSION SHOULD GRANT DPC'S REQUESTED INCENTIVES AND HOW EACH INCENTIVE IS TAILORED TO THE DEMONSTRABLE RISKS AND CHALLENGES OF THE HRL PROJECT.

A. The HRL Project will increase reliability and reduce congestion (and, as described in the Petition, it meets the Commission's criteria for qualifying for a rebuttable presumption). In addition, each of the requested incentives meets the nexus test relating the risks and challenges of the HRL Project to the incentives requested. The rationale for each incentive is summarized below and discussed in detail in subsequent sections.

Hypothetical Capital Structure

There are several reasons why DPC should be granted a hypothetical capital structure of 35% equity/65% debt (“35% equity to total capitalization”, or simply “35% equity ratio”). The hypothetical capital structure:

1. Provides financial metrics that are consistent with DPC’s improving financial ratios and solidifying the company’s target credit rating of “A”. Providing a hypothetical capital structure of 35% equity provides key metrics on the HRL debt that are consistent with: 1) the substantial size and risks of the HRL Project, 2) DPC’s improving actual financial metrics, 3) DPC’s projected company-wide financial ratios including projected increases in DPC’s equity ratio, and 4) financial metrics of “A” rated G&Ts . These key metrics are debt service coverage ratio (“DSC”), times interest earned ratio (TIER), funds from operations to debt ratio (FFO/Debt), funds from operations to interest ratio (FFO/Interest), and equity to total capitalization ratio.

The substantial debt associated with the HRL Project will increase the long term debt on DPC’s balance sheet and the interest expense that must be serviced. The improved metrics on the HRL debt service provided by a hypothetical capital structure sends the investment community a consistent message that DPC can absorb the long term debt from the HRL Project and is committed to achieving its Strategic Financial Management Policy set by its Board of Directors of being an “A” rated utility with at least two credit rating agencies. DPC is currently rated “A” by S&P and A3 by Moody’s, which is the equivalent of an "A-" S&P rating. DPC's target credit rating for Moody's is A2, the equivalent of an "A" S&P rating. DPC's credit rating has become increasingly important as G&Ts have become less reliant on uncertain Rural Utilities Service (RUS) funding and are increasingly likely to finance many future capital projects from the commercial market. (See Exhibit DPC-1, Moilien testimony describing the indenture process giving DPC flexibility to obtain financing from non-RUS sources). A higher credit rating for DPC will thus contribute to lower financing costs for future commercially-financed capital projects, including potentially large regional transmission projects.

2. **Provides a return to reflect the risk of the HRL Project.** The additional return from a 35% equity ratio encourages DPC to invest in this Project, which is not routine and has a higher risk profile and level of uncertainty than other more routine transmission projects in which DPC has invested in the past. The additional return is warranted given the substantial risks the HRL Project faces (see Sections IV in particular) and the risks incurred by DPC's 25 member distribution cooperatives for their responsibilities for the debt service associated with the HRL Project.... If DPC does not receive compensation reflecting the higher risk of transmission projects such as the HRL Project, a large, complex multi-jurisdictional transmission project, then given its constrained capital, it would make more sense for DPC to invest in other, more routine projects and let investor-owned utilities (IOUs) like Xcel

invest in large regional transmission projects.[1] This outcome would increase transmission rates and discourage joint transmission investment and collaboration in the region.

3. **Helps prevent DPC from subsidizing Xcel/NSP ratepayers in the DPC pricing zone.** DPC is a Load Serving Entity ("LSE") in MISO with load located in the NSP pricing zone as well as its own pricing zone. Similarly, Xcel/NSP is an LSE with load in the DPC pricing zone[2] as well as its own pricing zone. DPC loads in the NSP pricing zone are paying a substantially higher revenue requirement for the same per dollar amount of HRL investment than Xcel/NSP's load in the DPC pricing zone.[3] Therefore, DPC is effectively subsidizing Xcel/NSP's customers through its much lower cost structure. This occurs even though DPC is faced with similar risks as Xcel/NSP for the same Project, together with the additional risks associated with DPC being a minority participant. A hypothetical capital structure on DPC's HRL investment provides DPC some ability to mitigate the large disparity in returns and revenue requirement on the HRL investment.

4. **Lowers long term costs to MISO ratepayers.** A hypothetical capital structure on the HRL Project will encourage the DPC Board of Directors to

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[1] See Exhibit 1, Moilien testimony for discussion of DPC's capital constraints.

[2] After the HRL Project is complete, DPC estimates that approximately 26% (252 MW) of DPC's load in the DPC pricing zone is non-DPC member load including about 173 MWs of Xcel/NSP load. The remaining 74% of the load in the DPC pricing zone pays the DPC bundled rate consistent with Module B, Section 37.3(a) of the MISO tariff.

[3] Note that even with a hypothetical capital structure, Xcel/NSP's revenue requirements are substantially higher than DPC's revenue requirements because Xcel/NSP pays income taxes, has a higher historical cost of debt and a higher equity ratio. See discussion in Section X and Exhibit DPC-10.

support future transmission investments in the region. If, however, DPC chose not to invest in future large transmission projects due to insufficient return on projects such as the HRL Project, given its risks, the vast majority, or the entire void will be filled by IOUs—with significantly higher revenue requirements, resulting in higher MISO rates for all MISO ratepayers. For example, the revenue requirements of Xcel/NSP for the HRL Project are about 66% higher per dollar of investment than that of DPC when using DPC's actual 2011 equity ratio in its Attachment O. Even with a 35% equity ratio for DPC for the HRL Project, the revenue requirements of Xcel/NSP are still 51% higher than DPC's revenue requirements (see detailed discussion in Section X and Exhibits DPC-9 and DPC-10).

5. **Encourages joint development of transmission in the MISO region.** DPC's request for returns approaching those allowed to the major investor on the HRL Project, Xcel/NSP, is consistent with Order 679, which encourages a broad pool of investors (see below for further discussion). A diversified pool of investors facilitates collaborative transmission planning and smoother regulatory approvals. This will be increasingly important as MISO continues its efforts to build new major regional transmission projects such as Multi-value Projects (MVPs), which typically cross multiple service territories and state jurisdictions within MISO.

6. **Is less than the equity ratios that have been recently provided to other entities reliant on non-equity financing.** The Commission has previously provided hypothetical capital structures of 50% equity to total capitalization

ratio for Citizens Energy. Addressing recent CapX2020 incentive requests, the Commission has approved a 50% equity to total capitalization ratio for Central Minnesota Municipal Power Agency ("CMMPA"), and a 45% equity ratio for both Missouri River Energy Services ("MRES") and WPPI Energy ("WPPI"), for the duration of the financing associated with their respective shares of CapX2020 projects.

Abandoned Plant Recovery

The HRL Project still requires substantial state and federal approvals related to permitting and right-of-way. The HRL Project has been approved by the Minnesota Public Utilities Commission (MPUC), however, two parties, one a municipality and the other a group of affected landowners, have filed appeals on the Route Decision with the Minnesota Court of Appeals in September, 2012 and these appeals are pending.[4] Although the Public Service Commission of Wisconsin (PSCW) also approved the HRL Project in June 2012, judicial review of the Wisconsin Certificate of Public Convenience and Necessity (CPCN) may affect the cost and timing of the HRL Project and the validity of the CPCN.[5] In addition, federal permits have not yet been received. The RUS is expected to

[4] On September 10, 2012, Oronoco Township filed an appeal on the Route Decision, and on September 12, 2012, landowners in Cannon Falls appealed the Route Decision. On September 20, 2012, the Minnesota Court of Appeals issued an order joining the cases (AR-1607 & AR-1632 respectively)[4]. Although a date for the Court to issue a decision has not been scheduled, at this time, it appears a decision may be issued by July 2013.

[5] NoCapX 2020 and the Citizens Energy Task Force filed a Petition for Review of the CPCN decision on August 16, 2012 in Circuit Court for Dane County, Wisconsin (Case No. 12-CV-5328). On October 26, 2012, the Circuit Court issued a decision granting the motion to strike the Petition for Review filed by the PSCW.

issue its Record of Decision regarding the Federal Environmental Impact Statement (FEIS) in mid-November, 2012. In addition, the HRL Project still requires permits from the Army Corps of Engineers for wetlands and river crossings including the Mississippi River, and, the U.S. Fish and Wildlife Service will need to grant permission for the Project to cross a National Wildlife Refuge (see Exhibit DPC-6). The HRL Project is also complex because it is located in two states and is to be jointly owned by an IOU, a G&T (DPC), two municipal joint action agencies, and an individual municipality. These entities have different governance and decision-making processes. They also have different methods to finance their respective shares of the Project, and the various bond issuers and lenders all need to become comfortable with the ownership structure of the Project.

Uncertainty with respect to ownership rights has been highlighted with the recent complaint filed at the Commission by American Transmission Company (ATC) claiming rights to 50% of the HRL 345kV facilities.[6] This creates uncertainty regarding whether the existing participants of the HRL Project will be able to own their respective anticipated shares of the Project, and raises the prospect of some participants being denied ownership (in full or in part), putting at risk expenditures incurred to date. As some of the comments filed by HRL Project participants in Docket No. EL13-9-000 note, the filing of the complaint by ATC may adversely affect certain participants' ability to finance their portions of

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[6] *See,* ATC Complaint filed in FERC Docket EL13-9.

the Project, and may delay the execution of the ownership, construction management, and other Project agreements until the issues raised in ATC's complaint are resolved. These factors make regulatory approvals and project decision-making more complex, and make the threat of abandoned plant real. Given that threat, there are four reasons why the HRL Project warrants granting DPC's request for abandoned plant recovery. This incentive:

1. **Helps protect DPC from a cancellation decision by the major investor in the HRL Project.** Because DPC is a minority investor in the HRL Project, DPC alone will not be able to control a decision to cancel the project by the majority owner that has a much more substantial ownership percentage. For example, if either the appeal of the Minnesota Route Decision or judicial review of the Wisconsin CPCN is successful, or ATC is successful in Docket No. EL13-9, the project could be cancelled, modified or significantly delayed.
2. **Mitigates the financial impact of a cancelled project.** The HRL Project represents a major investment for DPC. Without this approved incentive, if the Project were cancelled, DPC would have to raise rates to members to fully absorb pre-construction and construction costs it has incurred to the date of the project cancellation. Granting of this incentive by the Commission would ensure that prudent DPC costs will be allocated consistent with the MISO Tariff in order to mitigate the costs incurred up through project cancellation. This incentive assures that for its load located in the NSP pricing zone, DPC will not be forced to pay the investment costs DPC would incur on a cancelled

project *plus* a share of the abandoned plant costs of the other HRL owners that have already received this incentive such as Xcel/NSP[7] and WPPI.

3. **Provides cost recovery assurance to credit rating agencies.** This incentive gives comfort to credit rating agencies that if HRL is cancelled, DPC may avail itself of a regulatory mechanism to recover its prudently incurred costs, in accordance with the MISO Tariff. Combined with the other requested incentive of a hypothetical capital structure, abandoned plant cost recovery makes DPC's debt burden from the HRL Project less onerous, thus leaving a positive impact on credit rating agencies and contributing to lower or future financing costs for DPC.

Q. HAVE INCENTIVES BEEN GRANTED TO OTHER OWNERS IN THE HRL PROJECT?

A. Yes. The HRL Project has previously been approved by the Commission as qualifying for incentives under the standards set forth under Order 679 and Commission precedent. In October, 2012 the Commission granted WPPI a hypothetical capital structure, abandoned plant cost recovery and the establishment of a regulatory asset.[8] In 2007, the Commission granted 100%

[7] Twenty percent of Xcel/NSP costs associated with the HRL Project (a RECB 1 project) will be shared throughout MISO and the remaining 80% based on Line Outage Distribution Factor (LODF). Because DPC joined MISO as a Transmission Owner after the HRL Project was approved by MISO, DPC's costs for the HRL Project are not eligible for RECB 1 treatment (also see Iverson testimony, Exhibit 5).

[8] *WPPI Energy*, 141 FERC ¶ 61,004 (2012) ("*WPPI Energy")*.

construction work in progress (CWIP) in rate base and abandoned plant cost recovery to Xcel/NSP, the majority owner in the HRL Project.[9]

Q. WHY IS DPC NOT REQUESTING 100% CWIP IN RATE BASE?

A. DPC expects to finance the capital expenditures during the construction period of the HRL Project with a relatively low cost line of credit and thus does not expect to experience significant cash flow strain or significant financing costs during the construction period. As a result, DPC is not requesting recovery of CWIP in rate base (see Moilien testimony, Exhibit DPC-1).

Q. HAS THE COMMISSION RECOGNIZED THE IMPORTANCE OF PROVIDING INCENTIVES TO NON-IOU JOINT OWNERS OF LARGE, RISKY TRANSMISSION PROJECTS?

A. Yes. The importance of G&T and public power investment in new transmission is fully supported by Commission policy. The Commission said in Order No. 679:

> We agree with comments that public power participation can play an important role in the expansion of the transmission system…. [T]o the extent our jurisdiction allows, the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates with jurisdictional entities as part of a proposal for incentives for a particular joint project. Encouraging public power participation in such projects is consistent with the goals of section 219 by encouraging a deep pool of participants.[10]

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[9] *Xcel Energy Services, Inc.*, 121 FERC ¶ 61,284 (2007) ("*Xcel*").

[10] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294, at 43,332 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222, P 354 (2006) ("Order 679"), *on reh'g*, Order No. 679-A, 72 Fed. Reg. 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2006), *clarified*, 119 FERC ¶ 61,062 (2007).

The Commission reiterated its desire for joint ownership in Order No. 679-A: "[T]he Commission will look favorably on an incentive request that includes public power joint ownership."[11] In Order No. 890, the Commission also stated:

> The Commission believes there are benefits to joint ownership of transmission facilities, particularly large backbone facilities, both in terms of increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the transmission grid by transmission customers.[12]

Further, in Order No. 1000 (P 776), the Commission restated its desire for joint ownership.[13] Significantly, the Commission said in *CMMPA*:[14]

> 19. We agree with Petitioners that we have authority to consider and grant their request for incentive rate treatment. In Order No. 679, the Commission stated that it would, "to the extent [its] jurisdiction allows, entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates with jurisdictional entities as part of a proposal for incentives." 23/
>
> 23/ Order No. 679, FERC [Stats. & Regs.] ¶ 31,222[,] P 354. We also noted that encouraging public power participation in such projects is consistent with the goals of

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[11] Order No. 679-A, P 102.

[12] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266, 12,340 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, P 593 (2007) ("Order No. 890"), *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 74 Fed. Reg. 12,540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), order *on clarification*, Order No. 890-D, 74 Fed. Reg. 61,511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

[13] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 136 FERC ¶ 61,051, P 776 (2011), ("Order 1000"), order on reh'g, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), order on reh'g 141 FERC ¶ 61,044 (2012) ("[W]e reiterate here our statement in Order No. 890 that we believe there are benefits to joint ownership of transmission facilities, particularly large backbone facilities, both in terms of increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the transmission grid by transmission customers." (footnote omitted)).

[14] *Central Minnesota Municipal Power Agency, et al.*, 134 FERC ¶ 61,115, P 19 & n.23 (2011) ("*CMMPA*").

> section 219 of the FPA by encouraging a deep pool of participants.

Commissioner Norris' concurring opinion in *WPPI Energy* supported the Commission's historical desire for and approval of joint investment:

> Public power participation in the joint ownership of new transmission remains as important as ever as we continue to develop the infrastructure necessary to ensure that our nation's energy system is reliable and efficient. As I have previously stated, joint ownership encourages a deeper and more collaborative pool of participants in the transmission development process and can generate key support for transmission projects that often face difficult siting decisions at the state and local levels.
>
> … The CapX2020 initiative represents a great example of how joint ownership in the upper Midwest can harness the collaboration of eleven utilities, their regulators and the public to expand the transmission grid to meet increased demand and support renewable energy development.[15]

IV. NEXUS TEST

Q: HOW DO THE REQUESTED INCENTIVES FOR THE HRL PROJECT MEET THE REQUIREMENT OF SHOWING A NEXUS BETWEEN THE INCENTIVE SOUGHT AND THE INVESTMENT BEING MADE AND ITS ASSOCIATED RISKS?

A: In examining whether the nexus requirement has been met, the Commission considers whether the project or group of projects is "routine." In reaching a conclusion as to whether a project is non-routine, the Commission notes the

[15] *WPPI Energy*, Norris concurring, at 1.

interplay between the nexus test and the routine or non-routine nature of projects, referencing that

> when an applicant has adequately demonstrated that the project for which it requests an incentive is not routine, that applicant has, for purposes of the nexus test, *shown that the project faces risks and challenges that merit an incentive*. By definition, projects that are not routine under our analysis articulated above face inherent risks and challenges and/or provide benefits that are worthy of incentives.[16]

There are many reasons why the HRL Project is not routine and poses unusual risks to DPC:

1. **The HRL Project has been regionally planned.** HRL has been planned in conjunction with MISO and was included in Project 1024 of the 2008 MISO Transmission Expansion Plan (MTEP08). The Commission has previously held that regional projects are by definition, not routine.[17]

2. **HRL is a large investment for DPC.** The HRL Project would be the first 345kV transmission project owned by DPC in whole or in part, and is much more complex compared to previous DPC transmission projects. DPC's estimated $52 million dollar investment in the HRL Project represents an increase of about 23% in net transmission plant over its existing net transmission assets of about $225 million.

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[16] *Commonwealth Edison Co.*, 122 FERC ¶ 61,037, P 27 (quoting *Baltimore Gas & Elec. Co.*, 120 FERC ¶ 61,084, P 54 (2007) ("*BG&E*")) (emphasis added).

[17] *BG&E***,** at P 58.

3. **The HRL Project will be jointly-owned and has multiple types of owners.** In addition to DPC (a G&T), the expected HRL owners consist of an IOU (Xcel/NSP), municipal joint action power agencies (Southern Minnesota Municipal Power Agency and WPPI), and a municipal electric utility (Rochester Public Utilities). As a result, such a diverse mix of owners makes project governance and approvals more complex. Different stakeholders, state regulators and different governance structures all prolong decision-making by the Project participants, often requiring more negotiation and compromise than if any one utility, or any one type of owner, constructed a transmission project without bringing in ownership diversity. The anticipated ownership percentages in the HRL Project are: Xcel/NSP (64%), Southern Minnesota Municipal Power Agency (13%), DPC (11%), Rochester Public Utilities (9%) and WPPI (3%). As discussed earlier, the ATC complaint filed in Docket EL13-9 laying claim to 50% ownership of the HRL Project could place these ownership percentages in jeopardy.

In addition, the HRL Project is DPC's first experience with multiple owners jointly owning transmission facilities, and the same is true for the other HRL participants save Xcel/NSP. The ownership structure, while it has its advantages, has the potential to add complexity to right-of-way acquisition, construction decisions, and operation and maintenance of the Project, thus increasing the risk of the Project.

4. **DPC has not previously owned 345 kV transmission facilities.** As described above, DPC's participation in the HRL Project will be DPC's first transmission project of 345 kV or more.

5. **DPC has limited control over whether the HRL Project is cancelled.** As a minority owner, DPC not only assumes the risks of the Project itself, it is subject to the individual risks of the other Project participants. If the major participant in the HRL Project, Xcel/NSP, decides to withdraw from the HRL Project due to some unforeseen reason beyond DPC's control, such as regulatory uncertainty regarding revenue recovery or ownership (*e.g.*, the ATC complaint in Docket No. EL13-9), the withdrawal of Xcel/NSP's substantial investment and experienced project management team could change the economics of the Project and cause other participants to withdraw.

6. **The HRL Project represents a significant increase in transmission capacity in the upper Midwest and will provide capacity for renewables.** The HRL Project is a high voltage 345kV line that significantly increases transmission capacity in the region. The HRL Project will (i) provide for increasing demand in Rochester MN, Winona MN, and La Crosse WI, (ii) maintain the reliability of the regional transmission system, (iii) support the interconnection of new generation, and (iv) increase the power transfer capability from Minnesota into Wisconsin. By increasing the ability to transfer energy and capacity from Minnesota into Wisconsin, it reduces congestion on the transmission system (see Iverson testimony, Exhibit DPC-6). The HRL Project will increase the capability to move renewable

electricity east (*i.e.*, from the wind-rich areas of western Minnesota and the Dakotas). The Commission has previously found that construction of transmission facilities designed to provide access to remote renewable energy resources is not routine. *See, e.g., PacifiCorp*, 125 FERC ¶ 61,076 at P 45 (2008); *Green Energy Express LLC*, 129 FERC ¶ 61,165 at P 33 (2009).

7. **The HRL Project spans multiple jurisdictions.** The HRL Project spans multiple jurisdictions. Rather than being located in a single state, the HRL Project is geographically located in two different states, Minnesota and Wisconsin. Thus, it requires approvals from two sets of state utility regulators (Minnesota PUC and the PSCW) and other state agencies responsible for transportation and natural resources. One of the challenges of crossing state lines is that the right-of-way ("ROW") easements have to match up on either side of state lines and the permits issued by each side must be valid at the same time. If the Minnesota Route Decision appeal or the Wisconsin CPCN judicial review is successful, the final route design in Minnesota or Wisconsin could change, thus raising the prospect of having to change the combined approved route, resulting in further delays. In addition to the two state jurisdictions, the Project will cross the Mississippi River and federal land which involves federal jurisdiction.

8. **The HRL Project still requires permits and right-of-way acquisition that can cause route changes, construction delays and cost increases.** Demonstrating the risk, complexity and the non-routine nature associated with siting this Project, multiple routes were considered for the HRL Project.

Three main crossings of the Mississippi River were evaluated (La Crescent, Winona, and Alma). In Wisconsin alone, approximately eight route combinations were considered. There were also many route options considered in Minnesota. The MPUC issued the Route Permit for the line in Minnesota in May, 2012 and the PSCW issued the Wisconsin CPCN in June, 2012, but both may be affected by judicial review proceedings. In addition to these state approvals, the HRL Project requires federal permits. The Rural Utilities Service (RUS) is the lead federal agency responsible for developing a Federal Environmental Impact Statement (FEIS) for the HRL Project to comply with the National Environmental Policy Act. The FEIS is complete and the RUS is expected to issue a Record of Decision in mid-November, 2012. Various other federal, state and local permits still must be obtained, such as permits from the Army Corps of Engineers for wetlands and river crossings including the Mississippi River, and the U.S. Fish and Wildlife Service must grant permission for the Project to cross a National Wildlife Refuge.[18]

Further, the right-of-way easements have not yet been secured in either Wisconsin or Minnesota. The process of obtaining such easements could result in delays and/or increases in the cost of land acquisition. Additional permits will also need to be secured from the Wisconsin and Minnesota Departments of Transportation for use of or crossings of highway rights-of-

[18] *See*, Exhibit DPC-7.

way including the crossing of the Great River Road / National Scenic Byway (see Iverson testimony, Exhibit DPC-6). Water quality certifications from both Minnesota and Wisconsin are also required.

9. **The cost of the HRL Project has considerable variability.** The cost for the HRL Project has increased from about $345 million in 2007 (cited in the 2007 Xcel/NSP incentive filing) to the current estimate of $471 million. This estimate could still change. The risk of cost increases still exists due to, among other things, additional permitting costs, right-of-way acquisition costs, the potential for construction cost increases, and uncertainties regarding the ATC complaint in Docket No. EL13-9. Judicial review proceedings in Minnesota and Wisconsin could also affect the chosen route causing further cost uncertainty.

10. **The HRL Project uses advanced technologies.** Order No. 679 requires parties seeking transmission rate incentives to provide a technology statement describing the advanced technologies used and considered by the requesting party. The testimony of Jerome Iverson, Exhibit DPC-6, provides the detailed technology statement for the HRL Project.

Q: HAS THE COMMISSION PREVIOUSLY RULED ON WHETHER THE HRL PROJECT IS NON-ROUTINE?

A: Yes, on two separate occasions. First, the Commission determined that the NSP Expansion Projects (which includes the HRL Project) are non-routine investments in its approval of the 2007 Xcel rate incentives.[19] Second, the Commission recently determined in *WPPI Energy* that the HRL Project (referred to in that order as the La Crosse Project) was non-routine.[20]

V. HYPOTHETICAL CAPITAL STRUCTURE

Q. HOW IS THE DPC REQUEST FOR A HYPOTHETICAL CAPITAL STRUCTURE FOR THE HRL PROJECT CONSISTENT WITH THE COMMISSION'S OBJECTIVE OF ENCOURAGING PUBLIC POWER PARTICIPATION IN NEW TRANSMISSION INVESTMENT?

A. A hypothetical capital structure for DPC encourages DPC and other public power entities and G&Ts to build new transmission and to participate in transmission initiatives, such as CapX2020. Encouraging G&Ts and public power to invest and participate in these industry groups increases the likelihood of successful siting. Additionally, as mentioned earlier in this testimony, the Commission stated in Order 679 the desirability of having a deep pool of public power participants. The Commission noted that in certain circumstances such as a project with diverse sponsors (which is the case with the HRL Project), a hypothetical capital structure may be appropriate:

> The Commission finds that hypothetical capital structures may be effective for development of consortium projects…. This can be especially important for projects with a diverse set of sponsors, some of which have different capital structures.[21]

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[19] *Xcel*, at PP 59-63.

[20] *WPPI Energy*, at P 12-14.

[21] Order 679, P 131.

Q. PLEASE DISCUSS DPC'S PARTICIPATION STATUS IN THE HRL PROJECT AND POTENTIALLY OTHER MAJOR TRANSMISSION PROJECTS AND WHY A HYPOTHETICAL CAPITAL STRUCTURE IS IMPORTANT TO DPC.

A. The HRL Project is a large, jointly owned, multi jurisdictional transmission project and thus, presents risks not present in more routine projects (see risks detailed above). In addition, DPC is currently also investigating additional transmission investments in some other regional projects, including MISO MVPs. If granted a hypothetical capital structure on its HRL investment, DPC will be more likely to participate in these future transmission projects. This is particularly true in light of the fact that DPC's capital budget is constrained and is closely watched by credit agencies to ensure that DPC's can comfortably meet it long term debt service obligation. Moody's has an expectation going forward of reduced capital expenditures by DPC over the near term as compared to capital spending levels incurred several years ago. (See Moilien testimony, Exhibit DPC-1). If the returns on major transmission projects are not viewed as being commensurate with their risk, DPC will likely direct its limited capital budget to other necessary capital projects and let the major transmission investment be made by IOUs such as Xcel/NSP or transmission companies such as ATC and ITC-Midwest. This will discourage regional collaboration, make it more difficult to successfully site transmission projects, and increase transmission rates in the region more than if lower-cost entities such as G&Ts and public power make some of the transmission investment.

Q. PLEASE SUMMARIZE HOW DPC'S PLAN TO FINANCE THE HRL INVESTMENT.

A. The HRL Project currently has a construction schedule beginning in 2013 and the Project is expected to be in service in early 2016. The DPC investment in the HRL Project is expected to be about $52 million and DPC intends to finance the HRL Project with long term debt from the U.S. Rural Utilities Service (RUS). See Moilien testimony, Exhibit DPC-1. The planned term on the RUS loan will be 30 years. DPC expects its RUS loan application for the HRL Project to be approved sometime in 2013. Under the standard RUS policy, RUS will not disburse the funds and determine the interest rate on the debt until the project is fully complete and all work order costs are finalized (see Moilien testimony, Exhibit DPC-1). There is usually a significant lag in determining the final costs because, for example, there is often restoration right-of-way work that takes place well after the transmission line is energized. DPC estimates that it will take 12-18 months after the Project is energized until DPC receives the final accounting of costs from the HRL Construction Manager Xcel. Given that the HRL Project is expected to be in service in early 2016, the final cost figures for the HRL Project are not expected to be available for RUS until 2017, and thus loan proceeds are not expected until 2017 (see Moilien testimony, Exhibit DPC-1). Until the permanent financing is received from RUS, DPC intends to fund its portion of the construction costs of the HRL Project with a syndicated line of credit.[22]

Q. IF RUS FINANCING IS NOT AVAILABLE, HOW WILL DPC FINANCE THE HRL PROJECT?

A. If funds are not available for the HRL Project from RUS due to federal budget cuts or other reasons, DPC will finance the Project with long term debt from commercial sources such as commercial banks and other institutional investors (see Moilien testimony, Exhibit DPC-1).

Q. WHAT INTEREST RATES ON THE RUS HRL DEBT ARE ASSUMED IN THE ANALYSIS SUBSTANTIATING THE REQUEST FOR A HYPOTHETICAL CAPITAL STRUCTURE?

A. The interest rate on the RUS debt the analysis used to fund the HRL Project is based on the interest rates used in DPC's official financial forecast approved by its Board of Directors in May, 2012 (see Exhibit DPC-2). The interest rate on the RUS debt used in the analysis is 5.25%, the forecasted rate for 2017, when disbursement of the RUS loan is expected to occur. The forecasted RUS interest rate in 2017 is less than the interest rate used in a recent RUS loan application update made by DPC in July, 2012. This update was on a $262 million loan to fund multiple DPC projects that will be disbursed over the next five years. RUS

[22] DPC will capitalize its financing costs (AFUDC) until the project goes into service in early 2016. In 2016 there will be interest payments on the line of credit but no principal payment. In 2017, both interest and principal payments on the RUS debt begin. The interest rate for the line of credit is forecasted to be 2.50% in 2016 in accordance with DPC's May, 2012 official financial forecast approved by its Board of Directors.

required DPC to support this updated loan application using a 5.50% interest rate for long term debt in its 10 year financial forecast and to conduct a sensitivity scenario using a 6.5% long term interest rate.

To the extent the Project is delayed due to permitting, right-of-way acquisition difficulties as described above and in Section IV, or other reasons, the loan interest rates could be higher, as the RUS interest rate for 2018 and beyond is forecasted to be higher.

Q. PLEASE SUMMARIZE HOW DPC'S REQUEST FOR A HYPOTHETICAL CAPITAL STRUCTURE MEETS THE NEXUS TEST.

A. As a not-for-profit, non-stock G&T cooperative, DPC cannot raise equity capital through a stock offering. Increases in DPC's equity ratio primarily come from increases in its net margin (net income) after covering DPC's cost of providing service. With a hypothetical capital structure on the HRL Project for the life of the financing, DPC will secure financial metrics on the HRL Project debt that are consistent with; 1) the size, complexity and risks of the Project, 2) DPC's improving actual financial results since 2009, 3) DPC's budgeted and projected company-wide financial ratios including its forecasted equity ratio, and 4) Moody's metrics for "A" rated G&Ts and DPC's goal of solidifying an "A" credit rating with its credit rating agencies.

The request for a hypothetical capital structure for the HRL Project investment is tailored to achieve the necessary financial metrics and assure credit rating agencies that DPC has taken steps to ensure adequate funds to make the required debt service payments on the HRL debt and reflect the significant non-routine risks of the project. The following provides further substantiation for DPC's specific request for a hypothetical capital structure using 35% equity for the duration of the financing associated with the HRL investment.

Q. WHAT FACTORS ARE IMPORTANT TO A G&T's CREDIT RATING?

A. There are many factors that affect a G&T's credit rating. S&P does not make public its methodology. On the other hand, Moody's has a well-known published methodology of the factors it uses to determine credit ratings for G&T cooperatives.[23] Five key quantitative factors tracked by Moody's related to debt service are the Debt Service Coverage (DSC) ratio, Times Interest Earned Ratio (TIER), funds from operations divided by debt (FFO/Debt), funds from operations divided by interest (FFO/Interest), and equity to total capitalization ratio.[24] Moody's calculates a G&T's three year average of each of these metrics and then maps each average to the Moody's range associated with a particular credit rating. The first four of Moody's metrics are related to debt service and have earnings or

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[23] See Exhibit 3 for Moody's Global Corporate Finance Rating Methodology for U.S. Generation & Transmission Cooperatives, December, 2009. See pages 16-17 for all rating factors and pages 13 and 14 for quantitative metrics and their respective weightings. Moody's considers both historical and projected metrics. The ranges of metric values are still applicable today. See Exhibit 4, page 1 for Moody's June 26, 2012 Dairyland Power Credit Opinion and DPC's historical metrics.

[24] DSC = (Net margins, as represented by net profit after tax before unusual items + Interest + Depreciation & Amortization) / (Interest + Principal Payment). Note that because this calculation begins with net margin, both interest and depreciation & amortization are added back to the numerator. An equivalent calculation in the numerator is operating income plus depreciation & amortization, which is similar to the Fitch formula.

TIER = (Net margins, as represented by net profit after tax before unusual items + Interest + Income Tax) / Interest

FFO/Debt = Funds from operations / (Short Term Debt + Long Term Debt)

FFO/Interest = (Funds from operations + Interest expense)/ Interest expense

Funds from Operations is defined as Net Margin + Depreciation + Amortization
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earnings plus depreciation and amortization in the numerator. DSC covers both principal and interest in the denominator, TIER has only interest in the denominator, FFO/Debt has total outstanding debt in the denominator, and FFO/Interest has interest in the denominator.

Q. OF THE MOODY'S FINANCIAL METRICS, WHY IS DSC PARTICULARLY RELEVANT TO THIS ANALYSIS?

A. Because DSC considers margin (numerator) and both principal and interest payments (denominator), it provides one of the best metrics for associating the required financial performance of a particular project's debt to the company's overall metrics, and in turn its targeted credit rating. Moreover, DPC and other G&Ts and public power entities use DSC as a primary driver for setting margin levels generated from member rates, and credit rating agencies consistently use some form of DSC in their comparisons.[25] Because DSC is a primary driver for setting member rates, it also influences the results of other performance metrics.

Q. SPECIFICALLY, WHY IS THE COVERAGE RATIO ON THE DEBT SERVICE ISSUED TO SUPPORT THE HRL PROJECT AN IMPORTANT METRIC AND HOW DOES A HYPOTHETICAL CAPITAL STRUCTURE ENHANCE THIS METRIC?

A. The DSC on the debt used to finance the HRL Project consists of the return (margin) on the HRL Project plus recovery of depreciation expense. This cash flow provides the coverage and assurance to lenders and credit rating agencies

[25] For coverage ratios, Moody's tracks both DSC and TIER, Fitch tracks DSC and S&P tracks fixed charge coverage which is similar to DSC and includes any capacity payments from purchased power.

that DPC is able to meet its HRL obligations, including debt principal and interest payments. In addition, the cash flow provided by the HRL Project will be a component of DPC's company-wide DSC and the return from the requested hypothetical capital structure on the HRL investment will help ensure that DPC's company-wide debt service coverage will not be adversely affected, thus avoiding an increase of member rates.

Q. WHAT WAS DPC'S ACTUAL DSC IN RECENT YEARS?

A. The average actual DPC DSC in the last three years has been 1.23. (2009 = 1.13, 2010 = 1.36, and 2011 = 1.20.) DPC uses the DSC ratio as a key component in setting the rates charged to its members. The budgeted DSC for 2012 is 1.24.

Q. WHAT ARE DPC'S CURRENT CREDIT RATINGS AND WHAT IS DPC'S CREDIT RATING GOAL?

A. DPC's current credit ratings are "A" (S&P) and Moody's A3 (Moody's equivalent of an "A-" with S&P). DPC is not rated by Fitch. DPC has a goal of improving its Moody's rating to A2 which would be the equivalent of its current S&P "A" rating (see Moilien testimony Exhibit DPC-1). Becoming rated A2 by Moody's would give DPC some leeway to withstand unexpected downturns in margin and/or unexpected increases in capital expenditures without falling out of Moody's "A" category into the "B" category, which would result in significantly higher financing costs. This goal of solidifying an "A" credit rating for both credit rating agencies is consistent with DPC's Strategic Financial Management Policy and related Strategic Financial Plan approved by the DPC Board of Directors in 2010 and updated in 2012 (see Moilien testimony, Exhibit DPC-1).

The DPC financial policy is designed to produce financial metrics to ensure that DPC maintains its "A" credit rating to secure access to external funding adequate to finance all necessary capital expenditures and to optimize member value through lowest possible financing costs. Over the last three years, consistent with this financial policy, DPC's financial metrics have improved. As discussed previously, securing access to commercial funding is a necessary goal for most G&Ts including DPC because their traditional financing source, RUS, has become much more limited in terms of the types of loans that can be made, and its ability to make loans could be vulnerable to federal budget cuts.[26] (See Moilien testimony, Exhibit DPC-1). As a result, DPC has been entertaining financing offers from commercial financing sources for long term debt to be able to supplement RUS funding, as appropriate. By solidifying its "A" credit rating by achieving financial metrics consistent with an "A" rated G&T, DPC helps to ensure the lowest possible financing costs from commercial sources. Obtaining financial metrics on the HRL debt consistent with DPC's improving trend helps ensure the company-wide metrics are not impaired.

Q. WHAT FINANCIAL PERFORMANCE IS REQUIRED IN ORDER FOR DPC TO ACHIEVE AN A2 MOODY'S RATING, THUS SOLIDIFYING AN "A" CREDIT RATING WITH BOTH CREDIT AGENCIES?

[26] Since 2009, 11 G&Ts have received approval of indentures from the RUS allowing them to obtain financing outside of RUS. Another 15 have submitted their applications and are awaiting RUS approval. As stated by Moody's, "an indenture (for DPC) that will allow for long-term borrowing outside of RUS has been approved. It is Moody's view that the indenture conversion is credit positive, as it will provide Dairyland additional financing flexibility, especially in times when RUS funding might be constrained." See Exhibit DPC-5, June 26, 2012 Dairyland Power Cooperative Credit Opinion, page 3.

A. The Moody's rating of A3 has a stable outlook. Moody's has made it clear, however, that DPC must continue to show improvement in its financial metrics in order to keep its A3 credit rating (let alone improve to its desired A2 rating). For example, its June, 26, 2012 credit opinion on DPC Moody's stated:[27]

> … the stable rating outlook also incorporates an expectation that key financial credit metrics will continue to improve over the near to intermediate term horizon.
>
> A reversal of the recent trend of improvement in financial metrics would be viewed negatively. For example, FFO/Debt greater than 6% and FFO + interest / interest greater than 2.0 times on a sustained basis would be more fitting of the current rating level. Failure to achieve these levels as anticipated would place pressure on the rating or outlook.

Moody's also stated in the same report that in order to improve its credit rating to DPC's target of A2, the equivalent of the current S&P "A" rating, DPC would have to show additional improvement on key metrics:[28]

> if Dairyland can improve and maintain its metrics at higher levels (for example, greater than 7.5% for FFO/Debt and greater than 2.2 times for FFO interest coverage on a sustained basis), the rating could be revised upward.

Q. WHAT COMPANY-WIDE DSC FOR DPC IS CONSISTENT WITH OBTAINING A SOLID "A" (A2) CREDIT RATING FROM MOODY'S?

A. The Moody's Ratings Methodology range of DSCs of all "A" rated G&Ts (A1, A2 &A3) is 1.2 - 1.4.[29] When evaluating a specific utility, credit rating agencies

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[27] See Exhibit DPC-5, page 4.

[28] *Id*.

[29] See Exhibit DPC-4, page 14, Moody's Global Corporate Finance Rating Methodology for U.S. Generation & Transmission Cooperatives, December, 2009. This methodology and metrics ranges for each level of credit rating are still in place. (The mapping on DPC's June 2012 Credit Opinion, Exhibit DPC-5, page 4, is consistent with the 2009 methodology.)

such as Moody's will consider the average of the last three years when calculating its DSC and will also take into consideration the budgeted DSC going forward. The average actual DSC for DPC for the last three years has been 1.23 (see above), which is a significant improvement over the prior three year average of 1.01 but still in the lower range of Moody's "A" range. Consistent with its improving trend required by Moody's, and its goal of being rated A2 by Moody's, DPC's budgeted DSC for 2012 is 1.24 and its forecast is for DSCs of 1.30 and 1.34 for 2013 and 2014, respectively (see Moilien testimony Exhibit DPC-1). This improvement would place DPC's DSC in what would be considered the mid-range of Moody's "A" credit rating, the equivalent of Moody's A2 category.

Q. HAVE DPC'S OTHER KEY METRICS ALSO IMPROVED CONSISTENT WITH MOODY'S EXPECATIONS AND DPC'S GOAL OF BECOMING A SOLID "A" RATED G&T?

A. Yes. Moody's Ratings Methodology range of TIERs of "A" rated G&Ts is 1.2 - 1.4 (similar to the range for DSCs) (see Exhibit DPC-4, page 14 for metrics ranges). DPC's 2009-2011 three year TIER average of 1.26 is approaching the desired middle of the Moody's range. DPC's TIER has steadily improved over the last three years: 2009 = 1.17, 2010 =1.25, 2011 = 1.37. Consistent with its improving trend, DPC's budgeted TIER for 2012 is 1.49.

Moody's Ratings Methodology range of FFO/Debt of "A" rated G&Ts is 6% to 10%. DPC's 2009-2011 three year average of 5.28% is short of the minimum. However, in the last three years, DPC's ratio has improved from

4.34% to 5.76% and 5.74%, falling just short of the minimum for Moody's "A" rated G&Ts. DPC's budgeted FFO/Debt for 2012 is 6.16, continuing its steady improvement and achieving the minimum of the range of Moody's "A" rated G&Ts.

Moody's Ratings Methodology range of FFO/Interest of "A" rated G&Ts is a ratio of 2 to 2.5. DPC's 2009-2011 three year average of 2.22 is in the middle of the Moody's range. This ratio has also steadily improved over the last three years: 2009 = 2.04, 2010 = 2.28, and 2011 =2.35. DPC's budget for 2012 is 2.56, continuing DPC's trend of improvement.

Q. BASED ON DPC'S IMPROVING METRICS AND THE HRL PROJECT RISKS, WHAT LEVEL OF DSC SHOULD DPC RECEIVE ON THE HRL DEBT TO BE CONSISTENT WITH ITS GOAL OF AN "A2" MOODY'S CREDIT RATING?

A. Obtaining a DSC of at least 1.30 on the debt for DPC's HRL Project is consistent with the recent and projected improvements in the DSC ratio and is consistent with DPC's financial policy and its goal of achieving an A2 rating from Moody's. A DSC of 1.30 falls in the middle of Moody's A rated range of 1.2 - 1.4 (as mentioned previously, Moody's "A" ratings can be A1, A2, or A3). In addition, a DSC of 1.30 on the HRL debt reflects that DPC needs sufficient coverage on the HRL Project debt, a large project for DPC with much higher than normal risks, as described above in Section IV.

Q. WHAT IS DPC'S CURRENT AND PROJECTED EQUITY TO TOTAL CAPITALIZATION RATIO?

A. The DPC equity to total capitalization at December 31, 2011 was 14.6%.[30] This compares to 12.9% for December 31, 2009. Given DPC's plans to continue to set member rates at levels necessary to continue improving its key metrics, DPC expects that this improving trend in equity to total capitalization will continue as other key metrics such as DSC continue to improve (See Moilien testimony, Exhibit DPC-1). DPC's 10 year financial forecast approved by its Board of Directors in May, 2012 forecasts DPC's equity to total capitalization ratio to increase to 22.2% in 2017 and 26.7% by 2021. A supplementary forecast approved by its Board of Directors in July, 2012 showed the equity to total capitalization ratio continuing to increase to 30.9% by 2024. The average increase in DPC's projected equity ratio from 2011 to 2024 is about 1.25% per year.

Q. WITHOUT A HYPOTHETICAL CAPITAL STRUCTURE, WHAT IS THE PROJECTED DSC ON THE HRL DEBT?

A. If DPC's 2011 actual equity ratio of 14.6% were used in the return calculation for the HRL investment, the $ 52 million of investment in the HRL Project would be expected to yield a simple average DSC of only 1.04 from 2016 (the expected in-service date) through 2046, the expected maturity date of the RUS

[30] Note that DPC's 2011 corporate equity to total capitalization ratio of 14.6% is lower than the figure of 16.5% reported on DPC's 2011 Attachment O because the corporate ratio includes current maturities on long term debt and the line of credit in the denominator whereas the Attachment O does not. This difference in equity ratios is forecasted to significantly narrow over the next 10 years as the denominator is forecasted to grow at a faster rate than the numerator.

loan (see Exhibit DPC-11).[31] The DSC for the HRL investment would be projected to fall under the targeted 1.30 in 2019, thus cash flows received by DPC after that point that would be insufficient to provide a 1.30 DSC. Consistent with its improving actual and forecasted DSC that it charges its own members and its goal of achieving a solid Moody's "A" credit rating (A2), DPC needs at least a 1.30 DSC on the HRL Project investment.

Q. WHAT HYPOTHETICAL CAPITAL STRUCTURE FOR THE HRL INVESTMENT IS CONSISTENT WITH A DSC OF 1.30?

A. There are two methods to calculate the hypothetical capital structure necessary in order to achieve a 1.30 DSC on the HRL debt. The first method calculates the equity ratio necessary to obtain a simple average DSC of 1.30 on the HRL debt over the 2016-2046 period.[32] This method results in a required equity ratio of 46.7% (see Exhibit DPC-12). This equity level of 46.7% raises the simple average DSC on the HRL debt from 1.04 to 1.30. The second method[33] is generally superior as it recognizes the time value of obtaining higher DSCs in earlier years. It obtains the DSC by calculating the present value of the return on rate base plus depreciation divided by the present value of the debt service payments (see Exhibit DPC-13). In order to obtain a present value DSC of 1.30

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[31] Note that the first principal payment on the RUS debt for the HRL Project is expected in 2017. Assuming a 30 year term, the last principal payment would be in 2046.

[32] Method 1: DSC for each year = Return plus depreciation / Principal and interest payments. Then calculate the simple average DSC over the total number of years.

[33] Method 2: DSC_{PV} = PV of the return plus depreciation for all years / PV of principal and interest payments for all years. The return = weighted average cost of capital X rate base. Method 2 uses the Excel goal seek function to find the required equity ratio in the WACC necessary to achieve a 1.30 $DSC_{PV.}$

under Method 2, the required equity to total capitalization ratio is 35.7%. This equity ratio is less than the equity ratio under Method 1 due to the time value associated with the higher DSCs in earlier years.

Q. WHAT HYPOTHETICAL CAPITAL STRUCTURE FOR THE HRL INVESTMENT IS DPC REQUESTING?

A. DPC is requesting a 35% hypothetical capital structure. This represents a rounding downward from the 35.7% equity ratio derived above. Compared to using DPC's actual equity ratio, providing a hypothetical capital structure of 35% equity for the HRL Project will produce a present value DSC of 1.29,[34] which would prevent the DSC on the HRL investment from falling below the company's targeted DSC of 1.30 for another eight years (until 2027). DPC would thus avoid having to raise rates to members in that timeframe to maintain DPC's goal of at least a 1.30 DSC.

Q. WHAT ADDITIONAL RISKS DO DPC'S MEMBERS ASSUME AS OWNERS IN DPC THAT WARRANT A HYPOTHETICAL CAPITAL STRUCTURE?

A. DPC's 25 distribution cooperatives are the owners of DPC. In the cooperative business model, they are both customers and owners. This is in contrast to IOUs owned by their shareholders, the vast majority of which are not customers of the company. In the event that an IOU defaulted on its debt, shareholders' risk is

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[34] The hypothetical capital structure to reach a present value DSC of 1.30 is 35.7%. Because DPC is rounding off (downward) its requested equity ratio to an even 35%, the present value DSC associated with the requested 35% equity ratio is 1.29 rather than 1.30.

limited to the loss of their stock and they are not obligated to making the bondholders whole. The distribution cooperatives are responsible for all of DPC's cost of service, including debt service, through increases in the wholesale rate. Their all-requirements contracts with DPC obligate them as owners and customers to assume rate increases in order to make the debt service payments and ensure all debt is repaid. The value of the security provided by DPC's all-requirements contracts is a key factor relied upon by the ratings agencies in determining DPC's credit rating.[35]

Q. DO THE OTHER THREE METRICS OF TIER, FFO/DEBT, AND FFO/INTEREST ALSO SUPPORT THE REQUEST FOR A 35% EQUITY RATIO?

A. Yes. Exhibits DPC-14 through DPC-17 show that the requested 35% equity ratio yields results that are consistent with DPC's improving trend and the additional risk of the HRL Project compared to the rest of the DPC assets. The present value TIER is 1.51 on DPC's HRL investment compared to 2011 DPC TIER of 1.37 and a budgeted TIER for 2012 of 1.49. Therefore, although the present value TIER level is above the Moody's range of "A" rated utilities, a 1.51 TIER on the HRL investment is consistent with DPC's improving TIERs (see Exhibit DPC-14).

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[35] See Exhibit DPC-5, Moody's June 26, 2012 Credit Rating Opinion, page 1, where Moody's lists "Long-term wholesale power contracts and rate-setting autonomy" as a positive ratings driver. Also see page 2 under Rating Rationale: "Dairyland's A3 issuer rating primarily reflects the company's rate setting authority, which is not subject to state public utility commission regulation, and the full requirements contracts with its distribution members that allow Dairyland to set rates at a level sufficient to recover its costs and achieve the financial metrics required by the terms of its debt." Also see page 4, which weights "Member Load Served and Regulatory Status" as 20% of the total credit rating.

A 35% equity ratio on the HRL investment achieves FFO/Debt of 11.62% on a present value basis (see Exhibit DPC-15). This ratio has improved significantly over the past from a low point of 3% in 2008 to 5.74% in 2011 and a 2012 budget of 6.2%. The FFO/Debt over the last three years has improved on an incremental basis at a much higher rate in order to increase the company-wide FFO/Debt, which is dragged down by legacy debt. That is, in order to "move the needle" of the company-wide FFO/Debt ratio, DPC must have an incremental FFO/Debt in the current year that is higher than its past performance. For example, for the last three years, the incremental FFO/Debt ratio (change in margin divided by change in long term debt) has been 20.65% (see Exhibit DPC-16). This incremental level over the last three years and the HRL level of 11.62% are fully consistent with moving DPC's companywide ratio into the 6% - 10% Moody's range required of "A" rated utilities.

Lastly, a 35% equity ratio on the HRL investment achieves an FFO/Interest ratio of 2.16 on a present value basis, which is consistent with DPC's three year average of 2.22, the 2012 budget of 2.56 and the range of Moody's range of "A" rated utilities of 2.0 - 2.5 (see Exhibit DPC-17).

Q. HOW DOES THE REQUESTED 35% EQUITY RATIO COMPARE TO MOODY'S RANGE OF "A" RATED G&Ts?

A. Although the requested 35% equity to total capitalization on the HRL Project is at the top of the range of Moody's "A" rated G&Ts of 20% - 35%, it is consistent with DPC's improving equity to total capitalization ratio (projected at 30.9% in 2024, or about 1.25% per year) and reflects a return in line with the substantial non-routine risks present in the Project and DPC members' ultimate obligation to pay rates sufficient to repay the RUS loan for the HRL Project.

Q. HOW WILL THE CREDIT RATING AGENCIES VIEW THE GRANTING OF A HYPOTHETICAL CAPITAL STRUCTURE ON THE HRL PROJECT?

A. The requested 35% equity ratio combined with abandoned plant cost recovery will be viewed favorably by the credit rating agencies by providing a level of return necessary to service the HRL debt and continuing DPC's recent improvements in its financial performance. The additional assurance to the credit rating agencies provided by a hypothetical capital structure on the HRL Project is particularly important given that the HRL Project is: 1) DPC's first high voltage (345 kV and above) transmission project, 2) a substantial portion of DPC's transmission investment (23% of existing net transmission plant), and 3) higher risk to DPC as compared to other more routine transmission projects.

Q. WHY WILL DPC BE PLACED AT A DISADVANTAGE COMPARED TO INVESTOR-OWNED UTILITIES IF IT IS NOT ALLOWED A HYPOTHETICAL CAPITAL STRUCTURE ON THE HRL INVESTMENT?

A. DPC is paying for its load in the NSP pricing zone based on Xcel/NSP revenue requirements through MISO transmission rates reflecting Xcel/NSP's higher equity ratios, income taxes and a higher cost of debt. This is in stark contrast to the Xcel/NSP's customers in the DPC pricing zone which are paying revenue requirements of DPC that are substantially lower, reflecting a much lower equity ratio, lower historical interest rates on debt and no income taxes paid due to DPC's tax-exempt status.

For example, compare the revenue requirement per dollar of transmission investment for DPC and for Xcel/NSP, the largest owner in both the HRL Project and the overall "NSP" zone. Using NSP's equity ratio of 54.0% in its latest Attachment O (August, 2012) and the requested DPC hypothetical capital structure of 35% equity, Xcel/NSP's revenue requirement is about 51% higher. (See Section X and Exhibit DPC-10 showing how DPC has substantially lower revenue requirements than Xcel/NSP). Because DPC risks are at least as great as Xcel/NSP (and probably higher due to its minority ownership, its higher ratio of investment in the Project to total transmission investment than Xcel/NSP's and its members' responsibilities to pay rates sufficient to cover DPC's debt service), a hypothetical capital structure should be approved for DPC to partially address this large disparity in equity ratios and revenue requirements. If not, DPC would be discouraged from making these types of complex transmission investments.

Q. HOW DOES A HYPOTHETICAL CAPITAL STRUCTURE ENCOURAGE FURTHER TRANSMISSION INVESTMENTS BY DPC, OTHER G&TS, AND PUBLIC POWER?

A. DPC chooses to invest its funds based on an evaluation of need and the expected risk and return of various projects. Proposed new transmission projects compete for funds with other types of projects such as generation and more routine transmission projects. New, more complex high voltage transmission projects must provide returns that reflect the risks of the projects if DPC is to participate.

If DPC does not receive returns reflecting the higher risks of investments such as the HRL Project, then it will naturally choose to invest in other projects that have returns that fairly compensate its members for the project risks. Other G&Ts and public power entities face similar investment choices.

Over the long run, not having DPC (and other public power entities and G&Ts) participate in regional transmission projects would cause regional rates to be higher than with their participation because IOUs (with higher equity ratios, higher financing costs and income tax costs) would fill in the investment void. In addition, not having G&Ts and public power involved would discourage transmission investment in the MISO region as a whole because, among other things, permitting would be more difficult if only IOUs invested.[36] Moreover, without G&T and public power participation there could be less political and regulatory support for new transmission as a whole, and could cause the IOUs, G&Ts and public power to be at odds with one another instead of working together. This runs counter to Order 679 which encourages G&Ts and public power to invest in transmission.

Q. WHY IS DPC ASKING FOR A HYPOTHETICAL CAPITAL STRUCTURE FOR THE DURATION OF FINANCING OF THE HRL PROJECT RATHER THAN ONLY THROUGH THE CONSTRUCTION FINANCING PHASE?

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[36] *WPPI Energy*, Norris concurring at 1.

A. In previous incentive rate filings, many applicants asked for Commission-approved hypothetical capital structures only through the construction financing phase with the applicants ultimately planning to issue equity. However, DPC, being a non-stock cooperative, cannot issue equity. For example, in Green Power Express LP (Docket No. ER09-681) and Tallgrass Transmission and Prairie Wind Transmission (Docket Nos. ER09-35-000 and ER09-36-000), applicants planned on issuing common stock (thus immediately raising their equity ratio to their targeted level of equity) once their transmission "product" became viable and the market would absorb an equity offering. DPC, by contrast, has no ability to issue common stock and, therefore, a hypothetical capital structure is needed for both the construction period and the remaining financing life of the project in order to provide the returns necessary to achieve the DSC and other key metrics consistent with achieving a solid "A" rating.

Achieving an "A" rating with both credit agencies will enable DPC to finance its future projects, (including potential transmission projects), retain access to capital markets, and ensure more attractive interest rates in the commercial market. In addition, DPC's request for a hypothetical capital structure for the length of the financing is consistent with DPC members having the ultimate responsibility for DPC's cost of service including debt service for the length of the financing rather than just through the construction phase. In fact, DPC and the distribution cooperatives previously agreed to extend the all requirements contracts (now extended through 2055)[37] in order to fully cover the duration of newly issued long term debt. The Commission has previously approved a hypothetical capital structure for the duration of the financing for other CapX2020 members who are reliant on non-equity financing such as CMMPA, MRES and WPPI.[38] DPC's HRL debt is expected to be 30 year debt with the final maturity in 2046. The number of years for the debt is determined by RUS and may change slightly from 30 years, based on market conditions.

Approving DPC's request for a hypothetical capital structure for the entire period of debt financing combined with abandoned plant cost recovery will contribute positively to DPC's credit rating, and encourage DPC participation in future transmission projects at more advantageous financing terms than would otherwise be available, which would tend to decrease costs to MISO ratepayers in the region.

VII. RECOVERY OF ABANDONED PLANT

Q. DOES DPC SEEK RECOVERY OF COSTS FOR ABANDONED PLANT RELATED TO THE HRL PROJECT?

A. Yes, similar to the approved filings of Xcel/NSP, the major investor in the HRL Project, and WPPI, DPC requests recovery of its abandoned transmission plant

[37] 23 of the 25 distribution cooperatives extended their all requirements contracts in the 2004-2005 timeframe. The remaining two distribution cooperatives extended their all requirements contracts in the 2005-2008 timeframe.

[38] *See CMMPA*, at P 31; *Missouri River Energy Services*, 138 FERC ¶ 61,045 at P 37 (2012). *WPPI Energy*, at P 32.

costs should the Project be cancelled for reasons that are beyond its control. Among the listed incentives in Order 679 is 100% recovery of prudently incurred costs of transmission facilities that "are cancelled or abandoned due to factors beyond the control of the public utility."[39] Because DPC has a small share relative to the lead investor in the HRL Project, it has correspondingly limited control over the decisions related to planning and operations and has little or no control whether the Project will be abandoned. If Xcel/NSP, with its large percentage ownership (64%) were to withdraw from participation in the HRL Project, the Project could terminate, thus leading to losses for all other participants, including DPC, unless recovery of abandoned plant is granted.

Q. SPECIFICALLY, WHAT RISKS EXIST FOR THE HRL PROJECT THAT PROVIDES THE NEXUS WITH THE REQUESTED INCENTIVE OF ABANDONED PLANT COST RECOVERY?

A. First, as pointed out previously, other key approvals still need to be obtained from state and federal agencies, including the Federal Environmental Impact Statement and RUS' Record of Decision, and the state regulatory agency approvals already obtained could be affected by judicial review proceedings. The HRL Project still has important state and federal permits outstanding regarding the route crossing the Upper Mississippi National Wildlife and Fish Refuge and its crossing of various rivers including the Mississippi River. Difficulties in obtaining these permits from the appropriate state and federal

[39]Order 679, P 155.

authorities could result in delaying the selection of the final route and jeopardizing the progress that has been obtained to date. Obtaining these permits can take considerable time and it is not a certainty that they can be obtained. In addition, the owners in the HRL Project must still acquire rights-of-way in both Minnesota and Wisconsin. DPC started committing capital and expenses in 2007 and expects it will not begin cost recovery for the HRL Project until at least June, 2017. This long lag of up to 11 years (and the risk of further delay due to issues/risks described above and in Section IV), places a financial burden on DPC and its members.

Second, the HRL Project will be jointly-owned and have multiple types of owners. HRL owners are comprised of an IOU, a G&T (DPC), two municipal joint action agencies and a municipal utility, making project governance and decision-making more complex, with different entities each having their own set of interests that still must be jointly negotiated through a common set of Project Agreements. Obtaining financing by the various participants also presents complications, since a variety of financing entities[40] will need to become comfortable with the Project. Just recently, the issue of ownership rights for the HRL Project has been highlighted with the recent complaint filed in Docket No. EL13-9 at the Commission by ATC claiming ownership rights to 50% of the HRL Project. This creates uncertainty regarding whether the existing participants of the HRL Project will continue to own their share and raises the

[40] For example, municipal bonds for joint action agencies and municipals, RUS debt for DPC, and commercial market debt for IOUs.

prospect of some participants being denied ownership and complicating financing for the Project.

Q. HOW CAN THESE PROJECT RISKS FOR THE HRL PROJECT IMPACT DPC FINANCIALLY?

A. There would be a significant rate impact to DPC. DPC is a Load Serving Entity ("LSE") in MISO with load located in the NSP pricing zone as well as its own pricing zone. Similarly, Xcel/NSP is an LSE with load in the DPC pricing zone as well as its own pricing zone. If the Project were cancelled for reasons beyond the control of the Project participants, Xcel/NSP would be authorized to recover its abandoned plant costs from all load in the NSP pricing zone, including DPC load. Such authorization also extends to WPPI, since it has load in the NSP pricing zone but not in the DPC pricing zone. In contrast, if the Commission declined to authorize DPC to recover the costs of its abandoned plant, DPC could not recover abandoned plant costs from Xcel/NSP even though Xcel/NSP has load in DPC's pricing zone.

Q. IS THE ABANDONED PLANT COST RECOVERY INCENTIVE ESPECIALLY IMPORTANT FOR DPC?

A. Yes. Without the ability to recover its prudently incurred costs of abandoned plant, DPC and other G&Ts and public power would be discouraged from investing in future projects. Approval of this requested incentive would give DPC the assurance that it alone will not be forced to pay DPC's abandoned plant costs incurred on a cancelled HRL Project, while also sharing the abandoned plant costs of Xcel/NSP and WPPI, investors that have already received this incentive for the HRL Project.

In addition, this incentive gives credit rating agencies assurance that if the HRL Project is cancelled, DPC has a regulatory mechanism to recover its prudently incurred costs. This lessens risk and contributes to a more favorable credit rating for DPC. This is important given DPC's need to maintain its current A3 Moody's rating and its goal of achieving an A2 rating.

DPC is a relatively small transmission owner with a balance sheet that would suffer from a write off of abandoned plant costs without the opportunity to recover such costs through its rates under Attachment O of MISO's Tariff. Of course, if the Commission authorized DPC to recover abandoned plant costs and DPC sought such recovery, the amount to be recovered, and the prudence of the underlying expenditures, would be established and subject to Commission review through a subsequent filing.

VIII. RETURN ON EQUITY

Q. WHAT ROE IS DPC UTILIZING IN ITS ANALYSIS?

A. DPC is not requesting an additional ROE incentive adder. DPC's analysis used the generally-applicable ROE for MISO transmission owners of 12.38%. This ROE is the standard MISO ROE currently in use by nearly all of the MISO TOs, including G&Ts, municipal joint action agencies, and municipals. The Wolverine

Order[41] set the standard of utilizing a comparable ROE for G&Ts, public power and IOUs within MISO. This level of ROE for public power entities was confirmed in the MidAmerican Energy case [42] and in the Commission's *CMMPA*[43] and *WPPI Energy* [44] incentive rate orders.

IX. PACKAGE OF INCENTIVES

Q. HOW IS THE TOTAL PACKAGE OF INCENTIVES TAILORED TO ADDRESS THE DEMONSTRABLE RISKS AND CHALLENGES OF THE HRL PROJECT?

A. Besides demonstrating that there is a nexus between the project risks and each individual incentive, the nexus requirement under Order No. 679 requires incentive rate applicants to demonstrate that their total package of incentives is tailored to the risks and challenges of the specific project. The primary concern addressed by this requirement is that applicants not receive incentives that are inconsistent or incompatible with other requested incentives. For example, this might happen if an applicant seeks incentives that reduce the risks of a project in addition to an incentive-based increase in the ROE to account for higher risks associated with that project. Here, the incentives requested by DPC are consistent and compatible.

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[41] *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,219 (2004), *order on reh'g*, 112 FERC ¶ 61,351 (2005).

[42] *Midwest Independent. Transmission System. Operator, Inc.*, 128 FERC ¶ 61,047, P 24 (2009).

[43] *CMMPA*, at PP 22-33.

[44] *WPPI Energy*, at P 32.

In order for DPC to mitigate the risks inherent in the HRL Project, which has higher risk than other DPC projects, DPC requests both incentives of a hypothetical capital structure and abandoned plant cost recovery (also see discussion of each incentive above). A hypothetical capital structure provides a return consistent with the higher risk of the HRL Project. Granting abandoned plant cost recovery does not reduce the need for a hypothetical capital structure. If there is insufficient return associated with the investment, then the investors will not pursue the Project regardless of whether they are granted the ability to recover abandoned plant costs. A risky project such as the HRL Project requires a commensurate return. In addition, as explained above, abandoned plant cost recovery provides regulatory certainty and assurance that DPC members alone would not have to absorb DPC's abandoned investments for the HRL Project not recovered due to factors outside of DPC control, and at the same time pay for the abandoned plant costs incurred by other Project participants.

These two incentives work together to reduce risks presented by the HRL investment and remove potential obstacles to construction of this and other future projects. Without these incentives, there would be a much reduced willingness of DPC and other G&Ts and public power entities to invest in major new transmission projects. This outcome would lead to increased MISO rates in the region.

In addition, the investment community and the credit rating agencies will look favorably on these incentives because the added return from a hypothetical capital structure provides the required coverage on the HRL debt to ensure DPC's financial metrics continue to improve to achieve its targeted “A2” credit rating for Moody’s from the current A3 rating and solidify its existing “A” credit rating with S&P. A hypothetical capital structure combined with abandoned plant cost recovery work together to provide the return and management of risk necessary for achieving financial strength and future access to a broad base of financing.

The Commission has in prior cases approved multiple rate incentives for particular projects, many of which have involved other Capx2020 owners. These included CWIP and abandoned plant cost recovery incentives in the Xcel/NSP, OTP (twice), and ALLETE incentive rate orders; hypothetical capital structures, abandoned plant cost recovery, and CWIP in rate base for Great River Energy (GRE), CMMPA and MRES; and a hypothetical capital structure, abandoned plant cost recovery and regulatory asset for WPPI. In particular, the *Xcel* and *WPPI Energy* incentive rate orders specifically addressed the HRL Project.

X. JUST AND REASONABLE STANDARD

Q. PLEASE DISCUSS WHY DPC’S REQUEST FOR INCENTIVES IS JUST AND REASONABLE?

A. The Commission has stated in many declaratory orders on transmission incentives that the applicant seeking declaratory approval must subsequently demonstrate in a FPA Section 205 filing that the resulting rates will be just and reasonable and not unduly discriminatory or preferential. As a result, since this is not a Section 205 filing, DPC defers detailed discussion of why its ATRR and rates are just and reasonable for the subsequent filing. Nevertheless, the following provides an overall discussion of why the requested incentives are both just and reasonable.

Q. WHY IS A DPC HYPOTHETICAL CAPITAL STRUCTURE APPLIED TO THE HRL PROJECT JUST AND REASONABLE?

A. In assessing whether a proposed hypothetical capital structure is just and reasonable, the Commission considers several factors, including the need to raise significant levels of new debt and equity capital, the maintenance of an investment grade rating to access a broad base of investors and obtaining financing at reasonable cost and lower overall cost of capital, and whether the proposed hypothetical structure is within the range of actual capital structures for investor-owned transmission owners.[45] As explained above, authorizing DPC to use a hypothetical capital structure provides the necessary coverage on the debt related to the HRL Project. Without the requested hypothetical capital structure, the DSC and other key metrics[46] applicable to the HRL Project will be a drag on the continuing improvement in DPC's metrics and inconsistent with DPC's goal of solidifying its "A" credit rating.

A hypothetical capital structure provides sufficient return to reassure credit rating agencies that DPC will adequately service the HRL debt and thus positively impact future debt financings.

[45] *Green Power Express LP*, 127 FERC ¶ 61,031, PP 74-75 (2009).

[46] TIER, FFO/Debt, and FFO/Interest.

DPC's requested equity ratio is also just and reasonable because it is lower than the 54% equity ratio of Xcel/NSP, the majority investor in the HRL Project. Granting a hypothetical capital structure to DPC is warranted because otherwise, DPC will be required to pay for Xcel/NSP's HRL Project facilities based on Xcel/NSP's 54% equity for DPC's load in the NSP pricing zone, while Xcel/NSP load in the DPC pricing zone will be paying for the HRL Project based on DPC's much lower equity ratio for DPC's HRL Project facilities in the DPC pricing zone. Even if DPC were granted its request for a hypothetical capital structure, its revenue requirement would still be significantly less than that of Xcel/NSP for the same transmission investment.

Lastly, the requested equity ratio is less than the equity ratios that have been recently provided to public power entities reliant on non-equity financing such as Citizens Energy, CMMPA, MRES and WPPI.

Q. SPECIFICALLY, WHAT RATE BENEFIT DOES A G&T LIKE DPC BRING TO THE MISO PRICING ZONES, EVEN WITH THE GRANTING OF A HYPOTHETICAL CAPITAL STRUCTURE?

A. DPC, as a G&T, historically has a lower cost of financing (from government-backed RUS debt) than IOUs, has a lower equity ratio, and pays no state and federal income taxes. Consequently, the total revenue requirement for load in the DPC pricing zone (including Xcel/NSP load) associated with the same dollar level of investment will be substantially lower than Xcel/NSP's revenue requirement. Exhibit DPC-10 shows that if DPC is granted a hypothetical capital structure of 35% equity, Xcel/NSP's revenue requirement would still be 51%

higher than DPC's.[47] This calculation is shown in the Exhibit 10 two separate ways—each getting the same answer.[48]

Thus, DPC's participation in the HRL Project benefits all LSEs with load in the DPC pricing zone, including Xcel/NSP. For future cost-shared projects, DPC's participation will benefit all MISO ratepayers as compared to having the investments made only by IOUs. Therefore, transmission investment by G&Ts like DPC and public power entities should be encouraged through the granting of a hypothetical capital structure. Encouraging public power and G&T participation by providing incentives lowers the overall revenue requirement of MISO rates compared to what it would be without G&T and public power participation.

Granting DPC's request for a hypothetical capital structure for the life of the financing will work to ensure that DPC and other G&Ts and public power entities in the MISO region continue to invest in transmission, thus reducing long-term rates to MISO customers as compared to what rates would be without their participation.

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[47] Exhibit DPC-10 assumes Xcel/NSP's combined federal and state tax rate of 49.6%, its actual equity ratio of 54.0% and its historical cost of debt of 5.70% (per NSP's latest Attachment O of August, 2012). For DPC, this calculation assumes a hypothetical capital structure of 35%, an income tax rate of zero and its historical cost of debt of 4.65% (per DPC's latest Attachment O). By way of comparison, Exhibit DPC-9 shows that NSP's revenue requirement is 66% higher when using the DPC 2011 actual equity ratio in their Attachment O of 16.5% (rather than the requested 35%).

[48] Method 1 grosses up the equity return for taxes and then calculates the revenue requirement (the tax impact is reflected through the higher required equity return before taxes). Method 2 is the long-hand version whereby taxes are calculated through an iterative approach reflecting that taxes feed back into the revenue requirement calculation.

Q. WHY IS ABANDONED PLANT COST RECOVERY JUST AND REASONABLE?

A. This incentive has been approved in the *Xcel* and *WPPI Energy* incentive rate orders which included the HRL Project. It has also been approved in the GRE, OTP (twice), ALLETE, CMMPA, and MRES incentive rate orders for other CapX2020 projects. For the abandoned plant cost recovery incentive, DPC is seeking Commission approval to allow recovery of 100% of the prudently incurred costs of the HRL Project facilities that are cancelled or abandoned for reasons beyond its control and recover a return on the unamortized balance of any abandoned plant costs. However, DPC is not seeking approval of any specific abandoned costs at this time. Rather, as required by Order No. 679, DPC will make a subsequent filing with the Commission to recover in rates any costs it incurs associated with the HRL Project that is abandoned for reasons beyond DPC's control.

In that subsequent filing (if any), DPC would have an opportunity to demonstrate to the Commission that the Project was abandoned for reasons beyond its control and that there is no double recovery of those costs. Because DPC is not at this time seeking to recover any specific costs associated with abandoned plant cost recovery, granting DPC's request for abandoned plant cost recovery has no present or specific rate effect.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Dairyland Power Cooperative | Docket No. EL13-__-000

AFFIDAVIT

I, the undersigned, being duly sworn, on oath depose and state that the above and foregoing Prepared Testimony of James Pardikes is the testimony of the undersigned, and that the testimony and exhibits sponsored by me, to the best of my knowledge, information and belief, are true, correct, accurate, and complete.

James Pardikes
James Pardikes

Subscribed and sworn to before me
this 9th day of November, 2012.

Donna Carpenter
Notary Public, Lake County, Illinois
My commission expires: August 26 2015

"OFFICIAL SEAL"
DONNA CARPENTER
NOTARY PUBLIC, STATE OF ILLINOIS
MY COMMISSION EXPIRES AUGUST 26, 2015

Estimated Revenue Requirement Difference Between DPC and Xcel/NSP
Using Actual Capital Structure for DPC of 83.5% Debt and 16.5% Equity

	DPC	NSP
Rate Base Investment	$ 1,000	$ 1,000
ROE (standard MISO ROE)	12.38%	12.38%
Cost of Debt (DPC planned debt cost & NSP Att O)	4.65%	5.70%
% Debt (wo/hypoth cap struct for DPC)	83.50%	46.00%
% Equity (wo/hypoth cap struct for DPC)	**16.50%**	54.00%
Income Tax Rate (combined state/federal rate)	0%	49.6%
O&M & Other Taxes as % of Gross Investment (Pass-thru cost of NSP 6.80% , the likely partners responsible for O&M on La Crosse)	6.80%	6.80%
O&M and Other Taxes (e.g., property)	$ 68	$ 68
Depreciation Life of Transmission (years)	40	40

Method 1 Calculations ***(gross up method):***	**DPC**	**NSP**	**Difference**
Long Term Debt ($)	$ 1,000	$ 460	
Implied Equity ($)--(w/ actual equity for DPC @16.5% equity)	$ 198	$ 540	
Debt Component of Return	0.0388	0.0262	
Equity Component of Return (gross up equity component for taxes for IOU only)	0.0204	0.1327	
Pre Tax Return on Rate Base (%) (reflects debt return & equity return grossed up for taxes)	5.93%	15.90%	
Pre Tax Return ($) (pre-tax return % X rate base)	$ 59.25	$ 158.97	
Income Taxes	$ -	$ 65.90	
Interest	$ 46.50	$ 26.22	
Depreciation	$ 25	$ 25	
Revenue Requirement (pre-tax return + O&M & oth taxes + deprec)	$ 152.25	$ 251.97	$ 99.71
Estimated Percentage Difference in Rev Req Between Xcel/NSP and DPC			**65.5%**

***Method 2 Calculations** (interative taxes method):*		DPC		NSP		Difference
Debt Return Component (%)		0.0388		0.0262		
Equity Return Component (%) (no gross up of equity)		0.0204		0.0669		
Total Return (%)		5.93%		9.31%		
Return ($) (not grossed up for taxes)	$	59.25	$	93.07		
Income Statement:		**DPC**		**NSP**		
Revenue Requirement (return not grossed up for taxes + O&M & oth taxes + dep)	$	152.25	$	186.07		
O&M and Oth Taxes	$	68	$	68		
Depreciation	$	25	$	25		
Interest	$	46.50	$	26.22		
Income Before Taxes (before revenue gross up for taxes)	$	12.75	$	66.85		
Income Taxes First Iteration	$	-	$	33.19		
Income Taxes Second Iteration	$	-	$	16.47		
Income Taxes Third Iteration	$	-	$	8.18		
Income Taxes Fourth Iteration	$	-	$	4.06		
Income Taxes Fifth Iteration	$	-	$	2.01		
Income Taxes Sixth Iteration	$	-	$	1.00		
Income Taxes Seventh Iteration	$	-	$	0.50		
Income Taxes Eight Iteration	$	-	$	0.25		
Income Taxes Ninth Iteration	$	-	$	0.12		
Income Taxes Tenth Iteration	$	-	$	0.06		
Income Taxes Eleventh Iteration	$	-	$	0.03		
Income Taxes Twelfth Iteration			$	0.01		
Income Taxes Thirteenth Iteration			$	0.01		
Total Income Taxes	$	-	$	65.89		
Total Rev Requirement With Taxes	$	152.25	$	251.96	$	99.71
Estimated Percentage Difference in Rev Req Between Xcel/NSP and DPC						**65.5%**

Estimated Revenue Requirement Difference Between DPC and Xcel/NSP
Using Hypothetical Capital Structure for DPC of 70% Debt and 35% Equity

		DPC		NSP		
Rate Base Investment	$	1,000	$	1,000		
ROE (standard MISO ROE)		12.38%		12.38%		
Cost of Debt (DPC & XCEL Att O)		4.65%		5.70%		
% Debt (w/hypoth cap struct for DPC)		65.00%		46.00%		
% Equity (w/hypoth cap struct for DPC)		**35.00%**		54.00%		
Income Tax Rate (combined state/federal rate)		0%		49.6%		
O&M & Other Taxes as % of Gross Investment (Pass-thru cost of NSP 6.80% , the likely partners responsible for O&M on La Crosse)		6.80%		6.80%		
O&M and Other Taxes (e.g., property)	$	68	$	68		
Depreciation Life of Transmission		40		40		
Method 1 Calculations ***(gross up method):***		**DPC**		**NSP**		**Difference**
Long Term Debt ($)	$	1,000	$	460		
Implied Equity ($)--(w/hypoth equity for DPC @35% equity)	$	538	$	540		
Debt Component of Return		0.0302		0.0262		
Equity Component of Return (gross up equity component for taxes for IOU only)		0.0433		0.1327		
Pre Tax Return on Rate Base (%) (reflects debt return & equity return grossed up for taxes)		7.36%		15.90%		
Pre Tax Return ($) (pre-tax return % X rate base)	$	73.56	$	158.97		
Income Taxes	$	-	$	65.90		
Interest	$	46.50	$	26.22		
Depreciation	$	25	$	25		
Revenue Requirement (pre-tax return + O&M & oth taxes + deprec)	$	166.56	$	251.97	$	85.41

Estimated Percentage Difference in Rev Req Between Xcel and DPC **51.3%**

Method 2 Calculations ***(interative taxes method):***		**DPC**		**NSP**		**Difference**
Debt Return Component (%)		0.0302		0.0262		
Equity Return Component (%) (no gross up of equity)		0.0433		0.0669		
Total Return (%)		7.36%		9.31%		
Return ($) (not grossed up for taxes)	$	73.56	$	93.07		
Income Statement:		**DPC**		**NSP**		
Revenue Requirement (return not grossed up for taxes + O&M & oth taxes + dep)	$	166.56	$	186.07		
O&M and Oth Taxes	$	68	$	68		
Depreciation	$	25	$	25		
Interest	$	46.50	$	26.22		
Income Before Taxes (before revenue gross up for taxes)	$	27.06	$	66.85		
Income Taxes First Iteration	$	-	$	33.19		
Income Taxes Second Iteration	$	-	$	16.47		
Income Taxes Third Iteration	$	-	$	8.18		
Income Taxes Fourth Iteration	$	-	$	4.06		
Income Taxes Fifth Iteration	$	-	$	2.01		
Income Taxes Sixth Iteration	$	-	$	1.00		
Income Taxes Seventh Iteration	$	-	$	0.50		
Income Taxes Eight Iteration	$	-	$	0.25		
Income Taxes Ninth Iteration	$	-	$	0.12		
Income Taxes Tenth Iteration	$	-	$	0.06		
Income Taxes Eleventh Iteration	$	-	$	0.03		
Income Taxes Twelfth Iteration	$	-	$	0.01		
Income Taxes Thirteenth Iteration	$	-	$	0.01		
Total Income Taxes	$	-	$	65.89		
Total Rev Requirement With Taxes	$	166.56	$	251.96	$	85.41
Estimated Percentage Difference in Rev Req Between Xcel and DPC						**51.3%**

Dairyland Power Cooperative
Actual Capital Structure
Debt Service Coverage Ratios

DPC Debt Service Coverage Ratios with Actual Capital Structure

DPC Actual Capital Structure

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate Base	$ -	$ -	$ -	$ 55,104,738	$ 55,104,738	$ 53,727,120	$ 52,349,501	$ 50,971,883	$ 49,594,264	$ 48,216,646	$ 46,839,027	$ 45,461,409	$ 44,083,791	$ 42,706,172	$ 41,328,554	$ 39,950,935	$ 38,573,317	$ 37,195,698
Depreciation	$ -	$ -	$ -	$ -	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618
Return	$ -	$ -	$ -	$ 3,265,204	$ 3,265,204	$ 3,183,574	$ 3,101,944	$ 3,020,313	$ 2,938,683	$ 2,857,053	$ 2,775,423	$ 2,693,793	$ 2,612,163	$ 2,530,533	$ 2,448,903	$ 2,367,273	$ 2,285,643	$ 2,204,013
Total Return + Dep	$ -	$ -	$ -	$ 3,265,204	$ 4,642,822	$ 4,561,192	$ 4,479,562	$ 4,397,932	$ 4,316,302	$ 4,234,672	$ 4,153,042	$ 4,071,412	$ 3,989,781	$ 3,908,151	$ 3,826,521	$ 3,744,891	$ 3,663,261	$ 3,581,631
Outstanding Debt	$ -	$ -	$ -	$ -	$ 51,863,400	$ 51,863,400	$ 51,076,434	$ 50,248,152	$ 49,376,386	$ 48,458,851	$ 47,493,147	$ 46,476,742	$ 45,406,977	$ 44,281,048	$ 43,096,009	$ 41,848,755	$ 40,536,020	$ 39,154,367
Principal Payment	$ -	$ -	$ -	$ -	$ 747,711	$ 786,966	$ 828,282	$ 871,767	$ 917,534	$ 965,705	$ 1,016,404	$ 1,069,766	$ 1,125,928	$ 1,185,039	$ 1,247,254	$ 1,312,735	$ 1,381,653	$ 1,454,190
Interest Payment	$ -	$ -	$ -	$ 1,377,618	$ 2,722,829	$ 2,683,574	$ 2,642,258	$ 2,598,773	$ 2,553,005	$ 2,504,835	$ 2,454,135	$ 2,400,774	$ 2,344,611	$ 2,285,500	$ 2,223,286	$ 2,157,805	$ 2,088,886	$ 2,016,349
Total Debt Service Payment	$ -	$ -	$ -	$ 1,377,618	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual DSC Ratio	**-**	**-**	**-**	**2.37**	**1.34**	**1.31**	**1.29**	**1.27**	**1.24**	**1.22**	**1.20**	**1.17**	**1.15**	**1.13**	**1.10**	**1.08**	**1.06**	**1.03**

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	NPV	Simple Avg
Rate Base	$ 35,818,080	$ 34,440,461	$ 33,062,843	$ 31,685,224	$ 30,307,606	$ 28,929,988	$ 27,552,369	$ 26,174,751	$ 24,797,132	$ 23,419,514	$ 22,041,895	$ 20,664,277	$ 19,286,658	$ 17,909,040	$ 16,531,421	$ 15,153,803		
Depreciation	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618		
Return	$ 2,122,382	$ 2,040,752	$ 1,959,122	$ 1,877,492	$ 1,795,862	$ 1,714,232	$ 1,632,602	$ 1,550,972	$ 1,469,342	$ 1,387,712	$ 1,306,081	$ 1,224,451	$ 1,142,821	$ 1,061,191	$ 979,561	$ 897,931		
Total Return + Dep	$ 3,500,001	$ 3,418,371	$ 3,336,741	$ 3,255,111	$ 3,173,480	$ 3,091,850	$ 3,010,220	$ 2,928,590	$ 2,846,960	$ 2,765,330	$ 2,683,700	$ 2,602,070	$ 2,520,440	$ 2,438,810	$ 2,357,180	$ 2,275,549		
Outstanding Debt	$ 37,700,176	$ 36,169,641	$ 34,558,753	$ 32,863,293	$ 31,078,821	$ 29,200,664	$ 27,223,905	$ 25,143,365	$ 22,953,597	$ 20,648,867	$ 18,223,138	$ 15,670,058	$ 12,982,942	$ 10,154,751	$ 7,178,081	$ 4,045,136		
Principal Payment	$ 1,530,535	$ 1,610,888	$ 1,695,460	$ 1,784,472	$ 1,878,156	$ 1,976,760	$ 2,080,540	$ 2,189,768	$ 2,304,731	$ 2,425,729	$ 2,553,080	$ 2,687,116	$ 2,828,190	$ 2,976,670	$ 3,132,945	$ 3,297,425		
Interest Payment	$ 1,940,004	$ 1,859,651	$ 1,775,080	$ 1,686,068	$ 1,592,383	$ 1,493,780	$ 1,390,000	$ 1,280,772	$ 1,165,809	$ 1,044,811	$ 917,460	$ 783,423	$ 642,350	$ 493,870	$ 337,594	$ 173,115		
Total Debt Service Payment	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540		
Annual DSC Ratio	**1.01**	**0.98**	**0.96**	**0.94**	**0.91**	**0.89**	**0.87**	**0.84**	**0.82**	**0.80**	**0.77**	**0.75**	**0.73**	**0.70**	**0.68**	**0.66**	**1.12**	**1.04**

DPC Debt Service Coverage Ratios with Hypothetical Capital Structure (DSC_{AVG} = 1.30)

DPC Hypothetical Capital Structure
Equity = 46.7%
Debt = 53.3%

	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Base	$ -	$ -	$ -	$ 55,104,738	$ 55,104,738	$ 53,727,120	$ 52,349,501	$ 50,971,883	$ 49,594,264
Depreciation	$ -	$ -	$ -	$ -	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618
Return	$ -	$ -	$ -	$ 4,552,446	$ 4,552,446	$ 4,438,635	$ 4,324,824	$ 4,211,013	$ 4,097,201
Total Return + Dep	$ -	$ -	$ -	$ 4,552,446	$ 5,930,065	$ 5,816,253	$ 5,702,442	$ 5,588,631	$ 5,474,820
Outstanding Debt	$ -	$ -	$ -	$ -	$ 51,863,400	$ 51,863,400	$ 51,076,434	$ 50,248,152	$ 49,376,386
Principal Payment	$ -	$ -	$ -	$ -	$ 747,711	$ 786,966	$ 828,282	$ 871,767	$ 917,534
Interest Payment	$ -	$ -	$ -	$ 1,377,618	$ 2,722,829	$ 2,683,574	$ 2,642,258	$ 2,598,773	$ 2,553,005
Total Debt Service Payment	$ -	$ -	$ -	$ 1,377,618	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual DSC Ratio	**-**	**-**	**-**	**3.30**	**1.71**	**1.68**	**1.64**	**1.61**	**1.58**

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate Base	$ 48,216,646	$ 46,839,027	$ 45,461,409	$ 44,083,791	$ 42,706,172	$ 41,328,554	$ 39,950,935	$ 38,573,317	$ 37,195,698
Depreciation	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618
Return	$ 3,983,390	$ 3,869,579	$ 3,755,768	$ 3,641,957	$ 3,528,146	$ 3,414,335	$ 3,300,523	$ 3,186,712	$ 3,072,901
Total Return + Dep	$ 5,361,009	$ 5,247,198	$ 5,133,386	$ 5,019,575	$ 4,905,764	$ 4,791,953	$ 4,678,142	$ 4,564,331	$ 4,450,520
Outstanding Debt	$ 48,458,851	$ 47,493,147	$ 46,476,742	$ 45,406,977	$ 44,281,048	$ 43,096,009	$ 41,848,755	$ 40,536,020	$ 39,154,367
Principal Payment	$ 965,705	$ 1,016,404	$ 1,069,766	$ 1,125,928	$ 1,185,039	$ 1,247,254	$ 1,312,735	$ 1,381,653	$ 1,454,190
Interest Payment	$ 2,504,835	$ 2,454,135	$ 2,400,774	$ 2,344,611	$ 2,285,500	$ 2,223,286	$ 2,157,805	$ 2,088,886	$ 2,016,349
Total Debt Service Payment	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual DSC Ratio	**1.54**	**1.51**	**1.48**	**1.45**	**1.41**	**1.38**	**1.35**	**1.32**	**1.28**

	2031	2032	2033	2034	2035	2036	2037	2038
Rate Base	$ 35,818,080	$ 34,440,461	$ 33,062,843	$ 31,685,224	$ 30,307,606	$ 28,929,988	$ 27,552,369	$ 26,174,751
Depreciation	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618
Return	$ 2,959,090	$ 2,845,279	$ 2,731,468	$ 2,617,656	$ 2,503,845	$ 2,390,034	$ 2,276,223	$ 2,162,412
Total Return + Dep	$ 4,336,708	$ 4,222,897	$ 4,109,086	$ 3,995,275	$ 3,881,464	$ 3,767,653	$ 3,653,841	$ 3,540,030
Outstanding Debt	$ 37,700,176	$ 36,169,641	$ 34,558,753	$ 32,863,293	$ 31,078,821	$ 29,200,664	$ 27,223,905	$ 25,143,365
Principal Payment	$ 1,530,535	$ 1,610,888	$ 1,695,460	$ 1,784,472	$ 1,878,156	$ 1,976,760	$ 2,080,540	$ 2,189,768
Interest Payment	$ 1,940,004	$ 1,859,651	$ 1,775,080	$ 1,686,068	$ 1,592,383	$ 1,493,780	$ 1,390,000	$ 1,280,772
Total Debt Service Payment	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540
Annual DSC Ratio	**1.25**	**1.22**	**1.18**	**1.15**	**1.12**	**1.09**	**1.05**	**1.02**

	2039	2040	2041	2042	2043	2044	2045	2046	NPV	Simple Avg
Rate Base	$ 24,797,132	$ 23,419,514	$ 22,041,895	$ 20,664,277	$ 19,286,658	$ 17,909,040	$ 16,531,421	$ 15,153,803		
Depreciation	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618		
Return	$ 2,048,601	$ 1,934,790	$ 1,820,978	$ 1,707,167	$ 1,593,356	$ 1,479,545	$ 1,365,734	$ 1,251,923		
Total Return + Dep	$ 3,426,219	$ 3,312,408	$ 3,198,597	$ 3,084,786	$ 2,970,975	$ 2,857,163	$ 2,743,352	$ 2,629,541		
Outstanding Debt	$ 22,953,597	$ 20,648,867	$ 18,223,138	$ 15,670,058	$ 12,982,942	$ 10,154,751	$ 7,178,081	$ 4,045,136		
Principal Payment	$ 2,304,731	$ 2,425,729	$ 2,553,080	$ 2,687,116	$ 2,828,190	$ 2,976,670	$ 3,132,945	$ 3,297,425		
Interest Payment	$ 1,165,809	$ 1,044,811	$ 917,460	$ 783,423	$ 642,350	$ 493,870	$ 337,594	$ 173,115		
Total Debt Service Payment	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540		
Annual DSC Ratio	**0.99**	**0.95**	**0.92**	**0.89**	**0.86**	**0.82**	**0.79**	**0.76**	**1.40**	**1.30**

Dairyland Power Cooperative
Net Present Value DSC Ratio = 1.30
Hypothetical Capital Structure

DPC Debt Service Coverage Ratios with Hypothetical Capital Structure (DSC_{PV} = 1.30)

DPC Hypothetical Capital Structure
Equity = 35.7%
Debt = 64.3%

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate Base	$ -	$ -	$ -	$ 55,104,738	$ 55,104,738	$ 53,727,120	$ 52,349,501	$ 50,971,883	$ 49,594,264	$ 48,216,646	$ 46,839,027	$ 45,461,409	$ 44,083,791	$ 42,706,172	$ 41,328,554	$ 39,950,935	$ 38,573,317	$ 37,195,698
Depreciation	$ -	$ -	$ -	$ -	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618
Return	$ -	$ -	$ -	$ 4,084,343	$ 4,084,343	$ 3,982,234	$ 3,880,126	$ 3,778,017	$ 3,675,908	$ 3,573,800	$ 3,471,691	$ 3,369,583	$ 3,267,474	$ 3,165,366	$ 3,063,257	$ 2,961,148	$ 2,859,040	$ 2,756,931
Total Return + Dep	$ -	$ -	$ -	$ 4,084,343	$ 5,461,961	$ 5,359,853	$ 5,257,744	$ 5,155,635	$ 5,053,527	$ 4,951,418	$ 4,849,310	$ 4,747,201	$ 4,645,093	$ 4,542,984	$ 4,440,875	$ 4,338,767	$ 4,236,658	$ 4,134,550
Outstanding Debt	$ -	$ -	$ -	$ -	$ 51,863,400	$ 51,863,400	$ 51,076,434	$ 50,248,152	$ 49,376,386	$ 48,458,851	$ 47,493,147	$ 46,476,742	$ 45,406,977	$ 44,281,048	$ 43,096,009	$ 41,848,755	$ 40,536,020	$ 39,154,367
Principal Payment	$ -	$ -	$ -	$ -	$ 747,711	$ 786,966	$ 828,282	$ 871,767	$ 917,534	$ 965,705	$ 1,016,404	$ 1,069,766	$ 1,125,928	$ 1,185,039	$ 1,247,254	$ 1,312,735	$ 1,381,653	$ 1,454,190
Interest Payment	$ -	$ -	$ -	$ 1,377,618	$ 2,722,829	$ 2,683,574	$ 2,642,258	$ 2,598,773	$ 2,553,005	$ 2,504,835	$ 2,454,135	$ 2,400,774	$ 2,344,611	$ 2,285,500	$ 2,223,286	$ 2,157,805	$ 2,088,886	$ 2,016,349
Total Debt Service Payment	$ -	$ -	$ -	$ 1,377,618	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual DSC Ratio	**-**	**-**	**-**	**2.96**	**1.57**	**1.54**	**1.51**	**1.49**	**1.46**	**1.43**	**1.40**	**1.37**	**1.34**	**1.31**	**1.28**	**1.25**	**1.22**	**1.19**

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	NPV	Simple Avg
Rate Base	$ 35,818,080	$ 34,440,461	$ 33,062,843	$ 31,685,224	$ 30,307,606	$ 28,929,988	$ 27,552,369	$ 26,174,751	$ 24,797,132	$ 23,419,514	$ 22,041,895	$ 20,664,277	$ 19,286,658	$ 17,909,040	$ 16,531,421	$ 15,153,803		
Depreciation	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618		
Return	$ 2,654,823	$ 2,552,714	$ 2,450,606	$ 2,348,497	$ 2,246,388	$ 2,144,280	$ 2,042,171	$ 1,940,063	$ 1,837,954	$ 1,735,846	$ 1,633,737	$ 1,531,629	$ 1,429,520	$ 1,327,411	$ 1,225,303	$ 1,123,194		
Total Return + Dep	$ 4,032,441	$ 3,930,333	$ 3,828,224	$ 3,726,115	$ 3,624,007	$ 3,521,898	$ 3,419,790	$ 3,317,681	$ 3,215,573	$ 3,113,464	$ 3,011,356	$ 2,909,247	$ 2,807,138	$ 2,705,030	$ 2,602,921	$ 2,500,813		
Outstanding Debt	$ 37,700,176	$ 36,169,641	$ 34,558,753	$ 32,863,293	$ 31,078,821	$ 29,200,664	$ 27,223,905	$ 25,143,365	$ 22,953,597	$ 20,648,867	$ 18,223,138	$ 15,670,058	$ 12,982,942	$ 10,154,751	$ 7,178,081	$ 4,045,136		
Principal Payment	$ 1,530,535	$ 1,610,888	$ 1,695,460	$ 1,784,472	$ 1,878,156	$ 1,976,760	$ 2,080,540	$ 2,189,768	$ 2,304,731	$ 2,425,729	$ 2,553,080	$ 2,687,116	$ 2,828,190	$ 2,976,670	$ 3,132,945	$ 3,297,425		
Interest Payment	$ 1,940,004	$ 1,859,651	$ 1,775,080	$ 1,686,068	$ 1,592,383	$ 1,493,780	$ 1,390,000	$ 1,280,772	$ 1,165,809	$ 1,044,811	$ 917,460	$ 783,423	$ 642,350	$ 493,870	$ 337,594	$ 173,115		
Total Debt Service Payment	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540	$ 3,470,540		
Annual DSC Ratio	**1.16**	**1.13**	**1.10**	**1.07**	**1.04**	**1.01**	**0.99**	**0.96**	**0.93**	**0.90**	**0.87**	**0.84**	**0.81**	**0.78**	**0.75**	**0.72**	**1.30**	**1.21**

DPC Times Interest Earned Ratios with Hypothetical Capital Structure (TIER $_{NPV}$ = 1.51)

DPC Hypothetical Capital Structure
Equity = 35%
Debt = 65%

	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Base	$ -	$ -	$ -	$ 55,104,738	$ 55,104,738	$ 53,727,120	$ 52,349,501	$ 50,971,883	$ 49,594,264
Return	$ -	$ -	$ -	$ 4,053,229	$ 4,053,229	$ 3,951,898	$ 3,850,568	$ 3,749,237	$ 3,647,906
Total Return	$ -	$ -	$ -	$ 4,053,229	$ 4,053,229	$ 3,951,898	$ 3,850,568	$ 3,749,237	$ 3,647,906
Outstanding Debt	$ -	$ -	$ -	$ -	$ 51,863,400	$ 51,863,400	$ 51,076,434	$ 50,248,152	$ 49,376,386
Interest Payment	$ -	$ -	$ -	$ 1,377,618	$ 2,722,829	$ 2,683,574	$ 2,642,258	$ 2,598,773	$ 2,553,005
Total Debt Interest Payment	$ -	$ -	$ -	$ 1,377,618	$ 2,722,829	$ 2,683,574	$ 2,642,258	$ 2,598,773	$ 2,553,005
TIER	**-**	**-**	**-**	**2.94**	**1.49**	**1.47**	**1.46**	**1.44**	**1.43**

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate Base	$ 48,216,646	$ 46,839,027	$ 45,461,409	$ 44,083,791	$ 42,706,172	$ 41,328,554	$ 39,950,935	$ 38,573,317	$ 37,195,698
Return	$ 3,546,575	$ 3,445,245	$ 3,343,914	$ 3,242,583	$ 3,141,252	$ 3,039,922	$ 2,938,591	$ 2,837,260	$ 2,735,930
Total Return	$ 3,546,575	$ 3,445,245	$ 3,343,914	$ 3,242,583	$ 3,141,252	$ 3,039,922	$ 2,938,591	$ 2,837,260	$ 2,735,930
Outstanding Debt	$ 48,458,851	$ 47,493,147	$ 46,476,742	$ 45,406,977	$ 44,281,048	$ 43,096,009	$ 41,848,755	$ 40,536,020	$ 39,154,367
Interest Payment	$ 2,504,835	$ 2,454,135	$ 2,400,774	$ 2,344,611	$ 2,285,500	$ 2,223,286	$ 2,157,805	$ 2,088,886	$ 2,016,349
Total Debt Interest Payment	$ 2,504,835	$ 2,454,135	$ 2,400,774	$ 2,344,611	$ 2,285,500	$ 2,223,286	$ 2,157,805	$ 2,088,886	$ 2,016,349
TIER	**1.42**	**1.40**	**1.39**	**1.38**	**1.37**	**1.37**	**1.36**	**1.36**	**1.36**

	2031	2032	2033	2034	2035	2036	2037	2038	2039
Rate Base	$ 35,818,080	$ 34,440,461	$ 33,062,843	$ 31,685,224	$ 30,307,606	$ 28,929,988	$ 27,552,369	$ 26,174,751	$ 24,797,132
Return	$ 2,634,599	$ 2,533,268	$ 2,431,937	$ 2,330,607	$ 2,229,276	$ 2,127,945	$ 2,026,615	$ 1,925,284	$ 1,823,953
Total Return	$ 2,634,599	$ 2,533,268	$ 2,431,937	$ 2,330,607	$ 2,229,276	$ 2,127,945	$ 2,026,615	$ 1,925,284	$ 1,823,953
Outstanding Debt	$ 37,700,176	$ 36,169,641	$ 34,558,753	$ 32,863,293	$ 31,078,821	$ 29,200,664	$ 27,223,905	$ 25,143,365	$ 22,953,597
Interest Payment	$ 1,940,004	$ 1,859,651	$ 1,775,080	$ 1,686,068	$ 1,592,383	$ 1,493,780	$ 1,390,000	$ 1,280,772	$ 1,165,809
Total Debt Interest Payment	$ 1,940,004	$ 1,859,651	$ 1,775,080	$ 1,686,068	$ 1,592,383	$ 1,493,780	$ 1,390,000	$ 1,280,772	$ 1,165,809
TIER	**1.36**	**1.36**	**1.37**	**1.38**	**1.40**	**1.42**	**1.46**	**1.50**	**1.56**

	2040	2041	2042	2043	2044	2045	2046	NPV	Simple Avg
Rate Base	$ 23,419,514	$ 22,041,895	$ 20,664,277	$ 19,286,658	$ 17,909,040	$ 16,531,421	$ 15,153,803		
Return	$ 1,722,622	$ 1,621,292	$ 1,519,961	$ 1,418,630	$ 1,317,299	$ 1,215,969	$ 1,114,638		
Total Return	$ 1,722,622	$ 1,621,292	$ 1,519,961	$ 1,418,630	$ 1,317,299	$ 1,215,969	$ 1,114,638		
Outstanding Debt	$ 20,648,867	$ 18,223,138	$ 15,670,058	$ 12,982,942	$ 10,154,751	$ 7,178,081	$ 4,045,136		
Interest Payment	$ 1,044,811	$ 917,460	$ 783,423	$ 642,350	$ 493,870	$ 337,594	$ 173,115		
Total Debt Interest Payment	$ 1,044,811	$ 917,460	$ 783,423	$ 642,350	$ 493,870	$ 337,594	$ 173,115		
TIER	**1.65**	**1.77**	**1.94**	**2.21**	**2.67**	**3.60**	**6.44**	**1.51**	**1.80**

DPC Funds From Operations / Debt Ratios with Hypothetical Capital Structure (FFO / Debt $_{NPV}$ = 11.62%)

DPC Hypothetical Capital Structure
Equity = 35%
Debt = 65%

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate Base	$ -	$ -	$ -	$ 55,104,738	$ 55,104,738	$ 53,727,120	$ 52,349,501	$ 50,971,883	$ 49,594,264	$ 48,216,646	$ 46,839,027	$ 45,461,409	$ 44,083,791	$ 42,706,172	$ 41,328,554	$ 39,950,935	$ 38,573,317	$ 37,195,698
Depreciation	$ -	$ -	$ -	$ -	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618
Return	$ -	$ -	$ -	$ 4,053,229	$ 4,053,229	$ 3,951,898	$ 3,850,568	$ 3,749,237	$ 3,647,906	$ 3,546,575	$ 3,445,245	$ 3,343,914	$ 3,242,583	$ 3,141,252	$ 3,039,922	$ 2,938,591	$ 2,837,260	$ 2,735,930
Total Funds From Operations	$ -	$ -	$ -	$ 4,053,229	$ 5,430,847	$ 5,329,517	$ 5,228,186	$ 5,126,855	$ 5,025,525	$ 4,924,194	$ 4,822,863	$ 4,721,532	$ 4,620,202	$ 4,518,871	$ 4,417,540	$ 4,316,209	$ 4,214,879	$ 4,113,548
Outstanding Debt	$ -	$ -	$ -	$ -	$ 51,863,400	$ 51,863,400	$ 51,076,434	$ 50,248,152	$ 49,376,386	$ 48,458,851	$ 47,493,147	$ 46,476,742	$ 45,406,977	$ 44,281,048	$ 43,096,009	$ 41,848,755	$ 40,536,020	$ 39,154,367
FFO / Debt	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**10.47%**	**10.28%**	**10.24%**	**10.20%**	**10.18%**	**10.16%**	**10.15%**	**10.16%**	**10.18%**	**10.20%**	**10.25%**	**10.31%**	**10.40%**	**10.51%**

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	NPV	Avg
Rate Base	$ 35,818,080	$ 34,440,461	$ 33,062,843	$ 31,685,224	$ 30,307,606	$ 28,929,988	$ 27,552,369	$ 26,174,751	$ 24,797,132	$ 23,419,514	$ 22,041,895	$ 20,664,277	$ 19,286,658	$ 17,909,040	$ 16,531,421	$ 15,153,803		
Depreciation	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618		
Return	$ 2,634,599	$ 2,533,268	$ 2,431,937	$ 2,330,607	$ 2,229,276	$ 2,127,945	$ 2,026,615	$ 1,925,284	$ 1,823,953	$ 1,722,622	$ 1,621,292	$ 1,519,961	$ 1,418,630	$ 1,317,299	$ 1,215,969	$ 1,114,638		
Total Funds From Operations	$ 4,012,217	$ 3,910,887	$ 3,809,556	$ 3,708,225	$ 3,606,894	$ 3,505,564	$ 3,404,233	$ 3,302,902	$ 3,201,572	$ 3,100,241	$ 2,998,910	$ 2,897,579	$ 2,796,249	$ 2,694,918	$ 2,593,587	$ 2,492,256		
Outstanding Debt	$ 37,700,176	$ 36,169,641	$ 34,558,753	$ 32,863,293	$ 31,078,821	$ 29,200,664	$ 27,223,905	$ 25,143,365	$ 22,953,597	$ 20,648,867	$ 18,223,138	$ 15,670,058	$ 12,982,942	$ 10,154,751	$ 7,178,081	$ 4,045,136		
FFO / Debt	**10.64%**	**10.81%**	**11.02%**	**11.28%**	**11.61%**	**12.01%**	**12.50%**	**13.14%**	**13.95%**	**15.01%**	**16.46%**	**18.49%**	**21.54%**	**26.54%**	**36.13%**	**61.61%**	**11.62%**	**14.40%**

Incremental FFO / Debt Calculation

MOODY'S	2011	2010	2009	Incremental 2011 minus 2009
NET MARGIN	$ 18,226,560	$ 13,161,411	$ 12,160,961	$ 6,065,599
PATCAP	$ -	$ -	$ -	
INC STMT DEPR	$ 37,276,147	$ 42,292,441	$ 32,478,000	$ 4,798,147
AFUDC	$ (1,411,200)	$ (1,545,303)	$ (3,629,186)	$ 2,217,986
AFUDC-EQUITY	$ (696,000)	$ (524,000)	$ (1,255,000)	$ 559,000
CLEARING ACCT DEPR	$ 2,246,000	$ 2,489,000	$ 2,463,000	$ (217,000)
Total FFO	$ 55,643,518	$ 55,873,549	$ 42,217,775	$ 13,423,732
SYNDICATED LOC	$ 139,200,000	$ 104,000,000	$ 96,812,000	$ 42,388,000
BOOK VALUE LTD	$ 872,283,016	$ 856,961,000	$ 849,668,000	$ 22,615,016
Total Debt	$ 1,011,483,016	$ 960,961,000	$ 946,480,000	$ 65,003,016

Note: Per Moody's the syndicated line of credit is included in the FFO/Debt calculation

Incremental FFO / Debt % 20.65%

DPC Funds From Operations / Interest Ratios with Hypothetical Capital Structure (FFO / Interest$_{NPV}$ = 2.16)

DPC Hypothetical Capital Structure
Equity = 35%
Debt = 65%

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate Base	$ -	$ -	$ -	$ 55,104,738	$ 55,104,738	$ 53,727,120	$ 52,349,501	$ 50,971,883	$ 49,594,264	$ 48,216,646	$ 46,839,027	$ 45,461,409	$ 44,083,791	$ 42,706,172	$ 41,328,554	$ 39,950,935	$ 38,573,317	$ 37,195,698
Depreciation	$ -	$ -	$ -	$ -	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618
Return	$ -	$ -	$ -	$ 4,053,229	$ 4,053,229	$ 3,951,898	$ 3,850,568	$ 3,749,237	$ 3,647,906	$ 3,546,575	$ 3,445,245	$ 3,343,914	$ 3,242,583	$ 3,141,252	$ 3,039,922	$ 2,938,591	$ 2,837,260	$ 2,735,930
Total Funds From Operations	$ -	$ -	$ -	$ 4,053,229	$ 5,430,847	$ 5,329,517	$ 5,228,186	$ 5,126,855	$ 5,025,525	$ 4,924,194	$ 4,822,863	$ 4,721,532	$ 4,620,202	$ 4,518,871	$ 4,417,540	$ 4,316,209	$ 4,214,879	$ 4,113,548
Outstanding Debt	$ -	$ -	$ -	$ -	$ 51,863,400	$ 51,863,400	$ 51,076,434	$ 50,248,152	$ 49,376,386	$ 48,458,851	$ 47,493,147	$ 46,476,742	$ 45,406,977	$ 44,281,048	$ 43,096,009	$ 41,848,755	$ 40,536,020	$ 39,154,367
Interest Payment	$ -	$ -	$ -	$ 1,377,618	$ 2,722,829	$ 2,683,574	$ 2,642,258	$ 2,598,773	$ 2,553,005	$ 2,504,835	$ 2,454,135	$ 2,400,774	$ 2,344,611	$ 2,285,500	$ 2,223,286	$ 2,157,805	$ 2,088,886	$ 2,016,349
Total Debt Interest Payment	$ -	$ -	$ -	$ 1,377,618	$ 2,722,829	$ 2,683,574	$ 2,642,258	$ 2,598,773	$ 2,553,005	$ 2,504,835	$ 2,454,135	$ 2,400,774	$ 2,344,611	$ 2,285,500	$ 2,223,286	$ 2,157,805	$ 2,088,886	$ 2,016,349
FFO / Interest	**-**	**-**	**-**	**2.94**	**1.99**	**1.99**	**1.98**	**1.97**	**1.97**	**1.97**	**1.97**	**1.97**	**1.97**	**1.98**	**1.99**	**2.00**	**2.02**	**2.04**

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	NPV	Simple Avg
Rate Base	$ 35,818,080	$ 34,440,461	$ 33,062,843	$ 31,685,224	$ 30,307,606	$ 28,929,988	$ 27,552,369	$ 26,174,751	$ 24,797,132	$ 23,419,514	$ 22,041,895	$ 20,664,277	$ 19,286,658	$ 17,909,040	$ 16,531,421	$ 15,153,803		
Depreciation	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618	$ 1,377,618		
Return	$ 2,634,599	$ 2,533,268	$ 2,431,937	$ 2,330,607	$ 2,229,276	$ 2,127,945	$ 2,026,615	$ 1,925,284	$ 1,823,953	$ 1,722,622	$ 1,621,292	$ 1,519,961	$ 1,418,630	$ 1,317,299	$ 1,215,969	$ 1,114,638		
Total Funds From Operations	$ 4,012,217	$ 3,910,887	$ 3,809,556	$ 3,708,225	$ 3,606,894	$ 3,505,564	$ 3,404,233	$ 3,302,902	$ 3,201,572	$ 3,100,241	$ 2,998,910	$ 2,897,579	$ 2,796,249	$ 2,694,918	$ 2,593,587	$ 2,492,256		
Outstanding Debt	$ 37,700,176	$ 36,169,641	$ 34,558,753	$ 32,863,293	$ 31,078,821	$ 29,200,664	$ 27,223,905	$ 25,143,365	$ 22,953,597	$ 20,648,867	$ 18,223,138	$ 15,670,058	$ 12,982,942	$ 10,154,751	$ 7,178,081	$ 4,045,136		
Interest Payment	$ 1,940,004	$ 1,859,651	$ 1,775,080	$ 1,686,068	$ 1,592,383	$ 1,493,780	$ 1,390,000	$ 1,280,772	$ 1,165,809	$ 1,044,811	$ 917,460	$ 783,423	$ 642,350	$ 493,870	$ 337,594	$ 173,115		
Total Debt Interest Payment	$ 1,940,004	$ 1,859,651	$ 1,775,080	$ 1,686,068	$ 1,592,383	$ 1,493,780	$ 1,390,000	$ 1,280,772	$ 1,165,809	$ 1,044,811	$ 917,460	$ 783,423	$ 642,350	$ 493,870	$ 337,594	$ 173,115		
FFO / Interest	**2.07**	**2.10**	**2.15**	**2.20**	**2.27**	**2.35**	**2.45**	**2.58**	**2.75**	**2.97**	**3.27**	**3.70**	**4.35**	**5.46**	**7.68**	**14.40**	**2.16**	**3.01**