ENERGY STRATEGIES

UTAH TRANSMISSION STUDY:

A Study of the Options and Benefits to Unlocking Utah's Resource Potential

January 21, 2021

Prepared by Energy Strategies for the Utah Office of Energy Development

TECHNICAL REPORT

Utah Transmission Study
Technical Report
January 21, 2021

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About the Study and this Report

During the 2019 Utah Legislative Session, Senate Bill 3 allocated funds for an analysis of the Utah electrical transmission grid. A Transmission Working Group (TWG), guided by the Utah Governor's Office of Energy Development (Utah GOED), was formed to provide input and help guide the study process. The Utah GOED released a request for proposal in the spring of 2020 with the goal of engaging a contractor to analyze and report on the Utah transmission system. The goal of the study was to identify transmission constraints to accessing Utah's resource potential and to provide options to address them.

Energy Strategies was selected to perform the Utah Transmission Study, providing interim deliverables to the TWG. A summary of the study results, methods, and assumptions are presented in this technical report. This report and a web-based Executive Summary can be accessed through the Utah OED website via the following URL:

https://energy.utah.gov/energy-information/utah-transmission-study/

This report is intended for policymakers and energy industry professionals. It contains some technical information that requires knowledge of transmission planning concepts and terms.

Energy Strategies thanks the members of the TWG and the Utah GOED for their support in completing the study. In addition, Energy Strategies appreciated the data, models, and coordination provided by PacifiCorp.

Disclaimers

This publication was prepared based on Energy Strategies' independent study work sponsored by the Utah OED and is provided as is with no guarantees of accuracy. There are no warranties or guarantees, express or implied, relating to this work, and neither Energy Strategies nor the Utah OED are liable for any damages of any kind attributable to the use of this report or other study materials.

The report does not represent the views of the Utah GOED, TWG members, or their employees. The study was not designed to replace or supplant mandated transmission planning or interconnection processes, including those regulated by the Federal Regulatory Energy Commission (FERC) that are performed at the local, regional, or interregional level by transmission owners in Utah. It also does not replace or supplant resource planning performed under various jurisdictions, such as those efforts conducted as a part of PacifiCorp's of integrated resource planning. This work is informational and does not represent a plan to construct specific power infrastructure facilities.

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1.0 INTRODUCTION

1.1 Utah's Grid

Utah's abundant natural resources drive a thriving state-wide energy economy. Centrally located in western electricity markets, and with historic investments in a wide range of energy-producing technologies, Utah has set a precedent as one of the West's most fuel diverse and resource rich energy producers. Recent investments in renewable resources such as solar and wind energy, as well as energy storage, are changing Utah's resource mix. Unlocking opportunities for continued investment in a broad suite of generation and storage technologies will leave Utah well positioned to compete in Western electricity markets while also providing its customers with low-cost and reliable power.

As new electric generation resources are developed throughout the state, Utah's transmission grid must expand and adapt. Key transmission corridors approaching flow limits will require upgrades as the result of a changing electricity landscape.

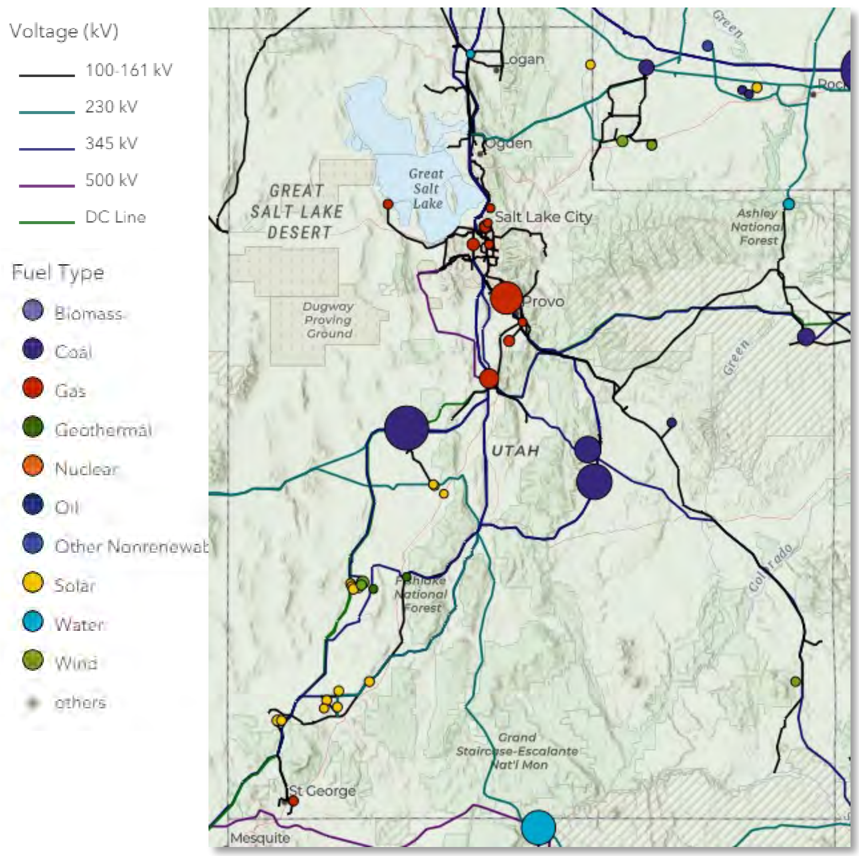

Figure 1: Generation Resources and High Voltage Transmission in Utah

Utah's transmission grid delivers electric power from generation resources to the state's urban and industrial centers. Of Utah's 31 TWh of annual energy consumption, a vast majority of Utah electricity is consumed in a region along the Wasatch Front known as the "PacifiCorp East (PACE) load center". The PACE load center primarily encompasses Salt Lake, Utah, Davis, and Weber counties and accounts for over 75% of the state's population.

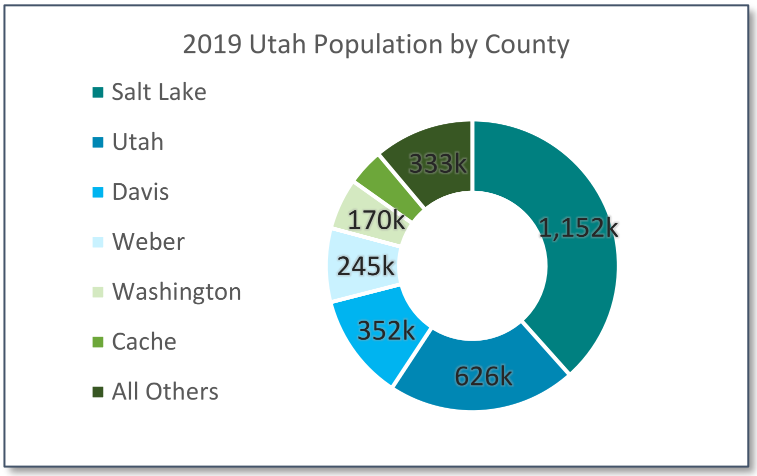

Figure 2: Population of Utah Counties

Apart from flows along inter-state transmission corridors, power on the Utah grid generally flows from the state's generation resources toward the PACE load center. Utah's grid has been designed around a north-south transmission backbone that helps power flow into the load center from generation resources located primarily in the Central and Southern portion of the state.

> ***Much of Utah's generation fleet is located outside of load centers, requiring transmission along a common north-to-south backbone to deliver electricity to Utah's communities and industries.***

Utah's in-state resource mix is currently dominated by coal and gas-fired thermal generation. However, the PacifiCorp generation interconnection queue[1] indicates that there is commercial interest in the development of gigawatts of in-state solar, wind, and storage projects seeking to come online in the

Table 1: Largest Power Plants in Utah

Power Plant	Fuel Type	Capacity (MW)
Intermountain	Coal	1,800
Hunter	Coal	1,361
Lake Side Power	Gas	1,210
Huntington	Coal	909
Currant Creek	Gas	555

[1] A (generally) federally-regulated application process through which generation plant developers apply for and obtain interconnection to the transmission grid.

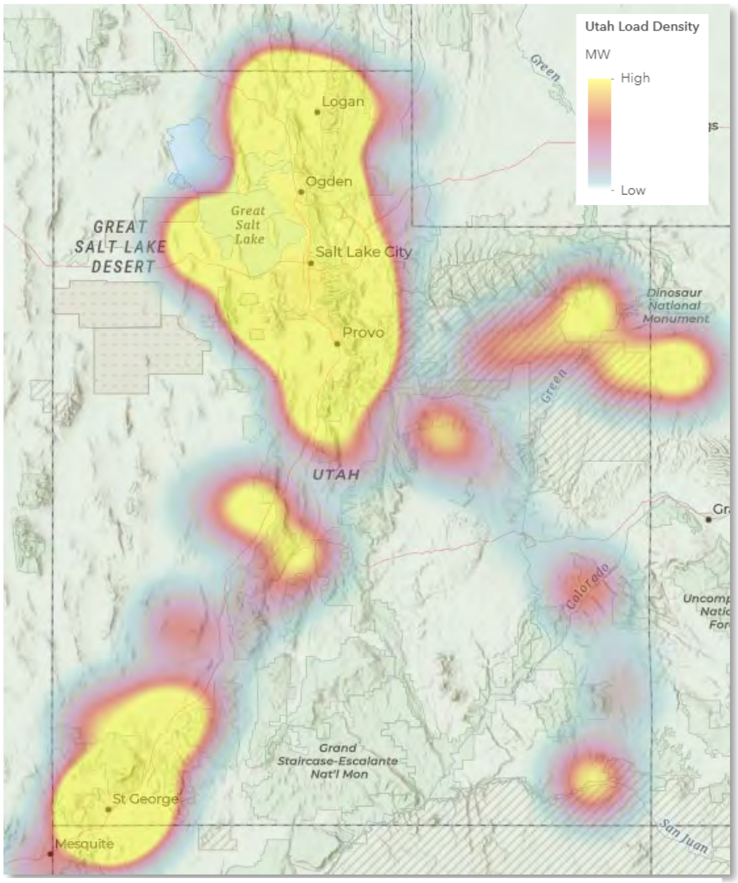

Figure 3: Heatmap of Utah Loads

next 5-10 years. If built, this capacity will likely cause additional stress on Utah's transmission backbone.

Centrally located in the West, Utah has strong inter-state transmission connections with Wyoming, Arizona, Nevada, Idaho, and California.[2] Though many of these connections are used by Utah to import and export power from/to neighboring states, changing market conditions and grid investment outside of Utah could change flows on the Utah transmission system.[3]

1.2 Utah Transmission Study

In 2019, the Utah State Legislature identified the need to assess Utah's transmission grid to identify potential constraints limiting access to Utah's in-state energy resources. A stakeholder-based Transmission Working Group (TWG), guided by the Utah Governor's Office of Energy Development (Utah GOED), was formed to solicit and guide the study.

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[2] The connection with California is achieved by WECC Path 27 – a high voltage DC transmission line routed through Nevada.

[3] https://westernenergyboard.org/wp-content/uploads/2019/12/12-10-19-ES-WIEB-Western-Flexibility-Assessment-Final-Report.pdf

In early 2020, Energy Strategies – a Salt Lake City-based energy consultancy – was selected as the contractor to perform the analysis through a competitive RFP process. The study, which utilized publicly available data and utility-grade modeling tools, had the following goals:

1. Identify transmission constraints that limit access to Utah's energy resource potential;
2. Provide strategies to address such constraints; and
3. Consider the costs, economic impact, and technical feasibility of the identified strategies.

This report presents the methodology, results, and key findings of the Utah Transmission Study.

1.3 Report Organization

The report is organized into sections, as follows:

- **2.0 Analytical Approach** summarizes the five-step study method, models and data sources used to perform the Utah Transmission Study.
- **3.0 Inventory of Utah's Grid** outlines the transmission infrastructure that exists today, how it is used, and what plans are already in place to expand the grid.
- **4.0 Future Transmission Needs** assesses demands on the Utah Transmission grid to accommodate generation resources in the near-term (5-years), medium-term (10-years), and long-term (20-years). Resource scenarios developed around these time frames reflect a range of future outcomes forecasting the capacity of generation builds that the Utah grid may need to accommodate.
- **5.0 Transmission Constraints** identifies bottlenecks on the Utah transmission system resulting from forecasted resource scenarios.
- **6.0 Grid Solutions** identifies grid infrastructure upgrades required to unlock Utah's in-state resource potential.

- **7.0 Economic Benefits to Utah** quantifies economic benefits resulting from grid infrastructure solutions.
- **8.0 Findings and Observations** addresses the goals of this study, highlighting the most critical takeaways while adding important context to the results.
- **9.0 Technical Appendix** captures technical details not included in the body of the report.

2.0 ANALYTICAL APPROACH

Energy Strategies performed the Utah Transmission Study by following a five-step approach:

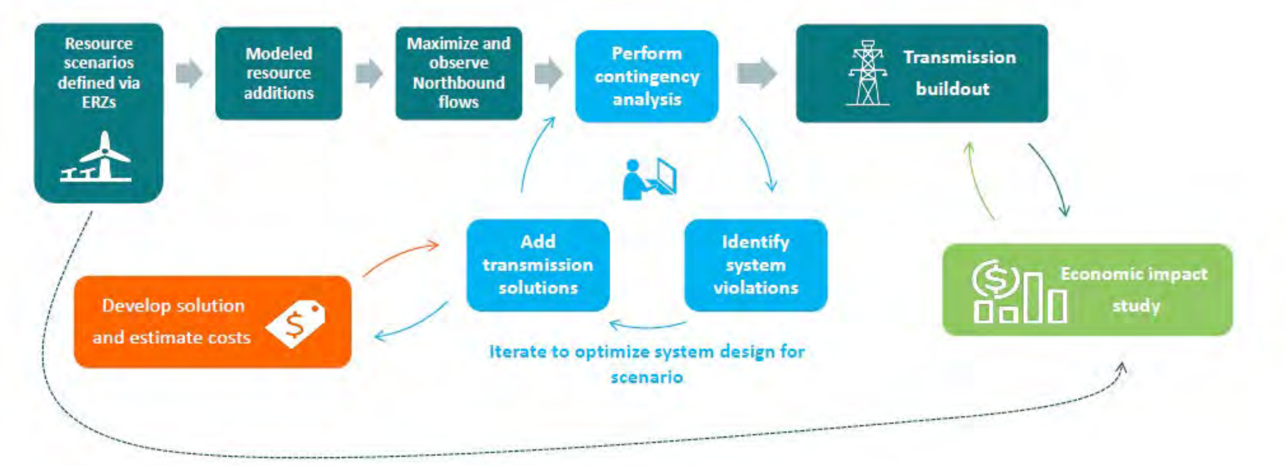
Figure 4: Energy Strategies' Analytical Approach for the Utah Transmission Study

First, Energy Strategies gathered data to explore the current and near-future state of Utah's transmission system to provide context for the remainder of the study. Geospatial and structured data were compiled, defined, and are summarized in this report via a series of maps and data tables.

Second, Energy Strategies developed and defined a set of resource scenarios ("scenarios") and "Energy Resource Zones" ("ERZs") to support the transmission evaluation. Three scenarios – base, mid, and high-development – were created to reflect a wide-range of potential resource development outcomes, capturing the uncertain nature of future demand of the Utah grid. Scenarios were developed for the 5-, 10-, and 20-year forward-looking horizon. The ERZs were informed by data from utility resource plans, commercial interest from generation developers, and resource quality data (such as solar and wind production potential). The ERZs were used to site generation in each scenario.

Third, potentially constrained transmission corridors were identified by comparing resource additions and associated transmission requirements with contractually Available Transfer Capability (ATC) on the system. Five constrained corridors on the Utah grid were identified as having the potential for future congestion and were the subject of further investigation.

Figure 5: Summary of Study Process to Identify Transmission Solutions



Fourth, Energy Strategies performed independent modeling of the resource scenarios using a power system reliability model to identify upgrades that add transmission capacity sufficient to deliver the resources to Utah loads. A high-level cost analysis of the potential solutions informed the grid buildout. In addition, an economic impact assessment was performed to demonstrate how investment in Utah transmission and generation could impact the state's economy.

The results of this analysis helped to inform the study's findings regarding constrained areas, potential transmission solutions, and resulting economic development impacts for Utah.

2.1 Technical Methods

The study methods outlined above required several technical analyses. These analyses are briefly summarized below:

- **Power system modeling –** Energy Strategies used models that simulate grid reliability to identify grid solutions that helped to relieve constrained corridors and improve access to new generation resources. PacifiCorp, which owns and operates most of the transmission in Utah, coordinated with Energy Strategies and provided a starting-point study model that was tailored to accomplish the goals of the study. Energy Strategies used this model to test potential transmission solutions and evaluate system performance.

Details on the study cases and power system modeling methods are outlined in *6.0 Grid Solutions*.

- **Line routing and cost estimates –** Energy Strategies estimated capital costs of resource and transmission additions considered in the study. This analysis was used to help consider tradeoffs between transmission investments and to inform the economic impact assessment described below. All cost data in the report are provided in 2018 dollars.

  Generation cost estimates were based on NREL's 2020 Annual Technology Baseline (ATB) report[4], which is updated annually and is one of the premier sources of cost estimates for a wide range of generation technologies. The cost estimates represent the "overnight" construction costs to build the generation and do not include ongoing operational or maintenance costs. The capital costs of future resources added in the scenarios were based on future costs that are consistent with a moderate level of technological improvement in which research and development spending continues at current levels and no technological breakthroughs occur.

  To estimate the cost of potential transmission upgrades, Energy Strategies used the WECC Environmental Data Viewer[5], which is a GIS-based line routing tool that allows the user to develop preliminary transmission routes by avoiding high-cost and high-environmental risk areas. The resulting routes and associated line-miles were costed out using the WECC Transmission Capital Cost Tool.[6] The transmission capital cost analysis takes into account per mile line costs (by voltage and conductor type), right-of-way cost estimates by land classification, substation cost by voltage and bus design, and overhead line configuration.[7] The study did not include a detailed assessment of the ability to

[4] https://www.nrel.gov/news/program/2020/2020-annual-technology-baseline-electricity-data-now-available.html

[5] https://ecosystems.azurewebsites.net/WECC/Environmental/

[6] https://www.wecc.org/Administrative/TEPPC_TransCapCostCalculator_E3_2019_Update.xlsx

[7] Costs also include allowance of funds used during construction (AFUDC). The cost analysis assumed a new line position/bay was required for new transmission lines or transformers, and that right-of-way costs were consistent with BLM Cost Zone 4. The study assumed desert/barren land and lattice tower construction for new transmission lines.

expand versus use existing rights-of-way, nor did it include detailed studies of substation or lower-voltage transmission equipment, the upgrading of which would be an incremental cost not captured in this analysis. The study also does not include detailed analysis of individual generator interconnections and therefore may understate total transmission upgrade costs.

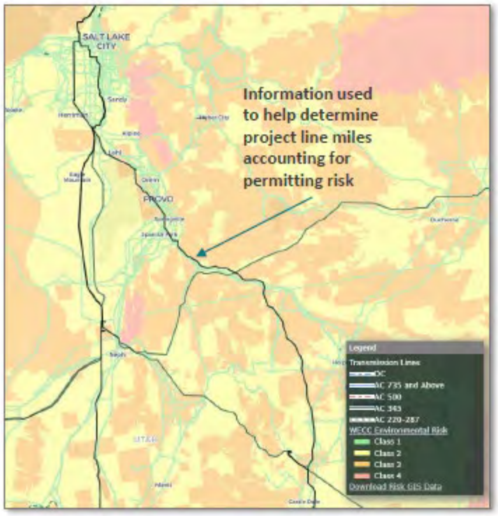


Figure 6: WECC Transmission Routing Tool

The costing analysis for generation and transmission was performed as an exploratory-level analysis and is not based on contractor quotes or detailed estimates for specific projects. As a result, the costs contained herein should be assumed to have a margin of error of at least +/- 30-40%, consistent with industry practice for early-stage costing studies.

A summary of the cost assumptions for generation technologies and transmission can be found in Appendix *9.1 Generation and Transmission Costs*.

- **Economic impact analysis –** One of the goals of the study was to estimate the economic development impacts of the resource scenarios and transmission solutions. To accomplish this, a Utah-specific version of the IMPLAN economic input/output tool was populated with information from NREL's JEDI models and third parties. The IMPLAN model, which represents over 500 sectors and is one of the most widely used commercial economic input/output models, was used to estimate the impacts of energy investment and operations on Utah employment, state economic activity, and tax revenue.

  The economic impact analysis considers direct, indirect, and induced economic development in the state required to support the level of energy development envisioned in the scenarios. It considered potential labor and investment "leakage" into other states or regions, adjusting this parameter based on the physical location of the generation and transmission additions. Sector-specific analysis within the model was based on complex relationship that are represented via multipliers, local purchase percentages, and other factors that allow it to capture spending and industry-to-industry effects. The analysis was performed for both the construction (temporary) and operational (permanent) impact periods for generation and transmission investment.

Results from the economic impact analysis can be found in *7.0 Economic Benefits to Utah*. Further details regarding the assumptions and methods used to perform the analysis are provided in the Appendix *9.2 Economic Impact Assessment*.

2.2 Study Scope and Footprint

This report focuses on the in-state transmission solutions required to meet in-state resource development. While many of Utah's transmission corridors connect with neighboring states' transmission systems, the focus of this study included only in-state resource development, transmission solutions, and economic benefits to the State of Utah. Out-of-state resource impacts and an evaluation of opportunities to export Utah generation to neighboring states was not included in the scope.

3.0 INVENTORY OF UTAH'S GRID

The study included a data driven inventory of the Utah transmission system as it exists today. This inventory establishes the framework of the study and supports the subsequent analyses of transmission constraints, potential resource scenarios, and the effectiveness of various transmission solutions. Results include maps and charts to illustrate the Utah transmission infrastructure that exists today, how it is used, and what plans are in place to expand the grid.

The information listed below was utilized to inventory the Utah grid.

Table 2: Information Used in Grid Inventory

Data	Source	Description
Existing Transmission	Homeland Infrastructure Foundation Level Data and other 3rd Party Vendors	GIS layer of all existing Utah transmission including metadata on paths
Planned Transmission	PacifiCorp Transmission Plans & WECC Annual Progress Reports	All confirmed transmission builds
Proposed Transmission	PacifiCorp Transmission Plans & WECC Annual Progress Reports	Un-confirmed/contracted transmission builds
Load	WECC 2021 HS Powerflow Case	Load buses across Utah expressed in terms of geographic density weighted by load
Generation Resources	S&P Global Market Intelligence	In Utah, classified by resource type, nameplate capacity >20 MW, includes ownership

3.1 Utah's Grid Today

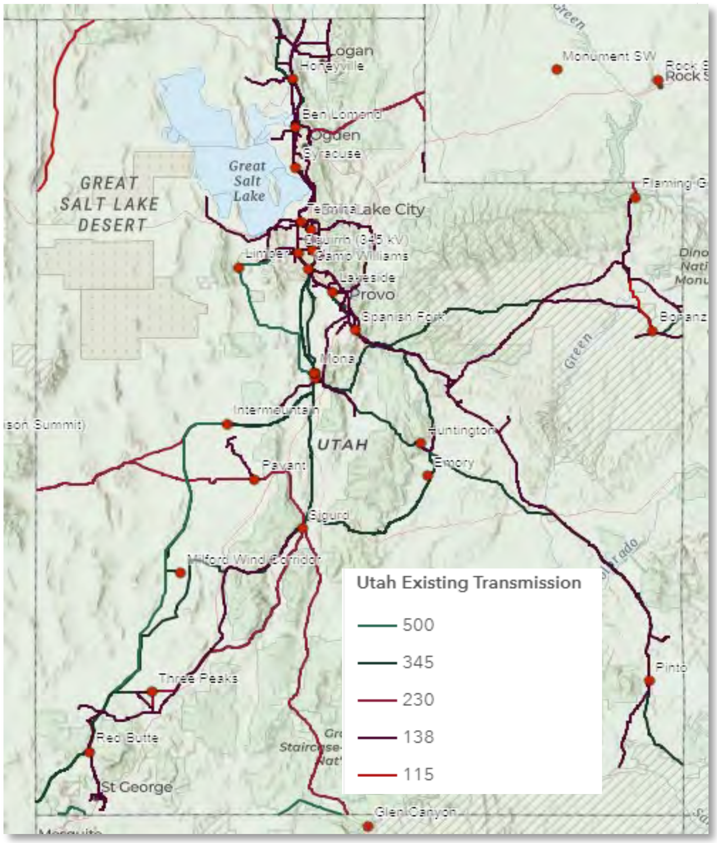


Figure 7: Existing Transmission in Utah

Utah's grid delivers safe and reliable electric power to millions of residents and hundreds of thousands of businesses, industrial customers, and institutions. PacifiCorp owns and operates the majority of the transmission system and distribution system in the state, with more than 7,000 miles of lines in operation today. Other major transmission owners in Utah include the Intermountain Power Agency – which owns the HVDC line between Intermountain Power Plant (IPP) and Los Angeles, Western Area Power Administration – which owns transmission that delivers federal hydro projects in and around the state of Utah (most notably Glen Canyon Dam), and Deseret Power Electric Coop – which is the primary owner of a 345 kV line between Bonanza power plant in Eastern Utah and Mona, as well as a few other line-miles connecting communities in East Utah.

The Utah high-voltage system (>100 kV) consists mainly of 345 kV and contains almost as many line-miles of 100 – 161 kV. Major high-voltage substations are concentrated along the Wasatch Front but are also spread across the state at key transmission connections.

Northern Utah Grid

The transmission system in Northern Utah connects to PacifiCorp's Idaho and Wyoming assets, and provides ties to Idaho Power's system. Power flows in this area often flow from Wyoming into the PACE load center as Wyoming is a major power exporter. The Ben Lomond substation acts as the main aggregation point in Northern Utah, combining imports from Wyoming and Idaho, and delivering them to Utah's load centers along the Wasatch Front. The Terminal substation, northwest of Salt Lake City, is the major point through which electricity is delivered into Utah's largest urban load center.

Figure 8: Power Grid in Northern Utah

PACE (PacifiCorp East) Load Center & Wasatch Front South Cutplane

Substations and lines within the PACE load center distribute power to Wasatch Front communities. Major substations within the PACE load center include Terminal, Midvalley, Camp Williams, and 90th South substations – though new substations have been developed in recent years. The grid extends westward into the West Desert, and eastward across the Wasatch Range to access hydroelectric power from seasonal snowmelt. Along Utah Lake, Lakeside gas-fired power plant (1,210 MW) provides reliable power for much of the Wasatch Front range. The grid extends southward from the PACE load center along two major corridors on either side of Utah Lake. On the west side, Camp Williams connects to the Mona & Clover substations. On the east side of Utah Lake, the transmission grid travels through Utah County communities, and aggregates into the Spanish Fork substation. Flows in this area of the grid typically flow south-to-north during stressed conditions to deliver power from Central and Southern Utah to Wasatch Front and Northern Utah communities. This “pinch point” is known as the Wasatch Front South cutplane.

Mona & Central Utah

Mona is the state’s most central substation -- interconnecting transmission owned by PacifiCorp, Deseret G&T, and Los Angeles Department of Water & Power (LADWP). Mona helps to interconnect the Intermountain Power Plant located at Delta, Utah and the HVDC line between PACE and LADWP.

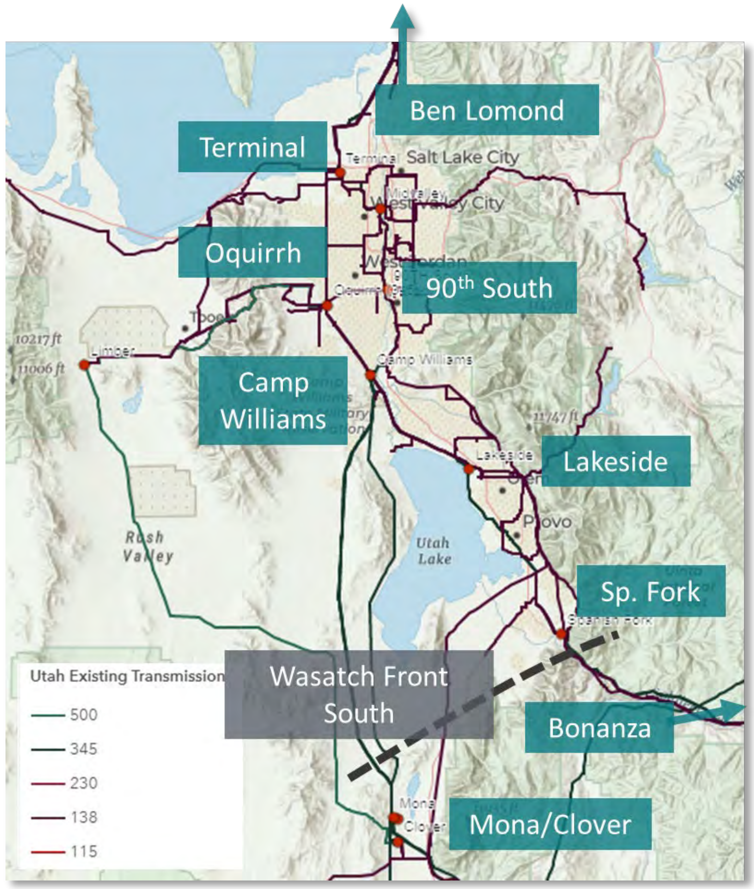
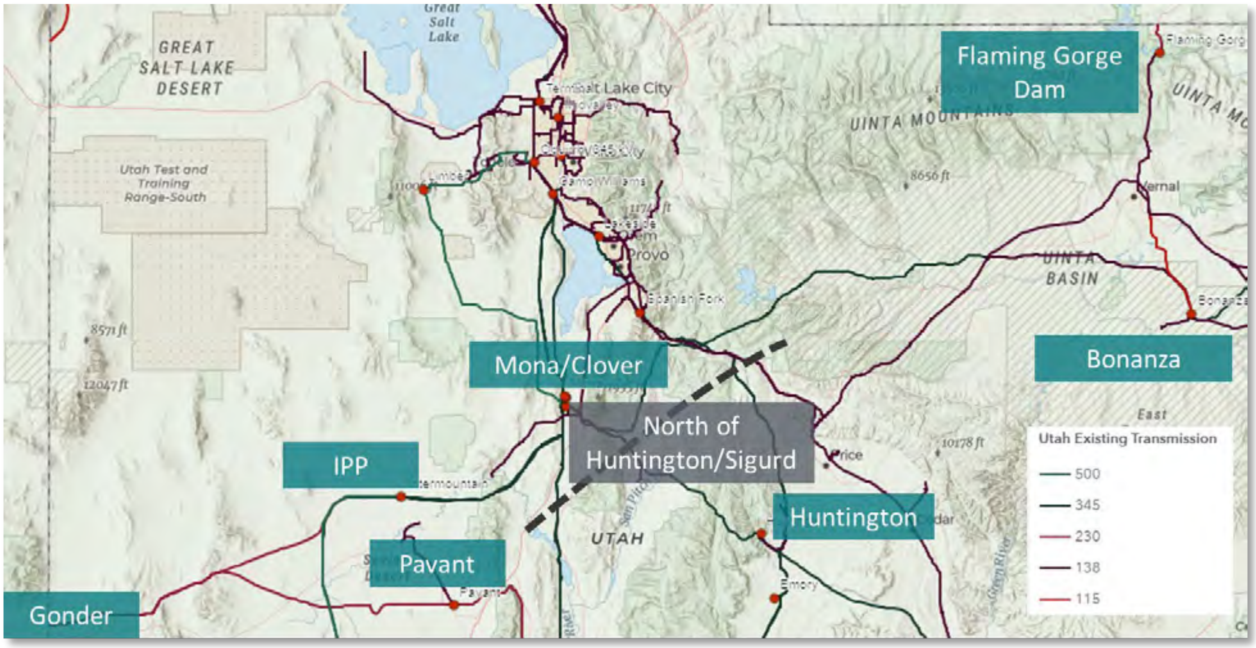


Figure 9: PACE Load Center and Wasatch Front South (WFS) Cutplane

Bonanza represents a major substation for power transfer between Utah and Colorado. The major transmission line between Bonanza and Mona is owned by Deseret G&T. Deseret G&T’s transmission system primarily delivers power from the Bonanza Coal Power Plant to Mona, but also has lower voltage transmission to Vernal and other communities in East Utah. Flaming Gorge Dam is also connected to the Utah grid in the Northeastern part of Utah.

Further west of the Intermountain substation is the Gonder-Pavant line, which helps to import or export power with the Nevada Energy system. Interconnection with Nevada’s transmission system is also achieved through the TOT-2C path which is built through Southwestern Utah.

Figure 10: Central Utah Transmission Grid



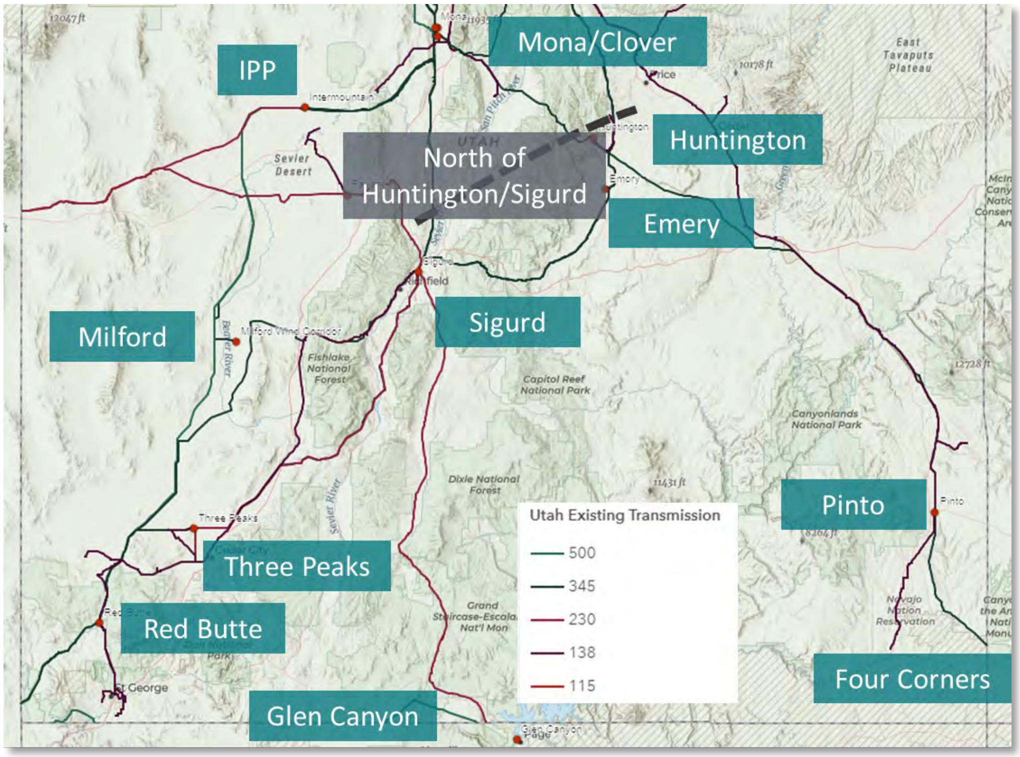
Southern Utah and North of Huntington/Sigurd Cutplane

In general, power generated in Southern Utah must travel through one of two paths to reach the PACE load center. First, the Sigurd substation in Central Utah "aggregates" flows from the south and west and helps to deliver this power north to Mona and into the PACE load center. Second, power may flow further east through the Emery and Huntington substations, and from there, either over to Mona substation, or more directly north to the Spanish Fork substation. This "pinch point" of the grid is known as the North of Huntington/Sigurd cutplane. For a full list of the transmission lines included in the Wasatch Front South (WFS) and North of Huntington/Sigurd Cutplanes, see Section 9.5 in the Technical Appendix.

South of these points, there are three primary paths connecting Central Utah to high solar resource quality in Southern Utah: a 345 kV transmission corridor to Red Butte near St. George (TOT 2C), a 230 kV line connecting Sigurd to Glen Canyon (TOT 2B2), and a 345 kV line connecting the Four Corners region to the PACE load center via the Pinto substation (TOT 2B1).

Both TOT 2C and TOT 2B2 typically delivers power north through the Sigurd substation (although flows can occur southbound during certain times of year and grid conditions). A vast majority of power flows from the Four Corners region must flow through Huntington, Mona, or Spanish Fork substations.

Figure 11: Southern Utah Transmission Grid



3.2 Summary of Planned Transmission Projects

The following projects are considered "planned" for purposes of this study. These projects were identified via a review of local transmission plans and Western Electricity Coordinating Council (WECC) progress reports submitted by Utah transmission owners. The subsequent evaluation of potential grid constraints and solutions in Utah was based on a system that assumes these upgrades are constructed. The list includes only those Utah projects planned to be in-service prior to the end of 2025 as longer-term forecasts of transmission additions can be highly uncertain.

Table 3: Planned Transmission Upgrades in Utah

Project	Owner	In-service	Miles
Camp Williams - Oquirrh 345 kV Rebuild	PacifiCorp	5/15/2025	8.3
Gateway Central: Oquirrh - Terminal 345 kV #3 & #4 Double Circuit Line	PacifiCorp	5/31/2024	14.5
Camp Williams 345 kV Transformer and 138 kV Yard Additions	PacifiCorp	5/15/2024	N/A
Harvest 138 kV Substation	PacifiCorp	5/15/2025	N/A
Path C Transmission Improvements	PacifiCorp	5/15/2024	Various
Nibley 138 kV transformer and Nibley - Hyrum City Rebuild	PacifiCorp	5/15/2022	N/A
Central Utah High Voltage Mitigation	PacifiCorp	5/15/2022	N/A
Gateway South	PacifiCorp	5/15/2024	422

3.3 Proposed Transmission Upgrades by Third Parties

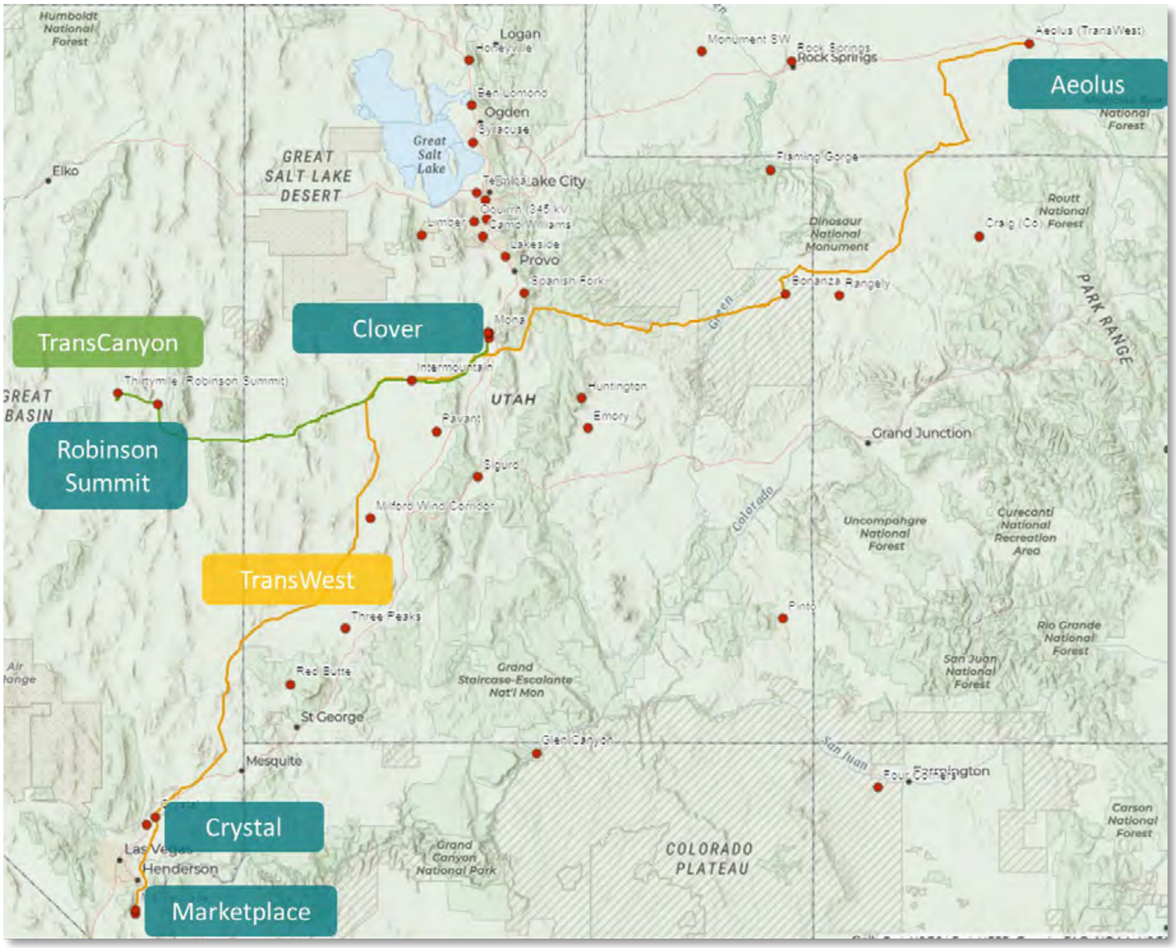
These projects are under development by independent transmission developers and were only considered as candidate solutions to the extent they resolved identified constraints.

The TransWest Express (TWE) Transmission Project consists of three segments that, when considered together, will connect Wyoming, Utah, and southern Nevada. The project includes:

1. A 405-mile, bi-directional 3,000 MW, ±500 kV, high voltage direct current (HVDC) transmission system with terminals in south-central Wyoming and central Utah (the WY-IPP DC Project)
2. A 278-mile 1,500 MW 500 kV alternating current (AC) transmission line with terminals in central Utah and southeastern Nevada (the IPP-Crystal 500 kV AC Project)
3. A 50-mile, 1,680 MW 500 kV AC transmission line with terminals in southeastern Nevada and southwestern Nevada (the Crystal-Eldorado 500 kV AC Project)

TransCanyon is developing the 213-mile Cross-Tie Transmission Project, a proposed 1500 MW, 500 kV single circuit HVAC transmission project that will connect central Utah and east-central Nevada. The project will connect PacifiCorp's planned 500 kV Clover substation with NV Energy's existing 500 kV Robinson Summit substation.

Figure 12: Proposed Inter-state Transmission Upgrades: Cross-Tie and TransWest Express



4.0 FUTURE TRANSMISSION NEEDS

Future transmission needs for the Utah system were based on forecasted amounts of in-state resource additions in the near-term (5-years), medium-term (10-years), and long-term (20-years). The approach:

1) Approximates cumulative in-state resource additions, by technology type, that may occur in the future (called "Resource Scenarios" or "scenarios"); and
2) Approximates the location where resource additions are likely to take place (known as "Energy Resource Zones" or "ERZs").

The combination of these analyses provided Energy Strategies with a representation of potential future resource additions that were used to estimate future demands on the Utah grid.

Key data sources used to inform potential transmission needs include integrated resource plans from Utah utilities, the PacifiCorp interconnection queue, and renewable resource quality data sourced from NREL.

4.1 Resource Scenarios

Resource scenarios represent plausible future buildouts of generation resources in Utah.[8] Since PacifiCorp serves the majority of load in Utah, its 2019 Integrated Resource Plan (IRP) was used as the primary source of information in developing the scenarios. Energy Strategies

[8] Out-of-state resource additions were not analyzed as part of this study but are likely to impact transmission availability in the study timeframe.

complemented the IRP data with assumptions regarding achievement of municipal and county renewable energy goals (e.g., Salt Lake City, Summit County, Moab), and the potential need to serve other utility loads with new resources located in Utah due to load growth.

The three scenarios (Base, Mid, and High) represent a range of future scenarios for in-state resource development. The basis for the scenarios is described below:

- **Base Scenario –** Aligns with PacifiCorp's 2019 IRP Preferred Portfolio resource forecast. Incremental additions of solar, wind, battery, and solar + battery in Utah from 2021-2038 from the IRP were included in this scenario. In addition, 50% of the incremental gas resources planned for PacifiCorp East from 2021-2038 were included in Utah. The Base Scenario also assumed that city and county renewable goals are achieved and minor additions by other municipalities occur.

- **Mid Scenario –** The scenario was created using data from PacifiCorp's 2019 IRP Acquisition Path Analysis, which describes how changes in planning environment may influence future resource procurement activities. The scenario assumed that half of the increase/decrease in resources outlined in that study occurs in PacifiCorp East. The High Customer Preference Resource Demand "trigger event" details how the preferred portfolio ("Base" portfolio in our scenarios) changes. In the scenario, the zero-to-ten-year timeframe ("Near Term Resource Acquisition Strategy") sees expanded renewable resource procurement (including battery storage) and new gas peaking capacity decreased. For the eleven-to-twenty-year timeframe ("Long-Term Resource Acquisition Strategy") the procurement of renewable resources and battery storage expanded further. The Mid Scenario also assumed expanded city and county renewable goals and included expanded in-state additions by other municipalities.

- **High Scenario –** The scenario was created by doubling the size of the incremental resource additions identified in the Mid Scenario. The High Scenario assumed a greater expansion of city and county renewable goals and included higher additions by other municipalities.

The tables below summarize the scenarios.

Table 4: Summary of Resource Scenarios

Scenario	What is represents…	Additions by 2040
Base	Preferred IRP portfolio, city/counties achieve renewable goals, minor additions by other municipalities (+5-10% of their load)	+5.4 GW
Mid	High customer preference IRP portfolio, city/counties with renewable goals expand (+5% of Base), additions by other municipalities (7.5-10% of their load)	+7.1 GW
High	2x Mid scenario IRP additions, city/counties with renewable goals expand further (+10% of Base), additions by other municipalities increase (10-20% of their load)	+9.0 GW

The scenarios are summarized by technology type and addition year below.

Table 5: Cumulative Resource Additions in Utah

Cumulative Additions in Utah (MW)				
Scenario	**Technology**	**2025**	**2030**	**2040**
Base Case	Solar + Storage	1,610	2,950	4,040
	Solar	-	-	-
	Wind	130	230	360
	Battery	30	70	330
	Gas	-	280	720
	Solar & Solar + Storage	1,610	2,950	4,040
	Total	**1,770**	**3,530**	**5,450**
Mid Case	Solar + Storage	1,690	3,200	4,500
	Solar	20	110	480
	Wind	150	350	600
	Battery	70	190	870
	Gas	-	190	630
	Solar & Solar + Storage	1,710	3,310	4,980
	Total	**1,930**	**4,040**	**7,080**
High Case	Solar + Storage	1,760	3,490	5,090
	Solar	30	210	430
	Wind	170	480	870
	Battery	100	310	1,460
	Gas	-	660	1,100
	Solar & Solar + Storage	1,790	3,700	5,520
	Total	**2,060**	**5,150**	**8,950**

4.2 Energy Resource Zones (ERZs)

Ten ERZs were identified in Utah to represent the geographic regions in which generation assets are likely to be developed in the study timeframe. Resources in the scenarios were allocated to the ERZs based on a combination of 1) the PacifiCorp interconnection queue (accessed in September 2020), 2) data regarding generators with Large Generator Interconnection Agreements (LGIAs) that will allow them to interconnect to the system, and 3) for wind and solar resources, areas with high resource quality. While many of the ERZs forecast development of only one resource type, some ERZs include two or more technology types (e.g., battery storage and solar developments are both likely to occur in Central Utah, according to the PacifiCorp queue).

Energy Strategies allocated resources in the scenarios to the ERZs. The cumulative addition capacities in the Base, Mid, and High resource scenarios were split according to set allocations to determine cumulative additions of each resource type at each ERZ for a given scenario.

Figure 13: Energy Resource Zones identified in the Utah Transmission Study

To develop a preliminary understanding of resource development areas in Utah, Energy Strategies leveraged PacifiCorp interconnection queue data and data regarding generators that have executed interconnection agreements. This data contained indications of point of interconnection (substation) and the county in which each prospective resource is located. Geospatial representations of the PacifiCorp queue that were used in this study can be found in Section 9.3: PacifiCorp Queue and LGIA.

Slightly different approaches were taken for each resource type based on the availability of data. These methodologies are also described in the Technical Appendix (Section 9.4).

4.3 Summary of Resource Scenarios and ERZs

The combination of the resource scenarios and ERZs are combined to provide a forecast of resource deployment for each resource type.[9]

Table 6: Solar and Solar + Storage ERZ Cumulative Resource Additions

Year	Energy Resource Zone	Cumulative Additions (MW)		
		Baseline	Mid	High
2025	Central Utah	219	233	244
	St. George	302	320	335
	Far South	97	103	107
	West Desert	116	124	129
	Northern Utah	164	174	182
	Mona	576	612	641
	Four Corners	136	145	151
	Total	**1,610**	**1,710**	**1,790**
2030	Central Utah	402	451	504
	St. George	553	620	693
	Far South	177	199	222
	West Desert	213	239	268
	Northern Utah	300	336	376
	Mona	1,056	1,185	1,325
	Four Corners	249	280	313
	Total	**2,950**	**3,310**	**3,700**
2040	Central Utah	550	678	752
	St. George	757	933	1,034
	Far South	242	299	331
	West Desert	292	360	399
	Northern Utah	410	506	561
	Mona	1,446	1,783	1,976
	Four Corners	342	421	467
	Total	**4,040**	**4,980**	**5,520**

[9] While this study distinguished between standalone solar ("Solar") and coupled "Solar + Storage" developments during analysis, they are presented as a single resource type ("Solar and Solar + Storage") in this report for conciseness.

Table 7: Wind ERZ Cumulative Resource Additions

Year	Energy Resource Zone	Cumulative Additions (MW)		
		Baseline	Mid	High
2025	Milford	65	75	85
	Southeastern UT	65	75	85
	Total	**130**	**150**	**170**
2030	Milford	115	175	240
	Southeastern UT	115	175	240
	Total	**230**	**350**	**480**
2040	Milford	180	300	435
	Southeastern UT	180	300	435
	Total	**360**	**600**	**870**

Table 8: Battery ERZ Cumulative Resource Additions

Year	Energy Resource Zone	Cumulative Additions (MW)		
		Baseline	Mid	High
2025	PACE Load Center	6	15	21
	Northern Utah	8	19	28
	Mona	10	24	34
	West Desert	5	12	17
	Total	**30**	**70**	**100**
2030	PACE Load Center	15	40	65
	Northern Utah	19	53	86
	Mona	24	65	106
	West Desert	12	32	53
	Total	**70**	**190**	**310**
2040	PACE Load Center	69	182	306
	Northern Utah	92	242	406
	Mona	113	297	499
	West Desert	56	149	250
	Total	**330**	**870**	**1,460**

All gas developments were assumed to occur in the Central Utah ERZ to represent potential conversion or replacement of coal-fired generation in that area. Geothermal generation did not have sufficient commercial activity to warrant the creation of an ERZ.

Table 9: Natural Gas ERZ Cumulative Additions

Year	Energy Resource Zone	Cumulative Additions (MW)		
		Baseline	Mid	High
2025	Central Utah	0	0	0
	Total	**0**	**0**	**0**
2030	Central Utah	280	190	660
	Total	**280**	**190**	**660**
2040	Central Utah	720	630	1,100
	Total	**720**	**630**	**1,100**

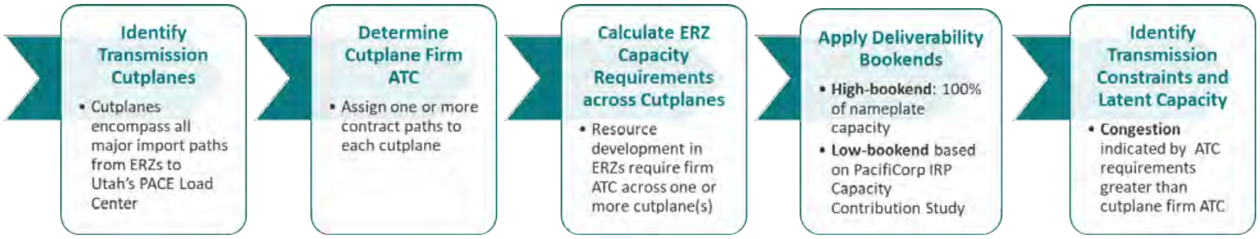
4.4 Future Transmission Needs in Utah

Based on the analysis of existing resource plans and load forecast data, the Utah transmission system may need to accommodate between 1.7 and 2 GW of new resources by 2025, between 3.5 and 5.1 GW by 2030, and 5.5 to 9 GW of new capacity by 2040. The analysis of future transmission needs assessed the grid’s ability to accommodate the Base, Mid, and High case portfolios.

5.0 TRANSMISSION CONSTRAINTS

Utilizing the scenarios presented in *4.0 Future Transmission Needs,* this analysis determined which transmission constraints may limit delivery of resources located in ERZs based on transmission availability on Utah's transmission system. As a result of this analysis, Energy Strategies identified five constrained cutplanes on the Utah grid for which to study transmission solutions.

Figure 14: Methodology for Identifying Transmission Constraints



5.1 Utah Contractual System

In the Western Interconnection, only the California ISO and Alberta Electric System Operator allow transmission to be utilized based on real-time system flows. With few exceptions, the remainder of the West, including Utah, generally manages transmission rights based on the "rated path" or "contract path" methodology. Under these methods, transmission is made available when there is ATC from the requested Point-of-Receipt (POR) to the Point-of-Delivery (POD). If there is no ATC to grant service, the transmission provider will study the service request to determine the extent system upgrades are necessary to grant the requested service.

In a contract path system, transmission service must be reserved and purchased from a specific POR to a specific POD to move power. Typically, a POR is where the resource is located, and the POD is where the load is located. The link between the two is called the "contract path". Physical flows on the grid will not follow contract paths. The actual electric power takes the path of least resistance and may impact different parts of the transmission system. Therefore, actual power flows can differ significantly from transmission contracts and reservations. In some cases, this parallel management of the physical versus the contractual grid can cause some amount of transmission capacity to go unused.

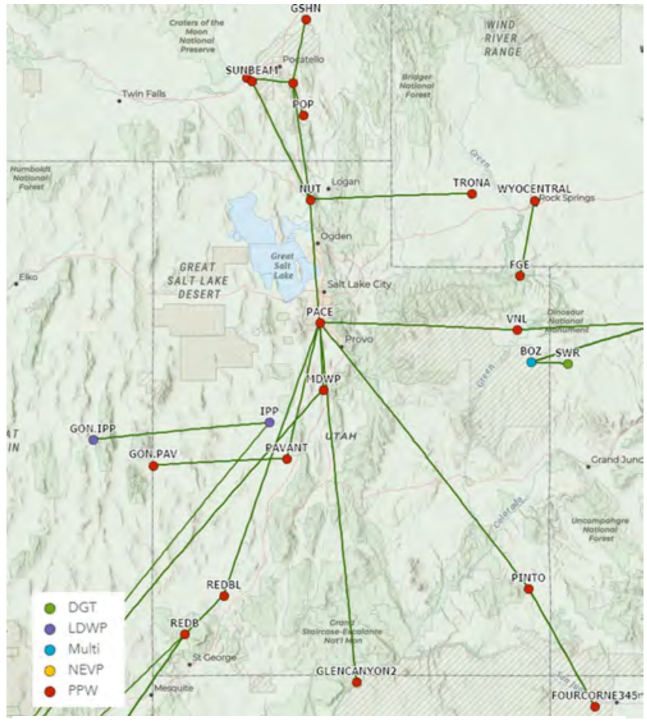


Figure 15: Utah Contract Paths

Transmission Rights and ATC Methodology

A determination of transfer capability for a given path requires a study that measures the ability of the grid to reliably transfer power from one area to another over all of the lines between those two areas – these lines are sometimes called an “interface”, “path”, or “cutplane”. For such interfaces, we define two terms that are used throughout the remainder of the study.

Table 10: Contractual Terminology in the Utah Transmission Study

Data	Source	Purpose/Description
Total Transmission Capacity (TTC)	OATI OASIS	Maximum reliable transfer capacity available for firm and non-firm reservations along contract paths (POR/PODs)
Firm Available Transfer Capability (ATC)	OATI OASIS	Firm (guaranteed) contract capacity available along contract paths (POR/PODs)

Generally, if there is no ATC on a path, the path is considered “fully utilized” or “congested”. The only way to add generation resources that deliver power along that contract path is to expand the TTC of the path or operate the new resource within existing amounts of firm (or non-firm) transmission capacity. However, both options have economic and operational trade-offs.

Transmission providers are required to post information about transmission availability so transmission customers can evaluate their options and reserve capacity.[10] ATC and TTC data are available for up to a 10-year time horizon, though some transmission providers provide data for 5-years or less. Energy Strategies used a proprietary automated technique to search postings for any POR/PODs either in the state of Utah, or up to one segment away. We manually reviewed these contract paths for inclusion/exclusion in the study since some are duplicative (or in series with one another). Since not all contract paths had 10-years of ATC/TTC data, the latest years' worth of data was assumed. Energy Strategies acknowledges that many contracts have a 5-year roll-over period (right of first refusal), and that these long-term contracts are subject to change. It was also assumed in all cases, that ATC/TTC in 2040 was equal to that of 2030.

Table 11: Firm ATC for Utah Contract Paths to PACE[11]

POR	POD	2020 ATC	2025 ATC	2030 ATC
GLENCANYON2	PACE	0	200	295
VNL	PACE	0	138	138
UINTA	PACE	19	19	19
PINTO	PACE	0	331	331
PAVANT	PACE	129	129	129
NUT	PACE	203	536	1,036
HUNTER	PACE	1,254	1,253	0
MDWP	PACE	0	628	811

Table 11 shows the long-term firm ATC values posted these paths in a 10-year time horizon. In general, it can be observed that ATC frees up over time, and that the grid is near or at transfer limits in the near-term (2020). The existing system (2020) is heavily congested for deliveries into the PACE load center. There is very little ATC available from the south, and more ATC from the north. By 2025 and 2030, some ATC "frees up", but overall, the system has limited ATC and only on select paths.

[10] This is done through an online secure website call OASIS, or Open Access Same-time Information System.

[11] Data accessed on https://www.oasis.oati.com/

This study's use of ATC rather than TTC, allows existing long-term contracts to be considered appropriately. Firm ATC represents capacity available to contract and deliver new and incremental resources without any new transmission upgrades. The firm ATC values (available in 10-year time horizon) reflect some planned, though not proposed, transmission upgrades.

5.2 Challenges Associated with Methodology

At its core, this task relies on a mapping between contract paths (POR/PODs) and the physical transmission system. However, contract paths do not exactly align with the physical transmission system, nor do they necessarily represent complexities tied to series/radial transmission paths as evidenced in Figure 16.

Contract paths may represent networked or looped transmission lines providing power transfer from a POR to a POD. Therefore, multiple PORs delivering to a single POD may utilize transmission capacity (and thus impact the ATC) of each other.

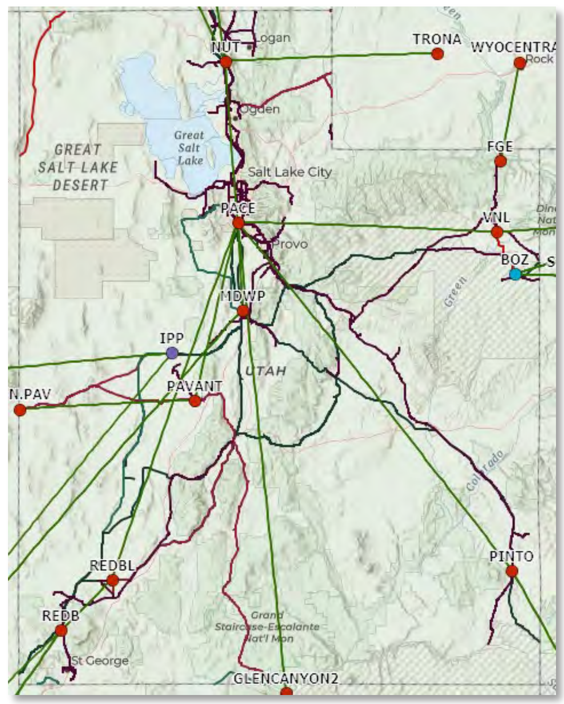


Figure 16: Utah Contractual System Overlaid with Physical Transmission Grid

5.3 Identifying Transmission Cutplanes

Energy Strategies identified seven cutplanes for consideration and of these, only five were ultimately selected for further analysis. All cutplanes were evaluated with the objective of measuring the impact of transferring power from ERZs to the PACE load center (though physical power can flow in the opposite direction along some of these cutplanes some of the time). Cutplanes represent a "cross-section" collection of multiple transmission lines or contract paths, allowing the capacity through multiple contract paths to be considered coincidently. The cutplanes chosen for study were consistent with PacifiCorp transmission planning literature and established WECC Transfer paths. These cutplanes are shown in the Figure 17. The transmission lines assumed to be included in the Wasatch Front South and North of Huntington/Sigurd cutplanes are tabulated in *Section 9.5* of the Technical Appendix.

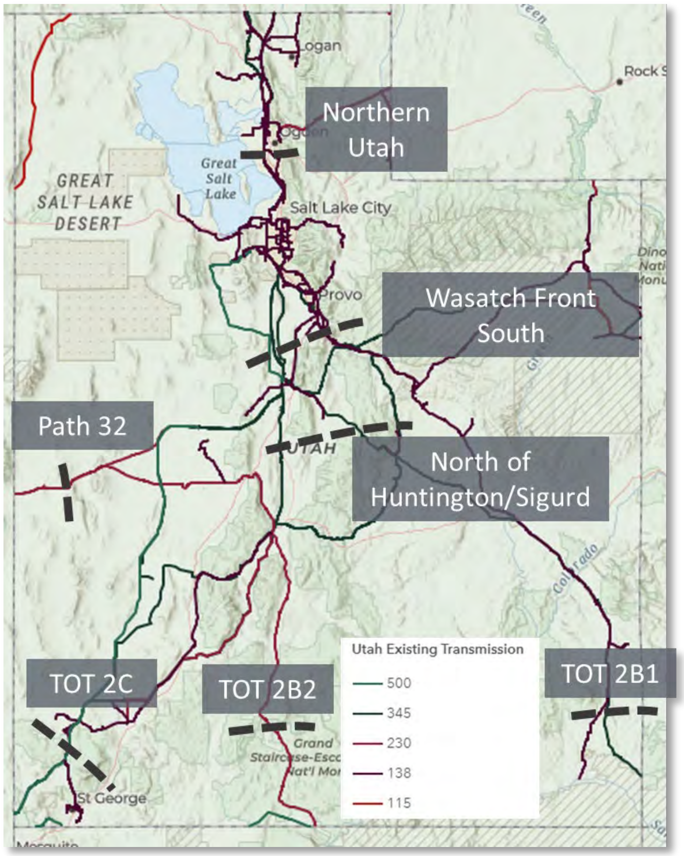


Figure 17: Cutplanes Analyzed to Identify Constraints

5.4 Cutplane Firm ATC

The firm ATC across a given cutplane was determined by assigning one or more contract paths to each cutplane. The ATC of all paths included in a cutplane were summed to represent the cutplane ATC. This methodology assumes delivery of new resources to the PACE load center and minimal local consumption of incremental generation located at ERZs. ATC determinations for all seven cutplanes are outlined in Table 12. [12, 13]

Table 12: Cutplane ATC

Cutplane	Point of Receipt	Point of Delivery	2025 Firm ATC (MW)	2030 Firm ATC (MW)
North of Huntington / Sigurd (NHS)	GLENCANYON2	MPAC	200	295
	REDBL	MPAC	243	243
	PINTO	PACE	331	331
	HUNTER	MPAC	1253	0
	Huntington/Sigurd Total		2027	869
Wasatch Front South (WFS)	MPAC	PACE	628	811
	HUNTER	PACE	1253	0
	Wasatch Front South Total		1881	811
Northern Utah	NUT	PACE	536	1036
Tot 2B2	GLENCANYON2	MPAC	200	295
Tot 2B1	FOURCORNE345	PACE	331	331
TOT 2C	REDBL	MPAC	243	243
Path 32	PAVANT	PACE	129	129

Contract paths included in the North of Huntington/Sigurd (NHS) and Wasatch Front South (WFS) cutplanes are consistent with the physical lines that represent these cutplanes as outlined in PacifiCorp Transmission planning literature. However, these contract paths may represent networked or looped transmission providing power transfer from a POR to a POD. Therefore, multiple PORs delivering to a single POD may utilize transmission capacity along the same physical lines and would thus impact the ATC of each other. Energy Strategies took special care to avoid “double counting” ATC for looped/networked transmission paths. Additionally, we assume that existing transmission commitments (ETC) are continued or replaced within the study period.

[12] Note: MPAC = PacifiCorp Point of Receipt/Delivery (POR/POD) at Mona Substation. NUT = Northern Utah

[13] Transmission contracts are reserved from Point of Receipt (POR) to Point of Delivery (POD).

Table 12 indicates that Hunter-PACE ATC drops from 1,253 MW to 0 MW in year-end 2025. Energy Strategies believes this to represent pending contract roll-over for 2026-2030, which has yet to occur. For all other paths, ATC either remains the same or increases from 2025 to 2030. Note that for some paths, ATC data was not available through 2030. If this was the case, Energy Strategies assumed the most recent year for which data was available. All ATC values from 2030 were assumed for 2040, since ATC data is not yet available for a time horizon greater than 10 years on OATI OASIS. We do not believe that this ATC takes into account incremental procurements that may occur in 2021-2022, so these values may overestimate the capacity of ATC available and this factor was taken into consideration in the identification of potentially congested cutplanes.

5.5 Cutplane ATC Requirements

ERZ-to-Cutplane Mappings

To determine the how much ERZ cumulative additions will affect study cutplanes, Energy Strategies made ERZ-to-cutplane mappings. These mappings determine whether each ERZ's cumulative additions would require capacity across a given cutplane to deliver power to the PACE load center. It was assumed that resources required capacity across the cutplanes at a level consistent with their nameplate capacity.

This approach implies that new resources are built with the objective of serving PACE load center loads, not local loads, and that they output must be deliverable during all hours. ERZ-to-cutplane mappings were made based on the assumed substation(s) of interconnection for each ERZ using engineering judgement. For example, a resource developed in Northern Utah would require capacity across the Northern Utah cutplane to deliver power to the PACE load center. Alternatively, a resource developed in St. George, Utah would require capacity across TOT 2C, NHS and WFS cutplanes to deliver its power to the PACE load center.

Table 13: Assumed ERZ Interconnection Locations

ERZ	Interconnection Substation
Central Utah	Sigurd
St. George	Red Butte (35%), Three Peaks (35%), West Cedar (15%), Parowan (15%)
Far South	Glen Canyon
West Desert	Oquirrh
Northern Utah	Ben Lomond
Mona	Mona (75%), Clover (25%)
Four Corners	Four Corners
Milford	Milford
Southeastern UT	Pinto
PACE Load Center	Terminal

Table 14: ERZ-to-Cutplane Mappings

ERZ	North of Huntington/ Sigurd	Wasatch Front South	Northern Utah	Tot 2B2	Tot 2B1	Tot 2C	Path 32 (Gon-Pav)
Central Utah	✓	✓	-	-	-	-	-
St. George	✓	✓	-	-	-	✓	-
Far South	✓	✓	-	✓	-	-	-
West Desert	-	-	-	-	-	-	-
North Utah	-	-	✓	-	-	-	-
Mona	-	✓	-	-	-	-	-
Four Corners	✓	✓	-	-	✓	-	-
Milford	-	✓	-	-	-	-	✓
Southeast UT	✓	✓	-	-	✓	-	-
PACE Center	-	-	-	-	-	-	-

The following guiding principles were assumed to make ERZ-to-cutplane mappings:

1. All Central and Southern Utah resource development assumed to use capacity across both NHS and WFS cutplanes.
2. Developments at West Desert and PACE Load Center ERZs are assumed inside the PACE load center and do not cross any cutplanes in delivering power to the PACE load center.
3. Although current wind developments at Milford are delivered to LADWP via the HVDC line at Intermountain, this study assumes any future developments would be delivered to the PACE load center via Intermountain, and thus would avoid the NHS cutplane, but not WFS.

4. Southeastern UT wind development assumed to interconnect to Pinto-PACE line, therefore requires both NHS and WFS cutplane capacity.

Calculating Cutplane ATC Requirements

Cutplane ATC requirements were determined by summing the ERZ developments for all ERZs mapped to a given cutplane. For example, the TOT 2B1 ATC requirement would be the sum of cumulative additions in the Southeastern UT and the Four Corners ERZ's ATC.

5.6 Deliverability

In many cases, firm transmission capacity is reserved for new resources so that the capacity is available 100% of the time even if the resource rarely uses the full allocation. Resources with this amount of transmission are "deliverable" and can be relied on to meet loads during emergency events.

An alternative and commonly used approach for deliverability is to reserve only enough capacity for a resource so that it can deliver its output to loads during system peaks or other critical conditions. In most areas of the country, variable resources like wind and solar can be expected to produce below their installed capacity during periods when resource adequacy is a concern. Considering resource expected output and deliverability under a defined set of system conditions helps ensure that the system has adequate, but efficient, build-out of transmission and is commonly practiced in Regional Transmission Organizations (RTOs). For example, if a 100 MW wind resource in a given system is relied on to provide 20% of its nameplate capacity during critical system conditions, it needs at least 20 MW of firm transmission capacity to be deliverable during such conditions. Depending how much transmission is ultimately built and allocated, this approach can cause economic transmission congestion. However, in some cases, some amount of congestion may be less costly than the cost of new transmission expansion.

For this study, we adopted a conservative assumption and assumed that 100% of the nameplate capacity of a new resource requires transmission capacity across a given cutplane. This approach is consistent with the intent of this study, which was to identify potentially congested corridors and to identify possible transmission upgrades. The alternative approach, which assumes firm transmission capacity is required only up to the capacity contribution of a given resource (e.g., 10% for solar or 20% for wind), would have resulted in this study identifying less congestion on the grid and requiring fewer upgrades to accommodate the resource scenarios.

5.7 Transmission Constraints and Latent Capacity

Each of the cutplanes was assessed for constraints and latent capacity by comparing the cutplane ATC, shown in Table 12, with its corresponding ATC requirement shown in Table 15.

Table 15: Firm ATC Requirement (MW) Transmission Study Cutplanes (High Bookend)

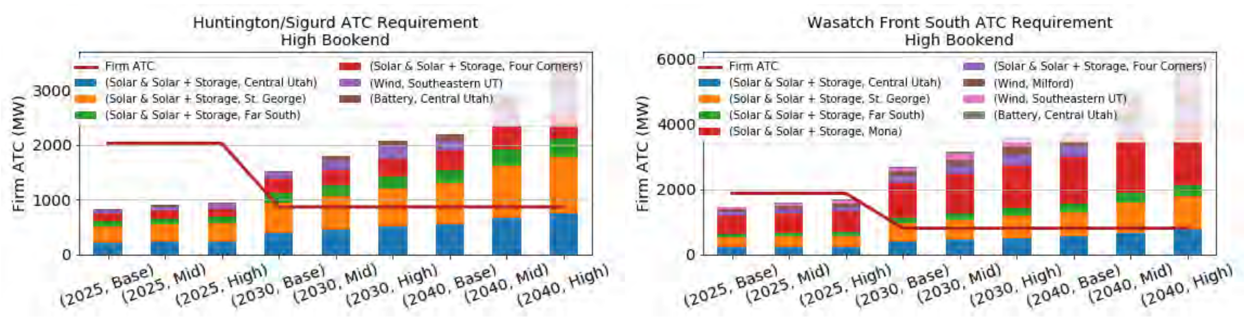
Year	Case	North of Huntington/Sigurd	Wasatch Front South	Northern Utah	Tot 2B2	Tot 2B1	Tot 2C	Path 32
2025	Base	829	1,470	172	97	201	302	65
	Mid	899	1,587	193	103	220	320	75
	High	957	1,683	210	107	236	335	85
2030	Base	1,520	2,691	319	177	364	553	115
	Mid	1,789	3,149	389	199	455	620	175
	High	2,078	3,642	462	222	553	693	240
2040	Base	2,184	3,810	502	242	522	757	180
	Mid	2,928	5,011	748	299	721	933	300
	High	3,518	5,929	966	331	902	1,034	435

Table 16: Firm ATC Requirement (MW) Transmission Study Cutplanes (Low Bookend)

Year	Case	North of Huntington/Sigurd	Wasatch Front South	Northern Utah	Tot 2B2	Tot 2B1	Tot 2C	Path 32
2025	Base	247	432	57	29	53	90	12
	Mid	274	470	70	31	57	95	14
	High	296	501	80	32	60	99	15
2030	Base	457	795	108	53	96	166	21
	Mid	547	926	148	58	114	182	32
	High	643	1068	189	64	133	200	43
2040	Base	706	1172	209	73	135	227	32
	Mid	988	1542	369	84	172	262	54
	High	1282	1923	541	94	211	294	78

Graphs for all cutplanes are shown in Figure 18 - Figure 21. In these graphs, bars represent ATC requirements from the various resource types with power flowing through that cutplane as determined by the ERZ-to-cutplane mappings. Energy Strategies interpreted transmission congestion any time the ATC requirement (bar) exceeded or approached the ATC (red line).

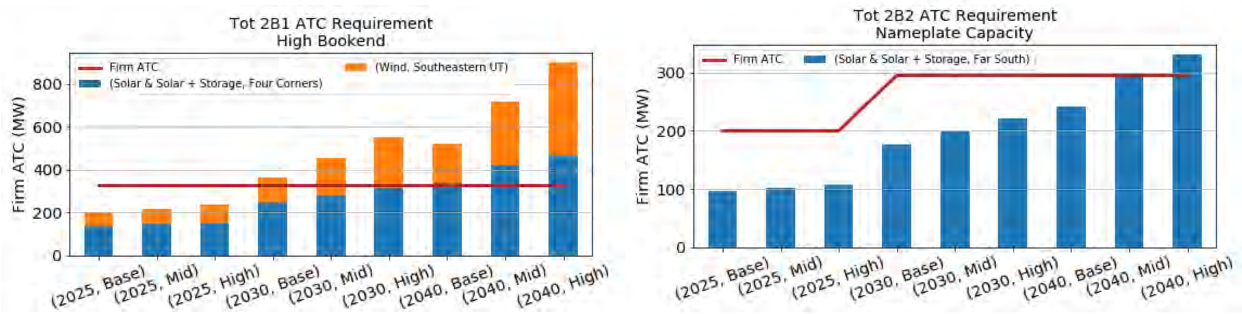
Figure 18: ATC Requirements of North of Huntington/Sigurd & Wasatch Front South Cutplanes



The North of Huntington/Sigurd cutplane results in Figure 18 indicate congestion from new resource development as early as 2030. According to this analysis, the Wasatch Front South (WFS) cutplane (shown in Figure 18) is projected to experience congestion from new resource development by 2030 or 2025.

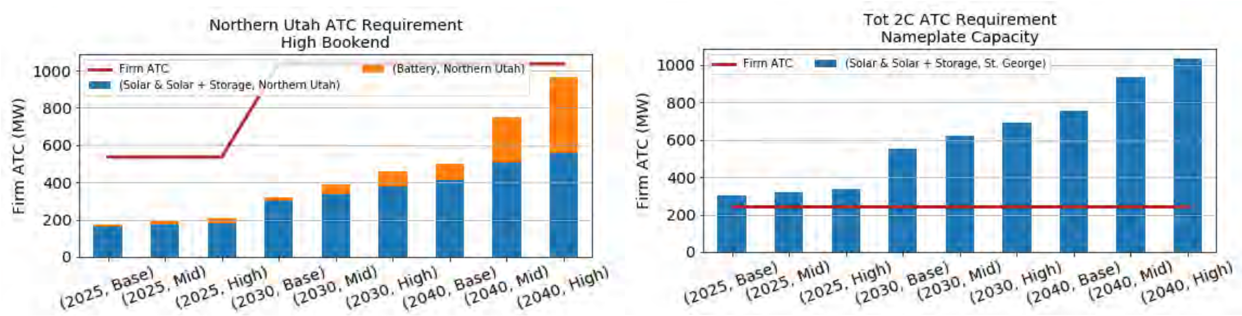
Along these two cutplanes, resources from a variety of forecasted Southern and Central Utah developments will increase power flows – indicating the need for transmission solutions to be focused in these areas.

Figure 19: ATC Requirements of TOT 2B1 & TOT 2B2 Cutplanes



Capacity along TOT 2B1, is projected to be utilized by both wind and solar developments in the Four Corners and Southeastern UT regions. The TOT 2B2 path projects congestion as early as 2030.

Figure 20: ATC Requirements of Northern Utah and TOT 2C Cutplanes



The Northern Utah path shows no indication of congestion due to in-state resources because of recent transmission upgrades along the path as outlined in Table 3. A high capacity of solar and solar + storage developments in the St. George area are likely to drive congestion along TOT 2C as early as 2025.

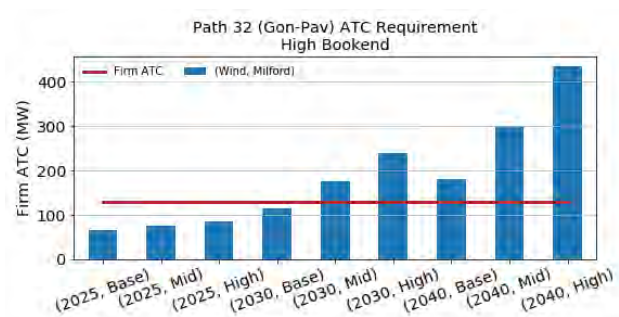


Figure 21: ATC Requirements of Path 32 Cutplane

Path 32 (Gonder-Pavant) indicates limited ATC and congestion as early as 2030.

Findings of Transmission Congestion Analysis

Based on probable magnitude and locations of future resource development in Utah as forecasted in this study, and consideration of available transmission capacity, we identified five potentially congested transmission cutplanes or corridors prioritized into two tiered groups.

Wasatch Front South and North of Huntington/Sigurd show signs of future congestion and represent "pinch points" on the grid, hampering access to most central and southern Utah resources. These two cutplanes are classified as Tier 1 – meaning transmission upgrades will be likely to occur in almost any transmission expansion solution when integrating new resources.

Tier 2 prioritization includes lines that access Glen Canyon, Four Corners, and Red Butte ERZs and may limit access to resources in these areas depending on how many resources are deployed.

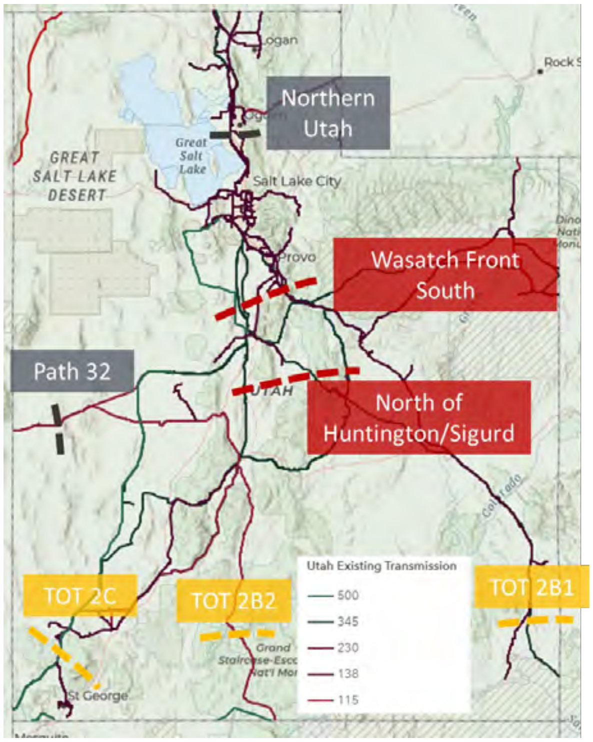


Figure 22: Tier 1 Cutplanes (Red) and Tier 2 Cutplanes (Yellow)

6.0 GRID SOLUTIONS

One of the primary goals of the study was to identify potential grid solutions that help to relieve constrained corridors and improve access to new generation resources. Based on an assessment that combined forecasted levels of transmission availability and estimated future resource needs on the system, the study identified five potential constrained corridors, as outlined in *5.0 Transmission Constraints*.

After identifying the constrained corridors, Energy Strategies performed power system modeling to identify “wire” or “non-wire” transmission solutions (“solutions”) that add transmission capacity necessary to achieve the resource scenarios. A technically viable solution, for the purposes of this project, was an infrastructure addition that materially increases the transfer capacity of a constrained corridor to help deliver resources. In addition to this technically analysis, Energy Strategies developed cost estimates for the candidate transmission solutions to help identify cost-efficient buildouts that met the technical needs of the resource scenarios.

The following sections describe the modeling work and introduce the identified grid solutions and their cost.

6.1 Modeling Setup

Energy Strategies performed alternating current (AC) power system modeling concentrated on a 2030 study year. The modeling focused on the PacifiCorp East balancing area, but the studies included full representation of the entire WECC region. Generally, the study focused on identifying transmission solutions that address south-to-north constrained flow conditions, although the transmission solutions were tested in a “southbound” case as well to ensure the additions did not cause new reliability issues. Study work did not include identifying interconnection upgrades for specific generators.

The “northbound” flow study was based on a powerflow case provided by PacifiCorp. The case modeled the TOT2B and TOT2C paths at their forecasted transmission obligation level, with resources in southern Utah dispatched at high output to stress the Southern portion of the Utah system. By using this scenario as a starting point, the study was able to identify the upgrades necessary to accommodate additional resources above and beyond current system obligations. The study case assumptions are outlined below in Table 17.

Table 17: Summary of Study Case Assumptions

Study Assumption	Description of Data
Year and Load Condition	2030 Heavy Summer base case with high loads in Utah. 2030 study year selected to reasonably limit study years and cases that needed to be compiled by PacifiCorp. Load forecast provided by PacifiCorp.
Topology	Case represents all major existing and planned transmission lines, paths, substations, and loads in Utah and surrounding WECC system.
Planned Transmission	Study assumed that all planned transmission projects are constructed and are in-service by 2030, including Path C improvements, Gateway South, and Oquirrh – Terminal #3/#4 345-kV lines. Therefore, transmission additions identified in study are incremental to already-planned upgrades.
Future Resources	Case includes all future resources identified as designated network resources in PacifiCorp TSR queue as of November 2020. Any interconnection upgrades associated with these resources are modeled. No other queued generators or represented in the study as incremental additions are represented via the ERZ resource modeling.
ERZ Mapping and Interconnection of Resources in Scenarios	For each scenario, ERZs were mapped using a combination of PacifiCorp queue data and resource quality for wind and solar resources. Queue data was mapped to each ERZ using county information and predictions on where development was likely to occur. Interconnection substations were determined for each ERZ based on PacifiCorp queue data, and cumulative additions were “injected” at each ERZs substation in the Powerflow case. This modeling approach ignores the need for collector systems.
Source/Sink Modeling	New generation within the ERZs dispatched in the scenarios were sunk to on the PacifiCorp Utah system at major load centers.
Dispatch of New Generators	New resource and storage additions were dispatched at their nameplate capacity to conservatively estimate transmission upgrades required to deliver the full output of the resource during all conditions.

Energy Strategies made updates to the study case provided by PacifiCorp in order to accomplish the goals of the study. Specifically, new resources were modeled on the system, in accordance with the ERZs and the resource scenarios. After making this addition, Energy Strategies performed an assessment designed to identify viable grid buildouts.

6.2 Powerflow Assessment

A benchmark powerflow assessment was performed on study cases with new resources added consistent with the Base, Mid, and High resources scenarios. No addition transmission upgrades were included in this initial benchmark study. Contingency analysis was performed on the system, consistent with NERC TPL category P1, P2, and P7 outages.[14] Monitoring for reliability violations was focused on the >200-kV transmission system and included a ties and certain transmission elements in neighboring areas. [15]

Review of the study results identified and focused on reliability violations caused by the resource additions. Table 18 shows the total number of thermal and unsolved violations observed in each scenario.

Table 18: Number of Thermal and Unsolved Issues by Voltage Class & Category

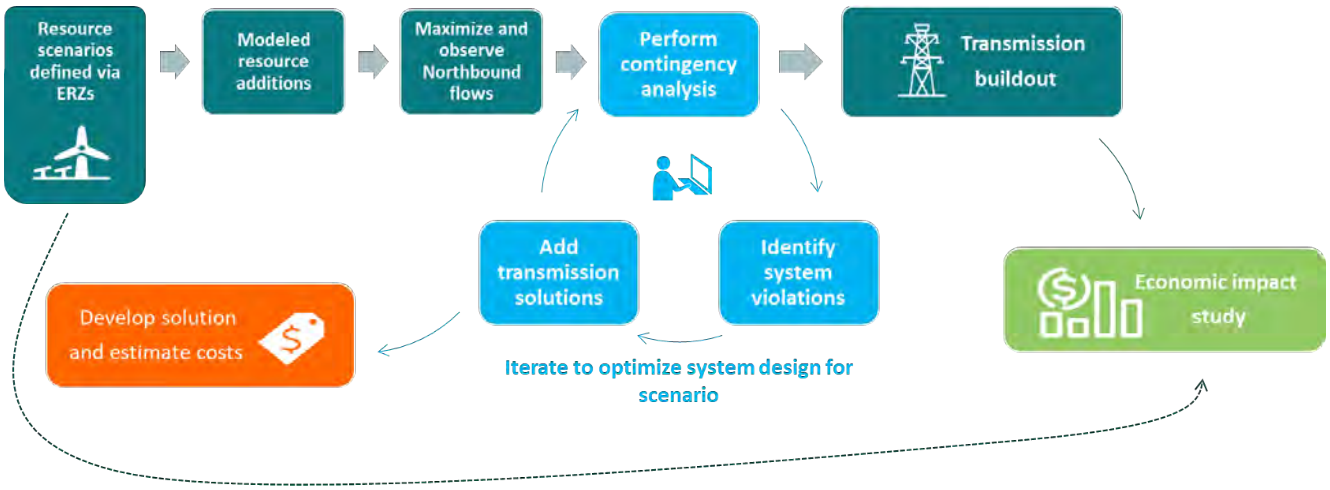
Voltage Class	Benchmark	Base	Mid	High
System	4	36	42	45
500	0	0	0	0
345	0	2	18	86
230	0	3	14	14
Total	**4**	**41**	**74**	**145**

[14] Outages were provided by PacifiCorp and reviewed by Energy Strategies for completes and applicability to the study.

[15] Elements between 100 -200 kV with new unsolved contingency issues were addressed during the development of transmission solutions. Certain lower-voltage issues can be addressed via system redispatch. The study may not have mitigated all lower-voltage reliability issues.

Energy Strategies used the study results to identify and develop over 45 candidate transmission upgrades that were tested in subsequent studies to determine their effectiveness at resolving identified reliability issues. The overall study process and interaction with the resource scenarios and economic impact analysis is summarized below.

Figure 23: Modeling Process to Identify Upgrades



In addition to evaluating the technical performance of the transmission additions, Energy Strategies also developed cost estimates for the transmission additions to help assess the economic tradeoffs associated with various buildouts. The process by which these cost estimates were developed is described in *2.1 Technical Methods*.

By evaluating the performance of individual and combined sets of transmission upgrades, and their costs, Energy Strategies was able to converge upon a transmission buildout that was able to create additional transfer capability on the Utah grid to relieve year 2030 grid constraints and integrate resources modeled consistent with the Base, Mid, and High resource scenarios.

6.3 Non-wires Assessment

In some cases, new transmission projects can be avoided through non-wires solutions, such as energy storage, demand response or Remedial Action Schemes (RAS). In the case of energy storage, the battery (or other storage technology) can be sited and operated so that it alleviates grid constraints when they occur, which allows the grid to accommodate high flow levels that it could without the battery. Similarly, demand response – which is the rapid reduction of loads – can be used to reduce loading on the grid, which allows operators to push more flow down a given set of lines. RAS can be implemented to mitigate system performance issues by preemptively detecting predetermined system conditions and using automatic corrective actions such as adjusting generation, load and/or reconfiguring transmission elements.

These alternatives were considered as non-wires solutions in the study process above, serving in place of transmission upgrades. However, analysis determined that these non-wires solutions could not be relied upon based on the location and magnitude of the constraints. Specifically, storage and demand-side resources would have had to provide an extreme amount of capacity to provide the level of required reliability, and there were questions about the ability to rely on these non-wire options for more than a handful of hours per month or year. Additionally, RAS implementation generally requires vast communication infrastructure investment and can be very difficult to implement for multiple complex contingency conditions. For this reason, the findings in this study focus on transmission alternatives. There may be certain project-specific instances in which non-wire options will apply and could be viable in Utah.

6.4 Transmission Buildouts

The term buildout refers to the combination of two or more transmission solutions identified in this study that were combined to deliver the resource scenarios modeled in the assessment. The cost estimates provided in the following sections for each buildout does not include *all* of the potential transmission upgrade costs. Upgrades required to physically interconnect the generation in the resource scenario to the grid are best determined on a project-by-project basis and are therefore excluded.

Baseline and Mid Resource Scenario Buildouts

The Baseline and Mid resource scenarios specified the addition of 3,530 MW and 4,040 MW, respectively, of new generation capacity in Utah. Analysis identified a buildout that would upgrade or add a total of 210 miles of transmission at a cost of approximately $325 million. The buildout was the same for the two resource scenarios. Upgrades include over 100 miles of new 345 kV lines, nearly 100 miles of upgraded 230 kV line, and several major transformer upgrades, along with ancillary substation and line termination work. Transmission additions identified in the Baseline and Mid resource scenario buildouts are outlined in Figure 24 and Table 19.

Figure 24: Base and Mid Resource Scenario Buildout

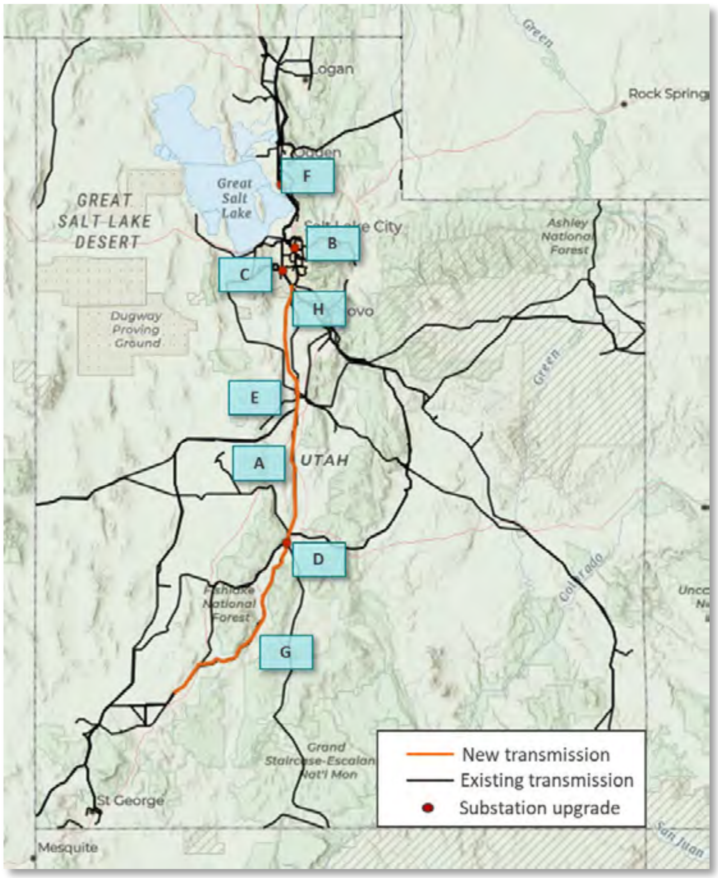


Table 19: Transmission Additions in Base/Mid Resource Scenario Buildout

ID	Transmission Addition	Cost Estimate ($M)	Length (mi.)
A	New Sigurd - Clover 345 kV	128	67
B	New Midvalley 345/138 kV Transformer	13	-
C	New Oquirrh 345/138 kV Transformer	13	-
D	New Sigurd 345/230 kV Transformer	13	-
E	New Mona - Clover 345 kV	15	3
F	New Syracuse 345/138 kV Transformer	13	-
G	Parowan - Sigurd 230 kV Upgrade	38	94
H	New Mona - Camp Williams 345 kV	91	46

High Resource Scenario Buildout

The High resource scenario assumed that 5,150 MW of resources are added to the Utah grid by 2030. Analysis identified a buildout that expands on the Baseline/Mid buildout, totaling 291 miles of transmission at a cost of $578 million. The buildout includes an addition 50 miles of 345 kV lines beyond what was identified for the Base/Mid scenario, along with a major reinforcement of the transmission system south of Salt Lake City. Transmission additions identified in the High resource scenario buildout is outlined in Figure 25 and Table 20.

Figure 25: High Resource Scenario Buildout

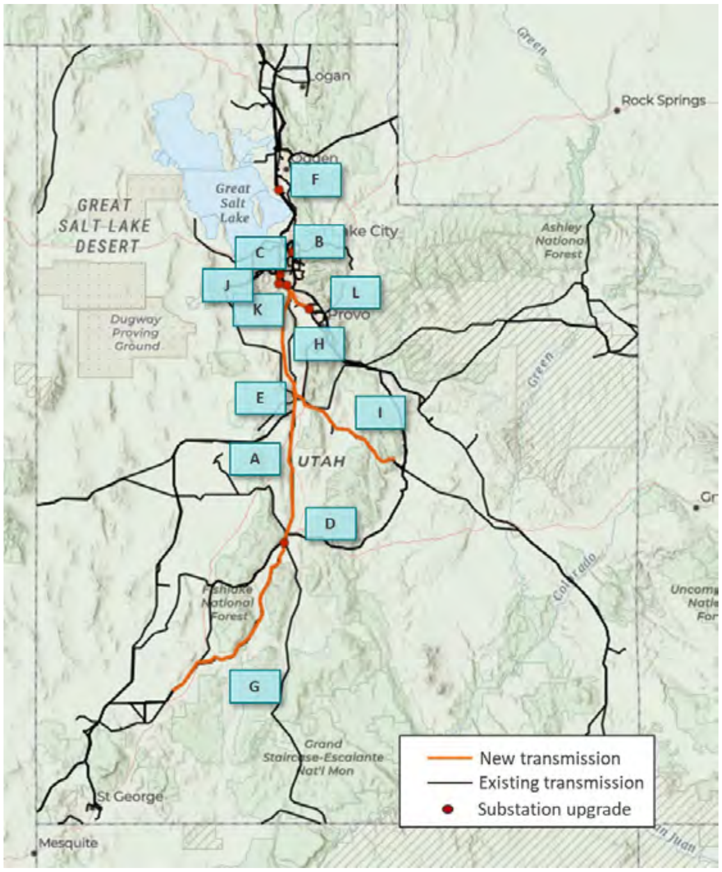


Table 20: Transmission Additions in High Resource Scenario Buildout

ID	Transmission Addition	Cost Estimate ($M)	Length (mi.)
A	New Sigurd - Clover 345 kV	128	67
B	New Midvalley 345/138 kV Transformer	13	-
C	New Oquirrh 345/138 kV Transformer	13	-
D	New Sigurd 345/230 kV Transformer	13	-
E	New Mona - Clover 345 kV	15	3
F	New Syracuse 345/138 kV Transformer	13	-
G	Parowan - Sigurd 230 kV Upgrade	38	94
H	New Mona - Camp Williams 345 kV	91	60
I	New Huntington - Mona 345 kV Line	115	46
J	New 126th S 345 kV expansion, 345 kV line, & 345/138 kV transformer	39	5
K	New Bangeter 345 kV expansion, 345 kV line, & 345/138 kV transformer	38	4
l	New TriCity 345 kV expansion, 345 kV line, & 345/138 kV transformer	60	13

The study scope did not address all substation or lower-voltage transmission upgrades and, as a result, the buildouts do not address all <200-kV transmission issues. Therefore, additional upgrades beyond those identified are likely to be required.

Additional Buildouts

Three ERZs and associated constraints in Southern Utah were very sensitive to assumptions about how many resources might be developed in those areas (see *4.3 Summary of Resource Scenario ERZs*). According to this study, if resource development exceeds certain thresholds, transmission upgrades beyond those identified in the above scenarios will be required. Specifically, assuming the transmission builds for the High resource scenario are built, the need for additional upgrades is triggered when Four Corners area development surpasses 260 MW, Glen Canyon additions surpass 325 MW, and St. George region development surpasses 825 MW. The cost of potential upgrades that allow resource levels above these thresholds is $179 million and results in 209 line-miles of new and upgraded transmission. The buildout to accommodate additional resources in these zones is provided below in Figure 26 and Table 21.

Figure 26: Buildout for Additional Generation

Table 21: Buildouts for Additional Generation

ID	Transmission Addition	Resource Scenario	Cost Estimate ($M)	Length (mi.)
M	Upgrade Glen Canyon – Sigurd 230 kV Line	Pinto & Glen Canyon	65	160
N	New Mona - Camp Williams 345 kV	St. George	91	46
O	New Mona - Clover 345 kV	St. George	15	3
P	New Cedar 230/138 kV Transformer	St. George	9	-

This buildout represents the transmission necessary to accommodate a “what if” scenario in which the resource location assumptions are skewed more toward Southern Utah and less toward Central Utah.

6.5 Grid Solutions

The transmission buildouts for the Baseline, Mid, and High resource scenarios represent transmission investments that would help Utah unlock between 3.5 and 5.2 GW of new generation capacity by 2030. The transmission expansion primarily takes place along Utah's north-south transmission backbone. Non-wire solutions were considered but were deemed to not be a viable solution for this study given the magnitude of the constraints on the transmission system. The transmission additions would help the state meet forecasted in-state generation needs and would result in up to $578 million in transmission investment. While these upgrades will help tap resources that may otherwise not be accessed, Utah should maximize use of the existing system prior to building such upgrades.

7.0 ECONOMIC BENEFITS TO UTAH

Transmission planning analyses often estimate the benefits grid investments may bring to the utility or region planning the project. Increased reliability, lower operating costs, access to new resources, generation capacity deferment, among others, represent electric-sector specific benefits that are often quantified and compared against the cost of transmission project to help weight the net cost (or benefit) of the investment. This study did not include an electric sector focused benefit-cost assessment of grid investments (although benefits in the form of increased resource access are reported). Instead, this study focuses on broad state-level, multi-sector economic development implications associated with new investment in generation and transmission within Utah.

The results of the economic impact analyses are presented below. A summary of the methodology is provided in *2.1 Technical Methods* and additional details are outlined in the Appendix within *9.1 Generation and Transmission Costs* as well as *9.2 Economic Impact Assessment.*

7.1 Capital Cost Estimates

The study estimates the capital cost of future generation and transmission buildouts in Utah. The analysis of transmission costs was used to help consider tradeoffs between potential transmission buildouts. The transmission and generation costs were used an input into the economic impact assessment.

The cost estimates for the transmission buildouts are presented by upgrade and by scenario in *6.4 Transmission Buildouts.* The table below summarizes total incremental transmission costs by scenario.

Table 22: Estimated Cost of 2030 Transmission Buildout (2018$)

Scenario	Capital Cost Estimate ($M)	New/Upgraded Line Miles (mi.)
Base	$325	210
Mid	$325	210
High	$578	291

The table below outlines, by technology type and year, the cost associated with constructing the generation in each scenario. The cost represents the cumulative capital investment associated with all resources in the portfolio. Note these costs do not include potential interconnection upgrades for specific generation facilities.

Table 23: Estimated Cost of Generation Buildouts (2018$)

		Cumulative Capital Cost Estimate ($M)		
Scenario	**Technology**	**2025**	**2030**	**2040**
Base	Solar + Storage	2,364	3,898	5,021
	Solar	-	-	-
	Wind	180	302	445
	Battery	30	63	249
	Gas	-	251	632
	Total	**2,574**	**4,515**	**6,347**
Mid	Solar + Storage	2,481	4,210	5,549
	Solar	22	97	379
	Wind	207	452	728
	Battery	70	168	655
	Gas	-	171	551
	Total	**2,781**	**5,099**	**7,862**
High	Solar + Storage	2,584	4,565	6,213
	Solar	-	150	318
	Wind	235	615	1,045
	Battery	100	272	1,094
	Gas	-	593	973
	Total	**2,919**	**6,195**	**9,643**

As indicated in the table, total generation investment associated with the scenario ranges from $2.5 to $2.9 billion by 2025, $4.5 to $6.2 billion by 2030, and $6.3 to $9.6 billion by 2040. By comparing the 2030 generation costs against the 2030 transmission costs, we see that transmission costs are small relative to the cost to construct the generation.

The following table shows the total capital cost – generation plus transmission – of each 2030 scenario.

Table 24: Total Scenario Cost (2030 only)

Scenario	Generation Cost ($M)	Transmission Cost ($M)	Total Capital Cost ($M)
Base	$4,515	$325	$4,840
Mid	$5,099	$325	$5,424
High	$6,195	$578	$6,773

7.2 Economic Impact Assessment (EIA)

The IMPLAN input-output (I-O) model was used to perform the EIA of energy investment in Utah. IMPLAN uses annual, regional data to map businesses' and households' buying/selling relationships in order to predict how specific economic changes will impact a regional economy. The IMPLAN model includes numerous built-in metrics for industries, such as employment, output, local spending coefficients, industry-specific spending patterns, payroll, exports and imports, profit margins, and so on. In this case, energy industry specific adjustments were made to default assumptions to ensure that the study achieved the goals of the project.

Utah-specific impacts from transmission and generation investments are summarized using the following metrics:

- **Total investment (or gross inputs) –** Represents the total capital investment by companies to set-up and construct a generation or transmission facility. This value includes both construction services and capital equipment purchases. Due to leakage, not all of the total investment is realized inside the State of Utah.

- **Investment in Utah (or net inputs) –** Gross inputs are adjusted according to the estimated level of in-state purchases during the construction phase. Level of in-state purchases were determined uniquely for each type of energy production/transmission using a combination of IMPLAN and NREL JEDI assumptions.

- **Employment (or Jobs) –** Jobs created or sustained in each scenario. IMPLAN's employment estimates are in terms of full-time equivalent positions. For construction jobs, employment is in terms of job-years (i.e., equivalent number of full-time persons employed over the course of one-year).[16]

- **Labor Income –** Represents wages, salary, and benefits collected by employees, contractors, and other paid workers to support the given project. This category excludes income accrued to owners and investors.

- **Gross State Product (GSP) –** GSP is a more conservative, and accurate, measure of impact than Output because it only quantifies the value-added by companies to the inputs that they received. Technically speaking, GSP includes employee compensation, proprietor income, taxes on production and imports and other property income, and excludes the value of intermediate inputs.

- **Output –** Also sometimes referred to as "sales," output refers to the economic value of a good or service rendered in the marketplace. Wholesale and retail sectors are treated slightly differently, in that industry specific margins are taken into account.

- **Taxes –** For this study, taxes are inclusive of property, sales/excise and income at the state and local levels. IMPLAN's model accounts for many state specific nuances in tax collections. Given that the energy sector is regularly subject to sales tax exemptions specific to alternative energy, gross sales estimates were significantly discounted in this study.

A summary of the EIA results for the scenarios are summarized below.

Jobs

- The temporary (construction) job contributions range from 10,910 job-years in the 2025 Base scenario to 39,198 job-years in the 2040 High scenario.
- Permanent job contributions (i.e., from operations) range from 257 jobs in the 2025 Base Scenario to 988 jobs in the 2040 High scenario.

Taxes

- The temporary (construction) tax contributions range from $136.4 million in the 2025 Base scenario to $3.65 billion in the 2040 High scenario.

[16] For example, if a project were to be equally spread over two years and there were a total of 100 job-years, then there would be 50 job-years reported for each of the two years.

- Permanent tax contributions (i.e., from operations) range from $9.19 million in the 2025 Base scenario to $32.67 million in the 2040 High scenario.

Labor Income

- The temporary (construction) labor income contributions range from $630.7 million in the 2025 Base scenario to $2.26 billion in the 2040 High scenario.
- Permanent labor income contributions (i.e., from operations) range from $22.78 million in the 2025 Base scenario to $85.14 million in the 2040 High scenario.

Gross state product (GSP)

- The temporary (construction) GSP tax contributions range from $996.56 million in the 2025 Base scenario to $3.65 billion in the 2040 High scenario.
- Permanent GSP contributions (i.e., from operations) range from $62.29 million in the Base scenario to $230.48 million in the 2040 High scenario.

Sales (output)

- The temporary (construction) sales (output) range from $1.87 billion in the 2025 Base scenario to $3.65 billion in the 2040 High scenario.
- Permanent sales (output) contributions (i.e., from operations) range from $62.29 million in the Base scenario to $230.48 billion in the 2040 High scenario.

Tables summarizing the balance of the results are presented below. Note that each table corresponds to a specific year and scenario and are presented in 2018 dollars. Also note that only the 2030 scenarios include the economic impacts of the transmission build-out.

Table 25: 2025 Scenarios, Summary Statistics (excludes transmission)

			Temporary Contributions		Permanent Contributions	
Scenario	Total Investment by 2025 ($M)	Local Investment in Utah ($M)	New Temporary Utah Jobs (FTE)	New Temporary Tax Revenue ($M)	New Permanent Utah Jobs (FTE)	New Permanent Tax Revenue ($M)
Base	$2,825.08	$1,091.82	10,910	$136.44	257	$9.19
Mid	$2,780.76	$1,094.93	11,763	$147.38	278	$9.50
High	$2,919.40	$1,146.35	12,315	$154.72	292	$10.04

Table 26: Table 2: 2030 Scenario, Summary Statistics (includes transmission)

			Temporary Contributions		Permanent Contributions	
Case	Total Investment by 2025 ($M)	Local Investment in Utah ($M)	New Temporary Utah Jobs (FTE)	New Temporary Tax Revenue ($M)	Total Investment by 2025 ($M)	Local Investment in Utah ($M)
Base Case	$4,840	$1,858	19,981	$256	485	$16
Mid Case	$5,424	$2,080	22,323	$287	546	$19
High Case	$6,773	$2,536	27,216	$358	689	$23

Table 27: 2040 Scenario, Summary Statistics (excludes transmission)

			Temporary Contributions		Permanent Contributions	
Case	Total Investment by 2025 ($M)	Local Investment in Utah ($M)	New Temporary Utah Jobs (FTE)	New Temporary Tax Revenue ($M)	Total Investment by 2025 ($M)	Local Investment in Utah ($M)
Base Case	$6,347.19	$2,439.51	26,281	$336.43	641	$20.70
Mid Case	$7,862.13	$3,023.00	32,437	$416.16	798	$26.56
High Case	$9,643.38	$3,651.23	39,198	$510.29	988	$32.67

Table 28: 2025 Scenario, Detailed Statistics ($M) (excludes transmission)

	Temporary Contributions			Permanent Contributions		
Scenario	Labor Income	Gross State Product	Output	Labor Income	Gross State Product	Output
Base	$630.7	$996.6	$1,886.8	$22.8	$62.3	$115.0
Mid	$679.9	$1,074.7	$2,034.3	$24.6	$67.5	$124.7
High	$711.8	$1,125.5	$2,130.0	$25.9	$71.1	$131.5

Table 29: 2030 Scenario, Detailed Statistics ($M) (includes transmission)

	Temporary Contributions			Permanent Contributions		
Scenario	Labor Income	Gross State Product	Output	Labor Income	Gross State Product	Output
Base	$1,154	$1,840	$3,441	$43	$114	$211
Mid	$1,289	$2,054	$3,849	$48	$131	$243
High	$1,570	$2,519	$4,677	$60	$160	$298

Table 30: 2040 Scenario, Detailed Statistics ($M) (excludes transmission)

	Temporary Contributions			Permanent Contributions		
Scenario	Labor Income	Gross State Product	Output	Labor Income	Gross State Product	Output
Base	$1,517.9	$2,413.3	$4,524.7	$55.7	$147.9	$270.7
Mid	$1,873.3	$2,977.6	$5,592.9	$69.4	$188.1	$346.0
High	$2,262.6	$3,607.5	$6,749.4	$85.1	$230.5	$423.3

8.0 FINDINGS AND DISCUSSION

The following sections present the study's findings and highlight important observations and key considerations that help to put the results into context.

8.1 Study Findings

The study resulted in five key findings. These findings are driven heavily by the methods, assumptions, and purpose of the analysis.

1. **Utah has excellent electricity generation potential and energy development activity, but future generation buildouts will increase congestion on the transmission grid.** The analysis of resource plans and load forecasts conducted as a part of this study suggests that Utah may need to add between 5.5 and 9 GW of new power generation capacity by 2040. The high-end of this newly installed capacity would *double* the amount of generation capacity in the state. Wind, solar, and energy storage will make up the bulk of these additions, according to utility resource plans. This build-out of generation – excluding transmission costs – could lead to a $3.6 billion increase in state domestic product by 2040.

2. **By 2025, resource additions in Utah are likely to be limited by transmission constraints on key paths in Southern and Central Utah.** Based on the plausible in-state buildouts of generation and storage considered in this study, such additions will cause major congestion on the grid. Transmission grid "pinch points" in Central Utah hamper access to resources in the central and southern half of the state. Addressing these constraints is critical to delivering power to Utah's load centers. In addition, there are long lines that connect Central Utah to St. George, Glen Canyon, and the Four Corners region that may also become constrained, depending on how many resources are built out in those areas. Across the grid, the severity of this congestion is expected to increase in the 2030's and 2040's as increasing amounts of new generation and storage are forecasted to be added to the grid and must be delivered to loads.

3. **Transmission expansion along Utah's north-south backbone system will be required to address the grid constraints and to support the levels of generation and storage**

buildout envisioned in this study. This finding is based on power system modeling that confirms that Utah's current and planned grid is unlikely to be able to accommodate forecasted resource deployment without transmission system upgrades. While perhaps viable for specific projects, non-wires solutions were not effective at providing the required magnitude of transfer capability. Therefore, new transmission is likely to be required.

4. **A transmission buildout in Utah can help tap in-state resource potential.** Study work performed as a part of this project identified transmission builds that would unlock a significant portion of Utah's resource potential, which would help the state meet forecasted needs by 2030. The High resource scenario results in a transmission build for 2030 that adds 291 miles of new and upgraded transmission lines, cost approximately $578 million, and would help to access more than 5,000 MW of new generation and storage capacity. A more modest in-state expansion of 3,500 to 4,000 MW was enabled through the addition of 210 line-miles of new and upgraded transmission at a cost of $325 million. Interconnection costs of the resource scenarios represent an incremental cost not considered in the study.
5. **Investment in in-state transmission and power generation can cause major economic benefits to accrue to Utah, suggesting new jobs and economic growth as potential reasons to unlock Utah's resource potential with transmission expansion.** The investments in the transmission system and new power generation will have many impacts, including economic benefits to Utah's economy. The 2030 generation and transmission buildout considered in the study could drive between 19,980 and 27,200 temporary construction jobs and an additional 485 – 689 permanent jobs in the state. In addition, the buildouts could drive between $1.9 and $2.5 billion in local investment, $256 to $358 million in additional one-time tax revenue, and between $16 and $23 million in permanent incremental tax revenue.

While this study does not recommend specific transmission upgrades or the development of specific generators or technologies, or timelines for such investments, it does indicate that Utah will have a pressing need to expand its bulk power grid and doing so, through strategies like those presented in this study, could result in major economic development within the state.

8.2 Study Observations

In addition to the above findings, a number of relevant observations were identified through the course of this work:

1. **Should Utah's utilities transition to participation in an organized energy market (such as an RTO), physical constraints instead of the contract path constraints evaluated in this study would be a more appropriate means for identifying constrained corridors.** An organized wholesale electricity market could drive the need for more transmission because, for instance, it would provide clearer economic signals around operational transmission congestion. On the other hand, an organized market would likely squeeze as much capacity as possible out of the existing and planned transmission system.

2. **The study conservatively assumed that 100% of the nameplate capacity of new resources must be fully deliverable. The amount of transmission upgrades identified would decrease if weather-dependent resources like wind and solar were assumed to have lower dispatch levels consistent with their typical output during stressed conditions.** However, since the goal of this work was to identify upgrades to mitigate transmission constraints, the study adopted this conservative analytical approach which focuses on pure capacity additions. Certain transmission upgrades may be avoided if new generators were delivered to loads using rights currently used by transmission customers for other purposes.

3. **A 500-kV build option could be further studied with neighboring states.** There could be interregional benefits to completing a 500 kV loop by connecting the new Clover 500 kV substation in Central Utah with either the Nevada or Arizona/New Mexico 500-kV backbone systems. Such expansion would create a transmission "superhighway" connection between Wyoming and Southwest, with Utah as key on/off-ramp.

   This option was significantly more expensive than solutions presented in this study, but if broader benefits or regionally-focused scenarios were considered, higher-voltage upgrades may be beneficial to the system and region.

4. **Development in West Desert (Path 27) requires upgrades and was not a focus of study.** ERZs in the West Desert showed initial promise of accommodating new resources and being a focus of the study. However, the 230 kV system is fairly limited in this area and the cost of accessing the area was high relative to the assumed level of resource development. Construction of transmission lines between the Sigurd 345 kV substation

and Gonder 345 kV substation located in Nevada could allow for additional integration of renewables.

5. **The transmission buildouts presented in this study represent only a portion of the transmission costs required to interconnect and fully deliver resources.** Additional upgrades may be required to collect, interconnect, and deliver resources to loads. In addition, the study likely overlooks additional upgrades that may be required on the lower-voltage system.

6. **The magnitude of southern Utah transmission upgrades depends on resource development in the area**. There is very limited capacity available to add resources in the St. George, Glen Canyon, and Four Corners ERZs. If resources are deployed in significant amount in these areas, major lines must be constructed along several transmission corridors in Southern Utah. Such conceptual lines were identified in this study.

8.3 Study Considerations and Caveats

The following add context to the study results and how they should be interpreted.

1. **This study is not intended as a cost-benefit analysis and is not an optimized build-out nor a "construction plan"**. The study considers the cost of transmission, as well as the economic development benefits of new resources and transmission construction/operation, but it does not include an electric-sector focused benefit vs. cost analysis that might be used to consider investment tradeoffs and would include additional benefit categories.

2. **This study does not supplant local or regional transmission planning analyses and plans.** Transmission providers in Utah have federally-regulated obligations around providing different types of transmission and interconnection service to customers and retail load. This analysis does not consider all aspects of such obligations and is focused on a high-level assessment of the magnitude of potential transmission needs to increase access to Utah generation. As such, there may be alternative or more effective transmission options not identified in this study. For example:

    - Corridors may be space-limited, which could drive alternative transmission lines or configurations

- ➢ Substation expansions to accommodate new transmission additions may be limited, which could drive alternative transmission lines or configurations
- ➢ Study did not include comprehensive permitting risk assessment and, instead, used a simplified tool
- ➢ Transmission may be required sooner or later than what is demonstrated in this scenario-based study

Generally, the study was performed at a high-level focusing on major transmission constraints on the system.

3. **Study does not replace or replicate individual utility resource planning efforts.** Individual utilities perform integrated resource planning to meet state requirements or otherwise optimize their generation resources, and this study used that information to the extent it was available. However, while this study sought to determine where the resources identified by these utilities might be best sited, it does not replace those more detailed assessments.

4. **Study did not focus on opportunities for Utah to develop transmission that facilitates export of generation to neighboring states.** Such analyses would have identified a different set of transmission solutions and would require consideration of a broader set of benefits.

5. **The results and findings herein are not designed to apply to a particular generator, nor do they represent transmission solutions to a particular system performance issues that may be observed in planning studies.**

These factors notwithstanding, we are confident in the reasonableness of the assumptions relied on for this study and consider the results to be an informative and useful road-map for Utah utilities, transmission providers, generators and policy makers as the state continues to consider opportunities to access Utah's resource potential.

9.0 TECHNICAL APPENDICES

9.1 Generation and Transmission Costs

The tables below summarize the transmission and generation capital costs used in the study. The transmission costs were sourced from the WECC Transmission Capital Cost Calculator Tool. The capital cost estimates were based on NREL 2020 ATB forecasts.

Table 31: Per-mile Transmission Line Costs

Transmission Line Type	Per Mile Cost (2018$)
230 kV Single Circuit	$1,024,335
230 kV Double Circuit	$1,639,820
345 kV Single Circuit	$1,434,290
345 kV Double Circuit	$2,295,085
500 kV Single Circuit	$2,048,670
500 kV Double Circuit	$3,278,535

The per-mile cost assumptions above do not include right-of-way costs, AFUDC/overhead costs, or the assumed terrain difficulty multiplier. In addition, they do not include line termination cost. Substation costs were also sourced from the WECC tool.

Generation cost assumptions represent the overnight construction costs and do not including ongoing expenses. Total costs, by technology type and installation year, are outlined in the table below. All cost trajectories assume the R&D investment continues at a level similar to today and no substation innovations or new technologies are introduced to the market.

Table 32: Per-mile Transmission Line Costs

	Capital Cost (2018$/kW)			Notes
Technology Type	2025	2030	2040	
Solar PV	$1,094	$836	$762	1.34 DC-to-AC inverter loading ratio Single-axis tracking
Solar PV + Storage	$1,468	$1,145	$1,030	Assumes storage capacity equals half of solar capacity and co-location causes 8% price reduction
Storage	$1,004	$817	$715	Lithium-ion battery storage, 4-hour
Wind	$1,381	$1,227	$1,102	Assumes Class 3 resource quality
Gas CT	$925	$898	$865	Gas combustion turbine

9.2 Economic Impact Assessment

Points Consulting (PC) assisted Energy Strategies with this economic impact analysis (EIA). Though Energy Strategies provided inputs and answered questions about the project, all analysis and conclusions are an independent third-party assessment by Points Consulting.

About the Project

Energy Strategies provided Points Consulting (PC) the project background and assumptions upon which PC created impact scenarios. Information provided by Energy Strategies included total capital expenditures, megawatt production, and geographic location of investment. Scenarios were provided for three-time horizons (2025, 2030, and 2040), three levels of intensity (base, mid, and high) and across five energy generation and transmission fields.

Economic Impact Methodology & Terminology

To generate this EIA, PC used the IMPLAN input-output (I-O) model. IMPLAN is a subscription-based tool that utilized data from a wide variety of public-sector sources to measure economic activities for all 3,000+ counties in the United States. IMPLAN uses annual, regional data to map businesses' and households' buying/selling relationships in order to predict how specific economic changes will impact a regional economy. With the model users are allowed to change metrics such as employment, earnings, and output (or sales) for any of 546 sectors, and see how those changes would ripple across all sectors of the regional economy. The IMPLAN model includes numerous built-in metrics for industries, such as employment, output, local spending coefficients, industry-specific spending patterns, payroll, exports and imports, profit margins, and so on. In this case, PC evaluated IMPLAN's default assumptions and made adjustments where necessary to ensure that each scenario most closely matches the scenarios outlined by Energy Strategies.

PC used the standard three channels of impact that are included in any EIA. Added together these channels result in the total economic impact to a region. These channels are identified as follows:

- Direct effect – effects directly upon a given industry/industries selected by the user. In this case, industries include various types of energy production and energy transmission.
- Indirect effect – effects upon the selected industries' supply-chains. In other words, how changes in production at the direct level affect purchase of required product and service inputs. Indirect effects measure not only first-round supply chain affects but also effects on industries that sell to those industries (i.e., secondary and tertiary supply chain impacts). Indirect effects are the first component of "multiplier effects."
- Induced effect – effects of increased spending of households' wages on locally produced goods and services. Induced effects are the second component of "multiplier effects."

One issue that occasionally causes confusion for users of EIA are the duration of impacts. Categories tabulated for the construction phase are one-time, based on the duration of the project. In other words, impacts will be the same regardless of whether construction requires 6 months or 30 months. Alternatively, metrics related to the operations phase exist annually, as long as the facility continues operating at the same scale.

Project-Specific Methodology Notes

DATA SOURCES

Energy Strategies provided the key input metrics for the analyses which included the total overnight construction costs of each proposed installation by energy type and the installed cumulative megawatt capacity. They also provided data on the overnight costs of the transmission grid expansion.

Detailed construction and operations budgets were obtained from the JEDI energy models: *Jobs & Economic Development Impact Models* (Jobs and Economic Development Impact (JEDI) Models | NREL), produced by the National Renewable Energy Laboratory (NREL). Specifically, PC reviewed the JEDI Natural Gas Model, Wind Model, Concentrating Solar Power Model, and the Transmission Line Model. The most important metric in these models was the detailed construction and operations budgets.

A 2019 IMPLAN (Economic Impact Analysis for Planning | IMPLAN) model for Utah State was constructed to calculate the economic impacts. Additionally, the Emsi database (Emsi: Labor Market Analytics (economicmodeling.com) was also available to assist with results validation. Lastly, at the request of Energy Strategies, all of the results of this study are reported in constant 2018 dollars (both inputs and outputs).

ANALYSES

There were four basic analyses address within the study. These four were ultimately adjusted within spreadsheets using linear scaling techniques to arrive at the end results.

- First, were the construction contributions of the powerplants. These contributions are temporary and are assumed to have a one-year duration for each project.
- The second analysis measures the contributions from the construction of the transmission grid. These contributions are temporary and the jobs are also reported in job-years.
- The third analysis measures the contributions of the operations of the power plants which are reported annually.
- The fourth analysis measures the contributions of the operations of the transmission grid which also occur annually.

Individual analyses were conducted for the construction and operations by energy type, by case, and by scenario. Overall, PC completed 41 construction model runs and 41 operation runs, for a total of 82 individual analyses.

ECONOMIC BASE ASSUMPTION

This analysis is founded on economic base theory. A local or regional economy has two types of industries: base industries and non-base industries. Any economic activity that brings money into the local economy from the outside is considered a base industry. A base industry is sometimes identified as an export industry, which is defined as any economic activity that brings new monies into the community from outside. For example, base industries can include high-technology companies, federal government operations, and other manufacturing and service firms. Firms providing services to individuals living outside the region's trade center, such as medical and legal services, are included in the region's economic base. Payments from state and federal governments (including Social Security, Medicare, university funding, retirement accounts, and welfare payments) are sources of outside income to businesses and residents. These are counted as part of the economic base.

Non-base industries are defined as economic activity within a region that support local consumers and businesses within the base sector. They re-circulate incomes generated within the region from the base industries. Such activities include, but are not limited to, shopping malls that serve the local population, business and personal services consumed locally, barbers, medical services consumed locally, and local construction contracts. Non-base industries support the base industries.

Base industries are sometimes confused with non-base industries. For example, some county economies have large retail trade sectors that produce a paradox: they employ a substantial percentage of the workforce but actually contribute little to the local economy because most of the retail sales are local. They bring little new money into the community. Thus, it appears from the size effect that the retail trade sector contributes a large amount of employment and earnings to the economy. Most of this employment and earning activity is allocated or attributed to other local "export" industries that bring revenues into the community from outside sales. From an economic base perspective, which determines the economic "drivers" of the economy, the retail trade sector is much smaller. Only the retail trade activities serving visitors from outside the area can be counted as economic base activity.

Economic base analysis is important for identifying the vital export industries of a region. Non-base industries, on the other hand, are important for keeping money within a region and stimulating local economic activity for residents. In this respect, non-base industries are said to deepen the economy while export industries are said to broaden it. For example, suppose a

Utah patient elects surgery at a Salt Lake City hospital instead of traveling to a medical center in San Francisco, California. The substitution of local services for an imported service represents an increase in the demand for local business services. Keeping income in the community enhances the multiplier effects of the export industries. The overall effect of import substitution can be viewed as an analogous increase in demand for an export industry.

EXPENDITURE-DRIVEN APPROACH

Electricity markets are regionally vast and not limited to political boundaries, such as Utah's state border. Electricity produced from a specific power plant tends to be diffused across large regional markets. Identification of the specific geographical location of the end-use of revenues and expenditures from electrical power plants can be problematic and was outside the scope of this study. The approach of this analysis is to focus on the expenditures generated within Utah that could be reasonably validated.

IDENTIFYING UTAH CONSTRUCTION EXPENDITURES

This study focused on evaluating the key input drivers of the economic contribution analysis for the energy projects. The most important metric was the determination of the portion of construction and operating expenditures that occurred in Utah and the portion that occurred out-of-state. Only in-state expenditures are counted towards the calculations of the economic contributions. For energy projects, a substantial portion of the plant and equipment are manufactured out-of-state and are not included in the calculation of the economic contributions. Out-of-state imports are, however, still taxed at the standard Utah sales tax rate, so they are considered within that section of our analysis.

In Table 4, the total overnight construction costs are situated in the column labeled Gross Inputs. Adjacent to this column are the Net Inputs which represents the estimated dollar expenditures occurring in Utah state. Net inputs include both the direct labor expenses and the materials and supplies purchased in Utah. The percentage of in-state expenditures per project ranges from a low of 24% for wind energy projects to 42% for solar projects. This is consistent with other energy related projects conducted by the principal investors of this project.

Identifying Utah Labor Expenditures

Several important assumptions were made in this analysis with regards to direct labor. It was assumed that the general contractors would largely be from Utah-based companies and the suppliers and contractors in the supply chain would give preference to Utah-based companies. The labor needed for energy projects would be mostly drawn from the Utah labor market. This would be partially dependent on the projects' location within the state. Utah has an excellent interstate and highway system, making most construction sites accessible to commuting workers. PC estimate that about 88% of all construction labor would be drawn within the Utah labor market. If the general contractor were chosen outside the state, then the labor component would be reduced accordingly. It was also assumed that most of the professional expertise needed for the projects would be acquired in Utah.

Construction Inputs to IMPLAN

IMPLAN has thirteen construction sectors in the model. The sector most applicable is IMPLAN *Sector 52: Construction of new power and communication structures.* The sector has a detailed production function that tracks the backward linkages of energy construction expenditures throughout all other sectors in the economy. Where more detailed sector data was available, it was utilized in the calculation of the economic impacts. Some professional services were identified separately in the budgets and they were entered into the IMPLAN *Sector 457: Architectural, engineering, and related services.* Management services (where identified) were entered into *Sector 462: Management consulting services.* Retail trade was reported separately in some cases and entered into the IMPLAN *Sector 405 Retail - Building material and garden equipment and supplies stores.*

The IMPLAN model is very robust, allowing for both high level analyses when data is limited and much more granular results when greater data is available. Our team used a mix of both levels of detail in this analysis.

Operating Expenditure Inputs to IMPLAN

The JEDI models report operating revenue and expenditure budgets. PC utilized the data from these budgets in calculating the economic contributions from the operations of the energy plants. PC included only the operating contributions created by the expenditure flows from actual plant and transmission operations. The results exclude the majority of the financing and owner return expenditures which are assumed to largely flow out-of-state.

Multipliers

The average employment multiplier for temporary (construction) projects was 1.85. For every one direct construction job, a total of 1.85 jobs are average multiplier was 1.67. The average labor income multiplier was 1.67. The gross state product multiplier was 1.75. The average sales (output) multiplier was 1.82. These multipliers are in the standard range for construction projects in a state economy the size of Utah.

The average employment multiplier for permanent operations jobs was 4.26. For every direct operations job, a total of 4.26 jobs are created in the economy (including the multiplier effects). The average multiplier for labor income was 2.15. The gross state product multiplier was 1.72. The average sales (output) multiplier was 1.84. These are in the standard range for energy generation in a state economy the size of Utah.

The average employment multiplier for temporary construction jobs was 1.85. For every direct construction job, a total of 1.85 jobs are created in the economy (including the multiplier effects). The labor income average multiplier was 1.67. The gross state product multiplier was 1.75. The average sales (output) multiplier was 1.82. These are all in the standard range for a state economy the relative size of Utah.

Detailed EIA Scenario Tables

Detailed tables for each of the scenarios provided by Energy Strategies are provided in the following tables. All data can be cross-referenced across Tables 4 through 6 using the first three columns of information (Type, Year, and Case/Scenario). Please note, in interest of preserving space, all monetary values are in $M.

Construction Phase: Model Inputs and Percent In-State Spending Capture

Type	Year	Case/Scenario	Net Inputs	Gross Inputs	In-State %
Transmission	30	Base/ Mid Case	$100.5	$325.0	31%
Transmission	30	High Case	$178.6	$577.8	31%
Wind	25	Base Case	$43.9	$179.5	24%
Wind	30	Base Case	$73.9	$302.2	24%
Wind	40	Base Case	$109.0	$445.4	24%
Wind	25	Mid Case	$50.7	$207.1	24%
Wind	30	Mid Case	$110.7	$452.5	24%
Wind	40	Mid Case	$178.1	$727.9	24%
Wind	25	High Case	$57.4	$234.8	24%
Wind	30	High Case	$150.5	$615.0	24%
Wind	40	High Case	$255.6	$1,044.7	24%
Solar + Storage	25	Base Case	$958.9	$2,364.0	41%
Solar + Storage	30	Base Case	$1,581.2	$3,898.2	41%
Solar + Storage	40	Base Case	$2,036.5	$5,020.8	41%
Solar + Storage	25	Mid Case	$1,006.5	$2,481.5	41%
Solar + Storage	30	Mid Case	$1,707.7	$4,210.3	41%
Solar + Storage	40	Mid Case	$2,250.8	$5,549.2	41%
Solar + Storage	25	High Case	$1,048.2	$2,584.2	41%
Solar + Storage	30	High Case	$1,851.6	$4,565.0	41%
Solar + Storage	40	High Case	$2,520.0	$6,212.9	41%
Solar	25	Base Case	-	-	
Solar	30	Base Case	-	-	
Solar	40	Base Case	-	-	
Solar	25	Mid Case	$9.2	$21.9	42%
Solar	30	Mid Case	$41.0	$97.1	42%
Solar	40	Mid Case	$160.1	$379.1	42%
Solar	25	High Case	-	-	
Solar	30	High Case	$63.6	$150.5	42%

Solar	40	High Case	$134.4	$318.1	42%
Battery	25	Base Case	$12.2	$30.1	41%
Battery	30	Base Case	$25.5	$62.8	41%
Battery	40	Base Case	$100.9	$248.7	41%
Battery	25	Mid Case	$28.5	$70.3	41%
Battery	30	Mid Case	$68.3	$168.3	41%
Battery	40	Mid Case	$265.5	$654.5	41%
Battery	25	High Case	$40.7	$100.4	41%
Battery	30	High Case	$110.3	$272.0	41%
Battery	40	High Case	$443.8	$1,094.2	41%
Natural Gas	25	Base Case	$76.8	$251.4	31%
Natural Gas	30	Base Case	$76.8	$251.4	31%
Natural Gas	40	Base Case	$193.2	$632.2	31%
Natural Gas	25	Mid Case	-	-	
Natural Gas	30	Mid Case	$52.1	$170.6	31%
Natural Gas	40	Mid Case	$168.5	$551.4	31%
Natural Gas	25	High Case	-	-	
Natural Gas	30	High Case	$181.1	$592.7	31%
Natural Gas	40	High Case	$297.4	$973.5	31%

Construction Phase: Model Outputs and Taxes

Type	Y	Case/ Scenario	Jobs	Labor Income	Gross State Product	Output	Prop-erty	Sales/Excise	Income	Total
Trans-mission	NA	Base/ Mid Case	1,065	$60.6	$107.1	$177.7	$1.4	$13.3	$2.4	$17.1
Trans-mission	NA	High Case	1,893	$107.8	$190.4	$315.8	$2.4	$23.6	$4.3	$30.3
Wind	25	Base Case	435	$24.6	$43.1	$76.0	$0.61	$7.65	$0.98	$9.25
Wind	30	Base Case	733	$41.4	$72.6	$128.0	$1.03	$12.88	$1.65	$15.57
Wind	40	Base Case	1,080	$61.0	$107.0	$188.7	$1.52	$18.99	$2.43	$22.94
Wind	25	Mid Case	502	$28.4	$49.8	$87.7	$0.71	$8.83	$1.13	$10.67
Wind	30	Mid Case	1,097	$62.0	$108.7	$191.7	$1.55	$19.29	$2.47	$23.31
Wind	40	Mid Case	1,765	$99.7	$174.9	$308.3	$2.49	$31.03	$3.97	$37.49
Wind	25	High Case	569	$32.1	$56.4	$99.4	$0.80	$10.01	$1.28	$12.09
Wind	30	High Case	1,491	$84.2	$147.8	$260.5	$2.10	$26.22	$3.35	$31.68
Wind	40	High Case	2,533	$143.1	$251.1	$442.5	$3.57	$44.54	$5.70	$53.81
Solar + Storage	25	Base Case	10,343	$598.5	$941.4	$1,788.0	$12.53	$90.13	$22.94	$125.59

Solar + Storage	30	Base Case	17,056	$986.9	$1,552.4	$2,948.4	$20.66	$148.62	$37.82	$207.10
Solar + Storage	40	Base Case	21,968	$1,271.1	$1,999.5	$3,797.5	$26.61	$191.42	$48.72	$266.74
Solar + Storage	25	Mid Case	10,857	$628.2	$988.2	$1,876.8	$13.15	$94.60	$24.08	$131.83
Solar + Storage	30	Mid Case	18,421	$1,065.9	$1,676.7	$3,184.5	$22.31	$160.52	$40.85	$223.68
Solar + Storage	40	Mid Case	24,279	$1,404.8	$2,209.9	$4,197.1	$29.41	$211.56	$53.84	$294.82
Solar + Storage	25	High Case	11,307	$654.2	$1,029.1	$1,954.6	$13.70	$98.52	$25.07	$137.29
Solar + Storage	30	High Case	19,973	$1,155.7	$1,817.9	$3,452.7	$24.19	$174.04	$44.29	$242.53
Solar + Storage	40	High Case	27,183	$1,572.8	$2,474.2	$4,699.1	$32.93	$236.86	$60.28	$330.07
Solar	25	Base Case	-	-	-	-	-	-	-	-
Solar	30	Base Case	-	-	-	-	-	-	-	-
Solar	40	Base Case	-	-	-	-	-	-	-	-
Solar	25	Mid Case	96	$5.5	$8.7	$16.5	$0.12	$0.82	$0.21	$1.14
Solar	30	Mid Case	425	$24.6	$38.7	$73.5	$0.51	$3.62	$0.94	$5.08
Solar	40	Mid Case	1,658	$96.0	$151.0	$286.7	$2.01	$14.14	$3.68	$19.83
Solar	25	High Case	-	-	-	-	-	-	-	-
Solar	30	High Case	658	$38.1	$59.9	$113.8	$0.80	$5.61	$1.46	$7.87
Solar	40	High Case	1,392	$80.5	$126.7	$240.6	$1.69	$11.87	$3.09	$16.64
Battery	25	Base Case	132	$7.6	$12.0	$22.8	$0.16	$1.15	$0.29	$1.60
Battery	30	Base Case	275	$15.9	$25.0	$47.5	$0.33	$2.39	$0.61	$3.34
Battery	40	Base Case	1,088	$63.0	$99.0	$188.1	$1.32	$9.48	$2.41	$13.21
Battery	25	Mid Case	307	$17.8	$28.0	$53.2	$0.37	$2.68	$0.68	$3.73
Battery	30	Mid Case	736	$42.6	$67.0	$127.3	$0.89	$6.42	$1.63	$8.94
Battery	40	Mid Case	2,864	$165.7	$260.7	$495.0	$3.47	$24.95	$6.35	$34.77
Battery	25	High Case	439	$25.4	$40.0	$75.9	$0.53	$3.83	$0.97	$5.33
Battery	30	High Case	1,190	$68.9	$108.3	$205.7	$1.44	$10.37	$2.64	$14.45
Battery	40	High Case	4,787	$277.0	$435.8	$827.6	$5.80	$41.72	$10.62	$58.13
Natural Gas	25	Base Case	-	$0.0	$0.0	$0.0	$0.00	$0.00	$0.00	$0.00
Natural Gas	30	Base Case	853	$48.9	$82.6	$139.4	$1.07	$10.34	$1.92	$13.34
Natural Gas	40	Base Case	2,145	$122.8	$207.7	$350.5	$2.69	$26.01	$4.83	$33.53
Natural Gas	25	Mid Case	-	-	-	-	-	-	-	-
Natural Gas	30	Mid Case	579	$33.2	$56.1	$94.6	$0.73	$7.02	$1.30	$9.05

Natural Gas	40	Mid Case	1,871	$107.1	$181.2	$305.7	$2.35	$22.69	$4.22	$29.25
Natural Gas	25	High Case	-	-	-	-	-	-	-	-
Natural Gas	30	High Case	2,011	$115.2	$194.7	$328.5	$2.52	$24.38	$4.53	$31.44
Natural Gas	40	High Case	3,303	$189.1	$319.8	$539.6	$4.14	$40.05	$7.44	$51.63

Operations Phase: Model Outputs and Taxes

Type	Y	Case/Scenario	Jobs	Labor Income	Gross State Product	Output	Property	Sales/Excise	Income	Total
Trans-mission	30	Base/ Mid Case	32	$2.8	$7.2	$15.2	$0.3	$0.6	$0.1	$1.1
Trans-mission	30	High Case	57	$5.0	$12.8	$27.1	$0.6	$1.1	$0.2	$1.9
Wind	25	Base Case	24	$1.8	$7.0	$13.6	$0.39	$0.69	$0.10	$1.18
Wind	30	Base Case	41	$3.1	$11.8	$22.9	$0.66	$1.16	$0.16	$1.98
Wind	40	Base Case	61	$4.5	$17.4	$33.7	$0.97	$1.70	$0.24	$2.92
Wind	25	Mid Case	28	$2.1	$8.1	$15.7	$0.45	$0.79	$0.11	$1.36
Wind	30	Mid Case	61	$4.6	$17.6	$34.2	$0.99	$1.73	$0.24	$2.96
Wind	40	Mid Case	99	$7.4	$28.4	$55.1	$1.59	$2.78	$0.39	$4.76
Wind	25	High Case	32	$2.4	$9.2	$17.8	$0.51	$0.90	$0.13	$1.54
Wind	30	High Case	84	$6.3	$24.0	$46.5	$1.34	$2.35	$0.33	$4.03
Wind	40	High Case	142	$10.7	$40.7	$79.1	$2.28	$4.00	$0.56	$6.84
Solar + Storage	25	Base Case	229	$20.7	$54.6	$100.2	$2.38	$4.17	$0.93	$7.48
Solar + Storage	30	Base Case	378	$34.1	$90.0	$165.2	$3.92	$6.88	$1.54	$12.34
Solar + Storage	40	Base Case	487	$43.9	$115.9	$212.7	$5.05	$8.86	$1.98	$15.90
Solar + Storage	25	Mid Case	241	$21.7	$57.3	$105.1	$2.50	$4.38	$0.98	$7.86
Solar + Storage	30	Mid Case	409	$36.8	$97.2	$178.4	$4.24	$7.43	$1.66	$13.33
Solar + Storage	40	Mid Case	538	$48.6	$128.2	$235.1	$5.58	$9.79	$2.19	$17.57
Solar + Storage	25	High Case	251	$22.6	$59.7	$109.5	$2.60	$4.56	$1.02	$8.18
Solar + Storage	30	High Case	443	$40.0	$105.4	$193.4	$4.59	$8.06	$1.80	$14.45
Solar + Storage	40	High Case	603	$54.4	$143.5	$263.2	$6.25	$10.97	$2.45	$19.67
Solar	25	Base Case	-	-	-	-	-	-	-	-
Solar	30	Base Case	-	-	-	-	-	-	-	-

Solar	40	Base Case	-	-	-	-	-	-	-	-
Solar	25	Mid Case	2	$0.2	$0.5	$0.9	$0.02	$0.04	$0.01	$0.07
Solar	30	Mid Case	9	$0.8	$2.2	$4.1	$0.10	$0.17	$0.04	$0.31
Solar	40	Mid Case	37	$3.3	$8.8	$16.1	$0.38	$0.67	$0.15	$1.20
Solar	25	High Case	-	-	-	-	-	-	-	-
Solar	30	High Case	15	$1.3	$3.5	$6.4	$0.15	$0.27	$0.06	$0.48
Solar	40	High Case	31	$2.8	$7.3	$13.5	$0.32	$0.56	$0.13	$1.01
Battery	25	Base Case	3	$0.3	$0.7	$1.3	$0.03	$0.05	$0.01	$0.10
Battery	30	Base Case	6	$0.5	$1.5	$2.7	$0.06	$0.11	$0.02	$0.20
Battery	40	Base Case	24	$2.2	$5.7	$10.5	$0.25	$0.44	$0.10	$0.79
Battery	25	Mid Case	7	$0.6	$1.6	$3.0	$0.07	$0.12	$0.03	$0.22
Battery	30	Mid Case	16	$1.5	$3.9	$7.1	$0.17	$0.30	$0.07	$0.53
Battery	40	Mid Case	64	$5.7	$15.1	$27.7	$0.66	$1.16	$0.26	$2.07
Battery	25	High Case	10	$0.9	$2.3	$4.3	$0.10	$0.18	$0.04	$0.32
Battery	30	High Case	26	$2.4	$6.3	$11.5	$0.27	$0.48	$0.11	$0.86
Battery	40	High Case	106	$9.6	$25.3	$46.4	$1.10	$1.93	$0.43	$3.46
Natural Gas	25	Base Case	-	$0.0	$0.0	$0.0	$0.13	$0.23	$0.08	$0.44
Natural Gas	30	Base Case	27	$2.0	$3.5	$5.5	$0.13	$0.23	$0.08	$0.44
Natural Gas	40	Base Case	69	$5.0	$8.9	$13.8	$0.33	$0.57	$0.20	$1.10
Natural Gas	25	Mid Case	-	-	-	-	-	-	-	-
Natural Gas	30	Mid Case	19	$1.4	$2.4	$3.7	$0.09	$0.16	$0.05	$0.30
Natural Gas	40	Mid Case	60	$4.4	$7.7	$12.0	$0.29	$0.50	$0.17	$0.96
Natural Gas	25	High Case	-	-	-	-	-	-	-	-
Natural Gas	30	High Case	64	$4.7	$8.3	$12.9	$0.31	$0.54	$0.18	$1.03
Natural Gas	40	High Case	106	$7.8	$13.7	$21.2	$0.50	$0.88	$0.30	$1.69

About Points Consulting

At Points Consulting (PC) we believe in the power of peoples' interests, passions, and behaviors to shape the world arounds us. Now more than ever, people are the primary factor in the success of businesses, organizations and communities. For that reason, our work is focused not only on how people impact communities and organizations, but how to align their potential to create more successful outcomes for all.

We partner with a variety of industries including state and local government agencies, higher education, not-for-profits, real estate developers, and private companies to understand and unleash the power of the workforce in our midst. Built on our experience advising hundreds of high performing organizations, Points Consulting strives to answer complex economic questions and recommend workable solutions. In summary, at Points Consulting we believe in "Improving Economies. Optimizing Workforce."

PC has 13+ years' experience conducting economic impact analysis (EIA), as well as other regional market and industry analyses. Much or our work is focused on issues specific to rural western communities in state such as Washington, Wyoming, Utah and Idaho. Specifically related to EIA, our team has conducted 30+ boutique economic impact analyses over the past 10-years including recent engagements with institutions such as the Kentucky Cabinet for Economic Development, Cal Poly- San Luis Obispo, and Purdue University.

9.3 PacifiCorp Queue and LGIA

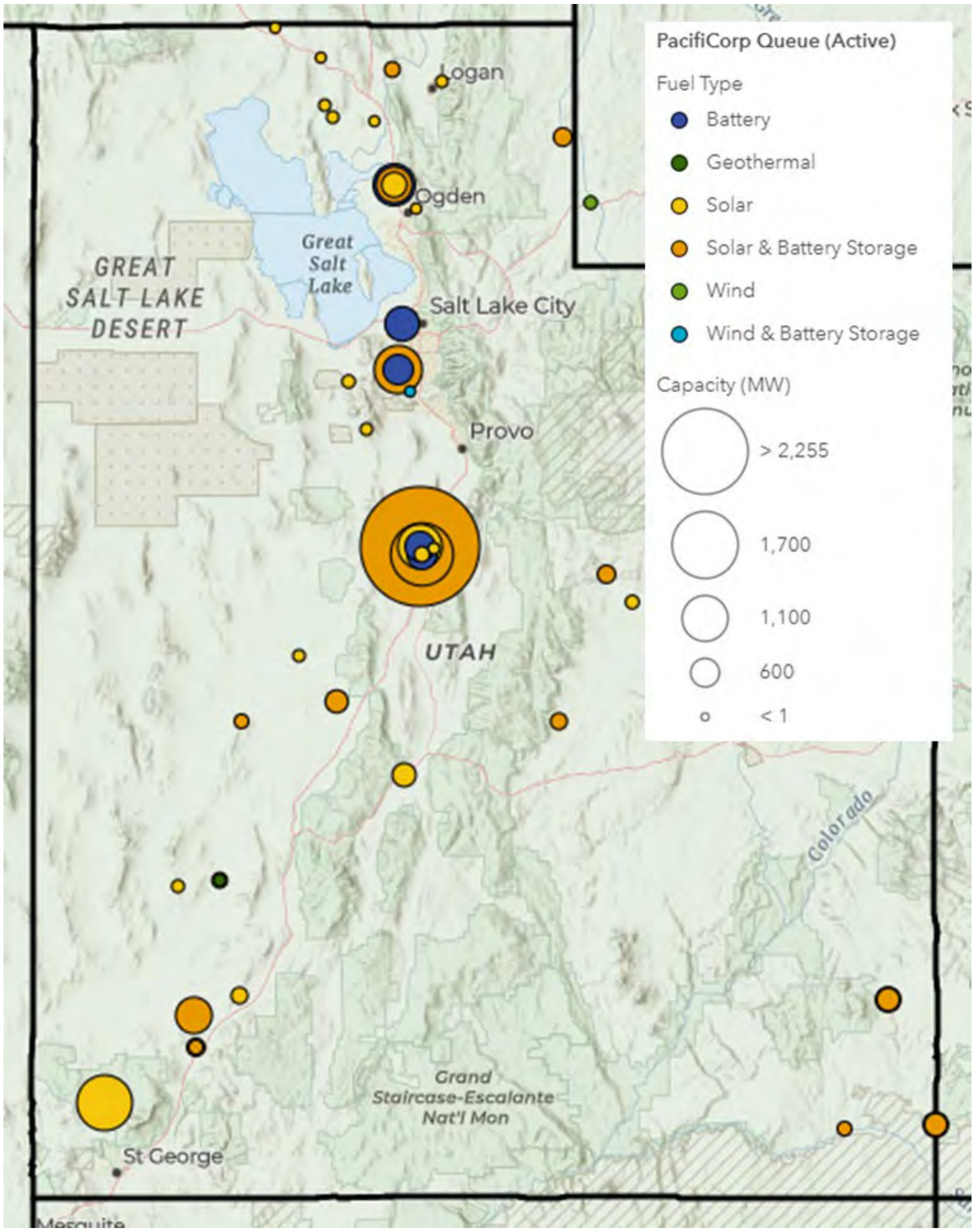


Figure 27: PacifiCorp Active Queue (accessed mid-2020)

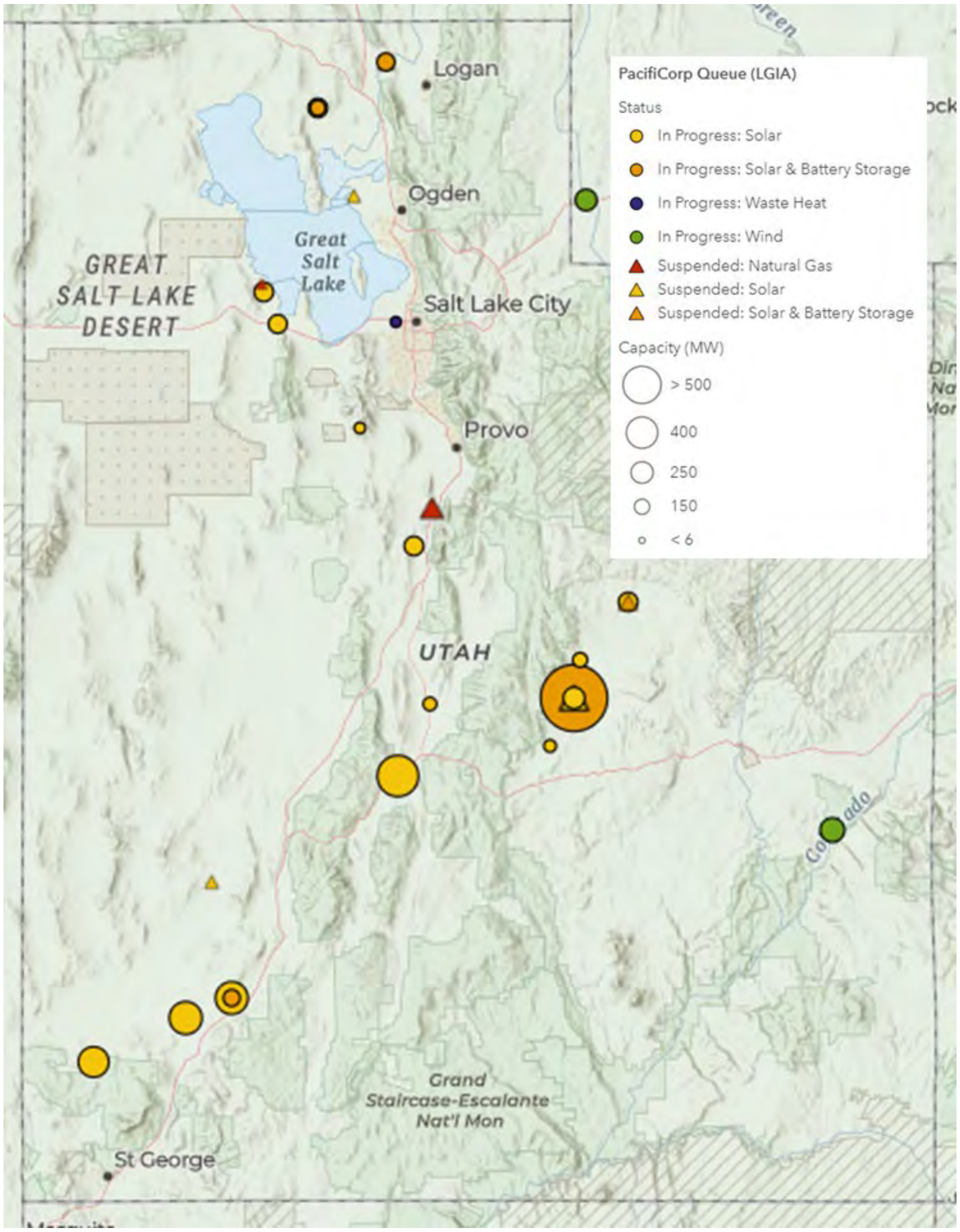


Figure 28: PacifiCorp Large Generation Interconnection Agreements (LGIA) (accessed mid-2020)

9.4 ERZ Data

Solar ERZs Allocations

In order to determine likely development locations for Solar and Solar + Storage in the state of Utah, Energy Strategies utilized a County-to-ERZ mapping. Prospective developments in each county would be mapped to a certain ERZ (e.g., all developments in Washington County would be considered developed within the St. George ERZ). The County-to-ERZ mapping can be seen in Table 33.

Table 33: County to ERZ Mapping

County	ERZ Zone
Emery	Central Utah
Sevier	Central Utah
Iron	St. George
Grand	Other
Uinta	Other
Tooele	West Desert
Box Elder	Northern Utah
Carbon	Mona
Juab	Mona
Sanpete	Mona
Salt Lake	West Desert
Washington	St. George
San Juan	Four Corners
Millard	Central Utah
Rich	Northern Utah
Beaver	Central Utah
Cache	Northern Utah
Weber	Northern Utah

This mapping was used with the PacifiCorp Queue and LGIA to determine queued capacities for each ERZ. The proportion of each ERZs capacity to all queued capacity represented it's "queue-based allocation" percentage. It was assumed that Standalone Solar (referred to as "Solar") and coupled Solar + Storage (referred to as "Solar + Storage") would be sited in equal proportions across all Utah ERZs. As such, queued projects for Solar and Solar + Storage were modeled together and are presented as a single resource type for the remainder of the study.

Table 34: Queue-Based Allocations for Solar & Solar + Storage

ERZ	Solar & Solar + Storage Queued Capacity (MW)	Queue-Based Allocation Percentage
Central Utah	1817	14.6%
St. George	2452	19.7%
Far South	0	0.0%
West Desert	1023	8.2%
Northern Utah	1387	11.2%
Mona	4574	36.8%
Four Corners	1175	9.5%
Total	**12,428**	**100%**

Adjustments to Queue-Based ERZ Allocations for Solar

Upon review of geospatial solar resource quality data, Energy Strategies used engineering judgement to adjust these allocations to utilize all three southern transmission branches. In the queue-based allocations above, the Far South ERZ (representing south-central Utah) shows no prospective solar developments. To fully utilize the TOT2B2 transmission path (Glen Canyon to Sigurd), Energy Strategies allocated 6% of in-state PV development to Glen Canyon – subtracting allocation percentages equally from the other 6 solar ERZs.

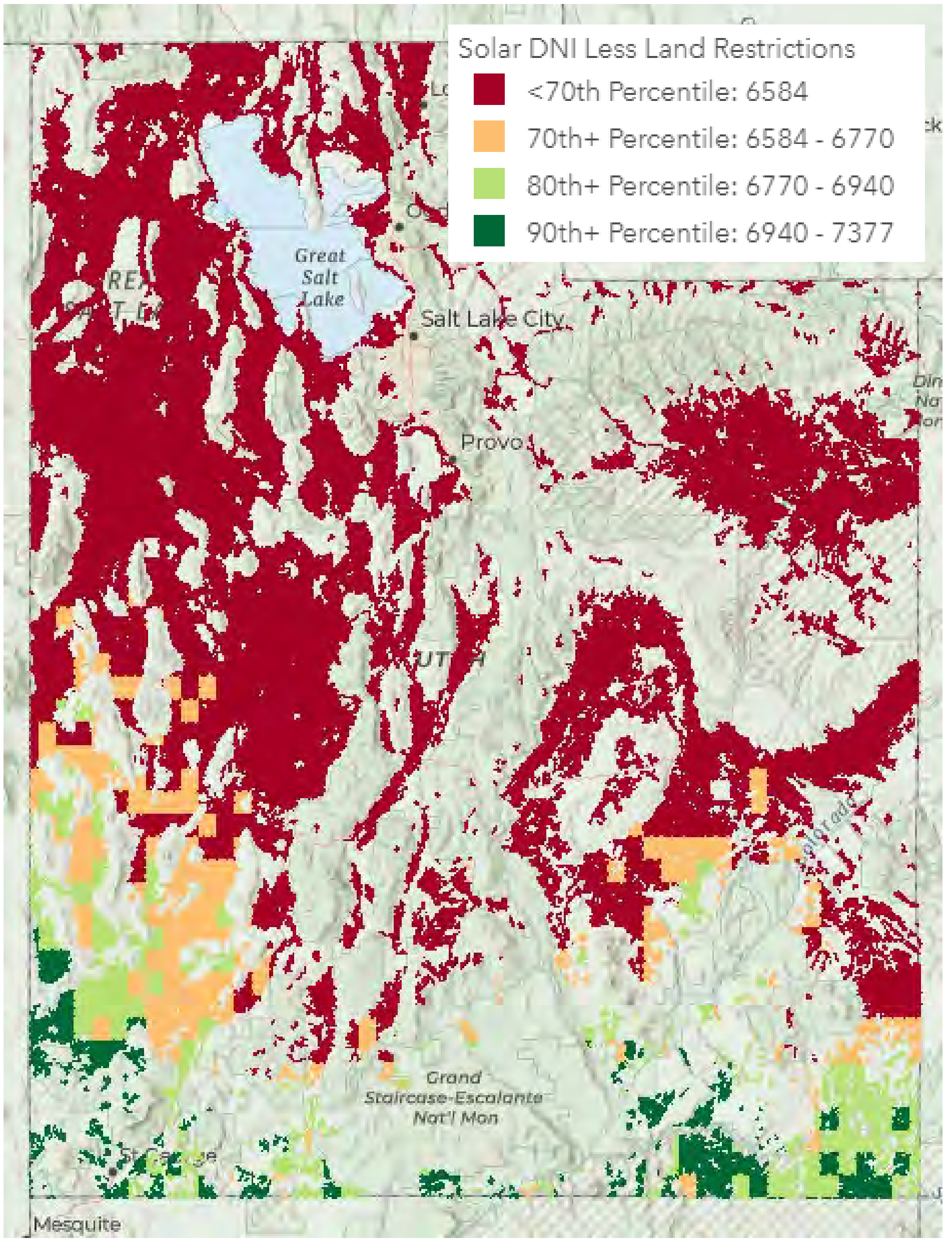


Figure 29: NREL GIS Layer of Solar Direct Normal Irradiance (DNI) in Utah

Table 35: Adjustments to Solar & Solar + Storage Allocations

ERZ	Solar + Battery Queued Capacity (MW)	Queue-Based Allocations	TOT2B2 Adjustment	Methodology	Final Allocations
Central Utah	1,817	15%	-1.0%	Adjusted 6% to Far South. Spread the decreases equally between the remaining ERZs.	13.6%
St. George	2,452	20%	-1.0%		18.7%
Far South	0	0%	6.0%		6.0%
West Desert	1,023	8%	-1.0%		7.2%
Northern Utah	1,387	11%	-1.0%		10.2%
Mona	4,574	37%	-1.0%		35.8%
Four Corners	1,175	9%	-1.0%		8.5%

This adjustment resulted in a well-rounded and geographically diverse representation of Solar and Solar + Storage development within the state of Utah in the study time frame.

Wind ERZ Allocations

A handful of utility-scale wind projects have been developed (or are currently under development) in the state of Utah. Based on resource quality information, knowledge of existing projects, and the PacifiCorp queue, Energy Strategies surmised that, if utility-scale wind were to be developed in-state in the coming 20 years, it would likely be in either one of two wind corridors: the Milford wind corridor in West-Central Utah, or possibly some locations in Southeast Utah. According to this logic, Energy Strategies split up prospective wind development 50/50 between these two ERZs.

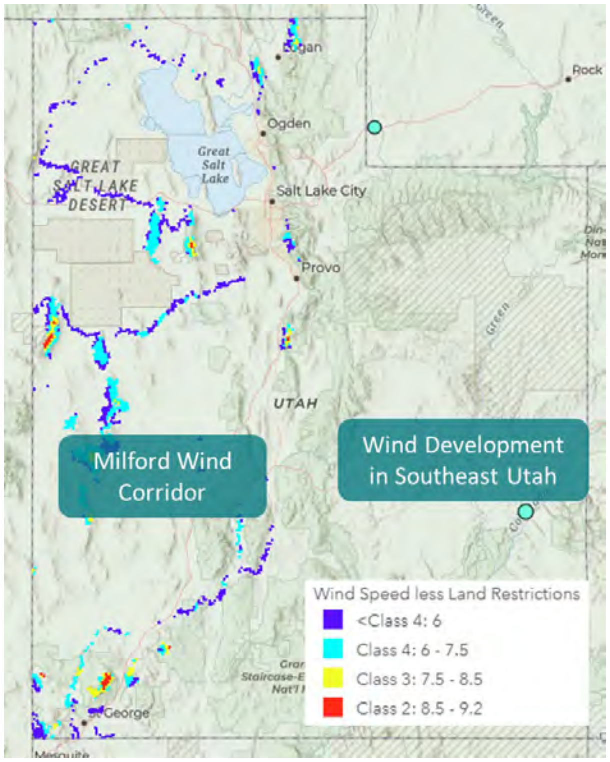


Figure 30: Wind Speed Class (excluding land restrictions), and Wind in PacifiCorp Active Queue

Battery ERZ Allocations

Energy Strategies utilized PacifiCorp queue data to determine the locations of battery-storage projects. Not surprisingly, most prospective battery storage projects in the queue are located along or close to the Wasatch Front. We can expect much of the state's battery storage to be developed near Utah's commercial and industrial centers inside the PACE load center.

Table 36: Queue-Based ERZ Allocations for Battery Storage

ERZ	Queued Standalone Battery Capacity (MW)	Allocation Percentage
PACE Load Center	490	20.9%
Northern Utah	650	27.8%
Central Utah	800	34.2%
West Desert	400	17.1%

9.5 Transmission Lines in WFS and NHS Cutplanes

Table 37: Transmission Lines Included in the North of Huntington-Sigurd Cutplane

North of Huntington/Sigurd Cutplane					
Element	PAC Study	2030 HS Case	Base	Mid	High
Huntington - Spanish Fork 345 kV #1	X	X	X	X	X
Emery - Spanish Fork 345 kV #1	X	X	X	X	X
Mona - Huntington 345 kV #1	X	X	X	X	X
Sigurd - Clover - Mona 345 kV #1	X	X	X	X	X
Sigurd - Clover - Mona 345 kV #2	X	X	X	X	X
New Sigurd - Clover - Mona 345 kV #2			X	X	X
New Mona - Huntington 345 kV #2					X

Table 38: Transmission Lines Included in the Wasatch Front South (WFS) Cutplane

Wasatch Front South (WFS) Cutplane					
Element	PAC Study	2030 HS Case	Base	Mid	High
Camp Williams - Mona 345 kV #1	X	X	X	X	X
Camp Williams - Mona 345 kV #2	X	X	X	X	X
Camp Williams - Mona 345 kV #3	X				
Camp Williams - Mona 345 kV #4	X	X	X	X	X
Spanish Fork - Huntington 345 kV #1	X	X	X	X	X
Spanish Fork - Emery 345 kV #1	X	X	X	X	X
Oquirrh - Clover 345 kV #1	X	X	X	X	X
Dry Creek - Nebo 138 kV #1	X	X	X	X	X
Clover - Camp Williams 345 kV		X	X	X	X
New Camp Williams - Mona 345 kV #5			X	X	X

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