WORK
MEETING

Heber City Corporation

Memo

To: Mayor and City Council

From: Mark K. Anderson

Date: 07/30/2015

Re: City Council Agenda Items for August 6, 2015

<u>WORK MEETING</u> Begin at 5:30 p.m.

<u>Item 1 – Jason Norland, Heber Light and Power Presentation:</u> Jason Norlan, Heber Light & Power General Manager, is coming before the Council to present information on a recent rate study performed for HL&P and the associated proposed electrical rate increase. Jason has provided the attached rate study and information that he will review with the Council. A public hearing on the proposed rate increase will be held on August 5th at 6:00 p.m. at the Heber City Offices.

<u>Item 2 – Clayton Vance and Bart Mumford, Discuss Pros and Cons of Narrow Roads:</u> At the last City Council meeting, the Council expressed a desire to talk about road standards and whether or not streets should be public or private. Councilman Rowland has invited Clayton Vance (local architect and member of the Planning Commission) to make a presentation on the pros and cons of narrower roads and Bart Mumford, City Engineer has prepared the enclosed memo on the issue as well. In speaking with Clayton, he will have his presentation materials available early next week.

<u>Item 3 – Alejandro Raygoza and James Neville, BYU MPA Students – Brief Analysis on Impact Fees in Utah:</u> Alejandro Raygoza and James Neville are BYU MPA students that have been interning with Ryan Starks at the Heber Valley Tourism and Economic Development (HVTED) office this summer. They have asked for an opportunity to present to the City Council a brief summary of information that they have gathered on impact fees in Utah. Enclosed is the report that they have prepared.

<u>Item 4 – Discuss Revised Draft of the Mountain Valley RV Resort Zone Change and Covenants Running with the Land:</u> Staff has met with Millstream to review proposed changes to the Zone Change agreement. As noted in the staff report, the format of the agreement has changed to make it less cumbersome. In addition changes have been made to the provisions regarding maintenance of the planter strip, which gives more options for the maintenance of this area if the City were to allow access to

2400 South to the developer. Staff sees some advantage to this. Lastly, with regard to paragraph 3(c)(iii), Millstream was not anticipating participating the extension of 2400 South for some time and is proposing that the time value of money be considered if this contribution is made in the next four years. Enclosed is an email from Brad Lyle that provides clarity on a proposed discount rate of 6% and how that would be calculated. The Council should discuss this and agree upon a discount rate/formula that would be included in the agreement.

Item 5 – Discuss Removing the Main Street Park Railing: Councilman Rowland has asked that this item be placed on the agenda for discussion, the concern being that the retaining wall on the northwest corner of the park overly restricts pedestrian traffic during the Farmer's Market and creates a safety concern. I have spoken with Mark Rounds and Wes Greenhalgh about this issue and have visited the site myself. Attached are some pictures of the area in question. Our observations are as follows:

- From the stairs by the bandstand to the southern end of the retaining wall is approximately 200 feet
- The sidewalk is narrowed by about 10" for approximately 130' from the stairs southward (This is because an additional retaining wall was constructed to support the failing wall)
- The grade difference from the sidewalk to the grass varies from approximately 2" on the south to 18" on the north
- If the retaining wall is removed and stairs are installed, a 48' landing (at the top of the stairs) will need to be installed and handrails will need to be installed every 60" if there are two or more steps. (A step has a 7" rise and 11" run)
- On the southern end, the grade of the grass could be changed, the further north you go the more impact to the existing landscaping and sprinkler system
- The Council should discuss how wide of sidewalk they want in this area, as the existing sidewalk would likely need to be replaced

Wes Greenhalgh has put together an unsolicited drawing of a proposed solution for consideration which is enclosed. This would be the least costly alternative, but I have some concern about the slope of the grass on the northern end.

Once we understand the desired design, staff can bring back cost estimates to complete the work and determine what budget amendment would be necessary.

TAB 1

HEBER LIGHT & POWER

2015
ELECTRIC RATE STUDY REPORT

BY:

R. E. Pender, Inc.

JULY 23, 2015

1. INTRODUCTION

R. E. Pender, Inc. ("Consultant") has completed a Cost of Service Study and Rate Design Analysis (collectively the "2015 Rate Study") for Heber Light & Power ("Client" or "HLP"). The subject work was carried out in accordance with a Professional Services Agreement ("PSA"), dated October 28, 2014. The Scope of Work outlined in the PSA is attached hereto as Exhibit A. This report represents one of the final work tasks contemplated by PSA and hence the completion of the project. The Consultant wishes to gratefully acknowledge the contributions of the HLP staff in preparing the 2015 Rate Study. Without their knowledgeable and timely assistance, the successful completion of the project would not have been possible. Following is a more detailed discussion of the various aspects of the subject study.

2. GENERAL BACKGROUND INFORMATION

a. ***Heber Light & Power.*** Headquartered in Heber City, Utah, HLP is a municipal-owned electric utility that serves about 10,700[1] customers in Wasatch County. The entire service area covers about 120 square miles in what is referred to as the Heber Valley. The utility's service area spans east to the Uinta National Forest, west to the entrance of Snake Creek Canyon in Midway City, south to the UDOT weigh station and north to Coyote Lane on Highway 40. Along with its electric distribution system, HLP owns and operates two hydroelectric generators and three gas/diesel generating plants with an overall generating capacity of 16 megawatts. Prior to the current economic slowdown, annual customer growth averaged a robust 15-25% per year; however, recently, the growth has been a very modest 2-3% per year. The customer base includes approximately 9,400 residential and 1,300 commercial customers. Heber Light & Power also provides street lighting for the cities of Heber and Midway, the town of Charleston and Wasatch County. In addition, residential area lighting is provided upon customer request.

   Heber Light & Power is has deployed an automated metering infrastructure (AMI) system which allows the utility to capture a variety of customer usage data from both customer classes. The utility has been collecting data on commercial demands and analyzing the impact

[1] As of year-end 2014.

on these customers of implementing a demand charge. In addition, these meters also provide automated billing data for the Company's billing system.

Also, Heber Light & Power operates a 24-hour, 7 day a week dispatch department. One of the responsibilities of this department is the purchase and scheduling of energy. The department maintains a database of hourly system peaks for each day of the year. The database contains several years' history. Combined, the AMI and dispatch information provide detailed results of electricity sales and energy purchases – much of which was used in the 2015 Rate Study.

b. ***HLP Current Electric Rates.*** HLP currently has two primary rate classes; residential and commercial. In 2009, the utility unbundled its residential rate by identifying a service fee and modifying the energy rates to reflect a two-block inverted rate structure. The commercial tariff consists only of a three-tier block energy rate (i.e., no base charge and no demand charge). A third, less significant tariff applies to street and security lighting which are charged a flat monthly fee. A copy of HLP's current electric rate tariffs are shown in the attached Appendix B. Because of the small, rural nature of Heber Light & Power's service territory, no large industrial customers are currently served by the utility.

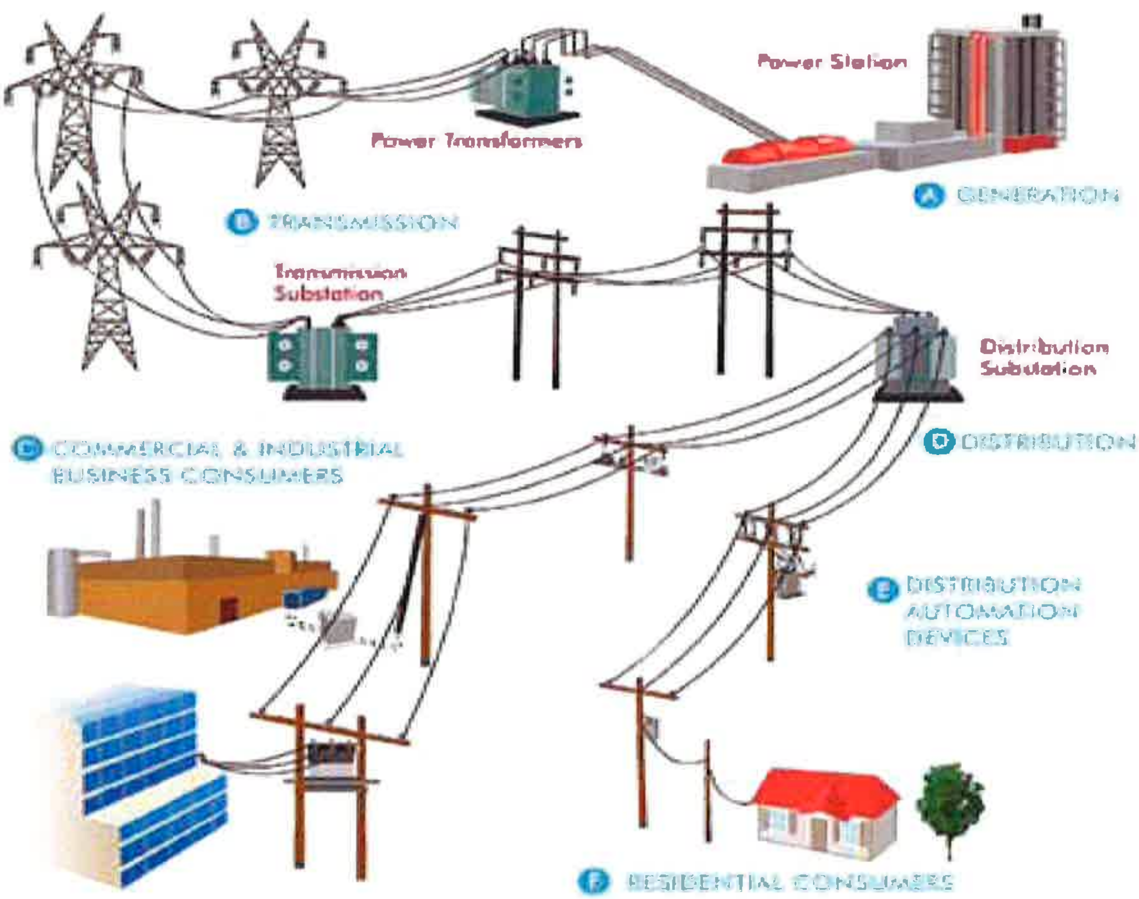
c. ***R. E. Pender, Inc.*** Located in the Orlando, Florida area, R. E. Pender, Inc. is solely-owned by Robert E. Pender, ASA. The firm was founded in 2005 for the purpose of providing consulting services in the areas of appraisals and valuations; wholesale and retail utility rate studies; economic feasibility studies; contract compliance reviews; and litigation support. Mr. Pender began his consulting career with R. W. Beck, Inc., where he advanced to the position of Principal and Senior Director. He has been recognized and qualified as an expert before the courts and regulatory commissions in the areas of utility appraisals and utility rates and regulation. He has testified before circuit courts, Federal District Court, the Federal Energy Regulatory Commission, arbitration panels and utility regulatory commissions in the District of Columbia, New York, Ohio, New Mexico, Pennsylvania and Kansas. Mr. Pender received his B.S. degree in Accounting and Business Administration from Indiana State University in 1977. He has completed several valuation courses through the American Society of Appraisers and is certified by that organization as an Accredited Senior Appraiser – Public

Utilities. Affiliations include the American Society of Appraisers, the International Association of Assessing Officers, and the American Water Works Association.

3. IMPORTANT CONCEPTS AND TERMS

The following narrative provides a description and/or explanation of certain concepts and terms that are essential to understanding the various analyses undertaken for the 2015 Rate Study.

a. ***The Power Delivery System.*** Following is an illustration of a typical power delivery system, the various parts of which drive the utility's expenses and investment-related costs that must be recovered through rates.



b. ***The Purpose of Ratemaking.*** The overarching purpose of utility ratemaking is to establish various rates and charges for the provision of the utility service (electric service in the immediate case) to its various customers. Inherent in the rate setting process are three primary goals:

- Recover the utility's annual revenue requirements (e.g., expenses, debt service, reserve contributions, etc.);
- Carryout specific goals and objectives (e.g. shift demand, encourage conservation, eliminate intra-class subsidization, etc.)
- Address consumer concerns that rates are fair, equitable and non-discriminatory.

c. ***The Cost of Service Study.*** The cost of service study is performed to determine the utility's revenue requirements by rate class that will be used to establish the appropriate rates and charges. It is based on the principles of "cost causation" and "intergenerational equity." Cost causation simply means that those who cause the utility to incur its costs should be responsible for payment of such costs. The intergeneration equity principle insures that future ratepayers who may benefit from the investments made by the utility today pay their fair share of such investments in the future. The cost of service study involves several analytical steps. The first step is to determine the total system revenue requirements that will be included in the study. Following is a list of revenue requirements typical for a municipal electric utility like HLP.

- Production O&M (including fuel);
- Purchased power expenses;
- Distribution O&M;
- Customer-related expenses;
- Administrative & general expenses;
- Debt Service;
- Payments to reserve accounts; and
- Return (dividends and/or payments to the general fund).

Revenue requirements are typically determined for an annual period (e.g., fiscal year) and may rely on the utility's budget or actual expenses with pro-forma adjustments to reflect a future normalized operating period. Once total revenue requirements have been determined, the next step is functionalize the revenue requirements according the major operating functions of the utility (i.e., generation, transmission, distribution and customer-related). The functionalized costs are then allocated to the various rate classes using appropriate allocation factors. For example, variable costs such as fuel expenses would be allocated using energy (kilowatt-hour) sales by rate class. The final step in the cost of service study is to compare total allocated revenue requirements to the total estimated revenues under current rates (for the test period) to determine if there is a revenue deficiency or excess, all by rate class. The final step will indicate whether a rate increase or decrease is justified for each rate class.

d. ***Rate Design.*** Rate design is another important aspect of the rate study. The utility may see a need to change the structure of its rates or develop new rates based on changes in the customer makeup or operational characteristics of the utility. It may also introduce new rates (e.g., time-of-use) in order to influence the consumption patterns of certain customers. Rate design can be considered an art rather than an exact science because it is based largely on certain assumptions about customer behavior (e.g., consumption patterns) in the future. It is not unusual to have several iterations of rate design before the final version is selected.

e. ***Demand.*** Measured in kilowatts ("kW") or kilovolt-amperes ("kVa"). A kW is equal to 1,000 watts and is determined through metering devices at specific intervals (e.g., a 60-minute reading). Types of demand can include coincident peak demand, non-coincident peak demand and billing demand. Coincident demand is the sum of two or more demands which occur in the same demand interval. For example, system coincident peak demand refers to the highest demand measured for the entire electric system during a specific period, usually month or year. Non-coincident demand is the sum of two or more individual demands which do not occur in the same demand interval. Billing demand for a customer is normally based on the highest 15-minute reading during the monthly billing cycle.

f. ***Energy.*** Measured in kilowatt-hours (kWh) over a specific time period (e.g., month or year). Also referred to as consumption (in the case of customer usage) and output (in the case of generating plants). Billed energy is the metered kWh for the customer during the monthly billing cycle.

g. ***Customer Classes.*** Refers to groups of customers exhibiting, for the most part, the same demand and usage characteristics. Major customer classes for an electric utility normally include:

- Residential (e.g., single-family homes; condominiums, apartments);
- Commercial (e.g., small and large retail businesses);
- Industrial (e.g., large power users engaged in manufacturing);
- Other (e.g. street lights, sales to public authorities).

An electric utility can have a multitude of customer classes for which it offers electric service and establishes rates for such service. In addition to those noted above, other customer (or rate) classes can include irrigation service, non-profit (e.g., churches); security lights; master-metered apartments; and low-income housing, among others. As noted previously HLP's current customer classes include Residential, Commercial and Street/Security Lighting.

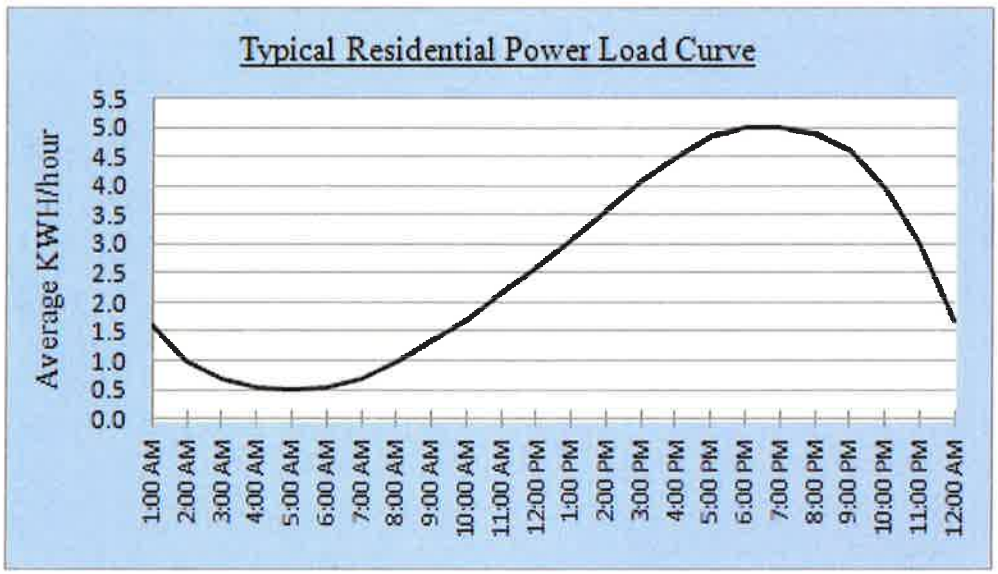
h. ***Load Factor.*** Load Factor is the ratio of the average demand for a specific period to the maximum or peak demand for that same period (e.g., month, year, etc.). For example, the system load factor for say the month of January would be calculated as follows:

Total System Energy (kWh) ÷ 744 hours = Average Demand

Average Demand ÷ System Peak Demand = Load Factor

Load factor measures how well the electric system (i.e., facilities and equipment) installed to serve load is being utilized. That is, the higher the load factor, the better the utilization. Load factor can be calculated for the entire system, customer classes and individual customers – assuming adequate metering exists. If metering data is not available, "proxy" load factors can be estimated from load research data or from industry studies.

Load factor is an important element when considering the cost allocation process in the cost of service study. Normally, the residential customer class will have a lower load factor than the commercial class and the commercial class will have a lower load factor than the industrial class. Thus, residential customers are the least efficient users of the electric system and, as a customer class, will be allocated proportionately more fixed (or demand-related) costs than the commercial and industrial classes. Following is an illustration of a typical residential load curve measured over a 24-hour period.



As you can see, the highest demand (kW) during the day of 5.0 kW was experienced about 6:00 – 7:00 p.m. – the time of day when everyone is home, dinner is being prepared, television is on, the heating/air conditioning system is operating and perhaps the washing machine is running. If you were to add up all of the individual readings (24) indicated by the curve, it would indicate that this residential customer consumed approximately 60.0 kWh. When the 60 kWh is divided by 24 it results in average demand of 2.5 kW; therefore, the load factor for this 24-hour period is 50.0 percent (2.5 kW / 5.0 kW).

i. ***Losses.*** Every electric system experiences some level of electric losses. Losses, which are an inevitable part of system operations, are due to normal resistance; transformation and other physical attributes of the system. Losses (both demand and energy) can be measured at several points on the system through metering installed at substations and at customer premises. Losses for an electric system typically range from 5 percent to 6 percent – measured as the difference in load at the input to electric system (i.e., generator bus-bar) to the end-user (i.e., customer meter).

4. DESCRIPTION OF WORK PERFORMED

a. ***Data/Information Request.*** Work on the project was initiated by the preparation of a data/information request (see Appendix C) which was forwarded to the Client prior to the kick-off meeting. In general, the data request covered a variety of items that are typically needed for a utility cost of service study (e.g., audited financial statements; customer and sales forecasts; historical billing data, among others).

b. ***Kick-off Meeting***. A project kick-off meeting was held via teleconference on November 5, 2014. The purpose of the meeting was to (i) establish communication protocols; (ii) review the Consultant's work plan; (iii) review the data/information request; (iv) gather some general information about HLP and its service area; and (v) discuss potential changes to existing rates and charges.

c. ***Data Collection and Analysis***. Data responses received from HLP were reviewed for reasonableness, understanding and applicability and compiled in a project workbook. When necessary, data that was to be utilized in the COS Study was analyzed and put in required format for use in the COS model. For example, historical billing data for commercial customers was analyzed to determine a suitable non-coincident peak load factor for the commercial class.

d. ***Preliminary COS Study***. Using a spreadsheet model[2] previously developed by the Consultant, a COS analysis was constructed specific to HLP's needs; primarily with regard to rate structure and cost classifications. Once the COS model was constructed, the data inputs

[2] The COS model is an Excel© spreadsheet utilized for prior rate studies performed by the Consultant. The model calculates annual revenue requirements by rate classification and annual billing summaries under present and proposed rates.

were refined as necessary for input to the model. Data inputs primarily include test-year expenses; annual billing determinants; and data for development of the cost allocation factors. The HLP COS model is comprised of ten (10) individual modules or worksheets that perform various COS and rate design functions. These modules are generally described as follows:

Worksheet Name	Schedule Designation	Description
Summary	Summary	Summary of Revenues and Revenue Excess/Deficiency Under Present and Proposed Rates by Rate Class
Cost of Service	Schedule A	Allocation of Revenue Requirements for the Projected Test Year 2015
Analysis of Revenue Requirements	Schedule B	Analysis of Test Year Operating Expenses and Other Revenue Requirements
KWH Sales Allocation Factors	Schedule C	Development of Allocation Factors based on Energy Sales for the Test Year 2015
Customer Allocation Factors	Schedule D	Development of Allocation Factors based on Number of Customers for the Test Year 2015
Demand Allocation Factors - Non-Coincident Peak	Schedule E	Development of Allocation Factors based on Non-Coincident Peak Demand Data for the Test Year 2015
Demand Allocation Factors - 12-Month Coincident Peak	Schedule F	Development of Allocation Factors based on Coincident Peak Demand Data for the Test Year 2015
Calculation of Estimated Revenues Under Existing Rates	Schedule G	Calculates Revenues under Existing Rates Under Customer/Sales Forecast for Test Year 2015
Calculation of Estimated Revenues Under Proposed Rates - (Current Design)	Schedule H-1	Calculates Revenues under Proposed Rates Under Customer/Sales Forecast for Test Year 2015 Using Required ATB Increase.
Calculation of Estimated Revenues Under Proposed Rates - (Proposed Design)	Schedule H-2	Calculates Revenues under Proposed Rates Under Customer/Sales Forecast for Test Year 2015 Using Required ATB Increase.
Billing Comparison Under Present and Proposed Rates – New Design	Schedule I	Compares Total Monthly Charges Under Present and Proposed Rates at Various Consumption Levels.

e. ***Preliminary Rate Design***. The Consultant was requested by HLP staff to perform an initial rate design that split the Commercial class into three groups or sub-classes; small commercial, medium commercial and large commercial. The rate design of the Residential class was to remain as it is currently. It was also decided to leave the tariff for Street Lights unchanged until HLP completes a detailed inventory of its street and security lights.

f. ***Review of Preliminary COS Study and Rate Design***. After completion of the Preliminary COS Study, the Consultant reviewed the preliminary results with HLP staff via teleconference on June 4, 2015. The purpose of the conference call was threefold: (i) review the COS model and the preliminary results; (ii) review the major assumptions and considerations used for the COS Study; and (iii) discuss the proposed rate design. To facilitate these discussions, the Consultant prepared a spreadsheet that compared HLP's current rates and the proposed rates with those of Rocky Mountain Power and other municipal utilities in Utah (see attached Exhibit B).

g. ***Finalize COS, Board Presentations and Report.*** The initial "preliminary" version of the COS Study and rate design was presented to the HLP Board via teleconference on June 24, 2015. After additional review and input by the HLP Staff, the Consultant finalized the COS Study and proposed rate design in its current version on July 7, 2015. A copy of the final COS Study is attached hereto as Exhibit A.

5. IMPORTANT ASSUMPTIONS & CONSIDERATIONS

As with any undertaking of this nature, the COS Study required that certain assumptions and considerations be made with regard to financial and operating conditions which may affect the outcome of the study. The major assumptions and considerations used in the HLP COS Study are as follows:

a. Determination of Test-Year Revenue Requirements (Ref: Schedule B of COS Study)

- The test-year selected for the COS Study was calendar year 2015.
- The primary source for the operating expense revenue requirements was the 2015 Master Budget.
- Depreciation expense ($1,860,000) was excluded because the principal payment on debt was included as a revenue requirement.
- Projected annual Debt Service ($1,201,083) includes both interest and principal payments and is based on the latest debt service schedules supplied by HLP staff. Debt Service was calculated as a five-year average for the period 2015 – 2019.

- Capital Additions Paid from Cash ($1,470,211) includes renewals and replacements and other improvements not funded through debt and impact fees.
- Consistent with the annual budget, an amount for Reserve Funding ($135,000) was included as a revenue requirement.
- Revenue Credits totaling $151,054 includes such things as connection fees, pole attachment revenue, interest income and penalty fees on accounts receivables.
- Customer-related costs included in Generation were determined to be $296,157 and was based on an analysis of such costs by HLP staff.
- All Administration and General Expenses were functionalized to Generation, Distribution and Customer categories based on salaries and wages for each of those functions.
- Debt Service and Capital Additions Paid from Cash were functionalized to the Generation, Distribution and Customer categories based on Gross Plant balances as of December 31, 2014.
- The only categories of test-year expenses that were considered to be entirely energy related are the Gas Generation, Energy Rebates and Purchased Power expenses.

b. Determination of kWh Sales Allocation Factors (Ref: Schedule C of COS Study)

- The kWh allocation factors used in the COS Study relied on a projection of kWh sales as presented in the HLP 2015 Master Budget.
- An independent calculation of 2015 kWh Sales was performed in order to test the reasonableness of the projected monthly customers calculated on Schedule D.
- Energy sales (kWh) for Street Lights were reduced by 1/3 to take into account the current saturation of LED lights.

c. Customer Allocation Factors (Ref: Schedule D of COS Study)

- Utilized actual data for 2012, 2013 and 2014 based on information provided by HLP.
- Projected customers for Residential & Commercial were calculated based on an assumed growth rate of 2.0 percent.

- The estimated number of Street Light accounts for Residential (85) and Commercial (14) is based on information supplied by HLP.

d. Demand Allocation Factors – Non-Coincident Peak (Ref: Schedule E of COS Study)

- Commercial Load Factor (0.4300) was determined through an analysis of AMI data provided by HLP.
- Residential Load Factor (0.4320) is based on Rocky Mountain Power most recent rate filing before the Utah Public Service Commission in Docket No. 13-035-184.

e. Demand Allocation Factors – Coincident Peak (Ref: Schedule F of COS Study)

- Class 12-CP Load Factors (line 2) are based on data obtained from a recent RMP rate filing with the Utah Public Service Commission (Docket No. 13-035-184).
- Estimated 12-CP demands by rate class were adjusted to fit actual for years 2012 through 2014.
- Estimated 12-CP demands by rate class for Year 2015 were calculated using the average load factor indicated for years 2012 through 2014.

f. Special Adjustments (Ref: Summary Schedule of COS Study

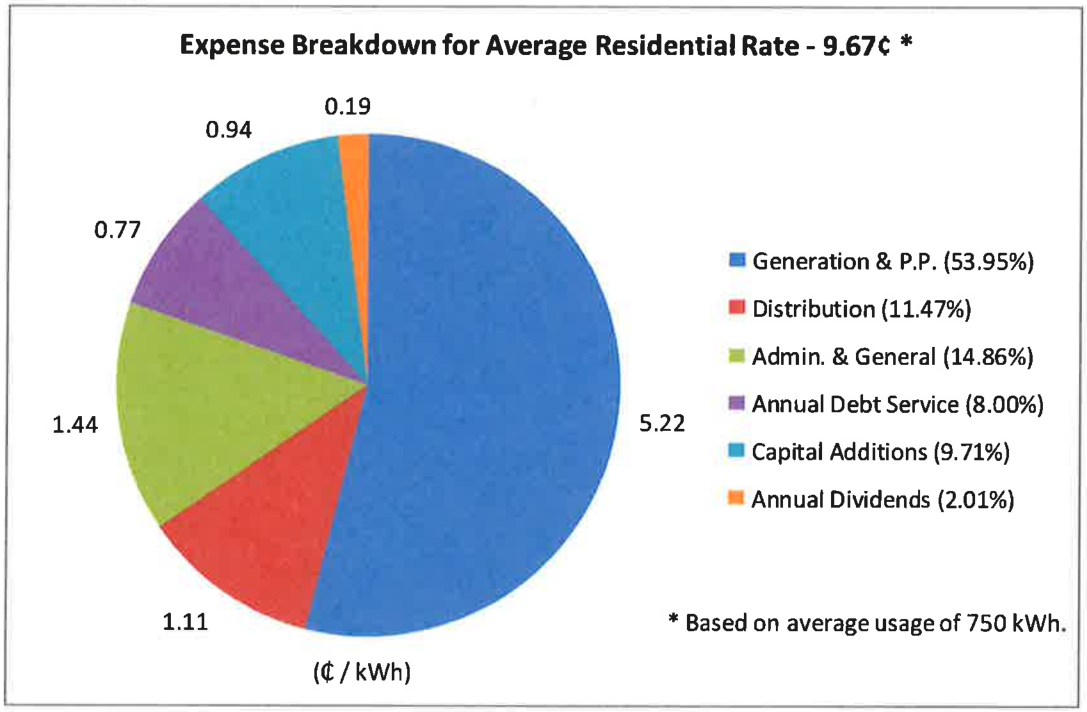
- Total Allocated Revenue Requirements were adjusted to account for the fact that certain city Street Light accounts are considered "donated" accounts; that is the annual revenues and associated revenue requirements for these accounts are absorbed by the utility. Therefore, the allocated annual revenue requirements for these accounts were reallocated to the Residential and Commercial rate classes since the subject Street Lights provide a direct benefit to the customers in these classes (see lines 4-6 and 10-12 of the Summary).

6. COS STUDY RESULTS

The results of the COS Study are shown in the Summary schedule of the COS analyses (Exhibit A). As shown on line 13 of the Summary, the COS Study indicates that, under current rates, there is a total revenue requirement deficiency of some $841.8 thousand or 5.98 percent. By rate class, the deficiency amounts to $471.8 thousand (5.98 percent) for Residential and $378.9 thousand (6.1 percent) for Commercial. For Street Lights, there is a revenue excess of $8.9 thousand (48.4

percent). For purposes of rate design, we have assumed an across-the-board increase of 6.0 percent.

The COS Study also shows that of the total revenue requirements, 47.3 percent are Demand-related, 48.0 percent are Energy-related and 4.7 percent are Customer-related. The following chart provides a breakdown of the types of expenses that would be recovered through proposed rates for Residential customers assuming a 6.0 percent increase in current rates.



7. RATE DESIGN RESULTS

As mentioned above, the Consultant was requested to design new rates for the Commercial class while leaving the rate structure for Residential and Street/Security Lights unchanged. The Commercial class was bifurcated into three sub-classes: (i) Small Commercial/General Service; Medium Commercial/General Service; and (iii) Large Commercial/General Service. The Small Commercial rate class is for customers having a monthly demand of less than or equal to 30 kW; Medium Commercial is applicable to customers having a demand greater than 30 kW but less than or equal to 250 kW; and Large Commercial is reserved for customers having a monthly demand of greater than 250 kW. The rate structure for Small Commercial was changed to a two-tier energy (i.e., the first 1,000 kWh and above 1,000 kWh) rate coupled with a monthly base/customer service charge and a demand charge. The same is true for Medium Commercial which also has a two-tier energy rate (i.e., the first 10,000 kWh and above 10,000 kWh) and a base/customer service charge and demand charge. For Large Commercial, all energy rate is charged at a single rate with a base/customer service charge and a demand rate. Following are the subject rates reflecting the proposed 6.0 percent increase and the new rate structure for the Commercial class.

- Residential
  Monthly Base/Customer Charge - $12.70
  Energy Charge
    First 1,000 kWh - 7.98¢ per kWh
    All Additional kWh - 10.02¢ per kWh
- Small Commercial / General Service (<=30 kW)
  Monthly Base/Customer Charge – $8.00
  Demand Charge – 8.90 per kW
  Energy Charge
    First 1,000 kWh - 7.80¢ per kWh
    All Additional kWh - 4.60¢ per kWh
- Medium Commercial / General Service (>30 kW and <=250kW)
  Monthly Base/Customer Charge – $15.20
  Demand Charge – 10.00 per kW
  Energy Charge
    First 10,000 kWh - 6.04¢ per kWh
    All Additional kWh - 4.60¢ per kWh
- Large Commercial / General Service (>250 kW)
  Monthly Base/Customer Charge - $26.90
  Demand Charge – $13.50 per kW
  Energy Charge
    All kWh - 4.60¢ per kWh

8. OBSERVATIONS / RECOMMENDATIONS

- Current rates need to be increased in order to fully recover annual revenue requirements.
- The proposed 6.0% increase will achieve full recovery of test-year revenue requirements.
- HLP should conduct a complete inventory of its street / security lights by size, type and ownership.

- HLP should continue to collect/analyze data from its AMI system in order to monitor the impact of the proposed rates and charges and for potentially new rates and charges in future, including:
    - Time-of-use (day) rates.
    - Load factor analyses for cost of service / ratemaking.
    - Impact of customer-supplied resources (net metering).
- HLP should consider a power factor correction mechanism in its rate tariff for the large commercial / general service.
- HLP may want to consider classifying and billing 3-phase residential service as small commercial / general service.

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APPENDIX A
PSA SCOPE OF WORK

Cost of Service Study/Rate Design Work for Heber Light & Power By R. E. Pender, Inc.

Description of Consulting Services, Schedule and Budget

Proposed Scope of Work:

Task 1 - Kick-off Meeting. The Consultant and HLP shall meet to:

1. review the outcome of the 2014 rate study and discuss proposed changes;
2. discuss the Consultant's basic plan of action and HLP's support for the current study;
3. establish the basic goals and objectives of the current cost of service study/rate design process;
4. discuss potential changes to existing rates and charges and possible new rates and charges for evaluation in the cost of service study and rate design alternatives; recommendation
5. review the initial data request and HLP's response (to be prepared and submitted by the Consultant prior to the meeting); and
6. discuss changes, if any, to the scope of work, schedule, or budget.

Note: It is contemplated that Task 1 will be conducted via teleconference with the HLP staff involved in the rate study.

Task 2 - Compile, Review and Analyze Data. After all of the data and information has been received from HLP, the Consultant shall:

1. compile the data and information in a suitable format for analysis,
2. review the data and information for reasonableness prior to input in the cost of service model, and
3. consult with HLP to clarify or correct, to the extent reasonably practicable, questionable and/or incomplete data.

Task 3 - Perform Preliminary Cost of Service Study. The Consultant shall prepare a fully distributed cost of service study for the test year (e.g., FY 2015) including:

1. determine the pro-forma test-year revenue requirements (by rate class) applicable

to the operating conditions for the test-year,

2. use a cost of service model typical for municipal electric systems, adjusted as necessary for HLP operating conditions,

3. allocate fixed costs to non-demand metered customers (e.g., residential customers) based on demand data from load research data provided by HLP, gathered through prior rate studies or publicly available load research studies, and

4. review and input test year operating costs in the cost of service model based on 2015 budget data provided by HLP.

Task 4 - Perform Billing/Revenue Comparison. The Consultant shall calculate the estimated test-year revenues under HLP's current rates by applying HLP's current rates to the projected demand and energy requirements for the test year. The Consultant shall then compare these estimated test-year revenues to the estimated revenue requirements determined in the allocated cost of service.

Task 5 - Review of Preliminary Results of Cost of Service Study. Upon completion of the foregoing tasks, the Consultant will meet with HLP staff (in-person or via teleconference, as preferred) to review:

1. the preliminary results of the cost of service study,

2. the Consultant's methods, assumptions (if any) and data used in the study, and

3. the range of rate increases/decreases by rate class.

This review may be combined with the review of the preliminary rate design in Task 7.

Task 6 - Prepare Preliminary Rate Design. The Consultant will design preliminary rates and charges based on the allocated revenue requirements from the cost of service study. The preliminary rate design will include any new rates and/or changes to HLP's existing rates. Modifications to existing rates may include:

1. implementation of an automatic annual base rate adjustment,

2. shifting more revenue requirements into the service charge,

3. implementation of an energy efficiency/renewable surcharge, inclusive of a fully developed program,

4. implementation of time of day/use rates, and

5. implementation of a demand charge for large and small demand-metered commercial customers.

The preliminary rates and charges will be tested or evaluated through a billing distribution analysis to ensure the recovery of allocated revenue requirements, in total and by rate class.

Task 7 – Review/Finalize Preliminary Rate Design. The Consultant will meet with HLP staff (via teleconference) to review the results of the preliminary rate design. New rates and charges will be further evaluated for such things as customer acceptance, fairness and ease of implementation. After review by staff, Consultant will finalize rate design and prepare revised tariff sheets (if requested).

Task 8 - Prepare Draft/Final Report. Upon completion of Tasks 1-7, the Consultant shall prepare a final draft report including the cost of service study, rate design and related analysis. After HLP reviews the draft report, the Consultant shall complete a final report on the cost of service study, rate design and related analysis. The final report shall include an evaluation of the proposed rates to insure the full recovery of test-year revenue requirements and draft rate schedules to be approved by HLP's Board. Consultant will also prepare a PowerPoint presentation for review at the HLP Board meeting.

Proposed Schedule

Consultant proposes the following schedule for completing the project tasks identified above. Any adjustments to the proposed schedule during the course of the project will be discussed with and approved by the Client.

HL&P Cost of Service & Retail Rate Design - Project Schedule									
	Weeks Following Authorization to Proceed								
Project Task	1	2	3	4	5	6	7	8	9
1. Kick-off Meeting									
2. Data Collection, Review & Analysis									
3. Perform Cost of Service Study									
4. Perform Billing/Revenue Comparison									
5. Finalize Cost of Service									
6. Perform Preliminary Rate Design									
7. Review & Finalize Rate Design									
8. Prepare Report / Presentation									

Proposed Budget

The following table outlines the Consultant's best estimate of the time, labor cost and expenses for completing HL&P's Cost of Service and Rate Design Project. Consultant proposes a budget of $19,100 for completing the scope of services set forth in Section 2 above. The not-to exceed budget includes 2 trips (2 man days each) to meet with HLP staff and/or attendance at the HLP Board meeting.

Cost Proposal

Project Task	No. Of Hours	Estimated Labor	Estimated Expenses	Total Cost
1. Kick-off Meeting	2	$300.00		$300.00
2. Compile, Review and Analyze Data	10	1,500.00		1,500.00
3. Perform Cost of Service Study	30	4,500.00		4,500.00
4. Perform Billing / Revenue Comparison	8	1,200.00		1,200.00
5. Review & Finalize Cost of Service Study	10	1,500.00		1,500.00
6. Perform Preliminary Rate Design	20	3,000.00		3,000.00
7. Review and Finalize Rate Design	16	2,400.00	1,000.00	3,400.00
9. Prepare Report / Presentation	18	2,700.00	1,000.00	3,700.00
Grand Total	**116**	**$17,100.00**	**$2,000.00**	**$19,100.00**

If, during the course of the project, there are significant changes to the basic approach, project scope, etc. (all as approved by the Client), the project budget will be modified accordingly. Estimated labor costs are based on the Consultant's standard hourly billing rate of $150.00. The expenses shown above are those estimated to be incurred by the Consultant directly related to the project. The Consultant will bill the Client at cost for any directly incurred expenses such as airfare, hotel, long distance telephone charges, meals and other incidental charges, and overnight delivery charges. Consultant will not bill Client for computer costs, and normal copying costs. Any travel time required during the normal business day will be charged to the Client at the normal hourly billing rate.

Invoices will be submitted to Client once each month (normally the 1st day) during the course of the project and are due and payable within 30 days.

APPENDIX B
HLP ELECTRIC RATE TARIFFS

HEBER LIGHT AND POWER RATE SCHEDULE

Residential Service

Monthly Service Charge $ 12.00
Plus Applicable Sales and
Miscellaneous Taxes

7.525 cents per kwh first 1,000 kwh
9.45 cents per kwh all additional kwh

Commercial Service

Minimum Monthly $6.50
Plus Applicable Sales and
Miscellaneous Taxes

No Demand Charges

14.92 cents per kwh first 500 kwh
10.45 cents per kwh next 500 kwh
7.99 cents per kwh all additional kwh

Where a Customer takes service from the Company's available lines of 7,200 volts or higher and provides and maintains all transformers and other necessary equipment, a discount of three percent of the gross primary metered kilowatt hours may be applied.

Public Lighting

Customer provides Light and associated equipment
$6.50 per month - Energy only
(Based on 150 watt Light)

Yard Lighting

Customer is required to pay for the Installation of Pole and Fixture
Energy Charge - $6.50 per month
(Based on 150 watt Light)

NSF Check Charge

$15.00

Net Metering

Renewable "Feed In" Rate – 7.2 cents for all kwh
Avoided Cost "Feed In' Rate – 3.1 cents for all kwh
Meter Installation Charge - $150.00

Temporary Power Supply

Installation and Removal Charge - A fee of $200.00, payable in advance, is charged for installation and removal of temporary power supply facilities.
Monthly Rental Charge – A monthly rental charge of $7.00 will be included in the monthly bill.

Effective for All Billings Beginning June 15, 2011

APPENDIX C
DATA / INFORMATION REQUEST

Heber Light & Power
FY 2015 Electric Retail Rate Study

Initial Data/Information Request

Please provide the following data and information to be used in completing the above-stated study for Heber Light & Power ("HLP").

Data/Information Request

1. A copy of HLP's audited financial statements (i.e., annual report) for FY 2013.
2. If available, a copy of HLP's detailed utility financial operating report for the most recent month ending in FY 2014 showing fiscal year results to date. Alternatively, a copy of the HLP detailed expense ledger (by primary and sub-account) for each of the months in FY 2014.
3. A copy of the monthly utility billing data ("Billing and Usage Summary") for FY 2014 (January through the most recent month available) showing energy sales and revenues by rate class and consumption levels (if available).
4. A copy of the monthly utility billing registers ("Billing Register Cust. Type Count") for FY 2014, showing the number of billed customers by month.
5. A copy of HLP's most recently prepared operating and capital budgets for FY 2015 and the five-year period FY 2015 – FY 2019 (if available).
6. A narrative discussion of any known changes in HLP's power supply portfolio (e.g., generating unit retirements) contemplated over the next 3-5 years.
7. A forecast of HLP's annual debt service requirements for the next five (5) fiscal years 2015 – 2019, broken down by bond issue and purpose (e.g., generation project; distribution project, etc.). Provide for both existing debt and any new debt contemplated over the next five years.
8. A narrative discussion of any anticipated changes regarding the quarterly payments made to the owner cities for FY 2014, FY 2015 and thereafter.
9. A copy of the HLP electric system detailed plant (original cost and accumulated depreciation by plant account) ledger for fiscal year end 2013.
10. Please provide a description of any abnormal or atypical expenses that were incurred by/for the HLP electric system during the most recently completed fiscal year or included in the expense budget for FY 2015.
11. A narrative discussion of any known events or changes in the HLP service area that may impact HLP operations in the near-term (1-5 years). Events/changes can include such things as the anticipated addition/loss of a major customer load and new regulatory requirements, among others.

* * *

EXHIBIT A
COS STUDY

Heber Light & Power

Electric Utility Cost of Service Study / Rate Design
For the Projected Test Year Ending FY 2015

TABLE OF CONTENTS

Heber Light & Power
Electric Utility Cost of Service Study

SUMMARY
Revenue Excess/Deficiency Under Present and Proposed Rates
for the Projected Test Year FY 2015
($)

Ln.	Description	Ref.		Residential			Commercial				Street Lights	Total System
				Tier 1	Tier 2	Total	Tier 1	Tier 2	Tier 3	Total		
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Revenues from Existing Rates											
1	Base	Sch. G	$	1,353,340	-	1,353,340	-	-	-	-	92,274	1,445,614
2	Energy	Sch. G	$	4,990,285	1,539,634	6,529,919	819,347	397,866	4,953,146	6,170,359	-	12,700,278
3	Demand	Sch. G	$	-	-	-	-	-	-	-	-	-
4	Total Revenue from Existing Rates	CALC	$	6,343,625	1,539,634	7,883,259	819,347	397,866	4,953,146	6,170,359	92,274	14,145,892
5	Less: Donated Street Light Accounts	CALC	$	-	-	-	-	-	-	-	(73,819)	(73,819)
6	Revised Revenue from Existing Rates	CALC	$	6,343,625	1,539,634	7,883,259	819,347	397,866	4,953,146	6,170,359	18,455	14,072,073
	Total Allocated Revenue Requirements											
7	Demand	Sch. A	$	3,131,271	769,286	3,900,557	242,328	168,006	2,735,515	3,145,850	11,329	7,057,736
8	Energy	Sch. A	$	3,070,314	754,310	3,824,624	254,251	176,273	2,870,109	3,300,633	29,857	7,155,114
9	Customer	Sch. A	$	608,513		608,513	86,081			86,081	6,410	701,005
10	Total Allocated Revenue Requirements	CALC	$	6,810,099	1,523,596	8,333,694	582,661	344,279	5,605,624	6,532,564	47,596	14,913,854
11	Reallocation of Donated S.L. Accounts	CALC	$	17,443	3,902	21,345	1,492	882	14,358	16,732	(38,077)	-
12	Restated Allocation of Rev. Requirements	CALC	$	6,827,542	1,527,498	8,355,039	584,153	345,161	5,619,982	6,549,296	9,519	14,913,854
13	Revenue Excess (Deficiency)	CALC	$	(483,917)	12,136	(471,780)	235,194	52,705	(666,836)	(378,937)	8,936	(841,781)
14	Ratio of Revenue to Allocated Revenue Req.	CALC	#	0.93	1.01	0.95	1.41	1.16	0.88	0.94	1.94	0.95
15	***Unadjusted Required Increase (Decrease)***	CALC	%	***7.63%***	***-0.79%***	***5.98%***	***-28.71%***	***-13.25%***	***13.46%***	***6.14%***	***-48.42%***	***5.98%***
16	***Across Board Required Rate Increase***	CALC	%	***5.98%***	***5.98%***	***5.98%***	***5.98%***	***5.98%***	***5.98%***	***5.98%***	***5.98%***	***5.98%***
17	Across the Board Revenue Increase	CALC	$	379,471	92,100	471,571	49,013	23,800	296,294	369,106	1,104	841,781
	Restated Revenue Requirements											
18	Total	CALC	$	6,723,096	1,631,734	8,354,830	868,359	421,666	5,249,440	6,539,465	19,559	14,913,854
19	Demand	CALC	$	3,091,268	823,886	3,915,154	361,150	205,771	2,561,699	3,128,620	4,656	7,048,430
20	Energy	CALC	$	3,031,089	807,848	3,838,937	378,919	215,895	2,687,741	3,282,555	12,269	7,133,761
21	Customer	CALC	$	600,739	-	600,739	128,290	-	-	128,290	2,634	731,663
22	Total	CALC	$	6,723,096	1,631,734	8,354,830	868,359	421,666	5,249,440	6,539,465	19,559	14,913,854
23	Projected kWh Sales	Sch. C	kWh	66,316,078	16,292,426	82,608,504	5,491,600	3,807,331	61,991,816	71,290,747	644,878	154,544,130
24	Less: Donated SL Accounts	CALC	kWh	-	-	-	-	-	-	-	(515,903)	(515,903)
25	Adjusted kWh Sales	CALC	kWh	66,316,078	16,292,426	82,608,504	5,491,600	3,807,331	61,991,816	71,290,747	128,976	154,028,227
26	Average Cost Per kWh Under Current Rates	CALC	$/kWh	0.09566	0.09450	0.09543	0.14920	0.10450	0.07990	0.08655	0.14309	0.09136
27	Average Cost Per kWh Under ATB Increase	CALC	$/kWh	0.10138	0.10015	0.10114	0.15813	0.11075	0.08468	0.09173	0.15165	0.09683
	Rate Increase (Decrease)											
28	Per Unit	CALC	$/kWh	0.00572	0.00565	0.00571	0.00893	0.00625	0.00478	0.00518	0.00856	0.00547
29	Percent	CALC	%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%

Heber Light & Power
Electric Utility Cost of Service Study

SUMMARY
Revenue Excess/Deficiency Under Present and Proposed Rates
for the Projected Test Year FY 2015
($)

Ln.	Description	Ref.		Residential Tier 1	Residential Tier 2	Residential Total	Commercial Tier 1	Commercial Tier 2	Commercial Tier 3	Commercial Total	Street Lights	Total System
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Rev. Requirement Breakdown (%)											
30	Demand	CALC	%	21.0%	5.2%	26.2%	1.6%	1.1%	18.3%	21.1%	0.1%	47.3%
31	Energy	CALC	%	20.6%	5.1%	25.6%	1.7%	1.2%	19.2%	22.1%	0.2%	48.0%
32	Customer	CALC	%	4.1%	0.0%	4.1%	0.6%	0.0%	0.0%	0.6%	0.0%	4.7%
33	Total	CALC	%	45.7%	10.2%	55.9%	3.9%	2.3%	37.6%	43.8%	0.3%	100.0%
34	Purchased Power as Percent of Total R.R.	CALC	%	40.26%	44.21%	40.98%	38.96%	45.72%	45.72%	45.12%	56.01%	42.84%
	Per-unit Annual Revenue Requirements											
35	Demand	CALC	$/kW			179.35				165.31	63.24	172.63
36	Energy	CALC	$/kWh			0.0465				0.0460	0.0190	0.0462
37	Customer	CALC	$/Cust.&Lt.			63.92				96.50	2.23	61.43
38	Total	CALC	$/kWh			0.1011				0.0917	0.0303	0.0965
	Total Annual kWh Sales											
39	Winter (Nov. - May)	CALC	kWh	39,293,146	10,083,753	49,376,898	3,208,889	2,224,976	33,832,714	39,266,579	376,179	89,019,657
40	Summer (June - Oct.)	CALC	kWh	27,022,932	6,208,674	33,231,606	2,282,711	1,582,354	28,159,103	32,024,168	268,699	65,524,473
41	Total	CALC	kWh	66,316,078	16,292,426	82,608,504	5,491,600	3,807,331	61,991,816	71,290,747	644,878	154,544,130
	Average Monthly kWh Sales											
42	Winter (Nov. - May)	CALC	kWh	5,613,307	1,440,536	7,053,843	458,413	317,854	4,833,245	5,609,511	53,740	12,717,094
43	Summer (June - Oct.)	CALC	kWh	5,404,586	1,241,735	6,646,321	456,542	316,471	5,631,821	6,404,834	53,740	13,104,895
44	Total	CALC	kWh	5,526,340	1,357,702	6,884,042	457,633	317,278	5,165,985	5,940,896	53,740	12,878,677

SCHEDULE A

Heber Light and Power
Electric Utility Cost of Service Study

COST OF SERVICE
Allocation of Revenue Requirements
for the Projected Test Year FY 2015
($)

Ln.	Description	Ref.	Projected Test Year Rev. Req.	Allocation Basis	Residential			Commercial				Street Lights	Total System
					Tier 1	Tier 2	Total	Tier 1	Tier 2	Tier 3	Total		
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Allocation Factors												
1	No. of Customers	Sch. D			0.868059		0.868059	0.122797			0.122797	0.009144	1.000000
2	kWh Sales	Sch. C			0.429108	0.105422	0.534530	0.035534	0.024636	0.401127	0.461297	0.004173	1.000000
3	NCP Demand	Sch. E			0.429204	0.105446	0.534650	0.035707	0.024756	0.403083	0.463547	0.001803	1.000000
4	CP Demand	Sch. F			0.481508	0.118296	0.599804	0.030744	0.021315	0.347050	0.399109	0.001088	1.000000
	Allocation of Revenue Requirements												
	Generation												
5	Energy-related	Sch. B	649,911	kWh Sales	278,882	68,515	347,397	23,094	16,011	260,697	299,802	2,712	649,911
6	Demand-related	Sch. B	801,949	CP Demand	386,145	94,867	481,012	24,655	17,093	278,317	320,065	872	801,949
7	Customer-related	Sch. B	296,157	# of Cust.	257,082		257,082	36,367			36,367	2,708	296,157
8	Sub-total Generation	CALC	1,748,017		922,108	163,383	1,085,491	84,116	33,104	539,014	656,234	6,292	1,748,017
	Purchased Power Costs												
9	Energy-related	Sch. B	6,388,878	kWh Sales	2,741,517	673,531	3,415,048	227,024	157,396	2,562,751	2,947,170	26,659	6,388,878
	Distribution												
10	Demand-related	Sch. B	1,789,511	NCP Demand	768,065	188,697	956,762	63,899	44,301	721,322	829,522	3,227	1,789,511
	Administrative & General												
11	Generation-related	Sch. B	483,168	CP Demand	232,649	57,157	289,806	14,854	10,299	167,683	192,836	526	483,168
12	Distribution-related	Sch. B	1,183,138	NCP Demand	507,807	124,757	632,565	42,247	29,290	476,903	548,439	2,133	1,183,138
13	Customer-related	Sch. B	365,903	# of Cust	317,625		317,625	44,932			44,932	3,346	365,903
14	Sub-total Administrative & General	CALC	2,032,208		1,058,082	181,914	1,239,996	102,033	39,588	644,586	786,208	6,005	2,032,208
15	Total Operating Expenses	CALC	11,958,614		5,489,772	1,207,525	6,697,297	477,072	274,390	4,467,673	5,219,134	42,183	11,958,614
	Other Requirements												
	Annual Debt Service												
16	Generation-related	Sch. B	384,364	CP Demand	185,074	45,469	230,543	11,817	8,193	133,394	153,403	418	384,364
17	Distribution-related	Sch. B	816,719	NCP Demand	350,539	86,120	436,659	29,163	20,219	329,206	378,587	1,473	816,719
18	Customer-related	Sch. B	0	# of Cust	-		-	-			-	-	-
19	Total Debt Service	CALC	1,201,083		535,613	131,589	667,202	40,980	28,411	462,599	531,990	1,891	1,201,083
	Capital Adds Paid from Cash												
20	Generation-related	Sch. B	235,193	CP Demand	113,247	27,822	141,070	7,231	5,013	81,624	93,868	256	235,193
21	Distribution-related	Sch. B	1,209,786	NCP Demand	519,245	127,567	646,813	43,198	29,950	487,645	560,792	2,181	1,209,786
22	Customer-related	Sch. B	25,231	# of Cust	21,902		21,902	3,098			3,098	231	25,231
23	Total Capital Additions	CALC	1,470,211		654,395	155,390	809,785	53,527	34,963	569,268	657,759	2,668	1,470,211

SCHEDULE A

Heber Light and Power
Electric Utility Cost of Service Study

COST OF SERVICE
Allocation of Revenue Requirements
for the Projected Test Year FY 2015
($)

Ln.	Description	Ref.	Projected Test Year Rev. Req.	Allocation Basis	Residential			Commercial				Street Lights	Total System
					Tier 1	Tier 2	Total	Tier 1	Tier 2	Tier 3	Total		
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Other Requirements (cont.)												
	Reserve Funding												
24	Generation-related		21,596	CP Demand	10,399	2,555	12,954	664	460	7,495	8,619	23	21,596
25	Distribution-related		111,087	NCP Demand	47,679	11,714	59,393	3,967	2,750	44,777	51,494	200	111,087
26	Customer-related		2,317	# of Cust	2,011		2,011	284			284	21	2,317
27	Total Reserve Funding		135,000		60,089	14,268	74,357	4,915	3,210	52,272	60,398	245	135,000
28	Total Other Requirements	CALC	2,806,294		1,250,097	301,247	1,551,344	99,422	66,584	1,084,140	1,250,147	4,803	2,806,294
29	Sub-total Revenue Requirements	CALC	14,764,908		6,739,869	1,508,772	8,248,641	576,494	340,974	5,551,813	6,469,281	46,986	14,764,908
	Revenue Credits												
30	Genation - Demand	Sch. B	(14,181)	CP Demand	(6,828)	(1,678)	(8,506)	(436)	(302)	(4,921)	(5,660)	(15)	(14,181)
31	Generation - Energy	Sch. B	(27,604)	kWh Sales	(11,845)	(2,910)	(14,755)	(981)	(680)	(11,073)	(12,734)	(115)	(27,604)
32	Distribution-related	Sch. B	(106,564)	NCP Demand	(45,738)	(11,237)	(56,975)	(3,805)	(2,638)	(42,954)	(49,398)	(192)	(106,564)
33	Customer-related	Sch. B	(2,704)	# of Cust	(2,348)		(2,348)	(332)			(332)	(25)	(2,704)
34	Total Revenue Credits	CALC	(151,054)		(66,759)	(15,824)	(82,583)	(5,554)	(3,620)	(58,949)	(68,123)	(347)	(151,054)
35	Sub-total Net Revenue Requirements	CALC	14,613,854		6,673,110	1,492,948	8,166,058	570,940	337,353	5,492,864	6,401,158	46,639	14,613,854
36	Annual Dividends (Return)	Sch. B	300,000	Sub-total R.R.	136,989	30,648	167,637	11,721	6,925	112,760	131,406	957	300,000
37	Total Net Revenue Requirements	CALC	14,913,854		6,810,099	1,523,596	8,333,694	582,661	344,279	5,605,624	6,532,564	47,596	14,913,854
	Demand Related Rev. Requirements												
38	Operating Expenses	CALC	4,257,765		1,894,666	465,479	2,360,145	145,655	100,983	1,644,225	1,890,863	6,758	4,257,765
39	Other Requirements	CALC	2,778,746		1,226,184	301,247	1,527,431	96,040	66,584	1,084,140	1,246,764	4,552	2,778,746
40	Revenue Credits	CALC	(120,745)		(52,566)	(12,914)	(65,480)	(4,241)	(2,940)	(47,876)	(55,057)	(208)	(120,745)
41	Sub-Total Demand Related	CALC	6,915,766		3,068,284	753,811	3,822,095	237,454	164,627	2,680,489	3,082,569	11,102	6,915,766
42	Add: Annual Dividends	CALC	141,970		62,987	15,475	78,462	4,875	3,380	55,026	63,280	228	141,970
43	Total Demand Related	CALC	7,057,736		3,131,271	769,286	3,900,557	242,328	168,006	2,735,515	3,145,850	11,329	7,057,736
	Energy Related Rev. Requirements												
44	Operating Expenses	CALC	7,038,789		3,020,399	742,047	3,762,445	250,118	173,407	2,823,448	3,246,972	29,371	7,038,789
45	Revenue Credits	CALC	(27,604)		(11,845)	(2,910)	(14,755)	(981)	(680)	(11,073)	(12,734)	(115)	(27,604)
46	Sub-Total Energy Related	CALC	7,011,185		3,008,553	739,137	3,747,690	249,137	172,727	2,812,375	3,234,239	29,256	7,011,185
47	Add: Annual Dividends	CALC	143,929		61,761	15,173	76,934	5,114	3,546	57,734	66,394	601	143,929
48	Total Energy Related	CALC	7,155,114		3,070,314	754,310	3,824,624	254,251	176,273	2,870,109	3,300,633	29,857	7,155,114
49	Sub-total Demand and Energy	CALC	14,212,850		6,201,586	1,523,596	7,725,181	496,579	344,279	5,605,624	6,446,482	41,186	14,212,850

Heber Light and Power
Electric Utility Cost of Service Study

COST OF SERVICE
Allocation of Revenue Requirements
for the Projected Test Year FY 2015
($)

Ln.	Description	Ref.	Projected Test Year Rev. Req.	Allocation Basis	Residential			Commercial				Street Lights	Total System
					Tier 1	Tier 2	Total	Tier 1	Tier 2	Tier 3	Total		
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Customer Related Rev. Requirements												
50	Operating Expenses	CALC	662,060		574,707		574,707	81,299			81,299	6,054	662,060
51	Other Requirements	CALC	27,548		23,913		23,913	3,383			3,383	252	27,548
	Revnue Credits	CALC	(2,704)		(2,348)		(2,348)	(332)			(332)	(25)	(2,704)
52	Sub-Total Customer Related	CALC	686,903		596,273	-	596,273	84,350	-	-	84,350	6,281	686,903
53	Add: Annual Dividends	CALC	14,101		12,241	-	12,241	1,732	-	-	1,732	129	14,101
54	Total Customer Related	CALC	701,005		608,513	-	608,513	86,081	-	-	86,081	6,410	701,005
55	Total Revenue Requirements	CALC	14,913,854		6,810,099	1,523,596	8,333,694	582,661	344,279	5,605,624	6,532,564	47,596	14,913,854

SCHEDULE B

Heber Light and Power
Electric Utility Cost of Service Study

COST OF SERVICE
Analysis of Revenue Requirements
for the Projected Test Year FY 2015
($)

Ln.	Description	Unadjusted Rev. Req. [1]	Adjustments	Rev. Req. for Allocation	Generation Related			Distribution Related	Customer Related	Total Rev. Req.
					Demand	Energy	Total			
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Generation									
1	Gas Generation	629,911	-	629,911	-	629,911	629,911	-	-	629,911
2	Heber Gas Plant	-	-	-	-	-	-	-	-	-
3	O & M Generation Plants	238,027	-	238,027	238,027	-	238,027	-	-	238,027
4	Energy Rebates	20,000	-	20,000		20,000	20,000	-	-	20,000
5	Wages - Plants [2]	587,650	-	587,650	369,451	-	369,451	-	218,199	587,650
6	Insurance Costs	158,311	-	158,311	158,311	-	158,311	-	-	158,311
7	Employee Benefits & Retire. [2]	114,119	-	114,119	36,161	-	36,161	-	77,958	114,119
8	Sub-total Generation	1,748,017	-	1,748,017	801,949	649,911	1,451,860	-	296,157	1,748,017
	Purchased Power Costs									
9	Total (w/o Contingency)	6,388,878	-	6,388,878	-	6,388,878	6,388,878	-	-	6,388,878
10	Contingency	-	-	-	-	-	-	-	-	-
11	UAMPS Line Items	-	-	-	-	-	-	-	-	-
12	Total Purchased Power Costs	6,388,878	-	6,388,878	-	6,388,878	6,388,878	-	-	6,388,878
	Distribution									
13	Wages - Distribution System	849,891	-	849,891	-	-	-	849,891	-	849,891
14	Repairs and Maintenance	263,131	-	263,131	-	-	-	263,131	-	263,131
15	Materials	49,865	-	49,865	-	-	-	49,865	-	49,865
16	Vehicle Expense	119,942	-	119,942	-	-	-	119,942	-	119,942
17	Communications	130,845	-	130,845	-	-	-	130,845	-	130,845
18	Depreciation	1,860,000	(1,860,000)	-	-	-	-	-	-	-
19	Medical Insurance	209,087	-	209,087	-	-	-	209,087	-	209,087
20	Employee Benefits & Retirement	166,750	-	166,750	-	-	-	166,750	-	166,750
21	Total Distribution Expenses	3,649,511	(1,860,000)	1,789,511	-	-	-	1,789,511	-	1,789,511
	Administrative & General [3]									
22	Salaries	828,517	-	828,517	200,035	-	200,035	489,829	138,653	828,517
23	Board Compensation	35,814	-	35,814	8,647	-	8,647	21,174	5,993	35,814
24	Building Expenses	43,400	-	43,400	10,478	-	10,478	25,659	7,263	43,400
25	Office Supplies	79,580	-	79,580	19,214	-	19,214	47,049	13,318	79,580
26	Travel & Training	71,381	-	71,381	17,234	-	17,234	42,201	11,946	71,381
27	Misc/Professional Services	162,035	-	162,035	39,121	-	39,121	95,797	27,117	162,035
28	Medical Insurance	245,564	-	245,564	59,288	-	59,288	145,180	41,095	245,564
29	Employee Benefits & Retirement	158,364	-	158,364	38,235	-	38,235	93,627	26,502	158,364
30	Payroll Taxes	201,553	-	201,553	48,663	-	48,663	119,160	33,730	201,553
31	Liability Insurance	175,000	-	175,000	42,252	-	42,252	103,462	29,286	175,000
32	Bad Debt Expense	31,000	-	31,000	-	-	-	-	31,000	31,000
33	Total A&G Expenses	2,032,208	-	2,032,208	483,168	-	483,168	1,183,138	365,903	2,032,208
34	Total Operating Expenses	13,818,614	(1,860,000)	11,958,614	1,285,117	7,038,789	8,323,906	2,972,648	662,060	11,958,614

Heber Light and Power
Electric Utility Cost of Service Study

COST OF SERVICE
Analysis of Revenue Requirements
for the Projected Test Year FY 2015
($)

Ln.	Description	Unadjusted Rev. Req. [1]	Adjustments	Rev. Req. for Allocation	Generation Related Demand	Generation Related Energy	Generation Related Total	Distribution Related	Customer Related	Total Rev. Req.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Other Revenue Requirements									
35	Annual Debt Service [4]	1,201,083	-	1,201,083	384,364	-	384,364	816,719	-	1,201,083
36	Capital Adds Paid from Cash	1,470,211	-	1,470,211	235,193	-	235,193	1,209,786	25,231	1,470,211
37	Reserve Funding	135,000	-	135,000	21,596	-	21,596	111,087	2,317	135,000
38	Total Other Revenue Requirements	2,806,294	-	2,806,294	641,154	-	641,154	2,137,592	27,548	2,806,294
39	Sub-total Revenue Requirements	16,624,908	(1,860,000)	14,764,908	1,926,271	7,038,789	8,965,060	5,110,241	689,608	14,764,908
	Revenue Credits									
40	Connection Fees	(31,091)	-	(31,091)	-	-	-	(31,091)	-	(31,091)
41	Interest Income	(20,707)	-	(20,707)	(6,627)	-	(6,627)	(14,080)	-	(20,707)
42	Pole Attachment Revenue	(41,352)	-	(41,352)	-	-	-	(41,352)	-	(41,352)
43	Receivables Penalty Income	(57,904)	-	(57,904)	(7,554)	(27,604)	(35,159)	(20,041)	(2,704)	(57,904)
44	Total Revenue Credits	(151,054)	-	(151,054)	(14,181)	(27,604)	(41,785)	(106,564)	(2,704)	(151,054)
45	Sub-Total Revenue Requirements	16,473,854	(1,860,000)	14,613,854	1,912,090	7,011,185	8,923,275	5,003,676	686,903	14,613,854
46	Annual Dividends (Return)	300,000	-	300,000	39,252	143,929	183,181	102,718	14,101	300,000
47	Total Revenue Requirements	16,773,854	(1,860,000)	14,913,854	1,951,342	7,155,114	9,106,456	5,106,394	701,005	14,913,854

[1] Primary source for inputs is the 2015 Master Budget.
[2] Customer-related salaries provided by HLP.
[3] Allocation based on Distribution of Salaries & Wages to Generation, Distribution and Customer functions.

	Total Wages	G&D Allocation	G,D & C Allocation
Generation (Adjusted)	347,077	29.00%	24.14%
Distribution	849,891	71.00%	59.12%
Sub-total G&T	1,196,968	100.00%	
Customer	240,573		16.74%
Total	1,437,541		100.00%

[4] Based on an analysis of average debt service for years 2015-2019.
[5] Capital Additions and Reserve Funding funtionalized using the Gross Plant In Service balances as of year-end 2014.
General Plant portion was functionalized based on the distribution of Salaries and Wages shown above.

	Gross Plant	Percent of Total	Capital Additions	Reserve Funding
Generation	$ 6,656,076	13.52%	$ 198,792	18,254
Distribution	37,522,285	76.22%	1,120,650	102,902
General	5,048,138	10.25%	150,769	13,844
Total	$ 49,226,499	100.00%	$ 1,470,211	$ 135,000

Heber Light and Power
Electric Utility Cost of Service Study

KWH SALES ALLOCATION FACTORS
For the Projected Test Year FY 2015

Ln.	Description	Ref.	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	Percent of Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(j)	(k)	(l)	(m)	(n)
	Year 2012															
	kWh Sales															
1	Residential	[1]	8,081,838	7,134,160	6,342,037	5,542,158	5,023,049	5,553,442	6,671,245	7,296,432	6,137,125	5,257,903	6,356,570	5,666,464	75,062,423	53.60%
2	Commercial	[1]	5,332,418	5,434,315	4,877,117	4,872,926	5,238,195	5,829,072	6,035,135	6,398,187	5,931,016	5,002,304	5,071,468	4,952,913	64,975,066	46.40%
3	Total	CALC	13,414,256	12,568,475	11,219,154	10,415,084	10,261,244	11,382,514	12,706,380	13,694,619	12,068,141	10,260,207	11,428,038	10,619,377	140,037,489	100.00%
	Number of Customers															
4	Residential	Sch. D	8,471	8,484	8,495	8,546	8,632	8,691	8,763	8,826	8,859	8,861	8,802	8,766	104,196	88.30%
5	Commercial	Sch. D	1,138	1,129	1,133	1,132	1,150	1,163	1,155	1,169	1,168	1,162	1,164	1,144	13,807	11.70%
6	Total	CALC	9,609	9,613	9,628	9,678	9,782	9,854	9,918	9,995	10,027	10,023	9,966	9,910	118,003	100.00%
	Average Usage per Customer															
7	Residential	CALC	954.1	840.9	746.6	648.5	581.9	639.0	761.3	826.7	692.8	593.4	722.2	646.4	720.4	
8	Commercial	CALC	4,685.8	4,813.4	4,304.6	4,304.7	4,555.0	5,012.1	5,225.2	5,473.2	5,077.9	4,304.9	4,356.9	4,329.5	4,706.0	
	Year 2013															
	kWh Sales															
9	Residential	[1]	8,962,117	8,033,280	6,325,608	5,979,944	5,157,596	5,931,472	7,597,175	7,228,737	6,366,561	5,700,581	6,441,754	8,320,128	82,044,953	54.90%
10	Commercial	[1]	5,855,807	5,591,399	4,857,678	4,910,878	5,313,838	6,218,177	6,354,693	6,494,096	5,947,677	5,177,633	5,233,994	5,430,312	67,386,182	45.10%
11	Total	CALC	14,817,924	13,624,679	11,183,286	10,890,822	10,471,434	12,149,649	13,951,868	13,722,833	12,314,238	10,878,214	11,675,748	13,750,440	149,431,135	100.00%
	Number of Customers															
12	Residential	Sch. D	8,778	8,784	8,837	8,881	8,923	9,004	9,054	9,060	9,097	9,132	9,092	9,071	107,713	88.25%
13	Commercial	Sch. D	1,162	1,173	1,171	1,181	1,193	1,195	1,192	1,211	1,214	1,212	1,223	1,208	14,335	11.75%
14	Total	CALC	9,940	9,957	10,008	10,062	10,116	10,199	10,246	10,271	10,311	10,344	10,315	10,279	122,048	100.00%
	Average Usage per Customer															
15	Residential	CALC	1,021.0	914.5	715.8	673.3	578.0	658.8	839.1	797.9	699.9	624.2	708.5	917.2	761.7	
16	Commercial	CALC	5,039.4	4,766.8	4,148.3	4,158.2	4,454.2	5,203.5	5,331.1	5,362.6	4,899.2	4,272.0	4,279.6	4,495.3	4,700.8	
	Year 2014															
	kWh Sales															
17	Residential	[1]	8,748,427	7,811,762	6,054,936	6,061,988	5,581,577	5,835,041	7,426,555	6,839,670	6,434,835	5,767,291	6,290,442	7,779,232	80,631,756	53.57%
18	Commercial	[1]	5,874,415	5,563,034	4,817,651	5,154,834	5,669,903	6,351,078	7,114,006	6,443,991	6,619,889	5,520,150	5,242,287	5,517,778	69,889,016	46.43%
19	Total	CALC	14,622,842	13,374,796	10,872,587	11,216,822	11,251,480	12,186,119	14,540,561	13,283,661	13,054,724	11,287,441	11,532,729	13,297,010	150,520,772	100.00%
	Number of Customers															
20	Residential	Sch. D	9,054	9,058	9,110	9,186	9,283	9,298	9,394	9,399	9,469	9,455	9,446	9,415	111,567	87.59%
21	Commercial	Sch. D	1,306	1,310	1,307	1,316	1,316	1,306	1,318	1,317	1,322	1,335	1,325	1,329	15,807	12.41%
22	Total	CALC	10,360	10,368	10,417	10,502	10,599	10,604	10,712	10,716	10,791	10,790	10,771	10,744	127,374	100.00%
	Average Usage per Customer															
23	Residential	CALC	966.2	862.4	664.6	659.9	601.3	627.6	790.6	727.7	679.6	610.0	665.9	826.3	722.7	
24	Commercial	CALC	4,498.0	4,246.6	3,686.0	3,917.0	4,308.4	4,863.0	5,397.6	4,892.9	5,007.5	4,134.9	3,956.4	4,151.8	4,421.4	
	3-Year Avg. Usage per Customer															
25	Residential	CALC	980.4	872.6	709.0	660.6	587.1	641.8	797.0	784.1	690.7	609.2	698.9	796.6	734.9	
26	Commercial	CALC	4,741.1	4,608.9	4,046.3	4,126.7	4,439.2	5,026.2	5,318.0	5,242.9	4,994.9	4,237.3	4,197.7	4,325.5	4,609.4	

Heber Light and Power
Electric Utility Cost of Service Study

KWH SALES ALLOCATION FACTORS
For the Projected Test Year FY 2015

Ln.	Description	Ref.	JAN (a)	FEB (b)	MAR (c)	APR (d)	MAY (e)	JUN (f)	JUL (g)	AUG (h)	SEP (i)	OCT (j)	NOV (k)	DEC (l)	Total (m)	Percent of Total (n)
	Year 2015 - Projected															
	Estimated No. of Customers															
27	Residential	Sch. D	9,431	9,446	9,462	9,478	9,494	9,510	9,525	9,541	9,557	9,573	9,589	9,605	114,211	
28	Commercial	Sch. D	1,331	1,333	1,336	1,338	1,340	1,342	1,345	1,347	1,349	1,351	1,354	1,356	16,122	
29	Total	CALC	10,762	10,780	10,798	10,816	10,834	10,852	10,870	10,888	10,906	10,924	10,943	10,961	130,333	
	Average Usage per Customer															
30	Residential	CALC [2]	966.2	862.4	664.6	659.9	601.3	627.6	790.6	727.7	679.6	610.0	665.9	826.3	8,682	
31	Commercial	CALC [2]	4,498.0	4,246.6	3,686.0	3,917.0	4,308.4	4,863.0	5,397.6	4,892.9	5,007.5	4,134.9	3,956.4	4,151.8	53,060	
	Estimated kWh Sales															
32	Residential	CALC	9,112,405	8,146,732	6,288,994	6,254,633	5,708,277	5,967,797	7,530,429	6,943,199	6,494,753	5,839,328	6,385,707	7,936,251	82,608,504	53.68%
33	Commercial	CALC	5,987,833	5,662,547	4,923,278	5,240,548	5,773,788	6,527,826	7,257,488	6,589,916	6,755,434	5,587,619	5,355,319	5,629,151	71,290,747	46.32%
34	Total	CALC	15,100,238	13,809,280	11,212,272	11,495,181	11,482,064	12,495,623	14,787,917	13,533,115	13,250,186	11,426,947	11,741,026	13,565,402	153,899,251	100.00%
	kWh Consumption by Rate Schedule															
35	Residential Tier 1	[3]	6,436,442	6,120,996	5,365,896	5,225,131	4,719,721	5,061,862	5,824,314	5,788,717	5,454,829	4,893,211	5,520,299	5,904,660	66,316,078	42.91%
36	Residential Tier 2	[3]	2,728,592	2,098,421	1,093,675	873,840	544,675	1,002,908	1,955,476	1,610,761	1,058,508	581,020	1,097,035	1,647,515	16,292,426	10.54%
37	Total Residential		9,165,034	8,219,417	6,459,571	6,098,971	5,264,396	6,064,771	7,779,789	7,399,478	6,513,337	5,474,231	6,617,334	7,552,175	82,608,504	53.45%
38	Commercial Tier 1	[3]	476,766	469,485	453,841	451,852	443,120	447,244	453,796	462,700	458,204	460,768	458,927	454,899	5,491,600	3.55%
39	Commercial Tier 2	[3]	338,705	334,986	313,049	310,436	300,153	302,525	318,987	327,224	317,056	316,561	313,700	313,947	3,807,331	2.46%
40	Commercial Tier 3	[3]	5,498,190	5,221,880	4,462,295	4,203,856	4,974,654	5,952,431	6,078,515	6,210,847	5,630,506	4,286,805	4,798,195	4,673,643	61,991,816	40.11%
41	Total Commercial	CALC	6,313,662	6,026,351	5,229,185	4,966,144	5,717,926	6,702,200	6,851,298	7,000,771	6,405,766	5,064,133	5,570,822	5,442,489	71,290,747	46.13%
42	Security Lighting	[4]	53,740	53,740	53,740	53,740	53,740	53,740	53,740	53,740	53,740	53,740	53,740	53,740	644,878	0.42%
43	Total kWh Sales	CALC	15,532,436	14,299,507	11,742,495	11,118,855	11,036,062	12,820,711	14,684,827	14,453,989	12,972,843	10,592,104	12,241,896	13,048,404	154,544,130	100.00%

[1] Input from spreadsheet "Analysis of Historical Billing Data.xlsx."
[2] Assumes Residential and Commercial will experience same level of usage as experienced in 2014.
[3] Breakdown based on information contained in the 2014 Sales Forecast.
[4] Input from 2015 Sales Forecast worksheet but reduced by 1/3 to account for the number of LED lights in the system.

SCHEDULE D

Heber Light & Power
Electric Utility Cost of Service Study

CUSTOMER ALLOCATION FACTORS
For the Projected Test Year FY 2015

Ln.	Description	Ref.	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Average	Percent of Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Year 2012															
1	Residential	[1]	8,471	8,484	8,495	8,546	8,632	8,691	8,763	8,826	8,859	8,861	8,802	8,766	8,683	88.30%
2	Commercial	[1]	1,138	1,129	1,133	1,132	1,150	1,163	1,155	1,169	1,168	1,162	1,164	1,144	1,151	11.70%
3	Total		9,609	9,613	9,628	9,678	9,782	9,854	9,918	9,995	10,027	10,023	9,966	9,910	9,834	100.00%
	Year 2013															
4	Residential	[1]	8,778	8,784	8,837	8,881	8,923	9,004	9,054	9,060	9,097	9,132	9,092	9,071	8,976	88.25%
5	Commercial	[1]	1,162	1,173	1,171	1,181	1,193	1,195	1,192	1,211	1,214	1,212	1,223	1,208	1,195	11.75%
6	Total		9,940	9,957	10,008	10,062	10,116	10,199	10,246	10,271	10,311	10,344	10,315	10,279	10,171	100.00%
	Year 2014															
7	Residential	[1]	9,054	9,058	9,110	9,186	9,283	9,298	9,394	9,399	9,469	9,455	9,446	9,415	9,297	87.59%
8	Commercial	[1]	1,306	1,310	1,307	1,316	1,316	1,306	1,318	1,317	1,322	1,335	1,325	1,329	1,317	12.41%
9	Total		10,360	10,368	10,417	10,502	10,599	10,604	10,712	10,716	10,791	10,790	10,771	10,744	10,615	100.00%
	Customer Growth Rate (Percent)															
10	Residential	CALC	3.38%	3.33%	3.56%	3.68%	3.70%	3.43%	3.54%	3.20%	3.39%	3.30%	3.59%	3.64%	3.48%	
11	Commercial	CALC	7.13%	7.72%	7.40%	7.82%	6.97%	5.97%	6.82%	6.14%	6.39%	7.19%	6.69%	7.78%	7.00%	
12	Total	CALC	3.83%	3.85%	4.02%	4.17%	4.09%	3.74%	3.93%	3.54%	3.74%	3.76%	3.96%	4.12%	3.89%	
	Year 2015 (Projected)															
	Estimated Number of Customers															
13	Residential	CALC [3]	9,431	9,446	9,462	9,478	9,494	9,510	9,525	9,541	9,557	9,573	9,589	9,605	9,483	87.59%
14	Less: Estimated SL Accounts	[4]	85	85	85	85	85	85	85	85	85	85	85	85	85	0.79%
15	Net Residential	CALC	9,346	9,361	9,377	9,393	9,409	9,425	9,440	9,456	9,472	9,488	9,504	9,520	9,398	86.81%
16	Commercial	CALC [3]	1,331	1,333	1,336	1,338	1,340	1,342	1,345	1,347	1,349	1,351	1,354	1,356	1,343	12.41%
17	Less: Estimated SL Accounts	[4]	14	14	14	14	14	14	14	14	14	14	14	14	14	0.13%
18	Net Commercial	CALC	1,317	1,319	1,322	1,324	1,326	1,328	1,331	1,333	1,335	1,337	1,340	1,342	1,329	12.28%
19	Total Street Light Accounts	CALC	99	99	99	99	99	99	99	99	99	99	99	99	99	0.91%
20	Total Customers	CALC	10,762	10,780	10,798	10,816	10,834	10,852	10,870	10,888	10,906	10,924	10,943	10,961	10,827	100.00%

[1] Input from spreadsheet "Analysis of Historical Billing Data.xlsx."
[2] Estimated based on a review of historical billing data for year 2010.
[3] Based on an assumed customer growth rate of 2.00%
[4] Based on information supplied by HLP -- represents the number of street light accounts.

SCHEDULE E

Heber Light & Power
Electric Utility Cost of Service Study

DEMAND ALLOCATION FACTORS - NON-COINCIDENT PEAK
For the Projected Test Year 2015

			Estimated NCP Demands (kW)									
			Residential			Commercial				Street Lights	Total System
Ln.	Description	Ref.	Tier 1	Tier 2	Total	Tier 1	Tier 2	Tier 3	Total		
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(j)	(k)
	Projected 2014										
1	kWh Sales	Sch. C	66,316,078	16,292,426	82,608,504	5,491,600	3,807,331	61,991,816	71,290,747	644,878	154,544,130
2	NCP Load Factor	CALC	43.2000%	43.2000%	43.2000%	43.0000%	43.0000%	43.0000%	43.0000%	100.0000%	43.2097%
3	Estimated NCP Demand	CALC	17,523.9	4,305.2	21,829.2	1,457.9	1,010.8	16,457.4	18,926.1	73.6	40,829
4	Percent of Total	CALC	42.9204%	10.5446%	53.4650%	3.5707%	2.4756%	40.3083%	46.3547%	0.1803%	100.0000%
5	"Proxy" NCP Load Factors	[1]	0.4320	0.4320	0.4320	0.4300	0.4300	0.4300	0.4300	1.0000	N/A

[1] Residenital load factor estimated based on information contained in RMP's most recent rate filing before the UPSC, Docket No. 13-035-184.
Commercial load factor based on an analysis of demand data supplied by HLP.

SCHEDULE F

Heber Light & Power
Electric Utility Cost of Service Study

DEMAND ALLOCATION FACTORS - 12-MONTH COINCIDENT PEAK
For the Projected Test Year 2015

Ln.	Description	Ref.	Residential Tier 1 (a)	Residential Tier 2 (b)	Residential Total (c)	Commercial Tier 1 (d)	Commercial Tier 2 (e)	Commercial Tier 3 (f)	Commercial Total (g)	Street Lights (j)	Total System (k)
			Estimated CP Demands (kW)								
	FY 2012										
1	Total kWh Sales	Sch. C	60,258,269	14,804,154	75,062,423	5,005,097	3,470,037	56,499,932	64,975,066	644,878	140,682,367
2	Class 12-CP Load Factor	[1]	55.9%	55.9%	55.9%	72.5%	72.5%	72.5%	72.5%	256.1%	
3	Preliminary 12-CP kW Demand	CALC	12,305.5	3,023.2	15,328.7	788.1	546.4	8,896.2	10,230.7	28.7	25,588.2
4	Percent of Total System	CALC	48.09%	11.81%	59.91%	3.08%	2.14%	34.77%	39.98%	0.11%	100.00%
5	12-CP kW Demand (Fit to Actual)	CALC	11,274.2	2,769.8	14,044.0	722.0	500.6	8,150.6	9,373.2	26.3	23,443.6
6	Restated LF Based on 12-CP Fit	CALC	61.0%	61.0%	61.0%	79.1%	79.1%	79.1%	79.1%	279.6%	68.5%
	FY 2013										
7	Total kWh Sales	Sch. C	65,863,673	16,181,280	82,044,953	5,190,827	3,598,805	58,596,550	67,386,182	644,878	150,076,013
8	Class 12-CP Load Factor	[1]	55.9%	55.9%	55.9%	72.5%	72.5%	72.5%	72.5%	225.0%	
9	Preliminary 12-CP kW Demand	CALC	13,450.2	3,304.4	16,754.7	817.3	566.7	9,226.4	10,610.3	32.7	27,397.7
10	Percent of Total System	CALC	49.09%	12.06%	61.15%	2.98%	2.07%	33.68%	38.73%	0.12%	100.00%
11	12-CP kW Demand (Fit to Actual)	CALC	12,441.2	3,056.5	15,497.8	756.0	524.1	8,534.2	9,814.4	30.3	25,342.4
12	Restated LF Based on 12-CP Fit	CALC	60.4%	60.4%	60.4%	78.4%	78.4%	78.4%	78.4%	243.2%	67.6%
	FY 2014										
	Total kWh Sales	Sch. C	64,729,193	15,902,563	80,631,756	5,383,623	3,732,470	60,772,922	69,889,016	644,878	151,165,650
	Class 12-CP Load Factor	[1]	55.9%	55.9%	55.9%	72.5%	72.5%	72.5%	72.5%	225.0%	
	Preliminary 12-CP kW Demand	CALC	13,218.6	3,247.5	16,466.1	847.7	587.7	9,569.0	11,004.4	32.7	27,503.2
	Percent of Total System	CALC	48.25%	11.85%	60.10%	3.09%	2.15%	34.93%	40.17%	0.12%	100.39%
	12-CP kW Demand (Fit to Actual)	CALC	11,779.3	2,893.9	14,673.2	755.4	523.7	8,527.1	9,806.2	30.3	24,414.6
	Restated LF Based on 12-CP Fit	CALC	62.7%	62.7%	62.7%	81.4%	81.4%	81.4%	81.4%	243.2%	70.7%
	3-Year Average										
13	12-CP kW Demand	CALC	11,831.6	2,906.8	14,738.3	744.5	516.1	8,404.0	9,664.6	28.3	24,393.0
14	Percent of Total System	CALC	48.50%	11.92%	60.42%	3.05%	2.12%	34.45%	39.62%	0.12%	100.00%
15	Load Factor	CALC	60.7%	60.7%	60.7%	78.8%	78.8%	78.8%	78.8%	261.4%	68.1%
	Projected 2015										
16	kWh Sales	Sch. C	66,316,078	16,292,426	82,608,504	5,491,600	3,807,331	61,991,816	71,290,747	644,878	154,544,130
17	12-CP Load Factor	CALC	60.7%	60.7%	60.7%	78.8%	78.8%	78.8%	78.8%	261.4%	68.1%
18	12-CP kW Demand	CALC	12,467	3,063	15,530	796	552	8,986	10,333	28	25,891.3
	Fit to Load Forecast	CALC	12,756	3,134	15,890	814	565	9,194	10,573	29	26,492.0
19	Percent of Total	CALC	48.1508%	11.8296%	59.9804%	3.0744%	2.1315%	34.7050%	39.9109%	0.1088%	100.0000%

Ln.	Annual System Summary	System Energy	Average kW Demand	12-month Avg. CP at System Input	Assumed Annual Loss Factor	Estimated 12-CP at Meter	12-CP Load Factor	Ratio of Metered 12-CP to 12-CP at System Input
20	FY 2010	144,753,058	16,524	24,042	6.00%	22,599	0.6873	0.9400
21	FY 2011	142,171,059	16,230	23,641	6.00%	22,223	0.6865	0.9400
22	FY 2012	145,499,976	16,610	24,940	6.00%	23,444	0.6660	0.9400
23	FY 2013	164,309,864	18,757	26,960	6.00%	25,342	0.6957	0.9400
24	FY 2014	165,003,160	18,836	25,973	6.00%	24,415	0.7252	0.9400
25	Average	152,347,423	17,391	25,111	6.00%	23,605	0.6926	0.9400

[1] Based on information obtained from Rocky Mountain Power's most recent retail rate case before the UPSC, Docket No. 13-035-184.

Heber Light & Power
Electric Utility Cost of Service Study

ESTIMATED REVENUES UNDER EXISTING BASE RATES
For the Projected Test Year 2015

Ln.	Description	Ref.	Residential Tier 1	Residential Tier 2	Residential Total	Commercial Tier 1	Commercial Tier 2	Commercial Tier 3	Commercial Total	Street Lights	Total System
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Existing Base Rates										
	Residential										
1	Base Charge		12.00								
	Energy Charge										
2	First 1000 kWh		0.07525								
3	Over 1000 kWh			0.09450							
	Commercial										
4	Minimum Monthly					6.50	6.50	6.50			
	Energy Charge										
5	First 500 kWh					0.1492					
6	Next 500 kWh						0.1045				
	All Additional kWh							0.0799			
	Street Lights (Charge per Light)										
	High Pressure Sodium										
7	150 Watts									6.50	
	Projected kWh Sales (kWh)										
8	January	Sch. C	6,436,442	2,728,592	9,165,034	476,766	338,705	5,498,190	6,313,662	53,740	15,532,436
9	February	Sch. C	6,120,996	2,098,421	8,219,417	469,485	334,986	5,221,880	6,026,351	53,740	14,299,507
10	March	Sch. C	5,365,896	1,093,675	6,459,571	453,841	313,049	4,462,295	5,229,185	53,740	11,742,495
11	April	Sch. C	5,225,131	873,840	6,098,971	451,852	310,436	4,203,856	4,966,144	53,740	11,118,855
12	May	Sch. C	4,719,721	544,675	5,264,396	443,120	300,153	4,974,654	5,717,926	53,740	11,036,062
13	June	Sch. C	5,061,862	1,002,908	6,064,771	447,244	302,525	5,952,431	6,702,200	53,740	12,820,711
14	July	Sch. C	5,824,314	1,955,476	7,779,789	453,796	318,987	6,078,515	6,851,298	53,740	14,684,827
15	August	Sch. C	5,788,717	1,610,761	7,399,478	462,700	327,224	6,210,847	7,000,771	53,740	14,453,989
16	September	Sch. C	5,454,829	1,058,508	6,513,337	458,204	317,056	5,630,506	6,405,766	53,740	12,972,843
17	October	Sch. C	4,893,211	581,020	5,474,231	460,768	316,561	4,286,805	5,064,133	53,740	10,592,104
18	November	Sch. C	5,520,299	1,097,035	6,617,334	458,927	313,700	4,798,195	5,570,822	53,740	12,241,896
19	December	Sch. C	5,904,660	1,647,515	7,552,175	454,899	313,947	4,673,643	5,442,489	53,740	13,048,404
20	Total	CALC	66,316,078	16,292,426	82,608,504	5,491,600	3,807,331	61,991,816	71,290,747	644,878	154,544,130
21	Percent of Total System	CALC	42.911%	10.542%	53.453%	3.553%	2.464%	40.113%	46.130%	0.417%	100.000%
22	Average Number of Customers (Lights)	Sch. D	9,398		9,398				1,329	1,183	11,911

Heber Light & Power
Electric Utility Cost of Service Study

ESTIMATED REVENUES UNDER EXISTING BASE RATES
For the Projected Test Year 2015

Ln.	Description	Ref.	Residential Tier 1	Residential Tier 2	Residential Total	Commercial Tier 1	Commercial Tier 2	Commercial Tier 3	Commercial Total	Street Lights	Total System
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Estimated Revenue ($)										
23	**Base Charge**	CALC	1,353,340		1,353,340					92,274	1,445,614
	Energy Charge										
24	January	CALC	484,342	257,852	742,194	71,134	35,395	439,305	545,834	-	1,288,028
25	February	CALC	460,605	198,301	658,906	70,047	35,006	417,228	522,281	-	1,181,187
26	March	CALC	403,784	103,352	507,136	67,713	32,714	356,537	456,964	-	964,100
27	April	CALC	393,191	82,578	475,769	67,416	32,441	335,888	435,745	-	911,514
28	May	CALC	355,159	51,472	406,631	66,113	31,366	397,475	494,954	-	901,585
29	June	CALC	380,905	94,775	475,680	66,729	31,614	475,599	573,942	-	1,049,622
30	July	CALC	438,280	184,792	623,072	67,706	33,334	485,673	586,714	-	1,209,786
31	August	CALC	435,601	152,217	587,818	69,035	34,195	496,247	599,476	-	1,187,294
32	September	CALC	410,476	100,029	510,505	68,364	33,132	449,877	551,374	-	1,061,879
33	October	CALC	368,214	54,906	423,121	68,747	33,081	342,516	444,343	-	867,463
34	November	CALC	415,403	103,670	519,072	68,472	32,782	383,376	484,629	-	1,003,702
35	December	CALC	444,326	155,690	600,016	67,871	32,807	373,424	474,102	-	1,074,118
36	Total	CALC	4,990,285	1,539,634	6,529,919	819,347	397,866	4,953,146	6,170,359	-	12,700,278
37	Average Energy Charge ($/kWh	CALC	0.0753	0.0945	0.0790	0.1492	0.1045	0.0799	0.0866	-	0.0822
38	**Total Revenues (Base Rate)**	CALC	6,343,625	1,539,634	7,883,259	819,347	397,866	4,953,146	6,170,359	92,274	14,145,892

Heber Light & Power
Electric Utility Cost of Service Study

ESTIMATED REVENUES UNDER PROPOSED RATES
For the Projected Test Year 2015
(Current Design Using Proposed 6.0% Increase by Rate Class)

Ln.	Description	Ref.	Residential Tier 1 (a)	Residential Tier 2 (b)	Residential Total (c)	Commercial Tier 1 (d)	Commercial Tier 2 (e)	Commercial Tier 3 (f)	Commercial Total (g)	Street Lights (h)	Total System (i)
	Proposed Base Rates										
1	**Proposed Base Rate Increase**		6.00%	6.00%		6.00%	6.00%	6.00%		6.00%	
	Residential										
2	Base Charge	CALC	12.72								
	Energy Charge										
3	First 1000 kWh	CALC	0.0798								
4	Over 1000 kWh	CALC		0.1002							
	Commercial										
	Energy Charge										
5	First 500 kWh	CALC				0.15820					
6	Next 500 kWh	CALC					0.11080				
7	All Additional kWh	CALC						0.08470			
	Street Lights (Charge per Light)										
	High Pressure Sodium										
8	150 Watts	CALC								6.89	
	Projected kWh Sales (kWh)										
9	January	CALC	6,436,442	2,728,592	9,165,034	476,766	338,705	5,498,190	6,313,662	53,740	15,532,436
10	February	CALC	6,120,996	2,098,421	8,219,417	469,485	334,986	5,221,880	6,026,351	53,740	14,299,507
11	March	CALC	5,365,896	1,093,675	6,459,571	453,841	313,049	4,462,295	5,229,185	53,740	11,742,495
12	April	CALC	5,225,131	873,840	6,098,971	451,852	310,436	4,203,856	4,966,144	53,740	11,118,855
13	May	CALC	4,719,721	544,675	5,264,396	443,120	300,153	4,974,654	5,717,926	53,740	11,036,062
14	June	CALC	5,061,862	1,002,908	6,064,771	447,244	302,525	5,952,431	6,702,200	53,740	12,820,711
15	July	CALC	5,824,314	1,955,476	7,779,789	453,796	318,987	6,078,515	6,851,298	53,740	14,684,827
16	August	CALC	5,788,717	1,610,761	7,399,478	462,700	327,224	6,210,847	7,000,771	53,740	14,453,989
17	September	CALC	5,454,829	1,058,508	6,513,337	458,204	317,056	5,630,506	6,405,766	53,740	12,972,843
18	October	CALC	4,893,211	581,020	5,474,231	460,768	316,561	4,286,805	5,064,133	53,740	10,592,104
19	November	CALC	5,520,299	1,097,035	6,617,334	458,927	313,700	4,798,195	5,570,822	53,740	12,241,896
20	December	CALC	5,904,660	1,647,515	7,552,175	454,899	313,947	4,673,643	5,442,489	53,740	13,048,404
21	Total	CALC	66,316,078	16,292,426	82,608,504	5,491,600	3,807,331	61,991,816	71,290,747	644,878	154,544,130
22	Percent of Total System	CALC	42.911%	10.542%	53.453%	3.553%	2.464%	40.113%	46.130%	0.417%	100.000%
23	Average Number of Customers (Lights)	Sch. D	9,398		9,398				1,329	237	10,965
24	Average Usage Per Customer	CALC	588.0		732.5				4,468.6	226.8	1,174.6

Heber Light & Power
Electric Utility Cost of Service Study

ESTIMATED REVENUES UNDER PROPOSED RATES
For the Projected Test Year 2015
(Current Design Using Proposed 6.0% Increase by Rate Class)

Ln.	Description	Ref.	Residential Tier 1	Residential Tier 2	Residential Total	Commercial Tier 1	Commercial Tier 2	Commercial Tier 3	Commercial Total	Street Lights	Total System
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Estimated Revenue ($)										
25	**Base Charge**	CALC	1,434,540		1,434,540					19,595	1,454,136
	Energy Charge										
26	January	CALC	513,403	273,323	786,726	75,424	37,529	465,697	578,650		1,365,376
27	February	CALC	488,241	210,199	698,440	74,272	37,116	442,293	553,682		1,252,122
28	March	CALC	428,011	109,553	537,564	71,798	34,686	377,956	484,440		1,022,004
29	April	CALC	416,783	87,533	504,315	71,483	34,396	356,067	461,946		966,261
30	May	CALC	376,469	54,560	431,029	70,102	33,257	421,353	524,712		955,740
31	June	CALC	403,759	100,461	504,221	70,754	33,520	504,171	608,445		1,112,665
32	July	CALC	464,576	195,880	660,456	71,790	35,344	514,850	621,984		1,282,441
33	August	CALC	461,737	161,350	623,087	73,199	36,256	526,059	635,514		1,258,601
34	September	CALC	435,104	106,031	541,135	72,488	35,130	476,904	584,522		1,125,657
35	October	CALC	390,307	58,201	448,508	72,893	35,075	363,092	471,061		919,568
36	November	CALC	440,327	109,890	550,217	72,602	34,758	406,407	513,767		1,063,984
37	December	CALC	470,985	165,032	636,017	71,965	34,785	395,858	502,608		1,138,625
38	Total	CALC	5,289,702	1,632,012	6,921,714	868,771	421,852	5,250,707	6,541,330	-	13,463,045
39	Average Energy Charge ($/kWh)	CALC	0.0798	0.1002	0.0838	0.1582	0.1108	0.0847	0.0918	-	0.0871
40	**Total Revenues (Base Rate)**	CALC	6,724,242	1,632,012	8,356,255	868,771	421,852	5,250,707	6,541,330	19,595	14,917,180
41	**Total Revenue Requirement per COS**	CALC	6,827,542	1,527,498	8,355,039	584,153	345,161	5,619,982	6,549,296	9,519	14,913,854
42	**Difference**	CALC	(103,299)	104,514	1,215	284,618	76,692	(369,275)	(7,965)	10,076	3,326
43	Assumed Monthly Usage	kWh/Cust.			750.0				4,650		
44	Proposed Weighted Average Rate	$/kWh			0.0967				0.0954		
45	Current Weighted Average Rate	$/kWh			0.0913				0.0900		
46	Percent Increase				6.00%				6.01%		

Heber Light & Power
Electric Utility Cost of Service Study

ESTIMATED REVENUES UNDER PROPOSED RATES
For the Projected Test Year 2015
(New Design Using Required Increase by Rate Class)

Ln.	Description	Ref.	Residential Tier 1	Residential Tier 2	Residential Total	Small General Service - <30kW Tier 1	Small General Service - <30kW Tier 2	Small General Service - <30kW Total	Medium General Service - 30-250kW Tier 1	Medium General Service - 30-250kW Tier 2	Medium General Service - 30-250kW Total	Large General Service - >250kW Tier 1	Large General Service - >250kW Tier 2	Large General Service - >250kW Total	Total Commercial	Street Lights	Total System
			(a)	(b)	(c)	(d)	(e)	(f)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Proposed Base Rates																
	Residential																
1	Base Charge	CALC	12.70														
	Energy Charge																
2	First 1000 kWh	CALC	0.0798														
3	All Additional kWh	CALC		0.1002													
	Small General Service (=<30 kW)																
4	Base Charge	CALC				8.00											
5	Demand Charge	CALC				8.90											
	Energy Charge																
6	First 1000 kWh	CALC				0.0780											
7	All Additional kWh	CALC					0.0460										
	Medium General Service (>30 and <=250 kW)																
8	Base Charge	CALC							15.20								
9	Demand Charge	CALC							10.00								
	Energy Charge																
10	First 10,000 kWh	CALC							0.0604								
11	All Additional kWh	CALC								0.0460							
	Large General Service (>250 kW)																
12	Base Charge											26.90					
13	Demand Charge	CALC										13.50					
	Energy Charge																
14	First 50,000 kWh	CALC										0.0460					
15	All Additional kWh	CALC											0.0460				
	Street Lights (Charge per Light)																
	High Pressure Sodium																
16	150 Watts	CALC	0.80			0.63			0.59			0.53				6.95	
	Projected kWh Sales (kWh)																
17	January	CALC	6,436,442	2,728,592	9,165,034	1,530,134	908,450	2,438,584	1,270,674	887,206	2,157,879	918,628	798,570	1,717,199	6,313,662	53,740	15,532,436
18	February	CALC	6,120,996	2,098,421	8,219,417	1,492,659	886,201	2,378,860	1,189,550	830,563	2,020,113	870,578	756,799	1,627,377	6,026,351	53,740	14,299,507
19	March	CALC	5,365,896	1,093,675	6,459,571	1,279,813	759,834	2,039,647	1,029,640	718,912	1,748,551	770,867	670,120	1,440,987	5,229,185	53,740	11,742,495
20	April	CALC	5,225,131	873,840	6,098,971	898,055	533,181	1,431,236	1,126,083	786,250	1,912,333	868,009	754,566	1,622,575	4,966,144	53,740	11,118,855
21	May	CALC	4,719,721	544,675	5,264,396	974,588	578,619	1,553,207	1,159,885	809,851	1,969,736	1,174,223	1,020,760	2,194,983	5,717,926	53,740	11,036,062
22	June	CALC	5,061,862	1,002,908	6,064,771	1,196,161	710,169	1,906,329	1,274,990	890,219	2,165,209	1,407,292	1,223,369	2,630,662	6,702,200	53,740	12,820,711
23	July	CALC	5,824,314	1,955,476	7,779,789	964,509	572,635	1,537,144	1,451,871	1,013,720	2,465,591	1,523,860	1,324,702	2,848,562	6,851,298	53,740	14,684,827
24	August	CALC	5,788,717	1,610,761	7,399,478	1,545,583	917,623	2,463,206	1,350,520	942,955	2,293,475	1,200,493	1,043,597	2,244,090	7,000,771	53,740	14,453,989
25	September	CALC	5,454,829	1,058,508	6,513,337	1,067,498	633,781	1,701,279	1,444,550	1,008,609	2,453,159	1,204,365	1,046,963	2,251,328	6,405,766	53,740	12,972,843
26	October	CALC	4,893,211	581,020	5,474,231	810,371	481,122	1,291,493	1,181,674	825,065	2,006,739	944,682	821,219	1,765,902	5,064,133	53,740	10,592,104
27	November	CALC	5,520,299	1,097,035	6,617,334	1,324,503	786,366	2,110,869	1,091,527	762,122	1,853,649	859,305	747,000	1,606,304	5,570,822	53,740	12,241,896
28	December	CALC	5,904,660	1,647,515	7,552,175	1,141,957	677,987	1,819,944	1,189,038	830,206	2,019,244	857,698	745,603	1,603,301	5,442,489	53,740	13,048,404
29	Total	CALC	66,316,078	16,292,426	82,608,504	14,225,830	8,445,969	22,671,799	14,760,000	10,305,679	25,065,679	12,600,000	10,953,269	23,553,269	71,290,747	644,878	154,544,130
	Percent of Rate Class	CALC	80.28%	19.72%	100.00%	19.95%	11.85%	31.80%	20.70%	14.46%	35.16%	17.67%	15.36%	33.04%	100.00%		
30	Percent of Total System	CALC	42.91%	10.54%	53.45%	9.21%	5.47%	14.67%	9.55%	6.67%	16.22%	8.15%	7.09%	15.24%	46.13%	0.42%	100.00%
31	Average Number of Customers (Lights)	Sch. D	9,398		9,398	1,185	1,185	1,185	123	123	123	21	21	21	1,329	237	10,964
32	Average Monthly kWh Sales per Customer	CALC	588.0		732.5	1,000.0	593.7	1,593.7	10,000.0	6,982.2	16,982.2	50,000.0	43,465.4	93,465.4	4,470.2		1,174.7

Heber Light & Power
Electric Utility Cost of Service Study

ESTIMATED REVENUES UNDER PROPOSED RATES
For the Projected Test Year 2015
(New Design Using Required Increase by Rate Class)

Ln.	Description	Ref.	Residential Tier 1	Residential Tier 2	Residential Total	Small General Service - <30kW Tier 1	Small General Service - <30kW Tier 2	Small General Service - <30kW Total	Medium General Service - 30-250kW Tier 1	Medium General Service - 30-250kW Tier 2	Medium General Service - 30-250kW Total	Large General Service - >250kW Tier 1	Large General Service - >250kW Tier 2	Large General Service - >250kW Total	Total Commercial	Street Lights	Total System
			(a)	(b)	(c)	(d)	(e)	(f)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Projected Demands (kW)																
33	January	INPUT				7,123.9		7,123.9	6,652.8		6,652.8	3874.4		3,874.4	17,651.1		
34	February	INPUT				7,012.7		7,012.7	6,379.5		6,379.5	3682.4		3,682.4	17,074.6		
35	March	INPUT				6,915.3		6,915.3	6,322.0		6,322.0	3930.7		3,930.7	17,168.0		
36	April	INPUT				4,984.6		4,984.6	6,497.2		6,497.2	5137.3		5,137.3	16,619.1		
37	May	INPUT				5,514.2		5,514.2	6,803.5		6,803.5	7187.7		7,187.7	19,505.4		
38	June	INPUT				6,389.6		6,389.6	7,324.0		7,324.0	7659.6		7,659.6	21,373.2		
39	July	INPUT				5,053.4		5,053.4	7,877.0		7,877.0	7896.1		7,896.1	20,826.6		
40	August	INPUT				8,613.4		8,613.4	8,056.2		8,056.2	7263.9		7,263.9	23,933.5		
41	September	INPUT				6,057.9		6,057.9	8,021.0		8,021.0	7616.0		7,616.0	21,694.9		
42	October	INPUT				4,603.0		4,603.0	6,551.5		6,551.5	5865.8		5,865.8	17,020.3		
43	November	INPUT				7,515.2		7,515.2	6,432.3		6,432.3	5051.9		5,051.9	18,999.4		
44	December	INPUT				5,905.2		5,905.2	6,432.1		6,432.1	4840.5		4,840.5	17,177.8		
45	Total	CALC				75,688.4		75,688.4	83,349.3		83,349.3	70,006.3		70,006.3	229,044.0		
46	Average Monthly Demand per Customer	CALC				5.32		5.32	56.47		56.47	277.80		277.80	14.36		
	Estimated Revenue ($)																
47	**Base Charge**	CALC	1,432,285		1,432,285	113,807		113,807	22,435		22,435	6,779		6,779	143,021	19,732	1,595,038
	Demand Charge																
48	January	CALC				63,402		63,402	66,528		66,528	52,304		52,304	182,235		182,235
49	February	CALC				62,413		62,413	63,795		63,795	49,712		49,712	175,920		175,920
50	March	CALC				61,546		61,546	63,220		63,220	53,065		53,065	177,831		177,831
51	April	CALC				44,363		44,363	64,972		64,972	69,354		69,354	178,689		178,689
52	May	CALC				49,076		49,076	68,035		68,035	97,034		97,034	214,145		214,145
53	June	CALC				56,868		56,868	73,240		73,240	103,405		103,405	233,512		233,512
54	July	CALC				44,976		44,976	78,770		78,770	106,597		106,597	230,343		230,343
55	August	CALC				76,659		76,659	80,562		80,562	98,063		98,063	255,284		255,284
56	September	CALC				53,915		53,915	80,210		80,210	102,816		102,816	236,942		236,942
57	October	CALC				40,967		40,967	65,515		65,515	79,188		79,188	185,670		185,670
58	November	CALC				66,885		66,885	64,323		64,323	68,200		68,200	199,409		199,409
59	December	CALC				52,556		52,556	64,321		64,321	65,347		65,347	182,224		182,224
60	Total	CALC	-		-	673,626		673,626	833,493		833,493	945,085		945,085	2,452,205		2,452,205
61	Average Demand Charge ($/kW)	CALC				8.90		8.90	10.00		10.00	13.50		13.50	10.71		35.03
	Energy Charge																
62	January	CALC	513,403	273,323	786,726	119,350	41,789	161,139	76,749	40,811	117,560	42,257	36,734	78,991	357,690		1,144,416
63	February	CALC	488,241	210,199	698,440	116,427	40,765	157,193	71,849	38,206	110,055	40,047	34,813	74,859	342,107		1,040,547
64	March	CALC	428,011	109,553	537,564	99,825	34,952	134,778	62,190	33,070	95,260	35,460	30,826	66,285	296,323		833,887
65	April	CALC	416,783	87,533	504,315	70,048	24,526	94,575	68,015	36,167	104,183	39,928	34,710	74,638	273,396		777,711
66	May	CALC	376,469	54,560	431,029	76,018	26,616	102,634	70,057	37,253	107,310	54,014	46,955	100,969	310,914		741,942
67	June	CALC	403,759	100,461	504,221	93,301	32,668	125,968	77,009	40,950	117,959	64,735	56,275	121,010	364,938		869,159
68	July	CALC	464,576	195,880	660,456	75,232	26,341	101,573	87,693	46,631	134,324	70,098	60,936	131,034	366,931		1,027,387
69	August	CALC	461,737	161,350	623,087	120,555	42,211	162,766	81,571	43,376	124,947	55,223	48,005	103,228	390,942		1,014,029
70	September	CALC	435,104	106,031	541,135	83,265	29,154	112,419	87,251	46,396	133,647	55,401	48,160	103,561	349,627		890,762
71	October	CALC	390,307	58,201	448,508	63,209	22,132	85,341	71,373	37,953	109,326	43,455	37,776	81,231	275,898		724,406
72	November	CALC	440,327	109,890	550,217	103,311	36,173	139,484	65,928	35,058	100,986	39,528	34,362	73,890	314,360		864,577
73	December	CALC	470,985	165,032	636,017	89,073	31,187	120,260	71,818	38,189	110,007	39,454	34,298	73,752	304,019		940,036
74	Total	CALC	5,289,702	1,632,012	6,921,714	1,109,615	388,515	1,498,129	891,504	474,061	1,365,565	579,600	503,850	1,083,450	3,947,145	-	10,868,859
75	Average Energy Charge ($/kWh)	CALC	0.0798	0.1002	0.0838	0.0780	0.0460	0.0661	0.0604	0.0460	0.0545	0.0460	0.0460	0.0460	0.0554	-	0.0703
76	**Total Revenues (Base Rate)**	CALC	6,721,987	1,632,012	8,353,999	1,897,048	388,515	2,285,562	1,747,432	474,061	2,221,493	1,531,464	503,850	2,035,315	6,542,371	19,732	14,916,102
77	**Total Allocated Revenue Requirement**				8,354,830			2,284,266			2,219,124			2,036,075	6,539,465	9,519	14,903,815
78	**Difference**				(831)			1,297			2,369			(761)	2,905	10,213	12,287

Heber Light & Power
Electric Utility Cost of Service Study

ESTIMATED REVENUES UNDER PROPOSED RATES
For the Projected Test Year 2015
(New Design Using Required Increase by Rate Class)

Ln.	Description	Ref.	Residential Tier 1	Residential Tier 2	Residential Total	Small General Service - <30kW Tier 1	Small General Service - <30kW Tier 2	Small General Service - <30kW Total	Medium General Service - 30-250kW Tier 1	Medium General Service - 30-250kW Tier 2	Medium General Service - 30-250kW Total	Large General Service - >250kW Tier 1	Large General Service - >250kW Tier 2	Large General Service - >250kW Total	Total Commercial	Street Lights	Total System
			(a)	(b)	(c)	(d)	(e)	(f)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Reallocation of Revenue Requirements for Rate Design																
	Total Revenue Requirements - As Calculated																
79	Demand	CALC	3,091,268	823,886	3,915,154	1,125,957		1,125,957	1,053,116		1,053,116	949,548		949,548	3,128,620	2,266	7,046,040
80	Energy	CALC	3,031,089	807,848	3,838,937	655,023	388,891	1,043,914	679,619	474,521	1,154,140	580,162	504,339	1,084,501	3,282,555	5,971	7,127,464
81	Customer	CALC	600,739	-	600,739	114,395		114,395	11,869		11,869	2,026		2,026	128,290	1,282	730,311
82	Total	CALC	6,723,096	1,631,734	8,354,830	1,895,374	388,891	2,284,266	1,744,603	474,521	2,219,124	1,531,736	504,339	2,036,075	6,539,465	9,519	14,903,815
83	Calculated Increase in Rates	CALC			6.00%			6.00%			6.00%			6.00%	6.00%	-48.42%	5.91%
84	Proposed Increase in Rates	INPUT			6.00%			6.00%			6.00%			6.00%	6.00%	6.00%	6.00%
	Total Revenue Requirements - As Proposed																
85	Demand	CALC	3,091,268	823,886	3,915,154	1,125,957	-	1,125,957	1,053,116	-	1,053,116	949,548	-	949,548	3,128,620	4,656	7,048,430
86	Energy	CALC	3,031,089	807,848	3,838,937	655,023	388,891	1,043,914	679,619	474,521	1,154,140	580,162	504,339	1,084,501	3,282,555	12,271	7,133,764
87	Customer	CALC	600,739	-	600,739	114,395		114,395	11,869		11,869	2,026		2,026	128,290	2,635	731,664
88	Total	CALC	6,723,096	1,631,734	8,354,830	1,895,374	388,891	2,284,266	1,744,603	474,521	2,219,124	1,531,736	504,339	2,036,075	6,539,465	19,562	14,913,858
	Proposed Rate Tilts																
89	Demand to Customer	INPUT	21.25%	21.25%	21.25%			0.00%			1.00%			0.50%			
90	Demand to Energy	INPUT	0.00%	0.00%	0.00%			40.00%			20.00%			0.00%			
	Reallocation for Rate Design																
91	Base / Customer Charge	CALC	1,257,633	175,076	1,432,709	114,395	-	114,395	22,400	-	22,400	6,774	-	6,774	143,569	19,562	1,595,840
92	Demand Charge	CALC	N/A	N/A	N/A	675,574	-	675,574	831,961	-	831,961	944,800	-	944,800	2,452,335		2,452,335
93	Energy Charge	CALC	5,465,463	1,456,658	6,922,121	1,105,406	388,891	1,494,297	890,242	474,521	1,364,763	580,162	504,339	1,084,501	3,943,561	-	10,865,682
94	Total	CALC	6,723,096	1,631,734	8,354,830	1,895,374	388,891	2,284,266	1,744,603	474,521	2,219,124	1,531,736	504,339	2,036,075	6,539,465	19,562	14,913,858
	Preliminary Rate Design																
95	Base / Customer Charge ($/Cust.)	CALC	12.70		12.70	8.00		8.00	15.20		15.20	26.90		26.90			
96	Demand Charge ($/kW)	CALC	N/A	N/A	N/A	8.90		8.90	10.00		10.00	13.50		13.50			
97	Energy Charge - Calculated ($/kWh)	CALC	0.0824	0.0894	0.0838	0.0777	0.0460	0.0659	0.0603	0.0460	0.0544	0.0460	0.0460	0.0460			
98	Energy Charge for Block Rate ($/kWh)	$/kWh	0.0798	0.1002		0.0780	0.0460		0.0604	0.0460		0.0460	0.0460				
99	Assumed Average Monthly kWh Usage	kWh/Cust.			732.5			1,593.7			16,982.2			93,465.4			
100	Assumed Average Monthly kW Demand	kW/Cust.			N/A			5.3			56.5			277.8			
101	Average Monthly Charge - Proposed	$			71.13			160.66			1,505.08			8,076.65	0.0917		
102	Average Monthly Charge - Existing	$			67.12			180.79			1,410.33			7,521.33	0.0866		
103	Percent Increase				5.97%			-11.13%			6.72%			7.38%	5.98%		

Heber Light & Power
2015 Electric Rate Study

Monthly Billing Comparison at Various Usage Levels
Present vs. Proposed Rates

RESIDENTIAL

Present Rates:

Base Charge	$ 12.00
Energy Charge	
First 1000 kWh	0.0753
All Additional kWh	0.0945

Proposed Rates:

Base Charge	12.70
Energy Charge	
First 1000 kWh	0.0798
All Additional kWh	0.1002

Useage Level		Under Current Rates			Under Proposed Rates				Increase	Percent Increase
Energy	Demand	Base	Energy	Total	Base	Demand	Energy	Total	(Decrease)	(Decrease)
500	N/A	12.00	37.65	49.65	12.70	N/A	39.90	52.60	2.95	5.9%
750	N/A	12.00	56.48	68.48	12.70	N/A	59.85	72.55	4.08	6.0%
1,000	N/A	12.00	75.30	87.30	12.70	N/A	79.80	92.50	5.20	6.0%
1,250	N/A	12.00	98.93	110.93	12.70	N/A	104.85	117.55	6.62	6.0%
1,500	N/A	12.00	122.55	134.55	12.70	N/A	129.90	142.60	8.05	6.0%
1,750	N/A	12.00	146.18	158.18	12.70	N/A	154.95	167.65	9.47	6.0%
2,000	N/A	12.00	169.80	181.80	12.70	N/A	180.00	192.70	10.90	6.0%
2,500	N/A	12.00	217.05	229.05	12.70	N/A	230.10	242.80	13.75	6.0%
3,000	N/A	12.00	264.30	276.30	12.70	N/A	280.20	292.90	16.60	6.0%
3,500	N/A	12.00	311.55	323.55	12.70	N/A	330.30	343.00	19.45	6.0%

SMALL COMMERCIAL

Present Rates:

Base Charge	$ 6.50
Energy Charge	
First 500 kWh	0.1492
Next 500 kWh	0.1045
All Additional kWh	0.0799

Proposed Rates:

Base Charge	8.00
Demand Charge	8.90
Energy Charge	
First 1000 kWh	0.0780
All Additional kWh	0.0460

Assumed Load Factor: 40.0%

Useage Level		Under Current Rates			Under Proposed Rates				Increase	Percent Increase
Energy	Demand	Base	Energy	Total	Base	Demand	Energy	Total	(Decrease)	(Decrease)
1,000	3.4	6.50	149.20	155.70	8.00	30.48	78.00	116.48	(39.22)	-25.2%
1,250	4.3	6.50	152.98	159.48	8.00	38.10	89.50	135.60	(23.88)	-15.0%
1,500	5.1	6.50	179.10	185.60	8.00	45.72	101.00	154.72	(30.88)	-16.6%
2,000	6.8	6.50	206.75	213.25	8.00	60.96	124.00	192.96	(20.29)	-9.5%
2,500	8.6	6.50	246.70	253.20	8.00	76.20	147.00	231.20	(22.00)	-8.7%
3,000	10.3	6.50	286.65	293.15	8.00	91.44	170.00	269.44	(23.71)	-8.1%
3,500	12.0	6.50	326.60	333.10	8.00	106.68	193.00	307.68	(25.42)	-7.6%
4,000	13.7	6.50	366.55	373.05	8.00	121.92	216.00	345.92	(27.13)	-7.3%
4,500	15.4	6.50	406.50	413.00	8.00	137.16	239.00	384.16	(28.84)	-7.0%
5,000	17.1	6.50	446.45	452.95	8.00	152.40	262.00	422.40	(30.55)	-6.7%

Heber Light & Power
2015 Electric Rate Study

Monthly Billing Comparison at Various Usage Levels
Present vs. Proposed Rates

MEDIUM COMMERCIAL

Present Rates:

Base Charge	$	6.50
Energy Charge		
First 500 kWh		0.1492
Next 500 kWh		0.1045
All Additional kWh		0.0799

Proposed Rates:

Base Charge	15.20	Assumed Load Factor:	41.2%
Demand Charge	10.00		
Energy Charge			
First 10,000 kWh	0.0604		
All Additional kWh	0.0460		

Useage Level		Under Current Rates			Under Proposed Rates				Increase	Percent Increase
Energy	Demand	Base	Energy	Total	Base	Demand	Energy	Total	(Decrease)	(Decrease)
10,000	33.3	6.50	845.95	852.45	15.20	332.73	604.00	951.93	99.48	11.67%
11,000	36.6	6.50	925.85	932.35	15.20	366.01	650.00	1,031.21	98.86	10.60%
12,000	39.9	6.50	1,005.75	1,012.25	15.20	399.28	696.00	1,110.48	98.23	9.70%
13,000	43.3	6.50	1,085.65	1,092.15	15.20	432.55	742.00	1,189.75	97.60	8.94%
14,000	46.6	6.50	1,165.55	1,172.05	15.20	465.83	788.00	1,269.03	96.98	8.27%
15,000	49.9	6.50	1,245.45	1,251.95	15.20	499.10	834.00	1,348.30	96.35	7.70%
16,000	53.2	6.50	1,325.35	1,331.85	15.20	532.37	880.00	1,427.57	95.72	7.19%
17,000	56.6	6.50	1,405.25	1,411.75	15.20	565.65	926.00	1,506.85	95.10	6.74%
18,000	59.9	6.50	1,485.15	1,491.65	15.20	598.92	972.00	1,586.12	94.47	6.33%
19,000	63.2	6.50	1,565.05	1,571.55	15.20	632.19	1,018.00	1,665.39	93.84	5.97%

LARGE COMMERCIAL

Present Rates:

Base Charge	$	6.50
Energy Charge		
First 500 kWh		0.1492
Next 500 kWh		0.1045
All Additional kWh		0.0799

Proposed Rates:

Base Charge	26.90	Assumed Load Factor:	46.1%
Demand Charge	13.50		
Energy Charge			
All kWh	0.0460		

Consumption		Under Current Rates			Under Proposed Rates				Increase	Percent Increase
Energy	Demand	Base	Energy	Total	Base	Demand	Energy	Total	(Decrease)	(Decrease)
50,000	148.6	6.50	4,041.95	4,048.45	26.90	2,006.64	2,300.00	4,333.54	285.09	7.04%
60,000	178.4	6.50	4,840.95	4,847.45	26.90	2,407.96	2,760.00	5,194.86	347.41	7.17%
70,000	208.1	6.50	5,639.95	5,646.45	26.90	2,809.29	3,220.00	6,056.19	409.74	7.26%
80,000	237.8	6.50	6,438.95	6,445.45	26.90	3,210.62	3,680.00	6,917.52	472.07	7.32%
90,000	267.6	6.50	7,237.95	7,244.45	26.90	3,611.94	4,140.00	7,778.84	534.39	7.38%
100,000	297.3	6.50	8,036.95	8,043.45	26.90	4,013.27	4,600.00	8,640.17	596.72	7.42%
110,000	327.0	6.50	8,835.95	8,842.45	26.90	4,414.60	5,060.00	9,501.50	659.05	7.45%
120,000	356.7	6.50	9,634.95	9,641.45	26.90	4,815.92	5,520.00	10,362.82	721.37	7.48%
130,000	386.5	6.50	10,433.95	10,440.45	26.90	5,217.25	5,980.00	11,224.15	783.70	7.51%
140,000	416.2	6.50	11,232.95	11,239.45	26.90	5,618.58	6,440.00	12,085.48	846.03	7.53%

EXHIBIT B
RATE COMPARISON UNDER PRESENT & PROPOSED RATES

Heber Light & Power
2015 Rate Study

Rate Comparison Worksheet
Proposed Rates Based on 6.0% Increase and New Rate Structure for Commercial
HLP vs. RMP and Other Utah Municipal Utilities

Line No.	Rate Description	HLP Current		HLP Proposed		Rocky Mountain Power		Bountiful City		City of Hurricane		Price City	
	Residential												
1	Base/Customer Charge		12.00		12.70		6.00		4.20		11.00		3.74
	Energy Rate												
2	All								0.0925				
3	Tier 1	1st 1000 kWh	0.07525	1st 1000 kWh	0.07980	1st 400 kWh	0.08850			1st 800 kWh	0.07490	1st 400 kWh	0.09635
4	Tier 2	All Additional	0.09450	All Additional	0.10020	Next 600 kWh	0.10927			801 - 2000 kWh	0.08560	Next 200 kWh	0.11257
5	Tier 3					All Additional	0.14451			All Additional	0.09630	All Additional	0.13243
6	Tier 4												
7	Tier 5												
	Estimated Monthly Charge												
8	**750 kWh**		**68.44**		**72.55**		**79.64**		**73.58**		**67.18**		**84.66**
	Commercial - All												
9	Base/Customer Charge		None										
	Energy Rate												
10	Tier 1	1st 500 kWh	0.14920										
11	Tier 2	Next 500 kWh	0.10450										
12	Tier 3	All Additional	0.07990										
	Estimated Monthly Charge												
13	**3,600 kWh**		**334.59**										
19	***Small Commercial (Demand)***			=< 30 kW		=< 30 kW		=< 30 kW				=<30 kW	
20	Base Charge / Customer Rate				8.00		10.00		7.14		16.00		18.80
	Energy Rate												
21	Tier 1			1st 1000 kWh	0.0780	1st 1500 kWh	0.11263	1st 1500 kWh	0.1112	1-800 kWh	0.0749	1st 500 kWh	0.05944
22	Tier 2			All Additional	0.0460	All Additional	0.06317	All Additional	0.0624	801 - 1500 kWh	0.0856	All Additional	0.06242
23	Tier 3									1501 - 25000 kWh	0.0827		
24	Demand Rate			All kW	8.90	> 15 kW	8.68	> 15 kW	8.21	> 50 kW	7.60	All kW	8.31
	Estimated Monthly Charge												
25	**1,600 kWh / 5.3 kW**				**160.77**		**185.26**		**180.18**		**144.11**		**161.22**
	Medium Commercial/Industrial (Demand)			>30kW - <250kW		=< 1000 kW		> 30 kW				> 35 kW	
26	Base Charge / Customer Rate				15.20		54.00		26.25		16.00		18.80
	Energy Rate												
27	Tier 1			1st 10,000 kWh	0.0604	All kWh	0.03664	All kWh	0.0473	1-800 kWh	0.0749	1st 10,000 kWh	0.05944
28	Tier 2			All Additional	0.0460					801 - 1500 kWh	0.0856	Next 90,000 kWh	0.06242
29	Tier 3									1501 - 25000 kWh	0.0827	All Additional	0.06553
30	Demand Rate			All kW	10.00		12.46	All kW	13.13	> 50 kW	7.60	All kW	12.01
	Estimated Monthly Charge												
31	**17,000 kWh / 56.5 kW**				**1,506.20**		**1,380.79**		**1,572.20**		**1,467.09**		**1,728.68**
	Large Commercial / Industrial (Demand)			>250 kW		=< 1000 kW		> 30 kW				> 35 kW	
26	Base Charge / Customer Rate				26.90		54.00		26.25		300.00		18.80
	Energy Rate												
27	Tier 1			All kWh	0.0460	All kWh	0.03664	All kWh	0.0473	All kWh	0.05030	1st 10,000 kWh	0.05944
28	Tier 2											Next 90,000 kWh	0.06242
29	Tier 3											All Additional	0.06553
30	Demand Rate			All kW	13.50		12.46	All kW	13.13	All kW	8.75	All kW	12.01
	Estimated Monthly Charge												
31	**93,500 kWh / 277.8 kW**				**8,078.20**		**6,940.76**		**8,096.31**		**7,433.80**		**9,161.24**

Heber Light & Power
2015 Rate Study

Rate Comparison Worksheet
Proposed Rates Based on 6.0% Increase and New Rate Structure for Commercial
HLP vs. RMP and Other Utah Municipal Utilities

Line No.	Rate Description	HLP Current		HLP Proposed		Payson City		Murray City		Springville City		All Other Avg. Charge
	Residential											
1	Base/Customer Charge		12.00		12.70		12.71		3.35		11.00	
	Energy Rate											
2	All											
3	Tier 1	1st 1000 kWh	0.07525	1st 1000 kWh	0.07980	1st 400 kWh	0.07998	1st 600 kWh	0.08600	1st 400 kWh	0.07700	
4	Tier 2	All Additional	0.09450	All Additional	0.10020	Next 400 kWh	0.10900	All Additional	0.09630	Next 600 kWh	0.09400	
5	Tier 3					Next 400 kWh	0.11899			All Additional	0.11600	
6	Tier 4					Next 400 kWh	0.11900					
7	Tier 5					All Additional	0.12000					
	Estimated Monthly Charge											
8	**750 kWh**		**68.44**		**72.55**		**82.85**		**69.40**		**74.70**	**76.00**
	Commercial - All											
9	Base/Customer Charge		None									
	Energy Rate											
10	Tier 1	1st 500 kWh	0.14920									
11	Tier 2	Next 500 kWh	0.10450									
12	Tier 3	All Additional	0.07990									
	Estimated Monthly Charge											
13	**3,600 kWh**		**334.59**									
19	***Small Commercial (Demand)***			=< 30 kW				< 35 kW		=<35 kW		
20	Base Charge / Customer Rate				8.00		2.00		8.39		25.00	
	Energy Rate											
21	Tier 1			1st 1000 kWh	0.0780	1st 1000 kWh	0.11790	1st 1500 kWh	0.09250	1st 500 kWh	0.11772	
22	Tier 2			All Additional	0.0460	Next 14,000 kWh	0.08104	All Additional	0.04680	Next 9,500 kWh	0.09110	
23	Tier 3					All Additional	0.06525			All Additional	0.06080	
24	Demand Rate			All kW	8.90	> 5 kVA	7.40	All kW > 5 kW	11.75	> 5 kW	6.20	
	Estimated Monthly Charge											
25	**1,600 kWh / 5.3 kW**				**160.77**		**170.74**		**155.35**		**185.93**	**168.97**
	Medium Commercial/Industrial (Demand)			>30kW - <250kW				> 35 kW		> 35 kW		
26	Base Charge / Customer Rate				15.20		100.00		20.99		35.00	
	Energy Rate											
27	Tier 1			1st 10,000 kWh	0.0604	1st 25,000 kWh	0.06460	All kWh	0.04360	1st 10,000 kWh	0.11610	
28	Tier 2			All Additional	0.0460	Next 25,000 kWh	0.06244			Next 90,000 kWh	0.07830	
29	Tier 3					All Additional	0.06112			All Additional	0.07070	
30	Demand Rate			All kW	10.00	> 5 kVA	7.39	All kW	12.37	All kW	6.90	
	Estimated Monthly Charge											
31	**17,000 kWh / 56.5 kW**				**1,506.20**		**1,578.79**		**1,461.10**		**2,099.45**	**1,612.58**
	Large Commercial / Industrial (Demand)			>250 kW				> 35 kW		> 35 kW		
26	Base Charge / Customer Rate				26.90		100.00		20.99		35.00	
	Energy Rate											
27	Tier 1			All kWh	0.0460	1st 25,000 kWh	0.06460	All kWh	0.04360	1st 10,000 kWh	0.11610	
28	Tier 2					Next 25,000 kWh	0.06244			Next 90,000 kWh	0.07830	
29	Tier 3					All Additional	0.06112			All Additional	0.07070	
30	Demand Rate			All kW	13.50	All kVa	6.63	All kW	12.37	All kW	6.90	
	Estimated Monthly Charge											
31	**93,500 kWh / 277.8 kW**				**8,078.20**		**7,776.53**		**7,533.98**		**9,650.87**	**8,084.79**

Heber Light & Power

Rate Structure Modification

2015 Company Highlights

- Company

- Customers:
  - Residential: 9,400
  - Commercial: 1,300
- Line Miles:
  - 46kV: 13.5 mi.
  - Distribution: 390 mi.
- Internal Generation
  - Hydro: 3 MW - 4 Units
  - Thermal: 13 MW - 7 Units
- Employees: 36

2015 Company Highlights

- Company
- Safety & Recognition

- APPA RP3 Award
- 

APPA Safety Award of Excellence
- IPSA 5-years Without a Lost-Time Accident

2015 Company Highlights

- Company
- Safety & Recognition
- Last Rate Review & Modification

- Heber Light & Power last had a rate increase in 2011.
- Rates increased across the board at 4.50%

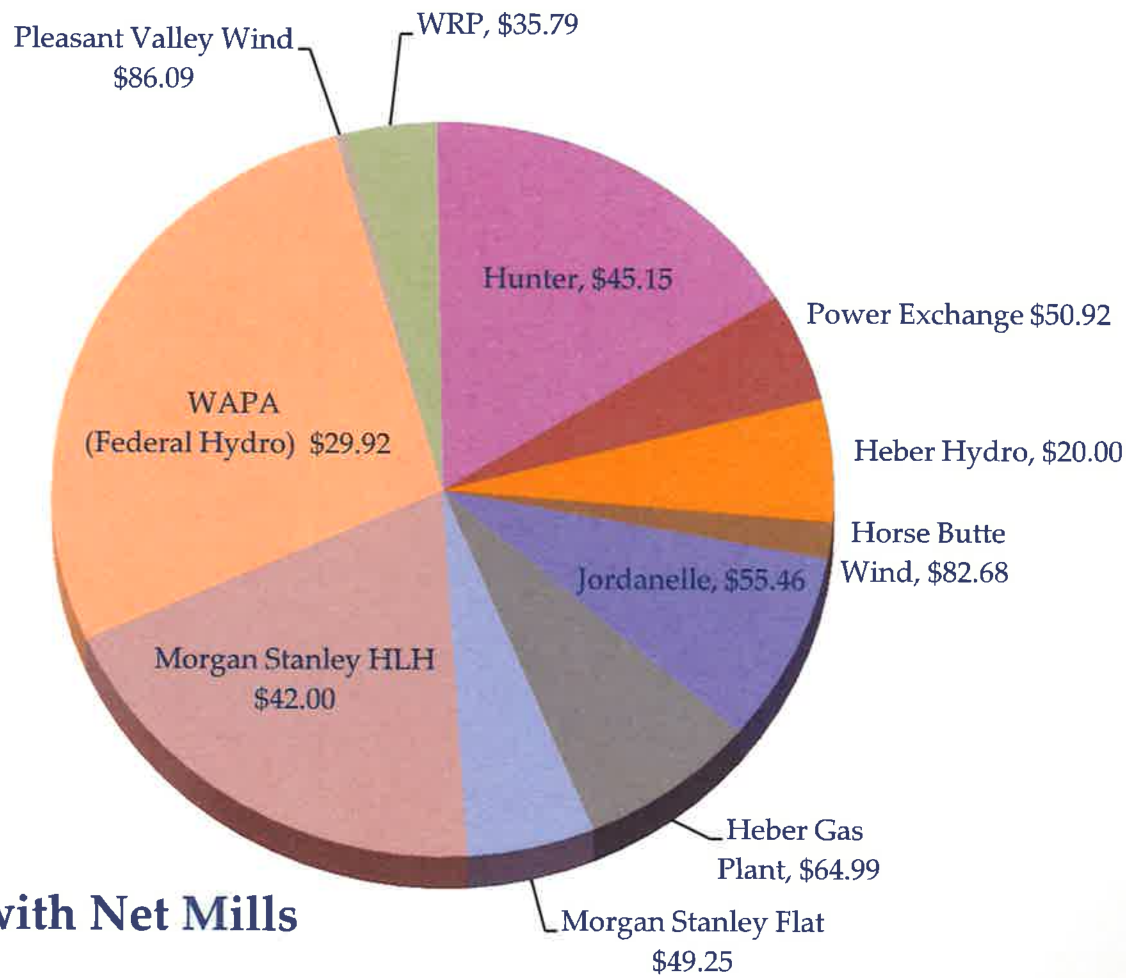
2015 Rate Modification Need

- Strategic Plan

	Upcoming Projects	Impact Fee Related %	Project Duration Start	Project Duration Finish	Projected Cost ($1,000) Total	Projected Cost ($1,000) Impact Fee
Distribution	Distribution Capacitors / VAR Control	0%	2015	2018	$80	$0
	CL 401 Rebuild (Charleston Reconductor)	60%	2015	2018	$450	$270
	Additional Circuits out of Jailhouse to the East	100%	2015	2018	$560	$560
	Underground System Improvements	0%	2015	2019	$194	$0
	Tie from 702 up to 500 East in Heber (HB304)	100%	2016	2016	$250	$250
	Heber Sub to Cloyes Sub Distribution Rebuild	60%	2016	2017	$350	$210
	North Distribution Line Rebuild (RMP Partnership - Phase 2)	0%	2016	2017	$1,240	$0
	Heber Substation 2 Additional Circuits (South & West)	100%	2016	2018	$360	$360
	Reconductor Center Street to 1200 South	60%	2019	2019	$150	$90
	Reconductor Pine Canyon Road - Midway	60%	2019	2019	$180	$108
Substation	Gas Plant 2 Transformer Replacement	0%	2014	2015	$223	$0
	Replacement Recloser for Joslyn Reclosers	0%	2015	2015	$25	$0
	Heber Substation 2nd Transformer	100%	2015	2016	$615	$615
	2nd Point of Interconnect Substation	50%	2015	2017	$5,500	$2,750
	Midway Substation - High Side Rebuild	0%	2018	2018	$500	$0
	Cloyes LTC Rebuild	0%	2019	2019	$40	$0
Generation	Lower Snake Creek Plant Upgrade	0%	2015	2016	$240	$0
	Annual Generation Capital Improvements	0%	2015	2019	$271	$0
	Unit Overhauls	0%	2015	2019	$556	$0
	New Generator (3-6 MW)	0%	2019	2020	$9,000	$0
Other	Annual Systems and Technology Upgrade	0%	2015	2019	$322	$0
	Annual Tool & Equipment Purchases	0%	2015	2019	$225	$0
	Annual Vehicle Program	0%	2015	2019	$750	$0
Buildings	Operations Asphalt / Curb Improvements	0%	2015	2015	$103	$0
	Generator Fire Suppression System	0%	2015	2015	$107	$0
	Training Room Furniture	0%	2015	2015	$32	$0
	Land Swap Residual Purchase	0%	2015	2015	$145	$0
	New Office Building	0%	2018	2018	$1,000	$0
					$23,388	**$5,213**

2015 Rate Modification Need

- Strategic Plan
- Resource Portfolio



2015 Portfolio Mix with Net Mills

2015 COS Rate Design Study

- Revenue Requirement
  - Analysis of current system along with estimated asset needs.
  - Revenue calculations completed to match anticipated budget.
  - Revenues allocated amongst customer classes based upon relative cost drivers.

2015 COS Rate Design Study

- Revenue Requirement
- Residential Structure
  - Base Charge
  - Two Tier Energy Rate

2015 COS Rate Design Study

- Revenue Requirement
- Residential Structure
- Commercial Structure

- Small Commercial
  - Base Charge
  - Demand Charge
  - Two Tier Energy
- Medium Commercial
  - Base Charge
  - Demand Charge
  - Two Tier Energy
- Large Commercial
  - Base Charge
  - Demand Charge
  - Single Tier Energy

2015 COS Rate Design Study

- Revenue Requirement
- Residential Structure
- Commercial Structure
- Existing vs. Proposed

Residential	Current	Proposed
Base Charge	$12.00	$12.70
Energy - 1st 1,000 kWh	$0.075	$0.080
Energy - All Additional	$0.095	$0.102
Small Commercial (<=30 kW)	Current	Proposed
Energy - 1st 500 kWh	$0.149	
Energy – 2nd 500 kWh	$0.105	
Energy - All Additional	$0.080	
Base Charge		$8.000
Demand Charge per kWh		$8.900
Energy - 1st 1,000 kWh		$0.078
Energy - All Additional		$0.046
Medium Commercial (>30kW and <=250kW)	Current	Proposed
Energy - 1st 500 kWh	$0.149	
Energy – 2nd 500 kWh	$0.105	
Energy - All Additional	$0.080	
Base Charge		$15.20
Demand Charge per kW		$10.00
Energy - 1st 10,000 kWh		$0.060
Energy - All Additional		$0.046
Large Commercial (>250kW)	Current	Proposed
Energy - 1st 500 kWh	$0.149	
Energy – 2nd 500 kWh	$0.105	
Energy - All Additional	$0.080	
Base Charge		$26.90
Demand Charge per kW		$13.50
Energy		$0.046

2015 COS Rate Design Study

- Revenue Requirement
- Residential Structure
- Commercial Structure
- Existing vs. Proposed
- Impacts to Average Customer

Current and Proposed Bill by Class Comparison				
Class	Average Usage/ Demand	Current Bill	Proposed Bill	Change/Month
Residential	750 kWh	$68.44	$72.55	$4.11
Small Commercial	1,600 kWh/ 5 kW	$181.29	$160.77	($20.52)
Medium Commercial	17,000 kWh/ 56 kW	$1,411.75	$1506.2	$94.45
Large Commercial	93,500 kWh / 277 kW	$7,524.10	$8,078.20	$554.10

2015 Rate Comparison

Line No.	Rate Description	HLP Current		HLP Proposed		Payson City		Murray City		Springville City		All Other Avg. Charge
	Residential											
1	Base/Customer Charge		12.00		12.70		12.71		3.35		11.00	
	Energy Rate											
2	All											
3	Tier 1	1st 1000 kWh	0.07525	1st 1000 kWh	0.07960	1st 400 kWh	0.07996	1st 600 kWh	0.06600	1st 400 kWh	0.07700	
4	Tier 2	All Additional	0.09450	All Additional	0.10020	Next 400 kWh	0.10900	All Additional	0.09530	Next 600 kWh	0.09400	
5	Tier 3					Next 400 kWh	0.11890			All Additional	0.11600	
6	Tier 4					Next 400 kWh	0.11900					
7	Tier 5					All Additional	0.12000					
	Estimated Monthly Charge											
8	750 kWh		68.44		72.55		82.85		69.40		74.70	76.00
	Commercial - All											
9	Base/Customer Charge		None									
	Energy Rate											
10	Tier 1	1st 500 kWh	0.14920									
11	Tier 2	Next 500 kWh	0.10150									
12	Tier 3	All Additional	0.07980									
	Estimated Monthly Charge											
13	3,600 kWh		334.59									
19	*Small Commercial (Demand)*			=< 30 KW				< 35 KW		=<35 KW		
20	Base Charge / Customer Rate				8.00		2.00		8.39		25.00	
	Energy Rate											
21	Tier 1			1st 1000 kWh	0.0780	1st 1000 kWh	0.11790	1st 1500 kWh	0.09250	1st 500 kWh	0.11772	
22	Tier 2			All Additional	0.0460	Next 14,000 kWh	0.08104	All Additional	0.04680	Next 9,500 kWh	0.09110	
23	Tier 3					All Additional	0.06525			All Additional	0.06080	
24	Demand Rate			All KW	0.90	> 5 KVA	7.40	All kW > 5 kW	11.75	> 5 kW	0.20	
	Estimated Monthly Charge											
25	1,600 kWh / 5.3 kW				160.77		170.74		155.35		185.93	168.97
	Medium Commercial/Industrial (Demand)			>30kW - <250kW				> 35 kW		> 35 kW		
26	Base Charge / Customer Rate				15.20		100.00		20.99		35.00	
	Energy Rate											
27	Tier 1			1st 10,000 kWh	0.0604	1st 25,000 kWh	0.06460	All kWh	0.04360	1st 10,000 kWh	0.11610	
28	Tier 2			All Additional	0.0460	Next 25,000 kWh	0.06244			Next 90,000 kWh	0.07830	
29	Tier 3					All Additional	0.06112			All Additional	0.07070	
30	Demand Rate			All KW	10.00	> 5 KVA	7.39	All kW	12.37	All kW	6.90	
	Estimated Monthly Charge											
31	17,000 kWh / 56.5 kW				1,506.20		1,578.79		1,461.10		2,099.45	1,612.58
	Large Commercial / Industrial (Demand)			>250 kW				> 35 kW		> 35 kW		
20	Base Charge / Customer Rate				20.90		100.00		20.99		35.00	
	Energy Rate											
27	Tier 1			All kWh	0.0460	1st 25,000 kWh	0.06460	All kWh	0.04360	1st 10,000 kWh	0.11610	
28	Tier 2					Next 25,000 kWh	0.06244			Next 90,000 kWh	0.07830	
29	Tier 3					All Additional	0.06112			All Additional	0.07070	
30	Demand Rate			All KW	13.50	All kVa	6.63	All kW	12.37	All kW	6.90	
	Estimated Monthly Charge											
31	93,600 kWh / 277.8 kW				8,078.20		7,776.53		7,533.08		9,660.87	8,084.70

Conclusion

- Closing thoughts
- Questions

TAB 2

HEBER CITY CORPORATION

ENGINEERING STAFF REPORT

MEETING TYPE:	Regular Council Meeting	MEETING DATE:	March 16, 2006
SUBMITTED BY:	Bart L Mumford	FILE NO.:	06027
APPROVED BY:	Mark K. Anderson		
SUBJECT:	**STONE CREEK SUBDIVISION - CITY LOCAL ROAD WIDTH STANDARD**		

PURPOSE

To provide information to the Council regarding the City's Local road width standard, and public vs private roads.

RECOMMENDED ACTION

That the City Council maintain the current Local road standard, and continue to allow private roads in unusual situations where the City standard road cannot be met or poses an additional burden to the City.

BACKGROUND/HIGHLIGHTS

At the July 16, 2015, Council Work meeting, discussion occurred on whether the roads in the Stone Creek Subdivision should be public rather than private as was previously approved. Also, if the City should adopt a narrower road standard for City roads with the Local classification. The following is a discussion of these two interrelated issues.

Local roads are usually operated and maintained by the City unless there is some unique aspect of the roads that justifies shifting some of the cost burden to those it serves rather than the City at large; i.e. road mainly benefits a select group, community is gated, road does not meet adopted City standards, etc. In these cases the City has allowed some roads to be private and maintained by an HOA, primarily in the PC zone. Ideally public and private roads would be constructed to the same asphalt width standard, but this has not always been politically desirable. The current City Local public road standard is 60-feet of right of way, 36-feet of asphalt, with high back curb as shown in Exhibit A.

In the case of Stone Creek, which is in the City's PC zone, a narrower Local road standard was approved by the Council in their original subdivision master plan, and subsequently in the Red Ledges development. This standard consisted of 50-feet of right of way, 26-feet of asphalt, low back curb, and a private storm drain system. The decision to allow narrower road widths in the PC zone in certain cases was the result of a compromise reached between the City and the developers. It allowed them to construct a road that the City philosophically disagreed with in return for accepting the cost of operating and maintaining those roads and drainage facilities.

MINIMUM LOCAL ROAD WIDTHS

Before the question of public vs. private roads can be addressed. The question of minimum Local road widths needs to be considered. Once the minimum road width is decided a decision on whether those roads are public or private can be made. The following information should be considered before making a decision on these issues.

First, this discussion only applies to roads designated as Local roads, or roads with the narrowest width generally allowed by the City. These roads usually see minimal, low speed residential traffic, from properties adjacent to the road. These roads are not anticipated to be corridors for moving traffic in, out, or through an area like collector or arterial roads do. The primary purpose of Local roads is traffic access and utility corridors.

Second, there is no one standard Local road adopted by all Cities. Minimum standard road widths can be found ranging from less than 26-feet to more than 40-feet. These standards are based as much on a Cities philosophy and history as they are on empirical data. Planners and developers tend to favor narrow width's (20' to 28'). Law Enforcement, Emergency Services, and Public Works, tend to favor wider widths (30' to 40'). The following are some of the tradeoffs to consider:

1. Reasons typically cited as positives for narrower road widths include improved aesthetics to some, reduced speeds, increased safety, minimized road cuts on steep slopes, reduced asphalt installation and maintenance costs, reduced drainage, room for larger lots or increased density, etc.
2. Reasons typically cited as positives for wider road widths center on accessibility and flexibility for emergency services (ambulance, law enforcement, and fire), school buses, and garbage collection; reduced underground utility maintenance and replacement costs; fewer problems with snow removal; less interference from trees overhanging streets, etc.
3. Narrow roads tend to work better in rural environments where homes are further apart, have plenty of off street parking, traffic volumes are low (less than 300 - 500 ADT), and curbs are not required which allow vehicles to drive outside of the roadway when necessary. Narrow roads have also worked in urban areas where on-street parking is restricted or prohibited, low back curbs are allowed, and alley ways are provided behind homes.
4. The City eliminated its low back curb standard in 2005 and required high back curb because of problems with vehicles parking on park strips, sidewalks, and yards which is aesthetically unappealing. Low back curbs also hindered snow plowing because the plow blades would overrun the curb and damage property and landscaping which had to be repaired by the City.

5. Some fire districts have had to acquire special fire equipment to operate in the narrower roads in their Cities; i.e. Pleasant Grove and Park City.
6. Narrower road asphalt costs less to repair, replace, and seal; and is the safer. However, there are additional expenses that are usually not taken into account associated with repairing or replacing the underground utilities in those roads because there is less room to work in. Utilities often must be placed next to, under, or behind the curb and gutter. As subdivisions age and infrastructure needs change, or are replaced, additional costs are incurred because the roads must be completely closed and the old utilities removed to make room for the new utilities. Exhibit B shows the space constraints in the narrow road standard approved for Stone Creek and Red Ledges.
7. If utilities are moved to the park strip to accommodate narrower roads then the conflicts with meter cans, sewer cleanouts, trees, etc. must be addressed.
8. The County and Midway originally had 26-foot and 27-foot minimum asphalt road widths. In recent years they concluded these were too narrow and increased their standards to 30-foot and 34-foot respectively. The Cobblestone development prompted the change in the County due to struggles keeping vehicles off the streets, difficulties with snow plowing, and the potential conflict with overhanging trees. It should be noted that the County's 30-foot standard allows for low back curb so that it can be driven across in an emergency which is something the City has chosen to discontinue. The City itself experimented with narrower road widths in some of its first subdivisions and later increased those widths due to similar problems. Exhibit C shows some of those streets in heavy snow years and limited access for public services.
9. The Fire District more recently has had issues with the narrow roads at the Retreat by Jordanelle due to contractors and homeowners parking on the road and blocking access. The District had to suspend construction projects until alternative parking arrangements could be made. The District has also had concerns with projects like the City's Liberty Station which meets the minimum fire code criteria but provides little flexibility in emergencies when people behave the most irrationally.

CONCLUSION

Based on the above considerations I believe that the current Heber City asphalt road width, or something similar, has been a good compromise that has worked well for the City and balanced the competing interests and resources that are available. It allows two 10-foot traffic lanes, which meets the Fire District's requirement of a 20-foot unobstructed clear zone, and allows 8-feet for parking on either side of the road, assuming residential homes are constructed on both sides of the street. This standard allows the City flexibility for future facilities maintenance, requires less intensive code enforcement, and facilities emergency and utility services. Any Local roads that do not meet this standard should be considered candidates for designating them as private roads.

Should the Council choose to pursue a narrower asphalt width for a citywide road standard, it is recommended that the following be considered:

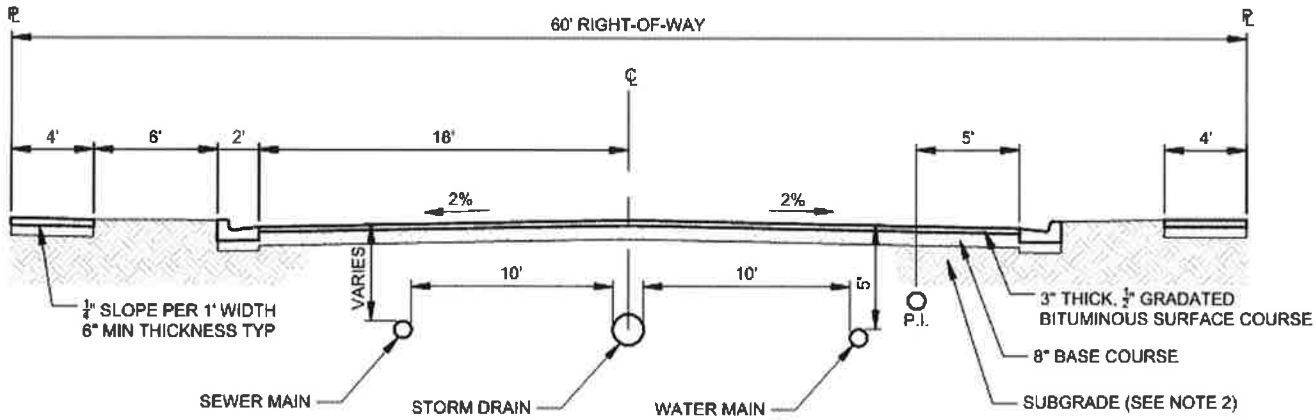
1. Increase lot setbacks 10-feet to 15-feet to allow for more driveway vehicle storage.
2. Lower the highest zoning densities to decrease demand for vehicle on street public parking.
3. Require development to provide alternate parking storage areas maintained by HOA's in subdivisions for residents and visitors.
4. Allocate additional enforcement resources to address increased parking violations on streets and sidewalks, and violations by residents pushing and piling driveway snow into the streets.
5. Add alleys for vehicle parking and utilities behind lots.
6. Implement agreed upon changes before changing the Local road standard.

FISCAL IMPACT
Varies

LEGAL IMPACT
None

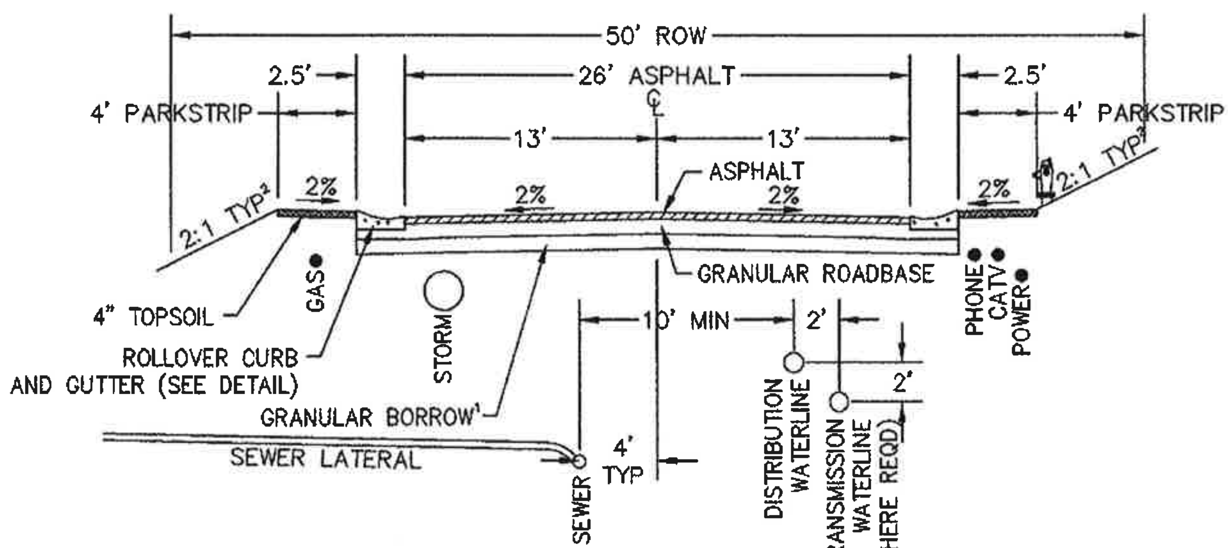
06027SR StoneCr RdWidths 150806.doc

EXHIBIT A



CURRENT HEBER
RESIDENTIAL LOCAL

EXHIBIT B



ROAD CROSS SECTION – 50' RIGHT OF WAY
(NOT TO SCALE)

RED LEDGES PRIVATE LOCAL

EXHIBIT C

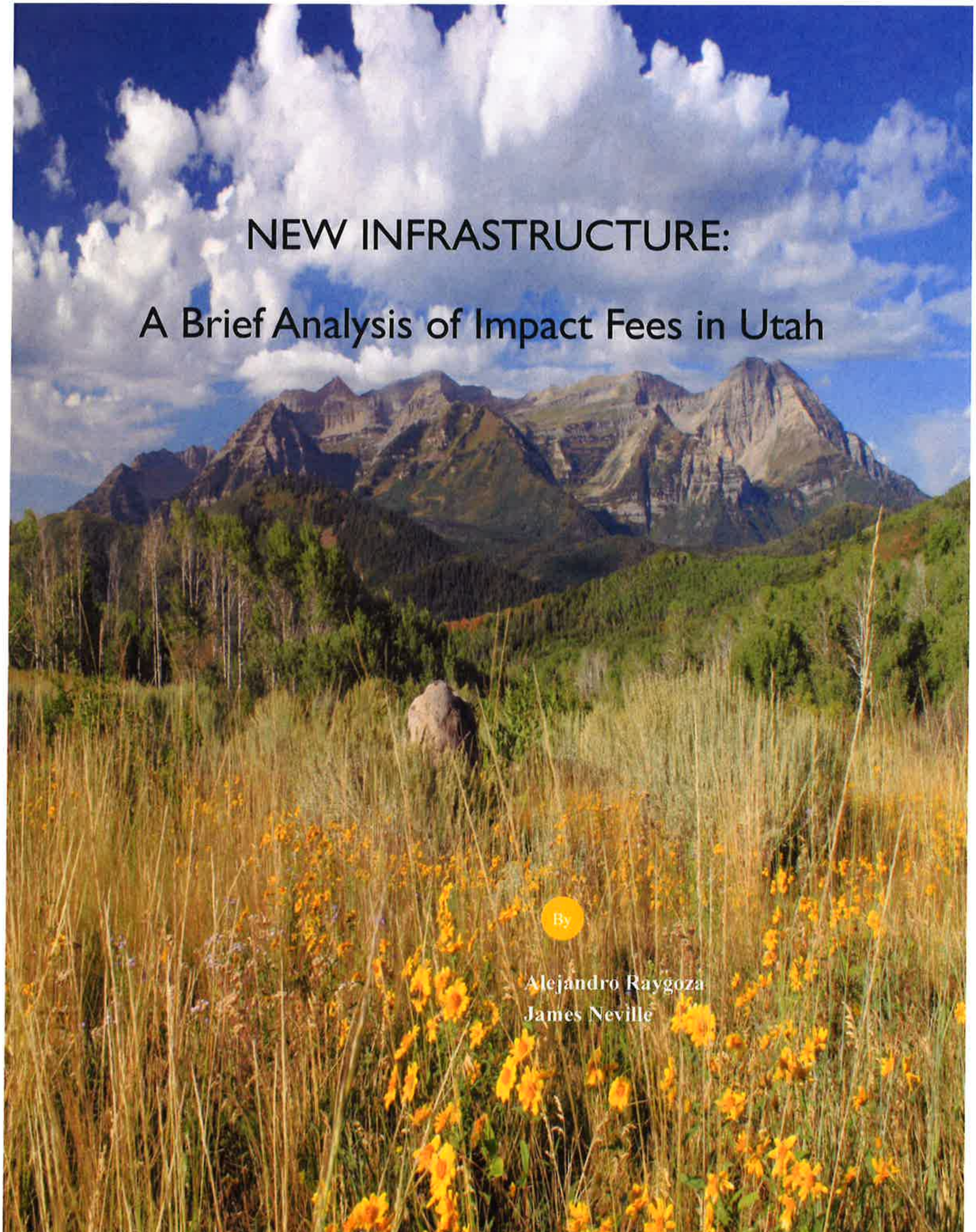

650 S. 200 E.
24' Path / 34' Asphalt
02/06/2008


100 W. Lucern Dr
21' Path / 26' Asphalt
02/06/2008

TAB 3

NEW INFRASTRUCTURE:

A Brief Analysis of Impact Fees in Utah



By

Alejandro Raygoza
James Neville

CONTENTS

IMPACT FEE FUNDAMENTALS

According to the Utah Office of Property Rights, impacts fees are

> A one-time charge imposed by local governments to mitigate the impact of local infrastructure caused by new development. Growth in the form of new homes and businesses requires expansion or enlargement of public facilities **to maintain the same level and quality** of public services for all residents of a community. Impact fees help fund expansion of public facilities necessary to accommodate new growth.

COSTS ASSOCIATED WITH GROWTH

We must keep in mind that impact fees can only be used for development purposes that will be the result or impact of growth in the community. Furthermore, money collected from impact fees can only be used for the category from which it was collected (e.g., road impact fees can only be used for construction of roads). Impact fees cannot be used to maintain or fix current infrastructure, or be used to increase the level or quality of services.

While the absolute value of impact fees from different cities can be compared, one should not make any judgements about the appropriateness of the amount charged by City X or City Y based solely on these figures.

To help us recognize costs associated with growth, here are some important terms found in a Salt Lake City council report that we need to be familiar with:

Growth: To determine if a project is solely related to growth, we ask "Is this project designed to maintain the current level of service as growth occurs?" and "Would the City still need this capital project if it weren't growing at all?" Growth projects are only necessary to maintain the City's current level of service as growth occurs. It is thus appropriate to include 100 percent of their cost in the impact fee calculations. An example of a purely growth related project would be additional park acreage to continue the current ratio of acreage to population.

Repair & Replacement: We ask, "Is this project related only to fixing existing infrastructure?" and "Would the city still need it if it weren't growing at all?" Repair and replacement projects have nothing to do with growth. Therefore, it is not appropriate to include any of their cost in the impact fee calculations. One example of this type of project would be a playground replacement.

MITIGATING LOSSES

Economic loss is minimized when the citizen's value of the added infrastructure is close to the actual amount paid in impact fees.

Upgrade: We ask, "Would this project improve the city's current level of service?" and "Would the city still do it even if it weren't growing at all?" Upgrade projects have nothing to do with growth. It is thus not appropriate to include any of their cost in the impact fee calculations.

Mixed: Some capital projects are partially necessitated by growth, but also include an element of repair, replacement, and/or upgrade. In this instance, a cost amount between 0 and 100 percent should be included in the fee calculations. Although the project might be an upgrade of or replacement to an existing facility, its scope will create capacity necessary to serve projected growth.

Notice

For this study we only took into account impact fees charged by each city. Other fees may apply that have not been included.

HOW ARE IMPACT FEES DETERMINED?

Impact fees are governed by the Impact Fees Act, found in Chapter 11-36a of the Utah Code. As part of the act, the state of Utah requires cities to conduct a thorough analysis and prepare a long-term (10+ years) development plan.

After future capital investment expenses are estimated along with the cost to maintain the existing level of public services, cities calculate the portion of the cost that pertains to growth. It is based on this figure that cities do their impact fee calculations. (Office of Property Rights, 2015)

Table 1: Impact Fees Use

Purpose:	Yes	No
Increasing quality of service		✗
Fix or replace current infrastructure		✗
Upgrade current capital		✗
New infrastructure associated with growth needed to offer same level of service	✓	

APPLES VS ORANGES

While the absolute value of impact fees from different cities can be compared, one should not make any judgements about the appropriateness of the amount charged by City X or City Y based solely on these values. This is because cities differ greatly one from another. This should not be surprising since the costs of two identical houses would not have the same cost in two different cities; the cost of land, materials, labor, permits, etc., will most definitely vary. Even within the same city, some areas are more expensive than others.

Something similar affects impact fees. Think of cities as the providers of a bundle of infrastructure and services. Every city is unique in what they have to offer to their residents. This is why some people decide to live New York while others flee from big cities and choose to live in Montana.

So how can we know if we are doing it right? We know that we cannot argue on the grounds of absolute values, but we can analyze our assumptions and check our estimates. Since impact fees calculations depend on the future total cost of development associated with growth, two things we could do are to make sure that the values that we use to estimate the cost are reasonable, and that the cost of development is fairly distributed among those who pay the impact fees.

All things considered...

Though cities have some discretion on how they allocate development costs and calculate their impact fees, this process should not be arbitrary, but rather founded on sound economic/financial analysis as well as population growth projections and public service demand forecasts. A Council Staff Report done by Salt Lake City in 2014 contains the following important questions which can aid in starting or evaluating a city's impact fees calculation process:

1. Who is currently served by the city police, fire, parks, and streets/transportation departments? This includes the number of residential units and non-residential square feet.
2. What is the current level of service provided by the city? Since an important purpose of impact fees is to fund the capital facility necessary to maintain the current service level, it is necessary to know the levels of service it is currently providing to the community.
3. What current assets allow the city to provide this level of service? This provides a current inventory of assets used by the city, such as facilities, land and equipment (where eligible). In addition, each asset's replacement value was calculated and summed to determine the total value of the departments' current assets.
4. What is the current investment per residential household and non-residential square foot? In other words, how much have current residential and non-residential land uses "paid into" the total value of current departmental assets?
5. What future growth is expected in the city? How many new residential households and non-residential square feet will the city serve over the IFFP period? How many more people will be demanding a continuation of the current level of service enjoyed by city residents?
6. What new infrastructure is required to serve future growth? For example, how many new parks or fire stations will be needed by the city within the next ten years to maintain the current service level?
7. What impact fee is required to pay for the new infrastructure? We calculated an apportionment of new infrastructure costs to future residential and nonresidential land-uses for the City. Then, using this distribution, the impact fees were determined. (Bruno & Sean, 2014)

ECONOMIC IMPLICATIONS OF IMPACT FEES

Impact fees can be thought of as a type of excise tax, except in this case there is a benefit directly derived from the fee. This is important to know because generally taxes lead to substantial economic losses. In respect of impact fees, economic losses can be mitigated by providing services and infrastructure that homebuyers and businesses value. This loss is minimized when the citizens' value of the added infrastructure is close to the actual amount paid in impact fees.

WHAT ABOUT PROPERTY TAXES?

When considering impact fees we must also think about property taxes. This is because the property tax base is the total cost of the property, and since impact fees tend to raise the price of homes and buildings, the amount paid in property taxes increases as well. To understand this process better, we should recall the concept of capitalization.

CAPITALIZATION OF COSTS AND BENEFITS

Capitalization is the present value of future costs and benefits. Explained in the vernacular, this means that the promised new infrastructure and services that will be financed by impact fees will increase the current value of the homes, and consequently, the price of new homes and buildings will increase as well. When doing cost benefit analysis of this sort, we must think in terms of present value because the money we use today to pay impact fees will not have the same value in the future. Thus, if we use a discount rate to calculate the present value of those benefits in the future, we could compare the amount paid in impact fees against the present value of the future development. If the fee is equal to the present value, then we can say that our impact fee calculations were right. We must not forget, though, that each individual values things differently. For some the benefits will be greater than the cost, for others the opposite will be true.

IMPACT FEE EQUILIBRIUM

If used properly, impact fees can be a great way to alleviate the burden on local governments associated with building new infrastructure. However, as we discussed earlier, if we are not careful, impact fees can lead to big economic losses.

Regarding taxes, economist Arthur Laffer explains that there is an optimal point of taxation beyond which, tax revenue falls rather than increases. Think about it, if the personal income tax rate suddenly increased to 90%, many individuals would decrease the amount of hours they work, some would even stop working altogether, and others would even leave the country. **Similarly, if cities overcharge businesses and developers in their impact fees, they will choose to invest somewhere else.** In this case, the optimal point for impact fees is where the total amount paid in impact fees equals the present value of the promised infrastructure and services.

Get your money's worth

The Office of the Property Rights Ombudsman (OPRO) is a mediator between governments and the private sector to protect and preserve property rights. OPRO responds to requests for advice. They provide their expertise free of charge.

Furthermore, the OPRO can do a confidential advisory opinion. For only $150, any party to a dispute involving local land use regulations or impact fees can request that the OPRO investigate an issue and provide a written opinion outlining how the law would be applied to the matter if it went to court and why.

HEBER CITY'S IMPACT FEES

Heber City does not anticipate a total build-out for a few decades, but they are properly planning how the City's public facilities will be taken care of now. The collection of impact fees from new development is one way to offset the cost of adding and/or expanding the existing infrastructure. Because population growth, property values, inflation, zoning, and other variables change from year to year, Heber City adjusts their impact fees periodically. The city has adopted a policy that indexes cost of improvements to inflation and automatically adjusts impact fees. Heber City charges impact fees for four main purposes. The process of calculating how much is to be paid is based on a variety of details.

For example, **the street impact fee** is based on how many trips per day a new development is going to create. The Institute of Transportation Engineers has a book about trip generation. From extensive studies, they predict how many new trips per day certain types of developments will create. A new industrial building will create 6.96 trips per 1000 square feet. A new office building will create 11.01 trips per 1000 square feet. Hotels create 8.5 new trips per day for each room. After determining how many trips a development will create, that number is multiplied by $84 to determine how much will be paid in street impact fees.

The culinary impact fee is a flat rate based on the meter size. For example, a 1.0'' meter has a culinary impact fee of $4,571. A 2.0'' meter has a fee of $18,280.

The sewer impact fee is calculated using the number of gallons used per day. This is calculated by determining how many water fixtures a new development will have and how much water each fixture will use. For example, an automatic clothes washer has a unit value of 3, a shower has a unit value of 2, a drinking fountain has a unit value of 0.5, and a bathroom group (shower, tub, and sink) has a unit value of 5. The gallons per day by unit is 11 for industrial and office buildings and 22 for hotels. After multiplying the unit value by the gallons per day by unit then that number is divided by 211 which is the residential equivalent of gallons per day. This number multiplied by $1,311 gives the final amount due for the Heber City sewer impact fee and by $3,290 which gives the final amount due to the Heber Valley Special Service District, collected by Heber City. When you add those two numbers together then you know what the final sewer impact fee amount will be.

The irrigation impact fee is calculated by taking the square feet of the new development (subtracting the building and parking) and multiplying that number by $0.10.

There are other fees associated with building and development; however, these are the four fees which Heber City charges as part of their impact fees for commercial development. These funds will allow the city to accommodate for the growth of the city while maintaining the same level of service they currently provide.

Table 2: Estimated Impact Fee Costs

Heber City		Total
Shop and Warehouse	$	25,798
Office	$	39,812
Hotel	$	293,226

Saving for a rainy day?

According to OPRO, money raised from impact fees should be used within 6 years. Though the burden of proof falls on the plaintiff and proving that funds have not been used is difficult, companies can and have sued cities on this matter.

IMPACT FEE COMPARISON

This section contains the expected amount that a hotel, a warehouse, and an office would have to pay in impact fees in 10 different cities (For building specs refer to appendix 1).

With the help of Utah city officials and staff, we prepared two tables. One informs us of the different types of impact fees that are collected by each city, and the other one shows the total amount that should be paid for each building.

We must reiterate that these values are only estimates and are not meant to represent rankings of any sort, rather they are meant to indicate how vastly impact fees can differ from one city to another. Four reasons why these values cannot be used to rank cities are that:

1. As mentioned before, cities offer different public services at different levels
2. Geographical location affects development costs
3. For some cities, Lindon for example, the road impact fee only applies in certain areas of the city. Thus, the total amount paid in impact fees will depend on the location of the building.
4. Some cities require the payment of other impact fees that are not collected by the city itself. Consequently, City X may appear cheaper than City Y while in reality City X's impact fees may more expensive when the fees not collected by the city are added.

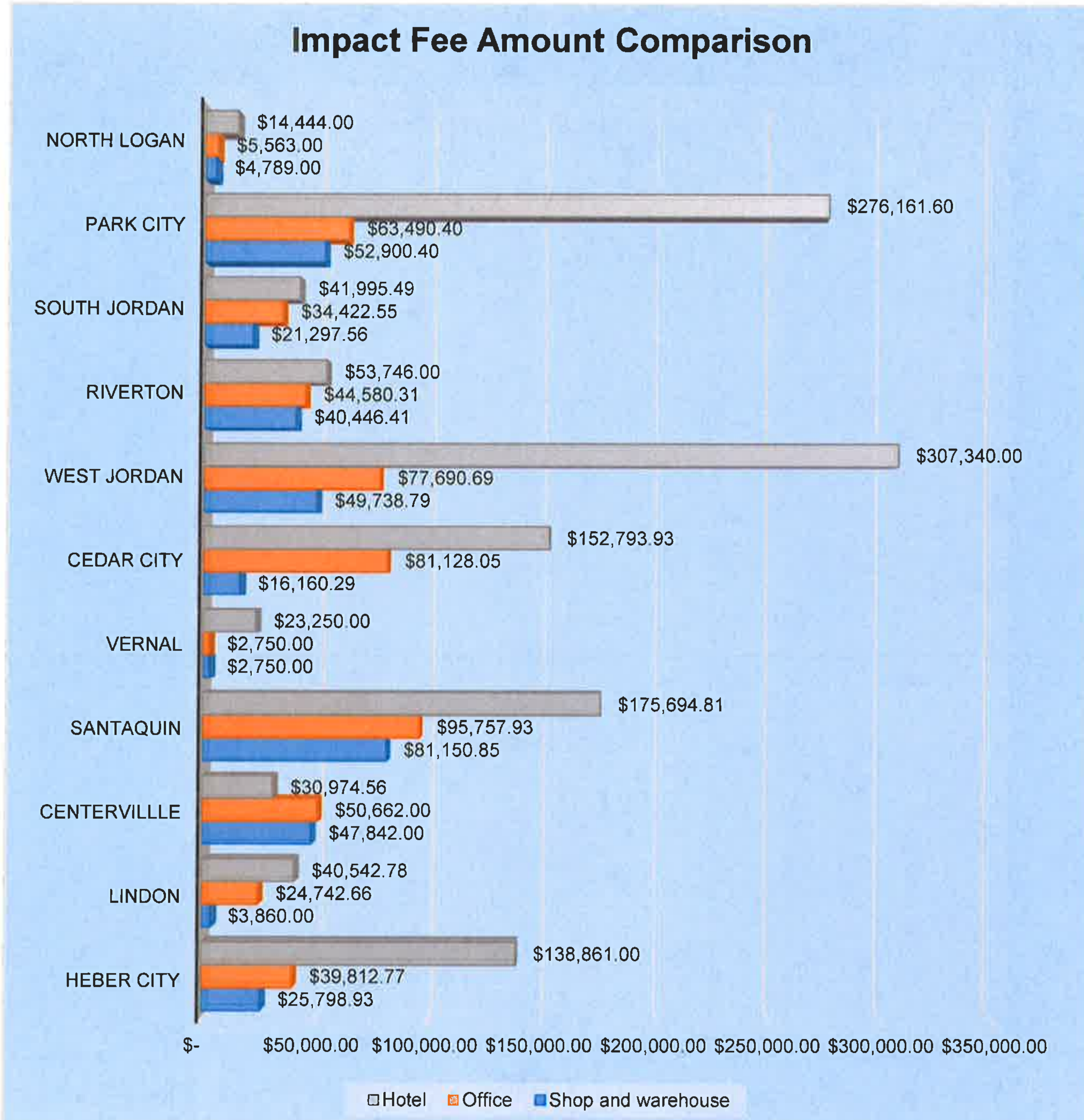
*For more details refer to appendix 1.

Did you know?

The number one complaint that the Utah Office of Property Rights Ombudsman receives regarding impact fees is that cities often inflate their current level of services and the amount required to maintain it.

Table 3: Impact Fees per City

	Centerville	Lindon	North Logan	Santaquin	Vernal	Cedar City	West Jordan	Riverton	South Jordan	Park City	Heber City
Water	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Sewer		✓	✓	✓	✓	✓	✓	✓			✓
Storm Water	✓	✓				✓	✓	✓	✓		
Road			✓	✓		✓	✓	✓	✓	✓	✓
Pressurized Irrigation				✓							✓
EMS/Fire	✓			✓		✓	✓		✓		
Police				✓		✓	✓		✓	✓	
Water Meter Fee	✓			✓							
Water Acquisition						✓					
Parks/Trails										✓	



RECAP AND CONCLUSION

As we have seen, it is impossible to compare impact fees across different cities. The methods used to calculate impact fees vary greatly from city to city and so do the amounts charged. If developers and investors feel that the cost of the fee is higher than the value to them, cities may face a significant reduction in investment that would reduce their economic growth rate. To avoid this, city officials should regularly evaluate their projections and impact fee calculation methods.

APPENDIX 1 BUILDING SPECS

All impact fees calculations were based on the following values:

	Shop and Warehouse	Office	Hotel
Size (sq. feet)	24,000.00	30,000.00	58,669.00
Meter Size	1 inch	1 inch	2 inch
Fixtures	20	20	400
Sewer Residential Unit Eq.	1.3	1.3	46.9
Rooms	-	-	80
Total Land (acres)	6	6	2
Total Land (sq. feet)	261,360	261,360	87120

APENDIX 2 - CITIES PRELIMIRARY CALCULATIONS

Heber	Road	Water	Sewer	Irrigation	Total
Shop and warehouse	$ 14,031	$ 4,571	$ 5,997	$ 1,200	$ 25,799
Office	$ 27,745	$ 4,571	$ 5,997	$ 1,500	$ 39,813
Hotel	$ 56,120	$ 18,280	$ 61,511	$ 2,950	$ 138,861

North Logan	Road	Water	Sewer	Total
Shop and warehouse	$ 423	$ 3,319	$ 1,047	$ 4,789
Office	$ 1,197	$ 3,319	$ 1,047	$ 5,563
Hotel	$ 471	$ 10,621	$ 3,352	$ 14,444

Centerville	Fire/EMS	Water Fee	Water Develop.	Storm Water	Total
Shop and warehouse	$ 600	$ 310	$ 23,466	$ 23,466	$ 47,842
Office	$ 3,420	$ 310	$ 23,466	$ 23,466	$ 50,662
Hotel	$ 14,081	$ 1,250	$ 7,822	$ 7,822	$ 30,975

Vernal	Water	Sewer	Total
Shop and warehouse	$ 1,250	$ 1,500	$ 2,750
Office	$ 1,250	$ 1,500	$ 2,750
Hotel	$ 3,250	$ 20,000	$ 23,250

Lindon	Sewer	Water	Storm Water	Total
Shop and warehouse	$ 2,581	$ 1,279	$ 10,441	$ 14,301
Office	$ 2,581	$ 1,279	$ 10,441	$ 14,301
Hotel	$ 34,413	$ 2,649	$ 3,480	$ 40,543

Park City	Parks, Trails	Police	Road	Water	Total
Shop and warehouse	$ -	$ 10,680	$ 7,680	$ 34,540	$ 52,900
Office	$ -	$ 16,650	$ 12,300	$ 34,540	$ 63,490
Hotel	$ 80,000	$ 37,600	$ 20,400	$ 138,162	$ 276,162

South Jordan	Public Safety	Water	Storm Water	Road	Parks	Total
Shop and warehouse	$ 1,356	$ 5,324	$ 956	$ 13,662	$ -	$ 21,298
Office	$ 1,005	$ 5,324	$ 1,118	$ 26,976	$ -	$ 34,423
Hotel	$ 322	$ 5,324	$ 3,240	$ 33,022	$ 87	$ 41,995

Riverton	Road	Storm Water	Parks	Sewer	Water	Total
Shop and warehouse	$ 27,456	$ 3,362	$ 2,675	$ 2,903	$ 4,050	$ 40,446
Office	$ 31,020	$ 3,932	$ 2,675	$ 2,903	$ 4,050	$ 44,580
Hotel	$ 32,720	$ 11,398	$ 2,675	$ 2,903	$ 4,050	$ 53,746

West Jordan	Fire	Police	Road	Storm	Water	Sewer	Total
Shop and warehouse	$ 4,296	$ 1,248	$ 31,536	$ 7,128	$ 3,266	$ 2,265	$ 49,739
Office	$ 6,090	$ 2,130	$ 53,520	$ 10,420	$ 3,266	$ 2,265	$ 77,691
Hotel	$ 7,198	$ 10,738	$ 245,617	$ 38,256	$ 3,266	$ 2,265	$ 307,340

Cedar City	Drainage	EMS/Fire	Police	Sewer	Road	Water	Water Acquisition	Total
Shop and warehouse	$ 3,162	$ 6	$ 1,061	$ 1,488	$ 5,977	$ 2,994	$ 1,472	$ 16,160
Office	$ 4,514	$ 7,089	$ 3,774	$ 1,488	$ 59,798	$ 2,994	$ 1,472	$ 81,128
Hotel	$ 8,816	$ 13,847	$ 7,372	$ 1,488	$ 116,804	$ 2,994	$ 1,472	$ 152,794

Santaquin	Sewer	Water	Water Meter	EMS	Police	Road	Irrigation	With Irrigation
Shop and warehouse	$ 4,000	$ 2,190	$ 400	$ 108	$ 228	$ 643	$ 73,582	$ 81,151
Office	$ 16,000	$ 2,190	$ 400	$ 2,834	$ 1,666	$ 946	$ 71,722	$ 95,758
Hotel	$120,000	$ 6,988	$ 770	$ 5,479	$ 3,221	$ 30,417	$ 8,820	$ 175,695

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TAB 4

Mark Anderson

From:	Brad Lyle <brad@millstreamgroup.com>
Sent:	Thursday, July 30, 2015 3:26 PM
To:	manderson@ci.heber.ut.us
Cc:	Tony Kohler (tkohler@ci.heber.ut.us); Dave Nelson
Subject:	RV Resort Zone Change Agreement

Mark,

In an effort to avoid confusion with City Council at the 8/6 work meeting about the implementation of the staff request to modify the road construction triggering event found on page 3, section 3.c.iii we would offer the following formula for consideration to be included in the document. The actual road construction number is not as significant as the assumed number of years to be discounted back to present value and the discount rate. Those are the key factors. If the city wants to get a best guess from Bart Mumford as to cost we're fine with that but we simply put in $100,000 so they can get the idea of how the discounting is done and the end result.

If you assume;

1. Shelton's wouldn't develop for at least 4 years, triggering mechanism 3.c.i , which is what our notes reflect was the intent of that provision, and
2. We wouldn't have any need to develop the road until we break ground on phase 3 of the property, conservatively 4 years also, which was the intent of 3.c.ii,

Then you would take the estimated cost for 40% of the 36 foot wide road, let's say our 40% equals $100,000 and input that as the future value, input 0 as payment, we suggest 6% is very fair for our opportunity cost of funds and input 4 years of discount, then compute the future value back to today's dollars and we would contribute $79,209 for road construction tomorrow.

Best,

Brad Lyle, CCIM, CPM, ALC
Millstream Group LLC
Summit Commercial Real Estate
380 East Main Street, Building B, 2nd Floor
Midway, Utah 84049
Office 435-657-1400 Ext. 318
Fax 888-229-0194
Cell 435-671-2525
brad@millstreamgroup.com

Heber City Council
Meeting date: August 13, 2015
Report by: Anthony L. Kohler

Re: Millstream RV Park Agreement

Last year the city approved a zone change from R-3 Residential to C-2 Commercial subject to an agreement with Millstream, the developer of the RV Park. Staff recently has met with Millstream to better understand Millstream's comments on the proposed agreement and how to better draft the agreement to be consistent with approvals and to have clear consistent language throughout the document.

Format of the agreement. The previous draft was cumbersome because it had a copy of a road proposal as an exhibit, yet the agreement amended the exhibit with contrasting language. The agreement also addressed property sales that had already closed between adjoining property owners, which is no longer necessary to address. And the agreement had language that conflicted with one of the exhibits regarding facilities along the western edge of the RV Park. The proposed agreement has been modified to address these inconsistencies.

Planter strip maintenance. Since Millstream cannot use the road except for emergency purposes, they would like to minimize their maintenance of the planter strip to xeriscape landscaping. They are willing to fully landscape the area if the city takes on the maintenance; and they would be willing to maintain full landscaping of the area if they were provided with the option of full access to the street. Millstream is not proposing to utilize the street for primary access to the property, but would feel more comfortable about maintaining the street landscaping if the option was there for the future. This access would likely occur only if the use of the property changed from an RV park.

ZONE CHANGE AGREEMENT
Mountain Valley RV Resort

THIS AGREEMENT is entered into this ______ day of __________________, 2014, by and between Heber City (the "City") and MWE Mountain Valley RV Resort(the "Developer").

WHEREAS, the Developer has proposed a zone change for a portion of the following described property from R-3 Residential to C-2 Commercial:

LEGAL DESCRIPTION:

Parcel ID:	**00-0020-1133**
Parcel Serial:	**OHE-1689-0-008-045-0000**

Excepting the western 20 feet of the following described property:

PARCEL 1:

BEGINNING AT A POINT 100 RODS WEST OF THE SOUTHEAST CORNER OF SECTION 8, IN TOWNSHIP 4 SOUTH OF RANGE 5 EAST OF THE SALT LAKE MERIDIAN; AND RUNNING THENCE WEST 20 RODS; THENCE NORTH 80 RODS; THENCE EAST 6.10 RODS; THENCE SOUTH 37°50' EAST 22.66 RODS; THENCE SOUTH 62.11 RODS TO THE PLACE OF BEGINNING.

EXCEPTING THEREFROM ANY PORTION OF THE ABOVE LEGAL THAT MAY LIE WITHIN THE BOUNDARIES OF U.S. HIGHWAY 40.

PARCEL 2:

BEGINNING AT THE SOUTHWEST CORNER OF THE SOUTHEAST QUARTER OF SECTION 8, IN TOWNSHIP 4 SOUTH OF RANGE 5 EAST OF THE SALT LAKE MERIDIAN; AND RUNNING THENCE EAST 10 CHAINS; THENCE NORTH 20 CHAINS; THENCE WEST 10 CHAINS; THENCE SOUTH 20 CHAINS TO THE PLACE OF BEGINNING.

LESS AND EXCEPTING THAT PORTION OF GROUND CONVEYED BY THAT CERTAIN BOUNDARY LINE AGREEMENT RECORDED SEPTEMBER 28, 2006 AS ENTRY NO. 308337 IN BOOK 895 AT PAGE 47 OF OFFICIAL RECORDS.

ALSO LESS AND EXCEPTING THAT PORTION OF GROUND CONVEYED BY THAT CERTAIN BOUNDARY LINE AGREEMENT RECORDED SEPTEMBER 11, 2007 AS ENTRY NO. 325804 IN BOOK 949 AT PAGE 1098 OF OFFICIAL RECORDS.

WHEREAS, Developer has submitted a proposed concept plan for the expansion of an existing RV Resort, attached as Exhibit "1", which has been reviewed by staff and approved by the Planning Commission and City Council;

NOW, THEREFORE, the Parties hereby agree as follows:

1. **Compliance with Prior Agreements.** Parties acknowledge the terms and conditions of the previous Development Agreement dated October 11, 2012, attached as Exhibit 3 for reference, will apply to Phase 2 and Phase 3 of the RV Resort.

2. **Compliance with Approved RV Resort Expansion Plans.** The RV Resort Expansion Master Plan dated February 26, 2015 and shown in Exhibit 1 is the approved site plan for development of Phase 2 and Phase 3 of the RV Resort. The RV Resort shall be developed in a manner consistent with that site plan.

    a. **Lighting.** Lighting will comply with city standards imposed in the Phase 1 RV Resort which require hooded lights to minimize their intrusiveness.

    b. **Noise.** RV owners will not be allowed to operate generators within the RV Park.

    c. **Periphery Development Standards.** Option C of the Berg Engineering letter dated October 20, 2014, specifies approved development standards for portions of Phase 2 and 3 of the RV Resort, restated below in items 2.c.i. through 2.c.iv., with the exception of underlined verbiage, which is added for clarification of intent of the approved concept plan.

        i. Provide a 30 foot setback from the new westerly property line to nearest RV pad or building.

        ii. Install an 8 foot solid vinyl fence on top of a 2 foot concrete retaining wall at the new westerly property line.

        iii. Install a berm with evergreen and aspen trees along the RV Resort side of the fence, landscaped <u>in a manner consistent with the berms along the RV Resort's Highway 40 frontage as shown in Exhibit 2.</u>

        iv. Locate the trash dumpster, pavilions, fire pits and restroom buildings as shown on the approved final plan.

    d. **Open Space and Recreation Areas.** Open space and amenities shall be provided and maintained for the exclusive use of the RV Resort's customers and not the general public, similar to that shown on the proposed development plan in Exhibit 1, and will include a clubhouse and other recreational courts, a pool and spa, a dog park, a pavilion, a trail system and open landscaping areas.

3. **2400 South Street.** Heber City and Developer previously agreed to terms for the construction and dedication of 2400 South in a letter dated November 4, 2014 from Berg Engineering. The terms from that letter are restated below in items 3.a. through 3.d. below, with item 3.c.iii. added after the agreement was originally accepted due to new circumstances.

   a. The Mountain Valley RV Resort will dedicate a 72 foot right-of-way to Heber City for 2400 South Street along its southern property line. The road right-of-way will be dedicated to Heber City with construction of the roadway as outlined in Item c.

   b. The Mountain Valley RV Resort will participate in forty percent (40%) of the road construction costs for a local 36 foot wide road. Sewer, culinary water and pressurized irrigation improvements are already installed in the proposed road. Anticipated improvements include a 44 foot wide asphalt collector road, curb, gutter, sidewalk, storm drain, power for street lights and landscaping on the north side of road. Heber City is responsible for the 60% of the costs for the local road and the cost to upgrade the road to a collector road standard.

   c. The portion of 2400 South Street adjacent to the Mountain Valley RV Resort will be constructed when one of the following occurs:

      i. The segment of road between the Mountain Valley RV Resort and Highway 40 is under construction. Heber City shall notify the Mountain Valley RV Resort six (6) months prior to the beginning of construction for this segment of road.

      ii. As a condition of approval for Phase 3 of the Mountain Valley RV Park expansion, construction of 2400 South will be completed with the construction of the final phase of the RV Resort expansion.

      iii. **Addendum to original 2400 South Agreement.** If properties adjoining and to the south of the Mountain Valley RV Park develop as a school, the timing of the road dedication and construction will occur concurrent with construction of the school. Provided, however, Developer's participation in the road construction costs will be updated with the time value of money if construction occurs prior to item 3.c.i. and 3.c.ii. above.

d. The Mountain Valley RV Resort shall construct 2400 South Street. Heber City shall approve the bid amount for the road construction from the Mountain Valley RV Resort. A construction and cost sharing agreement between Heber City and the Mountain Valley RV Resort will be completed prior to the commencement of work on the road.

e. Access onto 2400 South and 2110 South shall be restricted to any required secondary access for emergency access or fire egress.

f. The fence along 2400 South shall be setback 3 feet from the sidewalk.

g. **2400 South Planter Strip.**

   i. The Mountain Valley RV Resort will landscape and maintain the Planter Strip along its frontage on the north side of 2400 South with a low maintenance xeriscape landscaping, with such plan to be agreed upon between city staff and Developer at time of development of 2400 South; or

   ii. Developer will install lawn, trees, an irrigation system and dedicate water rights for a Planter Strip to be landscaped in a manner consistent with the Planter Strip along Wheeler Road to the west in the Wheeler Park Subdivision. Heber City will take on long term maintenance responsibilities for the Planter Strip. In the event the City elects to permit Developer's property full access to 2400 South, Developer will take on long term maintenance responsibilities for the Planter Strip.

4. Once this agreement is signed by the respective parties with the requisite authority to bind the city and the developer it shall be recorded with Wasatch County Recorder. Thereafter the Zone Change Ordinance will be executed by Heber City and these obligations will become binding upon the parties.

5. This agreement and the attached Exhibits contain the entire agreement between the parties and no statements, promises or inducements made by either party shall be binding unless modified by a written document approved by both parties.

6. This agreement shall be a covenant running with the land and shall be binding upon the parties and their assigns and

successors in interest.

7. In the event there is a failure to perform any of the obligations of this agreement and it becomes necessary for either party to employ the services of an attorney, whether such attorney is inside counsel or private counsel, either with or without litigation, on appeal or otherwise, the prevailing party in the controversy shall be entitled to recover its reasonable attorney's fees and any costs and expenses incurred to enforce this agreement.

IN WITNESS WHEREOF, the Parties hereto have hereunto set their hands the day and year this agreement was first above written.

DATED this ________ day of ____________________, 2015.

HEBER CITY:

By: ________________________________

Alan McDonald, Mayor

ATTEST:

____

Heber City Recorder

Millstream Properties LLC, Developer:

By: ________________________________

David M. Nelson, Manager

STATE OF UTAH)
: ss.
COUNTY OF WASATCH)

On this _______ day of ________________, 2015, personally appeared before me the above named authorized representative of Developer, who duly acknowledged to me that Developer is the owner in fee of the land in the Mountain Valley RV Park and executed the same as such.

____

NOTARY PUBLIC

EXHIBIT 1: RV RESORT MASTER PLAN

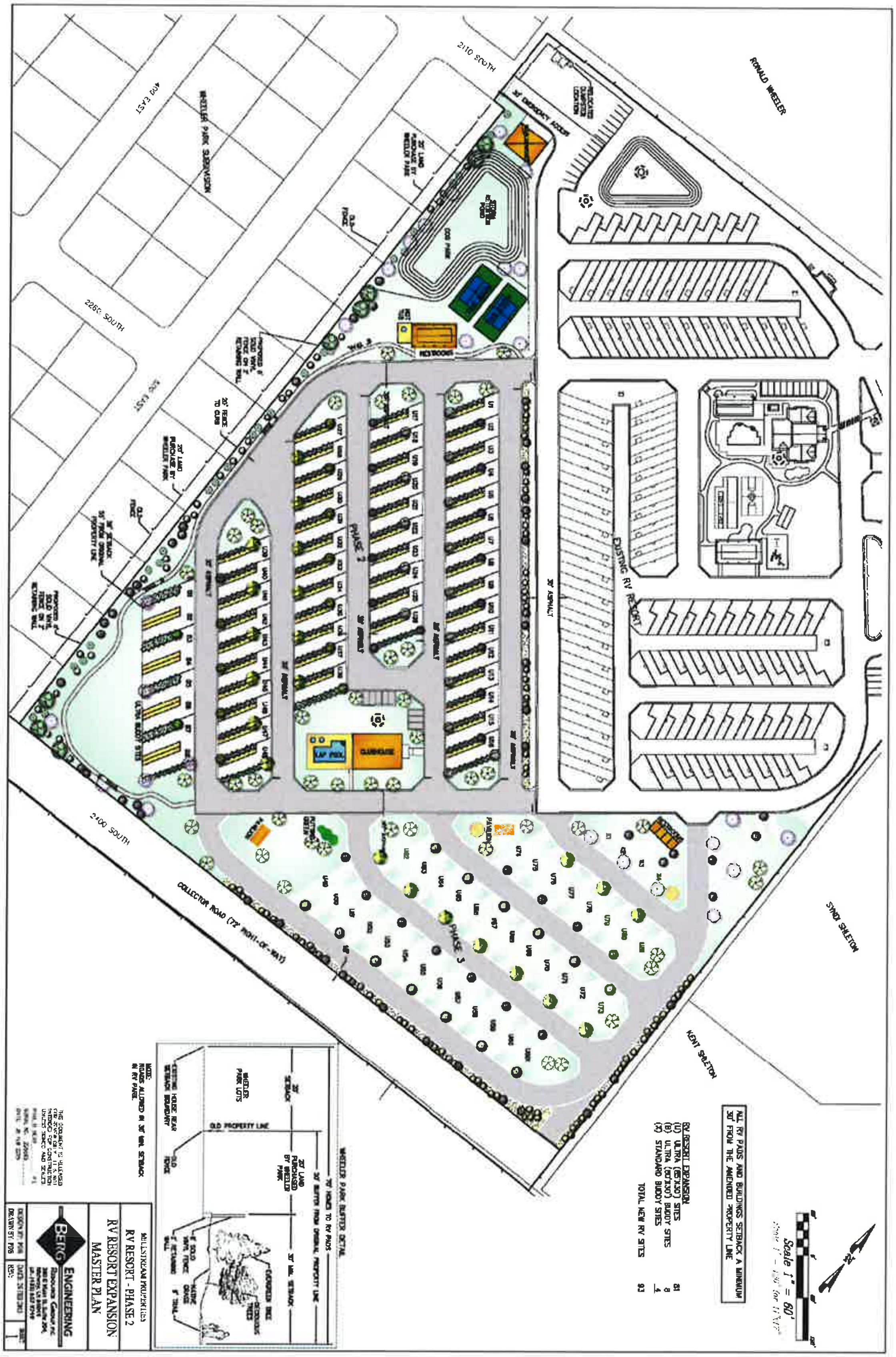
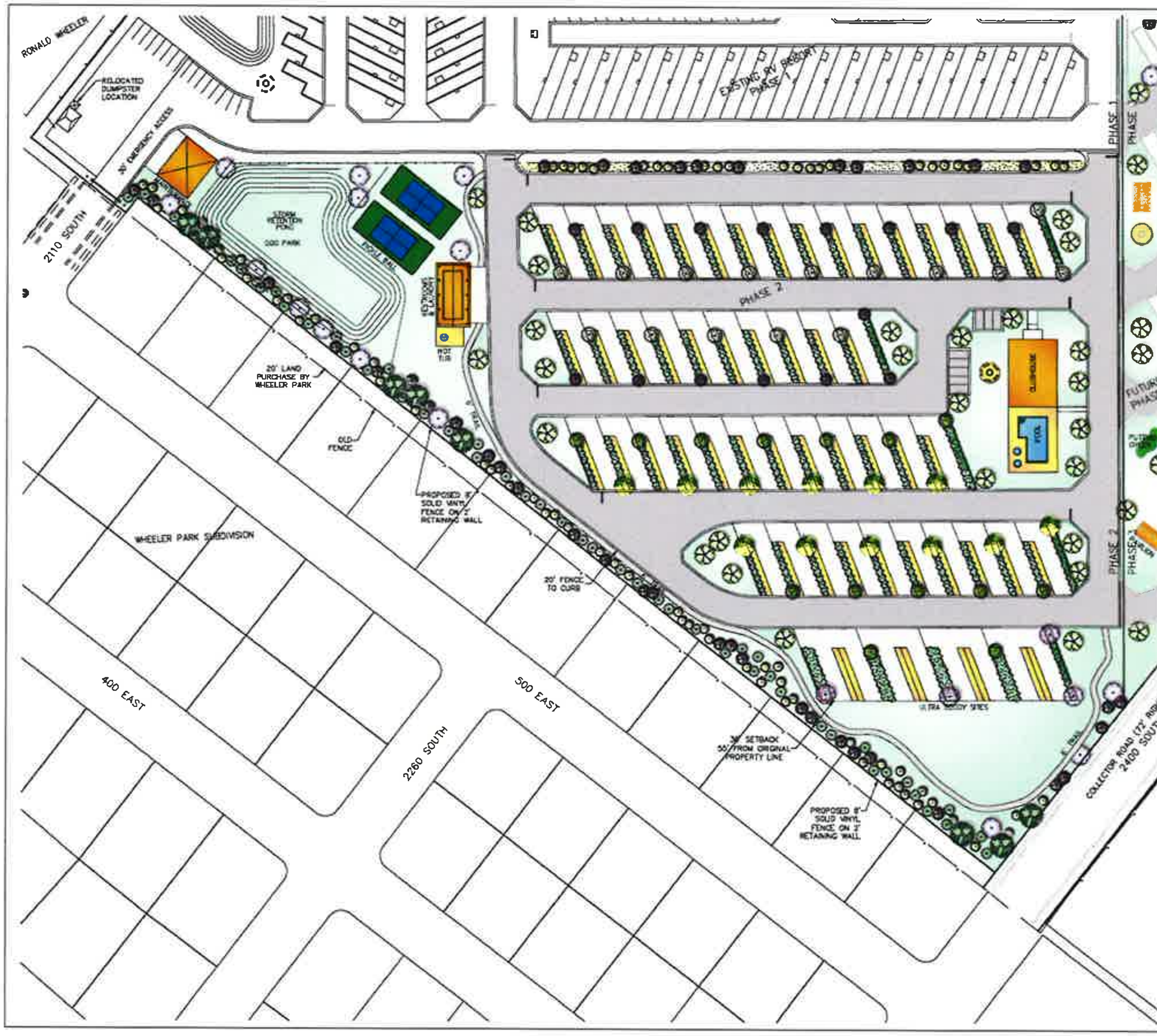


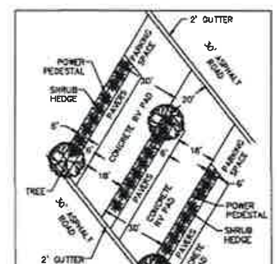
EXHIBIT 2: PHASE 3 LANDSCAPING PLAN



Scale 1" = 50'
Scale 1" = 100' for 11"x17"

PLANT SCHEDULE

TREES	QTY	COMMON NAME / BOTANICAL NAME	CONT	CAL	SIZE
	20	Autumn Purple Ash / Fraxinus americana 'Autumn Purple'	B & B	2"Cal	
	85	Canada Red Chokecherry / Prunus virginiana 'Canada Red'	B & B	2.5"Cal	
	8	[illegible] Cottonwood Standard / Populus deltoides '[illegible]'	B & B	2"Cal	
	48	Green Ash / Fraxinus pennsylvanica	B & B	2.5"Cal	
	48	Hoopsi Blue Spruce / Picea pungens glauca 'Hoopsii'	B & B		8'-10'
	22	Littleleaf Linden / Tilia cordata	B & B	2.5"Cal	
	130	Quaking Aspen / Populus tremuloides	B & B	2"Cal	
	27	Skyline Honeylocust / Gleditsia triacanthos 'Skyline'	B & B	2.5"Cal	
	15	Spring Snow Crab Apple / Malus x 'Spring Snow'	B & B	2"Cal	
SHRUB AREAS	**QTY**	**COMMON NAME / BOTANICAL NAME**	**CONT**		
	931	Shrub Hedge / Shrub Hedge	5 gal		
GROUND COVERS	**QTY**	**COMMON NAME / BOTANICAL NAME**	**CONT**		
	13,574 sf	2-4" Rock Mulch / Rock Mulch	mulch		
	216,305 sf	Kentucky Bluegrass / Poa pratensis	sod		



TYPICAL RV PAD

THIS DOCUMENT IS RELEASED FOR REVIEW ONLY. IT IS NOT INTENDED FOR CONSTRUCTION UNLESS SIGNED AND SEALED.
CARL N. BERG L.A.
SERIAL NO. 7492790
DATE: 27 MAR 2015

MILLSTREAM PROPERTIES
RV RESORT - PHASE 2

PHASE 2
LANDSCAPE PLAN

berg LANDSCAPE ARCHITECTS

DESIGN BY: PDB DRAWN BY: PDB	DATE: 27 MAR 2015 REV.	SHEET 4

7

EXHIBIT 3: DEVELOPMENT AGREEMENT

DEVELOPMENT AGREEMENT
AND
COVENANT RUNNING WITH THE LAND
Millstream RV Park

THIS AGREEMENT entered into this 11 day of October, 2012, by and between Heber City, hereinafter referred to as "City" and the undersigned as "Developer".

Whereas:

Millstream Properties LLC, owns approximately 29.23 acres along US Highway 40 in Heber City at approximately 2120 South Highway 40. Approximately 14.70 acres of the property is located in the C-2 commercial zone.

Recreation vehicle courts are a permitted use in the C-2 Commercial Zone under Section 18.28.030.P of the Heber City Municipal Code.

The Heber City Planning Commission reviewed the concept plan for the proposed recreation vehicle development on March 8, 2012.

The Heber City Planning Commission granted final approval for the recreation vehicle development on April 24, 2012.

NOW, THEREFORE, the parties hereby agree as follows.

Developer shall:

1. Improve US Highway 40 to allow safe movement of traffic on the highway and for users of the RV Park. A general description of the improvements that will be required by UDOT include:

    a. Installation of a deceleration lane from approximately Airport Road to the project entrance.
    b. Installation of an acceleration lane from the project entrance to approximately 1,030 feet to the south.
    c. Installation of a left turn lane for traffic turning into the RV Park

2. Design and construct approximately 1,750 feet of a first offsite sewer line from East Airport Road to the south property line of the RV Park along US Highway 40. Also, Design and construct approximately 3,100 feet of a second offsite sewer line from East Airport Road to the Flood

Channel to the north, if UDOT approval is obtained. City will be provided copies of bids received prior to beginning construction for review and approval. Said sewer line is part of the Heber City master plan to serve commercial properties along US Highway 40 and funded through impact fees. Upon final acceptance of sewer line, Heber City will reimburse Millstream Properties the cost of the sewer lines less the amount due for sewer impact fees for the RV Park development. In the future, Heber City will complete any remaining sections of the sewer line downstream from East Airport Road to make the sewer operational if these sections are not able to be completed with the project.

3. Design and construct approximate 1,750 feet of water line from East Airport Road to the south property line RV Park along US Highway 40. City will be provided copies of bids received prior to beginning construction for review and approval. Said water line is part of the Heber City master plan to serve commercial properties along US Highway 40 and funded through impact fees. Upon final acceptance of water line, Heber City will reimburse Millstream Properties the cost of the water line less the amount due for water impact fees for the RV Park development.

4. Construct a temporary sewer lift station on the property. The sewer lift station will pump collected sewage from the RV Park to the existing sewer system in the Wheeler Park Subdivision if the second offsite US Highway 40 sewer line is not extended downstream by this project or others. Millstream Properties is responsible for construction, operation, and maintenance of the temporary lift station. Once the second offsite US Highway 40 sewer is extended and operational, Millstream Properties will be responsible for abandoning the temporary lift station and begin using the gravity sewer within 120 days.

5. Dedicate and record a utility and access easement to Heber City for the public water mains, fire hydrants, and meters with in the development.

6. Dedicate a trail easement and install an eight foot (8') asphalt trail along the property frontage of US Highway 40. Record a deed restriction on the property to construct an asphalt trail, per City standards, at such time as the City requires.

7. The intent of the RV Park is for short term and seasonal recreational visitors. Stays longer than 6 months will be prohibited per the management and operations plans for the RV Park, violation of which may include revocation of the

park business license.

8. Millstream Properties will provide an onsite manager for the RV Park. The manager will have a full time residence living quarters in the upstairs of the office / recreation center building. In addition to the onsite manager, Millstream Properties will also have 24 hour on call property management service available for the RV Park.

Heber City shall:

1. Reimburse Millstream Properties for the first and second offsite sewer lines installed by the project in US Highway 40 from East Airport Road to the Flood Channel to the north. Said reimbursement will be due within 60 days after final City acceptance of the project and facilities, and based on the actual cost paid for the work as shown in copies of the construction invoices submitted to the City.

2. Reimburse Millstream Properties for the water line installed in US Highway 40 from East Airport Road to the south property line of the RV Park. Said reimbursement will be due within 60 days after final City acceptance of the project and facilities, and based on the actual cost paid for the work as shown in copies of the construction invoices submitted to the City.

3. Extend and complete the gravity sewer line downstream of East Airport Road, where the sewer line in US Highway 40 constructed by this project ends, within five (5) years of the date this agreement, if not completed by this project.

4. Allow building permits to be released for the construction of the office / recreation center building and other RV Park buildings once:

    a. water system, including all fire hydrants within the development is complete, tested, and approved by Heber City.
    b. water systems ability to provide fire protection to the structures under construction is verified by the Wasatch County Fire Department.
    c. a minimum 30 foot access road to structures is completed and open at all times.

   Occupancy will not be granted until the overall project receives final acceptance by the City.

All water mains, fire hydrants, and meters designated as public facilities within the development will be dedicated, controlled, and maintained by Heber City. All water facilities downstream of the water meter will be controlled and maintained by Millstream Properties. Modifications to the public water facilities require prior written approval from Heber City.

All sewer, storm water, and irrigation facilities within the project are private and the responsibility of Millstream Properties. The private pool within the project will not be allowed to drain or discharge into the sewer system without written permission from Heber City.

In the event there is a Failure to Perform under this Agreement and it becomes reasonably necessary for any party to employ the services of an attorney in connection therewith (whether such attorney be in-house or outside counsel), either with or without litigation, on appeal or otherwise, the losing party to the controversy shall pay to the successful party reasonable attorney's fees incurred by such party and, in addition, such costs and expenses as are incurred in enforcing this Agreement;

This Agreement contains the entire agreement between the parties, and no statement, promise or inducement made by either party hereto, or agent of either party hereto which is not contained in this written Agreement shall be valid or binding; and this Agreement may not be enlarged, modified or altered except in writing approved by the parties.

Time is of the essence of this Agreement. In case any party shall fail to perform the obligations on its part at the time fixed for the performance of such obligations by the terms of this Agreement, the other party or parties may pursue any and all remedies available in equity, at law, and/or pursuant to the terms of this Agreement.

This Agreement shall be a covenant running with the land, and shall be binding upon the parties and their assigns and successors in interest. This Agreement shall be recorded with the Wasatch County Recorder.

IN WITNESS WHEREOF, the parties hereto have hereunto set their hands the day and year this agreement was first above written.

DATED this 11 day of October, 2012.

HEBER CITY:

By: [signature]
David Phillips, Mayor

HEBER CITY CORPORATE Seal WASATCH COUNTY, UTAH

Attest by:

[signature: Michelle Kellogg]
Michelle Kellogg, City Recorder

OWNER, Manager

By: [signature]
Millstream

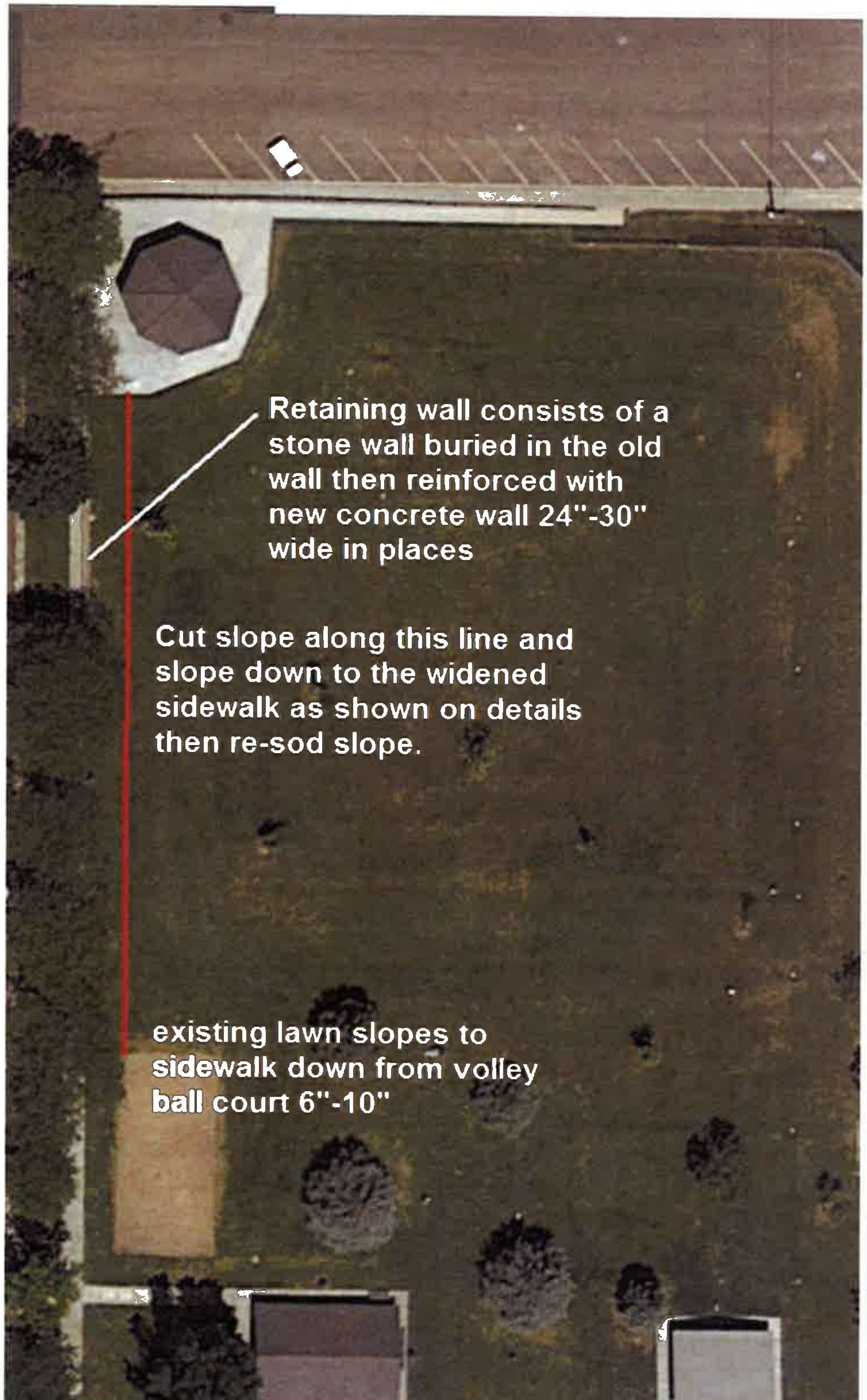
STATE OF UTAH)
: ss.
COUNTY OF WASATCH)

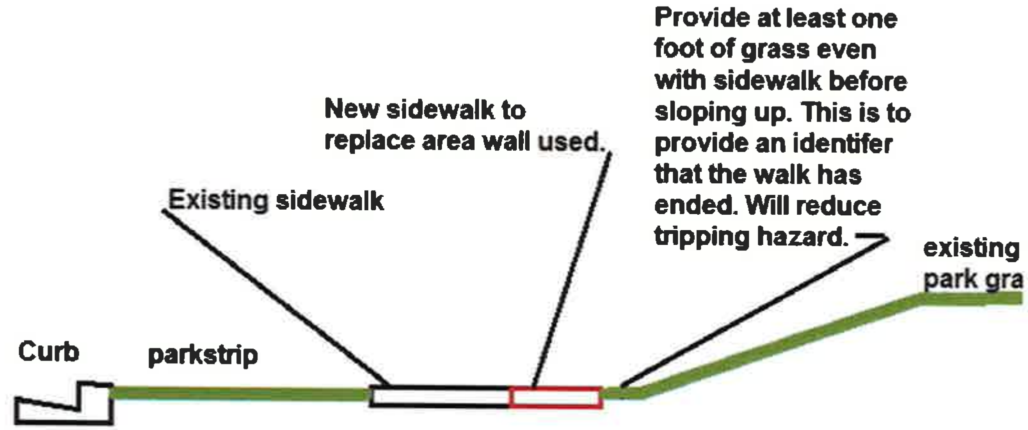
On this 19 day of September, 2012, personally appeared before me the above named Owner, who duly acknowledged to me that he is the owner in fee and executed the same as such.

[signature: Bradley Stewart Lyle]
NOTARY PUBLIC

Bradley Stewart Lyle
Notary Public State of Utah
My Commission Expires on:
July 7, 2015
Comm. Number: 610257

TAB 5

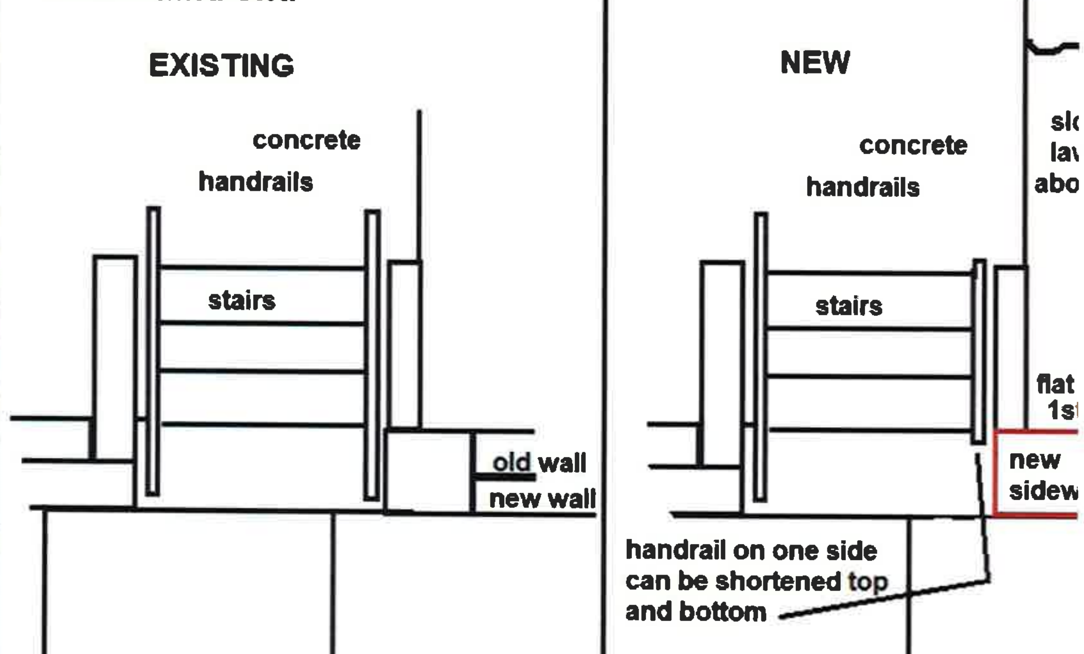




I believe that the reason for the retaining wall was to maximize the level playing field for the ball diamond. Since that is no longer used (and the fence should be removed) the need for the level lawn is un-necessary.

A sloped lawn will be safer than a series of steps which will become a tripping hazard (not a normal walking path and hard to visually distinguish even in normal daylight.) Sloped lawn on the other hand is not the normal walking path and the surface is acknowledged as irregular and less taken for granted as a carefree walking surface.

Bandstand end




NO DOGS IN PARK


BELLOWS GLASS