BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN UTAH AND FOR APPROVAL OF ITS PROPOSED ELECTRIC SERVICE SCHEDULES AND ELECTRIC SERVICE REGULATIONS	)	**Docket No. 11-035-200**
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AN ACCOUNTING ORDER TO DEFER THE COSTS RELATED TO THE DECOMMISSIONING OF THE CARBON PLANT	)	**Docket No. 12-035-79**
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A DEFERRED ACCOUNTING ORDER REGARDING COSTS INCURRED FOR NAUGHTON UNIT 3 SELECTIVE CATALYTIC REDUCTION SYSTEM, PULSE JET FABRIC FILTER SYSTEM AND RELATED ENVIRONMENTAL UPGRADES	)	**Docket No. 12-035-80**

SETTLEMENT STIPULATION

This Settlement Stipulation ("Stipulation") is entered into in Docket Nos. 11-035-200, 12-035-79 and 12-035-80 by and among the parties whose signatures appear on the signature pages hereof (collectively referred to herein as the "Parties" and individually as a "Party").

1. The Parties have conducted settlement discussions over the course of several days and had meetings on June 28, 2012, July 18, 23, 25 and 31, 2012, and August 1, 2012 to which all intervening parties to the dockets that are the subject of this Stipulation were invited. In

addition, drafts of this Stipulation were circulated to all intervening parties for review and comment on July 25, 30 and 31, 2012, and August 1, 3 and 6, 2012 and there have been further discussions among various parties. This Stipulation has been entered into by the Parties after consideration of the views of all intervening parties expressed during that process. No intervening party opposes this Stipulation.

2. The Parties represent that this Stipulation is just and reasonable in result, will result in rates that are just and reasonable and will provide the Company a reasonable opportunity to earn its authorized return. The Parties recommend that the Public Service Commission of Utah ("Commission") approve the Stipulation and all of its terms and conditions. The Parties request that the Commission make findings of fact and reach conclusions of law based on the evidence and on this Stipulation and issue an appropriate order thereon.

BACKGROUND

Docket No. 11-035-200

3. On February 15, 2012, Rocky Mountain Power ("Company" or "Rocky Mountain Power") filed an application, together with pre-filed testimony and exhibits from eighteen witnesses, and revised tariff sheets, in Docket No. 11-035-200 ("2012 GRC") requesting authority to increase its retail electric utility service rates in Utah by approximately $172.3 million per annum or an average overall increase of 9.7 percent including a requested return on equity of 10.2%, effective October 12, 2012. Rocky Mountain Power's request was based upon a forecast test period ending May 31, 2012, using a 13 month average rate base with a historical base period of twelve months ending June 30, 2011.

4. On February 16, 2012, the Commission issued its Notice of Scheduling Conference setting a scheduling conference to be held February 24, 2012.

5. On March 2, 2012, the Commission issued its Scheduling Order setting a procedural schedule. Hearings were scheduled to begin July 31, 2012 on cost of capital, August 20, 2012 on revenue requirement and August 29, 2012 on cost of service, rate spread and rate design.

6. On April 10, 2012, the Company filed corrections and updates to limited categories of its net power costs ("NPC").

7. On April 30, 2012, the Company filed a second set of corrections and updates to the same limited categories of its NPC.

8. On May 11, 2012, the Company filed its NPC Update pursuant to the Scheduling Order.

9. On May 31, 2012, intervenors filed cost of capital direct testimony.

10. On June 11, 2012, intervenors filed revenue requirement direct testimony. In their testimony, intervenors proposed numerous adjustments to the Company's requested rate increase.

11. On June 22, 2012, intervenors filed cost of service direct testimony.

12. On June 27, 2012, the Company and intervenors filed cost of capital rebuttal testimony.

13. On June 28, 2012, parties held settlement discussions.

14. On July 13, 2012, parties filed revenue requirement rebuttal testimony. The Company's rebuttal testimony reduced its requested rate increase to $155.7 million, based on updates and corrections to its direct testimony and acceptance of certain adjustments proposed by intervenors.

15. On July 18, 2012, parties held settlement discussions and intervenors filed cost of capital surrebuttal testimony.

16. On July 23, 25 and 31, 2012 and August 1, 2012, parties held further settlement discussions.

17. The Parties have reached a compromise as specified herein on the rate increase that should be approved in the 2012 GRC on the terms and conditions provided in this Stipulation.

18. On July 23, 26, 30 and 31, 2012 and August 2, 2012, the Commission granted motions to amend the schedule in this docket to change the filing date for cost of service and rate design rebuttal testimony and other matters based on the Parties ongoing settlement discussions.

Docket No. 12-035-79

19. On May 1, 2012, Rocky Mountain Power filed an application for an accounting order in Docket No. 12-035-79 to defer costs related to the decommissioning of the Carbon Plant (hereinafter "Carbon Plant Deferred Accounting docket").

20. On May 16, 2012, the Division of Public Utilities ("DPU") filed comments on the application.

21. On June 18, 2012, the Commission issued its scheduling order setting a procedural schedule in the case, scheduling hearings for November 28, 2012.

Docket No. 12-035-80

22. On May 3, 2012, Rocky Mountain Power filed an application for a deferred accounting order in Docket No. 12-035-80 regarding costs incurred for Naughton Unit 3 Selective Catalytic Reduction System, Pulse Jet Fabric Filter System, and Related Environmental Upgrades (hereinafter "Naughton 3 Development Costs docket").

23. On May 16, 2012, the DPU filed comments on the application.

24. On June 18, 2012, the Commission issued its scheduling order setting a procedural schedule in the case, scheduling hearings for November 28, 2012, immediately

following the hearing in Docket No. 12-035-79, and reserving November 29, 2012 in the event it is necessary to continue the hearing.

SETTLEMENT TERMS

For purposes of this Stipulation, the Parties agree and recommend the Commission approve the following:

25. The Parties agree that the Company should be allowed to implement a multi-year rate plan ("Plan") that will provide a measure of rate certainty to customers while affording the Company a reasonable opportunity to earn its authorized rate of return and recover its costs of service through at least August 31, 2014. In reaching this Stipulation, various Parties have considered and relied upon many different factors and considerations, including but not limited to a) the 2012 GRC as a justification for the stipulated two-step rate increase, b) Company representations as to the Company's business plan and its implications for the Company's next projected rate case, c) the projected in-service date of the Mona to Oquirrh transmission line, d) timing considerations, e) the Carbon Plant Deferred Accounting docket, f) the Naughton 3 Development Costs docket, g) the next depreciation study anticipated to be filed in 2012, and h) various other factors.

26. Other than as set forth in this Stipulation, the Parties have not agreed on any specific adjustments or regulatory principles at issue in this Docket. The components are as follows:

Step 1 Rate Change

27. The Parties agree that Rocky Mountain Power should be permitted to implement a Step 1 general rate increase in the amount of $100.0 million for service effective on and after October 12, 2012.

Step 2 Rate Change

28. The Parties agree that Rocky Mountain Power should be permitted to implement a Step 2 general rate increase in the amount of $54.0 million for service effective on and after September 1, 2013, if the Mona-Oquirrh transmission line is in service. If the Mona-Oquirrh transmission line is not in service by September 1, 2013, then the Step 2 rate increase, and the corresponding changes to the base levels of net power costs ("NPC") and renewable energy credits ("RECs"), discussed below, will be delayed until the Mona-Oquirrh transmission line is placed into service.

Cost of Capital

29. The Parties agree that the Company's allowed cost of capital and capital structure will be as shown in Table 1 below:

Table 1

Overall Cost of Capital			
Component	Percent of Total	Cost	Weighted Average
Long-term Debt	47.6%	5.37%	2.56%
Preferred Stock	0.3%	5.43%	0.02%
Common Stock Equity	52.1%	9.80%	5.11%
TOTAL	100.0%		7.68%

Net Power Costs

30. The Parties agree that a base NPC amount of $1.479 billion annually total Company, or $636.0 million annually on a Utah-allocated basis, should be established as the base NPC beginning on the Step 1 rate effective date of October 12, 2012. Table 2 below reflects the stipulated level of base Energy Balancing Account ("EBA") costs (the base NPC less wheeling revenue) in dollars per megawatt hour ("$/MWh"), in base rates by month for EBA measurement purposes. Exhibit A1 to this Stipulation provides details showing the stipulated $/MWh calculations and the allocation of EBA costs among rate schedules. EBA costs allocated

to special contracts, whether or not they're included in the composite NPC allocator in Exhibit A1, will be subject to the terms of the contracts. The monthly base NPC amounts for the purpose of EBA filings will be the monthly test period base NPC amounts stated in Table 2 below until such time as new base NPC amounts are set in a general rate case or other proceeding filed on or after January 1, 2014.

Table 2

	Utah EBA $/MWh
June	$ 26.694
July	26.819
August	27.685
September	27.648
October	25.293
November	24.260
December	23.286
January	23.870
February	24.191
March	24.723
April	24.899
May	25.114
Total	$ 25.439

31. The Parties agree that any balance of deferred NPC as determined by the Commission and associated carrying charges as determined by the Commission in the EBA application previously filed by the Company in Docket No. 12-035-67, will be collected or refunded over a two-year period from the effective date of the approved rate change in that Docket, with no carrying charges during such two-year collection or refund period.

32. The Parties agree that any balance of deferred NPC as determined by the Commission in the next EBA application to be filed by the Company in March 2013 will be

collected or refunded over a two-year period from the effective date of the approved rate change in that Docket, with carrying charges accruing through December 31, 2012 but no carrying charges thereafter or during such two-year collection or refund period.

33. The Company agrees that, in addition to reporting the calculation of base monthly NPC as set forth in Exhibit A1, the Company will also report the calculation of base monthly NPC by the alternative methods set forth in Exhibit A2 and Exhibit A3.

Renewable Energy Credits (REC) Revenues in 2013 and 2014 RBA

34. The Parties agree that the base REC revenues in rates for RBA purposes should be set at $25.0 million effective with the Step l rate increase on October 12, 2012.

35. The Parties agree that the base REC revenues in rates for RBA purposes should be set at $10.0 million effective with the Step 2 rate increase, anticipated to be September 1, 2013, subject to Paragraph 28.

36. The Parties agree that any difference between base REC revenues and actual REC revenues as determined by the Commission for calendar year 2012 should be recovered or returned over a one-year period from the effective date of the approved rate change to collect or refund such balance, with a carrying charge.

37. The Parties agree that any difference between base REC revenues and actual REC revenues as determined by the Commission for calendar year 2013 should be recovered or returned over a three-year period from the effective date of the approved rate change to collect or refund such balance, with no carrying charges during such three-year collection or refund period.

38. The Parties agree that any difference between base REC revenues and actual REC revenues as determined by the Commission for calendar year 2014 should be recovered or returned over a two-year period from the effective date of the approved rate change to collect or refund such balance, with no carrying charges during such two-year collection or refund period.

39. The Parties agree that, as an incentive for the Company to aggressively market RECs and obtain additional value, the Company should be permitted to keep ten percent (10%) of the revenues it obtains from the sales of its RECs incremental to the current Utah-allocated projected test year revenues of $25 million through May 31, 2013, and thereafter incremental to the revenues received under contracts entered into after July 1, 2012. A table listing the contracts as of July 1, 2012 to be excluded from this incentive is included as Confidential Exhibit B to this Stipulation.

Future Rate Cases

40. The Company agrees that it will not file its next general rate case ("2014 GRC") or a major plant addition case in Utah (a) prior to January 1, 2014 or (b) with a rate effective date prior to September 1, 2014.

41. The Parties agree that in the Company's 2014 GRC application, the Company will use, and the Parties will not oppose, use of a forecast test period of July 1, 2014 through June 30, 2015, with a 13-month average rate base, if the Company files its application prior to March 1, 2014. If the Company files its application on or after March 1, 2014, the Company will use, and the Parties will not oppose, use of a forecast test period ending no later than 16 months from the month in which the application is filed, with a 13-month average rate base.

42. The Parties agree that in the Company's next general rate case application, the Company shall address in its cost of service testimony issues raised in the Commission's June 25, 2012 Action Request including the treatment of cash working capital, interest expense and income taxes. The Company agrees to specifically identify in its direct testimony any changes to its model or otherwise, that address these issues.

Depreciation Study

43. As required by prior Commission order in Docket No. 07-035-13, the Company will file its required depreciation study by December 31, 2012, for review during 2013. The Company will request that the new depreciation rates have an effective date of January 1, 2014, for purposes of financial reporting; however, the effective date for purposes of financial reporting will ultimately be determined by Commission order. The Parties agree that the Commission-approved depreciation rates should not be reflected in customer rates in Utah until new base rates are implemented on or after September 1, 2014.

44. The Parties request Commission approval for the Company to establish an accounting order that will allow it to monthly defer and track (i) for future recovery, any aggregate net increase in Utah allocated depreciation expense in excess of $2.0 million annually, or (ii) for refund to customers, any aggregate net decrease in Utah allocated depreciation expense, for the period beginning on the latter of January 1, 2014, or the effective date of the Commission Order approving new depreciation rates ("Depreciation Order"), until the date that new depreciation rates are reflected in customer rates on or after September 1, 2014. The amount to be booked into such account shall be the difference in depreciation expense calculated using depreciation rates as approved in the Depreciation Order as compared to depreciation expense calculated using depreciation rates in effect as of the date of this Stipulation. The proposed treatment of this deferred depreciation expense is further described in <u>Exhibit C</u> to this Stipulation.

45. The Parties further agree that the Company should be allowed to recover or be required to refund the deferred depreciation expense beginning on the effective date of the 2014 GRC, as modified by future cost of service studies in future rate cases, and shall be amortized over a period not to extend beyond June 30, 2031, with no carrying charge. Any such recovery

or refund shall be allocated to customers as determined by the Commission in the 2014 GRC. The Company agrees to propose an allocation of any deferred amount in the 2014 GRC and all Parties reserve their right to respond. Depreciation relating to the Carbon Plant and the Klamath dam facilities should not be included in this deferral and nothing in this paragraph shall be construed as applying to the accounting treatment of the Carbon Plant or the Klamath dam facilities, both of which are described below. Other than as expressly stated in this Stipulation, nothing in this Stipulation shall limit the Parties' rights to take such positions as they deem appropriate in the Company's depreciation filing.

Carbon Plant

46. The Parties agree that the Company's pending application for a Deferred Accounting Order for the Carbon Plant should be granted and that two accounting orders should be entered, one to authorize the Company to transfer the remaining Carbon Plant balances upon retirement from electric plant in service and accumulated depreciation ("Remaining Carbon Balances"), and one to authorize the Company to book to a deferred account removal costs associated with the Carbon Plant ("Carbon Removal Costs").

47. The Parties agree that the amortization of the prudently incurred Remaining Carbon Balances shall be as set forth in Paragraph 11 of the Company's pending application for a Deferred Accounting Order for the Carbon Plant in Docket No. 12-035-79 resulting in the Remaining Carbon Balances being amortized from the date of transfer of the net plant balances to the regulatory asset through 2020.

48. The Parties agree that the Commission's order approving this Stipulation should authorize recovery from Utah ratepayers of Utah's allocated share of the prudently incurred Carbon Removal Costs from the retirement date of the Carbon Plant, currently estimated to occur in April 2015, through 2020. The filed depreciation study will calculate a depreciation rate

based on the remaining plant balance using an end of life date for the Carbon Plant currently estimated to be 2015. The projected removal costs will be identified in the calculation of the new depreciation expense and excluded from Carbon depreciation rates in Utah and recorded as removal costs in the Carbon Removal Costs regulatory asset addressed in this Stipulation. The difference between the depreciation rate effective in 2014 and the current depreciation rate based on the prior decommissioning date of 2020 will be included in the Remaining Carbon Balances regulatory asset.

49. Neither this Stipulation nor a Commission Order authorizing a deferred accounting order for such costs should be construed as determining prudence, recovery or ratemaking treatment of any deferred Carbon Removal Costs. The Parties agree that the Company should propose updates to the deferred Carbon Removal Costs balance with each future rate case filing, based on the best available removal cost projection. Any balances or adjustments approved by the Commission in future rate case orders should be amortized over the period as determined by the Commission in such dockets. Any changes to projected Carbon Removal Cost estimates will be specifically identified and explained as part of each Company general rate case filing, including the 2014 GRC. Other than as expressly stated in this Stipulation, nothing in this Stipulation shall limit the Parties' rights to take such positions they deem appropriate regarding the prudence or recovery of Carbon Removal Costs.

50. The Parties agree not to argue against cost recovery of Remaining Carbon Balances or Carbon Removal Costs on "used and useful" grounds, i.e., because costs are being recovered after the plant is closed.

FERC Rate Case Deferred Revenues

51. The Parties agree that the Company will defer for later refund to or collection from Utah ratepayers Utah's allocated share of all revenues booked in the Company's FERC

Account 456.1 resulting from its pending Federal Energy Regulatory Commission ("FERC") rate case in FERC Docket No. ER11-3643-000 including refunds, incremental to the FERC revenues projected by the Company in this docket, for the entire period from July 1, 2012 through the effective date of the 2014 GRC, in a manner consistent with the treatment of FERC revenues in Docket No. 10-035-124. Once FERC has issued a final order in FERC Docket No. ER11-3643-000, the Company will include the deferred balance in the next annual EBA filing as a credit to the EBA balance to reflect a 100 percent pass-through of all such incremental revenues to customers. The FERC deferral account will not accrue a carrying charge.

Naughton Unit 3 Development Costs

52. The Parties agree that the pending Naughton Unit 3 Development Costs application wherein the Company requested an accounting order authorizing it to record a regulatory asset associated with the development, design, engineering and initial procurement costs incurred to meet state and federal emission requirements as set forth in Docket No. 12-035-80 should be approved in accordance with Paragraph 53 below.

53. The Parties agree that Utah's allocated share of the Naughton Unit 3 development costs of $7.9 million incurred prior to the Company's decision to convert the unit to natural gas will be deferred and fully amortized by September 1, 2014, thereby providing full recovery to the Company from the rates agreed to in this Stipulation prior to the effective date of new rates resulting from the 2014 GRC.

Cost of Service, Rate Spread and Rate Design

54. The Step 1 and Step 2 rate increases set forth in Paragraphs 27 and 28 above should be allocated to general tariff customer classes and applied to general tariff customer rates as set forth in Exhibit D to this Stipulation. Exhibit D also includes the monthly billing comparisons for the Step 1 and 2 rate changes. Special contract rates are not established by this

Stipulation, and will be governed by the terms of the applicable contract approved by the Commission. The Parties agree the customer charge should increase to $5 per month for single-phase residential customers and to $10 per month for 3-phase residential customers until there is a change to the customer charge by Commission order.

55. For purpose of Utah cost of service studies, the Company agrees to propose a plan for a new Stress Factor study by July 1, 2013 and to request that the Commission hold a technical conference to review the plan and take comments from interested parties. The Company's study plan shall be shared with interveners to the current docket no later than two weeks prior to the scheduled technical conference. The Company shall provide the completed study to intervenors in the current case at least two months before its next general rate case.

56. The Parties agree that the "Application" paragraph of tariff Schedule 8 should be modified effective October 12, 2012 to allow any Schedule 8 customer whose peak load has not exceeded 1,000 kW for a period of 18 consecutive months to be moved to Schedule 6. Prior to the filing date of the 2014 GRC, interested parties agree to discuss alternative qualification provisions for Schedules 6 and 8, and to solicit input from other interested parties on any proposed modifications to the same. If there is no consensus among the parties during the discussions, the Company agrees in connection with its 2014 GRC filing to provide Parties with revenue requirement and cost of service results using both the qualification/Application provisions specified herein and an alternative qualification/Application provision requested by the Utah Association of Energy Users ("UAE") following such discussions.

57. Any of the Parties that are interested will meet by November 1, 2012 to discuss potential ways to improve bill messaging to residential customers, including the cost of implementing such changes. The topics of discussion will include, but not be limited to, (1) potential renaming of the residential energy blocks to identify higher usage, (2) prominent

language on residential bills identifying usage with greatest efficiency and conservation opportunities and the cost of electricity associated with that usage and directing customers to Company websites for information about energy efficiency opportunities and incentives, and (3) ways to improve clarity for customers in understanding their bills. Other parties who may have interest in this discussion will also be invited to attend. Discussions will be completed by February 1, 2013. If changes are agreed to by the Company, the Company will make its best efforts to implement such changes on bills prior to the 2013 summer season. Following approval of this stipulation by the Commission, the Company also agrees to include education about the new second tier non-summer rate in its bill insert as soon as practicable, as close to the start of the non-summer season as possible.

Klamath Depreciation, Relicensing and Allocation of KHSA Dam Removal

58. The Parties agree the Company should be permitted to depreciate the Klamath Dam facilities on an accelerated basis from June 1, 2012 through December 31, 2022 at rates that will fully depreciate the asset by the end of calendar year 2022. The depreciation rate will be reset annually based on any new additions. Utah's allocated share of such facilities is included in rates agreed to in this Stipulation and should be included in future Utah rates to reflect the revised depreciation schedule. The Company may recover a return on and return of such investment by including the depreciation and/or amortization in expense and the net unrecovered balance in rate base through calendar year 2022, even if the plant is shutdown prior to 2022. The depreciation life may be reconsidered if there are material changes in circumstances with respect to the relicensing or decommissioning of Klamath Dam facilities.

59. The Parties agree that recovery of Utah's allocated share of total Company Klamath-related relicensing and process costs in the amount of $81,814,435 are included in rates agreed to in this Stipulation and should be included in future Utah rates to amortize recovery of

such costs from October 12, 2012 through the end of calendar year 2022 with a carrying charge at the authorized long-term cost of debt. The carrying charge should be added to the unamortized balance monthly beginning on October 12, 2012. Since carrying charges will continue to be accrued, the net unrecovered relicensing and process costs will be excluded from rate base in future rate case proceedings.

60. Notwithstanding the preceding paragraphs 58 and 59, the Company agrees that it may not recover from Utah ratepayers in this or any other proceeding any dam removal or removal related costs associated with the Klamath Hydroelectric Settlement Agreement ("KHSA"), including but not limited to "Facilities Removal", the "Secretarial Determination", the "State Cost Cap", or the implementation of the "Definite Plan" or "Detailed Plan" related to the Klamath Hydroelectric Project, and whether funded or incurred by a "Party" or "Parties", "States", or the "Dam Removal Entity," as these terms are defined and used in the KHSA. The Company's agreement includes, without limitation, no recovery from Utah ratepayers of any dam removal or removal related cost resulting from any amendment to or substitute agreement for the KHSA, or dispute resolution, alternate or substitute funding, financing mechanism substitution, or shortfall funding described by the KHSA. Nothing in this paragraph shall preclude the Company from applying for recovery from Utah ratepayers of Utah's allocated share of costs that are prudently incurred by the Company in connection with: (i) "Decommissioning", as defined in the KHSA, and (ii) operation and maintenance of the Klamath Project for continued generation. Nothing in this paragraph, paragraphs 58 or 59, or in this Stipulation shall (i) preclude the Company from applying for recovery from Utah ratepayers of Utah's allocated share of costs that are prudently incurred by the Company in connection with potential future proceedings before the Federal Energy Regulatory Commission to relicense or decommission and/or remove the Klamath Project facilities, or (ii) be construed as approval or

disapproval of any such future Company application for recovery from Utah ratepayers of costs identified in the immediately preceding sentence, nor as a waiver, compromise or limit of any party's rights, defenses, remedies, duties, or jurisdictional objections available under Federal or Utah law in connection with any such application.

Utah Solar Program

61. A proposed Utah Solar Incentive Program ("Solar Program") is being considered by certain Parties and the Commission in Docket No. 11-035-104. Assuming a Solar Program is approved by the Commission prior to the Step 1 effective date of October 12, 2012, the Parties request permission for the Company to add any approved surcharge to recover costs of such Solar Program to the Step 1 rate increase effective October 12, 2012. Parties agree that such surcharge should not be shown as a separate line item on the bill. This Stipulation does not imply any Party's support for or opposition to any Solar Program.

Special Contracts

62. The Parties agree that the rate spread for the Step 1 and Step 2 rate increases as shown in Exhibit D reflect additional revenues to be received from base rate changes to special contracts in effect as of the effective date of this Stipulation. Increases for special contract customers, including those related to EBA and RBA applications, shall be governed by the terms of their contracts.

Other Items

63. The Parties stipulate to the admission into evidence in the 2012 GRC of all pre-filed testimony that has been filed to date in the cost of capital, revenue requirement and cost of service phases of this case. This stipulation to the admission of the testimony does not represent an agreement by the Parties as any positions taken in such testimony.

64. The Parties agree that, conditioned upon Commission approval of this Stipulation, neither UIEC's Motion to Disqualify or, in the Alternative to Require the Development of Models to Assist the Commission in Evaluating the Proposals of All of the Parties, nor Rocky Mountain Power's Motion to Strike Pre-Filed Supplemental Direct Testimony of J. Robert Malko filed in the 2012 GRC need be resolved by the Commission and, no Party need respond to said Motions.

65. Except as otherwise provided herein, the Parties agree not to seek a new deferred accounting order for costs incurred or revenues received before September 1, 2014, unless the need for the order is caused by a natural disaster or emergency, or the request results from the Division or the Office carrying out their statutory duties. The Parties agree that EBA and RBA mechanism filings will continue on their normal schedules.

GENERAL TERMS AND CONDITIONS

66. Not all Parties agree that each aspect of this Stipulation is warranted or supportable in isolation. Utah Code Ann. § 54-7-1 authorizes the Commission to approve a settlement so long as the settlement is just and reasonable in result. While the Parties are not able to agree that each specific component of this Stipulation is just and reasonable in isolation, all of the Parties agree that this Stipulation as a whole is just and reasonable in result and in the public interest.

67. All negotiations related to this Stipulation are confidential, and no Party shall be bound by any position asserted in negotiations. Except as expressly provided in this Stipulation, and in accordance with Utah Admin. Code R746-100-10.F.5, neither the execution of this Stipulation nor the order adopting it shall be deemed to constitute an admission or acknowledgment by any Party of the validity or invalidity of any principle or practice of regulatory accounting or ratemaking; nor shall they be construed to constitute the

basis of an estoppel or waiver by any Party; nor shall they be introduced or used as evidence for any other purpose in a future proceeding by any Party except in a proceeding to enforce this Stipulation.

68. The Parties agree that no part of this Stipulation or the formulae and methodologies used in developing the same or a Commission order approving the same shall in any manner be argued or considered as precedential in any future case except with regard to issues expressly called-out and resolved by this Stipulation. This Stipulation does not resolve and does not provide any inferences regarding, and the Parties are free to take any position with respect to any issues not specifically called-out and settled herein.

69. The Parties request that the Commission hold a hearing on this Stipulation. Rocky Mountain Power, the DPU, and the OCS each will, and other Parties may, make one or more witnesses available to explain and offer further support for this Stipulation. The Parties shall support the Commission's approval of this Stipulation. As applied to the Division and the Office, the explanation and support shall be consistent with their statutory authority and responsibility.

70. The Parties agree that if any person challenges the approval of this Stipulation or requests rehearing or reconsideration of any order of the Commission approving this Stipulation, each Party will use its best efforts to support the terms and conditions of this Stipulation. As applied to the DPU and the OCS, the phrase "use its best efforts" means that they shall do so in a manner consistent with their statutory authority and responsibility. In the event any person seeks judicial review of a Commission order approving this Stipulation, no Party shall take a position in that judicial review proceeding in opposition to the Stipulation.

71. Except with regard to the obligations of the Parties under the four immediately preceding paragraphs of this Stipulation, this Stipulation shall not be final and binding on

the Parties until it has been approved without material change or condition by the Commission.

72. This Stipulation is an integrated whole, and any Party may withdraw from it if it is not approved without material change or condition by the Commission or if the Commission's approval is rejected or materially conditioned by a reviewing court. If the Commission rejects any part of this Stipulation or imposes any material change or condition on approval of this Stipulation or if the Commission's approval of this Stipulation is rejected or materially conditioned by a reviewing court, the Parties agree to meet and discuss the applicable Commission or court order within five business days of its issuance and to attempt in good faith to determine if they are willing to modify the Stipulation consistent with the order. No Party shall withdraw from the Stipulation prior to complying with the foregoing sentence. If any Party withdraws from the Stipulation, any Party retains the right to seek additional procedures before the Commission, including presentation of testimony and cross-examination of witnesses, with respect to issues resolved by the Stipulation, and no party shall be bound or prejudiced by the terms and conditions of the Stipulation.

73. This Stipulation may be executed by individual Parties through two or more separate, conformed copies, the aggregate of which will be considered as an integrated instrument.

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DATED this ___ day of August 2012.

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