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

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

February 4, 2013

Ms. Kate Whitney, Administrator
Utility Division
Montana Public Service Commission
1701 Prospect Avenue
Helena, MT 59620

Re: General Gas Rate Application
Docket No. D2012.9.100

Dear Ms. Whitney:

Enclosed please find Montana-Dakota Utilities Co.'s responses to the Montana Public Service Commission data requests dated December 21, 2012, January 8, 2013, January 17, 2013 and January 21, 2013. Responses to the following requests are attached:

PSC-018	PSC-074	PSC-082	PSC-132
PSC-041	PSC-075	PSC-083	PSC-133
PSC-056	PSC-076	PSC-084	PSC-134
PSC-069	PSC-077	PSC-088	PSC-135
PSC-070	PSC-078	PSC-089	PSC-136
PSC-071	PSC-079	PSC-092	PSC-140
PSC-072	PSC-080	PSC-094	
PSC-073	PSC-081	PSC-123	

Sincerely,

Rita C. Mulkern

Rita A. Mulkern
Director of Regulatory Affairs

Attachments
cc: Service List

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 21, 2012
DOCKET NO. D2012.9.100

PSC-018

Regarding: Outside consultant reports
Witness: Applicable Witness

a. **Please provide white paper/executive summaries for all outside consultant reports in 2010, 2011, and year-to-date 2012.**

b. **For each report, please indicate whether the study (ies) is performed every year. If not, how often is the study (ies) performed, and what is the useful life of the study (ies)?**

Response:

a. Please see Attachment A for the MDU Resources Group, Inc. Actuarial Reports for 2010, 2011 and 2012. Please see Attachment B for Montana-Dakota's Cost Allocation Study.

b. The Actuarial Reports are provided annually.

Updated Response (a) to include a Cost Allocation Study performed by Concentric Energy Advisors in 2012, provided as Attachment B.

Response No. PSC-118
Attachment B

Cost Allocation Study

Prepared for

Montana-Dakota Utilities Co.

September 14, 2012

I. Executive Summary

Concentric Energy Advisors ("Concentric") was retained by Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company"), a division of MDU Resources ("Resources"), on June 11, 2012 to perform a study of the method used by Resources to allocate Administrative and General ("A&G") costs to Montana-Dakota and Resources' subsidiaries (collectively, Montana-Dakota and Resources' subsidiaries are referred to herein as the "business units"). Specifically, Concentric was asked to evaluate and determine the reasonableness of the Corporate Capitalization Factor, which is based on total invested capital at the business units and has been used since 2006. This report presents the analyses and findings of the study (the "Cost Allocation Study").

Concentric performed a survey of allocation methodologies in place at a number of U.S. regulated utilities. While there is a significant diversity of allocation practices across the U.S., corporate service allocation generally follows cost causation principles for the purpose of determining accurate business unit costs. In order for cost allocation to be effective, it must be fairly determined and consistently applied, with fairness being determined by the degree to which allocated costs reflect the benefits received by a parent company's business units. Cost allocation also inherently involves some degree of judgment.

Concentric reviewed and evaluated the reasonableness of the Corporate Capitalization Factor and the appropriateness of that factor given Resources' corporate organization and the way in which Resources' manages its business units. Concentric also reviewed and considered other possible allocation methods based on Concentric's understanding of practices used within the U.S. regulated utility industry. Based on our review, Concentric concluded the following regarding the Corporate Capitalization Factor:

- Given the mix of companies within the Resources family, the Corporate Capitalization Factor is an effective means by which to allocate common costs that cannot be direct charged or allocated based upon usage;
- The Corporate Capitalization Factor has produced reasonable allocation results as compared to other available allocation methods;
- Based on Concentric's analyses and other considerations discussed in this report, we conclude that the Corporate Capitalization Factor approach is reasonable and appropriate for Resources.

- In addition to these conclusions, Concentric has made additional observations and recommendations in Section IX of this report.

II. Background

Montana-Dakota filed a general electric rate case in North Dakota in April 2010 (Case No. PU-10-124). In that proceeding, the North Dakota Public Service Commission ("PSC" or the "Commission") approved three settlement agreements between the Company and the PSC Advocacy Staff ("Staff"). As part of a November 8, 2010 Settlement Agreement, Montana-Dakota agreed to perform certain studies before filing its next general rate case and such studies were to be conducted by a mutually agreeable independent consultant. One of the agreed upon studies was a Cost Allocation Study of the method by which Resources allocates A&G costs to Montana-Dakota. The Cost Allocation Study was to entail a review of the corporate allocation process and the affiliate transactions used to allocate costs associated with Resources and other affiliates to Montana-Dakota. The focus of the Cost Allocation Study was the Corporate Capitalization Factor employed by Resources to allocate unassigned (*i.e.*, not directly assigned or allocated based on a usage-based factor) A&G costs.

This report summarizes the Cost Allocation Study performed by Concentric. The remainder of this report is organized as follows: Section III provides the scope of the Cost Allocation Study; Section IV summarizes Concentric's approach to conducting the review; Section V provides an overview of Resources' corporate structure; Section VI summarizes Resources' corporate departments and provides a summary of Resources' current allocation method, as well as the method by which Montana-Dakota's affiliates allocate costs to the Company; Section VII provides an overview of utility industry allocation practices; Section VIII contains an analysis of Resources' allocation practices; and Section IX contains Concentric's opinion regarding the reasonableness of Resources' allocation practices, as well as our conclusions.

III. Cost Allocation Study Scope

The Cost Allocation Study includes the following three components:

1. Review and summary of the current method of corporate (*i.e.*, Resources) and affiliate allocations or assignment to Montana-Dakota, with a focus on the Corporate Capitalization Factor;
2. Review of methodologies used by other utility companies; and

3. Analysis of whether the Company's corporate cost allocation (*i.e.*, the allocation using the Corporate Capitalization Factor) is fair and reasonable when compared to other generally accepted cost allocation methodologies used in the utility industry.

The Cost Allocation Study's scope includes a review of costs allocated by Resources to Montana-Dakota, and did not further consider any re-allocation of those amounts to Montana-Dakota's various jurisdictions or between gas and electric services. The Cost Allocation Study's scope also did not include a financial audit of the amounts recorded as corporate services costs or the allocations themselves. In addition, while Concentric undertook to understand Resources' allocations under methods other than the Corporate Capitalization Factor (*i.e.*, direct assignment and usage-based allocations), we did not analyze alternatives to those methods other than to note they appear to be reasonable and consistent with industry practice. Similarly, Concentric did not undertake to assess alternatives to inter-company charges between Montana-Dakota and its affiliated business units. Rather, Concentric focused on the Corporate Capitalization Factor, evaluated U.S. utility industry alternatives for allocation of general corporate costs, and analyzed the *pro forma* effect on Montana-Dakota if different allocation practices were in place. The results of the Cost Allocation Study are informational, and are not suggestive of any over- or under-collection of costs by the Company over the period of review (*i.e.*, 2006 to 2011).

IV. <u>Approach</u>

Concentric's approach to the Cost Allocation Study included the following steps:

1. Concentric reviewed Resources' policy statement regarding the allocation of administrative costs and general overheads to Resources' business units (*see*, Attachment A, Policy No. 50.9, *Allocation of Administrative Costs*).
2. Concentric sent initial written data requests to the Company seeking background information and preliminary data to assist in our understanding of the Company's allocation practices.
3. Concentric met with key individuals from Resources, Montana-Dakota, and Staff in a kick-off meeting held at Resources' corporate office on July 9, 2012. The purpose of the kick-off meeting was to review and clarify the scope of the Cost Allocation Study, gain an understanding for the impetus for the study, and obtain a summary-level understanding of the Company's cost allocation methodology.

4. Following the kick-off meeting, Concentric met with key individuals from Resources and Montana-Dakota to gain a deeper understanding of the Company's allocation calculations, to ask follow-up questions, and review data provided by the Company in response to Concentric's initial data requests. The in-person meetings were followed by a second set of written data requests. Through the course of the review, Concentric also generated two more sets of data requests, and held additional interviews to further our understanding of the data responses.
5. Concentric next consolidated our internal knowledge regarding industry allocation practices, and supplemented that knowledge with research regarding utility allocation methods.
6. Concentric narrowed U.S. utilities' diverse allocation practices into three representative categories for purposes of performing our *pro forma* analyses.
7. Concentric's *pro forma* analyses involved performing cost allocation calculations using methods other than the Corporate Capitalization Factor based on historical data from 2006 to 2011. Those analyses provided a range of outcomes based on allocation alternatives. Concentric evaluated each outcome to understand why it resulted in differing allocation percentages, and then assessed where the Corporate Capitalization Factor allocation fell in relation to the range of alternatives.
8. Concentric also assessed the reasonableness of the Corporate Capitalization Factor given the corporate organizational structure of Resources, as well as the circumstances currently faced by the Company.
9. The evaluation described in steps 6 and 7 formed the basis for Concentric's conclusions regarding the fairness and reasonableness of the Company's corporate allocation practices.

V. Corporate Overview

Resources is a diversified natural resource company with capital intensive business units. Montana-Dakota is a regulated division of Resources that generates, transmits, and distributes electricity and distributes natural gas in jurisdictions in North Dakota, Montana, South Dakota, and Wyoming. Resources has another regulated division (Great Plains Natural Gas Company), and its wholly owned subsidiaries include (1) MDU Energy Capital, LLC, parent of Cascade Natural Gas Corporation, and Intermountain Gas Company, and (2) Centennial Energy Holdings, Inc., parent of

WBI Holdings, Inc. (pipeline, energy services, exploration and production), Knife River Corporation (construction materials and contracting), MDU Construction Services Group, Inc. (construction services), and Centennial Energy Resources LLC and Centennial Holdings Capital LLC. Centennial Holdings Capital LLC is in turn the parent company of FutureSoure Capital Corp. ("FutureSource"), which, along with Montana-Dakota, is the joint owner of Resources' corporate office building and land, as well as the corporate aircraft and hangar.

As of December 31, 2011, Resources' had 8,021 employees, although that number typically fluctuates over the course of the year depending on the construction programs at Resources' business units. Montana-Dakota serves approximately 127,000 electric customers and 245,000 gas customers. The Company has interests in approximately 521 MW of generating capacity.[1]

VI. Current Allocation Methods

This sections contains a review and summary of the services provided by Resources to the utility division and Resources' subsidiaries (*i.e.*, the business units), a review of the purpose of cost allocation, and an overview of the current method of corporate (*i.e.*, Resources) and affiliate allocations or assignments to Montana-Dakota, with a focus on the Corporate Capitalization Factor.

Resources' Corporate Departments and Services

Resources has the following departments that provide services to the business units: (1) Communications and Public Affairs; (2) Corporate Accounting and Planning; (3) Enterprise Technology Services; (4) Human Resources ("HR"); (5) Internal Auditing; (6) Investor Relations; (7) Legal; (8) Payroll Shared Services; (9) Procurement Shared Services; (10) Risk Management; (11) Tax and Compliance; (12) Travel; and (13) Treasury Services. In addition, as stated above, Resources' corporate offices and the corporate aircraft and hangar are co-owned by FutureSource and Montana-Dakota.

Resources' corporate departments that provide services to the business units are similar to those that are centralized within other U.S. utility holding companies.[2] While U.S. utility companies

1 MDU Resources Group Inc., SEC Form 10-K for the period ended December 31, 2011, filed February 24, 2012.

2 The services are also consistent with the types of services offered by a "service company" and a "centralized shared service company", as codified in the U.S. Code of Federal Regulations. Specifically, 18 CFR 366.1 defines a service company as, "any associate company within a holding company system organized specifically for the purpose of providing non-power goods or services or the sale of goods or construction work to any public utility in the same holding company system." 18 CFR 367.1(a)(7) defines a centralized shared service

have implemented various organizational structures to centralize common services, the objective of such structures is to minimize duplication of effort and reduce costs. In general, the benefits of shared services are the efficiencies and cost advantages that can be achieved by centralizing certain functions as opposed to distributing those functions among individual affiliated companies. Centralizing functions allows for better standardization of processes, reduced duplication of services, and provides for the potential of more efficient specialization.

Cost Allocation Overview

Cost allocation is the process by which costs are assigned from one cost pool to another in order to reflect shared benefits that are received by the entity to which costs are allocated. Cost allocation serves several strategic purposes, including the determination of accurate business unit costs. Cost allocation also supports executive management in managing, evaluating, and making decisions regarding its business units. For an owner of rate-regulated utility operations, cost allocation also serves to provide a utility with information regarding the utility's total cost of providing service. Regulated utilities generally seek to recover corporate allocations through rates.

In order for cost allocation to be effective, it must be fairly determined and consistently applied. In the case of the allocation of corporate overhead to business units and subsidiaries, *fairness* is often determined by a measure of corporate benefits received by the business units. Effective cost allocation is also transparent and reasonably automated, and results in relatively stable levels of assigned costs. Cost allocation also inherently involves some degree of judgment.

Resources/Montana-Dakota Cost Allocation

Resources uses a formal, automated approach to allocating its costs to its business units. In general terms, Resources' approach involves the accumulation of costs within its accounting system using a detailed accounting code block, followed by a monthly allocation and account clearance process. Within its allocation approach, Resources employs three methods to allocate costs: (1) direct assignment, (2) usage-based allocation, and (3) the use of a Corporate Capitalization Factor to allocate any costs not allocated by one of the first two methods.

Direct assignment is used for incremental costs incurred by Resources that are expended for purposes that benefit one or more specific business units. For example, if Internal Auditing

company as, "a service company that provides services such as administrative, managerial, financial, accounting, recordkeeping, legal or engineering services, which are sold, furnished, or otherwise provided (typically for a charge) to other companies in the same holding company system."

performed an internal audit specific to Montana-Dakota, any incremental costs (*e.g.*, travel) associated with the internal audit would be charged directly to Montana-Dakota.

Usage-based allocations are used for Resources' Shared Services functions. Those functions include: Payroll Shared Services; Procurement Shared Services; Time Entry Shared Services; Accounts Payable Shared Services; and Enterprise Technology Services ("ETS"). For example, Procurement Shared Services costs are allocated to the business units using five equally-weighted allocation factors based on each business unit's: (1) number of VISA cards; (2) amount of expenditures paid for with VISA cards; (3) total national account spend (which represents each business unit's participation in bulk purchases); (4) number of construction equipment acquisitions; and (5) number of fleet acquisitions. A summary of Resources' methodologies by which it allocates its Shared Service functions is provided as Attachment B to this report.

The Corporate Capitalization Factor is used for all other Resources' costs that are budgeted for accounting purposes at the parent company level, and is used for those departments for which a specific usage-based driver may not be clearly identifiable or practicably applied.[3] Resources' business units also receive an allocation of FutureSource costs.[4] As previously mentioned, the focus of this Cost Allocation Study is the Corporate Capitalization Factor as applied to corporate department costs.

Costs are accumulated for allocation in Resources' and Montana-Dakota's JD Edwards accounting system through the use of a detailed coding system. The basic accounting structure consists of three main items: (1) the department incurring the cost; (2) the type of cost (*e.g.*, straight time, materials, *etc.*); and (3) a work order, which is used to accumulate costs for large O&M projects and for allocation purposes. For instance, payroll for an employee in the Legal department would be coded to 980-7110-00029995, with 980 representing the Legal Department, 7110 representing straight time, and 00029995 representing corporate costs to be allocated using the Corporate Capitalization Factor. That system of cost recording allows for automation in the process of accumulation and allocation of costs.

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3 Note, certain costs that are managed by Resources departments but that are directly charged for accounting purposes to MDU cost centers (*e.g.*, insurance coverage and treasury services costs) bypass the corporate allocation process but are in effect directly assigned to MDU.

4 As stated previously, Montana-Dakota is a part owner of the corporate office and corporate aircraft and hangar. Thus, any allocations to the Company from FutureSource are adjusted to reflect that ownership share. For example, if the allocation from FutureSource in a given allocation period were to be less than the MDU's ownership interest in the corporate office and corporate aircraft and hangar, then the Company would receive a credit to reflect the difference between its allocation share and its ownership share.

At each month end Montana-Dakota downloads the costs accumulated in those accounts that are to be allocated into an Excel spreadsheet, and performs the allocation. Journal entries are created in Excel and then uploaded to the accounting system. The result of Resources' allocation process (*i.e.*, direct charging, usage-based allocation, and allocation based on the Corporate Capitalization Factor), is that all costs are cleared from Resources' books and allocated among the business units.

The Corporate Capitalization Factor is based on total invested capital at each business unit. Total invested capital is defined as total equity plus preferred stock and current and non-current long-term debt (including capital lease obligations). Since January 1, 2008, Resources has calculated the Corporate Capitalization Factor at two times during the year using the average twelve month balance of invested capital at each business unit: as of September 30th of the preceding year to be used for January through June; and as of March 31st of the current year to be used for July through December.

Resources instituted the Corporate Capitalization Factor in 2006. Prior to 2006, Resources' costs were allocated based on an equally weighted two factor formula consisting of (1) the three-year average of net property, plant, and equipment, and (2) the three year average of the number of full time employees. However, Montana-Dakota requested a review of the allocation policy in 2005 to evaluate its appropriateness and fairness. In performing its evaluation of the two-factor method, the Company noted the following:

- Net property, plant, and equipment excluded the broader range of assets used in Resources' diversified businesses; and
- The definition of a full time employee excluded part-time and seasonal employees that potentially made up a significant portion of the workforce at Resources' non-utility subsidiaries.

Both of those factors resulted in Montana-Dakota bearing a disproportionate percentage of corporate costs. As a result, Resources switched to the use of the Corporate Capitalization Factor.

Resources has made two modifications to the Corporate Capitalization Factor since its inception. The first modification, which was made in 2008 and is described above, was to make a change from an annual factor to a semi-annual factor. The second modification, which was made in 2011, changed the term "business segment" to "business unit." Neither change had a material effect on the allocation of Resources' costs to Montana-Dakota.

The following table shows the allocations from Resources to Montana-Dakota for the period 2006 to 2011. The table provides details on costs allocated under the three allocation methods, as well as the percentage of Resources' total that was allocated to Montana-Dakota under each method. Table 1 represents the final result of all allocations from Resources to Montana-Dakota in the review period. As stated previously, Concentric's focus in the Cost Allocation Study was on the allocation of corporate department costs (*e.g.*, HR, Treasury, Legal, *etc.*) using the Corporate Capitalization Factor.

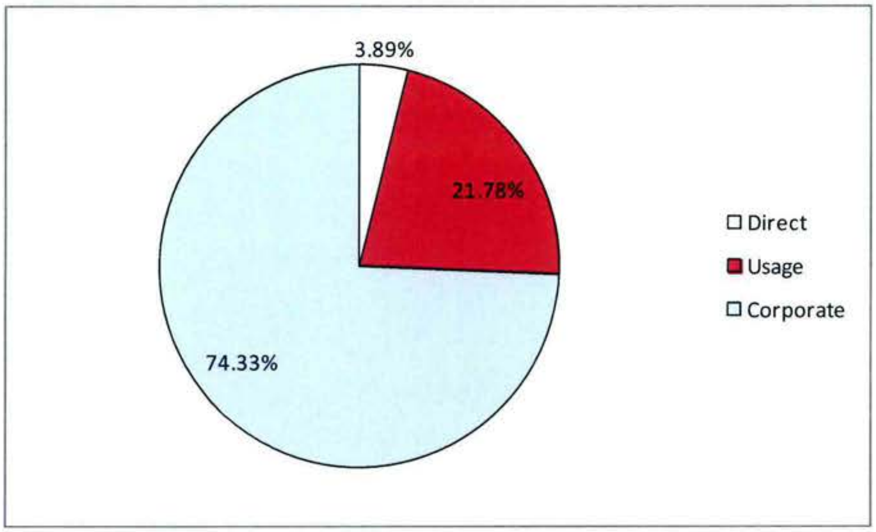
Table 1: Corporate Allocations from Resources to Montana-Dakota, 2006 – 2011

	2006	2007	2008	2009	2010	2011
Direct Assigned	$1,311,417	$1,565,715	$471,011	$305,011	$397,956	$206,080
Montana-Dakota % of Resources' Total	23.12%	22.78%	18.00%	9.72%	19.20%	11.35%
Usage-Based	$1,440,455	$1,744,886	$1,103,608	$1,120,731	$1,113,690	$1,152,739
Montana-Dakota % of Resources' Total	42.24%	31.14%	21.32%	21.84%	20.42%	20.74%
Corporate Capitalization Factor	$3,849,208	$3,565,869	$2,750,092	$2,351,350	$2,928,317	$3,934,780
Montana-Dakota % of Resources' Total	13.62%	11.97%	9.25%	9.89%	14.26%	15.54%
Total	$6,601,080	$6,876,470	$4,324,711	$3,777,092	$4,439,963	$5,293,599
Montana-Dakota % of Resources' Total	17.68%	16.27%	11.52%	11.79%	15.82%	16.19%[5]

In addition, the following chart provides the breakdown of the percentage of the total costs allocated to Montana-Dakota from Resources.

5 Per the Company, the total pool of costs to be allocated increased in 2011 due to factors that included increases in employee benefit costs due to decreases in the underlying value of assets. In addition, the allocation percentages for Montana-Dakota have increased from 2008-2009 to 2010-2011 due to factors that include the addition by Montana-Dakota of new generating capacity, which required additional capitalization.

Chart 1: Breakdown of Costs Allocated to Montana-Dakota by Resources, 2011



Affiliate Allocations

Montana-Dakota's affiliates provide a number of services to the Company. Those services include: natural gas purchases; transportation and storage of natural gas; construction services; purchase of affiliate companies' surplus equipment, when economically beneficial; and cost sharing of training, *etc.*, when economically beneficial. In general, Montana-Dakota employs competitive processes for the services its sources from its affiliates. Charges for those services are, for the most part, direct charged to Montana-Dakota.

VII. Utility Industry Allocation Practices

It is common in the U.S. for services to be provided by and for regulated utilities by affiliated companies. In the past, where affiliated regulated utilities operated in multiple jurisdictions, it was common to see the affiliated utilities operate as stand-alone utilities. In today's business environment, it is common for these multi-jurisdictional companies to consolidate like functions either at the holding company level or within a centralized shared services company organized specifically to provide such services in an effort to reduce costs and achieve organizational efficiencies. The same is true of companies that own and operate both regulated utilities and other, non-regulated subsidiaries. Where there are common functions, the opportunity exists to consolidate the functions, thereby reducing costs.

There is no single approach by which shared services costs are assigned to the recipients of such services. Companies typically adhere to cost-causation principles that state that the company that derives a benefit from a service should bear the cost of such service in direct proportion to the benefit derived from such service. To adhere to cost causation principles, companies generally employ three methodologies by which costs are allocated: (1) direct assignment, (2) usage-based costing (sometimes referred to "activity-based" costing), and (3) the use of general allocators. Companies typically use some combination of all three methodologies. While direct assignment is the most accurate method by which to allocate costs, that method is not always practical or effective. Specifically, if a corporate department offers services that are not associated with an identified business unit, or are not readily assigned using the direct method, then indirect assignment through usage-based allocators or general allocators is appropriate.

As discussed previously in this report, the selection of an indirect allocation method serves several strategic purposes, including the determination of accurate business unit costs. The allocation factor selected should result in each business unit receiving a fair and reasonable amount of allocated costs that is reasonably reflective of the benefits derived by each business unit.

Across the U.S. utility industry, there is significant diversity among the allocation methods employed. There are two key sources of differences among U.S. utility allocation practices: (1) the level of detail at which costs are accumulated for allocation purposes (*i.e.*, by company, by department, by service, *etc.*); and (2) the allocation factor applied to the accumulated costs.

In terms of the level at which costs are accumulated, a more detailed level, such as by department, is only required if the costs of different departments will be allocated using different factors. Some U.S. utilities use that approach to corporate cost allocation, choosing allocation methods on a department-by-department basis. Thus, for example, costs in the HR department are allocated based on one factor, Communications department costs are allocated based on a different factor, Treasury services on another factor, *etc.* In those instances, corporate department costs would need to be accumulated separately for allocation purposes. If HR, Communications, and Treasury services, in this example, were all allocated using the same factor, then there would be no need to break out the costs of each department for allocation purposes.[6]

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6 As a practical matter, most utility holding companies, including Resources, capture costs at the department level and further capture costs by cost type and other characteristics, such as by work order. The process of cost accumulation referred to in this report relates to the accumulation of costs specifically for allocation purposes.

Allocation factors for A&G costs that are not directly allocated (also referred to as "residual allocation methods") also vary significantly across U.S. utilities. Variants include the use of one versus multi-factored allocators, as well as the allocators themselves. There are also several allocation methods that have been used by the Federal Energy Regulatory Commission ("FERC") and adopted by non-FERC regulated utilities, but those approaches are simply additional variants of residual allocation methods. Examples of FERC allocation methods include the Massachusetts Formula (based on ratios of gross plant, gross revenues, and labor), the Modified Massachusetts Formula (based on ratios of net plant and labor), and the Distrigas Method (based on ratios of gross plant, net operating revenues, and labor) (those approaches are collectively referred to herein as the "FERC Methods"). Lastly, there are U.S. utilities that allocate residual costs using weightings based on the percentage of direct and usage-based allocations that the utility receives from the corporate parent or shared services organization (referred to herein as the "Pro Rata Method").

Information regarding allocation practices for U.S. utilities can be found in various informational filings and rate proceeding filings. Regulated utilities that receive services from a centralized shared service company are required to file a Form 60 Annual Report with the FERC. That report provides information regarding the nature of the services provided by the shared services companies and the costs of such services. It also provides information regarding the allocation factors used by the filing company. In addition, some state regulators, such as Illinois and Maryland, require that utilities file their cost allocation manuals with the regulator at defined periods or when changes to the manuals are made. Furthermore, some utilities disclose their allocation methods as part of rate proceedings.

Attachment C provides the allocators used for indirect A&G expenses by a sample of U.S. utilities. As shown in the attachment, there is significant diversity in practice among U.S. utilities in terms of the allocation factors used. It is important to note that this attachment represents utilities' residual allocators, such as the Corporate Capitalization Factor, not the usage-based allocators that utilities may apply. General allocators are those that are usually applied to A&G departments in which employees provide services across business units and for which a usage-based allocator is not readily identifiable or reasonable to apply. Of the companies and methods surveyed, more than 80% used multi-factored allocators to allocate residual costs, while the remaining companies used a one-factor approach. The most commonly used allocation factors among the companies and methods surveyed were (1) measures of assets or property, plant, and equipment (*e.g.*, assets, gross plant, and net plant); (2) measures of labor (*e.g.*, payroll expense and number of employees); and (3) measures of revenue.

VIII. Analysis of Resources' Allocation Practices

Concentric's evaluation of Resources' allocation practices involved the following steps:

1. Interviews with Resources' and Montana-Dakota's management to gain an understanding of the allocation methodology and Corporate Capitalization Factor, as well as the underlying factors that led Resources to adopt its current methodology;
2. Independent performance of Resources' allocation methodology for the period from 2006 through 2011 to enhance our understanding of the allocation calculations and to set a baseline for comparative analyses;
3. Evaluation of the clarity of the Resources' allocation approach, the consistency with which it has been applied, and the appropriateness of the approach given Resources' corporate organization and the specific circumstances faced by Resources and its business units; and
4. Analysis of other allocation methodologies to determine the reasonableness of Resources' approach vis-à-vis alternative approaches.

Concentric's understanding of Resources' allocation practices is provided in Section VI. The results of Concentric's independent performance of Resources' allocation methodology for corporate department costs for the period 2006 through 2011, is provided below in Table 2. Those percentages are consistent with those used by Resources' to allocate corporate costs over the study period.

Table 2: Montana-Dakota Corporate Capitalization Factor and Corporate Allocations, 2006 – 2011[7]

	2006	2007	2008	2009	2010	2011
Montana-Dakota Corporate Capitalization Factor	13.6%	11.7%	12.0%	11.9%	13.4%	15.3%

Concentric's evaluation of the appropriateness of Resource's allocation approach given Resources' corporate organization and the specific circumstances faced by Resources and its business units involved a review of both the organizational structure of Resources and the nature of its business units. As discussed above, Resources', of which Montana-Dakota is a division, is the parent of capital-intensive subsidiaries such as pipelines, energy services, exploration and production services, construction materials and contracting, and construction services. Resources' non-utility business units are not widely found in other U.S. utility holding companies, suggesting that the application of industry-wide allocation practices to Resources may not be practical or reasonable. Total invested capital (*i.e.*, the basis of the Corporate Capitalization Factor) is indicative of the relative size of each business unit, and is the basis on which Resources' executive management manages, evaluates, and makes decisions regarding its business units. In that regard, the Corporate Capitalization Factor provides a reasonable basis upon which to allocate costs to each business unit.

In addition, Concentric found that the allocation policies and procedures are clearly established, straight forward, transparent, and consistently applied. Specifically, Resources provides its allocation policy and procedures in Policy No. 50.9, *Allocation of Administrative Costs* (*see*, Attachment A). As described in Section VI, Resources uses its accounting system to automatically accumulate costs into pools to be allocated. In addition, as shown in Table 2, above, the Corporate Capitalization Factor has resulted in a reasonably stable percentage of costs being allocated to Montana-Dakota over the period in which that allocator has been in effect.

However, it is generally recognized that there is no "correct" way to allocate costs that are not directly assigned, and multiple methods and allocators can produce fair and reasonable results. In addition, while total invested capital is a reasonable basis upon which to allocate costs based on

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7 The allocation factors included in the table differ from those presented in Table 1. The reason for the difference is that while Resources calculates separate factors for Montana-Dakota (including Great Plains) and MDU Energy Capital, LLC (parent of Cascade Natural Gas Corporation and Intermountain Gas Company) (collectively, the "Utility Group"), the Utility Group is treated as one entity and re-allocates the total Utility Group corporate overhead to the three companies based on year end capitalization in order to reflect more current data in the allocation. As stated previously, Concentric's focus was on Resources' allocation of costs, not on any further re-allocation of those costs.

Resources' organizational structure and the businesses it operates, it is not necessarily the primary driver of the degree to which each business unit benefits from Resources' corporate services. For instance, business units may benefit from corporate HR services based on the number of employees or total payroll at each business unit. In that example, to the extent that a business unit's relative total invested capital significantly diverges from its relative number of employees of total payroll, then that business unit may receive an under or over-allocation of corporate HR costs.

To test the reasonableness of the Corporate Capitalization Factor versus other allocation methods and factors that are currently used by other U.S. regulated utilities, Concentric first collected data from the Company regarding alternative allocators. Those allocators, along with Montana-Dakota's respective percentage of Resources' total for that allocator, are provided in Table 3:

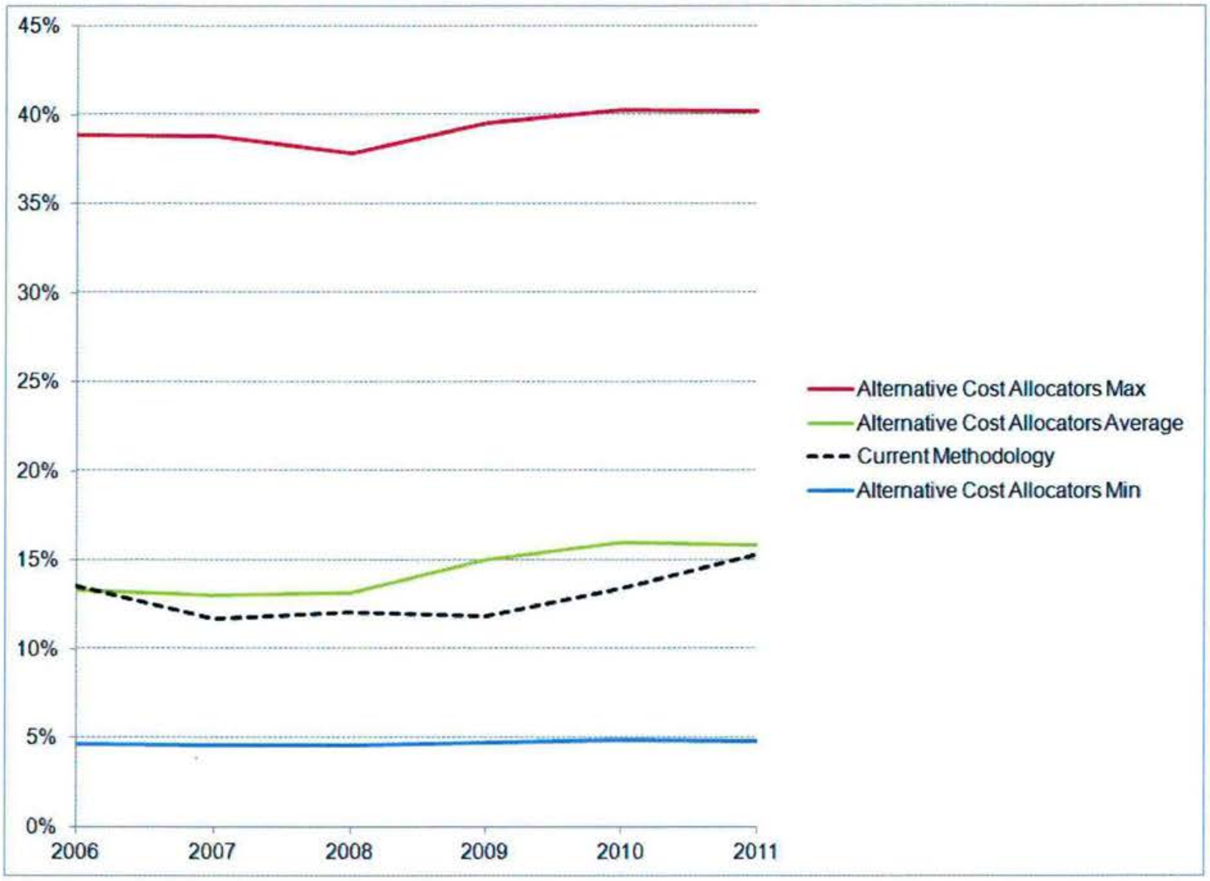
Table 3: Alternative Cost Allocators, 2006 – 2011[8]

	2006	2007	2008	2009	2010	2011
Gross Plant	21.0%	18.3%	16.7%	18.9%	19.2%	19.0%
Net Plant	16.2%	15.5%	14.8%	18.4%	19.6%	19.8%
Total Assets	38.8%	38.8%	37.8%	39.6%	40.3%	40.2%
Total Equity	9.9%	9.9%	10.3%	13.0%	13.8%	14.1%
Total Long-term Debt	14.6%	15.7%	17.2%	18.6%	19.6%	18.5%
Gross Revenues	13.0%	11.8%	12.1%	12.1%	12.7%	12.5%
Gross Margin	5.7%	5.8%	5.7%	6.5%	7.3%	7.2%
O&M Expense	4.7%	4.6%	4.6%	4.7%	4.9%	4.8%
Net Revenues	6.9%	8.4%	10.2%	[1]	17.6%	16.7%
Employees	8.6%	7.8%	8.3%	10.1%	11.5%	12.1%
Payroll	7.4%	6.9%	6.8%	8.3%	9.0%	9.0%
Corporate Capitalization Factor	13.6%	11.7%	12.0%	11.9%	13.4%	15.3%

[1] Resources' total net revenues were negative in 2009, and thus have been excluded from Concentric's calculations.

8 The alternative allocators were calculated using annual data, as opposed to an average of monthly data as is used for the Corporate Capitalization Factor. In Concentric's opinion, annual data provided results that were sufficiently comparable to the Corporate Capitalization Factor for purposes of our evaluation.

Chart 2: Alternative Cost Allocations, 2006-2011



Concentric next developed an allocation model and performed a series of *pro forma* allocation analyses using allocation methods and factors that are representative of approaches used in the U.S. regulated utility industry. Those allocation methods and factors are described below:

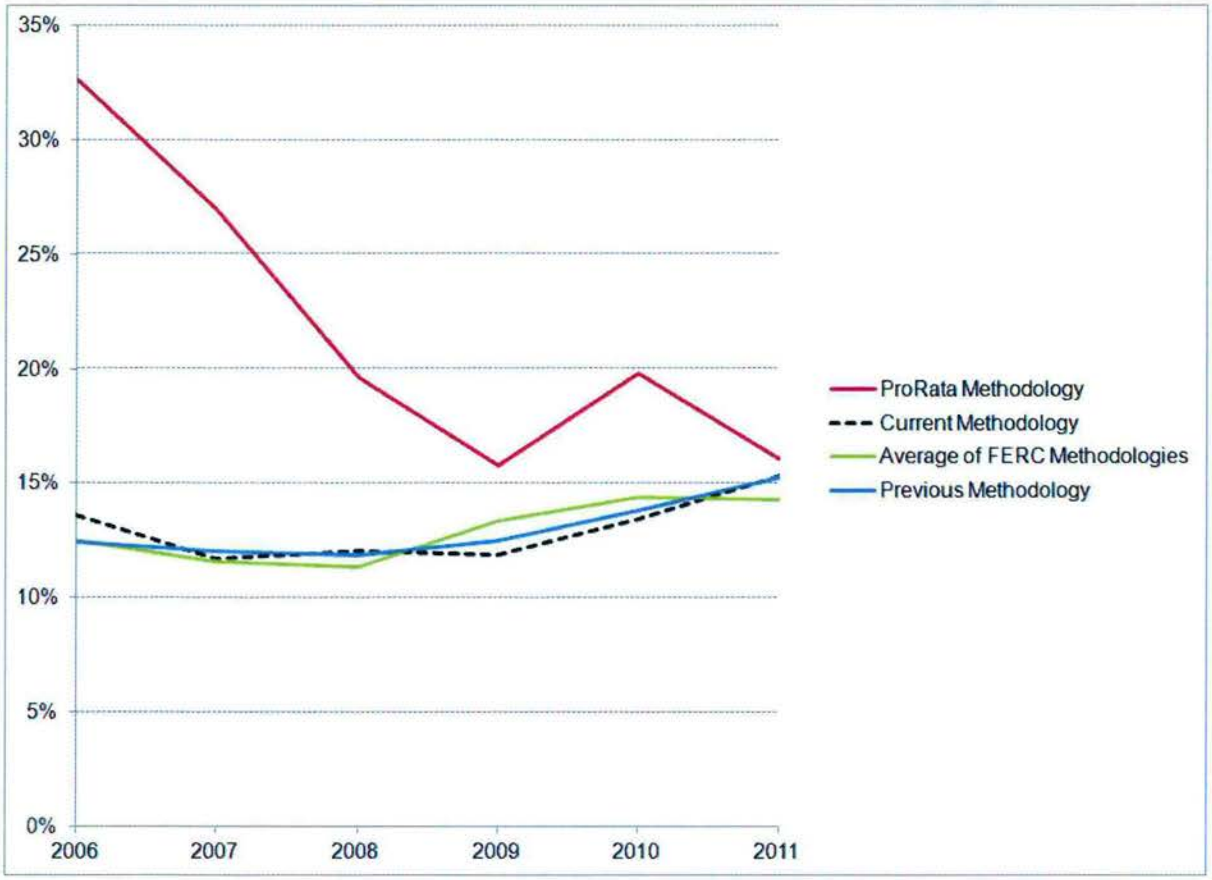
1. *FERC Methods (average of the following):*
    a. Massachusetts Formula
    b. Modified Massachusetts Formula
    c. Distrigas Method
2. *Average of net plant and employees* – this method is an approximation of Resources' two-factor allocation approach prior to the adoption of the Corporate Capitalization Factor.
3. *Pro Rata Method* – this methodology allocates residual A&G expenses based on the proportion of direct and usage-based costs that are allocated to the Company.

Concentric developed the allocation factors in consideration of the fact that the majority of U.S. regulated utilities use multi-factor allocation methods rather than a single-factor method. In addition, while industry practice is diverse, Concentric found that the FERC Methods and variants thereof (including Resources' prior two-factor method) that include measures of assets, labor, and revenues, are the most widely employed allocation methods. Further, the Pro Rata Method puts additional emphasis on cost causation principles as it allocates residual costs using percentages that best represent the amount of benefits received by the utility for shared services allocated directly or by usage-based methods. Concentric's analysis thus provided a basis from which to evaluate whether Resources' allocation methodology and factors are fair and reasonable compared to alternative practices utilized across the U.S. utility industry and adequately adhere to cost causation principles.

Pro Forma Allocation Model Results

The results of the allocation model are presented in the chart below. Under each method, Concentric determined the total percentage of corporate department A&G costs that would be allocated to Montana-Dakota under that method. The results of each method are provided separately in the chart.

Chart 3: Alternative Cost Allocation Methodologies, 2006-2011



As shown in the chart above, the Corporate Capitalization Factor approximated the *pro forma* results of Resources' previous two-factor method, as well as an average of the FERC Methods in most of the years in Concentric's review period. The Corporate Capitalization Factor also fell significantly below the Pro Rata Method in every year except for 2011. Those results indicate that, compared to alternative allocation methods, the Corporate Capitalization Factor results in reasonable allocations to Montana-Dakota.

IX. Conclusion

Based on the analyses performed by Concentric, as well as other considerations discussed above, Concentric reached the following conclusions regarding Resources' allocation practices and the Corporate Capitalization Factor:

- The provision of services by Resources to its business units is a prudent approach to providing common services within the Resources family of companies;
- Resources' allocation policies and procedures are clearly established, straight forward, transparent, and consistently applied;
- Given the mix of companies within the Resources family, the Corporate Capitalization Factor is an effective means by which to allocate common costs that cannot be direct charged or allocated based upon usage;
- For allocations of residual costs, other U.S. regulated utilities use from one to four-factor allocation methods. More than 80% of the regulated utilities surveyed employed multi-factor allocation methods;
- Allocation practices are company and circumstance-specific. While there is no consensus in terms of industry practice, the FERC Methods and variants thereof, which include measures of assets, labor, and revenues, are the most widely employed allocation methods;
- Despite the more prevalent use in the industry of multi-factor allocation methods that consider measures of assets, labor, and revenues, a recasting of the Corporate Capitalization Factor allocation process employing other commonly used allocation factors did not produce materially different results, with the exception of the Pro Rata method, which would have lead to significantly greater allocations of costs to Montana-Dakota in the review period;
- The resetting of the Corporate Capitalization Factor semi-annually is appropriate, and minimizes the lag between when changes in a business unit's capital funding requirements occur and the Corporate Capitalization Factor is updated;
- There is a practice among some U.S. utilities of allocating corporate costs on a department-by-department basis. While that approach may adhere more closely to cost causation principles than the use of a single allocation method for all corporate departments (which is also a common practice in the U.S.), it comes with a different level of administrative burden. In addition, for Montana-Dakota, Concentric does not believe that approach would have produced materially different results over the review period;

- Resources' should evaluate the continued reasonableness of the Corporate Capitalization Factor on a periodic basis or as circumstances warrant. Such an evaluation, performed every three-to-five years or as circumstances (*e.g.*, changes in corporate organization) dictate, will ensure the continued fairness and reasonableness of the current approach.

MDU RESOURCES GROUP, INC.

1200 West Century Avenue, P.O. Box 5650
Bismarck, North Dakota 58506-5650

POLICY STATEMENTS
Policy No. 50.9
Allocation of Administrative Costs and General Overheads to Business Units

Effective Date:
July 1, 2011

I. PURPOSE

A. It is the policy of the Company to allocate MDU Resources Group, Inc.'s (MDU) administrative costs and general expenses to MDU's business units.

II. SCOPE

A. The allocation procedures described herein are intended to allocate only those MDU administrative and general expenses applicable to multiple business unit operations. In those instances where administrative and general expenses incurred relate only to a specific business unit, that expense will be assigned directly to the applicable business unit with no allocation to other business units.

B. The allocation policy and procedure implemented by this Statement is intended to utilize those allocation methodologies which appropriately allocate MDU's general and administrative expenses to the applicable business units. General and administrative expenses shall also include the costs of the facilities and other property used in providing services to the business units. Ownership and operating costs for these facilities and other property shall be based on a cost of service calculation. Such cost of service methodology provides for an annual return on the value of property used and useful in providing service plus necessary and proper annual operating expenses, taxes and depreciation.

III. PROCEDURE

A. The allocation factors developed to apportion MDU's unassigned general and administrative costs, including payroll, shall be based on the corporate capitalization factor which is based on 12 month average capitalization at March 31, effective July 1 and at September 30, effective January 1. Capitalization includes total equity and current and non-current long-term debt (including capital lease obligations).

B. Business unit employees who perform services for affiliated business units on a noncompetitive basis shall determine the time devoted to those other business units and shall recover the payroll costs through an administrative fee to be charged to and recovered from such other business units.

C. As indicated in paragraph II.B., the ownership and operating costs related to providing services to the business units shall be assigned directly where so determinable or otherwise allocated using the appropriate factor. Facilities and other property utilized in providing services include the corporate office, computers, telephones and furniture and fixtures. Components included in cost of service for these facilities and other property include operation and maintenance expense, depreciation, property taxes, income taxes and a pretax return on the investment.

D. MDU allocable general and administrative costs shall be charged to the business units on a monthly basis.

IV. ADMINISTRATION

A. The President and Chief Executive Officer of MDU Resources Group, Inc. has the responsibility and authority for the overall administration of this policy and procedure. Establishment and implementation of procedures to administer the policy and procedure is the responsibility of MDU's Vice President, Controller and Chief Accounting Officer.

Prepared and
Reviewed By: /s/ Nicole A. Kivisto
Nicole A. Kivisto
Vice President, Controller and
Chief Accounting Officer

Approved By: /s/ Terry D. Hildestad
Terry D. Hildestad
President and Chief
Executive Officer

Date: July 1, 2011

MDU Resources Shared Services
Pricing Methodology - Effective for 2012

Note: MDU Resources' use of Shared Services – MDU Resources costs for each shared services function are charged based on the corporate allocation factor.

761 – Payroll Shared Services

Payroll Shared Services costs are invoiced based on the number of employees paid and stated as a cost per check. The word check, for this purpose, generically refers to paper paychecks, direct deposits and paycard transactions.

Checks are charged on a tiered structure, intended to recognize the fixed or baseline effort associated with maintaining a payroll cycle and associated reporting, regardless of number of people paid. It is also intended to reward consolidation of multiple pay groups and companies where possible and to align charges with the additional effort required to maintain multiple pay groups and pay cycles.

The monthly volume for this step pricing is accumulated individually for each pay cycle processed.

Checks for weekly pay cycles, cost per check based on the number of checks written per month:
$ 5.00 per check for the first 500 checks
$ 3.25 per check for the next 1000 checks
$ 0.75 per check for each additional check

Checks for non-weekly pay cycles, cost per check based on the number of checks written per month:
$ 5.00 per check for the first 1000 checks
$ 3.25 per check for the next 2000 checks
$ 0.75 per check for each additional check

There is a $500 per month minimum charge for each operating company.

762 – Procurement Shared Services

Procurement Shared Services costs are invoiced based on five separate factors, all carrying an equal weight of 20%. The factors are:

- Number of Visa Cards as of 8/1/11
- Total Visa Spend for 2010
- National Account Spend for 2010
- Number of Construction Equipment Acquisitions in 2010
- Number of Fleet Acquisitions in 2010

766 – Time Entry Shared Services

Service provided 100% to the MDU Utility Group.

767 – Accounts Payable Shared Services

Accounts Payable Shared Services costs are invoiced based on three factors:

- Percentage of FTEs worked by MDUR AP Analyst (33.33%)
- Number of payments processed based on activity from 7/1/10 through 6/30/11 (20.83%)
- Number of vouchers processed by AP Shared Services staff based on activity from 7/1/10 through 6/30/11 (45.84%)

Enterprise Technology Services (ETS)

There are several ETS departments, and each is billed out based on its own criteria. They are as follows:

Application Services (765) There are three components to the invoicing structure for Applications Services, they are as follows:

1. MDU Resources costs specific to the AS/400 are invoiced upon the AS/400 allocation as agreed to by MDU and WBI. Approximately 17.7% of our costs will be invoiced this way.
2. MDU Resources costs specific to the Operations/Server Maintenance will be billed out based on the number of servers that are supported for a particular business unit. The servers are divided into two pools. Servers which are housed in the data center and are supported locally by the operations group (weighted 75%) and those servers which are located in the field and serviced remotely by the operations group (weighted 25%). Approximately 18.2% of our costs will be invoiced this way.
3. The remaining costs of Application Services will be invoiced to MDUR and will be further allocated based on the corporate factor. Approximately 64.1% of our costs will be allocated this way.

Customer Relations (965) – Two factors are used in the invoicing of the enterprise costs associated with customer relations. 87.5% of the costs are associated with the help desk. Those costs are invoiced based upon the number of devices supported by customer relations. The metric used to determine device counts is devices that have checked into active directory during a 60 day period in the summer of 2011. The remaining 17.3% of the costs are for the customer relations PC support group. These costs are invoiced based upon the actual time logged from 01/01/11 to 7/31/11 for this function.

Communications (971) – Enterprise charges for the communications group are invoiced using four separate factors. They and their estimated % of work are:

4. Wide Area Network/Local Area Network/Metropolitan Area Network- Number of business unit locations (35%)
5. Internet/Security – Number of user accounts (34%)
6. Voice – Number of Voice Gateways/Servers (30%)
7. Off Network Access (1%)

Each of these four areas is assigned a percentage (identified above). Those portions of the costs are invoiced via the above identified denominators.

Operations (972) – Enterprise costs for the operations group are invoiced based upon the number of servers that are supported for a particular business unit. The servers are divided into two pools. Servers which are housed in the data center and are supported locally by the operations group (weighted 75%) and those servers which are located in the field and serviced remotely by the operations group (weighted 25%).

Security (977) – Enterprise costs for the security group are distributed via the number of devices in active directory that have been on the network during a 60 day period in the summer of 2011.

Finance and Administration (982) –. Costs for the finance and administration group are invoiced based upon the combined methodologies of the five previously identified ETS groups.

Alternative Cost Allocation Methodologies

			Multi-Factor Methodology										
		ProRata	Assets	Payroll	Revenue	Employees	O&M Expenses	Gross Plant	Gross Margin	Equity	Capitalization	Net Plant	Net Income
MDU Resources	Current Methodology										X		
	Previous Methodology					X						X	
FERC Methodologies	Distrigas Method			X	X			X					
	Massachusetts Method			X	X			X					
	Modified MA Method			X								X	
FERC Form 60's [1]	Allegheny Energy Service Corp									X			
	Alliant Energy Corp Services Inc	X											
	Black Hills Service Company, LLC		X	X					X				
	CenterPoint Energy Service Company, LLC		X			X			X				
	Dominion Resources Services, Inc						X						
	Duke Energy Business Services, LLC			X				X	X				
	Exelon Business Services Company, LLC		X	X	X								
	FirstEnergy Service Company									X			
	Iberdrola USA Management Corp			X	X			X					
	Integrys Business Support, LLC		X				X						
	LG&E and KU Services Company		X		X	X							
	National Grid Corp Services		X		X		X						
	NiSource Corp Services Company			X									
	Northeast Utilities Service Company							X					X
	PHI Service Company						X	X					
	PNMR Services Company	X											
	PPL Services Company					X	X				X		
	Progress Energy Service Company, LLC		X		X	X							
	SCANA Services, Inc			X	X			X					
	Xcel Energy Services Inc		X		X	X							
Additional Concentric Research	Ameren Corp [2]	X											
	Baltimore Gas and Electric Co (Exelon/Constellation) [3]		X			X			X	X			
	Northern Utilities, Inc (Unitil) [3]			X									
	PacificCorp Utah (Midamerican) [4]		X	X									
	Pacific Gas and Electric Company [5]		X			X	X						
	OtterTail Corp [6]		X	X	X								
Methodology Frequency:		**3**	**12**	**12**	**10**	**8**	**6**	**7**	**4**	**3**	**2**	**2**	**1**

Sources:

[1] 2011 FERC Form 60 Schedule XXI - Methods of Allocation
[2] Ameren General Services Agreement
[3] 2009 Cost Allocation Manual
[4] Direct Testimony of Michael Brosch, Docket No. 99-035-10
[5] 2011 FERC Form 1
[6] 2010 Cost Allocation Manual

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 8, 2013
DOCKET NO. D2012.9.100

PSC-041

Regarding: Base Salary for Stock Ownership
Witness: Jones

a. **What is the required multiple of base salary for stock ownership for each company officer?**

b. **Are all officers in compliance- if not who and why not?**

c. **Is any of this stock from the Total Rewards Program a restricted shares program?**

d. **If (c) is yes, how much and to which company officer?**

Response:

a. Executives are required to own common stock valued at one to four times base salary, depending on salary grade level.

Stock acquired through purchases on the open market, participation in the Company's 401K Retirement Plan, long-term incentive program and Dividend Reinvestment and Direct Stock Purchase Plan will be considered in ownership calculations as will ownership of company stock by a spouse.

Requirements for stock ownership are expressed as a multiple of base salary, depending on the salary grade level of the executive. It is recognized that each executive may need up to five years from participation in the long-term incentive program or a promotion with a significant increase in base salary to fulfill these requirements.

The level of stock ownership compared to the requirements will be determined based on the closing sale price of the stock on the last trading day of the year and base salary at December 31 of each year and will be monitored annually with a report to the Compensation Committee at the February meeting.

The Compensation Committee of the Board of Directors of MDU Resources Group, Inc. shall have final discretion and may amend any of the stock ownership policy requirements, as the Committee deems appropriate. In the event an executive is not in compliance with the Policy, the Compensation Committee may, in its sole discretion, grant an extension of time to meet the ownership requirements or take such other action as it deems appropriate to enable the executive to achieve compliance with the Policy. Such action may include, but not be limited to, establishing mandatory holding requirements with respect to all or part of any new Long-Term Performance Based Incentive Plan awards net of taxes.

b. Yes, the Compensation Committee has approved that the Officers are in compliance.

c. No.

d. Not Applicable.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 17, 2013
DOCKET NO. D2012.9.100

PSC-056

Regarding: New customer bills
Witness: Gardner, Aberle

a. **Please provide copies of the revamped consumer bills discussed by Mr. Gardner on p. 6 of his prefiled testimony for residential and small firm general service customers.**

b. **Please provide a copy of the most recent JD Power and Associates survey results for MDU customers.**

Response:

a. Please see Attachment A for examples of customer bills for a Residential and Small Firm General Service customer. The watermark indicates the bills were produced out of a test environment and the watermark will not display on bills sent to customers.

b. The requested information is the proprietary information of a third party which Montana-Dakota is only allowed to use on a subscription basis. Montana-Dakota cannot, consistent with its legal obligations with its subscriber, provide the requested information.

Response No. PSC-056
Attachment A

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve®

SERVICE FOR

ACCOUNT NUMBER	DATE DUE
	Oct 4, 2012
BILL DATE	**AMOUNT DUE**
Sep 12, 2012	$53.14

www.montana-dakota.com

ACCOUNT SUMMARY

Previous Balance	$77.09
Payment Received 9/7/2012 Thank you	-77.09
Current Gas Charges	11.06
Current Electric Charges	42.08
Amount Due on 10/4/12	**$53.14**

Any balance remaining after the due date is subject to a late payment charge of 1.00% per month.

CUSTOMER SERVICE & EMERGENCY SERVICE
1-800-638-3278
Emergencies: 24 hours a day
Non-emergencies: Mon-Fri, 7 AM - 7 PM
Email: *customerservice@mdu.com*
Mail: Montana-Dakota Utilities Co.,
Attn: Customer Service, PO Box 7608, Boise, ID 83707-1608. Please include your account number.

CALL BEFORE YOU DIG 811

October

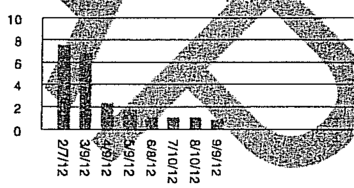
S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29	30	31			

Payment Due ▲
See "Ways to Pay Your Bill" on the back of this page.

Gas Charges

BILLING PERIOD 8/11/12 - 9/9/12 **DAYS** 30
METER NUMBER 012607079
METER READ DATE 9/9/12
Next scheduled read 10/10/12
RATE 60 - Residential Gas

USAGE HISTORY (Dk)



	Sep 12
Average Daily Dk	0.03
Average regional temp	68
Days in billing period	30

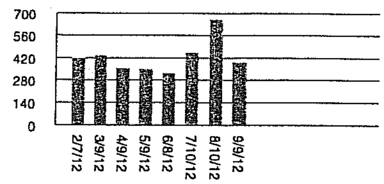
CURRENT READING	PREVIOUS READING	DIFFERENCE	THERM FACTOR	Dk USED
621.9	- 621.1	= 0.8	x 1.138694	= 0.9

Basic Service Charge	6.35
Distribution Delivery 0.9 Dk x $1.126	1.01
Cost of Gas 0.6 Dk x $3.898	2.34
Cost of Gas 0.3 Dk x $4.284	1.29
USBC 0.9 Dk x $0.0655	0.06
CTA 0.9 Dk x $0.01	0.01
Total Charges	**$11.06**

Electric Charges

BILLING PERIOD 8/11/12 - 9/9/12 **DAYS** 30
METER NUMBER 011435402
METER READ DATE 9/9/12
Next scheduled read 10/10/12
RATE 10 - Residential Electric

USAGE HISTORY (Kwh)



	Sep 12
Average Daily Kwh	13.33
Average regional temp	68
Days in billing period	30

CURRENT READING	PREVIOUS READING	TOTAL USED
18388	- 17988	= 400 Kwh

Basic Service Charge 30 Days at $0.18	5.40
Energy 400 Kwh x $0.06813	27.25
Fuel & Purchased Power 280 Kwh x $0.02065	5.78
Fuel & Purchased Power 120 Kwh x $0.0252	3.02
USBC 400 Kwh x $0.001566	0.63
Total Charges	**$42.08**

PLEASE KEEP THIS PORTION FOR YOUR RECORDS.

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT, MAKING SURE THE RETURN ADDRESS SHOWS IN THE ENVELOPE WINDOW.

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

ACCOUNT NUMBER

DATE DUE
Oct 4, 2012

AMOUNT DUE
$53.14

UTE 42.08
UTG 11.06

☐ **Has your mailing address or phone number changed?**
Check here and provide details on back.

To donate to Energy Share of MT enter amount on line. (Tax Deductible)

+ $ ______
Energy Share of MT donation

Please enter amount enclosed
$

PO BOX 5600
BISMARCK ND 58506-5600

Write account number on check and make payable to MDU.

6352

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve®

Customer Service: 1-800-638-3278 • 7 a.m.-7 p.m. Monday-Friday
Call volume is generally higher on Mondays, for faster service please call Tuesday-Friday.
www.montana-dakota.com

Ways to Pay Your Bill

Easy-Pay: Automatically pay your bill each month by having Montana-Dakota Utilities withdraw your preauthorized payment from your financial institution each month. To enroll, call 1-800-638-3278 or complete the Easy-Pay Enrollment authorization form located on our website, **www.montana-dakota.com**, and return with a voided check.

Pay By Phone or Online: We accept payments through Western Union® Speedpay®, a third-party service provider. You will find the Speedpay link on our website or simply call toll-free 1-866-263-5185 and follow the prompts. Payments can be made 24/7 using your credit card, debit card or electronic transfer from a checking, money market or savings account. You will need your utility account number (available on your bill) to process your payment. Western Union® Speedpay® charges a $3.95 convenience fee per transaction for this service.

Payment Locations: Pay by cash, check or money order at one of our payment locations; there is no charge for this service. Call Customer Service or visit our website for the nearest payment location. Payments made at a payment location are not credited to yo account until they are received by Montana-Dakota Utilities.

By Mail: Mail your payment to Montana-Dakota Utilities Co., P.O. Box 5600, Bismarck, N 58506-5600. Be sure to allow time for mailing so your payment is received by the due dat

Balanced Billing: This billing plan levels out your monthly bill so you can reduce fluctuations brought on by changes in the weather and the cost of energy. To enroll, complete the Balance Billing form located on our website or contact Customer Service at 1-800-638-3278.

Payment Due Date: Your bill is past due if not paid within 22 days after it is mailed. If yo are paying with a credit card or paying at one of our payment locations in response to a Disconnection of Service Notice, please contact Montana-Dakota at 1-800-638-3278 an let us know that payment has been made.

Billing Terms and Definitions

The rates reflected on your bill have been approved by the Public Service Commission or Public Utilities Commission in the state where service is provided. Copies of the company's current tariffs are available at www.montana-dakota.com.

Basic Service Charge or Base Rate: A monthly or daily charge designed to recover a portion of the fixed costs incurred in providing utility service regardless of how much energy is used.

Constant: A fixed value used to convert meter readings to actual energy use when certain equipment is used in the metering process such as current and potential transformers.

Cost of Gas: This charge recovers the cost of gas itself as well as other related costs Montana-Dakota incurs from its pipeline suppliers in providing natural gas service. The cost is strictly a pass-through to customers and does not provide Montana-Dakota with a profit.

CTA – Conservation Tracking Adjustment: A charge that provides funding for Commission-approved conservation programs in the states of MT and SD.

Demand Charge: A charge designed to recover the demand or peak-related costs associated with the delivery of electric service from the generation source to your meter.

Distribution Delivery Charge or Energy Charge: A volumetric charge to recover the costs of delivering energy to your meter. This amount varies with the amount of energy used.

DDSM – Distribution Delivery Stabilization Mechanism: A charge applicable to gas service provided in ND and SD designed to adjust for the over- or under-collection of distribution delivery revenues due to actual temperature deviations from normal temperatures. This adjustment is applicable during the billing periods Nov. 1-May 1.

Dk – Dekatherms: The Dk billed is reflective of the total amount of natural gas used in the billing period. The amount of natural gas used as measured by the gas meter is converted to Dk by applying a therm factor to the measured use.

Fuel and Purchased Power: This charge recovers the fuel and purchased power costs the company incurs in supplying its customers with electricity. This cost is a pass-through to customers and is subject to change on a monthly basis for customers served in MT and ND.

Fuel Cost Adj: Adjustment per Kwh to reflect changes in the cost of fuel and purchased power the company incurs in supplying its customers with electricity. This adjustment is a pass-throug to customers and is subject to change on a monthly basis in SD.

Kw – Kilowatt: The Kw billed is the peak demand (or maximum 15-minute measured demand) f electricity during the billing period or the minimum Kw amount as stated in the company's tariff

Kwh – Kilowatt-hour: The Kwh billed is the total amount of electricity used in the billing period.

Kvar Penalty: A penalty applicable to a customer operating its facilities outside the power fact range stated on the company's tariffs.

Power Supply Cost Adj: Adjustment per Kwh to reflect changes in the cost of fuel and purchas power the company incurs in supplying its customers with electricity. This adjustment is a pass-through to customers and is subject to change on an annual basis in WY.

TCA – Transmission Cost Adjustment: A charge per Kwh applicable to electric service provide in ND for recovery of transmission related expenditures and investments net of revenues received from others. The TCA is subject to change on an annual basis.

Therm Factor: The therm factor adjusts the amount of natural gas measured by the meter for the heat content and atmospheric pressure of the gas delivered to a customer's premise. This conversion ensures that all customers are billed based on the heat value of the gas during the applicable billing period.

USBC – Universal System Benefits Charge: A charge that provides funding for conservation an low-income programs in the state of MT as required by the Montana State Legislature.

Important Customer Information

If you have questions regarding your bill or service, please call Montana-Dakota Customer Service **FIRST** at 1-800-638-3278. If you cannot pay your bill at this time, we are **willing to make satisfactory payment arrangements.** If your questions are not resolved after you have called Customer Service, you may contact the regulatory agencies governing in the state service is provided:

- MT PSC: 1-800-646-6150 or write to P.O. Box 202601, Helena, Montana 59620-2601
- ND PSC: Write to 600 E. Boulevard, Bismarck, ND 58505-0480
- SD PUC: 1-605-773-3201
- WY PSC: Write to 2515 Warren Avenue, Suite 300 Cheyenne, WY 82002

Payments made by check or electronically that are dishonored by the bank will be assessed returned payment fee.

When you provide a check as payment, you authorize us to use information from your check either to make a one-time electronic fund transfer from your account or to process the payment as a check transaction. When we use information from your check to make an electronic fund transfer (EFT), funds may be withdrawn from your account as soon as the same day we receive your payment. The transaction will appear on your bank statement as EFT and you will not receive a copy or an image of your check from your financial institution.

Payments marked with a restrictive legend (Paid in Full, for example) will not act as an accor and satisfaction without our express prior written approval.

Moving? To avoid being billed for service you have not used, please contact us at least two business days before you want service disconnected.

Has your mailing / email address or phone number changed?

Please provide details here and check the box on the front of this stub.

Account No. ______________________

Name: ______________________

Mailing Address: ______________________

City: ______________ State: __________ ZIP: __________

Phone: (______) ______________ Email: ______________

2

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve®

SERVICE FOR

ACCOUNT NUMBER	DATE DUE
	Oct 4, 2012
BILL DATE	AMOUNT DUE
Sep 12, 2012	$53.14

www.montana-dakota.com

ACCOUNT SUMMARY

Previous Balance	$77.09
Payment Received 9/7/2012 Thank you	-77.09
Current Gas Charges	11.06
Current Electric Charges	42.08
Amount Due on 10/4/12	**$53.14**

Any balance remaining after the due date is subject to a late payment charge of 1.00% per month.

CUSTOMER SERVICE & EMERGENCY SERVICE
1-800-638-3278
Emergencies: 24 hours a day
Non-emergencies: Mon-Fri, 7 AM - 7 PM
Email: *customerservice@mdu.com*
Mail: Montana-Dakota Utilities Co.,
Attn: Customer Service, PO Box 7608, Boise, ID 83707-1608. Please include your account number.

CALL BEFORE YOU DIG **811**

October

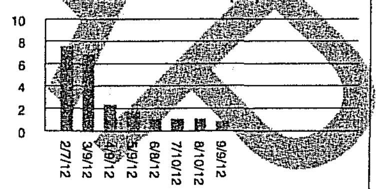
S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29	30	31			

Payment Due ▲
See "Ways to Pay Your Bill" on the back of this page.

Gas Charges

BILLING PERIOD 8/11/12 - 9/9/12
DAYS 30
METER NUMBER 012607079
METER READ DATE 9/9/12
Next scheduled read 10/10/12
RATE 60 - Residential Gas

USAGE HISTORY (Dk)



	Sep 12
Average Daily Dk	0.03
Average regional temp	68
Days in billing period	30

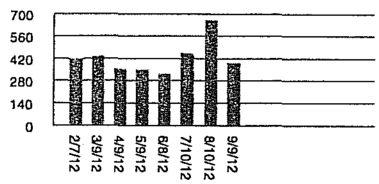
CURRENT READING	PREVIOUS READING	DIFFERENCE	THERM FACTOR	Dk USED
621.9	- 621.1	= 0.8	x 1.138694	= 0.9

Basic Service Charge	6.35
Distribution Delivery 0.9 Dk x $1.126	1.01
Cost of Gas 0.6 Dk x $3.898	2.34
Cost of Gas 0.3 Dk x $4.284	1.29
USBC 0.9 Dk x $0.0655	0.06
CTA 0.9 Dk x $0.01	0.01
Total Charges	**$11.06**

Electric Charges

BILLING PERIOD 8/11/12 - 9/9/12
DAYS 30
METER NUMBER 011435402
METER READ DATE 9/9/12
Next scheduled read 10/10/12
RATE 10 - Residential Electric

USAGE HISTORY (Kwh)



	Sep 12
Average Daily Kwh	13.33
Average regional temp	68
Days in billing period	30

CURRENT READING	PREVIOUS READING	TOTAL USED
18388	- 17988	= 400 Kwh

Basic Service Charge 30 Days at $0.18	5.40
Energy 400 Kwh x $0.06813	27.25
Fuel & Purchased Power 280 Kwh x $0.02065	5.78
Fuel & Purchased Power 120 Kwh x $0.0252	3.02
USBC 400 Kwh x $0.001566	0.63
Total Charges	**$42.08**

PLEASE KEEP THIS PORTION FOR YOUR RECORDS.

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT, MAKING SURE THE RETURN ADDRESS SHOWS IN THE ENVELOPE WINDOW.

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

ACCOUNT NUMBER

DATE DUE
Oct 4, 2012

AMOUNT DUE
$53.14

UTE 42.08
UTG 11.06

☐ **Has your mailing address or phone number changed?**
Check here and provide details on back.

To donate to Energy Share of MT enter amount on line. (Tax Deductible)

\+ $ ________
Energy Share of MT donation

Please enter amount enclosed

$

Write account number on check and make payable to MDU.

PO BOX 5600
BISMARCK ND 58506-5600

6352

2

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve®

Customer Service: 1-800-638-3278 • 7 a.m.-7 p.m. Monday-Friday
Call volume is generally higher on Mondays, for faster service please call Tuesday-Friday.
www.montana-dakota.com

Ways to Pay Your Bill

Easy-Pay: Automatically pay your bill each month by having Montana-Dakota Utilities withdraw your preauthorized payment from your financial institution each month. To enroll, call 1-800-638-3278 or complete the Easy-Pay Enrollment authorization form located on our website, **www.montana-dakota.com**, and return with a voided check.

Pay By Phone or Online: We accept payments through Western Union® Speedpay®, a third-party service provider. You will find the Speedpay link on our website or simply call toll-free 1-866-263-5185 and follow the prompts. Payments can be made 24/7 using your credit card, debit card or electronic transfer from a checking, money market or savings account. You will need your utility account number (available on your bill) to process your payment. Western Union® Speedpay® charges a $3.95 convenience fee per transaction for this service.

Payment Locations: Pay by cash, check or money order at one of our payment locations; there is no charge for this service. Call Customer Service or visit our website for the nearest payment location. Payments made at a payment location are not credited to you account until they are received by Montana-Dakota Utilities.

By Mail: Mail your payment to Montana-Dakota Utilities Co., P.O. Box 5600, Bismarck, NE 58506-5600. Be sure to allow time for mailing so your payment is received by the due date

Balanced Billing: This billing plan levels out your monthly bill so you can reduce fluctuations brought on by changes in the weather and the cost of energy. To enroll, complete the Balance Billing form located on our website or contact Customer Service at 1-800-638-3278.

Payment Due Date: Your bill is past due if not paid within 22 days after it is mailed. If you are paying with a credit card or paying at one of our payment locations in response to a Disconnection of Service Notice, please contact Montana-Dakota at 1-800-638-3278 and let us know that payment has been made.

Billing Terms and Definitions

The rates reflected on your bill have been approved by the Public Service Commission or Public Utilities Commission in the state where service is provided. Copies of the company's current tariffs are available at www.montana-dakota.com.

Basic Service Charge or Base Rate: A monthly or daily charge designed to recover a portion of the fixed costs incurred in providing utility service regardless of how much energy is used.

Constant: A fixed value used to convert meter readings to actual energy use when certain equipment is used in the metering process such as current and potential transformers.

Cost of Gas: This charge recovers the cost of gas itself as well as other related costs Montana-Dakota incurs from its pipeline suppliers in providing natural gas service. The cost is strictly a pass-through to customers and does not provide Montana-Dakota with a profit.

CTA – Conservation Tracking Adjustment: A charge that provides funding for Commission-approved conservation programs in the states of MT and SD.

Demand Charge: A charge designed to recover the demand or peak-related costs associated with the delivery of electric service from the generation source to your meter.

Distribution Delivery Charge or Energy Charge: A volumetric charge to recover the costs of delivering energy to your meter. This amount varies with the amount of energy used.

DDSM – Distribution Delivery Stabilization Mechanism: A charge applicable to gas service provided in ND and SD designed to adjust for the over- or under-collection of distribution delivery revenues due to actual temperature deviations from normal temperatures. This adjustment is applicable during the billing periods Nov. 1-May 1.

Dk – Dekatherms: The Dk billed is reflective of the total amount of natural gas used in the billing period. The amount of natural gas used as measured by the gas meter is converted to Dk by applying a therm factor to the measured use.

Fuel and Purchased Power: This charge recovers the fuel and purchased power costs the company incurs in supplying its customers with electricity. This cost is a pass-through to customers and is subject to change on a monthly basis for customers served in MT and ND.

Fuel Cost Adj: Adjustment per Kwh to reflect changes in the cost of fuel and purchased power the company incurs in supplying its customers with electricity. This adjustment is a pass-through to customers and is subject to change on a monthly basis in SD.

Kw – Kilowatt: The Kw billed is the peak demand (or maximum 15-minute measured demand) for electricity during the billing period or the minimum Kw amount as stated in the company's tariffs.

Kwh – Kilowatt-hour: The Kwh billed is the total amount of electricity used in the billing period.

Kvar Penalty: A penalty applicable to a customer operating its facilities outside the power factor range stated on the company's tariffs.

Power Supply Cost Adj: Adjustment per Kwh to reflect changes in the cost of fuel and purchased power the company incurs in supplying its customers with electricity. This adjustment is a pass-through to customers and is subject to change on an annual basis in WY.

TCA – Transmission Cost Adjustment: A charge per Kwh applicable to electric service provided in ND for recovery of transmission related expenditures and investments net of revenues received from others. The TCA is subject to change on an annual basis.

Therm Factor: The therm factor adjusts the amount of natural gas measured by the meter for the heat content and atmospheric pressure of the gas delivered to a customer's premise. This conversion ensures that all customers are billed based on the heat value of the gas during the applicable billing period.

USBC – Universal System Benefits Charge: A charge that provides funding for conservation and low-income programs in the state of MT as required by the Montana State Legislature.

Important Customer Information

If you have questions regarding your bill or service, please call Montana-Dakota Customer Service **FIRST** at 1-800-638-3278. If you cannot pay your bill at this time, we are **willing to make satisfactory payment arrangements.** If your questions are not resolved after you have called Customer Service, you may contact the regulatory agencies governing in the state service is provided:

- MT PSC: 1-800-646-6150 or write to P.O. Box 202601, Helena, Montana 59620-2601
- ND PSC: Write to 600 E. Boulevard, Bismarck, ND 58505-0480
- SD PUC: 1-605-773-3201
- WY PSC: Write to 2515 Warren Avenue, Suite 300 Cheyenne, WY 82002

Payments made by check or electronically that are dishonored by the bank will be assessed returned payment fee.

When you provide a check as payment, you authorize us to use information from your check either to make a one-time electronic fund transfer from your account or to process the payment as a check transaction. When we use information from your check to make an electronic fund transfer (EFT), funds may be withdrawn from your account as soon as the same day we receive your payment. The transaction will appear on your bank statement as EFT and you will not receive a copy or an image of your check from your financial institution.

Payments marked with a restrictive legend (Paid in Full, for example) will not act as an accord and satisfaction without our express prior written approval.

Moving? To avoid being billed for service you have not used, please contact us at least two business days before you want service disconnected.

Has your mailing / email address or phone number changed?

Please provide details here and check the box on the front of this stub.

Account No. ______________________

Name: ______________________

Mailing Address: ______________________

City: ______________ State: __________ ZIP: __________

Phone: (   ) ______________ Email: ______________________

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-069
Regarding: Retention rates and growth
Witness: Gaske

a. **When you did your forecast for retention rate growth, did you use future projections or historical retention rates for the proxy companies? Please explain.**

b. **When you projected dividend growth, did you use future projections based on the 1+.625g or use average historical dividend growth for the companies? Please explain.**

Response:

a. As described on page 18 of his Prepared Direct Testimony, Dr. Gaske calculated retention growth rates using forecasts of dividends, earnings, and returns on equity for the proxy group from the Value Line Investment Survey. Exhibit No.___(JSG-2), Schedule 2 shows that Dr. Gaske used Value Line's forecasts for the 2015-2017 period in his calculation of retention growth rates.

b. As described on pages 18-19 of his Prepared Direct Testimony, Dr. Gaske conducted three separate DCF analyses based on three different estimates of future dividend growth. All three estimates of future dividend growth are based on future projections of retention growth and earnings growth. Dr. Gaske did not use historical dividend growth in his calculation of retention growth rates.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-070

Regarding: General modeling
Witness: Gaske

a. **When you did your analysis using the proxy group, did you in addition outside the proxy group, use an analysis of MDU to determine if your proxy group was in fact a reasonably valid proxy group? Please explain.**

b. **If the answer to "a." above is yes, please supply the analysis.**

c. **If the answer to "a." above is no, what assurances can you provide that the proxy group you selected is at all valid? Please explain.**

d. **Why did you disregard companies that did not pay dividends in your proxy group? Please explain your rationale.**

Response:

a. It is not clear what this question is asking. The proxy group was selected to be a reasonable proxy for Montana-Dakota's Montana natural gas distribution operations. A comparison of these operations to various characteristics of the proxy companies is contained in Dr. Gaske's testimony.

b. Not Applicable.

c. As described on page 17 of his Prepared Direct Testimony, Dr. Gaske applied certain screening criteria to select a proxy group of natural gas distribution companies that are comparable to Montana-Dakota's Montana natural gas distribution operations. Specifically, in order to ensure that the proxy company is primarily engaged in the natural gas distribution business, Dr. Gaske eliminated any company that did not derive at least 70 percent of its operating income from regulated natural gas distribution operations in 2011, and that did not have at least 70 percent of its total assets devoted to the provision of natural gas distribution service in 2011.

d. Dr. Gaske eliminated companies that did not pay dividends from his proxy group because it is not possible to perform a discounted cash flow analysis on companies that do not pay a dividend. As discussed on page 15 of Dr. Gaske's Prepared Direct Testimony, the DCF method reflects the assumption that the market price of common stock represents the present value of the stream of all future dividends that investors expect the firm to pay. The DCF method suggests that investors in common stocks expect to realize returns from two sources: a current dividend yield, plus expected growth in the value of their shares as a result of future dividend increases.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-071
Regarding: Flotation Costs
Witness: Gaske

a. **If, based on your Schedule 3 of Exhibit No. __ (JSG-2), the representative sample for flotation costs is 3.81 percent, why do you use 4.0 percent for your flotation cost adjustment for MDU?**

b. **Are flotation costs included in the price of a stock purchase by an investor?**

c. **Are flotation costs relevant to an investor? Please explain.**

d. **In your DCF study of natural gas companies, did you reduce the stock price by the flotation costs that were included? Why or why not?**

e. **Doesn't the investor required return already include flotation costs? Why or why not?**

Response:

a. Dr. Gaske used a flotation cost adjustment of 4.00 percent in order to approximate the actual flotation costs paid by natural gas distribution companies between January 2000 and June 2012. In order to demonstrate the effect of the flotation cost adjustment, Dr. Gaske re-calculated his DCF analyses using a flotation cost adjustment of 3.81 percent and compared the results to those presented on page 34 of his Prepared Direct Testimony. The table below demonstrates that the results only differ by between 0.01 and 0.02 percent.

	Flotation Cost Adj. = 4.00%			Flotation Cost Adj. = 3.81%		
	Retention Growth DCF Analysis	Basic Analysts DCF	Blended Growth Rate Analysis	Retention Growth DCF Analysis	Basic Analysts DCF	Blended Growth Rate Analysis
High	11.48%	9.62%	10.55%	11.46%	9.61%	10.53%
3rd Quartile	11.18%	9.40%	9.58%	11.16%	9.38%	9.56%
Median	9.16%	8.78%	8.91%	9.14%	8.76%	8.89%
1st Quartile	8.81%	7.53%	8.30%	8.79%	7.52%	8.28%
Low	7.64%	7.39%	8.23%	7.62%	7.38%	8.22%

b. No, flotation costs are not included in the price of a stock purchase by an investor on the secondary market. However, flotation costs are incurred by the issuing company on the primary market, and the proceeds from the stock issuance are reduced by the amount of flotation costs. For example, if a company issues $100 in common stock and flotation costs are 4.0%, then the company will receive $96 in actual proceeds from the issuance and sale of stock, but the balance sheet will show the value of common equity as $100. That is, flotation costs are not current expenses, but are properly reflected on the balance sheet under "paid-in capital".

c. As explained on page 15 of Dr. Gaske's Prepared Direct Testimony, flotation costs are relevant to investors. The purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital the regulated company would incur to raise money in the "primary" markets. Therefore, an estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost-of-capital that the regulated company requires in order to raise capital on reasonable terms in the "primary" markets.

   When a company issues new common equity in order to raise cash for investment in plant, or, to otherwise run its operations, it does so in the "primary" market. The "primary" market is defined very simply as the market in which the stock is first sold in order to raise cash funds to be used by the issuer. In this "primary" market, the company generally hires an investment banker, or a syndicate of bankers and brokers, to float its stock issue to the public. Associated with a company raising cash funds through a "primary" market sale of common equity there are significant costs of preparing and filing documents with regulatory agencies, and issuing prospectuses. In addition, in the "primary" market the issuing company generally must pay a significant percentage of the proceeds from the stock issuance to the investment banker, or the syndicate of bankers and brokers, who finds the investors who will provide cash to the issuing company.

   Once stock has been issued to investors in the "primary market", those investors who initially provided cash to the issuing company may re-sell or "trade" the stock with other investors in the "secondary" market. Much of the trading in the "secondary" market occurs on stock exchanges, and buyers and sellers are not required to file prospectuses with a stock exchange commission. The crucial difference between stock issued in the "primary" market and stock traded in the "secondary" market is that the issuing company does not receive any additional funds when its stock trades in the "secondary" market. Instead, the ownership of the stock merely changes hands between various investors. In addition, the brokerage fees associated with buying and selling stock in the "secondary" market generally are incurred by both the buyer and the seller, and are a small fraction of the level of the flotation costs incurred by a company that attempts to raise cash by issuing stock in the "primary" market.

d. No, Dr. Gaske did not reduce the stock price in his DCF analysis by the flotation costs that were incurred. In order to provide an allowed rate of return that is sufficient to attract capital on reasonable terms, the return must provide a margin that is sufficient to ensure that stock can be issued without diluting the value of the existing shareholders' investment. This requires that the entire return must be increased by the amount of the flotation cost percentage.

e. The investor required return includes flotation costs because those are real and legitimate costs of issuing common equity that are not otherwise recovered in rates. The DCF model uses stock prices from the secondary market as a proxy for the cost of capital in the primary market. However, flotation costs are not reflected in the secondary market prices of the common stock and, therefore are not reflected in the secondary market DCF results. Since the DCF results do not include flotation costs, those costs must be added to the DCF results to determine the actual return required in the primary market.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-072
Regarding: Basic DCF analysis (Page 23)
Witness: Gaske

a. **Please explain why using the median is the statistically more accurate reflection of the cost of capital vs. using the mean. Provide reference to and a copy of the professional article on which this is based.**

b. **What was the mean Basic DCF analysis common equity cost of the proxy group?**

Response:

a. Determining the cost of equity for Montana-Dakota's Montana natural gas distribution operations is not a pure mathematical or statistical operation, but rather requires the use of judgment. The mean is the arithmetic average of a sample, while the median is the midpoint of the values, the point at which half of the values are above and half are below. The mean is affected by every value in a sample and is more susceptible to the effect of outliers, especially in a small sample size. Given the small sample size and the range of results for each DCF analysis, Dr. Gaske believes that the median result is the more reasonable of the two indicators of central tendency when one does not know the shape of the underlying probability distribution of the sample data, and the sample group is small. This is covered under the topic of non-parametric estimation in many introductory statistics textbooks. For example:

> *For a random sample from a [non-normal distribution] population, the sample mean has approximately zero efficiency relative to the sample median.**
>
> ---
>
> ** In fact the sample mean is just as variable as a single observation. This is because a wildly deviant observation is likely to occur in the sample, pulling the mean way off target. On the other hand, the median is unaffected by one wild observation.*[1]

In addition, sometime in the 1990's the U.S. FERC adopted a policy of using the median of the proxy group as the best estimator of central tendency in

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[1] Wonnacott and Wonnacott, *Introductory Statistics for Business and Economics*, John Wiley & Sons (1972), p. 158.

rate of return analyses in order to eliminate any excessive influence of outliers. Dr. Gaske is following the same convention.

b. The table below compares the mean and median results for Dr. Gaske's three DCF analyses. As shown in the table, two of the three mean DCF results are higher than the median DCF results.

	Retention Growth DCF Analysis	Basic Analysts DCF	Blended Growth Rate Analysis
Median	9.16%	8.78%	8.91%
Mean	9.65%	8.56%	9.11%

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-073

Regarding: Dividend growth
Witness: Gaske

a. **Is dividend yield a direct function of stock price? In other words, the higher the dividend, the higher the stock price? Please explain.**

b. **When you proposed the 1+.625g for the quarterly growth rate, did you apply that to the proxy group and its existing dividend growth rate to estimate the accuracy of your model? Why or why not?**

Response:

a. Yes, for any given dividend the dividend yield is a direct function of the stock price. Specifically, the dividend yield is calculated by dividing the current annual dividend by the average stock price over a specified time period, such as 90 days. However, the stock price is not necessarily a direct function of the dividend yield since the stock price is a joint function of the dividend, the expected growth rate, and the cost of capital in DCF theory.

b. This question suggests that the growth rate estimate is being set equal to 1+.625g. However, 1+.625g is a factor used to adjust the dividend yield when dividends are paid quarterly. As explained on page 14 of Dr. Gaske's Prepared Direct Testimony, the dividend yield was adjusted to reflect the future timing of growth in expected dividend payments. A description of the derivation of this adjustment formula is contained in Attachment A. The expected growth rate is both a factor used to adjust the quarterly dividend yield, and a separate term in the DCF formula. In both instances it is based on analysts' forecasts. Please see response Nos. PSC-074, PSC-076 and PSC-077.

DOES THE FERC DCF MODEL REFLECT THE COMMISSION'S REASONING?

by
J. Stephen Gaske
Vice President, H. Zinder & Associates

In its Order No. 420, issued May 20, 1985, the Federal Energy Regulatory Commission specified that the following Discounted Cash Flow (DCF) rate of return model should be used in establishing the annual generic benchmark rate of return for electric utilities[1]:

$$k = \frac{Do}{Po} [1 + .5 g] + g \qquad (1)$$

where,

k = the cost of common equity capital

Do = the current annual dividend (most recent quarterly dividend multiplied by four)

Po = the current price per share

g = the expected annual dividend growth rate.

In subsequent generic rate of return proceedings the Commission has reaffirmed the use of this model,[2] even though it fails to reflect the Commission's own assumptions regarding the payment of dividends. Whether any given cost-of-capital model is "correct" depends on how well it reflects reasonable assumptions. The purpose of this article is to demonstrate the contrast between the FERC DCF rate of return model and the Commission's stated assumptions regarding the pattern of dividends and dividend increases expected by investors on average.

The reasoning used to justify the FERC DCF model in Order

No. 420 was apparently an attempt to split the difference between the basic constant growth DCF model which assumes that dividends are received annually:

$$k = \frac{Do}{Po} [1 + g] + g \qquad (2)$$

and the constant growth DCF model which assumes that dividends are received continuously:

$$k = \frac{Do}{Po} + g \qquad (3)$$

The Commission believed, with justification, that a realistic model would yield cost of capital estimates that fall somewhere between the estimates produced by equations (2) and (3).

FERC Assumptions

In its Order No. 442, FERC described the assumptions that it thought would be reflected in its DCF model (equation (1)) when it wrote the following:

> The Commission's analytical process in deciding to reevaluate the model formulation was to start with the general form of the DCF model and make certain assumptions. The first two are the standard assumptions that dividends grow at the same rate each year, and that the required rate of return is the same in every period. The next two assumptions reflect (1) the fact that dividends are paid quarterly, and (2) that the annual dividend increase, on average, occurs halfway through the year. The latter assumption was made in the model used in Order No. 420. The Commission there noted that "from the perspective of the average company or the average investor, the next dividend increase is a half year away."3 (emphasis added)

The Commission reiterated its assumption that a dividend increase occurs at mid-year for the typical utility at several other points in Order No. 442.[4] In addition, both the Commission and Staff, in its analyses, have consistently adopted the implicit assumption that the next quarterly dividend will be received in three months.

The DCF model adopted by FERC does not reflect the Commission's assumptions expressed in various orders, however. To see why, it is helpful to assume a hypothetical utility that pays quarterly dividends on a calendar basis on March 31, June 30, September 30, and December 31 each year. Annual dividend increases occur with the fourth quarterly dividend paid each year. If we assume that the middle of the year occurs on July 1, the next end-of-year dividend increase is six months (or a "half year") away.

Analogously, the FERC model assumes that the middle of the calendar year occurs on April 1 and that, on average, annual end-of-year dividend increases are <u>nine months</u> away. This modelling error is described in greater detail in the next section.

Alternatively, the FERC model can be derived by assuming that, on average, the next annual dividend increase is expected in six months, but that the next quarterly dividend payment is expected today. Neither FERC nor its Staff has ever expressed or implied the assumption that, on average, investors expect to receive the next dividend today, however.

<u>A Model Based On FERC Assumptions</u>

If we assume that the middle of the year occurs on July 1, the investor can expect the next dividend at the current rate in three months and the end-of-year dividend increase in six months.

Incorporating the assumptions that "the next dividend increase is a half year away" and the next dividend is one quarter away results in the following DCF model:

$$k = \frac{Do}{4Po}\left[(1+k)^{.75} + \underline{(1+g)}(1+k)^{.5} + (1+g)(1+k)^{.25} + (1+g)\right] + g \qquad (4)$$

The only difference between this model and the FERC model is that this model multiplies the second term in brackets by 1+g. Equation (4) assumes that the next dividend at the current rate will be received in three months, or one-quarter year. The $(1+k)^{.75}$ term in brackets is associated with this first dividend. The second dividend is assumed to be received in six months, or one-half year. To be consistent with the Commission's assumptions, the model shown in equation (4) represents the dividend to be received "a half year away" as including the annual dividend increase, hence, the second term in brackets is $(1+g)(1+k)^{.5}$.

To see the difference in results between this model and the FERC model, assume that a utility currently pays a quarterly dividend of $0.25 per share, that its stock price is $10.00, and that investors expect an annual average rate of growth of five percent. Under these assumptions the FERC model estimates that investors require a rate of return of 15.83 percent while the equation (4) model indicates a required rate of return of 15.97 percent.

<u>Elimination of Dividend Reinvestment Income</u>

The investor required rate of return estimated using equation (4) overstates the required rate of return for ratemaking since it includes the return that investors expect to earn during part of the year by reinvesting the dividends received in the first three quarters of the year.

In an appendix to the FERC Staff Report on Ratemaking Rate of Return that accompanied Order No. 442-A, Staff begins with the version of equation (4) which assumes that, on average, the next dividend increase is expected in nine months and the next dividend is to be received in three months. From this model Staff then proceeds to demonstrate that elimination of the dividend reinvestment portion of the return from the market required rate of return (Staff's version of equation (4)) leads to equation (1).

If, instead, we begin with the Commission's assumption that "the next dividend increase is a half year away," equation (4) describes investors' effective market required rate of return, k-mkt. The required rate of return estimated using this model includes the partial year return which investors have an opportunity to earn on their own by reinvesting the first three quarterly dividends. The portion of the effective market rate of return that is associated with dividend reinvestment is:

$$k\text{-div} = \frac{Do}{4Po}\left(\left[(1+k)^{.75}-1\right]+(1+g)\left[(1+k)^{.5}-1\right]+(1+g)\left[(1+k)^{.25}-1\right]\right) \quad (5)$$

Subtracting equation (5) from equation (4) yields the following required ratemaking rate of return, k-reg:

$$(k\text{-mkt}) - (k\text{-div}) = \frac{Do}{4Po}\left[1 + (1+g) + (1+g) + (1+g)\right] + g$$

$$= k\text{-reg} = \frac{Do}{Po} \; [\; 1 + .75\; g\;] \; + \; g \qquad (6)$$

Equation (6) is the DCF model that correctly reflects the Commission's stated assumptions regarding the timing of dividends and dividend increases. For a utility with a current dividend of \$0.25 per share, stock selling at \$10.00 and an expected growth rate of five percent, this model indicates that the required return for ratemaking is 15.375 percent as opposed to the 15.25 percent indicated by the FERC model (equation (1)). Use of a DCF model in the form of equation (6) will result in an allowed benchmark rate of return equal to the cost of common equity capital for the typical utility under the assumptions that there are quarterly dividends, the next dividend increase is a half year away, and the next dividend is expected in three months. These are the assumptions that FERC has consistently expressed or implied in its various Orders.

An Alternative Model

Since the time that Order No. 420 was issued, FERC has reconsidered its use of the equation (1) model, but in Order Nos. 442-A, 461 and 489 the Commission decided to continue using this model. Apparently, FERC is unaware of the discrepancy between its model and the assumptions that it believes are reflected in its model. This discrepancy is particularly apparent in Order No. 461 where the Commission used a numerical example to demonstrate that its model "...attempts to approximate the average amount of dividends that the average investor (or, equivalently, investors in the average company) would expect to receive during the first

TABLE 1

ORDER NO. 461 EXAMPLE

Dividend Increased During Quarter	Dividend Received 3/31	6/30	9/30	12/31	Total
1	$0.25	$0.25	$0.25	$0.26	$1.01
2	$0.25	$0.25	$0.26	$0.26	$1.02
3	$0.25	$0.26	$0.26	$0.26	$1.03
4	$0.26	$0.26	$0.26	$0.26	$1.04
				Average	$1.025

.025/.05 = .5

.025/.04 = .625

TABLE 2

CORRECTED EXAMPLE

Dividend Increased During Quarter	Dividend Received 3/31	6/30	9/30	12/31	Total
1	$0.25	$0.25	$0.25	$0.2625	$1.0125
2	$0.25	$0.25	$0.2625	$0.2625	$1.0250
3	$0.25	$0.2625	$0.2625	$0.2625	$1.0375
4	$0.2625	$0.2625	$0.2625	$0.2625	$1.0500
				Average	$1.03125

.03125/.05 = .625

year."[5] The numerical example in the Order contained a significant mathematical error, however.

The Order No. 461 example was designed to show the average portion of the expected annual dividend growth rate that an investor would expect to receive during the first year if the annual dividend increase has an equal probability of occurring in any of the next four quarters. The example, reproduced in Table 1, assumes that the stock is purchased on January 1, the most recent quarterly dividend was $0.25 per share, and the dividend growth rate is five percent.

Although it started with the assumption that the dividend growth rate is <u>five</u> percent, the Order No. 461 example erroneously proceeded to show the average dividends that would be paid each quarter if the growth rate is <u>four</u> percent. This can be seen in Table 1 by observing that the increased dividend is $0.26 rather than the $0.2625 which would be required for a five percent growth rate.

The Order No. 461 example divided the average first year dividend increase associated with a four percent growth rate, 2.5 percent, by the five percent growth rate to conclude that the dividend yield multiplier should be [1 + .5g]. However, dividing the average dividend increase in the example by four percent--the increase actually employed in the Order No. 461 example--leads to the conclusion that the Commission's reasoning in Order No. 461 requires the dividend yield multiplier to be [1 + .625g]. The same conclusion is also reached in Table 2 which reflects a five percent annual dividend growth rate and divides the average first year dividend increase by five percent.

Order No. 461 did not provide a reasonable justification for the FERC DCF model. It was only by coincidence that the mathematical error in the example happened to lead, erroneously, to the conclusion that the FERC model correctly reflected the Commission's assumptions. By the reasoning in Order No. 461, if the mathematical error is corrected, the Commission should be using the following DCF model:

$$k = \frac{Do}{Po} \left[1 + .625\, g \right] + g \qquad (7)$$

Although the .625 growth rate factor in equation (7) is at the mid-point between the .75 factor in equation (6) and the .5 factor in the FERC model (equation (1)), equation (7) cannot be derived directly from any reasonable set of assumptions regarding the timing of dividends and dividend increases. It is clearly reasonable to assume that, on average, the next annual dividend increase is a half year away. Both equations (1) and (6) can be derived from this assumption.

On the other hand, since the next quarterly dividend, on average, will be received at the mid-point between today, as assumed in equation (1), and three months from today, as assumed in equation (6), equation (7) could be considered to be an ad hoc model representing a simple average of the dividend timing assumptions in the alternative models given by equations (1) and (6).

Conclusions

As this article points out, Order No. 442 contains a modelling error and Order No. 461 contains a mathematical error in translating the Commission's stated reasoning into an appropriate model for establishing the generic rate of return. As a result, the FERC DCF model does not reflect a reasonable set of assumptions.

It is not posible to construct a quarterly dividend model that satisfies both the assumption that the next dividend increase is a half year (2 quarters) away and the assumption that the next dividend payment is a half quarter away. Equation (7) could be justified as an approximate adjustment to account for the average time until the next quarterly dividend payment. However, since FERC has consistently expressed the assumptions that the next dividend is a full quarter away[6] and the next dividend increase is a half year away, the only model that correctly reflects the Commission's assumptions is equation (6).

Although the difference between equation (6) and the FERC model is likely to lead to a rate of return difference of only 10-12 basis points, the total dollars involved on an industry-wide basis are quite substantial. This is particularly true if other commissions look to the FERC generic rate of return formula as the proper method. The Commission rejected the models given by equations (2) and (3) because these models did not properly reflect reasonable assumptions regarding the timing of dividends and dividend increases. After devoting a great deal of time and effort to establishing reasonable assumptions in its various generic rate of return proceedings, it would be a shame for FERC to continue to use a DCF model that, because of simple mathematical errors, fails to reflect those assumptions.

NOTES

1. FERC Order No. 420, 50 Fed. Reg. at 30,208 (May 29, 1985).

2. FERC Order No. 442-A, 51 Fed. Reg. 22,505 (June 20, 1986); FERC Order No. 461, 52 Fed. Reg. 11 (Jan. 2, 1987); FERC Order No. 489, 53 Fed. Reg. 3,342 (Feb. 5, 1988).

3. FERC Order No. 442, 51 Fed. Reg. 343 (Jan. 6, 1986) at page 19 of the original order.

4. For example, at page 22 of Order No. 442 the Commission quotes the language of Order No. 420 in stating that "...from the perspective of the average company or the average investor, the next dividend increase is a half year away." Similarly, page 23 of Order No. 442 contains the assertion that "(t)he Commission's model assumes a dividend increase occurs at mid-year for the typical utility."

5. FERC Order No. 461 (pages 17-18), quoting Order No. 420, 50 Fed. Reg. at 21,806.

6. For example, see equation (6) at page 19 of Order No. 442 and page 26 where the Commission describes its assumptions.

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PSC-074

Regarding: Retention Growth
Witness: Gaske

a. **Please explain why the 3-5 year retention growth rate is a minimum "cruising speed" that can be maintained indefinitely.**

b. **Did you use the past history of the proxy groups in your model to estimate the accuracy of your model? Please explain.**

c. **Did you use the past history of MDU in the model and compare it to the proxy group to estimate the accuracy of the model group when compared to MDU? Please explain.**

Response:

a. The earnings retention growth rate is widely recognized as a fundamental driver of growth for a company[2] and it is often referred to as "sustainable" growth.[3] However, there are additional drivers for growth which is why analysts' growth rate forecasts can diverge from the retention growth rate forecast. Dr. Gaske has not undertaken a study of the historical accuracy of Value Line's retention/sustainable growth rate forecasts, but it is reasonable to believe that investors rely on this widely-circulated service as a source in forming their expectations concerning future retention growth rates that companies can sustain indefinitely.

The retention growth rates that are forecast to occur 3-5 years in the future generally are normalized in the sense that they do not reflect temporary or short-term variations in the values of the forecast variables. As explained on page 19 of Dr. Gaske's Prepared Direct Testimony, although companies may experience extended periods of growth for other reasons, in the long-term growth in earnings and dividends per share depends in part on the amount of earnings that is being retained and reinvested in the company. Thus, the primary determinants of growth for the proxy companies will be (i) their ability to find and develop profitable opportunities; (ii) their ability to generate profits that can be reinvested in order to sustain growth; and (iii) their willingness and inclination to reinvest available profits. Expected future retention rates provide a general measure of these determinants of expected growth, particularly items (ii) and (iii). For that reason, in Dr. Gaske's view, the retention growth rate forecasts provide a reasonable approximation of the

[2] See, for example, M.E. Gordon, The Cost of Capital to a Public Utility, Michigan State University (1974).
[3] See R.A. Morin, New Regulatory Finance, Public Utility Reports, Inc. (2006), pages 303-308.

minimum sustainable growth rate that companies can be expected to maintain indefinitely in the future.

b. No. This question may reflect a misunderstanding concerning the growth rate estimation process used in Dr. Gaske's analysis. He has not used a model to produce his own forecasts of future growth rates. Instead, because the goal is to determine what growth rates other investors in the market expect when they buy and sell the stocks of the proxy companies, Dr. Gaske is relying on the published forecasts produced by investment analysts which investors rely on to make their investment decisions. As noted in one textbook on this topic:

> *"... caution must be used in extrapolating past trends into the distant future. A more prudent procedure is to rely on analysts' growth forecasts that capture historical trends, the sustainability of such trends, and the expected industry circumstances."*[4]

Since the process of estimating the cost of equity is forward looking, the DCF model assumes that the market price of a share of common stock represents the discounted present value of the stream of all future cash flows that investors expect. For that reason, the relevant growth rate is what investors expect to receive from the firm in the future, and the Value Line retention growth rate forecasts are one indicator of investors' expectations. Dr. Gaske did not compare the Value Line projected retention growth rates for each proxy group company to historical growth rates because such a comparison would not provide useful information concerning investors' expectations for the future. Please see Response Nos. PSC-076 and PSC-077.

c. No, for the same reasons as stated in Response No. PSC-074, parts (a) and (b) above. Further, Dr. Gaske did not perform an individual DCF analysis of MDU Resources Group, Inc.

[4] See R.A. Morin, New Regulatory Finance, Public Utility Reports, Inc. (2006), pages 285-286.

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PSC-075

Regarding: Retention growth DCF cost of capital
Witness: Gaske

In your analysis you state that the cost of equity of the proxy groups ranges from 7.64 percent to 11.48 percent. You go on to state that the median is 9.16 percent and the third quartile is 11.18 percent.

a. Why is the median a more accurate estimation than the mean for the cost of capital? Please provide at least two professional publications by someone other than yourself supporting that position.

b. Please explain why the third quartile is relevant in the estimation of the cost of capital. Please provide at least two professional publications by someone other than yourself supporting that position.

c. Please explain why the first, second and fourth quartiles would not be equally as valid for the estimation of the cost of capital.

Response:

a. Please see response No. PSC-072a.

b. Dr. Gaske's DCF analyses of the proxy group of natural gas distribution companies produce a range of returns for natural gas distribution operations in general. After using a proxy group to establish a range, it is then necessary to position Montana-Dakota's Montana natural gas distribution operations within the range based on the risks of these regulated operations relative to the risks of the proxy companies. Just as the high, the low and the median are commonly used to delineate the characteristics of the proxy results, the quartile values provide a somewhat finer delineation of the data. Dr. Gaske's assessment of the risks faced by Montana-Dakota's Montana natural gas distribution operations relative to the proxy group is used to determine where, within that range of returns, the Company's required ROE falls. Page 33 of Dr. Gaske's Prepared Direct Testimony notes that Montana-Dakota's Montana natural gas distribution operations face overall business risks that are near the top of the range relative to those of the proxy companies. Therefore, as stated on page 35 of his Prepared Direct Testimony, Dr. Gaske recommended an ROE of 10.50 percent which is at the top of the range for his Blended Growth Rate DCF analysis. Dr. Gaske also noted that his recommendation falls between the median and third quartile results of his Retention Growth DCF analysis. Therefore, Dr. Gaske considered the third quartile results of his DCF analyses when recommending an ROE for Montana-Dakota's Montana natural gas distribution operations. Dr. Gaske is not aware of any professional publications that specifically recommend using the third quartile of the proxy group when estimating the cost of capital for Montana-Dakota's Montana natural gas distribution operations. The analysis of the distribution of proxy returns is specifically related to the comparison of risks as between the proxy group and Montana-Dakota's Montana natural gas distribution operations.

c. The first quartile is not relevant to Dr. Gaske's estimation of the cost of equity for Montana-Dakota's Montana natural gas distribution operations because as stated in part (b) above, based on the relative business risk of Montana-Dakota's Montana natural gas distribution operations, the Company's cost of equity falls at the *top* of the range of Dr. Gaske's Blended Growth Rate DCF analysis. The second and fourth quartiles are relevant because they represent the median and maximum results and were considered by Dr. Gaske when recommending an ROE for Montana-Dakota's Montana natural gas distribution operations.

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PSC-076

Regarding: Basic DCF
Witness: Gaske

Please answer the questions concerning the retention growth DCF cost of capital for the basic DCF cost of capital.

Response:

Please see Response No. PSC-074. There is a substantial body of evidence in the finance literature that establishes the validity of using analysts' estimates as the growth rate input for DCF analyses.

For example, a 1986 article entitled "Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return" by Dr. Robert Harris, demonstrated that financial analysts' earnings forecasts (referred to in the article as "FAF") in a Constant Growth DCF formula are an appropriate method of calculating the expected market risk premium.[5] In that regard, Dr. Harris noted that:

...a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices. Such studies typically employ a consensus measure of FAF calculated as a simple average of forecasts by individual analysts.[6]

Dr. Harris further noted that,

Given the demonstrated relationship of FAF to equity prices and the direct theoretical appeal of expectational data, it is no surprise that FAF have been used in conjunction with DCF models to estimate equity return requirements.[7]

In a somewhat later article, Professors Carleton and Vander Weide performed a study to determine whether projected earnings growth rates are superior to historical measures of growth in the implementation of the DCF model.[8] Although the purpose of that study was to "investigate what growth expectation is embodied in the firm's current

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5 Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, 1986 at 66.

6 *Ibid.*, at 59. Emphasis added.

7 *Ibid.*, at 60.

8 James H. Vander Weide, Willard T. Carleton, *Investor growth expectations: Analysts vs. history*, The Journal of Portfolio Management, Spring, 1988.

stock price,"[9] the authors clearly indicate the importance of earnings projections in the context of the DCF model. Professors Carleton and Vander Weide concluded that:

...our studies affirm the superiority of analysts' forecasts over simple historical growth extrapolations in the stock price formation process. Indirectly, this finding lends support to the use of valuation models whose input includes expected growth rates.[10]

Similarly, in an article entitled *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts,* Harris and Marston presented "estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts".[11] In addition to other findings, Harris and Marston reported that,

...in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in estimating return requirements provides reasonable empirical results that can be useful in practical applications.[12]

More recently (2004), the Carleton and Vander Weide study was updated to determine whether the finding that analysts' earnings growth forecasts are relevant in the stock valuation process still holds. The results of that updated study continued to demonstrate the importance of analysts' earnings forecasts, including the application of those forecasts to utility companies.[13] Similarly, Brigham, Shome and Vinson noted that "*evidence in the current literature indicates that (1) analysts' forecasts are superior to forecasts based solely on time series data; and (2) investors do rely on analysts' forecasts.*"[14]

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9 *Ibid.*, at 78.

10 *Ibid.*, at 82.

11 Robert S. Harris, Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992.

12 *Ibid.*, at 63.

13 Advanced Research Center, *Investor Growth Expectations*, Summer, 2004.

14 *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985.

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PSC-077

Regarding: Blended growth rate analysis
Witness: Gaske

Did you compare historical earnings growth rates and retention growth rates in your analysis as a check to determine the validity of your models? Why or why not?

Response:

Please see Response Nos. PSC-074 and PSC-076. This question may reflect a misunderstanding concerning the growth rate estimation process used in Dr. Gaske's analysis. He has not used a model to produce his own forecasts of future growth rates. Instead, because the goal is to determine what growth rates other investors in the market expect when they buy and sell the stocks of the proxy companies, Dr. Gaske is relying on the published forecasts produced by investment analysts which investors rely on to make their investment decisions. It has been shown repeatedly in the finance literature that investors rely on these forecasts and that their values are incorporated in stock prices.

Dr. Gaske considered all three DCF analyses simultaneously when recommending an ROE for Montana-Dakota's Montana natural gas distribution operations.

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PSC-078
Regarding: Risk Premium Approach
Witness: Gaske

a. **Have you done a risk premium approach isolating returns post Lehman Brothers bankruptcy in 2008? If so, please provide your workpapers. If not, why not?**

b. **Did you perform the risk premium approach for the proxy group? If so, please provide your workpaper. If not, why not?**

c. **Were the similarly sized companies included in the proxy group? Please explain.**

Response:

a. As stated on page 24 of Dr. Gaske's Prepared Direct Testimony, his Risk Premium Analysis provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. Dr. Gaske uses the Risk Premium Analysis to test the reasonableness of his DCF results and not as an alternative to the DCF analyses. To the extent that the Lehman Brothers bankruptcy in 2008 caused investors to recognize that ownership of common stock is even more risky than previously believed, Dr. Gaske would expect the equity risk premium between common stocks and corporate bonds would be higher after the Lehman Brothers bankruptcy. However, the time period since the Lehman Brothers bankruptcy has been too short to calculate a meaningful long-term average risk premium comparable to the one in his analysis.

   In order to estimate the current required risk premium for large company common stocks, it is possible to use an alternative approach. Using the Bloomberg Professional service, Dr. Gaske performed a DCF calculation on the S&P 500 companies based on the dividend yields and long-term growth rates as of October 31, 2012. These calculations are shown on Attachment A. The secondary market required ROE for the S&P 500 is 12.79 percent. The average yield on long-term corporate bonds in October 2012 was 3.97 percent. Subtracting this yield from the S&P 500 required return produces an indicated risk premium of 8.82 percent (12.79 – 3.97 = 8.82). In contrast, as discussed on page 25 of Dr. Gaske's testimony, the long-run average risk premium over the return on long-term corporate bonds has been 5.40 percent. This indicates that the current required risk premium is considerably higher than the historical average, which may be the result of the financial market meltdown in 2008.

b. Dr. Gaske's Risk Premium Analysis compares the annual return on large company common stocks to the annual return on long-term corporate bonds from 1926-2011 using data from Ibbotson Associates. In addition, Dr. Gaske performed a similar analysis comparing the returns of small company stocks to returns on long-term corporate bonds over the same time period. Because these risk premiums are for the stock market as a whole, a risk premium analysis for the proxy companies would be identical to the risk premium analysis described in his testimony, except that the size categories for each of the proxies might be different. Dr. Gaske did not perform such calculations for the proxy companies because they would not aid in the task of estimating the cost of common equity for Montana-Dakota's Montana gas distribution operations.

c. No. As shown on Exhibit_(JSG-2), Schedule 2, the gas distribution companies in the proxy group are substantially larger than the natural gas distribution operations of Montana-Dakota in Montana in terms of total assets, operating revenue and operating income. The DCF results for the proxy group do not reflect the additional risk associated with the small size of Montana-Dakota's Montana natural gas distribution operations. For that reason, it is appropriate to choose an ROE toward the upper end of the range of results produced by the DCF analysis. As shown by Dr. Gaske's Risk Premium Analysis, the excess return required by investors for small company stocks is much higher than for large company stocks.

S&P/TSX

Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	BEst Long-Term Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Advantage Oil & Gas Ltd	AAV	168.4	3.60	n/a	n/a	606.2	0.04%	n/a	n/a
Aecon Group Inc	ARE	55.8	11.51	2.43	10.00	642.4	0.04%	0.00%	0.00%
AGF Management Ltd	AGF/B	92.5	9.97	10.83	n/a	921.8	0.06%	0.01%	n/a
Agnico-Eagle Mines Ltd	AEM	171.5	56.39	1.42	16.50	9,672.5	0.58%	0.01%	0.10%
Agrium Inc	AGU	149.3	105.18	0.97	19.52	15,704.6	0.94%	0.01%	0.18%
Aimia Inc	AIM	172.2	14.96	4.28	n/a	2,576.1	0.15%	0.01%	n/a
Alacer Gold Corp	ASR	286.9	5.48	n/a	33.54	1,572.1	0.09%	n/a	0.03%
Alamos Gold Inc	AGI	120.2	19.55	1.00	45.48	2,350.1	0.14%	0.00%	0.06%
Algonquin Power & Utilities Corp	AQN	169.0	6.91	4.49	n/a	1,168.0	0.07%	0.00%	n/a
Alimentation Couche Tard Inc	ATD/B	133.7	49.06	0.61	18.00	6,559.2	0.39%	0.00%	0.07%
Allied Properties Real Estate Investment Trust	AP-U	60.1	31.60	4.18	n/a	1,898.1	0.11%	0.00%	n/a
AltaGas Ltd	ALA	104.5	33.65	4.28	n/a	3,516.0	0.21%	0.01%	n/a
ARC Resources Ltd	ARX	307.0	24.25	4.95	n/a	7,444.0	0.45%	0.02%	n/a
Argonaut Gold Inc	AR	92.6	10.63	n/a	71.00	983.8	0.06%	n/a	0.04%
Artis Real Estate Investment Trust	AX-U	110.1	16.34	6.61	n/a	1,798.2	0.11%	0.01%	n/a
Astral Media Inc	ACM/A	53.1	40.88	n/a	n/a	2,172.4	0.13%	n/a	n/a
Atco Ltd/Canada	ACO/X	50.7	73.79	1.78	n/a	3,744.5	0.22%	0.00%	n/a
Athabasca Oil Corp	ATH	399.6	12.09	n/a	n/a	4,830.6	0.29%	n/a	n/a
Atlantic Power Corp	ATP	119.2	14.96	7.69	n/a	1,784.0	0.11%	0.01%	n/a
AuRico Gold Inc	AUQ	282.1	8.34	n/a	90.50	2,353.0	0.14%	n/a	0.13%
Aurizon Mines Ltd	ARZ	164.4	4.57	n/a	5.00	751.4	0.05%	n/a	0.00%
B2Gold Corp	BTO	392.7	4.13	n/a	96.00	1,621.8	0.10%	n/a	0.09%
Bank of Montreal	BMO	650.2	59.02	4.88	7.00	38,372.3	2.30%	0.11%	0.16%
Bank of Nova Scotia	BNS	1,179.5	54.25	4.20	8.33	63,987.7	3.83%	0.16%	0.32%
Bankers Petroleum Ltd	BNK	252.9	2.84	n/a	n/a	718.3	0.04%	n/a	n/a
Banro Corp	BAA	200.8	4.62	n/a	n/a	927.5	0.06%	n/a	n/a
Barrick Gold Corp	ABX	1,000.6	40.39	1.98	-4.00	40,414.1	2.42%	0.05%	-0.10%
Baytex Energy Corp	BTE	120.7	45.45	5.81	n/a	5,485.0	0.33%	0.02%	n/a
BCE Inc	BCE	774.0	43.66	5.20	3.34	33,795.0	2.03%	0.11%	0.07%
Bell Aliant Inc	BA	227.8	27.12	7.01	3.00	6,178.5	0.37%	0.03%	0.01%
Birchcliff Energy Ltd	BIR	141.5	8.19	n/a	n/a	1,158.9	0.07%	n/a	n/a
Black Diamond Group Ltd	BDI	41.2	21.58	3.34	n/a	888.1	0.05%	0.00%	n/a
BlackPearl Resources Inc	PXX	285.4	3.41	n/a	n/a	973.1	0.06%	n/a	n/a
Boardwalk Real Estate Investment Trust	BEI-U	47.8	64.27	2.99	n/a	3,074.4	0.18%	0.01%	n/a
Bombardier Inc	BBD/B	1,440.4	3.80	2.63	14.37	5,473.3	0.33%	0.01%	0.05%
Bonavista Energy Corp	BNP	169.2	17.91	8.04	n/a	3,030.0	0.18%	0.01%	n/a
Bonterra Energy Corp	BNE	19.8	44.80	6.96	n/a	887.8	0.05%	0.00%	n/a
Brookfield Asset Management Inc	BAM/A	624.1	34.38	1.63	n/a	21,458.1	1.29%	0.02%	n/a
Brookfield Office Properties Inc	BPO	504.1	15.38	3.60	n/a	7,753.8	0.46%	0.02%	n/a
CAE Inc	CAE	258.7	10.99	1.82	12.05	2,843.3	0.17%	0.00%	0.02%
Calfrac Well Services Ltd	CFW	44.7	22.91	4.36	30.70	1,024.4	0.06%	0.00%	0.02%
Calloway Real Estate Investment Trust	CWT-U	107.1	28.95	5.35	n/a	3,100.9	0.19%	0.01%	n/a
Cameco Corp	CCO	395.3	19.37	2.07	6.93	7,657.9	0.46%	0.01%	0.03%
Canadian Apartment Properties REIT	CAR-U	93.7	24.48	4.56	n/a	2,292.6	0.14%	0.01%	n/a
Canadian Imperial Bank of Commerce/Canada	CM	405.8	78.56	4.79	6.67	31,878.5	1.91%	0.09%	0.13%
Canadian National Railway Co	CNR	433.4	86.24	1.74	13.80	37,372.4	2.24%	0.04%	0.31%
Canadian Natural Resources Ltd	CNQ	1,095.2	30.10	1.40	9.00	32,966.4	1.98%	0.03%	0.18%
Canadian Oil Sands Ltd	COS	484.6	21.20	6.60	-8.00	10,272.6	0.62%	0.04%	-0.05%
Canadian Pacific Railway Ltd	CP	172.7	91.88	1.52	15.20	15,870.1	0.95%	0.01%	0.14%
Canadian Real Estate Investment Trust	REF-U	68.0	41.64	3.58	n/a	2,831.1	0.17%	0.01%	n/a
Canadian Tire Corp Ltd	CTC/A	78.0	71.46	1.68	6.65	5,575.3	0.33%	0.01%	0.02%
Canadian Utilities Ltd	CU	87.3	67.00	2.64	n/a	5,852.2	0.35%	0.01%	n/a
Canadian Western Bank	CWB	78.3	29.56	2.17	10.00	2,315.4	0.14%	0.00%	0.01%
Canexus Corp	CUS	121.9	8.58	6.38	n/a	1,045.7	0.06%	0.00%	n/a
Canfor Corp	CFP	142.8	14.24	n/a	n/a	2,032.8	0.12%	n/a	n/a
Capital Power Corp	CPX	69.6	21.41	5.89	n/a	1,490.6	0.09%	0.01%	n/a
Capstone Mining Corp	CS	381.3	2.47	n/a	18.00	941.8	0.06%	n/a	0.01%
Catamaran Corp	CCT	205.1	46.90	n/a	25.50	9,618.5	0.58%	n/a	0.15%
CCL Industries Inc	CCL/B	31.4	36.98	2.11	n/a	1,160.7	0.07%	0.00%	n/a
Celestica Inc	CLS	186.2	7.25	n/a	10.00	1,350.0	0.08%	n/a	0.01%
Celtic Exploration Ltd	CLT	105.7	26.08	n/a	n/a	2,757.0	0.17%	n/a	n/a
Cenovus Energy Inc	CVE	754.8	35.23	2.50	11.00	26,592.4	1.59%	0.04%	0.18%
Centerra Gold Inc	CG	236.4	11.33	1.41	136.50	2,678.1	0.16%	0.00%	0.22%
CGI Group Inc	GIB/A	272.5	26.13	n/a	10.00	7,121.4	0.43%	n/a	0.04%
Chartwell Seniors Housing Real Estate Investment Trust	CSH-U	171.0	10.27	5.26	n/a	1,756.2	0.11%	0.01%	n/a
China Gold International Resources Corp Ltd	CGG	396.3	4.25	n/a	n/a	1,684.4	0.10%	n/a	n/a
Chorus Aviation Inc	CHR/B	105.4	3.11	19.29	n/a	327.9	0.02%	0.00%	n/a
CI Financial Corp	CIX	283.1	23.34	4.11	n/a	6,607.6	0.40%	0.02%	n/a
Cineplex Inc	CGX	62.0	31.00	4.35	n/a	1,922.9	0.12%	0.01%	n/a
CML HealthCare Inc	CLC	89.8	8.47	8.91	-8.00	760.9	0.05%	0.00%	0.00%
Cogeco Cable Inc	CCA	33.1	38.16	2.62	13.03	1,263.8	0.08%	0.00%	0.01%
Colossus Minerals Inc	CSI	106.3	5.67	n/a	n/a	602.6	0.04%	n/a	n/a
Cominar Real Estate Investment Trust	CUF-U	123.6	23.85	6.04	n/a	2,947.5	0.18%	0.01%	n/a
Constellation Software Inc/Canada	CSU	21.2	114.56	3.49	n/a	2,427.6	0.15%	0.01%	n/a
Corus Entertainment Inc	CJR/B	79.9	22.61	4.25	7.10	1,807.1	0.11%	0.00%	0.01%
Cott Corp	BCB	95.2	7.63	n/a	n/a	726.4	0.04%	n/a	n/a
Crescent Point Energy Corp	CPG	348.8	41.50	6.65	n/a	14,477.0	0.87%	0.06%	n/a
Crew Energy Inc	CR	120.8	7.69	n/a	n/a	929.2	0.06%	n/a	n/a
Crombie Real Estate Investment Trust	CRR-U	49.9	15.09	5.90	n/a	752.4	0.05%	0.00%	n/a

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Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	BEst Long-Term Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Davis & Henderson Corp	DH	59.2	20.96	5.92	n/a	1,241.5	0.07%	0.00%	n/a
Denison Mines Corp	DML	384.7	1.29	n/a	n/a	496.2	0.03%	n/a	n/a
Detour Gold Corp	DGC	112.7	28.14	n/a	5.00	3,170.0	0.19%	n/a	0.01%
Dollarama Inc	DOL	73.8	63.09	0.70	20.00	4,658.6	0.28%	0.00%	0.06%
Dorel Industries Inc	DII/B	27.2	35.71	3.32	16.00	971.0	0.06%	0.00%	0.01%
Dundee Corp	DC/A	51.9	25.10	n/a	n/a	1,301.5	0.08%	n/a	n/a
Dundee Precious Metals Inc	DPM	125.4	9.19	n/a	n/a	1,152.9	0.07%	n/a	n/a
Dundee Real Estate Investment Trust	D-U	96.8	36.65	5.99	n/a	3,549.3	0.21%	0.01%	n/a
Eldorado Gold Corp	ELD	713.1	14.76	0.81	65.50	10,525.0	0.63%	0.01%	0.41%
Emera Inc	EMA	123.9	34.90	4.01	n/a	4,325.1	0.26%	0.01%	n/a
Empire Co Ltd	EMP/A	33.7	58.19	1.65	7.00	1,960.3	0.12%	0.00%	0.01%
Enbridge Inc	ENB	797.6	39.74	2.84	11.50	31,695.0	1.90%	0.05%	0.22%
Enbridge Income Fund Holdings Inc	ENF	39.7	23.25	5.32	n/a	924.0	0.06%	0.00%	n/a
Encana Corp	ECA	736.3	22.50	3.55	30.00	16,566.8	0.99%	0.04%	0.30%
Endeavour Silver Corp	EDR	99.2	9.07	n/a	n/a	899.6	0.05%	n/a	n/a
Enerflex Ltd	EFX	77.6	11.53	2.08	n/a	895.2	0.05%	0.00%	n/a
Enerplus Corp	ERF	197.8	16.05	6.73	n/a	3,174.0	0.19%	0.01%	n/a
Ensign Energy Services Inc	ESI	153.2	14.93	2.81	23.80	2,287.5	0.14%	0.00%	0.03%
Extendicare Inc/US	EXE	85.3	8.17	10.28	n/a	697.3	0.04%	0.00%	n/a
Fairfax Financial Holdings Ltd	FFH	19.6	370.51	2.74	n/a	7,254.6	0.43%	0.01%	n/a
Finning International Inc	FTT	171.9	23.45	2.39	10.00	4,030.8	0.24%	0.01%	0.02%
First Capital Realty Inc	FCR	201.4	18.50	4.54	n/a	3,725.3	0.22%	0.01%	n/a
First Majestic Silver Corp	FR	115.6	23.09	n/a	10.00	2,669.2	0.16%	n/a	0.02%
First Quantum Minerals Ltd	FM	476.3	22.45	0.54	10.39	10,693.2	0.64%	0.00%	0.07%
FirstService Corp/Canada	FSV	28.7	28.71	n/a	13.00	824.1	0.05%	n/a	0.01%
Fortis Inc/Canada	FTS	190.1	33.77	3.55	n/a	6,420.0	0.38%	0.01%	n/a
Fortuna Silver Mines Inc	FVI	125.3	5.54	n/a	28.00	694.0	0.04%	n/a	0.01%
Franco-Nevada Corp	FNV	145.6	57.51	1.04	4.00	8,374.2	0.50%	0.01%	0.02%
Freehold Royalties Ltd	FRU	65.7	20.28	8.28	n/a	1,333.2	0.08%	0.01%	n/a
Gabriel Resources Ltd	GBU	380.1	2.42	n/a	n/a	919.8	0.06%	n/a	n/a
Genivar Inc	GNV	50.8	21.81	6.88	n/a	1,106.9	0.07%	0.00%	n/a
Genworth MI Canada Inc	MIC	98.7	20.46	6.26	n/a	2,019.3	0.12%	0.01%	n/a
George Weston Ltd	WN	128.2	64.84	2.22	10.00	8,311.8	0.50%	0.01%	0.05%
Gibson Energy Inc	GEI	101.2	22.96	4.53	n/a	2,322.5	0.14%	0.01%	n/a
Gildan Activewear Inc	GIL	121.6	34.01	0.87	13.67	4,135.4	0.25%	0.00%	0.03%
Goldcorp Inc	G	811.2	45.15	1.17	45.50	36,626.4	2.20%	0.03%	1.00%
Granite Real Estate Inc	GRT	46.8	36.62	5.46	n/a	1,715.0	0.10%	0.01%	n/a
Great-West Lifeco Inc	GWO	949.8	23.00	5.35	9.00	21,845.9	1.31%	0.07%	0.12%
H&R Real Estate Investment Trust	HR-U	187.5	24.13	5.18	n/a	4,525.3	0.27%	0.01%	n/a
Harry Winston Diamond Corp	HW	84.9	14.33	n/a	n/a	1,216.3	0.07%	n/a	n/a
Home Capital Group Inc	HCG	34.7	50.85	1.73	n/a	1,764.0	0.11%	0.00%	n/a
HudBay Minerals Inc	HBM	172.0	9.27	2.16	16.00	1,594.1	0.10%	0.00%	0.02%
Husky Energy Inc	HSE	982.0	27.05	4.44	1.00	26,563.4	1.59%	0.07%	0.02%
IAMGOLD Corp	IMG	376.2	15.50	1.67	6.50	5,831.0	0.35%	0.01%	0.02%
IGM Financial Inc	IGM	253.3	39.63	5.43	n/a	10,037.3	0.60%	0.03%	n/a
Imperial Oil Ltd	IMO	847.6	44.19	1.09	2.00	37,455.4	2.24%	0.02%	0.04%
Industrial Alliance Insurance & Financial Services Inc	IAG	90.6	27.35	3.58	9.00	2,477.4	0.15%	0.01%	0.01%
Inmet Mining Corp	IMN	69.4	51.50	0.39	1.61	3,572.3	0.21%	0.00%	0.00%
Intact Financial Corp	IFC	129.6	61.25	2.61	n/a	7,935.2	0.48%	0.01%	n/a
Inter Pipeline Fund	IPL-U	271.5	22.03	4.77	n/a	5,981.9	0.36%	0.02%	n/a
Jean Coutu Group PJC Inc/The	PJC/A	102.5	15.01	1.87	6.00	1,537.8	0.09%	0.00%	0.01%
Just Energy Group Inc	JE	139.4	10.22	12.13	n/a	1,424.4	0.09%	0.01%	n/a
Keyera Corp	KEY	77.3	48.48	4.21	n/a	3,748.7	0.22%	0.01%	n/a
Kinross Gold Corp	K	1,139.5	9.92	1.57	28.00	11,304.0	0.68%	0.01%	0.19%
Kirkland Lake Gold Inc	KGI	70.2	9.86	n/a	n/a	691.7	0.04%	n/a	n/a
Labrador Iron Ore Royalty Corp	LIF	64.0	29.25	5.13	42.00	1,872.0	0.11%	0.01%	0.05%
Lake Shore Gold Corp	LSG	415.6	0.80	n/a	n/a	332.5	0.02%	n/a	n/a
Laurentian Bank of Canada	LB	28.1	44.45	4.23	5.00	1,249.8	0.07%	0.00%	0.00%
Legacy Oil + Gas Inc	LEG	143.3	7.14	n/a	n/a	1,023.3	0.06%	n/a	n/a
Linamar Corp	LNR	64.7	22.00	1.45	n/a	1,423.6	0.09%	0.00%	n/a
Loblaw Cos Ltd	L	281.5	34.62	2.43	9.00	9,743.9	0.58%	0.01%	0.05%
Lundin Mining Corp	LUN	582.9	5.20	n/a	9.56	3,031.1	0.18%	n/a	0.02%
MacDonald Dettwiler & Associates Ltd	MDA	31.8	56.00	2.32	6.00	1,783.2	0.11%	0.00%	0.01%
Magna International Inc	MG	233.5	44.40	2.45	10.91	10,369.5	0.62%	0.02%	0.07%
Major Drilling Group International	MDI	79.1	10.33	1.94	n/a	817.6	0.05%	0.00%	n/a
Manitoba Telecom Services Inc	MBT	66.7	33.53	5.07	3.71	2,237.8	0.13%	0.01%	0.00%
Manulife Financial Corp	MFC	1,814.7	12.34	4.21	10.00	22,393.3	1.34%	0.06%	0.13%
Maple Leaf Foods Inc	MFI	140.0	11.10	1.44	n/a	1,554.5	0.09%	0.00%	n/a
Martinrea International Inc	MRE	83.0	7.18	n/a	n/a	595.9	0.04%	n/a	n/a
MEG Energy Corp	MEG	194.7	36.48	n/a	35.00	7,102.9	0.43%	n/a	0.15%
Methanex Corp	MX	94.0	29.94	2.41	27.50	2,813.6	0.17%	0.00%	0.05%
Metro Inc	MRU	97.4	58.92	1.46	8.00	5,741.4	0.34%	0.01%	0.03%
Mullen Group Ltd	MTL	81.1	20.71	4.83	18.90	1,680.5	0.10%	0.00%	0.02%
National Bank of Canada	NA	161.9	77.18	4.09	8.50	12,494.6	0.75%	0.03%	0.06%
Nevsun Resources Ltd	NSU	199.1	4.73	2.17	19.00	941.6	0.06%	0.00%	0.01%
New Gold Inc	NGD	462.2	11.69	n/a	24.50	5,402.6	0.32%	n/a	0.08%
Nexen Inc	NXY	530.0	23.85	0.84	-26.00	12,640.6	0.76%	0.01%	-0.20%
Niko Resources Ltd	NKO	51.6	12.72	n/a	n/a	656.9	0.04%	n/a	n/a
Nordion Inc	NDN	62.0	6.50	n/a	n/a	402.7	0.02%	n/a	n/a

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Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	BEst Long-Term Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
North West Co Inc/The	NWC	48.4	23.40	4.44	n/a	1,132.0	0.07%	0.00%	n/a
Northern Property Real Estate Investment Trust	NPR-U	31.9	31.34	4.88	n/a	1,001.2	0.06%	0.00%	n/a
Northland Power Inc	NPI	85.3	19.36	5.58	n/a	1,650.5	0.10%	0.01%	n/a
Novagold Resources Inc	NG	279.8	4.85	n/a	n/a	1,357.0	0.08%	n/a	n/a
OceanaGold Corp	OGC	263.3	3.50	n/a	n/a	921.5	0.06%	n/a	n/a
Onex Corp	OCX	114.9	40.20	0.27	n/a	4,618.6	0.28%	0.00%	n/a
Open Text Corp	OTC	58.4	53.68	n/a	10.00	3,137.3	0.19%	n/a	0.02%
Osisko Mining Corp	OSK	388.8	9.81	n/a	147.00	3,814.5	0.23%	n/a	0.34%
Pacific Rubiales Energy Corp	PRE	295.1	23.49	1.82	29.81	6,932.7	0.42%	0.01%	0.12%
Pan American Silver Corp	PAA	152.3	21.91	0.91	18.50	3,336.4	0.20%	0.00%	0.04%
Paramount Resources Ltd	POU	89.8	33.80	n/a	n/a	3,033.7	0.18%	n/a	n/a
Parkland Fuel Corp	PKI	66.9	17.04	5.99	-4.70	1,140.2	0.07%	0.00%	0.00%
Pason Systems Inc	PSI	82.0	16.27	2.70	32.70	1,333.7	0.08%	0.00%	0.03%
Pembina Pipeline Corp	PPL	289.6	27.93	5.80	n/a	8,089.1	0.48%	0.03%	n/a
Pengrowth Energy Corp	PGF	505.4	5.99	8.01	n/a	3,027.6	0.18%	0.01%	n/a
Penn West Petroleum Ltd	PWT	476.9	12.97	8.33	n/a	6,185.6	0.37%	0.03%	n/a
PetroBakken Energy Ltd	PBN	173.5	12.61	7.61	n/a	2,187.3	0.13%	0.01%	n/a
Petrobank Energy & Resources Ltd	PBG	99.6	13.72	n/a	n/a	1,367.2	0.08%	n/a	n/a
Petrominerales Ltd	PMG	89.7	8.01	6.24	n/a	718.2	0.04%	0.00%	n/a
Peyto Exploration & Development Corp	PEY	143.9	24.40	2.95	n/a	3,510.9	0.21%	0.01%	n/a
Poseidon Concepts Corp	PSN	81.1	14.77	7.31	n/a	1,197.8	0.07%	0.01%	n/a
Potash Corp of Saskatchewan Inc	POT	861.6	40.15	2.05	3.13	34,594.4	2.07%	0.04%	0.06%
Power Corp of Canada	POW	411.1	24.23	4.79	n/a	9,962.0	0.60%	0.03%	n/a
Power Financial Corp	PWF	708.2	25.78	5.43	n/a	18,256.7	1.09%	0.06%	n/a
Precision Drilling Corp	PD	276.3	7.15	n/a	29.70	1,975.7	0.12%	n/a	0.04%
Premier Gold Mines Ltd	PG	149.0	5.61	n/a	n/a	835.9	0.05%	n/a	n/a
Pretium Resources Inc	PVG	94.8	13.54	n/a	n/a	1,284.0	0.08%	n/a	n/a
Primaris Retail Real Estate Investment Trust	PMZ-U	92.8	23.41	5.21	n/a	2,172.7	0.13%	0.01%	n/a
Progress Energy Resources Corp	PRQ	235.7	20.12	n/a	n/a	4,741.9	0.28%	n/a	n/a
Progressive Waste Solutions Ltd	BIN	115.0	19.33	2.90	4.25	2,222.0	0.13%	0.00%	0.01%
Quebecor Inc	QBR/B	43.4	34.84	0.57	3.34	1,512.0	0.09%	0.00%	0.00%
Reitmans Canada Ltd	RET/A	52.1	12.42	6.44	12.00	647.7	0.04%	0.00%	0.00%
Research In Motion Ltd	RIM	524.2	7.88	n/a	17.50	4,130.4	0.25%	n/a	0.04%
Rio Alto Mining Ltd	RIO	173.9	5.67	n/a	14.00	986.2	0.06%	n/a	0.01%
RioCan Real Estate Investment Trust	REI-U	295.9	27.24	5.07	n/a	8,061.5	0.48%	0.02%	n/a
Rogers Communications Inc	RCI/B	402.8	43.84	3.60	10.47	17,658.1	1.06%	0.04%	0.11%
RONA Inc	RON	121.4	10.26	1.36	n/a	1,245.5	0.07%	0.00%	n/a
Royal Bank of Canada	RY	1,444.4	56.94	4.22	6.77	82,244.1	4.93%	0.21%	0.33%
Rubicon Minerals Corp	RMX	287.6	3.54	n/a	n/a	1,018.1	0.06%	n/a	n/a
Russel Metals Inc	RUS	60.1	27.90	5.02	n/a	1,678.1	0.10%	0.01%	n/a
Saputo Inc	SAP	197.0	43.83	1.92	10.00	8,632.3	0.52%	0.01%	0.05%
Savanna Energy Services Corp	SVY	85.4	6.95	5.18	80.00	593.2	0.04%	0.00%	0.03%
Secure Energy Services Inc	SES	104.2	9.55	n/a	n/a	995.1	0.06%	n/a	n/a
SEMAFO Inc	SMF	273.2	4.00	1.00	n/a	1,092.8	0.07%	0.00%	n/a
Shaw Communications Inc	SJR/B	421.2	21.76	4.46	5.10	9,165.1	0.55%	0.02%	0.03%
ShawCor Ltd	SCL/A	57.4	44.50	0.90	n/a	2,555.5	0.15%	0.00%	n/a
Sherritt International Corp	S	296.9	4.32	3.52	31.00	1,282.8	0.08%	0.00%	0.02%
Shoppers Drug Mart Corp	SC	207.3	41.63	2.55	5.00	8,628.7	0.52%	0.01%	0.03%
Silver Standard Resources Inc	SSO	80.7	15.17	n/a	n/a	1,224.9	0.07%	n/a	n/a
Silver Wheaton Corp	SLW	353.9	40.25	0.98	16.56	14,243.8	0.85%	0.01%	0.14%
Silvercorp Metals Inc	SVM	170.7	6.19	1.62	n/a	1,056.8	0.06%	0.00%	n/a
SNC-Lavalin Group Inc	SNC	151.0	40.23	2.19	8.00	6,076.0	0.36%	0.01%	0.03%
Stantec Inc	STN	45.8	34.40	1.74	11.50	1,575.4	0.09%	0.00%	0.01%
Sun Life Financial Inc	SLF	594.1	24.77	5.81	9.00	14,715.9	0.88%	0.05%	0.08%
Suncor Energy Inc	SU	1,535.9	33.52	1.55	-5.00	51,482.3	3.09%	0.05%	-0.15%
Superior Plus Corp	SPB	112.2	9.76	6.15	n/a	1,095.5	0.07%	0.00%	n/a
Tahoe Resources Inc	THO	145.4	20.36	n/a	n/a	2,961.0	0.18%	n/a	n/a
Talisman Energy Inc	TLM	1,032.3	11.32	2.38	5.00	11,686.1	0.70%	0.02%	0.04%
Taseko Mines Ltd	TKO	190.5	2.73	n/a	36.00	520.1	0.03%	n/a	0.01%
Teck Resources Ltd	TCK/B	576.7	31.70	2.52	-0.06	18,280.2	1.10%	0.03%	0.00%
TELUS Corp	T	174.9	64.84	3.76	7.77	11,341.2	0.68%	0.03%	0.05%
Thompson Creek Metals Co Inc	TCM	168.7	2.62	n/a	54.50	442.1	0.03%	n/a	0.01%
Thomson Reuters Corp	TRI	825.5	28.12	4.49	9.00	23,214.4	1.39%	0.06%	0.13%
Tim Hortons Inc	THI	154.7	49.58	1.69	12.00	7,669.5	0.46%	0.01%	0.06%
TMX Group Ltd	X	53.7	51.08	n/a	n/a	2,744.3	0.16%	n/a	n/a
Torex Gold Resources Inc	TXG	603.2	2.08	n/a	n/a	1,254.6	0.08%	n/a	n/a
Toromont Industries Ltd	TIH	76.3	19.60	2.45	n/a	1,495.2	0.09%	0.00%	n/a
Toronto-Dominion Bank/The	TD	914.0	81.23	3.79	8.27	74,245.8	4.45%	0.17%	0.37%
Tourmaline Oil Corp	TOU	165.2	33.00	n/a	n/a	5,450.6	0.33%	n/a	n/a
TransAlta Corp	TA	251.1	15.92	7.29	n/a	3,998.2	0.24%	0.02%	n/a
TransCanada Corp	TRP	704.9	44.97	3.91	n/a	31,700.5	1.90%	0.07%	n/a
Transcontinental Inc	TCL/A	65.5	10.30	5.63	3.00	675.0	0.04%	0.00%	0.00%
TransForce Inc	TFI	93.7	18.23	2.85	n/a	1,707.4	0.10%	0.00%	n/a
TransGlobe Energy Corp	TGL	73.4	10.76	n/a	n/a	790.2	0.05%	n/a	n/a
Trican Well Service Ltd	TCW	146.4	11.92	2.52	8.80	1,745.6	0.10%	0.00%	0.01%
Trilogy Energy Corp	TET	90.8	27.34	1.54	n/a	2,481.4	0.15%	0.00%	n/a
Trinidad Drilling Ltd	TDG	120.9	6.62	3.02	n/a	800.1	0.05%	0.00%	n/a
Turquoise Hill Resources Ltd	TRQ	1,001.6	7.81	n/a	n/a	7,822.3	0.47%	n/a	n/a
Uranium One Inc	UUU	957.2	2.17	n/a	53.00	2,077.1	0.12%	n/a	0.07%

S&P/TSX

Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	BEst Long-Term Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth	Secondary Market Investor Required Return	Flotation Cost Adj.	Primary Market Cost of Capital
Valeant Pharmaceuticals International Inc	VRX	298.1	55.80	n/a	15.33	16,631.9	1.00%	n/a	0.15%			
Veresen Inc	VSN	196.6	12.89	7.75	n/a	2,534.4	0.15%	0.01%	n/a			
Vermilion Energy Inc	VET	98.6	47.75	4.77	n/a	4,707.4	0.28%	0.01%	n/a			
Viterra Inc	VT	371.8	15.74	0.95	n/a	5,851.9	0.35%	0.00%	n/a			
Wajax Corp	WJX	16.7	44.70	7.25	n/a	748.1	0.04%	0.00%	n/a			
West Fraser Timber Co Ltd	WFT	42.9	60.49	0.93	n/a	2,592.7	0.16%	0.00%	n/a			
Westjet Airlines Ltd	WJA	126.3	18.05	1.77	30.39	2,279.6	0.14%	0.00%	0.04%			
Westport Innovations Inc	WPT	55.0	27.90	n/a	30.00	1,534.8	0.09%	n/a	0.03%			
Westshore Terminals Investment Corp	WTE	74.3	28.32	4.66	n/a	2,102.8	0.13%	0.01%	n/a			
Whitecap Resources Inc	WCP	127.1	7.95	n/a	n/a	1,010.4	0.06%	n/a	n/a			
Wi-Lan Inc	WIN	121.3	5.32	2.63	20.00	645.3	0.04%	0.00%	0.01%			
Yamana Gold Inc	YRI	751.5	20.17	1.29	35.70	15,157.0	0.91%	0.01%	0.32%			
								2.99%	8.59%	**11.71%**	1.04	**12.18%**

S&P 500

Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	BEst Long-Term Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
3M Co	MMM	691.9	87.60	2.69	11.50	60,613.2	0.46%	0.01%	0.05%
Abbott Laboratories	ABT	1,569.3	65.52	3.11	10.04	102,822.8	0.79%	0.02%	0.08%
Abercrombie & Fitch Co	ANF	82.6	30.58	2.29	18.50	2,525.1	0.02%	0.00%	0.00%
Accenture PLC	ACN	750.5	67.41	2.40	12.50	50,590.1	0.39%	0.01%	0.05%
ACE Ltd	ACE	339.8	78.65	2.49	9.65	26,725.9	0.20%	0.01%	0.02%
Adobe Systems Inc	ADBE	495.1	34.00	n/a	11.40	16,831.9	0.13%	n/a	0.01%
ADT Corp/The	ADT	229.9	41.51	n/a	n/a	9,541.5	0.07%	n/a	n/a
Advanced Micro Devices Inc	AMD	707.6	2.05	n/a	4.50	1,450.5	0.01%	n/a	0.00%
AES Corp/VA	AES	748.0	10.45	1.53	8.50	7,816.6	0.06%	0.00%	0.01%
Aetna Inc	AET	334.5	43.70	1.60	10.50	14,617.7	0.11%	0.00%	0.01%
Aflac Inc	AFL	468.7	49.78	2.81	14.77	23,333.1	0.18%	0.01%	0.03%
Agilent Technologies Inc	A	348.4	35.99	1.11	10.52	12,540.5	0.10%	0.00%	0.01%
AGL Resources Inc	GAS	117.5	40.83	4.51	4.00	4,798.2	0.04%	0.00%	0.00%
Air Products & Chemicals Inc	APD	211.7	77.53	3.30	10.69	16,413.6	0.13%	0.00%	0.01%
Airgas Inc	ARG	77.0	88.97	1.80	12.46	6,854.4	0.05%	0.00%	0.01%
Akamai Technologies Inc	AKAM	177.3	37.99	n/a	14.50	6,735.9	0.05%	n/a	0.01%
Alcoa Inc	AA	1,067.2	8.57	1.40	10.00	9,145.9	0.07%	0.00%	0.01%
Alexion Pharmaceuticals Inc	ALXN	194.3	90.38	n/a	40.23	17,559.6	0.13%	n/a	0.05%
Allegheny Technologies Inc	ATI	107.2	26.35	2.73	15.00	2,824.7	0.02%	0.00%	0.00%
Allergan Inc/United States	AGN	301.0	89.92	0.22	13.61	27,063.0	0.21%	0.00%	0.03%
Allstate Corp/The	ALL	418.2	39.98	2.20	9.00	16,720.5	0.13%	0.00%	0.01%
Altera Corp	ALTR	320.6	30.48	1.31	7.75	9,771.1	0.07%	0.00%	0.01%
Altria Group Inc	MO	2,025.1	31.80	5.53	6.90	64,398.4	0.49%	0.03%	0.03%
Amazon.com Inc	AMZN	453.0	232.82	n/a	32.26	105,457.7	0.81%	n/a	0.26%
Ameren Corp	AEE	242.6	32.88	4.87	-4.00	7,977.8	0.06%	0.00%	0.00%
American Electric Power Co Inc	AEP	485.2	44.44	4.23	4.33	21,564.5	0.17%	0.01%	0.01%
American Express Co	AXP	1,119.1	55.97	1.43	9.68	62,633.9	0.48%	0.01%	0.05%
American International Group Inc	AIG	1,476.3	34.93	n/a	12.33	51,566.7	0.40%	n/a	0.05%
American Tower Corp	AMT	395.4	75.29	1.22	17.93	29,766.1	0.23%	0.00%	0.04%
Ameriprise Financial Inc	AMP	207.4	58.37	3.08	10.55	12,105.9	0.09%	0.00%	0.01%
AmerisourceBergen Corp	ABC	251.6	39.44	1.32	12.00	9,924.6	0.08%	0.00%	0.01%
Amgen Inc	AMGN	768.0	86.55	1.66	9.34	66,466.6	0.51%	0.01%	0.05%
Amphenol Corp	APH	161.0	60.13	0.70	18.50	9,680.1	0.07%	0.00%	0.01%
Anadarko Petroleum Corp	APC	499.8	68.81	0.52	7.60	34,388.4	0.26%	0.00%	0.02%
Analog Devices Inc	ADI	298.9	39.11	3.07	12.33	11,690.2	0.09%	0.00%	0.01%
Aon PLC	AON	318.7	53.95	1.17	8.33	17,192.1	0.13%	0.00%	0.01%
Apache Corp	APA	391.2	82.75	0.82	7.85	32,373.0	0.25%	0.00%	0.02%
Apartment Investment & Management Co	AIV	145.5	26.69	3.00	9.44	3,884.6	0.03%	0.00%	0.00%
Apollo Group Inc	APOL	111.9	20.08	n/a	9.80	2,247.6	0.02%	n/a	0.00%
Apple Inc	AAPL	940.7	595.10	1.78	21.27	559,805.8	4.29%	0.08%	0.91%
Applied Materials Inc	AMAT	1,237.5	10.60	3.40	8.67	13,117.4	0.10%	0.00%	0.01%
Archer-Daniels-Midland Co	ADM	658.6	26.84	2.61	10.00	17,677.5	0.14%	0.00%	0.01%
Assurant Inc	AIZ	78.7	37.81	2.22	11.00	2,975.9	0.02%	0.00%	0.00%
AT&T Inc	T	5,707.0	34.59	5.09	6.50	197,405.1	1.51%	0.08%	0.10%
Autodesk Inc	ADSK	226.9	31.84	n/a	16.20	7,224.5	0.06%	n/a	0.01%
Automatic Data Processing Inc	ADP	484.5	57.79	2.73	9.67	27,999.5	0.21%	0.01%	0.02%
AutoNation Inc	AN	121.8	44.40	n/a	20.48	5,406.3	0.04%	n/a	0.01%
AutoZone Inc	AZO	36.9	375.00	n/a	16.65	13,849.5	0.11%	n/a	0.02%
AvalonBay Communities Inc	AVB	96.9	135.56	2.86	10.14	13,137.1	0.10%	0.00%	0.01%
Avery Dennison Corp	AVY	101.5	32.38	3.34	7.00	3,285.4	0.03%	0.00%	0.00%
Avon Products Inc	AVP	432.1	15.49	5.94	-0.06	6,692.7	0.05%	0.00%	0.00%
Baker Hughes Inc	BHI	439.6	41.97	1.43	23.00	18,452.0	0.14%	0.00%	0.03%
Ball Corp	BLL	154.7	42.83	0.93	10.00	6,627.1	0.05%	0.00%	0.01%
Bank of America Corp	BAC	10,777.3	9.32	0.43	13.45	100,444.1	0.77%	0.00%	0.10%
Bank of New York Mellon Corp/The	BK	1,168.6	24.71	2.10	17.63	28,876.3	0.22%	0.00%	0.04%
Baxter International Inc	BAX	547.2	62.63	2.87	9.00	34,273.1	0.26%	0.01%	0.02%
BB&T Corp	BBT	699.5	28.95	2.76	6.50	20,251.7	0.16%	0.00%	0.01%
Beam Inc	BEAM	158.4	55.56	1.48	12.81	8,798.9	0.07%	0.00%	0.01%
Becton Dickinson and Co	BDX	199.6	75.68	2.38	7.40	15,102.3	0.12%	0.00%	0.01%
Bed Bath & Beyond Inc	BBBY	229.2	57.68	n/a	14.70	13,220.1	0.10%	n/a	0.01%
Bemis Co Inc	BMS	103.3	33.05	3.03	6.00	3,413.4	0.03%	0.00%	0.00%
Berkshire Hathaway Inc	BRK/B	1,086.4	86.35	n/a	n/a	93,809.0	0.72%	n/a	n/a
Best Buy Co Inc	BBY	336.7	15.21	4.47	5.08	5,120.7	0.04%	0.00%	0.00%
Big Lots Inc	BIG	59.6	29.13	n/a	11.45	1,735.1	0.01%	n/a	0.00%
Biogen Idec Inc	BIIB	236.6	138.22	n/a	15.83	32,702.4	0.25%	n/a	0.04%
BlackRock Inc	BLK	167.2	189.68	3.16	12.67	31,709.8	0.24%	0.01%	0.03%
BMC Software Inc	BMC	159.5	40.70	n/a	12.50	6,490.2	0.05%	n/a	0.01%
Boeing Co/The	BA	754.1	70.44	2.50	11.17	53,117.2	0.41%	0.01%	0.05%
BorgWarner Inc	BWA	117.0	65.82	n/a	19.55	7,703.4	0.06%	n/a	0.01%
Boston Properties Inc	BXP	150.9	106.30	2.07	5.78	16,036.0	0.12%	0.00%	0.01%
Boston Scientific Corp	BSX	1,372.9	5.14	n/a	9.57	7,056.6	0.05%	n/a	0.01%
Bristol-Myers Squibb Co	BMY	1,650.7	33.25	4.09	7.18	54,885.4	0.42%	0.02%	0.03%
Broadcom Corp	BRCM	512.0	31.54	1.27	15.00	16,145.9	0.12%	0.00%	0.02%
Brown-Forman Corp	BF/B	128.9	64.06	1.46	12.50	8,254.5	0.06%	0.00%	0.01%
CA Inc	CA	459.3	22.52	4.44	10.00	10,343.1	0.08%	0.00%	0.01%
Cablevision Systems Corp	CVC	212.3	17.42	3.44	6.80	3,697.6	0.03%	0.00%	0.00%
Cabot Oil & Gas Corp	COG	210.2	46.98	0.17	n/a	9,877.2	0.08%	0.00%	n/a
Cameron International Corp	CAM	246.3	50.64	n/a	17.00	12,471.5	0.10%	n/a	0.02%

S&P 500

Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	BEst Long-Term Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Campbell Soup Co	CPB	316.0	35.27	3.29	6.25	11,145.3	0.09%	0.00%	0.01%
Capital One Financial Corp	COF	581.3	60.17	0.33	9.72	34,976.8	0.27%	0.00%	0.03%
Cardinal Health Inc	CAH	341.1	41.13	2.67	10.50	14,028.8	0.11%	0.00%	0.01%
CareFusion Corp	CFN	221.9	26.56	n/a	9.84	5,894.1	0.05%	n/a	0.00%
CarMax Inc	KMX	228.8	33.75	n/a	12.79	7,722.4	0.06%	n/a	0.01%
Carnival Corp	CCL	594.5	37.88	2.64	15.00	22,519.1	0.17%	0.00%	0.03%
Caterpillar Inc	CAT	653.3	84.81	2.45	11.00	55,403.7	0.42%	0.01%	0.05%
CBRE Group Inc	CBG	328.2	18.02	n/a	13.33	5,914.5	0.05%	n/a	0.01%
CBS Corp	CBS	596.8	32.40	1.48	10.91	19,337.2	0.15%	0.00%	0.02%
Celgene Corp	CELG	423.0	73.32	n/a	23.73	31,013.4	0.24%	n/a	0.06%
CenterPoint Energy Inc	CNP	427.4	21.67	3.74	5.67	9,261.5	0.07%	0.00%	0.00%
CenturyLink Inc	CTL	622.7	38.38	7.56	2.56	23,897.3	0.18%	0.01%	0.00%
Cerner Corp	CERN	171.6	76.19	n/a	19.00	13,071.5	0.10%	n/a	0.02%
CF Industries Holdings Inc	CF	62.7	205.19	0.78	12.00	12,864.8	0.10%	0.00%	0.01%
CH Robinson Worldwide Inc	CHRW	161.5	60.33	2.19	14.80	9,741.8	0.07%	0.00%	0.01%
Charles Schwab Corp/The	SCHW	1,274.1	13.58	1.77	17.87	17,302.4	0.13%	0.00%	0.02%
Chesapeake Energy Corp	CHK	665.4	20.26	1.73	7.23	13,481.1	0.10%	0.00%	0.01%
Chevron Corp	CVX	1,962.1	110.21	3.27	-0.92	216,247.4	1.66%	0.05%	-0.02%
Chipotle Mexican Grill Inc	CMG	31.5	254.53	n/a	20.83	8,016.7	0.06%	n/a	0.01%
Chubb Corp/The	CB	261.9	76.98	2.13	7.44	20,161.1	0.15%	0.00%	0.01%
Cigna Corp	CI	288.4	51.00	0.08	10.56	14,706.5	0.11%	0.00%	0.01%
Cincinnati Financial Corp	CINF	162.7	39.84	4.09	5.00	6,481.4	0.05%	0.00%	0.00%
Cintas Corp	CTAS	124.9	41.81	1.53	11.17	5,222.2	0.04%	0.00%	0.00%
Cisco Systems Inc	CSCO	5,290.1	17.14	3.27	9.50	90,671.7	0.69%	0.02%	0.07%
Citigroup Inc	C	2,932.5	37.39	0.11	10.49	109,646.2	0.84%	0.00%	0.09%
Citrix Systems Inc	CTXS	187.0	61.81	n/a	15.71	11,556.3	0.09%	n/a	0.01%
Cliffs Natural Resources Inc	CLF	142.5	36.27	6.89	11.00	5,168.3	0.04%	0.00%	0.00%
Clorox Co/The	CLX	129.6	72.30	3.54	8.42	9,371.1	0.07%	0.00%	0.01%
CME Group Inc/IL	CME	332.3	55.93	3.22	14.73	18,586.2	0.14%	0.00%	0.02%
CMS Energy Corp	CMS	265.2	24.32	3.95	6.00	6,449.8	0.05%	0.00%	0.00%
Coach Inc	COH	283.9	56.05	2.14	12.71	15,912.3	0.12%	0.00%	0.02%
Coca-Cola Co/The	KO	4,485.2	37.18	2.74	7.49	166,758.3	1.28%	0.04%	0.10%
Coca-Cola Enterprises Inc	CCE	287.0	31.44	2.04	6.86	9,024.8	0.07%	0.00%	0.00%
Cognizant Technology Solutions Corp	CTSH	298.6	66.65	n/a	18.13	19,899.4	0.15%	n/a	0.03%
Colgate-Palmolive Co	CL	472.5	104.96	2.36	8.66	49,591.7	0.38%	0.01%	0.03%
Comcast Corp	CMCSA	2,118.9	37.51	1.73	14.34	79,480.2	0.61%	0.01%	0.09%
Comerica Inc	CMA	190.3	29.81	2.01	6.64	5,674.2	0.04%	0.00%	0.00%
Computer Sciences Corp	CSC	155.2	30.45	2.63	8.00	4,725.9	0.04%	0.00%	0.00%
ConAgra Foods Inc	CAG	407.5	27.84	3.59	6.67	11,345.7	0.09%	0.00%	0.01%
ConocoPhillips	COP	1,213.9	57.85	4.56	-0.49	70,223.8	0.54%	0.02%	0.00%
CONSOL Energy Inc	CNX	227.7	35.16	1.42	12.00	8,004.3	0.06%	0.00%	0.01%
Consolidated Edison Inc	ED	292.9	60.38	4.01	3.26	17,684.8	0.14%	0.01%	0.00%
Constellation Brands Inc	STZ	158.9	35.34	n/a	10.88	5,616.9	0.04%	n/a	0.00%
Cooper Industries PLC	CBE	161.5	74.94	1.12	14.25	12,102.0	0.09%	0.00%	0.01%
Corning Inc	GLW	1,477.8	11.75	3.06	12.00	17,364.6	0.13%	0.00%	0.02%
Costco Wholesale Corp	COST	432.4	98.43	1.12	13.27	42,563.5	0.33%	0.00%	0.04%
Coventry Health Care Inc	CVH	133.9	43.64	1.15	12.00	5,841.6	0.04%	0.00%	0.01%
Covidien PLC	COV	480.1	54.95	1.89	9.00	26,381.3	0.20%	0.00%	0.02%
CR Bard Inc	BCR	82.3	96.19	0.83	9.20	7,917.6	0.06%	0.00%	0.01%
Crown Castle International Corp	CCI	293.0	66.75	n/a	36.90	19,560.3	0.15%	n/a	0.06%
CSX Corp	CSX	1,031.4	20.47	2.74	15.00	21,112.3	0.16%	0.00%	0.02%
Cummins Inc	CMI	190.1	93.58	2.14	12.25	17,786.4	0.14%	0.00%	0.02%
CVS Caremark Corp	CVS	1,272.2	46.40	1.40	13.50	59,031.8	0.45%	0.01%	0.06%
Danaher Corp	DHR	692.7	51.73	0.19	15.00	35,832.8	0.27%	0.00%	0.04%
Darden Restaurants Inc	DRI	128.6	52.62	3.80	12.46	6,767.3	0.05%	0.00%	0.01%
DaVita Inc	DVA	95.4	112.52	n/a	12.33	10,734.4	0.08%	n/a	0.01%
Dean Foods Co	DF	184.8	16.84	n/a	5.75	3,112.7	0.02%	n/a	0.00%
Deere & Co	DE	391.7	85.44	2.15	13.00	33,464.0	0.26%	0.01%	0.03%
Dell Inc	DELL	1,734.6	9.23	3.47	7.33	16,010.4	0.12%	0.00%	0.01%
Denbury Resources Inc	DNR	391.2	15.33	n/a	n/a	5,997.1	0.05%	n/a	n/a
DENTSPLY International Inc	XRAY	141.9	36.84	0.60	11.50	5,228.7	0.04%	0.00%	0.00%
Devon Energy Corp	DVN	404.5	58.21	1.37	6.10	23,545.9	0.18%	0.00%	0.01%
Diamond Offshore Drilling Inc	DO	139.0	69.24	5.05	18.00	9,626.4	0.07%	0.00%	0.01%
DIRECTV	DTV	627.9	51.11	n/a	19.20	32,089.6	0.25%	n/a	0.05%
Discover Financial Services	DFS	504.8	41.00	0.98	10.67	20,695.8	0.16%	0.00%	0.02%
Discovery Communications Inc	DISCA	145.8	59.02	n/a	21.90	8,607.9	0.07%	n/a	0.01%
Dollar Tree Inc	DLTR	230.3	39.87	n/a	17.10	9,183.1	0.07%	n/a	0.01%
Dominion Resources Inc/VA	D	574.6	52.78	4.00	4.85	30,327.9	0.23%	0.01%	0.01%
Dover Corp	DOV	179.0	58.22	2.40	14.67	10,422.0	0.08%	0.00%	0.01%
Dow Chemical Co/The	DOW	1,199.2	29.30	4.37	14.33	35,137.5	0.27%	0.01%	0.04%
DR Horton Inc	DHI	319.3	20.96	0.72	10.00	6,692.4	0.05%	0.00%	0.01%
Dr Pepper Snapple Group Inc	DPS	208.1	42.85	3.17	7.41	8,917.6	0.07%	0.00%	0.01%
DTE Energy Co	DTE	172.1	62.10	3.99	5.00	10,685.7	0.08%	0.00%	0.00%
Duke Energy Corp	DUK	703.9	65.69	4.66	4.40	46,241.5	0.35%	0.02%	0.02%
Dun & Bradstreet Corp/The	DNB	44.9	81.04	1.88	10.00	3,637.2	0.03%	0.00%	0.00%
E*TRADE Financial Corp	ETFC	286.1	8.36	n/a	26.00	2,391.4	0.02%	n/a	0.00%
Eastman Chemical Co	EMN	153.4	59.24	1.76	10.33	9,085.5	0.07%	0.00%	0.01%
Eaton Corp	ETN	337.6	47.22	3.22	10.25	15,941.5	0.12%	0.00%	0.01%

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Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	BEst Long-Term Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
eBay Inc	EBAY	1,294.0	48.29	n/a	14.60	62,486.5	0.48%	n/a	0.07%
Ecolab Inc	ECL	292.9	69.60	1.15	14.75	20,386.4	0.16%	0.00%	0.02%
Edison International	EIX	325.8	46.94	2.77	0.98	15,293.6	0.12%	0.00%	0.00%
Edwards Lifesciences Corp	EW	115.7	86.83	n/a	17.25	10,047.4	0.08%	n/a	0.01%
EI du Pont de Nemours & Co	DD	932.5	44.52	3.86	6.10	41,513.6	0.32%	0.01%	0.02%
Electronic Arts Inc	EA	318.4	12.35	n/a	16.55	3,932.2	0.03%	n/a	0.00%
Eli Lilly & Co	LLY	1,160.5	48.63	4.03	-0.23	56,432.8	0.43%	0.02%	0.00%
EMC Corp/MA	EMC	2,106.7	24.42	n/a	14.80	51,444.5	0.39%	n/a	0.06%
Emerson Electric Co	EMR	727.3	48.43	3.30	12.00	35,224.3	0.27%	0.01%	0.03%
Ensco PLC	ESV	232.0	57.82	2.59	18.00	13,413.7	0.10%	0.00%	0.02%
Entergy Corp	ETR	177.3	72.58	4.57	3.50	12,869.8	0.10%	0.00%	0.00%
EOG Resources Inc	EOG	270.0	116.49	0.58	10.64	31,455.0	0.24%	0.00%	0.03%
EQT Corp	EQT	149.6	60.63	1.45	30.00	9,071.0	0.07%	0.00%	0.02%
Equifax Inc	EFX	119.6	50.04	1.44	11.00	5,984.7	0.05%	0.00%	0.01%
Equity Residential	EQR	302.7	57.41	2.35	8.28	17,376.6	0.13%	0.00%	0.01%
Estee Lauder Cos Inc/The	EL	237.0	61.62	0.85	14.03	14,601.1	0.11%	0.00%	0.02%
Exelon Corp	EXC	853.6	35.78	5.87	-1.42	30,540.8	0.23%	0.01%	0.00%
Expedia Inc	EXPE	122.1	59.15	0.88	13.17	7,220.3	0.06%	0.00%	0.01%
Expeditors International of Washington Inc	EXPD	210.5	36.61	1.53	9.33	7,707.9	0.06%	0.00%	0.01%
Express Scripts Holding Co	ESRX	810.8	61.54	n/a	16.88	49,893.6	0.38%	n/a	0.06%
Exxon Mobil Corp	XOM	4,615.9	91.17	2.50	3.38	420,835.2	3.22%	0.08%	0.11%
F5 Networks Inc	FFIV	78.7	82.48	n/a	18.00	6,492.4	0.05%	n/a	0.01%
Family Dollar Stores Inc	FDO	115.4	65.96	1.27	14.10	7,612.0	0.06%	0.00%	0.01%
Fastenal Co	FAST	296.3	44.70	1.88	18.77	13,245.6	0.10%	0.00%	0.02%
Federated Investors Inc	FII	103.9	23.24	4.13	8.00	2,414.9	0.02%	0.00%	0.00%
FedEx Corp	FDX	314.1	91.99	0.61	10.74	28,893.1	0.22%	0.00%	0.02%
Fidelity National Information Services Inc	FIS	294.6	32.87	2.43	12.86	9,683.9	0.07%	0.00%	0.01%
Fifth Third Bancorp	FITB	897.5	14.53	2.75	2.78	13,040.2	0.10%	0.00%	0.00%
First Horizon National Corp	FHN	247.1	9.31	0.43	8.33	2,300.8	0.02%	0.00%	0.00%
First Solar Inc	FSLR	87.0	24.31	n/a	9.50	2,114.2	0.02%	n/a	0.00%
FirstEnergy Corp	FE	418.2	45.72	4.81	1.50	19,120.8	0.15%	0.01%	0.00%
Fiserv Inc	FISV	133.5	74.94	n/a	12.13	10,002.5	0.08%	n/a	0.01%
FLIR Systems Inc	FLIR	151.1	19.43	1.44	12.00	2,934.9	0.02%	0.00%	0.00%
Flowserve Corp	FLS	50.0	135.49	1.06	11.00	6,772.3	0.05%	0.00%	0.01%
Fluor Corp	FLR	167.0	55.85	1.15	13.43	9,325.2	0.07%	0.00%	0.01%
FMC Corp	FMC	137.4	53.52	0.67	11.38	7,353.3	0.06%	0.00%	0.01%
FMC Technologies Inc	FTI	237.7	40.90	n/a	15.33	9,723.2	0.07%	n/a	0.01%
Ford Motor Co	F	3,743.1	11.16	1.79	10.61	41,773.4	0.32%	0.01%	0.03%
Forest Laboratories Inc	FRX	265.7	33.71	n/a	14.16	8,956.5	0.07%	n/a	0.01%
Fossil Inc	FOSL	60.8	87.10	n/a	18.23	5,299.3	0.04%	n/a	0.01%
Franklin Resources Inc	BEN	212.6	127.80	0.85	12.67	27,170.7	0.21%	0.00%	0.03%
Freeport-McMoRan Copper & Gold Inc	FCX	949.2	38.88	3.22	n/a	36,906.8	0.28%	0.01%	n/a
Frontier Communications Corp	FTR	998.5	4.72	8.47	-10.01	4,713.0	0.04%	0.00%	0.00%
GameStop Corp	GME	123.4	22.83	4.38	9.27	2,817.9	0.02%	0.00%	0.00%
Gannett Co Inc	GCI	229.8	16.90	4.73	6.00	3,883.4	0.03%	0.00%	0.00%
Gap Inc/The	GPS	480.9	35.72	1.40	10.98	17,179.0	0.13%	0.00%	0.01%
General Dynamics Corp	GD	353.1	68.08	3.00	8.00	24,037.0	0.18%	0.01%	0.01%
General Electric Co	GE	10,558.8	21.06	3.23	10.33	222,369.3	1.70%	0.06%	0.18%
General Mills Inc	GIS	645.2	40.08	3.29	7.75	25,860.6	0.20%	0.01%	0.02%
Genuine Parts Co	GPC	155.1	62.58	3.16	8.32	9,706.2	0.07%	0.00%	0.01%
Genworth Financial Inc	GNW	491.6	5.96	n/a	5.00	2,930.1	0.02%	n/a	0.00%
Gilead Sciences Inc	GILD	756.6	67.16	n/a	19.98	50,811.1	0.39%	n/a	0.08%
Goldman Sachs Group Inc/The	GS	479.4	122.39	1.63	11.03	58,675.8	0.45%	0.01%	0.05%
Goodyear Tire & Rubber Co/The	GT	245.0	11.41	n/a	43.84	2,795.0	0.02%	n/a	0.01%
Google Inc	GOOG	262.0	679.77	n/a	14.55	178,080.7	1.36%	n/a	0.20%
H&R Block Inc	HRB	271.1	17.70	4.52	11.00	4,798.6	0.04%	0.00%	0.00%
Halliburton Co	HAL	928.0	32.29	1.11	20.50	29,964.7	0.23%	0.00%	0.05%
Harley-Davidson Inc	HOG	227.9	46.76	1.33	13.00	10,656.6	0.08%	0.00%	0.01%
Harman International Industries Inc	HAR	67.2	41.93	1.43	20.00	2,816.2	0.02%	0.00%	0.00%
Harris Corp	HRS	113.6	45.78	3.23	4.00	5,198.8	0.04%	0.00%	0.00%
Hartford Financial Services Group Inc	HIG	435.8	21.71	1.84	9.50	9,461.5	0.07%	0.00%	0.01%
Hasbro Inc	HAS	130.2	35.99	4.00	9.00	4,686.9	0.04%	0.00%	0.00%
HCP Inc	HCP	452.1	44.30	4.51	5.41	20,026.5	0.15%	0.01%	0.01%
Health Care REIT Inc	HCN	259.0	59.43	4.98	6.09	15,393.9	0.12%	0.01%	0.01%
Helmerich & Payne Inc	HP	105.7	47.80	0.59	n/a	5,052.1	0.04%	0.00%	n/a
Hershey Co/The	HSY	165.7	68.85	2.44	8.10	11,409.3	0.09%	0.00%	0.01%
Hess Corp	HES	341.5	52.26	0.77	3.80	17,847.4	0.14%	0.00%	0.01%
Hewlett-Packard Co	HPQ	1,966.2	13.85	3.81	3.50	27,231.3	0.21%	0.01%	0.01%
HJ Heinz Co	HNZ	320.2	57.51	3.58	7.33	18,416.6	0.14%	0.01%	0.01%
Home Depot Inc/The	HD	1,507.4	61.38	1.89	15.75	92,526.8	0.71%	0.01%	0.11%
Honeywell International Inc	HON	783.4	61.24	2.68	10.50	47,973.7	0.37%	0.01%	0.04%
Hormel Foods Corp	HRL	262.9	29.53	2.03	8.50	7,762.8	0.06%	0.00%	0.01%
Hospira Inc	HSP	165.1	30.69	n/a	1.53	5,067.3	0.04%	n/a	0.00%
Host Hotels & Resorts Inc	HST	724.8	14.46	2.21	9.97	10,479.9	0.08%	0.00%	0.01%
Hudson City Bancorp Inc	HCBK	528.2	8.49	3.77	-3.00	4,481.7	0.03%	0.00%	0.00%
Humana Inc	HUM	161.7	74.27	1.40	9.80	12,010.4	0.09%	0.00%	0.01%
Huntington Bancshares Inc/OH	HBAN	855.5	6.39	2.50	5.33	5,466.5	0.04%	0.00%	0.00%
Illinois Tool Works Inc	ITW	463.4	61.33	2.48	7.48	28,423.3	0.22%	0.01%	0.02%

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Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	BEst Long-Term Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Ingersoll-Rand PLC	IR	301.0	47.03	1.36	11.00	14,156.1	0.11%	0.00%	0.01%
Integrys Energy Group Inc	TEG	78.3	54.04	5.03	5.50	4,230.7	0.03%	0.00%	0.00%
Intel Corp	INTC	4,976.0	21.63	4.16	9.98	107,606.0	0.82%	0.03%	0.08%
IntercontinentalExchange Inc	ICE	72.8	131.00	n/a	13.50	9,531.8	0.07%	n/a	0.01%
International Business Machines Corp	IBM	1,129.9	194.53	1.75	9.50	219,805.7	1.68%	0.03%	0.16%
International Flavors & Fragrances Inc	IFF	81.5	64.62	2.10	3.00	5,265.0	0.04%	0.00%	0.00%
International Game Technology	IGT	267.1	12.84	1.87	13.00	3,429.6	0.03%	0.00%	0.00%
International Paper Co	IP	437.3	35.83	3.35	5.00	15,669.7	0.12%	0.00%	0.01%
Interpublic Group of Cos Inc/The	IPG	431.4	10.10	2.38	5.00	4,357.0	0.03%	0.00%	0.00%
Intuit Inc	INTU	295.4	59.42	1.14	13.71	17,550.9	0.13%	0.00%	0.02%
Intuitive Surgical Inc	ISRG	39.8	542.22	n/a	19.14	21,560.3	0.17%	n/a	0.03%
Invesco Ltd	IVZ	448.2	24.32	2.84	12.50	10,900.7	0.08%	0.00%	0.01%
Iron Mountain Inc	IRM	171.6	34.60	3.12	13.00	5,938.7	0.05%	0.00%	0.01%
Jabil Circuit Inc	JBL	205.6	17.34	1.85	12.00	3,564.4	0.03%	0.00%	0.00%
Jacobs Engineering Group Inc	JEC	129.7	38.59	n/a	13.23	5,006.7	0.04%	n/a	0.01%
JC Penney Co Inc	JCP	219.1	24.01	n/a	21.77	5,260.2	0.04%	n/a	0.01%
JDS Uniphase Corp	JDSU	229.8	9.69	n/a	n/a	2,226.8	0.02%	n/a	n/a
JM Smucker Co/The	SJM	109.5	85.64	2.43	7.50	9,373.6	0.07%	0.00%	0.01%
Johnson & Johnson	JNJ	2,757.0	70.82	3.45	6.51	195,253.6	1.50%	0.05%	0.10%
Johnson Controls Inc	JCI	683.9	25.75	2.80	12.00	17,610.7	0.13%	0.00%	0.02%
Joy Global Inc	JOY	105.9	62.45	1.12	16.80	6,612.1	0.05%	0.00%	0.01%
JPMorgan Chase & Co	JPM	3,799.6	41.68	2.88	7.25	158,367.3	1.21%	0.03%	0.09%
Juniper Networks Inc	JNPR	526.6	16.57	n/a	14.00	8,725.6	0.07%	n/a	0.01%
Kellogg Co	K	357.7	52.32	3.36	7.90	18,716.7	0.14%	0.00%	0.01%
KeyCorp	KEY	936.2	8.42	2.38	6.58	7,882.8	0.06%	0.00%	0.00%
Kimberly-Clark Corp	KMB	394.9	83.45	3.55	8.44	32,953.7	0.25%	0.01%	0.02%
Kimco Realty Corp	KIM	407.0	19.52	4.30	14.83	7,943.8	0.06%	0.00%	0.01%
Kinder Morgan Inc/Delaware	KMI	1,036.9	34.71	4.15	7.00	35,990.1	0.28%	0.01%	0.02%
KLA-Tencor Corp	KLAC	166.5	46.52	3.44	10.00	7,746.3	0.06%	0.00%	0.01%
Kohl's Corp	KSS	234.5	53.28	2.40	13.00	12,494.6	0.10%	0.00%	0.01%
Kraft Foods Group Inc	KRFT	592.0	45.48	n/a	6.00	26,924.2	0.21%	n/a	0.01%
Kroger Co/The	KR	527.6	25.22	2.38	8.91	13,305.8	0.10%	0.00%	0.01%
L-3 Communications Holdings Inc	LLL	96.6	73.80	2.71	1.67	7,125.7	0.05%	0.00%	0.00%
Laboratory Corp of America Holdings	LH	94.6	84.73	n/a	12.25	8,015.5	0.06%	n/a	0.01%
Lam Research Corp	LRCX	177.3	35.40	n/a	10.00	6,277.3	0.05%	n/a	0.00%
Legg Mason Inc	LM	135.1	25.48	1.73	13.00	3,441.3	0.03%	0.00%	0.00%
Leggett & Platt Inc	LEG	141.0	26.53	4.37	15.00	3,740.7	0.03%	0.00%	0.00%
Lennar Corp	LEN	159.6	37.47	0.43	8.00	5,979.5	0.05%	0.00%	0.00%
Leucadia National Corp	LUK	244.6	22.70	1.10	n/a	5,552.0	0.04%	0.00%	n/a
Life Technologies Corp	LIFE	175.3	48.91	n/a	8.98	8,573.7	0.07%	n/a	0.01%
Lincoln National Corp	LNC	279.2	24.79	1.29	4.10	6,920.7	0.05%	0.00%	0.00%
Linear Technology Corp	LLTC	235.5	31.26	3.20	10.33	7,360.2	0.06%	0.00%	0.01%
Lockheed Martin Corp	LMT	323.6	93.67	4.91	7.83	30,310.4	0.23%	0.01%	0.02%
Loews Corp	L	393.6	42.28	0.59	n/a	16,641.5	0.13%	0.00%	n/a
Lorillard Inc	LO	129.4	116.01	5.34	9.15	15,016.9	0.12%	0.01%	0.01%
Lowe's Cos Inc	LOW	1,140.6	32.38	1.98	16.13	36,931.5	0.28%	0.01%	0.05%
LSI Corp	LSI	557.6	6.85	n/a	15.33	3,819.3	0.03%	n/a	0.00%
Ltd Brands Inc	LTD	287.4	47.89	2.09	12.54	13,764.3	0.11%	0.00%	0.01%
LyondellBasell Industries NV	LYB	575.2	53.39	3.00	9.67	30,708.9	0.24%	0.01%	0.02%
M&T Bank Corp	MTB	127.5	104.10	2.69	16.54	13,268.7	0.10%	0.00%	0.02%
Macy's Inc	M	402.5	38.07	2.10	10.27	15,324.0	0.12%	0.00%	0.01%
Marathon Oil Corp	MRO	705.4	30.06	2.26	-0.54	21,205.3	0.16%	0.00%	0.00%
Marathon Petroleum Corp	MPC	338.3	54.93	2.55	11.00	18,582.7	0.14%	0.00%	0.02%
Marriott International Inc/DE	MAR	315.5	36.48	1.43	20.22	11,510.9	0.09%	0.00%	0.02%
Marsh & McLennan Cos Inc	MMC	544.2	34.03	2.70	8.08	18,519.0	0.14%	0.00%	0.01%
Masco Corp	MAS	357.1	15.09	1.99	10.00	5,388.6	0.04%	0.00%	0.00%
Mastercard Inc	MA	119.3	460.93	0.26	17.93	54,977.9	0.42%	0.00%	0.08%
Mattel Inc	MAT	343.1	36.78	3.37	9.00	12,620.4	0.10%	0.00%	0.01%
McCormick & Co Inc/MD	MKC	120.1	61.62	2.01	8.00	7,401.5	0.06%	0.00%	0.00%
McDonald's Corp	MCD	1,008.4	86.80	3.55	9.96	87,531.8	0.67%	0.02%	0.07%
McGraw-Hill Cos Inc/The	MHP	278.0	55.28	1.85	9.50	15,367.8	0.12%	0.00%	0.01%
McKesson Corp	MCK	236.0	93.31	0.86	14.33	22,024.9	0.17%	0.00%	0.02%
Mead Johnson Nutrition Co	MJN	203.8	61.66	1.95	11.50	12,564.1	0.10%	0.00%	0.01%
MeadWestvaco Corp	MWV	174.8	29.69	3.37	10.00	5,189.8	0.04%	0.00%	0.00%
Medtronic Inc	MDT	1,020.1	41.58	2.50	6.43	42,417.4	0.32%	0.01%	0.02%
Merck & Co Inc	MRK	3,045.6	45.63	3.68	4.79	138,972.2	1.06%	0.04%	0.05%
MetLife Inc	MET	1,062.3	35.49	2.09	10.00	37,699.3	0.29%	0.01%	0.03%
MetroPCS Communications Inc	PCS	364.1	10.21	n/a	11.12	3,717.5	0.03%	n/a	0.00%
Microchip Technology Inc	MCHP	193.7	31.35	4.48	10.00	6,072.3	0.05%	0.00%	0.00%
Micron Technology Inc	MU	1,017.6	5.43	n/a	12.54	5,520.3	0.04%	n/a	0.01%
Microsoft Corp	MSFT	8,416.5	28.54	3.22	10.95	240,163.8	1.84%	0.06%	0.20%
Molex Inc	MOLX	95.6	25.97	3.39	11.67	2,481.7	0.02%	0.00%	0.00%
Molson Coors Brewing Co	TAP	156.2	43.14	2.97	3.92	6,736.9	0.05%	0.00%	0.00%
Mondelez International Inc	MDLZ	1,774.6	26.54	1.96	7.86	47,099.2	0.36%	0.01%	0.03%
Monsanto Co	MON	534.6	86.07	1.74	11.23	46,012.8	0.35%	0.01%	0.04%
Monster Beverage Corp	MNST	176.4	44.67	n/a	17.00	7,881.1	0.06%	n/a	0.01%
Moody's Corp	MCO	222.3	48.16	1.33	11.00	10,706.0	0.08%	0.00%	0.01%
Morgan Stanley	MS	1,975.5	17.38	1.15	11.00	34,334.3	0.26%	0.00%	0.03%

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Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	BEst Long-Term Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Mosaic Co/The	MOS	296.9	52.34	1.91	5.14	15,539.4	0.12%	0.00%	0.01%
Motorola Solutions Inc	MSI	280.5	51.68	2.01	n/a	14,496.2	0.11%	0.00%	n/a
Murphy Oil Corp	MUR	194.3	60.00	2.08	10.00	11,655.4	0.09%	0.00%	0.01%
Mylan Inc/PA	MYL	407.5	25.34	n/a	10.24	10,326.8	0.08%	n/a	0.01%
Nabors Industries Ltd	NBR	290.4	13.49	n/a	8.00	3,917.3	0.03%	n/a	0.00%
NASDAQ OMX Group Inc/The	NDAQ	166.9	23.81	2.18	7.65	3,973.7	0.03%	0.00%	0.00%
National Oilwell Varco Inc	NOV	426.4	73.70	0.65	13.50	31,427.3	0.24%	0.00%	0.03%
NetApp Inc	NTAP	363.3	26.90	n/a	14.83	9,773.2	0.07%	n/a	0.01%
Netflix Inc	NFLX	55.5	79.09	n/a	21.71	4,393.1	0.03%	n/a	0.01%
Newell Rubbermaid Inc	NWL	288.4	20.64	2.91	9.13	5,952.6	0.05%	0.00%	0.00%
Newfield Exploration Co	NFX	135.0	27.12	n/a	11.50	3,660.7	0.03%	n/a	0.00%
Newmont Mining Corp	NEM	491.2	54.55	2.57	-3.00	26,797.6	0.21%	0.01%	-0.01%
News Corp	NWSA	1,568.8	23.92	0.71	12.97	37,526.1	0.29%	0.00%	0.04%
NextEra Energy Inc	NEE	423.2	70.06	3.43	5.13	29,649.8	0.23%	0.01%	0.01%
NIKE Inc	NKE	360.7	91.38	1.58	12.30	32,957.1	0.25%	0.00%	0.03%
NiSource Inc	NI	284.9	25.47	3.77	n/a	7,256.6	0.06%	0.00%	n/a
Noble Corp	NE	252.6	37.61	1.38	13.00	9,500.4	0.07%	0.00%	0.01%
Noble Energy Inc	NBL	177.8	95.01	1.05	7.00	16,895.4	0.13%	0.00%	0.01%
Nordstrom Inc	JWN	201.0	56.77	1.90	12.89	11,410.5	0.09%	0.00%	0.01%
Norfolk Southern Corp	NSC	316.0	61.35	3.26	15.00	19,389.2	0.15%	0.00%	0.02%
Northeast Utilities	NU	313.8	39.30	3.49	7.64	12,332.5	0.09%	0.00%	0.01%
Northern Trust Corp	NTRS	240.5	47.78	2.51	4.08	11,491.9	0.09%	0.00%	0.00%
Northrop Grumman Corp	NOC	245.4	68.69	3.20	3.33	16,859.5	0.13%	0.00%	0.00%
NRG Energy Inc	NRG	227.8	21.56	1.67	-13.70	4,912.3	0.04%	0.00%	-0.01%
Nucor Corp	NUE	317.5	40.13	3.64	8.50	12,739.6	0.10%	0.00%	0.01%
NVIDIA Corp	NVDA	619.5	11.97	n/a	14.33	7,415.1	0.06%	n/a	0.01%
NYSE Euronext	NYX	246.0	24.76	4.85	15.60	6,091.0	0.05%	0.00%	0.01%
O'Reilly Automotive Inc	ORLY	116.1	85.68	n/a	17.67	9,943.7	0.08%	n/a	0.01%
Occidental Petroleum Corp	OXY	809.9	78.96	2.74	-2.63	63,953.4	0.49%	0.01%	-0.01%
Omnicom Group Inc	OMC	264.2	47.91	2.50	6.00	12,656.9	0.10%	0.00%	0.01%
ONEOK Inc	OKE	204.6	47.30	2.79	16.00	9,678.2	0.07%	0.00%	0.01%
Oracle Corp	ORCL	4,819.1	31.05	0.77	13.54	149,631.7	1.15%	0.01%	0.16%
Owens-Illinois Inc	OI	164.5	19.49	n/a	8.67	3,206.7	0.02%	n/a	0.00%
PACCAR Inc	PCAR	353.0	43.34	1.85	10.25	15,299.0	0.12%	0.00%	0.01%
Pall Corp	PLL	114.4	62.96	1.59	12.84	7,205.0	0.06%	0.00%	0.01%
Parker Hannifin Corp	PH	149.4	78.66	2.08	6.00	11,755.3	0.09%	0.00%	0.01%
Patterson Cos Inc	PDCO	110.3	33.40	1.68	12.33	3,685.5	0.03%	0.00%	0.00%
Paychex Inc	PAYX	363.5	32.43	4.07	9.50	11,786.9	0.09%	0.00%	0.01%
Peabody Energy Corp	BTU	268.3	27.90	1.22	12.00	7,486.5	0.06%	0.00%	0.01%
Pentair Ltd	PNR	209.5	42.24	2.08	13.50	8,851.3	0.07%	0.00%	0.01%
People's United Financial Inc	PBCT	336.0	12.03	5.32	7.00	4,041.5	0.03%	0.00%	0.00%
Pepco Holdings Inc	POM	228.9	19.87	5.44	5.00	4,548.0	0.03%	0.00%	0.00%
PepsiCo Inc	PEP	1,546.9	69.24	3.11	8.78	107,104.2	0.82%	0.03%	0.07%
PerkinElmer Inc	PKI	114.1	30.93	0.91	11.41	3,528.2	0.03%	0.00%	0.00%
Perrigo Co	PRGO	93.5	115.01	0.28	11.31	10,758.8	0.08%	0.00%	0.01%
PetSmart Inc	PETM	108.2	66.39	0.99	18.34	7,182.5	0.06%	0.00%	0.01%
Pfizer Inc	PFE	7,469.5	24.87	3.54	3.48	185,766.0	1.42%	0.05%	0.05%
PG&E Corp	PCG	430.0	42.52	4.28	4.00	18,282.9	0.14%	0.01%	0.01%
Philip Morris International Inc	PM	1,685.7	88.56	3.84	10.60	149,287.5	1.14%	0.04%	0.12%
Phillips 66	PSX	626.9	47.16	2.12	10.00	29,565.7	0.23%	0.00%	0.02%
Pinnacle West Capital Corp	PNW	109.5	52.97	4.12	5.33	5,802.5	0.04%	0.00%	0.00%
Pioneer Natural Resources Co	PXD	123.0	105.65	0.08	15.85	12,998.8	0.10%	0.00%	0.02%
Pitney Bowes Inc	PBI	200.6	14.36	10.45	n/a	2,881.2	0.02%	0.00%	n/a
Plum Creek Timber Co Inc	PCL	161.6	43.90	3.83	5.00	7,094.2	0.05%	0.00%	0.00%
PNC Financial Services Group Inc	PNC	529.0	58.19	2.75	3.64	30,782.5	0.24%	0.01%	0.01%
PPG Industries Inc	PPG	153.4	117.08	2.02	7.00	17,954.2	0.14%	0.00%	0.01%
PPL Corp	PPL	580.7	29.58	4.87	5.00	17,178.2	0.13%	0.01%	0.01%
Praxair Inc	PX	297.1	106.21	2.07	10.59	31,557.8	0.24%	0.01%	0.03%
Precision Castparts Corp	PCP	145.3	173.07	0.07	12.45	25,155.4	0.19%	0.00%	0.02%
priceline.com Inc	PCLN	49.8	573.77	n/a	19.84	28,588.1	0.22%	n/a	0.04%
Principal Financial Group Inc	PFG	293.6	27.54	3.05	13.00	8,085.4	0.06%	0.00%	0.01%
Procter & Gamble Co/The	PG	2,734.2	69.24	3.25	7.56	189,318.1	1.45%	0.05%	0.11%
Progressive Corp/The	PGR	604.7	22.30	1.83	7.75	13,484.8	0.10%	0.00%	0.01%
Prologis Inc	PLD	460.7	34.29	3.27	3.93	15,796.6	0.12%	0.00%	0.00%
Prudential Financial Inc	PRU	464.0	57.05	2.54	14.50	26,471.2	0.20%	0.01%	0.03%
Public Service Enterprise Group Inc	PEG	505.9	32.04	4.43	0.30	16,210.2	0.12%	0.01%	0.00%
Public Storage	PSA	171.6	138.63	3.17	5.34	23,784.1	0.18%	0.01%	0.01%
PulteGroup Inc	PHM	386.3	17.34	n/a	10.00	6,698.8	0.05%	n/a	0.01%
QEP Resources Inc	QEP	178.1	29.00	0.28	15.00	5,165.4	0.04%	0.00%	0.01%
QUALCOMM Inc	QCOM	1,703.3	58.58	1.71	15.14	99,773.7	0.76%	0.01%	0.12%
Quanta Services Inc	PWR	209.2	25.93	n/a	17.50	5,424.9	0.04%	n/a	0.01%
Quest Diagnostics Inc	DGX	159.0	57.72	1.18	11.63	9,175.6	0.07%	0.00%	0.01%
Ralph Lauren Corp	RL	60.3	153.69	1.04	12.33	9,270.9	0.07%	0.00%	0.01%
Range Resources Corp	RRC	162.6	65.36	0.24	10.00	10,629.4	0.08%	0.00%	0.01%
Raytheon Co	RTN	329.9	56.56	3.54	9.00	18,657.3	0.14%	0.01%	0.01%
Red Hat Inc	RHT	193.3	49.17	n/a	17.00	9,505.8	0.07%	n/a	0.01%
Regions Financial Corp	RF	1,413.0	6.52	0.61	8.00	9,212.8	0.07%	0.00%	0.01%
Republic Services Inc	RSG	365.3	28.35	3.32	6.60	10,355.6	0.08%	0.00%	0.01%

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Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	BEst Long-Term Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Reynolds American Inc	RAI	558.9	41.64	5.67	7.68	23,274.6	0.18%	0.01%	0.01%
Robert Half International Inc	RHI	141.8	26.89	2.23	14.33	3,813.1	0.03%	0.00%	0.00%
Rockwell Automation Inc	ROK	141.1	71.06	2.65	15.00	10,030.0	0.08%	0.00%	0.01%
Rockwell Collins Inc	COL	142.2	53.58	2.24	8.28	7,616.5	0.06%	0.00%	0.00%
Roper Industries Inc	ROP	97.8	109.17	0.50	15.00	10,677.8	0.08%	0.00%	0.01%
Ross Stores Inc	ROST	223.9	60.95	0.92	13.50	13,648.4	0.10%	0.00%	0.01%
Rowan Cos Plc	RDC	124.2	31.71	n/a	13.00	3,938.3	0.03%	n/a	0.00%
RR Donnelley & Sons Co	RRD	180.3	10.02	10.38	5.00	1,806.6	0.01%	0.00%	0.00%
Ryder System Inc	R	51.1	45.12	2.75	8.97	2,306.2	0.02%	0.00%	0.00%
Safeway Inc	SWY	239.6	16.31	4.29	8.49	3,907.9	0.03%	0.00%	0.00%
SAIC Inc	SAI	341.8	10.99	4.37	3.87	3,756.7	0.03%	0.00%	0.00%
Salesforce.com Inc	CRM	138.7	145.98	n/a	25.28	20,250.5	0.16%	n/a	0.04%
SanDisk Corp	SNDK	241.5	41.76	n/a	16.85	10,086.9	0.08%	n/a	0.01%
SCANA Corp	SCG	131.3	49.08	4.03	4.34	6,444.2	0.05%	0.00%	0.00%
Schlumberger Ltd	SLB	1,327.6	69.53	1.58	17.00	92,305.9	0.71%	0.01%	0.12%
Scripps Networks Interactive Inc	SNI	114.7	60.72	0.79	15.07	6,963.1	0.05%	0.00%	0.01%
Seagate Technology PLC	STX	392.1	27.32	4.69	7.63	10,711.4	0.08%	0.00%	0.01%
Sealed Air Corp	SEE	194.2	16.22	3.21	5.50	3,149.3	0.02%	0.00%	0.00%
Sempra Energy	SRE	241.7	69.75	3.44	7.00	16,858.5	0.13%	0.00%	0.01%
Sherwin-Williams Co/The	SHW	103.1	142.58	1.09	13.02	14,701.0	0.11%	0.00%	0.01%
Sigma-Aldrich Corp	SIAL	120.3	70.14	1.14	7.11	8,439.7	0.06%	0.00%	0.00%
Simon Property Group Inc	SPG	313.1	152.21	2.89	5.68	47,657.6	0.37%	0.01%	0.02%
SLM Corp	SLM	469.4	17.58	2.84	-4.30	8,252.1	0.06%	0.00%	0.00%
Snap-on Inc	SNA	58.2	77.33	1.76	10.00	4,503.0	0.03%	0.00%	0.00%
Southern Co/The	SO	874.8	46.84	4.18	5.50	40,975.5	0.31%	0.01%	0.02%
Southwest Airlines Co	LUV	738.0	8.82	0.45	15.75	6,509.0	0.05%	0.00%	0.01%
Southwestern Energy Co	SWN	349.1	34.70	n/a	n/a	12,114.6	0.09%	n/a	n/a
Spectra Energy Corp	SE	652.9	28.87	4.23	5.00	18,848.4	0.14%	0.01%	0.01%
Sprint Nextel Corp	S	3,000.4	5.54	n/a	5.00	16,622.1	0.13%	n/a	0.01%
St Jude Medical Inc	STJ	314.0	38.26	2.40	10.22	12,012.5	0.09%	0.00%	0.01%
Stanley Black & Decker Inc	SWK	168.8	69.30	2.83	8.00	11,696.9	0.09%	0.00%	0.01%
Staples Inc	SPLS	682.4	11.52	3.82	8.23	7,857.5	0.06%	0.00%	0.00%
Starbucks Corp	SBUX	760.0	45.90	1.48	17.43	34,884.0	0.27%	0.00%	0.05%
Starwood Hotels & Resorts Worldwide Inc	HOT	196.0	51.85	2.41	18.15	10,161.4	0.08%	0.00%	0.01%
State Street Corp	STT	479.1	44.57	2.15	5.75	21,353.7	0.16%	0.00%	0.01%
Stericycle Inc	SRCL	85.9	94.76	n/a	16.00	8,142.3	0.06%	n/a	0.01%
Stryker Corp	SYK	380.2	52.60	1.62	10.00	19,998.6	0.15%	0.00%	0.02%
SunTrust Banks Inc	STI	538.8	27.20	0.74	14.36	14,655.9	0.11%	0.00%	0.02%
Symantec Corp	SYMC	693.9	18.19	n/a	7.50	12,622.1	0.10%	n/a	0.01%
Sysco Corp	SYY	586.6	31.07	3.48	10.00	18,225.8	0.14%	0.00%	0.01%
T Rowe Price Group Inc	TROW	254.9	64.94	2.09	14.00	16,550.9	0.13%	0.00%	0.02%
Target Corp	TGT	654.9	63.75	2.26	12.60	41,748.9	0.32%	0.01%	0.04%
TE Connectivity Ltd	TEL	427.8	32.18	2.61	15.00	13,766.9	0.11%	0.00%	0.02%
TECO Energy Inc	TE	216.6	17.87	4.92	3.67	3,870.3	0.03%	0.00%	0.00%
Tenet Healthcare Corp	THC	104.2	23.60	n/a	11.00	2,458.8	0.02%	n/a	0.00%
Teradata Corp	TDC	168.6	68.31	n/a	14.75	11,517.1	0.09%	n/a	0.01%
Teradyne Inc	TER	187.6	14.62	n/a	11.75	2,742.6	0.02%	n/a	0.00%
Tesoro Corp	TSO	139.8	37.71	1.59	34.81	5,271.7	0.04%	0.00%	0.01%
Texas Instruments Inc	TXN	1,120.8	28.09	2.99	9.50	31,483.4	0.24%	0.01%	0.02%
Textron Inc	TXT	281.8	25.21	0.32	31.50	7,104.8	0.05%	0.00%	0.02%
Thermo Fisher Scientific Inc	TMO	365.6	61.06	0.85	10.94	22,320.6	0.17%	0.00%	0.02%
Tiffany & Co	TIF	126.6	63.22	2.02	13.73	8,006.1	0.06%	0.00%	0.01%
Time Warner Cable Inc	TWC	306.4	99.11	2.26	14.78	30,363.8	0.23%	0.01%	0.03%
Time Warner Inc	TWX	948.9	43.45	2.39	13.52	41,230.7	0.32%	0.01%	0.04%
Titanium Metals Corp	TIE	175.1	11.71	2.56	15.00	2,050.0	0.02%	0.00%	0.00%
TJX Cos Inc	TJX	736.1	41.63	1.11	12.13	30,643.9	0.23%	0.00%	0.03%
Torchmark Corp	TMK	95.4	50.59	1.19	9.00	4,826.2	0.04%	0.00%	0.00%
Total System Services Inc	TSS	188.1	22.49	1.78	9.71	4,229.7	0.03%	0.00%	0.00%
Travelers Cos Inc/The	TRV	381.4	70.94	2.59	7.75	27,060.0	0.21%	0.01%	0.02%
TripAdvisor Inc	TRIP	129.5	30.29	n/a	17.25	3,923.5	0.03%	n/a	0.01%
Tyco International Ltd	TYC	462.0	26.87	2.23	13.00	12,413.9	0.10%	0.00%	0.01%
Tyson Foods Inc	TSN	291.9	16.81	0.95	7.33	4,907.2	0.04%	0.00%	0.00%
Union Pacific Corp	UNP	470.4	123.03	1.95	13.20	57,872.9	0.44%	0.01%	0.06%
United Parcel Service Inc	UPS	726.3	73.25	3.11	9.58	53,203.6	0.41%	0.01%	0.04%
United States Steel Corp	X	144.3	20.39	0.98	6.50	2,941.9	0.02%	0.00%	0.00%
United Technologies Corp	UTX	916.5	78.16	2.74	12.96	71,637.1	0.55%	0.02%	0.07%
UnitedHealth Group Inc	UNH	1,021.5	56.00	1.52	10.25	57,203.6	0.44%	0.01%	0.04%
Unum Group	UNM	280.0	20.28	2.56	10.00	5,678.4	0.04%	0.00%	0.00%
Urban Outfitters Inc	URBN	145.5	35.76	n/a	18.44	5,204.2	0.04%	n/a	0.01%
US Bancorp	USB	1,880.0	33.21	2.35	7.57	62,434.8	0.48%	0.01%	0.04%
Valero Energy Corp	VLO	551.6	29.10	2.41	6.30	16,051.7	0.12%	0.00%	0.01%
Varian Medical Systems Inc	VAR	110.7	66.76	n/a	10.67	7,391.3	0.06%	n/a	0.01%
Ventas Inc	VTR	295.6	63.27	3.92	5.21	18,699.8	0.14%	0.01%	0.01%
VeriSign Inc	VRSN	155.3	37.07	n/a	15.50	5,755.4	0.04%	n/a	0.01%
Verizon Communications Inc	VZ	2,854.0	44.64	4.61	6.43	127,402.6	0.98%	0.05%	0.06%
VF Corp	VFC	109.9	156.48	2.22	12.40	17,203.1	0.13%	0.00%	0.02%
Viacom Inc	VIAB	463.4	51.27	2.15	12.20	23,760.3	0.18%	0.00%	0.02%
Visa Inc	V	527.4	138.76	0.95	18.71	73,185.8	0.56%	0.01%	0.10%

S&P 500

Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	BEst Long-Term Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Vornado Realty Trust	VNO	185.8	80.21	3.44	-2.87	14,904.2	0.11%	0.00%	0.00%
Vulcan Materials Co	VMC	129.4	45.97	0.09	9.67	5,948.0	0.05%	0.00%	0.00%
Wal-Mart Stores Inc	WMT	3,361.4	75.02	2.12	10.18	252,175.5	1.93%	0.04%	0.20%
Walgreen Co	WAG	944.1	35.23	3.12	12.40	33,259.1	0.25%	0.01%	0.03%
Walt Disney Co/The	DIS	1,794.3	49.07	1.22	11.56	88,045.1	0.67%	0.01%	0.08%
Washington Post Co/The	WPO	6.2	333.51	2.94	n/a	2,076.4	0.02%	0.00%	n/a
Waste Management Inc	WM	463.9	32.74	4.34	2.80	15,188.1	0.12%	0.01%	0.00%
Waters Corp	WAT	87.7	81.81	n/a	9.08	7,172.9	0.05%	n/a	0.00%
Watson Pharmaceuticals Inc	WPI	127.6	85.95	n/a	12.89	10,971.2	0.08%	n/a	0.01%
WellPoint Inc	WLP	325.2	61.28	1.88	10.50	19,927.5	0.15%	0.00%	0.02%
Wells Fargo & Co	WFC	5,289.6	33.69	2.61	11.13	178,206.6	1.37%	0.04%	0.15%
Western Digital Corp	WDC	245.2	34.23	2.92	2.13	8,393.4	0.06%	0.00%	0.00%
Western Union Co/The	WU	602.4	12.70	3.94	11.01	7,650.4	0.06%	0.00%	0.01%
Weyerhaeuser Co	WY	540.7	27.69	2.46	5.00	14,971.2	0.11%	0.00%	0.01%
Whirlpool Corp	WHR	77.9	97.68	2.05	n/a	7,604.8	0.06%	0.00%	n/a
Whole Foods Market Inc	WFM	184.7	94.73	0.59	19.43	17,493.5	0.13%	0.00%	0.03%
Williams Cos Inc/The	WMB	627.3	34.99	3.57	12.00	21,950.2	0.17%	0.01%	0.02%
Windstream Corp	WIN	588.0	9.54	10.48	-3.21	5,609.5	0.04%	0.00%	0.00%
Wisconsin Energy Corp	WEC	230.5	38.47	3.12	4.75	8,865.6	0.07%	0.00%	0.00%
WPX Energy Inc	WPX	199.0	16.94	n/a	n/a	3,371.7	0.03%	n/a	n/a
WW Grainger Inc	GWW	69.5	201.41	1.59	14.35	13,997.0	0.11%	0.00%	0.02%
Wyndham Worldwide Corp	WYN	140.3	50.40	1.83	18.60	7,069.5	0.05%	0.00%	0.01%
Wynn Resorts Ltd	WYNN	100.5	121.06	1.65	9.00	12,169.2	0.09%	0.00%	0.01%
Xcel Energy Inc	XEL	487.6	28.25	3.82	4.70	13,775.3	0.11%	0.00%	0.00%
Xerox Corp	XRX	1,272.5	6.44	2.64	n/a	8,195.2	0.06%	0.00%	n/a
Xilinx Inc	XLNX	262.2	32.76	2.69	14.00	8,588.7	0.07%	0.00%	0.01%
XL Group PLC	XL	305.7	24.74	1.78	8.33	7,563.2	0.06%	0.00%	0.00%
Xylem Inc/NY	XYL	185.6	24.26	1.67	11.00	4,502.5	0.03%	0.00%	0.00%
Yahoo! Inc	YHOO	1,184.6	16.81	n/a	12.67	19,913.4	0.15%	n/a	0.02%
Yum! Brands Inc	YUM	451.8	70.11	1.91	11.00	31,676.3	0.24%	0.00%	0.03%
Zimmer Holdings Inc	ZMH	174.7	64.21	1.12	9.82	11,217.2	0.09%	0.00%	0.01%
Zions Bancorporation	ZION	184.1	21.47	0.19	7.75	3,953.7	0.03%	0.00%	0.00%
								2.27%	10.40%

Secondary Market Investor Required Return	Flotation Cost Adj.	Primary Market Cost of Capital
12.79%	1.04	**13.30%**

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PSC-079

Regarding: Business Risks – Q34
Witness: Gaske

a. **What is the relatively undiversified local economy to which you refer?**

b. **Why did you not select a proxy group more in line with the size of MDU's gas operations? Please explain.**

c. **Is it common to have a portion of fixed costs recovered in volumetric rates? Please explain.**

d. **Does the proxy group you've selected, have portions of its fixed costs recovered in volumetric rates? Please explain.**

e. **Would not the phenomenon of under recovery of costs be somewhat mitigated if MDU's Montana gas utility had rate cases more frequently than once every 8 years? Please explain.**

Response:

a. As described on page 6 of Dr. Gaske's Prepared Direct Testimony, Montana-Dakota provides natural gas distribution service to approximately 76,000 customers in eastern Montana. The service territory included many small towns and rural areas. The economy of eastern Montana is primarily based on ranching, wheat farming, oil and gas drilling, and coal mining. In Dr. Gaske's view, the economy of the Company's service territory is characterized by agriculture and natural resources, which indicates that the economy is not as diversified as some other regions of the country, and which increases the risk that a major employer or industry might experience a downturn that would significantly affect demand for natural gas distribution service.

b. The selection of proxy group companies is limited to those gas distribution companies which are publicly-traded, and which have dividend payments and estimated growth rates from reliable sources such as Value Line and Zacks. It would not be possible to develop a proxy group of publicly-traded gas distribution companies that are comparable in size to the gas distribution of Montana-Dakota in Montana. Consequently, Dr. Gaske has selected companies that are comparable in terms of their business and operating profiles, and then has made adjustments to reflect specific differences in risk between Montana-Dakota's gas distribution operations in Montana and the proxy group companies.

c. In the past it has been very common for a substantial portion of fixed costs to be recovered in the volumetric portion of rates. This practice has become less common in recent years as more jurisdictions have approved the implementation by gas distribution companies of revenue decoupling mechanisms and straight fixed-variable rate designs. As shown on Exhibit_(JSG-2), Schedule 4, more than 65 percent of the customers served by the proxy group companies are located in jurisdictions that have revenue decoupling mechanisms that break the link between fixed costs and customer usage.

d. As Shown in Exhibit_(JSG-2), fewer than 35 percent of the customers served by the proxy group companies are located in jurisdictions that are not covered by revenue decoupling mechanisms.

e. While more frequent rate cases could mitigate regulatory lag and under-recovery of costs, it would not be beneficial to Montana-Dakota's gas distribution customers in Montana. More frequent rate filings would result in higher rate case expenses, which would be spread over a relatively small customer base.

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PSC-080

Regarding: Decoupling – Q34
Witness: Gaske

Are you saying on lines 12-21 on page 28 of your testimony that MDU would be less risky if it had a decoupling mechanism in place? Please explain.

Response:

Yes. Revenue decoupling is one factor that distinguishes the risks of Montana-Dakota's Montana gas distribution operations from those of the proxy group companies. As shown in Exhibit_(JSG-2), Schedule 4, the majority of companies in the proxy group operate in jurisdictions with revenue decoupling mechanisms. To the extent that Montana-Dakota had revenue decoupling for its gas distribution operations, the company would be more comparable to the proxy group.

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PSC-081

Regarding: Regulatory Risk
Witness: Gaske

Please quantify in comparison to your proxy group the additional regulatory risk being borne by MDU.

Response:

As shown on Attachment A, Standard and Poor's and Regulatory Research Associates both rate the regulatory environment in Montana below the weighted average of the regulatory environments in the jurisdictions served by the proxy group companies. It is not possible to precisely quantify the effect of regulatory risk on the cost of equity for Montana-Dakota's Montana natural gas distribution operations. Instead, Dr. Gaske considered the elevated level of regulatory risk in Montana when determining where, within the range of returns produced by the proxy group, the cost of equity for Montana-Dakota's Montana natural gas distribution operations falls.

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Regulatory Risk

Proxy Group Company		Utility	State	[1] RRA Numeric Ranking	[2] RRA Ranking Description	[3] S&P Numeric Ranking	[4] S&P Ranking Description	# of Customers	% of Total Customers	% of Total Customers (exluding Tennessee)
AGL Resources Inc.	GAS	Atlanta Gas Light Company	GA	6	Average / 1	4	More credit supportive	1,541,000	12%	13%
AGL Resources Inc.	GAS	Northern Illinois Gas Company	IL	2	Below Average / 2	2	Less credit supportive	2,188,000	17%	18%
AGL Resources Inc.	GAS	Elizabethtown Gas	NJ	4	Average / 3	3	Credit supportive	276,000	2%	2%
AGL Resources Inc.	GAS	Florida City Gas	FL	7	Above Average / 3	3	Credit supportive	103,000	1%	1%
AGL Resources Inc.	GAS	Elkton Gas	MD	2	Below Average / 2	2	Less credit supportive	6,000	0%	0%
AGL Resources Inc.	GAS	Chattanooga Gas Company	TN	6	Average / 1			62,000	0%	1%
AGL Resources Inc.	GAS	Virginia Natural Gas, Inc.	VA	8	Above Average / 2	3	Credit supportive	278,000	2%	2%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	CO	6	Average / 1	3	Credit supportive	110,900	1%	1%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	GA	6	Average / 1	4	More credit supportive	59,982	0%	0%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	IL	2	Below Average / 2	2	Less credit supportive	22,537	0%	0%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	IA	7	Above Average / 3	4	More credit supportive	4,281	0%	0%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	KS	5	Average / 2	3	Credit supportive	128,207	1%	1%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	KY	6	Average / 1	3	Credit supportive	176,246	1%	1%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	LA	6	Average / 1	3	Credit supportive	343,598	3%	3%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	MS	7	Above Average / 3	2	Less credit supportive	258,913	2%	2%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	MO	5	Average / 2	2	Less credit supportive	55,890	0%	0%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	TN	6	Average / 1			130,395	1%	1%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	TX	3	Below Average / 1	2	Less credit supportive	1,873,236	15%	15%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	VA	8	Above Average / 2	3	Credit supportive	22,373	0%	0%
Laclede Group, Inc.	LG	Laclede Gas Company	MO	5	Average / 2	2	Less credit supportive	639,895	5%	5%
New Jersey Resources Corp.	NJR	New Jersey Natural Gas Company	NJ	4	Average / 3	3	Credit supportive	495,383	4%	4%
Northwest Natural Gas Company	NWN	Northwest Natural Gas Company	OR	4	Average / 3	3	Credit supportive	606,988	5%	5%
Northwest Natural Gas Company	NWN	Northwest Natural Gas Company	WA	4	Average / 3	2	Less credit supportive	72,555	1%	1%
Piedmont Natural Gas Company, Inc.	PNY	Piedmont Natural Gas Company, Inc.	NC	7	Above Average / 3	3	Credit supportive	671,434	5%	5%
Piedmont Natural Gas Company, Inc.	PNY	Piedmont Natural Gas Company, Inc.	SC	6	Average / 1	4	More credit supportive	132,169	1%	1%
Piedmont Natural Gas Company, Inc.	PNY	Piedmont Natural Gas Company, Inc.	TN	6	Average / 1			166,216	1%	1%
South Jersey Industries, Inc.	SJI	South Jersey Gas Company	NJ	4	Average / 3	3	Credit supportive	348,868	3%	3%
Southwest Gas Corp.	SWX	Southwest Gas Corp.	AZ	4	Average / 3	2	Less credit supportive	1,001,476	8%	8%
Southwest Gas Corp.	SWX	Southwest Gas Corp.	CA	6	Average / 1	4	More credit supportive	181,644	1%	1%
Southwest Gas Corp.	SWX	Southwest Gas Corp.	NV	5	Average / 2	3	Credit supportive	662,249	5%	5%
MDU Montana			MT	3	Below Average / 1	2	Less credit supportive			
Total Number of Customers								12,619,435		
Total Number of Customers (excluding Tennessee)								12,260,824		
Proxy Group Weighted Average				4.42	Average / 3	2.66	Credit supportive			

[1] Regulatory Research Associates, Commissions, RRA Ranking; Above Average/1= 9, Above Average/2= 8, Above Average/3= 7, Average/1= 6, Average/2= 5, Average/3= 4, Below Average/1= 3, Below Average/2= 2, Below Average/3= 1

[2] RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint, Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid range rating; and, 3, a weaker (less constructive) rating. We endeavor to maintain an approximately equal number of ratings above the average and below the average.

[3] Most credit supportive =5; More credit supportive =4; Credit supportive=3; Less credit supportive=2; Least credit supportive=1

[4] Standard and Poor's, Ratings Direct, Standard & Poor's Revises Its U.S.= Utility Regulatory Assessments, December 28, 2012 page 3[

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PSC-082
Regarding: Financial Risk
Witness: Gaske

a. **Does MDU, as a division of MDU Resources, as a result of not having its own bonds outstanding, share in the risk of the other non-regulated divisions of MDU Resources? Please explain.**

b. **If your answer to "a." above is no, are the assets of MDU as a division of MDU Resources used to secure that debt? Please explain.**

c. **If your answer to "a." is yes, does the inherent riskiness of non-regulated business have an effect on the bond ratings of MDU Resources? Please explain.**

Response:

a. No, Montana-Dakota as a division of MDU Resources, issues debt under MDU Resources. The only debt issued at the MDU Resources level is debt for Montana-Dakota's utility operations. Debt for the non-regulated companies is issued at the subsidiary level and not issued as MDU Resources debt. There are no credit facilities that contain cross-default provisions between MDU Resources and any of its subsidiaries.

b. No, currently MDU Resources does not possess a First Mortgage Indenture but rather issues non-secured senior notes.

c. Not applicable.

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PSC-083

Regarding: Summary and Conclusions
Witness: Gaske

a. **Which companies in your proxy group were in which quartile of your table 3?**

b. **Please explain why you selected the median rather than the mean in your analysis.**

Response:

a. The table below indicates by ticker symbol which companies were in each quartile of Table 3.

	Retention Growth DCF Analysis	Basic Analysts DCF	Blended Growth Rate Analysis
High	SJI	SJI	SJI
3rd Quartile	GAS, NJR	GAS, ATO	GAS, NJR
Median	NWN, SWX	NWN, PNY	ATO, NWN
1st Quartile	ATO, LG	LG, NJR	LG, PNY
Low	PNY	SWX	SWX

b. Please see response No. PSC-072.

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PSC-084

Regarding: Risk premium analysis and DCF results
Witness: Gaske

a. **If the median of each of the DCF estimation methods were lower than the 9.8 percent risk premium estimate, why did you recommend an ROE of 10.5 percent, especially given your testimony that the financial risks are less than the proxy group?**

b. **Given the Bakken oil boom, is not the customer base of MDU growing rather than shrinking? Please explain.**

Response:

a. As discussed on pages 35-36 of Dr. Gaske's Prepared Direct Testimony, while Montana-Dakota's financial risks are slightly below average relative to the proxy group, the company has business risks that are above average. Overall, Dr. Gaske concluded that the risks of Montana-Dakota's Montana natural gas distribution operations are near the top of the range relative to those of the proxy group. Therefore, Dr. Gaske recommended an ROE of 10.50 percent, which is at the top of the range produced by the Blended Growth Rate DCF analysis.

b. Dr. Gaske's understanding is that the Bakken oil shale development has not had a significant effect on the Montana gas distribution operations of Montana-Dakota. As discussed on page 6 of Dr. Gaske's Prepared Direct Testimony, while the average number of customers for Montana-Dakota's Montana natural gas distribution business has been growing slightly in recent years, the average usage per customer has been declining due to energy efficiency and conservation. Further, Montana-Dakota has not needed to make significant capital investments in its Montana gas distribution territory in order to serve additional customer demand due to growth associated with the Bakken oil shale development.

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PSC-088

Regarding: Supporting information
Witness: Robinson

Please provide a copy of all correspondence, notes, memoranda, emails, etc., containing or reflecting information obtained from MDU personnel used in the development of depreciation parameters, methods, technologies, etc., in the depreciation study where such items of information were of a significant or meaningful nature. The information should be provided by account, clearly identifying the source of the information, the impact such information had on any proposed mortality characteristics, and all underlying workpapers, assumptions, considerations, and material reviewed and/or relied upon in sufficient detail to permit verification of the accuracy of each item of information obtained.

Response:

Please see the enclosed CD for the electronic file entitled 'MDU Exhibit PSC-088-Database & Ind Data – Copy.zip'.

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PSC-089

Regarding: Supporting information
Witness: Robinson

a. **Please provide a copy of all correspondence, notes, memos, emails, etc., associated with all communications between your company and MDU personnel regarding information applicable to the development of life or salvage proposals.**

b. **Please provide all underlying assumptions, considerations and material reviewed and/or relied upon by the MDU personnel to arrive at each item of information provided to you that impacts the life and/or salvage proposals reflected in the depreciation study. The response should identify the account or accounts to which each item of information applies.**

Response:

a-b. Please see Response No. PSC-088.

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PSC-092

Regarding: Depreciation Reports
Witness: Robinson

a. **For each group in your analysis, please specify what categories are in each group and percentage of that group. For example if Group X has poles and vehicles, please specify the categories "Poles – XX%", "Vehicles – XX percent."**

b. **Did you investigate that aspect of the grouping? Not only age but category groupings? Why or why not?**

Response:

a-b. Please see Response No. PSC-091.

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PSC-094
Regarding: On site visit
Witness: Robinson

Please provide a copy of all site visit notes, pictures, etc., associated with any site visits performed by you, specifically identifying the dates and times associated with the visual inspection of each specific type of property.

Response:

Please see the enclosed CD for the electronic file entitled 'MDU Exhibit PSC-094-Site Tour Info.pdf'.

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PSC-123
RE: Customer growth
Witness: Jay Skabo

Has the Company attempted to isolate load growth attributable to the growth in oil production occurring in that part of its service territory located near the Bakken field?

Response:

Montana-Dakota has not attempted to isolate load growth attributable to the growth in the Bakken oil fields, however, as stated on page 7 of Mr. Skabo's testimony, Montana-Dakota examined its customer growth between December 31, 2004, at the time of the last general rate case, and December 31, 2011 where there has been an increase of approximately 6,040 natural gas customers with the majority of the growth occurring in Billings. Areas in far eastern Montana are part of the Badlands Region, and in this area, most of the growth has occurred within the last two years due to growth in the Bakken oil fields.

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PSC-132
RE: Consolidated Company
Witness: J. Stephen Gaske

a. **Why is it reasonable for the proxy group you select to exclude gas local distribution companies that, like MDU, are embedded within a highly diversified parent corporation?**

b. **You state on p. 16, lines 20-21, that "the market-based DCF analysis of Montana-Dakota's natural gas distribution operations as a stand-alone company is not possible." Isn't it possible to make an educated guess by pro-rating the share of MDU's natural gas utility operations from its consolidated parent's operations and so impute a dividend or other value on which a DCF analysis relies?**

Response:

a. Because the gas distribution companies embedded within diversified holding companies do not have publicly-traded common stocks, the stock prices, risks and cost of capital for the holding companies reflect the diversified operations and are not specific to the gas distribution subsidiaries. Therefore, in order to isolate the cost of capital for the gas distribution subsidiaries we start by estimating the cost of capital for relatively pure gas distribution companies that have publicly-traded stock.

   In developing a proxy group of comparable companies for Montana-Dakota's Montana natural gas distribution operations, it is reasonable to select companies that engage in the same line of business – natural gas distribution. Because Dr. Gaske was not assessing the cost of equity for Montana-Dakota's parent company, MDU Resources Group, Inc., it is not reasonable to select a proxy group of highly diversified holding companies that are not comparable to Montana-Dakota's Montana natural gas distribution operations.

b. In Dr. Gaske's view, it is not possible to make an educated guess of the cost of equity for Montana-Dakota's Montana natural gas distribution operations based on the cost of equity for the parent company. The parent company, MDU Resources Group, Inc., is a diversified enterprise that engages in several other lines of business, and it is impossible to determine what percentage of the company's stock price, dividend, and future growth prospects are attributed to natural gas distribution operations by investors and the company's management. Consequently, it is necessary to use a proxy group of natural gas distribution companies, as Dr. Gaske has done, to estimate the cost of equity for Montana-Dakota's Montana natural gas distribution operations.

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PSC-133

RE: Proxy Group
Witness: J. Stephen Gaske

a. Identify the companies you eliminated from the proxy group because they did not have investment-grade bond ratings, p. 17, lines 8-10.

b. Identify the companies you eliminated because they did not pay dividends or have future growth estimates, p. 17, lines 12-13.

Response:

a. Out of the initial group of publicly-traded gas distribution companies, no companies were eliminated from the proxy group because they did not have investment-grade bond ratings.

b. Out of the initial group of publicly-traded gas distribution companies, no companies were eliminated from the proxy group because they did not pay dividends or have future growth estimates.

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PSC-134
RE: Risk profile
Witness: J. Stephen Gaske

You indicate that "Montana-Dakota's Montana gas distribution operations face some particular risks that distinguish the Company from the proxy group of distribution companies," p. 27, lines 7-9.

a. Have you studied whether the local economies where members of the proxy group do business are more or less diversified than MDU's?

b. Have you studied the unemployment rate or economic growth rates of the local economies where members of the proxy group do business in comparison to that of MDU's local service territory in Montana?

c. Are you aware of any modifications to MDU's energy efficiency and conservation efforts recently that would heighten or reduce the risk to MDU of relying on volumetric rates because energy efficiency programming has either increased or declined, respectively?

d. Have you identified whether other members of the proxy group have weather normalization provisions in their tariffs?

e. Have you studied the likelihood of a risk that a major business would experience a downturn, which you state on page 28, lines 4-8, will actually come to pass?

Response:

a. Yes.

b. Dr. Gaske reviewed state-level data on the unemployment rate and economic growth rates of the local economies served by the proxy group companies.

c. No, Montana-Dakota saw modest participation in its Montana natural gas energy efficiency programs during 2012 and anticipates future participation will remain the same or decline. The conservation taking place outside the Company sponsored energy efficiency programs is a risk as discussed on page 6 of Dr. Gaske's Prepared Direct Testimony.

d. Yes.

e. Dr. Gaske has not quantified the likelihood that a major customer would experience a downturn, and he does not believe this likelihood can be quantified. However, the oil and gas drilling business has a long tradition of significant boom-and-bust cycles depending on economic conditions and prices for the commodities. In addition, more diversified economies generally are expected to have less likelihood of major downturns than less diversified economies.

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PSC-135

RE: Regulatory Research Associates paper
Witness: J. Stephen Gaske

Provide the document referred to in footnote 15, p. 31.

Response:

Please see Attachment A.

Regulatory Research Associates
REGULATORY FOCUS

MONTANA REGULATORY REVIEW -- JUNE 8, 2011

Montana Public Service Commission (PSC)
1701 Prospect Avenue
P.O. Box 202601
Helena, MT 59620-2601
(406) 444-6199

Please note that the sections below are updated through 6/8/11, but are maintained on a real-time basis in the Commission Profiles section of our website.

No. of Commissioners	5 full-time
Method of Selection	Elected in statewide elections
Term of Office	4 years -- staggered terms
Chairman	Elected by fellow Commissioners for a two-year term
Governor	Brian Schweitzer (D)--serving a four-year term that extends to January 2013

Commissioners	Party	Began Serv.	Term Ends	Background
Travis Kavulla (Chairman)	R	1/11	1/15	Freelance journalist; Gates Scholar; editor
Gail Gutsche (Vice Chairman)	D	1/09	1/13	State Legislator; small business owner
Brad Molnar	R	1/05	1/13	State Legislator; building contractor
John Vincent	D	1/09	1/13	State Legislator; Speaker of the Montana House of Representatives
Bill Gallagher	R	1/11	1/15	Farmer; hotel owner and operator; insurance sales manager

Miscellaneous Issues:

<u>Commissioner Selection</u>--Commissioners are elected in statewide elections from each of five districts.

<u>Services Regulated</u>--In addition to private and investor-owned electric and gas utilities, as well as telecommunications and water utilities, the PSC regulates buses, taxicabs, motor carriers, and utility securities issuances.

<u>Staff Contact</u>--Kate Whitney, Administrator, Utility Division (406) 444-3056 (Section updated 6/8/11)

RRA Evaluation:

We view the Montana regulatory environment as somewhat restrictive from an investor perspective. While a recent rate case was resolved via a settlement that included a return on equity that was slightly above industry averages, the PSC commonly authorizes equity returns that are slightly below prevailing industry averages. After almost a decade of indecision, in 2007, the state finally abandoned its move towards implementing retail competition in the electric industry. Around the same time, the Commission rejected the proposed merger of <u>NorthWestern Corp.</u> and Babcock & Brown Infrastructure Ltd. Although NorthWestern sold its generation assets during the state's flirtation with retail competition, utilities are now permitted to seek PSC pre-approval for new generation resource additions. However, inclusion of construction work in progress in rate base is not permitted, which contributes to regulatory lag. By comparison, the gas arena has been more stable, as full retail choice has been in place for more than a decade, and gas utilities are now permitted to acquire upstream assets. Both the electric and gas utilities have mechanisms in place that facilitate the recovery of commodity and related costs. In a recent PSC action of note, the Commission authorized one of the state's utilities to implement a pilot decoupling mechanism for small-volume electric customers.

However, the decision has been appealed and the parties have reached an agreement calling for the mechanism to be terminated. We continue to accord Montana regulation a Below Average/1 rating. (Section updated 6/8/11)

Department Budget: The PSC's fiscal-2011 budget is approximately $3.5 million, derived from a tax on utility revenues. (Section updated 6/8/11)

Commissioner Salaries: Chairman-$88,500, Commissioners-$87,600 (Section updated 6/8/11)

Commission Staff: The PSC Staff consists of 34 members. (Section updated 6/8/11)

Consumer Interest: The consumer interest is represented by the Montana Consumer Counsel (MCC). The MCC, which operates independently of the PSC, is appointed by the Legislature's Consumer Committee for an unspecified term. The current MCC, Robert Nelson, has held the position since 1988. (Section updated 6/8/11)

Rate Case Timing/ Interim Procedures: The PSC must render a final decision in a rate case within nine months of a filing. If no order has been issued by the end of the nine-month period, the utility may place a requested increase into effect, subject to refund. We note that a recent (decided in December 2010) NorthWestern Corp. rate case took over a year to complete; the case was delayed due to the PSC's finding that the company's rate application did not meet the state's minimum filing requirements. In most rate cases, the Commission has authorized interim rate changes on a subject to refund basis, usually within two to four months after the date of filing. (Section updated 6/8/11)

Return on Equity: The most recent rate case decision that specified a return on equity (ROE) was issued on Dec. 9, 2010, when the PSC adopted modified electric and gas rate settlements for NorthWestern Corp., authorizing the company a 10% ROE for its electric operations and a 10.25% ROE for its gas operations. In that decision, the Commission reduced the electric ROE agreed to by the parties by 25 basis points to 10%. We note that NorthWestern and the PSC Staff have reached an agreement in an appeal of the case that would, among other things, restore the authorized ROE to 10.25%. The appeal is pending. Previously, in 2008, in the context of a proceeding in which NorthWestern sought approval to include its ownership interest in the Colstrip Unit 4 plant in rate base, the PSC approved a 10% ROE for the company's investment in the facility (FN 11/14/08). In 2009, in the context of a proceeding in which NorthWestern applied for PSC approval to construct the Mill Creek plant, the PSC adopted a 10.25% ROE for the company's investment in that facility (FN 5/22/09). NorthWestern does business in the state as NorthWestern Energy. In 2008, the PSC established a 10.25% ROE for MDU Resources' (MDU's) electric operations following a settlement. MDU is authorized a 12% ROE for its gas operations, as established in 1996 in a small rate case. MDU does business in Montana as Montana-Dakota Utilities. (Section updated 6/8/11)

Rate Base and Test Period: The PSC generally relies on an average original-cost rate base for a historical test period, adjusted for known-and-measurable changes within 12 months beyond the end of the test period. The PSC generally does not permit construction work in progress to be included in rate base. (Section updated 6/8/11)

Alternative Regulation: State statutes allow the PSC to approve up to a 200-basis-point return on equity (ROE) premium for demand-side management program investments. To date, no such premium has been requested. From 1996 through 1998, NorthWestern Corp. (then Montana Power) operated under an electric alternative regulation plan, that provided for earnings in excess of an 11.4% ROE to be shared equally with ratepayers.

MDU Resources (MDU) utilizes a monthly fuel and purchased power cost adjustment mechanism. Incremental changes in fuel and purchased power costs, and off-system sales margins are to be shared by ratepayers and shareholders on a 90%/10% basis through this mechanism, which is to terminate on Dec. 31, 2011, unless extended by the PSC. (Section updated 6/8/11)

Court Actions: PSC decisions may be appealed first to a Montana District Court and then to the

State Supreme Court. On Jan. 26, 2011, NorthWestern Corp. filed an appeal with the District Court regarding the PSC's Dec. 9, 2010 decision in a general rate proceeding (FN 2/18/11). The parties to the appeal have reached an agreement calling for, among other things, the company's authorized ROE for electric operations to be raised to 10.25%, and for NorthWestern to terminate its pilot electric decoupling mechanism (See the Return on Equity and Adjustment Clauses sections). The appeal is pending. (Section updated 6/8/11)

Legislation:

The Montana Legislature convenes on the first Monday in January in odd-numbered years for a maximum of 90 legislative days. The Senate currently has 28 Republicans and 22 Democrats, and the House of Representatives has 68 Republicans and 32 Democrats. The 2011 session adjourned on April 28.

On March 25, 2011, H.B. 92 was enacted, requiring the PSC to utilize an avoided-cost approach to establish long-term purchased power contracts between qualifying small power producers and the state's electric utilities.

On April 28, 2011, Gov. Schweitzer vetoed House Bill (H.B.) 59, legislation that would have expanded the established parameters for qualifying hydro facilities from which electric utilities could have procured power in order to comply with the state's renewable portfolio standards. Gov. Schweitzer also vetoed similar legislation, Senate Bill 109, on April 13, 2011. (Section updated 6/8/11)

Corporate Governance:

Generic/Legislation--The PSC has authority over mergers involving utilities (see the Merger Activity section), corporate reorganizations, affiliate relationships, and securities issuances. The PSC is statutorily authorized to review and approve "material affiliate transactions" including: dividend payments from a regulated energy utility to a corporate parent company, as the PSC may limit such payments if the proposed amounts would place the regulated energy utility's credit quality or property in jeopardy; inter-company loans or other extensions of credit or advances of working capital between a regulated energy utility and an affiliate; the use of proceeds from security issuances for which the assets of the regulated energy utility are pledged; and, external borrowing of a regulated energy utility with a term greater than 120 days. Utilities that have signed settlements with the PSC (e.g., NorthWestern Corp. -- see below) regarding the separation of their non-regulated businesses are exempt from the statute's requirements.

In 2004, the PSC approved a settlement that resolved an investigation into NorthWestern's financial condition and affiliate transactions. The Consent Order incorporated the provisions of a settlement that had been filed in NorthWestern's bankruptcy proceeding, including: the separation of NorthWestern's utility assets from unregulated operations, with all debt associated with non-utility assets or activities to be held by affiliates or subsidiaries and to be non-recourse to the parent company; and, limits on non-utility investments until the company achieves a credit rating of BBB+. The U.S. Bankruptcy Court subsequently adopted the settlement. In late-2004, the Court approved NorthWestern's amended Chapter 11 reorganization plan, and the plan became effective upon the company's emergence from bankruptcy in November 2004. (Section updated 6/8/11)

Merger Activity:

In 1998, the PSC approved the sale of PacifiCorp's electric operations in Montana to Flathead Electric Cooperative; the merger was completed in 1999. In 2002, the PSC adopted a settlement that approved NorthWestern Corp.'s acquisition of the electric and gas distribution assets owned by Montana Power (MP). The settlement and PSC order provided for the implementation of a $30 million customer credit for one year beginning July 1, 2002, and the recovery of $244.7 million in electric restructuring transition costs over 27 years through a competitive transition charge. This surcharge is to remain in place despite the state's return to a traditional regulatory paradigm. The acquisition was subsequently completed, and NorthWestern began operating the former MP assets as NorthWestern Energy.

In 2004, the PSC issued a statement of criteria to be utilized for evaluating proposals to acquire NorthWestern. At that time, the Commission stated that, in accordance with past PSC practice, it would assert its authority to review any sale or transfer of NorthWestern's Montana-jurisdictional operations. The PSC noted that the settlement reached in the context of NorthWestern's bankruptcy case in

2004 (see the Corporate Governance section) would be binding on any successor company. The PSC stated that an acquirer of the company should be a financially stable, investment-grade utility, and that any acquisition premium would not be recoverable through rates. In addition, the acquirer must: be committed to fund the company's pension plan at a level not below NorthWestern's then-current funding forecast; be committed to long-term ownership of the utility; show a "demonstrable Montana focus" that would occur through the maintenance of a Montana headquarters of either the company or a separate Montana utility subsidiary; have no operating ties to South Dakota or Nebraska; have strong utility management experience; and, demonstrate "financial and management ability to acquire an appropriate electricity supply under the Commission's guidelines."

In 2006, NorthWestern and Babcock & Brown Infrastructure Ltd. (B&B) reached a definitive agreement, whereby B&B would acquire NorthWestern. However, the PSC ultimately rejected the merger, finding that the proposed transaction presented "risk of harm to NorthWestern's financial integrity" and to Montana ratepayers. Specifically, the PSC opined that "the proposed ownership of NorthWestern presents the likelihood that NorthWestern's capital structure will deteriorate and become unacceptably leveraged" due to B&B's intention "to extract excessive equity" from NorthWestern in order to recover the merger acquisition premium. In accordance with the terms of the PSC's bankruptcy-related Consent Order and aforementioned statement of criteria, the companies had agreed that: NorthWestern's utility assets would be owned and operated independently from Babcock & Brown's other businesses; NorthWestern would not pledge its Montana assets to secure the indebtedness or provide financing to affiliated businesses, except in accordance with state statutes; NorthWestern would not enter into any contract with an affiliate for which the costs would be recovered in utility rates, except in accordance with state statutes; and, NorthWestern would maintain separate books for its utility operations. (Section updated 6/8/11)

Electric Regulatory Reform/ Industry Restructuring:

Legislation--Legislation enacted in 1997 required full retail competition to be implemented for customers of NorthWestern Corp. (then Montana Power) by July 1, 2007. As per the law, the company sold its generation assets in 1999 and subsequently entered into purchased power contracts with competitive suppliers to serve provider-of-last-resort (POLR) customers. Legislation enacted in 2003 amended the law by delaying the implementation date of full retail competition to July 1, 2027 from July 1, 2007. Under the 2003 law, large commercial and industrial customers had the option to switch to competitive suppliers and also had a one-time option to return to the POLR for service beginning in 2004, but no customers chose to return to the POLR.

In 2007, legislation was enacted that largely repealed the retail competition provisions of the law. Specifically, the legislation: eliminated the requirement for the implementation of full retail competition; authorized the incumbent utilities to request PSC pre-approval of new generation resource additions, with such resources to be ultimately included in the utility's rate base upon completion; prohibits existing retail choice customers with monthly demand of at least 5,000 KW from returning to the utility, unless the customer can demonstrate that such a supply arrangement will not adversely impact the utility's other customers; requires that all supply arrangements between the utility and its customers be regulated by the PSC; permits existing retail choice customers with monthly demand below 5,000 KW to elect to receive supply from the utility -- those customers that return to the utility would be prohibited from choosing an alternate supplier at a later date; prohibits existing full-service customers with monthly demand below 5,000 KW from switching to an alternate supplier; continues to require the PSC to establish mechanisms through which the utility can recover its supply costs -- the PSC would be permitted to include other utility costs and expenses in such a mechanism, if those costs are found to be in the public interest; and, requires the utility to sequester a minimum of 50% of the carbon dioxide produced by a generation facility until state or federal standards for sequestration are adopted.

Company-Specific Plans--In 1997, in accordance with the then-existing law, NorthWestern Corp. filed a transition plan seeking recovery of certain stranded costs. In 2002, the PSC adopted a settlement setting the net present value of NorthWestern's transition costs at $244.7 million, and authorized recovery of this amount via a surcharge that would be in place through 2029. This surcharge remains in place despite the state's return to a traditional regulatory paradigm. The surcharge is trued-up at the end of each year. (Section updated 6/8/11)

Gas Regulatory Reform/ Industry Restructuring:

Legislation--Since 1997, gas utilities have been permitted to offer open access to transmission, storage, and distribution facilities, and have been allowed to provide customers with the option to choose a natural gas supplier. A local distribution company (LDC) that offers customer choice is required to functionally separate gas production and gathering from transmission, storage, and distribution services, and remove production and gathering investments from rate base. An LDC may apply to the PSC for recovery of transition costs. Upon PSC approval, a utility may finance fixed transition costs with securitization bonds. Gas utilities that have implemented customer choice may acquire gas gathering and production facilities and request PSC approval to include such assets in rate base, as permitted by state law.

Customer Choice--Transportation-only service for large-volume customers has been available for several years, and retail choice for small customers was phased in by 2002. NorthWestern Corp. and MDU Resources (MDU) utilize cost recovery mechanisms to recover gas supply costs incurred to serve default customers.

Stranded Cost Recovery--Under state law, NorthWestern may recover stranded gas production assets and related regulatory assets over a 15-year period. In 1997, the PSC adopted settlements authorizing NorthWestern to implement a surcharge for gas production assets for the recovery of $35.6 million of such costs, and a second surcharge for the recovery of $24.3 million of production-related regulatory assets and conservation investments. Securitization of these costs is permitted, and $62.7 million of such bonds were issued in 1998 (see the Securitization section.) State law effectively precludes MDU from recovering stranded gas-related assets through a surcharge. (Section updated 6/8/11)

Securitization:

In 1998, the PSC approved NorthWestern Corp.'s application to issue up to $65 million of gas retail competition transition bonds. A special purpose entity formed by the company subsequently issued $62.7 million of transition bonds, and the proceeds were used to reduce the company's outstanding debt and equity. State law permitted NorthWestern to request PSC approval to issue electric transition securitization bonds; however, no action to securitize these stranded costs was taken. (Section updated 6/8/11)

Adjustment Clauses:

In accordance with the state's restructuring statutes, NorthWestern Corp. (then Montana Power) sold its generation assets in 1999 and subsequently entered into purchased power contracts with competitive suppliers to serve provider-of-last-resort customers. NorthWestern recovers supply costs through a cost recovery mechanism, adjusted monthly, under which rates are based on estimated loads and electricity costs for the upcoming tracking period. The PSC reviews and adjusts rates for differences between estimates and actual results. NorthWestern is also permitted to recoup revenues lost as a result of demand-side management programs in the context of its annual default supply cost recovery filings.

MDU Resources (MDU) utilizes a monthly-adjusted fuel and purchased power cost adjustment mechanism that contains certain incentive provisions (see the Alternative Regulation section). The mechanism is to terminate on Dec. 31, 2011, unless extended by the PSC.

On Dec. 9, 2010, the PSC authorized NorthWestern to implement a pilot decoupling mechanism for its residential and small general service electric customers in the context of a general rate case. The mechanism excludes revenue variations due to weather. The pilot program is to be in effect for a four-year period. We note that the decoupling mechanism and certain other aspects of the PSC's Dec. 9, 2010 decision are the subject of an appeal pending before the District Court (see the Court Actions section). The parties to the appeal have reached a settlement that, among other things, calls for the decoupling mechanism to be terminated.

MDU and NorthWestern are permitted to track changes in the cost of purchased gas and other gas costs through separate tariffs. The companies defer, for later recovery or refund, gas expenses that are in excess of, or less than, the costs recovered through current rate levels. MDU Resources' also utilizes a tracking (decoupling) mechanism to recover the costs associated with gas conservation programs, as well as to recoup revenues lost as a result of the programs. This mechanism excludes the effects of weather on revenues. (Section updated 6/8/11)

Integrated Resource Planning:

The state's utilities file resource plans every two years, and generally use a 20-year planning horizon. The filings are largely informational, and PSC approval is not required. We note that the two largest Montana utilities operate under different resource planning frameworks, as NorthWestern Corp. is a restructured utility and MDU Resources is a vertically integrated utility.

Legislation enacted in 2007 largely repealed previously-enacted electric restructuring statutes (see the Electric Regulatory Reform/Industry Restructuring section) and authorized the utilities to seek PSC pre-approval of new generation resource additions, including the ratemaking parameters to apply to the individual projects for the life of the project (see the Return on Equity section).

On March 25, 2011, legislation was enacted requiring the PSC to utilize an avoided-cost approach to establish long-term purchased power contracts between qualifying small power producers and the state's electric utilities. (Section updated 6/8/11)

Renewable Energy:

State law requires Montana's electric utilities to procure at least 15% of their supply from renewable resources by 2015. Beginning in 2008, providers were required to obtain at least 5% of their generation from renewable resources, with the threshold rising to 10% in 2010, and to 15% in 2015. (Section updated 6/8/11)

Jim Davis

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-136
RE: CAPM
Witness: J. Stephen Gaske

Confirm that you did not engage in CAPM analysis and, if you did not, explain why.

Response:

Dr. Gaske confirms that he did not perform a CAPM analysis in this proceeding. As discussed in more detail below, Dr. Gaske questions the ability of the CAPM to produce valid and reliable estimates of the cost of equity due to concerns with the ability of Beta to measure risk and how to determine the appropriate equity risk premium.

Although the early academic literature appeared to validate the CAPM, subsequent research casts serious doubt on its empirical validity. In a 1992 article, "The Cross Section of Expected Stock Returns," *Journal of Finance*, 47:427-465 (June 1992), Eugene Fama and Kenneth French examined the relationship between Beta and the returns earned by companies. This article essentially re-visited the research from the late 1960's and early 1970's that appeared to verify Beta as a reasonable measure of risk and required return. That earlier research primarily relied on data from the 1960's and found a significant correlation between actual stock returns and certain measures of Beta. In other words, stocks with high Betas tended to experience higher returns, and stocks with low Betas tended to experience lower returns. It was therefore assumed that "Beta" is an accurate measure of the risk that is relevant for determining the cost of capital.

The 1992 Fama and French article recognized that there are numerous ways to calculate "Beta" and the authors tested thousands of different Beta calculations over hundreds of different holding periods between 1963 and 1990. Their 1992 article found that there was no statistically significant relationship between Betas and stock returns in the vast majority of different time periods. In other words, Beta could not explain the level of returns on stocks and, therefore, one could not assume that Beta can accurately measure the risks that are relevant for determining the cost of capital. The notable exception to that finding occurred for some Betas generally measured during the 1960's. The ultimate conclusion of this comprehensive analysis was that Beta was not significantly related to stock returns, and that the supposed verification of Beta during the early 1970's was a statistical anomaly. Although they found that the level of Beta does not correlate well with the returns on common stocks, Fama and French found that firm size (with smaller companies requiring higher returns) and market-to-book ratio are the two variables that best explain

Response No. PSC-136 continued.

the returns for common stocks.[15] With regard to these findings Value Line commented as follows:

> Indeed, Professor Fama concluded, 'The fact is that Beta, as the sole variable explaining returns on stocks, is dead.' These findings support previous studies that have called into question the real-world applicability of the CAPM Beta, including papers by Keim (Financial Analysts Journal, 1986), and Roll (Journal of Financial Economics, 1977). Never before, however, has the lack of a statistically significant relationship between beta and return been so rigorously and dramatically established.[16]

The intuitive basis of the CAPM is that investors will seek to be compensated for the relative systematic (or non-diversifiable) risk of a given stock in relation to a risk free investment and the broader market for equities. Many academics and practitioners question whether Beta, in the best of circumstances, can plausibly measure the true risk characteristics of a firm and advise that there are other risks that may influence investors' decisions. The CAPM assumes that any risk that can be diversified in an investors' portfolio, is diversified, and therefore irrelevant to the cost of capital. However, this assumption may not represent actual investor behavior; and it is likely that diversification reduces a firm's relevant risks less than the CAPM theory assumes. For example, a comprehensive study of Canadian stock returns concluded that:

> The empirical study on the Canadian equity market demonstrates the existence of size premia based on data from 1993 to 2007. Results also indicate that beta, the CAPM's risk measure, was a weak measure to explain expected returns for smaller firms as smaller firms have a high unsystematic risk component.[17]

To the extent that variables other than Beta are able to explain variations in return that are not explained by Beta, diversification does not eliminate all unsystematic risks and the CAPM cannot be considered to be an adequate measure of the cost of capital.

Though the CAPM has a plausible theoretical basis, its application also is often the source of controversy and exhaustive debate among practitioners. For example, the expected future market equity risk premium is difficult to quantify, and involves debates concerning the preference for ex-ante or ex-post methodologies, averaging conventions, time period covered, etc. The second most contested factor is the controversy surrounding Beta, which has no theoretically correct method of quantification and has been shown to be a poor indicator of actual stock returns.

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[15] Fama and French, "The Cross-Section of Expected Stock Returns," *Journal of Finance*, Vol. XLVII, No. 2, June 1992, 427-465.
[16] Value Line Industry Review, March 13, 1992, p. 1-8.
[17] Wilhelm, K., "Size Premia in the Canadian Equity Market," *Journal of Business Valuation*, May 2009, p. 19.

Response No. PSC-136 continued.

Moreover, there is debate on whether Beta should be adjusted towards the market mean or the utility-sector mean, or whether it is appropriate to use a raw Beta without adjustment. All of these factors lead to questions on whether the CAPM may reliably track the capital costs of a regulated utility.

Application of the CAPM – and more specifically, estimation of investors' expectation of a forward-looking "Beta" – is based on the concept that the value of each individual stock (or other investment) has a reasonably fixed, known and measureable sensitivity to changes in the value of a market portfolio consisting of all other investments in the economy. However, there are several fundamental problems with the CAPM that have been established in the finance literature.

First, there are no theoretically correct time intervals for measuring the returns and risks that are relevant for investors, but the calculated level of Beta can be very different when different measurement intervals are used. Therefore, the selection of time intervals for measuring Beta – and by extension the level of Beta – is an arbitrary decision that cannot be defended on either theoretical or empirical grounds.

Second, the Beta and risk-premium inputs to the CAPM generally are based on historical rather than forecasted information. However, there is no theoretically correct *historical* time period (e.g., two years, five years, 10 years, etc.) over which to measure the *future* Beta that investors currently expect, and there is significant evidence that Beta does not remain constant from one period to the next. Thus, a Beta measured using historical data cannot provide an accurate estimate of the level of risk investors currently expect on a forward-looking basis.

Third, although several early studies conducted approximately 40 years ago were thought to have validated the accuracy of the CAPM, more complete empirical studies since that time have shown that the CAPM is not accurate and that the results of early studies may have been a statistical anomaly. In general, Beta estimates do not have a strong correlation with the returns earned on investments and therefore Beta estimates would not be expected to provide valid estimates of the relative cost of common equity.

Although Beta is supposed to be the measure of how sensitive the return on a particular stock is relative to the return on a diversified market portfolio, there are no theoretically correct time intervals for measuring that sensitivity. For example, one could measure Beta using an annual interval that calculates the relationship between the return on a stock and the return on the market portfolio from one year to the next. However, it would be equally "correct" to measure Beta by calculating the relationship between the returns that occur each month. Similarly, the theory allows Beta to be measured using the rates of return that occur weekly, or daily, or any other time period the analyst chooses. Because there are no theoretically correct time intervals for measuring the returns, it is an arbitrary choice

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as to which time intervals to use. Many studies, including Levhari and Levy[18] and Hawawini[19], have shown that the level of Beta can be very different depending on the time interval selected for measuring returns. For example, Hawawini cites Eastman Kodak as one example where the Beta was 1.25 based on daily returns, but it was 0.93 based on monthly returns.[20] Discrepancies of this magnitude are not unusual when different return intervals are used to estimate the value of Beta. Because the level of Beta is sensitive to the time intervals of the returns used in its calculation, and the time intervals used are selected arbitrarily, the level of Beta used in a CAPM analysis ultimately is an arbitrarily selected number. An arbitrarily selected Beta cannot be considered to be a reasonable or accurate method for estimating the cost of common equity.

Investors' current requirements and expectations for the future are not necessarily the same as the past. Thus, even if we ignore the problem that there is no theoretically accurate or reliable way to measure what "Beta" has been in the past, there is no reason to believe that investors currently perceive the same risks and require the same premiums for risk that were experienced in the past. Instead, investors' current expectations for "Beta" are forward-looking and not historical. Moreover, it is not unusual for calculated Betas to shift from one period to the next in ways that appear to be unrelated to any changes in risk.

In addition to the proven inaccuracy and unreliability of Beta, the market risk premium is another important component of the CAPM equation that changes over time. Historical market risk premia are less reliable than reasonable forecasts because the historical average relationships between equity returns and bond yields may not reflect the current circumstances. Further, analysts who use the CAPM approach often ignore the current level of interest rates in estimating a risk premium.

From a conceptual perspective, the CAPM has many weaknesses that make it an unreliable method for estimating the cost of common equity capital. In a 2004 article that reviewed the history of attempts to test the validity of the CAPM, Fama and French concluded that:

Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems

[18] Levhari, D. and Levy, H., "The Capital Asset Pricing Model and the Investment Horizon," *Review of Economics and Statistics* (February 1977), 92-104.

[19] Hawawini, G., "Why Beta Shifts as the Return Interval Changes," *Financial Analysts Journal* (May-June 1983), 73-77.

[20] Ibid., p. 73.

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may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model.[21]

For all of the reasons discussed above, Dr. Gaske does not believe the CAPM should be considered to be a valid or reliable method for estimating the cost of common equity capital for a regulated company such as Montana-Dakota's Montana natural gas distribution operations.

[21] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *Journal of Economic Perspectives*, Volume 18, Number 3, Summer 2004, at 25.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-140
RE: Asset Write Down
Witness: Applicable

Does MDU have any anticipated gas related write downs that are anticipated but not included in the filing of the general rate as of today's date?

Response:

Montana-Dakota has no anticipated write-downs applicable to its Montana gas operations.