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Technical Report
NREL/TP-7A40-64969
November 2015

Contract No. DE-AC36-08GO28308

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National Renewable Energy Laboratory
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Foreword

The Salton Sea and the surrounding region face a wide range of environmental concerns from reduced inflows and other environmental factors, including exposed, potentially emissive lake beds; rising salinity; and impacts to aquatic and migratory avian species. A restoration program is urgently needed to address these concerns. Funded through a grant from the State of California Natural Resources Agency, under Agreement No. 0540-SSA 1, the Salton Sea Authority (SSA) is preparing the Salton Sea Funding and Feasibility Action Plan to address this need.

The broad goal of the Salton Sea Funding and Feasibility Action Plan is to develop an updated vision for the Salton Sea and surrounding region that matches funding realities with needs. The project has three specific goals:

- Provide a healthy environment for residents around the Salton Sea
- Work toward a Salton Sea and bordering habitat that sustains enough aquatic life to provide habitat for wildlife on the Pacific flyway
- Help revitalize the economy around the Salton Sea and in Imperial and Riverside Counties.

Goals and objectives for the project can be divided into the following categories: planning and engineering, environmental, and financing and feasibility which includes evaluating land development options and alternative energy sources. The restoration program is divided into seven benchmarks: 1) Work Plan, 2) Data Compilation, 3) Alternatives Evaluation, 4) Conceptual Plans, 5) Funding Evaluation from Real Estate Development Sources, 6) Funding Evaluation from Renewable Energy Sources, and 7) Final Report.

The Authority retained Tetra Tech to serve as the prime contractor to help complete the plan. Tetra Tech's subcontractor, the National Renewable Energy Laboratory (NREL), was retained to prepare a report analyzing the potential of various renewable energy technologies to financially contribute to Salton Sea restoration efforts in partial completion of benchmark 6.

In 2013, the Imperial Irrigation District commissioned a preliminary study on the potential for renewable energy projects in the Salton Sea region to partially fund the restoration of the Salton Sea. This feasibility study examined the revenue potential from renewable energy project development in the Imperial Valley and estimated that roughly $4.1 billion might be realizable over the study period of 2016 to 2045. This study specifically seeks to confirm and refine these prior revenue potential estimates, provide a technical review of the renewable energy technologies under consideration, and develop estimates of the region’s developable production potential through the year 2030.

Acknowledgments

This work is made possible through and in support of the goals of the State of California, Tetra Tech, and the Salton Sea Authority. The authors would like to thank the interest and support of the many contributors to this report, including: the U.S. Department of Energy, Imperial Irrigation District, Imperial and Riverside Counties, the U.S. Bureau of Reclamation, the California Natural Resources Agency, the California Public Utilities Commission, and the Los Angeles Department of Water and Power. Additional thanks to NREL contributors Connie Komomua, Erik Ness, Anelia Milbrandt, Niall O'Connor, and Nick Grue for their invaluable support of the project.

List of Acronyms

AC	alternating current
APS	Arizona Public Service
a-Si	amorphous silicon
ASTER	Advanced Spaceborne Thermal Emission and Reflection Radiometer
BLM	Bureau of Land Management
BWRO	brackish water reverse osmosis
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCNG	combined cycle natural gas generator
CdTe	cadmium telluride
CIGS	copper indium gallium selenide
CO2	carbon dioxide
CPUC	California Public Utility Commission
CPV	concentrating photovoltaics
CSP	concentrating solar power
DC	direct current
DOE	U.S. Department of Energy
DRECP	Desert Renewable Energy Conservation Plan
DSC	dye-sensitized solar cell
EHV	extra-high voltage
EIM	energy imbalance market
EISA	Energy Independence and Security Act
EPA	Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
FCEV	fuel cell electric vehicles
GEA	Geothermal Energy Association
gge	gallons gasoline equivalent
ggm	gallons per minute
GHG	greenhouse gas
GIS	geographic information system
gpm	gallons per minute
GW	gigawatt
GWh	gigawatt hour
HTF	heat-transfer fluid
IID	Imperial Irrigation District
IOU	investor-owned utility
IRP	integrated resource plans
ITC	investment tax credit
kg	kilogram
KGRA	known geothermal resource area
LADWP	Los Angeles Department of Water and Power
LCOE	levelized cost of energy
LCZ	lower convective zone
LDV	light-duty vehicles
LH2	liquid hydrogen
MED	multi-effect distillation
MLD	mineral leasing districts
MMBTU	one million British Thermal Units
MSF	multi-stage flash
MT	magnetotelluric
MW	megawatt

MWh	megawatt hour
NADB	North American Development Bank
NCZ	non-convective zone
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
ORC	organic Rankine cycle
PG&E	Pacific Gas and Electric Company
PILT	payments in lieu of taxes
PPA	power purchase agreement
ppm	parts per million
PRODES	Promotion of Renewable Energy for Water Production through Desalination
PV	photovoltaics
QSA	Quantification Settlement Agreement
R&D	research and development
RD&D	research, development, and demonstration
REZ	renewable energy zones
ROW	right-of-way
RPM	Resource Planning Model
RPS	renewable portfolio standard
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SEBASS	Spatially Enhanced Broadband Array Spectrograph System
SEZ	solar energy zones
SGI	Synthetic Genomics, Inc.
SGSP	salinity gradient solar ponds
SMR	steam methane reforming
SONGS	San Onofre Generating Station
SRP	Salt River Project
SSA	Salton Sea Authority
SWRCB	State Water Resources Control Board
SWRO	seawater reverse osmosis
TDS	total dissolved solids
TEP	Tucson Electric Power
TES	thermal energy storage
TRL	technology readiness level
UCZ	upper convective zone
USDA	U.S. Department of Agriculture
USGS	United States Geological Survey
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
ZEV	zero emission vehicles

Abstract

This report summarizes the potential for renewable energy development in the Salton Sea region, as well as the potential for revenues from this development to contribute financially to Salton Sea restoration costs. Based on Tetra Tech estimates, the Salton Sea will recede most rapidly between 2020 and 2030, exposing roughly 30,000 acres of playa around the entire Salton Sea, of which approximately 11,000 acres will be exposed within the Salton Sea known geothermal resource area (KGRA). The exposed land within the KGRA is potentially available for development of geothermal projects, and the remaining land may be suitable for algal biomass, solar PV, salinity-gradient solar ponds, or for construction of wetlands/habitat.

Key findings reveal the technical potential for the following:

- Geothermal development by 2030 is estimated at 1.05 GW to 1.81 GW of generation capacity.
- Solar photovoltaics and concentrating solar power is estimated at 1.8 GW and 1.3 GW, respectively.
- Algal biomass potential is estimated at up to 40 million gallons of algal biofuel per year, or 600,000 tons of algal food and feed annually. Algal biomass development could potentially cover large tracts of exposed playa, absorb a portion of existing irrigation fertilizer runoff, and generate an additional revenue stream from biofuel sales.
- Potential mineral recovery of lithium from Salton Sea geothermal brines is estimated at 54,000 to 122,000 metric tons annually by 2030, with significant uncertainty due to limited well data. Although no commercial geothermal brine mineral recovery projects exist currently, this technology has been verified as technically viable at pilot-plant scale in the Salton Sea KGRA.

The potential for an additional tax on generation to fund Salton Sea restoration is also examined. Based on analysis using the California Public Utilities Commission's Renewable Portfolio Standard (RPS) calculator, it appears that any "restoration adder" on generation located in the region could disadvantage the development of these resources in comparison to other regions. Any adder would need to reflect market conditions, as even the addition of a relatively small $5 per megawatt-hour restoration charge to the cost of new Salton Sea renewable energy projects could make them significantly more expensive than competing alternatives in the regional supply pool.

The development of the renewable energy technologies examined within the report will generate local tax revenues, environmental mitigation fees, regional economic development from construction, geothermal royalty payments to the state and counties from development on BLM lands, and land lease revenues from development on Imperial Irrigation District-owned lands. Land lease revenues were the primary revenue stream examined. Under current conditions, if the amounts estimated in the report are fully developed by 2030, geothermal land lease royalties that could be usable for Salton Sea restoration would range between $7 million–$15 million annually, depending primarily on lease rates and power purchase agreement pricing. Additional revenue streams from development of renewable energy projects could potentially range from $5.6 million to $77.8 million annually, but are dependent on future changes in technology and policy conditions.

Executive Summary

Overview

The U.S. Department of Energy's (DOE) National Renewable Energy Laboratory (NREL) conducted a comprehensive analysis to evaluate the potential of various renewable energy technologies to financially contribute to the restoration of the Salton Sea.

In 2013, the Imperial Irrigation District (IID) commissioned a preliminary study on the potential for renewable energy projects in the Salton Sea region to partially fund the restoration of the Salton Sea. IID's feasibility study examined the revenue potential from land leases in the Imperial Valley for renewable energy projects, and estimated that roughly $4.1 billion might be realizable over the study period of 2016 to 2045.

This report, *The Potential for Renewable Energy Development to Benefit Restoration of the Salton Sea: Analysis of Technical and Market Potential,* specifically seeks to confirm and refine these prior revenue potential estimates, provide a technical review of the renewable energy technologies under consideration, and develop estimates of the region's developable production potential through the year 2030.

The Salton Sea

The Salton Sea, with a surface area of roughly 365 square miles, is the largest lake in California. It was created in 1905 when the Colorado River flooded, broke through diversion canals, and flowed freely into the Salton Basin for close to two years. By the time the break was fixed, the Salton Sea was created and became a popular recreational area for campers, boaters, and anglers.

Salinity

Water inflows from irrigation runoff bring several million tons of salt annually to the Salton Sea. There are no outflowing rivers or streams, so water primarily escapes through evaporation, leaving salt and other minerals behind. Over the years, the salinity of the Salton Sea has become higher than that of the nearby Pacific Ocean. While few fish species, with the exception of tilapia, have been able to survive, the Salton Sea surroundings have become an important wildlife habitat, home to North America's largest population of migratory waterfowl outside of the Everglades.

Figure ES-1: Salton Sea migratory birds.

Drought

California is undergoing a record-setting drought that began in 2012. Salton Sea agricultural and rainwater inflows have diminished and water conservation measures call for Colorado River water to be transferred from agricultural to urban use in San Diego and the Coachella Valley.

As a result, the water level of the sea is expected to fall significantly, leaving a dry and dusty lake bed, commonly called a *playa*. For the purposes of this report, playa exposed by the recession of the Salton Sea shore from 2010 levels will be defined as "offshore".

Restoration

The Salton Sea and the surrounding region face a wide range of environmental concerns from reduced inflows and other environmental factors, including exposed, potentially emissive lakebeds; rising salinity; and impacts to aquatic and migratory avian

species. A restoration program is being explored to address these concerns. This report examines the potential for renewable energy resources to help fund long-term restoration efforts of the Salton Sea.

Study Areas

To identify the land available for renewable energy development in the Salton Sea study area, geographic information system methods were used to compile land use shapefiles from the multiple stakeholders in the region. The Desert Renewable Energy Conservation Plan (DRECP), Imperial County, Riverside County, Imperial Irrigation District, and the U.S. Bureau of Land Management (BLM) all contributed data to the analysis.

The Salton Sea Study Area is as follows:

- The national border with Mexico was established as the southern border.
- The northern and eastern borders were extended to the eastern extent of Riverside County in order to incorporate the BLM's Riverside East solar energy zone (SEZ).
- The western border was extended to roughly correspond to the DRECP.
- The Salton Sea playa was listed as a potentially developable area, although there is uncertainty concerning both the rate of recession and additional costs for development in this land area.

Credit: Douglas, Barnum, U.S. Geological Survey

Figure ES-2: Looking south at the Salton Sea.

Within the Salton Sea study area, the southern half of the Salton Sea has been identified as the primary area of opportunity for significant development, primarily due to the presence of large tracts of potentially developable public and private land, existing and planned projects, and greater opportunity for future transmission export. This does not preclude development in other areas; potentially developable solar resources exist within the West Chocolate Mountains SEZ as well.

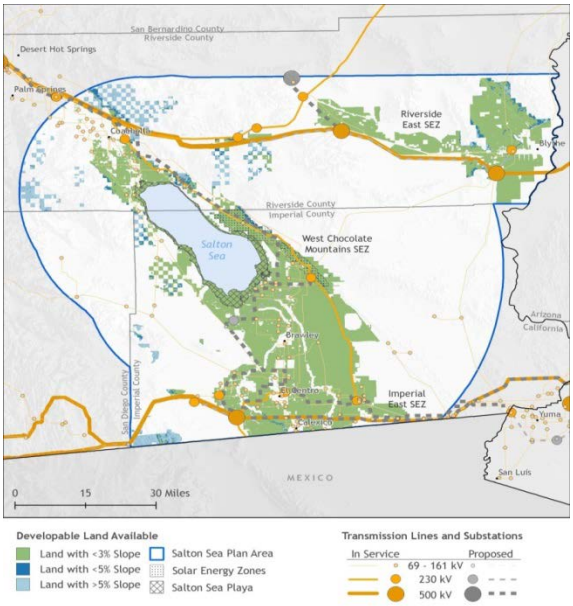

Figure ES-3: Total Developable Renewable Energy Land.

Evaluations

Technologies considered in this report are:

- Electricity production from geothermal
- Mineral recovery from geothermal fluids
- Electricity production from solar photovoltaics (PV), concentrating solar power (CSP), and salinity-gradient solar ponds (SGSP)
- Hydrogen production
- Biofuels and nutraceutical production from algae pond cultivation.

Wind is not evaluated in the report due to the minimal resource potential within the region.

In addition to renewable energy technologies and their coproducts, desalination of the Salton Sea from renewable energy is also discussed as a potential benefit to restoration.

Renewable Energy Potential

Of the commercially available renewable energy technologies, geothermal, solar photovoltaics (PV) and concentrating solar power (CSP) have the greatest technical potential for development. The resource potential, costs, and estimated revenue streams from these technologies are summarized in Table ES-1.

Constraints

Market factors are the biggest constraint on development. Development on the playa itself will be constrained by the rate at which the shoreline recedes, and although playa may be exposed in a given year, there will likely be an additional lag in development due to variability in Salton Sea water levels and potentially muddy site conditions.

Despite the large total resource potential, constraints such as proximity to transmission access and regional cost-competitiveness of the electricity generated may limit the technical potential of the power generation technologies before 2030.

Additionally, PV and CSP require between 5 and 10 acres per megawatt (MW), so larger scale projects over 20 MW could be limited by the availability of contiguous land parcels.

Table ES-1. Salton Sea Renewable Energy Resource Potential and Costs

Technology	Land Developable by 2030 (acres)	Undeveloped Energy Resource Potential	Resource Potential Developable by 2030	Current levelized-cost ($/MWh)***	Estimated levelized-cost in 2030 ($/MWh)***
New Geothermal power (KGRA*)	50,330	1.78 GW - 2.94 GW	1.05-1.81 GW	$107-$131	$107-$131
Mineral recovery from geothermal brines (KGRA)	50,330	115-222 thousand MT Lithium	54.3-122 thousand MT Lithium	Not commercial	Not available
Onshore Solar PV	14,405	31.9 GW	1.8 GW	$100-$113	$49-$94
Offshore Solar PV	9,938	4.2 GW	1.25 GW	$100-$113**	$49-$94**
Onshore CSP	13,147	23.9 GW	1.3 GW	$181	$84-$132
Offshore Algal Biofuels	32,821	39M gal/year	Not commercial	$>10/Gallon	$3/gallon
Offshore Salinity-Gradient Solar Ponds	9,938	0.444 GW	.1 GW	$80-110	Not available

*Known geothermal resource areas, **offshore playa construction requirements may result in higher LCOE,
***Exclude state and federal incentives, but are inclusive of MACRS depreciation. Deal provisions, such as: escalation rate, ITC, term length, state income and sales tax rates, project financing, and additional grid services can all result in a disparity between the LCOE and ultimate PPA price of a technology.

Assumptions and Conditions in Table ES-1

- The figures for geothermal power and mineral recovery include the developable land within the KGRAs for reference, but the resource potentials are solely calculated based on volumetric assessments of the geothermal resource.
- The figures for PV and CSP refer to developable land and resource potential within one mile of 138kV to 230kV transmission access, excluding the land within the KGRAs.
- The undeveloped potential for PV and CSP refers to developable land and resource potential within five miles of 138kV to 230kV transmission access.
- Resource potentials are mutually exclusive; developing a CSP system on a piece of land would preclude installing PV on the same piece of land.
- The underlying data set used for cost estimates in this report is the *NREL Annual Technology Baseline and Standard Scenarios*.
- The cost assumptions do not reflect state or federal incentives, such as the investment tax credit, but are inclusive of Modified Accelerated Cost Recovery System (MACRS) depreciation.
- Specific cost-related assumptions can be found in Appendix B of the full report.

Credit: EnergySource

Figure ES-4: A geothermal plant on the Salton Sea.

Geothermal

The Salton Sea area has exceptional geothermal resources, with one of the largest geothermal anomalies in the United States located at the southern end of the Sea in Imperial County.

Electricity Production

There are roughly 232,000 acres of developable land within the various Imperial County KGRAs, of which 1,851 acres lie within 1 mile of a 138 kV to 230 kV substation. Approximately 50,000 acres lie within 5 miles of a 138 kV to 230 kV substation, which could allow for future geothermal development. Additionally, geothermal power plants have relatively small footprints; thus constructed wetlands, algae farms, and renewable energy projects could be interspersed with geothermal plants within the KGRA. An additional benefit of geothermal development is that infrastructure such as roads and berms will be created and can then be utilized by other projects.

The technical potential for geothermal development is constrained by both the availability of surface land area, as well as the

underlying geothermal resource. For the purposes of this analysis, the required surface area is assumed to be available, and the technical potential is determined through volumetric resource estimates of the underlying reservoir. Using this volumetric resource assessment method, the maximum remaining developable geothermal capacity by 2030 within this area is roughly 1,800 MW. However, the Salton Sea KGRA comprises 1,350 MW of this capacity, and much of that resource is still under water within the Salton Sea.

Although the offshore resource is not currently accessible, Tetra Tech provided water recession forecasts that were used to estimate that 370 MW to 570 MW of the offshore resource could be developable by 2030.

Mineral Recovery

Mineral recovery of lithium from Salton Sea geothermal brines could potentially produce up to $860 million annually in total business revenues, with up to $25.8 million going to IID via annual royalties of 3% on gross revenues. For a high-temperature 50 MW geothermal power plant, mineral recovery of lithium at current market prices could yield $91 to $118 million in annual revenues. This is a nascent technology and revenue estimates are highly uncertain because: 1) the cost structure of such mineral recovery operations may not be adequate to encourage businesses to enter the market, and 2) the degree to which potential increases in demand for lithium-based products may outstrip supply and impact market prices.

Solar Technologies

Given the generally strong solar resource in the Salton Sea area, a variety of solar electric or solar thermal technologies may be suitable for development within the region. However, note that because both PV and CSP require similar conditions, developing a CSP system on a piece of land would preclude installing PV systems on the same piece of land. Although electricity production from salinity-gradient solar ponds has been technically proven, it has not been established in the U.S. as an economically viable power production technology to date. The low-grade heat produced by this technology may also be supplied to other processes, including: desalination, algae pond heating, food processing, and other industrial processes.

Solar Photovoltaics

There are 815,271 acres in the Salton Sea study area with less than 5% slope that could potentially accommodate 103 GW of PV generation. Within this area, 14,405 acres lie within 1 mile of 138 kV to 230 kV transmission access and could accommodate 1.8 GW of PV, which is a conservative estimate of the resource that could be developable by 2030. Although the total capacity potential is extremely large, the developable potential is significantly smaller, due to proximity to transmission, land access, financing, and utility demand, among others.

Concentrating Solar Power

There are 771,656 acres in the Salton Sea study area with less than 3% slope, which could potentially accommodate 77 GW of CSP. Within this area, 13,147 acres lie within 1 mile of 138 kV to 230 kV transmission access which could accommodate 1.3 GW of CSP.

Due to the strong solar resource and relatively low slope constraints, there is a very high technical potential for CSP projects in the Salton Sea study area. However, as was noted in the solar PV section, while this capacity may be technically feasible, CSP development is also constrained by numerous other factors, including its relative economic competitiveness and potential avian impacts.

Capacity factors for CSP technologies vary widely, with a range between 25% and 49%.

Salinity-Gradient Solar Ponds

The total salinity-gradient solar pond (SGSP) resource potential in this area is estimated to be 444 MW, based on 26,628 acres of potential playa within 1 mile of transmission, and an assumed power density of 60 acres/MW. The current cost of power from SGSP is estimated to be within the range of $80-$110/MWh, but the technology is still nascent, making predictions about the likely cost in 2030 subject to significant uncertainty.

Given that SGSP projects have not yet been developed within the region, 100 MW was estimated to be technically developable by 2030, although this does not account for transmission or economic viability, which are still uncertain.

Hydrogen Production

Hydrogen can be produced by reforming natural gas or splitting water molecules using any primary energy resource, including the resources abundant in the Salton Sea region.

Credit: NREL, Michael Penev, 19206

Figure ES-5: The first hydrogen fueling station, Los Angeles, CA.

California has several policies in place to accelerate the adoption of hydrogen fuel cell electric vehicles (FCEV). The biggest market for FCEVs is expected to be Los Angeles, which currently leads California in hydrogen station installations. However, the Salton Sea is 150 miles from Los Angeles, with transportation/delivery costs adding significantly to the cost of the delivered hydrogen compared to facilities operating closer to the city, and there are considerable uncertainties surrounding the rate at which FCEVs might be deployed.

Current projections are that the total number of FCEVs in California might be roughly 18,500 by 2020. Based on projected FCEV adoption rates and due to the comparatively low cost of natural gas, it does not appear likely that hydrogen from the Salton Sea region would be competitive in the Los Angeles market until at least 2030.

Algae Pond Cultivation

Strains of algae have been identified that can grow in brackish, saline, and even hypersaline water.

Biofuels

The study area appears to be a favorable region for development of algal biomass resources due to the presence of large volumes of highly saline water, large tracts of unused playa and high insolation.

Algal ponds offer similar benefits as solar ponds to the local environment: covering the recently exposed soil and thereby reducing the potential for dust emissions. There are currently 32,821 acres of total developable land on the playa (unconstrained by transmission access), which could produce roughly 39 million gallons of biofuels per year.

Current costs are roughly $17/gallon and would need to decrease substantially for this

technology to be viable. Algal biofuel production is still pre-commercial and is unlikely to be cost-competitive with crude oil by 2030, barring the implementation of Renewable Fuel Standards for algal biofuel consumption.

Credit: Nature Beta Technologies Ltd, Ei

Figure ES-6: Algae raceway ponds; Large-scale algae biomass production

Nutraceuticals

The production of cosmetic and dietary products, such as beta-carotene or spirulina, is commercial at scale, with operating plants in numerous countries. Notably, Synthetic Genomics, Inc. performs research and development and test-scale operations near the southern tip of the Salton Sea, and has been consulted concerning the feasibility of further development of algal ponds for nutraceutical products on the exposed Salton Sea playa. Further study of the Salton Sea's water quality is required, but development of an algal biomass pilot plant on exposed Salton Sea playa could verify whether this technology is viable in the region.

Desalination

In addition to the potential of renewable energy technologies and their coproducts to financially contribute to the restoration of the Salton Sea, the added benefit these technologies could bring to the high salinity levels of the Salton Sea was explored.

Desalination from renewable energy could provide a significant potential benefit to Salton Sea restoration efforts by feeding desalinated water back into the Sea and addressing the increasing salinity problem directly. Although this method is technically feasible, there is a cost, and returning fresh water to the Sea at zero or near-zero cost requires an alternative source of revenue for the process, such as salt sales.

The type of energy required is a pivotal consideration when considering renewable-energy powered desalination. Wind or Solar PV could be used to power an all-electric desalination process, although accommodation would have to be made for fluctuation in the resource. From a technical perspective, batteries can be added, but this is unlikely to be economically attractive.

The more interesting case for renewable energy desalination in the Salton Sea region is the potential to use geothermal or solar thermal energy with a thermal-desalination process. The benefit of this approach is that the process can be designed to run 24/7 for smoother operation of the desalination treatment process. In the case of geothermal, such high availability is routine. For solar thermal, storage of the solar heat transfer fluid could be incorporated to separate solar collection from energy use and ensure a much higher availability.

Currently, there appears to be one desalination company operating by the Salton Sea. Several pilot-scale projects have operated on the edge of the Salton Sea, with a combined capacity of approximately 25,000 gal/day. These plants currently rely on low temperature steam provided by adjacent geothermal plants, but could also potentially utilize low-grade heat from salinity gradient solar ponds in the future.

Economic Outlook

Table ES-2 summarizes potential mitigation revenues under current policy and technology conditions within the Salton Sea region. The development of geothermal and solar projects will generate tax revenues, environmental mitigation fees, regional economic development, geothermal royalty payments from development on BLM lands, and land lease revenues from development of IID-owned playa for Salton Sea development from power generation projects.

Estimated restoration revenue streams in previous studies have typically assumed that development in the Salton Sea region is sufficiently attractive from an economic standpoint to absorb the additional impact of a restoration charge on a project's cash flows while still providing a regionally competitive return on investment. However, based on modeling of potential scenarios, it has been determined that any additional tax on generation to support Salton Sea restoration may disadvantage the development of these resources relative to other renewable resources in the region.

Any added tax would need to reflect market conditions, as even the addition of a relatively small $5 per megawatt-hour restoration charge to the cost of new Salton Sea geothermal projects could make them significantly more expensive than competing alternatives in the regional supply pool.

Similarly, a $5/MWh charge for solar could result in the area's best resources becoming more expensive than competing projects. As modeled in the CPUC RPS Calculator, the area's solar resources could slip by about 7 percentage points in competitiveness in the California renewable energy supply curve, meaning that 49,000 GWh of competing projects may become economically superior. For context, the modeled incremental demand from increasing California's RPS to 50% may be between 44,000 GWh and 74,000 GWh.

Table ES-2. Summary of Potential Mitigation Revenues under Current Conditions

	Current Conditions [Annual Millions]	Notes: See Appendix C for full calculations
Geothermal (KGRA)*	$7 to 15	Onshore: BLM land lease royalties: $1-3 Offshore: IID land lease royalties : $6 -12
Solar PV (onshore)	$0	Available onshore land is predominantly private, and BLM Solar Energy Zone royalties are currently fully allocated to the U.S. Treasury.
CSP (onshore)	$0	
Other:		
AB 1471 (CA 2014 Water Bond)	$0 to 14.3	Total CA water bond is $475M, $200M assumed as upper limit given other obligations.
Total (annual):	$7 to 29.3	Annual revenues calculated assuming 14 years, from 2016-2030. Figures do not account for inflation or the time value of money.
14 year total:	$98 to 410.2	Note: The mitigation revenues in Tables ES-2 and ES-3 are additive.

* Geothermal projects should be given first priority for development on the KGRA, but due to their small overall footprint once projects are established, this acreage may be developable for other technologies as well.

This might not be significant under scarcity conditions, but it could be a major handicap in a market characterized by large surpluses. There are some options, such as streamlined permitting or partnership with the North American Development Bank, that could be explored to improve the economic competitiveness of Salton Sea renewables such that they might be able to absorb a restoration tax while still remaining attractive to nearby power markets. However, in general developers are opposed to the concept of a restoration adder.

Future Revenue Potential

There is potential for greater demand for renewable energy beyond 2030, driven by California policy, such as AB 32, which calls for 80% greenhouse gas reductions below 1990 levels by 2050 and the recent passage of the 50% RPS target. However, with indications of minimal economic headroom for a Salton Sea restoration tax on renewable energy development in the region between 2015 and 2030, additional potential revenue generation mechanisms for the Salton Sea Authority were explored. The primary revenue potential mechanism examined was land lease royalties, as these are existing costs associated with development that would be less likely to disadvantage projects' regional cost-competitiveness. Table ES-3 summarizes these potential revenues in 2016 through 2030. Although there may be between $78.4 million and $1.09 billion in potential revenues, additional sources of revenues will still be required to fund the proposed restoration options ($2.3 billion to $8.9 billion).

Table ES-3. Summary of Potential Mitigation Revenues under Future Conditions

	Potential Future Conditions [Annual Millions]	Notes: See Appendix C for full calculations
Mineral recovery from geothermal brines (offshore KGRA)	$0 to 25.8	Assumes offshore development of up to 570 MW of geothermal, 3% IID royalty rate on gross lithium sales
Algal biofuels (offshore non-KGRA)*	$1.2 to 2.3	Assumes $3/gal cost competiveness by 2030, 1-2% IID land lease rate on gross proceeds.
Salinity Gradient Solar Ponds (offshore non-KGRA)*	$0.6 to 1.6	Assumes $80-$100/MWh PPA, 90% capacity factor, IID land lease rate (1-2% - gross proceeds).
Solar PV (offshore non-KGRA)*	$1 to 3	Assumes $40-60/MWh PPA, 23.2% capacity factor, IID land lease rate (1-2% - gross proceeds).
Solar PV (onshore BLM Solar Energy Zones)	$1.5-4.4	Assumes passage of S-1407and development of 1.8 GW of BLM SEZ's. Assumes $40-60/MWh PPA, 23.2% capacity factor, royalty rate between 1-2% of gross proceeds.
Other:		
Desert Renewable Energy Conservation Plan - Habitat Restoration	$3.5 to $44.6	Lower case based on allocable revenues to desert pupfish habitat, upper case is for full habitat restoration amounts for Imperial & Riverside Counties
Total (annual):	$5.6 to 77.8	The potential revenues above typically require a change in policy, development of the offshore playa, or technological developments.
14 year total:	$78.4 to 1,089.2	

* The potential development of off-shore acreage outside of the KGRA is mutually exclusive. e.g: Full development of the available acreage by algal biofuels precludes development by Solar PV or Salinity Gradient Solar Ponds. Total revenue estimates reflect the highest and lowest potential revenues from these three technologies ($0.6 to 3 million annually).

Recommended Next Steps

Geothermal

Further analysis is required to refine estimates of the developable geothermal potential on the playa. The developable offshore potential is based on the percentage of playa exposed within the estimated bounds of the reservoir, but more accurate estimates can be achieved through volumetric assessment of the offshore resource. Further study of the geotechnical soil conditions of the playa, from a construction standpoint, would also be required to refine offshore cost estimates.

Geothermal Fluid Mineral Recovery

Since no geothermal recovery operations are commercially operating at the time of this report, a detailed manufacturing and supply chain study is needed to validate the likelihood that mineral recovery is a viable business opportunity for the region.

Salinity-Gradient Solar Ponds

Further analysis of the economic viability of salinity-gradient solar ponds, as well as the detailed investigation of the technical potential for synergy between this technology and algae development or desalination, will be required to determine if a commercial-scale plant would be feasible in the region.

Algal Biofuels

Further study of the Salton Sea's water quality is required, but development of an algal biomass pilot plant on exposed Salton Sea playa could verify whether this technology is viable in the region. Development of an algal biomass pilot plant on exposed Salton Sea playa could verify whether this proposed renewable energy restoration mechanism is viable. NREL has discussed this proposed mechanism with two organizations currently exploring pilot studies at this location, UCSD and Synthetic Genomics, Inc., which operates an R&D facility next to the Salton Sea.

Interactive Analysis Tool

As part of the analysis conducted above, NREL has developed an interactive, web-based mapping tool that incorporates the data used in the report's analysis. This tool is intended to enable stakeholders to visualize renewable energy development scenarios under various conditions, such as proximity to transmission, estimated playa recession, and land ownership. Due to data use restrictions, some data is not viewable at the sub-county level. If the layers under the Developable Land Substation Buffer directory do not display on the map, please zoom out until the layer becomes visible, or uncheck this layer to zoom in on other layers. This tool can be accessed at: http://maps.nrel.gov/salton-sea.

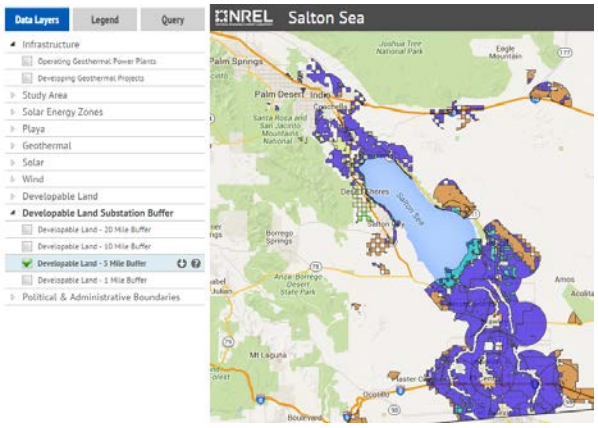

Figure ES-7: RE Development Scenario Mapping Tool Screenshot

Market Competitiveness

Due to ongoing significant changes in federal regulatory policies, increasing state RPS goals, shifts in technology costs and adoption, and accelerated plant retirements, further study of the role and value of the Salton Sea's renewable resources within regional power systems and markets is required. A variety of models and tools exist that can be utilized to assess the opportunities and challenges of developing the Salton Sea's renewable resources within the broader and rapidly changing California and Western markets. Capacity expansion models can be used to

develop future scenarios of the market potential and transmission needs of different renewable and non-renewable options at high spatial resolution for particular focus regions, such as Southern California. Production cost models can be used to assess the operational impacts—including renewable curtailment, plant operational flexibility, transmission congestion, and changing electricity imports and exports—under future infrastructure conditions. Running these models for the Salton Sea region, with a focus on geothermal and solar, can help demonstrate the ability of regional resources to cost-effectively meet California's energy and climate objectives. Development of this analysis would help provide valuable input to ongoing planning efforts such as the DRECP and the recently announced Renewable Energy and Transmission Initiative (RETI) 2.0.

Renewable Energy Policies

Policies favorable to renewable energy could create a unique benefit to development within the region. These could include utilizing the North American Development Bank for development expertise and to leverage interest rate cost savings, streamlining permitting requirements, and providing certainty surrounding environmental permitting costs. Additional potential developments which could affect these findings include the implementation of more aggressive in-state renewable energy capacity goals, and additional project cost declines uniquely benefitting the Salton Sea region (i.e., local incentives, exceptional transmission access).

Royalty Payment Structures

Geothermal royalty structures and mineral leasing receipts are current potential sources of funding for restoration efforts. Additional potential revenues could be realized through the passage of U.S. Senate bill 1407, which would amend the revenue distribution for solar and wind energy authorizations on BLM land to include distributions to states and counties. On payments associated with renewable energy development and production, the State of California could also make efforts to pass more specific support mechanisms, such as the CA Senate Bill 1139, which required 500 MW of geothermal energy between 2015 and 2024.

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1 Introduction

Outflows from the Colorado River rapidly filled the Salton basin between 1905 and 1907, giving rise to the Salton Sea, which is now the largest lake in California. The salinity of this body of water exceeds that of the Pacific Ocean and continues to increase to levels that only the tilapia fish have been able to survive. Numerous freshwater species, most notably the endangered desert pupfish, continue to live in the surrounding marshes, canals, and rivers (U.S. Fish & Wildlife Service 2008). The Salton Sea has also become a major avian habitat, with over 400 species sighted to date. Due to continuing concerns surrounding water scarcity in the state of California, the Quantitative Settlement Agreement (QSA) was signed in 2003 and clarified in a court ruling in 2013. Water conservation measures in the agreement call for the water to be transferred from regional agricultural to urban use in San Diego and the Coachella Valley. Pursuant to this agreement, mitigation inflows to the Salton Sea will be discontinued in 2017. Also pursuant to this agreement, the state of California agreed to statutory and contractual obligations to ensure the restoration of the Salton Sea.

The Salton Sea and the surrounding region face a wide range of environmental concerns from reduced inflows and other environmental factors, including exposed, potentially emissive lakebeds; rising salinity; and impacts to aquatic and migratory avian species. A restoration program is urgently needed to address these concerns.[1]

After commissioning a study listing the various restoration alternatives, with estimated construction costs of between $2.3 billion for the lowest cost alternative and $8.9 billion for the preferred alternative, sources of funding summing to roughly $32 million as of 2013 have been acquired thus far, with a 2013 state audit identifying the total estimated funding for Salton Sea restoration as $114 million.[2]

Through a grant from the State of California Natural Resources Agency, under Agreement No. 0540-SSA 1, the Salton Sea Authority has retained Tetra Tech to serve as the prime contractor to help complete the plan. Tetra Tech's subcontractor, the National Renewable Energy Laboratory (NREL), was retained to prepare a report analyzing the potential of various renewable energy technologies to contribute financially to Salton Sea restoration efforts. In 2013, the Imperial Irrigation District (IID) commissioned a preliminary study on the potential for renewable energy projects in the Salton Sea region to partially fund the restoration of the Salton Sea. This feasibility study examined the revenue potential from land leases in the Imperial Valley for renewable energy project, and estimated that roughly $4.1 billion might be realizable over the study period of 2016 to 2045. This study specifically seeks to confirm and refine these prior revenue potential estimates, provide a technical review of the renewable energy technologies under consideration, and develop estimates of the region's developable production potential through the year 2030.

[1] *Id.*
[2] California State Auditor. "California State Auditor Report 2013-101". November 2013. https://www.bsa.ca.gov/pdfs/reports/2013-101.pdf. Accessed 6/2/15.

2 Developable Renewable Energy Land Area

To identify the land available for renewable energy development in the Salton Sea study area (Figure 1), geographic information system (GIS) methods were used to compile land use shapefiles from the multiple stakeholders in the region. The Desert Renewable Energy Conservation Plan (DRECP), Imperial County, Riverside County, IID, and the U.S. Bureau of Land Management (BLM) all contributed to the final selection of developable land.

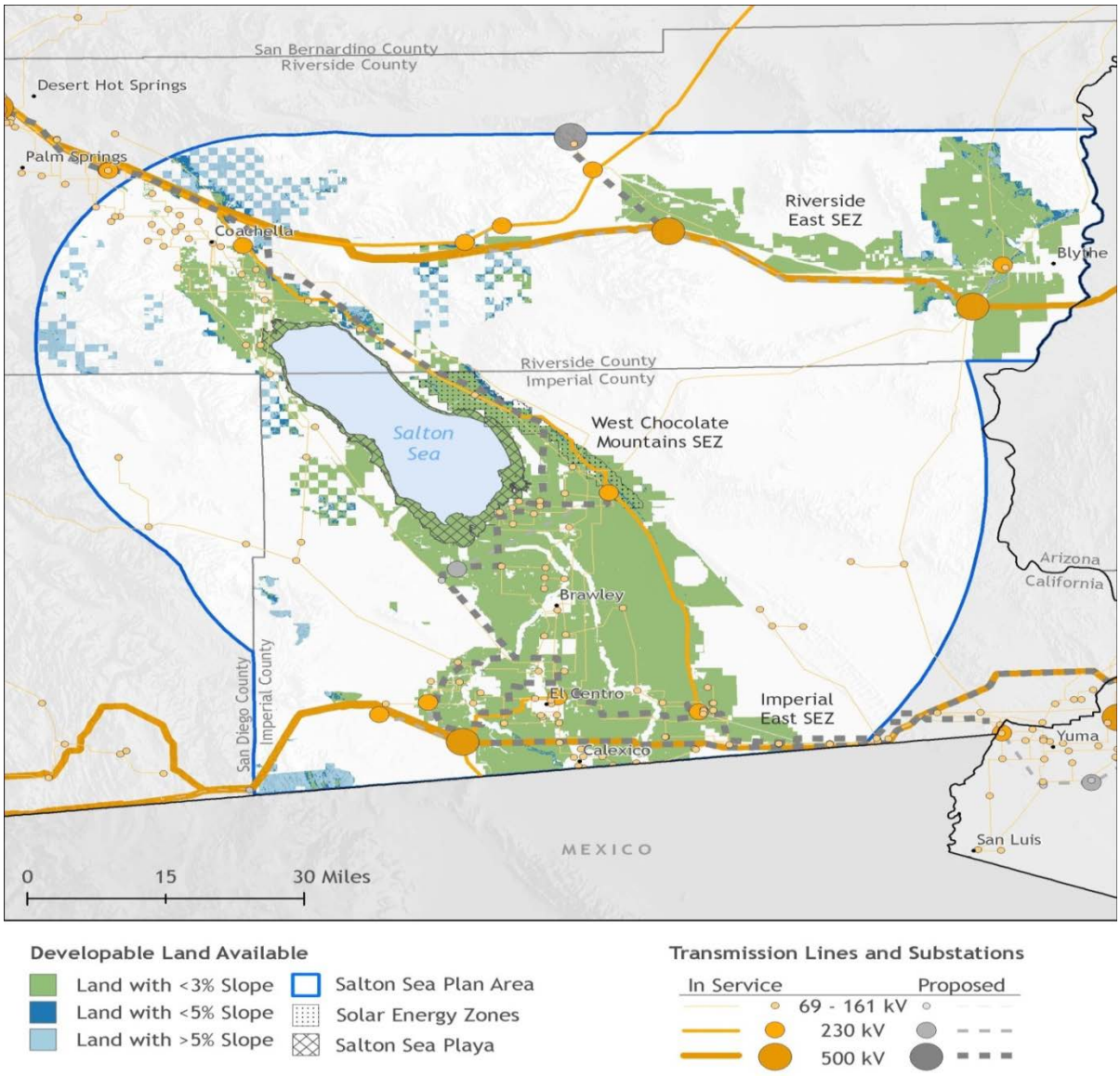


Figure 1. Total developable renewable energy land.[3]

[3] Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM.

2.1 Salton Sea Plan Area

The Salton Sea Plan area is described as follows. The national border with Mexico was established as the southern border. The northern and eastern borders were extended to the eastern extent of Riverside County in order to incorporate the Riverside East solar energy zone (SEZ). The western border was extended to roughly correspond to the DRECP Plan boundary. The Salton Sea playa was listed as a potentially developable area as well, although there is uncertainty concerning both the rate of recession and additional costs for development within this land area.

2.2 Land Exclusions

The first level of land exclusion applied to the Salton Sea study area was all land outside of the DRECP Preferred Alternative Plan that did not fall into one of the following designations:

- Development focus areas
- DRECP variance lands
- Future assessment areas
- Special analysis areas
- Tribal lands.

The draft DRECP is a collaborative environmental planning effort between numerous state and federal agencies to ensure efficient biological mitigation and conservation in California's desert environments. This group has already conducted a thorough research process that considered multiple interests in the region and that provided a reasonable starting point for the Salton Sea analysis. Using the draft DRECP Preferred Alternative Plan as a starting point, NREL led stakeholder meetings with representatives from Imperial County, Riverside County, IID, and BLM to refine decisions on which land types to include in the Salton Sea study area.

Following the stakeholder meetings, the second level of land exclusion focused on land-use designations provided by the counties. In this step, cities, residential areas, commercial areas, industrial areas, conservation and habitat areas, parks, and mountainous land were excluded from the study area. The final level of exclusion applied federal land considerations and excluded all military land and BLM Areas of Critical Environmental Concern. The most notable exclusion of military land was the West Chocolate Mountain Gunnery Range and other military bases within the region; due to their continued operation of training exercises in these regions, these areas are not considered to be suitable for the development of renewable energy. The remaining land comprised the final developable land dataset that represent areas suitable for renewable energy development.

2.3 Developable Land by Technology

The developable land was further refined for each technology considered based on the individual technology constraints. Only land with less than 5% slope was considered for solar photovoltaics (PV), land with less than 3% slope was considered for concentrating solar power (CSP), land within previously-identified known geothermal resource areas (KGRA) was considered for geothermal, and only land on the Salton Sea playa was considered for algal biofuels and salinity

gradient solar ponds (SGSP). Land shown as "no slope constraint" indicates that the land was developable based on land exclusions listed above but exceeded 5% slope. The total land available for each technology is shown in Table 1. Although developable land within the KGRAs was excluded from all other technologies, it was assumed that this land would be a first priority for geothermal development, although it may be possible to intersperse these technologies alongside future geothermal plants.

Table 1. Total Developable Land by Technology

Technology	Developable land (acres)	Developable Land Within 1 Mile of 138kV-230kV Trans. Access	Developable Land Within 1 Mile of 500kV Trans. Access	Developable Land Within 5 Miles of 138kV-230kV Trans. Access	Developable Land Within 5 Miles of 500kV Trans. Access
Geothermal (KGRA)	232,051 (1.78 GW 2.94 GW)	1851 (1.78 GW 2.94 GW)*	0	50,330	58
PV	815,271 (103 GW)	14,405 (1.8 GW)	56.5 (.007 GW)	251,853 (31.9 GW)	73,563 (9.3 GW)
CSP	771,656 (77 GW)	13,147.1 (1.3 GW)	56.5 (.006 GW)	238,874 (23.9 GW)	72,617 (7.3 GW)
SGSP (offshore)	26,628 (0.444 GW)	0	0	9,938	0
Algal biofuels (offshore)	32,821	0	0	9,938	0

*While developable land is required for development, geothermal capacity is more accurately estimated based on volumetric assessment in Section 4.1, rather than an acres/MW assumption.
Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM.

2.4 Land Ownership

The primary land classifications within the developable area of the Salton Sea region are private lands within Imperial and Riverside Counties, followed by BLM ownership. The BLM has currently identified the Imperial East, Riverside East, and Chocolate Mountain SEZs as priority areas for utility-scale solar development. Of the total available area under BLM ownership, 203,051 acres fall within the SEZs. Development within the BLM SEZs will likely be governed by the BLM's competitive leasing program. Based on discussions with BLM, currently all solar and wind energy right-of-way revenue receipts (acreage fee and megawatt (MW) capacity fee) are allocated to the Treasury, although federal legislation could potentially change this allocation in the future. Revenues from geothermal royalty payments are currently shared with the states and counties within which a project is located. Development on Riverside or Imperial County land will likely require negotiations with the individual landowners in the development area of interest. Also of note are the 20,563 acres owned by the Torres-Martinez Desert Cahuilla Indian

Tribe; however, renewable energy development on tribal lands is often subject to separate regulations.

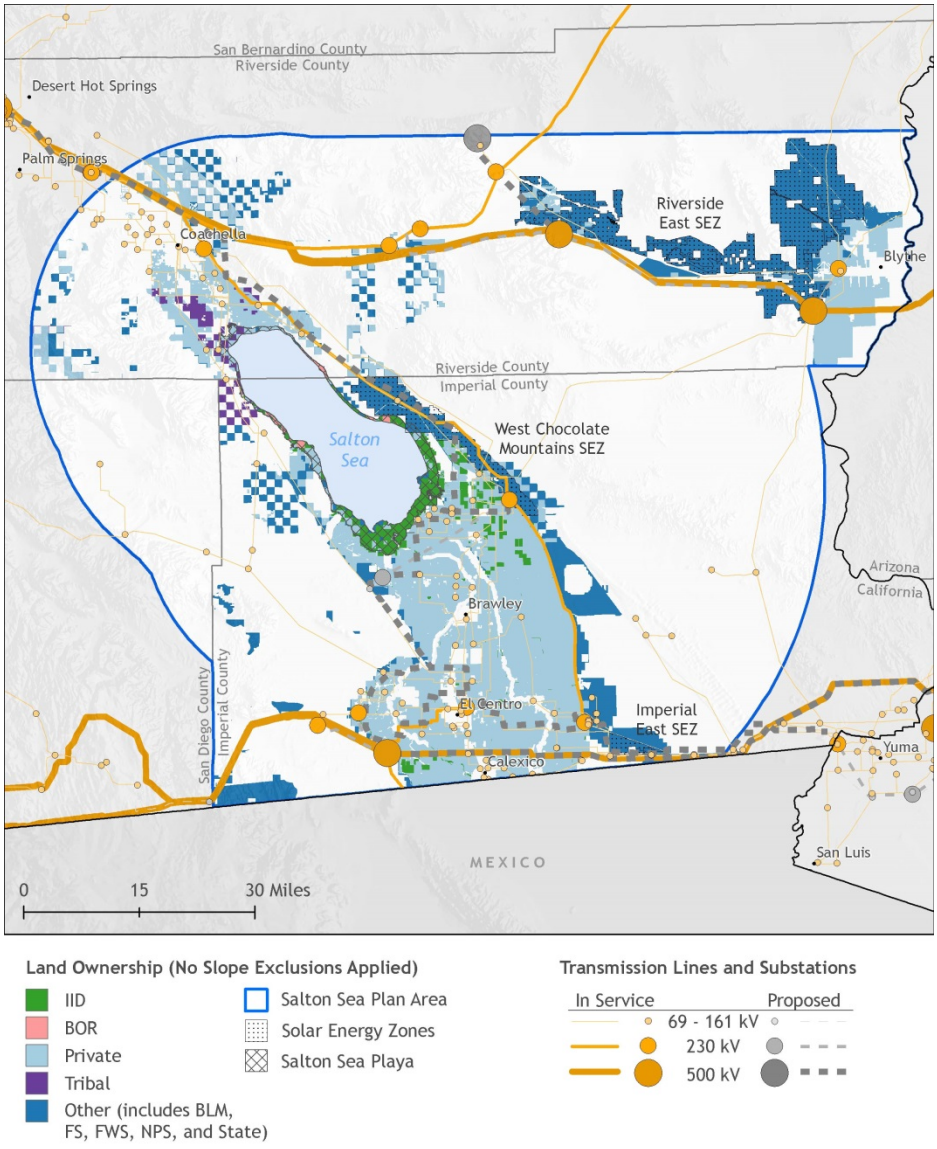


Figure 2. Total developable renewable energy land by ownership type.[4]

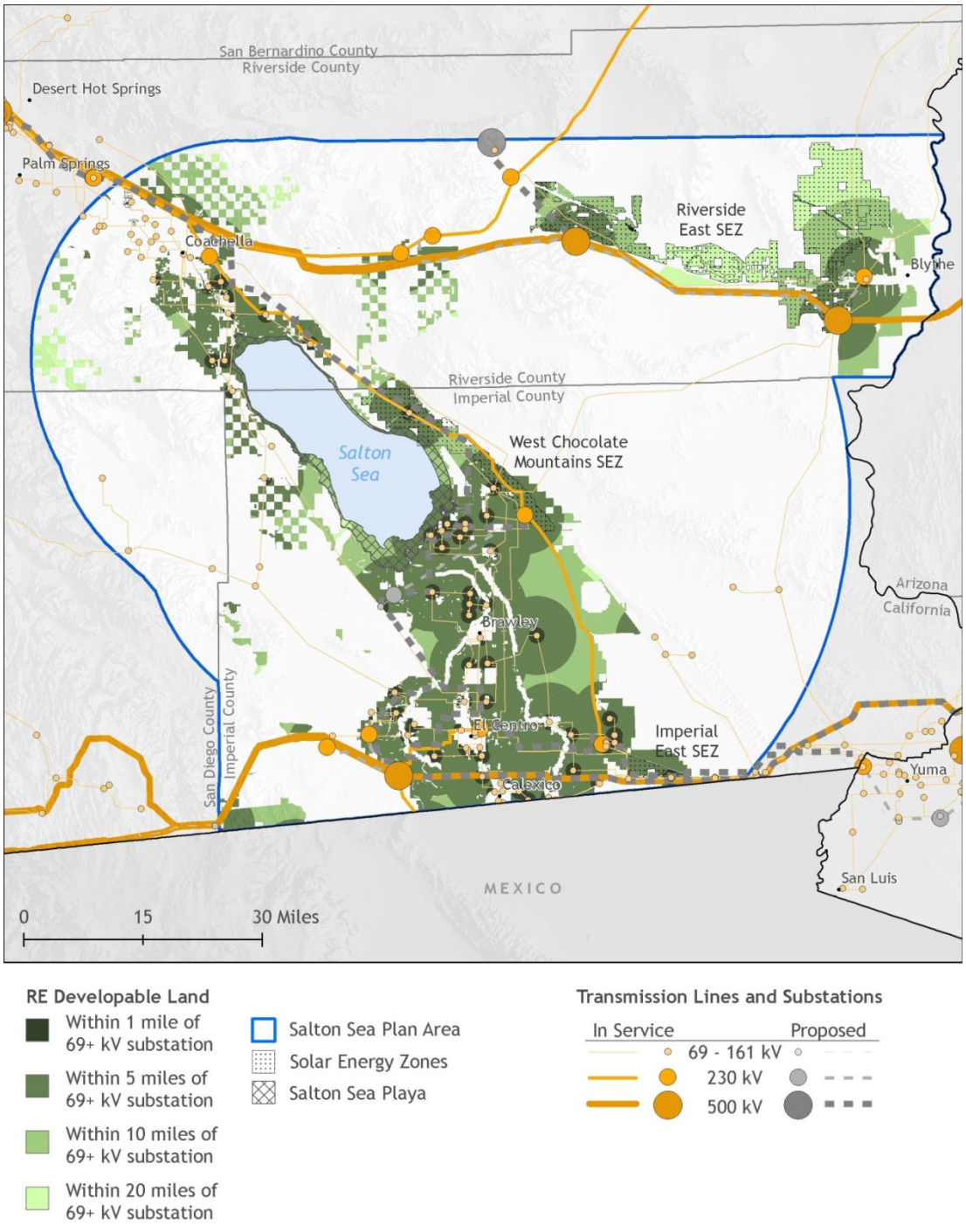
2.5 Transmission Capacity

As shown in Table 1, the developable land was screened to identify its proximity to electric substations in the region. The developable land was grouped into categories of 1, 5, 10, and 20 miles from large substations (500 kV) and small substations (138 kV, 161 kV, or 230 kV). A one mile radius from substations between 138 kV and 230 kV was selected as the most likely

[4] Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM. Ventyx Velocity Suite 2014.

developable land area for the majority of projects, with the caveat that development of transmission infrastructure could have a significant impact on the future developable area (Figure 3). Most of the transmission infrastructure in the region is developed by the utilities: IID, San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE). The Western Area Power Administration (WAPA) also has some lines for supporting service to small public power entities. In the part of Arizona adjacent to the study area, the main utilities are Arizona Public Service (APS) and Salt River Project (SRP). However, development of transmission lines is costly, with the typical cost per mile for a 230 kV transmission line between $940,000 and $960,000.[5] Although the completion date for many of the proposed lines is still uncertain, the northern line (Devers-Colorado River) just went on line, and the line into Arizona (North Gila-Imperial Valley 2) is scheduled for completion in 2019. These subsets of developable land provide an additional tool for ranking the areas of highest potential for renewable energy development.

[5] https://www.wecc.biz/Reliability/2014_TEPPC_Transmission_CapCost_Report_B+V.pdf

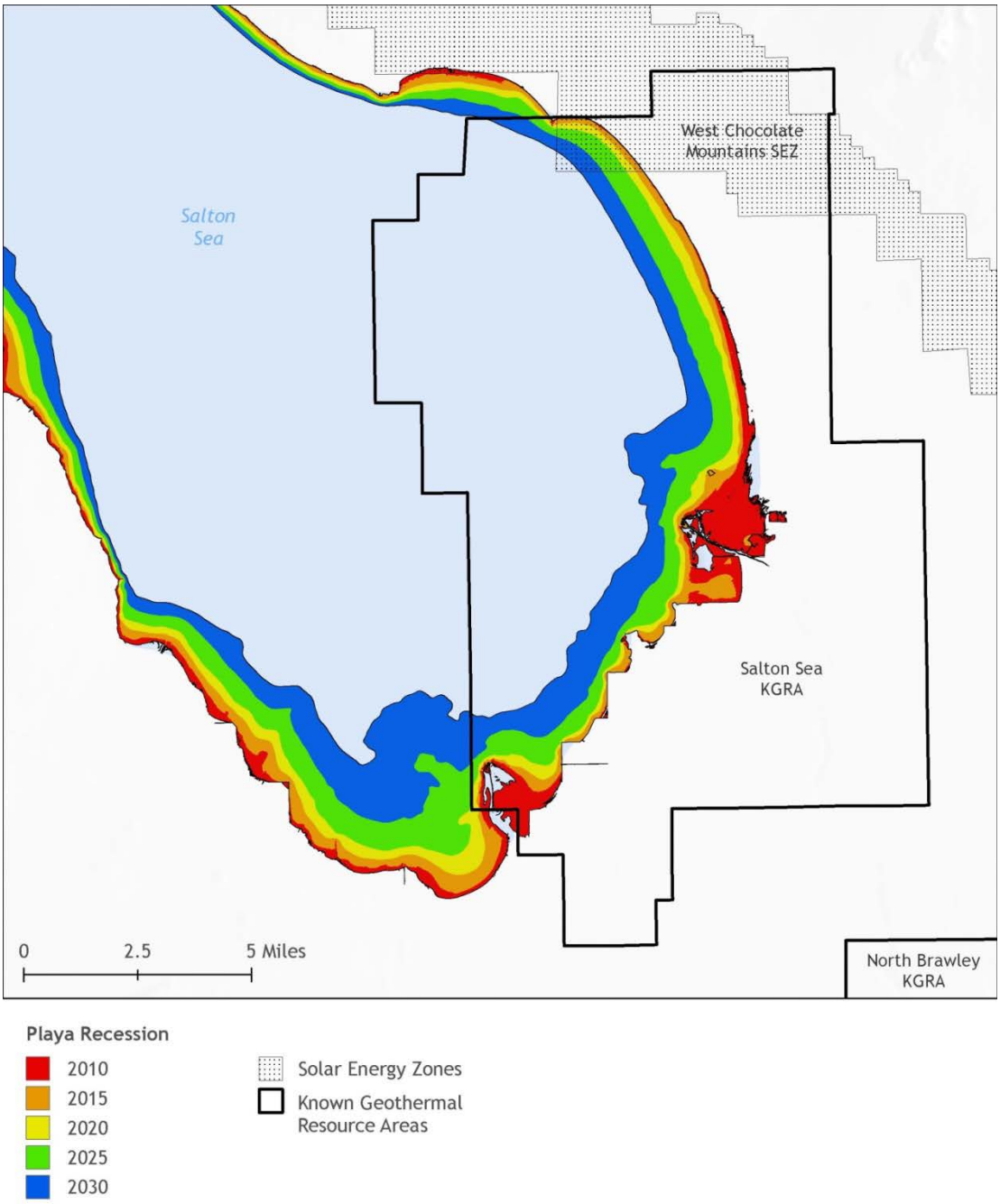


Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM; Ventyx Velocity Suite 2014

Figure 3. Transmission capacity within the Salton Sea region.

2.6 Playa Recession Exposure Rates

For the purposes of this report, playa exposed by the recession of the Salton Sea shore from 2010 levels will be defined as "offshore". Figure 4 and Table 2 show the projected recession rates at the southern end of the Salton Sea. The dataset was received from Tetra Tech and reflects playa recession estimates through the study period. Although playa exposure will also occur on the north end, given the presence of the developable geothermal potential currently offshore within the Salton Sea KGRA, the southern end was examined in greater detail. Based on the modeled recession rates, the Salton Sea will recede most rapidly between 2020 and 2030, exposing roughly 30,000 acres of playa around the entire Salton Sea, of which approximately 11,000 acres will be exposed within the Salton Sea KGRA. The Salton Sea is expected to slightly reverse its recession between 2040 and 2050; this is due to the fact that as salinity levels increase, the rate of evaporation decreases, allowing the lake to become larger, albeit at a higher salinity. Given the indication that Salton Sea levels will fluctuate over the study period, it is practical to assume that exposed playa will not be immediately developable at the date of exposure.



Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Tetra Tech Playa Recession Data

Figure 4. Playa recession exposure rates.

Table 2: Playa Recession Exposure Table

	Area of Water - total (acres)	Area of Playa - total (acres)	Area of Water - Salton Sea KGRA only (acres)	Area of Playa - Salton Sea KGRA only (acres)
Salton Sea: full body	233,400	-	52,800	-
Full Playa	111,100	122,200	13,500	39,300
2010 Recession	226,400	7,000	49,800	3,100
2015 Recession	220,000	13,400	47,900	5,000
2020 Recession	213,400	20,000	46,000	6,800
2025 Recession	199,600	33,800	41,100	11,700
2030 Recession	182,700	50,700	34,900	18,000
2035 Recession	181,400	52,000	34,400	18,500
2040 Recession	173,900	59,500	30,900	22,000
2045 Recession	177,600	55,800	32,600	20,200
2050 Recession	175,000	58,300	31,400	21,500

Data Source: Tetra Tech Playa Recession Data

3 Renewable Energy Potential

Of the commercially available renewable energy technologies, geothermal, solar PV, and CSP have the most significant technical potential for development. All of these resources have large total resource potential, but constraints such as proximity to transmission access and regional cost-competitiveness of the power generated, limit the technical potential. Solar PV and CSP require between 5 and 10 acres/MW alternating current (AC), so larger scale projects could be limited by non-contiguous land parcels as well. Development on the playa will be constrained by recession rates and although playa may be exposed in a given year, there will likely be an additional lag in development due to variability in Salton Sea water levels and potentially muddy site conditions.

Within the Salton Sea study area, the southern half of the Salton Sea (both onshore and offshore) has been identified as the primary area of opportunity for significant development, primarily due to the presence of large tracts of potentially developable farm land, existing and planned projects, and greater opportunity for future transmission export capacity due to existing infrastructure. This does not preclude development in other areas; however, potentially developable solar resources exist within the West Chocolate Mountains SEZ as well.

Table 3. Summary of Developable Capacity by Technology in 2030

Technology	Total Potential (GW unless otherwise specified)	Generation Potential (GWh/yr)	Existing Capacity (GW unless otherwise specified)
Geothermal (onshore)	0.68–1.24	4,765–8,690	0.6
Geothermal (offshore)	0.37 - 0.57	2,593–3,995	0
Solar PV	1.8	3,672	5.87
CSP	1.3	4,732	0.25
SGSP	0.1	788	0
Brine Mineral Recovery	54,000 MT Li 122,000 MT Li	N/A	0
Algal Biofuels (offshore)	39,385,674 gal/ year	N/A	0
Algal Food and Feed (offshore)	600,000 tons/year	N/A	0

*Data Sources: See Tables 10-14 and Table 19 of this report.

The development of a project may reduce the technical potential[6] of another resource by removing land available for development. For example, if there are both solar PV and CSP potentials for a parcel of land and a solar PV project is developed on that parcel, the technical potential for CSP will decrease because the land is no longer available. That is, the capacity potentials listed in Table 3 are independent, may refer to the same land area, and are not additive.

3.1 Geothermal

Geothermal energy is heat from the Earth. It is a clean, renewable resource that provides energy for a variety of applications, including power generation and commercial, industrial, and residential direct heating. It is considered a renewable resource because the heat emanating from the interior of the Earth is inexhaustible in human time scales. Geothermal energy is available everywhere; however, accessing the resource can be difficult and expensive due to physical requirements that constrain the ability to achieve a viable system. Geothermal energy systems are comprised of two primary components: subsurface and surface systems.

The subsurface system is called the geothermal reservoir (Figure 5) (Geothermal 2005). In order for a reservoir to be viable for geothermal energy utilization, there must be adequate heat, permeability, and fluid present. A geothermal reservoir is formed by a confluence of geologic processes that 1) create permeability in a rock formation and 2) deliver heat and fluid to the permeable rock unit. Depending on the heat source and local geologic constraints, the

[6] Technical potential refers to the renewable resource that it is technically possible to use. It does not incorporate economic factors which impact the cost to harvest the resource, or other factors such as transmission availability.

geothermal fluid can be in the form of hot water or steam. This hot water/steam can then be tapped by drilling wells. The wells permit the geothermal fluid to flow (or be pumped) from the reservoir to the surface so that it can be utilized for the desired end use application. In locations where no hydrothermal reservoir exists, it is possible to drill wells that inject fluid into areas of hot dry rock as much as three miles below the Earth's surface to create an artificial geothermal reservoir. However, the Salton Sea area has plentiful high-temperature hydrothermal resources and "enhanced geothermal systems" are not needed, therefore, they are not addressed in this report.

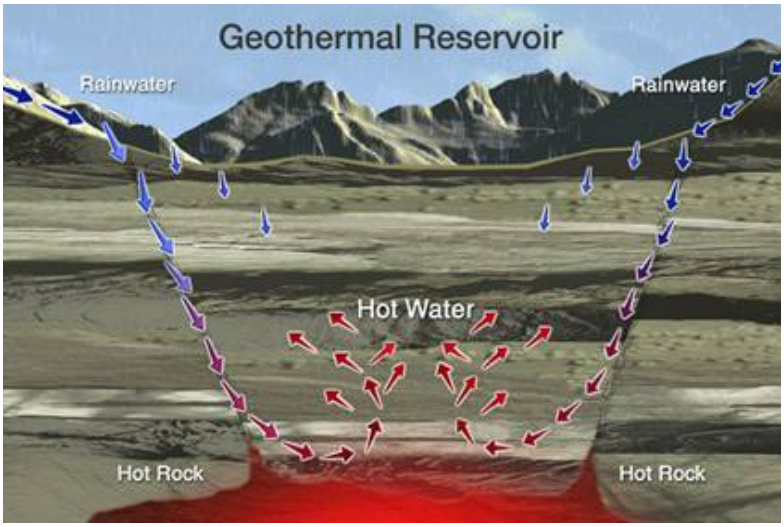


Figure 5. Schematic of a geothermal reservoir. *Illustration from Geothermal Energy Association*

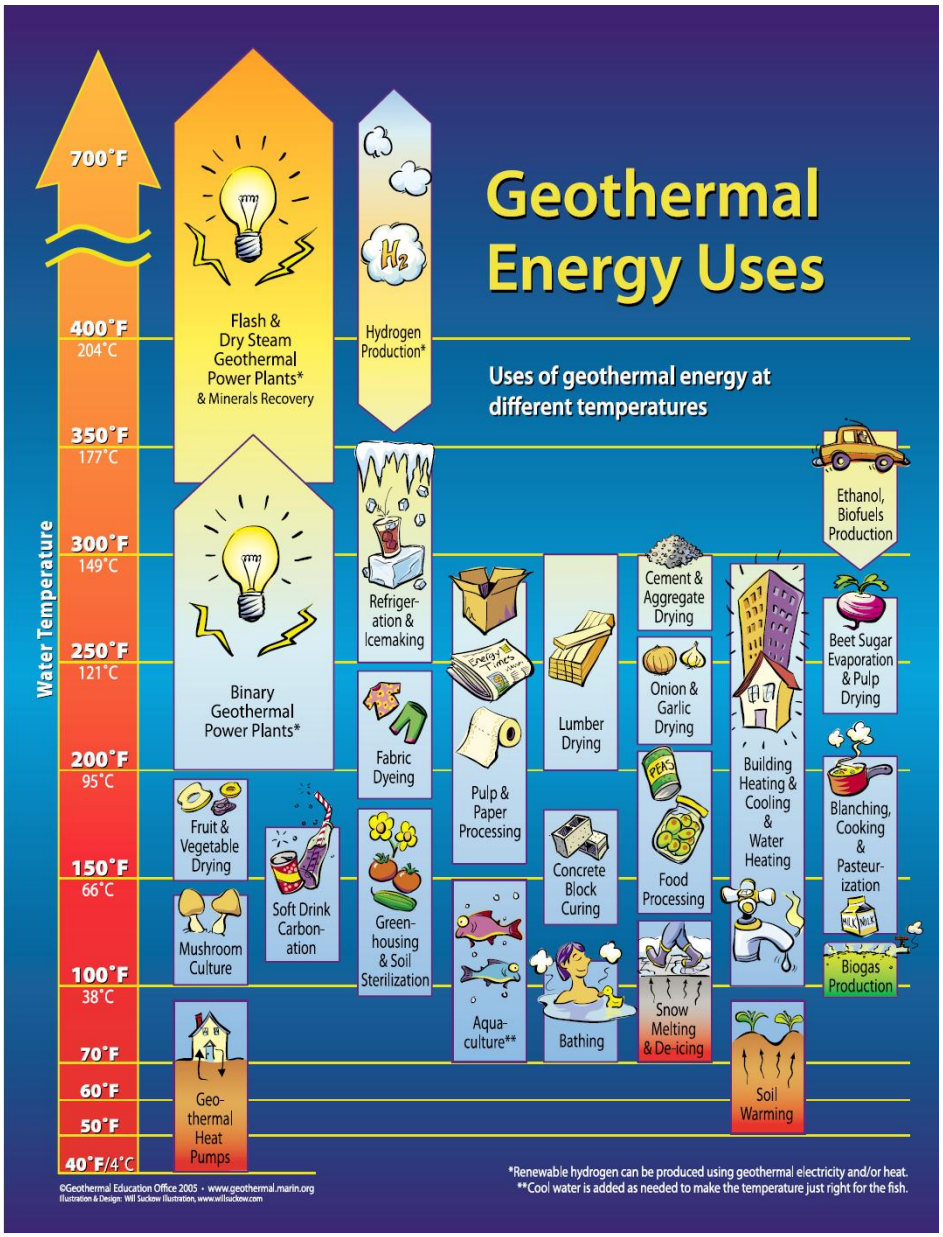
Geothermal electricity generation passes the fluid (steam or brine) through a turbine that is connected to a generator. The primary determinants of the type (flash or binary) and capacity (MW) of a plant are the temperature of the geothermal resource and the sustainable flow rate of the geothermal fluid.

Flash steam plants utilize steam from the geothermal brine, and re-inject any leftover water. Binary cycle power plants do not flash the geothermal brine, instead the brine is used to flash a working/secondary (i.e., binary) fluid with a much lower boiling point

In general, a higher temperature and/or flow rate will equate to more power generation. For the Imperial Valley, the minimum temperature of the geothermal resource is typically 300°F with flow rates in excess of 1,000 gallons per minute (gpm) per well.

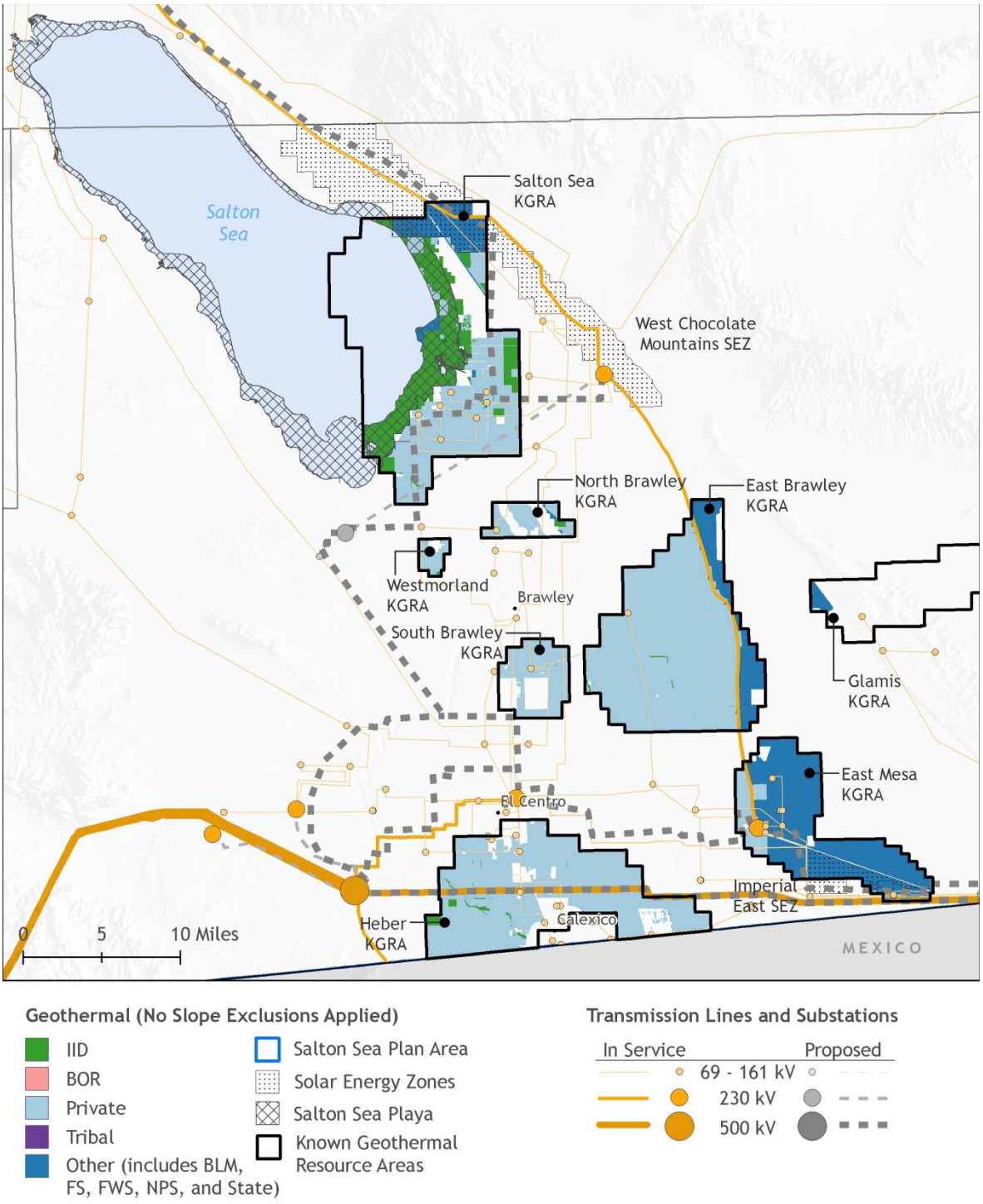
Geothermal fluids can be used without involving a power plant for a variety of direct-use applications such as: space heating and cooling, food preparation, hot spring bathing and spas (balneology), agriculture, aquaculture, greenhouses, and industrial processes. Required resource temperatures can be much lower for direct-use applications depending on the desired end use (Figure 6) (Geothermal 2005). Viable flow rates can be in the 100s of gpm per well range.

Geothermal energy could provide very high temperature heat for desalination, electric generation, and some industrial uses, as well as possible low-grade heat or brine for algae ponds.



Source: GEO 2005

Figure 6. Direct-use applications versus temperature requirements.



Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM; Ventyx Velocity Suite 2014

Figure 7. Total developable land for geothermal electric resource.

Total developable land within the Salton Sea region KGRA as presented in Table 1 are estimates based solely on land area and exclude important criteria for more accurate geothermal capacity

estimation, such as reservoir temperature and volume. There are roughly 233,000 acres[7] of developable land within the various Imperial County KGRAs, of which 1,851 acres lie within 1 mile of a 138 kV to 230 kV substation. However, 50,329 acres lie within 5 miles of a 138 kV to 230 kV substation, which could allow for future transmission development. Additionally, geothermal power plants have small footprints; that is, they require little land compared to coal and nuclear power plants. An entire geothermal field uses 1-8 acres per MW.[8] Given this relatively low land use, development of solar photovoltaics on KGRA land within the playa may also be potentially feasible after development of the geothermal resource in the area has occurred. An additional potential benefit of this geothermal development is that infrastructure such as roads and berms will be created, which can then be utilized by other projects.

The technical potential for geothermal development can be constrained by both the availability of surface land area, as well as the underlying geothermal resource. For the purposes of this analysis, the surface area was assumed to be available, and the technical potential was primarily determined by volumetric resource estimates of the underlying geothermal reservoir. A more detailed analysis of the range of likely developable geothermal potential is discussed further.

Geothermal Resource Potential of Imperial County

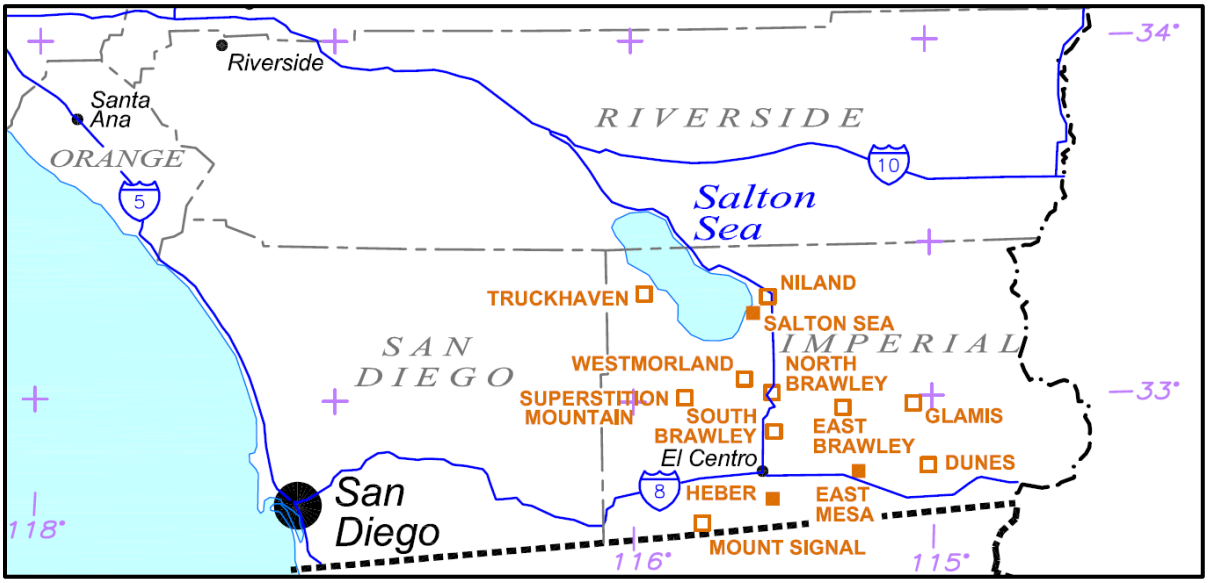
The Imperial Valley is geologically located in the Salton Trough, where the North American Plate and Pacific Plate are moving past each other. This plate movement causes basins to pull apart, allowing magma to rise closer to the surface, and resulting in a large geothermal anomaly. The San Andreas Fault terminates near the south end of the Salton Sea, with its fault surfaces perpendicular to the pull-apart basin. These faults constitute a permeable medium for up flow and out flow of heat flux and circulation of hydrothermal fluids.

One of the largest geothermal anomalies in the United States is located at the south end of the Salton Sea. There are thirteen documented geothermal prospects in Imperial County:

- Salton Sea
- Niland
- Westmorland
- Glamis
- East Mesa
- Heber
- Dunes
- Superstition Mountain
- North Brawley
- East Brawley
- South Brawley (Mesquite)
- Mount Signal
- Truckhaven

[7] There are 379,787 acres within the KGRAs, of which 232,051 acres are developable.
[8] EERE Geothermal Technologies Program, http://energy.gov/eere/geothermal/geothermal-power-plants-minimizing-land-use-and-impact. Accessed 8/24/2015.

Nine of the thirteen geothermal prospects have been classified as KGRAs, designated by the United States Geological Survey (USGS) as having potential for beneficial exploitation of the geothermal resource suspected to exist in the area. Only four of these prospects currently have operating geothermal plants: East Mesa, Heber, North Brawley, and Salton Sea.



Source: *GeothermEx 2004, modified by NREL*

Figure 8. Location map for documented geothermal prospects in Imperial County.

Based on data from the GEA, the current nameplate geothermal capacity in Imperial County is 715.2 MW, but the operational capacity is only 602.1 MW (Table 4). The nameplate capacity of a geothermal power plant is determined by the generator's manufacturer and indicates the maximum output a generator can produce without exceeding design thermal limits. The Salton Sea area has the majority of the nameplate (installed) capacity, with 402.2 MW in Imperial County.

Table 4. Current Status of Operating Power Plants in Imperial County

Geothermal Areas	Power Plant Name	Operator	Type	Nameplate Capacity (MW)	Operational Capacity (MW)
East Mesa	Ormesa I	Ormat	Binary	26.2	18.4
	Ormesa IE	Ormat	Binary	5	5
	Ormesa II	Ormat	Double Flash	24	18
	Ormesa IH	Ormat	Binary	8.8	6
	Ormesa II Upgrade	Ormat	Binary	4.3	4.3
	GEM II	Ormat	Double Flash	21.6	9
	GEM III	Ormat	Double Flash	21.6	12
	GEM Bottoming Unit	Ormat	Binary	9	7.4
	Total			120.5	80.1

Geothermal Areas	Power Plant Name	Operator	Type	Nameplate Capacity (MW)	Operational Capacity (MW)
Heber	Heber I	Ormat	Double Flash	52	37
	Heber II (SIGC)	Ormat	Binary	48	42
	Goulds ll	Ormat	Binary	16	13.3
	Goulds l	Ormat	Binary	10.5	10
	Heber South	Ormat	Binary	16	13.3
	Total			**142.5**	**115.6**
North Brawley	North Brawley	Ormat	Binary	50	27
	Total			**50**	**27**
Salton Sea	Salton Sea I	CalEnergy Generation	Single Flash	10	9
	Vulcan	CalEnergy Generation	Double Flash	40	40
	Salton Sea III	CalEnergy Generation	Double Flash	54	49
	Salton Sea II	CalEnergy Generation	Double Flash	20	17
	Salton Sea IV	CalEnergy Generation	Double Flash	51	43
	Salton Sea V	CalEnergy Generation	Double Flash	58.3	54
	Del Ranch (Hoch)	CalEnergy Generation	Double Flash	35.8	35.8
	Elmore	CalEnergy Generation	Double Flash	35.8	35.8
	Leather	CalEnergy Generation	Double Flash	35.8	35.8
	CE Turbo	CalEnergy Generation	Single Flash	11.5	10
	Hudson Ranch 1	Energy Source	Triple Flash	50	50
	Total			**402.2**	**379.4**
Imperial County	Total Capacity			715.2	602.1

Source: GEA 2015

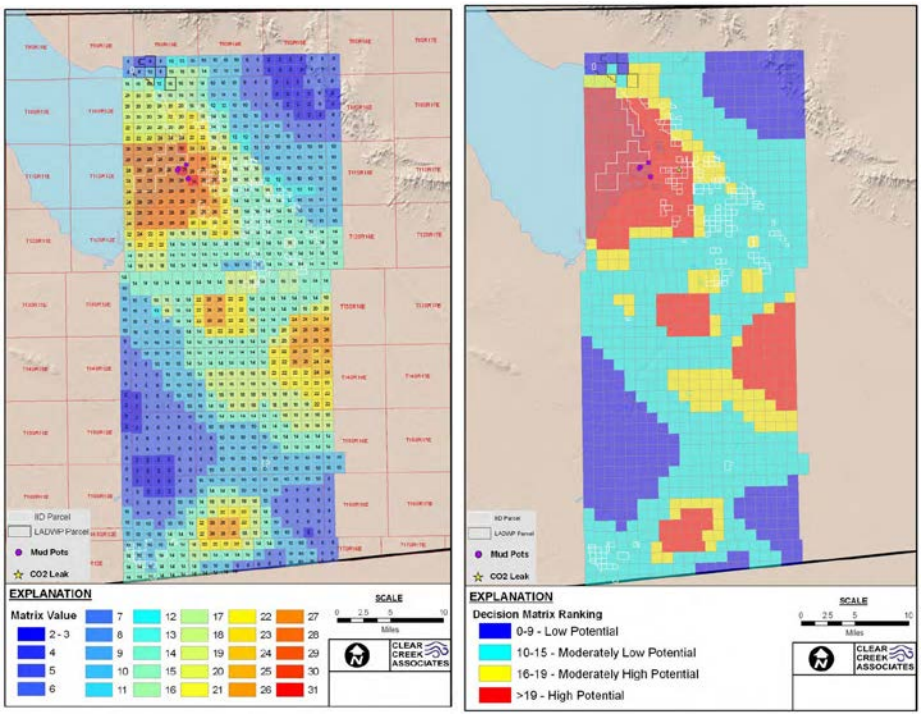
Geothermal Resource Assessment

In support of IID, a separate geothermal resource assessment study was conducted by using remote sensing techniques (Jones et al. 2011). The aim of the study was to detect the surficial evidences of deeper thermal activity. The investigators used airborne hyperspectral imagery from the Spatially Enhanced Broadband Array Spectrograph System (SEBASS) and satellite-based Advanced Spaceborne Thermal Emission and Reflection Radiometer (ASTER) imagery.

Remote sensing data is calibrated with pre-existing surface and subsurface data sets such as:

- Presence in a KGRA: geology, stratigraphy, hydrogeology
- Geophysical data: bouguer gravity mapping, magnetotelluric (MT) resistivity surveys, and seismic refraction studies
- Heat flow mapping and temperature gradients.

The result of this study was a weighted prioritization matrix for geothermal resource potential of the area (Figure 9). Each township, measuring six miles by six miles, was divided into 36 cells of approximately one square mile each based on the abundance and quality of data. After evaluating the available data, a decision matrix was used to score areas between 2 and 31, with those cells scoring 19 or higher determined to have the greatest geothermal potential (Figure 9) (Jones et al. 2011).



Source: EES Consulting 2013

Figure 9. Geothermal remote sensing prioritization matrix.

Left: Matrix Values - Prioritized According to Geothermal Resource Potential; Right: Ranked Values According to Geothermal Resource Potential

Geochemistry

Geothermal brines of Imperial Valley are usually hypersaline, having between 150,000 parts per million (ppm) and 300,000 ppm total dissolved solids (TDS) content. The Salton Sea geothermal area has the highest salinity in the region. However, there are some geothermal areas with relatively low salinity brines, such as the Truckhaven and East Mesa areas (4,500 ppm to 7,500 ppm, respectively). In the KGRAs of Imperial County, resource temperatures range from 250°F to 600°F (Table 5). However, based on discussions with contacts from an existing plant in the

region, reservoir depths of 4,000-8,000, and a maximum reservoir temperature of 550°F are a more realistic range for the region.

Table 5. Temperature and Total Dissolved Solids Content of Geothermal Areas in Imperial County

Geothermal Areas	Reservoir Depth (ft)	Average Reservoir Temperature (°F)	TDS Content (ppm)
Salton Sea	4,000	600	250,000-300,000
East Mesa	6,000	350	7,500
Heber	6,000	360	14,000
North Brawley	7,000	525	150,000
East Brawley	12,000	400	150,000
South Brawley	13,500	500	250,000
Niland	N/A	N/A	N/A
Mount Signal	N/A	275	N/A
Dunes	4,000	250	N/A
Superstition Mountain	N/A	N/A	N/A
Glamis	5,000	250	N/A
Truckhaven	7,000	350	4,500
Westmorland	7,000	325	26,000

Source: Heuberger 2006

The brine compositions may vary from well to well depending on the depth of production and the temperature of the different parts of the reservoir. In addition, the composition of a particular well may vary as a function of the total production time, the rate of flow, and the nature of the underlying sediments. Table 6 represents the average concentrations of elements in the brine and gas phase of geothermal fluids in KGRAs (Heuberger 2006).

Table 6. Typical Geothermal Brine and Gas Chemistry of Imperial Valley KGRAs

Dissolved Solids (in mg/L)		Salton Sea	Westmorland	Brawley	Heber	East Mesa
Sodium	Na	52,000.00	10,000.00	22,000.00	4,200.00	2,600.00
Potassium	K	14,000.00	1,400.00	3,800.00	260	190
Calcium	Ca	24,000.00	690	8,100.00	880	130
Magnesium	Mg	106	188	34	5.4	3.4
Chloride	Cl	145,000	18,000.00	46,000.00	7,900.00	3,900.00
Sulfate	SO_4	84	57	-	99	155
Bicarbonate	HCO_3	140	2,900.00	49	27	490
Arsenic	As	11	-	2.6	0.1	0.16
Boron	B	350	63	140	14	5.4
Barium	Ba	433	-	363	3.8	2.2
Copper	Cu	4	0.07	0.11	0.53	0.03
Fluoride	F	9	2.24	-	1.6	2
Iron	Fe	2,300.00	0.3	65	22	2.2
Lithium	Li	211	48	100	9.5	6.3
Manganese	Mn	1,200.00	2.8	190	2.7	0.42
Nickel	Ni	4	-	-	0.03	-
Lead	Pb	100	3.8	1.1	1.9	0.09
Strontium	Sr	500	-	340	53	38
Zinc	Zn	660	0.04	14	0.83	0.07

	Salton Sea		East Mesa	
Non-condensable Gases (in mg/kg)		Range	Mean	Range	Mean
Hydrogen Sulfide	H_2S	1.6 - 6.0	3.2	0.12 - 1.6	0.54
Ammonia	NH	20 - 40	35	1.3 - 8.1	4.5
Carbon Dioxide	CO_4	1,100 - 3,800	1,700	270 - 2,300	1,100
Methane	CO_4	10-Mar	6	4.0 - 56	33
Hydrogen	H_2	0.0016 - 0.002	0.0018	0.005 - 0.007	0.0064

Source: Heuberger 2006

Volumetric Resource Assessment

The primary method applied in USGS assessments for evaluating the production potential of identified geothermal systems is the volume method. In this method, the recoverable heat is estimated from the thermal energy available in a reservoir of uniformly porous and permeable rock using a thermal recovery factor, R_g, which accounts for the fraction of the reservoir's energy that can be turned into power.

The electric power generation potential from an identified geothermal system depends on the thermal energy present in the reservoir, $q_{R,}$ the amount of thermal energy that can be extracted from the reservoir at the wellhead, q_{WH}, and the efficiency with which that wellhead thermal energy can be converted to electric power. This information is relevant to the volumetric resource assessment, as the thermal energy contained in the reservoir is an important piece of the overall calculation of the ultimate electric power generation potential.

The amount and quality of technical data available from the geothermal resource areas is highly variable. On one hand, geothermal areas with existing facilities with long production histories or have enough drilling information to prove the existence of commercial production conditions, can allow a reasonably accurate assessment of the ultimate potential and electricity generation capacity of the field. On the other hand, for geothermal areas that have been identified from surface exploration, but with no deep drilling to confirm the presence of a commercial reservoir, the potential and electric generation capacity can only be assumed based on averages at other fields in similar settings.

In early stages of geothermal resource assessment, electrical power generation capacities of the resource areas can be estimated using a probabilistic (Monte Carlo) method applied to a calculation of heat in place (the stored thermal energy in a geothermal reservoir). This probabilistic approach is based on volumetric assessment of the geothermal reservoir. To be able to perform volumetric calculations, some geothermal system and reservoir variables should be estimated. These variables are:

- Surface area of the geothermal system
- Thickness of the system (vertical distance between top and bottom surfaces of the reservoir rocks)
- Reservoir temperature
- Recovery factor
- Porosity of the rocks
- Heat and density of the rock and water.

To take uncertainties of these criteria into account, a most-likely value is selected, together with a minimum value and a maximum value that define an approximately normal probability distribution around the most-likely value. The minimum, most-likely, and maximum values of each criterion are then used in probabilistic simulation (based on Monte Carlo random-number sampling) to calculate estimated generation capacity based on the accessible heat in place at the resource area. Results are expressed in terms of MW capacity for life-time of the power plant (i.e., 30 years). In order to convert thermal energy into electrical energy, there are some other parameters to be estimated such as: electric conversion coefficient, load factor, system cut-off temperature, and system delta temperature (the difference between inlet and outlet design temperatures, which is used to calculate the exergy, or maximum useful energy, of the system).

Results of probabilistic calculations can be expressed in terms of minimum (90% cumulative probability), most-likely (modal), mean, and the standard deviation of the mean. It must be emphasized that the generation capacity estimate is based on calculated heat in place. This does not guarantee that a given resource in which there has been little or no drilling will have the reservoir permeability required to allow commercial production of hot water or steam to a power plant. That can be established only by drilling and testing the production zone.

One of the most recent electricity generation capacity estimates based on volumetric assessment calculations was conducted by GeothermEx for the California Energy Commission in 2004. This estimate was based on a thirty-year production life. Table 7 summarizes resource capacity

estimates (GeothermEx 2004), as well as the reservoir volume from USGS, and surface areas estimates (Heuberger 2006) for each geothermal area in Imperial County.

Table 7. Electricity Generation Capacity Estimates for Imperial County Geothermal Areas Using Volumetric Assessment Methods

Geothermal Areas	Reservoir Volume Estimate (km^3)*	Minimum Resource Capacity (MW)†	Most Likely Generation Capacity (MW)†	Mean Resource capacity (MW)†	Nameplate Capacity in January 2015 (MW)**	Most Likely Developable Capacity (MW)
Salton Sea	127.7	1,350	1,750	1,880	402.2	1,348 (1,064††)
East Mesa	30	119	148	167	120.5	28.5
Heber	20	109	142	158	142.5	16
North Brawley	9	88	135	144	50	85
East Brawley	24	85	129	138	0	129
South Brawley	2	45	62	70	0	62
Niland	N/A	59	76	92	0	76††
Mount Signal	3.1	12	19	29	0	19
Dunes	1.95	7.4	11	18	0	11
Superstition Mountain	N/A	6	10	15	0	10
Glamis	N/A	4	6	11	0	6
Truckhaven	N/A	N/A	50**	N/A	0	50
Westmorland	N/A	N/A	N/A	N/A	0	N/A
TOTAL	217.75	1,884.4	2,448	2,722	715.2	1,840.5

* USGS; ** GEA 2015; † GeothermEx 2004; †† GeothermEx 2015 (unpublished update)

The most likely field generation capacity for all Imperial County geothermal areas is 2,448 MW. After subtracting the existing nameplate capacity from this figure, the estimated remaining undeveloped capacity is calculated to be 1,840.5 MW. The most likely developable capacity of the Salton Sea KGRA is 1,348 MW; however, in a 2014 study, this number was updated (but not published) by GeothermEx to 1,064 MW. For the purposes of this analysis, the published estimate in 2006 of 1,348 MW will be utilized.

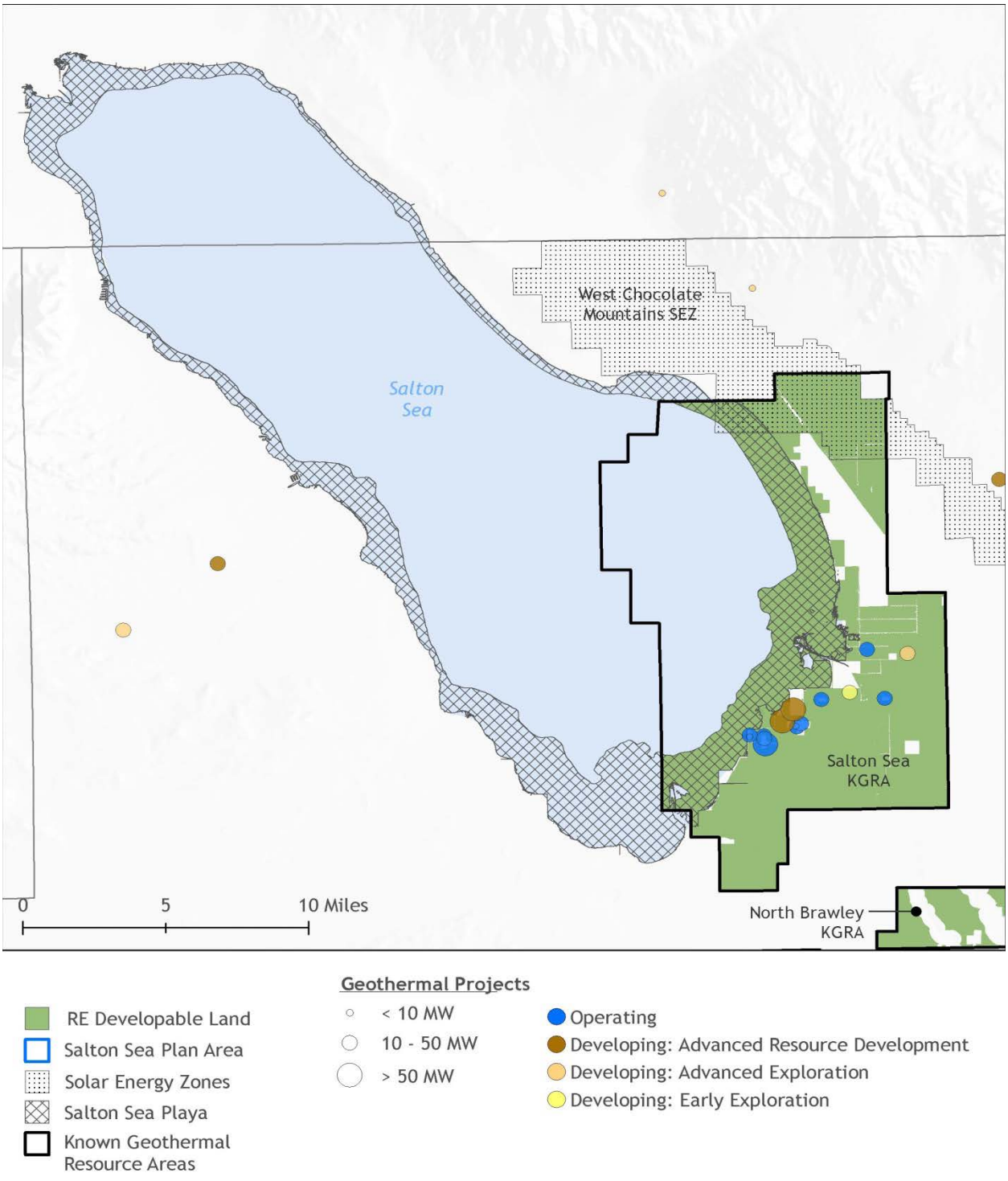
Resource Estimates for the Salton Sea KGRA

The geothermal resource potential of Salton Sea area has been investigated since the late 1970s and there are many different published estimates for long-term electric power production potential. The estimates are based on the investigators' assessments of reservoir area, thickness, volume, temperature, porosity, permeability, fluid mass and replacement capacity, stored heat, heat recoverability, and heat-to-electricity conversion efficiency. These estimates are listed in Table 8.

Table 8. Summary of Published Salton Sea Geothermal Area Resource Estimates

Reference Study	Resource Estimate (MW) for 30 years
Ermak, 1977	4,000
Younker and Kasameyer, 1978	1,300 to 8,700
Brook et al. , 1979	3,400
Meidav and Howard, 1979	30,000
Biehler and Lee, 1997	17,500
Elders,1989	2,500
Hulen et al. , 2002	2330
GeothermEx, 2004	1,750
EES Consulting, 2013	2,900

The Salton Sea KGRA is widely considered by many geothermal industry leaders as the best opportunity for growth in California in the near term. However, the majority of the proven resource is located within the offshore part of the area (Figure 10). The onshore portion of the geothermal reservoir in the Salton Sea area constitutes only 38.6% of the total, whereas the offshore part constitutes 61.4% (Hulen et al. 2002).



Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM; NREL Geothermal Prospector 2014.

Figure 10: Offshore portion of Salton Sea KGRA and recession estimate of the shoreline in 25 years.

It has been estimated that the offshore part of Salton Sea KGRA's potential is 1,430 MW. GeothermEx does not have a separation between onshore and offshore resources, but if the ratio

referenced above (Hulen et al. 2002) is utilized, the offshore part of the resource is calculated to be 1,075 MW. EES Consulting forecasts the possible offshore geothermal generation as 1,660 MW, including the low temperature gradient portion of the reservoir. The shoreline of the Salton Sea is receding at the estimated rates described in Figure 11. The current total area of water in the Salton Sea KGRA is calculated at 52,848 acres, which will recede to 34,854 acres, leaving 17,994 acres of playa area in 2030. This recession will likely allow for the development of offshore resource potential at Salton Sea KGRA (Figure 11). Based on the total water area in the Salton Sea KGRA, unit power generation capacity is calculated as 20 kW/acre (GeothermEx 2004), 27 kW/acre (Heuberger 2006), and 31.5 kW/acre (EES 2013). Then, the additional power generation capacity is calculated by multiplying the unit capacity with the total revealed playa area of Salton Sea in every five years interval (Figure 11). Maximum developable capacity at the Salton Sea offshore KGRA is estimated to reach up to 565 MW in 2030.

Table 9. Onshore and Offshore Portions of Salton Sea KGRA Based on Most Recent Resource Potential Estimates

Reference Study	Total Resource Estimate (MW)	Onshore Resource Estimate (MW)	Offshore playa Resource Estimate (MW)
Hulen et al. 2002	2,330	900	1,430
GeothermEx 2006	1,750	675	1,075
EES Consulting 2013	2,900	1,240	1,660

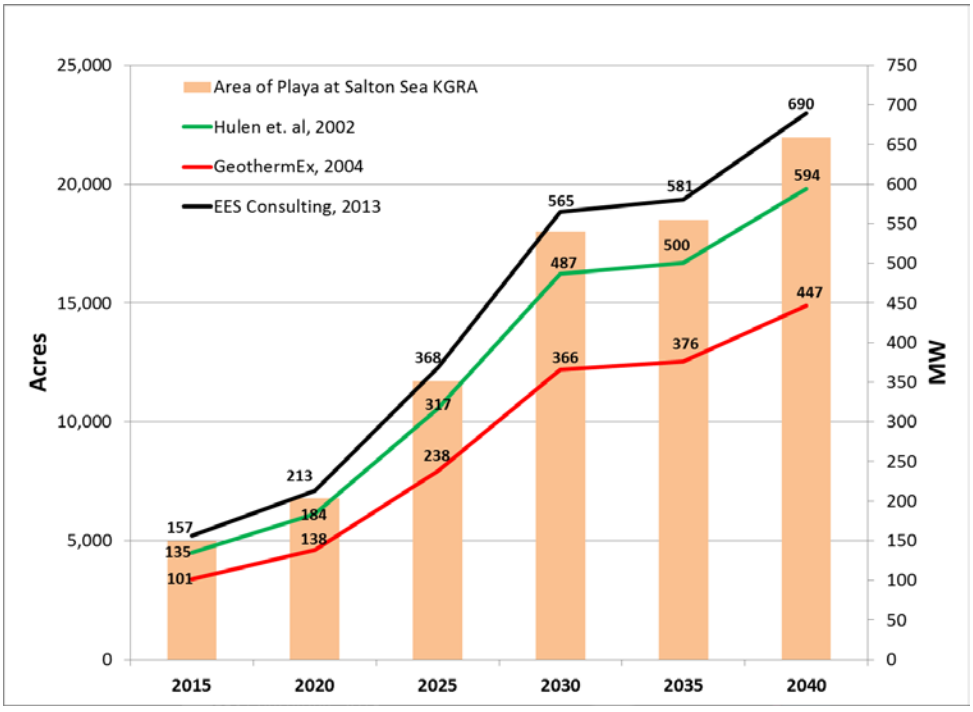
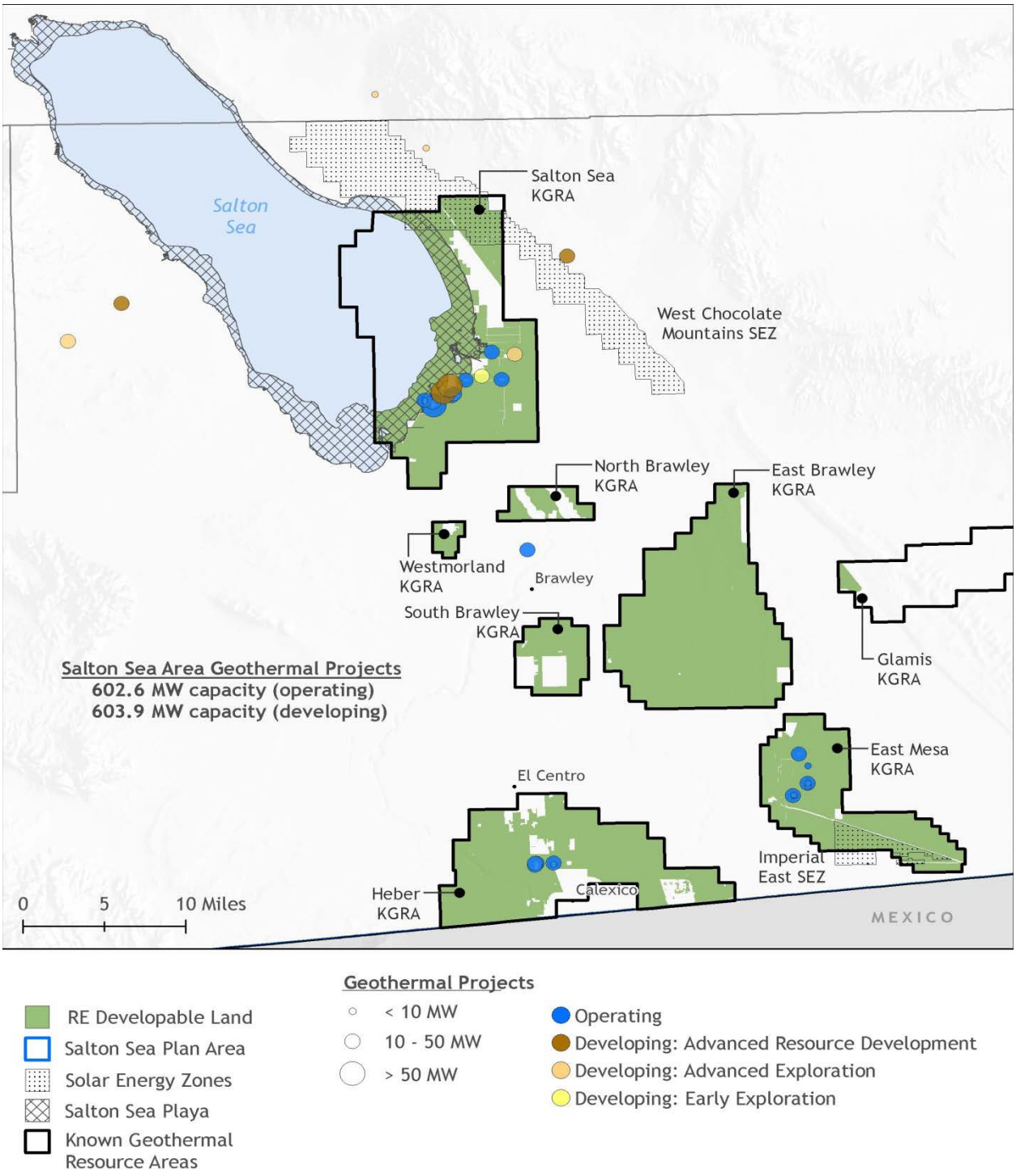


Figure 11. Potential development of offshore Salton Sea KGRA based on the shoreline recession in 25 years.

The generation figures in Table 10 assume a net capacity factor of 80%. For a water-cooled flash plant, a capacity factor of 94% was estimated, but in order to provide a conservative estimate of the likely generation after accounting for parasitic loads, a net capacity factor of 80% was assumed (Mines et al. 2015). Although there is a high capacity potential for this region, several key caveats for the region must be noted. Much of the geothermal resource in the Salton Sea is extremely high temperature, requires pumping of the resource, and often contains damaging silica that can result in scaling. These operational challenges can result in lower net capacity factors and higher operation and maintenance (O&M) costs than those of other regions. Based on industry knowledge, net power generation can be up to 40% less than gross power capacity (i.e., nameplate).

Second, in the oil and gas industry, directional drilling may reach up to 1 mile offset distance (Billman et al. 2000). However, in the geothermal industry, the typical directional well offset distance is between ¼ and ½ mile (Kuyumcu et al. 2013). Therefore, instead of directional wells, future projects will likely have to be constructed on playa with additional construction cost. Offshore playa development is estimated by an industry source to result in at least a 10% increase over typical geothermal costs.

Finally, there is already a significant amount of existing geothermal capacity in the region, with 600 MW of existing and operating plants as shown in Figure 12. Of these geothermal fields, the greatest concentration of projects is located within the Salton Sea field.



Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM; NREL Geothermal Prospector 2014.

Figure 12. Existing and developing geothermal plants.

Table 10. Developable Geothermal Capacity by 2030

Geothermal Area	Capacity Potential (GW)	Generation Potential (GWh/yr)
Salton Sea (onshore)*	0.68 - 1.24	4,765 – 8,690
Salton Sea (offshore)**	0.37 - 0.57	2,593 – 3,995
Imperial Valley (Other Areas) ***	0.50	3,504

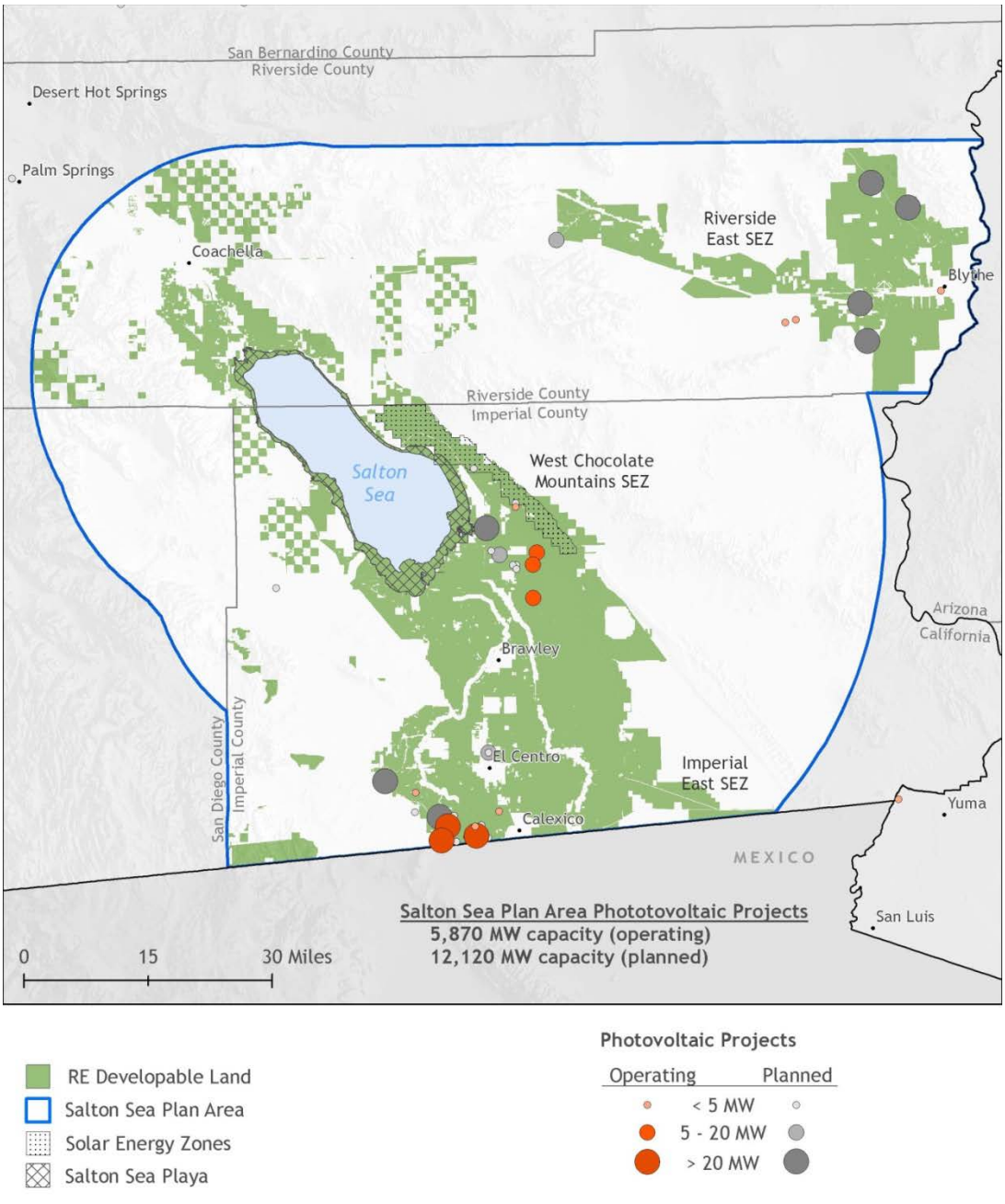
* Based on the range of estimates from EES Consulting, 2003, Hulen et al., 2002 and Geothermex, 2006
** Based on estimated accessible playa area in the offshore KGRA in 2030 as a portion of the estimated boundary of the geothermal reservoir. (Sources: Tetra Tech, Hulen et al., 2002)
*** Includes the remaining developable potential listed in the far-right column of Table 7 from all KGRA's other than the Salton Sea. These were not included in the likely developable potential, as they were unlikely to support a geothermal plant at an economic scale. (Source: Geothermex 2004)

3.2 Solar

Given the generally strong solar resource in the Salton Sea area (between 6 and 7.8 kWh/m2/day), a variety of solar electric or solar thermal technologies may be suitable for development within the region.

3.2.1 Photovoltaics

As shown in Figure 13, the Salton Sea area already has considerable operating and planned PV capacity.

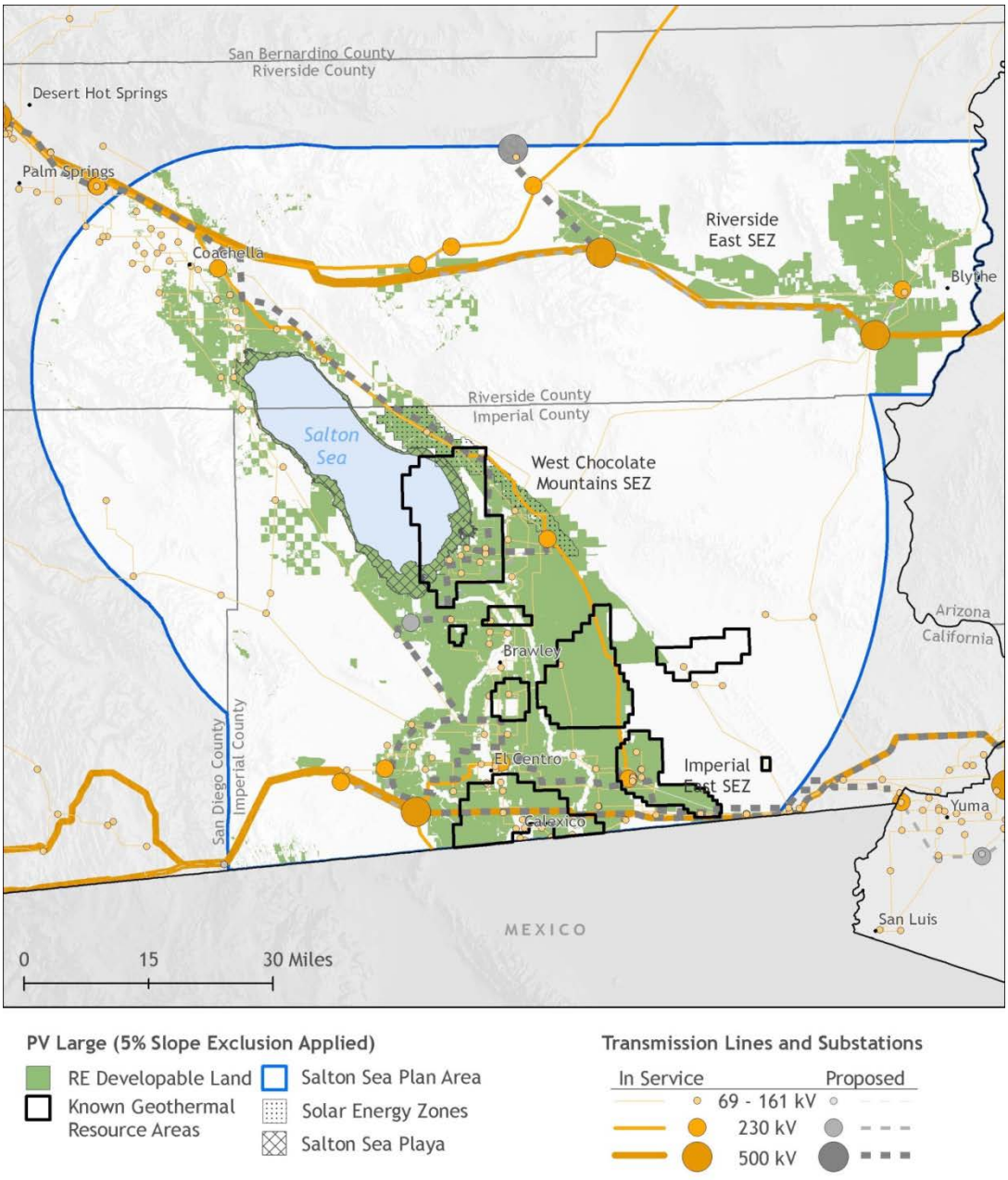


Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM; Ventyx Velocity Suite 2014.

Figure 13. Existing and planned PV projects.

The total solar PV resource in the Salton Sea Plan area is show in Table 11. This assumes a 20% capacity factor, and assumes average land use of 7.9 acres/MWac for large-scale PV plants. Based on a 2013 NREL study of 72% of all U.S. utility solar capacity, solar PV typically occupies between 7 acres and 10 acres/MW, with mean and median values of 7.9 and 8.5, respectively. Smaller utility-scale plants under 20 MW have been demonstrated to use a mean

6.3 acres/MW (Ong et al. 2013). Generation is estimated using SAM 2015-01-30[9] for a fixed-tilt, utility-scale PV plant using the Imperial, CA weather file.



Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM; Ventyx Velocity Suite 2014.

Figure 14. Developable solar PV resource.

[9] NREL System Advisor Model (SAM), https://sam.nrel.gov/, accessed 6/9/15.

Although the total capacity potential is extremely large, the developable potential is significantly smaller, due to transmission proximity, land access, financing, and utility demand constraints, among others. Of the total available area under BLM ownership, 203,051 acres fall within the SEZs.

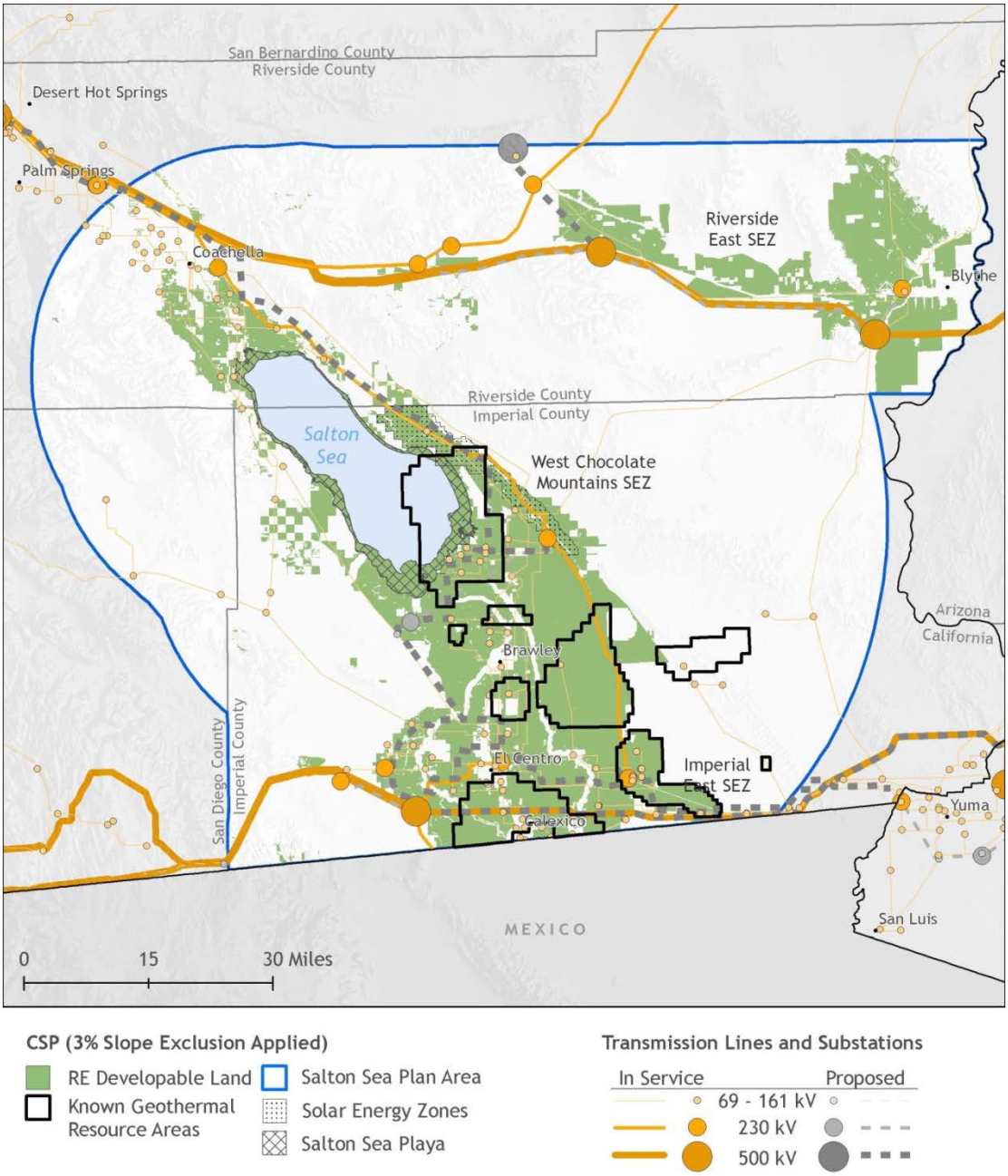
Construction of solar PV on the playa as a potential dust-mitigation measure was also examined. The Los Angeles Department of Water and Power (LADWP) has recently completed a 500 kW pilot project exploring solar PV development on the Owens Lakebed. Construction on the playa required additional costs for mobilization and transportation to work within the loose soil conditions (such as an access road and pre-existing gravel cover) but the system is operational. Development of solar PV on the playa may allow for an additional potential revenue stream for Salton Sea restoration, as the playa land is predominantly owned by the IID, while simultaneously providing a dust mitigation benefit from ground coverage by the panels. Additional geotechnical analysis of the Salton Sea playa would be required to determine whether development of solar PV would be technically feasible.

Table 11. Developable Solar PV Resource

Technology	Total Capacity Potential (GWac)	Generation Potential (GWh/yr)	Small Sub. Capacity Potential (GWac) 1 mi.	Large Sub. Capacity Potential (GWac) 1 mi.	Small Sub. Capacity Potential (GWac) 5 mi.	Large Sub. Capacity Potential (GWac) 5 mi.
Solar PV (onshore)	103	$2.10 \times 10^{5*}$	1.8	.007	31.9	9.3

*This PV estimate comes from SAM's default utility-scale PV case. A 110 MWdc (100MWac) fixed-tilt solar field using Imperial, CA weather data generates 204 GWhac/yr. This is calculated as 2040 GWhac/yr per GWac capacity. Small substations are defined as between 138 and 230 kV and large substations defined as 500kV.
Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM. Ventyx Velocity Suite 2014.

3.2.2 Concentrating Solar Power



Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM; Ventyx Velocity Suite 2014.

Figure 15. Developable concentrating solar power resource.

The total CSP resource in the Salton Sea Plan area is shown in Table 12. Due to the strong solar resource and relatively low slope constraints, there is a very high technical potential for CSP projects in the Salton Sea study area. However, as was noted in the solar PV section, while this capacity may be technically feasible, CSP development is also constrained by numerous other factors, including its relative economic competitiveness within the region. Capacity factors for various CSP technologies vary widely, and generation potential has been given as a range

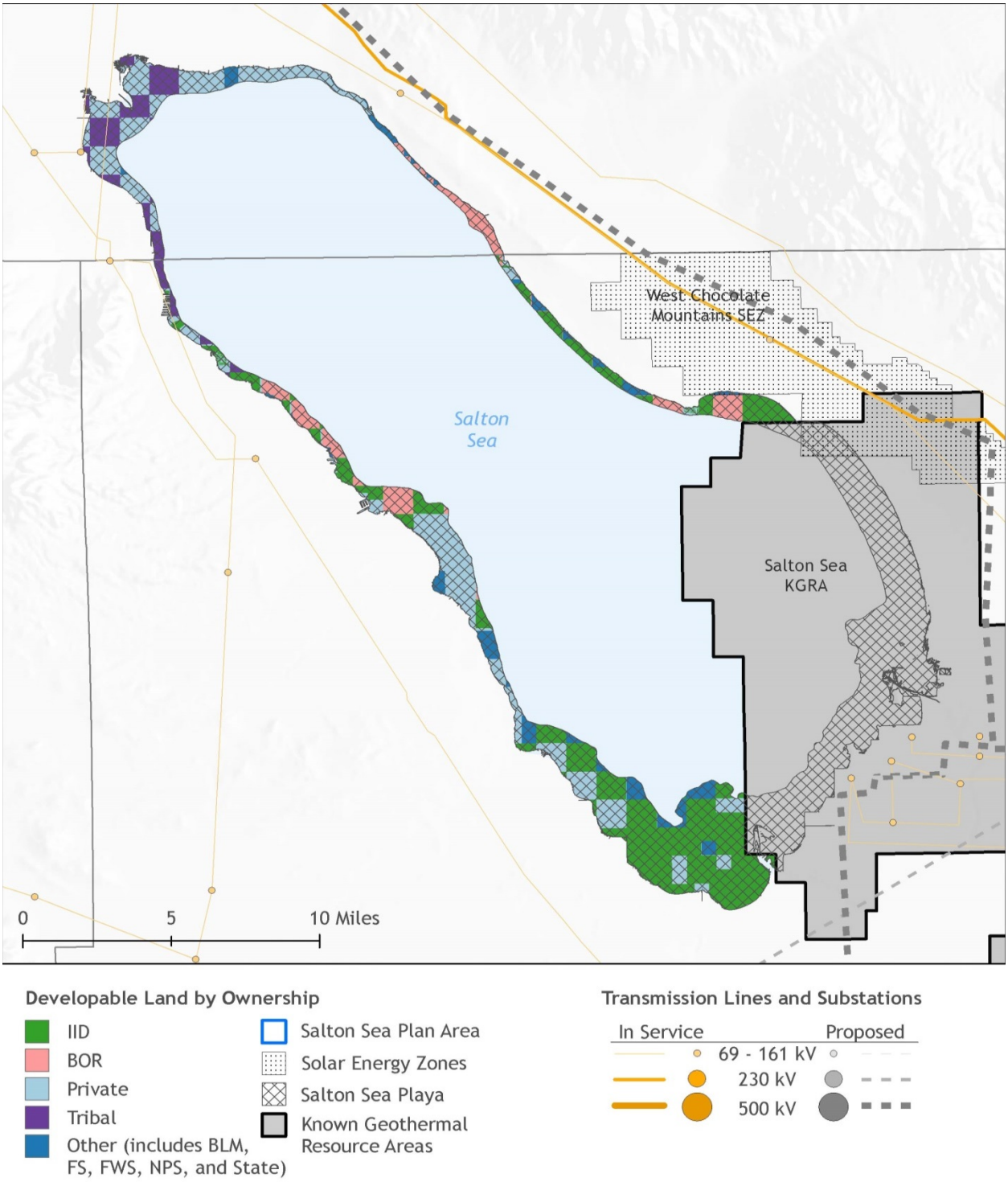
between 25% and 49%. The CSP potential was estimated using the default Parabolic Trough case (Physical Trough model) in SAM 2015-01-30. This plant is assumed to have six hours of thermal energy storage has a calculated capacity factor of 42% using the Imperial, CA weather file.

Table 12. Developable CSP Resource

Technology	Total Capacity Potential (GWac)	Generation Potential (GWh/yr)	Small Sub. Capacity Potential (GWac) 1 mi.	Large Sub. Capacity Potential (GWac) 1 mi.	Small Sub. Capacity Potential (GWac) 5 mi.	Large Sub. Capacity Potential (GWac) 5 mi.
Solar CSP (onshore)	77	$2.80 \times 10^{5*}$	1.3	.006	23.9	7.3

*This CSP estimate comes from SAM's default Physical Trough case. A 100 MWac,net trough plant with 6 hours of thermal energy storage using Imperial, CA weather data generates 364 GWhac/yr. This is calculated as 3,640 GWhac/yr per GWac capacity. Small substations are defined as between 138kV and 230 kV and large substations defined as 500kV. Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM. Ventyx Velocity Suite 2014.

3.2.3 Salinity Gradient Solar Ponds



Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM; Ventyx Velocity Suite 2014.

Figure 16. Developable SGSP resource.

The total potential SGSP resource on the Salton Sea playa is shown in Table 13. Although electricity production from salinity-gradient solar ponds has been technically proven, it has not been established as an economically viable power production technology to date. The low-grade heat (70°C -90°C) produced by this technology may also be supplied to other processes, including: desalination, algae pond heating, food processing, and other industrial processes. An additional benefit of SGSP development on the playa is its potential to cover large areas of exposed playa while also generating an additional value stream (heat or electricity).

Potential constraints to development on the playa include transmission access on the exposed playa, as well as construction limitations such as construction mobilization and earth moving equipment access on playa soil. Although the developable small substation capacity for SGSPs is listed as 0 in Table 13, interconnection with smaller 69 kV substations was not examined, and may be feasible for smaller projects. Given that SGSPs have not yet been developed within the region, 10 MW to 100 MW could be technically developable by 2030, although this does not account for transmission access or economic viability, which are still uncertain. Assuming that the full 26,628 acres within 10 miles of 138 kV to 230 kV transmission was developed would result in a total developable capacity of 444 MW.

Table 13. Total Developable SGSP Capacity

Technology	Total Capacity Potential (GW)	Generation Potential (GWh/yr)	Small Sub. Capacity Potential within 1 mile	Small Sub. Generation Potential within 1 mile
SGSP (offshore)	0.444*	3,500	0	0

*This SGSP estimate was calculated using the following assumptions: 60 Acres/MW. Thermal efficiency of 20%, and electric conversion rate of 5% was assumed (Wang et al. 2010). Global horizontal insolation from the same Imperial, CA weather file that was employed for the PV and CSP cases yields an annual GHI = 2,106 kWh/m2. Small substations are defined as between 138kV and 230 kV.

Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM. Ventyx Velocity Suite 2014.

3.3 Algal Biofuels

The United States currently imports approximately 50% percent of its petroleum. The production of transportation fuels consumes two-thirds of that petroleum. The distribution of petroleum into transportation fuels has been changing in recent years with gasoline sales declining. Even so, approximately 134 billion gallons of gasoline were consumed in 2013, along with 59 billion gallons of diesel and 21 billion gallons of jet fuel.[10] Though imports have been declining due to increased domestic production of petroleum, issues regarding dependence on foreign supply, as well as price volatility and growing concerns about global warming have led to an international movement toward renewable energy generation and carbon emission reduction.

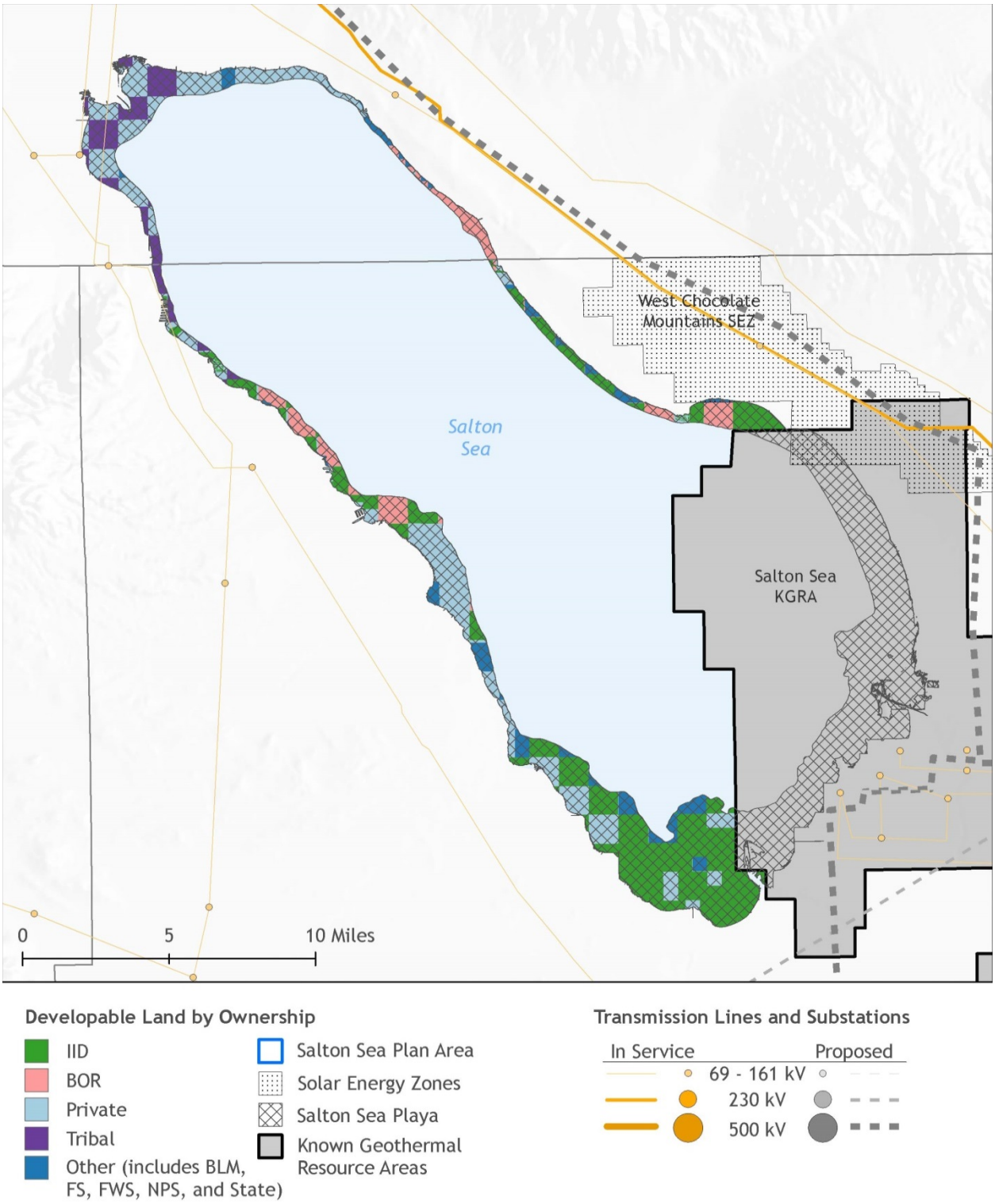
[10] AEO2014 is available on the EIA website, http://www.eia.gov/forecasts/aeo/.

Due to the reduced water flow into the Salton Sea and the resulting evaporation and shrinkage of the sea, additional playa will be exposed as the shores recede. One of the technologies that could potentially be developed on this playa is algal biofuel biorefineries.

Since the beginning of the Aquatic Species Program in 1978, U.S. Department of Energy (DOE), projects and partnerships have made great strides in the effort to develop an algae-based biofuel substitute for diesel, jet fuel and gasoline. Algal biofuels may be a potential solution to some of the problems facing the Salton Sea for a number of reasons:

- Algal cultivation depends on large scale availability of flat, unproductive land to allow for establishment of cultivation facilities. The least capital intensive means to grow algae involves large scale open ponds (known as raceway ponds).These are typically very shallow (approximately 6.5 ft) to maximize the amount of light that can be absorbed by each photosynthetic algal cell with minimal self-shading. Even with shallow ponds, biomass concentrations in culture rarely rise above 1 g/L. In order to generate sufficient biomass for production of fuels and take advantage of economies of scale, a single algae farm will likely cover as much as 10,000 acres. Although many areas that could be used for algal cultivation have been identified in the United States, the deployment of large scale algal ponds in the Salton Sea playa could provide an additional benefit of covering the recently exposed soil, reducing the environmental challenges of potentially toxic dust to be spread by the wind.
- Algal cultivation depends on large volumes of water. Although some of that water can be recycled after the algae are harvested and concentrated, a significant amount will be lost due to evaporation. In a scenario involving freshwater cultivation, the evaporation would lead to competition for dwindling resources needed for drinking water, irrigation water, or industrial process water. However, algae do not need to grow in freshwater. Strains have been identified that can grow in brackish, saline, and even hypersaline water. The evaporating waters of the Salton Sea have been shown to be ideal (in terms of both salt content and nutrient availability) for algal cultivation, which has become a problem in its own right as natural algal bloom/death cycles lead to oxygen deprivation for fish and bad smells from rotting algal biomass (Barringer 2014). Use of Salton Sea water for controlled algal cultivation could reduce the amount of fresh water needed for cultivation and could remove nutrients from the water reducing the potential for algal blooms.

An algal biofuel project at this location may provide value to the Salton Sea area in several ways. This initial evaluation is an important first step in determining the value of the project, both to IID and to the biofuel community as it could serve as a prototype large scale operation.



Data Sources: National Renewable Energy Laboratory; Desert Renewable Energy Conservation Plan; Riverside County, CA; Imperial County, CA; Imperial Irrigation District; BLM; Ventyx Velocity Suite 2014.

Figure 17. Developable algal pond resource.

The total potential algal biofuels production capacity is listed in Table 14. The capacity figure is determined primarily by an algae power density of 1,200 gal/acre/year across the Salton Sea's developable areas. To put this into perspective, algal productivity values as high as 1,500 gal/acre/year have been reported by the DOE-sponsored Cornell Consortium for work carried out in hybrid photobioreactor/open pond systems located in Kona Hawaii.[11] The study area was restricted to developable areas on the playa for several reasons. First, most forms of algal biofuel production are still pre-commercial and are not yet cost-competitive on a price per gallon basis. However, with the development of co-products, as well as an avoided-cost adder on exposed playa dust mitigation, algal biofuel production will likely become more financially attractive. Second, it appears that the exposed playa may be amenable to algae development, as several of the most widespread algae harvesting technologies in commercial operation (open unmixed and open raceway ponds) have high water requirements, cover large land areas, and are often sited in regions with high insolation. The developable land within the Salton Sea KGRA was also excluded, as development of geothermal projects on this land would likely take priority. However, due to the small footprint of geothermal plants, algal biofuel development within the KGRA acreage may be possible after full geothermal development has occurred. Since the Salton Sea's future evaporation rates are still uncertain, the ultimate area of exposed playa will vary. Potential constraints to development on the playa include transmission access on the exposed playa, as well as construction limitations such mobilization and earth moving equipment access on playa soil.[12] An area for future study would be an analysis of the developable potential of algae cultivation for nutrition or cosmetic supplements. Using 13g/m^2/day, a conservative figure for algal biomass productivity,[13] it is possible to estimate the annual production capacity for algal biomass on the developable playa (Table 14).

Table 14. Developable Playa and Potential Algal Production Capacity by 2030

Technology	Acreage	Algal Production Capacity (gal/year)
Algal Biofuels (offshore)	32,821.4	39,385,674.2
Algal Food and Feed (Offshore)	32,821.4	600,000 tons/year

Sources: ANL; NREL; PNNL. (June 2012)

Revenue Opportunities

Additional avenues for revenue development from algae exist, such as the development of fuels other than ethanol and co-products (protein and fertilizer). In addition, there is a potential for several synergies through co-development of geothermal resources, as the availability of geothermal heat and brine could provide low cost energy inputs for improved cultivation of algae in cool weather months. Although these co-product options are explored, they have not been

[11] "Five Energy Department Accomplishments in Algal Biofuels," accessed 4/29/2015, http://energy.gov/eere/articles/five-energy-department-accomplishments-algal-biofuels.
[12] http://www. syntheticgenomics.com/media/press/051613.html, accessed 6/5/15.
[13] This figure is discussed in more detail in "Renewable Diesel from Algal Lipids: An Integrated Baseline for Cost, Emissions, and Resource Potential from a Harmonized Model," http://www.nrel.gov/docs/fy12osti/55431.pdf.

analyzed in detail for Salton Sea restoration revenue potential, due to their early or pre-commercial nature.

- Most algal biofuel companies are exploring multiple fuel types as viable options, with only one company known to be involved almost solely in the production of ethanol (Algenol). Several other companies are targeting biodiesel or "drop-in" fuels such as renewable diesel and jet fuel, but these are not yet commercially available.
- Some current estimates about CO2 requirements, production cost for photobioreactors (Algenol's production cost) and open pond systems follow:
    - CO2 requirements are more likely around 25-30 kg CO2/gal, based on approximately 2.5 kg CO2/kg biomass.
    - $50/barrel of fuel is currently being reported by Algenol, which is also claiming production rates of 8,000 gal/acre/year.
    - The most recent published estimate for algal biofuel production is approximately $14/gal, based on algal biomass production costs of ~$1000/ton and ALU (algal lipid extraction and upgrading) with ethanol as a co-product based on fermentation of the algal sugars released in the extraction process (Davis et al 2012).
    - Concerning future price declines, a path to $3/gallon has been proposed in the DOE multi-year program plan. This primarily involves improvements in growth rates, as well as cultivation and harvesting processes.[14]

- One method for improving the economic scenario is through the production and marketing of value-added co-products. These products create additional revenue to help offset production costs. As the goals of the IID are to generate revenue from renewable energy products, coproducts could play an important role. As noted above, the NREL fractionation process can provide lipid, carbohydrate, and protein streams that can serve as feedstocks for a variety of coproducts with sales prices significantly higher than those of fuels.

Algae Oil Production and Wastewater Treatment

It is very likely that a significant R&D effort will be needed before algae oil production processes become sufficiently cost effective to compete with fossil fuels (even with greenhouse gas reduction subsidies). Although this does not detract from the long-term potential and promise, it does raise the issue of what type of co-products could be integrated into an algal oil production process to make it more attractive in the near-term. The first such co-product is water purification, or more specifically, municipal wastewater treatment.

Algae cultivation in municipal wastewater treatment ponds helps remove nitrogen and phosphorous from effluent water, in addition to concentrating heavy metals for easier removal. Potential advantages of utilizing these treatment ponds for cultivation of algae are well

[14] "Bioenergy Technologies Office Multi-Year Program Plan", March 2015, http://www.energy.gov/sites/prod/files/2015/04/f22/mypp_beto_march2015.pdf.

documented and could conceivably be used to treat Salton Sea water to allow it to be used for other purposes. A TurfScrubber type system could be deployed in the Salton Sea itself in addition to open pond deployment on the playa and the combined biomass could be used for conversion to products.

Dust Mitigation

As more and more playa is uncovered due to evaporation of the Salton Sea, concerns raised from atmospheric pollution from dust and accompanying heavy metals and other toxins arise for the surrounding area. Large scale deployment of open ponds or photobioreactors such as those developed by Solix could help mitigate this problem by covering large areas of playa.

Geothermal Energy Capture

Although algae have been found that can thrive in environments ranging from freezing to above boiling temperatures, it typically grows fastest at moderate temperatures. As temperatures drop below an optimal point (at night or during cooler months), growth slows down and can even stop. Although it has been shown that productivity will resume when a pond has thawed after being frozen solid, it is much more effective to maintain temperatures near the optimum. With an abundance of geothermal energy available in the Salton Sea area, it could be possible to prevent freezing, extend the growing season and maintain higher growth rates overall by using the geothermal energy to keep the cultivation medium near the growth temperature optimum.

Fertilizer

Fertilizer is a reasonably large volume co-product, assuming that the biomass doesn't contain substantial amounts of contaminants, such as viruses from wastewater or heavy metals from the CO2 source or from the water. The latter could be a problem with Salton Sea water. Accelergy is developing a fertilizer process based on the harvesting of nitrogen fixing cyanobacteria and using the biomass to amend especially degraded soils from mining operations. The living cyanobacteria can continue to fix nitrogen in the soil and thus continue to enrich the soil for an extended period. It is also possible to apply dead algal cells to soils simply to take advantage of the inherent nutrients present in the biomass.

Food and Feed

Human nutritional supplements and specialty animal feed are possible standalone products or co-products from algal oil production. Conventional animal feeds (e.g., soy protein or dried distiller's grains) have too low a value ($/ton) to allow for a sufficient co-product credit, after considering the cost of production (which would include drying of the feed). Algal biomass may need to be valued at a minimum of $500/ton to overcome the costs of drying. This is much higher than dried distiller's grains, and this target price could only be achieved if the quality could match such feed products as fish meal.

Specialty animal feeds, which have a higher value than conventional feeds but a lower one than human foods, have a large potential market. After extraction of the oil, the remaining biomass produced could contain as much as approximately 50% protein and other nutrients, most importantly carotenoids. There is a large market for animal feeds containing carotenoids, in particular lutein for chicken feeds, with zeaxanthin and beta-carotene also of interest. These markets are estimated at several million tons per year, nationwide. Algal biomass has a 0.5%

lutein concentration allowing for an added value for the algal biomass of about $1,000/ton. Currently, these markets are supplied by carotenoids derived from marigold plants.

Feeding studies with algal biomass involving fish, shellfish, cattle, pigs and chickens have been carried out, with variable results. Biomass may support growth of one species but not another. In some cases, algal biomass can be used as a supplement for more traditional feed materials.

Similarly, dried whole algal biomass and some of the components of algal biomass including omega-3 fatty acids and carotenoids are used as human food supplements of nutraceuticals. Specific algae including the cyanobacterium *Arthrospira platensis* (commonly known as Spirulina) and the eukaryotic alga *Chlorella* can be found in healthfood stores in powder or tablet form or as an ingredient in prepared foods and drinks.

A potential drawback of using Salton Sea biomass to produce food or feed could be the accumulation of various dissolved compounds in the water into the algal biomass. As the Salton Sea has evaporated, the concentration of these compounds is likely to have increased. One specific compound to consider is selenium, which is an essential nutrient at low concentrations with a minimum recommended daily human intake of 70 ug.[15] Higher doses can lead to selenosis or even death with a median lethal dose of 7 mg/kg to 7,000 mg/kg depending on the chemical form of the selenium. A report from the Dept. of Environmental Sciences at UC-Riverside indicates that the selenium concentration in the Salton Sea is approximately 1 ug/L. Assuming that algae cultivated in Salton Sea water could accumulate all of the Se present, the concentration in biomass would be about 1 ug/g biomass. Algal nutritional supplements typically contain 1 g dried biomass per tablet or 1 g per serving as a formulated product. The selenium dose from a single serving would be far below the recommended daily intake and more than an order of magnitude lower than a typical serving of such foods as tuna, steak, macaroni, or cottage cheese. If components of algal biomass such as omega-3 fatty acids or carotenoids were the desired product, it is likely that the selenium would be lost in the purification process and it would be unlikely to provide much of a problem.

Additional analysis would need to be carried out to determine the concentration of heavy metals such as lead, cadmium, or mercury. These metals could also be accumulated in the algal biomass and, unlike Se, could pose health risks for both humans and animals even at low doses.

Energy Recovery

Residual biomass can be anaerobically digested using proven technologies to create a biogas that typically contains 60% methane and 40% CO2 by volume. This gas may be used to offset natural gas to power the algal production facility with additional power used to feed the grid.

Glycerol, a byproduct of the biodiesel production process, may also be recycled to create energy. It is currently being evaluated by a number of groups as a feedstock for fermentation to produce ethanol or other biofuels.

[15] http://ods.od.nih.gov/factsheets/Selenium-HealthProfessional/

Nutrient Recovery

The liquid effluent from the anaerobic digestion process contains soluble nitrogen, which can be recovered in the form of ammonia for recycling in subsequent cultivation. It will also contain phosphorous, potassium and other inorganic micronutrients which can be recycled. Although nutrients from Salton Sea water have already been discussed as a valuable input, recycled effluent from anaerobic digestion can be used to supplement this.

Others

Many other higher value co-products (higher than the value of fuels) have been proposed for microalgal biofuels production, including pharmaceuticals and bioplastics. However, these products typically do not have large enough market volumes to help defray the high cost of algal biomass production and allow for co-production of significant levels of algal oil.

4 Additional Technical and Economic Potential

In addition to the technical potential of renewable energy technologies to provide electricity, the potential for desalination and geothermal brine mineral recovery was also examined. Applications of both technologies have already been technically demonstrated at the Salton Sea, however, their economic viability and scalability is still uncertain.

4.1 Desalination and Renewable Energy

Desalination is the process of removing dissolved salts from an impaired or low-quality water source to produce water with sufficiently low TDS's to be used for potable water or some other beneficial use. In the broadest case, the desalination process requires three primary components: 1) a source of impaired water for treatment, 2) a means of disposing of the concentrated brine or dewatered salts, and 3) energy to drive the desalination process. This section describes the options available for the use of renewable energy (solar electric, solar thermal, or geothermal) to power desalination processes in the Salton Sea region. Prior studies have concluded that desalination is a potential path for Salton Sea restoration. While one could utilize renewable-electric-powered reverse osmosis technology, the ability to use thermal-desalination technologies with energy from low-grade geothermal resources and/or solar ponds is a particularly attractive option for the region.

4.1.1 Regulatory and Environmental Hurdles

Some of the local agencies which will be required to perform a review include: the Colorado River Regional Water Quality Control Board, the Imperial County Planning & Development Services Office, and potentially the Imperial County Public Works Department.

The primary regulatory framework at the state level for desalination facilities will likely be the State Water Resources Control Board's proposed "Amendment to the Water Quality Control Plan for Ocean Waters to Address Desalination Facilities." These regulations primarily focus on coastal desalination facilities, but some aspects (intake screen slot size, brine disposal) could apply to proposed projects at the Salton Sea as well. Notably, since Salton Sea desalination is inland, all brine concentrate must be handled as part of the desalination process. However, rather than simply disposing of this brine concentrate, it may be possible to apply it to a beneficial use. The brine could either be further concentrated and evaporated to dryness, producing a potential salt product, or alternatively, piped into a salinity gradient solar pond.

Additional state regulations include the Porter-Cologne Water Quality Control Act, which vests authority in the State Water Board to control point-source discharges and the California Environmental Quality Act, which requires state and local agencies to minimize environmental impacts through environmental permitting processes.

Some possible environmental concerns include the creation of point-source pollution, brine contamination of groundwater, and brine runoff. Of additional environmental concern is the availability of Salton Sea surface water for desalination efforts, as desalination technologies require thousands of cubic meters of water each day to operate. These potential environmental concerns will need to be evaluated in relation to the proposed benefits of desalination.

4.1.2 Role of Desalination in Restoration Efforts

Desalination from renewable energy could provide a significant potential benefit for Salton Sea restoration efforts by feeding desalinated water back into the Sea and addressing the increasing salinity problem directly. Although this method is technically feasible, returning fresh water to the Sea at zero or near-zero cost requires an alternative source of revenue for the process, such as salt sales.

However, a strategy based on revenue from salt sales assumes that there is a developer with sufficient capital and technical expertise to execute on this type of integrated project, and several assumptions included in this high-level estimate may not materialize, such as the availability of a sufficient market price for salt, or an acceptable performance of the system at scale.

4.1.3 Desalination Technologies

Major types of commercial desalination technologies are listed Table 15. A detailed explanation of each of these technologies is beyond the scope of this report; for additional information, refer to other sources such as a 2009 report published by the Colorado School of Mines (CSM 2009) or an NREL-authored article in *Renewable and Sustainable Energy Reviews* (Al-Karaghouli and Kazmerski 2013). Desalination is a growing market worldwide, with rapid growth in the worldwide deployment of desalination technologies since the early 2000's, as shown in Figure 18. Early-generation technologies were primarily thermal, but membrane-based approaches have surpassed deployment of thermal desalination in recent years.

Table 15. Leading Desalination Technologies

Leading Desalination Technologies	Electric Energy Required	Thermal Energy Required	Comments
Electrodialysis	✓		
Reverse osmosis Brackish water reverse osmosis Seawater reverse osmosis	✓		RO is the most common desal technology. Brackish water has lower salinity than seawater.
Membrane distillation	✓	✓	
Thermal vapor compression	✓	✓	
Mechanical vapor compression	✓		Similar to TVC, but mechanical compression provides thermal input
Multi-stage Flash	✓	✓	Extensive use in Middle East; robust; large energy demand. Normally employs steam for thermal input.
Multi-Effect Distillation	✓	✓	More energy efficient than MSF. Normally employs steam for thermal input.

Source: CSM 2009

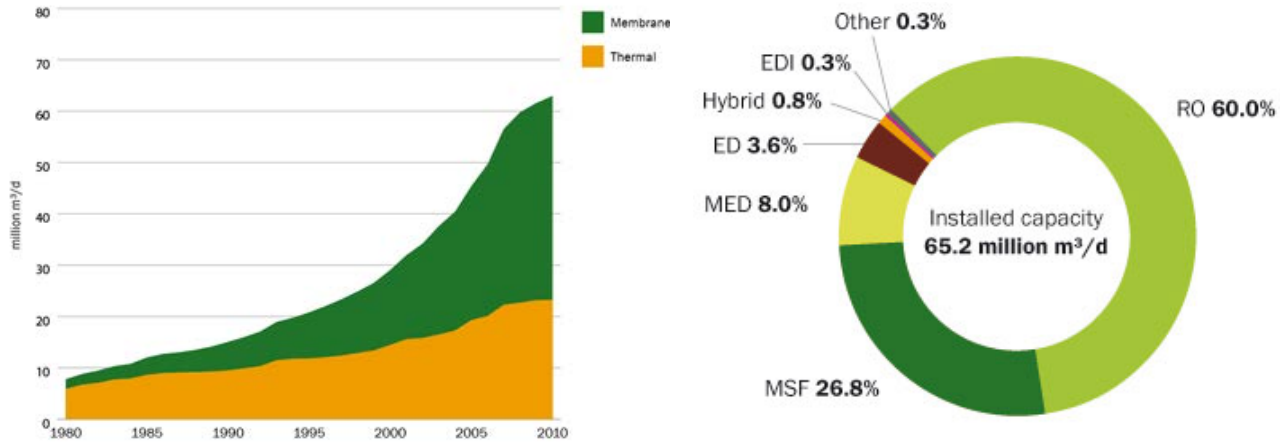


Figure 18. Desalination technology deployment worldwide. Images from Desaldata.com

Note: The growth of membrane-based technologies has exceeded that for thermal-based technologies. Reverse osmosis (RO) capacity now exceeds that for thermal systems such as multi-stage flash (MSF) and multi-effect distillation (MED).

Factors affecting the cost of water desalination include: intake water quality, plant capital cost, energy cost, labor and maintenance cost, concentrate disposal cost, and financing interest rate. Water desalination is an energy-intensive process, and energy costs typically account for about half of the total cost of produced water (Al-Karaghouli and Kazmerski 2013). Understanding the energy demands of different desalination technologies is essential for any discussion of combining renewable energy sources with water desalination. In particular, it is important to distinguish between electrical and thermal energy demands required for the different desalination processes. All technologies require electric power for pumping, sensors, and process controls, and in the case of reverse osmosis processes, electricity for pumping is the primary energy requirement. Reverse osmosis, the most commonly deployed and lowest-cost desalination technology, utilizes osmotic pressure differentials to drive separation of fresh water from the

concentrated brines. Other technologies, such as multi-stage flash (MSF) and multi-effect distillation (MED), use mainly thermal energy for the desalination process. These technologies can utilize low-grade thermal energy from solar or geothermal resources.

4.1.4 Existing Desalination Technologies in the Salton Sea

Currently, there appears to be one desalination company, Sephton Water Technology, Inc. operating by the Salton Sea. This company uses a vertical tube evaporation process that is a form of the MED technology discussed above. Since 2005, Sephton has operated several pilot-scale projects on the edge of Salton Sea, with a combined capacity of approximately 25,000 gal/day. These plants currently rely on low temperature steam provided by adjacent geothermal plants, but could also potentially utilize low-grade heat from salinity gradient solar ponds in the future.

4.1.5 Energy Demand by Desalination Technologies

Integration of desalination and renewable energy has been the topic of several reviews and programs. Promotion of Renewable Energy for Water Production through Desalination (PRODES) was a European program that produced a roadmap of renewable energy/desalination and documented over 130 demonstration and operating projects worldwide.[16] Al-Karaghouli and Kazmerski explored the potential of renewable energy and desalination and tabulated the energy demand for the primary desalination technologies (Table 16). Representative costs for electric energy and thermal energy are shown to provide context on the energy cost for desalinating water. For comparison, the total cost per cubic meter ranges from about \$0.5/m^3 to \$2/m^3 depending on the technology and plant capacity. Thus, in general terms, energy cost amounts to about half the total cost of water desalination.

Table 16. Typical Energy Consumption by Primary Desalination Technologies

Property	MSF	MED	TVC	MVC	SWRO	BWRO	ED
Typical capacity (1000-m^3/day)	50-70	5-15	10-30	0.1-3	< 130	< 100	< 145
Electric energy use (kWh/m^3)	2.5-5	2-2.5	1.6-1.8	7-12	4-6	1.5-2.5	2.6-5.5
approx. cost (\$/m^3) at \$0.1/kWh	0.3	0.2	0.2	1	0.5	0.2	0.4
Thermal energy use (MJ/m^3)	190-280	145-230	230	-	-	-	-
approx. cost (\$/m^3) at \$0.005/MJ*	1.1	0.9	1.2	-	-	-	-
Typical minimum temp. requirement	90°C	70°C	70°C	-	-	-	-

* 0.005 USD/MJ = 5.2 USD/MMBTU (Source: Al-Karaghouli and Kazmerski 2013)

The type of energy required is a pivotal consideration when considering renewable-energy powered desalination. Wind or Solar PV could be used to power an all-electric desalination process, although accommodation would have to be made for fluctuation in the resource. From a technical perspective, batteries can be added, but this is unlikely to be economically attractive.

The more interesting case for renewable energy desalination in the Salton Sea region is the potential to use geothermal or solar thermal energy with a thermal-desalination process. The benefit of this approach is that the process can be designed to run 24/7 for smoother operation of

[16] Roadmap for the development of desalination powered by renewable energy, http://www.prodes-project.org.

the desalination treatment process. In the case of geothermal, such high availability is routine. For solar thermal, storage of the solar heat transfer fluid could be incorporated to separate solar collection from energy use and ensure a much higher availability.

The first question when considering thermal desalination options is what temperature is required to drive the process. Most thermal-desalination technologies require an input temperature in the range from about 60°C to 110°C. The major commercial technologies, MSF and MED, are designed to utilize low-pressure steam at around 100ºC or higher. While this may be available via a geothermal or solar thermal source (e.g., exhaust steam from a renewable-powered steam turbine), a lower cost and more widely distributed resource is hot water in the form of low-temperature geothermal brine or solar thermal collectors such as flat plate collectors or solar ponds. In the case of geothermal energy, one could utilize low-grade geothermal heat directly, or integrate the desalination process with waste heat from a geothermal power plant. Tapping into low-grade heat at a geothermal plant obviates the need for new geothermal source wells; however, one must account for possible negative impacts on the operation of the geothermal power plant and maintenance of the geothermal reservoir temperature through reinjection. With either renewable resource, the direct use of thermal energy (i.e., without conversion losses to make electric power) can be very efficient.

MSF and MED are the most common thermal-desalination technologies worldwide. Smaller-scale, emerging thermal desalination technologies include membrane distillation and humidification. These systems have important advantages that enable coupling with waste heat or renewable-energy-driven systems such as geothermal or solar energy. Some advantages include the ability to operate at lower temperatures (50°C to 80°C), at higher brine concentrations, and at lower pressures than other thermal-driven or pressure driven systems. Other advantages are the ability of the system to operate intermittently without causing damage to the system and minimal chemicals required for pre-treatment of the feed water (Camacho et al. 2013).

4.1.6 Source Water Composition and effect on Desalination Technology Selection

Desalination technologies respond differently to changes in TDS. TDS is the amount of dissolved inorganic and organic constituents in water and is typically reported in mg/L. In seawater and many other brines the largest contribution to TDS is from sodium chloride; TDS is often referred to as salinity. Osmosis-based desalination processes are sensitive to the TDS level of the source water, while thermal treatment processes are relatively insensitive to source water quality. A specific example of this sensitivity is a comparison of brackish water reverse osmosis (BWRO) and seawater reverse osmosis (SWRO). As shown in Table 16, the energy consumption (and overall cost) of BWRO is less than SWRO due to the lower salinity of brackish water. Given the relatively high salinity of potential source waters in the region, thermal-desalination technologies will have a relative advantage over reverse osmosis.

Impaired source water options in the Imperial Valley include the Salton Sea itself, brackish groundwater, and geothermal brines. Various Imperial Valley entities have investigated desalination as an option for providing irrigation water because there is a significant amount of impaired groundwater available; however, these studies did not focus on renewable energy use to complement the process. A summary of typical source water TDS levels for the Imperial Valley is provided in Table 17.

Table 17. Total Dissolved Solids of Potential Source Water for Desalination for the Imperial Valley

Impaired source water	Source water TDS criterion	Source water TDS (mg/L)
groundwater	25th percentile	1,500
	75th percentile	390,000
geothermal brine	25th percentile	45,400
	75th percentile	260,000
surface water (Salton Sea)	Mean	50,000

(Sources: USGS 2014 (groundwater); National Geothermal Data System (geothermal brine); USBR 2007 (surface water)

Groundwater. Data for Imperial and Riverside Counties, California accessed from the 2014 United States Geological Survey show the groundwater quality varies widely with TDS concentration ranging from 300 mg/L to over 100,000 mg/L. In general, the groundwater is sodium chloride dominated. The dataset contains information on over 100 groundwater wells.

Geothermal brine. A data file from the Association of American State Geologists node on the National Geothermal Data System provides geothermal data for the Salton Trough. This dataset consists of roughly 40 wells, with TDS ranging from 1,400 to 385,000 mg/L. The geothermal brines of the Salton Trough are mostly sodium chloride dominated.

Surface water. A report from the U.S. Bureau of Reclamation provided the surface water quality data for the Salton Sea.[17] This report compares the water quality of the Salton Sea to the rivers that feed it, giving one example of the water quality for each. TDS of the Salton Sea given in the report is 44,000 mg/L, while the reported value in 2014 is closer to 55,000 mg/L. The dominant ion pair in the sea is sodium chloride. In addition, based on discussions with local operators, there appear to be issues with scaling, due to the presence of magnesium and calcium, that require additional measures to ensure smooth system operations.

Based on the relatively high TDS of available source water in the Salton Sea region, thermal desalination technologies are an attractive option.

4.1.7 Solar Ponds and Desalination

The combination of requirements at play in the Salton Sea region lead to a unique set of conditions for the use of geothermal energy, solar ponds, and desalination.

[17] U.S. Department of Interior Bureau of Reclamation, http://www.usbr.gov/lc/region/saltnsea/FinalSummaryRpt.pdf, accessed 6/10/2015.

Table 18. Use of Geothermal Energy, Solar Ponds, and Desalination

Inputs	Source(s)	Use
Hot geo-brine	geothermal production well	thermal input to geothermal power plant
Solar thermal energy	Sun	thermal input to solar pond
Impaired water	Salton Sea; groundwater; solar pond	source water for desalination
Outputs		
Electric power	geothermal plant	onsite pumps, fans, and controls; sale to grid
Fresh water	desalination plant	solar pond makeup; sale to local users
Cooled brine	geothermal plant	reinjection well; solar pond
Reject water	desalination plant	reinjection well; solar pond

In regions of good solar resource such as the Imperial Valley, solar ponds can deliver hot water at temperatures of approximately 70°C on an almost continuous basis (See Section 4 for additional detail). However, these ponds require extensive land area, high-salinity brine, and occasional make-up fresh water. In this instance, a large facility footprint may be a desirable feature as the solar ponds can reduce airborne dust from the exposed Salton Sea playa. Furthermore, the initial charge of high-salinity brine for solar ponds can be generated by tapping into the geothermal brines or from reject water off desalination processes. A conceptual schematic of the interconnection of the geothermal, solar pond, and desalination processes is depicted in Figure 19.

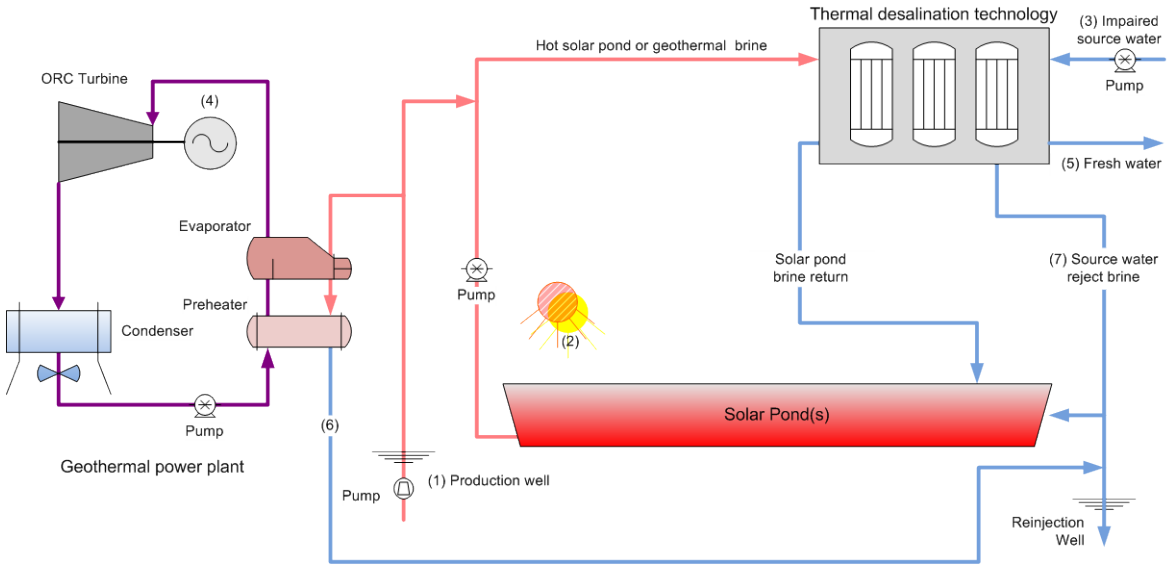


Figure 19. Thermal desalination process interfaced with a solar pond and a geothermal power plant. *Illustration by NREL*

The interconnectivity between the solar pond, geothermal plant, and desalination plant allows for a great deal of flexibility and synergy in the system operation. The solar pond can tap into high-salinity geo-brine or reject brine from the desalination plant for its initial charge of brine, thus avoiding the salt cost that is normally a substantial fraction of the cost for constructing a solar pond. Once the pond reaches full temperature, either solar or geothermal energy can be used to

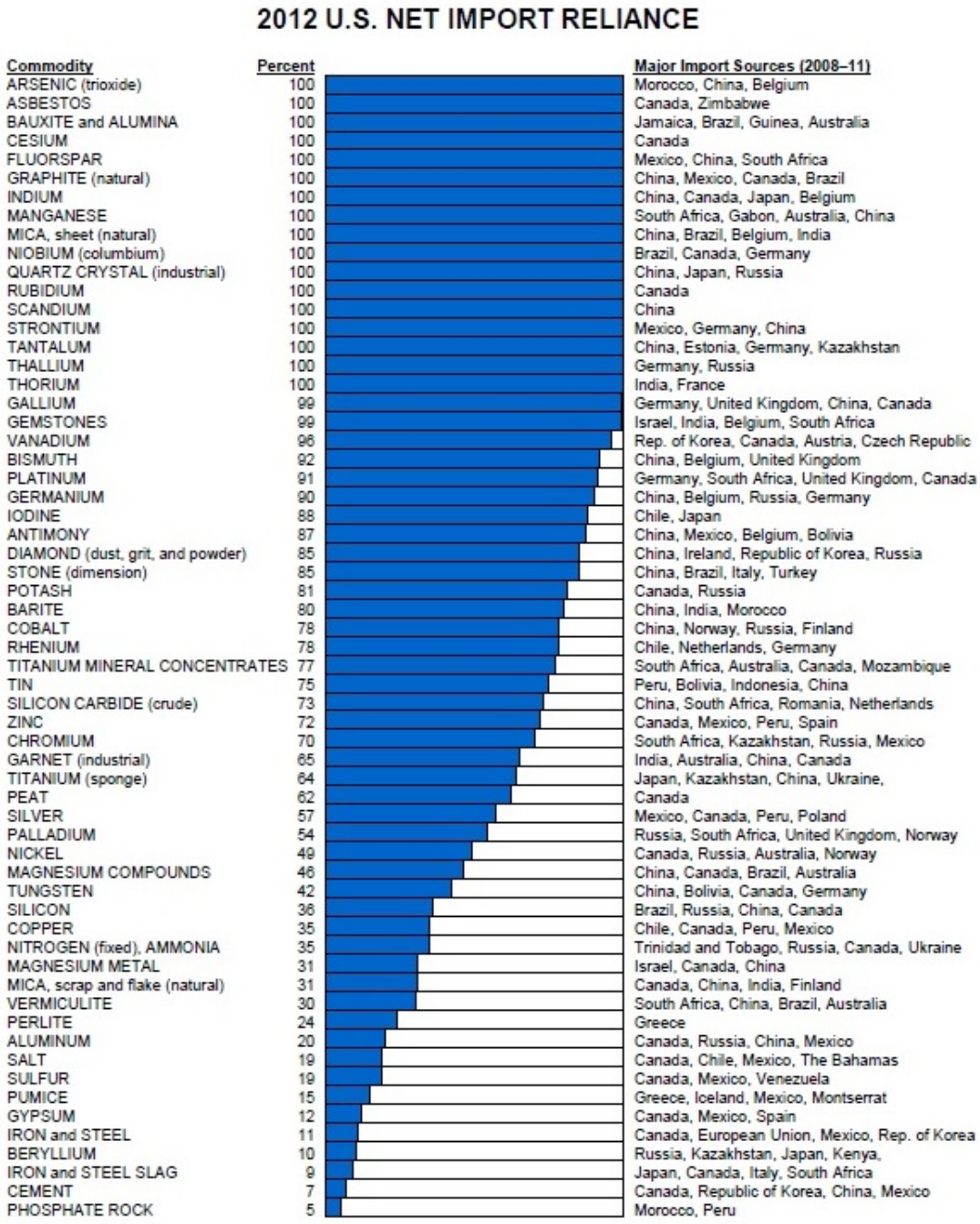
drive the thermal desalination process. If the geothermal resource is hot enough, electric power can be produced, although this is not essential for the geothermal/solar pond/desalination system.

The thermal desalination technology can be selected from several options that are capable of operating at temperatures of 90°C or less. Consultation with technology vendors and preliminary design work would be required to estimate overall system cost.

4.2 Geothermal Fluid Mineral Recovery

Geothermal fluids are potentially significant sources of valuable minerals and metals. With increasing worldwide demand for technology, and in particular, the increased consumer demand for clean energy technologies and electric vehicles, significant attention in both the United States and abroad has been turned to identifying "critical raw materials" and their market dynamics. The DOE's 2011 Strategic Materials Plan identified 16 minerals critical to clean energy technologies (Figure 20), and the U.S. Department of Defense issued a separate 2013 report which identified shortfalls in 23 strategic materials where supply will be outstripped by demand in the near future (Figure 21) (U.S. DOD 2013). The European Commission has also issued a similar list of 14 critical materials on which they are almost wholly dependent.[18] More generally, the United States relies entirely on foreign imports for 17 mineral commodities and relies on imports for >50% of more than 24 other minerals (as of 2013).[19]

[18] http://www.ukerc.ac.uk/publications/materials-availability-for-low-carbon-technologies.html
[19] http://www.usgs.gov/blogs/features/usgs_top_story/going-critical-being-strategic-with-our-mineral-resources/



Source: USGS 2013

Figure 20: U.S. import reliance on foreign minerals in 2012.

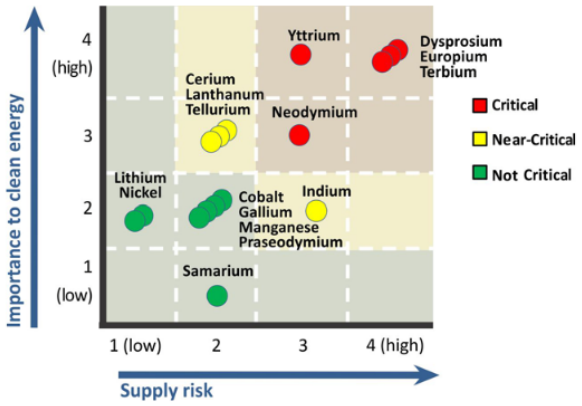


Figure ES-1. Short-Term (Present–2015) Criticality Matrix

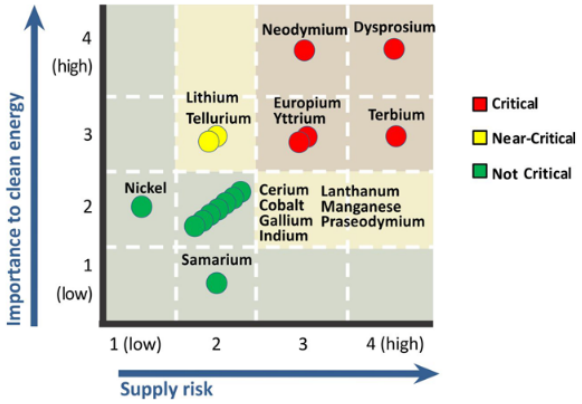


Figure ES-2. Medium-Term (2015–2025) Criticality Matrix

Source: DOE Critical Materials Strategy 2011

Figure 21: Strategic importance and scarcity of selected raw materials, 2011–2015

4.2.1 Estimated Potential Revenue

Previous estimates of potential revenue from mineral recovery have relied upon assumptions or high-level estimates only (EES 2013). This prior study estimates that a 50 MW geothermal plant could recover $237 million to $271 million in mining revenue, but these estimates were not verified. Attempts to duplicate this calculation (Table 19) are not directly comparable, as the prior study's estimates include potential revenue from other minerals in addition to lithium. As a result, these values could underestimate the potential gross revenue if other minerals are also recovered. Since no geothermal recovery operations are commercially operating as of the time of this report, further operational cost estimates are needed to validate the likelihood that mineral recovery is a viable business opportunity to produce the estimated revenue stream.

At any given location, the concentration of dissolved minerals is a function of the fluid temperature and pH, among others. Although lithium concentrations in the Salton Sea area are higher than other areas of the Imperial Valley, concentrations often vary considerably. For example, one study of the Salton Sea shows an average of 211 ppm, while another study

measured lithium concentrations between 215-300 in the O`Neill I.I.D. #1 well, 128-141 ppm in the Magmamax #1 well, and as 245 ppm in the Sinclair #4 well (Mainomi 1982).

In reviewing the following estimates of revenue in Table 19 below, it is also important to recall that the estimated MW-electric potential of a geothermal plant is a function of the reservoir volume, temperature, and well flow rate, while the actual volume of recovered minerals will be a function of the well flow rate and the mineral concentration (which is dependent on temperature). It then follows that flow rates in areas which provide high mineral concentrations (e.g., high temperature zones) may be lower than large area, lower-temperature resources. As a result, there is significant uncertainty in scaling mineral recovery potential from average well flow rates on a MW basis without first selecting wells with sufficiently high temperatures and/or mineral concentrations.

As an initial assessment, this report focuses on the recoverability and market for lithium only. While governments have not specifically identified lithium as a major strategic concern, supply security has become a significant priority of technology companies, and has spurred a wave of acquisitions and joint ventures. With this anticipated demand, opportunities to supply lithium from non-economic technologies today may become feasible in the near term.

Table 19. Assumptions and Estimation of Annual Royalty Revenue Derived from Lithium Mineral Recovery

Factor	Value	Source
Royalty rate	3%	Assumed – gross mineral recovery revenue
Li recovery efficiency	93%	Simbol plant estimate[20]
Lithium Carbonate price per kilogram	$6.6	Price for 99.5% battery grade[21]
Percent Li in Lithium Carbonate by weight	18.8%	Mass conversion factor[22]
Brine Li concentration (mg/L)	207-220	Median - Average of available Salton Sea geochemistry for wells >200 C[23]
Density of brine (kg/L)	1.006	Surface density of Salton Sea fluids[24]
Well deliverability (kg/hr per MW)	30,800–37,800	Representative flow test data and measured wellhead temperatures[25]
Gross geothermal water produced (thousand kg/yr)	120,504,541	2009 data from 21 operating geothermal wells in Salton Sea geothermal field[26]
Annual Gross Li Recovery Revenue – 50 MW plant	$91–$118 million	= Well Deliverability [kg/hr per MWe] X 24 hrs X 365 days X 50 MWe X 1/ density of brine at surface X average brine Li concentration X technology recovery efficiency X Lithium Carbonate/18.8% Li
Annual Gross Li Recovery Revenue – all current Salton Sea	$860 million	= Gross Well Production [kg/yr] X 1000/density of brine at surface X average brine Li concentration X technology recovery efficiency X Lithium Carbonate/18.8% Li
Annual Li Royalty from Recovery – 50 MW plant	$2.7–$3.6 million	Assumed 3% mineral rights royalty off gross revenue
Annual Li Royalty – all current Salton Sea	$25.8 million	Assumed 3% mineral rights royalty off gross revenue

Since mineral recovery only requires the drilling of production wells, this revenue stream could be pursued independently of geothermal power development. The $25.8 million revenue estimate is based on the likely offshore development capacity of 370 MW to 570 MW. Future revenue from mineral recovery will depend heavily on successful geothermal exploration efforts. Assuming all potential future geothermal capacity in the Salton Sea exhibit the average

[20] http://www.nytimes.com/2011/09/28/business/energy-environment/simbol-materials-plans-to-extract-lithium-from-geothermal-plants.html?_r=0
[21] http://minerals.usgs.gov/minerals/pubs/commodity/lithium/mcs-2015-lithi.pdf
[22] http://www.westernlithium.com/project/conversion-table/
[23] Argonne National Laboratory Geothermal Geochemistry Database, based on USGS Chemical data.
[24] http://earthsciences.ucr.edu/docs/awilliams_1997.pdf
[25] Long-term well test data from the Salton Sea Scientific Drilling Project of 370,000 kg/hr for 12 MWe (1992), http://www.osti.gov/geothermal/servlets/purl/7117310-R2c4nS/native/7117310.pdf and multiple Orita well flow testing by Ram Power of 500,000 lbs/hr (227,000 kg/hr) for 6 MWe (2010), http://ram-power.com/current-projects/orita-california. These estimates are in line with the CRC Handbook of Mechanical Engineering, which provides a Salton Sea average flow rate of 270,000 kg/hr.
[26] California Division of Oil, Gas, and Geothermal Resources (2010) Annual Report of Geothermal Operations. ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2009/0109geofin_09.pdf

characteristics assumed above, IID could realize an additional $39.3 million to $71.7 million in royalty revenues.[27]

4.2.2 Lithium

Although lithium recovery from subsurface or continental brines is a proven technology, no projects to date have produced lithium from geothermal brines on a commercial scale.

Commercial extraction from continental brines is based primarily on solar evaporation, which currently has a recovery efficiency of approximately 50%. By concentrating the brine prior to filtration techniques for lithium, other minerals "salt" out as fluid evaporates. A new technology by POSCO still uses evaporation and is specific to continental brines, but also includes a column filtration process[28] to increase lithium recovery efficiency to above 80%.[29]

The Hudson Ranch geothermal plant partnered with Simbol Minerals for their extraction processes.[30] Thus, this section focuses on a review of Simbol's patented technologies.

Figure 22 shows the general concept underlying Simbol's process for lithium extraction. This technology embodies the use of a coated porous inorganic substrate to selectively capture lithium, which is then washed for lithium removal and substrate recovery. Simbol's patent covers the use of substrates made from a range of materials: diatomaceous earth (i.e., silica-based), iron oxide, alumina (or activated alumina), or resins (e.g., poly aluminum hydroxyl chloride). The use of porous materials increases the amount of active areas for extraction, leading to high efficiency.

In 2013, Simbol reported that it had successfully produced battery grade lithium carbonate (99.99% purity)[31] from their additional patented process to remove impurities in the aqueous solution.[32] However, Simbol Technologies recently shut down operations at the Hudson Ranch plant. Based on available news sources, it appears that the plant had already established technical viability of their extraction process, and that operations were discontinued due to lack of financial resources.[33]

[27] Assumes production wells for an additional 680 to 1240 MW geothermal energy capacity to be available by 2030 (see estimates of geothermal capacity in this report).
[28] https://www.google.com/patents/US7157065?dq=POSCO+lithium&hl=en&sa=X&ei=OOUKVbS_ D4qLNr7Ug5gJ&ved=0CB0Q6AEwAA
[29] http://lithiuminvestingnews.com/7146/posco-lithium-brine-processing-technology-extraction-li3-energy-simbol-chile-signumbox/
[30] http://www.renewableenergyworld.com/rea/news/article/2012/05/49-9-mw-hudson-ranch-i-geothermal-plant-unveiled-in-calif
[31] http://www.simbolmaterials.com/who_we_are.htm
[32] https://www.google.com/patents/EP2536663B1?cl=en&dq=simbol+lithium+carbonate&hl=en&sa=X&ei=DxQLVYfWMoSXNtu0g9AE&ved=0CEEQ6AEwBQ
[33] http://www.desertsun.com/story/tech/science/energy/2015/02/03/lithium-plans-doubt-simbol-materials-fires-dozens/22828207/

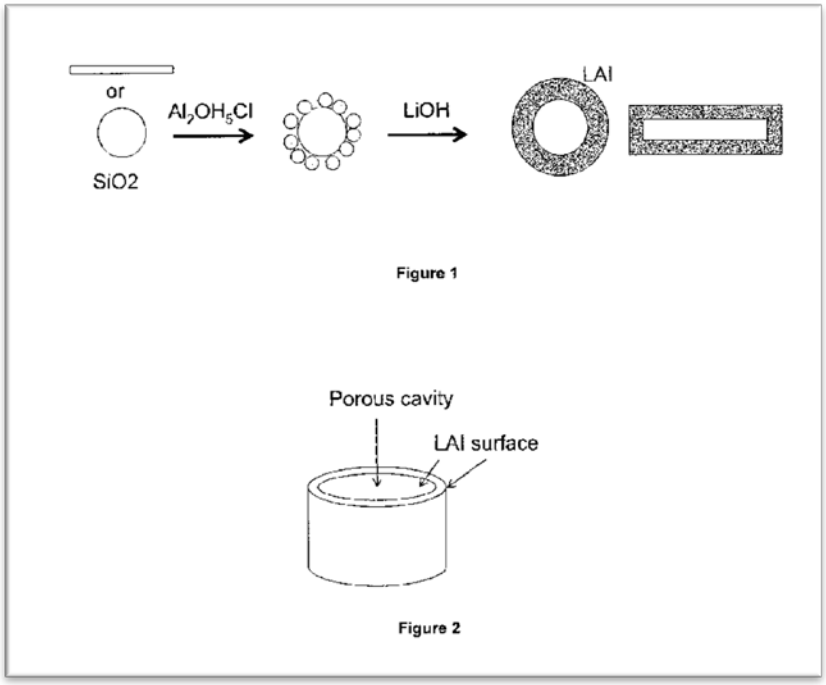


Figure 22: Schematic of lithium capture from geothermal brines using a substrate[34]

Lithium Supply

Currently, lithium is produced via either concentration from subsurface brines or concentration from hard rock mineral deposits. Depending on the end use, the form in which lithium is sold varies between compounds, metal, or mineral concentrates.

World lithium carbonate production in 2014 was estimated by the USGS to total 36,000 tons, a 5% increase from the 2013 total of 34,200 tons. Spodumene mining in Australia has remained the largest source of produced lithium, but is nearly matched by an increase in brine-derived lithium in Chile. As shown in Table 20, Argentina and China were the other largest producers of lithium carbonate from brines, while Zimbabwe and Portugal have derived production from spodumene and lepidolite mining, respectively.

Interest in lithium exploration has increased recently in the United States, Argentina, Bolivia, and Chile, with a primary focus in these countries on brine resources. By contrast, Canada and Australia have primarily focused on lithium from pegmatites.[35] Within the United States, interest has primarily been in the geothermal brines of the Salton Sea, as well as in the subsurface brines and clays of Nevada. Finally, preliminary studies in Wyoming suggest that reservoir brines in the Rock Springs Uplift could provide nearly 228,000t of lithium.[36]

[34] Lithium extraction composition and method of preparation, US Patent US 8637428 B1 34.
[35] http://minerals.usgs.gov/minerals/pubs/mcs/2015/mcs2015.pdf.
[36] http://minerals.usgs.gov/minerals/pubs/commodity/magnesium/myb1-2013-mgcom.pdf.

Table 20: Summary of Global Lithium Supplies (Production, Reserves, and Resources) and Sources*

	Production		Reserves	Resources	Source Type
	2013	2014			
United States	870	W	38,000	5,500,000	carbonate
Argentina	2,500	2,900	850,000	6,500,000	subsurface brine
Australia	12,700	13,000	1,500,000	1,700,000	ore: spodumene
Brazil	400	400	48,000	180,000	concentrates
Chile	11,200	12,900	7,500,000	> 7,500,000	subsurface brine
China	4,700	5,000	3,500,000	5,400,000	subsurface brine and concentrates
Portugal	570	570	60,000	N/A	ore: lepidolite
Zimbabwe	1,000	1,000	23,000	N/A	ore: amblygonite, eucryptite, lepidolite, petalite, spodumene
Bolivia		N/A	N/A	9,000,000	subsurface brine
World Total	34,000	36,000	13,500,000	39,500,000	

* Lithium as mineral concentrate, lithium carbonate, lithium chloride, and lithium hydroxide
N/A = Not available on a comparable basis
W = Withheld for business confidentiality

Source: USGS 2013 Minerals Yearbook[37]; USGS Minerals Commodity Survey January 2015[38]

Only one company has disclosed that it mines lithium in the United States (Rockwood Lithium). The company mines lithium carbonate from a 6,000 t/yr facility in Silver Peak, NV, and produces battery-grade lithium from a 5,000 t/yr facility in Kings Mountain, NC. Rockwood also produces lithium carbonate and chloride from brine holdings in Chile. FMC also holds a Lithium Division in which it processes compounds in Bessemer City, NC, but the lithium itself is sourced from holdings in Argentina. Western Lithium is currently exploring opportunities to produce lithium from clays in Nevada.[39]

Globally, lithium supply is primarily concentrated into a few major companies. Beyond FMC and Rockwood, other major suppliers in the lithium market include Chemical & Mining Co. of Chile Inc. and the Chinese materials company Chengdu Tianqi, who also recently acquired Australian company Talison Lithium.[40] Finally, as of January 12, 2015, global chemicals company Albermarle acquired Rockwood Holdings, parent company to Rockwood Lithium.[41]

New interest in resource exploration has been led primarily by private startups in Australia and Canada, such as Orocobre and Lithium Americas, but multiple upstream companies, such as Toyota Tsusho, have also signaled significant interest in acquiring lithium assets to secure their

[37] http://minerals.usgs.gov/minerals/pubs/mcs/2013/mcs2013.pdf.
[38] http://minerals.usgs.gov/minerals/pubs/mcs/2015/mcs2015.pdf.
[39] http://investorintel.com/rare-earth-intel/berry-on-marketing-trends-igniting-interest-in-batteries-and-their-raw-materials/.
[40] http://seekingalpha.com/article/2845376-orocobre-joins-the-lithium-oligopoly.
[41] http://www.rockwoodlithium.com/news-events/news/news/archive/showing/article/albemarle-corporation-completes-acquisition-of-rockwood-holdings/.

supply chain. Toyota has acquired exclusive rights to the lithium carbonate from Orocobre's project in Argentina, which may allow Toyota to expand its electric vehicle production.[42]

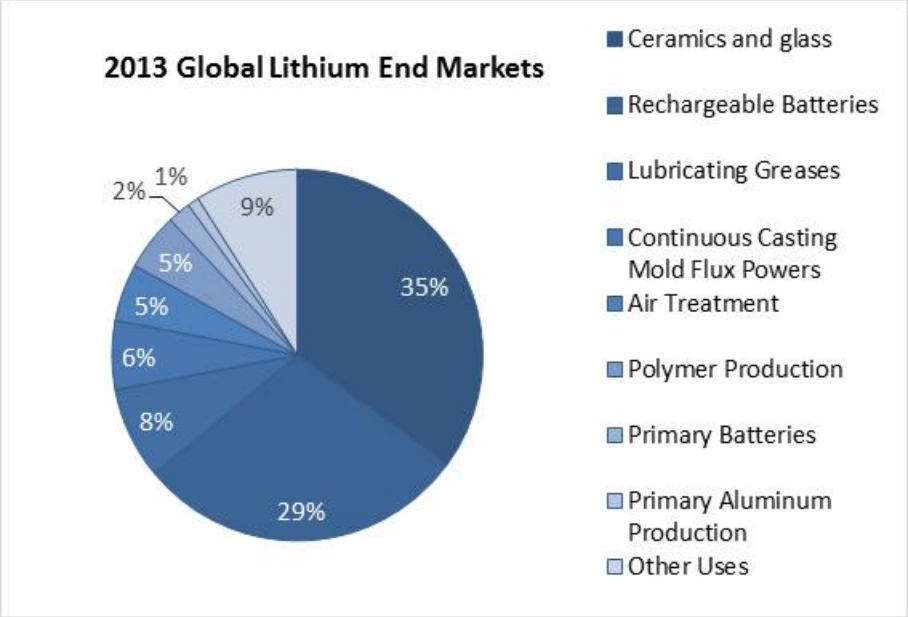
Lithium Demand

Globally, lithium is consumed primarily as lithium compounds rather than as lithium minerals (79% vs. 21%, respectively). Lithium carbonate accounted for the largest share of consumption in 2012 at approximately 48%, with lithium hydroxide in second at 15%. While the quality of lithium carbonate consumed was evenly split between technical-grade and battery-grade, the vast majority of lithium hydroxide was consumed as technical grade rather than battery grade (12% versus 3% of total consumption, respectively).[43] While multiple formulations of lithium batteries exist that require varying quantities of lithium, the lithium content of a lithium-ion cell is approximately 0.3 times the rated capacity in ampere-hours. For every typical automotive battery at 70-amp hours, this equates to 21 grams of lithium.[44] This content ratio would also hold for energy storage applications using lithium-ion cells.

In terms of global trade, lithium imports to the United States have originated primarily from Chile (58%) and Argentina (39%), but the volume of imports overall decreased nearly 20% in 2013 from 2012 levels. Exports of lithium produced in the United States primarily went to Japan (30%), Germany (22%), and Belgium (9%).[45]

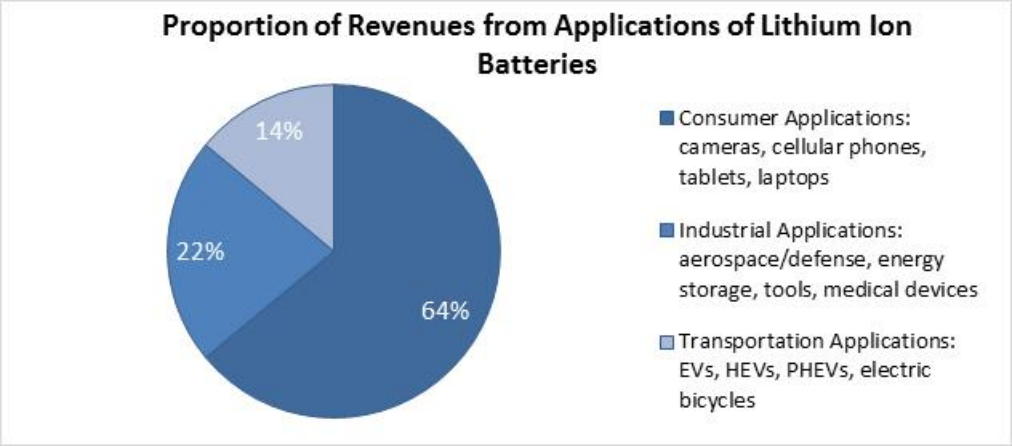
In terms of end uses, the majority of lithium is consumed for ceramics and glass in a wide range of industrial uses. Figure 23[46] illustrates the diversity of demand as of 2013. Other uses for lithium beyond those listed include alloys, chemicals (agrochemicals, pharmaceuticals, pool chemicals, dyes, pigments), additives to cement and concrete, and welding, among others.[47] Within the consumption of lithium for batteries, Figure 24[48] shows global revenues from lithium-ion batteries in 2012 were split between three major applications: consumer electronics, industrial, and transportation applications.

[42] http://seekingalpha.com/article/2845376-orocobre-joins-the-lithium-oligopoly.
[43] Technical grade is a slightly lower purity than battery grade (e.g., 99.3% purity vs. 99.5%, respectively) http://www.fmclithium.com/Portals/FMCLithium/content/docs/DataSheet/QS-PDS-1059%20r1.pdf.
[44] http://batteryuniversity.com/learn/article/is_lithium_ion_the_ideal_battery; http://www.allaboutcircuits.com/vol_1/chpt_11/3.html
[45] USGS Minerals Yearbook 2015
[46] USGS Minerals Yearbook 2015; Merriman, 2014
[47] USGS Minerals Yearbook 2015, Rockwood Lithium GmbH, 2014
[48] USGS Minerals Yearbook 2015; Merriman, 2014



Source: USGS Minerals Yearbook 2015

Figure 23: Breakdown of 2013 global lithium demand by end use products.

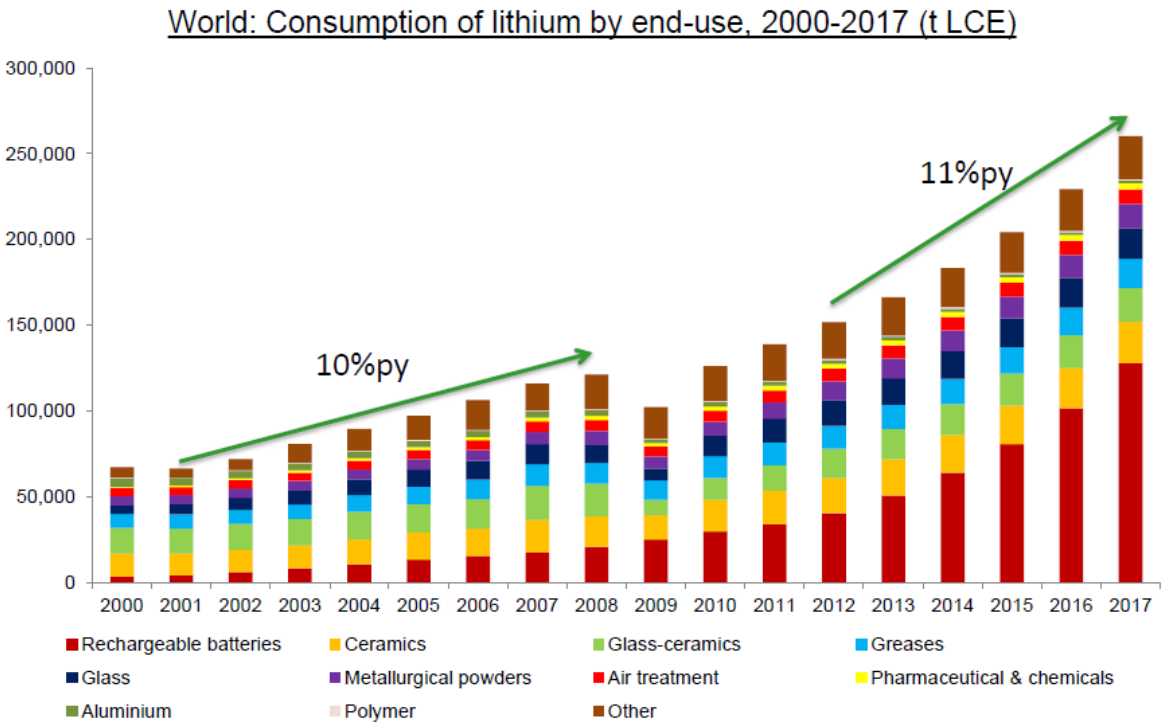


Source: USGS Minerals Yearbook 2015

Figure 24: Breakdown of 2012 global revenues of lithium ion batteries by application.

While growth of lithium-ion cell production globally has increased by 16% annually on average, estimates of annual growth in lithium demand is projected in the near term to average 11% per year, driven largely by demand for rechargeable batteries.[49] Energy storage applications are likely to also use lithium-ion batteries, but expected growth in demand is most likely for lithium ion batteries for vehicles- projections of which range from 22% to 41% annually until 2020 (Figure 25).

[49] Tesla Motors, Inc., 2014; Roskill 2013



Source: Roskill 2013

Figure 25: Historic and projected global lithium consumption, by end use.

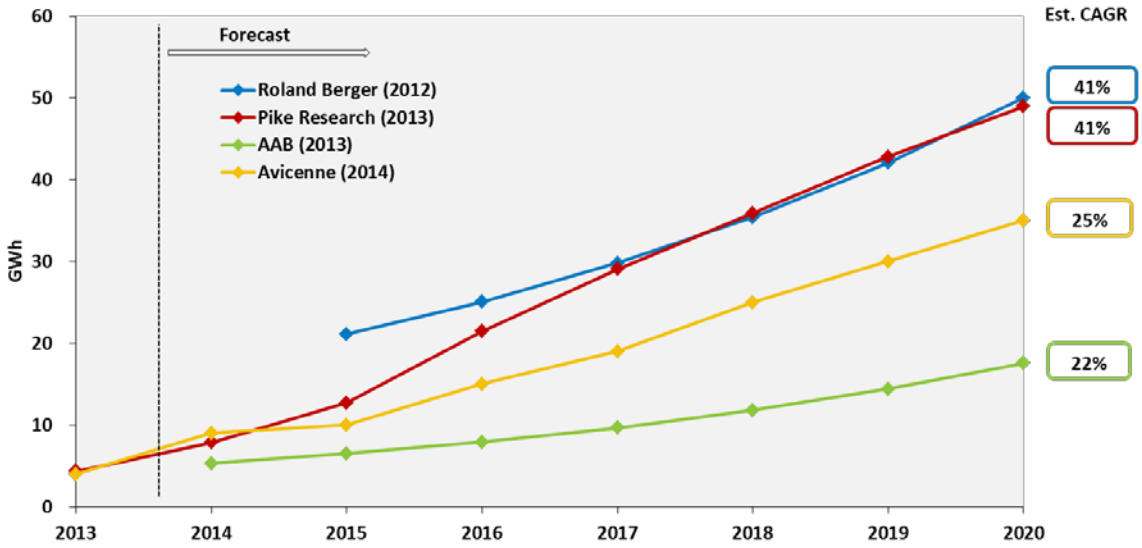
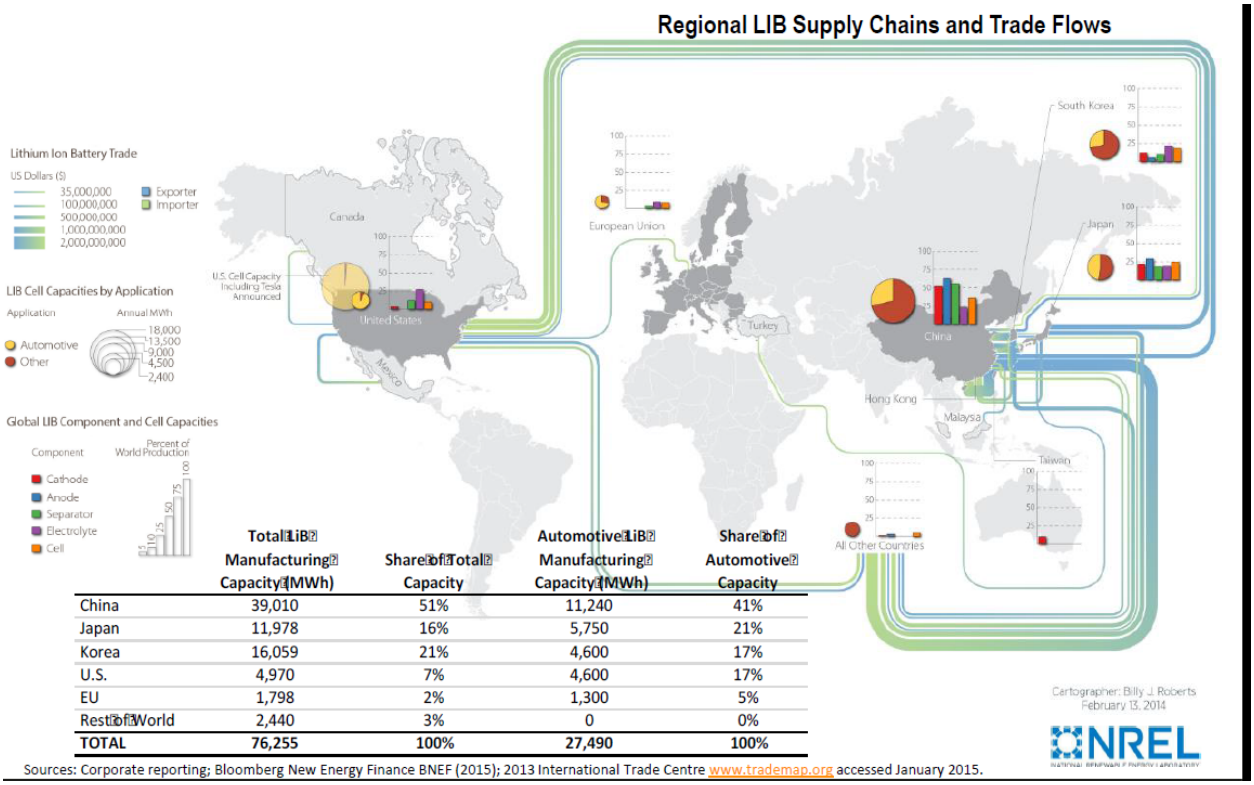


Figure 26: Projected growth in global li battery demand for automotive applications.[50]

The potential demand from battery production is thus not to be discounted; in China alone, domestic revenues from lithium-ion batteries increased 84% largely due to manufacturing for electric bicycles.[51] The entrenched supply chain for lithium ion batteries in Asia (shown as trade

[50] Chung, Donald, and Elgqvist, Emma, Automotive Lithium-ion Battery (LIB) Supply Chain and U.S. Competitiveness Considerations, 2014
[51] USGS Minerals Yearbook 2015; Antaike Minor Metal Monthly, 2014

flows in Figure 27) suggests this demand is not likely to shift regionally unless Tesla's planned gigafactory comes online in the United States.



	Total LiB Manufacturing Capacity (MWh)	Share of Total Capacity	Automotive LiB Manufacturing Capacity (MWh)	Share of Automotive Capacity
China	39,010	51%	11,240	41%
Japan	11,978	16%	5,750	21%
Korea	16,059	21%	4,600	17%
U.S.	4,970	7%	4,600	17%
EU	1,798	2%	1,300	5%
Rest of World	2,440	3%	0	0%
TOTAL	**76,255**	**100%**	**27,490**	**100%**

Sources: Corporate reporting; Bloomberg New Energy Finance BNEF (2015); 2013 International Trade Centre www.trademap.org accessed January 2015.

Figure 27: Regional supply chain capacity and trade flow for lithium-ion battery components.

Lithium Prices

Lithium is not a traded commodity, and thus spot prices are not readily available. Nevertheless, prices for customs unit values of lithium carbonate were $4.29 per imported kilogram in 2013, and $5.64 per exported kilogram. Prices for customs values of lithium hydroxide were $5.64 per imported kilogram and $7.43 per exported kilogram. For both types, exported lithium commands a higher price of approximately 28% over imports, potentially suggesting that United States-derived lithium is of higher quality. However, these exported prices have declined 10% from 2012; imported prices of lithium carbonate rose 4%, and imported prices of lithium hydroxide fell 5% from 2012.[52] Within China, 2013 prices for lithium ranged from $6,550 to $6,900 per metric ton for lithium hydroxide, while lithium carbonate ranged from $5,700 to $6,810 per metric ton; batter-grade lithium carbonate demanded $6,380 to $6,810 per metric ton, while technical-grade lithium carbonate demanded $5,700 to $6,100 per metric ton.[53]

4.2.3 Other Recoverable Minerals

Beyond the extraction of lithium, Simbol has also developed patented technologies for high-purity silica, manganese, and zinc. A schematic of this process is reproduced in Figure 61.

[52] USGS Minerals Yearbook 2015; Merriman, 2014
[53] USGS Minerals Yearbook 2015; Syrett, 2014

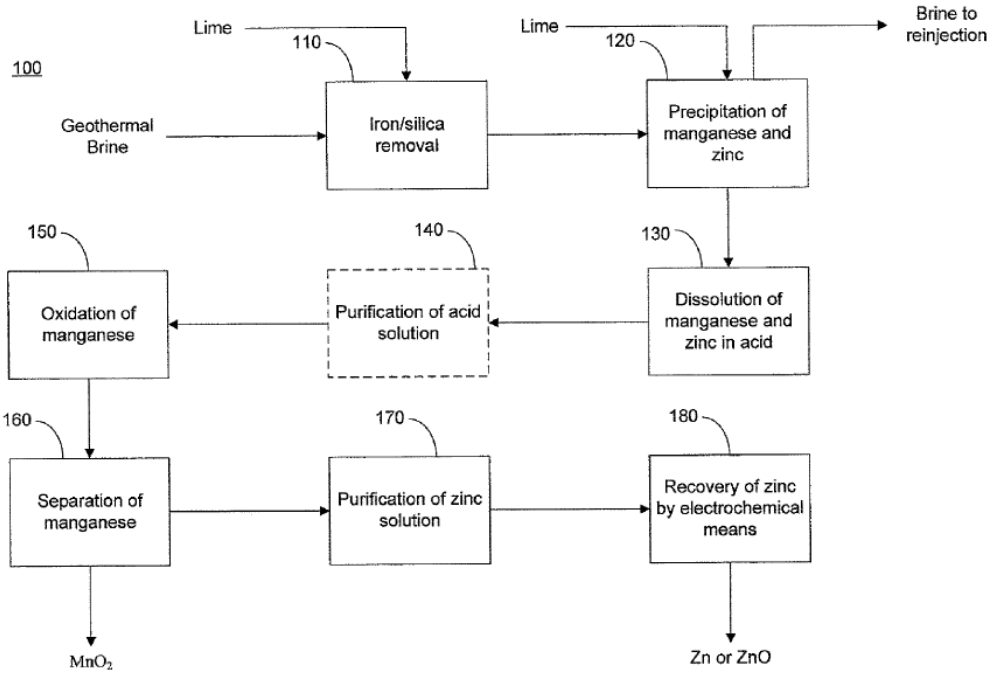


Figure 28: Process diagram for manganese and zinc removal from geothermal brines.[54]

High-purity zinc has been recovered economically and commercially from geothermal brines using a combination of solvent extraction, ion exchange, and electrowinning processes.[55] CalEnergy's mineral extraction plant produced 99.99% zinc from 2002-2004, and closed due to financial issues unrelated to mineral recovery.[56]

Morton International successfully operated a plant in the 1960s in Imperial Valley to extract various salts (calcium chloride, potassium chloride) from geothermal brines, and closed the facility due to a drop in prices. A similar plant in Mexico that extracted potassium chloride for fertilizers (Fertilizantes Mexicanos) was abandoned in the final stages of construction due to a drop in international prices.[57]

The most successful example of mineral recovery has been the extraction of boric acid, sodium perborate, and ammonium carbonate from the brines at Lardarello, Italy. While mineral recovery of boric acid has occurred at Larderello since 1818,[58] boric acid was produced both commercially and in high volumes between 1850 and 1975.[59]

4.2.4 Conclusion

This analysis currently focuses on the market landscape for lithium from geothermal brines because of the combination of near-commercial technology potential and the immediate and

[54] Simbol Minerals, Selective Recovery of Manganese & Zinc from Geothermal Brines, US Patent 8454816 B1
[55] https://www.google.com/patents/WO2009117354A2?cl=en&dq=calenergy+zinc+extraction&hl=en&sa=X&ei=RAwLVbrjB4eigwS_roH4DA&ved=0CB4Q6AEwAA
[56] http://www.renewableenergyworld.com/rea/blog/post/print/2014/08/value-creation-from-geothermal-fluids-beyond-batteries-for-tesla
[57] http://www.renewableenergyworld.com/rea/blog/post/print/2014/08/value-creation-from-geothermal-fluids-beyond-batteries-for-tesla
[58] http://www.ilpalio.org/brief_larderello.htm
[59] http://www.renewableenergyworld.com/rea/blog/post/2014/08/value-creation-from-geothermal-fluids-beyond-batteries-for-tesla?page=2

increasing demand for lithium-ion battery applications in both vehicles and energy storage. However, geothermal mineral recovery in the region could potentially target the extraction of multiple minerals, such as magnesium or zinc, in order to mitigate risk from price volatility.

While rare earth elements exist in geothermal brines, the concentration of these elements is often below detection levels. Determining the potential resource supply of these elements from geothermal brines requires further fundamental research. Furthermore, no technologies to date offer the potential to selectively recover these elements. However, should these elements become technically recoverable many rare earth elements have been identified as critical or strategic due to their projected demand in renewable energy and technology applications.

4.3 Hydrogen and Renewable Energy

California has several policies in place to accelerate the adoption of hydrogen fuel cell electric vehicles (FCEV) into the light- and medium/heavy-duty vehicle markets. California is a national leader in support for FCEV markets, and the Los Angeles metropolitan area in particular is recognized as a key early market among global cities in Germany, Japan and South Korea.[60] Los Angeles is unique in having a high population density, a high density of early adopters of advanced vehicle technologies (based upon historical sales of hybrid electric vehicles), and severe air quality issues requiring deep reductions in NOx emissions. As a state, California also leads in market support mechanisms for low-carbon transportation fuels and zero emission vehicles (ZEV), where the category of ZEVs includes plug-in hybrid electric vehicles, battery electric vehicles, and FCEVs. California's Low Carbon Fuel Standard is designed to accelerate innovation and market adoption of low carbon transportation fuels, and the ZEV Mandate requires auto makers to sell ZEVs within the state to meet increasingly stringent compliance targets. In addition to the Low Carbon Fuel Standard, California Air Resources Board (CARB) has established a renewable hydrogen requirement of 33% for any projects supported by state funds.[61]

A handful of automakers have just begun to commercialize FCEVs, with Hyundai offering a production vehicle for lease in 2014 and Toyota offering a production vehicle for sale or for lease in 2015. With the vehicle technology moving forward, infrastructure availability is a limiting barrier to successful market growth.[62] As evidence of the state's commitment, the California Energy Commission has recently allocated resources towards an unprecedented number of hydrogen stations in preparation for early FCEV market adoption, with the current 13 open public stations expected to expand to over 50 stations in coming years. Ultimately, current legislation allows up to 100 stations to be supported through around 2024, exceeding the 68 stations considered essential for early market growth.[63] Though projections of market growth are relatively modest, with some 18,500 vehicles expected in California by 2020,[64] Los Angeles is the focus of FCEV marketing activities and currently leads northern California in hydrogen station installations.

[60] http://www.theicct.org/hydrogen-fuel-cell-vehicle-infrastructure
[61] http://www.arb.ca.gov/msprog/hydprod/hydprod.htm
[62] Greene, D.L., Leiby, P.N., James, B.D., Perez, J., Melendez, M., Milbrandt, A., Unnasch, S., and Hooks, M. (2008). *Analysis of the Transition to Hydrogen Fuel Cell Vehicles & the Potential Hydrogen Energy Infrastructure Requirements* (2008 ed.). Oak Ridge National Laboratory.
[63] http://cafcp.org/sites/files/Roadmap-Progress-Report2014-FINAL.pdf
[64] http://www.arb.ca.gov/msprog/zevprog/ab8/ab8_report_final_june2014.pdf

The emphasis on building FCEV markets first in southern California is evident in the station location maps indicated in Figure 29. The left-hand map indicates 11 public hydrogen stations in operation as of early March 2015, while the right-hand map indicates the planned locations of the 50 stations funded to date by the California Energy Commission. As shown, early efforts to install stations have focused on Los Angeles, with only two public stations currently installed in northern California.

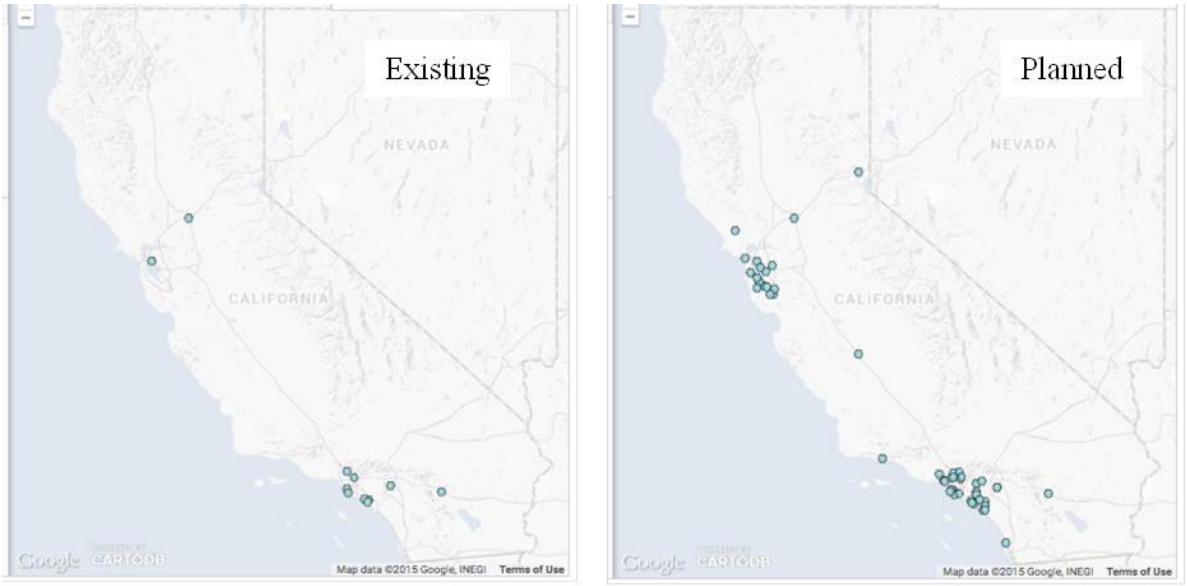


Figure 29. Existing and planned hydrogen station locations.[65]

Hydrogen can be produced from any primary energy resource, including coal, natural gas, nuclear resources, wind, solar and geothermal. For the Salton Sea region solar and geothermal resources are of particular interest. The delivery of hydrogen is a significant infrastructure undertaking, and Salton Sea is unique in being located some 150 miles from Los Angeles, and being traversed by major natural gas pipelines, as indicated in Figure 30. Early hydrogen delivery would be expected by gaseous or liquid tank truck, but at higher production volumes gaseous pipeline proves more economical. Rights of way for new hydrogen pipelines would prove relatively manageable due to existing natural gas pipelines within and along the northern border of Salton Sea (Figure 30). In addition, direct injection of hydrogen into natural gas pipelines is also a possible delivery method for early market growth. These and other issues are discussed in the following sections.

[65] AFDC Station Locator, available at: http://www.afdc.energy.gov/locator/stations

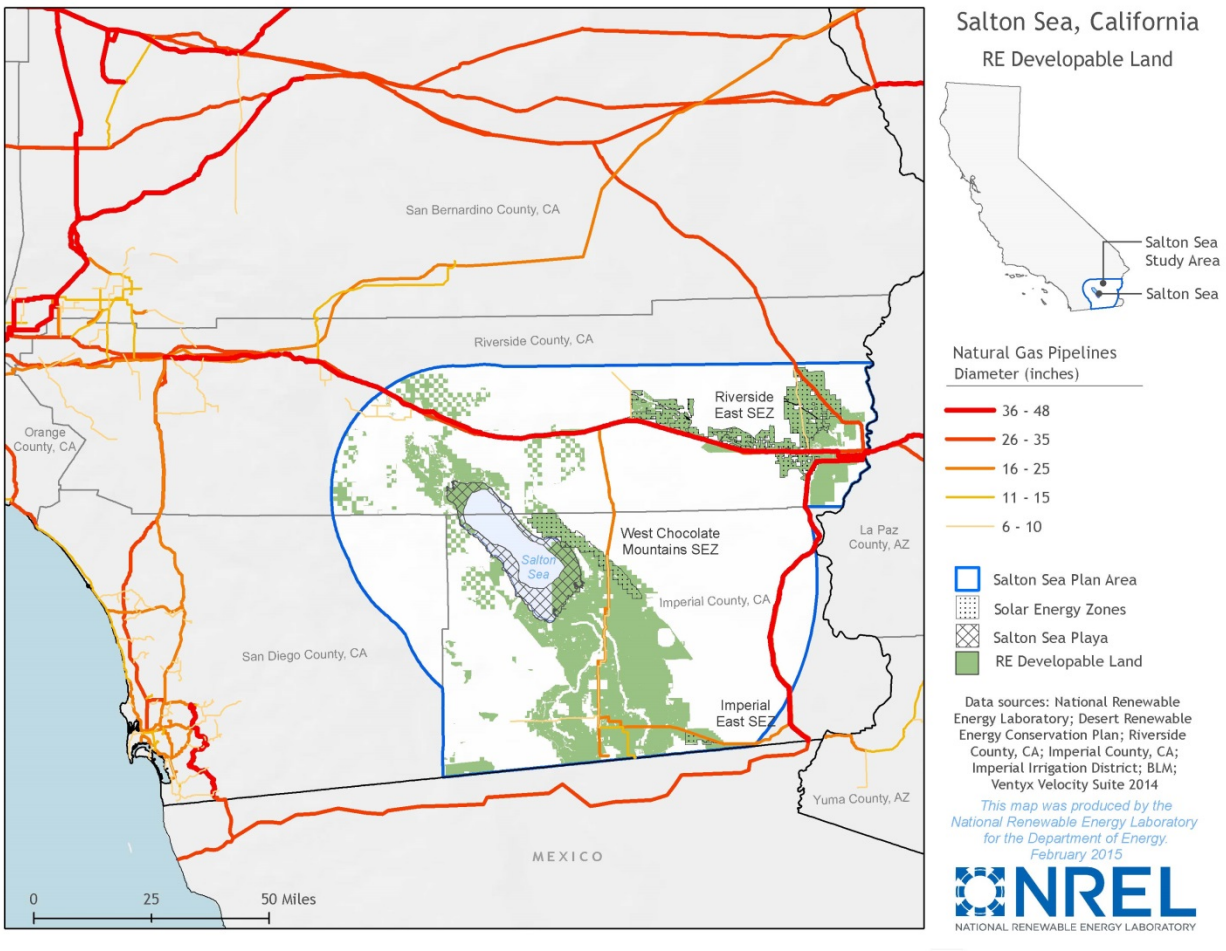


Figure 30. Major natural gas pipelines in the Salton Sea region

4.3.1 Hydrogen production

Most hydrogen used in commercial and industrial applications today is made from large-scale steam methane reforming (SMR) units collocated with petroleum refineries, as well as much smaller capacity electrolysis units for facilities where onsite production has an economic advantage over truck delivery. Most SMR hydrogen production is installed at petroleum refineries for use in removing sulfur and upgrading petroleum products. Electrolysis involves passing an electric current through a reactor to split water into gaseous hydrogen and gaseous oxygen. Given the very low prices of natural gas in the Unites States, SMR production is much more economical than electrolysis.

The Salton Sea region has significant potential to produce renewable hydrogen relative to other parts of the United States, due to the intensity of both geothermal and solar resources. Relying upon the technical potential estimates discussed earlier in this report for electricity generation from geothermal of solar resource via PV, it is possible to project comparable hydrogen production potentials using simple conversion efficiency values. These are reviewed in the upper portion of Table 21, for three types of electrolysis conversion:

- *Current technology.* Electrolysis at relatively small-scale with current conversion efficiency.

- *Future technology.* Projection of a mature future technology, mass produced and at a large scale with improved conversion efficiency.
- *High temperature electrolysis.* An electrolysis operating at high temperature in which water splitting is achieved with reduced electricity input (for example, a solid oxide electrolysis system). Electricity input requirement is reduced (here estimated at 45 kWh/kg) due to use of thermal energy as an input to the conversion process. Note that very high temperatures are required to allow for this type of electricity efficiency improvement, on the order of 300°F or more (Balta et al. 2009).

As indicated in the table, the electricity production potentials for Salton Sea translate to hydrogen production potentials on the order of millions of kilograms (kg) of hydrogen per day. As a point of reference, one kg of hydrogen has approximately the same energy content as a gallon of gasoline. Because hydrogen FCEVs are expected to be about twice as efficient as a conventional gasoline or diesel vehicle, the price of hydrogen can be divided by two to estimate a gallon gasoline equivalent (gge) per mile cost. For example, if a driver pays $10 per kg and then drives twice as far as a normal ICE vehicle, the cost to the hydrogen FCEV driver is roughly $5/gge.

The bottom section of Table 21 indicates the corresponding number of FCEVs that could be supported with these levels of hydrogen production. These vehicle totals range from 4.3 to 6.5 million FCEVs from hydrogen produced using geothermal electricity and 16.3 to 24.6 million FCEVs using PV solar electricity. Given that there are 0.8 light-duty vehicles (LDV) per person on average in the United States, and the current population of 24 million people within the Southern California region is expected to grow to 39 million by 2050[66], these production potentials would be sufficient to supply some 14% to 79% percent of all LDVs in Southern California in 2050 (if replaced with FCEVs).

Table 21. Hydrogen Technical Production Potentials and Total FCVs Supported

	Electrolysis Production		
Resource	Current Technology (million kg/day)	Future Technology (million kg/day)	High Temp. Electrolysis (million kg/day)
efficiency	*55 kWh/kg*	*50 kWh/kg*	*45 kWh/kg*
Geothermal	3.0	3.3	3.7
Solar PV	11.4	12.5	13.9
	Future FCEVs Supported (millions)		
fuel economy	*65 mpgge*	*80 mpgge*	*80 mpgge*
Geothermal	4.3	5.8	6.5
Solar PV	16.3	22.1	24.6

(Source: DOE Hydrogen and Fuel Cells Program Record 2014

Current projections by DOE[67] estimate future large-scale electrolysis production systems to provide hydrogen at a profited cost of $4.20 per kg (assuming an electricity price of $0.069/kWh

[66] http://www.america2050.org/southern_california.html
[67] http://www.hydrogen.energy.gov/pdfs/14004_h2_production_cost_pem_electrolysis.pdf

and efficiency of 50.2 kWh per kg), and current small-scale systems to provide hydrogen at a profited cost of $5.14 (assuming an electricity price of $0.061/kWh and efficiency of 54.6 kWh per kg). These cost estimates assume a production capacity of 50,000 kg per day for the future case, and 1,500 kg per day for the current case. The smaller current electrolysis case requires 3.4 MW of electricity at full power, and the large central future case requires 105 MW. Both estimates assume full utilization, and associated costs would increase at the lower utilization rates expected for remote, dedicated production from variable renewable resources such as solar.

The combination of geothermal and solar resources allows for multiple opportunities to improve upon the conversion of solar energy by utilizing renewable geothermal heat. In addition to the improved electrical efficiency discussed above for electrolysis, there may be an opportunity for hydrogen liquefaction efficiency to also be improved (Kanoglu et al. 2007), and the higher output pressure of high-temperature electrolysis units can reduce costs for gaseous compression equipment. Moreover, with sufficiently high temperatures, advanced thermochemical conversion processes may prove economic as these technologies become commercialized. For example, the Cu-Cl cycle (Balta et al. 2010) could prove promising and improve upon more conventional electrolysis systems. Alternatively, direct solar conversion processes may prove promising over the mid- to long-term (e.g., 10-20 years).

These production costs must be added to delivery costs, which include transmission, storage, distribution and dispensing, before determining the cost "at the pump" for FCEV drivers. These additional delivery costs may range from $2 per kg to $5 per kg and are very sensitive to volume and distance. As rough guidelines for the 150 mile delivery distance to Los Angeles, for relatively large production facilities within the Salton Sea region, exceeding about 10,000 to 20,000 kg/day, liquid hydrogen truck delivery may start to become competitive with gaseous truck delivery. At much larger volumes, around 0.5 to 1.0 million kg/day, gaseous pipeline delivery will begin to be more economical than liquid truck delivery. More detailed logistical and cost analyses with inputs specific to the region would be required to better understand these transitions between delivery modes at higher production capacities.

4.3.2 Delivery System Options

Some back-of-the-envelope cost estimates for liquid hydrogen (LH2) and pipeline delivery can provide an order of magnitude perspective on the market viability of producing hydrogen in the Salton Sea region. Costs associated with hydrogen delivery are likely to be favorable relative to the rest of the country for production in the Salton Sea area due to the combination of large-scale production and relatively short delivery distances to the Los Angeles basin and surrounding urban areas. Delivery to today's stations is largely by way of high pressure gaseous hydrogen trucks. At larger production volumes, LH2 trucks, costing approximately $1 million each and carrying 4,000 kg of hydrogen, could prove economically viable for delivery from the Salton Sea region. Assuming a future production volume of 200,000 kg/day, about 40 LH2 delivery trucks would be required, as well as a LH2 truck terminal near the point of production (perhaps with gathering lines from multiple production sites). The trucks themselves, therefore, would be on the order of $40 million in capital, not including the terminal. If typical stations at this point in time provide roughly 1200 kg/day to a regional FCEV fleet, this fleet of LH2 delivery trucks could supply a nominal network of some 150-200 hydrogen fueling stations with renewable hydrogen. At $4-$5 million per station at that average capacity (Melina and Penev 2013), the station network would have a capital cost of $0.6 to $1.0 billion. This network of stations would

have evolved over time, and would be switched to renewable LH2 delivery as production increases over time. Also, in actuality, LH2 delivery trucks would only be one mode of hydrogen supply within an even larger network of stations, which initially would be provided hydrogen produced from central SMR production facilities through either gaseous hydrogen or LH2 trucks. Therefore, in theory, an existing fleet of delivery trucks could switch from a natural gas central plant to a renewable production plant over time as capacity increases and if and when economics prove viable.

For larger production volumes in the long term, say 1 million kg/day, gaseous pipeline delivery would likely prove more economical than LH2 truck delivery. A general rule of thumb for hydrogen pipelines is $1 million per mile, escalating to $1.5 million per mile or even $2 million per mile with right-of-way (ROW) or terrain issues. Pipeline diameter does tend to increase overall costs, but installation and ROW costs tend to exceed material costs. A roughly 150 mile transmission pipeline to the Los Angeles basis could therefore cost some 150-250 million, not including any storage requirements and compressor stations. The distribution network within the urban area would also include significant costs, as 1 million kg/day could supply a network of approximately 830 hydrogen stations with an average output of 1200 kg/day. Again, assuming $4 million to $5 million per station for that average capacity (Melina and Penev 2013), the station network would have a capital cost of $3.3 billion to $4.1 billion. Again, this station network would have evolved over time. As a point of reference, there are about 3,000 major conventional (Melaina and Bremson 2008) gasoline stations serving the Los Angeles basin today.

4.3.3 Market Potential for Hydrogen Demand in Southern California

There are technical innovation and learning opportunities to reduce the cost of renewable hydrogen production below the costs reviewed in the previous section. Regardless of progress with these production and delivery technologies, there are significant uncertainties around the rate at which FCEVs might be deployed within the LDV and medium- and heavy-duty vehicle fleets. New advanced vehicle technologies can be inhibited from market growth by a number of cost and non-cost (Stephens 2013) market barriers. The market potential scenario discussed below is based upon a hydrogen success case developed by a National Academy of Sciences committee to determine a nation market potential of FCEVs. This scenario has been disaggregated to the urban area scale using a consistent scenario development framework within NREL's Scenario Evaluation and Regionalization Analysis (SERA) model.[68] Within this disaggregation of a national market share expansion trend, the city of Los Angeles is an early niche market and achieves more rapid market growth than any other city, but within the scenario total FCEV sales are still balanced at a national scale as successive cities begin to adopt FCEVs.

One change to the NAS study, which was published in 2008, is that the early transition years have been adjusted (pushed back in term of market share growth) to reflect more recent adoption estimates from the California Environmental Protection Agency, Air Resources Board (CARB 2004). As indicated in Figure 31, the simulated vehicle sales in Los Angeles approximate the point estimates for total California FCEV sales in 2014, 2017, and 2020, shown as squares. The Los Angeles FCEV sales fall short of these statewide estimates as more FCEVs are sold into other California urban areas. The rapid growth in subsequent years results in significant

[68] http://www.hydrogen.energy.gov/pdfs/progress10/vii_1_bush.pdf

economies of scale in vehicle production by 2025 to 2027 and exponential growth thereafter to achieve the same market share as the NAS report by 2050. Given the context provided in the NAS 2008 report, this rate of market growth should be considered a maximum feasible growth rate, adjusted in the early years for near-term expectations.

This disaggregated scenario for Los Angeles provides some perspective on the technical production potentials discuss above. For example, a renewable production facility with 100,000 kg/day capacity would dominate the FCEV market up to approximately 2025 to 2030, and therefore prove economically infeasible, especially given competition from hydrogen produced from natural gas. As additional market forces level the playing field for low-carbon fuels, and as sufficient demand for hydrogen develops with increased FCEV market adoption, this 100,000 kg/day facility would be a small part of the overall demand by approximately 2035 to 2040, when the total maximum feasible demand approaches 1.5 million kg/day to 2.7 million kg/day. Similarly, a 1 million kg/day facility would provide sufficient hydrogen for approximately 25% of all Los Angeles demand by 2050, and may therefore place significant upward pressure on prices within that timeframe, especially if sales are more modest than those indicated in Figure 32. On the other hand, in order to meet the California goal of an 80% reduction in greenhouse gases (GHG) (across all sectors) by 2050, most of the hydrogen supply in 2050 would need to be very low carbon; only a small fraction could still be produced from conventional natural gas. Provision of low-carbon hydrogen at this scale is consistent with others' studies of the technology adoption trends required to meet the 2050 GHG goal within the transportation sector (McCollum et al. 2012) and (Melaina and Webster 2011).

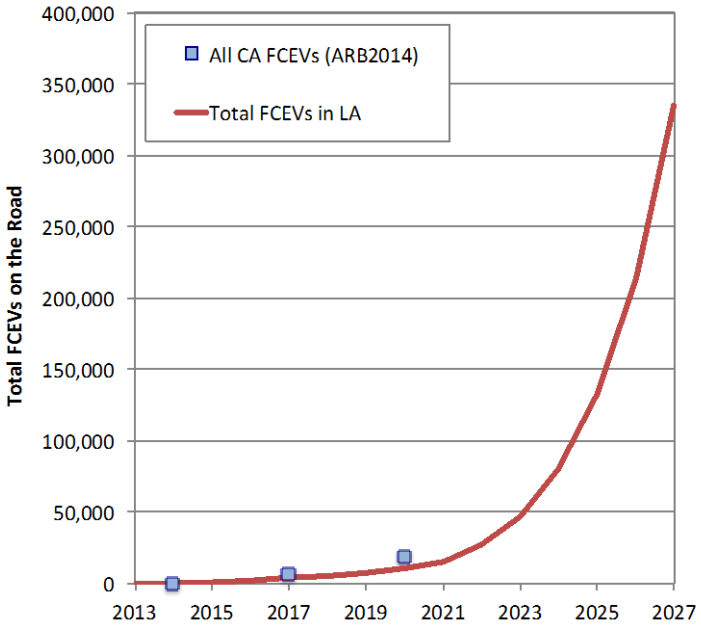
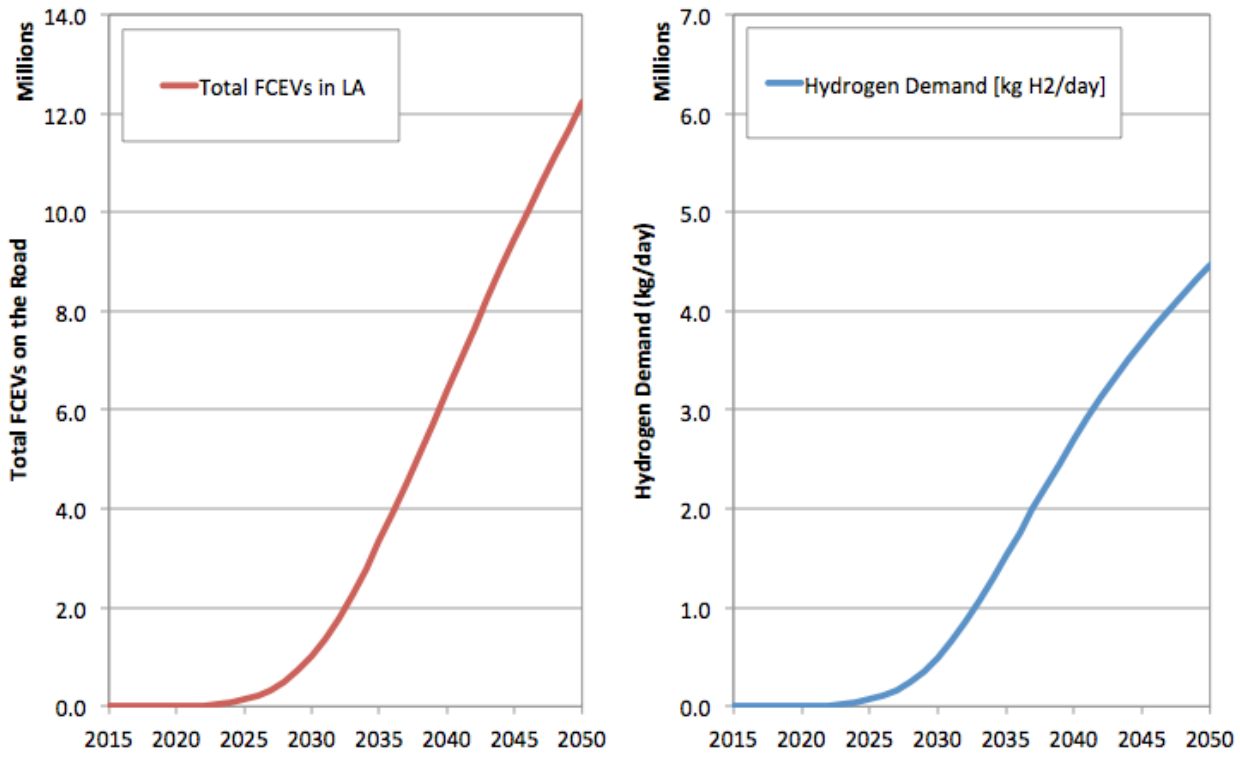


Figure 31. FCEV sales in Los Angeles and California in a hydrogen success scenario.



*Estimates derived from Table 21

Figure 32. Total FCEV sales in Los Angeles (left) and resulting hydrogen demand (right).

5 Additional Potential Revenues

Given that it appears that there will be minimal economic headroom for a Salton Sea restoration tax on renewable energy development in the region, additional potential revenue generation mechanisms for the Salton Sea Authority have been explored. These potential revenues include 1) existing federal and state revenue sources, as well as discussion of 2) additional potential funding and restoration cost reduction options. The development of these potential revenue streams will typically require a change in policy, development of the offshore playa, or further commercialization of a renewable technology.

Table 22. Summary of Potential Revenues

	Potential Future Conditions [Annual Millions]	Notes: See Appendix C for full calculations
Mineral recovery from geothermal brines (offshore KGRA)	$0 to 25.8	Assumes offshore development of up to 570 MW of geothermal, 3% IID royalty rate on gross lithium sales
Algal biofuels (offshore non-KGRA)*	$1.2 to 2.3	Assumes $3/gal cost competiveness by 2030, 1-2% IID land lease rate
Salinity Gradient Solar Ponds (offshore non-KGRA)*	$0.6 to 1.6	Assumes $80-$100/MWh PPA, 90% capacity factor, IID land lease rate (1-2% - gross proceeds).
Solar PV (offshore non-KGRA)*	$1 to 3	Assumes $40-60/MWh PPA, 23.2% capacity factor, IID land lease rate (1-2% - gross proceeds).
Solar PV (onshore BLM Solar Energy Zones)	$1.5-4.4	Assumes passage of HR 596 and development of 1.8 GW of BLM SEZ's. Assumes $40-60/MWh PPA, 23.2% capacity factor, royalty rate between 1-2% - gross proceeds.
Other:		
Desert Renewable Energy Conservation Plan - Habitat Restoration	$3.5 to $44.6	Lower case based on allocable revenues to desert pupfish habitat, upper case is for full habitat restoration amounts for Imperial & Riverside
Total (annual):	$5.6 to 77.8	The potential revenues above typically require a change in policy, development of the offshore playa, or technological developments.
14 year total:	$78.4 to 1,089.2	

* The potential development of off-shore acreage outside of the KGRA is mutually exclusive. e.g: Full development of the available acreage by algal biofuels precludes development by Solar PV or Salinity Gradient Solar Ponds. Total revenue estimates reflect the highest and lowest potential revenues from these three technologies ($0.6 to 3 million annually).

5.1 Desert Renewable Energy Conservation Plan

This revenue range assessment is a rough estimate based on the Draft DRECP report released in September, 2014; the final report may change substantially after the integration of comments from local, state and federal stakeholders. Currently, the proposed funds in the Draft DRECP appear to be dedicated to two main classes of activities: land acquisition mitigation and habitat restoration. Land acquisition mitigation refers to the purchase of land that will be set aside as undevelopable, in order to preserve existing wildlife habitat. Habitat restoration (also referred to as "Non-acquisition mitigation) within the report) refers to habitat infrastructure and actions, such as starling control, that restore existing degraded habitat.

The report currently identifies DRECP implementation fees (proposed environmental permitting fees required to implement the DRECP's objectives) as the primary source of funding for the proposed mitigation and conservation measures. However, given the variation in mitigation costs by region and Covered Activity, the proposed fees will be determined on a project-by-project basis. In order to ensure that renewable energy development in the development focus areas remains viable, the DRECP will attempt to establish greater permitting and environmental cost certainty and integrated transmission planning. While the Draft DRECP assumes 20 GW of renewable energy development in development focus areas, this is their upper bound estimate from a renewable energy development standpoint.

The draft report examined four scenarios, as well as a no-action and preferred alternative. These scenarios examined different allocations of implementation fees between land acquisition mitigation and habitat restoration. For the purposes of this report, the preferred alternative was examined, as it appeared to be the most likely scenario. Only habitat restoration revenues were considered. Table 23 is a summary of habitat restoration activities, and their DRECP-estimated costs from Appendix I of the draft report. [69]

Table 23. NPV of Non-Acquisition Mitigation Cost Estimates ($ Millions)

County	Habitat Enhancement	Fencing & Signage	Roost Habitat Creation, Enhancement, and Protection	Predator, Cowbird, or Starling Control	Total Estimated Cost
Imperial	$184.7	$16.3	$4.6	$4.6	$210.2
Inyo	$20.0	$1.8	$0.5	$0.5	$22.8
Kern	$61.2	$5.4	$1.5	$1.5	$69.7
Los Angeles	$25.3	$2.2	$0.6	$0.6	$28.8
Riverside	$211.0	$18.6	$5.3	$5.3	$240.0
San Bernardino	$284.9	$25.1	$7.1	$7.1	$324.3
San Diego	$15.1	$1.3	$0.4	$0.4	$17.1
TOTAL	$802.3	$70.6	$20.1	$20.1	$913.0

Source: Draft DRECP, Draft DRECP and EIR/EIS Appendix I, 2014

Due to the number of threatened species in the Imperial and Riverside region, it is likely that only a portion of these mitigation costs would be available for Salton Sea mitigation or restoration activities. Several species live in close proximity to the Salton Sea, including: most notably, the Desert Pupfish, but also the Yuma Clapper Rail, the Burrowing Owl, and potentially other threatened or endangered migratory bird species relying on the Salton Sea as a stopover on the Pacific flyway. Although these species live in close proximity to the Salton Sea, the regional impacts of the Salton Sea's degradation could adversely impact additional species, and therefore merit additional funding as well. Current activities supported under the Habitat Enhancement category include reseeding/replanting native vegetation, reintroducing native wildlife, restoring natural contours, restoring lost or degraded hydrologic or geomorphic functions, and increasing groundwater availability for dependent species.

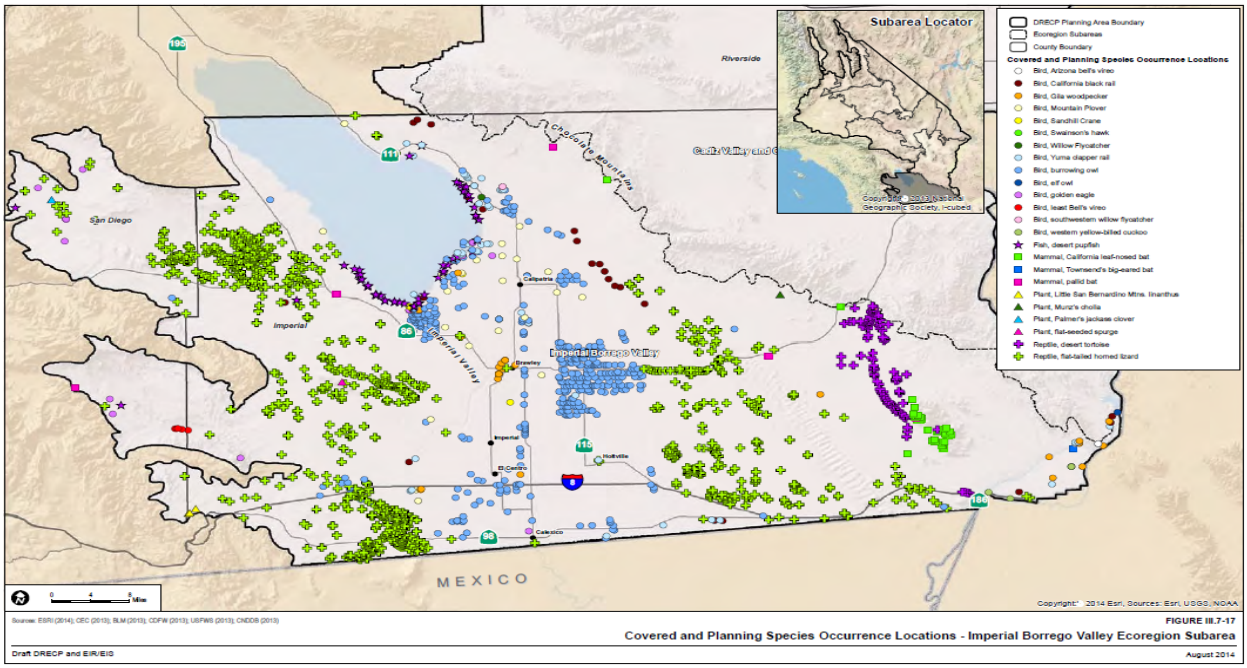
Given that the Desert Pupfish appears to be the species most directly affected by the degradation of the Salton Sea, the costs associated with this species have been estimated based on the following excerpts from the Draft DRECP. "Threats to the species include loss and degradation of suitable habitat through groundwater pumping or water diversion; contamination from agricultural return flows, as well as other contaminants; and physical changes to water properties involving suitable water quality; the effect of disease, competition, or predation; inadequate regulatory mechanisms; and endocrine disruptors". [70]

[69] Draft DRECP and EIR/EIS Appendix 1. Cost Estimate Methodology and Categories for DRECP Mitigation Cost Estimation. August 2014.
[70] DRECP Chapter III. 7. Biological Resources Chapter III. 7. 6. 1. 3. August 2014. P.160.

The revenue estimates performed are high-level, and based on limited habitat restoration information in the Draft DRECP, which includes a modeled habitat of 8,000 acres for the desert pupfish, which appears to be the primary proposed intervention. Two revenue calculations were performed to establish potential ranges for DRECP revenue for Salton Sea restoration. First, an estimation of the total revenue based on the portion of the DRECP's modeled desert pupfish required habitat of 8,000 acres was calculated, out of the total 47,000 planned acres for federally endangered species in the Imperial Borrego region (Figure 33).[71] By this pro-rata allocation of planned funds dedicated to the Imperial Borrego region, it could be expected that up to 17% of the $184.7 million, or $31.4 million, could potentially be allocated to desert pupfish habitat. Given that this $31.4 million is a net-present-value, this amount was undiscounted based on the DRECP's 3.6% discount rate and 25 year term to $49.58 million, or $3.5 million annually.

Alternatively, the upper revenue estimate assumed that the full Imperial ($184.7) and Riverside ($211) County Habitat Restoration costs were allocated to Salton Sea restoration efforts. These estimates were also undiscounted to $44.6 million in annual revenues.

Although the Draft DRECP also includes a section on air quality, and mentions the Salton basin as a nonattainment area for PM10 particulates, there are currently no proposed mitigation or restoration activities associated with this issue.



Source: DRECP Chapter III. 7. Biological Resources

Figure 33. Biological resources map of the Imperial Borrego region.

5.2 Land and Water Conservation Fund

The Land and Water Conservation Fund was established by Congress in 1965, and designates a portion of offshore oil and gas leases to federal and state conservation uses. According to the

[71] DRECP Chapter III. 7. Biological Resources Chapter III. 7. 6. 1. 3. August 2014. P.127.

DRECP, "California has received an average of approximately $50 million annually over the 45-year life of the fund, although less in recent years due to declining funding allocations.

According to the California Department of Parks and Recreation, "Priority development projects include trails, campgrounds, picnic areas, natural areas and cultural areas for recreational use." There is a 50% matching minimum, and although historical project sizes have been around $300,000, projects up to $4.1 million have been funded. Given the scope of mitigation and restoration efforts considered within the Salton Sea, it was assumed that only larger projects would be pursued under this Fund. Therefore, the average grant size was assumed as the minimum value, with a maximum range of $1 million. The maximum range appears to be unlikely as a reliable annual payment, but given the significant mitigation and restoration needs of the region, it may be possible to identify a series of discrete projects, or phases of projects, that would meet the Fund's requirements.

5.3 Public Lands Renewable Energy Development Act of 2015

(S.1407 – 114th Congress)

This bill, introduced in 2015, proposes to amend the revenue distribution for solar and wind energy authorizations to include distributions to states and counties. This bill would provide for the distribution of bonus bids, royalties, rentals, fees, and other payments as follows:

- 35% - Renewable Energy Resource Conservation Fund (increasing to 40% after 2030)
- 25% - County where the project is sited
- 25% - State where the project is sited
- 15% - BLM State offices for administration purposes (declining to 10% after 2030).

The bill calls for the Secretary of the Interior and the Secretary of Agriculture to establish a royalty level that would encourage production of solar or wind energy, ensure a fair return for the use of public lands, and encourage maximum energy generation within the areas' environmental constraints. As of the writing of this report, the bill had been introduced into the Senate on 5/20/2015.[72]

5.4 Water Quality, Supply, and Infrastructure Improvement Act of 2014

(Assembly Bill 1471)

Based on the existing approved funding, it appears that some portion of $475 million in funds approved from the California Water Bond (Proposition 1) may be available for various state obligations, including Salton Sea restoration work.[73] Within AB1471, this funding is specifically allocated for "Quantification Settlement Agreement (QSA), including Restoration of the Salton Sea," which may imply that additional liabilities included under the QSA could reduce the total funding allocated to Salton Sea restoration work. $200 million in funds for Salton Sea restoration was assumed as an upper limit, given the presence of other liabilities within the water bond.

[72] https://www.congress.gov/bill/113th-congress/house-bill/596
[73] http://www.leginfo.ca.gov/pub/13-14/bill/asm/ab_1451-1500/ab_1471_cfa_20140812_174138_sen_floor.html
http://awpw.assembly.ca.gov/sites/awpw.assembly.ca.gov/files/Corrected%20Prop.%201%20Fact%20Sheet.pdf

5.5 Existing and Proposed Royalty Payment Structures

Under existing policy, and based on discussion with contacts at BLM, there are currently no revenues of any kind from solar or wind energy authorizations on the public lands that go to States or counties. Solar and wind energy authorizations are land use authorizations under FLPMA, and are not like mineral leases that are issued under other authorities (Mineral Leasing Act and Coal Leasing Amendments Act). All revenues of any kind go to Treasury, including: lease rents, SEZ bid auction proceeds, and solar and wind energy ROW revenue receipts (acreage fee and MW capacity fee). Therefore, barring future policy changes, such as HR 596, the focus of this analysis will be on geothermal royalty structures, of which 50% of the proceeds are currently shared with the state.

5.5.1 Geothermal Royalty Structures

A potential source of funding for restoration efforts is the payments associated with developing and producing renewable energy on Federal land in the counties surrounding the Salton Sea. The current royalty payment structure for renewable energy resources on Federal land in the United States (with the exception of Alaska) is split between the U.S. Treasury and the state with 40% of the state share directed back to the county of origin. For example, if current East Mesa geothermal leases generate $100,000 in royalties, $50,000 will be returned to the State of California, and of this, $20,000 would go to Imperial County.

The royalty amount is not based on the value of the electricity sold to the utility. Rather, the current leases are all set at 10% of the value of steam, hot water, or other form of heat energy derived from the production of geothermal resources from the leases under what is called the Netback Method. This procedure derives the value of the geothermal resource by subtracting the lessee's costs of generating and transmitting electricity from the lessee's revenue resource upon which royalty is due. Through the provisions of the Netback Method established under 30 CFR 206.352, the lessee is allowed to deduct up to 99% of the royalty value upon which the 10% royalty rate is applied. This means that lessees are currently permitted to reduce $1 million of electricity down to $10,000, and then apply the 10% royalty rate to end up at a royalty payment of $1,000. However, the regulations for calculating royalties under the Netback Method were changed to a percent of gross proceeds under the Energy Policy Act of 2005 (EPAct 2005). So, for all leases issued after the passage of the EPAct 2005, there is a required 1.75% royalty rate of the gross proceeds for the first ten years of production, which increases to 3.75% after that.

The term of existing geothermal leases is 10 years with two optional 5-year extension periods, followed by one, final 5-year period if drilling has commenced before the end of the second 5-year extension. Beyond the royalty structure described above, annual rents per acre are also paid on competitive and non-competitive leases. For the former, the annual rental is $2 per acre in the first year, $3 per acre in years 2 to 10, and $5 per acre during the extensions. For the latter, annual rentals are now the same, but prior to EPAct 2005, they were $1 in years 1 through 10. These rents must always be paid, but the EPAct 2005 language allows for rents to be deducted from the 1.75% royalty rate of gross proceeds for the first ten years of production. So, while the royalty and rent payment structures differ based on various factors, including timing and legislation, both royalties and rents must be paid once production begins.

5.5.2 Mineral Leasing Receipts

Another potential source of funding is mineral leasing receipts from energy development. The most important factor at play with mineral leasing is the type of land where the energy development is occurring. On Federal land, the current structure under the Mineral Leasing Act of 1920 has 49% of mineral leasing receipts going to the state of origin. The only state where this is not the case is Alaska, which receives 88.2% of mineral leasing receipts. The other 51% of mineral leasing receipts goes to the Reclamation Fund (40%) and U.S. Treasury General Fund (11%). In 2014, California received $90.8 million in mineral leasing receipts. It is currently up to the state to decide how the funds are allocated. On other types of land, such as state-owned land, the division of mineral receipts is up to the State of California and any applicable legislation.

One potential option for increasing the total mineral leasing receipts could be to petition the Federal government to receive 88.2% instead of 49% of receipts. This could result in substantial additional revenues; for example, if $90.8 million is 49% of $185.3 million in mineral leasing receipts, then 88.2% would be $163.4 million. The State of California could then dedicate some portion of the increased receipts to Salton Sea restoration efforts.

There is also a Federal payment program called Payments in Lieu of Taxes, which is administered by the U.S. Department of the Interior. In 2014, California received $45.3 million from this program, with $3.4 million going to Imperial County and $3.3 million going to Riverside County. While the funds are typically provided to cover local emergency services or education, they can be used for any governmental purpose, including restoration efforts. At minimum, some portion of payments in lieu of taxes (PILT) funds would likely be eligible to cover restoration efforts at the Salton Sea, as they are critical to the economic development and progress of the region. Also, some states have passed legislation to receive the entire PILT payment so they can determine the appropriate breakdown by county. Another mineral lease management option has been explored by Utah and Colorado, which have passed laws establishing Mineral Leasing Districts (MLDs) that administer all the funding received from receipts. This removes mineral leasing receipts from the PILT equation so the payment to a county with a MLD would be higher than a county without an MLD, all else being equal. There are additional strategies to maximize state and county payments, so both the State of California and the Salton Sea Authority should do a follow-on study that identifies any additional opportunities that are not currently being pursued.

5.5.3 Future Steps

With these two sources of funding, there are opportunities to potentially generate additional funding for restoration efforts. On payments associated with renewable energy development and production, the State of California could take several steps. The State of California could make efforts to pass more specific support mechanisms, including CA Senate Bill 1139, which requires 500 MW of geothermal energy between 2015 and 2024. In addition, legislation specifically focused on encouraging development at the Salton Sea (streamlined environmental permitting) may also bolster renewable energy development in the region.

5.6 Transmission Revenues

After incorporating assumptions from the previous study of renewable energy revenue potential (EES Consulting 2013), and assuming IID ownership of the transmission capacity, minimum transmission revenues available for Salton Sea redevelopment were estimated at $179,000 to $357,000 per year (500 kVDC monopole versus 500 kVDC bipole). On a NPV basis, this amounts to between $2.2 million and $4.4 million from 2016 through 2045. Undiscounted, it amounts to between $5.4 million and $10.7 million.

5.6.1 Transmission Capacity Build out Opportunity

CAISO is currently exploring numerous transmission capacity additions to specifically address RPS compliance needs from Salton Sea renewable energy development, as well as the closure of the San Onofre Generating Station. It must be noted that these additional transmission projects were all characterized as facing challenging siting constraints of various severity.[74]

Based on discussion with IID, the IID has installed Path 42, increasing the thermal rating of the KN/KS line to 1,400 MW to 1,500 MW. Currently, roughly 75% of IID's Strategic Transmission Expansion Plan is fully permitted, and only requires ROW to still be purchased.

5.7 Restoration Cost Reduction

Based on data provided from the LADWP[75], there are three quoted dust mitigation measures in terms of $(millions)/sq. mile. The dust mitigation measures discussed include gravel, saltgrass, shallow pond, and tillage, summarized in the table below:

Table 24. Dust Mitigation Summary

Dust Mitigation Type	$(Millions)/Sq. Mile	$/Acre
Gravel	33	$51,563
Saltgrass	15	$23,438
Shallow pond	12.9	$20,156
Tillage	1.29	$2,016

(Source: Green 2014

The saltgrass and shallow pond methods also have significant water requirements, which may place an additional constraint on their deployment. As a conservative estimate of the value of any potential restoration cost reduction, from the perspective of establishing the minimum benefit of renewable energy project covering exposed playa, the tillage method assumption of $2,016/acre will be used for this calculation.

Development on the future exposed playa will likely carry additional challenges for both the construction and the operations and maintenance (O&M) of renewable energy projects. However, if the added value of playa coverage is monetized through a playa development incentive, or potentially even through the provision of exposed playa as freely developable land, the Salton Sea may be able to cover a portion of the exposed playa at a reduced cost.

[74] http://www.caiso.com/Documents/Presentation-ImperialCountyTransmissionConsulatation_Jul14_2014.pdf
[75] http://aridjournal.com/particulate-matters-emily-green/

Under the first example, a one-time restoration benefit incentive of $1,000/acre could be paid to any developer able to provide a durable, pre-approved dust mitigation measure (solar electric, geothermal, algae pond, renewable energy desalination, would be examples from the renewable energy sector, but other commercial purposes may also be applicable). Land-intensive technologies, such as algae or solar ponds, would benefit from a significant added revenue stream that could boost the project's economics, and the SSA would be able to fund dust mitigation efforts at a reduced rate.

Second, given the potentially significant costs associated with land acquisition and environmental permitting, offering pre-designated portions of unmitigated playa with reduced environmental permitting requirements could be an added economic incentive to development on the playa.

The benefit to development may still not outweigh the added complexity and cost to development of renewable energy projects on the playa. Additional detail from the LADWP Owens Lake solar PV project may provide additional certainty. Further study of the geotechnical soil conditions of the exposed playa, from a construction standpoint, would be required.

5.7.1 The North American Development Bank

The North American Development Bank (NADB) may be able to provide development expertise, as well as a lower cost of capital for both RE, desalination, and possibly even Salton Sea mitigation work. The NADB has a strong track record developing and financing numerous water and renewable energy-related projects. To date, 192 Border Environment Cooperation Commission-certified environmental infrastructure projects have been completed, worth roughly $2.25 billion in loans and grants. To qualify, projects must be within 100 km to the north, which includes most of the Salton Sea Study Area (Figure 34).

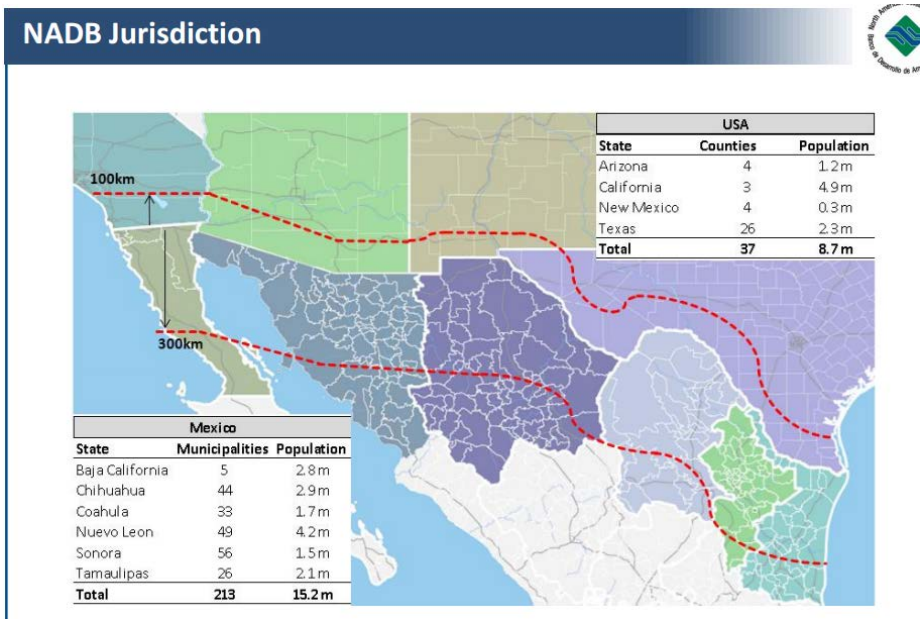


Figure 34. Qualified NADB assistance region. Image from North American Development Bank

The benefits provided by the NADB are as follows:

- *Loans.* The NADB's maximum loan amount is the lesser of the following: 85% of the total project cost, or $182 million for public sector projects and $110 million for private. These loans may be up to 25 year term loans with fixed or floating rates. Although rates will vary significantly based on project details, a rough calculation using details from the NADB website indicates a potential cost of debt between 2.58% and 7.83%.[76]
- *Technical Assistance*. Support project development with closing financing, project design, etc.
- *Grants*. Mostly focused on community infrastructure and wastewater treatment. Fairly small grant sizes ($2 million in CAP, ~$7.6 million in wastewater infrastructure).

Concerning eligible technologies, it appears that all major renewable energy technologies are eligible. Also notable is that desalination, water treatment, conservation and efficiency programs are also eligible. Finally, funding for "air quality" is available, which could potentially extend to dust mitigation work as well.

Several projects already completed in the Salton Sea area include: Ocotillo Wind (265 MW wind facility) and IVSC 1 (23 MW solar PV facility).

6 Conclusions

Of the commercially available renewable energy technologies, geothermal, solar PV, and CSP have the most significant technical potential for development. All of these technologies have large total resource potentials, but constraints, such as proximity to transmission access and regional cost-competitiveness of the power generated, may limit the economic potential. Based on extensive modeling within the CPUC calculator, it appears that any additional tax on generation for Salton Sea development would significantly disadvantage the development of these resources in comparison to other regions.

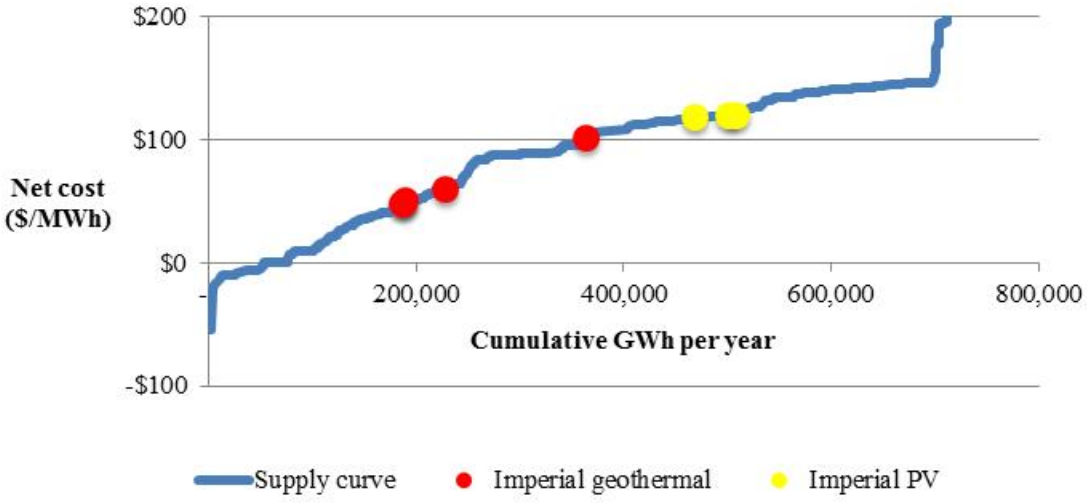
6.1 Market

The analysis conducted within Appendix B of the report supports the following overall conclusions about the market for Salton Sea renewables.

- Salton Sea renewables have no discernible headroom for bearing an additional cost earmarked for Salton Sea reclamation. Any added tax would need to reflect market conditions, as even the addition of a relatively small $5 per MWh restoration charge to the cost of new Salton Sea geothermal projects could make them more expensive than 2% to 3% (14,000 GWh to 21,000 GWh) of the competing California renewable energy supply pool. Similarly, a $5/MWh charge for solar would result in the area's best resources becoming more expensive than competing projects. As modeled in the RPS calculator, the area's resources would slip by about 7 percentage points in competitiveness in the California renewable energy supply pool, meaning that 49,000 GWh of competing projects would become economically superior. For context, the

[76] Commitment Fee - 0.075% on undisbursed loan balances Interest Rate (Treasury + .025-150 + 0.04). This is roughly 2.58%- 7.83%

modeled incremental demand from increasing the 33% California RPS to 50% may be between 44,000 GWh and 74,000 GWh.



Source: CPUC RPS Calculator

Figure 35: Net cost of potential new resources included in the RPS calculator (Point estimates of the range of net costs.[77]

- Both California and Arizona are likely to see higher demand for renewable resources in the Western Electricity Coordinating Council (WECC) region by 2020 and beyond. This demand is based on Integrated Resource Plans from the major California and Arizona utilities, and while it varies by utility, it primarily includes planned capacity from 2014 to 2024, with several plans extending through to 2034. This increase in demand will create opportunities for solar and geothermal located in the Salton Sea area, but power prices will need to be extremely competitive to compete with other regional low cost renewable resources. As an example, construction of the SunZia transmission line could lead to significant amounts of low cost wind becoming available from New Mexico.
- Salton Sea renewables will face different tradeoffs competing in the California and Arizona markets. While high power prices make the California market more lucrative, there are many choices for new renewable development. In Arizona, there are few practical alternatives to Salton Sea geothermal for renewable baseload, but power prices tend to be lower.
- Based on the Annual Technology Baseline, geothermal costs are not expected to change significantly from current levelized costs of energy between $107/MWh and 131/MWh. The scale of solar PV and CSP cost reductions are uncertain, but are projected to range between $49 and 94/MWh and $84 and 132/MWh, respectively, by 2030. These costs are exclusive of tax credits and other potential state and local incentives.

[77] Net cost = first-year PPA cost + transmission cost - market value of energy provided – capacity value

- CAISO also conducted a limited information-only assessment of two recently proposed transmission projects (Midway-Devers 500 kV AC line project and the Strategic Transmission Expansion Plan), and concluded that they might accommodate as much as 2,500 MW of additional renewable generation. Further, the construction of the HANG #2 500 kV line could result in an additional 600 MW to 700 MW that could be exported to Arizona.

6.2 Resource Confirmation

The analysis conducted within the report supports the following overall conclusions about the technical potential for Salton Sea renewables.

Table 25. Summary of Developable Capacity by Technology in 2030

Technology	Total Potential (GW unless otherwise specified)	Generation Potential (GWh/yr)	Existing Capacity (GW unless otherwise specified)
Geothermal (onshore)	0.68 - 1.24	4,765 – 8,690	0.6
Geothermal (offshore)	0.37 - 0.57	2,593 – 3,995	0
Solar PV	1.8	3,672	5.87
CSP	1.3	4,732	0.25
SGSP	0.1	788	0
Brine Mineral Recovery	54,000-122,000 MT Li	N/A	0
Algal Biofuels (offshore)	39,385,674 gal/year	N/A	0
Algal Food and Feed (offshore)	600,000 tons/year	N/A	0

Data Sources: Tables 10 through 14 and Table 19 of this report.

- There is a most likely total developable geothermal capacity of 1,840 MW in the Salton Sea region. This excludes the current operational capacity of 602.1 MW.
- The Salton Sea KGRA comprises 1,350 MW of the most likely developable capacity, much of which is still underwater within the Salton Sea. Figure 36 shows the potentially developable amounts over time. Although there is strong technical potential for development of the offshore geothermal resource, additional foundation and drilling requirements associated with building on the playa may make development uneconomic (Figure 36).

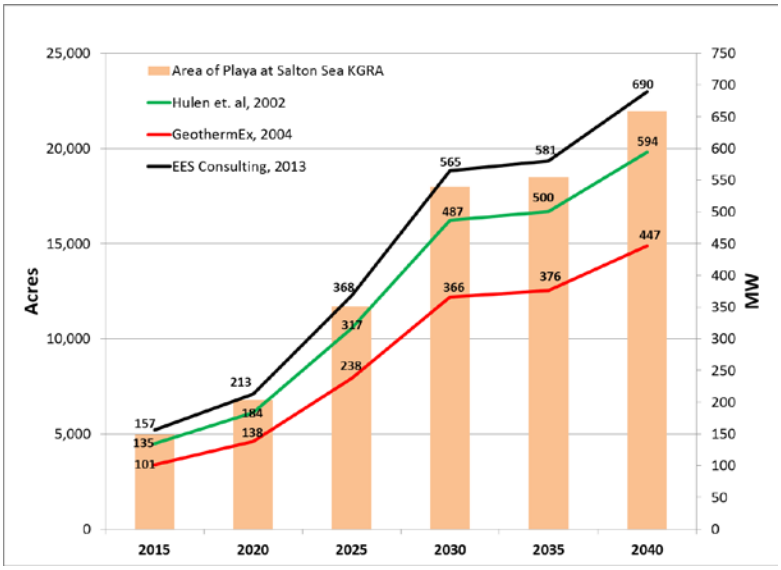


Figure 36. Potential development of offshore Salton Sea KGRA based on the shoreline recession in 25 years.

- Based on the modeled recession rates, the Salton Sea will recede most rapidly between 2020 and 2030, exposing roughly 30,000 acres of playa around the entire Salton Sea, of which approximately 11,000 acres will be exposed within the Salton Sea KGRA. The exposed land within the KGRA is potentially available for development for geothermal, and the remaining land may be suitable for solar PV, algal biomass, SGSP's, or for construction of wetlands/habitat. It should also be noted that the Salton Sea is expected to slightly reverse its recession between 2040 and 2050; this is due to the fact that as salinity increases, the evaporation rate decreases.
- Solar PV has the largest developable potential within 1 mile of 138 kV to 230 kV substation at 1.8 GW, followed by CSP at 1.3 GW. However, this region has a much larger technical potential of 31.9 GW and 23.9 GW, respectively, within 5 miles of existing 138 kV to 230 kV transmission substations. This additional capacity could be available if larger projects are able to absorb the additional costs of long interties, or if future transmission expansions are constructed in the region. This region has a total potential of 107 GW and 77 GW, respectively, although this would involve development of all available land, and is only included as an upper limit.

6.3 Potential Revenues from Renewable Energy Development

Based on the memo of understanding between the IID, Imperial County, and the Imperial Air District, the parties have agreed to cooperate in the development of renewable energy sources and allocate the potential revenues towards the restoration efforts. The development of the renewable energy technologies examined within the report will generate local tax revenues, environmental mitigation fees, regional economic development from construction, geothermal royalty payments to the state and counties from development on BLM lands, and land lease revenues from development of IID-owned playa for Salton Sea development from power generation projects.

A brief discussion of the potential revenues from each technology is summarized below; see Appendix C for full calculations:

- *Geothermal*:
    - Royalty payments from geothermal projects developed on BLM land could generate $1 million to $3 million annually for Salton Sea restoration efforts. This is assuming the full .68 GW to 1.24 GW of capacity is developed on BLM land and a range of PPA prices between $80 MWh and $100 MWh. The current total capacity developed on BLM land in the region is 80.1 MW at the East Mesa KGRA, so the quantity of BLM land that will be developed in the future is still uncertain.
    - The low and high land lease revenues for offshore projects on IID-owned playa were estimated at $6 million to $12 million annually, assuming that the estimated playa recession and developable offshore potential by 2030 are realized.
- *Solar:*
    - The low and high land lease revenues for onshore PV projects were estimated at $1.5 to $4.4 million, and assume the development of 1.8 GW of capacity within the BLM SEZ's, as well as the passage of HR 596, which would allocate BLM royalties from development back to the county and state.
    - An additional potential revenue stream from development of solar photovoltaics on the playa was considered, based on the following: an assumed 100% share of royalties for offshore IID projects, full development of the non-KGRA land within the playa exposed by 2030, and PPA prices between $60-$80/MWh. The total non-KGRA land within the playa, within 5 miles of a 138 kV to 230 kV substation, was 9,938 acres. A 7.9 acre/MW land use factor was applied to this acreage to determine the estimated capacity of 1.25 GW, and the production factor listed below in Table 11 was applied to this capacity. IID leases were assumed to range between 1-2% of gross proceeds. The low and high values for the estimated offshore IID land PV projects were $1 million to $3 million annually, assuming that the estimated playa recession and full development of the non-KGRA playa acreage by 2030 is realized. This 1.25 GW potential is not included in the likely developable solar capacity of 1.8 GW, due to the remaining uncertainty surrounding the feasibility of large-scale PV development on the Salton Sea playa.
- *Brine Mineral Recovery*. Potential revenues from lithium production could reach up to $25.8 million annually. However, the feasible taxable percentage of gross proceeds will be heavily dependent on the operating costs of the mineral recovery project. In general, technology is available for removal of most of the minerals mentioned above; however, the economics of deploying the technologies are marginal at this time, either due to the high cost of the extraction technology or to the market price of the mineral not being adequate.
- *Algae*. Although algal biofuel development appears to be technically viable in the region, this technology is currently pre-commercial and is unlikely to be cost-competitive in the

next 5 to 10 years. If algal biofuels reach $3/gallon cost competitiveness by 2030, between $1.2 to 2.3 million in potential mitigation revenues might be realizable, based on a 1-2% lease rate on gross proceeds. The Salton Sea appears to be a favorable region for development of algal biomass resources, due to the presence of highly saline water, large tracts of unused playa and high insolation.

- *Desalination*. Desalination from renewable energy could provide a significant potential benefit for Salton Sea restoration efforts by feeding desalinated water back into the Sea and addressing the increasing salinity problem directly. Although this method is technically feasible, returning fresh water to the Sea at zero or near-zero cost requires an alternative source of revenue for the process, such as salt sales. However, a strategy based on revenue from salt sales assumes that there is a developer with sufficient capital and technical expertise to execute on this type of integrated project, and several assumptions included in this high-level estimate may not materialize, such as the availability of a sufficient market price for salt, or an acceptable performance of the system at scale.
- *Hydrogen*. The Salton Sea region has significant potential to produce renewable hydrogen relative to other parts of the United States, and is 150 miles from Los Angeles, which is expected to be largest market for FCEVs. However, it does not appear that the Salton Sea region would be able to achieve the scale required for economic transportation until beyond 2030.

7 Observations

The results of this study support the following observations:

- The inclusion of any additional production tax on renewable power generation is likely to make renewable energy projects in the study area less attractive in comparison to neighboring regions. Both California and Arizona are likely to see higher demand for renewable resources in the WECC region by 2020 and beyond, but it appears that even a small additional tax of $5/MWh on generation for Salton Sea development would significantly disadvantage the development of these resources in comparison to other regions. While the magnitude of developable resources within the Salton Sea area is significant, this is also an indicator of the high level of competition that upcoming renewable energy projects will face when competing for space within a limited supply pool. Potential developments that could affect these findings include the implementation of more aggressive in-state renewable energy capacity goals, and additional project cost declines uniquely benefitting the Salton Sea region (i.e., local incentives, exceptional transmission access).
- There could be potential additional economic headroom for a $1/MWh to $5/MWh production tax if policies favorable to renewable energy create a unique benefit to development within the region. These policies could include utilizing the North American Development Bank for development expertise and to leverage interest rate cost savings, streamlining permitting requirements, and providing certainty surrounding environmental permitting costs.
- Legislative change from the Public Lands Renewable Energy Development Act could result in county revenues from solar development that could be allocated to Salton Sea

Restoration efforts. Under the existing payment structures, no BLM revenues from solar or wind development are distributed to the state or county, although this introduced legislation proposes to allocate 50% of competitive solar and wind lease revenues to the state and county.

- Salton Sea geothermal appears to be within a fairly competitive position on the total supply curve, especially when its additional value as a baseload renewable energy source is considered. In the near term, development of future geothermal resources will likely be constrained by PPA pricing, but could become more competitive as higher penetrations of renewable generation are reached in the California and Arizona market, and baseload renewable power becomes more valuable. Continuing to actively monitor the need for additional transmission capacity will ensure that the development of otherwise competitive projects is not constrained.
- Further analysis is required to refine estimates of the developable geothermal potential on the playa. The developable offshore potential is based on the percentage of playa exposed within the estimated bounds of the reservoir, but more accurate estimates can be achieved through volumetric assessment of the offshore resource. Further study of the geotechnical soil conditions of the exposed playa, from a construction standpoint, would also be required to refine offshore geothermal cost estimates.
- Although salinity-gradient solar ponds have not been established as an economically viable power production technology to date, the ability of this technology to provide an additional value stream (low-grade heat or electricity) while also covering large areas of exposed playa may make it suitable for development at the Salton Sea. Further analysis of the economic viability (Ability to secure construction financing and power purchase agreement), as well as the detailed investigation of the technical potential for synergy between this technology and algae development or desalination will be required to determine if a commercial-scale plant would be feasible in the region.
- Geothermal brine mineral recovery requires updated well data for more precise estimates of the recoverable potential. Well variability, both in terms of flow rate and lithium concentrations, is another significant obstacle to successful geothermal brine mineral recovery development, as future revenue from mineral recovery will depend heavily on successful geothermal exploration efforts.
- It appears that thermal desalination, and in particular, multi-effect distillation are especially suited for the region. This is based on the high TDS content of the Salton Sea surface water, as well as on the presence of low-grade geothermal and abundant solar resources. Low-temperature geothermal brine or solar thermal collectors such as flat plate collectors or solar ponds may be an ideal heat source, as they are lower cost and may cover additional exposed playa.
- Although the technology for algal biofuel production has not yet reached the commercial stage of development, commercialization is expected within the next 15 years. Due to the presence of highly favorable conditions, such as saline water, large tracts of unused playa, and high insolation, the Salton Sea could produce up to 40 million gallons of algal biofuel per year. Algal biomass development could potentially cover large tracts of exposed playa, absorb a portion of existing irrigation fertilizer runoff, and generate an

additional revenue stream from the sale of co-products, such as nutritional supplements like spirulina or beta carotene. Further study of the Salton Sea's water quality is required, but development of an algal biomass pilot plant on exposed Salton Sea playa could verify whether this proposed renewable energy restoration mechanism is viable. NREL has discussed this proposed mechanism with two organizations currently exploring pilot studies at this location, UCSD and Synthetic Genomics, Inc., which operates an R&D facility next to the Salton Sea.

- Renewable hydrogen production for fuel cell electric vehicles in the Salton Sea is not economically viable in the short-term; however, there is existing demand for hydrogen in the Los Angeles region from both crude petroleum refineries and the developing hydrogen transportation sector. The Salton Sea region may be able to provide renewable hydrogen for refineries, in order to reduce the carbon footprint of petroleum fuels and products (e.g. plastics). This market could be a viable near-term (2018-2020) path to commercialization for renewable hydrogen. Further study of the likely demand within this market, as well as the region's economic competitiveness for this opportunity, is required. Additional near-term potential markets for hydrogen include its use as a power plant fuel. If viable, serving any of these existing markets may advantageously position the region to meet future renewable hydrogen transportation demand.
- Due to ongoing significant changes in federal regulatory policies, increasing state RPS goals, shifts in technology costs and adoption, and accelerated plant retirements, further study of the power system in the U.S. West is required. A variety of models and tools exist that can be utilized to assess the opportunities and challenges. The NREL Resource Planning Model (RPM) model develops future scenarios of the market potential and transmission needs of different renewable and non-renewable options in the Western Interconnection, and at high spatial resolution for particular focus regions, such as Southern California. NREL also employs the PLEXOS production cost model to assess the operational impacts—including renewable curtailment, plant operational flexibility, transmission congestion, changing electricity imports and exports—under future infrastructure conditions. PLEXOS can be similarly employed to evaluate generating capacity and transmission scenarios in Southern California.

Appendix A: Technology Status Updates

This section reports on technology updates on the commercial status and prospects of geothermal energy systems solar power systems and algal biofuel production.

Geothermal Energy Systems

Utilization of geothermal energy comes in two primary forms: power generation and direct use.

Power Generation Technologies

Geothermal power plants come in three forms: dry steam, flash, and binary cycle. The type of plant deployed depends on resource temperature, and to some extent, developer preference.

Dry Steam

Dry steam plants are the oldest geothermal power plant type, first deployed at Lardarello in Italy in 1904. They are the simplest form of geothermal power plant. The plants draw steam from underground reservoirs directly into the turbine/generator unit (Figure A1) (GEO 2005). Emissions from dry steam plants are excess steam and very minor amounts of gases.

Resource temperature requirements for dry steam plants are high due to the need for steam to be present in the reservoir. Additionally, a geologic cap must be present above the reservoir in order to trap the steam in the subsurface. Because of this there are very few examples of steam reservoirs in the world and there are only two known underground resources of steam in the United States: the Geysers in northern California and Yellowstone National Park in Wyoming.

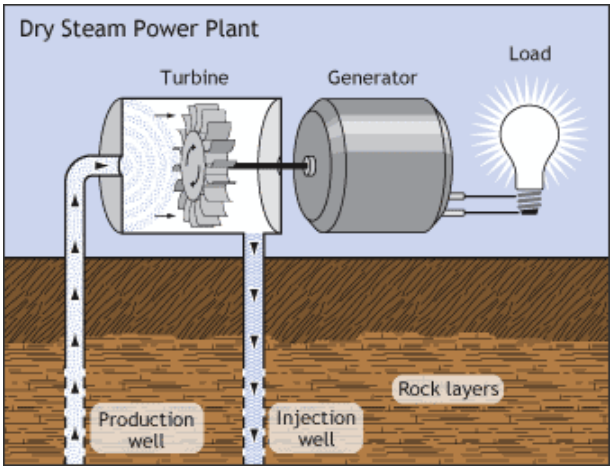


Figure A1. Schematic of a dry steam power plant. *Illustration from Geothermal Energy Association*

Flash Steam

Flash steam plants also utilize steam, but not directly from the reservoir (Figure A2). Geothermal brine flows up through a well under its own pressure (Kagel 2008). As it flows upward, the pressure decreases and some of the hot water boils into steam (this can also be accomplished in a "flash" tank at the surface). The steam is then separated from the water and passed through a turbine/generator unit. Any leftover water and condensed steam are injected back into the reservoir, making this a sustainable resource.

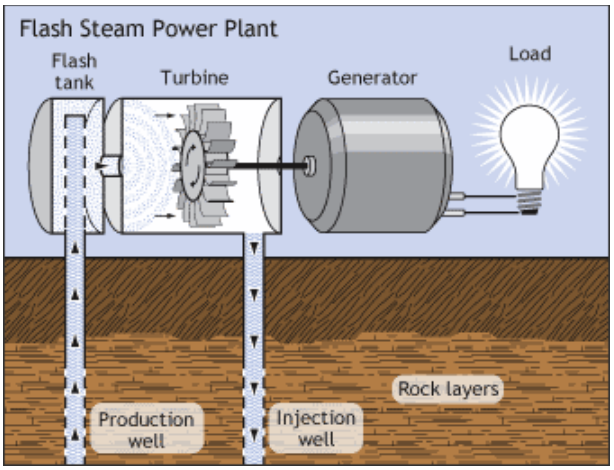


Figure A2. Schematic of a flash steam power plant. *Illustration from Geothermal Energy Association*

A common variation of the flash steam plant is the dual/double flash steam plant. In a double flash plant an additional flash tank is added after the primary (high pressure) turbine/generator unit(s) and the condensed steam (sometimes augmented with low pressure geothermal brine) is flashed again to turn a secondary (low pressure) turbine/generator unit.

Geothermal resource temperatures in excess of 360°F (182°C) can be used in flash plants to make electricity. Currently, flash plants are the most common form of geothermal power plants deployed in the U.S.; however, as development shifts to lower temperature geothermal resources, the trend is toward binary cycle power plants.

Binary Cycle

Binary cycle power plants do not flash the geothermal brine, instead the brine is used to flash a working/secondary (i.e., binary) fluid with a much lower boiling point (Kagel 2008). To accomplish this, a heat exchanger is used to transfer heat from the geothermal brine to the working fluid (Figure A3) (GEO 2005). Heat from the geothermal fluid causes the secondary fluid to flash to vapor, which then drives the turbine/generator unit(s). The organic rankine cycle binary power plant is the most commonly deployed version today and its commercial viability is well established.

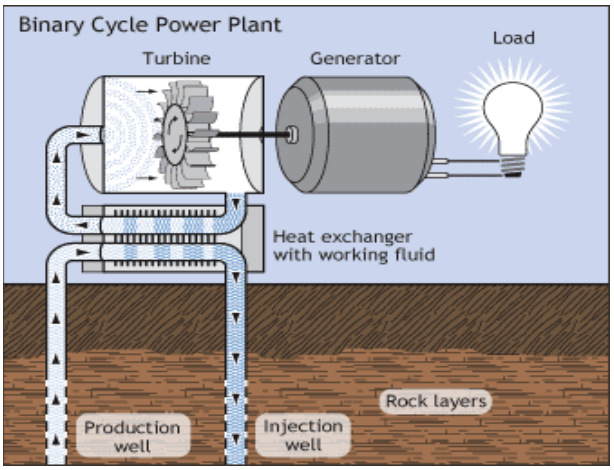


Figure A3. Schematic of a binary cycle power plant. *Illustration from Geothermal Energy Association*

Binary cycle power plants operate on water at lower temperatures of between 225°F and 360°F (in some cases lower brine temperatures can be used if the plant is water cooled). These types of plants have little to no emissions due to the physical separation of the geothermal brine and the working fluid during the process, making it a closed-loop system.

Advanced Technologies

There have been a number of industry advancements in recent years in geothermal power plant engineering, including:

- *Hybrid Flash/Binary Combined Cycle.* In this type of plant (Figure A4) (Bronicki 1995), the portion of the geothermal water which "flashes" to steam under reduced pressure is first converted to electricity with a backpressure steam turbine and the low-pressure steam exiting the backpressure turbine is condensed in a binary system (Kagel 2008). This can be a more effective use of the geothermal brine and take advantage of the benefits of both technologies. An example is the Puna Geothermal Power plant in Puna, Hawaii.
- *Triple Flash Steam Plants.* Yet another variation of the flash steam plant is separating the steam into three pressure streams instead of two. An example of this technology is the Hudson Ranch Plant near the Salton Sea (Geothermal 2013).
- *Mixed Working Fluid System.* The thermal efficiency of binary power plants is low compared to dry or flash steam plants; however, much research on advanced working fluids is currently under way to improve this efficiency. One such type is the Kalina cycle, which uses water and ammonia as the working fluid to improve efficiency (Kalina 2006). There are other possible mixed working fluid approaches to achieve higher efficiencies and/or lower temperature production of power.
- *Hybrid Cooling.* For air-cooled geothermal power plants, adequate cooling, especially in hot and dry climates, can be very difficult to achieve. In many cases, plant output can be diminished by up to 50% during the hottest days of summer. Research conducted by NREL has examined the effects of cooling the air with a fine mist before it enters the

condenser, with promising results of increased power while using much less water than conventional water cooled systems (Ashwood and Bharathan 2011).

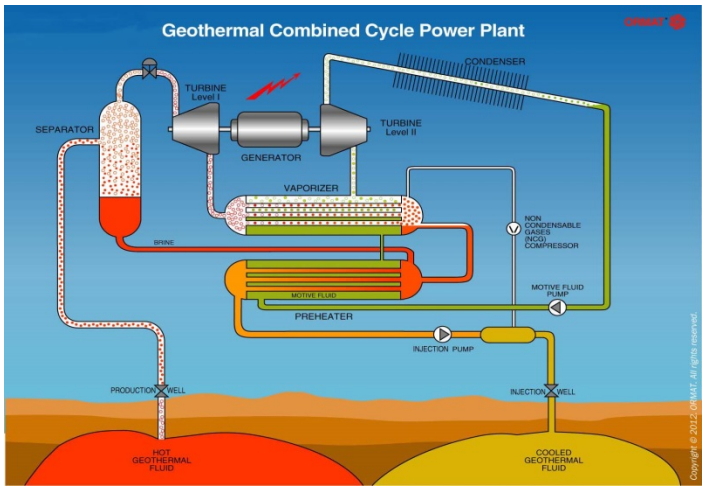


Figure A4. Flash/binary combined cycle plant. *Illustration from Geothermal Energy Association Cost*

Costs associated with geothermal power plant development include: exploration and permitting, well field development, power plant and cooling type (binary vs. flash, dry vs. wet), and other supporting infrastructure (i.e., pipelines, transmission, and roads). Table A1 shows a typical breakdown of costs and time for each development phase.

Table A1. Geothermal Project Development Cost Breakdown and Timing

Phase	Activity	Cost (% Total)	Time (years)
Resource Exploration and Evaluation	Exploration	0.2-0.5%	1-2 years
	Permitting	1-4%	
Exploration Drilling	Exploratory Drilling	4-6%	~1 year
Resource Development	Production Drilling	35-40%	1-2 years
	Steam Gathering	6-8%	
Plant Construction	Plant Construction	45-50%	1-2 years
	Transmission	2-4%	
		Total	5-7 years

The costs of developing a geothermal system are heavily weighted toward early expenses, rather than the costs of keeping them running. Well drilling and pipeline construction occurs first, followed by resource analysis of the drilling information. Next is design of the actual plant.

Power plant construction is usually completed concurrent with final field development. Based on the NREL Annual Technology Baseline[78] , the initial cost for the field and a binary power plant is ~$6,811 to $7,442 per installed kW in the United States. Flash plants are less costly at $6,487 to $7,088 per installed kW.[79] Operating and maintenance costs range from $216 to $368 per kW/yr.[80] Most geothermal power plants run at greater than 90% availability (i.e., producing electricity more than 90% of the time). The world average geothermal plant capacity factor is 75%. Table A2 summarizes typical geothermal investment costs, operating and maintenance costs, and capacity factors.

Geothermal development in the Salton Sea is expected to cost somewhat more than average due to engineering costs related to managing geothermal brine chemistry (possibly offset by mineral extraction), environmental costs, and higher drilling costs in the event resources are developed with directional drilling beneath the sea and playa. Although it does appear that development of geothermal projects on the playa will be technically viable, based on discussions with one geothermal developer, preliminary estimates are that these offshore geothermal costs could potentially be 10% higher than onshore geothermal construction due to additional foundation requirements.

Geothermal costs are not expected to decline significantly by 2030, and have been assumed to be stable in the modeled cost trajectories of the Annual Technology Baseline report. As O&M costs appear to be elevated in the Salton Sea region as well, these estimates were developed based on discussions with two separate sources, a developer within the geothermal industry, as well as the NREL RPM cost modeling team.

Table A2. Representative Current Utility-Scale Geothermal Costs (2015)

Technology	Capacity Factor	Total Capital Req'd ($/kW)*	Fixed O&M ($/kW-yr)
Binary Plant	80%	6,811-7,442	216-236
Flash Plant	94%	6,487-7,088	337-368

Does not include production tax credits, investment tax credits, loan guarantees or other incentive programs.

Source: NREL ATB

Geothermal Direct-Use Technologies

Direct-use geothermal systems are simple in design, consisting of a well field (production and injection wells, and submersible pumps), distribution piping (in-line pumps), and heat exchangers (to transfer heat from the pipeline to the application (Figure A5) (Canadian 2014). The direct-use applications (i.e., the demand side of the system) can, however, be complex and involved.

[78] NREL, Annual Technology Baseline and Standard Scenarios (web page, http://www.nrel.gov/analysis/ data_tech_baseline.html).
[79] US DOE Geothermal Energy Technology Evaluation Model (GETEM). http://www4.eere.energy. gov/geothermal/projects/1096 and http://www4.eere.energy.gov/geothermal/sites/default/files/documents/mines_getem_peer2013. pdf.
[80] Discussion with industry

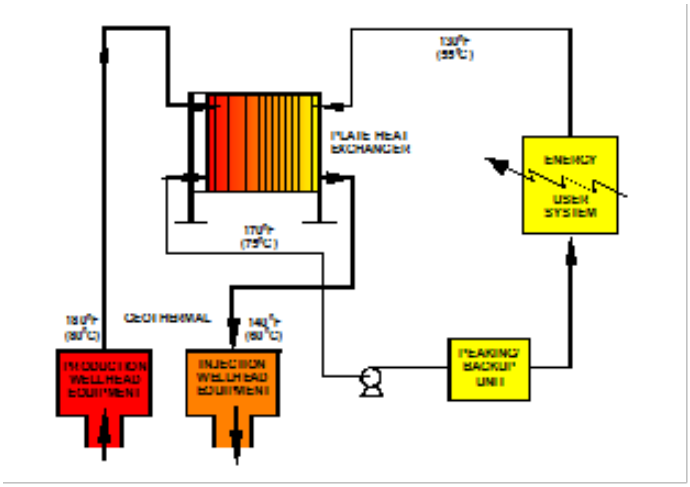
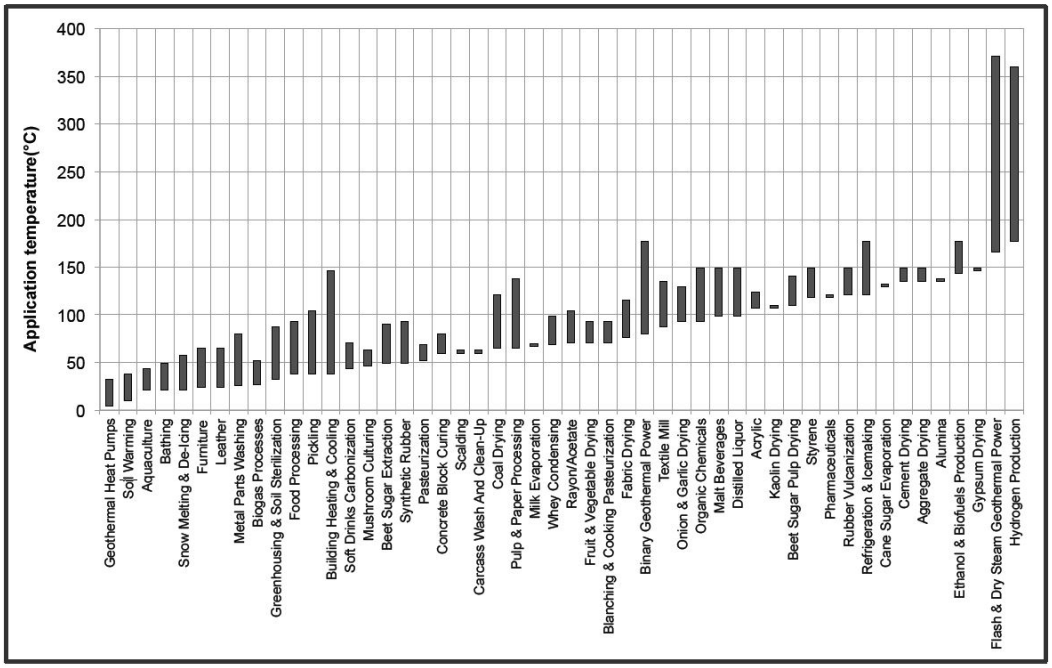


Figure A5. Typical direct-use geothermal heating system configuration. *Illustration from Geothermal Energy Association*

For the Imperial Valley, direct use applications would be worth considering for resource temperatures below those needed to achieve utility-scale power generation (here assumed to be <300°F). There are many direct-use applications (Figure A6) that fall into four broad categories (CanGEA 2014):

- Balneology (spas)
- Space heating (and cooling)
- Food growth and processing (aquaculture and agriculture)
- Industrial.

Based on what is known about the local geothermal resource, climate, and potential utilization needs, the most likely applications are food processing and industrial in nature.

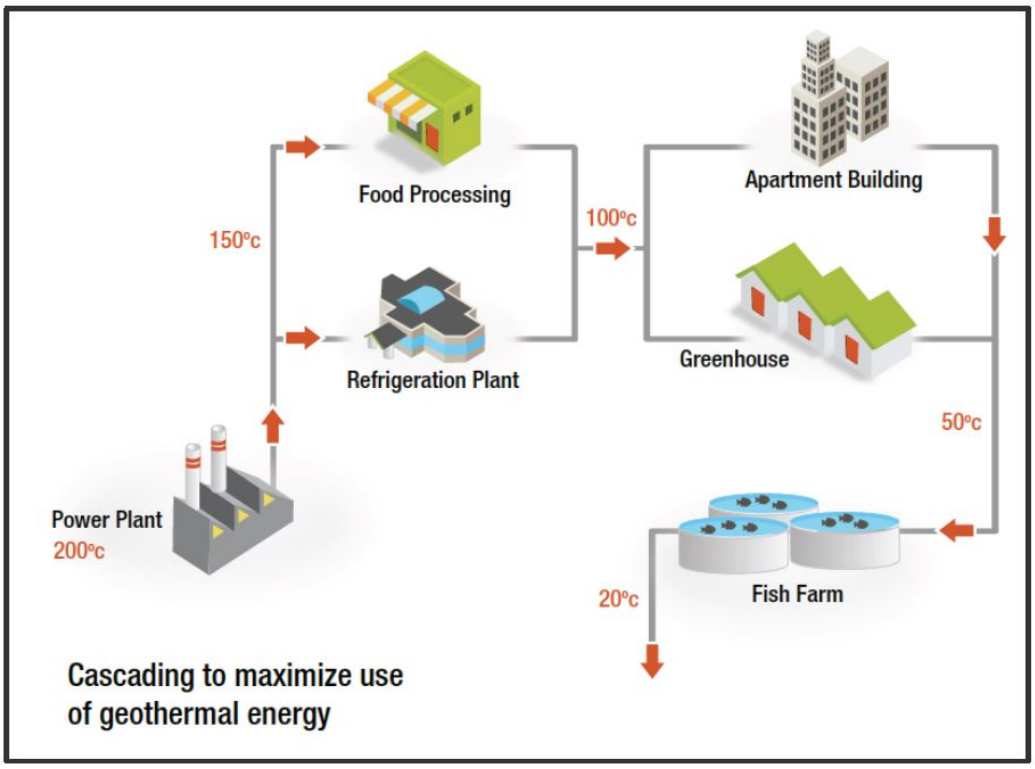


Source: CanGEA 2014

Figure A6. List of direct-use applications by temperature

The development of any direct-use system is costly, with most of the cost (50% to 70%) being sunk into the well field and the rest into the distribution system. Potential ways to mitigate the costs (to some extent) include:

- Using abandoned wells with adequate temperature and flow rate for direct-use application(s), but not power production
- Using the effluent (outlet) brine from an existing power plant
- Developing a cascaded geothermal system (Figure A7) (Canadian 2014) that combines as many geothermal applications as the system can support (this could be combined with 1 or 2 additional applications to further reduce costs).



Source: Canadian 2014

Figure A7. Example of a cascading direct-use system with power production.

Food Processing

Development of geothermal resources for direct-use applications has mostly occurred in northern states where space heating demands are high. These are also areas that would benefit from extended season (or even year round) agriculture (i.e., greenhouses). The Imperial Valley is an agricultural district that could potentially benefit from food processing applications such as fruit/vegetable drying, pasteurization, etc.

Industrial Processes

A broader set of direct-use applications that may be of interest fall in the industrial process category. In particular, two applications—desalination and mineral recovery—may have broad applications in the Imperial Valley. Brief overviews are given here. See Section 4.1 for a more in-depth analysis on desalination and mineral recovery potential in the Salton Sea.

Desalination. The concept of combining geothermal and desalination has been discussed in the literature for quite some time (Bujakowski et al. 2010). The geothermal energy can be used to run a power plant and the electricity utilized by an electrically driven desalination technology such as reverse osmosis or mechanical vapor compression. Or, it can be used directly for thermally driven desalination process such as multi-effect distillation of thermal vapor compression. Desalination has the potential to be a large scale local off taker of electricity. There is also potential for desalination to be a heat user, where heat could be delivered by either a power plant operator or via the revitalization of abandoned geothermal wells.

Mineral Recovery. There is strong interest in mineral recovery from geothermal brines. Recently the U.S. Department of Energy awarded up to $3 million in funding to advance geothermal mineral recovery R&D.[81] Additionally, there is an active mineral extraction plant working in the Salton Sea area; as well as at least one other (extracting zinc) in the past. Simbol Minerals has an agreement with Energy Source to extract lithium from effluent (outlet) brine exiting the Featherstone Plant before it is re-injected back into the subsurface. The project is currently at a demonstration scale, with a goal of 15 metric tons of extracted lithium annually.

In addition to lithium, other minerals that could be recovered from geothermal brine include zinc, manganese, cesium, rubidium, silica, etc. (Boucier et al. 2003). Silica is found at high levels in geothermal brines of the Imperial Valley and removal of it could be very beneficial to the mineral extraction industry as well as power plant operators. This is because silica acts as an inhibitor to extraction of most other minerals and silica can cause extensive and damaging scaling to well cases, which results in higher power plant O&M costs. There is a market for high purity silica; however, the cost to extract it and crystalize it in that form is marginal at this time.

In general, technology is available for removal of most of the minerals mentioned above; however, the economics of deploying the technologies are marginal at this time, either to the high cost of the extraction technology or the market price of the mineral not being adequate.

Solar Power Systems

Solar power systems are divided into technologies that directly convert sunlight into electricity (photovoltaics) and technologies that collect the sun's thermal energy. Solar thermal energy can be used directly for a variety of commercial and industrial purposes or can be converted into electricity via a thermo-electric power cycle. Solar thermal electric systems are known as CSP. Solar ponds are passive solar thermal collectors used for the production of low-grade heat for industrial processes or power production. The various technologies are listed in Table A3.

[81] http://energy. gov/eere/geothermal/downloads/low-temperature-mineral-recovery-program-foa-selections.

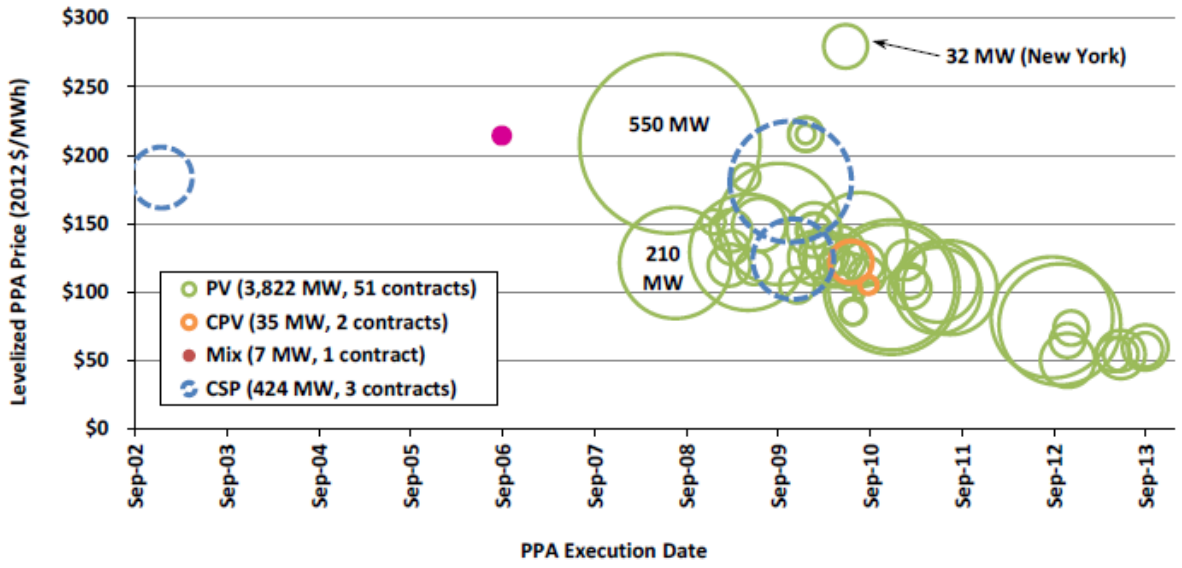
Table A3. Overview of Different Solar Technologies (NREL)

	PV	CSP Parabolic Trough	CSP Linear Fresnel	CSP Power Tower	CSP Dish / Engine	Solar Pond
Typical Operating Temp	ambient	390°C	450°C	565°C	750°C	70-90°C
Utility scale (>50 MW)	✓	✓	✓	✓	✓	
Distributed (<10MW)	✓				✓	✓
Energy Storage		✓		✓		✓
Hybrid with fossil energy		✓	✓	✓		
Water use (non-cooling)	♦ to none	♦♦	♦♦	♦♦	♦	**
Water use for cooling	-	preferred	preferred	preferred	-	-
Land Use (acre/MW)*	5-9	5-9	3-6	3-9	8-9	50-90
Land Slope	<5%	<3%	<3%	<5%	<5%	<5%
Commercial Maturity	low to high	high	low	medium	Low	low

* Values from utility-scale plants and proposed projects. Land use varies with resource quality, module or system efficiency, and inclusion of thermal energy storage. Plants with storage occupy more land per MW capacity, but less land per MWh generated.
** Evaporative losses occur from solar ponds, but water consumption data are not available.

All of the technologies listed in Table A3 have been technically demonstrated or are in commercial practice. As such, they are all at technology readiness levels of 8 or 9. Their level of commercial maturity is indicated as low to high, depending on the number of plants in operation. For example, dozens of parabolic trough plants have been in operation for years to decades, while linear Fresnel systems are just entering commercial use. The commercial maturity of PV technologies ranges from low to high depending on the specific cell architecture, as well as use of solar concentration and tracking. Dish/engine and solar pond systems have been demonstrated, but have little commercial deployment and consequently few cost data.

Cost for solar power technologies has fallen dramatically in the past few years due to new technology development, lower cost manufacturing, and deployment volume. Figure A8 (Bolinger and Weaver 2013) shows PPA prices for utility-scale solar projects in the United States. PPA prices are market prices that include tax incentives and subsidies. The project list is dominated by solar PV systems, with solar PV prices falling from $150/MWh to $200/MWh to about $70/MWh over the last few years. The sunset of the 30% solar investment tax credit (ITC) back to 10% at the end of 2016 will raise PPA prices as developers can no longer realize the larger subsidy. That change can be expected to raise PPA prices to about $10/MWh to $20/MWh.



Source: Bolinger and Weaver 2013

Figure A8. Levelized power purchase agreement price for utility-scale U.S. solar projects.

As indicated by Figure A10, PV systems are the most common and lowest cost solar power technology. CSP systems with thermal energy storage provide more consistent and often more valuable power, with fewer issues related to power integration, but at a higher levelized cost per kWh. Power generation with solar ponds is very low efficiency due to the low temperature of these systems; however, they can provide uninterrupted heat for industrial or commercial process.

Solar energy research at the federal level is driven by the objectives of the Department of Energy's SunShot Initiative.[82] This program has set the goal of achieving market-competitive solar power, without subsidies like the ITC, by 2020. The accepted target cost for utility-scale solar power under the SunShot program is $60/MWh, based on real 2010 dollars. The SunShot goals correspond to total capital required of about $1,000/kW for solar PV plants and $3,800/kW for CSP with enough thermal energy storage to provide a 66% capacity factor (Sunshot 2012). Data from the NREL Annual Technology Baseline[83] is summarized in Table A4.

Table A4. Representative Current and Future Utility-Scale Solar Costs

Technology	Capacity Factor	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
2015			
Utility-scale PV	14%-26%	2,986-3,670	16
CSP	25%-49%	8,272-10,168	71
2030			
Utility-scale PV	15%-27%	$1,094-$2,189	8
CSP	25%-49%	$3,710-6,177	51

Source: NREL ATB

[82] SunShot Initiative, accessed at http://energy.gov/eere/sunshot/about
[83] NREL, Annual Technology Baseline and Standard Scenarios (web page, http://www.nrel.gov/analysis/ data_tech_baseline.html).

Research under the SunShot program covers a wide range of topics that includes work to understand and develop basic components such as solar PV cells, heat transfer fluids, and optical materials and coatings; applied work on manufacturing processes and essential subsystems; modeling and analysis of the electric grid to understand and optimize integration of renewable power systems, exploring and attacking impediments to market penetration; and promoting workforce training and market transparency to help make solar deployment faster and more efficient. A summary of the entire program can be found in the SunShot Initiative Portfolio 2014.[84]

Impact of Airborne Dust on Solar Collectors

Airborne dust can inherently disrupt the transfer of solar energy to reflectors and collectors. The impact to collection efficiency varies with numerous factors, including technology type, dust characteristics, and humidity–the latter factors being highly location specific. The following summary is taken from a recent review of the issues in a 2012 Science Undergraduate laboratory Internship report (Sarver et al. 2012):

- The impact of dust and soiling is highly dependent on local conditions. Natural cleaning by rain and other moisture in temperate, tropical, and wet climates can be beneficial; however in arid, desert climates, occasional rain and dew can lead to more severe soiling problems due to cementation of settled dust.
- Dust degrades the energy delivery of both solar PV and CSP systems. Reduction in solar intensity reaching the solar converter has been evaluated and documented for the past five decades, and this reduction for uncleaned systems can be in the range of 20% to 50%, or more. For PV systems, the soiling derate assumption is site specific, but typically varies between 1.5 and 6% for the region in question depending primarily on rainfall, dust, and air pollution (Kimber et al. 2006). Soiling is a more critical issue for reflective, i.e., CSP-relevant, surfaces. Small losses in surface reflectivity of a mirror result in major losses in CSP performance. In general, concentrating systems are more sensitive to dust in the air and dust accumulation and require more maintenance from the perspective of dust mitigation.
- Much of the dust mitigation work has focused on the restorative approach, i.e., surface washing. The most common approach involves periodic cleaning with vehicle-mounted systems with forced water jets. Work has also looked at the effects of mechanical cleaning with air flows and air/water combinations from nozzles to reduce water consumption. The cleaning method of choice remains water washing with either demineralized water or dilute detergent solutions. These systems are very effective, typically maintaining surfaces within a few percentage points of their "clean" reflective or transmissive performance. The availability of high-purity water is critical and work has been devoted to minimizing water consumption during cleaning. Recommended cleaning intervals depend on the geographic location and climatic zone, and system performance should be estimated based on the average, soiled condition. Common cleaning intervals are every few days for CSP mirrors; solar PV systems are usually cleaned much less frequently. Water consumption with conventional truck-mounted

[84] SunShot Initiative, Tackling Challenges in Solar: 2014 Portfolio, U.S. Department of Energy, DOE/EE-1081, May 2014. Accessed at http://energy. gov/eere/sunshot/about.

sprayers for parabolic trough cleaning has been reported as 0.6-0.8 liters per square meter of collector area per event (Turchi et al. 2010).

- Research in preventative approaches includes both passive methods (which use coatings that prevent the attachment of the dust) and active methods (which actually repel the charged dust particles). Investigation of these more sophisticated methods continues with substantial inputs from the materials science, chemistry, physics, and engineering research communities. In the coatings area, recent developments with (super-) hydrophilic (and superhydrophobic) materials have led to some promising results that are potentially effective for both dry and "wet" dust conditions. However, the lifetime of these coating still needs to be validated. The inclusion of active layers to repel dust has grown out of interest and developments within the space industry. Several approaches have shown effectiveness and continue to be tested, evaluated, and analyzed for both technical and economic readiness.

A brief description of each of the solar technologies is provided in the following sections.

Solar Photovoltaic Technologies

Solar PV, as the name implies, are devices that convert sunlight directly into electricity. Solar PV generates power without no appreciable noise, pollution, or fuel consumption. Solar PV systems involve few moving parts and require little routine maintenance, especially compared with other power generation technologies. One disadvantage of solar PV and solar power in general is that it requires a large surface area per kW of power because sunlight is a diffuse resource. Efforts to make systems more efficient and to utilize unused or previously disturbed space, such rooftops or former agricultural land, can mitigate this problem.

A solar PV system consists of three basic subsystems: solar PV modules, power electronics, and structural and wiring hardware, commonly referred to as balance of system. PV module technology falls into two major technology groups, crystalline silicon and thin film, and there are two basic types of crystalline silicon (c-Si) PV: monocrystalline and multicrystalline. Silicon PV cells come in wafer form. Monocrystalline PV wafers are cut from single-crystal silicon ingots, while multicrystalline wafers are either cut from directionally solidified blocks or grown in thin sheets. In each case, the silicon is produced in such a way that an internal electric field is created in the wafer, and positive and negative electrical connections are added to form a cell as shown in Figure A9. The circuit is completed for each cell and multiple cells are then linked and encapsulated to form modules.

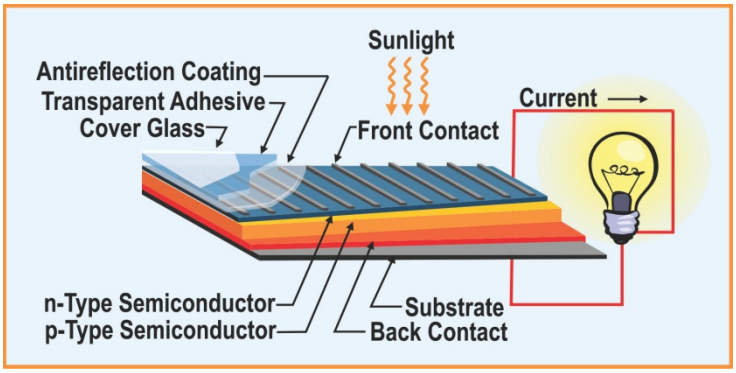


Figure A9. Typical PV cell construction. Illustration by NREL

In contrast, thin film PV is deposited directly onto a rigid or flexible substrate. This substrate/ film structure is then integrated with electrical connections to form a circuit. Thin-film PV may use any of several different substances and various deposition methods can be used on a variety of substrates. Thin-film PV technology is categorized according to the photovoltaic material used. These include:

- Amorphous silicon (a-Si) and other thin-film silicon
- Cadmium Telluride (CdTe)
- Copper indium gallium selenide (CIGS)
- Dye-sensitized solar cell (DSC) and other organic solar cells.

Currently, CdTe is the most commonly used thin-film material. CdTe thin-film PV modules tend to be lower cost and lower efficiency versus silicon modules, and advances continue to be made in all the cell technologies (Figure A10).

The power electronics are an essential part of the PV system, in particular, an inverter converts direct current (DC) to alternating current (AC), and a transformer steps the electricity up to the appropriate voltage. Finally, the remaining components and procedures required to produce a complete PV system—mounting and wiring hardware, installation, etc. —constitute the balance of system.

Solar PV systems can be fixed in position, often tilted toward the south (in the northern hemisphere), or mounted on a tracker to better capture sunlight throughout the day (Figure A11). There are also concentrating PV (CPV) technologies that use trackers and lenses or mirrors to focus the sun's rays onto a high-efficiency PV cell. CPV systems use concentrating optics and more efficient (but more expensive PV cells). Concentrating optics allow the design to focus more sunlight on the high-efficiency cell.

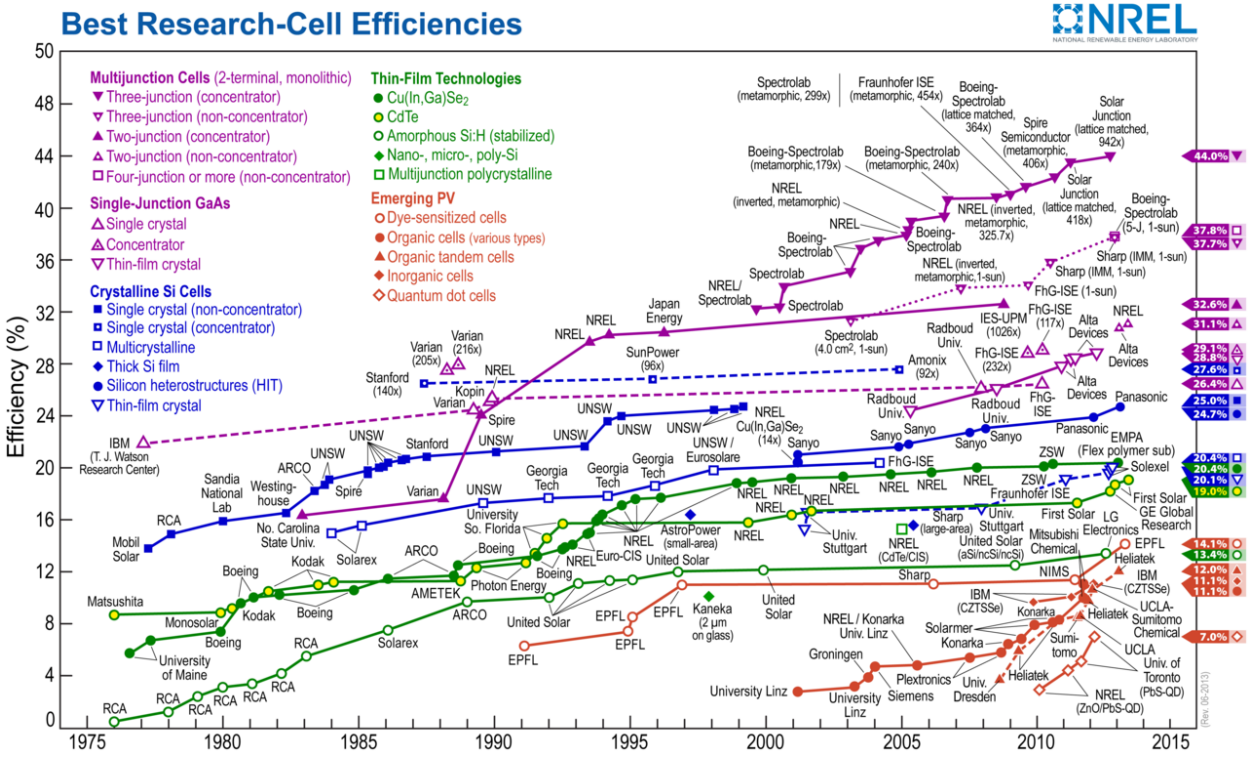
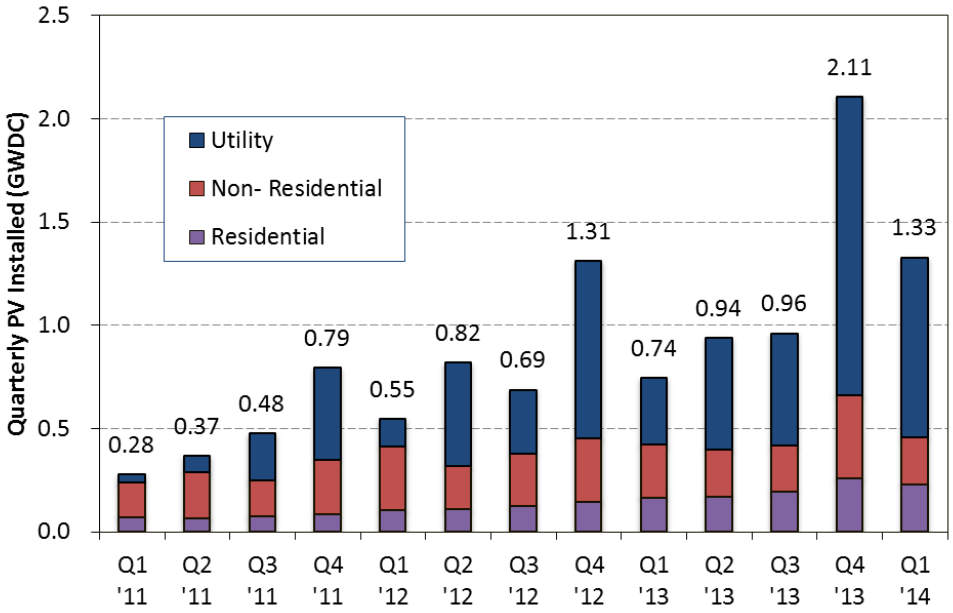


Figure A10. PV cell efficiencies for various technologies under standard laboratory conditions.

Figure A11. PV arrays placed in a fixed-tilt position or mounted on a tracker. *Photo by NREL*

As PV module and system costs have fallen in the last few years, PV installations have climbed across the United States (Figure A12). Utility-scale plants represent the lowest cost systems and have seen the greatest growth, with most deployment activity in California.



Source: GTM/SEIA U.S. Solar Market Insight Q1 2014

Figure A12. U.S. PV installations by market segment.

Concentrating Solar Power Systems

Concentration solar power systems differ from photovoltaic systems in that the solar energy is first captured as heat before being converting into electricity by a thermo-electric power cycle. CSP technologies include parabolic trough, linear Fresnel, power tower, and dish/engine systems. A major benefit of most CSP technologies is the ability to incorporate thermal energy storage to enhance reliability and dispatchability.

Parabolic Trough Systems

Parabolic trough power plants are the most mature of the CSP technologies, with over 3,500 MW in operation worldwide and some plants operating since the 1980s.[85] Trough power plants have large arrays of solar collectors that feature mirrors curved in the shape of a parabola (or trough) to focus sunlight onto a pipe (Figure A13). A heat-transfer fluid (HTF), often synthetic oil, flows through the receiver pipe and is heated by the absorbed sunlight. This hot fluid is used to generate steam that turns a conventional steam turbine/generator to produce electricity. The spent steam from the turbine is condensed into water and recirculated by feedwater pumps to be transformed back into high-pressure steam. Wet, dry, or hybrid cooling can be used to cool and condense the spent steam; the selection will influence water consumption, cycle performance, and cost. A parabolic trough plant is composed of several subsystems: solar collector field, receiver and associated HTF system, power block, thermal storage (optional), fossil-fired backup (optional), and necessary ancillary facilities (Figure A14).

[85] http://www.solarpaces.org/

Figure A13. Parabolic trough collector and receiver tube. *Photo from NREL 16604*

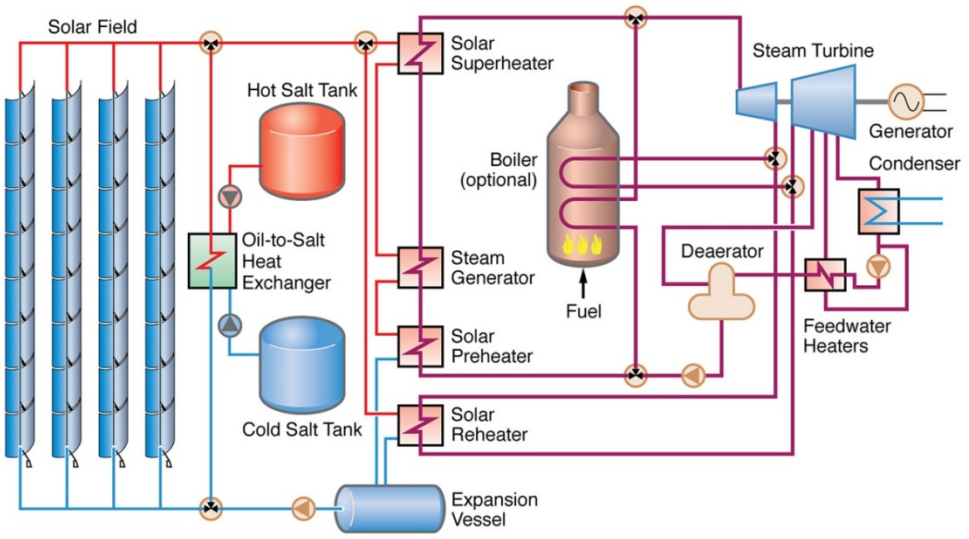


Figure A14. Simplified schematic of a parabolic trough power plant. *Illustration from Electric Power Research Institute*

Linear Fresnel

Linear Fresnel reflectors approximate the parabolic shape of a trough collector with long, ground-level rows of flat or slightly curved reflectors that reflect the solar rays onto an overhead linear receiver (Figure A15). A primary advantage of the linear Fresnel design versus the parabolic trough is the ability to keep the mirrors close to the ground and out of the wind. This feature, combined with flat reflectors and fixed receivers lead to lower capital costs relative to a parabolic trough plant. However, the collector simplicity advantages of the linear Fresnel system come with a cost; lower optical efficiency versus a parabolic trough. This lower optical efficiency is the main drawback of Fresnel systems with respect to troughs. On the positive side, the close-packing of linear Fresnel systems reduces the required land area compared to parabolic trough plants of equivalent capacity.

Parabolic trough and linear Fresnel are both line-focus systems. In the case of the trough, the receiver pipe moves with the parabolic collector. In a Fresnel system the receiver is mounted high above the collector mirrors and does not move. This is a significant advantage for a Fresnel receiver because a fixed receiver is easier to build and maintain; a moving receiver requires flexible joints where the HTF enters and exits.

Figure A15. Linear Fresnel system made by Areva. *Photo from NREL*

Taking advantage of the benefits of a fixed receiver, most linear Fresnel systems use a water/steam HTF. That is, water flows though the receiver tube and is converted directly to steam. Direct steam Fresnel systems have achieved steam temperatures of greater than 400°C and some vendors hope to reach 500°C or above. Direct steam generation means there is no expensive oil HTF, nor need for a set of heat exchangers between the solar field and the steam turbine, further simplifying the plant design.

Some researchers have suggested that linear Fresnel systems could be deployed with a molten-salt HTF, such as done with power towers. Like a power tower, the linear Fresnel's non-moving receiver makes it easier to handle the molten salt. A molten salt HTF also makes it much easier to incorporate thermal energy storage by simply holding hot salt in an insulated tank. However, linear Fresnel plants still have substantial piping and protecting against salt freezing is not a trivial matter. Linear Fresnel systems are not as established as parabolic troughs and long term performance and cost data are lacking.

Power Tower

Whereas a parabolic trough or linear Fresnel plant moves fluid to solar collectors, a power tower system (Figure A16) moves the sunlight to a centrally located receiver. In essence, power towers spend most of their effort to move light rather than HTF. Power towers use heliostats (flat or nearly flat mirrors) that reflect sunlight onto a receiver. A large power-tower plant can utilize tens of thousands of heliostats, each under computer control. For this reason, power towers can

be trickier to control than parabolic trough or linear Fresnel plants, but advances in software are overcoming these limitations.

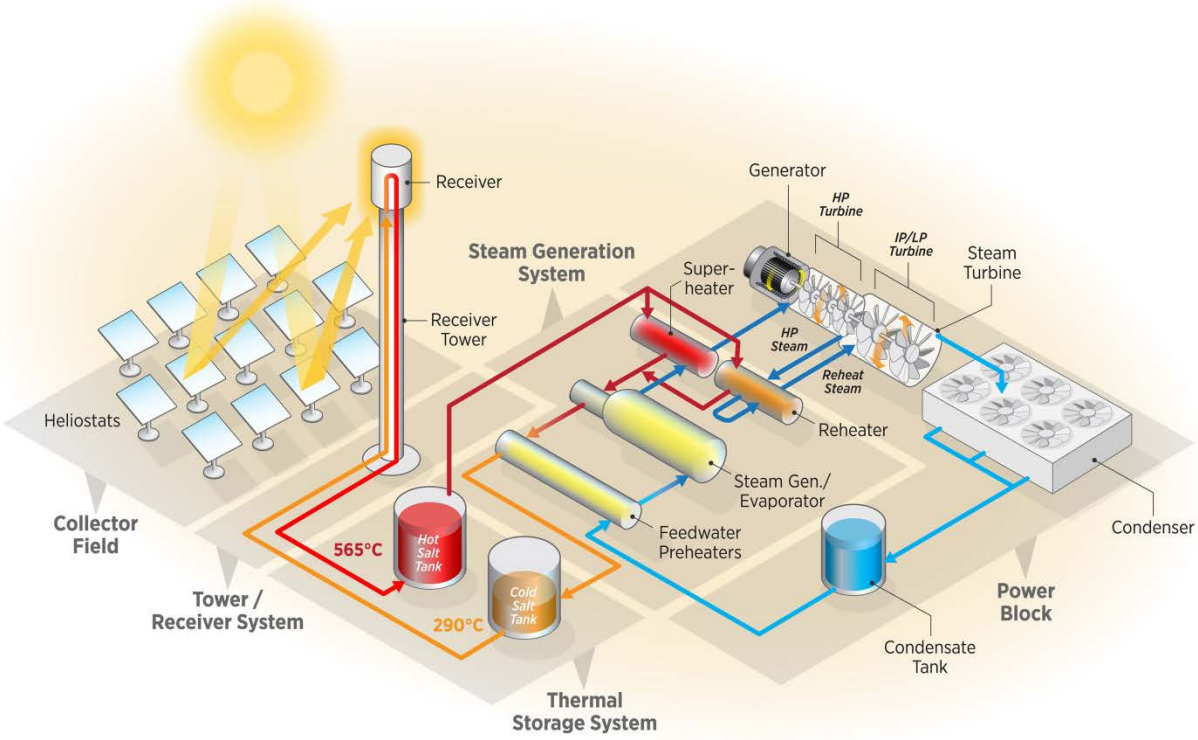


Figure A16. Schematic of a molten-salt power tower. *Illustration by NREL*

The two principal power tower designs are distinguished by the HTF in the receiver: steam or molten salt. In direct-steam power towers, heliostats reflect sunlight onto a receiver, which is basically a boiler mounted on top of a tower. Feedwater pumped from the power block is evaporated and superheated in the receiver to produce steam, which spins a turbine to generate electricity. Several characteristics of direct-steam power towers make them attractive: straightforward design; use of conventional boiler technology, materials, and manufacturing techniques; high thermodynamic efficiency; and low parasitic power consumption. Short-duration steam/water storage has been demonstrated at the 20 MW PS20 tower in Spain.

In a molten-salt power tower, "cold" salt at about 290°C is pumped from a storage tank to a receiver, where concentrated sunlight from the heliostat field heats the salt to about 565°C. The salt is typically a mixture of sodium and potassium nitrate, which is a blend known as "solar salt". The hot salt is collected in a storage tank, and when power generation is required, hot salt is pumped to the steam generator, which produces high-pressure steam to spin a turbine/generator. The now-cooler salt from the steam generator is returned to the cold storage tank to complete the cycle. Owing to the negligible vapor pressure of the salt, both storage tanks are at atmospheric pressure. By placing the storage between the receiver and the steam generator, solar energy collection is de-coupled from electricity generation, and one can produce power and collect sunlight at completely different rates. Thus, passing clouds or sunsets do not affect turbine output. A strong advantage of molten salt power towers is the low cost and high efficiency of thermal energy storage (TES). In a molten salt tower, TES is less than half the cost

of salt TES in trough plants because the larger temperature range across the storage system enables more energy to be stored per mass of salt.

The molten-salt power tower was first demonstrated at the 10 MW Solar Two project in the 1990s and has since been commercialized with 20 MW Gemasolar in Spain and 110 MW Crescent Dunes in the United States.

Figure A17. A molten-salt power tower. *Photo from NREL*

(Image credit NREL)

Dish / Engine Systems

Dish/engine CSP technology uses a reflector in the shape of a parabolic dish to concentrate sunlight. Parabolic dishes rotate about both the azimuth (compass direction) and elevation (height above ground) axes, constantly pointing at the sun as it crosses the sky. The reflected sunlight is directed at a receiver mounted on an arm extending out from the center of the dish (Figure A18). Within the receiver, a heater head collects this solar energy and uses the power to run an engine-driven generator to produce electricity.

Figure A18. 25 kW dish/Stirling engine system made by Tessera Solar. *Photo from NREL*

As a modular technology, dish/engine systems are replicated to the scale required to meet the needs of each project site, potentially satisfying loads from kW to GW. Dish systems can be installed on relatively uneven land, with 5% or more slope, thereby reducing the cost of site preparation for new projects.

Most dish systems use a form of the Stirling engine, although steam systems and air-Brayton turbines have been investigated. Dish/Stirling systems have demonstrated the highest in-the-field, solar-to-electric efficiency (31.4%) of any solar technology. Dish/Stirling systems are air-cooled by closed-loop systems (similar to an automobile engine), which, combined with the lack of a steam cycle, endow them with the lowest water use among all the CSP technologies.

Dish/engine systems do not have a central power block and circulating HTF, so integrating TES must be done at each engine. This modular design eliminates the economy of scale advantage enjoyed by centralized TES systems. Small TES designs using phase-change materials have been proposed for dish/engine systems, but none are in commercial use. Lack of TES means dish/engine systems compete directly with modular PV systems. As PV costs have fallen, dish/engine system have not obtained much commercial success and the two most prominent U.S. developers, Infinia and Tessera Solar, have gone out of business, although Infinia's technology has reemerged under Qnergy.

CSP Power Block

Parabolic trough, linear Fresnel, and power tower CSP technologies rely on steam Rankine power cycles that are essentially the same as those used in coal and nuclear power plants. These power cycles input high quality thermal energy, produce electric power, and discharge low-quality heat. All thermoelectric power systems require cooling. The cooling step in a Rankine power block condenses the low-pressure steam back into water for reuse. The water can then be efficiently pumped back to high pressure and returned to the boiler to produce high-pressure steam. The overall conversion efficiency of thermal energy into electricity directly depends on the temperatures of the heat source (hot) and the heat sink (cold). In modern CSP plants the gross thermal-to-electric efficiency is around 36%-42%, and overall solar-to-electric efficiency is around 22% to 25%.

Cycle efficiency is maximized when the highest possible heat source temperature and the lowest possible heat sink temperature are obtained:

$$Power\ Cycle\ Efficiency \propto 1 - \frac{T_{cold}}{T_{hot}}$$

Because of this relationship, power plant developers seek a cooling system that provides the lowest possible heat sink temperature. In general, the most convenient low-temperature heat sink is provided by water—either directly in the case of once-through cooling with a body of water or indirectly through evaporation. Where water is scarce or expensive, the water-cooled design may not be practical.

While water is the preferred medium for power-cycle cooling, its availability may be limited by policy or cost. Under these conditions, the CSP plant designer can opt for an air-cooled system or, if some water is available, a hybrid design that uses both air and water for cooling. An air-cooled condenser condenses the steam by forcing ambient air over a bundle of finned tubes containing the low-pressure steam. A typical hybrid system includes both an air cooled condenser and a wet-cooled tower operating in parallel and the size of each can be adjusted depending on the design intent. The basic attributes of these designs are summarized in Table A5 (Turchi et al. 2010).

Table A5. Characteristics of Different Cooling Methods

Cooling Type	Advantages	Disadvantages
Wet (cooling tower)	Lowest installed cost Low parasitic electricity consumption Typically provides lowest cooling temperature; gives highest power cycle efficiency	High water consumption Water treatment and waste water (blowdown) disposal required Cooling tower plume in cold weather
Dry (Air cooling)	No water consumption No water treatment required No cooling-tower or blowdown pond Lower O&M costs (excluding fan power)	More expensive equipment Higher parasitic electricity consumption Poorer cooling at high dry-bulb temps (cycle efficiency falls)
Hybrid	Reduced water consumption Potential for lower levelized energy cost compared to dry cooling Maintains good performance during hot weather	Complicated system involving wet and dry cooling; often highest capital cost Same disadvantages of wet system, but to lesser degree

(Source: Turchi et al. 2010).

CSP Thermal Energy Storage

A very important characteristic of CSP technologies is the ability to provide power even when the sun is not shining. This is possible because most CSP systems can incorporate TES. In its simplest form, TES is achieved by storing a CSP plant's hot HTF in a large insulated tank. Such a system is simple and efficient, but overall cost depends on the cost of the HTF.

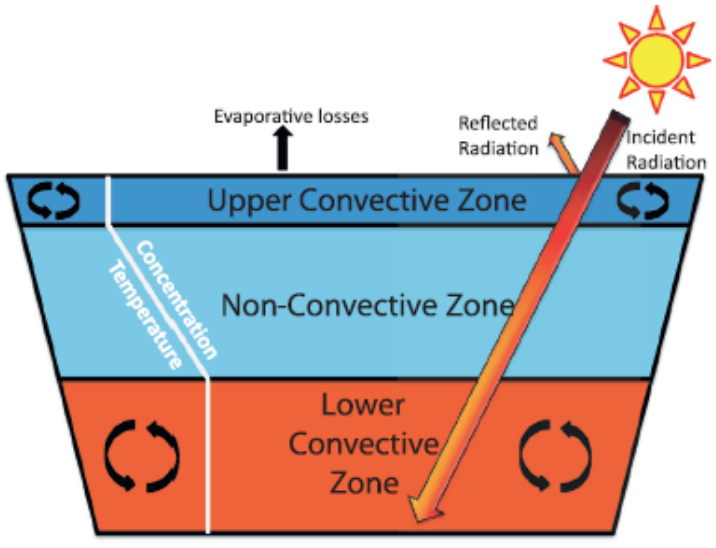
TES provides operating flexibility and enhanced dispatchability that can provide power when needed and makes life easier for electric grid operators. TES allows CSP plants to extend or shift

energy generation to coincide with peak load demands. TES differs from electricity storage (e. g. , batteries) in several key ways. TES is more efficient and better suited to large-scale than batteries, and TES systems cost less and last longer than batteries. However, a TES system only works because a CSP plant produces heat first and then uses that heat to produce electricity. That is, TES only works in association with a CSP plant.

The current commercial TES option for parabolic trough systems uses molten nitrate salt as the storage medium in an indirect, two-tank system. Implementation of this TES system into parabolic trough power plants requires an indirect configuration—different HTF and storage fluids—because the oil HTF is too expensive to store directly and the storage salt has a high freezing point and could possibly freeze in the solar collectors if used as the HTF. Implementation of two-tank TES into molten-salt power towers is accomplished using direct storage of the molten salt HTF. The direct configuration eliminates the need for the heat exchanger required with indirect TES, thereby reducing cost and increasing the performance of the TES system. Roundtrip efficiency of TES in power towers has been estimated at 98% (Pacheco 2002). Direct TES is currently used in the Gemasolar power tower plant in Spain and the Crescent Dunes power tower in the United States.

Solar Ponds

Unlike the active solar collectors of the CSP technologies, a solar pond is a passive solar-thermal collection device that collects and stores thermal energy in a stratified shallow pond (Ranjan and Kaushik 2014). Solar ponds utilize a high-salinity mixture to maintain a density differential between the upper layer of the pond and the lower layer of the pond. In practice, a salt-gradient solar pond is stratified into three primary layers: an upper convective zone (UCZ) which sunlight passes through and may lose heat due to evaporation, a non-convective zone (NCZ) where there is a thermal gradient but ideally no mass transfer, and a hot, lower convective zone (LCZ) where sunlight is absorbed (Figure A19) (Ruskowitz et al. 2014).

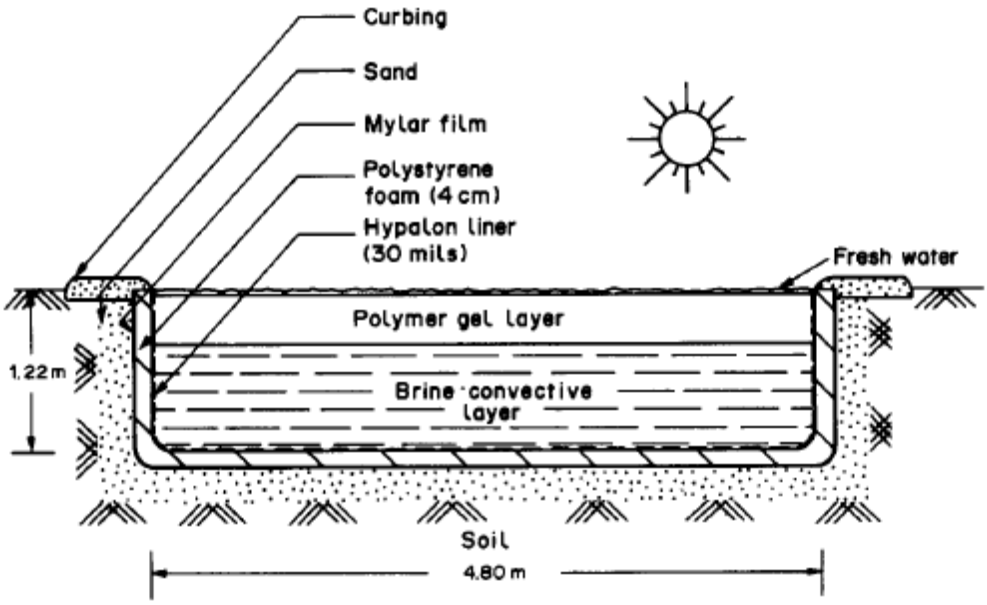


Source: Ruskowitz et al. 2014

Figure A19. Salt-gradient solar pond.

Energy is extracted from the LCZ of the solar pond either by pumping the hot brine out to a heat exchanger or installing heat transfer piping in the pond itself. The former approach has been favored. Hot brine is extracted from one end of the pond via a distribution network and returned at the opposite end of the pond. Salt is a major cost in the creation of a salt-gradient solar pond, so regions that have high-salinity fluids available are preferred. The salt concentration ranges from 20-30 weight percent in the LCZ to near zero at the UCZ. Some make water is usually required to offset evaporative losses.

The solar gel pond (Figure A20) (El-Housayni and Wilkins 1987) is an alternative approach that uses a layer of polymer gel to separate the UCZ and LCZ. The gel layer density is designed to float on the LCZ and clear plastic sheeting can be used to encapsulate the polymer. The impermeable gel layer makes set up and control of the salt pond easier and pond depth can be shallower than in a salt-gradient solar pond. The salinity of the LCZ is about 2-7 weight percent. Advantages of the solar gel pond include: lesser salt requirement, lower evaporation rate, easier pond thermal management, and higher solar-to-thermal efficiency. The primary downside of this approach is a higher capital cost compared to the salt-gradient solar pond due to the cost of the polymer gel. However, reports indicate that the solar gel pond has a lower cost of delivered energy.



Source: El-Housayni and Wilkins 1987

Figure A20. A solar gel pond uses a polymer gel to separate the UCZ and LCZ layers.

The concept of the solar pond had been around for decades, but commercial development has been lacking. Test and prototype systems have been operated in several countries, including the United States (Figure A21). The annual solar-to-thermal efficiency of solar ponds has been reported as 15% to 25% (Ranjan and Kaushik 2014). Wang and co-workers report organic Rankine cycle (ORC) thermal-to-electric efficiencies on the order of 4% to 5.6% operating at conditions that would be compatible with a solar pond (100°C solar output to 25°C condenser) (Wang et al. 2010). Assuming a 5% thermal-to-electric cycle efficiency, a solar pond's annual solar-to-electric conversion efficiency would be on the order of 1%, or ~10-20 times lower than a

PV or CSP power system. To date, this low power conversion efficiency has prevented economic power generation from a solar pond.

Solar ponds are best suited for supplying low-grade thermal energy in moderate latitude regions (±40°) with good sunlight. Temperatures reaching 100°C are possible, but ≈70°C is more typical. Their large thermal capacity offers 24/7 energy delivery. The ponds require large, relatively flat land areas, with a manageable individual pond area of several hectares (~10 acres). Agha estimated the cost of 70°C thermal energy from a solar pond at 1.4 to 2.3 ¢/kWh ($4-$6.7 per one million British Thermal Units (MMBTU)) depending on salt cost (Agha 2009). For comparison, natural gas costs in the United States are currently about at $2.85/MMBTU, but several times higher in much of the rest of the world.[86]

Figure A21. Solar pond test facility at the University of Texas El Paso. *Photo by NREL 08841*

Algal Biofuel Production

The opportunities and challenges of algae are plentiful. This section will describe the basic processes of algal biofuel production while addressing prominent opportunities and challenges which affect the IID.

The Role of Algae and Biofuels

While the most common biomass feedstocks utilized today are terrestrial plants, oil-rich, carbon dioxide (CO2)-utilizing photosynthetic microalgae are technically viable alternatives. Using algal feedstocks to produce fuel, however, will require critical innovation to make it an economically viable option. Estimates for the current commercial production costs of algal biomass are approximately $1,500 per ton. The two primary processes for conversion of algal

[86] US. Energy Information Administration. "Henry Hub Natural Gas Spot Price". 2015. http://www. eia. gov/dnav/ng/hist/rngwhhdM.htm, accessed April 27, 2015.

biomass to liquid transportation fuels will require technological advances in algal cultivation, harvesting and dewatering to reduce the cost to approximately $300 per ton (Davis et al. 2012).

Past Algal Biofuels Research Efforts

The Aquatic Species Program funded by DOE from 1978 to 1996 represents the most comprehensive research effort to date on fuels from algae. DOE invested $22.1 million (nominal dollars) cumulatively over this time frame (Sheehan et al. 1998) to study a variety of aquatic species for use in renewable energy production, including microalgae, macroalgae, and cattails. The Aquatic Species Program demonstrated the feasibility of algal culture as a source of oil through algal strain isolation and characterization, studies of algal physiology and biochemistry, genetic engineering, engineering and process development, coupled with outdoor demonstration scale-up of algal mass culture. Techno-economic analyses and resource assessments were important aspects of the program, and helped prioritize resources toward the most important scientific and technical barriers. The program was discontinued when the optimistic estimates for the cost of algal biofuel production were in the $40 to $60/barrel range, a factor of two or three times higher than the cost of petroleum at that time (less than $20/barrel in 1995). The program highlighted the need to understand and optimize the biological mechanisms of algal lipid accumulation and to find creative, cost-effective solutions for culture and process engineering development to isolate lipids from very dilute biomass suspensions.

DOE returned to the algal biofuels to overcome the limitations on production of biofuels from terrestrial biomass. The Billion Ton Study[87] coauthored by DOE and U.S. Department of Agriculture (USDA) determined that it was feasible to produce approximately 1 billion tons of terrestrial biomass in the United States in a sustainable fashion. Given the theoretical yields for conversion of cellulosic sugars to biofuel of approximately 70 gge per ton of biomass, it was clear that terrestrial biomass could only support the production of 70 billion gge per year, a significant amount, but small in comparison with the 240 billion gallons of petroleum which we consume each year.[88] An analysis of the resources available for cultivation of algae in the United States suggests that an equal amount of fuel could be produced each year from algal biomass (Wigmosta et al. 20011).

In 2008, DOE sponsored an Algal Biofuels Roadmapping workshop that identified the technology hurdles that needed to be overcome for commercial production of algal biofuels. The workshop and report, issued in 2010 set the stage for subsequent funding for R&D by DOE which includes funding for four multi-institutional algae consortia: [89]

- National Alliance for Advanced Biofuels and Bioproducts
- Sustainable Algal Biofuels Consortium
- Consortium for Algal Biofuels Commercialization
- Cornell Consortium.

DOE has also provided support for build out and operation of pilot and demonstration scale production facilities for the algal biofuel companies, Sapphire, Solazyme, and Algenol. In

[87] U.S. DOE 2011- http://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update. pdf
[88] http://www.eia.gov/tools/faqs/faq. cfm?id=23&t=10
[89] Information on all four consortia can be found here: http://energy.gov/sites/prod/files/2014/03/f14/algae_webinar.pdf.

addition, USDA provided a $50 million loan guarantee for the Sapphire demo facility. Since that time, DOE has issued a number of Funding Opportunity Announcements and has also provided non-competed funding for algal biofuel R&D at national labs and academic institutions.

NREL's current estimate for algal biofuel production is approximately $17/gal, based on ALU (algal lipid extraction and upgrading) with ethanol as a co-product based on fermentation of the algal sugars released in the extraction process (Davis et al. 2012).

Incentives for Biofuel

In recognition of the energy security and environmental benefits of renewable liquid fuel production, legislation in the United States has been passed to support implementation.

Renewable Fuels Standard (RFS)

The Energy Independence and Security Act of 2007 (EISA) established the annual renewable fuel volume targets, mandating an overall level of 36 billion gallons of renewable fuel be blended into transportation fuel annually by 2022. To achieve these volumes, the Environmental Protection Agency (EPA) calculates a percentage-based standard for the following year. Based on the standard, each refiner, importer and non-oxygenate blender of gasoline determines the minimum volume of renewable fuel that it must ensure is used in its transportation fuel.

Table A6. EISA 2022 Overall Volumes and Standards

Fuel Type	Volume (Billion Gal.)
Conventional biofuel or starch ethanol	15
Advanced biofuels	21
Cellulosic biofuels	16
Biomass-based diesel	1
Other advanced biofuels	4

Algal biomass can be used as a feedstock for the production of many different biofuels, depending on the conversion process. Algal lipids can be used to produce biodiesel or renewable diesel (diesel alternatives differentiated by their production methods), jet fuel and gasoline. Following lipid extraction, the remaining algal biomass can be converted to sugars and other simple molecules which can be used to produce ethanol and other advanced biofuels. It is generally understood that algal biofuels would fall under the heading of other advanced biofuels.

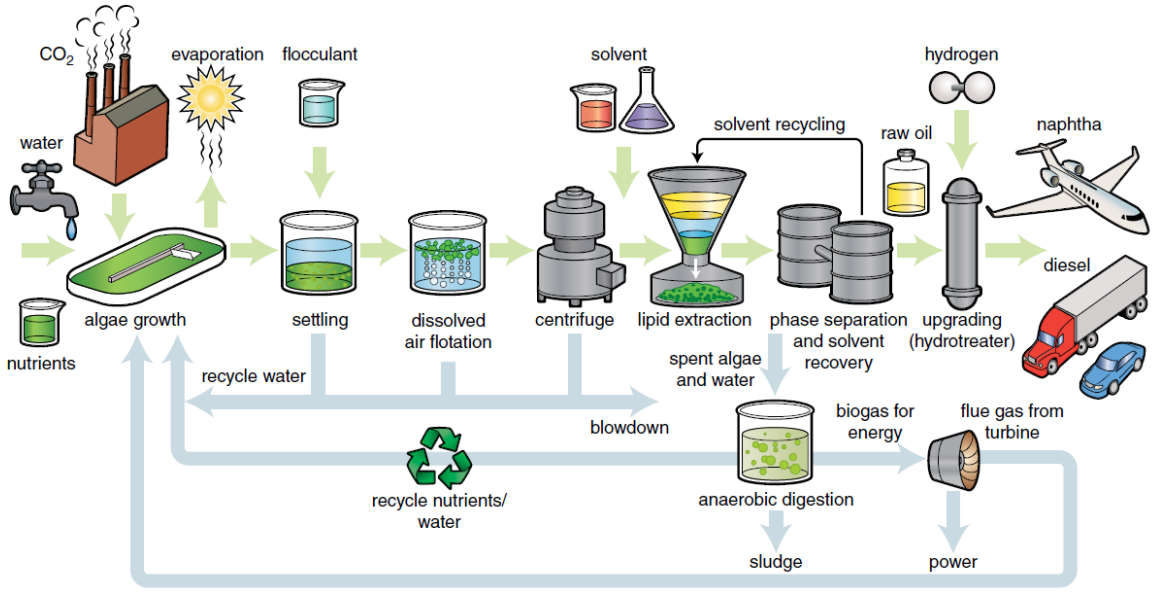
Carbon Pollution Emission Guidelines for Existing Stationary Sources

In June 2014, the EPA proposed rules for mitigation of CO2 emissions from power plants.[90] The proposed rules generally favored carbon capture and storage technologies such as underground sequestration over carbon capture and use technologies of the sort being developed for algal biofuels. The algal biofuels community has made its voice heard regarding these rules to gain more support for their commercialization plans, but the EPA has not yet indicated that it would change its position.

[90] Federal Register 2014, https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

Production Stages

The four main stages of algae-to-biofuel conversion are cultivation of the algae, harvesting of the algae, extracting the lipids and oils from the biomass, and conversion of the lipids or oils into a biofuel. Each of these stages offers a different set of challenges, some of which are mitigated by the resources available at the Salton Sea. A simplified version of an algal biofuels production process is shown in Figure A22.



Source: Pienkos et al. 2011

Figure A22. Algal biofuels production process.

Cultivation Technologies

The production of microalgae for nutritional supplements is presently a small industry worldwide, with approximately 6,000 tons (dry weight organic material) being produced autotrophically (with sunlight and CO2).[91] For comparison, a typical corn farmer produces about 10,000 tons of corn on 2,000 acres of crop land. However, the value of the microalgae crop to a food processer is about $10,000/ton (for specialty human food supplement markets) compared with $100/ton for the equivalent corn crop. The quality standards for algal cultivation for biofuel production are much lower than for food supplement production and thus the estimated cost for production is much lower as well (approximately $1000/ton). It has been calculated that algal biofuel production could be economically viable if the cost of biomass production could be lowered to approximately $300/ton. This will require improvements in the algal biology itself to achieve higher growth rates as well as reductions in the capital costs for the production system and operating costs for the harvest system.

A summary of the characteristics of the main cultivation systems is outlined in Table A7.

[91] http://www1.eere.energy.gov/bioenergy/pdfs/algal_biofuels_roadmap.pdf

Table A7. Summary of Algae Cultivation Characteristics (NREL)

	Large open, unmixed ponds	Open raceway, shallow mixed ponds	Closed Photobioreactors	Benthic Growth Production Systems
Operating Temperature	ambient	5-30°C	5-40°C	ambient
Animal feed		✓	✓	depends on water source
Wastewater treatment	✓	✓		✓
Biofuel production		✓	✓	✓
Fertilizer		✓	✓	✓
Cost/Ton	not applicable	moderate	high	low
Water use	♦ to none	♦♦♦	♦♦	♦ to none
Land Use (ton biomass/acre)	not applicable	10-100	10-100	10-100
Maximum Land Slope	<5%	<3%	<3%	not applicable
Commercial maturity*	Commercial	TRL 7	TRL 5-6	TRL 5-6

*It must be noted that the TRL of the systems designed to produce biomass is low, and therefore the information in the table is a rough approximation.

There are five basic technologies currently used for microalgae production. The first four systems utilize sunlight, water, CO2, nitrogen and phosphorous to establish favorable environments for algae to grow. The rate of photosynthesis and growth of the algae depends in part on the balance of nutrients. The fifth technology utilizes growth on sugars or other organic compounds in the dark (heterotrophic growth), and appears to have limited benefits for fuel applications. Each technology has a different approach for establishing and maintaining this optimum growth environment.

Four basic algae harvesting technologies:

- Large open, unmixed ponds, for wastewater treatment and desalinized production. Wastewater treatment ponds, "oxidation ponds," are not true algae production ponds, as no algal biomass is harvested (Figure A23). A few wastewater treatment ponds are of a "high rate ponds" design, discussed below. *Dunaliella salina* production in Australia uses very large saline evaporation ponds (>100 acres each). The algae dominate naturally in >100 g/L of salt and are produced at very low productivities (perhaps not much more than 1 ton/acre/yr). The algae are harvested by adsorption of polymers and their oil, which is very high in beta carotene, is extracted and sold commercially. The algal biomass has a value of >$50/kg, based on the beta carotene content.[92]

[92] http://www1.eere.energy.gov/bioenergy/pdfs/algal_biofuels_roadmap.pdf

Figure A23. Typical oxidation pond. [93]

- Open, raceway, shallow, mixed ponds, 15 to 35 cm deep are typically mixed with paddlewheels, lined with plastic or cement (if necessary), and between 1/2 and 3/4 acres in total area. These are called high-rate ponds because their productivity is much higher (by approximately a factor of ten) than the unmixed ponds. The high-rate ponds are the main system currently used for the production of Spirulina (*Arthrospira platensis*) production world-wide, and also for commercial *D. salina, Chlorella vulgaris*, and *Haematococcus pluvialis* (for astaxanthin) production (Figure A24). Circular mixed ponds are still used in *Chlorella* production systems in the Far East, but are slowly being displaced by raceway-type designs. Estimated averages for the bulk selling prices are about $10/kg for Spirulina, $20/kg for *Chlorella* and $100/kg for *Haematococcus* (with Chinese production costs lower than other countries).[94] Open ponds are the cultivation method of choice for four leading algae companies, Earthrise, Heliae, Sapphire, and Cellana. Until recently, only Sapphire was absolutely focused on biofuels, but changes within that organization indicate that it, too, has begun to focus on nearer term revenue generation with higher value products.

Figure A24. Spirulina production in open raceway ponds. *Photo from NREL*

- Closed photobioreactors, used in commercial operations have tubular reactors—either small diameter (approximately 5 cm) or larger diameter (>10 cm), the latter generally being of a thin, non-rigid plastic bag type. Many other designs have been used, including

[93] Figure 2.5: Oxidation pond for wastewater treatment (~100 ha, Napa, California). http://decarboni. se/publications/realistic-technology-and-engineering-assessment-algae-biofuel-production/21-current-and-potential-uses-microalgae-biomass

[94] http://www.biofuelsdigest. com/bdigest/2015/02/11/sapphire-energy-biofuels-digests-2015-5-minute-guide/).

flat plate reactors, hanging bag reactors, hemispherical dome reactors, etc. These closed photobioreactors are used to cultivate *H. pluvialis* commercially in Israel and in Hawaii and *C. vulgaris* in Germany, with typical prices well above $100/kg, but hanging bag photobioreactors are now being deployed by Algenol for conversion of CO2 to ethanol along with fuel coproducts generated through processing of the biomass. Photobioreactors with radically different configurations are being developed by Solix and BioProcess Algae.

Figure A25. Samples being drawn from a tubular bag photobioreactor. *Photo from NREL*

- Benthic growth production systems are being developed often to cultivate and harvest algae grown in polyculture mode rather than in uniculture mode with specific production strains. These processes make use of a solid support that provides a substrate for algal cell attachment. These supports may be placed in bodies of water or waste water ponds to take advantage of natural mixing and nutrient supply. They are designed to provide a growth support for the indigenous algal population which could include several different species as well as bacteria and other microorganisms. With a mixed population of natural organisms, it is thought that robust growth could be obtained, at a price of control over biomass quality. The solid support can be removed from the water and the algal biomass removed by scraping, resulting in biomass that has been dewatered without the expensive harvest/dewatering processes needed for growth of free-floating (planktonic) algae. The most well known system for benthic growth is known as the TurfScrubber, though the BioProcess Algae photobioreactor involves benthic growth under a plastic tent to provide an atmosphere enriched in CO2. Proterro is commercializing a novel benthic growth mode photobioreactor to produce sucrose with minimal water usage.

Figure A26. Algal Turf Scrubber® S-154 pilot plant in Central Florida.[95]

- Heterotrophic production of microalgae takes place in conventional fermentation tanks using sugars and O2. Although heterotrophic growth has been promoted as a means to produce biofuels, the primary practitioner of this approach, Solazyme, has focused its business plan on higher value products such as nutraceuticals, cosmaceuticals and food products. Others, including DSM have commercialized heterotrophic algal growth for production of omega-3 fatty acids such as docosahexaenoic acid and eicosopentenoic acid. For the sake of this study, heterotrophic growth will not be considered.

Cultivation Challenges

There remain significant challenges to each of the cultivation methods which have a direct cost impact on algal biofuel production.

Sustained Algae Cultivation in Open Ponds

The current technology for mass culture of microalgae is still in its infancy. Only a few strains are currently mass cultured on a large-scale (>1 hectare) and sustained, year-long basis (even if not produced year round). Some experience, in particular from the DOE Aquatic Species Program, suggests that it will be possible to isolate, from suitable natural environments, and screen (with an appropriate protocol) additional strains for mass culture.

The envisioned technology for algal biomass production is based on the production of sufficient inoculum to get an algal culture (re)started whenever required. If re-starts are required too often, the inoculum production effort quickly becomes a major cost, as is the case for commercial Chlorella production, and certainly will be too costly for biofuel production. The ability to reinoculate and resume production within a matter of days is, however, a distinct advantage over terrestrial crops in which a crop loss costs the entire growing cycle (typically a year).

The techniques required to establish a mass culture must first minimize both culture contaminants and algae grazers (rotifers, amoeba, and others) that can cause production ponds to crash. Over an extended period, even a relatively modest advantage in growth rate would allow a

[95] http://www.hydromentia.com/Products-Services/Algal-Turf-Scrubber/Product-Documentation/Assets/ATS-Technical-Brochure.pdf

minor contaminant to dominate the culture. Thus, it is imperative that the competitive advantage of any contaminants be reduced. In commercial algae mass culture (aside from Spirulina or Dunaliella, which use selective culture medium) this is achieved by mostly proprietary techniques, but includes limiting nutrient supplies to reduce the ability of the contaminants to grow. Rotifers and other grazers require different approaches, including occasional excursions in pond environmental conditions inimical to these animals. Even if weeds and grazers are successfully combated, there remain the viruses and other "diseases" (lytic bacteria, fungal infections, and others) to which algal cultures will be prone, and about which almost nothing is known. The situation may be compared to early agriculture, only at a microscopic scale and at a very fast tempo. Therefore, the rapid rates at which algal growth, contamination, grazing, infection, and recovery can unfold in a mass culture is a real advantage of these systems; and allows the study of these phenomena in weeks and months, instead of years and decades as with higher crops, as well as allow recovery of the affected cultures in days.

Algae Cultivation in Closed Bioreactors

Productivities in photobioreactors are limited by solar input, and growth technology cannot alter this limit. Many reports of improved areal productivity refer to the area of the growth vessel for the photobioreactor itself, and these numbers can be extremely high when the reactors are configured vertically. However, vertical photobioreactors must be situated far enough from each other so as to not shade each other. Thus, the basic limitation on areal productivity remains the same for both open ponds and closed photobioreactors.

Surface fouling due to bacteria, other organisms, and, in particular, algae, is one of the major problems encountered with closed photobioreactors. Cleaning the photobioreactors often becomes a major design and operational challenge. Another photobioreactor process issue is the inherent limitation in gas transfer through the closed system boundary. Both CO2 input and O2 evolution must be optimized for maximum productivity, and the lack of ability to be exchanged through the walls of can result in suboptimum concentrations of these gases in the photobioreactor.

Algal Harvesting

The potential oil yields (gal/acre) for algae are significantly higher than yields of oil seed crops (20 times higher than soybeans). Therefore, less algal biomass is required to produce biodiesel than from other biomass options. Low cost algal harvesting options do not currently exist, but this is an area of significant interest and effort for the private sector and for public-private partnerships such as the major consortium established by DOE, National Alliance for Advanced Biofuels, and Bio-Products.

Harvesting of algal biomass can be accomplished several ways. Attempts in the past have taken advantage of spontaneous settling of the algal cells, without using chemical flocculants. Other mechanisms include the auto flocculation process which depends on the co-precipitation of algal cells with calcium carbonate and other precipitates that form in hard waters subject to high pH. Aside from settling, in some cases the algal biomass will float, either due to buoyancy (e.g., high oil content) or by using a dissolved air floatation process, as is widely used in chemical flocculation. The use of small amounts of chemical flocculants (polymers) to aid in such a process could be cost effective, depending on the amount used. Nevertheless, a significant engineering research effort aimed at developing cost-effective algal harvesting techniques will be

required. In order to reduce cost and energy inputs, a three-stage harvesting process (flocculation, dissolved air floatation, and centrifugation) has been proposed by NREL (Davis et al. 2012).

Conversion of Algal Biomass to Biofuels

Interest in algal biomass as a biofuels feedstock has traditionally arisen from the high lipid content in algal cells that are grown under specific conditions (typically nitrogen starvation conditions). The differences between microscopic algal cells and seeds of oil-bearing terrestrial plants demand that different processes be employed for oil recovery. The most likely technology for algal oil recovery, currently in development, involves some form of solvent extraction (though other methods such as mechanical or electrochemical extraction have been proposed). Any process option is likely to be complicated, however, by the high water content of algal biomass. NREL has developed a wet processing of microalgae utilizing low pH, high temperature cell disruption. This process also causes hydrolysis of the algal carbohydrates and precipitation of the proteins. Fractionation of the components into lipid, carbohydrate, and proteins streams can be used for production of valuable coproducts to help drive the overall economics. Once the algal oil is recovered and suitably upgraded, the conversion processes to biodiesel or green diesel are fairly well understood.

Complications may still arise from differences in overall lipid content (i.e., relative levels of triacylglycerols, phospholipids, and glycolipids) that will occur with changes in algal populations and climatic variations. The high inorganic content of algal biomass implies that there will be a cost to supply nutrients, but the apparently high nutrient levels in Salton Sea water (indicated by natural algal blooms) will reduce the need for commercial nutrients. In addition, the potential to convert the unvalorized components of algal biomass to methane via anaerobic digestion will result in the production of nutrient-rich sludge which can be recycled to the algae ponds.

A fairly recent development in algal processing relies on thermochemical processing of wet algal biomass in a process called hydrothermal liquefaction. This process converts all of the algal biomass into “green crude” which can be catalytically converted to fuels. This process is being developed by Sapphire and by Algenol in conjunction with the Pacific Northwest National Laboratory to supply oil refiners with green crude that can be blended with petrocrude for upgrading into transportation fuels and other refinery products.

Commercialization Potential

The technical challenges discussed represent significant obstacles to the development of economically viable biofuels from algae and until a large-scale system has actually been built and demonstrated, many uncertainties remain. Issues such as pond construction materials, mixing, optimal pond scale, and CO2 delivery have been considered and even in some cases explored, but definitive answers await detailed and expensive scale-up evaluation. The availability of resources at the Salton Sea under consideration, make it an ideal location to develop such a demonstration facility.

Existing Algae Cultivation Technologies in the Salton Sea

Synthetic Genomics (SGI) is an algae company with a small (40 acre) research and production facility located 1 mile from the southern tip of the Salton Sea. They are developing processes for

the production of food and nutritional supplements. The value of protein for nutritional purposes is 3-4 times higher than the value of biofuels and so the path to commercialization can be shorter. SGI anticipates that a commodity product like fuels would require an algae farm of >1000 acres with unit ponds in the 5 to 10 acre range. They intend to scale up to a facility of several hundred acres to produce higher value products. They are taking advantage of the high salt concentration in Salton Sea water to grow marine and hypersaline strains of algae, though they noted that algal growth rates tend to decline with higher salt concentrations so productivity can be a problem. Even so, marine strains tend to be more robust than freshwater strains and less prone to pond crashes due to predators or pathogens. They are just as prone to competition with indigenous algal strains which can act as weeds and take over cultivation systems. Small scale production facilities will devote as much as 30% of the facility area for non-production operations (building, roads, etc.), but this percentage would drop to about 15% for larger scale production.

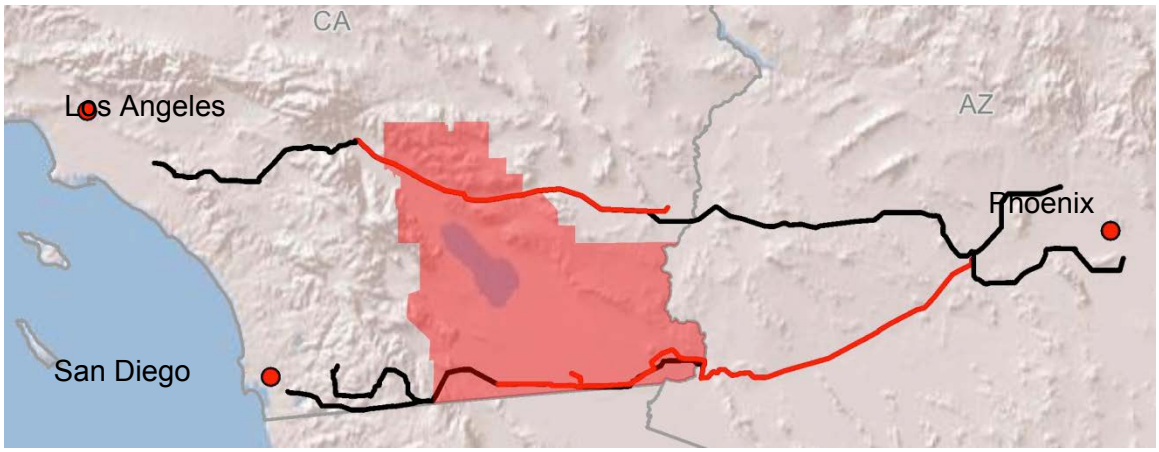
Appendix B: Energy Market Analysis

Market fundamentals will ultimately determine whether new renewable energy projects near the Salton Sea are economically competitive—and if so, whether they are competitive enough to bear the additional load of a Salton Sea restoration tax. This chapter examines the economic competitiveness of Salton Sea renewables in their most likely target markets, California, and Arizona.

The two markets are defined by the magnitude and coherence of their electricity demand, and by the transmission links from the IID balancing authority area. The map in Figure B1 shows the IID BA area and the connecting extra-high voltage (EHV) transmission paths. Historically, almost all of the power on this path across the Colorado River has flowed east to west, consisting mostly of power from the Palo Verde Nuclear Generating Station west of Phoenix supplying urban centers in Southern California.[96]

Nevertheless, the path has begun to accommodate counterflow in the opposite direction, including power from Salton Sea geothermal resources serving utility customers in Arizona. Both SRP and APS have PPAs with geothermal plants in the Salton Sea area.[97] The large potential for additional counterflow to the east means that in some cases, access to Arizona could be easier than access to the rest of California.

[96] Western Electricity Coordinating Council (WECC), Annual Path Data (spreadsheets), various years through 2012, https://www.wecc.biz/Reliability/2012 Path Data. xlsx.
[97] Salt River Project, "SRP taps into super-hot renewable energy resource" (press release), Sept. 17, 2013; Arizona Public Service, Renewable Energy Portfolio (fact sheet), January 2013, https://www.aps.com/en/Documents/pdf /company/RenewableEnergyPort.pdf.



Lines indicate 500 kV transmission to and from IID balancing authority area; red lines indicates planned upgrades.

Figure B1: Imperial Irrigation District with EHV transmission paths.[98]

With respect to market prices, southern California tends to be more lucrative than Arizona. From 2012 to 2014, wholesale power prices in southern California were 24% higher than prices at the Palo Verde hub near Phoenix. The data was compiled by *SNL Energy* for day-ahead trades of energy for on-peak delivery. Annual average trading hub prices:

	Palo Verde	SP15 (S. Cal.)
2014	$42.42	$52.20
2013	$37.66	$49.03
2012	$29.68	$35.30

The analysis detailed below supports the following overall conclusions about the market for Salton Sea renewables.

- Both California and Arizona are likely to see higher demand for renewable resources by 2020 and beyond.
- Salton Sea renewables face different tradeoffs competing in the two markets. While high power prices make the California market more lucrative, there are many choices for new renewable development, even for baseload renewables such as geothermal. In Arizona, however, there are few practical alternatives to Salton Sea geothermal for renewable baseload. Power prices tend to be lower in Arizona than in California, so Salton Sea geothermal will likely continue to be an above-cost resource for a longer period.
- Salton Sea renewables have no discernible headroom for bearing an additional cost earmarked for Salton Sea reclamation. In California, for example, adding $5/MWh on top of the cost new Salton Sea geothermal projects could result in an additional 2% to 3% of the supply pool being economically superior. Although there is not currently sufficient economic headroom for a power production tax, policies favorable to renewable energy (streamlined permitting, increased RPS targets) could create a unique benefit to development within the region that might offset the additional tax.

[98] Western Electricity Coordinating Council (WECC), Annual Path Data (spreadsheets), various years through 2012, https://www.wecc.biz/Reliability/2012 Path Data. xlsx.

This analysis begins with the supply side of the equation, focusing the cost of Salton Sea geothermal and solar resources relative to the cost of competing resources built elsewhere. It projects current technology costs into the near future, drawing on most recent information to estimate technology cost trajectories.

Examining the demand side begins with RPS policies in California and Arizona, including the recently-passed 50% RPS law, which was passed as of the publication of this report. The analysis takes account of existing development and new procurements identified in utility integrated resource plans (IRPs) to estimate the likely residual demand for additional renewables related to RPS requirements. Beyond 2030, there is a potential for greater demand for renewable energy demand driven by California policy, such as the executive order for 80% GHG reductions below 1990 levels by 2050, as well as California AB-32.

The analysis then examines transmission and other infrastructure issues that could affect the ability of Salton Sea renewables to reach potential markets. It reviews current transmission plans by CAISO and utilities, identifies transmission development obstacles, and analyses transmission capacity that would be required to export Salton Sea renewables to various markets.

All supply options for both markets are assumed to be on an even regulatory footing—i.e., there is no special mandate on any utility to procure Salton Sea renewables as opposed to generically sourced renewables.

Supply Trends

We construct the supply picture as follows.

- Identify the renewable resources most likely to compete in large volumes for the two markets
- Establish plausible benchmark points for comparing the cost of various renewable energy options
- Compare the competitiveness of the Salton Sea area's prevalent renewable options—geothermal and solar—against the same technologies from different geographic areas
- Project current renewable technology costs forward under a plausible range of assumptions, and assess how each technology tends to perform against the combined cycle natural gas (CCNG) benchmark
- Examine the competitive "headroom" of Salton Sea renewables (where "headroom" refers to the margin between the untaxed cost of Salton Sea renewables and the price point at which the resource would become uncompetitive).

This analysis necessarily deals with costs projected out to 2030, which, due to the rapid pace of cost and technology innovations in the renewable energy industry, are highly uncertain. To account for the uncertainty inherent in such projections for solar technologies, wind technologies, and natural gas, this analysis characterizes future cost as a plausible range, and not as a single value. This could lead to analytical outcomes that appear ambiguous, but only because they pragmatically reflect uncertainty about future costs.

This analysis relies on two tools for examining supply: NREL's Annual Technology Baseline and Standard Scenarios[99], an ongoing project to provide annual updates for technology cost and performance based on current market intelligence by NREL and the DOE; as well as the calculator developed by CPUC to evaluate resource portfolios for compliance with the state's RPS.

The Annual Technology Baseline provides annual updates for technology cost and performance based on current market intelligence by NREL and the DOE.[100] It also uses the most current analyses to track cost trajectories into the future.

The RPS Calculator includes estimates of undeveloped renewable energy potential based on a number of detailed resource assessments that screened resources based on various land use and performance criteria.[101] In this analysis, the RPS Calculator is used primarily to evaluate the competitiveness of Salton Sea renewables relative to other yet-undeveloped renewable energy options likely to be available for future demand in California. This part of the analysis combines a technology's cost with the value it brings to the market: the value of energy it would replace and the value of its contribution to system reliability. Conclusions about the relative competitiveness of Salton Sea renewables are based on where they fall on the value-ordered supply curve. The farther up a resource is, the more vulnerable it is to being dominated economically by other resource options.

For purposes of this analysis, the RPS Calculator's Imperial renewable energy zone is geographically equivalent to the Salton Sea study area and the IID balancing authority area. Geothermal and solar are the largest-volume renewable resources in Imperial zone, and these are assumed to be the primary resources from the Salton Sea area that would compete in the Arizona and California markets.[102]

Resources Competing for California

The California market for renewable power is large and has a diverse set of resource options. Table B1 shows the undeveloped and potential new resources included in the RPS Calculator, expressed as GWh of energy per year.

Most of California's undeveloped geothermal potential is in the Imperial zone. Apart from these resources, the largest amounts of new geothermal potential in the RPS Calculator is located elsewhere in California or in Nevada.

[99] NREL, Annual Technology Baseline and Standard Scenarios (web page, http://www.nrel.gov/analysis/ data_tech_baseline.html).
[100] NREL, Annual Technology Baseline and Standard Scenarios (web page, http://www.nrel.gov/analysis/ data_tech_baseline.html).
[101] California Public Utility Commission, RPS Proceeding Materials version 6.0+ (web page, http://www.cpuc.ca.gov/PUC/energy/Renewables/RPS+Proceeding+Materials+Version+6.htm
[102] About 10% of the renewable resources already developed in the Salton Sea area actually interconnected directly with CAISO rather than IID. For the demand and supply sections of this analysis, "Salton Sea area," "Imperial zone," and "IID" are geographic references that do not distinguish between interconnection with IID and with CAISO.

Table B1: Undeveloped Potential Resources in the RPS Calculator (GWh per year)

	All available	Imperial Zone
Large Solar PV (fixed tilt)*	404,016	22,244
Wind	212,277	1,008
Geothermal	39,294	10,681
Distributed Solar PV	30,705	
Biomass	29,834	290
Hydro	24,515	
Biogas	1,085	

*For the purposes of this table, we use fixed-tilt photovoltaics (PV) as indicative of all utility-scale solar potential, with the understanding that a specific site could be developed with tracking PV or thermal concentrating solar power (CSP).
(Source: CPUC RPS Calculator)

Southern California, Arizona, and southern Nevada have solar photovoltaic (PV) resources capable of producing with high capacity factors. The RPS Calculator places about 69% of the potential new capacity in California, with the most of remainder divided between Arizona (12%) and Nevada (11%). As a general rule, CSP can be a viable alternative for the flattest areas with good solar potential.

Wind accounts for 29% of potential new resources, with most of it spread among California, Wyoming, New Mexico and British Columbia. The resources in Wyoming and New Mexico indicate higher capacity factors than California's remaining undeveloped wind resources, and thus could be competitive even after taking into account long-distance transmission costs (Corbus et al. 2014).

Based on the volume of undeveloped potential, Salton Sea resources' most likely competitors in the California market include:

- For baseload renewable power production: geothermal resources from Nevada and elsewhere in California.
- For variable generation:
    - utility-scale PV from Nevada, Arizona, and elsewhere in California
    - wind from Wyoming.

Resources Competing for Arizona

Solar is Arizona's most prevalent indigenous renewable resource. After screening out areas that are environmentally sensitive or difficult to develop, the state has estimated 47,000 GWh/year of solar potential, all with very high capacity factors and relatively low cost per MWh of energy generated.

Wind is also a part of the Arizona renewables market, but its characteristics could change significantly with transmission expansion from New Mexico. The state has some wind potential in the north central and northwest part of the state. New Mexico's wind potential is larger, however, and has some of the highest capacity factors in the West. Two of Arizona's major

utilities—Salt River Project and Tucson Electric Power—are partners in a major transmission project that would enable delivery of up to 3,000 MW of New Mexico wind power to Phoenix and other markets in the state.[103]

Salton Sea geothermal projects may also be competitive in Arizona as baseload renewable power, however, as SRP in Arizona is a current buyer of geothermal power from the Salton Sea's 50 MW Hudson Ranch plant. For this analysis, the large-volume resources assumed most likely to compete with Salton Sea renewables in the Arizona market are in-state solar and wind power, and New Mexico wind power.

Benchmarking Costs

To understand how Salton Sea renewables might fare in the open market against competing supplies, we construct a cost benchmark using a hypothetical combined cycle natural gas generator (CCNG) built in California sometime between 2015 and 2030, operated as a baseload resource. Comparing renewable energy cost trends against this benchmark provides one indicator of the technology's economic strength. It also provides a market context for comparing two renewable options. For example, one renewable project's cost advantage over another might diminish in importance if both projects are substantially above the benchmark.

Figure B2 shows the CCNG cost benchmark used in this analysis. It is based on the following assumptions:

- The overnight capital cost of a newly built CCNG is $1,200/kW. We add $55/kW to this amount for dry-cooled configurations. This adder accommodates compliance with rules governing the use of once-through cooling, and it internalizes future operational risks due to the possibility of extended drought that could limit the availability of water for cooling.
- The CCNG is operated as a baseload plant, with a capacity factor of 85%.
- Greenhouse gas mitigation costs accelerate from a 2012 level of $10/metric ton at an inflation-adjusted rate of 5% per year.
- Natural gas supply costs are variable. Future changes in gas costs could result in combined cycle generation costs well outside the stated assumptions.

[103] U.S. Bureau of Land Management, Record of Decision for the SunZia Southwest Transmission Project, January 2015 (http://www.blm.gov/nm/st/en/prog/more/lands_realty/sunzia_southwest_transmission.html).

Source: All-in costs estimated by NREL. Upper and lower bounds are based on the forecasted price of natural gas under two scenarios used by EIA in its 2014 Annual Energy Outlook. The high price scenario assumes lower natural gas supply—specifically, that the ultimate recovery per shale gas, tight gas, and tight oil well is 50% lower than in EIA's reference case. The low price scenario assumes higher natural gas supply—specifically, that the ultimate recovery per shale gas, tight gas, and tight oil well is 50% higher and well spacing is 50% lower (or the number of wells left to be drilled is 100% higher) than in EIA's reference case. We assume a CCNG capital cost of $1,200/kW, plus an adder of $55/kW for dry cooling. Variable costs include a greenhouse gas offset adder of $10/metric ton, escalating from 2012 at a real annual rate of 5%.

Figure B2: Cost benchmark based on new cycle natural gas generator.

The potential variation in a CCNG's levelized cost of energy (LCOE) is captured in the potential variation in the price of natural gas. This benchmark uses forecasts by the Energy Information Administration (EIA) to represent scenarios for high gas prices and low gas prices. The high price scenario assumes lower natural gas supply—specifically, that the ultimate recovery per shale gas, tight gas, and tight oil well is 50% lower than in EIA's reference case for its 2014 Annual Energy Outlook. The low price scenario assumes higher natural gas supply—specifically, that the ultimate recovery per shale gas, tight gas, and tight oil well is 50% higher and that well spacing is 50% lower (that is, the number of wells left to be drilled is 100% higher) than in EIA's reference case.

Using these assumptions, the plausible cost range for a new CCNG built in 2015 is $72/MWh to $86/MWh (in constant 2015 dollars). This band increases to a plausible range of $81/MWh to $119/MWh in 2030. The implication is that renewable technologies with future costs falling within this band have the best chance of being economically competitive with a newly built CCNG plant.

Current Costs

Table B2 shows the current technology costs assumed for this analysis. They begin with costs developed for NREL's Annual Technology Baseline (v6.0). Because this analysis focuses on a specific geography, base costs are adjusted using state multipliers developed for the Western Electricity Coordinating Council.[104] These multipliers account for general differences in labor

[104] Energy and Environmental Economics, Capital Cost Review of Power Generation Technologies (final report and recommendations approved by WECC), March 2014, Table 33 (https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf).

costs, taxes, right-of-way values, and other factors that affect project costs. This estimate follows the methodology used by NREL to estimate transmission costs for Wyoming wind power:

$$\frac{AR}{MW \times CF \times 8{,}760 \times (1 - loss)}$$

where *AR* is the annual revenue requirement for the transmission project (dollars), *MW* is the transmission project's total transfer capability (megawatts), *CF* is the generator's annual capacity factor (%), and *loss* is the transmission project's line loss factor (%). Total transmission development costs are assumed to be 145% of capital costs, annualized at 7.7% over 50 years. Assumed capital cost for a 500 kV line from Wyoming to a CAISO interconnection is $3 billion; assumed capital cost for a 500 kV line from New Mexico to Arizona is $2 billion.

Of note, however, is that both these options depend on EHV transmission projects that are still in the permitting phase and do not yet exist.

Table B2. Renewable Technology Cost Assumptions (2015 dollars)

		Capital Cost[a] ($/kW)	Fixed O&M[a] ($/kW-yr)	LCOE ($/MWh)
Geothermal (flash)	in California	$7,088	$368	$128
	in Nevada	$6,487	$337	$117
Geothermal (binary)	in California	$7,442	$236	$134
	in Nevada	$6,811	$216	$122
Solar PV[b] (1-axis tracking)	in California	$3,670	$25	$127
	in Nevada	$3,359	$22	$116
	in Arizona	$2,986	$21	$103
Solar thermal (CSP) (12 hours storage)	in California	$10,168	$89	$217
	in Nevada	$9,306	$82	$198
	in Arizona	$8,272	$73	$176
Wind	in California	$2,091	$60	$97
	in Wyoming	$1,481	$46	$76[c]
	in New Mexico	$1,563	$48	$74[d]

[a]Base costs are from NREL's 2015 Annual Technology Baseline, v6.0, with the following WECC regional adjustment multipliers cited in footnote 11:

California:	1.18
Arizona:	0.96
New Mexico:	0.95
Nevada:	1.08
Wyoming:	0.90

[b]Solar PV costs are per kW_{AC}, assuming DC-to-AC inverter loading multiplier of 1.3.
[c]Includes long-distance EHV transmission cost of $29/MWh, assuming delivery to California.
[d]Includes long-distance EHV transmission cost of $22/MWh, assuming delivery to Arizona.

For geothermal and solar PV, the LCOE tends to be lower if the projects are sited in Nevada rather than California, which economically disadvantages Salton Sea renewables. We estimate

that Nevada geothermal and solar resources could have a 9% cost advantage over the same technologies built near the Salton Sea.

Apart from wind power from Wyoming and New Mexico, the resource with the lowest levelized cost is solar PV in Arizona. High productivity and lower project costs tend to give Arizona solar PV a 19% cost advantage over Salton Sea renewables, making it economically stronger in its home market. It is still currently more expensive than the CCNG benchmark, but as described in the next section, this could change within a few years.

Cost Trajectories for Major Renewable Energy Technologies

Tracking cost trajectories helps to understand how the technology's market competitiveness could change over time, relative to the CCNG cost benchmarks. The technology's all-in costs are measured by its LCOE at five-year increments based on trends in capital costs and fixed operation and maintenance (O&M) costs. These costs trajectories do not include geographic adjustments, because the purpose of this part of the analysis is to reflect changes over time, such as technology or cost innovations that are assumed to have an equivalent effect on new projects regardless of where they might be built. For solar technologies, the trajectories shown in the figures below are likely to play out similarly for any geography along the same latitude, due to similar insolation across the southwest. Further, it is likely that the current between-state differences, such as the cost of labor, will hold as these technology trajectories change over time.

Federal tax incentives are calculated as part of the LCOE only according to their provisions under current law. Otherwise, LCOE estimates for future years do not include the effect of the investment tax credit or the production tax credit.

Figures B3 through B5 illustrate the cost trends affecting Salton Sea renewables and their competing resources, benchmarked against natural gas. For each technology, LCOE is based on a 20-year cost recovery, 50% debt and 50% equity, and a weighted average capital cost of 8.9%.

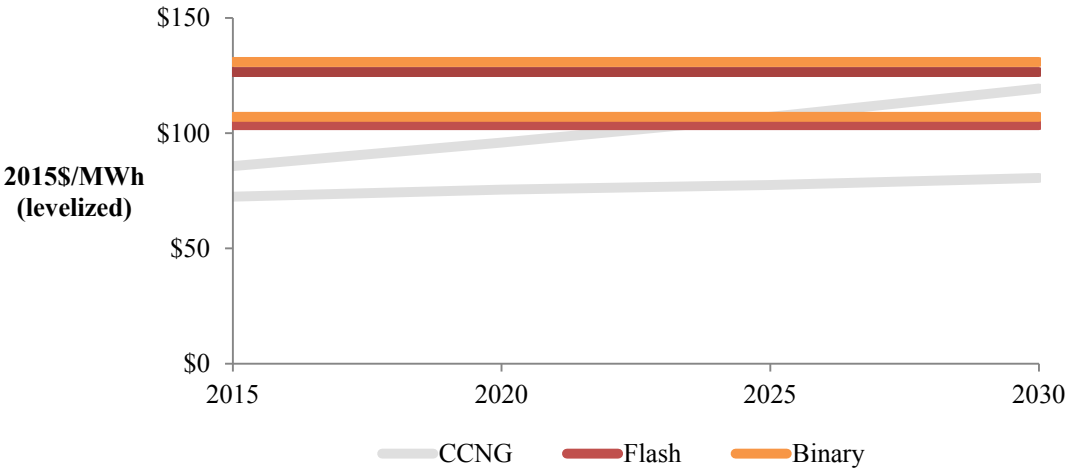
Geothermal development costs vary spatially based on site-specific conditions, and the differences can be significant. Figure B3 therefore depicts geothermal technology costs as a ±10% variation from the generic values used in the Annual Technology Baseline This captures a significant portion of the locational cost variation seen in today's geothermal market. Salton Sea geothermal tends to be in the higher part of this range due to the fact that the water from the underground heat reservoirs is briny, thus requiring more corrosion-resistant materials.

Geothermal costs overall are not expected to change significantly. Consequently, its projected time of economic opportunity is largely a function of how quickly the CCNG benchmark rises. These trends suggest a crossover point beginning around 2025 for the least-cost geothermal projects, expanding to the rest of the industry around 2030. However, the true cost of baseload geothermal, as compared to intermittent solar and its needed redundant backup, is still unresolved. The additional value of this baseload geothermal capacity to energy grids may make this technology more competitive over time, despite currently projected higher costs.

In contrast with geothermal, costs for new utility-scale solar development have been falling so rapidly that the uncertainty concerns the pace at which the reductions will continue into the

future. Thus the gaps between low and high cost projections shown in Figure B4 are relatively small today but tend to increase over time.

Utility-scale solar PV appears to be trending toward a period of increasing economic opportunity in California and the Southwest around 2020 if not sooner. Concentrating solar power (CSP) is starting at a much higher cost point, and is more likely to encounter its period of economic opportunity much later.



High and low projections are based on NREL Annual Technology Baseline, ±10% to account for potential project-specific variations. Gray lines indicate CCNG projected.

Figure B3: Geothermal cost trajectories.

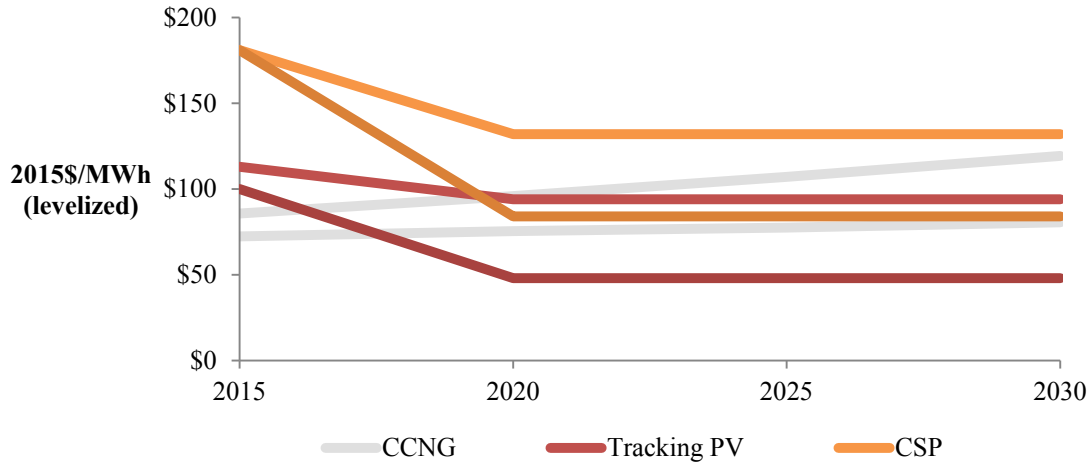
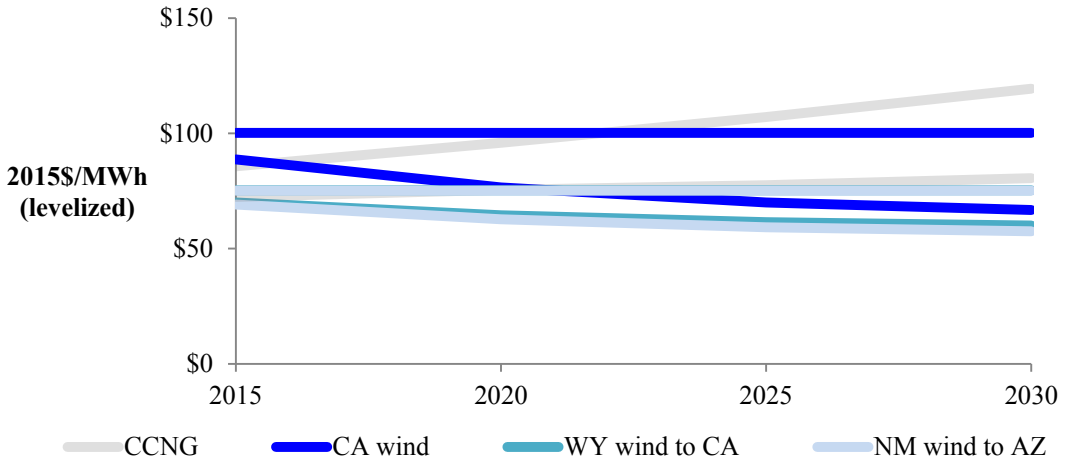


Figure B4: Utility-scale solar cost trajectories.



Wyoming wind to California includes a $29/MWh adder to account for bulk transmission costs to California. New Mexico wind to Arizona includes a $22/MWh adder to account for bulk transmission costs to Arizona.

Figure B5: Wind cost trajectories.

Up to now, wind has been the most cost-competitive renewable technology relative to CCNG. Most of the sites in California with the highest capacity factors have already been developed, however, leaving undeveloped areas where capacity factors tend to be lower. The cost trends for California wind resources shown in Figure B5 are based on the use of low wind speed turbines (higher towers and larger rotor diameters) and capacity factors of around 32%.

For Salton Sea resources, however, the economic competition from wind in the California market is most likely to come from Wyoming, where wind is more consistent and capacity factors are exceptionally high (around 49%). While the LCOE for Wyoming wind is low at the busbar, getting the power to California requires additional investments in EHV transmission. In the Arizona market, the economic competition from wind resources is most likely to come from New Mexico, which like Wyoming has a large amount of undeveloped resources with potentially high capacity factors. Costs declines are expected to continue, although at a slower pace than for solar PV.

Technical comparisons between technologies will often use LCOE as a metric because it controls for factors that are impossible to represent consistently and systematically. LCOE can be calculated with or without incentives such as the investment tax credit (ITC), flexibility that can facilitate cross-technology comparisons of underlying cost trends. Inputs are applied in a uniform manner, and factors that are site-specific such as insolation and local taxes can be captured in an objective and nondiscriminatory manner. LCOE inputs include, among other factors:

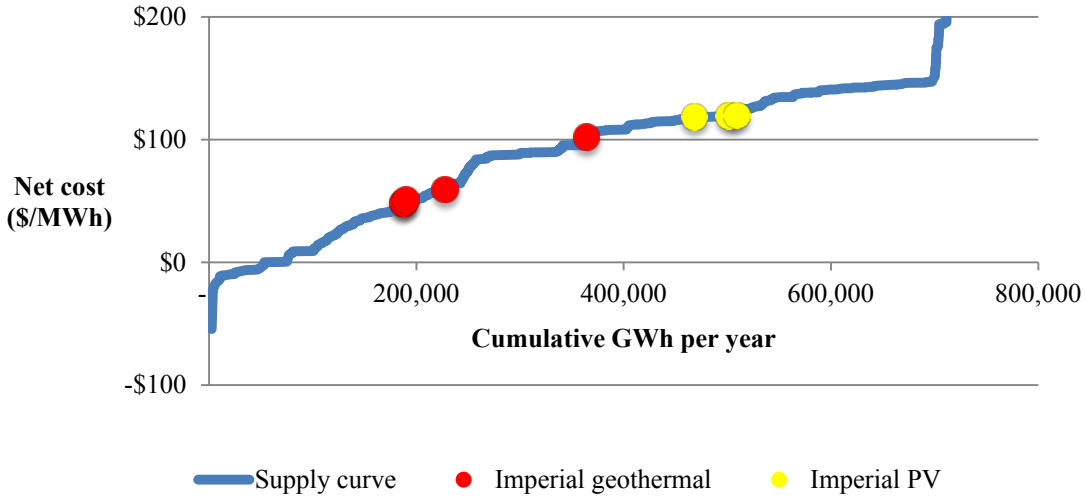
- market cost of panels, inverters, and other equipment related to production
- cost of land and site development
- applicable state and local taxes
- site insolation (raw kilowatts of sunshine per square meter of land, averaged over a typical year)

- the cost of capital (debt, equity, and the ratio between debt and equity)
- the rate of degradation in the equipment's productive capacity
- the number of years over which costs are to be recovered

What LCOE does not capture is the project-specific deal-making that ultimately leads to a PPA. For example, a purchaser may have a strong preference for low prices early in the contract term. This could lead to a PPA with a discounted first-year price, combined with an escalation clause that increases the price slightly each year. Deal provisions, such as: escalation rate, 30% ITC, term length, state income and sales tax rates, project financing, and additional grid services can all result in a disparity between the LCOE and ultimate PPA price of a technology.

Headroom

To test economic headroom, we measure how a hypothetical tax might affect the competitive position of Salton Sea renewables in the overall supply curve for potential new resources serving California. This "tax" represents additional revenue requirements placed on a new project that might be earmarked for financing Salton Sea reclamation efforts.



Source: CPUC RSP Calculator

Figure B6: Net cost of potential new resources included in the RPS calculator (Point estimates of the range of net costs.

Figure B6 shows the undeveloped resources included in the CPUC Calculator, ordered by the estimated net cost of each potential development. "Net cost" is calculated as the project's estimated first-year PPA price, minus the forecasted price of energy, minus the capacity value (how the project would keep the grid stable). Solar has a lower capacity value than geothermal because it is more variable and less controllable. Each point on the curve indicates how much potential generation exists at or below a given level of net cost. The net cost figures indicated in Figure B6 differ from the LCOE's summarized in the executive summary and the previous cost trajectories section due to their inclusion of numerous market factors such as transmission costs, capacity value, and market value of the energy provided. The LCOE calculations intentionally

exclude variable market factors and incentives such as the investment tax credit, in order to establish a cost baseline for the technologies under review.

Figure B6 suggests that the total supply curve for California comprises more than 700,000 GWh per year worth of renewable capacity. The amount of future demand that might ultimately be placed on this supply is subject to many variables, but one plausible indicator of the magnitude of demand is the effect of increasing the California RPS from 33% to 50%. The difference between the two targets, based on total retail electric sales in the state for 2013 and 2014, amounts to around 44,000 GWh annually.[105] A companion indicator is the additional amount of renewables selected by the RPS Calculator when modeling a 50% RPS, which is about 74,000 GWh per year more than when modeling a 33% RPS.

These two indicators suggest that demand for new renewables in California is unlikely to reach the higher-cost segments of the supply curve, even if demand is driven further beyond the 50% RPS target beyond 2030. Even among projects with lower net costs, competition is likely to be strong.

Salton Sea's least-cost, highest-value geothermal ranks near the 25th percentile of the supply curve, meaning its net cost is lower than 75% of all other options. The area's solar resources are further up the supply curve. The PV cost trends indicated in Figure B4 could lead to an overall improvement over time, but this advantage would accrue similarly to all other solar resources, which in total constitute more than half of the overall supply curve.

If new geothermal were to carry an additional $5/MWh burden to help finance Salton Sea reclamation, its competitive position on the supply curve would slip by 2 to 3 percentage points. That is, an additional 2% to 3% of the potential supply could become economically superior. This shift might not be significant under scarcity conditions, but it could be a significant handicap in a market characterized by large surpluses.

Put another way, if total demand amounts to around 10% to 15% of total supply, resources near the 25th supply percentile will already be facing intensely competitive conditions where even a small loss of position could be significant.

The area's best solar resources—which already tend to be in the most costly half of the overall supply curve—would slip by about 7 percentage points.

Demand Drivers: California

California has implemented two keystone policies promoting the development of a cleaner economy and lower electric utility emissions: the California Global Warming Solutions Act (Assembly Bill 32); and an ambitious RPS. These policies have incentivized renewable generation expansion across the state. The CARB recently published its updated AB 32 compliance plan, which calls for near zero emissions from the electric utility sector by 2050. In addition, Gov. Jerry Brown has directed the CPUC to assess pathways for increasing the state's RPS.

[105] These calculations are for general benchmarking purposes only and are not RPS demand forecasts. They do not account for new resources needed to meet the 33% RPS or for replacement needs that arise from the retirement of older renewable facilities.

The state has enacted other policies to support these statutory goals, including:

- A preferred resources procurement strategy
- The prohibition on conventional coal to serve as a baseload resource
- A battery storage mandate (to counteract the potential reliability concerns associated with expanding renewable generation).

Another key policy not directly associated with carbon reduction is California's requirement that existing power plants reduce water consumption, particularly through restricting the use of once-through cooling for thermal generation. This complicates the reliability picture because of the resulting retirement of existing generation and the potential for further retirements.

Renewables Portfolio Standard

One of the major drivers of carbon emission reductions in California has been the implementation of the state's RPS. Initially enacted in 2002,[106] California has since amended the RPS twice in 2006[107] and in 2011. The current RPS requires all electricity providers to achieve 33% renewable energy generation by 2020.[108] In 2013, California enacted Assembly Bill 327 granting the CPUC authority to expand the state's RPS through rulemaking.[109] The CPUC has an ongoing rulemaking that is in part focused on evaluating the expansion of the RPS program beyond the 33% target,[110] and as of the publication of this report, a 50% RPS target was recently passed into law.

California's current 33% RPS has three compliance periods. The first culminated at the end of 2013, when utilities were required to procure renewables in amounts no less than 20% of retail sales. Procurements must reach 25% by the end of 2016, and 33% by the end of 2020.[111]

In 2013, all the state's utilities were 99% in compliance with RPS requirements.[112] The CPUC expects that the state's investor-owned utilities (IOU) will meet the 25% target in 2016 based on existing and planned projects, but meeting the 2020 goal will require significantly more renewable generation over that which is already planned.[113]

California utilities can procure renewable generation from any location within the WECC provided they are consistent with the CPUC's three portfolio content categories[114] including:

- Category 1: qualifying renewable generation delivered to, or serving, a California balancing authority, without substituting electricity from another source (not less than 75% of procurements towards 2020 compliance).

[106] See bill here: http://www.energy.ca.gov/portfolio/documents/documents/SB1078.PDF.
[107] See bill here: http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_0101-0150/sb_107_bill_20060926_chaptered.pdf.
[108] See bill here: http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf.
[109] See bill here: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327&search_keywords.
[110] http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:56:3574229083682::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R1105005.
[111] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA25R&ee=1.
[112] http://emp.lbl.gov/sites/all/files/RPS%20Compliance%20Data_October%202014_0.xlsx.
[113] This figure can be found on page 4: http://www.cpuc.ca.gov/NR/rdonlyres/CA15A2A8-234D-4FB4-BE41-05409E8F6316/0/2014Q3RPSReportFinal.pdf.
[114] http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33RPSProcurementRules.htm.

- Category 2: qualifying renewable generation delivered to a California balancing authority, after being firmed and shaped by another source (not more than 25% of procurements towards 2020 compliance).
- Category 3: qualifying renewable generation that is not covered under Category 1 or 2, such as unbundled renewable energy credits (not more than 10% of procurements towards 2020 compliance).

These procurement requirements limit but do not preclude the potential for some out-of-state renewable providers to serve California's RPS requirements.[115] In 2013, out-of-state renewable generation accounted for about 20% of California's RPS-eligible generation.[116]

CAISO and PacifiCorp currently operate an energy imbalance market (EIM), which is expected to more cost effectively (Milligan et al. 2013) integrate regional renewable facilities into the system. NV Energy is scheduled to join the EIM in 2015; Puget Sound Energy in Washington is also studying the possible affiliation. If the EIM is successful as a tool for integrating wind and other variable renewables, it could to some extent reduce reliability advantage otherwise enjoyed by geothermal resources from the Salton Sea region and other areas.

AB 32 – Air Resources Board – State of California

California enacted AB 32 in 2006. The law requires the state to reduce its carbon emissions to 15% below 1990 levels by 2020 and to 80% below 1990 emissions by 2050.[117]

The law directs the CARB to develop regulations for achieving this goal. It authorized CARB to create a cap-and-trade program as a market-based platform for reducing aggregate emissions cost effectively. In 2014, California linked its emission program with Quebec and published the first update to their AB 32 compliance plan.[118] The plan prioritizes reductions in emissions from electric utilities and calls on the utility sector to reach near zero GHG emissions by 2050.

To implement the emission goals of AB 32, the state's energy agencies will develop rules to improve demand response and energy efficiency participation, and to streamline interconnection processes for distributed generators.[119]

Utility Procurement Policies

In line with the state's emphasis on renewable generation to meet electricity load, California has enacted three other policies that incentivize or address impacts of higher renewable generation on the grid.

Coal

In 2003 the California Energy Commission (CEC), CPUC, and California Consumer Power and Conservation Financing Authority developed a joint priority system to evaluate new generation

[115] SB 14 initially proposed in 2009 would have required utilities to procure renewable energy from only sources within the state and this policy was vetoed by then Governor Schwarzenegger. http://leginfo.ca.gov/pub/09-10/bill/sen/sb_0001-0050/sb_14_vt_20091012.html.
[116] See Table 25 page 326 http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF-small.pdf.
[117] See bill here: http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.html. The long term 2050 goal is based upon Governor Brown's Executive Order S-3-05: http://gov.ca.gov/news.php?id=1861.
[118] http://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.
[119][119] http://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

decisions. This system is referred to as the loading order and it prioritizes energy efficiency, demand response, and renewable generation over fossil fuel generation.

In 2006, the California legislature passed SB 1368 that set carbon emission performance standards for any California utility's owned or contracted baseload electricity generation.[120] The legislature determined that utilities could only contract with, invest in, or construct baseload generation sources that produce electricity at or below the carbon emission rate of a combined-cycle natural gas plant. The bill, in essence, precludes any future utility investment in coal-fired generation, unless it employs carbon capture and sequestration CCS technology or some other emission control technology.

Storage

Cost-effective electricity storage could marginally improve the demand for PV relative to the demand for baseload renewables such as geothermal. The California legislature enacted AB 2514 in 2010 to address the presence of more variable generation on the grid. The law requires the CPUC to evaluate the role energy storage systems can play in the broader market and if deemed appropriate develop procurement targets for each IOU to achieve by 2016 and 2021.[121] The CPUC responded by requiring Pacific Gas and Electric (PG&E), SCE, and SDG&E to procure a combined total of 1,325 MW of energy storage by 2020, with installations no later than 2024.[122]

The CPUC has set storage solicitation goals for the 2014 to 2016 biennial at 16 MW for SCE and SDG&E, along with an 80.5 MW goal for PG&E.[123] Whether the utilities meet these targets, and at what cost, will be in part contingent upon the slope of cost declines for battery storage.[124] Nevertheless, SCE has procured over 261 MW of battery storage that can be employed to achieve their mandated targets, which is significantly more than their biennial requirement.[125] If this trend continues, the CPUC may be inclined to support more renewable capacity to serve load requirements.

San Onofre Generating Station Retirement

In 2012, SCE, the operator of the San Onofre Generating Station (SONGS), identified a small radioactive steam leak and a systemic weakening of tubing within its newly installed steam generator system.[126] SCE announced the early retirement of both units at SONGS in June 2013.[127] CAISO has identified the retirement of SONGS as a risk to local reliability in the Los Angeles Basin. This retirement has significantly reduced system reserve margins across the Los Angeles Basin, enhancing the risk of service outages under heavy load conditions.[128] Service outages would be even more likely, in the event critical regional high-voltage transmission lines went out of service, resulting in deficient voltage levels. Finally, in the absence of SONGS, some

[120] Access the bill here: http://www.energy.ca.gov/emission_standards/documents/sb_1368_bill_20060929_chaptered.pdf.
[121] See bill here: http://www.leginfo.ca.gov/pub/09-10/bill/asm/ab_2501-2550/ab_2514_bill_20100929_chaptered.html. The law allowed public utilities to develop their own procurement plans if they determined that energy storage would be cost effective.
[122] See the decision here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF.
[123] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M127/K426/127426247.PDF.
[124] Wolff, Eric (2014). "Cheaper batteries from Tesla could transform the grid." *SNL Financial Inc.* www.snl.com.
[125] https://www.sce.com/wps/portal/home/procurement/solicitation/lcr/!ut/p/b0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOK9PF0cDd1NjDz9nQxdDRyDPS1cXD1cDYL9zfQLsh0VAQ4EJ6E!/.
[126] http://articles.latimes.com/2013/jun/07/local/la-me-0608-san-onofre-20130608. http://latimesblogs.latimes.com/lanow/2012/02/san-onofre-power-plant-leak.html.
[127] http://www.songscommunity.com/news2013/news060713.asp.
[128] http://www.caiso.com/Documents/BriefingSummer2012OperationsPreparedness-Presentation-Mar2012.pdf.

local transmission lines could be overloaded.[129] It should also be noted that the SONGS financial settlement along with natural gas replacement of SONGS is currently under review, investigation, and potential litigation.

To address these reliability concerns, the CPUC recently approved a plan to allow SCE and SDG&E to procure up to 3,300 MW of new generation.[130] The plan allows these utilities to procure a significant majority of this capacity from natural gas generators. Given the reliability benefits associated with geothermal generation, it is possible that these utilities might consider this generation in their procurement decisions.[131] We discuss the renewable generation component in the regional utility planning section below.

Once-Through Cooling

Though generally unrelated to these carbon and renewable integration policies, California's decision to regulate the cooling systems employed across the utility sector will also influence the overall market.

In 2010, the State Water Resources Control Board (SWRCB) approved a once through cooling phase out plan that impacted 19 power plants with a combined operating capacity over 17,500 MW.[132] SWCRB found that dry cooling systems were the best available technology and established this as the benchmark for compliance.[133] SWCRB phased in compliance with this regulation from 2010 through 2029 in order to reduce potential reliability impacts associated with installing new cooling systems, or utility decisions to retire certain plants.

Several obligated plants have since been retired, but in general, most plant owners have suggested they plan to retrofit their plants.[134] The Diablo Canyon Nuclear Plant is one example, though there has been controversy surrounding whether the costs associated with compliance are justified.[135] As a result, the future of the plant's 2,200 MW of generation is unclear. If the plant is retired, the CPUC may offer a similar procurement decision to that of SONGS, which could promote some expansion in renewable generation.

Demand Drivers: Arizona

Arizona has an RPS for utilities under state regulation. The interim goal for 2013 (the most recent compliance reports) was 4% of retail sales, gradually increasing each year to 15% of sales in 2025. The RPS requires 30% of each year's requirement to come from distributed resources, so the RPS-related demand for which Salton Sea resources will compete is 10.5% of retail sales by 2025. Salt River Project, the state's largest non-jurisdictional utility, has voluntarily adopted a comparable renewable energy goal.

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[129] http://www.caiso.com/Documents/2014SummerAssessment.pdf.
[130] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF.
[131] In 2014, legislators proposed SB 1139, which sought to require IOUs to leverage the reliability benefits of geothermal generation, but the bill did not pass. See bill language here: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB1139.
[132] http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf.
[133] This was in part based on a 2006 CEC study on this issue, see Maulbetsch, J.S. and DiFilippo, M.N. (2006). *Cost and Value of Water Use at Combined-Cycle Power Plants*. http://www.energy.ca.gov/2006publications/CEC-500-2006-034/CEC-500-2006-034.PDF.
[134] http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf.
[135] "SDG&E seeks to skip competitive bidding with Carlsbad power purchase deal." *SNL Financial Inc*. (2014), www.snl.com.

In 2013, both of the state's largest IOUs—APS and Tucson Electric Power (TEP)—were ahead of schedule with respect to both total renewable energy procurement and the carve-out for distributed generation. APS procurements came to 6.8% of sales, while TEP's came to 5.6%.

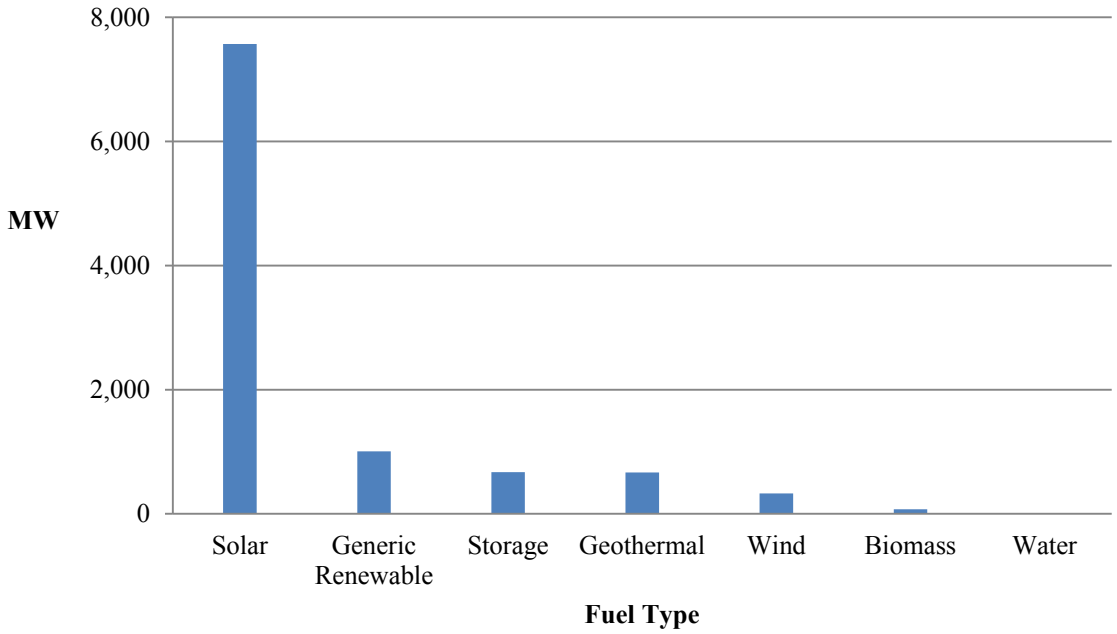
Regional Utility Planning

Integrated resource plans (IRP) indicate how utilities read and respond to short-term trends in supply and demand. This section examines the current IRPs of five California utilities: PG&E, SCE, LADWP, SDG&E, and IID. For the Arizona market, we evaluate the IRPs from the three largest utilities in the state: APS, SRP, and TEP.

Many of utilities expect to retire or discontinue purchase agreements with a portion of coal generation. Most of the replacement power is expected to come from renewables and natural gas resources, with much of the new renewable capacity directed towards compliance with state RPS requirements.

Most of the renewable procurements identified in utility IRPs are new solar photovoltaic capacity (Figure B7). Apart from unspecified renewable procurements, new storage capacity is a distant second, driven largely by AB 2510. Planned geothermal procurements are about 9% the size of planned solar procurements in terms of nameplate capacity.

Many of the planned solar procurements are associated with specific projects. Projects near the Salton Sea could compete for much of the demand not yet awarded, provided there is sufficient transmission capacity within a reasonable proximity. Arizona utilities could conceivably buy Salton Sea solar power, but as detailed in the previous discussion about supply, they are unlikely to be economically competitive with Arizona's in-state solar resources. Salton Sea geothermal projects may be competitive in Arizona as baseload renewable power, however, as SRP in Arizona is a current buyer of geothermal power from the Salton Sea's 50 MW Hudson Ranch plant.



Sources: PG&E, SCE, LADWP, SDG&E, and IID Integrated Resource Plans

Figure B7. Regional renewable planned capacity expansion based on current IRPs.

Though most of these utilities are expecting to meet RPS requirements through increased solar capacity, some intend to add geothermal capacity. Of these, about half of the expected new capacity is associated with planned projects (IID, SCE, and SRP), while the Salton Sea region could serve the remaining 250 MW of new geothermal capacity sought by APS and LADWP. However, these utilities do not expect to procure new geothermal until 2020-2025.

Pacific Gas & Electric

PG&E is the largest electric utility in the state of California[136] with 5.1 million electricity customers across the northern and central portions of the state.[137] PG&E expects load to increase to about 23,000 MW by 2020.

The utility anticipates adding 855 MW of net new contracted renewable capacity to its fleet, but PG&E notes that it expects to be short about 597 GWhs of RPS eligible renewable generation by 2020. The utility has since put out a solicitation for up to 1,600 GWhs per year of renewable generation for RPS compliance.[138]

Most of PG&E's procurement historically has been from solar.[139] Of the projects expected to come online through 2020, none are located in either Imperial or Riverside counties.[140]

[136] http://www.eia.gov/electricity/state/california/xls/sept03ca.xls.
[137] http://www.pge.com/en/about/company/profile/index.page.
[138] http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RPS2014/RPS_Solicitation_Protocol_01052015.pdf.
[139] See http://www.cpuc.ca.gov/NR/rdonlyres/A00F02FF-B55F-40AF-AECF-AA258DD74378/0/RPS_Project_Status_Table_2014_November.xls. And http://www.pge.com/en/myhome/saveenergymoney/cleanenergyca/newsroom/article/toputility.page.
[140] http://www.cpuc.ca.gov/NR/rdonlyres/A00F02FF-B55F-40AF-AECF-AA258DD74378/0/RPS_Project_Status_Table_2014_November.xls.

Southern California Edison

SCE is the second largest electric utility in California[141] serving about 5 million electric customers across southern California.[142] SCE does not disclose its current load in its long term procurement plan, but it does expect its capacity need to increase from about 10,900 MW in 2015 to 13,739 MW by 2021.[143]

In response to the retirement of SONGS and local transmission constraints, the CPUC authorized SCE to procure up to 2,500 MW of new capacity through 2021.[144] SCE has since signed contracts for a total of 2,220 MW including 1,700 MW of natural gas, 261 MW of energy storage, 211 MW of demand response, and 50 MW of solar.[145,146]

Even though storage performed well in this capacity solicitation, SCE expects to meet much of its RPS requirements through solar resources. Currently, SCE has over 3,000 MW of prospective solar projects pending approval from the CPUC.[147] In comparison, SCE intends to procure 225 MW of new geothermal capacity, through its recent power purchase agreement with the geothermal Geysers Plant. Despite this addition, SCE anticipates that geothermal as a percentage of its renewable generation mix will decline over its planning period.[148]

It is likely that SCE will require more renewable generation[149] to meet future RPS obligations, though it is unclear when they will procure it.[150] Solar from the Salton Sea region could compete for a part of SCE's future needs.[151]

Los Angeles Department of Water and Power

LADWP is the third largest utility in California[152] with 3.8 million electric customers in the Los Angeles metropolitan area.[153] LADWP served a load of 5,680 MW in 2014 and they expect this to increase to 7,065 MW by 2034.

LADWP intends to procure over 2,000 MW of new renewable energy capacity through 2034. This generation will position the utility to meet 40% of total demand with renewable resources by 2030. LADWP expects much of this new capacity to be sourced from solar, with a near-term goal of 800 MW of local solar by 2023. In the event this local solar expansion can be

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[141] http://www.eia.gov/electricity/state/california/xls/sept03ca.xls.
[142] http://www.edison.com/content/dam/eix/documents/investors/sec-filings-financials/c8189_EIX-SCE_2013_10K_As_Filed_2481.pdf.
[143] http://www.cpuc.ca.gov/NR/rdonlyres/8AB05FC4-80D3-4679-AC09-41EABDA5131B/0/SCE2010LTPP2AB57BundledProcurementPlanAppendices_PUBLIC.pdf.
[144] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF.
[145] https://www.sce.com/wps/portal/home/procurement/solicitation/lcr/!ut/p/b0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOK9PF0cDd1NjDz9nQxdDRyDPS1cXD1cDYL9zfQLsh0VAQ4EJ6E!/.
[146] https://www.sce.com/wps/portal/home/procurement/solicitation/lcr/!ut/p/b0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOK9PF0cDd1NjDz9nQxdDRyDPS1cXD1cDYL9zfQLsh0VAQ4EJ6E!/.
[147] http://www.cpuc.ca.gov/NR/rdonlyres/A00F02FF-B55F-40AF-AECF-AA258DD74378/0/RPS_Project_Status_Table_2014_November.xls.
[148] http://www.cpuc.ca.gov/NR/rdonlyres/8AB05FC4-80D3-4679-AC09-41EABDA5131B/0/SCE2010LTPP2AB57BundledProcurementPlanAppendices_PUBLIC.pdf.
[149] http://www.cpuc.ca.gov/NR/rdonlyres/CA15A2A8-234D-4FB4-BE41-05409E8F6316/0/2014Q3RPSReportFinal.pdf.
[150] It is also possible that the utility could renew contracts, or repower existing renewable facilities, which could temper their demand for new capacity. http://www.cpuc.ca.gov/NR/rdonlyres/CA15A2A8-234D-4FB4-BE41-05409E8F6316/0/2014Q3RPSReportFinal.pdf.
[151] For example, SCE's largest planned project is the 406 MW expansion at the existing Imperial Valley Solar PV Project in Imperial County, California. http://www.cpuc.ca.gov/NR/rdonlyres/A00F02FF-B55F-40AF-AECF-AA258DD74378/0/RPS_Project_Status_Table_2014_November.xls.
[152] http://www.eia.gov/electricity/state/california/xls/sept03ca.xls.
[153] https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=OPLADWPCCB419127&RevisionSelectionMethod=LatestReleased.

implemented without adverse impacts on the grid, LADWP will look to procure more solar resources within its service territory.

Though LADWP expects to procure much of its renewable generation from solar, at current it expects to add 166 MW of geothermal over its planning period. Of this capacity, 100 MW is not yet associated with a project and developers in the Salton Sea region could be well situated to meet this demand. However, LADWP notes that this procurement goal could be reduced if solar costs decline and higher solar penetration does not pose a reliability risk.[154] Thus, if LADWP's plans come to fruition, the utility may not represent a large market for Salton Sea generators either solar or geothermal.

San Diego Gas & Electric

SDG&E is the fourth largest utility in California,[155] with 1.4 million electric customers across San Diego and Orange counties.[156] SDG&E anticipates a load requirement of 4,850 MW in 2015 and they expect this to increase to nearly 5,360 MW by 2024.[157]

SDG&E was also impacted by the retirement of SONGS, and the CPUC granted SDG&E the authority to procure an additional 500 MW to 800 MW of capacity by 2020 to replace SONGS. Of this generation, at minimum SDG&E is required to procure 25 MW of storage capacity, along with 175 MW of additional preferred resources. The utility can then procure 600 MW from any source, for which the utility has expressed interested in purchasing the electricity from the proposed natural gas-fired Carlsbad Energy Center (636 MW)[158].

Much of SDG&E's current renewable mix is associated with solar generation and they expect to add an additional 275 MW of solar to meet future RPS requirements.[159] As noted, even if SDG&E purchases Carlsbad, they may still procure up to 175 MW of additional renewable capacity.[160]

SDG&E currently has no geothermal in its procurement, and has given little indication it would procure geothermal resources to meet future needs, which would represent a departure from their recent practices.[161] Historical practice suggests that SDG&E may procure solar generation and projects from the Salton Sea region.

Imperial Irrigation District

IID is the sixth largest electric utility in the state of California with 145,000 customers across Riverside and San Diego counties.[162] IID had a peak load requirement of 1,160 MW in 2013 and they expect load to increase to about 1,615 MW by 2033.

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[154] https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=OPLADWPCCB419127&RevisionSelectionMethod=LatestReleased.
[155] http://www.eia.gov/electricity/state/california/xls/sept03ca.xls.
[156] http://www.sdge.com/aboutus.
[157] https://www.sdge.com/sites/default/files/regulatory/PUBLIC-SDGE-Bundled-Plan.pdf.
[158] "SDG&E seeks to skip competitive bidding with Carlsbad power purchase deal." *SNL Financial Inc*. (2014), www.snl.com.
[159] https://www.sdge.com/sites/default/files/regulatory/PUBLIC-SDGE-Bundled-Plan.pdf.
[160] SDG&E will make its final procurement decision in early 2016: http://www.sdge.com/all-source-2014-rfo.
[161] https://www.sdge.com/sites/default/files/regulatory/PUBLIC-SDGE-Bundled-Plan.pdf.
[162] http://www.iid.com/Modules/ShowDocument.aspx?documentid=9280.

IID expects the retirement of its share in the coal-fired San Juan Generating Station to require 150 MW of replacement baseload resources, which they anticipate will be sourced from a renewable project. IID expects that this project along with the addition of between 30 MW and 50 MW of geothermal and between 20 MW and 60 MW of solar in the 2017-2020 timeframe will keep them in compliance with their RPS requirements.

Arizona

Arizona is a key potential market for Salton Sea renewables because of its easy access. Most of the power on existing transmission across the Colorado River flows east-to-west into California; there is significant counterflow capability in the opposite direction that could accommodate sales to Arizona without major transmission additions.

APS is the largest retailer of electricity in Arizona[163] with over 1.2 million customers.[164] APS's service territory spans nearly 35,000 square miles across much of the central portion of the state.[165] In 2014, APS served a load of 8,125 MW and they expect load to increase to over 12,980 MW by 2029.

APS plans add about 425 MW of renewable energy through 2029 to remain in compliance with the Arizona RPS.[166] Of this capacity, APS intends to add 242 MW of solar, 150 MW of geothermal, and 33 MW of wind capacity. The utility did not link this capacity with specific projects or locations. It is likely given Arizona's strong solar resources and APS's procurement history that they would procure solar generation from in-state.[167] APS could look to the Salton Sea for additional geothermal generation, and in fact already has one PPA in place for 11 MW.[168] APS' IRP, however, does not anticipate procuring either until at the earliest 2023.

SRP is the second largest retail electricity provider in Arizona and the largest public utility in the state.[169] SRP serves nearly one million customers across 3,000 square miles in the Phoenix Metropolitan area.[170] In 2013, SRP had a peak load requirement of about 7,450 MW and they expect that to increase to about 7,700 MW by 2016.[171]

As a public utility, SRP is not required to comply with Arizona's RPS, but it has adopted a voluntary sustainable resource standard in which it has committed to meeting 20% of its retail load through renewable and energy efficiency resources by 2020.[172] In SRP's 2012 IRP they suggested they would procure 156 MW from renewable generation sources through 2016. SRP

[163] EIA (2013). *Table 3. Top Five Retailers of Electricity, with End Use Sectors, 2012 Arizona*. http://www.eia.gov/electricity/state/arizona/xls/sept03az.xls.
[164] See APS (2014). *Integrated Resource Plan.* http://www.aps.com/library/resource%20alt/2014_IntegratedResourcePlan.pdf. Accessed 7/8/14.
[165] See APS (2014). *Integrated Resource Plan.* http://www.aps.com/library/resource%20alt/2014_IntegratedResourcePlan.pdf. Accessed 7/8/14.
[166] APS (2014). *Integrated Resource Plan.* http://www.aps.com/library/resource%20alt/2014_IntegratedResourcePlan.pdf. Accessed 7/8/14.
[167] APS (2014). *Integrated Resource Plan.* Accessed 7/8/14 from: http://www.aps.com/library/resource%20alt/2014_IntegratedResourcePlan.pdf. See also SNL Financial Inc. www.snl.com. Accessed 7/8/14.
[168] CE Turbo.
[169] EIA (2013). *Table 3. Top Five Retailers of Electricity, with End Use Sectors, 2012 Arizona*. http://www.eia.gov/electricity/state/arizona/xls/sept03az.xls.
[170] SRP (2014). *2014 SRP Annual Report*: http://www.srpnet.com/about/financial/pdfx/AnnualReport-FY2014_web.pdf.
[171] SRP (2012). *Integrated Resource Plan FY 2013*. http://ww2.wapa.gov/sites/western/es/irp/Documents/SRP2013.pdf. Accessed 7/21/14.
[172] SRP (2014). *Resource Stewardship Sustainability Portfolio*. http://www.srpnet.com/environment/earthwise/pdfx/ResourceStewardship.pdf.

has since signed contracts to purchase 64 MW of solar capacity within Arizona[173] and 113 MW of geothermal generation from two facilities one each in Utah[174] and California.[175]

These planned projects will contribute to SRP's compliance with their sustainability goal, while diversifying SRP's renewable energy portfolio.[176] It is unclear whether SRP will procure additional renewable generation to meet its goal at this time, so at least over the short term SRP may not be in the market for renewable generation from the Salton Sea region.

TEP is the third largest utility in Arizona[177] and it serves 400,000 customers mainly across the Tucson metro area, in Pima County.[178] TEP had a peak load requirement of nearly 2675 MW in 2014 and they expect this to increase to about 3200 MW by 2028.

To satisfy its RPS requirements, TEP expects to add 321 MW of new renewable capacity by 2028, split between solar (227 MW) and wind (94 MW). TEP has already announced several projects slated to come online in 2015 that will help meet its RPS requirements, all of which are located in Arizona.

TEP has not announced projects associated with the remaining capacity (224 MW), which will primarily be sourced from solar generators (181 MW). TEP has historically procured solar generation entirely within the state[179] and we can expect that trend to continue. It is possible that TEP could source the remaining 43 MW of wind from developers in the Salton Sea region, but they do not expect to procure this wind generation until 2023-24. Therefore, TEP will likely not procure renewable generation from the Salton Sea region until 2023 at the earliest, and it is uncertain how competitive wind generation from this region would be at that time.

Transmission Capability from IID into CAISO

Of the 768 MW of the geothermal generation now operating in the Salton Sea area, about two-thirds is under contract to Southern California Edison and uses most of the transfer capability from IID into CAISO. The permanent retirement of SONGS and the resulting local reliability issues temporarily limited transfer capability even further, but CAISO projects that recommended mitigations and the approved projects in Southern California area will restore overall deliverability from IID to what it was before SONGS retirement.

In its draft transmission plan for 2014 and 2015, CAISO estimates that existing transmission and upgrades under way can accommodate between 500 MW and 750 MW of new generation from IID into southern California, after taking into account generation in IID that is already connected to the CAISO system or is under construction. In addition, based on discussion with IID, there is currently 900 MW of capacity on Path 42, and significant deliverability out of the IID BA.

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[173] Harelson, Scott (2014). *SRP Signs Deal with sPower for Solar Energy Facility near Florence.* http://www.srpnet.com/newsroom/releases/112014.aspx.
[174] SRP (2014). *Third Quarter Report SRP Fiscal Year 2014*. http://www.srpnet.com/about/financial/pdfx/FY2014/ 3rdOtrRpt FY2014.pdf. The Cove Fort facility is in early development and SNL Financial does not have a confirmed operation date for the plant.
[175] SRP (2014). *Resource Stewardship Sustainability Portfolio*. http://www.srpnet.com/environment/earthwise/pdfx/ResourceStewardship.pdf.
[176] SRP (2014). *Resource Stewardship Sustainability Portfolio*. http://www.srpnet.com/environment/earthwise/pdfx/ResourceStewardship.pdf.
[177] EIA (2013). *Table 3. Top Five Retailers of Electricity, with End Use Sectors, 2012 Arizona*. http://www.eia.gov/electricity/state/arizona/xls/sept03az.xls.
[178] TEP (2014). *Tucson Electric Power 2014 Integrated Resource Plan*. https://www.tep.com/doc/planning/2014-TEP-IRP.pdf. Accessed 7/7/14.
[179] See TEP (2014). *Tucson Electric Power 2014 Integrated Resource Plan*. https://www.tep.com/doc/planning/2014-TEP-IRP.pdf and SNL Financial Inc. data www.snl.com. Accessed 7/7/14.

CAISO also conducted a limited information-only assessment of two recently proposed projects, and concluded that they might accommodate as much as 2,500 MW of renewable generation.[180]

Competitive Edge of Salton Sea Renewables

The Salton Sea area could be a source of renewable power in both the California and Arizona markets, but it is unlikely to have any economic headroom to accommodate the additional revenue burden of Salton Sea reclamation. Developing geothermal and solar projects in the Salton Sea area tends to be more expensive than the same technologies developed in Arizona or Nevada. This is due largely to differences in the cost of labor, taxes, and other expenses that tend to be higher in the state of California.[181] Policies favorable to renewable energy could create a unique benefit to development within the region. These could include utilizing the North American Development Bank for development expertise and to leverage interest rate cost savings, streamlining permitting requirements, and providing certainty surrounding environmental permitting costs. Additional potential developments which could affect these findings include the implementation of more aggressive in-state renewable energy capacity goals, and additional project cost declines uniquely benefitting the Salton Sea region (i.e., local incentives, exceptional transmission access).

While the Salton Sea has abundant solar resources with potentially high productivity, so too do competing areas in California, Arizona and Nevada. Global horizontal irradiance is about the same across the three-state region from Las Vegas, NV down to Yuma, AZ, so the amount of energy produced for every megawatt of installed capacity is equally high.[182] Cost per megawatt of installed capacity is likely to be lower in Arizona, putting Salton Sea PV at an economic disadvantage in that market relative to in-state solar. While cost reductions are trending toward parity with natural gas on an LCOE basis around 2020 (if not sooner), these improvements will help competing solar areas just as much as they will help Salton Sea.

The Arizona market may be friendlier to Salton Sea geothermal because it has no significant geothermal resource potential of its own. Transmission access—as counterflow on the EHV path between Imperial and Phoenix—could also favor Salton Sea geothermal in serving Arizona load. Even if it is easier to reach, however, the Arizona market could be softer. The largest utilities seem to be ahead of their RPS-related procurement needs. In addition, wholesale prices tend to be lower in Arizona than in California, which could exacerbate resistance to above-market costs.

[180] The projects are the Midway–Devers 500 kV AC line project, and the Western Area Power Administration's Strategic Transmission Expansion Plan (STEP). Both were submitted in CAISO's 2014 request window.
[181] Energy and Environmental Economics, Capital Cost Review of Power Generation Technologies (final report and recommendations approved by WECC), March 2014, Table 33 (https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf).
[182] NREL, Solar Power Prospector (geographic information system mapping tool), "Avg. annual GHI," queried March 2015.

Appendix C: Revenue Potential Calculations

Table C1. Potential Revenue under Current Conditions

	Estimate	Cap. Factor	PPA price (low)	PPA price (high)	GW Cap. (low)	GW Cap. (high)	Lease rate % royalties
Potential Revenue under Current Conditions	Revenue Potential Calculation= Capacity factor X 8760 X GW Capacity X 1000 X PPA Price (MWh) X Lease rate						
Geothermal (IID KGRA) Offshore (low)	$6,223,104.00	0.8	80	N/A	0.37	N/A	3%
Geothermal (IID KGRA) Offshore (high)	$11,983,680.00	0.8	N/A	100	N/A	0.57	3%
Geothermal (IID KGRA) Offshore (low)	$1,334,323.20	0.8	80	N/A	.68	N/A	.0175/5=0.35%*
Geothermal (IID KGRA) Offshore (high)	$3,041,472.00	0.8	N/A	100	N/A	1.24	.0175/5=0.35%*
AB 1471 (CA 2014 Water Bond)	Total CA water bond is $475M, $200M assumed as upper limit given other liabilities within water bond. $200,000,000/14= $14,285,714.29						

* For all geothermal leases issued after the passage of the EPAct 2005, there is a required 1.75% royalty rate of the gross proceeds for the first ten years of production, which increases to 3.75% afterwards. Currently, 20% of these royalties are allocated to the project county. Given the required development and construction period for geothermal projects, and study period through 2030, the initial 10-year royalty rate was assumed. See section 5.5.1 for additional detail.

Table C2. Potential Revenue under Future Conditions

	Estimate	Cap. Factor	PPA price (low)	PPA price (high)	Acreage	Acre/MW	GW Cap.	Lease rate % royalty
Potential Revenue under Future Conditions	Revenue Potential Calculation= Capacity factor X 8760 X GW Capacity X 1000 X PPA Price (MWh) X Lease rate Capacity Calculation= (Acreage/ Acre/MW) /1000							
Mineral recovery from geothermal brines (offshore KGRA) (Low-High)	$0 M assumes that mineral recovery from geothermal brines does not reach commercialization by 2030. $25.8M assumes that mineral recovery from geothermal brines reaches commercialization by 2030, and that revenues from plant operations are sufficient to accommodate a 3% IID geothermal royalty rate on gross proceeds (the current land lease royalty rate assessed on gross PPA proceeds of geothermal plants). See section 4.2.1 for full calculation.							
Algal biofuels (offshore non-KGRA)*	$1.2 to 2.3M. Assumes $3/gal cost competiveness by 2030,1-2% IID land lease rate: Low: $3/gal X 39,000,000 gallons X .01= $1,170,000 High: $3/gal X 39,000,000 gallons X .02= 2,340,000							
Salinity Gradient Solar Ponds (offshore non-KGRA)* (Low)	$630,720	0.9	80	N/A	N/A	N/A	0.1	1%
Salinity Gradient Solar Ponds (offshore non-KGRA)* (High)	$1,576,800	0.9	N/A	100	N/A	N/A	0.1	2%
Solar PV (offshore non-KGRA) (Low)	$1,022,663	.232	40	N/A	9,938	7.9	1.258	1%
Solar PV (offshore non-KGRA) (High)	$3,067,990	.232	N/A	60	9,938	7.9	1.258	2%
Solar PV (onshore BLM SEZ) (Low)	$1,463,270	.232	40	N/A	N/A	N/A	1.8	1%
Solar PV (onshore BLM SEZ) (High)	$4,389,811	.232	N/A	60	N/A	N/A	1.8	2%
Desert Renewable Energy Conservation Plan - Habitat Restoration	DRECP revenues were calculated based on the Draft DRECP non-acquisition mitigation cost estimates from Table 23 EIR/EIS Appendix I, 2014. These costs were given as net-present values, and were undiscounted in order to ensure equal comparison with the other potential revenues. The DRECP nominal discount rate (excluding inflation) is 3.6% over a 25 year period. Low estimate calculated based on a pro-rata allocation of the Imperial County Habitat Restoration costs. This pro-rata allocation was based on the proportion of acreage allocated to the endangered pupfish, compared to the total habitat restoration acreage for all species (8,000/47,000)= 17% The high estimate assumes that the full Imperial and Riverside County Habitat Restoration costs were allocated to Salton Sea restoration efforts.							

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