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DISTRICT COUNCIL

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SUBMISSION ON NOTIFIED APPLICATION CONCERNING RESOURCE CONSENT

(Form 13)

Section 95A Resource Management Act 1991

To: The Chief Executive
Central Otago District Council
PO Box 122
Alexandra 9340
resource.consents@codc.govt.nz

DETAILS OF SUBMITTER

Full name: Richard John Healey

Contact person (if applicable):
Richard Healey

Electronic address for service of submitter: rjh@netcasterz.com

Telephone: +64 212288191

Postal address (or alternative method of service under *section 352* of the Act):
8 Owen St, Green Island, Dunedin 9018, Otago

This is a submission on the following resource consent application: RC No: **240065**

Applicant: **Helios OTA Op LP** Valuation No: **2828012800**

Location of Site: **48 Ranfurly-Naseby Road**

Brief Description of Application: **Land Use Consent to Construct, Operate and Maintain a Solar Farm (Maniatoto Plain Solar Farm) being a Renewable Electricity Generation Activity in a Rural Resource Area.**

The specific parts of the application that my submission relates to are:
(give details, attach on separate page if necessary)

Attached

This submission is: *(attach on separate page if necessary)*

Include:

- *whether you support or oppose the specific parts of the application or wish to have them amended; and*
- *the reasons for your views.*

Attached

I/We seek the following decision from the consent authority:
(give precise details, including the general nature of any conditions sought)

Attached

I ~~support~~/oppose the application OR neither ~~support~~ or oppose (select one) Oppose

I wish / ~~do not wish~~ to be heard in support of this submission (select one) I wish to be heard

I ~~am~~/am not* a trade competitor for the purposes of section 308B of the Resource Management Act 1991 (select one) I am not

~~***I/We am/am not (select one) directly affected by an effect of the subject matter of the submission that:**~~

~~**(a) adversely affects the environment; and**~~

~~**(b) does not relate to trade competition or the effects of trade competition.**~~
~~**Delete this paragraph if you are not a trade competitor.*~~

*I/We will consider presenting a joint case if others make a similar submission**
Delete this paragraph if not applicable.

I will consider a joint submission

~~I request/~~do not request (select one), pursuant to [section 100A](#) of the Act, that you delegate your functions, powers, and duties to hear and decide the application to 1 or more hearings commissioners who are not members of the local authority. ***"See note 4 below as you may incur costs relating to this request."***

Richard Healey

19/12/2024

Signature **Date**

(to be signed by submitter or person authorised to sign on behalf of submitter)

In lodging this submission, I understand that my submission, including contact details, are considered public information, and will be made available and published as part of this process.

Notes to submitter

1. If you are making a submission to the Environmental Protection Authority, you should use form 16B.

The closing date for serving submissions on the consent authority is the 20th working day after the date on which public or limited notification is given. If the application is subject to limited notification, the consent authority may adopt an earlier closing date for submissions once the consent authority receives responses from all affected persons.

2. You must serve a copy of your submission on the applicant as soon as is reasonably practicable after you have served your submission on the consent authority.

3. If you are a trade competitor, your right to make a submission may be limited by the trade competition provisions in Part 11Aof the Resource Management Act 1991.

4. If you make a request under section 100A of the Resource Management Act 1991, you must do so in writing no later than 5 working days after the close of submissions and you will be liable to meet the additional costs of the hearings commissioner or commissioners, compared to our hearing panel. Typically these costs range from $3,000 - $10,000.

5. Please note that your submission (or part of your submission) may be struck out if the authority is satisfied that at least 1 of the following applies to the submission (or part of the submission):

- **it is frivolous or vexatious:**
- **it discloses no reasonable or relevant case:**
- **it would be an abuse of the hearing process to allow the submission (or the part) to be taken further:**
- **it contains offensive language:**

it is supported only by material that purports to be independent expert evidence, but has been prepared by a person who is not independent or who does not have sufficient specialised knowledge or skill to give expert advice on the matter.

Background:

I am a regular visitor to the Maniototo – and have been for over five decades. I have contributed to the creation and implementation of a significant destination event centred within two kilometres of the Northern boundary of the proposed Helios BESS and solar generation site, The Great Naseby Waterrace. I travel to the Maniototo many times a year to capture its unique landscape via photography – particularly astrophotography. During those visits I often stay at a property immediately adjacent to the site of this proposal.

I am also a veteran of New Zealand's electricity supply industry and my position on the need for the safe, reliable and economically attainable supply of electricity to New Zealand homes and businesses is well established. During the 46 years that I have devoted to building the generation, distribution and end point facilities that contribute to that safe, reliable and economically viable system, I have worked in roles from digging holes to managing distribution teams and consulting for EDB's. Fault analysis is now a particular focus of my effort.

This proposal:

I object to the totality of this proposal. It is predicated on a morass of misrepresentation, omission and inadequate explanation.

It often holds as fact things that are simply not true. From an engineering perspective, the attached reports contain glaring omissions and provide conclusions that simply cannot be attributed to the supporting data. The conclusions held within the application are often not supported by the lived experience of people who have spent entire lifetimes in the affected area.

By the numbers:

On page 438 Helios make the bold, and completely unsupportable claim that

"There is no increased risk of fire with a solar farm. Solar panels are not flammable. The components are encapsulated in glass and cannot support a fire. All major electrical components such as inverters and transformers will be containerised. Electrical wiring from panels to inverters is undergrounded".

I start with this paragraph simply because it encapsulates, within 47 words, so many gross oversimplifications, misrepresentations of fact and unsupportable assertions that I consider it a very good guide to the value of the application as a whole.

From the top, there is a demonstrably increased risk of fire associated with a solar farm. This installation involves over one million electrical connections for the panels alone and thousands of kilometres of interconnecting wire suspended over a fuel load that has increased flammability due to the increase in local temperature that the panels themselves create. Simply enormous amounts of energy flow through those conductors. In the event of a failure of any component associated with the panels the energy likely cannot be removed from that system because, ultimately, that energy is the sun - and you cannot turn off the sun.

Solar panels are flammable, they are generally not "encapsulated in glass" (a bi-facial panel might be, but there is no indication from Helios about the type or flammability class of the panels they intend to use, and bi-facial panels are unlikely to be employed). A small percentage of panels are "double glass" but, as with so many elements of this installation, the applicant has provided no information about the panels they intend to use. I can find no data that suggest double glass panels have a lower risk of being the point of inception for a fire than any other type.

To a very high degree, the most common encapsulant on solar panels is not glass, but EVA film, an extremely flammable polymer.

This paper: https://epublications.marquette.edu/cgi/viewcontent.cgi?article=1086&context=chem_fac , which outlines the researchers attempts to overcome the obvious problems associated with the use of EVA, contains these words "The ease of ignition and subsequent flaming combustion with the release of large volumes of toxic smoke prohibit the application of EVA-based materials in high temperature service environments."

Even if the panels proposed for use here were "encapsulated in glass", that encapsulation is extremely unlikely to survive a fire of any significant size - which may be initiated in any one of the, literally, millions of electrical components that make up the installation.

There exists an IEC standard (IEC 61730-2) that divides PV panels into one of three categories according to their propensity to spread a fire once they are ignited. Those categories are: Flame spread should not exceed: Class A – 1.82 m, Class B – 2.40 m, & Class C – 3.90 m under defined test conditions.

We are not told what category of panels Helios intends to employ.

In my view, Helios's claim extends beyond the disingenuous into the realms of the deceitful. Solar panels are not some benign, foolproof, rock-like component that perform in a foolproof way due to some inherently safe characteristic. They are one part of a system that envelopes literally millions of potential points of failure, a system which is designed to transmit large quantities of a potentially lethal form of energy.

Simply by confining their comments to the solar panels themselves – and not the system as a whole – Helios have sought to sustain the unsustainable, the idea that a system containing millions of discrete electrical connections, spaced evenly across a fuel load that has been dried by the increased ambient temperatures created by the installation itself, that is transmitting huge amounts of energy, at potentially dangerous voltages, somehow adds no risk of fire. The idea is inconceivable.

PV panels present many challenges at the design and construction phase, not the least of which is the fact that, unlike almost all other forms of generation, you can not turn off the generator – you cannot switch off the sun. This characteristic alone leads to a plethora of problems for PV installs. Once a fire has initiated within a panel, or within its surroundings, damage to the insulation of the conductors that link the panels together is almost assured. Damaged insulation will often lead to arcing that is likely to persist – because the source of energy, the sun, can not be switched off and it is extremely unlikely that any protection devices will be available to disconnect the failure point from the rest of any given solar string.

It's important to understand that Utility scale solar does not run at 12 Volts, nor 24V. With large solar installations there is a massive economic driver to use the highest available voltage in an installation. While each panel may only produce a few tens of Volts, those panels are connected in series to produce hundreds and - sometimes - over a thousand Volts. That increase in Voltage comes with an increase in risk. Insulation levels of every part of every component become critical to the safety of the installation as a whole. Those elevated Voltages also pose a risk to life for anyone engaged in containing a fire once it starts.

We are not dealing with ten or fifteen PV panels placed on a roof and producing a few tens of Volts. Here we are dealing with a totally different proposition. With increased scale comes increased risk, with massively increased scale comes massively increased risk.

Damaged interconnecting string conductors present two additional challenges to fire prevention and remediation. Water, used during firefighting operations may in fact contribute to the fire through increased, unintended, current flow and subsequent arcing. Damaged conductors will continue to feed into a short circuit until the sun goes down -unless that circuit is protected by an effective means of disconnection - which is extremely unlikely for a single string. Re-ignition of the fire from such an arc is a very real possibility. With DC current there is no zero-crossing point, once an arc is established the arc will likely self-sustain. In AC systems, an event may cause an arc to form, but the voltage of the system drops to zero 100 times a second and if the event that caused the arc to initiate is no longer present then there is a chance for the arc to extinguish.

To illustrate just how much effort has gone into attempting to mitigate the risks presented by solar panels themselves, as opposed to the BoS, I list below the standards referenced by IEC 61730-1:2023, a standard which specifies and describes the fundamental construction requirements for photovoltaic (PV) modules.

IEC 60216-1, Electrical insulating materials – Thermal endurance properties – Part 1: Ageing

procedures and evaluation of test results

IEC 60216-2, Electrical insulating materials – Thermal endurance properties – Part 2:

Determination of thermal endurance properties of electrical insulating materials – Choice of test criteria

IEC 60216-5, Electrical insulating materials – Thermal endurance properties – Part 5: Determination of relative temperature index (RTE) of an insulating material

IEC 60243-1:2013, Electric strength of insulating materials – Test methods – Part 1: Tests at power frequencies

IEC 60243-2:2013, Electric strength of insulating materials – Test methods – Part 2: Additional requirements for tests using direct voltage

IEC 60269-6, Low-voltage fuses – Part 6: Supplementary requirements for fuse-links for the protection of solar photovoltaic energy systems

IEC 60364-7-712, Low voltage electrical installations – Part 7-712: Requirements for special installations or locations – Solar photovoltaic (PV) power supply systems

IEC 60417, Graphical symbols for use on equipment, available at https://www.graphical-symbols.info/equipment

IEC 60529, Degrees of protection provided by enclosures (IP code)

IEC 60664-1:2020, Insulation coordination for equipment within low-voltage systems – Part 1:Principles, requirements and tests

IEC 60695-11-10, Fire hazard testing – Part 11-10: Test flames – 50 W horizontal and vertical flame test methods

IEC TS 60904-1-2, Photovoltaic devices – Part 1-2: Measurement of current-voltage characteristics of bifacial photovoltaic (PV) devices

IEC 60950-1:2005, Information technology equipment – Safety – Part 1: General requirements

IEC 61032:1997, Protection of persons and equipment by enclosures – Probes for verification

IEC 61140, Protection against electric shock – Common aspects for installation and equipment

IEC 61215 (all parts), Terrestrial photovoltaic (PV) modules – Design qualification and type approval

IEC 61730-2, Photovoltaic (PV) module safety qualification – Part 2: Requirements for testing

IEC TS 61836, Solar photovoltaic energy systems – Terms, definitions and symbols

IEC 62548, Photovoltaic (PV) arrays – Design requirements

IEC 62788-1 (all parts), Measurement procedures for materials used in photovoltaic modules –

IEC 61730-1:2023 ED3

https://standards.iteh.ai/catalog/standards/sist/5eef43fe-6c78-41aa-9cf9-b8ae88fdf715/iec-61730-1-2023-ed3

IEC 62788-1-2, Measurement procedures for materials used in photovoltaic modules – Part 1-2:

Encapsulants – Measurement of volume resistivity of photovoltaic encapsulants and other polymeric materials

IEC TS 62788-2, Measurement procedures for materials used in photovoltaic modules – Part 2: Polymeric materials – Frontsheets and backsheets

IEC 62788-2-1, Measurement procedures for materials used in photovoltaic modules – Part 2-1: Polymeric materials – Frontsheets and backsheets – Safety requirements

IEC 62790:2020, Junction boxes for photovoltaic modules – Safety requirements and tests

IEC 62852, Connectors for DC-application in photovoltaic systems – Safety requirements and tests

IEC 62930, Electric cables for photovoltaic systems with a voltage rating of 1,5 kV DC

IEC TS 63126, Guidelines for qualifying PV modules, components and materials for operation at high temperatures

IEC TR 63225, Incompatibility of connectors for DC-application in photovoltaic systems

ISO 1456, Metallic and other inorganic coatings – Electrodeposited coatings of nickel, nickel plus chromium, copper plus nickel and of copper plus nickel plus chromium

ISO 1461, Hot dip galvanized coatings on fabricated iron and steel articles – Specifications and test methods

ISO 2081, Metallic and other inorganic coatings – Electroplated coatings of zinc with

supplementary treatments on iron or steel

ISO 2093, Electroplated coatings of tin – Specification and test methods

ISO 7010, Graphical symbols – Safety colours and safety signs – Registered safety signs,

available at https://www.iso.org/obp

ISO 9224:2012, Corrosion of metals and alloys – Corrosivity of atmospheres – Guiding values

for the corrosivity categories

EN 50618, Electric cables for photovoltaic systems

UL 746B, Standard for Polymeric Materials – Long Term Property Evaluations

IEC/IEEE 82079-1, Preparation of information for use (instructions for use) of products – Part 1:Principles and general requirements.

That list should provide some idea of the complexity involved in the construction of PV panels.

Quantifying the degree of risk from fire within PV installations is complicated by the lack of compulsory reporting of such events and by the lack of a suitable database for the collection of such data, nevertheless, some research is available.

In the paper "Worldwide scientific landscape on fires in photovoltaic" [1] the authors say ***"There is a lack of comprehensive data on fires caused by PV installations, which are usually classified as 'other' incidents. As a reference, a frequency analysis shows 0.289 fires per MW installed, or 28.9 fires per GW installed (Ong et al., 2022)"***

They go further and agree with my own analysis of solar based fire risks precisely ***"Potential fire hazards in PV systems are a critical concern that requires thorough analysis and mitigation strategies (Juarez-Lopez et al., 2023). Extinguishing a fire in a photovoltaic electrical installation is a challenging task. This is due to the unique characteristic of photovoltaic modules, which continue to produce energy despite the presence of fire. It is important to note that electricity continues to flow through the installation, even during a fire. For instance, the cables of a photovoltaic installation can carry up to 1500V of direct current. In other words, water alone cannot extinguish a fire as it poses an added danger of electrocution."*** [1]

In an issue of Solar titled "A Review of Photovoltaic Module Failure and Degradation Mechanisms: Causes and Detection Techniques" [2] The authors state:

"Furthermore, some PV failures, such as cell cracks, propagate rapidly [33,34]; if undetected, they will cause a significant cost loss that may reach up to 10 times the equipment cost [38]. This is because some undetected failures may lead to fire and catastrophic damage to the entire PV system [39]. For instance, critical degradation in some PV modules in an array system leads to mismatch, increasing

the PV module's temperature and subsequently leading to fire [40,41]. Critical degradation in PV modules was also highlighted as initiating fire in a research project based in Germany [39]. Fire can also be caused by hotspot failure, primarily driven by other failure mechanisms that elevate the operating temperature to a hazardous level, and eventually cause a fire [42,43]. There have been 80 fire incidents involving PVs in the United Kingdom alone [44].

While many of the listed failures are for rooftop mounted solar, the underlying systems and components, particularly the panels, share many characteristics with utility scale installs. Image 1 (below) is taken from this paper [2] and shows a hot spot created by an internal fault in the panel.

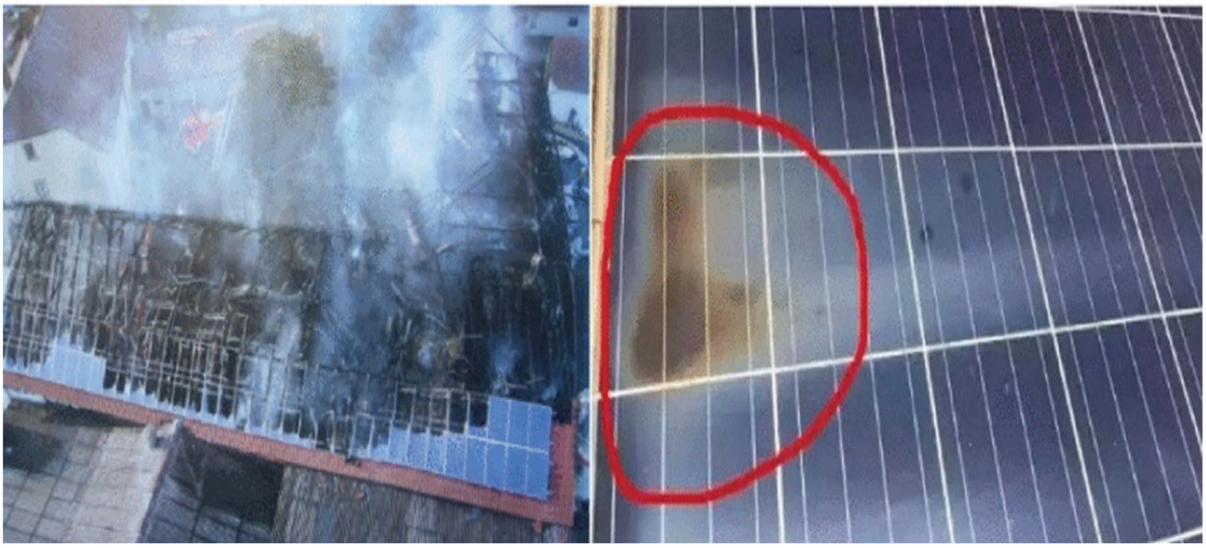

Image 1 Fire initiated by a hotspot in a PV panel

In the same paper [2], the authors say:

"The fire caused by PV failures not only results in power reduction and cost losses, but it may sadly lead to fatalities; twenty-two casualties related to fire incidents stemming from PV failures were reported in the UK by BRE National Solar Centre."

The report quoted above [3] identified 63 components that could be labelled with accuracy as the cause of the PV fires. Of those 65 components, three can fairly be said to be indistinguishable from the same components used at utility scale – DC connector, DC cables and the PV panels themselves. Of those components 12 connector failures, 5 cable failures and five failures of the PV modules themselves are listed.

TUV, an internationally renowned and respected test and verification authority [4] in their paper Assessing Fire Risks in Photovoltaic Systems and Developing Safety concepts for Risk Minimization say this specifically about the flammability of glass/glass panels:

“In other words, under relatively low stress, e.g. with a smaller electric arc turned off by an arc detector, no independent spread of fire occurred on these specimens. On the other hand, once a full-scale fire develops in a PV module, it can continue burning and thereby spread the fire to other elements. This is also the case with glass-glass modules.”

TUV undertook a wide range of tests that quantified the relative risk of failure presented by individual elements of solar panels, the toxic residue left in firefighting water, the level of toxic fumes generated by a solar panel fire, the risk to life through electrical hazards to first responders and any other factors – <u>all things which, according to the applicant, do not exist.</u>

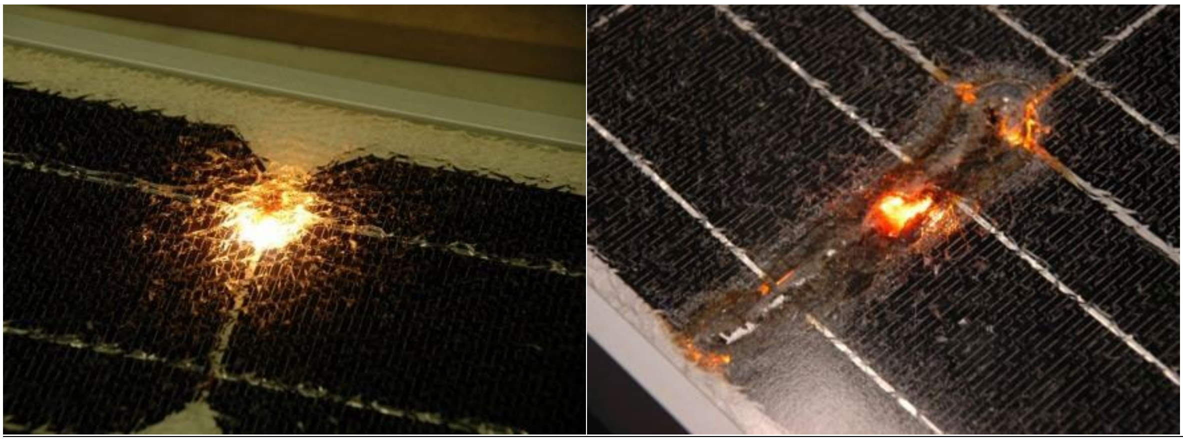

Image 2 Testing by TUV showing hot spotting within a solar panel caused by an electrical fault

TUV say:

“Past discussions on fire hazards from PV systems have focused on the supposedly more critical DC currents. Owing to the numerous electrical connections, the many components exposed to weather and the self-stabilization of any electric arcs given the current source characteristic of the solar cells, the risk of fire emergence in the PV generator sector is estimated to be significantly higher than in the AC part.”

TUV also conducted experiments which looked at the behaviour of arcs formed when a soldered junction within a solar panel failed. Individual modules are soldered to a common bus within each panel. The Naseby proposal involves many millions (best guess tens of millions) of such connections. They found:

“Electric arcs were then ignited that generated temperatures far above the melting temperature (600°C) of (e.g.) thermally pre-stressed glass (Figure 3-42). The front glass and the photoactive silicon layers melted and formed burning droplets The electric arc will continue burning until sufficient voltage for maintaining it is no longer available. This situation can be attained by turning off the voltage or by increasing the distance between the electric arc contacts. If this distance is so

large that the available voltage no longer suffices, the electric arc will extinguish itself. This time can be very long, however (several minutes).

The electric arc burns not only at the direct contacts of the cell, but it can also continue burning between the cells. The electric arc will then move back and forth between the cells. Owing to the large amount of available material, the contacts will burn down only slightly. In the lab experiments the electric arc was always extinguished by turning off the voltage. The electric arc burning the longest was turned off after 16 minutes. During this time the electric arc moved several times from one cell side to the other.

Until the electric arc was extinguished, it emitted a great deal of heat, greatly damaging the surrounding module materials. The latter also burned, but after a period of time extinguished themselves after the electric arc was turned off. Until then, the flames were intensively blazing from the underside of the module, however. In cases of very long-burning electric arcs the temperatures increase until the glass melts (1,000°C to 1,500°C) and liquid silicon drips down from the module."

As would be expected given the results from there flammability testing, TUV also carefully measured the toxic gas emission, level of toxic residue and toxic components in water used to extinguish the fires. The data varies substantially by panel type and is best read in full however their conclusion is fairly simple to understand:

"Depending on the technology, the fire residue from PV modules can contain concentrations of lead or cadmium that can create critical levels of contamination in the soil. Professional disposal of fire residue and, if necessary, soil replacement are therefore urgently recommended."

Water use to quench the fires contained significant levels of lead, but not above regulatory levels, however the measured cadmium concentration in the quench water indicates possibly critical soil contamination from CdTe modules

The burning panels generated large amounts of smoke, which produce obvious problems, but were relatively free of contaminants.

According to a report by FireTrace International: [4]

"Statistics from the Australian PV Institute show that PV installations in the country increased from around 7.3GW in January 2018 to more than 20.7GW in December 2020.6 However, while the increase in PV installations in Australia during the period was less than three-fold, data from Fire and Rescue New South Wales (NSW)

showed that there was a six-fold increase in the number of solar fires attended by firefighters in the period 2018 to 2020, according to reports in 2020, Fire and Rescue (NSW) attended 139 solar fires, compared to 22 in 2018."

That report also lists some interesting statistics from the TÜV:

With regard to the data that is actually available, the US Department of Energy's Solar Energy Technologies Office has cited a study conducted by European testing and certification company TÜV Rheinland – entitled 'Assessing Fire Risks in Photovoltaic Systems and Developing Safety Concepts for Risk Minimization' – which found that, in approximately half of 430 cases of fire or heat damage in PV systems, the PV system itself was considered the "cause or probable cause.

Solar installers, especially at utility scale often hype the capability of arc detection systems. Such systems seek to identify a developing (or developed) arc in an electrical system and to shut that system down before significant damage can be done. Similar systems are used in electricity distribution to identify and eliminate the risk from fallen power lines. The working principle is that an arc has a specific "signature" that it imposes on the system as a detectable waveform. There are significant problems with this approach however, as highlighted by the TÜV:

(an electric arc detector is)"moreover useful only if it can be assumed to reliably detect electric arcs. Electric arcs in modules produce different noise patterns than those in serial terminals. Different cable lengths greatly differ in their dampening of electric arc signatures. Interference from inverters, switching transients, or coupled radio signals can mask or overlay the noise coming from the electric arc. Only very robust detection algorithms tested on different systems can ensure real added utility here."

A web article from CoverNote [5], a New Zealand Insurance Industry online magazine also quoted from the FireTrace paper:

"However, in many emerging industries, risks are often harder to measure, leading to exposures and losses. One such industry is solar energy, which has been growing rapidly in recent years due to the shift to renewable energy.

A recent report by Firetrace International found that the solar industry is potentially underestimating the risk of fire at solar farms, partly due to a shortage of data on solar farm fires. The report also said that research into the issue has given rise to suspicions that fires at solar farms have been under-reported.

"To be clear, fire risk is present across all utility scale, high voltage, renewable energy from wind to solar to battery storage systems," Ross Paznokas, global business development manager, clean energy at Firetrace International, told Corporate Risk and Insurance. "Fire risks cannot be totally engineered out.

"With the expected exponential growth of renewable energy as well as aging infrastructure, the number of fire occurrences will only increase. One thing that operators tend to overlook is addressing these fire risks with fire mitigation strategies. Often, owners will simply rely on their insurance provider to cover a loss, if that does occur, rather than implementing the likes of fire suppression technology."

According to Paznokas, solar asset owners and major OEMs are reluctant to discuss or publicly acknowledge a loss attributable to fire. This means that there is a lack of data and definitive case studies to draw insights from.

With regard to data that is actually available, Paznokas said that the US Department of Energy's Solar Energy Technologies Office cited a study conducted by European testing and certification company TÜV Rheinland, titled Assessing Fire Risks in Photovoltaic Systems and Developing Safety Concepts for Risk Minimization. The study found that in approximately half of 430 cases of fire or heat damage in photovoltaic (PV) systems, the PV system itself was considered the "cause or probable cause."

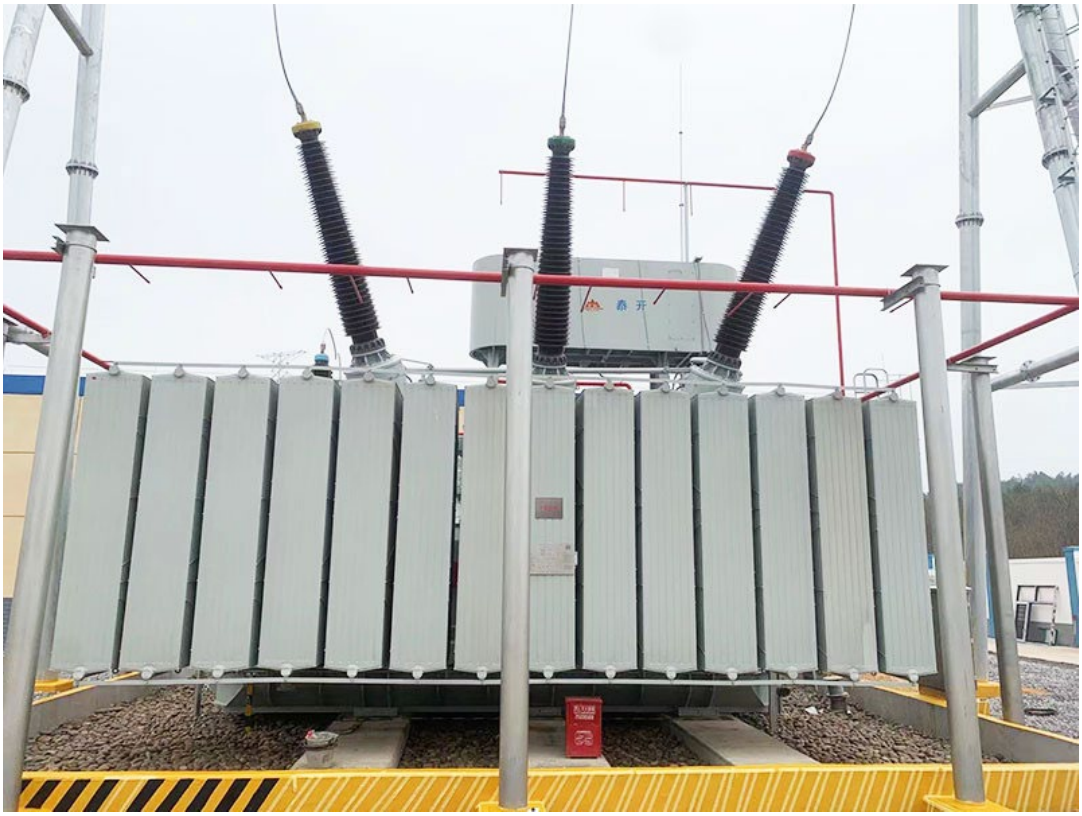

Image 3: 150MVA 33/220KV transformer

Helios claims that “***All major electrical components such as inverters and transformers will be containerised”.*** The reality is shown in *image 2*.

Helios plan to install two 150MVA 33/220KV transformers as part of their build, according to Helios, those transformers hold 107,600L of transformer oil, a little over half the capacity I would have guessed. I say “according to Helios” because the company gives no clue in their application as to the manufacturer or transformer type in use - and I suspect that the quoted volume is simply a number pulled out of the air by the applicant and their consultants. One thing that I can almost guarantee however is that they will not be specified as filled with FR3 class (reduced flammability) oil. These transformers are likely to weigh 230 tonnes each.

These components, the largest single components on site, will not and cannot be containerised. Nor will the outdoor bus of the substation, with its many exposed conductors and connections, be containerised.

Containerisation is, in any case, no guarantee of protection from the risk of fire in the event of an electrical failure. A good example of this concept is a BESS unit – which is containerised but fitted with pressure relief / blast vents and /or active ventilation systems to reduce the risk of explosion, vents which allow the release of flammable (and often burning) gasses into the surrounding environment. Indeed, the 150MVA transformers themselves will each be fitted with an overpressure release device which is designed to vent gasses in the same way.

Containerisation may contain the fire for some defined amount of time, or it might seek to limit the spread of fire to one element of plant, but only when specifically designed for that purpose - and the effectiveness of that design is never guaranteed.

Invertors are containerised primarily as an aid to transport and installation. They are also usually fitted with forced ventilation, certainly the case here since their cooling systems are listed by the applicant as a potential source of noise pollution. I have not yet seen an inverter that purports to have a container with a fire rating – although they may exist.

To say that a given piece of equipment is containerised is meaningless without data on both the equipment and the container. We are given no such data; the comment therefore is meaningless as well as demonstrably untrue.

It has taken just 3550 words to make my point about the veracity of the applicant’s documentation, I’m now left to deal with the remaining eight “***Electrical wiring from panels to inverters is undergrounded”.***

Nothing in the application allows for accurate measurement of the position of any given thing on the site. The scale given on the most helpful map is only relevant when the document is printed at a specific size and that size is not shown on the map. It is possible however to approximate the distance from an average inverter placement to the end of an average row and compare that to the total string length.

While it might be technically possible to take the cabling from each panel and bury it as close to that panel as possible (as implied in the wording used by the applicant), in the real world that is not a feasible solution.

Principally, three options exist for the connect arrangement of these panels, in series, in parallel or a mixture of series and parallel. Typically, these panels run at around 37V at peak power. From the application we can deduce that the most common row length is 104 panels. 104 panels, when wired in series, would have a peak voltage of 3,848V – far too high for the inverters or connection systems. That would suggest that each inverter will accept energy from half a row to its North and Half of the row to its South. The voltages presented to the inverter are still a little above expected levels (1500V) however I have made no allowance for voltage drop and my assumptions of panel voltage may be a little high.

It seems likely therefore that the panels in each row will be wired in series (each panel connected directly to the panel next to it) rather than each panel being connected in parallel (each panel connected to two, much larger conductors that then transport the energy to the inverter). This is absolutely the normal arrangement for this type of installation.

Why is this important? When you compare the length of cabling above ground, from panel to panel, to the length of cabling from the end of each row to the nearest inverter, it is possible to calculate that average ratio of likely above ground cable length to underground cable length, for the most common string, is around 12 to 1. Working from these parameters I calculate that there will be more than 700km of inter-panel wiring above ground.

Clearly the applicant understands that buried wiring is less prone to mechanical damage through panel movement, impact damage, weathering and, particularly, fire damage. It seems likely to me that the applicant should have written ***“one twelfth of the electrical wiring from panels to inverters is underground”*** or, perhaps, ***“700km of inter-panel wiring is exposed above ground”***

In summary, it seems clear to me that the applicants’ comments, as quoted 3700 words ago, are fundamentally designed to mislead and that they reveal an appalling attitude toward dealing with both the Maniototo community and the truth.

An installation for the National good?

The applicant has proposed that this proposed build is one of “national importance” both in discussions with residents and in the press. I think it is vitally important to address that proposition – because it must certainly influence how this application is viewed by council and the community.

While it is absolutely true that government’s current policy decisions are driving New Zealand towards a position where electricity makes up a far larger proportion of our total energy needs, MBIE suggests that by 2050 we will need to increase electricity generation by between 35% and 82% [6], the most important element is surely that we get there with as little carbon embodied in the solution as possible.

Understanding the CO_2e embodied in electricity is a complex difficult task [7].

Mbie [6] suggest (reference scenario) that electricity will make up 47.3% of our total energy usage by 2050, up from the 24% it currently represents. Under that scenario, New Zealand would consume 62.1TWh of electricity a year. This proposal, if you believe the applicants modelling, will deliver 630GWh of energy each year, that would be about 1% of our total needs in 2050. How could that possibly be a bad thing?

Solar has a single, huge, advantage over almost all other means of generating electricity – it can be used to generate at exactly the place the energy is used. Which is just as well because solar output peaks when demand is lowest, both by time of day and seasonally, and it has a much higher embodied CO_2e [8] content than many alternatives. It is essential to understand this simple, but vitally important proposition.

If you generate electricity remotely from the end user then two major factors impact the equation for that energy’s embodied carbon, transmission losses (effectively heating the whole environment in an unproductive way) and the carbon cost of building the, potentially massive, increase in infrastructure needed to transport that energy. The further from the place that you produce the energy to the place that you consume it, the larger the embodied carbon content is.

Behind the meter solar (rooftop solar) is uniquely placed to eliminate both of these hidden sources of carbon emissions. By producing energy exactly where it will be used, you can eliminate 100% of transmission losses and 100% of the carbon embodied in transmission assets.

According to Transpower [9], there current transmission losses amount to 107,851 tCO_2e. To place that in perspective, a light vehicle that complies with New Zealand’s 2023 emissions standards would travel 743,000,000km to generate a similar amount of carbon. Transpower’s data do not account for the massive amount of carbon embodied in the transmission grid, they do not provide a figure for the embodied carbon in the transmission asset that constitute a huge and hidden emissions cost. From the same report, Transpower added 50,000t CO2e maintaining and building their grid this year (image3).

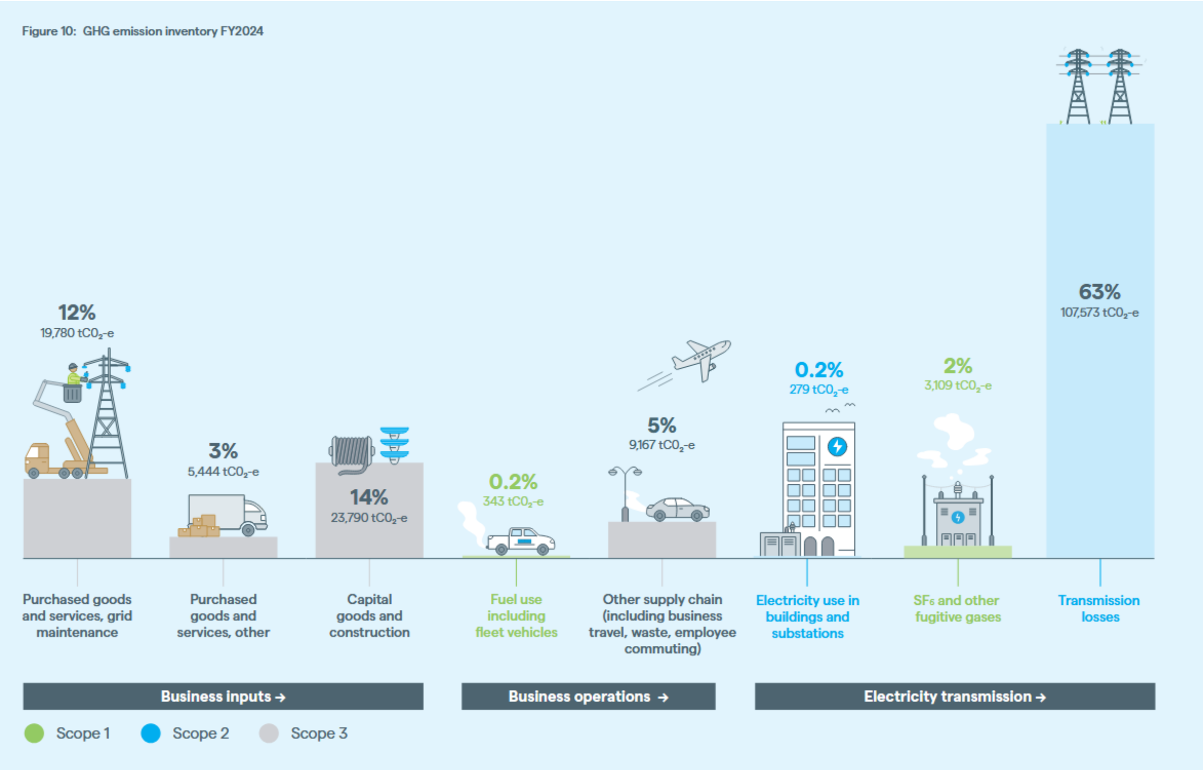

Image 4 Transpowers Carbon Footprint

But the picture going forward tells a worrying story. Transpower intends to increase their annual capex spend from a ten-year average of $400M pa to $1.4B pa from 2027 onwards [10]. That's a 350% increase in spend to achieve a relatively modest increase in energy use of 60% (midpoint prediction) by 2050. How can that be? Are we planning on vastly increasing the amount of energy we move around the country – well beyond the levels of our predicted increase in production? Transpower's carbon footprint will grow apace with the dramatically increased level of spend, as will our electricity bills.

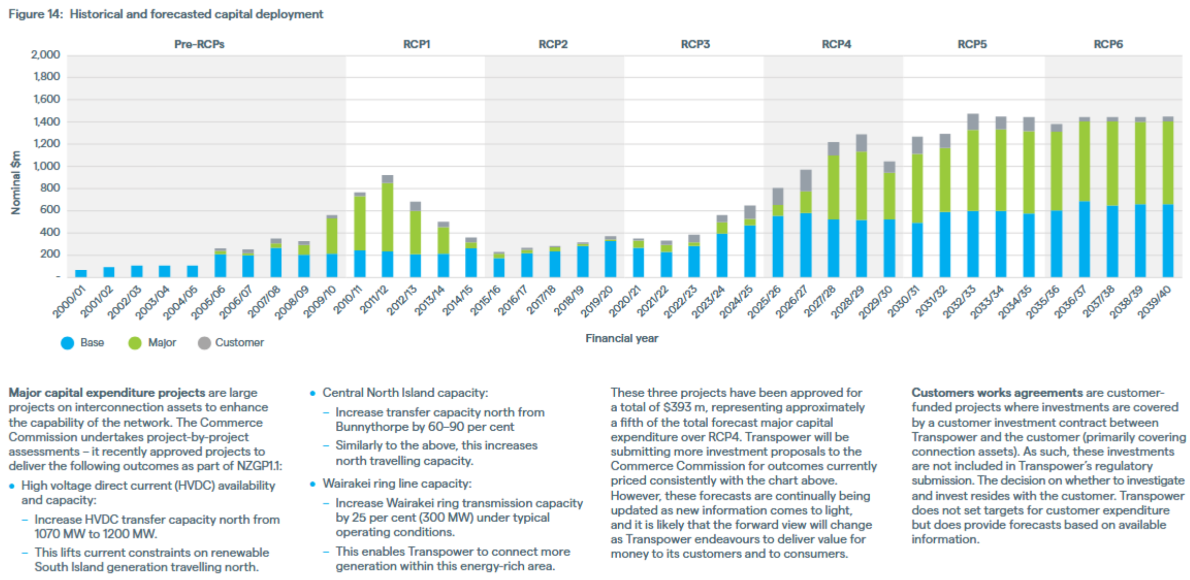

Image 5 Predicted Transpower Capex

Data from EMI [10], collected at the time of writing, shows net flow of electricity North through the HVDC link of 11.884TWh for the previous five years. That's an average Northward flow of electricity of 272.85MW over that period. Image 5 shows the same information graphically.

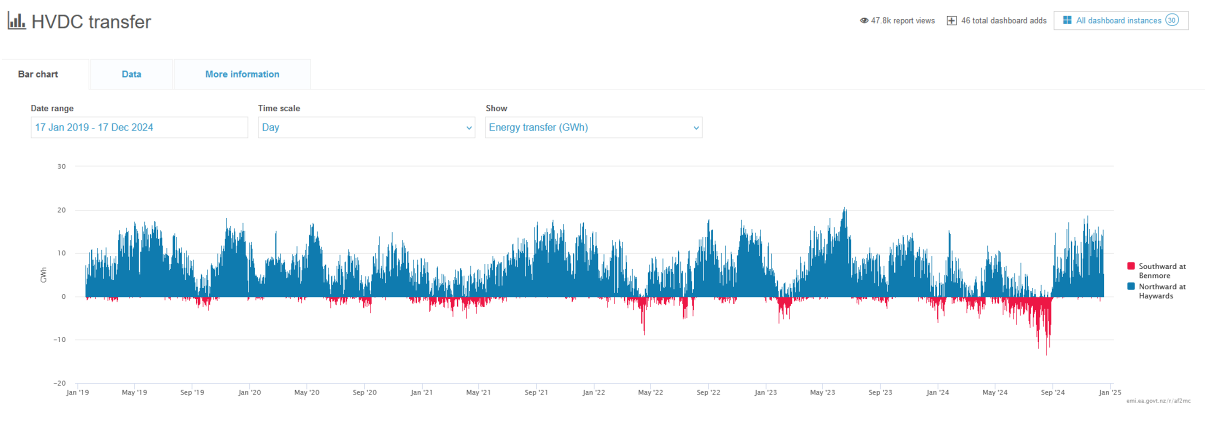

Image 6 Energy transfer via the HVDC link

How much energy is lost in transmission? That's a very difficult question because a number of factors influence the outcome. Line losses are not linear, pushing twice the amount of energy, at the same voltage, over a line does not result in twice the losses – it results in four times the losses. Pushing 10 times the amount of energy results in 100 times the losses. So, if I send 100kWh of energy over a line and lose 10kwh of energy, it follows that sending 200kWh of energy over the same line will result in loss of 40kWh. The first quantity of energy had line losses of 10% adding the same amount of energy again resulted in the loss of 30% of the transmitted energy – over exactly the same lines.

There are also other types of losses in the system, some of which are approximately linear.

Fortunately, we have a guide to loss factors in two ways. Transpower publish figures for their average calculated losses – but that doesn't help us to understand a particular case – and the market runs regional pricing which bumps up the wholesale price of electricity based on losses and line constraints. It's not a perfect measure – but it does offer some insight.

Image 6 shows the regional pricing data as at 18:43 on December 17th 2024. The trend towards higher wholesale prices as you move further North in the country is obvious, that trend is the norm and reflects the additional cost of supply caused by line losses and supply constraints as a result of a large supply of energy in the South and a large demand in the North.

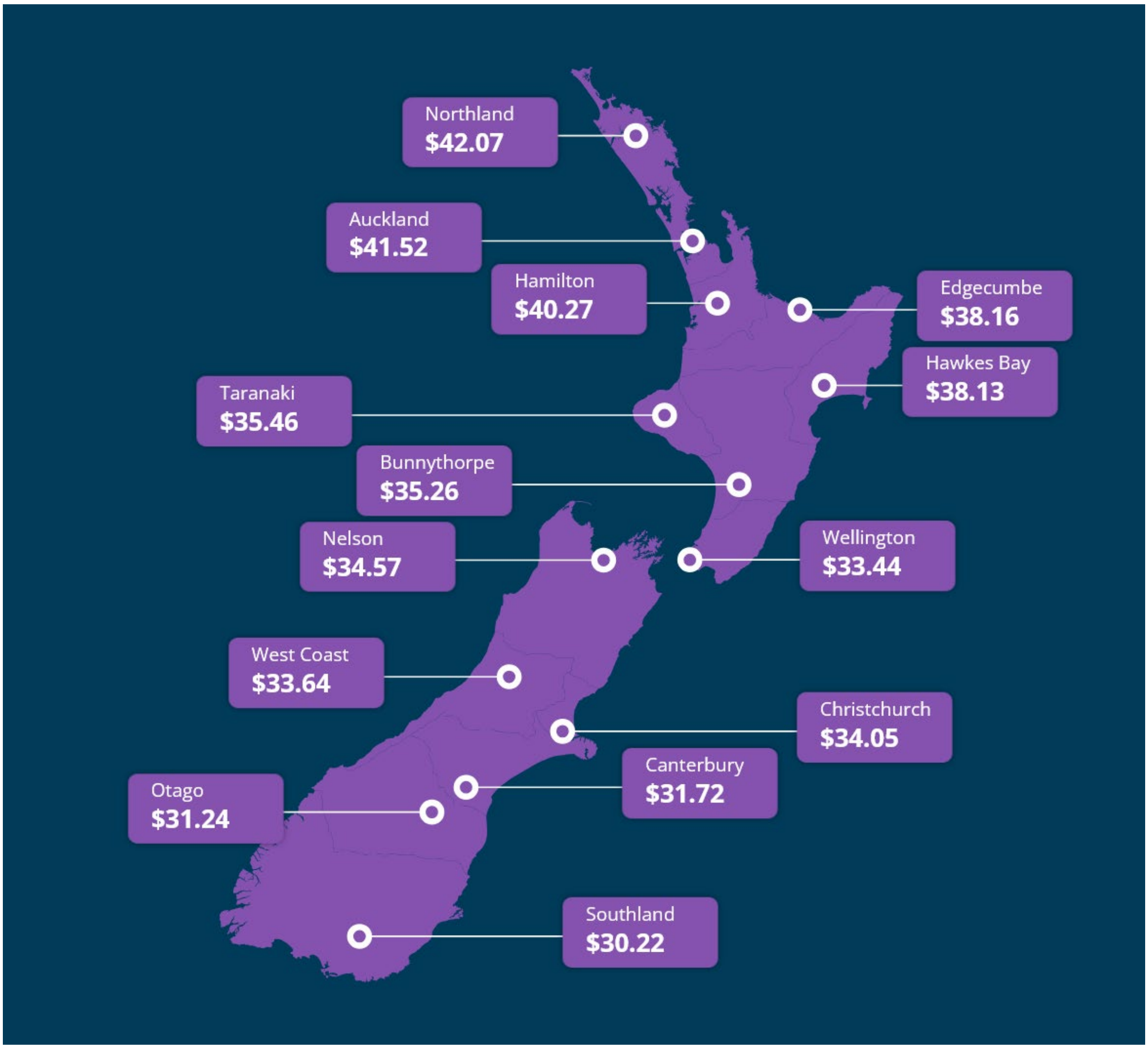

Image 7 EM6 Regional pricing data 17/12/2024

In this example, Northland is paying a 32% price premium for its electricity over the price paid in Southland. This is broadly the long-term average price differential.

This seems to add up to a great argument for building new generation in the North Island, close to the existing major centres of load. There is also a good case for generation in North Canterbury – but there is a very weak case for new generation any further South. Even in a "dry" year, the South Island would be in a comfortable position if it was not exporting almost 300MW of power North continuously in the leadup to that event.

Transpower have now updated their grid model to reflect the likely decommissioning of the Tiwai Point aluminium smelter in 2024. Decommissioning Tiwai would have a considerable net effect, Tiwai uses about 15GWh of energy every day. That's nine times the amount of energy that the applicant claims they expect from the Maniototo proposal. The upgrade to the Roxburgh-Livingston line was commissioned primarily over concerns that Tiwai would close in 2025 and that there would be no way of delivering the energy it now uses further North. In ten years the Maniototo project could represent a significant roadblock to that energy transfer, necessitating yet another horrendously expensive grid upgrade.

All of these plans for a greater level of electrification in New Zealand come with a hefty price tag. The Boston group calculated in 2022 that New Zealand would need to spend $8B on transmission assets and $22B on distribution assets each decade to meet decarbonisation goals. [12]

The applicant – and others – will no doubt argue that increased load growth will happen in the South Island too – and that we should prepare for that. Here's the thing, predicting load growth in New Zealand is a bit like trying to predict the lotto numbers, you might think you have it right – but the odds are monumentally stacked against you. How fast will the uptake of EV's be? Will large energy consumers, who must compete on world markets, survive in the coming world of markedly higher electricity prices? What new battery or energy storage technology is just around the corner? Will perovskites improve solar cell efficiency to the point that all current systems will be unable to maintain the ability to compete on price? Will population growth decline to even lower levels? What will be the uptake of rooftop solar over the next two decades?

The New Zealand electricity sector is an area where just in time principals are the only effective way to maintain an economically viable industry. It may take ten years for the planning, procurement and build of a replacement for the HVDC link but the lead time for an appropriately sized solar install close to the ultimate end user is a small fraction of that. In any case, any increased generation capacity in the South Island is needed from Christchurch North.

Is new solar generation in the lower South Island a build of national importance? No it is not. It is the wrong use of the technology, at the wrong scale, in the wrong place. Building in the Maniototo, far from where most of the energy will be used, simply ensures that more carbon will be embodied in the additional generation that will be necessary to supply the energy wasted in total transmission losses and more carbon will be embedded in the transmission assets necessary to carry that energy to end users.

But it's worse than that.

This proposal includes the installation of a BESS, a Battery Energy Storage System. In this case we don't know the exact size of the installation or, critically, the type of chemistry that will be employed. What we are told is that:

"A BESS will be situated in the central west area of the Site, within a fenced off area next to the substation. The BESS will cover an approximate area of 2,000 m2 (0.2 ha), with each battery unit approximately 3 m high. This is likely to comprise a series of 3 MW packaged battery units with the most likely options to be: 32 x Tesla Megapack; or 14 Power Electronics FS4390K 4.39 MW inverters with 10 banks of GridSolv Quantum Units."

In consultation with residents (Golf Club drop in session, hosted by the applicant October 2023) Helios (S. Brookes, J. Schlichhting) told G.Crossan, T. Crossan, N. Voice and R.Voice that the battery installation would consist of two "container sized units". It has now morphed into (maybe?) 32 containers and 1200 tonnes of plant – just for the battery units themselves. It is not possible to address the proposal precisely because, as with so much of the applicant's documentation, there is no detail.

Gridsolv Quantum units are available in four sizes. They are sized at 1491kWh, 1629kWh, 4073kWh and 5016kWh – they are not available in 3MW units. "Bank" is not a unit of measure that can be applied to Wartsila BESS units. They vary in size between 17.3 m3 and 41m3 [13].

What Helios are saying in effect is – "give us permission to build a thing". As with most things in life, the devil is in the detail and here we have no detail.

Wartsila are keen to tell us that their batteries comply with NFPA 855 -Standard for the Installation of Stationary Energy Storage Systems, however, what they don't show is that NFPA 855 contains this list of exemptions for Electric Power Utilities

"Electric Power Utility Exemptions

- ***Temporary ESS out of scope***
- ***Plans and specifications***
- ***Emergency Operations Plan***
- ***Listing***

- ***Retrofits***
- ***Energy Storage Management System***
- ***Elevation Restrictions***
- ***Mobile ESS***
- ***Size and Separation***
- ***Smoke and Fire Detection***
- ***Fire Suppression***
- ***Water Supply***
- ***System Interconnections***
- ***Commissioning***
- ***Operations***
- ***Decommissioning***
- ***Explosion Control"*** [14]

Can we rely on standards in this area? Not according to Guillermo Rein, a professor of fire science at Imperial College London [15]. He is quoted here in an article in Wired magazine:

"The first layer of fire safety is preventing that initial spark from happening. Most fire testing involves ferreting out faults in individual battery cells—something the industry, which makes millions of those cells each year for all kinds of energy applications, does well, explains Rein. But as they are packed into larger groups for grid-scale systems, testing becomes more complex, and the pathways to ignition multiply: coolant leaks, shorting electronics, faulty installation. Not every pathway is reproducible in the lab, says Rein, who authored a 2020 review of battery safety standards, which he describes as "chaotic."

In the absence of extensive tests on large grid batteries, the "foundation" of safety design in the grid battery industry is making tweaks in response to real-world incidents, Rein says. They include a system in Surprise, Arizona, that in 2019 caught fire and later exploded, after fire suppressants mixed with the burning batteries, turning the warehouse in which they were installed into a pressure cooker. Nine first responders were injured. Two years later, near Geelong, Australia, a fire broke out during testing at what was then the world's largest battery installation, a collection of Tesla Megapacks, the EV maker's grid storage product. High winds spread the flames from one Megapack to a neighboring device, and the blaze took four days to put out."

Here's another quote from that article:

"There's still a lot of engineering that is believed to be best-practice but not completely proven. Steve Kerber, Fire Safety Research Institute"

Rein is listed as a co-author of a meta-analysis on the fire safety of Lithium Ion batteries, which really relates to all Lithium battery chemistries, [16] that highlights the same concerns:

"During safety testing and certification, industries perceive that there is a lack of harmonisation in the mode of abuse that leads to thermal runaway. There are no representative and repeatable methods for all relevant failure modes, and many test methods are not representative of field failures. There are multiple controversies around the best method to induce thermal runaway. While there are several recognised international standards for every industry that uses LIBs, a major concern shared by all industries is that the available standards are not always representative of real-world scenarios.

Further controversy can be found in pass/fail criteria in various standards for thermal runaway. More research is needed to understand first how an internal short-circuit develops within a battery, before a method to reliably reproduce it can be defined. To prevent thermal runaway at the pack scale, the development of more fault tolerant, fail-safe or fail-soft systems is needed. Yet, there is no industry consensus on safe system designs and performance-based methodologies."

It would be a potentially catastrophic mistake for Council to allow this proposal to proceed based on compliance with current codes and regulations. It is abundantly clear that, worldwide; authorities, manufacturers and communities are struggling to get out in front of the hazards embodied in battery storage technology. The cynic inside me suspects that the applicant - based on their interactions with the community, the absence of critical detail from their application, their initial obfuscation of the scale of the battery installs and – critically – their completely inadequate submission on the nature and hazards posed by battery chemistry, seek to take advantage of that almost universal lack of regulation and understanding. The critical thinker, standing to the right of my cynical self, is drawn to agree.

Quantifying the level of utility scale, battery storage system fires worldwide is difficult. There is no system of compulsory reporting so data acquisition must rely on what existing national databases there are plus scouring the media for relevant reports.

Fortunately, a US research body, EPRI maintain a database of utility scale Bess failures [17] in just such a manner. Image 7 (below) illustrates that failures reduced dramatically from 2018 to 2020, but that the rate of failure has declined very slowly since then. The current rate of failure is shown as 0.2 failures per GWh installed – so a 20% chance of failure for every GWh of installed battery each year. The Helios proposal is for (maybe?) 0.125GWh of storage. Using the EPRI data for the latest year we could calculate that the risk of failure in this installation is 0.2 (the risk per GWh) x 0.125 (the GWh capacity of the batteries), so 2.5% chance of failure in this year. We could also extrapolate that number to predict a 25% chance of failure over the first ten years of operation.

Is that a fair estimate of risk? In the absence of compulsory reporting to an openly accessible database, it is the only estimate of risk that we have.

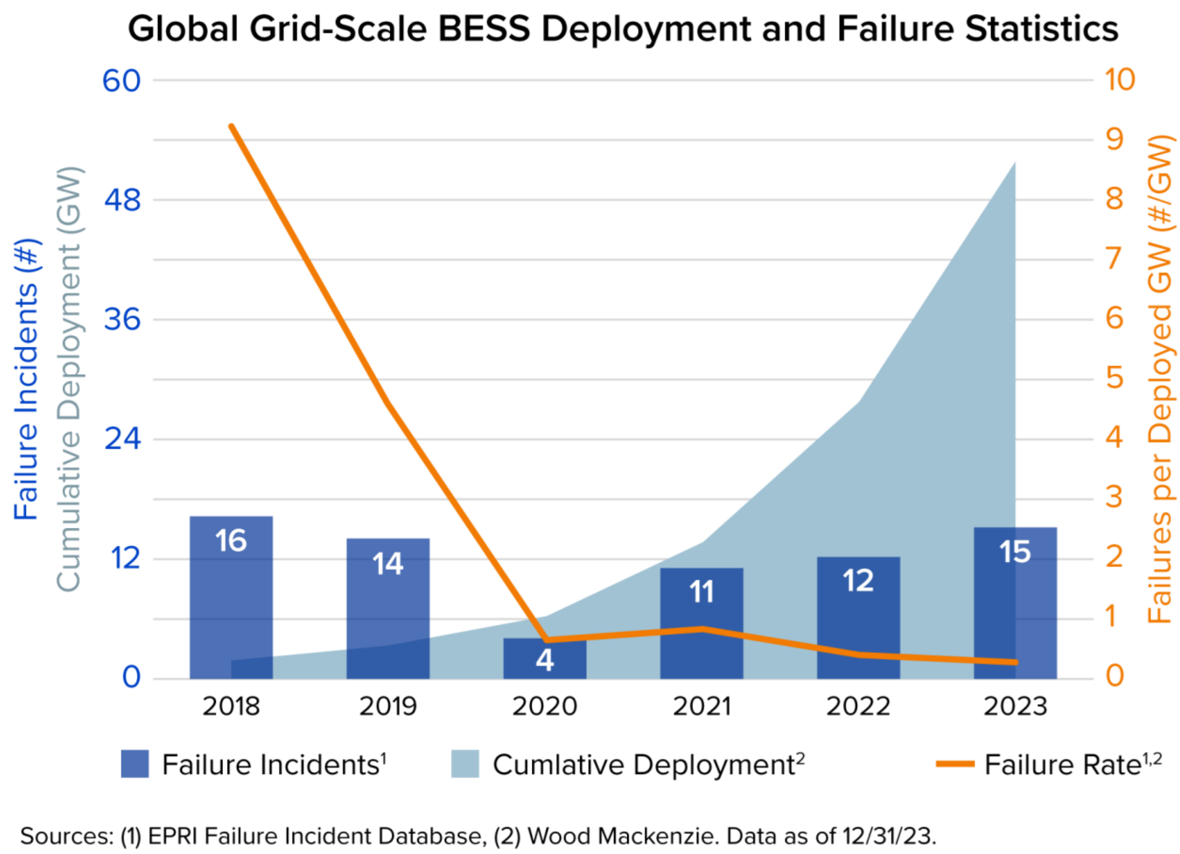

Image 8 BESS failure database.

The database lists six failures this year, almost all drawn from media articles. Of those six failures, four were in the US, one in Singapore and one in Japan. Manufacturers are seldom listed but Tesla features in four database entries, one of which (Bouldercombe Aus Sept 2023) has a failure age listed as 0.1 years. Image 8 illustrates very nicely what will undoubtedly become the front end a well-defined bathtub curve of failures. Bathtub curves feature a high number of failures soon after installation followed by a relatively failure free period of operation then a rapidly increasing rate of failures before the system reaches end of life. Here we see the first half of that curve, we can only speculate about when the far end of the curve will begin to appear.

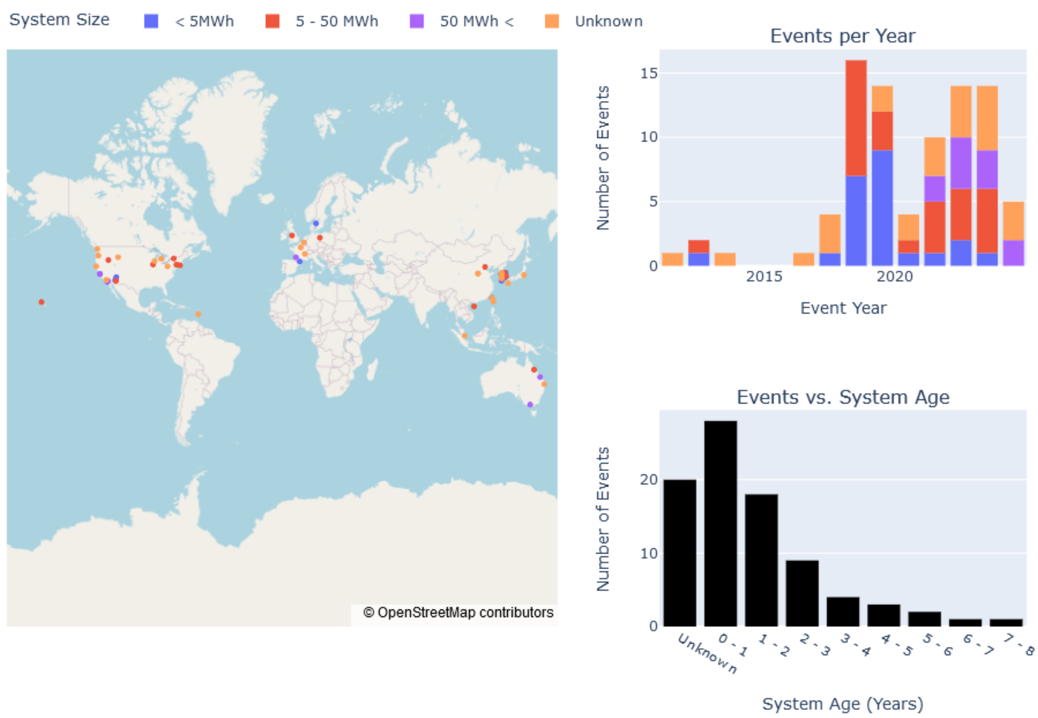

Image 9 EPRI Utility Scale Storage Failure Database

Catastrophic failure of a BESS installation is a very real risk. Reliance on even the most up to date standard as an insurance against bad outcomes is foolish. It must be assumed that the possibility of failure in one or more of the BESS units proposed by Helios is high. The community need to be informed of the very real risk of fire and of the downstream effects of such a fire.

None of this will come as news to anyone who has researched battery storage systems, but it will certainly come as news to anyone who has relied on the information supplied by the applicant. Reviewing their published literature, it will probably come as a surprise to FENZ too.

Apparently unknown to the applicant, fire is a foreseeable hazard associated with solar panels, BoS components and BESS. They also seem to be completely unaware of the downstream consequences of such an event.

There is another element related to the applicant's characterisation of BESS uses that must be addressed. In their application Helios say:

"***The purpose of the BESS is to help manage the flows of energy generated by the solar panels and enable energy to be released into the National Grid overnight when solar energy is not being generated.***"

This is a complete inversion of reality, nothing could be further from the truth. It shows an abject disregard for the principles of honesty and transparency when dealing with the community.

One of the applicants consultants, Marshal Day, correctly summarise the mode of operation of a BESS in this environment:

"The battery storage may operate to both export and import AC energy to and from the grid. It is likely that during periods of low demand, AC energy will be imported from the grid and stored in the batteries for later export – this can occur at night"

The BESS is present to facilitate arbitrage. Its primary role is to import energy when it is cheap (usually the middle of the night) from other generators and dump it back on the market when it is expensive – the classic case of buy low sell high. It will also store some of the output of the Solar array, when that output occurs at times when energy is cheap, in order to dump it back into the market when prices are favourable (typically 17:00). During this process a considerable amount of the energy is lost to things like inverter losses and the entire concept is described as round-trip efficiency. For a Tesla MegaPack, that round trip efficiency means that between 8.3% and 13% of the energy are lost in the transaction. I strongly suspect that the BESS will be by far the most profitable element of this installation.

To understand the incentives that drive behaviours in the area of energy storage you need to understand a little about New Zealand's energy market. Image 10 (below) shows the range of prices paid for electricity on the spot market in New Zealand for two days starting December 16th 2024. A few things should be immediately obvious, between 0:30 and 4:00 in the morning electricity was essentially free. Prices went as low as $0.02 per MWh. By 08:30 on the 16th prices in the North Island had risen to $250:23 per MWh – but prices in the South Island had only risen to $85.04 and then, only for a single hour. If you are operating a BESS installation you will be importing electricity from the grid furiously from shortly after midnight and waiting for your chance to dump it back on the market at about 8:30. As you export solar during the day you will take out the normal mid-afternoon troughs by charging your batteries from your own energy and dump that back into the market for what is normally a peak about 17:30. With your batteries completely depleted, you sit and wait to complete the recharge soon after midnight.

You will notice also, that on the 16th North Island prices were five to eight times higher than South Island prices. If you are operating a BESS at Naseby then the energy you are importing each morning is probably coming from North Island wind. No one can store wind, if it is blowing then you might as well be generating. So, you might think that's a good result for New Zealand Inc. But we are back to the problem of transmission losses. If that BESS unit was sitting next to a windfarm in the North Island, then the benefit would be obvious, you could avoid transmission losses almost entirely and in the morning you would be ready to deliver that energy – minus round trip losses – back on to the market.

But the Naseby install is not in the North Island. That North Island wind energy will likely be subject to transmission and conversion losses as it passes south, round trip losses at Naseby then transmission and conversion losses as it heads North again to the end user.

Image 10 Wholesale energy prices over two days

Which brings us to the topic of noise. I am not a sound engineer, but I have had to deal with sound engineers many times over the last forty years over the noise generated by electrical plant – particularly transformers. Transformer noise has a component, based at 100Hz and its harmonics that humans find extremely irritating. That low frequency hum is very good at penetrating structures and is not easily attenuated. That lack of attenuation is the reason you can hear the base notes from the party next door so well.

In their report, Marshal Day, pay scant attention to the two power transformers on site. I assume that they think that their position makes them an unlikely source for complaint. I do not. Marshal Day assume a generated noise level around 90bBA. I think that is a little undercooked. I also am inclined to believe that the strongly tonal base noise will contribute greatly to the way in which it degrades the quality of life for people nearby. Fan noise however tends to be a wide mix of frequencies.

Added to those two problems is the blast wall shown on the applicants plans between the two transformers. Similar structures are common in substations – but are always carefully designed to reduce noise impact, in this case it will likely exacerbate it. If, as I suspect, transformer noise at full load will be more like 93 -95dBA at the two meter receiving plane specified by AS/NZS 60076.10.1:2009 then the transformers have the potential to breach the nighttime noise limits at well over 1000m, without allowing for significant tonality or the effects of a structure within a few metres. At site MP1, noise levels will still be at 30dBA – well above the early morning ambient readings in the report. As Marshal Day correctly point out, energy trading activity will certainly take the transformers to maximum power (and therefore maximum noise) in the early hours of every morning.

Of particular concern to all residents and visitors must be the noise generated by driving many thousands of steel post into the ground to facilitate the mounting of the panels. The pressure level nominated for the pile driver seems reasonable – but I am very aware that the noise generated by pile driving, especially steel piles, is very dependent on the type of ground that they are being driven into. At least at the start of construction and at regular intervals it should be a condition of consent that all construction activities are the subject of a comprehensive noise survey for the entire build period.

I cannot agree with Marshal Day that a Construction Noise and Vibration Management Plan may not be required. The build on this site will take at least two years to complete, disruption to the lives of residents is inevitable, the creation of such a plan seems entirely necessary and reasonable.

Nor can I agree that because construction will occur all over the site it should not have to comply with an overall 5dBA reduction in the allowable noise levels that they have outlined for construction in their submission. This project will, very clearly, extend beyond the 20 week guideline.

Toxicity – BESS fires

I am left simply aghast by the approach of Beca used during the creation of appendix F – Hazardous substance assessment. Surely our aim here is to honestly and fairly look at the hazards involved in this proposal – and the steps necessary to protect the community from those hazards - not to take the narrowest possible view of the requirements of the HSNO Act? I have already listed credible sources who have completed thorough research and who provide valuable insight into the hazardous nature of material left by a PV panel fire [19] [1]. Many more are available. But now it is necessary to address perhaps the most worrying aspect of this proposal. The likely outcome of a fire in a BESS unit.

I have already briefly covered the data that is available on the probability of a BESS fire [18], but it is of extreme importance that the BESS is not seen simply as a storage point for a very large quantity of highly flammable liquid (the electrolyte in a lithium battery using the most common chemistries has an energy density only slightly less than petrol). This part of my submission is, unfortunately, more complex than it would otherwise be because of the extreme lack of detail provided by the applicant around the specific type of electrical equipment to be employed in their proposal.

The output from a fire in a BESS unit is dependant on many factors, the battery chemistry, the state of charge of the battery, the success – or not – of the various layers of fire prevention measures employed. Perhaps the most cited paper on the subject is by Larson [20], Toxic fluoride gas emissions from lithium-ion battery fires. In this paper he looks at emissions from LiCoO2, LiFePO4 and LiNiCoAlO2-LiAlTiPO4 chemistries.

Larson undertook a series of experiments to quantify the “the risks associated with gas and smoke emissions from malfunctioning lithium-ion batteries”. Chief among his concerns were the production of Hydrogen Fluoride and Phosphoryl fluoride, the latter is a chemical that can later become Hydrogen Fluoride if it meets water.

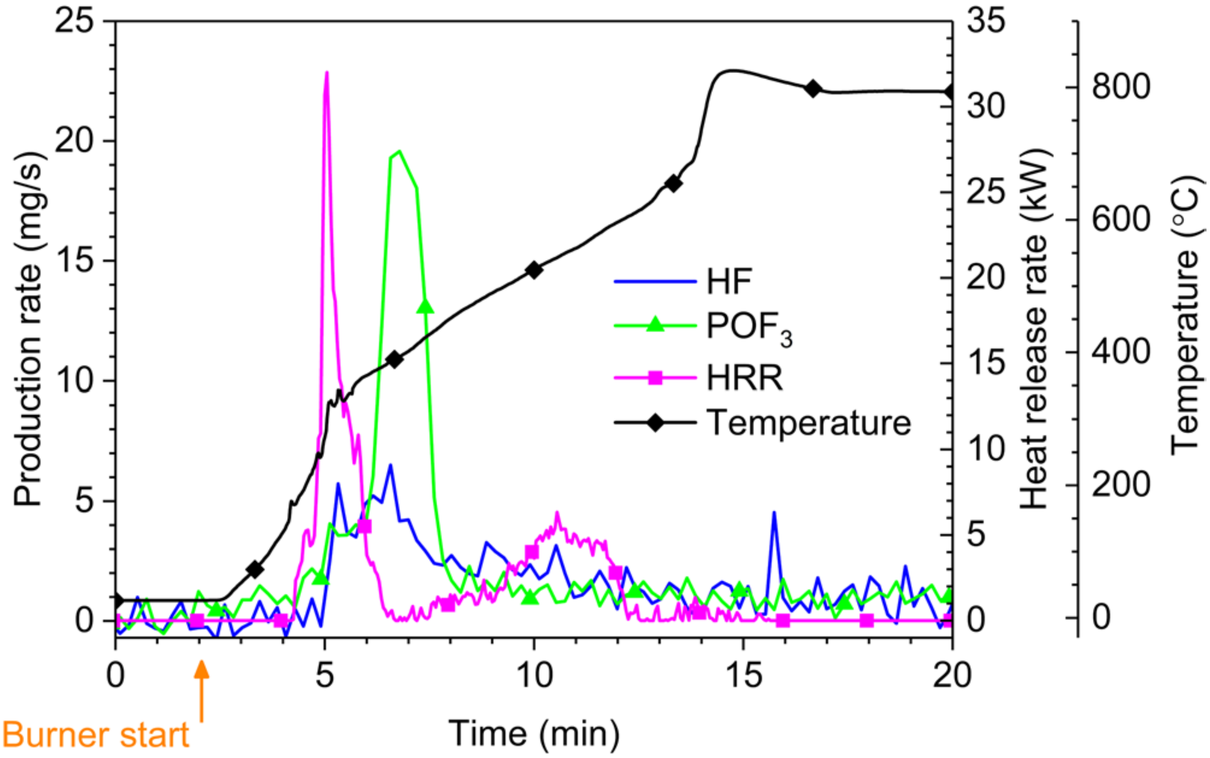

Image 11 From Larson, Hydrogen Fluoride production in fires.

Hydrogen Fluoride is a colourless gas with a very high level of toxicity that transforms into Hydrofluoric acid when absorbed into water. Hydro Fluoric acid is another very dangerous chemical that does not behave like other acids in that its acidity does not change linearly with dilution. Heavily diluted HF acid is extremely weak, however at higher concentrations it changes character remarkably and has an effective pH of -11. In either form HF is extremely dangerous to life and health.

Larson conducted a series of experiments, using two separate measuring techniques, at many different states of charge, with repeatability phases for validation – and summed up his findings as:

"Significant amounts of HF, ranging between 20 and 200 mg/Wh of nominal battery energy capacity, were detected from the burning Li-ion batteries. The measured HF levels, verified using two independent measurement methods, indicate that HF can pose a serious toxic threat, especially for large Li-ion batteries and in confined environments. The amounts of HF released from burning Li-ion batteries are presented as mg/Wh. If extrapolated for large battery packs the amounts would be 2–20 kg for a 100 kWh battery system, e.g. an electric vehicle and 20–200 kg for a 1000 kWh battery system, e.g. a small stationary energy storage. The immediate dangerous to life or health (IDLH) level for HF is 0.025 g/m3 (30 ppm)22 and the lethal 10 minutes HF toxicity value (AEGL-3) is 0.0139 g/m3 (170 ppm)23. The release of hydrogen fluoride from a Li-ion battery fire can therefore be a severe risk and an even greater risk in confined or semi-confined spaces."

At Naseby, the proposal is (maybe?) to install 3.8MWh units. If we use the upper-level numbers for gas production from Larsen we can calculate that the total weight of HF gas produced by a fire in a single unit would be 760kg.

The IDLH (immediately dangerous to life or health) level of Hydrogen Fluoride is 0.025g/m3 of air. So 760kg of hydrogen fluoride is enough gas to make 3,000,000 cubic metres of air an immediate danger to life or health. The AEGL3 level for HF gas is 170parts per million – so a single pack could produce 54,700m^3 of toxic air at that level. AEGL-3 is the airborne concentration, expressed as parts per million (ppm) or milligrams per cubic meter (mg/m3), of a substance above which it is predicted that the general population, including susceptible individuals, could experience life-threatening health effects or death.

The applicant must be aware of the many, well reported, examples of off-gassing from BESS fires and the effect of those events on communities. Yet their "consultation" with this community and their application for consent do not mention the issue at all. How can that be?

Some battery chemistries (principally LiFePO4 chemistries) are, laughably, sometimes referred to as "non-toxic". This is far from the truth. Given the right circumstances, LiFePO4 batteries will produce more Hydrogen Fluoride than the other chemistries tested by Larson.

In a very recent paper, Assessment of Run-Off Waters Resulting from Lithium-Ion Battery Fire-Fighting Operations [21], run off water from battery fires was analysed using Inductively Couple Plasma Optical Emission Spectroscopy, Inductively Couple Plasma Mass Spectrometry, Ion Chromatography, Liquid Chromatography and Gas Chromatography. All cells used MSC chemistry.

Table 3. Analysis of 23 PAHs in the water before application and in the three samples after extinguishing. QL = quantification limit. (Expanded: k = 2) Uncertainty of analysis for HAPs is 15% for all species.

PAH (Polycyclic Aromatic Hydrocarbons)					
	QL	Reference	Test 1 (Module A)	Test 2 (Module A)	Test 3 (Module B)
Naphtalène (ng/L)	10.0	<LQ	1279.2	2792.2	3114.6
Acénaphtylène (ng/L)	40.0	<LQ	2421.7	2405.1	1193.4
méthyl-1.naphtalène (ng/L)	10.0	<LQ	26.8	459.4	667.1
méthyl-2.naphtalène (ng/L)	10.0	<LQ	203.2	<LQ	2058.4
Acénaphtène (ng/L)	2.0	<LQ	34.1	110.6	275.7
Fluorene (ng/L)	2.0	<LQ	74.1	752.3	1055.0
Phénanthrène (ng/L)	4.0	5.7	360.9	3026.8	2581.6
Anthracène (ng/L)	2.0	<LQ	10.6	330.5	303.3
Fluoranthène (ng/L)	2.0	10.8	57.7	1280.9	349.8
Pyrène (ng/L)	2.0	7.2	45.1	1279.8	20.5
méthyl-2.fluoranthène (ng/L)	4.0	<LQ	7.3	45.1	21.3
B(a)A (ng/L)	2.0	<LQ	24.8	185.7	131.8
Chrysene (ng/L)	2.0	<LQ	32.5	212.3	40.8
Retene (ng/L)	2.0	<LQ	104.9	170.7	19.8
B(e)P (ng/L)	2.0	<LQ	7.5	306.3	50.4
B(j)F (ng/L)	20.0	<LQ	<LQ	106.3	<LQ
B(b)F (ng/L)	2.0	<LQ	34.6	259.6	5.8
B(k)F (ng/L)	2.0	<LQ	8.3	81.0	8.2
B(a)P (ng/L)	2.0	<LQ	13.0	163.9	20.8
D(a.h)A (ng/L)	2.0	<LQ	<LQ	36.7	4.5
benzo(ghi)P (ng/L)	2.0	<LQ	13.3	169.6	4.1
Indèno (ng/L)	4.0	<LQ	35.2	162.1	11.8
Coronene (ng/L)	2.0	<LQ	4.0	54.0	<LQ

Image 12 Detected levels of PAH in runoff water

Image 12 shows the results for Polycyclic Aromatic Hydrocarbons. Repeated contact between PAHs and skin can cause redness and skin inflammation. PAH-contaminated human skin exposed to sunlight can cause DNA damage. In laboratory studies, animals exposed to levels of some PAHs over long periods developed lung cancer from inhalation. In laboratory studies, animals exposed to levels of some PAHs over long periods developed stomach cancer from ingesting PAHs in food.

Of special concern is the presence of B(a)P at up to 163.9 ppm:

"Specific attention should be paid to B(a)P as it is class 1 on the IARC scale (proven carcinogen). According to the potential ecotoxicological impact of those products, one should pay specific attention to the potential impact of runoff water."

Table 7. Extrapolation of the experimental results to a real application and extinguishing. The last column presents the PNEC of the compound when available on ECHA website [36].

Substance	Test 1 (Module A)	Test 2 (Module A)	Test 3 (Module B)	PNEC Freshwater
Al (mg/L)	8.7	5.9	6.2	-
Co (mg/L)	0.05	2.6	0.6	0.00106
Cu (mg/L)	0.04	0.05	0.3	0.0063
Fe (mg/L)		Test 1 (module A)	Test 2 (module A)	Test 3 (module B)
Li (mg/L)	pH	5.2	5.9	11
Mn (mg/L)	0.1	3.4	0.5	0.034
Na (mg/L)	1.8	3.3	2.2	-
Ni (mg/L)	0.4	9.8	3.3	-
P (mg/L)	23.5	22.6	0.5	-
Fluorides (mg/L)	16.6	18.3	7.8	0.89
Chlorides (mg/L)	3.9	7.3	16.9	-
EMC (mg/L)	16.1	11.8	n/a	0.062
EC (mg/L)	126.2	92.2	n/a	5.9
Naphthalene (mg/L)	0.00015	0.00056	0.00026	0.0024

Image 13 Levels of detected contaminants.

Image 13 shows the level of detected contaminants in the runoff water from the experiments. The PNEC levels (right hand column) are the Predicted No Effect Concentrations, below that concentration the contaminants are not expected to effect on the ecosystem. Levels of cobalt were found to be at up to 2000 times the PNEC, manganese was at 100 times the PNEC, many elements do not have a listed PNEC

Particle sizes ranged down to nanometric scale.

In their paper "Meta-analysis of heat release and smoke gas emission during thermal runaway of lithium-ion batteries" [22], the authors point out that emissions vary dramatically according to cell type, state of charge and other factors. This is not data that manufacturers provide.

Carbon monoxide and Hydrogen cyanide are also gases of concern generated in lithium battery fires – but in an open-air environment their effect will, hopefully, be drastically reduced. Hydrogen Fluoride on the other hand has been observed as a slowly expanding cloud hugging the ground, behaviour that suggests it has already partially combined with water vapour. Hydrogen Fluoride is toxic without the need for ingestion, it can be readily absorbed by the skin. Once in airways, Hydrogen Fluoride combines with water to create Hydrofluoric acid, which can create very high levels of tissue damage. Eyes are another part of the anatomy which are commonly damaged by Hydrogen Fluoride for obvious reasons.

In their report, Beca say:

"A range of electrolytes can be present depending on the specific BESS. This can include Ethylene Carbonate, Diethyl Carbonate, Ethyl Methyl Carbonate and Dimethyl Carbonate which as been used in Table 1. Dimethyl Carbonate was selected for the assessment as it is the most hazardous (flammable) to cover the worst-case scenario." But which is most toxic? And What about the heavy metals and other contaminants in the batteries and panels. I am not interested in what components of the proposal are listed in the HSNO act or the district plan, I am interested in the outcomes for the community – as should be Helios, as should be Beca.

The proposed site sits on a particularly permeable land mass where recent drilling has shown the water table to be only seven metres down. Any resource consent must take into account the potential for irremediable damage to the aquifer.

Lithium battery fires often result in shelter in place orders for the surrounding community. This fire lasted two days from October 30th 2024 https://www.hazardexonthenet.net/article/210248/Fire-at-one-of-world-s-largest-lithium-ion-battery-facilities-forces-evacuations.aspx . This fire, on September 24th 2024 in Quebec also resulted in a shelter in place order: https://logfret.com/authorities-issue-shelter-in-place-orders-as-firefighters-respond-to-lithium-battery-fire-at-port-of-montreal/?lang=ja. Here, A fire erupted inside a solar battery storage container at the Valley Center Energy Storage Facility in northern San Diego County, California. The fire occurred when a battery storage unit caught fire, according to Terra-Gen, the owner of the energy storage facility. The Valley Center Energy Storage Facility, is a standalone 139 MW energy storage project in a commercial-industrial zone. Homes and businesses near the site were evacuated and a local shelter-in-place order was put into effect https://www.pv-magazine.com/2023/09/20/california-energy-storage-facility-hit-by-lithium-ion-battery-fire/. In response to Battery Fire near Escondido, September 2024, an Evacuation Order and Shelter-In Place order were Issued. https://www.alertsandiego.org/en-us/incident-page.1311.html. On May 17, 2024 (Otay Mesa) – The #CaminoFire at Gateway Energy Storage, a lithium battery storage facility in Otay Mesa, flared up overnight and prompted county officials to issue an evacuation warning for businesses in the surrounding area due to the potential for release of toxic gasses. The fire has also resulted in a shelter-in-place order for nearby Donovan State Prison. https://www.eastcountymagazine.org/fire-otay-battery-storage-facility-prompts-evacuation-warnings-shelter-place-order-donovan-prison.

I could carry on for page after page – or you could simply enter "battery fire shelter in place" into your favourite search engine and scroll for the next few hours.

The concept of sheltering in place might work for humans, most of the time, but how does it work for animals? How does it work for flocks that have taken generations to establish, for the horses at Trevalada that have been their owner's life's work or for farm dogs, pets or the local bird life?

It is not conceivable that Helios were unaware of this common very outcome related to the use of lithium battery storage – yet in their "community consultation" they never raised the issue, in their printed material they have consistently attempted to minimise or deny completely the easily verifiable risks associated with their proposal. I would suggest that they have proven themselves to be people completely unfit to undertake a project of this nature.

To view a BESS fire from the perspective of a firefighter injured in an attempt extinguish it you could watch this video. To quote Captain Hunter Clare, the company didn't have a mitigation action plan – we were their plan
https://youtu.be/USnTf1JPgts?si=PkTmfRx2EWWAFnxw .

Three years later Captain Clare faced a second BESS fire, for three days they stood back and watched the fire burn. They then used two robots, one with satellite telemetry, to open the door to the BESS facility – how many robots with satellite communication do we have in Naseby? The fire was eventually extinguished after 12 days.

If a Bess is installed in Naseby, there needs to be extensive community involvement, extensive upskilling by FENZ, an audible alarm system attached to the BESS which triggers with any abnormal function of any unit, the units need to be on a seismically strengthened, impermeable pad that is fitted with a bund capable of holding all of the water that might be involved in a BESS fire, a system for safely removing and disposing of that water as well as an irrevocable letter of credit or other bond that is available to compensate residents for the entirely predictable losses they may face as a result of the applicants operations – and the mother of all emergency response plans.

Glint and Glare.

Helios were first asked for their glint and glare report, at my request, on 5/10/2023. A promise was made by Helios to provide the report once they returned to the office.

A follow up email was sent to Helios on 12/10/2023. Their reply stated that no glint and glare report existed – but that a visit would happen once it was completed, and a copy would be handed over

12/10/2023 a second email was sent asking that Helios keep their original promise.

15/10/2023 Helios sent extracts of a generic glint and glare report and said that their report was not yet finished.

15/3/2024 mitigation planting plan posted – no glint and glare report

6/3/2024 again requested Helios keep their promise

27/3/2024 glint and glare report provided.

That report is dated 26/9/2023 and signed by N Logan. <u>The report was completed before the first meeting, the meeting at which a promise was made to provide the report.</u>

Helios have proven again that they can't be trusted to partner with Maniototo community.

Helios state:

"Solar panels are designed to absorb sunlight rather than reflect it. Solar panels incorporate anti-reflective coatings to maximise the absorption of energy. Glare is not a safety issue, as evidenced by the prevalence of solar farms being developed inside and around airports in New Zealand and overseas."

Once again, Helios attempt to trivialise an issue that is incredibly important to the community. Glare IS a safety issue – a major one in relation to roadways - that is well understood and accepted worldwide. There own Glint and Glare report lists the many (inadequate) ways that they propose to mitigate it. It is also something with the power to severely impact the community's quiet enjoyment of their properties. When challenged by council to prove their assertion that ignoring the glint and glare effects on minor roads was "international best practice" (!) the applicant referenced a booklet produced by a private company based in Surrey. I would suggest that is not the approach of a competent organisation.

What we are considering her is a sea of glass. The anti-reflective coating may make a percent or two of difference in the production of glint and glare – but the glint and glare will happen in any case.

The property group, in their report, claim:

The construction of the Māniatoto Plain solar farm (proposed) and the Solar Bay solar farm (consented) would introduce solar farms to the rural environment, however, would not materially alter the landscape characteristics.

I am not sure how to respond to this proposition other than to suggest that covering more than 600 hectares of the plain with a layer reflective and refractive glass, installing more than thirty iso container sized objects in the middle of a field, along with more than 70 slightly smaller containers randomly placed within the Maniototo's new black sea, building six 24m high towers at the centre and then constructing a tail of pylons heading away from it all would seem to me to "materially alter the landscape characteristics" in a very large way indeed.

Itp make several claims as to the existence of "international best practice" with regard to glint and glare, including this one:

"Major roads such as State Highways would be considered more sensitive to the effects of glare than local roads where the speed of travel is reduced."

Reduced speed of travel is not a phenomenon that I have experienced on New Zealand minor roads, unlike the UK we do not have a system of Motorways and A and B roads with their own speed limits. Our speed limits tend to be far more homogonous and the widespread use of metaled roads in country areas introduces a whole new element into the problem of dealing with sudden, unexpected sunstrike.

Here is what the applicant says in the report:

"The summary table of modelling shows that glare potential is possible towards four of the identified road receptors and five observation points.

Low or no impact is predicted for seven of the road receptors identified in the Study. A high impact is predicted for Ranfurly-Naseby Road and Ranfurly Back Road which means that mitigation is not required but is recommended to reduce impacts".

Yes, you read that correctly, a high impact from sunstrike is expected on the Ranfurly-Naseby Road and the Ranfurly Back Road which means that mitigation is not required. Are these people sociopathic? Do they care not at all about the possibility of road accidents that are initiated by sunstrike from something they have built? They phrase this as if they are doing the community a favour by planting the smallest trees they can find in unfavourable growing conditions and hoping for the best – eventually.

We have rules that limit the size and brightness of roadside billboards because of the danger that they will momentarily distract drivers – but these guys are suggesting that a sea of glass, reflecting the sun has an effect that they don't need to worry about. They should bring with them a group of American Indians – because they are already providing the cowboys.

Boffa Miskell say:

"Where occasional long distance views of more than 6 km to the Site may be available from distant elevated hill slopes, the benefits of perimeter mitigation screening will be limited due to the angle of view and there is potential for the whole site to be visible. However, by avoiding development in large internal areas such as around the central wetland and on several of the key faces, and infill planting within internal shelterbelts, the coverage of built form is broken up. Any views will typically be in the context of the range of land uses across the wider Maniototo/ Māniatoto Basin and would comprise a small and distant part of the view."

Let me translate that for you, mitigation measures will not work at all for any observer on any one of the many hills that surround the site. Glare, by its very nature, is highly specular. It dissipates very slowly due to the effects of atmospherics. Just because an observer is at some distance, it does not mean that they are unaffected.

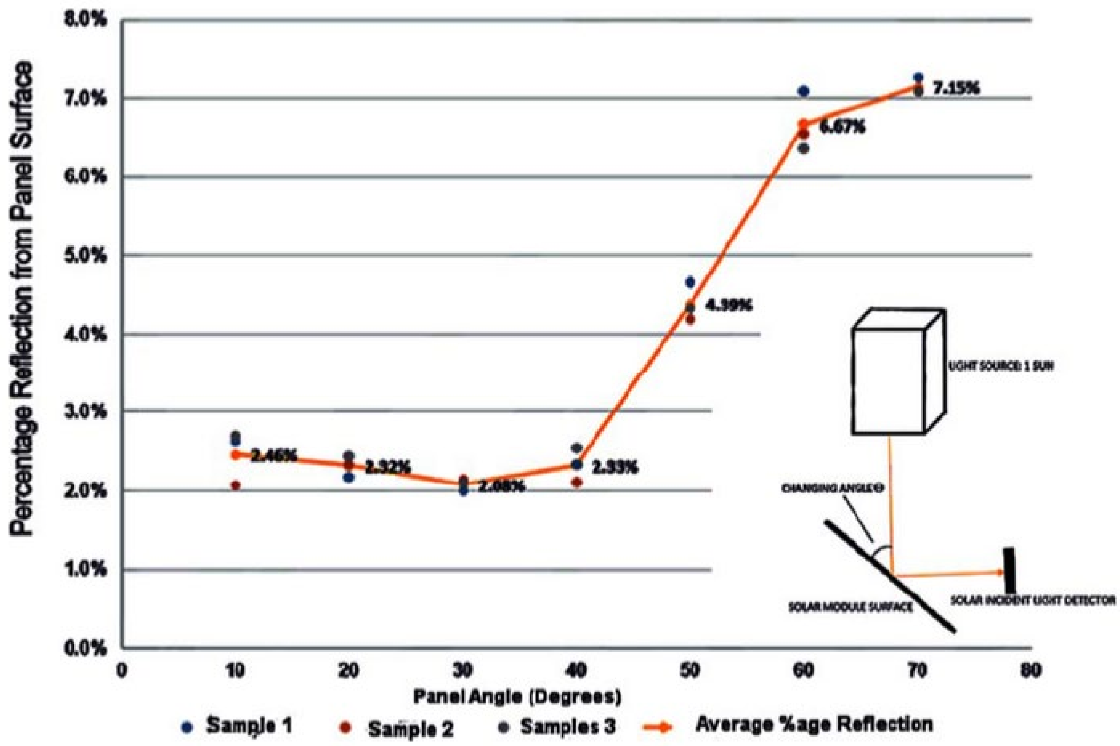

Image 14 taken from "General Design Procedures for Airport-Based Solar Photovoltaic Systems"

ITP's study mentions in passing that the degree of reflection is dependent on the angle of incidence while imply through their graphics that the reflection from solar glass is minor. Image 14 shows the actual measured reflection from solar panels – and it is not minor for large angles of incidence.

If these panels tracked the sun in three dimensions, the problem they produce from glare would be very low. They do not track the sun in three dimensions. As the seasons change, the sun tends to move higher and lower in the sky, the panels do not track that change, in fact, the panels, as proposed here, are never perpendicular to the sun because they lie perfectly flat in the North / South access and the sun is never directly overhead. In the mornings and in the evenings, when the sun is low in the sky, this angle between the sun and the panels is slight in this North / South axis and the level of reflection is high.

ITP quote Pager Power as a source of international best practice. Pager Power say that best practice is to model using receiver points every 200m along a roadway. ITP claim to have modelled nine road routes – but only measured at what appears to be nine points in total. I estimate that, conservatively, there is risk of glare on thirty kilometres of roadway, that would suggest that a well-constructed report would consider glare at 120 points. ITP do not explain their methodology in a way that allows confidence that the study represents the true likely outcome.

Similarly, ITP tell us that they have modelled a small number of reflecting surfaces. I read this to mean that they have chosen a single point, central to a large mass of panels and calculated glare angles for that point source. Once again, their chosen point of reference, Pager power, suggest modelling a reflecting surface as a large number of points spaced at 20 M intervals. ITP do not explain their methodology in a way that allows confidence that the study represents the true likely outcome.

Pager Power also defines, for each of their reflectors and receptors, an elevation. Elevation is a critical component in any Glint and Glare study. No alternative measure of elevation is used (transect). ITP do not explain their methodology in a way that allows confidence that the study represents the true likely outcome.

Given the lack of detail about the methodology used in the creation of their report, I consider it to be of little value.

Likewise, the mitigation proposed is almost comical. The lived experience of residents closest to the areas where plantings are proposed suggests that much of the “screen” plantings will take years, if not decades to reach an acceptable height. But the glare and the danger from sunstrike on roads and the loss of amenity values for neighbours will begin with the installation of the first panel. Which leads on to the installation process.

The glint and glare study is only valid once the solar tracking program is fully operational. Until that point in time the glint and glare study has no value at all – but the hazard still exists. The applicant proposes nothing to mitigate this situation, in fact they don’t even mention it exists.

An option does exist that would mitigate the problems caused by sun strike, the option recently mandated at the new gold mine at Millers flat. At Millers Flat Council mandated several kilometres of Bunding with the dual purpose of providing a visual and noise barrier to the mining operation. Given the very real risk to the safety of the community and visitors from sunstrike, and the reduction in amenity value for local resident caused by noise and glare, I suggest that a condition of consent should be the creation of earth bunds four metres high in areas that are currently proposed for planting, with planting still going ahead to soften the visual impact of the bunds. This is the only option that will remove this risk from the community with any degree of certainty and in a timely manner.

Water, an irreplaceable resource.

It is more than a little ironic that that the applicant proposes to set their power transformers on an impermeable concrete pad, bund them to a height that will contain the total volume of oil that they contain and install an oil separation device down stream when, only a few metres away they propose installing more than 1,000 tonnes of equipment, with have hugely higher rates of failure and which contain a witches brew of potentially toxic chemicals and metals, without any pad, without any bunding and without any plan for containment. There exist several watercourses that lead off this property, at least one of them leads to Ranfurly. This is not acceptable. Conditions of consent must contain a plan to completely contain any spill from the BESS units as a matter of the highest priority.

During the leadup to this application the applicant has consistently told the community that they intend to convey the electricity between the site and the Ranfurly substation by way of multiple 220kV cables. I never believed that this was the intention of the applicant. No company in New Zealand has the capability to install, joint, terminate and test cables at this voltage. As far as I am aware, no one but Transpower owns cables operating at this voltage. Such an install would be extremely expensive and provisioned as a turnkey project delivered from outside the country. Maintenance would also involve bringing crews in from offshore. In short, I have always believed that a tower line was the real intention of the applicant.

Nothing in this application defines the asset type that will be used for inter-connection. I suspect this will prove to be just one more example of the applicant's refusal to deal honestly with the community.

Decommissioning

Solar farms have a very bad reputation worldwide for leaving their mess behind when they eventually fold. Typically, solar farms avoid buying the land on which they sit – thus avoiding landowner responsibility for any mess they leave. Cost of remediation for solar farms is very substantial. The NREL [23] publishes data on expected cost of remediation and using their data this installation will have a midpoint cost estimate of 195,5120,000 to decommission (2021 NZ$).

It is critical that consent conditions anticipate early failure and designed end of life scenarios. If Helios cut and run the citizens of the Maniototo can not be left picking up the bill for the mess left behind. Clearly the bond, irrevocable letter of credit or other instrument used to protect the community from those potential cost must be substantial and comprehensive.

In summary, I have only hit on the high points in this submission. The applicant's decision to back the period for submissions up against Christmas has had the effect that it was always likely to have in such a busy period of life. It is clear to me that the processes, systems and regulations in place in New Zealand have yet to catch up with the risks and benefits of a proposal such as this. That means that difficult – and possibly groundbreaking – decisions must be made by Council and their planners. But those decisions must be made, the vitality of the community on the Maniototo depends on it.

This is the wrong project, in the wrong place at the wrong time, built by the wrong people

- for the many, many reasons that I have outlined her.

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