Service Date: June 30, 2011

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF NorthWestern Energy's Application for Approval for Authority to Establish Increased Natural Gas and Electric Delivery Service Rates	))))	REGULATORY DIVISION DOCKET NO. D2009.9.129 ORDER NO. 7046i

IN THE MATTER OF NorthWestern Energy's Application for Approval for Authority to Establish Increased Natural Gas and Electric Delivery Service Rates	))))	REGULATORY DIVISION DOCKET NO. D2007.7.82 ORDER NO. 7046i

ORDER ON REMAND

(This Order revises Order No. 7046h in the manner directed by Order of the Montana First Judicial District Court, Lewis and Clark County, in Cause No. DDV-2011-79.)

APPEARANCES

For the Applicant:
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For the Intervenors:
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Charles Magraw, Attorney at Law, 501 8th Ave., Helena, Montana 59601, appearing on behalf of District XI Human Resource Council and Natural Resources Defense Council

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Donald Quander, Attorney at Law, Holland & Hart, 401 North 31st St., Suite 1500, Billings, Montana 59101, appearing on behalf of Montana Large Customer Group

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Before:
GREG JERGESON, Chairman
KEN TOOLE, Vice Chairman
BRAD MOLNAR, Commissioner
GAIL GUTSCHE, Commissioner
JOHN VINCENT, Commissioner

Commission Staff:
Leroy Beeby, Rate Analyst
Al Brogan, Chief Legal Counsel
Eric Eck, Revenue Requirements Bureau Chief
Scott Fabel, Rate Analyst
Justin Kraske, Staff Attorney
Will Rosquist, Economics & Rate Design Bureau Chief
Neil Templeton, Rate Analyst
Kate Whitney, Regulatory Division Administrator

PROCEDURAL HISTORY

1. On October 16, 2009, NorthWestern Energy (NWE) filed an Application for Authority to Establish Increased Natural Gas and Electric Delivery Service Rates and Implement Allocated Cost of Service and Rate Design Proposals (Application). In the Application, NWE requested that rates for electric delivery service be increased to raise an additional $15,517,645 per year and that rates for natural gas delivery service be increased to raise an additional $1,966,400 per year. NWE also requested establishment of an inverted block rate design for natural gas and electric residential customers.

2. Concurrent with its Application, NWE requested interim increases in electric delivery revenues of $12,428,133, or 5.59 percent, on a uniform basis, and in gas delivery revenues of $1,758,208, or 1.77 percent, on a uniform basis.

3. On October 30, 2009, NWE filed a Motion for Leave to Supplement General Rate Case Filing. On November 13, 2009, the Commission issued a Notice of Commission Actions that denied the motion, found the rate case filing deficient, and informed NWE it could remedy the identified deficiencies by re-filing a complete rate application.

4. On November 18, 2009, NWE filed a Motion for Reconsideration and Motion to Bifurcate General Rate Case Application. The Commission granted reconsideration on

November 24, 2009, and, on the same date, decided to allow NWE to remedy the deficiencies identified in the November 13, 2009, Notice of Commission Actions by (1) filing a supplement to the original filing addressing the identified shortcomings no later than January 15, 2010, (2) agreeing that the Commission has until February 2, 2010, to determine whether the application as supplemented meets the minimum filing requirements, (3) waiving the 9-month time period set forth in § 69-3-302(1), MCA, to October 11, 2010, and (4) responding to discovery that is submitted to it prior to the issuance of a procedural order.

5. Procedural Order 7046a was issued on December 18, 2009.

6. On January 5, 2010, NWE filed a motion to consolidate this docket with Phase 2 of Docket D2007.7.82. The motion was granted on January 12, 2010.

7. NWE filed its Supplemental Allocated Cost of Service and Rate Design Testimony on January 15, 2010.

8. On March 31, 2010, the procedural schedule in the docket was suspended due to delays caused by discovery disputes. It was re-established on May 25, 2010.

9. On June 23, 2010, the Commission issued a Notice of Additional Issues in which NWE was directed to file testimony related to its energy efficiency programs and plans.

10. Intervenor and cross-intervenor response testimony was submitted by Montana Consumer Counsel (MCC), Large Customer Group (LCG), and Human Resource Council District XI/Natural Resources Defense Council (HRC/NRDC).

11. NWE submitted rebuttal testimony and testimony concerning the additional issues identified by the Commission.

12. On July 8, 2010, the Commission issued Interim Order 7046g by which NWE was granted interim rate increases of $12,395,640 for the electric utility and $1,361,517 for the natural gas utility.

13. The Commission issued a Notice of Public Hearing on August 17, 2010.

14. NWE and MCC submitted a Stipulation and Settlement Agreement concerning revenue requirements issues (Revenue Requirement Stipulation) on September 17, 2010.

15. On September 20, 2010, NWE, MCC, LCG, and HRC/NRDC submitted a Stipulation and Settlement Agreement concerning the allocation of the stipulated electric and natural gas revenue requirements among NWE's customer classes based upon embedded cost studies (Cost

Allocation Stipulation). As part of the Cost Allocation Stipulation, LCG joined in the Revenue Requirement Stipulation.

16. The Commission held a public hearing in this proceeding September 20-24, 2010, in Helena, Montana.

17. NWE, MCC, LCG and HRC/NRDC submitted post-hearing briefs.

Summary of Prefiled Revenue Requirements Testimony

NWE Direct Testimony

Robert C. Rowe

18. Rowe, NWE's president and chief executive officer, said NWE's filing consists of a revenue requirements case based on the 2008 test year with known and measurable changes through 2009, a proposal for electric and natural gas allocated cost of service (ACOS) that reduces for certain customer classes the rate impacts that NWE's ACOS studies indicate are appropriate, and a proposal for rate design that Rowe asserted will provide a stronger energy efficiency signal to customers. Rowe emphasized that the filing is focused on NWE's Montana-jurisdictional electric and natural gas transmission and distribution costs, not on supply costs.

19. Rowe provided an overview of NWE's electric and natural gas utility operations as well as a summary of various ongoing NWE activities and initiatives. He said that, from a financial standpoint, NWE has improved operating cash flows and liquidity, which has reduced NWE's interest costs, has obtained more credit from energy supply providers, and has improved its debt ratings from the credit ratings agencies, which allows NWE to borrow long-term at attractive rates.

20. NWE requested a return on equity (ROE) of 10.9 percent, which Rowe noted is at the bottom end of the range recommended by NWE witness Avera. Rowe said NWE's proposed capital structure of approximately 51 percent debt/49 percent equity was developed using a methodology that is consistent with the Commission's evaluation of NWE's capital structure in Order 6852f in Docket D2007.7.82.

21. Rowe pointed out that NWE delayed filing this case in order to submit a reduced rate increase request that resulted from an IRS tax ruling regarding accounting for capital expenditures and repair expenses. *See* Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property, 73 Fed. Reg. 12,838-01 (March 10, 2008). Instead

of seeking a $24 million increase in electric delivery service rates and a $4.8 million increase in natural gas storage and delivery rates, which would have been the case prior to the IRS notification regarding this tax change, NWE's application seeks a $15.5 million electric increase and a $2 million natural gas increase.

22. Rowe said NWE proposes implementation of embedded ACOS studies rather than marginal cost studies in this filing and going forward because embedded cost inputs and methods are generally less controversial. Rowe said NWE's proposed rate design is intended to moderate the class revenue requirement responsibilities that resulted from combining the impacts of the revenue requirement increases and the embedded ACOS studies. NWE proposed an inclining block rate structure for residential customers that is designed to provide residential customers a price signal to conserve energy. NWE also proposed that supply and delivery services rates be presented as bundled on the bill so customers can more easily understand the "all-in" costs of the services they use and see the price signal mentioned above. This is part of the move back toward vertical integration of supply and distribution.

23. Rowe said that although NWE is not proposing decoupling in this filing, the utility expects to do so in the near future after consulting with the stakeholder group NWE formed to explore the issue.

Brian B. Bird

24. Bird, NWE's chief financial officer and treasurer, testified that NWE is seeking a capital structure of 50.55 percent debt and 49.45 percent equity, cost of debt of 5.76 percent, cost of equity of 10.9 percent, and cost of capital of 8.3 percent.

25. Bird explained the capitalization methodology used to develop the recommended capital structure is consistent with the PSC's final order in NWE's last general rate case. He calculated the Montana regulated electric and gas rate base to be $952 million, the long-term debt to be $481.2 million, and derived equity to be $470.7 million, resulting in the 50.55 percent debt to capitalization ratio. Bird explained that two items that were excluded from the actual rate base calculation were included in his calculation of capital structure: the $38.8 million of rate base reduction agreed to in the Stipulation Agreement in Docket D2007.7.82 and the deduction for total gross cash requirement of $25.1 million.

26. Bird contended that the 50.55 percent/49.45 percent calculated capital structure most accurately reflects the true capitalization of the Montana utility businesses and is also the capital structure that will allow NWE to maintain its investment grade credit ratings.

27. Regarding the cost of debt, Bird said NWE determined the total long-term debt as of December 31, 2008, by identifying all debt and capital lease obligations related to the Montana utility, excluding $250 million of bonds to re-capitalize the Colstrip 4 asset and to finance the Mill Creek generation project and $55 million of bonds to finance the remaining debt portion of the Mill Creek generation project. Bird explained these amounts were excluded because they belong to the Montana generation assets and are covered under separate rate cases. The 5.76 percent cost of debt was then calculated by dividing the total annual cost of long-term debt by the long-term debt balance.

28. Regarding NWE's proposed cost of equity of 10.9 percent, Bird said that NWE relied on the analysis performed by NWE witness William Avera, in which Avera concluded that an appropriate ROE range for NWE is 10.9 percent to 12.4 percent.

29. Bird said NWE's proposed rate of return of 8.30 percent is the cost of debt and cost of equity weighted by the percentage of debt and rate base-derived equity.

William Avera

30. Avera, a financial consultant, testified in support of NWE's proposed ROE and capital structure. Avera determined that a fair ROE for NWE would fall in the range of 10.9 percent to 12.4 percent. He said he arrived at this recommended range after evaluating NWE's operations and finances and those of the utility industry generally and conducting analyses to estimate the current cost of equity. He based his conclusions on his analysis of a proxy group of 18 comparable utilities and comparable non-utility companies, his evaluation of expected earned rates of return for utilities, and his application to the proxy groups of two quantitative approaches for estimating ROE: discounted cash flow analysis (DCF) and the capital asset pricing model (CAPM). Avera's DCF analyses implied cost of common equity estimates ranging from 11.3 percent to 12.4 percent for the utility proxy group and 12 percent to 13.4 percent for the non-utility group. His CAPM approach implied 10.9 percent for the utility proxy group and 11.5 percent for the non-utility proxy group. His evaluation of utilities' rates of return implied an equity cost range of 11.5 percent to 12.5 percent. Avera claimed that NWE's requested ROE of 10.9 percent is reasonable and if anything, a conservative ROE.

31. Regarding NWE's capital structure, Avera concluded that a common equity ratio of approximately 50 percent is reasonable based on his findings that it is consistent with utilities in his proxy group, that a conservative financial posture is warranted for NWE due to the uncertainties associated with NWE's small size, and that the investors expect a greater equity cushion to accommodate higher operating risks and the pressures of financing capital investments.

Kendall G. Kliewer

32. Kliewer, NWE's vice president and controller, attested to the accuracy of the actual accounting data submitted as part of this filing. He stated that NWE allocates its administrative costs among its three regulatory jurisdictions and its ownership interest in Colstrip 4 by using a 3-factor formula consisting of gross plant, margin and labor. Kliewer said NWE also uses a 3-factor formula comprised of plant, customers, and operation and maintenance (O&M) labor expense to allocate shared costs between electric and natural gas operations. Kliewer explained the two normalization adjustments to NWE's income statements related to the categories of pension costs and intra-company rent on capitalized common assets. Finally, Kliewer noted that NWE's administrative and general expenses in this filing include stock-based compensation costs, which he said were calculated in accordance with Statement of Financial Accounting Standards No. 123R, Share-Based Payment (SFAS No. 123R).

Wayne M. Hitt

33. Hitt, NWE's corporate taxes director, testified in support of all income and property tax related items included in NWE's filing. Hitt stated that income taxes in this filing have been calculated in a manner consistent with the methodology approved by the Commission in prior rate proceedings and that plant-related tax adjustments have been flowed through to customers as usual. He provided workpapers detailing the various adjustments to electric and natural gas rate base that resulted from deferred income taxes and the computation of income taxes. Hitt explained that an adjustment to 2008 property taxes referred to in a table in NWE witness DiFronzo's testimony resulted from adjustments to include 2008 net plant additions and to exclude property tax refunds related to a settlement with the Montana Department of Revenue for the years 2005-2007.

Daniel R. Reardon

34. Reardon, a NWE senior accountant, presented exhibits depicting the actual 13-month average rate bases as of December 31, 2008, for the natural gas and electric utilities, including adjustments for known and measurable changes. In addition, Reardon explained the calculation of the annual depreciation expense amount of $1,292,040, which was allocated two-thirds to the electric utility and one-third to the natural gas utility.

Patrick J. DiFronzo

35. DiFronzo, NWE's regulatory affairs manager, sponsored the natural gas and electric utility income statement exhibits and explained and supported with workpapers the adjustments that NWE made to the actual expenses in developing the test period cost of service. He also sponsored exhibits showing the calculation of NWE's revenue requirements for the natural gas and electric utilities.

Cheryl A. Hansen

36. Hansen, a NWE senior analyst, sponsored exhibits presenting the 2008 test year electric billing determinants and explained how they were derived. She also discussed her exhibit that presents NWE's electric actual and proposed revenues.

LCG Direct Testimony

Michael P. Gorman

37. Gorman disagreed with the capital structure proposed by NWE witness Bird and recommended the Commission reject the adjustments NWE made to rate base to arrive at it. He disputed NWE's adjustment to rate base for regulatory assets that increased the percentage of common equity to total capital from 45.86 percent to 49.45 percent. He objected also to NWE's adjustment for total gross cash requirement. Gorman contended that the result of NWE's method of determining capital structure is a total capital structure that does not equal the utility rate base. He recommended the Commission set NWE's capital structure in the same way as it did in the last NWE rate case (Docket D2007.7.82), which Gorman said was to subtract the utility debt amount from rate base to produce the common equity amount, then to set capital structure weights by combining utility debt and common equity, which in total equaled the utility combined electric and gas rate base. He noted that the Commission said the resulting 52 percent/48 percent capital structure was close to NWE's consolidated capital structure and did not include goodwill.

38. Gorman argued that NWE's proposed adjustment to rate base and capital structure for the regulatory assets will result in increasing NWE's rate of return and operating income in this case. He claimed the effect of the increased operating income would be to provide a partial return on the regulatory assets that the Commission found should not be permitted to earn a rate of return.

39. Gorman said Bird's claim that the total gross cash requirement adjustment made to rate base will result in more of a short-term capitalization mix is inappropriate because the rate of return should reflect long-term capital costs, not short-term capital needs.

40. Gorman recommended a capital structure of 54.14 percent debt/45.86 percent equity, which he said was derived using the Commission's direction in Docket D2007.7.82. Gorman asserted his proposed capital structure is comparable to the 44 percent common equity ratio reported by NorthWestern Corp. in March 2010, and more in line with NorthWestern Corp.'s year-end 2008 financial statements that showed common equity of total capital, after common equity is adjusted to remove goodwill, of 32.2 percent.

41. Gorman explained that he estimated NWE's cost of common equity using: (1) a constant growth DCF model; (2) a sustainable growth DCF model; (3) a multi-stage growth DCF model; (4) a risk premium (RP) model; and (5) CAPM. He applied these models to the same utility proxy group used by NWE witness Avera.

42. Gorman's three DCF models produced these results:

Constant growth DCF model	10.86%
Sustainable growth DCF model	9.77%
Multi-stage growth DCF model	9.98%
Average DCF return	10.20%

43. Gorman claimed his constant growth DCF model is not reasonable because short-term analyst growth rate projections which are its bases are not reasonable estimates of long-term sustainable growth and should not be used on a stand-alone basis. He recommended it be averaged with his other DCF estimates to produce a reasonable DCF point estimate that can be used to derive NWE's return on equity. He said the constant growth DCF model based on the sustainable growth approach is based on a growth rate that is sustainable in the long term in comparison to GDP growth, but may not reflect analysts' short-term growth outlooks. He said the multi-stage growth DCF model return reflects the expectation of changing growth rates over time.

44. Gorman's RP model produced a return estimate in the range of 9.74 percent to 10.15 percent, with a midpoint of 9.95 percent. Application of his final model, the CAPM analysis, which Gorman based on a low-end market risk of 5.7 percent, high-end market RP of 6.5 percent, a risk-free rate of 5.2 percent, and a beta of 0.74, produced an equity return in the range of 9.40 percent to 9.98 percent, with a midpoint of 9.69 percent.

45. Gorman's recommended ROE range for NWE is 9.7 percent to 10.2 percent. The midpoint of this range is 9.95 percent, which he rounded to 10 percent. He asserted that an authorized ROE of 10 percent will support internal cash flows that will be adequate to maintain NWE's current investment grade bond rating.

46. Gorman disagreed with NWE witness Avera's ROE analysis and recommendation of a 10.9 percent ROE. Gorman asserted that Avera's DCF analysis was flawed and should be disregarded because: (1) his use of a non-utility proxy group, which is riskier than the utility industry, produced an inflated ROE; (2) his projected growth rate estimates, which were higher than the projected long-term growth rate of the U.S. economy, are unreasonably high; and (3) his use of stale market data do not reflect the current improved market environment. According to Gorman, if Avera's DCF analysis was updated to reflect the current market, it would produce a DCF ROE in the range of 10.2 percent to 11 percent, with an average of 10.6 percent. Applying a multi-stage growth DCF model to Avera's utility proxy group yields an ROE of 9.9 percent, Gorman said.

47. Gorman took issue with Avera's CAPM analysis, claiming the market risk premium upon which it was based is overstated and unreliable because it was premised on a DCF return produced by too-high projected growth rates. Gorman produced a CAPM in the range of 8.7 percent to 9.3 percent, with a midpoint of 9 percent, by applying what he termed "reasonable" adjustments to Avera's calculation.

48. Gorman also rejected Avera's expected earnings analysis because Gorman stated the ROE Avera produced using this analysis was not developed from observable market data and did not measure the investor expected or required return for assuming investment risk.

MCC Direct Testimony

Albert Clark

49. Clark addressed all revenue requirement issues in the filing, except for the appropriate capital structure and cost of capital, and offered comments regarding the purchase of the Montana Power Company (MPC) by NWE and the impact that sale had on Montana ratepayers.

50. Clark contended the PSC's approval of the sale of MPC to NWE was based in part on incorrect or incomplete information provided by MPC and NWE during the approval process. Clark asserted the sale was supposed to be a "stock sale" rather than an "asset sale." However, he said, NWE now says, through its witness Hitt in response to a data request, that, legally, the acquisition was a purchase of Touch America's equity interest, but for tax purposes, it was treated as an asset sale. As an asset sale, he said, ratepayers lost the accumulated deferred income taxes that were on the MPC books at the time of sale. He contended that since these deferred income taxes were removed from NWE's books, ratepayers no longer receive the rate base offset that recognizes the customer-contributed nature of these funds. Clark estimated the annual revenue impact on ratepayers to be $18.5 million. According to Clark, the PSC could impute a rate base deduction for the deferred income taxes, but by doing so, NWE's Montana utility would not be able to use accelerated depreciation for tax purposes going forward; rather, NWE would be on a "flow-through" actual-taxes-paid basis for both tax and ratemaking purposes. In a response to an MCC data request on this subject in the Docket D2007.7.82 proceeding, NWE said the ratepayer benefit of the use of accelerated depreciation in that case's test year was $12 million. Clark said he does not recommend the PSC impute a rate base deduction for the lost deferred income taxes now, but is raising PSC awareness of the issue.

51. Clark recommended rejecting NWE's post-test-year adjustments that are based on NWE's 2009 operating budget, especially since the entire 12 month post-test-year adjustment period is available on an actual basis, given the circumstances of this case. Clark specified the adjustments he proposes to the NWE's pro forma results of operations, many of them based on actual 2009 costs: reduce uncollectible expense by $146,021 for the electric utility and $156,358 for the gas utility; update miscellaneous revenues to actual for 2009; reduce payroll-related taxes to reflect a tax rate of 6.70 percent; adjust the levels of group dental, group life insurance, long-term disability, medical, vision, and other fringe benefits to reflect actual 2009 expense for these items; update labor transfer credits to actual 2009; reduce NWE's dues to the Edison Electric Institute to exclude costs for legislative advocacy and policy research and public

relations; remove stock-based incentive plans expenses that are provide incentives beyond ordinary compensation packages; adjust property and liability insurance premium expenses to actual 2009; reduce property tax expenses by $2.9 million for the electric utility and $1.4 million for the gas utility; and reduce electric and gas utility revenues and transmission revenues to recognize the closure of the Smurfit-Stone plant in Frenchtown.

52. Rate base adjustments proposed by Clark are to adjust the cash working capital requirement for the electric and gas utilities based on NWE's updated lead/lag analysis, and adjust the unamortized SAP development costs, gas storage sales, and Milwaukee line cost to reflect the average of the actual 2009 monthly amounts. Finally, Clark proposed adjusting NWE's pro forma income statement to increase interest expense by $3.3 million and $1.5 million for the electric and gas utilities, respectively, as a result of synchronizing interest expense with the capital structure and rate base, plus non-rate-base construction work in progress. Those proposed increases result in a decrease of $1.3 million in current income tax expense for the electric utility and $579,100 for the gas utility, according to Clark.

53. Clark concluded that NWE is over-earning, on a pro forma basis, on its gas and electric utilities in Montana. He recommended a revenue decrease for the electric utility of $1,993,430 and for the gas utility of $3,120,430.

Dr. John Wilson

54. Before addressing the issues of rate of return and capital structure, Wilson first explained he does not propose a disallowance for "phantom" income tax expense in this docket, but he advised the PSC that the issue of NWE's use of its net operating loss (NOL) balance to offset actual income tax payments will likely be a significant issue in future rate cases.

55. Wilson agreed with NWE witness Avera's use of the DCF model for estimating a cost of equity for NWE, but he disputed Avera's DCF outcome. Wilson argued that Avera improperly excluded certain DCF calculations for his utility proxy group, should not have relied on DCF-estimated capital costs for his non-utility proxy group in his determination of NWE's ROE, and used analysts' earnings growth forecasts that tend to overstate actual investor capital costs. Wilson disputed Avera's use in his CAPM model of long-term interest rates as risk-free and with what Wilson termed Avera's excessive risk premium spreads. Wilson disagreed with Avera's conclusions regarding NWE's relative risks, his views on regulatory risk, and his "expected earnings approach."

56. Wilson applied the DCF model to Avera's utility proxy group, except that Wilson updated the analysis with recent information and presented results for the entire proxy group without excluding outliers that produced DCF estimates above 16 percent and at or below 8 percent as Avera did. Wilson's constant growth DCF results without any exclusions and his results excluding estimates that are either 3 percent above or below NWE's current ROE of 10.75 percent both produced costs of equity in the 10 percent to 11 percent range, with an average of 10.7 percent when no results were excluded and 10.5 percent with high and low values excluded.

57. As an alternative to the constant growth DCF model, Wilson also applied the "fundamental" DCF approach to estimate NWE's cost of common equity, which resulted in an average equity cost of for the utility proxy group of 9.5 percent. Wilson explained that the fundamental DCF approach uses retained earnings as the measure of expected growth rather than relying on analysts' forecasts of future growth.

58. Regarding the CAPM model, Wilson said it is a widely used approach that estimates ROE by evaluating the relative risks of alternative investments. Wilson's application of the CAPM model to the utility proxy group resulted in a 6.7 percent cost of equity. According to Wilson, the difference between his estimated CAPM ROE and the 11.5 percent that Avera's CAPM model produced is that Avera incorrectly used a risky 20-year bond interest rate as the risk-free component of his calculation and Avera's risk premium of 9.3 percent is a DCF-derived result that did not produce a legitimate CAPM cost of equity.

59. Regarding Avera's earnings approach analysis, Wilson contended it mistakenly assumes that Value Line's projected earnings rates are the rates of return that investors expect to realize on their equity investments, when actually Value Line's projected earnings rates are stated in relation to the projected book value of equity. When Wilson performed his own expected earnings analysis of the utility proxy group, his result was an average market cost of equity of 8.2 percent.

60. Regarding NWE's capital structure, Wilson disagreed with NWE's proposal for what Wilson called a "constructed" capital structure. According to Wilson, the capitalization proposed by NWE is significantly different from its actual capitalization as reported in its FERC Form 1 annual report. Wilson calculated NWE's equity ratio, net of goodwill, to be 36.6 percent at year end 2008 and 30.8 percent at year end 2009.

61. Wilson claimed NWE witness Bird's calculation of rate base at $952 million was incorrect because it improperly included rate base deductions that were included in the Docket D2007.7.82 Stipulation Agreement, it failed to exclude negative cash working capital in the amounts of $15.3 million from electric rate base and $9.1 million from gas rate base, and it incorrectly excluded all unsecured debt supporting utility rate base in the amounts of $108 million in 2008 and $66 million in 2009.

62. According to Wilson, NWE's capital structure should be based on its financial statements, using the audited debt and equity amounts, less goodwill. At year-end 2008, NWE's long-term debt on FERC Form 1 was $708,148,650 and its equity, less goodwill, was $408,403,645, resulting in a debt/equity ratio of 64.4 percent/36.6 percent.

63. Wilson found no merit in Avera's suggestion that NWE's proposed ROE is warranted due to the risks associated with NWE's small size, its' supposed inability to recover its "flotation costs," its exposure to an unsettled economic environment, the volatility in its fuel and purchased power and gas costs, and the risks of regulatory limitations on cost recovery. Wilson countered that NWE is not a small company; it has recovered its flotation costs for debt issuances and has not had any equity-related flotation costs; that in uncertain economic times investments in regulated utilities are typically considered less risky than other types of investments; NWE is substantially protected from volatile fuel and purchased power costs because it has comprehensive gas and electric trackers in place; and the idea that regulators should raise rates of return now to compensate for the potential risk of a disallowance in the future is not persuasive.

64. Wilson testified that his analyses indicate an ROE in the range of 8.5 percent to 10.5 percent. To calculate a rate of return on rate base, he used a 9.5 percent ROE, and a target capital structure of 60 percent debt/40 percent equity to arrive at his recommended authorized rate of return on rate base of 7.28 percent.

NWE Rebuttal Testimony

Robert C. Rowe

65. Rowe said NWE accepted or proposed several adjustments in rebuttal testimony that have resulted in reducing its request for an annual increase in natural gas utility revenues to $1,499,069 and reducing its request for an annual increase in electric utility revenues to $13,624,230. According to Rowe, the revised natural gas request equates to an overall

percentage increase of 1.46 percent. He said the revised electric request equates to an overall percentage increase of 6.11 percent.

66. Regarding the ROE issue, Rowe pointed out that NWE proposed an ROE at the bottom of its witness's recommended range because NWE is sensitive to customer impacts and also decided to make a straightforward filing instead of gaming the contested case process by selecting an ROE at the top of the range under the assumption the PSC would select an ROE in the middle. Rowe also emphasized that NWE needs an ROE that continues to attract investment and that a positive PSC decision on ROE should help to maintain the strong credit ratings that currently benefit NWE and its customers.

67. Rowe stated that MCC witness Wilson's recommended 60 percent debt/40 percent equity capital structure is not appropriate for NWE's Montana operations. Rowe said NWE did not agree with all of MCC witness Al Clark's adjustments which resulted in certain components of rate base valued at December 2009, while the remainder are valued at December 2008. He said Clark's proposals are contrary to past Commission decisions and traditional ratemaking practices.

Brian Bird

68. Bird provided rebuttal testimony to address arguments made by LCG witness Gorman and MCC witness Wilson.

69. Bird disagreed with Gorman that NWE's methodology to establish capital structure was inconsistent with PSC Order 6852f in Docket D2007.7.82. Bird contended the Commission's calculation of capital structure was clear in that order and he said NWE followed that methodology. He said Order 6852f prescribed $931 million as the rate base amount to be used as a proxy for capitalization, exclusive of adjustments for working cash or the $38.8 million reduction to gross property, plant and equipment (PP&E). Bird said his proposed adjustments to rate base are intended to ensure the capital structure calculation is consistent with Order 6852f in that those items are again excluded. According to Bird, the adjustments he made to rate base related to working cash and PPE derive a total rate base that is a reasonable proxy for NWE's Montana utility long-term capitalization. He argued that using the rate base amounts as presented in NWE witness Reardon's exhibits without making these two adjustments would significantly understate the true long-term capitalization of the Montana utility.

70. Regarding the idea of basing NWE's Montana utility capital structure on its consolidated capital structure, Bird said NWE had not considered it because NWE is following the PSC methodology. However, he said, if its consolidated capital structure is used as a basis for evaluating the reasonableness of NWE's proposed capital structure, as Gorman did, then adjustments would have to be made, such as recognizing the additional money NWE added to its pension funds in 2009, the $87 million spent on Mill Creek in 2009, and the $27 million payout to settle the *Ammondson* litigation. According to Bird, removing those three items from NorthWestern's 2009 capital structure would result in an adjusted consolidated debt to capital ratio of 50.3 percent, which is close to NWE's proposed Montana capital structure.

71. Regarding MCC witness Wilson's recommendations on capital structure, Bird objected to his proposed reduction of common equity capital by a goodwill amount of $355 million, which would reduce the 2008 equity ratio to 36.6 percent and the 2009 ratio to 30.8 percent. Bird claimed that Wilson's proposed methodology of using the consolidated debt to equity of NWE does not comply with the final orders in Dockets D2007.7.82 and D2008.8.95. Bird asserted the Commission has accepted NWE's approach to using the Montana utility's rate base minus the Montana utility's long-term debt to derive the equity capital of the Montana utility business. Bird argued that Wilson's proposal to use NWE's consolidated debt to capitalization with a reduction for goodwill is not appropriate for calculating the Montana utility capital structure in this docket.

72. Bird disagreed as well with Wilson's second proposed capital structure methodology that increased the Montana utility's long-term debt by including the outstanding amount under NWE's unsecured credit facility and also did not include the working cash and PP&E adjustments that NWE argues are appropriate. Bird contended Wilson's methodology incorrectly includes short-term debt in the total debt calculation and incorrectly reduces the Montana rate base used as a proxy for capitalization by the $38.8 million PP&E adjustment specified in the Stipulation and by $24.4 million due to gross cash requirement.

73. On the issue of credit ratings, Bird listed four reasons why he disagreed with and found irrelevant Gorman's methodology of approximating NWE's credit metrics and credit ratings using his proposed capital structure and ROE: (1) rating agencies use NWE's consolidated financial results, not the business by jurisdiction, to calculate NWE's credit metrics; (2) rating agencies apply several adjustments to reported financial results to derive the credit metrics

including, among other things, imputing debt based on operating leases, pension obligations, and power purchase agreements; (3) the criteria for assigning a credit rating are based on qualitative as well as financial metrics; and (4) Gorman ignores the effects of regulatory lag created by the use of a historical test year in an environment of increasing costs.

74. Bird argued that Wilson's proposed capital structure of 60 percent debt and 40 percent equity is not reasonable because: (1) as discussed above, Bird claimed that if NWE's 2009 consolidated financial statements are used as the basis of deriving capital structure for the Montana utility, then adjustments to NWE's total 2009 debt related to several non-recurring items (pension plan funding, Mill Creek costs, litigation payout) would result in an adjusted total debt to capitalization of 50.3 percent, which is close to NWE's proposed Montana capital structure; and (2) if NWE's actual consolidated total debt to capitalization were 60 percent, it is likely that NWE's secured credit ratings would be lower than the current ratings and NWE's investors would require a higher ROE than 10.9 percent to reflect the greater risk of a company with that much debt.

<u>William Avera</u>

75. Avera responded to the ROE recommendations of Wilson and Gorman and to Wilson's capital structure testimony, and addressed the ROE implications of HRC witness Cavanagh's recommendation for a pilot decoupling program.

76. Addressing Wilson's criticism of his DCF analysis, Avera listed four areas of his disagreement with Wilson's analysis: (1) Wilson discounts Avera's reliance on analysts' growth forecasts as biased, while Avera recognizes in his DCF model investors' perceptions and expectations; (2) Wilson inappropriately applies the DCF model based on his personal views rather than relying on the capital markets for guidance regarding investors' expectations; (3) Wilson's removal of outliers was flawed and unsupported; and (4) Wilson's "fundamental" DCF is flawed, incomplete and inconsistent with better alternatives for reflecting how investors value stocks. Avera argued that Wilson's criticism of Avera's use of a "riskier" non-utility proxy group in his DCF analysis is unsupported and incorrect. Similarly, Avera argued that Wilson's suggestion that market-to-book ratios be examined when applying the expected earnings approach is unfounded and unsupported.

77. Avera said Wilson's CAPM analysis should be entirely disregarded because, according to Avera, it falls below Wilson's own standards of reasonableness. Avera claimed its flaws include

applying the CAPM analysis based on Wilson's assessment of historical, not projected, rates of return and risk premiums, which results in CAPM estimates that significantly understate investors' required rate of return and the inappropriate use by Wilson of geometric, rather than arithmetic, averages for stock returns. Avera defended his use of forward-looking expectations in his CAPM evaluation, which Wilson had criticized as producing an equity risk premium that is too high, by asserting his analysis focused appropriately on actual investors' expectations. Regarding Wilson's use of short-term Treasury bill rates as a basis for CAPM equity cost estimates, Avera said he agreed with LCG witness Gorman that long-term government bonds are the appropriate basis for the CAPM approach.

78. Turning to the testimony of Gorman, Avera's summary of his rebuttal included the following: (1) Avera disputed Gorman's criticisms of analysts' growth rates, asserting the criticisms are unfounded and inconsistent with Gorman's contrary observation that those growth rates are accurate predictors of future returns; (2) Avera claimed that flaws in Gorman's multi-stage DCF and risk premium analysis lead to understated cost of equity estimates; (3) Avera contended Gorman's CAPM applications are inconsistent with the underlying assumptions of this approach and produce cost of equity estimates that are far below investors' required return; and (4) contrary to Gorman's criticisms of Avera's expected earnings approach, Avera asserts it is consistent with the regulatory and economic principles advanced by Gorman's testimony.

79. Avera said his rebuttal testimony demonstrates that Wilson's and Gorman's ROE recommendations are too low to be credible and insufficient to compensate NWE's investors when evaluated against the results of the expected earnings approach for the proxy group. He also concluded that Wilson and Gorman did not consider the impact of flotation costs in contradiction to the findings of the financial literature and economic requirements underlying a fair ROE.

80. In addition, Avera affirmed HRC witness Cavanagh's position that the introduction of revenue decoupling for NWE would not warrant an adjustment to the Company's authorized return. Avera stated that investors would view decoupling as supportive of NWE's financial integrity, but there is no evidence that such a mechanism would result in a measurable change in the NWE's investment risk or ROE relative to the proxy companies. He added that because the utilities in the proxy groups operate under a variety of rate design and adjustment mechanisms,

the impact of utilities' ability to mitigate the risk of declining revenues and cash flows is already reflected.

Kendall Kliewer

81. Kliewer disagreed with MCC witness Al Clark's elimination of all test period expenses for NWE's long term incentive plan (LTIP). According to Kliewer, the LTIP should remain in NWE's cost of service because it is designed to be part of each recipient's total compensation and it aligns long-term employee interests with the interests of NWE's shareholders and customers. He said NWE's total compensation package is also intended to provide incentives to employees to meet company goals, and achievement of the goals benefits ratepayers as well as shareholders. According to Kliewer, if the PSC disallowed LTIP expenses, NWE would have to consider eliminating or reducing the LTIP benefit, which could result in the loss of key employees, or raising base salaries to maintain competitive compensation packages for key employees.

82. Kliewer disagreed with Clark's adjustment to labor transfer credits. He contended the 2009 labor transfer credit is based on an allocation of actual 2009 labor costs related to construction activities that occurred in 2009. The request to update labor transfer credits to actual 2009 amounts as proposed by Clark would provide a change to expense without a corresponding rate base adjustment for 2009 plant additions, resulting in an inconsistency or mismatch between rate base and related expenses in the cost of service.

83. Finally, based on NWE's most recent projections, Kliewer reduced NWE's pension expense in the amount of $310,000 for the natural gas utility and $690,000 for the electric utility.

Wayne Hitt

84. Hitt rebutted Wilson's discussion of NOLs and Wilson's and Clark's discussions of the loss of deferred tax liabilities upon NWE's acquisition of MPC. He said that, although no adjustment or disallowance was proposed by MCC's witnesses related to these items, NWE wanted to make clear its position on them. Hitt asserted NWE's Montana utility income tax expenses should exclude consideration of NorthWestern Corp.'s consolidated income and losses from non-regulated activities, income and losses from business in other regulatory jurisdictions, and income and losses from outside of the test period. He said the absence of cash payments to taxing authorities does not convert specific income taxes resulting from Montana utility income

tax expense into "phantom taxes." He argued that using NOLs, which are a cash-equivalent receivable due from the taxing authorities and held by NorthWestern Corp., to pay a tax obligation does not lessen the fact that a tax obligation arises from Montana Utility taxable income.

85. Regarding the deferred tax issue, Hitt said that imputing a rate base reduction relating to the 2002 deferred tax balance would violate the normalization requirements of the Internal Revenue Code (IRC) and preclude NWE from using accelerated tax depreciation. He explained that loss of the ability to use accelerated tax depreciation would result in the loss of deferred tax benefits and harm ratepayers. Hitt added that there is no basis to assume that Clark's estimated revenue impact would be applicable to the current 2008 test period.

86. He asserted that, contrary to Wilson's claims, the tax treatment of the MPC acquisition was determined under the IRC and was not subject to NorthWestern's discretion. Because the transaction was treated as an acquisition of assets under the IRC, Hit said the sale led to the recapture of the accelerated depreciation which made up the deferred tax balance under the IRC, thereby eliminating the deferred tax balance.

<u>Daniel R. Reardon</u>

87. Reardon updated NWE's rate bases with adjustments to cash working capital. He disagreed with MCC witness Clark's proposed rate base adjustments to SAP, gas storage sales and the Milwaukee Line because they effectively result in a 13-month average rate base balance at year end 2009 for those items while all other components of rate base are calculated at the 13-month average year end 2008 balances. Reardon said that, although known and measurable changes are allowed by PSC rule, those changes are typically made to O&M expenses, not to rate base items such as plant in service and those adjusted by Clark. Reardon argued that the known and measurable changes standard should be consistently and properly applied, rather than allowing parties to pick and choose when and when not to make adjustments for them. He said rate base should not be calculated using a different test period for the individual components in rate base. Reardon cited PSC findings in PSC Order 5709d in Docket 93.6.24 in which he said the PSC has previously determined that these types of adjustments to rate base are not allowed.

88. Reardon stated that virtually all of the components of the natural gas and electric rate bases proposed by NWE are based upon the actual December 2008 13-month average balances. According to Reardon, the only exception is cash working capital, which both NWE and MCC

have historically agreed, and also agree in this filing, to update the O&M expenses that are included in the calculation of working cash.

Patrick J. DiFronzo

89. DiFronzo updated the natural gas utility and electric utility income statements and revenue requirements exhibits. The natural gas income statement revenue and expense adjustments included an increase in transportation revenues due to the expiration in April 2010 of a discount provided to Energy West, the closure of the Smurfit-Stone plant, and reductions in miscellaneous revenues and uncollectible expense. The natural gas income statement was also updated to reflect actual 2009 administrative and general expenses. DiFronzo said Clark recommended similar adjustments for the most part. DiFronzo's adjustment to property and liability expense is a $75,336 reduction compared to Clark's $276,451, and DiFronzo provided support for his adjustment. DiFronzo updated the natural gas income statement to reflect adjustments for taxes other than income taxes, pension expense, working cash, and interest synchronization.

90. DiFronzo updated the electric utility income statement with adjustments to revenue and expense to reflect rate schedule and transmission decreases due to the closure of the Smurfit-Stone plant, an increase in actual 2009 miscellaneous revenues, and a reduction in uncollectible expense. Administrative and general expenses were updated to reflect actual 2009 expenses. DiFronzo disagreed with Clark's proposed reduction to the other fringe benefits expense in the amount of $190,349; DiFronzo said it should be $216,502. He also disputed Clark's proposed reduction to property and liability expense of $601,133; DiFronzo said the correct amount is $165,404 and provided support for this adjustment. DiFronzo updated the electric income statement to reflect adjustments for taxes other than income taxes, property taxes, pension expense, working cash, and interest synchronization.

Cheryl A. Hansen

91. Hansen updated the electric operating revenues to reflect 2009 actual amounts in the miscellaneous revenues category and an adjustment to other operating revenues to reflect the Smurfit-Stone plant closure in early 2010. According to Hansen, the Smurfit-Stone related adjustments include a $65,956 decrease in network scheduling and dispatching revenue, a $1,226,013 decrease in network Open Access Transmission Tariff revenue, and a $708,580

decrease in GS-2 choice customer class revenue. She explained that NWE routinely adjusts loads to reflect known changes for its large customers, both increases and decreases. She asserted it is appropriate to design rates using a market that is most representative of loads in place when revenues are recovered. Hansen noted that Clark recommended similar adjustments.

Revenue Requirement Stipulation

92. The Revenue Requirement Stipulation (Attachment A to this Order) submitted by NWE and MCC, and subsequently joined by LCG, resolved those parties' contested revenue requirements-related issues. HRC/NRDC, the remaining active party in this proceeding, took no position on revenue requirements issues and did not oppose the stipulation.

93. The stipulating parties agreed as follows:

(a) NWE's electric delivery rates should be increased by $7,660,766 and its natural gas delivery rates decreased by $988,963. The electric rate increase is $4,734,874 less than the interim rates authorized in July by the Commission. The natural gas rate adjustment is $2,350,480 less than the authorized interim natural gas rates.

(b) The stipulated revenue adjustments were derived based on: (1) an authorized ROE of 10.25 percent (subject to (c) below), cost of long-term debt of 5.76 percent, and a capital structure of 52 percent debt and 48 percent equity; (2) the removal of NWE's stock-based incentive plan expenses in the amounts of $1,623,935 for the electric utility and $729,594 for the gas utility; and (3) all other cost of service items as reflected in NWE's rebuttal filing in this proceeding.

(c) The stipulating parties did not resolve any issues related to the revenue decoupling mechanism proposal in this docket, including whether NWE's ROE should be adjusted if the Commission approves implementation of a decoupling pilot.

Summary of Cost of Service/Rate Design Prefiled Testimony

Electric Cost of Service and Rate Design

NWE Direct Testimony

<u>Patrick R. Corcoran</u>

94. Patrick Corcoran, NWE's Vice President of Government and Regulatory Affairs, described four steps that underlie NWE's rate proposals. Step 1 calculated NWE's revenue requirement, which consists of plant costs, operating expenses, taxes, interest paid on debt, and

an opportunity to earn a reasonable profit. Step 2 allocated the costs that make up the revenue requirement to various customer classes based on Allocated Cost of Service (ACOS) studies. ACOS studies can reflect either embedded (accounting) and/or marginal (cost of next incremental unit) costs. Step 3 modified the ACOS study results to mitigate unacceptable customer bill impacts. Step 4 designed individual rates for billing customers. Rate designs are guided by both embedded and marginal costs. He proposed using embedded cost of service studies to set class revenue responsibilities and design rates for delivery services and marginal cost studies to set class revenue responsibilities and design rates for electricity supply services.

95. Corcoran testified that NWE's primary ACOS objective is to properly allocate the costs of providing utility service among various customer classes based on cost causation and design rates that recover the allocated costs. He stressed, however, that NWE also considers customer bill impacts.

96. NWE applied the following rate moderation criteria: (1) move class revenues toward embedded costs, (2) cap class increases at 9 percent for electric delivery service; and (3) limit the total bill impact to no more than about 15 percent for large residential customers.

97. Corcoran acknowledged that PSC rules recognize marginal cost principles, but contended that they do not prohibit using embedded cost studies. He recommended that the PSC adopt embedded ACOS studies as the preferred approach to allocating costs in this filing and going forward.

98. Corcoran introduced the results of NWE's embedded and marginal delivery cost of service analyses.

99. Corcoran noted that charging supply rates equal to marginal costs would mean an average increase for all classes of more than 63 percent. His tracker rate design proposal maintains the relative marginal cost shapes, by class, but moderates the rates so they do not collect more than allowed supply costs. He recommended that the PSC implement this approach as soon as possible after the PSC issues a final order in this case.

100. Corcoran also proposed an inverted-block rate design for the residential class, asserting that inverted-block rates are easy to understand, easy to meter and bill, promote conservation, and protect small users, which often include low-income customers and senior citizens. He said the residential inverted-block rate design: (1) sends meaningful price signals through the

tail-block rate to 70 percent-80 percent of customers, (2) limits the maximum bill impact to about 15 percent for large users, and (3) sufficiently differentiates the initial- and tail-block rates.

101. Corcoran set the initial block at 350 kilowatt-hours (kWh) and recommended a tail-block price multiplier of 1.2; that is, the tail-block price would be 1.2 times the average electricity supply tracker rate. For example, if the residential class tracker rate were $0.05224/kWh, the tail-block rate would be 1.2 times $0.05224, or $0.06269/kWh. Corcoran did not recommend inverted-block rates for the general service customer classes due to the wide variation of commercial and industrial customers' sizes and usage patterns.

102. Corcoran discussed the total bill impacts of NWE's revenue requirement, cost of service and rate design proposals.

103. Corcoran recommended continuing the unbundled tariff structure in order to preserve NWE's ability to determine the revenues different rates produce. He said business reporting and regulatory filings, like supply trackers, require NWE to develop, present, and track various rate/revenue components. However, he said because customers could be confused by the amount of information in bills, NWE recently consolidated various rate elements on its billing statements by summarizing total bill amounts for all delivery services and all supply services. The new billing statements show customers the total electricity price per kWh in order to convey price signals that encourage efficient electricity usage.

104. Corcoran explained NWE's proposals regarding its reactive power factor adjustment charge. Most of NWE's transmission and substation level customers have large motor loads that create inductive-type reactive power. Tariffs for these customer classes include a reactive power cost adjustment charge. In the past, NWE set the per KVAR (kilovolt-amps reactive) reactive power charge equal to the per KVAR cost of capacitors that cancel reactive power. NWE used engineering studies to estimate the cost of installing capacitors on the system, and Corcoran recommended continuing this practice. He estimated the cost to install a representative capacitor to correct for the power factor of transmission and substation level customers. The result is an annual charge of $3.48 per KVAR, compared to the current charge of $1.14 per KVAR. The increase results from two factors: (1) the current charge is based on cost estimates performed in the mid-1990s, and (2) the cost estimates underlying the current charge reflect the cost of distribution system capacitors instead of higher-cost capacitors that NWE would use to correct the power factors of substation and transmission voltage level customers.

105. Corcoran recommended adding tariff provisions specifying that the charge only applies to those KVAR needed to bring a customer to a 90 percent power factor, which NWE deems acceptable. He also proposed tariff provisions clarifying that meters capable of measuring reactive quantities are standard on all GS-2 class customers, specifying that the power factor calculation is made at the time of a customer's monthly maximum or billing demand, and specifying that a customer has 120 days after notification of a poor power factor to correct it before the reactive power charge is assessed.

106. Regarding NWE's electric line extension policy, Corcoran recommended a $1,000 free extension allowance for residential customers, which he calculated by multiplying the applicable transmission and distribution rates by average annual residential kWh consumption for a three-year period. For General Service and Irrigation non-demand-metered customers, he recommended determining the free extension allowance by multiplying $0.05/kWh by an estimate of the customer's annual kWh consumption. For General Service and Irrigation demand-metered customers, the free extension allowance would be determined by multiplying $0.03/kWh by an estimate of the customer's annual kWh consumption. Corcoran's proposed free extension allowances would apply only to the primary line extension; he said customers should be responsible for the service line connecting the meter to the transformer. Corcoran also recommended charging for multiple line extension cost estimates per location per year. He noted that a similar charge already exists in NWE's natural gas tariff. He proposed other minor tariff changes that clarify existing provisions and/or make the electric tariff consistent with the natural gas tariff.

107. Finally, Corcoran proposed adding 15 new ownership cost ranges for lighting service to accommodate customers' unique and more expensive lighting fixtures and to reflect increasing costs.

Gary L. Goble

108. Gary Goble, a consultant with Management Applications Consulting, Inc., testified that he quantified electric long-run marginal costs, by class, consistent with PSC minimum rate case filing rules. He also provided an embedded cost study, which he recommended for setting class revenue responsibilities for delivery services. He testified that embedded cost studies are more conventional than marginal cost studies, are used more for rate design purposes, are fairer and

more transparent than marginal cost studies, and, therefore, are more reasonable for allocating costs.

109. Goble testified that marginal cost studies estimate the cost of providing an additional unit of service. Electric utilities provide the following services: supply, transmission and distribution delivery systems, connections to the delivery system, preparing and processing bills, responding to customer inquiries, and other services. Utilities incur both short- and long-run marginal costs to provide service. He said short-run costs vary instantly with changes in consumption while long-run costs change over time as a utility adjusts plant investments in response to changes in consumption. He used the cost of a few more kWh of electricity as an example of short-run marginal costs, and the cost of expanding transmission or distribution capacity to serve additional peak load as an example of long-run marginal costs. In theory, marginal cost-based utility pricing promotes appropriate consumption decisions and efficient allocation of society's resources because when consumers confront prices that accurately reflect the change in costs that will occur from their decision to consume, they make informed and economically efficient decisions regarding their use of utility service.

110. Based on input from NWE's planning and operations personnel, and numerical cost analyses, Goble determined that summer peak load is the dominant planning criterion and primarily drives marginal transmission and distribution costs. He said NWE expects future summer electric loads to grow faster than winter electric loads, and added that since physical capability for most electric equipment is limited by temperature equipment designed for summer peak load can handle even higher winter peak load. Accordingly, he classified all marginal delivery costs as related to summer coincident peak-hour demand.

111. He contended that changes in demand (load) have no cost consequences unless they occur at the time of system peak and, therefore, chose not to measure transmission and distribution costs on a time-of-use basis. He said sunk investments can serve additional load unless the load occurs at the time of the system peak, so only peak loads cause NWE to invest in additional transmission and distribution facilities.

112. Goble's electric embedded cost study covered just NWE's delivery costs (transmission, distribution, customer). Goble began his embedded cost study by identifying cost functions and then he either directly assigned or allocated all major revenue requirement items to them. When he could not directly assign a cost to a cost function, he applied a functionalization factor. He

classified the functionalized embedded costs as capacity-related, energy-related, or customer-related. The classification process simultaneously allocated to customer classes. For example, costs in the transmission, distribution substation, distribution lines, and distribution transformer functions were allocated to customer classes using the capacity-related allocation factors 12CP, NonCP, NonCPLines, and Transformer, respectively. These allocation factors effectively classify the costs for these functions as capacity-related as they allocate the functionalized costs to customer classes.

113. Goble summarized the allocators that attribute functionalized revenue requirement components to rate classes. He explained that he derived these allocators from external information and that they are pivotal to his embedded cost study. The allocators are:

> 12CP – He applied this allocator to the transmission function revenue requirement. It reflects the simple average of estimated class contributions to the load in the peak hour of each month. He said applying the 12CP allocator to the transmission function revenue requirement is consistent with FERC precedent and recognizes the importance of year-round loads. The class demands that underlie the allocator are based on actual loads or NWE's load research data (when actual load data were not available).
>
> NonCP – He applied this allocator to the distribution substation function revenue requirement. It reflects class contributions to the sum of each class's peak demand. The class demands underlying this allocator are based on NWE's load research data excluding loads that do not use the distribution system.
>
> NonCPLines – He applied this allocator to the distribution revenue requirement for overhead lines, poles, underground cable and conduit. This allocator is the NonCP allocator excluding loads served directly from substations.
>
> MeterCost – He applied this allocator to the revenue requirement for meters. He developed the allocator from his marginal cost study's estimate of the metering cost per customer, including installation. He multiplied that cost per customer by the number of customers to produce a "Replacement Cost New" estimate for each class, on which the allocator is based.
>
> Services – He applied this allocator to the revenue requirement for services. He developed the allocator the same way he developed his MeterCost allocator, using his marginal cost study's estimate of service cost per customer multiplied by the number of customers.
>
> MeterRdg – He developed a meter reading allocator in a two-step process. First he segregated meter reading costs into automated meter reading, manual meter reading, and readings based on load research. Then he used the number of each type of meter reading method for each customer class to set the allocator.

CustRecords – He allocated customer records expenses to rate classes based on the number of customers, reasoning that the costs of the computerized customer records system do not differ by rate class.

Customer – He allocated other customer costs using the number of customers; that is, the allocator is identical to the CustRecords allocator.

Lighting – Lighting investment and lighting expenses are segregated in the FERC uniform system of accounts, so lighting revenue requirements are directly assigned.

114. Based on the embedded cost study results, Goble concluded that uniformly increasing current rates to yield the new delivery service revenue requirement would cause inter-class subsidies, where subsidy means a difference between embedded costs and revenue produced. He found that GS-2 Substation and GS-2 Transmission rates should be reduced and Residential, Irrigation, and Lighting rates should be increased. Regarding cost functions, he said transmission rates should be reduced slightly and distribution and customer charges should be increased slightly.

115. Goble acknowledged that the PSC has used marginal costs to design rates by rule and in practice. However, he contended that it is uncommon in the industry to allocate costs of service using marginal cost principles. He said regulatory commissions commonly use embedded or fully distributed cost studies to allocate cost responsibility. He agreed that marginal costs are important to developing rates, but recommended using embedded costs to assign revenue responsibility among customer classes.

116. Goble testified that embedded costs are better defined than marginal costs because: (1) embedded costs are measured and marginal costs are estimated, (2) embedded costs equal a utility's revenue requirement, marginal costs diverge from the revenue requirement and, therefore, must be reconciled, (3) embedded costs are set out in the utility's books and records, but methods for estimating marginal costs are debatable, (4) embedded costs do not involve debating whether to use short- or long-run marginal costs, (5) embedded costs are known and measurable, marginal costs can be estimated using a wide variety of methods, (6) embedded costs are actual costs, marginal costs often reflect forecasts that are subject to error, (7) marginal costs are easy to manipulate for a desired result because they rely on many assumptions, (8) marginal cost studies use fixed charge rates and discount rates that are debatable, embedded costs use the utility's cost of capital, (9) several widely accepted, published authorities specify

how to calculate embedded costs, but no widely accepted, published authorities specify the methods for estimating marginal costs, and (10) marginal cost methods rely on statistical analyses that may yield invalid results. He emphasized that marginal costs are relevant for pricing – they can be useful for identifying pricing components or time periods that should bear more or less weight. However, he believes embedded costs are far better for developing class revenue requirements.

117. Given the fact that demand for delivery service is highly inelastic, Goble said there are few benefits to using marginal costs as a resource rationing mechanism for the delivery system and it is more practical and reasonable to set delivery system rates using embedded costs.

118. Goble's testimony addressed ARM. 38.5.8211, a supply procurement guideline which requires NWE to consider time-of-use rates, seasonal rates, blocked rates, and tiered rates. He did not exhaustively analyze all pricing options and recommended further analysis before the PSC adopts the pricing options listed in the rule. Although he found no cost basis for an inclining block rate design, he testified that such a rate design could be justified if usage above some base level is more sensitive to price changes. In economic terms, above some basic usage level demand for electricity becomes more price elastic. An inverted block rate design might be justified if it permits rates for the more price elastic demand to more accurately reflect marginal costs.

119. Regarding electric rate design, Goble provided two sets of rate design results, one based on marginal costs, the other embedded costs. He said rate design issues can be separated into supply issues and delivery issues, pointing out that supply tracker filings address supply cost recovery and rate design.

120. Goble described, class-by-class, the rate design process, using the results of his embedded cost study, limiting class delivery service revenue increases to 9 percent and requiring all classes to bear some of the overall delivery services revenue requirement increase:

> Residential – Increase monthly customer charges by the overall system average rate increase and round to the nearest five cents. Scale transmission and distribution charges from the embedded cost study as necessary to achieve an overall residential delivery service revenue requirement increase of 9%, thus moderating the 24% residential delivery service revenue requirement increase indicated by the cost study.
>
> General Service-1 – Increase monthly customer charges by the overall system average rate increase and round to the nearest five cents. Scale transmission and distribution demand and energy charges resulting from the embedded cost study as necessary to better

match component costs, subject to rate moderation criteria. Increase GS-1 secondary non-demand sub-class revenue requirements 8.15%, GS-1 secondary demand revenue requirements 4.95%, GS-1 primary non-demand revenue requirements 5.25%, and GS-1 primary demand revenue requirements 4.49%.

General Service-2 – Increase monthly customer charges by overall system average rate increase and round to the nearest five cents. Although the embedded cost study indicates GS-2 revenues should decrease, NWE's rate moderation plan requires all classes to bear some of the overall delivery services revenue requirement increase. So increase GS-2 substation sub-class revenue requirements 4.00% and GS-2 transmission revenue requirements 2.85%.

Irrigation – Increase monthly customer charges by overall system average rate increase rounded to the nearest five cents. Increase transmission and distribution charges based on component costs from the embedded cost study as necessary to achieve an overall, moderated 9.00% class revenue requirement increase.

Lighting – Increase transmission and distribution charges 5.84%, O&M and billing charges 6.16% to better reflect component costs from the embedded cost study. Increase fixture charges as necessary to achieve a 6.16% class revenue requirement increase.

Goble testified that the above class rate designs reasonably recover the costs of service, do not cause any undue customer impacts or hardships, are not unduly discriminatory, and reflect a consistent application of recognized ratemaking standards.

121. Goble applied a similar rate design approach to the results of his marginal cost study.

MCC Direct Testimony

Dr. John W. Wilson

122. Wilson urged the PSC to reject NWE witness Goble's cost allocation and pricing philosophy that Wilson contended reflects a view that energy charges should be eliminated and revenue requirements should be recovered through fixed monthly facilities charges.

123. Wilson testified that marginal cost pricing is a cornerstone of economic efficiency; however, he also acknowledged arguments that the benefits of marginal cost pricing in the utility sector depend on marginal cost pricing in all major sectors of the economy under conditions of competitive equilibrium, which does not exist in the real world. Wilson said it is more important for prices to reflect marginal energy costs because customers can more directly influence their bills and resource allocation through consumption decisions. In contrast, marginal cost-based customer charges and demand charges are less likely to affect consumption decisions and, therefore, efficient resource allocation.

124. Wilson asserted that NWE's marginal cost study is really a projected embedded cost study (fully distributed cost study based on predicted future cost levels). Using NWE's marginal cost model as a starting point, Wilson made several modifications to illustrate how dramatically different marginal costs of service result from his recommended changes. Generally, he eliminated expenses he believes are non-incremental (rents, common overhead costs, some customer-related expenses, uncollectible tracker revenue, labor costs for meter installation), classified secondary lines (service lines) as demand- and energy-related instead of customer-related, and classified one-half of transmission, substation, primary, and secondary distribution costs, including transformers, as energy-related (he classified the other one-half as demand-related and assigned those costs on the basis of 12 monthly coincident peak demands).

125. Wilson's modified marginal cost of service model indicates that residential customer charges should be \$3.28/mo., compared to NWE's \$20.00/mo. For small commercial customers, Wilson's modified study results in a \$4.92/mo. customer charge, compared to NWE's \$25.73/mo. Overall, Wilson's modified marginal cost study indicates that residential and small commercial customers' rates should be reduced by about 12 percent and 16 percent, respectively. However, because he does not believe NWE's marginal cost model properly estimates marginal costs, he did not recommend that the PSC use his modified cost of service results for rate design purposes.

126. Wilson testified that the most important use of an embedded cost study is to appropriately allocate a portion of a utility's revenue requirement to each customer class, which can then be used as a guide to setting rates for each class. As with NWE's marginal cost study, Wilson objected to the way Goble classified and allocated transmission and distribution plant costs in its embedded cost study, and for the same reasons. That is, Goble classified transmission, substation, primary and secondary distribution line, and transformer plant costs solely as demand-related costs and attributed none of these costs to customer classes on the basis of energy use. Wilson testified that this approach assigns greater cost responsibility to small customers; residential customers are assigned 52.7 percent of NWE's distribution plant costs even though they account for 41.5 percent of distribution voltage energy deliveries.

127. Wilson prepared an alternative embedded cost study using Goble's embedded cost of service model. Wilson's alternative embedded cost study classified and allocated one-half of transmission and distribution plant costs in proportion to customer class energy use. He also

modified the measure of customer class demand Goble used to classify and allocate the remaining one-half of transmission and distribution plant costs. He classified substation and primary distribution line costs using an average of the 12 monthly coincident peak demands of each class (12-CP) instead of the single highest peak (1-CP). He said a 12-CP allocator is more stable and consistent from year-to-year and is a more representative indication of demand responsibility. He allocated the demand portion of transformers and secondary distribution lines (service lines) in proportion to each class's non-coincident peak demand (NCP), asserting that these are the only portions of the transmission-distribution network that are truly location specific. Finally, Wilson created a composite of Goble's embedded cost study allocators for meters, meter reading and energy use. He applied the composite allocator to customer records costs and other customer costs, stating that he prefers this approach to NWE's, which assumes customer records and other customer costs are entirely unrelated to customer size, revenues, or the functions performed for customers. According to Wilson, once the above changes are made to Goble's embedded cost study, there is no longer a valid cost basis for increasing residential and small business customers' rates.

128. Wilson recommended against increasing customer charges in this case because they do not provide useful price signals and do not contribute to efficient resource allocation or energy conservation. He advocated reducing the residential customer charge to \$3.50/mo. and said similar reductions to customer charges for other classes would be reasonable. He also recommended against increasing demand charges for demand metered customers. Instead, he said any revenue shortfall from a particular customer class should come from increasing energy charges.

129. Wilson recommended rejecting NWE's proposed residential class inverted block rate structure. He agreed that blocked rate structures can improve price signals if the tail block better reflects marginal energy costs, but said that justification does not exist here because NWE's incremental energy costs are generally less than the base residential rate of \$0.08/kWh. He also asserted that a residential inverted block rate design would discriminate between residential customers without cost justification and lead to large bill increases for customers that use more than 350 kWh/mo.

LCG Direct Testimony

Dr. Alan Rosenberg

130. Rosenberg testified that the fundamental starting point and guideline for spreading NWE's total revenue requirement among customer classes should be the cost of serving each customer class. He contended that cost-based rates are fair, reasonable, and promote rate stability, conservation and efficiency. He said that prices that properly reflect demand, energy, and customer costs signal customers to manage their loads appropriately, which in turn signals NWE on the need for new investment. He asserted that, ideally, rates should be unbundled so that customers know what they are paying for, and added that because not all customers use all services, unbundled rates are a prerequisite for cost-based rates.

131. Rosenberg testified that this case is focused on NWE's delivery costs and that supply costs are not an issue. Rosenberg said that for delivery service cost functions he prefers embedded cost of service studies over marginal cost of service studies for spreading revenue requirements to customer classes. He said embedded cost studies are tied to actual costs that are the basis for a utility's revenue requirement and the PSC can have more confidence in them.

132. Regarding NWE's embedded cost study, Rosenberg found NWE's classification and allocation of transmission function costs on the basis of 12 coincident peaks (12-CP) defensible. He acknowledged that the transmission system is used on a continuous basis to deliver energy, but said the pertinent question is: what usage characteristic drives the need to expand or reinforce the system? He contended that additional usage when the system is not stressed does not impact the level of transmission plant or the costs NWE incurs. Accordingly, he asserted energy should play no role in a cost study's allocation process. He pointed out that the National Association of Regulatory Utility Commissioners' (NARUC's) Electric Utility Cost Allocation Manual identifies six methods for allocating transmission costs, all but one of which rely on just peak demands. Rosenberg agreed with NWE's approach to allocating substation function costs.

133. Regarding NWE's marginal cost study, Rosenberg pointed out that NWE's estimated marginal costs exceed revenue requirements, necessitating an adjustment to the marginal costs. He said this can be accomplished in two ways: (1) adjust each class's marginal cost by the ratio of current revenue to total marginal costs, or (2) adjust the transmission marginal costs and distribution/customer marginal costs separately so the sum of class revenues for each function will equal the functional revenues. He recommended the second option, asserting that it aids in unbundling rates and conveying accurate price signals.

134. Regarding rate design, Rosenberg disagreed with Corcoran's proposed, moderated class revenue allocations, which limit delivery service revenue increases to no more than 9 percent, and preclude any class from receiving a revenue decrease. He pointed out that Docket D2009.9.129 is consolidated with Phase II (cost of service/rate design) of Docket D2007.7.82, which resulted in a stipulated overall revenue increase and a uniform percentage adjustment to all rates. He said there was no cost basis in Docket D2007.7.82 for uniformly increasing all rates; it was simply an expedient pending resolution of Phase II.

135. To resolve Phase II of Docket D2007.7.82, Rosenberg recommended increasing rates for those classes with below average system rates of return, according to the results of the cost study, but no more than 5 percent. He recommended reducing rates for those customer classes with above system average rates of return by at least half the amount indicated in the cost study, but no more than 15 percent.

136. Rosenberg then recommended that the PSC further adjust revenues toward costs in Docket D2009.9.129. He advised increasing rates for customer classes with below system average rates of return according to the cost study, but no more than 14 percent, and reducing rates for customer classes with above system average rates of return by at least half the amount indicated by the cost study, but no more than 15 percent.

137. Rosenberg testified that his class revenue allocation proposal results in a total bill increase (including supply) for an average residential customer of about $5.90 per month, or 8.5 percent. He added that even if the PSC adopts his recommendation, the GS-2 customer class will still be paying more than its share of delivery service costs, as measured by either NWE's embedded cost study or its marginal cost study.

HRC/NRDC Direct Testimony

Dr. Thomas M. Power

138. Power, an economist and consultant, listed his several concerns with the assumptions underlying NWE's embedded cost of service analysis. He took issue with NWE's "predominant use" approach that focused on just one of several cost determinants because it led NWE to conclude that just three factors affected its costs – peak demand, energy consumption, and number of customers – when most elements of an electric and gas utility serve multiple purposes and cannot be assigned entirely to just one of those purposes. He recommended a cost of service analysis using mixed allocators combining more than one cost factor.

139. Power agreed with NWE witness Goble's testimony in support of allocating transmission plant costs to classes based on 12 monthly coincident peaks, but contended that this broad view should be applied as well to the allocation of substations and distribution lines, which NWE allocated based on a method similar to the single coincident peak approach.

140. Power argued that peak load allocators for electric transmission and distribution costs should be tempered by combining them with other allocators rather than assuming, as he said NWE does, that these costs are determined entirely by the capacity of the lines and are proportional to the capacity.

141. Regarding electric transformer costs, Power claimed that although NWE classified them as demand costs, the utility allocates transformer costs on a per-customer basis rather than based on contribution to non-coincident peak, which is the allocator used for other distribution costs. He suggested an alternative calculation of the number of transformers per customer that would reduce the percentage of transformer costs that would be allocated to the residential customer class. Power recommended that transformer costs be allocated on the same basis as costs for transmission, substations and wires. That general allocation approach proposed by Power is that peak demand allocations be combined with annual energy usage allocators to produce a 50 percent demand/50 percent energy allocator. He said his proposed allocation method would reduce the costs allocated to small, non-demand-metered customers and increase costs for larger demand-metered customers, and subsequently reduce those customers' revenue responsibility.

142. Power testified in support of NWE's proposed inclining block rate structure for residential customers, but recommended the initial electric block should be set at 200 kWh rather than 350 kWh as NWE proposed. He said his proposal would lead to more efficient pricing by exposing less consumption to the lower initial block rate.

143. According to Power, NWE's method of applying a multiplier of 1.2 to the average residential electricity supply cost to set the electric rate tail block rate represents a modest step toward marginal cost pricing for electricity supply.

144. Power said that data provided by NWE show that 72 percent of NWE's electric customers receiving Low Income Energy Assistance Program (LIEAP) benefits would see lower bills under NWE's 350-kWh initial block than with an unblocked rate design. 68 percent of all residential electric customers' bills would be lower, he said. Power asserted that, under his

proposed 200-kWh initial block, 69 percent of LIEAP electric customers' bills would be lower, compared with 65 percent of all residential electric bills.

145. Power contended it is an established fact that low-income households tend to consume less electricity and natural gas than higher-income households and therefore will benefit from inclining block rates. In Montana, it may be that only one-fifth of the households that are eligible for assistance from the Low Income Energy Assistance Program (LIEAP) actually receive LIEAP benefits because the low-income households with higher energy usage have the greatest motivation to seek LIEAP assistance while many non-participating low-income households report that the LIEAP payments are not worth the effort of applying. Power cited data from the federal government in 2004 that supports the theory that LIEAP recipients consume more energy than other low-income households in general.

146. Power recommended replacing NWE's current lost revenue adjustment mechanism (LRAM) that allows NWE to recover lost revenues associated with its natural gas and electricity energy conservation programs with full per-customer decoupling. His proposed decoupling mechanism would include tracking and an annual true-up to reconcile actual fixed-cost revenues from energy sales with the per-customer fixed-cost recovery authorized by the PSC in the last general rate case. Over-collections of fixed costs would be refunded to customers. Under-collections would be recovered through increased rates. Power acknowledged that NWE already conducts significant energy efficiency programs and that the lost revenue recovery mechanism already protects NWE from under-collecting its fixed costs due to its conservation programs; however, he argued that decoupling will better align the utility's energy efficiency incentives with the PSC's energy efficiency policy objectives and will make regulation more supportive of that policy.

Ralph Cavanagh

147. Cavanagh, NRDC's Energy Program Co-Director, introduced and testified in support of HRC/NRDC's revenue decoupling proposal. Citing market barriers to energy efficiency investment and studies that demonstrate customers' reluctance to invest in energy efficiency unless the payback time is short, he said that energy prices would have to increase significantly to induce customers to make long-term energy efficiency investments. Rather than increasing rates, however, he urged the PSC to pursue cost-effective energy efficiency through coordinated

application of utility investments and government standards. Cavanagh applauded NWE's use of targeted incentives and education that has resulted in increased energy efficiency savings by NWE, including NWE's estimate of savings in 2010 of more than 1 percent of projected sales. But Cavanagh pointed out that decreased energy sales due to energy efficiency programs reduces NWE's recovery of fixed costs. He claimed that every additional 1 percent reduction in electricity use and demand by residential and small general service customers that is not covered by the existing lost revenue recovery mechanism would reduce NWE's annual fixed-cost recovery by $2.4 million, while every 1 percent increase would have the opposite effect. Shareholder impacts are at least 10 times that amount, he said. (The example provided by Cavanagh of savings not covered by the lost revenue recovery mechanism is improvements in the design and administration of efficiency standards.) Cavanagh argued that shareholder losses could increase even more if NWE implemented tiered rates because some savings will come from the highest price tier.

148. According to Cavanagh, the disadvantages of LRAMs include: (1) they do not cover savings outside of utility programs; and (2) they maintain the link between utilities' financial health and retail sales and encourage savings on paper over actual savings. He said the advantages of decoupling include: (1) it is comprehensive in scope; (2) it reduces the opportunities for disagreements over energy savings for which NWE is or is not responsible; and (3) it is easier to administer because it requires only periodic reviews of changes in NWE's sales and the number of customers.

149. Cavanagh's recommendation for a four-year decoupling pilot program consists of these elements: (1) Establishment of a per-customer, non-fuel revenue requirement charge for residential and small general service electricity and natural gas customers based on NWE's authorized fixed costs of service, averaged across the covered customer classes. The existing LRAM would still apply to the other customer classes. (2) An annual comparison of NWE's per-customer non-fuel revenues with its PSC-authorized cost recovery level, with over-collections refunded to customers through a rate decrease and under-collections restored to NWE through a rate increase. Rate volatility would be mitigated by calculating the annual adjustment as an average applied to all classes based on the net over/under recoveries for all combined classes. (3) A 3 percent cap on rate increases or decreases, with unrecovered balances carried forward. (4) Continuation of NWE's practice of expensing its energy efficiency

investments while NWE, through a collaborative process, develops a proposal for PSC consideration for a method of equitable customer/shareholder sharing of the economic benefits of energy efficiency improvements.

150. Cavanagh anticipated and rebutted arguments against decoupling. First, he disputed the argument that decoupling guarantees utility profits and reduces a utility's incentive to operate efficiently by asserting that decoupling would not guarantee any specific level of profit or insulate NWE against the risk of failing to achieve profitability objectives due to internal inefficiencies. He disagreed with the contention that decoupling insulates a utility from the effects of an economic downturn while at the same time exposing customers to rate increases. According to Cavanagh, his decoupling proposal would leave NWE exposed to reductions in customer growth associated with economic downturns. He added that maximizing energy efficiency investments through decoupling is the best way to protect customers from unaffordable bills. Cavanagh said it is fair to include only NWE's residential and small general service customers in his recommended decoupling proposal because they produce more than 80 percent of NWE's revenue requirement. His proposal does not include adjusting sales for weather abnormalities during the annual true-up because he believes the risks and benefits of weather-related adjustments cut both ways.

151. According to Cavanagh, there is no way to predict without experience what the effect of decoupling will be on NWE's overall risk profile and cost of capital and, therefore, its authorized rate of return. If there is no reduction in NWE's rate of return with decoupling, Cavanagh said customers will still benefit by reductions in their bills due to increased energy efficiency, by protection against high bills associated with extreme weather, and by receiving refunds from NWE for any gains in fixed-cost recovery associated with unanticipated increases in system-wide electricity use.

152. Cavanagh said that 17 states have adopted decoupling for one or more gas utilities and 13 for electric utilities.

153. In order to provide NWE with a profit incentive if its customers take advantage of cost-effective conservation measures, Cavanagh recommended that the PSC allow NWE and its customers to share the economic benefits of cost-effective energy efficiency improvements. He suggested that a collaborative stakeholder process be employed to develop such a benefit-sharing proposal for PSC consideration.

NWE Rebuttal Testimony

Patrick R. Corcoran

154. Corcoran testified that although MCC's witnesses dispute the need for a residential inverted block rate design from a pure marginal cost perspective, they did not address the real reason NWE proposed such a rate structure – to encourage conservation of electricity. He added that while NWE's inclining block rate design is reasonable, Power's recommendation to adjust the initial block from 350 kWh to 200 kWh may be an acceptable alternative.

155. With respect to rate moderation, Corcoran testified that while it is important to consider cost of service in designing rates, all other rate design goals should also be considered. Accordingly, he said the rate impact on any one customer group must be considered alongside the rate impacts on all other customer groups. He pointed out that the PSC must consider the interests of the consuming public, not just residential customers.

156. Finally, Corcoran testified that NWE supports implementing a revenue decoupling pilot. He recommended that the PSC limit its review of decoupling in this case to the policy question of whether such a pilot should proceed. If the PSC decides to proceed with a decoupling pilot, Corcoran recommended that NWE's stakeholder group work out the details. NWE would make a compliance filing some time later that would present the modeled impacts of decoupling on customers and lay out associated administrative, accounting and reporting requirements. Corcoran strongly recommended that if the PSC decides to proceed with decoupling that it be on a trial basis so that decoupling can be tested while protecting both NWE and its customers from unreasonable impacts.

Gary L. Goble

157. Goble contended that NWE's marginal cost study is sound and the results are reliable, despite Wilson's and Power's criticisms. He suggested that the PSC consider modifying NWE's study according to its own findings in this case and use the modified study as a guide for future cases. He said this approach would avoid the need to repeatedly litigate arcane cost methods. He added that the PSC could do the same thing with NWE's embedded cost study. He noted that Wilson, Power, and Rosenberg all relied on the embedded cost model NWE developed as a starting point for their own cost allocation and rate design proposals in this case. He reiterated that he finds embedded cost studies preferable to marginal cost studies for delivery cost functions. Whatever cost study the PSC chooses, Goble recommended that the PSC establish a

cost study precedent so there is a standard against which future cost study methods and results can be evaluated and reviewed. He said that without such a precedent all issues are open to debate and parties that do not benefit from the results strategically advocate rejecting the cost study.

158. Goble discussed the changes in his embedded cost study brought on by intervenor testimony. The most significant change replaces the transformer allocator with a non-coincident peak (NCP) demand allocator. Goble agreed with Power that the original transformer allocator contained an error, but determined that the information needed to correct the error does not exist. Therefore he recommended using a NCP allocator in this case. Goble also made several changes to his marginal cost study.

159. Goble disagreed with Wilson and Power that the embedded cost study should classify and allocate transmission costs 50 percent on the basis of energy use and 50 percent on the basis of class contributions to 12 coincident peak demands. He acknowledged that the transmission system provides a number of services, including delivering energy over time and during off-peak periods, but asserted that because the transmission system is designed and expanded to meet peak demand, its ability to deliver energy in off-peak periods is a by-product of transmission investment, not a <u>cause</u> of transmission investment. He added that if the transmission system were designed only to deliver energy without regard to peak demand, it would be less costly to build and maintain but would be unreliable when demand rises above an average level. Accordingly, he concluded that peak demand is the factor that drives the next increment of transmission investment. In response to Wilson's assertion that transmission lines are built to link energy generation to the system, Goble pointed to NWE witness John Leland's testimony that today transmission lines connecting generators to the transmission system are built by the generators, not NWE.

160. Goble contended that a number of recognized authorities subscribe to a cause-and-effect relationship between peak demand and transmission costs. He added that he is not aware of any state that has classified and allocated 50 percent of transmission costs as energy-related, and that Wilson did not provide any orders from other utility commissions supporting his position.

161. In response to Power's assertion that half of all transmission costs should be classified as energy-related because it is energy sales that economically justify grid expansion, Goble countered that this reasoning is overly simplistic and fundamentally flawed. He contended that if

it were possible to bill each customer on the basis of their contribution to peak demands, which cause the design and construction of the transmission system, Power's point would be moot. He noted that real world-metering limitations prevent ideal billing arrangements. He concluded that Power confuses cause and effect; he stated that utility revenues are irrelevant to the measurement of marginal costs, but Power wants prices to drive the calculation of marginal costs. Goble contended that if transmission rates were not energy rates, then, using Power's logic, transmission costs should not be classified as energy related.

162. Goble similarly disagreed with Wilson's and Power's recommendations to classify 50 percent of substation, distribution lines, and transformers as 50 percent energy-related. He stated that Wilson and Power relied on arguments for classifying distribution costs that are similar to the arguments they made for classifying transmission costs. Goble responded that transmission facilities are different than distribution facilities in terms of voltage levels, costs per mile, and the effect of localized loads and system diversity.

163. With respect to transformers, Goble acknowledged and agreed with a problem Power pointed out regarding how Goble assigned transformer costs to customer classes. Accordingly, Goble abandoned that method in his rebuttal testimony and instead recommended classifying transformer costs as demand-related and allocating those costs to customer classes in proportion to the classes' non-coincident peak demands, a method he contended is consistent with NARUC's Electric Utility Cost Allocation Manual.

164. With respect to service lines, Goble disagreed with Wilson's recommendation to classify and allocate 50 percent of these costs on the basis of energy use and 50 percent on the basis of 12 CP demand. Goble asserted that Wilson seemed to contradict his testimony in response to data request NWE-088b. Goble added that all intervenors appeared to accept his allocation of meter costs.

165. Finally, Goble disagreed with Wilson's proposal to classify and allocate customer records costs on the basis of one-third meter investment, one-third meter reading expense, and one-third energy. He said Wilson provided no support for his proposal and said NWE's method reflects industry-standard practices that are consistent with the NARUC Electric Utility Cost Allocation Manual.

166. Goble disagreed with Wilson that NWE's marginal cost study is really a fully distributed cost study that reflects predicted future costs for each type of equipment and service. He

asserted that NWE's marginal cost study closely follows the marginal cost methods outlined in NARUC's Electric Utility Cost Allocation Manual as well as the generic marginal cost model in the PSC's rules and standard industry practices.

167. Goble responded to Wilson's criticism that NWE included secondary lines (service drops) and transformers in the customer function and his questions as to whether continued service by existing customers or loss of a customer would cause additional costs or allow NWE to avoid costs. Goble argued that NARUC and other recognized authorities acknowledge that transformers can be assigned to the customer cost function and, therefore, it would be unreasonable for the PSC to reject NWE's cost study based on Wilson's argument.

168. Goble also addressed Wilson's assertion that marginal costs should reflect the resource costs or cost savings of retaining or losing an existing customer. Goble replied that existing meter, service and transformer costs are sunk and, therefore, not relevant to estimating marginal costs. However, since NWE must continue to serve existing customers and stand ready to replace and maintain equipment serving existing customers, a customer's decision to remain a customer will cause additional meter, service and line transformer costs. Goble asserted that the annualized cost of funding the on-going life-cycle replacement of existing equipment calculated using an economist's fixed charge rate is the same as the marginal cost for new transformers, meters and service lines. He states that the annualized marginal costs imposed by new and existing customers, when stated as a series of payments that escalate with inflation, are the same and, therefore, there is no difference in the long-run marginal costs of serving existing and new customers. He concluded that distinguishing between the marginal costs to serve existing and new customers is meaningless.

169. Wilson testified that NWE's marginal costs result in price signals that customers cannot meaningfully respond to. Goble countered that that is not a requirement for measuring marginal costs. Rather, Goble asserted that the rate design process interprets marginal costs in developing marginal cost-based prices. Goble agreed, for example, that it is relatively less important that customer charges reflect marginal costs because customer demand is not responsive to customer charges. However, he asserted that that is irrelevant to the proper method of measuring marginal customer costs.

170. Goble disagreed with Wilson that rents and common overhead costs such as supervision and engineering and miscellaneous expenses will not change if demand changes. According to

Goble, Wilson focused on short-run marginal costs rather than long-run costs. Goble countered that rents are payments for use of plant and equipment necessary to operate the utility. He said that if the rented plant had been purchased, there would be no question that the investment or its carrying costs would be included in the measurement of marginal costs. Accordingly, he concluded that if the rented equipment is used to serve incremental loads, or would be avoided with a decrease in loads, it should be included a calculation of marginal costs. Supervision and engineering expenses are directly related to the operation and maintenance of transmission and distribution facilities. In the long run, the more O&M activities NWE undertakes, the more supervision is required. Similarly, the more extensive NWE's transmission and distribution system, the more engineering support will be needed for O&M.

171. Goble testified that he agreed with Power that the residential inclining block rate is a good first step toward marginal cost pricing for electricity. However, he disagreed with Power that he overestimated the marginal cost of electricity supply by failing to adjust for the effect of inflation. According to Goble, Power appeared to overlook the fact that NWE discounted the nominal forecast of electricity pricing in order to develop a levelized cash flow stream in 2011 dollars.

172. Regarding delivery service rate design, Goble recommended that the PSC use his embedded cost study to define each customer class's revenue requirement. He added that the PSC should use, to the extent possible, the component costs (i.e., costs classified as demand-, energy-, and customer-related) in the embedded cost study to develop tariff rate components. Accordingly, he disagreed with Wilson's recommendation to decrease customer charges and leave demand charges at their current levels.

John Leland

173. John Leland, NWE's Manager of Regional Systems Planning and Engineering, addressed the factors that cause additional transmission investment and the transmission planning principles he communicated to Goble. Leland disputed how Wilson and Power characterized what causes transmission investment in today's working environment. Contrary to Wilson's testimony, Leland asserted that NWE no longer builds transmission to link loads with generating plants. He said that, under current regulatory structures, a developer of a proposed new generating plant must build and pay for facilities and equipment located between the new generating plant and NWE's transmission system. NWE's governing principle for planning the

transmission system is maintaining system reliability. Accordingly, he disputed Wilson's assertion that NWE would incur capital intensive transmission costs to access low cost energy sources, saying Wilson attributed a generation concept to transmission designed to reliably meet peak load.

174. Leland testified that the appropriate size of a transmission line is not impacted in any way by the energy that flows over time across the transmission line. He also said that once a transmission line is constructed, under normal operating conditions, transmission operation and maintenance costs should not be influenced by the energy transmitted, regardless of the timing of such transmission.

MCC Cross-Intervenor Response Testimony

Dr. John Wilson

175. Wilson opposed the revenue decoupling proposal offered by HRC/NRDC witnesses Power and Cavanagh. Wilson pointed out several possible unintended consequences of decoupling. First, he noted that fixed rates (as opposed to the fixed revenues associated with decoupling), which create opportunities for gains or losses between rate cases, can provide a utility incentives to enhance productivity and efficiency. Decoupling could weaken these incentives.

176. Second, decoupling adjusts the utility's rates outside of the normal rate case setting where all of the utility's costs are considered and cost increases are balanced with cost reductions. Decoupling would abandon this matching principle for a piecemeal focus on only one factor that affects profitability.

177. Third, decoupling transfers normal sales level risks, which all businesses face in a market economy, from the utility to its customers. Wilson stated that this risk shifting should result in substantially reduced rate of return allowances because the traditional opportunity to earn a fair return would be replaced with much stronger profit protection.

178. Wilson testified that the PSC should consider whether it is these unintended consequences outweigh the problem decoupling is supposed to solve, which he characterized as NWE's assumed proclivity to enhance its profits between rate cases by promoting uneconomic sales growth and curtailing potential conservation. He pointed out that the PSC has already adopted a lost revenue recovery mechanism and that NWE is heavily engaged in extensive conservation and demand-side management efforts that are systematically enforced by regulatory

requirements like electricity supply cost trackers and resource procurement plans. He added that a decoupling mechanism would eliminate the requirement for NWE to demonstrate the connection between conservation efforts and sales reductions in order to qualify for revenue recovery.

179. Ultimately, Wilson questions whether incremental energy conservation gains from decoupling justify the management incentive, efficiency, productivity and risk shifting costs it would impose.

LCG Cross-Intervenor Response Testimony

Dr. Alan Rosenberg

180. Rosenberg criticized Wilson for not explaining whether prices should reflect short-run or long-run marginal costs, for not producing a marginal cost study he considers reasonable, and for not recommending specific rates for all NWE's customers. He said that while cost of service experts can legitimately disagree over allocation methods, and multiple methods are supported in the literature and regulatory precedents, Wilson's recommendation to allocate a large portion of almost every cost function on the basis of annual energy is overly simplistic, totally arbitrary and divorced from the realities of system planning. He reiterated that he finds NWE's cost of service methods reasonable in this case.

181. Rosenberg testified that the principle cost allocation disagreements in this case are: (1) should cost causation be measured by a marginal cost of service study or an embedded cost of service study, and (2) how should the costs be classified (energy, demand, customer) and how should they be allocated (coincident demands, multiple coincident demands, non-coincident demands). He added that there is a strong consensus that an embedded cost study is more appropriate for determining delivery rates, leaving only the second disagreement.

182. Rosenberg criticized Wilson's recommendation to re-classify 50 percent of transmission costs in NWE's embedded cost study as energy-related. He maintained that the primary cost drivers associated with capital investment in transmission assets are: (1) the distance between generators and load, and (2) the maximum customer demand the system is designed to serve. He said neither of these two factors is impacted by total energy use. On grounds that energy use, separate and apart from increasing NWE's peak load, does not cause a need for additional transmission, Rosenberg concluded energy use is irrelevant to transmission cost causation. He

added that even assuming energy use is relevant, Wilson's classification of 50 percent of transmission costs as energy-related is arbitrary.

183. Rosenberg testified that Wilson's recommendation to classify 50 percent of distribution costs as energy-related is inconsistent with NARUC's Electric Utility Cost Allocation Manual, which is clear that distribution costs are either demand-related or customer-related. He added that there is no empirical, engineering, or economic basis for classifying any portion of distribution costs as energy-related.

184. Rosenberg disputes Wilson's assertion that there is no valid cost basis for raising NWE's residential and small business rates. He said Wilson's own "corrected" embedded cost study shows that the GS-1 customer class produces a return of 68 percent of the system average return. And although Wilson's study shows the residential class producing a return very close to the system average return, 101.7 percent, Rosenberg asserted that this result assumes current residential class revenue is $102.2 million, when in fact it is $95.6 million. Rosenberg concludes that Wilson's "corrected" embedded cost study really shows that there is no valid reason for increasing GS-2 rates, and a rate reduction is justified.

HRC/NRDC Cross-Intervenor Response Testimony

Dr. Thomas M. Power

185. Power noted his agreement with Wilson on two points: (1) it would be inappropriate to treat all transmission and distribution costs as peak demand-related and some of the costs should be allocated to customers on the basis of energy use; and (2) the PSC can still design rates based on marginal costs if it allocates costs on the basis of embedded costs.

186. Power disagreed with Wilson's assertion that NWE's recent and prospective incremental energy costs are sufficiently below the base residential rate of about $0.08/kWh to eliminate marginal cost justification for a residential inverted block rate design. Power said that this might be true considering just current and projected regional market prices, but it is not true considering economic and environmental costs of producing and consuming electricity. He asserted that conservation oriented electric rates, like NWE's residential inverted block proposal, are a prerequisite for the success of energy conservation programs because they more accurately signal the total social costs of producing and consuming electricity.

187. Power also questioned Wilson's argument that an inverted block rate design would unfairly discriminate among residential customers and may, in certain cases, favor high-income

customers over low-income customers. Power contended that low-income customers, as a group, use less electricity than middle- or higher-income households. He said the way to address low-income households that use large amounts of electricity is through targeted energy efficiency programs.

Natural Gas Cost of Service and Rate Design

NWE Direct Testimony

Patrick R. Corcoran

188. The steps Corcoran described that underlie NWE's electric cost of service and rate design proposals also apply to NWE's natural gas rate proposals. As he did concerning the electric utility, Corcoran proposed using embedded cost of service studies to set class revenue responsibilities and design rates for natural gas delivery services. The same general rate moderation criteria apply, except Corcoran proposed capping cost allocation increases at 3 percent for natural gas delivery service.

189. Corcoran introduced the results of NWE's embedded and marginal delivery cost of service analyses related to natural gas.

190. Corcoran outlined NWE's proposed inclining block rate design for residential natural gas supply. The proposed blocks for natural gas consumption are 0 – 8 dekatherms (Dkt) per month for the initial block, and greater than 8 Dkt/month for the tail block. A residential customer using up to 8 Dkt in a given month would pay the lower initial rate for all gas consumed. A customer using more than 8 Dkt would pay the initial rate for the first 8 Dkt, and the higher tail block rate for all additional consumption. Inclining block rates were proposed only for the residential class.

191. Corcoran discussed the total bill impacts of NWE's revenue requirement, cost of service and rate design proposals.

192. Corcoran proposed additional natural gas tariff language to address the possible addition of large, variable load shippers to the customer base, and to introduce and clarify line extension policy. Large variable shippers would be added to Schedule GTC-1, the general terms and conditions for on-system transportation service. Corcoran proposed four additions to this schedule:

-Large variable load shippers would be defined in Section 1 as any shipper with firm daily consumption over 5,000 Dkt and with the ability to increase hourly flows at a rate greater than 200 Dkt/hour;

-Section 2 would be amended to change maximum allowed sulfur content from 20 grains per 100 cubic feet to 2.0 grains per 100 cubic feet;

-Section 8 would be amended to define a uniform delivery rate and specify that variance from the uniform rate will not be detrimental to the pipeline or injurious to other shippers or customers; and

-Section 16 would be amended to specify that large variable load shippers may require unique individual agreements and facilities.

193. Corcoran proposed to amend NWE's line extension policy to amend the extension allowance to customers for extension of the main distribution line. The allowance would not exceed the extension of the main line and would not apply to extension of service lines. The rationale is that distribution line extensions are generally used by and benefit other customers, but service lines generally benefit only one customer. Residential customers would receive up to $900 in allowance; all other Core customers would be eligible for $3.26/Dkt applied to the customer's estimated annual consumption. The allowance for Non-Core customers would be determined on an individual basis.

Gary L. Goble

194. Goble performed and filed a marginal cost of service study to meet requirements in ARM 38.5.176, but his embedded cost study served as the basis for determining his proposed cost of delivery service allocation.

195. Goble used three metrics to allocate natural gas delivery costs in his marginal cost and embedded cost analyses: design day demand, winter usage, and summer usage. Winter is five months from November to March, and summer is seven months from April to October.

Design day demand is used to allocate capacity costs. It represents the load on the coldest day for which the utility plans to provide reliable service. The design day is the primary planning criterion used to determine sizing of supply, storage, transmission, and distribution capacity. If the temperature plunged below the temperature used in the design day, NWE might have to order partial curtailments to meet load priorities.

196. Goble used a "predominant use" concept to classify plant. He argued that the predominant use of natural gas transmission and distribution plant is to maintain design day deliverability. Therefore Goble classified this plant as 100 percent capacity. If the plant is built to accommodate design day loads it will operate with excess capacity, and hence with capacity costs equaling zero, at all other times. Consequently, Goble argued that transmission and distribution costs should be assigned to customer classes according to their design day demands.

197. Currently the design day is assumed to have an average temperature of minus 23 degrees Fahrenheit. Regression analysis was used to estimate design day demand per customer for each customer class.

198. Design day demand is estimated in dekatherms, and may vary across functions and customer classes. In the embedded cost model, transmission costs are classified as capacity costs, and are allocated according to estimated design day demand. Because the estimated demand for the residential class equals 40.4 percent of total demand {135,220 Dkt / 334,685 Dkt}; the residential class is allocated 40.4 percent of transmission costs.

199. The winter and summer seasons are periods that are used to estimate firm retail load with losses (sendout). Seasonal loads are estimated in dekatherms, and are multiplied by estimated average seasonal commodity prices to produce seasonal marginal commodity cost estimates weighted by seasonal load.

MCC Direct Testimony

George L. Donkin

200. Donkin agreed with Goble's use of an embedded cost model to determine delivery costs, but disagreed with Goble's predominant use method, which classified all transmission and most distribution costs 100 percent as capacity costs, and allocated them according to design day demand. In response, Donkin proposed a variation in which he classified transmission and distribution costs 50 percent capacity and 50 percent commodity. Donkin allocated capacity costs according to design day demand, and the commodity classification according to annual volumes. He argued that NWE's pipeline system costs have been incurred to meet both design day demand and annual demand.

201. Regarding moderation, Donkin recommended that: 1) no customer class allocation should increase more than 10 percent; 2)any revenue increases should be distributed first to firm utilities, DBU transportation, and TBU transportation, up to the 10 percent cap; 3) any additional

increase should be distributed to the Core classes in proportion to Core class revenues at current rates; and 4) any revenue decrease distributed to the Core classes should be double any decrease distributed to firm utilities or the firm transportation classes.

202. Donkin recommended the PSC reject NWE's proposed inclining block rate structure for the residential gas customers. His reasons for opposing the proposal included: (1) if the tail block rate significantly exceeds the marginal cost of gas supply, ratepayers will make inefficient consumption decisions; (2) AECO gas prices are a reasonable proxy for marginal costs; (3) because of tracker recovery of financial hedging losses, historical tracker costs have significantly exceeded the AECO price; (4) because of continued participation in financial hedging, future tracker costs are likely to significantly exceed the AECO price; (5) the proposed tail block rate equals the tracker rate plus 10 percent; and (6) future tail block rates are likely to significantly exceed the marginal cost of gas supply, causing inefficient consumption decisions.

HRC/NRDC Direct Testimony

Dr. Thomas M. Power

203. Power objected to NWE's "predominant use" approach that focused on just one of several cost determinants because: 1) the analysis excludes other important cost determinants; 2) it focuses on design day delivery system use rather than delivery system use throughout the year; and 3) it fails to recognize actual economic-engineered relationships. Power argued that NWE builds and maintains natural gas delivery systems in expectation of profitable sales across a significant part every year, not one day in 30 years.

204. For natural gas transmission and distribution systems, Power recommended assigning costs according to winter volumes. He judged that this allocator reflected both peak period use and commodity delivery. Power said winter volume allocations indicate that utility and firm transportation customers are significantly underpaying for delivery services while residential and small commercial customers are overpaying.

205. Power testified in support of NWE's proposed inclining block rate structure for residential natural gas customers, but contended that NWE's proposal to set the initial block at 8 Dkt per month would reduce the incentive to conserve natural gas for almost half the year. He recommended setting the initial block at 4 Dkt for the heating season (November through May) and 2 Dkt for the remaining months. Regarding the tail block rate, Power supported as reasonable NWE's use of a 1.1 multiplier applied to actual natural gas supply cost.

Ralph Cavanagh

206. Cavanagh's testimony in support of the HRC/NRDC decoupling proposal is summarized earlier in this order in the Electric Cost of Service/Rate Design section.

NWE Rebuttal Testimony

Patrick R. Corcoran

207. Regarding the proposed inclining block rate structure for residential natural gas supply, Corcoran testified that Donkin's recommendation to discard the inclining block proposal on a marginal cost basis fails to address the intent of the proposal. Corcoran asserted that the intent is primarily to send price signals to customers that encourage them to conserve natural gas. If the tail block is significantly above marginal cost, the encouragement is strengthened.

208. Corcoran also discussed Power's proposal to reduce NWE's initial block set point of 8 Dkt/month to 4 Dkt/month in winter and 2 Dkt/month in summer. Corcoran testified that while he believes NWE's proposal is appropriate, Power's adjustments may be acceptable if PSC adopts them.

209. Corcoran expressed support for the HRC/NRDC decoupling proposal.

Gary L. Goble

210. In response to Donkin's assertion that some transmission and distribution costs are incurred to meet annual demand, Goble reiterated his previous position that transmission and distribution facilities are constructed to meet design day requirements, and that changes in peak sendout requirements on any other day impose no significant costs to the utility. Goble testified that NWE does not build transmission lines in order to minimize commodity costs, and that PSC should reject Donkin's recommendation to classify 50 percent of transmission and distribution costs as commodity costs, and reject Power's recommendation to assign some or all transmission and distribution costs according to winter volumes.

211. Goble argued that increasing the off peak price per Dkt may decrease use of delivery facilities that are already under-utilized during the off peak. He claimed that Donkin recommended that delivery service be priced below its cost, and said that this would lead to inefficient allocation of resources.

Marc T. Mullowney

212. Mullowney rebutted Donkin's testimony asserting that NWE's pipeline system costs have been incurred to meet both design day demand and annual demand. Mullowney asserted that the

only metric used to determine transmission system expansion is projected design day load. He also asserted that average daily load has no impact on the sizing of transmission facilities. The sizing of gas transmission plant is solely based upon projected design day demand. Mullowney asserted that if facilities are designed to meet design day load, they will meet average daily requirements with no additional investment.

213. Mullowney also testified that O&M expenses do not vary significantly with the volume of gas flowing through the line. O&M costs will increase by a very small amount as annual throughput increases.

HRC/NRDC Cross Intervenor Response Testimony

Dr. Thomas M. Power

214. Power agreed with Donkin that transmission and distribution costs should be allocated to customer classes partly on the basis of commodity consumption, not just on the basis of design day demand and that marginal cost pricing can be pursued even when costs are allocated using embedded cost of service analysis.

215. Power disagreed with Donkin's claim that inclining block rates are not appropriate for residential natural gas customers because the tail block rate would be set at a level significantly greater than marginal cost. Donkin claimed the inflated tail block rate would send erroneous price signals and encourage inefficient consumption.

216. Power disagreed with Donkin's use of AECO futures strips as a proxy for long run marginal cost. Power argued that futures strip prices ignored the significant long run social costs associated with the production and use of natural gas. If these social costs are considered, the long run marginal cost should be significantly greater than an AECO strip price.

217. Power also argued that substantial distortion may be inherent in the price signal due to the use of embedded delivery costs as a proxy for marginal delivery costs. In combination with imprecise estimates of marginal supply costs and external social costs, he said this makes the measure of the net hedging contribution to marginal cost distortion very difficult to estimate. Also, he noted that the tail block rate will be adjusted monthly as the tracker rate is adjusted. Power concluded that Donkin probably overestimated the gas cost "add-on" that NWE's net hedging costs represent, and that the proposed rate design remains a good first step toward a rate structure that encourages energy efficiency in the residential use of natural gas.

Summary of NWE's Prefiled Additional Issues Testimony

William Thomas

218. Thomas, NWE's Manager of Regulatory Support Services, responded to the PSC-identified additional issues, which pertained to energy efficiency. Thomas said that detailed information on NWE's DSM programs has been provided to the PSC in the Company's annual electric and natural gas supply tracking filings and biennial electric and natural gas procurement plans. This information includes two reports commissioned by NWE and provided by Nexant, Inc. titled Energy End Use and Load Profile Study and Assessment of Energy Efficiency Potentials (2010-2019).

219. Thomas reported the per-unit costs of NWE's DSM programs, based on the program administrator perspective (a.k.a. the utility cost perspective).[1] Thomas compared the electric DSM resource costs with a number of electricity supply resources included in NWE's 2009-2010 electricity supply cost tracker filing. These costs range from $29.25/MWh (Judith Gap) to $65.50/MWh (JP Morgan). He compared the natural gas DSM resource costs to an average of all NWE's wholesale natural gas supply transactions, including hedging, equal to $4.7441/Dkt, provided in Docket D2010.5.49.

220. He testified that NWE's current rate of energy efficiency resource acquisition is reasonable and that NWE ranks high among utilities in Montana, the Pacific Northwest, and the entire U.S. electric utility sector. NWE was unable to locate rankings for natural gas utilities.

221. Thomas stated that NWE plans to further expand its DSM acquisition rates, increase its level of DSM contractor resources, add internal staff, and build on its past success. He added that while NWE is always trying to identify new, cost-effective DSM measures and introduce new programs, its current DSM portfolio is relatively mature, having operated for many years. Noting that DSM program evaluations are time and resource intensive projects, he said independent program evaluations of mature programs should occur every 5 years. NWE's last comprehensive DSM program evaluation occurred in 2007. NWE plans to conduct the next program evaluation at the conclusion of the 2010-2011 tracker period.

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[1] The per-unit DSM cost information provided in Ex. NWE-25, p. 6, Table 1, contained several errors.

Cost Allocation Stipulation

222. The Cost Allocation Stipulation (Attachment B to this Order) was agreed to and submitted by all of the active parties in this docket (NWE, MCC, LCG, and HRC/NRDC). The stipulating parties agreed that embedded, rather than marginal, cost studies should be used as the basis for cost allocation for electric and natural gas delivery services in this docket. The parties also accepted for future use NWE's embedded cost models as filed in this docket, while noting differences of opinion exist as to various inputs and cost allocators within the models.

223. The Cost Allocation Stipulation allocates the stipulated electric revenue requirement as depicted in the following table:

	Final allocation	**Percent change**
Residential	$98,849,243	3.42%
GS-1 secondary non-demand	$15,999,574	-1.00%
GS-1 secondary demand	$81,200,510	5.58%
GS-1 primary non-demand	$18,330	5.58%
GS-1 primary demand	$9,224,523	0.00%
GS-2 substation demand	$6,364,736	-5.00%
GS-2 transmission demand	$2,004,368	-10.00%
Irrigation non-demand	$235,675	5.58%
Irrigation demand	$3,698,481	5.58%
Lighting non-demand	$11,627,195	5.58%
Total	$229,222,633	

224. The stipulated natural gas revenue requirement would be allocated as depicted in the following table:

	Final allocation	Percent change
Residential	$55,172,067	-1.00%
General service	$28,797,897	-1.00%
Utility	$268,727	-1.00%
DBU – Transportation	$2,090,496	-1.00%
TBU - Transportation	$10,837,246	-1.00%
Storage	$5,445,707	-0.00%
DBU – Interruptible transmission	$14,941	-1.00%
TBU – Interruptible transmission	$364,000	-1.00%
Total	$102,991,079	

225. The stipulating parties also recommended the Commission begin a rulemaking to examine the Commission's administrative rules related to allocated cost of service, including whether to use embedded cost studies for delivery services and marginal cost studies for energy supply services.

FINDINGS OF FACT AND COMMISSION DECISIONS

Revenue Requirements Issues

226. No party to the docket presented evidence in opposition to the Revenue Requirement Stipulation, which was introduced as Exhibit NWE-1. This Stipulation differs in two specific ways from the revenue requirement stipulation approved by the Commission in Docket D2007.7.82.

227. First, in this docket the intervenors filed revenue requirements testimony. This enabled the Commission to examine the revenue requirement advocacy positions of the parties prior to the hearing in this docket. In contrast, in Docket D2007.7.82, the suggested revenue authorization was stipulated to prior to the filing of testimony of MCC.

228. Second, unlike the stipulation in Docket D2007.7.82, here the parties agreed to a capital structure and a return on equity. In the Revenue Requirement Stipulation, the parties agreed to a capital structure of 52 percent debt, 48 percent equity and an ROE of 10.25 percent for both

electric and gas (with the caveat that any issues related to the decoupling proposal remain unresolved, including whether NWE's ROE should be adjusted if the Commission approves implementation of a decoupling pilot). The actual cost of debt of 5.76 percent was used in the calculation of the overall rate of return. The overall rate of return of 7.92 percent is the lowest overall rate of return for NWE and its predecessor, Montana Power Company, for the last 30 years.

229. The disclosure of the stipulated capital structure and inclusion of the cost of both the debt and equity makes the Revenue Requirement Stipulation very transparent. Further transparency is provided by noting that all other cost of service items submitted by NWE in its rebuttal filing were included in the settled revenue requirement. The lack of transparency in stipulations presented in previous general rate cases has been a criticism made by several commissioners, including former Commissioner Rowe, now the CEO of NWE. This approach represents real progress in the development of stipulations and may represent a standard to be followed by parties in the future when stipulations are developed.

230. Upon review and consideration, the PSC finds the Revenue Requirement Stipulation provides a reasonable outcome to this proceeding, is in the public interest, and results in rates that are just and reasonable.

Cost of Service/Rate Design Issues

Cost Allocation Stipulation

231. Throughout this case the parties engaged in a spirited debate over cost allocation theories and methods. Ultimately, NWE, LCG, MCC and HRC/NRDC reached a settlement regarding the allocation of electric and natural gas utility revenue requirements to customer classes. This stipulation was introduced as Exhibit NWE-2 (Attachment B to this order). The stipulated class revenue allocations reflect the parties' consideration of NWE's embedded costs of service, marginal costs of service, and rate moderation principles. Ex. NWE-2, Tr. pp. 265, 578, 669.

232. Assigning revenue responsibility to customer classes is fraught with complexity, competing economic views, and social equity issues. After weighing the alternatives for allocating revenue responsibility presented in this case, and considering corresponding rate impacts, the PSC finds that the cost of service stipulation reasonably resolves the cost allocation issues in this case and results in overall rates that are just, reasonable, and in the public interest.

NWE is authorized to implement the stipulated class revenue allocations, beginning on January 1, 2011, by uniformly changing each tariff rate by the applicable percentage amount shown in the stipulation for each customer class. In making rate changes, NWE must round monthly customer charges to the nearest five cents.

233. According to the stipulation, the parties agree that the electric and natural gas embedded cost of service models filed by NWE in this case are acceptable for use in future cost of service cases, although they differ regarding which inputs and cost allocators are appropriate. The parties also recommend that the PSC consider revising ARM 38.5.176-177 and address the appropriateness of embedded cost studies for delivery services and marginal cost studies for supply services.

234. The PSC cannot change ARM 38.5.176-177 in this order and it need not decide whether to change its rules before resolving cost of service issues in this case. The parties made compelling arguments in favor of embedded cost studies for delivery services, and the PSC authorizes NWE to use its embedded cost model for delivery services in its next cost of service case. The PSC directs NWE to improve its spreadsheet model, to the extent possible and without reducing transparency, so that the model can adapt to changes in the total revenue requirement being allocated. Although NWE is authorized file an embedded cost of service analysis for delivery services in its next rate case, NWE should not neglect economic theories and analysis. Promoting economically efficient consumption decisions remains a primary goal of the rate design process and the PSC expects NWE's rate design proposals to reflect a thorough consideration of economic principles.

235. The annual electric and natural gas revenue requirements approved in this order are lower than those approved in Interim Order 7046g. Accordingly, NWE must rebate the difference to customers, with interest at 10.75 percent, over a six month period beginning January 1, 2011. NWE must calculate the natural gas rebate based on the difference between the interim approved rates and the lawful rates effective on October 16, 2009 (the date the PSC received NWE's rate application). In a compliance filing NWE must initially estimate rebates for the period starting on the effective date of Interim Order 7046g through December 31, 2010. NWE must true-up the rebates no later than March 1, 2011, using actual billing determinants. NWE must implement rebates through uniform adjustments to all tariff rates until the full amount of the rebate is returned.

Decoupling and Inverted Block Rate Design

236. The Commission declines to approve the decoupling and inclining block rate proposals.

Other issues

237. NWE proposed using electric marginal supply costs to develop allocation factors for setting class revenue responsibilities and rates in the company's electricity supply cost tracker. NWE witness Corcoran illustrated the process in Exhibit NWE-27 (PRC-3S). The proposed allocation factors reflect each class's share of NWE's estimated marginal cost revenues. Corcoran testified that this approach would maintain the relative marginal cost shape of class revenue responsibility while recovering only allowed tracker costs. He recommended that the PSC implement the approach as soon as possible after the PSC issues a final order in this case.

238. No party responded directly to NWE's electricity supply cost allocation proposal, although HRC/NRDC witness Power testified that NWE's levelized unit marginal supply costs are too high because they include the effect of future inflation (NWE used these unit marginal supply costs to estimate class marginal cost revenues). NWE witness Goble disputed Power's contention in rebuttal testimony.

239. Conceptually, by attempting to reflect marginal cost considerations NWE's proposed electricity supply cost allocation method appears to be an improvement over current practice, which is sales-based with a cap on class revenue changes that, while reasonable historically, may not be warranted today. However, because parties neither engaged NWE's proposal nor robustly debated NWE's method of estimating marginal supply costs, the PSC is reluctant to adopt the cost allocation approach in this case. NWE should resubmit its proposal in its next annual tracker case and consider whether its marginal cost estimates warrant refreshing.

240. The PSC approves NWE's proposed electric line extension tariff changes, reactive power tariff changes, and new ownership cost ranges in the electric lighting tariff. These proposals are reasonable and were not contested.

241. The PSC also approves NWE's proposed natural gas line extension tariff changes and its proposals regarding large variable load shippers in tariff schedule GTC-1. These proposals are reasonable and were not contested. NWE submitted a marked up tariff in its supplemental filing that changed the base security deposit on allocated cushion gas for firm storage customers from $2.50 per dekatherm to $5.95 per dekatherm. This change was not described further in testimony. The purpose of the security deposit is to compensate the utility for loss if the

customer fails to replace the allocated gas. The current tariff allows the utility to revise the base rate in response to changing market conditions. Because this proposed change was not fully described in testimony, and because the utility is allowed to revise the base rate, the PSC denies NWE's proposed tariff change; the base rate must remain $2.50 per dekatherm. NWE should submit revised language in a future filing that fully explains the process used by the utility to determine the value of cushion gas security.

242. Any conclusion of law that is properly a finding of fact is hereby adopted as such if necessary to preserve the validity of this Order.

CONCLUSIONS OF LAW

1. Any finding of fact that is properly a conclusion of law is incorporated herein and adopted as such.

2. The Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this docket. § 69-3-104, MCA.

3. The Commission supervises, regulates, and controls public utilities pursuant to Title 69, Chapter 3, MCA. § 69-3-102, MCA.

4. NorthWestern Corporation d/b/a NorthWestern Energy is a public utility subject to the jurisdiction of the Commission. § 69-3-101, MCA.

5. Public utilities are required to provide reasonably adequate service and facilities at just and reasonable rates. The rates approved in this Order are just and reasonable. § 69-3-201, MCA.

ORDER

1. The PSC approves the Revenue Requirement Stipulation.

2. The PSC approves the Cost Allocation Stipulation and directs NWE to implement the stipulated class revenue allocations, beginning on January 1, 2011, by uniformly changing each tariff rate by the applicable percentage amount shown in the stipulation for each customer class.

3. The PSC authorizes NWE to use its embedded cost model for delivery services in NWE's next cost of service case.

4. The PSC approves NWE's proposed tariff changes related to electric and natural gas line extensions, reactive power charge, new electric lighting ownership cost ranges, and large variable load natural gas shippers.

5. The annual electric and natural gas revenue requirements approved in this order are lower than those approved in Interim Order 7046g. As a result, NWE must rebate the difference to customers, with interest at 10.75 percent, over a six-month period beginning January 1, 2011. NWE must calculate the natural gas rebate based on the difference between the interim approved rates and the lawful rates effective on October 16, 2009.

6. NWE must file compliance tariffs within 20 days of the service date of this order which incorporate the provisions of this Order.

7. All findings of fact and conclusions of law that can properly be considered an Order and that should be considered as such to preserve the integrity of this Order are incorporated herein as an Order.

8. All pending objections, motions, and arguments not specifically having been ruled on in this Order shall be deemed denied, to the extent that such denial is consistent with this Order.

DONE AND DATED this 28th day of June 2011 by a vote of 3 to 2.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

TRAVIS KAVULLA, Chairman

GAIL GUTSCHE, Vice Chair

W.A. GALLAGHER, Commissioner (dissenting)

BRAD MOLNAR, Commissioner (dissenting)

JOHN VINCENT, Commissioner

ATTEST:

Verna Stewart
Commission Secretary

(SEAL)

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DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

*****

IN THE MATTER of NorthWestern Energy's Application for Authority to Establish Increased Natural Gas and Electric Delivery Service Rates And Implement Allocated Cost of Service and Rate Design Proposals	) UTILITY DIVISION)) DOCKET NO. D2009.9.129))
IN THE MATTER OF NorthWestern Energy's Application for Approval for Authority to Establish Increased Natural Gas and Electric Delivery Service Rates	) UTILITY DIVISION)) DOCKET NO. D2007.7.82)

STIPULATION AND SETTLEMENT AGREEMENT OF NORTHWESTERN ENERGY AND THE MONTANA CONSUMER COUNSEL

NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern" or "NWE") and the Montana Consumer Counsel ("MCC"), by and through their undersigned representatives, hereby submit to the Montana Public Service Commission ("Commission") this Stipulation and Settlement Agreement ("Stipulation"), and agree and stipulate as follows:

1. On October 16, 2009, NorthWestern submitted its general rate case filing in Docket D2009.9.129 (the "Application"). On January 15, 2010, a Notice of Commission Action was issued consolidating Phase II of Docket D2007.7.82 into Docket D2009.9.129. In the Application, NWE requested that rates for electric delivery service be increased to raise an additional $15,517,645 per year and

ATTACHMENT A

that rates for natural gas delivery service be increased to raise an additional $1,966,400 per year.

2. The MCC intervened in this Docket, opposing a rate increase of the magnitude requested by NorthWestern, the manner in which NorthWestern proposed to allocate its revenue deficiency among customer classes, and the subsequent proposed adoption of a revenue decoupling mechanism.

3. The Direct Testimony of the MCC expert witnesses was filed in this Docket on June 3, 2010. The MCC expert witnesses submitted cross-intervenor testimony on July 15, 2010. In those testimonies, the MCC witnesses recommended a natural gas delivery service rate decrease of $3,120,430 and an electric delivery service rate decrease of $1,993,430. The MCC also proposed an alternative allocation of the respective electric and natural gas costs of service among customer classes, as well as opposed the implementation of the decoupling mechanism proposed in this Docket.

4. On July 8, 2010, the Commission issued interim rate Order No. 7046g in the Docket ("Interim Rate Order") setting interim rate increases of $12,395,640 for NorthWestern's electric regulated delivery service and $1,361,517 for NorthWestern's natural gas regulated delivery service. The Interim Rate Order implemented the interim rate increases on a uniform percentage basis to all customer classes.

5. The revenue requirement presented by NorthWestern in this Docket included, for both electric and natural gas delivery services, an overall rate of return of 8.30% using NWE's proposed capital structure of 50.55% debt and 49.45% equity, a return on equity of 10.90% and debt cost of 5.76%. The revenue requirements presented by MCC in this Docket for both delivery utilities included a weighted cost of capital based on a capital structure of 60% debt and

40% equity. MCC proposed an overall rate of return of 7.28%, using a 9.5% rate of return on equity and a cost of long-term debt of 5.8%.

6. For settlement purposes, a fair and equitable partial resolution of this Docket has been reached. This settlement resolves the revenue requirement related issues between NorthWestern and the MCC and is one which would result in the establishment of just and reasonable rates, as further described herein:

A. NorthWestern will be authorized, on a final basis, to receive a rate increase of $7,660,766 for its electric utility delivery service and a rate decrease of $988,963 for its natural gas utility delivery service ("Authorized Revenue Adjustments"). The Authorized Revenue Adjustments are $4,734,874 less than authorized by in the Interim Rate Order for the electric utility and $2,350,480 less than authorized in the Interim Rate Order for the natural gas utility.

B. The Authorized Revenue Adjustments are derived for purposes of this Stipulation as follows:

1) an authorized overall rate of return 7.92%, using an authorized rate of return on equity of 10.25% (subject to ¶ 8B.), cost of long-term debt of 5.76% and a capital structure of 52% debt and 48% equity;

2) the removal of expenses associated with NorthWestern's stock-based incentive plans, which total $1,623,935 for the electric utility and $729,594 for the natural gas utility; and

3) all other cost of service items as submitted in NWE's July 15, 2010 Rebuttal Filing in this Docket.

7. Although the ultimate impact on each customer class will be dependent on the final allocated costs of service and rate designs authorized by the Commission, the above Authorized Revenue Adjustments result in an overall percentage increase of 3.46% for electric utility delivery service and an overall percentage decrease of 0.95% for natural gas delivery service.

8. NorthWestern and MCC understand and agree that this Stipulation is only a partial settlement of the disputed issues in this Docket. Specifically, NorthWestern and MCC understand and agree that this Stipulation does not resolve:

A. Any of the issues related to the manner in which NorthWestern proposes to allocate its revenue requirements among customer classes and the development of rate designs; or

B. Any of the issues related to the proposed revenue decoupling mechanism including, without limitation, whether NorthWestern's authorized cost of equity should be adjusted if the Commission chooses to implement a revenue decoupling pilot.

9. The Commission, after the completion of contested case proceedings in this Docket, should be moved in its discretion to issue a final order approving, adopting, and implementing the terms of this Stipulation, and ordering NorthWestern to submit tariffs in accordance with the final order in this Docket.

10. NorthWestern and the MCC present this Stipulation as a reasonable, partial settlement of the contested issues in this Docket. No party's position in this Docket is accepted by the other parties by virtue of their entry into this Stipulation, nor does it indicate their acceptance, agreement, or concession as to the validity of any particular theory or rate making principle, cost of service determination, or legal principle embodied, or arguably embodied, in this Stipulation. Furthermore, neither party hereafter shall be deemed to be bound by any asserted position, and no finding of fact or conclusion of law, other than those agreed to herein, shall be deemed to be implicit in this Stipulation.

11. The entry of an Order by the Commission approving this Stipulation shall not be deemed to work any estoppel upon either party or to otherwise establish or create any limitation on or precedent of the Commission.

12. This Stipulation shall not become effective and binding upon the parties and shall be of no force and effect unless and until accepted and approved by the Commission as to all of the terms and conditions contained herein without modification. If the Commission fails to approve this Stipulation and Agreement as agreed to herein by the parties, either in whole or in part, or if the Commission adds or removes any terms or conditions not agreeable by the parties, either party shall, at its sole option, have the right to withdraw from this Stipulation with all of its rights reserved. The Stipulation and all its parts shall then be null and void, and the parties shall not be bound by any provision of it, and it shall have no force or effect whatsoever.

13. The parties hereby acknowledge that this Stipulation and Agreement is the result of a voluntary, negotiated settlement between the Parties pursuant to ARM § 38.2.3001, and agree that this Stipulation, inclusive of the compromises and settlements contained herein, is in the public interest.

14. This Stipulation may be executed in one or more counterparts and each counterpart shall have the same force and effect as an original document, fully executed by the parties. Any signature page of this Stipulation may be detached from any counterpart of this Stipulation without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Stipulation identical in form hereto but having attached to it one or more signatures page(s).

IN WITNESS WHEREOF, the parties hereto have executed this Stipulation this 17th day of September, 2010.

Montana Consumer Counsel

By: ______________________
Robert Nelson
Montana Consumer Counsel

NorthWestern Energy

By: ______________________
Robert C. Rowe
President & CEO

C-49

MASTER FILE

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

*****

IN THE MATTER of NorthWestern Energy's Application for Authority to Establish Increased Natural Gas and Electric Delivery Service Rates And Implement Allocated Cost of Service and Rate Design Proposals	) UTILITY DIVISION)) DOCKET NO. D2009.9.129))
IN THE MATTER OF NorthWestern Energy's Application for Approval for Authority to Establish Increased Natural Gas and Electric Delivery Service Rates	) UTILITY DIVISION)) DOCKET NO. D2007.7.82)

STIPULATION AND SETTLEMENT AGREEMENT OF THE MONTANA CONSUMER COUNSEL, THE LARGE CUSTOMER GROUP, DISTRICT XI/NATURAL RESOURCES DEFENSE COUNCIL AND NORTHWESTERN ENERGY

Montana Consumer Counsel ("MCC"), the Large Customer Group ("LCG"), the Human Resource Council, District XI/Natural Resources Defense Council ("HRC/NRDC") and NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern" or "NWE"), individually referred to as a "Party" and collectively as the "Parties," by and through their undersigned counsel, hereby submit to the Montana Public Service Commission ("Commission") this Stipulation and Settlement Agreement ("Stipulation"), and agree and stipulate as follows:

1. On October 16, 2009, NorthWestern submitted its general rate case filing in Docket D2009.9.129 (the "Application"). On January 15, 2010, a Notice of

ATTACHMENT B

Commission Action was issued consolidating Phase II of Docket D2007.7.82 into Docket D2009.9.129. In the Application, NWE proposed to allocate its revenue requirement among customer classes based upon an embedded cost model.

2. The MCC intervened in this Docket opposing the manner in which NorthWestern proposed to allocate its revenue requirement among customer classes.

3. The LCG intervened in this Docket opposing the manner in which NorthWestern proposed to allocate its revenue requirement among customer classes.

4. HRC/NRDC intervened in this Docket opposing the manner in which NorthWestern proposed to allocate its revenue requirement among customer classes.

5. The Direct Testimonies of the MCC expert witnesses were filed in this Docket on June 3, 2010. In those testimonies, the MCC supported the use of embedded costs as the preferred cost allocation methodology in this Docket, but proposed an alternative allocation of the respective electric and natural gas costs of service among customer classes.

6. The Direct Testimony of the LCG expert witness was filed in this Docket on April 5, 2010. In that testimony, the LCG supported the use of embedded costs as the preferred electric cost allocation methodology in this Docket, but proposed an alternative allocation of the electric cost of service among customer classes and an alternative rate moderation plan.

7. The Direct Testimony of the HRC/NRDC expert witnesses were filed in this Docket on June 8, 2010. In that testimony, HRC/NRDC supported the use of embedded costs as the preferred cost allocation methodology in this

Docket, but proposed an alternative allocation of the respective electric and natural gas costs of service among customer classes.

8. For settlement purposes, a fair and equitable partial resolution of this Docket has been reached. This settlement resolves the allocation of NorthWestern's revenue requirements among the customer classes and is one which would be in the public interest, as further described herein:

A. The Parties agree that embedded cost studies rather than marginal cost studies, should be used for electric and natural gas delivery services for this Docket. The Parties also agree that the embedded cost models filed by NorthWestern and used by the Parties in this Docket are acceptable for future use, recognizing that there are differences of opinion regarding the various inputs and cost allocators within the models.

B. For NorthWestern's electric utility, the stipulated revenue requirement is allocated among NorthWestern's customer classes and is based upon embedded cost studies in this Docket as follows:

	Final Allocation	Percent Change
Residential Non Demand	$98,849,243	3.42%
GS-1 Secondary Non Demand	$15,999,574	-1.00%
GS-1 Secondary Demand	$81,200,510	5.58%
GS-1 Primary Non Demand	$18,330	5.58%
GS-1 Primary Demand	$9,224,523	0.00%
GS-2 Substation Demand	$6,364,736	-5.00%
GS-2 Transmission Demand	$2,004,368	-10.00%
Irrigation Non Demand	$235,675	5.58%
Irrigation Demand	$3,698,481	5.58%
Lighting Non Demand	$11,627,195	5.58%
Total	$229,222,633	

The allocations identified above are also supported by the marginal cost studies submitted in this Docket. The column above labeled "Percentage Change" shows either the percentage increase or decrease of revenue requirement allocation to each particular customer class as compared to the level of current rate revenues in the electric Statement H of NorthWestern's rebuttal filing.

C. For NorthWestern's natural gas utility, the stipulated revenue requirement is allocated among NorthWestern's customer classes and is based upon embedded cost studies in this Docket as follows:

	Final Allocation	Percentage Change
Residential	$ 55,172,067	-1.00%
General Service	$ 28,797,897	-1.00%
Utility	$ 268,727	-1.00%
DBU - Transportation	$ 2,090,496	-1.00%
TBU - Transportation	$ 10,837,246	-1.00%
Storage	$ 5,445,707	0.00%
DBU - Interruptible Trans.	$ 14,941	-1.00%
TBU - Interruptible Trans.	$ 364,000	-1.00%
Total	$ 102,991,079	

The allocations identified above are also supported by the marginal cost study submitted in this Docket. The column above labeled "Percentage Change" shows the percentage decrease of revenue requirement allocation to each particular customer class as compared to the level of current rate revenues in the natural gas Statement H of NorthWestern's rebuttal filing.

D. The Parties recommend the Commission initiate a rulemaking to examine the Administrative Rules of Montana ("ARM") Section 38.5.176, Statement L – Allocated Cost of Service and ARM § 38.5.177, Statement M – Rate Design, including the appropriateness of cost of service studies based upon embedded costs for delivery services and marginal costs for energy supply services for future cost studies to be submitted to the Commission.

9. The Parties understand and agree that this Stipulation is only a partial settlement of the disputed issues in this Docket. Specifically, the Parties understand and agree that this Stipulation does not resolve:

A. Any of the issues related to the manner in which NorthWestern proposes to design rates for delivery services and energy supply; or

B. Any of the issues related to the proposed revenue decoupling mechanism including, without limitation, whether NorthWestern's authorized cost of equity should be adjusted if the Commission chooses to implement a revenue decoupling pilot.

10. The MCC and NorthWestern entered into that certain Stipulation and Settlement Agreement dated September 17, 2010, wherein the MCC and NWE reached agreement related to the revenue requirement portion of this Docket ("Revenue Requirement Stipulation"). By this Stipulation, the LCG hereby joins in the Revenue Requirement Stipulation as a settling party. HRC/NRDC, having not asserted a position on the revenue requirement portion of NorthWestern's Application, does not oppose the Revenue Requirement Stipulation.

11. The Commission, after the completion of contested case proceedings in this Docket, should be moved in its discretion to issue a final order approving, adopting, and implementing the terms of this Stipulation, and ordering NorthWestern to submit tariffs in accordance with the final order in this Docket.

12. The Parties present this Stipulation as a reasonable, partial settlement of the contested issues in this Docket. With the exception of

paragraph 8.A. above, no Party's position in this Docket is accepted by the other Parties by virtue of their entry into this Stipulation, nor does it indicate their acceptance, agreement, or concession as to the validity of any particular theory or rate making principle, or legal principle embodied, or arguably embodied, in this Stipulation. Furthermore, no Party hereafter shall be deemed to be bound by any asserted position, and no finding of fact or conclusion of law, other than those agreed to herein, shall be deemed to be implicit in this Stipulation.

13. The entry of an order by the Commission approving this Stipulation shall not be deemed to work any estoppel upon either party or to otherwise establish or create any limitation on or precedent of the Commission.

14. This Stipulation shall not become effective and binding upon the Parties and shall be of no force and effect unless and until accepted and approved by the Commission as to all of the terms and conditions contained herein without modification. If the Commission fails to approve this Stipulation as agreed to herein by the Parties, either in whole or in part, or if the Commission adds or removes any terms or conditions not agreeable by the Parties, any Party shall, at its sole option, have the right to withdraw from this Stipulation with all of its rights reserved. The Stipulation and all its parts shall then be null and void, and the Parties shall not be bound by any provision of it, and it shall have no force or effect whatsoever.

15. The Parties hereby acknowledge that this Stipulation and Agreement is the result of a voluntary, negotiated settlement between the Parties pursuant to ARM § 38.2.3001, and agree that this Stipulation, inclusive of the compromises and settlements contained herein, is in the public interest.

16. This Stipulation may be executed in one or more counterparts and each counterpart shall have the same force and effect as an original document, fully executed by the parties. Any signature page of this Stipulation may be

detached from any counterpart of this Stipulation without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Stipulation identical in form hereto but having attached to it one or more signatures page(s).

IN WITNESS WHEREOF, the parties hereto have executed this Stipulation this 20th day of September, 2010.

Montana Consumer Counsel

By: ______________________
Robert Nelson
Montana Consumer Counsel

Human Resource Council, District XI/
Natural Resources Defense Council

By: ______________________
Chuck Magraw
Attorney for HRC/NRDC

Large Customer Group

By: ______________________
Thorvald Nelson
Attorney for LCG

NorthWestern Energy

By: ______________________
Jason B. Williams
Attorney for NorthWestern