SYNERGIES BETWEEN GEOTHERMAL AND SOLAR PV GENERATION

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ABSTRACT

By virtue of its infrastructure, each developed geothermal field represents an option to install solar power. Indeed, solar farms are steadily appearing as co-generation sources in geothermal fields internationally.

As New Zealand progressively increases the share of interruptible, renewable generation, the consequential difficulties for grid stability and supply are impolitely "hatching out." The question thus arises: are there configurations of baseload and a variable-load generation that can help manage these emerging issues?

This paper examines a general business case for co-locating solar PV generation with an existing baseload geothermal plant. The assessment considers economic synergies with the existing site (consents, land, infrastructure & capabilities), speed to market, direct customers, external (non-rival) benefits to the grid, as well as interconnection and regulatory constraints. The results suggest there will be net benefits to co-locating variables with baseload generation where conditions permit and as electrical consumption increases rapidly with decarbonisation. Furthermore, the concept is applicable to other baseload renewables such as hydro generation and other forms of variable renewable energy (VRE).

1. INTRODUCTION

Geothermal operators around the globe are experimenting with combining solar and geothermal technology in response to commercial and technical forces. To date, operators have installed two direct solar augmentation projects and five solar PV projects (Table 1). The solar augmentation projects have employed solar gathering devices (trough-shaped thermal collectors) to improve the thermodynamic performance of binary power plants through heating the primary or separated fluid before entering the energy converter or turbine.

In contrast, solar PV developments mainly target economic benefits by altering the project intra-day generation profile[1], as insurance against liquidated damages under various price purchase agreements, or simply to earn incremental margins on low-cost, tax incentivised solar panels.

Table 1: Solar-Geothermal projects

Field	Operator	Resource Type	Solar Class	Capacity	COD
Stillwater	Enel	Low temperature	Augmentation	17 MW th	2015
Ahuachapan	LaGeo	High temp. & gas	Augmentation		2007
The Geysers	Calpine	High temperature	Solar PV	0.9 MW ac	2005
Stillwater	Enel	Low temperature	Solar PV	26 MW ac	2012
Patua	Cyrq	Low temperature	Solar PV	10 MW ac	2017
Heber	RET[2]	Low temperature	Solar PV	14 MW ac	2014
Tungsten	Ormat	Low temperature	Solar PV	7 MW ac	2019

Ormat is planning a second solar PV (18 MW ac) facility at Tungsten[3], while Cyrq is exploring the feasibility of a geothermal-solar-thermal storage plant at North Valemy and Zoru Energy plans to add a 3.6 MW ac solar PV hybrid at Alasehir. These companies are attempting to combine geothermal with other technologies to allow for intra-day generation shifting and fast-ramping peaking. This is particularly important in the WECC[4] market, where solar PV suppresses load (and prices) during mid-day but imposes very high ramp rates in the evening peak transition.

Pumped low-temperature systems use a lot of electrical power for pumping, and so in the summer months, binary power plants, using fin-fan air cooling, have a high power demand and suppressed output during the day. By maximising output during the day, solar generation thus compliments air-cooled plants with high parasitic loads.

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[1] By covering the parasitic load
[2] Renewable Energy Trust Capital
[3] Press reports a cost of USD $15 million backed by a $75.5/MWh PPA price
[4] Western Electricity Coordinating Council

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While the New Zealand electricity market does not (yet) experience the high summer load peaks typical of many northern hemisphere power systems, the grid manages winter intra-day swings largely through hydro and open cycle gas turbines. As the country moves towards decarbonisation, the industry is looking geothermal solutions relevant to displacing thermal peaking.

Patua solar plant by Cyrq Energy near the Patua geothermal power plant, Nevada (source: video screenshot)

Stillwater hybrid geothermal-solar plant, Nevada (source: Enel, video screenshot)

Figure 1: Patua[5] solar-geothermal (left) and Stillwater[6] hybrid solar thermal – solar PV-geothermal (right)

2. PROJECT SETTING & COMPATIBILITY CONSIDERATIONS

2.1 Geothermal Project Settings

Geothermal resources suitable for power generation can broadly be categorised as "volcanic systems" (high relief or island arc) e.g. Indonesia, or "continental systems," e.g. the Rift Valley. In many parts of the world, geothermal resources occur in areas remote from major load centres with challenging terrain, making them less attractive for solar co-development.

In contrast, New Zealand's main geothermal resource area (the Taupō Volcanic zone "TVZ") is a "continental system", located close to residential and industrial demand and having relatively benign accessible terrain. Consequently, the geothermal systems in the TVZ are well-suited for co-development with other renewables (refer to the examples in Figure 1).

Geothermal power developments are also suitable for solar co-development because they typically cover a substantial land area in order to access sufficient volumes of the underlying reservoir. Many geothermal developments are associated with large landholdings, and some of these co-exist and share the land with other users (e.g. forestry or cropping (Indonesia), pasture (New Zealand)).

For this study, the authors assessed a hypothetical solar development alongside a new geothermal development, with sufficient geothermal resource, land, and transmission interconnection capacity to accommodate a solar development. We assume that the geothermal project passes financial approval on its own merit (as a stand-alone project). While our premises rest on new development, the principles equally apply to brownfield geothermal sites with available land and interconnection capacity.

This paper is agnostic to the choice of geothermal energy conversion technology (power plant type), assuming that the current pricing ($/kW) and efficiency between conventional condensing steam turbine generator and organic Rankine cycle (ORC or Binary) plant are comparable. This assumption is valid and supported by data from the Jacobs reference project database[7].

Some technical considerations on surface facility operation (wells and steam gathering system) and power plant technology selection that could impact an adjacent solar farm are:

- Potential presence of hydrogen sulphide (H_2S) gas around well pads, piping vents and power plant non-condensable gas discharge points (typically the cooling tower / fin-fan cooler discharge for dispersion), and its impact on materials selection. H_2S is corrosive and care must be taken in materials selection and in particular on (field) electronics. There are many proven solutions for geothermal applications, and these may need to be adopted in the solar farm as appropriate, ditto for personnel protective measures.

- Potential for the cooling tower plume from a "wet cooling tower" as typically used on a conventional condensing plant to mist or precipitate on the solar panels. Wet cooling towers are most favourably aligned along the direction of the prevailing wind to minimise recirculation. The potential impact on solar panels can be mitigated through the placement of the panels at a sufficient distance from the cooling tower and avoiding prevailing downwind locations.

- ORC (Binary) plant typically uses "dry cooling", utilising fin-fan air coolers for waste heat rejection. While these do not have a moist plume, they do require considerable flat land area and may constrain the solar potential on a tight site with constraints on available land.

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[5] https://www.thinkgeoenergy.com/cyrq-energy-opens-solar-plant-at-its-patua-geothermal-facilities/
[6] https://www.thinkgeoenergy.com/stillwater-nv-triple-hybrid-geothermal-and-solar-plant/
[7] Proprietary to Jacobs, compiled and updated from world-wide project data available in both Public and Private domains

2.2 Solar Farm Projects - Siting and Design

Solar farms are rapidly becoming economically viable in New Zealand, and developers have announced over 300 MW ac of new projects over the next four years. There are three main types of ground-mounted array systems for solar farms: fixed-tilt arrays, single-axis trackers, and dual-axis trackers. Compared to a fixed-tilt PV array, a single-axis tracking system can potentially increase yield but requires more land to reduce shading losses. Single-axis trackers are the most common tracking systems installed today. Dual-axis trackers, being more complex, incur increased capital and operating costs and require additional land.

The design concept for the solar farm is consistent with the standard design practice for large-scale ground-mounted solar farms. The overall layout is not optimised to maximise power generation but to provide a balanced approach to maximising the number of modules within the orientation of the land and row spacing requirements. The major equipment selection is assumed commercially available from reputable manufacturers with requisite industry-standard certifications and warranties.

Solar farms are land-intensive, and the cost of land and civil works constitutes a significant component of the development cost. For this study, it is assumed the developer owns the land by right, and so the cost of land is excluded.

Typically, solar farm sites are selected with the following key features in mind:

- Close proximity to roads, sub-transmission lines, and zone substations
- Flattish terrain preferably clear of forest/bush/scrub (other than minor shelterbelts)
- Low land value across large land parcels
- High levels of solar irradiation, and low irradiation variance.

For this paper, the authors have evaluated both fixed-tilt and single-axis trackers with monofacial modules, as well as single-axis trackers with bifacial modules.

Figure 2: Fixed tilt (left) and single-axis tracker (right) systems used in ground-mounted solar PV systems

2.3 Fixed Tilt & Trackers

A fixed tilt system positions the PV modules at a “fixed” tilt and orientation. For most fixed-tilt PV systems, modules should always face true north in the southern hemisphere or true south in the northern hemisphere. Tilt angle is also an important parameter for capturing maximum solar radiation on its plane. This angle is site-specific and depends on the daily and yearly seasonal variation of solar irradiance at a particular location.

Solar tracker systems automatically adjust the positions of the PV modules so that the PV modules consistently “track” the sun throughout the day. Compared to a fixed-tilt PV array, a single- or dual-axis tracking system can potentially increase the yield for the same size array. Single-axis trackers are the most common tracking systems installed today. Although a dual-axis tracker can increase the yield by 5%-10% above a single-axis tracker, single-axis trackers are more cost-effective and reliable.

Given single-axis trackers can always produce a higher annual yield than fixed-tilt systems, there are technical issues that can limit the trackers’ technical and economic viability. These issues are mainly; wind loads (modules stowed in a flat position during high winds reduces yield), site topography (installation typically limited to grades less than 10% and no undulation) and soil conditions (additional torque from trackers means larger and deeper piles are required).

2.4 Solar PV Modules

Across the industry, PV modules continue to gain in efficiency, with increasing power outputs available (up to 600Wp). Bifacial PV module costs are falling and a recent study[8] indicates that the combination of bifacial PV modules and single-axis tracker results in the lowest LCOE in many locations[9]. For this study, the authors have considered 550Wp monofacial and 545Wp bifacial modules.

2.5 Inverters

A solar inverter is an integral part of a solar PV system, converting the direct current output of PV modules to alternating current. Inverters can also provide reactive power support to the system (even at night), although they do introduce some harmonics into the system. For this study, the authors have considered a 20MW ac system comprising five 4 MW inverters.

2.6 Slope Considerations

As discussed, ground undulations can limit tracker viability as most single-axis trackers have restrictions on a slope, typically of ≤10° on North-South slopes. Sun-facing slopes are desirable for the horizontal N-S axis trackers as they offer increased solar irradiance. Based on preliminary modelling, trackers on a 10° slope can generate 4 to 6% more power than trackers on flat ground. This improves project economics and may also suit some geothermal sites with moderate terrain.

For the purpose of this study, the authors have based assumptions on selecting the flattest sites utilising Google Earth™.

2.7 Common Features and Site Assumptions for this study

The study presumes that a solar PV farm is installed to augment a new greenfield geothermal development. Several recent geothermal developments were evaluated using public domain cadastral data and Google Earth™ to model a conceptual 100MWe scale geothermal power development.

The land area required for the geothermal development includes the power plant, administration and lay down and common areas, as well as land for well pads, separation stations, and road and piping corridors, and area for future make-up well pads and a future power plant. These land packages have a significant surplus area that can be used for other purposes.

In the solar PV concept development (factored from reference plants), two contiguous blocks of approx. 20 ha total were assumed available on suitable terrain while avoiding constraints such as the geothermal power plant cooling tower. With a ground coverage ratio (GCR) of 50% (where GCR = area of PV modules/total land area), the achievable solar output is estimated to be approx.. 20 MW ac. Fewer, larger blocks were assumed, as with suitable terrain, they can be populated with regularly spaced rows. This assumption of 50% GCR is achievable, although at the optimistic end of the scale for fixed-tilt and tracker systems. In real-world settings, fixed-tilt panels could be installed on multiple (smaller) land parcels.

The solar farm is assumed to follow on from the initial geothermal development and leverages site preparation, planning and management activities, so allowances for "engineering and owner costs", and "estimating margin" are reduced to 5% each. It is also assumed that there is sufficient capacity assumed in the geothermal project to support the next stage of geothermal expansion and the solar augmentation. This includes all administrative and shared facilities (e.g. administration and workshops), and importantly sufficient capacity in the substation and grid connection. These items are not included in the solar cost estimate.

3. MODELLING COMBINED GEOTHERMAL & SOLAR DEVELOPMENT

3.1 A note on the basis of assumptions between geothermal and solar developments

By nature, solar resources (also wind, and to a lesser degree hydro) can be far more accurately measured, quantified and assessed prior to development compared to a geothermal resource, which until "drilled and proven" relies on indirect and inferred measurements, and assessment by analogy and probabilistic methods. In contrast, robust solar irradiation data, power yields, and cost data are readily available for this study. That said, the geothermal model assumptions and methodology are, in the authors' experience, appropriate and valid in the current New Zealand setting.

3.2 Modelling Geothermal Development

The geothermal power development is assumed to be the core or anchor project providing baseload generation, in this case, 100MWe net. The geothermal project has attained a final investment decision as a stand-alone project on its own merit. The co-located solar farm is assumed to be developed as a separate project to augment the geothermal generation, and as such, is evaluated on the incremental costs and benefits.

3.3 Model Assumptions

A simple capital and operating model for a greenfield geothermal project development was built up based on information in the Jacobs reference project database, acknowledging established benchmarks and taking into account trends on more recent projects. The base data is denominated in United States Dollars (USD) and has been converted to New Zealand Dollars, and construction costs

[8] Jacobs © 2021

[9] https://www.pv-magazine.com/2020/08/19/bifacial-modules-the-challenges-and-advantages/ and https://www.pv-tech.org/bifacial-with-single-axis-trackers-is-low-cost-king-for-global-solar-seris/

adjusted to a New Zealand basis using the Arcadis International Construction Cost Index 2020/2021[10]. The key parameters used for the greenfield geothermal project evaluation are set out in Table 2.

Table 2: Cost Assumptions and Basis for Geothermal Powerplant Development

	Units	Range	Assumed Value
CAPITAL COSTS[11]			
Well cost (production & injection)	USD / well	5 to 10	6
Well CAPEX (1)	% overall project	35% to 50%	(40%) 1600
FCRS CAPEX (2)	USD / kW installed	250 to 650	350
Powerplant CAPEX (3)	USD / kW installed	900 to 1,800	1,050
Civil works CAPEX (4)	USD / kW installed	400 to 800	400
Engineering, construction supervision, + estimating margin (5)	10% + 10% (20% total)	-	(15%) 600
Total CAPEX (6)	USD / kW installed		4,000
OPERATIONAL COSTS[12]			
Annual O&M costs (7)	USD / MWh	10 to 30	17
Well decline rate (8)	% (exponential)	resource dependent	3
FCRS (sustaining capital) (8)	% / year	complexity dependent	4

Notes:
(1) Typically, 35 to 50% of total project cost depending on resource type and well productivity
(2) Fluid collection and reinjection system (steam field surface facilities) – cost dependant on a resource (low to high enthalpy) and terrain/complexity. The assumed value accounts for a medium enthalpy resource in benign terrain
(3) Recent reference data indicates this is a reasonable assumption for both condensing and ORC plants at ~100MW scale
(4) Assumes a reasonable compact development in benign terrain with good access to the site
(5) Typical owner engineering and supervisions costs and allowance for "known unknowns."
(6) Total development cost including exploration and initial production wells to COD
(7) Consistent with a New Zealand based reference to cost (2019)
(8) Reservoir (well) decline rate and FCRS sustaining capital costs are resource and location-specific. The authors have assumed reasonable typical values for a good resource in a New Zealand setting

General Assumptions
(9) Land – assumed already owned by owner-developer and is treated as 'sunk cost.'
(10) Transmission/Interconnection – transmission line/interconnection costs excluded as they are very location specific
(11) Finance costs – excluded from this study (noting WACC / discount rate is assumed at 7%)
(12) Advisors costs – assumed included under the total CAPEX unit installed cost

The geothermal power plant development model evaluates the project capital and operating costs for the project and calculates the net present value (NPV) and levelised cost of energy (LCOE) for given financial parameters. The model outputs for a 100MWe geothermal power plant development is compared to a 20 MW ac solar farm with the same financial assumptions in Table 5.

3.4 Modelling Solar Development

3.4.1 Solar Data

For the purpose of the analysis below, the authors utilised solar irradiance data from PVsyst (Meteonorm 8.0) for the Taupō Volcanic Zone region. Meteonorm provides the long-term monthly meteorological data for any location on the earth, which can then be used to produce a synthetic hourly meteorological data set.

3.4.2 Solar Potential, Technology Selection, and Yield

Three commercially available technologies in current use in New Zealand, were evaluated. These ranged in complexity and cost from relatively simple/low to moderately high. The three scenarios modelled were: (a) Fixed Tilt (30°) with monofacial modules, (b) Single Axis Trackers (SAT) with mono facial modules, and (c) SAT with bifacial modules.

The authors have undertaken an energy yield assessment based on the high-level design parameters described in Table 3 below. The energy yield simulations have been carried out using PVsyst software (Version 7.2.4).

[10] https://www.arcadis.com/en/knowledge-hub/perspectives/global/2021/international-construction-costs-2021
[11] Source: Jacobs reference project data base and modelling tools
[12] Source: US Dept. Energy / ESMAP Technical Report 002/12 / NZ Ministry of Business Innovation & Employment, March 2020 (Lawless, van Campen & Randle)

Table 3: Solar Model Parameters and Outputs (for nominal 20 MAW ac)

Parameter	**Fixed Tilt 30°**	**SAT (monofacial)**	**SAT (bifacial)**
Orientation / Tilt	0° (North) / 30°	0° (North) / ± 60°	0° (North) / ± 60°
PV Modules	550 Wp	550 Wp	545 Wp
Number of Modules	38,175	38,175	38,532
Nominal PV Power (kWp)	20,996 kWp	20,996 kWp	21,000 kWp
Ground Cover Ratio (GCR)	50% – assumed same for all options		
Module Area	98,000 m^2 (9.8 ha) – assumed same for all options		
Total Area	195,200m^2 (19.5 ha) – assumed same for all options		
Annual Generation	**32.8 GWh**	**36.4 GWh**	**37.5 GWh**

The monthly average energy production for two of the proposed systems are presented in Figure 3 below. The year one energy yield value below accounts for all expected module degradation in the first year of operation. However, the energy yield does not account for any unavailability losses, which should be considered in a financial model. In addition, long-term degradation should also be applied, beginning in the first quarter of the second year of operation. In recent years, the industry has moved on to new technologies, including half-cut monocrystalline modules, which reduce electrical stresses and losses, and as a result, manufacturers of these types of modules are offering 30-year performance warranties with an even lower degradation rate. For this study, the authors have assumed a long-term degradation value of 0.44% per annum[13].

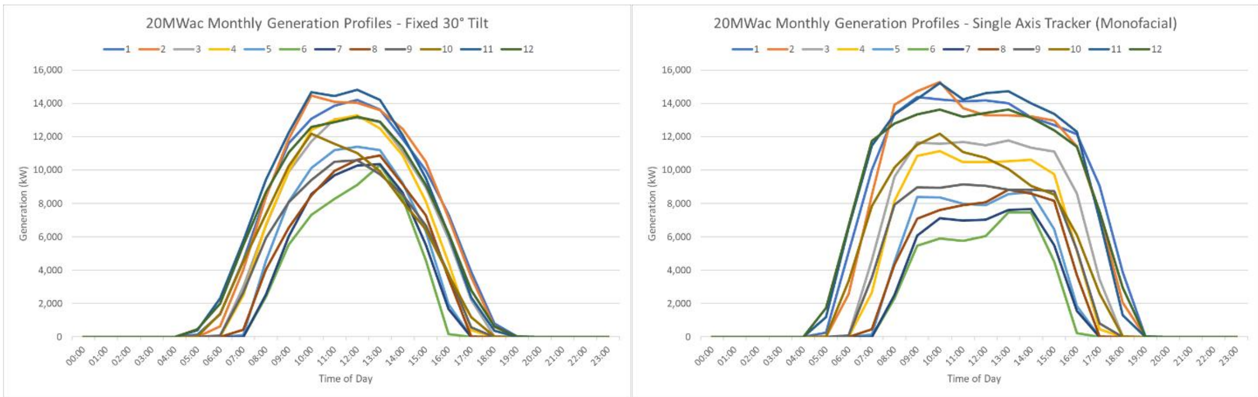

Figure 3: Monthly generation profiles: Fixed 30° Tilt 32.8 GWh/year (left) and SAT mono facial 34.6 GWh/year (right)

Note: (1) that the single-axis tracker scenario flattens/widens the daily profiles. However, peak power is reduced in winter months compared to the fixed-tilt scenario, (2) for trackers, the width of profiles is very similar between the mono and bifacial panels, with the difference in peak most pronounced in summer months and little difference in peak in winter months.

3.4.3 Key Assumptions: Land Purchase, Capital Costs, Operating and Maintenance Costs

The study assumes that the owner/developer has purchased the land required for the solar farm sites as part of the land parcel required for the geothermal development due to the large area required for the surface facilities (well pads, cross-country piping etc.). The solar project economic analysis thus treats the land purchase cost as sunk.

For panels, mono facial solar PV module costs were based on recent average market prices for solar PV modules[14], and bifacial PV modules were estimated to be US 4c/Wp higher given recent trends.

The costs for "other capital cost items" such as the key electrical equipment, logistics, civil works, installation and project management were estimated based on information from recent projects taken from the Jacobs reference project database and in-house cost models. An allowance was made for the Owner's costs, including project management, engineering and advisory (5%) and "estimating margin" (5%). This is based on a percentage of the total capital costs (equipment and installation) with loss of economies of scale assumed for smaller solar farms, typically between 10 ~ 20%. Operational and maintenance costs were established from reference to international studies on solar O&M costs from NREL and EPRI[15].

[13] LONGI 25 year linear performance warranty for monofacial modules = 0.55% / 30 year life = 0.45% per annum

[14] PV Insights – average spot prices for Mono High Efficiency PERC modules in international markets. http://pvinsights.com/ as at 28 May 2021

[15] Electric Power Research Institute (EPRI), "Budgeting for Solar PV Plant Operations & Maintenance : Practices and Pricing", December 2015, https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2016/160649r.pdf NREL, 2017, ibid.

3.4.4 CAPEX and OPEX Cost Summary for Technology Selection

The solar potential and generation outputs from the PVsyst model were taken, and a technology screen exercise was carried out on a first pass estimate of capital, operating costs and LCOE. This capital, operating and performance figures are summarised in Table 4 :

Table 4: Screening Estimate for 20 MW ac solar farms

	Units	Fixed Tilt 30°	SAT (monofacial)	SAT (bifacial)
Nominal PV power	kWp	20,996	20,996	21,000
CAPEX	NZD / MWp	1.22	1.32	1.38
OPEX	NZD'k / MWp / year	25.60	30.38	30.38
CAPEX and ANNUAL OPEX (year 0 absolute values)				
CAPEX	NZD	25.615 million	27.715 million	28.979 million
OPEX (annual)	NZD / year	537.5 k	637.9 k	637.9k
Annual Generation	GWh	32.8	36.4	37.5
Indicative LCOE (1)	**NZD / MWh**	**82.88**	**82.39**	**82.96**
Note (1) cashflows discounted at 7.0%, energy flows discounted at 7.44% (7% base + 0.44% annual degradation) (2) Model expressed in NZD using exchange rate USD/NZD = 0.74				

The SAT option with mono facial panels has the broadest generation profiles and gave the lowest indicative LCOE, and so was selected to take forward as the preferred option. The fact that the indicative LCOE is close between all options is discussed in 4.1 Observations and Discussion below.

3.4.5 Notes and Industry Trends

NREL (2017) reports that O&M costs for solar farms have been tracking downwards for the last 10 years, and as of 2017, the average O&M expense was $US18.5/kWp per annum for a 100MWp single-axis tracking solar farm and $US15.4/kWp for a 100MWp fixed-tilt solar farm. The authors' assumptions are consistent with these, allowing for dis-economies of scale from smaller solar farm sizes. The authors make the following notes on assumptions:

- No allowance for connection charges (as the transmission connection assets have been factored into the Capex) or maintenance of the transmission connection assets are incorporated in the electrical balance of plant maintenance calculation.

- No allowance for any community funds or ongoing environmental mitigation that might be required as part of the resource consent. It is the author's opinion that development, manufacturing and scale economies have been worked through in the solar PV market supply side, and that the downward pressure on headline prices ($/kW installed) will ease, and so solar PV project prices will tend to stabilise as a "maturing technology".

3.4.6 Economic Analysis

The geothermal and solar options taken forward (high enthalpy 2 phase resource – condensing steam turbine and single-axis tracked mono facial respectively) were evaluated on a discounted energy and cash flow basis over a 25 year period (with 25 years being a reasonable position between geothermal and solar plants). The assumptions and model outputs for the solar and geothermal plant evaluations are set out in Table 5 below.

Table 5: Project Cost Model Summary

	Units	Geothermal	Solar	Combined
Financial / Economic	(USD:NZD = 0.74)			
Economic Life	years	30+	20 to 30	25 yr study period
WACC / Discount Rate	%	7.0	7.0	7.0
Energy Discount Rate	%	in performance model	7.44	
Technical				
Capacity	MW	105 gross / 100 net	20 MW ac	120 MW.net
Capacity Factor	%	95%	20%	
Annual Generation	MW	875.974	364	912.374
Total Generation	GWh	10047.8	417.5 (4%)	100464.32
Costs				
Capital Cost	USD.M (PV)	421.04	20.04	441.08
Sustaining capital	USD.M (NPV)	94.166		
Operating Cost	USD.M (NPV)	158.634	5.41	164.044
Total Cost	USD.M (NPV)	673.84	25.45	699.29

LCOE	**USD / MWh**	**67.07**	**60.97**	**66.83**
(USD:NZD = 0.74)	**NZD / MWh**	**90.63**	**82.39**	**90.31**
Notes: Typically, many companies calculate their average cost of capital (WACC) and use it as their discount rate when budgeting for a new project.				

Overall, the authors are comfortable that the base case and variable costs assumed for the geothermal and different solar farm sizes and configurations are appropriate for the purpose of this study given the AACE[16] Class 5 level of accuracy assumed (-25%/+100%).

For the geothermal cost estimate, while major equipment and EPC costs are better known from the market, there is considerable uncertainty in the resource conditions and well costs which account for approximately 40% of the cost.

For the solar farm, this is not a stand-alone grid-connected installation, for which anecdotal evidence suggests an LCOE range of NZD 95 to $105+. The sturdy figure of LCOE NZD 82.39 should be treated as optimistic, and the authors expect a range of NZD 83 to 90.

4. MODEL FINDINGS

4.1 Observations and Discussion

Geothermal power development is the main project and provides firm baseload renewable generation at high availability and capacity factors (typically 93% to 98%). The solar farm is installed to monetise the geothermal project land and augment the baseload geothermal with solar generation to cover load during the day.

Geothermal and solar power investments are financial compliments. Geothermal power developments combine high unit installed costs (USD 4,000//kW for this study) with very high availability. Conversely, solar farms have low unit installed costs (USD 955/kW this study), combined with low capacity factors, resulting in a typically higher Levelized cost of electricity (LCOE).

The economics of the solar project critically relies on the sunk costs accrued by the geothermal project to achieve a comparable LCOE.

A fixed tilt system has the lowest CAPEX and OPEX, the mono facial SAT system has a higher initial CAPEX and moderately higher OPEX, with the bifacial option being a marginal increase on this. The modelling shows that mono facial trackers give the lowest LCOE and appear the more favourable option. Note: in sites with higher solar irradiance (e.g. Australia), industry studies suggest bifacial units appear more favourable

The capacity of 20 MW ac for the study case for solar was selected at 20 MW ac because it is scalable with modular key components and the authors have good information in this size range. In addition, significantly more than that could constrain the capacity for a future geothermal power plant unit. A future, more detailed study might consider starting at 10 MW ac with the base case at 20 MW ac and the upside at 30 MW ac to see if there are material economies of scale.

The calculated LCOE is very close between all options and certainly within the bounds of uncertainty given the concept nature and assumptions of this study. So, the conclusion drawn is that for a real-world application, should the initial economics from a study level look attractive, then all three options should be considered in more detail at the feasibility stage.

The economics of solar are more nuanced than for geothermal, as the benefits derive from both direct and indirect factors:

- Direct revenue from selling the generation,
- Offsets or avoided costs to existing carbon emissions.
- Portfolio benefits related to how the rest of the supply portfolio works around solar to reduce risks in managing the overall sales portfolio; and
- Grid benefits accruing to local generation (for example, for a geothermal plant, the field 11 kV system may be tied to the local network via a 33 kV feeder), so the network is effectively strengthened by local generation. This is because the inverters can provide reactive power support (even at night). On the downside, they do introduce some harmonics into the system, which is an area that is of concern to the network operator.

The solar farm, when operational, would displace the parasitic and auxiliary loads from the geothermal steam field and power plant, which for this concept development would be around 5Mwe. Project economics depends on understanding the underlying price arbitrage of this displacement.

Interestingly, the loss of a solar peak resulting from a tracker is not a liability, as the solar peak occurs during the mid-day drop in load. In addition, the broader profile of the solar output resulting from trackers provides generation closer to the morning and

[16] Association for the Advancement of Cost Engineering (https://web.aacei.org/)

afternoon peak load periods, reducing the grid system's ramp-up rates. So commercially, maximising a peak output may have limited portfolio value for the generator-retailer's book.

5. CONCLUSION

The use of solar PV to augment geothermal power generation has been proven to be technically feasible at several locations worldwide, although information on the commercial outcome is not available in the public domain.

Blending baseload and variable load renewable generation will be necessary to meet New Zealand's ambitious targets of 95% to 98% renewable generation by 2035 and net zero emissions by 2050[17].

The bulk of New Zealand's existing renewable electricity is primarily hydropower and geothermal power. It seems unlikely that any new conventional hydropower schemes will be consented and developed, so our remaining geothermal resources plus variable sources like wind and solar will have to do the heavy lifting.

This study shows the technical and commercial synergies with the co-location of variable renewable energy with baseload geothermal generation. With benefits being improved use of available land, synergies with geothermal assets (facilities, operations, grid connection etc.), improved economics on the incremental generation, and the ability to provide some local grid support.

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