Preliminary Cost and Economic Performance Assessment of Utility-Scale Solar Photovoltaics at the Snohomish County, Washington's Tulalip Tribes' "Big Flats" Site

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Abstract

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The U.S. Department of Energy (DOE) launched its SunShot Initiative in 2011 to reduce the costs of utility-scale, commercial, and residential solar photovoltaic (PV) installations by 2020 (U.S. DOE, 2018). As of 2017, the DOE reached its goal for utility-scale solar PV to be cost competitive with conventional power resources, without the aid of subsidies and incentives, at $0.06 per kilowatt-hour (kWh), or $1 per watt ($/W) (U.S. DOE, 2018). In this 2010-2017 period, a quick drop in levelized costs from $0.28 to $0.06 per kWh and an increase of installed capacity from 3 gigawatts (0.1% of US electricity supply) to 47 gigawatts (1% of US electricity supply) is proof of the growth and expected further growth of solar PV technology (U.S. DOE, 2018). With a new SunShot target for 2030, this initiative seeks to cut the levelized costs, or the total costs of a solar PV system over its 30-year lifetime of production of energy, of utility-scale by an additional 50% to just $0.03/kWh, which would spur more solar PV installation growth and

make it one of the most cost-effective electricity generation sources (U.S. DOE, 2018). The Tulalip Tribe of Snohomish County, Washington have shown continued interest in a utility-scale solar PV deployment on its Big Flats site despite low Western Washington solar resources. The costs and financial parameters associated with developing on the former superfund site presents extra costs and challenges that impacts the application of the SunShot Initiative's goals of $1/W. These common extra engineering costs to ensure the superfund site continues functioning properly may be realized in the form of an added 25% to the total direct costs of a solar PV system (Olis, Salasovich, Mosey, & Victoria, 2013). As well, a $1 million grid interconnection fee may reasonably be expected to occur as the site does not have a substation and the nearby transmission lines may be inadequate to support a utility-scale solar PV system (Olis et al, 2013). Systematic Analysis Model (SAM), a cost and performance model developed by the National Renewable Energy Laboratory (NREL), was used to estimate preliminarily the levelized costs of electricity, or LCOE, which is a common metric to assess the economic viability of an energy development. SAM estimated the LCOE for 1 megawatt (MW), 2MW, 3MW, and 4MW installation sizes, and then compared those to the necessary contracted power purchase agreement (PPA) prices. These prices are essential for all utility-scale energy projects that connect to the local electrical utility's grid and are the price the energy developer must sell its produced energy system at to break even or earn a profit. In general, a project with a LCOE estimate equal to or less than the potential PPA contract price agreed upon by the energy producer and the energy purchaser, or utility, is considered economically viable. SAM not only produced these estimates but also produced their corresponding cash flows, internal rates of return (IRRs), and net present values. The Tulalip Tribes were assumed to select an equity flip financial structure, where an equity tax investor and the tribe share the ownership of the solar PV project and the federal

investment tax incentives are accessed. The PPA prices between the Tulalip Tribes and the Snohomish County Public Utility District No.1 (SNO PUD) for each MW size were simulated in SAM until the LCOE estimates were less than the PPA prices, and the IRRs and net present values for the equity tax investor were acceptable to ensure an investor would be found for the project.. Yet, none of the sizes resulted in a realistic PPA price (around $0.10/kWh) or positive net present values and attractive IRRs for the Tulalip Tribes. These unrealistic PPA prices have the potential to become more attainable through negotiations between the Tulalip Tribes and the SNO PUD and the implementation of renewable energy credit (REC) values. If the Tulalip Tribes would be willing to accept low net present values and IRRs for the solar PV project, then the 3MW and 4MW system sizes appear to be the most economically viable among the options with PPA prices of $0.14/kWh and $0.13/kWh respectively. Importantly, the net capital costs were assumed to be paid in cash or through grants by the Tulalip Tribe which rely on the tribe's ability to qualify for certain state and local programs. In conclusion, the economic viability of a solar PV installation on Big Flats depends on how the SNO PUD chooses to prioritize its energy supply mix, assess the costs and benefits of renewables versus conventional energy sources, and meet state renewable energy compliance laws for the years 2020 and 2021.

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The Tulalip Tribes: Snohomish County, Washington

Viewed as an attractive avenue for implementing a tribe's climate change adaptation goals, renewable energy development in partnership with neighboring non-tribal communities, utilities, and governments has begun to evolve as national energy demand increases. In combination with an awareness of the effects of climate change and the need for sustainable and clean energy development, many tribes have invested in renewable energy deployments on both large and small scales ranging from rural electrification to utility-scale and grid-tied connections (Powel & Long, 2010; Meisen & Erberich, 2016). The scale of these deployments depends heavily on tribal energy goals, project site suitability, and is influenced by state and federal laws and policies. Across the U.S., tribal entities are stereotypically viewed as economically and socially marginalized, politically disempowered, and subject to the negative impacts of the prevailing status-quo of fossil fuel energy production, extraction, and consumption (Powell & Long, 2010). However, the "thoughtful alternative" of renewable energy investment to this status quo has been gaining ground in tribal environmental movements, even when the potential for fossil-fuel energy development may be a more lucrative option (Powell & Long, 2010).

With numerous renewable energy sources to choose from, most tribal entities have found success deploying wind and solar energy installations (Meisen & Erberich, 2016). These two common options are viewed as having a "cleaner" reputation compared to hydroelectric, geothermal, and biomass renewable energy options (Meisen & Erberich, 2016). However, considering most renewable energy on tribal lands has been developed and operated by non-tribal entities, the realization of improved tribal sovereignty and economic development through renewable energy development is unfortunately difficult to accomplish (Meisen & Erberich, 2016). This "ownership dilemma" leads to two options; forfeit control of the project and lease the

land and its resources to outside developers, or directly own a renewable energy project and accept a possibly economically unviable venture (Jones & Necefer, 2016). This dilemma coincides with the common uncertainties and challenges experienced by all renewable energy investors and developers; infrastructure limitations, environmental impacts, public opposition, uncertain financial options, and trouble accessing state and federal financial incentives (Jones & Necefer, 2016).

The Tulalip Tribes of Snohomish County near Marysville, Washington have for decades recognized the catastrophic impacts of changing climatic conditions on its surrounding marine and terrestrial ecosystems, culture and livelihoods, and have adapted accordingly with habitat restoration and renewable energy projects (Tulalip Tribes Natural Resources Department, 2017). The Tulalip Climate Adaptation Plan, a holistic strategy to adapt to climate change, is a sound example of its dedication to analyzing and assessing the risks and strategies to abate these risks (Tulalip Tribes Natural Resources Department, 2017). Collaboration with outside partners such as non-governmental organizations and governmental departments in this Plan aims to establish a networked community equipped to increase climate change resilience (Tulalip Tribes Natural Resources Department, 2017). A successful example of this partnership is the Qualco Energy Biodigester renewable project. This project was formed as a non-profit partnership between the Tulalip Tribes, Northwest Chinook Recovery, and Sno/Sky Agricultural Alliance aiming to reduce harmful pollution runoff into the surrounding salmon habitat (SNO PUDb, 2018). This biogas system can generate up to 450 kilowatts (kWs), or enough energy to power 300 homes, proving the potential for the development of renewable energies as a collaboration between tribal and non-tribal members (SNO PUDb, 2018). The Tulalip Tribes have also deployed a small-scale solar photovoltaic (PV) (see Glossary) installation at its Betty J. Taylor Early Learning Academy,

which received partial funding from the Snohomish County Public Utility District No.1 (SNO PUD) (SNO PUDa, 2018). The 16.6kW solar PV energy system provides energy to the school, real-time solar data for visitors, and aims to encourage sustainability in the community while also acting as a pilot project for the tribe's investment in solar PV technology (SNO PUDa, 2018). Both Tulalip Tribes' renewable energy projects have standing relationships with the SNO PUD which purchases biogas energy created from Qualco Energy Project as part of its renewable energy power supply mix.

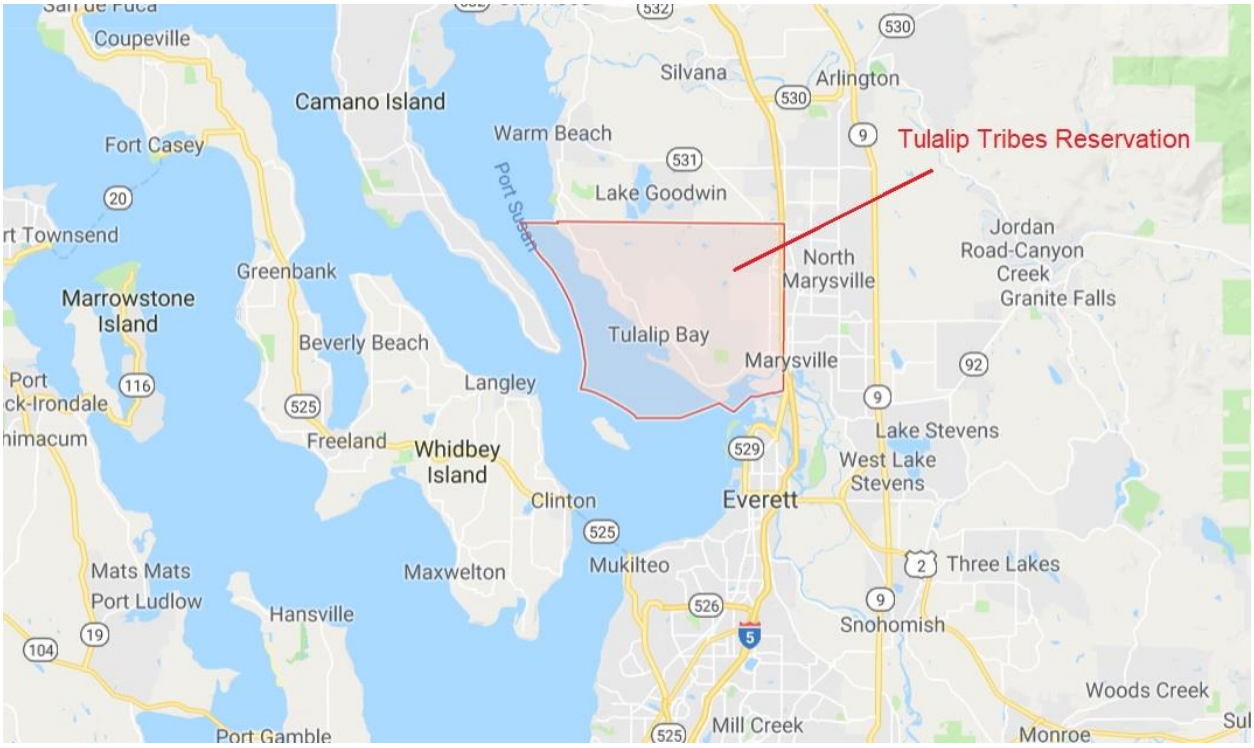

Figure 1. Map of Tulalip Tribes Reservation in Snohomish County (Source: Google Maps)

The Tulalip Tribes and its partners currently sell energy produced from the Qualco Energy Project to the SNO PUD through a power purchase agreement, or PPA (see Glossary). A PPA defines the terms between the energy producer and purchaser as well as the expected revenue stream of project and is seen as the most important financial tool for a utility-scale

project (International Finance Corporation [IFC], 2015). With a PPA, the energy system owner can be a third-party investor who has access to state and federal tax incentives, or it could even be the Tulalip Tribes themselves as a non-profit partnership or as a co-operative utility they may form to access the incentives (National Renewable Energy Laboratory [NREL], 2009). The PPA financial model allows the energy system owner to enter into a long-term contract with an energy purchaser, typically a utility, who purchases 100% of the energy produced from the system (NREL, 2009). This model also ensures access to relevant federal and state tax credits and incentives, potentially leading to a 50% financial return, thereby limiting financial risk and resulting in economic viability of the project (NREL, 2009). The more robust the PPA, the fewer the risks and uncertainty around the revenue stream of developing the project is (IFC, 2015).

The Qualco Energy Project's PPA originated with the Puget Sound Energy utility but in recent years entered into a contract with the SNO PUD after project partners were offered a more lucrative contract price (Sheets, 2013). Since 2014, when the SNO PUD took over the PPA from Puget Sound Energy, it has paid the Qualco Energy Project $47.84 per megawatt hour (MWh), or close to $0.05 per kilowatt hour (kWh) (Sheets, 2013). That contract price has steadily increased to $67.60/MWh as of 2018, or close to $0.07/kWh (Sheets, 2013). The partners net approximately $300,000 each year, with funds being used for system upgrades, other environmental projects, and bond payments (Sheets, 2013). Seen as a success to the project partners, the project is looking to expand in the coming years (Sheets, 2013).

After the deployment of the earlier mentioned 16kW solar PV system, the Tulalip Tribes are exploring development of large scale solar PV projects on its reservation as an investment into clean energy, including that of its superfund site Big Flats (Environmental Protection Agency [EPA] Region 10, 2017). While the Tulalip Tribes face a multitude of external roadblocks it is

also presented with a unique opportunity by the former superfund site. Relatively supportive state and federal policies, a standing relationship with the SNO PUD, and strong desire and funding give the Tulalip Tribes an edge to develop on Big Flats. Therefore, a "cliental" narrative is expressed throughout this paper, as well as the preference for maintaining a share of the ownership of solar PV project.

Utilizing previous technical and cost assessments as reference and a detailed financial model, the analysis section of this paper will assess: whether it could be economically viable for the Tulalip Tribes to develop a utility-scale solar PV on Big Flats; what size is most profitable; how federal incentives were accessed through complex financing structures, and which state incentives relevant to the success of such a development are accessible through a partnership with the SNO PUD.

The Snohomish County Public Utility District (SNO PUD)

The SNO PUD is the second largest publicly owned electric utility in the state of Washington, serving over 348,000 electric customers (SNO PUD, 2017). It services all of Snohomish County, Camano Island, and the Tulalip Tribes (SNO PUD, 2017). The SNO PUD invests in numerous renewable energy projects including hydroelectricity, biomass, wind, and biogas (SNO PUD, 2018). It also provides its customers with technical assistance and buy-in solar programs to satisfy its Integrated Resource Plan (IRP) (SNO PUD, 2017; SNO PUD, 2018a). "Integrated resource planning is a comprehensive process that considers how a utility will meet its objective to provide reliable electric service to its customers at the lowest, reasonable cost under a variety of futures. This process must also consider the risks and uncertainties inherent in a rapidly changing and complex industry" (SNO PUD, 2018a, p.1).

The SNO PUD's 2017 IRP was developed to analyze different scenarios to cross-compare growth in energy demand from 2018-2037 (SNO PUD, 2018a). It created alternative portfolio scenarios of different loads, carbon, resource forecasts, resiliency, least cost and least risk, and conservation potential to establish its planning standards (SNO PUD, 2018a). These standards are necessary to establish biennial conservation targets, elect renewable compliance methods, and compare to the preferred portfolio and action plan (SNO PUD, 2018a). The SNO PUD has identified energy efficiency measures and cost-effective conservation as the long-term strategy to meet any future energy load demand, with the need for additional power supplies not occurring until 2021 (SNO PUD, 2018a). This stems from its commitment to the Bonneville Power Administration, SNO PUD-owned hydroelectric supplies, and smaller supplies from wind and customer-owned generators (SNO PUD, 2018a). Historically, this utility's ability to provide reliable and affordable energy has depended on the winter and summer season's electricity supply from hydroelectric dams. Therefore, as the summer season provides electricity surpluses from snowpack melting and powering the hydroelectric dams, the winter season exhibits electricity deficits. The increased electricity demand is strategically met through complimentary energy sources (SNO PUD, 2018a). This chosen strategy is a result of the SNO PUD purchasing 83% of its power from the Bonneville Power Administration whose source is predominantly from the Federal Columbia River Power System consisting of 31 federally owned hydroelectric dams (SNO PUD, 2018a). The overwhelming commitment the SNO PUD has toward using Bonneville Power Administration as an energy source is essential in meeting peak energy demand. Although the SNO PUD receives part of its power supply mix from wind, landfill gas, and biomass, there are no existing solar sources despite incentives and programs calling for utilities to have a greater use of diversified renewables resources (SNO PUD, 2018b). How the Bonneville Power

Administration's ownership of transmission lines and flexible or inflexible relationship with the SNO PUD will impact its decisions to partner with and invest in the Tulalip Tribes' solar PV project on Big Flats is beyond the scope of this research.

Washington and its neighboring states in the Pacific Northwest are subject to a series of environmental policies and regulations. These include the national level Clean Air Act and Clean Power Plan, and the state level Energy Independence Act (I-937). To address greenhouse gas emissions, and specifically carbon dioxide emissions, the electric industry is pressured to improve energy efficiency programs and reduce emissions amid uncertainty of how the externalities caused by fossil fuel consumption (e.g. climate change, sea level rise, habitat degradation) will impact the economy and ecosystem.

Adopted by Washington state in 2006, the I-937 requires electric utilities serving over 25,000 customers and their IRPs to obtain 15% of their electricity from renewable sources excluding hydroelectricity by the year 2020 (SNO PUDd, 2018). The I-937 allows the SNO PUD to choose between three methods to demonstrate compliance with the 15% requirement earning them Renewable Energy Credits (RECs), while also requiring the selection of the most cost-effective energy method (SNO PUDd, 2018). Each REC represents 1MWh of renewably sourced electricity and can be viewed as the environmental benefit of deploying that renewable energy (Washington State Senate Committee Services, 2006). These tradeable credits can be bought and sold in the energy marketplace, yet must be verified by the Department of Community, Trade, and Economic Development's tracking system (Washington State Senate Committee Services, 2006).

Interestingly, a production incentive from the I-937 allows the SNO PUD to receive extra RECs towards certain investments in renewable energy facilities smaller than 5MW (Kandra, 2007). If the SNO PUD owns or has a PPA with a distributed generation facility such as a solar

PV installation on Big Flats, the RECs created from the energy generated or purchased from the Tulalip Tribes may count for twice the regular REC value (i.e. increased by a factor of 2) (Kandra, 2007). In the PUD's 2017 Mid-Year Report, "Method 1" was elected from RCW 19.285.040 which states that "A qualifying utility must serve its load with an increasing percentage or target of eligible renewable resources, RECs or a combination of both, by a certain date" (SNO PUDd, 2018 p.1). The PUD reported 2017 targets were approximately 89MWhs, or 73% of its 2020 target of approximately 123,00 MWhs (SNO PUDd, 2018). This information may imply that the SNO PUD could be more receptive or are presently researching new potential renewable energy electricity sources, such as solar PV on Big Flats, to comply with the 2020 15% requirement.

There are different ways the SNO PUD can attain RECs to remain compliant and simultaneously benefit the Tulalip Tribes. Although PPAs are generally structured to have RECs remain with the system owner, the SNO PUD can negotiate to buy the RECs along with the electricity produced on Big Flats. This can drive up the PPA price to compensate the Tulalip Tribes, and therefore the sale of these RECs can provide an important source of cash flow to the Tribes. These circumstances necessitate an internal cost comparison the Tulalip Tribes. If the recouped REC values from Big Flats is cheaper than the purchase of RECs in the marketplace, then it could be assumed the SNO PUD would opt for investing in Big Flats. Further, the costs and benefits of the SNO PUD investing in Big Flats compared to other potential and larger renewable energy investments and REC sources plays a role in the utility's decision-making. There is uncertainty surrounding the future of these I-937 compliance laws and whether the percentage requirements will remain constant at 15% or increase after the year 2020 (SNO PUD, 2017). There is also the concern about the looming reduced availability of these RECs to purchase

over the next 20 years, which should be further assessed in a separate analysis. This future percentage requirement uncertainty and reduced availability may encourage the SNO PUD to invest in Big Flats as a sure way to access RECs and remain compliant. With the assumption that the I-937 15% requirement is to stay constant, the SNO PUD's 2017 Draft IRP is banking on using 50MW of short term capacity contracts through 2022 and adding 116MW of natural gas after 2022 (SNO PUD, 2017). How solar PV on Big Flats fits into the options for short-term capacity additions of 50MW is of high interest and could be solidified as an attractive option depending on the economics of the installation. Further, whether the SNO PUD would be interested in a continued investment on Big Flats past 2022 would need to be negotiated between both parties and depends on the dynamic of the project partnership.

The Tulalip Tribes and SNO PUD Potential Partnership for Big Flats

Considering most utility-scale (see Glossary) renewable energy projects require the participation of multiple entities, a strong partnership and shared vision between a tribe and its serving electrical utility company is essential. The dynamics of this relationship will depend upon how the ownership of the project is structured and which financial tools are utilized. Due to the variety of scales and applications for renewable energy projects, the Tulalip Tribes and other tribal entities have a choice between 3 common ownership scenarios: land lease, direct-ownership, and flip structure (EPA Region 10, 2017; Meisen & Erberich, 2016). These scenarios allow tribes to match their energy project with their unique goals whether they desire gaining energy independence, increasing economic development, or improving tribal sovereignty (EPA Region 10, 2017; Meisen & Erberich, 2016).

Commonly, tribes enter into land-lease agreements; where an outside developer owns and operates the renewable energy installation, and the tribe receives rent from their leased land to reduce financial risks (Meisen & Erberich, 2016). One example of this is the Moapa Southern Paiute Solar Project, which has a 25-year PPA with the Los Angeles Department of Water and Power (First Solar, 2017). Located on 2,000 acres of the Moapa River Indian Reservation in Clark County, NV the project installed 250MW of solar PV through its owners Capital Dynamics and its developers First Solar, Inc. (First Solar, 2017). The power generated from this massive utility-scale installation can serve 111,000 Californian homes per year and displace 341,000 metric tons of carbon dioxide annually (First Solar, 2017). Per First Solar, the Moapa community is expected to receive millions of dollars in revenue from lease payments, the purchase of local materials, and from consulting fees (First Solar, 2017). The Moapa Community was also promised to continually be involved in the project to ensure that the business venture provides employment opportunities for qualified tribal members and residents (First Solar, 2017). “First Solar is committed to being a good neighbor through our community involvement and through the environmentally sensitive design of our solar projects" (First Solar, 2017, p.1). In addition, First Solar claims that, along with the Bureau of Land Management and US Fish and Wildlife Services, it has provided the Moapa community close to $1.6 million in desert tortoise protection mitigation fees via the Environmental Impact Statement and Biological Opinion that was conducted for the project (First Solar, 2017). It remains to be seen whether this specific land-lease scenario can aid the Moapa community in achieving its renewable energy goals and if it can be replicated and applied elsewhere.

The direct-ownership scenario is fitting for tribes who, like the Tulalip Tribes, would prefer to maintain control and management over the project design and its potential revenue (EPA

Region 10, 2017). This scenario allows tribes to finance their capital-intensive projects by issuing bonds, receiving grants, or from tribal revenue (EPA Region 10, 2017). For instance, the Rosebud Sioux Tribe of South Dakota installed a wind turbine while maintaining direct-ownership and creatively funding the project (Meisen & Erberich, 2016). The Rosebud Sioux Tribe was in the process of completing a required IRP to receive hydroelectricity from a federal dam when the tribe coincidentally discovered a high wind speed resource (Meisen & Erberich, 2016). This natural resource made it very competitive for the tribe to receive a grant for 50% of the total costs of the wind turbine from the Department of Energy (Meisen & Erberich, 2016). The grant was then matched with funds from the sale of RECs and a loan from the USDA Rural Electrical Service (Meisen & Erberich, 2016). This successful experience encouraged the Rosebud Sioux to invest in a 30MW wind farm in 2007, yet this project's difficulty in accessing federal Production Tax Credits (PTCs) (see Glossary) forced the tribe to switch from a direct ownership to a flip structure project (Haukaas, 2007).

A flip structure is another finance scenario for tribes to develop renewable energy by combining direct ownership and land lease methods with the aim to remain debt free (Meisen & Erberich, 2016). This complex financing structure allows renewable energy developers lacking sufficient taxable income to partner with equity tax investors with expertise in accessing tax benefits (Mendelsohn, Kreycik, Bird, Schwabe, & Cory, 2012). Equity partnership flips and sale leasebacks between developers and investors are gaining popularity for utility-scale solar PV facilities to manage their preferred level of financial risk and reward (Mendelsohn et al, 2012). This structure allows tribes to lease out their land to developers or recruit an investor to utilize tax incentives unavailable to tribes due to their non-profit status; typically 35-55% equity ownership for the tribe and 45-65% equity ownership for the investor (Mendelsohn et al, 2012). The shared

equity ownership percentages are based on percentage contributions to total installed capital costs of a project and is negotiated as a function of achieving a return on investment target year (Mendelsohn et al, 2012). In general, the lower percentage an investor contributes in capital costs to a project, the higher their returns on investment (Mendelsohn et al, 2012). The internal rate of return (IRR) (see Glossary) on investment year is the flip year when the project's benefit stream, both tax benefit and cash, are reached and is reallocated from the equity investor to the developer (Mendelsohn et al, 2012). The flip year is set to occur after all the tax benefits have been captured and requires a minimum of 5.5 years or the investor risks losing all the benefits received thus far (Mendelsohn et al, 2012). The share of the project's cash and tax benefits pre-flip and post-flip the IRR target year is a simple reversal. Before the designated IRR target year occurs, the investor receives 99% of the tax benefits and the developer receives the remaining 1% (Mendelsohn et al, 2012). 100% of the cash revenue also goes to the investor before the flip year. Post-flip however, the investor is typically left with 10% of the project's cash revenue and 10% of the tax benefits, with the remaining majority of the share switching to the developer.

Regardless of the ownership route taken for developing solar PV on Big Flats, a utility-scale sized installation will require a PPA with the SNO PUD. As previously mentioned, the Tulalip Tribes have had continued success with a PPA for its Qualco Energy Project, which also utilized the SNO PUD's Small Renewables Program. The success of this project was realized with a satisfactory PPA price compared to the costs of the energy system. This program has a specific method to determining the PPA price contract that accounts for numerous variables (SNO PUDc, 2018). This contract determines the PPA price among parties and is expressed in dollars per MWh ($/MWh) of energy produced for each year, for up to 5 years (SNO PUDc, 2018). The price is equal to the sum of: a set energy price in $/MWh, transmission and distribution loss

credits, tradable REC values, deferral of system upgrades credits, generation capacity cost credits, and distributed generation credits (see Glossary for all terms)(SNO PUDc, 2018).

Despite the limited number of solar installations in its service area, the SNO PUD's Small Renewables Program provides an important opportunity for utility-scale solar installations. SNO PUD customers have expressed the preferred benefits of a diversified power supply portfolio, thereby increasing the demand for renewable energy sources other than hydroelectricity (SNO PUDe, 2018). The program establishes the price for the energy generated and its environmental benefits; as well as determining whether a source meets the criteria of the interconnection and credit requirements (SNO PUDd, 2018). These requirements refer to the capacity size limit between 100kws and 2MWs and the eligibility of the energy source respectively (SNO PUDd, 2018). This program would allow for the Big Flats site to be sized at a 1MW and 2MW utility-scale installation. However, it must be noted that the total aggregated MW capacity of this program is limited to 10MW for all SNO PUD's serving territory, and it is unclear how much of this capacity is still available to be taken advantage of by the Tulalip Tribes (SNO PUDd, 2018). Installation sizes larger than 2MW and their subsequent interconnection eligibility to the SNO PUD's electric grid need to be reviewed on case-by-case basis (SNO PUDd, 2018). Eligible utility-scale energy developers that aim to interconnect to the SNO PUD's electric grid system are required to follow a complicated 9-step connection process that can range from 12 to 36 months in length (SNO PUDd, 2018). The Bonneville Power Administration, owner of most of the transmission lines in Snohomish County, may also require its own interconnection process. Therefore, the Tulalip Tribes are encouraged to begin these interconnection processes early in the project and concurrently.

The Tulalip Tribes selecting a flip structure route for solar PV on Big Flats allows them to acquire less financial risk and it presents the opportunity to pursue its relationship with the SNO PUD. Despite the attractiveness of complete project control from direct-ownership, the benefits the Tulalip Tribes would experience from a flip structure include reduced capital expenses and the prospect to further engage with the SNO PUD and its renewable energy agenda. Besides solar PV on Big Flats requiring cooperation to connect to the SNO PUD's electric grid, the site may reasonably result in a beneficial transaction between both parties. With a large scale solar installation on Big Flats, the Tulalip Tribes would advance its climate change adaption strategy and the SNO PUD would positively impact its renewable energy compliance requirements. Should the SNO PUD opt to partially fund the project or invest in another manner, this publicized partnership could boost the solar PV market in Washington. This improved symbiotic relationship could also enhance each participant's energy and economic goals through the transaction and leverage of RECs as discussed above. For these reasons, a flip structure scenario was assumed to be most economically beneficial to the Tulalip Tribes in this analysis.

Superfund Site: Big Flats

Big Flats is a promising 143-acre site for a utility-scale solar PV deployment due to its size, severely limited alternative use, proximity to transmission lines, and minimal slope (US Army Corps of Engineers, 2008). This former landfill and superfund site is near Quil Ceda Village and the soon-to-be finished Tulalip Quil Ceda Casino 2 (EPA Region 10, 2017). Proximity to these major and future energy demands as well as the I-5 corridor may justify a utility-scale solar development. Such a development would support the Tulalip Tribes' climate adaptation mission as well as provide an additional power source for the surrounding area (US

Army Corps of Engineers, 2008). The site (Figure 2) contains two operable units; an on-source area on the landfill, and an off-source area on the surrounding environmentally sensitive intertidal zone (EPA Region 10, 2017). Big Flats has had monitoring of its seven-layer cover system, or cap membrane, and any possible leachate seepage into nearby wetlands that will continue until 2031 or beyond (EPA Region 10, 2017; EPA Region 10, 2013). Tribal representatives monitor the system to produce monthly reports essential to current compliance requirements of this site and its future viability as a solar PV option. The seven-layer cover system and its continued degradation, settlement, and weight restrictions (e.g. 25 pounds per square inch) are of great concern to the feasibility of solar PV installation, in addition to the potential for high winds facing Big Flats on the exposed North Ebey Island of the Snohomish River delta (EPA Region 10, 2017). A concrete, ballast-weighted foundation would allow for greater distribution of the systems weight over the landfill cover system to adjust for any weight bearing limitations (EPA Region 10, 2017). A fixed-mounted system, although less efficient than single and dual-axis tracking systems, would be more cost-effective and guarantees the landfill cap membrane would not be punctured and any future settlement that occurs would not impact the systems tilt and alignment (Kiatreungwattana, Mosey, Jones-Johnson, Dufficy, Bourg, Conroy, Keenan, Michaud, & Brown, 2013).

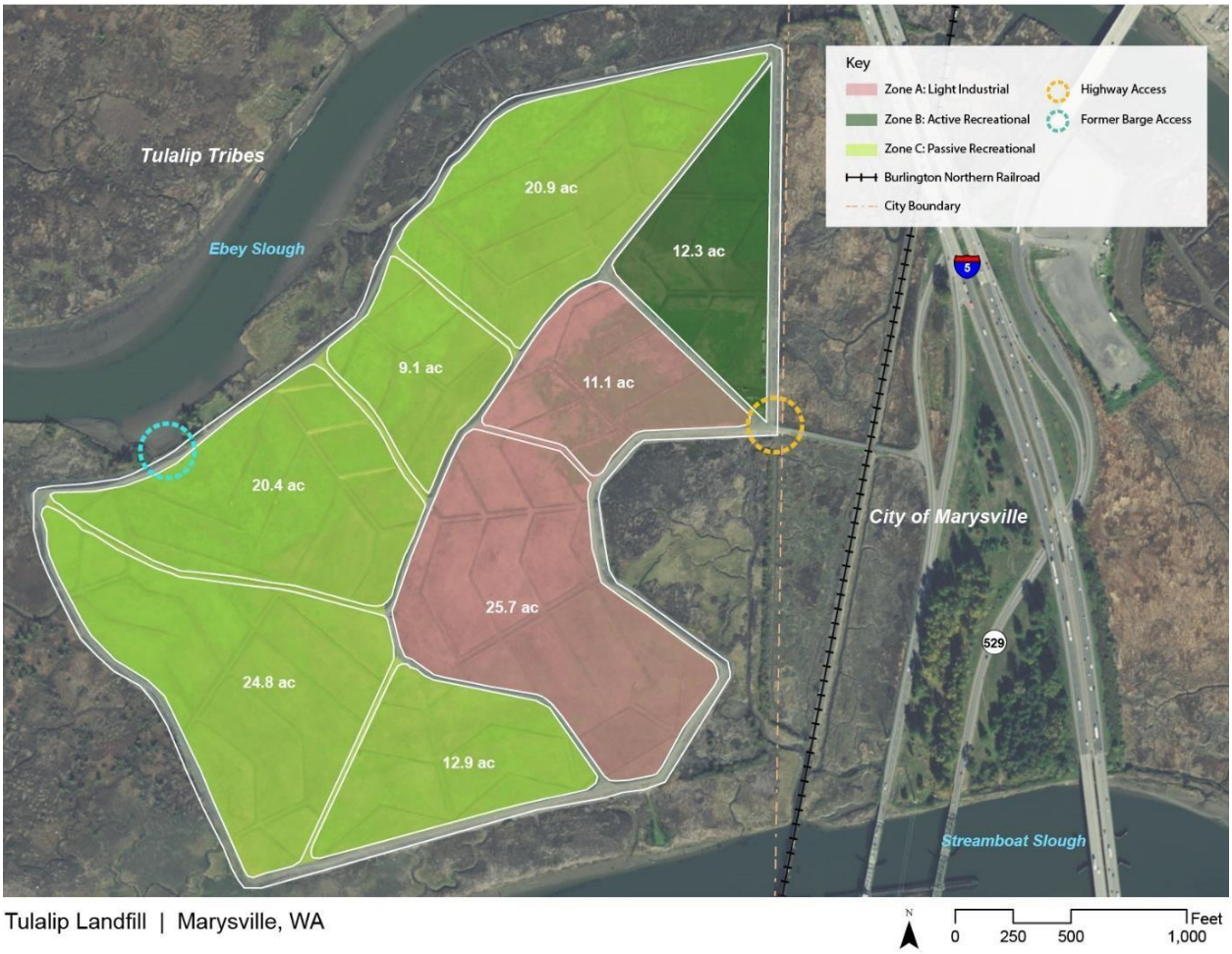

Figure 2. Big Flats hypothetical zones for re-use (Source: EPA Region 10, 2017. Tulalip landfill superfund site reuse assessment. Tulalip Indian Reservation, Marysville, WA. Page 4 (see Appendix C))

Overall, as of the 2013 Five-Year Report, landfill observations and inspections follow the operating and maintenance (O&M) plan state that the landfill cap membrane, the annual surveys of slopes (requiring a maximum of 2%), and past seepage of contaminated sediments into nearby wetlands are performing adequately (EPA Region 10, 2013). Trends continue to follow the original estimated settlement range; however, a geotechnical study of soil depth on top of the protective membrane is necessary. “Since 2005, the amount of settlement has generally been less than 0.1 feet per year across the site. Based on review of the 2012 survey data, the rate of

settlement increased slightly over the last year and it is recommended that the survey continue to be performed annually" (EPA Region 10, 2013, p.22). Despite these satisfactory monitoring reports, routine maintenance activities are still recommended to address the minor landfill cap membrane settlement each year that are not specified in these reports, especially in two specific areas on the Northeast area of the cap (EPA Region 10, 2013). This settlement can be greatly increased by heavy rainfall and subsequent ponding, but remedied through continued maintenance of drainage systems, rainfall collection systems, and proper road design (EPA Region 10, 2013). The next Five-Year Review will be conducted no later than April 24, 2018 (EPA Region 10, 2013).

Other physical restraints of concern on Big Flats are: there does not appear to be a substation on the site; it is unknown if the nearest transmission lines need to be upgraded; the site could become sensitive to future sea level rise; and the site is located near 100 year floodplains (EPA Region 10, 2017). The remedy for these concerns can be realized through interconnection studies in conjunction with the SNO PUD to establish whether the nearby transmission lines are adequate to handle a multi-MW load increase. Based off online mapping tools, the entirety of Big Flats should be resistant to sea level rise and 100-year floods according to Department of Ecology's Coastal Atlas map. The development of solar PV on Big Flats also proves to insignificantly affect the surrounding Chinook salmon critical habitat, as well as other species of interest, recreational, and commercial operations per Washington's Marine Spatial Planning online mapping tool. More information and analyses of detailed mapping is needed to absolutely guarantee social and ecological resiliency. This is necessary as there could be a possibility that access roads and transmission operations on Big Flats are affected by longer-term sea level rise and floods as climate change impacts increase in the future.

The Tulalip Tribal Board continues to show strong interest in pursuing a solar PV installation to "contribute to the economic development of the Tribe and potentially provide jobs and training, such as solar panel assembly and installation" (EPA Region 10, 2017, p.2). This is apparent through its past actions to assess the site (EPA Region 10, 2017). In June of 2017, the EPA's Region 10 "Tulalip Landfill Superfund Site Reuse Assessment" was conducted by a contractor to weigh the options of transforming Big Flats into a recreational site, a traditional and subsistence site, and a light industrial site for solar energy production (EPA Region 10, 2017). This assessment reviewed the history of the site and the Tulalip Tribes' longstanding goals for its reuse, including a consistent interest in a large-scale solar PV installation. After EPA, EPA consultants, and Tulalip tribal members met to discuss these reuse options, a suggested reuse map was constructed showing the eastern portion of Big Flats (Figure 2's Zone A in pink) to be the best option for a solar project due to its proximity to and likely access to utilities and transmission lines, road access, and better visibility to deter any vandalism (EPA Region 10, 2017).

The EPA examined 2 ownership scenarios to assess the potential of Big Flats for solar: "Direct Tribal Ownership/Simple Return on Investment" of a tribally owned 1MW system scenario; and a "Land Lease Scenario" where the Tulalip Tribes receive lease fees for the land used for a 1MW system using 4-6 acres (EPA Region 10, 2017). The first scenario assumed the power generated could be sold by the tribe to the SNO PUD at a negotiated PPA price of $0.10/kWh (EPA Region 10, 2017). This assessment provided the preliminary cost estimates of a 100kW and 1MW system on Big Flats, with these assumptions that: 4-6 acres of land were needed per MW installed; total system costs were between $2.5-4/W; and O&M costs were $15/kW/year (EPA Region 10, 2017). The assessment's results also portrayed the benefits of accessing the SNO PUD Solar Express Rebate (up to $8,000 max) and the federal Investment Tax

Credit incentive for 30% of the total capital costs (EPA Region 10, 2017). Tulalip Site Reuse Assessment results for a 1MW installation provided simple payback periods ranging from 18.7-27 years with and without incentives respectively. The formula for finding this range is as follows: "Simple Payback = System cost / (year 1 revenue (or savings) – year one O&M cost" (EPA Region 10, 2017, p.11). This recent site assessment ended with a recommendation by the EPA Region 10 for a more detailed lifecycle payback approach that would consider the benefits and revenues, which could then be compared to the costs of the system (EPA Region 10, 2017).

Integrating a solar PV system on a former landfill requires an assessment of how the characteristics of a site and its cover system limits the application of a solar system's foundation, tracking system, and the economic considerations (Kiatreungwattana et al, 2013). A common concern for deploying solar PV in Western Washington is its relatively low solar radiation. Best practices for evaluating whether a former landfill site is economically viable suggest a minimum solar radiation of 3.5 kWh/m2/day (Kiatreungwattana et al, 2013). Big Flats experiences an average solar radiation of 3.2 kWh/m2/day. Despite this low solar resource, reaching economic viability is still possible by accessing incentives and assessing specific performance and financial aspects (Kiatreungwattana et al, 2013).

The Levelized Cost of Electricity (LCOE) and the Systematic Analysis Model (SAM)

In most energy cost studies, the success of renewable energy deployments depends heavily on the overall economic competitiveness among alternate technology options. The levelized cost of electricity (LCOE) is a standard measure that allows for a comparative analysis of competing generation technologies in the electric power sector and represents the stream of equal payments in discounted real dollars over the expected energy production of an energy system (U.S. Energy

Information Administration [EIA], 2018; Branker, Pathak, & Pearce, 2011; Wang, Kurdgelashvii, Byrne, & Barnett, 2011). The LCOE provides a lifecycle cost estimate expressed in dollars per kWh ($/kWh) derived from an energy system's costs and its lifetime energy production (EIA, 2018). This $/kWh measure represents the average cost of generating electricity from an energy system based on individual site characteristics. General inputs into LCOE calculations include: "capital costs, fuel costs, fixed and variable operations and maintenance costs (O&M) costs, financing costs, an assumed utilization rate for each plant type," and available incentives and tax credits (EIA, 2018, p.1). For a utility-scale solar PV system, the estimated LCOE of the system is compared to a negotiated PPA price with the energy purchasers, or electric utility, that is agreed upon before any developments are initiated to provide the energy system owner the chance to assess whether that PPA price will compensate their estimated LCOE (NREL, 2009). Therefore, the LCOE is the approximation for what price the energy system owner must sell at through a PPA to eventually break even, or potentially earn a profit, over the energy system's lifecycle (EIA, 2018). Below is the EIA's simplified formula for estimating the LCOE, where the fixed charge factor implements the discount rate (Namovicz, 2013). The EIA is part of the U.S. Department of Energy and the principle agency of the Federal Statistical System (Office of the Federal Register, 2018). The EIA seeks to promote the understanding of renewable, nuclear, natural gas, coal, and electric energy, and how it interacts with the environment and economy (Office of the Federal Register, 2018).

$$LCOE = \frac{fixed\ charge\ factor + capital\ costs + fixed\ O\&M}{annual\ expected\ generation\ hours} + variable\ O\&M + fuel$$

LCOE estimates can provide policymakers, utilities, and energy system owners with a screening tool that estimates a single metric cost for an energy system, yet not all economic aspects are considered in this simplified estimate (Namovicz, 2013; Branker et al, 2011). Differing financial structures impact renewable energy projects dependent on federal government incentives and their subsequent LCOE estimates (Mendelsohn et al, 2012). Considering the Tulalip Tribes would likely require an equity tax investor, the economics associated with a PPA for solar PV on Big Flats would not be accounted for using simplified LCOE estimates alone. For this analysis, an additional financial tool is implemented to account for the equity investment aspects of a utility-scale project using a PPA: The NREL's Systematic Analysis model, or SAM.

SAM is an economic and performance model that can support decision-makers, policy analysts, technology developers, and researchers by predicting the cost of energy for a grid-connected renewable energy installation (NREL, 2010). Through the EPA's Re-Powering America's Lands Initiative, several feasibility studies of the economics and performances of solar PV with similar contaminated land characteristics to Big Flats have been conducted by the NREL and its EPA partners using SAM. The performance analysis piece of SAM can produce the hourly energy output of different system sizes, while the economic and financial piece of the model can produce the annual cash flow over a period of years (NREL, 2010).

For PPA models, SAM assumes that the estimated LCOE can be used for evaluating alternative energy projects and these projects' economic viability by comparing it to the PPA price. This implies again that a project is economically viable when its LCOE is less than or near equal to the PPA price to cover all project costs and meet the assumed internal rate of return (IRR) requirements. SAM provides a choice between "real LCOE", or the constant dollar value adjusted for inflation, and "nominal LCOE", or the current dollar value, estimates. SAM suggests

the use of "real LCOE" estimates be examined for long-term analyses to account for inflation over the project life. The DOE opts to use the "real LCOE" for comparative analyses of solar PV project costs. SAM suggests the comparison of "real LCOE" and "levelized PPA" estimates, or the PPA price adjusted for annual escalation rates, be accompanied by IRRs, positive net present values, reasonable payback periods, reasonable capacity factors, size of debt, and cash flow or benefits to properly assess the economic viability of a project. Due to the acceptance by the U.S. government of this SAM format, this preliminary feasibility assessment method was used for Big Flats as a precursor for the Tulalip Tribe's professional feasibility assessment to be conducted soon.

SAM also provided the opportunity to address the real-world technical and financial concerns that were omitted from the 2017 "Tulalip Landfill Superfund Site Reuse Assessment:" a cash flow analysis; IRRs; net present values (see Glossary); discount rates; panel and inverter efficiency, site solar resource; the option to model a flip structure ownership structure; and the option to simulate a range of PPA prices. This analysis also incorporated a larger amount of useable acreage to support multi-MW installation sizes to compare their economic viability. With no major concern of shading from trees or buildings at this site, approximately 37 acres are assumed available to develop on as seen in Figure 2's Zone A (EPA Region 10, 2017). This analysis also provided the opportunity to consider specific landfill development costs and any typical grid interconnection costs; 25% of total capital costs, and $1 million respectively (Olis et al, 2013). Each of these extra costs can reasonably be assumed to arise as landfills require numerous measures to prevent puncturing of the cap membrane, and if there are unsatisfactory transmission lines or there is a need for a substation on the site it may cost up to $1 million per mile for these improvements (Olis et al, 2013). SAM considered these omitted costs and more

detailed financial parameters to provide a realistic preliminary feasibility assessment for the Tulalip Tribes. The comparative analysis of 1MW, 2MW, 3MW, and 4MW sizes should supplement the EPA Region 10's "Tulalip Landfill Superfund Site Reuse Assessment" results to compare how larger installation sizes will affect the economics and performance of solar PV on Big Flats. This analysis should also supply the Tulalip Tribes with more detailed knowledge into the overall suitability of the site.

SAM Cost and Economic Performance Model Inputs and Assumptions for Big Flats

All Scenario SAM Project System Assumptions

Array sizes: 1-4MW

Acres needed: Approximately 5-20 acres depending on MW size

Module: iTek iT-275-HE (Washington made), ground or rack mounted, 20-degree fixed-tilt, azimuth 180-degree, ground coverage ratio 0.3

Inverter: PV Powered PVP100 kW-208 [208V] 208V [CEC 2018]

System performance degradation rate: 0.5% per year

Solar Resource and location: Downloaded weather file from NREL's National Solar Radiation Database (NSRDB) to get the most up-to-date data (from 1998-2014) weather data for long- term cash flow analysis

1. Average global horizontal 3.20/kWh/m2/day
2. Average direct normal 3.2/kWh/m2/day
3. System Latitude/Longitude 48.05, -122.18 (0.25miles from center of Figure 2's Zone A)

System Costs:

1. Grid interconnection: $1 million (Olis et al, 2013)

2. Land preparation and transmission: 25% of direct cost (Olis et al, 2013)
3. O&M costs: $15/kW/year for 25 years with added inverter replacement cost in year 15 of $265/kW/year (EPA Region 10, 2017; Olis et al, 2013)

Default assumptions:

1. Zero losses from: external shading loss from trees and buildings, self-shading loss from panels for fixed array, snow covering array losses
2. Other default direct, indirect, and installed costs, and system losses
3. Time of Delivery Factors: Uniform dispatch weekday and weekend hour-by-month multipliers applied to PPA price. Prepared by California electric utility companies
4. Depreciation (state and federal): 5-year MACRS allocation 92%, 15-year MACRS allocation 1.5%, 5-year straight line allocation 0%, 15-year straight line allocation 1.5%, 20-year straight line allocation 3.5%, 39-year straight line allocation 0%, non-depreciable assets allocation 1.5%,and a bonus depreciation 0%
5. Tax and Insurance Rates: 35%/year Federal income tax rate, 7%/year State income tax rate, 5% sales tax rate of total direct costs, 0.5% annual insurance rate of total installed cost, and 100% property tax of assessed value
6. Reserve Accounts: 1.75%/year interest on reserves, working capital reserve for 6 months of operating costs, and major equipment replacement reserve accounts of $0.25/W

All Scenario SAM Project System Financial Parameters

All Equity Partnership Flip for Analysis Period of 25 years:

1) Share of Equity: 35% Equity Tax Investor and 65% Tulalip Tribes (Developer)

2) Pre-flip (before 9 years) share of project cash: 100% Equity Tax Investor and 0% Tulalip Tribes (Developer)
3) Post-flip (after 9 years) share of project cash: 10% Equity Tax Investor and 90% Tulalip Tribes (Developer)
4) Pre-flip (before 9 years) share of tax benefits: 99% Equity Tax Investor and 1% Tulalip Tribes (Developer)
5) Post-flip (after 9 years) share of tax benefits: 10% Equity Tax Investor and 90% Tulalip Tribes (Developer)

Tulalip Tribes (Developer) Capital Recovery: 25-year duration Inflation rate: 1.5% per year (Olis et al, 2013)

Real discount rate: 3.5%

Nominal discount rate: 5.05% (Olis et al, 2013)

Solution and Simulation Mode: Specify PPA Price to calculate resulting IRR. IRR target year of 9 years (e.g. year when ownership flip occurs). 0% escalation PPA rate per year.

Federal and State Incentives: Federal Investment Tax Credit of 30% of direct capital costs as one-time upfront cost reduction for equity investor. State production-based incentive (PBI) for using Washington-made solar panels of $0.05/kWh for years 2020 and 2021 only (EPA Region 10, 2017; Olis et al, 2013).

Each simulation was performed using SAM's "Photovoltaic PVWatts Detailed" performance parameter and the PPA "Equity Flip Structure" financial parameter. This "flip, no-debt structure" assumes an outside equity investor who is taxable, unlike the Tulalip Tribes, would be willing to invest a share of the total installed costs of the solar development and recoup

its investments through accessing the federal tax incentive over a 9-year period. For Big Flats, the investor would make the most sense to be Snohomish County whom conducted its own feasibility assessment using this same methodology in 2013 for a solar PV installation on its Cathcart Landfill. However, if the Tulalip Tribes were to form a co-operative utility or LLC, they would be able to access the federal tax incentive themselves without the need for a taxable equity tax investor. Therefore, It was assumed that such a group has not been formed yet in the tribe.

As the Tulalip Tribes are not a taxable entity, it was explicitly assumed that the 30% federal Investment Tax Credit must be accessed through an equity tax investor, with a priority to provide the investor with an IRR at approximately 4.72-7.48%. Subsequently, the Tulalip Tribes were assumed to be able to accept low net present values and a lower IRR at approximately1.79-2.34%. Further, the default IRR ownership flip year was assumed to occur in the 9th year. Equity tax investors are required to assume risk in a project for a minimum of 66 months, or 5.5 years to access the federal Investment Tax Credit or risk losing all of the tax benefits (Mendelsohn et al, 2012). An equity flip structure share of 35% by the investor and 65% by the Tulalip Tribes was assumed to be necessary to achieve the highest investor IRR possible. This flip structure percentage differs from the earlier discussed example of 45-65% paid by the investor and 35-55% paid by a tribe or developer to, again, create the highest IRR for the investor. The Tulalip Tribes were assumed to pay its 65% share of the total costs of each MW size system using cash to avoid acquiring any debt and keep down total costs. Lastly, the specific PPA price ranges were chosen to create a situation where each MW size installation's LCOE was less than the PPA price. The "real LCOE" number was assumed as the accurate LCOE value to consider, as was stated in the previous section. The "nominal LCOE," although expressed in each full SAM report provided in the Appendix B, is not to be examined. A sensitivity analysis is also provided in Appendix D to

express how the 25% extra development costs for developing solar PV on a landfill effect the economic viability of each MW size. These results will not be discussed but will provide a reference for how the LCOE and PPA prices would vary should the extra costs to develop on Big Flats be less than the estimated 25% and cost only 15%. Of course, it is possible for the extra development costs to be more than 25% of the total direct costs.

There were many other assumptions made using SAM's default inputs due to a lack of knowledge concerning the exact financial and physical parameters that affected the subsequent SAM results. For instance, self-shading from the arrangement of solar panel rows was assumed to be zero, which underestimates the loss of efficiency of the entire system. The time-of-delivery (TOD) factors (e.g. multipliers that apply to the PPA price) used were the default inputs supplied by SAM that were based on California electric utilities and could greatly overestimate the performance of the entire system. Other assumptions included: zero efficiency loss from snow; no battery storage; default lifetime PV array performance degradation of 0.5% per year; default 0% transformer losses; default 1% AC losses; and default DC losses from the central inverter.

SAM Results for 1MW, 2MW, 3MW, and 4MW and Discussion

Results

Figure 3. SAM Results for 1MW

Metric	Value
Annual energy (year 1)	1,022,430 kWh
Capacity factor (year 1)	11.7%
Energy yield (year 1)	1,024 kWh/kW
Performance ratio (year 1)	0.77
PPA price (year 1)	17.00 ¢/kWh
PPA price escalation	0.00 %/year
Levelized PPA price (nominal)	17.00 ¢/kWh
Levelized PPA price (real)	14.51 ¢/kWh
Levelized COE (nominal)	19.40 ¢/kWh
Levelized COE (real)	16.57 ¢/kWh
Investor IRR	7.10 %
Year investor IRR acheived	9
Investor IRR at end of project	7.48 %
Investor NPV over project life	$29,618
Developer IRR at end of project	2.07 %
Developer NPV over project life	$-358,245
Net capital cost	$2,672,862

Figure 4. SAM Results for 2MW

Metric	Value
Annual energy (year 1)	2,044,766 kWh
Capacity factor (year 1)	11.7%
Energy yield (year 1)	1,024 kWh/kW
Performance ratio (year 1)	0.77
PPA price (year 1)	15.00 ¢/kWh
PPA price escalation	0.00 %/year
Levelized PPA price (nominal)	15.00 ¢/kWh
Levelized PPA price (real)	12.81 ¢/kWh
Levelized COE (nominal)	16.78 ¢/kWh
Levelized COE (real)	14.33 ¢/kWh
Investor IRR	5.22 %
Year investor IRR acheived	9
Investor IRR at end of project	6.13 %
Investor NPV over project life	$22,748
Developer IRR at end of project	2.41 %
Developer NPV over project life	$-510,848
Net capital cost	$4,343,225

Figure 5. SAM Results for 3MW

Metric	Value
Annual energy (year 1)	3,070,593 kWh
Capacity factor (year 1)	11.7%
Energy yield (year 1)	1,024 kWh/kW
Performance ratio (year 1)	0.77
PPA price (year 1)	14.00 ¢/kWh
PPA price escalation	0.00 %/year
Levelized PPA price (nominal)	14.00 ¢/kWh
Levelized PPA price (real)	11.95 ¢/kWh
Levelized COE (nominal)	15.78 ¢/kWh
Levelized COE (real)	13.47 ¢/kWh
Investor IRR	4.77 %
Year investor IRR acheived	9
Investor IRR at end of project	5.67 %
Investor NPV over project life	$17,744
Developer IRR at end of project	2.23 %
Developer NPV over project life	$-748,060
Net capital cost	$6,019,064

Figure 6. SAM Results for 4MW

Metric	Value
Annual energy (year 1)	4,093,044 kWh
Capacity factor (year 1)	11.7%
Energy yield (year 1)	1,024 kWh/kW
Performance ratio (year 1)	0.77
PPA price (year 1)	13.00 ¢/kWh
PPA price escalation	0.00 %/year
Levelized PPA price (nominal)	13.00 ¢/kWh
Levelized PPA price (real)	11.10 ¢/kWh
Levelized COE (nominal)	15.08 ¢/kWh
Levelized COE (real)	12.87 ¢/kWh
Investor IRR	5.18 %
Year investor IRR acheived	9
Investor IRR at end of project	5.54 %
Investor NPV over project life	$16,719
Developer IRR at end of project	1.59 %
Developer NPV over project life	$-1,154,651
Net capital cost	$7,689,426

Discussion

As expected, the LCOE estimates decreased as the MW size installed increased, due to economies of scale. The economies of scale refer to the advantages of increasing the size of an installation so that the fixed costs are spread out over more units of output and more savings occur (Borenstein, 2012). Yet, none of the simulations resulted in economic viability near a $0.10/kWh PPA price that was assumed to be reasonable in the EPA Region 10's 2017 "Tulalip Landfill Superfund Site Reuse Assessment" for Big Flats. The lowest PPA price was met by the 4MW installation size at $0.13/kWh, but also incurred the lowest IRR and net present value for the Tulalip Tribe (Figure 6). The 3MW system size resulted in a PPA price of $0.14/kWh, just $0.01/kWh higher than the 4MW system, and resulted in the second highest IRR for the Tulalip Tribe among all the sizes (Figure 5). With the all equity flip structure, the Tulalip Tribe would have to pay $4,998,127 and $3,912,392 in cash for the 4 and 3MW sizes respectively.

The relative comparability between these two system sizes and their values may provide the Tulalip Tribes with their best options, while still producing substantial investor IRRs around 4.77-5.18%. If the Tulalip Tribes are willing to front these cash investments or find funding from grants, then the 4MW and 3MW sizes appear to most promising. Yet, both simulations resulted in a negative net present value and a positive IRR only ranging between 1.59-2.23 % for the Tulalip Tribes as the developers (Figures 5 and 6). These unsatisfactory parameters do not produce economic viability; however, this does not necessarily mean that the Tulalip Tribes should not proceed with the project. In other words, if the Tulalip Tribes value a solar PV deployment on Big Flats greater than what SAM's estimated negative net present values and low IRRs have captured, then these SAM results could be viewed as more economically viable. For instance, should the Tulalip Tribes value a parameter excluded from SAM, such as the environmental benefits of

reduced carbon emissions, then these personal values may make the 4MW and 3MW sizes more attractive in the Tulalip Tribes' opinion.

As mentioned in previous sections, the applicability of the SNO PUD's Small Renewables Program PPA contract price formula to the 1MW and 2MW sizes may positively impact their corresponding SAM results. For instance, the value of RECs for these qualifying sizes being multiplied by a factor of 2 may be able to increase the economic viability by reducing their corresponding LCOE estimates. However, with the 1MW system size preliminary results requiring a PPA price of $0.17/kWh, it does not seem realistic to expect that the REC values would be able to compensate for such a high price (Figure 3). It is more likely that the 2MW system size requiring a PPA price of $0.15/kWh could be positively impacted by its corresponding REC values (Figure 4). Both sizes also resulted in higher investor IRRs and less negative net present values than the 3 and 4 MW sizes.

For the 3MW and 4MW sizes that are not eligible for the Small Renewables Program, it is unclear how the SNO PUD would react to the necessary PPA prices of $0.14/kWh and $0.13/kWh respectively. While their REC values could possibly be greater than the 1MW and 2MW system sizes due to their greater energy production and the I-937 incentive discussed earlier, both the 3MW and 4MW system sizes could incur extra wheeling costs (see Glossary) from the SNO PUD and the Bonneville Power Administration. Typically, as a project takes shape the negotiations between the system owner and the energy purchaser occur to determine the price and terms (IFC, 2015). For Big Flats, the potential PPA prices may be determined by the SNO PUD's obligation to meet I-937 requirements using the Small Renewables Program PPA price formula. These terms may also be influenced by the SNO PUD's priorities and parameters as a

public utility; thereby allowing the potential possibility of a higher PPA price that eventually exceeds these preliminary LCOE estimates (IFC, 2015).

Difficulty in setting a realistic PPA price near $0.10/kWh questions the preliminary economic viability of solar PV on Big Flats. However, the word "preliminary" is of upmost importance, as further analysis and more detailed financial information relative to the Tulalip Tribes, potential equity tax investors, and a higher negotiated PPA price could more accurately aid in the decision to develop or not. Decision-grade feasibility assessments and investment-grade feasibility assessments for developing utility-scale solar PV on a former landfill provide varying levels of detailed performance and financial modeling (Kiatreungwattana et al, 2013). A decision-grade, or preliminary, feasibility assessment provides a conceptual design of the systems "module type, mounting system, anchoring system, and inverters, plus cost estimates for these components and their installation" (Kiatreungwattana et al, 2013, p.17). Estimates are developed to analyze the cost and benefits of the system and its performance characteristics to determine whether the project's economic metrics and regulatory considerations warrant its future development (Kiatreungwattana et al, 2013). Once a decision is made to continue or abandon the project, a more in-depth investment-grade feasibility assessment analyzing the internal rate of return, levelized cost of electricity, and payback periods should follow (Kiatreungwattana et al, 2013). While this analysis aimed to provide a decision-grade feasibility assessment, both types of assessments components were touched on using SAM.

Conclusion

Assessing the feasibility of deploying solar PV, beyond a basic economic approach, is a complicated task that requires a simultaneous examination of physical characteristics, relevant

policies, and the financial options available. The methodology for assessing a solar PV energy project will generally aim to assess economic viability regardless of how strong or how weak an area's solar resource may be. Federal and state grant and incentive programs are what provide the solar industry a vital funding source to reach economic viability while some of the costs are still higher than those of choice fossil fuels deployments. Which feasibility methodology a tribe in Western Washington may opt for may be influenced by past renewable energy project experiences or any limitations of the available sites to develop on. Use of the NREL's SAM cost and performance model aimed to supply the Tulalip Tribes with preliminary estimates until a professional and extensively detailed assessment is eventually completed. These SAM simulation results demonstrated the difficulty in assessing the feasibility of a solar PV installation on Big Flats with high landfill development costs, despite a strong desire by the Tulalip Tribes to complete this project. This was evident through the challenge of setting a realistic PPA price with the SNO PUD that was compatible with each MW size's estimated LCOE which concurrently resulted in attractive IRRs and positive net present values for both entities. Through grant accumulations, the Tulalip Tribes may be able to accept lower IRRs and net present values that resulted from SAM to recruit several competing equity tax investors. Further, if the Tulalip Tribes value a solar PV installation on Big Flats in ways that were not captured through SAM, then it is possible that its financial parameter results could be underestimated. This allowance would of course require an internal evaluation among the Tulalip Tribes.

Although the benefits from solar PV were not entirely accounted for through these economic viability estimates for the Tulalip Tribes, individual renewable projects and their unique characteristics and beneficiaries may be able to capture these benefits in other ways. This can be better realized when the fossil fuel source the renewables are displacing are perceived to have

little value and large environmental consequences (Borenstein, 2012). However, carbon taxes and market-based approaches to reducing carbon emissions have yet to influence the Washington legislature, and relying on the I-937 carbon policy seems to be the current choice policy. Revisiting the I-937 compliance standards come 2020 to increase from 15% must be a priority to capture these economic benefits and hold electric utilities accountable for their energy supply source decisions. As natural gas plants have and continue to be cost-effective compared to competing renewable technologies, the context in which they are compared continues to be a point of opportunity (Borenstein 2012). If governments wish to attempt to implement policies and taxes in favor of renewable energy in our modern electricity systems, then specific levelized costs and benefits of competing technologies must be further developed and adjusted (Borenstein, 2012). These adjustments could more accurately represent the true market value of renewable energy sources, thereby quantifying the climate change externalities the energy source is displacing (Borenstein, 2012). While climate change continues to negatively impact coastal communities like the Tulalip Tribes; how these communities, their electric utility providers, and their State legislature decide to invest in future energy resources will impact the economic viability of renewable energy deployments.

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Appendix A. Glossary

Deferral of system upgrades credits: "A credit will be computed for the value of deferred distribution system upgrades will be added to the Contract Price for Contract Terms of no less than five years" (SNO PUDc, 2018, p.3))
Distributed generation credits: "A fixed dollar value of 50% of the Tradable REC Value can be added to the Contract Price for each megawatt-hour produced by a resource recognized as an eligible renewable under the then current renewable portfolio standards established by the Washington Energy Independence Act (I-937), codified at RCW §19.285.030, provided the resource also qualifies as Distributed Generation under RCW §19.285.030(9) and is eligible to receive the 2x multiplier" (SNO PUDc, 2018, p.3)
Generation capacity cost credits: "A credit for the capacity contribution the resource provides to Snohomish PUD during certain on-peak winter months will be added to the Contract Price for Contract Terms of no less than five years" (SNO PUDc, 2018, p.3)
Grid interconnection: electrical tie-in point where an energy project connects to the electrical grid (Olis et al, 2013)
Internal rate of return: "IRR calculations assume a neutral NPV (a value of zero) and solve for the discount rate. The discount rate of an investment when NPV is zero is the investment's IRR, essentially representing the projected rate of growth for that investment. Because IRR is necessarily annual — it refers to projected returns on a yearly basis — it allows for the simplified comparison of a wide variety of types and lengths of investments" (Investopedia, 2018)
Modified accelerated cost recovery system (MACRS): accelerated depreciation schedule incentive that allows renewable energy projects to depreciate over an accelerated five-year schedule (Mendelsohn et al, 2012, p.1)
Net present value (NPV): "Net present value (NPV) is the difference between the present value of cash inflows and the present value of cash outflows over a period of time. NPV is used in capital budgeting to analyze the profitability of a projected investment or project." "A positive net present value indicates that the projected earnings generated by a project or investment (in present dollars) exceeds the anticipated costs (also in present dollars). Generally, an investment with a positive NPV will be profitable, and an investment with a negative NPV will result in a net loss. This concept is the basis for the Net Present Value Rule, which dictates that the only investments that should be made are those with positive NPV values" (Investopedia, 2018)
Power purchase agreement (PPA): a contract to sell electricity, usually on a utility-scale level, at a negotiated rate over a fixed period of time (Mendelsohn et al, 2012)
Production tax credit (PTC): "a federal tax credit of $0.022/kilowatt-hour (kWh) inflation adjusted for the first 10 years of generation from qualifying renewable energy facilities. The PTC is available for wind project through the end of 2012 and for other qualifying technologies such as biomass, geothermal, and marine and hydrokinetic resources through 2013. The PTC is not applicable to solar projects" (Mendelsohn et al, 2012, p.1)
Solar photovoltaics (PV): renewable energy technology that "converts energy from solar radiation directly into electricity. Solar PV cells are the electricity-generating component of a solar energy system" (Olis et al, 2013, p.5)
Time of Day (TOD) factors: causes the power purchase agreement (PPA) price to vary depending on what time of day the energy is produced due to its value changing between night and daytime (Meisen & Erberich, 2016)

Tradable Renewable Energy Credit (REC) values: "A value for the tradable REC for each megawatt-hour of electrical output produced by the resource can be added to the Contract Price if the resource is recognized as an eligible renewable under the then current renewable portfolio standards established by the Washington Energy Independence Act (I-937), codified at Revised Code of Washington ("RCW") §19.285.030. This value will be determined based on the most recent and available REC market pricing for the period" (SNO PUDc, 2018, p.3)
Transmission and distribution loss credits: "1) regional transmission losses that would otherwise be incurred in moving power from outside of Snohomish PUD's service territory to the utility's electric system; and 2) distribution losses avoided by developing the resource inside Snohomish PUD's service territory" (SNO PUDc, 2018, p.3)
Utility-scale: large-scale generation in open space, typically 1 Mega Watt (MW) size and larger needing grid interconnection (Borenstein, 2012)
Wheeling costs: costs associated with grid connected energy projects that may be added on by transmission line owners or electrical utility owners

Appendix B. SAM full simulation reports for 1-4MW systems

System Advisor Model Report

Photovoltaic System	999 DC kW Nameplate	City and state unknown
All Equity Partnership Flip	$2.66/W Installed Cost	48.05 N, -122.18 E GMT -8

Performance Model

Modules	
iTek iT-275-HE	
Cell material	Mono-c-Si
Module area	1.63 m²
Module capacity	272.85 DC Watts
Quantity	3,660
Total capacity	998.63 DC kW
Total area	5,980 m²

Inverters	
PV Powered: PVP100 kW-208	
Unit capacity	100 AC kW
Input voltage	295 - 480 VDC DC V
Quantity	8
Total capacity	800 AC kW
DC to AC Capacity Ratio	1.25
AC losses (%)	1.00

Array	
Strings	305
Modules per string	12
String voltage (DC V)	385.20
Tilt (deg from horizontal)	20.00
Azimuth (deg E of N)	180
Tracking	no
Backtracking	-
Self shading	no
Rotation limit (deg)	-
Shading	no
Snow	no
Soiling	yes
DC losses (%)	4.44

Performance Adjustments	
Availability/Curtailment	none
Degradation	0.5 %/yr
Hourly or custom losses	none

Annual Results (in Year 1)	
GHI kWh/m²/day	3.20
POA kWh/m²/day	3.00
Net to inverter	1,086,000 DC kWh
Net to grid	1,022,000 AC kWh
Capacity factor	11.7
Performance ratio	0.77

Financial Model

Project Costs	
Total installed cost	$2,658,726
Salvage value	$0

Analysis Parameters	
Project life	25 years
Inflation rate	1.5%
Real discount rate	3.5%

Financial Targets and Constraints	
Solution mode	Calculate IRR
PPA price (bid price)	17 cents/kWh
PPA escalation rate	0 %/year

Tax and Insurance Rates	
Federal income tax	35 %/year
State income tax	7 %/year
Sales tax (% of indirect cost basis)	5%
Insurance (% of installed cost)	0.5 %/year
Property tax (% of assessed val.)	0 %/year

Incentives	
Federal ITC	30%
Depreciation	Depreciation allocations defined with no bounus depreciation
State PBI	0.05 $/kWh2 yrs

Results	
Nominal LCOE	19.4 cents/kWh
PPA price (year one)	17 cents/kWh
Project IRR	7.1% in Year 9
Investor NPV	$29,600
Developer NPV	$-358,200
Investor IRR	7.5%
Developer IRR	2.1%

System Advisor Model Report

Photovoltaic System	2.0 DC MW Nameplate	City and state unknown
All Equity Partnership Flip	$2.16/W Installed Cost	48.05 N, -122.18 E GMT -8

Performance Model

Modules	
iTek iT-275-HE	
Cell material	Mono-c-Si
Module area	1.63 m²
Module capacity	272.85 DC Watts
Quantity	7,320
Total capacity	2 DC MW
Total area	11,960 m²

Inverters	
PV Powered: PVP100 kW-208	
Unit capacity	100 AC kW
Input voltage	295 - 480 VDC DC V
Quantity	17
Total capacity	1.7 AC MW
DC to AC Capacity Ratio	1.17
AC losses (%)	1.00

Array	
Strings	610
Modules per string	12
String voltage (DC V)	385.20
Tilt (deg from horizontal)	20.00
Azimuth (deg E of N)	180
Tracking	no
Backtracking	-
Self shading	no
Rotation limit (deg)	-
Shading	no
Snow	no
Soiling	yes
DC losses (%)	4.44

Performance Adjustments	
Availability/Curtailment	none
Degradation	0.5 %/yr
Hourly or custom losses	none

Annual Results (in Year 1)	
GHI kWh/m²/day	3.20
POA kWh/m²/day	3.00
Net to inverter	2,172,000 DC kWh
Net to grid	2,044,000 AC kWh
Capacity factor	11.7
Performance ratio	0.77

Financial Model

Project Costs	
Total installed cost	$4,317,452
Salvage value	$0

Analysis Parameters	
Project life	25 years
Inflation rate	1.5%
Real discount rate	3.5%

Financial Targets and Constraints	
Solution mode	Calculate IRR
PPA price (bid price)	15 cents/kWh
PPA escalation rate	0 %/year

Tax and Insurance Rates	
Federal income tax	35 %/year
State income tax	7 %/year
Sales tax (% of indirect cost basis)	5%
Insurance (% of installed cost)	0.5 %/year
Property tax (% of assessed val.)	0 %/year

Incentives	
Federal ITC	30%
Depreciation	Depreciation allocations defined with no bounus depreciation
State PBI	0.05 $/kWh2 yrs

Results	
Nominal LCOE	16.8 cents/kWh
PPA price (year one)	15 cents/kWh
Project IRR	5.2% in Year 9
Investor NPV	$22,700
Developer NPV	$-510,800
Investor IRR	6.1%
Developer IRR	2.4%

System Advisor Model Report

Photovoltaic System	3.0 DC MW Nameplate	City and state unknown
All Equity Partnership Flip	$1.99/W Installed Cost	48.05 N, -122.18 E GMT -8

Performance Model

Modules	
iTek iT-275-HE	
Cell material	Mono-c-Si
Module area	1.63 m²
Module capacity	272.85 DC Watts
Quantity	10,992
Total capacity	3 DC MW
Total area	17,960 m²

Inverters	
PV Powered: PVP100 kW-208	
Unit capacity	100 AC kW
Input voltage	295 - 480 VDC DC V
Quantity	25
Total capacity	2.5 AC MW
DC to AC Capacity Ratio	1.20
AC losses (%)	1.00

Array	
Strings	916
Modules per string	12
String voltage (DC V)	385.20
Tilt (deg from horizontal)	20.00
Azimuth (deg E of N)	180
Tracking	no
Backtracking	-
Self shading	no
Rotation limit (deg)	-
Shading	no
Snow	no
Soiling	yes
DC losses (%)	4.44

Performance Adjustments	
Availability/Curtailment	none
Degradation	0.5 %/yr
Hourly or custom losses	none

Annual Results (in Year 1)	
GHI kWh/m²/day	3.20
POA kWh/m²/day	3.00
Net to inverter	3,262,000 DC kWh
Net to grid	3,070,000 AC kWh
Capacity factor	11.7
Performance ratio	0.77

Financial Model

Project Costs	
Total installed cost	$5,981,616
Salvage value	$0

Analysis Parameters	
Project life	25 years
Inflation rate	1.5%
Real discount rate	3.5%

Financial Targets and Constraints	
Solution mode	Calculate IRR
PPA price (bid price)	14 cents/kWh
PPA escalation rate	0 %/year

Tax and Insurance Rates	
Federal income tax	35 %/year
State income tax	7 %/year
Sales tax (% of indirect cost basis)	5%
Insurance (% of installed cost)	0.5 %/year
Property tax (% of assessed val.)	0 %/year

Incentives	
Federal ITC	30%
Depreciation	Depreciation allocations defined with no bounus depreciation
State PBI	0.05 $/kWh2 yrs

Results	
Nominal LCOE	15.8 cents/kWh
PPA price (year one)	14 cents/kWh
Project IRR	4.8% in Year 9
Investor NPV	$17,700
Developer NPV	$-748,000
Investor IRR	5.7%
Developer IRR	2.2%

System Advisor Model Report

Photovoltaic System	4.0 DC MW Nameplate	City and state unknown
All Equity Partnership Flip	$1.91/W Installed Cost	48.05 N, -122.18 E GMT -8

Performance Model

Modules	
iTek iT-275-HE	
Cell material	Mono-c-Si
Module area	1.63 m²
Module capacity	272.85 DC Watts
Quantity	14,652
Total capacity	4 DC MW
Total area	23,941 m²

Inverters	
PV Powered: PVP100 kW-208	
Unit capacity	100 AC kW
Input voltage	295 - 480 VDC DC V
Quantity	33
Total capacity	3.3 AC MW
DC to AC Capacity Ratio	1.21
AC losses (%)	1.00

Array	
Strings	1,221
Modules per string	12
String voltage (DC V)	385.20
Tilt (deg from horizontal)	20.00
Azimuth (deg E of N)	180
Tracking	no
Backtracking	-
Self shading	no
Rotation limit (deg)	-
Shading	no
Snow	no
Soiling	yes
DC losses (%)	4.44

Performance Adjustments	
Availability/Curtailment	none
Degradation	0.5 %/yr
Hourly or custom losses	none

Annual Results (in Year 1)	
GHI kWh/m²/day	3.20
POA kWh/m²/day	3.00
Net to inverter	4,348,000 DC kWh
Net to grid	4,093,000 AC kWh
Capacity factor	11.7
Performance ratio	0.77

Financial Model

Project Costs	
Total installed cost	$7,640,342
Salvage value	$0

Analysis Parameters	
Project life	25 years
Inflation rate	1.5%
Real discount rate	3.5%

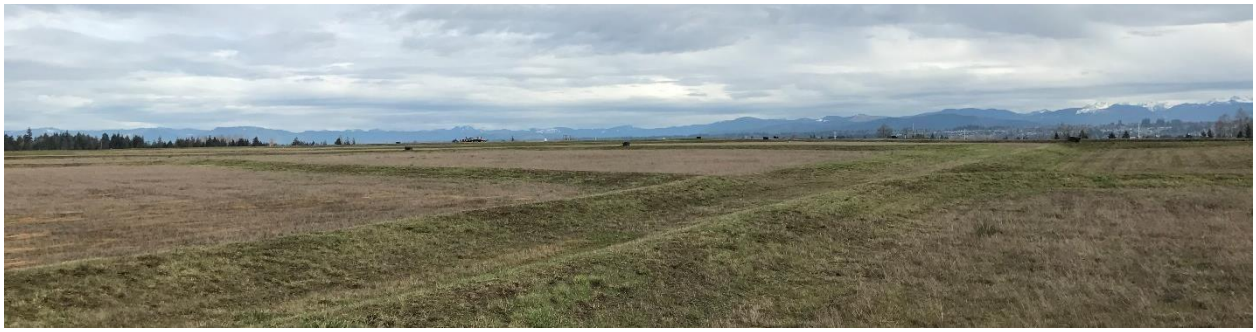
Financial Targets and Constraints	
Solution mode	Calculate IRR
PPA price (bid price)	13 cents/kWh
PPA escalation rate	0 %/year

Tax and Insurance Rates	
Federal income tax	35 %/year
State income tax	7 %/year
Sales tax (% of indirect cost basis)	5%
Insurance (% of installed cost)	0.5 %/year
Property tax (% of assessed val.)	0 %/year

Incentives	
Federal ITC	30%
Depreciation	Depreciation allocations defined with no bounus depreciation
State PBI	0.05 $/kWh2 yrs

Results	
Nominal LCOE	15.1 cents/kWh
PPA price (year one)	13 cents/kWh
Project IRR	5.2% in Year 9
Investor NPV	$16,700
Developer NPV	$-1,154,600
Investor IRR	5.5%
Developer IRR	1.6%

Appendix C. EPA Region 10's Tulalip Landfill Superfund Site Reuse Assessment



Tulalip Landfill Superfund Site Reuse Assessment

Tulalip Indian Reservation, Marysville, WA

June 22, 2017

Reuse Considerations

Future use of the Tulalip Landfill is dependent on a few key factors:

- No adverse impacts to the integrity of the landfill system and cover.
- Engineering study to determine load bearing capacity of proposed use.
- EPA and Tribal review and approval of future use plans.

Additional details are provided below based on a review of previous site documents and information shared during the March 17th site tour. The map on page 4 identifies potential reuse zones based on remedy components, access, surrounding land use, and visibility from highway.

Remedial Components

The future use of the site will need to be compatible with the containment system including the need for long-term monitoring and ensuring there are no adverse impacts to the integrity of the system and cap cover. Specific detail about reuse considerations is provided in the Operations and Maintenance Manual – Post Closure Care Tulalip Landfill (2001) and Ready for Reuse Determination Tulalip Landfill Site (2014). Any reuse will need to consider the following remedial considerations:

- *Load bearing capacity* – avoid loads that might punch through or strain the composite cap and liner system or cause differential settlement.
- *Landfill cover* – maintain integrity of the landfill's cover, which includes the liner and soil cover.
- *Drainage system* – maintain positive surface drainage. The cover was designed to direct stormwater offsite through a series of pipes and prevent stormwater from penetrating the landfill.
- *Landfill gas control system* – account for landfill gas by installing control systems beneath any buildings.
- *Construction and routine use* – consider differential settlement in building design and utility connections; consider load bearing capacity when stockpiling materials and heavy equipment used during construction, and maintain permanent access to remedial components.

Based on the best currently available information, the load bearing capacity for temporary equipment use on site is 25 pounds per square inch (psi). Additional testing would be needed to establish a load bearing capacity to support potential industrial uses. Additional considerations are provided in the next section based on reuse types.

Access and Location

- The site currently has only one vehicular entry off State Route 529 on the east. There is no left turn when exiting the site and traffic is routed through a neighborhood to exit.
- An active rail line at the entrance can sometimes cause delays accessing or exiting the site.
- There are navigable waters on the north-west and southern edge of site and the site may be accessible by barge (former barge access point is noted on the map)
- Any new access points would need to preserve the site's perimeter berm.

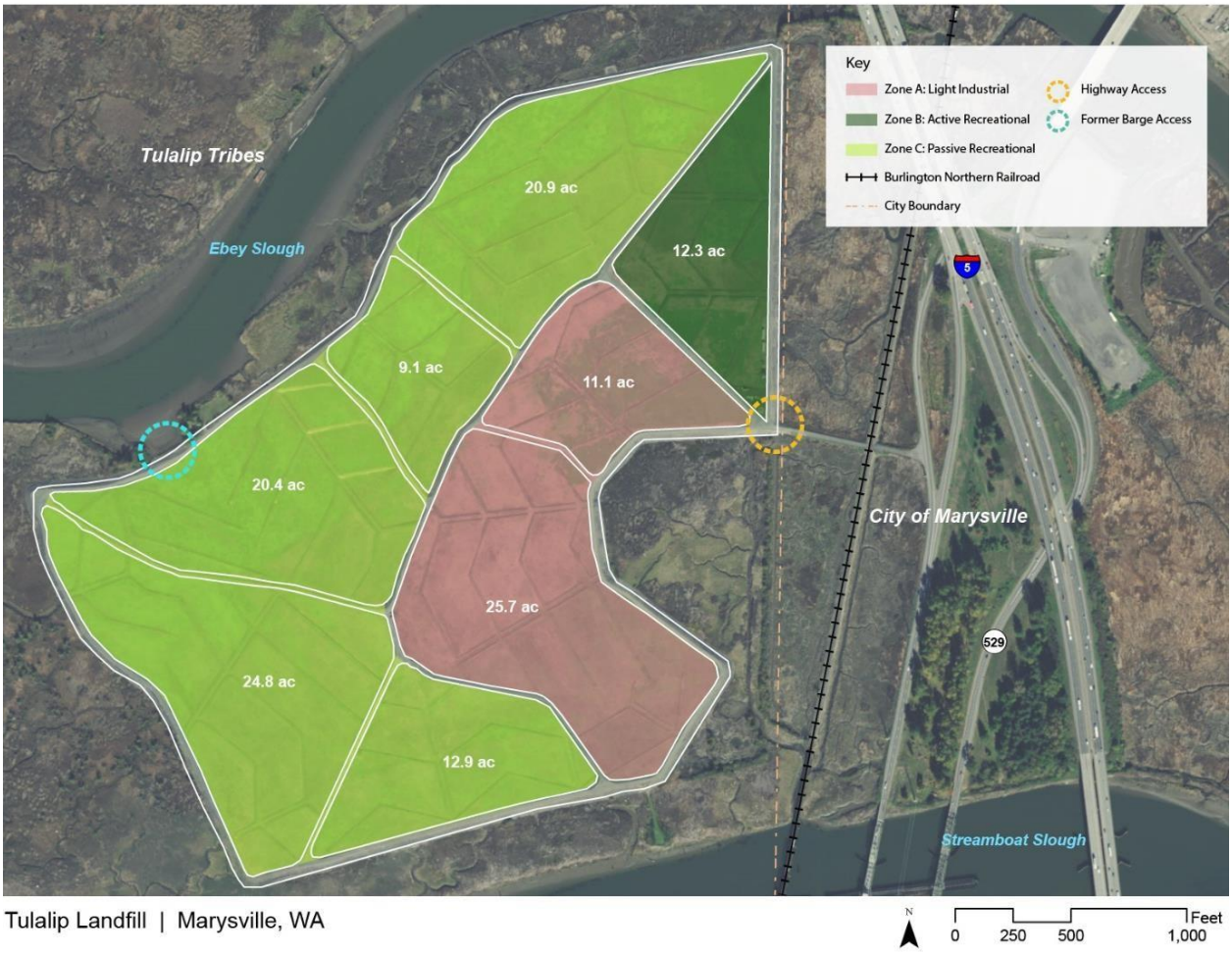
Surrounding Land Use

- As per the Tulalip Tribes Comprehensive Land Use Plan, the site is zoned "Industrial" and the wetlands north and west of site are zoned as "Conservation".
- The land immediately east of the site is zoned general industrial under the City of Marysville zoning.
- The entire site and surrounding wetland are designated as "Culturally Sustainable Area" as part of Tulalip Tribes Comprehensive Land Use Plan.
- If recreational use is preferred, the western portion of the site may be most suitable due its proximity to other conservation lands and separate from the industrial area.
- The site is in proximity to a number of recreational amenities in the City that include a golf course, community and waterfront parks, walking loops and fitness stations. The Tulalip reservation has one golf course and a number of open spaces by the waterfront. A closer study to determine the gaps in recreational amenities may be helpful while considering recreational uses for the site.

Reuse Suitability Zones

The map below identifies potential reuse suitability zones based on reuse considerations including remedial components, access, surrounding land use, and visibility from highway. The table on the following page provides additional details about each reuse suitability zone and remedial considerations.

Figure 1: Reuse Suitability Zone Map



Summary

Since the design and implementation of the remedy, the Tulalip Tribes have expressed interest in reusing the landfill for industrial and recreational uses that are protective of the remedy. Based on currently available information, potential barriers to reuse include:

- uncertainty of allowable uses based on load bearing capacity
- additional fill needed to protect landfill cover system
- added construction costs for developing on a landfill that may be cost prohibitive
- lack of precedent for industrial development on similar landfills

Key next steps in understanding redevelopment potentials include: 1) conducting an engineering study to confirm load bearing capacity of the landfill for desired use(s) and 2) confirm which uses are permitted under the current industrial zoning.

Attachment A: Solar as Potential Landfill Reuse

Solar systems can be well-suited for landfill sites that have large, flat, un-shaded areas on top of which to build. Because of development restrictions often placed on landfills, solar projects can be feasible

projects, with the potential to generate some economic benefit on a site that might otherwise have limited redevelopment options.

System Considerations

Solar resource: A site's solar resource affects a project's economic viability. The Marysville area has an average solar resource, estimated at 3.40 kWh/m^2/day. Solar radiation levels of 6 kWh/ m^2/day are considered excellent.

Solar foundations: Because of the need to protect the vegetative cover, a ballast-weighted ground-mounted system would be the best-suited option for a solar project at Tulalip Landfill. The size and weight of the concrete footers can be designed to meet any cover weight bearing limitations. Solar developers will typically have deadweight estimates or requirements for their systems, in pounds per square foot (psf) or pounds per square inch (psi), that can be compared to the weight bearing capacity of the cover.

Landfill Load Bearing Capacities In Massachusetts, load bearing capacities are often included in state use permits for solar projects on top of landfills. For example, at the Scituate Landfill, the cover bearing pressure was calculated at 6.9 psi (1000 psf). At Falmouth Landfill, the cover bearing pressure was estimated at 7 psi. Systems can also be designed/engineered to meet stringent weight bearing limitations. At the Braintree Landfill, the solar system (ballasts, racking system, panels) was estimated to have a final bearing pressure of 3 psi.

Hypothetical solar PV system size, generation and cost estimates for a potential project at the landfill are highlighted below. Estimates cover two different sized systems - a smaller system that could potentially be net metered (owner receives credit for solar energy generated) with SCPUD and a larger utility-scale system (1 MW would at present be the largest single solar installation in the state). Costs in the solar industry are changing rapidly and any potential project could see reduced costs in future years. See pages 10-14 for more information about the potential financial impact of 1 MW solar array.

Table 1: Preliminary Solar PV System Size and Cost Estimates

Estimated Size	Estimated Output	Installed Costs	Annual O&M Costs
100 kW	110 - 115 MWh	$300K – $400K	$1.5K – 2K
1 MW	1,080– 1,150 MWh	$2.5 – $4M	$15K – 20K

Assumptions:
System Costs: $2.50 - $4.00/Watt installed. Assumes additional site prep costs needed to accommodate project on top of landfill cap; no incentives included.
O&M Costs: $15/kW/year.
Area needed: 4 - 6 acres / MW of AC nameplate capacity.
Output estimated based on average crystalline silicon PV system in Everett, WA.

Solar Incentives

Identifying and leveraging applicable incentives is an important element in whether a project will be economically viable.

Federal Incentives/Programs

- Business Energy Investment Tax Credit: entities with no federal income tax liability cannot directly access this incentive if they own a solar system.
- Department of Energy Tribal Energy Program: promotes tribal energy sufficiency, economic development and employment through the use of renewable energy.

State Incentives

- Renewable Portfolio Standard: Washington state mandates that 15% of utilities' electricity production must come from renewable resources by 2020, but standard lacks a solar carve out.
- Renewable Energy Cost Recovery Incentive: a production-based incentive with rates up to $1.08/kWh for community solar (shared ownership model) depending on technology and where equipment is manufactured. Incentive capped at $5,000 per investor. Note: Many utilities have already reached their program targets and no longer accept new applicants.

Utility Incentives

- Solar Express Rebate: Snohomish County PUD offers solar rebates at $300 per kW installed, up to $2,000 for residential and $8,000 for industrial/commercial systems. Rebate expires in 2017.
- Net metering: available on a first-come, first-served basis until the generating capacity of net-metered systems equals 0.5% of a utility's peak 1996 demand. Systems up to 100 kW eligible.

Solar Reuse Considerations

Remedy Compatibility: Solar development is likely compatible with the existing cover, but remedy constraints (e.g., weight bearing limits) should be clarified so any additional load testing or any specific design requirements to account for cover limitations is fully understood.

Solar Reuse Suitability: The site offers significant land area suitable for some scale of solar development. Limited current market demand for utility-scale (>1 MW) solar in Western Washington and an average solar resource may be the biggest current project limitations.

Phasing: Solar could be considered in phases at the site, and provide an opportunity to net meter a smaller system with a local utility as well as test landfill cover compatibility at a smaller scale.

Ownership / Development Options: There are a range potential ownership options for a solar project including: 1) Direct Tribal Ownership, 2) Land Lease, 3) Third-party Ownership Lease, and 4) Community Solar (shared ownership). The current legal status for third-party solar power purchase agreements (PPAs) in Washington state is unclear. See Table 2: Project Development Scenarios for more information.

Potential Financial Impact of Hypothetical 1 MW PV Solar Array at Tulalip Landfill, Marysville, WA

Given the wide diversity of potential entities (tribal entities, private land owners, local governments, federal government) that can host a PV solar project on their land, a "one-size-fits all" project structure will not fully capture the different type of project arrangements possible at the landfill. Property owners/site hosts face a range of financial, operational and strategic considerations that may favor one project structure over another.

Two potential scenarios have been envisioned to evaluate potential financial implications to the tribe of each option.

1. Simple Return on Investment Scenario (or Simple Payback) - potential impacts based on tribal ownership of a 1 MW solar system
2. Land Lease Scenario - the Tulalip tribe receives lease fees for the land based on the acreage used for a project or the size of the PV solar system (e.g., 1 MW)

The development of a renewable energy project is a complex process reliant on available incentives, partnership between multiple parties, suitable market conditions and other factors that must be identified and managed throughout the project. Any solar energy project at the Site will depend on the ability of the tribe to identify and work with project partners who can deliver electricity at a competitive price and the ability of project partners to enter into a long-term purchase agreement with an electric utility or other user.

Potential Job Creation for Solar

Manufacturing and installing solar energy systems can be a source of job creation. The majority of jobs created by solar projects are tied to site preparation and project design and construction and include skilled craft labor such as engineers, assemblers, sales representatives and installers. The University of California at Berkeley has compiled data that indicates 25 construction-related jobs per MW have historically been created in Europe's solar industry, and estimates 25-30 construction-related jobs per MW for US projects.

Option 1) Direct Ownership Simple Payback

Simple payback can help illustrate the importance of net upfront costs and energy purchase price on the financial outlook for a project.

A project 1 MW in size was chosen because it would represent one of the largest solar projects in western Washington and is a project size that helps illustrate how project assumptions can influence payback. However, the final size of any PV solar project at the Site will be determined by available project funding and/or by the amount that power can be sold for to an energy utility or other end user.

Simple payback provides a rough estimate of whether an initial investment might be worthwhile. Simple payback is useful for making "ballpark" estimates, but its usefulness is limited because it does not take into account future savings or costs (such as annual O&M costs) over the expected life of a project.
Simple Payback = System cost / (year 1 revenue (or savings) – year one O&M cost)

Scenario Assumptions:

Project System Information

Array Size: 1 MW
DC to AC Efficiency: 0.78
Array tilt: at latitude
Installed Cost: $2.5 - 4 / Watt installed[1]
Maintenance Cost: $15/kW/Year
System Latitude/Longitude: 48.038704, -122.186723
Estimated system output year 1: 1,080,000 kWh
Acres Needed: 4-6 acres depending on technology type and panel efficiency

Financial Incentives Considered

Federal 30% Credit: Investment Tax Credit (ITC) treated as one-time upfront cost reduction. State Tax Credit: Snohomish County PUD Solar Express Rebate maxed at $8,000 for industrial/commercial systems

Electricity Purchase

The scenario assumes power generated at the landfill could be sold by the tribe to the local utility district at a negotiated priced (analyzed at $0.10/kWh in this scenario)

To account for factors such as periodic or annual costs, a more detailed life cycle payback approach could be used. Life cycle payback takes into account the benefits (i.e., revenues) of a solar electric system over its operating lifetime and compares that to all the costs of the system over the same period of time.

Table 3 provides a simple pay back estimate for 3 scenarios related to direct tribal ownership of a system, including the ability of the tribe to take advantage of the 30% ITC through a for-profit entity as well as the commercial/industrial PUD rebate.

Table 3: Simple Payback, $2.5/W Installed

	1 MW, No Incentives	1 MW, 30% ITC	1 MW, 30% ITC, SCPUD rebate
Initial Cost	$2,500,000	$2,500,000	$2,500,000
Incentive(s)	-	($750,000)	($758,000)
Net Upfront Cost	$2,500,000	$1,750,000	$1,742,000
System Output/Payback			

[1] Uncertainty over the weight bearing limitations of the cap and other remedy protectiveness issues makes installed costs difficult to predict for the landfill. However, landfill solar projects tend to have slightly increased costs due to the engineering and design and construction accommodations (e.g., concrete ballasts) that needs to be done to meet any limitations presented by the landfill cap.

Initial System Output (kWh)	1,080,000	1,080,000	1,080,000
Potential revenue (energy sold for $0.10/kWh)	$108,000	$108,000	$108,000
Estimated O&M Year 1	($15,000)	($15,000)	($15,000)
Net Year 1 revenue	$93,000	$93,000	$93,000
Simple Payback (years)	**27 years**	**18.8 years**	**18.7 years**

Table 4 illustrates how relatively small changes in project assumptions can make a difference in estimated payback.

Table 4: Sensitivity Analysis

	Base Case – 1 MW, 30% ITC	**System output increased to 1,350 MWh** [2]	**Energy sold for $0.08/kWh**	**Annual O&M $20/kW**	**Installed cost $2/Watt**
Simple Payback	18.8 years	14.6 years	24.5 years	19.9 years	15.1 years

Option 2) Land Lease Scenario

The goal of the land lease scenario is to illustrate potential revenue impacts from an alternative solar project development option - one where there is no direct ownership (i.e., by the Tribe or a tribal owned entity) of a solar energy system. Under a land lease scenario, a solar energy developer would pay to lease or rent land (base rent) at the site on which they would own and build a solar energy system.

Some solar purchase agreements and solar land leases can include a price escalator (i.e., rent paid increases over time). The estimated numbers in Table 5 keep base rent at the same level over a 20-year time horizon.

Scenario Assumptions:

Project System Information

Array Size: 1 MW

A solar system would be developer-owned and financed

[2] This output represents the hypothetical performance of a 1 MW solar system located in Kennewick, WA which has an average annual solar resource of 4.5 kWh/m^2/day (compared to 3.5 for Everett). The stronger solar resource means a potential 25% increase in the output of a similarly-sized solar system.

Acres Needed: 3-5 acres depending on technology and efficiency
System Ownership: Owned by third-party project developer

Land Lease Terms

The assessment surveyed both policy documents (e.g., the U.S. Bureau of Land Management's (BLM's) Solar Energy Interim Rental Policy) as well as other publicly available information to identify a range of land lease fees from planned, existing and potential solar projects.

BLM rental rates are generally low - $15 to $300 per acre. However, the BLM also charges a per MW capacity fee of several thousand dollars per MW in addition to the base rent. Other solar projects have lease fees ranging from $250 per acre up to $8,000 per acre, with an average lease rate of $2,100 per acre.

Some developers will estimate lease fees based on the size of the solar system (MW). These fees can range from $7,500 to $15,000 per MW depending on the developer and local markets for the power.

The analysis assumes a lease would be fixed price and based on project footprint acreage.

Table 5: Land Lease Revenue Estimates (1 MW solar system)

	Annual Base Rent	**20-Year Estimate (constant dollars)**
Acres leased	5	5
$350/acre	$1,750	$35,000
$500/acre	$2,500	$50,000
$1000/acre	$5,000	$100,000
$2500/acre	$12,500	$250,000
$5000/acre	$25,000	$500,000

The value of the land lease will vary by developer, the project site and market considerations (e.g., the current REC market as appropriate). The Tribe should expect lease fees to be an important point of negotiation with a potential project developer under a land lease approach.

Appendix D. SAM Results for 1MW-4MW with 15% extra development costs

1MW Results

Metric	Value
Annual energy (year 1)	1,022,430 kWh
Capacity factor (year 1)	11.7%
Energy yield (year 1)	1,024 kWh/kW
Performance ratio (year 1)	0.77
PPA price (year 1)	16.00 ¢/kWh
PPA price escalation	0.00 %/year
Levelized PPA price (nominal)	16.00 ¢/kWh
Levelized PPA price (real)	13.66 ¢/kWh
Levelized COE (nominal)	18.58 ¢/kWh
Levelized COE (real)	15.86 ¢/kWh
Investor IRR	7.24 %
Year investor IRR acheived	9
Investor IRR at end of project	7.40 %
Investor NPV over project life	$26,473
Developer IRR at end of project	1.72 %
Developer NPV over project life	$-379,357
Net capital cost	$2,555,730

2MW Results

Metric	Value
Annual energy (year 1)	2,044,766 kWh
Capacity factor (year 1)	11.7%
Energy yield (year 1)	1,024 kWh/kW
Performance ratio (year 1)	0.77
PPA price (year 1)	14.00 ¢/kWh
PPA price escalation	0.00 %/year
Levelized PPA price (nominal)	14.00 ¢/kWh
Levelized PPA price (real)	11.95 ¢/kWh
Levelized COE (nominal)	15.96 ¢/kWh
Levelized COE (real)	13.63 ¢/kWh
Investor IRR	5.28 %
Year investor IRR acheived	9
Investor IRR at end of project	5.90 %
Investor NPV over project life	$16,224
Developer IRR at end of project	1.99 %
Developer NPV over project life	$-552,830
Net capital cost	$4,108,961

3MW Results

Metric	Value
Annual energy (year 1)	3,070,593 kWh
Capacity factor (year 1)	11.7%
Energy yield (year 1)	1,024 kWh/kW
Performance ratio (year 1)	0.77
PPA price (year 1)	13.00 ¢/kWh
PPA price escalation	0.00 %/year
Levelized PPA price (nominal)	13.00 ¢/kWh
Levelized PPA price (real)	11.10 ¢/kWh
Levelized COE (nominal)	14.96 ¢/kWh
Levelized COE (real)	12.77 ¢/kWh
Investor IRR	4.82 %
Year investor IRR acheived	9
Investor IRR at end of project	5.36 %
Investor NPV over project life	$7,947
Developer IRR at end of project	1.76 %
Developer NPV over project life	$-811,110
Net capital cost	$5,667,284

4MW Results

Metric	Value
Annual energy (year 1)	4,093,044 kWh
Capacity factor (year 1)	11.7%
Energy yield (year 1)	1,024 kWh/kW
Performance ratio (year 1)	0.77
PPA price (year 1)	13.00 ¢/kWh
PPA price escalation	0.00 %/year
Levelized PPA price (nominal)	13.00 ¢/kWh
Levelized PPA price (real)	11.10 ¢/kWh
Levelized COE (nominal)	14.65 ¢/kWh
Levelized COE (real)	12.51 ¢/kWh
Investor IRR	3.84 %
Year investor IRR acheived	9
Investor IRR at end of project	4.94 %
Investor NPV over project life	$-4,018
Developer IRR at end of project	2.19 %
Developer NPV over project life	$-900,059
Net capital cost	$7,220,515