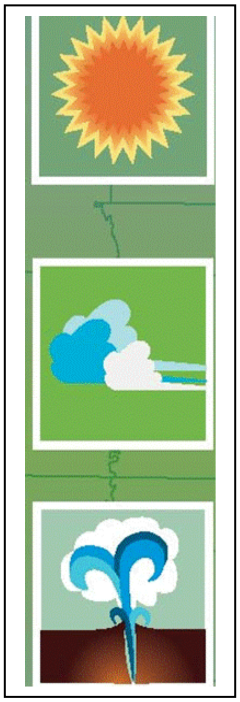
UREZ Phase II



Utah Renewable Energy Zone (UREZ) Task Force, Phase II

Zone Identification and Scenario Analysis

FINAL REPORT

September, 2010

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Preface

This report was prepared for the State of Utah Governor's Energy Advisor and the Utah Geological Survey, State Energy Program by Black & Veatch Special Projects Corporation (referred to as "Black & Veatch" or "B&V") and is based on information not within the control Black &Veatch. Black & Veatch has neither verified nor rendered an independent judgment of the validity of data developed by others. While it is believed that the information, data and opinions contained herein will be reliable under the conditions and subject to the limitations set forth herein, Black & Veatch does not guarantee the accuracy thereof. Use of this report or any information contained therein shall constitute a waiver and release of Black & Veatch from and against all claims and liability, including but not limited to liability for special, incidental, indirect or consequential damages, in connection with such use.

The scenarios described in this report were developed in conjunction with the UREZ Technical Working Groups, and represent conceptual resource and transmission development. Many of the assumptions used in the scenarios were developed by the UREZ Phase II Task Force and Technical Working Groups for purposes of completing the Phase II project. These may not reflect current state policy, nor are they intended to be a proposal for future state policy or regulations.

This document was formatted using Adobe Systems Acrobat software, Version 9.

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Glossary of Terms

Following is a list of terms used in the UREZ Report. The glossary is designed to identify terms used within this report. A comprehensive glossary of electricity terms is available on the Federal Energy Regulatory Commission website. (http://www.ferc.gov/help/glossary.asp)

Alternating Current (AC) – In alternating current the movement (or flow) of electric charge periodically reverse direction. Electricity delivered to business and residences is AC and majority of the transmission lines, including high voltage lines, are AC current.

Accelerated Depreciation – refers to any one of several methods by which a company, for 'financial accounting' and/or tax purposes, depreciates a fixed asset in such a way that the amount of depreciation taken each year is higher during the earlier years of an asset's life.

Available Transmission Capacity (ATC) – Available transmission capacity is a measure of the electric transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

AFUDC – Allowance for Funds Used During Construction (AFUDC) is approval by the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for inclusion in rates of the cost of borrowing funds until a project is placed into operation.

Busbar Cost – The levelized cost of energy (LCOE) of a generation unit based on total life-cycle cost of generation at a facility normalized by the total generation from the facility. Busbar cost is expressed in units of dollars per MWh.

Conceptual Transmission System – This is a representation of the existing electrical transmission system used for high-level planning and screening-level cost estimation.

Capacity Factor - The ratio of the electrical energy produced by a generating unit for the period of time compared to the electrical energy that could have been produced at continuous full-power operation during the same period.

Capacity Value – The capacity value of a generating resource is based on its ability to provide dependable and reliable capacity during peak periods when the system requires reliable resources for stable operation. In UREZ Phase II, this is calculated using the capacity factor of a particular resource during peak periods and the cost of capacity during those periods.

Energy Value – The energy value represents the expected marginal cost of generation in the region where the resource is located.

Equity Cost – Also knows as Cost of Equity, is the minimum rate of return a firm must offer shareholders to compensate for waiting for their returns, and for bearing some risk.

Firm Capacity – Firm Capacity is the amount of energy available for production or transmission which can be (and in many cases must be) guaranteed to be available at a given time. Firm energy refers to the actual energy guaranteed to be available.

Generation Tie-line (gen-tie) – Transmission line designed to deliver energy from a generation resource to the network transmission system.

Integration Cost – The indirect costs required to integrate intermittent resources with the transmission system. Integration costs are expressed in units of dollars per MWh.

Load - Electric load is end-use device or customer that receives power from the electric system.

Net Present Value (NPV) – Net present value is the difference between the present value of cash inflows and the present value of cash outflows.

Resource Plan – Detailed summary of all types of resources (type of generation, amount of energy, etc) required to complete a specific task such as an resource portfolio standard (RPS).

Right-of-Way (ROW) – The land used by a utility (including transmission lines) by obtaining legal right of passage over property owned by another person or entity.

Transmission Cost – Estimated cost of delivering energy from a generation resource to a specific location on the transmission system. This includes the cost of all transmission line equipment such as lines and substations, as well as the cost of construction, land, financing, AFUDC and permitting.

Tax Life – The number of years over which tax liability is incurred by the revenues of an asset.

Unit Capital Cost – Total all-in capital cost (the estimated installed cost of generating resources including equipment, construction, land, transmission interconnection, financing, AFUDC and permitting) divided by the installed capacity.

Western Interconnection – The Western Interconnection is one of the three major alternating current (AC) power grids in North America and includes 11 western US states, part of Texas, Alberta and British Columbia as well as part of northern Baja California Norte, Mexico.

Western Electric Coordinating Council (WECC) – WECC is the Regional Entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.

Executive Summary

Renewable energy development is economic development, and Utah has a wealth of renewable energy resource potential for electricity generation. Where the Utah Renewable Energy Zone (UREZ) Phase I report[1] identified significant potential wind, solar, and geothermal resource zones, UREZ Phase II is focused on evaluating the transmission needed to bring renewable energy generation to markets. This report considers the potential of resource zones and identifies the transmission requirements necessary to deliver the energy from these zones to Utah consumers and energy markets in the Western Interconnect.[2] While the report provides scenarios and examples of generation and transmission, the model is designed to enable the resource and transmission industry to evaluate their own development and transmission objectives. It is hoped that this tool will assist business in realizing the economic development potential of Utah's renewable energy resources for markets in Utah and the West.

This report was developed by Black & Veatch in conjunction with the UREZ II Economic, Technical Transmission, Zone Selection & Identification (Zone Selection), and Policy and Funding Work Groups and Task Force members.

ES.1 Resource Identification, Zone Identification & Ranking

The UREZ Phase II effort identified approximately 25,000 MW of potential renewable generating resources located in twenty-seven (27) zones in Utah. These zones are designated based on concentrations of renewable energy sources from the UREZ Phase I Report and estimates of theoretical potential of electrical energy capacity. These zones are not equivalent to the "Renewable Energy Development Zone" defined in Utah Code Annotated §63M-1-2803(7). Furthermore, it is recognized that potentially developable resources exist outside of the zones. This report is not an attempt to provide a project-level assessment of energy resource quality or project development potential. Interested individuals should consult with industry professionals about resource and transmission development at the project level.

Zones were identified based on the criteria developed by the Zone Selection Work Group. These criteria were intended to ensure the zones are appropriate for transmission planning. These criteria ensured that zones are large enough to justify the construction of transmission to reach them and that the resources in the zones can be feasibly collected

[1] The UREZ Phase 1 Report is available at: http://geology.utah.gov/sep/renewable_energy/urez/phase1/
[2] The Western Interconnect is the transmission region served by the Western Energy Coordinating Council (WECC).

and delivered to the transmission system. These criteria also ensure that no single potential project constitutes a zone in and of itself. Not all potential renewable generation located in Utah is included in an identified zone.

These zones were ranked based on the potential cost and economic value of the resources within them, and assumptions about the transmission required to deliver the energy from these resource areas to both Utah consumers and to the energy markets within the Western Interconnect. Figure ES-1 depicts the zones identified in UREZ Phase II, and Table ES-1 details the resources located within each zone, by resource type.

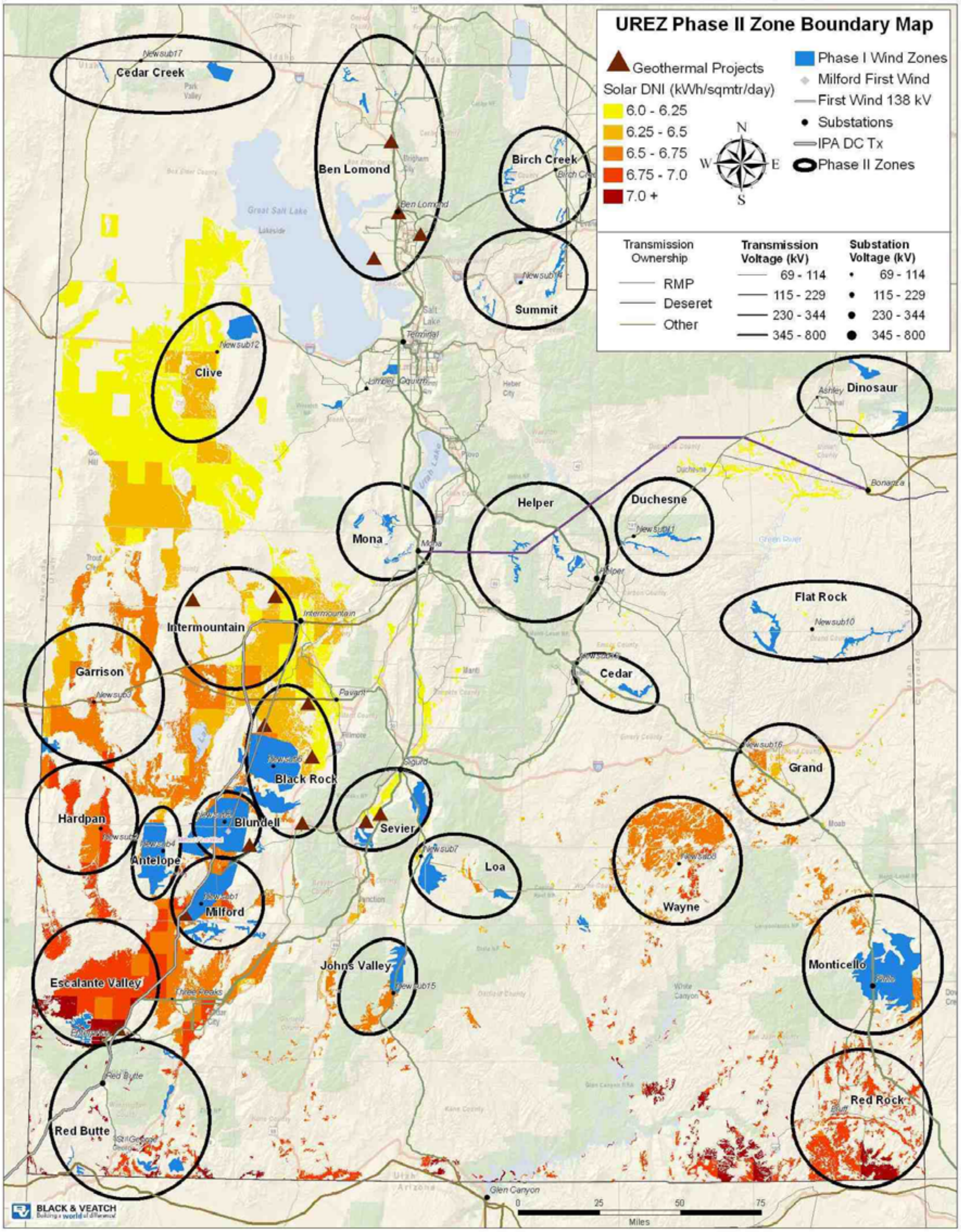

Figure ES-1. UREZ Phase II Zone Boundary Map.

Table ES-1. Renewable Energy Resources by Zone, MW.

Zone	Geothermal	Solar	Wind	Total
Antelope		357	500	857
Ben Lomond	48		255	303
Birch Creek			405	405
Black Rock	124	1,394	700	2,218
Blundell	81	676	600	1,357
Cedar			250	250
Cedar Creek			315	315
Clive		1,876	250	2,126
Dinosaur			300	300
Duchesne			320	320
Escalante Valley	12	2,133	230	2,375
Flat Rock			500	500
Garrison		1,508	120	1,628
Grand		226		226
Hardpan		776		776
Helper			480	480
Intermountain	50	1,564		1,614
Johns Valley		233	400	633
Loa		48	300	348
Milford	94	805	860	1,759
Mona			420	420
Monticello		356	500	856
Red Butte		261	520	781
Red Rock		1,164		1,164
Sevier	28	115	260	403
Summit			390	390
Wayne		1,204		1,204
Grand Total	***437***	***14,696***	***8,875***	***24,008***

Source: Black & Veatch Analysis for UREZ Phase II

ES.1.1 Zone Ranking

Using criteria developed in conjunction with the Technical Working Groups, Black & Veatch ranked the UREZ zones based on the cost-effectiveness of the resources located in each zone. Zones were aggregated into quartiles (by percentage of potential energy generation) and ranked, with quartile 1 representing the most cost-effective resources that are likely the most attractive for potential development and quartile 4 representing the least cost-effective resources with likely the lowest development interest. The goal for quartile ranking of zones is to segregate the more cost-effective zones from the lesser cost-effective zones without addressing minor differences in the ordinal zone rankings. A more detailed discussion of the resource and zone ranking process in included in Section 3 of this report. Table ES-2 details the zones, including zone name, potential energy and capacity of resources in the zone, and the quartile ranking each zone.

Table ES-2. UREZ Phase II Zones Ranked Into Quartiles.

Quartile	Zone	Capacity (MW)	Energy (GWh/yr)
1	Helper	480	1,285
	Summit	390	1,003
	Cedar Creek	315	770
	Birch Creek	405	991
	Flat Rock	500	1,169
	Duchesne	320	730
	Cedar	250	550
	Mona	420	930
	Dinosaur	300	620
	Ben Lomond	303	902
	Loa	348	787
	Red Butte	781	1,841
2	Blundell	1,357	3,544
	Antelope	857	1,941
	Milford	1,759	4,174
	Monticello	856	1,839
3	Sevier	403	933
	Johns Valley	633	1,269
	Black Rock	2,218	5,216
	Escalante Valley	2,375	4,714
	Red Rock	1,164	2,265
	Hardpan	776	1,482
4	Garrison	1,628	3,114
	Intermountain	1,614	3,217
	Wayne	1,204	2,287
	Grand	226	421
	Clive	2,126	3,851

Source: Black & Veatch analysis for Phase II of the UREZ Initiative.

ES.2 Conceptual Transmission Development

The existing Utah electric grid is highly utilized, with little available transmission capacity (ATC) to deliver energy from the identified zones to the load centers in Utah and to export renewable energy out of state. Understanding this constraint, UREZ Phase II designed a "conceptual" transmission grid to deliver energy from the zones to Utah customers and the Western Interconnect markets. The analysis used the Terminal substation near Salt Lake City as the proxy delivery point for all energy used within Utah. For exported energy, the study identified major substations near the Utah border for energy deliveries. The development of the transmission grid is further explained in Section 5 of this report.

The conceptual transmission system is based on the current high-voltage transmission grid in Utah, with new transmission identified to interconnect zones to the grid or to increase the transfer capacity between zones and delivery points. ATC was identified by the Technical Working Group for several existing transmission corridors, which was included as available transmission in the conceptual grid. When these corridors are modeled in the scenario analysis and the UREZ Generation and Transmission Model, the ATC is utilized prior to the addition of any new conceptual transmission. It is important to note that the conceptual transmission system does not represent actual planned transmission and that engineering, permitting, feasibility and siting activities would need to take place before actual transmission lines or substations would be built. The conceptual transmission grid is depicted on Figure ES-2.

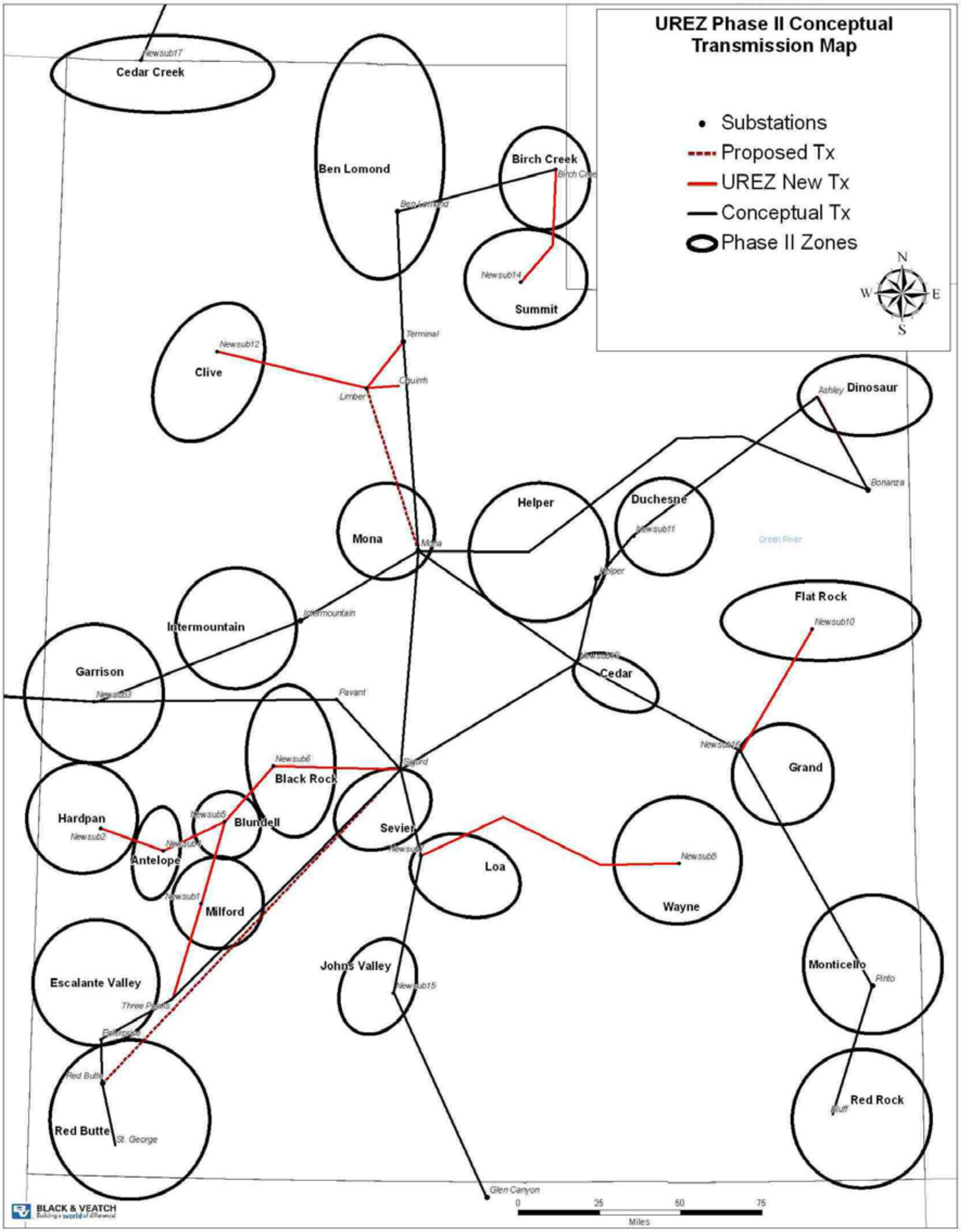

Figure ES-2. UREZ Phase II Conceptual Representation of the Existing Transmission System.

ES.3 Scenario Analysis

The UREZ Phase II effort did not develop a "resource plan" to access resources. Rather a set of scenarios, designed to represent a plausible range of generation and transmission development through 2025, was developed by the Technical Working Group. These scenarios describe the quantities and types of renewable energy development that may occur, identify the locations where resources would be developed, and designate whether the energy generated by these resources would be consumed within Utah or exported to users outside of Utah.

Utah has a Renewable Portfolio Goal (RPG) described as producing twenty percent of electricity from renewable energy sources by 2025. The exact calculation is defined in Utah Code Annotated Title 10, Chapter 19 and Title 54 Chapters 2, 12 and 17. All of the scenarios modeled assume a portion of the RPG will be met by Utah resources, and that Utah resources will also be developed and exported to serve out-of-state renewable energy demand. None of the scenarios assume that all of Utah's RPG will be met only by Utah resources. The scenarios assume that the RPG requirements will be met by generation resources in Utah, by generation resources imported from outside Utah, and qualifying equivalent resources such as energy efficiency. This analysis made no assumptions about the location of imported generation. The analysis included the following scenarios:

- Reference Case – the reference case is designed to be the "most likely" renewable development scenario. This scenario assumes resources will be developed to meet 50 percent of the 2025 Utah RPG goal and half that amount (25 percent) to export out-of-state.
- Low Development - this scenario assumes resources will be developed to meet 25 percent of the 2025 Utah RPG goal and an equivalent amount to export out-of-state.
- High Development - the high development scenario assumes that half of Utah's renewable energy goal will be served by resources developed in Utah and an equivalent amount of development for export out-of-state.
- "Best Projects" Development - this assumes the same level of demand as the reference case scenario, but is somewhat different than all other cases in the methodology for resource selection. While the resource selection for all other scenarios is based partially on average zone economics, this scenario is based on the development of the lowest cost of generation resources in the state, ignoring the aggregated zone economics.

- Development Timing – this scenario assumes that a certain amount of wind and geothermal resources will be developed in different time horizons as agreed upon by the working groups.

Section 6.0 details the design and results of the individual scenarios. Below is a summary comparison and discussion of the resources, along with cost and transmission required for each scenario.

ES.1.2 Energy and Capacity Demand by Scenario

To develop each scenario, a projected level of renewable development was determined for years 2015, 2020 and 2025. The projected renewable energy generation for each scenario is provided below in Table ES-3.

Table ES-3. Projected Renewable Energy Development Levels by Year (GWh).

Year:	Low Development	Reference Case, Best Projects Development, Development Timing	High Development
2015	2,269	3,404	4,538
2020	3,404	5,106	6,808
2025	4,538	6,808	9,077

Source: UREZ Phase II Technical Working Group.

ES.1.3 Resource Development by Scenario

All of the scenarios have a preponderance of wind in the resource mix, with somewhat less geothermal. The busbar and transmission costs of wind and geothermal resources are typically below $125/MWh, while the cost of solar is generally over $140/MWh. Figure ES-3 depicts the generation by resources type for each scenario. Figure ES-4 shows the capacity additions by resource type for each scenario.

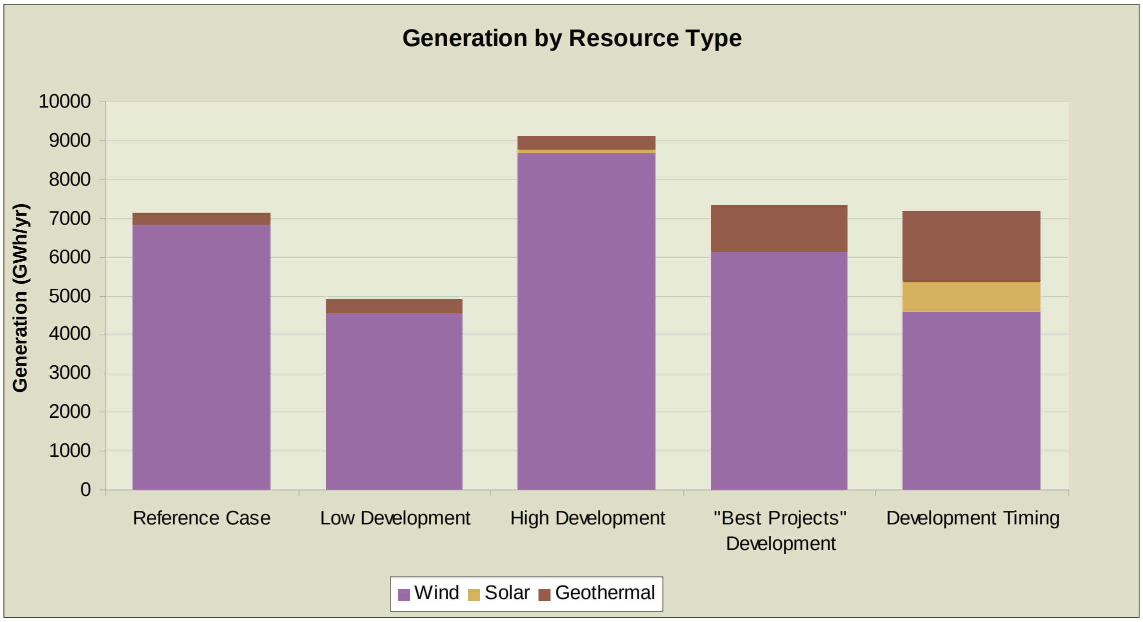

Figure ES-3. Annual Generation Output by Resource Type (GWh/yr).

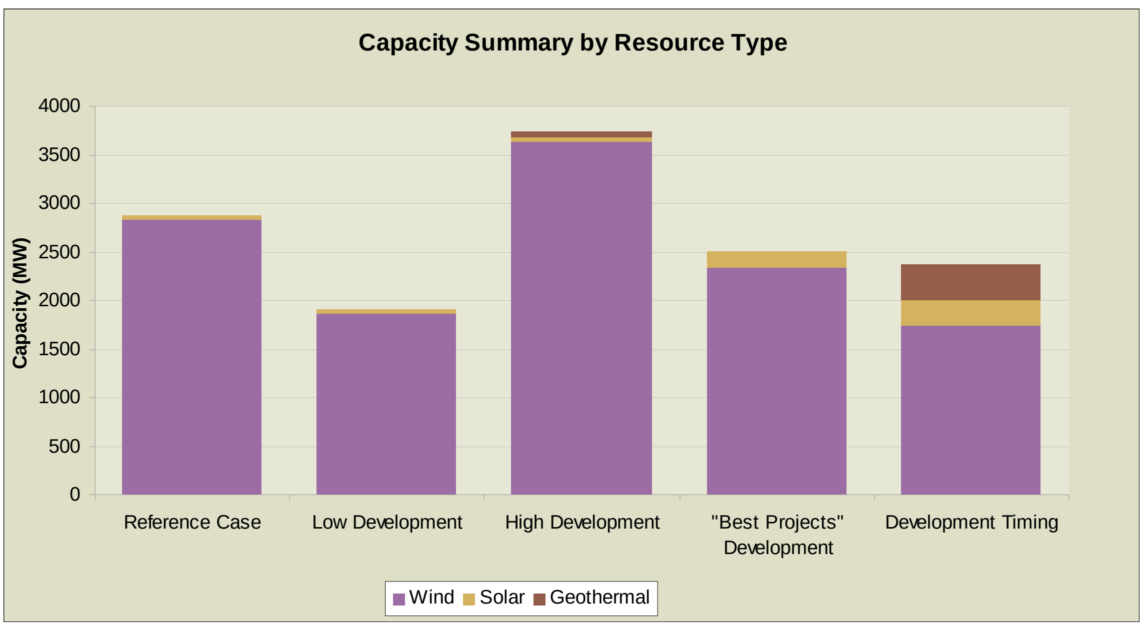

Figure ES-4. Capacity Requirements by Resource Type (MW).

ES.1.4 Costs

The projected costs for the development, including the cost of both transmission and generation resources, was between $5.2 billion for the low development case and

$10.2 billion for the high development case (2010 dollars). A summary of the costs for each scenario are provided in Table ES-4 below.

Table ES-4. Capital Cost of Development by Scenario.

Scenario	Total Cost (Million $)	Total MW	Total GWh/yr
Reference Case	7,723	2,883	7,162
Low Development	5,328	1,908	4,891
High Development	10,154	3,731	9,119
"Best Projects" Development	6,731	2,501	7,324
Development Timing	7,771	2,368	7,198

Source: Black & Veatch Analysis for UREZ Phase II.
Note: Capital costs include both the cost of generation and transmission resources.

Another comparison of the scenarios is the comparison of the average delivered cost of energy for each scenario. Using this method for comparison, the Best Projects scenario is the lowest average premium cost scenario while the Low Development scenario, which has the lowest total cost, has the highest average premium cost ($/MWh). Figure ES-5 depicts the average delivered cost of energy by scenario.

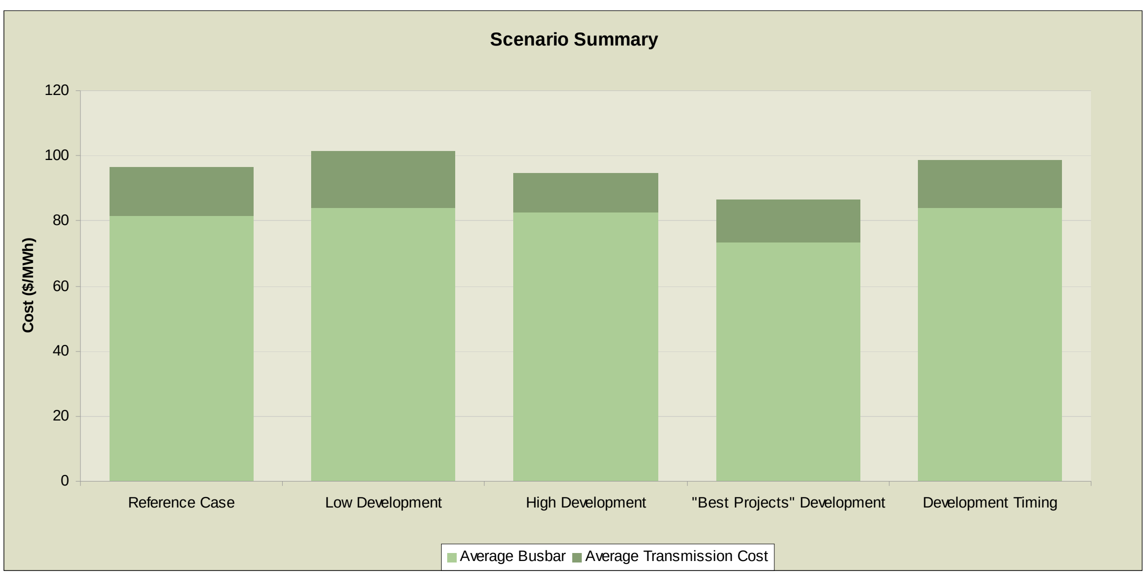

Figure ES-5. Cost of Energy by Scenario ($/MWh).

An additional metric by which to compare the scenarios is the unit capital cost required to develop each scenario, or the capital cost on a per-MW basis. The

Development Timing scenario, which includes a large quantity of solar resource, has a substantially higher unit capital cost, as would be expected. The other four scenarios are much closer in their unit capital costs. Figure ES-6 depicts a comparison of the unit capital costs for each scenario.

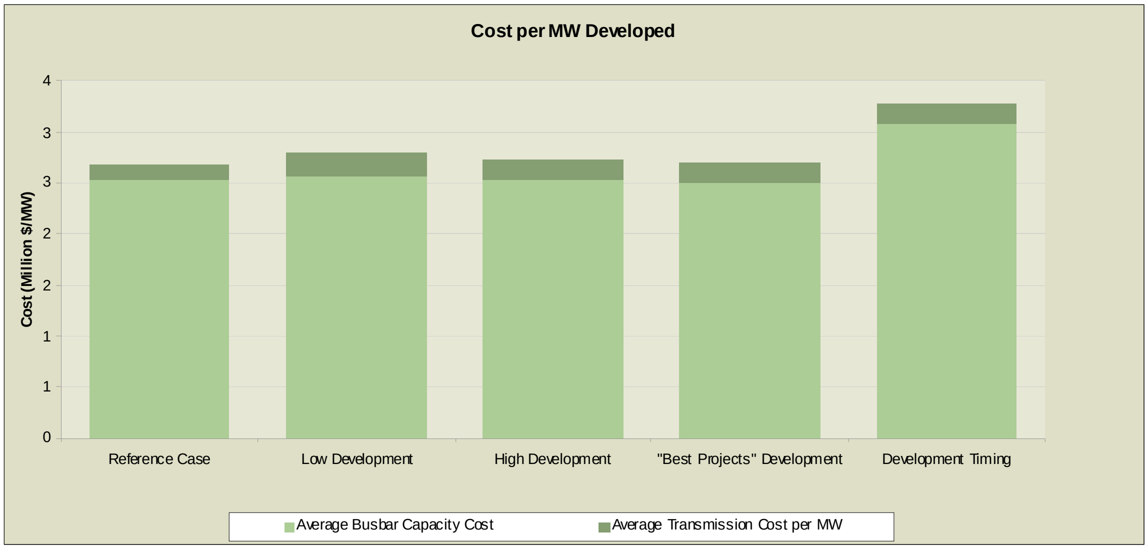

Figure ES-6. Unit Capital Cost of Development by Scenario.

1.0 Overview of UREZ Phase II Approach

1.1 Background and Objectives

The UREZ Phase II effort is an extension of the work completed in UREZ Phase I during 2008 and early 2009. UREZ Phase I focused on the identification and quantification of the renewable resource potential in Utah, while Phase II seeks to quantify the value of these potential resources and rank zones for potential development of transmission to access desirable areas. The objectives of Phase II are to:

- Identify policies or market mechanisms that would facilitate transmission planning and permitting for renewable energy projects,
- Quantify cost-effective generation potential, and
- Identify necessary transmission to bring resources to market. [3]

This report identifies 27 Renewable Energy Zones for the purpose of evaluating potential resource development and transmission scenarios. These zones are designated based on concentrations of renewable energy sources from the UREZ Phase I Report and estimates of theoretical potential of electrical energy capacity. These zones are not equivalent to the "Renewable Energy Development Zone" defined in Utah Code Annotated §63M-1-2803(7). Furthermore, it is recognized that potentially developable resources exist outside of the zones. This report is not an attempt to provide a project-level assessment of energy resource quality or project development potential. Interested individuals should consult with industry professionals about resource and transmission development at the project level.

1.2 Work Groups

To complete the Phase II effort, UREZ established four work groups designed to focus on the various components of the effort. The work groups met frequently to identify issues requiring resolution and assist Black & Veatch in developing appropriate modeling assumptions. The objectives of each work group are detailed below.

- **Economic Work Group**:
    - Use information from Technical Transmission Work Group to help determine total cost of project including $/kWh, construction costs, etc.

[3] Utah Geological Survey, Utah Renewable Energy Zone Task Force web site: http://geology.utah.gov/sep/renewable_energy/urez/index.htm

- **Technical Transmission Work Group**:
    - Identify the technical transmission needs for each selected zone
    - Figure transmission costs of zones to interconnect
    - Breakdown of cost per mile by kV
    - Consider low, med, and high renewable energy development scenarios
    - Use Western Renewable Energy Zones[4] (WREZ) for preliminary screening
- **Zone Selection and Identification Work Group**:
    - Select criteria to rate zones
    - Rate Utah Renewable Energy Zones into classes
    - Select zones based on agreed upon criteria
    - Choose model areas of study for UREZ report that fit into budget
- **Policy and Funding Work Group**:
    - Develop principles for consideration by UGREEN Board[5]
    - Summarize federal and state regulatory framework surrounding new transmission
    - Assess transmission funding for interstate and intrastate load centers
    - Identify barriers and pathways to transmission in Utah

While initially distinct from one another, the Economics, Zone Selection and the Technical Transmission Work Groups often met together as a single work group to consider and develop modeling assumptions and methodologies. This report refers to the consolidated group as the "Technical Work Group." The Policy and Funding Work Group is considering issues important to energy policy-making in Utah and anticipates using information developed in the Phase II analysis for these purposes.

1.3 Analytical Approach

The analytical approach is detailed below. UREZ Phase I zones were refined into the Phase II zones, which often contained multiple resource types. Subsequently, the economics of the resulting zones and the multiple "projects" that made up each zone were analyzed. This resulted in a dataset characterizing the performance and economics of the zones. This dataset served as an input into the scenario analysis as well as the UREZ Transmission Model.

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[4] The Western Governors Association's Western Renewable Energy Zone (WREZ) initiative developed transmission assumptions for estimating the cost and operating characteristics of new transmission in the western U.S. Additional information on these assumptions, and the WREZ resource analysis and modeling, may be found at:
http://www.westgov.org/index.php?option=com_content&view=article&id=219&Itemid=81

[5] Utah Generated Renewable Energy Electricity Network Authority, Utah Code Annotated Title 63H, Chapter 2.

1.3.1 Zone Identification

Wind, solar and geothermal renewable energy zones were identified in Phase I by the UREZ Task Force. In Phase II these zones were refined to allow for an economic analysis of the resources included in the zones and the development of conceptual transmission designs to access the resources, using a set of zone selection criteria identified by the Zone Selection and Identification Work Group. These criteria ensured that zones were large enough to justify the construction of transmission facilities to reach them and that the resources in the zones could be feasibly collected and delivered to the transmission system. It also ensures that no single potential project constitutes a zone in and of itself. In total, 27 zones were identified. The criteria and process used to refine the zones are presented in greater detail in Section 2.

1.3.2 Zone Ranking

Once the zone refinement was completed, an economic analysis of the zones was conducted. To do this Black & Veatch calculated the busbar generation cost for each of the resources in each zone using assumptions developed by the UREZ work groups and Black & Veatch. These were combined into a single metric that represents the overall value of each zone, known as the ranking score. This ranking score provided the basis for identifying the zones used in the scenario analysis.

1.3.3 Conceptual Transmission Design and Analysis

Conceptual transmission designs were developed to interconnect resources to the transmission grid for the lowest-cost 50 percent of the identified zones. These designs and a set of cost and performance assumptions were developed by the work groups and Black & Veatch to characterize the costs of transmission for each of the highest ranking zones.

1.3.4 Scenario Development

The Phase II effort did not identify a preferred resource and transmission develop plan to meet the Utah RPG. Instead, the working groups developed a set of scenarios, designed to represent a plausible range of generation and transmission development through 2025. These scenarios describe the quantities and types of renewable energy development that might occur, identify the locations where resources could be developed, and indicate whether the energy generated by these resources would be consumed within Utah or exported to users outside of Utah.

All of the scenarios modeled assume a portion of the RPG will be met by Utah resources, and that Utah resources will also be developed and exported to serve out-of-state renewable energy demand. None of the scenarios assume that all of Utah's RPG will be met only by Utah resources. The scenarios assume that the RPG requirements will be met by generation resources in Utah, by generation resources imported from outside Utah, and qualifying equivalent resources such as energy efficiency. This analysis made no assumptions about the location of imported generation. The analysis included the following scenarios:

- Reference Case – the reference case is designed to be the most likely renewable development scenario as defined by the work groups and task force. This scenario assumes resources will be developed to meet 50 percent of the 2025 Utah RPG and half that amount (25 percent) to export out-of-state.
- Low Development - this scenario assumes resources will be developed to meet 25 percent of the 2025 Utah RPG and an equivalent amount to export out-of-state.
- High Development - the high development scenario assumes that half of Utah's renewable energy goal will be served by resources developed in Utah and an equivalent amount of development for export to out-of-state.
- "Best Projects" Development - this assumes the same level of demand as the reference case scenario, but is somewhat different than all other cases in the methodology for resource selection. While the resource selection for all other scenarios is based partially on average zone economics, this scenario is based on the development of the lowest cost of generation resources in the state, ignoring aggregate zone economics.[6]
- Development Timing – Development Timing – this scenario assumes that a certain amount of wind and geothermal resources will be developed in different time horizons as agreed upon by the working groups.

Section 6 details the assumptions used to develop the individual scenarios and provides the results of the scenario analysis.

[6] Section 3 includes a detailed discussion of resource ranking and zone ranking methodology.

2.0 Zone Refinement and Identification

In Phase I, zones were identified for each resource type. In Phase II, zones were expanded to include multiple resource types in a single zone. In Phase II, zones were defined not only based on their physical proximity to each other, but also based on their proximity to transmission interconnection points. Resources could be physically disparate, but if they had a common transmission interconnection, they were grouped into a single zone. This process is detailed below.

In addition to Phase I zone refinement there were several changes to the resource characteristics in Phase II, including the addition of solar photovoltaic technologies and the elimination of geothermal energy from unspecified locations. These are detailed in Section 4 of the report.

2.1 Phase II Zone Refinement

Solar and geothermal zones identified in Phase I were refined before the Phase II zones were identified. Phase I geothermal and solar zones covered vast areas, making it difficult to design a transmission approach to interconnect all of the resources. Refinements to these zones were made in Phase II to make the zones more appropriate for conceptual transmission planning.

2.1.1 Solar Zones

Solar zones in Phase I are orders of magnitude larger in physical size and potential generating capacity than the wind and geothermal zones. There is significantly more generating potential than could be reasonably expected to be developed. Additionally, at this resolution of analysis, the costs, capacity factors and output profiles of these resources do not vary significantly across large areas where resource quality is the same. As a result, it is not necessary to quantify all the technically available resources to adequately model them for transmission planning. The zones were refined to simplify modeling and make the analysis more useful for planning.

Two refinements to the solar zones were made. First, only the solar resources identified in Phase I located within approximately 50 miles of existing transmission corridors containing transmission lines were characterized in Phase II. Second, the solar resource potential quantified in Phase II was limited to approximately 15,000 MW, equivalent to over three times the anticipated Utah RPG. To limit the solar resource, certain resource quality constraints were imposed on the solar resources in the zones. The solar resources in areas with direct normal insolation (DNI) levels from 6.0 to 6.5

kWh/m^2/day and terrain slopes of less than or equal to 1 percent were quantified. Additionally, the solar resources in areas with DNI levels from 6.5 to 7.25 kWh/m^2/day with terrain slopes of less than or equal to 3 percent were quantified. These constraints ensured that only the most likely to be developed solar resources were quantified in each zone. The resources selected are geographically disbursed, so that as many zones as possible include solar resources.

2.1.2 Geothermal Zones

Phase I identified the potential for geothermal generation in large areas of the state rather than specific locations. Phase I also identified discovered as well as undiscovered, theoretical geothermal resources. Given the much higher certainty about the developability of the discovered resources, Phase II only considered these discovered resources. Discovered resource potential is assigned to specific locations identified by GeothermEx in the WREZ initiative and refined by the consultants in the UREZ Phase I study.

2.1.3 Wind Zones

Phase I map and report identified a number of discrete wind resource areas. Phase II characterized these resources in more detail than was provided in Phase I, but did not identify any additional wind resource areas for inclusion in Phase II. Wind resources were incorporated into the UREZ Phase II zones using the zone criteria detailed in Section 3, below.

2.2 Zone Identification

Once the refinements were made to the Phase I zones, Phase II zones were identified based on the zone identification criteria created by the Zone Selection work group. These criteria were intended to ensure the zones are appropriate for transmission planning, that zones are large enough to justify the construction of transmission to reach them, and that the resources in the zones can be feasibly collected and delivered to the transmission system. These criteria also ensure that no single potential project constitutes a zone in and of itself. The zone identification criteria used were as follows:

- **Common Interconnection**: Phase I zones were grouped into Phase II zones when they had common transmission interconnections. This was evaluated based on their location around existing transmission corridors or possible new transmission corridors. These groupings often included multiple resource types.

- **Physical Size**: Zone boundaries were at maximum approximately 50 miles from a theoretical interconnection point along an existing transmission corridor. Most of the resources identified in the proposed Phase II zones are within 25 miles of an existing transmission corridor.
- **Capacity**: Zones needed to contain at least 200 MW of generating capacity after taking into account all Phase II zone refinements, enough to justify a 138 kV transmission line.
- **Project Diversity**: Zones needed to include areas in which multiple projects could reasonably be expected to be developed. This was intended to prevent UREZ from planning transmission to specific projects.

2.2.1 Environmental Consideration in Zone Identification

The UREZ Phase I analysis included environmental criteria in its zone selection process. The environmental criteria identified in the Phase I process was utilized in Phase II. No additional environmental screening criteria was developed or used in the Phase II zone assessment.

2.2.2 Phase II Zones

Twenty-seven Phase II zones were identified based on the zone selection criteria. These zones were accepted by the UREZ Phase II work groups and are depicted on Figure 2-1.

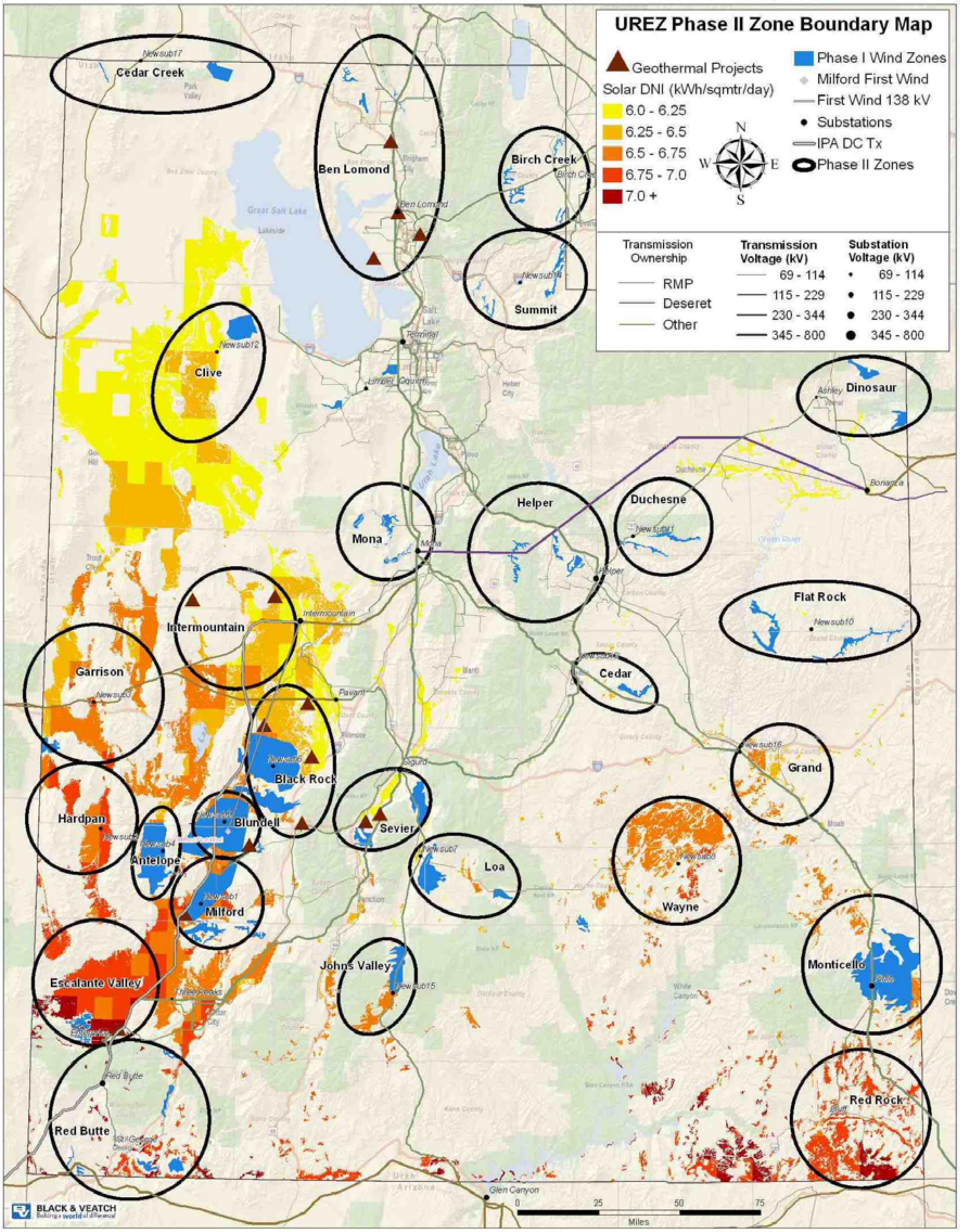


Figure 2-1. UREZ Phase II Zone Boundary Map.

2.2.3 Zone Data

The generating capacity and annual energy generation from each resource type quantified within each Phase II zone is presented in Tables 2-1 and 2-2 below.

Table 2-1. Generating Capacity By Resource and by Zone, MW.

Zone Name	Geothermal	Solar	Wind	Total
Antelope		357	500	857
Ben Lomond	48		255	303
Birch Creek			405	405
Black Rock	124	1,394	700	2,218
Blundell	81	676	600	1,357
Cedar			250	250
Cedar Creek			315	315
Clive		1,876	250	2,126
Dinosaur			300	300
Duchesne			320	320
Escalante Valley	12	2,133	230	2,375
Flat Rock			500	500
Garrison		1,508	120	1,628
Grand		226		226
Hardpan		776		776
Helper			480	480
Intermountain	50	1,564		1,614
Johns Valley		233	400	633
Loa		48	300	348
Milford	94	805	860	1,759
Mona			420	420
Monticello		356	500	856
Red Butte		261	520	781
Red Rock		1,164		1,164
Sevier	28	115	260	403
Summit			390	390
Wayne		1,204		1,204
Total	***437***	***14,696***	***8,875***	***24,008***

Source: Black & Veatch analysis for Phase II of the UREZ initiative

Table 2-2. Theoretical Annual Generation by Resource and Zone, GWh/yr.

Zone Name	Geothermal	Solar	Wind	Total
Antelope		687	1,268	1,955
Ben Lomond	336		566	902
Birch Creek			991	991
Black Rock	869	2,602	1,783	5,254
Blundell	639	1,311	1,635	3,584
Cedar			550	550
Cedar Creek			770	770
Clive		2,971	523	3,494
Dinosaur			620	620
Duchesne			730	730
Escalante Valley	84	4,341	546	4,971
Flat Rock			1,169	1,169
Garrison		2,808	308	3,116
Grand		422		422
Hardpan		1,558		1,558
Helper			1,285	1,285
Intermountain	350	2,863		3,214
Johns Valley		448	833	1,281
Loa		88	700	788
Milford	659	1,588	2,005	4,252
Mona			930	930
Monticello		675	1,179	1,854
Red Butte		551	1,328	1,879
Red Rock		2,413		2,413
Sevier	196	207	527	930
Summit			1,003	1,003
Wayne		2,312		2,312
Total	***3,133***	***27,846***	***21,249***	***52,228***

Source: Black & Veatch analysis for the Phase II of the UREZ initiative.

3.0 Resource Ranking Methodology and Assumptions

This section details the methodology used for the evaluation and ranking of renewable energy resources analyzed in Phase II of UREZ. This analysis incorporates technical and economic assumptions as well as the resource valuation methodology developed by the UREZ Economics and Zone Selection work groups to analyze geothermal, solar and wind resources.

3.1 Resource Ranking Methodology

Resources zones in Phase II were ranked twice. They were ranked first by the average busbar cost of all resources included in the zone in order to eliminate the most expensive zones from consideration. They were then ranked by their “premium cost”, a a single metric that combines the generation cost, transmission cost, capacity value, and energy value of the resources of each zone that represents the overall economic merit of the zone. The premium cost represents the costs of a renewable energy resource above (or below) its value to the system into which it is selling its power. A lower premium cost (including negative values) is indicative of a more valuable renewable energy project or zone. The premium cost was calculated using the following formula:

Premium Cost =
Generation Cost + Transmission Cost – Energy Value – Capacity Value

A discussion of the premium cost components is provided below.

3.1.1 Generation Cost

The cost of generation is calculated as the levelized cost of generating power over the life of a particular resource. This is referred to as the “busbar cost,” and includes the cost of the generation tie line required to bring the resource to the grid. Busbar cost is calculated on a $/MWh basis, allowing resources to be compared with other, different resource types with different costs and operating over different time periods. It is calculated using a simple financial model that considers the project from the point of view of a developer, including the developer’s direct costs, charges and incentives, as well as an expected rate of return on equity. Specifically, it considers:

- Operations and maintenance costs
- Cost of equity investment in capital
- Cost of financing capital
- Taxes, including investment and production credits

Other costs, such as insurance, property taxes, development fees, interest during construction, and debt service reserve funds are included within these major categories. Black & Veatch has strived to make the model as simple as possible while still maintaining an appropriate level of accuracy for comparing the relative generation cost of different projects employing different renewable energy technologies. The simplifying assumptions allow the model to serve its analytical purpose while being streamlined enough to quickly evaluate many resources. Because of the simplifications, the model is not intended to simulate the precise financial performance of any one project. Use of the model in this way would be inappropriate.

Line items and calculations in the Cost of Generation Calculator are outlined below. A screenshot of the calculator is included in Figure 3-1.

- **NPV for Equity Return**: A cost of equity is assumed as part of the financial assumptions. This number is treated as a hurdle which the project must reach. The project must generate sufficient income from power sales to obtain this return on equity. The net present value (NPV) for equity return discounts all cash flows associated with the project by this prescribed return to generate a present value. If this metric is zero, the project is returning exactly the prescribed amount to equity investors. Positive values mean that the project generates excess revenues, and negative values mean that it does not generate enough.
- **Levelized Cost of Generation**: The actual cost of generation used in the model escalates over time. The levelized cost of generation is the constant cost (no escalation) that produces the same net present value as the actual modeled costs of generation over the life of the project. This single metric is the main output of the model.
- **Annual Generation**: The annual generation for the project is calculated based on an 8,760 hour year, the project capacity and the assumed capacity factor.
- **Cost of Generation**: The year-one cost of generation is chosen such that the NPV for equity return is zero. Costs of generation in later years are escalated by the assumed value.
- **Fixed Operations and Maintenance (FOM)**: FOM is calculated from the assumed dollars per kilowatt of capacity per year, the project capacity and the assumed escalation value.
- **Variable Operations and Maintenance (O & M)**: Variable O & M is calculated from the assumed dollars per megawatt-hour, the annual generation and the assumed escalation value.
- **Fuel Cost**: Annual generation, net plant heat rate, fuel cost and annual escalation of fuel cost determine the annual fuel cost for the project.

- **Debt Service**: Mortgage-style principal and interest payments are calculated for the proportion of the project that is assumed to be financed, the debt rate and the term of the financing.
- **Tax Depreciation**: Depreciation of project assets are calculated for tax purposes. These numbers are based on the Modified Accelerated Cost Recovery System (MACRS) depreciation schedules detailed in the table at the bottom of the spreadsheet. The percent of capital cost to be depreciated is also an input. For simplification, only one depreciation schedule is assumed to apply to a project.
- **Production Tax Credit (PTC)**: The production tax credit is modeled using three parameters: the dollars per megawatt-hour credit, the annual escalation of the credit, and the duration of PTC availability in years.
- **Investment Tax Credit (ITC)**: ITC eligible projects are credited the prescribed percent of their capital costs in year one.
- **Taxes**: Projects pay an all-in combined tax rate on their taxable income (operating revenue less operating expenses and depreciation) and are credited for applicable tax credits (PTC and ITC).
- **Total**: These are the cash flows associated with the project, including the equity investment portion of the overall capital costs (accounted for as a single value in year zero).
- **Solving for Year-One Cost of Generation**: Since NPV for equity return is linear with respect to year one cost of generation, the relationship can be defined by two points. In the “Calculation” box at the top of the spreadsheet, two cost scenarios ($0 and $5) are run using Excel’s “TABLE()” function. The equation for the resulting line is solved for when NPV for equity return is zero and the value is set as the year-one cost of generation.

Cost of Generation Calculator

All inputs are in blue.

Technology Assumptions	
Project Capacity (MW)	100
Capital Cost ($/kW)	$2,400
Fixed O&M ($/kW)	$50
Fixed O&M Escalation	2.5%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	2.5%
Fuel Cost ($/MBtu)	$0
Fuel Cost Escalation	2.5%
Heat Rate (Btu/kWh)	0
Capacity Factor	35%

Financial/Economic Asumptions	
Debt Percentage	60%
Debt Rate	7.5%
Debt Term (years)	15
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
Energy Price Escalation	2.5%
Tax Rate	40%
Cost of Equity	15%
Discount Rate	10.5%

Incentives	
PTC ($/MWh)	$21
PTC Escalation	2.5%
PTC Term (years)	10
ITC	0%

Outputs	
NPV Equity Return	$0
LCOE	$81.97

Calculation		
Cap Cost		##########
	0	
	0	-79935527.9
	5	-74177547.4
slope		1151596.1

5

Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Annual Generation (MWh)		306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600	306,600
Power Price		$69.41	$71.15	$72.93	$74.75	$76.62	$78.53	$80.50	$82.51	$84.57	$86.69	$88.85	$91.08	$93.35	$95.69	$98.08	$100.53	$103.04	$105.62	$108.26	$110.97
Total Operating Revenue		**$21,281,969**	**$21,814,019**	**$22,359,369**	**$22,918,353**	**$23,491,312**	**$24,078,595**	**$24,680,560**	**$25,297,574**	**$25,930,013**	**$26,578,263**	**$27,242,720**	**$27,923,788**	**$28,621,883**	**$29,337,430**	**$30,070,866**	**$30,822,637**	**$31,593,203**	**$32,383,033**	**$33,192,609**	**$34,022,424**
Fixed O&M		$5,000,000	$5,125,000	$5,253,125	$5,384,453	$5,519,064	$5,657,041	$5,798,467	$5,943,429	$6,092,014	$6,244,315	$6,400,423	$6,560,433	$6,724,444	$6,892,555	$7,064,869	$7,241,491	$7,422,528	$7,608,091	$7,798,294	$7,993,251
Variable O&M		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Cost		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Operating Expenses		**$5,000,000**	**$5,125,000**	**$5,253,125**	**$5,384,453**	**$5,519,064**	**$5,657,041**	**$5,798,467**	**$5,943,429**	**$6,092,014**	**$6,244,315**	**$6,400,423**	**$6,560,433**	**$6,724,444**	**$6,892,555**	**$7,064,869**	**$7,241,491**	**$7,422,528**	**$7,608,091**	**$7,798,294**	**$7,993,251**
Interest Payment		$10,800,000	$10,386,498	$9,941,983	$9,464,130	$8,950,437	$8,398,218	$7,804,582	$7,166,424	$6,480,403	$5,742,931	$4,950,149	$4,097,908	$3,181,749	$2,196,878	$1,138,142	$0	$0	$0	$0	$0
Principal Payment		$5,513,362	$5,926,864	$6,371,379	$6,849,232	$7,362,925	$7,915,144	$8,508,780	$9,146,939	$9,832,959	$10,570,431	$11,363,213	$12,215,454	$13,131,613	$14,116,484	$15,175,220	$0	$0	$0	$0	$0
Debt Service		**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$16,313,362**	**$0**	**$0**	**$0**	**$0**	**$0**
Tax Depreciation		$48,000,000	$76,800,000	$46,080,000	$27,648,000	$27,648,000	$13,824,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Taxable Income		($42,518,031)	($70,497,479)	($38,915,739)	($19,578,229)	($18,626,190)	($3,800,664)	$11,077,511	$12,187,721	$13,357,595	$14,591,017	$15,892,148	$17,265,447	$18,715,690	$20,247,997	$21,867,855	$23,581,146	$24,170,675	$24,774,942	$25,394,315	$26,029,173
PTC		$6,438,600	$6,745,200	$6,745,200	$7,051,800	$7,051,800	$7,358,400	$7,358,400	$7,665,000	$7,971,600	$7,971,600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC		$0																			
Taxes		**($23,445,812)**	**($34,944,192)**	**($22,311,496)**	**($14,883,092)**	**($14,502,276)**	**($8,878,666)**	**($2,927,396)**	**($2,789,911)**	**($2,628,562)**	**($2,135,193)**	**$6,356,859**	**$6,906,179**	**$7,486,276**	**$8,099,199**	**$8,747,142**	**$9,432,459**	**$9,668,270**	**$9,909,977**	**$10,157,726**	**$10,411,669**
Total	***(96,000,000)***	***23,414,420***	***35,319,848***	***23,104,378***	***16,103,630***	***16,161,161***	***10,986,857***	***5,496,126***	***5,830,694***	***6,153,198***	***6,155,780***	***(1,827,924)***	***(1,856,186)***	***(1,902,199)***	***(1,967,686)***	***(2,054,508)***	***14,148,688***	***14,502,405***	***14,864,965***	***15,236,589***	***15,617,504***

MACRS Depreciation Schedules																				
5	0.2	0.32	0.192	0.1152	0.1152	0.0576	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0.1429	0.2449	0.1749	0.1249	0.0893	0.0892	0.0893	0.0446	0	0	0	0	0	0	0	0	0	0	0	0
15	0.05	0.095	0.0855	0.077	0.0693	0.0623	0.059	0.059	0.0591	0.059	0.0591	0.059	0.0591	0.059	0.0591	0.0295	0	0	0	0
20	0.0375	0.07219	0.06677	0.06177	0.05713	0.05285	0.04888	0.04522	0.04462	0.04461	0.04462	0.04461	0.04462	0.04461	0.04462	0.04461	0.04462	0.04461	0.04462	0.04461

Figure 3-1. Example Generation Cost Calculation for a Wind Project.

3.1.2 Transmission Costs

Transmission costs were considered in the scenario analysis of each zone to which a conceptual transmission design was developed. These were the 50 percent of zones with the lowest weighted average busbar cost based on their generation resources alone. Transmission costs included line and substation, right of way, and operations and maintenance costs. The cost of transmission was calculated on a per MWh basis for each zone using the same levelized cost model used to calculate busbar cost. The assumptions that were used to estimate transmission costs in Phase II of UREZ, including financing assumptions, are included in Section 4.0.

3.1.3 Energy Value

An integral component of the resource valuation is the value of energy delivered by the generating resources. The energy value is intended to reflect the marginal cost of generation in the region where the resource is located. Since the analysis will value the capacity of a resource independently of the energy price, it is appropriate to consider only the marginal cost of generation in determining the energy value of a resource.

Phase II used an hourly electric price forecast for Salt Lake developed for the WREZ initiative to value the energy generated by Utah's renewable energy resources. This forecast was developed using the Ventyx ProMod production simulation software, which projected hourly market energy prices based on the dispatch of generating resources to meet hourly electric demand throughout the Western Energy Coordinating Council (WECC). This market price represents the value (opportunity cost) for the renewable energy generated. A major component of the price forecast is generator fuel costs, as the price of energy in the market is highly correlated to the market price of fuel, especially the price of natural gas, which is the marginal fuel in the WECC a majority of the time. In the ProMod model each generator is assigned a cost of fuel. Where available and known, such as at coal-fired generation stations, this represents the contract price of the fuel. For gas-fired power plants this typically includes a commodity price of gas and the cost to deliver this gas to each station. For the WREZ forecast the average delivered cost of gas to Utah gas-fired generating plants was approximately $6.50/mmbtu. The market price used to value the energy was the Salt Lake City price point included in the WREZ analysis, as the vast majority of Utah's energy demand is located in the Wasatch Front area, which includes Salt Lake City.

A portion of the renewable energy generated in Utah is anticipated to be purchased by out of state customers, and the Salt Lake City energy price forecast is used to value this energy as well. This is because it is speculative to attempt to identify specific buyer(s) or the value of the energy at any buyers delivery point. Since the out of state buyer would presumably value the power at the same price or a higher price than buyers in Utah, using Utah prices for valuing the energy is a conservative assumption.

3.1.4 Capacity Value

The capacity value of a generating resource is based on its ability to provide dependable and reliable capacity during peak periods when the system requires reliable resources for stable operation. Resources that can provide firm capacity have a higher capacity value than resources that cannot. Phase II will use the WREZ capacity value, which is equivalent to the annual cost of a new combustion turbine placed in service in the WECC. This value is $156/kW-year.

3.2 Financial Assumptions

The financial assumptions used in the cost of generation calculation for renewable energy resources in this study are shown below. The financial assumptions used in the cost of transmission are separate and detailed in Section 6.0. As most announced renewable generation being developed in Utah today is by non-utility merchant generators, Phase II assumes merchant generator project ownership.

Table 3-1. Financing Assumptions.

Technology	Economic Life (yrs)	Debt: Equity (ratio)	Debt Term (yrs)	Interest Rate (%)	Equity Cost (%)	Tax Life (yrs)
Geothermal	20	80/20	20	7.5 %	17.5%	5
Solar PV	20	80/20	20	7.5 %	17.5%	5
Solar Thermal	20	80/20	20	7.5 %	17.5%	5
Wind	20	80/20	20	7.5 %	17.5%	5

The economic life is the useful life of the project from the developer's perspective. While each technology may have a different economic life (i.e. geothermal may be 15 years, wind 25 years and hydro 50 years), 20 years is a typical renewable resource contract term and is assumed for all resources in this analysis.

The financing structure is assumed to be the same for all technologies. It is a representative structure for the financing of renewable energy projects owned by merchant generators. The debt term and rate are appropriate given the economic life of typical projects of these types and expected prevailing interest rates over time.

The cost of equity is an approximation of the return on investment that a renewable energy project investor would require, taking into account the rate of return that an investor could receive on a comparable investment. It is understood that the cost of equity varies among technologies and projects based on the perceived risk and numerous other factors. In the absence of a generally accepted set of assumptions, it seems there is not adequate justification for assuming differences among technologies.

The tax life is the depreciation schedule for project assets. Tax incentives permit accelerated depreciation for most renewable projects and are described further in the next section.

There are several additional assumptions that are made to support the economic analysis, which were developed in consultation with the Utah Division of Public Utilities (DPU):

- Combined federal and state income tax rate: 38 percent
- Discount rate: 10.5 percent
- General inflation: 2.0 percent

3.2.1 Renewable Energy Financial Incentives

A number of financial incentives are available for the installation and operation of renewable energy technologies. The incentives available to new renewable energy facilities and those that were applied to the economic analysis of UREZ resources are briefly discussed below.

3.2.2 U.S. Federal Government

The predominant federal incentive for renewable energy has been offered through the U.S. tax code in the form of tax deductions, tax credits, and accelerated depreciation. An advantage of this form of incentive is that it is defined in the tax code and is not subject to annual congressional appropriations or other limited budget pools (such as grants and loans). Tax-related incentives include:

- Section 45 Production Tax Credit (PTC)
- Section 48 Investment Tax Credit (ITC)
- Accelerated depreciation

The Section 45 PTC is available to private entities subject to taxation for the production of electricity from various renewable energy technologies. The income tax credit amounts to 1.5 cents/kWh (subject to annual inflation adjustment and equal to 2.1 cents/kWh in 2010) of electricity generated by wind, geothermal, and closed-loop biomass. The credit is also available to solar facilities installed prior to 2006. The credit is equal to 0.75 cents/kWh (inflation adjusted, equal to 1.0 cents/kWh in 2010) for all other renewable energy technologies. A problem with the credit is the ever-present threat of expiration, which promotes boom and bust building patterns. The PTC was recently extended in February 2009 to the end of 2012 for wind and the end of 2013 for all other resources as part of HR 1, the American Recovery and Reinvestment Act (ARRA, or the "Stimulus Bill"). Major provisions of the Section 45 PTC are presented in Table 3-2.

Table 3-2. Major Production Tax Credit Provisions.

Resource	Eligible In-service Dates	Credit Size*	Special Considerations
Wind	12/31/93 - 12/31/12	**Full**	Cannot also take investment tax credit
Geothermal	12/31/99 - 12/31/13	**Full**	Cannot also take investment tax credit
Solar	10/22/04 - 12/31/13	**Full**	Cannot also take investment tax credit; eligibility expired Dec. 31, 2005

Source: Black & Veatch research.
Notes:
* All PTCs are inflation-adjusted and equaled $21/MWh ("full") or $10/MWh ("half") in 2009.

Section 48 ITC effectively offsets a portion of the initial capital investment in a project. The Energy Policy Act of 2005 modified the ITC to include additional resources and increased the credit amount. While utilities originally were not eligible to receive the ITC, the extension of the ITC passed in 2008 changed this wording to allow utilities to claim the ITC if they have a tax burden. In addition, ARRA expanded the eligibility to a broader range of resources. The ITC provisions are now:

- Solar – Eligible solar equipment includes solar electric and solar thermal systems. The credit amount for solar is 30 percent for projects that come online prior to December 31, 2016; otherwise, it is 10 percent.
- Geothermal – Geothermal includes equipment used to produce, distribute, or use energy derived from a geothermal deposit. The credit amount for geothermal is 30 percent for plants that come online prior to December 31, 2012, but cannot be taken in conjunction with the PTC.
- Wind – Units must be placed into service by December 31, 2012 and cannot be taken in conjunction with the PTC.

One major non-tax related incentive to come from the ARRA is a new renewable energy grant program. Project owners with a tax burden can receive a grant after the project is placed into service equal to 30 percent of the project's capital cost. Projects must begin construction by the end of 2010, and must be placed into service by 2012 (wind), 2016 (solar), or 2013 (all other eligible resources). If the grant is utilized, the project cannot apply the benefits of the PTC or ITC. Since this program will largely have an impact similar to that of the 30 percent ITC program, it is not modeled separately in the financial pro forma.

The language of the PTC extension does not allow claiming of both the PTC and the ITC. Project developers must choose one or the other. For capital-intensive solar projects, the ITC is typically more attractive. The ITC also interacts with accelerated depreciation, as discussed further below.

Section 168 of the Internal Revenue Code contains a Modified Accelerated Cost Recovery System (MACRS) through which certain investments can be recovered through accelerated depreciation deductions. There is no expiration date for the program. Under this program, certain power plant equipment may qualify for 5-year, 200 percent (i.e., double) declining-balance depreciation, while other equipment may also receive less favorable depreciation treatment. Renewable energy property that will receive MACRS includes solar (5-year), wind (5-year), geothermal (5-year), qualifying hydropower (5-year) and biomass (7-year). Typically, the majority of the project capital cost, but not all, can be depreciated on an accelerated schedule.

The accelerated depreciation law also specifies that the depreciable basis is reduced by the value of any cash incentives received by the project, and by half of any federal investment tax credits (e.g., the ITC). This provision has the effect of lowering the depreciable basis to 95 percent for projects that receive the 10 percent ITC and 85 percent for projects that take the 30 percent ITC.

In Phase II of UREZ, the cost of generation for all resources was modeled assuming they received the 30 percent ITC and 5 years MACRS depreciation. The assumption was that even if specific renewable energy incentives will expire, a similar level of support from the US Federal government will continue into the future.

3.2.3 Utah State Incentives

Utah offers a number of renewable energy tax incentives. These are not included programmatically in the modeling of these resources, due to the fact that they have a relatively small effect on the cost of generation or are based on incentives to specific development zones and projects, which cannot be easily projected. However, the UREZ Transmission Model is sufficiently flexible as to allow users to include these or other incentives.

Utah offers renewable generators a state sales tax exemption. Utah also offers a PTC and ITC depending on the technology and the size of the project. State PTC and ITC incentives concerning solar, geothermal and wind are outlined below:

1) Wind and Geothermal projects that are over 660kW (which are the only projects being considered in UREZ Phase II) are eligible for a Production Tax Credit of $0.0035 cents per kWh produced for the first four years of operation.
2) Solar projects are eligible for an ITC of 10% of the project cost with a maximum of $50,000.

Other Utah incentives are discretionary and are also not included in the model on a programmatic basis. The model has the capability to include cost adjustments, so any new programmatic or individual project incentives may be added by the user.

3.3 Quartile Analysis of Zones

It is very important to consider the uncertainty in the estimates used to value resources. By their very nature, these estimates include a wide margin of error. For example, it would not be prudent to eliminate potential zones from consideration if the difference in their ranking score is 5 percent, but the margin of error is 20 percent.

For this reason, average busbar costs for each zone were generalized and each zone was represented by the quartile of the distribution of all scores into which it falls based on the potential energy generated within the zone. This enabled the Zone Selection work group to compare the general relative average busbar costs of zones against each other without addressing minor differences in their costs. Zones that fell into the first two quartiles were considered for the scenario analysis.

All UREZ zones ranked into quartiles based on busbar cost are shown below. The first table shows example zones, their generating capacities, estimated annual generation, and energy weighted average busbar costs. The second table shows the same data, with the quartile of each zone’s energy weighted average busbar cost added and the zones labeled with these quartiles.

Table 3-3. UREZ Phase II Zones Individually Ranked.

Zone	Capacity (MW)	Energy (GWh/yr)	Energy Weighted Average Busbar Cost ($/MWh)
Helper	480	1,285	71
Summit	390	1,003	74
Cedar Creek	315	770	77
Birch Creek	405	991	77
Flat Rock	500	1,169	80
Duchesne	320	730	82
Cedar	250	550	85
Mona	420	930	86
Dinosaur	300	620	90
Ben Lomond	303	902	91
Loa	348	787	93
Red Butte	781	1,841	102
Blundell	1,357	3,544	109
Antelope	857	1,941	110
Milford	1,759	4,174	115
Monticello	856	1,839	116
Sevier	403	933	116
Johns Valley	633	1,269	121
Black Rock	2,218	5,216	130
Escalante Valley	2,375	4,714	158
Red Rock	1,164	2,265	166
Hardpan	776	1,482	172
Garrison	1,628	3,114	174
Intermountain	1,614	3,217	177
Wayne	1,204	2,287	179
Grand	226	421	184
Clive	2,126	3,851	198

Source: Black & Veatch analysis for Phase II of the UREZ Initiative.

Table 3-4. UREZ Phase II Zones Ranked Into Quartiles.

Quartile	Zone	Capacity (MW)	Energy (GWh/yr)
1	Helper	480	1,285
	Summit	390	1,003
	Cedar Creek	315	770
	Birch Creek	405	991
	Flat Rock	500	1,169
	Duchesne	320	730
	Cedar	250	550
	Mona	420	930
	Dinosaur	300	620
	Ben Lomond	303	902
	Loa	348	787
	Red Butte	781	1,841
2	Blundell	1,357	3,544
	Antelope	857	1,941
	Milford	1,759	4,174
	Monticello	856	1,839
3	Sevier	403	933
	Johns Valley	633	1,269
	Black Rock	2,218	5,216
	Escalante Valley	2,375	4,714
	Red Rock	1,164	2,265
	Hardpan	776	1,482
4	Garrison	1,628	3,114
	Intermountain	1,614	3,217
	Wayne	1,204	2,287
	Grand	226	421
	Clive	2,126	3,851

Source: Black & Veatch analysis for Phase II of the UREZ Initiative.

3.4 Zone Ranking for the Scenario Analysis

While zones were ranked once based on busbar cost in order to identify a set of zones appropriate for the scenario analysis, zones were also ranked based on premium cost within the scenario analysis itself. This ranking enabled Black & Veatch to select the highest value zones and projects to meet each scenario's goals. Dependent on the scenario, this analysis was done by either calculating the energy-weighted average premium cost for each zone, or by calculating the premium cost for each project within each zone. Zones or projects were selected to meet the various scenario goals based on their premium costs.

4.0 Renewable Energy Resource Characterization

This section describes the resource characteristics and cost assumptions used in the Phase II analysis to characterize the performance and economics of the geothermal, solar and wind resources identified in UREZ Phase I. The costs and characteristics included in this report are representative of the "best" currently-available commercial resources as of December, 2009. We note there is a substantial amount of ongoing renewable energy resource research and development, and many believe the cost of renewable energy will continue to decline as recent history has demonstrated. While this may occur, it is highly speculative to project the costs and characteristics of these emerging technologies. Accordingly, we have chosen to model the "best" current technologies as a proxy for future renewable resources[7].

4.1 Geothermal

Geothermal zones identified in Phase I were characterized as large general areas of geothermal resource potential that will be refined for the transmission analysis in Phase II. The proposed refinement of geothermal zones is described in section 2.0 above. The costs of geothermal projects are highly site-specific and will be based on the costs of these projects estimated in the WREZ initiative. Capacity factors and production profiles were developed by Black & Veatch.

4.1.1 Cost Characteristics

Capital costs for each theoretical geothermal plant were estimated based on GeothermEx capital costs for theoretical geothermal projects evaluated in the WREZ study. These costs ranged from approximately \$4,000 to \$7,000 per kW, with the majority of the resources costing less than \$6,000/kW. Operating costs for each geothermal project were based on estimated operating costs created by GeothermEx for the WREZ project.

A theoretical cost of transmission interconnection for each resource was developed by measuring the distance between specific project locations and the nearest transmission line and assuming a point-to-point interconnection between the project and the transmission system. Generation tie-lines and interconnecting substations were sized based on the capacity of the interconnecting resource.

[7] An excellent source of information regarding current and emerging technologies in the National Renewable Energy Laboratory. Current information on resources may be found at: http://www.nrel.gov/library/

4.1.2 Performance Characteristics

UREZ Phase I identified large areas with potentially developable geothermal resources and estimated the developable resource potential in these areas. In Phase II, it was necessary for transmission design purposes to assign the resource capacity across large areas to theoretical project locations inside these areas. It was decided in conversations with the UREZ Phase I geothermal consultants that these project locations would be where GeothermEx located potential projects in the WREZ initiative, as well as a couple of other locations specified by the UREZ Phase I geothermal consultants. The generating capacity assigned to the UREZ Phase I zones were distributed over these various project locations.

In the WREZ initiative, GeothermEx determined whether or not each project location it identified would likely be a binary or flash geothermal resource. These distinctions were used in Phase II. The majority of the resources assessed are binary.

For each theoretical geothermal project, a 12x24 production profile was created to represent the project's output. For dry-cooled binary plants, these production profiles will vary based on ambient temperature at the project site. For flash type plants, a flat 12x24 production profile at the capacity factor of the plant was created.

In dry cooled binary plants, plant output decreases with increases in ambient temperature. The ambient temperature effect on dry cooled geothermal plants was modeled by a National Renewable Energy Lab (NREL) study and was applied to the UREZ geothermal resources.[8] taken from the NREL study, shows the modeled effect of ambient temperature on dry cooled binary plant output.

[8] Kutscher, C., Cosentaro, D. "Assessment of Evaporative Cooling Enhancement Methods for Air-Cooled Geothermal Power Plants." Presented at the Geothermal Resources Council Annual Meeting, Reno, NV. September 22-25, 2002. NREL/CP-550-23294.

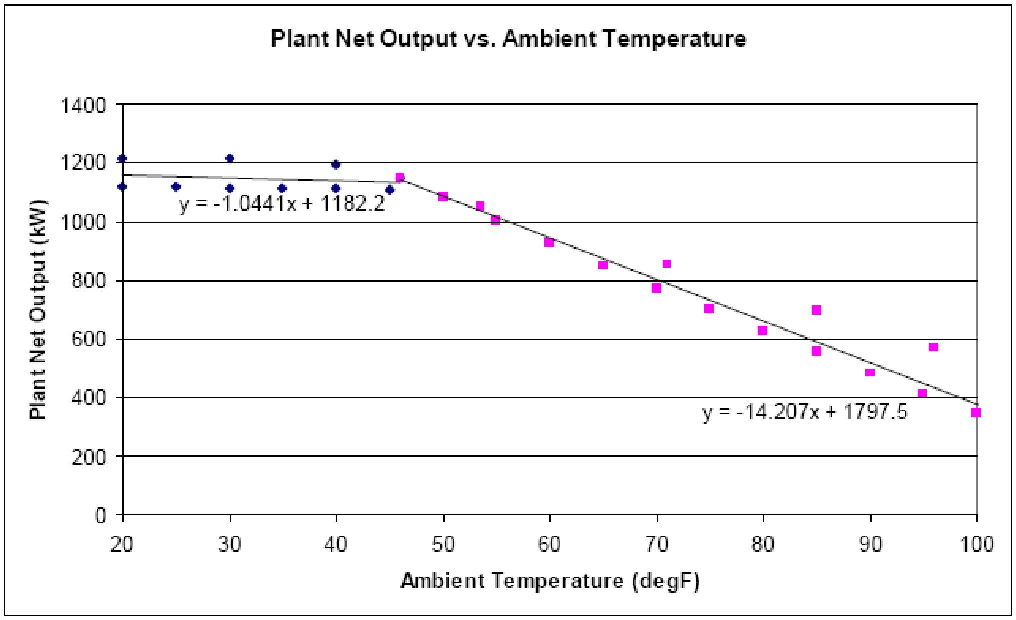


Figure 4-1. Plant Output vs. Ambient Temperature.

Ambient temperature information for each potential geothermal site in UREZ Phase II was collected from NREL data[9], and the functions from the above figure were applied to determine expected plant output as a percentage of nameplate capacity. Capacity factors for all binary resources and 80 percent and 90 percent for flash resources.

4.2 Solar

Solar zones identified in UREZ Phase I included all areas where solar resources met the minimum resource quality, slope and developability criteria. This analysis quantified large areas across the state representing over 800,000 MW of solar generating potential. The methodology used to refine the solar zones is detailed in section 2.0. This limits potential solar development to approximately 15,000 MW, and only characterizes solar resources located within 50 miles of the transmission system.

Three technologies were modeled in the solar resource areas in Phase II, while the Phase I solar analysis considered only a concentrating solar thermal technology. In addition to modeling a concentrated solar thermal technology (defined in Phase II as a dry-cooled trough plant without storage capability), Phase II considered two different

[9] NREL, National Solar Radiation Data Base, Available: http://rredc.nrel.gov/solar/old_data/nsrdb/tmy2/, 2009

types of solar photovoltaic (PV) technologies, including a flat-plate thin film technology and a single-axis tracking crystalline technology. No further resource analysis was done in Phase II, but it was assumed that the solar resources identified in Phase I could be captured using either the default solar thermal technology or either of two solar PV technologies. For the zone quartile ranking and the premium cost analysis, the default technology, solar thermal, was assumed and modeled.

4.2.1 Cost Characteristics

A flat capital cost for each solar technology was used. This was used because the cost variation across the large areas evaluated in UREZ will not be extreme and small variations could not be accurately characterized at this high level of analysis.

Capital costs include all owners' costs, such as interest during construction, insurance and access roads among plant facilities. They did not include transmission interconnection or roads connecting the theoretical facilities to the main roads. The capital and operating costs used for each solar technology are shown in the table below.

Table 4-1. Solar Technology Costs.

Solar Thermal Dry-Cooled	
Performance	
Capacity Factor (percent)	20 to 28
Economics (2010$)	
Total Project Cost ($/kW)	5,350
Consolidated O&M ($/MWh)	30
Single-Axis Tracking Crystalline ($/kW$_{ac}$)	
Performance	
Capacity Factor (percent)	23 to 31
Degradation	0.75 percent/year
Economics (2010$)	
Total Project Cost ($/kWe)	4,500
Consolidated O&M ($/MWh)	19 to 26
Fixed-tilt Thin Film ($/kW$_{ac}$)	
Performance	
Capacity Factor (percent)	18 to 27
Degradation	1 percent/year
Economics (2010$)	
Total Project Cost ($/kWe)	3,975
Consolidated O&M ($/MWh)	13 to 24
Notes: Solar PV values on a kWe and net AC basis.	

Transmission interconnection costs were added to the above capital costs. These were estimated for each zone as point to point transmission interconnections from the generator to the transmission system. The distance from the nearest transmission line to the midpoint of each Phase II zone was the basis for calculating the generation-tie line cost for all the solar resource inside that zone. Generation-tie lines for all solar resources were estimated based on the assumed project size for the modeled solar technology. For solar thermal this default size was 125 MW and for solar PV, this default size was 50 MW.

4.2.2 Performance Characteristics

Resource Size and Technology Types

The solar thermal technology modeled is a dry cooled parabolic trough technology without storage that is 125 MW in size. This is a common size for solar thermal plants proposed and under development in the US today. Two solar PV technologies are modeled: fixed tilt thin-film and single-axis tracking crystalline.

Capacity Factors and Production Profiles

Capacity factors and production profiles for solar thermal and solar PV were developed by Black & Veatch. The general methodologies for developing these production profiles are detailed below.

<u>Solar Thermal</u>

A unique production profile was created by Black & Veatch for the resource located in each Phase II zone. The resource capacity factor is derived as the arithmetic mean of the production profile.

<u>Solar Photovoltaic</u>

For solar PV technologies, production profiles and capacity factors are calculated for each Phase II zone's center point and applied to all resources inside that zone. For a solar PV project, capacity factor is the ratio of its AC delivered energy over a year and its AC energy output if it had operated at full nameplate capacity the entire time.

Black & Veatch used data and models developed by the NREL as a basis for the capacity factor analysis for photovoltaic modules. High resolution solar irradiance data are available from NREL in geographic information system (GIS) format. These data include global horizontal, latitude tilt and direct normal monthly irradiance values for 10km x 10km grid squares. NREL derived the solar irradiance data from many years of satellite images covering the United States.

Black & Veatch used a proprietary tool to calculate energy production. The inputs for this tool include the NREL solar irradiance data, temperature data, geographical location, day and hour. The tool outputs average hourly energy production by month for both tracking crystalline silicon and fixed tilt thin film technologies.

4.3 Wind

Wind zones identified in Phase I were both an appropriate size for transmission design and included capacity factor and resource size information. The Utah Geological Survey (UGS) has historical ground proofed wind data for many of the sites that make up the wind zone analysis. When possible, these data were used to generate production profiles for the wind analysis. Where UGS data were not available, correlations with wind maps provided by NREL were used.

4.3.1 Cost Characteristics

Capital costs are driven largely by the project size and the project terrain type. A base capital cost per kW was identified for each project size category across the state based on that project's size, its underlying terrain type and Black & Veatch's knowledge and experience. Capital costs include all owners' costs, such as interest during construction, taxes, insurance and access roads among plant facilities. They did not include transmission interconnection or roads connecting the facility to the main roads.

Wind resources identified in Phase I consist of projects of different sizes, based on the size of the Phase I zones in which they are located. Wind zone sizes range from 50 MW to 500 MW. For the purposes of estimating their cost characteristics, Phase I wind zones were categorized as projects in the following size groups: 35-60 MW; 60-70 MW; 70-100 MW; and 100+ MW.

The base capital and operating costs for each wind project size are shown in the table below.

Table 4-2. Base Wind Capital Costs.

Project Size (MW)	Base Capital Cost ($/kW)
100+	$2,300
70-100	$2,350
60-70	$2,400
35-60	$2,450

Source: Black & Veatch research for Phase II of UREZ.

Once base capital costs were assigned to each wind zone, construction costs, which represent approximately 12 percent of total project costs were then adjusted based on the terrain slope of each wind zone. Terrain multipliers for wind construction costs developed based on Black & Veatch experience with projects of this size are as follows.

Table 4-3. Wind Construction Cost Terrain Multipliers.

Terrain Type	Grade (percent)	Multiplier
Flat Terrain	Less than 4	1.00
Hills Terrain	4 to 8	1.05
Mountain Terrain	8 to 10	1.15
Aggressive Mountain Terrain	Greater than 10	1.30
Source: Black & Veatch research for Phase II of UREZ.		

Transmission interconnection costs were estimated for each wind zone as point-to-point transmission interconnections from the generator to the transmission system. The cost of the point- to-point system and the interconnecting substations was based on the distance from the center point of the Phase I wind zone to the nearest transmission line. The size of the generation tie lines required for wind resources were determined based on the assumed project size in that zone.

4.3.2 Performance Characteristics

Black & Veatch created expected hourly energy production profiles in 12x24 format for each of the wind zones identified in the Phase I. The profiles were created using meteorological (MET) mast data from the Utah Anemometer Loan Program, the NREL Western Wind and Solar Integration Study (WWSIS) and the UREZ Phase 1 report.

While Phase I did not characterize the projected production profiles for the identified resource zones, the UGS had production profile data and met tower information for approximately 77 sites in Utah through its Anemometer Loan Program. UGS furnished Black & Veatch with this information along with projected capacity factor information for each resource area identified in UREZ Phase I.

Using criteria developed jointly with UGS, Black & Veatch developed energy production profiles for the 51 wind energy zones identified in the UREZ Phase 1 report. The profiles were created using MET mast data from the Utah Anemometer Loan Program where possible, and augmented with projected wind data developed by the National Renewable Energy Lab (NREL) Western Wind and Solar Integration Study (WWSIS). The 12x24 profiles were then adjusted to match the UREZ Phase I capacity factors for the wind resource areas.

5.0 Transmission Resource Characterization

A primary goal of the Phase II study is to identify the transmission that may be necessary to deliver Utah's renewable energy resources to load, either in Utah or out-of-state locations. Phase II modeled in a conceptual way the existing high-voltage transmission system in Utah, including all major existing and planned transmission corridors. The high-voltage system in Utah is primarily owned and managed by Rocky Mountain Power Company (RMP), with a small transmission system owned and operated by Deseret Generation and Transmission Co-operative (DG&T). A 500 kV DC line, owned and operated by the Intermountain Power Agency (IPA), has a terminus point at the Intermountain substation in central Utah, extending from Intermountain to Southern California.

The renewable resources to be developed during the planning horizon will use the existing transmission to the extent possible, but additional transmission will likely be required to deliver all of the renewable energy generated in the scenario analyses. In Phase II transmission requirements for the scenarios were identified and conceptual transmission to deliver this energy to customers was modeled.

5.1 Available Transfer Capability

The existing transmission system in Utah is heavily utilized, with prevailing line flows in a southerly and westerly direction. It is difficult to estimate the future dependable available transfer capability (ATC) for a transmission line, as this will be a factor of energy demand, generation by other resources and the configuration of the transmission system overall. However, the Technical Working Group determined it is reasonable to assume there is directional ATC on lines that would counter-flow the prevailing energy flow. Table 5-1 shows the amount of ATC that was assumed to be available over different lines in the scenario analysis and UREZ Transmission Model.

Table 5-1. Available Transfer Capability Assumptions by Line.

Segment	ATC, MW	Reverse Direction ATC, MW
Ben Lomond to Terminal	0	0
Birch Creek to Ben Lomond	0	0
Bluff to Pinto	0	0
Bonanza to Ashley	0	0
Enterprise to Three Peaks	0	0
Helper to Newsub11	0	0
Intermountain to Mona	0	100
Limber to Newsub12	0	0
Limber to Oquirrh	0	0
Limber to Terminal	0	0
Mona to Bonanza	0	0
Mona to Limber	0	0
Mona to Sigurd	0	0
Mona to Terminal	0	0
Newsub1 to Three Peaks	0	0
Newsub10 to Newsub16	0	0
Newsub11 to Ashley	0	0
Newsub13 to Helper	0	0
Newsub13 to Mona	0	0
Newsub13 to Newsub16	0	1500
Newsub14 to Birch Creek	500	0
Newsub15 to Glen Canyon	0	0
Newsub16 to Pinto	0	0
Newsub17 to Ben Lomond	0	0
Newsub2 to Newsub4	0	0
Newsub3 to Gonder	0	0
Newsub3 to Intermountain	0	0
Newsub3 to Pavant	0	100
Newsub4 to Newsub5	0	0
Newsub5 to Newsub1	0	0
Newsub6 to Newsub5	0	0
Newsub7 to Newsub15	0	0
Newsub8 to Newsub7	0	0
Pavant to Sigurd	0	0
Red Butte to Enterprise	0	0
Red Butte to Sigurd	0	0
Sigurd to Newsub13	0	0
Sigurd to Newsub6	0	0
Sigurd to Newsub7	0	0
Sigurd to Three Peaks	0	0
St. George to Red Butte	0	1500
Terminal to Populus	500	0

5.2 Incremental Transmission Development

It is highly likely that additional transmission will be required to deliver energy generated from renewable resources to Utah customers and out-of-state buyers. This includes both transmission to access renewable resource areas and transmission additions to expand the existing transmission network. Phase II developed a conceptual transmission network designed to interconnect resource zones to the grid and augment the existing transmission network. It is important to note that the conceptual network represents general transmission corridors for theoretical future development rather than specific lines. To the extent that development will require new transmission the specific lines will be proposed by the project proponent(s).

The conceptual transmission system layout is based on the existing network layout. The working group decided that this is a reasonable assumption given that most of the new transmission development in the state will come in the form of upgrades to the existing network or development of lines in or adjacent to existing corridors. Transmission corridor route characteristics and mileage were estimated under this assumption. Figure 5-1 depicts the conceptual transmission system overlaid on the current transmission network.

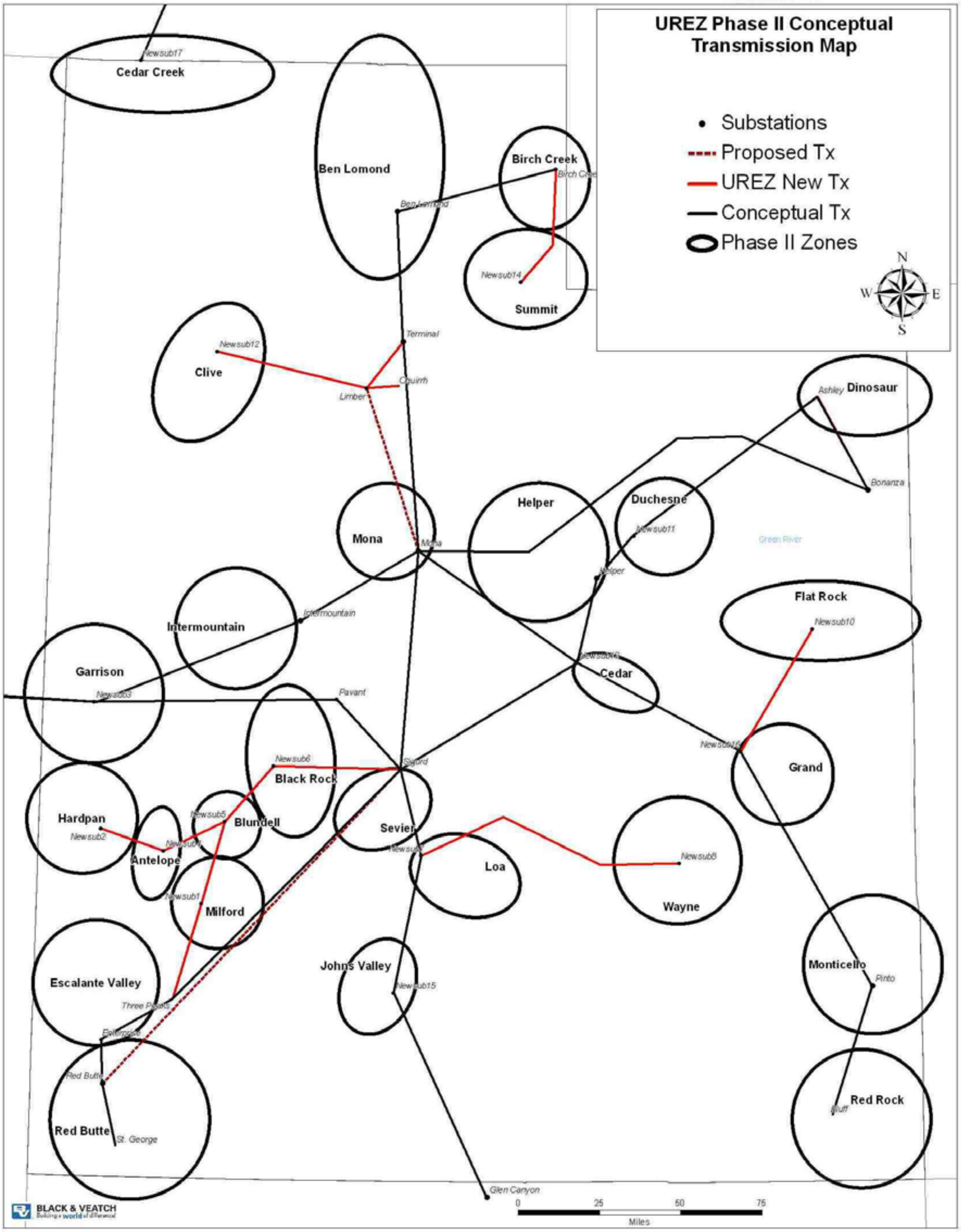


Figure 5-1. UREZ Phase II Conceptual Representation of the Existing Transmission System.

5.3 Energy Delivery Points

It was assumed that all renewable energy generated for Utah consumption was delivered to the Wasatch Front, where the vast majority of Utah energy demand is located. For the scenario analysis and the UREZ Transmission model, the delivery point is specified as Rocky Mountain Power's Terminal substation near Salt Lake City.

To model energy deliveries out of Utah, it was necessary to specify out of state delivery points for each zone. Phase II assumed that energy exported for out-of-state consumption would be delivered to the substations from the list below nearest to the specific zone along the conceptual transmission system. The substations below were assumed to serve as gateways to other portions of the western grid.

Table 5-2. Out of State Delivery Points (Substations).

Pinto	Gonder, NV
Ben Lomond	Mona
Bonanza	Glen Canyon, AZ
Red Butte	Intermountain

5.4 Transmission Ownership

Transmission has traditionally been developed by utilities within their respective service territories, though the Federal Energy Regulatory Commission (FERC) allows for the ability for "merchant" transmission development. While Phase II makes no assumption regarding the future ownership of actual new transmission facilities, for purpose of transmission costing, utility financing of new transmission facilities was assumed. The financing assumptions used in the cost of transmission calculations, provided on Table 5-3 below, are designed to reflect "typical" investor-owned utility (IOU) financing costs.

Table 5-3. IOU Transmission Financing Cost Assumptions.

Cost Factor	**Investor-owned Utility**
AFUDC	10 percent of capital cost
Economic Life	20 years
Debt Percentage	60 percent
Debt Term	20 years
Interest Rate	7 percent
Equity Cost	11 percent
Tax Life	15 years
Discount Rate	8.60 percent
Tax Rate	38 percent

5.5 Transmission Characteristics

New transmission facilities included in the Phase II analysis ranged from 138kV to 500 kV in size. In addition to the transmission lines, new facilities will generally require new substations. It was assumed that each zone would require the development of one new substation of the appropriate size, based on the total amount of generating capacity being modeled in that zone. Below is a description of the transmission facility characteristics and costs to be used in the study.

5.5.1 Line Characteristics and Costs

Table 5-4 details the cost and characteristics for the new transmission lines.

Table 5-4. Transmission Line Cost & Characteristics.						
Line Size	**Capacity (MW)**	**Cap Cost ($000/mile)**	**ROW Width feet**	**Phase/Pole Current (amps)**	**Typical Conductors**	**No. of Conductor per phase**
500 kV AC Single	1500	1800	175	1823	1590 ACSR	3
500 kV AC Double	3000	2880	175	1823	1590 ACSR	3
345 kV AC Single	750	1260	160	1321	1272 ACSR	2
345 kV AC Double	1500	2016	160	1321	1272 ACSR	2
230 kV AC Single	400	900	150	1057	1272 ACSR	1
230 kV AC Double	800	1440	150	1057	1272 ACSR	1
138 kV AC Single	200	550	100	880	1272 ACSR	1
138 kV AC Double	400	1000	100	880	1272 ACSR	1
ROW Cost: $9,478 per acre						

5.5.2 Substation Costs

Noted above, new transmission will likely require new and/or expanded substations. One substation of the appropriate size will be modeled for each zone. Substations will be sized based on the maximum interconnecting voltage into or out of the substation, based on the amount of generating capacity that is being modeled in each zone. The estimated costs for the substations are on Table 5-5 below.

Table 5-5. Substation Costs.	
Line Size	**Substation Capital Cost ($million)**
500 kV AC Single	50
500 kV AC Double	80
345 kV AC Single	40
345 kV AC Double	64
230 kV AC Single	35
230 kV AC Double	56
138 kV AC Single	8
138 kV AC Double	10

5.5.3 Operation & Maintenance Cost

In addition to the capital costs of the transmission facilities it was necessary to account for the continuing operating cost of the facilities. This was modeled as a fixed operating and maintenance cost, at 3 percent of the capital cost of the transmission line per year. This includes property taxes and insurance (1.8 percent) and labor and equipment (1.2 percent).

5.5.4 Losses

Transmission line losses are a function of line voltage, line loading and transmission line distance. As UREZ Phase II is only considering transmission within Utah, Phase II will use a line loss factor consistent with the Open Access Transmission Tariff (OATT) average loss factor charge for interconnecting generation. For DG&T the factor is 3.48 percent, while PacifiCorp's current OATT loss factor is 4.48 percent. As most new generation will likely interconnect to the PacifiCorp system, we propose a loss factor of 4.4 percent. This loss factor is applied to the total generation from a zone when its cost of transmission is calculated.

5.5.5 Integration Costs

The integration cost of a project is the indirect operation cost to the transmission system to accommodate the generation from the project into the grid. These costs will vary significantly by resource control area based on the specific characteristics of the loads and resources within that area. The WREZ initiative developed integration costs for each technology that reflected the approximate average integration cost based on several studies of various electric systems. The Utah Public Service Commission recently approved a forecasted cost to integrate wind into the PacifiCorp utility system in Docket No. 09-035-23 and this value has been incorporated into the modeling assumptions. [10]

For solar and geothermal technologies, Phase II adopted the values developed by the WREZ initiative. We note alternative (user-defined) values may be used in the UREZ transmission model with ease. Table 5-6 provides the integration cost by technology for the base case.

[10] February 18, 2010, Report and Order on Revenue Requirement, Cost of Service and Spread of Rates, "In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations

Table 5-6. Integration Costs by Resource Type.	
Type	**Costs ($/MWh)**
Wind	$6.64/MWh
Solar Thermal	$2.50/MWh
Photovoltaic	$2.50/MWh
Geothermal	$0.00/MWh

6.0 Scenario Analysis

As discussed in the Executive Summary, UREZ Phase II did not identify an optimal set of renewable resource and transmission lines to meet a specific demand target. Rather a set of scenarios, designed to represent a plausible range of generation and transmission development through 2025, was developed by the Technical Working Group. These scenarios identify the demand for renewable energy by Utah and out-of-state customers and establish parameters regarding plan construction. Using these parameters, Black & Veatch developed portfolios of generating resources and transmission infrastructure to achieve the scenario targets using the resource selection and portfolio development criteria described in Section 2. This section provides the detailed results of these scenarios and describes the resource and transmission development that would potentially be required for each scenario. Prior to the discussion of specific portfolios, the basis for the scenario targets is detailed.

6.1 Expected Resource Development

An important assumption in Phase II is the assessment of how much renewable generation is likely to be built in Utah between now and 2025 to meet both in and out-of-state demand. Black & Veatch conducted an assessment of the potential Utah demand for renewable resources based on future state energy loads, renewable procurement targets, and estimated demand reduction due to energy efficiency measures. Black & Veatch and the work groups then assessed whether existing renewable resources may be used to meet the state goals. An assessment of out-of-state demand for Utah renewable energy generation was a more subjective exercise, based on the expert judgment of several Technical Working Group participants.

6.1.1 Utah Renewable Planning Goal in 2025

Utah has established a goal to serve 20 percent of load with renewable energy by 2025. This is a goal rather than a requirement, and it is a goal that may be met in a variety of ways, including the use of energy generated outside of Utah.

Projected electric energy requirements for Utah in 2025 are anticipated to total 49,116 GWh/yr.[11] To achieve the Utah RPG goal of 20 percent renewable energy generation in this year, renewable energy generation or generation equivalents from qualifying resources would need to be 9,077 GWh/yr, taking into consideration

[11] Black & Veatch estimate of 2025 requirements included in the Western Renewable Energy Zone analysis of statewide electric demand, 2009.

reductions due to the implementation of energy efficiency programs. The calculation is detailed on Table 6-1, below.

6.1.2 Interim Renewable Development Benchmarks

The Utah RPG is only expressed for year 2025, though it is likely that renewable development and procurement will occur during the years prior to 2025. For planning purposes UREZ developed interim benchmarks for renewable development for years 2015 and 2020. The renewable demand and resource development numbers provide a simple ramp up to the amount of generation required to meet the Utah renewable energy goal in 2025 over time, beginning with 10% of resource developed by 2015 and 15% developed by 2020. The expected energy quantities for these years are detailed on Table 6-1.

6.1.3 Energy Efficiency

Utah has expressed its interest in implementing additional energy efficiency programs (EE), and Rocky Mountain Power, in its 2008 IRP, has proposed demand side management programs over the 2010-2025 period. To develop a state-wide forecast of EE for UREZ scenario modeling, we assume that all load serving entities in Utah will achieve comparable levels of EE energy reduction to PacifiCorp.[12] The projected impact of energy efficiency on state energy load is shown on Table 6-1

Table 6-1. RPG and Interim Benchmarks.

Year	Energy Requirements (GWh/yr	Energy Efficiency (GWh/yr)	Net Energy Requirements (GWh/yr)	RPG and Interim Benchmark (% of load)	RPG and Interim Benchmark (GWh/yr)
2015	42,525	1,445	41,080	10%	4,108
2020	45,731	2,532	43,199	15%	6,480
2025	49,116	3,731	45,385	20%	9,077
Source: UREZ Phase II Work Groups.					

6.1.4 Existing Renewable Generation

There are a number of hydroelectric and wind power facilities operating in Utah that may contribute to the Utah RPG, though it is uncertain at this time how much of the

[12] The PacifiCorp 2008 IRP was acknowledged by the Utah Public Service Commission on April 1, 2010.

energy produced by these facilities will be counted towards the RPG. UREZ assumes, for planning purposes, no energy from existing qualifying renewable resources should be counted towards achievement of the RPG.

6.2 Development Scenarios

The development scenarios reflect alternative views of how much renewable development will occur over the next 15 years in Utah. They were constructed by estimating what percentage of the Utah RPG would be served by in-state resources, and estimating the amount of generation capacity that will be developed for export. These estimates are based on the professional judgment and general consensus among Work Group participants.

All of the scenarios assume a portion of Utah's RPG will be served by Utah resources, and there will be additional resource development to serve out-of-state renewable energy demand. None of the scenarios assume that all of Utah's RPG will be met by Utah resources alone. The scenarios assume that the RPG requirements will be met by generation resources in Utah, and also by generation resources outside Utah, or qualifying equivalent resources such as energy efficiency. As it is impossible to determine where imported energy will come from, this analysis made no assumptions about this. The analysis included the following scenarios:

- Reference Case
- Low Development
- High Development
- "Best Projects" Development
- Development Timing

Table 6-2 provides a summary of the anticipated annual energy requirements from renewable resources for each scenario in 2015, 2020 and 2025.

Table 6-2. Summary of Renewable Energy Development Scenarios, GWh/yr.

Year:	Low Development	Reference Case, Best Projects Development, Development Timing	High Development
2015	2,269	3,404	4,538
2020	3,404	5,106	6,808
2025	4,538	6,808	9,077

Source: UREZ Phase II Technical Working Group.

Figure 6-1 depicts the estimated cumulative capacity additions needed to generate the energy in Table 6-2, assuming a weighted average 30 percent capacity factor of all renewable resources in Utah. The capacity factor may vary significantly depending on the resources developed.

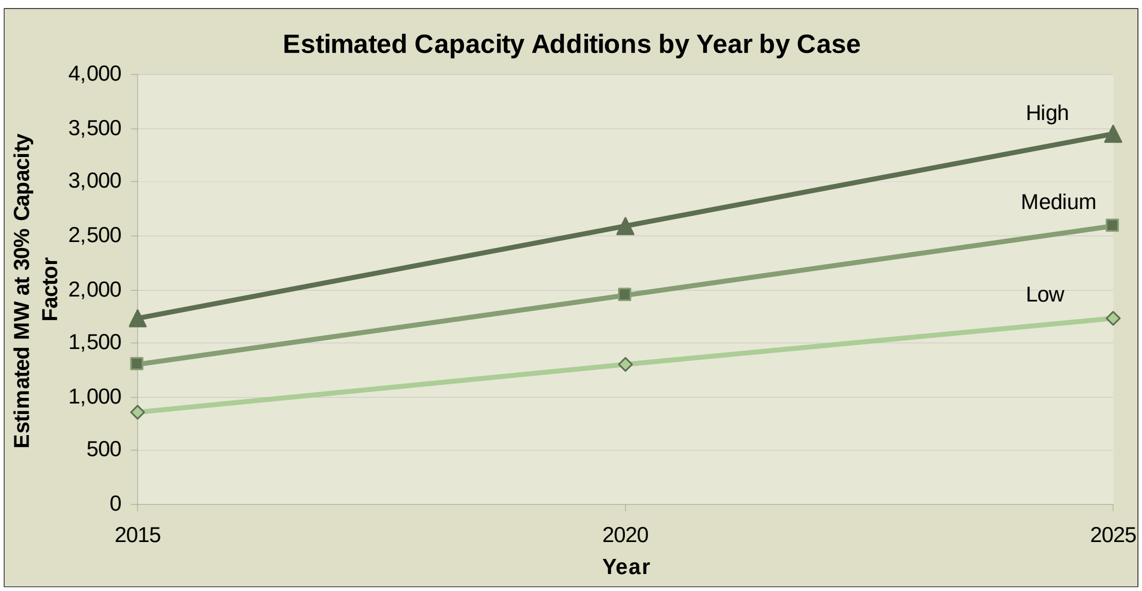


Figure 6-1. Estimated Capacity Additions by Year by Case.

6.3 Reference Case

6.3.1 Development Requirements

The reference scenario considered the medium renewable energy development case in year 2025. Resources were developed for in-state consumption to meet 50 percent of the 2025 Utah RPG goal. Enough resources were also developed to meet half that amount for export out-of-state. Details are provided on Table 6-3.

Table 6-3. Medium Renewable Energy Development Case.

Year:	**2015**	**2020**	**2025**
a. Generated in UT, consumed in UT (GWh)	2,269	3,404	4,538
b. Generated out-of-state, consumed in UT (GWh)	2,269	3,404	4,538
Total RPG eligible generation used in UT (a+b) (GWh)	4,538	6,808	9,077
c. Generated in UT, exported out-of-state (GWh)	1,135	1,702	2,269
Total UT renewable generation (a+c) (GWh)	3,404	5,106	6,808
Total anticipated capacity additions in Utah* (MW)	1,300	1,950	2,600

This case assumes ½ of Utah's renewable energy goal is served with renewable energy resources developed in Utah, and ½ of this amount is developed for export out-of-state.

* Note: Capacity (MW) of additions is estimated assuming a 30 percent average capacity factor.

6.3.2 Resource Selection

The economics of each entire zone were considered in determining the zones that would be developed under this scenario. First, the top 2 quartiles of zones discussed and listed in the Executive Summary were ranked based on energy weighted average premium cost. The top ranking zones were selected to meet or exceed the generation goal. Figure 6-2 shows the location of the selected zones.

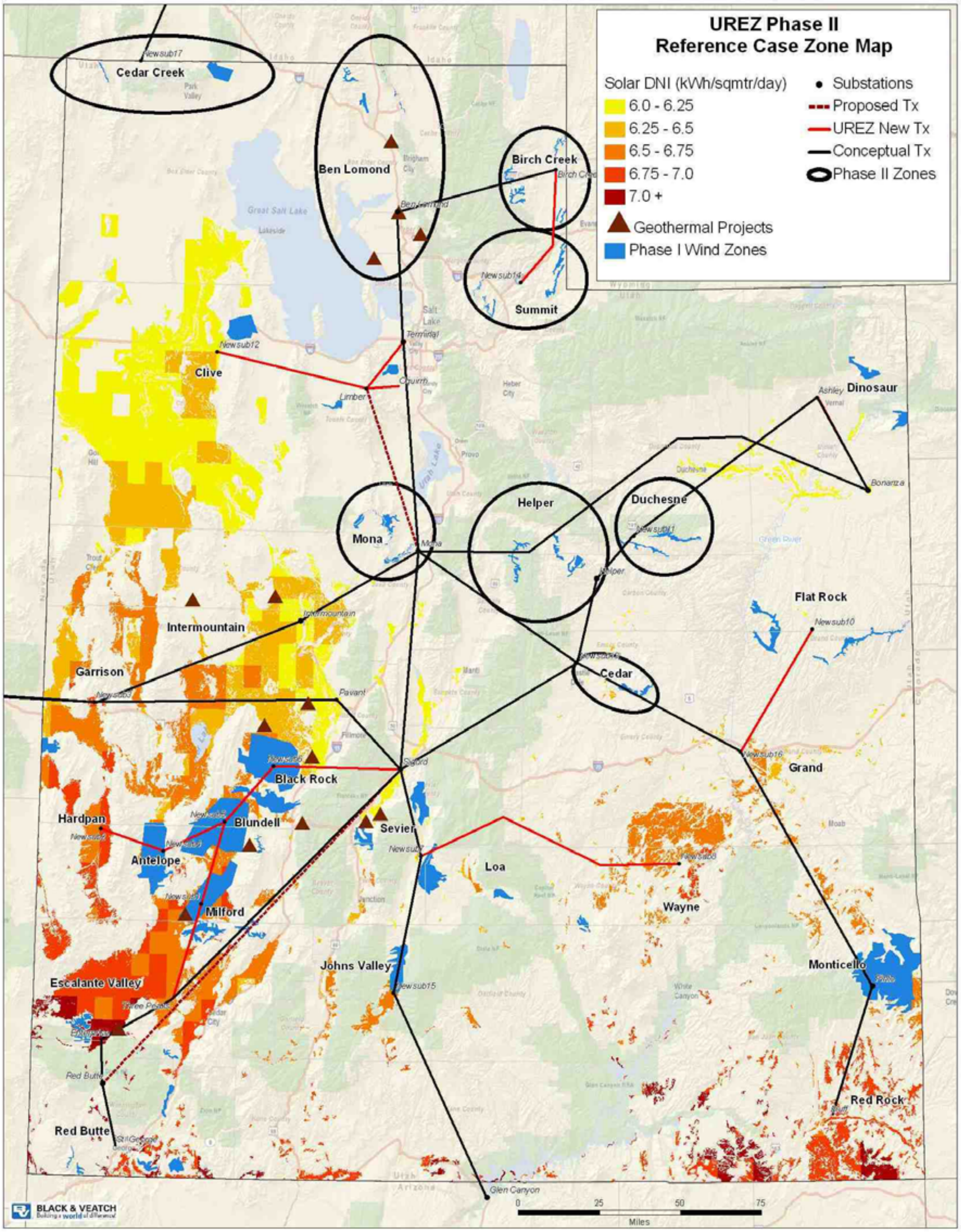


Figure 6-2. Reference Case Zone Map.

Table 6-3 provides a list of the projects included in the scenario, including project name, location and size (MW). The table also provides the economic details for each project including the busbar, transmission, integration and delivery costs, as well as the expected resource energy and capacity values.

UREZ Zone	Project	Busbar Cost $/MWh	Transmission Cost $/MWh	Integration and Delivery Cost $/MWh	Energy Value $/MWh	Capacity Value $/MWh	Total Above Market Cost of Energy $/MWh	Resource Size MW
Summit	Summit Wind 2	$72	$17	6.62	$66	$18	$15	140
Summit	Summit Wind 1	$75	$17	6.62	$66	$18	$19	200
Helper	Helper Wind 3	$69	$14	6.62	$61	$13	$20	200
Ben Lomond	Ben Lomond Geothermal 1	$87	$8	0.00	$62	$11	$26	24
Ben Lomond	Ben Lomond Wind 2	$76	$8	6.62	$62	$6	$27	60
Helper	Helper Wind 1	$77	$14	6.62	$61	$13	$28	60
Helper	Helper Wind 2	$74	$14	6.62	$62	$8	$29	220
Mona	Mona Wind 1	$82	$9	6.62	$62	$10	$30	200
Summit	Summit Wind 3	$87	$17	6.62	$66	$18	$31	50
Mona	Mona Wind 3	$90	$9	6.62	$63	$14	$33	120
Birch Creek	Birch Creek Wind 2	$78	$15	6.62	$62	$7	$34	150
Birch Creek	Birch Creek Wind 3	$78	$15	6.62	$63	$7	$34	180
Ben Lomond	Ben Lomond Wind 1	$97	$8	6.62	$63	$18	$36	50
Ben Lomond	Ben Lomond Wind 3	$95	$8	6.62	$63	$14	$38	70
Duchesne	Duchesne Wind 2	$81	$17	6.62	$62	$8	$39	180
Ben Lomond	Ben Lomond Wind 4	$101	$8	6.62	$63	$18	$39	75
Mona	Mona Wind 2	$99	$9	6.62	$63	$14	$43	100
Birch Creek	Birch Creek Wind 1	$87	$15	6.62	$63	$7	$43	75
Ben Lomond	Ben Lomond Geothermal 4	$103	$8	0.00	$62	$11	$43	8
Ben Lomond	Ben Lomond Geothermal 2	$103	$8	0.00	$62	$11	$44	8
Ben Lomond	Ben Lomond Geothermal 3	$103	$8	0.00	$62	$11	$44	8
Cedar Creek	Cedar Creek Wind 2	$81	$32	6.62	$63	$18	$44	250
Cedar	Cedar Wind 1	$87	$15	6.62	$62	$7	$45	250
Duchesne	Duchesne Wind 1	$88	$17	6.62	$62	$8	$47	140
Cedar Creek	Cedar Creek Wind 1	$72	$32	6.62	$62	$6	$47	65

Figure 6-3. Reference Case Economic Results.

A supply curve of the selected resource is depicted in Figure 6-4. Wind has the lowest and highest premium costs, while geothermal resources fall within the curve. The premium cost for the selected projects range from $14/MWh to $44/MWh.

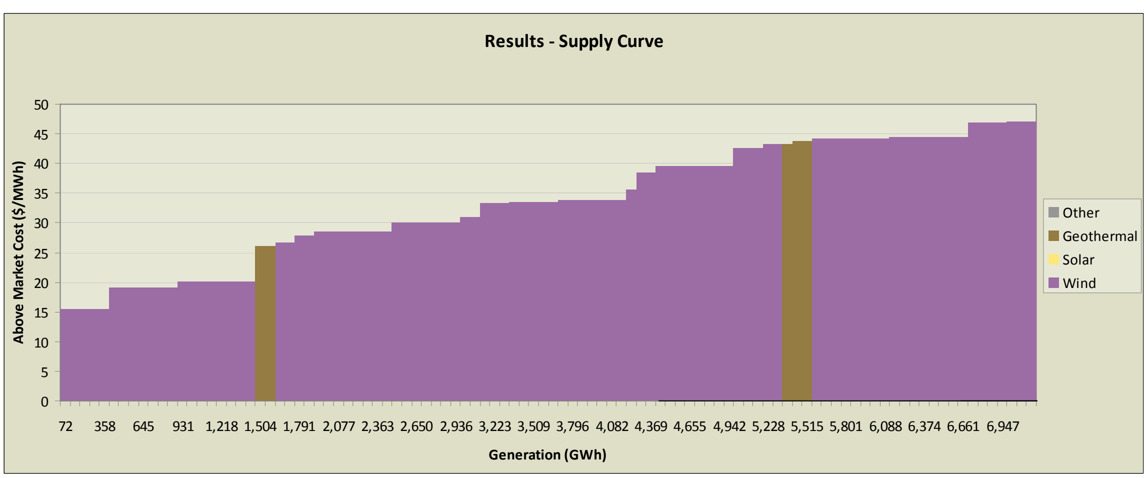
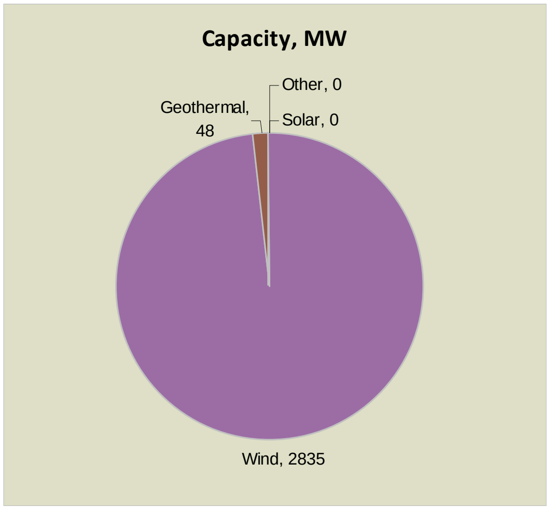


Figure 6-4. Reference Case Supply Curve.

6.3.3 Resource Capacity Energy, Capacity and Operating Profile

The capacity mix consists mostly of wind and 4 geothermal projects. Geothermal contributes only 1.6 percent of the capacity and 5 percent of the yearly generation developed in the portfolio, as shown in Figure 6-5.



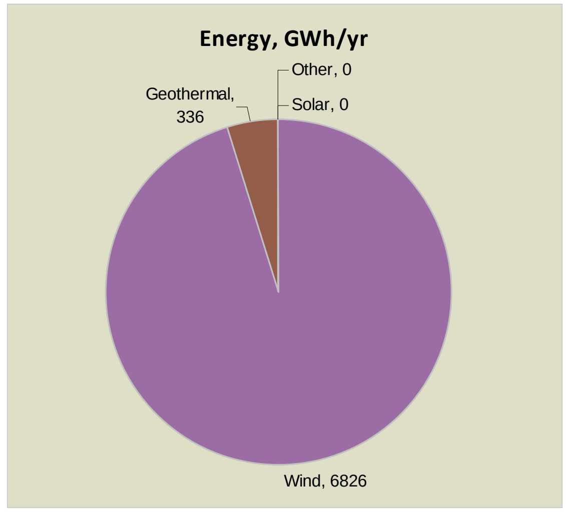


Figure 6-5. Reference Case Capacity and Energy Charts.

The composite production profile, shown in Figure 6-6, provides the typical 24-hour profile for this portfolio for the months of January, April and July. The profiles lack significant mid-afternoon peaks, characteristic of solar, as there is no solar in the scenario portfolio. The scenario capacity factor averages around 40 percent in January, 35 percent April and approximately 15 percent in July. Maximum capacity factor, resulting in maximum generation, occurs early in the afternoon in January.

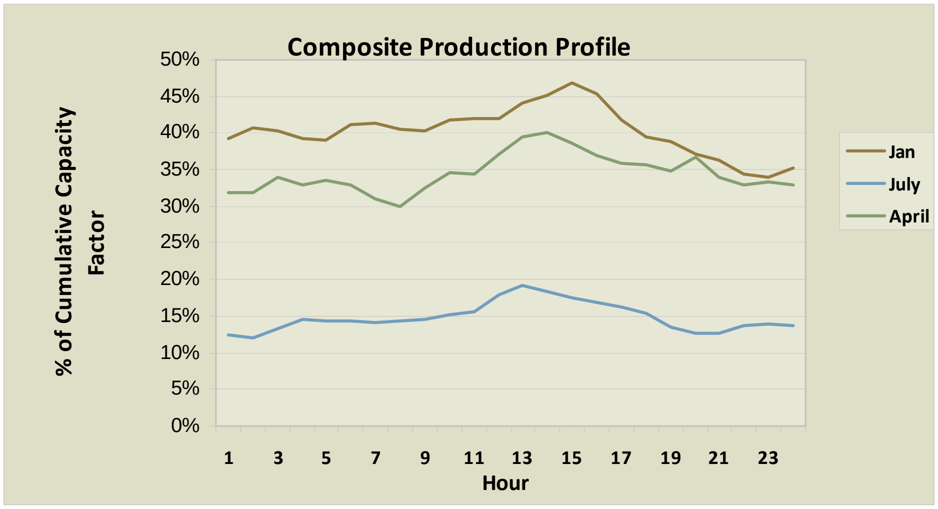


Figure 6-6. Reference Case Composite Production Profile.

6.3.4 Transmission Development

The transmission necessary for the portfolio was determined using the UREZ Generation and Transmission Model. The solution developed by the model includes lines that need to be developed, the size and the cost. The transmission model uses all available ATC when determining what transmission is required and also takes into account the diurnal pattern of resources using the line, thus minimizing the size of the lines. This approach captures the benefits of developing zones that can share transmission to deliver the energy.

The reference case development scenario results show a need to develop 8 transmission lines, detailed in Figure 6 7. Existing lines with ATC were used in the solution, with the ATC filled prior to determining the requirements for the new transmission lines. A map of the segments utilized is provided in Figure 6-8. The segments in blue represent the incremental transmission required.

Transmission Line Characteristics				
Transmission Corridor	*Type*	*No lines*	*Corridor Length (mi)*	*Line rated capacity*
Ben Lomond to Terminal	138 kV AC Single - existing	1	46	200
	345 kV AC Single - new	1	46	750
Birch Creek to Ben Lomond	138 kV AC Single - existing	1	55	200
	138 kV AC Double - new	1	55	400
Newsub11 to Helper	138 kV AC Single - existing	1	19	200
	138 kV AC Single - new	1	19	200
Mona to Terminal	500 kV AC Single - existing	1	69	1500
	138 kV AC Single - new	0		200
Helper to Newsub13	138 kV AC Single - existing	1	32	200
	138 kV AC Double - new	1	32	400
Newsub13 to Mona	138 kV AC Single - existing	1	69	200
	345 kV AC Single - new	1	69	750
Newsub14 to Birch Creek	138 kV AC Single - existing	1	39	200
	138 kV AC Double - new	1	39	400
Newsub17 to Ben Lomond	138 kV AC Single - existing	1	208	200
	138 kV AC Single - new	1	208	200

Figure 6-7. Reference Case Transmission Additions.

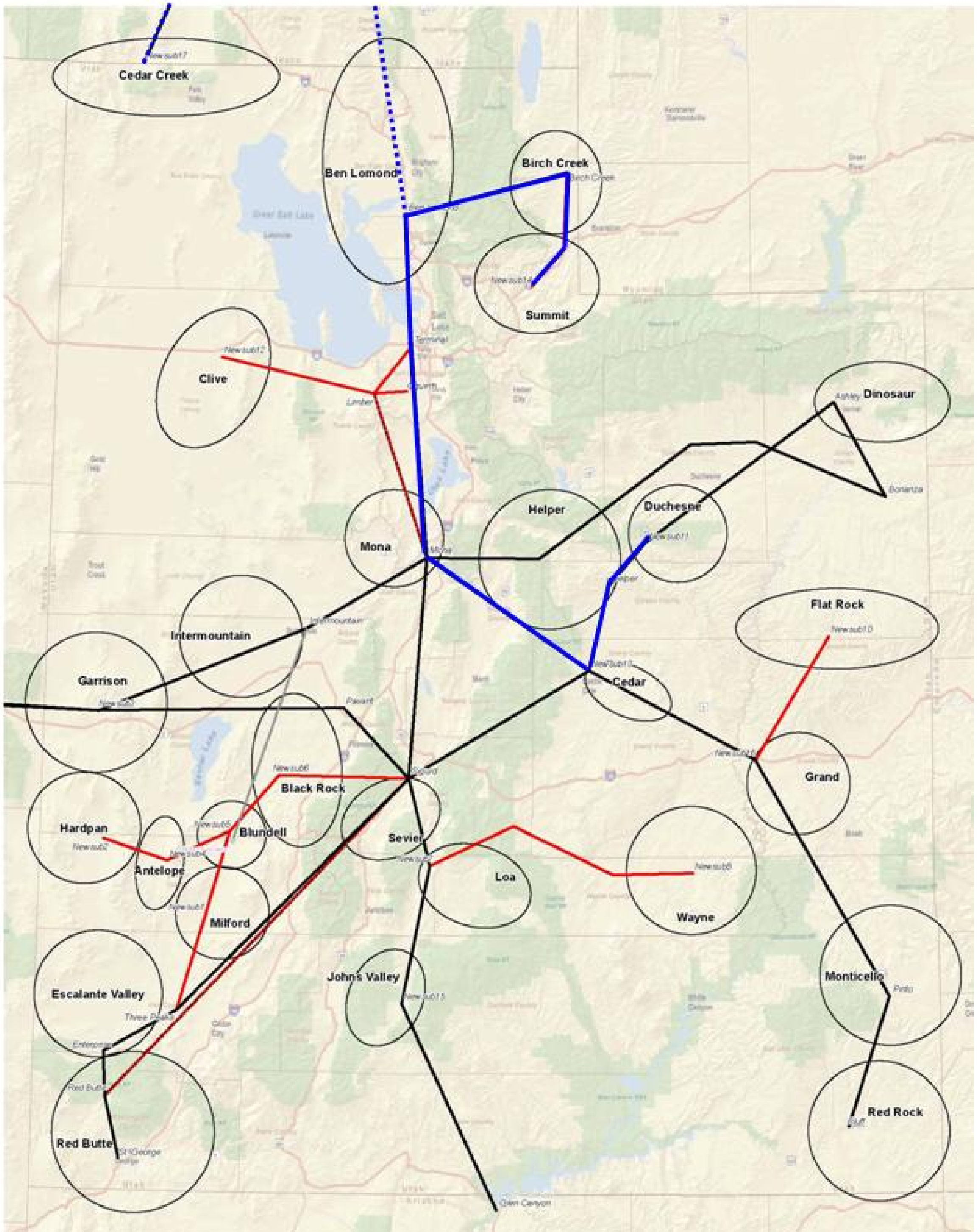


Figure 6-8. Reference Case Conceptual Transmission Map.

A summary of the energy delivered from each zone, and the transmission cost to deliver the energy, is detailed in Table 6-4. Costs presented are energy-weighted average dollars per MWh.

Table 6-4. Reference Case Average Trans. Cost by Zone ($/MWh).

Zone	Generation (GWh/yr)	Transmission cost ($/MWh)
Summit	1,003	17
Helper	1,285	14
Cedar Creek	770	32
Mona	930	0
Ben Lomond	902	8
Birch Creek	991	15
Cedar	550	15
Duchesne	730	17

6.4 Low Development Scenario

6.4.1 Development Requirements

The low development scenario was designed to add resources to generate energy to serve 25 percent of the RPG and an equivalent amount of energy generation for export out-of-state. Scenario energy requirements are detailed on Table 6-5 below.

Table 6-5. Low Development Scenario.

Year:	2015	2020	2025
a. Generated in UT, consumed in UT (GWh)	1,135	1,702	2,269
b. Generated out-of-state, consumed in UT (GWh)	3,404	5,106	6,808
Total RPG eligible generation used in UT (a+b) (GWh)	4,538	6,808	9,077
c. Generated in UT, exported out-of-state (GWh)	1,135	1,702	2,269
Total UT renewable generation (a+c) (GWh)	2,269	3,404	4,538
Total anticipated capacity additions in Utah* (MW)	850	1,300	1,700

This case assumes ¼ of Utah’s renewable energy goal is served with renewable energy resources developed in Utah, with an equal amount of resources developed for export out-of-state.

* Note: Capacity (MW) of additions is estimated assuming a 30 percent average capacity factor.

6.4.2 Resource Selection

The approach used to select the projects in scenario is based on zone economics, same as the reference scenario. Figure 6-9 shows the five resource zone used for this scenario.

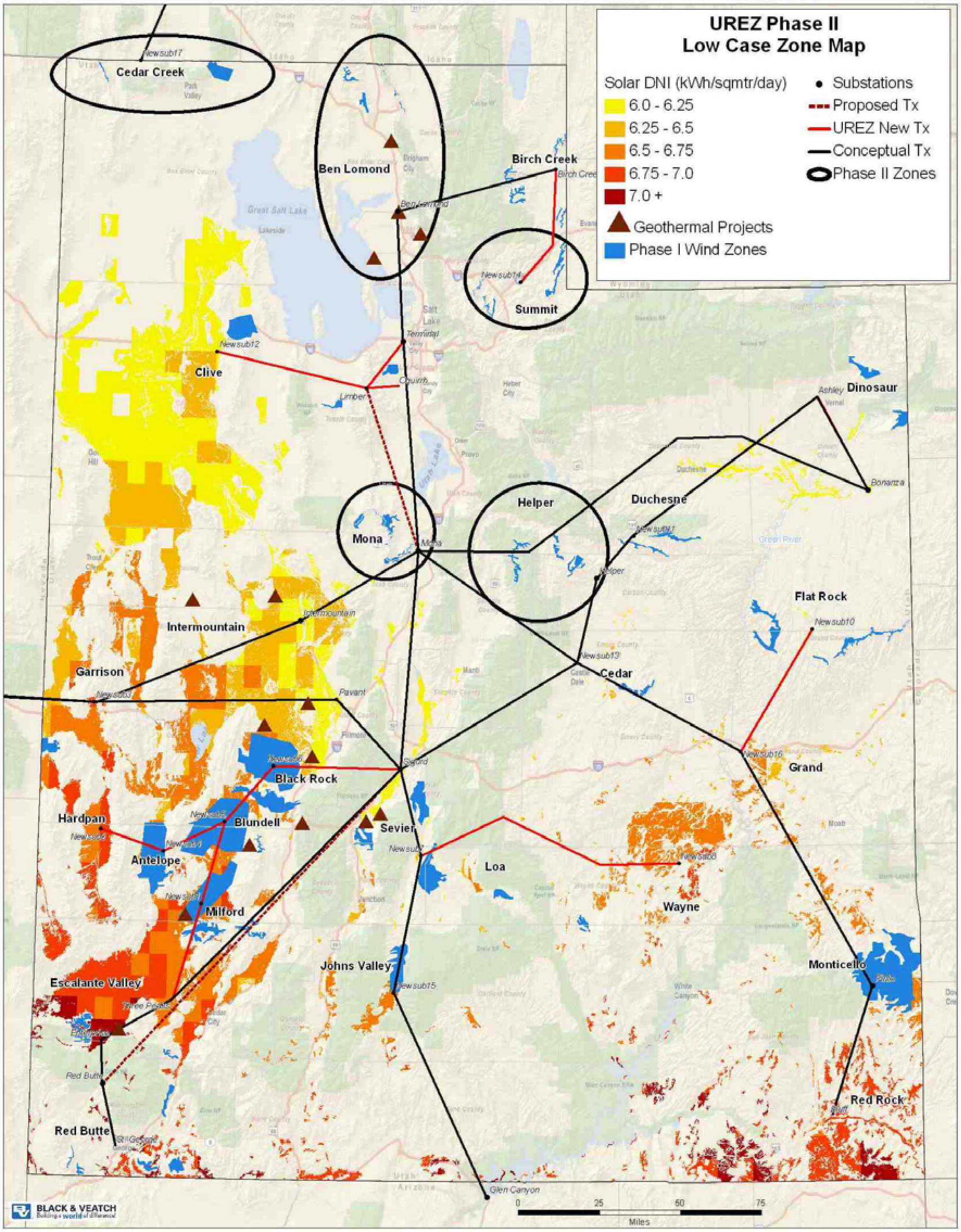


Figure 6-9. Low Development Scenario Zone Map.

Figure 6-10 provides a list of the projects included in the scenario, including project name, location and size (MW). The table also provides the economic details for

each project including the busbar, transmission, integration and delivery costs, as well as the expected resource energy and capacity values.

UREZ Zone	Project	Busbar Cost $/MWh	Transmission Cost $/MWh	Integration and Delivery Cost $/MWh	Energy Value $/MWh	Capacity Value $/MWh	Total Above Market Cost of Energy $/MWh	Resource Size MW
Summit	Summit Wind 2	$72	$21	$7	$66	$18	$20	140
Helper	Helper Wind 3	$69	$17	$7	$61	$13	$24	200
Summit	Summit Wind 1	$75	$21	$7	$66	$18	$24	200
Ben Lomond	Ben Lomond Geothermal 1	$87	$9	$0	$62	$11	$27	24
Ben Lomond	Ben Lomond Wind 2	$76	$9	$7	$62	$6	$28	60
Mona	Mona Wind 1	$82	$9	$7	$62	$10	$30	200
Helper	Helper Wind 1	$77	$17	$7	$61	$13	$32	60
Helper	Helper Wind 2	$74	$17	$7	$62	$8	$32	220
Mona	Mona Wind 3	$90	$9	$7	$63	$14	$33	120
Summit	Summit Wind 3	$87	$21	$7	$66	$18	$36	50
Ben Lomond	Ben Lomond Wind 1	$97	$9	$7	$63	$18	$36	50
Ben Lomond	Ben Lomond Wind 3	$95	$9	$7	$63	$14	$39	70
Ben Lomond	Ben Lomond Wind 4	$101	$9	$7	$63	$18	$40	75
Mona	Mona Wind 2	$99	$9	$7	$63	$14	$43	100
Ben Lomond	Ben Lomond Geothermal 4	$103	$9	$0	$62	$11	$44	8
Ben Lomond	Ben Lomond Geothermal 2	$103	$9	$0	$62	$11	$45	8
Ben Lomond	Ben Lomond Geothermal 3	$103	$9	$0	$62	$11	$45	8
Cedar Creek	Cedar Creek Wind 2	$81	$33	$7	$63	$18	$45	250
Cedar Creek	Cedar Creek Wind 1	$72	$33	$7	$62	$6	$48	65

Figure 6-10. Low Development Scenario Economics Results.

The Low Development scenario supply curve is a slightly truncated version of the Reference Case supply curve. The premium costs for the selected resources range from $20/MWh to $48/MWh. Note that though the projects selected are a subset of the reference case the premium cost for the projects are different, this is due to varying transmission cost, discussed later in this section.

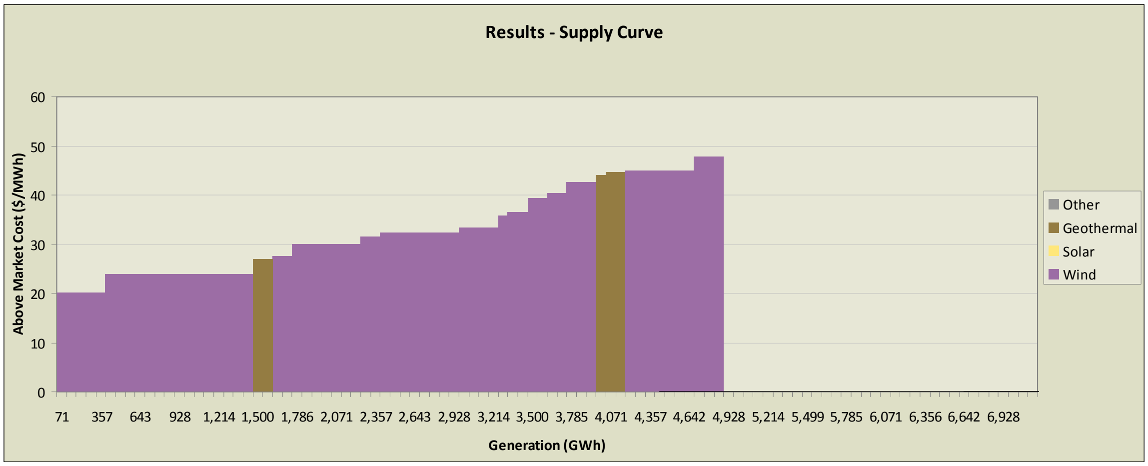


Figure 6-11. Low Development Scenario Supply Curve.

6.4.3 Resource Capacity Energy, Capacity and Operating Profile

The capacity in the scenario consists mostly of wind resources, with a small portion of geothermal. Geothermal contributes only 2.5 percent of the capacity and 7 percent of the yearly generation developed in the portfolio as shown in Figure 6-12.

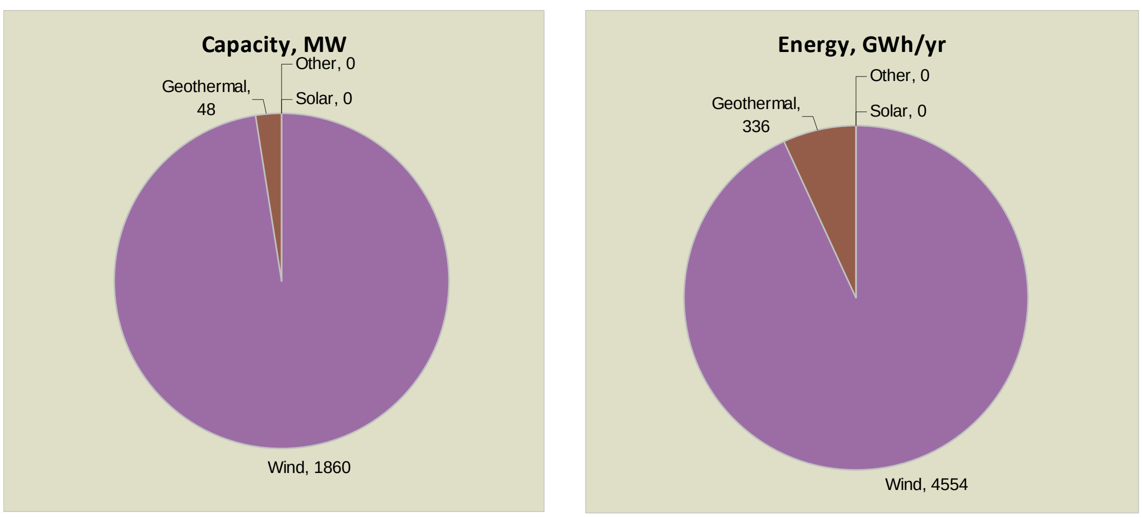


Figure 6-12. Low Development Scenario Capacity and Energy Charts.

The composite production profile, shown in Figure 6-13, provides the typical 24-hour profile for the months of January, April and July. As with the reference scenario, the profiles lack significant mid-afternoon peaks, characteristic of solar as there is no solar in the scenario portfolio. The composite profile is similar to the reference scenario. The capacity factor averages around 40 percent in January, 35 percent April, and approximately 15 percent in July. The maximum generation occurs early in the afternoon in January.

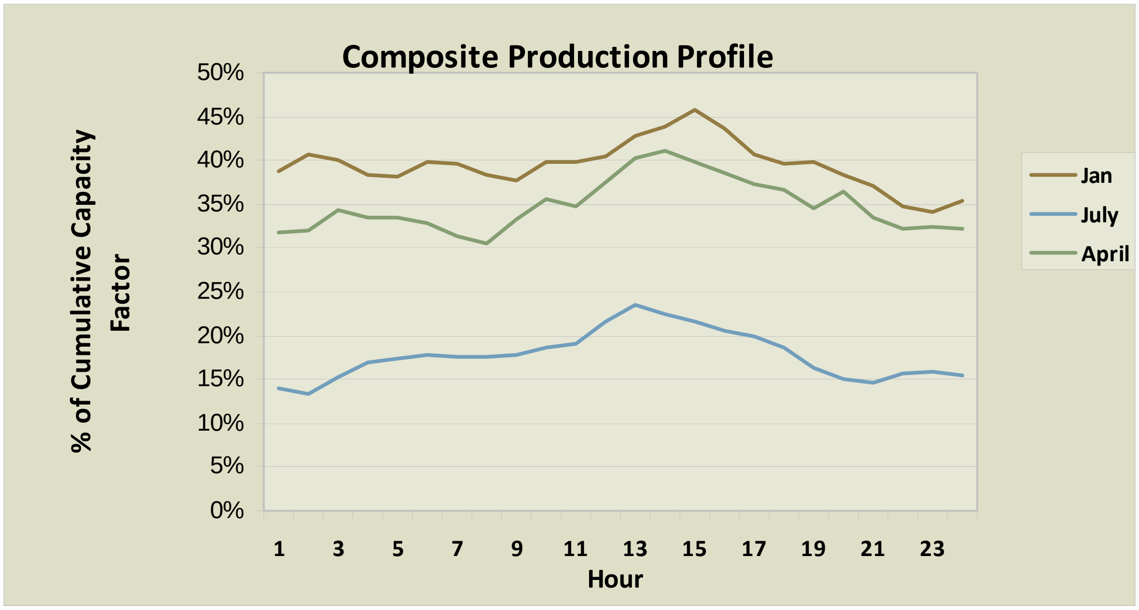


Figure 6-13. Low Development Scenario Composite Production Profile.

6.4.4 Transmission Development

New transmission necessary to deliver the portfolio generation to load was determined using the UREZ generation and transmission model. As discussed before, the transmission solution takes into account the zones that will be sharing transmission lines; thus it provides the transmission for the entire scenario, not for individual zones functioning independently. This approach captures the benefits of developing zones that can share transmission to deliver the energy. Due to this approach, different premium costs results for the same projects in the reference and low development scenarios.

The low development scenario required the addition of seven transmission lines, listed on Figure 6-14. A map of the segments is provided in Figure 6-15.

Transmission Corridor	*Type*	*No lines*	*Corridor Length (mi)*
Ben Lomond to Terminal	138 kV AC Single - existing	1	46
	138 kV AC Single - new	3	46
Birch Creek to Ben Lomond	138 kV AC Single - existing	1	55
	138 kV AC Double - new	1	55
Mona to Terminal	500 kV AC Single - existing	1	69
	138 kV AC Single - new	0	
Helper to Newsub13	138 kV AC Single - existing	1	32
	138 kV AC Double - new	1	32
Newsub13 to Mona	138 kV AC Single - existing	1	69
	138 kV AC Double - new	1	69
Newsub14 to Birch Creek	138 kV AC Single - existing	1	39
	138 kV AC Double - new	1	39
Newsub17 to Ben Lomond	138 kV AC Single - existing	1	208
	138 kV AC Single - new	1	208

Figure 6-14. Low Development Scenario Transmission Additions.

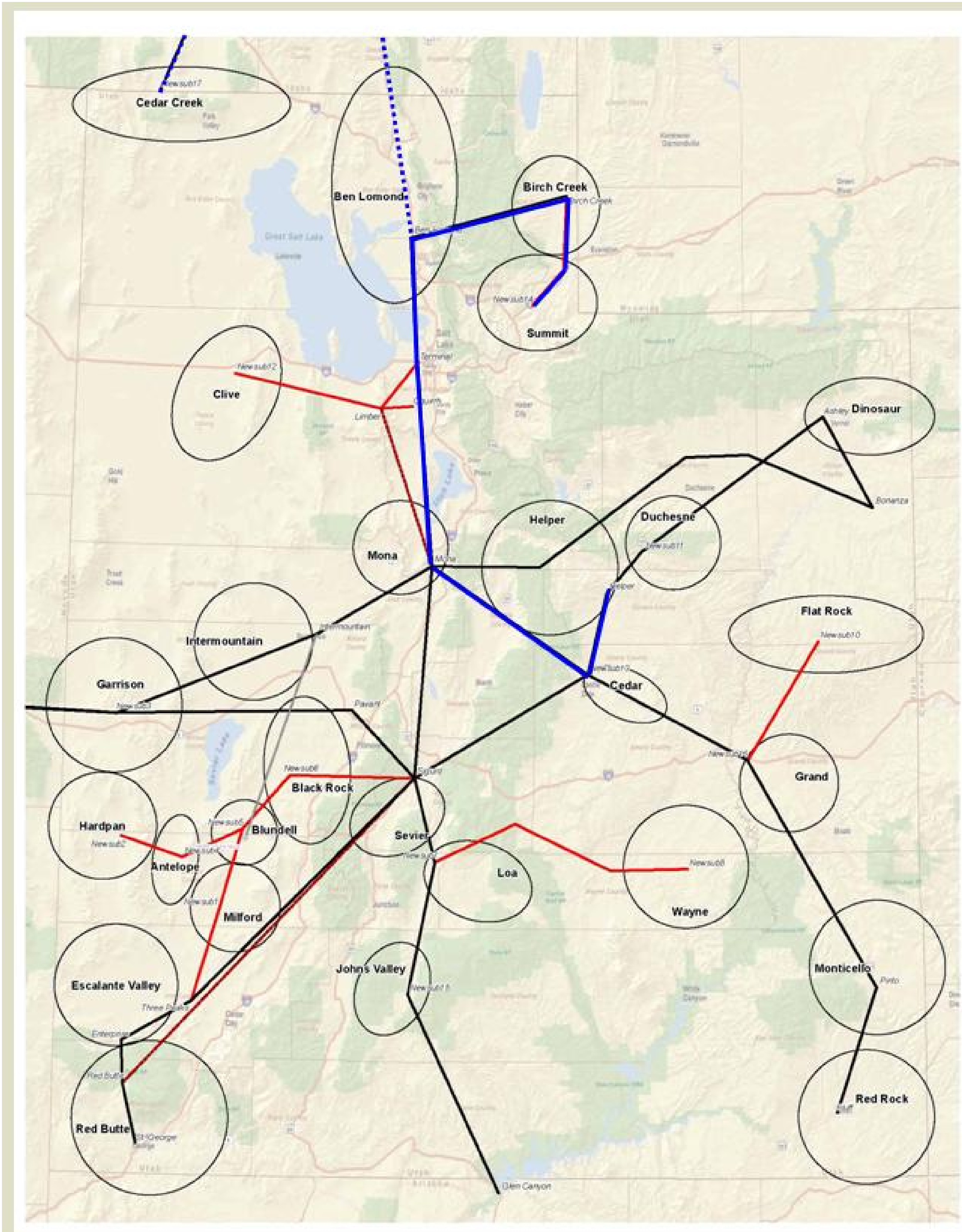


Figure 6-15. Low Development Scenario Conceptual Transmission Map.

A summary of the energy delivered from each zone, and the transmission cost to deliver the energy, is detailed in Table 6-6. Costs presented are energy-weighted average dollars per MWh.

Table 6-6. Low Development Scenario Avg. Trans. Cost by Zone ($/MWh).

Zone	Generation (GWh/yr)	Transmission cost ($/MWh)
Summit	1,003	21
Helper	1,285	17
Cedar Creek	770	33
Mona	930	0
Ben Lomond	902	9

6.5 High Development Scenario

6.5.1 Development Requirements

The high development scenario assumes that half of Utah's renewable energy goal will be served by resources developed in Utah and an equivalent amount of development for export to out-of-state.

Table 6-7. High Development Scenario.

Year:	2015	2020	2025
a. Generated in UT, consumed in UT (GWh)	2,269	3,404	4,538
b. Generated out-of-state, consumed in UT (GWh)	2,269	3,404	4,538
Total RPG eligible generation used in UT (a+b) (GWh)	4,538	6,808	9,077
c. Generated in UT, exported out-of-state (GWh)	2,269	3,404	4,538
Total UT renewable generation (a+c) (GWh)	4,538	6,808	9,077
Total anticipated capacity additions in Utah* (MW)	1,700	2,600	3,500

This case assumes ½ of Utah's renewable energy goal is served with renewable energy resources developed in Utah, and an equal amount is developed for export out-of-state.

* Note: Capacity (MW) of additions is estimated assuming a 30 percent average capacity factor.

6.5.2 Resource Selection

The approach used to select the projects for this scenario is based on zone economics, with sufficient zones selected to meet the energy generation requirements in the scenario. Given the high generation requirements, substantially more zones were selected in the high case for development. Figure 6-16 depicts the selected zones.

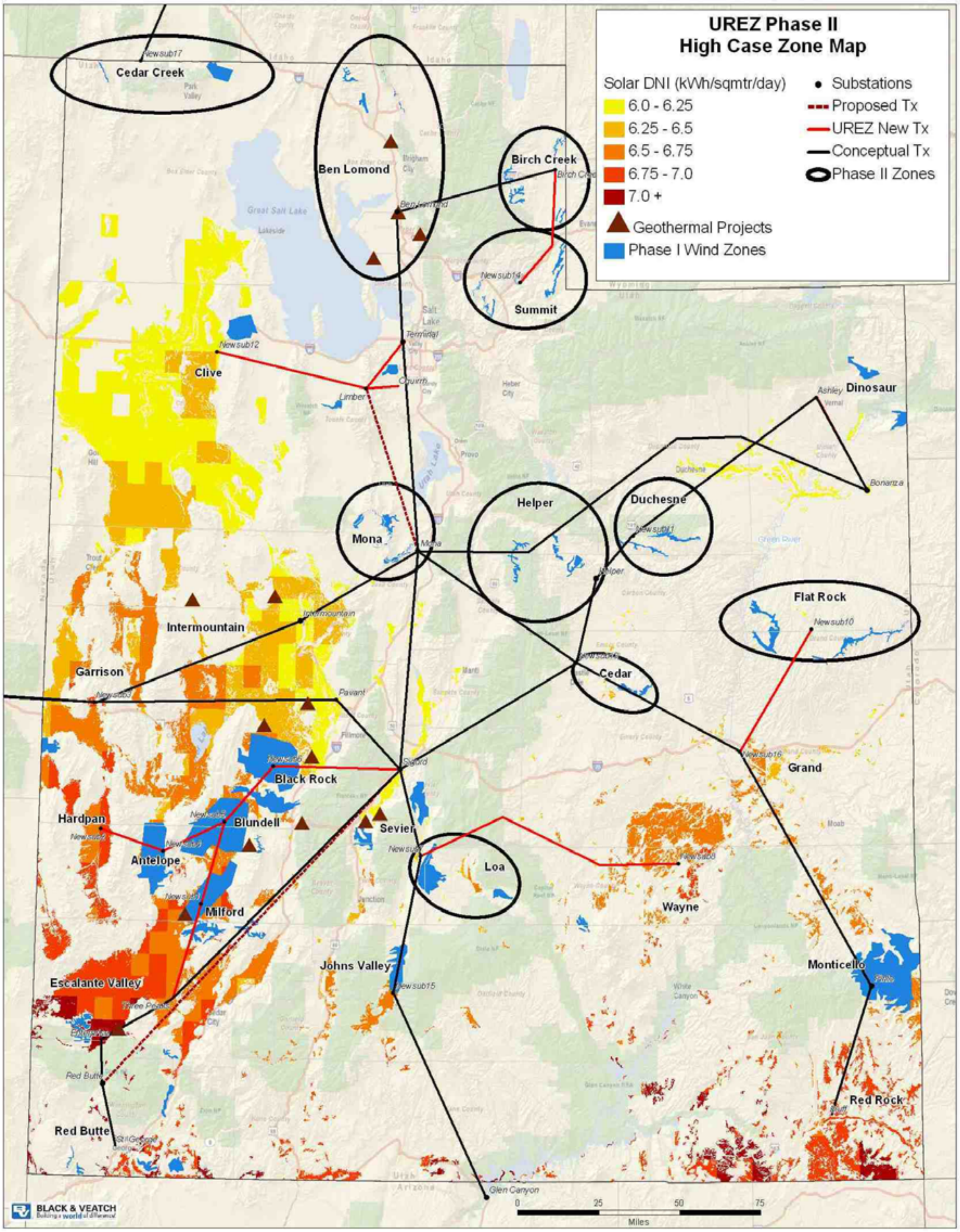


Figure 6-16. High Development Scenario Zone Map.

Figure 6-17 provides a list of the projects included in the scenario, including project name, location and size (MW). The table also provides the economic details for

each project including the busbar, transmission, integration and delivery costs, as well as the expected resource energy and capacity values.

UREZ Zone	Project	Busbar Cost $/MWh	Transmission Cost $/MWh	Integration and Delivery Cost $/MWh	Energy Value $/MWh	Capacity Value $/MWh	Total Above Market Cost of Energy $/MWh	Resource Size MW
Summit	Summit Wind 2	$72	$17	$7	$66	$18	$15	140
Summit	Summit Wind 1	$75	$17	$7	$66	$18	$19	200
Helper	Helper Wind 3	$69	$13	$7	$61	$13	$19	200
Ben Lomond	Ben Lomond Geothe	$87	$8	$0	$62	$11	$26	24
Ben Lomond	Ben Lomond Wind 2	$76	$8	$7	$62	$6	$27	60
Helper	Helper Wind 1	$77	$13	$7	$61	$13	$27	60
Helper	Helper Wind 2	$74	$13	$7	$62	$8	$28	220
Summit	Summit Wind 3	$87	$17	$7	$66	$18	$31	50
Mona	Mona Wind 1	$82	$10	$7	$62	$10	$31	200
Birch Creek	Birch Creek Wind 2	$78	$15	$7	$62	$7	$34	150
Birch Creek	Birch Creek Wind 3	$78	$15	$7	$63	$7	$34	180
Mona	Mona Wind 3	$90	$10	$7	$63	$14	$34	120
Ben Lomond	Ben Lomond Wind 1	$97	$8	$7	$63	$18	$36	50
Ben Lomond	Ben Lomond Wind 3	$95	$8	$7	$63	$14	$38	70
Duchesne	Duchesne Wind 2	$81	$16	$7	$62	$8	$39	180
Ben Lomond	Ben Lomond Wind 4	$101	$8	$7	$63	$18	$39	75
Loa	Loa Wind 2	$79	$18	$7	$61	$9	$39	50
Birch Creek	Birch Creek Wind 1	$87	$15	$7	$63	$7	$43	75
Ben Lomond	Ben Lomond Geothe	$103	$8	$0	$62	$11	$43	8
Mona	Mona Wind 2	$99	$10	$7	$63	$14	$44	100
Ben Lomond	Ben Lomond Geothe	$103	$8	$0	$62	$11	$44	8
Ben Lomond	Ben Lomond Geothe	$103	$8	$0	$62	$11	$44	8
Cedar	Cedar Wind 1	$87	$14	$7	$62	$7	$44	250
Cedar Creek	Cedar Creek Wind 2	$81	$32	$7	$63	$18	$44	250
Duchesne	Duchesne Wind 1	$88	$16	$7	$62	$8	$46	140
Loa	Loa Wind 1	$84	$18	$7	$61	$5	$47	250
Cedar Creek	Cedar Creek Wind 1	$72	$32	$7	$62	$6	$47	65
Flat Rock	Flat Rock Wind 2	$81	$24	$7	$62	$7	$47	250
Flat Rock	Flat Rock Wind 1	$84	$24	$7	$62	$6	$51	250
Loa	Loa Solar 1	$193	$18	$3	$69	$51	$104	48

Figure 6-17. High Development Scenario Economic Results.

The lowest premium cost project is wind at $15/MWh, and the highest premium cost project is solar thermal at $100/MWh, as depicted on the premium cost-based supply curve on Figure 6-18. The premium cost for geothermal resources ranges from $26/MWh to $44/MWh.

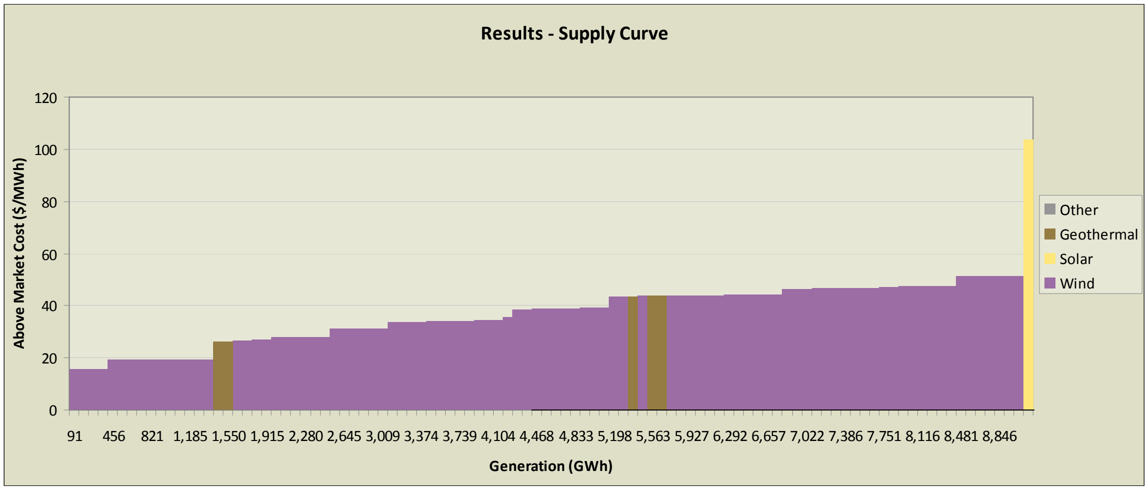


Figure 6-18. High Development Scenario Supply Curve.

6.5.3 Resource Capacity Energy, Capacity and Operating Profile

Due to the high generation goal, one solar resource is included in the portfolio. Both solar and geothermal are approximately 1.3 percent of the total capacity as shown in Figure 6-19 below. Solar and geothermal contribute 1 percent and 4 percent, respectively, to the generation mix.

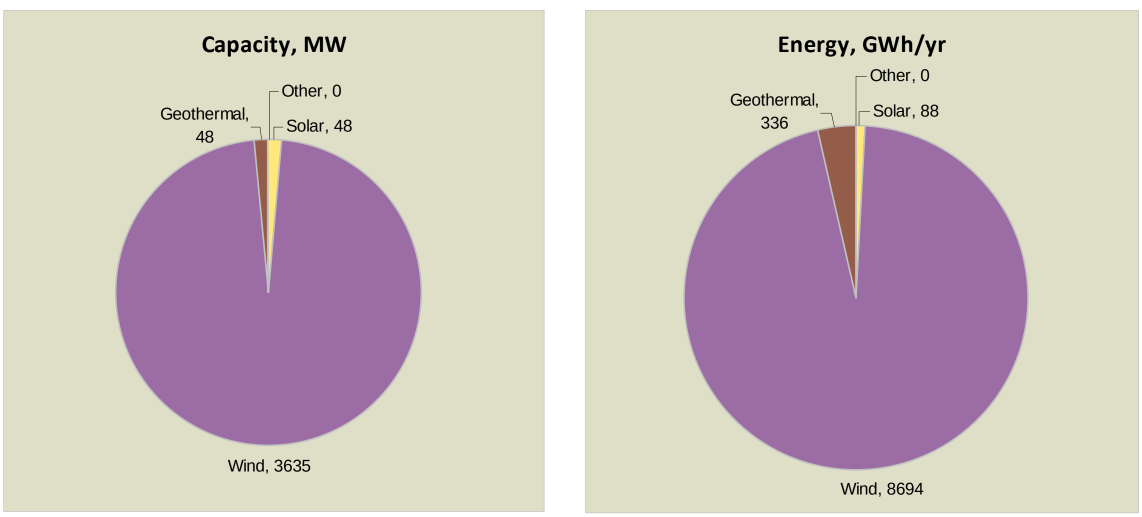


Figure 6-19. High Development Scenario Capacity and Energy Charts.

The composite production profile, shown in Figure 6-20, provides the typical 24-hour profile for the months of January, April and July. As with the reference and low scenarios, the generation profile lacks a significant mid-afternoon peaks characteristic of solar generation, because a minimal amount of solar is present in the portfolio. Overall the composite profile is similar to the reference scenario. The capacity factor averages 40 percent in January, 35 percent in April and 17 percent in July. Maximum simultaneous resource generation occurs early in the afternoon in January.

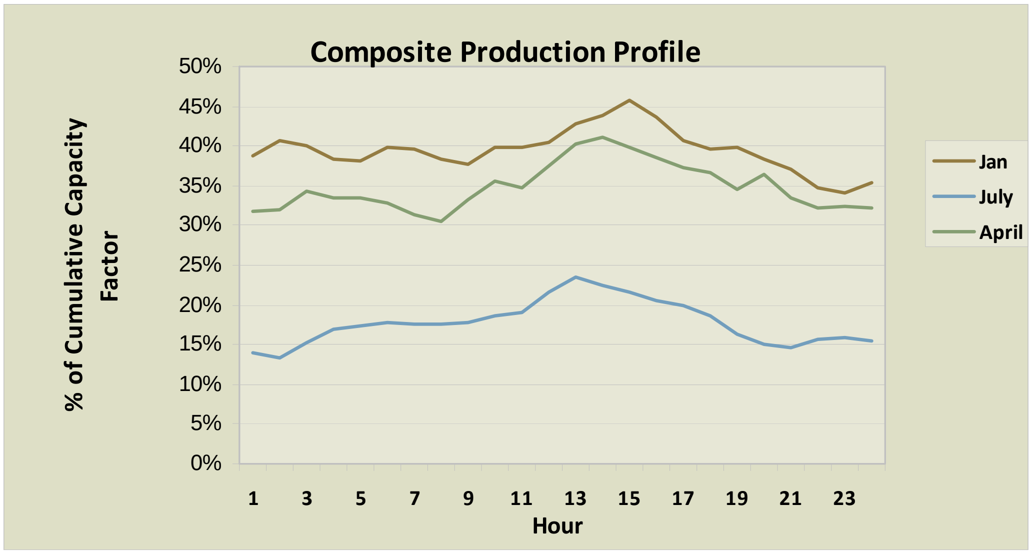


Figure 6-20. High Development Scenario Composite Production Profile.

6.5.4 Transmission Development

The high development scenario results identify a need for 12 transmission lines, as detailed on Figure 6-21, below. A map depicting the new segments is provided on Figure 6-22.

Transmission Line Characteristics

Transmission Corridor	*Type*	*No lines*	*Corridor Length (mi)*
Ben Lomond to Terminal	138 kV AC Single - existing	1	46
	345 kV AC Single - new	1	46
Birch Creek to Ben Lomond	138 kV AC Single - existing	1	55
	138 kV AC Double - new	1	55
Newsub11 to Helper	138 kV AC Single - existing	1	19
	138 kV AC Single - new	1	19
Sigurd to Mona	138 kV AC Single - existing	1	69
	138 kV AC Single - new	1	69
Mona to Terminal	500 kV AC Single - existing	1	69
	138 kV AC Single - new	1	69
Newsub10 to Newsub16	138 kV AC Single - existing	1	44
	138 kV AC Double - new	1	44
Helper to Newsub13	138 kV AC Single - existing	1	32
	138 kV AC Double - new	1	32
Newsub13 to Mona	138 kV AC Single - existing	1	69
	345 kV AC Single - new	1	69
Newsub16 to Newsub13	138 kV AC Single - existing	1	61
	138 kV AC Double - new	1	61
Newsub14 to Birch Creek	138 kV AC Single - existing	1	39
	138 kV AC Double - new	1	39
Newsub17 to Ben Lomond	138 kV AC Single - existing	1	208
	138 kV AC Single - new	1	208
Newsub7 to Sigurd	138 kV AC Single - existing	1	29
	138 kV AC Single - new	1	29

Figure 6-21. High Development Scenario Transmission Additions.

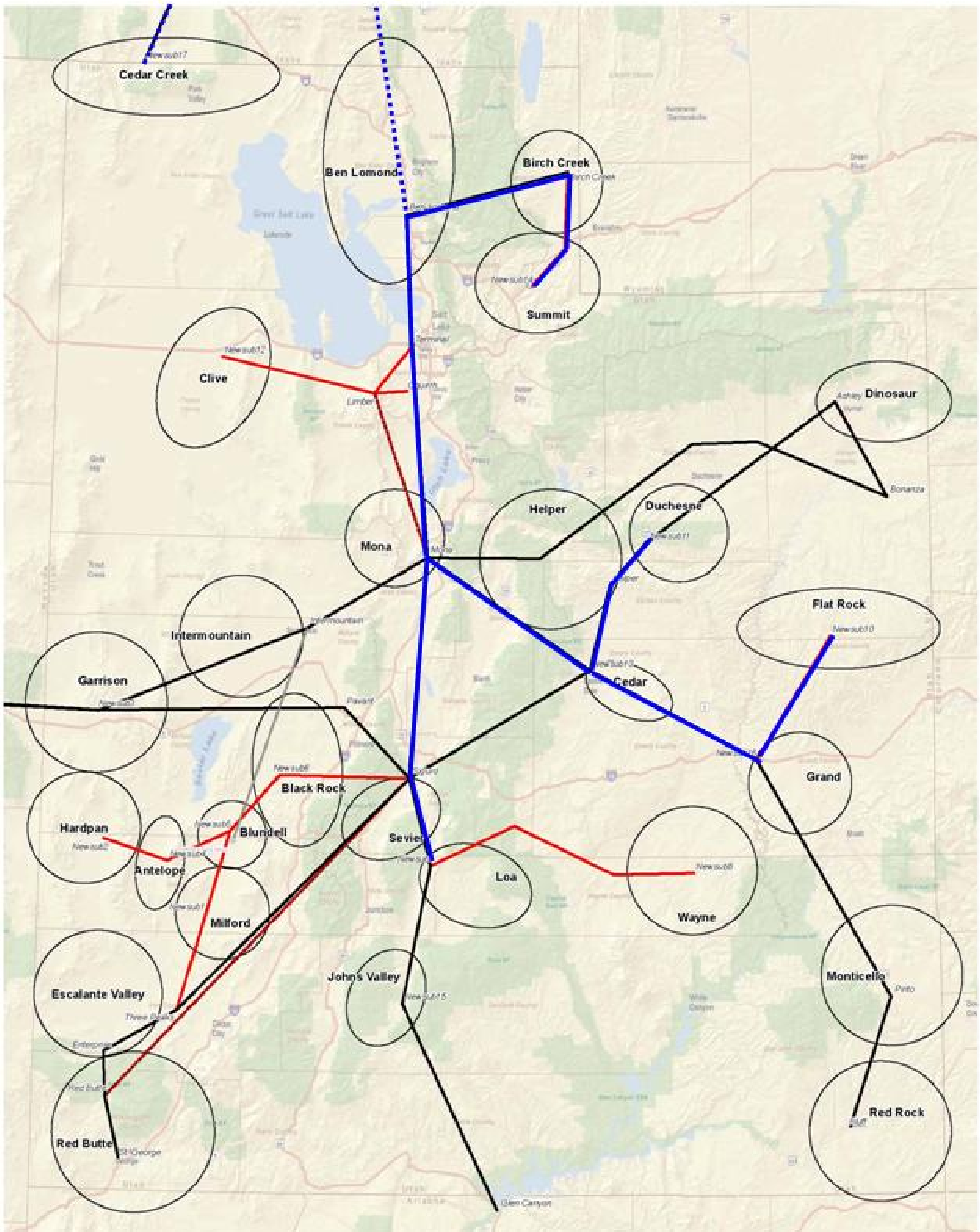


Figure 6-22. High Development Scenario Conceptual Transmission Map.

A summary of the energy delivered from each zone, and the transmission cost to deliver the energy, is detailed in Table 6-8. Costs presented are energy-weighted average dollars per MWh.

Table 6-8. High Development Scenario Avg. Trans. Cost by Zone ($/MWh).

Zone	Generation (GWh/yr)	Transmission cost ($/MWh)
Summit	1,003	17
Helper	1,285	13
Cedar Creek	770	32
Mona	930	10
Ben Lomond	902	8
Birch Creek	991	15
Cedar	550	14
Duchesne	730	16
Flat Rock	1,169	24
Loa	788	18

6.6 Best Projects Development Scenario

6.6.1 Development Requirements

The Best Projects development case used the same energy demand and requirements as the Reference case (the medium demand case). Resources were developed to meet 50 percent of the 2025 Utah RPG goal and half that amount to export out-of-state.

Table 6-9. Best Projects Development Scenario.

Year:	2015	2020	2025
a. Generated in UT, consumed in UT (GWh)	2,269	3,404	4,538
b. Generated out-of-state, consumed in UT (GWh)	2,269	3,404	4,538
Total RPG eligible generation used in UT (a+b) (GWh)	4,538	6,808	9,077
c. Generated in UT, exported out-of-state (GWh)	1,135	1,702	2,269
Total UT renewable generation (a+c) (GWh)	3,404	5,106	6,808
Total anticipated capacity additions in Utah (MW)	1,300	1,950	2,600

This case assumes ½ of Utah's renewable energy goal is served with renewable energy resources developed in Utah, and ½ of this amount is developed for export out-of-state.

* Note: Capacity (MW) of additions is estimated assuming a 30 percent average capacity factor.

6.6.2 Resource Selection

Unlike the other scenarios, the projects selected for inclusion in the Best projects development scenario are based on project economics rather than zone economics. In this case, individual projects could be selected to meet the scenario goal, rather than only entire zones. All projects from all resource zones were ranked based on projected premium cost, and the lowest cost projects were selected to meet the generation requirement.

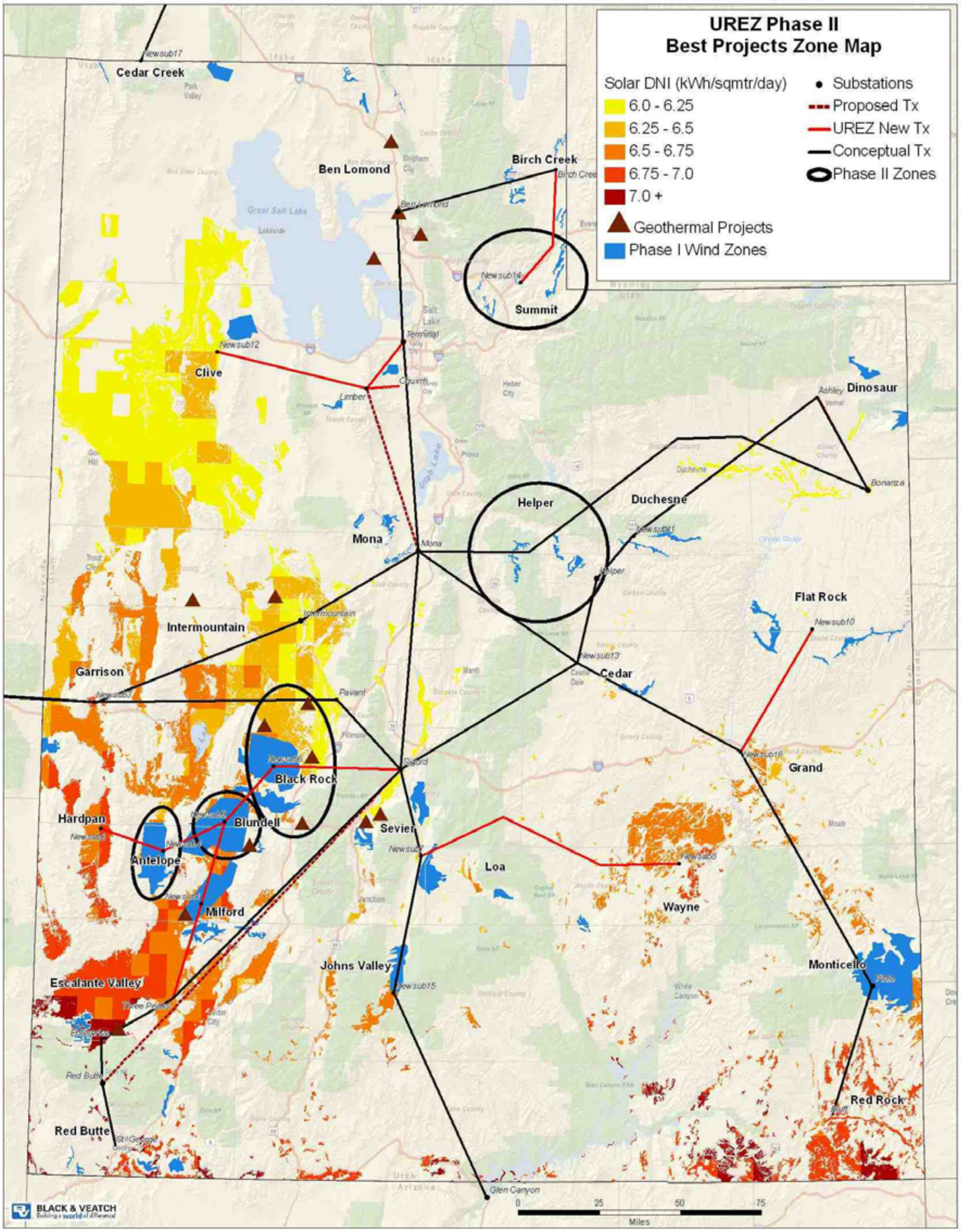


Figure 6-23. Best Projects Development Scenario Zone Map.

Figure 6-24 provides a list of the projects included in the scenario, including project name, location and size (MW). The table also provides the economic details for

each project including the busbar, transmission, integration and delivery costs, as well as the expected resource energy and capacity values.

UREZ Zone	Project	Busbar Cost $/MWh	Transmission Cost $/MWh	Integration and Delivery Cost $/MWh	Energy Value $/MWh	Capacity Value $/MWh	Total Above Market Cost of Energy $/MWh	Resource Size MW
Black Rock	Black Rock Wind 1	$71	$8	$7	$63	$21	$6	200
Blundell	Blundell Geothermal	$75	$10	$0	$63	$18	$8	81
Blundell	Blundell Wind 1	$69	$10	$7	$62	$16	$11	500
Black Rock	Black Rock Wind 2	$76	$8	$7	$63	$21	$11	500
Blundell	Blundell Wind 2	$72	$10	$7	$62	$16	$14	100
Black Rock	Black Rock Geotherm	$82	$8	$0	$62	$14	$17	80
Antelope	Antelope Wind 1	$74	$15	$7	$62	$16	$22	500
Summit	Summit Wind 2	$72	$24	$7	$66	$18	$24	140
Summit	Summit Wind 1	$75	$24	$7	$66	$18	$27	200
Helper	Helper Wind 3	$69	$25	$7	$61	$13	$32	200

Figure 6-24. Best Projects Development Scenario Economic Results.

The supply curve in Figure 6-25 depicts the premium cost of the resources. These range from $6/MWh to $32/MWh, which is the lowest cost of all scenarios.

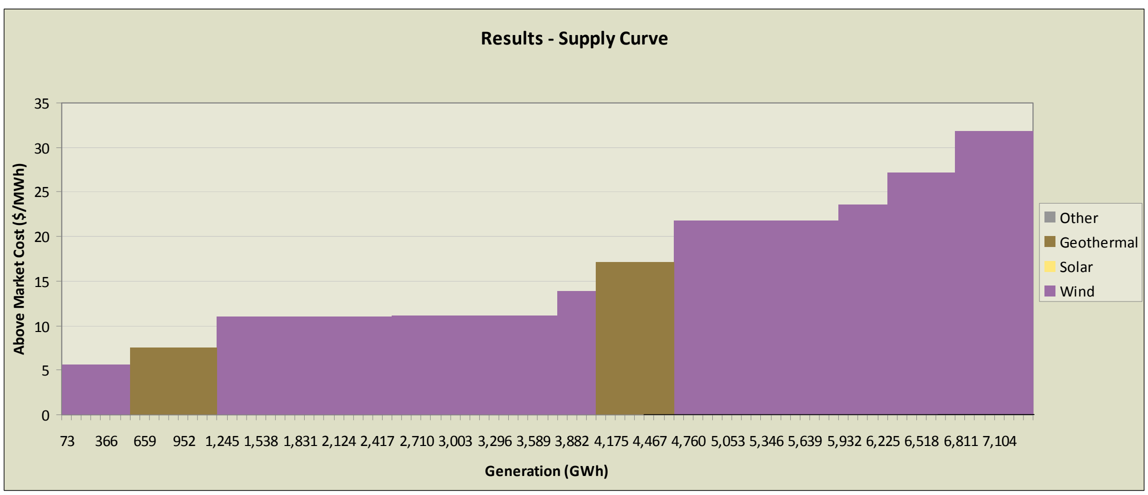
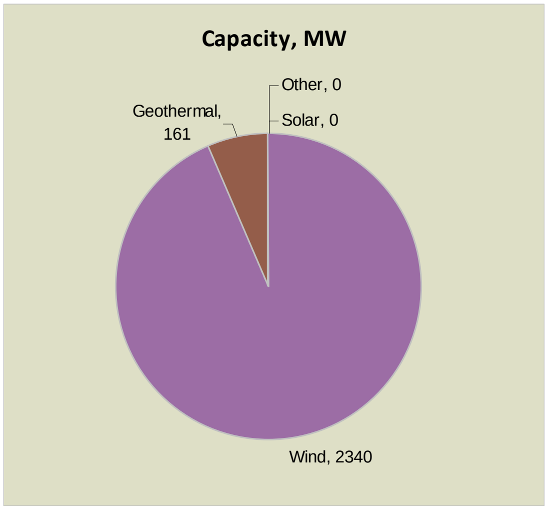


Figure 6-25. Best Projects Development Scenario Supply Curve.

6.6.3 Resource Capacity Energy, Capacity and Operating Profile

While the majority of the resources developed are wind, geothermal makes up a sizeable portion of the resources. Geothermal is approximately 6 percent of the capacity and 16 percent of the yearly generation as shown in Figure 6-26.



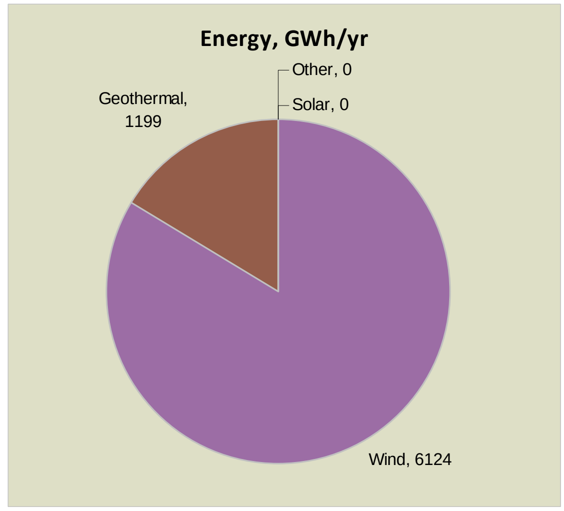


Figure 6-26. Best Projects Development Scenario Capacity and Energy Charts.

The composite production profile, shown in Figure 6-27, provides the typical 24-hour generation profile for the months of January, April and July. The overall composite profile is similar to the reference scenario, with an average generating capacity factor of 40 percent in January, 35 percent in April and 27 percent in July. The average capacity factor in July is significantly higher than the reference, low and high development scenarios. The maximum generation, occurs during the off-peak hours during the winter.

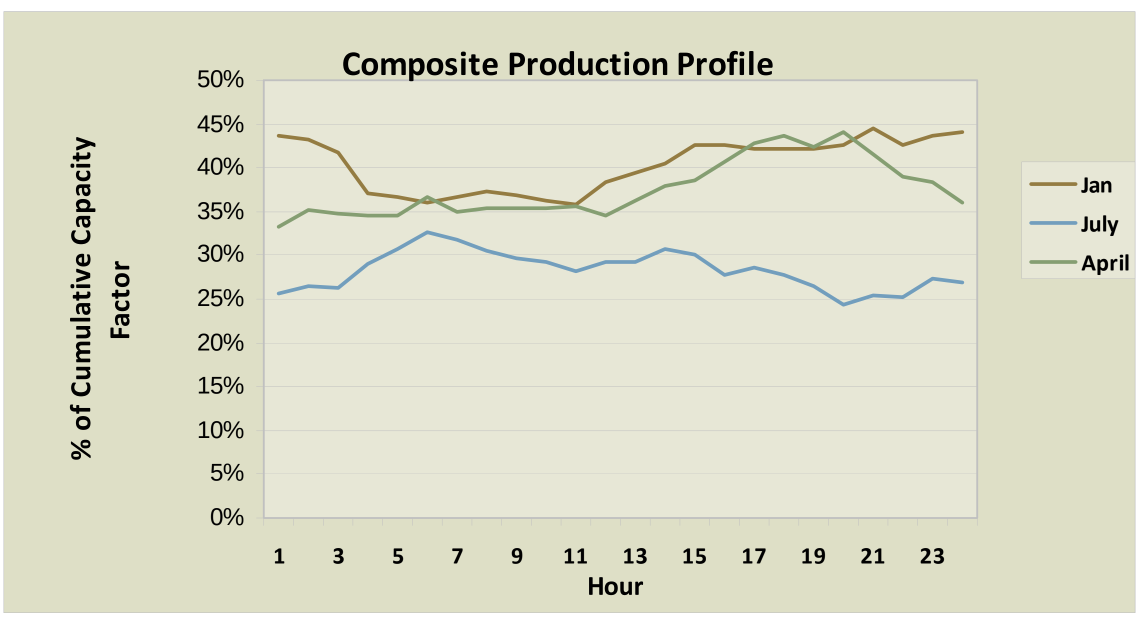


Figure 6-27. Best Projects Development Scenario Composite Production Profile.

6.6.4 Transmission Development

The best projects development scenario would require development of 10 transmission lines, detailed on Figure 6-28 below. A map depicting the required segments is provided in Figure 6-29. Unlike the earlier scenarios, transmission would be developed in the Southwest portion of the State.

Transmission Line Characteristics

Transmission Corridor	*Type*	*No lines*	*Corridor Length (mi)*
Ben Lomond to Terminal	138 kV AC Single - existing	1	46
	230 kV AC Single - new	1	46
Birch Creek to Ben Lomond	138 kV AC Single - existing	1	55
	138 kV AC Single - new	1	55
Sigurd to Mona	138 kV AC Single - existing	1	69
	500 kV AC Single - new	1	69
Mona to Terminal	500 kV AC Single - existing	1	69
	138 kV AC Single - new	0	
Helper to Newsub13	138 kV AC Single - existing	1	32
	138 kV AC Single - new	1	32
Newsub13 to Mona	138 kV AC Single - existing	1	69
	138 kV AC Single - new	1	69
Newsub14 to Birch Creek	138 kV AC Single - existing	1	39
	230 kV AC Single - new	1	39
Newsub4 to Newsub5	138 kV AC Single - existing	1	21
	230 kV AC Single - new	1	21
Newsub5 to Newsub6	138 kV AC Single - existing	1	23
	345 kV AC Single - new	1	23
Newsub6 to Sigurd	138 kV AC Single - existing	1	39
	500 kV AC Single - new	1	39

Figure 6-28. Best Projects Development Scenario Transmission Additions.

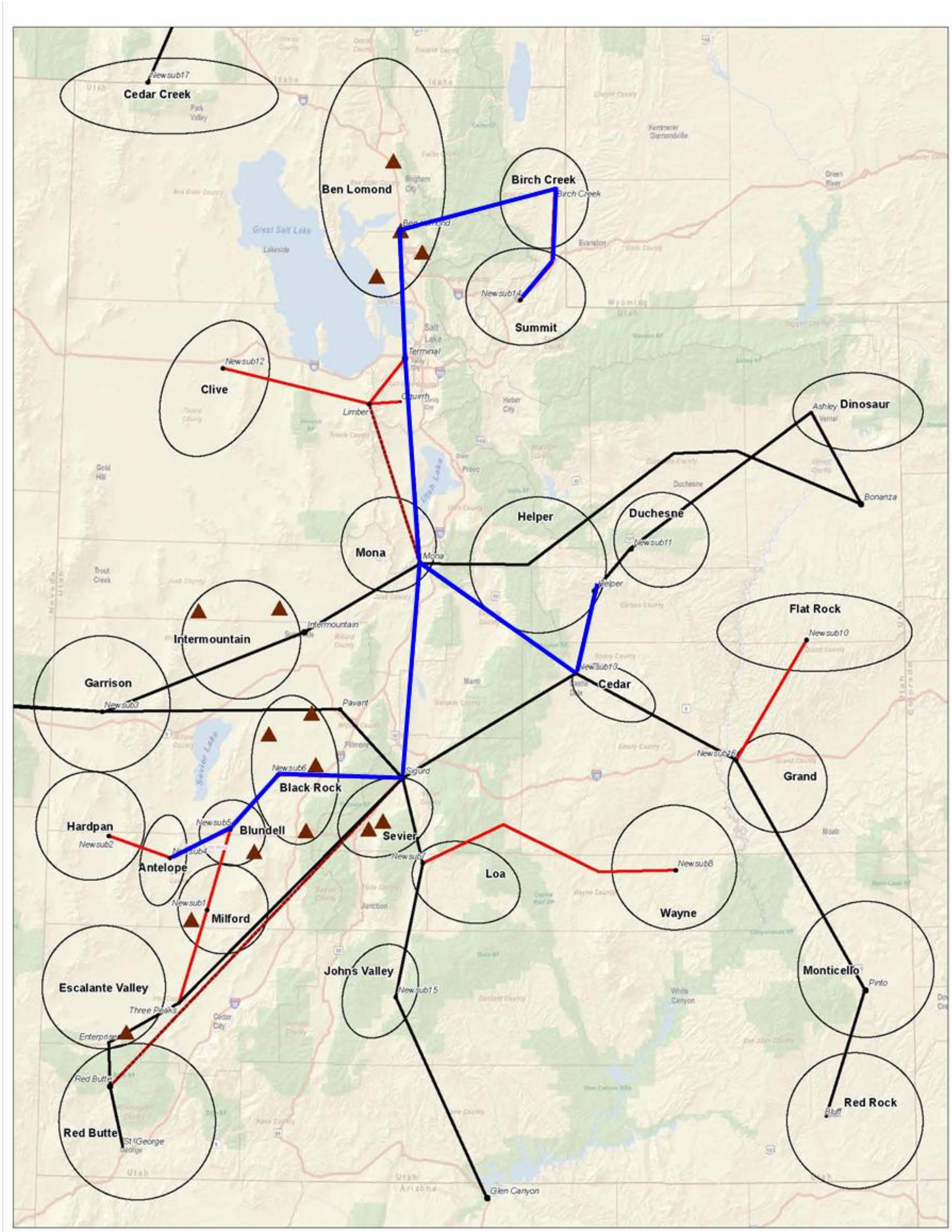


Figure 6-29. Best Projects Development Scenario Conceptual Transmission Map.

A summary of the energy delivered from each zone, and the transmission cost to deliver the energy, is detailed on Table 6-10. Costs presented are energy-weighted average dollars per MWh.

Table 6-10. Best Projects Scenario Avg. Trans. Cost by Zone ($/MWh).

Zone	Generation (GWh/yr)	Transmission cost ($/MWh)
Black Rock	2,343	8
Blundell	2,273	10
Helper	555	25
Antelope	1,268	15
Summit	885	24

6.7 Development Timing Scenario

The Development Timing Scenario is designed to better reflect current renewable development in Utah rather than present a theoretical portfolio, as the other scenarios included in this analysis represent. The scenario acknowledges current development activity of solar PV and geothermal in Utah, but limits this development in the near-term and mid-term to what the Technical Working Group agreed was "achievable" levels. The solar development limit is 100 MW by 2015 and 500 MW by 2020, while the geothermal development level is 100 MW in 2015 and 300 MW in 2020.

6.7.1 Development Requirements

The Development Timing scenario used the same energy demand and requirements as the Reference Case scenario (the medium demand case). Resources were developed to meet 50 percent of the 2025 Utah RPG goal and half that amount to export out-of-state.

Table 6-11. Development Timing Scenario.

Year:	**2015**	**2020**	**2025**
a. Generated in UT, consumed in UT (GWh)	2,269	3,404	4,538
b. Generated out-of-state, consumed in UT (GWh)	2,269	3,404	4,538
Total RPG eligible generation used in UT (a+b) (GWh)	4,538	6,808	9,077
c. Generated in UT, exported out-of-state (GWh)	1,135	1,702	2,269
Total UT renewable generation (a+c) (GWh)	3,404	5,106	6,808
Total anticipated capacity additions in Utah (MW)	1,300	1,950	2,600

This case assumes ½ of Utah's renewable energy goal is served with renewable energy resources developed in Utah, and ½ of this amount is developed for export out-of-state.

* Note: Capacity (MW) of additions is estimated assuming a 30 percent average capacity factor.

6.7.2 Resource Selection

Black & Veatch constructed a set of portfolios using the Utah Generation and Transmission model that met the constraints outlined by the Technical Working Group. Resources were selected to meet these development goals in 2015 and 2020, with additional lowest cost resources added to meet the remaining energy requirements for 2015, 2020 and 2025. The resources developed by 2015, 2020 and 2025 are listed on Figure 6-30, Figure 6-31 and Figure 6-32, respectively.

UREZ Zone	Project	Busbar Cost $/MWh	Transmission Cost $/MWh	Integration and Delivery Cost $/MWh	Energy Value $/MWh	Capacity Value $/MWh	Total Above Market Cost of Energy $/MWh	Generation GWh/yr	Resource Size MW
Black Rock	Black Rock Wind 1	$71	$9	$7	$63	$21	$6	540	200
Blundell	Blundell Geothermal 1	$75	$11	$0	$63	$18	$9	639	81
Black Rock	Black Rock Wind 2	$76	$9	$7	$63	$21	$12	1243	500
Summit	Summit Wind 2	$72	$22	$7	$66	$18	$22	376	140
Summit	Summit Wind 1	$75	$22	$7	$66	$18	$25	509	200
Ben Lomond	Ben Lomond Geothermal 1	$87	$21	$0	$62	$11	$39	168	24
Red Butte	Red Butte Solar 1	$167	$14	$3	$68	$41	$82	264	125

Figure 6-30. Development Timing Scenario Economic Results - 2015.

UREZ Zone	Project	Busbar Cost $/MWh	Transmission Cost $/MWh	Integration and Delivery Cost $/MWh	Energy Value $/MWh	Capacity Value $/MWh	Total Above Market Cost of Energy $/MWh	Generation GWh/yr	Resource Size MW
Black Rock	Black Rock Geothermal 1	$82	$9	$0	$62	$14	$18	561	80
Black Rock	Black Rock Geothermal 3	$86	$9	$0	$62	$10	$27	140	20
Black Rock	Black Rock Geothermal 4	$89	$9	$0	$62	$11	$30	112	16
Black Rock	Black Rock Geothermal 2	$100	$9	$0	$62	$11	$41	56	8
Ben Lomond	Ben Lomond Geothermal 4	$103	$21	$0	$62	$11	$57	56	8
Ben Lomond	Ben Lomond Geothermal 2	$103	$21	$0	$62	$11	$57	56	8
Ben Lomond	Ben Lomond Geothermal 3	$103	$21	$0	$62	$11	$57	56	8
Blundell	Blundell Solar 1	$142	$11	$3	$68	$35	$60	235	125
Red Butte	Red Butte Solar 1	$167	$14	$3	$68	$41	$82	264	125

Figure 6-31. Development Timing Scenario Economic Results - 2020.

UREZ Zone	Project	Busbar Cost $/MWh	Transmission Cost $/MWh	Integration and Delivery Cost $/MWh	Energy Value $/MWh	Capacity Value $/MWh	Total Above Market Cost of Energy $/MWh	Generation GWh/yr	Resource Size MW
Blundell	Blundell Wind 1	$69	$11	$7	$62	$16	$13	1361	500
Helper	Helper Wind 3	$69	$26	$7	$61	$13	$33	555	200

Figure 6-32. Development Timing Scenario Economic Results 2025.

In total, 18 projects were selected for development, as detailed in Table 6-12. Figure 6-33 shows the zones where the selected projects are located.

Table 6-12. Development Timing Scenario Project List.

Project Name	Capacity (MW)	Generation (GWh/yr)
Red Butte Solar 1	125	264
Blundell Geothermal 1	81	639
Ben Lomond Geothermal 1	24	168
Summit Wind 2	140	376
Black Rock Wind 1	200	540
Summit Wind 1	200	509
Black Rock Wind 2	500	1243
Black Rock Geothermal 1	80	561
Black Rock Geothermal 3	20	140
Black Rock Geothermal 4	16	112
Ben Lomond Geothermal 2	8	56
Ben Lomond Geothermal 4	8	56
Ben Lomond Geothermal 3	8	56
Black Rock Geothermal 2	8	56
Red Butte Solar 1	125	264
Blundell Solar 1	125	242
Blundell Wind 1	500	1361
Helper Wind 3	200	555

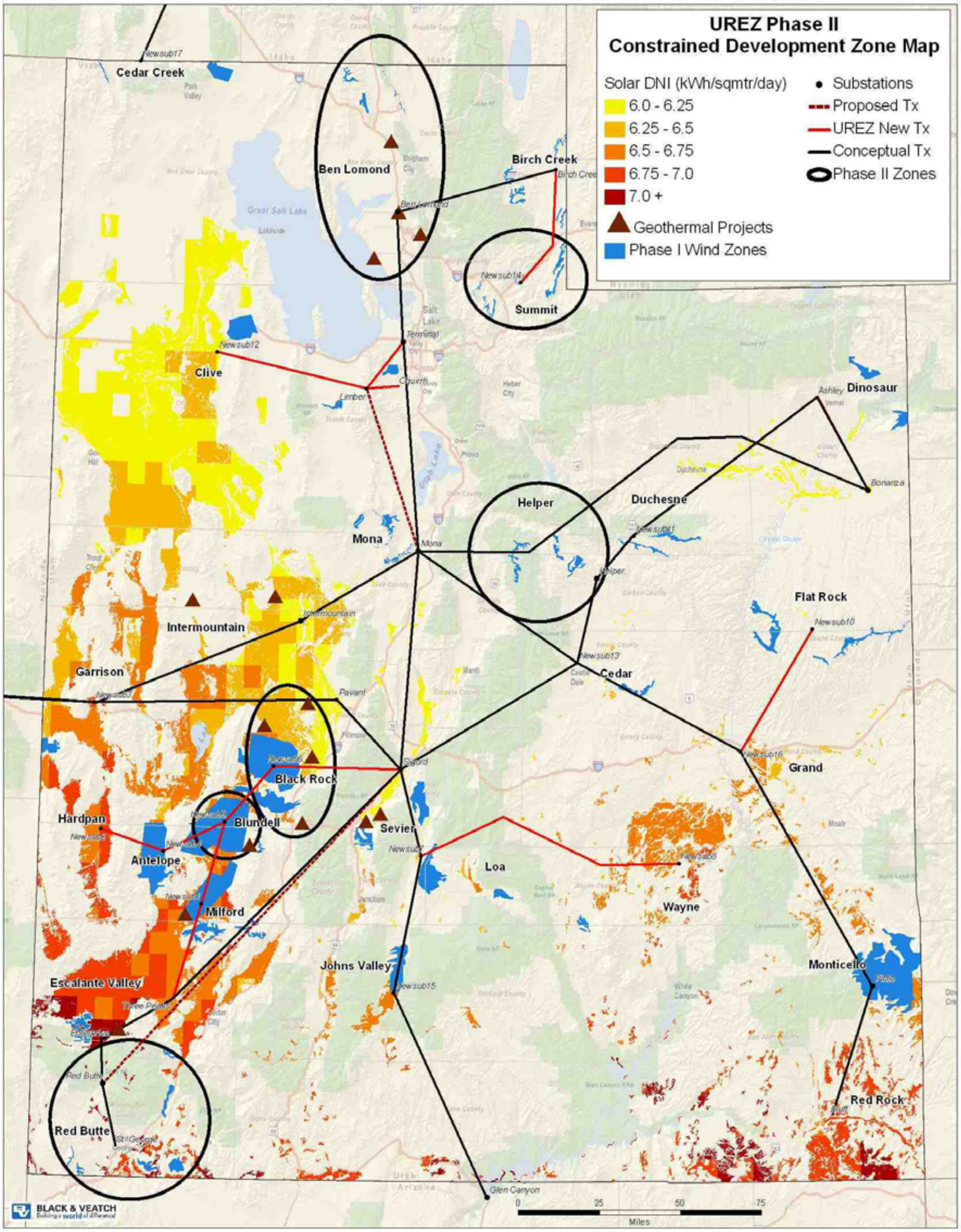


Figure 6-33. Development Timing Scenario Zone Map.

The supply curve of selected resources is presented on Figure 6-34, below. The premium costs for the resources vary from $6/MWh to $82/MWh, with the lowest priced project being a wind project, and the highest, a solar project. Premium cost of geothermal project varies from $9/MWh and $57/MWh.

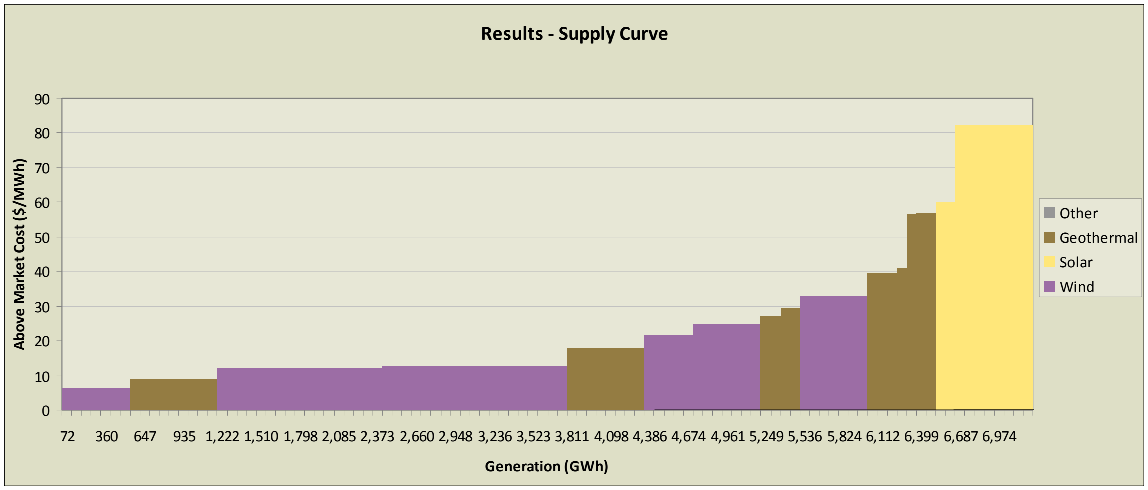


Figure 6-35. Development Timing Scenario Supply Curve.

6.7.3 Resource Capacity Energy, Capacity and Operating Profile

The development goals defined under this scenario increased the solar and geothermal resources in the capacity developed and the generation. Solar is 16 percent of the portfolio capacity and 11 percent of the generation. Geothermal is 11 percent of the capacity and 26 percent of the total generation. Figure 6-36 show the capacity and generation mix.

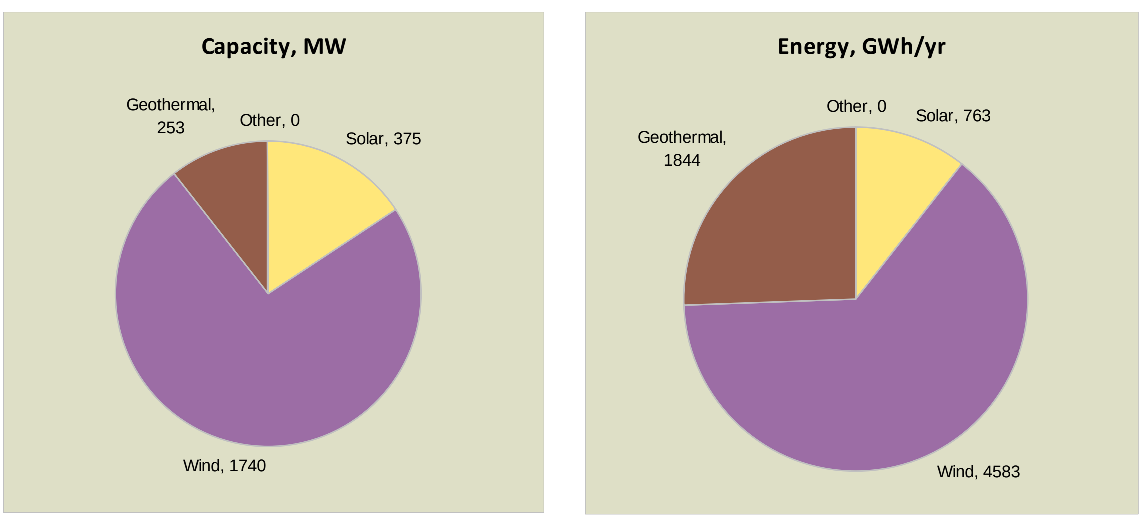


Figure 6-36. Development Timing Scenario Capacity and Energy Charts.

The composite production profile, shown in Figure 6-37, provides the typical 24-hour profile during the months of January, April and July. Due to the addition of the solar resources in the portfolio, the composite profile has a peak during the middle of the day. The average capacity factor in July is significantly higher than for the other development scenarios, again reflecting the addition of solar resources in the portfolio.

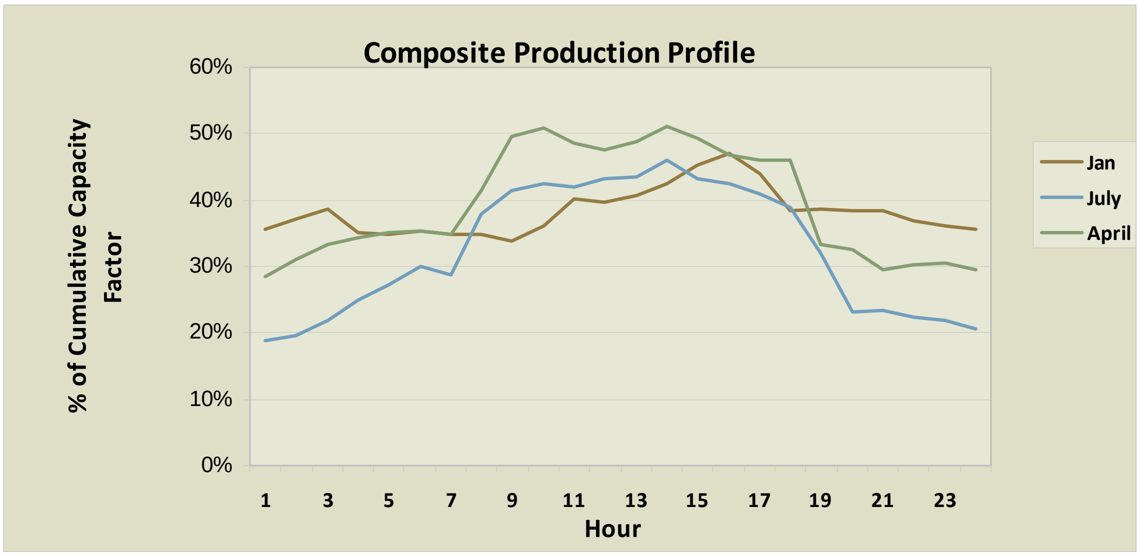


Figure 6-37. Development Timing Scenario Composite Production Profile.

6.7.4 Transmission Development

The scenario would require development of 13 new transmission lines, listed on Figure 6-38. A map of the segment is provided in Figure 6-39.

Transmission Line Characteristics

Transmission Corridor	*Type*	*No lines*	*Corridor Length (mi)*
Ben Lomond to Terminal	138 kV AC Single - existing	1	46
	230 kV AC Single - new	1	46
Birch Creek to Ben Lomond	138 kV AC Single - existing	1	55
	138 kV AC Single - new	1	55
Enterprise to Three Peaks	138 kV AC Single - existing	1	31
	138 kV AC Single - new	0	
Sigurd to Mona	138 kV AC Single - existing	1	69
	500 kV AC Single - new	1	69
Mona to Terminal	500 kV AC Single - existing	1	69
	138 kV AC Single - new	1	69
Helper to Newsub13	138 kV AC Single - existing	1	32
	138 kV AC Single - new	1	32
Newsub13 to Mona	138 kV AC Single - existing	1	69
	138 kV AC Single - new	1	69
Newsub14 to Birch Creek	138 kV AC Single - existing	1	39
	230 kV AC Single - new	1	39
Newsub5 to Newsub6	138 kV AC Single - existing	1	23
	230 kV AC Single - new	1	23
Red Butte to Enterprise	138 kV AC Single - existing	1	15
	138 kV AC Single - new	0	
Newsub6 to Sigurd	138 kV AC Single - existing	1	39
	230 kV AC Double - new	1	39
Three Peaks to Sigurd	138 kV AC Single - existing	1	117
	138 kV AC Single - new	0	
St. George to Red Butte	138 kV AC Single - existing	1	20
	138 kV AC Single - new	0	

Figure 6-38. Development Timing Scenario Transmission Additions.

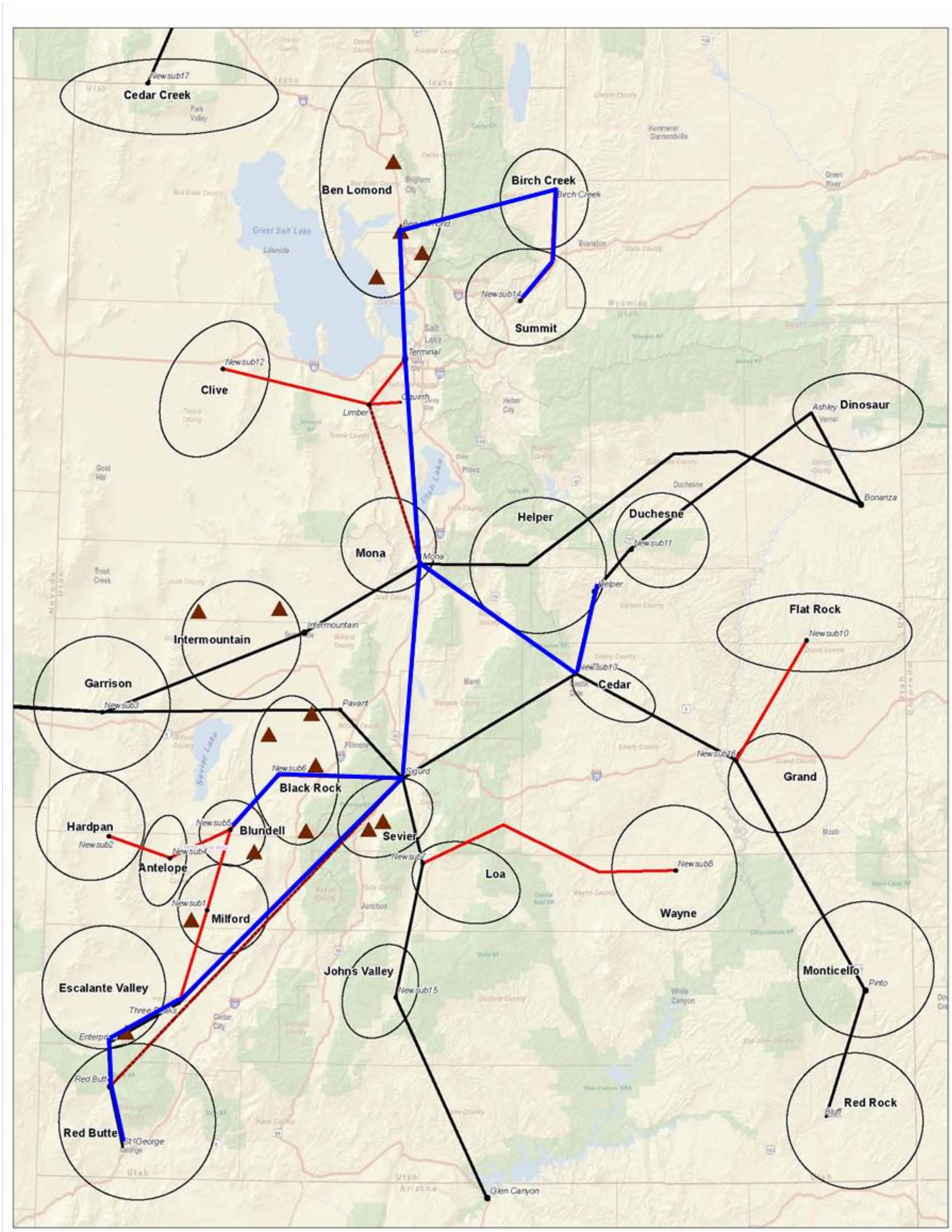


Figure 6-39. Development Timing Scenario Conceptual Transmission Map.

A summary of the energy delivered from each zone, and the transmission cost to deliver the energy, is detailed in Table 6-13. Costs presented are energy-weighted average dollars per MWh.

Table 6-13. Development Timing Scenario Avg. Trans. Cost by Zone ($/MWh).

Zone	Generation (GWh/yr)	Transmission cost ($/MWh)
Ben Lomond	336	21
Black Rock	2,652	9
Blundell	2,234	11
Helper	555	26
Red Butte	528	28
Summit	885	22

6.8 Scenario Results

6.8.1 Resource Development by Scenario

All of the scenarios have a preponderance of wind in the resource mix, with a lesser amount of geothermal and solar. The busbar and transmission costs of wind and geothermal resource are typically below $125/MWh, while the cost of solar is generally over $140/MWh. Despite the higher value of energy from solar, based on its time of delivery coincident with peak energy demand, it remains less competitive than wind in Utah.

Figure 6-40 shows the generation mix for each scenario based on the resource energy generation in 2025. Figure 6-41 shows the capacity additions by resource type for each scenario.

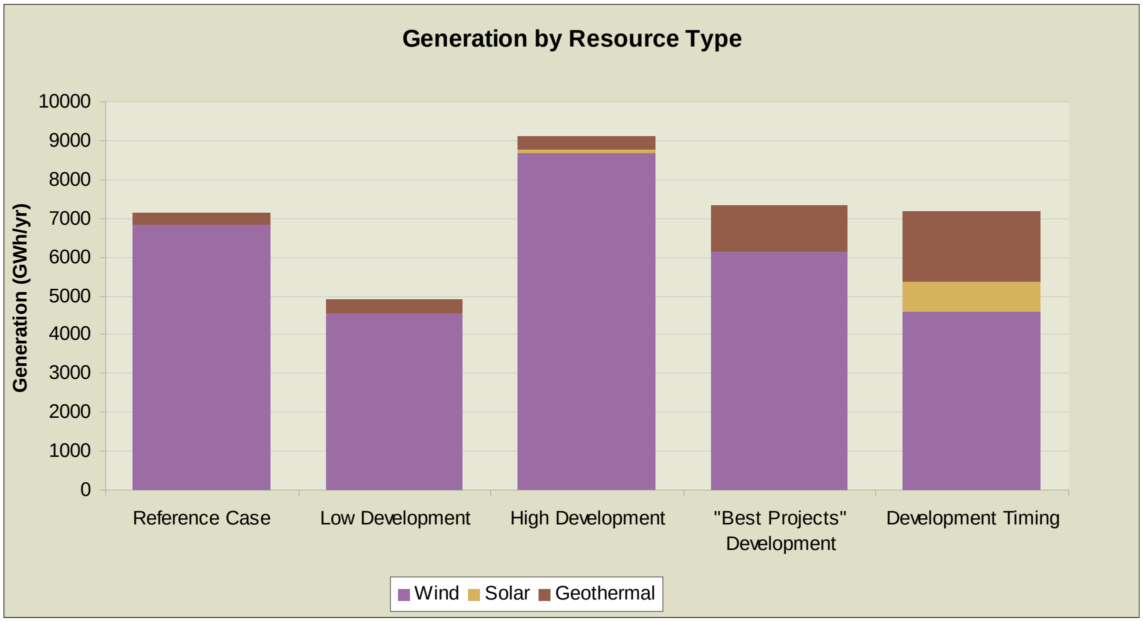


Figure 6-40. Annual Generation by Scenario and Resource Type.

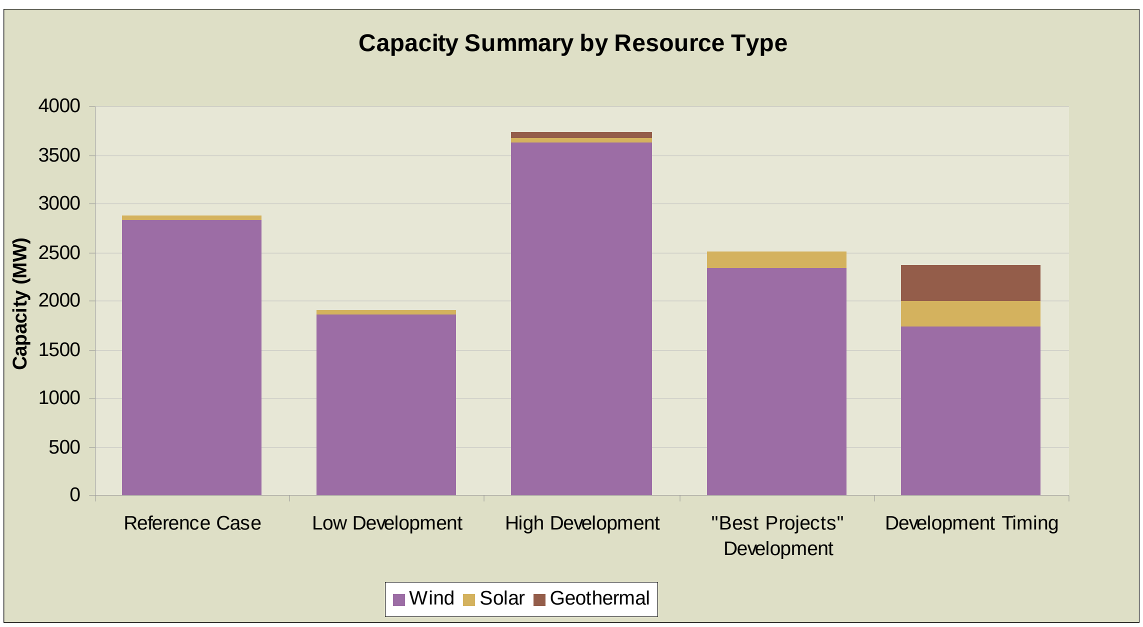


Figure 6-41. Capacity Requirements by Scenario and Resource Type.

6.8.2 Resource Location by Scenario

Consistent with the finding that the wind and geothermal resources are most cost-effective, zones that were mostly wind and/or geothermal tended to show up again and again in many of the scenarios. Table 6-14 identifies the zones that were included in each scenario.

Table 6-14. UREZ Zones by Scenario.

Zone Name	Reference Case	**Low Development**	**High Development**	"Best Projects" Development	Development Timing
Antelope				✓	
Ben Lomond	✓	✓	✓		✓
Birch Creek	✓		✓		
Black Rock				✓	✓
Blundell				✓	✓
Cedar	✓		✓		
Cedar Creek	✓	✓	✓		
Duchesne	✓		✓		
Flat Rock			✓		
Helper	✓	✓	✓	✓	✓
Loa			✓		
Mona	✓	✓			
Red Butte			✓		✓
Summit	✓	✓	✓	✓	✓

6.8.3 Costs

The costs for the development, including the cost of both transmission and generation resources, was between $5.2 billion for the low development case and $10.2 billion for the high development case. A summary of the costs for each scenario are provided in Table 6-15 below.

Table 6-15. Capital Cost of Development by Scenario.

Scenario	Total Cost (Million $)	Total MW	Total GWh/yr
Reference Case	7,723	2,883	7,162
Low Development	5,328	1,908	4,891
High Development	10,154	3,731	9,119
"Best Projects" Development	6,731	2,501	7,324
Development Timing	7,771	2,368	7,198

Source: Black & Veatch Analysis for UREZ Phase II.
Note: Capital costs include both the cost of generation and transmission resources.

Another comparison of the scenarios is the comparison of the average delivered cost of energy for each scenario. Using this as a comparison the Best Projects scenario is the lowest average premium cost scenario while the Low Development scenario, which has the lowest total cost, has the highest average premium cost ($/MWh). Figure 6-42 depicts the average delivered cost of energy by scenario.

Figure 6-42. Cost of Energy by Scenario.

An additional metric by which to compare the scenarios is the unit capital cost required to develop each scenario, or the capital cost on a per-MW basis. The development timing scenario, which includes a large quantity of solar resources, has a substantially higher unit capital cost, as would be expected. The other four scenarios are much closer in their unit capital costs. Figure 6-43 depicts a comparison of the unit capital costs for each scenario.

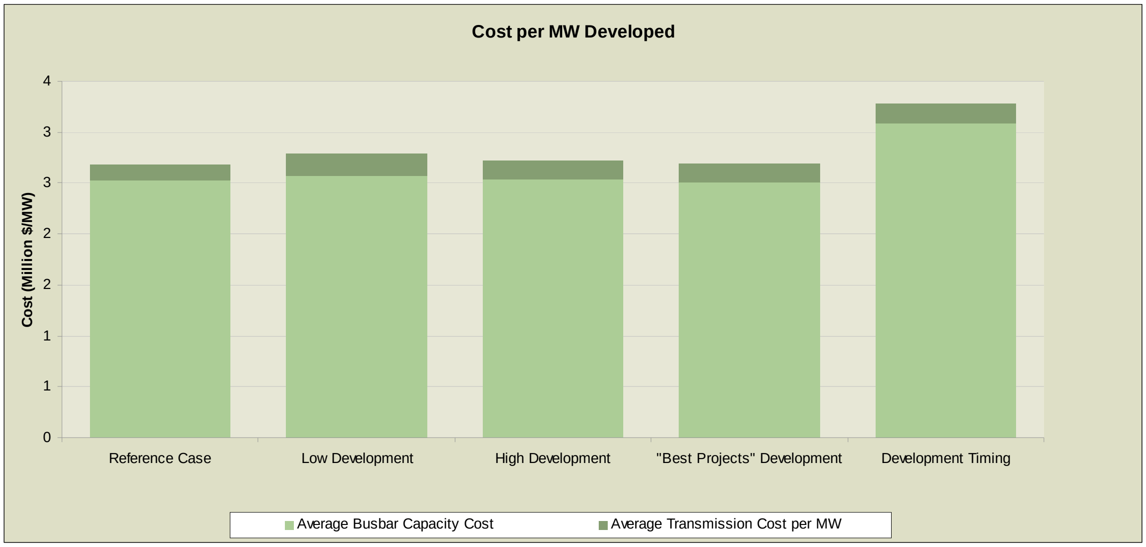


Figure 6-43. Unit Capital Cost of Development by Scenario.

Appendix A. Renewable Energy Zone and Conceptual Transmission Map

The UREZ Phase II Renewable Energy Zone and Conceptual Transmission Map may be downloaded from the Utah Geological Survey website.

http://geology.utah.gov/sep/renewable_energy/urez/phase2/index.htm

Appendix B. UREZ Generation & Transmission Model

The UREZ Phase II Generation & Transmission Model (GTM) is an Excel tool used to develop renewable scenarios and conduct scenario analysis. A copy of the model and User Guide may be downloaded from the Utah Geological Survey website.

http://geology.utah.gov/sep/renewable_energy/urez/phase2/index.htm

Appendix C. Barriers and Pathways to Renewable Energy and Transmission Development in Utah

Appendix D. Analytic Approach and Assumptions: Zone Identification, Resource and Transmission Assessment

A copy of the UREZ Phase II Analytic Approach and Assumptions: Zone Identification, Resource and Transmission Assessment document may be downloaded from the Utah Geological Survey website.

http://geology.utah.gov/sep/renewable_energy/urez/phase2/index.htm

Appendix E. Public Comments on Draft Final Report

Appendix E. Public Comments on the Draft Final Phase II UREZ Report

The UREZ Phase II project held two public comment periods on the Draft Final Report. The first was in May 2010, and the second was in July 2010. Four public comments were received. While the comments were greatly appreciated, none of the comments was substantive enough to have brought changes to the Report. Therefore, no changes were made to the Report as a result of the public comments received in May. No public comments were received in July.

- Comment 1. May 3, 2010,email from Gary D. Tassainer, PE, Tasco Engineering, Inc.

- Comment 2. May 3, 2010, email from Garth Barker with a document written for the WECC planning teams outlining some Utah projects.

- Comment 3. May 3, 2010, Letter from Robert Webster, Magnum Energy

- Comment 4. May 5, 2010, Letter from Jim Catlin, Wild Utah; Tiffany Bartz, Southern Utah Wilderness Alliance; Alex Daue, The Wilderness Society – BLM Action Center; Joro Walker, Western Resource Advocates; Kirk Robinson, Western Wildlife Conservancy, with 2 maps showing overlays of roadless areas and wildlife habitat areas.

All comments are provided here as Appendix E. to the UREZ Phase II report.

Comment 1: (via email)
While the report is very well done and the Utah noted resources are valid but they are certainly not competitive with Wyoming or Dakota and possibly Montana wind resources. Utah renewable resources will not be considered a viable or competitive alternative to coal until the state legislature makes the RPG an RPS and puts some teeth into what is now a thought. This concept has been used in many other states as the state office is fully aware, but with the coal lobbying forces, renewable energy will not be implemented and we (Utah) will remain in the "way back" as far as developing our resources. You can point to First Wind, but that entire resource is being sold to California and thus should not even count in the Utah mix.

We have been developing Wind Resources (Utah and Wyoming) for over ten years. We were part of the initial investigation statewide with Christine Mikell, of the State Energy Office, but if Utah wind is going to be a reality, then this state must enact an RPS.

If this is not done, then the state is wasting money studying the alternatives.

By the way, we are capable of producing a report and would have liked to have been asked instead of using Utah tax money for an out-of-state engineering company.

Gary D. Tassainer, PE
Tasco Engineering, Inc

Comment 2: (via email) from **Garth Barker** garthbarker@gmail.com
Please find attached comment on UREZ Phase 11.

Section No.	Page No.	Comment
2.0	2-1	Section 2 discusses changes made to UREZ Phase I geothermal and winds zones. The report should also identify all changes made to Phase I wind zones.
Section No.	**Page No.**	**Comment**
1.0	1.3.	It's becoming very apparent that transmission planning without adding storage elements will fall far short of expectations. This is outlined in both the **SANDIA REPORT** SAND2010-0815 and **Exploration of Resource and Transmission Expansion Decisions in the Western Renewable Energy Zone Initiative LBNL-3077E** There are proposed storage projects located in Utah that will redefine how transmission is addressed to meet renewable energy projects. Attached is a document written for the WECC planning teams outlining those Utah projects. Please note that one storage project named Parker Knoll located in Piute County, Utah will have the ability to increase variable renewable capacity from 30% to 60% by adding efficiency and time-shifting. This does in fact change the RPS potential for Utah. The UREZ11 report does a good job of defining potential issues with renewable integration onto the grid but when adding storage elements the values and benefits change dramatically, storage can defer the need for new transmission by removing congestion, improve T&D elements and firm renewable energy while increasing capacity.

Strong Reasons to consider Closed Loop Pumped Storage in WECC Transmission Expansion Planning

Abstract
Considering the multiple efforts directed at addressing current and future transmission needs, Symbiotics, a Run of River hydro and pumped hydro energy storage developer, is herein presenting to the WECC, additional considerations for the transmission planning process that includes several projects in progress, which have not been considered in the past. Concerning tools and elements that can, and most likely will, shape the future look of America's energy grid, including the present and future onslaught of renewable energy, one element hasn't been fully recognized for its transmission and distribution values; grid scale bulk storage.

Symbiotics is changing the paradigm of pumped hydro storage by presenting their Closed Loop Pumped Storage (CLPS) projects as transmission assets that (1) stabilize the Grid;(2) reduce the need for new transmission and fossil fuel' backup' generation;(3)

paired with intermittent resources like wind or solar powered generation result in firm, clean, reliable and cheap electricity. CLPS, strategically located with existing and future variable energy resources can result in a completely GhG free renewable resource product.

Within the following text, Symbiotics intends to present a closer analytical view of the value and potential worth of CLPS) and its integration into the grid using two of their current projects as examples, Parker Knoll CLPS and North Eden CLPS; its Symbiotics' hope that the WECC transmission planning committees will use this information when modeling future transmission scenarios.

More so than viewing the transmission grid plan only as a way to connect present and future renewable energy, Symbiotics intends to show that storage, as a grid tool, can perform multiple tasks that not only solve issues connected with variable renewable energy but also improve regional energy reliability, improve optimal operation of the existing generation fleet, reduce transmission congestion, in some cases defer the need for transmission upgrade, while increasing transmission capacity. In view of approaching climate change regulation/legislation, storage, strategically added to the grid, will remove the need for future fossil fuel generation.

Note: *During project site selection Symbiotics addressed the same concerns, factors and variables TEPPC includes in their planning scenarios including; environmental policy, water and land use, restricted lands, wildlife and habitat, and regulatory structures; included in the site selection model was project proximity to major transmission elements with additional attention placed on potential renewable energy zones; later confirmed by Western Governors Association WREZ studies.*

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Company Description

Symbiotics is a privately held, multi-disciplinary renewable resource company engaged in the development, construction and operation of run-of-river and closed loop pumped storage hydro projects in North America. Symbiotics provides environmental assessment, development, licensing, engineering, construction management and operating services for its own proprietary projects as well as for 3rd party owners. In addition, the Company has developed a proprietary database capable of identifying, evaluating and prioritizing potential run-of-river and closed loop pumped storage (CLPS) project development opportunities on the basis of multiple user defined criteria.

Symbiotics is currently performing licensing and development work under contract for 2 parties in connection with 4 hydroelectric projects in development. The Company is currently operating 4 separate hydroelectric generating stations for 3rd parties. It is proceeding on a proprietary basis in the licensing of 4 RoR projects and 4 CLPS projects and has received additional preliminary permits on 30 separate RoR projects and 6 CLPS. Symbiotics has filed (but not received) new preliminary permit applications with the

FERC on 5 RoR and 1 CLPS sites. The Company has successfully licensed 4 projects since formation, including 2 in 2009. Construction on the most recently licensed projects is expected to commence in late 2010.

Headquartered in Logan, Utah, the Company conducts business through offices in Oregon, Idaho, Texas and Florida and employs [34] people.

Symbiotics principals have a 30-year successful track record that includes:

- ► 250 environmental projects since 1975
- ► Environmental studies on 19 FERC projects for third-party owners
- ► 3 hydroelectric plants currently operated for third-party owners
- ► 4 new FERC licenses
- ► 3 projects under construction
- ► 44 permits at various stages of development
- ► 60+ years of utility, regulatory, trading and structuring expertise, including PPA negotiations and project finance.

Projects

It is a concern of Symbiotics that hydro and storage have not attained a place in the WECC transmission planning studies; the potential of these technologies and their placement in the planning scenario will have the potential to change the look of the grid. Though hydro has been tagged as a generation element that's not expected to grow, that stable base energy source does have a future. Recently the DOE signed a MOU with other Federal agencies to review hydro potential; Symbiotics has been pursuing and licensing hydro projects since 2000.

The following discusses Symbiotics hydro projects' agenda overview; including their slated pumped storage projects (CLPS).

As of 2006, there was an estimated 99 GW of hydroelectric capacity in the U.S. [1], which has grown by roughly 18% from 1995-2005.[2] The EIA expects total hydroelectric generation will increase approximately 1 GW from 2009 to 2030, again, this estimate will likely prove to be conservative given recent government incentives for renewable energy. It also must be noted that the EIA's estimate of incremental hydroelectric production growth takes into account the probable retirement and removal of 10 to 20 GW's of large hydro electric projects that will not be re-licensed by FERC based on mandates imposed by the Wild and Scenic Rivers Act. Much of this lost capacity will be made up by the development of much smaller, more environmentally sensitive, low impact hydroelectric projects such as the four projects recently licensed by Symbiotics. There are an estimated 5,677 feasible sites with undeveloped or underdeveloped capacity of approximately 30 GW[3], a majority of which are small hydro projects (25 MW or smaller)[4], 57% (17GW of capacity) of these sites already have existing dams or impoundment but do not have

[1] IEA Key Facts 2008.

[2] Haresh Khemani, *Past, Present and Future of Hydroelectric Power Plants*, 2008.

[3] Idaho National Laboratories and Department of Energy.

[4] Department of Energy, *Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants*, 2006.

power generation, while another 14% (4.3 GW of capacity) of sites have generation but are underdeveloped. In 2008 there was a significant resurgence in licensing activity by companies and municipalities attempting to license new run-of-river low impact hydroelectric projects on existing dams. Since January 2008, FERC has issued new preliminary permits on these facilities totaling well in excess of 1 GW. In addition, there are currently approximately 2,500 non-federal hydropower projects subject to relicensing, many of these qualifying as low impact projects which could present low risk/high return investment opportunities. Another consideration of small hydro is that it is mostly located around rural America's agricultural communities where it usually has the opportunity to back feed the transmission system with steady, firm energy; an added value of that renewable energy.

Locations of Symbiotics proposed projects are shown below in Figures 1 - 3.

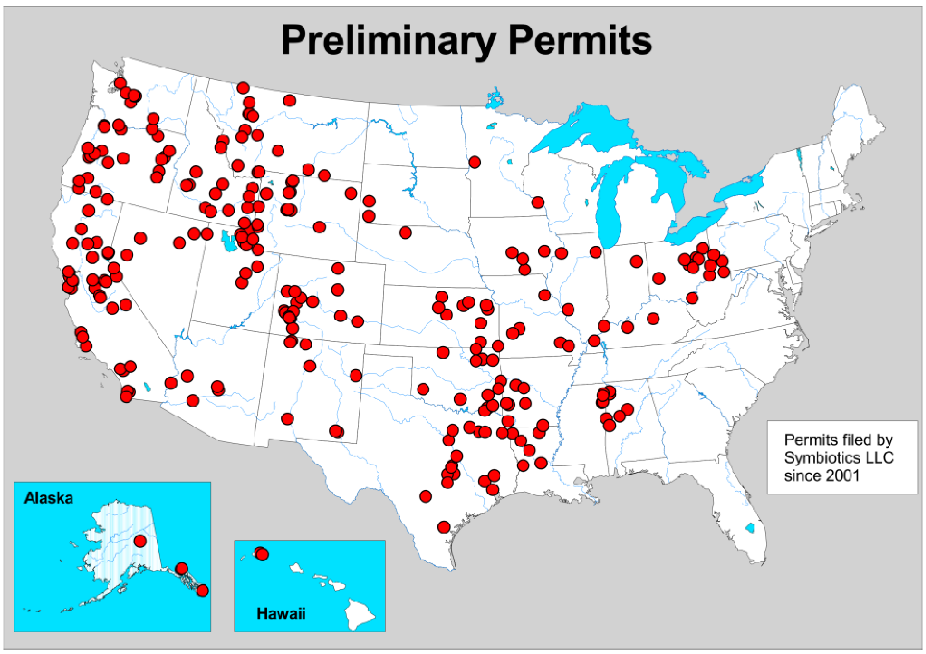

Figure 1. Permits filed.

Figure 2. Projects licensed or nearing licensing.

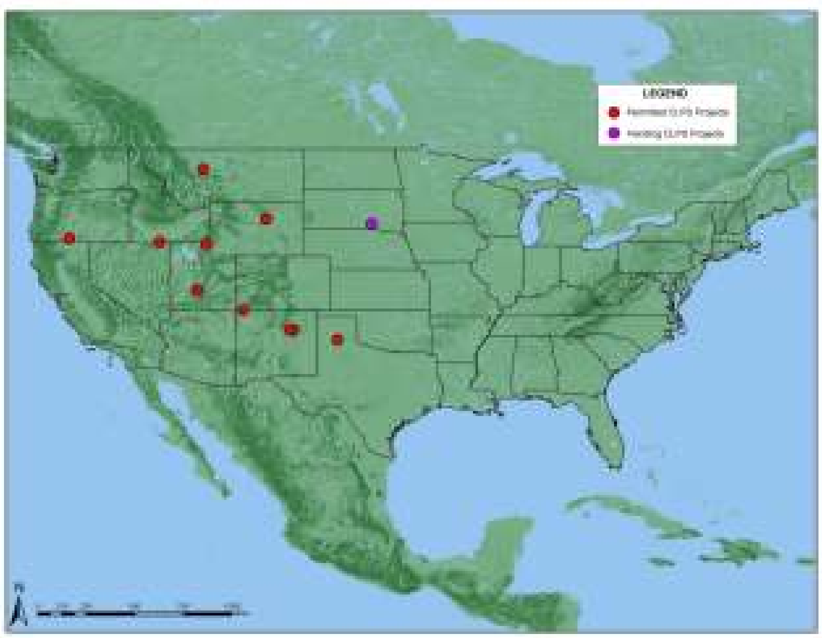

Figure 3. Closed Loop Pumped Storage projects either undergoing licensing or pending permitting processes.

It should be noted that Symbiotics CLPS's projects are strategically located near major transmission corridors as well as potential renewable hub locations per WGA's WREZ.

Overview of Closed Loop Pumped Storage

In its simplest form, a CLPS project stores energy in the form of water pumped from a lower elevation reservoir to a higher elevation. Low-cost off-peak electric power is used to run the pumps. During periods of high electrical demand the stored water is then released through turbines. The off-peak nature of the pumping process allows for exceptional storage and utilization of intermittent renewable and other readily available, low cost, off-peak generation resources. A general schematic of a CLPS facility is presented below in Figure 4. described above continue to materialize and facilitate the development and operation of intermittent energy resources, the need for large utility scale Energy Storage products is receiving increased attention.

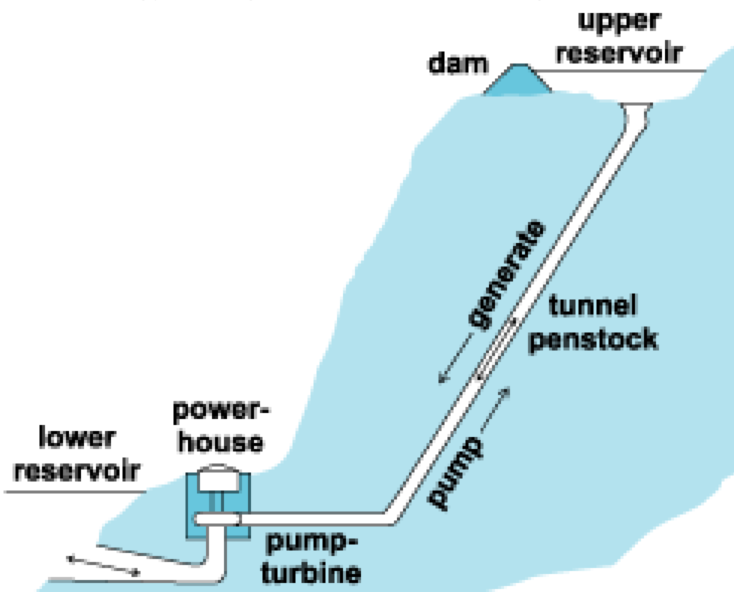

Figure 4.

The wind and sun are important sources of renewable energy but can only provide power under certain conditions. These intermittent energy sources can be enhanced by hydropower pumped storage projects such as those by Symbiotics.

Initially, the purpose of pumped storage projects is to provide peak energy and lend support to the large scale renewable projects proposed within the WECC system. Pumped storage can also enhance the value and function of sporadic electricity generation by effectively storing it. Symbiotics believes at least 10,000 MW of storage will be needed to meet RPS standards for all western states by 2020. For instance, wind energy requires 3mw to 5mw of additional frequency regulation electric ancillary service for every 100mw installed and would also benefit from the load shifting ability of storage. One of the other benefits of storage is the ability to provide black start, meeting the minute by minute energy demand of load centers.

Grid scale bulk storage, integrated at key locations, renewable energy, particularly wind, can increase that renewable's efficiency capacity from approximately 30% to over 60%, doubling the value of that renewable resource turning marginal renewable opportunities into profitable opportunities. Rising curtailment issues associated with wind can be mitigated with integrated grid storage facilities. Compared to other advancing forms of energy storage, pumped hydro, even with its initial high cost of construction, over shadows other current storage technologies with its long life, plentiful siting opportunities, and overall low installed cost though it is recognized that other forms of storage have a place in the grid to perform beneficial services. CLPS, with its relatively benign environmental footprint and social acceptability may be the most prudent storage system of choice on a regional scale, in spite of siting challenges.

Addressing Environmental Concerns of Site Location

A critical consideration for the development of pumped storage facilities has been environmental concerns during the water withdrawal process. The focal concern, which in some cases has been the project's fatal flaw and in other cases has led to numerous project delays, centers around the impact of water flow on wildlife located directly on navigable waterways. To circumvent these kinds of problems, as a cornerstone of project design Symbiotics has declined to locate pumped storage projects directly on or adjacent to existing water sources. Rather, Symbiotics has focused on the design of closed-loop, off-channel projects which minimize waterway environmental impact—hence the term closed loop pumped storage (CLPS). This design locates the project away from the source of the initial fill of the lower reservoir and then relies on either intermittent spot purchases or natural recharge to keep the project reservoirs at required operating levels.

CLPS Storage Application to the Grid

Examples used are Symbiotics' North Eden CLPS project and Parker Knoll CLPS project; both are located in Utah. North Eden is designed to generate 700mw; Parker Knoll has generation capacity of 1330mw. Each is designed to provide at full generation capacity ten hours of peak hour electricity (time to get through a heat wave, a cold snap, a calm wind day, or an unexpected plant outage). The particular attributes of these large storage projects, because of their locations and design will:

- Reduce congestion of existing transmission, increase transmission capacity and increase utilization of existing T&D assets.
- T&D upgrade deferral.
- Reduction of I^2R losses if energy is transmitted during off peak times.
- Enable effective, optimal integration (firming) of intermittent renewables by storing off peak wind to prevent "curtailment "and return a firm product to regional load centers.
- Provide a Demand Response resource on a regional rather than area bases.
- Black Start and Spinning Reserves.
- Minute by minute availability.
- Projects are well-suited to provide some ancillary services, especially load following, regional regulation, electric supply reserve capacity and…
- Time-shifting (shaping) or Time of Delivery low-priced energy. (move energy where and when its needed)
- CLPS reduces or eliminates the need for redundant "backup" intermittent fossil fuel resources thus reducing CO_2, SO_2, and NOx. And H_2S emissions.
- The true cost of CLPS can be quite low from a GRID perspective; the equation is:

True cost of CLPS = nominal cost of CLPS - {NPV of capacity, energy, and carbon credits provided (sold} – {value of fossil fuel back-up plants avoided}-{value of avoided transmission build}

Conclusion

When Symbiotics started looking at the value/benefit of storage for existing and projected renewable energy development, answering peak energy demand was the foremost consideration while increasing the value of variable energy resources; however it became quite clear that storage would play a far more important role in the energy grid. The site location of storage defines the particular benefits of that element; these benefits were an integral part of the modeling effort. It's notable that various types of storage need to be integrated into the entire grid; from the utility distribution level thru grid size application to meet the energy security goals of the nation.

Symbiotics CLPS projects are the first storage fundamentals in the plan that help accomplish the Nations goal of energy independence; benefits of the strategically placed CLPS examples are mentioned in this conclusion.

Grid sized storage off sets the need for additional fossil fuel generation while enabling optimal use of the existing generation resources thus reducing ramping which is not an efficient method of meeting demand; the looming climate change regulations will address this issue. Symbiotics CLPS examples are placed downstream of projected large renewable energy projects enabling storage to not only help realize a more efficient renewable product but add the time-shifting value as well. CLPS is well positioned to provide ancillary services including load following, reserve capacity, and regional regulation as a help aid for distributed storage resources at utility level distribution.

Being properly placed, storage becomes a significant factor in reducing grid congestion issues on existing transmission lines, defers the need for transmission upgrade, allows economic re- dispatch, and improves long distance transmission of renewable energy and affords a smooth transition into a workable National energy system. Increasing the efficiency of existing T&D elements with storage will extend the life of some T&D equipment. Storage does increase transmission capacity and can deliver a less "lumpy" product to regional load centers enabling utility level energy management to easier address aggregators at that scale.

Symbiotics CLPS projects have a projected long life of 50 years or more, this is an important factor, it ensures the certainty of the resource allowing an amount of dependability and flexibility other storage types may not offer. From a social and esthetic viewpoint, CLPS projects are welcomed by the public, in part, due to their locations and removal from the aquatic resources. Symbiotics has placed their CLPS projects away from recreational locations when considering location to ease mitigation of any social/economic/environmental issues.

Symbiotics encourages the WECC transmission planning teams to consider including CLPS projects into the most recent transmission planning effort.

Information from both Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide SAND2010-0815 Feb2010 and The Role of Energy Storage with Renewable Electricity Generation Technical Report NREL/TP-6A2-47187Jan 2010 was also used in this document.

Comment 3:

MAGNUM

May 3, 2010

UREZ Task Force
324 South State Street, Suite 500
Salt Lake City, UT 84111

RE: UREZ Task Force

Dear Task Force Members,

Magnum Energy LLC, a Salt Lake City-based bulk storage developer, appreciates the opportunity to provide input and comment to the UREZ Task Force. Magnum Energy is currently permitting a natural gas storage facility near Delta, Utah. The site would also be well suited to build a multi-phase Compressed Air Energy Storage (CAES) facility. Magnum Energy believes that based on the three goals of UREZ Phase II: (1) Identify policies or market mechanisms that would facilitate transmission planning (2) Quantify cost-effective generation potential, and (3) Identify necessary transmission to bring resources to market, the UREZ Phase II group should acknowledge the valuable contribution Compressed Air Energy Storage (CAES) can contribute to the ultimate development of Utah Renewable Resources.

CAES could be built at Magnum's site to use off-peak renewable generated electricity to pump air into large underground salt caverns. The compressed air can be released on demand to turn a gas turbine and generate electricity. This process in effect takes off-peak renewable power, stores it, and then places it back on the grid during peak hours. Due to the intermittent nature of most renewable resources, there are significant hurdles to developing high penetration levels of renewable energy. CAES can alleviate these issues by optimizing both the generation and transmission assets involved in producing and delivering renewable energy to market.

Renewable generation is enhanced through CAES because the stored energy can simultaneously firm, shape, and store renewable energy. CAES makes renewable projects more attractive to developers as it provides the opportunity for price arbitrage and selling the resource at the most opportune time. Furthermore, the shaping ability provided by CAES alleviates one of the most prominent negative aspects of renewable energy, its intermittent nature. CAES is not only an asset to generators; it is also a valuable asset to transmission and grid operators as a tool

3165 Millrock Drive, Suite 330 Salt Lake City, Utah 84121 801-993-7001 (Office) 801-993-7025 (Fax)

for load-leveling, frequency regulation, and ramping. The technology can be used as a peaking generation resource, therefore increasing grid optimization. Integrating increasing amounts of renewable assets into the transmission grid is one of the top concerns facing regulators and grid operators today, and it is important that a report with the intent of identifying policies that facilitate transmission planning consider the promotion of CAES as a viable option for fulfilling this objective.

CAES is a proven technology that has been implemented successfully for almost two decades. According to a recent article by Frank Maisano that appeared in SNL Financial, "Compressed air energy storage technologies have emerged as the best option for grid managers and utility experts to better balance the performance of a future grid that will feature more renewable power." Furthermore, Utah Governor Gary Herbert recently signed Senate Bill 104 into law which expanded the state's definition of 'renewable resources' to include compressed air energy storage. The passage of the bill recognizes the State Legislature's recognition of this resource as a viable option for meeting the state's renewable portfolio goal. We believe that the UREZ Phase II Report will more accurately report the large potential development of Utah Renewable Resources if the opportunities provided by CAES are duly noted.

Thank you again for the opportunity to provide comments and for the work the Task Force has done to date.

Sincerely,

Robert Webster
Chief Operating Officer

3165 Millrock Drive, Suite 330 Salt Lake City, Utah 84121 801-993-7001 (Office) 801-993-7025 (Fax)

Comment 4:

WILD UTAH PROJECT

68 S. Main Street, Suite 400
Salt Lake City, UT 84101
Phone: (801) 328-3550
e-mail: info@wildutahproject.org

May 05, 2010

Elise Brown and Mary Ann Wright
State Energy Program
Utah Geological Survey

Re: Wild Utah Project Comments on UREZ Phase II report

Dear Elise and Mary Ann,

Thank you for this opportunity to comment on the *Utah Renewable Energy Zone (UREZ) Task Force, Phase II Zone Identification and Scenario Analysis* Draft Report. This is a very impressive report detailing a great deal of work by the UREZ Phase 2 Task Force and Black and Veatch, and represents a job well done. The model is state-of-the-art and the scenarios that we have reviewed use the most up to date inputs possible, make good sense and are easy, even for lay-people like us, to understand. This model will no doubt play an important role as the UREZ and the state of Utah move forward towards the goal to generate 20% of Utah's electricity from renewable resources by 2025.

Since we do not have specific comments on the model or the scenario development, or even specific comments on the report, we opted not to use the special comment form you provided, but instead providing our comments in this letter. We will use this opportunity to offer up some thoughts to the Phase 2 Task Force, State Energy program, utilities and renewable energy developers, as we all move forward after the Phase 2 UREZ process comes to a close. In particular, we focus on future land use and land management issues that may arise if and when developers propose large scale renewable energy developments in areas that are important to Utah's wildlife.

Potential conflicts that may arise with future large scale renewable energy development siting within wildlands

The original Phase 1 process wisely screened out Forest Service inventoried roadless areas from consideration for renewable energy zones, but neglected to do so for Bureau of Land Management (BLM) areas. Our first attached map displays how the inventoried roadless BLM lands overlap with both the Phase 1 potential wind and solar energy polygons, and the proposed Phase 2 renewable energy zones. It is important that the state and potential renewable energy developers avoid BLM inventoried roadless areas as we move forward from the Phase 2 process and into Utah's renewable energy future. First, the scientific literature is replete with studies and evidence that confirm that roadless

WWW.WILDUTAHPROJECT.ORG

areas are perhaps the most important lands to conserve from a biological perspective. These roadless areas are of particular value because they are characterized by an increased health and function of watersheds in the absence of the effects of roads and concomitant erosion, increased population viability of species within areas with less human influences, and greater biodiversity in roadless areas (and this is the same for deserts and forests). Thus, in general there will be a higher likelihood of proposed renewable energy facilities running into conflicts with state-listed sensitive species such as rare plants and sage grouse in these roadless areas. Second, the Utah Wilderness Coalition will likely raise objection to any proposed large scale renewable energy facility inside the areas designated in the America's Red Rock wilderness proposal (the same inventoried roadless BLM lands displayed in our map). Most of the lands that the Utah Wilderness Coalition identified in their wilderness proposal have also been found by BLM to possess wilderness characteristics.

The good news is that because most of the solar polygons must be on lands with very little slope, and most of the roadless areas by definition are not flatlands, but in the more mountainous zones, there is actually very little overlap between the inventoried roadless BLM lands and the renewable polygons. In fact, we are very encouraged and pleased by this, as it seems like any future large scale renewable energy facility ultimately sited in Utah's West Desert or Colorado Plateau region can readily be designed to avoid roadless areas that are under consideration for wilderness designation

Other issues that may arise with eventual siting of large scale renewable energy facilities involve potential conflicts with certain rare and imperiled native wildlife, namely sage grouse, Rocky Mountain bighorn sheep, Utah prairie dog and certain sensitive raptor species[5]. While currently occupied sage grouse (*Centrocercus urophansianus*) winter and brooding habitat by and large do not overlap with most of the Phase 2 zones (see our second map), there are certain zones, such as the Birch Creek, Summit, Dinosaur, and Flat Rock zones, where future wind development could potentially conflict with sage grouse seasonal needs. Of particular concern is the Monticello Zone, where both potential wind and solar resources are squarely on top of a extremely rare and sensitive subspecies of sage grouse (and candidate species for protection under the Endangered Species Act) – the Gunnison Sage grouse (*Centrocercus minimus*).

Very little is known about wind energy and sage grouse, but oil and gas field developments within the range of the sage grouse often have caused measureable effects to their populations. Activities and disturbance related to both energy development scenarios are believed to pose some similar threats to the grouse. Sage grouse populations typically decline following oil and gas development, and birds have been displaced from habitat near infrastructure and locations with human disturbance. Notably, it has been shown that female grouse nesting in developed areas had lower annual survival rates.

[5] While we do not directly speak to the issue of future renewable energy siting and raptor concerns, we have been coordinating with Hawkwatch International, who is submitting comments on this point under separate cover.

Chick mortality rates also were higher within sight of oil wells (Becker et al. 2009)[6]. The well known Hollaran study (2005)[7] recommends a 3 km buffer between any disturbance from oil/gas wells and breeding activity (leks). Until we have specific data on wind power, it is wise to employ these buffers around leks when determining where to site wind turbines. Prior to siting new wind or solar developments in occupied sage grouse habitat, a buffered analysis of population breeding grounds will identify if the site has enough remaining locations for wind power or solar power that make the site economically feasible. Sound policy may dictate that areas particularly important to sage grouse should be off limits to development.

In terms of potential conflicts with future renewable development and Rocky Mountain bighorn sheep (*Ovis canadensis*), our second map indicates that while bighorn sheep habitat by and large does not overlap with most of the Phase 2 zones, there would seem to be the greatest degree of potential overlap with wind power in the Flat Rock zone and bighorn sheep year-long range. Wind turbines can displace bighorn sheep from their habitat because of this species' aversion to the built environment amplified by the increased human use of wind power sites facilitated by the added road network. We also did an overlay of the desert bighorn subspecies of bighorn sheep (*Ovis canadensis nelsoni*), which primarily resides in southern Utah, and did not feel we even needed to include that subspecies on the map as there does not appear to be any overlap with the renewable polygons within the Phase 2 zones.

In terms of potential conflicts with future renewable development and Utah prairie dog (*Cynomys parvidens – a federally threatened species*) habitat, our second map indicates while most of the known prairie dog habitat does not overlap with the Phase 2 zones, there may be some issues with Utah prairie dogs and future siting of both wind and solar power within the Loa and Johns Valley zones. To get a more detailed account of exactly how proposed wind or solar developments in the Loa and Johns Valley zones could potentially impact prairie dogs, we requested that the Utah Division of Wildlife Resources overlay the Phase 2 zones and wind and solar polygons with occupied Utah prairie dog colonies. They reported back to us that "the Loa zone is the most concerning," as 30% of the area within the solar polygons within the Loa Zone currently contains active prairie dog colonies, and 11% of the area within the wind polygons within the Loa Zone currently contains active prairie dog colonies. It is also notable that 16% of the area within the solar polygons within the Johns Valley Zone currently contains active prairie dog colonies. Utah prairie dogs, like all prairie dogs, rely on unimpacted soils in which to dig their extensive burrow systems. Wind and solar energy development on top of prairie dog towns would destroy colonies, just like other ground disturbing activities do.

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[6] Becker, J.M. J.D Tagstad, C. A. Duberstein, and J. L. Downs. 2009. Sage grouse and wind energy: biology, habits and potential effects of development. Prepared for the U.S. Department of Energy by Pacific Northwest National Laboratory.

[7] Holloran MJ. 2005. Greater Sage-Grouse *(Centrocercus urophasianus)* Population Response to Natural Gas Field Development in Western Wyoming. Doctoral dissertation, Department of Zoology and Physiology, University of Wyoming, Laramie

Again, we bring up these matters regarding potential future conflicts with certain critically important Utah wildlife to recommend that the state, in conjunction with renewable energy developers, do their best to avoid these biologically important places when it eventually comes time to site large scale renewable energy projects. Obviously, when it is time to determine exact locations of where to site new renewable facilities, detailed on-the-ground analysis, including surveys and Utah Division of Wildlife records of sensitive species known or suspected to occur in the proposed facility locations, will have to be conducted.

A note on public lands renewable energy siting

The focus for UREZ phases 1 and 2 so far seems to give disproportionate attention to utility scale, centralized generation on public lands over centralized and dispersed generation in the built environment. This in turn raises the issue of whether there are economic advantages that accrue to wind and solar power providers when they locate their facilities on public rather than private lands. We have yet to find economic research that fully answers this question. But based on a few preliminary phone calls to county assessors, BLM realty staff, and the state property tax commission, it seems that BLM lands have a lower operating cost for wind generation over private lands. The costs for leasing and property taxes for the Spanish Fork Wind Project, for example, appear to be about three times the cost compared to BLM lands. These rates and fees should be open to discussion, since it would seem that they can potentially shape the preferred decision on where to ultimately site new wind developments.

Opportunities for renewable energy development on previously disturbed land, and the built environment

We encourage the UREZ task force to encourage opportunities to site renewable energy projects on previously disturbed land, such as abandoned or unproductive agricultural lands and brownfield sites. Siting projects on such lands avoids impacts to undisturbed lands, may reduce the need for new transmission capability, and can provide community benefits including cleanup of contaminated sites and economic development opportunities.

The Environmental Protection Agency, partnering with the National Renewable Energy Laboratory, has developed significant information on potential brownfields re-development as part of their "RE-Powering America's Lands" initiative[8]. Several states already boast success stories for such development, such as a PV array on a landfill at Fort Carson in Colorado and a wind farm on an old steel mill in Lackawanna, New York. We recommend that as the UREZ Task Force moves forward, that you contact EPA to learn more about how these opportunities can be incorporated into the future UREZ planning.

[8] http://www.epa.gov/oswercpa/

On a final note, as we move forward from the Phase 2 UREZ initiative, we should recognize that social and economic policies will largely shape just how much renewable power comes from the built environment. Utah already has some excellent incentives for businesses and residences to install roof top systems. We hope Utah will amplify efforts to site additional renewable energy efforts in the built environment. It seems to make sense for the UREZ Task Force to begin studying the economics of renewable energy both in open space and in the built environment and considering the subsidies and policy changes that might shape these efforts. Having such information will help the state make an even more informed decision on the future of renewable energy.

Thank you again for inviting and considering these comments. We wish to once again commend the Phase 2 Task Force, and Black and Veatch for a job very well done.

Sincerely,

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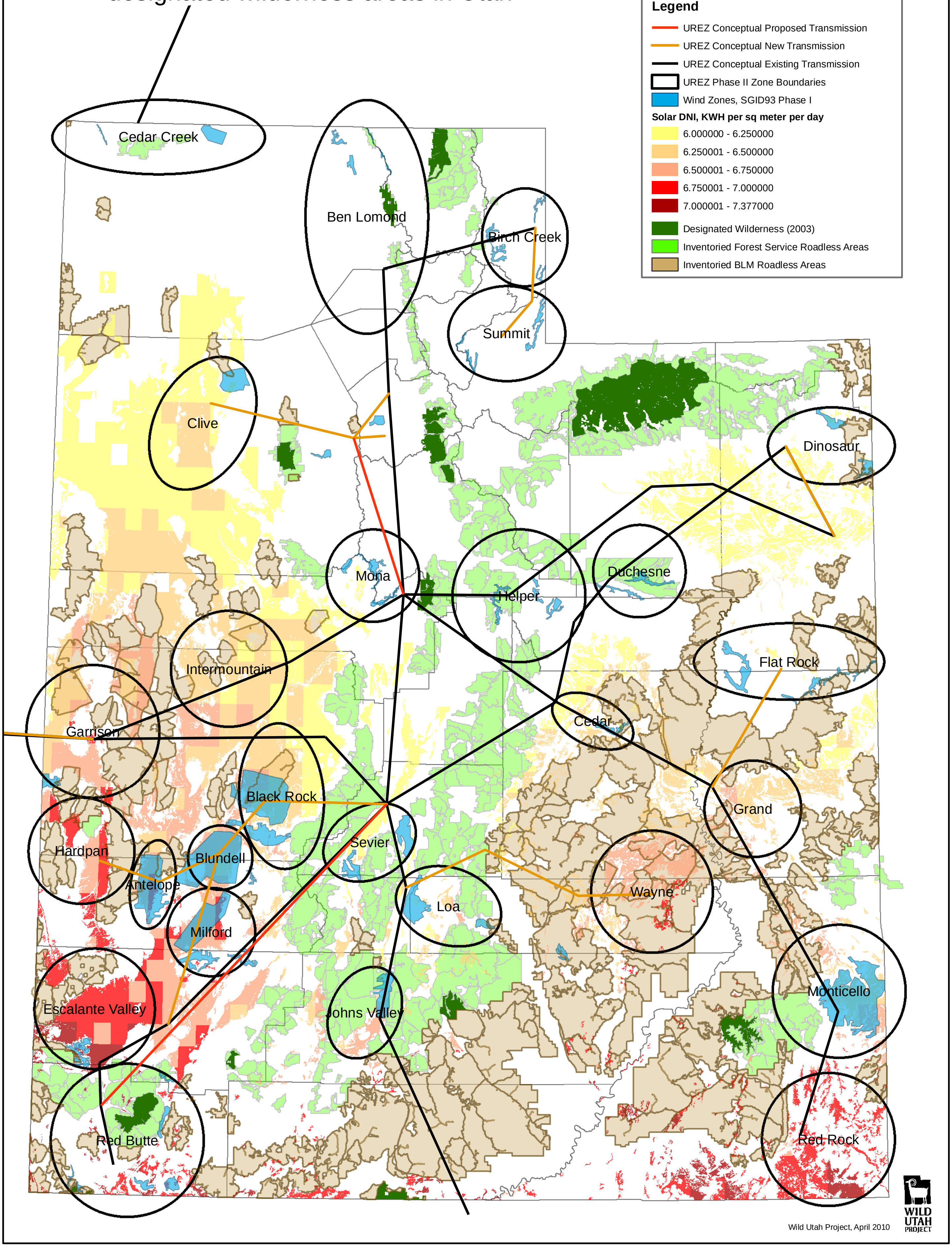
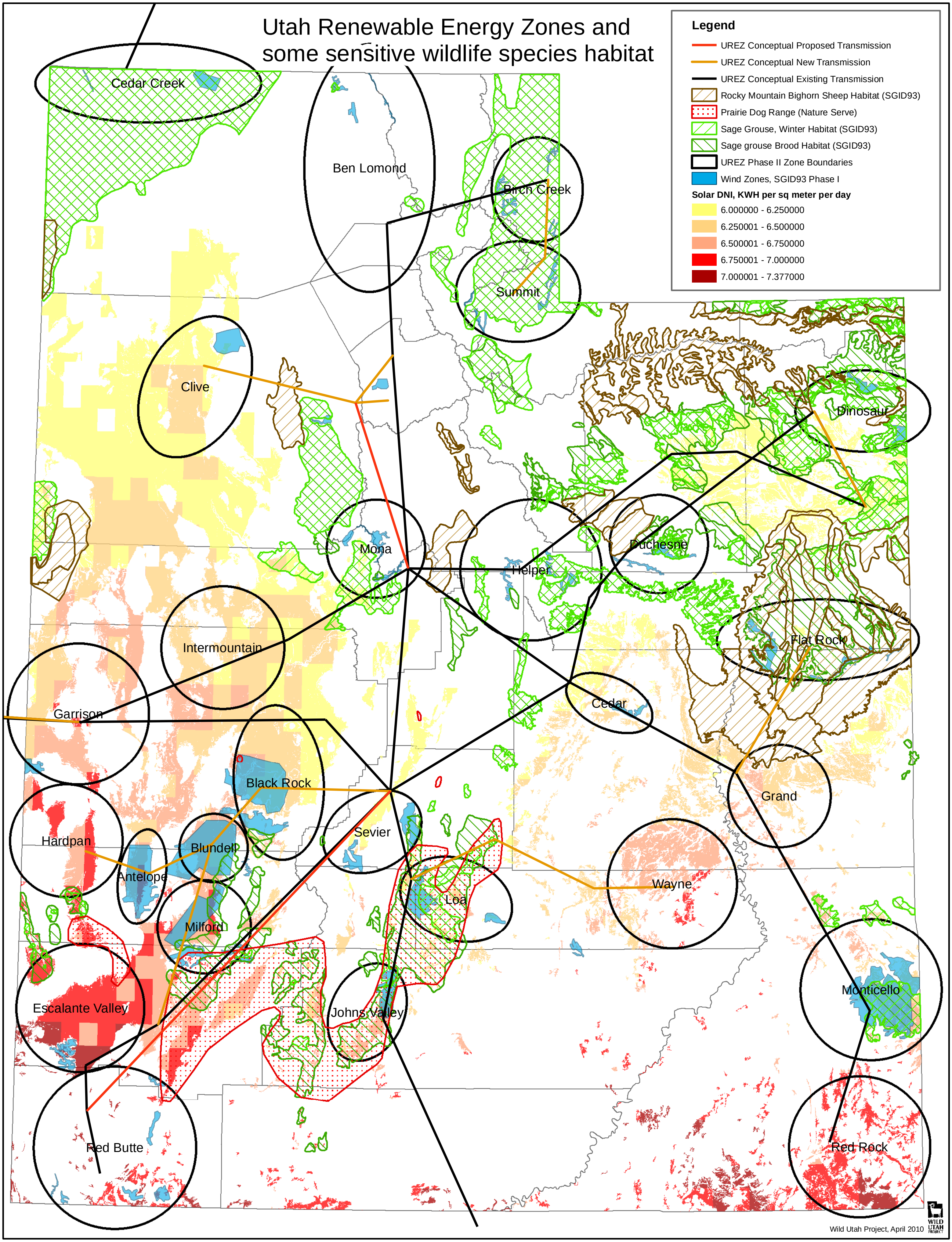
Utah Renewable Energy Zones and inventoried roadless areas and designated wilderness areas in Utah



Wild Utah Project, April 2010


Utah Renewable Energy Zones and some sensitive wildlife species habitat
Legend
UREZ Conceptual Proposed Transmission
UREZ Conceptual New Transmission
UREZ Conceptual Existing Transmission
Rocky Mountain Bighorn Sheep Habitat (SGID93)
Prairie Dog Range (Nature Serve)
Sage Grouse, Winter Habitat (SGID93)
Sage grouse Brood Habitat (SGID93)
UREZ Phase II Zone Boundaries
Wind Zones, SGID93 Phase I
Solar DNI, KWH per sq meter per day
6.000000 - 6.250000
6.250001 - 6.500000
6.500001 - 6.750000
6.750001 - 7.000000
7.000001 - 7.377000
Cedar Creek
Ben Lomond
Birch Creek
Summit
Clive
Dinosaur
Mona
Helper
Duchesne
Intermountain
Flat Rock
Garrison
Cedar
Black Rock
Grand
Sevier
Hardpan
Blundell
Antelope
Wayne
Loa
Milford
Monticello
Escalante Valley
Johns Valley
Red Butte
Red Rock
Wild Utah Project, April 2010
WILD UTAH PROJECT